2015

INTEGRATED RESOURCE PLAN

REDACTED

April 21, 2015 **Case No. 2015-______**

EAST KENTUCKY POWER COOPERATIVE

A Touchstone Energy® Cooperative

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Page Reference	Filing Requirement	Description
a – 64-69 b – 49 c – 48 d – 49 e – 49 f – 42 g – 38,39,40,98-108 h – 52, 53, 56	807 KAR 5:058 Section 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: (a) Average annual number of customers by class as defined in subsection (1) of this section; (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; (c) Recorded and weather-normalized coincident peak demand in summer and winter for the system; (d) Total energy sales and coincident peak demand to retail and wholesale customers for which the utility has firm, contractual commitments; (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; (f) Annual energy losses for the system; (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; (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.
38-40	807 KAR 5:058 Section 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.

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SECTION 1.0

EXECUTIVE SUMMARY

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EXECUTIVE SUMMARY

1.1 General Overview

807 KAR 5:058 Section 5.(1) Description of the utility, its customers, service territory, current facilities, and planning objectives.

East Kentucky Power Cooperative Inc. ("EKPC") is a not-for-profit, member-owned generation and transmission cooperative located in Winchester, Kentucky. EKPC provides wholesale electricity to its 16 owner-member distribution cooperatives, which serve approximately 525,000 Kentucky homes, farms, businesses and industries across 87 counties. Owner-member distribution cooperatives served by EKPC include:

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

EKPC owns and operates coal-fired generation at Dale Station in Clark County (149 MW), Cooper Station in Pulaski County (341 MW), and Spurlock Station in Mason County (1,346 MW). EKPC also owns and operates gas-fired generation at Smith Station in Clark County (774 MW summer rating). EKPC also owns and operates Landfill Gas to Energy renewable generation facilities in Boone County (3.2 MW), Laurel County (4.0MW), Greenup County (2.4 MW), Hardin County (2.4 MW) and Pendleton County (3.2MW).

EKPC purchases hydropower from the Southeastern Power Administration ("SEPA") on a long-term basis. Laurel Dam (70 MW) historically has been a reliable resource. However, due to various repair projects, EKPC's 100 MW allocation from the Cumberland System has not provided dependable capacity and energy for several years and is not expected to be considered 100% dependable until spring 2018. Once the dam repairs are completed, the capacity should return to firm dependable status for the long-term.

In total, EKPC owns and/or purchases 2,794 MW of generation. EKPC operates within the PJM Interconnection, Inc. ("PJM"), which has over 180,000MW of generation. EKPC's all-time peak demand of 3,507 MW occurred on February 20, 2015.

EKPC owns and operates a 2,938-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 SERC Reliability Corporation ("SERC"). EKPC maintains 73 normally closed free-flowing interconnections with its neighboring utilities.

1.2 Load Forecast

In order to align the load forecast process with the IRP process, EKPC's load forecast is prepared every three years in accordance with EKPC's Rural Utilities Service (RUS) approved Work Plan. The Work Plan details the methodology used in preparing the projections. EKPC prepares the load forecast by working jointly with each member system to prepare its load forecast. Member system projections are then summed to determine EKPC's forecast. Member systems use their load forecasts in developing construction work plans, long-range work plans, and financial forecasts. EKPC uses the load forecast in such areas as demand-side management analyses, marketing analyses, transmission planning, power supply planning, and financial forecasting.
The forecast indicates that for the period 2015 through 2034, total energy requirements will increase by 1.4 percent per year. Winter and summer net peak demand will increase by 1.0 percent and 1.5 percent, respectively. Annual load factor is projected to grow from 48 percent to 51 percent.

1.3 Demand Side Management ("DSM")

EKPC selects Demand-Side Management ("DSM") programs to offer on the basis of meeting customer preferences and resource planning objectives in a cost-effective manner. EKPC analyzes DSM measures and programs using both qualitative and quantitative criteria. These criteria include customer acceptance, measure applicability, savings potential, and cost-effectiveness. The cost-effectiveness of DSM resources is analyzed in a rigorous fashion using standard (California) tests.

For the 2015 IRP, EKPC has enhanced its DSM planning capabilities by undertaking a comprehensive study of energy efficiency (EE) savings potential. For the EE potential study, GDS Associates, Inc. ("GDS") conducted a cost-effectiveness screening of a comprehensive set of measures using the Total Resource Cost test from the California standard. This resulted in a greater number of DSM measures receiving cost-benefit analysis and a comprehensive evaluation of DSM measures for this IRP.

EKPC prepared cost and participation estimates for all of the DSM programs, and conducted a final cost-effectiveness analysis for each DSM program using the widely accepted "DSMore" software tool.

1.4 Power Supply Actions

EKPC desires to keep its plans as flexible as possible to be able to adjust to market and load conditions as needed. EKPC continues to monitor its load and all economic power supply alternatives. EKPC joined PJM on June 1, 2013, which has significantly impacted its operations and improved its ability to economically serve its native load. EKPC realized significant savings benefits from operating within PJM from June 1, 2013 through March 31, 2014, as described in its report to the Kentucky Public Service Commission on May 31, 2014. EKPC's winter energy shortfalls were met this year with Power Purchase Agreements ("PPA"). EKPC plans to continue to utilize PPAs, which can be shaped to best match EKPC's load requirements in the short-term, unless a more advantageous alternative is identified. Even though PJM has sufficient capacity to serve the EKPC winter load during the winter peak season, energy prices are not guaranteed, can be extremely volatile, thus making it challenging for EKPC to secure reasonably priced energy to supply its winter peak system load.

Due to the Mercury and Air Toxics Standards (MATS) environmental regulation, EKPC will be placing its Dale Station on inactive status and rerouting the duct system at Cooper 1 to utilize the existing scrubber on Cooper 2. EKPC is also considering other proposed environmental regulations, including the Clean Power Plan and regulations for water and waste. EKPC chose to reroute the duct system at Cooper 1 based on results from a Request for Proposals ("RFP") for Power Supply Alternatives it issued in 2012. Results of that RFP were evaluated and documented in Case No. 2013-00259.

1.5 Recommended Plan of Action

807 KAR 5:058 Section 5.(5) Steps to be taken during the next three (3) years to implement the plan.

EKPC exists to serve its member-owner cooperatives by safely delivering reliable and affordable energy and related services. EKPC's objective of the power supply plan is to develop an economic, reliable plan, while simultaneously mitigating financial and operational risks. EKPC has an on-going planning process and this IRP represents only one snapshot in time of the process. Changing conditions will warrant changes to this IRP.

To meet its objective, EKPC will take the following actions in the near term:

- Continue to monitor economic and load growth conditions
- Continue to develop and promote DSM programs
- Continuously compare PPA costs against other power supply alternatives identified in the RFP process
- Continue to maximize the operational and economic benefits realized by being a member of PJM
- Work with Federal and State stakeholders to ensure the economic viability of EKPCs existing and future resources to meet the challenges and opportunities in complying with current and proposed environmental regulations

1.6 Issues or Uncertainties that Could Affect Successful Implementation of Plan

807 KAR 5:058 Section 5.(6) Discussion of key issues or uncertainties that could affect successful implementation of the plan.

As with any plan, there are risks and uncertainties associated with the recommended plan of action.

- *Continue to monitor economic and load growth conditions.* Today's financial environment provides an economic opportunity to invest in capital infrastructure. If EKPC were to miss significant changes in its load conditions that would warrant investing in capital intensive power supply projects, then the long-term impact to member owners may be higher financing costs for future projects. Therefore, monitoring economic and load conditions is critical to EKPC's plans, along with remaining aware of project opportunities.
- *Continue to develop and promote DSM programs.* EKPC desires to develop reasonable and economic DSM programs. Participation in these programs by retail customers will ultimately determine the amount of energy savings and capacity that is avoided. EKPC uses California tests to cost justify its DSM tariffs. The California tests compare DSM programs to the avoided costs of capacity and energy. EKPC is pursuing DSM programs that pass the Total Resource Cost (TRC) tests. Power supply plans will need to be adjusted according to the actual amount of DSM realized. EKPC has kept its power supply plans flexible, which will help facilitate DSM implementation, in that EKPC plans to make purchases to cover peaking power supply requirements. These purchases allow for the maximum amount of DSM to be developed while not placing the EKPC power supply system at risk.
- *Continuously compare PPA costs against other power supply alternatives identified in the RFP process.* EKPC is short on capacity to supply its winter peak period load. PJM provides enough capacity to cover EKPC's winter peak load, but prices for that energy are not secured. EKPC's experiences in January of 2014 and February of 2015 solidified the need to secure price hedges for its winter load position. PPAs, along with owned generation, have met most but not all needs for EKPC during the 2014-2015 winter peak period. That need will increase when the Dale 3 and 4 units are placed on inactive status

in April 2016, due to not being compliant with the EPA Mercury and Air Toxic Standard ("MATS") rules. EKPC will either need to continue to enter into PPAs going forward or pursue other economic power supply alternatives identified in its RFP process. EKPC will seek to find the most economical alternative to meet its power supply requirements and meet future EPA rules. EKPC refreshed its RFP offers in summer 2014 and is currently negotiating with a third party for a potential long term solution to its winter capacity needs.

- *Continue to maximize the operational and economic benefits realized by being a member of PJM.* EKPC joined PJM on June 1, 2013. EKPC identified significant cost benefits that accrued to its members from June 1, 2013 through March 31, 2014 in its annual report to the Public Service Commission dated May 31, 2014. EKPC anticipates it will have realized similar or greater savings when it files that same annual report in 2015. EKPC actively participates on the PJM Committees and in stake holder processes. EKPC provides continuing education to its System Operators to keep them certified to operate within the PJM system, as well as to other key personnel to ensure that opportunities for improvement are being recognized and utilized.
- *Work with Federal and State stakeholders to ensure the economic viability of EKPCs existing and future resources to meet the challenges and opportunities in complying with current and proposed environmental regulations.* EKPC is committed to deliver reliable and affordable energy from appropriately diversified fuel sources to its Owner-Members, and to work with federal and state stakeholders to ensure the economic viability of EKPC's existing and future resources to meet the challenges and opportunities in complying with current and proposed environmental regulations.

1.7 EKPC Demand-Side Management and Renewable Energy "Collaborative"

The Collaborative completed its work October 23, 2013 and produced a report of its findings. That report is included in this IRP as Exhibit DSM-9 of the DSM Technical Appendix.

1.8 Organization of the 2015 IRP

807 KAR 5:058 Section 4.(2) Each plan filed shall identify the individuals responsible for its preparation, who shall be available to respond to inquiries during the commission's review of the plan.

Individuals responsible for the preparation of the IRP include:

David Crews, Senior Vice President of Power Supply

Craig Johnson, Senior Vice President of Power Production and Construction

Julia Tucker, Director of Power Supply Planning

Jerry Purvis, Director of Environmental Affairs

Sally Witt, Manager of Load Forecasting

Darrin Adams, Director of Planning, Design and Construction

Scott Drake, Manager of Corporate Technical Services

Robin Hayes, Manager of Performance and Improvement

Sandy Mollenkopf, Load Forecast Analyst

Patrick Woods, Director of Regulatory and Compliance

Legal Counsel: Mark David Goss and David Samford, Goss Samford PLLC

807 KAR 5:058 Section 4.(1) The integrated resource plan shall be clearly and concisely organized so that it is evident to the commission that the utility has complied with reporting requirements described in subsequent sections.

EKPC's 2015 IRP is organized in accordance with the sequencing of the planning process, while clearly cross-referencing the appropriate citation to 807 KAR 5:058.

EKPC used the PSC Staff Report of the 2012 IRP as a starting point in their analysis for this 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").

1.9 Significant Changes from 2012

807 KAR 5:058 Section 6. Significant Changes. All integrated resource plans, shall have a summary of significant changes since the plan most recently filed. This summary shall describe, in narrative and tabular form, changes in load forecasts, resource plans, assumptions, or methodologies from the previous plan. Where appropriate, the utility may also use graphic displays to illustrate change

EKPC joined PJM on June 1, 2013

EKPC integrated its operations into the PJM market on June 1, 2013. PJM operates a reliability constrained two-settlement Energy Market that matches Day-Ahead load requirements with economic generation and demand resources and balances the actual needs in Real-Time. EKPC's generation fleet is now economically dispatched with PJM's other generation and demand resources (over 180,000 MW) which has significantly affected EKPC's electric power procurement and energy accounting practices. As expected, EKPC's total power supply costs to its owner-members have decreased subsequent to integration, due to the economies of scale of a much larger system dispatch. EKPC identified a substantial net savings realized through March 2014, as documented in its letter to Mr. Jeff Derouen, Executive Director of the Kentucky Public Service Commission, dated May 31, 2014.

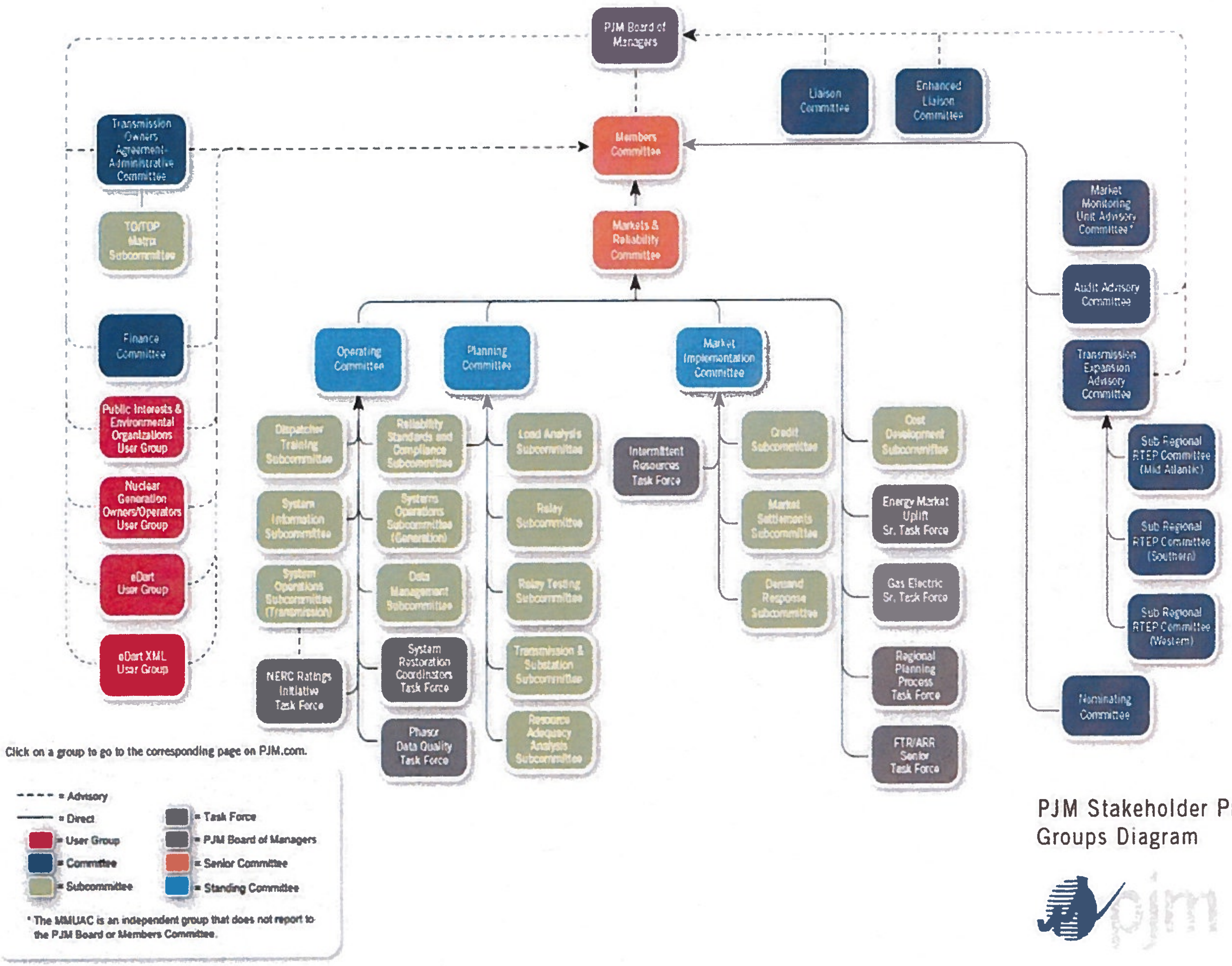
In addition to the daily Energy Market interactions, EKPC also participates in PJM's Capacity Market auctions along with the Annual Revenue Rights and Financial Transmission Rights auctions.

EKPC's obligation to PJM for capacity is defined via the Capacity Market auctions. EKPC's minimum obligation as a Load Serving Entity ("LSE") within PJM requires that EKPC either provide or secure enough capacity to cover its summer peak load plus approximately 3% reserves. PJM carries more than a 3% capacity reserve margin, however, EKPC's load diversity with the PJM market allows the net impact on EKPC to be roughly 3%. This defines the minimum amount of capacity that EKPC needs to secure its load coverage. However, this minimum capacity requirement does not define or guarantee any energy rates. The only way to guarantee a maximum cost on energy is to secure enough resources for use in the PJM Energy Market to provide price hedges on energy usage. Therefore, EKPC's capacity requirement may only be summer peak plus reserves but its energy cost maximum exposure continues to be during the winter peak season when EKPC's load is at its highest levels. EKPC continues to need to hedge its energy price exposure throughout the year.

As a member of PJM, EKPC is actively involved in the PJM Stakeholder Process. The Stakeholder Process is comprised of two Senior Committees (Members Committee and the Markets and Reliability Committee), three additional Standing Committees (Market Implementation, Operating, and Planning Committees), Subcommittees or Working Groups created by these five Committees, and User Groups established in accordance with PJM's Operating Agreement.

Reports and proposals move from the subcommittees and working groups to their "parent" Standing Committee and from there to the "parent" Senior Committee. Policies approved by this Stakeholder Process then move from the Senior Committee to the PJM Board of Directors for approval. Policies receiving approval by the PJM Board of Directors are then submitted to FERC for approval if required.

EKPC is represented on each of the Senior and Standing Committees. EKPC is also represented on the Subcommittees and Working Groups which have been deemed crucial to EKPC. The EKPC representatives to the PJM Committees, Subcommittees, and Working Groups meet monthly to discuss the issues and policy development within the PJM Stakeholder Process and report to EKPC's Senior Executives. Please see the PJM Organizational Chart on the following page or you may visit the following link to view the same: http://www.pjm.com/committees-and-groups/committees.aspx.



PJM Stakeholder Process Groups Diagram

Cooper #1 Retrofit

On August 21, 2013, EKPC filed an application, pursuant to KRS 278.020(1), KRS 278.183, and 807 KAR 5:001, Sections 14 and 15, requesting a Certificate of Public Convenience and Necessity ("CPCN") for the rerouting of certain duct work at its J. S. Cooper Generating Station ("Cooper Station") near Burnside, Kentucky, and approval of an amendment to its environmental compliance plan for purposes of recovering the costs of this project through EKPC's environmental surcharge (PSC Case No. 2013-00259). The Cooper Station consists of two baseload coal-fired electric generating units. Cooper Unit 1, which became operational in 1965, has a rated capacity of 116 megawatts ("MW") and Cooper Unit 2, which became operational in 1969, is rated at 225 MW of capacity. EKPC proposed to re-route the existing duct work for Cooper Unit 1 such that its emissions are able to flow to the Cooper Unit 2's Air Quality Control System ("AQCS") to enable Cooper Unit 1 to satisfy certain air emission regulations. The capital cost of the project is estimated to be $15 million, with annual ongoing operating and maintenance costs of approximately $2.6 million. The anticipated cost of the project to the average residential retail customer is approximately $0.35 per month. On February 20, 2014, The Kentucky Public Service Commission issued an Order granting EKPC's request for the CPCN. The construction is scheduled to begin in the summer of 2015 with the tie-in of the new duct work during the month of October 2015. The system will be commissioned in November to ensure performance and reliability prior to the winter months and the Federal MATS compliance deadline in April 2016.

DSM Program Enhancements

EKPC sponsored an Energy Efficiency Potential Study performed by GDS. The project scope included detailed energy efficiency potential study for residential and commercial/industrial customers resulting in a more comprehensive set of DSM measures evaluated.

With an increased focus on DSM programs, EKPC procured and implemented a new DSM Program Tracking System provided by Direct Technology. The system supports efficient and more comprehensive data collection, program administration, and reporting capabilities.

Three existing energy efficiency programs were expanded to offer multiple rebates levels based on the amount of energy savings. The following programs changed from offering 1 rebate to offering 3 rebate levels:

- Button-up Weatherization
- Heat Pump Retrofit
- Touchstone Energy Home – New home construction

All program changes were approved by the PSC via DSM program tariff changes.

New DSM programs have been, or are being, added to the DSM program portfolio. The following programs received PSC tariff approval:

- Appliance Recycling Program (ARP) offers a $50 incentive per working and recycled refrigerator and/or freezer.
- ENERGY STAR Appliance Program (ESAP) offers rebates ranging from $50-$300 for 7 different ENERGY STAR qualified appliance types.
- ENERGY STAR Manufactured Home incentivizes the manufactured home factories to upgrade new homes from HUD standards to ENERGY STAR standards.

The following program tariff is being filed contemporaneously with this IRP:

- Low Income with Community Action Program leverages the Community Action Agencies of Kentucky to provide additional funding to improve the energy efficiency of low income housing. This program's DSM tariff is under review by the PSC.

Discussion of differences between 2015 IRP Load Forecast and the 2012 IRP Load Forecast

The 2015 IRP load forecast differs from the 2012 IRP load forecast in multiple aspects. While previous load forecasts had shown downward revisions (graphically shown in Figure 1-1, 1-2 and 1-3) for several previous IRP updates, the 2015 IRP load forecast projections are similar to the 2012 projections for energy indicating an end to this trend. Given this, EKPC believes there is more upside risk than downside for this forecast. Residential customers show an overall downward revision from 2012. This is due in part to the fact that the actual customers were coming in lower than projected in the 2012 IRP load forecast. Total commercial and industrial sales show an upward revision in the short term. While some member systems are continuing to struggle due to the economy, especially in the Eastern part of the state, others are seeing new commercial and industrial growth. Tables 1-1 and 1-2 display comparisons between the 2012 and 2015 load forecasts used in the IRPs for pre-DSM and post-DSM, respectively.

Table 1-1
Forecast Comparison – Pre-DSM
2015 IRP Versus 2012 IRP

		2015	2012*	Difference
Residential Sales, MWh	2015	7,116,809	7,214,785	-97,976
	2020	7,545,866	7,762,969	-217,103
	2025	8,014,115	8,447,041	-432,926
Total Commercial and Industrial Sales, MWh	2015	5,253,942	5,243,362	10,580
	2020	5,916,745	5,901,140	15,605
	2025	6,416,079	6,448,624	-32,545
Residential Customers	2015	495,084	513,141	-18,057
	2020	516,467	551,347	-34,880
	2025	541,888	591,485	-49,597
Net Winter Peak, MW	2015	3,338	3,320	18
	2020	3,502	3,628	-126
	2025	3,650	3,958	-308
Net Summer Peak, MW	2015	2,484	2,611	-127
	2020	2,696	2,841	-145
	2025	2,897	3,095	-198
Total Requirements, MWh	2015	13,439,174	13,530,522	-91,348
	2020	14,635,885	14,845,233	-209,348
	2025	15,690,271	16,187,502	-497,231

Table 1-2
Forecast Comparison – Post DSM
2015 IRP Versus 2012 IRP

		2015	2012*	Difference
Residential Sales, MWh	2015	7,085,268	6,862,801	222,467
	2020	7,151,117	7,073,245	77,872
	2025	7,249,485	7,632,317	-382,832
Total Commercial and Industrial Sales, MWh	2015	5,214,702	5,200,296	14,406
	2020	5,877,505	5,858,068	19,437
	2025	6,376,839	6,405,545	-28,706
Residential Customers	2015	495,084	513,141	-18,057
	2020	516,467	551,347	-34,880
	2025	541,888	591,485	-49,597
Net Winter Peak, MW	2015	3,201	3,063	138
	2020	3,261	3,270	-9
	2025	3,321	3,542	-221
Net Summer Peak, MW	2015	2,324	2,376	-52
	2020	2,428	2,569	-141
	2025	2,566	2,797	-231
Total Requirements, MWh	2015	13,368,393	13,135,472	232,921
	2020	14,381,207	14,112,437	268,770
	2025	15,387,167	15,329,699	57,468

* Please note the numbers reflected in Tables 1-1 and 1-2 for 2012 do not match the data in the 2012 IRP report. In 2012, the Residential Class included Seasonal sales and customers. In 2015, these are reported separately. In order to make a valid comparison, the seasonal customers and sales were subtracted from the 2012 data. Likewise, 2012 combined commercial, industrial, public buildings and lighting. These were subtracted for the purposes of the above comparisons.

Figure 1-1
Comparison of Load Forecasts
Net Total Energy Requirements (Millions MWh)

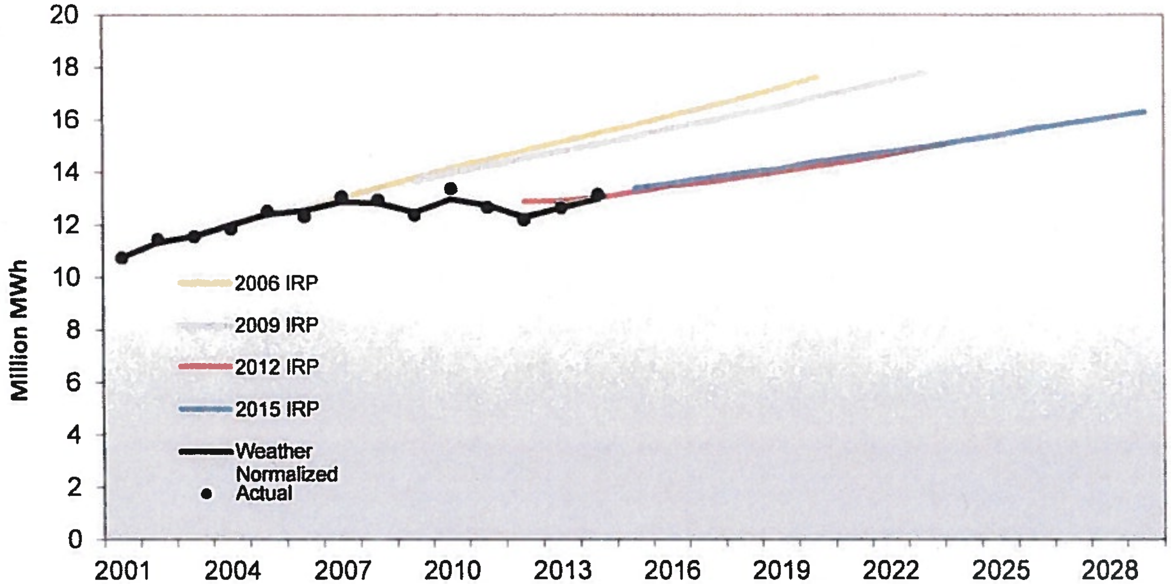


Figure 1-2
Comparisons of Load Forecasts
Winter Peak Demand Projections (MW)

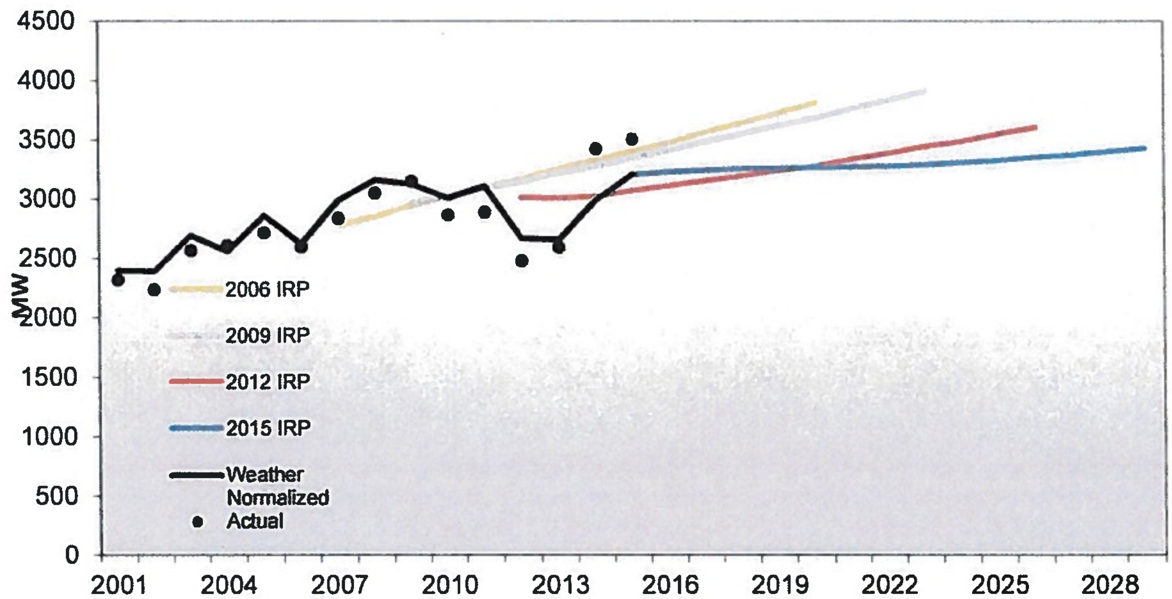
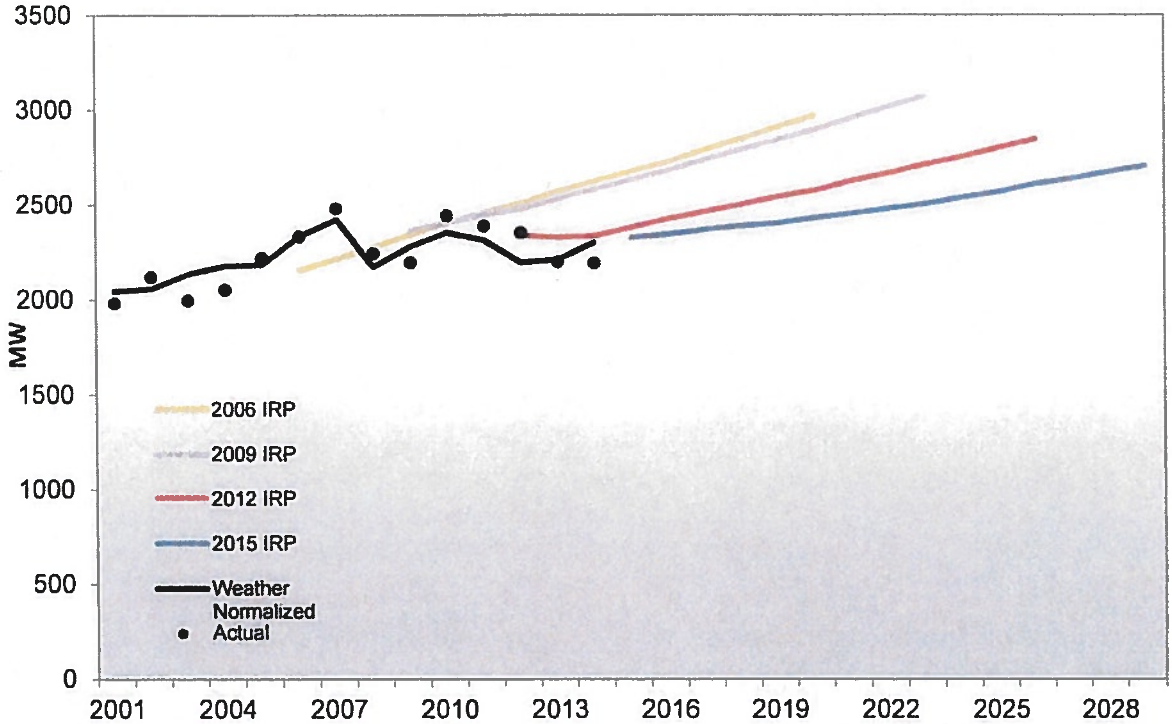


Figure 1-3
Comparison of Load Forecasts
Summer Peak Demand Projections (MW)



DSM Differences

In the 2012 IRP, the DSM projections were based on a technical feasibility analysis. At that time, EKPC noted that these projections would need to be refined to better match what could be achieved year by year.

For this 2015 IRP, EKPC has fine-tuned its DSM modeling projections to narrow the gap between its theoretical and actual peak demand and energy savings. EKPC has significantly enhanced its DSM planning capabilities by undertaking a comprehensive study of energy efficiency (EE) savings potential. This study was performed by GDS.

EKPC set a goal of achieving the equivalent of 1% of annual retail sales in new DSM annual kWh savings each year. The findings from the potential study show that this goal is achievable in the medium and long term. However, the levels of activity and spending far outstrip current performance and budgeting. In fact, EKPC is currently producing 0.2% of annual retail sales in new DSM annual kWh.

In order to narrow this gap, EKPC has established a ramp-up period of six years (2015-2020) during which time the plan is to steadily increase the investment in DSM resources so that the goal of 1% of annual retail savings by the year 2020 may be achieved. Participation projections reflect this steady increase in the years 2015-2020 then leveling off at participation levels that consistently achieve the 1% goal thereafter (from 2020-2029).

As a result, the 2015 IRP impacts are projected to be lower than the 2012 IRP impacts in the early years of the plan.

Table 1-3 presents the differences between the 2012 DSM plan and the 2015 DSM plan. When comparing the values, keep in mind that the base year for the 2012 plan was 2006, while the base year for the 2015 plan is 2014. This means for example that the 395,050 MWh of savings in 2015 from the 2012 plan represented nine years of participation, while the 78,967 MWh in the 2015 plan represents one year of participation.

Section 5.0 – Demand Side Management – provides the details of the DSM plan.

Table 1-3

Forecast Comparison between the IRP for DSM impact projections
2012 Versus 2015

	2012 IRP			2015 IRP		
Year	Impact on Energy Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)	Impact on Energy Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2015	395,050	322	307	78,967	137	160
2016	470,983	346	337	117,270	153	182
2017	545,245	367	361	163,280	169	202
2018	619,377	388	382	242,331	188	224
2019	683,801	406	395	336,804	212	249
2020	732,796	422	407	452,573	241	268
2021	781,988	438	419	551,746	263	284
2022	801,546	449	426	637,754	282	298
2023	822,287	460	433	715,315	298	310
2024	840,096	470	439	790,815	314	321
2025	857,803	480	446	856,275	329	331
2026	875,526	490	452	923,237	344	341
2027				987,854	359	351
2028				1,042,324	372	359
2029				1,086,303	383	367

Difference between 2015 Expansion Plan and 2012 Expansion Plan

In comparison to the 2012 IRP, the projected capacity needs in the 2015 IRP are 400 MWs lower by the year 2026. See Table 1-4 below. EKPC joined PJM on June 1, 2013 and its future capacity requirements changed accordingly. PJM bases its members' capacity requirements on summer peak loads. However, EKPC continues to need to economically supply energy for its winter load requirements in addition to the PJM summer capacity requirements.

Table 1-4

EKPC Projected Major Capacity Additions

2012 IRP Capacity Available on January 1 — Winter Season Capacity

Year	Baseload Capacity	Peaking/ Intermediate Capacity	Cumulative Capacity Additions
	(MW)		
2015			
2016		275	275
2017			275
2018		100 Seasonal Purchase(s)	375
2019			375
2020		100 Seasonal Purchase(s)	475
2021			475
2022		100 Seasonal Purchase(s)	575
2023		275	850
2024			850
2025			850
2026			850
2027			850
2028			850
2029			850

2015 IRP Capacity Available on January 1 — Winter Season Capacity

Year	Baseload Capacity	Peaking/ Intermediate Capacity	Cumulative Capacity Additions
	(MW)		
2015			
2016		150 Seasonal Purchase(s)	150
2017		250 Seasonal Purchase(s)	400
2018			400
2019			400
2020			400
2021			400
2022			400
2023			400
2024			400
2025			400
2026		50 Renewable Energy PPA	450
2027			450
2028		50 Renewable Energy PPA	500
2029		50 Renewable Energy PPA	550

SECTION 2.0

PSC STAFF REPORT ON THE 2012 IRP RECOMMENDATIONS

SECTION 2.0

PSC Staff Recommendations to EKPC's 2012 IRP

2.1 Introduction

EKPC submitted its 2012 IRP (PSC Case No. 2012-00149) to the Commission on April 20, 2012. The report submitted by EKPC provided its plan to meet the power requirements of its 16 member distribution cooperatives over the period from 2012 to 2026. On September 26, 2013, EKPC received the Commission Staff's Report on the 2012 Integrated Resource Plan of East Kentucky Power Cooperative, Inc. The purpose of the report was to review and evaluate EKPC's 2012 IRP in accordance with the requirements of 807 KAR 5:058, Section 11(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.

2.2 PSC Staff Recommendations

807 KAR 5:058 Section 11.(4) A utility shall respond to the staff's comments and recommendations in its next integrated resource plan filing. (17 Ky.R. 1289; Am. 1720; eff. 12-18-90; 21 Ky.R. 2799; 22 Ky.R. 287; eff. 7-21-95.)

Below are the Commission Staff's recommendations and EKPC's responses from the 2012 IRP and EKPC's responses.

Load Forecasting

- **Include a detailed analysis of the potential impact of future environmental requirements that may be applicable to burning fossil fuels (including but not limited to, restrictions on emissions of CO2 and other greenhouse gases, carbon capture and sequestration, and a tax on carbon) and an explanation of how these potential impacts are incorporated into EKPC's present forecasts or how the potential impacts will be incorporated into future forecasts.**

Legal and Environmental experts provide interpretation of the pending rules to EKPC's Production, Construction and Engineering groups, as well as Burns and McDonnell, Owner-

Engineer. Owner-Engineer develops cost estimates for Production under the advice of legal counsel. The cost estimates are shared with Finance to be placed in the Long Range Financial Forecast. EKPC has provided a detailed description of potential new and pending environmental regulations in Section 9.0 of this report. Future wholesale rate predictions are developed in the Long Range Financial Forecast; that rate forecast is then used as input into the load forecast model. Therefore, impacts of future environmental regulations are incorporated into the EKPC planning cycle via the load forecast projections. The detailed considerations are discussed in Section 9.0.

- **EKPC should continue to report on how its actual energy and demand levels compare to its forecasted levels for the time periods between IRP filings.**

As noted in previous IRPs, the load forecasts have shown decreases from previous forecasts for several years. EKPC believes this reflects the slower than expected economic recovery since 2008. The downward revisions have stabilized in the 2015 projections when compared to previous iterations of the load forecast. Details and graphs are shown on pages 52-53 in Section 3.0.

- **EKPC should continue to include a detailed analysis of how the impact of federal mandatory efficiency improvements for appliances are reflected in its demand forecasts, as well as in the energy forecasts, along with the associated values, for its residential, commercial and industrial customer classes.**

EKPC is a member of Itron's Energy Forecasting Group and as such, receives from Itron, electric appliance efficiency trend projections for the East South Central U.S. Census Division (which comprises the states of Alabama, Kentucky, Mississippi, and Tennessee) based on information from the Energy Information Administration (EIA). These trend projections capture the impact of federal mandatory efficiency improvements as well as the impacts of other factors. These equipment efficiency trends are used with EKPC specific saturations in the EKPC residential energy models.

For the small commercial class energy forecast, EKPC has been using a statistical model that estimates total class sales as a function of several variables, including electricity price, economic activity, number of customers, and prior sales. These regression equations are developed for each member cooperative. EKPC selected this model because it performed best in predicting total sales.

EKPC also tested the detailed statistically adjusted end-use (SAE) modeling approach for the small commercial class. This is significant because the SAE model explicitly accounted for the impact of federal mandatory efficiency improvements. In fact, EKPC used data from EIA on efficiency trends as one of the driving variables for its SAE model. But the results of the analysis showed that the SAE model did not perform as well as the model EKPC ultimately selected.

Selecting which forecasting model to use is an art that involves tradeoffs. EKPC chose the model that performed better overall at estimating total class sales, although in so doing EKPC sacrificed the ability to isolate the impacts of certain factors that drive total class sales – such as the impact of federal equipment efficiency standards.

- **EKPC should continue to review the potential impact of new and pending environmental requirements, including carbon, and report separately how these requirements have been incorporated, along with their associated impacts, into its load forecasts and related risk analysis.**

Legal and Environmental experts provide interpretation of the pending rules to EKPC's Production, Construction and Engineering groups, as well as Burns and McDonnell, Owner-Engineer. Owner-Engineer develops cost estimates for Production under the advice of legal counsel. The cost estimates are shared with Finance to be placed in the Long Range Financial Forecast. EKPC has provided a detailed description of potential new and pending environmental regulations in Section 9.0 of this report. Future wholesale rate predictions are developed in the Long Range Financial Forecast; that rate forecast is then used as input into the load forecast model. Therefore, impacts of future environmental regulations are incorporated into the EKPC planning cycle via the load forecast projections. The detailed considerations are discussed in Section 9.0.

- **EKPC should discuss and report separately the impact on demand and energy forecasts of any projected increases in the price of electricity to its ultimate customers in its next IRP. The price elasticity of the demand for electricity should be fully examined and discussed, and a sensitivity analysis should be performed.**

EKPC engaged GDS to conduct an independent study to estimate price elasticity of demand from primary source data to allow EKPC to verify and refine the elasticity assumptions that have been assumed for previous planning analyses, and to provide a basis for elasticity assumptions used in future load forecasts. Additionally, the study entailed conducting secondary research to identify price elasticity study results conducted by other electric utilities and research firms.

Based on the analysis conducted, various model specifications produce stable elasticity estimates for the residential and commercial customer classes. Results at the aggregate EKPC level produce reliable estimates of long-term price elasticity of demand for electricity consumption. The range of values estimated from models at the member cooperative level is somewhat volatile but within a reasonable range of the aggregate estimates. GDS recommends use of the aggregate model results for purposes of analyzing load response to price anywhere in the EKPC territory. Furthermore, the estimates derived in this analysis are consistent with the price elasticity assumptions used by the US Energy Information Administration for its Annual Energy Outlook forecasting, providing greater confidence in the results obtained herein, which are also consistent with EKPC's current assumptions.

- GDS recommends using a RESIDENTIAL price elasticity in the range of -0.20 TO -0.30 as a reasonable assumption for load forecasting residential price sensitivities.

- GDS recommends using a COMMERCIAL price elasticity in the range of -0.05 TO -0.15 as a reasonable assumption for load forecasting commercial price sensitivities.

The report in its entirety is provided in the Technical Appendix Load Forecast– Exhibit LF-1.

- **Provide detailed support for the climate data used to determine normal weather. This should include, but not be limited to, the length of time chosen (i.e., 30 years or another period), the weather stations providing the data, a description of EKPC's efforts to attain the most current data available, and evidence showing that its methodology represents a reliable predictor of future weather for IRP purposes.**

Forecasted load growth is based on the assumption of normal weather as defined by the National Oceanic and Atmospheric Administration (NOAA). Historical weather data is from NOAA weather stations located at seven airports in or near the EKPC system:

- Blue Grass Airport (LEX) in Lexington, KY
- Bowling Green/Warren County Regional Airport (BWG) in Bowling Green, KY
- Cincinnati/Northern Kentucky International Airport (CVG) in Covington, KY
- Huntington Tri-State Airport (HTS) in Huntington, WV
- Julian Carroll Airport (JKL) in Jackson, KY
- Louisville International Airport (SDF) in Louisville, KY
- Pulaski County Airport (SME) in Somerset, KY

NOAA normals are based on "1981-2010 U.S. Climate Normals". NOAA updates the normal assumption every decade. EKPC performed analysis using 15, 20, and 30 years of history ending with March 2014, which was the most recent data available at the time. However, when evaluating forecast results that were based on the 30 year NOAA normal, actual to forecast comparison was reasonable and provided acceptable results, therefore no basis to change. EKPC also reviewed ITRON's 2013 Weather Normalization Survey of Industry Practices. While some utilities have moved from using 30 years of history to 10 years, 30 years is still the most widely accepted practice.

Demand-Side Management

- **EKPC should fine tune its DSM modeling projections in its next IRP in order to close the gap between its theoretical and actual peak demand and energy savings.**

For this 2015 IRP, EKPC has fine-tuned its DSM modeling projects to narrow the gap between its theoretical and actual peak demand and energy savings. EKPC has set the goal of achieving the equivalent of 1% of its annual retail sales in new DSM annual kWh savings each year. The findings from the potential study show that this goal may be achievable in the medium- and long-term. However, the levels of activity and spending far outstrip current performance and budgeting. In fact, EKPC is currently producing 0.2% of annual retail sales in new DSM annual kWh.

In order to narrow this gap, EKPC has established a ramp-up period of six years (2015-2020) during which time it plans to steadily increase its investment in DSM resources so that the goal of 1% of annual retail savings by the year 2020 can be attained. Participation projections reflect this steady increase in the years 2015-2020, then leveling off at participation levels that consistently achieve the 1% goal thereafter (from 2020-2029).

- **EKPC should report on the work of its Collaborative and provide the dates of all Collaborative meetings that take place after the issuance of this report and prior to the filing of its next IRP.**

The EKPC Demand-Side Management and Renewable Energy Collaborative was a joint project of EKPC, its 16 owner-member cooperatives, the Sierra Club, the Kentucky Environmental Foundation, and Kentuckians for the Commonwealth.

This group met quarterly over the two-year period that it was in existence (March 2011 – April 2013) to evaluate and recommend actions for EKPC to expand deployment of renewable energy and demand-side management, and to promote collaboration among participants in the implementation of those ideas.

The Collaborative produced two annual reports which provided the dates of the Collaborative meetings, summarized those meetings, and presented reports and recommendations from the work groups. These annual reports are provided as Exhibit DSM-9 in Technical Appendix – Demand Side Management to this IRP.

- **EKPC should include all environmental costs, as they become known, in future benefit/cost analyses.**

EKPC has included all known environmental costs in the avoided costs it used to conduct benefit/cost analyses on DSM resources for this plan.

- **EKPC should continue studying the PJM capacity markets for economic opportunities related to its DSM and energy-efficiency programs and participate at the earliest, most practical time.**

EKPC studies the PJM capacity markets for opportunities related to its DSM and energy-efficiency programs. EKPC is currently participating in the capacity auction with its demand response resources. At this time, EKPC is not yet bidding energy efficiency programs into the capacity market, although we continue to study that opportunity. Historically, we have concluded that our energy efficiency programs cannot bear the cost of the EM&V rigor needed to meet PJM's standards.

There is great uncertainty at the present time regarding whether and how demand side resources will participate in the PJM capacity markets in the future. This uncertainty stems from the May 2014 DC Circuit Court of Appeals ruling (the "EPSA" decision) on Federal Energy Regulatory Commission ("FERC") jurisdiction over demand response. In its May 23, 2014 ruling, the DC Circuit Court of Appeals vacated FERC Order 745, which set compensation rates for demand response in wholesale energy markets. The ruling also called into question FERC's jurisdiction to regulate the participation of retail energy customers in wholesale capacity markets.

Soon after the Appeals Court decision, FirstEnergy filed a complaint with FERC, arguing that the decision applies with equal force to capacity markets, and demanding that it force PJM to unwind its May 2014 Base Residual Auction to exclude the 11,000 or so megawatts of demand response that won bids for the 2017/2018 season.

In January 2015, the U.S. Solicitor General, on behalf of the FERC, filed a Supreme Court challenge to the lower court ruling.

There are several scenarios that could develop based on how the Supreme Court proceeds. PJM has filed a stop-gap plan to attempt to cope with the uncertainty. The proposal would allow demand response to participate in the May 2015 Base Residual Auction in the capacity markets in the event the Supreme Court declines to hear the appeal.

In any event, it is very likely that there will be significant changes to the manner in which demand response resources participate in the PJM wholesale markets. EKPC will continue to monitor developments and direct its future participation accordingly.

- **EKPC should include an update on bidding its peak savings from DSM into the PJM capacity markets.**

The following table provides the amount of demand response peak savings that EKPC has offered to date into the PJM capacity markets:

EKPC DR Capacity Bid in PJM

Year	MW
2013/2014	83.3
2014/2015	128.2

- **EKPC should work with its member cooperatives to further educate and encourage them and their customers about the importance of DSM, energy efficiency, and energy conservation.**

EKPC conducts multiple meetings per year with the member services staff of the owner-member cooperatives. EKPC also conducts multiple training sessions each year with the energy advisors from the member cooperatives. When EKPC launched three new DSM programs for 2014, it had multiple training sessions with member cooperative staff educating them on how these programs work. Typically fourteen member systems are represented at training sessions. Those attending include energy advisors, member service staff or other personnel.

- **EKPC should fully involve all members of the Collaborative to identify new cost-effective DSM programs, best practices, and opportunities for enhancement of its existing programs.**

The Collaborative focused on identifying new programs and best practices and enhancing existing programs. Collaborative members provided valuable suggestions for new program ideas and EKPC enhanced and changed programs based on their advice. For example, EKPC expanded the Envirowatts program and received tariff approval in 2014 to add in wind, solar, and hydro resources in addition to landfill gas.

Collaborative members also encouraged EKPC with its plans to move ahead with its low-income program and its ENERGY STAR appliances program. The Collaborative also recommended that EKPC continue to promote the How$martKY on-bill financing program in partnership with the Mountain Association for Community Economic Development ("MACED"). Five member cooperatives are now participating, and more are interested in participating in the future.

- **EKPC should continue to work with stakeholders in developing energy-efficiency reporting guidelines, standards, and templates.**

EKPC has developed energy-efficiency reporting standards and templates by working with stakeholders. This work set the stage for EKPC to set up its new DSM Tracking System, which became operational in 2014.

- **EKPC should report, by year, on its DSM programs' energy savings and peak-demand reductions.**

EKPC produces an annual report on DSM program savings that is submitted to the Public Service Commission. The 2013 annual report was provided to the PSC in April of 2014. EKPC also held an informal conference with the Commission to review the report. EKPC will produce this report each year. The report for 2014 is currently being prepared and will be provided to the Commission when finished. The 2013 Annual Report is included in Exhibit DSM-2 of the Demand-Side Management Technical Appendix.

Supply-Side Resources and Environmental Compliance

- **Discuss and provide analysis with regard to EKPC's 12 percent planning reserve margin and its effects on its capacity expansion plans as they relate to the slightly less than 3 percent reserve margin required by PJM.**

EKPC was short on winter capacity to cover its winter peak load plus an acceptable reserve margin (12%) when it entered into PJM. EKPC had more than sufficient capacity to cover its summer peak load plus the approximate 3% reserve required by PJM. Based on historical price duration curves and PJM market operations, EKPC believed it could rely on the PJM energy market to serve its unhedged winter position in an economic and reliable manner. The polar vortex that occurred in January 2014 and February 2015 changed the PJM energy market significantly and permanently. EKPC's experience during that time solidified the need to secure energy hedges for its winter load position. EKPC purchased 200MW of third party PPAs through the 2014-15 winter peak season. EKPC will need to continue to cover its winter peak load with either self-owned generation or firm PPAs, whichever is more economical. EKPC refreshed its RFP offers in summer 2014 and is currently negotiating with a third party for a potential long term solution to its winter capacity needs.

- **Continue to pursue cost-effective opportunities and provide information concerning cogeneration, renewables, and exploration of stranded gas opportunities.**

EKPC concurs with the Staff's recommendation and has provided more details in Section 8.0 on this topic.

- **Discuss the effect joining PJM has had on the KU/LG&E transmission line contract and the included interconnections.**

EKPC's membership in PJM has not had any significant impact on the interconnection agreement that is in place between EKPC and KU/LG&E. This interconnection agreement establishes the terms and conditions mutually agreed upon by EKPC and KU/LG&E for both existing and future transmission interconnections between the two companies' systems. No substantive changes were made to the interconnection agreement when EKPC became a PJM member in 2013. EKPC and KU/LG&E continue to coordinate closely in the planning and operations of the two systems, in a very similar manner as was done prior to EKPC's integration into PJM. However, EKPC is obligated to meet PJM's requirements for the planning and operations of its system. Therefore, EKPC must consider these requirements when coordinating these activities with KU/LG&E. Since integrating into PJM, EKPC has observed that its consideration of PJM requirements has not significantly impacted coordination of activities with KU/LG&E.

- **Discuss the pending/ongoing plant modifications required to meet EPA or other environmental legislation. Further, EKPC included no CO2 costs in the supply side evaluation and did not specifically address CO2 issues in its compliance planning. Although EKPC provided what it believed was appropriate rationale for not doing so, the Staff believes that EKPC should have made some attempt to evaluate the impact of potential CO2 rules. Staff views the exclusion of CO2 from the IRP as a shortcoming and therefore recommends that EKPC provide a complete discussion of compliance actions and plans relating to current and pending environmental regulations within the next resource plan.**

EKPC has provided an extensive review of current and pending environmental regulations in Section 9.0 of this report. EKPC discusses the potential Clean Power Plan ("CPP") (CO2 regulation) in this section. The current proposal does not propose that a tax be levied on CO2 but rather a maximum CO2 emissions rate. EKPC is considering all of its options to meet this rate; however, the CPP rule is not final. The Commonwealth of Kentucky may develop its own State Implementation Plan ("SIP") to meet any final rule. EKPC has not proposed anything in its long term power supply plan in this IRP that would be contrary to or negated by the Clean Power

Plan implementation; however, EKPC cannot be certain that its power supply plan submitted in this IRP will fully comply with the Clean Power Plan until the rule is finalized.

- **Summarize, and include in EKPC's next IRP filing, the information in the annual PJM transition reports filed as a result of Case No. 2012-00169 and inform the Commission of its effects on EKPC's reliable production of power.**

EKPC identified its costs and benefits from June 1, 2013 (entry into PJM) through March 31, 2014, as shown in the following table. Given the required filing date of the report, it was not feasible for EKPC to provide data through May 31, 2014. It takes approximately six weeks after the final operating day of a given month to adequately assemble all of the data associated with that operational month. In 2015, EKPC can offer a full 12 month view from April 1, 2014 through March 31, 2015. However, that 12 month view will not be coincident with the PJM 12 month operating year.

In the following table, the Administrative Costs and Transmission Costs are based on accounting entries in EKPC's General Ledger and reflect actual out of pocket costs. Trade Benefits are based on a detailed modeling effort. EKPC utilized its production cost model ("RTSim" – the same model used for its Integrated Resource Plan analysis) and simulated what its operations as a stand-alone Balancing Authority would have cost and compared that to the actual costs from operating within PJM. EKPC modeled actual loads, actual prices, actual generating unit availability statistics and estimated transmission availability from outside resources. This methodology is similar to the methodology utilized in the study completed and entered into EKPC's request to the Commission to join PJM. The difference being that the PJM costs are now actually a known quantity instead of an estimated price. Capacity Benefits are based on the actual cleared Reliability Pricing Model ("RPM") results and are shown on the monthly PJM invoice. The Avoided Point-to-Point ("PTP") Transmission Charges are based on the contract that EKPC had with PJM to purchase 400 MW of firm transmission and the published tariff associated with that purchase, it does not include additional charges for actual energy transactions on the transmission. The original estimate of these costs and benefits were provided on a ten year Net Present Value basis and the following table is only for the ten month operational period from June 1, 2013 through March 31, 2014.

REDACTED

Category	Costs [Millions]	Benefits [Millions]
Administrative Costs	[redacted]	
Transmission Costs		
Trade Benefits		[redacted]
Capacity Benefits		
Avoided PTP Transmission Charges		
Subtotal	[redacted]	
Net Benefits		

Projection of Future Benefits and Costs of PJM Membership

Finally, the December 20, 2012 Order directs EKPC to provide "a projection of future benefits and costs reflecting the most recent PJM capacity auction results." EKPC substituted known cost and benefit data into the worksheet used in the original analysis to project future benefits and costs. The original study was time and resource intensive and EKPC has no reason to believe the underlying basis of the analysis has changed significantly except for the actual costs and benefits that have been realized. The following table reflects inclusion of actual data along with original projections for the remainder of the study. The net benefits have diminished some due to the lower than anticipated value of the capacity market in 2016/17. The Base Residual Auction for 2017/18 was recently held and the clearing price was $120/MW-Day, which is closer to the original assumptions than last year's price. Additionally, the first year of Trade Benefits has been significantly greater than the projected value and the market indicates that the likelihood of this trend continuing makes sense.

Category	Costs [Millions]	Benefits [Millions]
Administrative Costs	[redacted]	
Transmission Costs		
Trade Benefits		[redacted]
Capacity Benefits		
Avoided PTP Transmission Charges		
Subtotal	[redacted]	
Net Benefits		

EKPC has experienced similar operations since filing the above data. EKPC believes it will see as much or more benefit from its operations in PJM to be reported in the second annual filing later this year than it saw in the first report in 2014.

- **Report on the ongoing SEPA construction and its effects on EKPC's hydropower.**

EKPC was notified in February 2007 of dangerous seepage issues identified by the Corps of Engineers at Wolf Creek and Center Hill Dams on the Cumberland System. As a result of safety concerns related to the potential failure of the dams, emergency changes were made in operations of the dams which significantly changed the availability of power from the Cumberland System. As a result of these operational changes, EKPC was unable to schedule power from the

Cumberland System. Power was received on a run of river basis as scheduled by the Corps to meet constraints of the emergency operations. Major projects were initiated by the Corps to alleviate the seepage issues at the two dams. Construction at Wolf Creek was essentially completed in Spring of 2013, and the dam is currently operating under normal conditions. The Center Hill project is still underway and is estimated to be completed in late 2017. With normal operation at Wolf Creek, SEPA was able to return to scheduling capacity from the Cumberland System on July 1, 2014. However, due to the loss of part of the storage capability of Center Hill Dam due to operational constraints, EKPC cannot schedule the full amount of allocated capacity as it did prior to 2007. Laurel Dam was unaffected by the seepage repair projects and EKPC continues to schedule 70MW from it. EKPC currently schedules up to 87MW of the 100MW available prior to 2007 from the Cumberland System. However, the 87MW may be reduced further due to maintenance or operational issues. EKPC receives a capacity declaration from SEPA each week for the following week and EKPC provides SEPA a schedule based on that declaration. It is anticipated that operations will continue in this manner until the Center Hill seepage project is completed and normal operations are restored by Spring 2018.

SECTION 3.0

LOAD FORECAST

SECTION 3.0

LOAD FORECAST AND LOAD RESEARCH ACTIVITIES

3.1 Summary

East Kentucky Power Cooperative Inc. (EKPC) is a generation and transmission electric cooperative located in Winchester, Kentucky. EKPC is owned by 16 member systems who serve approximately 525,000 retail meters. Member systems served by EKPC include:

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

EKPC's load forecast is prepared every three years in accordance with EKPC's Rural Utilities Service (RUS) approved Work Plan. The Work Plan details the methodology used in preparing the projections. EKPC prepares the load forecast by working jointly with each member system to prepare their load forecast. Member system projections are then summed to determine EKPC's forecast. Member systems use their load forecasts in developing construction work plans, long range work plans, and financial forecasts. EKPC uses the load forecast in such areas as demand-side management analyses, marketing analyses, transmission planning, power supply planning, and financial forecasting.

The forecast indicates that for the forecast period of 2015 through 2034, total energy requirements will increase by 1.4 percent per year. Winter and summer net peak demand will increase by 1.0 percent and 1.5 percent, respectively. Annual load factor is projected to grow from 48 percent to 51 percent, which reflects the historical average. Historical and projected winter peak demands, summer peak demands, total energy requirements, and annual load factor are presented in Tables 3-1, 3-2 and 3-3.

Energy projections by RUS classification are detailed in Table 3-5. These projections indicate that during the forecast period of 2015 to 2034, sales to the residential class will increase 1.1 percent per year, and total commercial and industrial sales will increase by 1.8 percent per year. Growth rates are shown in Table 3-1a.

Table 3-1a
Projected Energy and Peak Demand Growth
Compound Annual Rates of Change

	2015-2019 (%)	2015-2024 (%)	2015-2034 (%)
Total Energy Requirements	1.4	1.5	1.4
• Residential Sales	1.2	1.2	1.1
• Total Commercial and Industrial Sales	2.2	2.1	1.8
Net Winter Peak Demand	0.7	0.8	1.0
Net Summer Peak Demand	1.3	1.5	1.5

Factors considered when preparing the forecast include historical customer growth, historical energy sales and peak demands, regional economic growth, electric appliance saturation and efficiency trends, electricity rates, and weather.

The official Board approved load forecast includes the impacts of a 5-year DSM plan. This plan consists of existing DSM programs. This plan assumes no new programs and no new participants after the fifth year. A separate DSM plan was developed for inclusion in the capacity plan as a resource that includes new programs. Details are in Section 5.0 - Demand Side Management of this report. Tables 3-2 and 3-3 show the winter and summer peak demand impacts. Table 3-4 shows the DSM impact on energy requirements.

Table 3-1
Historical and Projected Peak Demands and Total Requirements

Season	Actual Winter Peak Demand (MW)	Adjusted Winter Peak Demand (MW)	Year	Actual Summer Peak Demand (MW)	Adjusted Summer Peak Demand (MW)	Adjusted Total Requirements (MWh)	Load Factor (%)
2002-2003	2,568		2003	1,996		11,568,314	51.4%
2003-2004	2,610		2004	2,052		11,865,797	51.8%
2004-2005	2,719		2005	2,220		12,527,829	52.6%
2005-2006	2,599		2006	2,332		12,331,272	54.2%
2006-2007	2,840		2007	2,481		13,080,367	52.6%
2007-2008	3,051		2008	2,243		12,948,091	48.3%
2008-2009	3,152		2009	2,195		12,370,308	44.8%
2009-2010	2,868		2010	2,443		13,376,292	53.2%
2010-2011	2,891		2011	2,388		12,666,998	50.0%
2011-2012	2,481		2012	2,354		12,190,070	55.9%
2012-2013	2,597		2013	2,199		12,644,590	55.6%
2013-2014	3,425		2014	2,192		13,163,516	43.9%
2014-2015		3,207	2015		2,334	13,368,393	47.6%
2015-2016		3,239	2016		2,363	13,563,866	47.7%
2016-2017		3,259	2017		2,396	13,781,894	48.3%
2017-2018		3,282	2018		2,428	13,974,738	48.6%
2018-2019		3,302	2019		2,456	14,147,514	48.9%
2019-2020		3,338	2020		2,502	14,436,649	49.2%
2020-2021		3,365	2021		2,541	14,633,457	49.6%
2021-2022		3,390	2022		2,581	14,842,021	50.0%
2022-2023		3,418	2023		2,619	15,043,007	50.2%
2023-2024		3,455	2024		2,665	15,290,328	50.4%
2024-2025		3,488	2025		2,707	15,514,584	50.8%
2025-2026		3,530	2026		2,762	15,807,528	51.1%
2026-2027		3,568	2027		2,801	16,013,662	51.2%
2027-2028		3,610	2028		2,845	16,241,455	51.2%
2028-2029		3,651	2029		2,885	16,454,469	51.4%

Table 3-2
Historical and Projected Winter Peak Demand

Season	Unadjusted Peak Demand (MW)	Additional Demand-Side Management (MW)	Adjusted Peak Demand (MW)
2002-2003	2,568	-133	2,435
2003-2004	2,610	-123	2,487
2004-2005	2,719	-104	2,615
2005-2006	2,599	-122	2,477
2006-2007	2,840	-91	2,749
2007-2008	3,051	-95	2,956
2008-2009	3,152	-26	3,126
2009-2010	2,868	-129	2,739
2010-2011	2,891	-126	2,765
2011-2012	2,481	-131	2,350
2012-2013	2,597	-96	2,501
2013-2014	3,425	-112	3,313
2014-2015	3,338	-131	3,207
2015-2016	3,378	-139	3,239
2016-2017	3,407	-148	3,259
2017-2018	3,438	-156	3,282
2018-2019	3,466	-164	3,302
2019-2020	3,502	-164	3,338
2020-2021	3,529	-164	3,365
2021-2022	3,554	-164	3,390
2022-2023	3,582	-164	3,418
2023-2024	3,618	-163	3,455
2024-2025	3,650	-162	3,488
2025-2026	3,691	-161	3,530
2026-2027	3,728	-160	3,568
2027-2028	3,769	-159	3,610
2028-2029	3,808	-157	3,651

Table 3-3
Historical and Projected Summer Peak Demand

Year	Unadjusted Peak Demand (MW)	Additional Demand-Side Management (MW)	Adjusted Peak Demand (MW)
2003	1,996	-151	1,845
2004	2,052	-104	1,948
2005	2,220	-10	2,210
2006	2,332	-144	2,188
2007	2,481	-135	2,346
2008	2,243	-149	2,094
2009	2,195	-114	2,081
2010	2,443	-146	2,297
2011	2,388	-122	2,266
2012	2,354	-94	2,260
2013	2,199	-104	2,095
2014	2,192	-104	2,088
2015	2,484	-150	2,334
2016	2,524	-161	2,363
2017	2,568	-172	2,396
2018	2,611	-183	2,428
2019	2,650	-194	2,456
2020	2,696	-194	2,502
2021	2,735	-194	2,541
2022	2,775	-194	2,581
2023	2,812	-193	2,619
2024	2,857	-192	2,665
2025	2,897	-190	2,707
2026	2,950	-188	2,762
2027	2,988	-187	2,801
2028	3,031	-186	2,845
2029	3,070	-185	2,885

Table 3-4
Total Energy Requirements

Year	EKPC Sales to Members (MWh)	EKPC Own Use (MWh)	Transmission Losses (MWh)	Actual Net Total Requirements (MWh)	Gross Total Requirements (MWh)	Additional Demand Side Management (MWh)	Weather-Normalized Net Total Requirements (MWh)
2003	11,190,871	9,123	368,320	11,568,314			11,569,542
2004	11,537,505	9,106	319,186	11,865,797			12,032,530
2005	12,060,461	8,903	458,465	12,527,829			12,410,850
2006	11,892,304	7,568	431,400	12,331,272			12,561,140
2007	12,582,259	7,491	490,617	13,080,367			12,885,901
2008	12,646,147	7,932	294,012	12,948,091			12,835,913
2009	11,981,908	8,247	380,153	12,370,308			12,479,632
2010	12,811,907	8,654	555,731	13,376,292			12,977,048
2011	12,289,090	10,146	367,762	12,666,998			12,751,204
2012	11,943,404	8,811	235,192	12,190,070			12,299,006
2013	12,426,020	8,270	210,300	12,644,590			12,656,553
2014	12,890,114	8,246	265,157	13,163,516			12,994,317
2015	12,983,289	8,343	447,542		13,439,174	-70,781	13,368,393
2016	13,197,742	8,379	458,642		13,664,763	-100,897	13,563,866
2017	13,438,057	8,416	469,098		13,915,571	-133,677	13,781,894
2018	13,654,376	8,453	478,365		14,141,194	-166,457	13,974,738
2019	13,851,977	8,489	486,285		14,346,751	-199,236	14,147,514
2020	14,130,274	8,527	497,084		14,635,885	-199,236	14,436,649
2021	14,319,472	8,564	504,657		14,832,693	-199,236	14,633,457
2022	14,518,240	8,601	512,455		15,039,296	-197,275	14,842,021
2023	14,706,794	8,639	520,439		15,235,872	-192,865	15,043,007
2024	14,938,774	8,676	529,126		15,476,576	-186,248	15,290,328
2025	15,144,656	8,714	536,901		15,690,271	-175,687	15,514,584
2026	15,411,443	8,752	553,085		15,973,280	-165,751	15,807,528
2027	15,604,205	8,791	560,451		16,173,447	-159,786	16,013,662
2028	15,817,019	8,829	568,818		16,394,666	-153,211	16,241,455
2029	16,015,460	8,868	576,691		16,601,019	-146,550	16,454,469

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The proportion of total energy sales represented by each class is not expected to change significantly through the end of the forecast period. Details follow in Table 3-5.

Table 3-5
Class Sales

Year	Residential Sales (MWh)	Seasonal Sales (MWh)	Small Comm. Sales (MWh)	Public Buildings (MWh)	Large Comm. & Industrial Sales (MWh)	Other Sales (MWh)	Total Retail Sales (MWh)
2003	6,205,364	13,445	1,550,251	21,753	2,881,781	7,448	10,680,042
2004	6,337,737	13,846	1,597,841	22,974	3,032,313	7,497	11,012,208
2005	6,751,545	14,501	1,729,486	22,530	3,017,603	7,714	11,543,379
2006	6,545,584	13,882	1,777,896	22,196	3,057,184	8,235	11,424,977
2007	6,998,555	14,679	1,861,951	26,426	3,124,042	8,459	12,034,112
2008	7,055,278	14,531	1,872,811	34,074	3,083,590	9,476	12,069,760
2009	6,789,142	13,080	1,787,113	35,507	2,831,936	9,067	11,465,845
2010	7,388,899	13,959	1,935,184	39,809	2,845,857	9,505	12,233,213
2011	6,967,415	12,774	1,892,091	38,468	2,889,143	9,846	11,809,737
2012	6,572,947	227	1,883,243	35,194	2,901,689	9,601	11,402,901
2013	6,905,017	300	1,917,729	37,215	3,017,925	9,845	11,888,031
2014	7,190,266	329	1,984,326	38,009	3,067,731	9,952	12,290,613
2015	7,116,809	318	1,996,862	37,860	3,257,080	10,086	12,419,015
2016	7,199,040	323	2,038,435	38,778	3,337,584	10,234	12,624,394
2017	7,283,342	329	2,080,437	39,451	3,440,200	10,387	12,854,146
2018	7,367,004	334	2,123,865	39,862	3,519,215	10,540	13,060,820
2019	7,455,700	340	2,168,939	40,486	3,573,690	10,698	13,249,853
2020	7,545,866	346	2,214,180	41,243	3,702,565	10,856	13,515,056
2021	7,634,550	352	2,258,394	41,806	3,749,885	11,014	13,696,001
2022	7,725,997	359	2,303,360	42,206	3,802,950	11,172	13,886,044
2023	7,817,409	365	2,349,882	42,599	3,844,856	11,330	14,066,441
2024	7,914,171	371	2,398,920	42,941	3,920,737	11,486	14,288,626
2025	8,014,115	378	2,447,930	43,263	3,968,149	11,647	14,485,482
2026	8,110,072	383	2,496,649	43,591	4,078,084	11,802	14,740,581
2027	8,201,757	389	2,542,048	43,929	4,124,892	11,944	14,924,959
2028	8,291,671	393	2,585,118	44,279	4,195,083	12,078	15,128,622
2029	8,376,465	398	2,627,461	44,631	4,257,257	12,203	15,318,415

Note: Member systems' Form 7 data for 2014 were not available.

Table 3-5 continued
Total Sales and Requirements

Total Retail Sales (MWh)	Office Use (MWh)	% Loss	EKPC Sales to Members (MWh)	EKPC Office Use (MWh)	Transmission Loss (%)	Net Total Requirements (MWh)	Year
10,680,042	7,681	4.5	11,190,871	9,123	3.3	11,568,314	2003
11,012,208	8,289	4.5	11,537,505	9,106	2.8	11,865,797	2004
11,543,379	8,617	4.2	12,060,461	8,903	3.8	12,527,829	2005
11,424,977	8,924	3.9	11,892,304	7,568	3.6	12,331,272	2006
12,034,112	10,291	4.3	12,582,259	7,491	3.9	13,080,367	2007
12,069,760	10,431	4.5	12,646,147	7,932	2.3	12,948,091	2008
11,465,845	10,169	4.2	11,981,908	8,247	3.1	12,370,308	2009
12,233,213	10,401	4.4	12,811,907	8,654	4.2	13,376,292	2010
11,809,737	9,742	3.8	12,289,090	10,146	2.9	12,666,998	2011
11,402,901	9,120	4.4	11,943,404	8,811	2.0	12,190,070	2012
11,888,031	9,978	4.2	12,426,020	8,270	1.7	12,644,590	2013
12,290,613	9,581	4.3	12,855,119	8,306	3.3	13,245,535	2014
12,419,015	9,581	4.3	12,983,289	8,343	3.3	13,368,393	2015
12,624,394	9,581	4.3	13,197,742	8,379	3.4	13,563,866	2016
12,854,146	9,581	4.3	13,438,057	8,416	3.4	13,781,894	2017
13,060,820	9,581	4.3	13,654,376	8,453	3.4	13,974,738	2018
13,249,853	9,581	4.3	13,851,977	8,489	3.4	14,147,514	2019
13,515,056	9,581	4.3	14,130,274	8,527	3.4	14,436,649	2020
13,696,001	9,581	4.3	14,319,472	8,564	3.4	14,633,457	2021
13,886,044	9,581	4.3	14,518,240	8,601	3.4	14,842,021	2022
14,066,441	9,581	4.3	14,706,794	8,639	3.4	15,043,007	2023
14,288,626	9,581	4.3	14,938,774	8,676	3.4	15,290,328	2024
14,485,482	9,581	4.3	15,144,656	8,714	3.4	15,514,584	2025
14,740,581	9,581	4.3	15,411,443	8,752	3.5	15,807,528	2026
14,924,959	9,581	4.3	15,604,205	8,791	3.5	16,013,662	2027
15,128,622	9,581	4.3	15,817,019	8,829	3.5	16,241,455	2028
15,318,415	9,581	4.3	16,015,460	8,868	3.5	16,454,469	2029

Note: Member systems' Form 7 data for 2014 were not available.

3.2 Load Forecast

3.2.1 Introduction

The forecast used in the IRP was approved November 2014 by the EKPC Board of Directors and approved by RUS in March 2015. Key assumptions and trends used in the preparation of the load forecast are described in this section along with a discussion of the EKPC service area. Projected peak demand, annual energy requirements, and growth rates are summarized. The load forecast report is provided in the Load Forecast Technical Appendix.

EKPC prepares a load forecast by working jointly with its member systems in preparing their individual load forecasts. Member system projections are then summed to determine EKPC's forecast. Factors considered in preparing the forecasts include historical customer growth, historical energy sales and peak demand, national, regional, and local economic performance, appliance saturations and efficiencies, population and housing trends, service area industrial development, electric price, household income, and weather. Each member system reviews the preliminary forecast for reasonability. Final projections reflect analysis of historical and projected data combined with the experience and judgment of the member system manager and staff. In recognition of the uncertainty present in long-term forecasting, both high and low projections are also prepared.

The major steps in developing the load forecasts are:

1. EKPC prepares a preliminary load forecast for each member system that is based on retail sales forecasts for six classes - residential, seasonal residential, small commercial, large commercial and industrial, public authorities, and public street and highway lighting. The classifications are taken from the Rural Utilities Service (RUS) Form 7, which contains 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 sales to members. Seasonal peak demands are projected by applying load factors for winter and summer to total purchased power for each member system.

2. EKPC meets with each member system to discuss its preliminary forecast. Member system personnel present at the meetings include the President/CEO and other key staff members. During the meeting, preliminary projections are reviewed and, if necessary, revised as mutually agreed upon. Member systems often have access to regional information not available to EKPC; thus, the member systems may elect to use assumptions different from preliminary forecast assumptions. There is close collaboration between EKPC and its member systems. This working relationship is vital for both EKPC and the member systems to have significant input into the load forecast process. Input from member systems includes industrial development, subdivision growth, and other specific service area information. The meeting also provides an opportunity for the member system to critique assumptions used and overall results of the preliminary forecast. The resulting forecasts reflect a combination of EKPC's structured forecast methodology tempered by the judgment and experience of member system staff.

3. EKPC then compiles its forecast, which is the summation of the 16 member system forecasts.

EKPC plans to conduct a comprehensive review of all aspects of its load forecasting process and evaluate possible enhancements. These will be submitted to RUS in the next work plan; due December 2015.

3.2.2 Input Assumptions Overview

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

1. EKPC's member systems will add almost 70,000 residential customers during the 15-year forecast period. This represents an increase of 0.9 percent per year.
2. EKPC uses an economic model in developing 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 forecast period. Employment is forecasted to stay relatively flat, with an average growth rate of 0.2 percent per year through the forecast period. Regional households are projected to grow at an average of 0.5 percent per year through the forecast period.

3. As of 2013, approximately 79 percent of all new households have electric heat and about 89 percent of all new households have electric water heating. Nearly all new homes will have electric air conditioning, either central or room. Details are provided in the Load Forecast Technical Appendix.
4. Residential customer growth and local area economic activity are the major determinants of small commercial growth.
5. Forecasted load growth is based on the assumption of normal weather, as defined by the NOAA, occurring during the forecast period.

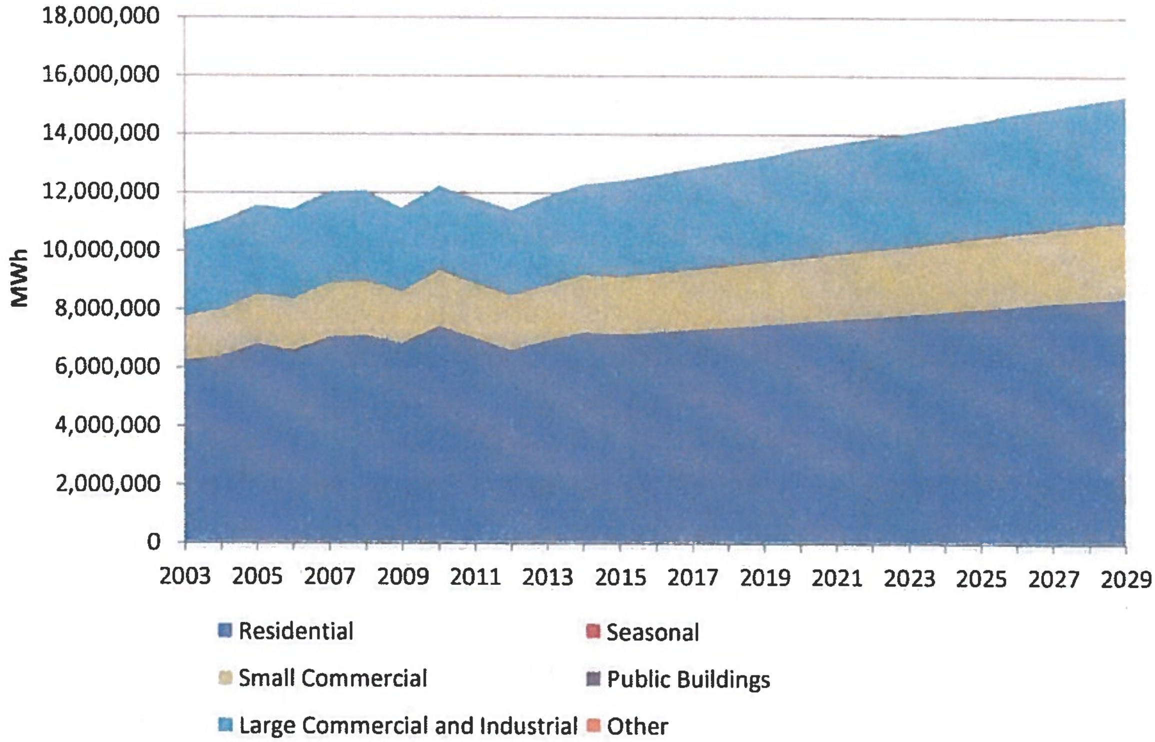
EKPC subscribes to IHS Global Insight, Inc. (IHS), for analysis regarding regional economic performance. IHS is a widely used consulting firm with expertise in economic analyses. They collect and monitor data, provide forecasts and analyses, and offer consulting advice to clients in business, financial, and government organizations. IHS collects historical Kentucky county level data for many economic variables, develops forecasting models based on the data, and provides the resulting forecasts to EKPC.

EKPC calculates each member system's share of its region's economy by dividing its actual (as adjusted for reclassifications) and forecast residential consumer count by the total number of households in the region. The share is then applied to all economic variables (including households, employment, population, real gross county product and total real personal income) before they are used in other models.

3.2.3 Discussion of Service Area

In EKPC's service area, electricity is the primary method for water heating and home heating. Around 86 percent of all homes have electric water heating, and about 63 percent have electric heat as a primary fuel. In 2013, nearly 58 percent of EKPC's member system retail sales were to the residential class and residential customer use averaged 1,175 kWh per month. Figure 3-1 illustrates the class allocations of total energy sales.

Figure 3-1
Components of Member System Retail Sales



The economy of EKPC's service area is quite varied. Areas around Lexington and Louisville have a significant amount of manufacturing industry. The region around Cincinnati contains a growing number of retail trade and service jobs while the eastern and southeastern portions of EKPC's service area are dominated by the mining industry. Tourism is an important aspect of EKPC's southern and southwestern service areas, with Lake Cumberland and Mammoth Cave National Park contributing to jobs in the service and retail trade industries. All of these areas have experienced declines due to the recession beginning 2008 and have not fully recovered. IHS projections indicate growth will quickly rebound in the next three years and slow to more moderate growth afterward. Other factors negatively impacting the mining sector are the current and pending EPA regulations concerning coal.

3.2.4 Summary of Results

The forecast indicates that for the forecast period, total energy requirements will increase by 1.4 percent per year. Winter and summer net peak demand will increase by 1.0 percent and 1.5 percent, respectively. Annual load factor is projected to increase from 48 percent to 51 percent, which reflects the historical average. Table 3-6 summarizes historical and projected demand and total requirements growth rates.

Table 3-6
Historical and Projected Energy and Peak Demand Growth
Compound Annual Rates of Change

	Historical Growth Rates			2014 Forecast Growth Rates		
	2009-2014	2004-2014	1994-2014	2015-2019	2015-2024	2015-2034
Total Energy Requirements	1.3%	1.0%	3.3%	1.4%	1.5%	1.4%
Net Winter Peak Demand	1.3%	2.9%	3.1%	0.7%	0.8%	1.0%
Net Summer Peak Demand	0.1%	0.7%	2.3%	1.3%	1.5%	1.5%

Table 3-7 displays energy sales in the last five years by consumer class. Table 3-8 gives the weather normalized coincident peak demands of the previous five years. Table 3-9 displays weather normalized and actual energy sales and requirements for 2009 through 2013. Tables 3-10 and 3-11 display historical summaries of energy sales and coincident peak demand for firm contractual commitments and interruptible contracts, respectively.

Table 3-7
EKPC Recorded Annual Energy Sales (MWh) and Energy Requirements (MWh), 2009-2013

	2009	2010	2011	2012	2013
Total Residential	6,789,142	7,388,899	6,967,415	6,572,947	6,905,017
Residential Seasonal	13,080	13,959	12,774	227	300
Small Commercial	1,787,113	1,935,184	1,892,091	1,883,243	1,917,729
Large Commercial/ Industrial	2,831,936	2,845,857	2,889,143	2,901,689	3,017,925
Public Authorities	35,507	39,809	38,468	35,194	37,215
Other	9,067	9,505	9,846	9,601	9,845
Total Sales	11,465,845	12,233,213	11,809,737	11,402,901	11,888,031
Office Use	10,169	10,401	9,742	9,120	9,978
% Loss	4.2	4.4	3.8	4.4	4.2
EKPC Sales to Members	11,981,908	12,811,907	12,289,090	11,943,404	12,426,020
EKPC Office Use	8,247	8,654	10,146	8,811	8,270
Transmission Loss (%)	3.1	4.2	2.9	2.0	1.7
Net Total Requirements	12,370,308	13,376,292	12,666,998	12,190,070	12,644,590

Note: Member systems' Form 7 data for 2014 were not available.

Table 3-8
Weather Normalized Coincident Peak Demands

Year	Season	Actual Peak	Adjusted Peak
		MW	MW
2010	Winter	2,868	3,012
	Summer	2,443	2,353
2011	Winter	2,891	3,111
	Summer	2,388	2,313
2012	Winter	2,481	2,672
	Summer	2,354	2,196
2013	Winter	2,597	2,661
	Summer	2,199	2,211
2014	Winter	3,425	2,995
	Summer	2,192	2,300

Table 3-9 EKPC Weather Normalized Annual Energy Sales (MWh) and Energy Requirements (MWh), 2009-2013					
	2009	2010	2011	2012	2013
Total Retail Sales by Member Systems					
Recorded	11,465,845	12,233,213	11,809,737	11,402,901	11,888,031
Weather Normalized	11,567,176	11,868,087	11,888,244	11,504,803	11,899,278
EKPC					
Recorded	12,370,308	13,376,292	12,666,998	12,190,070	12,644,590
Weather Normalized	12,479,632	12,977,048	12,751,204	12,299,006	12,656,553

Note: Member systems' Form 7 data for 2014 were not available. Data is not normalized by class.

Table 3-10
Energy Sales and Firm Coincident Demand

	2009	**2010**	**2011**	**2012**	**2013**	**2014**
Energy Sales (MWh)*	11,981,908	12,811,907	12,289,090	11,943,404	12,426,020	12,890,114
Coincident Peak Demand (MW)**	3,126	2,739	2,765	2,350	2,501	3,313

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

Table 3-11
Energy Sales and Non-Firm Demand

	2009	**2010**	**2011**	**2012**	**2013**	**2014**
Energy Sales (MWh)*	NA	NA	NA	NA	NA	NA
Coincident Peak Demand (MW)	26	129	126	131	96	112

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

Discussion of differences between 2015 IRP Load Forecast and the 2012 IRP Load Forecast

The 2015 IRP load forecast differs from the 2012 IRP load forecast in multiple aspects. While previous load forecasts had shown downward revisions (graphically shown in Figure 3-2, 3-3 and 3-4) for several updates, the 2015 IRP load forecast projections are similar to the 2012 projections for energy indicating an end to this trend. Given this, EKPC believes there is more upside risk than downside for this forecast. Residential customers show an overall downward revision from 2012. This is due in part to the fact that the actual customers were coming in lower than projected in the 2012 IRP load forecast. Total commercial and industrial sales show an upward revision in the short term. While some member systems are continuing to struggle due to the economy, specifically in the Eastern part of the state, others are seeing new commercial and industrial growth. Tables 3-11a and 3-11b display comparisons between the 2012 and 2015 load forecasts used in the IRPs for pre-DSM and post-DSM, respectively.

Table 3-11a
Forecast Comparison – Pre-DSM
2015 IRP Versus 2012 IRP

		2015	2012*	Difference
	2015	7,116,809	7,214,785	-97,976
Residential Sales, MWh	2020	7,545,866	7,762,969	-217,103
	2025	8,014,115	8,447,041	-432,926
	2015	5,253,942	5,243,362	10,580
Total Commercial and Industrial Sales, MWh	2020	5,916,745	5,901,140	15,605
	2025	6,416,079	6,448,624	-32,545
	2015	495,084	513,141	-18,057
Residential Customers	2020	516,467	551,347	-34,880
	2025	541,888	591,485	-49,597
	2015	3,338	3,320	18
Net Winter Peak, MW	2020	3,502	3,628	-126
	2025	3,650	3,958	-308
	2015	2,484	2,611	-127
Net Summer Peak, MW	2020	2,696	2,841	-145
	2025	2,897	3,095	-198
	2015	13,439,174	13,530,522	-91,348
Total Requirements, MWh	2020	14,635,885	14,845,233	-209,348
	2025	15,690,271	16,187,502	-497,231

Table 3-11b
Forecast Comparison – Post DSM
2015 IRP Versus 2012 IRP

		2015	2012*	Difference
	2015	7,085,268	6,862,801	222,467
Residential Sales, MWh	2020	7,151,117	7,073,245	77,872
	2025	7,249,485	7,632,317	-382,832
	2015	5,214,702	5,200,296	14,406
Total Commercial and Industrial Sales, MWh	2020	5,877,505	5,858,068	19,437
	2025	6,376,839	6,405,545	-28,706
	2015	495,084	513,141	-18,057
Residential Customers	2020	516,467	551,347	-34,880
	2025	541,888	591,485	-49,597
	2015	3,201	3,063	138
Net Winter Peak, MW	2020	3,261	3,270	-9
	2025	3,321	3,542	-221
	2015	2,324	2,376	-52
Net Summer Peak, MW	2020	2,428	2,569	-141
	2025	2,566	2,797	-231
	2015	13,368,393	13,135,472	232,921
Total Requirements, MWh	2020	14,381,207	14,112,437	268,770
	2025	15,387,167	15,329,699	57,468

* Please note the numbers reflected in Tables 3-11a and 3-11b for 2012 do not match the data in the 2012 IRP report. In 2012, the Residential Class included Seasonal sales and customers. In 2014, these are reported separately. In order to make a valid comparison, the seasonal customers and sales were subtracted from the 2012 data. Likewise, 2012 combined commercial, industrial, public buildings and lighting. These were subtracted for the purposes of the above comparisons.

Figure 3-2
Comparison of Load Forecasts
Net Total Energy Requirements (Millions MWh)

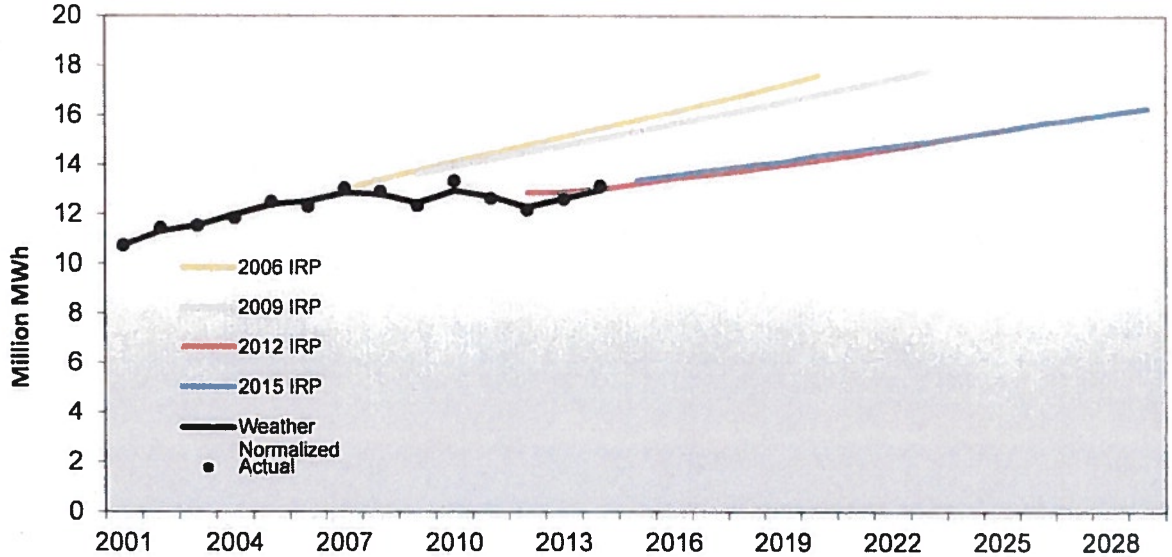


Figure 3-3
Comparisons of Load Forecasts
Winter Peak Demand Projections (MW)

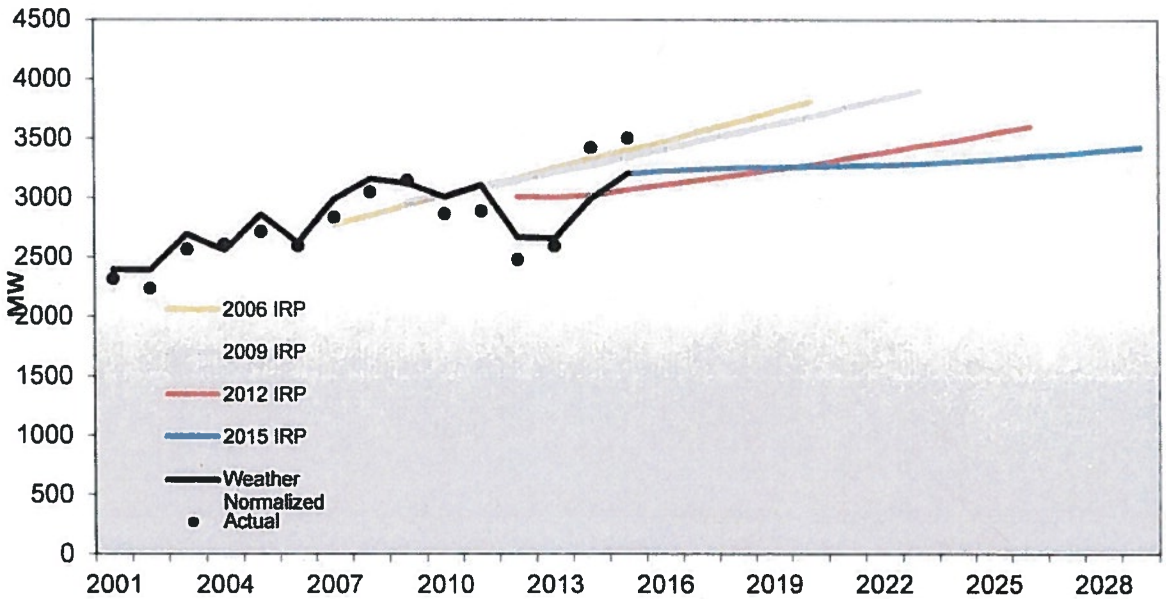
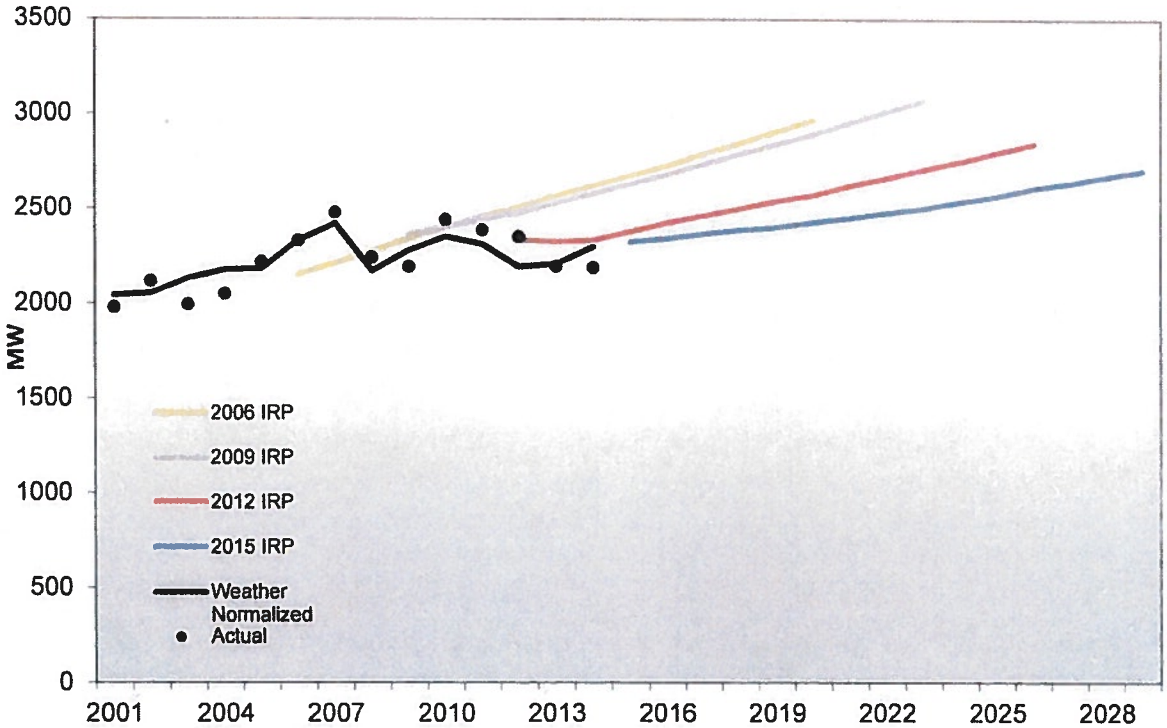


Figure 3-4
Comparison of Load Forecasts
Summer Peak Demand Projections (MW)



DSM Differences

In the 2012 IRP, the DSM projections were based on a technical feasibility analysis. At that time, EKPC noted that these projections would need to be refined to better match what could be achieved year by year.

For this 2015 IRP, EKPC has fine-tuned its DSM modeling projections to narrow the gap between its theoretical and actual peak demand and energy savings. EKPC has significantly enhanced its DSM planning capabilities by undertaking a comprehensive study of energy efficiency (EE) savings potential. This study was performed by GDS.

EKPC set a goal of achieving the equivalent of 1% of annual retail sales in new DSM annual kWh savings each year. The findings from the potential study show that this goal is achievable in the medium and long term. However, the levels of activity and spending far outstrip current performance and budgeting. In fact, EKPC is currently producing 0.2% of annual retail sales in new DSM annual kWh.

In order to narrow this gap, EKPC has established a ramp-up period of six years (2015-2020) during which time the plan is to steadily increase the investment in DSM resources so that the goal of 1% of annual retail savings by the year 2020 may be achieved. Participation projections reflect this steady increase in the years 2015-2020 then leveling off at participation levels that consistently achieve the 1% goal thereafter (from 2020-2029).

As a result, the 2015 IRP impacts are projected to be lower than the 2012 IRP impacts in the early years of the plan.

Table 3-11c presents the differences between the 2012 DSM plan and the 2015 DSM plan. When comparing the values, keep in mind that the base year for the 2012 plan was 2006, while the base year for the 2015 plan is 2014. This means for example that the 395,050 MWh of savings in 2015 from the 2012 plan represented nine years of participation, while the 78,967 MWh in the 2015 plan represents one year of participation.

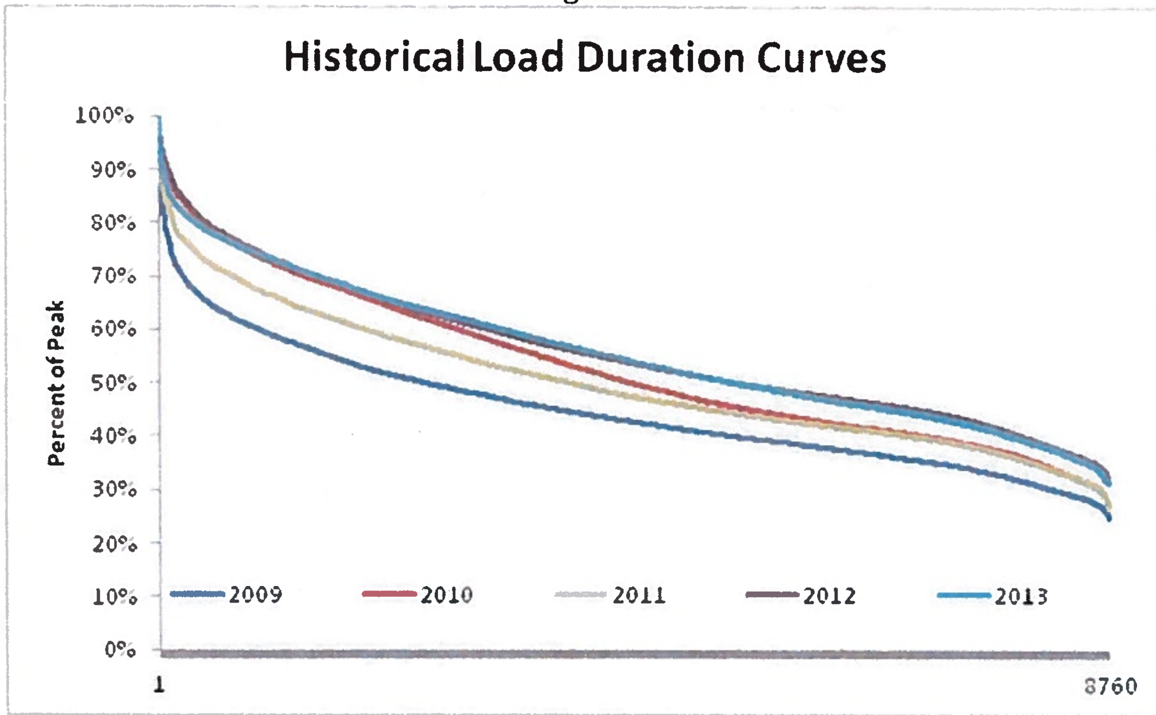
Section 5.0 – Demand Side Management – provides the details of the DSM plan.

Table 3-11c
Forecast Comparison between the IRP for DSM impact projections
2012 Versus 2015

	2012 IRP			2015 IRP		
Year	Impact on Energy Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)	Impact on Energy Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2015	395,050	322	307	78,967	137	160
2016	470,983	346	337	117,270	153	182
2017	545,245	367	361	163,280	169	202
2018	619,377	388	382	242,331	188	224
2019	683,801	406	395	336,804	212	249
2020	732,796	422	407	452,573	241	268
2021	781,988	438	419	551,746	263	284
2022	801,546	449	426	637,754	282	298
2023	822,287	460	433	715,315	298	310
2024	840,096	470	439	790,815	314	321
2025	857,803	480	446	856,275	329	331
2026	875,526	490	452	923,237	344	341
2027				987,854	359	351
2028				1,042,324	372	359
2029				1,086,303	383	367

Figure 3-5 illustrates historical load duration curves.

Figure 3-5



Multistate

These sections are not applicable as EKPC is not part of a multistate integrated utility system.

Customer class growth rates and annual energy growth rates are reported in Tables 3-12 and 3-13. Forecasted monthly sales for the first two years of the forecast are presented by class in Table 3-14.

Table 3-12
Consumer Growth by Consumer Class

Average Growth Rates	Time Period	Residential	Seasonal Residential	Commercial and Industrial ≤ 1000 KVA	Commercial and Industrial > 1000 KVA	Public Street and Highway Lighting	Other Public Authorities	Total
5-Year	2008-2013	0.4%	-53.8%	0.8%	0.5%	-1.3%	2.2%	0.3%
	2014-2019	0.8%	1.4%	1.3%	2.4%	1.3%	0.7%	0.8%
10-Year	2003-2013	1.0%	-31.3%	2.2%	0.1%	1.2%	2.0%	1.0%
	2014-2024	0.9%	1.4%	1.3%	1.6%	1.3%	0.9%	0.9%
15-Year	1998-2013	1.6%	-21.3%	2.9%	2.5%	2.3%	2.0%	1.6%
	2014-2029	0.9%	1.4%	1.3%	1.5%	1.1%	0.9%	0.9%
20-Year	1993-2013	1.9%	-15.3%	3.0%	3.4%	2.5%	2.2%	1.9%
	2014-2034	0.9%	1.4%	1.2%	1.3%	1.0%	0.8%	0.9%

Note: Member systems' Form 7 data for 2014 were not available.

Table 3-13
Energy Sales Growth by Consumer Class

Average Growth Rates	Time Period	Residential	Seasonal Residential	Commercial and Industrial ≤ 1000 KVA	Commercial and Industrial > 1000 KVA	Public Street and Highway Lighting	Other Public Authorities	Total
5-Year	2008-2013	-0.4%	-54.0%	0.5%	-0.4%	0.8%	1.8%	-0.3%
	2014-2019	0.8%	0.6%	1.8%	3.1%	1.5%	1.3%	1.5%
10-Year	2003-2013	1.1%	-31.6%	2.2%	0.5%	2.8%	5.5%	1.1%
	2014-2024	1.0%	1.2%	1.9%	2.5%	1.4%	1.2%	1.5%
15-Year	1998-2013	2.0%	-21.6%	2.8%	2.8%	3.8%	5.2%	2.3%
	2014-2029	1.0%	1.3%	1.9%	2.2%	1.4%	1.1%	1.5%
20-Year	1993-2013	2.5%	-16.1%	3.4%	5.8%	3.4%	5.1%	3.3%
	2014-2034	1.0%	1.2%	1.8%	2.0%	1.2%	1.0%	1.4%

Note: Member systems' Form 7 data for 2014 were not available.

Table 3-14
Monthly Class Energy Sales Forecasts
2015 – 2016

Year	Month	Residential Sales (MWh)	Seasonal Residential Sales (MWh)	Comm. & Ind. ≤ 1000 KVA Sales (MWh)	Public Authorities Sales (MWh)	Public Street & Highway Sales (MWh)	Comm. & Ind. > 1000 KVA Sales (MWh)	Total Retail Sales (MWh)	System Peak Demand (MW)
2015	1	815,989	16	162,818	3,087	823	265,989	1,248,722	3,207
2015	2	766,843	12	162,662	3,084	822	266,675	1,200,098	2,592
2015	3	662,496	13	163,210	3,095	824	267,362	1,096,999	2,391
2015	4	532,648	11	162,612	3,083	821	269,635	968,810	1,870
2015	5	458,477	25	162,807	3,087	822	270,322	895,540	1,889
2015	6	484,585	43	171,357	3,249	865	272,812	932,912	2,267
2015	7	565,533	46	172,252	3,266	870	273,499	1,015,466	2,334
2015	8	573,469	52	172,473	3,270	871	274,185	1,024,319	2,263
2015	9	508,837	34	172,496	3,270	872	274,872	960,380	2,172
2015	10	456,590	22	164,169	3,113	829	273,752	898,475	1,639
2015	11	547,517	20	164,585	3,121	831	274,439	990,513	2,370
2015	12	743,827	22	165,422	3,137	834	273,538	1,186,781	2,889
Total		7,116,809	318	1,996,862	37,860	10,086	3,257,080	12,419,015	
2016	1	825,417	17	166,208	3,162	835	272,564	1,268,202	3,239
2016	2	775,703	12	166,049	3,159	834	273,266	1,219,023	2,618
2016	3	670,151	13	166,607	3,170	836	273,970	1,114,747	2,415
2016	4	538,803	11	165,997	3,158	833	276,300	985,101	1,889
2016	5	463,774	26	166,197	3,162	834	277,004	910,996	1,912
2016	6	490,184	44	174,924	3,328	878	279,555	948,914	2,295
2016	7	572,067	47	175,839	3,345	882	280,259	1,032,439	2,363
2016	8	580,095	53	176,063	3,349	883	280,962	1,041,406	2,291
2016	9	514,716	34	176,087	3,349	884	281,665	976,737	2,199
2016	10	461,866	23	167,586	3,188	841	280,519	914,023	1,655
2016	11	553,843	21	168,012	3,196	843	281,223	1,007,138	2,394
2016	12	752,422	23	168,866	3,213	846	280,299	1,205,669	2,918
Total		7,199,040	323	2,038,435	38,778	10,234	3,337,584	12,624,394	

Note: Generation is determined by PJM market prices, not load requirements.

3.3 Details of Assumptions

3.3.1 Regional Economic Model

EKPC combines county-level forecasts from IHS's county-level economic forecasts released on March 1, 2014, into regional economic forecasts based on member system service territory boundaries. EKPC calculates each member system's share of its region's economy by dividing its actual (as adjusted for reclassifications) and forecasted residential consumer count by the total number of households in the region. The share is then applied to all economic variables (including households, employment, population, real gross county product and total real personal income) before they are used in other models. Table 3-15 shows how counties are assigned to regions.

Table 3-15
Regional Economic Model, Counties by Region

Central South	Central North	South	Central	North	North East	East
Allen	Bullitt	Adair	Anderson	Boone	Bath	Bell
Barren	Hardin	Boyle	Bourbon	Bracken	Boyd	Breathitt
Butler	Henry	Casey	Clark	Campbell	Carter	Clay
Cumberland	Jefferson	Garrard	Fayette	Carroll	Elliott	Estill
Edmonson	Larue	Green	Franklin	Gallatin	Fleming	Floyd
Grayson	Meade	Lincoln	Harrison	Grant	Greenup	Harlan
Hart	Nelson	Marion	Jessamine	Kenton	Lawrence	Jackson
Metcalfe	Oldham	McCreary	Madison	Owen	Lewis	Johnson
Monroe	Shelby	Pulaski	Mercer	Pendleton	Mason	Knott
Simpson	Spencer	Russell	Scott		Menifee	Knox
Warren	Trimble	Taylor	Woodford		Montgomery	Laurel
	Washington	Wayne			Nicholas	Lee
					Powell	Leslie
					Robertson	Letcher
					Rowan	Magoffin
						Martin
						Morgan
						Owsley
						Perry
						Pike
						Rockcastle
						Whitley
						Wolfe

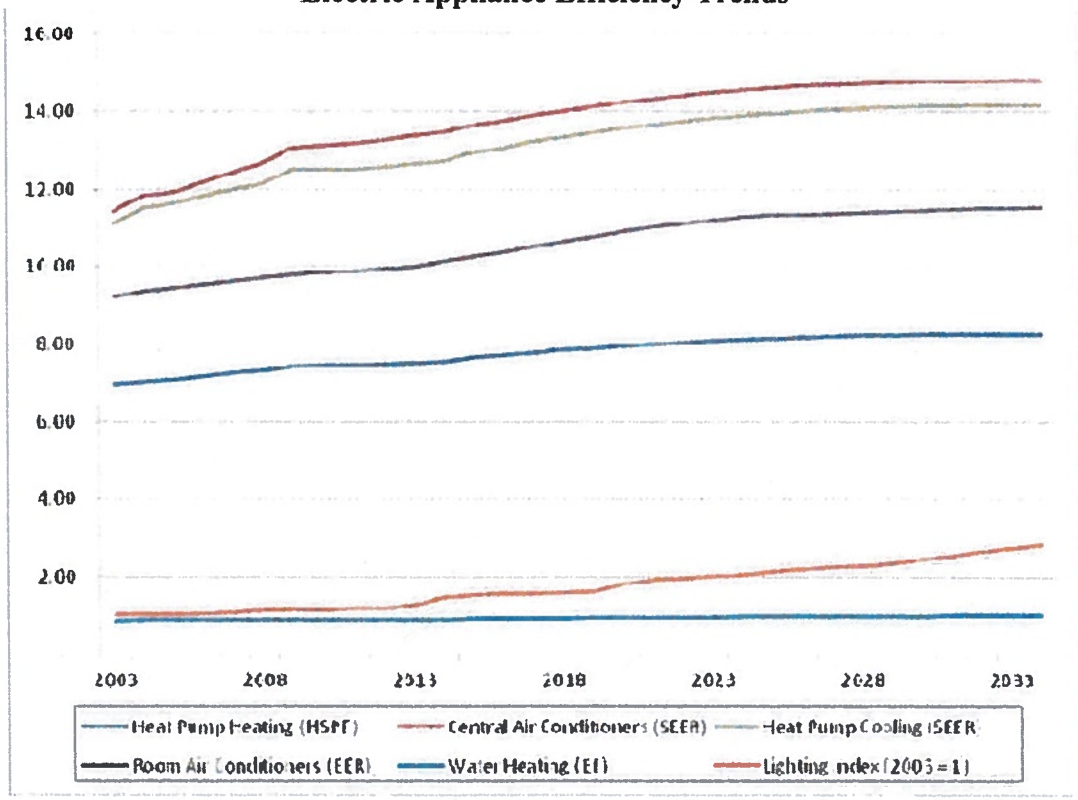
3.3.2 Electric Appliance Saturation and Efficiency Trends

Every 2-3 years since 1981, EKPC has surveyed its member systems' residential consumers to gather information on electric appliance saturation and other factors affecting electricity demand. EKPC projects these saturations for each member system as a function of time. The "2014 Load Forecast" incorporates data from surveys through 2013 as follows:

- Approximately 63 percent of EKPC customers have electric as a primary fuel for heat.
- Approximately 98 percent of EKPC customers have some type of air conditioning.
- Approximately 86 percent of EKPC customers have electric water heaters.

EKPC is a member of Itron's Energy Forecasting Group and as such, receives from Itron electric appliance efficiency projections for the East South Central U.S. Census Division (which comprises the states of Alabama, Kentucky, Mississippi, and Tennessee) based on information from the Energy Information Administration (EIA). Figure 3-6 displays the EIA efficiency projections.

Figure 3-6
Electric Appliance Efficiency Trends



3.3.3 Electricity Rates

The wholesale power cost projections used in the "2014 Load Forecast" are from EKPC's "Ten-Year Financial Forecast, 2013-2022", which was approved by EKPC's Board of Directors in October 2013.

3.3.4 Weather

The forecasts rely on NOAA weather stations located at seven airports in or near the EKPC system. Normals for most member systems are based on "1981-2010 U.S. Climate Normals". EKPC uses the following weather stations:

- Blue Grass Airport (LEX) in Lexington, KY:
- Bowling Green/Warren County Regional Airport (BWG) in Bowling Green, KY:
- Cincinnati/Northern Kentucky International Airport (CVG) in Covington, KY:
- Huntington Tri-State Airport (HTS) in Huntington, WV:
- Julian Carroll Airport (JKL) in Jackson, KY:
- Louisville International Airport (SDF) in Louisville, KY:
- Pulaski County Airport (SME) in Somerset, KY:

3.4 Discussion of Models

3.4.1 Forecast Model Summary

Models are used to develop the load forecast for each member system for each class reported to RUS. A brief overview of each is provided with additional information regarding the models and resulting forecasts.

3.4.1.1 Residential Sales

EKPC models the monthly residential consumers and monthly residential energy sales as a function of various economic variables where appropriate. These variables include:

- Customer and energy sales history
- Households
- Population density
- Employment
- Real gross county product
- Real total personal income
- Consumer price index
- Base 55 heating degree days
- Base 30 heating degree days
- Base 65 cooling degree days
- Autoregressive terms, which account for historical error for a certain number of months

3.4.1.2 Small Commercial Sales

EKPC models the monthly small commercial consumers and monthly small commercial energy sales as a function of various economic variables where appropriate. These variables include:

- Customer and energy sales history
- Residential customer counts
- Households
- Population density
- Employment
- Real gross county product
- Real total personal income
- Consumer price index
- Base 55 heating degree days
- Base 30 heating degree days
- Base 65 cooling degree days
- Autoregressive terms, which account for historical error for a certain number of months

3.4.1.3 Large Commercial and Industrial Sales

EKPC models the monthly large commercial and industrial consumers based on input from the individual member systems and monthly large commercial and industrial energy sales are modeled as a function of the real gross county product for that given service territory. Member systems remain in regular contact with their largest consumers and are generally aware of current production and future expansion plans, so they project energy sales for existing consumers and identified expected new consumers in this class for the next 3 years.

3.4.1.4 Seasonal Sales

Seasonal sales are made to customers with seasonal accounts such as vacation homes and weekend retreats and camps. Seasonal sales are relatively small and, as of 2013, only one member system reports seasonal residential consumers. Monthly seasonal customers and monthly seasonal energy sales are modeled as a function of residential customers.

3.4.1.5 Public Building Sales

Public Building sales include sales to accounts such as government buildings and libraries. The sales are relatively small and, as of 2013, only two member systems report other public authorities consumers. Monthly public building customers and monthly are modeled as a function of residential customers.

3.4.1.6 Public Street and Highway Lighting Sales

This class is relatively small and is projected as a function of residential sales. There are 12 member systems that report this class.

3.4.1.7 Peak Demand

Future seasonal peak demands are calculated by applying load factors for winter and summer to total purchased power for each member system.

3.5 Forecast Model Results

3.5.1 Residential Sales Forecast

As of 2013, residential consumers account for 58.1 percent of total energy sales at the EKPC system level. The average number of residential customers served by EKPC is expected to increase from approximately 492,000 in 2014 to 562,000 in 2029. Sales to the residential class are expected to grow 1.0 percent per year during the forecast period. Projected average monthly use per customer remains relatively flat throughout the forecast period. Table 3-16 displays the result of the 2014 Load Forecast for the residential class. Residential sales are not classified into heating and non-heating.

Table 3-16
Residential Class
Historical and Projected Customers and Sales

	Consumers			Use Per Consumer			Class Sales		
	Annual Average	Annual Change	Percent Change	Monthly Average (kWh)	Change (kWh)	Percent Change	Total (MWh)	Annual Change (MWh)	Percent Change
2003	441,636	10,469	2.4%	1,171	-21	-1.8%	6,205,364	38,835	0.6%
2004	451,117	9,481	2.1%	1,171	0	0.0%	6,337,737	132,373	2.1%
2005	456,103	4,986	1.1%	1,234	63	5.4%	6,751,545	413,808	6.5%
2006	465,784	9,681	2.1%	1,171	-62	-5.1%	6,545,584	-205,961	-3.1%
2007	471,584	5,800	1.2%	1,237	66	5.6%	6,998,555	452,971	6.9%
2008	479,039	7,455	1.6%	1,227	-9	-0.8%	7,055,278	56,723	0.8%
2009	480,527	1,488	0.3%	1,177	-50	-4.1%	6,789,142	-266,136	-3.8%
2010	481,868	1,341	0.3%	1,278	100	8.5%	7,388,899	599,757	8.8%
2011	482,351	483	0.1%	1,204	-74	-5.8%	6,967,415	-421,484	-5.7%
2012	487,769	5,418	1.1%	1,123	-81	-6.7%	6,572,947	-394,468	-5.7%
2013	489,630	1,861	0.4%	1,175	52	4.7%	6,905,017	332,070	5.1%
2014	492,071	2,441	0.5%	1,218	42	3.6%	7,190,266	285,249	4.1%
2015	495,084	3,013	0.6%	1,198	-20	-1.6%	7,116,809	-73,457	-1.0%
2016	498,597	3,513	0.7%	1,203	5	0.4%	7,199,040	82,231	1.2%
2017	502,594	3,997	0.8%	1,208	4	0.4%	7,283,342	84,302	1.2%
2018	506,924	4,330	0.9%	1,211	3	0.3%	7,367,004	83,662	1.1%
2019	511,581	4,657	0.9%	1,214	3	0.3%	7,455,700	88,696	1.2%
2020	516,467	4,886	1.0%	1,218	3	0.3%	7,545,866	90,166	1.2%
2021	521,337	4,870	0.9%	1,220	3	0.2%	7,634,550	88,684	1.2%
2022	526,404	5,067	1.0%	1,223	3	0.2%	7,725,997	91,447	1.2%
2023	531,235	4,831	0.9%	1,226	3	0.3%	7,817,409	91,412	1.2%
2024	536,435	5,200	1.0%	1,229	3	0.3%	7,914,171	96,762	1.2%
2025	541,888	5,453	1.0%	1,232	3	0.2%	8,014,115	99,944	1.3%
2026	547,199	5,311	1.0%	1,235	3	0.2%	8,110,072	95,957	1.2%
2027	552,278	5,079	0.9%	1,238	2	0.2%	8,201,757	91,685	1.1%
2028	557,219	4,941	0.9%	1,240	2	0.2%	8,291,671	89,914	1.1%
2029	561,948	4,729	0.8%	1,242	2	0.2%	8,376,465	84,794	1.0%

***Note:** Member systems' Form 7 data for 2014 were not available.*

3.5.2 Small Commercial Sales Forecast

As of 2013, small commercial consumers account for 16.1 percent of total energy sales at the EKPC system level. The commercial and industrial classes have been significantly impacted by the economic downturn of 2008. Most notably, the unemployment rate reached an all-time high that year and has only recently begun approaching prerecession levels. The automotive industry experienced sharp declines in response to the national economic downturn of 2008 and has not fully rebounded. EKPC member systems serve many of the satellite industrial and commercial customers that produce parts for Toyota Manufacturing of Kentucky and as a result of the aforementioned circumstances were negatively impacted. Table 3-17 displays the results of the 2014 Load Forecast for the small commercial class. Sales for resale for EKPC purposes, defined as off system sales, are not considered in the load forecast.

Table 3-17
Small Commercial Class
Historical and Projected Customers and Sales

	Consumers			Use Per Consumer			Class Sales		
	Annual Average	Annual Change	Percent Change	Annual Average (MWh)	Change (MWh)	Percent Change	Total (MWh)	Annual Change (MWh)	Percent Change
2003	26,664	-412	-1.5%	58	0	0.3%	1,550,251	-27,339	-1.7%
2004	28,122	1,458	5.5%	57	-1	-2.3%	1,597,841	47,590	3.1%
2005	30,608	2,486	8.8%	57	0	-0.6%	1,729,486	131,645	8.2%
2006	30,200	-408	-1.3%	59	2	4.2%	1,777,896	48,410	2.8%
2007	30,981	781	2.6%	60	1	2.1%	1,861,951	84,055	4.7%
2008	32,035	1,054	3.4%	58	-2	-2.7%	1,872,811	10,860	0.6%
2009	32,381	346	1.1%	55	-3	-5.6%	1,787,113	-85,698	-4.6%
2010	32,505	124	0.4%	60	4	7.9%	1,935,184	148,071	8.3%
2011	32,654	149	0.5%	58	-2	-2.7%	1,892,091	-43,093	-2.2%
2012	33,047	393	1.2%	57	-1	-1.7%	1,883,243	-8,848	-0.5%
2013	33,292	245	0.7%	58	1	1.1%	1,917,729	34,486	1.8%
2014	33,696	404	1.2%	59	1	2.2%	1,984,326	66,597	3.5%
2015	34,030	334	1.0%	59	0	-0.4%	1,996,862	12,536	0.6%
2016	34,466	436	1.3%	59	0	0.8%	2,038,435	41,573	2.1%
2017	34,931	465	1.3%	60	0	0.7%	2,080,437	42,002	2.1%
2018	35,434	503	1.4%	60	0	0.6%	2,123,865	43,428	2.1%
2019	35,925	491	1.4%	60	0	0.7%	2,168,939	45,074	2.1%
2020	36,435	510	1.4%	61	0	0.7%	2,214,180	45,241	2.1%
2021	36,946	511	1.4%	61	0	0.6%	2,258,394	44,214	2.0%
2022	37,469	523	1.4%	61	0	0.6%	2,303,360	44,966	2.0%
2023	37,986	517	1.4%	62	0	0.6%	2,349,882	46,522	2.0%
2024	38,514	528	1.4%	62	0	0.7%	2,398,920	49,038	2.1%
2025	39,048	534	1.4%	63	0	0.6%	2,447,930	49,010	2.0%
2026	39,557	509	1.3%	63	0	0.7%	2,496,649	48,719	2.0%
2027	40,042	485	1.2%	63	0	0.6%	2,542,048	45,399	1.8%
2028	40,486	444	1.1%	64	0	0.6%	2,585,118	43,070	1.7%
2029	40,923	437	1.1%	64	0	0.6%	2,627,461	42,343	1.6%

***Note:** Member systems' Form 7 data for 2014 were not available.*

3.5.3 Large Commercial and Industrial Sales Forecast

As of 2013, large commercial and industrial consumers account for 25.4 percent of total energy sales at the EKPC system level. In 2013, there were 135 retail customers classified as large commercial and industrial customers. The total annual usage was greater than the annual usage of the small commercial class. Approximately half of EKPC's large commercial customers are manufacturing plants, which like the small commercial class, have not fully recovered from the 2008 recession. Table 3-18 displays the results of the 2014 Load Forecast for the large commercial and industrial class.

Table 3-18
Large Commercial and Industrial Class
Historical and Projected Customers and Sales

	Consumers			Use Per Consumer			Class Sales		
	Annual Average	Annual Change	Percent Change	Annual Average (MWh)	Change (MWh)	Percent Change	Total (MWh)	Annual Change (MWh)	Percent Change
2003	134	22	19.6%	21,506	-3,376	-13.6%	2,881,781	94,969	3.4%
2004	138	4	3.0%	21,973	467	2.2%	3,032,313	150,532	5.2%
2005	139	1	0.7%	21,709	-264	-1.2%	3,017,603	-14,710	-0.5%
2006	135	-4	-2.9%	22,646	936	4.3%	3,057,184	39,581	1.3%
2007	122	-13	-9.6%	25,607	2,961	13.1%	3,124,042	66,858	2.2%
2008	132	10	8.2%	23,361	-2,246	-8.8%	3,083,590	-40,452	-1.3%
2009	138	6	4.5%	20,521	-2,839	-12.2%	2,831,936	-251,654	-8.2%
2010	125	-13	-9.4%	22,767	2,246	10.9%	2,845,857	13,921	0.5%
2011	127	2	1.6%	22,749	-18	-0.1%	2,889,143	43,286	1.5%
2012	130	3	2.4%	22,321	-428	-1.9%	2,901,689	12,546	0.4%
2013	135	5	3.8%	22,355	34	0.2%	3,017,925	116,236	4.0%
2014	128	-7	-5.2%	23,967	1,612	7.2%	3,067,731	49,806	1.7%
2015	133	5	3.9%	24,489	523	2.2%	3,257,080	189,349	6.2%
2016	135	2	1.5%	24,723	234	1.0%	3,337,584	80,504	2.5%
2017	140	5	3.7%	24,573	-150	-0.6%	3,440,200	102,616	3.1%
2018	143	3	2.1%	24,610	37	0.2%	3,519,215	79,015	2.3%
2019	144	1	0.7%	24,817	207	0.8%	3,573,690	54,475	1.5%
2020	145	1	0.7%	25,535	718	2.9%	3,702,565	128,875	3.6%
2021	146	1	0.7%	25,684	149	0.6%	3,749,885	47,320	1.3%
2022	147	1	0.7%	25,870	186	0.7%	3,802,950	53,065	1.4%
2023	147	0	0.0%	26,155	285	1.1%	3,844,856	41,906	1.1%
2024	150	3	2.0%	26,138	-17	-0.1%	3,920,737	75,881	2.0%
2025	150	0	0.0%	26,454	316	1.2%	3,968,149	47,412	1.2%
2026	156	6	4.0%	26,142	-313	-1.2%	4,078,084	109,935	2.8%
2027	156	0	0.0%	26,442	300	1.1%	4,124,892	46,808	1.1%
2028	158	2	1.3%	26,551	110	0.4%	4,195,083	70,191	1.7%
2029	160	2	1.3%	26,608	57	0.2%	4,257,257	62,174	1.5%

***Note:** Member systems' Form 7 data for 2014 were not available.*

3.5.4 Seasonal Sales Forecast

This class includes seasonal accounts such as vacation homes, weekend retreats, and camps. As of 2013, only one member system reports seasonal residential consumers, which account for less than 0.1 percent of total energy sales at the EKPC system level. Table 3-19 displays the results of the 2014 Load Forecast for the seasonal sales class.

Table 3-19
Seasonal Class
Historical and Projected Customers and Sales

	Consumers			Use Per Consumer			Class Sales		
	Annual Average	Annual Change	Percent Change	Monthly Average (kWh)	Change (kWh)	Percent Change	Total (MWh)	Annual Change (MWh)	Percent Change
2003	4,046	90	2.3%	277	-20	-6.6%	13,445	-631	-4.5%
2004	4,162	116	2.9%	277	0	0.1%	13,846	402	3.0%
2005	4,297	135	3.2%	281	4	1.4%	14,501	655	4.7%
2006	4,371	74	1.7%	265	-17	-5.9%	13,882	-619	-4.3%
2007	4,459	88	2.0%	274	10	3.7%	14,679	797	5.7%
2008	4,463	4	0.1%	271	-3	-1.1%	14,531	-149	-1.0%
2009	4,420	-43	-1.0%	247	-25	-9.1%	13,080	-1,451	-10.0%
2010	4,490	70	1.6%	259	12	5.1%	13,959	879	6.7%
2011	4,518	28	0.6%	236	-23	-9.1%	12,774	-1,185	-8.5%
2012	67	-4,451	-98.5%	282	47	19.8%	227	-12,547	-98.2%
2013	94	27	40.3%	266	-16	-5.8%	300	73	32.2%
2014	95	1	1.1%	289	23	8.5%	329	29	9.8%
2015	96	1	1.1%	276	-13	-4.4%	318	-11	-3.5%
2016	98	2	2.1%	275	-1	-0.5%	323	6	1.7%
2017	99	1	1.0%	277	2	0.8%	329	5	1.7%
2018	100	1	1.0%	278	1	0.5%	334	5	1.7%
2019	102	2	2.0%	278	-1	-0.2%	340	6	1.7%
2020	103	1	1.0%	280	2	0.8%	346	6	1.8%
2021	105	2	1.9%	279	-1	-0.2%	352	6	1.8%
2022	106	1	1.0%	282	3	1.0%	359	6	1.8%
2023	108	2	1.9%	282	-1	-0.2%	365	6	1.8%
2024	110	2	1.9%	281	-1	-0.2%	371	6	1.7%
2025	111	1	0.9%	284	3	1.0%	378	6	1.7%
2026	113	2	1.8%	282	-1	-0.5%	383	6	1.5%
2027	114	1	0.9%	284	2	0.7%	389	5	1.3%
2028	115	1	0.9%	285	0	0.1%	393	5	1.3%
2029	116	1	0.9%	286	1	0.4%	398	4	1.1%

Note: As of 2012, one member system ceased reporting residential seasonal customers.

***Note:** Member system Form 7 data for 2014 was not available.*

3.5.5 Public Building Sales Forecast

Public Building sales include sales to accounts such as government buildings and libraries. As of 2013, only two member systems report other public authorities consumers, which account for 0.3 percent of total energy sales at the EKPC system level. Table 3-20 displays the results of the 2014 Load Forecast for the public building sales class.

Table 3-20
Public Building Class
Historical and Projected Customers and Sales

	Consumers			Use Per Consumer			Class Sales		
	Annual Average	Annual Change	Percent Change	Monthly Average (kWh)	Change (kWh)	Percent Change	Total (MWh)	Annual Change (MWh)	Percent Change
2003	907	18	2.0%	1,999	81	4.3%	21,753	1,301	6.4%
2004	916	9	1.0%	2,090	91	4.6%	22,974	1,221	5.6%
2005	910	-6	-0.7%	2,063	-27	-1.3%	22,530	-444	-1.9%
2006	931	21	2.3%	1,987	-76	-3.7%	22,196	-334	-1.5%
2007	969	38	4.1%	2,273	286	14.4%	26,426	4,230	19.1%
2008	993	24	2.5%	2,860	587	25.8%	34,074	7,648	28.9%
2009	998	5	0.5%	2,965	105	3.7%	35,507	1,433	4.2%
2010	1,047	49	4.9%	3,168	204	6.9%	39,809	4,302	12.1%
2011	1,084	37	3.5%	2,957	-211	-6.7%	38,468	-1,341	-3.4%
2012	1,096	12	1.1%	2,676	-281	-9.5%	35,194	-3,274	-8.5%
2013	1,109	13	1.2%	2,796	120	4.5%	37,215	2,021	5.7%
2014	1,111	2	0.2%	2,851	55	1.9%	38,009	794	2.1%
2015	1,116	5	0.5%	2,827	-24	-0.8%	37,860	-149	-0.4%
2016	1,124	8	0.7%	2,875	48	1.7%	38,778	918	2.4%
2017	1,133	9	0.8%	2,902	27	0.9%	39,451	673	1.7%
2018	1,142	9	0.8%	2,909	7	0.2%	39,862	411	1.0%
2019	1,153	11	1.0%	2,926	17	0.6%	40,486	624	1.6%
2020	1,164	11	1.0%	2,953	27	0.9%	41,243	757	1.9%
2021	1,177	13	1.1%	2,960	7	0.2%	41,806	563	1.4%
2022	1,188	11	0.9%	2,961	1	0.0%	42,206	400	1.0%
2023	1,201	13	1.1%	2,956	-5	-0.2%	42,599	393	0.9%
2024	1,213	12	1.0%	2,950	-6	-0.2%	42,941	342	0.8%
2025	1,225	12	1.0%	2,943	-7	-0.2%	43,263	322	0.7%
2026	1,237	12	1.0%	2,937	-6	-0.2%	43,591	328	0.8%
2027	1,247	10	0.8%	2,936	-1	0.0%	43,929	338	0.8%
2028	1,259	12	1.0%	2,931	-5	-0.2%	44,279	350	0.8%
2029	1,268	9	0.7%	2,933	2	0.1%	44,631	352	0.8%

Note: *Member systems' Form 7 data for 2014 were not available.*

3.5.6 Public Street and Highway Lighting Sales Forecast

This class represents street lighting. As of 2013, 12 member systems report public street and highway lighting consumers, which account for 0.1 percent of total energy sales at the EKPC system level. Table 3-21 displays the results of the 2014 Load Forecast for the other sales class.

Table 3-21
Public Street and Highway Lighting Class
Historical and Projected Customers and Sales

	Consumers			Use Per Consumer			Class Sales		
	Annual Average	Annual Change	Percent Change	Annual Average (MWh)	Change (MWh)	Percent Change	Total (MWh)	Annual Change (MWh)	Percent Change
2003	366	13	3.7%	20	0	1.1%	7,448	341	4.8%
2004	377	11	3.0%	20	0	-2.3%	7,497	49	0.7%
2005	390	13	3.4%	20	0	-0.5%	7,714	217	2.9%
2006	420	30	7.7%	20	0	-0.9%	8,235	521	6.8%
2007	434	14	3.3%	19	0	-0.6%	8,459	224	2.7%
2008	441	7	1.6%	21	2	10.2%	9,476	1,017	12.0%
2009	425	-16	-3.6%	21	0	-0.7%	9,067	-409	-4.3%
2010	423	-2	-0.5%	22	1	5.3%	9,505	438	4.8%
2011	416	-7	-1.7%	24	1	5.3%	9,846	341	3.6%
2012	414	-2	-0.5%	23	0	-2.0%	9,601	-245	-2.5%
2013	412	-2	-0.5%	24	1	3.0%	9,845	244	2.5%
2014	418	6	1.5%	24	0	-0.4%	9,952	107	1.1%
2015	427	9	2.2%	24	0	-0.8%	10,086	134	1.3%
2016	431	4	0.9%	24	0	0.5%	10,234	148	1.5%
2017	438	7	1.6%	24	0	-0.1%	10,387	153	1.5%
2018	441	3	0.7%	24	0	0.8%	10,540	153	1.5%
2019	446	5	1.1%	24	0	0.4%	10,698	158	1.5%
2020	451	5	1.1%	24	0	0.4%	10,856	158	1.5%
2021	456	5	1.1%	24	0	0.3%	11,014	158	1.5%
2022	463	7	1.5%	24	0	-0.1%	11,172	158	1.4%
2023	470	7	1.5%	24	0	-0.1%	11,330	158	1.4%
2024	475	5	1.1%	24	0	0.3%	11,486	156	1.4%
2025	480	5	1.1%	24	0	0.3%	11,647	161	1.4%
2026	484	4	0.8%	24	0	0.5%	11,802	155	1.3%
2027	487	3	0.6%	25	0	0.6%	11,944	142	1.2%
2028	493	6	1.2%	24	0	-0.1%	12,078	134	1.1%
2029	496	3	0.6%	25	0	0.4%	12,203	125	1.0%

***Note:** Member systems' Form 7 data for 2014 were not available.*

3.6 Peak Demand Forecast and Scenarios

3.6.1 Peak Demand and Scenario Results

In addition to the forecasted peaks, high and low cases are developed. The same methodology is used; however, the starting summary dataset is different. Instead of using the sum of the member system files, two new models are built: one reflecting assumptions that result in optimistic economic growth and extreme weather conditions and one reflecting pessimistic economic growth and mild weather conditions. 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 annual degree days +/-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.

   Therefore, the high scenario for the residential price forecast is constructed to have a 3.2% compound annual growth rate, while the low scenario is constructed to have a 1.6% 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 the forecast period, the projected number of residential customers increases at a growth rate of 0.9%. 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.

These resulting adjustments were applied to the forecast period's compound annual growth rate in the base case customer count forecast resulting in a high customer case of 1.6% growth rate and 0.3% for the low case growth rate. This relationship was preserved in preparing the monthly customer counts for the high and low case scenarios.

4. Small and Large Commercial customer and energy – Small commercial customer growth is correlated to residential customer growth and the relationship was maintained when developing the high and low cases. Therefore, based upon the resulting high and low residential customer forecasts, the small commercial customers were impacted accordingly. For the large class, given year to year customer change is small, the low case was based upon no new customers for the forecast period. The high case was based on adding one new customer per year. For energy, small and large commercial usage is not as weather sensitive as residential usage, however, price does impact usage. Therefore, the low case assumes higher prices while the high case assumes lower prices.

Adjusting these assumptions leads to different customer forecasts which in turn results in different energy forecasts. The results are shown in Table 3-22 and Figures 3-7, 3-8, and 3-9 for the following cases:

Low Case - Pessimistic economic assumptions with mild weather causing lower loads
Base Case - Most probable economics assumptions with normal weather (Base Case pre DSM)
High Case - Optimistic economic assumptions with severe weather causing higher loads.

Table 3-22
Scenarios
Peak Demands and Total Requirements
Pre-DSM

Impacts due to interruptible contracts have been subtracted.

Total Winter Peak Demand (MW)				Total Summer Peak Demand (MW)				Total Requirements (MWh)			
Season	Low Case	Base Case	High Case	Year	Low Case	Base Case	High Case	Year	Low Case	Base Case	High Case
2014-2015	3,127	**3,254**	3,318	2015	2,350	**2,400**	2,444	2015	13,151,597	**13,368,393**	13,659,065
2015-2016	3,146	**3,294**	3,387	2016	2,364	**2,440**	2,507	2016	13,201,297	**13,563,866**	13,971,740
2016-2017	3,170	**3,323**	3,443	2017	2,369	**2,484**	2,575	2017	13,196,430	**13,781,894**	14,303,995
2017-2018	3,157	**3,354**	3,506	2018	2,376	**2,527**	2,641	2018	13,205,184	**13,974,738**	14,628,946
2018-2019	3,150	**3,382**	3,565	2019	2,387	**2,566**	2,703	2019	13,234,562	**14,147,514**	14,929,298
2019-2020	3,150	**3,418**	3,627	2020	2,410	**2,612**	2,778	2020	13,363,207	**14,436,649**	15,334,499
2020-2021	3,142	**3,445**	3,682	2021	2,418	**2,651**	2,837	2021	13,407,741	**14,633,457**	15,654,837
2021-2022	3,130	**3,470**	3,738	2022	2,426	**2,691**	2,901	2022	13,456,119	**14,842,021**	16,000,969
2022-2023	3,146	**3,498**	3,800	2023	2,438	**2,728**	2,964	2023	13,526,293	**15,043,007**	16,350,037
2023-2024	3,151	**3,534**	3,869	2024	2,442	**2,773**	3,036	2024	13,556,076	**15,290,328**	16,743,525
2024-2025	3,166	**3,566**	3,933	2025	2,454	**2,813**	3,103	2025	13,630,755	**15,514,584**	17,116,385
2025-2026	3,161	**3,607**	4,009	2026	2,450	**2,866**	3,184	2026	13,622,873	**15,807,528**	17,568,379
2026-2027	3,175	**3,644**	4,084	2027	2,461	**2,904**	3,252	2027	13,687,464	**16,013,662**	17,943,843
2027-2028	3,183	**3,685**	4,165	2028	2,467	**2,947**	3,326	2028	13,726,483	**16,241,455**	18,349,186
2028-2029	3,188	**3,724**	4,246	2029	2,471	**2,986**	3,399	2029	13,757,899	**16,454,469**	18,752,071

Figure 3-7
Total Energy Requirements Scenario

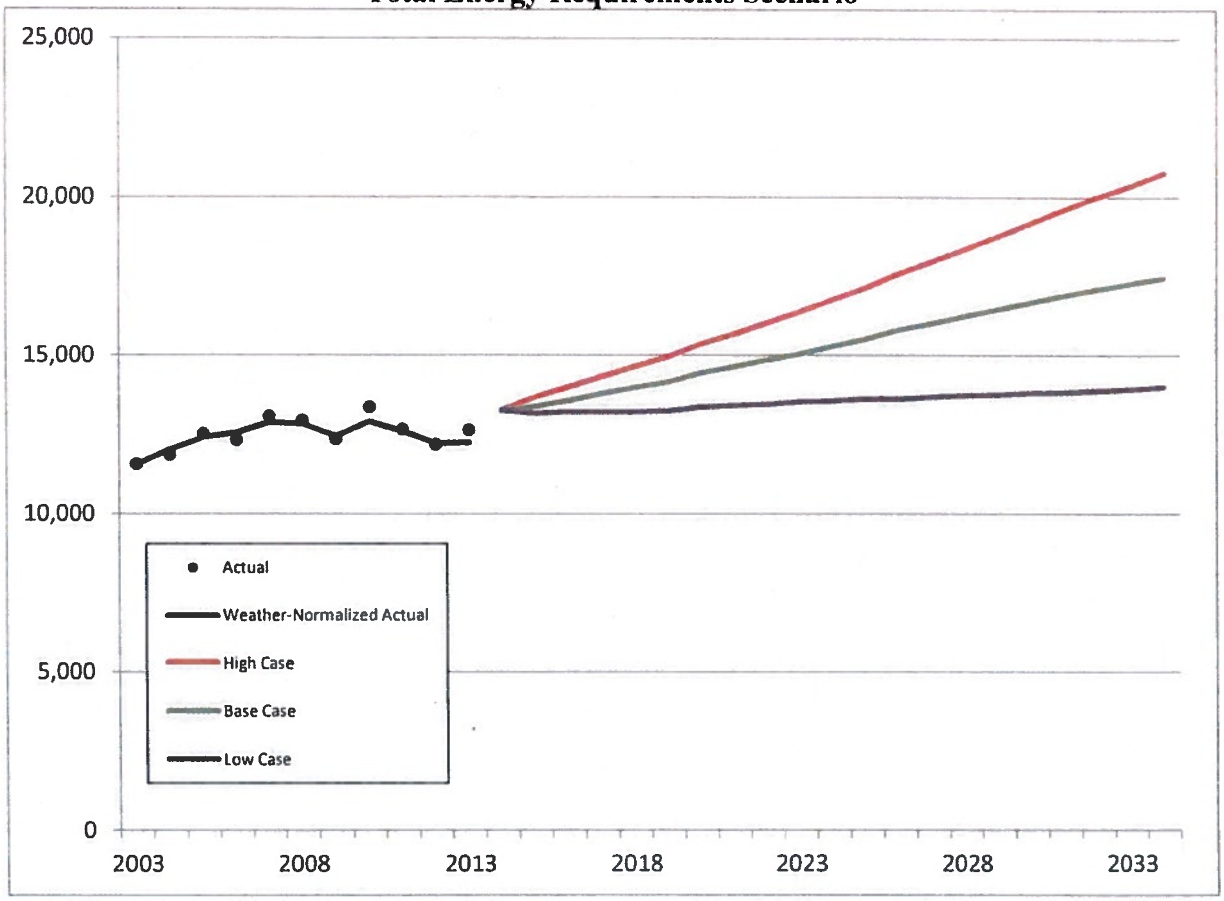


Figure 3-8
Total Winter Peak Scenario

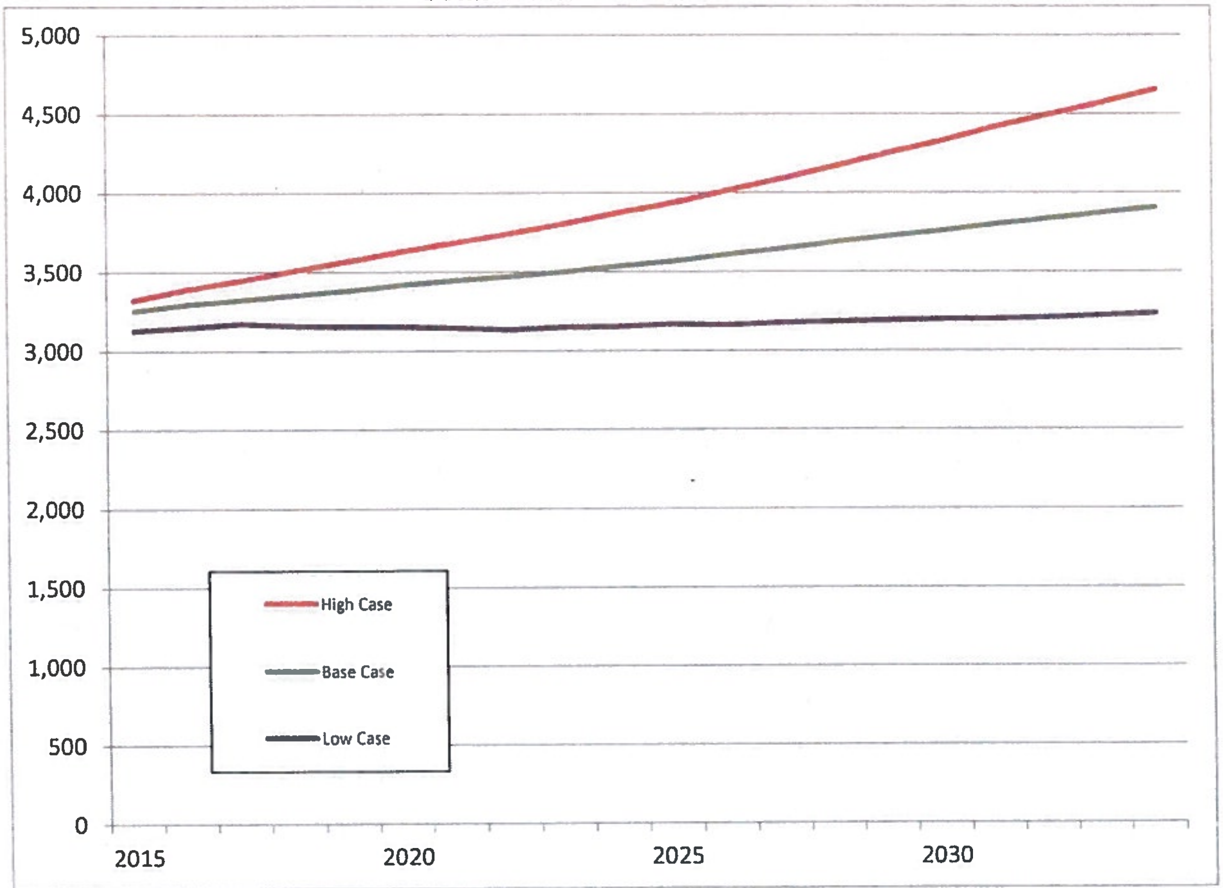
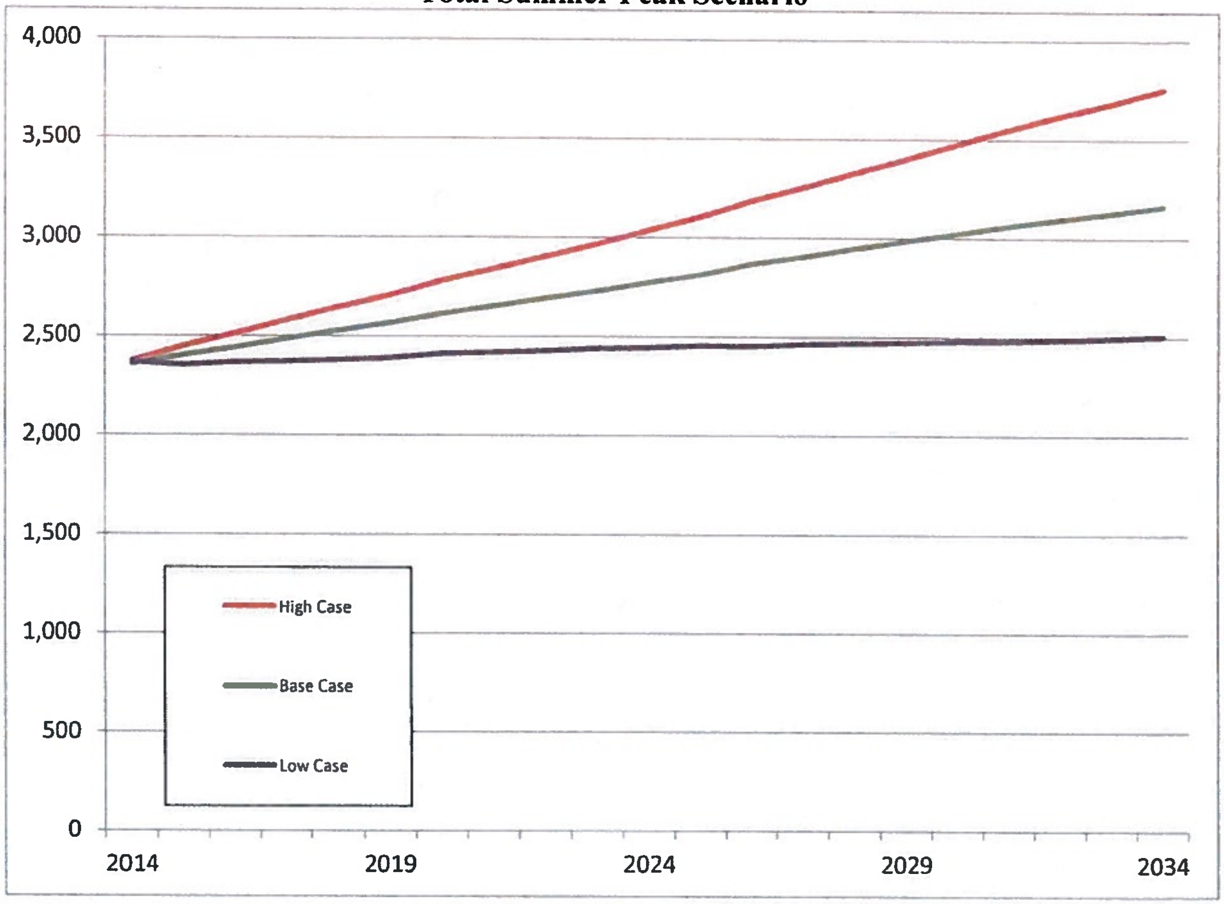


Figure 3-9
Total Summer Peak Scenario



3.7 Load Research and Research and Development Activities

3.7.1 Load Research

As previously stated, EKPC conducts an appliance saturation survey every two to three years. In addition, EKPC has a load research program which consists of over 550 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 used in end-use forecasting methodologies to project energy 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 member systems' 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 127 load profile meters installed and collecting data.
2. Small Commercial & Industrial: These are nonresidential customers whose demand is less than 50 kW. There are 45 load profile meters installed and collecting data.
3. Medium Commercial & Industrial: Includes customers whose peak demands are between 50 and 350 kW. There are 61 load profile meters installed and collecting data.
4. Large Power: Customers whose peak demands are greater than 350 kW. There are 317 meters installed.

Although not formally approved, the following projects have been proposed for implementation in 2015.

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 2014.
2. Borrowed data: EKPC will continue to monitor and evaluate the transferability of load data from other utilities.

3.7.2 Research and Development

In addition to Load Research, EKPC undertakes research projects as appropriate. EKPC has implemented two (2) small DSM research projects to quantify potential benefits and costs.

- EKPC implemented an existing manufactured home improvement research project. The goal of the project is to quantify the annual kWh and KW savings for improvements to typical post 1976 manufactured homes and compare those savings to the implementation costs. Improvements were performed on 22 manufactured homes served by a member system having typical energy usage patterns. Improvements included the removal of existing insulation beneath the home floor, installation of open-cell spray foam insulation to the floor, and the installation of a vapor barrier on exposed ground. In addition to providing a permanent R-19 value insulation to the home floor, the spray foam also improves home air leakage by sealing the floor leaks and sealing the duct system air leaks. On an average, home air leakage was improved by more than 20%. EKPC is working with the member system to quantify the average reduction in kWh usage for the homes. Usage data will be analyzed after sufficient kWh usage data is captured during the heating and cooling seasons.

- EKPC partnered with one member system to test Grid-Interactive Electric Thermal Storage (GETS). The GETS system was installed on 10 electric water heaters and 10 room electric thermal storage (ETS) heaters. The GETS system controls when energy is utilized to heat either the water or the ETS bricks based on a signal from PJM. The signal from PJM is the same signal received by typical power plant generating units instructing them to increase or decrease electric output to match the load demands of the system. This signal is provided by PJM every four (4) seconds. PJM has a GETS water heater installed in the lobby of their corporate office and is very supportive of this technology concept. EKPC and other power producers in the PJM footprint receive financial compensation from PJM for providing load-following services regardless if the product providing the service is a large generating unit or a basic water heater. Throughout 2015, EKPC will evaluate the performance of the GETS system including all benefits and costs.

SECTION 4.0

EXISTING AND COMMITTED CAPACITY RESOURCES SUMMARY

SECTION 4.0

EXISTING AND COMMITTED CAPACITY RESOURCES SUMMARY

4.1 Existing EKPC Generating Facilities

EKPC currently owns and operates 2,671 MW of summer capacity. This capacity is located at 9 separate sites with a total of 35 generating units. Fuel sources include coal, natural gas and landfill gas.

Coal Fired Units

Dale Station

The first plant built by EKPC was the William C. Dale Station located in Ford, Kentucky, which is on the Kentucky River in Clark County. All four units at Dale Station are pulverized coal fired units. The first two units have a rated capacity of 23 MW each and began commercial operation on December 1, 1954. EKPC idled these two units. The third unit is capable of producing 74 MW and began operation on October 1, 1957. The fourth unit is also rated at 75 MW and began operation on August 9, 1960. Units 3 and 4 are anticipated to be idled on April 16, 2016.

Cooper Station

The second plant EKPC built was the John Sherman Cooper Station located near Somerset on Lake Cumberland. The station has one 116 MW unit that became operational on February 9, 1965, and one 225 MW unit that began operating commercially on October 28, 1969. Both units are pulverized coal units. A pollution control system was added to the Cooper 2 unit and began commercial operation in summer 2012. A duct reroute project is currently underway which will route the flue gas from unit one into the pollution control system as well. This project will be complete and in commercial operation before April 2016.

Spurlock Station

The most recent coal fired plant constructed by EKPC is the Hugh L. Spurlock Station situated near Maysville, Kentucky on the Ohio River. The station consists of four units. The first one is a 300 MW unit that began commercial operation on September 1, 1977. Unit 2 is a 510 MW unit that began operating on March 2, 1981. Both of these units are conventional pulverized coal units with FGD technology.

On March 1, 2005, Unit 3 became operational. It is a 268 MW unit. The fourth unit became operational on April 1, 2009. It is a 268 MW unit. Both units 3 and 4 are fluidized bed boiler technology.

Peaking Capacity

EKPC has three ABB GT 11N2 combustion turbines, four General Electric Co. 7EA combustion turbines, and two General Electric Co. LMS 100 combustion turbines located at the J. K. Smith plant site in eastern Clark County near the Kentucky River. The ABB turbines, which went commercial in 1999, have a summer rating of 110 MW each and a winter rating of 142 MW each. Two of the GE turbines went commercial in 2001 and two in 2005. Each has a summer rating of 73 MW and a winter rating of 100 MW. The two LMS 100 turbines became operational in 2010. Each has a summer rating of 76 MW and a winter rating of 101 MW.

Landfill Gas

EKPC owns and operates 14.4 MW of landfill gas capacity generated at 5 sites throughout Kentucky.

Steam Load

On February 15, 2012, International Paper acquired Temple-Inland, the parent company of Inland Container Corporation. The International Paper Corporation is a corrugated paper recycling facility adjacent to EKPC's Spurlock Station. The facility has an expected peak electrical load of approximately 24 MW and an equivalent of 29 MW in steam. The steam is supplied from Spurlock Unit 2 on a normal basis but can also be supplied from Spurlock Unit 1 when needed. On average, International Paper operates 99.1 percent of the time and Spurlock 2 operates at an average of 510 MW.

807 KAR 5:058 Section 8.(3)(b)(1-11) 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.

Table 8.(3)(b(1-11)-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	74 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,	None	None	None	None
Retirement/Inactive Dates	4/15/2015	4/15/2015	4/15/2016	4/15/2016

Table 8.(3)(b)(1-11)-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	300 MW	510 MW	268 MW	268 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/Inactive Dates						

Table 8.(3)(b)(1-11)-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 *	110 MW	110 MW	110 MW	73 MW	73 MW	73 MW	73 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/Inactive Dates	None	None	None	None	None	None	None

*Summer Rating

Table 8.(3)(b)(1-11)-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 *	76 MW	76 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/Inactive Dates	N/A	N/A

*Summer Rating

Table 8.(3)(b)(1-11)-5

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	Not Permitted	Existing	Existing	Decommissioned
Commercial Operation	9/22/03	9/9/03	9/15/03	2/1/06	1/15/06	1/07	11/09
Type	Gas	Gas	Gas	Gas	Gas	Gas	Gas
Net Dependable Capability	3.2 MW	2.4 MW	3.2 MW		2.4 MW	3.2 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,	None	None	None	None	None	None	None
Deratings, Retirement/Inactive Dates							Decommissioned in February 2015

REDACTED

807 KAR 5:058 Section 8.(3)(b)(12) Resource Assessment and Acquisition Plan. (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. (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: (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).

	ACTUAL															
Dale 1	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Capacity Factor	0.00	-														
Availability Factor	1.00	1.00														
Average Heat Rate (Btu/kWh)	-	-														
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 (%)		-														
O&M Escalation (%)		0														

	ACTUAL															
Dale 2	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Capacity Factor	0.00	-														
Availability Factor	1.00	1.00														
Average Heat Rate (Btu/kWh)																

REDACTED

	-	-	
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 (%)		-	
O&M Escalation (%)			0

Dale 3	ACTUAL 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capacity Factor	0.02	0.09	0.02													
Availability Factor	0.87	0.98	0.98													
Average Heat Rate (Btu/kWh)	14,245	12,120	12,244													
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]													
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]													
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]													
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]													
Capital Cost Escalation (%)		-	-													
O&M Escalation (%)		0	2.4													

Dale 4	ACTUAL 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capacity Factor	0.01	0.11	0.03													
Availability Factor	0.87	0.98	0.98													
Average Heat Rate (Btu/kWh)	16,608	11,674	11,760													
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]													
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]													
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]													
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]													

REDACTED

Capital Cost Escalation (%)		-	-
O&M Escalation (%)		0	2.4

Cooper 1	ACTUAL 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capacity Factor	0.48	0.62	0.47	0.43	0.37	0.37	0.33	0.34	0.30	0.29	0.29	0.28	0.28	0.30	0.31	0.34
Availability Factor	0.91	0.87	0.90	0.90	0.86	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94
Average Heat Rate (Btu/kWh)	11,096	10,786	10,836	10,842	10,888	10,912	10,950	10,960	11,028	11,062	11,090	11,102	11,139	11,121	11,076	11,048
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

Cooper 2	ACTUAL 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capacity Factor	0.38	0.48	0.49	0.46	0.36	0.33	0.29	0.28	0.23	0.21	0.21	0.21	0.21	0.23	0.25	0.29
Availability Factor	0.88	0.82	0.88	0.88	0.82	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)	10,575	10,184	10,178	10,181	10,193	10,203	10,221	10,223	10,236	10,247	10,254	10,262	10,273	10,265	10,249	10,242
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

Spurlock 1	ACTUAL 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capacity Factor	0.66	0.75	0.76	0.77	0.73	0.78	0.73	0.86	0.58	0.56	0.53	0.50	0.49	0.55	0.51	0.66

REDACTED

Availability Factor	0.91	0.88	0.90	0.90	0.84	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92
Average Heat Rate (Btu/kWh)	10,655	10,346	10,353	10,335	10,334	10,344	10,373	10,238	10,432	10,442	10,449	10,455	10,469	10,451	10,492	10,440
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

Spurlock 2	ACTUAL 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capacity Factor	0.81	0.82	0.80	0.83	0.78	0.84	0.83	0.82	0.80	0.80	0.79	0.78	0.78	0.79	0.78	0.80
Availability Factor	0.84	0.90	0.88	0.90	0.85	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92
Average Heat Rate (Btu/kWh)	10,173	9,989	9,988	9,969	9,970	9,974	9,988	10,004	10,029	10,035	10,043	10,052	10,055	10,040	10,056	10,023
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

Gilbert Unit	ACTUAL 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capacity Factor	0.80	0.72	0.79	0.80	0.78	0.79	0.78	0.75	0.75	0.74	0.74	0.73	0.73	0.74	0.73	0.75
Availability Factor	0.80	0.82	0.90	0.90	0.88	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)	9,765	9,860	9,848	9,832	9,838	9,844	9,869	9,910	9,926	9,937	9,951	9,959	9,967	9,947	9,965	9,916
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

REDACTED

Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

Spurlock 4	ACTUAL 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capacity Factor	0.79	0.83	0.79	0.83	0.76	0.83	0.82	0.81	0.80	0.80	0.80	0.79	0.79	0.80	0.79	0.80
Availability Factor	0.84	0.90	0.86	0.90	0.83	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)	10,068	9,780	9,792	9,777	9,793	9,781	9,791	9,804	9,822	9,827	9,831	9,844	9,844	9,832	9,845	9,822
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

Smith CT1	ACTUAL 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capacity Factor	0.03	0.0167	0.0178	0.0185	0.0402	0.0445	0.0363	0.0383	0.0374	0.0387	0.0371	0.0386	0.0394	0.0404	0.0388	0.0273
Availability Factor	0.82	0.72	0.87	0.87	0.85	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87
Average Heat Rate (Btu/kWh)	12,870	12,534	12,581	12,590	12,550	12,623	12,655	12,647	12,584	12,588	12,587	12,582	12,564	12,557	12,602	12,596
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

ACTUAL

REDACTED

Smith CT2	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capacity Factor	0.06	0.0162	0.0165	0.0172	0.0378	0.0416	0.0335	0.0354	0.0363	0.0378	0.0364	0.0377	0.0384	0.0396	0.0380	0.0259
Availability Factor	0.99	0.87	0.72	0.87	0.85	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87
Average Heat Rate (Btu/kWh)	12,904	12,653	12,808	12,820	12,744	12,842	12,891	12,875	12,662	12,652	12,636	12,636	12,629	12,613	12,653	12,702
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

Smith CT3	ACTUAL 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capacity Factor	0.06	0.0152	0.0161	0.0168	0.0372	0.0408	0.0330	0.0348	0.0358	0.0370	0.0361	0.0373	0.0377	0.0389	0.0377	0.0253
Availability Factor	1.00	0.87	0.87	0.72	0.85	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87
Average Heat Rate (Btu/kWh)	13,088	12,818	12,892	12,900	12,813	12,906	12,944	12,936	12,706	12,715	12,665	12,676	12,691	12,660	12,692	12,829
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

Smith CT4	ACTUAL 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capacity Factor	0.09	0.06	0.06	0.06	0.09	0.10	0.08	0.08	0.08	0.09	0.09	0.09	0.09	0.10	0.09	0.09
Availability Factor	0.93	0.92	0.92	0.94	0.92	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94
Average Heat Rate (Btu/kWh)	12,012	12,026	11,967	12,037	12,096	12,045	11,991	11,940	11,877	11,873	11,886	11,868	11,847	11,837	11,839	11,863
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

REDACTED

Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[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]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

Smith CT5	ACTUAL 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capacity Factor	0.08	0.07	0.07	0.07	0.12	0.11	0.09	0.09	0.09	0.10	0.10	0.10	0.10	0.10	0.10	0.09
Availability Factor	0.93	0.88	0.92	0.94	0.92	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94
Average Heat Rate (Btu/kWh)	11,830	11,683	11,660	11,666	11,720	11,731	11,753	11,743	11,735	11,729	11,734	11,731	11,721	11,725	11,731	11,741
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

Smith CT6	ACTUAL 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capacity Factor	0.08	0.07	0.07	0.07	0.11	0.11	0.09	0.09	0.09	0.10	0.10	0.10	0.10	0.10	0.09	0.09
Availability Factor	0.93	0.88	0.92	0.94	0.92	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94
Average Heat Rate (Btu/kWh)	11,779	11,699	11,675	11,686	11,747	11,747	11,780	11,763	11,755	11,746	11,752	11,749	11,740	11,740	11,742	11,765
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

REDACTED

Smith CT7	ACTUAL 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capacity Factor	0.08	0.07	0.06	0.07	0.11	0.11	0.09	0.09	0.09	0.10	0.10	0.10	0.10	0.10	0.10	0.09
Availability Factor	0.98	0.94	0.88	0.94	0.92	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94
Average Heat Rate (Btu/kWh)	11,729	11,775	11,742	11,771	11,830	11,795	11,820	11,797	11,776	11,765	11,772	11,763	11,757	11,753	11,765	11,793
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

Smith CT 9	ACTUAL 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capacity Factor	0.10	0.22	0.20	0.18	0.26	0.28	0.23	0.25	0.25	0.26	0.25	0.25	0.26	0.27	0.27	0.26
Availability Factor	0.91	-	-	0.88	0.84	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92
Average Heat Rate (Btu/kWh)	9,567	9,076	9,112	9,187	9,079	9,051	9,080	9,095	9,068	9,064	9,066	9,056	9,032	9,041	9,028	9,059
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation		0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

Smith CT 10	ACTUAL 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capacity Factor	0.11	0.21	0.20	0.18	0.25	0.27	0.24	0.24	0.25	0.25	0.25	0.26	0.26	0.26	0.26	0.25
Availability Factor	0.83	0.88	0.88	0.88	0.84	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92
Average Heat Rate (Btu/kWh)																

REDACTED

	9,689	9,139	9,169	9,263	9,118	9,096	9,146	9,146	9,110	9,102	9,080	9,065	9,044	9,075	9,030	9,093
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

Landfill Gas Projects	ACTUAL 2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capacity Factor	0.57	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77
Availability Factor	0.96	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Average Heat Rate (Btu/kWh)	12,303	11,895	11,895	11,895	11,895	11,895	11,895	11,895	11,895	11,895	11,895	11,895	11,895	11,895	11,895	11,895
Fuel Cost ($/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M ($/kW/Yr)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Production Cost ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

SECTION 5.0

DEMAND SIDE MANAGEMENT

SECTION 5.0

DEMAND SIDE MANAGEMENT

5.1 Introduction

807 KAR 5:058 Section 8(2)(b) The utility shall describe and discuss all options considered for inclusion in the plan including: (b) Conservation and load management or other demand-side programs not already in place.

East Kentucky Power Cooperative (EKPC) selects Demand-Side Management (DSM) programs to offer on the basis of meeting customer needs and resource planning objectives in a cost-effective manner. EKPC analyzes DSM measures and programs using both qualitative and quantitative criteria. These criteria include customer acceptance, measure applicability, savings potential, and cost-effectiveness. The cost-effectiveness of DSM resources is analyzed in a rigorous fashion using standard (California) tests for cost-effectiveness.

This IRP evaluates the costs and benefits of both existing and new DSM programs to be implemented by EKPC in partnership with its Member Systems.

These efforts are to comply with:

> "Each electric utility shall integrate energy efficiency resources into its plan and shall adopt policies establishing cost-effective energy efficiency resources with equal priority as other resource options. In each integrated resource plan, certificate case, and rate case, the subject electric utility shall fully explain its consideration of cost-effective energy efficiency resources as defined in the Commission's IRP regulation (807 KAR 5058)." – *In the Matter of Consideration of the New Federal Standards of the Energy Independence and Security Act of 2007,* Rehearing Order, Case No. 2008-00408, p.10 (Ky. P.S.C. July 24, 2012).

5.2 DSM Planning Process

For the 2015 IRP, EKPC has enhanced its DSM planning capabilities by undertaking a comprehensive study of energy efficiency (EE) savings potential.

For the EE potential study, GDS conducted a cost-effectiveness screening of a comprehensive set of measures using the Total Resource Cost test from the California standard. This resulted in a greater number of DSM measures receiving cost-benefit analysis and a comprehensive evaluation of DSM measures for this IRP.

EKPC evaluated 207 DSM measures for the 2015 Integrated Resource Plan. These include 54 residential energy efficiency measures, 82 commercial efficiency measures, and 66 industrial measures, plus 5 demand response programs.

For more details on the energy efficiency measures and the results of the economic screening of those measures, please see the GDS Energy Efficiency Potential report (included as Exhibit DSM-1 in the DSM Technical Appendix). All five of the demand response programs are included as resources in this plan. Those five demand response programs include the following: Direct Load Control (DLC) of AC&WH for residential, DLC for Commercial Central AC, Large Interruptible, Other Interruptible and C&I Demand Response.

Individual energy efficiency measures were then bundled together according to program categories, both existing and new. EKPC then prepared cost and participation estimates for all of the DSM programs, and conducted a final cost-effectiveness analysis for each DSM program using the DSMore software tool.

For three programs, cost-effectiveness analysis was done for individual measures in that program as well: Direct Load Control of Air Conditioners and Water Heaters (2 measures), ENERGY STAR® Appliances (7 measures), and Commercial & Industrial Equipment Rebate (5 measures). All of the programs were shown to be cost-effective using the TRC test.

All programs that were implemented in 2014, plus any additional programs in the tariff approval process, are considered "Existing" for the purposes of this IRP. "New" programs target measures with significant potential that are not included in Existing programs.

For this 2015 IRP, EKPC has fine-tuned its DSM modeling projects to narrow the gap between its theoretical and actual peak demand and energy savings. In order to close this gap, EKPC has established a ramp-up period of six years (2015-2020) during which time it plans to steadily increase its investment in DSM resources so that EKPC attain its goal of 1% of annual retail savings by the year 2020.

The DSM portfolio for the 2015 IRP includes fourteen (14) Existing programs, and eleven (11) New programs.