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April 21, 2009

RECEIVED
APR 21 2009
PUBLIC SERVICE COMMISSION

Mr. Jeffrey Derouen
Executive Director
Public Service Commission
211 Sower Boulevard
P. O. Box 615
Frankfort, Kentucky 40602-0615

Re: East Kentucky Power Cooperative, Inc.
2009 Integrated Resource Plan
PSC Case No. 2009-00106

Dear Mr. Derouen:

Please find enclosed for filing with the Commission documents relating to the 2009 Integrated Resource Plan ("IRP") of East Kentucky Power Cooperative, Inc. ("EKPC"). This filing includes an original and ten copies of EKPC's Petition for Confidential Treatment of Information. Attached to the original Petition are sections of the 2009 EKPC IRP containing the information which is sought to be treated confidentially.

Redacted copies of the 2009 EKPC IRP filing are attached to the ten copies of the Petition. Additionally, one unbound redacted copy of the IRP is enclosed.

Intervenors in EKPC's 2006 IRP case have been notified of this filing.

Very truly yours,

Mark David Goss

Enclosures

EAST KENTUCKY POWER COOPERATIVE

A Touchstone Energy Cooperative

RECEIVED

APR 21 2009

PUBLIC SERVICE
COMMISSION

Integrated Resource Plan

Case No. 2009-00106

REDACTED

April 21, 2009

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Section 4

Format

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Section 4

4. Format

4.(1) Organization

This plan is organized by using the Section and Subsection numbers found in the Administrative Regulation 807 KAR 5:058, "Integrated Resource Planning by Electric Utilities." This report is filed with the Public Service Commission of Kentucky in compliance with the aforementioned regulation.
The format of the report is outlined below.

- Integrated Resource Plan – Case No. 2009-00106 (Bound Herein)

  1) Table of Contents
  2) Section 4. Format
  3) Section 5. Plan Summary
  4) Section 6. Significant Changes
  5) Section 7. Load Forecasts
  6) Section 8. Resource Assessment and Acquisition Plan – Two (2) EKPC Interconnected System Maps (Bound Herein)
  7) Section 9. Financial Information

- 2008 Load Forecast Report (CD)

  8) Section 1.0 Executive Summary
  9) Section 2.0 Load Forecast Methodology
  10) Section 3.0 Load Forecast Discussion
  11) Section 4.0 Regional Economic Model
  12) Section 5.0 Residential Customer Forecast
  13) Section 6.0 Residential Sales Forecast
  14) Section 7.0 Commercial and Other Sales Forecast
  15) Section 8.0 Peak Demand Forecast and High and Low Case Scenarios
  16) Appendix A: RUS Form 341 & Board Resoulutions
  17) Appendix A: Member System Load Forecast Reports
  18) Appendix B: Customer and Energy Model Definitions and Results

- Technical Appendix (CD)

  19) Executive Summary
  20) Major Enhancements since last IRP
  21) Introduction
  22) Comprehensive DSM Measure List
  23) Qualitative Screening Process
  24) Qualitative Screening Results
  25) Quantitative Evaluation Process
  26) Quantitative Screening Results
  27) Recommendations
  28) Estimated Impacts
  29) Factoring Environmental Cost Considerations into DSM Evaluation

4.(2) Identification of individuals responsible for preparation of the plan.

James Lamb, Senior Vice-President, Power Supply
Julia Tucker, Director, Power Supply Planning
Darrin Adams, Manager, Transmission Planning
Sally Witt, Manager, Resource Planning

Legal counsel:
Mark David Goss, Frost Brown Todd

Section 5

Plan Summary

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Section 5

5. Plan Summary

5.(1) Description of the utility, its customers, service territory, current facilities, and planning objectives.

East Kentucky Power Cooperative Inc. ("EKPC") is a generation and transmission electric cooperative located in Winchester, Kentucky. It serves 16 member distribution cooperatives who serve approximately 500,000 retail customers. Member distribution cooperatives currently served by EKPC are listed below:

Big Sandy RECC	Jackson Energy Cooperative
Blue Grass Energy Coop. Corp.	Licking Valley RECC
Clark Energy Cooperative, Inc.	Nolin RECC
Cumberland Valley Electric	Owen Electric Cooperative, Inc.
Farmers RECC	Salt River Electric Cooperative
Fleming-Mason Energy Cooperative, Inc.	Shelby Energy Cooperative, Inc.
Grayson RECC	South Kentucky RECC
Inter-County Energy Coop. Corp.	Taylor County RECC

EKPC owns and operates three coal fired generating stations – Dale Station (196 MW), Cooper Station (341 MW), and Spurlock Station (1,396 MW). EKPC's newest coal fired unit is Spurlock Station Unit 4 (278 MW) that began commercial operation on April 1, 2009. EKPC has three 150 MW gas fired combustion turbines (450 MW - winter rating) and four 98 MW gas fired combustion turbines (392 MW – winter rating) at Smith Station. Two new 97 MW combustion turbines (194MW – winter rating) are currently being constructed at the Smith Station and are expected to be operational by December 1, 2009. In addition, EKPC owns and operates 15.2 MW of landfill gas generating plant capacity with an additional 1.6 MW under construction that will be operational in 2009.

EKPC purchases 170 MW of hydropower from the Southeastern Power Administration ("SEPA") on a long-term basis. The 70MW at Laurel Dam has continued to be reliable capacity. However, due to various dam repair projects, the 100MW provided from the Cumberland System has not been dependable capacity during the past two years and is not expected to be considered dependable for another three to four years. Once the dam repairs are completed, the capacity should return to firm dependable status for the long term. EKPC also has a contract with Duke Energy Ohio to purchase the output of the Green-Up Hydro facility through 2010. Greenup Hydro is run-of-river generation located on the Ohio River with an average winter capacity of 35 MW.

In total, EKPC has approximately 3,191 MW available during winter peak periods as of the end of year 2009. In 2008, EKPC's peak load was 3,051 MW and energy requirements for sales to its members were 12,948 GWh.

EKPC owns and operates a 2,910-circuit mile network of high voltage transmission lines consisting of 69 kV, 138 kV, 161 kV, and 345 kV lines, and all the related substations. EKPC is a member of the Southeast Electric Reliability Council ("SERC"). EKPC maintains 63 normally closed free-flowing interconnections with its neighboring utilities.

EKPC submitted its 2006 IRP (PSC Case No. 2006-00471) to the Commission on October 21, 2006. The report submitted by EKPC provided its plan to meet the power requirements of its 16 member distribution cooperatives, along with the then expected Warren RECC load, over the period from 2006 to 2020. EKPC subsequently learned that Warren RECC would not become a member of the EKPC system. On January 30, 2008, EKPC received the Commission Staff's Report on the 2006 Integrated Resource Plan of East Kentucky Power Cooperative, Inc. The purpose of the report was to review and evaluate EKPC's 2006 IRP in accordance with the requirements of 807 KAR 5:058, Section 12(3), which requires the Commission Staff to issue a report summarizing its review of each IRP filing and offer suggestions and recommendations to be considered in subsequent filings.

The EKPC IRP Team, which consists of various personnel within the organization, used the PSC Staff Report as a starting point in their analysis for the next IRP. The PSC Staff Report recommendations along with the basic requirements of the Commission's regulations became the foundation leading to this Integrated Resource Plan ("IRP").

EKPC's objective of the power supply plan is to develop a low cost, reliable plan to serve its Member Systems, while simultaneously mitigating risk. EKPC has an on-going planning process and this IRP represents only one snapshot in time of the process. Changing conditions may warrant changes to this IRP.

PSC Staff Recommendation for 2006 IRP

The following summary of recommendations from the PSC Staff Report on EKPC's 2006 IRP was used as guidance in the development of EKPC's 2009 IRP. EKPC's response follows each recommendation.

Load Forecast

- ***Provide a more complete description of each model, component and variable for each model including the class models, regional economic model, peak models and the high / low variation in peak demand.***

  In the technical appendix of this 2009 IRP document, in the 'Model Specifications and Results' directory, there is a file for each member system. Each file has the regression model specifications for each class and the resulting statistics. Additionally, variables used in the models are defined in the Word document 'Model Variable List Equations and Defn.doc'. The regional model datasets are included in the 'Economic Analysis Results' directory. As explained in Section 4 of the 2008 Load Forecast Report (included in the appendix), Global Insight performed the analyses and provided county level data to EKPC for use in the forecasts. For more details, see Section 4 of the 2008 Load Forecast Report which is included in its entirety in the appendix. Similarly, the datasets for the peak models as well as the high/low variation is located in the 'Scenario Data' directory and the explanation of the methodology is in Section 8 of the 2008 Load Forecast Report.

- ***Provide a complete description of how the economic and demographic data is constructed for the seven economic regions, including how the data is manipulated so as to be useful for forecasting individual member system class usage.***

  Please refer to Section 4 of the 2008 Load Forecast Report for explanation of how the economic regional data is derived. See Section 5, 6 and 7 for explanations as to how those variables are used to project customers per class and ultimately use per customer or class usage.

- ***Provide a complete description of the assumptions made and how they are manipulated to produce the high and low case variations in the seasonal peak demand forecasts.***

Please refer to Section 8 of the 2008 Load Forecast Report pages 71-81 for a complete description of the methodology. The 'Scenario Data' directory on the included CD contains the datasets used in the models.

- ***Provide an expanded discussion comparing the 2006 load forecast with the forecasts supporting the next IRP. Specifically, include a comparison of how assumptions and inputs (major drivers) in the models changed after it became apparent that Warren RECC would not join the EKPC system and how the generation that would have supported the Warren RECC load was then needed for existing customers.***

As discussed in Section 3 of the 2008 Load Forecast Report, the major changes in the 2008 Load Forecast are:

1.) The 2006 formal report and load forecast included the addition of Warren RECC as an EKPC member beginning in April 2008. However, Warren RECC is not going to become an EKPC member.

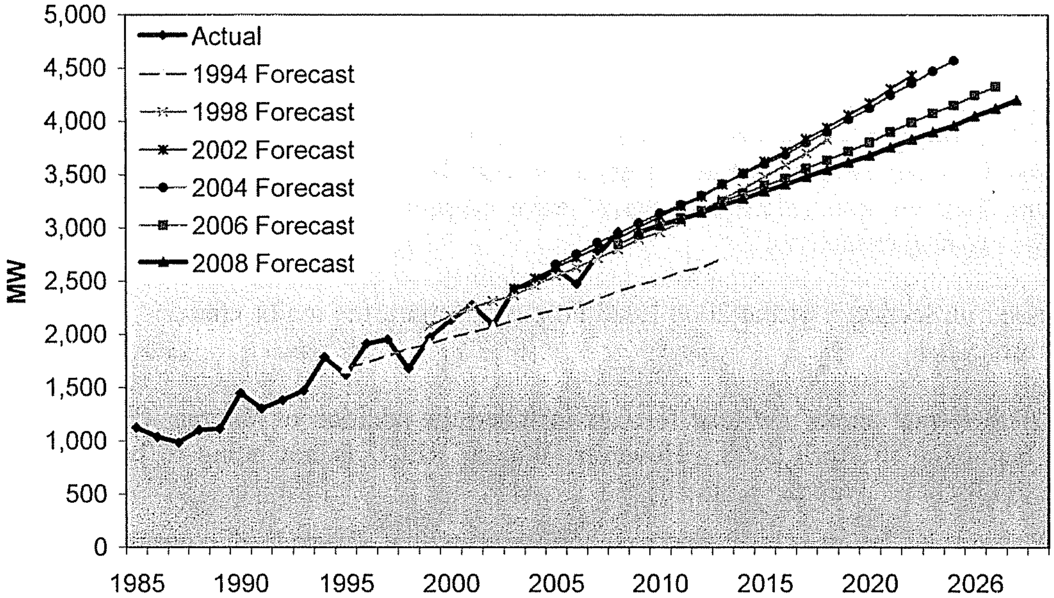
2.) EKPC and its member systems have implemented a direct load control program. The implementation plan indicates installing 10,000 control devices on water heaters and/or air conditioners each year for the next 5 years. This will result in 15 MW being clipped off the winter peak and 60 MW off the summer peak. These reductions are reflected in the load forecast.

3.) In late 2007 and all of 2008, the nation has experienced an economic downturn. Gas and coal prices have increased dramatically. The housing market has fallen. The economy is in a recession. While the 2008 forecast was prepared prior to the full effect being seen, the 2006 and 2007 data indicated a slowing down of growth for the member systems was beginning. Therefore, the 2008 forecast does reflect a more pessimistic outlook than prior forecasts. The table and figures on the following pages show the differences between the forecasts, as well as a comparison of the peak demand projections for the past several forecasts, including the 2006 without Warren.

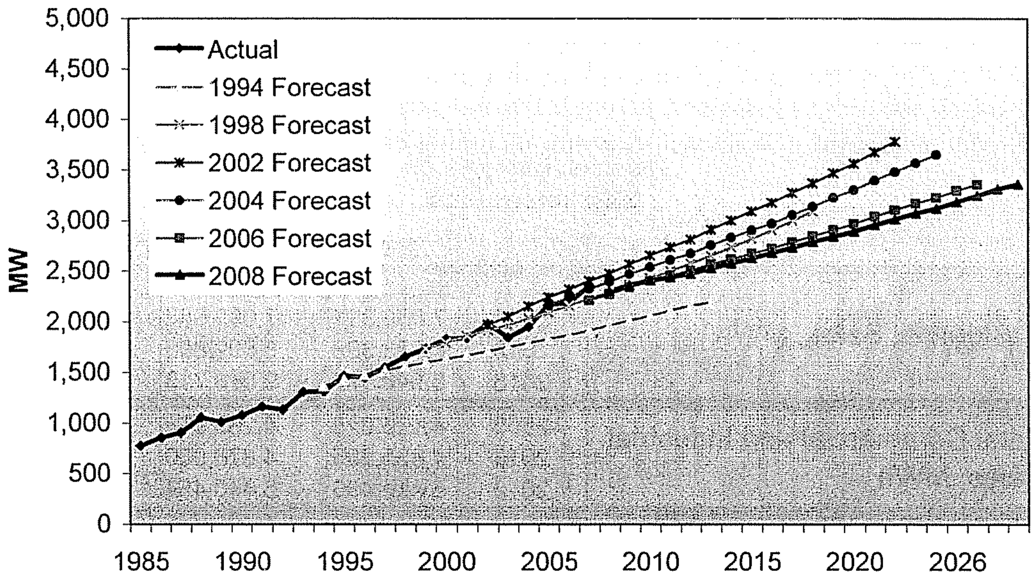
Forecast Comparison
2008 Versus 2006

		2008	Without Warren 2006	Difference
Residential Sales, MWh	2008	7,032,311	7,099,687	-67,376
	2013	7,773,389	8,092,806	-319,417
	2018	8,540,177	9,078,713	-538,536
Total Commercial and Industrial Sales, MWh	2008	4,126,020	4,265,695	-139,675
	2013	4,855,986	4,876,900	-20,914
	2018	5,414,466	5,440,454	-25,988
Gallatin Steel, MWh per Year	2008-2018	968,960	968,960	
Residential Customers	2008	480,233	487,370	-7,137
	2013	518,075	538,602	-20,527
	2018	559,160	590,201	-31,041
Net Winter Peak MW	2008	2,962	2,848	114
	2013	3,215	3,251	-36
	2018	3,547	3,638	-91
Net Summer Peak MW	2008	2,302	2,273	29
	2013	2,529	2,569	-40
	2018	2,790	2,848	-58

Historical Load Forecast Studies
Winter Peak Demand Projections



Historical Load Forecast Studies
Summer Peak Demand



The table below excludes Warren for all forecasts, 2004, 2006 and 2008.

Forecast Comparison

2008 Versus 2006 Versus 2004
Excludes Warren

	Year	2008	2006	2004	Difference 2008 and 2006		Difference 2008 and 2004	
Total Requirements, MWh	2010	13,959,302	14,138,674	13,193,248	-179,372	-1.3%	766,054	5.8%
	2015	15,335,690	15,787,203	16,778,196	-451,513	-2.9%	-1,442,506	-8.6%
	2020	16,855,275	17,601,161	19,128,773	-745,886	-4.2%	-2,273,498	-11.9%
	2025	18,422,561	19,519,545		-1,096,984	-5.6%		
Net Winter Peak MW	2010	3,087	3,021	3,113	66	2.2%	-26	-0.8%
	2015	3,345	3,398	3,579	-53	-1.6%	-234	-6.5%
	2020	3,680	3,804	4,099	-124	-3.3%	-419	-10.2%
	2025	4,052	4,248		-196	-4.6%		
Net Summer Peak MW	2010	2,406	2,403	2,516	3	0.1%	-110	-4.4%
	2015	2,630	2,674	2,880	-44	-1.6%	-250	-8.7%
	2020	2,893	2,968	3,278	-75	-2.5%	-385	-11.7%
	2025	3,186	3,298		-112	-3.4%		

The following table, "EKPC Load Requirements & Resources," shows EKPC's load requirements compared to existing capacity based on the 2006 Load Forecast Report, **excluding Warren's** load requirements. The table does not include Spurlock 4 or Smith CTs 9 and 10 or any future capacity additions.

EKPC Load Requirements & Resources
(Without Warren)

	Peak Forecast		Reserves Required*		Capacity Required		Existing Capacity		Capacity Deficit/ (Surplus)	
Year	**WIN**	**SUM**	**WIN**	**SUM**	**WIN**	**SUM**	**WIN**	**SUM**	**WIN**	**SUM**
2007	2,773	2,213	333	266	3,106	2,479	2,754	2,543	352	(64)
2008	2,848	2,274	342	273	3,190	2,547	2,754	2,543	436	4
2009	2,938	2,342	353	281	3,291	2,623	2,726	2,515	565	108
2010	3,021	2,404	362	288	3,383	2,692	2,726	2,515	657	177
2011	3,094	2,457	371	295	3,465	2,752	2,691	2,475	774	277

*Assumes a 12% reserve margin.

Demand Side Management:

- ***Continue to evaluate and pursue DSM opportunities to the same extent and scope as reflected in this, EKPC's 2006 IRP.***

In the 2009 IRP, EKPC has again developed a comprehensive list (103 measures this time in comparison to 93 in 2006) of new DSM measures to consider. This set of DSM measures covers all classes and major end uses, and includes a robust set of available technologies and strategies for producing energy and capacity savings. Several of the measures and programs that were added also passed the qualitative and quantitative screening. Not only that, but several provide substantial additional savings. In addition, EKPC has assigned more ambitious participation goals for many of its planned new DSM programs. The end result is that the projected savings estimates ten years out are substantially higher in this 2009 IRP than they were in the 2006 IRP. The impact is particularly dramatic on the energy requirements side, where the 2009 IRP projects tenth-year savings of over 450,000 MWh versus 135,000 MWh in the 2006 IRP.

- ***Consider DSM as an environmental compliance option in addition to a resource option, or, at minimum, explain why it has not done so or cannot do so.***

  EKPC has endeavored to identify all major cost-effective demand-side management options and included ambitious goals for its planned new DSM programs in this 2009 IRP. The cost-effectiveness method places a value on environmental compliance because the alternative avoidable environmental compliance costs for conventional supply are captured in the avoided costs that are used to value DSM savings. In other words, the value of DSM as a resource is combined with the value of DSM as an environmental compliance option in determining its cost-effectiveness for inclusion in the integrated plan. Environmental compliance is a multi-faceted challenge, and DSM does not address all forms of compliance. For example, best available control technology requirements cannot be relaxed because of reduced loadings on a generating unit. However, output based environmental regulation (cap and trade approaches) are more suitable for considering DSM as a compliance option.

- ***Based on Federal actions at the time, EKPC should include explicit discussion in its next IRP of its plans for managing carbon emissions.***

  At the time that this 2009 IRP was prepared, there was no defined Federal regulation of carbon emissions. However, it is certainly likely that in the next few years some form of Federal control of carbon emissions will occur. In this 2009 IRP, EKPC has imputed a cost of $40 per ton for carbon emissions based on previous legislation proposed under the Bingaman and Lieberman-Warner Bills. This value has been used to perform the Societal Test on the DSM programs.

- ***Based on the extent to which "new" DSM programs are being implemented, reflect their estimated load impacts in EKPC's load forecast or, in the alternative, in the sensitivity analyses, of its load forecast.***

  EKPC has one new DSM program that falls into this category at the time of the preparation of the 2009 IRP, and that is the Direct Load Control for Air Conditioners and Water Heaters program. The implementation of this program was in its infancy at the end of 2008. As a result, EKPC has treated this DLC program as a "New" program in the 2009 IRP. It is being accounted for in the sensitivity analysis.

Supply-Side Resource Assessment:

- ***EKPC should expand its universe of supply-side options in preparing its next IRP, as the AG suggests. It should specifically follow up on its response that it will perform a detailed evaluation of supercritical coal-fired units in developing self-build options in conjunction with its next RFP for supply-side resources.***

  For the 2009 IRP, the supply side alternatives the production cost model had to choose from was expanded to include:

  Combustion turbines
  Combined Cycle units
  Coal units including fluidized bed and subcritical technologies
  Renewable resources including wind, solar, biomass and hydro
  Various purchases and partnering alternatives.

  Demand side options were also considered as a resource to meet system demand needs.

EKPC has well defined and justified its base load generating needs through 2013, when the Smith 1 CFB unit will come on-line. EKPC's next IRP will be due in 2012, and that plan will provide an updated assessment of load growth and resource commitments. Continued monitoring and subsequent analysis will be required to assess the best technology for the next increment of base load capacity in accordance with the Commission's regulations.

- ***EKPC should address in detail in its next IRP the AG's comments concerning its transmission system constraints.***

  EKPC regularly identifies transmission projects and upgrades that are required for maintaining the capability of its transmission system in order to meet the demands of its Member Systems. Transmission projects and long range work plans are discussed in Section 8 of this IRP.

Integration and Plan Optimization:

- ***EKPC should more fully integrate the analyses of potential DSM programs into the optimization process of its IRP so that DSM is considered, to the greatest extent possible, in the same manner as supply-side resources.***

A set of twenty-three new DSM programs passed both the qualitative and quantitative screening in this 2009 IRP and therefore are suggested for implementation. The quantitative screening consists of a static look at cost-effectiveness using avoided costs.

A second check on the cost-effectiveness of this portfolio of 23 programs occurs in the integration phase of this IRP. Sensitivities were performed by producing a resource plan with and without this DSM portfolio.

The following tables summarize the difference between these two sensitivities with respect to the resulting resource plan.

	Peak Forecast		DSM Resources		DSM Affected Peak	
YEAR	WIN	SUM	WIN	SUM	WIN	SUM
2009	2,969	2,387	27	43	2,942	2,344
2010	3,039	2,442	56	89	2,983	2,353
2011	3,100	2,507	83	132	3,017	2,375
2012	3,160	2,593	104	169	3,056	2,424
2013	3,232	2,687	125	207	3,107	2,480
2014	3,293	2,736	140	216	3,153	2,520
2015	3,363	2,790	155	226	3,208	2,564
2016	3,427	2,844	167	233	3,260	2,611
2017	3,502	2,903	179	240	3,323	2,663
2018	3,568	2,959	191	246	3,377	2,713
2019	3,637	3,013	191	244	3,446	2,769
2020	3,701	3,063	192	242	3,509	2,821
2021	3,781	3,129	188	238	3,593	2,891
2022	3,854	3,190	184	235	3,670	2,955
2023	3,925	3,245	180	231	3,745	3,014

2009 Plan Assuming No DSM Capacity Available on January 1 Winter Season Capacity				2009 Plan Assuming DSM Capacity Available on January 1 Winter Season Capacity			
Year	Baseload Capacity	Peaking/ Intermediate Capacity	Cumulative Capacity Additions	Year	Baseload Capacity	Peaking/ Intermediate Capacity	Cumulative Capacity Additions
	(MW)				(MW)		
2009	30		30	2009			
2010	278 (Spurlock 4) 2 Landfill gas	200 LMS 200 Seas Purch	710	2010	278 (Spurlock 4) 2 Landfill Gas	200 LMS 200 Seas Purch	680
2011			710	2011			680
2012		200	910	2012		100	780
2013			910	2013			780
2014	278 (Smith 1)	100	1,288	2014	278 (Smith 1)		1,058
2015		50	1,338	2015		50	1,108
2016		100	1,438	2016			1,108
2017			1,438	2017	30		1,138
2018			1,438	2018			1,138
2019			1,438	2019		100	1,238
2020		100	1,538	2020		100	1,338
2021	200	100	1,838	2021	200		1,538
2022			1,838	2022			1,538
2023		300	2,138	2023	300		1,838

The DSM and non-DSM expansion plans were compared by Net System Costs, a value produced by the production cost model, RTSim. The Net System Costs includes the cost generation (coal, natural gas, methane, hydro), the cost of purchases, and the value of sales. Using this measure, the expansion plan incorporating DSM is 13% less costly than the plan with no DSM assumed.

- ***EKPC's next IRP should explicitly discuss its actions to date and actions it will take in the future in order to comply with the terms of the settlements it reached with the U.S. Department of Justice and the U.S. Environmental Protection Agency regarding alleged violations of various provisions of the Clean Air Act.***

  During 2007, EKPC settled two lawsuits with the U.S. Environmental Protection Agency ("EPA") resulting in the execution of two Consent Decrees.

  Under the terms of the New Source Review Consent Decree ("NSR CD"), EKPC paid $750,000 in civil penalties to the EPA, agreed to install certain emissions monitoring equipment and controls, and agreed to report emissions.

The NSR CD mainly consists of implementing the Selective Catalytic Reduction ("SCR") and Flue Gas Desulfurization ("FGD") technologies on Spurlock 1 and 2, a decision to either shut Dale 3 and 4 down or place pollution controls on Cooper Unit 2. The NSR CD places system-wide allowance SOx and NOx caps on the respective units and in the Title V operating air permits. The NSR CD requires EKPC to report the progress in meeting the CD obligations to the Department of Justice ("DOJ") and EPA every 6 months through 2015.

In compliance with the NSR CD, EKPC has installed and is currently operating Scrubber ("FGD") and SCR technologies at Spurlock 2. A scrubber is substantially complete on Spurlock 1 and will be operational prior to the 2009 summer peak operating season. The SCR for Spurlock 1 is already in operation.

In the NSR CD, the EPA gave EKPC the option to either install and continuously operate NOx and SO2 emission controls at Cooper Unit 2 or retire and permanently cease operation of Dale Units 3 and 4 by December 31, 2012. EKPC also has the option of repowering Dale Units 3 and 4 by May 31, 2014. The decision to either install new emission controls at Cooper Unit 2 or retire Dale Units 3 and 4 must be submitted in writing to the EPA no later than December 31, 2009. Based on this stipulation, EKPC initiated a study to evaluate its options. Burns & McDonnell Engineering Company was hired to provide plant evaluations and develop specific cost and operating characteristics for each viable option available to EKPC. Eight options were developed and analyzed. In addition to the economic impacts, several significant environmental regulation changes and consideration of potential future regulations were driving factors in the decision making process. EKPC's conclusion of the analysis was that construction of emission controls at Cooper Station was the best long term alternative for EKPC and its member systems. EKPC filed for a Certificate of Public Convenience and Necessity requesting environmental controls be installed at the Cooper Unit 2 facility – PSC Case No. 2008-00472.

On January 17, 2006, EKPC received Notice of Violation ("NOV") from the EPA alleging violations of the Federal Clean Air Act's Acid Rain Program and NOx SIP Call Allowance Trading Program at Dale Units 1 and 2. At issue was EPA's allegation that EKPC incorrectly reported the turbine, rather than the generator, nameplate ratings, thus placing the Units under the Acid Rain Program. On February 10, 2006, EKPC received an NOV from the Kentucky Environmental and Public Protection Cabinet regarding the same matter. The NOVs covered the years 2000 through 2004.

The parties executed a Consent Decree ("Acid Rain CD") entered on November 30, 2007. Under the terms of the Acid Rain CD, EKPC must make six annual payments of $1,900,000 (Fixed Penalty Payment), totaling $11,400,000. EKPC made the second installment of this fixed penalty payment in December 2008. In addition to the Fixed Penalty Payment, EKPC is subject to a Contingent Penalty Payment for a period of five years, based on audited consolidated financial statements for the years 2008 through 2012. EKPC will be subject to the Contingent Penalty Payment if certain financial ratios are achieved. EKPC has currently reserved approximately $17,021,000 for such contingent penalty payments. In December 2007, based on the terms of the Acid Rain CD, EKPC surrendered 4,107 NOx allowances and 15,311 SO2 allowances. EKPC agreed under the Acid Rain CD to place low NOx burners on Dale Unit 1 and 2 and to enroll the units in the Acid Rain program. This work is complete.

5.(2) Description of models, methods, data, and key assumptions used to develop the results contained in the plan.

Load Forecast

EKPC's load forecast methodology includes regional economic modeling that incorporates historical data on population, income, employment levels and wages. This data is collected county by county from the U. S. Bureau of Labor Statistics ("BLS") and the U.S. Bureau of Economic Analysis ("BEA").

EKPC uses Metrix products for forecasting hourly load, annual energy, and seasonal peaks. MetrixND uses monthly weather and calendar data inputs to produce seasonal peaks and energy. MetrixLT uses historical hourly load data and daily weather and calendar data to calibrate to the forecasted seasonal peak demands and energy.

Key forecast assumptions used in developing the EKPC and member system load forecasts are:

-Regional population projections are based upon forecasts provided by Global Insight.

-EKPC's member systems will add approximately 165,000 residential customers by 2028. This represents an increase of 1.5 percent per year.

-EKPC uses an economic model to help develop its load forecast. The model uses data for 87 Kentucky counties in seven geographic regions. The economy of these counties will experience modest growth over the next 20 years. The average unemployment rate will remain relatively flat at 5.5 percent during the 2008 to 2028 timeframe. Total employment levels will rise by 320,000 jobs. Regional population will grow from approximately 3.5 million people in 2008 to 4.0 million people in 2028, an average growth of 0.7 percent per year.

-From 2008 through 2028, approximately 75 percent of all new households will have electric heat. Eighty-five percent of all new households will have electric water heating. Nearly all new homes will have electric air conditioning, either central or room.

-Over the forecast period, naturally occurring appliance efficiency improvements is expected to decrease residential retail sales nearly 4% or approximately 500,000 MWh. Appliances particularly affected are refrigerators, freezers, and air conditioners.

-Residential customer growth and local area economic activity will be the major determinants of small commercial growth.

-Forecasted load growth is based on the assumption of normal weather, as defined by the National Oceanic and Atmospheric Administration, occurring over the next 20 years. Seven different stations are used depending on geographic location of the member system.

Demand-Side Management

Over the past 25 years, EKPC member systems have offered various demand-side management ("DSM") marketing programs to the retail consumer. These programs have been developed to meet the needs of the end consumer and to delay the need for additional generating capacity. In order to satisfy these needs, a diverse menu of marketing programs has been developed and deployed.

This IRP evaluates the benefits and costs of existing DSM marketing programs and screens new marketing programs to be implemented in partnership with member systems. EKPC utilizes DSMANAGER, a computer program created by the Electric Power Research Institute ("EPRI"), in order to evaluate the relative benefits of these programs.

New DSM/marketing programs are reviewed and discussed in Section 7. EKPC and Member Systems will continue to work together to implement these programs as they fit their organizational goals.

Supply Side Resources

EKPC's existing capacity consists of base load coal fired units and peaking units (SEPA hydro and combustion turbines).

EKPC utilizes various resources in the Resource Planning Process. Detailed cost information is developed from sources such as industry expert consultants, ACES Power Marketing, EVA fuel and emissions forecasts, specialized databases such as Global Energy, as well as specific research done on market websites such as NYMEX, Evolution Markets, EIA, Chicago Climate Exchange and others. Cost information is also based on current projects and budget estimates. EKPC hired Navigant Consulting to review input assumptions for this study. The RTSim model is used for detailed production costing and emission estimating studies. This program simulates system operation on an hourly chronological basis.

RTSim's Resource Optimizer was used to produce EKPC's optimal expansion plan. The optimizer evaluated a variety of resource options, startup dates, and market and load conditions to produce the lowest cost plans. Supply side capacity alternatives considered in this study included:

- Combustion Turbines (Peaking)
- Combined Cycles (Intermediate)
- Coal Fired Units (Base Load)
- Various Term Purchases
- Renewable Generation

In general, the construction cost for peaking units is the least, with intermediate capacity and base load capacity costing progressively more. The reverse is true, however, for variable costs, with base load capacity having the lowest variable production costs. Renewable generation tends to have significantly higher capital costs than traditional generating units, but it also has more environmental benefits.

5.(3) Summary of forecasts of energy and peak demand, and key economic and demographic assumptions or projections underlying these forecasts.

EKPC's most recent load forecast (*EKPC 2008 Load Forecast Report, August 2008*) projects that total energy requirements are expected to increase by 2.0 percent per year over the 2008 through 2028 period. Net winter peak demand will increase by approximately 1,300 MW, and net summer peak demand will increase by approximately 1,100 MW. Annual load factor projections are remaining steady at approximately 52 percent. See response to 5.2 for specific assumptions related to the load forecast.

Energy Sales and Peak Demands Growth Rates	2008-2013	2008-2018	2008-2028
Total Energy Requirements	2.3%	2.1%	2.0%
Residential Sales	2.0%	2.0%	2.0%
Total Commercial and Industrial Sales (Excluding Gallatin Steel)	3.3%	2.8%	2.3%
Firm Winter Peak Demand	1.1%	1.5%	1.7%
Firm Summer Peak Demand	1.9%	1.9%	1.9%

Year	Residential Sales (MWh)	Seasonal Sales (MWh)	Small Comm. Sales (MWh)	Public Buildings (MWh)	Large Comm. Sales (MWh)	Gallatin Steel (MWh)	Other Sales (MWh)	Total Retail Sales (MWh)
2009	7,240,039	15,203	2,005,467	28,093	2,345,827	969,012	10,580	12,614,222
2010	7,374,611	15,683	2,059,958	28,667	2,443,048	969,150	10,821	12,901,939
2011	7,493,203	16,065	2,114,817	29,256	2,506,190	968,960	11,061	13,139,552
2012	7,646,800	16,585	2,169,237	29,837	2,569,877	967,411	11,298	13,411,045
2013	7,773,389	16,975	2,223,152	30,404	2,632,834	967,031	11,533	13,655,317
2014	7,903,386	17,368	2,277,104	30,963	2,698,010	968,462	11,769	13,907,062
2015	8,059,377	17,855	2,331,968	31,516	2,748,980	968,404	12,004	14,170,103
2016	8,233,250	18,401	2,387,430	32,073	2,814,845	968,850	12,239	14,467,087
2017	8,387,245	18,846	2,442,770	32,622	2,857,240	966,792	12,474	14,717,988
2018	8,540,177	19,298	2,498,092	33,159	2,916,374	966,524	12,707	14,986,331
2019	8,713,969	19,857	2,553,229	33,693	2,967,431	966,412	12,940	15,267,531
2020	8,899,636	20,436	2,608,961	34,232	3,025,391	968,439	13,173	15,570,267
2021	9,059,814	20,908	2,665,418	34,773	3,086,839	968,256	13,405	15,849,412
2022	9,230,462	21,444	2,722,020	35,323	3,154,493	968,089	13,637	16,145,470
2023	9,401,535	21,959	2,778,618	35,874	3,207,786	966,278	13,870	16,425,919

Year	Total Retail Sales (MWh)	Office Use (MWh)	% Loss	EKPC Sales to Members (MWh)	EKPC Office Use (MWh)	Transmission Loss (%)	Total Requirements (MWh)
2009	12,614,222	9,984	4.3	13,188,540	8,165	3.3	13,647,057
2010	12,901,939	9,984	4.3	13,490,439	8,205	3.3	13,959,302
2011	13,139,552	9,984	4.3	13,739,781	8,250	3.3	14,217,198
2012	13,411,045	9,984	4.3	14,024,740	8,295	3.3	14,511,928
2013	13,655,317	9,984	4.3	14,281,078	8,339	3.3	14,777,060
2014	13,907,062	9,984	4.3	14,545,167	8,384	3.3	15,050,207
2015	14,170,103	9,984	4.3	14,821,184	8,429	3.3	15,335,690
2016	14,467,087	9,984	4.3	15,132,793	8,473	3.3	15,657,979
2017	14,717,988	9,984	4.3	15,396,169	8,518	3.3	15,930,390
2018	14,986,331	9,984	4.3	15,677,759	8,562	3.3	16,221,635
2019	15,267,531	9,984	4.4	15,972,833	8,607	3.3	16,526,826
2020	15,570,267	9,984	4.4	16,290,399	8,652	3.3	16,855,275
2021	15,849,412	9,984	4.4	16,583,321	8,696	3.3	17,158,239
2022	16,145,470	9,984	4.4	16,893,987	8,741	3.3	17,479,553
2023	16,425,919	9,984	4.4	17,188,356	8,786	3.3	17,784,014

Winter Season	Net Peak Demand (MW)	Summer Season	Net Peak Demand (MW)
		2009	2,363
2009 - 10	3,029	2010	2,406
2010 - 11	3,087	2011	2,442
2011 - 12	3,143	2012	2,475
2012 - 13	3,215	2013	2,529
2013 - 14	3,275	2014	2,579
2014 - 15	3,345	2015	2,630
2015- 16	3,408	2016	2,680
2016 - 17	3,482	2017	2,737
2017 - 18	3,547	2018	2,790
2018 - 19	3,617	2019	2,843
2019-20	3,680	2020	2,893
2020-21	3,760	2021	2,957
2021-22	3,833	2022	3,016
2022-23	3,904	2023	3,071

Overview of Key Variables

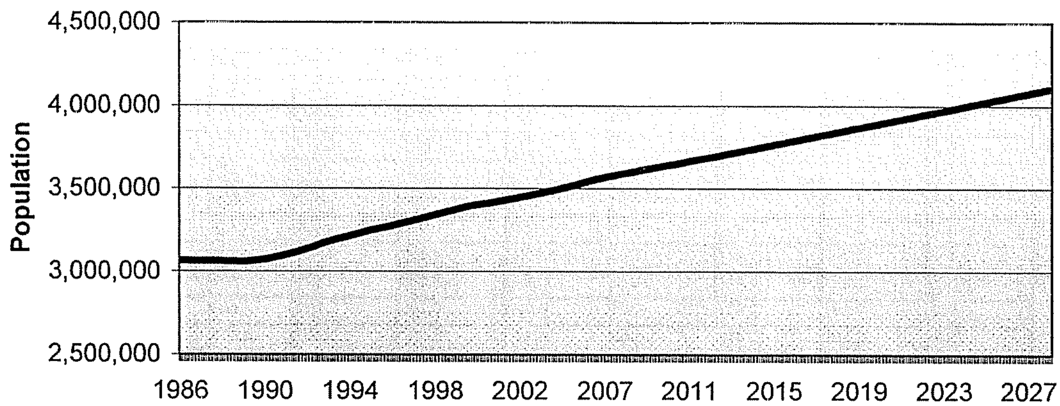
Changes in regional employment and income are important determinants of customer and sales growth. Population forecasts are used to project residential class customers; regional household income is used to project residential sales; and regional economic activity is used to project small commercial sales. Section 4 of the 2008 Load Forecast Report explains the analysis process.

Key Load Forecast Variables
Percent Change

	1995-2005	2005-2015	2015-2025
Population	8%	7%	7%
Total Employment	12%	11%	8%
Per Capita Income	23%	21%	19%

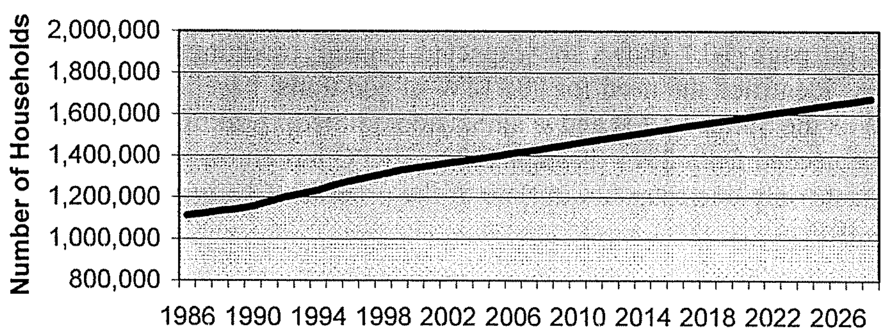
An important variable that impacts the load forecast is regional population. Historical population grew rapidly during the seventies and slowed during the second half of the eighties. The growth increased during the late nineties and early two-thousands and presently, has slowed down. Given the decline the economy is currently exhibiting, population growth is expected to be low for the next several years.

Total Population, All Regions



As is shown, the current forecast shows household growth is projected to be low to moderate. This trend is being seen for surrounding states as well.

Total Number of Households, All Regions



5.(4) Summary of the utility's planned resource acquisitions including improvements in operating efficiency of existing facilities, demand-side programs, non-utility sources of generation, new power plants, transmission improvements, bulk power purchases and sales, and interconnections with other utilities.

Planned Resource Acquisitions

EKPC's objective of the power supply plan is to develop a low cost, reliable plan to serve its Member Systems, while simultaneously mitigating risk. Utilizing a reserve margin of 12%, the projected needs are shown in Table 5.(4)-1 and are detailed in Section 8. Table 5.(4)-1 lists annual peak demand figures and compares resulting capacity requirements with existing and committed resources. EKPC will need over 1,500 MW of additional resources to serve projected loads by 2023.

Table 5.(4)- 1
EKPC Projected Capacity Needs
(MW)

Year	Projected Peaks		12% Reserves		Total Requirements		Existing Resources		Capacity Needs	
	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum
2009	2,942	2,344	353	281	3,295	2,625	3,130	2,409	165	216
2010	2,983	2,353	358	282	3,341	2,635	2,720	2,509	621	126
2011	3,017	2,375	362	285	3,379	2,660	2,685	2,469	694	191
2012	3,056	2,424	367	291	3,423	2,715	2,675	2,459	748	256
2013	3,107	2,480	373	298	3,480	2,778	2,675	2,459	805	319
2014	3,153	2,520	378	302	3,531	2,822	2,675	2,459	856	363
2015	3,208	2,564	385	308	3,593	2,872	2,675	2,459	918	413
2016	3,260	2,611	391	313	3,651	2,924	2,675	2,459	976	465
2017	3,323	2,663	399	320	3,722	2,983	2,675	2,459	1,047	524
2018	3,377	2,713	405	326	3,782	3,039	2,675	2,459	1,107	580
2019	3,446	2,769	414	332	3,860	3,101	2,675	2,459	1,185	642
2020	3,509	2,821	421	339	3,930	3,160	2,675	2,459	1,255	701
2021	3,593	2,891	431	347	4,024	3,238	2,675	2,459	1,349	779
2022	3,670	2,955	440	355	4,110	3,310	2,675	2,459	1,435	851
2023	3,745	3,014	449	362	4,194	3,376	2,675	2,459	1,519	917

Table 5.(4)- 2 on page 5-17 shows the expected capacity additions based on the 2009 IRP. EKPC's IRP has identified the need for 808 MW of additional base load capacity after 2010, of which 278 MW is the Smith 1 CFB and is already committed. Additionally, 350 MW of peaking capacity will be needed from 2011 through 2023. EKPC has an on-going planning process and this IRP represents only one snapshot in time of the process. Changing conditions may warrant changes to this IRP.

Table 5.(4)- 2
2009 Plan Assuming DSM
Capacity Available on January 1
Winter Season Capacity

Year	Baseload Capacity	Peaking/ Intermediate Capacity	Cumulative Capacity Additions
	(MW)		
2009			
2010	278 (Spurlock 4) 2 Landfill Gas	200 LMS 200 Seas Purch	680
2011			680
2012		100	780
2013			780
2014	278 (Smith 1)		1,058
2015		50	1,108
2016			1,108
2017	30		1,138
2018			1,138
2019		100	1,238
2020		100	1,338
2021	200		1,538
2022			1,538
2023	300		1,838

Improvement in Operational Efficiency of Existing Facilities
EKPC recognizes that maintenance management for existing units is vital to keeping facilities efficient. EKPC has developed a long-range plan of maintenance needs for each of the existing generating units. This plan is discussed in Section 8 of the IRP.

Demand-Side Management
The plan described in Table 5.(4)-2 includes the evaluation of new DSM programs. In the 2009 IRP, EKPC has again developed a comprehensive list (103 measures this time in comparison to 93 in 2006) of new DSM measures to consider. This set of DSM measures covers all classes and major end uses, and includes a robust set of available technologies and strategies for producing energy and capacity savings. Details are discussed in Section 7 and Section 8 of this document.

Non-Utility Sources of Generation
EKPC is working very diligently to seek power supply options other than construction of its own generation. This includes discussions with other utilities and non-utilities. The discussions have covered partnerships, joint ventures, and long-term power purchase contracts. This work is ongoing.

New Power Plants
In an Order dated August 29, 2006 in Case No. 2005-00053, the Commission granted a Certificate of Public Convenience and Necessity ("CPCN") to EKPC to construct the 278 MW Smith circulating fluidized bed coal-fired unit ("Smith CFB") which is shown in Table 5.(4)-2, and five 90 MW combustion turbines ("Smith CTs 8-12") in Clark County. On May 11, 2007, in PSC case No. 2006-00564 the commission granted that EKPC should retain the Certificates of Public Convenience and Necessity for Spurlock 4, Smith CFB 1, and 2 new Smith CTs. EKPC surrendered its certificate for the other 3 Smith CTs.

The plan calls for additional capacity throughout the study period, as discussed in detail in Section 8 of this document.

Transmission Improvements
EKPC regularly identifies transmission projects and upgrades that are required for maintaining the capability of its transmission system in order to meet the demands of its Member Systems. Transmission projects are discussed in Section 8 of this IRP.

Bulk Power Purchases and Sales
EKPC has a purchase power agreement with Duke Energy Ohio to purchase the entire output of the Greenup hydro project, which averages 35 MW during winter peak conditions, through the end of 2010.

Interconnections with other Utilities
EKPC participates in joint planning efforts with neighboring utilities to ascertain the benefits of potential interconnections, which can include increased power transfer capability, local area system support, and outlet capability for new generation. EKPC's existing interconnections and their contract path capabilities are discussed in detail in Section 8.

5.(5) Steps to be taken during the next three (3) years to implement this plan.

EKPC and its 16 member systems must initiate an aggressive Demand Side Management / Marketing effort in order to realize the amount of DSM benefits that have proven as valid power supply. In addition to residential conservation and load management programs, both of which are currently being implemented, EKPC and its member distribution cooperatives will enhance their efforts in (a) commercial and industrial DSM, and (b) demand response programs.

DSM programs represent complex power supply, and must be carefully designed, managed, and assessed. Demonstration or pilot programs may precede complete implementation, in order to test their validity and reasonableness. An example of this is EKPC and its members' real time pricing pilot program.

A second implementation step will involve EKPC evaluating its need for non DSM peaking resources. Finally, during this period, EKPC intends to pursue wholesale rate design changes, in order to provide the most appropriate price signal possible to its 16 member distribution cooperatives.

5.(6) Discussion of key issues or uncertainties that could affect successful implementation of the plan.

Key uncertainties that could affect successful implementation of this plan are (a) load growth, (b) DSM quantities and response, (c) fuel prices, and (d) cost to emit CO2. Each issue is addressed below.

Load Growth Uncertainty
EKPC's peak and energy growth rates are projected to be 2% per year, much lower than historical growth rates. Should actual growth be higher than forecast, the reserve margin that has been designed into this plan will provide for reliable service. Should actual growth be lower than forecast, EKPC's expansion plan relies heavily on non-capital intensive resources like DSM, purchases, and combustion turbines. Therefore, EKPC's risk of stranded assets is low.

DSM Quantities and Response
Unlike traditional generators, whose contribution to power supply can largely be quantified, some DSM measures cannot. For example, while the effect of a large-scale insulation program is generally known, customer behavior in response to additional insulation may be different than what has been assumed. In order to treat DSM programs as securely as other power supply resources, EKPC and its members will need to commit time and resources and perform rigorous impact evaluations.

Fuel Prices
During 2008, EKPC purchased natural gas for prices ranging from \$4 to \$14 per MMBtu – this represents a large price swing. While fuel price assumptions must be made in order to prepare a long-term resource plan, it is important to put the underlying uncertainty of fuel prices in perspective. EKPC planning models look at many different values of correlated fuel prices in order to come up with a robust resource plan.

Cost To Emit CO2
EKPC has prepared this resource plan with the assumption that there will be a cost to emit CO2. EKPC believes that there is high uncertainty about the cost level, and has therefore looked at many possible prices of CO2. EKPC has addressed CO2 uncertainty in the following way – should actual CO2 prices be lower than forecast, planned natural gas and coal generation will look better than assumed. Should actual CO2 prices be higher than forecast, planned purchases and DSM programs will look better than assumed. In summary, EKPC has proposed a diverse resource plan as a strategy for supplying least cost power supply to its 16 member distribution systems.

Section 6

Significant Changes

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Section 6

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.

Major Differences Between EKPC's 2008 and 2006 Load Forecasts

The major changes in the 2008 Load Forecast are:
1.) The 2006 formal report and load forecast included the addition of Warren RECC as an EKPC member beginning in April 2008. However, Warren RECC is not going to become an EKPC member.

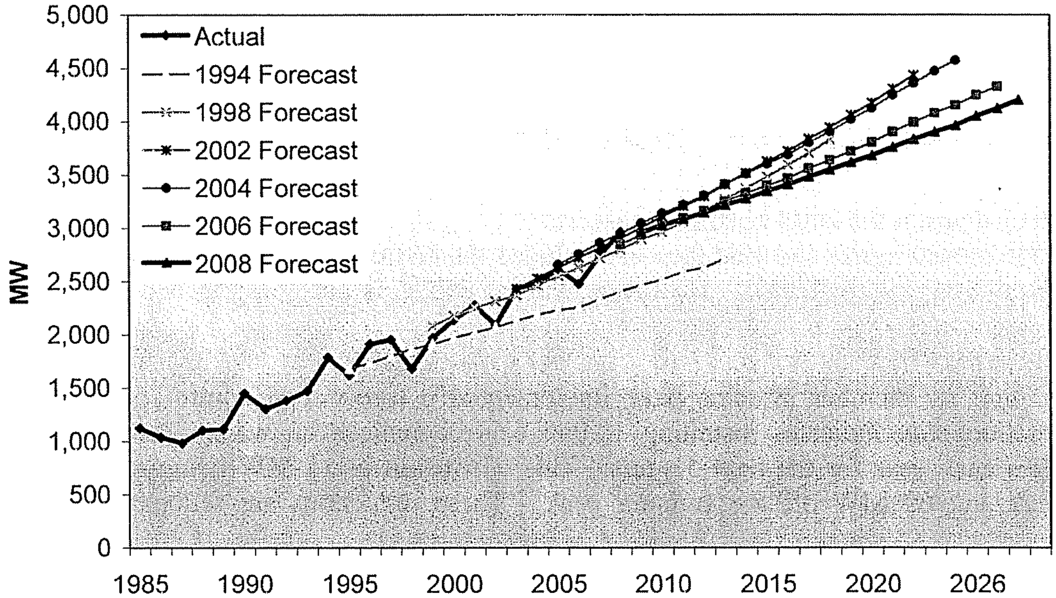
2.) EKPC and its member systems have implemented a direct load control program. The implementation plan indicates installing 10,000 control devices on water heaters and/or air conditioners each year for the next 5 years. This will result in 15 MW being clipped off the winter peak and 60 MW off the summer peak. These reductions are reflected in the load forecast.

3.) In late 2007 and all of 2008, the nation has experienced an economic downturn. Gas and coal prices have increased dramatically. The housing market has fallen. The economy is in a recession. While the 2008 forecast was prepared prior to the full effect being seen, the 2006 and 2007 data indicated a slowing down of growth for the member systems was beginning. Therefore, the 2008 forecast does reflect a more pessimistic outlook than prior forecasts. The table below shows the differences between the forecasts. The graphs on page 6-2 compare the peak demand projections for the past several official EKPC load forecasts.

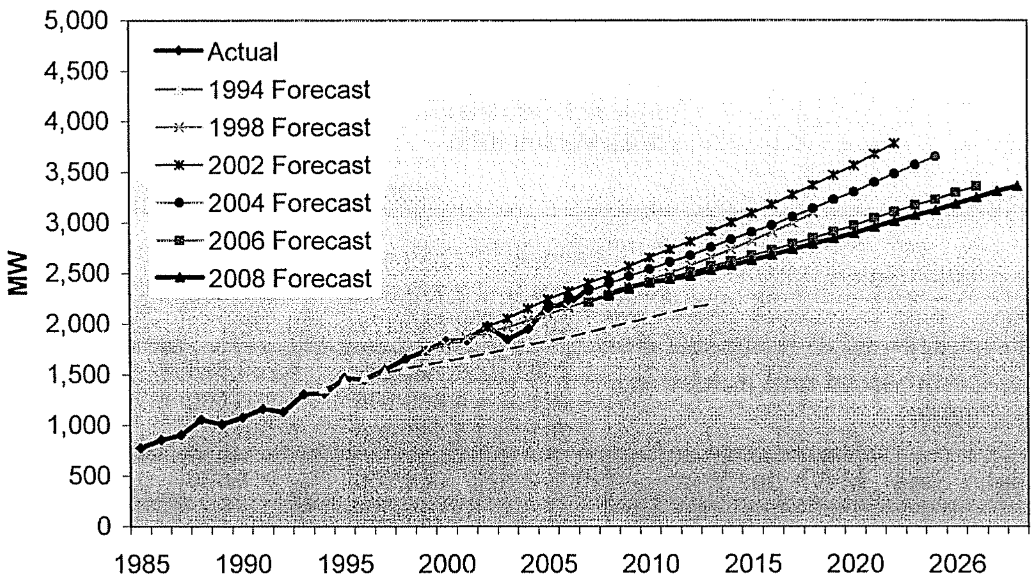
Forecast Comparison
2008 Versus 2006

		2008	Without Warren 2006	Difference
Residential Sales, MWh	2008	7,032,311	7,099,687	-67,376
	2013	7,773,389	8,092,806	-319,417
	2018	8,540,177	9,078,713	-538,536
Total Commercial and Industrial Sales, MWh	2008	4,126,020	4,265,695	-139,675
	2013	4,855,986	4,876,900	-20,914
	2018	5,414,466	5,440,454	-25,988
Gallatin Steel, MWh per Year	2008-2018	968,960	968,960	
Residential Customers	2008	480,233	487,370	-7,137
	2013	518,075	538,602	-20,527
	2018	559,160	590,201	-31,041
Net Winter Peak MW	2008	2,962	2,848	114
	2013	3,215	3,251	-36
	2018	3,547	3,638	-91
Net Summer Peak MW	2008	2,302	2,273	29
	2013	2,529	2,569	-40
	2018	2,790	2,848	-58

Historical Load Forecast Studies
Winter Peak Demand Projections



Historical Load Forecast Studies
Summer Peak Demand



Significant Changes to DSM since the last IRP

EKPC has made several improvements to its DSM planning since the 2006 IRP. Including:

(1) More comprehensive set of DSM measures evaluated, incorporating feedback from member cooperatives, the Attorney General, Kentucky Division of Energy, environmental stewards, and other parties.

(2) Increased environmental avoided cost adder for societal test.

(3) Updated avoided costs for capacity to match current plans for transmission, distribution, and generation investment (including environmental compliance costs).

(4) Changing load impacts to account for changes in Federal appliance efficiency standards.

(5) Accounts for the Kentucky tax incentives provided in 2008 legislation.

(6) Sensitivity testing to examine impact of changes in assumptions on impact levels and cost-effectiveness.

(7) Enhanced program designs to incorporate lessons learned in the field as well as best practice in the industry.

Significant Changes in the Resource Plan

In the 2009 IRP, the resource plan is significantly different due to the following:

1) Expansion of supply side resource alternatives.

For the 2009 IRP modeling, the supply side alternatives to choose from was expanded to include:

Combustion turbines
Combined Cycle units
Coal units including fluidized bed and subcritical technologies
Renewable resources including wind, solar, biomass and hydro
Various purchases and partnering alternatives.

2) As discussed previously in *Significant Changes to DSM since last IRP* above, increased participation in demand side management programs resulted in lower capacity needs.

3) As discussed previously in *Major Differences Between EKPC's 2008 and 2006 Load Forecasts* on page 6-1, the 2008 load forecast shows lower load growth rates due to the exclusion of Warren RECC from the forecast and impacts of an economic recession.

As a result, the capacity needs for the 2009 IRP are lower than the 2006 IRP by more than 800 MW by the year 2020. See table on the following page.

EKPC Projected Major Capacity Additions

2006 IRP				2009 IRP			
Capacity Available on January 1				Capacity Available on January 1			
Winter Season Capacity				Winter Season Capacity			
Year	Baseload Capacity	Peaking/ Intermediate Capacity	Cumulative Capacity Additions	Year	Baseload Capacity	Peaking/ Intermediate Capacity	Cumulative Capacity Additions
	(MW)				(MW)		
2009	278 (Spurlock 4)	485 (Smith CTs 8-12)	763	2009			
2010	278 (Smith 1)		1041	2010	278 (Spurlock 4) 2 Landfill Gas	200 LMS 200 Seas Purch	680
2011			1041	2011			680
2012			1041	2012		100	780
2013	300		1,341	2013			780
2014			1,341	2014	278 (Smith 1)		1,058
2015	300		1,641	2015		50	1,108
2016		100	1,741	2016			1,108
2017		100	1,841	2017	30		1,138
2018			1,841	2018			1,138
2019	300		2,141	2019		100	1,238
2020			2,141	2020		100	1,338
				2021	200		1,538
				2022			1,538
				2023	300		1,838

Section 7

Load Forecast

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7. Load Forecasts

The plan shall include historical and forecasted information regarding loads.

7.(1) The information shall be provided for the total system and, where available, disaggregated by the following customer classes:
7.(1)(a) Residential heating.
7.(1)(b) Residential nonheating.
7.(1)(c) Total residential (total of paragraphs (a) and (b) of this subsection).
7.(1)(d) Commercial.
7.(1)(e) Industrial.
7.(1)(f) Sales for resale.
7.(1)(g) Utility use and other.

Response: The data provided in the following subsections conform to the specifications given unless otherwise noted.

The utility shall also provide data at any greater level of disaggregation available.
7.(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:

7.(2)(a) Average annual number of customers by class as defined in subsection (1) of this section.

EKPC Average Number of Customers by Class, 2004-2008

Year	Residential*	Commercial	Industrial**	Utility Use and Other***	Total Customers
2004	456,345	28,125	136	377	484,983
2005	463,393	30,594	138	389	494,514
2006	470,599	30,194	134	420	501,347
2007	476,719	30,981	121	434	508,255
2008	484,495	32,035	132	441	517,103

Notes: * Residential Class consists of Residential, Seasonal and Public Buildings.
EKPC does not have heating versus non-heating residential customer counts.
** Industrial is labeled "Large Commercial" in EKPC's Load Forecast Report.
*** Utility Use and Other includes lighting.

7.(2)(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.

Response: Table 1 below shows recorded sales by class and total requirements. EKPC does not weather normalize by class, however, Table 2 below shows actual and weather normalized for retail sales and total requirements.

Table 1:

EKPC Recorded Annual Energy Sales (MWh) and Energy Requirements (MWh), 2004-2008

Year	2004	2005	2006	2007	2008
Residential Heating	4,513,321	4,839,330	4,599,396	4,967,050	4,843,681
Residential Non-Heating	1,861,236	1,949,247	1,984,843	2,072,611	2,260,201
Total Residential*	6,374,557	6,788,577	6,584,239	7,039,660	7,103,882
Commercial	1,598,111	1,733,390	1,777,897	1,861,952	1,872,811
Industrial**	1,989,780	2,020,875	2,078,245	2,137,525	2,256,099
Gallatin Steel	1,047,466	992,824	978,939	986,518	827,490
Utility Use and Other***	7,498	7,713	8,236	8,457	9,477
Total Sales	11,017,413	11,543,379	11,427,556	12,034,113	12,069,760
Office Use	8,289	8,617	8,924	10,291	9,925
% Loss	4.4	4.2	3.8	4.3	3.9
EKPC Sales to Members	11,537,505	12,060,460	11,892,304	12,582,260	12,569,735
EKPC Office Use	9,106	8,902	7,568	7,491	7,912
Transmission Loss (%)	2.8	3.8	3.6	3.9	2.9
Total Requirements	11,865,797	12,527,829	12,331,272	13,080,367	12,948,091

Notes: * Residential Class consists of Residential, Seasonal and Public Buildings.
** Industrial is labeled "Large Commercial" in EKPC's Load Forecast Report.
*** Utility Use and Other includes lighting.

Table 2:

EKPC Weather Normalized Annual Energy Sales (MWh) and Energy Requirements (MWh), 2004-2008

	2004	2005	2006	2007	2008
Total Retail Sales by Member Cooperatives					
Recorded	11,017,413	11,543,379	11,427,556	12,034,113	12,069,760
Weather Normalized	11,124,391	11,383,421	11,626,079	11,725,885	11,665,038
EKPC					
Recorded	11,865,797	12,527,829	12,331,272	13,080,367	12,948,091
Weather Normalized	11,981,013	12,354,230	12,545,495	12,745,342	12,513,917

7.(2)(c) Recorded and weather-normalized coincident peak demand in summer and winter for the system.

Year	Season	Actual Peak	Adjusted Peak
		MW	MW
2004	Winter	2,610	2,562
	Summer	2,052	2,179
2005	Winter	2,719	2,863
	Summer	2,220	2,198
2006	Winter	2,599	2,624
	Summer	2,332	2,333
2007	Winter	2,840	2,984
	Summer	2,481	2,423
2008	Winter	3,051	3,163
	Summer	2,243	2,172

7.(2)(d) Total energy sales and coincident peak demand to retail and wholesale customers for which the utility has firm, contractual commitments.

	2004	**2005**	**2006**	**2007**	**2008**
Energy Sales (MWh)*	11,537,505	12,060,460	11,892,304	12,582,260	12,569,735
Coincident Peak Demand (MW)**	2,487	2,615	2,477	2,749	2,956

* Total sales to members.
** Firm peak demand.

7.(2)(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.

	2004	**2005**	**2006**	**2007**	**2008**
Energy Sales (MWh)*	NA	NA	NA	NA	NA
Coincident Peak Demand (MW)	123	104	122	91	95

* Interruptible energy is not recorded separately. Decrease in sales due to interruption is small.

7.(2)(f) Annual energy losses for the system.

	Distribution Loss at Member System Level		Transmission Loss	
	% Loss	Energy Loss (MWh)	% Loss	Annual Energy Loss (MWh)
2004	4.4	511,435	2.8	318,941
2005	4.2	508,101	3.8	458,141
2006	3.8	455,482	3.6	431,136
2007	4.3	537,416	3.9	490,336
2008	3.9	489,663	2.9	370,218

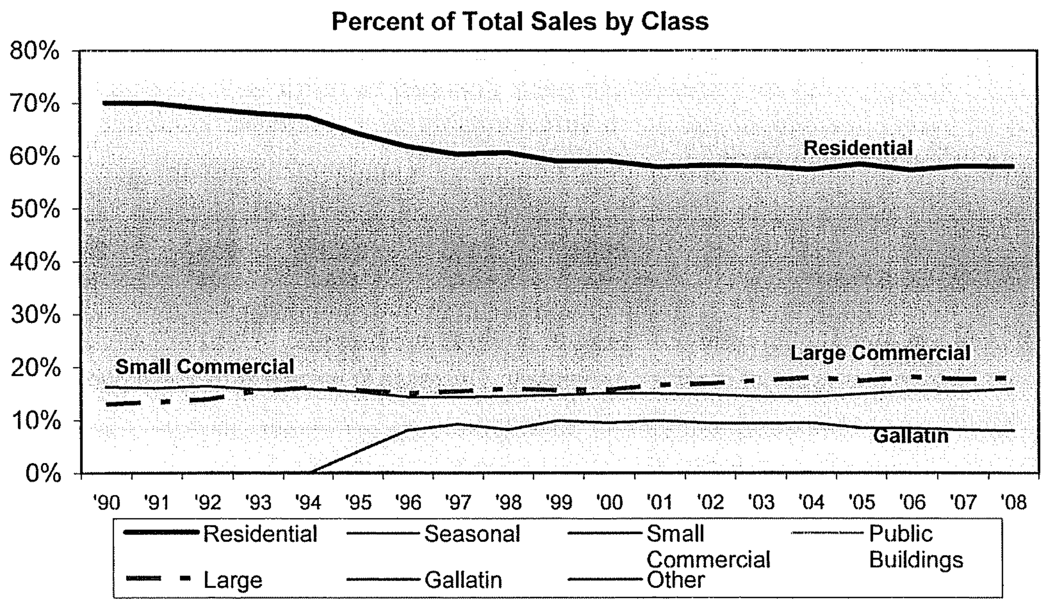
7.(2)(g) Identification and description of existing demand-side programs and an estimate of their impact on utility sales and coincident peak demands including utility or government sponsored conservation and load management programs.

Response: Identification and description of existing demand-side programs are identified and briefly described in Section 8, Table 8.(3)(e)-1 on page 8-17. For program by program demand and sales impacts, see response in Section 8, 8.(3)(e)(3). This data includes existing DSM and DLC programs but not load impacts from proposed programs. The new programs' load impacts were incorporated into the load data later in the integrated analysis. For more detailed information on existing programs, see the report entitled *Demand Side Management Analysis* in the *Technical Appendix*.

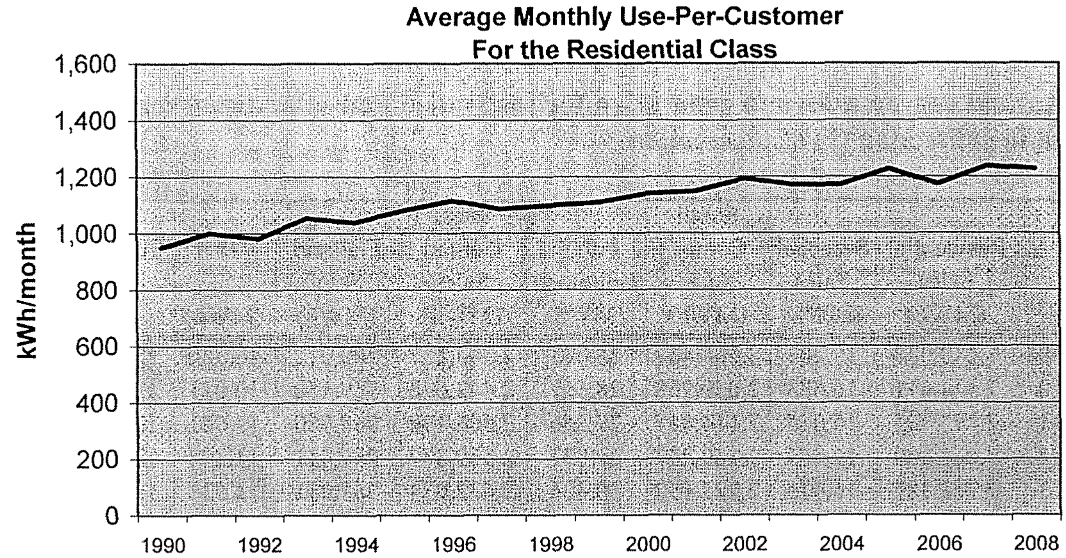
7.(2)(h) Any other data or exhibits, such as load duration curves or average energy usage per customer, which illustrate historical changes in load or load characteristics.

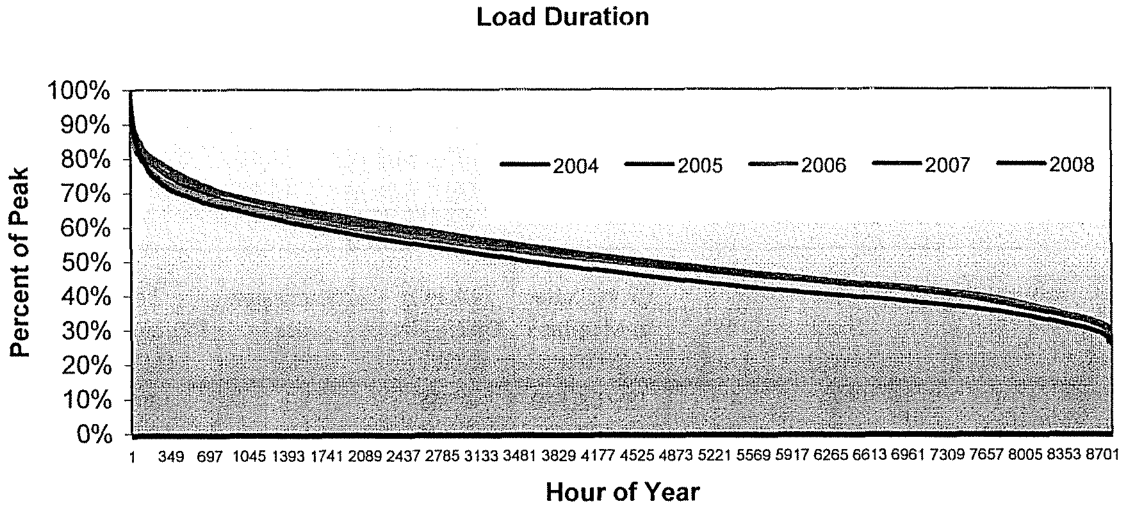
Response: Historical sales and customer data represent the summation of the 16 member systems data from the RUS Form 7s. EKPC data is as reported on the RUS Form 12. Unless otherwise noted, all data is actual, not weather normalized.

Historical percentage share of class sales is shown below. The EKPC member systems continue to be predominately residential.



Given EKPC member systems' consumers have nearly 60% of electric heat saturation, over 95% with some form of air conditioning and 87% with electric water heaters, average use per household is continuing to increase. The following page shows actual historical use per customer. Given these high saturations of weather sensitive appliances, weather extremes can impact sales significantly.





7.(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.

Response: The following information pertaining to energy sales and peak demand forecasts conform to the specifications outlined in Section 7.3 to the fullest extent possible.

7.(4) The following information shall be filed for each forecast:

7.(4)(a) Annual energy sales and generation for the system and sales disaggregated by class as defined in subsection (1) of this section.

Year	Residential Sales (MWh)	Seasonal Sales (MWh)	Small Comm. Sales (MWh)	Public Buildings (MWh)	Large Comm. Sales (MWh)	Gallatin Steel (MWh)	Other Sales (MWh)	Total Retail Sales (MWh)
2009	7,240,039	15,203	2,005,467	28,093	2,345,827	969,012	10,580	12,614,222
2010	7,374,611	15,683	2,059,958	28,667	2,443,048	969,150	10,821	12,901,939
2011	7,493,203	16,065	2,114,817	29,256	2,506,190	968,960	11,061	13,139,552
2012	7,646,800	16,585	2,169,237	29,837	2,569,877	967,411	11,298	13,411,045
2013	7,773,389	16,975	2,223,152	30,404	2,632,834	967,031	11,533	13,655,317
2014	7,903,386	17,368	2,277,104	30,963	2,698,010	968,462	11,769	13,907,062
2015	8,059,377	17,855	2,331,968	31,516	2,748,980	968,404	12,004	14,170,103
2016	8,233,250	18,401	2,387,430	32,073	2,814,845	968,850	12,239	14,467,087
2017	8,387,245	18,846	2,442,770	32,622	2,857,240	966,792	12,474	14,717,988
2018	8,540,177	19,298	2,498,092	33,159	2,916,374	966,524	12,707	14,986,331
2019	8,713,969	19,857	2,553,229	33,693	2,967,431	966,412	12,940	15,267,531
2020	8,899,636	20,436	2,608,961	34,232	3,025,391	968,439	13,173	15,570,267
2021	9,059,814	20,908	2,665,418	34,773	3,086,839	968,256	13,405	15,849,412
2022	9,230,462	21,444	2,722,020	35,323	3,154,493	968,089	13,637	16,145,470
2023	9,401,535	21,959	2,778,618	35,874	3,207,786	966,278	13,870	16,425,919

Year	Total Retail Sales (MWh)	Office Use (MWh)	% Loss	EKPC Sales to Members (MWh)	EKPC Office Use (MWh)	Transmission Loss (%)	Total Requirements (MWh)
2009	12,614,222	9,984	4.3	13,188,540	8,165	3.3	13,647,057
2010	12,901,939	9,984	4.3	13,490,439	8,205	3.3	13,959,302
2011	13,139,552	9,984	4.3	13,739,781	8,250	3.3	14,217,198
2012	13,411,045	9,984	4.3	14,024,740	8,295	3.3	14,511,928
2013	13,655,317	9,984	4.3	14,281,078	8,339	3.3	14,777,060
2014	13,907,062	9,984	4.3	14,545,167	8,384	3.3	15,050,207
2015	14,170,103	9,984	4.3	14,821,184	8,429	3.3	15,335,690
2016	14,467,087	9,984	4.3	15,132,793	8,473	3.3	15,657,979
2017	14,717,988	9,984	4.3	15,396,169	8,518	3.3	15,930,390
2018	14,986,331	9,984	4.3	15,677,759	8,562	3.3	16,221,635
2019	15,267,531	9,984	4.4	15,972,833	8,607	3.3	16,526,826
2020	15,570,267	9,984	4.4	16,290,399	8,652	3.3	16,855,275
2021	15,849,412	9,984	4.4	16,583,321	8,696	3.3	17,158,239
2022	16,145,470	9,984	4.4	16,893,987	8,741	3.3	17,479,553
2023	16,425,919	9,984	4.4	17,188,356	8,786	3.3	17,784,014

7.(4)(b) Summer and winter coincident peak demand for the system.

Winter Season	Net Peak Demand (MW)	Summer Season	Net Peak Demand (MW)
		2009	2,363
2009 - 10	3,029	2010	2,406
2010 - 11	3,087	2011	2,442
2011 - 12	3,143	2012	2,475
2012 - 13	3,215	2013	2,529
2013 - 14	3,275	2014	2,579
2014 - 15	3,345	2015	2,630
2015- 16	3,408	2016	2,680
2016 - 17	3,482	2017	2,737
2017 - 18	3,547	2018	2,790
2018 - 19	3,617	2019	2,843
2019-20	3,680	2020	2,893
2020-21	3,760	2021	2,957
2021-22	3,833	2022	3,016
2022-23	3,904	2023	3,071

7.(4)(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.

Year	Month	Residential Sales (MWh)	Seasonal Sales (MWh)	Small Comm. Sales (MWh)	Public Buildings Sales (MWh)	Large Comm. Sales (MWh)	Gallatin Steel (MWh)	Other Sales (MWh)	Total Retail Sales (MWh)	Net System Peak Demand (MW)
2009	1	823,485	1,632	158,863	2,613	196,047	78,733	877	1,262,251	2,962
2009	2	791,297	1,611	164,652	2,622	186,918	72,984	879	1,220,963	2,674
2009	3	674,979	1,453	162,539	2,624	191,614	87,121	880	1,121,210	2,439
2009	4	548,640	1,190	161,522	2,129	190,745	80,100	876	985,203	1,831
2009	5	472,694	1,020	162,132	2,150	192,494	88,198	877	919,565	2,010
2009	6	496,137	1,096	172,531	2,200	196,491	84,861	878	954,193	2,178
2009	7	563,622	1,149	177,806	2,200	203,167	75,239	880	1,024,063	2,363
2009	8	569,726	1,102	176,368	2,200	204,298	84,892	882	1,039,467	2,326
2009	9	504,850	1,033	176,944	2,245	197,350	84,314	884	967,619	2,195
2009	10	480,660	1,079	164,344	2,223	195,100	75,711	886	920,003	1,901
2009	11	571,314	1,268	163,174	2,200	194,543	83,890	887	1,017,277	2,286
2009	12	742,635	1,570	164,593	2,687	197,060	72,969	893	1,182,407	2,794
Total		7,240,039	15,203	2,005,467	28,093	2,345,828	969,012	10,580	12,614,222	
2010	1	841,588	1,709	166,846	2,672	201,464	78,666	897	1,293,843	3,029
2010	2	804,665	1,650	168,540	2,676	199,455	73,023	899	1,250,908	2,734
2010	3	694,141	1,498	167,529	2,680	202,869	86,391	900	1,156,008	2,493
2010	4	567,892	1,244	166,642	2,195	199,778	80,652	896	1,019,298	1,869
2010	5	486,242	1,075	167,078	2,203	201,461	88,141	897	947,097	2,048
2010	6	501,851	1,116	177,159	2,250	205,389	84,342	898	973,005	2,253
2010	7	564,244	1,164	178,674	2,252	206,035	75,723	900	1,028,992	2,406
2010	8	571,709	1,125	179,896	2,253	207,910	84,818	902	1,048,614	2,367
2010	9	511,201	1,063	180,320	2,271	206,536	84,245	904	986,540	2,232
2010	10	493,303	1,117	169,129	2,252	204,075	75,654	906	946,436	1,940
2010	11	585,007	1,313	168,387	2,236	202,783	83,826	908	1,044,460	2,337
2010	12	752,769	1,609	169,758	2,726	205,293	73,668	914	1,206,737	2,856
Total		7,374,611	15,683	2,059,958	28,667	2,443,048	969,150	10,821	12,901,939	

7.(4)(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.

Response: Program by program demand and sales impacts are shown in Section 8, 8.(3)(e)(3). The following table shows the estimated aggregate impact of all existing programs on energy sales and system peak demands:

Negative values denote reductions in load requirements while positive values denote increases in load requirements. Impacts from existing programs are captured in the load forecast.

Table 7.(4)(d)-1
Load Impacts of Existing Programs

(negative value= reduction in load)

Year	Impact on Energy Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
1999	9,335	-164.1	-23.3
2000	10,881	-71.8	-117.3
2001	11,279	-89.5	-148.1
2002	7,493	-194.0	-152.4
2003	3,553	-182.9	-162.7
2004	-1,069	-174.3	-117.2
2005	-5,012	-157.8	-24.4
2006	-10,074	-177.8	-160.0
2007	-14,231	-148.6	-151.9
2008	-17,302	-193.3	-145.5
2009	-16,666	-186.9	-145.4
2010	-16,666	-186.9	-145.4
2011	-16,666	-186.9	-145.4
2012	-16,666	-186.9	-145.4
2013	-16,666	-186.9	-145.4
2014	-16,666	-186.9	-145.4
2015	-16,666	-186.9	-145.4
2016	-16,666	-186.9	-145.4
2017	-16,666	-186.9	-145.4
2018	-16,666	-186.9	-145.4
2019	-16,666	-186.9	-145.4
2020	-16,666	-186.9	-145.4
2021	-16,666	-186.9	-145.4
2022	-16,666	-186.9	-145.4
2023	-16,666	-186.9	-145.4

7.(4)(e) Any other data or exhibits which illustrate projected changes in load or load characteristic.

Response: See 7.(4)(d) above.

7.(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:

7.(5)(a) For the base year and the four (4) years preceding the base year:

7.(5)(a)(1) Recorded and weather normalized annual energy sales and generation;
7.(5)(a)(2) Recorded and weather-normalized coincident peak demand in summer and winter.

7.(5)(b) For each of the fifteen (15) years succeeding the base year.

7.(5)(b)(1) Forecasted annual energy sales and generation.
7.(5)(b)(2) Forecasted summer and winter coincident peak demand.

Response: Section 7.5 does not apply to EKPC.

7.(6) A utility shall file all updates of load forecasts with the commission when they are adopted by the utility.

Response: The 2008 Load Forecast Report and appendices are included. The Board of Directors approved the Load Forecast on September 9, 2008. In March 2009, RUS approved the load forecast.

7.(7) The plan shall include a complete description and discussion of:

7.(7)(a) All data sets used in producing the forecasts.

Response: A complete list of all datasets is included in the appendix. The most crucial datasets include: regional economic data, historical sales and customer data, electric price history and forecast, historical weather, appliance saturation and efficiency data.

7.(7)(b) Key assumptions and judgments used in producing forecasts and determining their reasonableness.

Response: Key forecast assumptions used in developing the EKPC and member system load forecasts are:

- Regional population projections are based upon forecasts provided by Global Insight.
- EKPC's member systems will add approximately 165,000 residential customers by 2028. This represents an increase of 1.5 percent per year.
- EKPC uses an economic model to help develop its load forecast. The model uses data for 87 Kentucky counties in seven geographic regions. The economy of these counties will experience modest growth over the next 20 years. The average unemployment rate will remain relatively flat at 5.5 percent during the 2008 to 2028 timeframe. Total employment levels will rise by 320,000 jobs. Regional population will grow from approximately 3.5 million people in 2008 to 4.0 million people in 2028, an average growth of 0.7 percent per year.

- From 2008 through 2028, approximately 75 percent of all new households will have electric heat. Eighty-five percent of all new households will have electric water heating. Nearly all new homes will have electric air conditioning, either central or room.
- Over the forecast period, naturally occurring appliance efficiency improvements is expected to decrease residential retail sales nearly 4% or approximately 500,000 MWh. Appliances particularly affected are refrigerators, freezers, and air conditioners.
- Residential customer growth and local area economic activity will be the major determinants of small commercial growth.
- Forecasted load growth is based on the assumption of normal weather, as defined by the National Oceanic and Atmospheric Administration, occurring over the next 20 years. Seven different stations are used depending on geographic location of the member system.

7.(7)(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).

Response: EKPC prepares a load forecast by working jointly with its member systems in preparing their individual load forecasts. The general steps followed by EKPC in developing its load forecast are summarized as follows:

1. EKPC prepares a preliminary forecast for each of its member systems which is based on retail sales forecasts for six classes: residential, seasonal, small commercial, public buildings, large commercial, and other. The classifications are taken from the Rural Utilities Services ("RUS") Form 7, which contains publicly available retail sales data for member systems. EKPC's sales to member systems are then determined by adding distribution losses to total retail sales. EKPC's total requirements are estimated by adding transmission losses to total sales. Seasonal peak demands are determined by applying peak factors for heating, cooling, and water heating to energy. The same methodology is used in developing each of the 16 member system forecasts.

2. EKPC meets with each member system to discuss their preliminary forecast. Member system staff at these meetings include the manager and other key individuals. The RUS General Field Representative ("GFR") is also invited to attend the meetings.

3. The preliminary forecast is usually revised based on mutual agreement of EKPC staff, member system's Manager and staff, and the RUS GFR. This final forecast is approved by the board of directors of each member system.

4. The EKPC forecast is the summation of the forecasts of its 16 members.

EKPC has divided its members' service area into seven economic regions with economic activity projected for each. Regional forecasts for population, income and employment are developed and used as inputs to residential customer and small commercial customer and energy forecasts. Therefore, EKPC's economic assumptions regarding its load forecast are consistent.

Energy sales are forecasted using regression analysis for each class as reported on the RUS Form 7. Variables include electric price, economic activity, and regional population growth. Customer growth is also projected with regression analysis using economic variables such as population.

Seasonal peak demands are projected using the summation of monthly energy usages and load factors for the various classes of customers. Residential energy usage components include heating, cooling, water heating, and other usage. Using load factors, demand is calculated for each component and then summed to obtain the residential portion of the seasonal peak. Small commercial and large commercial classes use load factors on the class usage to obtain the class contribution to the seasonal peak. High and low case projections have been constructed around the base case forecast. Weather and customer growth assumptions are two significant inputs to the high and low cases.

7.(7)(d) The utility's treatment and assessment of load forecast uncertainty.

Response: In addition to the forecasted peaks, high and low cases around the base case are developed. The same methodology is used, however, the starting summary file is different. Instead of using the sum of the member system files, two new models are built: one reflecting assumptions that result in high usage and one with assumptions that result in low usage. The assumptions that are varied include:

1. Weather: based on historical heating and cooling degree day data, alternate weather projections were developed based upon the 90th and 10th percentile to reflect extreme and mild weather, respectively. The resulting forecasts reflect cases assuming base case HDD +/-12% and CDD +/-20%.

2. Electric price: The general approach is to use price forecasts that are available and use the growth rates from those forecasts to prepare the high and low growth rates around the growth patterns for the base case residential price forecast. The manner in which the price of electricity will change in the future is primarily a function of how prices change for the underlying fixed and variable components of electricity rates.

   The growth rate for the fixed portion of the electricity rate was estimated by relying on high and low case forecasts for the producer price index ("PPI") for electricity. The growth rate for the variable portion of the electricity rate was estimated by using the high and low scenarios for the fuel forecast.

   Therefore, the high scenario for the residential price forecast is constructed to have a 3.1% compound annual growth rate, while the low scenario is constructed to have a 0.8% compound annual growth rate. The adjustments to growth rate are applied to the base case on an annual basis.

3. Residential customers: In the EKPC base case load forecast for 2008 through 2027, the projected number of residential customers increases at a growth rate of 1.5%. The basic approach to preparing high and low case scenarios for the future number of residential customers is to determine the

magnitude of variation in the past between long term average growth rates and higher or lower growth rates during shorter periods of time.

First, the data on the historic monthly household counts for the period from 1986 through 2007 was prepared. Next, the compound annual growth rate in households were calculated for each rolling ten year period beginning with the period 1986 to 1996 and ending with the period 1997 through 2007. This produced a set of twelve compound annual growth rate values each representing a unique ten year span. Maximum and minimum values were determined. The highest growth was used to prepare the high case scenario, while the 10 year period that experienced the lowest growth was used to prepare the low case scenario.

These resulting adjustments were applied to the 20 year compound annual growth rate in the base case customer count forecast (that value is 1.5%) to produce the high case (1.9%) and low case (1.1%) compound annual growth rate forecast scenarios. Essentially, the high case has a 26% higher growth rate than the base case, while the low case has a 24% lower growth rate than the base case. This relationship was preserved in preparing the monthly customer counts for the high and low case scenarios.

4. Small and Large Commercial energy – energy was modeled probabilistically, assuming a normal distribution and a standard deviation based on the historical data; the resulting 90%/10% output was used as the forecasted class energy. The energy forecasts for the high and low case are produced using probabilistic modeling in @RISK. The customer and energy forecasts are added to the residential forecast to produce the system forecast.

Adjusting these assumptions leads to different customer forecasts which in turn results in different energy forecasts. The large steel mill is a non-weather sensitive, interruptible load. This results in no impact on winter or summer peak scenarios because the load is assumed to be interrupted, and the energy is not impacted by adjusting weather assumptions. The pessimistic case does assume this large load is 50% of the base case assumption. The results are shown on pages 7-13 through 7-16 for the following cases:

Case 1 - Pessimistic economic assumptions with mild weather causing lower loads
Case 2 - Most probable economic assumptions with severe weather causing higher loads
Case 3 (Base) - Most probable economics assumptions with normal weather (Base Case)
Case 4 - Most probable economic assumptions with severe weather causing higher loads
Case 5 - Optimistic economic assumptions with severe weather causing higher loads.

Scenarios
Peak Demands

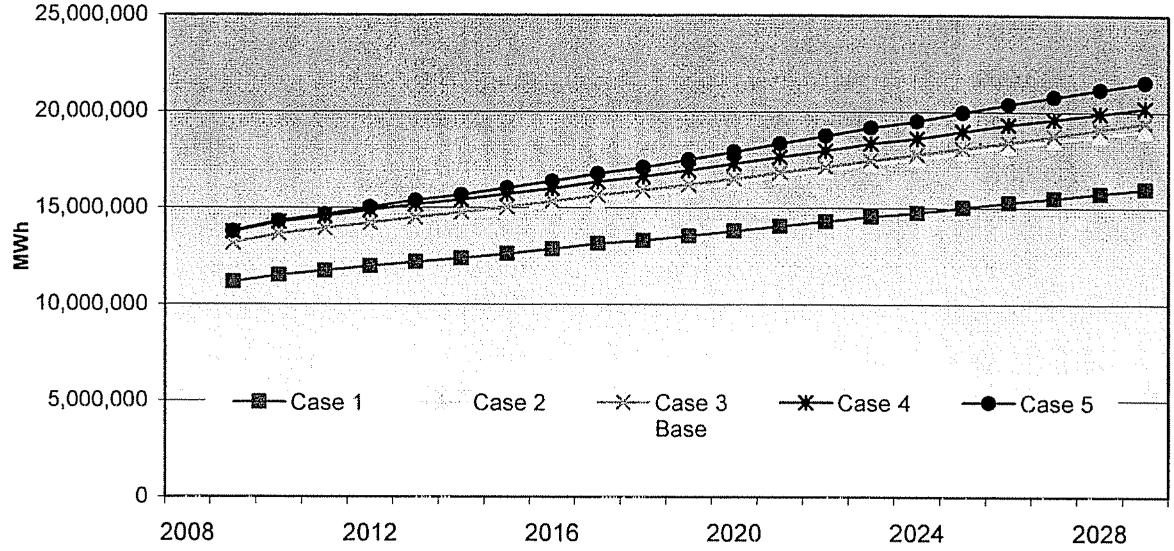
Total Winter Peak Demand (MW)						Total Summer Peak Demand (MW)					
Season	Case 1	Case 2	Case 3 Base	Case 4	Case 5	Year	Case 1	Case 2	Case 3 Base	Case 4	Case 5
2008 - 09	2,764	2,833	**2,962**	3,294	3,312	2009	2,107	2,204	**2,363**	2,499	2,511
2009 - 10	2,801	2,879	**3,029**	3,346	3,377	2010	2,142	2,239	**2,406**	2,536	2,555
2010 - 11	2,853	2,943	**3,087**	3,421	3,465	2011	2,179	2,280	**2,442**	2,581	2,608
2011 - 12	2,894	2,996	**3,143**	3,482	3,540	2012	2,204	2,311	**2,475**	2,615	2,650
2012 - 13	2,943	3,055	**3,215**	3,550	3,623	2013	2,251	2,356	**2,529**	2,663	2,706
2013 - 14	2,996	3,120	**3,275**	3,625	3,713	2014	2,295	2,406	**2,579**	2,718	2,769
2014 - 15	3,052	3,183	**3,345**	3,698	3,803	2015	2,343	2,451	**2,630**	2,767	2,828
2015 - 16	3,108	3,246	**3,408**	3,771	3,893	2016	2,391	2,498	**2,680**	2,820	2,890
2016 - 17	3,157	3,313	**3,482**	3,848	3,987	2017	2,434	2,552	**2,737**	2,878	2,958
2017 - 18	3,211	3,382	**3,547**	3,928	4,085	2018	2,479	2,600	**2,790**	2,932	3,023
2018 - 19	3,271	3,456	**3,617**	4,013	4,189	2019	2,533	2,658	**2,843**	2,995	3,097
2019 - 20	3,317	3,521	**3,680**	4,088	4,284	2020	2,573	2,709	**2,893**	3,051	3,163
2020 - 21	3,383	3,601	**3,760**	4,181	4,396	2021	2,631	2,771	**2,957**	3,120	3,243
2021 - 22	3,439	3,676	**3,833**	4,268	4,504	2022	2,679	2,830	**3,016**	3,184	3,320
2022 - 23	3,487	3,734	**3,904**	4,335	4,593	2023	2,721	2,870	**3,071**	3,230	3,377
2023 - 24	3,539	3,801	**3,965**	4,413	4,692	2024	2,770	2,922	**3,121**	3,287	3,447
2024 - 25	3,608	3,885	**4,052**	4,510	4,813	2025	2,830	2,986	**3,186**	3,359	3,532
2025 - 26	3,663	3,951	**4,125**	4,587	4,914	2026	2,877	3,031	**3,248**	3,410	3,597
2026 - 27	3,718	4,016	**4,204**	4,664	5,014	2027	2,925	3,075	**3,311**	3,461	3,661
2027 - 28	3,773	4,082	**4,283**	4,740	5,115	2028	2,972	3,119	**3,362**	3,512	3,726

Scenarios
Energy Requirements

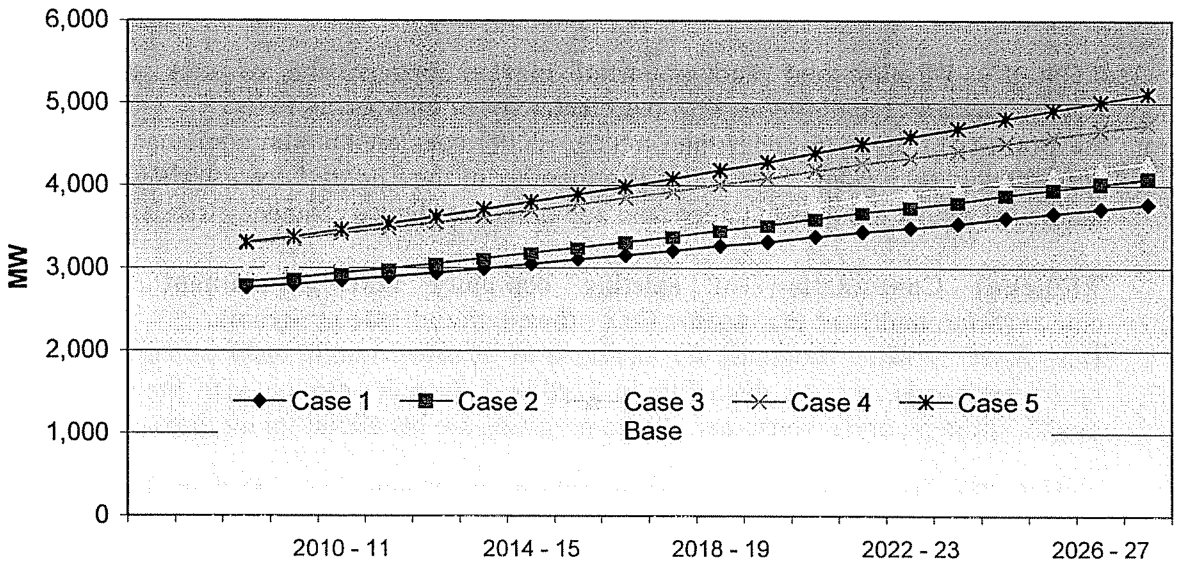
Total Requirements
Includes Gallatin Steel
(MWh)

Year	Case 1	Case 2	Case 3 Base	Case 4	Case 5
2009	11,509,472	13,424,210	**13,647,057**	14,278,380	14,343,406
2010	11,732,142	13,692,443	**13,959,302**	14,553,021	14,662,606
2011	11,974,953	14,000,378	**14,217,198**	14,875,273	15,033,161
2012	12,200,580	14,287,211	**14,511,928**	15,176,342	15,384,981
2013	12,392,213	14,518,776	**14,777,060**	15,416,821	15,675,828
2014	12,619,800	14,809,546	**15,050,207**	15,722,936	16,036,745
2015	12,863,579	15,088,307	**15,335,690**	16,017,515	16,388,896
2016	13,146,559	15,407,842	**15,657,979**	16,355,537	16,788,421
2017	13,321,999	15,667,031	**15,930,390**	16,627,705	17,120,648
2018	13,556,221	15,969,097	**16,221,635**	16,947,543	17,505,178
2019	13,820,661	16,301,633	**16,526,826**	17,298,494	17,923,506
2020	14,066,638	16,646,190	**16,855,275**	17,661,216	18,356,671
2021	14,315,359	16,960,286	**17,158,239**	17,992,613	18,758,555
2022	14,553,913	17,300,889	**17,479,553**	18,351,696	19,192,040
2023	14,762,964	17,544,576	**17,784,014**	18,612,146	19,527,263
2024	15,038,687	17,894,803	**18,106,328**	18,982,349	19,978,202
2025	15,295,739	18,218,671	**18,422,561**	19,325,942	20,402,986
2026	15,532,467	18,495,567	**18,751,416**	19,623,062	20,784,856
2027	15,769,195	18,772,463	**19,099,314**	19,920,181	21,166,727
2028	16,005,923	19,049,360	**19,447,211**	20,217,301	21,548,597

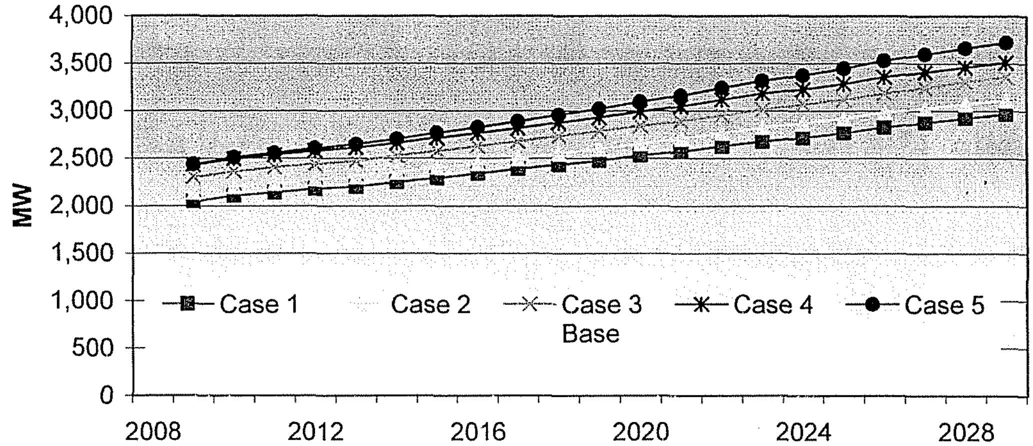
Total Energy Requirements



Total Winter Peak



Total Summer Peak



7.(7)(e) The extent to which the utility's load forecasting methods and models explicitly address and incorporate the following factors.

7.(7)(e)(1) Changes in prices of electricity and prices of competing fuels.

Response: Price is an input into the energy models as is price elasticity.

7.(7)(e)(2) Changes in population and economic conditions in the utility's service territory and general region.

Response: EKPC relies on regional economic conditions. See Response 7.(7)(c) on page 7-10.

7.(7)(e)(3) Development and potential market penetration of new appliances, equipment, and technologies that use electricity or competing fuels.

Response: In order to understand trends, EKPC does conduct an appliance saturation survey every two years. EKPC also is a member of the Energy Forecaster's Group. This main goal of this group is to understand and model appliance efficiency trends.

7.(7)(e)(4) Continuation of existing company and government sponsored conservation and load management or other demand-side programs.

Response: Existing programs will continue to be offered until analyses shown there is no benefit to do so. As described in Section 8, benefits can be seen for EKPC, the member system, or the consumer. Some programs are beneficial for all three.

7.(7)(f) Research and development efforts underway or planned to improve performance, efficiency, or capabilities of the utility's load forecasting methods.

Response: Plans are to evaluate the process for integrating demand side management/conservation efforts and response to price/economic issues for the next forecast.

7.(7)(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.

Response: As previously stated, EKPC does conduct an appliance saturation survey every two years. This is an effort to stay apprised of saturation of household appliances. In addition, EKPC has a load research program which consists of over 600 meters on residential, commercial and industrial customers. EKPC and its member systems work together to collect load research data that are needed for various analyses at the retail level, such as the design of marketing programs. Load research data are employed in end-use forecasting methodologies to project sales and demand and also provides information for demand estimates for cost of service studies and/or rate cases for EKPC and the member systems. Standard estimates and statistics are developed for each month of a study including:

- Class Demand at System Peak Hour
- Class Demand at Class Peak Hour
- Hourly Class Demands on System Peak Day
- Hourly Class Demands on Class Peak Day
- Coincidence and Load Factors
- Class Energy Use
- Class Non-Coincident Peak Demands
- Class Time-Of-Use statistics.

The most traditional method for obtaining load data is metering, usually with a time-of-use or load profile recording meter. To be useful statistically, however, a sample of sufficient size must be metered from EKPC's population base. The advantage of metering is that it provides results explicitly for a particular service area or rate class for a given time period (peak hour). Compared to other alternatives, this method is more expensive and generally takes a longer time to provide meaningful data; however, its reliability is relatively high. Metered data can also become outdated rather quickly, which is why EKPC maintains a continuous load research project, targeted at member system rate classes. EKPC has also used metering in end-use studies such as air source heat pumps, electric thermal storage, and geothermal heating and cooling systems.

Load research projects have and will continue to be a part of EKPC's research efforts. Current on-going load research projects include:

1. Residential: Includes customers that are billed in the residential class. There are 178 load profile meters installed and collecting data.
2. Small Commercial & Industrial: These are nonresidential customers whose demand is less than 50 kW. There are 78 load profile meters installed and collecting data.
3. Medium Commercial & Industrial: Includes customers whose peak demands are between 50 and 350 kW. There are 76 load profile meters installed and collecting data.
4. Large Power: Customers whose peak demands are greater than 350 kW. There are 295 meters installed.

Although not formally approved, the following projects have been proposed for implementation in 2009.

1. Complete analysis to issue reports for internal use of class studies and large power: EKPC plans to compile the historical data looking at growth rates. The reports will include data through 2007.

2. Borrowed data: EKPC will continue to monitor and evaluate the transferability of load data from other utilities.

Real Time Pricing Pilot

Real Time Pricing ("RTP") is an electricity rate structure in which retail energy prices change very frequently, usually hourly, and with short notice, usually day-ahead. These hourly prices are designed to reflect the utility's expected hourly marginal cost of providing incremental load. These hourly costs can also reflect market costs, such as power purchases. RTP assists the customer to make an energy usage decision based upon the utility's true cost of providing incremental energy. RTP also recognizes and allows for the fact that the value of energy is specific to each user and is dynamic.

Through RTP price response, the overall system reliability can be improved. Retail consumers can back off usage when wholesale prices are high, ultimately providing a dampening effect upon outside power purchases and may avoid dispatching costly generation such as combustion turbines. RTP customers are often able to lower their cost of energy but in a manner that is beneficial to the utility. Participants have an incentive to innovate with economic energy efficiency programs and equipment.

There are five components to the RTP price: (1) system lambda which includes variable fuel, variable O&M and variable emission allowance costs of the marginal generating unit, or a purchase if it is the marginal resource, (2) reliability cost, (3) transmission cost, (4) losses, and (5) a risk adder. The first component of the RTP price is complex and the most difficult to determine. There will be a RTP price quoted for each hour of the day.

The Commission approved a 3-year RTP pilot program for EKPC on February 1, 2008. Since the February 2008 approval of the pilot program, EKPC has been working to develop the components of the RTP price, establishing a secure website to post the RTP prices on, establishing procedures to ensure the posted RTP prices are accurate and current, and training EKPC personnel on the operation of the pilot program. EKPC has developed the outline for a marketing effort for RTP. Education and training efforts for the member cooperative personnel are in the earliest stages of development, and will have to be completed before the RTP pilot program can be offered to potential customers.

(Section 7 technical discussions, descriptions, and supporting documentation are contained in the technical appendix.)

Section 8

Resource Assessment and Acquisition Plan

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Section 8

8. Resource Assessment and Acquisition Plan

8.(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.

The resource planning process at EKPC is based on a least cost approach and also incorporates a risk evaluation. The planning cycle begins with the load forecast that is developed every two years. A new load forecast was developed in 2008. Based on the load forecast, EKPC's capacity needs are evaluated to determine the timing, quantity, and proper mix of resources. An evaluation of the status of technologies is part of the planning process. EKPC continually evaluates power supply alternatives based on the most recent load forecast and current cost and financial data. The current resource plan is shown in Section 5(4) on page on page 5-17. Alternatives for supplying future resource needs are evaluated on a present worth of revenue requirements basis. Both supply-side options and demand-side options are evaluated during the planning process. EKPC is required by Rural Utilities Service ("RUS") under most circumstances to undergo a Request for Proposals ("RFP") process to evaluate resource alternatives. Various alternatives such as self-build options, power purchases, construction of new capacity by partnering with other companies, unit participation proposals, distributed generation, and DSM proposals are typically evaluated during the RFP process.

The optimization module in EKPC's production cost model, RTSim, was used to develop the resource plan in the 2009 IRP. The RTSim Resource Optimizer incorporates risk analysis, optimization, and detailed production cost simulation to determine the lowest cost plans while simultaneously mitigating risk.

8.(2) The utility shall describe and discuss all options considered for inclusion in the plan including:

8.(2)(a) Improvements to and more efficient utilization of existing utility generation, transmission, and distribution facilities;

Existing Generation

Maintenance management for existing generation is vital to keeping the generating facilities reliable, productive, efficient and cost effective. EKPC has developed a long-range plan of maintenance needs for each of the existing generating units, which is discussed in the following subsection. EKPC has also considered retirement and repowering options. These topics are addressed later in this section.

Maintenance of Existing EKPC Generating Units

Current facilities at Dale Station were placed in operation in 1954-60, Cooper Station in 1965-69, and Spurlock Station in 1977-81, with the Gilbert Unit in 2005 and Spurlock 4 in 2009. J. K. Smith Station combustion turbines were placed in operation in 1999, 2001, and 2005. Two additional combustion turbines are under construction at the time of this filing and are anticipated to be complete December 2009. Each of EKPC's generating plants were state-of-theart at the time of their construction and were designed to operate under conditions existing at that time. The continued operation of these plants requires both normal maintenance and a systematic review of current conditions needed for continued operation.

In 1987, EKPC began work on a formal maintenance program called MEAGER 2000 (Maintaining Electrical and Generating Equipment Reliability). MEAGER 2000 was intended to enable EKPC to reach the year 2000 by operating existing facilities in the most cost-effective manner. The objective of MEAGER 2000 was to develop a coordinated program of condition assessment and analysis of the fitness of EKPC's generating equipment and facilities. Revised now to MEAGER 2029, it mitigates escalating energy costs by identification of issues. Through proper planning and implementation, EKPC effectively manages operations, while meeting environmental compliance regulations, to provide reliable, economical electric service to its member systems and their retail consumers.

This plan for maintenance was developed following the review of various plant subsystems, assimilation of operational data, and review of past operating history. The plan explores the cost of options available for construction. These cost options look at the age of the facility, fuel cost, EKPC reserve margin, EKPC's overall financial condition, the ability to purchase and/or sell power during this period, and changes that may be required by environmental and regulatory agencies.

Methodology for MEAGER Program

The MEAGER Program was developed in 1987 and is updated on a regular basis by EKPC personnel. It was formally updated in 1993 by Stanley Consultants. The areas addressed in the development of the current plan include generating plant performance, operation, and maintenance. To prepare the update this year, the following tasks were completed:

1. Reviewed the original MEAGER 2000 Study.
2. Reviewed the most current annual update prepared by EKPC.
3. Meetings and phone calls were made during the year to discuss future needs for each individual plant.
4. The best-known options were recommended, priced in current-year dollars, and assigned an estimated completion date.
5. Prepared a final report to be submitted to EKPC's Board of Directors.

Each specific major project scheduled in the MEAGER Study is again reviewed and justified prior to requesting approval from the EKPC Board of Directors for implementation of the project. Prior to requesting this approval, an economic analysis is conducted taking into account costs and timing of the project, to ensure that completion of the proposed project is the most economical decision for EKPC. Justifications are developed based on the economic analysis and any other benefits such as safety or regulatory requirements. The economic analysis results and justification are then presented to the Board along with a request to approve the project.

Subsequent to the approval, technical specifications are prepared and requests for bids are solicited. The bids are then evaluated, and a recommendation is made to the Board to proceed with the project. Assuming the project is approved, a letter is sent to RUS for their approval of the project, when required. After all approvals are received, work is completed under EKPC supervision.

2009 MEAGER Study

The MEAGER 2029 Program covers the time frame of 2009 through 2029. Table 8.(2)(a)-1 through Table 8.(2)(a)-19 on pages 8-64 through 8-81 in the Supporting Documentation lists the major projects planned for each plant during this 20-year period.

Unit Repowering Options

East Kentucky Power Cooperative ("EKPC") entered into a Consent Decree ("CD") with the United States Environmental Protection Agency ("EPA") in 2007. In the CD, the EPA gave EKPC the option to either install and continuously operate NOx and SO2 emission controls at Cooper Unit 2 or retire and permanently cease operation of Dale Units 3 and 4 by December 31, 2012. EKPC also has the option of repowering Dale Units 3 and 4 by May 31, 2014. The decision to either install new emission controls at Cooper Unit 2 or retire Dale Units 3 and 4 must be submitted in writing to the EPA no later than December 31, 2009. Based on this stipulation, EKPC initiated a study to evaluate its options. Burns & McDonnell Engineering Company was hired to provide plant evaluations and develop specific cost and operating characteristics for each viable option available to EKPC. Eight options were developed and analyzed. EKPC's conclusion of the analysis was that construction of emission controls at Cooper Station was the best long term alternative for EKPC and its member systems. EKPC has requested a Certificate of Public Convenience and Necessity for environmental controls to be installed at the Cooper Unit 2 facility – PSC Case No. 2008-00472. Detailed analysis is included in the documentation in that case.

Based on various analyses, EKPC does not plan to retire or repower any of its 10 existing coal-fired units during the 15-year planning horizon, through 2023.

Carbon Capture Research

Teaming with major power companies, the University of Kentucky's Center for Applied Energy Research ("CAER") has formed an industrial-governmental-academic consortium called the Carbon Management Research Group ("CMRG"). The CMRG will carry out a ten-year program of research to develop and demonstrate cost-effective and practical technologies for reducing and managing CO2 in existing coal-fired electric power plants. The intention is to position electric utilities to respond to a carbon-constrained economy prior to the imposition of environmental rules. Its purpose is to maintain and strengthen coal's competitive advantage as a least-cost fuel for electricity production, while improving environmental quality.

The Commonwealth of Kentucky has committed to providing a match against industry financial support at 1:1, up to $1M per year for the first two years starting in 2008. After this period, funding will depend on resources made available by the state. Participating utilities contribute $200k each year. Currently, EKPC, AEP, Duke-KY, and E.On. are members of the CMRG. Big

Rivers will likely join. Both the Electric Power Research Institute ("EPRI") and the Cooperative Research Network ("CRN") have expressed an interest in becoming members of CMRG.
Three research projects on CO_2 capture and separation will be performed:

- Investigation of Post-Combustion CO_2 Control Technologies using the CAER's Pilot Plant.
- Slip-Stream Investigation of Post-Combustion CO_2 Control Technologies at Consortium Members' Power Plant(s).
- Development of Chemical Looping Combustion/Gasification for Solid Fuels.

Transmission System

Introduction

EKPC designs its transmission system to provide adequate capacity for reliable delivery of EKPC generating resources to its member distribution cooperatives, and for long-term firm transmission service that has been reserved on the EKPC system. EKPC's transmission planning criteria specifies that the system must be designed to meet projected customer demands for simultaneous outages of a transmission facility and a generating unit during peak conditions in summer and winter.

EKPC's transmission system is geographically located in roughly the eastern two-thirds of Kentucky. The transmission system approaches the borders of Kentucky in the north, east, and south, and stretches to approximately the Interstate 65 corridor in the west. The system is comprised of approximately 2,910 circuit miles of line at voltages of 69, 138, 161, and 345 kV, and 63 free-flowing interconnections with neighboring utilities. EKPC's interconnections with neighboring utilities have been established to improve the reliability of the transmission system and to provide access to external generation resources for economic and/or emergency purchases. Table 8.(2)(a)-20 (page 8-82) through Table 8.(2)(a)-23 (page 8-85) list each of EKPC's free-flowing interconnections.

Interconnections

EKPC participates in joint planning efforts with neighboring utilities to ascertain the benefits of potential interconnections, which can include increased power transfer capability, local area system support, and outlet capability for new generation. It should be noted that actual transfer capabilities are unique to actual system conditions, as affected by generation dispatch, outage conditions, load level, third-party transfers, etc.

Membership in Southeast Electric Reliability Corporation ("SERC")

EKPC is a member of SERC. From the SERC website, SERC is "responsible for promoting and improving the reliability, adequacy, and critical infrastructure of the bulk power supply systems in all or portions of 16 central and southeastern states. Owners, operators, and users of the bulk power system in these states cover an area of approximately 560,000 square miles and comprise what is known as the SERC Region." SERC is one of eight regional entities with delegated authority from the North American Electric Reliability Corporation ("NERC"); the regional entities and all members of NERC work to safeguard the reliability of the bulk power systems throughout North America. NERC has been certified by the Federal Energy Regulatory Commission ("FERC") as the Electric Reliability Organization ("ERO") for North America. NERC has established Reliability Standards that the electric utilities operating in North America must adhere to. There are presently 126 Reliability Standards that have been approved by FERC and are, therefore, in effect. EKPC is required to comply with 90 of these standards based upon its responsibility for various functions, such as Balancing Authority, Resource Planner, Transmission Operator, etc. Many additional standards are currently under development, and the development of new standards is certain to continue. EKPC continues to identify and refine planning practices that will ensure compliance with these NERC Reliability Standards.

EKPC actively participates in SERC activities and studies. Each year, EKPC participates in SERC assessments of transmission system performance for the summer and winter peak load periods. In these assessments, potential operating problems on the interconnected bulk transmission system are identified. EKPC annually supplies SERC with data needed for development of current and future load flow computer models. These models are used by EKPC and other SERC members to analyze and screen the interconnected transmission system for potential problems.

EKPC adheres to SERC's guidelines for transmission and generation planning and operations. With all of the SERC members following these guidelines, each member system can be assured of having adequate facilities for normal and emergency (outage) conditions. Participation in SERC enhances the reliability of each member system without having to install excess generation and transmission capacity to provide a comparable level of reliability. SERC recently performed a NERC audit and EKPC was found to be fully compliant with all standards audited.

Transmission Expansion Plan

Transmission constraints, and the ability to address them in a timely manner, represent important planning considerations for ensuring that peak-load requirements are met in a reliable manner. EKPC's Transmission Planning Department works closely with other groups at EKPC -- such as Power Delivery Operations, Engineering, Power Delivery Maintenance, and Resource Planning -- to coordinate activities and address reliability issues. EKPC also seeks input from other external parties, including potential generation developers regarding issues or needs related to the EKPC transmission system.

EKPC's transmission expansion plan includes a combination of new transmission line and substation facilities and upgrades of existing facilities during the 2009-2023 period to provide an adequate and reliable system for existing and forecasted future native load customers and existing and requested future generation resources.

Transmission expansion plans are developed and updated on an annual basis. Power-flow analysis and reliability indices are used to predict problem areas on the transmission system. Various alternatives for mitigating these problems are then formulated and analyzed. The transmission expansion projects that provide the desired level of reliability and adequacy at a reasonable cost are then added into the plan. Note that transmission planning, like all EKPC planning processes, is ongoing, and changing conditions may warrant changes to the transmission plan.

Distribution System

EKPC is an all-requirements power supplier for 16 member-system distribution cooperatives in Kentucky. In addition to designing, owning, operating, and maintaining all transmission facilities, EKPC also is responsible for all delivery points (distribution substations), including the planning of these delivery points in conjunction with the respective member systems. EKPC monitors peak distribution substation transformer loads seasonally to identify potential loading issues for delivery points to member systems. Furthermore, EKPC and the member systems jointly develop load forecasts for each delivery point that are used to identify future loading issues. EKPC uses a three-year planning horizon for distribution substation planning. EKPC and the member systems use a joint planning philosophy based on a "one-system" concept. This planning approach identifies the total costs on a "one-system" basis – i.e., the combined costs for EKPC and the member system – for all alternatives considered. Generally, the alternative with the lowest one-system cost is selected for implementation, unless there are overriding system benefits for a more expensive alternative.

EKPC has developed a Transmission Construction Work Plan for 2009-2011. This plan is based on detailed engineering analyses, and includes transmission and distribution substation projects that are relatively firm in nature. Maps of EKPC's existing transmission system and of the EKPC transmission system showing interconnected facilities plus EKPC's planned future facilities in 2009-2011 are included at the end of this document.

EKPC also develops a 15-year expansion plan. The analysis used to develop this plan is less detailed. Many of the projects beyond the initial 3-year period are conceptual in nature, and are more likely to change in scope and date, or to be cancelled and replaced with a different project. EKPC's 15-year expansion plan for the 2009-2023 period is included as

Table 8.(2)(a)-24 on page 8-86 through Table 8.(2)(a)-37 on page 8-99. This 15-year expansion plan includes approximately 118 miles of new line construction (69 kV and higher), 233 miles of existing line re-conductors/rebuilds, and 219 miles of high-temperature conductor upgrades. It also includes the construction of several new switching stations (single voltage level) and substations (two different voltage levels), upgrades of existing transformers, and the installation of a total of 387 MVARs of new transmission capacitor bank capability.

EKPC and its member systems continue to work jointly to install capacitors at the distribution system level to provide more efficient use of the EKPC generation, transmission, and distribution substation systems. Studies are performed to identify where power factor correction will provide the greatest benefits to the system versus the costs for the equipment.

Generation Related Transmission

When evaluating potential power supply resources, the cost of required transmission-system modifications associated with each resource is included in the analysis. Some resource alternatives are site-specific and transmission plans can be developed that are directly relevant for those resource alternatives. Other resource alternatives are generic units for which no specific site has been yet identified. For those generic units, an average cost of transmission is used in the cost analysis.

EKPC performs studies for transmission requirements for units connected to the EKPC transmission system after an official request has been submitted per EKPC's Open Access Transmission Tariff ("OATT"). This process is performed in a consistent, non-discriminatory manner. Only those projects necessary for firm generation resources (existing and future) are identified in EKPC's transmission expansion plan.

EKPC's latest generation expansion plan includes two new Combustion Turbines ("CTs") at J.K. Smith scheduled for commercial operation in December 2009, and a new steam turbine/generator base load unit at J.K. Smith (CFB Unit #1) scheduled for commercial operation in October 2013.

The transmission expansion requirements for these units have been evaluated. For the two CTs at J.K. Smith with a net output of 84 MW summer and 98 MW winter (CTs 9 and 10), the transmission requirements and associated costs are as follows:

- Construct approximately 33 miles of 345 kV line using 2-954 MCM ACSR from the J.K. Smith Substation to intercept E.ON's Brown North-Pineville 345 kV circuit #2 at a new substation site called West Garrard (estimated cost of $41,750,000).
- Construct a new 345 kV switching substation at the West Garrard site (estimated cost of (estimated cost of $6,500,000).
- Install 345 kV terminal facilities at J.K. Smith for termination of the new J.K. Smith-West Garrard 345 kV line (estimated cost of $715,000).
- Install 345 kV terminal facilities at J.K. Smith for connection of the generating step-up ("GSU") transformer for J.K. Smith CTs #9 and #10 (estimated cost of $410,000).
- E.ON constructs facilities to terminate the Brown North-Pineville 345 kV circuit #2 at Brown, Pineville, and West Garrard (estimated cost of $7,000,000).

All of these projects except addition of terminal facilities at E.ON's Pineville Substation are scheduled to be completed by December 2009. The terminal facility additions at the Pineville Substation are scheduled to be completed by May 2010.

For the proposed J.K. Smith CFB Unit #1 scheduled for October 2013, minimal transmission expansion is required. The transmission expansion projects identified for CTs 9 and 10 provide additional capacity to accommodate the expected net output of the CFB unit, estimated to be 278 MW (as well as potential future generation additions at the J.K. Smith site). The additional projects required for the CFB unit are:

- Construct a J.K. Smith Backup Power 69-13.8 kV, 11.2/14 MVA distribution substation and associated 0.1-mile 69 kV tap line by June 2010 to satisfy construction power requirements and future requirements for plant service (estimated cost of $640,000).
- Construct 1.2 miles of 345 kV line between the existing J.K. Smith 345 kV Substation and the J.K. Smith CFB Unit location using 2-954 MCM ACSR conductor by June 2012 (estimated cost of $1,235,000).
- Replace 138 kV terminal equipment at J.K. Smith, Dale, Fawkes, and Powell County to increase the limits of the J.K. Smith-Dale, J.K. Smith-Fawkes, and J.K. Smith-Powell County 138 kV lines to the conductor capability by December 2012 (estimated cost of $500,000).

A generic average cost of $70/kW (2009$) was used for the transmission facilities associated with the future EKPC generating unit additions beyond the two CTs and the CFB Unit #1 at J.K. Smith. This generic average cost was based upon historical costs for transmission expansion associated with generation projects.

Import Capability

EKPC routinely assesses the ability to import power from external sources into the EKPC control area. Import capability is assessed from markets to the north and to the south as part of the normal planning process. Also, EKPC performs import capability studies as a participant in SERC's annual system assessments.

EKPC designs its transmission system to be capable of importing at least 500 MW from regions either north or south of Kentucky. EKPC's studies indicate that EKPC's existing import capability from either the TVA system or the PJM system is approximately 1000 MW. In performing these studies, EKPC attempts to identify external facilities that would limit import capability for EKPC based on the information available in the latest NERC Multiregional Modeling Working Group series of power flow cases. However, real-time market and transmission-system conditions may result in system limitations that are significantly different from those predicted in these studies. Available Transfer Capacity ("ATC") calculations are performed by Regional Transmission Organizations (such as PJM and MISO), Independent Transmission Organizations (such as the SPP ITO) and Reliability Coordinators (such as TVA). These results are coordinated to ensure that the lowest value for a particular path is set as the ATC. Such studies utilize updated data for transmission and generation outages, market transactions, and system load to predict expected system flows. Therefore, it is difficult to predict the availability of transmission capacity for imports into the EKPC system. EKPC generally chooses to procure an adequate amount of transmission from markets to the north and/or south well in advance of peak seasons to ensure import capability.

8.(2)(b) Conservation and load management or other demand-side programs not already in place;

EKPC evaluated 103 new DSM measures for the 2009 Integrated Resource Plan ("IRP"). A two-step process was used in the evaluation: (1) Qualitative Screening, and (2) Quantitative Evaluation.

Thirty-one (31) new measures passed the Qualitative Screen and were passed on to Quantitative Evaluation. In some cases, several measures were combined into one program. Also, a few of the measures did not lend themselves to quantitative analysis. A total of 25 new DSM Programs were prepared for the Quantitative Evaluation.

The results for the cost-effectiveness tests were generally favorable for the DSM programs. Of the 25 DSM Programs that were evaluated, 23 produced a Total Resource Cost test benefit-cost ratio of greater than 1.0. These 23 programs are considered "new" programs whose load impacts are not reflected in the base case load forecast.

In addition to these new Programs, EKPC also has eleven (11) Existing Programs in its DSM portfolio. DSM resources consist of customer energy programs that seek to change the power consumption of customer facilities in a way that meets planning objectives. They include conservation, load management, demand response, and other demand-side programs.

EKPC's DSM analysis is conducted on an aggregate basis, with all member cooperatives combined, rather than on an individual cooperative basis.

For this 2009 IRP, EKPC first developed a comprehensive list of 103 new DSM measures to consider. This set of DSM measures covers all classes and major end-uses, and includes a robust set of available technologies and strategies for producing energy and capacity savings. This list was produced after careful review of several sources, including (1) PSC staff recommendations from the 2006 IRP; (2) feedback from Kentucky Department of Energy, the Attorney General's office, and other relevant state agencies; (3) the current programs and IRPs of other Kentucky utilities; and (4) best practice DSM programs offered by utilities around the country.

The following three Tables (one for each major customer class) present the list of 103 DSM measures that were considered as DSM resource options:

Complete List of DSM Measures & Results of Qualitative Screen
Measures that passed the Qualitative Screen are IN BOLD

Residential

1 **Residential Efficient Lighting**
2 **Direct Load Control - air conditioners & water heaters**
3 **Programmable thermostats with electric furnace heat**
4 **ENERGY STAR® Refrigerator**
5 **ENERGY STAR® Room Air Conditioner**
6 **ENERGY STAR® Clothes Washers**
7 Cold climate heat pump
8 **Heat retrofit/ early replace: resistance to heat pump**
9 Inefficient heat pump to geothermal early replacement
10 SEER 10 heat pump to SEER 15 early replacement
11 Ductless mini-split heat pump
12 Inefficient Central Air Conditioner to SEER 15
13 High efficiency furnace fan motors
14 **Low income weatherization**
15 **Enhanced Button-Up (air sealing)**
16 **Enhanced Tune-Up (duct sealing)**
17 **Enhanced Touchstone Home (thermal sealing/bypass)**
18 Ceiling Fans
19 Multi-family program
20 **Mobile home retrofit program**
21 Polarized Refrigerant oxidant agent
22 **ENERGY STAR® Central Air Conditioner**
23 Low flow showerhead with faucet aerator/pipe insulation
24 Heat pump water heater
25 Instantaneous water heater
26 Solar water heater
27 Room AC exchange & recycle program
28 ENERGY STAR® Dishwashers
29 Refrigerator/Freezer Recycling
30 Remove old second refrigerators
31 Removed old second freezers
32 ENERGY STAR® Freezers
33 ENERGY STAR® Home electronics
34 ENERGY STAR® Windows
35 ENERGY STAR® Dehumidifiers
36 Heat pump dryer
37 Efficient pool pump
38 Well water pump
39 High efficiency outdoor lighting
40 LED lighting
41 **Direct load control - pool pump**
42 **Time of use rates**
43 Inclining block rates
44 Passive Solar (new construction)
45 Photovoltaics (customer sited)
46 Wind turbine (customer sited)

Commercial

1 **Commercial HVAC**
2 **Demand Response**
3 **Commercial Building Performance**
4 **Commercial New Construction**
5 **Efficient refrigeration equipment**
6 **Small C&I audit program**
7 Building operator certification program
8 **Geothermal heat pump**
9 Evaporative cooling
10 Advanced ventilation
11 High efficiency HVAC motors
12 **Early replacement inefficient unitary/split system HVAC**
13 Cool roof program
14 High performance glazings
15 **Duct sealing**
16 Thermal energy storage
17 Heat pump water heaters
18 Drain heat recovery water heaters
19 **LED exit signs**
20 **Advanced lighting program**
21 Efficient cooking equipment
22 Efficient clothes washers
23 **ENERGY STAR® Vending machines**
24 Energy Management Systems
25 DLC of irrigation pumps
26 **DLC of central air conditioners**
27 **Energy efficient schools**
28 Farms program: fans, pumps, irrigation
29 Time of use rates
30 Combined heat & power
31 Stand-by generation program
32 Daylighting
33 Solar hot water
34 Photovoltaics
35 Wind turbine

Industrial/Other

1 **Motors**
2 **Variable speed drives**
3 **Demand Response**
4 **Compressed air**
5 Industrial process
6 Process cooling
7 Refrigerated Warehouse
8 High efficiency transformers
9 Automotive and transportation sector equipment
10 Livestock, equine, poultry and meat processing sector
11 Chemicals sector
12 Machinery/machine tools sector
13 Aluminum sector
14 Plastics sector
15 Computer and electronics sector
16 Combined heat and power
17 Other onsite generation (conventional)
18 Photovoltaics
19 Wind turbine
20 LED Traffic signals
21 Water/Wastewater Treatment facilities
22 Conservation Voltage Reduction

Additional details on the evaluation of DSM resources for inclusion in this 2009 IRP are contained in the report titled *Demand-Side Management Analysis* on page DSM-11, which can be found in the Technical Appendix.

8.(2)(c) Expansion of generating facilities, including assessment of economic opportunities for coordination with other utilities in constructing and operating new units;

Renewable Energy Resources RFP 2008

Resource Planning issued a Request for Proposal ("RFP") for renewable energy resources in April 2008. The intent of the RFP was to determine availability of renewable energy in and around the Commonwealth. The proposal did not limit the type of generation or the amount of energy, but only specified the following categories as possible forms of generation: wind, solar, biomass, hydro, geothermal, and recycled energy.

From the range of possibilities, thirty-six companies submitted a Notice of Intent ("NOI") to file an RFP. The responses included solar, wind, hydro, biomass, and waste heat, with over 2500MWe offered.

Many of the NOI respondents followed through with a proposal. There were several developers that submitted a proposal without a NOI. The total number of bids received was 22. This pool covered solar, wind, hydro, biomass, waste heat, and municipal solid waste. The total megawatt offering was almost 2200. From the 22 responses, 12 were selected for the Short List. This group represented over 900MWs.

The projects and developers were evaluated on their viability to produce the project submitted. This included discussion of past projects, pricing basis, and financial stability. As renewable energy ("RE") is a developing field, several developers are new to the field, but offer the potential to bring a small project online to continue resource portfolio diversification.

Although no specific project or projects have been selected for final development, several fuel supply studies and potential partnerships are being developed. With the increased interest and support for renewable energy, it is anticipated that developers will begin to offer more projects to EKPC.

Renewable Energy RFP summary

- Received 22 Bids
- Types of Offers Received
  - 1 Biodiesel
  - 4 Biomass
  - 1 Hydro
  - 2 MSW
  - 5 Solar
  - 1 Waste Heat
  - 8 Wind
- 14 Projects in Kentucky
- One wind project in KY
- Seven wind projects out of state
- Hydro a combination of dams in IL / WV / PA
- Continue working with viable offers
  - Continue working with wood fuel suppliers for potential biomass generation at Cooper Station and Spurlock Station. Trying to set up test burn at Cooper Station.
  - Enter into site study with a wind developer in Kentucky.
- Continue looking for alternatives
  - Some bidders will be back when projects are more fully developed
  - EK receives phone calls weekly relating to its interest in renewables
  - National Renewables Cooperative Organization ("NRCO")

The renewable generation and cost characteristics from the proposals provided information for resource optimization modeling.

Following is a discussion and listing of resource alternatives considered in this integrated resource plan. The following resources in Table 8.(2)(c)- 1 were included in the optimization model for consideration. Please note these resource alternatives reflect only capital costs; O&M costs are not provided in this table.

Table 8.(2)(c)- 1

Resource	**Capacity Type**	**Capacity (MW)**	**Primary Fuel**	Projected Capital Cost (2007$)	
				$/kW	$million
Circulating Fluidized Bed (Future CFB)	Base load	278	Coal	[redacted]	[redacted]
Subcritical Pulverized Coal	Base load	325	Coal	[redacted]	[redacted]
LMS100 CT	Peaking	97	Natural Gas	[redacted]	[redacted]
7EA CT	Peaking	98	Natural Gas	[redacted]	[redacted]
Combined Cycle	Peaking/Intermediate	268	Natural Gas	[redacted]	[redacted]
Unit Power Purchase	Base load	200	Coal	N/A	N/A
Unit Power Purchase	Base load	200	Emission Free	N/A	N/A

Other power supply resources that were considered include supercritical pulverized coal units, hydropower, windpower, and landfill gas to energy projects. EKPC is currently utilizing the circulating fluidized bed technology to take advantage of lower quality, lower cost coals.

EKPC is required by the Rural Utilities Service to undergo an RFP process to evaluate capacity resources to meet future needs. EKPC has used this process successfully for a number of years and plans to continue to use the RFP process. The RFP allows both utility and non-utility generators or developers to propose capacity resources to EKPC of a variety of technologies and quantities of capacity. EKPC will evaluate those proposals as set forth in the RFP. The evaluation is based on economics, reliability, maturity of technology, and risk associated with the proposal.

8.(2)(d) Assessment of nonutility generation, including generating capacity provided by cogeneration, technologies relying on renewable resources, and other nonutility sources.

EKPC will continue to consider non-utility generation on a case by case basis or as part of an RFP process as discussed above in Section 8.(2)(c).

8.(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.

EKPC is not part of a multi-state system nor does it purchase more than fifty (50) percent of its energy needs from another company.

8.(3)(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.

See attached maps at the end of this document.

8.(3)(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;**
2. **Unit number(s);**
3. **Existing or proposed location;**
4. **Status (existing, planned, under construction, etc.);**
5. **Actual or projected commercial operation date;**
6. **Type of facility;**
7. **Net dependable capability, summer and winter;**
8. **Entitlement if jointly owned or unit purchase;**
9. **Primary and secondary fuel types, by unit;**
10. **Fuel storage capacity;**
11. **Scheduled upgrades, deratings, and retirement dates;**

See Table 8.(3)(b)11-1 through Table 8.(3)(b)11-7 in Section 8 Supporting Documentation on pages 8-100 through 8-106 for information regarding Section 8.(3)(b)1-11.

8.(3)(b) continued

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;
b. Anticipated annual average heat rate;
c. Costs of fuel(s) per millions of British thermal units (MMBtu);
d. Estimate of capital costs for planned units (total and per kilowatt of rated capacity);
e. Variable and fixed operating and maintenance costs;
f. Capital and operating and maintenance cost escalation factors;
g. Projected average variable and total electricity production costs (in cents per kilowatt-hour).

See Table 8.(3)(b)12-1 through Table 8.(3)(b)12-14 in Section 8 Supporting Documentation on pages 8-107 through 8-119 for information regarding question 8.(3)(b)1-12.

8.(3)(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.

See Table 8.(3)(c)- 1 in the Supporting Documentation of Section 8 on page 8-119.

8.(3)(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.

Two of Spurlock Station's generating units feature circulating fluidized bed technology that allow them to burn a wide range of fuels, including switchgrass. EKPC is part of a four-year project with the University of Kentucky's College of Agriculture and local farms to study using switchgrass, which is native to Kentucky, as fuel for its power plants. In December 2008, EKPC mixed about 70 tons of processed switchgrass into the coal feedstock of the first clean-coal unit built at Spurlock Station. EKPC's proposed Smith CFB #1 unit at Smith Station in Clark County also is planned to feature this technology.

Additional non-utility generation projections are shown in Table 8.(3)(d)-1 in the Supporting Documentation of Section 8 on page 8-120.

8.(3)(e) For each existing and new conservation and load management or other demand-side programs included in the plan:

This 2009 IRP includes eleven Existing DSM programs and twenty-three New DSM programs.

DSM program design and implementation are complex and dynamic undertakings. It is possible that DSM programs that are selected through this evaluation process may not be implemented as they have been described in this document. DSM programs that are ultimately launched will first be subjected to a much more rigorous program design effort. In certain cases, a demonstration or pilot project may precede full-scale implementation to test the validity of the program concept. This could mean that certain program concepts are modified.

8.(3)(e)(1). Targeted classes and end-uses;

The following tables provide the targeted classes and end-uses for the Existing and New DSM programs included in the plan. More detailed program descriptions can be found in Exhibits DSM-8 and DSM-9 in report titled *Demand-Side Management Analysis*, which can be found in the Technical Appendix.

Table 8.(3)(e)(1)- 1
Existing Programs

Program Name	Class	**End-uses**
Electric Thermal Storage	Residential	**Space Heating**
Electric Water Heater	Residential	**Water Heating**
Geothermal Heating & Cooling	Residential	**Space Heating, Space Cooling, Water Heating**
Air Source Heat Pump	Residential	**Space Heating, Space Cooling**
Tune-Up HVAC Maintenance	Residential	**Space Heating, Space Cooling**
Button-Up Weatherization	Residential	**Space Heating, Space Cooling**
Touchstone Energy ("TSE") Home	Residential	**Space Heating, Space Cooling, Water Heating**
TSE Manufactured Home	Residential	**Space Heating, Space Cooling**
Compact Fluorescent Lighting	Residential	**Lighting**
Gallatin Steel Interruptible	Industrial	**Various**
Other Interruptible	**Industrial**	**Various**

Table 8.(3)(e)(1)- 2
New Programs

Program Name	Class	End-uses
Direct Load Control for Air Conditioners and Water Heaters	Residential	**Space Cooling, Water Heating**
Residential Efficient Lighting	Residential	**Lighting**
ENERGY STAR® Clothes Washer	Residential	**Clothes Washing, Clothes Drying, Water Heating**
ENERGY STAR® Room Air Conditioner	Residential	**Space Cooling**
ENERGY STAR® Refrigerator	Residential	**Refrigeration**
Programmable Thermostat with Electric Furnace Retrofit	Residential	**Space Heating, Space Cooling**
Enhanced TSE Home	Residential	**Space Heating, Space Cooling, Water Heating**
Replace Furnace with Heat Pump	Residential	**Space Heating, Space Cooling**
Low Income Weatherization	Residential	**Space Heating, Space Cooling, Water Heating, Lighting**
Home Performance with ENERGY STAR®	Residential	**Space Heating, Space Cooling**
Mobile Home Retrofit	Residential	**Space Heating, Space Cooling, Water Heating, Lighting, Refrigeration**
ENERGY STAR® Central Air Conditioner	Residential	**Space Cooling**
DLC for Pool Pumps	Residential	**Pool Pumping**
C&I Demand Response	Commercial	**Various**
Commercial Efficient HVAC	Commercial	**Space Cooling, Space Heating**
Commercial Building Performance	Commercial	**Space Cooling, Space Heating, Ventilation**
Commercial New Construction	Commercial	**Lighting, Space Cooling, Space Heating**
Commercial Efficient Refrigeration	Commercial	**Refrigeration**
DLC Commercial Central Air	Commercial	**Space Cooling**
Commercial Advanced Lighting	Commercial	**Lighting**
Industrial Premium Motors	Industrial	**Drive Power**
Industrial Variable Speed Drives	Industrial	**Drive Power**
Compressed Air	**Industrial**	**Compressed Air**

8.(3)(e)(2). Expected duration of the program;

The following tables provide the expected duration of the program. For each existing program, the lifetime of the measure savings is given. For each new program, the number of years that new participants are served is given as well as the lifetime of the measure savings:

Table 8.(3)(e)(2)- 1
Existing Programs - Duration

Program Name	**Savings Lifetime**
Electric Thermal Storage	**20 years**
Electric Water Heater	**12 years**
Geothermal Heating & Cooling	**20 years**
Air Source Heat Pump	**20 years**
Tune-Up HVAC Maintenance	**12 years**
Button-Up Weatherization	**15 years**
Touchstone Energy ("TSE") Home	**20 years**
TSE Manufactured Home	**20 years**
Compact Fluorescent Lighting	**7 years**
Gallatin Steel Interruptible	**20 years**
Other Interruptible	**20 years**

Table 8.(3)(e)(2)- 2
New Programs - Duration

Program Name	New Participants	**Savings Lifetime**
Direct Load Control for Air Conditioners and Water Heaters	5 years	**20 years**
Residential Efficient Lighting	10 years	**7 years**
ENERGY STAR® Clothes Washer	10 years	**12 years**
ENERGY STAR® Room Air Conditioner	10 years	**15 years**
ENERGY STAR® Refrigerator	10 years	**15 years**
Programmable Thermostat with Electric Furnace Retrofit	10 years	**11 years**
Enhanced TSE Home	10 years	**20 years**
Replace Furnace with Heat Pump	10 years	**20 years**
Low Income Weatherization	10 years	**15 years**
Home Performance with ENERGY STAR®	15 years	**12 years**
Mobile Home Retrofit	15 years	**12 years**
ENERGY STAR® Central Air Conditioner	10 years	**15 years**
DLC for Pool Pumps	5 years	**20 years**
C&I Demand Response	3 years	**20 years**
Commercial Efficient HVAC	10 years	**15 years**
Commercial Building Performance	10 years	**7 years**
Commercial New Construction	10 years	**20 years**
Commercial Efficient Refrigeration	10 years	**10 years**
DLC Commercial Central Air	5 years	**20 years**
Commercial Advanced Lighting	10 years	**10 years**
Industrial Premium Motors	10 years	**15 years**
Industrial Variable Speed Drives	10 years	**15 years**
Compressed Air	**10 years**	**7 years**

8.(3)(e)(3). Projected energy changes by season, and summer and winter peak demand changes;

Load changes for the Existing programs have been accounted for in the Load Forecast.

The following tables provide the projected annual energy, summer peak demand and winter peak demand changes for each Existing DSM program (pages 8-21 through 8-31) and New DSM program (pages 8-32 through 8-43) included in the plan:

Load Impacts of DSM Programs

Existing Programs:

Electric Thermal Storage Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
1998	4,252	27,334	-15.4	**0.0**
1999	4,688	30,135	-17.0	**0.0**
2000	5,229	33,618	-19.0	**0.0**
2001	5,558	35,738	-20.2	**0.0**
2002	5,792	37,241	-21.0	**0.0**
2003	5,997	38,565	-21.8	**0.0**
2004	6,129	39,413	-22.2	**0.0**
2005	6,373	40,981	-23.1	**0.0**
2006	6,498	41,791	-23.6	**0.0**
2007	6,616	42,549	-24.0	**0.0**
2008	6,735	43,320	-24.4	**0.0**
2009	6,855	43,402	-25.3	**0.0**
2010	6,855	43,402	-25.3	**0.0**
2011	6,855	43,402	-25.3	**0.0**
2012	6,855	43,402	-25.3	**0.0**
2013	6,855	43,402	-25.3	**0.0**
2014	6,855	43,402	-25.3	**0.0**
2015	6,855	43,402	-25.3	**0.0**
2016	6,855	43,402	-25.3	**0.0**
2017	6,855	43,402	-25.3	**0.0**
2018	6,855	43,402	-25.3	**0.0**
2019	6,855	43,402	-25.3	**0.0**
2020	6,855	43,402	-25.3	**0.0**
2021	6,855	43,402	-25.3	**0.0**
2022	6,855	43,402	-25.3	**0.0**
2023	6,855	43,402	-25.3	**0.0**
2024	**6,855**	**43,402**	**-25.3**	**0.0**

Electric Water Heater Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
1998	3,359	200	0.0	**0.0**
1999	4,308	258	0.1	**0.0**
2000	5,096	307	0.1	**0.0**
2001	5,852	353	0.1	**0.0**
2002	6,735	406	0.1	**0.0**
2003	7,611	460	0.1	**0.0**
2004	8,297	502	0.1	**0.0**
2005	8,975	544	0.1	**0.0**
2006	9,519	550	0.1	**0.0**
2007	9,933	547	0.1	**0.0**
2008	9,950	512	0.1	**0.0**
2009	10,000	591	0.1	**0.1**
2010	10,000	591	0.1	**0.1**
2011	10,000	591	0.1	**0.1**
2012	10,000	591	0.1	**0.1**
2013	10,000	591	0.1	**0.1**
2014	10,000	591	0.1	**0.1**
2015	10,000	591	0.1	**0.1**
2016	10,000	591	0.1	**0.1**
2017	10,000	591	0.1	**0.1**
2018	10,000	591	0.1	**0.1**
2019	10,000	591	0.1	**0.1**
2020	10,000	591	0.1	**0.1**
2021	10,000	591	0.1	**0.1**
2022	10,000	591	0.1	**0.1**
2023	10,000	591	0.1	**0.1**
2024	**10,000**	**591**	**0.1**	**0.1**

Geothermal Heating & Cooling Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
1998	2,287	-4,884	-9.9	**-2.1**
1999	2,684	-5,732	-11.7	**-2.5**
2000	3,045	-6,503	-13.2	**-2.8**
2001	3,417	-7,297	-14.8	**-3.2**
2002	3,724	-7,953	-16.2	**-3.5**
2003	3,914	-8,359	-17.0	**-3.6**
2004	4,071	-8,694	-17.7	**-3.8**
2005	4,215	-9,002	-18.3	**-3.9**
2006	4,353	-9,296	-18.9	**-4.0**
2007	4,499	-9,608	-19.5	**-4.2**
2008	4,544	-9,704	-19.7	**-4.2**
2009	4,544	-9,704	-19.7	**-4.2**
2010	4,544	-9,704	-19.7	**-4.2**
2011	4,544	-9,704	-19.7	**-4.2**
2012	4,544	-9,704	-19.7	**-4.2**
2013	4,544	-9,704	-19.7	**-4.2**
2014	4,544	-9,704	-19.7	**-4.2**
2015	4,544	-9,704	-19.7	**-4.2**
2016	4,544	-9,704	-19.7	**-4.2**
2017	4,544	-9,704	-19.7	**-4.2**
2018	4,544	-9,704	-19.7	**-4.2**
2019	4,544	-9,704	-19.7	**-4.2**
2020	4,544	-9,704	-19.7	**-4.2**
2021	4,544	-9,704	-19.7	**-4.2**
2022	4,544	-9,704	-19.7	**-4.2**
2023	4,544	-9,704	-19.7	**-4.2**
2024	**4,544**	**-9,704**	**-19.7**	**-4.2**

Air Source Heat Pump Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
1998	296	272	0.7	**-0.1**
1999	640	586	1.6	**-0.2**
2000	1,029	943	2.6	**-0.3**
2001	1,499	1,371	3.7	**-0.4**
2002	2,069	1,892	5.1	**-0.6**
2003	2,715	2,482	6.7	**-0.8**
2004	3,531	3,227	8.8	**-1.0**
2005	4,046	3,699	10.1	**-1.1**
2006	4,690	4,287	11.7	**-1.4**
2007	5,071	4,633	12.6	**-1.4**
2008	5,414	4,947	13.4	**-1.5**
2009	5,414	4,947	13.4	**-1.5**
2010	5,414	4,947	13.4	**-1.5**
2011	5,414	4,947	13.4	**-1.5**
2012	5,414	4,947	13.4	**-1.5**
2013	5,414	4,947	13.4	**-1.5**
2014	5,414	4,947	13.4	**-1.5**
2015	5,414	4,947	13.4	**-1.5**
2016	5,414	4,947	13.4	**-1.5**
2017	5,414	4,947	13.4	**-1.5**
2018	5,414	4,947	13.4	**-1.5**
2019	5,414	4,947	13.4	**-1.5**
2020	5,414	4,947	13.4	**-1.5**
2021	5,414	4,947	13.4	**-1.5**
2022	5,414	4,947	13.4	**-1.5**
2023	5,414	4,947	13.4	**-1.5**
2024	**5,414**	**4,947**	**13.4**	**-1.5**

Tune-Up HVAC Maintenance Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
1998	2,341	-3,455	-2.6	**-1.0**
1999	2,455	-3,623	-2.8	**-1.1**
2000	2,584	-3,814	-2.9	**-1.1**
2001	2,686	-3,964	-3.0	**-1.2**
2002	2,860	-4,221	-3.2	**-1.2**
2003	3,198	-4,720	-3.6	**-1.4**
2004	3,706	-5,470	-4.2	**-1.6**
2005	4,037	-5,958	-4.5	**-1.8**
2006	4,373	-6,447	-4.9	**-1.9**
2007	4,598	-6,057	-4.6	**-1.8**
2008	4,687	-4,810	-3.7	**-1.4**
2009	5,037	-4,382	-3.3	**-1.3**
2010	5,037	-4,382	-3.3	**-1.3**
2011	5,037	-4,382	-3.3	**-1.3**
2012	5,037	-4,382	-3.3	**-1.3**
2013	5,037	-4,382	-3.3	**-1.3**
2014	5,037	-4,382	-3.3	**-1.3**
2015	5,037	-4,382	-3.3	**-1.3**
2016	5,037	-4,382	-3.3	**-1.3**
2017	5,037	-4,382	-3.3	**-1.3**
2018	5,037	-4,382	-3.3	**-1.3**
2019	5,037	-4,382	-3.3	**-1.3**
2020	5,037	-4,382	-3.3	**-1.3**
2021	5,037	-4,382	-3.3	**-1.3**
2022	5,037	-4,382	-3.3	**-1.3**
2023	5,037	-4,382	-3.3	**-1.3**
2024	**5,037**	**-4,382**	**-3.3**	**-1.3**

Button-Up Weatherization Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
1998	4,210	-11,029	-8.4	**-3.3**
1999	4,691	-12,289	-9.3	**-3.6**
2000	5,218	-13,670	-10.4	**-4.0**
2001	5,696	-14,922	-11.3	**-4.4**
2002	6,174	-16,174	-12.3	**-4.8**
2003	6,670	-17,474	-13.3	**-5.2**
2004	7,167	-18,776	-14.3	**-5.5**
2005	7,585	-19,871	-15.1	**-5.9**
2006	8,131	-21,301	-16.2	**-6.3**
2007	8,617	-22,574	-17.1	**-6.7**
2008	9,093	-23,821	-18.1	**-7.0**
2009	9,593	-23,504	-17.9	**-6.9**
2010	9,593	-23,504	-17.9	**-6.9**
2011	9,593	-23,504	-17.9	**-6.9**
2012	9,593	-23,504	-17.9	**-6.9**
2013	9,593	-23,504	-17.9	**-6.9**
2014	9,593	-23,504	-17.9	**-6.9**
2015	9,593	-23,504	-17.9	**-6.9**
2016	9,593	-23,504	-17.9	**-6.9**
2017	9,593	-23,504	-17.9	**-6.9**
2018	9,593	-23,504	-17.9	**-6.9**
2019	9,593	-23,504	-17.9	**-6.9**
2020	9,593	-23,504	-17.9	**-6.9**
2021	9,593	-23,504	-17.9	**-6.9**
2022	9,593	-23,504	-17.9	**-6.9**
2023	9,593	-23,504	-17.9	**-6.9**
2024	**9,593**	**-23,504**	**-17.9**	**-6.9**

Touchstone Energy Home

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
1998	0	0	0.0	**0.0**
1999	0	0	0.0	**0.0**
2000	0	0	0.0	**0.0**
2001	0	0	0.0	**0.0**
2002	0	0	0.0	**0.0**
2003	0	0	0.0	**0.0**
2004	44	-139	-0.1	**0.0**
2005	176	-553	-0.6	**-0.1**
2006	352	-1,103	-1.1	**-0.3**
2007	466	-1,462	-1.5	**-0.4**
2008	571	-1,790	-1.8	**-0.5**
2009	611	-2,004	-2.2	**-0.5**
2010	611	-2,004	-2.2	**-0.5**
2011	611	-2,004	-2.2	**-0.5**
2012	611	-2,004	-2.2	**-0.5**
2013	611	-2,004	-2.2	**-0.5**
2014	611	-2,004	-2.2	**-0.5**
2015	611	-2,004	-2.2	**-0.5**
2016	611	-2,004	-2.2	**-0.5**
2017	611	-2,004	-2.2	**-0.5**
2018	611	-2,004	-2.2	**-0.5**
2019	611	-2,004	-2.2	**-0.5**
2020	611	-2,004	-2.2	**-0.5**
2021	611	-2,004	-2.2	**-0.5**
2022	611	-2,004	-2.2	**-0.5**
2023	611	-2,004	-2.2	**-0.5**
2024	**611**	**-2,004**	**-2.2**	**-0.5**

Touchstone Energy Manufactured Home

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
1998	0	0	0.0	**0.0**
1999	0	0	0.0	**0.0**
2000	0	0	0.0	**0.0**
2001	0	0	0.0	**0.0**
2002	0	0	0.0	**0.0**
2003	1	-6	0.0	**0.0**
2004	7	-39	0.0	**0.0**
2005	11	-62	0.0	**0.0**
2006	12	-67	0.0	**0.0**
2007	13	-73	0.0	**0.0**
2008	13	-73	0.0	**0.0**
2009	23	-129	-0.1	**0.0**
2010	23	-129	-0.1	**0.0**
2011	23	-129	-0.1	**0.0**
2012	23	-129	-0.1	**0.0**
2013	23	-129	-0.1	**0.0**
2014	23	-129	-0.1	**0.0**
2015	23	-129	-0.1	**0.0**
2016	23	-129	-0.1	**0.0**
2017	23	-129	-0.1	**0.0**
2018	23	-129	-0.1	**0.0**
2019	23	-129	-0.1	**0.0**
2020	23	-129	-0.1	**0.0**
2021	23	-129	-0.1	**0.0**
2022	23	-129	-0.1	**0.0**
2023	23	-129	-0.1	**0.0**
2024	**23**	**-129**	**-0.1**	**0.0**

Compact Fluorescent Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
1998	0	0	0.0	**0.0**
1999	0	0	0.0	**0.0**
2000	0	0	0.0	**0.0**
2001	0	0	0.0	**0.0**
2002	37,700	-3,698	-0.6	**-0.4**
2003	75,400	-7,395	-1.2	**-0.8**
2004	113,100	-11,093	-1.7	**-1.2**
2005	150,800	-14,790	-2.3	**-1.7**
2006	188,500	-18,488	-2.9	**-2.1**
2007	226,200	-22,186	-3.5	**-2.5**
2008	263,900	-25,883	-4.1	**-2.9**
2009	263,900	-25,883	-4.1	**-2.9**
2010	263,900	-25,883	-4.1	**-2.9**
2011	263,900	-25,883	-4.1	**-2.9**
2012	263,900	-25,883	-4.1	**-2.9**
2013	263,900	-25,883	-4.1	**-2.9**
2014	263,900	-25,883	-4.1	**-2.9**
2015	263,900	-25,883	-4.1	**-2.9**
2016	263,900	-25,883	-4.1	**-2.9**
2017	263,900	-25,883	-4.1	**-2.9**
2018	263,900	-25,883	-4.1	**-2.9**
2019	263,900	-25,883	-4.1	**-2.9**
2020	263,900	-25,883	-4.1	**-2.9**
2021	263,900	-25,883	-4.1	**-2.9**
2022	263,900	-25,883	-4.1	**-2.9**
2023	263,900	-25,883	-4.1	**-2.9**
2024	**263,900**	**-25,883**	**-4.1**	**-2.9**

Gallatin Steel Interruptible

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
1998	1	0	-93.0	**-4.0**
1999	1	0	-108.0	**-4.0**
2000	1	0	-12.0	**-86.0**
2001	1	0	-27.0	**-116.0**
2002	1	0	-129.0	**-119.0**
2003	1	0	-109.0	**-125.0**
2004	1	0	-97.0	**-97.0**
2005	1	0	-97.0	**0.0**
2006	1	0	-107.0	**-136.0**
2007	1	0	-83.0	**-127.0**
2008	1	0	-127.0	**-120.0**
2009	1	0	-120.0	**-120.0**
2010	1	0	-120.0	**-120.0**
2011	1	0	-120.0	**-120.0**
2012	1	0	-120.0	**-120.0**
2013	1	0	-120.0	**-120.0**
2014	1	0	-120.0	**-120.0**
2015	1	0	-120.0	**-120.0**
2016	1	0	-120.0	**-120.0**
2017	1	0	-120.0	**-120.0**
2018	1	0	-120.0	**-120.0**
2019	1	0	-120.0	**-120.0**
2020	1	0	-120.0	**-120.0**
2021	1	0	-120.0	**-120.0**
2022	1	0	-120.0	**-120.0**
2023	1	0	-120.0	**-120.0**
2024	**1**	**0**	**-120.0**	**-120.0**

Interruptible Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
1998		0	-14.0	**-17.0**
1999		0	-17.0	**-12.0**
2000		0	-17.0	**-23.0**
2001		0	-17.0	**-23.0**
2002		0	-17.0	**-23.0**
2003		0	-24.0	**-26.0**
2004		0	-26.0	**-7.0**
2005		0	-7.0	**-10.0**
2006		0	-15.0	**-8.0**
2007		0	-8.0	**-8.0**
2008	4	0	-8.0	**-8.0**
2009	4	0	-8.0	**-8.0**
2010	4	0	-8.0	**-8.0**
2011	4	0	-8.0	**-8.0**
2012	4	0	-8.0	**-8.0**
2013	4	0	-8.0	**-8.0**
2014	4	0	-8.0	**-8.0**
2015	4	0	-8.0	**-8.0**
2016	4	0	-8.0	**-8.0**
2017	4	0	-8.0	**-8.0**
2018	4	0	-8.0	**-8.0**
2019	4	0	-8.0	**-8.0**
2020	4	0	-8.0	**-8.0**
2021	4	0	-8.0	**-8.0**
2022	4	0	-8.0	**-8.0**
2023	4	0	-8.0	**-8.0**
2024	**4**	**0**	**-8.0**	**-8.0**

New Programs:
Direct Load Control for Air Conditioners and Water Heaters

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2009	9,000	-1,713	-3.1	-11.9
2010	18,000	-3,426	-6.1	-23.7
2011	27,000	-5,140	-9.2	-35.6
2012	36,000	-6,853	-12.2	-47.5
2013	45,000	-8,567	-15.3	-59.3
2014	45,000	-8,567	-15.3	-59.3
2015	45,000	-8,567	-15.3	-59.3
2016	45,000	-8,567	-15.3	-59.3
2017	45,000	-8,567	-15.3	-59.3
2018	45,000	-8,567	-15.3	-59.3
2019	45,000	-8,567	-15.3	-59.3
2020	45,000	-8,567	-15.3	-59.3
2021	45,000	-8,567	-15.3	-59.3
2022	45,000	-8,567	-15.3	-59.3
2023	45,000	-8,567	-15.3	-59.3
2024	45,000	-8,567	-15.3	-59.3

Residential Efficient Lighting

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2009	200,000	-19,616	-3.1	-2.2
2010	400,000	-39,232	-6.1	-4.4
2011	600,000	-58,848	-9.2	-6.6
2012	800,000	-78,464	-12.3	-8.8
2013	1,000,000	-98,080	-15.4	-11.0
2014	1,200,000	-117,696	-18.4	-13.2
2015	1,400,000	-137,312	-21.5	-15.4
2016	1,600,000	-137,312	-21.5	-15.4
2017	1,800,000	-137,312	-21.5	-15.4
2018	2,000,000	-137,312	-21.5	-15.4
2019	2,000,000	-117,696	-18.4	-13.2
2020	2,000,000	-98,080	-15.4	-11.0
2021	2,000,000	-78,464	-12.3	-8.8
2022	2,000,000	-58,848	-9.2	-6.6
2023	2,000,000	-39,232	-6.1	-4.4
2024	2,000,000	-19,616	-3.1	-2.2

ENERGY STAR® Clothes Washer

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2009	1,750	-667	-0.1	**-0.1**
2010	3,500	-1,335	-0.3	**-0.1**
2011	5,250	-2,002	-0.4	**-0.2**
2012	7,000	-2,670	-0.6	**-0.3**
2013	8,750	-3,337	-0.7	**-0.3**
2014	10,500	-4,005	-0.8	**-0.4**
2015	12,250	-4,672	-1.0	**-0.5**
2016	14,000	-5,340	-1.1	**-0.5**
2017	15,750	-6,007	-1.2	**-0.6**
2018	17,500	-6,675	-1.4	**-0.7**
2019	17,500	-6,675	-1.4	**-0.7**
2020	17,500	-6,675	-1.4	**-0.7**
2021	17,500	-6,007	-1.2	**-0.6**
2022	17,500	-5,340	-1.1	**-0.5**
2023	17,500	-4,672	-1.0	**-0.5**
2024	**17,500**	**-4,005**	**-0.8**	**-0.1**

ENERGY STAR® Room Air Conditioner

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2009	1,200	-131	0.0	**-0.2**
2010	2,400	-262	0.0	**-0.3**
2011	3,600	-392	0.0	**-0.5**
2012	4,800	-523	0.0	**-0.7**
2013	6,000	-654	0.0	**-0.8**
2014	7,200	-785	0.0	**-1.0**
2015	8,400	-915	0.0	**-1.2**
2016	9,600	-1,046	0.0	**-1.3**
2017	10,800	-1,177	0.0	**-1.5**
2018	12,000	-1,308	0.0	**-1.7**
2019	12,000	-1,308	0.0	**-1.7**
2020	12,000	-1,308	0.0	**-1.7**
2021	12,000	-1,308	0.0	**-1.7**
2022	12,000	-1,308	0.0	**-1.7**
2023	12,000	-1,308	0.0	**-1.7**
2024	**12,000**	**-1,177**	**0.0**	**-1.5**

ENERGY STAR® Refrigerator

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2009	3,670	-360	0.0	**-0.1**
2010	7,340	-719	-0.1	**-0.1**
2011	11,010	-1,079	-0.1	**-0.2**
2012	14,680	-1,439	-0.1	**-0.2**
2013	18,350	-1,798	-0.2	**-0.3**
2014	22,020	-2,158	-0.2	**-0.3**
2015	25,690	-2,517	-0.2	**-0.4**
2016	29,360	-2,877	-0.3	**-0.4**
2017	33,030	-3,237	-0.3	**-0.5**
2018	36,700	-3,596	-0.3	**-0.5**
2019	36,700	-3,596	-0.3	**-0.5**
2020	36,700	-3,596	-0.3	**-0.5**
2021	36,700	-3,596	-0.3	**-0.5**
2022	36,700	-3,596	-0.3	**-0.5**
2023	36,700	-3,596	-0.3	**-0.5**
2024	**36,700**	**-3,237**	**-0.3**	**-0.5**

Programmable Thermostat with Electric Furnace Retrofit

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2009	1,100	-973	0.0	**-0.2**
2010	2,200	-1,945	0.0	**-0.4**
2011	3,300	-2,918	0.0	**-0.6**
2012	4,400	-3,890	0.0	**-0.7**
2013	5,500	-4,863	0.0	**-0.9**
2014	6,600	-5,835	0.0	**-1.1**
2015	7,700	-6,808	0.0	**-1.3**
2016	8,800	-7,780	0.0	**-1.5**
2017	9,900	-8,753	0.0	**-1.7**
2018	11,000	-9,725	0.0	**-1.9**
2019	11,000	-9,725	0.0	**-1.9**
2020	11,000	-8,753	0.0	**-1.7**
2021	11,000	-7,780	0.0	**-1.5**
2022	11,000	-6,808	0.0	**-1.3**
2023	11,000	-5,835	0.0	**-1.1**
2024	**11,000**	**-4,863**	**0.0**	**-0.9**

Enhanced Touchstone Energy Home

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2009	1,000	-2,798	-2.6	**-0.7**
2010	2,000	-5,595	-5.3	**-1.4**
2011	3,000	-8,393	-7.9	**-2.2**
2012	4,000	-11,190	-10.6	**-2.9**
2013	5,000	-13,988	-13.2	**-3.6**
2014	6,000	-16,785	-15.9	**-4.3**
2015	7,000	-19,583	-18.5	**-5.0**
2016	8,000	-22,380	-21.2	**-5.7**
2017	9,000	-25,178	-23.8	**-6.5**
2018	10,000	-27,975	-26.5	**-7.2**
2019	10,000	-27,975	-26.5	**-7.2**
2020	10,000	-27,975	-26.5	**-7.2**
2021	10,000	-27,975	-26.5	**-7.2**
2022	10,000	-27,975	-26.5	**-7.2**
2023	10,000	-27,975	-26.5	**-7.2**
2024	**10,000**	**-27,975**	**-26.5**	**-7.2**

Replace Furnace with Heat Pump

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2009	250	-1,928	0.0	**0.0**
2010	500	-3,856	0.0	**-0.1**
2011	750	-5,784	0.0	**-0.1**
2012	1,000	-7,712	0.0	**-0.2**
2013	1,250	-9,640	0.0	**-0.2**
2014	1,500	-11,568	0.0	**-0.3**
2015	1,750	-13,496	0.0	**-0.3**
2016	2,000	-15,424	0.0	**-0.4**
2017	2,250	-17,352	0.0	**-0.4**
2018	2,500	-19,279	0.0	**-0.5**
2019	2,500	-19,279	0.0	**-0.5**
2020	2,500	-19,279	0.0	**-0.5**
2021	2,500	-19,279	0.0	**-0.5**
2022	2,500	-19,279	0.0	**-0.5**
2023	2,500	-19,279	0.0	**-0.5**
2024	**2,500**	**-19,279**	**0.0**	**-0.5**

Low Income Weatherization

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2009	1,088	-3,557	-2.7	**-1.1**
2010	2,176	-7,114	-5.4	**-2.1**
2011	3,264	-10,671	-8.1	**-3.2**
2012	4,352	-14,228	-10.8	**-4.2**
2013	5,440	-17,785	-13.5	**-5.3**
2014	6,528	-21,342	-16.2	**-6.3**
2015	7,616	-24,899	-18.9	**-7.4**
2016	8,704	-28,456	-21.6	**-8.4**
2017	9,792	-32,013	-24.3	**-9.5**
2018	10,880	-35,570	-27.0	**-10.5**
2019	10,880	-35,570	-27.0	**-10.5**
2020	10,880	-35,570	-27.0	**-10.5**
2021	10,880	-35,570	-27.0	**-10.5**
2022	10,880	-35,570	-27.0	**-10.5**
2023	10,880	-35,570	-27.0	**-10.5**
2024	**10,880**	**-32,013**	**-24.3**	**-9.5**

Home Performance with ENERGY STAR®

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2009	1,700	-4,522	-3.7	**-1.0**
2010	3,400	-9,045	-7.3	**-2.1**
2011	5,100	-13,567	-11.0	**-3.1**
2012	6,800	-18,090	-14.7	**-4.2**
2013	8,500	-22,612	-18.4	**-5.2**
2014	10,200	-27,135	-22.0	**-6.3**
2015	11,900	-31,657	-25.7	**-7.3**
2016	13,600	-36,180	-29.4	**-8.3**
2017	15,300	-40,702	-33.0	**-9.4**
2018	17,000	-45,225	-36.7	**-10.4**
2019	18,700	-49,747	-40.4	**-11.5**
2020	20,400	-54,269	-44.0	**-12.5**
2021	22,100	-54,269	-44.0	**-12.5**
2022	23,800	-54,269	-44.0	**-12.5**
2023	25,500	-54,269	-44.0	**-12.5**
2024	**25,500**	**-49,747**	**-40.4**	**-11.5**

Mobile Home Retrofit

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2009	500	-1,730	-0.9	**-0.3**
2010	1,000	-3,461	-1.8	**-0.5**
2011	1,500	-5,191	-2.7	**-0.8**
2012	2,000	-6,921	-3.6	**-1.0**
2013	2,500	-8,652	-4.4	**-1.3**
2014	3,000	-10,382	-5.3	**-1.5**
2015	3,500	-12,112	-6.2	**-1.8**
2016	4,000	-13,843	-7.1	**-2.0**
2017	4,500	-15,573	-8.0	**-2.3**
2018	5,000	-17,303	-8.9	**-2.5**
2019	5,500	-19,034	-9.8	**-2.8**
2020	6,000	-20,764	-10.6	**-3.0**
2021	6,500	-20,764	-10.6	**-3.0**
2022	7,000	-20,764	-10.6	**-3.0**
2023	7,500	-20,764	-10.6	**-3.0**
2024	**7,500**	**-19,034**	**-9.8**	**-2.8**

ENERGY STAR® Central Air Conditioner

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2009	1,900	-1,095	0.0	**-1.1**
2010	3,800	-2,191	0.0	**-2.2**
2011	5,700	-3,286	0.0	**-3.3**
2012	7,600	-4,381	0.0	**-4.3**
2013	9,500	-5,477	0.0	**-5.4**
2014	11,400	-6,572	0.0	**-6.5**
2015	13,300	-7,667	0.0	**-7.6**
2016	15,200	-8,763	0.0	**-8.7**
2017	17,100	-9,858	0.0	**-9.8**
2018	19,000	-10,953	0.0	**-10.9**
2019	19,000	-10,953	0.0	**-10.9**
2020	19,000	-10,953	0.0	**-10.9**
2021	19,000	-10,953	0.0	**-10.9**
2022	19,000	-10,953	0.0	**-10.9**
2023	19,000	-10,953	0.0	**-10.9**
2024	**19,000**	**-9,858**	**0.0**	**-9.8**

Direct Load Control for Pool Pumps

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2009	1,500	-12	0.0	**-1.0**
2010	3,000	-25	0.0	**-2.0**
2011	4,500	-37	0.0	**-2.9**
2012	6,000	-49	0.0	**-3.9**
2013	7,500	-61	0.0	**-4.9**
2014	7,500	-61	0.0	**-4.9**
2015	7,500	-61	0.0	**-4.9**
2016	7,500	-61	0.0	**-4.9**
2017	7,500	-61	0.0	**-4.9**
2018	7,500	-61	0.0	**-4.9**
2019	7,500	-61	0.0	**-4.9**
2020	7,500	-61	0.0	**-4.9**
2021	7,500	-61	0.0	**-4.9**
2022	7,500	-61	0.0	**-4.9**
2023	7,500	-61	0.0	**-4.9**
2024	**7,500**	**-61**	**0.0**	**-4.9**

Commercial & Industrial Demand Response

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2009	150	-1,716	-6.0	**-6.0**
2010	350	-4,005	-13.9	**-13.9**
2011	500	-5,721	-19.9	**-19.9**
2012	500	-5,721	-19.9	**-19.9**
2013	500	-5,721	-19.9	**-19.9**
2014	500	-5,721	-19.9	**-19.9**
2015	500	-5,721	-19.9	**-19.9**
2016	500	-5,721	-19.9	**-19.9**
2017	500	-5,721	-19.9	**-19.9**
2018	500	-5,721	-19.9	**-19.9**
2019	500	-5,721	-19.9	**-19.9**
2020	500	-5,721	-19.9	**-19.9**
2021	500	-5,721	-19.9	**-19.9**
2022	500	-5,721	-19.9	**-19.9**
2023	500	-5,721	-19.9	**-19.9**
2024	**500**	**-5,721**	**-19.9**	**-19.9**

Commercial Efficient HVAC

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2009	300	-455	0.0	**-0.1**
2010	600	-911	-0.1	**-0.3**
2011	900	-1,366	-0.1	**-0.4**
2012	1,200	-1,822	-0.2	**-0.6**
2013	1,500	-2,277	-0.2	**-0.7**
2014	1,800	-2,733	-0.3	**-0.9**
2015	2,100	-3,188	-0.3	**-1.0**
2016	2,400	-3,643	-0.4	**-1.2**
2017	2,700	-4,099	-0.4	**-1.3**
2018	3,000	-4,554	-0.4	**-1.5**
2019	3,000	-4,554	-0.4	**-1.5**
2020	3,000	-4,554	-0.4	**-1.5**
2021	3,000	-4,554	-0.4	**-1.5**
2022	3,000	-4,554	-0.4	**-1.5**
2023	3,000	-4,554	-0.4	**-1.5**
2024	**3,000**	**-4,099**	**-0.4**	**-1.3**

Commercial Building Performance

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2009	425	-1,424	-0.3	**-0.3**
2010	850	-2,848	-0.6	**-0.6**
2011	1,275	-4,273	-0.9	**-0.9**
2012	1,700	-5,697	-1.1	**-1.2**
2013	2,125	-7,121	-1.4	**-1.5**
2014	2,550	-8,545	-1.7	**-1.8**
2015	2,975	-9,969	-2.0	**-2.1**
2016	3,400	-9,969	-2.0	**-2.1**
2017	3,825	-9,969	-2.0	**-2.1**
2018	4,250	-9,969	-2.0	**-2.1**
2019	4,250	-8,545	-1.7	**-1.8**
2020	4,250	-7,121	-1.4	**-1.5**
2021	4,250	-5,697	-1.1	**-1.2**
2022	4,250	-4,273	-0.9	**-0.9**
2023	4,250	-2,848	-0.6	**-0.6**
2024	**4,250**	**-1,424**	**-0.3**	**-0.3**

Commercial New Construction

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2009	140	-1,526	-0.1	**-0.3**
2010	280	-3,051	-0.3	**-0.7**
2011	420	-4,577	-0.4	**-1.0**
2012	560	-6,103	-0.6	**-1.4**
2013	700	-7,628	-0.7	**-1.7**
2014	840	-9,154	-0.9	**-2.1**
2015	980	-10,680	-1.0	**-2.4**
2016	1,120	-12,205	-1.1	**-2.7**
2017	1,260	-13,731	-1.3	**-3.1**
2018	1,400	-15,257	-1.4	**-3.4**
2019	1,400	-15,257	-1.4	**-3.4**
2020	1,400	-15,257	-1.4	**-3.4**
2021	1,400	-15,257	-1.4	**-3.4**
2022	1,400	-15,257	-1.4	**-3.4**
2023	1,400	-15,257	-1.4	**-3.4**
2024	**1,400**	**-15,257**	**-1.4**	**-3.4**

Commercial Efficient Refrigeration

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2009	37	-484	0.0	**-0.1**
2010	74	-968	-0.1	**-0.1**
2011	111	-1,452	-0.1	**-0.2**
2012	148	-1,935	-0.2	**-0.3**
2013	185	-2,419	-0.2	**-0.4**
2014	222	-2,903	-0.3	**-0.4**
2015	259	-3,387	-0.3	**-0.5**
2016	296	-3,871	-0.4	**-0.6**
2017	333	-4,355	-0.4	**-0.6**
2018	370	-4,839	-0.5	**-0.7**
2019	370	-4,355	-0.4	**-0.6**
2020	370	-3,871	-0.4	**-0.6**
2021	370	-3,387	-0.3	**-0.5**
2022	370	-2,903	-0.3	**-0.4**
2023	370	-2,419	-0.2	**-0.4**
2024	**370**	**-1,935**	**-0.2**	**-0.3**

Direct Load Control of Commercial Central Air

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2009	1,200	-39	0.0	**-2.6**
2010	2,400	-79	0.0	**-5.2**
2011	3,600	-118	0.0	**-7.9**
2012	4,800	-158	0.0	**-10.5**
2013	6,000	-197	0.0	**-13.1**
2014	6,000	-197	0.0	**-13.1**
2015	6,000	-197	0.0	**-13.1**
2016	6,000	-197	0.0	**-13.1**
2017	6,000	-197	0.0	**-13.1**
2018	6,000	-197	0.0	**-13.1**
2019	6,000	-197	0.0	**-13.1**
2020	6,000	-197	0.0	**-13.1**
2021	6,000	-197	0.0	**-13.1**
2022	6,000	-197	0.0	**-13.1**
2023	6,000	-197	0.0	**-13.1**
2024	**6,000**	**-197**	**0.0**	**-13.1**

Commercial Advanced Lighting

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2009	600	-3,913	-0.4	**-0.6**
2010	1,200	-7,827	-0.8	**-1.2**
2011	1,800	-11,740	-1.3	**-1.8**
2012	2,400	-15,654	-1.7	**-2.4**
2013	3,000	-19,567	-2.1	**-2.9**
2014	3,600	-23,480	-2.5	**-3.5**
2015	4,200	-27,394	-2.9	**-4.1**
2016	4,800	-31,307	-3.3	**-4.7**
2017	5,400	-35,220	-3.7	**-5.3**
2018	6,000	-39,134	-4.2	**-5.9**
2019	6,000	-35,220	-3.7	**-5.3**
2020	6,000	-31,307	-3.3	**-4.7**
2021	6,000	-27,394	-2.9	**-4.1**
2022	6,000	-23,480	-2.5	**-3.5**
2023	6,000	-19,567	-2.1	**-2.9**
2024	**6,000**	**-15,654**	**-1.7**	**-2.4**

Industrial Premium Motors

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2009	50	-676	-0.1	**-0.1**
2010	100	-1,351	-0.1	**-0.1**
2011	150	-2,027	-0.2	**-0.2**
2012	200	-2,703	-0.2	**-0.3**
2013	250	-3,378	-0.3	**-0.4**
2014	300	-4,054	-0.3	**-0.4**
2015	350	-4,730	-0.4	**-0.5**
2016	400	-5,405	-0.4	**-0.6**
2017	450	-6,081	-0.5	**-0.7**
2018	500	-6,757	-0.5	**-0.7**
2019	500	-6,757	-0.5	**-0.7**
2020	500	-6,757	-0.5	**-0.7**
2021	500	-6,757	-0.5	**-0.7**
2022	500	-6,757	-0.5	**-0.7**
2023	500	-6,757	-0.5	**-0.7**
2024	**500**	**-6,081**	**-0.5**	**-0.7**

Industrial Variable Speed Drives

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2009	35	-3,753	-0.3	**-0.4**
2010	70	-7,506	-0.6	**-0.8**
2011	105	-11,260	-0.9	**-1.2**
2012	140	-15,013	-1.2	**-1.6**
2013	175	-18,766	-1.5	**-2.0**
2014	210	-22,519	-1.8	**-2.4**
2015	245	-26,272	-2.1	**-2.9**
2016	280	-30,026	-2.4	**-3.3**
2017	315	-33,779	-2.7	**-3.7**
2018	350	-37,532	-3.0	**-4.1**
2019	350	-37,532	-3.0	**-4.1**
2020	350	-37,532	-3.0	**-4.1**
2021	350	-37,532	-3.0	**-4.1**
2022	350	-37,532	-3.0	**-4.1**
2023	350	-37,532	-3.0	**-4.1**
2024	**350**	**-33,779**	**-2.7**	**-3.7**

Compressed Air

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2009	7	-1,144	-0.1	**-0.1**
2010	14	-2,289	-0.2	**-0.2**
2011	21	-3,433	-0.3	**-0.4**
2012	28	-4,577	-0.4	**-0.5**
2013	35	-5,721	-0.5	**-0.6**
2014	42	-6,866	-0.5	**-0.7**
2015	49	-8,010	-0.6	**-0.9**
2016	56	-8,010	-0.6	**-0.9**
2017	63	-8,010	-0.6	**-0.9**
2018	70	-8,010	-0.6	**-0.9**
2019	70	-6,866	-0.5	**-0.7**
2020	70	-5,721	-0.5	**-0.6**
2021	70	-4,577	-0.4	**-0.5**
2022	70	-3,433	-0.3	**-0.4**
2023	70	-2,289	-0.2	**-0.2**
2024	**70**	**-1,144**	**-0.1**	**-0.1**

8.(3)(e)(4). Projected cost, including any incentive payments and program administrative costs;

The projected costs for each Existing and New DSM programs are shown below in Table 8.(3)(e)(4)- 1. Cost values are the present value of the future stream of costs for that element. EKPC rebates are paid to the member cooperative distribution systems. Distribution system rebates are paid to program participants. More details on program costs and cost-effectiveness can be found in Exhibits of the report titled *Demand-Side Management Analysis*, which can be found in the Technical Appendix.

Table 8.(3)(e)(4)- 1
Existing and New DSM Program Costs

	Program Costs				
	Present value, 2009 $				
Existing Program	Distribution System Admin	EKPC Admin	Distribution System Rebates	EKPC Rebates	Customer Investment
Electric Thermal Storage	$ 234,277	$ 193,393	$ 496,116	$ -	$ 1,910,964
Electric Water Heater	$ 29,859	$ 7,656	$ 38,281	$ -	$ 47,851
Geothermal Heating & Cooling	$ 66,761	$ 50,760	$ 153,122	$ -	$ 903,420
Air Source Heat Pump	$ 996,825	$ 153,122	$ 1,378,099	$ 689,049	$ 6,014,342
Tune-Up HVAC Maintenance	$ 844,085	$ 29,093	$ 696,705	$ 401,945	$ 803,891
Button-Up Weatherization	$ 650,769	$ 34,452	$ 918,733	$ 1,466,144	$ 2,155,193
TSE Manufactured Home	$ 16,537	$ 26,796	$ 19,140	$ 19,140	$ 91,873
Compact Fluorescent Lighting	$ -	$ 642,194	$ -	$ -	$ -

Please note that the interruptible programs are rate programs and not marketing programs. Their costs are not tracked using the DSM/marketing tracking system and therefore are not reported here. These forward looking costs are not reported for the Touchstone Energy Home because it is replaced in the plan by the Enhanced TSE Home program.

		Program Costs				
		Present value, 2009 $				
New Program		Distribution System Admin	EKPC Admin	Distribution System Rebates	EKPC Rebates	Customer Investment
Direct Load Control for Air Conditioners and Water Heaters		$ -	$ 25,276,435	$ 11,543,099	$ 11,543,099	$ -
Residential Efficient Lighting		$ -	$ 2,808,422	$ -	$ 3,321,402	$ 5,978,524
ENERGY STAR® Clothes Washer		$ 200,973	$ 76,561	$ 669,909	$ 334,955	$ 3,215,564
ENERGY STAR® Room Air Conditioner		$ 137,810	$ 76,561	$ 229,683	$ 114,842	$ 689,049
ENERGY STAR® Refrigerator		$ 280,979	$ 11,682	$ 561,958	$ 280,979	$ 1,010,606
Programmable Thermostat with Electric Furnace Retrofit		$ 126,326	$ 38,281	$ 210,543	$ 105,271	$ 631,629
Enhanced TSE Home		$ 4,322,676	$ 520,368	$ -	$ 4,322,676	$ 10,933,585
Replace Furnace with Heat Pump		$ 470,454	$ 172,626	$ 1,080,669	$ 774,296	$ 6,504,606
Low Income Weatherization		$ 23,550,362	$ 345,342	$ -	$ 17,677,790	$ -
Home Performance with ENERGY STAR®		$ 5,128,056	$ 599,488	$ 13,257,226	$ 13,257,226	$ 20,401,835
Mobile Home Retrofit		$ 1,508,252	$ 559,523	$ 4,201,607	$ 4,201,607	$ 7,180,638
ENERGY STAR® Central Air Conditioner		$ 3,201,428	$ 260,184	$ 1,634,792	$ 3,617,281	$ 3,792,766
DLC for Pool Pumps		$ -	$ 2,401,371	$ 1,990,184	$ 1,990,184	$ -
C&I Demand Response		$ 2,081,904	$ 841,148	$ 7,506,464	$ 7,506,464	$ 5,489,560
Commercial Efficient HVAC		$ 34,452	$ 76,561	$ 803,891	$ 953,185	$ 1,239,798
Commercial Building Performance		$ 1,156,447	$ 186,436	$ 1,977,071	$ 1,869,747	$ 3,945,934
Commercial New Construction		$ 241,677	$ 207,386	$ 3,717,875	$ 4,284,457	$ 7,458,905
Commercial Efficient Refrigeration		$ 70,819	$ 76,561	$ 273,361	$ 821,500	$ 545,306
DLC Commercial Central Air		$ -	$ 3,035,347	$ 2,976,858	$ 2,976,858	$ -
Commercial Advanced Lighting		$ -	$ 1,339,184	$ 1,836,196	$ 4,601,864	$ 7,939,595
Industrial Premium Motors		$ 5,742	$ 76,561	$ 382,805	$ 1,148,416	$ 856,718
Industrial Variable Speed Drives		$ 4,019	$ 76,561	$ 2,636,762	$ 6,699,091	$ 5,386,069
Compressed Air		$ 187,575	$ 229,683	$ 803,891	$ 991,465	$ 1,607,782

8.(3)(e)(5). Projected cost savings, including savings in utility's generation, transmission and distribution costs.

The projected cost savings for each Existing and New DSM programs are shown below in Table 8.(3)(e)(5)- 1. Values shown are the benefits in the Total Resource Cost test. In the case of multi-fuel programs, cost increases are netted against savings. Cost values are the present value of the future stream of costs for that element. More details on program costs and cost-effectiveness can be found in the Exhibits of the report titled *Demand-Side Management Analysis*, which can be found in the Technical Appendix.

Table 8.(3)(e)(5)- 1
Existing and New DSM Program Cost Savings

	Present value, 2009 $
Existing Program	Projected Cost Savings
Electric Thermal Storage	$ 4,889,947
Electric Water Heater	$ 1,012,152
Geothermal Heating & Cooling	$ 3,013,072
Air Source Heat Pump	$ 4,749,728
Tune-Up HVAC Maintenance	$ 4,673,919
Button-Up Weatherization	$ 13,581,869
TSE Manufactured Home	$ 526,551
Compact Fluorescent Lighting	$ 12,700,713

	Present value, 2009 $
New Program	Projected Cost Savings
Direct Load Control for Air Conditioners and Water Heaters	$ 59,253,160
Residential Efficient Lighting	$ 67,377,789
ENERGY STAR® Clothes Washer	$ 6,137,535
ENERGY STAR® Room Air Conditioner	$ 1,549,627
ENERGY STAR® Refrigerator	$ 2,130,074
Programmable Thermostat with Electric Furnace Retrofit	$ 3,959,538
Enhanced TSE Home	$ 32,796,054
Replace Furnace with Heat Pump	$ 11,394,124
Low Income Weatherization	$ 36,882,474
Home Performance with ENERGY STAR®	$ 51,195,116
Mobile Home Retrofit	$ 16,035,543
ENERGY STAR® Central Air Conditioner	$ 12,144,031
DLC for Pool Pumps	$ 3,807,488
C&I Demand Response	$ 30,488,783
Commercial Efficient HVAC	$ 3,272,002
Commercial Building Performance	$ 5,511,330
Commercial New Construction	$ 11,349,222
Commercial Efficient Refrigeration	$ 2,156,547
DLC Commercial Central Air	$ 10,010,934
Commercial Advanced Lighting	$ 19,515,479
Industrial Premium Motors	$ 4,175,664
Industrial Variable Speed Drives	$ 23,155,351
Compressed Air	$ 3,962,654

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:

8.(4)(a) On total resource capacity available at the winter and summer peak:

1. Forecast peak load;

Table 8.(4)(a)- 1
EKPC Projected Capacity Needs (MW)

Year	Projected Peaks		12% Reserves		Total Requirements		Existing Resources		Capacity Needs	
	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum
2009	2,942	2,344	353	281	3,295	2,625	3,130	2,409	165	216
2010	2,983	2,353	358	282	3,341	2,635	2,720	2,509	621	126
2011	3,017	2,375	362	285	3,379	2,660	2,685	2,469	694	191
2012	3,056	2,424	367	291	3,423	2,715	2,675	2,459	748	256
2013	3,107	2,480	373	298	3,480	2,778	2,675	2,459	805	319
2014	3,153	2,520	378	302	3,531	2,822	2,675	2,459	856	363
2015	3,208	2,564	385	308	3,593	2,872	2,675	2,459	918	413
2016	3,260	2,611	391	313	3,651	2,924	2,675	2,459	976	465
2017	3,323	2,663	399	320	3,722	2,983	2,675	2,459	1,047	524
2018	3,377	2,713	405	326	3,782	3,039	2,675	2,459	1,107	580
2019	3,446	2,769	414	332	3,860	3,101	2,675	2,459	1,185	642
2020	3,509	2,821	421	339	3,930	3,160	2,675	2,459	1,255	701
2021	3,593	2,891	431	347	4,024	3,238	2,675	2,459	1,349	779
2022	3,670	2,955	440	355	4,110	3,310	2,675	2,459	1,435	851
2023	3,745	3,014	449	362	4,194	3,376	2,675	2,459	1,519	917

Notes:

1. Existing Resources (as of January 1, 2009) do not include Spurlock 4, Smith CTs 9 and 10, or Smith CFB 1; however includes 170MW from SEPA throughout the period.
2. Greenup Hydro output given credit for providing 35MW winter capacity and 40 MW summer capacity through 2010.
3. The impact of existing DSM programs is included in the load forecast.
4. There is no capacity from non-utility sources.
5. There are currently no planned retirements.

2. Capacity from existing resources before consideration of retirements;
See Table 8.(4)(a)- 1 above.

8.(4) continued

3. **Capacity from planned utility-owned generating plant capacity additions;**
   See Table 8.(4)(a)- 2 below.
4. **Capacity available from firm purchases from other utilities;**
   See Table 8.(4)(a)- 2 below.
5. **Capacity available from firm purchases from nonutility sources of generation;**
   See Table 8.(4)(a)- 2 below.

Table 8.(4)(a)- 2
EKPC Projected Capacity Additions and Reserves (MW)

Year	Other Cap.	Base Load Capacity Additions		Peaking/ Intermediate Cap. Additions		Total Capacity		Reserves		Reserve Margin	
		Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum
2009	2*		268*			3,130	2,679	200	383	6.40%	14.28%
2010	200	268*		194*	166*	3,384	2,945	455	741	13.44%	25.15%
2011						3,349	2,905	368	648	11.00%	22.31%
2012				98	74	3,437	2,969	428	667	12.46%	22.48%
2013						3,437	2,969	365	585	10.61%	19.71%
2014		278*	278*			3,715	3,247	662	936	17.82%	28.84%
2015	50					3,765	3,197	653	789	17.36%	24.68%
2016						3,765	3,197	583	717	15.48%	22.44%
2017	30					3,795	3,227	539	683	14.20%	21.17%
2018						3,795	3,227	470	611	12.37%	18.94%
2019				98	74	3,893	3,301	505	634	12.97%	19.21%
2020				98	74	3,991	3,375	548	663	13.73%	19.63%
2021	200					4,191	3,575	697	846	16.64%	23.65%
2022						4,191	3,575	595	750	14.19%	20.97%
2023		278	278			4,469	3,853	864	1072	19.33%	27.83%

Notes:
*Commited capacity additions.
Other Capacity is composed of the following:
200MW Winter Seasonal Peaking Purchase
50MW Seasonal Energy Purchase/Sale
30MW Biomass PPA
200MW Emission Free PPA

8.(4) continued

6. Reductions or increases in peak demand from new conservation and load management or other demand-side programs;

The following table provides the reductions in peak demand from New DSM programs:

Table 8.(4)(a) 6- 1
Reductions in Peak Demand from New DSM Programs
(negative value = reduction in load)

Year	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2009	-23.5	-30.2
2010	-49.1	-62.4
2011	-72.6	-92.7
2012	-90.2	-116.9
2013	-107.8	-141.2
2014	-122.3	-150.0
2015	-136.8	-158.8
2016	-147.9	-165.1
2017	-159.0	-171.4
2018	-170.1	-177.7
2019	-170.7	-175.8
2020	-171.4	-173.8
2021	-167.3	-170.4
2022	-163.3	-166.9
2023	-159.2	-163.5
2024	-147.5	-155.8

7. **Committed capacity sales to wholesale customers coincident with peak;**
   See Table 8.(4)(a)- 1 on page 8-48.
8. **Planned retirements;**
   There are currently no planned retirements.
9. **Reserve requirements;**
   EKPC uses 12% reserve requirements for planning purposes. See Table 8.(4)(a)- 2 on page 8-49.
10. **Capacity excess or deficit;**
    See Table 8.(4)(a)- 1 on page 8-48.
11. **Capacity or reserve margin.**
    See Table 8.(4)(a)- 2 on page 8-49.

8.(4)(b) On planned annual generation:

> **1. Total forecast firm energy requirements;**
> **2. Energy from existing and planned utility generating resources disaggregated by primary fuel type;**
> **3. Energy from firm purchases from other utilities;**
> **4. Energy from firm purchases from nonutility sources of generation; and**

See Table 8.(4)(b)-1 in the Supporting Documentation of Section 8 on page 8-120 for information regarding Section 8.(4)(b)1-4.

> **5. Reductions or increases in energy from new conservation and load management or other demand-side programs;**

The following table presents the reductions in energy from New DSM programs:

Table 8.4(b)5.- 1
Reductions in Energy from New DSM Programs
(negative value = reduction in load)

Year	Impact on Energy Requirements (MWh)
2009	-54,232
2010	-109,041
2011	-163,275
2012	-215,793
2013	-268,309
2014	-319,063
2015	-369,814
2016	-398,383
2017	-426,952
2018	-455,519
2019	-435,190
2020	-413,888
2021	-385,666
2022	-357,445
2023	-329,222
2024	-284,723

8.(4)(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.

See Table 8.(4)(c)-1 in the Supporting Documentation of Section 8 on page 8-121 for information regarding Section 8.(4)(c).

8.(5) The resource assessment and acquisition plan shall include a description and discussion of:

8.(5)(a) General methodological approach, models, data sets, and information used by the company;

Supply Side Optimization and Modeling

The primary model used in developing the resource plan was RTSim from Simtec, Inc., of Madison, WI. The RTSim production cost model calculates the hour-by-hour operation of the generation system including, unit hourly generation and commitment and power purchases and sales, including economy and day ahead transactions, and daily and monthly options. Generating unit input includes expected, Monte Carlo forced outages, unit ramp rates, and unit startup characteristics. The RTSim model uses a Monte Carlo simulation to capture the statistical variations of unit forced outages and deratings, load uncertainty, market price uncertainty, and fuel price uncertainty. Monte Carlo simulation requires repeated simulations (iterations) of the time period analyzed to simulate system operation under different outcomes of unit forced outages and deratings, load uncertainty, market price uncertainty, and fuel price uncertainty. The production cost model is simulating the actual operation of the power system in supplying the projected customer loads using a statistical range of inputs.

For this study, the model used the statistical load methodology. There is one set of load data in the model, which was created from the EKPC Load Forecast 2008. Around this forecasted load, a range of distributions created four additional loads to define the high and low range of the potential loads to be examined. The model draws load data a few days at a time from the different forecasts (to represent weather patterns) to assemble the hourly loads to be simulated. Each iteration of the model draws a new load forecast to simulate. Actual and forecasted market prices, natural gas prices, coal prices, and emission costs are correlated to the load data used in the simulation. Five hundred (500) iterations are used in the model simulations.

RTSim's Resource Optimizer was used to perform the optimization of the resource plan. The Resource Optimizer automatically sets up and runs the RTSim production cost model to perform simulations of a large number of potential resource plans to determine the optimum plan. Because the basic RTSim model is used by the Resource Optimizer model, the Resource Optimizer uses the same data and detailed analysis that is used in the production cost model simulation, except that future units are set as resource alternatives. Any future resources to be considered by the Resource Optimizer are set up with several potential future commercial operation dates. The annualized fixed costs for capital are included along with the variable costs associated with a particular resource. A minimum and maximum amount of capacity to be added by the model is specified to correspond to a specified reserve margin. The Resource Optimizer can simulate thousands of combinations of potential resources to determine the lowest cost plans. The new resources have to be simulated in operation with the current resources to determine the optimum expansion for the system. The lowest cost plans are determined from the present value of total production cost and annual fixed costs of future alternatives.

The Resource Optimizer constructs expansion plans to meet certain criteria, then simulates each plan and calculates the present value of each plan as compared to doing nothing. Some of the inputs needed by the Resource Optimizer are the minimum and maximum future capacity needs, resource alternatives, the annualized fixed cost of the resource alternatives, and the potential in-service dates for the alternatives. The resource alternatives are modeled with the same detail as the existing and committed units in the model. In development of this IRP, the Resource Optimizer was set to try up to 2500 unique expansion plans, with each of those simulated with 5 iterations. Each iteration varies loads, fuel and market prices, and forced outages. The Resource Optimizer was run for the time period 2012 through 2028. Since EKPC's resource needs through 2011 will be met through capacity additions as a result of RFP No. 2004-01, there was no need to start the optimizer before 2012. The results on page 8-55 include the five lowest cost plans out of 2500 plans simulated. Table 8.(5)(a)- 1 (page 8-54) is a summary of the top five plans, followed by the model output of those plans as shown in Table 8.(5)(a)- 2 on page 8-55.

These five plans were reviewed to determine if the operation dates of the near term resources were in fact achievable based on recent experience. Resources were placed in EKPC's expansion plan spreadsheet based on these plans in order to build up to a 12% reserve margin. The criteria for minimum capacity additions in the model are actually just below 12% to allow some flexibility in timing of units. However, units can be added in some years when only a small amount of capacity was needed. Therefore, shifting of units was made to allow some flexibility in the reserve margin and to eliminate or defer higher cost gas-fired units.

Since market prices and natural gas prices are correlated to the load data, and the load data simulates various weather patterns including periods of high and low loads, the result is a robust simulation of a variety of load and market conditions. Risk analysis is thereby incorporated into the simulation.

Table 8.(5)(a)- 1

Resource Optimizer Plan Summary

Cumulative Min Cap	Incremental Cap	Year	Type	Plan 1	Plan 2	Plan 3	Plan 4	Plan 5	Final Plan*
267	0	2012	Base						
			Interm						
			Pking	98	98	98	98	98	98
327	59	2013	Base						
			Interm						
			Pking						
434	107	2014	Base						
			Interm						
			Pking	98	98		98	98	
600	166	2015	Base						
			Interm						
			Pking			98			
820	220	2016	Base						
			Interm						
			Pking						
1107	287	2017	Base	30	30				30
			Interm						
			Pking						
1450	343	2018	Base			30	30	30	
			Interm						
			Pking						
1866	417	2019	Base						
			Interm						
			Pking					98	98
2349	482	2020	Base						
			Interm						
			Pking	98	196	98	98		98
2920	571	2021	Base	200	200	200		200	200
			Interm						
			Pking						
3571	652	2022	Base				200		
			Interm						
			Pking	98		98	98	98	
4302	731	2023	Base	278		278	278	278	278
			Interm						
			Pking		98				

* All additions in the Final Plan are assumed to go in service in October prior to the year shown.

DSM AFFECTED BASE RESOURCE OPTIMIZATION

Total tries: 2500

Top Cases with specific resource and in-service date

Table 8.(5)(a)- 2

Case 1:		Case 4:	
Seasonal Peaking Purchase	1, 1,2010	Seasonal Peaking Purchase	1, 1,2009
Seasonal Diversity Purchase	1, 1,2015	Seasonal Diversity Sale	1, 1,2014
Seasonal Diversity Sale	1, 1,2015	Seasonal Diversity Purchase	1, 1,2015
Biomass - PPA	1, 1,2017	Biomass - PPA	1, 1,2018
Emission Free PPA	1, 1,2021	Emission Free PPA	1, 1,2022
PEAKING CT	1, 1,2012	PEAKING CT	1, 1,2012
PEAKING CT	1, 1,2014	PEAKING CT	1, 1,2014
PEAKING CT	1, 1,2020	PEAKING CT	1, 1,2020
PEAKING CT	1, 1,2022	PEAKING CT	1, 1,2022
Base load CFB	1, 1,2023	Base load CFB	1, 1,2023
PEAKING CT	1, 1,2026	PEAKING CT	1, 1,2026
PEAKING CT	1, 1,2027	PEAKING CT	1, 1,2027
PEAKING CT	1, 1,2028	PEAKING CT	1, 1,2027
Case 2:		Case 5:	
Seasonal Peaking Purchase	1, 1,2010	Seasonal Peaking Purchase	1, 1,2009
Seasonal Diversity Purchase	1, 1,2015	Seasonal Diversity Sale	1, 1,2015
Seasonal Diversity Sale	1, 1,2015	Seasonal Diversity Purchase	1, 1,2014
Biomass 3 PPA	1, 1,2017	Biomass - PPA	1, 1,2018
Emission Free PPA	1, 1,2021	Emission Free PPA	1, 1,2021
PEAKING CT	1, 1,2012	PEAKING CT	1, 1,2012
PEAKING CT	1, 1,2014	PEAKING CT	1, 1,2014
PEAKING CT	1, 1,2020	PEAKING CT	1, 1,2019
PEAKING CT	1, 1,2020	PEAKING CT	1, 1,2022
PEAKING CT	1, 1,2023	Base load CFB	1, 1,2023
Base load CFB	1, 1,2024	PEAKING CT	1, 1,2024
PEAKING CT	1, 1,2027	PEAKING CT	1, 1,2025
PEAKING CT	1, 1,2028	PEAKING CT	1, 1,2028
Case 3:			
Seasonal Peaking Purchase	1, 1,2012		
Seasonal Diversity Purchase	1, 1,2014		
Seasonal Diversity Sale	1, 1,2015		
Biomass - PPA	1, 1,2018		
Emission Free PPA	1, 1,2021		
PEAKING CT	1, 1,2012		
PEAKING CT	1, 1,2015		
PEAKING CT	1, 1,2020		
PEAKING CT	1, 1,2022		
Base load CFB	1, 1,2023		
PEAKING CT	1, 1,2025		
PEAKING CT	1, 1,2026		
PEAKING CT	1, 1,2028		

Demand-Side Management Resource Screening and Assessment

DSM resources consist of customer energy programs that seek to change the power consumption of customer facilities in a way that meets planning objectives. They include conservation, load management, demand response, and other demand-side programs. EKPC's DSM analysis is conducted on an aggregate basis, with all member cooperatives combined, rather than on an individual cooperative basis. EKPC has used a two-step process to screen and evaluate DSM resources for inclusion in this plan: (1) Qualitative Screening, and (2) Quantitative Evaluation.

The first step, Qualitative Screening, is a qualitative assessment of a large number of potential DSM measures. This set of DSM measures covers all classes and major end-uses, and includes a robust set of available technologies and strategies for producing energy and capacity savings. This list was produced after careful review of several sources, including (1) PSC staff recommendations from the 2006 IRP; (2) feedback from Kentucky Department of Energy, the Attorney General's office, and other relevant state agencies; (3) the current programs and IRPs of other Kentucky utilities; and (4) best practice DSM programs offered by utilities around the country.

In the Qualitative Screening step, each measure is scored against four criteria (see Table 8.(5)(c)- 1 on page 8-58 for a listing of the criteria).

Measures which pass the Qualitative Screening move on to the second step, which is a more rigorous Quantitative Evaluation. Measures are turned into DSM programs. In some cases, measures are combined into one program. The Quantitative Evaluation considers all quantifiable benefits and costs of the program, and scores each program according to standard cost-effectiveness tests.

EKPC uses the EPRI *DSManager* software package to conduct the more detailed quantitative evaluation. *DSManager* calculates the impact of DSM programs on utilities and their customers. *DSManager* produces a quantitative estimate of the costs and benefits for each of the parties using simplified but powerful and flexible models of the electric system and its customers. *DSManager* determines the cost-effectiveness of DSM programs by reporting results according to the cost-benefit tests established in the California Standard Practice Manual for Economic Analysis of Demand Side Programs[1].

DSM programs which pass the Quantitative Evaluation are passed on to the integrated analysis for inclusion in the IRP.

Additional detail on this process is contained in the report titled *Demand-Side Management Analysis*, which can be found in the Technical Appendix.

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[1] California Public Utilities Commission and California Energy Commission, "Standard Practice Manual for Economic Analysis of Demand-Side Management Programs," Document Number P400-87-006, December 1987.

8.(5)(b) Key assumption and judgments used in the assessment and how uncertainties in those assumptions and judgments were incorporated into analyses;

See 8.(5)(a) on page 8-52.

8.(5)(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;

See 8.(5)(a) on page 8-52 for information regarding selection of the supply side resources.

Demand-Side Management Screening

EKPC has used a two-step process to screen and evaluate DSM resources for inclusion in this plan: (1) Qualitative Screening, and (2) Quantitative Evaluation. A detailed report of this DSM analysis titled *Demand-Side Management Analysis* can be found in the Technical Appendix.

The first step is a qualitative assessment of a large number of potential DSM measures. In the Qualitative Screening step, each measure is scored against four criteria. Measures which pass the Qualitative Screening move on to the second step, which is a more rigorous Quantitative Evaluation. Measures are turned into DSM programs. In some cases, measures are combined into one program. The Quantitative Evaluation considers all quantifiable benefits and costs of the program, and scores each program according to standard cost-effectiveness tests. DSM programs which pass the Quantitative Evaluation are passed on to the integrated analysis for inclusion in the IRP.

EKPC developed four criteria it would use to screen DSM measures in the Qualitative Screening step. The four criteria chosen capture the major considerations as to whether a measure is suitable for robust quantitative analysis. The criteria consider the customer, the measure itself, the savings, and the economics. Each potential DSM measure was evaluated based on a scale of 1 to 5 against each of the four criteria.

The four criteria and a description of each are shown as Table 8.(2)(c)- 1 on page 8-58.

Qualitative Screening criteria

Scoring system: 1 – 5 , where 1 means POOR and 5 means EXCELLENT

Table 8.(5)(c)- 1

CRITERIA	COMMENTS/EXAMPLES
1. Customer Acceptance	What will the response of customers be to the offer to participate in the program or to install the measure(s) in their facilities? POOR = measures that reduce the quality of the energy service equipment, are excessively difficult to install, or might interfere with vital activities in the establishment (home, business, industrial plant).
2. Measure Applicability	Have the efficiency gains been superseded by standards or code requirements? Is the measure commercially available today? Measures that are still in the R&D stage or that are no longer manufactured would score low on this criteria. Will the measure save energy or demand in the EKPC climate? Is the measure a good fit for the DSM objectives that EKPC has? Is there a better measure available for the same end-use application? Example: Triple glazed windows versus low e double pane window.
3. Savings Potential	How substantial are the savings likely to be? How measurable or quantifiable are the savings? Is the measure technically reliable such that savings are assured? Is the marketplace capturing the savings already without a utility program? POOR = Savings are small or not easily quantified
4. Cost Effectiveness	Given typical savings, typical measure costs, and a conservative (high) estimate of future avoided energy and capacity costs, how cost effective is this program likely to be using the Total Resource Cost test? POOR = clearly below 1 (say 0.3 on the TRC using a high estimate of future avoided costs) EXCELLENT = clearly above 1 (say 3-5 or higher on the TRC)

DSM measures which received a combined score of 15 or higher were passed on to the next phase, the Quantitative Evaluation Process. EKPC uses the EPRI *DSManager* software package to conduct the more detailed quantitative evaluation. *DSManager* calculates the impact of DSM programs on utilities and their customers. *DSManager* produces a quantitative estimate of the costs and benefits for each of the parties using simplified but powerful and flexible models of the electric system and its customers.

DSManager determines the cost-effectiveness of DSM programs by reporting results according to the cost-benefit tests established in the California Standard Practice Manual for Economic Analysis of Demand Side Programs[2]. EKPC uses these tests to examine cost-effectiveness from three major perspectives: participant cost ("PC"), ratepayer impact measure ("RIM"), and total resource cost ("TRC"). A fourth perspective, the societal cost ("SC"), is treated as a variation on

[2] California Public Utilities Commission and California Energy Commission, "Standard Practice Manual for Economic Analysis of Demand-Side Management Programs," Document Number P400-87-006, December 1987.

the TRC test. The results of each perspective can be expressed in a variety of ways, but in all cases, it is necessary to calculate the net present value of program impacts over the life cycle of those impacts. *DSManager* uses this information to calculate the benefit/cost (b/c) ratio for each of these four tests.

These tests are not intended to be used individually or in isolation. The results of tests that measure efficiency, such as the TRC and the SC, must be compared not only to each other, but also to the RIM test. This multi-perspective approach will require reviewers to consider tradeoffs between the various tests.

EKPC is a full requirements Generation and Transmission provider for its 16 member cooperatives. Each cooperative is an independent not for profit corporation and operates distinct from EKPC. As a result, it is necessary to examine the impacts of DSM programs separately for EKPC and for the typical distribution cooperative. *DSManager* has the functionality to enable the user to separately report the RIM test for EKPC and for the distribution cooperative.

Time is a critical element in DSM analysis. It is important to represent time within a year and over a period of many years. *DSManager* divides the year into seasons and representative days. These days are usually related to weather and to patterns of human activity. EKPC has selected 48 representative days to model the calendar year, four for each month. Each day is modeled using 24 hourly loads. This is true both for the utility system, individual end-uses, and DSM program impacts.

The daytypes are: High Weekday, Medium Weekday, Low Weekday, and Weekend. High, medium, and low refer to the EKPC system loads.

Each of the 25 DSM programs was modeled in detail with *DSManager*. The model includes for each DSM program:

- 48-daytype hourly load profiles for targeted end-uses with and without the proposed program
- Lifetime of the measure savings
- Incremental measure costs (participant costs)
- EKPC and distribution cooperative administrative costs
- Rebates to customers, and from EKPC to the cooperative
- Detailed retail and wholesale rate schedules
- Customer participation levels

In addition to the detailed modeling of the DSM programs, *DSManager* also includes a detailed model of the supply side costs. Major categories of supply side costs that are accounted for by the model include:

- Marginal energy costs (by year, daytype, and hour)
- Marginal generation capacity costs (by category and year, including seasonal allocation)
- Marginal transmission & distribution capacity costs (by year, incl. seasonal allocation)
- Fossil fuel (natural gas & propane) costs (by year)
- Environmental externality costs (costs not internalized in energy or capacity costs; chiefly carbon related)

Factoring Environmental Cost Considerations into DSM Evaluation

EKPC has explicitly factored environmental costs into this evaluation of DSM resources. There are three major categories of environmental cost: (1) the cost of purchasing allowances; (2) the capital costs of compliance at power plants; and (3) externality costs.

EKPC has accounted for all three categories of environmental cost in its DSM evaluation. The following table describes how this was accomplished:

Table 8.(5)(c)- 2
Accounting for Environmental Costs

ENVIRONMENTAL COST	WHERE ACCOUNTED FOR	SPECIFICS
Allowance purchases	Marginal energy costs	SOx and NOx
Capital investments for compliance	Marginal capacity costs	Primarily Scrubbers, SCRs, other controls
Externalities	Externality adder	Used in Societal Cost test; value is set to $40/ton. Value based on estimates for what future allowance prices could be in a marketplace with a cap and trade program for carbon.

8.(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;

EKPC has been using a 12% reserve margin. The reserve margin is the amount of capacity in excess of that required to meet the projected peak load. Reserves are necessary to reduce the risks posed by forced outages, transmission constraints, load forecast deviations or other unforeseen events that can prevent a utility from being able to meet its load requirements. Previous studies indicate this reserve level provides appropriate reliability.

8.(5)(e) Existing and projected research efforts and programs which are directed at developing data for future assessments and refinements of analyses;

The RTSim production cost model and its Resource Optimizer are updated frequently by Simtec, Inc., based on its view of the power industry and how to account for risk and uncertainty, and also based on the needs of the users of the model. RTSim offers a great deal of flexibility in how inputs are modeled and many inputs are distributions of values. The statistical load data and corresponding fuel prices and market prices, and probability distributions for forced outages and other inputs, provide a distribution of possible outcomes rather than just an expected value. EKPC plans to continue to refine and improve its modeling data, fuel market forecasts, and emission market forecasts.

8.(5)(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

This section describes EKPC compliance with the Clean Air Act amendments of 1990 as well as subsequent environmental legislation such as the Clean Air Interstate Rule ("CAIR") and the Clean Air Mercury Rule ("CAMR"). CAIR was issued in 2005 and set new annual reductions of SO2 and NOx emissions. There is a two-phase implementation of the CAIR rules as follows:

NOx Phase I: Begins 1/1/2009
SO2 Phase I: Begins 1/1/2010
NOx Phase II: Begins 1/1/2015
SO2 Phase II: Begins 1/1/2015

EKPC believes that it will be able to meet the CAIR standards. BART ("Best Available Retrofit Technology") modeling has been performed for eligible EKPC units. Results show that EKPC BART eligible units' emissions will be below the BART trigger limits after scrubbers and SCRs are applied.

CAMR was also issued in 2005 and is a two phase reduction in mercury emissions timed as follows:

Phase I: Begins 1/1/2010
Phase II: Begins 1/1/2018

EKPC believes that Phase I mercury reductions will result from adding emission control equipment for NOx and SO2. Implementing Phase II mercury reductions may require new technology. EKPC has a system limit for SO2 and NOx emissions that it must meet.

EKPC is planning with the assumption that regulation of carbon dioxide will become a reality in the near future. EKPC will continue to research carbon dioxide issues and monitor improvements in technology for controlling its production.

The main environmental issues that EKPC faces in the next fifteen years are permitting and installing pollution control devices to control Sulfur Dioxide ('Sox"), Nitrogen Oxide ("NOx") and Particulate Matter Emissions ("PM") to ensure compliance. Furthermore, the Kentucky Division for Air Quality ("KDAQ") has informed all KY utilities that they will be issuing new Mercury (Hg) regulations in the near future. EKPC entered into two Consent Degrees ("CD") with the Environmental Protection Agency to lower emissions on several system coal-fired units.

Sulfur Dioxide

EKPC will install Scrubber technologies on its pulverized coal ("PC") units at Spurlock and Cooper 2 to control SO2 emissions. In addition, EKPC has built and operates two Circulating Fluid Bed ("CFB") units at Spurlock that burn coal in combination with limestone to produce lime (CaO) that reacts with the SO2 created during combustion to reduce SO2 emissions. EKPC's CFB generators are expected to achieve an overall SO2 removal rate of over 99%.

EKPC has or will install and operate two Wet Scrubbers on Spurlock Units 1 and 2. The Scrubber on Unit 2 is operational and meeting a CD mandated 95% SO2 reduction. The new Unit 1 Scrubber will begin operation the spring of 2009, two months earlier than originally scheduled.

Nitrogen Oxide
EKPC is operating Spurlock Unit 1 & 2 Selective Catalytic Reduction ("SCRs") year round. An SCR will be constructed for Cooper Unit 2 in 2012. All CFB units use SNCR for NOx reduction. All EKPC pulverized coal ("PC") units currently use low NOx burners.

Particulate Matter
EKPC will use a combination of Electro-Static Precipitators ("ESP") fabric filter pulse jet baghouses and Wet ESPs ("WESP") to meet current and upcoming regulations.

Spurlock Unit 1 uses a cold side ESP in combination with a WESP to lower Particulate Matter ("PM"). The Unit 1 WESP will begin operation the spring of 2009. Spurlock Unit 2 uses a hot side ESP in combination with an operating WESP. Both Spurlock CFBs use a fabric filter pulse jet baghouses for PM control. The Smith 1 CFB unit will also use a fabric filter pulse jet baghouse. Cooper Unit 2 will add a baghouse in 2012 .

Mercury
EKPC has been informed by the Kentucky Division for Air Quality ("KDAQ") that Mercury regulations are forth coming. For the last few years, EKPC has been testing plant mercury removal rates. In addition, EKPC runs weekly mercury analysis on all plants. The addition of SCRs and scrubbers on four of EKPC's units will remove mercury as a co-benefit.

Consent Decree
In 2007, EKPC entered into two Consent Decrees ("CD") with the Environmental Protection Agency ("EPA"). The first CD involves units at Spurlock, Cooper and Dale Units 3 & 4. The second CD is an Acid Rain issue for Dale Units 1 & 2. The first CD involves the addition of pollution control devices set to timelines, in addition to system wide tonnage caps on SOx and NOx emissions. The acid rain CD involves the addition of pollution control devices for Dale Unit 1 & 2 to meet the acid rain requirements.

8.(5)(g) Consideration given by the utility to market forces and competition in the development of the plan.

EKPC is constantly monitoring fuel and market power prices and analyzing the data. EKPC also monitors various industry publications to see what actions other companies in the power industry are undertaking or considering. In addition EKPC participates in seminars or training opportunities offered by various consultants on current topics. EKPC is a member of the Alliance for Cooperative Energy Services ("ACES") Power Marketing group and Cooperative Research Network ("CRN") and uses them for market intelligence.

Section 8

Supporting Documentation

Table 8.(2)(a)-1

Spurlock

Description	Date
Spurlock Unit No. 4 Construction & Equip. (Completion)	2009
Scrubber - Unit No. 1 (completion)	2009
Construction of Spurlock Construction Road Entrance	2009
Bed and Flyash Silo for Unit No. 4	2009
Replace Units No. 1 and No. 2 Air Dryers	2009
Support Facility - Study	2009
Unit 1 Low NOx Boiler Modifications, including but not limited to:	2009
SP467 - Unit 1 SSH Sootblowers	
SP513 - Replace Unit 1 Waterwalls	
SP525 - Boiler Nose Extension	
SP514 - Replace Unit No. 1 Burners	
Unit 1 Boiler Chemical Clean	2009
Replace Unit No. 1 Feedwater Heaters No. 6 & No. 7	2008-2009
Replace Unit No. 1, 2, & 3 Operator Control Stations	2008-2009
Install Nash Air removal Pump in Unit No. 1	2008-2009
Landfill Expansion	2009
Unit 1 Generator Enhanced SLMS Unit	2009
Emergency Back-up Power	2009
Coal Unloading Bypass Chutes	2009
Replace Reverse Osmosis Membrane	2009
Paint Clarifier	2009
Remote Racking for 4160 Volt Switchgear	2009
Replace Unit 3 SA and PA Dampers	2009
Unit No. 1 - Non-Return Check Valve Upgrade	2009
Unit No. 2 - Non-Return Check Valve Upgrade	2009
Purchase Additional Wheel Unloader	2009
Purchase CAT/JLG Telehandler	2009
HVAC	2009
Elevator and Cranes	2009
Overhaul Four Pulverizers - Unit No. 1	2009
Wireless Network	2009
Rebuild Pulverizer - Unit No. 1	2009
Outage Boiler Inspection - Unit No. 1	2009
Boiler Life Accessment - Unit No. 1	2009
Scaffold Boiler - Unit No. 1	2009
Boiler Feed Pump Overhaul - Unit No. 1	2009
Overhaul B.W.C.P. - Unit No. 2	2009
Pulverizer Maintenance - Unit No. 2	2009
Outage Boiler Inspection - Unit No. 2	2009

Table 8.(2)(a)-2

Spurlock

Description	Date
Outage Boiler Inspection - Unit No. 3	2009
Clean Boiler - Unit No. 3	2009
Clean Boiler - Unit No. 4	2009
Outage - Precipitator Inspection and Repair - Unit No. 1	2009
Outage - Precipitator Inspection and Repair - Unit No. 2	2009
Dredge River	2009
Overhaul Unit 3 Crushers	2009
Ash Haul Road Maintenance (Rock/Stone)	2009
Steel Balls for Limestone Ball Mills - Unit No. 1 Scrubber	2009
Scrubber Contract Maintenance - Unit No. 1 Scrubber	2009
Steel Balls for Limestone Ball Mills - Unit No. 2 Scrubber	2009
Scrubber Contract Maintenance - Unit No. 2 Scrubber	2009
Overhaul (1) Circulating Water Pumps - Unit No. 3	2009
Build Dam C Landfill	2010
Remanufacture/Replacement Coal Scraper	2010
Inspect/Overhaul Turbine Valves Unit No. 3	2010
Paint Elevator Water Storage Tank	2010
Overhaul Unit 1 Boiler Feed Pump	2010
Overhaul Unit 1 Circulating Water Pump	2010
Remote Racking for 480 Volt Switchgear	2010
Remanufacture/Replacement Wheel Unloader	2010
Support Facility	2010
Roof Recoating	2010
Outage Boiler Inspect/Repair - Unit No. 1	2010
Overhaul (4) Pulverizers - Unit No. 1-Completed 2009	2010
Boiler Feed Pump Overhaul - Unit No.1	2010
Scaffold Boiler - Unit No. 1	2010
Overhaul B.W.C.P. - Unit No. 2	2010
Overhaul Pulverizers - Unit No. 2	2010
Outage Boiler Inspcction/Repair - Unit No. 2	2010
Scaffold Boiler - Unit No. 4	2010
Refractory - Unit No. 4	2010
Refractory - Unit No. 3	2010
Outage - Precipitator Inspection and Repairs - Unit No. 1	2010
Outage - Precipitator Inspection and Repairs - Unit No. 2	2010
Dredge River	2010
Overhaul (1) Circulating Water Pumps - Unit No. 3	2010
Purchase Diaphragms for Unit 2 Turbine	2010
Steel Balls for Limestone Ball Mills - Unit 2 Scrubber	2010

Table 8.(2)(a)-3

Spurlock

Description	Date
Steel Balls for Limestone Ball Mills - Unit 1 Scrubber	2010
Replace Unit No. 2 Economizer Inlet Headers	2011-2012
Refractory - Unit No. 4	2011
Outage Boiler Inspection - Unit No. 3	2011
Clean Boiler - Unit No. 3	2011
Scaffold Boiler - Unit No. 3	2011
Refractory - Unit No. 3	2011
Rebag 1/4 of Unit #3 Baghouse	2011
Outage Boiler Inspection - Unit No. 4	2011
Clean Boiler - Unit No. 4	2011
Steel Balls for Limestone Ball Mills - Unit No. 1 Scrubber	2011
Scrubber Ball Mill Reline - Unit No. 1 Scrubber	2011
Overhaul (4) Pulverizers - Unit No. 1	2011
Outage Boiler Inspect/Repair - Unit No. 1	2011
Outage - Precipitator Inspection and Repairs - Unit No. 1	2011
Furnish and Install Unit No. 1 SCR Catalyst	2011
Steel Balls for Limestone Ball Mills - Unit No. 2 Scrubber	2011
Outage Boiler Inspect/Repair - Unit No. 2	2011
Outage - Precipitator Inspection and Repairs - Unit No. 2	2011
Pulverizer Maintenance - Unit No. 2	2011
Overhaul B.W.C.P. - Unit No. 2	2011
Barge Unloader Rebuild	2012
Replace Dozer	2012
Replace Portion DMW's Unit No. 2 Boiler	2012
Replace Hot Reheat Terminal Tubes	2012
Refractory - Unit No. 3	2012
Scaffold Boiler - Unit No. 3	2011
Outage Boiler Inspection - Unit No. 3	2012
Clean Boiler - Unit No. 3	2012
Inspect/Overhaul Unit No. 3 Turbine Valves	2012
Outage Boiler Inspection - Unit No. 4	2012
Clean Boiler - Unit No. 4	2012
Scaffold Boiler - Unit No. 4	2012
Refractory - Unit No. 4	2012
Inspect/Overhaul Unit No. 4 Turbine Valves	2012
Rebag 1/4 of Unit #4 Baghouse	2012
Steel Balls for Limestone Ball Mills - Unit No. 1 Scrubber	2012
Overhaul (4) Pulverizers - Unit No. 1	2012
Outage Boiler Inspect/Repair - Unit No. 1	2012
Outage - Precipitator Inspection and Repairs - Unit No. 1	2012
Inspect/Overhaul Unit No. 1 Turbine Valves	2012
Steel Balls for Limestone Ball Mills - Unit No. 2 Scrubber	2012
Scrubber Ball Mill Reline - Unit No. 2 Scrubber	2012
Outage Boiler Inspect/Repair - Unit No. 2	2012
Outage - Precipitator Inspection and Repairs - Unit No. 2	2012
Pulverizer Maintenance - Unit No. 2	2012

Table 8.(2)(a)-4
Spurlock

Description	Date
Overhaul B.W.C.P. - Unit No. 2	2012
Inspect/Overhaul Unit No. 2 Turbine Valves	2012
Major Overhaul - Unit No. 2	2012
Refractory - Unit No. 4	2013
Outage Boiler Inspection - Unit No. 3	2013
Clean Boiler - Unit No. 3	2013
Refractory - Unit No. 3	2013
Rebag 1/4 of Unit #3 Baghouse	2013
Outage Boiler Inspection - Unit No. 4	2013
Clean Boiler - Unit No. 4	2013
Steel Balls for Limestone Ball Mills - Unit No. 1 Scrubber	2013
Scrubber Ball Mill Reline - Unit No. 1 Scrubber	2013
Overhaul (4) Pulverizers - Unit No. 1	2013
Outage Boiler Inspect/Repair - Unit No. 1	2013
Outage - Precipitator Inspection and Repairs - Unit No. 1	2013
Steel Balls for Limestone Ball Mills - Unit No. 2 Scrubber	2013
Outage Boiler Inspect/Repair - Unit No. 2	2013
Outage - Precipitator Inspection and Repairs - Unit No. 2	2013
Pulverizer Maintenance - Unit No. 2	2013
Overhaul B.W.C.P. - Unit No. 2	2013
Generator Field Rewind - Unit No. 1	2014
Replace Unit No. 1 Condenser	2014
Replace Scraper	2014
Replace Secondary Superheater – Unit No. 1	2014
Replace Unit No. 1 Interm. Reheater	2014
Replace Unit No. 1 Inlet Reheater Lower Loops	2014
Major Ash Bridge Repair	2014
Retube Reboiler - Units No. 1 and No. 2 (Inland)	2014
Clean Boiler - Unit No. 3	2014
Scaffold Boiler - Unit No. 3	2014
Clean Boiler - Unit No. 4	2014
Refractory - Unit No. 4	2014
Rebag 1/4 of Unit #4 Baghouse	2014
Steel Balls for Limestone Ball Mills - Unit No. 1 Scrubber	2014
Overhaul (4) Pulverizers - Unit No. 1	2014
Outage - Precipitator Inspection and Repairs - Unit No. 1	2014
Turbine Overhaul - Unit No. 1	2014
Furnish and Install Unit No. 1 SCR Catalyst	2014
Steel Balls for Limestone Ball Mills - Unit No. 2 Scrubber	2014
Scrubber Ball Mill Reline - Unit No. 2 Scrubber	2014
Outage - Precipitator Inspection and Repairs - Unit No. 2	2014
Pulverizer Maintenance - Unit No. 2	2014
Overhaul B.W.C.P. - Unit No. 2	2014
Clean Boiler - Unit No. 3	2015
Refractory - Unit No. 3	2015
Inspect/Overhaul Unit No. 3 Turbine Valves	2015
Rebag 1/4 of Unit #3 Baghouse	2015

Table 8.(2)(a)-5
Spurlock

Description	Date
Clean Boiler - Unit No. 4	2015
Scaffold Boiler - Unit No. 4	2015
Inspect/Overhaul Unit No. 4 Turbine Valves	2015
Steel Balls for Limestone Ball Mills - Unit No. 1 Scrubber	2015
Scrubber Ball Mill Reline - Unit No. 1 Scrubber	2015
Overhaul (4) Pulverizers - Unit No. 1	2015
Outage - Precipitator Inspection and Repairs - Unit No. 1	2015
Inspect/Overhaul Unit No. 1 Turbine Valves	2015
Steel Balls for Limestone Ball Mills - Unit No. 2 Scrubber	2015
Outage - Precipitator Inspection and Repairs - Unit No. 2	2015
Pulverizer Maintenance - Unit No. 2	2015
Inspect/Overhaul Unit No. 2 Turbine Valves	2015
Clean Boiler - Unit No. 3	2016
Major Overhaul - Unit No. 3 Turbine Generator	2016
Clean Boiler - Unit No. 4	2016
Refractory - Unit No. 4	2016
Rebag 1/4 of Unit #4 Baghouse	2016
Steel Balls for Limestone Ball Mills - Unit No. 1 Scrubber	2016
Overhaul (4) Pulverizers - Unit No. 1	2016
Outage - Precipitator Inspection and Repairs - Unit No. 1	2016
Steel Balls for Limestone Ball Mills - Unit No. 2 Scrubber	2016
Scrubber Ball Mill Reline - Unit No. 2 Scrubber	2016
Outage - Precipitator Inspection and Repairs - Unit No. 2	2016
Pulverizer Maintenance - Unit No. 2	2016
Overhaul B.W.C.P. - Unit No. 2	2016
Clean Boiler - Unit No. 3	2017
Scaffold Boiler - Unit No. 3	2017
Refractory - Unit No. 3	2017
Rebag 1/4 of Unit #3 Baghouse	2017
Clean Boiler - Unit No. 4	2017
Steel Balls for Limestone Ball Mills - Unit No. 1 Scrubber	2017
Scrubber Ball Mill Reline - Unit No. 1 Scrubber	2017
Overhaul (4) Pulverizers - Unit No. 1	2017
Outage - Precipitator Inspection and Repairs - Unit No. 1	2017
Furnish and Install Unit No. 1 SCR Catalyst	2017
Steel Balls for Limestone Ball Mills - Unit No. 2 Scrubber	2017
Outage - Precipitator Inspection and Repairs - Unit No. 2	2017
Pulverizer Maintenance - Unit No. 2	2017
Overhaul B.W.C.P. - Unit No. 2	2017
Furnish and Install Unit No. 2 SCR Catalyst	2017
Clean Boiler - Unit No. 3	2018
Inspect/Overhaul Unit No. 3 Turbine Valves	2018
Clean Boiler - Unit No. 4	2018
Scaffold Boiler - Unit No. 4	2018
Refractory - Unit No. 4	2018
Major Overhaul - Unit No. 4 Turbine Generator	2018
Inspect/Overhaul Unit No. 4 Turbine Valves	2018

Table 8.(2)(a)-6
Spurlock

Description	Date
Rebag 1/4 of Unit #4 Baghouse	2018
Steel Balls for Limestone Ball Mills - Unit No. 1 Scrubber	2018
Overhaul (4) Pulverizers - Unit No. 1	2018
Outage - Precipitator Inspection and Repairs - Unit No. 1	2018
Inspect/Overhaul Unit No. 1 Turbine Valves	2018
Steel Balls for Limestone Ball Mills - Unit No. 2 Scrubber	2018
Scrubber Ball Mill Reline - Unit No. 2 Scrubber	2018
Outage - Precipitator Inspection and Repairs - Unit No. 2	2018
Pulverizer Maintenance - Unit No. 2	2018
Overhaul B.W.C.P. - Unit No. 2	2018
Inspect/Overhaul Unit No. 2 Turbine Valves	2018
Major Overhaul - Unit No. 1	2018
Clean Boiler - Unit No. 3	2019
Refractory - Unit No. 3	2019
Rebag 1/4 of Unit #3 Baghouse	2019
Clean Boiler - Unit No. 4	2019
Steel Balls for Limestone Ball Mills - Unit No. 1 Scrubber	2019
Scrubber Ball Mill Reline - Unit No. 1 Scrubber	2019
Overhaul (4) Pulverizers - Unit No. 1	2019
Outage - Precipitator Inspection and Repairs - Unit No. 1	2019
Steel Balls for Limestone Ball Mills - Unit No. 2 Scrubber	2019
Outage - Precipitator Inspection and Repairs - Unit No. 2	2019
Pulverizer Maintenance - Unit No. 2	2019
Overhaul B.W.C.P. - Unit No. 2	2019
Clean Boiler - Unit No. 3	2020
Scaffold Boiler - Unit No. 3	2020
Clean Boiler - Unit No. 4	2020
Refractory - Unit No. 4	2020
Rebag 1/4 of Unit #4 Baghouse	2020
Steel Balls for Limestone Ball Mills - Unit No. 1 Scrubber	2020
Overhaul (4) Pulverizers - Unit No. 1	2020
Outage - Precipitator Inspection and Repairs - Unit No. 1	2020
Steel Balls for Limestone Ball Mills - Unit No. 2 Scrubber	2020
Scrubber Ball Mill Reline - Unit No. 2 Scrubber	2020
Outage - Precipitator Inspection and Repairs - Unit No. 2	2020
Pulverizer Maintenance - Unit No. 2	2020
Clean Boiler - Unit No. 3	2021
Refractory - Unit No. 3	2021
Inspect/Overhaul Unit No. 3 Turbine Valves	2021
Rebag 1/4 of Unit #3 Baghouse	2021
Clean Boiler - Unit No. 4	2021
Scaffold Boiler - Unit No. 4	2021
Inspect/Overhaul Unit No. 4 Turbine Valves	2021
Steel Balls for Limestone Ball Mills - Unit No. 1 Scrubber	2021
Scrubber Ball Mill Reline - Unit No. 1 Scrubber	2021
Overhaul (4) Pulverizers - Unit No. 1	2021
Outage - Precipitator Inspection and Repairs - Unit No. 1	2021
Inspect/Overhaul Unit No. 1 Turbine Valves	2021

Table 8.(2)(a)- 7

Spurlock

Description	Date
Furnish and Install Unit No. 1 SCR Catalyst	2021
Steel Balls for Limestone Ball Mills - Unit No. 2 Scrubber	2021
Outage - Precipitator Inspection and Repairs - Unit No. 2	2021
Pulverizer Maintenance - Unit No. 2	2021
Overhaul B.W.C.P. - Unit No. 2	2021
Inspect/Overhaul Unit No. 2 Turbine Valves	2021
Clean Boiler - Unit No. 3	2022
Clean Boiler - Unit No. 4	2022
Refractory - Unit No. 4	2022
Rebag 1/4 of Unit #4 Baghouse	2022
Steel Balls for Limestone Ball Mills - Unit No. 1 Scrubber	2022
Overhaul (4) Pulverizers - Unit No. 1	2022
Outage - Precipitator Inspection and Repairs - Unit No. 1	2022
Steel Balls for Limestone Ball Mills - Unit No. 2 Scrubber	2022
Scrubber Ball Mill Reline - Unit No. 2 Scrubber	2022
Outage - Precipitator Inspection and Repairs - Unit No. 2	2022
Pulverizer Maintenance - Unit No. 2	2022
Overhaul B.W.C.P. - Unit No. 2	2022
Clean Boiler - Unit No. 3	2023
Scaffold Boiler - Unit No. 3	2023
Refractory - Unit No. 3	2023
Rebag 1/4 of Unit #3 Baghouse	2023
Clean Boiler - Unit No. 4	2023
Steel Balls for Limestone Ball Mills - Unit No. 1 Scrubber	2023
Scrubber Ball Mill Reline - Unit No. 1 Scrubber	2023
Overhaul (4) Pulverizers - Unit No. 1	2023
Outage - Precipitator Inspection and Repairs - Unit No. 1	2023
Steel Balls for Limestone Ball Mills - Unit No. 2 Scrubber	2023
Outage - Precipitator Inspection and Repairs - Unit No. 2	2023
Pulverizer Maintenance - Unit No. 2	2023
Overhaul B.W.C.P. - Unit No. 2	2023
Clean Boiler - Unit No. 3	2024
Inspect/Overhaul Unit No. 3 Turbine Valves	2024
Clean Boiler - Unit No. 4	2024
Scaffold Boiler - Unit No. 4	2024
Refractory - Unit No. 4	2024
Inspect/Overhaul Unit No. 4 Turbine Valves	2024
Rebag 1/4 of Unit #4 Baghouse	2024
Steel Balls for Limestone Ball Mills - Unit No. 1 Scrubber	2024
Overhaul (4) Pulverizers - Unit No. 1	2024
Outage - Precipitator Inspection and Repairs - Unit No. 1	2024
Inspect/Overhaul Unit No. 1 Turbine Valves	2024
Turbine Overhaul - Unit No. 1	2024
Furnish and Install Unit No. 1 SCR Catalyst	2024
Steel Balls for Limestone Ball Mills - Unit No. 2 Scrubber	2024
Scrubber Ball Mill Reline - Unit No. 2 Scrubber	2024
Outage - Precipitator Inspection and Repairs - Unit No. 2	2024
Pulverizer Maintenance - Unit No. 2	2024

Table 8.(2)(a)-8
Spurlock

Description	Date
Overhaul B.W.C.P. - Unit No. 2	2024
Inspect/Overhaul Unit No. 2 Turbine Valves	2024
Furnish and Install Unit No. 2 SCR Catalyst	2024
Clean Boiler - Unit No. 3	2025
Refractory - Unit No. 3	2025
Rebag 1/4 of Unit #3 Baghouse	2025
Clean Boiler - Unit No. 4	2025
Steel Balls for Limestone Ball Mills - Unit No. 1 Scrubber	2025
Scrubber Ball Mill Reline - Unit No. 1 Scrubber	2025
Overhaul (4) Pulverizers - Unit No. 1	2025
Outage - Precipitator Inspection and Repairs - Unit No. 1	2025
Steel Balls for Limestone Ball Mills - Unit No. 2 Scrubber	2025
Outage - Precipitator Inspection and Repairs - Unit No. 2	2025
Pulverizer Maintenance - Unit No. 2	2025
Clean Boiler - Unit No. 3	2026
Scaffold Boiler - Unit No. 3	2026
Major Overhaul - Unit No. 3 Turbine Generator	2026
Clean Boiler - Unit No. 4	2026
Refractory - Unit No. 4	2026
Rebag 1/4 of Unit #4 Baghouse	2026
Steel Balls for Limestone Ball Mills - Unit No. 1 Scrubber	2026
Overhaul (4) Pulverizers - Unit No. 1	2026
Outage - Precipitator Inspection and Repairs - Unit No. 1	2026
Steel Balls for Limestone Ball Mills - Unit No. 2 Scrubber	2026
Scrubber Ball Mill Reline - Unit No. 2 Scrubber	2026
Outage - Precipitator Inspection and Repairs - Unit No. 2	2026
Pulverizer Maintenance - Unit No. 2	2026
Overhaul B.W.C.P. - Unit No. 2	2026
Clean Boiler - Unit No. 3	2027
Refractory - Unit No. 3	2027
Inspect/Overhaul Unit No. 3 Turbine Valves	2027
Rebag 1/4 of Unit #3 Baghouse	2027
Clean Boiler - Unit No. 4	2027
Scaffold Boiler - Unit No. 4	2027
Inspect/Overhaul Unit No. 4 Turbine Valves	2027
Steel Balls for Limestone Ball Mills - Unit No. 1 Scrubber	2027
Scrubber Ball Mill Reline - Unit No. 1 Scrubber	2027
Overhaul (4) Pulverizers - Unit No. 1	2027
Outage - Precipitator Inspection and Repairs - Unit No. 1	2027
Inspect/Overhaul Unit No. 1 Turbine Valves	2027
Furnish and Install Unit No. 1 SCR Catalyst	2027
Steel Balls for Limestone Ball Mills - Unit No. 2 Scrubber	2027
Outage - Precipitator Inspection and Repairs - Unit No. 2	2027
Pulverizer Maintenance - Unit No. 2	2027
Overhaul B.W.C.P. - Unit No. 2	2027
Inspect/Overhaul Unit No. 2 Turbine Valves	2027
Clean Boiler - Unit No. 3	2028
Clean Boiler - Unit No. 4	2028

Table 8.(2)(a)-9

Spurlock

Description	Date
Refractory - Unit No. 4	2028
Major Overhaul - Unit No. 4 Turbine Generator	2028
Rebag 1/4 of Unit #4 Baghouse	2028
Steel Balls for Limestone Ball Mills - Unit No. 1 Scrubber	2028
Overhaul (4) Pulverizers - Unit No. 1	2028
Outage - Precipitator Inspection and Repairs - Unit No. 1	2028
Steel Balls for Limestone Ball Mills - Unit No. 2 Scrubber	2028
Scrubber Ball Mill Reline - Unit No. 2 Scrubber	2028
Outage - Precipitator Inspection and Repairs - Unit No. 2	2028
Pulverizer Maintenance - Unit No. 2	2028
Overhaul B.W.C.P. - Unit No. 2	2028
Major Overhaul - Unit No. 2	2028
Clean Boiler - Unit No. 3	2029
Scaffold Boiler - Unit No. 3	2029
Refractory - Unit No. 3	2029
Rebag 1/4 of Unit #3 Baghouse	2029
Clean Boiler - Unit No. 4	2029
Steel Balls for Limestone Ball Mills - Unit No. 1 Scrubber	2029
Scrubber Ball Mill Reline - Unit No. 1 Scrubber	2029
Overhaul (4) Pulverizers - Unit No. 1	2029
Outage - Precipitator Inspection and Repairs - Unit No. 1	2029
Steel Balls for Limestone Ball Mills - Unit No. 2 Scrubber	2029
Outage - Precipitator Inspection and Repairs - Unit No. 2	2029
Pulverizer Maintenance - Unit No. 2	2029
Overhaul B.W.C.P. - Unit No. 2	2029

Table 8.(2)(a)-10

Cooper

Description	Date
Turbine Overhaul - Unit No. 1	2009
Replace Reheat Superheater Tubes-Unit No. 1-Installation	2009
No. 2 Feedwater Heater - Unit No. 1	2009
Cooper Retrofit Project - Unit No. 2	2009
Replace Waterwall Tubes - Unit No. 1	2009
High Energy Piping and Testing - Unit No. 1	2009
Rebuild Submerged Chain - Unit No. 1	2009
Acid Clean - Unit No. 2	2009
Purchase Critical Spare CW Pump Motor Drive-Unit No. 2	2009
Replace Service Supply Line to Flyash Silo Structure ($74,000)&Replace Boster Pump Header Unit 2 ($173,000)	2009
Replace Dynamic Classifiers with High Spin Stationary on Unit No. 2 and PA Curve Vertification	2009
Install Sequence of Event Equipment (SOE) for Unit 1 & 2	2009
Install Runoff Pond Irrigation Pump, Headers, and Heads	2009
Purchase Critical Spare Condensate Pump Motor - Unit 2	2009
Outage for Unit No. 1	2009
Outage for Unit No. 2	2009
Additional Oil Coolers	2009
Inspect and Test Hi-Voltage Breakers Starters, Motor Control Center (Outage)	2009
Rebuild 1A Hyd. Turbine/Pump	2009
Paint Siding and Roffing of Structure	2009
Time Driven Unit No. 1 Major Maintenance Inspection	2009
Time Driven Unit No. 1 Major Maintenance Inspection Brush Assembly	2009
Cooper Retrofit Project - Unit No. 2	2010
Scaffold for Unit No. 2 Boiler ($250,000) and Test ($25,000)	2010
Remanufacturer/Replacement Wheel Loader	2010
Critical Spare - CW Pump Motor for Unit No. 1	2010
Cooper Unit 1 - Addition of SCR, Dry CFB FGD, and Baghouse	2010
Cooper Retrofit Project - Unit No. 2	2011
Cooper Unit 1 - Addition of SCR, Dry CFB FGD, and Baghouse	2011
Replace Submerged Drag Chain Units No. 1 and No. 2	2012
Cooper Retrofit Project - Unit No. 2	2012
Cooper Unit 1 - Addition of SCR, Dry CFB FGD, and Baghouse	2012
Major Overhaul - Unit No. 2	2012
Upgrade Unit No. 1 Mark V/EX2000 Controls	2012
High Energy Piping and Testing - Unit No. 2	2012
Rebuld Submerged Chain Housing - Unit No. 2	2012
Replace Primary Superheat Panels - Unit No. 2	2012
Replace Reheat Panels - Unit No. 2	2012
Replace Economizer - Unit No. 2	2012
Overhaul Unit No. 2 Condensate Pumps	2012

Table 8.(2)(a)-11

Cooper

Description	Date
Replace Kamatsu Loader	2012
Cooper Unit 1 - Addition of SCR, Dry CFB FGD, and Baghouse	2013
Replace Submerged Drag Chain Units No. 1 and No. 2	2014
Replace Switchgear – Unit No. 2	2014
High Energy Piping and Testing - Unit No. 2	2014
Replace Primary Superheater - Unit No. 1	2014
Turbine Valve Outage - Unit No. 1	2014
High Energy Hanger and Piping Testing - Unit No. 1	2014
Cooper Unit 1 - Addition of SCR, Dry CFB FGD, and Baghouse	2014
Secondary Superheat - Unit No. 1	2015
Rebuild Circulating Water Pump - Unit No. 1	2015
Condenser Tubes - Unit No. 1	2015
Replace Unit No. 1 Mechanical Dust Collectors	2015
Replace Submerged Drag Chains – Units No. 1 and No. 2	2016
High Energy Piping and Testing - Unit No. 2	2017
Turbine Valve Outage - Unit No. 2	2017
Scaffold for Unit No. 1 Boiler	2017
High Energy Hanger and Piping Testing - Unit No. 1	2018
Replace Submerged Drag Chains – Units No. 1 and No. 2	2018
Rebuild Circulating Water Pump - Unit No. 2	2019
Major Overhaul - Unit No. 1	2019
High Energy Piping and Testing - Unit No. 1	2019
Replace Submerged Drag Chain - Units No. 1 & No. 2	2020
Scaffold Unit No. 2 Boiler	2020
Rebuild Circulating Water Pump - Unit No. 1	2020
Replace Submerged Drag Chain - Units No. 1 and No. 2	2022
High Energy Piping and Testing - Unit No. 2	2022
Major Overhaul - Unit No. 2	2022
Hydraulic Turbine - Unit No. 1	2023
Replace Submerged Drag Chain - Units No. 1 and No. 2	2024
Hydraulic Turbine Unit No. 2	2024
High Energy Piping and Testing - Unit No. 1	2024
Turbine Valve Outage - Unit No. 1	2024
Rebuild Circulating Water Pump - Unit No. 2	2025
Replace Submerged Drag Chain - Units No. 1 and No. 2	2026
Low Pressure Feedwater Heater	2027
Turbine Valve Outage - Unit No. 2	2027
High Energy Piping and Testing - Unit No. 2	2027
Scaffold - Unit No. 1 Boiler	2027
Replace Submerged Drag Chain - Units No. 1 and No. 2	2028

Table 8.(2)(a)-12

Dale

Description	Date
Major Overhauls - Units No. 1 and No. 2 (Scheduled for 2008 but moved to 2009.)	2009
Inspect/Rebuild Control Valves Unit No. 4	2009
Clean No. 4 Ash Pond	2009
Repair River Bank at No. 4 Ash Pond	2009
Acid Clean - Unit No. 3 Boiler	2009
Rebuild Unit 1 and Unit 3B Circulating Water Pumps	2009
Install Additional Sootblowers Units 1 and 2 Boilers	2009
New Wheel Loader for Blending of Fuel	2009
Backup Diesel Generator	2009
Purchase Skytrack	2009
Clean No. 4 Ash Pond, Completion	2010
Valve and Bearing Inspection - Unit No. 3 Turbine	2010
Automated Coal Tripper Car	2010
Inspect/Rebuild Control Valves Units No. 1 and No. 2	2011
Clean No. 2 Ash Pond	2011
Clean No. 2 Ash Pond, Completion	2012
Inspect/Rebuild Control Valves Unit No. 4	2012
Inspect/Rebuild Control Valves Units No. 1 and No. 2	2012
Acid Clean - Unit No. 4 Boiler	2013
Inspect/Rebuild Control Valves Unit No. 3	2013
Clean No. 4 Ash Pond	2013
Econ. & Pri. Superheater Upgrade - Unit No. 4	2014
Clean No. 4 Ash Pond, Completion	2014
Clean No. 2 Ash Pond	2015
Retube Condensers - Units No. 1 and No. 2	2015
Inspect/Rebuild Control Valves Units No. 1 and No. 2	2015
Major Overhaul Unit No. 4	2016
Clean No. 2 Ash Pond, Completion	2016
Retube Condenser - Unit No. 4	2016
Acid Clean Unit No. 3	2017
Major Overhaul Unit No. 3	2017
Clean No. 4 Ash Pond	2017
Retube Condenser - Unit No. 3	2017
Clean No. 4 Ash Pond, Completion	2018
Upgrade Generation Tubes and Refractory No. 1 and No. 2	2018
Inspect/Rebuild Control Valves - Unit No. 4	2019
Clean No. 2 Ash Pond	2019
Major Overhauls - Units No. 1 and No. 2	2019
Clean No. 2 Ash Pond, Completion	2020
Inspect/Rebuild Control Valves - Unit No. 3	2020
Clean No. 4 Ash Pond	2021
Clean No. 4 Ash Pond, Completon	2022
Inspect/Rebuild Control Valves - Unit No. 4	2022
Inspect/Rebuild Control Valves - Units No. 1 and No. 2	2022
Acid Clean Unit No. 4	2023
Inspect/Rebuild Control Valves - Unit No. 3	2023
Clean No. 2 Ash Pond	2023

Table 8.(2)(a)-13

Dale

Description	Date
Clean No. 2 Ash Pond, Completion	2024
Inspect/Rebuild Control Valves Units No. 1 and No. 2	2024
Clean No. 4 Ash Pond	2025
Inspect/Rebuild Control Valves - Units No. 1 and No. 2	2025
Clean No. 4 Ash Pond, Completion	2026
Major Overhaul Unit No. 4	2026
Major Overhaul Unit No. 3	2027
Clean No. 2 Ash Pond	2027
Clean No. 2 Ash Pond, Completion	2028
Major Overhual Units No. 1 and No. 2	2028

Table 8.(2)(a)-14

Smith Station

Description	Date
Smith Unit 1 Coal-Fired Unit	2009
Combustion Turbine Units No. 9 and No. 10, Completion	2009
Unit No. 7 Combustion Inspection	2009
Unit Nos. 4, 5, and 6 Boroscope ($30,840) and A-Inspection for Unit Nos. 1, 2, and 3 ($93,000)	2009
Refurbished LCI Change Out – Unit No. 2	2009
Critical Capital Spare Parts	2009
Refurbished Parts – Stock	2009
Unit No. 4 Combustion Inspection	2010
Smith Unit 1 Coal-Fired Unit	2010
Refurbished LCI Change Out – Unit No. 1	2010
Boroscope Unit Nos 5, 6, & 7 ($51,000) and A-Inspection Unit Nos. 1, 2, & 3 ($123,000)	2010
Critical Capital Spare Parts	2010
Unit No. 5 Combustion Inspection	2011
Smith Unit 1 Coal-Fired Unit	2011
Critical Spare Parts	2011
Catalyst Replacement – Units No. 9 and No. 10	2012
Smith Unit 1 Coal-Fired Unit	2012
Unit No. 6 Combustion Inspection	2013
Controls System Upgrade	2013
LCI Change-Out-Alstom Units 1,2,&3 Replacement/Refurbishment	2013
Smith Unit 1 Coal-Fired Unit	2013
Unit No. 4 Hot Gas Path Inspcetion	2014
Unit No. 1 Major Inspection	2015
Catalyst Replacement Units No. 9 and No. 10	2015
Unit No. 5 Combustion Inspection	2016
Unit No. 2 Major Inspection	2016
LCI Change-Out-Alstom Units 1,2,&3 Replacement/Refurbishment	2016
Unit No. 3 Major Inspection	2017
Unit No. 6 Hot Gas Path Inspection	2017
Catalyst Replacement Units No. 9 and No. 10	2018
Unit No. 7 Hot Gas Path Inspection	2018
LCI Change-Out-Alstom Units 1,2,&3 Replacement/Refurbishment	2018
Unit No. 4 Combustion Inspection	2019
Unit No. 5 Combustion Inspection	2020
Catalyst Replacemen – Units No. 9 and No. 10	2021
Hot Gas Path – Units No. 9 and No. 10	2021
Unit No. 6 Combustion Inspection	2022
Unit No. 7 Combustion Inspection	2022
Major Overhaul Unit No. 1	2022
LCI Change-Out-Alstom Units 1,2,&3 Replacement/Refurbishment	2022
Unit No. 4 Major Inspection	2023
Catalyst Replacement Units No. 9 and No. 10	2024

Table 8.(2)(a)-15
Smith Station

Description	Date
Unit No. 1 Major Inspection	2024
Unit No. 2 Major Inspection	2025
Unit No. 5 Major Inspection	2025
Unit No. 3 Major Inspection	2026
Unit No. 6 Major Inspection	2026
Unit No. 7 Major Inspection	2027
Catalyst Replacement Units No. 9 and No. 10	2027
Unit No. 4 Combustion Inspection	2027
Unit No. 5 Combustion Inspection	2028
Unit No. 6 Combustion Inspection	2029

Table 8.(2)(a)-16

Landfill Gas

Description	Date
Bavarian Unit No. 1 - Major Overhaul	2009
Bavarian Unit No. 2 - Major Overhaul	2009
Bavarian Unit No. 3 - Major Overhaul	2009
Bavarian Unit No. 4 - Major Overhaul	2009
Green Valley No. 2 - Major Overhaul	2009
Install Unit No. 4 at Hardin County	2009
25 MW Wind Farm - Study	2009
Mason County - (Continuation)	2008-2009
Laurel Ridge No. 1 - Major Overhaul	2010
Green Valley No. 1 - Major Overhaul	2010
Green Valley No. 2 - Major Overhaul	2010
Green Valley No. 3 - Major Overhaul	2010
Install Unit No. 4 at Hardin County (Continuation)	2010
Install Unit No. 4 at Green Valley	2010
Install Unit No. 5 at Pendleton County	2010
Construction of Site No. 7	2010
25 MW Wind Farm	2010
Laurel Ridge No. 4 - Major Overhaul	2010
Laurel Ridge No. 2 - Major Overhaul	2011
Laurel Ridge Unit No. 3 - Major Overhaul	2012
Hardin County Unit No. 1 - Major Overhaul	2012
Hardin County Unit No. 2 - Major Overhaul	2012
Hardin County Unit No. 3 - Major Overhaul	2012
Laurel Ridge Unit No. 5 - Major Overhaul	2012
Install Unit No. 5 at Hardin County	2012
Pendleton County Unit No. 1 - Major Overhaul	2013
Pendleton County Unit No. 2 - Major Overhaul	2013
Pendleton County Unit No. 4 - Major Overhaul	2013
Pendleton County Unit No. 3 - Major Overhaul	2014
Bavarian Unit No. 1 - Major Overhaul	2015
Bavarian Unit No. 2 - Major Overhaul	2015
Bavarian Unit No. 3 - Major Overhaul	2015
Bavarian Unit No. 4 - Major Overhaul	2015
Mason County Unit No. 1 - Major Overhaul	2015
Laurel Ridge Unit No. 2 - Major Overhaul	2016
Green Vallely Unit No. 1 - Major Overhaul	2016
Green Vallely Unit No. 2 - Major Overhaul	2016
Green Vallely Unit No. 3 - Major Overhaul	2016
Green Vallely Unit No. 4 - Major Overhaul	2016
Hardin County Unit No. 4 - Major Overhaul	2016
Laurel Ridge Unit No. 1 - Major Overhaul	2017
Site No. 7 Unit No. 1 - Major Overhaul	2017
Site No. 7 Unit No. 2 - Major Overhaul	2017
Laurel Ridge Unit No. 3 - Major Overhaul	2018
Hardin County Unit No. 1 - Major Overhaul	2018

Table 8.(2)(a)-17

Landfill Gas

Description	Date
Hardin County Unit No. 2 - Major Overhaul	2018
Hardin County Unit No. 3 - Major Overhaul	2018
Laurel Ridge Unit No. 5 - Major Overhaul	2018
Hardin County Unit No. 5 - Major Overhaul	2018
Pendleton County Unit No. 5 - Major Overhaul	2018
Pendleton County Unit No. 1 - Major Overhaul	2019
Pendleton County Unit No. 2 - Major Overhaul	2019
Pendleton County Unit No. 4 - Major Overhaul	2019
Pendleton County Unti No. 3 - Major Overhaul	2020
Bavarian Unit No. 1 - Major Overhaul	2021
Bavarian Unit No. 2 - Major Overhaul	2021
Bavarian Unit No. 3 - Major Overhaul	2021
Bavarian Unit No. 4 - Major Overhaul	2021
Green Valley Unit No. 2 - Major Overhaul	2021
Mason County Unit No.1 - Major Overhaul	2021
Laurel Ridge Unit No. 2 - Major Overhaul	2022
Laurel Ridge Unit No. 4 - Major Overhaul	2022
Green Valley Unit No. 3 - Major Overhaul	2022
Green Valley Unit No. 1 - Major Overhaul	2022
Hardin County Unit No. 4 - Major Overhaul	2022
Construct Hardin County Phase II - Unit Nos. 6, 7, and 8	2022
Laurel Ridge Unit No. 1 - Major Overhaul	2023
Pendleton County Unit No. 5 - Major Overhaul	2023
Green Valley Unit No. 4 - Major Overhaul	2023
Site No. 7 Unit No. 1 - Major Overhaul	2023
Site No. 7 Unit No. 2 - Major Overhaul	2023
Laurel Ridge Unit No. 3 - Major Overhaul	2024
Hardin County Unit No. 1 - Major Overhaul	2024
Hardin County Unit No. 2 - Major Overhaul	2024
Hardin County Unit No. 3 - Major Overhaul	2024
Laurel Ridge Unit No. 5 - Major Overhaul	2024
Hardin County Unit No. 5 - Major Overhaul	2024
Pendleton County Unit No. 5 - Major Overhaul	2024
Pendleton County Unit No. 1 - Major Overhaul	2025
Pendleton County Unit No. 2 - Major Overhaul	2025
Pendleton County Unit No. 4 - Major Overhaul	2025
Pendleton County Unit No. 3 - Major Overhaul	2026
Mason County Unit No. 1 - Major Overhaul	2026
Bavarian Unit No. 1 - Major Overhaul	2027
Bavarian Unit No. 2 - Major Overhaul	2027
Bavarian Unit No. 3 - Major Overhaul	2027
Bavarian Unit No. 4 - Major Overhaul	2027
Laurel Ridge Unit No. 2 - Major Overhaul	2028
Laurel Ridge Unit No. 4 - Major Overhaul	2028
Green Valley Unit No. 3 - Major Overhaul	2028

Table 8.(2)(a)-18

Landfill Gas

Description	Date
Green Valley Unit No. 1 - Major Overhaul	2028
Green Valley Unit No. 2 - Major Overhaul	2028
Hardin County Unit No. 4 - Major Overhaul	2028
Hardin County Unit No. 6 - Major Overhaul	2028
Hardin County Unit No. 7 - Major Overhaul	2028
Hardin County Unit No. 8 - Major Overhaul	2028
Site 7 Unit No. 1 - Major Overhaul	2029
Site 7 Unit No. 2 - Major Overhaul	2029
Laurel Ridge Unit No. 1 - Major Overhaul	2029
Pendleton County Unit No. 5 - Major Overhaul	2029

Table 8.(2)(a)-19

Environmental

Mercury Monitoring Program	2008-2010
CEM Equipment - Spurlock	2008-2010

Table 8.(2)(a)-20
EKPC Free-Flowing Interconnection Capability

				Ratings in MVA			
				Summer		Winter	
No.	From (EKPC)	To	Voltage kV	Normal	Emergency	Normal	Emergency
AEP							
1	.Argentum	Millbrook Park	138	200	200	200	200
2	.Argentum	Grays Branch	69	49	49	55	55
3	.Falcon	Falcon	69	22	25	25	27
4	.Leon	Leon	69	39	46	54	54
5	.Thelma	Thelma	69	53	67	82	83
		Total:		363	387	416	419
DP&L							
6	. Spurlock	Stuart	345	1255	1374	1255	1374
Duke Energy-OHIO							
7	.Boone	Buffington	138	298	298	389	389
8	.Spurlock	Zimmer	345	1489	1489	1792	1792
		Total:		1787	1787	2181	2181
E.ON							
9	.Avon	Loudon Avenue	138	196	239	242	279
10	.Baker Lane	Baker Lane Tap	69-138	96	117	121	139
11	.Beattyville	Beattyville	69	90	115	141	156
12	.Beattyville	Beattyville Tap	161-69	58	66	72	72

Table 8.(2)(a)-21
EKPC Free-Flowing Interconnection Capability

				Ratings in MVA			
				Summer		Winter	
No.	From (EKPC)	To	Voltage kV	Normal	Emergency	Normal	Emergency
13	.Beattyville-Powell Co.	Delvinta	161	167	201	167	223
14	.Bonds Mill Jct.	Bonds Mill	69	72	72	72	72
15	.Bonnieville	Bonnieville	69-138	44	54	55	64
16	.Boonesboro North Tap	Boonesboro North	69-138	129	143	143	143
17	.Bracken Co.	Carntown	69	41	41	72	72
18	.Bracken Co.	Sharon	69	35	35	65	65
19	.Cedar Grove Ind. Park	Blue Lick	161	235	281	320	329
20	.Clay Village	Clay Village Tap	69	36	37	42	43
21	.Cooper	Elihu	161	235	289	279	305
22	.Crooksville Jct.	Fawkes	69	77	89	95	98
23	.East Bardstown	Bardstown Ind.	69	53	57	64	66
24	.Fawkes	Fawkes	138	230	287	287	287
25	.Fawkes	Fawkes Tap	138	230	296	256	356
26	.Gallatin Co.	Ghent	138	230	268	287	287
27	.Garrard Co.	Lancaster	69	72	101	72	101
28	.Green Co.	Greensburg	69	53	57	64	66
29	.Green Hall Jct.	Delvinta	161	176	201	223	223
30	.Hodgenville	Hodgenville	69	49	49	82	88
31	.Hodgenville	New Haven	69	49	49	82	88
32	.Kargle	Elizabethtown	69	67	67	88	88
33	.Laurel Co.	Hopewell	69	72	76	85	88
34	.Liberty Church Tap	Farley	69	51	51	72	72
35	.Marion Co.	Lebanon	161-138	192	230	242	272
36	.Murphysville	Kenton	69	53	67	69	69

Table 8.(2)(a)-22
EKPC Free-Flowing Interconnection Capability

				Ratings in MVA			
				Summer		Winter	
No.	From (EKPC)	To	Voltage kV	Normal	Emergency	Normal	Emergency
37	.Murphysville	Sardis	69	41	50	60	66
38	.Nelson Co.	Nelson Co Tap	69-138	144	153	172	177
39	.North London	North London	69	72	76	85	88
40	.North Springfield	Springfield	69	53	54	61	61
41	.Owen Co.	Bromley	69	57	57	97	98
42	.Owen Co.	Owen Co. Tap	69-138	144	153	172	177
43	.Paris	Paris Tap	138-69	129	160	191	196
44	.Penn	Scott Co.	69	38	38	72	72
45	.Pittsburg Tap	Pittsburg	161-69	116	131	139	143
46	.Renaker	Cynthiana Sw.	69	53	66	82	88
47	.Rogersville Jct.	Rogersville	69	77	89	95	98
48	.Rowan Co.	Rodburn	138	143	191	143	191
49	.Sewellton	Union Underwear	69	41	41	75	75
50	.Shelby Co.	Shelby Co. Tap	69	73	76	86	88
51	.Somerset	Ferguson South	69	89	89	132	132
52	.Somerset	Somerset South	69	56	56	78	82
53	.Spurlock	Kenton	138	259	268	287	287
54	.Stephensburg	East View	69	49	49	64	66
55	.Taylor Co.	Taylor Co.	161-69	93	105	120	124
56	.Tharp Jct.	Elizabethtown	69	73	86	95	98
57	.Union City	Lake Reba Tap	138	245	304	364	400
		Total:		5133	5927	6529	7018

Table 8.(2)(a)-23
EKPC Free-Flowing Interconnection Capability

				Ratings in MVA			
				Summer		Winter	
No.	**From (EKPC)**	**To**	**Voltage kV**	**Normal**	**Emergency**	**Normal**	**Emergency**
TVA							
58	McCreary Co.	McCreary Co.	69-161	197	197	281	281
59	McCreary Co.	Winfield	69	73	76	86	88
60	Russell Co. Tap	Wolf Creek	161	312	312	335	335
61	Summershade	Summershade	161	268	312	415	415
62	Summershade Tap	Summershade	161	228	247	259	279
63	Wayne Co.	Wayne Co.	69-161	120	122	122	122
		Total:		1198	1266	1498	1520
		Grand Total:		9736	10741	11879	12512

Table 8.(2)(a)-24

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2009-2023)	
A. New Transmission Lines and Transmission Substations **Project Description**	**Needed In-Service Date**
Construct approximately 2.5 miles of 69 kV line using 556.5 MCM ACSR conductor from Clay Lick Junction to Van Arsdell Distribution Substation.	5/2009
Construct 161 kV terminal facilities at Barren County to provide enhanced protection of the 161-69 kV autotransformer	5/2009
Install a 2nd 345-138 kV, 450 MVA transformer at the J.K. Smith Substation	6/2009
Construct approximately 12 miles of 69 kV line using 954 MCM ACSR conductor from Fall Rock to Tyner.	6/2009
Purchase a 345-138 kV, 450 MVA spare autotransformer.	6/2009
Replace the existing Bonnieville 138/69 kV, 47.62 MVA transformer with a 93.3 MVA transformer (use existing spare transformer from Goddard).	6/2009
Install a generator step up (GSU) transformer for J.K. Smith CT's #9 & #10 and construct a new 345 kV line from the existing J.K. Smith Substation to the new GSU.	7/2009
Provide 161 kV terminal facilities at McCreary County Substation for TVA's Huntsville – McCreary County 161 kV line.	8/2009
Purchase a 345-20 kV, 405 MVA spare GSU transformer for Gilbert #3 and Spurlock #4	10/2009
Construct approximately 35.5 miles of 345 kV line using 2-954 KCM ACSR from the J.K. Smith Substation to intercept KU's Brown North-Pineville 345 kV Line at a new substation site ("West Garrard") near Lancaster, KY. Construct a 345 kV switching substation at West Garrard. EON provides 345 kV terminal facilities at Brown and Pineville and 345 kV line connections at West Garrard.	12/2009
Purchase a 161-138 kV, 200 MVA spare autotransformer.	12/2009
Install 2-138 kV line breakers at the Stanley Parker Substation.	12/2009
Reconfigure the 138 kV transfer breaker at Fawkes substation (S62-859) to act both as a transfer breaker and a line breaker for the KU Fawkes line.	12/2009
Construct a 138-69 kV substation at a new site ("Central Hardin") located near Kargle distribution substation, at the crossing point of KU's Hardin County-Hardinsburg 138 kV line and EKPC's Kargle-Etown 69 kV line section.	5/2010
Replace the existing Dale #3 generator step up (GSU) transformer with a new transformer.	11/2010
Replace the existing Dale 138-69 kV, 82.5 MVA autotransformer with a new 125 MVA transformer.	12/2010
Install a 69 kV breaker at Thelma Substation to act as a line breaker for the line extending to the AEP Thelma 138-69-46 kV substation.	12/2010
Install two (2) 69 kV circuit breakers at the Zachariah 69 kV Substation.	12/2010

Table 8.(2)(a)-25

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2009-2023)	
A. New Transmission Lines and Transmission Substations (continued) **Project Description**	**Needed In-Service Date**
Construct a 138-69 kV substation at a new site ("Webster Road") located near the Richardson distribution substation, on the Duke Energy-Ohio Buffington-Hands 138 kV line. Construct approximately 1 mile of 69 kV double circuit line, using 556.5 MCM ACSR conductor, from the Webster Road Substation to the Turkey Foot-Richardson 69 kV line.	5/2011
Construct a 69 kV switching substation at Turkey Foot Junction on the Boone County-Stanley Parker 69 kV circuit.	5/2011
Construct a 138-69 kV substation at Hebron. Construct approximately 2 miles of 69 kV line, using 556.5 MCM ACSR conductor, from the Hebron Substation to Bullittsville.	12/2011
Construct approximately 4.2 miles of 69 kV line, using 266.8 KCM ACSR conductor, from the Keith Substation to EON's Owenton Substation.	12/2011
Construct a 4-breaker 69 kV EKPC-AEP switching substation at Index Junction, connecting EKPC's Index-West Liberty line section with AEP's Morehead-Index line section.	12/2011
Construct 8.75 miles of 69 kV line between the Big Creek and Goose Rock Substations using 556.5 KCM ACSR conductor.	12/2011
Close the existing normally open 69 kV interconnection between EKPC and AEP at Helechawa. Install 2-69 kV line breakers at Helechawa.	12/2011
Construct a 3-breaker 69 kV switching substation at Hunt Farm Junction.	12/2011
Construct approximately 1.2 miles of 345 kV line, using 2-954 KCM ACSR conductor, from the J.K. Smith CT Substation to the new J.K. Smith CFB site. Install a generator step up (GSU) transformer for J.K. Smith CFB #1 Unit .	6/2012
Install a generator step-up (GSU) transformer for J.K. Smith CFB #1	6/2012
Construct a 3-breaker 69 kV switching substation at Norwood Junction.	12/2012
Operate the Goldbug-Wofford (LGEE) 69 kV line normally closed	5/2013
Construct 12.8 miles of 69 kV line using 954 MCM ACSR conductor from Coburg to Green County. Construct a 69 kV switching substation at Coburg Junction. Install a 69 kV line breaker at Green County Substation.	12/2013
Construct approximately 1.3 miles of 69 kV line, using 266.8 KCM ACSR conductor, from the Mercer County Industrial Substation to the EON Harrodsburg #1 Substation.	12/2013
Construct a 4-breaker 69 kV switching substation at Bonds Mill Junction	12/2013

Table 8.(2)(a)-26

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2009-2023)	
A. New Transmission Lines and Transmission Substations (continued) **Project Description**	**Needed In-Service Date**
Construct a 138-69 kV substation at the existing West Bardstown Junction switching station. Construct approximately 1 mile of 138 kV line, using 556.5 MCM ACSR conductor, from the West Bardstown Junction Substation to EON's Bardstown-Nelson County 138 kV line. Install two 138 kV circuit breakers at the Nelson County Substation.	5/2014
Construct a 161/69 kV substation at a new site ("Clinton County") located between Snow and Upchurch. Construct a 4.5 mile 69 kV line using 954 MCM ACSR conductor between the Snow, Clinton County, Upchurch Distribution Substations. Construct a 9 mile, 161 kV line using 954 MCM ACSR conductor from the Clinton County Substation to the USACE 161 kV switching substation at Wolf Creek. Install 161 kV terminal facilities at Wolf Creek for the line to Clinton County.	12/2014
Construct 3.7 miles of 69 kV line (161 kV construction) using 954 MCM ACSR conductor from Fox Hollow Substation to Patton Road Junction. Connect this new line in series with to the existing Summer Shade-Patton Road Junction 69 kV line, forming a 2nd 69 kV circuit from Fox Hollow to Summer Shade. Add a 69 kV breaker at the Fox Hollow and Summer Shade Substations to accommodate this new circuit.	12/2016
Construct 8.6 miles of 69 kV line (138 kV construction) using 954 MCM ACSR conductor from Mercer County Industrial Park to Van Arsdell.	12/2017
Replace the existing Powell County 138/69 kV, 100 MVA transformer with a 150 MVA transformer.	12/2017
Construct a 69 kV, 3-breaker switching substation at Munk Junction. Operate the Renaker-Williamstown 69 kV Line normally closed.	5/2018
Replace the existing Bullitt County 161-69 kV, 100 MVA autotransformer with a new 125 MVA transformer.	12/2019

Table 8.(2)(a)-27

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2009-2023)	
B. Transmission Line Re-conductor/Rebuild Projects **Project Description**	**Needed In-Service Date**
Rebuild the existing 1/0 ACSR Bonds Mill Junction-Clay Lick Junction 69 kV line section (2.7 miles) using 556.5 MCM ACSR conductor.	7/2009
Re-conductor the 4/0 ACSR Burkesville-Snow Junction 69 kV line section (10.07 miles) using 556.5 MCM ACSR conductor.	9/2009
Rebuild the 1/0 ACSR North London-Tyner 69 kV line (16.69 miles) using 954 MCM ACSR conductor. Operate this line & the Beattyville-Tyner 69 kV line normally closed.	12/2009
Rebuild the 1/0 ACSR Tyner-McKee 69 kV line section (9.30 miles) using 556.5 MCM ACSR conductor.	7/2010
Re-conductor the 4/0 ACSR Norwood Junction-Shopville 69 kV line section (6.3 miles) using 556.5 MCM ACSR conductor.	12/2010
Re-conductor the 3/0 ACSR portion of the Pine Knot-Whitley City 69 kV line section (0.20 miles) using 556.5 MCM ACSR conductor.	12/2010
Re-conductor the 4/0 ACSR EK Munfordville Tap-KU Munfordville Tap 69 kV line section (2.0 miles) using 556.5 MCM ACSR conductor.	5/2011
Re-conductor the 1/0 ACSR West Bardstown Junction-West Bardstown 69 kV line section (4.5 miles) using 556.5 MCM ACSR conductor.	5/2011
Re-conductor the 266.8 MCM ACSR section of the Baker Lane-Holloway Junction 69 kV line section (1.28 miles) using 556.5 MCM ACSR conductor.	5/2011
Re-conductor the 2/0 ACSR Owen County-New Castle 69 kV line section (19.6 miles) using 556.5 MCM ACSR conductor.	12/2011
Re-conductor the 2/0 ACSR Renaker-Lees Lick 69 kV line section (7.2 miles) using 556.5 MCM ACSR conductor.	12/2011
Re-conductor the 3/0 ACSR Beattyville Distribution-Oakdale Junction 69 kV line section (3.9 miles) using 556.5 MCM ACSR conductor.	12/2011
Re-conductor the 4/0 ACSR Three Links Junction-Conway Junction 69 kV line section (1.5 miles) using 556.5 MCM ACSR conductor.	12/2011
Re-conductor the 266.8 MCM ACSR portion of the Stephensburg-Central Hardin 69 kV line section (0.21 miles) using 556.5 MCM ACSR conductor.	12/2011
Re-conductor the 4/0 ACSR KU Munfordville Tap-Horse Cave Tap 69 kV line section (6.83 miles) using 556.5 MCM ACSR conductor.	12/2012
Re-conductor the 3/0 ACSR Murphysville-Snow Hill Junction 69 kV line section (16.1 miles) using 556.5 MCM ACSR conductor.	5/2012
Re-conductor the 4/0 ACSR Albany-Snow Junction 69 kV line section (4.4 miles) using 556.5 MCM ACSR conductor.	12/2012

Table 8.(2)(a)-28

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2009-2023)	
B. Transmission Line Re-conductor/Rebuild Projects (continued) **Project Description**	**Needed In-Service Date**
Re-conductor the 4/0 ACSR Three Links Junction-Brodhead 69 kV line section (8.2 miles) using 556.5 MCM ACSR conductor.	12/2012
Re-conductor the 266.8 MCM ACSR portion of the Kargle-Etown KU 69 kV line section (1.4 miles) using 556.5 MCM ACSR conductor.	5/2014
Re-conductor the 266.8 MCM ACSR Murphysville-Plumville 69 kV line (9.9 miles) using 556.5 MCM ACSR conductor.	5/2015
Re-conductor the 2/0 ACSR Grants Lick-Griffin Junction 69 kV line section (5.8 miles) using 556.5 MCM ACSR conductor.	5/2016
Re-conductor the 3/0 ACSR Fort Knox Junction-Rineyville Junction 69 kV line section (0.44 miles) using 556.5 MCM ACSR conductor.	12/2016
Re-conductor the 2/0 ACSR Lees Lick-Penn 69 kV line section (13.6 miles) using 556.5 MCM ACSR conductor.	5/2017
Re-conductor the 3/0 and 4/0 ACSR Snow Hill Junction-Headquarters-Millersburg Junction 69 kV line sections (8.92 miles) using 556.5 MCM ACSR conductor.	5/2017
Re-conductor the 266.8 MCM ACSR Fayette-Davis 69 kV line section (3.15 miles) using 556.5 MCM ACSR conductor.	5/2017
Re-conductor the 266.8 MCM ACSR Goddard-Plummers Landing-Hilda-Rowan County 69 kV line (19.14 miles) using 556.5 MCM ACSR conductor.	12/2017
Re-conductor the 1/0 and 2/0 ACSR Renaker-Williamstown-Munk Junction 69 kV line sections (23.36 miles) using 556.5 MCM ACSR conductor.	5/2018
Rebuild the 1/0 ACSR Stephensburg-Glendale 69 kV line section (9.0 miles) using 556.5 MCM ACSR conductor.	5/2020
Rebuild the 1/0 ACSR Glendale-Hodgenville 69 kV line section (8.7 miles) using 556.5 MCM ACSR conductor.	5/2020
Re-conductor the 556.5 MCM ACSR Etown KU-Tharp Junction 69 kV line section (2.11 miles) using 954 MCM ACSR conductor.	12/2021
Re-conductor the 3/0 ACSR Rineyville Junction-Smithersville Junction 69 kV line section (2.87 miles) using 556.5 MCM ACSR conductor.	5/2022
Re-conductor the 266.8 MCM ACSR Davis-Nicholasville 69 kV line section (4.0 miles) using 556.5 MCM ACSR conductor.	5/2023

Table 8.(2)(a)-29

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2009-2023)	
C. Transmission Line Conductor Temperature Upgrade Projects **Project Description**	**Needed In-Service Date**
Increase the maximum operating temperature of the 4/0 ACSR Temple Hill-Patton Road Junction 69 kV line section (2.2 miles) to at least 176°F.	6/2009
Increase the maximum operating temperature of the 1/0 ACSR Glendale-Hodgenville 69 kV line section (8.7 miles) to at least 160°F.	6/2009
Increase the maximum operating temperature of the 4/0 ACSR Headquarters-Millersburg Junction 69 kV line section (5.12 miles) to at least 130°F.	6/2009
Increase the maximum operating temperature of the 266.8 MCM ACSR Helechawa-Sublett Junction 69 kV line section (19.88 miles) to at least 167°F.	6/2009
Increase the maximum operating temperature of the 266.8 MCM ACSR Hunt Farm Junction-Perryville 69 kV line section (5.17 miles) to at least 167°F.	6/2009
Increase the maximum operating temperature of the 3/0 ACSR Liberty KU Tap – Peyton's Store 69 kV line section (10.7 miles) to at least 125°F.	5/2010
Increase the maximum operating temperature of the 4/0 ACSR North Springfield-South Springfield Junction 69 kV line section (9.9 miles) to at least 125°F.	5/2010
Increase the maximum operating temperature of the 4/0 ACSR Milton-Bedford 69 kV line section (8.7 miles) to at least 125°F.	5/2010
Increase the maximum operating temperature of the 266.8 MCM ACSR Vine Grove-Radcliff Junction 69 kV line section (1.36 miles) to at least 130°F.	5/2010
Increase the maximum operating temperature of the 4/0 ACSR Russell Springs Tap 69 kV line section (1.2 miles) to at least 130°F.	5/2010
Increase the maximum operating temperature of the 266.8 MCM ACSR Smithersville Tap 69 kV line section (0.85 miles) to at least 135°F.	5/2010
Increase the maximum operating temperature of the 266.8 MCM ACSR Fredricksburg Junction-North Springfield 69 kV line section (7.26 miles) to at least 125°F.	5/2010
Increase the maximum operating temperature of the 4/0 ACSR Balltown Tap 69 kV line section (3.5 miles) to at least 125°F.	5/2010
Increase the maximum operating temperature of the 266.8 MCM ACSR Bronston Tap 69 kV line section (4.1 miles) to at least 125°F.	5/2010
Increase the maximum operating temperature of the 4/0 ACSR Millersburg Junction-Sideview 69 kV line section (12.88 miles) to at least 125°F.	5/2010
Increase the maximum operating temperature of the 266.8 MCM ACSR EKPC Office-Treehaven Tap 69 kV line section (0.43 miles) to at least 125°F.	5/2010
Increase the maximum operating temperature of the 266.8 MCM ACSR Treehaven Tap-Van Meter 69 kV line section (2.31 miles) to at least 130°F.	5/2010

Table 8.(2)(a)-30

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2009-2023)	
C. Transmission Line Conductor Temperature Upgrade Projects (continued) **Project Description**	**Needed In-Service Date**
Increase the maximum operating temperature of the 266.8 MCM ACSR Radcliff Junction-Radcliff 69 kV line section (0.83 miles) to at least 125°F.	5/2010
Increase the maximum operating temperature of the 266.8 MCM ACSR Tharp Tap 69 kV line section (0.11 miles) to at least 125°F.	5/2010
Increase the maximum operating temperature of the 266.8 MCM ACSR Coburg Junction-Garlin Tap 69 kV line section (1.5 miles) to at least 130°F.	5/2010
Increase the maximum operating temperature of the 266.8 MCM ACSR Bacon Creek Junction-South Corbin 69 kV line section (1.91 miles) to at least 125°F.	5/2010
Increase the maximum operating temperature of the 4/0 ACSR Stephensburg-Upton Junction 69 kV line section (10.76 miles) to at least 145°F.	5/2011
Increase the maximum operating temperature of the 266.8 MCM ACSR portion of the Kargle-Etown KU 69 kV line section (1.4 miles) to at least 248°F.	5/2011
Increase the maximum operating temperature of the 1/0 ACSR & 266.8 MCM ACSR Manchester-Goose Rock 69 kV line section (7.39 miles) to at least 125°F.	5/2011
Increase the maximum operating temperature of the 266.8 MCM ACSR Sideview-Reid Village 69 kV line section (6.9 miles) to at least 125°F.	5/2011
Increase the maximum operating temperature of the 3/0 ACSR, 4/0 ACSR & 266.8 MCM ACSR Lynch KU-Arkland Junction 69 kV line section (3.97 miles) to at least 125°F.	5/2011
Increase the maximum operating temperature of the 266.8 MCM ACSR Albany-South Albany 69 kV line section (2.0 miles) to at least 125°F.	5/2011
Increase the maximum operating temperature of the 4/0 ACSR Bardstown Shopping Center Tap 69 kV line section (0.18 miles) to at least 125°F.	5/2011
Increase the maximum operating temperature of the 266.8 MCM ACSR East Somerset Tap 69 kV line section (0.33 miles) to at least 125°F.	5/2011
Increase the maximum operating temperature of the 266.8 MCM ACSR Booneville Tap 69 kV line section (0.25 miles) to at least 125°F.	5/2011
Increase the maximum operating temperature of the 266.8 MCM ACSR Cave City Tap 69 kV line section (4.2 miles) to at least 125°F.	5/2011
Increase the maximum operating temperature of the 266.8 MCM ACSR Rowan County-Elliottville 69 kV line section (5.83 miles) to at least 125°F.	5/2011
Increase the maximum operating temperature of the 4/0 ACSR Burlington Tap-Bullittsville 69 kV line section (3.5 miles) to at least 125°F.	5/2011
Increase the maximum operating temperature of the 266.8 MCM ACSR Index Tap 69 kV line section (3.2 miles) to at least 125°F.	5/2011

Table 8.(2)(a)-31

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2009-2023)	
C. Transmission Line Conductor Temperature Upgrade Projects (continued) **Project Description**	**Needed In-Service Date**
Increase the maximum operating temperature of the 3/0 ACSR Fort Knox Junction-Rineyville Junction 69 kV line section (0.44 miles) to at least 284°F.	12/2011
Increase the maximum operating temperature of the 1/0 ACSR Glendale-Hodgenville 69 kV line section (8.7 miles) to at least 185°F.	5/2014
Increase the maximum operating temperature of the 2/0 ACSR Etown-Tunnel Hill Junction 69 kV line section (3.36 miles) to at least 275°F.	5/2015
Increase the maximum operating temperature of the 1/0 ACSR Stephensburg-Glendale 69 kV line section (9.0 miles) to at least 266°F.	5/2016
Increase the maximum operating temperature of the 3/0 ACSR Rineyville Junction-Smithersville Junction 69 kV line section (2.87 miles) to at least 284°F.	5/2016
Increase the maximum operating temperature of the 556.5 MCM ACSR Etown KU-Tharp Junction 69 kV line section (2.11 miles) to at least 284°F.	5/2017
Increase the maximum operating temperature of the 1/0 ACSR Glendale-Hodgenville 69 kV line section (8.7 miles) to at least 266°F.	5/2019
Increase the maximum operating temperature of the 4/0 ACSR Stephensburg-Upton Junction 69 kV line section (10.76 miles) to at least 150°F.	5/2019
Increase the maximum operating temperature of the 556.5 MCM ACSR Tharp Junction-Etown EK #1 69 kV line section (1.7 miles) to at least 284°F.	5/2021
Increase the maximum operating temperature of the 266.8 MCM ACSR Denny-Bronston Junction 69 kV line section (8.0 miles) to at least 125°F.	5/2023
Increase the maximum operating temperature of the 2/0 ACSR Tunnel Hill Junction-Lyman B. Williams 69 kV line section (1.45 miles) to at least 275°F.	5/2023
Increase the maximum operating temperature of the 556.5 MCM ACSR Kargle-Etown KU 69 kV line section (2.85 miles) to at least 284°F.	5/2023
Increase the maximum operating temperature of the 556.5 MCM ACSR Etown EK #1-Etown EK #2 69 kV line section (0.04 miles) to at least 284°F.	12/2023

Table 8.(2)(a)-32

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2009-2023)	
D. Capacitor Bank Additions **Project Description**	**Needed In-Service Date**
Re-size the existing Bill Wells 69 kV, 14.4 MVAR capacitor bank to 9.6 MVAR	5/2009
Re-size the existing Booneville 69 kV, 13.2 MVAR capacitor bank to 9.6 MVAR	5/2009
Re-size the existing Frenchburg 69 kV, 10.8 MVAR capacitor bank to 7.2 MVAR	5/2009
Re-size the existing Index 69 kV, 10.8 MVAR capacitor bank to 7.2 MVAR	5/2009
Re-size the existing Sinai 69 kV, 13.78 MVAR capacitor bank to 9.18 MVAR	5/2009
Install a 19.8 MVAR, 69 kV capacitor bank at Temple Hill Substation.	5/2009
Re-size the existing Albany 69 kV, 12 MVAR capacitor bank to 8.4 MVAR	7/2009
Re-size the existing Cynthiana 69 kV, 12 MVAR capacitor bank to 8.4 MVAR	7/2009
Re-size the existing HT Adams 69 kV, 9.6 MVAR capacitor bank to 7.2 MVAR	7/2009
Re-size the existing Greenbriar 69 kV, 15.6 MVAR capacitor bank to 12.0 MVAR	7/2009
Install a 6.12 MVAR, 69 kV capacitor bank at Headquarters Substation	12/2009
Re-size the existing 3M 69 kV, 9.6 MVAR capacitor bank to 8.4 MVAR	12/2009
Install a 28.06 MVAR, 69 kV capacitor bank at Murphysville Substation.	5/2010
Install a 10.72 MVAR, 69 kV capacitor bank at Middle Creek Substation	12/2010
Install a 25.51 MVAR, 69 kV capacitor bank (#2) at Shelby County Substation.	5/2012
Install a 26.53 MVAR, 69 kV capacitor bank at North Springfield Substation.	12/2012
Install a 10.72 MVAR, 69 kV capacitor bank at Elliottville Substation.	5/2013
Install a 9.18 MVAR, 34.5 kV capacitor bank at Gallatin County Substation.	5/2013
Install a 26.53 MVAR, 69 kV capacitor bank at Goddard Substation.	5/2013
Install a 16.33 MVAR, 69 kV capacitor bank at Holloway Substation.	12/2013
Re-size the existing Clay Village 9.2 MVAR, 69 kV capacitor bank to 11.225 MVAR	12/2013
Install a 25.51 MVAR, 69 kV capacitor bank at West London Substation.	12/2014
Install a 17.86 MVAR, 69 kV capacitor bank at the Taylorsville EKPC Substation	12/2014
Re-size the existing Coburg 69 kV, 8.4 MVAR capacitor bank to 14.4 MVAR	12/2015
Install a 12.25 MVAR, 69 kV capacitor bank at Maggard Substation.	12/2015
Re-size the existing Tyner 69 kV, 16.33 MVAR capacitor bank to 26.53 MVAR.	12/2015
Install a 38.27 MVAR, 69 kV capacitor bank at Etown EKPC Substation	12/2016
Install a 13.78 MVAR, 69 kV capacitor bank at Emanuel Substation.	12/2016
Install a 12.25 MVAR, 69 kV capacitor bank at Floyd Substation.	12/2016
Install a 13.78 MVAR, 69 kV capacitor bank at Knob Lick Substation.	5/2017
Re-size the existing East Bernstadt 69 kV, 16.2 MVAR capacitor bank to 30.6 MVAR.	12/2017
Re-size the existing Three Links Junction 69 kV, 16.2 MVAR capacitor bank to 23.4 MVAR.	12/2017
Install a 12.25 MVAR, 69 kV capacitor bank at Three Links Substation.	12/2017

Table 8.(2)(a)-33

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2009-2023)	
D. Capacitor Bank Additions (continued) **Project Description**	**Needed In-Service Date**
Re-size the existing Booneville 69 kV, 9.6 MVAR capacitor bank to 13.2 MVAR	12/2017
Install a 12.25 MVAR, 69 kV capacitor bank at Hargett Substation	12/2017
Re-size the existing Cedar Grove 69 kV, 10.8 MVAR capacitor bank to 20.41 MVAR.	5/2018
Install a 6.12 MVAR, 69 kV capacitor bank at Cabin Hollow Substation	12/2018
Install a 22.96 MVAR, 69 kV capacitor bank at Bonnieville Substation	12/2019
Re-size the existing West Bardstown 69 kV, 13.78 MVAR capacitor bank to 16.84 MVAR.	12/2021

Table 8.(2)(a)-34

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2009-2023)	
E. Terminal Facility Upgrades **Project Description**	**Needed In-Service Date**
Upgrade the existing 69 kV, 400A metering CTs, 600A disconnect switches #633 and #635, and all 4/0 copper jumpers at Somerset with higher-rated equipment. Remove switch #640 at Somerset.	6/2009
Replace the existing 69 kV, 600A switches and metering CTs at Bonnieville associated with the Bonnieville 138-69 kV transformer with 1200A equipment. Replace the existing 69 kV bus with 2.5 inch IPS at Bonnieville.	6/2009
Replace the 69 kV, 600A circuit breaker W8-628 at Bonnieville associated with the Bonnieville 138-69 kV autotransformer with a 1200A breaker. Install a 138 kV circuit-switcher for protection of the 138-69 kV autotransformer.	12/2010
Replace the 69 kV, 600A switch W17-635 in the EON Rogersville-Rogersville Junction 69 kV line with a 1200A switch.	12/2010
Replace the 138 kV, 1200A line trap at Spurlock associated with the Spurlock-Kenton 138 kV line with a 1600A line trap.	5/2011
Replace the 69 kV, 600A switch W5-635 at Etown associated with the Tharp Junction-Etown #2 69 kV line with a 1200A switch.	12/2011
Replace the two(2) 600A low side breaker disconnects (N35-713,715) associated with the Dale 138-69 kV transformer with 2000A switches.	5/2012
Increase the ratings of the JK Smith-Dale, Fawkes, and Powell County 138 kV line terminals to 2000A.	12/2012
Replace the 69 kV, 600A switch S81-605 in the Crooksville Junction-Hickory Plains 69 kV line with a 1200A switch.	12/2016
Replace the 69 kV, 600A switch S77-605 at the Slat Substation tap point with a 1200A switch.	12/2017
Replace 600A switch S408-605 at the Russell Springs KU Substation tap point with a 1200A switch.	12/2017
Replace the 138 kV, 1200A line traps at the J.K. Smith and Fawkes Substations associated with the J.K. Smith-Fawkes 138 kV line with 1600A line traps.	12/2018

Table 8.(2)(a)-35

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2009-2023)	
F. Distribution Substation Projects **Project Description**	**Needed In-Service Date**
Upgrade the existing Brooks 69-12.5 kV, 11.2/14 MVA Substation to 15/20/25 MVA	4/2009
Construct a new Deatsville 69-12.5 kV, 11.2/14 MVA distribution substation and associated 69 kV tap line (0.1 mile).	6/2009
Construct a new Bekaert #3 69-25 kV, 15/20/25 MVA Substation and associated 69 kV tap line (0.1 mile)	6/2009
Construct a new Cedar Grove Industrial #2 161-12.5 kV, 12/16/20 MVA Substation and associated 161 kV tap line (0.1 mile)	6/2009
Construct a new Keith #2 69-25 kV, 11.2/14 MVA Substation and associated 69 kV tap line (0.1 mile)	8/2009
Construct a new Bonanza 69-13.2 kV, 11.2/14 MVA Substation and associated 69 kV tap line (1.74 miles)	12/2009
Construct a new Gregory Road 69-12.5 kV, 5 MVA Substation and associated 69 kV tap line (0.1 mile)	12/2009
Construct a new Jabez 161-25 kV, 12/16/20 MVA Substation and associated 161 kV tap line (0.65 mile)	12/2009
Upgrade the existing Zollicofer 69-12.5 kV, 5 MVA Substation to 11.2/14 MVA	12/2009
Construct a new Moransburg 138-25 kV, 12/16/20 MVA Substation and associated 138 kV tap line (0.2 mile)	2/2010
Construct a new Richwood 138-12.5 kV, 12/16/20 MVA Substation and associated 69 kV tap line (0.1 mile)	5/2010
Upgrade the existing Alcan #2 69-12.5 kV Substation, 11.2/14 MVA to 15/20/25 MVA	5/2010
Construct a new J.K. Smith 69-13.8 kV, 11.2/14 MVA Substation and associated 69 kV tap line (0.1 mile)	6/2010
Construct a new Belleview 69-12.5 kV, 11.2/14 MVA Substation and associated 69 kV tap line (6.9 miles)	12/2011

Table 8.(2)(a)-36

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2009-2023)	
F. Transformer Tap Changes **Project Description**	**Needed In-Service Date**
Bekaert #1,2 distribution transformers (67 to 65.2 kV).	5/2009
Cave City distribution transformer (68.8 to 67 kV)	5/2009
East Kentucky Office distribution transformer (68.8 to 65.2 kV)	5/2009
Hillsboro distribution transformer (70.73 to 69 kV).	5/2009
Holloway distribution transformer (67 to 65.2 kV).	5/2009
Pea Sticks distribution transformer (67 to 65.2 kV).	5/2009
Shopville distribution transformer (67 to 65.2 kV).	5/2009
Treehaven distribution transformer (67 to 65.2 kV)	5/2009
Ballard distribution transformer (67 to 65.2 kV).	12/2009
Clay Village distribution transformer (67 to 65.2 kV).	12/2009
HT Adams distribution transformer (67 to 65.2 kV).	12/2009
Index distribution transformer (67 to 65.2 kV).	12/2009
Perryville distribution transformer (67 to 65.2 kV).	12/2009
Thelma distribution transformer (67 to 65.2 kV).	12/2009
Volga distribution transformer (67 to 65.2 kV).	12/2009
Asahi distribution transformer (67 to 65.2 kV).	5/2010
West Liberty distribution transformer (67 to 65.2 kV).	12/2010
3M distribution transformer (67 to 65.2 kV).	5/2011
Boone County 138/69 kV autotransformer (138 kV to 134.55 kV).	5/2011
Cynthiana distribution transformer (67 to 65.2 kV).	5/2011
Stanley Parker 138/69 kV autotransformer (138 kV to 134.55 kV).	5/2011
Brodhead distribution transformer (67 to 65.2 kV).	12/2011
Crockett distribution transformer (67 to 65.2 kV).	12/2011
Maretburg distribution transformer (67 to 65.2 kV).	12/2011
South Fork distribution transformer (68.8 to 65.2 kV).	12/2011
Rectorville distribution transformer (67 to 65.2 kV).	5/2012
Cabin Hollow distribution transformer (69 to 67.275 kV).	12/2013
Tyner distribution transformer (68.8 to 65.2 kV).	12/2013
Beam distribution transformer (67 to 65.2 kV).	5/2014
Cedar Grove distribution transformer (67 to 65.2 kV).	5/2014
Charters distribution transformer (67 to 65.2 kV).	5/2014
Sinai distribution transformer (67 to 65.2 kV).	5/2014

Table 8.(2)(a)-37

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2009-2023)	
G. Transformer Tap Changes (continued) **Project Description**	**Needed In-Service Date**
Green Hall distribution transformer (165.025 to 161 kV)	12/2014
Hickory Plains distribution transformer (67 to 65.2 kV)	12/2014
Carson distribution transformer (70.275 to 69 kV).	5/2015
Coburg distribution transformer (67 to 65.2 kV)	12/2015
Hinkle distribution transformer (67.275 to 65.55 kV).	5/2017
McKinney's Corner distribution transformer (67 to 65.2 kV).	5/2017
Oven Fork distribution transformer (67 to 65.2 kV).	5/2017
Denny 161/69 kV autotransformer (161 kV to 156.975 kV).	12/2017
Rice Station distribution transformer (67 to 65.2 kV).	12/2017
Whitley City distribution transformer (67 to 65.2 kV).	12/2017
Mazie distribution transformer (67 to 65.2 kV).	5/2018
Summersville distribution transformer (67 to 65.2 kV).	5/2018

Table 8.(3)(b)11-1

Generating Plant Data

Dale Station

	Unit 1	**Unit 2**	**Unit 3**	**Unit 4**
Location	Ford, KY	Ford, KY	Ford, KY	Ford, KY
Status	Existing	Existing	Existing	Existing
Commercial Operation	Dec. 1, 1954	Dec. 1, 1954	Oct 1, 1957	Aug 9, 1960
Type	Steam	Steam	Steam	Steam
Net Dependable Capability	23 MW	23 MW	75 MW	75 MW
Entitlement (%)	100	100	100	100
Primary Fuel Type	Coal	Coal	Coal	Coal
Secondary Fuel Type	None	None	None	None
Fuel Storage (Tons)	70,000 for Plant Site	70,000 for Plant Site	70,000 for Plant Site	70,000 for Plant Site
Scheduled Upgrades, Deratings, Retirement Dates	None	None	None	None

Table 8.(3)(b)11-2

Generating Plant Data

	Cooper Station		Spurlock Station			
	Unit 1	**Unit 2**	**Unit 1**	**Unit 2**	**Gilbert**	**Unit 4**
Location	Somerset, KY	Somerset, KY	Maysville, KY	Maysville, KY	Maysville, KY	Maysville, KY
Status	Existing	Existing	Existing	Existing	Existing	Existing
Commercial Operation	Feb. 9, 1965	Oct. 28, 1969	Sept. 1, 1977	Mar. 2, 1981	March 1, 2005	April 1, 2009
Type	Steam	Steam	Steam	Steam	Steam	Steam
Net Dependable Capability	116 MW	225 MW	325 MW	525 MW	268 MW	278 MW
Entitlement (%)	100	100	100	100	100	100
Primary Fuel Type	Coal	Coal	Coal	Coal	Coal	Coal
Secondary Fuel Type	None	None	None	None	None	None
Fuel Storage (Tons)	250,000 for Plant Site	250,000 for Plant Site	105,000	175,000	105,000	105,000
Scheduled Upgrades, Deratings, Retirement Dates						

Table 8.(3)(b)11-3

Generating Plant Data

	Smith Combustion Turbines						
	Unit 1	**Unit 2**	**Unit 3**	**Unit 4**	**Unit 5**	**Unit 6**	**Unit 7**
Location	**Trapp, KY**	**Trapp, KY**	**Trapp, KY**	**Trapp, KY**	**Trapp, KY**	**Trapp, KY**	**Trapp, KY**
Status	Existing	Existing	Existing	Existing	Existing	Existing	Existing
Commercial Operation	3/1/99	1/1/99	4/1/99	11/10/01	11/10/01	1/12/05	1/12/05
Type	Gas	Gas	Gas	Gas	Gas	Gas	Gas
Net Dependable Capability	150 MW	150 MW	150 MW	98 MW	98 MW	98 MW	98 MW
Entitlement (%)	100	100	100	100	100	100	100
Primary Fuel Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
Secondary Fuel Type	Fuel Oil	Fuel Oil	Fuel Oil	Fuel Oil	Fuel Oil	Fuel Oil	Fuel Oil
Fuel Storage (Gallons)	4 million total	4 million total	4 million total	4 million total	4 million total	4 million total	4 million total
Scheduled Upgrades, Deratings, Retirement Dates	None	None	None	None	None	None	None

Table 8.(3)(b)11-4

Generating Plant Data

Smith Combustion Turbines

	Unit 9	Unit 10
Location	Trapp, KY	Trapp, KY
Status	Committed	Committed
Commercial Operation	2009	2009
Type	Gas	Gas
Net Dependable Capability	97 MW	97 MW
Entitlement (%)	100	100
Primary Fuel Type	Natural Gas	Natural Gas
Secondary Fuel Type	N/A	N/A
Fuel Storage (Gallons)	N/A	N/A
Scheduled Upgrades, Deratings, Retirement Dates	N/A	N/A

Table 8.(3)(b)11-5

Generating Plant Data

	Smith 1
Location	Trapp, KY
Status	Committed
Commercial Operation	Oct 2013
Type	Steam
Net Dependable Capability	278 MW
Entitlement (%)	100
Primary Fuel Type	Coal
Secondary Fuel Type	None
Fuel Storage (Tons)	230,000
Scheduled Upgrades, Deratings, Retirement Dates	N/A

Table 8.(3)(b)11-6

Generating Plant Data

	Bavarian	**Green Valley**	**Laurel Ridge #1-4**	**Laurel Ridge #5**	**Hardin Co.**	**Pendleton Co.**	**Mason Co.**
Location	Boone, KY	Greenup Co., KY	Lily, KY	Lily, KY	Hardin Co., KY	Pendleton Co., KY	Mason Co, KY
Status	Existing	Existing	Existing	Existing	Existing	Committed	Committed
Commercial Operation	9/22/03	9/9/03	9/15/03	2/1/06	1/15/06	1/07	
Type	Gas	Gas	Gas	Gas	Gas	Gas	Gas
Net Dependable Capability	3.2 MW	2.4 MW	3.2 MW	0.8 MW	2.4 MW	3.2 MW	1.6 MW
Entitlement (%)	100	100	100	100	100	100	100
Primary Fuel Type	Methane	Methane	Methane	Methane	Methane	Methane	Methane
Secondary Fuel Type	None	None	None	None	None	None	None
Fuel Storage	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Scheduled Upgrades, Deratings, Retirement Dates	None	None	None	None	None	None	None

Table 8.(3)(b)11-7

Generating Plant Data

	Future CFB 1
Location	Undetermined
Status	Proposed
Commercial Operation	Oct 2022
Type	Steam
Net Dependable Capability	278 MW
Entitlement (%)	100
Primary Fuel Type	Coal
Secondary Fuel Type	None
Fuel Storage (Tons)	230,000
Scheduled Upgrades, Deratings, Retirement Dates	N/A

Table 8.(3)(b)12-1

	ACTUAL															
Dale 1	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Capacity Factor	0.59	0.52	0.49	0.50	0.48	0.50	0.34	0.39	0.40	0.39	0.43	0.45	0.48	0.36	0.36	0.24
Availability Factor	0.98	0.81	0.90	0.90	0.90	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89
Average Heat Rate (Btu/kWh)	12,353	12,129	12,180	12,177	12,179	12,156	12,231	12,213	12,204	12,200	12,183	12,182	12,171	12,230	12,204	12,254
Fuel Cost ($/MMBtu)	[redacted]															
Variable O&M ($/MWh)																
Fixed O&M ($/kW/Yr)																
Variable Production Cost ($/MWh)																
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	1.1	2.7	2.7	2.7	2.7	2.3	2.2	2.4	2.4	2.4	2.4	2.4	2.4	2.4
	ACTUAL															
Dale 2	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Capacity Factor	0.58	0.55	0.53	0.53	0.55	0.53	0.39	0.43	0.44	0.44	0.47	0.48	0.52	0.40	0.39	0.28
Availability Factor	0.97	0.83	0.93	0.93	0.98	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91
Average Heat Rate (Btu/kWh)	12,170	11,909	11,969	11,967	11,965	11,934	12,007	12,003	11,996	11,992	11,971	11,967	11,956	12,014	11,993	12,054
Fuel Cost ($/MMBtu)	[redacted]															
Variable O&M ($/MWh)																
Fixed O&M ($/kW/Yr)																
Variable Production Cost ($/MWh)																
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	1.1	2.7	2.7	2.7	2.7	2.3	2.2	2.4	2.4	2.4	2.4	2.4	2.4	2.4

Table 8.(3)(b)12-2

	ACTUAL															
Dale 3	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Capacity Factor	0.64	0.49	0.45	0.43	0.43	0.48	0.34	0.38	0.40	0.39	0.43	0.44	0.47	0.36	0.36	0.27
Availability Factor	0.98	0.91	0.91	0.91	0.91	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89
Average Heat Rate (Btu/kWh)	11,470	11,714	11,785	11,848	11,728	11,645	11,827	11,771	11,770	11,751	11,717	11,703	11,681	11,862	11,852	12,008
Fuel Cost ($/MMBtu)	[redacted]															
Variable O&M ($/MWh)	[redacted]															
Fixed O&M ($/kW/Yr)	[redacted]															
Variable Production Cost ($/MWh)	[redacted]															
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	1.1	2.7	2.7	2.7	2.7	2.3	2.2	2.4	2.4	2.4	2.4	2.4	2.4	2.4
	ACTUAL															
Dale 4	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Capacity Factor	0.57	0.61	0.60	0.58	0.60	0.63	0.56	0.58	0.59	0.59	0.61	0.61	0.61	0.57	0.57	0.53
Availability Factor	0.90	0.92	0.92	0.92	0.92	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
Average Heat Rate (Btu/kWh)	11,806	11,602	11,564	11,634	11,565	11,499	11,613	11,580	11,550	11,552	11,523	11,517	11,505	11,598	11,603	11,700
Fuel Cost ($/MMBtu)	[redacted]															
Variable O&M ($/MWh)	[redacted]															
Fixed O&M ($/kW/Yr)	[redacted]															
Variable Production Cost ($/MWh)	[redacted]															
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	1.1	2.7	2.7	2.7	2.7	2.3	2.2	2.4	2.4	2.4	2.4	2.4	2.4	2.4

Table 8.(3)(b)12-3

	ACTUAL															
Cooper 1	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Capacity Factor	0.88	0.56	0.47	0.53	0.66	0.63	0.44	0.50	0.52	0.52	0.57	0.58	0.61	0.49	0.50	0.38
Availability Factor	0.90	0.79	0.91	0.91	0.91	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89
Average Heat Rate (Btu/kWh)	10,384	10,070	10,112	10,091	10,057	10,038	10,117	10,091	10,081	10,073	10,063	10,060	10,049	10,108	10,094	10,174
Fuel Cost ($/MMBtu)	[redacted]															
Variable O&M ($/MWh)																
Fixed O&M ($/kW/Yr)																
Variable Production Cost ($/MWh)																
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	1.1	2.7	2.7	2.7	2.7	2.3	2.2	2.4	2.4	2.4	2.4	2.4	2.4	2.4
	ACTUAL															
Cooper 2	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Capacity Factor	0.77	0.69	0.63	0.65	0.66	0.60	0.53	0.55	0.56	0.57	0.59	0.59	0.61	0.56	0.56	0.52
Availability Factor	0.91	0.92	0.92	0.92	0.92	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
Average Heat Rate (Btu/kWh)	10,346	9,920	9,944	9,925	9,927	9,958	10,017	9,997	9,985	9,984	9,967	9,961	9,949	9,990	9,995	10,031
Fuel Cost ($/MMBtu)	[redacted]															
Variable O&M ($/MWh)																
Fixed O&M ($/kW/Yr)																
Variable Production Cost ($/MWh)																
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	1.1	2.7	2.7	2.7	2.7	2.3	2.2	2.4	2.4	2.4	2.4	2.4	2.4	2.4

Table 8.(3)(b)12-4

	ACTUAL															
Spurlock 1	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Capacity Factor	0.79	0.78	0.83	0.80	0.81	0.80	0.76	0.77	0.78	0.78	0.79	0.79	0.80	0.76	0.76	0.72
Availability Factor	0.91	0.86	0.95	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
Average Heat Rate (Btu/kWh)	10,200	9,924	10,063	10,051	10,034	10,044	10,102	10,085	10,075	10,077	10,062	10,056	10,044	10,092	10,099	10,145
Fuel Cost ($/MMBtu)	[redacted]															
Variable O&M ($/MWh)																
Fixed O&M ($/kW/Yr)																
Variable Production Cost ($/MWh)																
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	1.1	2.7	2.7	2.7	2.7	2.3	2.2	2.4	2.4	2.4	2.4	2.4	2.4	2.4
	ACTUAL															
Spurlock 2	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Capacity Factor	0.80	0.91	0.88	0.94	0.89	0.88	0.84	0.85	0.86	0.86	0.87	0.88	0.89	0.85	0.84	0.80
Availability Factor	0.73	0.93	0.89	0.95	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89
Average Heat Rate (Btu/kWh)	10,118	9,907	9,902	9,892	9,885	9,894	9,945	9,930	9,919	9,923	9,909	9,903	9,892	9,939	9,950	9,992
Fuel Cost ($/MMBtu)	[redacted]															
Variable O&M ($/MWh)																
Fixed O&M ($/kW/Yr)																
Variable Production Cost ($/MWh)																
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	1.1	2.7	2.7	2.7	2.7	2.3	2.2	2.4	2.4	2.4	2.4	2.4	2.4	2.4

Table 8.(3)(b)12-5

	ACTUAL															
Gilbert Unit	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Capacity Factor	0.87	0.84	0.80	0.83	0.83	0.83	0.82	0.82	0.82	0.82	0.82	0.83	0.83	0.82	0.81	0.81
Availability Factor	0.85	0.91	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89
Average Heat Rate (Btu/kWh)	9,839	9,776	9,815	9,761	9,759	9,759	9,775	9,771	9,766	9,767	9,763	9,762	9,758	9,780	9,790	9,816
Fuel Cost ($/MMBtu)	[redacted]															
Variable O&M ($/MWh)																
Fixed O&M ($/kW/Yr)																
Variable Production Cost ($/MWh)																
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	1.1	2.7	2.7	2.7	2.7	2.3	2.2	2.4	2.4	2.4	2.4	2.4	2.4	2.4
Spurlock 4	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Capacity Factor		0.52	0.73	0.79	0.81	0.82	0.81	0.81	0.81	0.81	0.81	0.81	0.82	0.81	0.80	0.80
Availability Factor		0.83	0.85	0.88	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89
Average Heat Rate (Btu/kWh)		9,899	9,862	9,744	9,684	9,685	9,700	9,696	9,691	9,693	9,689	9,687	9,684	9,705	9,715	9,741
Fuel Cost ($/MMBtu)		[redacted]														
Variable O&M ($/MWh)																
Fixed O&M ($/kW/Yr)																
Variable Production Cost ($/MWh)																
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	1.1	2.7	2.7	2.7	2.7	2.3	2.2	2.4	2.4	2.4	2.4	2.4	2.4	2.4

Table 8.(3)(b)12-6

	ACTUAL															
Smith CT1	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Capacity Factor	0.02	0.06	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.01	0.01	0.00	0.00	0.00
Availability Factor	0.99	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96
Average Heat Rate (Btu/kWh)	15,598	12,567	12,963	12,995	12,879	12,926	12,842	12,988	12,955	12,949	12,939	12,740	12,589	12,570	12,680	12,521
Fuel Cost ($/MMBtu)	[redacted]															
Variable O&M ($/MWh)																
Fixed O&M ($/kW/Yr)																
Variable Production Cost ($/MWh)																
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0.2	1.7	2.9	2.7	2.9	2.7	2.4	2.4	2.5	2.5	2.5	2.5	2.5	2.5	2.5
	ACTUAL															
Smith CT2	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Capacity Factor	0.03	0.06	0.03	0.03	0.02	0.02	0.01	0.01	0.01	0.02	0.02	0.01	0.01	0.00	0.00	0.00
Availability Factor	0.97	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96
Average Heat Rate (Btu/kWh)	15,763	12,652	13,100	13,173	13,005	13,018	13,002	13,097	13,050	13,045	12,983	12,834	12,748	12,758	12,847	12,738
Fuel Cost ($/MMBtu)	[redacted]															
Variable O&M ($/MWh)																
Fixed O&M ($/kW/Yr)																
Variable Production Cost ($/MWh)																
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0.2	1.7	2.9	2.7	2.9	2.7	2.4	2.4	2.5	2.5	2.5	2.5	2.5	2.5	2.5

Table 8.(3)(b)12-7

	ACTUAL															
Smith CT3	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Capacity Factor	0.06	0.07	0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.02	0.02	0.02	0.01	0.01	0.01	0.00
Availability Factor	0.59	0.96	0.96	0.94	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96
Average Heat Rate (Btu/kWh)	16,453	12,487	12,994	13,052	13,067	13,071	13,065	13,131	13,115	13,101	13,059	12,938	12,792	12,886	12,924	12,941
Fuel Cost ($/MMBtu)	[redacted]															
Variable O&M ($/MWh)																
Fixed O&M ($/kW/Yr)																
Variable Production Cost ($/MWh)																
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0.2	1.7	2.9	2.7	2.9	2.7	2.4	2.4	2.5	2.5	2.5	2.5	2.5	2.5	2.5
	ACTUAL															
Smith CT4	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Capacity Factor	0.03	0.14	0.09	0.08	0.05	0.06	0.03	0.03	0.04	0.04	0.04	0.03	0.03	0.01	0.02	0.01
Availability Factor	1.00	0.95	0.99	0.99	0.99	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97
Average Heat Rate (Btu/kWh)	12,599	11,890	12,383	12,391	12,408	12,401	12,453	12,362	12,468	12,438	12,406	12,126	12,097	12,151	12,136	12,235
Fuel Cost ($/MMBtu)	[redacted]															
Variable O&M ($/MWh)																
Fixed O&M ($/kW/Yr)																
Variable Production Cost ($/MWh)																
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0.2	1.7	2.9	2.7	2.9	2.7	2.4	2.4	2.5	2.5	2.5	2.5	2.5	2.5	2.5

Table 8.(3)(b)12-8

	ACTUAL															
Smith CT5	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Capacity Factor	0.01	0.17	0.07	0.06	0.05	0.06	0.03	0.03	0.04	0.04	0.05	0.04	0.04	0.02	0.02	0.02
Availability Factor	0.99	0.99	0.95	0.99	0.99	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97
Average Heat Rate (Btu/kWh)	12,355	11,994	12,379	12,381	12,395	12,423	12,486	12,463	12,519	12,471	12,448	12,388	12,296	12,452	12,315	12,516
Fuel Cost ($/MMBtu)	[redacted]															
Variable O&M ($/MWh)																
Fixed O&M ($/kW/Yr)																
Variable Production Cost ($/MWh)																
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0.2	1.7	2.9	2.7	2.9	2.7	2.4	2.4	2.5	2.5	2.5	2.5	2.5	2.5	2.5

	ACTUAL															
Smith CT6	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Capacity Factor	0.03	0.18	0.06	0.05	0.05	0.05	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.02	0.03	0.02
Availability Factor	0.96	0.99	0.99	0.95	0.99	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97
Average Heat Rate (Btu/kWh)	12,115	12,010	12,340	12,336	12,367	12,344	12,432	12,539	12,470	12,409	12,340	12,364	12,333	12,434	12,419	12,484
Fuel Cost ($/MMBtu)	[redacted]															
Variable O&M ($/MWh)																
Fixed O&M ($/kW/Yr)																
Variable Production Cost ($/MWh)																
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0.2	1.7	2.9	2.7	2.9	2.7	2.4	2.4	2.5	2.5	2.5	2.5	2.5	2.5	2.5

Table 8.(3)(b)12-9

	ACTUAL															
Smith CT7	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Capacity Factor	0.03	0.09	0.05	0.05	0.06	0.06	0.03	0.05	0.04	0.05	0.04	0.04	0.04	0.02	0.04	0.02
Availability Factor	1.00	0.93	0.99	0.99	0.95	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97
Average Heat Rate (Btu/kWh)	12,076	11,812	12,237	12,264	12,318	12,230	12,412	12,581	12,438	12,349	12,252	12,443	12,385	12,367	12,487	12,501
Fuel Cost ($/MMBtu)	[redacted]															
Variable O&M ($/MWh)	[redacted]															
Fixed O&M ($/kW/Yr)	[redacted]															
Variable Production Cost ($/MWh)	[redacted]															
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0.2	1.7	2.9	2.7	2.9	2.7	2.4	2.4	2.5	2.5	2.5	2.5	2.5	2.5	2.5

Table 8.(3)(b)12-10

Landfill Gas Projects	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Capacity Factor	0.98	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.94	0.94
Availability Factor	0.84	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97
Average Heat Rate (Btu/kWh)	12199	11,850	11,850	11,850	11,850	11,850	11,850	11,850	11,850	11,850	11,850	11,850	11,850	11,850	11,850	11,850
Fuel Cost ($/MMBtu)	[redacted]															
Variable O&M ($/MWh)	[redacted]															
Fixed O&M ($/kW/Yr)	[redacted]															
Variable Production Cost ($/MWh)	[redacted]															
Capital Cost Escalation (%)																
O&M Escalation (%)		0.2	1.7	2.9	2.7	2.9	2.7	2.4	2.4	2.5	2.5	2.5	2.5	2.5	2.5	2.5

Table 8.(3)(b)12-11

Smith 1 (CFB)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Capacity Factor						0.23	0.83	0.83	0.84	0.83	0.84	0.84	0.85	0.83	0.82	0.80
Availability Factor						0.97	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89
Average Heat Rate (Btu/kWh)						9,588	9,590	9,578	9,571	9,573	9,562	9,552	9,542	9,600	9,617	9,672
Fuel Cost ($/MMBtu)						[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)						[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)						[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)						[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation (%)		-	-	-	-	2.8	2.9	2	1.9	2.3	2.2	2.2	2.2	2.2	2.2	2.2
O&M Escalation (%)		-	-	-	-	2.7	2.7	2.3	2.2	2.4	2.4	2.4	2.4	2.4	2.4	2.4
Future CFB	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Capacity Factor															0.15	0.80
Availability Factor															0.89	0.90
Average Heat Rate (Btu/kWh)															9,806	9,667
Fuel Cost ($/MMBtu)															[redacted]	[redacted]
Variable O&M ($/MWh)															[redacted]	[redacted]
Fixed O&M ($/kW/Yr)															[redacted]	[redacted]
Variable Production Cost ($/MWh)															[redacted]	[redacted]
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	2.2	2.2
O&M Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	2.4	2.4

Table 8.(3)(b)12-12

Smith CT 9	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Capacity Factor		0.02	0.22	0.24	0.25	0.25	0.15	0.18	0.18	0.19	0.21	0.22	0.24	0.17	0.18	0.13
Availability Factor		-	-	0.94	0.98	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96
Average Heat Rate (Btu/kWh)		9,428	9,877	9,852	9,789	9,814	9,953	9,958	9,901	9,866	9,774	9,805	9,789	9,909	9,917	9,996
Fuel Cost ($/MMBtu)		[redacted]														
Variable O&M ($/MWh)		[redacted]														
Fixed O&M ($/kW/Yr)		[redacted]														
Variable Production Cost ($/MWh)		[redacted]														
Capital Cost Escalation		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation		0.2	1.7	2.9	2.7	2.9	2.7	2.4	2.4	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Smith CT 10	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Capacity Factor		0.02	0.18	0.21	0.26	0.25	0.16	0.18	0.20	0.20	0.23	0.24	0.25	0.19	0.18	0.14
Availability Factor		0.75	0.85	0.94	0.98	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96
Average Heat Rate (Btu/kWh)		9,331	9,760	9,747	9,841	9,855	10,018	9,968	9,968	9,910	9,875	9,885	9,836	9,988	9,906	10,045
Fuel Cost ($/MMBtu)		[redacted]														
Variable O&M ($/MWh)		[redacted]														
Fixed O&M ($/kW/Yr)		[redacted]														
Variable Production Cost ($/MWh)		[redacted]														
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0.2	1.7	2.9	2.7	2.9	2.7	2.4	2.4	2.5	2.5	2.5	2.5	2.5	2.5	2.5

Table 8.(3)(b)12-13

Future CT 1	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Capacity Factor				0.02	0.08	0.10	0.06	0.06	0.08	0.07	0.10	0.10	0.09	0.07	0.08	0.05
Availability Factor				0.86	0.97	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98
Average Heat Rate (Btu/kWh)				12,307	12,599	12,659	12,675	12,655	12,678	12,658	12,620	12,620	12,605	12,742	12,732	12,813
Fuel Cost ($/MMBtu)				[redacted]												
Variable O&M ($/MWh)				[redacted]												
Fixed O&M ($/kW/Yr)				[redacted]												
Variable Production Cost ($/MWh)				[redacted]												
Capital Cost Escalation (%)		-	-	0.3	1.4	2.4	2.8	2.1	1.9	2.2	1.8	1.8	1.8	1.8	1.8	1.8
O&M Escalation (%)		-	-	2.9	2.7	2.9	2.7	2.4	2.4	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Future CT 2	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Capacity Factor											0.01	0.07	0.09	0.07	0.06	0.04
Availability Factor											1.00	1.00	1.00	1.00	1.00	1.00
Average Heat Rate (Btu/kWh)											12,318	12,477	12,528	12,695	12,665	12,742
Fuel Cost ($/MMBtu)											[redacted]					
Variable O&M ($/MWh)											[redacted]					
Fixed O&M ($/kW/Yr)											[redacted]					
Variable Production Cost ($/MWh)											[redacted]					
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	1.8	1.8	1.8	1.8	1.8	1.8
O&M Escalation (%)		-	-	-	-	-	-	-	-	-	2.5	2.5	2.5	2.5	2.5	2.5

Table 8.(3)(b)12-14

Future CT 3	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Capacity Factor												0.01	0.05	0.04	0.03	0.02
Availability Factor												1.00	1.00	1.00	1.00	1.00
Average Heat Rate (Btu/kWh)												12,157	12,372	12,552	12,487	12,619
Fuel Cost ($/MMBtu)												[redacted]				
Variable O&M ($/MWh)												[redacted]				
Fixed O&M ($/kW/Yr)												[redacted]				
Variable Production Cost ($/MWh)												[redacted]				
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	1.8	1.8	1.8	1.8	1.8
O&M Escalation (%)		-	-	-	-	-	-	-	-	-	-	2.5	2.5	2.5	2.5	2.5

Table 8.(3)(c)- 1

Power Transactions															
(GWH)	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Power Purchases	0	331.2	332.8	337.6	331.2	329.6	414	422	680.8	678.8	676.8	681.52	2428.8	2430.8	2432.8
Market Purchase	398.98	174.61	173.61	411.04	369.75	154.08	185.40	209.85	249.80	303.76	376.84	504.76	329.84	372.98	223.45
Duke Energy (Greenup)	302.0	302.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SEPA	257.0	253.1	259.2	262.3	258.5	256.9	259.4	255.9	258.6	257.6	258.3	259.7	257.4	256.2	254.0
Total Purchases	2967.0	3070.9	2776.6	3022.9	2972.5	2754.6	2873.8	2903.8	3206.2	3258.1	3330.9	3466.0	5037.0	5082.0	4933.3
Market Power Sales	8.7	23.2	40.4	2.4	10.3	85.8	181.4	187.8	196.9	200.3	188.3	171.0	333.2	376.1	630.2

Table 8.(3)(d)-1

Non-Utility Generation (GWH)	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Non-Utility Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Renewables*	0	0	0	0	0	0	0	0	262.8	262.8	262.8	263.52	262.8	262.8	262.8

* Generation from landfill gas to energy projects are included in the response to 8.(3)(b) and 8.(4)(c).

Table 8.(4)(b)-1

Forecast Energy	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Requirements (GWh)	13,927.28	14,081.13	14,256.87	14,607.50	14,908.32	14,941.54	15,290.62	15,543.82	15,797.79	16,171.10	16,356.37	16,794.60	17,199.37	17,505.65	17,914.81
(as modeled)															
Generation (GWH)															
Coal	12,132.25	10,529.70	11,658.00	12,958.70	14,230.60	15,040.60	15,477.90	16,499.60	16,960.40	17,867.60	18,164.80	18,326.20	18,756.20	19,661.30	19,903.30
Natural Gas	697.7	609.8	637.4	676.2	688.3	400.6	468.6	509.6	541.7	629.8	641.7	700.1	477.3	509.6	355.7
Landfill Gas	139.2	139.1	139.1	139.5	139.1	139.1	139.1	139.5	139.1	139.1	139.1	139.5	139.1	139.0	138.9
Total	12,969.14	11,278.56	12,434.55	13,774.36	15,057.99	15,580.33	16,085.66	17,148.66	17,641.24	18,636.51	18,945.60	19,165.82	19,372.54	20,309.98	20,397.92
Purchases (GWH)															
Firm Purchases-SEPA	257.0	253.1	259.2	262.3	258.5	256.9	259.4	255.9	258.6	257.6	258.3	259.7	257.4	256.2	254.0
Firm Purchases-Other Utilities	302.0	633.2	332.8	337.6	331.2	329.6	414.0	422.0	418.0	416.0	414.0	418.0	2166.0	2168.0	2170.0
Firm Purchases-Non-Utilities	0	0	0	0	0	0	0	0	262.8	262.8	262.8	263.52	262.8	262.8	262.8
Total	559.0	886.3	592.0	599.9	589.7	586.5	673.4	677.9	939.4	936.4	935.1	941.2	2686.2	2687.0	2686.8

Table 8.(4)(c)-1

Fuel Input (1,000s MBTU)															
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Coal	121,559	123,440	127,582	127,660	131,035	136,812	139,301	141,106	140,417	142,701	143,547	145,740	138,361	141,130	150,570
Natural Gas	8,372	6,767	7,011	7,346	7,550	4,385	5,150	5,604	5,961	6,929	7,044	7,684	5,261	5,623	3,930
Total	129,932	130,208	134,593	135,006	138,585	141,196	144,451	146,710	146,377	149,630	150,592	153,424	143,621	146,753	154,500
Fuel Input (Physical Units)															
Coal (1,000s Tons)	5,356	5,473	5,656	5,694	5,894	6,292	6,400	6,480	6,449	6,549	6,586	6,683	6,358	6,513	7,079
Natural Gas (1,000s mcf)	8,252	6,670	6,910	7,240	7,441	4,322	5,076	5,523	5,875	6,829	6,943	7,573	5,185	5,542	3,873

Section 9
Financial Information

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Section 9

9. Financial Information

9.(1) Present (base year) value of revenue requirements stated in dollar terms;

(2) Discount rate used in present value calculations;

(3) Nominal and real revenue requirements by year; and

(4) Average system rates (revenues per kilowatt hour) by year.

Table 9-1 provides the Present (base year) value of revenue requirements stated in dollar terms for the 2009 Integrated Resource Plan and the Nominal and Real Revenue Requirements (in $millions) from the Member Systems. The Average Rate for each of the forecast years included in the plan is defined as the Nominal Revenue Requirements divided by the total Sales to Members (in cents/kWh) and is also included in Table 9- 1 on page 9-1.

The discount rate used in present value calculations is [redacted]. This rate is based on the weighted average cost of EKPC's outstanding long-term debt as of December 31, 2008.

Table 9- 1
East Kentucky Power Cooperative, Inc.
Revenue Requirements and Average System Rates

Year	Sales to Members (MWh)	Total From Members Nominal $ ($000)	Total From Members Real 2009 $ * ($000)	Total From Members PV @ 9.45% ($000)	Nominal Cents per kWh	Real Cents per kWh Real 2009$
2009	[redacted]					
2010	[redacted]					
2011	[redacted]					
2012	[redacted]					
2013	[redacted]					
2014	[redacted]					
2015	[redacted]					
2016	[redacted]					
2017	[redacted]					
2018	[redacted]					
2019	[redacted]					
2020	[redacted]					
2021	[redacted]					
2022	[redacted]					
2023	[redacted]					
			**PV =	[redacted]		

*Assumes an annual inflation rate of [redacted]

** Present value of revenue requirements using EKPC's discount rate of [redacted] and a base date of 12/31/08.

Transmission System Map

Confidential Information

Redacted

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED
APR 21 2009
PUBLIC SERVICE COMMISSION

In the Matter of:

A REVIEW PURSUANT TO 807 KAR 5:058	)
OF THE 2009 INTEGRATED RESOURCE	)
PLAN OF EAST KENTUCKY POWER	) **CASE NO. 2009-00106**
COOPERATIVE, INC.	)

PETITION FOR CONFIDENTIAL TREATMENT OF INFORMATION

Comes now the petitioner, East Kentucky Power Cooperative, Inc. ("EKPC") and, as grounds for this Petition for Confidential Treatment of Information (the "Petition"), states as follows:

1. This Petition is filed in conjunction with the filing of EKPC's 2009 Integrated Resource Plan ("IRP") in this case, and relates to confidential information contained in that filing that is entitled to protection pursuant to 807 KAR 5:001 Section 7 and KRS §61.878 (1)(c) 1, and related sections.

2. The information designated as confidential in the IRP includes projected fuel costs, projected capital costs of potential generation facilities, and projected operations and maintenance costs (IRP Section 8), projections of revenue requirements, interest rates and escalation rates (IRP Section 9), and member system rate projections, forecasts, and other sensitive information concerning new large electric loads (IRP Technical Appendix included on the attached CD.) Disclosure of this information to utilities, independent power producers and power marketers that compete with EKPC for sales in the bulk power market, would allow such competitors to determine EKPC's

power production costs for specific periods of time under various operating conditions and to use such information to potentially underbid EKPC in transactions for the sale of surplus bulk power, which would provide an unfair commercial advantage to competitors of EKPC.

3. Disclosure of confidential information contained in IRP Section 8 relating to the estimated costs of future generation projects to potential bidders in future EKPC requests for proposals for generating capacity, or disclosure of confidential projections of fuel costs to potential fuel suppliers, could facilitate manipulation of bids, resulting in less competitive proposals and potentially higher future generation costs for EKPC. Such a situation would create an unfair commercial advantage to competitors of EKPC for the reasons stated and could artificially increase power costs to EKPC's member systems.

4. As part of the IRP filing, beginning at page 8-120, and in compliance with 807 KAR 5:058 Section 8, EKPC has included two maps detailing critical system infrastructure. One is a transmission planning work plan map entitled, "East Kentucky Power Cooperative Three Year Work Plan (November 2008 – December 2011)". The other is an EKPC System Map entitled, "East Kentucky Power Cooperative Service Center Territory Map". These maps both contain all or a combination of the exact geographic locations of EKPC generation stations, existing substations, proposed substations, service centers, high voltage transmission lines exceeding 69kV, and foreign utilities' high voltage transmission lines.

Location data of critical utility structures is very sensitive information and could provide a security risk for EKPC and its Member Systems.

KRS 61.878(1)(k) exempts from the public domain, except through Court Order, "All public records or information the disclosure of which is prohibited by federal law or regulation." Disclosure of transmission line locations, as well as the other types of sensitive data contained on the referenced maps, is specifically protected as Critical Energy Infrastructure Information per certain Orders of the Federal Energy Regulatory Commission (See, Order numbers 630, 630-A, 643, 649, 662, 683 and 702, and PL02-1-000).

The Commission is requested to afford these maps detailing Critical Energy Infrastructure Information confidential treatment.

5. Along with this Petition, EKPC has enclosed one copy of confidential sections of its 2009 IRP, with the confidential information identified by highlighting or other designation, and 10 copies with the confidential information redacted. The identified confidential information is not known outside of EKPC and is distributed within EKPC only to persons with a need to use it for business purposes. It is entitled to confidential treatment pursuant to 807 KAR 5:001 Section 7 and KRS §61.878(1)(c) 1, for the reasons stated hereinabove, as information which would permit an unfair commercial advantage to competitors of EKPC if disclosed. The subject information is also entitled to protection pursuant to KRS §61.878(1)(c) 2 c, as records generally recognized as confidential or proprietary which are confidentially disclosed to an agency in conjunction with the regulation of a commercial enterprise.

WHEREFORE, EKPC respectfully requests the Public Service Commission to grant confidential treatment to the identified information and deny public disclosure of said information.

Respectfully submitted,

Mark David Goss
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Lexington, KY 40507-1749
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Counsel for East Kentucky Power Cooperative, Inc.

CERTIFICATE OF SERVICE

This is to certify that an original and 10 copies of the foregoing Petition for Confidential Treatment of Information in the above-styled case were hand delivered to the office of the Public Service Commission, 211 Sower Boulevard, Frankfort, KY 40601 this 21st day of April, 2009. Further, this is to certify that copies of the foregoing Petition for Confidential Treatment of Information in the above-styled case were transmitted by first-class U.S. mail to: Hon. Dennis G. Howard, II, Assistant Attorney General, Utility and Rate Intervention Division, 1024 Capital Center Drive, Suite 200, Frankfort, Kentucky 40601-8204; and, Hon. Michael L. Kurtz, Boehm, Kurtz and Lowry, 36 East Seventh Street, Suite 1510, Cincinnati, Ohio 45202, pursuant to 807 KAR 5:001, Section 7(2)(c).

Counsel for East Kentucky Power Cooperative, Inc.