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December 20, 2013

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PUBLIC SERVICE
COMMISSION

HAND DELIVERED

Jeff R. Derouen
Executive Director
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

RE: Kentucky Power Company's Integrated Resource Planning Report

Dear Mr. Derouen:

Please find enclosed and accept for filing Kentucky Power Company's Integrated Resource Planning Report. It consists of four volumes. Volumes A-C are the redacted version of the report. The confidential information redacted from Volumes A-C is contained in Volume D, which is being filed with the Company's Motion for Confidential Treatment.

The Company is filing one unbound copy of Volumes A-D. It also is filing ten bound copies of Volumes A-C.

An index cross-referencing the provisions of the report to the applicable regulatory requirements is included in Chapter 1 (Volume A) of the report.

A copy of Volume D will be provided to those parties executing an appropriate non-disclosure agreement.

Finally, I enclose for the Commission's review and approval a copy of the text of the public notice required by 807 KAR 5:058, Section 10. By the Company's calculations, the notice must be submitted to the appropriate news agencies prior to January 10, 2014 to be published in accordance with the Commission's regulations.

Please do not hesitate to contact me if you have any questions.

Very truly yours,

Mark R. Overstreet

cc: Michael L. Kurtz (Volumes A-C)
Dennis G. Howard (Volumes A-C)
John Davies (Volumes A-C)

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PUBLIC SERVICE
COMMISSION

AEP KENTUCKY POWER

A unit of American Electric Power

INTEGRATED RESOURCE PLANNING REPORT
TO THE
KENTUCKY PUBLIC SERVICE COMMISSION

Submitted Pursuant to
Commission Regulation 807 KAR 5:058

VOLUME A

Case No. 2013-_______

December 20, 2013

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Exhibit 4-17

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EXECUTIVE SUMMARY

The Integrated Resource Plan (IRP or Plan) is based upon the best available information at the time of preparation. However, changes that may impact this plan can, and do, occur without notice. Therefore this plan is not a commitment to a specific course of action, since the future is highly uncertain, particularly in light of the current economic conditions, access to capital, the movement towards increasing use of renewable generation and end-use efficiency, as well as current and future environmental regulations, including proposals to control greenhouse gases. The implementation action items as described herein are subject to change as new information becomes available or as circumstances warrant.

An IRP explains how a utility company plans to meet the projected capacity (*i.e.,* peak demand) and energy requirements of its customers. By Kentucky rule, Kentucky Power Company (Kentucky Power or Company) is required to provide an IRP that encompasses a 15-year forecast period (2014-2028). Kentucky Power's 2013 IRP has been developed using the Company's current assumptions for:

- Customer load requirements – peak demand and energy;
- Commodity prices – coal, natural gas, on-peak and off-peak power prices, capacity and emission prices;
- Supply-side alternative costs – including fossil fuel and renewable generation resources; and
- Demand-side program costs and analysis.

As shown in its 2013 IRP, Kentucky Power has a plan to provide adequate supply and demand resources to meet its peak load obligations for the next fifteen years. The key components of this plan are for Kentucky Power to:

- Transfer a 50% undivided ownership interest of the Mitchell Plant (780 MW) from affiliate Ohio Power Company (OPCo) to Kentucky Power, to replace the 800 MW Big Sandy Unit 2 which is scheduled to retire in 2015 (Mitchell Transfer);
- Convert Big Sandy Unit 1 (278 MW) to burn natural gas instead of coal;

- Continue to purchase power from the Rockport Units;
- Make increased investment in demand-side management; and
- Purchase the output of the 58.5 MW ecoPower Hazard, LLC[1] (ecoPower) biomass plant starting in 2017.

Additionally, Kentucky Power considered the purchase of 100 MW of wind power as part of this IRP process and as a result of the evaluation performed, may pursue a Purchase Power Agreement (PPA) for wind power for delivery beginning in 2015. Kentucky Power evaluated other supply- and demand-side measures and, as a result, expects that utility-scale solar resources will become economically justifiable by 2020 and that customer-owned solar generation will begin to be economical to customers prior to that, further reducing the requirements for new utility-owned generation. At the same time, these 'non-traditional' resources will provide the Company with much-needed *energy* resources.

Environmental Compliance Issues

The 2013 IRP considers final and proposed future U.S. Environmental Protection Agency (EPA) regulations that will impact fossil-fueled electric generating units (EGU).

The analyses used in developing this IRP assume that greenhouse gas (GHG) legislation or regulation on existing units will eventually be implemented. However, rather than a more comprehensive cap-and-trade approach, it is assumed that the resulting impact would be in the form of a carbon dioxide (CO_2) "tax" which would take effect beginning in 2022. The cost of CO_2 emissions is expected to stay within the \$15-\$20/metric ton range over the long-term analysis period.

[1] As approved by the Kentucky Public Service Commission (Commission) in Case No. 2013-00144 by Order dated October 10, 2013

Summary of Kentucky Power Resource Plan

Kentucky Power's total internal energy requirements are forecasted to increase at an average annual rate of 0.1% over the IRP planning period (2014-2028). Kentucky Power's corresponding summer and winter peak internal demands are forecasted to grow at average annual rates of 0.3% and 0.1%, respectively, with annual peak demand expected to continue to occur in the winter season through 2028.

To determine the appropriate level of additional demand-side, distributed, and renewable resources, Kentucky Power utilized the *Plexos*® Linear Program (LP) optimization model to develop a "least-cost" resource plan. Although the IRP planning period is limited to 15 years (through 2028), the *Plexos*® modeling was performed through the year 2040 so as to properly consider various cost-based "end-effects" for the resource alternatives being considered.

As a result of the modeling, and taking into account the Stipulation and Settlement Agreement surrounding the Mitchell Transfer, et al (Mitchell Settlement Agreement)[2], Kentucky Power developed a **Preferred Portfolio**. To arrive at the Preferred Portfolio composition, Kentucky Power developed *Plexos*®-derived, "optimum" portfolios under five commodity price forecasts. The Preferred Portfolio is intended to provide the lowest reasonable cost of (peak) demand and energy to Kentucky Power's customers while meeting environmental and reliability constraints and reflecting emerging preference for, and the viability of customer self-generation. This portfolio:

- Receives 50% of the Mitchell Plant in 2014.
- Retires Big Sandy Unit 2 in 2015.
- Converts Big Sandy Unit 1 to natural gas fired operation in 2016.
- Assumes the addition of 100 MW of wind energy from a Federal Production Tax Credit (PTC) eligible wind project beginning in 2015.
- Implements customer and grid energy efficiency (EE) programs so as to

[2] As approved by the Commission in Case No. 2012-00578, by Order dated October 7, 2013.

reduce energy requirements by 260 GWh (or 4% of projected energy needs) by 2028.

- Purchases the output of the 58.5 MW ecoPower biomass plant beginning in 2017.
- Adds utility-scale solar beginning in 2020; total solar capacity reaches 90 MW (nameplate) in 2028.
- Recognizes additional distributed solar capacity will be added by customers, starting in 2016, of about 3 MW (nameplate) and ramping up to about 41 MW (nameplate) by 2028.

Specific Kentucky Power capacity and energy production changes over the forecast period associated with the Preferred Portfolio are shown in **Figures ES-1a and ES-1b**, respectively, and their relative impacts to Kentucky Power's capacity and energy position are shown in Figures **ES-2a** and **ES-2b** respectively.

Figure ES-1a
Kentucky Power PJM Capacity Changes

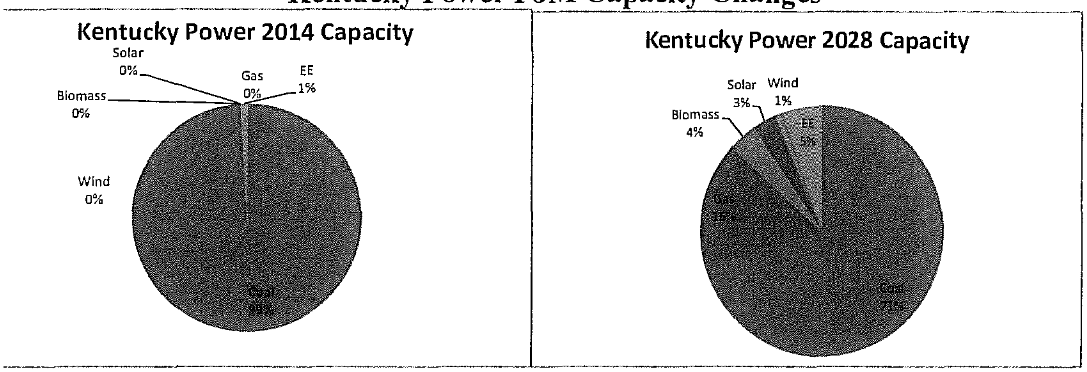
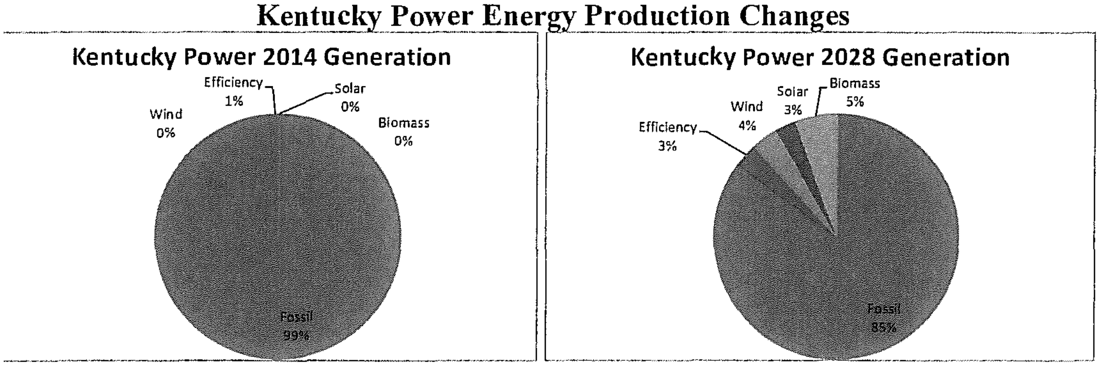
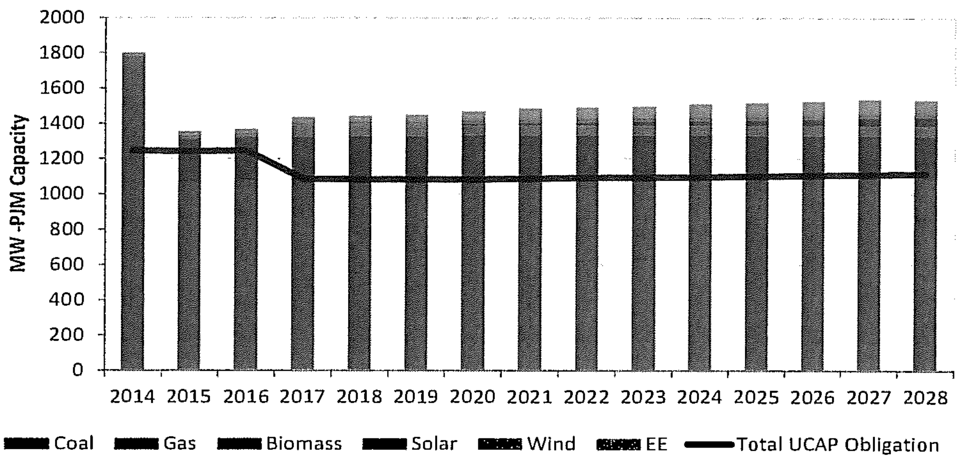


Figure ES-1b
Kentucky Power Energy Production Changes



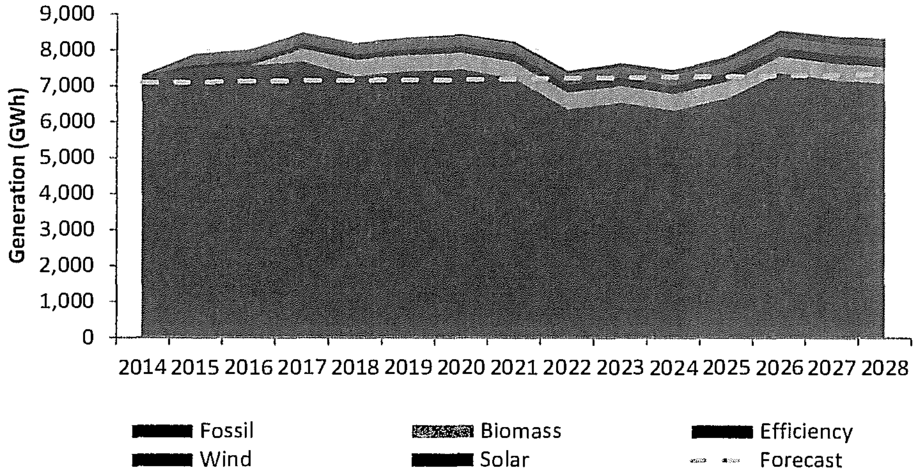
Figures ES-1a and ES-1b indicate that this Preferred Portfolio would reduce Kentucky Power's reliance on coal-based generation as part of its portfolio of resources, thereby enhancing fuel diversity. Specifically, the Company's capacity mix attributable to coal-fired assets would decline from 99% -to- 71% over the planning period. Gas assets and renewables increase from 0% -to- 16% and 1% -to- 13% repectively over the planning period. Similarly, Kentucky Power's energy mix attributable to fossil-based generation would comparably decrease from 99% -to- 85% over the period. The Preferred Portfolio highlights the fact that, while the Company may appear to have more than ample capacity to reliably meet the needs of its customers, without the addition of "energy resources", it would not be long from an *energy* perspective at all times. Moreover, the layers of non-traditional energy resources being added as part of this planning process would serve to hedge Kentucky Power's exposure to (PJM) energy market volatility, producing a lower-risk solution than one that relies on market purchases.

Figure ES-2a
Kentucky Power PJM Capacity Position[3]



[3] Capacity position, and the underlying peak demand forecast,"transition" reflected in the 2017/18 PJM Planning Year (2017) is largely a function of utilizing PJM's own estimate of AEP Zonal peak demand allocated to Kentucky Power through the 2016/17 Planning Year (2016), then shifting to AEP's (lower) estimate of a stand-alone Kentucky Power peak demand (diversified to be coincident with PJM peak) thereafter.

Figure ES-2b
Kentucky Power Energy Position



The following **Table ES-1** provides a summary of the Preferred Portfolio resource optimization modeling under the base case commodity pricing scenario:

Table ES-1

Kentucky Power Company
2013 Integrated Resource Plan
Cumulative Resource Changes (2014-2028)

Preferred Portfolio

IRP Yr.	PJM Plan Year[A]	(Cumulative) RETIREMENTS / DERATES: Fossil	(Cumulative) RESOURCE ADDITIONS: Mitchell Transfer	Biomass	DSM: Existing[E]	DSM: New EE	DSM: VVO	Wind[F]	Solar[G]: Distributed	Solar[G]: Utility-Scale	Cumul. NET CHANGE	Resulting Kentucky Power PJM Reserve Margin	(Cumulative) NAMEPLATE ADDITIONS: Wind	Solar: Distributed	Solar: Utility-Scale
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW		MW	MW	MW
1	2014[B]	-	780	-	5	1	4	0	0	0	791	64.6% [B]	0	0	0
2	2015[B]	(800) [C]	780	-	7	3	4	13	0	0	8	20.6% [B]	100	0	0
3	2016[B]	(810) [D]	780	-	9	5	4	13	1	0	2	19.7% [B]	100	3	0
4	2017	(810)	780	59	10	6	4	13	1	0	63	40.2%	100	3	0
5	2018	(810)	780	59	11	7	4	13	2	0	66	40.8%	100	4	0
6	2019	(810)	780	59	12	10	4	13	2	0	69	41.0%	100	5	0
7	2020	(810)	780	59	12	14	4	13	3	4	79	42.2%	100	7	10
8	2021	(810)	780	59	13	17	8	13	3	8	90	42.6%	100	8	20
9	2022	(810)	780	59	13	17	8	13	4	11	95	42.4%	100	11	30
10	2023	(810)	780	59	14	17	8	13	5	15	101	42.8%	100	13	40
11	2024	(810)	780	59	14	21	8	13	6	19	110	43.5%	100	17	50
12	2025	(810)	780	59	14	23	8	13	8	23	117	43.1%	100	21	60
13	2026	(810)	780	59	14	25	8	13	10	27	125	43.4%	100	26	70
14	2027	(810)	780	59	14	27	8	13	12	30	133	43.4%	100	33	80
15	2028	(810)	780	59	14	23	8	13	16	34	136	43.2%	100	41	90
						44 TOTAL DSM								131 TOTAL Solar	

[A] PJM Planning Year is effective June 1.
[B] Kentucky Power collectively-participated with affilated AEP-East operating companies in these established PJM (Capacity) Planning Years, electing the Fixed Resource Requirement (FRR) ('self'-)planning option through the 2016 PJM Planning Year. *For purposes of this IRP* only, beginning with the 2017 Planning Year Kentucky Power is assumed to be a 'stand-alone' entity.
[C] Big Sandy Plant (Unit 2) retirement effective approximately June 1, 2015, concurrent with implementation of U.S. EPA Mercury and Air Toxics Standards (MATS) Rules.
[D] Big Sandy Plant (Unit 1) gas conversion derate
[E] Represents estimated contribution from current/known Kentucky Power program activity reflected in the Company's load and demand forecast; All incremental impacts are included as "resources" outside of the load forecast
[F] Due to the intermittency of wind resources, PJM initially recognizes 13% of wind resource 'nameplate' MW rating for ICAP determination purposes.
[G] Due to the intermittency of solar resources, PJM initially recognizes 38% of solar resource 'nameplate' MW rating for ICAP determination purposes.

Note: Totals may reflect rounding

Conclusion

This IRP provides for reliable electric utility service, at reasonable cost, through a combination of supply-side resources, renewable supply- and demand-side programs. Kentucky Power will provide for adequate capacity resources to serve its customers' peak demand and required PJM Interconnection, LLC (PJM) reserve margin needs throughout the forecast period.

Moreover, this IRP will serve to also recognize Kentucky Power's even more-pressing *energy* position prospectively. The highlighted Preferred Portfolio offers incremental resources that will provide—in addition to the needed PJM installed *capacity* (ICAP) to achieve mandatory PJM (summer) peak demand requirements—additional *energy* so as to protect the Company's customers from being exposed to PJM energy markets that could be influenced by many external factors, including the impact of carbon, going-forward.

The IRP process is a continuous activity; assumptions and plans are continually reviewed as new information becomes available and modified as appropriate. Indeed, the capacity and energy resource plan reported herein reflects, to a large extent, assumptions that are subject to change; it is simply a snapshot of the future at this time. This IRP is not a commitment to a specific course of action, as the future is highly uncertain. The resource planning process is becoming increasingly complex when considering pending regulatory restrictions, technology advancement, changing energy supply pricing fundamentals, uncertainty of demand and EE advancements. These complexities necessitate the need for flexibility and adaptability in any ongoing planning activity and resource planning processes. Lastly, the ability to invest in extremely capital-intensive generation infrastructure is increasingly challenged in light of current economic conditions and the impact of all these factors on Kentucky Power's customers will be a primary consideration in this report.

1.0 OVERVIEW AND SUMMARY

1.1 General Remarks

The AEP-East utilities that own generation[4] have for decades operated as part of the AEP integrated public utility holding company system under the now-repealed Public Utility Holding Company Act of 1935. As part of that arrangement, those companies coordinated the planning and operations of their respective generating resources pursuant to the AEP Interconnection Agreement (Pool or Pool Agreement).[5]

On December 17, 2010, in accordance with Section 13.2 of the Pool Agreement, each of the Pool members provided notice to the other members (and to American Electric Power Service Corporation (AEPSC), as agent) to terminate the Pool Agreement (which includes the Interim Allowance Agreement (IAA)), on January 1, 2014. As a result, effective January 1, 2014, Kentucky Power will be responsible for its own generation resources and will need to maintain an adequate level of power supply resources to individually meet its *own* load requirements for capacity and energy, including any required reserve margin.[6]

This IRP document presents a plan for Kentucky Power to meet its obligations as a stand-alone company. Pursuant to that Plan, **Table 1** shows the Company's resource additions and reductions for the period 2014-2028. This includes the addition of a 50

[4] Kentucky Power, Appalachian Power Company (APCo), Indiana Michigan Power Company (I&M), and OPCo.

[5] The Pool Agreement, which has been amended several times, is on file with the Federal Energy Regulatory Commission (FERC) as Rate Schedule No. 11).

[6] Three of the current Pool Members – Kentucky Power, APCo, and I&M –together with AEPSC, have agreed to participate under a new arrangement ("the Power Coordination Agreement (PCA)"), which provides the opportunity for the members to collectively participate in the organized power markets of a regional transmission organization and provides an off-system sales allocation methodology. Kentucky Power, APCo, and I&M together with OPCo and affiliate AEP Generation Resources have agreed to enter into an interim arrangement (the Bridge Agreement) to provide for the allocation of the cost of meeting pre-existing PJM Fixed Resource Requirement (FRR) capacity obligations and settling existing marketing and trading positions that will survive termination of the Pool Agreement. Additional information regarding the PCA and the Bridge Agreement as they pertain to Kentucky Power can be found in FERC Docket No. ER13-234. These proposed agreements have been submitted to FERC.

percent ownership share of the Mitchell units in 2014; retirement of Big Sandy Unit 2 in 2015; conversion of Big Sandy Unit 1 to gas-fired operation in 2016; a 58.5 MW biomass resource in 2017; a potential 100 MW (nameplate) wind resource in 2015; the incorporation of incremental levels of demand-side management EE resources; as well as the eventual introduction of small amounts of solar resources over the planning period. Such solar resources taking the form of both (centralized) utility-scale solar and customer-elected distributed solar.

Table 1: Resource Additions

Kentucky Power Company
2013 Integrated Resource Plan
Cumulative Resource Changes (2014-2028)
Preferred Portfolio

		(Cumulative) RETIREMENTS / DERATES	(Cumulative) RESOURCE ADDITIONS										(Cumulative) NAMEPLATE ADDITIONS		
IRP	PJM	Fossil	Mitchell	Biomass	DSM			Wind[F]	Solar[G]		Cumul. NET	Resulting Kentucky Power PJM Reserve	Wind	Solar	
Yr.	Plan Year[A]		Transfer		Existing[E]	New EE	VVO		Distributed	Utility-Scale	CHANGE	Margin		Distributed	Utility-Scale
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW		MW	MW	MW
1	2014[B]	-	780	-	5	1	4	0	0	0	791	64.6% [B]	0	0	0
2	2015[B]	(800) [C]	780	-	7	3	4	13	0	0	8	20.6% [B]	100	0	0
3	2016[B]	(810) [D]	780	-	9	5	4	13	1	0	2	19.7% [B]	100	3	0
4	2017	(810)	780	59	10	6	4	13	1	0	63	40.2%	100	3	0
5	2018	(810)	780	59	11	7	4	13	2	0	66	40.8%	100	4	0
6	2019	(810)	780	59	12	10	4	13	2	0	69	41.0%	100	5	0
7	2020	(810)	780	59	12	14	4	13	3	4	79	42.2%	100	7	10
8	2021	(810)	780	59	13	17	8	13	3	8	90	42.6%	100	8	20
9	2022	(810)	780	59	13	17	8	13	4	11	95	42.4%	100	11	30
10	2023	(810)	780	59	14	17	8	13	5	15	101	42.8%	100	13	40
11	2024	(810)	780	59	14	21	8	13	6	19	110	43.5%	100	17	50
12	2025	(810)	780	59	14	23	8	13	8	23	117	43.1%	100	21	60
13	2026	(810)	780	59	14	25	8	13	10	27	125	43.4%	100	26	70
14	2027	(810)	780	59	14	27	8	13	12	30	133	43.4%	100	33	80
15	2028	(810)	780	59	14	23	8	13	16	34	136	43.2%	100	41	90
						44 TOTAL DSM								131 TOTAL Solar	

[A] PJM Planning Year is effective June 1.
[B] Kentucky Power collectively-participated with affiliated AEP-East operating companies in these established PJM (Capacity) Planning Years, electing the Fixed Resource Requirement (FRR) ('self'-)planning option through the 2016 PJM Planning Year. *For purposes of this IRP* only, beginning with the 2017 Planning Year Kentucky Power is assumed to be a 'stand-alone' entity.
[C] Big Sandy Plant (Unit 2) retirement effective approximately June 1, 2015, concurrent with implementation of U.S. EPA Mercury and Air Toxics Standards (MATS) Rules.
[D] Big Sandy Plant (Unit 1) gas conversion derate
[E] Represents estimated contribution from current/known Kentucky Power program activity reflected in the Company's load and demand forecast; All incremental impacts are included as "resources" outside of the load forecast
[F] Due to the intermittency of wind resources, PJM initially recognizes 13% of wind resource 'nameplate' MW rating for ICAP determination purposes.
[G] Due to the intermittency of solar resources, PJM initially recognizes 38% of solar resource 'nameplate' MW rating for ICAP determination purposes.

Note: Totals may reflect rounding

1.1.1 Planning Process Summary

The recommended plan provides the lowest practical cost solution through a combination of traditional supply, renewable, and demand-side investments. The tempered load growth combined with additional renewable resources and other additional supply-side resources, and increased DR/EE initiatives reduce the need for new capacity until beyond the end of the IRP forecast period (2028). Kentucky Power is expected to have adequate resources to serve its customers' requirements throughout the forecast period. Section 1.6.1, provides an analysis of Kentucky Power's stand-alone position for the forecast period.

The planning process is a continuous activity, assumptions and plans are continually reviewed as new information becomes available and modified as appropriate. Indeed, the capacity and energy resource plan reported herein reflects, to a large extent, assumptions that are subject to change; it is simply a snapshot of the future at this time. This IRP is not a commitment to a specific course of action, as the future is highly uncertain. The resource planning process is becoming increasingly complex when considering pending regulatory restrictions, technology advancement, changing energy supply pricing fundamentals, uncertainty of demand and EE advancements. These complexities necessitate the need for flexibility and adaptability in any ongoing planning activity and resource planning processes. Lastly, the ability to invest in extremely capital-intensive generation infrastructure is increasingly challenged in light of current economic conditions and the impact of all these factors on Kentucky Power's customers will be a primary consideration in this report.

1.2 Planning Objectives

(807 KAR 5:058 Sec. 5.1)

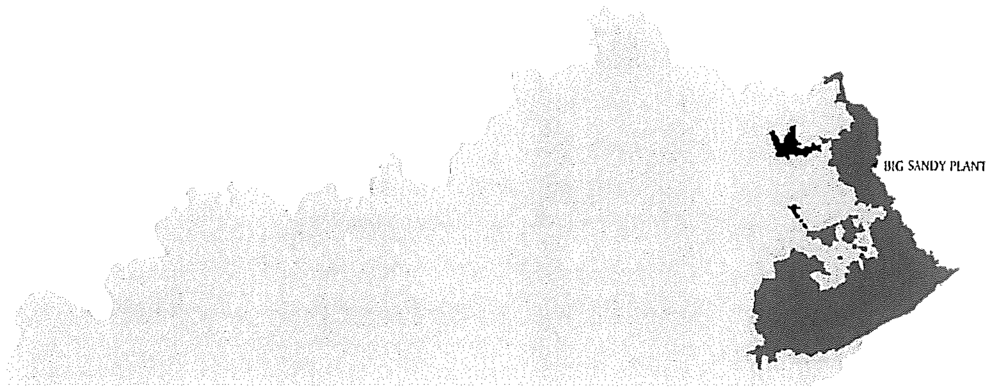
The primary objective of power system planning is to assure the reliable, adequate and economical supply of electric power and energy to the consumer, in an environmentally compatible manner. Implicit in this primary objective are related objectives, which include, in part: (1) maximizing the efficiency of operation of the power supply system, and (2) encouraging the wise and efficient use of energy.

Other objectives of a resource plan include planning flexibility, creation of an optimum asset mix, adaptability to risk and affordability. In addition, given unique impact on generation of environmental compliance, the planning effort must be in concert with anticipated long-term requirements as established by the environmental compliance planning process.

1.3 Company Operations

Kentucky Power serves 173,000 retail customers in a 3,762 square-mile area in eastern Kentucky (See **Figure 1**). There is a population of 429,000 in counties served by Kentucky Power in whole or partially. The principal industries served are primary metals, chemicals and allied products, petroleum refining and coal mining. The Company also sells and transmits power, at wholesale, to two Kentucky municipalities; the City of Olive Hill and the City of Vanceburg.

Figure 1: Kentucky Power Service Territory



Kentucky Power's internal load usually peaks in the winter; the all-time peak internal demand of 1,678 megawatts (MW) occurred on January 25, 2008. On August 24, 2007, an all-time summer peak internal demand of 1,358 MW was experienced. Of Kentucky Power's total internal energy requirements in 2012, which amounted to 7,155 gigawatt-hours (GWh), residential, commercial, and industrial energy sales accounted for 31.3%, 18.9%, and 42.8%, respectively. Public street and highway lighting, sales for resale, and all other categories accounted for the remainder.

As of December 2013, Kentucky Power owns and operates the 1,078 MW, coal-fired Big Sandy Plant, consisting of an 800-MW unit and a 278-MW unit, at Louisa, Kentucky, and has a unit power agreement with AEP Generating Company (AEG), an affiliate, to purchase 393 MW of capacity from the Rockport Plant, located in southern Indiana, through December 7, 2022, which is the end of the purchase agreement period.[7] For purposes of the development of this long-term IRP, however, it has been assumed that this purchase agreement would be extended beyond the end of the planning period. Lastly, Kentucky Power will also own a 780 MW share of the Mitchell Plant Units 1 and 2, located at Captina, West Virginia, beginning January 1, 2014.

The AEP System's generating eastern operating companies, including Kentucky Power, are electrically interconnected by a high capacity transmission system extending from Virginia to Michigan. This eastern transmission system, consisting of an integrated 765-kV, 500-kV, and 345-kV, extra-high-voltage (EHV) network, together with an extensive underlying 138-kV transmission network, and numerous interconnections with neighboring power systems, is planned, constructed, and operated to provide a reliable mechanism to transmit the electrical output from the AEP System–East Zone generating plants to the principal load centers and to provide open access transmission service pursuant to FERC Order No. 888.

AEP transferred functional control of transmission facilities in the Eastern part of its system to the PJM Interconnection, LLC, a regional transmission organization (RTO) in 2004. This transfer was approved by the Kentucky Public Service Commission in Case No. 2002-00475 order dated May 19, 2004. The PJM RTO assumed the monitoring, market operations and planning responsibilities of these facilities. In addition, PJM assumed the Open Access Same Time Information System (OASIS) responsibility including the evaluation and disposition of requests for transmission services over the AEP System–East Zone transmission system. PJM also became the North American Electric Reliability Council (NERC) Reliablity Coordinator for the AEP System-East Zone transmission system. AEP-East continues to maintain and physically operate all of its transmission facilities. AEP-East retains operational responsibility for those facilities that are not under PJM functional control, and is involved in the various operations, and planning stakeholder processes of PJM. In addition, PJM directs the dispatch of the AEP

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[7] The purchase agreement calls for Kentucky Power to acquire 30% of AEG's 50% share of both Units 1 (1,320 MW) and Unit 2 (1,300 MW)

System-East Zone generating resources to meet minute-to-minute loads and determines the planning reserve required to maintain generation resource adequacy.

1.4. Load Forecasts

(807 KAR 5:058 Sec. 5.2.,5.3., and 5.4.)

It should be noted that the load forecasts presented herein began development in early 2013 and were finalized in July 2013 and, therefore, do not reflect the experience for the summer season of 2013 and later, or other relevant changes.[8]

Kentucky Power's forecasts of energy consumption for the major customer classes were developed using both short-term and long-term econometric models. These energy forecasts were determined in part by forecasts of the regional economy, which, in turn, are based on the December 2012 national economic forecast of Moody's Analytics. The forecasts of seasonal peak demands were developed using an analysis of energy and load shapes that estimates hourly demand.

Some of the key assumptions on which the load forecast is based include:

- moderate economic growth;
- slow growth in energy prices;
- generally slow decline in the Company's service-area population; and
- normal weather.

Table 2 provides a summary of the "base" forecasts of the seasonal peak internal demands and annual energy requirements for Kentucky Power for the planning years 2014 to 2028. The forecast data shown on this table reflects adjustments for filed EE programs. In addition, inherent in the forecast are the impacts of past customer

[8]The load forecasts (as well as the historical loads) presented in this report reflect the traditional concept of internal load, *i.e.*, the load that is directly connected to the utility's transmission and distribution system and that is provided with bundled generation and transmission service by the utility. Such load serves as the starting point for the load forecasts used for generation planning. Internal load is a subset of *connected load*, which also includes directly connected load for which the utility serves only as a transmission provider. Connected load serves as the starting point for the load forecasts used for transmission planning.

conservation and load management activities, including demand-side management (DSM) programs already in place.

Table 2: Peak Internal Demand and Energy Requirements Including Approved EE

Table 2 Kentucky Power Company Forecast of Peak Internal Demand and Energy Requirments Including Approved Energy Efficiency Impact 2014-2028			
	Peak Internal Demand		
Year	Summer (MW)	Winter Following (MW)	Internal Energy Req'ts (GWh)
2014	1,132	1,431	6,958
2015	1,133	1,432	6,953
2016	1,134	1,431	6,970
2017	1,137	1,431	6,975
2018	1,139	1,432	6,979
2019	1,141	1,430	6,986
2020	1,142	1,436	6,997
2021	1,149	1,439	7,012
2022	1,154	1,438	7,036
2023	1,157	1,438	7,056
2024	1,158	1,444	7,072
2025	1,166	1,448	7,090
2026	1,171	1,452	7,112
2027	1,176	1,454	7,134
2028	1,179	1,459	7,158
% Average Growth rate, 2014-2028	0.3	0.1	0.1
Note: Kentucky Power interruptible load is assumed to be not available for interruption at the time of the seasonal peaks			

As Table 2 indicates, during the period 2014-2028, Kentucky Power's base internal energy requirements are forecasted to increase at an average annual rate of 0.1%, while the corresponding summer and winter peak internal demands are forecasted to grow at average annual rates of 0.3% and 0.1%, respectively. Kentucky Power's annual peak demand is expected to continue to occur in the winter season. However, as a member of PJM, Kentucky Power is *only* obligated to plan to meet its summer peak given that PJM is, itself, summer peaking.

Table 3 shows Kentucky Power's load forecast information as in Table 2 except that the peak demands and energy requirements have been increased, where appropriate, to exclude the impact of the approved EE Kentucky programs assumed to be implemented during the forecast period. A comparison of the data shown on Tables 2 and 3 indicates that the approved EE program effects are relatively minor and do not significantly affect the long-term load growth rates.

Table 3: Peak Internal Demand and Energy Requirements Excluding Approved EE

Table 3
Kentucky Power Compnay
Forecast of Peak Internal Demand and Energy Requirments
Excluding Approved Energy Efficiency Impact
2014-2028

	Peak Internal Demand		
Year	**Summer (MW)**	**Winter Following (MW)**	**Internal Energy Req'ts (GWh)**
2014	1,137	1,442	7,004
2015	1,140	1,445	7,014
2016	1,143	1,447	7,043
2017	1,147	1,448	7,056
2018	1,150	1,450	7,066
2019	1,153	1,449	7,077
2020	1,155	1,456	7,092
2021	1,162	1,460	7,108
2022	1,167	1,459	7,133
2023	1,170	1,459	7,154
2024	1,172	1,465	7,169
2025	1,179	1,470	7,187
2026	1,185	1,474	7,209
2027	1,190	1,475	7,231
2028	1,193	1,480	7,255
% Average Growth rate, 2014-2028	0.3	0.2	0.2

Note: Kentucky Power interruptible load is assumed to be not available for interruption at the time of the seasonal peaks

1.5 DSM Programs and Impacts

(807 KAR 5:058 Sec. 5.4)

Kentucky Power has offered a variety of conservation and DSM programs since 1994 that are designed to encourage customers to use electricity efficiently, achieve energy conservation, and reduce the level of future peak demands for electricity. Kentucky Power greatly expanded its EE programs in 2010 and now offers 12 programs for its residential and commercial customers. From 2008 through 2013, these programs have installed efficiency measures that are saving Kentucky customers approximately 48 GWh annually. Kentucky Power will continue to benefit from the load impacts from these traditional DSM programs for many years. These load impacts are "embedded" in the base load forecast of the integrated resource plan. Additionally, Kentucky Power continues to provide peak demand options such as time-of-day tariffs.

Since Kentucky's last IRP, the EE landscape has changed dramatically. First and foremost, the provisions of the Energy Independence and Security Act of 2007 (EISA 2007) are nearly fully phased in, limiting the impacts of utility lighting programs, prospectively. Lighting programs have constituted the bulk of energy savings for Kentucky programs and programs nationwide.

EISA 2007 requires that screw-in lighting be 25% more efficient than traditional incandescent lights by the end of 2013, which has resulted in the typical 100, 75, and 60 watt incandescent light bulbs being phased out. Compact Fluorescent Lamp (CFL) bulbs, as part of an EE program, may still represent savings over the increased standard, as there are some substitutes, notably, efficient halogens. However, by year-end 2019, the standard increases to preclude any substitutes, and the CFL bulb becomes the de facto standard. Similarly, the commercial T-12 light has been prohibited from manufacture or import since mid-2012. Replacing T-12 lights with T-8 lights has constituted the bulk of commercial lighting programs nationwide but eventually, as old stock is consumed, will no longer be considered as an option for utility lighting programs. The long-term load forecast recognizes this and assumes all lighting will be at the mandated standards. This makes any energy savings associated with traditional lighting programs short-lived, as they become implicit in the load forecast.

Further expansion of Kentucky's programs or development of new programs must reflect this evolution. It is unrealistic to expect energy savings associated with lighting programs of the past to translate to prospective programs with substantially non-lighting measures.

The Company has been continually working with the Kentucky Power DSM Collaborative (which was established in November 1994 to develop Kentucky Power's DSM plans) to ensure that DSM programs are implemented as effectively and efficiently as possible and are helping Kentucky customers save energy. Over the years, the Kentucky Power DSM Collaborative has worked closely in reviewing, recommending and endorsing DSM programs for Kentucky Power customers. Through continuously monitoring the program performance, program participation level and DSM market potential, the Collaborative has recommended the addition, deletion and modification of various DSM programs. The development of Kentucky Power's DSM programs by the Collaborative incorporated the Collaborative's perspectives on those aspects of integrated resource planning that related to demand-side management.

Table 4 lists the existing DSM programs that are currently being offered in Kentucky.

EE programs are included in this IRP in one of two ways: current, approved programs that are expected to continue through the forecast period by way of the impacts of those programs being included in the load forecast; and incremental demand-side programs which were evaluated with all other resource options and included in the plan, if warranted.

Table 4: Kentucky Power Existing DSM Programs

Kentucky Power Existing DSM Programs
1. Targeted Energy Efficiency Program
2. High Efficiency Heat Pump -Mobile Home Program,
3. Mobile Home New Construction Program
4. Modified Energy Fitness Program
5. High Efficiency Heat Pump Program
6. Energy Education for Students Program
7. Community Outreach Compact Fluorescent Lighting (CFL) Program
8. Residential HVAC Diagnostic and Tune-up
9. Residential Efficient Products
10. Small Commercial HVAC Diagnostic Tune-up
11. Small Commercial High Efficiency Heat Pumpm/Air Conditioner
12. Commercial Incentive

1.6 Supply-Side Resource Expansion

(807 KAR 5:058 Sec. 5.4.)

In the planning process, several considerations impact Kentucky Power's assessment of supply-side resources, namely:

- age of the fossil-fueled generation fleet;
- impact of final and proposed future EPA regulations, state legislated renewable portfolio standards (RPS) and voluntary Clean Energy Goals;
- current mix of capacity which relies heavily on baseload generating assets; and
- availability and cost of alternative assets including utility-scale solar and wind.

These factors provide both objective and subjective data that play into the construction of Kentucky Power's ultimate, Preferred Portfolio. In summary, the following represent going-in supply-side resources assumptions that lead to the development of that portfolio. The Plan recognizes:

- the transfer of a 50% undivided ownership interest in the Mitchell Plant on January 1, 2014,
- the retirement of Big Sandy Unit 2 in 2015,
- the conversion of Big Sandy Unit 1 to gas in 2016, and

- Kentucky Power also expects to purchase 58.5 MW of capacity and energy from the ecoPower biomass facility beginning in 2017.
- AEPSC on behalf of the Company issued a Request for Information (RFI) on October 18, 2013 for non-binding indicative responses for a 100 MW (nameplate) power purchase agreement.

First, **Table 5** compares projected **summer** peak demands—net of DSM—with the projected capacity for Kentucky Power and presenting the resulting reserve margins *prior to any new capacity additions* (*i.e.,* going-in). Again, this represents the (summer) capacity planning criterion that Kentucky Power is obligated to uphold in PJM.

Table 5: Summer Peak Going-In Reserve

Projected Peak Demands, Capabilities and Margins At Time of Summer Peak (UCAP) 2014-2028				
	Peak Demand (MW)	Capability (MW)	Reserve (MW)	Margin (%)
2014	1,259	1,783	524	64.1%
2015	1,278	1,316	38	18.7%
2016	1,304	1,326	22	17.6%
2017	1,159	1,326	167	32.3%
2018	1,160	1,331	171	32.6%
2019	1,161	1,331	170	32.5%
2020	1,162	1,336	174	32.9%
2021	1,167	1,336	169	32.3%
2022	1,172	1,336	164	31.8%
2023	1,174	1,336	162	31.6%
2024	1,175	1,336	161	31.4%
2025	1,182	1,333	151	30.4%
2026	1,186	1,333	147	29.9%
2027	1,192	1,333	141	29.3%
2028	1,195	1,331	136	28.8%

In contrast, **Table 6** compares projected **winter** peak demands—net of DSM—with essentially the *same* projected capacity for Kentucky Power. This winter going-in capacity/reserve margin position is clearly unique for the Company in that it clearly sets forth the additional obligations around resource adequacy that must be considered by

Kentucky Power over-and-above the summer season obligations set forth by the PJM RTO.

Table 6: Winter Peak Going-In Reserve

Projected Peak Demands, Capabilities and Margins At Time of Winter Peak (UCAP) 2014-2028				
	Demand (MW)	Capability (MW)	Reserve (MW)	Margin (%)
2014	1,431	2,251	820	57.3%
2015	1,432	1,433	1	0.1%
2016	1,431	1,433	2	0.1%
2017	1,431	1,438	7	0.5%
2018	1,432	1,438	6	0.4%
2019	1,430	1,444	14	1.0%
2020	1,436	1,444	8	0.6%
2021	1,439	1,444	5	0.3%
2022	1,438	1,444	6	0.4%
2023	1,438	1,444	6	0.4%
2024	1,444	1,444	0	0.0%
2025	1,448	1,441	(7)	-0.5%
2026	1,452	1,441	(11)	-0.8%
2027	1,454	1,441	(13)	-0.9%
2028	1,459	1,438	(21)	-1.4%

1.6.1 Kentucky Power Stand Alone

(807 KAR 5:058 Sec. 5.4)

On page 5 of the Commission's Order dated December 13, 2004 in Case No. 2004-00420, "In the Matter of: Application of Kentucky Power Company for Approval of a Stipulation and Settlement Agreement Resolving State Regulatory Matters" (commonly referred to as the Rockport Settlement Agreement), the Company was directed that its future IRP's should reflect the resources available to Kentucky Power as a "stand-alone" utility, as well as the resources available to it as a member of any power-pooling arrangement that is anticipated to exist during the period reflected in the IRP. The motivation for such a historical perspective has now been affirmed by virtue of the upcoming elimination of the AEP Interconnection Agreement and the proposed adoption of the PCA which would effectively establish Kentucky Power as a 'stand-alone' entity from a planning perspective.

Therefore, the discussion and Exhibits in Chapter 4 of this report all reflect this planning solely from the perspective of Kentucky Power as a stand-alone company. Those Preferred Portfolio resources—as detailed in Chapter 4—ensure that, as a stand-alone utility, Kentucky Power would have adequate capacity to achieve its PJM minimum (capacity) reserve margin criterion through 2028 *and* would ensure that the Company will be able to provide sufficient, diverse resources to achieve its customers' *energy* requirements going-forward.

1.7 Significant Changes from the Previous IRP Filing

(807 KAR 5:058 Sec. 6)

Significant changes from the previously-filed 2009 IRP to this current 2013 IRP are as follows by major function:

Load Forecast

In the four years since the last IRP filing for the Company, there have been changes to the customer base in Kentucky. For example, the residential customer counts have decreased. The mining sector sales have been sharply reduced. Appliance and equipment efficiency standards continue to be a driving force in conserving energy and diminished electricity consumption. These, along with other factors, have resulted in a lowered load forecast. See Chapter 2, Sec. I. for further details.

Resource Planning

With regards to the resource planning aspect of this IRP report, the following changes have been addressed in this report:

- Dissolution of the AEP-East Pool – see Chapter 1, Section 1.1.
- Finalization of the MATS rule and the ultimate retirement of Big Sandy unit 2 and the decision to convert Big Sandy unit 1 to a gas-fired generating unit – see Chapter 4, Sections 4.2.3. and 4.3.2.
- Retail competition in Ohio resulting in the divestiture of Ohio Power's generating assets, making Mitchell Units 1 and 2 available to Kentucky Power – see Chapter 4, Section 4.3.4.

- Supply-side Plan – see comparison in Exhibit 4-15. The plan now includes a mix of specific renewable and traditional supplies.

DSM

The EE landscape, in Kentucky and nationwide, is one that is increasingly challenging. Economic conditions have not fully rebounded from the effects of the most recent recession, depressing energy and capacity prices. In addition, increased lighting standards have been fully phased-in, limiting the prospective savings possible with utility lighting programs, which have provided the bulk of savings to-date. Efficiency programs that provide the same level of energy savings for the cost and are as readily excepted by consumers have not yet emerged. As part of the Mitchell Transfer Stipulation and Settlement Agreement, Kentucky Power agreed to increase spending on cost-effective EE programs to $6 million annually by 2016.

Chapter 3 discusses in greater detail the process used to determine an appropriate level of prospective demand-side programs.

Environmental Compliance

This 2013 IRP considers the impacts of final and proposed EPA regulations to Kentucky Power generating facilities. In addition, the IRP development process assumes there may likely be future regulation of GHG/CO_2 emissions which would become effective at some point in the 2022 timeframe. Emission compliance requirements have a major influence on the consideration of new supply-side resources for inclusion in the IRP because of the potential significant effects on both capital and operational costs. Moreover, the cumulative cost of complying with these rules will ultimately have an impact on proposed retirement dates of existing coal-fueled units that would otherwise be forced to install emission control equipment. Details of AEP's strategy for compliance with each EPA rule, as it becomes effective, as well as the prospect of GHG regulation are provided in Section 4.2.4.

Fuel Procurement

There have been no significant changes in the area of fuel procurement practices since the 2009 IRP report.

1.8 Financial Information

(807 KAR 5:058 Sec. 9)

The average "real" rate per kWh expected to be paid by Kentucky Power customers from 2014 to 2028 that results directly from the costs and energy consumption impacts associated with this plan—only—is shown in **Table** 7. As previously stated, Kentucky Power does not expect to add any major new baseload generation during the 2014-2028 period, however, renewable projects and new EE programs will require modest investments and/or purchase obligations. With that, on a real (2014) dollar basis as reflected in Table 7, this Preferred Portfolio would not be anticipated to result in an increase in the price of power to the Company's customers.

Further, based on the load forecast to be discussed in Section 2 and a discount rate of 8.66%, each difference in CPW between alternatives of $1,000,000,000 (one billion dollars)—to be discussed in Chapter 4—equates to approximately 1.7 ¢/kWh

Table 7: Financial Effects*

Revenue Requirements Preferred Plan		
Year	Nominal ($/kWh)	Real ($2014/kWh)
2014	$ 0.087	$ 0.087
2015	$ 0.084	$ 0.083
2016	$ 0.092	$ 0.089
2017	$ 0.089	$ 0.084
2018	$ 0.091	$ 0.084
2019	$ 0.091	$ 0.082
2020	$ 0.093	$ 0.083
2021	$ 0.094	$ 0.082
2022	$ 0.107	$ 0.091
2023	$ 0.107	$ 0.090
2024	$ 0.109	$ 0.089
2025	$ 0.110	$ 0.088
2026	$ 0.110	$ 0.087
2027	$ 0.111	$ 0.086
2028	$ 0.112	$ 0.085

* Note: The Financial Effects represented do <u>not</u> consider the prospect of increases in Kentucky Power's transmission and distribution-related costs over this period, as well as increases in base generation-related costs not uniquely incorporated into the planning/modeling process.

1.9 Next Steps, Key Issues/Uncertainties

1.9.1 Implementation Steps

(807 KAR 5:058 Sec. 5.5)

Steps to be taken during the next three (3) years to implement the plan are as follows:

Wind Projects

Pursuant to the Mitchell Transfer Stipulation and Settlement Agreement approved by the Commission, Kentucky Power issuesd a Request for Information (RFI) on potential terms for a 100 MW wind PPA beginning in 2017. The Company received twenty-five non-binding proposals. The Company has not rendered any decision regarding any ultimate disposition plan pertaining to wind resources. Rather, a discussion of the wind proposals and Kentucky Power's preferred course of action are offered in Section 4.6.4.

Stipulated Energy Efficiency Spending

To realize the resource planning benefits associated with the incremental EE resources set forth in the IRP process, Kentucky Power will need to obtain customer acceptance and participation in the new and expanded DSM programs. In the near term, an expansion of current programs is the most practical way to adhere to the stipulated settlement agreement. Subsequently, new programs that, to the extent practicable, target customer segments and end uses identified in the analyses in Chapter 3 must be developed and introduced.

Load Forecasting

With regard to load forecasting, the Company will continue to evaluate and incorporate the effects of the economy and the EE programs including federal mandates and expanded EE programs.

1.9.2 Key Issues/Uncertainties

(807 KAR 5:058 Sec. 5.6)

Key issues or uncertainties that could affect successful implementation of the plan are as follows:

Resource Planning

The plan represented in this report meets the objectives mentioned above, having planning flexibility and adaptability to risk. Kentucky Power's supply-side plan does not entail much risk or uncertainty. Perhaps the uncertainty presenting the largest challenge is the potential impact of greenhouse gas rules for existing coal units. The Company believes that the impact of such rules, if any, will not be material until the early 2020's.

DSM

In the area of DSM, the key issues and/or uncertainties are: 1) the degree of customer acceptance of offered DSM programs in that achieving the high levels of EE will require customers to embrace these efforts in unprecedented numbers; 2) the impact on ratepayers and their ability to fund DSM programs, since ramping up customer participation to achieve planning levels will require up-front investment by ratepayers (*i.e.*, they will see increased bills); and 3) whether or not in today's economic climate, regulators will approve the increased spending that accompanies increasing levels of implementation of utility-sponsored DSM programs due to its impact upon customers' bills.

Load Forecasting

A major uncertainty is how strong will the economy be in the future. The economy has a direct impact on the Company's load. The Company provides a broad overview of a high and low economic forecast scenario. See Section 2.2 for more details.

Transmission

As a result of the AEP - East Zone transmission system's geographical location and expanse, as well as its numerous interconnections, the AEP-East Zone transmission system can be influenced by both internal and external factors. Facility outages, load changes, or generation redispatch on neighboring companies' systems, in combination with power transactions across the interconnected network, can affect power flows on AEP's eastern transmission facilities. As a result, the eastern transmission system is designed and operated to perform adequately even with the outage of its most critical transmission elements or the unavailability of generation. The AEP - East Zone transmission system conforms to the NERC Reliability Standards and the applicable Reliability*First* Corporation standards and performance criteria.

The AEP - East Zone transmission system assets are aging and some station equipment is becoming obsolete. Therefore, in order to maintain acceptable levels of reliability, significant investments will have to be made over the next ten years to proactively replace the most critical aging and obsolete equipment and transmission lines.

Environmental Compliance

Currently the Clean Air Interstate Rule (CAIR), which became effective in July 2005 and called for significant reductions of NO_X and SO_2, beginning in 2009 and 2010, respectively, has been remanded by the D.C. Circuit Court to the EPA for further rulemaking in response to the legal appeals of this rule. While EPA addresses the deficiencies identified by the Court, the compliance requirements of CAIR remain in effect. There is a great deal of uncertainty over what approach EPA will take to rewrite the CAIR and its associated compliance requirements. For purposes of planning, the AEP System expects the CAIR program to be replaced with a more restrictive policy.

As a replacement to the vacated Clean Air Mercury Rule (CAMR), EPA set forth the Mercury and Air Toxics Standards (MATS) Rule which became effective on April 16, 2012. The goal of the MATS Rule is to reduce hazardous air pollutants (HAPs) from coal- and oil-fired electric generating units. The final rule includes stringent emission limits for mercury, particulate matter (PM) (as a surrogate for non-mercury metals), as well as acid gases, with either hydrochloric acid (HCl) or SO_2 serving as surrogates for acid gases. The initial compliance date for the MATS Rule is April 16, 2015. The MATS Rule will likely have a significant impact on proposed retirement dates of older, non-controlled units and ultimately the timing for new capacity.

Finally, EPA continues to move forward in implementing a regulatory approach for controlling GHG emissions from power plants. In 2010, EPA promulgated the GHG Tailoring Rule that establishes thresholds for regulating GHG emissions from new power plants or from existing units that undergo major modifications. Also, on April 13, 2012, EPA proposed New Source Performance Standards (NSPS) for new fossil fuel power plants with a CO_2 emission limit of 1,000 lb/MWh, which is equivalent to the rate EPA assumes for a new natural gas combined cycle (CC) unit. EPA did not issue a final rule based on this proposal as expected. Under President Obama's direction, the EPA issued a revised proposal for the GHG NSPS for new sources on September 20, 2013, and must finalize them in a "timely fashion." This second proposal included a CO_2 emission limit of 1,100 lb./MWh for new fossil fuel power plants.

For existing sources, the EPA was directed to propose guidelines by June 1, 2014, and finalize those standards by June 1, 2015. States would develop and submit a plan to EPA for implementing the existing source standards by June 30, 2016. The scope and timing of these requirements have not yet been determined. Such GHG rules could impose greater operating costs on Kentucky Power Company's power plants in future years.

Coal Market Uncertainties

Coal market price volatility has increased due to various events affecting the supply and demand posture of coal in the international markets. Various countries have lessened their previously stated export coal quantities to rebuild domestic stockpiles, which caused all international coal markets to tighten and prices to rise significantly. Additionally, the decreased value of the U.S. dollar relative to most major foreign currencies contributed to U.S. coal being more competitive based on price in the international export market. There also has been an increasingly strong demand for coal world wide, especially in emerging economies, along with sustained coal consumption in the United States. Early last year the global demand for coal seemed insatiable and that demand placed a significant upward pressure on the price of coal. Conversely, since last fall, there was a slow down in the world and U.S. economies, that reduced demand for U.S. coal and has effectively lowered the market price.

1.10 Cross Reference Table

(807KAR5:058 SECTION 4)

Kentucky Power has included a Cross Reference Table below that lists the section and sub-section numbers found in Administrative Regulation 807KAR5:058 "Integrated Resource Planning by Electric Utilities" along with the corresponding report Sections and/or Exhibits of Kentucky Power's IRP Plan. This Cross Reference Table is provided in order to satisfy Section 4 of the IRP regulation.

Cross Reference Table
IRP Regulation (807 KAR 5:058)

	Report Reference
May 31, 2013 Letter: Pursuant to the Commission's Order of March 29, 2004, in Administrative Case No. 387 ("Admin 387"), each jurisdictional electric generating utility is required to file annual resource information with the Commission. Certain information relates to the demand and energy forecasts and reserve margins. Given the actual and projected price increases resulting from new environmental requirements which the generating utilities are being required to address, recent Staff Reports analyzing the generation utilities' integrated resource plans have included recommendations regarding price elasticity issues. For example, the recent Staff Report issued in Case No. 2012-00140 included the following recommendation: "Staff recommends that LG&E/KU discuss the impact on demand of recent and projected increases in the price of electricity to their customers in the next IRP. The price elasticity of the demand for electricity should be fully examined and a sensitivity analysis performed." Due to the increasing impact that price elasticity will have on electric utility sales and revenues, the Staff and Commission ask that you provide a detailed discussion of the consideration given to price elasticity in the forecasted demand, energy and reserve margin information provided with the annual Admin 387 resource assessments. For the Admin 387 forecasted information filed earlier in 2013, we ask that you provide the discussion of price elasticity no later than June 30, 2013. For succeeding years, the price elasticity discussion should be provided as a supplement to the information required by the Admin 387 Order.	Section 2.7
Kentucky IRP Standard: Case No. 2008-00408 Order dated July 24, 2012 (Ordering paragraph 9 amended August 6, 2012, *nunc pro tunc*) Each electric utility shall integrate energy efficiency resources into its plans and shall adopt policies establishing cost-effective energy efficiency resources with equal priority as other resource options. In each integrated resource plan, certificate case, and rate case, the subject electric utility shall fully explain its consideration of cost-effective energy efficiency resources as defined in the Commission's IRP regulation (807 KAR 5:058).	Chapter 3, Sections 3.5.5 and 3.5.6
807 KAR 5:058. Integrated resource planning by electric utilities	
Section 1. General Provisions	
(1) This administrative regulation shall apply to electric utilities under commission jurisdiction except a distribution company with less than $10,000,000 annual revenue or a distribution cooperative organized under KRS Chapter 279.	
(2) Each electric utility shall file triennially with the commission an integrated resource plan. The plan shall include historical and projected demand, resource, and financial data, and other operating performance and system information, and shall discuss the facts, assumptions, and conclusions, upon which the plan is based and the actions it proposes.	
(3) Each electric utility shall file ten (10) bound copies and one (1) unbound, reproducible copy of its integrated resource plan with the commission.	
Section 2. Filing Schedule. (1) Each electric utility shall file its integrated resource plan according to a staggered schedule which provides for the filing of integrated resource plans one (1) every six (6) months beginning nine (9) months from the effective date of this administrative regulation.	
(a) The integrated resource plans shall be filed at the specified times following the effective date of this administrative regulation:	
1. Kentucky Utilities Company shall file nine (9) months from the effective date;	
2. Kentucky Power Company shall file fifteen (15) months from the effective date;	In compliance with the KPSC's Order in Case No. 2012-00344 dated 7-30-12, the Company will file before 12-31-13.
3. East Kentucky Power Cooperative, Inc. shall file twenty-one (21) months from the effective date;	
4. The Union Light, Heat & Power Company shall file twenty-seven (27) months from the effective date;	
5. Big Rivers Electric Corporation shall file thirty-three (33) months from the effective date; and	
6. Louisville Gas & Electric Company shall file thirty-nine (39) months from the effective date.	
(b) The schedule shall provide at such time as all electric utilities have filed integrated resource plans, the sequence shall repeat.	
(c) The schedule shall remain in effect until changed by the commission on its own motion or on motion of one (1) or more electric utilities for good cause shown. Good cause may include a change in a utility's financial or resource conditions.	
(d) If any filing date falls on a weekend or holiday, the plan shall be submitted on the first business day following the scheduled filing date.	

Cross Reference Table IRP Regulation (807 KAR 5:058)	Report Reference
(2) Immediately upon filing of an integrated resource plan, each utility shall provide notice to intervenors in its last integrated resource plan review proceeding, that its plan has been filed and is available from the utility upon request.	The Company will comply with this requirement.
(3) Upon receipt of a utility's integrated resource plan, the commission shall establish a review schedule which may include interrogatories, comments, informal conferences, and staff reports.	
Section 3. Waiver. A utility may file a motion requesting a waiver of specific provisions of this administrative regulation. Any request shall be made no later than ninety (90) days prior to the date established for filing the integrated resource plan. The commission shall rule on the request within thirty (30) days. The motion shall clearly identify the provision from which the utility seeks a waiver and provide justification for the requested relief which shall include an estimate of costs and benefits of compliance with the specific provision. Notice shall be given in the manner provided in Section 2(2) of this administrative regulation.	No Waivers have been requested.
Section 4. Format	
(1) The integrated resource plan shall be clearly and concisely organized so that it is evident to the commission that the utility has complied with reporting requirements described in subsequent sections.	Chapter 1.0 - Cross-reference Table
(2) Each plan filed shall identify the individuals responsible for its preparation, who shall be available to respond to inquiries during the commission's review of the plan.	Direct Inquiries to Ranie K Wohnhas, KPCo's Managing Director of Regulatory and Finance. The lead preparers for Chapters 2, 3, and 4 are Randy Holliday (Economic Forecasting), William Castle (Resource Planning - DSM) and John Torpey (Resource Planning - Supply/Integration), respectively.
Section 5. Plan Summary	
The plan shall contain a summary which discusses the utility's projected load growth and the resources planned to meet that growth. The summary shall include at a minimum:	Chapter 1.0
(1) Description of the utility, its customers, service territory, current facilities, and planning objectives;	Chapter 1.2 and Chapter 1.3
(2) Description of models, methods, data, and key assumptions used to develop the results contained in the plan;	Chapter 1.4 , Chapter 2 Sections 2.1, 2.2, 2.3 and 2.4.
(3) Summary of forecasts of energy and peak demand, and key economic and demographic assumptions or projections underlying these forecasts;	Chapter 1.4
(4) Summary of the utility's planned resource acquisitions including improvements in operating efficiency of existing facilities, demand-side programs, nonutility sources of generation, new power plants, transmission improvements, bulk power purchases and sales, and interconnections with other utilities;	Chapter 1, Sections 1.4, 1.5, 1.6 Chapter 4.4.1 and Exhibit 4-18
(5) Steps to be taken during the next three (3) years to implement the plan;	Chapter 1.9.1
(6) Discussion of key issues or uncertainties that could affect successful implementation of the plan.	Chapter 1.9.2
Section 6. Significant Changes	
All integrated resource plans, shall have a summary of significant changes since the plan most recently filed. This summary shall describe, in narrative and tabular form, changes in load forecasts, resource plans, assumptions, or methodologies from the previous plan. Where appropriate, the utility may also use graphic displays to illustrate changes.	Chapter 1.7 and Chapter 2.9 and Chapter 3.1.1 and Exhibit 4-15
Section 7. Load Forecasts	
The plan shall include historical and forecasted information regarding loads.	Chapter 2.5.1 and Chapter 2.5.2
(1) The information shall be provided for the total system and, where available, disaggregated by the following customer classes:	Chapter 2.5 note Residential forecast in aggregate
(a) Residential heating;	Chapter 2.10
(b) Residential nonheating;	Chapter 2.10
(c) Total residential (total of paragraphs (a) and (b) of this subsection);	Chapter 2.5
(d) Commercial;	Chapter 2.5
(e) Industrial;	Chapter 2.5
(f) Sales for resale;	Chapter 2.5
(g) Utility use and other.	Chapter 2.5
The utility shall also provide data at any greater level of disaggregation available.	Chapter 2.5

Cross Reference Table IRP Regulation (807 KAR 5:058)	Report Reference
(2) The utility shall provide the following historical information for the base year, which shall be the most recent calendar year for which actual energy sales and system peak demand data are available, and the four (4) years preceding the base year:	Chapter 2.10
(a) Average annual number of customers by class as defined in subsection (1) of this section;	Chapter 2.10
(b) Recorded and weather-normalized annual energy sales and generation for the system, and sales disaggregated by class as defined in subsection (1) of this section;	Chapter 2.10
(c) Recorded and weather-normalized coincident peak demand in summer and winter for the system;	Chapter 2.10
(d) Total energy sales and coincident peak demand to retail and wholesale customers for which the utility has firm, contractual commitments;	Chapter 2.10
(e) Total energy sales and coincident peak demand to retail and wholesale customers for which service is provided under an interruptible or curtailable contract or tariff or under some other nonfirm basis;	Chapter 2.10
(f) Annual energy losses for the system;	Chapter 2.10
(g) Identification and description of existing demand-side programs and an estimate of their impact on utility sales and coincident peak demands including utility or government sponsored conservation and load management programs;	Chapter 2.5.2; Chapter 3.1.2; Chapter 3.8
(h) Any other data or exhibits, such as load duration curves or average energy usage per customer, which illustrate historical changes in load or load characteristics.	Chapter 2.10
(3) For each of the fifteen (15) years succeeding the base year, the utility shall provide a base load forecast it considers most likely to occur and, to the extent available, alternate forecasts representing lower and upper ranges of expected future growth of the load on its system. Forecasts shall not include load impacts of additional, future demand-side programs or customer generation included as part of planned resource acquisitions estimated separately and reported in Section 8(4) of this administrative regulation. Forecasts shall include the utility's estimates of existing and continuing demand-side programs as described in subsection (5) of this section.	Chapter 2.5
(4) The following information shall be filed for each forecast:	
(a) Annual energy sales and generation for the system and sales disaggregated by class as defined in subsection (1) of this section;	Chapter 2.5
(b) Summer and winter coincident peak demand for the system;	Chapter 2.5
(c) If available for the first two (2) years of the forecast, monthly forecasts of energy sales and generation for the system and disaggregated by class as defined in subsection (1) of this section and system peak demand;	Chapter 2.5
(d) The impact of existing and continuing demand-side programs on both energy sales and system peak demands, including utility and government sponsored conservation and load management programs	Chapter 2.5, Chapter 2.6.
(e) Any other data or exhibits which illustrate projected changes in load or load characteristics.	Chapter 2.3.3.2 and 2.3.3.3
(5) The additional following data shall be provided for the integrated system, when the utility is part of a multistate integrated utility system, and for the selling company, when the utility purchases fifty (50) percent of its energy from another company:	
(a) For the base year and the four (4) years preceding the base year	
1. Recorded and weather normalized annual energy sales and generation;	Chapter 2.10
2. Recorded and weather-normalized coincident peak demand in summer and winter.	Chapter 2.10
(b) For each of the fifteen (15) years succeeding the base year:	
1. Forecasted annual energy sales and generation;	Chapter 2.5
2. Forecasted summer and winter coincident peak demand.	Chapter 2.5
(6) A utility shall file all updates of load forecasts with the commission when they are adopted by the utility.	Chapter 2.12.3
(7) The plan shall include a complete description and discussion of:	
(a) All data sets used in producing the forecasts;	Chapter 2 Appendix Vol. B
(b) Key assumptions and judgments used in producing forecasts and determining their reasonableness;	Chapter 2.3 and 2.4 and Chapter 2 Appendix Vol. B

Cross Reference Table IRP Regulation (807 KAR 5:058)	Report Reference
(c) The general methodological approach taken to load forecasting (for example, econometric, or structural) and the model design, model specification, and estimation of key model parameters (for example, price elasticities of demand or average energy usage per type of appliance);	Chapter 2.2, 2.3 and 2.4
(d) The utility's treatment and assessment of load forecast uncertainty;	Chapter 2.8
(e) The extent to which the utility's load forecasting methods and models explicitly address and incorporate the following factors:	Chapter 2.3 and Chapter 2 Appendix Vol. B
1. Changes in prices of electricity and prices of competing fuels;	Chapter 2.3, 2.7 and Chapter 2 Appendix Vol. B
2. Changes in population and economic conditions in the utility's service territory and general region;	Chapter 2.3 and Chapter 2 Appendix Vol. B
3. Development and potential market penetration of new appliances, equipment, and technologies that use electricity or competing fuels; and	Chapter 2.3 and Chapter 2 Appendix Vol. B
4. Continuation of existing company and government sponsored conservation and load management or other demand-side programs.	Chapter 2.3 and Chapter 2 Appendix Vol. B
(f) Research and development efforts underway or planned to improve performance, efficiency, or capabilities of the utility's load forecasting methods; and	Chapter 2.9.3
(g) Description of and schedule for efforts underway or planned to develop end-use load and market data for analyzing demand-side resource options including load research and market research studies, customer appliance saturation studies, and conservation and load management program pilot or demonstration projects.	Chapter 2.10
Technical discussions, descriptions, and supporting documentation shall be contained in a technical appendix.	Chapter 2 Appendix Vol. B
Section 8. Resource Assessment and Acquisition Plan	
(1) The plan shall include the utility's resource assessment and acquisition plan for providing an adequate and reliable supply of electricity to meet forecasted electricity requirements at the lowest possible cost. The plan shall consider the potential impacts of selected, key uncertainties and shall include assessment of potentially cost-effective resource options available to the utility.	Chapter 4.0
(2) The utility shall describe and discuss all options considered for inclusion in the plan including:	
(a) Improvements to and more efficient utilization of existing utility generation, transmission, and distribution facilities;	Chapter 4.3.2.2
(b) Conservation and load management or other demand-side programs not already in place;	Chapter 3.4 and Chapter 3.5
(c) Expansion of generating facilities, including assessment of economic opportunities for coordination with other utilities in constructing and operating new units; and	Chapter 4
(d) Assessment of nonutility generation, including generating capacity provided by cogeneration, technologies relying on renewable resources, and other nonutility sources.	Chapter 4.3.4 and Chapter 4.3.2.3
(3) The following information regarding the utility's existing and planned resources shall be provided. A utility which operates as part of a multistate integrated system shall submit the following information for its operations within Kentucky and for the multistate utility system of which it is a part. A utility which purchases fifty (50) percent or more of its energy needs from another company shall submit the following information for its operations within Kentucky and for the company from which it purchases its energy needs.	
(a) A map of existing and planned generating facilities, transmission facilities with a voltage rating of sixty-nine (69) kilovolts or greater, indicating their type and capacity, and locations and capacities of all interconnections with other utilities. The utility shall discuss any known, significant conditions which restrict transfer capabilities with other utilities.	Confidential Exhibits 4-16 & Confidential Exhibit 4-17 Vol. D
(b) A list of all existing and planned electric generating facilities which the utility plans to have in service in the base year or during any of the fifteen (15) years of the forecast period, including for each facility:	
1. Plant name;	Exhibit 4-2 and Exhibits 4-12 and 4-13
2. Unit number(s);	Exhibit 4-2 and Exhibits 4-12 and 4-13
3. Existing or proposed location;	Exhibit 4-2 and Exhibits 4-12 and 4-13
4. Status (existing, planned, under construction, etc.);	Exhibit 4-2 and Exhibits 4-12 and 4-13
5. Actual or projected commercial operation date;	Exhibit 4-2 and Exhibits 4-12 and 4-13
6. Type of facility;	Exhibit 4-2 and Exhibits 4-12 and 4-13
7. Net dependable capability, summer and winter;	Exhibit 4-2 and Exhibits 4-12 and 4-13
8. Entitlement if jointly owned or unit purchase;	Exhibit 4-2 and Exhibits 4-12 and 4-13

Cross Reference Table IRP Regulation (807 KAR 5:058)	Report Reference
9. Primary and secondary fuel types, by unit;	Exhibit 4-2 and Exhibits 4-10 through 4-13
10. Fuel storage capacity;	Exhibit 4-2 and Exhibits 4-10 through 4-13
11. Scheduled upgrades, deratings, and retirement dates;	Exhibits 4-10 through 4-13
12. Actual and projected cost and operating information for the base year (for existing units) or first full year of operations (for new units) and the basis for projecting the information to each of the fifteen (15) forecast years (for example, cost escalation rates). All cost data shall be expressed in nominal and real base year dollars.	
a. Capacity and availability factors;	Exhibits 4-5 and Confidential 4-6 Vol. D
b. Anticipated annual average heat rate;	Exhibits 4-5 and Confidential 4-6 Vol. D
c. Costs of fuel(s) per millions of British thermal units (MMBtu);	Exhibit 4-3 and Confidential Exhibit 4-4 Vol. D
d. Estimate of capital costs for planned units (total and per kilowatt of rated capacity);	Chapter 4.C.2.a. and Confidential Exhibit 4-9 Vol. D
e. Variable and fixed operating and maintenance costs;	Exhibit 4-3 and Confidential Exhibit 4-4 Vol. D
f. Capital and operating and maintenance cost escalation factors;	Chapter 4.3.5.2
g. Projected average variable and total electricity production costs (in cents per kilowatt-hour).	Confidential Exhibit 4-4 Vol. D
(c) Description of purchases, sales, or exchanges of electricity during the base year or which the utility expects to enter during any of the fifteen (15) forecast years of the plan.	Exhibits 4-10 through 4-13
(d) Description of existing and projected amounts of electric energy and generating capacity from cogeneration, self-generation, technologies relying on renewable resources, and other nonutility sources available for purchase by the utility during the base year or during any of the fifteen (15) forecast years of the plan.	Chapter 4.3.4.1 and Chapter 4.3.2.1
(e) For each existing and new conservation and load management or other demand-side programs included in the plan:	
1. Targeted classes and end-uses;	Chapter 3.8; Chapter 3.5.5. and Exhibit 3-3
2. Expected duration of the program;	Chapter 3.5.7
3. Projected energy changes by season, and summer and winter peak demand changes;	Chapter 3.5.6, Exhibit 3-4, and Chapter 3.8, Filed DSM Programs see Chapters 2.6 and Chapter 2.5.2
4. Projected cost, including any incentive payments and program administrative costs; and	Chapter 3.8; Chapter 3.5.7 and Exhibit 3-5
5. Projected cost savings, including savings in utility's generation, transmission and distribution costs.	Chapter 3.5.7, Chapter 3.8
(4) The utility shall describe and discuss its resource assessment and acquisition plan which shall consist of resource options which produce adequate and reliable means to meet annual and seasonal peak demands and total energy requirements identified in the base load forecast at the lowest possible cost. The utility shall provide the following information for the base year and for each year covered by the forecast:	
(a) On total resource capacity available at the winter and summer peak:	
1. Forecast peak load;	Exhibits 4-10 through 4-13
2. Capacity from existing resources before consideration of retirements;	Exhibits 4-10 through 4-13
3. Capacity from planned utility-owned generating plant capacity additions;	Exhibits 4-10 through 4-13
4. Capacity available from firm purchases from other utilities;	Exhibits 4-10 through 4-13
5. Capacity available from firm purchases from nonutility sources of generation;	Exhibits 4-10 through 4-13
6. Reductions or increases in peak demand from new conservation and load management or other demand-side programs;	Exhibits 4-10 through 4-13, filed DSM Program Chapter 2.6 and Chapter 2.5.2 Also Exihibt 3-4
7. Committed capacity sales to wholesale customers coincident with peak;	Exhibits 4-10 through 4-13
8. Planned retirements;	Exhibits 4-10 through 4-13
9. Reserve requirements;	Exhibits 4-10 through 4-13
10. Capacity excess or deficit;	Exhibits 4-10 through 4-13
11. Capacity or reserve margin.	Exhibits 4-10 through 4-13
(b) On planned annual generation:	
1. Total forecast firm energy requirements;	Exhibit 4-14
2. Energy from existing and planned utility generating resources disaggregated by primary fuel type;	Exhibit 4-14
3. Energy from firm purchases from other utilities;	Exhibit 4-14
4. Energy from firm purchases from nonutility sources of generation; and	Exhibit 4-14

Cross Reference Table

IRP Regulation (807 KAR 5:058)	Report Reference
5. Reductions or increases in energy from new conservation and load management or other demand-side programs;	Exhibit 3-4 and Exhibit 4-14
(c) For each of the fifteen (15) years covered by the plan, the utility shall provide estimates of total energy input in primary fuels by fuel type and total generation by primary fuel type required to meet load. Primary fuels shall be organized by standard categories (coal, gas, etc.) and quantified on the basis of physical units (for example, barrels or tons) as well as in MMBtu.	Exhibit 4-14
(5) The resource assessment and acquisition plan shall include a description and discussion of	
(a) General methodological approach, models, data sets, and information used by the company;	Chapters 4.1, 4.3 and 4.5
(b) Key assumption and judgments used in the assessment and how uncertainties in those assumptions and judgments were incorporated into analyses;	Chapter 1.9
(c) Criteria (for example, present value of revenue requirements, capital requirements, environmental impacts, flexibility, diversity) used to screen each resource alternative including demand-side programs, and criteria used to select the final mix of resources presented in the acquisition plan;	Chapters 4.1 and 4.5
(d) Criteria used in determining the appropriate level of reliability and the required reserve or capacity margin, and discussion of how these determinations have influenced selection of options;	Chapter 4.2.2
(e) Existing and projected research efforts and programs which are directed at developing data for future assessments and refinements of analyses;	Chapter 4.3.4
(f) Actions to be undertaken during the fifteen (15) years covered by the plan to meet the requirements of the Clean Air Act amendments of 1990, and how these actions affect the utility's resource assessment; and	Chapter 4.2.4
(g) Consideration given by the utility to market forces and competition in the development of the plan.	Chapter 4.3.4.1
Technical discussion, descriptions and supporting documentation shall be contained in a technical appendix.	Chapter 4.9
Section 9. Financial Information	
The integrated resource plan shall, at a minimum, include and discuss the following financial information:	
(1) Present (base year) value of revenue requirements stated in dollar terms;	Chapter 1.8 Financial Information, Table 7
(2) Discount rate used in present value calculations;	Chapter 1.8 Financial Information, Table 7
(3) Nominal and real revenue requirements by year; and	Chapter 1.8 Financial Information, Table 7
(4) Average system rates (revenues per kilowatt hour) by year.	Chapter 1.8 Financial Information, Table 7
Section 10. Notice	
Each utility which files an integrated resource plan shall publish, in a form prescribed by the commission, notice of its filing in a newspaper of general circulation in the utility's service area. The notice shall be published not more than thirty (30) days after the filing date of the report.	The Company intends to publish Notices on or before January 20, 2014.
Section 11 Procedures for Review of the Integrated Resource Plan	
(1) Upon receipt of a utility's integrated resource plan, the commission shall develop a procedural schedule which allows for submission of written interrogatories to the utility by staff and intervenors, written comments by staff and intervenors, and responses to interrogatories and comments by the utility.	
(2) The commission may convene conferences to discuss the filed plan and all other matters relative to review of the plan.	
(3) Based upon its review of a utility's plan and all related information, the commission staff shall issue a report summarizing its review and offering suggestions and recommendations to the utility for subsequent filings.	
(4) A utility shall respond to the staff's comments and recommendations in its next integrated resource plan filing.	The Company intends to comply with this requirement.

2.0 LOAD FORECAST

2.1 Summary of Load Forecast

2.1.1 Forecast Assumptions

(807 KAR 5:058 Sec. 5.2.)

The load forecasts for Kentucky Power and the other operating companies in the AEP System are based on a forecast of U.S. economic growth provided by Moody's Analytics. The load forecasts presented herein are based on a Moody's Analytics economic forecast issued in December 2012 and on Kentucky Power load experience prior to 2013. Moody's Analytics projects moderate growth in the U.S. economy during the 2014-2028 forecast period, characterized by a 2.4% annual rise in real Gross Domestic Product (GDP), and moderate inflation as well, with the implicit GDP price deflator expected to rise by 1.9% per year. Industrial output, as measured by the Federal Reserve Board's (FRB's) index of industrial production, is expected to grow at 0.6% per year during the same period. For the regional economic outlook, the December 2012 forecast developed by Moody's Analytics was utilized. The outlook for Kentucky Power's service area projects employment growth of 0.2% per year during the forecast period and real regional income per-capita growth of 2.3%.

Inherent in the load forecasts are the impacts of past customer energy conservation and load management activities, including company-sponsored EE programs already implemented. The load impacts of future, or expanded, EE programs are analyzed and projected separately, and appropriate adjustments applied to the load forecasts.

2.1.2 Forecast Highlights

Kentucky Power's total internal energy requirements, including the effects of approved EE programs, are forecasted to increase at an average annual rate of 0.1% from 2014 to 2028. The corresponding summer and winter peak internal demands are forecasted to grow at an average annual rate of 0.3% and 0.1%, respectively. Kentucky Power's annual peak demand is expected to continue to occur in the winter season.

The load effects of the continuation of approved energy efficiency (EE) programs generally increase in time through about the year 2021 and then remain relatively stable. Over the 15-year forecast period, the projected approved EE has minimal effect on load growth. The expected annual rate of growth in internal energy requirements, as well as in the summer and winter peak internal demands, after accounting for approved EE, is relatively unchanged from the growth rate without approved EE. The effects of EE and other DSM programs beyond those that have been filed will be discussed in Chapter 3.

2.2 Overview of Forecast Methodology

(807 KAR 5:058 Sec. 5.2. and Sec. 7.7.c.)

Kentucky Power's load forecasts are based mostly on econometric, supplemented with state-of-the-art statistically adjusted end-use, analyses of time-series data – producing an internally consistent forecast. This consistency is enhanced by model logic expressed in mathematical terms and quantifiable forecast assumptions. This is helpful when analyzing future scenarios and developing confidence bands. Additionally, econometric analysis lends itself to objective model verification by using standard statistical criteria. This is particularly helpful because it allows apples-to-apples comparisons of different companies and forecast periods.

In practice, econometric analysis highlights alternatives in forecasting models that may not be immediately obvious to the layperson. Likewise, professional judgment is required to interpret statistical criteria that are not always clear-cut. Kentucky Power's analysts strive to interpret this data to produce as useful and as accurate a forecast as possible.

In pursuit of that goal, Kentucky Power's energy requirements forecast is derived from two sets of econometric models: 1) a set of monthly short-term models and 2) a set of long-term models, with some using monthly data and others using annual data. This procedure permits easier adaptation of the forecast to the various short- and long-term planning purposes that it serves.

For the first full year of the forecast, the forecast values are governed exclusively by the short-term models, using billed or metered energy sales. The long-term sales are billed.

The short- and long-term forecasts are blended during the second six months of the second year of the forecast. The blending ensures a smooth transition from the short-term to the long-term forecast.

The blended sales forecasts are converted to billed and accrued energy sales, which are consistent with the energy generated.

In both sets of models, the major energy classes are analyzed separately. Inputs such as regional and national economic conditions and demographics, energy prices, weather factors, special information such as known plans of specific major customers, and informed judgment are all used in producing the forecasts. The major difference between the two is that the short-term models use mostly trend, seasonal, and weather variables, while the long-term models use structural variables, such as population, income, employment, energy prices, and weather factors, as well as trends. Supporting forecasting models are used to predict some inputs to the long-term energy models. For example, natural gas models are used to predict sectoral natural gas prices that then serve as inputs.

Either directly, through national economic inputs to the forecast models, or indirectly, through inputs from supporting models, Kentucky Power's load forecasts are influenced greatly by the outlook for the national economy. For the load forecasts reported herein, Moody's Analytic's December 2012 forecast was used as the basis for that outlook. Moody's Analytics's regional forecast, which is consistent with its national economic forecast, was used for the regional economic forecast of income, employment, households, output, and population

The demand forecast model is a series of algorithms for allocating the monthly net internal energy to hourly demand. The inputs into forecasting hourly demand are internal energy, weather, 24-hour load profiles and calendar information.

Flow charts depicting the structure of the models used in projecting Kentucky Power's electric load requirements are shown in Exhibits 2-1. **Exhibit 2-1(a)** depicts the stages in the development of the Company's short-term and long-term internal energy requirements forecasts, along with schematic of the sequential steps for the peak demand and internal energy requirements forecasting. **Exhibit 2-1(b)** identifies in greater detail the variables included in the short-term and long-term energy requirements forecasting models. Displays of model equations, including the results of various statistical tests, along with data sets, are provided in the Appendix. Customer sensitive information will be provided as Chapter 2-Confidential Appendix, Customer Sensitive Information, and is provided in the Confidential Supplement.

2.3 Forecast Methodology for Internal Energy Requirements

(807 KAR 5:058 Sec. 5.2.and Sec. 7.7.b, c. and e.)

2.3.1 General

This section provides a detailed description of the short-term and long-term models employed in producing the forecasts of Kentucky Power's energy consumption, by customer class. For the purposes of the load forecast, the short term is defined as the first two years, and the long term as the third forecast year and beyond.

Conceptually, the difference between short- and long-term energy consumption relates to changes in the stock of electricity-using equipment, rather than the passage of time. The short term covers the period during which changes are minimal, and the long term covers the period during which changes can be significant. In the short term, electric energy consumption is considered to be a function of an essentially fixed stock of equipment. For residential and commercial customers, the most significant factor influencing the short term is weather. For industrial customers, economic forces that determine inventory levels and factory orders also influence short-term utilization rates. The short-term models recognize these relationships and use weather and recent load growth trends as the primary variables in forecasting monthly energy sales.

Over time, demographic and economic factors such as population, employment, income, and technology determine the nature of the stock of electricity-using equipment, both in size and composition. Long-term forecasting models recognize the importance of these variables and include most of them in the formulation of long-term energy forecasts.

Relative energy prices also have an impact on electricity consumption. One difference between the short-term and long-term forecasting models is energy prices, which are only included in long-term forecasts. In the short-term, conusmers have little opportunity to respond to changes in price. In the long term, however, constraints are lessened as durable equipment is replaced and as price expectations come to fully reflect price changes.

2.3.2 Short-term Forecasting Models

The goal of Kentucky Power's short-term forecasting models is to produce an accurate load forecast for the first full year into the future. To that end, the short term forecasting models generally employ a combination of monthly and seasonal binaries, time trends, and monthly heating/cooling degree-days in their formulation. The heating and cooling degree-days are measured at weather stations in the Company's service area. The forecasts relied on autoregressive integrated moving average (ARIMA) models.

The estimation period for the short-term models was January 2003 through January 2013.

2.3.2.1 Residential and Commercial Energy Sales

Residential and commercial energy sales are developed using ARIMA models to forecast usage per customer and number of customers. The usage models relate usage to lagged usage, lagged error terms, heating and cooling degree-days and binary variables. The customer models relate customers to lagged customers, lagged error terms and binary variables. The energy sales forecasts are a product of the usage and customer forecasts.

2.3.2.2 Industrial Energy Sales

Short-term industrial energy sales are forecast separately for 10 large industrial customers in Kentucky and for the remainder of industrial energy customers segregated into manufacturing and mining load. These 12 short-term industrial energy sales models relate energy sales to lagged energy sales, lagged error terms and binary variables. The industrial models are estimated using ARIMA models. The short-term industrial energy sales forecast is a sum of the forecasts for the 10 large industrial customers and the forecasts for the remainder of the manufacturing and mining customers.

2.3.2.3 All Other Energy Sales

The All Other Energy Sales category for Kentucky Power includes public street and highway lighting (or other retail sales) and sales to municipals. Kentucky Power's municipal customers include the cities of Vanceburg and Olive Hill.

Both the other retail and municipal models are estimated using ARIMA models. Kentucky Power's short-term forecasting model for public street and highway lighting energy sales includes binaries, and lagged energy sales. The sales-for-resale model includes binaries, heating and cooling degree-days, lagged error terms and lagged energy sales.

2.3.3 Long-term Forecasting Models

The goal of the long-term forecasting models is to produce a reasonable load outlook for up to 30 years in the future. Given that goal, the long-term forecasting models employ a full range of structural economic and demographic variables, electricity and natural gas prices, weather as measured by annual heating and cooling degree-days, and binary variables to produce load forecasts conditioned on the outlook for the U.S. economy, for the Company's service-area economy, and for relative energy prices.

Most of the explanatory variables enter the long-term forecasting models in a straightforward, untransformed manner. In the case of energy prices, however, it is assumed, consistent with economic theory, that the consumption of electricity responds to changes in the price of electricity or substitute fuels with a lag, rather than instantaneously. This lag occurs for reasons having to do with the technical feasibility of quickly changing the level of electricity use even after its relative price has changed, or with the widely accepted belief that consumers make their consumption decisions on the basis of expected prices, which may be perceived as functions of both past and current prices.

There are several techniques, including the use of lagged price or a moving average of price that can be used to introduce the concept of lagged response to price change into an econometric model. Each of these techniques incorporates price information from previous periods to estimate demand in the current period.

The general estimation period for the long-term load forecasting models was 1990-2012. The long-term energy sales forecast is developed by blending the last half of the second year of the short-term forecast with the long-term forecast. The energy sales forecast is developed by making a billed/unbilled adjustment to derive billed and accrued values, which are consistent with monthly generation.

2.3.3.1 Supporting Models

In order to produce forecasts of certain independent variables used in the internal energy requirements forecasting models, several supporting models are used, including a natural gas price model and a regional coal production model for the Kentucky Power service area. These models are discussed below.

2.3.3.1.1 Retail Natural Gas and Electricity Pricing Forecasts

In order to produce forecasts of certain independent variables used in the long-term internal energy requirements forecasting models, a supporting forecast was developed, *i.e.,* a natural gas price forecast for the Company's service area.

The forecast price of natural gas used in Kentucky Power's energy models comes from a forecast of state natural gas prices for four primary consuming sectors: residential, commercial, industrial and electric utilities. The forecast of sectoral prices was assumed to have the same growth as the East North Central region of the U.S. sectoral prices. The regional U.S. natural gas price forecasts were obtained from U.S. DOE/EIA's 2013 Annual Energy Outlook.

The sectoral electricity prices are developed using internal information on anticipated prices for the near-term. In the long-term, electricity price growth patterns were obtained from U.S. Department of Energy / Energy Information Agency (DOE/EIA)'s 2013 Annual Energy Outlook.

2.3.3.1.2 Regional Coal Production Model

A regional coal production forecast is used as an input in the mine power energy sales model. In the coal model, regional production depends mainly on Eastern U.S. coal production, as well as on binary variables that reflect the impacts of special occurrences, such as strikes. In the development of the regional coal production forecast, projections of Eastern U.S. coal production were obtained from U.S. DOE/EIA's "2013 Annual Energy Outlook." The estimation period for the model was 1991-2012.

2.3.3.2 Residential Energy Sales

(807 KAR 5:058 Sec. 7.4.e.)

Residential energy sales for Kentucky Power are forecasted using two models, the first of which projects the number of residential customers, and the second of which projects kWh usage per customer. The residential energy sales forecast is calculated as the product of the corresponding customer and usage forecasts.

2.3.3.2.1 Residential Customer Forecasts

The long-term residential customer forecasting model is linear and monthly. The model for the Company's service area is depicted as follows:

$$Customers = f(population, employment, customers_{-1})$$

The population provides a measure for household formation, while service area employment provides a measure of economic growth in the region, which will also affect customer growth. The lagged dependent variable captures the adjustment of customer growth to changes in the economy. There are also binary variables to capture monthly variations in customers, unusual data points and special occurrences.

The customer forecast is blended with the short-term residential customer forecast to produce a final forecast.

2.3.3.2.2 Residential Energy Usage Per Customer

The residential usage model is estimated using a Statistically Adjusted End-Use Model (SAE), which was developed by Itron, a consulting firm with expertise in energy modeling. This model assumes that use will fall into one of three categories: heat, cool and other. The SAE model constructs variables to be used in an econometric equation like the following:

$$Use = f(Xheat, Xcool, Xother)$$

The Xheat variable is derived by multiplying a heating index variable by a heating use variable. The heating index incorporates information about heating equipment saturation; heating equipment efficiency standards and trends; and thermal integrity and size of homes. The heating use variable is derived from information related to billing days, heating degree-days, household size, personal income, gas prices and electricity prices.

The Xcool variable is derived by multiplying a cooling index variable by a cooling use variable. The cooling index incorporates information about cooling equipment saturation; cooling equipment efficiency standards and trends; and thermal integrity and size of homes. The cooling use variable is derived from information related to billing days, heating degree-days, household size, personal income, gas prices and electricity prices.

The Xother variable estimates the non-weather sensitive sales and is similar to the Xheat and Xcool variables. This variable incorporates information on appliance and equipment saturation levels; average number of days in the billing cycle each month; average household size; real personal income; gas prices and electricity prices.

The appliance saturations are based on historical trends from Kentucky Power's residential customer survey. The saturation forecasts and and efficiency trends are based on DOE forecasts and analysis by Itron. The thermal integrity and size of homes are for the East North Central Census Region and are based on DOE and Itron data.

The number of billing days is from internal data. Economic and demographic forecasts are from Moody's Analytics and the electricity price forecast is developed internally.

The SAE model is estimated using a linear regression model. It is a monthly model for the period January 1995 through February 2013. This model incorporates the effects of the Energy Policy Act of 2005 (EPAct 2005), the Energy Independence and

Security Act of 2007 (EISA 2007), American Recovery and Reinvestment Act of 2009 (ARRA) and Energy Improvement and Extension Act of 2008 (EIEA 2008) on the residential energy.

The long-term residential energy sales forecast is derived by multiplying the "blended" customer forecast by the usage forecast from the SAE model.

2.3.3.3 Commercial Energy Sales
(807 KAR 5:058 Sec. 7.4.e.)

Long-term commercial energy sales are forecast using a SAE model. This model is similar to the residential SAE model. The functional model is as follows:

$$Energy = f(Xheat, Xcool, Xother)$$

As with the residential model, Xheat is determined by multiplying a heating index by a heat use variable. The variables incorporate information on heating degree-days, heating equipment saturation, heating equipment operating efficiencies, square footage, average number of days in a billing cycle, commercial output, population and electricity price.

The Xcool variable uses measures similar to the Xheat variable, except it uses information on cooling degree-days and cooling equipment, rather than those items related to heating load.

The Xother variable measures the non-weather sensitive commercial load. It uses non-weather sensitive equipment saturations and efficiencies, as well as billing days, commercial output and electricity price information.

The saturation, square footage and efficiencies are from the Itron base of DOE data and forecasts. The saturations and related items are from DOE's *2012 Annual Energy Outlook*. Billing days and electricity prices are developed internally. The commercial output measure is real commercial gross regional product from Moody's Analytics. The equipment stock and square footage information are for the East North Central Census Region.

The SAE is a linear regression for the period January 2000 through February 2013. As with the residential SAE model, the effects of EPAct 2005, EISA 2007, ARRA and EIEA 2008 are captured in this model.

2.3.3.4 Industrial Energy Sales

2.3.3.4.1 Manufacturing

Manufacturing energy sales are estimated using a quarterly model, which is depicted as follows:

$$Energy = f(electricprice, metal\sin dex, grpmanufacturing)$$

The manufacturing forecasting model relates energy sales to real price of electricity, FRB production indexes for primary metals, gross regional product for manufacturing and binary variables. The prices are modeled using 36-month moving averages. The dependent and independent variables are modeled in logarithmic form.

2.3.3.4.2 Mine Power

Mine Power energy sales are estimated using a quarterly model, which is depicted as follows:

$$Energy = f(electricprice, coalproduction)$$

The forecast of Kentucky Power's mine power energy consumption for non-associated mining companies is produced with a model relating mine power energy sales to regional coal production and a 36-month moving average of electric price to mine power customers. This model is specified as linear, with the dependent and independent variables in logarithmic form.

2.3.3.5 All Other Energy Sales

The forecast of public street and highway lighting relates energy sales to service area commercial employment and binary variables. The model is specified as linear with the dependent and variable in linear form and the independent variable in logarithmic form.

The municipal energy sales model is specified as linear. Municipal energy sales are modeled relating energy sales to service area gross regional product, electricity prices, heating and cooling degree-days and binary variables.

2.3.3.6 Blending Short- and Long-Term Sales

Values for the portion of the forecast horizon from March 2013 to December 2014 are generally taken from the short-term process. Values for the period of January 2015 to June 2015 are generally obtained by blending the results from the short-term and long-term models. This blending process combines the two forecasts by assigning weights to each forecasted value where these weights transition from favoring the short-term values initially to favoring the long-term values by the end of the blending period. Beyond the blending period, the long-term values are utilized. However, in the case of Kentucky Power, two of the retail classes (industrial and other ultimate) and one of the wholesale customers utilized the long-term forecast throughout the forecast horizon in order to best utilize the long-term methodology's capability of anticipating turning points in economic growth.

2.3.3.7 Billed/Unbilled and Losses

a. Billed/Unbilled Analysis

Unbilled energy sales are forecast using the same methodology that is used by the Company to compute actual unbilled sales each month as part of its closing process. The Company starts with the projected monthly internal energy requirements forecast, subtracts the forecasted billed sales and estimate for line losses to derive the forecasted net unbilled sales.

b. Losses and Unaccounted-For Energy

Energy is lost in the transmission and distribution of the product. This loss of energy from the source of production to consumption at the premise is measured as the average ratio of all FERC revenue class energy sales measured at the premise meter to the net internal energy requirements metered at the source. In modeling, Company loss study results are incorporated to apply losses to each revenue class.

2.4 Forecast Methodology for Seasonal Peak Internal Demand

(807 KAR 5:058 Sec. 5.2. and Sec. 7.7.b and c.)

The demand forecast model is a series of algorithms for allocating the monthly blended FERC revenue class sales to hourly demand. The inputs into forecasting hourly demand are blended FERC revenue class sales, energy loss multipliers, weather, 24-hour load profiles and calendar information.

The weather profiles are developed from representative weather stations in the service area. Twelve monthly profiles of average daily temperature that best represent the cooling and heating degree-days of the specific geography are taken from the last 30 years of historical values. The consistency of these profiles ensures the appropriate diversity of the company loads.

The 24-hour load profiles are developed from historical hourly company or jurisdictional load and end-use or revenue class hourly load profiles. The load profiles were developed from segregating, indexing and averaging hourly profiles by season, day types (weekend, midweek and Monday/Friday) and average daily temperature ranges. The end-use and class profiles were obtained from Itron, Inc. Energy Forecasting load shape library and modeled to represent each company or jurisdiction service area.

In forecasting, the weather profiles and calendars dictate which profile to apply and the sales plus losses results dictate the volume of energy under the profile. In the end, the profiles are benchmarked to the aggregate energy and seasonal peaks through the adjustments to the hourly load duration curves of the annual 8,760 hourly values. These 8,760 hourly values per year are the forecast load of the individual companies of AEP-East that can be aggregated by hour to represent load across the spectrum from end-use or revenue classes to total AEP in the PJM AEP Zone. Net internal energy requirements are the sum of these hourly values to a total company energy need basis. Company peak demand is the maximum of the hourly values from a stated period (month, season or year).

2.5 Load Forecast Results

2.5.1 Load Forecast Including Approved EE Impacts (Base Forecast)

(807 KAR 5:058 Sec. 7.1.c.-g., Sec. 7.3, Sec. 7.4.a-d, Sec.7.5.b.1.-2.)

Exhibit 2-2 presents Kentucky Power's annual internal energy requirements, disaggregated by major category (residential, commercial, industrial and other internal sales, as well as losses) on an actual basis for the years 2008-2012 and on a forecast basis for the years 2014-2028, with 2013 data being nine months actual and three months forecast. The exhibit also shows annual growth rates for both the historical and forecast periods. Please note that the residential load is forecast in aggregate and the distinction between heating and non-heating load is reflected in the heating saturations contained in the SAE model.

Exhibit 2-3 shows for Kentucky Power actual and forecasted summer, winter and annual peak internal demands, along with annual total energy requirements. Also shown are the associated growth rates and annual load factors.

Exhibit 2-4 shows further disaggregation of Kentucky Power's forecasted annual internal energy requirements, along with the associated summer and winter peak demands. **Exhibits 2-5** and **2-6** show, for the first two full years of the forecast period, *i.e.,* 2014 and 2015, Kentucky Power's disaggregated energy requirements on a monthly basis, along with monthly peak demands.

2.5.2 Load Forecast Excluding EE Impacts

(807 KAR 5:058 Sec. 7.1.c-g., Sec. 7.2.g., Sec. 7.3. and Sec. 7.4.a.-d, Sec. 7.5.b.1 and Sec. 7.5.b.2. and Sec. 8.4.a.6.)

Exhibit 2-7 lists the approved EE adjustments (discussed in Chapter 3) that were used in the base forecasts of internal energy requirements and seasonal peak internal demands by the Company. The resulting forecasts, which reflect the load prior to these adjustments, are presented in **Exhibits 2-8** through **2-12** in the same order as Exhibits 2-2 to 2-6.

2.6 Impact of Conservation and Demand-Side Management

(807 KAR 5:058 Sec. 7.4.d.)

Since the mid-1970s, conservation, caused in part by higher energy prices and in part by Company-sponsored conservation and DSM programs, has reduced the rate of growth of energy sales and peak demand on the entire AEP System and its operating companies.

Higher energy prices and regulatory requirements have stimulated technological improvements in the EE of new electric appliances and industrial machinery, and in the thermal integrity of residential and commercial structures. The effect of these improvements has been to decrease average electricity consumption per customer. It is also believed that higher energy prices have had the effect of inducing a permanent change in consumer attitudes toward energy conservation, which has tended to reduce average energy consumption at all levels of price and technological development.

The Company has recognized both its responsibility to encourage its customers to make wise use of all energy resources, and its expertise in the field of energy consumption planning, and has for some years pursued the policy of providing its customers with opportunities to use energy wisely. It has done so through both educational programs and active promotional programs aimed at broad customer groups. And, through its DSM programs, the Company has maintained an active interest and participation in various programs for improving the cost-effectiveness of customer electricity use. Descriptions of the Company's efforts in this regard are given in Chapter 3 of this report.

As for the load forecast, the impact of conservation on load is captured by the inclusion of energy price variables in the forecasting equations. The impact of past customer conservation and load management activities, including embedded EE installations, is part of the historical record of electricity use, and, in that sense, is intrinsically reflected in the load forecast. The load impacts of approved EE installations are analyzed and projected separately, and appropriate adjustments are made to derive the base load forecast.

The use of the SAE models for the residential and commercial sectors has enabled the Company to capture the anticipated effects of EPAct 2005, EISA 2007, ARRA and EIEA 2008. The SAE models reflect not only equipment efficiencies, but also factors related to the building stock. These models reflect the EIA assessment of efficiency trends as provided in the *2012 Annual Energy Outlook.*

2.7 Energy-Price Relationships

(807 KAR 5:058 Sec. 7.7.e.1.)

An understanding of the relationship between energy prices and energy consumption is crucial to developing a forecast of electricity consumption. In theory, the effect of a change in the price of a good on the consumption of that good can be disaggregated into two effects, the "income" effect and the "substitution" effect. The income effect refers to the change in consumption of a good attributable to the change in real income incident to the change in the price of that good. For most goods, a decline in real income would induce a decline in consumption. The substitution effect refers to the change in the consumption of a good associated with the change in the price of that good relative to the prices of all other goods. The substitution effect is assumed to be negative in all cases; that is, a rise in the price of a good relative to other, substitute goods would induce a decline in consumption of the original good. Thus, if the price of electricity were to rise, the consumption of electricity would fall, all other things being equal. Part of the decline would be attributable to the income effect; consumers must make decisions on how to allocate their budget to purchase electricity services and other goods and services after the price of electricity rises. Part would be attributable to the substitution effect; consumers would substitute relatively cheaper fuels for electricity once its price had risen.

The magnitude of the effect of price changes on consumption differs over different time horizons. In the short-term, the effect of a rise in the price of electricity is severely constrained by the ability of consumers to substitute other fuels or to incorporate more electricity-efficient technology. (The fact that the Company's short-term energy consumption models do not include price as an explanatory variable is a reflection of the belief that this constraint is severe).

In the long-term, however, the constraints on substitution are lessened for a number of reasons. First, durable equipment stocks begin to reflect changes in relative energy prices by favoring the equipment using the fuel that was expected to be cheaper; second, heightened consumer interest in saving electricity, backed by willingness to pay for more efficiency, spurs development of conservation technology; third, existing technology, too expensive to implement commercially at previous levels of energy prices, becomes feasible at the new, higher energy prices; and fourth, normal turnover of electricity-using equipment contributes to a higher average level of EE. For these reasons, energy price changes are expected to have an effect on long-term energy consumption levels. As a reflection of this belief, most of the Company's long-term forecasting models, including the residential, commercial, manufacturing and mine power energy sales models, directly incorporate the price of electricity as an explanatory variable. In these cases, the coefficient of the price variable provides a quantitative measure of the sensitivity of the forecast value to a change in price. The residential models also incorporate the price of natural gas to consumers in the state of Kentucky.

For these reasons, energy price changes are expected to have an effect on long-term energy consumption levels. As a reflection of this belief, most of the Company's long-term forecasting models, including the residential, commercial, manufacturing and mine power energy sales models, incorporate the price of electricity as an explanatory variable. The residential Statistically Adjusted End-Use (SAE) Model uses price in development of explanatory variables. There are a variety of short- and long-run elasticities utilized in this analysis. In addition to electricity prices, the residential SAE model utilizes the price of natural gas and associated cross-price elasticities. Likewise, the commercial SAE model incorporates electricity price and an associated price elasticity to develop explanatory variables. Manufacturing and mine power have price as an explanatory variable. In these cases, the coefficient of the price variable provides a quantitative measure of the sensitivity of the forecast value to a change in price.

2.8 Forecast Uncertainty and Range Of Forecasts

(807 KAR 5:058 Sec. 7.7.d.)

Even though load forecasts are created individually for each of the operating companies in the AEP-East Zone, and aggregated to form the AEP–East Zone total, forecast uncertainty is of primary interest at the System level, rather than the operating company level. Thus, regardless of how forecast uncertainty is characterized, the analysis begins with AEP-East Zone load.

Among the ways to characterize forecast uncertainty are: (1) the establishment of confidence intervals with a given percentage of possible outcomes, and (2) the development of high- and low-case scenarios that demonstrate the response of forecasted load to changes in driving-force variables. Kentucky Power continues to support both approaches. However, this report uses scenarios for capacity planning sensitivity analyses.

The first step in producing high- and low-case scenarios was the estimation of an aggregated "mini-model" of AEP System–East Zone internal energy requirements. This approach was deemed more feasible than attempting to calculate high and low cases for each of the many equations used to produce the load forecasts for all operating companies. The mini-model is intended to represent the full forecasting structure employed in producing the base-case forecast for the AEP System–East Zone and, by association, for the Company. The dependent variable is total AEP System–East Zone internal energy requirements, excluding sales to the two aluminum reduction plants in the AEP System–East Zone service area. This aluminum load is a large and volatile component of total load, which is treated judgmentally, not analytically, in the load forecast. It is simply added back to the alternative forecasts produced by the mini-model to create low- and high-case scenarios for total internal energy requirements. The independent variables are real service area gross regional product (GRP), the average real price of electricity to all AEP System–East Zone customer classes, the average real price of natural gas in the seven states served by AEP System–East Zone, and AEP System–East Zone service-area heating and cooling degree-days. Acceptance of this particular specification was based on the usual statistical tests of goodness-of-fit, on the reasonableness of the elasticity's derived from the estimation, and on a rough agreement between the model's load prediction and that produced by the disaggregated modeling approach followed in producing the base load forecast.

Once a base-case energy forecast had been produced with the mini-model, low and high values for the independent variables were determined. The values finally decided upon reflected professional judgment. The low- and high-case growth rates in real GRP for the forecast period were 1.1% and 2.3% per year, respectively, compared to 1.8% for the base case. Real electricity price high and low cases assumed average annual growth rates of 0.5% and 0.3%, respectively. Meanwhile, the base case for real electricity price assumed an average annual growth of 0.4%. Variations in weather were not considered, thus the value of heating and cooling degree-days remained the same in all cases.

For Kentucky Power, the low-case and high-case energy and peak demand forecasts for the last forecast year, 2028, represent deviations of about 8% below and 6% above, respectively, the base-case forecast. In this regard, the low-case and high-case growth rates in summer peak internal demand for the forecast period were -0.3% and 0.7% per year, respectively, compared to 3% per year for the base case.

The low-case, base-case and high-case forecasts of summer and winter peak demands and total energy requirements (including approved EE impacts) for Kentucky Power are tabulated in **Exhibits 2-13**. Graphical displays of the range of forecasts of internal energy requirements and summer peak demand for Kentucky Power are shown in **Exhibit 2-14**.

The corresponding range of load forecasts excluding approved EE impacts is shown in **Exhibits 2-15**.

2.9 Significant Changes from Previous Forecast

(807 KAR 5:058 Sec. 6)

2.9.1 Energy Forecast

During the four years since the last IRP filing with the Commission, the nation's and Kentucky Power's service areas economies have all experienced significant changes and therefore the load forecast for Kentucky Power reflects a more modest outlook.

Exhibit 2-16 provides a tabular comparison of the 2009 and 2013 forecasts of total internal energy requirements (including EE impacts). **Exhibit 2-17** shows the comparison for Kentucky Power in graphical form. As these exhibits indicate, Kentucky Power's 2013 energy forecast is lower than the 2009 forecast in terms of magnitude (1,950 GWh, or 21.7%, lower for year 2023) and long-term average annual growth rate (0.2% vs. 0.7%).

An examination of the sectoral changes in the Kentucky Power forecast may provide a better understanding of the changes in the aggregate forecast. The forecasted levels of the sectoral components for the year 2023 did not change uniformly with the 21.7% decrease in the forecast of total energy requirements. Specifically, the residential, commercial and industrial energy sales forecasts were decreased by 9.7%, 19.2%, and 25.7%, respectively, while the losses forecast was decreased by 46.0%.

Factors contributing to the decrease in the residential and commercial energy sales forecasts include impacts of a sluggish economy, deteoriating residential customer base, a re-evaluation of expected long-term trends in residential and commercial consumption patterns in light of what has been experienced historically. The changed assumptions reflect the effect of updated information obtained or developed since the 2009 forecast, along with changing perceptions of the future.

For the industrial sector, the decrease reflects more recent trends that have evolved since the 2008-09 recession. In addition, the coal industry faces more downward pressures that have negatively affected the forecast.

2.9.2 Peak Internal Demand Forecast

Exhibit 2-18 provides a tabular comparison of the 2009 and 2013 forecasts of the winter and summer peak internal demand (including EE impacts) for both. This exhibit indicates that for the winter of 2023/24, Kentucky Power's 2013 peak demand forecast is 20.1% lower than the 2009 forecast. Likewise, the Company's 2013 peak demand forecast for summer 2023 is 22.0 % lower than 2009 forecast. These decreases reflect the change in the forecast for total energy requirements and an evaluation of the weather normal peak experience.

2.9.3 Forecasting Methodology

(807 KAR 5:058 Sec. 7.7.f)

Opportunities to enhance forecasting methods are explored by Kentucly Power on a continuing basis. The Company evaluates each sector for changing growth patterns and determines the factors that may be the underlying causes for such changes. For example, the industrial forecast was lowered due to a changing economic landscape and diminished expectations for the coal industry.

2.10 Additional Load Information

(807 KAR 5:058 Sec. 7.1.a. and b., Sec. 7.2.a-f. and h., Sec. 7.5.a.1 and 2 and Sec. 7.7.g.)

Additional information provided for the purposes of this report includes the following:

- **Exhibit 2-19**: Kentucky Power, Average Annual Number of Customers by Class, 2008-2012.
- **Exhibits 2-20** and **2-21**: Kentucky Power, Annual Internal Load by Class (GWh), 2008-2012.
- **Exhibits 2-22** and **2-23**: Kentucky Power Recorded and Weather-Normalized Peak Internal Load (MW) and Energy Requirements (GWh), 2008-2012. In addition, Normalized Annual Internal Sales by Class (GWh), 2008-2012.
- **Exhibit 2-24**: Kentucky Power, Profiles of Monthly Peak Internal Demands, 2007 2012 (Actual), 2022 and 2027.

The historical profiles presented in Exhibit 2-22 have not been adjusted to reflect normal weather patterns and, therefore, may vary to some degree from the forecast patterns projected for 2022 and 2027. These patterns also reflect the expectation that Kentucky Power will continue to experience its annual peak demand in the winter season.

Currently, the Company has one customer with interruptible provisions in its contracts. The Company conducted its most recent residential customer survey in the winter of 2013. However, the survey was not completed in time to be used in the load forecast contained in this report and the previous survey was relied upon. As in the past, this updated survey will provide information on appliance saturations, along with other useful information to better understand the residential load.

2.11 Data-Base Sources

Sources from within the Company that were used in developing the Company's load forecasts are as follows:

1. Sales for Resale Reports (Form ST-18);
2. daily, monthly and annual System Operation Department reports;
3. monthly financial reports;
4. monthly kWh and revenue SIC reports; and
5. residential tariff schedules and fuel clause summaries for all operating companies.

The data sources from outside the Company are varied and include state and federal agencies, as well as Moody's Analytics. **Exhibit 2-25** identifies the data series and associated sources, along with notes on adjustments made to the data before incorporation into the load forecasting models.

2.12 Other Topics

2.12.1 Residential Energy Sales Forecast Performance

Exhibit 2-26 provides a comparison of actual vs. the 2009 forecast of Kentucky Power's residential energy sales for the years 2009-2012. The gap between actual and forecast residential energy sales generally widened over the four-year period. During this period the number of residential customers declined. Another factor affecting sales is the impact of more stringent efficiency standards being mandated by Congress. Both of these factors will continue to have major influences on residential energy sales over the forecast period.

2.12.2 Peak Demand Forecast Performance

Exhibit 2-27 provides a comparison of actual vs. the 2009 forecast of Kentucky Power's seasonal internal peak demands for 2009-2012. The exhibit also compares the calculated weather-normalized demands with the forecast values, thus indicating the extent to which weather affected actual demands.

There have been many changes in the local service over the four years since the 2009 forecast was filed. For, example the residential customer base has eroded, there have been additional energy legislation enacted and the commercial and industrial sectors experienced load decreases between 2009 and 2012. Items, such as these, have contributed to a diminished outlook for peak demand growth. In addition, recent trends in normalized demand growth are evaluated when developing the forecast.

2.12.3 Forecast Updates

(807 KAR 5:058 Sec. 7.6.)

Each year the Company provides updates to the load forecast in response to requests related to Administrative Case 387.

2.12.4 KPSC Staff Issues Addressed

On March 4, 2011, the Commission issued their Staff's report on Kentucky Power's 2009 IRP and requested that the Company address certain issues in its next IRP report (this report). The following issues pertaining to load forecasting are restated from the Staff report and addressed below:

1. **Kentucky Power should consider disaggregating its residential customer class in its SAE models to gain further insight into usage patterns and future energy needs. Disaggregating the commerical class may also provide additional insights.**

   The Company has disaggrated its residential forecast into heating, cooling, lighting and other energy, Also, the Company has disaggregated its commercial sector into heating, cooling and other energy. Both of these disaggregations are used in the development of the peak demand forecast.

2. **Provide a comparison of forecasted winter and summer peak demands with actual results for the period following Kentucky Power's 2009 IRP, along with a discussion of the reasons for the differences between forecasted and actual peak demands.**

   See Section 2.12.2 where this issue has been addressed.

3. **Provide a comparison of the annual forecast of residential energy sales, using the current econometric models, with actual results for the period following the 2009 IRP. Include a discussion of the reasons for the differences between forecasted and actual results.**

   See Section 2.12.1 where this issue has been addressed.

4. **Given that Kentucky Power's service area economy is not expected to perform as well as the rest of the region, the possibilityof either federal emissions-limiting legislation or targeted EPA actions limiting various emissions may have significant impacts on Kentucky Power's service territory. In its next IRP, Kentucky Power should explicitly account for potential federal legislation imposing stricter emissions limits on its generation in its forecasts and risk analysis. Potential EPA actions limiting emissions should also be explicitly accounted for in the forecasts and risk analysis.**

   The Company's risk analysis for its resource portfolio considers the impacts of various Federal mandates. The load forecast includes an outlook of rising prices over the forecast horizon, which were determined by internal company information and EIA price outlook in the longer term. The timing and impact of specific rules and regulations have not been evaluated, but rising prices are consistent with more stringent environmental standards.

2.13 Chapter 2 Exhibits

The exhibits related to Chapter 2 follow:

Exhibit 2-1(a)

Kentucky Power Company Internal Energy Requirements and Peak Demand Forecasting Method

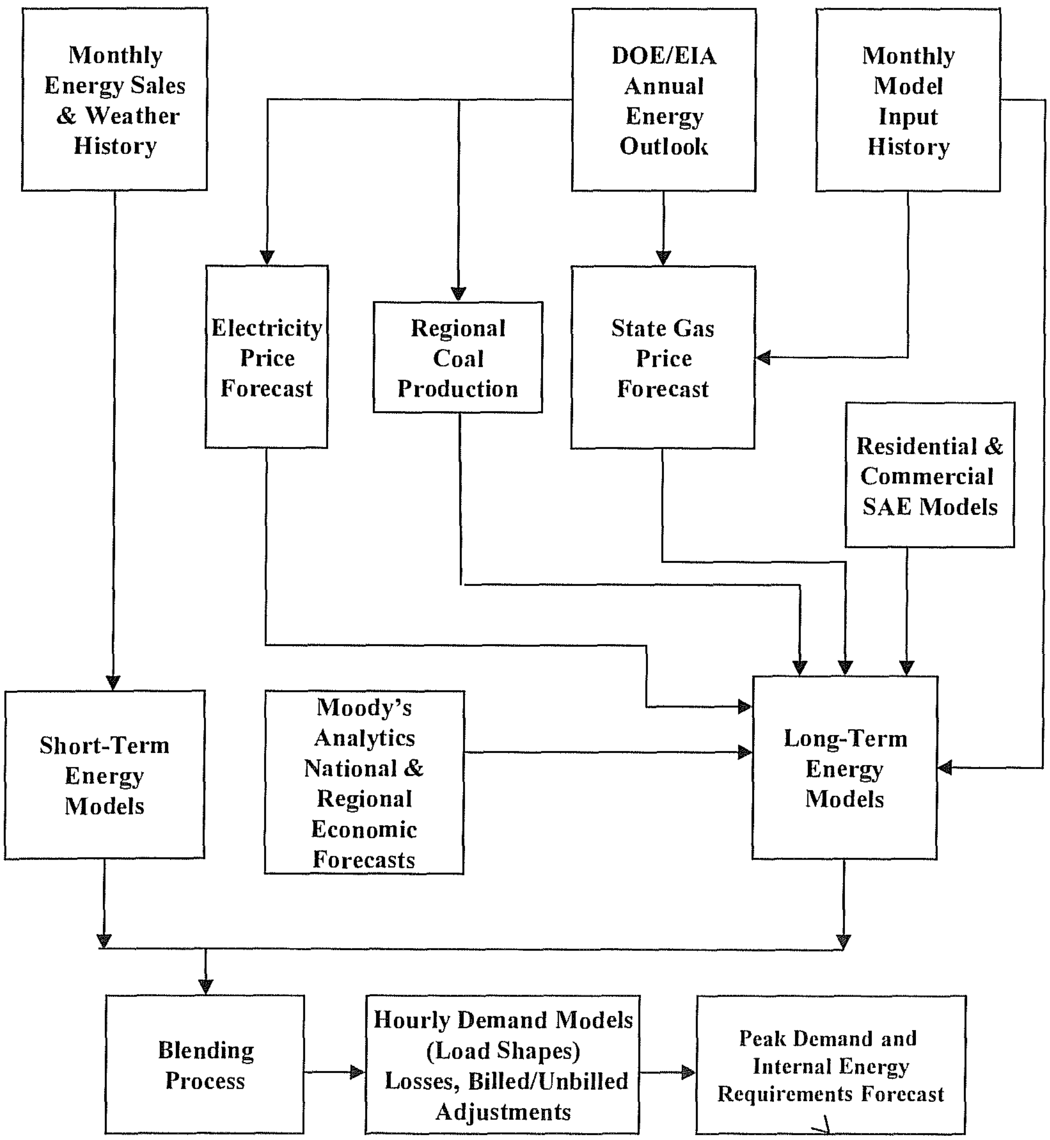


Exhibit 2-1(b)

KENTUCKY POWER COMPANY
VARIABLES EMPLOYED IN FORECAST MODELS OF ENERGY SALES

	Residential Customers		Residential Energy Sales		Commercial Customers	Commercial Energy Sales		Manufacturing Energy Sales		Mine Power Energy Sales		All Other Energy Sales	
Variable	Short Term	Long Term	Short Term	Long Term	Short Term	Short Term	Long Term	Short Term	Long Term	Short Term	Long Term	Short Term	Long Term
Binary	X	X	X	X	X	X	X	X	X	X	X	X	X
Time Trend	X		X	X	X	X		X		X		X	
Electricity Price				X			X		X		X		X
Natural Gas Price				X									X
Residential Appliance Saturations				X									
Service Area Employment		X											
Service Area Personal Income				X									
Service Area Population		X		X			X						
Residential Customers				X									
Heating Degree-Days			X	X		X	X					X	X
Cooling Degree-Days			X	X		X						X	X
Gross Regional Product							X		X				X
FRB Industrial Production Index									X				
Commercial Employment													X
Coal Production											X		

Exhibit 2-2

Kentucky Power Company
Annual Internal Energy Requirements and Growth Rates
2008-2028

Including EE Impacts

	Residential Sales		Commercial Sales		Industrial Sales		Other Internal Sales		Losses		Total Internal Energy Requirements	
	GWH	% Growth	GWH	% Growth	GWH	% Growth	GWH	% Growth	GWH	% Growth	GWH	% Growth
Actual												
2008	2,481	--	1,429	--	3,322	--	110	--	568	--	7,910	--
2009	2,426	-2.2	1,426	-0.2	3,206	-3.5	104	-5.7	395	-30.5	7,557	-4.5
2010	2,614	7.7	1,469	3.0	3,256	1.5	112	7.5	474	20.1	7,924	4.9
2011	2,342	-10.4	1,381	-6.0	3,250	-0.2	105	-6.4	470	-0.8	7,548	-4.8
2012	2,241	-4.3	1,350	-2.2	3,060	-5.9	105	0.0	400	-15.0	7,155	-5.2
Forecast												
2013 (1)	2,292	2.3	1,337	-0.9	2,895	-5.4	105	0.0	464	16.1	7,093	-0.9
2014	2,267	-1.1	1,346	0.7	2,828	-2.3	106	1.6	410	-11.7	6,958	-1.9
2015	2,247	-0.9	1,351	0.3	2,838	0.3	107	1.0	410	0.0	6,953	-0.1
2016	2,245	-0.1	1,355	0.3	2,853	0.5	109	1.1	409	-0.2	6,970	0.3
2017	2,236	-0.4	1,359	0.3	2,866	0.5	109	0.6	405	-1.1	6,975	0.1
2018	2,231	-0.2	1,361	0.1	2,869	0.1	110	0.5	407	0.6	6,979	0.1
2019	2,231	0.0	1,364	0.2	2,873	0.1	110	0.5	407	-0.1	6,986	0.1
2020	2,226	-0.2	1,368	0.3	2,883	0.3	111	0.5	410	0.7	6,997	0.2
2021	2,225	0.0	1,376	0.6	2,893	0.4	112	0.5	406	-0.9	7,012	0.2
2022	2,223	-0.1	1,382	0.5	2,910	0.6	112	0.5	409	0.7	7,036	0.3
2023	2,222	0.0	1,390	0.6	2,921	0.4	113	0.5	411	0.4	7,056	0.3
2024	2,223	0.0	1,398	0.6	2,927	0.2	113	0.4	411	0.1	7,072	0.2
2025	2,225	0.1	1,408	0.7	2,932	0.2	114	0.4	410	-0.2	7,090	0.2
2026	2,227	0.1	1,418	0.7	2,941	0.3	114	0.4	412	0.4	7,112	0.3
2027	2,229	0.1	1,426	0.6	2,949	0.3	115	0.4	415	0.9	7,134	0.3
2028	2,234	0.2	1,436	0.7	2,957	0.3	115	0.3	416	0.1	7,158	0.3
Average Annual Growth Rates:												
2008-2012		-2.5		-1.4		-2.0		-1.3		-8.4		-2.5
2014-2028		-0.1		0.5		0.3		0.6		0.1		0.2

Note: (1) Data for 2013 are nine months actual and three months forecast.

Exhibit 2-3

Kentucky Power Company
Seasonal and Annual Peak Demands, Energy Requirements and Load Factor
2008-2028

Including EE Impacts

	Summer Peak			Winter Peak (1)			Annual Peak, Energy and Load Factor				
	Date	MW	% Growth	Date	MW	% Growth	MW	% Growth	GWH	% Growth	Load Factor %
Actual											
2008	06/09/08	1,249	--	01/16/09	1,674	--	1,678	--	7,910	--	53.7
2009	08/10/09	1,163	-6.9	01/08/10	1,543	-7.8	1,674	-0.2	7,557	-4.5	51.5
2010	08/04/10	1,310	12.6	12/15/10	1,596	3.4	1,596	-4.7	7,924	4.9	56.7
2011	07/11/11	1,240	-5.3	01/04/12	1,378	-13.7	1,522	-4.6	7,548	-4.8	56.6
2012	06/29/12	1,183	-4.6	01/23/13	1,409	2.2	1,378	-9.5	7,155	-5.2	59.1
Forecast											
2013 (2)		1,138	-3.8		1,432	1.6	1,409	2.2	7,093	-0.9	57.5
2014		1,132	-0.5		1,431	-0.1	1,432	1.6	6,958	-1.9	55.5
2015		1,133	0.1		1,432	0.1	1,431	-0.1	6,953	-0.1	55.5
2016		1,134	0.1		1,431	0.0	1,432	0.1	6,970	0.3	55.6
2017		1,137	0.2		1,431	0.0	1,431	0.0	6,975	0.1	55.6
2018		1,139	0.2		1,432	0.1	1,431	0.0	6,979	0.1	55.7
2019		1,141	0.2		1,430	-0.1	1,432	0.1	6,986	0.1	55.7
2020		1,142	0.1		1,436	0.4	1,430	-0.1	6,997	0.2	55.8
2021		1,149	0.6		1,439	0.2	1,436	0.4	7,012	0.2	55.7
2022		1,154	0.4		1,438	0.0	1,439	0.2	7,036	0.3	55.8
2023		1,157	0.2		1,438	-0.1	1,438	0.0	7,056	0.3	56.0
2024		1,158	0.1		1,444	0.5	1,438	-0.1	7,072	0.2	56.2
2025		1,166	0.6		1,448	0.3	1,444	0.5	7,090	0.2	56.0
2026		1,171	0.4		1,452	0.3	1,448	0.3	7,112	0.3	56.0
2027		1,176	0.5		1,454	0.1	1,452	0.3	7,134	0.3	56.1
2028		1,179	0.3		1,459	0.4	1,454	0.1	7,158	0.3	56.2
Average Annual Growth Rates:											
2008-2012			-1.3			-4.2		-4.8		-2.5	
2014-2028			0.3			0.1		0.1		0.2	

Notes: (1) Actual winter peak for year may occur in the 4th quarter of that year or in the 1st quarter of the following year.
(2) Data for 2013 are nine months actual and three months forecast.

Exhibit 2-4

Kentucky Power Company
Annual Internal Load
2014-2023

Including EE Impacts

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Internal Energy (GWH)															
Residential	2,267	2,247	2,245	2,236	2,231	2,231	2,226	2,225	2,223	2,222	2,223	2,225	2,227	2,229	2,234
Commercial	1,346	1,351	1,355	1,359	1,361	1,364	1,368	1,376	1,382	1,390	1,398	1,408	1,418	1,426	1,436
Industrial	2,828	2,838	2,853	2,866	2,869	2,873	2,883	2,893	2,910	2,921	2,927	2,932	2,941	2,949	2,957
Total Other Ultimate	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
Total Ultimate Sales	6,453	6,446	6,463	6,472	6,472	6,479	6,487	6,505	6,525	6,544	6,559	6,577	6,597	6,615	6,638
Municipals	96	97	98	98	99	100	100	101	101	102	102	103	103	104	104
Total Sales-for-Resale	96	97	98	98	99	100	100	101	101	102	102	103	103	104	104
Total Internal Sales	6,548	6,543	6,561	6,570	6,571	6,579	6,588	6,605	6,627	6,646	6,661	6,680	6,700	6,719	6,742
Total Losses	410	410	409	405	407	407	410	406	409	411	411	410	412	415	416
Total Internal Energy	6,958	6,953	6,970	6,975	6,979	6,986	6,997	7,012	7,036	7,056	7,072	7,090	7,112	7,134	7,158
Internal Peak Demand (MW)															
Summer	1,132	1,133	1,134	1,137	1,139	1,141	1,142	1,149	1,154	1,157	1,158	1,166	1,171	1,176	1,179
Preceding Winter	1,431	1,432	1,431	1,431	1,432	1,430	1,436	1,439	1,438	1,438	1,444	1,448	1,452	1,454	1,459

Exhibit 2-5
Kentucky Power Company
Monthly Internal Load
2014

Including EE Impacts

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Internal Energy (GWH)													
Residential	302.5	232.8	216.3	136.9	133.1	154.3	190.4	184.2	141.5	142.4	171.3	261.6	2,267
Commercial	126.1	105.3	112.3	98.8	109.2	114.2	121.0	117.1	106.7	118.8	102.3	114.4	1,346
Industrial	234.9	219.9	242.8	233.9	247.9	232.6	225.9	235.3	213.4	256.1	245.5	240.2	2,828
Total Other Ultimate	1.1	0.9	0.9	0.8	0.8	0.7	0.7	0.8	0.8	1.0	1.0	1.1	11
Total Ultimate Sales	664.6	558.8	572.3	470.4	491.0	501.8	538.0	537.5	462.5	518.4	520.1	617.2	6,453
Municipals	10.6	8.6	7.9	6.9	6.6	7.4	8.6	8.5	7.0	7.1	7.6	9.0	96
Total Sales-for-Resale	10.6	8.6	7.9	6.9	6.6	7.4	8.6	8.5	7.0	7.1	7.6	9.0	96
Total Internal Sales	675.2	567.4	580.2	477.3	497.6	509.1	546.6	545.9	469.5	525.5	527.7	626.2	6,548
Total Losses	54.0	45.3	16.9	38.3	20.1	40.9	30.2	43.8	37.7	-6.1	42.3	46.6	410
Total Internal Energy	729.2	612.7	597.1	515.6	517.6	550.0	576.8	589.8	507.2	519.4	570.0	672.8	6,958
Internal Peak Demand (MW)	1,300	1,432	1,176	986	931	1,032	1,132	1,063	967	910	1,096	1,247	1,432

Exhibit 2-6
Kentucky Power Company
Monthly Internal Load
2015

Including EE Impacts

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Internal Energy (GWH)													
Residential	300.1	232.1	215.3	136.7	136.6	151.9	188.6	183.8	140.5	136.0	170.6	254.7	2,247
Commercial	125.3	104.3	111.4	98.2	114.3	116.2	120.4	116.8	106.7	118.5	103.7	115.0	1,351
Industrial	236.1	220.6	243.4	234.4	251.7	233.7	225.8	235.8	214.3	255.2	245.1	241.9	2,838
Total Other Ultimate	1.1	0.9	1.0	0.8	0.8	0.7	0.7	0.8	0.8	1.0	1.1	1.1	11
Total Ultimate Sales	662.5	557.9	571.0	470.2	503.4	502.4	535.5	537.3	462.3	510.7	520.4	612.7	6,446
Municipals	10.6	8.6	8.0	6.9	6.6	7.5	8.6	8.6	7.2	7.1	7.6	9.3	97
Total Sales-for-Resale	10.6	8.6	8.0	6.9	6.6	7.5	8.6	8.6	7.2	7.1	7.6	9.3	97
Total Internal Sales	673.2	566.5	579.1	477.1	509.9	509.9	544.1	545.9	469.5	517.8	528.0	622.0	6,543
Total Losses	53.9	45.4	18.0	38.3	6.8	40.9	32.4	43.8	37.6	0.5	42.4	49.9	410
Total Internal Energy	727.1	611.9	597.0	515.4	516.8	550.8	576.6	589.7	507.1	518.4	570.3	671.9	6,953
Internal Peak Demand (MW)	1,298	1,431	1,175	985	929	1,033	1,133	1,064	968	910	1,095	1,245	1,431

Exhibit 2-7

Kentucky Power Company
Estimated Approved EE Impacts
on Forecasted Energy Requirements and Peak Demands

	Energy Requirements Impacts GWH						Peak Demand Impacts MW	
Year	Residential	Commercial	Industrial	Other Retail	Losses	Total	Summer	Winter Following
2013*	4	2	0	0	1	7	0	8
2014	30	12	0	0	4	46	5	11
2015	40	16	0	0	5	61	7	13
2016	47	20	0	0	6	73	9	15
2017	52	23	0	0	6	81	10	17
2018	55	25	0	0	7	87	11	18
2019	57	27	0	0	7	92	12	19
2020	58	29	0	0	7	94	12	20
2021	59	30	0	0	8	96	13	21
2022	59	30	0	0	8	97	13	21
2023	59	30	0	0	8	97	14	21
2024	59	30	0	0	8	97	14	21
2025	59	30	0	0	8	97	14	21
2026	59	30	0	0	8	97	14	21
2027	59	30	0	0	8	97	14	21
2028	59	30	0	0	8	97	14	21

Note: *Data for 2013 are three months forecast.

Exhibit 2-8

Kentucky Power Company
Annual Internal Energy Requirements and Growth Rates
2008-2028

Excluding EE Impacts

	Residential Sales		Commercial Sales		Industrial Sales		Other Internal Sales		Losses		Total Internal Energy Requirements	
	GWH	% Growth	GWH	% Growth	GWH	% Growth	GWH	% Growth	GWH	% Growth	GWH	% Growth
Actual												
2008	2,481	--	1,429	--	3,322	--	110	--	568	--	7,910	--
2009	2,426	-2.2	1,426	-0.2	3,206	-3.5	104	-5.7	395	-30.5	7,557	-4.5
2010	2,614	7.7	1,469	3.0	3,256	1.5	112	7.5	474	20.1	7,924	4.9
2011	2,342	-10.4	1,381	-6.0	3,250	-0.2	105	-6.4	470	-0.8	7,548	-4.8
2012	2,241	-4.3	1,350	-2.2	3,060	-5.9	105	0.0	400	-15.0	7,155	-5.2
Forecast												
2013 (1)	2,296	2.5	1,339	-0.8	2,895	-5.4	105	0.0	466	16.4	7,100	-0.8
2014	2,298	0.1	1,358	1.4	2,828	-2.3	106	1.6	414	-11.2	7,004	-1.4
2015	2,287	-0.5	1,367	0.6	2,838	0.3	107	1.0	415	0.3	7,014	0.1
2016	2,292	0.2	1,375	0.5	2,853	0.5	109	1.1	415	0.1	7,043	0.4
2017	2,288	-0.2	1,382	0.5	2,866	0.5	109	0.6	411	-1.0	7,056	0.2
2018	2,287	-0.1	1,386	0.3	2,869	0.1	110	0.5	414	0.7	7,066	0.1
2019	2,288	0.1	1,391	0.4	2,873	0.1	110	0.5	414	0.0	7,077	0.2
2020	2,284	-0.2	1,397	0.4	2,883	0.3	111	0.5	417	0.8	7,092	0.2
2021	2,284	0.0	1,405	0.6	2,893	0.4	112	0.5	414	-0.9	7,108	0.2
2022	2,282	-0.1	1,412	0.5	2,910	0.6	112	0.5	417	0.7	7,133	0.4
2023	2,281	0.0	1,420	0.6	2,921	0.4	113	0.5	418	0.4	7,154	0.3
2024	2,282	0.0	1,429	0.6	2,927	0.2	113	0.4	418	0.1	7,169	0.2
2025	2,285	0.1	1,439	0.7	2,932	0.2	114	0.4	418	-0.2	7,187	0.2
2026	2,287	0.1	1,448	0.6	2,941	0.3	114	0.4	419	0.3	7,209	0.3
2027	2,288	0.1	1,457	0.6	2,949	0.3	115	0.4	423	0.9	7,231	0.3
2028	2,294	0.2	1,466	0.6	2,957	0.3	115	0.3	423	0.1	7,255	0.3
Average Annual Growth Rates:												
2008-2012		-2.5		-1.4		-2.0		-1.3		-8.4		-2.5
2014-2028		0.0		0.5		0.3		0.6		0.2		0.3

Note: Data for 2013 are nine months actual and three months forecast.

Exhibit 2-9

Kentucky Power Company
Seasonal and Annual Peak Demands, Energy Requirements and Load Factor
2008-2028

Excluding EE Impacts

	Summer Peak			Winter Peak (1)			Annual Peak, Energy and Load Factor				
	Date	MW	% Growth	Date	MW	% Growth	MW	% Growth	GWH	% Growth	Load Factor %
Actual											
2008		1,249	--		1,674	--	1,678	--	7,910	--	53.7
2009		1,163	-6.9		1,543	-7.8	1,674	-0.2	7,557	-4.5	51.5
2010		1,310	12.6		1,596	3.4	1,596	-4.7	7,924	4.9	56.7
2011		1,240	-5.3		1,378	-13.7	1,522	-4.6	7,548	-4.8	56.5
2012		1,183	-4.6		1,409	2.2	1,378	-9.5	7,155	-5.2	59.1
Forecast											
2013 (2)		1,138	-3.8		1,440	2.2	1,409	2.2	7,100	-0.8	57.5
2014		1,137	0.0		1,442	0.1	1,440	2.2	7,004	-1.4	55.5
2015		1,140	0.2		1,445	0.2	1,442	0.1	7,014	0.1	55.5
2016		1,143	0.2		1,447	0.1	1,445	0.2	7,043	0.4	55.6
2017		1,147	0.3		1,448	0.1	1,447	0.1	7,056	0.2	55.7
2018		1,150	0.3		1,450	0.2	1,448	0.1	7,066	0.1	55.7
2019		1,153	0.3		1,449	-0.1	1,450	0.2	7,077	0.2	55.7
2020		1,155	0.2		1,456	0.5	1,449	-0.1	7,092	0.2	55.9
2021		1,162	0.6		1,460	0.3	1,456	0.5	7,108	0.2	55.7
2022		1,167	0.5		1,459	0.0	1,460	0.3	7,133	0.4	55.8
2023		1,170	0.3		1,459	-0.1	1,459	0.0	7,154	0.3	56.0
2024		1,172	0.1		1,465	0.5	1,459	-0.1	7,169	0.2	56.1
2025		1,179	0.6		1,470	0.3	1,465	0.5	7,187	0.2	56.0
2026		1,185	0.4		1,474	0.3	1,470	0.3	7,209	0.3	56.0
2027		1,190	0.4		1,475	0.1	1,474	0.3	7,231	0.3	56.0
2028		1,193	0.3		1,480	0.4	1,475	0.1	7,255	0.3	56.2
Average Annual Growth Rates:											
2008-2012			-1.3			-4.2		-4.8		-2.5	
2014-2028			0.3			0.2		0.2		0.3	

Note: (1) Actual winter peak for year may occur in the 4th quarter of that year or in the 1st quarter of the following year.
(2) Data for 2013 are nine months acutal and three months forecast.

Exhibit 2-10

Kentucky Power Company
Annual Internal Load
2012-2021

Excluding EE Impacts

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Internal Energy (GWH)															
Residential	2,298	2,287	2,292	2,288	2,287	2,288	2,284	2,284	2,282	2,281	2,282	2,285	2,287	2,288	2,294
Commercial	1,358	1,367	1,375	1,382	1,386	1,391	1,397	1,405	1,412	1,420	1,429	1,439	1,448	1,457	1,466
Industrial	2,828	2,838	2,853	2,866	2,869	2,873	2,883	2,893	2,910	2,921	2,927	2,932	2,941	2,949	2,957
Total Other Ultimate	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
Total Ultimate Sales	6,495	6,503	6,530	6,547	6,553	6,564	6,574	6,593	6,615	6,634	6,649	6,667	6,687	6,705	6,728
Municipals	96	97	98	98	99	100	100	101	101	102	102	103	103	104	104
Total Sales-for-Resale	96	97	98	98	99	100	100	101	101	102	102	103	103	104	104
Total Internal Sales	6,591	6,599	6,628	6,645	6,652	6,663	6,675	6,694	6,716	6,735	6,751	6,769	6,790	6,809	6,832
Total Losses	414	415	415	411	414	414	417	414	417	418	418	418	419	423	423
Total Internal Energy	7,004	7,014	7,043	7,056	7,066	7,077	7,092	7,108	7,133	7,154	7,169	7,187	7,209	7,231	7,255
Internal Peak Demand (MW)															
Summer	1,137	1,140	1,143	1,147	1,150	1,153	1,155	1,162	1,167	1,170	1,172	1,179	1,185	1,190	1,193
Preceding Winter	1,442	1,445	1,447	1,448	1,450	1,449	1,456	1,460	1,459	1,459	1,465	1,470	1,474	1,475	1,480

Exhibit 2-11

Kentucky Power Company

Monthly Internal Load

2014

Excluding EE Impacts

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Internal Energy (GWH)													
Residential	306.4	236.2	219.0	139.0	134.9	156.4	192.9	186.7	143.8	144.3	173.4	264.7	2,298
Commercial	127.3	106.3	113.3	99.8	110.2	115.2	122.1	118.2	107.8	119.8	103.2	115.4	1,358
Industrial	234.9	219.9	242.8	233.9	247.9	232.6	225.9	235.3	213.4	256.1	245.5	240.2	2,828
Total Other Ultimate	1.1	0.9	0.9	0.8	0.8	0.7	0.7	0.8	0.8	1.0	1.0	1.1	11
Total Ultimate Sales	669.7	563.3	576.0	473.5	493.7	504.8	541.6	541.0	465.8	521.2	523.2	621.4	6,495
Municipals	10.6	8.6	7.9	6.9	6.6	7.4	8.6	8.5	7.0	7.1	7.6	9.0	96
Total Sales-for-Resale	10.6	8.6	7.9	6.9	6.6	7.4	8.6	8.5	7.0	7.1	7.6	9.0	96
Total Internal Sales	680.2	571.9	584.0	480.4	500.4	512.2	550.1	549.5	472.9	528.3	530.7	630.4	6,591
Total Losses	54.1	45.1	17.5	38.7	20.6	41.2	30.1	43.8	37.5	-5.5	43.2	47.3	414
Total Internal Energy	734.3	617.0	601.4	519.2	520.9	553.4	580.3	593.2	510.4	522.8	574.0	677.6	7,004
Internal Peak Demand (MW)	1,308	1,440	1,183	992	936	1,037	1,137	1,068	972	915	1,103	1,255	1,440

Exhibit 2-12
Kentucky Power Company
Monthly Internal Load
2015

Excluding EE Impacts

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Internal Energy (GWH)													
Residential	305.2	236.6	219.0	139.6	139.0	154.5	191.8	187.1	143.4	138.3	173.4	258.8	2,287
Commercial	126.8	105.8	112.8	99.5	115.5	117.5	121.8	118.3	108.2	119.7	104.9	116.4	1,367
Industrial	236.1	220.6	243.4	234.4	251.7	233.7	225.8	235.8	214.3	255.2	245.1	241.9	2,838
Total Other Ultimate	1.1	0.9	1.0	0.8	0.8	0.7	0.7	0.8	0.8	1.0	1.1	1.1	11
Total Ultimate Sales	669.2	563.9	576.1	474.3	507.0	506.4	540.2	541.9	466.7	514.3	524.4	618.2	6,503
Municipals	10.6	8.6	8.0	6.9	6.6	7.5	8.6	8.6	7.2	7.1	7.6	9.3	97
Total Sales-for-Resale	10.6	8.6	8.0	6.9	6.6	7.5	8.6	8.6	7.2	7.1	7.6	9.3	97
Total Internal Sales	679.8	572.5	584.1	481.2	513.6	513.9	548.8	550.6	473.9	521.5	532.0	627.5	6,599
Total Losses	54.1	45.1	18.7	38.8	7.5	41.3	32.4	43.7	37.4	1.3	43.6	50.7	415
Total Internal Energy	733.9	617.6	602.8	520.1	521.1	555.2	581.1	594.3	511.3	522.8	575.6	678.2	7,014
Internal Peak Demand (MW)	1,308	1,442	1,185	993	936	1,039	1,140	1,071	975	917	1,104	1,256	1,442

Exhibit 2-13

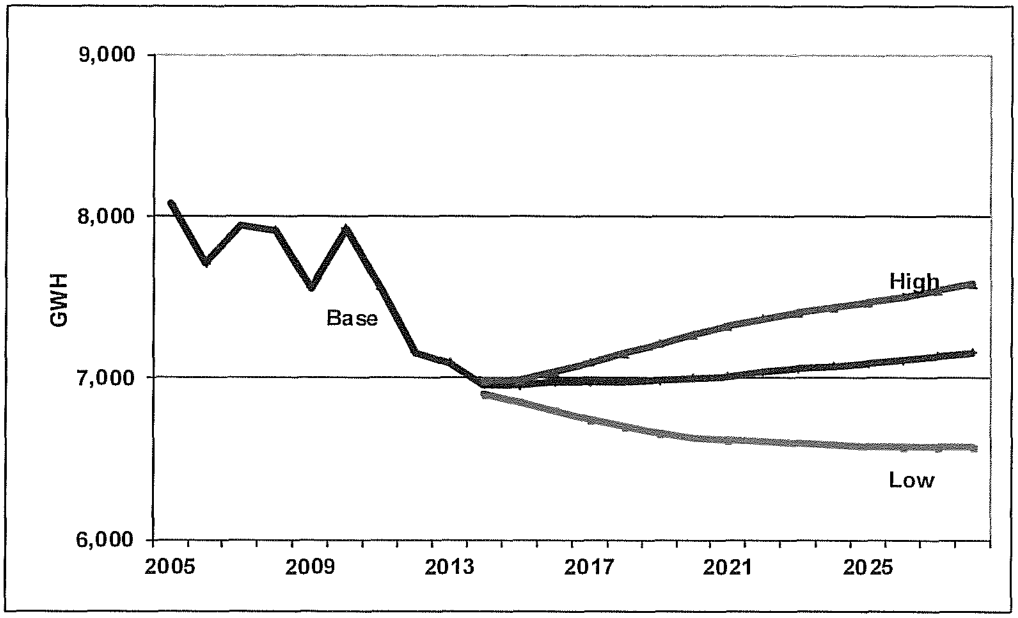
Kentucky Power Company
Low, Base and High Case for
Forecasted Seasonal Peak Demands and Internal Energy Requirements
2014-2028

Including EE Impacts

	Summer Peak Internal Demands (MW)			Winter (Following) Peak Internal Demands (MW)			Internal Energy Requirements (GWH)		
Year	Low Case	Base Case	High Case	Low Case	Base Case	High Case	Low Case	Base Case	High Case
2014	1,122	1,132	1,136	1,410	1,431	1,437	6,899	6,958	6,984
2015	1,116	1,133	1,138	1,397	1,432	1,445	6,850	6,953	6,984
2016	1,106	1,134	1,144	1,384	1,431	1,456	6,801	6,970	7,034
2017	1,099	1,137	1,156	1,374	1,431	1,466	6,744	6,975	7,095
2018	1,093	1,139	1,167	1,365	1,432	1,478	6,698	6,979	7,151
2019	1,088	1,141	1,178	1,356	1,430	1,485	6,659	6,986	7,209
2020	1,083	1,142	1,186	1,355	1,436	1,499	6,634	6,997	7,266
2021	1,084	1,149	1,199	1,352	1,439	1,507	6,616	7,012	7,318
2022	1,084	1,154	1,209	1,345	1,438	1,510	6,611	7,036	7,369
2023	1,082	1,157	1,214	1,339	1,438	1,512	6,600	7,056	7,405
2024	1,079	1,158	1,218	1,340	1,444	1,521	6,589	7,072	7,437
2025	1,082	1,166	1,228	1,340	1,448	1,528	6,580	7,090	7,469
2026	1,083	1,171	1,235	1,339	1,452	1,535	6,577	7,112	7,503
2027	1,084	1,176	1,243	1,335	1,454	1,539	6,575	7,134	7,539
2028	1,083	1,179	1,249	1,336	1,459	1,548	6,574	7,158	7,579
Average Annual Growth Rate % **2014-2028**	-0.3	0.3	0.7	-0.4	0.1	0.5	-0.3	0.2	0.6

Exhibit 2-14
Kentucky Power Company
Range of Forecasts

Internal Energy Requirements



Winter Peak Demand

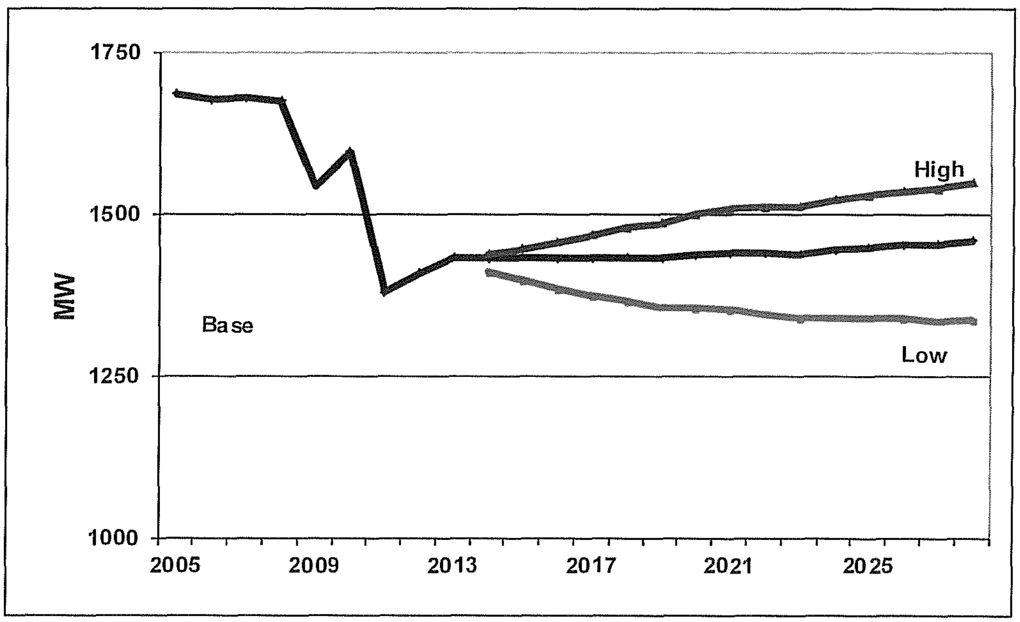


Exhibit 2-15

Kentucky Power Company
Low, Base and High Case for
Forecasted Seasonal Peak Demands and Internal Energy Requirements
2012-2026

Excluding EE Adjustments

	Summer Peak Internal Demands (MW)			Winter (Following) Peak Internal Demands (MW)			Internal Energy Requirements (GWH)		
Year	Low Case	Base Case	High Case	Low Case	Base Case	High Case	Low Case	Base Case	High Case
2014	1,128	1,137	1,141	1,431	1,443	1,448	6,945	7,004	7,030
2015	1,123	1,140	1,145	1,423	1,444	1,450	6,911	7,014	7,045
2016	1,115	1,143	1,153	1,412	1,447	1,460	6,873	7,043	7,106
2017	1,109	1,147	1,166	1,401	1,448	1,473	6,825	7,056	7,177
2018	1,104	1,150	1,178	1,392	1,449	1,485	6,786	7,066	7,239
2019	1,100	1,153	1,190	1,384	1,451	1,497	6,750	7,077	7,301
2020	1,096	1,155	1,199	1,376	1,450	1,505	6,728	7,092	7,360
2021	1,097	1,162	1,212	1,376	1,457	1,519	6,712	7,108	7,414
2022	1,098	1,167	1,222	1,373	1,460	1,528	6,708	7,133	7,466
2023	1,096	1,170	1,228	1,367	1,460	1,531	6,697	7,154	7,502
2024	1,093	1,172	1,232	1,360	1,459	1,533	6,686	7,169	7,534
2025	1,096	1,179	1,242	1,362	1,465	1,543	6,677	7,187	7,566
2026	1,097	1,185	1,249	1,361	1,470	1,549	6,674	7,209	7,601
2027	1,098	1,190	1,257	1,360	1,474	1,556	6,672	7,231	7,637
2028	1,097	1,193	1,262	1,356	1,475	1,560	6,671	7,255	7,676
Average Annual Growth Rate % 2012-2026	-0.2	0.3	0.7	-0.4	0.2	0.5	-0.3	0.3	0.6

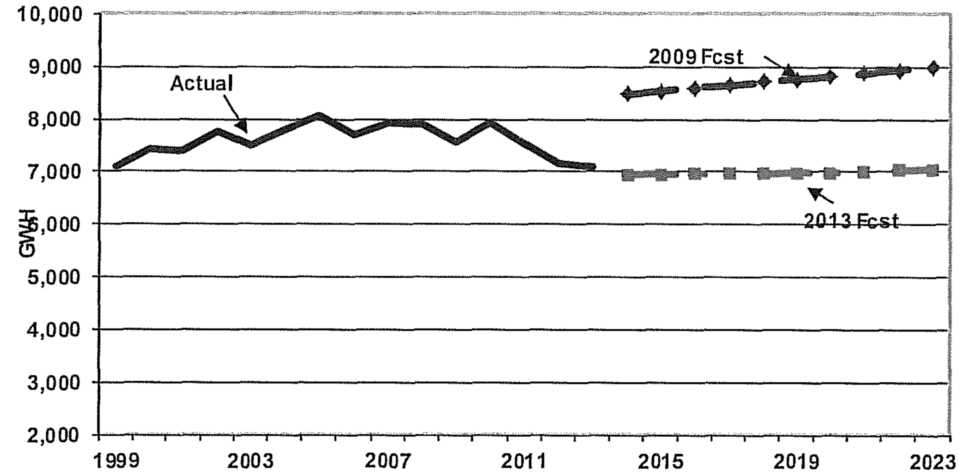
Exhibit 2-16
Kentucky Power Company
Total Internal Energy Requirements
Comparison of 2009 and 2013 Forecasts

Including EE Impacts

Forecast Year	2013 Forecast GWH	2009 Forecast GWH	Change From 2009 Forecast GWH	Change From 2009 Forecast Percent
2009	-	7,963	-	-
2010	-	8,144	-	-
2011	-	8,286	-	-
2012		8,354	-	-
2013		8,417	-	-
2014	6,958	8,472	-1,513	-17.9
2015	6,953	8,530	-1,577	-18.5
2016	6,970	8,593	-1,622	-18.9
2017	6,975	8,651	-1,675	-19.4
2018	6,979	8,707	-1,729	-19.9
2019	6,986	8,762	-1,776	-20.3
2020	6,997	8,816	-1,819	-20.6
2021	7,012	8,874	-1,863	-21.0
2022	7,036	8,940	-1,904	-21.3
2023	7,056	9,007	-1,950	-21.7
2014-2023 Growth Rate (%)	0.2	0.7		

Exhibit 2-17
Kentucky Power Company
Comparison of Forecasts

Internal Energy Requirements



Winter Peak Demand

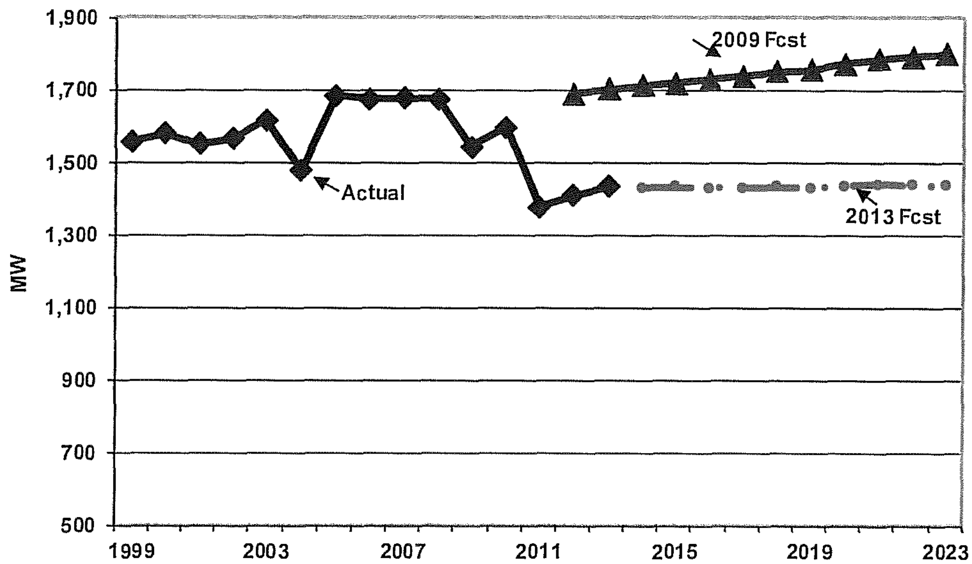


Exhibit 2-18

Kentucky Power Company
Summer and Winter Following Peak Internal Demands
Comparison of 2009 and 2013 Forecasts

Including EE Impacts

	Winter Following Peak				Summer Peak			
Forecast Year	2013 Forecast MW	2009 Forecast MW	Change From 2009 Forecast MW	Change From 2009 Forecast Percent	2013 Forecast MW	2009 Forecast MW	Change From 2009 Forecast MW	Change From 2009 Forecast Percent
2009	-	1,639	-	-	-	1,308	-	-
2010	-	1,668	-	-	-	1,338	-	-
2011	-	1,672	-	-	-	1,357	-	-
2012	-	1,689	-	-	-	1,364	-	-
2013	-	1,700	-	-	-	1,379	-	-
2014	1,431	1,711	-280	-16.4	1,132	1,389	-258	-18.5
2015	1,432	1,717	-285	-16.6	1,133	1,400	-267	-19.1
2016	1,431	1,728	-297	-17.2	1,134	1,408	-274	-19.5
2017	1,431	1,739	-308	-17.7	1,137	1,420	-283	-20.0
2018	1,432	1,750	-318	-18.1	1,139	1,431	-292	-20.4
2019	1,430	1,754	-324	-18.5	1,141	1,441	-300	-20.8
2020	1,436	1,771	-335	-18.9	1,142	1,448	-305	-21.1
2021	1,439	1,784	-345	-19.3	1,149	1,462	-313	-21.4
2022	1,438	1,791	-353	-19.7	1,154	1,474	-320	-21.7
2023	1,438	1,799	-361	-20.1	1,157	1,483	-327	-22.0
2014-2023 Growth Rate (%)	0.1	0.6			0.2	0.7		

Exhibit 2-19

Kentucky Power Company
Average Annual Number of Customers by Class
2008-2012

	2008	2009	2010	2011	2012
A. Residential					
1. Heating Customers	84,501	85,124	85,499	85,541	85,570
2. Nonheating Customers	59,605	58,505	57,472	56,319	55,359
3. Total	144,105	143,628	142,971	141,860	140,929
B. Commercial	29,729	29,554	29,790	29,964	30,059
C. Industrial					
1. Manufacturing	963	979	977	961	954
2. Mine Power	469	459	448	445	415
3. Total	1,433	1,438	1,425	1,406	1,368
D. Other Ultimate Sales					
1. Street Lighting	379	373	391	411	401
2. Other	0	0	0	0	0
3. Total	379	373	391	411	401
E. Total Ultimate Sales	175,646	174,993	174,578	173,642	172,757
F. Internal Sales for Resale					
1. Municipals	2	2	2	2	2
2. Other	0	0	0	0	0
3. Total	2	2	2	2	2
G. Total Internal Sales	175,648	174,995	174,580	173,644	172,759

Exhibit 2-20

Kentucky Power Company
Annual Internal Load by Class (GWH)
2008-2012

	2008	2009	2010	2011	2012
A. Residential					
1. Heating Customers	1,682	1,650	1,786	1,601	1,526
2. Nonheating Customers	799	776	828	741	715
3. Total	2,481	2,426	2,614	2,342	2,241
B. Commercial	1,429	1,426	1,469	1,381	1,350
C. Industrial					
1. Manufacturing	2,262	2,202	2,276	2,293	2,289
2. Mine Power	1,059	1,005	980	956	771
3. Total	3,322	3,206	3,256	3,250	3,060
D. Other Ultimate Sales					
1. Street Lighting	10	10	10	11	11
2. Other	0	0	0	0	0
3. Total	10	10	10	11	11
E. Total Ultimate Sales	7,242	7,068	7,349	6,983	6,661
F. Internal Sales for Resale					
1. Municipals	100	94	101	94	94
2. Other	0	0	0	0	0
3. Total	100	94	101	94	94
G. Total Internal Sales	7,342	7,162	7,450	7,077	6,755
H. Losses	568	395	474	470	400
I. Total Internal Load	7,910	7,557	7,924	7,548	7,155

Exhibit 2-21

Kentucky Power Company
Wholesale Customers
Coincident Seasonal Demand (MW) and Annual Energy (MWh)
2008-2012

	Summer Coincident Demand		Winter Following Coincident Demand		Energy	
Year	Vanceburg	Olive Hill	Vanceburg	Olive Hill	Vanceburg	Olive Hill
2008	12.0	4.9	16.0	7.1	71,822.6	29,835.6
2009	10.5	4.9	13.8	6.0	66,257.5	29,012.4
2010	13.6	5.5	14.8	7.1	73,119.1	29,967.4
2011	12.8	5.5	12.4	5.4	67,586.4	28,021.9
2012	13.5	5.3	13.6	5.9	69,396.6	26,127.7

Exhibit 2-22

Kentucky Power Company
Recorded and Weather-Normalized Peak Load (MW) and Energy (GWH)
2008-2012

Kentucky Power Company	2008	2009	2010	2011	2012
A. Peak Load - Summer					
1. Recorded	1,249	1,163	1,310	1,240	1,183
2. Weather-Normalized	1,192	1,189	1,262	1,229	1,105
B. Peak Load - Winter					
1. Recorded	1,674	1,543	1,596	1,378	1,409
2. Weather-Normalized	1,534	1,524	1,413	1,468	1,432
C. Energy					
1. Recorded	7,910	7,557	7,924	7,548	7,155
2. Weather-Normalized	7,874	7,610	7,728	7,595	7,290

Exhibit 2-23

Kentucky Power Company
Normalized Annual Internal Sales by Class (GWH)
2008-2012

	2008	2009	2010	2011	2012
A. Residential	2,460	2,453	2,501	2,369	2,315
B. Commercial	1,429	1,438	1,439	1,387	1,364
C. Industrial	3,322	3,206	3,256	3,250	3,060
D. Other Ultimate Sales	10	10	10	11	11
E. Total Ultimate Sales	7,221	7,108	7,206	7,016	6,749
F. Internal Sales for Resale	100	94	100	94	95
G. Total Internal Sales	7,322	7,203	7,306	7,110	6,844

Exhibit 2-24
Kentucky Power Company
Profiles of Monthly Peak Internal Demands
2007 and 2012 (Actual)
2022 and 2027

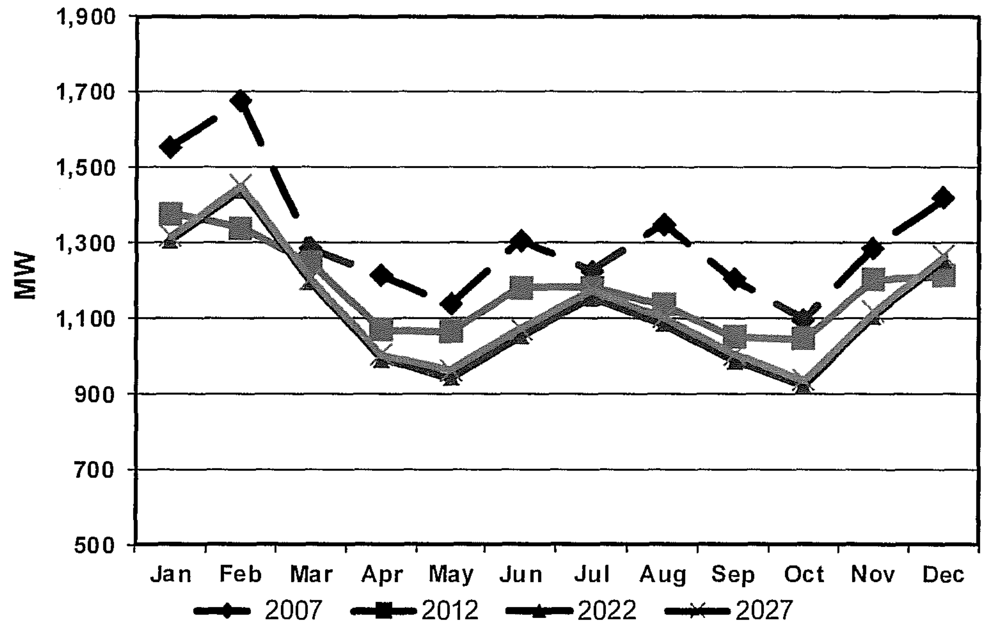


Exhibit 2-25

KENTUCKY POWER COMPANY LOAD FORECAST DATA SOURCES OUTSIDE THE COMPANY					
DATA SERIES	FREQUENCY	GEOGRAPHIC	INTERVAL	SOURCE	ADJUSTMENT
Average Daily Temperatures at time of Daily Peak Load	Daily	Selected weather stations throughout the AEP System	1982-2012	NOAA (1)	None
Heating and Cooling Degree-Days	Monthly	Selected weather stations throughout the AEP System	1/82-02/13	NOAA (1)	Annual Sums used in long-term models
FRB Production Index, Manufacturing	Monthly	U. S.	1984:1-2012:12 2013:1-2042:12	BOG/FRB (3) Moody's Analytics (2)	None None
Implicit GDP Price Deflator	Monthly	U. S.	1984:1-2012:12 2013:1-2042:12	Moody's Analytics (2)	None
Kentucky Natural Gas Prices by Sector	Monthly	U. S.	1973-2012:12	DOE/EIA (4)	None
U.S. Natural Gas Prices Forecast by Sector	Annually	U. S.	2010-2035	DOE/EIA (5)	None
U. S. Coal Production and Consumption	Annually	U. S.	1975-2030	DOE/EIA (5)	None
Eastern Kentucky Coal Production	Monthly	Eastern Kentucky DOE Region	1991-2012	DOE/EIA	None
Employment (Total and Selected Sectors), Gross Regional Product, Personal Income and Population	Montly	Selected Kentucky Counties	1980-2042	Moody's Analytics (2)	None

Source Citations:
(1) "Local Climatological Data," National Oceanographic and Atmospheric Administration.
(2) December 2013 Forecast, Moody's Analytics.
(3) Board of Governors of Federal Reserve System, "Federal Reserve Statistical Release," 1984-2012
(4) U. S. Department of Energy/Energy Information Administration "Natural Gas Monthly", Selected Issues.
(5) U. S. Department of Energy/Energy Information Administration "2013 Annual Energy Outlook" and "Weekly and Monthly Coal Production," Selected Issues.

Exhibit 2-26
Kentucky Power Company
Residential Energy Sales
2009-2012
Actual vs. 2009 IRP

	Residential Energy Sales -GWH			
Year	Actual	2009 Forecast	GWH Difference	% Difference
2009	2,426	2,492	-67	-2.7
2010	2,614	2,466	147	6.0
2011	2,342	2,449	-107	-4.4
2012	2,241	2,438	-197	-8.1
Year	Weather Normalized	2009 Forecast	GWH Difference	% Difference
2009	2,453	2,492	-39	-1.6
2010	2,501	2,466	35	1.4
2011	2,369	2,449	-80	-3.3
2012	2,315	2,438	-124	-5.1

Exhibit 2-27
Kentucky Power Company
Seasonal Peak Demands
2009-2012
Actual vs. 2009 Forecast

Summer Peak Demand - MW					Winter Peak Demand - MW				
Summer	Actual	2009 Forecast	MW Difference	% Difference	Winter	Actual	2009 Forecast	MW Difference	% Difference
2009	1,163	1,308	-145	-11.1	**2009/10**	1,543	1,639	-96	-5.9
2010	1,310	1,338	-28	-2.1	**2010/11**	1,596	1,668	-72	-4.3
2011	1,240	1,357	-117	-8.6	**2011/12**	1,378	1,672	-294	-17.6
2012	1,183	1,364	-181	-13.3	**2012/13**	1,409	1,689	-280	-16.6
Summer	Weather Normalized	2009 Forecast	MW Difference	% Difference	Winter	Weather Normalized	2009 Forecast	MW Difference	% Difference
2009	1,189	1,308	-120	-9.1	**2009/10**	1,524	1,639	-115	-7.0
2010	1,262	1,338	-76	-5.7	**2010/11**	1,413	1,668	-254	-15.2
2011	1,229	1,357	-127	-9.4	**2011/12**	1,468	1,672	-204	-12.2
2012	1,105	1,364	-259	-19.0	**2012/13**	1,432	1,689	-257	-15.2

3.0 DEMAND-SIDE MANAGEMENT PROGRAMS

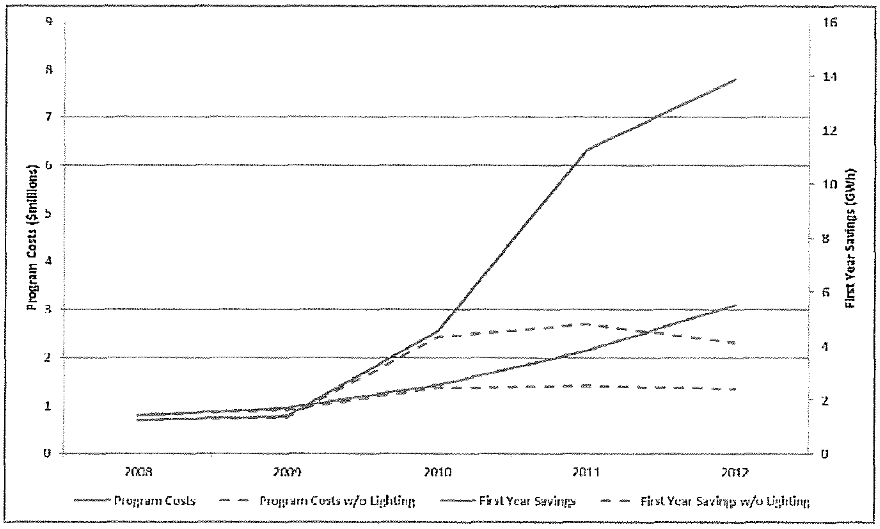
3.1 Kentucky Power Demand Reduction and Energy Efficiency Programs

3.1.1 Changing Conditions

(807 KAR 5:058 Sec. 6)

Since the last IRP, Kentucky Power has markedly increased the size of its DSM programs. Spending has effectively tripled while claimed energy savings, as measured by "first year" energy savings, have quadrupled. However, as evidenced by **Figure 2**, the increases have come primarily from lighting programs.

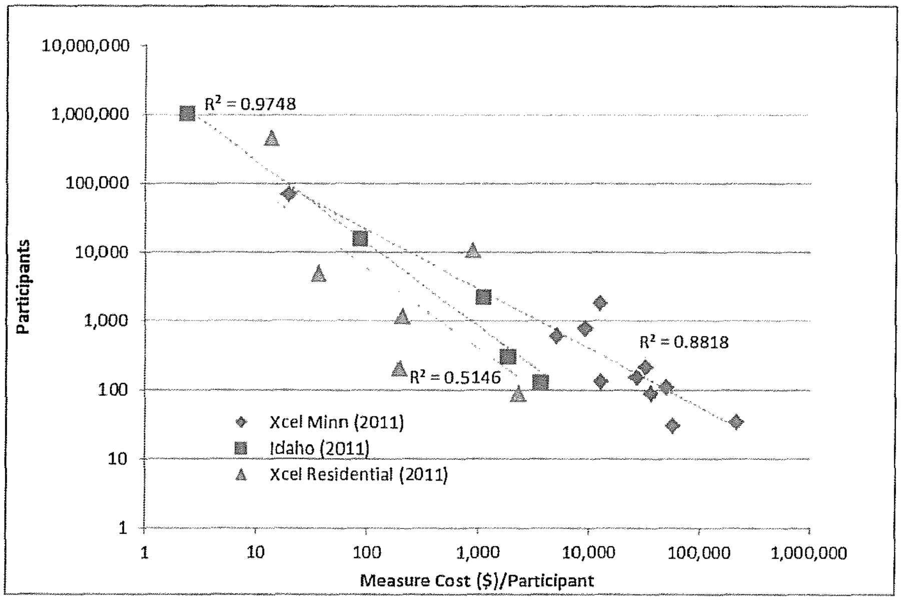
Figure 2: DSM Programs Costs and Savings



This succcess may not be readily duplicated in future periods due to the full phase-in of lighting standards that began in 2010. EISA 2007 requires that screw-in lighting be 25% more efficient than traditional incandescent lights by the end of 2013 which has resulted in the typical 100, 75, 60 and 40 watt incandescent light bulbs being phased out. CFL bulbs, as part of an EE program, may still represent savings over the increased standard, as there are some substitutes, notably, efficient halogens. However, by year-end 2019, the standard increases to preclude any substitutes, and the CFL bulb becomes the de facto standard. Similarly, the commercial T-12 light has been prohibited from manufacture or import since mid-2012. Replacing T-12 lights with T-8 lights has constituted the bulk of commercial lighting programs nationwide but eventually, as old stock is consumed, will no longer be considered as an option for utility lighting programs. The long-term load forecast recognizes this and assumes lighting will be at the mandated standards. This makes any capacity savings associated with traditional lighting programs short-lived, as they become implicit in the load forecast.

As a result, the programs that have constituted the foremost basis of utility EE programs nationwide, namely residential and commercial lighting programs, have, and will continue to have absent any new market transforming technologies, diminished basis, effectiveness, and impact. While that eventuality was not wholly unforeseen, viable substitute programs that have the same "bang-for-the-buck" and resultant popularity with consumers have not materialized. More generally, the single biggest hurdle to participation is the cost of the measure. **Figure 3** shows this relationship for two separate utilities for which data were available. The lower cost programs consist primarily of lighting and other high bang-for-the-buck, low-cost measures. A similarly inexpensive, highly cost-effective technology has yet to emerge.

Figure 3: Participation in EE Programs Relationship to Measure Cost



3.1.2 Existing Programs

(807 KAR 5:058 Sec. 7.2.g)

Kentucky Power has offered a variety of DR and EE programs designed to encourage customers to use electricity efficiently, conserve energy and utilize cost-effective electrotechnologies. These include a series of information, education, and technical assistance, as well as financial incentive programs for our residential, and commercial customers.

Existing EE programs include those that have been filed with and approved by the Commission. These programs are as follows:

1. Targeted Energy Efficiency Program
2. High Efficiency Heat Pump-Mobile Home Program
3. Mobile Home New Construction Program
4. Modified Energy Fitness Program
5. High Efficiency Heat Pump Program
6. Energy Education for Students Program
7. Community Outreach Compact Fluorescent Lighting (CFL) Program
8. Residential HVAC Diagnostic and Tune-up
9. Residential Efficient Products
10. Small Commercial HVAC Diagnostic Tune-up
11. Small Commercial High Efficiency Heat Pumpm/Air Conditioner
12. Commercial Incentive

The effects of current programs are embedded in the load forecast as described in Chapter 2. The Company and the Kentucky Power DSM Collaborative (which was established in November 1994 to develop Kentucky Power's DSM plans) have developed DSM programs which are implemented as effectively and efficiently as possible to help Kentucky customers save energy. Both past and present programs are described in the Kentucky Power DSM Status Report 2012, filed with the Commission on April 5, 2013.

3.2 DSM Goals and Objectives

Today's DSM programs continue to encourage the wise and prudent use of electricity, stressing activities that are cost-effective, promote efficiency, conserve, and alter consumption patterns. These programs are intended to benefit the consumer and conserve natural resources. The specific objectives of the Company's DSM activities:

- Promoting energy conservation to customers;
- Reducing future peak demands;
- Continuing efforts and cost-effective programs designed to provide the best possible service to customers;
- Promoting electric applications that improve system load factor;
- Striving for retention of existing customers;
- Encouraging new off-peak electrical applications; and
- Providing guidance and assistance to customers facing equipment replacement decisions.

To be effective, programs have been designed to meet local and regional needs and customer characteristics.

3.3 Customer & Market Research Programs

Successful demand-side management programs require a thorough understanding of customer electrical usage characteristics, appliance ownership, conservation activities, demographic characteristics, opinions and attitudes, and, perhaps most importantly, customers' needs for electric service. An understanding of these factors helps in the identification of load modifications, which may be advantageous to both the customer and the Company; permits an assessment of their potential impact; and helps in the development of programs to solicit customer participation. The Company utilizes data from the Company's load research studies, customer surveys, customer billing database and specific program-related market research to obtain this information.

Load research and customer billing data are one resource utilized to determine the specific customer and/or end-use demand and energy usage characteristics for DSM program evaluation. End-Use load research metering information, for example, associated with the evaluation of DSM programs on appliances such as heat pump, water heater, air conditioners, fluorescent lighting equipment, etc., can also be used, as appropriate, for DSM program evaluations.

The market research activities implemented by Kentucky Power have included DSM market/process evaluation studies. These studies focused on assessing participant satisfaction with the various measures included in each DSM program, assisting in determining the impact on demand by persistence and by the number of free riders, assessing the effectiveness of the program's delivery mechanisms, assisting in determining additional program/product benefits, and gaining insight into market potential.

3.4 DSM Program Screening & Evaluation Process

(807 KAR 5:058 Sec. 8.2.b.)

3.4.1 Overview

The process for evaluating DSM impacts for Kentucky Power is practically divided into two spheres, "existing programs" and "future impacts." Existing programs, those programs that are well defined, follow a time-worn process for screening and ultimate approval as explained below. Their impacts are propagated throughout the load forecast. Future impacts, less defined, are developed with a dynamic modeling process using generic cost and impact data. This is described in Section 3.5.

In the case of Kentucky Power, the DSM Collaborative has been responsible for performing the function of DSM program screening and evaluation for Kentucky Power. The Collaborative, whose initial members represented residential, commercial, and industrial customers, was established to develop Kentucky Power's DSM plans, including program designs, budgets and cost-recovery mechanisms. The residential and commercial members of the Collaborative continue to review the Kentucky Power DSM programs and modify them as appropriate.

For Kentucky Power, the evaluation process considers the DSM program's cost-effectiveness from all perspectives and incorporates cost-recovery mechanisms. In this regard, the Collaborative decides which DSM programs are to be screened for potential implementation in Kentucky Power's service territory.

Through a continual monitoring process, the Company has utilized a vast amount of data collected from each of the DSM programs to appropriately re-design and re-evaluate the programs so as to improve their cost-effectiveness and better target customers for the programs. Data obtained from load research, customer billing, customer surveys and market research have all been collected from the various DSM programs, and detailed load impacts have been estimated from the information acquired in the field. The Company has provided DSM Status Reports to the Commission semi-annually since the start of program implementation in 1996, furnishing information on program participation levels, costs and estimated load impacts. Additionally, seven Kentucky Power DSM Evaluation Reports were submitted to the Commission, on August 15, 1997, August 16, 1999, August 14, 2002, August 15, 2005 and August 25, 2008, August 15, 2011 and August 15, 2012, respectively. These reports provided extensive results of the screening and evaluation of each of the DSM programs implemented.

3.4.2 Existing Program Screening Process

The DSM screening process used by Kentucky Power involved a cost-benefit analysis for each of the DSM programs with recommendation for extension of operation based on prospective cost performance. This included application of the Total Resource Cost (TRC) and Ratepayer Impact Measure (RIM) tests, as well as the Utility Cost Test (UCT) and the Participant Cost Test (PCT), as defined in the California Standard Practice Manual. In this connection, the evaluation of the cost-effectiveness of a given DSM program involves the determination of the net present worth of the program's benefits and costs over the study period, which normally includes a retrospective analysis of the previous two year program operation. Under the TRC test, such benefits and costs are viewed from the combined perspective of all rate-payers, whereas under the RIM test, the benefits and costs are viewed from the perspective of the non-participant, and is synonymously referred to as the "non-participant test." The benefits and costs under the UCT test are viewed from the perspective of the utility, and under the Participant test, from the perspective of the program participant.

The major supply-side benefits used in the cost-benefit analysis of DSM programs are avoided energy (production) costs and avoided demand/capacity costs (for generation, transmission and distribution). These costs are valued on a marginal $/MWh and/or $/kW basis, as appropriate. A detailed approach (peak and off-peak periods, by season) was used to develop avoided production costs. Marginal production costs at peak and off-peak periods in the summer and winter seasons were applied to the appropriate DSM program impacts. The marginal production costs were estimated year-by-year for the forecast period based on a production cost computer model.

The benefits, costs and load impacts estimated in the cost-benefit analysis reflect the assumptions regarding replacement and persistence of each measure within the DSM programs over the study period. Also, the analysis considered the benefits from SO_2 emission credits, NO_X market price, estimates for CO_2 costs based on expected legislation, and expected additional system sales, thereby improving the cost-effectiveness of each DSM measure.

3.5 Evaluating DR/EE Impacts for Future Periods

(807 KAR 5:058 Sec. 8.2.b.)

3.5.1 Assessment of Achievable Potential

The amount of EE and Demand Response that are available are typically described in three groups: technical potential, economic potential, and achievable potential. Briefly, the technical potential encompasses all known efficiency improvements that are possible, regardless of cost, and thus, cost-effectiveness. The logical subset of this pool is the economic potential. Most commonly, the TRC test is used to define economic potential. This compares the avoided cost savings achieved over the life of a measure/program with its cost to implement it, regardless of who paid for it. The third set of efficiency assets, and the one of greatest practical value, is that which is achievable.

Of the total potential, only a fraction is achievable and only then over time. Why all economic measures are not adopted by rational consumers speaks to the existence of "market barriers." Barriers such as lack of access to capital and lack of information are addressed with utility-based EE and DR programs. How much effort and money is deployed towards removing or lowering the barriers is a policy decision made state by state.

3.5.1.1 Consumer Programs

EE measures save money for customers billed on a "per kilowatt-hour" usage basis. The trade-off is reduced volumetric utility charges on the customer bill for any conservation created through either behavioral change, more efficient consumption, or any up-front investment in a building/appliance/equipment modification, upgrade, or any new technology that produces a change in the utility load shape through its deployment. On the participatory side, if the consumer feels that the new technology is a viable substitute and will pay back in the form of reduced bills over an acceptable period of time, the consumer will adopt, accept, or undertake it.

EE measures include efficient lighting, weatherization, efficient pumps and motors, efficient HVAC infrastructure, and efficient appliances. Often, multiple measures are bundled into a single program that might be offered to either residential or commercial/industrial customers in order to deliver these products in a cost-effective manner.

Efficiency measures will, in all cases, reduce the amount of energy consumed, but some measures may have limited effectiveness at the time of peak demand. EE is viewed as a readily deployable, relatively low cost, and clean energy resource that provides many benefits. According to a March 2007 DOE study, such benefits include:

Economics	Reduced energy intensity provides competitive advantage and frees economic resources for investment in non-energy goods and services
Environment	Saving energy reduces air pollution, the degradation of natural resources, risks to public health and global climate change
Infrastructure	Lower demand lessens constraints and congestion on the electric transmission and distribution systems
Security	EE can lessen our vulnerability to events that cut off energy supplies

Unlike supply-side resources, demand-side resources, particularly EE resources, require consumers achieve reduced consumption. While an analysis may indicate that an "investment" in a particular measure is cost-effective, it does not guarantee that conservation will be universally achieved or adopted as technology adoption can be dependent upon many other factors as well, including ease of adoption, market delivery methods, market barriers, and customer economics.

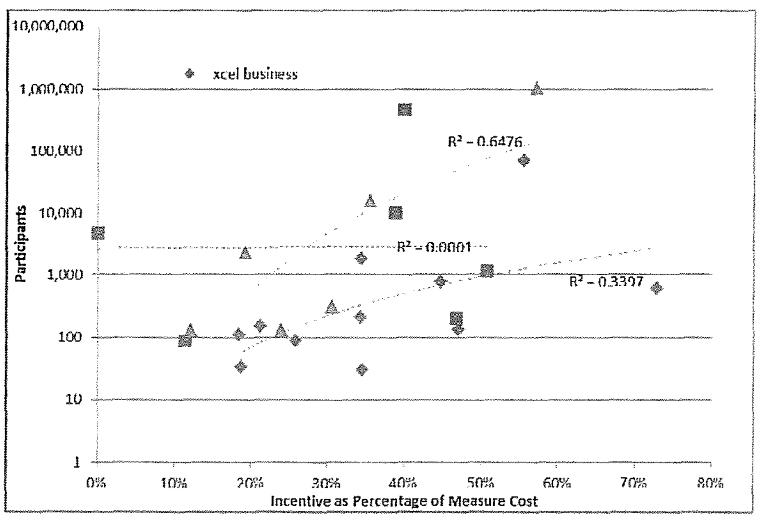
Market barriers to efficiency exist which limit the rate and ultimate level at which efficiency measures are adopted by consumers (program participants). These typically include: high initial cost, uncertainty about performance, and "agency" problems, where the person buying an appliance may not benefit from the improved efficiency.

To overcome many of the participant barriers noted above, a portfolio of programs may often include several of the following elements:

- Consumer education
- Technical training
- Energy audits
- Rebates and discounts for efficient appliances, equipment and buildings
- Industrial process improvements

The level of incentives (rebates or discounts) offered to participants is a major determinant in the pace of market transformation and measure adoption. To achieve rapid adoption of efficiency measures, it is reasonable to expect increased program costs associated with higher consumer incentives, higher administrative costs and marketing. However, this relationship is not as strong (**Figure 4**) as the prior relationship of measure cost to participation, as shown by the same data.

Figure 4: Relationship of Incentive Percentage to Participation



Thus, it is safe to say that the over-riding factor affecting participation and "first year" program savings/achievement is the availability of inexpensive energy saving measures. Until the next breakthrough in this area emerges, it is unrealistic to expect program achievement that aligns with mandates conceived during a period where relatively inexpensive (lighting, primarily) programs were responsible for the bulk of the savings.

3.5.1.2 Smart Meters

"Smart meters" are meters that receive and transmit information about energy consumption that is available not only to the utility, but also the consumer. Enhanced information, such as rates that vary with the time of day is enabled with a smart meter. The promise of a smart meter is with the information in the hands of the individual customers; they are better positioned to make decisions to reduce consumption at time of peak.

3.5.1.3 Demand Response

Peak demand, measured in megawatts (MW), can be thought of as the amount of power used at the time of maximum power usage. In the PJM zone, this maximum (System peak) is likely to occur on the hottest summer weekday of the year, in the late afternoon. This happens as a result of the near-simultaneous use of air conditioning by the majority of customers, as well as the normal use of other appliances and (industrial) machinery. At all other times during the day, and throughout the year, the use of power is less.

As peak demand grows with the economy and population, new capacity must ultimately be built. To defer construction of new power plants, the amount of power consumed at the peak must be reduced. In addition to "passive" or "non-dispatchable" resources like EE and VVO, "active" or "dispatchable" resources, which have impacts primarily only at times of peak demand, include:

- *Interruptible loads*. This refers to a contractual agreement between the utility and a large consumer of power, typically an industrial customer. In return for reduced energy costs, an industrial customer agrees to "interrupt" or reduce power consumption during peak periods, freeing up that capacity for use by other consumers.

- *Direct load control*. Very much like an (industrial) interruptible load, but accomplished with many more, smaller, individual loads. Commercial and residential customers, in exchange for monthly credits or payments, allow the energy manager to deactivate or cycle discrete appliances, typically air conditioners, hot water heaters, lighting banks, or pool pumps during periods of peak demand. These power interruptions can be accomplished through various media such as FM-radio signals that activate switches, or through a digital "smart" meter that allows activation of thermostats and other control devices. Often, these smaller loads can be aggregated by curtailment service providers (CSP) so that they meet RTO minimum requirements.
- *Time-differentiated rates*. Offers customers different rates for power at different times during the year and even the day. During periods of peak demand, power would be relatively more expensive, encouraging conservation. Rates can be split into as few as two rates (peak and off-peak) and to as often as 15-minute increments known as "real-time pricing." Accomplishing real-time pricing would typically require digital (smart) metering to "download" pricing signals from a utility host system.

On a broad scale, direct load control-type programs are typically more expensive as similar infrastructure is needed to achieve smaller load reductions. Moreover, these programs can also introduce consumer dissatisfaction since the "economic choice" is removed from the customer.

The following section seeks to quantify the potential for demand response in Kentucky's service territory should the need arise.

Potential demand response resources are limited to commercial or industrial demand response. To determine a reasonably achievable level, demand response participants in Kentucky Power affiliate companies were surveyed to determine their industry and the percentage of their load that they committed, on average, to PJM. Translating these same relationships to Kentucky Power yield the following potential by industry (**Table 8**). There may be circumstances that limit the utility of this simple extrapolation, and it is unknown whether these customers would participate. Given Kentucky Power's current and expected capacity position within PJM, it is not necessary to aggressively pursue all available demand response at this time.

Table 8: DR Potential

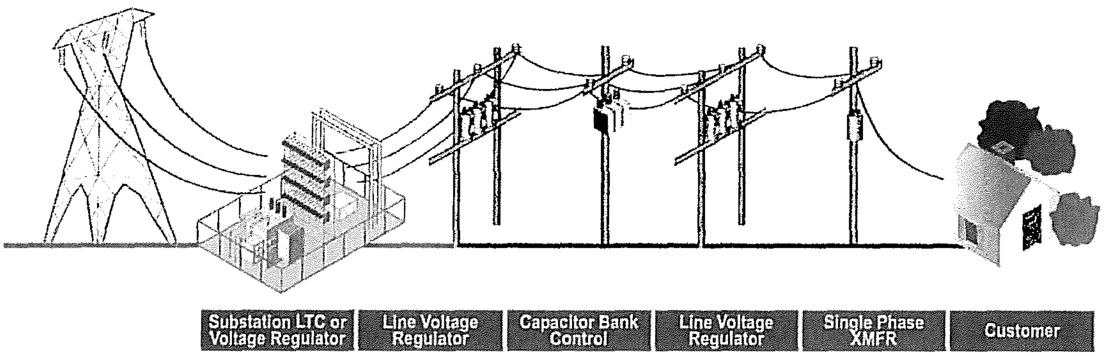
MW	Industry
24	Mining
12	Chemicals
19	Refining
36	Primary Metals
1	Telecommunications
2	Electric, Gas, Sanitary Services
3	Hospitals
1	Other
97	

3.5.1.4 Volt VAR Optimization (VVO)

VVO is a smart grid technology that falls under the gridSMART® umbrella of programs. VVO provides all of the benefits of power factor correction, voltage optimization, and condition-based maintenance in a single, optimized package. In addition, VVO enables conservation voltage reduction (CVR) on a utility's system. CVR is a process by which the utility systematically reduces voltages in its distribution network, resulting in a proportional reduction of load on the network. A 1% reduction in voltage typically results in a 1% reduction in load.

As the electric infrastructure was built out in the last century, distribution systems were designed to ensure end-users received voltages ranging from 114 to 126 volts in accordance with national standards. Most utility systems were designed so that customers close to the substation received voltages close to 126 volts and customers farther from the substation received lower voltages. This design kept line construction costs low because voltage regulating equipment was only applied when necessary to ensure the required minimum voltages were provided. However, since most devices operated by electricity, especially motors, are designed to operate most efficiently at 115 volts, any "excess" voltage is typically wasted, usually in the form of heat. Tighter voltage regulation, enabled by smart-grid infrastructure, allows end-use devices to operate more efficiently without any action on the part of consumers (**Figure 5**). Consumers will simply use less energy to accomplish the same tasks.

Figure 5: Electric Energy Consumption Optimization



3.5.1.5 Distributed Generation (DG)

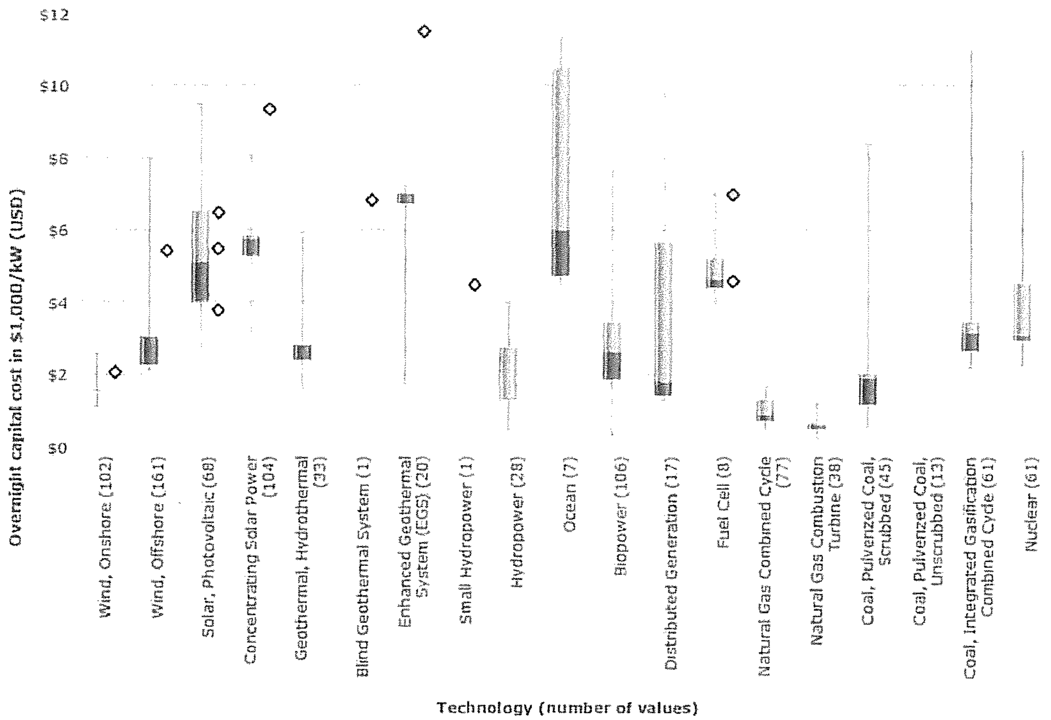
DG can take multiple forms from rooftop (or pole-mounted) solar photovoltaic (PV) panels to combined heat and power (CHP), fuel cells, micro-turbines, diesel internal combustion engines, and small wind turbines. From the perspective of the utility, these different "behind-the-meter" technologies are the same in that they result in a *reduction to load* and *additional incremential costs to the utility to accommodate*, but are owned by the customer with a cost at a prescribed amount: either the retail net metering or PURPA rates. Operating characteristics are different and so corresponding the "resource value" to the utility will vary.

3.5.1.6 Technologies Considered But Not Evaluated

Some DG alternatives include: microturbines, fuel cells, CHP, and residential and small commercial wind were not specifically evaluated. However, distributed generation was modeled as a resource that cost either the (full retail) net metering rate or the PURPA rate as appropriate.

Currently, these technologies cost more than other utility-scale options and were not considered for wide-scale utility implementation. Their costs will continue to be monitored. **Figure 6** shows the significant variation in capital costs for DG and where the costs are relative to other generating technologies[9].

Figure 6: Distributed Generation Capital Costs



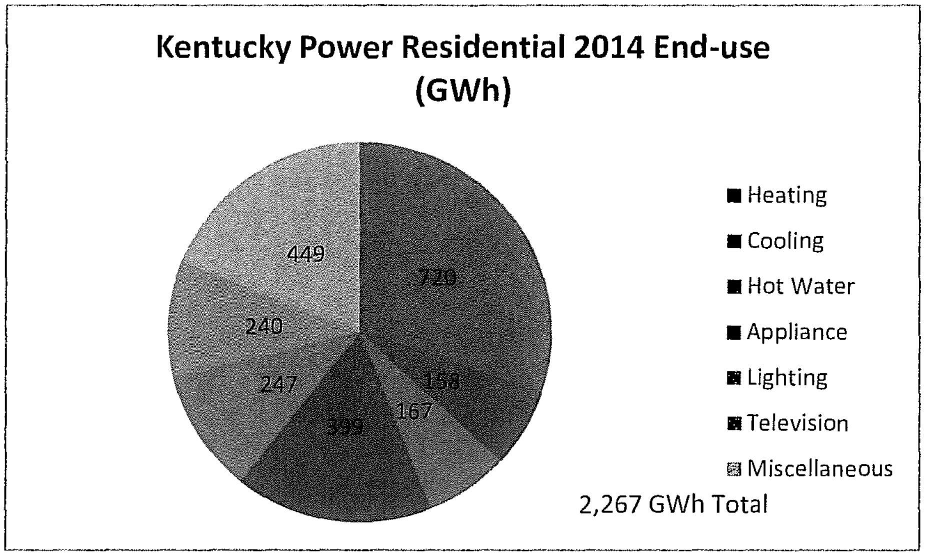
3.5.2 Determining Expanded Programs for the IRP

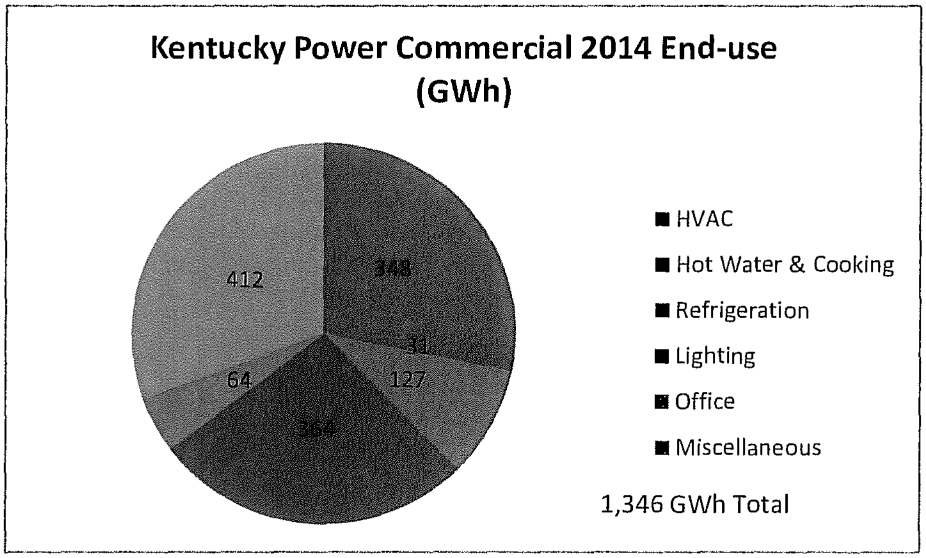
Energy Efficiency

To determine the economic demand-side additions to the plan, a determination was made as to the cost of incremental EE programs as well as the ability to expand current programs. **Figure 7** shows the make up of consumption in Kentucky Power's Residential and Commercial sectors.

[9] http://www.nrel.gov/analysis/tech_cost_dg.html

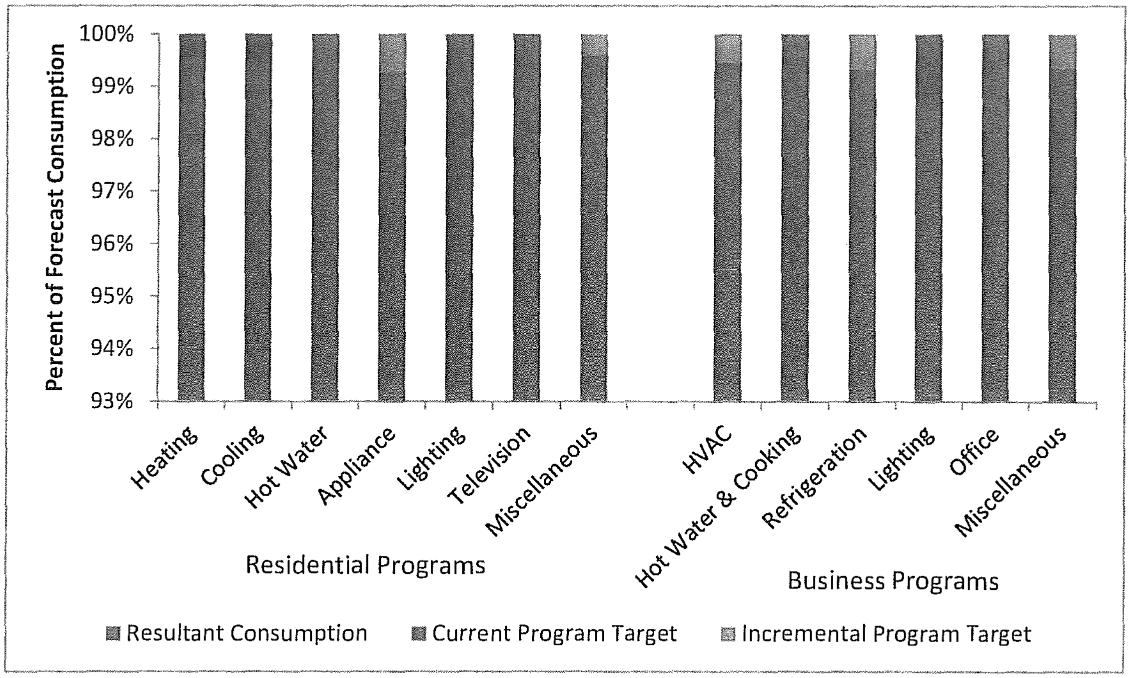
Figure 7: Residential and Commercial 2014 End-use in GWh





Current programs target certain end-uses in both sectors, primarily lighting. Incremental programs can further target those areas or address other end-uses. To determine which end-uses are targeted, in what amounts, Kentucky Power looked at public information from one of the leading EE program administrators, Efficiency Vermont. Efficiency Vermont provides comprehensive and fairly detailed information on the end-uses that are impacted by a utility program as well as measure and program costs. Kentucky Power adapted these measures to fit the climate of Kentucky. **Figure 8** shows the current program targeted end-uses as well as the end-uses that a comprehensive, Vermont-style program would further target.

Figure 8: Current and Incremental End-use Program Target



What can be seen from the chart is that Kentucky Power is already targeting residential heating, cooling and lighting measures in amounts equal to or greater than Vermont. Incremental opportunity may lie in residential appliances and miscellaneous, commercial refrigeration and miscellaneous, and an expansion of commercial HVAC programs. Adoption of these programs is limited to amounts that are commensurate with those seen in Vermont.

In the recent Mitchell Transfer Stipulation and Settlement Agreement, Kentucky Power agreed to increase spending on cost-effective programs from the current level of approximately \$3 million annually to \$4 million in 2014, \$5 million in 2015, and \$6 million thereafter. The Preferred Portfolio described in Chapter 4 includes program levels in concert with that agreement.

VVO

Volt VAR Optimization (VVO) equipment is an additional resource that reduces end-use consumption. This resource is available in amounts that can be reasonably installed and tested in a given year

Demand Response

While introduction of a tariff that allows for the aggregation of smaller commercial and industrial loads would likely result in meaningful resources becoming available, this IRP does not add these resources due to Kentucky Power's current reserve margin. Other options, including expanded residential DR may also be considered in the future.

Distributed Generation

DG resources were evaluated using a solar PV resource, as this is likely the primary distributed resource. Solar also has favorable characteristics in that it produces the majority of its energy at times when power prices in PJM are their highest. Costs were the full net metering rate, which is the credit required by regulation. In spite of relatively low current retail rates, customer-sited distributed generation costs the utility more than the PJM value it provides. **Figure 9** shows the dynamic in effect.

Figure 9: Solar Dynamic Effects

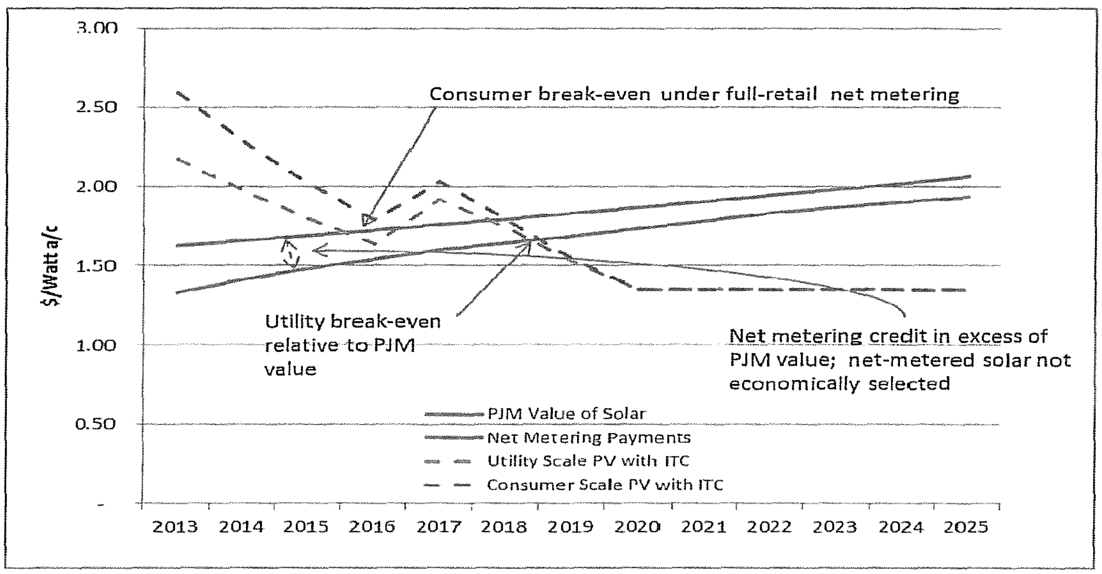


Figure 9 demonstrates a couple of key points regarding distributed generation generally, and distributed solar specifically. First, from the standpoint of the utility, on the basis of revenue requirements, the full net metering retail rate exceeds the PJM value of the capacity and energy provided, typically. Conversely, from the perspective of the customer receiving the full retail rate, this arrangement becomes economic in the near term. This dynamic has been the source of some controversy recently as utilities with high exposure to distributed solar in the Desert Southwest have sought to change net metering rules to ameliorate what amounts to a subsidy to consumers that self-generate at the expense of those customers who do not do so.

With regard to utility-owned (or purchased) solar generation, it is expected to become economic around 2020. This has potentially important implications for Kentucky Power given its exposure to market energy costs, particularly if carbon costs materialize as expected. The addition of generation that has no fuel or emissions costs may prove to be a valuable hedge against volatile fuel and emissions costs.

3.5.5 Evaluating Incremental Demand-Side Resources

(807 KAR 5:058 Sec. 8.3.e.1.)

The *Plexos*® model that will be further discussed in Chapter 4 allows the user to input demand-side EE, DR, and VVO as "resources" and model them along-side supply-side, and all other options. Resources were constructed with the following cost profiles (stated in "cost/first-year savings"):

Table 9: Incremental Demand-side Resources Cost Profiles

Kentucky Power				
Residential	Annual GWh	Cost ($000)	Measure Life	Shape
Electric Cooking	1.0	$1,156	14	Residential Other
Refrigerator	2.0	$951	12	Residential Other
Miscellaneous	2.0	$500	9	Residential Other
Commercial				
Cooling	2.0	$184	16	Commercial Cooling
Refrigeration	1.0	$285	11	Commercial Other
Miscellaneous	3.0	$917	10	Commercial Other

Further detail of the per participant costs is included in **Table 12** of the Chapter 3 Appendix.

VVO

Table 10: VVO Cost Profile

	GWh	Cost ($000)	Measure Life	Shape
VVO 1	22.1	6,250	20	VVO
VVO 2	18.6	6,250	20	VVO

Demand Response

DR resources would be assumed to be at a cost that is less than the PJM RPM cost of capacity. This assumption is in line with how these resources are typically priced to ensure a margin of profitability exists for curtailment service providers. However, as previously mentioned, given the Company's current (PJM) capacity length resulting from the Preferred Portfolio, there would be little incentive to offer such enrollment program in the near-term.

Customer-Owned (Distributed) Solar

Customer-owned resources, generally, and solar resources, specifically were modeled as a stream of payments valued at the full-retail rate which is consistent with current net metering rules. This treatment is independent of assumptions of installation and operating costs of the solar resources, as they are borne by the customer, and are not part of revenue requirements. This is consistent with how other demand-side resources are modeled.

3.5.6 Optimizing the Incremental Demand-side Resources

(807 KAR 5:058 Sec. 8.3.e.3.)

The *Plexos*® software views demand-side resources as non-dispatchable "generators" that produce energy similar to non-dispatchable supply-side generators such as wind or solar. Thus, the value of each resource is impacted by the hours of the day and time of the year that it "generates" energy. *Plexos*® optimized under five different economic scenarios.

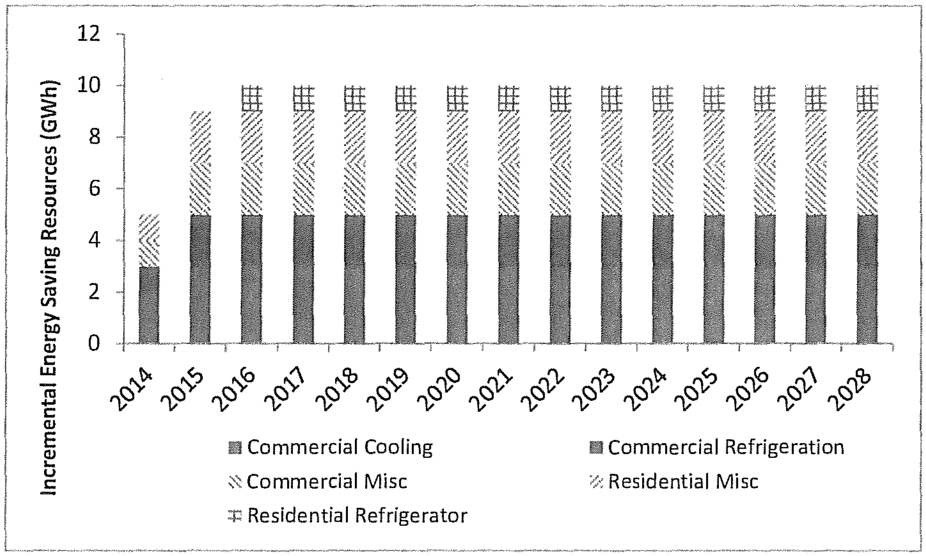
3.5.7 Expected Program Costs and Benefits

(807 KAR 5:058 Sec. 8.3e.2,4, and 5.)

<u>Energy Efficiency</u>

EE resources optimized in equal amounts under all five economic scenarios. The Commercial Cooling and Commercial Refrigeration measures were selected in every year in the forecast period beginning in 2014; adding an incremental 3 GWh of annual energy reductions each year. The failure to select other measures in any of the scenarios reflects the wide gulf in the relative cost-effectiveness of the measures. These additions, in these quantities, would not constitute an expansion of programs that is in concert with the Mitchell Stipulation and Settlement Agreement. The preferred portfolio adds additional efficiency programs to approximate the spending targets in the agreement, increasing the incremental efficiency resources from 3 GWh to 5 GWh in 2014 and 10 GWh by 2016 as depicted in **Figure 10**. That level, along with the current programs, represents energy savings of 0.9% of residential and commercial sector consumption annually.

Figure 10: Incremental Energy Savings Resources



VVO

The VVO resources that are currently being installed and are expected to be operational in 2014 were allowed to optimize in 2014 and did under all economic scenarios. Circuits where less savings are expected optimize at different times, depending on the economic scenario. The "blocks" of VVO consist of bundles of circuits that save between 3-4 MWs of summer peak demand and 18-24 GWh of energy annually. **Table 11** shows the schedule when VVO resources optimized under different economic scenarios.

Table 11: VVO Blocks

	VVO Blocks				
	Base Band	Low Band	High Band	High CO2	No CO2
2014	1	1	1	1	1
2015	0	0	0	0	0
2016	0	0	0	0	0
2017	0	0	0	0	0
2018	0	0	0	0	0
2019	0	0	0	0	0
2020	0	0	0	0	0
2021	3	1	3	3	3
2022	0	2	0	0	0
2023	0	0	0	0	0
2024	0	0	0	0	0
2025	0	0	0	0	0
2026	0	0	0	0	0
2027	0	0	0	0	0
2028	0	0	0	0	0

These estimates are subject to future revision as more operational information is gained from the installation that is currently underway.

Distributed Solar

From the perspective of Kentucky Power, distributed solar resources did not optimize under any economic scenario during the planning period as discussed in Section 3.5.2.

The estimated cost to Kentucky Power's *customers* to implement the expanded programs in the Preferred Portfolio, including Distributed Solar, are included in **Table 13** in the Chapter 3 Appendix.

3.5.8 Discussion and Conclusion

Incremental EE programs, above programs that are currently approved, will cost more than current programs as non-lighting meaures are implemented in greater proportion. Further expansion into the commercial sector may provide the more cost-effective prospective programs incremental to the current portfolio, although, it will likely take a more comprehensive approach, which remains cost-effective in total, to reach the spending targets in the Mitchell Stipulation and Settlement Agreement.

The current VVO program that is underway has been validated from an economic perspective. The model did not optimize an expansion of the program until next decade, but that result is subject to the realization of operational and cost data that will arise from the current program.

DG, when compensated at the full retail net metering rate, as required by current rules, is not economical from a (utility) revenue requirements perspective. *However*, that excess compensation does improve the economics from a DG consumer perspective, making it likely Kentucky Power will see these resources being added on the system by its customers over the time.

3.6 Issues Addressed in KPSC Staff Report

The Commission issued their Staff's report on Kentucky Power's 2009 Integrated Resource Plan and requested that the Company address certain issues in its next IRP report (this report). The following issues pertaining to DSM are restated from the Staff report and addressed below:

Kentucky Power should work to increase its portfolio of DSM programs to assist in achieving demand reductions and further examine the expansion of current programs.

Kentucky Power expanded its program portfolio from seven residential programs to twelve residential and commercial programs. Further, the Company has agreed to increase spending on cost-effective programs to $6 million annually by 2016.

3.7 Chapter 3, Appendix - DSM Program Descriptions

(807 KAR 5:058 Sec. 7.2g. and Sec. 8.3.e.1, 3-5)

1. Targeted Energy Efficiency Program

The Kentucky Power Targeted Energy Efficiency Program (TEE) provides weatherization and EE services to qualifying residential customers who need help reducing their energy bills. The Company provides funding for this program through the Kentucky Community Action network of not-for-profit community action agencies. The program funding and service is supplemental to the Weatherization Assistance Programs offered by local community action agencies. This program provides energy saving improvements to existing homes. Program services can include these items, as applicable and per program guidelines:

- Energy audit
- Air infiltration diagnostic test to find air leaks
- Air leakage sealing
- Attic, floor, side-wall insulation
- Duct sealing and insulation
- High efficiency compact fluorescent light bulbs (CFLs)
- Domestic hot water heating insulation (electric)
- Customer education on home energy efficiency
- Partial funding High efficiency heat pump (restrictions apply)

2. High Efficiency Heat Pump-Mobile Home Program

The Kentucky Power Mobile Home High Efficiency Heat Pump Program (MHHP) offers an incentive to residential customers who live in a mobile home and upgrade their central electric resistance heating system with a new, high efficiency heat pump unit. To qualify, the new heat pump unit must have a minimum rating of 13 SEER (Seasonal Energy Efficiency Ratio) and 7.7 HSPF (Heating Seasonal Performance Factor).

3. Mobile Home New Construction Program

The Kentucky Power Mobile Home New Construction Program (MHNC) offers an incentive to residential customers who purchase a new mobile home having an insulation upgrade and a high efficiency heat pump unit. To qualify, the new heat pump unit must have a minimum rating of 13 SEER (Seasonal Energy Efficiency Ratio) and 7.7 HSPF (Heating Seasonal Performance Factor).

4. Modified Energy Fitness Program

The Kentucky Power Modified Energy Fitness Program (MEF) provides weatherization and EE services to qualifying residential customers who need help reducing their energy bills. This program provides energy saving improvements to existing homes. Program services can include these items, as applicable and per program guidelines:

- Complete energy audit with customized report
- Air infiltration diagnostic test to find air leaks
- Energy savings booklet
- Energy conservation measures installed (per program guidelines)

5. High Efficiency Heat Pump Program

The Kentucky Power High Efficiency Heat Pump Program (HEHP) offers an incentive to residential customers who upgrade their central electric resistance heating system or existing less efficient heat pump system to a new, high efficiency heat pump unit. To qualify, the new heat pump unit must have a minimum rating of 13 SEER (Seasonal Energy Efficiency Ratio) and 7.7 HSPF (Heating Seasonal Performance

Factor) for resistance heat upgrade, or 14 SEER and 8.2 HSPF for upgrading from a less efficient existing heat pump to a high efficiency heat pump unit.

6. Energy Education for Students Program

The Kentucky Power Student Energy Education Program (EEFS) targets 7th grade students at participating schools within the Kentucky Power Company service territory. The program introduces them to various aspects of responsible energy use and conservation. With this program, students use math and science skills to learn how energy is produced and used, and methods to conserve energy that can easily be applied in their own homes.

The Company partners with the National Energy Education Development Project (NEED) to implement this program. NEED is an established and respected energy education organization that has been presenting programs for teachers and students in Eastern Kentucky for many years. The program, provided at no cost to participating school systems, includes:

- Professional development for teachers where they will receive classroom curriculum and educational materials on energy, electricity, economics and the environment
- Each Student receives compact fluorescent lights (CFLs) to help students apply their classroom learning at home
- An opportunity for participating students and their families to make the ENERGY STAR® Pledge

7. Community Outreach Compact Fluorescent Lighting (CFL) Program

Through the CFL Outreach Program, Kentucky Power distributes compact fluorescent lights (CFLs) to customers at company-sponsored community events. The program aims to educate and encourage customers to save money by using energy efficient lighting. The company sponsors community distribution events throughout the year where a package of CFLs is distributed to each qualifying residential customer. Customer energy education is also provided at these events.

8. Residential HVAC Diagnostic and Tune-up

The residential and commercial customer will be offered an incentive when receiving this Diagnostic and Tune-up service from a participating, state licensed contractor. It will help extend the life of the system, reduce energy costs and improve the interior comfort of your business. The diagnostic and tune-up service includes testing for inefficiencies in air conditioning and heat pump systems due to air-restricted indoor or outdoor coils and over or under refrigerant charge.

9. Residential Efficient Products

The Kentucky Power Residential Efficient Products Program (REP) offers residential customers instant rebates on ENERGY STAR® lighting products at participating retail stores across our service territory. The program targets the purchase of lighting products through in-store promotion as well as special sales events. Customer incentives facilitate the increased purchase of high-efficiency products while in-store signage, sales associate training and support makes provider participation easier.

A convenient online store where you can shop for energy efficient lighting and get immediate discounts is also available, including specialty and hard-to-find CFLs.

10. Small Commercial HVAC Diagnostic Tune-up

The commercial customer will be offered an incentive when receiving this Diagnostic and Tune-up service from a participating, state licensed contractor. It will help extend the life of the system, reduce energy costs and improve the interior comfort of your business. The diagnostic and tune-up service includes testing for inefficiencies in air conditioning and heat pump systems due to air-restricted indoor or outdoor coils and over or under refrigerant charge.

11. Small Commercial High Efficiency Heat Pump/Air Conditioner

The commercial customer will receive financial incentives for upgrading to a new qualifying central air conditioning or heat pump system (up to a five-ton unit with a Consortium for Energy Efficiency (CEE) Tier 1 rating). The incentive helps offset the cost of the investment, and the improved efficiency can give long-term savings.

12. Commercial Incentive

The Kentucky Power Commercial Incentive Program (CIP) offers a convenient way to receive funding for common EE projects. The Commercial Inventive Program provides financial incentives to business customers who implement qualified energy-efficient improvements and technologies.

Incentives are available for a variety of energy-saving technologies in existing buildings and new construction projects. Choose from a menu of prescriptive measures with standardized incentives. The program menu includes, but is not limited to, incentives for:

- Lighting
- Heating, ventilation, and air conditioning (HVAC)
- Food Service and Refrigeration

A complete list of the eligible equipment and incentive amounts can be found in the Program Application located at KentuckyPower.com/save/programs.

Incremental Energy Efficiency Resource Cost Assumption Detail:

Table 12: EE Resource Costs

Program	Gross MWh	measure life	Incentives	participant costs	Net MWh	Net Lifetime MWh	Admin Costs	Net to Gross	Adjustments for Baseline	Adjusted First Year Savings	$/First year savings	% incentive	Year	Class	Program % of Sector
A/C	13.3	16	2,160	2,069	14.4	227.6	2,006	0.8	2.1	22.7	184	0.51	2011	Business	0.08%
Hot Water	5.5	10	1,794	680	6.0	59.6	2,006	0.8	1.0	4.4	861	0.73	2011	Business	0.00%
Industrial Process	96.0	13	10,145	35,414	96.6	1,260.1	2,006	0.8	1.0	76.8	158	0.22	2011	Business	0.11%
Lighting	12.0	13	3,935	2,245	12.5	166.6	2,006	0.6	0.5	3.6	1,645	0.64	2011	Business	0.26%
Motors	22.3	11	3,521	6,876	23.1	258.7	2,006	0.8	1.0	17.8	310	0.34	2011	Business	0.07%
Refrigeration	19.8	11	2,504	3,780	21.1	230.1	2,006	0.8	1.0	15.8	285	0.40	2011	Business	0.06%
All Other	5.6	10	2,104	(56)	5.8	57.5	2,006	0.8	1.0	4.5	917	1.03	2011	Business	0.12%
Total	12.2	13	3,444	2,316	12.7	160.8	2,006	0.7	0.7	6.2	873	0.60	2011	Business	0.67%

Program	Gross MWh	measure life	Incentives	participant costs	Net MWh	Net Lifetime MWh	Admin Costs	Net to Gross	Adjustments for Baseline	Adjusted First Year Savings (MWh)	$/First year MWh savings	% incentive	Year	Class	Program % of Sector
A/C	0.1	16	30	21	0.1	1.9	161	0.8	2.1	0.2	788	0.59	2011	Residential	0.01%
Cooking and Laundry	0.3	14	71	362	0.3	4.5	161	0.8	1.0	0.2	1,156	0.16	2011	Residential	0.03%
Lighting	2.1	7	197	33	2.5	17.1	161	0.5	0.8	0.8	453	0.86	2011	Residential	0.41%
Refrigeration	0.5	12	213	39	0.5	5.9	161	0.8	1.0	0.4	951	0.85	2011	Residential	0.05%
Space Heat	0.7	24	106	191	0.9	20.6	161	0.8	0.6	0.4	743	0.36	2011	Residential	0.01%
All Other	0.6	9	98	(44)	0.6	5.8	161	0.8	1.0	0.5	500	1.81	2011	Residential	0.09%
Total	1.3	8	157	70	1.5	11.5	161	0.5	0.8	0.6	545	0.69	2011	Residential	0.57%

Table 13: DSM Program Costs Estimates

Kentucky Power Demand-side Estimated Cost - Preferred Plan ($000)						
	Expanded Energy Efficiency	Approved Energy Efficiency	Sub-total Energy Efficiency	VVO	Distributed Solar (Net Metering)	Total DSM
2014	1,024	3,100	4,124	618	-	4,742
2015	1,996	3,162	5,158	618	-	5,776
2016	2,530	3,225	5,756	618	2,101	8,475
2017	2,581	3,290	5,871	618	714	7,203
2018	2,633	3,356	5,988	618	729	7,335
2019	2,685	3,423	6,108	618	743	7,469
2020	2,739	3,491	6,230	618	1,516	8,364
2021	2,794	3,561	6,355	1,086	1,547	8,988
2022	2,850	3,632	6,482	1,086	2,367	9,935
2023	2,907	3,705	6,611	1,086	2,414	10,112
2024	2,965	3,779	6,744	1,086	3,283	11,113
2025	3,024	3,854	6,879	1,086	4,186	12,151
2026	3,085	3,932	7,016	1,086	5,124	13,226
2027	3,146	4,010	7,156	1,086	6,969	15,212
2028	3,209	4,090	7,300	1,086	8,886	17,272

4.0 RESOURCE FORECAST

(807 KAR 5:058 Sec.8.1. and Sec. 8.2.d.)

4.1 Resource Planning Objectives

(807 KAR 5:058 Sec.8.5.a. and Sec. 8.5.c.)

The primary objective of power system planning is to assure the reliable, adequate and economical supply of electric power and energy to the consumer, in an environmentally compatible manner. Implicit in this primary objective are related objectives, which include, in part: (1) maximizing the efficiency of operation of the power supply system, and (2) encouraging the wise and efficient use of energy.

Other objectives of a resource plan include planning flexibility, creation of an optimum asset mix, adaptability to risk and affordability. In addition, given unique impact on generation of environmental compliance, the planning effort must be in concert with anticipated long-term requirements as established by the environmental compliance planning process.

4.2 Kentucky Power Resource Planning Considerations

4.2.1 General

(807 KAR 5:058 Sec.8.5.b.)

This IRP document presents a plan for Kentucky Power to meet its obligations as a stand-alone company operating in the PJM RTO.

Under the Preferred Portfolio, developed during this planning process, Kentucky Power is anticipated to meet its reserve margin requirements over the forecast period. **Exhibit 4-12** shows the annual capacity additions and resultant reserve margin for this Plan.

4.2.2 Generation Reliability Criterion

(807 KAR 5:058 Sec.8.5.d.)

On October 1, 2004, the AEP System-East Zone transferred functional control of its transmission facilities, as well as generation dispatch including the transmission and generation facilities owned by Kentucky Power, to PJM (the Commission approved this action by order dated September 10, 2003, in consolidated Cause Nos. 42350 and 42352). With that, the PJM Reliability Assurance Agreement defines the requirements surrounding various reliability criteria, including measuring and ensuring capacity adequacy. In that regard, each Load Serving Entity (LSE) in PJM is required to provide an amount of capacity resources determined by PJM based on several factors, including PJM's Installed Reserve Margin (IRM) requirement. The IRM is based on the amount of resources needed to maintain, among other things, a loss-of-load expectation of one day in ten years. Additionally, load diversity between each LSE and the PJM RTO zones and generating asset equivalent forced outage rates are other factors that impact each LSE's required minimum reserve levels.

The PJM RTO determines generation planning reserve requirements using probabilistic methods and a target loss of load criterion of one day in ten years. The method is similar to that historically used by Kentucky Power. PJM determines an installed capacity margin that has to be met by each of its members. This is converted into PJM Unforced Capacity (UCAP) requirements. However, for ease of understanding, the requirement is expressed in this report in terms of Installed Capacity (ICAP).

Although the current plan contains a changing mix of capacity through time, it also contains uncertainty surrounding the long-term forecast. As a result, Kentucky Power's IRM was held steady at the current 15.6% threshold for the remainder of the forecast period. However, it is important to note that PJM can revise the IRM annually as required, and as a result Kentucky Power will adjust the future IRM estimates accordingly.

In February 2007, AEPSC, as agent for the AEP System-East Zone LSEs, gave formal notice of its intent to opt-out of the initial PJM "Reliability Pricing Model" (RPM) capacity auction and, instead, meet its capacity resource obligation through participation in the optional, FERC-authorized Fixed Resource Requirement (FRR) construct. FRR requires Kentucky Power to set forth its future capacity resource plan under, essentially, a "self-planning" format. This is an approach that would, however, initially not give Kentucky Power access to those generating sources offered into the PJM capacity auction, but rather would allow Kentucky Power to be free to plan for and build (or buy) the required generating capacity that would best fit the needs of its customers - such capacity purchases being limited by rule to either non-PJM generation sources, or PJM generation sources not cleared/picked-up within the RPM auction process.

Kentucky Power and the remaining two cost-based affiliates that are party to the proposed PCA—APCo and I&M—have continued to opt out of the RPM capacity auction through the 2016/17 delivery year, for which the auction was held in May 2013 and will determine for each subsequent year whether to continue to utilize FRR for an additional year *or* to opt-in to the RPM auction for a minimum five-year period. That election for the next, 2017/18, delivery year has not yet been made.

4.2.3 Existing Pool and Bulk Power Arrangements

4.2.3.1 Interconnection Agreement

As stated in Section 1.1, on December 17, 2010, in accordance with Section 13.2 of the Pool Agreement, each of the Pool members provided notice to the other members (and to AEPSC, as agent) to terminate the Pool Agreement (which includes the IAA), on January 1, 2014. As a result, effective January 1, 2014, Kentucky Power will be responsible for its own generation resources and will need to maintain an adequate level of power supply resources to individually meet its own load requirements for capacity and energy, including any required reserve margin.

4.2.3.2 Transmission Agreement

The AEP System Transmission Agreement, updated and approved by FERC Order on October 29, 2010, provides for the sharing among the members of the AEP System-East Zone, including Kentucky Power, of the costs incurred by the members for the ownership, operation, and maintenance of their portions of the high voltage transmission system, in order to enhance equity among the members for the continued development of a reliable and economic high voltage system. Members having high voltage transmission investments greater than their respective load shares receive payments from members with investments less than their respective load shares.

4.2.3.3 PJM Membership

On October 1, 2004, the AEP System-East Zone, including Kentucky Power, joined PJM. PJM is a FERC-approved RTO that coordinates the movement of wholesale electricity in all or parts of thirteen states and the District of Columbia. PJM manages a regional planning process for expansion of the transmission system and continuously monitors the transmission grid. PJM operates a competitive wholesale electricity market and dispatches the generating units of its members, based on energy offers made by the members, seeking to provide the lowest possible cost of electricity within its footprint. PJM sets generation planning reserve requirements for its members.

4.2.4 Environmental Compliance

(807 KAR 5:058 Sec.8.5.f)

4.2.4.1 Introduction

In support of requirements found in 807 KAR 5:058 Sec.8.5.f, the following information provides background on both current and future environmental (including air emissions) regulatory compliance plan issues within the Kentucky Power system. The Company's goal is to develop a comprehensive plan that not only allows Kentucky Power to meet the future resource needs of the Company in a reliable manner, but also to meet increasingly stringent environmental requirements in a cost-effective manner.

4.2.4.2 Air Emissions

There are numerous air regulations that have been promulgated or that are under development, which will apply to Kentucky Power's facilities. Currently, air emissions from plants are regulated by Title V operating permits that incorporate the requirements of the Clean Air Act (CAA) and the State Implementation Plan (SIP). Other applicable requirements include those related to the Clean Air Interstate Rule (CAIR), MATS and the New Source Review (NSR) Consent Decree. Several air regulatory programs are under development and will apply to the Rockport and Mitchell plants, including those related to the regulation of GHG and revisions to the National Ambient Air Quality Standards (NAAQS) for SO_2, NO_x, fine particulate matter, and ozone.

Potential air emissions at Kentucky Power's units, including the Rockport and Mitchell units, are reduced through the use of all or some of a combination of electrostatic precipitators (ESP), low sulfur coal, low NO_x burners, over-fire air (OFA), activated carbon injection (ACI), Wet FGD, SCR, as well as dry fly-ash handling systems.

In past years, Kentucky Power has been a party to the IAA, Modification 1, effective 1996. Through this agreement, Kentucky Power jointly purchased SO_2 allowances procured for the AEP-East compliance. Additionally, any SO_2 allowance excesses or shortages were sold to or purchased from the other parties to the agreement if needed.

Environmental regulations have expanded beyond those covered by the IAA. For example, the IAA does not cover the allowance program established for emissions of NO_x. In addition, evolving environmental regulations such as the MATS Rule establish unit-level emission requirements, rather than system-wide emission caps.. For these reasons, on December 17, 2010, in accordance with Section 13.2 of the Pool Agreement, each of the Pool members provided notice to the other members (and to AEPSC, as agent) to also terminate the IAA, in addition to the Pool Agreement, on January 1, 2014.

4.2.4.3 Environmental Compliance Programs

4.2.4.3.1 Title IV Acid Rain Program

The Title IV Acid Rain Program rules were developed in response to the CAA Amendments of 1990 and required state environmental agencies to promulgate rules implementing the Federal program. Compliance with Title IV SO_2 requirements involved continually evaluating alternative fuel strategies, exercising opportunities to purchase sulfur dioxide allowances, and retrofit of post-combustion technologies in order to lower the overall cost of compliance.

The acid rain NO_x reduction program was also implemented using a two-phase approach, with the first phase becoming effective in 1996 and the second phase in 2000. Under the NO_x reduction program, the acid rain rules established annual NO_x rates that varied depending on boiler-type. However, the rules allowed companies to comply with the Title IV NO_x standards by using system-wide averaging plans. For Title IV NO_X compliance, AEP's strategy included installing low-NO_X burner technologies on its Phase II NO_X units and using an averaging plan for its remaining generating units.

4.2.4.3.2 NOx SIP Call

In addition to the Title IV NO_x reduction program, the NO_x SIP Call was designed to reduce the interstate transport of NO_x emissions that were determined to significantly impact downwind ozone concentrations. For those states opting to meet the obligations of the NO_x SIP call through a cap and trade program, the EPA included a model NO_x Budget Trading Program rule (40 CFR 96), which was developed to facilitate cost effective emissions reductions of NO_x from large stationary sources. The NO_x SIP Call rules generally required EGUs to reduce NO_x emissions to a level roughly equivalent to a 0.15-lb/mmBtu emission rate, applicable during the ozone season that runs from May 1st through September 30th each year. The initial compliance deadline for the NO_x SIP Call emission reductions was May 31, 2004. The SIP Call utilized an emissions allowance system that allowed AEP and Kentucky Power to comply with the rates by the most cost-effective method, which was either to install control technology, purchase allowances, or a mix of both.

Planning for the NO_x SIP Call allowances and emissions was performed for Kentucky Power and AEP-East utilizing the IRP process, review of emissions and control effectiveness, allowance availability, NO_x market prices and proposed regulatory changes. Projected emissions, including any future changes to the NO_x reduction effectiveness, were compared to the available allowance inventory including any potential effects of progressive flow control and projected inventory to determine the amount of allowances that were required to ensure compliance. Flow control provisions were included in the NO_x SIP Call to discourage excessive use of banked allowances in a particular ozone season. Flow control was triggered if the total number of banked allowances from all sources exceeded 10 percent of the region-wide NO_x emissions budget. The compliance plan for Big Sandy Plant to meet this requirement included installation of an OFA burner modification and water injection system and boiler tubes overlay on Unit 1 and installation of a selective catalytic reduction (SCR) system on Unit 2. The latter installation also required upgrading the Unit 2 ESP. Similar NO_X reduction technologies were implemented at other units across the AEP System. Beginning in 2009 with the commencement of CAIR, the NO_x Budget SIP Call Program and progressive flow control ended.

4.2.4.3.3 Clean Air Interstate Rule (CAIR)

On March 10, 2005, the EPA announced the CAIR, which called for significant reduction of SO_2 and NO_x from EGUs. The CAIR program incorporated three cap-and-trade programs: an ozone season NO_x reduction program that replaced the NO_x SIP Call program, an annual NO_x reduction program, and an annual SO_2 reduction program that was administered through the Title IV Acid Rain Program. In order for Kentucky Power to have maintained sufficient allowances to be compliant with the CAIR, it planned to purchase a significant number of allowances on an annual basis.

On July 11, 2008, the District of Columbia Circuit Court of Appeals issued a ruling vacating the CAIR and remanding the rule back to the EPA for revision. However, on December 23, 2008, the Court indicated in a second ruling that the CAIR was being remanded to EPA for revision and was not being vacated. Planning for compliance at this time for CAIR was necessary, but the Company was mindful that more stringent and restrictive emission policies would likely be the result of the revision.

EPA finalized the Cross State Air Pollution Rule (CSAPR) in 2011 to replace CAIR and reduce the interstate transport of NO_x and SO_2 emissions. The U.S. Court of Appeals for the District of Columbia Circuit vacated CSAPR in August 2012 based on the methodology used to establish emissions reductions and EPA's failure to allow states to develop their own emission reduction plans in the first instance. On June 24, 2013, the U.S. Supreme Court granted EPA's appeal of the D.C. Circuit decision to vacate CSAPR, with oral arguments being heard before the Court on December 10, 2013. A decision is not expected until 2014. CAIR requirements remain in place and no immediate action from states or affected sources is expected.

4.2.4.3.4 MATS Rule

The final MATS Rule became effective on April 16, 2012, with compliance required within three years of this date (with the possibility of a one-year administrative extension in certain circumstances). This rule regulates emissions of hazardous air pollutants (HAPs) from coal and oil-fired electric generating units. HAPs regulated by this rule are: 1) mercury; 2) several non-mercury metals such as arsenic, lead, cadmium and selenium; 3) various acid gases including hydrochloric acid (HCl); and 4) many organic HAPs. The MATS Rule includes stringent emission rate limits for several individual HAPs, including mercury. In addition, this rule contains alternative stringent emission rate limits for surrogates representing two classes of HAPs, acid gases and non-mercury particulate metal HAPs. The surrogates for the non-mercury particulate metal and acid gas HAPs are filterable particulate matter (PM) and HCl, respectively. The rule regulates organic HAPs through work practice standards.

AEP and Kentucky Power successfully tested and installed an active carbon injection (ACI) system to mitigate mercury emissions at the Rockport Plant (originally to meet the requirements of the now-vacated Clean Air Mercury Rule), and recently obtained approval from the Indiana Utility Regulatory Commission to install a dry sorbent injection (DSI) technology to assure compliance with the MATS requirements. The Mitchell Plant is anticipated to meet the requirements set forth in the MATS Rule without modification.

4.2.4.3.5 NSR Settlement

On October 9, 2007, AEP entered into a consent decree with the Department of Justice and other parties pertaining to the interpretation of the EPA's new source review (NSR) requirements (the "NSR Consent Decree"), with the purpose of the agreement being to settle all complaints filed against AEP and its affiliates, including Kentucky Power. Kentucky Power was required by the NSR Consent Decree to continuously operate low NO_X burners and burn a coal with a sulfur content no greater than 1.75 lb./mmBTU on an annual average basis as of Otober 9, 2007 for Big Sandy Unit 1, which is consistent with the unit's previous fuel specification. Kentucky Power was also required to continuously operate an SCR on Big Sandy Unit 2 by January 1, 2009. The NSR Consent Decree also required Kentucky Power to retrofit Big Sandy Unit 2 with an FGD system, or retire or repower the unit, by December 31, 2015.

The NSR Consent Decree also originally required AEP to retrofit SCR and FGD systems on Rockport Units 1 and 2, in which Kentucky Power owns a 15% interest, by December 31, 2017 and December 31, 2019, respectively.

Minor changes were made to the Consent Decree in 2009 and 2010 (the First and Second Modifications) to adjust the compliance dates for APCo's Amos Units 1 and 2 to correspond to actual outage schedules. These changes did not impact the Big Sandy or Rockport Plants.

On February 22, 2013, AEP, along with the DOJ, EPA, and other parties, filed a proposed Third Modification to the Consent Decree in the United States District Court for the Southern District of Ohio, Eastern Division. This Modification to the NSR Consent Decree allows AEP to install DSI on both units at Rockport Plant by April 16, 2015, and defer the installation of high efficiency scrubbers on Units 1 and 2 until December 31, 2025 and December 31, 2028, respectively.

The Third Modification to the Consent Decree also contains revised annual NO_x and SO_2 caps for the AEP operated coal units for AEP-East, of which Kentucky Power is a part. These annual caps are displayed in **Tables 14** and **15**.

Table 14: NSR Consent Decree Annual (AEP) NO_x Cap

Calendar Year	Annual Tonnage Limitations for NO_x
2009	96,000
2010	92,500
2011	92,500
2012	85,000
2013	85,000
2014	85,000
2015	75,000
2016, and each year thereafter	72,000

Table 15: Third Modification to the Consent Decree Annual (AEP) SO_2 Cap

Calendar Year	Annual Tonnage Limitations for SO_2
2016	145,000
2017	145,000
2018	145,000
2019-2021	113,000
2022-2025	110,000
2026-2028	102,000
2029, and each year thereafter	94,000

The Modified Consent Decree also established annual tonnage limits for SO_2 for the Rockport Plant. These annual caps—applicable to the full (100%)-plant are displayed in **Tabe 16**.

Table 16: Third Modification to the Consent Decree Annual SO_2 Cap for Rockport Plant

Calendar Year	Annual Tonnage Limitations for SO_2
2016	28,000
2017	28,000
2018	26,000
2019	26,000
2020-2025	22,000
2026-2028	18,000
2029, and each year thereafter	10,000

4.2.4.4 Future Environmental Rules

Several environmental regulations have been proposed that will apply to the electricity generating sector once finalized. The following is not meant to be comprehensive, but lists some of the major issues that will need to be addressed over the forecast period.

4.2.4.4.1 Coal Combustion Residuals (CCR) Rule

The EPA issued a proposed rule in June 2010 to address the management of residual byproducts from the combustion of coal in power plants (coal ash) and captured by emission control technologies, such as FGD. The proposed rule includes specific design and monitoring standards for new and existing landfills and surface impoundments, as well as measures to ensure and maintain the structural integrity of surface impoundment/ponds. The proposed CCR rulemaking would require the conversion of most "wet" ash impoundments to "dry" ash landfills, the relining or closing of any remaining ash impoundment ponds, and the construction of additional waste water treatment facilities by approximately January 1, 2018. Kentucky Power anticipates that the CCR Rule—based on the preliminary assumption that these residual materials may be categorized as "Subtitle D," or non-hazardous materials—would require plant modifications and capital expenditures (which are factored into this IRP) to address these requirements by, approximately, the 2018 timeframe. The final rule is expected in 2014.

4.2.4.4.2 Effluent Limitation Guidelines and Standards (ELG)

The EPA proposed an update to the ELG for the steam electric power generating category in the Federal Register on June 7, 2013. The ELG would require more stringent controls on certain discharges from certain EGUs and will set technology-based limits for waste water discharges from power plants with a main focus on process and wastewater from FGD, fly ash sluice water, bottom ash sluice water and landfill/pond leachate. Kenrucky Power anticipates that wastewater treatment projects will be necessary at the Rockport and Mitchell units and these have been considered as part of the respective long-term unit evaluations. The final rule is expected in 2014.

4.2.4.4.3 Clean Water Act "316(b)" Rule

A proposed rule for the Clean Water Act 316(b) was issued by the EPA on March 28, 2011, and final rulemaking is expected in early 2014. The proposed rule prescribes technology standards for cooling water intake structures that would decrease interference with fish and other aquatic organisms. Given that the Rockport and Mitchell units are already equipped with natural draft, hyperbolic cooling towers, the most significant potential impact of the proposed rule would be the need to install additional fish screening at the front of the water intake structure.

4.2.4.4.4 National Ambient Air Quality Standards (NAAQS)

The Clean Air Act requires the EPA to establish and periodically review NAAQS designed to protect public health and welfare. Several NAAQS have been recently revised or are under review, which could lead to more stringent SO_2 and NO_x limits. This includes NAAQS for SO_2 (revised in 2010), NO_2 (revised in 2010), fine particulate matter (revised in 2012), and ozone (expected to be revised in 2014). The scope and timing of potential requirements is uncertain.

4.2.4.4.5 GHG Regulations

For many years, the potential for requirements to reduce greenhouse gas emissions, including carbon dioxide, has been one of the most significant issues facing Kentucky Power and AEP. The EPA proposed GHG NSPS for fossil fuel-fired electric generating units in April, 2012. This proposed rule applies only to new sources and proposed an emission standard based on the performance of new natural gas combined cycle units. The EPA did not finalize this rule as expected in the second quarter of 2013. However, on June 25, 2013, President Obama announced a plan to address GHG emissions from fossil-fired power plants. Under President Obama's direction, the EPA issued a revised proposal for the GHG NSPS for new sources on September 20, 2013, and must finalize them in a "timely fashion." For existing sources, the EPA was directed to propose guidelines by June 1, 2014, and finalize those standards by June 1, 2015. States would develop and submit a plan to EPA for implementing the existing source standards by June 30, 2016. The scope and timing of these requirements have not yet been determined. Such GHG rules could impose greater operating costs on Kentucky Power's power plants in future years, either through retrofit costs, efficiency requirements, or potentially, some form of carbon tax and/or cap-and-trade construct.

4.2.4.5 Kentucky Power Environmental Compliance

This 2013 IRP considers the impacts of final and proposed EPA regulations to Kentucky Power generating facilities, inclusive of Big Sandy Unit 1, Rockport and Mitchell. In addition, the IRP development process assumes there will be future regulation of GHG/CO_2 emissions which would become effective at some point in the

2022 timeframe. Emission compliance requirements have a major influence on the consideration of new supply-side resources for inclusion in the IRP because of the potential significant effects on both capital and operational costs. Moreover, the cumulative cost of complying with these rules will ultimately have an impact on proposed retirement dates of existing coal-fueled units that would otherwise be forced to install emission control equipment.

4.3 Procedure to Formulate Long-Term Plan

(807 KAR 5:058 Sec.8.5.a.)

The following steps were involved to develop the resource plan presented in this report. These steps are as follows:

1. Develop the base-case load forecast.
2. Determine overall resource requirements.
3. Identify and screen DSM options.
4. Identify and screen supply-side resource options.
5. Integrate supply-side and demand-side options.
   a. Optimize expanded DSM programs.
   b. Develop optimal supply-side resource expansion plans with expanded DSM.
6. Analyze and Review.

A discussion of these steps follows.

4.3.1 Develop Base-Case Load Forecast

The development of the base-case load forecast is presented in Chapter 2. That initial forecast excludes adjustments for potential future (*i.e.,* expanded) DSM programs but does incorporate a continuation of currently approved programs.

4.3.2 Determine Overall Resource Requirements

The determination of overall resource requirements includes an evaluation of the adequacy of existing generating capability to meet the future forecasted load and peak demand requirements.

4.3.2.1 Existing and Committed Generation Facilities
(807 KAR 5:058 Sec.8.3.b.12.d., Sec. 8.3.d.)

Kentucky Power's existing installed generating capability (as of December, 2013) is shown as part of **Exhibit 4-2**. Kentucky Power's owned capacity consists of the 1,078 MW Big Sandy generating plant, located in Louisa, Kentucky. Kentucky Power also has a unit power agreement with AEP Generating Company (AEG), an affiliate, to purchase 15% (currently a total of 393 MW) of capacity from the two units at the Rockport Plant, located in southern Indiana. Both Kentucky Power Rockport unit power agreements run through December 7, 2022. For planning purposes, it has been assumed that the Rockport agreements extend indefinitely beyond that expiration date. Starting January 1, 2014, Kentucky Power will own 50%, or 780 MW, of both the Mitchell units, which are located in West Virginia and are currently owned by affiliate Ohio Power Company (OPCo).

4.3.2.2 Retrofit or Life Optimization of Existing Facilities
(807 KAR 5:058 Sec.8.2.a.)

Past experience has indicated that, with proper maintenance and operation, coal-fired units can expect to achieve operating lifetimes beyond the traditional nominal 50 to 60 years. Of course, the optimum achievable lifetime is highly unit-specific. Programs have been developed by AEP to attempt to achieve optimal operating lifetimes, and to do so as economically as possible. The work of component refurbishment or replacement is planned and carried out over a long period, so as to minimize total cost and the outage time required. Ultimately, however, retirement of older units must be considered as units become less economic from efficiency, cost, and environmental standpoints.

4.3.2.3 Renewable Energy Plans
(807 KAR 5:058 Sec.8.2.d.)

The State of Kentucky does not have a renewable energy requirement or renewable portfolio standard (RPS). Pursuant to the Mitchell Transfer Stipulation and Settlement Agreement, Kentucky Power agreed to evaluate the prospect of a potential purchase up to 100 MW of wind capacity. Renewable energy options are expected to compete economically with traditional supply-side options in the future.

4.3.2.4 Demands, Capabilities and Reserve Margins –Going-in

Exhibit 4-7 provides a projection of Kentucky Power's peak demands, capabilities and reserve margins for the summer season from 2014 through 2028, assuming no other new resources are added to the system. The projected data reflect the 'Base'-case load forecast, committed sales to non-affiliated utilities, and the amount of Kentucky Power's industrial interruptible load that can be interrupted at the time of the seasonal peak. The projected capabilities assume Big Sandy Unit 2 will be retired in 2015, and Big Sandy Unit 1 will be retired in 2031. It also assumes the transfer of 50% ownership of Mitchell Units 1 and 2 in 2014. Further, until Rockport Units 1 and 2 are fitted with full FGD "scrubbers," their output is subject to SO_2 emissions caps described in the Third Modified NSR Consent Decree previously highlighted in Table 15.

4.3.3 Identify and Screen DSM Options

The identification and screening of DSM options is described in detail in Chapter 3 of this report.

4.3.4 Identify and Screen Supply-side Resource Options

(807 KAR 5:058 Sec.8.2.d. and Sec. 8.5.e.)

4.3.4.1 Capacity Resource Options

(807 KAR 5:058 Sec.8.3.d. and Sec. 8.5.g.)

In addition to market capacity purchase options, new-build options were modeled to represent peaking and baseload/intermediate capacity resource options. To reduce the number of modeling permutations in *Plexos*®, the available technology options were limited to certain representative unit types. However, it is important to note that alternative technologies with comparable cost and performance characteristics may ultimately be substituted should technological or market-based profile changes warrant. The options assumed to be available for modeling analyses for Kentucky Power are presented in **Exhibit 4-9** of the Confidential Supplement. When applicable, Kentucky Power may take advantage of economical market opportunities in the form of limited-term bilateral capacity purchases and discounted generation asset purchases. Such market opportunities could be utilized to hedge capacity planning exposures should they emerge and create (energy) option value to the Company. Prospectively, these opportunities could take the place of currently planned resources and will be evaluated on a case-by-case basis.

4.3.4.2 New Supply-side Capacity Alternatives

As identified in Exhibit 4-9 of the Confidential Supplement, natural gas base/intermediate and peaking generating technologies were considered in this IRP as well as utility-scale solar and wind. However, in an attempt to reduce the problem size within the *Plexos*® modeling application, an economic screening process was used to analyze various options and develop a quantitative comparison for each type of capacity (baseload, intermediate, and peaking) on a forty-year, levelized basis. The options were screened by comparing levelized annual busbar costs over a range of capacity factors.

In this evaluation, each type of technology is represented by a line showing the relationship between its total levelized annual cost per kW and an assumed annual capacity factor. The value at a capacity factor of zero represents the fixed costs, including carrying charges and fixed O&M, which would be incurred even if the unit produced no energy. The slope of the line reflects variable costs, including fuel, emissions, and variable O&M, which increase in proportion to the energy produced.

The best of class technology determined by this screening process was taken forward to the *Plexos*® model. These generation technologies were intended to represent reasonable proxies for each capacity type (baseload, intermediate, peaking). Subsequent substitution of specific technologies could occur in any ultimate plan, based on emerging economic or non-economic factors not yet identified.

AEP's Generation organization is responsible for the tracking and monitoring of estimated cost and performance parameters for a wide array of generation technologies. Utilizing access to industry collaboratives such as EPRI and the Edison Electric Institute, AEP's association with architect and engineering firms and original equipment manufacturers as well as its own experience and market intelligence, this group continually monitors supply-side trends. **Table 17** offers a summary of the most recent technology performance parameter data developed.

Table 17: New Generation Technology Options

Key Supply-Side Resource Option Assumptions (a)(b)(c)

Type	Capability (MW) Std. ISO	Trans. Cost (e) ($/kW)	Emission Rates SO2 (g) (Lb/mmBtu)	Emission Rates NOx (Lb/mmBtu)	Emission Rates CO2 (Lb/mmBtu)	Capacity Factor (%)	Overall Availability (%)
Base / Intermediate							
Combined Cycle (1X1 GE7FA.05)	300	60	0.0007	0.009	116.0	60	89.1
Combined Cycle (2X1 GE7FA.05)	624	60	0.0007	0.009	116.0	60	89.1
Combined Cycle (2X1 GE7FA.05, w/ Duct Firing)	624	60	0.0007	0.009	116.0	60	89.1
Combined Cycle (2X1 GE7FA.05, w/ Duct Firing, Inlet Chillers)	624	60	0.0007	0.009	116.0	60	89.1
Combined Cycle (2X1 GE7FA.05, w/ Duct Firing, Blk Start)	624	60	0.0007	0.009	116.0	60	89.1
Combined Cycle (1X1 SGT6-5000, w/ Evap Coolers)	294	60	0.0007	0.010	116.0	60	89.1
Combined Cycle (2X1 SGT6-5000, w/ Evap Coolers)	609	60	0.0007	0.010	116.0	60	89.1
Combined Cycle (2X1 KA24-2, w/ Evap Coolers)	647	60	0.0007	0.011	116.0	60	89.1
Combined Cycle (2X1 M501GAC, w/ Duct Firing, Inlet Chillers)	780	60	0.0007	0.007	116.0	60	89.1
Peaking							
Combustion Turbine (2X1GE7EA)	164	57	0.0007	0.033	116.0	3	93.0
Combustion Turbine (2X1GE7EA,w/ Blk Start)	164	57	0.0007	0.033	116.0	3	93.0
Combustion Turbine (2X1GE7EA, w/ Inlet Chillers)	164	59	0.0007	0.009	116.0	3	93.0
Combustion Turbine (2X1GE7FA.05, w/ Inlet Chillers)	418	59	0.0007	0.007	116.0	3	93.0
Aero-Derivative (1X GE LM6000PF)	45	60	0.0007	0.093	116.0	3	95.0
Aero-Derivative (2X GE LM6000PF)	91	60	0.0007	0.093	116.0	3	95.0
Aero-Derivative (2X GE LM6000PF, w/ Blk Start)	91	60	0.0007	0.093	116.0	3	95.0
Aero-Derivative (1X GE LMS100PB)	98	59	0.0007	0.011	116.0	30	95.0
Aero-Derivative (2X GE LMS100PB, w/ Blk Start)	196	59	0.0007	0.093	116.0	30	95.0
Aero-Derivative (2X GE LMS100PB, w/ Inlet Chillers)	196	59	0.0007	0.007	116.0	25	95.0
Wartsila 22 X 20V34SG	201	60	0.0007	0.018	116.0	3	94.0

Notes:
(a) Installed cost, capability and heat rate numbers have been rounded.
(b) All costs in 2012 dollars. Assume 1.6% escalation rate for 2012 and beyond.
(c) $/kW costs are based on Standard ISO capability.
(e) Transmission Cost ($/kW,w /AFUDC).
(g) Based on 4.5 lb. Coal.

4.3.4.3 Baseload/Intermediate Alternatives

Coal and Nuclear baseload options were not included in this plan. For coal, the proposed EPA New Source Performance Standards (NSPS) rulemaking[10] effectively makes the construction of new coal plants environmentally/economically impractical due to the implicit requirement of carbon capture and sequestration (CCS) technology. For new nuclear construction, it is financially impractical since it requires (minimally) a $6,000/kW investment cost.

Intermediate generating sources are typically expected to serve a load-following and cycling duty and shield baseload units from that obligation. Historically, many generators have relied on older, smaller, less-efficient/higher dispatch cost, subcritical coal-fired units to serve such load-following roles. Over the last several years, these units' staffs have made strides to improve ramp rates, regulation capability, and reduce downturn (minimum load capabilities). As the fleet continues to age and subcritical units are retired or refueled, other generation dispatch alternatives and new generation will need to be considered to cost effectively meet this duty cycle's operating characteristics.

a. Natural Gas Combined Cycle (NGCC)

An NGCC plant combines a steam cycle and a combustion gas turbine cycle to produce power. Waste heat (~1,100°F) from one or more combustion turbines passes through a heat recovery steam generator (HRSG) producing steam. The steam drives a steam turbine generator which produces about one-third of the NGCC plant power, depending upon the gas-to-steam turbine design "platform," while the combustion turbines produce the other two-thirds.

The main features of the NGCC plant are high reliability, reasonable capital costs, operating efficiency (at 45-60% Low Heating Value), low emission levels, small footprint and shorter construction periods than coal-based plants. In the past 8 to 10 years, NGCC plants were often selected to meet new intermediate and certain baseload needs. NGCC plants may be designed with the capability of being "islanded" which would allow them, in concert with an associated diesel generator, to perform system restoration ("black start") services. Although cycling duty is typically not a concern, an issue faced by NGCC when load-following is the erosion of efficiency due to an inability to maintain optimum air-to-fuel pressure and turbine exhaust and steam temperatures. Methods to address these include:

- Installation of advanced automated controls.
- Supplemental firing while at full load with a reduction in firing when load decreases. When supplemental firing reaches zero, fuel to the gas turbine is cutback. This approach would reduce efficiency at full load, but would likewise greatly reduce efficiency degradation in lower-load ranges.
- Use of multiple gas turbines coupled with a waste heat boiler that will give the widest load range with minimum efficiency penalty.

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[10] On March 27, 2012, the US EPA issued proposed NSPS for GHG emissions from new power plants pursuant to section 111 of the Clean Air Act (CAA).

4.3.4.4 Peaking Alternatives

Peaking generating sources provide needed capacity during extreme high-use peaking periods and/or periods in which significant shifts in the load (or supply) curve dictate the need for "quick-response" capability. The peaks occur for only a few hours each year and the installed reserve requirement is predicated on a one day in ten year loss of load expectation, so the capacity dedicated to serving this reliability function can be expected to provide very little energy over an annual load cycle. As a result, fuel efficiency and other variable costs are of less concern. This capacity should be obtained at the lowest practical installed cost, despite the fact that such capacity often has very high energy costs. This peaking requirement is manifested in the system load duration curve.

In addition, in certain situations, peaking capacity such as combustion turbines can provide backup and some have the ability to provide emergency (Black Start) capability to the grid.

a. Simple Cycle Combustion Turbines (NGCT)

In "industrial" or "frame-type" combustion turbine systems, air compressed by an axial compressor (front section) is mixed with fuel and burned in a combustion chamber (middle section). The resulting hot gas then expands and cools while passing through a turbine (rear section). The rotating rear turbine not only runs the axial compressor in the front section but also provides rotating shaft power to drive an electric generator. The exhaust from a combustion turbine can range in temperature between 800 and 1,150 degrees Fahrenheit and contains substantial thermal energy. A simple cycle combustion turbine system is one in which the exhaust from the gas turbine is vented to the atmosphere and its energy lost, *i.e.*, not recovered as in a combined cycle design. While not as efficient (at 30-35% LHV), they are inexpensive to purchase, compact, and simple to operate.

b. Aeroderivatives (AD)

Aeroderivatives are aircraft jet engines used in ground installations for power generation. They are smaller in size, lighter weight, and can start and stop quicker than their larger industrial or "frame" counterparts. For example, the GE 7EA frame machine requires 20 minutes to ramp up to full load while the smaller LM6000 aeroderivative only needs 10 minutes from start to full load. However, the cost per kW of an aeroderivative is on the order of 20% higher than a frame machine.

The AD performance operating characteristics of rapid startup and shutdown make the aeroderivatives well suited to peaking generation needs. The aeroderivatives can operate at full load for a small percentage of the time allowing for multiple daily startups to meet peak demands, compared to frame machines which are more commonly expected to start up once per day and operate at continuous full load for 10 to 16 hours per day. The cycling capabilities provide aeroderivatives the ability to backup variable renewables such as solar and wind. This operating characteristic is expected to become more valuable over time as: a) the penetration of variable renewables increase; b) baseload generation processes become more complex limiting their ability to load follow and; c) intermediate coal-fueled generating units are retired from commercial service.

AD units weigh less than their industrial counterparts allowing for skid or modular installations. Efficiency is also a consideration in choosing an aeroderivative over an industrial turbine. Aeroderivatives in the less than 100 MW range are more efficient and have lower heat rates in simple cycle operation than industrial units of equivalent size. Exhaust gas temperatures are lower in the aeroderivative units.

Some of the better known aeroderivative vendors and their models include GE's LM series, Pratt & Whitney's FT8 packages, and the Rolls Royce Trent and Avon series of machines.[11]

4.3.4.5 Renewable Alternatives

Renewable generation alternatives use energy sources that are either naturally occurring (wind, solar, hydro or geothermal), or are sourced from a by-product or waste-

[11] Turbomachinery International, Jan/Feb. 2009; Gas Turbine World; EPRI TAG.

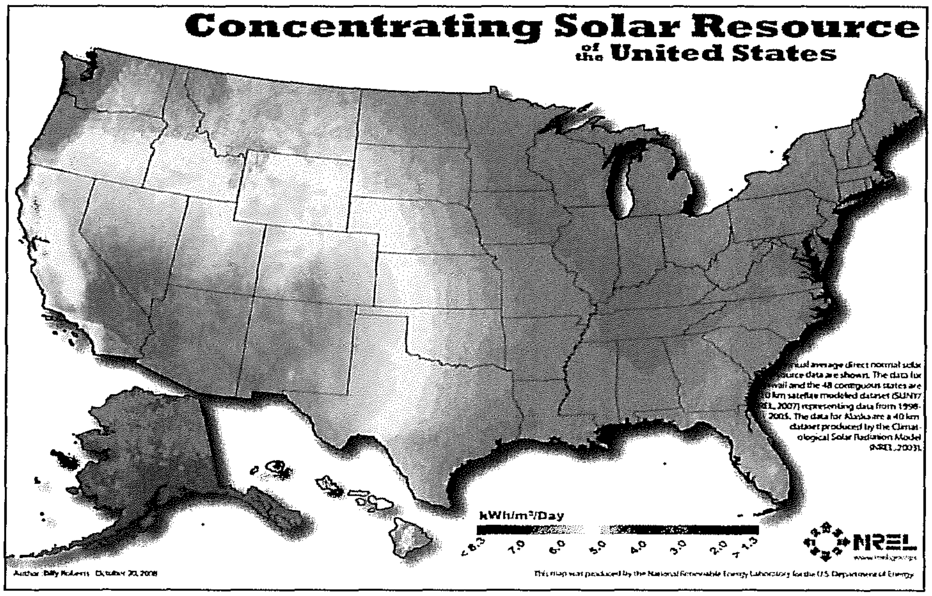
product of another process (biomass or landfill gas). In the recent past, development of these resources has been driven primarily as the result of renewable portfolio requirements. That is not universally true now as advancements in both solar PV and wind turbine manufacturing have brought costs down.

Because wind resources are not always productive during the time of system peak, these resources are assumed to have "useful capacity" equivalent to 13-14% of their nameplate capacity within PJM.

a. Utility-Scale Solar

Solar power takes a couple of viable forms to produce electricity: concentrating and photovoltaics. Concentrating solar – which heats a working fluid to temperatures sufficient to power a turbine - produces electricity on a large scale and is similar to traditional centralized supply assets in that way. Photovoltaics produce electricity on a smaller scale (2 kW to 20 MW per installation) and can be distributed throughout the grid. **Figure 11** shows the potential solar resource locations in the U.S.

Figure 11: United States Solar Power Locations

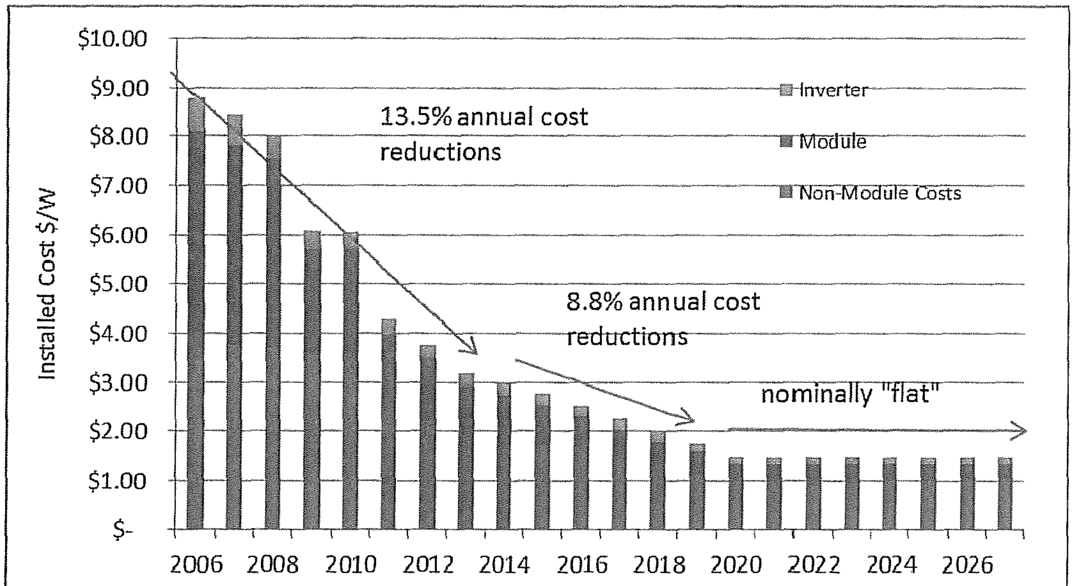


The cost of solar panels has declined considerably in the past decade. This has been mostly a result of reduced panel prices that have resulted from manufacturing efficiencies spurred by accelerating penetration of solar energy in Europe, Japan, and California.

With the trend firmly established, forecasts generally foresee declining nominal prices in the next decade as well.

Not only are utility scale solar plants getting less expensive, the costs to install solar panels in distributed locations, often on a rooftop, are lessening as associated hardware, such as inverters, racks, and wiring bundles become standardized (See **Figure 12**). If the projected cost declines materialize, both distributed and utility scale solar projects will be economically justifiable in the future.

Figure 12: Solar Panel Installed Cost



Source: Navigant Consulting and AEP Resource Planning

Utility solar plants require less lead time to build than fossil plants. There is not a defined limit to how much utility solar can be built in a given time. However, in practice, solar facilities are not added in an unlimited fashion. **Figure 13** shows the density of solar installations by county, with the vast majority of counties in PJM having less than 1 MW of solar installed. In the period from July 2012 – June 2013, solar photovoltaic constituted less than one-tenth of one percent of total generation in PJM.

For this reason, solar resources were considered available resources with some limits on the rate with which they could be chosen. Utility solar resources were made available up to 10 MW of incremental nameplate capacity starting in 2014. To provide some context around that, a typical commercial installation is 50 kW and effectively covers the surface of a typical "big box" retailer's roof. A 50 MW utility-scale solar "farm" consumes nearly 150 acres.

As with wind resources, solar resources' useful capacity is less than its nameplate rating. In PJM, that capacity credit is 38% of the nameplate rating. PJM's peak is in the late afternoon, around 5 p.m., well past the point that solar panels are producing at their peak, typically 1 p.m.

Time will tell whether solar can be implemented at a pace that approaches the limits incorporated, or perhaps, even exceed those limits.

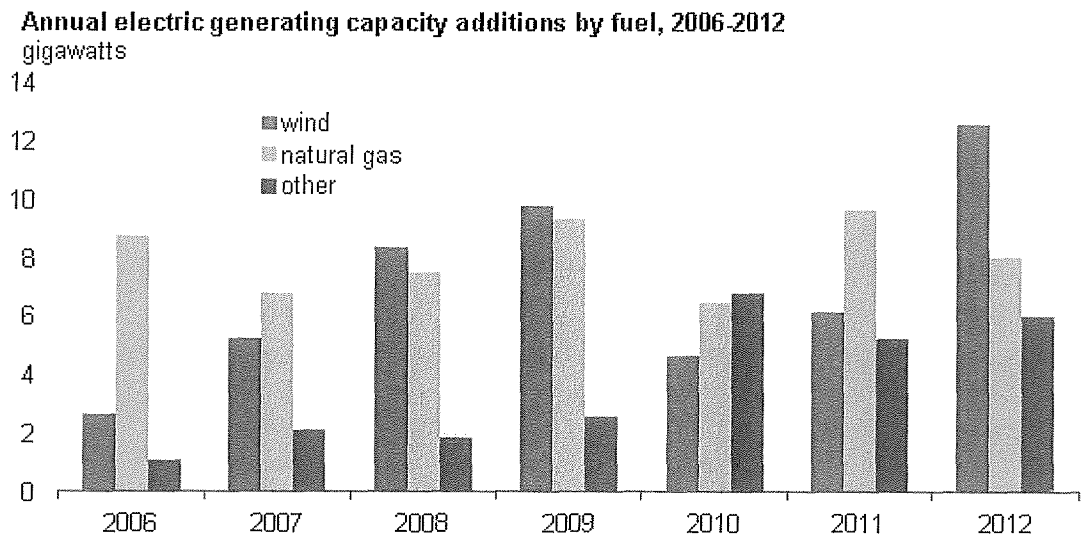
Figure 13: Density of Solar Installation by County

b. Wind

b.1 Modeling Wind Resources

Utility wind energy is generated by wind turbines with a range 1.0 to 2.5 MW, with a 1.5 MW turbine being the most common size used in commercial applications today with over 60,000 MW[12] of wind online in the United States as of December 31, 2012. **Figure 14** shows the annual electric generating capacity additions by fuel.

Figure 14: Annual Electric Generating Capacity Additions by Fuel



Typically, multiple wind turbines are grouped in rows or grids to develop a wind turbine power project which requires only a single connection to the transmission system. Location of wind turbines at the proper site is particularly critical as not only does the wind resource vary by geography, but its proximity to a transmission system with available capacity will factor into the cost.

Ultimately, as turbine production increases to match the significant increase in demand, the high capital costs of wind generation should begin to decline. Currently, the cost of electricity from wind generation is becoming competitive within PJM due largely to subsidies, such as the federal production tax credit as well as consideration given to (renewable energy certificate) REC values, if available, anticipated rising fuel costs and potential future carbon costs.

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[12] Data is from the American Wind Energy Association (AWEA) Fourth Quarter 2012 Market Report (http://www.awea.org).

A variable source of power in most non-coastal locales, with capacity factors ranging from 30 percent (in the eastern portion of the U.S.) to 50 percent (largely in more westerly portions of the U.S., including the Plains states), wind energy's life-cycle cost ($/MWh), excluding subsidies, is currently higher than the marginal (avoided) cost of energy, in spite of its negligible operating costs. Another obstacle with wind power is that its most critical factors (*i.e.*, wind speed and sustainability) are typically highest in very remote locations, and this forces the electricity to be transmitted long distances to load centers necessitating the build out of EHV transmission to optimally integrate large additions of wind into the grid. In the PJM region, wind is credited with 13% useful capacity, or wind turbines are, on average, producing at 13% of nameplate capacity at the time of PJM peak.

For modeling purposes, wind was considered under various timing and 'blocks'. Initially, information emanating from the Company's October 18, 2013, RFI was utilized to establish the prospect for a "nearer-term" (2017) wind resource opportunity. The cost and performance parameters provided in response to that RFI were summarized and grouped into the modeling based on whether the propsective offers were domiciled in Kentucky or "adjacent" to the state. Those prospective offers were then averaged, in a maximum annual block size of 100 MW, according to such grouping. Further, an additional near-term tranche of no more than 100 MW was considered which *did* incorporate the prospect of receiving federal PTC. For periods *beyond* 2017, such wind resources were considered using more "generic" cost and performance parameters, rather than information derived from the indicative RFI process. Those outer-year wind resources were also considered to be available in maximum 100 MW blocks at a cost according to the schedule shown in **Figure 15** with no prospect of the federal PTC which expires for projects not initiated before year-end 2013.

Further, for this IRP, wind resources are modeled as a REPA with the implicit 'build' costs assumed to decline over time, reflecting both increased efficiency or capacity factor of the turbines and decreasing manufacturing cost. While Kentucky is not rich in wind resources (see **Figure 16**), adjoining states such as Ohio, Indiana, Illinois, and Missouri may provide suitable sites for construction with limited requirements to build additional transmission.

Figure 15: Utility Wind Cost Assumption

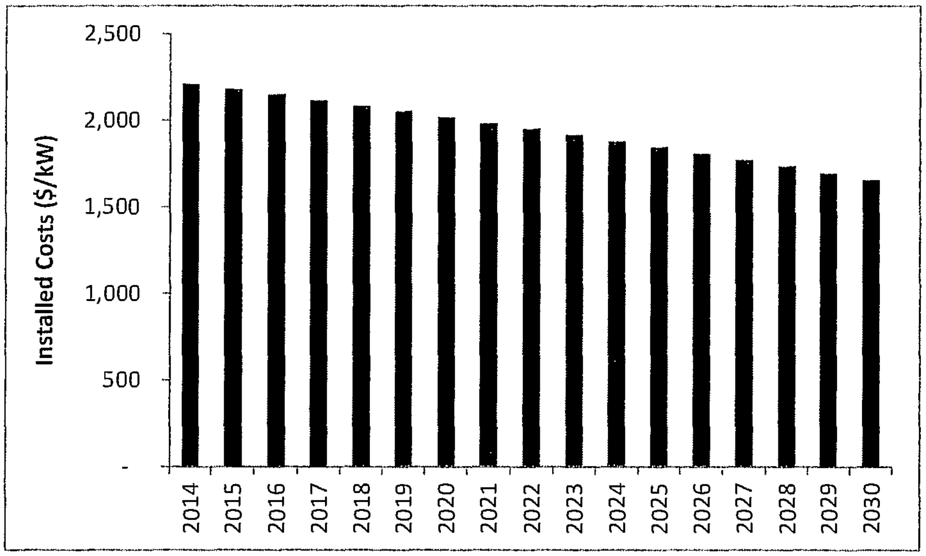
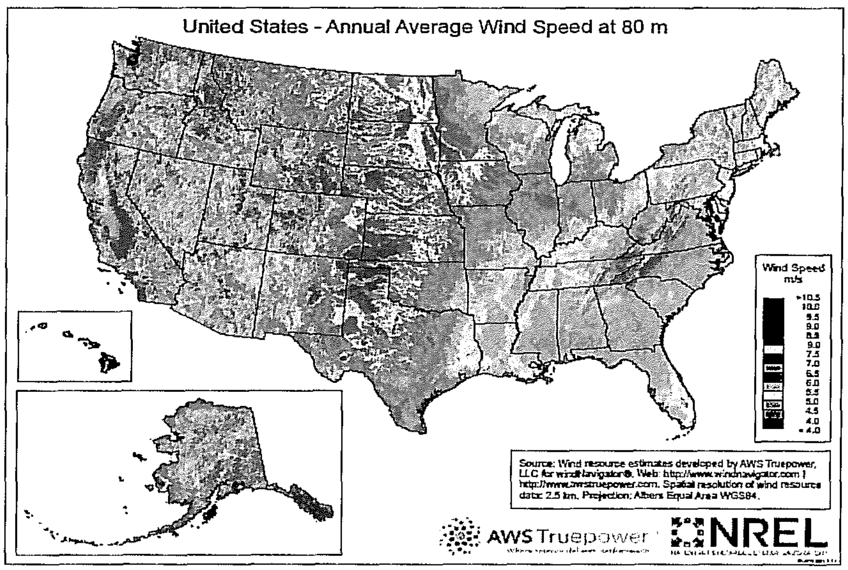


Figure 16 shows the wind resource locations in the U.S. and their relative potential.

Figure 16: United States Wind Power Locations



c. Hydro

The available sources of, particularly, larger hydroelectric potential have largely been exploited and those that remain must compete with the other uses, including recreation and navigation. The potentially lengthy time associated with environmental studies, Federal Army Corp of Engineer permitting, high up-front construction costs, and environmental issues (fish and wildlife) make hydro prohibitive at this time. No incremental hydroelectric resources were considered in this IRP.

d. Biomass

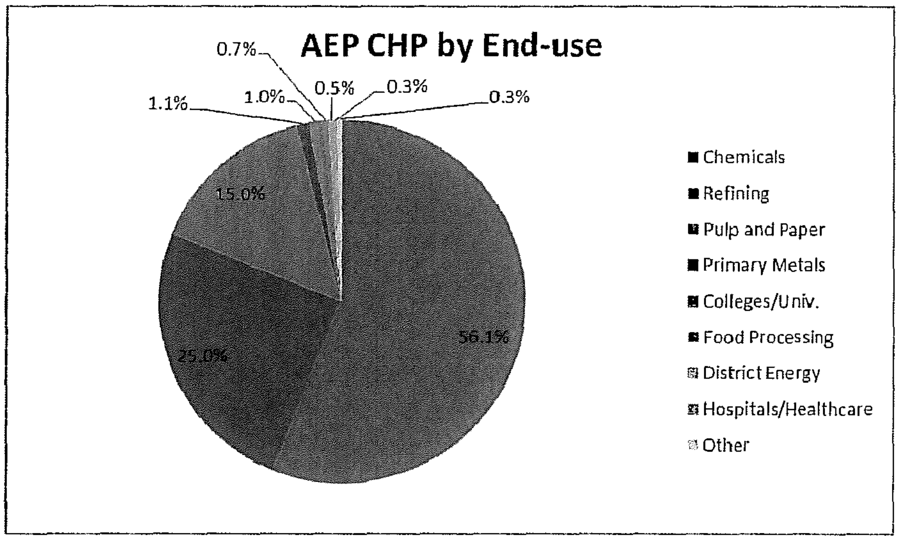
Biomass is a term that typically includes organic waste products (sawdust or other wood waste), organic crops (corn, switchgrass, poplar trees, willow trees, etc.), or biogas produced from organic materials, as well as select other materials. Biomass costs will vary significantly depending upon the feedstock. Biomass is typically used in power generation through the utilization of the biomass fuel in a steam generator (boiler) that subsequently drives a steam turbine generator; similar to the same process of many traditional coal fired generation units. Some biomass generation facilities use biomass as the primary fuel, however, there are some existing coal-fired generating stations that will use biomass as a blend with the coal.

The ecoPower biomass REPA is a 58.5 MW facility that burns waste wood generated by the lumber industry, and is slated for operation by 2017. Kentucky Power has agreed to purchase the power from this facility as part of a negotiated settlement agreement approved by the Commission.

e. Cogeneration

Cogeneration is a process where electricity is generated and the waste heat by-product is used for heating or other process, raising the net thermal efficiency of the plant. Currently, there is no co-generation or combined heat and power (CHP) on Kentucky Power's system. To take advantage of the increased efficiency associated with CHP, the host must have a ready need for the heat that is otherwise potentially wasted in the generation of electricity. In AEP's service territory, there are over 3,400 MW of CHP which serve the following industries (See **Figure 17**). The bulk of this CHP capacity is in Texas and Louisiana.

Figure 17: AEP CHP by End-use



The refining industry is a sizable part of Kentucky Power's industrial sector consumption, and it is concentrated in a single customer. Historically, Kentucky Power's low cost combined with the relatively high cost of natural gas, a primary fuel for cogeneration facilities, has made cogeneration uneconomical in Kentucky Power's service territory. Kentucky Power is occasionally approached by customers for help in evaluating CHP and co-generation opportunities, but the Company's relatively low avoided costs have been a significant barrier to-date for any serious implementation consideration.

4.3.5 Integrate Supply-Side and Demand-Side Options

The *Plexos®* model was used to study the long-term integration and optimization of various resource alternatives, and requires projections of various external parameters that primarily are driven by market forces. The input variables to the forecasts of these parameters include forecasts of fuels, load, emissions, emission retrofits, construction costs for capital projects, and others. Each input variable is shaped by government-provided historical data, government forecasts, leading energy-industry consultancies, AEP-internal views and the output of industry-accepted modeling tools, which apply economic principles and dispatch simulation to model the relationships of utility supply, transmission and demand to forecast market prices. *The refinement of modeling analysis is continuous*, but is immediately oriented toward emissions, renewables, volatile commodity prices and changing economic conditions.

4.3.5.1 Optimize Expanded DSM Programs

As described in Chapter 3, EE and VVO options that would be incremental to the current programs were modeled as resources within *Plexos*®. In this regard, they are "demand-side power plants" that produce energy according to their end use load shape. They have an initial (program) cost with no operating costs. They are "retired" at the end of their useful lives.

4.3.5.2 Optimize Other Demand-Side Resources

Customer-sited distributed generation, specifically distributed solar generation, was modeled as a purchase power agreement with the cost to the utility being the full retail rate, consistent with current net metering tariffs.

4.3.6 Analysis and Review

To develop the "Preferred Portfolio," Kentucky Power built resource portfolios that were optimized under five separate economic scenarios. These scenarios are described in Section 4.6.4. These five unique portfolios form the basis for the Preferred Portfolio resource plan, which is then further evaluated under a distribution of economic futures, often referred to as a Monte Carlo analysis, to determine the relative economic "risk" of the plan.

Kentucky Power's preferred plan presented herein is expected to provide adequate reliability over the forecast period.

The long-term capacity schedule reported herein is simply a snapshot of the future at this time, based on current thinking relative to various parameters, each having its own degree of uncertainty. The expansion reflects, to a large extent, assumptions that are subject to change. As the future unfolds, and as parameter changes are recognized and updated, input information are continually evaluated, and resource plans modified as appropriate.

Some key factors that can affect the timing of future capacity additions are the magnitude of future loads and capacity reserve requirements. The magnitude of the future load in any particular year is a function of load growth and DSM impacts. Capacity reserve requirements, as previously discussed, could vary depending on the average system generating-unit availability of both Kentucky Power and PJM.

4.4 Other Considerations and Issues

4.4.1 Transmission System

(807 KAR 5:058 Sec.5.4.)

4.4.1.1 General Description

The AEP-East Transmission System (eastern zone) consists of the transmission facilities of the six eastern AEP operating companies (Kentucky Power, Appalachian Power Company, Ohio Power Company, Indiana Michigan Power Company, Wheeling Power Company and Kingsport Power Company). This portion of the Transmission System is composed of approximately 15,000 miles of circuitry operating at or above 100 kV. The eastern zone includes over 2,100 miles of 765 kV overlaying 3,800 miles of 345 kV and over 8,900 miles of 138 kV circuitry. This expansive system allows AEP to economically and reliably deliver electric power to approximately 24,200 MW of customer demand connected to the AEP-East Transmission System that takes transmission service under the PJM open access transmission tariff (OATT).

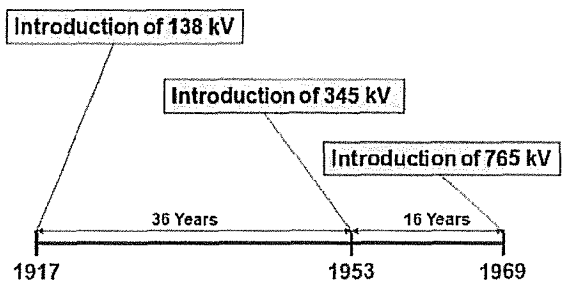
The AEP-East Transmission System is part of the Eastern Interconnection; the most integrated transmission system in North America. The entire AEP-East Transmission System is located within the Reliability*First* (RFC) geographic area. On October 1, 2004, AEP's eastern zone joined the RTO and now participates in the PJM markets.

As a result of the AEP-East Transmission System's geographical location and expanse as well as its numerous interconnections, the eastern Transmission System can be influenced by both internal and external factors. Facility outages, load changes, or generation re-dispatch on neighboring companies' systems, in combination with power transactions across the interconnected network, can affect power flows on AEP's transmission facilities. As a result, the AEP-East Transmission System is designed and operated to perform adequately even with the outage of its most critical transmission elements or the unavailability of generation. The eastern zone conforms to the NERC Reliability Standards and applicable RFC standards and performance criteria.

Despite the robust nature of the eastern zone, certain outages coupled with extreme weather conditions and/or power-transfer conditions can potentially stress the system beyond acceptable limits. The most significant transmission enhancement to the AEP-East Transmission System over the last few years was completed in 2006. This was the construction of a 90-mile 765 kV transmission line from Wyoming Station in West Virginia to Jacksons Ferry Station in Virginia. In addition, EHV/138 kV transformer capacity has been increased at various stations across the eastern Transmission System.

AEP's eastern zone assets are aging. **Figure 18** demonstrates the development of AEP's eastern Transmission Bulk Electric System. In order to maintain reliability, significant investments will have to be made in the rehabilitation of existing assets over the next decade.

Figure 18: Transmission Bulk Electric System Development



Over the years, AEP, and now PJM, entered into numerous study agreements to assess the impact of the connection of potential merchant generation to the eastern zone. Currently, there is more than 26,000 MW of AEP generation and approximately 6,000 MW of additional merchant generation connected to the eastern zone. AEP, in conjunction with PJM, has interconnection agreements in the AEP service territory with several merchant plant developers for approximately 1,000 MW of additional generation to be connected to the eastern zone over the next several years. There are also significant amounts of merchant generation under study for potential interconnection.

The integration of the merchant generation now connected to the eastern zone required incremental transmission system upgrades, such as installation of larger capacity transformers and circuit breaker replacements. None of these merchant facilities required major transmission upgrades that significantly increased the capacity of the transmission network. Other transmission system enhancements will be required to match general load growth and allow the connection of large load customers and any other generation facilities. In addition, transmission modifications may be required to address changes in power flow patterns and changes in local voltage profiles resulting from operation of the PJM and Midwest ISO markets.

The announced retirement of approximately 13,000 MW of generation in PJM, including 800 MW at the Big Sandy plant, will result in the need for power to be transmitted over a longer distance into the Kentucky area. In addition, these retirements will result in the loss of dynamic voltage regulation. Upon formal notification of retirement to PJM, the Big Sandy unit will be subject to deactivation studies to ensure reliability is not compromised by the retirement of the generation.

There are two areas in particular that will receive transmission enhancements to allow the reliable operation of the Kentucky Power transmission system.

- The Hazard Area Improvement Plan includes a comprehensive 138 kV transmission system improvement plan for implementation in AEP's Hazard, Kentucky area. Once implemented, the plan will alleviate thermal overloads, low voltage concerns, and improve transmission service reliability to the Hazard Area. This proposal includes establishing a new 138 kV source from Beaver Creek Station via Soft Shell Station to the Hazard area. A new twenty (20) mile line will be constructed from Soft Shell Station to Bonnyman Station to establish a second 138 kV source into the Hazard transmission system. These facilities are proposed to be in service by December 2014.
- PJM's 2015 Summer Regional Transmission Expansion Plan (RTEP) study revealed overloads on 345 kV and 138 kV facilities in the Tristate area during single-contingency outage conditions. System studies by AEP found that all of

these overloads could be alleviated by the installation of a second 765/345 kV transformer at the Baker Station in Kentucky. AEP has proposed a project to install a second Baker 765/345 kV transformer, as well as install two 765 kV and three 345 kV circuit breakers.

The transmission line miles in Kentucky include approximately 258 miles of 765 kV, 9 miles of 345 kV, 46 miles of 161 kV, 309 miles of 138 kV lines, 437 miles of 69 kV, and 147 miles of 46 kV lines. Confidential **Exhibit 4-16** displays a map of the entire AEP System-East Zone transmission grid, including Kentucky Power Company.

4.4.1.2 Transmission Planning Process

AEP and PJM coordinate the planning of the transmission facilities in the AEP System-East Zone through a "bottom up/top down" approach. AEP will continue to develop transmission expansion plans to meet the applicable reliability criteria in support of PJM's transmission planning process. PJM will incorporate AEP's expansion plans with those of other PJM member utilities and then collectively evaluate the expansion plans as part of its RTEP process. The PJM assessment will ensure consistent and coordinated expansion of the overall bulk transmission system within its footprint. In accordance with this process, AEP will continue to take the lead for the planning of its local transmission system under the provisions of Schedule 6 of the PJM Operating Agreement (OA). By way of the RTEP, PJM will ensure that transmission expansion is developed for the entire RTO footprint via a single regional planning process, assuring a consistent view of needs and expansion timing while minimizing expenditures. When the RTEP identifies system upgrade requirements, PJM determines the individual member's responsibility as related to construction and costs to implement the expansion. This process identifies the most appropriate, reliable and economical integrated transmission reinforcement plan for the entire region while blending the local expertise of the transmission owners such as AEP with a regional view and formalized open stakeholder input.

AEP's transmission planning criteria is consistent with NERC and Reliability*First* reliability standards. The AEP planning criteria are filed with FERC annually as part of AEP's FERC Form 715 and these planning criteria are posted on the AEP website.[13] Using these criteria, limitations, constraints and future potential deficiencies on the AEP transmission system are identified. Remedies are identified and budgeted as appropriate to ensure that system enhancements will be timed to address the anticipated deficiency.

PJM also coordinates its regional expansion plan on behalf of the member utilities with the neighboring utilities and/or RTOs, including the Midwest ISO, to ensure inter-regional reliability. The Joint Operating Agreement between PJM and the Midwest ISO provides for joint transmission planning.

4.4.1.3 System-Wide Reliability Measure

At the present time, there is no single measure of system-wide reliability that covers the entire system (transmission, distribution, and generation). However, in practice, transmission reliability studies are conducted routinely for seasonal, near-term, and long-term horizons to assess the anticipated performance of the transmission system. The reliability impact of resource adequacy (either supply- or demand-side) would be evaluated as an inherent part of these overall reliability assessments. If reliability studies indicate the potential for inadequate transmission reliability, transmission expansion alternatives and/or operational remedial measures would be identified.

4.4.1.4 Evaluation of Adequacy for Load Growth

As part of the on-going near-term/long-term planning process, AEP uses the latest load forecasts along with information on system configuration, generation dispatch, and system transactions to develop models of the AEP transmission system. These models are the foundation for conducting performance appraisal studies based on established criteria to determine the potential for overloads, voltage problems, or other unacceptable

[13] http://www.aep.com/about/codeofconduct/OASIS/TransmissionStudies/GuideLines/2013%20AEP%20PJM%20FERC%20715_Final_Part%204.pdf

operating problems under adverse system conditions. Whenever a potential problem is identified, AEP seeks solutions to avoid the occurrence of the problem. Solutions may include operating procedures or capital transmission reinforcements. Through this on-going process, AEP works diligently to maintain an adequate transmission system able to meet forecasted loads with a high degree of reliability.

In addition, PJM performs a Load Deliverability assessment on an annual basis using a 90/10[14] load forecast for areas that may need to rely on external resources to meet their demands during an emergency condition.

4.4.1.5 Evaluation of Other Factors

As a member of PJM, and in compliance with FERC Orders 888 and 889, AEP is obligated to provide sufficient transmission capacity to support the wholesale electric energy market. In this regard, any committed generator interconnections and firm transmission services are taken into consideration under AEP's and PJM's planning processes. In addition to providing reliable electric service to AEP's retail and wholesale customers, PJM will continue to use any available transmission capacity in the AEP-East transmission system to support the power supply and transmission reliability needs of the entire PJM – Midwest ISO joint market.

A number of generation requests have been initiated in the PJM generator interconnection queue. AEP currently has two active queue positions within Kentucky totaling approximately 647 MW (capacity). Of these two active queue positions, one is a biomass generation request and the other is a natural gas request. AEP, through its membership in PJM, is obligated to evaluate the impact of these projects and construct the transmission interconnection facilities and system upgrades required to connect any projects that sign an interconnection agreement. The amount of planned generation that will actually come to fruition is unknown at this time.

[14] 90% probability that the peak actual load will be lower than the forecasted peak load and 10% probability that the acutal peak load will be higher than the forecasted peak load.

4.4.1.6 Transmission Expansion Plans

The transmission system expansion plans for the AEP eastern zone are developed to meet projected future requirements. AEP uses power flow analyses to simulate normal conditions, and credible single and double contingencies to determine the potential thermal and voltage impact on the transmission system in meeting the future requirements.

As discussed earlier, AEP will continue to develop transmission reinforcements to serve its own load areas, in coordination with PJM, to ensure compatibility, reliability and cost efficiency.

4.4.1.7 Transmission Project Descriptions

A detailed list and discussion of the AEP transmission projects that have recently been completed or presently underway in Kentucky can be found under section 4.4.1.9 (Kentucky Transmission Projects) of this report. In addition, several other projects beyond the Kentucky Power area have also been completed or are underway across the AEP System-East Zone in PJM. While they do not directly impact Kentucky Power, such additions contribute to the robust health and capacity of the overall transmission grid, which also benefit Kentucky customers.

AEP's transmission system is anticipated to continue to perform reliably for the upcoming peak load seasons. AEP will continue to assess the need to expand its system to ensure adequate reliability for Kentucky Power customers within the Commonwealth of Kentucky. AEP anticipates that incremental transmission expansion will continue to provide for expected load growth.

4.4.1.8 FERC Form 715 Information

A discussion of the eastern AEP System reliability criteria for transmission planning, as well as the assessment practice used, is provided in AEP's FERC Form 715 Annual Transmission Planning and Evaluation Report, 2013 filing. That filing also provides transmission maps, and pertinent information on power flow studies and an evaluation and continued adequacy assessment of AEP's eastern zone.

As the Transmission Planner for AEP and AEP subsidiaries in the east, PJM performs all required studies to assess the robustness of the Bulk Electric System. All the models used for these studies are created by and maintained by PJM with input from all Transmission Owners, including AEP and its subsidiaries. Any request for current cases, models, or results should be requested from PJM directly. PJM is responsible for ensuring that AEP meets all NERC transmission planning requirements, including stability of the system.

Performance standards establish the basis for determining whether system response to credible events is acceptable. Depending on the nature of the study, one or more of the following performance standards will be assessed: thermal, voltage, relay, stability, and short circuit. In general, system response to events evolves over a period of several seconds or more. Steady state conditions can be simulated using a power flow computer program. A short circuit program can provide an estimate of the large magnitude currents, due to a disturbance, that must be detected by protective relays and interrupted by devices such as circuit breakers. A stability program simulates the power and voltage swings that occur as a result of a disturbance, which could lead to undesirable generator/relay tripping or cascading outages. Finally, a post-contingency power flow study can be used to determine the voltages and line loading conditions following the removal of faulted facilities and any other facilities that trip as a result of the initial disturbance.

The planning process for AEP's transmission network embraces two major sets of contingency tests to ensure reliability. The first set, which applies to both bulk and local area transmission assessment and planning, includes all significant single contingencies. The second set, which is applicable only to the Bulk Electric System, includes multiple and more extreme contingencies. For the eastern AEP transmission system, thermal and voltage performance standards are usually the most constraining measures of reliable system performance.

Sufficient modeling of neighboring systems is essential in any study of the Bulk Electric System. Neighboring company information is obtained from the latest regional or interregional study group models, the RFC base cases, the Eastern Interconnection Reliability Assessment Group (ERAG) and the Multiregional Modeling Working Group (MMWG) power flow library, the PJM base cases, or the neighboring company itself. In general, sufficient detail is retained to adequately assess all events, outages and changes in generation dispatch, which are contemplated in any given study.

4.4.1.9 Kentucky Transmission Projects

A brief summary of the transmission projects in Kentucky Power's service territory for the next five years is provided below. Project information includes the project name, a brief description of the projects scope, and the projected in-service year.

- **Hazard Area Improvements Projects** – This project, which includes the Bonnyman-Softshell line, will provide another 138 kV source of power into the Hazard area of eastern Kentucky. This project also includes associated station work. Once implemented, the plan will alleviate thermal overloads, low voltage concerns, and improve transmission service reliability to the Hazard Area. The projected in-service date for this project is December 2014.
- **Big Sandy Area Improvements** – This project will install a second 765/345 kV transformer at Kentucky Power Company's Baker 765 kV station, as well as two 765 kV and three circuit breakers at the station. The projected in-service date for this project is June 2015.
- **Thelma and Busseyville Station Upgrades** – This project includes station and line work along the Big Sandy – Thelma 138 kV circuit. It will address thermal overload concerns on the Big Sandy-Thelma 138 kV circuit. The projected in-service date for this project is June 2015.
- **Johns Creek and Stone Station Upgrades** – This project will install two new 138 kV circuit breakers at Johns Creek and one 138 kV circuit breaker at Stone Station. This project will provide enhanced reliability to customers, operational flexibility, and voltage support. The projected in-service date for this project is June 2015.
- **Dorton 138 kV Circuit Breaker Project** – This project will install three 138 kV circuit breakers and one circuit switcher at Dorton Station. This project will address thermal loading concerns and operational reliability concerns. The projected in-service date for this project is June 2015.

- **Cedar Creek Station Upgrades** – This project will install two new 138 kV circuit breakers at Cedar Creek Station. This project will provide operational benefits and provide voltage support for single-contingency line outages. The projected in-service date for this project is April 2016.

4.4.2 Fuel Adequacy and Procurement

a. General

The generating units of Kentucky Power are expected to have adequate fuel supplies to meet full-load burn requirements in both the short-term and the long-term. AEPSC, acting as agent for Kentucky Power, is responsible for the procurement and delivery of coal to Kentucky Power's generating stations, as well as setting coal inventory target level ranges and monitoring those levels. AEPSC's primary objective is to assure a continuous supply of quality coal at the lowest cost reasonably possible. Deliveries are arranged so that sufficient coal is available at all times. The consistency and quality of the coal delivered to the generating stations is also vitally important. The consistency of the sulfur content of the delivered coal is fundamental to Kentucky Power in achieving and maintaining compliance with the applicable environmental limitations.

b. Units

Kentucky Power relies on three coal-fired generating stations, Big Sandy, Rockport and Mitchell for its energy and capacity requirements. The Big Sandy generating station is located in Louisa, KY, and consists of two units with a total of 1,078 MW. Unit 1 is scheduled to be converted to exclusively burn natural gas and Unit 2 is scheduled to retire in 2015. The Rockport Generating Station, located in Spencer County, IN, consists of two 1,300 MW coal fired generating units. SO_2 emissions at Rockport are limited to 1.2 lb. SO_2/MMBtu. Compliance with the emission limit is achieved by using a blend of Powder River Basin low sulfur sub-bituminous coal and low sulfur bituminous coal from Colorado or eastern sources. The Mitchell generating station (50% of which will transfer to Kentucky Power in 2014) is located in Captina, WV and consists of two units with a total of 1,560 MW.

c. Procurement Process

Coal delivery requirements are determined by taking into account existing coal inventory, forecasted coal consumption, and adjustments for contingencies that necessitate an increase or decrease in coal inventory levels. Sources of coal are established by taking into account contractual obligations and existing sources of supply. Kentucky Power's total coal requirements are met using a portfolio of long-term arrangements, and spot-market purchases. Long-term contracts support a relatively stable and consistent supply of coal. When needed, spot purchases are used to provide flexibility in scheduling contract deliveries to accommodate changing demand and to cover shortfalls in deliveries caused by force majeure and other unforeseeable or unexpected circumstances. Occasionally, spot purchases may also be made to test-burn any promising and potential new long-term sources of coal in order to determine their acceptability as a fuel source in a given power plant's generating units.

d. Inventory

Kentucky Power attempts to maintain in storage at each plant an adequate coal supply to meet full-load burn requirements. However, in situations where coal supplies fall below prescribed minimum levels, programs have been developed to conserve coal supplies. In the event of a severe coal shortage, Kentucky Power would implement procedures for the orderly reduction of the consumption of electricity, in accordance with the Emergency Operating Plan.

e. Forecasted Fuel Prices

Kentucky Power specific forecasted annual fuel prices, by unit, for the period 2014 through 2028 are displayed in **Exhibit 4-4** of the Confidential Supplement.

4.5 Resource Planning Models

(807 KAR 5:058 Sec.8.5.a. and Sec.8.5.c.)

Information which describes the planning models (apart from the load forecasting models) utilized by Kentucky Power in developing its integrated resource plans is provided below.

4.5.1 *Plexos*® Model

Plexos® LP long-term optimization model, also known as "LT Plan®," served as the basis from which the Kentucky Power-specific capacity requirement evaluations were examined and recommendations were made. The LT Plan® model finds the optimal portfolio of future capacity and energy resources, including DSM additions that minimizes the cumulative present worth (CPW) of a planning entity's generation-related variable and fixed costs over a long-term planning horizon.

Plexos® accomplishes this by an objective function which seeks to minimize the aggregate of the following capital and production-related (energy) costs of the portfolio of resources:

- Fixed costs of capacity additions, *i.e.,* carrying charges on incremental capacity additions (based on a Kentucky Power-specific, weighted average cost of capital), and fixed O&M;
- Fixed costs of any capacity purchases;
- Program costs of (incremental) DSM alternatives;
- Variable costs associated with Kentucky Power's generating units. This includes fuel, start-up, consumables, market replacement cost of emission allowances, and/or carbon 'tax,' and variable O&M costs;
- Distributed, or customer-domiciled resources were effectively cost out at the equivalent of a full-retail "net metering" credit to those customers (*i.e.,* a "utility" perspective); and
- A 'netting' of the production revenue made into the PJM power market from Kentucky Power's generation resource sales *and* the cost of energy – based on unique load shapes from PJM purchases necessary to meet Kentucky Power's load obligation.

Plexos® executes the objective function described above while abiding by the following possible constraints:

- Minimum and maximum reserve margins;
- Resource addition and retirement candidates (*i.e.,* maximum units built);
- Age and lifetime of generators;
- Retrofit dependencies (SCR and FGD combinations);
- Operation constraints such as ramp rates, minimum up/down times, capacity, heat rates, etc.;
- Fuel burn minimum and maximums;
- Emission limits on effluents such as SO_2 and NO_X; and
- Energy contract parameters such as energy and capacity.

The model inputs that compose the objective function and constraints are considered in the development of an integrated plan that best fits the utility system being analyzed. *Plexos*® does not develop a full regulatory cost-of-service (COS) profile. Rather, it typically considers only the **relative** generation (G)-COS *that changes from plan-to-plan*, and not fixed "embedded" costs associated with existing generating capacity and demand-side programs that would remain constant under any scenario. Likewise, transmission costs are included only to the extent that they are associated with new generating capacity, or are linked to specific supply alternatives. In other words, generic (nondescript or non-site-specific) capacity resource modeling would typically not incorporate significant capital spends for transmission interconnection costs.

4.5.2 Demand-Side Screening

For a description of DR/EE screening, see Chapter 3, Section 3.4.

4.6 Major Modeling Assumptions

4.6.1 Planning & Study Period

The economic evaluations of this planning process were carried out over a 2014-

2028 planning period with discrete economic costs examined beyond that, through 2040, and terminal "end-effects" thereafter.

4.6.2 Load & Demand Forecast

The internal load and peak demand forecast is based on the July 2013 load forecast.

4.6.3 Capacity Modeling Constraints

The major system limitations that were modeled by use of constraints are elaborated on below. The LT Plan®, LP optimization algorithm operates constraints in tandem with the objective function in order to yield the least-cost resource plan.

- Maintain a PJM-required minimum reserve margin of roughly 15.6% per year as represented earlier in this report on the Kentucky Power "going-in" capacity position chart.
- Under the terms of the NSR Consent Decree (and Modified NSR Consent Decree), Kentucky Power and AEP agreed to annual SO_2 and NO_X emission limits for the AEP-East fleet of 16 coal-fueled power plants in Kentucky, Indiana, Ohio, Virginia and West Virginia, inclusive of Kentucky Power units.
- The restriction for consideration of new generation additions was assumed to not precede the PJM 2017/18 planning year given the typical minimal ~5-year timeframe to approve, permit, design and engineer, procure materials, construct and commission new fossil generation resources.

There are many variants of available supply-side and demand-side resource options and types. It is a practical limitation that not all known resource types are made available as modeling options. A screening of available supply-side technologies was performed with the optimum assets made subsequently available as options. Such screens for supply alternatives were performed for each of the major duty cycle "families" (baseload, intermediate, and peaking).

The selected technology alternatives from this screening process do not necessarily represent the optimum technology choice for that duty-cycle family. Rather, they reflect proxies for modeling purposes.

Other factors will be considered that will determine the ultimate technology type (*e.g.*, choices for peaking technologies: GE frame machines "E" or "F," GE LMS100 AD machines). The full list of screened supply options is included in Exhibit 3 of the Confidential Supplement.

Based on the established comparative economic screenings, the following specific supply alternatives were modeled in *Plexos*® for each designated duty cycle:

- *Peaking* capacity was modeled as blocks of seven, 86 MW GE-7EA Combustion Turbine units (summer rating of 78.5 MW x 7 = 550 MW), available beginning in 2017. Note: No more than one block could be selected by the model per year.
- *Intermediate* capacity was modeled as single natural gas Combined Cycle (2 x 1 GE-7FA with duct firing platform) units, each rated 618 MW (562 MW summer) available beginning in 2017.

  Note: In addition to the results of the comparative economic screening, due to the lack of significant resource need as well as the largely prohibitive cost and attendant construction risk, traditional baseload resources, as previously defined, were not considered in this modeling.

  In addition, beginning in the year 2020:

- Wind resources were made available up to 100 MW annually of incremental nameplate capacity.
- Utility-scale solar resources were available up to 10 MW annually of incremental nameplate capacity.
- DG, in the form of distributed solar resources, was limited to approximately 2.5% of energy consumption by 2028.
- EE resources—incremental to those included in the load forecast—were limited to realistically achievable levels in each year.

4.6.4 Wind RFI Evaluation and Assumptions

AEPSC on behalf of the Company issued a RFI on October 18, 2013 for non-binding indicative responses for a 100 MW (nameplate) power purchase agreement. The RFI was seeking responses from PJM wind resources (operating or planned) that could deliver energy, capacity, and renewable energy credits for a 20-year term starting on January 1, 2017; January 1, 2018; or another start date as described by the entity responding to the RFI. Responses to the RFI were received by AEPSC on November 15,

2013. A total of twelve developers provided responses representing 25 projects totaling 2,450 MW of PJM wind resources. Of the 2,450 MW of PJM wind resources, ~2,280 MW were in the developmental stage. The remaining ~170 MW of projects are currently in service. All responses to the RFI were from PJM resources representing nine states (IN, IL, KY, MD, NC, OH, PA, VA, WV).

4.6.5 Commodity Pricing Scenarios

Five commodity pricing scenarios were developed by AEPSC for Kentucky Power to enable *Plexos*® to construct resource plans under various long-term pricing conditions. The long-term power sector suite of commodity forecasts are derived from the proprietary *Aurora*^{XMP}. *Aurora*^{XMP} is a long-term fundamental production-costing tool developed by EPIS, Inc., that is driven by user-defined input parameters, not necessarily past performance which many modeling techniques tend to utilize. For instance, unit-specific fuel delivery and emission forecasts established by AEP Fuel, Emissions and Logistics (FEL), are fed into *Aurora*^{XMP}. Likewise, capital costs and performance parameters for various new-build generating options, by duty-type, are vetted through AEP Engineering Services and incorporated in the tool. AEP uses *Aurora*^{XMP} to model the eastern synchronous interconnect as well as ERCOT. In this report, the three distinct long-term commodity pricing scenarios that were developed for *Plexos*® are: a "base" view or, "Fleet Transition 1H2013 Base," a plausible "Fleet Transition 1H2013 Lower Band," and a plausible "Fleet Transition 1H2013 Higher Band." The scenarios are described below with the results shown in **Figure 19**.

a. Fleet Transition 1H2013 Base

This case recognizes the vacatur of CSAPR by decision of the U.S. Court of Appeals. Consequently, certain emission allowance values prior to 2015 revert back to levels in line with continued administration of the Clean Air Interstate Rule pending the promulgation of a valid replacement. Assumptions include:

- MATS Rule effective date as proposed with compliance beginning in 2015;
- Initially lower natural gas price due to the emergence of shale gas plays; and
- CO_2 emission pricing begins in 2022.

The specific effect of the MATS Rule are modeled in the development of the long-term commodity forecast by retiring the smaller, older coal units which would not be economic to retrofit with emission control equipment. The retirement time frame modeled is 2015 through 2017. Those remaining coal generating units will have some combination of controls necessary to comply with the EPA's rules. Incremental regional capacity and reserve requirements will largely be addressed with new natural gas plants. One effect of the expected retirements or the emission control retrofit scenario, is an over-compliance of the previous CSAPR emission limits. This will drive the emission allowance price to zero by 2018 or 2019.

b. Fleet Transition 1H2013 Lower Band

This case is best viewed as a plausible lower natural gas/energy price profile compared to the Fleet Transition 1H2013 Base. In the near term, Lower Band natural gas prices largely track the Base Case but, in the longer term, natural gas prices represent an even more significant infusion of shale gas. From a statistical perspective, this long-term pricing scenario is approximately one (negative) standard deviation from the Base Case and illustrates the effects of coal-to-gas substitution at plausibly lower gas prices. Like the Base Case scenario, CO_2 mitigation/pricing is assumed to start in 2022.

c. Fleet Transition 1H2013 Higher Band

Alternatively, this Higher Band scenario offers a plausible, higher natural gas/energy price "sensitivity" to the Base Case scenario. Higher Band natural gas prices reflect certain impediments to shale gas developments including stalled technological advances (drilling and completion techniques) and as yet unseen environmental costs. The pace of environmental regulation implementation is in line with Fleet Transition and Lower Band. Analogous to the Lower Band scenario, this Higher Band view, from a statistical perspective, is approximately, one (positive) standard deviation from the Base Case. Also, like the Base Case and Lower Band scenarios, CO_2 pricing is assumed to begin in 2022.

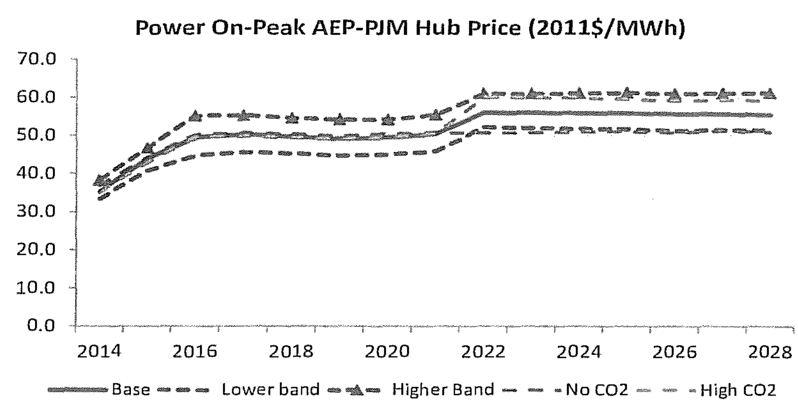
d. High CO_2

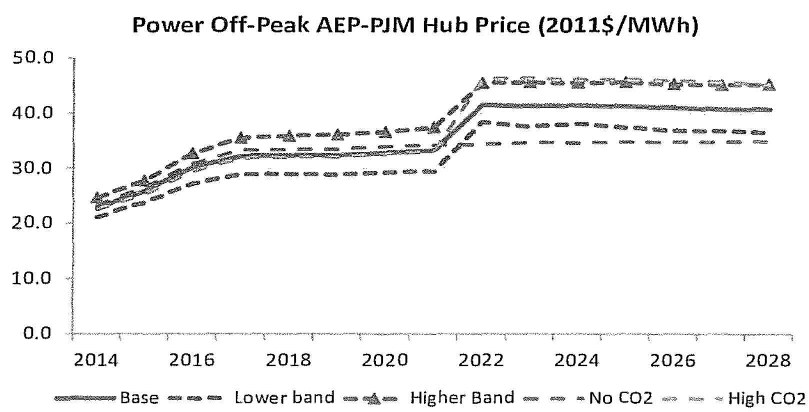
Built upon the assumption of a $25 per tonne CO_2 mitigation price beginning in 2022, the High CO_2 Scenario includes correlative price adjustments to natural gas and coal due to changes in consumption. This results in some retirement of coal-fired generating units around the implementation period. Natural gas and, to a lesser degree, renewable generation is built as replacement capacity.

e. No-CO_2

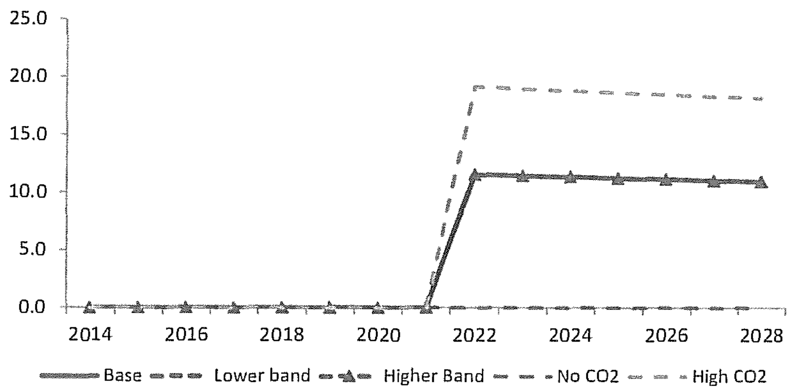
This "business as usual" scenario also includes the necessary correlative fuel price adjustments and best serves as a baseline to understand the market impact of the Fleet Transition 1H2013 Base Case and the High CO_2 Scenario. All three commodity pricing scenarios assume the same input parameters but for fuels and CO_2 mitigation pricing.

Figure 19: Commodity Prices

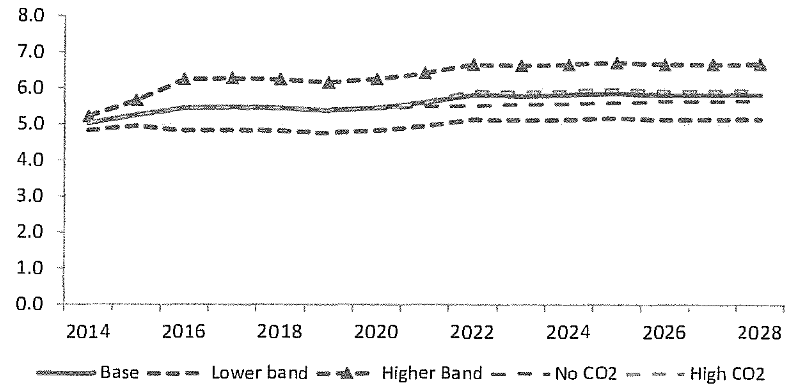




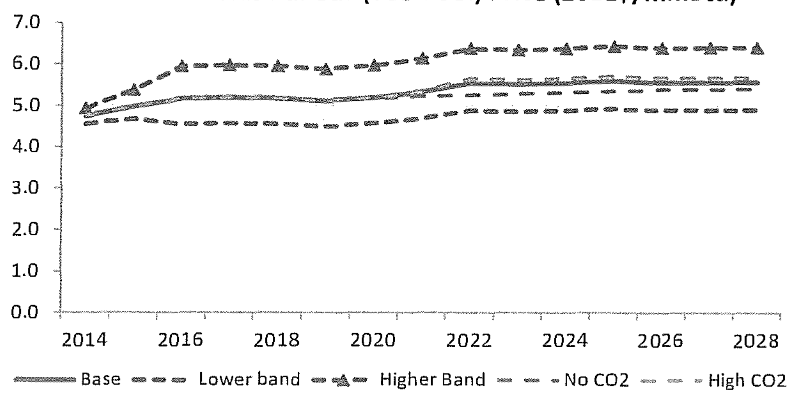
CO_2 Price (2011$/tonne)

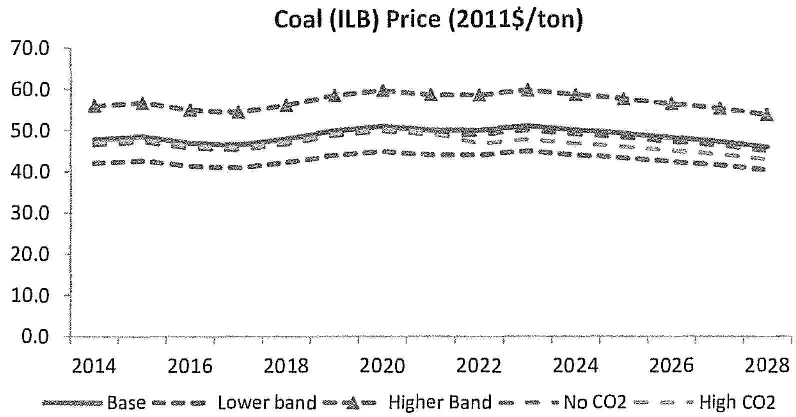


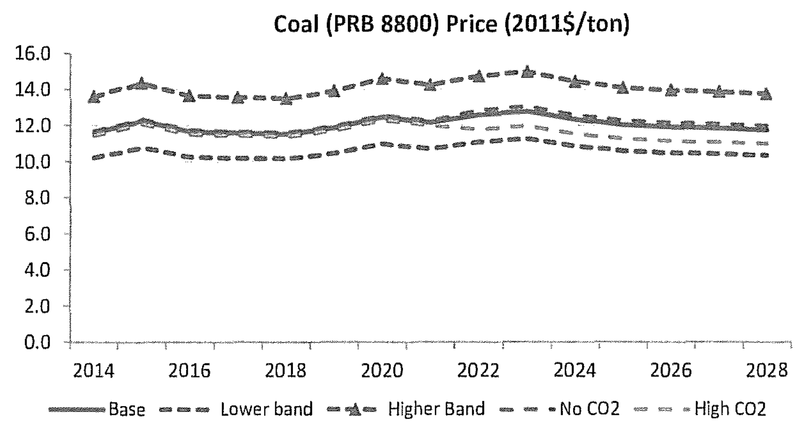
Natural Gas (TCO Delivered) Price (2011$/mmBtu)

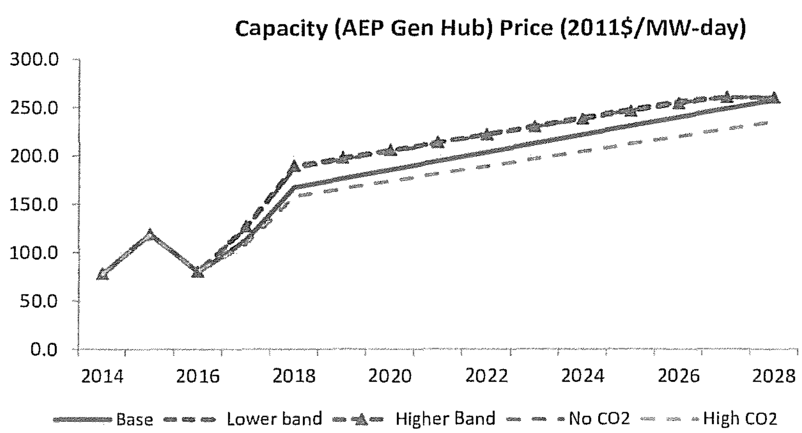


Natural Gas (TCO Pool) Price (2011$/mmBtu)




Coal (ILB) Price (2011$/ton)
70.0
60.0
50.0
40.0
30.0
20.0
10.0
0.0
2014
2016
2018
2020
2022
2024
2026
2028
Base
Lower band
Higher Band
No CO2
High CO2


Coal (PRB 8800) Price (2011$/ton)
16.0
14.0
12.0
10.0
8.0
6.0
4.0
2.0
0.0
2014
2016
2018
2020
2022
2024
2026
2028
Base
Lower band
Higher Band
No CO2
High CO2


Capacity (AEP Gen Hub) Price (2011$/MW-day)
300.0
250.0
200.0
150.0
100.0
50.0
0.0
2014
2016
2018
2020
2022
2024
2026
2028
Base
Lower band
Higher Band
No CO2
High CO2

4.7 Modeling Results

Plexos® constructed an optimized portfolio for each of the economic scenarios. A summary of the (nameplate MW) resource additions in each of the optimized plans is shown in **Table 18** below.

Table 18: Optimized Plans Summary Additions (2014-2028)

MW- nameplate	Wind	Solar	Efficiency	Total Additions
Base	100	90	25	215
Low	-	80	25	105
High	100	90	25	215
No Carbon	-	80	25	105
High Carbon	100	90	25	215

Although Kentucky Power has sufficient capacity to satisfy its PJM summer reserve margin criterion, *Plexos*® will consider the continued addition of resources that are economic; that is, resources that would offer value vis-à-vis the Company's avoided costs.

Stated another way, although Kentucky Power has sufficient capacity to satisfy its PJM summer *capacity* criterion, *Plexos*® will continue to add resources that are economic based on the inherent *energy* contribution. These resources would serve to reduce Kentucky Power's generation/production-related revenue requirement over the long-term. So, even though Kentucky Power has adequate capacity to serve its summer peak requirement without the addition of incremental resources through the planning period, since Kentucky Power's customers use significant amounts of energy, particularly during the winter, the failure to consider the addition of these resources would result in Kentucky Power's customers having greater exposure to PJM energy markets. This is also true if, or when, a "cost" for CO_2 emissions is effected as the Mitchell and Rockport coal units, as modeled, would be expected to run less often at that point. To summarize, *Plexos*® may add additional resources because it may produce energy at a cheaper cost than is expected in the (energy) replacement markets.

This energy position exposure is evidenced by the following two charts, first, under Base Commodity pricing (See **Figure 20**) and then under High CO_2 pricing (**Figure 21**). In sum, the addition of these non-traditional resources would then serve as a hedge to reduce exposure to (PJM) energy markets, which may be particularly desirable, depending on CO_2 costs.

Figure 20: Kentucky Power Energy Position under Base Commodity Forecast

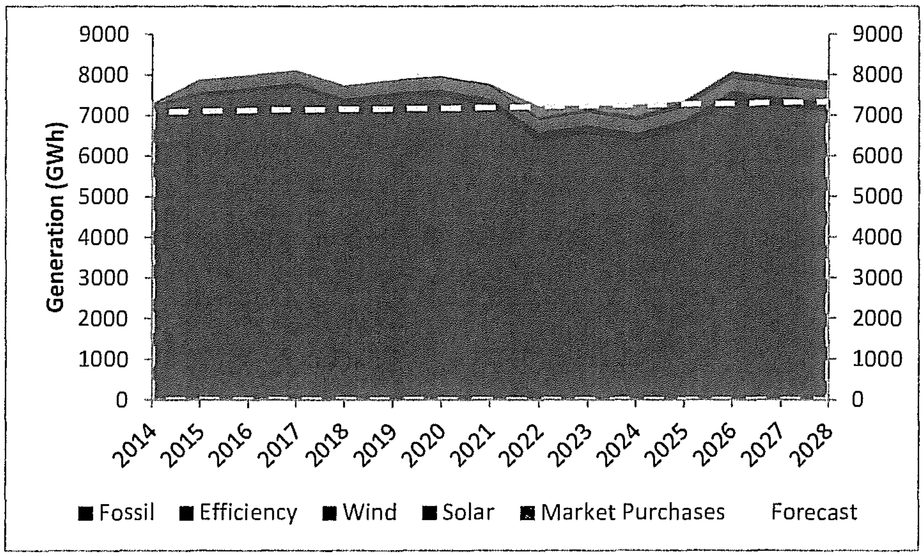
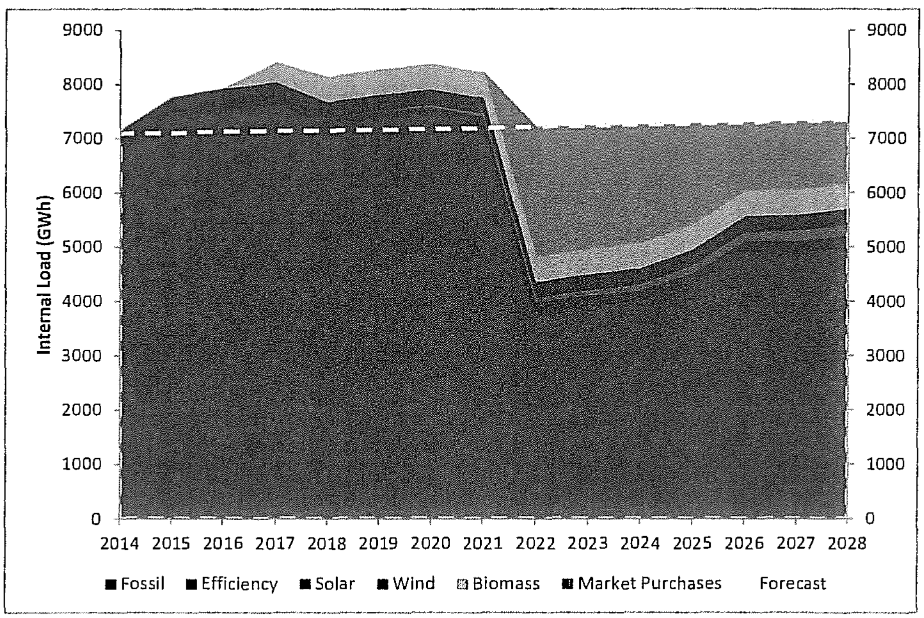


Figure 21: Kentucky Power Energy Position under High CO_2 Commodity Forecast

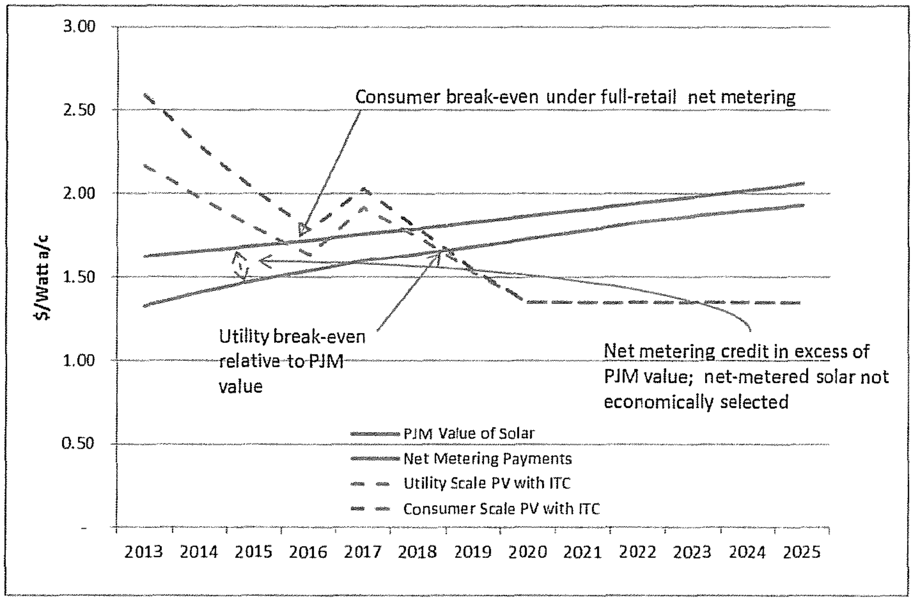


4.7.1 Construction of the Preferred Portfolio

Optimization under the five economic scenarios yielded five unique resource portfolios. Because much of Kentucky Power's resource portfolio is already in place, the differentiation that such different economic scenarios provded was somewhat muted. However, that result in itself, is valuable information in that it helps to solidify the path forward.

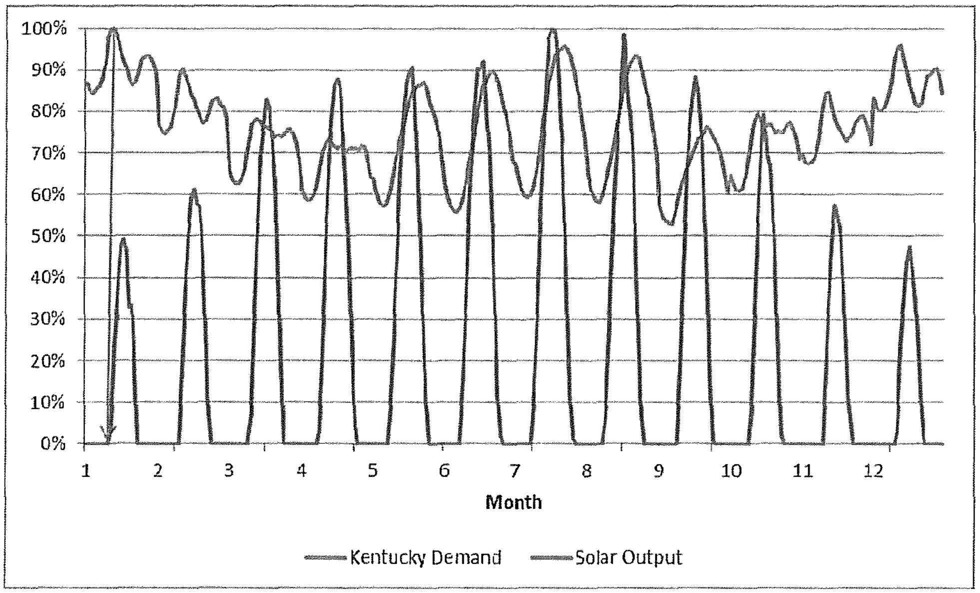
One missing element of all of the resultant portfolios is distributed generation, in particular, distributed solar generation. This resource is not selected primarily because of the way current net metering credits are determined. In essence, credits are given for the full retail cost of electricity, while the system benefits primarily from the energy and generation capacity benefits. Distributed solar produces its peak energy at approximately 1 p.m. on a typical day, while the PJM system peaks at (approximately) 5 p.m. **Figure 22** shows the relationship between expected solar costs and their value to the utility. The chart shows two things: First, with declining solar costs and current net metering rules, Kentucky Power DG consumers can potentially expect distributed solar power to become a cost-effective resource within five years. Second, under the same net metering compensation rules, these same resources are *not* economical additions from a (utility-based) revenue requirements perspective in that it would be less expensive to pay the avoided (PJM) market cost for capacity and energy as opposed to the net metering tariff.

Figure 22: Relationship between Expected Solar Costs and Utility value



The excess cost of net metering has been argued, by solar power advocates, to be fair compensation for off-setting other grid investments, including transmission and distribution additions. However, there is limited utility evidence to support that claim given the winter peaking nature of Kentucky Power. There is virtually no solar production at the hour of Kentucky Power's (winter) peak (typically a winter weekday morning) which nullifies that argument for Kentucky Power as shown in **Figure 23**.

Figure 23: Solar Production vs. Demand of Kentucky Power



However, the Preferred Portfolio recognizes that adoption of customer-sited generation, particularly solar panels, is likely given the net-metering economics. It is uncertain how quickly net metering will be adopted by customers. Currently, the net-metered capacity on Kentucky Power's system consists of 3 commercial customers totaling only 38 kW[15]. Given Kentucky Power's relatively low rates and depressed economic footprint, rapid adoption prior to 2020 is not likely. Thus, a nominal amount of distributed solar is added to the Preferred Portfolio in 2016, just prior to the reduction in the federal investment tax credit (ITC) from 30% to 10%and continuing at a reduced rate (**Figure 24**).

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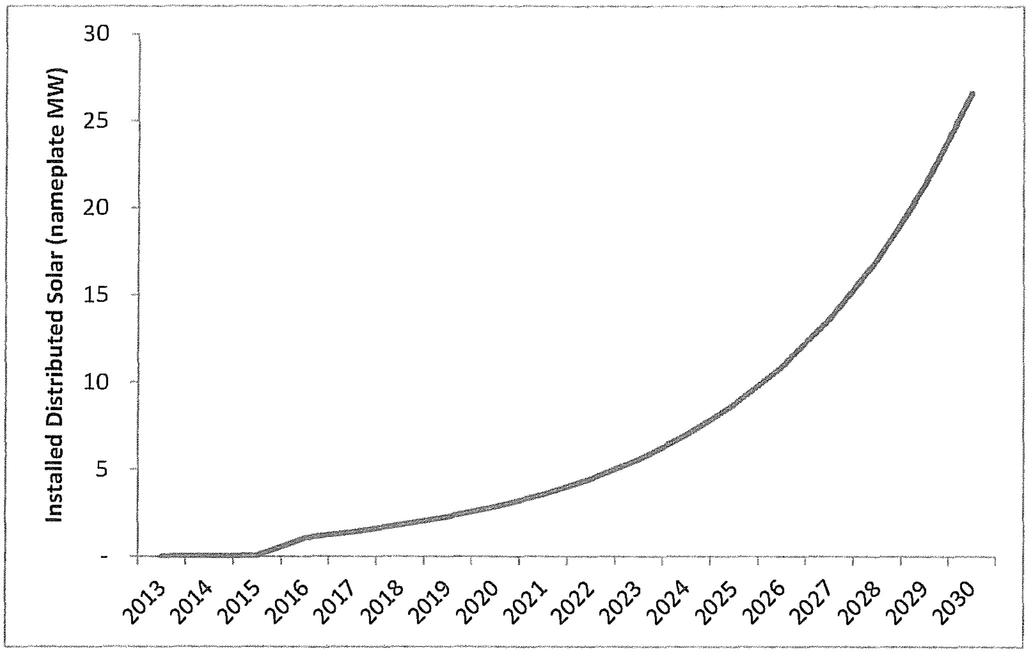
[15] EIA 826 data current as of 10/31/2013.

Figure 24: Preferred Portfolio Distributed Solar Adoption Assumption



The optimium portfolios did not add EE in quantities sufficient to comply with the Mitchell Transfer Stipulation and Settlement Agreement. It must be recognized, however, that there are limitations to the precision of using program costs and (adjusted) impacts from one state (Vermont) in another state (Kentucky). Ultimately, the costs and impacts of the incremental programs will be known and approval for those programs will be through the prescribed channels of the appropriate DSM Collaborative and ultimately the Commission. Thus, the Preferred Portfolio includes energy efficiency resources in amounts approximate to the those in the Agreement.

4.7.2 Preferred Portfolio summary

The Preferred Portfolio is largely based upon the *Plexos*® model-optimized portfolio, established under 'Base' long-term commodity pricing forecast, that imparts some practical considerations.

- First, it defers a currently-developed wind investment that takes advantage of the wind PTC until 2015 providing allowance for the time necessary for necessary additional analysis and regulatory approval.

- Second, a nominal amount of customer-owned, net-metered distributed solar is included. While not an optimal resource from the perspective of the utility in aggregate, given the economics from the perspective of individual customers under current net metering provisions, it is reasonable to expect some level of adoption of this resource by Kentucky Power customers.
- Third, additional customer-based EE programs were added to meet the terms of the Mitchell Transfer Stipulation and Settlement Agreement. With that, the later tranches of model-optimized VVO were set aside to accommodate these additional programs.

Table 19 offers a high-level summary of the Preferred Portfolio capacity resource (nameplate MW) additions over the 2014-2028 planning period, compared to the five model-optimized set of additions, by pricing scenario.

Table 19: Preferred Portfolio, Summary Additions (2014-2028)

MW- nameplate	Wind	Solar	Efficiency	Total Additions
Base	100	90	25	215
Low	-	80	25	105
High	100	90	25	215
No Carbon	-	80	25	105
High Carbon	100	90	25	215
Preferred Plan	100	132	31	263

Through 2028, the Preferred Portfolio results in approximately $29 million in incremental costs over the cost-optimized Base portfolio or a difference of approximately 0.05¢/kWh. These incremental costs are primarily the result of the assumption of non-economic (under current net metering rules) distributed resource additions, which may or may not materialize.

Table 20 shows the *Plexos*®-based output summary of the differences in present value of the Preferred Portfolio and the plan that results from a pure model optimization under the Base pricing economic scenario.

Table 20: Long-Term Economic Summary

Kentucky Power Company
2013 IRP
Plexos ® Long-Term Economic Analysis

SUMMARY

Cumulative Present Worth (CPW) of Generation Revenue Requirements - Preferred Plan vs. Optimized Plan
(2014$)

	IRP (15-Yr) Study Period: 2014-2028			*Total Study Period w/ 'End-Effects':* 2014-2040		
Plan Scenarios:	CPW $M	Change vs. "BASE Optimized" $M		CPW $M	Change vs. "BASE Optimized" $M	
BASE Pricing:						
Preferred Plan	2,442	29	*1.2%*	4,186	74	*1.8%*
Optimized Plan	2,414			4,112		

4. 8 Risk Analysis

In addition to evaluating the Preferred Portfolio for its ability to perform under the universe of likely economic backdrops, a portfolio that consisted of the "fossil-only" assets and the ecoPower facility was also evaluated to isolate the impacts associated with the incremental assets added in the Preferred Plan.

The two portfolios were evaluated using a Monte Carlo technique where input variables are randomly selected from a universe of possible values, given certain constraints and relationships. This offers an additional approach by which to "test" these plans over a distributed range of certain key variables. The output is, in turn, a distribution of possible outcomes, providing insight as to the risk or probability of a high CPW relative to the expected outcome.

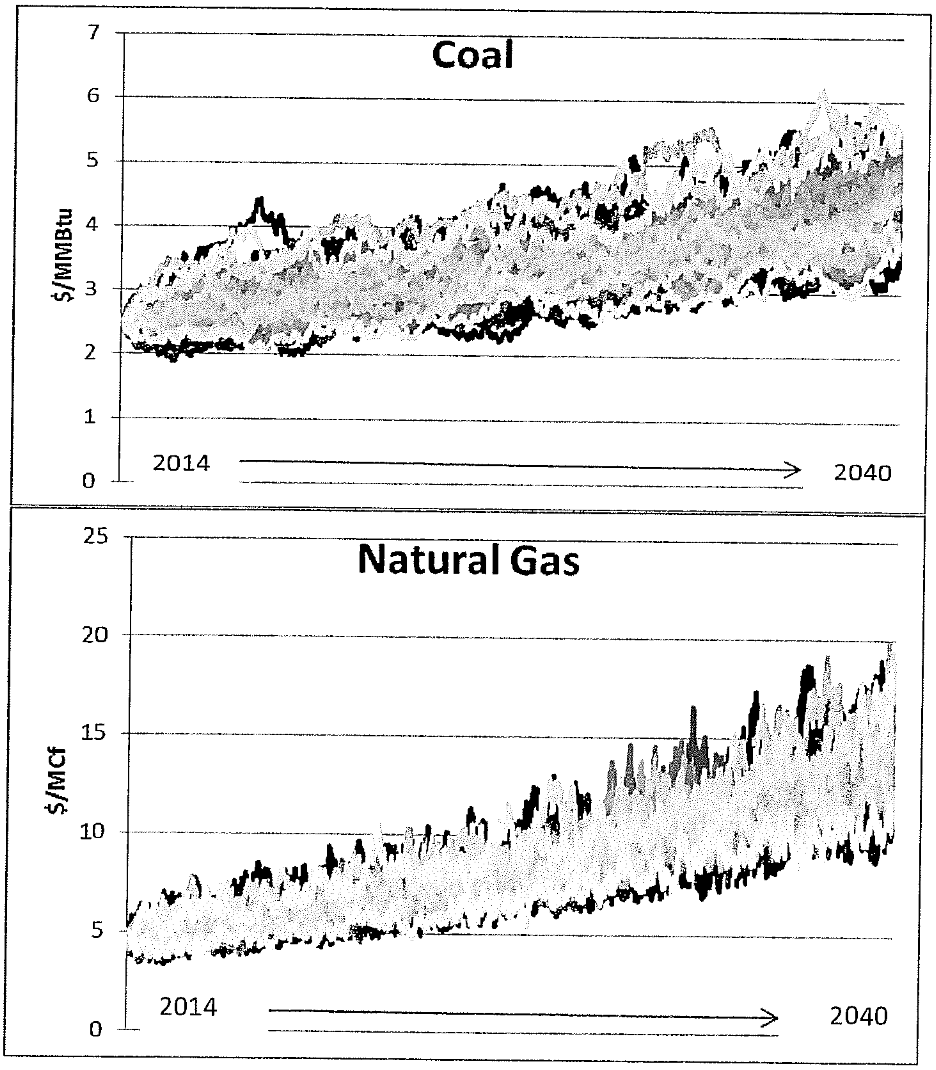
This study focused solely on the Kentucky Power portfolio of generating units. One-hundred risk iteration runs were performed with four risk factors being sampled. The results take the form of a distribution of possible revenue requirement outcomes for each plan. **Table 21** shows the input variables or risk factors within this IRP analysis and their historical relationships to each other.

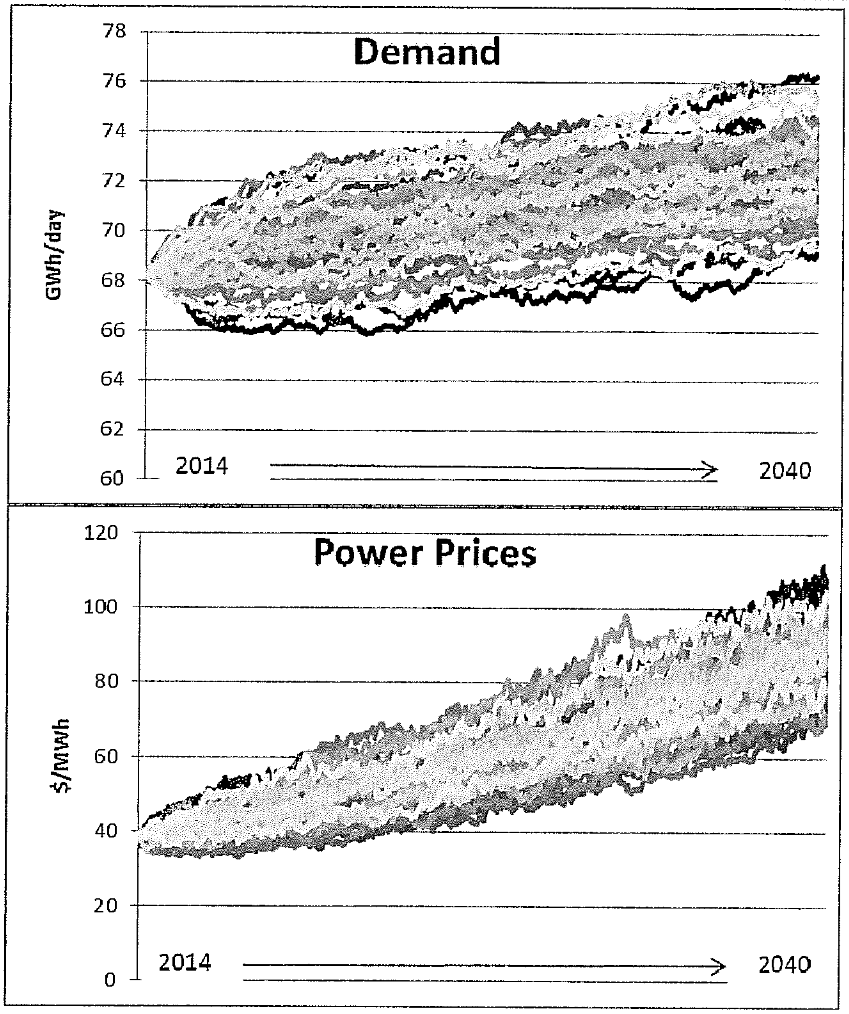
Table 21: Risk Factors and their Relationships

	Natural Gas	Coal	Power Prices	Demand
Natural Gas	1	0.18	0.47	0.08
Coal		1	0.53	-0.29
Power Prices			1	-0.19
Demand				1

The variables inputs, and their range of possible (nominal) values over those 100 iterations are shown in **Figure 25**.

Figure 25: Variable Input Ranges





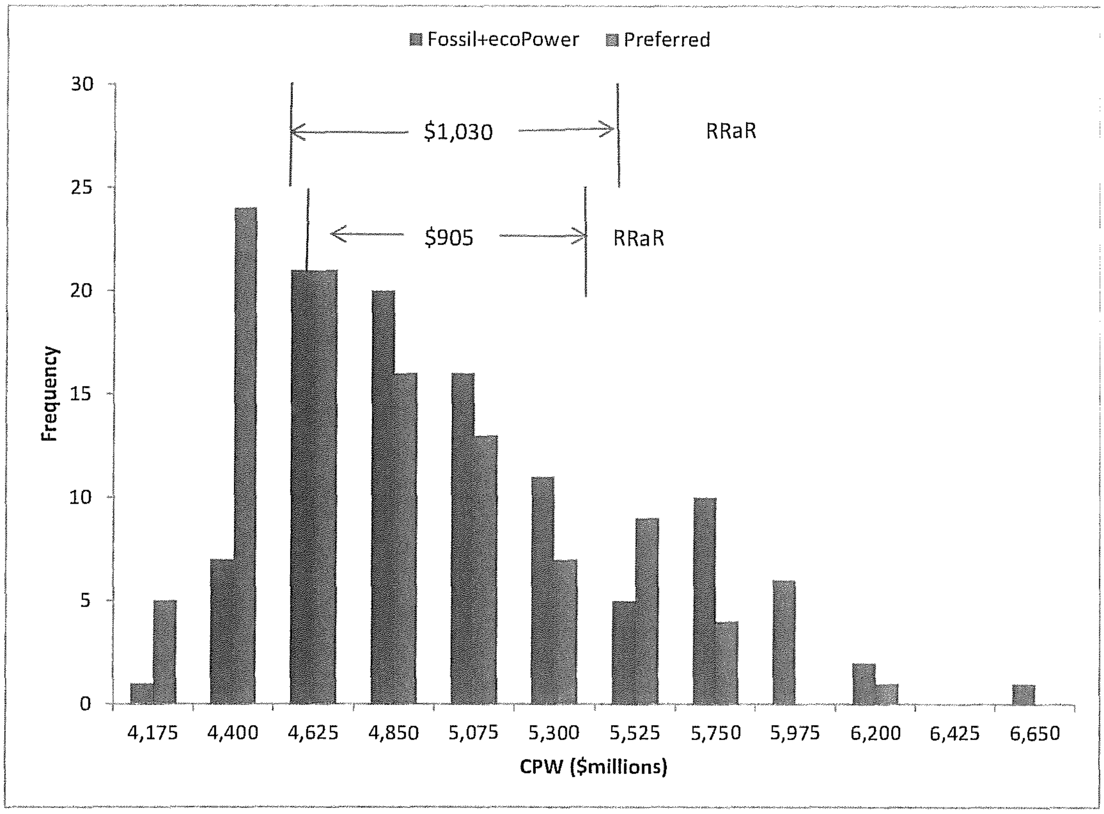
4.8.1 Modeling Process & Results & Sensitivity Analysis

(170 IAC 4-7-8(10)(B))

For each portfolio, the difference between its median and 95th percentile was identified as Revenue Requirement at Risk (RRaR). The 95th percentile is a level of required revenue sufficiently high that it will be exceeded, assuming the given plan is adopted, in five of the one-hundred simulations. Thus, it is 95% likely that those higher-end of revenue requirements would not be exceeded. The larger the RRaR, the greater the level of risk that customers would be subjected to adverse outcomes relative to the Base Case CPW.

Figure 25 illustrates the RRaR and the expected value graphically.

Figure 26: RRaR and Expected Value



The differences in RRaR between the portfolios do not appear to be significant. However, the addition of EE and solar generation, both distributed and utility-scale, work to reduce the risk or revenue requirement volatility. This is apparent by the reduction in RRaR associated with the Preferred Portfolio relative to the fossil-only portfolio.

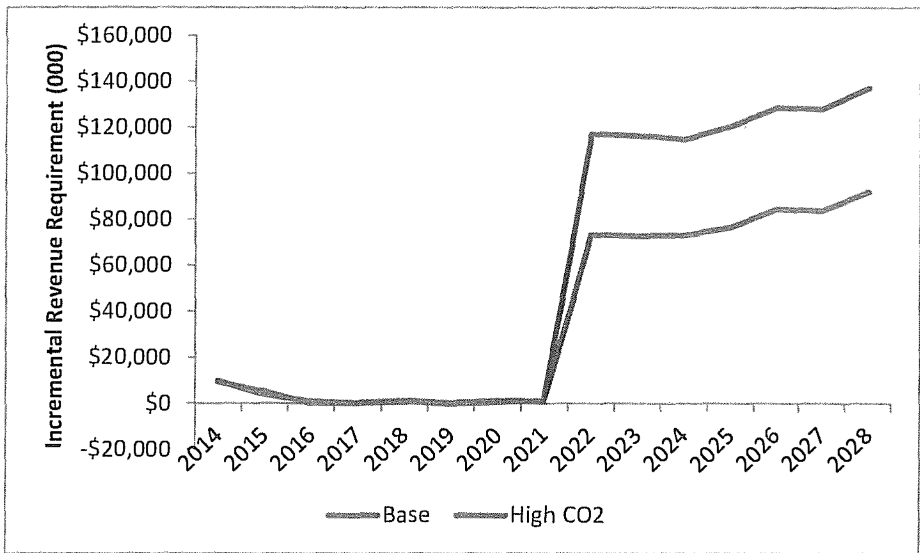
Based on the risk modeling performed, it is reasonable to conclude that the Preferred Portfolio represents a reasonable combination of expected costs and risk relative to the cost-risk profiles of a portfolio with more significant energy market exposure.

4.8.2 Sensitivity to CO_2 Pricing

To determine the cost of a CO_2 requirement on Kentucky Power, the optimum modeled portfolios for the "Base", "No CO_2" and "High CO_2" pricing scenarios are compared. The cost to Kentucky Power customers associated with the impacts of incorporating a carbon cost/price is expected to be $525 million in present value, measured from 2014-2040 (or approximately 1.1¢/kWh beginning in 2022), when considering the carbon pricing already inherent in the "Base" pricing scenario. The bulk of the additional costs begin in 2022, the assumed start date of a carbon tax, with some costs beginning sooner as cost reduction strategies are implemented.

In the event the High CO_2 pricing scenario is realized, that additional cost increases to $834 million in present value (approximately 1.8¢/kWh beginning in 2022). **Figure 27** shows the increased annual (nominal) revenue requirements of the expected Base case and High CO_2 case relative *versus* a modeled case with no cost for CO_2 (No CO_2 pricing scenario).

Figure 27: Annual Impacts of CO_2 Costs on Revenue Requirements



4.9 Kentucky Power Current Plan

The optimization results and associated risk modeling of this IRP show that, for Kentucky Power as a stand-alone entity in the PJM RTO, the addition of wind, solar, and customer and grid energy efficiency resources serve to reduce overall costs. The Preferred Portfolio results in reasonable costs when compared to other portfolios *while reflecting a level of distributed (solar) generation that is reasonable to expect will* *emerge under current cost assumptions and net metering arrangements.* The following are summary highlights of the Preferred Portfolio.

- Receives 50% of the Mitchell Plant in 2014.
- Retires Big Sandy Unit 2 in 2015.
- Converts Big Sandy Unit 1 to natural gas fired operation in 2016.
- Assumes the potential addition of 100 MW of wind energy from a PTC eligible wind project beginning in 2015.
- Implements customer and grid EE programs so as to reduce energy requirements by 260 GWh (or 4% of projected energy needs) by 2028.
- Purchases the output of the 58.5 MW ecoPower facility beginning in 2017.
- Adds utility-scale solar beginning in 2020; total solar capacity reaches 90 MW (nameplate) in 2028.
- Recognizes additional solar capacity will be added by customers, starting in 2016, of about 3 MW (nameplate) and ramping up to about 41 MW (nameplate) by 2028.

4.10 IRP Summary

Inasmuch as there are many assumptions, each with its own degree of uncertainty, which had to be made in carrying out the resource evaluations, changes in these assumptions could result in modifications in the resource plan reflected for Kentucky Power. The resource plan presented in this IRP is sufficiently flexible to accommodate possible changes in key parameters, including load growth, environmental compliance assumptions, fuel costs, and construction cost estimates. As such, changes and assumptions are recognized, updated, and refined, with input information reevaluated and resource plans modified as appropriate.

This 2013 Kentucky Power IRP provides for reliable electric utility service, at reasonable cost, through a combination of existing resources, renewable energy and demand-side programs. Kentucky Power will provide for adequate capacity and energy resources to serve its customers' peak demand, energy requirement and required PJM reserve margin needs throughout the forecast period.

4.11 KPSC Staff Issues Addressed

On March 4, 2011, the Commission issued their Staff's report on Kentucky Power's 2009 IRP and requested that the Company address certain issues in its next IRP report (this report). The following recommendations pertaining to Supply-Side Resource Assessment are restated from the Staff report and addressed below:

1. **Kentucky Power should identify the resources available to it as both a member of the AEP-East Power Pool and as a stand-alone utility. Kentucky Power should also include a detailed discussion of the then-current status of the AEP-East Power Pool, any changes or modifications that are under consideration, and the potential impacts to Kentucky Power.**

   Please see Exhibit 4-9 (in the Confidential Supplement to this filing) for a list and primary characteristics of capacity options screened. The list has been expanded and new options will be added as they become available. Also, see section 4.2.3 for discussion of the existing pool and bulk power arrangements. In sum, the elimination of the AEP Pool Agreement naturally results in Kentucky Power's resource planning being performed exclusively on a "stand-alone" basis.

2. **Kentucky Power should provide a specific discussion on the consideration given to renewable generation by Kentucky Power.**

   Please see section 4.3.4.5.

3. **Kentucky Power should discuss the existence of any cogeneration within its service territory and the consideration given to cogeneration in the resource plan.**

   Please see section 4.3.4.5.e.

4. **Kentucky Power should specifically identify and describe the net metering equipment and systems installed. A detailed discussion of the manner in which such resources are considered in its IRP should also be provided.**

   Please see sections 4.3.5.2 and 4.7.1.

5. **Kentucky Power should provide a detailed discussion of the consideration given to distributed generation**

   Please see sections 4.3.5.2, 3.5.1.5 and 3.5.1.6.

6. **Kentucky Power should provide a specific discussion of the improvements and more efficient utilization of transmission and distribution facilities as required by 807 KAR, Section 8 (2)(a). This information should be provided for the past three years and should address Kentucky Power's plans for the next three years.**

   Please see section 4.4.1.

7. **In addition to describing how Kentucky Power has addressed currently pending environmental regulations and perhaps new legislation, describe how Kentucky Power has specifically addressed such legislation. The next IRP should also address the expected impact on Kentucky Power of any then-potential environmental regulation or legislation.**

   Please see sections 4.2.4 and 4.7.

4.12 Chapter 4 Exhibits

Exhibit 4-1

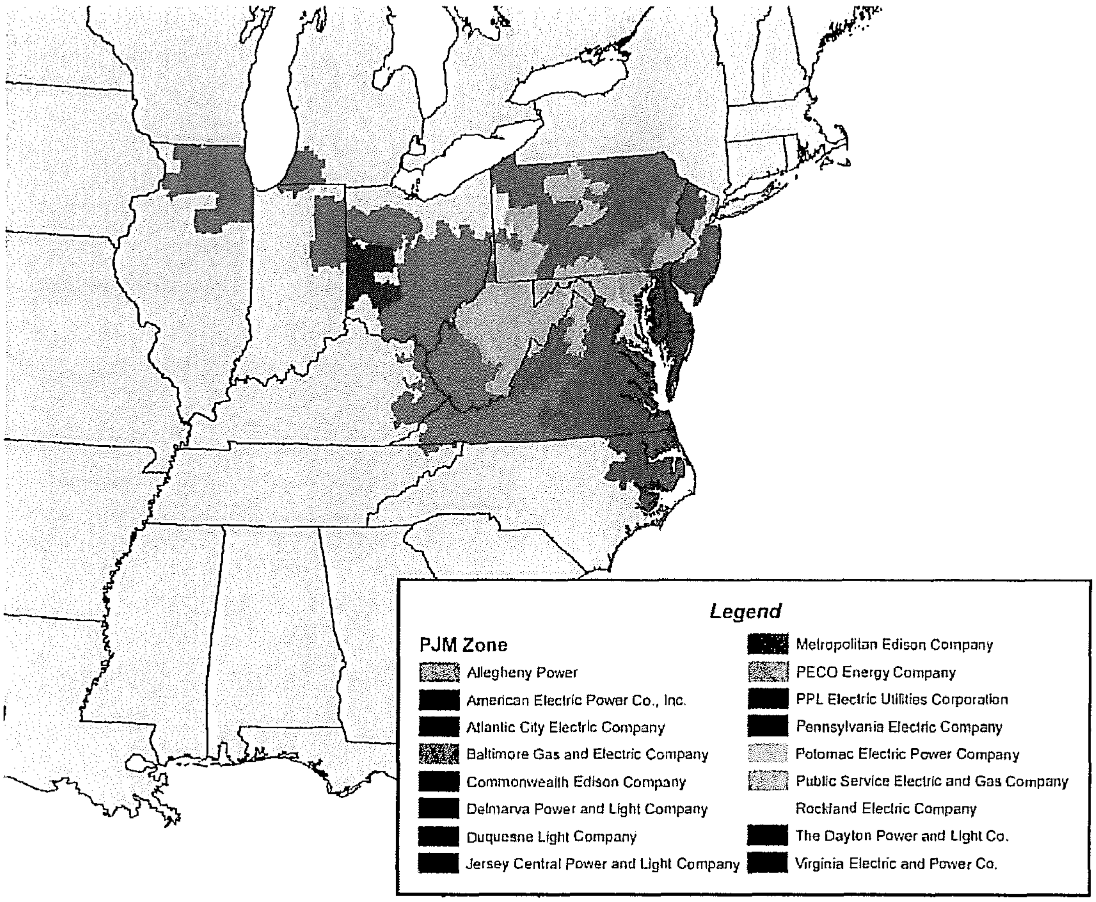


Exhibit 4-2
(807 KAR 5:058 Sec.8.3.b.1-10.)

Kentucky Power
Existing Generation Capacity as of December 2013

Plant Name	Location	Unit No.	In-Service Date	AEP Own/ Contract	Mode of Operation	Winter Capability (MW)	Summer Capability (MW)	Fuel Type	Plant Fuel Storage Capacity (Tons 000)	SCR Installation Year	FGD Installation Year	Super Critical	Age
Big Sandy	Louisa, KY	1	1963	O	Base	278	278	Coal	1,750	--	--	N	50
Big Sandy	--	2	1969	O	Base	800	800	Coal	--	2,004	2,015	Y	44
Rockport	Rockport, IN	1	1984	O	Base	198	198	Coal	--	2,017	2,017	Y	29
Rockport	--	2	1989	C	Base	195	195	Coal	--	2,019	2,019	Y	24
Kentucky Power Coal						1,471	1,471						40
Total Kentucky Power						1,471	1,471						40

Exhibit 4-3
(807 KAR 5:058 Sec.8.3.b.12.c and e.)

Kentucky Power STEAM GENERATING-CAPACITY COST INFORMATION 2012					
Plant Name (a)	Average Fuel Cost (c/Mbtu)	Non-Fuel Variable O&M ($000)	Fixed O&M ($000)	Average Variable Production Cost (c/kWh)	Average Total Production Cost (c/kWh)
Big Sandy	321.61	5,100	15,738	3.72	4.10
Mitchell	291.78	16,489	40,837	3.20	3.64
Rockport	221.40	13,786	180,073	3.06	3.20

Notes:
(a) Mitchell and Rockport data represent total plant capacities

Confidential Exhibit 4-4 (page 1)
(807 KAR 5:058 Sec.8.3.b.12.c.)

See Confidential Exhibit 4-4, the "Kentucky Power, Projected Average Variable Production Costs (2014-2028)" provided in the Confidential Supplement to this filing.

(Page 1 of 3)
REDACTED

KENTUCKY POWER COMPANY
STEAM GENERATING CAPACITY
Projected Average Fuel Costs (¢/MMBtu)
(2014 - 2028)

Unit	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Big Sandy 1															
Big Sandy 2															
Mitchell 1															
Mitchell 2															
Rockport 1															
Rockport 2															
BS1STGAS 1															

Confidential Exhibit 4-4 (page 2)
(807 KAR 5:058 Sec.8.3.b.12.g.)

See Confidential Exhibit 4-4, the "AEP System-East Zone, Projected Average Variable Production Costs (2014-2028)" provided in the Confidential Supplement to this filing.

(Page 2 of 3)
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KENTUCKY POWER COMPANY
STEAM GENERATING CAPACITY
Projected Average Variable Production Costs (¢/kWh)
(2014 - 2028)

Unit	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Big Sandy 1															
Big Sandy 2															
Mitchell 1															
Mitchell 2															
Rockport 1															
Rockport 2															
BS1STGAS 1															

Confidential Exhibit 4-4 (page 3)
(807 KAR 5:058 Sec.8.3.b.12.e.)

See Confidential Exhibit 4-4, the "Kentucky Power, Projected Non-Fuel Variable O&M (2014-2028)" provided in the Confidential Supplement to this filing.

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KENTUCKY POWER COMPANY
STEAM GENERATING CAPACITY
Projected Non-Fuel Variable O&M ($000)
(2014 - 2028)

Unit	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Big Sandy 1															
Big Sandy 2															
Mitchell 1															
Mitchell 2															
Rockport 1															
Rockport 2															
BS1STGAS 1															

Exhibit 4-5

(807 KAR 5:058 Sec.8.3.b.12.a. and b.)

Kentucky Power STEAM GENERATING-CAPACITY OPERATING INFORMATION 2012				
Plant Name	Unit Number	Capacity Factor (%)	Equivalent Availability Factor (%)	Average Heat Rate (Btu/kWh)
Big Sandy	1	30.28	60.26	10,441
	2	27.35	47.84	10,113
Mitchell	1	59.96	75.42	10,360
	2	50.27	64.65	9,638
Rockport	1	82.86	89.37	9,674
	2	80.33	87.15	9,881

Confidential Exhibit 4-6 (page 1)
(807 KAR 5:058 Sec.8.3.b.12.a.)

See Confidential Exhibit 4-6, Kentucky Power, Projected Operating Information provided in the Confidential Supplement to this filing.

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KENTUCKY POWER COMPANY
STEAM GENERATING CAPACITY
Projected Capacity Factors (%)
(2014 - 2028)

Unit	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Big Sandy 1															
Big Sandy 2															
Mitchell 1															
Mitchell 2															
Rockport 1															
Rockport 2															
BS1STGAS 1															

Confidential Exhibit 4-6 (page 2)
(807 KAR 5:058 Sec.8.3.b.12.a.)

See Confidential Exhibit 4-6, Kentucky Power, Projected Operating Information provided in the Confidential Supplement to this filing.

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KENTUCKY POWER COMPANY
STEAM GENERATING CAPACITY
Projected Equivalent Availability Factors (%)
(2014 - 2028)

Unit	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Big Sandy 1															
Big Sandy 2															
Mitchell 1															
Mitchell 2															
Rockport 1															
Rockport 2															
BS1STGAS 1															

Confidential Exhibit 4-6 (page 3)
(807 KAR 5:058 Sec.8.3.b.12.b.)

See Confidential Exhibit 4-6, Kentucky Power, Projected Operating Information provided in the Confidential Supplement to this filing.

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KENTUCKY POWER COMPANY
STEAM GENERATING CAPACITY
Projected Average Heat Rates (Btu/kWh)
(2014 - 2028)

Unit	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Big Sandy 1															
Big Sandy 2															
Mitchell 1															
Mitchell 2															
Rockport 1															
Rockport 2															
BS1STGAS 1															

Exhibit 4-7
Going-In PJM View

KENTUCKY POWER COMPANY
Projected Summer Peak Demands, Generating Capabilities, and Margins (UCAP)
Based on (July 2013) Load Forecast
(2012/2013 - 2030/2031)
2013 (Going-In)

Planning Year		Obligation to PJM: (1) Internal Demand (a)	(2) DSM (b)	(3) Projected DSM Impact (c)	(4) =(1)+(3) Net Internal Demand	(5) Interruptible Demand Response (d)	(6) Demand Response Factor	(7) Forecast Pool Req't (e)	(8) =((4)-((5)*(6)))*(7) UCAP Obligation	(9) Net UCAP Market Obligation (f)	(10) =(8)+(9) Total UCAP Obligation	Resources: (11) Existing Capacity & Planned Changes (g)	(12) Net Capacity Sales (h)	(13) Planned Capacity Additions: Units	(14) Planned Capacity Additions: MW (i)	(15) Annual Purchases	(16) =(11)-(12) + Sum(14) +(15) Net ICAP	(17) AEP EFDRd (j)	(18) =(16)*(1-(17)) Available UCAP	KPCo Position (MW): (19) =((11)-(12) +(15)) *(1-(17))-(10) Net Position w/o New Capacity	(20) =(18)-(10) Net Position w/ New Capacity
2012 /13	(k)	1,167	(3)	(1)	1,166	0	0.954	1.087	1,267	0	1,267	1,470	67				1,403	7.85%	1,293	26	26
2013 /14	(k)	1,136	(3)	(1)	1,135	0	0.957	1.089	1,236	0	1,236	1,470	50				1,420	4.65%	1,354	118	118
2014 /15	(k)	1,157	(5)	(1)	1,156	0	0.956	1.089	1,259	0	1,259	2,250	0				2,250	20.77%	1,783	524	524
2015 /16	(k)	1,180	(7)	(2)	1,178	0	0.958	1.085	1,278	0	1,278	1,432	0				1,432	8.09%	1,316	38	38
2016 /17	(k)	1,198	(9)	(3)	1,196	0	0.955	1.090	1,304	0	1,304	1,432	0				1,432	7.43%	1,326	22	22
2017 /18		1,066	(10)	(3)	1,063	0	0.955	1.090	1,159	0	1,159	1,432	0				1,432	7.43%	1,326	167	167
2018 /19		1,069	(11)	(5)	1,064	0	0.955	1.090	1,160	0	1,160	1,438	0				1,438	7.42%	1,331	171	171
2019 /20		1,072	(12)	(7)	1,065	0	0.955	1.090	1,161	0	1,161	1,438	0				1,438	7.42%	1,331	170	170
2020 /21		1,074	(12)	(9)	1,065	0	0.955	1.090	1,162	0	1,162	1,443	0				1,443	7.42%	1,336	174	174
2021 /22		1,081	(13)	(10)	1,071	0	0.955	1.090	1,167	0	1,167	1,443	0				1,443	7.42%	1,336	169	169
2022 /23		1,086	(13)	(11)	1,075	0	0.955	1.090	1,172	0	1,172	1,443	0				1,443	7.42%	1,336	164	164
2023 /24		1,088	(14)	(12)	1,077	0	0.955	1.090	1,174	0	1,174	1,443	0				1,443	7.42%	1,336	162	162
2024 /25		1,090	(14)	(12)	1,078	0	0.955	1.090	1,175	0	1,175	1,443	0				1,443	7.42%	1,336	161	161
2025 /26		1,097	(14)	(13)	1,084	0	0.955	1.090	1,182	0	1,182	1,440	0				1,440	7.42%	1,333	151	151
2026 /27		1,102	(14)	(13)	1,088	0	0.955	1.090	1,186	0	1,186	1,440	0				1,440	7.42%	1,333	147	147
2027 /28		1,107	(14)	(14)	1,093	0	0.955	1.090	1,192	0	1,192	1,440	0				1,440	7.42%	1,333	141	141
2028 /29		1,109	(14)	(14)	1,096	0	0.955	1.090	1,195	0	1,195	1,438	0				1,438	7.42%	1,331	136	136

Notes:
(a) *Based on (July 2013) Load Forecast (with implied PJM diversity factor)

(b) Existing plus approved and projected "Passive" EE, and VVO
(note: these values & timing are for reference only and are not reflected in position determination)

(c) For PJM planning purposes, the ultimate impact of new DSM is 'delayed' ~4 years to represent the ultimate recognition of these amounts through the PJM-originated load forecast process

(d) Demand Response approved by PJM in the prior planning year plus forecasted "Active" DR

(e) Installed Reserve Margin (IRM) = 15.6%(2012), 15.9%(2013-2014), 15.3%(2015), 15.6%(2016-2030)
Forecast Pool Requirement (FPR) = (1 + IRM) * (1 - PJM EFORd)

(f) Includes company MLR share of:
FRR view of obligations only

(g) Reflects the members ownership ratio of following summer capability assumptions:
Wind Farm PPAs (Where Applicable)

(g) continued
EFFICIENCY IMPROVEMENTS:
2018/19: Rockport 1: 36 MW (turbine)
2020/21: Rockport 2: 36 MW (turbine)
FGD DERATES:
2025/26: Rockport 1: 18 MW
2028/29: Rockport 2: 18 MW
DSI DERATES:
2014/15: Rockport 1-2: 0 MW each
GAS CONVERSION RERATES:
2016/17: Big Sandy 1: (18) MW
RETIREMENTS:
2015/16: Big Sandy 2
2025/26: Big Sandy 1

(h) Includes company's share of:
Ceredo/Darby/Glen Lyn Sale to AMPO,ATSI, and IMEA 2012/13 (171 MW)
Sale of 12 MW in 2012/13 and 13 MW in 2013/14 to Duke
Sale of 210 MW 2012/13 to EMMT
RPM Auction Sales 2012/13 - 2013/14 (646, 700)(MW UCAP)
3.6 MW capacity credit from SEPA's Philpot Dam via Blue Ridge contract

Plus: Estimated I&M nominations for PJM EE ('passive' DR program) levels
--reflected as a UCAP '<resource>'-- as part of PJM's emerging auction products (eff. 2014/15)

(i) New wind and solar capacity value is assumed to be 13% and 36% of namepla

(j) Beginning 2008/09, based on 12-month avg. AEP EFORd in eCapacity as of twelve months ended 9/30 of the previous year

(k) Actual PJM forecast

(*) Combustion Turbines (CT) added to maintain Black Start capability

Effective 1-1-2014, remaining capacity that was previously MLR'd will be allocated as follows:
1) SEPA => 100% to APCo

Exhibit 4-8
Going-In Kentucky Power Winter

KENTUCKY POWER COMPANY
Projected Winter Peak Demands, Generating Capabilities, and Margins (ICAP)
Based on (July 2013) Load Forecast
(2012/2013 - 2028/2029)
2013 (Going-In)

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
						=Sum(1-4)		=Sum(5-6)						=((8)-(9)) +Sum(11)+(12)	=(13)-(5)	=(14)/(5)*100	=(13)-(7)	=(16)/(7)*100
		Peak Demand - MW							Capacity - MW						Reserve Margin - MW			
Winter Season		Internal Demand (a)	Internal Wholesale Contracts	DSM (b)	Committed Sales (c)	Net Demand	Interruptible Demand	Total Demand	Existing Capacity & Planned Changes (d)	Committed Net Sales (e)	Planned Capacity Additions Units	Planned Capacity Additions MW (f)	Annual Purchases	Total Capacity	Reserve Margin Before Interruptible	% of Internal Demand	Reserve Margin After Interruptible	% of Internal Demand
2011/12	Actual	1,378	0	0	0	1,378	0	1,378	1,471	89				1,382	4	0.30	4	0.30
2012/13	Actual	1,409	0	0	0	1,409	0	1,409	1,471	58				1,413	4	0.30	4	0.30
2013/14		1,440	0	(6)	0	1,432	0	1,432	1,471	41				1,430	(2)	(0.10)	(2)	(0.10)
2014/15		1,442	0	(11)	0	1,431	0	1,431	2,251	0				2,251	820	57.30	820	57.30
2015/16		1,445	0	(13)	0	1,432	0	1,432	1,433	0				1,433	1	0.10	1	0.10
2016/17		1,446	0	(15)	0	1,431	0	1,431	1,433	0				1,433	2	0.10	2	0.10
2017/18		1,448	0	(17)	0	1,431	0	1,431	1,438	0				1,438	7	0.50	7	0.50
2018/19		1,450	0	(18)	0	1,432	0	1,432	1,438	0				1,438	6	0.40	6	0.40
2019/20		1,449	0	(19)	0	1,430	0	1,430	1,444	0				1,444	14	1.00	14	1.00
2020/21		1,456	0	(20)	0	1,436	0	1,436	1,444	0				1,444	8	0.60	8	0.60
2021/22		1,460	0	(21)	0	1,439	0	1,439	1,444	0				1,444	5	0.30	5	0.30
2022/23		1,459	0	(21)	0	1,438	0	1,438	1,444	0				1,444	6	0.40	6	0.40
2023/24		1,459	0	(21)	0	1,438	0	1,438	1,444	0				1,444	6	0.40	6	0.40
2024/25		1,465	0	(21)	0	1,444	0	1,444	1,444	0				1,444	0	0.00	0	0.00
2025/26		1,469	0	(21)	0	1,448	0	1,448	1,441	0				1,441	(7)	(0.50)	(7)	(0.50)
2026/27		1,473	0	(21)	0	1,452	0	1,452	1,441	0				1,441	(11)	(0.80)	(11)	(0.80)
2027/28		1,475	0	(21)	0	1,454	0	1,454	1,441	0				1,441	(13)	(0.90)	(13)	(0.90)
2028/29		1,480	0	(21)	0	1,459	0	1,459	1,438	0				1,438	(21)	(1.40)	(21)	(1.40)

Notes:

(a) *Based on (July 2013) Load Forecast (not coincident with PJM's peak)

(b) Existing plus approved and projected "Passive" EE, and VVO

(c) Includes companies MLR share of:

(d) Reflects the following Winter capability assumptions:
Wind Farm PPAs (Where Applicable)
EFFICIENCY IMPROVEMENTS:
2017/18: Rockport 1: 36 MW (turbine)
2019/20: Rockport 2: 36 MW (turbine)

(d) continued
FGD DERATES:
2025/26: Rockport 1: 18 MW
2028/29: Rockport 2: 18 MW
DSI DERATES:
2015/16: Rockport 1-2: 0 MW each
GAS CONVERSION RERATES:
2016/17: Big Sandy 1: (18) MW
RETIREMENTS:
2015/16: Big Sandy 2
2025/26: Big Sandy 1

(e) Includes company's share of.
Contractual share of remaining Mone capacity
Ceredo/Darby/Glen Lyn Sale to AMPO,ATSI, and IMEA 2012/13 (171 MW)
Sale of 12 MW in 2012/13 and 13 MW in 2013/14 to Duke
Sale of 210 MW 2012/13 to EMMT
RPM Auction Sales 2012/13 - 2013/14 (646, 700)(MW UCAP)
3.6 MW capacity credit from SEPA's Philpot Dam via Blue Ridge contract

(f) New wind and solar capacity value is assumed to be 13% and 6.67% of nameplate

(*) Combustion Turbines (CT) added to maintain Black Start capability

Effective 1-1-2014, remaining capacity that was previously MLR'd will be allocated as follows:
1) Remaining Mone Share => 100% to OPCo
2) SEPA => 100% to APCo

Confidential Exhibit 4-9
(807 KAR 5:058 Sec.8.3.b.12.d.)

See Confidential Exhibit 4-9, KPCo, New Generation Technologies provided in the Confidential Supplement to this filing.

AEP SYSTEM-EAST ZONE
New Generation Technologies
Key Supply-Side Resource Option Assumptions (a)(b)(c)

REDACTED

	Capability (MW)			Installed Cost (d)	Trans. Cost (e)	Full Load Heat Rate	Fuel Cost (f)	Variable O&M	Fixed O&M	Emission Rates			Capacity Factor	Overall Availability
Type	Std. ISO	Winter	Summer	($/kW)	($/kW)	(HHV,Btu/kWh)	($/MBtu)	($/MWh)	($/kW-yr)	SO_2 (g) (Lb/mmBtu)	NOx (Lb/mmBtu)	CO_2 (Lb/mmBtu)	(%)	(%)
Base/Intermediate														
Combined Cycle (1X1 GE7FA.05)	300				60					0.0007	0.009	116.0	60	89.1
Combined Cycle (2X1 GE7FA.05)	624				60					0.0007	0.009	116.0	60	89.1
Combined Cycle (2X1 GE7FA.05, w/ Duct Firing)	624				60					0.0007	0.009	116.0	60	89.1
Combined Cycle (2X1 GE7FA.05, w/ Duct Firing, Inlet Chillers)	624				60					0.0007	0.009	116.0	60	89.1
Combined Cycle (2X1 GE7FA.05, w/ Duct Firing, Blk Start)	624				60					0.0007	0.009	116.0	60	89.1
Combined Cycle (1X1 SGT6-5000, w/ Evap Coolers)	294				60					0.0007	0.010	116.0	60	89.1
Combined Cycle (2X1 SGT6-5000, w/ Evap Coolers)	609				60					0.0007	0.010	116.0	60	89.1
Combined Cycle (2X1 KA24-2, w/ Evap Coolers)	647				60					0.0007	0.011	116.0	60	89.1
Combined Cycle (2X1 M501GAC, w/ Duct Firing, Inlet Chillers)	780				60					0.0007	0.007	116.0	60	89.1
Peaking														
Combustion Turbine (2X1GE7EA)	164				57					0.0007	0.033	116.0	3	93.0
Combustion Turbine (2X1GE7EA,w/ Blk Start)	164				57					0.0007	0.033	116.0	3	93.0
Combustion Turbine (2X1GE7EA, w/ Inlet Chillers)	164				59					0.0007	0.009	116.0	3	93.0
Combustion Turbine (2X1GE7FA.05, w/ Inlet Chillers)	418				59					0.0007	0.007	116.0	3	93.0
Aero-Derivative (1X GE LM6000PF)	45				60					0.0007	0.093	116.0	3	95.0
Aero-Derivative (2X GE LM6000PF)	91				60					0.0007	0.093	116.0	3	95.0
Aero-Derivative (2X GE LM6000PF, w/ Blk Start)	91				60					0.0007	0.093	116.0	3	95.0
Aero-Derivative (1X GE LMS100PB)	98				59					0.0007	0.011	116.0	30	95.0
Aero-Derivative (2X GE LMS100PB, w/ Blk Start)	196				59					0.0007	0.093	116.0	30	95.0
Aero-Derivative (2X GE LMS100PB, w/ Inlet Chillers)	196				59					0.0007	0.007	116.0	25	95.0
Wartsila 22 X 20V34SG	201				60					0.0007	0.018	116.0	3	94.0

Notes: (a) Installed cost, capability and heat rate numbers have been rounded.
(b) All costs in 2012 dollars. Assume 1.6% escalation rate for 2012 and beyond.
(c) $/kW costs are based on Standard ISO capability.
(d) Total Plant & Interconnection Cost w/AFUDC (AEP-East rate of 6.12%,site rating $/kW).
(e) Transmission Cost ($/kW,w/AFUDC).
(f) Levelized Fuel Cost (40-Yr. Period 2014-2053)
(g) Based on 4.5 lb. Coal.
(h) Pittsburgh #8 Coal.

Due to termination of the AEP Pool and the fact that Kentucky Power is viewed as a stand-alone company going forward, all AEP-System data have been excluded in this report.

As a result, the following Exhibits provided in the last IRP are no longer applicable:

Confidential Exhibit 4-10

Confidential Exhibit 4-11

Exhibit 4-12
(807 KAR 5:058 Sec.8.3.b.1-11. and Sec. 8.3.c. and Sec. 8.4.a.)
Final CLR PJM View

KENTUCKY POWER COMPANY
Projected Summer Peak Demands, Generating Capabilities, and Margins (UCAP)
Based on (July 2013) Load Forecast
(2012/2013 - 2028/2029)
Final

Planning Year		(1) Internal Demand (a)	(2) DSM (b)	(3) Projected DSM Impact (c)	(4) =(1)+(3) Net Internal Demand	(5) Interruptible Demand Response (d)	(6) Demand Response Factor	(7) Forecast Pool Req't (e)	(8) =((4)-((5)*(6)))*(7) UCAP Obligation	(9) Net UCAP Market Obligation (f)	(10) =(8)+(9) Total UCAP Obligation	(11) Existing Capacity & Planned Changes (g)	(12) Net Capacity Sales (h)	(13) Planned Capacity Additions: Units	(14) MW (i)	(15) Annual Purchases	(16) =(11)-(12) + Sum(14) +(15) Net ICAP	(17) AEP EFORd (j)	(18) =(16)*(1-(17)) Available UCAP	(19) =((11)-(12)+(15))*(1-(17))-(10) Net Position w/o New Capacity	(20) =(18)-(10) Net Position w/ New Capacity
		Obligation to PJM										Resources								KPCo Position (MW)	
2012 /13	(k)	1,167	(3)	(1)	1,166	0	0.954	1.087	1,267	0	1,267	1,470	67				1,403	7.85%	1,293	26	26
2013 /14	(k)	1,136	(3)	(1)	1,135	0	0.957	1.089	1,236	0	1,236	1,470	50				1,420	4.65%	1,354	118	118
2014 /15	(k)	1,157	(5)	(1)	1,156	0	0.956	1.089	1,259	0	1,259	2,250	0	DSM (5 MW)	7		2,257	20.77%	1,788	524	529
2015 /16	(k)	1,180	(7)	(2)	1,178	0	0.958	1.085	1,278	0	1,278	1,432	0	DSM (2 MW) & 100 MW Nameplate Wind	16		1,455	8.09%	1,337	38	59
2016 /17	(k)	1,198	(9)	(3)	1,196	0	0.955	1.090	1,304	0	1,304	1,432	0	DSM (2 MW) & 3 MW Nameplate Solar	3		1,458	7.43%	1,350	22	46
2017 /18		1,066	(10)	(3)	1,063	0	0.955	1.090	1,159	0	1,159	1,432	0	DSM (2 MW) & 58.5 MW Biomass & 1 MW Solar	61		1,519	7.43%	1,406	167	247
2018 /19		1,069	(11)	(5)	1,064	0	0.955	1.090	1,160	0	1,160	1,438	0	DSM (1 MW) & 1 MW Nameplate Solar	1		1,526	7.42%	1,413	171	253
2019 /20		1,072	(12)	(7)	1,065	0	0.955	1.090	1,161	0	1,161	1,438	0	DSM (2 MW) & 1 MW Nameplate Solar	3		1,529	7.42%	1,416	170	255
2020 /21		1,074	(12)	(9)	1,065	0	0.955	1.090	1,162	0	1,162	1,443	0	DSM (5 MW) & 12 MW Nameplate Solar	10		1,544	7.42%	1,429	174	267
2021 /22		1,081	(13)	(10)	1,071	0	0.955	1.090	1,167	0	1,167	1,443	0	DSM (6 MW) & 12 MW Nameplate Solar	11		1,555	7.42%	1,440	169	273
2022 /23		1,086	(13)	(11)	1,075	0	0.955	1.090	1,172	0	1,172	1,443	0	13 MW Nameplate Solar	5		1,560	7.42%	1,444	164	272
2023 /24		1,088	(14)	(12)	1,077	0	0.955	1.090	1,174	0	1,174	1,443	0	DSM (1 MW) & 13 MW Nameplate Solar	6		1,566	7.42%	1,450	162	276
2024 /25		1,090	(14)	(12)	1,078	0	0.955	1.090	1,175	0	1,175	1,443	0	DSM (4 MW) & 13 MW Nameplate Solar	10		1,576	7.42%	1,459	161	284
2025 /26		1,097	(14)	(13)	1,084	0	0.955	1.090	1,182	0	1,182	1,440	0	DSM (2 MW) & 14 MW Nameplate Solar	7		1,580	7.42%	1,463	151	281
2026 /27		1,102	(14)	(13)	1,088	0	0.955	1.090	1,186	0	1,186	1,440	0	DSM (2 MW) & 15 MW Nameplate Solar	8		1,589	7.42%	1,471	147	285
2027 /28		1,107	(14)	(14)	1,093	0	0.955	1.090	1,192	0	1,192	1,440	0	DSM (2 MW) & 17 MW Nameplate Solar	9		1,598	7.42%	1,479	141	287
2028 /29		1,109	(14)	(14)	1,096	0	0.955	1.090	1,195	0	1,195	1,438	0	DSM (-5 MW) & 18 MW Nameplate Solar	3		1,599	7.42%	1,480	136	285

Notes: (a) *Based on (July 2013) Load Forecast (with implied PJM diversity factor)

(b) Existing plus approved and projected "Passive" EE, and VVO
(note: these values & timing are for reference only and are not reflected in position determination)

(c) For PJM planning purposes, the ultimate impact of new DSM is 'delayed' ~4 years to represent the ultimate recognition of these amounts through the PJM-originated load forecast process

(d) Demand Response approved by PJM in the prior planning year plus forecasted "Active" DR

(e) Installed Reserve Margin (IRM) = 15.6%(2012), 15.9%(2013-2014), 15.3%(2015), 15.6%(2016-2030)
Forecast Pool Requirement (FPR) = (1 + IRM) * (1 - PJM EFORd)

(f) Includes company MLR share of:
FRR view of obligations only

(g) Reflects the members ownership ratio of following summer capability assumptions:
Wind Farm PPAs (Where Applicable)

(g) continued
EFFICIENCY IMPROVEMENTS:
2018/19: Rockport 1: 36 MW (turbine)
2020/21: Rockport 2: 36 MW (turbine)
FGD DERATES:
2025/26: Rockport 1: 18 MW
2028/29: Rockport 2: 18 MW
DSI DERATES:
2014/15: Rockport 1-2: 0 MW each
GAS CONVERSION RERATES:
2016/17: Big Sandy 1: (18) MW
RETIREMENTS:
2015/16: Big Sandy 2
2025/26: Big Sandy 1

(h) Includes company's share of:
Ceredo/Darby/Glen Lyn Sale to AMPD,ATSI, and IMEA 2012/13 (171 MW)
Sale of 12 MW in 2012/13 and 13 MW in 2013/14 to Duke
Sale of 210 MW 2012/13 to EMMT
RPM Auction Sales 2012/13 - 2013/14 (646, 700)(MW UCAP)
3.6 MW capacity credit from SEPA's Philpot Dam via Blue Ridge contract

Plus: Estimated I&M nominations for PJM EE ('passive' DR program) levels –reflected as a UCAP '<resource>'– as part of PJM's emerging auction products (eff. 2014/15)

(i) New wind and solar capacity value is assumed to be 13% and 38% of namepl

(j) Beginning 2008/09, based on 12-month avg. AEP EFORd in eCapacity as of twelve months ended 9/30 of the previous year

(k) Actual PJM forecast

(*) Combustion Turbines (CT) added to maintain Black Start capability

Effective 1-1-2014, remaining capacity that was previously MLR'd will be allocated as follows:
1) SEPA => 100% to APCo

Exhibit 4-13
(807 KAR 5:058 Sec.8.3.b.1-11. and Sec. 8.3.c. and Sec. 8.4.a.)
Final CLR Winter View

KENTUCKY POWER COMPANY
Projected Winter Peak Demands, Generating Capabilities, and Margins (ICAP)
Based on (July 2013) Load Forecast
(2012/2013 - 2028/2029)
Final

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
						=Sum(1-4)		=Sum(5-6)						=((8)-(9)) +Sum(11)+(12)	=(13)-(5)	=(14)/(5)*100	=(13)-(7)	=(16)/(7)*100
		Peak Demand - MW							Capacity - MW						Reserve Margin - MW			
											Planned Capacity Additions							
Winter Season		Internal Demand (a)	Internal Wholesale Contracts	DSM (b)	Committed Sales (c)	Net Demand	Interruptible Demand	Total Demand	Existing Capacity & Planned Changes (d)	Committed Net Sales (e)	Units	MW (f)	Annual Purchases	Total Capacity	Reserve Margin Before Interruptible	% of Internal Demand	Reserve Margin After Interruptible	% of Internal Demand
2011/12	Actual	1,378	0	0	0	1,378	0	1,378	1,471	89				1,382	4	0.30	4	0.30
2012/13	Actual	1,409	0	0	0	1,409	0	1,409	1,471	58				1,413	4	0.30	4	0.30
2013/14		1,440	0	(8)	0	1,432	0	1,432	1,471	41				1,430	(2)	(0.10)	(2)	(0.10)
2014/15		1,442	0	(11)	0	1,431	0	1,431	2,251	0	DSM (5 MW)	7		2,258	827	57.80	827	57.80
2015/16		1,445	0	(13)	0	1,432	0	1,432	1,433	0	DSM (2 MW) & 100 MW Nameplate Wind	16		1,456	24	1.70	24	1.70
2016/17		1,446	0	(15)	0	1,431	0	1,431	1,433	0	DSM (2 MW) & 3 MW Nameplate Solar	2		1,458	27	1.90	27	1.90
2017/18		1,448	0	(17)	0	1,431	0	1,431	1,438	0	DSM (2 MW) & 58.5 MW Biomass & 1 MW Solar	60		1,523	92	6.40	92	6.40
2818/19		1,450	0	(18)	0	1,432	0	1,432	1,438	0	DSM (1 MW) & 1 MW Nameplate Solar	1		1,524	92	6.40	92	6.40
2019/20		1,449	0	(19)	0	1,430	0	1,430	1,444	0	DSM (2 MW) & 1 MW Nameplate Solar	3		1,533	103	7.20	103	7.20
2020/21		1,456	0	(20)	0	1,436	0	1,436	1,444	0	DSM (5 MW) & 12 MW Nameplate Solar	6		1,539	103	7.20	103	7.20
2021/22		1,460	0	(21)	0	1,439	0	1,439	1,444	0	DSM (6 MW) & 12 MW Nameplate Solar	7		1,546	107	7.40	107	7.40
2022/23		1,459	0	(21)	0	1,438	0	1,438	1,444	0	13 MW Nameplate Solar	1		1,547	109	7.60	109	7.60
2023/24		1,459	0	(21)	0	1,438	0	1,438	1,444	0	DSM (1 MW) & 13 MW Nameplate Solar	1		1,549	111	7.70	111	7.70
2024/25		1,485	0	(21)	0	1,444	0	1,444	1,444	0	DSM (4 MW) & 13 MW Nameplate Solar	5		1,554	110	7.60	110	7.60
2025/26		1,469	0	(21)	0	1,448	0	1,448	1,441	0	DSM (2 MW) & 14 MW Nameplate Solar	3		1,554	106	7.30	106	7.30
2026/27		1,473	0	(21)	0	1,452	0	1,452	1,441	0	DSM (2 MW) & 15 MW Nameplate Solar	3		1,557	105	7.20	105	7.20
2027/28		1,475	0	(21)	0	1,454	0	1,454	1,441	0	DSM (2 MW) & 17 MW Nameplate Solar	4		1,561	107	7.40	107	7.40
2028/29		1,480	0	(21)	0	1,459	0	1,459	1,438	0	DSM (-5 MW) & 18 MW Nameplate Solar	(3)		1,554	95	6.50	95	6.50

Notes:

(a) Based on (July 2013) Load Forecast (not coincident with PJM's peak)

(b) Existing plus approved and projected "Passive" EE, and VVO

(c) Includes companies MLR share of:

(d) Reflects the following Winter capability assumptions:
Wind Farm PPAs (Where Applicable)
EFFICIENCY IMPROVEMENTS:
2017/18: Rockport 1: 36 MW (turbine)
2019/20: Rockport 2: 36 MW (turbine)

(d) continued
FGD DERATES:
2025/26: Rockport 1: 18 MW
2028/29: Rockport 2: 18 MW
DSI DERATES:
2015/16: Rockport 1-2: 0 MW each
GAS CONVERSION RERATES:
2016/17: Big Sandy 1: (18) MW
RETIREMENTS:
2015/16: Big Sandy 2
2025/26: Big Sandy 1

(e) Includes company's share of:
Contractual share of remaining Mone capacity
Ceredo/Darby/Glen Lyn Sale to AMPO,ATSI, and IMEA 2012/13 (171 MW)
Sale of 12 MW in 2012/13 and 13 MW in 2013/14 to Duke
Sale of 210 MW 2012/13 to EMMT
RPM Auction Sales 2012/13 - 2013/14 (646, 700)(MW UCAP)
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(f) New wind and solar capacity value is assumed to be 13% and 6.67% of nameplate

(*) Combustion Turbines (CT) added to maintain Black Start capability

Effective 1-1-2014, remaining capacity that was previously MLR'd will be allocated as follows:
1) Remaining Mone Share => 100% to DPCo
2) SEPA => 100% to APCo

Exhibit 4-14
(807 KAR 5:058 Sec. 8.4.b.and c.)

KENTUCKY POWER COMPANY
Annual Internal Energy Requirements, Energy Resources and Energy Inputs
2014 - 2028

	Load and Energy Efficiency (GWh)			Energy Resources (GWh)							Energy Inputs (By Primary Fuel Type)			
	Energy Requirements (GWh)			Generation (By Primary Fuel Type)			Renewables/Purchases				Coal-fired Generation		Gas-fired Generation	
Year	Base Forecast Internal Energy Requirements	Energy Efficiency(A)	Adjusted Energy	Coal	Gas	Total	Utility Solar(B)	Distributed Solar	Wind	Total(C)	Tons (000)	MMBtu (000)	MCF (000)	MMBtu(000)
2014	6,751	(29)	6,722	7,381	0	7,381	0	0	0	7,381	3,286	73,395	0	0
2015	6,746	(38)	6,708	6,693	0	6,693	0	0	294	6,987	2,947	66,117	0	0
2016	6,763	(48)	6,715	7,028	77	7,104	0	2	294	7,399	3,134	69,086	890	912
2017	6,768	(58)	6,709	7,066	101	7,167	0	2	294	7,462	3,137	69,252	1,171	1,200
2018	6,771	(68)	6,703	7,003	109	7,113	0	3	294	7,409	3,105	68,594	1,262	1,294
2019	6,778	(78)	6,700	6,861	105	6,966	0	3	294	7,263	3,010	66,703	1,218	1,248
2020	6,789	(88)	6,701	6,859	96	6,956	23	4	294	7,276	2,992	67,010	1,120	1,148
2021	6,803	(121)	6,683	6,660	111	6,771	45	5	294	7,114	2,912	65,055	1,287	1,319
2022	6,827	(131)	6,696	5,895	64	5,959	68	7	294	6,326	2,551	57,553	737	755
2023	6,847	(140)	6,707	6,050	46	6,096	90	8	294	6,488	2,631	59,205	537	550
2024	6,862	(147)	6,715	6,016	45	6,061	113	10	294	6,478	2,622	58,867	530	543
2025	6,879	(152)	6,727	6,084	51	6,135	135	13	294	6,576	2,621	59,367	600	615
2026	6,900	(156)	6,744	6,763	72	6,834	158	16	294	7,301	2,946	65,936	833	854
2027	6,922	(160)	6,762	6,738	39	6,777	180	20	294	7,270	2,948	65,701	454	465
2028	6,945	(163)	6,782	6,507	94	6,601	204	25	294	7,123	2,809	63,384	1,090	1,117

Notes: (A) Represents incremental EE and VVO.
(B) Contracted purchased solar energy amounts
(C) Sum of Kentucky Power generated energy, energy purchased from other utilities, and wind purchases

Exhibit 4-15
(807 KAR 5:058 Sec.6)

Comparison of 2009 and 2013 Capacity Expansion Plans		
	2009 IRP	**2013 IRP**
Big Sandy Unit 1	Retire	Gas conversion
Big Sandy Unit 2	Retrofit	Retire
Mitchell Unit 1	Part of the AEP-East Pool	50% Transfer
Mitchell Unit 2	Part of the AEP-East Pool	50% Transfer
New Capacity Additions	- Added solar starting in 2011	- Adds utility-scale solar beginning in 2020
		- Adds distributed solar beginning in 2016
		-Assumes additions of 100 MW Wind starting in 2015
		- Implements customer and grid energy efficiency programs
		- Assumes addition of 58.5 MW biomass from ecoPower

Confidential Exhibit 4-16
(807 KAR 5:058 Sec.8.3.a.)

See Confidential Exhibit 4-16, the AEP System-East Zone, Transmission Facilities map provided in the Confidential Supplement to this filing.

Confidential Exhibit 4-16

AEP System-East Zone, Transmission Facilities Map

CONFIDENTIAL INFORMATION REDACTED

Confidential Exhibit 4-17
(807 KAR 5:058 Sec.8.3.a.)

See Confidential Exhibit 4-17, the AEP Transmission Line Network – Kentucky map provided in the Confidential Supplement to this filing.

Confidential Exhibit 4-17

AEP Transmission Line Network – Kentucky Map

CONFIDENTIAL INFORMATION REDACTED

Exhibit 4-18
(807 KAR 5:058 Sec.5.4.)

AEP External Ties located in Kentucky

From	To	Voltage (kV)	Interchange Rating (MVA) Normal/Emergency Summer	Winter
Duke Energy Midwest (DEM) (Formerly Cinergy, Formerly CG&E)				
Tanners Creek (AEP/I&M)	East Bend	345	1195/1315	1195/1315
East Kentucky Power Cooperative (EKPC)				
Millbrook Park (AEP/OPC)	Argentum	138	205/215	215/215
Falcon (AEP/KPC)	Falcon	69	35/35	35/35
Grays Branch (AEP/KPC)	Argentum	69	39/46	54/58
Grayson (AEP/KPC)	Grayson	69	20/20	20/20
Leon (AEP/KPC)	Leon	69	54/54	54/54
Pelfrey (AEP/KPC)	Pelfrey	69	19/19	49/49
Thelma (AEP/KPC)	Thelma	69	78/96	103/106
Salt Lick (AEP/KPC)	Salt Lick	46	38/46	52/58
		Total	**488/531**	**582/595**
E.ON US (LGEE) (Formerly LG&E, Formerly KU)				
Wooten (AEP/KPC)	Hyden	161	300/404	379/418
Hillsboro (AEP/OPC)	Kenton	138	159/191	191/191
Morehead (AEP/KPC)	Rodburn (Morehead)	69	69/72	72/72
		Total	**528/667**	**642/681**
Tennesee Valley Authority (TVA)				
Leslie (AEP/KPC)	Pineville	161	216/249	289/330