2019

INTEGRATED RESOURCE PLAN

REDACTED

April 1, 2019 **Case No. 2019-00096**

EAST KENTUCKY POWER COOPERATIVE

A Touchstone Energy® Cooperative

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Page Reference	Filing Requirement	Description
(a) 56 – 61 (b) 46 (c) 46 (d) 47 (e) 47 (f) 40 (g) 38, 80-90 (h) 18, 19, 45, 48	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.**
56 - 63	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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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 electricity to 16 owner-member distribution cooperatives with 588,000 meters at homes, farms and businesses in 87 Kentucky counties. EKPC does not directly serve any retail customers. Owner-members served by EKPC include:

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

EKPC owns and operates coal-fired generation at Cooper Station in Pulaski County (341MW) and Spurlock Station in Mason County (1,346MW). EKPC owns and operates gas-fired generation at Smith Station in Clark County (989MW winter rating) and Bluegrass Generation Station (Bluegrass) in Oldham County (567MW winter rating). EKPC also owns and operates Landfill Gas to Energy renewable generation facilities in Boone County (4.6MW), Laurel County (3.0MW), Glasgow (0.9MW), Greenup County (2.3MW), Hardin County (2.3MW) and Pendleton County (3.0MW). EKPC owns an 8.5MW solar generation facility in Clark County.

EKPC purchases hydropower from the Southeastern Power Administration (SEPA) on a long-term basis. Laurel Dam (70MW) historically has been a reliable resource. However, due to various dam and generator repair projects, EKPC’s 100MW allocation from the Cumberland System has not provided dependable capacity and energy for several years and is not expected to be considered fully available until the fall of 2020. Once the dam and generator repairs are completed, the capacity should return to firm dependable status for the long-term.

In total, EKPC owns and/or purchases 2,965MW (summer rating) of generation. EKPC operates within the PJM Interconnection, Inc. (PJM), which has over 180,000MW of generation. EKPC’s all-time peak demand of 3,507MW occurred on February 20, 2015.

EKPC owns and operates a 2,955-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 74 normally closed free-flowing interconnections with its neighboring utilities.

1.2 Load Forecast

EKPC's load forecast is prepared every two 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 owner-member to prepare its load forecast. The summation of these is the EKPC system forecast. Owner-members use their load forecasts in developing construction work plans, long-range work plans, and financial forecasts. EKPC uses the load forecast in demand side management analyses, marketing analyses, transmission planning, power supply planning, and financial forecasting.

The forecast indicates that for the period 2019 through 2033, total energy requirements will increase on average 1.4 percent per year. Winter and summer net peak annual demand will increase by 0.6 percent and 0.9 percent, respectively, on average.

1.3 Demand Side Management (DSM)

EKPC selects DSM programs to offer on the basis of meeting member 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 member 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 2019 IRP, EKPC had GDS Associates, Inc. (GDS) conduct an updated and enhanced study of energy efficiency (EE) and demand response (DR) savings potential. For this potential study, GDS conducted a cost-effectiveness screening of a comprehensive set of measures using the Total Resource Cost (TRC) test from the California standard.

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

EKPC has used the $3 million EE budget scenario from the GDS potential study to develop participation estimates for the DSM programs.

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 May 31, 2018, as described in its annual reports to the Kentucky Public Service Commission (Commission). EKPC's existing resource portfolio adequately meets its power supply requirements for the next five years. EKPC continuously looks at its resources and compares those to its expected load profile for the upcoming years. EKPC expects to utilize Power Purchase Agreements (PPA), 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 load during the winter peak season, energy prices are not guaranteed and can be extremely volatile. Therefore, EKPC plans to meet its winter peak load obligations with secured resources, and not be solely dependent on the market, thereby fulfilling a policy espoused by the Commission in prior cases.

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 owner-members 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 cost-effective DSM programs;
- Continue to evaluate winter peak energy and capacity needs and review against market and owned-generation options
- 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 EKPC's 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 owner-members may be higher financing costs for future projects. Therefore, monitoring economic and load conditions is critical to EKPC’s plans, as is remaining aware of project opportunities.
- *Continue to develop and promote cost-effective DSM programs*. EKPC desires to develop reasonable and economic DSM programs. Participation in these programs by retail members 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 TRC tests. EKPC has re-evaluated all of its DSM programs for cost-effectiveness. Some programs have been proposed to be eliminated and others have been modified. EKPC will continue to assess the cost-effectiveness of DSM programs as avoided costs change, and will adjust its portfolio as needed. 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.
- *Continue to evaluate winter peak energy and capacity needs and review against market and owned-generation options.* EKPC expects to be short on capacity to supply its winter peak period load in the 2024 time-frame. PJM provides enough capacity to cover EKPC's winter peak load, but prices for that energy are not hedged. EKPC’s experiences in January of 2014 and February of 2015 solidified the need to secure price hedges for its winter load position.

EKPC expects to have sufficient existing resources to meet its winter peak load needs for the next five years. In the 2024 time frame, EKPC will either need to enter into a PPA going forward or pursue other economic power supply alternatives to be identified in an RFP process. EKPC will seek to find the most economical alternative to meet its power supply requirements and comply with future Environmental Protection Agency (EPA) rules.

- *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 May 31, 2018 in its annual reports to the Commission. EKPC anticipates it will continue to realize similar savings going forward. EKPC actively participates in the PJM Committees and stakeholder processes. The current Chair of the Members Committee is an EKPC employee. 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 (Collaborative 2.0)

In 2015, EKPC worked with potential DSM and Renewable Energy stakeholders to develop a new DSM and Renewable Energy Collaborative. EKPC and the stakeholders agreed to a charter that established the new Collaborative 2.0. The Collaborative 2.0 met four times from September 2015-December 2018. At the December 2018 meeting, EKPC reviewed the cost-effective measures and the programs that EKPC and the owner-members planned to request the Commission to discontinue or change.

Materials including the meeting agendas can be found in Exhibit 8 of the DSM Technical Appendix.

1.8 Organization of the 2019 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
Julia Tucker, Director of Power Supply Planning
Jerry Purvis, Vice President of Environmental Affairs
Sally Witt, Manager of Load Forecasting
Fernie Williams, Manager of Resource and Renewable Planning
Darrin Adams, Director of Transmission Planning and Protection
Scott Drake, Manager of Corporate Technical Services
Robin Hayes, Director of Financial Planning and Analysis
Sandy Mollenkopf, Senior Load Forecast Analyst
Patrick Woods, Director of Regulatory and Compliance
Legal Counsel: David Samford, Goss Samford PLLC
L. Allyson Honaker, 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 2019 IRP is organized in accordance with the sequencing of the planning process, while clearly cross-referencing the appropriate citations to 807 KAR 5:058. EKPC used the Commission Staff Report of the 2015 IRP as a starting point in its analysis for this IRP. The Staff Report recommendations, along with the basic requirements of the Commission's regulations, became the foundation leading to this IRP.

1.9 Significant Changes from 2015

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

<u>EKPC joined PJM on June 1, 2013</u>

EKPC integrated its operations into the PJM market on June 1, 2013. While this change occurred before the 2015 IRP, it continues to drive significant operation changes and significant cost savings for EKPC. Therefore, it is discussed again in this IRP report. PJM operates a reliability constrained two-settlement Energy Market, that Day-Ahead matches load requirements with economic generation and demand resources and balances the actual needs in real-time. EKPC's generation fleet is economically dispatched with PJM's other generation and demand resources (over 180,000MW) 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 substantial net savings realized through May 31, 2018, as documented in its annual reports to the Executive Director of the Commission.

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.

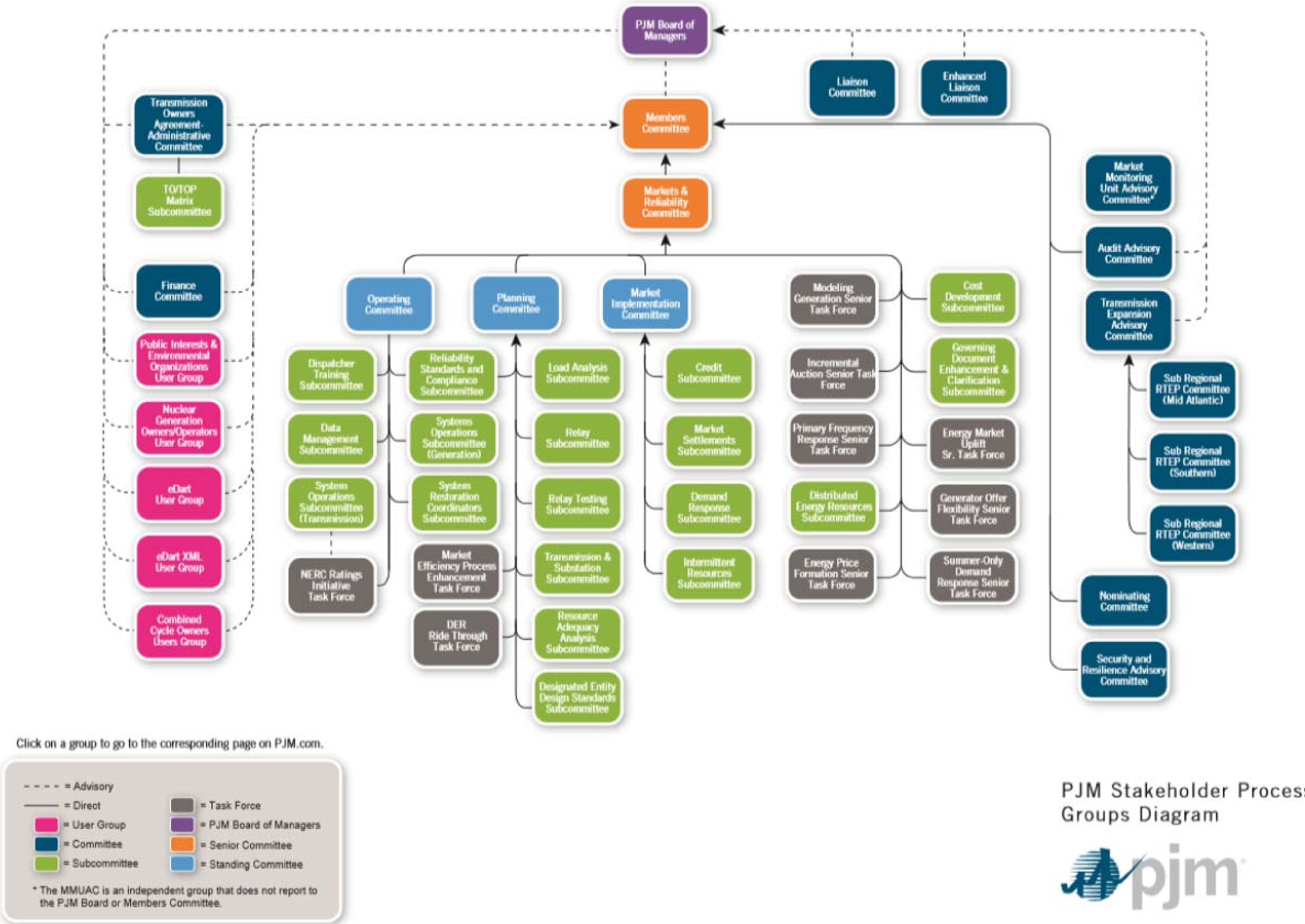
EKPC's obligation to PJM for capacity is defined via the Capacity Market auctions. EKPC's minimum obligation as a Load Serving Entity within PJM requires that EKPC either provide or secure enough capacity to cover its summer peak load plus approximately 3 percent reserves. PJM carries more than a 3 percent capacity reserve margin, however, EKPC's load diversity with the PJM market allows the net impact on EKPC to be roughly 3 percent. 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 entire 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 the Federal Energy Regulatory Commission (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 Organizational Chart on the following page or you may visit the following link to view the same.

https://www.pjm.com/-/media/committees-groups/committee-structure-diagram.ashx


PJM Board of Managers
Members Committee
Markets & Reliability Committee
Liaison Committee
Enhanced Liaison Committee
Transmission Owners Agreement-Administrative Committee
TO/TOP Matrix Subcommittee
Finance Committee
Public Interests & Environmental Organizations User Group
Nuclear Generation Owners/Operators User Group
eDart User Group
eDart XML User Group
Combined Cycle Owners Users Group
Operating Committee
Planning Committee
Market Implementation Committee
Dispatcher Training Subcommittee
Data Management Subcommittee
System Operations Subcommittee (Transmission)
NERC Ratings Initiative Task Force
Reliability Standards and Compliance Subcommittee
Systems Operations Subcommittee (Generation)
System Restoration Coordinators Subcommittee
Market Efficiency Process Enhancement Task Force
DER Ride Through Task Force
Load Analysis Subcommittee
Relay Subcommittee
Relay Testing Subcommittee
Transmission & Substation Subcommittee
Resource Adequacy Analysis Subcommittee
Designated Entity Design Standards Subcommittee
Credit Subcommittee
Market Settlements Subcommittee
Demand Response Subcommittee
Intermittent Resources Subcommittee
Modeling Generation Senior Task Force
Incremental Auction Senior Task Force
Primary Frequency Response Senior Task Force
Distributed Energy Resources Subcommittee
Energy Price Formation Senior Task Force
Cost Development Subcommittee
Governing Document Enhancement & Clarification Subcommittee
Energy Market Uplift Sr. Task Force
Generator Offer Flexibility Senior Task Force
Summer-Only Demand Response Senior Task Force
Market Monitoring Unit Advisory Committee*
Audit Advisory Committee
Transmission Expansion Advisory Committee
Sub Regional RTEP Committee (Mid Atlantic)
Sub Regional RTEP Committee (Southern)
Sub Regional RTEP Committee (Western)
Nominating Committee
Security and Resilience Advisory Committee
Click on a group to go to the corresponding page on PJM.com.
= Advisory
= Direct
= User Group
= Committee
= Subcommittee
= Task Force
= PJM Board of Managers
= Senior Committee
= Standing Committee
* The MMUAC is an independent group that does not report to the PJM Board or Members Committee.
PJM Stakeholder Process Groups Diagram
pjm

Retirement of Dale Station

All four units at Dale Station have been retired, Units 1 and 2 in April 2015 and Units 3 and 4 in April 2016. The power block is being demolished and should be completed by the summer of 2019. The substation will remain in place.

Purchase of Bluegrass Generation Station

EKPC expanded its peaking fleet in 2015 with the acquisition of the Bluegrass in Oldham County, Kentucky. The three Siemens 501FD-2 units were constructed in 2002. The summer rating for each is 167MW and the winter rating is 189MW. Bluegrass Unit 3 is under contract to May 2019, at which time it becomes fully available for EKPC's use.

Cooperative Solar One

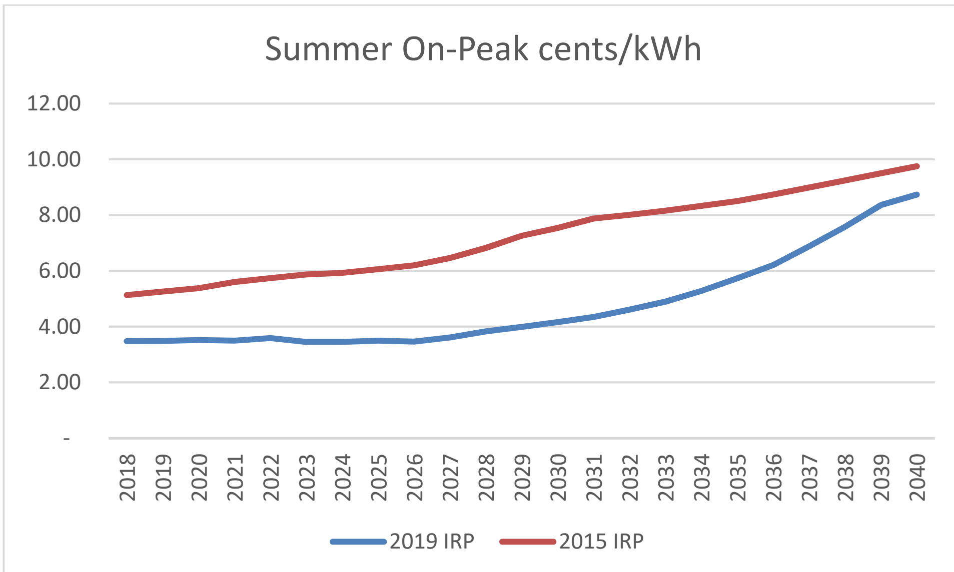
EKPC, along with its sixteen owner-members, implemented a community solar project in order to offer renewable solar energy to end users within the owner-members' service territories. This project is a result of the Demand Side and Renewable Energy Collaborative group's efforts. The 8.5MW facility began operations in November 2017. Marketing of the 25-year licenses continues under the Cooperative Solar program, which offers benefits of solar generation without the installation and maintenance requirements that would be necessary in a smaller home or office installation. This facility produced 13,859 MWh in 2018.

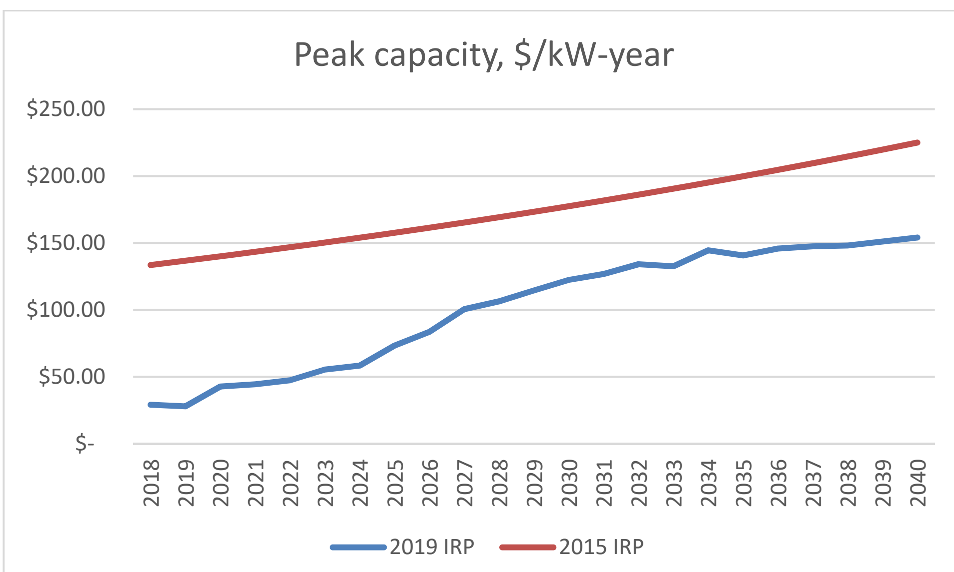
DSM Program Changes

EKPC updated its Energy Efficiency and Demand Response Potential Study (performed by GDS) for this plan. The project scope included a detailed energy efficiency and demand response potential study for residential and commercial/industrial retail members.

The operating environment for DSM has changed significantly since 2015. First, the avoided energy and capacity costs are significantly lower now. This in turn reduces the cost-effectiveness of DSM programs and measures. In some cases, this has resulted in programs and measures that had previously been cost-effective no longer being so.

The following graphs compare the avoided costs cited in the 2015 IRP with the avoided costs cited in this IRP:





Second, many of EKPC's owner-members have experienced revenue erosion that has negatively impacted their financial health. Third, the repeal of the Federal Clean Power Plan has removed any value that EE would have had as a compliance option. Finally, more stringent efficiency codes and standards have reduced the incremental savings for certain measures.

In response to this different operating environment, EKPC has made changes to its program offerings. Some programs have been discontinued, while others have been modified.

The following programs have been **eliminated**:

- ENERGY STAR® Appliances
- Appliance Recycling
- HVAC Duct Seal
- C&I Lighting
- Industrial Compressed Air

The following programs have been **modified**:

- Button-Up Weatherization
- Heat Pump Retrofit
- Touchstone Energy Home
- ENERGY STAR® Manufactured Home
- Residential Direct Load Control[1]

The remaining programs have **not changed**:

- CARES Low-Income Weatherization
- Residential Energy Audit (home information)
- Residential Efficient Lighting

EKPC has filed updated tariffs with the Commission that reflect these changes to programs. The tariffs which are proposed to be modified are currently in effect, but remain subject to further review by the Commission in Case No. 2019-00059.

[1] The tariff allows small commercial customers to participate. However, EKPC is not projecting to have any small commercial participants in this IRP.

DSM Differences

In the 2015 IRP, EKPC set a goal of achieving the equivalent of 1 percent of annual retail sales in new DSM annual kWh savings each year. At the time, EKPC was producing 0.2 percent of annual retail sales in new DSM annual kWhs. So the 2015 plan called for much higher levels of activity and spending.

In order to narrow this gap, EKPC established a ramp-up period of six years (2015-2020) to steadily increase the investment in DSM resources so that the goal of 1 percent of annual retail savings by the year 2020 may be achieved. After 2020, participation and funding were kept steady so the 1 percent goal would continue to be met.

Between 2015 and today, the situation has changed dramatically. Avoided costs are significantly lower, revenue erosion has emerged as a significant concern, and the Federal Clean Power Plan has been rescinded.

As a result, EKPC in this IRP has set participation levels for DSM programs to meet targeted funding levels. These targets correspond to the $3 million residential EE scenario in the GDS report.

EKPC will allocate that funding to existing programs. No new programs are proposed in this IRP.

In addition, EKPC and its owner-members have made the strategic decision to dedicate all DSM resources to the residential class. End-use residential members consume over 70 percent of the electricity produced by EKPC for its owner-members. Therefore, there are no non-residential EE programs proposed in this IRP. Should future conditions warrant it, EKPC's priorities for starting up non-residential EE programs would be lighting, HVAC, refrigeration, machine drive, and process heating & cooling.

Table 1-1 presents the differences between the 2015 DSM plan and the 2019 DSM plan. The 2015 plan impacts are adjusted for a 2018 base year to match the 2019 plan base year. Section 5.0 - Demand Side Management - provides more details of the DSM plan.

Table 1-1
Comparing DSM Impact projections from 2015 IRP with the 2019 IRP

	2015 IRP			2019 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)
2019	94,472	24	25	10,689	2	2
2020	211,241	53	44	20,622	5	3
2021	309,415	75	60	30,576	7	5
2022	395,423	94	74	40,518	9	7
2023	472,984	110	86	50,240	11	9
2024	548,484	126	97	59,552	12	11
2025	613,944	141	107	68,981	14	13
2026	680,906	156	117	78,411	15	15
2027	745,523	171	127	86,621	17	17
2028	799,993	184	135	94,765	18	19
2029	843,972	195	143	102,910	20	20

Discussion of differences between 2019 IRP Load Forecast and the 2015 IRP Load Forecast

The most significant differences are the base-year energy and members, the expansion of an industrial member and DSM impacts. In 2019, total energy requirements are a little over 400,000 MWh lower than the previous IRP, however, 20-year growth rates are the same at 1.4 percent annually. Similarly, the number of residential end-use retail members (retail members) in 2019 is 2,000 less than the previous IRP and the growth rate is slightly lower (0.7 vs 0.9 percent). [redacted]

Growth in use-per-member is dampened by energy efficiency improvements for appliances, as well as thermal integrity of structures. In general, homes have more connected load but it is not enough to offset efficiency impacts. This has been true for the last few years and is projected to continue. The owner-members in the eastern part of the state continue to struggle due to the economy and a decline in coal mining. Other owner-members are seeing new commercial and industrial growth, as well as subdivision development. Table 1-2 displays comparisons between the 2015 IRP and 2019 IRP load forecasts.

Table 1-2
Forecast Comparison
2019 IRP Versus 2015

		2019 IRP	2015 IRP	Difference
Residential Sales, MWh	2019	7,154,796	7,455,700	(300,904)
	2024	7,333,909	7,914,171	(580,262)
	2029	7,662,936	8,376,465	(713,529)
Total Commercial and Industrial Sales, MWh	2019	5,608,873	5,742,629	(133,756)
	2024	7,160,454	6,319,657	840,797
	2029	7,515,453	6,884,718	630,735
Residential Customers	2019	509,573	511,581	(2,008)
	2024	529,427	536,435	(7,008)
	2029	550,018	561,948	(11,930)
Net Winter Peak, MW	2019	3,258	3,302	(44)
	2024	3,401	3,455	(54)
	2029	3,514	3,651	(137)
Net Summer Peak, MW	2019	2,341	2,456	(115)
	2024	2,483	2,665	(182)
	2029	2,595	2,885	(290)
Total Requirements, MWh	2019	13,735,980	14,147,514	(411,534)
	2024	15,555,697	15,290,328	265,369
	2029	16,292,394	16,454,469	(162,075)

Lastly, the DSM impacts for the first five years in the load forecast are lower than the previous IRP load forecast as a result of lower spending and participation levels for DSM assumed for this IRP:

Table 1-3
DSM Impacts

2019 IRP	Energy (MWh)	Winter Peak (MW)	Summer Peak (MW)
Year 1	10,689	2	2
Year 2	20,622	5	3
Year 3	30,576	7	5
Year 4	40,518	9	7
Year 5	50,240	11	9
2015 IRP	**Energy (MWh)**	**Winter Peak (MW)**	**Summer Peak (MW)**
Year 1	31,541	22	41
Year 2	61,657	30	52
Year 3	94,437	39	63
Year 4	127,217	47	74
Year 5	159,996	55	85

Figure 1-1

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

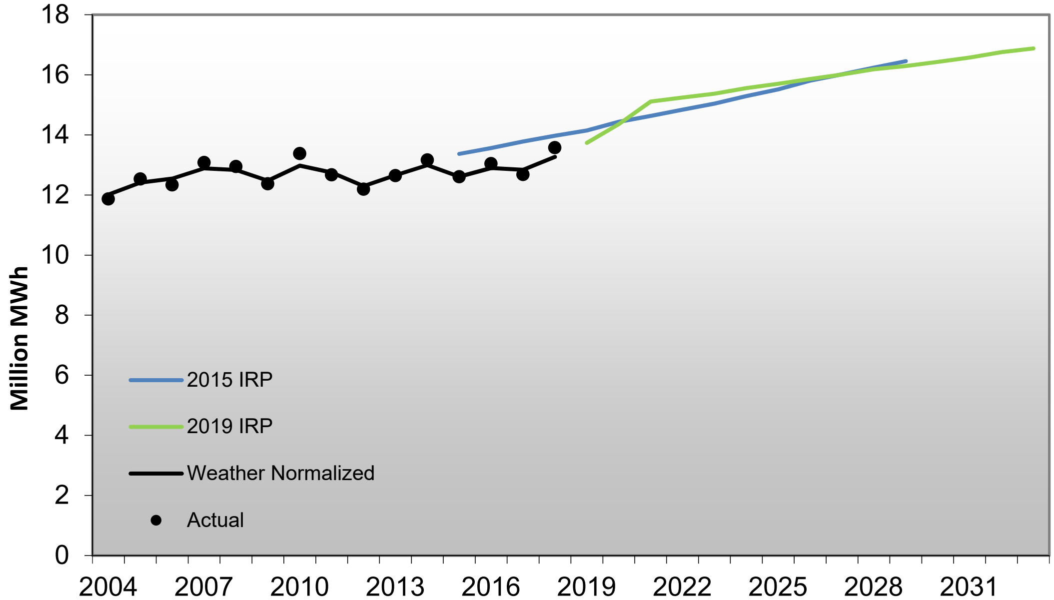


Figure 1-2

Comparisons of Load Forecasts
Winter Peak Demand Projections (MW)

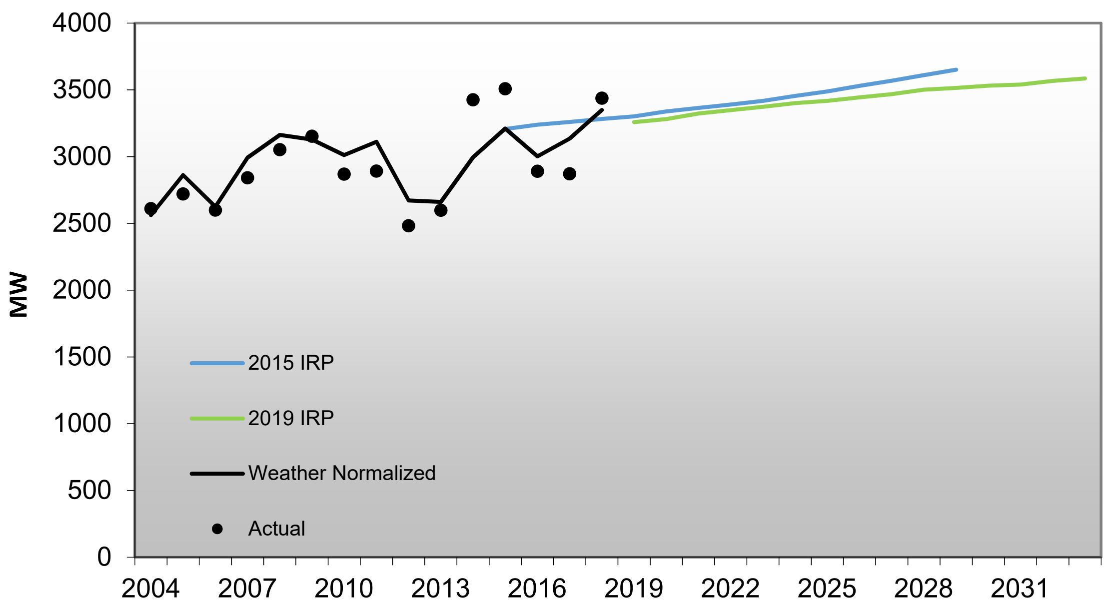
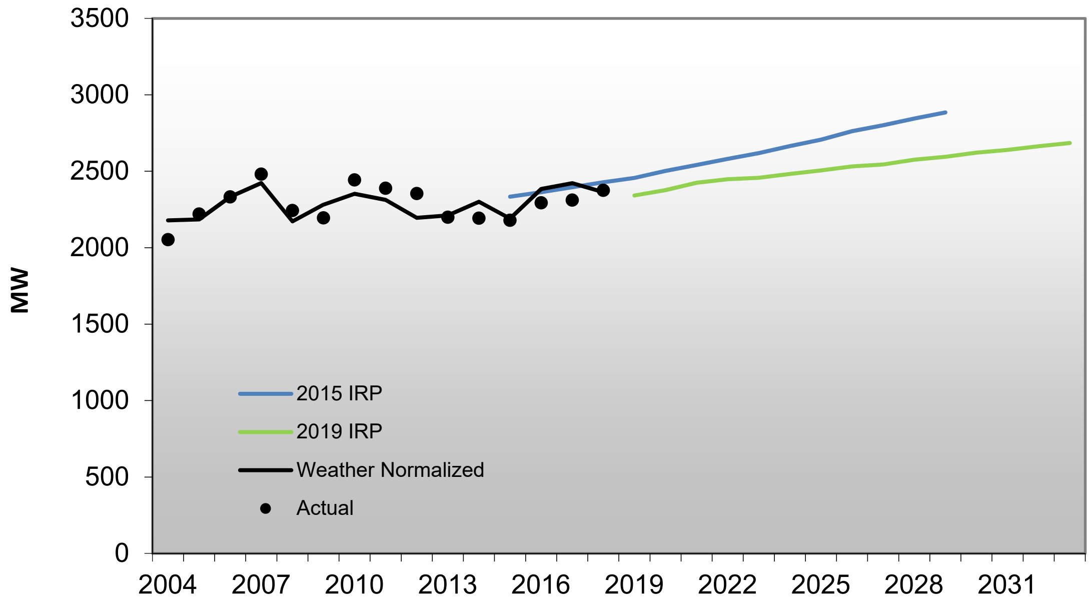


Figure 1-3

Comparison of Load Forecasts
Summer Peak Demand Projections (MW)



Difference between 2015 Expansion Plan and 2019 Expansion Plan

In comparison to the 2015 IRP, the projected capacity needs in this IRP are 350MWs lower by the year 2029 (see Table 1-4 below). EKPC purchased Bluegrass in 2015, which has 567MW of winter generation capacity.

Table 1-4

EKPC Projected Major Capacity Additions

	2015 IRP Capacity Available on January 1		
	Winter Season Capacity		
Year	Baseload Capacity	Peaking/ Intermediate Capacity (MW)	Cumulative Capacity Additions
2015			
2016		150 Seas Purch	150
2017		250 Seas Purch	400
2018			400
2019			400
2020			400
2021			400
2022			400
2023			400
2024			400
2025			400
2026		50 RE PPA	450
2027			450
2028		50 RE PPA	500
2029		50 RE PPA	550
2030			550
2031			550
2032			550
2033			550

	2019 IRP Capacity Available on January 1		
	Winter Season Capacity		
Year	Baseload Capacity	Peaking/ Intermediate Capacity (MW)	Cumulative Capacity Additions
2015			
2016			
2017			
2018			
2019			
2020			
2021			
2022			
2023			
2024		100 Win purch call option	100
2025			100
2026			100
2027			100
2028			100
2029		100 Win purch call option	200
2030			200
2031			200
2032			200
2033			200

SECTION 2.0

COMMISSION REPORT ON THE 2015 IRP RECOMMENDATIONS

SECTION 2.0

COMMISSION STAFF RECOMMENDATIONS TO EKPC'S 2015 IRP

2.1 Introduction

EKPC submitted its 2015 IRP (Case No. 2015-00134) to the Commission on April 21, 2015. The report submitted by EKPC provided its plan to meet the power requirements of its 16 owner-members over the period 2015 to 2029. On April 13, 2016, EKPC received the Commission Staff's Report on EKPC's 2015 IRP. The purpose of the report was to review and evaluate EKPC's 2015 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 from 2015 and EKPC's responses.

Load Forecasting

- **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.**

The 2015 IRP was based on the RUS-approved 2014 Load Forecast, revised for recent history. As shown in the graphs on pages 18-19, actual total requirements were on average 6 percent lower than projected, while winter and summer peak demand errors averaged 3 percent. Every year, energy was lower than projected, however, peak demands fluctuated both high and low. The 2018 load forecast corrects the higher energy bias which is attributed to energy efficiency impacts.

- **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 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 energy models, therefore, explicitly accounting for the impacts of federal mandatory efficiency improvements. Itron's detailed report is provided in the Load Forecast Appendix as EXHIBIT LF-1.

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

Legal and environmental experts provide guidance concerning all pending rules to EKPC's Production, Construction and Engineering groups, as well as EKPC's Owner-Engineer. The Owner-Engineer then develops cost estimates for Production. 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 an input into the load forecast model. Therefore, impacts of future environmental regulations are incorporated into the EKPC planning cycle via the load forecast projections.

Demand Side Management

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

In 2015, EKPC worked with potential DSM and Renewable Energy stakeholders to develop a new DSM and Renewable Energy Collaborative. EKPC and the stakeholders agreed to a charter that established the new "Collaborative 2.0."

Participants in Collaborative 2.0 are:

- EKPC
- EKPC's 16 owner-members
- Kentuckians for the Commonwealth
- COAP, Inc. (Christian Outreach with Appalachian People, Inc.)
- Kentucky Association of Manufacturers
- Kentucky Environmental Foundation
- KIUC (Kentucky Industrial Utility Customers)
- MACED (Mountain Association for Community Economic Development)
- Next Step
- Nucor
- Office of the Attorney General

The first Collaborative 2.0 meeting date was Sept. 29, 2015. See the agenda in Exhibit DSM-8. The first meeting was a review of Collaborative 1.0 results and updates from EKPC on DSM and Renewable Energy programs.

A second meeting was held on Feb. 2, 2016. See the agenda in Exhibit DSM-8. During this meeting, the Collaborative decided to create sub-teams focused on growing DSM programs. Three (3) sub-teams were created, sub-team leaders were identified, and Collaborative members were assigned. The three (3) sub-teams were:

- Residential DSM Programs
- Commercial & Industrial DSM Programs
- Marketing DSM Programs

These three sub-teams met and reported back to the whole Collaborative at the third Collaborative 2.0 meeting on June 27, 2017. See the agenda in Exhibit DSM-8. Possible DSM program enhancements were identified.

EKPC noticed sub-team attendance and participation declining. Near the same time, EKPC noticed other factors important to DSM programs, including lower avoided energy and capacity costs, increased cost-effectiveness scrutiny from the Commission, and the Clean Power Plan (CPP), essentially placed on hold. Also, it was time for EKPC to start a complete evaluation of all DSM programs for the IRP. Therefore, Collaborative 2.0 and its mission to grow DSM programs was halted until EKPC had current DSM program cost-effectiveness evaluations and reviews by EKPC executive staff and the owner-member CEOs.

EKPC hired GDS to complete a potential study for energy efficiency and demand response measures for the EKPC service territory. That study is included in this IRP (Refer to Exhibit DSM-1 in the DSM Appendix). From that cost-effectiveness study and additional DSM program information, EKPC and the owner-member CEOs determined the future energy efficiency and demand response programs most appropriate to provide to the retail members.

At the fourth Collaborative 2.0 meeting, held in December 2018, EKPC reviewed the cost-effective measures, and the programs that EKPC and the owner-members planned to request the Commission to discontinue or change. No Collaborative 2.0 report(s) have been created at this time.

- **EKPC should continue to 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 include an update on bidding its peak savings from energy efficiency and other DSM programs into the PJM capacity markets.**

Each year EKPC bids Demand Response (DR) capacity into the appropriate PJM Market. The following are the bids.

PJM Year (June-May)	MWs
2015-2016	131.6
2016-2017	141.7
2017-2018	118.0 (See Note 1)
2018-2019	118.8 (See Note 2)
2019-2020	120.3
2020-2021	121.8
2021-2022	[redacted] (See Note 3)

Note 1: PJM began requiring market participants, including EKPC, to include the calculation for the Winter Peak Load contribution as well as Summer Peak Load contributions for all DR assets being bid in the market. The new PJM market rules required EKPC to bid the lower of the two (2) calculations. For EKPC, the winter contribution is the lower contribution resulting in a lower bid in 2017-2018 when compared to 2016-2017.

Note 2: PJM implemented a new market called Capacity Performance (CP). The new CP market has new rules. One rule is that all assets must be able to reduce the load up to 12 hours when PJM calls for a demand response of the participating assets. EKPC and its owner-members know that controlling air conditioning and water heating for 12 hours will cause issues with participating members of the Direct Load Control (DLC) program. Therefore, EKPC did not bid DLC switches in the market for 2018-2019 and after. However, EKPC and its owner-members are still reaping the benefits for DLC switches. EKPC's annual load payments to PJM are determined by EKPC's contribution to the PJM five coincident peaks during the summer months. EKPC is predicting those five coincident peaks and managing DLC switches accordingly to minimize EKPC's payments to the PJM capacity market.

Note 3: [redacted]

Energy Efficiency Peak Savings

EKPC evaluated bidding energy efficiency peak demand savings into the DR market under the PJM rules for bidding energy efficiency. PJM has stringent measurement and verification requirements for participating programs to prove performance. The cost for EKPC to measure and verify energy efficiency programs would outweigh the benefits or payments received from PJM. Therefore, EKPC has not yet bid energy efficiency programs into the market, but will continue to evaluate that option.

Although EKPC isn't bidding energy efficiency peak demand savings into the PJM market, EKPC is benefitting. Participation in energy efficiency programs lowers owner-member summer peak demand resulting in lower annual capacity costs for EKPC from PJM.

- **EKPC should continue to work with its Member Cooperatives to further educate and encourage them and their customers about the importance of DSM, EE, and energy conservation.**

EKPC conducts multiple meetings per year with the member services staff of the owner-members. EKPC also conducts multiple training sessions each year with the energy advisors from the owner-members. EKPC has established a DSM Steering Committee made up of representatives from EKPC's owner-members as well as EKPC DSM staff. The Steering Committee provides guidance on program design and program priorities.

- **EKPC should continue to fully involve all members of the DSM 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. In 2015, EKPC worked with potential DSM and Renewable Energy stakeholders to develop a new DSM and Renewable Energy Collaborative. Collaborative members provided valuable suggestions for new program ideas. EKPC enhanced and changed programs based on their advice.

As stated previously, EKPC noticed that sub-team attendance and participation was declining, while other factors important to DSM programs could change DSM program cost-effectiveness. Given those factors, Collaborative 2.0 was halted in 2017 pending the results of cost-effectiveness evaluations and reviews by EKPC executive staff and the owner-member CEOs. After the cost-effectiveness evaluations were complete and results reviewed, the Collaborative 2.0 met in December 2017 to review cost-effectiveness results and DSM program impacts.

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

EKPC has developed energy-efficiency reporting standards and templates by working with stakeholders. EKPC continues to refine reports and capabilities of its DSM Tracking System in order to be responsive to the needs of stakeholders, including owner-members, program partners, and trade allies.

- **EKPC should continue to report, by year, on its DSM programs' energy savings and peak-demand reductions. EKPC should evaluate the Energy Star Appliances Program measures that may not be cost-effective based on updated appliance standards prior to the filing of its next IRP.**

EKPC produces an annual report on DSM program savings and costs. The latest annual report is for the 2017 program year. The report for 2018 is currently being prepared and will be provided to the Commission when it is completed. Annual reports for 2014-2017 are included in Exhibit DSM-2 of the Demand Side Management Technical Appendix.

In EKPC's updated DSM Potential study, it evaluated the cost-effectiveness of individual Energy Star Appliances Program measures and then it evaluated the program as a whole. Since the program is not currently cost-effective, EKPC removed that program from its DSM portfolio.

Supply-Side Resources and Environmental Compliance

- **Discuss in detail the terms and outcome the FERC decision concerning the transmission dispute between LG&E/ KU and EKPC has on the delivery of the excess Bluegrass power.**

EKPC has substations that are served from the LG&E/KU transmission system. EKPC pays LG&E/KU for use of its transmission system based on its FERC filed Network Integration

Transmission Services (NITS) tariff. Monthly charges are based on the peak load usage for that month. EKPC maintained at FERC that it should have the rights to use the LG&E/KU transmission system up to that peak amount at any time throughout the month. LG&E/KU maintained that EKPC only had the right to use the amount of transmission load that was on its system at any given time, over an hourly integrated period. FERC agreed with LG&E/KU. Therefore, the output from the Bluegrass must not exceed the total sum of the current hourly EKPC substation loads plus any additional transmission services that EKPC has purchased on the LG&E transmission system. EKPC has not purchased any long-term NITS from LG&E/KU but it has purchased daily transmission on multiple occasions to ensure that any output from Bluegrass that exceeds the amount of load that EKPC has at that time on the LG&E/KU transmission system can serve load not located on the LG&E/KU transmission system. EKPC monitors the load levels continuously and determines on a daily basis if it will need to purchase additional transmission rights to effectively manage its Bluegrass output.

- **Provide discussion regarding completion of the duct-reroute connecting the Cooper 1 discharge stream to Cooper 2's air quality control system.**

This project was proposed and chosen from the EKPC Request For Proposals (RFP) for new power supply in response to the potential closing of Dale Station and Cooper Unit 1. This project allowed Cooper Unit 1 to achieve compliance with the Mercury and Air Toxics Standards (MATS) and Regional Haze rule’s Best Available Retrofit Technology State Implementation Plan (BART) for Cooper Unit 1. Failure to comply with these regulations would have required Cooper Unit 1 to shut down, resulting in a loss of 116MW of capacity.

The Cooper Duct Re-route Project included new ductwork from the gas exit of Cooper Unit 1 Electrostatic Precipitator to the Cooper Unit 2 ductwork tie-in location, new exhaust gas regulating and isolation dampers, upgraded control system, and new continuous emissions monitoring system equipment. The Project scope also included foundations, support steel, access steel to support the new balance of plant (BOP) equipment, removal of the Cooper Unit 1 ID fan, demolition of the existing stack division wall, and sealing of the existing Cooper Unit 1 stack breaching. In addition to the new BOP equipment, the circulating dry scrubber (CDS) equipment was upgraded as necessary; including incorporating a modified hydrated lime feed system to allow dual hydrator operation, and longer fabric filter bags and cages to support the increased gas flow through the CDS equipment. A carbon injection skid was added to the scope to inject carbon after the dry scrubber and before the bag house to meet the mercury emissions limit when Cooper Unit 1 is running and Cooper Unit 2 is not.

The project Commercial Operation Date was originally planned for April 2016 but was achieved November 25, 2015. Project goals were met to allow Cooper Unit 1 to achieve compliance with MATS and BART and allowed the unit to continue to operate. The budget for the project was $15,000,000. Actual charges were $14,902,228, less than 1 percent under budget.

- **Discuss the pending/ongoing plant and facility modifications required to meet the current Clean Air Act, Clean Water Act, Clean Power Plan and future environmental legislation and regulations.**

EKPC has provided an extensive review of current and pending environmental regulations in Section 9.0 of this report. EKPC discusses the potential CPP (CO_2 regulation) in that section. The current proposal does not propose that a tax be levied on CO_2 but rather a maximum CO_2 emissions rate. EKPC is considering all of its options to meet this rate; however, the CPP rule is not final. The U.S. Supreme Court stayed the Rule until EPA could revisit it. EPA proposed a new Rule called the Affordable Clean Energy Rule (ACE) that somewhat reverses the CPP. ACE is based on the EPA Clean Air Markets Division existing coal fired emission rates provided in the public domain and a mechanism for coal-fired utilities to improve efficiency, thus lessening CO_2 emissions. The Commonwealth of Kentucky will develop its own State Implementation Plan (SIP) to meet the ACE 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 ACE or its implementation; however, EKPC cannot be certain, and does not represent, that its power supply plan submitted in this IRP will fully comply with the ACE until the final rule is published in the Federal Register. EKPC and other utilities expect EPA to produce a final rule in spring 2019.

- **Report on the ongoing SEPA construction and its effects on EKPC's ability to schedule hydro power.**

As a result of safety concerns related to the potential failure of two dams on the Cumberland River System, 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 US Army Corps of Engineers (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 Dam was 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 2019. In addition to the dam safety repair projects, major hydropower rehabilitation continues at all of the Cumberland River projects managed by the Corps. The necessary modifications and upgrades to these aging facilities, most with over 50 years of online service, also contribute to a reduced capacity for scheduling. Many of these major rehabilitation projects are scheduled to be completed in 2019 and 2020. 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 many of the major rehabilitation projects are completed in 2020.

- **EKPC should provide further analysis of observed lower-than-expected transmission loss values for 2012 and 2013, and a more detailed explanation of the cause, especially if those values continue to be lower-than-typical or change without a seemingly reasonable cause in recent years.**

Table 3-4 (Total Sales and Requirements) in Section 3 shows that EKPC's transmission losses decreased in 2012 and 2013 relative to the level seen in prior years. A significant change to the EKPC system occurred on June 1, 2013, when EKPC became a fully-integrated member of PJM. This integration into PJM has resulted in significant modifications to EKPC's power supply profile. The total MWh generated by EKPC-owned generating units decreased significantly after the integration as EKPC began purchasing significantly more power from the PJM market. This change has altered the power-flow patterns on the EKPC transmission system substantially. These changes in power-flows due to the shift to more off-system purchases throughout the year has provided the ancillary benefit of reducing the losses experienced on the transmission system for certain generation dispatch and demand scenarios.

In addition to the modified power-supply profile EKPC has experienced since integrating into PJM, another factor that has contributed to lower system losses is the establishment of three new interconnection points with Duke Energy-Ohio/Kentucky since 2012. Two of these interconnection points are at the Hebron Substation and the third is at the Webster Road substation. The addition of these interconnection points has enhanced the EKPC transmission system in the area, providing beneficial sources of power to EKPC's 69 kV system in these areas. This has improved the efficiency of the system and resulted in lower transmission losses for EKPC.

- **EKPC should continue to discuss the existence, and promotion of any cogeneration within its members' service territories and any focused consideration given to it.**

In 2018 EKPC purchased 2,847 MWh from its only contracted cogeneration facility. Prominent barriers to new combined heat and power projects include the large capital investment which many companies are not ready to make. These large investments require payback periods that may be long by their standards and these types of projects may not be directly related to the companies' main area of business. EKPC continues to work with one small rural facility which still plans to initially generate approximately 200kW from a poultry digester methane recovery operation. There are no other combined heat and power or cogeneration projects planned within the EKPC service territory of which EKPC is aware.

Two solar installations were completed in 2015 for two retail members. These facilities are each less than 100kW and utilize the cogeneration/small-power-producer tariff for excess generation. Total purchased energy was 54 MWh in 2018.

- **EKPC should continue to provide discussion of any distributed generation and the impact of such generation on its system and its members' systems.**

Two owner-members have installed generation resources at or near their offices. One such installation is a 2MW natural gas reciprocating generator. This has been in service since June of 2016. A second owner-member installed 300kW of solar photovoltaic resources. This facility went online in May of 2018.

- **EKPC should continue to discuss the existence, type, unit number and promotion of any Green Power utilized on its system and/or its members' systems.**

EKPC, along with its sixteen owner-members, implemented a community solar project in order to offer renewable solar energy to retail members within the owner-members' service territories. This project is a result of the Demand Side and Renewable Energy Collaborative group's efforts. The 8.5MW facility began operations in November 2017. Marketing of the 25-year licenses continues under the Cooperative Solar program, which offers benefits of solar generation without the installation and maintenance requirements that would be necessary in a smaller home or office installation. This facility produced 13,859 MWh in 2018.

In addition to one existing run-of-river hydro project, two additional run-of-river projects are scheduled to come online in 2019. This would be a total of 5.5MW of installed capacity.

- **EKPC should continue to list and describe the net-metering equipment and system types installed in its members' service territories and the impact on the system.**

EKPC canvases the owner-members annually to update the type and amounts of net metered systems in use within the EKPC service territory. There are currently approximately 2,849kW of solar voltaic installations taking advantage of the owner-members' net-metering tariff. This number continues to grow as solar voltaic prices continue to decrease. There are currently a few small wind turbine installations connected to the owner-member's distribution network that are taking advantage of the net-metering tariff. Combined, these add up to approximately 18kW. There are currently 348 net metered installations with a total of 2,867kW of installed capacity.

- **EKPC shall continue to provide a complete discussion of compliance actions and plans relating to current and pending environmental regulations in its future resource planning.**

EKPC has provided an extensive review of current and pending environmental regulations in Section 9.0 of this report.

- **EKPC shall continue to provide details of how uncertainty has been accounted for in the modeling of future projected loads and the supply and transmission provisions anticipated to meet those loads.**

As explained in Section 6.0 – Transmission and Distribution Planning, EKPC evaluates the performance of its transmission system using two load forecast scenarios – a 50/50 probability value (the load level that has an equal likelihood of either being exceeded or of not occurring in a given season) and a 10/90 probability value (the load level that has a 10 percent chance of being exceeded and a 90 percent chance of not occurring). These two scenarios are analyzed for both summer and winter peak seasons. When using a 50/50 forecast, EKPC performs transmission contingency analysis to ensure that the system is designed to provide adequate service at that load level even with a transmission facility and/or generator out of service. For the 10/90 forecast level, EKPC does not presently design its system for transmission-contingency conditions. That is, EKPC has deemed an extreme weather event equivalent to a contingency, and therefore does not design its system for a transmission or generator outage in conjunction with this weather event. However, EKPC has begun to simulate these contingencies at the 10/90 forecast level to identify potential constraints on its transmission system if such outages were to occur in conjunction with higher load levels. EKPC intends to implement transmission improvements to address some of the more severe constraint scenarios identified through this analysis going forward.

As stated in Section 8.0 – Integrated Resource Planning, the primary model used in developing the resource plan was RTSim from Simtec, Inc., of Madison, WI. The RTSim production cost model calculates the hour-by-hour operation of the generation system including unit hourly generation and commitment and power purchases and sales, including economy and day-ahead transactions in the PJM energy market, and daily and monthly options. Generating unit input includes expected outages, Monte Carlo simulated forced outages, unit ramp rates, and unit startup characteristics. The RTSim model uses a Monte Carlo simulation to capture the statistical variations of unit forced outages and deratings, load uncertainty, market price uncertainty, and fuel price uncertainty. Monte Carlo simulation requires repeated simulations (iterations) of the time period analyzed to simulate system operation under different outcomes of unit forced outages and deratings, load uncertainty, market price uncertainty, and fuel price uncertainty. The production cost model is simulating the actual operation of the power system in supplying the projected member loads using a statistical range of inputs.

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

- **EKPC shall provide details of types and locations of any non-transmission alternatives and technologies considered and/or modeled or utilized on its system and/or its members' systems, if not included in previous discussions.**

EKPC has included known non-transmission alternatives and technologies in previous discussions in this report.

SECTION 3.0

LOAD FORECAST

SECTION 3.0

LOAD FORECAST AND LOAD RESEARCH ACTIVITIES

3.1 Summary

EKPC's load forecast is prepared every two years in accordance with EKPC's RUS - approved Work Plan. EKPC's "2018 Load Forecast" was prepared pursuant to its "2018-2019 Load Forecast Work Plan" (Work Plan), which was approved by EKPC's Board of Directors in December 2017 and by RUS in December 2017. The Work Plan details the methodology used to develop the projections. The EKPC Load Forecasting Department works with the staff of each owner-member to prepare its forecast and then aggregates the 16 owner-member forecasts, adding forecasts of own use and losses, and subtracting planned demand side management to create EKPC's forecast. Owner-members use their load forecasts in developing construction work plans, long-range work plans, and financial forecasts. EKPC uses the load forecast for demand side management analyses, marketing analyses, transmission planning, power supply planning, and financial forecasting.

EKPC's load forecast projects total energy requirements to increase from 13.7 to 16.9 million MWh, an average of 1.4 percent per year over the 2019 through 2033 period. Net winter and summer peak demands will increase by approximately 330MW or 0.6 percent and 340MW or 0.9 percent respectively over weather normalized 2019 to 2033. Annual load factor projections are increasing from 48 percent to approximately 54 percent. Energy projections for the residential, small commercial, and large commercial classifications indicate that during the 2019 through 2033 period, sales to the residential class will increase by 0.7 percent per year, commercial and industrial sales ≤1000 KVA will increase by 0.8 percent per year, and commercial and industrial sales >1000 KVA will increase by 2.9 percent per year. Growth rates are shown in Table 3-1.

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

	2019-2033
Net Total Energy Requirements	1.4%
Residential Energy Sales	0.7%
Commercial and Industrial ≤ 1000 KVA Energy Sales	0.8%
Commercial and Industrial > 1000 KVA Energy Sales	2.9%
	2019-2033
Net Winter Peak Demand	0.6%
Net Summer Peak Demand	0.9%

Historical and projected total energy requirements, seasonal peak demands, and annual load factor for the EKPC system are presented in Table 3-2.

Factors considered when preparing the forecast include historical member growth, historical energy sales and peak demands, national, regional, and local economic performance, population and housing trends, service area industrial development, electric price, household income, appliance saturations and efficiencies, demand side management programs, and weather.

The load forecast includes the impacts of a 5-year DSM plan, which consists of existing DSM programs and assumes no new programs and no new participants after the fifth year. Table 3-3 shows the DSM impact on energy requirements and peak demands for the 5-year plan. Class sales are shown in Table 3-4.

Table 3-2
Historical and Projected Peak Demands and Total Requirements

Season	Winter Peak Demand (MW)	Year	Summer Peak Demand (MW)	Year	Total Requirements (MWh)	Load Factor (%)
2006 - 07	2,840	2007	2,481	2007	13,080,367	52.6%
2007 - 08	3,051	2008	2,243	2008	12,948,091	48.3%
2008 - 09	3,152	2009	2,195	2009	12,380,972	44.8%
2009 - 10	2,868	2010	2,443	2010	13,376,292	53.2%
2010 - 11	2,891	2011	2,388	2011	12,666,998	50.0%
2011 - 12	2,481	2012	2,354	2012	12,190,070	55.9%
2012 - 13	2,597	2013	2,199	2013	12,644,590	55.6%
2013 - 14	3,425	2014	2,192	2014	13,163,516	43.9%
2014 - 15	3,507	2015	2,179	2015	12,604,942	41.0%
2015 - 16	2,890	2016	2,293	2016	13,039,953	51.4%
2016 - 17	2,871	2017	2,311	2017	12,680,111	50.4%
2017 - 18	3,437	2018	2,375	2018	13,369,007	44.4%
2018 - 19	3,258	2019	2,341	2019	13,735,980	48.1%
2019 - 20	3,281	2020	2,377	2020	14,354,291	49.8%
2020 - 21	3,323	2021	2,425	2021	15,109,727	51.9%
2021 - 22	3,349	2022	2,448	2022	15,241,723	52.0%
2022 - 23	3,373	2023	2,457	2023	15,373,488	52.0%
2023 - 24	3,401	2024	2,483	2024	15,555,697	52.1%
2024 - 25	3,418	2025	2,505	2025	15,704,283	52.5%
2025 - 26	3,444	2026	2,532	2026	15,862,441	52.6%
2026 - 27	3,468	2027	2,545	2027	16,012,368	52.7%
2027 - 28	3,502	2028	2,576	2028	16,185,645	52.6%
2028 - 29	3,514	2029	2,595	2029	16,292,394	52.9%
2029 - 30	3,531	2030	2,622	2030	16,429,025	53.1%
2030 - 31	3,540	2031	2,639	2031	16,571,785	53.4%
2031 - 32	3,568	2032	2,664	2032	16,752,464	53.5%
2032 - 33	3,585	2033	2,685	2033	16,879,184	53.7%

Table 3-3
Impacts of Demand Response and Energy Efficiency Programs
Load Forecast 5-Year Plan

	Energy (MWH)	Winter Peak (MW)	Summer Peak (MW)
2019	-35,607	-121	-120
2020	-46,475	-163	-162
2021	-71,724	-261	-259
2022	-81,666	-263	-261
2023	-91,642	-265	-263
2024	-91,434	-265	-263
2025	-90,579	-265	-263
2026	-89,909	-264	-263
2027	-88,568	-264	-263
2028	-87,010	-264	-262
2029	-85,125	-263	-262
2030	-84,308	-263	-262
2031	-83,479	-263	-262
2032	-83,536	-263	-262
2033	-83,421	-263	-262

A separate DSM plan was developed for inclusion in the capacity plan as a resource that includes new participants in existing programs. Details are in Section 5.0 - Demand Side Management of this report.

Table 3-4
Class Sales

Year	Residential Sales (MWh)	Seasonal Sales (MWh)	Small Comm. Sales (MWh)	Public Buildings Sales (MWh)	Large Comm. Sales (MWh)	Public Street / Highway Lighting Sales (MWh)	Total Retail Sales (MWh)
2007	6,998,554	14,679	1,861,952	26,427	3,124,043	8,457	12,034,113
2008	7,055,277	14,531	1,872,811	34,074	3,083,589	9,477	12,069,760
2009	6,789,142	13,080	1,787,112	35,507	2,831,935	9,065	11,465,841
2010	7,388,901	13,959	1,935,479	39,809	2,845,857	9,503	12,233,507
2011	6,967,413	12,774	1,892,090	38,468	2,889,142	9,845	11,809,733
2012	6,577,784	227	1,883,241	35,194	2,901,688	9,600	11,407,734
2013	6,909,853	300	1,917,730	37,215	3,017,925	9,845	11,892,868
2014	7,142,350	370	1,919,198	39,753	3,246,287	9,916	12,357,874
2015	6,781,622	354	1,958,109	38,996	2,979,716	9,890	11,768,687
2016	6,847,090	416	1,951,787	37,627	3,296,495	9,940	12,143,355
2017	6,517,101	534	1,896,475	36,578	3,395,430	9,325	11,855,444
2018	7,055,642	503	1,958,436	39,136	3,398,144	8,912	12,460,774
2019	7,154,796	538	2,000,123	39,560	3,608,750	8,983	12,812,750
2020	7,188,311	574	2,025,733	40,028	4,144,183	9,051	13,407,879
2021	7,175,389	610	2,036,273	40,400	4,874,338	9,118	14,136,129
2022	7,207,766	649	2,052,964	40,819	4,940,304	9,185	14,251,687
2023	7,247,866	686	2,068,392	41,248	5,007,458	9,251	14,374,902
2024	7,333,909	725	2,089,435	41,702	5,071,019	9,333	14,546,124
2025	7,388,926	761	2,103,105	42,085	5,140,502	9,417	14,684,795
2026	7,457,583	797	2,123,423	42,522	5,198,169	9,501	14,831,995
2027	7,532,016	830	2,145,020	42,958	5,240,948	9,575	14,971,348
2028	7,623,433	873	2,170,088	43,422	5,287,182	9,639	15,134,636
2029	7,662,936	907	2,186,914	43,804	5,328,538	9,693	15,232,792
2030	7,712,076	938	2,205,939	44,218	5,389,079	9,742	15,361,992
2031	7,774,578	970	2,224,093	44,613	5,441,597	9,791	15,495,642
2032	7,863,946	1,008	2,246,697	45,039	5,497,115	9,840	15,663,646
2033	7,918,703	1,044	2,263,765	45,401	5,542,559	9,890	15,781,363

Note: Owner-members' Form 7 data for 2018 were not yet available.

Table 3-4 (continued)
Total Sales and Requirements

Year	Total Retail Sales (MWh)	Office Use (MWh)	% Loss	Purchased Power (MWh)	Own Use (MWh)	Purchased Power (MWh)	Losses	Total Requirements (MWh)
2007	12,034,113	10,291	4.3%	12,582,260	7,491	12,589,751	3.9%	13,080,367
2008	12,069,760	10,431	4.5%	12,646,146	7,932	12,654,078	2.3%	12,948,091
2009	11,465,841	10,173	4.2%	11,981,909	8,247	11,990,156	3.3%	12,380,972
2010	12,233,507	10,401	4.4%	12,811,906	8,654	12,820,560	4.3%	13,376,292
2011	11,809,733	9,742	3.8%	12,289,071	10,146	12,299,217	3.0%	12,666,998
2012	11,407,734	9,120	4.4%	11,943,406	8,811	11,952,217	2.0%	12,190,070
2013	11,892,868	9,977	4.0%	12,400,903	8,270	12,409,174	1.9%	12,644,590
2014	12,357,874	10,497	4.1%	12,898,402	8,246	12,906,648	2.0%	13,163,516
2015	11,768,687	10,008	4.3%	12,303,441	8,190	12,311,631	2.4%	12,604,942
2016	12,143,355	10,270	4.1%	12,674,244	8,203	12,682,447	2.8%	13,039,953
2017	11,855,444	9,992	3.9%	12,340,793	8,374	12,349,167	2.7%	12,680,111
2018	12,460,774	10,551	4.6%	13,004,293	8,367	13,012,660	2.6%	13,369,007
2019	12,812,750	10,551	4.6%	13,365,921	8,367	13,374,287	2.6%	13,735,980
2020	13,407,879	10,551	4.6%	13,968,806	8,367	13,977,173	2.6%	14,354,291
2021	14,136,129	10,551	4.6%	14,700,906	8,367	14,709,273	2.6%	15,109,727
2022	14,251,687	10,551	4.6%	14,821,699	8,367	14,830,065	2.6%	15,241,723
2023	14,374,902	10,551	4.6%	14,950,497	8,367	14,958,864	2.6%	15,373,488
2024	14,546,124	10,551	4.6%	15,129,343	8,367	15,137,709	2.6%	15,555,697
2025	14,684,795	10,551	4.6%	15,274,570	8,367	15,282,937	2.6%	15,704,283
2026	14,831,995	10,551	4.6%	15,428,671	8,367	15,437,038	2.6%	15,862,441
2027	14,971,348	10,551	4.6%	15,574,317	8,367	15,582,684	2.6%	16,012,368
2028	15,134,636	10,551	4.6%	15,744,973	8,367	15,753,340	2.6%	16,185,645
2029	15,232,792	10,551	4.6%	15,848,028	8,367	15,856,395	2.6%	16,292,394
2030	15,361,992	10,551	4.6%	15,983,080	8,367	15,991,447	2.6%	16,429,025
2031	15,495,642	10,551	4.6%	16,122,890	8,367	16,131,257	2.6%	16,571,785
2032	15,663,646	10,551	4.6%	16,298,441	8,367	16,306,807	2.6%	16,752,464
2033	15,781,363	10,551	4.6%	16,421,879	8,367	16,430,246	2.6%	16,879,184

Note: Owner-members' Form 7 data for 2018 were not yet available.

3.2 Load Forecast

3.2.1 Introduction

The forecast used in this IRP was approved in December 2018 by the EKPC Board of Directors and approved by RUS in February 2019. It was prepared pursuant to its "2018-19 Load Forecast Work Plan", which was approved by EKPC's Board of Directors in December 2017 and by RUS in December 2017.

The major steps in developing the load forecasts are:

1. Develop regional projections for economic variables. EKPC subscribes to IHS Global Insights, Inc. (IHS), in order to analyze regional economic performance. IHS is a widely used consulting firm with expertise in economic analyses. It collects and monitors data, provides forecasts and analyses, and offers consulting advice to clients in business, financial, and government organizations. IHS collects historical Kentucky county-level data for many economic variables and develops forecasts which are used in EKPC's owner-member models.
2. EKPC prepares a preliminary forecast for each of its owner-members for those classifications as reported on the RUS Form 7, which contains publicly available retail sales data for owner-members. These include: residential, seasonal, small commercial, public buildings, large commercial, and street and highway lighting. EKPC's sales to owner-members are then determined by adding distribution losses to total retail sales. EKPC's total requirements are estimated by adding transmission losses to total owner-member sales. Seasonal peak demands are determined by applying load factors for heating, cooling, and water heating to energy. The same methodology is used in developing each of the 16 owner-member forecasts.
3. EKPC meets with each owner-member to discuss their preliminary forecast. Owner-member staff at these meetings includes the President/CEO and other key individuals.

4. The preliminary forecast is revised based on mutual agreement of EKPC staff and the owner-member's President/CEO and staff. This final forecast is approved by the Board of Directors of each owner-member.
5. The EKPC forecast is the summation of the forecasts of its 16 owner-members.

There is close collaboration and coordination between EKPC and its owner-members in this process. This working relationship is essential since EKPC has no retail members. Input from owner-members relating to industrial development, subdivision growth, and other specific service area information is crucial to the preparation of accurate forecasts. Review meetings provide opportunities to critique the assumptions and the overall results of the preliminary forecast. The resulting load forecast reflects a combination of EKPC's structured forecast methodology combined with the judgment and experience of the owner-member staff.

3.2.2 Input Assumptions Overview

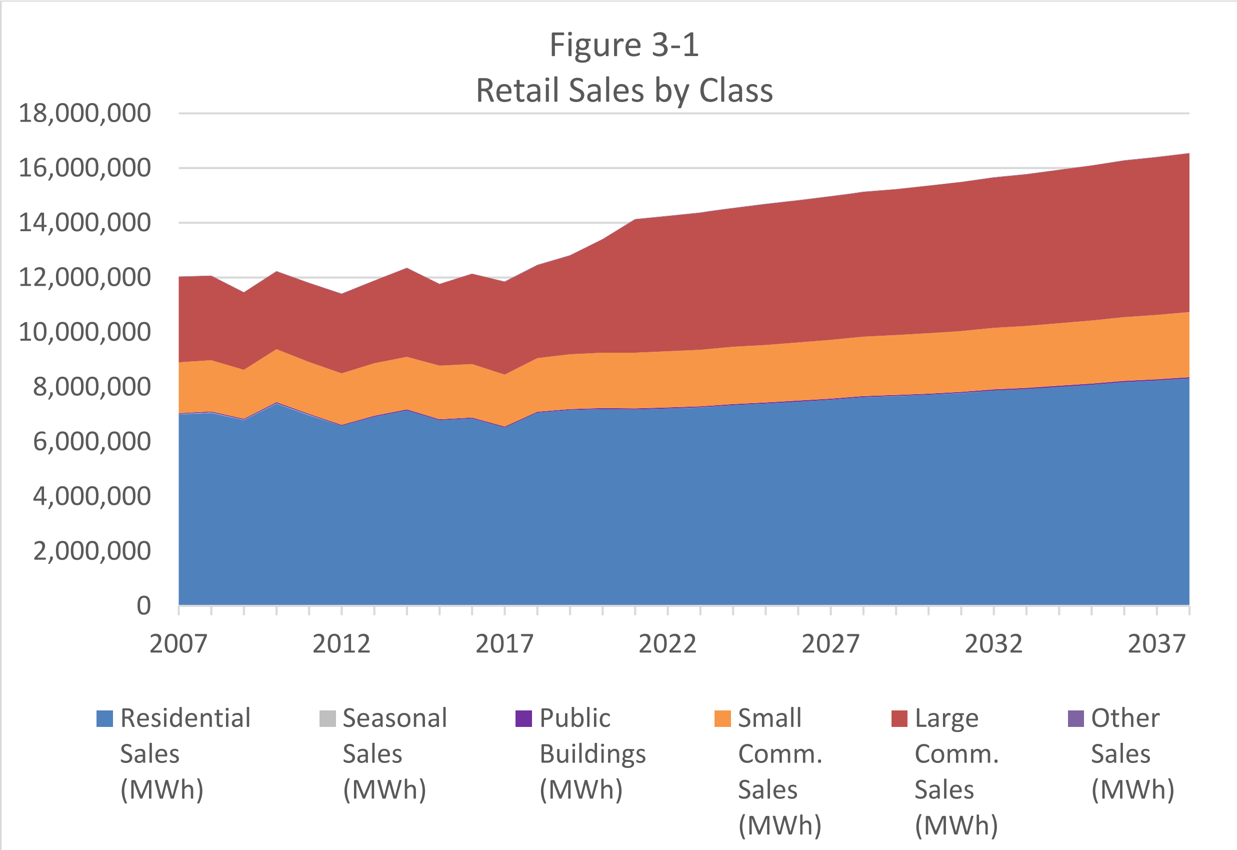
Key forecast assumptions used in developing the EKPC and owner-member load forecasts are:

1. EKPC's owner-members will add almost 56,000 residential retail members during the 15-year forecast period. This represents an increase of 0.7 percent per year.
2. EKPC uses an economic model in developing its load forecast. The county-level projections from IHS are segmented into regions using a geographic information system, ESRI, to represent owner-members' territories. This method is used to carve out the owner-member's portion of the county-level data resulting in forecasts that are more representative of the individual owner-members. The economy of these counties will experience modest growth over the forecast period. Employment forecasts show modest growth, with an average growth rate of 0.7 percent per year through the forecast period. Regional households are projected to grow at an average of 0.8 percent per year through the forecast period. Included in the Load Forecast Appendix is a report from IHS describing the short-term outlook and tables showing the long-term view are included in the Load Forecast Report.

3. As of 2018, approximately 80 percent of all new households have electric heat and about 85 percent of all new households have electric water heating. Nearly all new homes will have electric air conditioning, either central or room.
4. Over the forecast period, naturally occurring appliance efficiency improvements will have a dampening effect on residential retail sales. In addition to lighting, appliances particularly affected are heating and cooling.
5. Residential retail member growth and local area economic activity are the major determinants of small commercial growth.
6. Forecasted load growth is based on the assumption of normal weather, as defined by the 20 years of historical data (1998 – 2017). Seven different stations are used depending on geographic location of the owner-member.

3.2.3 Discussion of Service Area

In EKPC's service area, electricity is the primary method for water heating and home heating. Around 87 percent of all homes have electric water heating, and about 63 percent have electric heat as a primary fuel. In 2017, nearly 55 percent of EKPC's owner-member retail sales were to the residential class and residential retail member use averaged 1,083 kWh per month. Figure 3-1 illustrates the class allocations of total energy 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 Northern Kentucky contains a growing number of retail trade and service jobs. Mining has seen strong decreases due to regulatory changes as well as decreased natural gas prices, the most notable impacts being in eastern and southeastern regions. Tourism is an important aspect of EKPC's southern and southwestern service area, with Lake Cumberland and Mammoth Cave National Park contributing to jobs in the service and retail trade industries. This area suffered during the recession but is starting to notice an increase in activity in recent years as the economy strengthened and lake levels rose. Kentucky as a whole expects to see growth in the health care sector due to the aging population.

3.2.4 Historical Data and Forecast Results

Table 3-5 displays energy sales in the last five years by retail member class. Table 3-6 gives the weather normalized coincident peak demands of the previous five years. Table 3-7 displays weather normalized and actual energy sales and requirements for 2013 through 2017. Tables 3-8 and 3-9 display historical summaries of energy sales and coincident peak demand for firm contractual commitments and interruptible contracts, respectively. Figure 3-2 shows historical load duration curves for 2014 through 2018.

Table 3-5
EKPC Recorded Annual Energy Sales (MWh) and Energy Requirements (MWh), 2013 – 2017

	2013	2014	2015	2016	2017
Total Residential	6,909,853	7,142,350	6,781,622	6,847,090	6,517,101
Residential Seasonal	300	370	354	416	534
Small Commercial	1,917,730	1,919,198	1,958,109	1,951,787	1,896,475
Large Commercial/ Industrial	3,017,925	3,246,287	2,979,716	3,296,495	3,395,430
Public Authorities	37,215	39,753	38,996	37,627	36,578
Other	9,845	9,916	9,890	9,940	9,325
Total Sales	11,892,868	12,357,874	11,768,687	12,143,355	11,855,444
Office Use	9,977	10,497	10,008	10,270	9,992
% Loss	4.0%	4.1%	4.3%	4.1%	3.9%
EKPC Sales to Owner-Members	12,400,903	12,898,402	12,303,441	12,674,244	12,340,793
EKPC Office Use	8,270	8,246	8,190	8,203	8,374
Transmission Loss (%)	1.9%	2.0%	2.4%	2.8%	2.7%
Net Total Requirements	12,644,590	13,163,516	12,604,942	13,039,953	12,680,111

Note: Owner-Members' Form 7 data for 2018 were not yet available.

Table 3-6
Weather Normalized Coincident Peak Demands

Year	Season	Actual Peak MW	Adjusted Peak MW
2014	Winter	3,425	2,995
	Summer	2,192	2,300
2015	Winter	3,507	3,210
	Summer	2,179	2,190
2016	Winter	2,890	3,002
	Summer	2,293	2,384
2017	Winter	2,871	3,135
	Summer	2,311	2,421
2018	Winter	3,437	3,349
	Summer	2,375	2,363

Table 3-7
EKPC Weather Normalized Annual Energy Sales (MWh) and
Energy Requirements (MWh),
2014 – 2017

	2013	2014	2015	2016	2017
Total Retails Sales by Owner-Members					
Recorded	11,892,868	12,357,874	11,768,687	12,143,355	11,840,456
Weather Normalized	12,412,644	12,732,505	12,309,385	12,533,519	12,495,011
EKPC					
Recorded	12,644,590	13,163,516	12,604,942	13,039,953	12,680,111
Weather Normalized	12,656,553	12,994,317	12,611,027	12,895,262	12,838,462

Note: Owner-Members' Form 7 data for 2018 were not yet available.

Table 3-8
Energy Sales and Firm Coincident Demand

	2013	2014	2015	2016	2017	2018
Energy Sales (MWh)*	12,400,903	12,898,402	12,303,441	12,674,244	12,340,793	NA
Coincident Peak Demand (MW)**	2,501	3,313	3,485	2,783	2,760	3,323

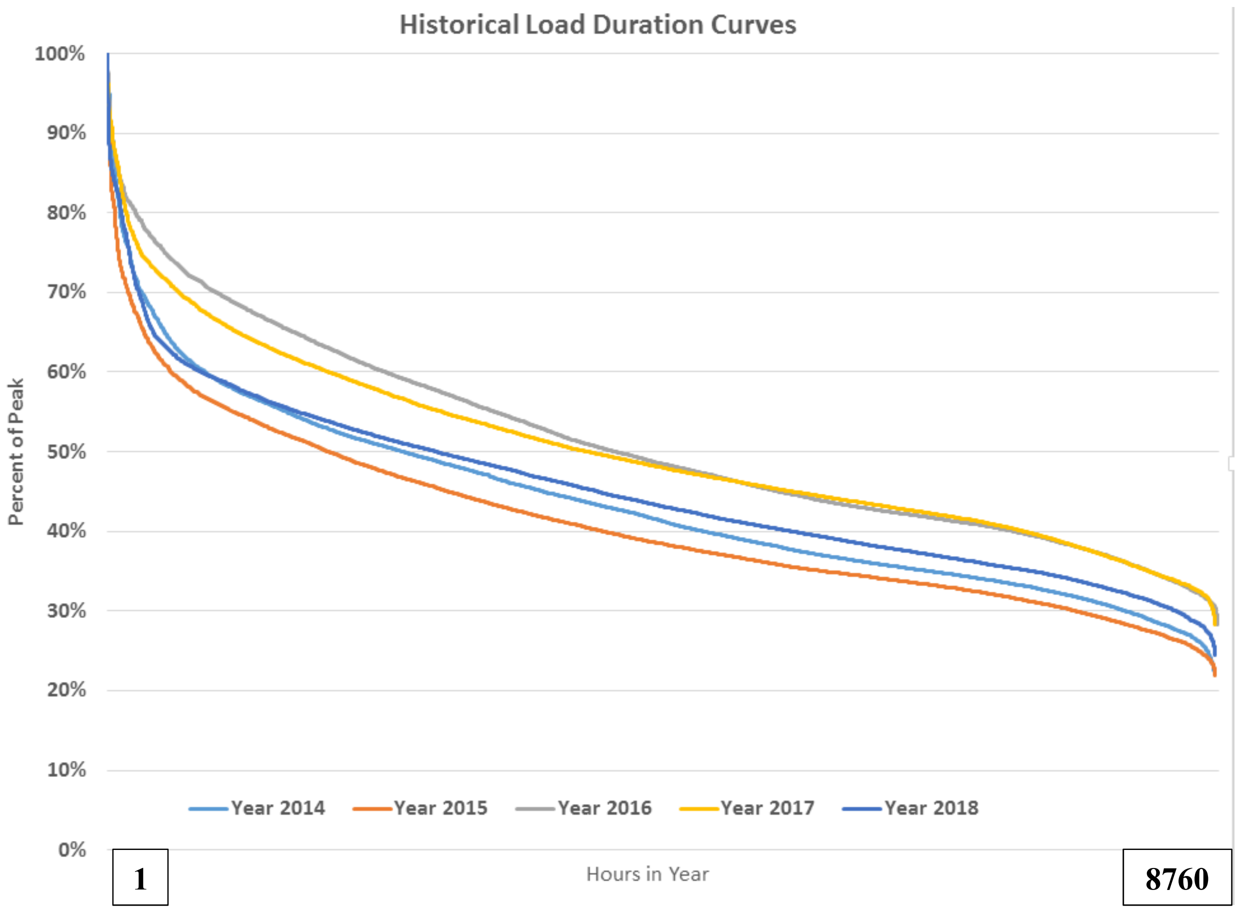
* Total sales to owner-members.
** Firm peak demand.

Table 3-9
Interruptible Energy Sales and Non-Firm Demand

	2013	2014	2015	2016	2017	2018
Energy Sales (MWh)*	NA	NA	NA	NA	NA	NA
Coincident Peak Demand (MW)	96	112	22	107	111	114

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

Figure 3-2



807 KAR 5:058 Section 7(5) The additional following data shall be provided for the integrated system, when the utility is part of a multistate integrated utility system, and for the selling company, when the utility purchases fifty (50) percent of its energy from another company:

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

Retail member class growth rates and annual energy growth rates are reported in Table 3-10. Forecasted monthly sales for the first two years of the forecast are presented by class in Table 3-11.

Table 3-10
Average Growth Rates
2019-2033

	Residential	Seasonal Residential	Commercial and Industrial ≤ 1000 KVA	Commercial and Industrial > 1000 KVA	Public Street and Highway Lighting	Other Public Authorities	Total
Retail Members	0.7%	4.7%	0.8%	1.3%	0.4%	1.2%	0.7%
Sales	0.7%	4.5%	0.8%	2.9%	0.6%	0.9%	1.4%

Table 3-11
Monthly Class Energy Sales Forecasts
2019 – 2020

		Sales (MWH)							**Peak Demand (MW)**
Year	Month	Residential	Seasonal	Small Commercial	Public Buildings	Large Commercial & Industrial	Public Street & Highway Lighting	Total Retail	System Coincident
2019	1	858,382	33	171,345	3,752	301,026	760	1,335,299	3,258
	2	767,145	31	162,989	4,154	278,037	758	1,213,114	2,996
	3	645,383	29	157,521	3,655	299,242	749	1,106,579	2,560
	4	498,825	23	155,369	3,235	297,065	738	955,256	2,009
	5	445,144	43	156,765	2,725	308,779	738	914,195	2,024
	6	502,775	74	168,156	3,014	306,595	733	981,347	2,383
	7	583,365	73	181,075	2,990	312,153	733	1,080,388	2,341
	8	602,704	72	188,126	3,250	319,064	737	1,113,954	2,270
	9	503,788	52	176,199	3,568	308,179	744	992,530	2,311
	10	454,171	39	161,999	3,145	305,210	753	925,317	1,935
	11	551,755	33	156,361	2,847	283,069	768	994,833	2,492
	12	741,359	36	164,217	3,227	290,330	770	1,199,938	2,755
Total		7,154,796	538	2,000,123	39,560	3,608,750	8,983	12,812,750	
2020	1	854,118	37	173,383	3,785	345,660	766	1,377,749	3,281
	2	790,082	35	167,315	4,190	319,277	764	1,281,663	3,015
	3	651,442	32	161,263	3,719	343,594	755	1,160,805	2,613
	4	499,602	25	157,120	3,269	341,224	744	1,001,983	2,149
	5	445,906	45	158,522	2,762	354,575	744	962,554	2,077
	6	504,244	77	169,993	3,052	352,065	739	1,030,171	2,417
	7	585,447	76	182,950	3,029	358,479	738	1,130,720	2,377
	8	604,557	75	190,065	3,291	366,345	743	1,165,075	2,305
	9	505,037	54	177,987	3,608	353,866	750	1,041,302	2,459
	10	454,492	42	163,600	3,182	350,444	759	972,518	2,069
	11	551,882	36	157,790	2,882	325,194	774	1,038,558	2,649
	12	741,502	39	165,745	3,259	333,461	776	1,244,782	2,803
Total		7,188,311	574	2,025,733	40,028	4,144,183	9,051	13,407,879	

3.3 Details of Assumptions

3.3.1 Regional Economic Model

EKPC combines county-level forecasts from IHS's county-level economic forecasts released first quarter 2018, (see EXHIBIT LF-2 of the Load Forecast Appendix) into regional economic forecasts based on owner-member service territory boundaries. EKPC calculates each owner-member's share of its region's economy by dividing its actual (as adjusted for reclassifications) and forecasted residential customer 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 3-12 shows how counties are assigned to regions.

Table 3-12
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

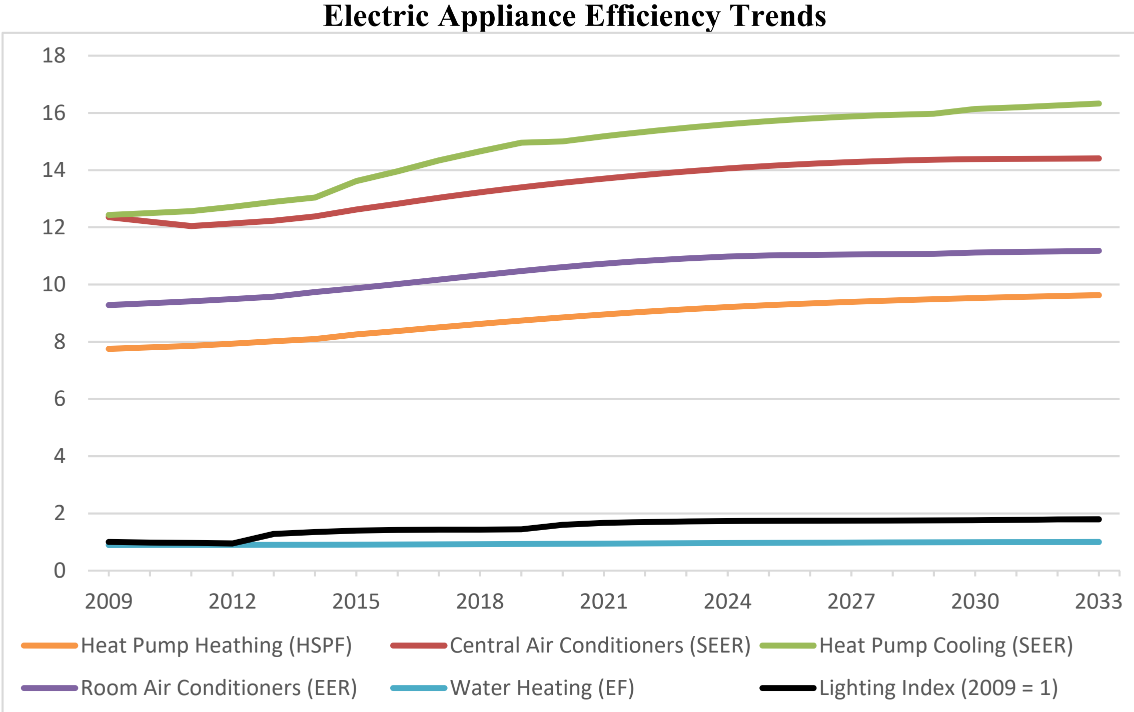
3.3.2 Electric Appliance Saturation and Efficiency Trends

Every 2-3 years since 1981, EKPC has surveyed its owner-members' residential retail members to gather information on electric appliance saturation and other factors affecting electricity demand. EKPC projects these saturations for each owner-member. Input from owner-members and other EKPC departments is sought during the development of the survey instrument. This year, questions regarding current ownership of electric vehicles and interest in purchasing one were included. The "2018 Load Forecast" incorporates appliance saturations into the models. The major drivers are:

- 63 percent of retail members have electric as a primary fuel for heat.
- 98 percent of retail members have some type of air conditioning.
- 87 percent of retail members have electric water heaters.

As previously mentioned, EKPC is a member of Itron's Energy Forecasting Group and as such, receives 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 EIA. Figure 3-3 displays the EIA efficiency projections. Additional details are provided in the Load Forecast Appendix.

Figure 3-3
Electric Appliance Efficiency Trends



3.3.3 Electricity Rates

The wholesale power cost projections used in the "2018 Load Forecast" are based on EKPC's board approved "Twenty-Year Financial Forecast, 2015-2034." These are layered with the owner-member distribution adders and price elasticities to develop the resulting year-over-year rate changes. Based on previous research studies and benchmarking, the elasticity assumptions for the residential class is between -.20 and -.30 and for commercial and industrial -.05 to -.15.

3.3.4 Weather

The forecasts rely on National Oceanic and Atmospheric Administration weather stations located at seven airports in or near the EKPC system. Normal weather for most owner-members is based on the historic 20-year values (1998-2017). 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 Hebron, 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 owner-member for each class reported to RUS.

3.4.1.1 Residential Sales

EKPC models the monthly residential retail members and monthly residential retail members' 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 retail members and monthly small commercial retail members' 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 retail members based on input from the individual owner-members and monthly large commercial and industrial energy sales are modeled as a function of the real gross county product for that given service territory. Owner-members remain in regular contact with their largest retail members and are generally aware of current production and future expansion plans. Therefore, the owner-members project energy sales for existing retail members and identify expected new retail members in this class for the next three years.

3.4.1.4 Seasonal Sales

Seasonal sales are made to retail members with seasonal accounts such as vacation homes and weekend retreats and camps. Seasonal sales are relatively small and, as of 2018, only one owner-member reports seasonal residential retail members.

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 2018, only two owner-members report other public authorities' members.

3.4.1.6 Public Street and Highway Lighting Sales

This class is relatively small and is projected as a function of retail member residential sales. There are eleven owner-members that report this class.

3.4.1.7 Peak Demand

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

3.5 Forecast Model Results

3.5.1 Residential Sales Forecast

As of 2017, residential retail members account for 55 percent of total energy sales at the EKPC system level. The average number of residential retail members served by EKPC's owner-members is expected to increase from approximately 510,000 in 2019 to 566,000 in 2033. Sales to the residential class are expected to grow 0.7 percent per year during the forecast period. Projected average monthly use per member remains relatively flat throughout the forecast period. Residential sales are not classified into heating and non-heating. Table 3-13 displays the results.

Table 3-13
Residential Class
Historical and Projected Retail Members and Sales

	Customers			***Use Per Customer***			***Class Sales***		
	Annual Average	Annual Change	% Change	Monthly Average (kWh)	Change (kWh)	% Change	Total (MWh)	Annual Change (MWh)	% Change
2007	471,585	6,021	1.3	1,237	65	5.5	6,998,554	450,394	6.9
2008	479,042	7,457	1.6	1,227	-9	-0.8	7,055,277	56,723	0.8
2009	480,527	1,485	0.3	1,177	-50	-4.1	6,789,142	-266,135	-3.8
2010	481,825	1,298	0.3	1,278	101	8.5	7,388,901	599,759	8.8
2011	482,351	526	0.1	1,204	-74	-5.8	6,967,413	-421,487	-5.7
2012	487,793	5,442	1.1	1,124	-80	-6.6	6,577,784	-389,629	-5.6
2013	489,738	1,945	0.4	1,176	52	4.6	6,909,853	332,069	5.0
2014	491,776	2,038	0.4	1,210	35	2.9	7,142,350	232,497	3.4
2015	494,297	2,521	0.5	1,143	-67	-5.5	6,781,622	-360,728	-5.1
2016	497,803	3,506	0.7	1,146	3	0.3	6,847,090	65,468	1.0
2017	501,421	3,618	0.7	1,083	-63	-5.5	6,517,101	-329,989	-4.8
2018	505,724	4,303	0.9	1,163	80	7.3	7,055,642	538,541	8.3
2019	509,573	3,849	0.8	1,170	7	0.6	7,154,796	99,154	1.4
2020	513,553	3,980	0.8	1,166	-4	-0.3	7,188,311	33,515	0.5
2021	517,489	3,936	0.8	1,155	-11	-0.9	7,175,389	-12,921	-0.2
2022	521,474	3,985	0.8	1,152	-4	-0.3	7,207,766	32,377	0.5
2023	525,475	4,001	0.8	1,149	-2	-0.2	7,247,866	40,100	0.6
2024	529,427	3,952	0.8	1,154	5	0.4	7,333,909	86,043	1.2
2025	533,403	3,976	0.8	1,154	0	0.0	7,388,926	55,017	0.8
2026	537,486	4,083	0.8	1,156	2	0.2	7,457,583	68,657	0.9
2027	541,620	4,134	0.8	1,159	3	0.2	7,532,016	74,434	1.0
2028	545,827	4,207	0.8	1,164	5	0.4	7,623,433	91,416	1.2
2029	550,018	4,191	0.8	1,161	-3	-0.2	7,662,936	39,503	0.5
2030	553,992	3,974	0.7	1,160	-1	-0.1	7,712,076	49,140	0.6
2031	557,944	3,952	0.7	1,161	1	0.1	7,774,578	62,502	0.8
2032	561,901	3,957	0.7	1,166	5	0.4	7,863,946	89,369	1.1
2033	565,838	3,937	0.7	1,166	0	0.0	7,918,703	54,756	0.7

Note: Owner-members' Form 7 data for 2018 were not yet available. Beginning in 2018 there is a reclassification from Small Commercial to Residential.

3.5.2 Small Commercial Sales Forecast

Owner-members classify commercial and industrial accounts into two groups. Retail members' whose annual peak demand is less than 1MW are classified as small commercial retail members and retail members' whose annual peak demand is greater than or equal to 1MW are classified as large commercial/industrial retail members. In 2017, there were more than 34,000 small commercial retail members on the system. Small commercial retail members are projected to grow to approximately 39,000 by 2033. As of 2017, small commercial retail members account for 16 percent of total energy sales at the EKPC system level. Table 3-14 displays the results of the 2018 Load Forecast for the small commercial class.

Table 3-14
Small Commercial Class
Historical and Projected Retail Members and Sales

	Customers			***Use Per Customer***			***Class Sales***		
	Annual Average	l Change	% Change	Annual Average (MWh)	Change (MWh)	% Change	Total (MWh)	Annual Change (MWh)	% Change
2007	30,981	788	2.6	60	1	2.1	1,861,952	84,055	4.7
2008	32,036	1,055	3.4	58	-2	-2.7	1,872,811	10,859	0.6
2009	32,380	344	1.1	55	-3	-5.6	1,787,112	-85,699	-4.6
2010	32,552	172	0.5	59	4	7.7	1,935,479	148,367	8.3
2011	32,654	102	0.3	58	-2	-2.5	1,892,090	-43,389	-2.2
2012	33,069	415	1.3	57	-1	-1.7	1,883,241	-8,850	-0.5
2013	33,287	218	0.7	58	1	1.2	1,917,730	34,489	1.8
2014	33,670	383	1.2	57	-1	-1.1	1,919,198	1,468	0.1
2015	34,117	447	1.3	57	0	0.7	1,958,109	38,912	2.0
2016	34,252	135	0.4	57	0	-0.7	1,951,787	-6,322	-0.3
2017	34,594	342	1.0	55	-2	-3.8	1,896,475	-55,312	-2.8
2018	34,318	-276	-0.8	57	2	4.1	1,958,436	61,961	3.3
2019	34,667	349	1.0	58	1	1.1	2,000,123	41,687	2.1
2020	35,011	344	1.0	58	0	0.3	2,025,733	25,610	1.3
2021	35,336	325	0.9	58	0	-0.4	2,036,273	10,541	0.5
2022	35,659	323	0.9	58	0	-0.1	2,052,964	16,691	0.8
2023	35,972	313	0.9	58	0	-0.1	2,068,392	15,428	0.8
2024	36,274	302	0.8	58	0	0.2	2,089,435	21,043	1.0
2025	36,573	299	0.8	58	0	-0.2	2,103,105	13,670	0.7
2026	36,872	299	0.8	58	0	0.1	2,123,423	20,318	1.0
2027	37,167	295	0.8	58	0	0.2	2,145,020	21,597	1.0
2028	37,477	310	0.8	58	0	0.3	2,170,088	25,068	1.2
2029	37,783	306	0.8	58	0	0.0	2,186,914	16,826	0.8
2030	38,087	304	0.8	58	0	0.1	2,205,939	19,025	0.9
2031	38,387	300	0.8	58	0	0.0	2,224,093	18,154	0.8
2032	38,691	304	0.8	58	0	0.2	2,246,697	22,604	1.0
2033	38,994	303	0.8	58	0	0.0	2,263,765	17,069	0.8

Note: Owner-members' Form 7 data for 2018 were not yet available.

3.5.3 Large Commercial and Industrial Sales Forecast

As of 2017, large commercial and industrial retail members account for 29 percent of total energy sales at the EKPC system level. In 2017, there were 149 retail members classified as large commercial and industrial retail member. Approximately half of large commercial retail members are manufacturing plants, which like the small commercial class, support the automotive industry. Table 3-15 displays the results of the 2018 Load Forecast for the large commercial and industrial class.

Table 3-15

Large Commercial and Industrial Class
Historical and Projected Retail Members and Sales

	Customers			***Use Per Customer***			***Class Sales***		
	Annual Average	Annual Change	% Change	Annual Average (MWh)	Change (MWh)	% Change	Total (MWh)	Annual Change (MWh)	% Change
2007	122	-13	-9.6	25,607	2,961	13.1	3,124,043	66,859	2.2
2008	132	10	8.2	23,361	-2,246	-8.8	3,083,589	-40,454	-1.3
2009	138	6	4.5	20,521	-2,839	-12.2	2,831,935	-251,654	-8.2
2010	125	-13	-9.4	22,767	2,246	10.9	2,845,857	13,922	0.5
2011	128	3	2.4	22,571	-195	-0.9	2,889,142	43,285	1.5
2012	130	2	1.6	22,321	-251	-1.1	2,901,688	12,546	0.4
2013	135	5	3.8	22,355	34	0.2	3,017,925	116,237	4.0
2014	136	1	0.7	23,870	1,515	6.8	3,246,287	228,362	7.6
2015	129	-7	-5.1	23,099	-771	-3.2	2,979,716	-266,571	-8.2
2016	138	9	7.0	23,888	789	3.4	3,296,495	316,779	10.6
2017	149	11	8.0	22,788	-1,100	-4.6	3,395,430	98,935	3.0
2018	152	3	2.0	22,356	-432	-1.9	3,398,144	2,714	0.1
2019	156	4	2.6	23,133	777	3.5	3,608,750	210,606	6.2
2020	160	4	2.6	25,901	2,768	12.0	4,144,183	535,433	14.8
2021	163	3	1.9	29,904	4,003	15.5	4,874,338	730,155	17.6
2022	165	2	1.2	29,941	37	0.1	4,940,304	65,966	1.4
2023	168	3	1.8	29,806	-135	-0.5	5,007,458	67,154	1.4
2024	169	1	0.6	30,006	200	0.7	5,071,019	63,561	1.3
2025	171	2	1.2	30,061	55	0.2	5,140,502	69,483	1.4
2026	175	4	2.3	29,704	-358	-1.2	5,198,169	57,667	1.1
2027	176	1	0.6	29,778	74	0.3	5,240,948	42,779	0.8
2028	178	2	1.1	29,703	-75	-0.3	5,287,182	46,234	0.9
2029	180	2	1.1	29,603	-100	-0.3	5,328,538	41,356	0.8
2030	183	3	1.7	29,449	-154	-0.5	5,389,079	60,541	1.1
2031	186	3	1.6	29,256	-193	-0.7	5,441,597	52,518	1.0
2032	188	2	1.1	29,240	-16	-0.1	5,497,115	55,518	1.0
2033	190	2	1.1	29,171	-69	-0.2	5,542,559	45,444	0.8

Note: Owner-members' Form 7 data for 2018 were not yet available.

3.5.4 Seasonal Sales Forecast

This class includes seasonal accounts such as vacation homes, weekend retreats, and camps. As of 2017, only one owner-member reports seasonal residential retail members, which account for less than 0.1 percent of total energy sales at the EKPC system level. Table 3-16 displays the results of the 2018 Load Forecast for the seasonal sales class.

Table 3-16
Seasonal Class
Historical and Projected Retail Members and Sales

	Customers			***Use Per Customer***			***Class Sales***		
	Annual Average	Annual Change	% Change	Monthly Average (kWh)	Change (MWh)	% Change	Total (MWh)	Annual Change (MWh)	% Change
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	46	19.6	227	-12,547	-98.2
2013	94	27	40.3	266	-16	-5.6	300	73	32.4
2014	115	21	22.3	268	2	0.9	370	70	23.5
2015	120	5	4.3	246	-23	-8.4	354	-17	-4.5
2016	125	5	4.2	277	31	12.8	416	62	17.5
2017	141	16	12.8	316	38	13.8	534	118	28.4
2018	151	10	7.4	277	-39	-12.3	503	-31	-5.8
2019	163	12	7.9	275	-2	-0.8	538	35	7.0
2020	176	12	7.6	272	-3	-0.9	574	36	6.6
2021	188	13	7.2	270	-2	-0.8	610	37	6.4
2022	201	12	6.6	269	-1	-0.2	649	39	6.4
2023	213	12	5.9	269	0	-0.1	686	37	5.7
2024	224	12	5.5	270	1	0.2	725	39	5.7
2025	236	11	5.1	269	-1	-0.2	761	35	4.9
2026	247	11	4.7	269	0	0.1	797	37	4.8
2027	256	10	4.0	270	1	0.2	830	33	4.2
2028	269	12	4.7	271	1	0.4	873	42	5.1
2029	280	11	4.2	270	-1	-0.3	907	34	3.9
2030	290	11	3.8	269	-1	-0.4	938	31	3.4
2031	301	10	3.6	269	0	-0.2	970	32	3.4
2032	312	11	3.7	269	1	0.2	1,008	38	3.9
2033	323	11	3.7	269	0	-0.1	1,044	36	3.5

Note: Owner-member Form 7 data for 2018 were not yet available. As of 2012, one owner-member ceased reporting residential seasonal retail members.

3.5.5 Public Building Sales Forecast

Public Building sales include sales to accounts such as government buildings and libraries. As of 2017, only two owner-members report this class, which account for 0.3 percent of total energy sales at the EKPC system level. Table 3-17 displays the results of the 2018 Load Forecast for the public building sales class.

Table 3-17
Public Building Class
Historical and Projected Retail Members and Sales

	Customers			***Use Per Customer***			***Class Sales***		
	Annual Average	Annual Change	% Change	Annual Average (MWh)	Change (MWh)	% Change	Total (MWh)	Annual Change (MWh)	% Change
2007	434	14	3.3	19	0	-0.6	8,457	221	2.7
2008	441	7	1.6	21	2	10.3	9,477	1,020	12.1
2009	424	-17	-3.9	21	0	-0.5	9,065	-413	-4.4
2010	424	0	0.0	22	1	4.8	9,503	438	4.8
2011	416	-8	-1.9	24	1	5.6	9,845	342	3.6
2012	414	-2	-0.5	23	0	-2.0	9,600	-245	-2.5
2013	412	-2	-0.5	24	1	3.0	9,845	244	2.5
2014	408	-4	-1.0	24	0	1.7	9,916	72	0.7
2015	411	3	0.7	24	0	-1.0	9,890	-26	-0.3
2016	404	-7	-1.7	25	1	2.2	9,940	50	0.5
2017	381	-23	-5.7	24	0	-0.5	9,325	-615	-6.2
2018	385	4	1.0	23	-1	-5.4	8,912	-413	-4.4
2019	386	1	0.3	23	0	0.5	8,983	71	0.8
2020	388	2	0.5	23	0	0.2	9,051	68	0.8
2021	390	2	0.5	23	0	0.2	9,118	67	0.7
2022	392	2	0.5	23	0	0.2	9,185	66	0.7
2023	394	2	0.5	23	0	0.2	9,251	67	0.7
2024	396	2	0.5	24	0	0.4	9,333	82	0.9
2025	399	3	0.8	24	0	0.1	9,417	84	0.9
2026	401	2	0.5	24	0	0.4	9,501	84	0.9
2027	403	2	0.5	24	0	0.3	9,575	74	0.8
2028	404	1	0.2	24	0	0.4	9,639	63	0.7
2029	405	1	0.2	24	0	0.3	9,693	54	0.6
2030	407	2	0.5	24	0	0.0	9,742	50	0.5
2031	408	1	0.2	24	0	0.3	9,791	49	0.5
2032	409	1	0.2	24	0	0.3	9,840	49	0.5
2033	410	1	0.2	24	0	0.3	9,890	50	0.5

Note: Owner-members Form 7 data for 2018 were not yet available.

3.5.6 Public Street and Highway Lighting Sales Forecast

This class represents street lighting. As of 2017, 11 owner-members report public street and highway lighting retail members, which account for 0.08 percent of total energy sales at the EKPC system level. Table 3-18 displays the results of the 2018 Load Forecast for the other sales class.

Table 3-18
Public Street and Highway Lighting Class
Historical and Projected Retail Members and Sales

	Customers			*Use Per Customer*			*Class Sales*		
	Annual Average	Annual Change	% Change	Annual Average (MWh)	Change (MWh)	% Change	Total (MWh)	Annual Change (MWh)	% Change
2007	434	14	3.3	19	0	-0.6	8,457	221	2.7
2008	441	7	1.6	21	2	10.3	9,477	1,020	12.1
2009	424	-17	-3.9	21	0	-0.5	9,065	-413	-4.4
2010	424	0	0.0	22	1	4.8	9,503	438	4.8
2011	416	-8	-1.9	24	1	5.6	9,845	342	3.6
2012	414	-2	-0.5	23	0	-2.0	9,600	-245	-2.5
2013	412	-2	-0.5	24	1	3.0	9,845	244	2.5
2014	408	-4	-1.0	24	0	1.7	9,916	72	0.7
2015	411	3	0.7	24	0	-1.0	9,890	-26	-0.3
2016	404	-7	-1.7	25	1	2.2	9,940	50	0.5
2017	381	-23	-5.7	24	0	-0.5	9,325	-615	-6.2
2018	385	4	1.0	23	-1	-5.4	8,912	-413	-4.4
2019	386	1	0.3	23	0	0.5	8,983	71	0.8
2020	388	2	0.5	23	0	0.2	9,051	68	0.8
2021	390	2	0.5	23	0	0.2	9,118	67	0.7
2022	392	2	0.5	23	0	0.2	9,185	66	0.7
2023	394	2	0.5	23	0	0.2	9,251	67	0.7
2024	396	2	0.5	24	0	0.4	9,333	82	0.9
2025	399	3	0.8	24	0	0.1	9,417	84	0.9
2026	401	2	0.5	24	0	0.4	9,501	84	0.9
2027	403	2	0.5	24	0	0.3	9,575	74	0.8
2028	404	1	0.2	24	0	0.4	9,639	63	0.7
2029	405	1	0.2	24	0	0.3	9,693	54	0.6
2030	407	2	0.5	24	0	0.0	9,742	50	0.5
2031	408	1	0.2	24	0	0.3	9,791	49	0.5
2032	409	1	0.2	24	0	0.3	9,840	49	0.5
2033	410	1	0.2	24	0	0.3	9,890	50	0.5

Note: Owner-members' Form 7 data for 2018 were not yet available.

3.6 Peak Demand Forecast and Scenarios

3.6.1 Peak Demand and Scenario Results

In addition to the base case peak demands and energy, high and low scenarios were developed. The same methodology is used to construct two new models: one reflecting assumptions that result in high usage and one with assumptions that result in low usage. Assumptions include:

1. Weather: Based on 15 years of historical heating and cooling degree day (HDD and CDD) data, alternate weather projections were developed based upon the 90th and 10th percentile to reflect extreme and mild weather, respectively. The resulting forecasts reflect cases assuming base case HDD +/-20% and CDD +/-30%.
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 bounding the base case residential price forecast. The growth rate for the electricity rate was estimated by using high and low case forecasts for the forward market prices for energy (source: ACES Power Marketing).

   The high scenario for the residential price forecast is constructed to have a 3.2 percent compound annual growth rate, while the low scenario is constructed to have a 1.1 percent compound annual growth rate compared to the base of 2.0 percent. The relationships between the base case residential class rates and the commercial, industrial and other class rates are maintained in scenario models.
3. Residential retail members: In the EKPC base case, the residential growth rate is 0.7 percent. The basic approach to preparing high and low case scenarios for the future number of residential retail members is to determine the magnitude of historical variation between long-term average growth rates and higher or lower growth rates during shorter periods of time. The resulting rate of 1.2 percent was used to produce the high case and 0.3 percent was used for the low case.
4. Small and Large Commercial retail member and energy: Small commercial retail member growth is correlated to residential retail members' growth and this relationship is maintained when developing the high and low cases. The industrial class was not changed.

Adjusting these assumptions leads to different retail member forecasts which in turn results in different energy and demand forecasts. The results are shown in Table 3-19 for the following cases:

Low Case - Pessimistic economic assumptions with mild weather
Base Case - Most probable economics assumptions with normal weather
High Case - Optimistic economic assumptions with severe weather

Table 3-19
Peak Demands and Total Requirements Scenarios

Net Requirements (MWh)				Net Winter Peak (MW)				Net Summer Peak (MW)			
Season	Low Case	Base Case	High Case	Year	Low Case	Base Case	High Case	Year	Low Case	Base Case	High Case
2017-18	12,853,511	**13,393,925**	13,978,835	2018	3,210	**3,234**	3,259	2018	2,357	**2,363**	2,369
2018-19	12,811,892	**13,735,980**	14,710,416	2019	3,235	**3,258**	3,283	2019	2,324	**2,341**	2,359
2019-20	13,353,036	**14,354,291**	15,426,015	2020	3,240	**3,281**	3,323	2020	2,347	**2,377**	2,407
2020-21	14,018,008	**15,109,727**	16,294,035	2021	3,266	**3,323**	3,383	2021	2,383	**2,425**	2,469
2021-22	14,101,417	**15,241,723**	16,494,152	2022	3,275	**3,349**	3,426	2022	2,394	**2,448**	2,504
2022-23	14,187,864	**15,373,488**	16,695,117	2023	3,282	**3,373**	3,469	2023	2,391	**2,457**	2,527
2023-24	14,326,392	**15,555,697**	16,950,423	2024	3,294	**3,401**	3,516	2024	2,404	**2,483**	2,566
2024-25	14,427,616	**15,704,283**	17,172,639	2025	3,294	**3,418**	3,550	2025	2,414	**2,505**	2,603
2025-26	14,532,543	**15,862,441**	17,407,068	2026	3,303	**3,444**	3,596	2026	2,428	**2,532**	2,644
2026-27	14,629,327	**16,012,368**	17,634,408	2027	3,309	**3,468**	3,639	2027	2,428	**2,545**	2,671
2027-28	14,745,669	**16,185,645**	17,890,591	2028	3,325	**3,502**	3,694	2028	2,446	**2,576**	2,718
2028-29	14,803,507	**16,292,394**	18,075,818	2029	3,320	**3,514**	3,726	2029	2,452	**2,595**	2,752
2029-30	14,896,939	**16,429,025**	18,289,937	2030	3,320	**3,531**	3,762	2030	2,466	**2,622**	2,794
2030-31	14,989,061	**16,571,785**	18,514,283	2031	3,313	**3,540**	3,789	2031	2,470	**2,639**	2,825
2031-32	15,110,689	**16,752,464**	18,782,076	2032	3,324	**3,568**	3,837	2032	2,482	**2,664**	2,865
2032-33	15,182,711	**16,879,184**	18,992,448	2033	3,325	**3,585**	3,874	2033	2,490	**2,685**	2,901

Note: 2017-2018 Winter Peak and 2018 Summer Peak are weather normalized actual values.

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 558 meters on residential, commercial and industrial retail members. EKPC and its owner-members 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 owner-members. 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 owner-members' 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 owner-member 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 retail members that are billed in the residential class. There are 135 load profile meters installed and collecting data.
2. Small Commercial & Industrial: These are non-residential retail members whose demand is less than 50 kW. There are 41 load profile meters installed and collecting data.
3. Medium Commercial & Industrial: Includes retail members whose peak demands are between 50kW and 350kW. There are 57 load profile meters installed and collecting data.
4. Large Power: Includes retail members whose peak demands are greater than 350kW. There are 325 meters installed and collecting data.

Although not formally approved, the following projects have been proposed for implementation in 2019.

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 2017.
2. Borrowed data: EKPC will continue to monitor and evaluate the transferability of load data from other utilities.

3.7.2 Research and Development

Since the 2015 IRP, EKPC has built a billing data load database consisting of meter data acquired by the advanced metering infrastructure (AMI) systems of the owner-members. This database will enable EKPC to perform detailed impact analysis of its DSM programs.

EKPC is now using the AMI meter data in this database to evaluate the impact of several DSM programs. For example, EKPC validated the peak demand savings for its Nest thermostat load control pilot in the summer of 2017. The Nest pilot was the starting point in the design of EKPC's new "Bring Your Own Thermostat" offering for Residential DLC. Also, in 2018, EKPC sponsored GoodCents® to enhance the sample design for the impact analysis of its Residential DLC program. GoodCents® is now using AMI data from EKPC's load database alongside the HOBO® data logger and other data logger samples.

Finally, EKPC is closely monitoring the development of electric vehicles (EVs) as a potential new load. Although EKPC has not performed any detailed studies of the potential energy and demand impacts of an expanding EV market, EKPC has been provided annual EV purchase rates in Kentucky by the Kentucky Energy and Environment Cabinet (EEC). The Volkswagen settlement allocated significant moneys to Kentucky to be administered by the EEC. Per the settlement, up to 15 percent of those monies can be allocated to public charging infrastructure in Kentucky. EKPC along with the other utilities in Kentucky developed and submitted a plan to EEC on how and where to invest those monies. Investment in public charging infrastructure is crucial to increase purchases of EVs by Kentuckians. At the same time, EKPC is studying ways to minimize the peak demand impacts on its system.

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, operates and/or has firm rights to approximately 3,437MW of winter capacity. This capacity is located at 11 separate sites with a total of 25 generating units. EKPC also has a firm purchase power agreement with the Southeastern Power Administration for 170MW of hydro power. Fuel sources include coal, natural gas, landfill gas, solar and hydro.

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 have been retired, Units 1 and 2 in April 2015 and Units 3 and 4 in April 2016. The power block is being demolished and should be completed by the summer of 2019. The substation will remain in place.

Cooper Station

The second plant EKPC built was the John Sherman Cooper Station located near Somerset on Lake Cumberland. The station has one 116MW unit that became operational on February 9, 1965, and one 225MW unit that became operational on October 28, 1969. Both units are pulverized coal units. A pollution control system was added to Cooper Unit 2 and began commercial operation in summer 2012. A duct reroute project, which routes the flue gas from Unit 1 into the Unit 2 pollution control system, was completed in 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. Unit 1 is a 300MW unit that began commercial operation on September 1, 1977. Unit 2 is a 510MW unit that began operating on March 2, 1981. Both of these units are conventional pulverized coal units with flue gas desulfurization (FGD) technology.

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

Steam Load

The International Paper Company has a corrugated paper recycling facility adjacent to EKPC's Spurlock Station. The facility has an expected peak electrical load of approximately 24MW and an equivalent of 29MW 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 Company operates 99.1 percent of the time.

Natural Gas/ Fuel Oil

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 on the Kentucky River. The ABB turbines, which went commercial in 1999, have a summer rating of 104MW each and a winter rating of 142MW each. Two of the GE turbines went commercial in 2001 and two in 2005. Each has a summer rating of 73MW and a winter rating of 88MW (93MW for Unit 4). The two LMS 100 turbines became operational in 2010. Unit 9 has a summer rating of 75MW and Unit 10 has a summer rating of 74MW. They both have a winter rating of 103MW.

EKPC expanded the peaking fleet in 2015 with the acquisition of the Bluegrass in Oldham County. The three Siemens 501FD-2 units were commercial in 2002. The summer rating for each is 167MW and the winter rating is 189MW. Bluegrass Unit 3 is under contract until May 2019, at which time it becomes fully available for EKPC's dispatch needs.

Renewable Sources

Landfill Gas

EKPC owns and operates 16.1MW of landfill gas capacity generated at 6 sites throughout Kentucky. The previously decommissioned Mason County unit was installed at Bavarian Landfill and was operational in October 2016. This brings Bavarian up to 4.6MW. The newest plant was installed at Glasgow LFGTE facility and became operational in December 2015 and has a single unit rated at 0.9MW.

Photo Voltaic Solar

Cooperative Solar Farm One was placed into operation on November 12, 2017. It is located adjacent to EKPC Headquarters in Winchester, KY. The 60 acre farm features 32,300 solar panels capable of producing up to 8.5MW.

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 4-1
Generating Plant Data

Dale Station	Unit 1	Unit 2	Unit 3	Unit 4
Location	Ford, KY	Ford, KY	Ford, KY	Ford, KY
Status	RETIRED	RETIRED	RETIRED	RETIRED
Commercial Operation	12/1/1954	12/1/1954	10/1/1957	8/9/1960
Type	Steam	Steam	Steam	Steam
Net Dependable Capability	23 MW	23 MW	75 MW	75 MW
Entitlement (%)	100	100	100	100
Primary Fuel Type	Coal	Coal	Coal	Coal
Secondary Fuel Type	None	None	None	None
Fuel Storage (Tons)	70,000 for Plant Site	70,000 for Plant Site	70,000 for Plant Site	70,000 for Plant
Retirement Dates	4/15/2015	4/15/2015	4/15/2016	4/15/2016

Table 4-2
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	2/9/1965	10/28/1969	9/1/1977	3/2/1981	3/1/2005	4/1/2009
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

Table 4-3
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	142 MW	142 MW	142 MW	93 MW	88 MW	88 MW	88 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

Table 4-4
Generating Plant Data

Smith Combustion Turbines

	Unit 9	Unit 10
Location	Trapp, KY	Trapp, KY
Status	Existing	Existing
Commercial Operation	2009	2009
Type	Gas	Gas
Net Dependable Capability	103 MW	103 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

Table 4-5
Generating Plant Data

Landfill Gas

	Bavarian	Green Valley	Laurel Ridge	Hardin Co.	Pendleton Co.	Glasgow
Location	Boone, KY	Greenup County, KY	Lily, KY	Hardin County, KY	Pendleton County, KY	Mason County, KY
Status	Existing	Existing	Existing	Existing	Existing	Existing
Commercial Operation	9/22/03	9/9/03	9/15/03	1/15/06	1/07	11/09
Type	Gas	Gas	Gas	Gas	Gas	Gas
Net Dependable Capability	4.6 MW	2.3 MW	3 MW	2.3 MW	3.0 MW	0.9 MW
Entitlement (%)	100	100	100	100	100	100
Primary Fuel Type	Methane	Methane	Methane	Methane	Methane	Methane
Secondary Fuel Type	None	None	None	None	None	None
Fuel Storage	N/A	N/A	N/A	N/A	N/A	N/A

Table 4-6
Generating Plant Data

Bluegrass Combustion Turbines

	Unit 1	**Unit 2**	**Unit 3**
Location	LaGrange, KY	LaGrange, KY	LaGrange, KY
Status	Existing	Existing	Existing
Commercial Operation	2002	2002	2002
Type	Gas	Gas	Gas
Net Dependable Capability	189 MW	189 MW	189 MW
Entitlement (%)	100	100	100
Primary Fuel Type	Natural Gas	Natural Gas	Natural Gas
Secondary Fuel Type	N/A	N/A	N/A
Fuel Storage (Gallons)	N/A	N/A	N/A
Scheduled Upgrades	Fuel Oil Secondary Fuel	Fuel Oil Secondary Fuel	Fuel Oil Secondary Fuel

Table 4-7
Generating Plant Data

Cooperative Solar

	Farm One
Location	Winchester, KY
Status	Committed
Commercial Operation	2017
Type	Solar
Net Dependable Capability	8.5 MW
Entitlement (%)	100
Primary Fuel Type	Solar

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															
Cooper 1	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Capacity Factor	[redacted]															
Availability Factor																
Average Heat Rate (Btu/kWh)																
Fuel Cost ($/MMBtu)																
Variable O&M ($/MWh)																
Fixed O&M ($/kW/Yr)																
Variable Production Cost ($/MWh)																
Capital Cost Escalation (%)																
O&M Escalation (%)																

	ACTUAL															
Cooper 2	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Capacity Factor	[redacted]															
Availability Factor																
Average Heat Rate (Btu/kWh)																
Fuel Cost ($/MMBtu)																
Variable O&M ($/MWh)																
Fixed O&M ($/kW/Yr)																
Variable Production Cost ($/MWh)																
Capital Cost Escalation (%)																
O&M Escalation (%)																

REDACTED

	ACTUAL															
Spurlock 1	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Capacity Factor	[redacted]															
Availability Factor																
Average Heat Rate (Btu/kWh)																
Fuel Cost ($/MMBtu)																
Variable O&M ($/MWh)																
Fixed O&M ($/kW/Yr)																
Variable Production Cost ($/MWh)																
Capital Cost Escalation (%)																
O&M Escalation (%)																

	ACTUAL															
Spurlock 2	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Capacity Factor	[redacted]															
Availability Factor																
Average Heat Rate (Btu/kWh)																
Fuel Cost ($/MMBtu)																
Variable O&M ($/MWh)																
Fixed O&M ($/kW/Yr)																
Variable Production Cost ($/MWh)																
Capital Cost Escalation (%)																
O&M Escalation (%)																

	ACTUAL															
Gilbert Unit	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Capacity Factor	[redacted]															
Availability Factor																
Average Heat Rate (Btu/kWh)																
Fuel Cost ($/MMBtu)																
Variable O&M ($/MWh)																
Fixed O&M ($/kW/Yr)																
Variable Production Cost ($/MWh)																
Capital Cost Escalation (%)																
O&M Escalation (%)																

REDACTED

	ACTUAL															
Spurlock 4	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Capacity Factor	[redacted]															
Availability Factor	[redacted]															
Average Heat Rate (Btu/kWh)	[redacted]															
Fuel Cost ($/MMBtu)	[redacted]															
Variable O&M ($/MWh)	[redacted]															
Fixed O&M ($/kW/Yr)	[redacted]															
Variable Production Cost ($/MWh)	[redacted]															
Capital Cost Escalation (%)	[redacted]															
O&M Escalation (%)	[redacted]															

	ACTUAL															
Smith CT1	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Capacity Factor	[redacted]															
Availability Factor	[redacted]															
Average Heat Rate (Btu/kWh)	[redacted]															
Fuel Cost ($/MMBtu)	[redacted]															
Variable O&M ($/MWh)	[redacted]															
Fixed O&M ($/kW/Yr)	[redacted]															
Variable Production Cost ($/MWh)	[redacted]															
Capital Cost Escalation (%)	[redacted]															
O&M Escalation (%)	[redacted]															

	ACTUAL															
Smith CT2	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Capacity Factor	[redacted]															
Availability Factor	[redacted]															
Average Heat Rate (Btu/kWh)	[redacted]															
Fuel Cost ($/MMBtu)	[redacted]															
Variable O&M ($/MWh)	[redacted]															
Fixed O&M ($/kW/Yr)	[redacted]															
Variable Production Cost ($/MWh)	[redacted]															
Capital Cost Escalation (%)	[redacted]															
O&M Escalation (%)	[redacted]															

REDACTED

	ACTUAL															
Smith CT3	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Capacity Factor	[redacted]															
Availability Factor																
Average Heat Rate (Btu/kWh)																
Fuel Cost ($/MMBtu)																
Variable O&M ($/MWh)																
Fixed O&M ($/kW/Yr)																
Variable Production Cost ($/MWh)																
Capital Cost Escalation (%)																
O&M Escalation (%)																

	ACTUAL															
Smith CT4	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Capacity Factor	[redacted]															
Availability Factor																
Average Heat Rate (Btu/kWh)																
Fuel Cost ($/MMBtu)																
Variable O&M ($/MWh)																
Fixed O&M ($/kW/Yr)																
Variable Production Cost ($/MWh)																
Capital Cost Escalation (%)																
O&M Escalation (%)																

	ACTUAL															
Smith CT5	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Capacity Factor	[redacted]															
Availability Factor																
Average Heat Rate (Btu/kWh)																
Fuel Cost ($/MMBtu)																
Variable O&M ($/MWh)																
Fixed O&M ($/kW/Yr)																
Variable Production Cost ($/MWh)																
Capital Cost Escalation (%)																
O&M Escalation (%)																

REDACTED

	ACTUAL															
Smith CT6	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Capacity Factor	[redacted]															
Availability Factor	[redacted]															
Average Heat Rate (Btu/kWh)	[redacted]															
Fuel Cost ($/MMBtu)	[redacted]															
Variable O&M ($/MWh)	[redacted]															
Fixed O&M ($/kW/Yr)	[redacted]															
Variable Production Cost ($/MWh)	[redacted]															
Capital Cost Escalation (%)	[redacted]															
O&M Escalation (%)	[redacted]															

	ACTUAL															
Smith CT7	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Capacity Factor	[redacted]															
Availability Factor	[redacted]															
Average Heat Rate (Btu/kWh)	[redacted]															
Fuel Cost ($/MMBtu)	[redacted]															
Variable O&M ($/MWh)	[redacted]															
Fixed O&M ($/kW/Yr)	[redacted]															
Variable Production Cost ($/MWh)	[redacted]															
Capital Cost Escalation (%)	[redacted]															
O&M Escalation (%)	[redacted]															

	ACTUAL															
Smith CT9	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Capacity Factor	[redacted]															
Availability Factor	[redacted]															
Average Heat Rate (Btu/kWh)	[redacted]															
Fuel Cost ($/MMBtu)	[redacted]															
Variable O&M ($/MWh)	[redacted]															
Fixed O&M ($/kW/Yr)	[redacted]															
Variable Production Cost ($/MWh)	[redacted]															
Capital Cost Escalation	[redacted]															
O&M Escalation	[redacted]															

REDACTED

	ACTUAL															
Smith CT 10	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Capacity Factor	[redacted]															
Availability Factor	[redacted]															
Average Heat Rate (Btu/kWh)	[redacted]															
Fuel Cost ($/MMBtu)	[redacted]															
Variable O&M ($/MWh)	[redacted]															
Fixed O&M ($/kW/Yr)	[redacted]															
Variable Production Cost ($/MWh)	[redacted]															
Capital Cost Escalation (%)	[redacted]															
O&M Escalation (%)	[redacted]															

	ACTUAL															
Bluegrass CT1	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Capacity Factor	[redacted]															
Availability Factor	[redacted]															
Average Heat Rate (Btu/kWh)	[redacted]															
Fuel Cost ($/MMBtu)	[redacted]															
Variable O&M ($/MWh)	[redacted]															
Fixed O&M ($/kW/Yr)	[redacted]															
Variable Production Cost ($/MWh)	[redacted]															
Capital Cost Escalation (%)	[redacted]															
O&M Escalation (%)	[redacted]															

	ACTUAL															
Bluegrass CT2	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Capacity Factor	[redacted]															
Availability Factor	[redacted]															
Average Heat Rate (Btu/kWh)	[redacted]															
Fuel Cost ($/MMBtu)	[redacted]															
Variable O&M ($/MWh)	[redacted]															
Fixed O&M ($/kW/Yr)	[redacted]															
Variable Production Cost ($/MWh)	[redacted]															
Capital Cost Escalation	[redacted]															
O&M Escalation	[redacted]															

REDACTED

	ACTUAL															
Bluegrass CT3	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Capacity Factor	[redacted]															
Availability Factor																
Average Heat Rate (Btu/kWh)																
Fuel Cost ($/MMBtu)																
Variable O&M ($/MWh)																
Fixed O&M ($/kW/Yr)																
Variable Production Cost ($/MWh)																
Capital Cost Escalation (%)																
O&M Escalation (%)																

	ACTUAL															
Landfill Gas Projects	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Capacity Factor	[redacted]															
Availability Factor																
Average Heat Rate (Btu/kWh)																
Fuel Cost ($/MMBtu)																
Variable O&M ($/MWh)																
Fixed O&M ($/kW/Yr)																
Variable Production Cost ($/MWh)																
Capital Cost Escalation (%)																
O&M Escalation (%)																

REDACTED

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.

EKPC selects DSM programs to offer on the basis of meeting member 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 member acceptance, measure applicability, savings potential, and cost-effectiveness. The cost-effectiveness of DSM resources is analyzed in a rigorous fashion using California tests for cost-effectiveness.

This IRP evaluates the costs and benefits of DSM programs to be implemented by EKPC in partnership with its owner-members.

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 5:058)." - *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. l0 (Ky. P.S.C. July 24, 2012).

5.2 DSM Planning Process

For the 2019 IRP, EKPC enhanced its DSM planning capabilities by sponsoring an updated study of energy efficiency (EE) and demand response (DR) savings potential conducted by GDS.

GDS conducted a cost-effectiveness screening of a comprehensive set of measures using the TRC 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. For more details on the energy efficiency and demand response measures, including the results of economic screening of those measures, please see the GDS Energy Efficiency and Demand Response Potential report (included as Exhibit DSM-1 in the DSM Technical Appendix).

The operating environment for DSM has changed significantly since 2015. Energy and capacity avoided costs have declined, and owner-members have been experiencing revenue erosion. In addition, the repeal of the Federal Clean Power Plan has reduced the need for major increases in DSM spending. As a result, in this IRP EKPC has set participation levels for DSM programs to meet targeted funding levels. These targets correspond to the $3 million residential EE scenario in the GDS report. EKPC will allocate that funding to existing programs. No new programs are proposed in this IRP.

In addition, EKPC and its owner-members have made the strategic decision to dedicate all DSM resources to the residential class. Therefore, there are no non-residential EE programs proposed in this IRP. Should future conditions warrant it, EKPC's priorities for starting up non-residential EE programs would be lighting, HVAC, refrigeration, machine drive, and process heating & cooling.

EKPC has proposed changes to its residential program offerings. Some programs have been discontinued, while others have been proposed to be modified.

The following programs have been proposed to be eliminated:

- ENERGY STAR® Appliances
- Appliance Recycling
- HVAC Duct Seal
- C&I Lighting
- Industrial Compressed Air

The following programs have been proposed to be modified:

Button-Up Weatherization: There will no longer be three tiers. The program will be Button-Up with Air Sealing only. This program will provide incentives for ceiling insulation and air sealing only. Furthermore, ceiling insulation will only receive a rebate if air sealing is also performed at the home.

Heat Pump Retrofit: This program will have two SEER levels rather than the previous 3. Ductless mini-split systems are new to the market and EKPC has seen significant growth in installations. Thus, three types of ductless mini-splits have been added: 1-head, 2-head, and 3-head units.

Touchstone Energy Home: This program will now have one efficiency target: 30 percent lower energy use than the typical home built in Kentucky.

ENERGY STAR® Manufactured Home: The rebate has been lowered to reflect lower energy savings per home.

Residential Direct Load Control: The water heater switch option is eliminated while the smart thermostat option for air conditioners has been added.[2]

The remaining programs have not changed:

- CARES Low-Income Weatherization
- Residential Energy Audit (home information)
- Residential Efficient Lighting

[2] The tariff allows small commercial customers to participate. However, EKPC is not projecting to have any small commercial participants in this IRP.

EKPC has filed updated tariffs with the Commission that reflect these changes to programs.

Guided by the findings in the GDS Potential Study, EKPC designed a set of energy efficiency and demand response programs, and prepared savings, participation, and cost estimates for those programs.

EKPC then conducted a final cost-effectiveness analysis for each DSM program using the *DSMore* software tool. All of the programs were shown to be cost-effective using the TRC test.

The DSM portfolio for this IRP includes seven energy efficiency programs and two demand response programs.

807 KAR 5:058 Section 8(3)(e)(1) 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. (e) For each existing and new conservation and load management or other demand-side programs included in the plan; (1) Targeted classes and end-uses.

The following table provides the targeted classes and end-uses for the DSM programs included in the plan. More detailed program descriptions can be found in Exhibit DSM-5 in the DSM Technical Appendix.

Table 5-1
Existing Programs

Program Name	Class	End-uses
Button-Up Weatherization	Residential	Space Heating, Space Cooling
CARES – Low Income	Residential	Space Heating, Space Cooling, Water Heating, Lighting
Heat Pump Retrofit	Residential	Space Heating, Space Cooling
Touchstone Energy (TSE) Home	Residential	Space Heating, Space Cooling, Water Heating
ENERGY STAR® Manufactured Home	Residential	Space Heating, Space Cooling
Residential Energy Audit	Residential	Space Heating, Space Cooling, Water Heating, Lighting
Residential Efficient Lighting	Residential	Lighting
Direct Load Control-Residential: AC switches[3]	Residential	Space Cooling
Direct Load Control-Residential: AC Bring Your Own Thermostat	Residential	Space Cooling

[3] The tariff allows small commercial customers to participate. However, EKPC is not projecting to have any small commercial participants in this IRP.

807 KAR 5:058 Section 8(3)(e)(2) 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. (e) For each existing and new conservation and load management or other demand-side programs included in the plan; (2) Expected duration of the program.

Expected duration of the program;

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

Table 5-2
Existing Programs – Duration

Program Name	New Participants	Savings Lifetime
Button-Up Weatherization	15 years	15 years
CARES – Low Income	15 years	15 years
Heat Pump Retrofit	15 years	20 years
Touchstone Energy (TSE) Home	15 years	20 years
ENERGY STAR® Manufactured Home	15 years	15 years
Residential Energy Audit	15 years	5 years
Residential Efficient Lighting	15 years	8 years
Direct Load Control-Residential: AC switches	15 years	15 years
Direct Load Control-Residential: AC Bring Your Own Thermostat	15 years	15 years

807 KAR 5:058 Section 8(3)(e)(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. (e) For each existing and new conservation and load management or other demand-side programs included in the plan: (3) Projected energy changes by season, and summer and winter peak demand changes.

The following tables provide the projected annual energy, summer peak demand and winter peak demand changes for each DSM program included in the plan. Load changes for the first five years (2019-2023) of new participation have been accounted for in the Load Forecast. Load changes for new participation in the years 2024-2033 are accounted for in the IRP. The load changes capture the impacts of future participants only.

Load Impacts of DSM Programs

Button-Up Weatherization Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2019	222	-797	-0.5	-0.2
2020	289	-1,037	-0.7	-0.2
2021	356	-1,277	-0.8	-0.2
2022	423	-1,518	-1.0	-0.3
2023	490	-1,758	-1.1	-0.3
2024	557	-1,999	-1.3	-0.4
2025	624	-2,239	-1.4	-0.4
2026	691	-2,480	-1.6	-0.5
2027	758	-2,720	-1.7	-0.5
2028	825	-2,960	-1.9	-0.6
2029	892	-3,201	-2.1	-0.6
2030	959	-3,441	-2.2	-0.7
2031	1,026	-3,682	-2.4	-0.7
2032	1,093	-3,922	-2.5	-0.8
2033	1,160	-4,162	-2.7	-0.8

CARES-Low Income program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2019	69	-326	-0.1	0.0
2020	144	-681	-0.2	-0.1
2021	219	-1,036	-0.3	-0.2
2022	294	-1,391	-0.4	-0.2
2023	369	-1,746	-0.5	-0.3
2024	444	-2,100	-0.6	-0.3
2025	519	-2,455	-0.7	-0.4
2026	594	-2,810	-0.9	-0.4
2027	669	-3,165	-1.0	-0.5
2028	744	-3,520	-1.1	-0.5
2029	819	-3,874	-1.2	-0.6
2030	894	-4,229	-1.3	-0.6
2031	969	-4,584	-1.4	-0.7
2032	1,044	-4,939	-1.5	-0.8
2033	1,119	-5,294	-1.6	-0.8

Heat Pump Retrofit program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2019	751	-5,913	0.0	-0.3
2020	1,444	-11,408	0.0	-0.6
2021	2,137	-16,904	0.0	-0.9
2022	2,830	-22,400	0.0	-1.1
2023	3,523	-27,895	0.0	-1.4
2024	4,216	-33,391	0.0	-1.7
2025	4,909	-38,886	0.0	-2.0
2026	5,602	-44,382	0.0	-2.3
2027	6,295	-49,878	0.0	-2.5
2028	6,988	-55,373	0.0	-2.8
2029	7,681	-60,869	0.0	-3.1
2030	8,374	-66,364	0.0	-3.4
2031	9,067	-71,860	0.0	-3.6
2032	9,760	-77,355	0.0	-3.9
2033	10,453	-82,851	0.0	-4.2

Touchstone Energy Home

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2019	485	-1,461	-1.2	-0.3
2020	955	-2,878	-2.4	-0.6
2021	1,425	-4,294	-3.5	-1.0
2022	1,895	-5,710	-4.7	-1.3
2023	2,365	-7,127	-5.9	-1.6
2024	2,835	-8,543	-7.0	-1.9
2025	3,305	-9,959	-8.2	-2.2
2026	3,775	-11,376	-9.4	-2.5
2027	4,245	-12,792	-10.5	-2.9
2028	4,715	-14,208	-11.7	-3.2
2029	5,185	-15,624	-12.9	-3.5
2030	5,655	-17,041	-14.0	-3.8
2031	6,125	-18,457	-15.2	-4.1
2032	6,595	-19,873	-16.4	-4.4
2033	7,065	-21,290	-17.5	-4.8

ENERGY STAR® Manufactured Home Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2019	175	-711	-0.2	-0.1
2020	325	-1,320	-0.3	-0.2
2021	475	-1,929	-0.4	-0.2
2022	625	-2,538	-0.6	-0.3
2023	775	-3,147	-0.7	-0.4
2024	925	-3,756	-0.9	-0.4
2025	1,075	-4,365	-1.0	-0.5
2026	1,225	-4,974	-1.1	-0.6
2027	1,375	-5,583	-1.3	-0.6
2028	1,525	-6,192	-1.4	-0.7
2029	1,675	-6,801	-1.6	-0.8
2030	1,825	-7,410	-1.7	-0.9
2031	1,975	-8,019	-1.8	-0.9
2032	2,125	-8,628	-2.0	-1.0
2033	2,275	-9,237	-2.1	-1.1

Residential Energy Audit Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2019	500	-274	-0.1	-0.1
2020	1,450	-797	-0.2	-0.2
2021	2,400	-1,319	-0.4	-0.3
2022	3,350	-1,841	-0.6	-0.4
2023	4,300	-2,364	-0.7	-0.5
2024	4,850	-2,677	-0.8	-0.6
2025	5,050	-2,807	-0.9	-0.6
2026	5,250	-2,937	-0.9	-0.6
2027	5,350	-3,002	-0.9	-0.7
2028	5,350	-3,002	-0.9	-0.7
2029	5,350	-3,002	-0.9	-0.7
2030	5,350	-3,002	-0.9	-0.7
2031	5,350	-3,002	-0.9	-0.7
2032	5,350	-3,002	-0.9	-0.7
2033	5,350	-3,002	-0.9	-0.7

Residential Lighting Program

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2019	5,500	-1,155	-0.2	-0.1
2020	11,000	-2,310	-0.4	-0.3
2021	16,500	-3,465	-0.5	-0.4
2022	22,000	-4,620	-0.7	-0.5
2023	27,500	-5,775	-0.9	-0.7
2024	33,000	-6,930	-1.1	-0.8
2025	38,500	-8,085	-1.3	-0.9
2026	44,000	-9,240	-1.4	-1.1
2027	44,000	-9,240	-1.4	-1.1
2028	44,000	-9,240	-1.4	-1.1
2029	44,000	-9,240	-1.4	-1.1
2030	44,000	-9,240	-1.4	-1.1
2031	44,000	-9,240	-1.4	-1.1
2032	44,000	-9,240	-1.4	-1.1
2033	44,000	-9,240	-1.4	-1.1

Direct Load Control: Residential Air Conditioner - Switches

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2019	250	-7	0.0	-0.2
2020	750	-21	0.0	-0.7
2021	1,250	-36	0.0	-1.2
2022	1,750	-50	0.0	-1.7
2023	2,250	-64	0.0	-2.1
2024	2,750	-78	0.0	-2.6
2025	3,250	-93	0.0	-3.1
2026	3,750	-107	0.0	-3.6
2027	4,250	-121	0.0	-4.0
2028	4,750	-135	0.0	-4.5
2029	5,250	-150	0.0	-5.0
2030	5,750	-164	0.0	-5.5
2031	6,250	-178	0.0	-5.9
2032	6,750	-192	0.0	-6.4
2033	7,250	-207	0.0	-6.9

Direct Load Control: Residential Air Conditioner – Bring Your Own Thermostat

(negative value = reduction in load)

Year	Participants	Impact on Total Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2019	250	-7	0.0	-0.2
2020	750	-21	0.0	-0.7
2021	1,250	-36	0.0	-1.2
2022	1,750	-50	0.0	-1.7
2023	2,250	-64	0.0	-2.1
2024	2,750	-78	0.0	-2.6
2025	3,250	-93	0.0	-3.1
2026	3,750	-107	0.0	-3.6
2027	4,250	-121	0.0	-4.0
2028	4,750	-135	0.0	-4.5
2029	5,250	-150	0.0	-5.0
2030	5,750	-164	0.0	-5.5
2031	6,250	-178	0.0	-5.9
2032	6,750	-192	0.0	-6.4
2033	7,250	-207	0.0	-6.9

807 KAR 5:058 Section 8(3)(e)(4) For each existing and new conservation and load management or other demand-side programs included in the plan; (4) Projected cost, including any incentive payments and program administrative costs.

The projected costs for each DSM program are shown below in Table 5-3. Cost values are the present value of the future stream of costs for that element, using a 7 percent discount rate. Distribution system rebates are paid to program participants. More details on program costs and cost-effectiveness can be found in the DSM Technical Appendix.

Table 5-3
DSM Program Costs

Program	Program costs Distribution System Admin	present value, 2019 $ using a 7% discount rate		Member Investment
		EKPC Admin	Rebates	
Button-Up Weatherization	$281,046	$54,805	$667,039	$1,686,542
CARES Low Income	$1,713,755	$219,220	$2,196,054	$1,005,403[4]
Heat Pump Retrofit	$1,354,751	$164,415	$4,918,396	$23,732,302
Touchstone Energy (TSE) Home	$2,221,664	$54,805	$3,874,996	$7,470,475
ENERGY STAR® Manufactured Home	$83,457	$359,982	$1,919,519	$1,919,519
Residential Energy Audit	$0	$1,644,147	$0	$659,048
Residential Efficient Lighting	$0	$54,805	$542,569	$1,446,850
Direct Load Control-Residential: AC switches	$0	$1,940,282	$1,171,482	$0
Direct Load Control-Residential: AC Bring Your Own Thermostat	$0	$1,433,989	$1,464,352	$0
Totals	$5,654,673	$5,926,450	$16,754,407	$37,920,139

[4] The participant costs for the CARES Low Income represent the Kentucky Housing share of measure costs. This is included (along with gas savings) in order to calculate the correct TRC for the program.

The projected cost savings for each DSM program are shown below in Table 5-4. Values shown are the benefits in the TRC test. Cost values are the present value of the future stream of costs for that element using a 7 percent discount rate.

Table 5-4
DSM Program Cost Savings

Program		present value, 2019 $ Projected Cost Savings
Button-Up Weatherization		$2,280,417
CARES – Low Income		$2,824,368[5]
Heat Pump Retrofit		$39,198,858
Touchstone Energy (TSE) Home		$15,630,312
ENERGY STAR® Manufactured Home		$4,030,227
Residential Energy Audit		$1,580,018
Residential Efficient Lighting		$4,167,267
Direct Load Control-Residential: AC switches		$5,673,783
Direct Load Control-Residential: AC Bring Your Own Thermostat		$5,673,783
Totals		$81,059,033

The TRC test for the entire portfolio yields a benefit-cost ratio of 1.64.

More details on program costs and cost-effectiveness can be found in the DSM Technical Appendix.

807 KAR 5:058 Section 8(5)(c) Criteria (for example, present value of revenue requirements, capital requirements, environmental impacts, flexibility, diversity) used to screen each resource alternative including demand-side programs, and criteria used to select the final mix of resources presented in the acquisition plan.

Please see pages 6-7 and 13-14 in the DSM technical appendix.

All DSM programs are evaluated based on the standard California tests.

[5] Includes gas cost savings

SECTION 6.0

TRANSMISSION AND DISTRIBUTION PLANNING

SECTION 6.0

TRANSMISSION AND DISTRIBUTION PLANNING

6.1 Introduction

807 KAR 5:058 Section 8(2)(a) The utility shall describe and discuss all options considered for inclusion in the plan including: (a) Improvements to and more efficient utilization of existing utility generation, transmission, and distribution facilities;

Transmission System

Introduction

EKPC's transmission system is geographically located in roughly the eastern two-thirds of Kentucky. The transmission system approaches the borders of Kentucky in the north, east, and south, and stretches to the Interstate 65 corridor in the west. The system is comprised of approximately 2,955 circuit miles of line at voltages of 69, 138, 161, and 345 kV, and includes 74 free-flowing interconnections with neighboring utilities. EKPC's interconnections with neighboring utilities have been established to improve the reliability of the transmission system and to provide access to external generation resources for economic and/or emergency purchases. Table 6-1 on pages 106-108 lists each of EKPC's free-flowing interconnections.

EKPC integrated into the PJM on June 1, 2013 and participates in the PJM markets. As a result, EKPC and PJM closely coordinate transmission planning activities for the EKPC system. EKPC and PJM work together to develop transmission expansion plans to comply with applicable PJM reliability criteria through the PJM transmission planning process. To meet local needs, EKPC designs its transmission system to provide adequate capacity for reliable delivery of EKPC generating resources to its owner-members, and for long-term firm transmission service that has been reserved on the EKPC system. EKPC's transmission planning criteria specify that the system must be designed to meet these projected member demands for simultaneous outages of a transmission facility and a generating unit during peak conditions in summer and winter.

Interconnections

Interconnections have been established with other utilities to increase the reliability of the transmission system and to provide potential access to other economic/emergency generating sources. The interconnections established with other utilities generally have provided stronger sources in specific areas of need within the EKPC system. This avoids the need to construct long, high-voltage transmission lines from the EKPC system and typically reduces EKPC's transmission-system losses.

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

EKPC has established one new interconnection -- with Duke Energy Ohio-Kentucky -- since the last IRP was completed. This new interconnection is between the EKPC and Duke Hebron 69 kV substations. This interconnection provides the needed system support to the electric system in the area, but has minimal power transfer benefits. EKPC is planning two new interconnections, a 69 kV interconnection with LG&E/KU at a new 69 kV switching station in Shelby County (December 2020), and a 161 kV interconnection with TVA at the Fox Hollow substation (December 2021). These new interconnections are needed to improve the reliability of the electric system in the area, and will have minimal power transfer benefits.

Membership in PJM Interconnection, Inc.

EKPC integrated into PJM on June 1, 2013. PJM is an RTO that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. Acting as a neutral, independent party, PJM operates a competitive wholesale electricity market and manages the high-voltage electricity grid to ensure reliability. PJM manages the high-voltage electricity grid to ensure reliability for more than 61 million people. PJM's long-term regional planning process provides a broad, interstate perspective that identifies the most effective and cost-efficient improvements to the grid to ensure reliability and economic benefits on a system wide basis. PJM is registered in the SERC region for the following reliability functions as described in the North American Electric Reliability Corporation (NERC) Reliability Functional Model for PJM Members: Balancing Authority (BA), Interchange Authority (IA), Planning Coordinator (PC), Reliability Coordinator (RC), Resource Planner (RP), Transmission Operator (TOP), Transmission Planner (TP), and the Transmission Service Provider (TSP).

EKPC and PJM coordinate their transmission planning activities for the EKPC system through a bottom-up/top-down approach. EKPC maintains responsibility for planning of the EKPC transmission system to adhere to EKPC's transmission planning criteria. The needs identified by EKPC through this local planning process are provided to PJM for review and approval. Once the need is verified by PJM, PJM then incorporates the local transmission plans into its Regional Transmission Expansion Plan (RTEP). The local plans of EKPC and other PJM member systems are therefore rolled up into the overall regional plan. At the same time, PJM performs all required assessments of the entire Bulk Electric System (BES) for its footprint to ensure performance with its planning criteria. Transmission projects are identified throughout the RTO footprint as needed to address violations of these criteria. These projects are then incorporated into the transmission plans of the applicable local transmission owner, thereby ensuring that these plans are considered in the development of the local transmission plans. PJM thereby ensures that an appropriate transmission expansion plan is developed for the entire region through a single planning process that provides a reliable, efficient, and economical integrated plan. PJM also coordinates its RTEP with neighboring utilities and RTOs, including MISO, LG&E/KU, and TVA to ensure interregional reliability.

Membership in SERC Reliability Corporation (SERC)

EKPC is a member of SERC. The SERC website (www.serc1.org), states that it is "one of seven Regional Entities delegated to perform certain functions from the Electric Reliability Organization (ERO) and is subject to oversight from the FERC. SERC promotes and monitors compliance with mandatory Reliability Standards, assesses seasonal and long-term reliability, monitors the bulk power system (BPS) through system awareness, and educates and trains industry personnel." Owners, operators, and users of the BPS in the SERC footprint cover an area of approximately

560,000 square miles. SERC is one of seven regional entities with delegated authority from NERC; the regional entities and all members of NERC work to safeguard the reliability of the BPSs throughout North America. NERC has been certified by the FERC as the ERO for North America. NERC has established Reliability Standards that the electric utilities operating in North America must adhere to. There are presently 100 Reliability Standards that have been approved by FERC and are therefore in effect. EKPC is required to comply with 46 of these standards based upon its responsibility for various functions. PJM is responsible for 13 other standards on EKPC's behalf based on PJM's registration as the Balancing Authority, Resource Planner, and Transmission Operator. PJM and EKPC have joint compliance responsibilities for 18 Reliability Standards and many additional standards are currently under development. PJM and EKPC continue to identify and refine planning practices that will ensure compliance with these NERC Reliability Standards.

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

EKPC adheres to SERC's guidelines for transmission and generation planning and operations. With all of the SERC members following these guidelines, each owner-member can have a high degree of confidence that the transmission system will be adequate for the normal and emergency (outage) conditions simulated. Participation in SERC enhances the reliability of each owner-member without having to install excess generation and transmission capacity to provide a comparable level of reliability.

Transmission Expansion (2015-2018)

From 2015-2018, EKPC implemented various transmission projects, summarized as follows:

- Eighteen transmission station modifications
    - One 138 kV station modification
    - Two 138 kV circuit switcher additions
    - One 161 kV circuit switcher addition
    - Four 69 kV breaker additions
    - One 161 kV breaker addition
    - One 138 kV breaker addition
    - One 161-69 kV transformer upgrade
    - Five 69 kV station upgrades
    - One 138 kV station upgrade
    - One terminal facilities upgrade
- Re-conductor/rebuild of existing line using larger (lower impedance, higher capacity) conductor
    - 40.76 miles – 69 kV
    - 3.81 miles - 345 kV
- Construction of 13.0 miles of new 69kV transmission lines
- High temperature upgrades of 69 kV transmission lines (67.9 miles)
- High temperature upgrades of 138 kV transmission lines (11.6 miles)
- Addition of one new 69 kV capacitor bank totaling 14.286 MVAR

Construction of new transmission lines within the EKPC system generally has resulted in reduction of system losses.

EKPC has continued to upgrade existing transmission-line conductors in an effort to increase the capacity of the transmission system. EKPC's re-conductor projects typically increase system capacity by 50 percent to 225 percent, depending on the sizes of the installed conductor and the replacement conductor that is used. In addition, by installing larger conductors, less voltage drop is seen on the system, deferring the need to construct new facilities to provide voltage support in an area. Transmission-system losses are also reduced due to the lower impedance of the larger replacement conductors. The amount of loss reduction varies, and is dependent on the hourly power flows on each particular line, but typical expectations for loss reduction range from 250,000 to 400,000 kWh per year when transmission line conductors are upgraded.

The addition of transmission capacitor banks provides better utilization of the existing transmission system by deferring the need for new transmission lines and/or substations. Transmission capacitor banks can also provide some transmission-system loss reductions when energized.

<u>Future Transmission Expansion</u>

Transmission constraints, and the ability to address them in a timely manner, represent important planning considerations for ensuring that peak-load requirements are met reliably. EKPC's Transmission Planning Department resides in our Engineering and Construction Business Unit, and works closely with other groups at EKPC like Power Delivery Operations, Power Delivery Maintenance, and Resource Planning to coordinate activities and address reliability issues. EKPC also seeks input from other external parties, including potential generation developers regarding issues or needs related to the EKPC transmission system. Additionally, the transmission expansion plan for the EKPC system is developed and reviewed through PJM's stakeholder process to ensure the needs of all external stakeholders are being addressed in combination with the needs of EKPC's owner-members on a comparable, non-discriminatory basis.

EKPC's transmission expansion plan includes a combination of new transmission lines and substation facilities and upgrades of existing facilities during the period from 2019 to 2033 to provide an adequate and reliable system for existing and forecasted native load members and existing and future generation resources.

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

EKPC's transmission work plan for the period from 2019 to 2022 is based on detailed engineering analyses, and includes transmission projects that are relatively firm in nature. These projects include the construction of new substations and transmission lines, as well as upgrades of existing substations and transmission lines. These improvements will meet growing member demand, enhance system reliability, and improve the efficiency of the system. Maps of EKPC's existing transmission system and of the EKPC transmission system showing interconnected facilities plus EKPC's planned future facilities are included in Section 11 of this report.

The planned improvements to the EKPC transmission system for the period from 2019 to 2022 are summarized as follows:

- Addition of one new 138-69 kV station
- Addition of a 161 kV station expansion at an existing 69 kV substation
- Upgrade of an existing 138-69 kV transformer
- Addition of two new 69 kV switching stations
- Seven transmission station modifications
    - One 138 kV circuit switcher addition
    - Four 161 kV circuit switcher additions
    - One 161 kV breaker addition
    - One 69 kV breaker addition
- Construction of 1.55 miles of new 69 kV line
- Construction of 0.55 miles of new 138 kV line
- Construction of 0.8 miles of new 161 kV line
- Installation of one new 69 kV capacitor banks (12.0 MVARs total)
- High-temperature upgrades of four 69 kV lines (13.2 miles total)
- High-temperature upgrade of one 138 kV line (9.5 miles total)
- Re-conductor/rebuild of 74.4 miles of 69 kV line
- Decouple one 138 kV double circuit line section
- Upgrade of five 69 kV terminal facilities
- Upgrade of one 138 kV reactor

The analysis used to develop the plan beyond the first four years is not necessarily less detailed than that used to develop the work plan for the first four years. The assumed system conditions are less certain than those used for the first four years of analysis. Many of the projects beyond the first four-year period are conceptual in nature, and are more likely to change in scope and date, or to be cancelled and replaced with a different project. EKPC's 15-year expansion plan for the 2019-2033 period is included as Table 6-2 on page 109 through Table 6-11 on page 114. This 15-year expansion plan includes approximately 1.55 miles of new 69 kV line construction, 0.55 miles of new 138 kV line construction, 4.3 miles of new 161 kV line construction, 116.3 miles of existing line 69 kV re-conductors/rebuilds, 10.6 miles of 69 kV lines rebuilt at 161 kV, 31.3 miles of high-temperature conductor upgrades, and twelve terminal facility upgrades. It also includes the addition of two new transmission stations, two new 69 kV switching stations, the upgrade of two 138-69 kV autotransformers, the addition of a 161-69 kV autotransformer, and the addition or upgrade of facilities at 10 transmission stations. It also includes the addition of 88.54 MVARs of new transmission capacitor bank capability.

The inherent advantages of high-temperature upgrades of existing lines, upgrades of power transformers, and the addition of transmission capacitor banks are mentioned above.

Construction of new transmission lines typically improves net system losses. EKPC expects to see a net overall reduction in system losses as a result of the planned construction of 1.55 miles of new 69 kV line, 0.55 miles of new 138 kV line, and 4.35 miles of new 161 kV line in the 2019-2033 period.

The planned transmission line re-conductors/rebuilds will enhance utilization of the existing transmission system by increasing the capacity of those lines. As discussed earlier, replacing existing conductors with larger conductors will also provide increased voltage support and will reduce system energy losses. Similarly, the planned upgrades of power transformers will provide more efficient system utilization by increasing capacity while reducing voltage drop and system energy losses.

Line terminal facility upgrades increase the effective thermal capacity of a transmission line to meet system needs while eliminating the need for a new line. Similarly, thermal upgrades on power transformer facility terminal equipment increase the effective thermal capacity of the facility to meet system needs while eliminating the need for a new or higher-capacity power transformer.

New switching stations increase system reliability by potentially eliminating thermal (overload) and (low) voltage problems and/or member outages associated with the loss of multiple line segments. Switching stations also increase system operational flexibility.

New transmission substations provide strong sources (of real MW and reactive MVAR power) to the network on the low-voltage side of the new substation. Thus, the new substations provide more efficient access to available support from the existing adjacent higher voltage network.

Generation Related Transmission

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

PJM and EKPC perform studies for transmission requirements for units connected to the EKPC transmission system after an official request has been submitted per PJM requirements. Only those projects necessary for firm (committed) generation resources (existing and future) are identified in EKPC's transmission expansion plan.

EKPC's generation expansion plan included in this IRP does not identify new generation additions during the planning period. Therefore, no assumptions regarding transmission facilities needed for future generation expansion within the EKPC system have been made for this IRP.

Import Capability

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

EKPC designs its transmission system to be capable of importing at least 500MW from regions either north or south of Kentucky. Import studies indicate that EKPC's import capability from the LG&E/KU interface ranges up to 850MW, depending on the time period being evaluated. EKPC imported up to 1,628MW in 2018 from its PJM interface, indicating that the import capability is in that range, even during winter peak conditions. Finally, the import capability from the TVA interface ranges up to 450 MW, depending on the time period.

EKPC's membership in PJM ensures an adequate amount of transmission from the PJM market for import capability. As part of PJM's planning process, a load deliverability assessment is performed annually using a 90/10 load forecast (i.e., the load level with a 90 percent probability of the actual peak demand being lower than the forecasted value and a 10 percent probability of the actual peak demand being higher) to ensure that the various zones within PJM (including EKPC) can meet extreme demand levels with external resources if necessary. This helps ensure that adequate transmission infrastructure is available to utilize the PJM market efficiently and to avoid the need for an excessive amount of generation reserves within the RTO.

Although these import studies indicate that during many periods EKPC can import large quantities of power, real-time market and transmission-system conditions may result in system limitations that are significantly different from those predicted in these studies. Available Transfer Capacity (ATC) calculations are performed by Regional Transmission Organizations (such as PJM and MISO), Independent Transmission Organizations (such as the LG&E/KU ITO) and Reliability Coordinators (such as TVA). These results are coordinated to ensure that the lowest value for a particular path is set as the ATC. Such studies utilize updated data for transmission and generation outages, market transactions, and system load to predict expected system flows. Therefore, it is difficult to predict the availability of transmission capacity for imports into the EKPC system. EKPC may pursue procurement of additional amounts of transmission from other supply sources in advance of peak seasons to ensure adequate import capability.

EKPC does not typically experience import and export transmission limitations on an operational basis due to limited ATC. EKPC's membership in PJM is one of the primary reasons for the elimination of historical constraints on imports and exports.

Extreme Weather Performance

EKPC annually performs an assessment of its transmission system for both summer and winter peak conditions. EKPC evaluates its system using two load forecasts – a 50/50 probability forecast and a 90/10 probability forecast. When evaluating system performance using a 50/50 forecast, contingency analysis is also performed on the system to ensure that the system is designed to provide adequate service at this load level even with a transmission facility and/or generator out of service. EKPC presently does not perform a contingency analysis when using the 90/10 probability forecast. EKPC considers an extreme weather event equivalent to a contingency, and therefore does not design its system for a transmission or generator outage in conjunction with this weather event. EKPC did not identify any constraints on the transmission system as part of the 2018 extreme weather analysis.

Distribution System

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

EKPC delivery points were improved in the 2015-2018 period through the construction of new substations, as well as through upgrades of existing substations, to meet growing member demand in certain areas, enhance reliability and improve the efficiency of the system.

From 2015-2018, EKPC implemented various distribution substation projects, summarized as follows:

- Construction of six new 20 MVA distribution substations
- Construction of one new 25 MVA distribution substation
- Addition of three new 20 MVA distribution transformers at existing stations
- Upgrade of one distribution transformer to 10 MVA
- Upgrades of nine existing distribution substations to 20 MVA
- Upgrade of one existing distribution substation to 25 MVA

New distribution delivery points enhance the utilization of the existing system by providing a new injection point into the existing distribution system. This will generally provide improved system energy losses, as well as increased voltage support. Distribution substation transformer additions and upgrades of existing distribution substation transformers also improve system efficiency by increasing capacity at an existing facility rather than building new facilities. These additions/upgrades reduce system impedance at the substation, which improves voltage drop and reduces energy losses. In addition to the substation improvements discussed above, EKPC also worked with its owner-members on various power factor improvement projects at the distribution level to increase available substation capacity, defer transmission construction projects, and reduce system losses. EKPC and its owner-members improved the power factor at several substations in this period.

Further improvements are planned for EKPC's distribution substation delivery points for the 2019-2022 period. These improvements include the construction of new distribution substations, as well as upgrades of existing substations. These improvements will meet growing member demand in certain areas, enhance system reliability, and improve the efficiency of the system.

The planned improvements to EKPC distribution substations for the 2019-2022 period are summarized as follows:

- Construction of seven new 20 MVA distribution substations
- Addition of three new 20 MVA distribution transformers at existing substations
- Upgrades of eight existing distribution substations to 20 MVA
- Upgrades of one existing distribution substation to 25 MVA

These distribution substation enhancements will improve system efficiency and utilization as described above.

In addition to these substation improvements, EKPC and its owner-members will continue to coordinate power factor improvement projects at the distribution level to increase available substation capacity, defer transmission construction projects, and reduce system losses. EKPC annually updates its power factor correction study to identify the substations which will provide the largest benefits for system utilization and efficiency through power factor correction. EKPC and its owner-members plan to continue to improve power factor at these locations to realize these benefits whenever feasible.

EKPC's 15-year expansion plan for the 2019-2033 period included as Table 6-5 on page 109 through Table 6-11 on page 114.

Table 6-1 (continued on next page)
EKPC Free-Flowing Interconnection Capability

No.	From (EKPC)	To	Voltage kV	Ratings in MVA			
				Summer		Winter	
				Normal	Emergency	Normal	Emergency
AEP							
1	Argentum	Millbrook Park	138	176	176	176	176
2	Argentum	Grays Branch	69	42	44	53	54
3	Falcon	Falcon	69	36	36	36	36
4	Helechawa	Lee City	69	54	54	54	54
5	Leon	Leon	69	55	71	73	85
6	Morgan County	Morgan County	69	72	72	72	72
7	Thelma	Thelma	69	69	74	83	83
AEP Total:				504	527	547	560
DP&L							
8	Spurlock	Stuart	345	1255	1374	1255	1374
DP&L Total:				1255	1374	1255	1374
Duke Energy-OHIO/KENTUCKY (DEOK)							
9	Boone	Buffington	138	247	274	296	328
10	Hebron	Hebron	138	96	117	121	139
11	Spurlock	Meldahl Dam	345	1274	1421	1648	1894
12	Webster Road	Webster Road	138	96	117	121	139
13	Hebron	Hebron	69	89	98	128	134
DEOK Total:				1713	1929	2186	2500
LG&E/KU							
14	Avon	Loudon Avenue	138	224	277	286	287
15	Baker Lane	Baker Lane Tap	138	96	117	121	139
16	Beattyville	Beattyville	69	101	124	149	163
17	Beattyville	Beattyville Tap	161-69	58	66	72	72
18	Beattyville-Powell Co.	Delvinta	161	167	204	167	227
19	Bonnieville	Bonnieville	69-138	89	109	112	129
20	Boonesboro North Tap	Boonesboro North	69-138	129	160	192	195
21	Bracken Co.	Carntown	69	41	41	72	72
22	Bracken Co.	Sharon	69	35	35	65	65
23	Cedar Grove Ind. Park	Blue Lick	161	289	289	380	380
24	Central Hardin	Hardin County	138	224	277	287	287
25	Central Hardin	Blackbranch	138	245	303	364	400
26	Clay Village	Clay Village Tap	69	35	39	47	47
27	Cooper	Elihu	161	235	289	279	305
28	Crooksville Jct.	Fawkes	69	89	98	128	134

No.	From (EKPC)	To	Voltage kV	Ratings in MVA			
				Summer		Winter	
				Normal	Emergency	Normal	Emergency
29	East Bardstown	Bardstown Ind.	69	53	66	81	89
30	Fawkes	Fawkes	138	229	296	287	370
31	Fawkes	Fawkes Tap	138	229	284	355	387
32	Gallatin Co.	Ghent	138	229	255	287	287
33	Garrard Co.	Lancaster	69	72	101	72	101
34	Goldbug	Wofford	69	42	46	60	63
35	Green Co.	Greensburg	69	53	66	81	87
36	Green Hall Jct.	Delvinta	161	178	204	223	227
37	Hodgenville	Hodgenville	69	53	60	81	89
38	Hodgenville	New Haven	69	49	49	81	89
39	Kargle	Elizabethtown	69	57	63	82	86
40	Laurel Co.	Hopewell	69	72	76	86	89
41	Liberty Church Tap	Farley	69	57	63	72	72
42	Marion Co.	Lebanon	161-138	192	220	234	250
43	Murphysville	Kenton	69	53	66	66	68
44	Murphysville	Sardis	69	41	50	60	66
45	Nelson Co.	Nelson Co Tap	69-138	144	152	172	178
46	North London	North London	69	73	76	86	89
47	North Springfield	Springfield	69	49	54	59	61
48	Owen Co.	Bromley	69	57	57	97	97
49	Owen Co.	Owen Co. Tap	69-138	139	152	172	178
50	Paris	Paris Tap	138-69	129	160	191	195
51	Penn	Scott Co.	69	56	56	82	82
52	Pittsburg Tap	Pittsburg	161-69	116	120	120	120
53	Renaker	Cynthiana Sw.	69	53	66	81	89
54	Rogersville Jct.	Rogersville	69	114	127	143	143
55	Rowan Co.	Rodburn	138	143	194	143	203
56	Sewellton	Union Underwear	69	41	41	75	75
57	Shelby Co.	Shelby Co. Tap	69	89	98	122	126
58	Somerset	Ferguson South	69	89	89	132	132
59	Somerset	Somerset South	69	56	56	78	82
60	South Anderson (624)	Bonds Mill (644)	69	89	98	128	134
61	South Anderson (634)	Bonds Mill (634)	69	89	98	128	134
62	Spurlock	Kenton	138	259	281	286	337
63	Stephensburg	Eastview	69	49	49	64	66
64	Taylor Co.	Taylor Co.	161-69	93	105	120	124
65	Tharp Jct.	Elizabethtown	69	89	98	128	134
66	Union City	Lake Reba Tap	138	245	284	364	387
67	West Garrard	West Garrard	345	1260	1403	1589	1624
LG&E/KU Total:				7237	8307	9489	10112
TVA							
68	McCreary Co.	Jellico	161	197	197	281	281
69	McCreary Co.	Wayne Co.	161	197	197	281	281
70	McCreary Co.	Winfield	161	313	313	399	399
71	Russell Co. Tap	Wolf Creek	161	267	298	335	335

No.	From (EKPC)	To	Voltage kV	Ratings in MVA			
				Summer		Winter	
				Normal	Emergency	Normal	Emergency
72	Summer Shade	Summer Shade	161	267	298	387	406
73	Summer Shade Tap	Summer Shade	161	207	247	259	279
74	Wayne Co.	Wayne Co.	161	118	122	118	122
TVA Total:				1566	1672	2060	2103
Grand Total:				12275	13809	15537	16649

Table 6-2

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2019 – 2033)	
A. New Transmission Lines	**Needed In-Service Date**
Loop the existing Dale-JK Smith 138 kV line section into the new Hunt 138-69 kV transmission substation via two new 138 kV line additions (0.55 miles).	12/2019
Construct a new North Shelby-Bekaert 69 kV line section using 556 ACSR/TW (1.55 miles)	12/2020
Construct new Fox Hollow-Fox Hollow Jct 161 kV line section using 795 MCM ACSR (0.8 miles)	12/2021
Construct a new Fox Hollow – Patton Road Jct 161 kV line section using 795 MCM ACSR (3.34 miles)	12/2032
Construct a new Summer Shade – Summer Shade Jct 161 kV line section using 795 MCM ACSR (0.15 miles)	12/2032

Table 6-3

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2019 – 2033)	
B. New Transmission Substations & Transmission Substation Additions **Project Description**	**Needed In-Service Date**
Construct a new Hunt 138-69 kV transmission substation including the addition of a 138-69 kV 100 MVA autotransformer	12/2019
Add a new 161 kV station, including a new 161-69 kV 150 MVA autotransformer, at Fox Hollow substation	12/2021
Add a second 161-69 kV autotransformer, including any associated bus work, at Bullitt County substation.	6/2028

Table 6-4

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2019– 2033)	
C. New Transmission Switching Stations **Project Description**	**Needed In-Service Date**
Construct a new Monticello 69 kV switching station.	12/2020
Construct a new Rineyville Jct. 69 kV switching station.	12/2021

Table 6-5

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2019 – 2033)	
D. Transmission Transformer Upgrades **Project Description**	**Needed In-Service Date**
Upgrade the existing Skaggs 138-69 kV 100 MVA autotransformer to 150 MVA	11/2019
Upgrade the existing West Berea 138-69 kV 100 MVA autotransformer to 150 MVA	12/2032

Table 6-6

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2019 – 2033)	
E. Terminal Facility Upgrades & Additions **Project Description**	**Needed In-Service Date**
Install a 138 kV circuit switcher addition on the 138-69 kV autotransformer at Powell County	6/2019
Install a 161 kV circuit switcher addition on the 161-138 kV autotransformer at Marion County	12/2019
Upgrade disconnect switch S408-605 associated with Russell Co-KU Russell Springs Tap 69 kV line section to 1200 Amp	12/2019
Install a 161 kV circuit switcher addition on the 161-69 kV autotransformer and install a 161 kV breaker addition on the TVA tie line at Summer Shade	12/2019
Install a 161 kV circuit switcher addition on the 161-69 kV autotransformer at Tyner	12/2019
Upgrade distance relay associated with Glendale-Hodgensville 69 kV line section to at least 90 MVA Winter LTE	6/2020
Upgrade disconnect switch W45-643 associated with Green Co 161-69 kV auto transformer to 2000 Amp	6/2020
Install a 161 kV circuit switcher addition on the 161-69 kV autotransformer at Green County	12/2020
Upgrade jumper associated with Green Co - KU Greensburg 69 kV line from 4/0 to 750 MCM CU	6/2020
Install a new 69 kV breaker on the Holloway line exit at Baker Lane	6/2020
Upgrade distance relay associated with Stephensburg-Glendale 69 kV line section to at least 100 MVA Winter LTE	6/2020
Upgrade the 138 kV reactor associated with the Spurlock – Kenton line section at Spurlock to 6.5 % 1600 Amp	6/2021
Upgrade CT associated with Clay Village - KU Clay Village Tap 69 kV line section to 600A; at least 75 MVA Winter LTE	12/2027
Upgrade distance relay associated with Clay Village - KU Clay Village Tap 69 kV line section to at least 75 MVA Winter LTE	12/2027
Adjust Summer Shade 69 kV capacitor bank setting to 1.010 p.u.	12/2027
Upgrade the 69 kV bus and jumpers at Denny substation.	6/2032
Upgrade CT associated with East Bardstown - KU East Bardstown 69 kV line section to 1200A; at least 100 MVA Winter LTE	12/2032
Install a 161 kV breaker on the Fox Hollow line exit at Summer Shade	12/2032
Upgrade overcurrent relay associated with the Powell County 138-69 kV autotransformer to at least 139 MVA	12/2032
Install a 161 kV breaker on the Summer Shade line exit at Fox Hollow	12/2032
Upgrade distance relay associated with Wayne County – Wayne County KY 161 kV line section to at least 167 MVA Winter LTE	12/2032
Upgrade overcurrent relay associated with the West Berea 138-69 kV autotransformer to at least 139 MVA	12/2032

Table 6-7

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2019 – 2033)	
F. Transmission Line Re-conductor/Rebuilds Project Description	**Needed In-Service Date**
Rebuild the existing 2/0 ACSR Elizabethtown-Nelson County 69 kV line section (14.50 miles) using 556.5 MCM ACSR/TW conductor.	6/2019
Decouple the double-circuited Spurlock- Maysville Industrial Tap 138 kV & Spurlock-Flemingsburg 138 kV line sections.	6/2019
Rebuild the existing 1/0 ACSR Stephensburg-Hodgenville 69 kV line section (17.80 miles) using 556.5 MCM ACSR/TW conductor.	6/2020
Rebuild the existing 3/0 ACSR Leon-Airport Road-Mazie 69 kV line sections (19.40 miles) using 556.5 MCM ACSR/TW conductor.	8/2020
Rebuild the existing 3/0 ACSR Monticello-Homestead 69 kV line section (1.96 miles) using 556.5 MCM ACSR/TW conductor.	12/2020
Rebuild the existing 3/0 ACSR McCreary Co Jct - KU Wofford 69 kV line section (20.7 miles) using 795 MCM ACSR conductor.	12/2022
Re-conductor the Brodhead-Three Links Jct. 69 kV line section (8.2 miles) using 556.5 MCM ACTW conductor.	12/2026
Re-conductor the existing 556.5 MCM ACSR/TW Tharp Tap-KU Elizabethtown 69kV line section, including the double circuit portion, (2.11 miles) to 795 MCM ACSR conductor.	12/2028
Re-conductor the existing 4/0 ACSR Boone – Williamstown 69 kV line section (28.5miles) to 556.5 MCM ACSR/ TW conductor.	12/2024
Re-conductor the existing 266.8 MCM ACSR Davis - Fayette 69 kV line section (3.15 miles) to 556.5 MCM ACSR/TW conductor.	12/2029
Convert the existing Summer Shade Jct to Patton Road Jct 69 kV line section to 161 kV (10.6 miles)	12/2032

Table 6-8

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2019 – 2033)	
G. Transmission Line High Temperature Upgrades **Project Description**	**Needed In-Service Date**
Increase MOT of the Cooper - Somerset #1 & #2 69 kV line section (3.4 miles) to 266°F (LTE of 248°F)	6/2019
Increase the MOT of Summer Shade-Edmonton-JB Galloway Jct 69 kV line section (7.7 miles) to 212°F.	6/2019
Increase the MOT of the J.K. Smith-Dale 138 kV line section (9.5 miles) to 275°F.	12/2019
Increase the MOT of Liberty Church Tap-Bacon Creek Tap 69 kV line section (2.1 miles) 266 MCM conductor to 266°F	6/2020
Increase the MOT of Plumville-Rectorville 69 kV line section (2.9 miles) to 212°F (LTE 185°F)	6/2032
Increase the MOT of Davis – Nicholasville 69 kV line section (4.0 miles) to 284°F (266°F. LTE).	6/2032
Increase the MOT of Elizabethtown – Tharp Tap 69 kV line section (1.7 miles) 266.8 MCM conductor to 302°F (284°F LTE).	12/2032

Table 6-9

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2019 – 2033)	
H. Capacitor Bank Additions **Project Description**	**Needed In-Service Date**
Install a new 12.0 MVAR, 69 kV capacitor bank at Bullitt County substation	6/2019
Install a new 25.511 MVAR, 69 kV capacitor bank at Liberty Junction substation	12/2023
Install a new 15.307 MVAR, 69 kV capacitor bank at Nelson County substation	6/2024
Resize the Sideview 69 kV capacitor bank from 6.12 MVAR to 10.204 MVAR.	12/2024
Install a new 16.327 MVAR, 69 kV capacitor bank at Owen County substation	12/2025
Install a new 15.31 MVAR, 69 kV capacitor bank at South Anderson substation	12/2032

Table 6-10

EKPC FOUR-YEAR DISTRIBUTION EXPANSION SCHEDULE (2019 – 2022)	
I. New Distribution Substations and associated Tap Lines Project Description	**Needed In-Service Date**
Construct a new Asahi #2 69-12.5 kV, 12/16/20 MVA Substation and associated 69 kV tap line (0.1 mile)	6/2019
Construct a new Contown 69-12.5 KV 12/16/20 MVA substation between Phil and Liberty Jct and associated 69 kV tap line (0.2 Miles).	6/2019
Construct a new Sharkey #2 138-25 kV 12/16/20 MVA Substation and associated 138 kV tap line (0.1 mile)	11/2019
Construct a new Duncannon Lane 69-12.5 kV 12/16/20 MVA substation between KU Fawkes-Crooksville. Tap point 7.5 mile from KU Fawkes towards Crooksville and associated 69 KV tap line (1.0 miles).	7/2020
Construct a new White Oak 69-12.5 kV 12/16/20 MVA Distribution Substation and Tap including retirement of the existing South Fork distribution substation.	12/2020
Construct a new Griffin 138-12.5 kV 12/16/20 MVA substation on the Stanley Parker-Spurlock 138 kV line section. Tap point will be 3.6 miles from this line section, including retirement of the existing Griffin substation.	12/2020
Construct a new Pekin Pike 69-12.5 kV, 12/16/20 MVA substation, tapping the Baker Ln-Holloway Jct 69 KV line section (6.4 miles).	5/2021
Construct a new Broughtontown 69-25 kV,12/16/20 MVA substation, tapping the EKPC Highland - Tommy Gooch 69 kV line section (7.4 miles).	12/2021
Construct a new MBUSA #2 69-12.5 kV, 12/16/20 MVA Substation and associated 69 kV tap line (0.1 mile)	6/2022
Construct a new Mineola Pike 138-12.5 kV 12/16/20 MVA base substation and associated 138 kV tap line to the DEOK 138 kV Constance substation (0.9 mile)	12/2022

Table 6-11

EKPC FOUR-YEAR DISTRIBUTION EXPANSION SCHEDULE (2019 – 2022)	
J. Distribution Substation Upgrades **Project Description**	**Needed In-Service Date**
Rebuild and upgrade the existing Floyd 69-12.5 kV 11.2/14 MVA distribution substation to 12/16/20 MVA	12/2019
Rebuild and upgrade the existing Summersville 69-12.5 kV 11.2/14 MVA distribution substation to 12/16/20 MVA	12/2019
Rebuild and upgrade the existing Lancaster 69-12.5 kV 11.2/14 MVA distribution substation to 12/16/20 MVA, Including Tap Rebuild	12/2020
Rebuild and upgrade the existing McKinney Corner 69-12.5 kV 6.0 MVA distribution substation to 12/16/20 MVA	12/2020
Rebuild and upgrade the existing Newfoundland 69-12.5 kV 11.2/14 MVA distribution substation to 12/16/20 MVA	12/2020
Upgrade the existing West Mt Washington 69-12.5 kV 11.2/14 MVA distribution transformer to 15/20/25 MVA	6/2021
Rebuild and upgrade the existing Highland 69-25 kV 11.2/14 MVA distribution substation to 12/16/20 MVA, including Tap Rebuild	12/2022
Rebuild and upgrade the existing Lees Lick 69-12.5 kV 11.2/14 MVA distribution substation to 12/16/20 MVA	12/2022
Rebuild and upgrade the existing Rockholds 69-12.5 kV 11.2/14 MVA distribution substation to 12/16/20 MVA	12/2022

SECTION 7.0

PLANS FOR EXISTING GENERATING UNITS

SECTION 7.0

PLANS FOR EXISTING GENERATING UNITS

7.1

Existing Generation

Maintenance management for existing generation assets is vital to keep them operating reliably, productively, efficiently, and cost effectively. EKPC has developed a long-range plan to satisfy maintenance needs for each of its existing generating units, which is discussed in the following subsection. EKPC completed the shutdown of Dale Power Station on April 15, 2016. Please also see the discussion in Section 1.4, Power Supply Actions, in the Executive Summary of this IRP.

7.2

Maintenance of Existing EKPC Generating Units

Current facilities were brought on line at Cooper Power Station in 1965-69, and Spurlock Power Station in 1977-81 for Units 1 and 2, the Gilbert Unit in 2005, and Unit 4 in 2009. J.K. Smith Station combustion turbines were placed in operation in 1999, 2001, 2005, and 2010. Bluegrass was purchased by EKPC on December 29, 2015 and the three units at that site started operating in 2002. Each of EKPC's generating plants was state-of-the-art at the time of their construction and was designed to operate under conditions existing at that time. The continued reliable operation of these plants requires both normal maintenance and systematic review of changing conditions.

EKPC has a formal maintenance planning process that seeks to identify needed major projects on a five-year horizon. A plan for maintenance is continuously developed following the review of numerous plant subsystems, assimilation of operational data, and review of past operating history. Through proper planning and implementation, EKPC effectively manages operations, while meeting environmental compliance regulations, to provide reliable, economical electric service to its owner-members and their retail members.

Methodology for Five-Year Major Projects Plan

The areas addressed in the development of the current plan include safety, generating plant performance, operation, maintenance, and regulatory compliance. On an annual cycle, the prior plan is reviewed and evaluated by plant operations staff, engineers, and environmental experts, to develop the newest plan. Each individual major project scheduled in the plan is further developed, reviewed and justified prior to requesting approval from the EKPC Board of Directors for implementation of the project. Prior to requesting this approval, an analysis is conducted taking into account costs, timing, and benefits of the project, to ensure that completion of the proposed project is the best decision for EKPC. Justifications are developed based on the economic analysis, risk, and other benefits such as safety or regulatory requirements. Depending on the cost of the project, the economic analysis results and justification are then presented to the Board along with a request to approve the project. Smaller projects follow the same basic path, but go through EKPC's normal internal approval process.

Current Five-Year Major Projects Study

This plan covers the period from 2019 through 2023. Table 7-1 through Table 7-5 on pages 117 – 129 lists the major projects planned for each plant during the five-year period.

Table 7-1
($100,000 and Above)
Bluegrass Station

Description	Operating Unit	Date
Hot Gas Path Inspection	OC00	2019
Hot Gas Path Inspection	OC03	2019
Bluegrass Dual Fuel Addition	OC01-03	2019
Torque Converter Overhaul	OC01	2019
CT Outlet Expansion Joints- Units 1-3	OC00	2019
Inlet Strut Modification- Units 1-3	OC00	2019
Hot Gas Path Inspection	OC01	2020
Bluegrass Dual Fuel Addition	OC01-03	2020
Paint Unit No. 3 Structure	OC00	2020
Torque Converter Overhaul	OC02	2020
Bluegrass Dual Fuel Addition	OC01-03	2021
Torque Converter Overhaul	OC03	2021
Bluegrass Hot Gas Path Inspection	OC02	2022
OC00 - Common		
OC01 - Bluegrass 1		
OC02 - Bluegrass 2		
OC03 - Bluegrass 3		

Table 7-2
($100,000 and Above)
Cooper Power Station

Description	Operating Unit	Date
High Energy Piping Assessment	CP02	2019
New Power Feed to Unit 2 Pulverizer	CP02	2019
Cooper Air Heater Bypass Duct	CP01	2019
Bottom Ash PLC Repl	CP01	2019
Bottom Ash PLC Repl	CP02	2019
PCM HVAC replacement	CP22	2019
Mechanical Overhaul Turbine includes turbine valves	CP01	2019
Structural Steel Painting	CP00	2020
Replace Turbine Bay Lights+A343	CP00	2020
Total Plant Drain and Water Systems	CP00	2020
High Energy Piping Assessment	CP01	2020
Overhaul 1B Boiler Feed Pump Fluid Drive	CP00	2020
Subchain Hydr Tensioning Assembly	CP02	2020
2A Circulating water pump rebuild	CP02	2020
General Service U1 relay upgrade	CP01	2020
Boiler Condition Assessment	CP01	2021
Mechanical Overhaul Turbine includes turbine valves	CP02	2022
Boiler Condition Assessment	CP02	2022
High Energy Piping Assessment	CP02	2023
CP00 - Common		
CP01 - Cooper 1		
CP02 - Cooper 2		

Table 7-3
($100,000 and Above)
Spurlock Power Station

Description	Operating Unit	Date
Removal And Replacement Of Top 2" Of Existing Blacktop	SP00	2019
Maintenance Shop Floor Coating	SP00	2019
Clean & Inspect River Intake	SP00	2019
Clean & Inspect Well Pumps	SP00	2019
Recoat SCU Tank	SP00	2019
Boiler Makeup Water System Capacity Upgrades - Phase 1	SP00	2019
Water Services Building Piping Replacement	SP00	2019
Overhaul (4) Pulverizers	SP01	2019
High Energy Piping Assessment	SP01	2019
Outage Boiler Inspection	SP01	2019
Outage Boiler Repairs	SP01	2019
Expansion Joint Repairs	SP01	2019
1B Boiler Feed Pump Overhaul	SP01	2019
Isolation Dampers on pulverizers	SP01	2019
Unit 1 and unit 2 Turbine Lube Oil Centrifuge Replacement	SP00	2019
Pulverizer Overhauls	SP02	2019
Rebuild pulverizer journals (3)	SP02	2019
Outage Boiler Inspection	SP02	2019
Outage Boiler Repairs	SP02	2019
2B BWCP Replacement	SP02	2019
Expansion Joint Repairs	SP02	2019
High Energy Piping	SP02	2019
2C Pulverizer gearbox rebuild	SP02	2019
Air Heater support and guide bearings	SP02	2019
Control Upgrade	SP02	2019
Outage Boiler & Airheater Repair	SP03	2019
Outage Boiler & Airheater Inspection	SP03	2019
CA-Pro high energy piping inspections	SP03	2019
3B Voith drive replacement	SP03	2019
Replace "Y" fuel feed pipes	SP03	2019
Motor Control Center Retrofit	SP03	2019
Outage Boiler & Airheater Repair	SP04	2019
Outage Boiler & Airheater Inspection	SP04	2019

Table 7-3 (continued)
($100,000 and Above)
Spurlock Power Station

Description	Operating Unit	Date
Robotic UT Inspection	SP04	2019
4B Feed Pump volute replacement	SP04	2019
CA-Pro high energy piping inspections	SP04	2019
ID, PA & SA Motor Overhaul	SP04	2019
SH & RH outlet header inspection	SP04	2019
U4 riser clamp inspection	SP04	2019
Replace Vortex Finders	SP04	2019
Refractory	SP03	2019
Boiler Bed nozzles (qty 430)	SP03	2019
Refractory	SP04	2019
Rebuild Limestone Mill Journals	SP04	2019
Boiler Bed nozzles (qty 1,129)	SP04	2019
Air Heater Module Replacement	SP04	2019
Outage- Precipitator Inspection And Repairs	SP04	2019
Replace Kirk Keys	SP04	2019
Replace TR Cables	SP04	2019
Outage- Precipitator Inspection And Repairs	SP02	2019
Replace TR Cables	SP02	2019
Filter bag Replacement	SP03	2019
Pulse valve replacement	SP03	2019
Pulse valve replacement	SP04	2019
Inspect & Repair Cells	SP00	2019
Upgrade Unloaded Barge Mooring Cells	SP00	2019
Upgrade Loaded Barge Mooring Cells	SP00	2019
Barge Unloader Bulk Lube Oil System	SP00	2019
Digging Ladder on CBU- Shaft removal	SP00	2019
Overhaul Crusher U1	SP01	2019
Replace Flights on SR2	SP01	2019
Overhaul Crusher 3&4	SP02	2019
Overhaul U4 Crushers	SP04	2019
Vac Truck Dump Station Clean Out & FGD Removal from Ash Pond & Landfilling	SP00	2019
Rebuild Scrubber Limestone Silo	SP20	2019
B Ball Mill Liner	SP20	2019

Table 7-3 (continued)
($100,000 and Above)
Spurlock Power Station

Description	Operating Unit	Date
WESP SIRS Clean/Inspect/Repair	SP21	2019
Scrubber Inlet Duct Repairs	SP21	2019
Paint/Recoat Top 150 ft of new U1 Chimney	SP21	2019
Oxidation Air Spray Headers	SP21	2019
WESP SIRS Clean/Inspect/Repair	SP22	2019
Turbine Valves	SP01	2019
Unit 1 Circulating Cooling Line Repairs at Condenser	SP01	2019
Repair/Replace CT Division Walls	SP02	2019
Condensor Expansion Joint Repl	SP02	2019
Cooling Tower Wetted Area Structure Repl	SP02	2019
Coating Replacement	SP02	2019
Cooling Tower Motor Control Repl	SP03	2019
Turbine Seals- Efficiency Upgrade	SP04	2019
Turbine Overhaul	SP04	2019
Generator Rewind	SP04	2019
Spurlock Backup Limestone Conveyor and TDF/Alternate Fuel Feeder	SP00	2019
Spurlock CCR/ELG Compliance WMB Pond	SP01 / SP02	2019
Spurlock CCR/ELG Compliance WMB Pond Chemical Feed	SP01 / SP03	2019
Spurlock CCR/ELG NIDS	SP03 / SP04	2019
Spurlock CCR/ELG WWT/BOP	SP01 / SP02	2019
Spurlock Coal Pile Runoff Pond Supplemental Storage	SP00	2019
Spurlock Landfill - Area D Phase 1 Construction	SP00	2019
Spurlock Landfill Area D Construction - Ponds and Stream Mitigation	SP00	2019
Spurlock NIDS Rotary Feeders	SP03	2019
Spurlock Plant CO2 System Replacement	SP00	2019
Spurlock Remote Fast Degas System	SP00	2019
Spurlock Transfer Tower 2 Bypass Chute	SP00	2019
Spurlock Unit 1 Absorber Spray Header Replacement	SP00	2019
Spurlock Unit 2 Absorber Spray Header Replacement	SP02	2019
Spurlock Unit 2 Cooling Twr Battery Bank	SP02	2019
Spurlock Unit 2 Feedwater Heater No. 5	SP02	2019
Spurlock Unit 2 Feedwater Heater No. 6	SP02	2019
Spurlock Unit 2 Feedwater Heater No. 7	SP02	2019

Table 7-3 (continued)
($100,000 and Above)
Spurlock Power Station

Description	Operating Unit	Date
Spurlock Unit 2 Pulverizer Cranes	SP02	2019
Spurlock Unit 3 Baghouse (Liner)	SP03	2019
Spurlock Unit 4 Baghouse (Liner)	SP04	2019
Spurlock Units 1 and 2 CCR/ELG Compliance	SP01 / SP02	2019
Unit 1 SCR Painting	SP00	2020
Paint Areas On North Side Of Boiler Building	SP00	2020
Unit 2 SCR & Precip Painting (Eng)	SP02	2020
Unit 1 Precip/Id Fan Platform Painting	SP01	2020
Clean & Inspect River Intake	SP00	2020
Clean & Inspect Well Pumps	SP00	2020
Water Services Building Piping Replacement	SP00	2020
Diesel Fire Pump Motor Replacement	SP00	2020
Unit 2 Elevator Overhaul	SP02	2020
Replace original section of underground fuel oil piping.	SP00	2020
Overhaul (4) Pulverizers	SP01	2020
High Energy Piping Assessment	SP01	2020
Outage Boiler Inspection	SP01	2020
Outage Boiler Repairs	SP01	2020
Boiler Chemical Clean	SP01	2020
Expansion Joint Repairs	SP01	2020
1A Boiler Feed Pump Overhaul	SP01	2020
Spurlock CCR/ELG Compliance WMB Pond	SP01 / SP02	2020
Spurlock CCR/ELG Compliance WMB Pond Chemical Feed	SP01 / SP02	2020
Spurlock CCR/ELG NIDS	SP03 / SP04	2020
Spurlock CCR/ELG WWT/BOP	SP01 / SP02	2020
Spurlock Coal Pile Runoff Pond Supplemental Storage	SP00	2020
Spurlock Landfill - Area C Phase 5	SP00	2020
Spurlock Plant CO2 System Replacement	SP00	2020
Spurlock Remote Fast Degas System	SP00	2020
Spurlock Unit 1 Absorber Spray Header Replacement	SP01	2020
Spurlock Unit 2 Absorber Spray Header Replacement	SP02	2020
Spurlock Unit 2 Feedwater Heater No. 5	SP02	2020
Spurlock Unit 2 Feedwater Heater No. 6	SP02	2020

Table 7-3 (continued)
($100,000 and Above)
Spurlock Power Station

Description	Operating Unit	Date
Boiler Penthouse Casing replacement 3 of 3	SP01	2020
Penthouse insulation work	SP01	2020
Pulverizer Overhauls	SP02	2020
Rebuild pulverizer journals (3)	SP02	2020
OUTAGE BOILER INSPECTION	SP02	2020
Outage Boiler Repairs	SP02	2020
2B BWCP Replacement	SP02	2020
EXPANSION JOINT REPAIRS	SP02	2020
High Energy Piping	SP02	2020
2C Pulverizer gearbox rebuild	SP02	2020
Economizer Outlet duct replacement	SP02	2020
2B ID Fan Rotor	SP02	2020
2A Boiler Feed Pump rebuild	SP02	2020
Penthouse cooling blowers	SP02	2020
Outage Boiler & Airheater Repair	SP03	2020
Outage Boiler & Airheater Inspection	SP03	2020
Robotic UT Inspection	SP03	2020
CA-Pro high energy piping inspections	SP03	2020
SH panel replacement	SP03	2020
Motor Control Center Retrofit	SP03	2020
Outage Boiler & Airheater Repair	SP04	2020
Outage Boiler & Airheater Inspection	SP04	2020
Robotic UT Inspection	SP04	2020
4B voith drive replacement	SP04	2020
CA-Pro high energy piping inspections	SP04	2020
Refractory	SP03	2020
REBUILD LIMESTONE MILL JOURNALS	SP03	2020
Refractory	SP04	2020
REBUILD LIMESTONE MILL JOURNALS	SP04	2020
OUTAGE- PRECIPITATOR INSPECTION AND REPAIRS	SP04	2020
REPLACE TR CABLES	SP04	2020
OUTAGE- PRECIPITATOR INSPECTION AND REPAIRS	SP02	2020
REPLACE TR CABLES	SP02	2020

Table 7-3 (continued)
($100,000 and Above)
Spurlock Power Station

Description	Operating Unit	Date
Upgrade Precipicator Hopper Gates	SP02	2020
Filter bag Replacement	SP04	2020
Incorp Insulation & Scaffolding (5yr Inspection)	SP00	2020
NH3 5yr Inspection	SP00	2020
INSPECT & REPAIR CELLS	SP00	2020
Dredge River around Unloading Cells	SP00	2020
Replace the Belt on UC5	SP00	2020
Upgrade Unloaded Barge Mooring Cells	SP00	2020
Upgrade Loaded Barge Mooring Cells	SP00	2020
Install a Catwalk on the River Side of UC4 Conveyor	SP00	2020
Replace SR2 Lower Slew Bearing	SP01	2020
OVERHAUL U3 CRUSHERS	SP03	2020
OVERHAUL U4 CRUSHERS	SP04	2020
#3 Dozer Powertrain Rebuild	SP00	2020
#3 Scraper Powertrain Rebuild	SP00	2020
Vac Truck Dump Station Clean Out & FGD Removal from Ash Pond & Landfilling	SP00	2020
ASH POND CLEANING	SP00	2020
WESP SIRS Clean/Inspect/Repair	SP21	2020
Scrubber Inlet Duct Repairs	SP21	2020
REPLACE 6 INLET EXPANSION JOINTS	SP21	2020
WESP SIRS Clean/Inspect/Repair	SP22	2020
COOLING TOWER WETTED AREA STRUCTURE REPL	SP01	2020
REBUILD 1B COOLING TOWER CIRC WATER PUMP	SP01	2020
REPAIR/REPLACE CT DIVISION WALLS	SP02	2020
U3 Cooling Tower Fill Replacement	SP02	2020
HMI UPGRADE FOR MARK VI SYSTEM	SP03	2020
TURBINE VALVE OUTAGE	SP03	2020
HMI UPGRADE FOR MARK VI SYSTEM	SP04	2020
REBUILD 2B COOLING TOWER CIRC WATER PUMP	SP02	2020
ID Fan Overhaul B	SP02	2020
13.8kV Motor Overhaul	SP02	2020
Baghouse filter replacement 3yr PM	SP03	2020
"B" Voith Drive 5yr PM	SP04	2020
Limestone Mill 3-4yr PM	SP04	2020

Table 7-3 (continued)
($100,000 and Above)
Spurlock Power Station

Description	Operating Unit	Date
OUTAGE BOILER INSPECTION	SP01	2021
Outage Boiler Repairs	SP01	2021
OUTAGE BOILER INSPECTION	SP02	2021
Outage Boiler Repairs	SP02	2021
OUTAGE BOILER INSPECTION	SP03	2021
Outage Boiler Repairs	SP03	2021
OUTAGE BOILER INSPECTION	SP04	2021
Outage Boiler Repairs	SP04	2021
ID Fan Overhaul A	SP02	2021
Pulverizer Gearbox Rebuild	SP02	2021
Limestone Mill 3-4yr PM	SP03	2021
"A" Voith Drive 5yr PM	SP04	2021
Baghouse filter replacement 3yr PM	SP04	2021
OUTAGE BOILER INSPECTION	SP01	2022
Outage Boiler Repairs	SP01	2022
OUTAGE BOILER INSPECTION	SP02	2022
Outage Boiler Repairs	SP02	2022
OUTAGE BOILER INSPECTION	SP03	2022
Outage Boiler Repairs	SP03	2022
OUTAGE BOILER INSPECTION	SP04	2022
Outage Boiler Repairs	SP04	2022
FD Fan Overhaul B	SP02	2022
Pulverizer Gearbox Rebuild	SP02	2022

Table 7-3 (continued)
($100,000 and Above)
Spurlock Power Station

Description	Operating Unit	Date
OUTAGE BOILER INSPECTION	SP01	2023
Outage Boiler Repairs	SP01	2023
OUTAGE BOILER INSPECTION	SP02	2023
Outage Boiler Repairs	SP02	2023
OUTAGE BOILER INSPECTION	SP03	2023
Outage Boiler Repairs	SP03	2023
OUTAGE BOILER INSPECTION	SP04	2023
Outage Boiler Repairs	SP04	2023
Major Turbine 10yr PM	SP01	2023
Turbine Valves 5yr PM	SP01	2023
WESP Plates	SP01	2023
Precipitator Major	SP01	2023
"A" Feed Pump 9yr PM	SP03	2023
"A" Voith Drive 5yr PM	SP03	2023
Baghouse filter replacement 3yr PM	SP03	2023
Baghouse cage replacement 6yr PM	SP03	2023
Limestone Mill 3-4yr PM	SP03	2023
SP00 – Common		
SP01 - Spurlock 1		
SP02 - Spurlock 2		
SP03 – Spurlock 3		
SP04 - Spurlock 4		
SP20 – Spurlock Scrubber Common		
SP21 - Spurlock Scrubber Unit 1		
SP22 - Spurlock Scrubber Unit 2		

Table 7-4
Smith CTs - Station

Description	Operating Unit	Date
Pulsation probes for Units 1-2	SM50	2019
5 year Breaker Maintenance	SM50	2019
Unit 9 Replace HPC Row 3 Blades	SM59	2019
Unit 2 C-Inspection refurbish parts	SM52	2019
Units No. 9 and 10 - Block Upgrade	SM59/60	2019
Smith - ISO Phase Units 9 & 10 Heating	SM59 / SM60	2019
Smith LMS 9 & 10 - CO2 Fire Protection Exciter Cabinets and Fuel Oil Skids	SM59 / SM60	2019
Structure, Paint Tank	SM50	2020
Structure Painting- Units 1-4 and bay	SM50	2020
Units 4-7 PACS Switchgear Improvements	SM50	2020
15 Yr Breaker Maintenance Units 3 and 2	SM50	2020
Unit 2 Generator Rotor Out Inspection	SM52	2020
Upgrade HPT for Unit No. 10	SM60	2020
Smith 10 Hot Section Upgrade	SM60	2020
Unit No. 4 - CI Inspection	SM54	2020
Unit No. 5 - CI Inspection	SM55	2020
Unit 2 C-Inspection	SM52	2020
Unit 10 Row 3-5 HPC Blade Replacement	SM60	2020
Unit No. 7 Refurbishment parts	SM57	2020
Demineralizer 2 resin replacement	SM52	2020
Intake Fan PLC Replacements on U1, 2, & 3	SM51,52,53	2020
Unit 2 Exhaust Repairs	SM52	2020
Waterwash or Cleaning for CO or Nox- No. 9 and 10	SM59,60	2020
Units No. 9 and 10 - Block Upgrade	SM59/60	2020
LMS IO Packs and N-Tron Switches	SM50	2020

Table 7-4 (continued)
Smith CTs - Station

Description	Operating Unit	Date
Generator Ckt Bkr 12 yr Maintenance	SM59	2021
Generator Ckt Bkr 12 yr Maintenance	SM60	2021
Unit 4 C-Inspection	SM54	2022
Unit 5 C-Inspection	SM55	2023
SM50 - Smith Units Common		
SM51 - Smith Unit 1		
SM52 - Smith Unit 2		
SM53 - Smith Unit 3		
SM54 - Smith Unit 4		
SM55 - Smith Unit 5		
SM56 - Smith Unit 6		
SM57 - Smith Unit 7		
SM59 - Smith Unit 9		
SM60 - Smith Unit 10		

Table 7-5
Landfill Gas

Description	Operating Unit	Date
Green Valley- Building Piling	LF01	2019
Laurel Ridge- Upgrade Switchgear Processors	LF02	2019
Laurel Ridge- Major Overhaul	Unit 2 & 3	2019
Bavarian- Upgrade Switchgear Processors	LF03	2020
Hardin- Major Overhaul	Unit 2	2020
Pendleton- Major Overhaul	Unit 1, 2, 4	2020
Bavarian- Major Overhaul	Unit 2	2021
Hardin - Major Overhaul	Unit 3	2021
Green Valley- Major Overhaul	Unit 2	2022
Laurel Ridge - Major Overhaul	Unit 1	2022
Bavarian- Major Overhaul	Unit 4, 5	2022
Pendleton- Major Overhaul	Unit 3	2022
Glasgow- Major Overhaul	Unit 1	2022
Green Valley- Major Overhaul	Unit 1, 3	2023
Bavarian- Major Overhaul	Unit 1, 3	2023

SECTION 8.0

INTEGRATED RESOURCE PLANNING

SECTION 8.0

INTEGRATED RESOURCE PLANNING

The following filing requirements are addressed in this section.

807 KAR 5:058 Section 5(4) Summary of the utility's planned resource acquisitions including improvements in operating efficiency of existing facilities, demand-side programs, nonutility sources of generation, new power plants, transmission improvements, bulk power purchases and sales, and interconnections with other utilities.

807 KAR 5:058 Section 8(1) The plan shall include the utility's resource assessment and acquisition plan for providing an adequate and reliable supply of electricity to meet forecasted electricity requirements at the lowest possible cost. The plan shall consider the potential impacts of selected, key uncertainties and shall include assessment of potentially cost-effective resource options available to the utility.

807 KAR 5:058 Section 8(2)(c) The utility shall describe and discuss all options considered for inclusion in the plan including: (c) Expansion of generating facilities, including assessment of economic opportunities for coordination with other utilities in constructing and operating new units.

807 KAR 5:058 Section 8(2)(d) The utility shall describe and discuss all options considered for inclusion in the plan including: (d) Assessment of nonutility generation, including generating capacity provided by cogeneration, technologies relying on renewable resources, and other nonutility sources.

807 KAR 5:058 Section 8(3)(c) 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. (c) Description of purchases, sales, or exchanges of electricity during the base year or which the utility expects to enter during any of the fifteen (15) forecast years of the plan.

807 KAR 5:058 Section 8(3)(d) 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. (d) Description of existing and projected amounts of electric energy and generating capacity from cogeneration, self-generation, technologies relying on renewable resources, and other nonutility sources available for purchase by the utility during the base year or during any of the fifteen (15) forecast years of the plan.

807 KAR 5:058 Section 8(4)(a) 1-5 and 7-11 The utility shall describe and discuss its resource assessment and acquisition plan which shall consist of resource options which produce adequate and reliable means to meet annual and seasonal peak demands and total energy requirements identified in the base load forecast at the lowest possible cost. The utility shall provide the following information for the base year and for each year covered by the forecast: (a) On total resource capacity available at the winter and summer peak: 1. Forecast peak load; 2. Capacity from existing resources before consideration of retirements; 3. Capacity from planned utility-owned generating plant capacity additions; 4. Capacity available from firm purchases from other utilities; 5. Capacity available from firm purchases from nonutility sources of generation; 7. Committed capacity sales to wholesale customers coincident with peak; 8. Planned retirements; 9. Reserve requirements; 10. Capacity excess or deficit; 11. Capacity or reserve margin.

807 KAR 5:058 Section 8(4)(a)(6) The utility shall describe and discuss its resource assessment and acquisition plan which shall consist of resource options which produce adequate and reliable means to meet annual and seasonal peak demands and total energy requirements identified in the base load forecast at the lowest possible cost. The utility shall provide the following information for the base year and for each year covered by the forecast: (a) On total resource capacity available at the winter and summer peak. (6) On planned annual generation: Reductions or increases in energy from new conservation and load management or other demand-side programs.

807 KAR 5:058 Section 8(4)(b) 1-4 The utility shall describe and discuss its resource assessment and acquisition plan which shall consist of resource options which produce adequate and reliable means to meet annual and seasonal peak demands and total energy requirements identified in the base load forecast at the lowest possible cost. The utility shall provide the following information for the base year and for each year covered by the forecast: (b) On planned annual generation: (1) Total forecast firm energy requirements; (2) Energy from existing and planned utility generating resources disaggregated by primary fuel type; (3) Energy from firm purchases from other utilities; (4) Energy from firm purchases from nonutility sources of generation.

807 KAR 5:058 Section 8(4)(b)(5) On planned annual generation: 5. Reductions or increases in energy from new conservation and load management or other demand-side programs.

807 KAR 5:058 Section 8(4)(c) The utility shall describe and discuss its resource assessment and acquisition plan which shall consist of resource options which produce adequate and reliable means to meet annual and seasonal peak demands and total energy requirements identified in the base load forecast at the lowest possible cost. The utility shall provide the following information for the base year and for each year covered by the forecast: (c) For each of the fifteen (15) years covered by the plan, the utility shall provide estimates of total energy input in primary fuels by fuel type and total generation by primary fuel type required to meet load. Primary fuels shall be organized by standard categories (coal, gas, etc.) and quantified on the basis of physical units (for example, barrels or tons) as well as in MMBtu.

807 KAR 5:058 Section 8(5)(a) The resource assessment and acquisition plan shall include a description and discussion of: (a) General methodological approach, models, data sets, and information used by the company.

807 KAR 5:058 Section 8(5)(b) The resource assessment and acquisition plan shall include a description and discussion of: (b) Key assumption and judgments used in the assessment and how uncertainties in those assumptions and judgments were incorporated into analyses.

807 KAR 5:058 Section 8(5)(d) The resource assessment and acquisition plan shall include a description and discussion of: (d) Criteria used in determining the appropriate level of reliability and the required reserve or capacity margin, and discussion of how these determinations have influenced selection of options.

807 KAR 5:058 Section 8(5)(g) The resource assessment and acquisition plan shall include a description and discussion of: (g) Consideration given by the utility to market forces and competition in the development of the plan.

8.1 Introduction

EKPC's mission is to serve its owner-members by safely delivering reliable, affordable and sustainable energy and related services. One of its strategic objectives is to actively manage EKPC's current and future asset portfolio to deliver reliable, affordable and sustainable energy from appropriately diversified sources, and work with federal and state stakeholders to ensure the economic viability of EKPC's existing and future resources to meet evolving regulatory challenges including preparation for future curbs on greenhouse gas emissions. To meet this strategic objective, EKPC will actively manage its current and future asset portfolio to diversify energy resources including renewable resources incorporating new technologies, DSM/EE programs, market and partnering opportunities, while striving to improve operating performance and efficiencies. In light of the growing risks related to changes to existing and new environmental rules, including future regulation of greenhouse gas emissions, EKPC will actively work with other electric utilities, businesses and industry, regulators and lawmakers to manage EKPC's compliance strategies while minimizing costs to its owner-members.

Alternatives for supplying future resource needs are evaluated on a present worth of revenue requirements basis, as well as a cash flow basis. Any major power supply acquisition will be made via an RFP process. The RFP process ensures that EKPC has adequately surveyed available resources in the market for delivery to serve the owner-members' load in a reliable, affordable and sustainable manner.

8.2 Resource Planning Methodology Overview

EKPC develops a detailed load forecast every two years, with the most recent being completed in 2018. This forecast was approved by the EKPC Board of Directors in December 2018, and was approved by RUS in February 2019. The load forecast was updated to reflect known conditions in 2018 and that data has been used in this IRP analysis.

Market and fuel prices are updated on a regular basis to ensure that current expectations are being modeled in the analysis. Based on this input data, the DSM alternatives are evaluated utilizing the standard California tests. Based on those results, the load is modified to reflect the DSM analyses prior to developing the capacity expansion plan. Additionally, EKPC conducted an environmental assessment of its existing units and included those results in this analysis prior to performing the expansion analysis.

8.3 Load Requirements to be Served

The forecast indicates that for the period 2019 through 2033, total energy requirements will increase by an average of 1.4 percent per year. Winter and summer net peak demand will increase by 0.6 percent and 0.9 percent, respectively. The DSM programs that were evaluated result in the following impacts on load.

Table 8-1
Load Impacts of DSM Programs

(negative value= reduction in load)

Year	Impact on Energy Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2019	-10,651	-2.2	-1.6
2020	-20,473	-4.1	-3.5
2021	-30,295	-6.0	-5.5
2022	-40,117	-8.0	-7.5
2023	-49,939	-9.9	-9.4
2024	-59,552	-11.7	-11.3
2025	-68,981	-13.5	-13.2
2026	-78,411	-15.3	-15.1
2027	-86,621	-16.9	-16.8
2028	-94,765	-18.4	-18.5
2029	-102,910	-20.0	-20.3
2030	-111,054	-21.6	-22.0
2031	-119,199	-23.1	-23.7
2032	-127,344	-24.7	-25.4
2033	-135,488	-26.3	-27.1

Details on the specific programs are provided in the DSM Technical Appendix.

8.4 Supply Side Optimization and Modeling

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

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

RTSim's Resource Optimizer was used to perform the optimization of the resource plan. The Resource Optimizer automatically sets up and runs the RTSim production cost model to perform simulations of a large number of potential resource plans to determine the optimum plan. Because the basic RTSim model is used by the Resource Optimizer model, the Resource Optimizer uses the same data and detailed analysis that is used in the production cost model simulation, except that future units are set as resource alternatives. Any future resources to be considered by the Resource Optimizer are set up with several potential future commercial operation dates. The annualized fixed costs for capital are included along with the variable costs associated with a particular resource. Resources considered included in Table 8-2 below.

<u>Traditional Resources</u>

Table 8-2

Resource	**Capacity Type**	**Capacity (MW)**	**Primary Fuel**	Projected Capital Cost (2016$)* $/kW	$M
LMS100 CT	Peaking	100	Natural Gas	[redacted]	
Combined Cycle	Peaking/Intermediate	300	Natural Gas		
Solar	Renewable	100	Solar		
Wind	Renewable	100	Wind		
Wind	Renewable	100	Wind		
PPA - Winter Seasonal Market	Power Purchase	100	n/a		
PPA - Winter Seasonal Market	Power Purchase	100	n/a		
PPA - Winter Seasonal Market	Power Purchase	100	n/a		

<u>Renewable and Partnering Opportunities</u>

EKPC is a member of the National Renewables Cooperative Organization (NRCO). NRCO offers cooperatives access to the necessary resources to thoroughly evaluate renewable energy projects without the expense of a dedicated staff. NRCO is active in the renewable energy marketplace on behalf of its members and customers, providing a centralized source of intelligence and opportunities. NRCO evaluates projects, presenting only the most promising to its members. NRCO facilitates transmission constraint modeling, Renewable Energy Credit market analysis, and engineering studies, and packages these into comprehensive recommendations. NRCO offers an established subscription process to participate in specific projects and can help members and customers with the ongoing operations and maintenance of those projects. By aggregating demand amongst multiple power supply cooperatives, NRCO offers developers a venue for efficiently reaching a larger and more diverse set of buyers. To date, EKPC has participated in the evaluation of out-of-state wind projects but has not found any that fit its generation expansion needs. NRCO assisted with the RFP, contract, and installation of the Cooperative Solar Farm One. The RFP solicitation, receiving responses, initial rankings, initial contract review, and installation monitoring were performed by NRCO.

The Kentucky River lock and dam system is located throughout the EKPC/owner-members' service territory. An owner-member is pursuing hydro-generation facilities via a power purchase agreement with a local developer. These facilities are projected to be online in 2019.

EKPC currently has six landfill gas-to-energy (LFGTE) facilities and continues to strive to improve performance at each of these facilities. 2018 generation from the existing EKPC facilities was approximately 92,165 MWh, down from 101,207 MWh in 2017 and up from 90,220 MWh in 2016. EKPC developed the City of Glasgow Landfill into a LFGTE project, and it went online in December 2015. There are other LFGTE opportunities being investigated within the EKPC service territory.

In 2018 EKPC purchased 2,847 MWh from its one contracted cogeneration facility. EKPC continues to work with one small rural facility which still plans to initially generate approximately 200 kW from a poultry digester methane recovery operation. There are no other combined heat and power or cogeneration projects planned within the EKPC service territory that EKPC is aware of at this time.

EKPC, along with its sixteen owner-members, implemented a community solar project in order to offer renewable solar energy to end users within the owner-member's service territories. This project is a result of the Demand Side and Renewable Energy Collaborative group's efforts. The 8.5MW facility began operations in November 2017. Marketing of the 25-year licenses continues under the Cooperative Solar program, which offers benefits of solar generation without the installation and maintenance requirements that would be necessary in a smaller home or office installation. This facility produced 13,859 MWh in 2018.

There are currently approximately 2,849kW of solar voltaic installations within the EKPC service territory taking advantage of the owner-member's net-metering tariff. This number continues to grow as solar voltaic prices continue to decrease. There are currently a few small wind turbine installations connected to the owner-member's distribution network that are taking advantage of the net-metering tariff. These combined add up to approximately 18kW.

Energy from non-utility cogeneration should remain flat at around 3,500 MWh per year or less for the next several years. Due to net-metering by owner-members' retail members, load reduction remains at or less than 500 MWh per year for the next several years.

Table 8-3
EKPC Projected Capacity Additions and Reserves
(MW)

Year	Other Cap.	Base Load Capacity Additions		Peaking/ Intermediate Cap. Additions		Total Capacity		Reserves		Reserve Margin	
		Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum
2019						3,241	3,128	0	70	-1%	34%
2020						3,430	3,128	0	71	5%	32%
2021						3,430	3,128	0	73	3%	29%
2022						3,430	3,128	0	73	2%	28%
2023						3,430	3,128	0	74	2%	27%
2024	100					3,530	3,128	0	74	4%	27%
2025						3,530	3,128	0	75	4%	26%
2026						3,530	3,128	0	76	3%	24%
2027						3,530	3,128	0	76	2%	24%
2028						3,530	3,128	0	77	1%	22%
2029	100					3,630	3,128	0	77	4%	21%
2030						3,630	3,128	0	78	3%	20%
2031						3,630	3,128	0	78	3%	20%
2032						3,630	3,128	0	79	2%	19%
2033						3,630	3,128	0	80	2%	18%

Notes: Other Capacity is composed of the following: 100MW x 2 PPA

A minimum and maximum amount of capacity to be added by the model is specified to correspond to a specified reserve margin. The Resource Optimizer can simulate thousands of combinations of potential resources to determine the lowest-cost plans. The new resources have to be simulated in operation with the current resources to determine the optimum expansion for the system. The lowest-cost plans are determined from the present value of total production cost and annual fixed costs of future alternatives.

The Resource Optimizer constructs expansion plans to meet certain criteria, then simulates each plan and calculates the present value of each plan as compared to doing nothing. Some of the inputs needed by the Resource Optimizer are the minimum and maximum future capacity needs, resource alternatives, the annualized fixed cost of the resource alternatives, and the potential in-service dates for the alternatives. The resource alternatives are modeled with the same detail as the existing and committed units in the model. In development of this IRP, the Resource Optimizer was set to try up to 2,500 unique expansion plans, with each of those simulated with five iterations. Each iteration varies loads, fuel and market prices, and forced outages. The Resource Optimizer was run for the time period 2019 through 2033. The results in Tables 8-4 and 8-5 on the following pages, show the five lowest cost plans out of 2,500 plans simulated.

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

Table 8-4
DSM AFFECTED BASE RESOURCE OPTIMIZATION
Total tries: 2,500
Top Cases with specific resource and in-service date

Case 1	
Seasonal Purchase	1-1-2024
Seasonal Purchase	1-1-2029

Case 2	
Seasonal Purchase	1- 1-2026
Intermediate Resource	1- 1-2030

Case 3	
Seasonal Purchase	1- 1-2023
Seasonal Purchase	1- 1-2024
Seasonal Purchase	1- 1-2032
Peaking Resource	1- 1-2032

Case 4	
Seasonal Purchase	1- 1-2024
Seasonal Purchase	1- 1-2027
Seasonal Purchase	1- 1-2030
Peaking Resource	1- 1-2032

Case 5	
Seasonal Purchase	1- 1-2025
Seasonal Purchase	1- 1-2025
Peaking Resource	1- 1-2033

Table 8-5
Resource Optimizer Plan Summary

Cumulative Min Cap	Incremental Cap	Year	Type	Plan 1	Plan 2	Plan 3	Plan 4	Plan 5	Final Plan*
16	0	2019	Peaking						
			Intermediate						
			Renewable						
			PPA						
-125	-141	2020	Peaking						
			Intermediate						
			Renewable						
			PPA						
-224	-99	2021	Peaking						
			Intermediate						
			Renewable						
			PPA						
-301	-77	2022	Peaking						
			Intermediate						
			Renewable						
			PPA						
-359	-58	2023	Peaking						
			Intermediate						
			Renewable						
			PPA			100			
-390	-31	2024	Peaking						
			Intermediate						
			Renewable						
			PPA	100		100	100		100
-407	-17	2025	Peaking						
			Intermediate						
			Renewable						
			PPA					200	
-401	6	2026	Peaking						
			Intermediate						
			Renewable						
			PPA		100				
-375	26	2027	Peaking						
			Intermediate						
			Renewable						
			PPA				100		
-323	52	2028	Peaking						
			Intermediate						
			Renewable						
			PPA						
-261	62	2029	Peaking						
			Intermediate						
			Renewable						
			PPA	100					100
-185	76	2030	Peaking						
			Intermediate		300				
			Renewable						
			PPA				100		
-93	92	2031	Peaking						
			Intermediate						
			Renewable						
			PPA						
23	116	2032	Peaking			100	100		
			Intermediate						
			Renewable						
			PPA			100			
151	128	2033	Peaking					100	
			Intermediate						
			Renewable						
			PPA						

These five plans were reviewed to determine if the operation dates of the near term resources were in fact achievable based on recent experience.

8.5 Reliability Criteria and Projected Capacity Needs

As stated in Section 6, Transmission and Distribution Planning, EKPC is a member of SERC. SERC promotes the development of reliability and adequacy arrangements among the systems, participates in the establishment of reliability standards, administers a regional compliance and enforcement program, and provides a mechanism to resolve disputes on reliability issues. As a member of PJM and SERC, EKPC plans capacity to meet its capacity resource requirements defined by PJM plus being aligned to economically hedge its winter peak load expectations. See the table below for the total amount of capacity expected to be required on the EKPC system.

Table 8-6
EKPC Projected Capacity Needs
(MW)

Year	Projected Peaks		3% Reserves		Total Requirements		Existing Resources		Capacity Needs	
	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum
2019	3,258	2,342	0	70	3,258	2,412	3,241	3,128	17.3	-716.6
2020	3,281	2,377	0	71	3,281	2,448	3,430	3,128	-149.6	-680.5
2021	3,323	2,425	0	73	3,323	2,498	3,430	3,128	-106.7	-630.2
2022	3,349	2,448	0	73	3,349	2,521	3,430	3,128	-81.5	-607.5
2023	3,373	2,457	0	74	3,373	2,531	3,430	3,128	-57.3	-596.9
2024	3,390	2,472	0	74	3,390	2,546	3,430	3,128	-40.6	-582.6
2025	3,404	2,492	0	75	3,404	2,567	3,430	3,128	-25.9	-560.9
2026	3,429	2,517	0	76	3,429	2,593	3,430	3,128	-1	-535.2
2027	3,451	2,528	0	76	3,451	2,604	3,430	3,128	21	-524.2
2028	3,483	2,558	0	77	3,483	2,635	3,430	3,128	53	-493.3
2029	3,494	2,575	0	77	3,494	2,652	3,430	3,128	64	-476.4
2030	3,509	2,600	0	78	3,509	2,678	3,430	3,128	79	-449.7
2031	3,517	2,616	0	78	3,517	2,694	3,430	3,128	87	-434.3
2032	3,543	2,638	0	79	3,543	2,717	3,430	3,128	113	-410.9
2033	3,559	2,658	0	80	3,559	2,738	3,430	3,128	129	-390.1

Notes: 1. Reserve requirement updated to meet PJM Summer reserve requirement of 3%.
2. DSM Impacted load forecast.

Table 8-7 below shows the expected capacity additions based on this IRP plan.

Table 8-7
EKPC Projected Major Capacity Additions
(MW)

Year	Baseload Capacity	Peaking/Intermediate Capacity	Cumulative Capacity Additions
2019			
2020			
2021			
2022			
2023			
2024		100	100
2025			100
2026			100
2027			100
2028			100
2029		100	200
2030			200
2031			200
2032			200
2033			200

EKPC will work with federal and state stakeholders to ensure the economic viability of future and existing resources to meet the challenges and opportunities presented by climate change issues. EKPC is driven to use its assets to deliver reliable, affordable and sustainable energy from appropriately diversified fuel sources. EKPC will carefully manage its portfolio of assets and pursue diversity of supply resources, including DSM/EE programs, market-based opportunities and risk related to climate change regulation/legislation. EKPC will continue to research and learn about related issues and opportunities.

Table 8-8

Power Transactions (GWH)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Power Purchases	0	0	0	0	0	58	64	50	54	59	120	117	131	144	162
Market Purchase	2,820	4,727	5,614	7,166	7,711	8,091	8,486	8,803	9,377	9,346	9,251	9,378	8,963	8,480	7,771
SEPA	258	261	257	257	257	259	260	257	257	257	257	258	260	257	258
Total Purchases	3,077	4,988	5,871	7,423	7,968	8,407	8,810	9,111	9,688	9,662	9,629	9,752	9,355	8,881	8,190
Market Power Sales	303	230	142	57	51	48	14	23	10	12	15	16	13	19	28

Table 8-9

Non-Utility Generation (GWH)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Non-Utility Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Renewables*	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

* Generation from solar and landfill gas-to- energy projects are included in the response to Table 4-5 and Table 4-7 and Table 8-11.

In the next several years, approximately 3,500 MWh of energy per year will be supplied from cogeneration and 100,000 MWh of energy per year from LFGTE (self-generated).

Table 8-10

Forecast Energy	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Requirements (GWh)	13,735.98	14,354.31	15,109.71	15,241.75	15,373.49	15,545.77	15,684.53	15,832.74	15,972.67	16,135.94	16,233.82	16,361.03	16,494.33	16,666.20	16,784.91
(as modeled)															
Generation (GWH)															
Coal	10,208.76	8,658.99	8,618.77	7,301.91	6,944.35	6,843.71	6,658.61	6,608.08	6,271.21	6,466.61	6,630.59	6,618.38	7,099.32	7,668.84	8,450.29
Natural Gas	906.6	1094.5	915.8	727.9	665.8	555.8	450.1	341.3	231.2	232.5	264.3	278.2	341.8	432.8	488.7
Landfill Gas	89.6	89.9	89.6	89.7	89.6	89.9	89.7	89.6	89.6	89.9	89.7	89.7	89.7	89.9	89.6
Solar	14.0	13.9	13.8	13.8	13.7	13.8	13.7	13.6	13.6	13.6	13.4	13.4	13.4	13.3	13.3
Total	11,219.02	9,857.26	9,638.04	8,133.36	7,713.44	7,503.17	7,212.09	7,052.59	6,605.65	6,802.68	6,997.94	6,999.63	7,544.16	8,204.86	9,041.92
Purchases (GWH)															
Firm Purchases-SEPA	258	261	257	257	257	259	260	257	257	257	257	258	260	257	258
Firm Purchases-Other Utilities	0	0	0	0	0	58	64	50	54	59	120	117	131	144	162
Firm Purchases-Non-Utilities	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	258	261	257	257	257	316	324	308	311	317	377	375	391	401	419

Table 8-11

Fuel Input (1,000s MBTU)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Coal	101,918	86,844	86,902	74,135	70,710	69,754	68,058	67,613	64,508	66,317	67,831	67,680	72,233	77,606	85,191
Natural Gas	8,648	10,421	8,804	7,047	6,471	5,398	4,373	3,315	2,251	2,263	2,581	2,712	3,338	4,226	4,801
Total	110,566	97,265	95,706	81,182	77,181	75,152	72,431	70,928	66,758	68,580	70,412	70,391	75,570	81,832	89,992
Fuel Input (Physical Units)															
Coal (1,000s Tons)	4,479	3,829	3,836	3,281	3,131	3,089	3,014	2,995	2,859	2,938	3,005	2,998	3,197	3,433	3,762
Natural Gas (1,000s mcf)	8,524	10,271	8,677	6,946	6,378	5,321	4,310	3,267	2,218	2,230	2,544	2,673	3,290	4,165	4,732

807 KAR Section 8(3) The following information regarding the utility's existing and planned resources shall be provided. A utility which operates as part of a multistate integrated system shall submit the following information for its operations within Kentucky and for the multistate utility system of which it is a part. A utility which purchases fifty (50) percent or more of its energy needs from another company shall submit the following information for its operations within Kentucky and for the company from which it purchases its energy needs.

EKPC only operates within the Commonwealth of Kentucky.

SECTION 9.0

COMPLIANCE PLANNING

SECTION 9.0

COMPLIANCE PLANNING

9.1 Introduction

The actions and how these actions affect the utility's resources assessment covered by this IRP to meet the requirements of the Clean Air Act amendments of 1990 (CAA), Clean Water Act (CWA) and Resource, Conservation and Recovery Act (RCRA) includes the following items.

EKPC is currently in compliance with the following CAA rules:

- New Source Performance Standards (NSPS);
  - NSPS Green-House Gas (GHG) for New, Modified and Reconstructed Fossil Fueled Units
- New Source Review (NSR);
- Title IV of the CAA and the rules governing pollutants that contribute to Acid Deposition (Acid Rain program);
- Title V operating permit requirements (Title V);
- Summer ozone trading program requirements promulgated after EPA action on Section 126 petitions and the Ozone SIP Call (Summer Ozone program);
- Clean Air Interstate Rule (CAIR) (Phased Out 12/31/15);
- Cross-State Air Pollution Rule (CSAPR);
- National Ambient Air Quality Standards (NAAQS) for Sulfur Dioxide (SO_2), Nitrogen Dioxide (NO2), Carbon Monoxide (CO), Ozone, Particulate Matter (PM), Particulate Matter 2.5 microns or less (PM 2.5) and Lead;
- Mercury Air Toxics Standards (MATS);
- EPA Affordable Clean Energy Rule (ACE), formerly known as the Clean Power Plan

EKPC is currently in compliance with the following other environmental rules affecting the power generation sector:

- Clean Water Act
  - Section 316(a,b)
  - Effluent Limitations Guidance (ELG)
  - Waters of the US (WOTUS)
- Resource Conservation and Recovery Act
  - Coal Combustion Rule

East Kentucky Power Cooperative is in compliance with the existing federal EPA rules. As a prudent utility, EKPC surveys the environmental waterfront for future rules, in draft, proposed and final form. EPA puts forth an annual report that describes its strategic plan going forward called "Working Together", FY 2018-2022 U.S. EPA Strategic Plan, published February 2018 and a "Year in Review 2018" from EPA acting Administrator, Andrew Wheeler.

The core mission of EPA's strategic plan for 2018-2022 is to improve: its air quality through its National Ambient Air Quality Standards; provide clean and safe water; revitalize land; prevent contamination; and ensure safety of chemicals in the marketplace via a return to "Cooperative Federalism" while maintaining environmental rules of law.

EKPC is complying with environmental laws and is in alignment with the core mission of the EPA's strategic plan. The CAA rules identified above are what EKPC expects to see the next four years which will impact the utility industry over the next 15 years. A description of each rule appears below and describes what impacts are expected.

I. New Source Review (NSR)

On January 28, 2004, the United States filed a complaint alleging that EKPC was out of compliance with the Prevention of Significant Deterioration provisions in Part C of Subchapter I of the Act, 42 U.S.C. §§ 7470-92 (NSR); NSPS, Title V and the federally-enforceable SIP developed by the Commonwealth of Kentucky. EKPC and the United States settled this action and entered into a Consent Decree memorializing the terms of the settlement, which was entered by the Court on September 27, 2007 (NSR CD).

On June 30, 2006, the United States and the Commonwealth of Kentucky filed a complaint alleging that EKPC was in violation of the Acid Rain Program and Title V. This matter was also settled, and the Consent Decree capturing the terms of the settlement was entered by the Court on November 30, 2007 (Acid Rain CD).

EKPC, in partnership with the EPA and the Kentucky Energy and Environmental Cabinet (KY Cabinet), worked diligently to implement and comply with the requirements of these two Consent Decrees.

On February 14, 2014, the United States filed a Joint Stipulation to terminate the Acid Rain CD, which was sustained by Court Order. The Court entered an Order terminating that Acid Rain CD on February 20, 2014. With respect to the NSR CD, the United States determined that EKPC met all the requirements for Conditional Termination. Upon EKPC's filing of a Certificate with the Court on June 16, 2017, the Conditional Termination was effective 45 days later. EKPC remains in compliance with the conditions of the two CDs through EKPC's air permits.

EKPC commits legal, environmental and production engineering resources to a NSR of engineering and outage projects. This process was put into place to prevent future NSR cases and settlements. Should the EPA change its interpretation for NSR, EKPC will modify its process to remain in alignment with the EPA NSR.

The EPA and Congress are considering reforms to the NSR rules. A bright line emissions test would assuage the shifting EPA NSR enforcement interpretations, which are costly to industry to defend. EKPC supports an hourly emissions test in lieu of the current actual-to-projected-actual emissions test. The hourly emissions test, which is used for the New Source Performance Standard (NSPS), evaluates increases in maximum hourly emissions, based on a five-year lookback. 40 CFR § 60.14(h). The hourly test would capture projects that allow the boiler to combust more fuel, thereby increasing the emissions from the boiler. It would promote certainty by removing the demand growth variable from the present NSR analysis. The hourly approach is consistent with the CAA definition of construction, which is a statutory justification for the NSR program.[6]

[6] 42 U.S.C. § 7475 (defining pre-construction requirements in the PSD program). The term "construction" when used in connection with any source or facility, includes the modification (as defined in section 7411(a) of this title) of any source or facility). *Id.* The term "modification" means any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted. 40 CFR § 52.21(b)(2).

In addition, EKPC also supports a bright line definition of the exclusion for "routine maintenance, repair and replacement",[7] so that EKPC can easily delineate which outage projects fall under this exception, thereby allowing EKPC to perform outage projects that improve plant efficiency and enable EKPC to repair components in its electric generating units with like-kind equipment. Rather, at-present, the exclusion is defined by an insistent collection of judicial opinions that provide little guidance to industry on which outage projects qualify for the exclusion.

II. <u>Electric Utility Steam Generating Units (EGU) Mercury and Air Toxics Standards (MATS)</u>

On March 16, 2011, EPA issued the proposed EGU maximum achievable control technology (MACT) rule to reduce emissions of toxic air pollutants from new and existing coal- and oil-fired EGUs. EPA finalized the MATS as the EGU MACT rule on December 16, 2011, to reduce emissions of heavy metals, including mercury (Hg), arsenic, chromium, and nickel, and acid gases, including hydrogen chloride (HCl) and hydrogen fluoride (HF). MATS allow sources to control surrogate emissions to demonstrate control of hazardous air pollutants (HAP) metals and HAP acid gases. Non-Hg metallic toxic air pollutants are captured by PM emission limits because these metals travel in particulate form in boiler gas paths. HCl and/or SO_2 are surrogates for all acid gas HAPs since they are controlled by the same mechanisms. Under MATS, mercury emissions are subject to limits and units must measure mercury emissions directly to demonstrate compliance. EGUs began compliance with the mercury, SO_2 or HCl, and PM limits for MATS beginning in the spring of 2015. On December 27, 2018, EPA proposed to revise the Supplemental Cost Finding for MATS, as well as the Clean Air Act required risk and technology review (RTR). However, if this Proposed Rule became a Final Rule, the requirements of MATS would not be changed.

EKPC conducted emissions testing of its units to determine the best way to achieve compliance with the MATS rule. This testing was conducted as part of an extensive engineering effort to ensure that EKPC's units complied with the Rule. The pollution control upgrades on Spurlock 1 and 2

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[7] 40 CFR 52.21(b)(2)(iii)(a): "Routine maintenance, repair and replacement. Routine maintenance, repair and replacement shall include, but not be limited to, any activity(s) that meets the requirements of the equipment replacement provisions contained in paragraph (cc) of this section."

and Cooper 2, as part of NSR CD, placed EKPC's units ahead of most EGU units for MATS compliance with minimal additional capital investment. Likewise, Spurlock 3 and 4 are equipped with Best Available Control Technology (BACT) and met the MATS rule limits without additional controls.

III. <u>Cross-State Air Pollution Rule (CSAPR)</u>

On July 6, 2011, EPA finalized CSAPR to require 27 states (Kentucky included) and the District of Columbia to significantly improve air quality by reducing power plant emissions that contribute to ozone and fine particle pollution in other states. This rule replaced EPA's 2005 CAIR rule that was remanded to EPA by the U.S. District Court of Appeals for the D.C. Circuit (D.C. Circuit). CSAPR required significant reductions in SO_2 and nitrogen oxides (NO_X) emissions that cross state lines. These pollutants react in the atmosphere to form fine particles and ground-level ozone and are transported long distances, making it difficult for other states to achieve the National Ambient Air Quality Standards (NAAQS). The rule called for the first phase emission reduction compliance to begin January 1, 2012 for annual SO_2 and NO_X and the second phase May 1, 2012 for ozone season NO_X reductions. On December 30, 2011, CSAPR was stayed by the D.C. Circuit in response to industry petitions challenging the rule. On August 21, 2012, CSAPR was vacated and remanded back to EPA. EPA appealed this decision and on April 29, 2014, the Supreme Court reversed the D.C. Circuit and reinstated CSAPR. The Court remanded the rule back to the D.C. Circuit to determine next steps and resolve the many pending appeals of the rule.

On June 26, 2014, the United States moved the D.C. Circuit to lift the stay on CSAPR but toll the original compliance deadlines by three years. On October 23, 2014, the D.C. Circuit granted the motion, and as a result, CSAPR was reinstated with Phase 1 beginning January 1, 2015 and Phase 2 starting January 1, 2017.

In November 2016, EPA proposed the CSAPR Update Rule (CSAPR II), addressing earlier court concerns and interstate transport of air pollution under the 2008 ozone NAAQS. The updated Rule became effective on December 27, 2016. The updated Rule does not affect the SO_2 allocations or the NOx allocations for 2015 and 2016. CSAPR NOx (CSAPR III) emissions allowances will likely be reduced further in the next couple of years to achieve compliance with the new 2015 ozone NAAQS (70 ppb). Future reductions in NOx allowances to comply with the 2015 ozone NAAQS are generally referred to as CSAPR III.

CSAPR III has not been issued, but is expected to follow the same methodology as CSAPR II, with some reductions in allowances for units that are in non-attainment areas or that have a significant contribution to non-attainment areas.

Bluegrass is located in Oldham County, which EPA recently designated as marginal nonattainment for the 2015 Ozone NAAQS. The rest of the fleet is in areas that are in attainment for ozone. The number of these allowances for Bluegrass is a small fraction of the allowances assigned to the EKPC fleet. The four Dale units will continue to have allowances assigned through 2020. After that, the allowances for the Dale units will go to the new unit set aside account. The EKPC fleet has roughly twice the number of allowances it needs to operate in 2019. Based on the allowances assigned under CSAPR II, EKPC should have sufficient allowances to operate normally under CSAPR III for the foreseeable future.

IV. <u>GHG Tailoring Rule (GHG)</u>

On May 13, 2010, the EPA issued a final rule that established emission thresholds for addressing GHG emissions from stationary sources under the CAA permitting programs. The GHG Tailoring rule set GHG thresholds for applicability under the NSR rules and Title V program. GHGs are considered one pollutant for NSR, which is composed of the weighted aggregate of CO_2, N_2O, SF_6, HFCs, PFCs, and methane (CH_4) into a combined CO_2 equivalent (CO_{2e}).

Under the original GHG Tailoring rule, if any of the stations made a physical or operational change that would result in a net increase of 75,000 tons per year or more of CO_2 equivalents CO_{2e}, EKPC must have obtained an NSR permit for the modification including the installation of Best Available Control Technology (BACT) for GHGs on the modified unit.

On June 23, 2014, the U.S. Supreme Court struck part of the GHG Tailoring Rule and held that a significant net emissions increase in GHGs alone cannot trigger NSR. NSR permitting requirements for GHGs can be triggered, but only if the physical or operational change also results in both a significant net emissions increase of GHGs and another PSD pollutant and that EPA has not yet set a significant emissions increase threshold for GHGs.

V. National Ambient Air Quality Standards (NAAQS)

If a county or counties are designated to be in a nonattainment for a NAAQS, the Cabinet will work with major sources contributing to nonattainment to implement Reasonably Achievable Control Technology (RACT) retrofits to bring the areas into attainment. Further, no permits can be approved by the Cabinet without a NAAQS compliance demonstration, which involves submitting computer modeling of emissions that shows that the Commonwealth will stay in attainment despite the permitted activity.

A. Carbon Monoxide

In January 2011, EPA proposed to retain the current primary CO NAAQS of 9 ppm (8-hour) and 35 ppm (1-hour). This rule was finalized in August 2011. As of September 27, 2010, all CO areas have been designated as maintenance areas. On April 11, 2014, the D.C. Circuit deferred to EPA's authority to set NAAQS, maintain the primary standard from 1971 and not set a secondary standard.

B. Sulfur Dioxide

EPA revised the primary SO_2 NAAQS in June 2010 to a one-hour standard of 75 ppb. On June 2, 2011, Kentucky made area designation recommendations for the new SO_2 standard. The Commonwealth recommended that Jefferson County be designated as a nonattainment area and that the remainder of the Commonwealth be designated as unclassifiable or attainment. On October 4, 2013, EPA designated part of Campbell County, KY (together with part of Clermont County, OH) as nonattainment and part of Jefferson County, KY as nonattainment. The attainment demonstration deadline for both nonattainment areas was April 6, 2015. The current secondary 3-

hour SO_2 standard is 0.5 ppm. The EPA proposed to retain both the SO_2 and NO_2 secondary standards in July 2011 and this final rule was published on April 3, 2012.

The EPA is proposing to retain its existing SO_2 NAAQS, but is weighing potential changes to its implementation, including potentially easing compliance by altering the formula for how the agency determines whether an area is attaining or violating the NAAQS. The EPA Administrator signed a proposed rule on May 25, 2018 to keep the existing standard of 75 parts per billion (ppb) of SO_2 averaged over one hour. The comment period for the proposed rule ended on July 23, 2018.

C. Nitrogen Dioxide

EPA revised the primary NO_2 NAAQS in January 2010. The new primary NAAQS for NO_2 is a one-hour standard of 100 ppb. EPA retained the existing primary and secondary annual standard of 53 ppb. On January 11, 2011, Kentucky made area designation recommendations for the new NO_2 standard and recommended that areas with monitors showing compliance be designated as in attainment and that the remainder of the Commonwealth be designated as unclassifiable. On June 28, 2011, EPA responded indicating its intent to designate the entire country as unclassifiable/attainment due to the limited availability of monitoring data. On August 3, 2011, the Commonwealth responded to EPA's proposed revision requesting that the areas that show compliance with area monitors are designated as attainment and that the remainder of the Commonwealth be designated as unclassifiable/attainment. Final designation of the entire United States as unclassified/attainment was made on February 17, 2012. A new monitoring system was implemented to measure NO_2 concentrations. EPA finalized a rule establishing a nation-wide monitoring on March 7, 2013 in two phases (2014 and 2017). Three years after the new monitoring system was implemented, EPA will re-evaluate the existing data and re-designate areas as necessary (2020). An initial compliance deadline of 2025 is contemplated. As mentioned above, in a final rule published on April 3, 2012, EPA retained the secondary NO_2 NAAQS of 0.053 ppm averaged over a year.

D. Ozone

On December 20, 2017, EPA provided notice to Kentucky concerning the air quality designations for the revised 2015 NAAQS Ozone Standards throughout Kentucky. The 2015 Ozone NAAQS

Ozone Standard lowered the 8-hour ozone standard from 0.075 parts per million (ppm) to 0.070 ppm.

EPA published a notification of availability and public comment period on January 5, 2018, concerning the state's designation recommendations for the 2015 NAAQS Ozone Standard. The Notification identified EPA's responses sent to the states, technical support information for designations, and opened the comment period for the 2015 NAAQS Ozone Standard designations. The Kentucky Nonattainment Designation Letter identified certain counties in Kentucky that EPA determined violate the 2015 NAAQS Ozone Standard and nearby areas that contribute to the violating areas.

The 2015 NAAQS Ozone Standard designations affect Bluegrass, owned and operated by EKPC, located in Oldham County, which is designated nonattainment as an area contributing to a 2015 NAAQS Ozone Standard violation. EKPC filed comments on this designation on February 5, 2018. All other EKPC generation facilities are located in areas in attainment with the standard. Despite EPA's ongoing re-examination of the NAAQS setting process, in an August 1, 2018 court filing, EPA expressed its intent not to reconsider the 2015 Ozone NAAQS.

E. Particulate Matter ($PM_{2.5}$)

In 1997, EPA adopted the 24-hour fine particulate NAAQS ($PM_{2.5}$) of 65 $\mu g/m^3$ and an annual standard of 15 µg/m3. In 2006, EPA revised this standard to 35 $\mu g/m^3$, and retained the existing annual standard. In December 2004, the following counties were designated as nonattainment under the 1997 standard: Boone, Campbell, Kenton, Boyd, Lawrence (partial), Bullitt, and Jefferson. This was modified in April 2005 and in October of 2009, the entire Commonwealth was designated as unclassifiable/attainment under the 2006 standard.

EPA tightened the primary $PM_{2.5}$ NAAQS to 12 $\mu g/m^3$ on January 15, 2013. On January 15, 2015, EPA issued final $PM_{2.5}$ designations. EPA designated Boone, Campbell, Keaton, Bullitt and Jefferson counties as nonattainment. EKPC does not have facilities in these counties.

F. Lead

In October 2008, EPA strengthened the primary lead NAAQS from 1.5 μg/m^3 to 0.15 μg/m^3. EPA has designated the Commonwealth as unclassifiable/attainment for the lead NAAQS. EPA retained this standard on September 16, 2016.

VI. Regional Haze Rule

The Regional Haze Rule has triggered the first in a series of once-per-decade reviews of impacts on visibility at pristine areas such as national parks, with a focus in the first review on large emission sources put into operation between 1962 and 1977. This first review, just now being completed, targets Best Available Retrofit Technology (BART) controls for SO_2, NO_x, and PM emissions. The threshold for being exempt from BART review is very stringent, such that coal-fired electrical generating stations are almost universally subject to BART.

A BART assessment includes an evaluation of SO_2 controls and post-combustion NO_x controls. Spurlock and Cooper Stations are subject to BART. EKPC submitted its Regional Haze compliance plans to the Cabinet, and the Cabinet submitted the plan for the Commonwealth to EPA who adopted it formally into Kentucky's SIP. EKPC installed SO_2, NOx and PM controls on Spurlock 1 and 2 and Cooper 2 to comply with the NSR CD, the Regional Haze rule, MATS, CSAPR and any NAAQS requirements. At this point, Spurlock and Cooper Stations' compliance with CSAPR equals Regional Haze Rule compliance. EKPC coal-fired fleet has remained in compliance with BART since its compliance date of April 2017.

VII. Clean Power Plan

The CPP finalized by EPA under the Obama administration was stayed by the United States Supreme Court on February 9, 2016. For EKPC, the rule required a drastic reduction in fossil fuel-fired generation in Kentucky. The Rule also required a 32-percent reduction in carbon dioxide emissions from the 2005 levels by 2030, a costly and unexpected additional decrease of 27% from the previously proposed rule's aggressive 2030 goal. The emission rates (and necessarily the state's resultant mass goals) for steam generating units were not achievable by any existing coal-fired units. To meet these limits, all existing owners of coal-fired steam generating units must decrease average CO_2 emissions by (a) shutting down some units, (b) running some or all fossil units much less each year, (c) immediately beginning the process of constructing replacement natural gas baseload generation, and/or (d) engaging in some form of regional market for procuring emissions rate credits or emission allowances.

A. CPP Repeal Rule

On March 28, 2017, President Trump signed an Executive Order (EO 17833), entitled "*Promoting Energy Independence and Economic Growth*," directing EPA to review and, if appropriate, suspend, revise, or rescind the CPP. EPA announced its intent to review and, if appropriate, suspend, revise or rescind the CPP on April 4, 2017. Subsequently, EPA proposed a rule repealing the CPP (October 16, 2017). Comments on the proposed repeal rule were filed April 26, 2018. Industry comments focused on all the legal flaws in the CPP. NRECA and individual G&Ts (including EKPC) focused on the disparate impact that the existing CPP would have on electric cooperatives. There is no known timeline for finalizing the CPP Repeal, but it is expected sometime in 2019.

The prior rule also assumed an unrealistic improvement in efficiency from coal units. EKPC cannot achieve any further efficiency improvements. EKPC is a leader in heat rate improvement measures and has some of the best performing units. All feasible efficiency improvements have been made and any additional requirements would unfairly penalize EKPC for having already made these improvements.

B. Affordable Clean Energy Proposed Rule

The replacement for the CPP was released on August 21, 2018. The proposed Rule is now called the Affordable Clean Energy (ACE) rule. EPA's general approach to the Rule is to clarify the Federal and state roles in rulemaking, with particular emphasis on granting states more authority to make decisions about how to implement the ACE. EPA also clarifies that the CPP exceeded the EPA's statutory authority and that the ACE rule would follow EPA's historic application of section 111, by focusing on technologies that could be cost-effectively implemented at a facility. EPA is also proposing revisions to the New Source Review program to clearly allow projects that improve unit efficiency, which may be required under ACE rule.

The proposed Rule uses an approach where EPA prepares guidelines on potential projects and best practices that can increase the efficiency of power plants. More efficient power plants emit less CO_2 because they need less fuel to produce electricity. States then consider these projects and practices on a boiler by boiler basis to determine the appropriate CO_2 emissions limits. In setting these limits states can consider future projects and practices that plants can implement and projects and practices that plants have already done. States will also consider the remaining useful life of the units, feasibility of implementing projects and practices, extraordinary cost impacts among other factors in setting CO_2 limits.

The proposal will revise the regulations under CAA Section 111(d) (the legal basis for the CPP and ACE). These revisions will ensure that the state-based approach continues as new rules are issued under CAA Section 111(d). The ACE proposal will clarify the test for whether a modification results in an emission increase by analyzing whether the project will increase a boiler's highest hourly emissions rate of pollutants before and after a proposed the project before looking to the whether there is a projected increase in annual emissions.

When the proposed ACE Rule becomes final, it will be challenged by dozens of interested parties and defended by dozens of others. Most states will line up on one-side or the other. In anticipation of the intensity of the NSR reform litigation, EPA is taking the position that the proposed revisions to the NSR program can be severed from the remainder of the ACE Rule for any legal challenge. EPA is hoping that the CO_2 portions of the ACE Rule will survive judicial review even if the NSR revisions do not. EPA projects that the ACE Rule can provide $400 million in annual net benefits. When fully implemented, the U.S. power sector CO_2 emissions could be reduced 33 percent to 34 percent below 2005 levels. This reduction is higher than the projected CO_2 emissions reductions from the CPP.

C. Reconsideration of CO_2 NSPS for New Utility Coal and Natural Gas Units (111(b) Rule)

EPA released proposed revisions to the 111(b) CO_2 rule (Proposed Rule) on December 6, 2018. The current 111(b) CO_2 rule applies, as do all 111(b) rules, to new EGUs. The primary goal of the Proposed Rule is to revise EPA's former finding that partial Carbon Capture and Sequestration (CCS) was the best system of emissions reduction (BSER) for CO_2 emissions from EGUs. The Proposed Rule determined that CCS is too costly, technically infeasible and geographically limited. Instead, EPA proposes to set BSER as units with the most efficient demonstrated steam cycle in combination with best operating practices.

Supercritical units (which includes ultra-supercritical units) are BSER for units with a heat input larger than 2,000 MMBtu/h. For units with a heat input equal to or less than 2,000 MMBtu/h are highly efficient subcritical units. The resulting emissions limits (Table 9-1) apply to new and reconstructed EGU and are a floor for modified EGUs. Coal refuse EGUs have a slightly higher limit.

Table 9-1
Summary of BSER and Proposed Standards for Affected Sources

Affected Source	BSER	Emissions Standard
New and Reconstructed Steam Generating Units and IGCC Units	**Most efficient generating technology in combination with best operating practices**	**1.) 1,900 lb CO_2/MWh-gross for sources with heat input > 2,000 MMBtu/h 2.) 2,000 lb CO_2/MWh-gross for sources with heat input ≤ 2,000 MMBtu/h or 3.) 2,200 lb CO_2/MWh-gross for coal refuse-fired sources**
Modified Steam Generating Units and IGCC Units	**Best demonstrated performance**	**A unit-specific emission limit determined by the unit's best historical annual CO_2 emission rate (from 2002 to the date of the modification); the emission limit will be no more stringent than 1.) 1,900 lb CO_2/MWh-gross for sources with heat input > 2,000 MMBtu/h 2.) 2,000 lb CO_2/MWh-gross for sources with heat input ≤ 2,000 MMBtu/h or 3.) 2,200 lb CO_2/MWh-gross for coal refuse-fired sources**

There is no change to new unit limits for combustion turbines, including natural gas combined cycle (NGCC) units. These limits are:

1. 1,000 lb CO_2/MWh-g or 1,030 lb CO_2/MWh-n for base load natural gas-fired units
2. 120 lb CO_2/MMBtu for non-base load natural gas-fired units
3. 120 to 160 lb CO_2/MMBtu for multi-fuel-fired units

The Proposed Rule uses a modification rule test that contemplates determining whether a modification triggers 111(b) by comparing hourly CO_2 emissions rates after change with the highest hourly emissions rate in the five years before. This test is contrary to the traditional NSPS modification test under 60.14(h) which looks at the maximum achievable hourly emissions rates in the five years before the project compared to hourly rates going forward. However, it is more consistent with the proposed NSR hourly emissions rate alternatives in the ACE proposal.

The Proposed Rule very briefly discusses the 2009 endangerment finding and the lack of an additional endangerment finding when the 111(b) rule was promulgated in 2015, but makes clear that EPA is not re-opening these issues or inviting comment on them. EPA seems unlikely to change the legal basis for the 111(d) rule.

The comment deadline was originally February 19, 2019, but the government shutdown delayed the deadline. The new deadline has not been set.

9.2 Additional Non-CAA New Rules

For completeness, EKPC is providing a summary of new Clean Water Act (CWA) rules and the Coal Combustion Residuals (CCR) rule.

I. <u>CWA 316(b) Rule</u>

A. <u>Background</u>

EPA published its final rule to regulate cooling water intake structures (CWIS) at existing facilities on August 15, 2014. The rule sets requirements that establish Best Technology Available (BTA) for minimizing adverse environmental impact from impingement mortality and entrainment mortality due to operation of CWIS. The Rule became effective on October 14, 2014.

Impingement mortality (IM) results from impingement of aquatic organisms on the cooling water intake structure, typically traveling water screens used to prevent debris from entering the cooling water circulating pumps and the steam condenser tubes. Entrainment mortality (EM) results when organisms that are entrained through the cooling water intake structure die due to the combined effects of mechanical stress from the pumps, thermal stresses from the heat transferred from the condensers, and application of any biocides.

Spurlock and Cooper Stations are subject to requirements of Section 316(b) of the Clean Water Act (CWA) to minimize adverse environmental impact due to IM and EM at the respective cooling water intakes because each: (1) holds a Kentucky Pollutant Discharge Elimination System (KPDES) permit, (2) has a design intake capacity that withdraws more than 2 million gallons per day (MGD) from WOTUS, and (3) withdraws at least 25 percent of the intake water for dedicated cooling purposes. EKPC's Smith and Bluegrass Stations are not subject to regulation under Section 316(b) as combustion turbine generation does not use cooling water.

The IM performance standard established in the final Rule is based on modified traveling screens with fish returns, and includes a compliance option based on survival rates after impingement as well as several alternative compliance approaches. In its rulemaking, EPA determined that there is no single technology that is BTA for EM. Therefore, the final Rule contains a national BTA standard for EM that establishes a process by which the permitting authority (in Kentucky, the Division of Water) determines EM mitigation requirements on a site-specific basis.

1. Impingement Mortality

As stated above, the final rule's IM performance standard is based on modified traveling screens with fish returns but 40 CFR 125.94(c) includes several compliance alternatives. The alternatives are:

a. Closed-cycle recirculating system
b. Design through-screen velocity ≤ 0.5 fps
c. Actual through-screen velocity ≤ 0.5 fps
d. Existing offshore velocity cap > 800 feet offshore
e. Modified traveling screens with fish return
f. A system of technologies and/or operational measures
g. Compliance with numeric impingement mortality performance standard

EPA described options a., b., and d. as "essentially" pre-approved technologies that require little if any demonstration for compliance. Options c., e., and f. were described as "streamlined" technologies that require monitoring and reporting requirements that ensure proper operation of the installed control technology. Option g. requires compliance with a numeric performance standard for IM. EPA does not anticipate that retrofit to closed-cycle cooling will be justified to mitigate IM alone. Each of these compliance alternatives has specific information submittal and monitoring requirements.

2. Entrainment Mortality

The Rule requires the Director of the Division of Water to establish BTA for EM for EKPC's facilities on a site-specific basis that reflects the Director's determination of "the maximum reduction in entrainment warranted after consideration of the relevant factors..." (§125.94(d)). For facilities with actual intake flows (AIF[8]) greater than 125 MGD, the rule requires the submission of a number of reports that provide information to be used as the basis of the Director's decision on BTA for EM. Facilities with AIF less than 125 MGD are not required to perform these studies but are still subject to a BTA determination by the Director under §125.98(f).

EPA stated in the preamble to the final Rule that "EPA is not implying or concluding that the 125 MGD threshold is an indicator that facilities withdrawing less than 125 MGD are (1) not causing any adverse impacts or (2) automatically qualify as meeting BTA". The Director has the discretion to still require some or all of these studies for facilities with an AIF less than 125 MGD "if there is reasonable concern regarding entrainment impacts."

As listed in §125.98(f)(2), a number of factors must be considered in the Director's determination, including:

- The number and types of organisms entrained, including federally-listed T&E species and/or critical habitat.
- Impact of particulate emissions and other pollutants.
- Land availability for entrainment technology.
- Remaining useful life of the plant.
- Quantified and qualitative social costs and benefits.

[8] AIF is the defined as the average rate of pumping by the facility over the last three years. AIF may account for days with zero flow. Five years after the effective date of the rule, the previous five years of record is used in calculating AIF.

Further, §125.98(f)(3) states that the Director may base the decision on the following factors "to the extent the applicant submitted information under 40 CFR 122.21(r):"

- Entrainment impacts on the waterbody.
- Thermal discharge impacts.
- Credit for flow reduction with unit retirement in the preceding 10 years.
- Impacts on reliability of energy delivery.
- Impacts on water consumption.
- Availability of water for reuse.

3. Information and Data Submittals

Section 122.21(r)(1)(ii) requires that all existing facilities with design intake flows of greater than 2 MGD submit to the Director information required under paragraphs (r)(2) and (3) and applicable provisions of paragraphs (4) through (8) Section 122.21 (r). For facilities with AIF greater than 125 MGD, the required additional studies include five additional reports described at §122.21(r)(9-13). The first is an entrainment characterization study (§122.21(r)(9)) with a minimum duration of two years. The entrainment study will support additional studies including a technical feasibility and cost study of entrainment mitigation measures (§122.21(r)(10)) which at minimum is to include closed-cycle cooling, fine mesh screens with a mesh size of 2 millimeters or smaller, and water reuse or alternate sources of cooling water. The Director may require evaluation of additional measures for entrainment mitigation. Additional studies include a Benefits Valuation Study (§122.21(r)(11)) and a Non-water Quality Environmental and Other Impacts Study (§122.21(r)(12)). Reports (10) through (12) require external peer review as provided by §122.21(r)(13). The reviewers are selected by the applicant and approved by the Director, and must have "appropriate qualifications". The applicant must provide an explanation for any "significant" reviewer comments that are not accepted.

The Director may reduce or waive some or all of the information required under paragraphs (r)(9) to (13) if the facility intends to comply with the BTA standards for entrainment using a closed-cycle recirculating system. The Director also has discretion to waive some of the submittal requirements under §122.21(r) if the intake is located in a manmade lake or reservoir and the fisheries are stocked and managed by a State or Federal natural resources agency or equivalent. Finally, existing facilities are required to submit any additional information deemed necessary by the National Pollutant Discharge Elimination System (NPDES) director to determine permit conditions and requirements, potentially including information requested by the U.S. Fish & Wildlife Service (USFWS) and/or the National Marine Fisheries Service under §125.98(h).

As to the timing of the information submittals and determinations of IM and EM requirements, for facilities with pending NPDES renewal applications as of the rule's effective date that will result in a renewal permit being issued before July 2018, the information and studies required by §122.21(r) should not be due until the next NPDES Permit application is submitted (i.e., the next 5-year permitting cycle). However, the permitting authority has discretion to establish a schedule for submitting the information in the next renewal permit. Additional IM and EM controls, if any, would be generally determined by the agency in the next permitting cycle along with any necessary compliance schedule for designing and installing any necessary controls.

B. Potential Spurlock Station 316(b) Requirements

1. Spurlock Station Cooling Water System Description

The cooling system consists of four evaporative mechanical draft cooling towers with a combined makeup water requirement of 21.6 MGD. Spurlock Station withdraws water for cooling tower makeup and other purposes from the Ohio River. The station's CWIS consists of two submerged passive wedgewire intake screens, an intake sump, and three vertical makeup water pumps. The screens consist of welded Type 304 stainless steel wedgewire strainer elements with circumferential 1/8 inch slot construction. They each have a design capacity of 14,050 gallons per minute (gpm) and a maximum through-slot velocity 0.5 fps at design flow. The calculated velocity through the strainer elements is 0.466 fps. Debris collected in the screen is periodically cleaned by a compressed air backwash system, which is capable of producing a backwash pressure of 150 pounds per square inch (psi).

Makeup water is withdrawn through the two submerged intake screens by gravity and flows into the intake sump. Each pump is rated for 5,000 gpm at 141.5 feet of head and is driven by a 250 hp/1.15 service factor, 1,180 rpm motor manufactured by General Electric. The cooling water intake structure does not employ traveling water screens.

2. Spurlock Station Compliance Options

Spurlock Station's passive wedgewire screens have a maximum design through-screen velocity of 0.5 fps; therefore, the intake screens should be considered BTA for IM under §125.94(c)(2). Spurlock Station's closed-cycle cooling system should also be considered BTA for IM under §125.94(c)(1).

Spurlock Station utilizes a closed-cycle recirculating cooling system with maximum makeup water demand of 21.6 MGD, which is substantially under the rule's AIF threshold of 125 MGD that would subject it to the rule's requirement for comprehensive entrainment studies. As discussed above, facilities with AIF less than 125 MGD are not required to perform the entrainment studies required under §§122.21(r)(9) through (13) but are still subject to a BTA determination by the Director under §125.98(f).

An additional factor that could impact the expectation that no additional controls will be required for IM or EM at Spurlock Station is whether there are potential issues with federally-listed threatened or endangered (T&E) species or designated critical habitat. A recent review of listed species in the vicinity of the Spurlock Station intake indicated two federally-listed endangered mussel species that may be present in the source waterbody, the fanshell (Cyprogenia stegaria) and the sheepnose (Plethobasus cyphyus). Of the two, the sheepnose is more likely to be present as it is known to occur within the Ohio River. There are no critical habitat designations in the adjacent segment of the Ohio River near Spurlock Station. With regard to T&E species, the Director, in consultation with the Services, determines additional control measures that may be required "to minimize incidental take, reduce or remove more than minor detrimental effects to federally-listed species and designated critical habitat, or avoid jeopardizing federally-listed species or destroying or adversely modifying designated critical habitat" under §125.94(g). At this point in time, EKPC is unaware of any potential impacts to T&E species.

Spurlock Station's KPDES permit was issued by the Kentucky Division of Water on October 23, 2018 with a compliance date of January 1, 2019. The KPDES permit confirms that Spurlock Station's existing closed-cycle recirculating cooling water system is BTA for both impingement and entrainment under the final Section 316(b) existing facilities rule. In addition, the Division allowed EKPC to submit existing data from other facilities on the well-studied Ohio River in lieu of an entrainment sampling requirement in that permit.

C. Potential Cooper Station 316(b) Requirements

1. Cooper Station Cooling Water System Description

The cooling system at the Cooper Station consists of two condensers equipped with once-through cooling systems. The permanent intake structures are located in Lake Cumberland approximately 25 feet from the shoreline and withdraw water at an elevation of 671 feet mean sea level (MSL), which under full pool conditions (723 feet MSL) is approximately 52 feet below the water surface.

The once-through cooling water system at Cooper Station has a design intake flow of approximately 208 MGD. Unit 1's intake has a design capacity of 89.2 MGD and consists of two 42-inch intake pipes, two hydraulic turbine pumps to lift water to the elevated screen house, two conventional traveling screens, two 32,000 gallon per minute (gpm) circulating water pumps, and a fish return system. The conventional traveling screens are 10 feet wide, have 3/8-inch screen openings, and a minimum maintained wetted screen depth of 30 feet. The estimated through-screen velocity at design flow is 0.34 fps. The estimated velocity at the two 42 inch intakes located in the lake at design flow is 7.2 fps.

Unit 2's intake has a design capacity of 118.9 MGD and consists of two 48-inch intake pipes, two hydraulic turbine pumps to lift water to the elevated screen house, two conventional traveling screens, two 40,000 gpm circulating water pumps, and a fish return system. The traveling screens are 10 feet wide, have 3/8-inch screen openings, and a minimum maintained wetted screen depth of 30 feet. The estimated through-screen velocity at design flow is 0.45 fps. The estimated through-pipe velocity at the two 48 inch intakes located in the lake at design flow is 7.3 fps.

An 8-cell cooling tower was also retrofitted to Unit 2 in 2007 and brought online in 2009, and was operated during warm water months to offset the elevated intake temperatures at the surface due to the lower lake levels that existed while Wolf Creek Dam was being repaired. When operating, the cooling tower has an average makeup water demand of 3.25 MGD, substantially reducing the cooling water supply requirement for Unit 2 and the overall demand for the station. The estimated through-pipe velocity at the Unit 2 intakes drops to 0.2 fps during cooling tower operation and the through-screen velocity drops to an estimated 0.012 fps.

The traveling screens are typically manually operated twice per day but may operate more frequently when the debris loads are high and increased differential pressure across the screens triggers automatic operation. Fish and debris are washed into a trough below the traveling screens and then conveyed through a pipe, which releases fish back into the lake.

2. Cooper Station Compliance Options

The calculated through-screen velocities are less than the 0.5 fps threshold; therefore, based on the Rule's definitions, the existing screens should be considered best technology available (BTA) for impingement mortality as a pre-approved technology under §125.94(c)(2). EKPC should only need to demonstrate that the screen design results in a through-screen velocity that does not exceed the 0.5 fps threshold under minimum water levels and maximum head differential. At Cooper Station, water level in the elevated wet wells for both intakes is independent of the lake level; therefore, the minimum maintained wetted screen depth of 30 feet would be used in the demonstration of compliance of the intake design. The final Rule deleted requirements for facilities to deploy technologies to avoid entrapment but required that entrapped organisms be included as impingement mortality. The Director may use his or her discretion to require additional controls if entrapment is considered to be a substantial concern.

While there are no biological compliance monitoring requirements for pre-approved technologies and no requirement to meet specific reductions in impingement mortality due to entrapment, the rule does specifically prohibit take of threatened or endangered species. Based on available information, there are no federally-listed species known to occur within Lake Cumberland near Cooper Station that would be susceptible to effects due to impingement or entrainment.

Cooper Station's design capacity of 223 MGD could potentially result in an AIF that exceeds the rule's 125 MGD threshold that would subject it to the requirement for an entrainment characterization study. However, several circumstances have resulted in an actual intake flow (AIF) of less than 100 MGD for the last three years, including:

- Low capacity factor for Unit 1 (approximately 30 percent or less).
- The units operate on one pump only from December through March when lake water temperatures are low.
- Operation of the Unit 2 cooling towers prior to return to normal lake levels in 2013.

EKPC has estimated that without seasonal operation of the Unit 2 cooling towers the combined flow reduction from the low Unit 1 capacity factor and winter operations on one circulating pump would potentially yield an AIF of approximately 155 MGD. Cooper Station will need to closely examine its ability to remain below the 125 MGD threshold (with or without including the Unit 2 cooling tower as part of the flow reduction strategy) to avoid being categorically included in the rule's requirement to submit reports for entrainment BTA under §§122.21(r)(9) through (13). Otherwise, EKPC would need to undertake extensive entrainment studies of the CWIS impacts of both Units 1 and 2. EKPC will evaluate the costs and other aspects of either seasonal or periodic operation of the Unit 2 cooling towers as a potential compliance option to remain below the 125 MGD threshold.

Even if Cooper Station can maintain flows below the 125 MGD threshold, facilities with an AIF less than 125 MGD are still subject to an entrainment BTA determination by the Director under §125.98(f) where the Director must determine "the maximum reduction in entrainment warranted after consideration of factors relevant for determining the best technology available for minimizing adverse environmental impact at each facility".

The factors which the Director must/may consider in the best professional judgement (BPJ) decision are listed above, with the Director given discretion as to the relative weighting of each factor. First and foremost amongst the factors is consideration of the numbers and types of organisms entrained (including federally-listed T&E species and designated critical habitat). With no current/known potential for impacts to T&E species, EKPC believes the Director would likely focus on the numbers and types of organisms entrained, for which existing site-specific data are not available.

This data gap may be filled through a literature search on the life history of the fish community present in Lake Cumberland, and in particular, the periods of peak reproductive activity and the distribution of early life stages in the water column. This information, along with the absence of federally-listed T&E species, would constitute an important component of the Baseline Biological Characterization to be submitted under §122.21(r)(4). Using available biological data, EKPC plans to evaluate whether the location of the submerged intake at a depth of 52 feet minimizes the potential for entrainment of these early life stages, and supports a determination by the Director that additional measures to reduce EM (such as use of the existing Unit 2 cooling towers) are not warranted.

Cooper Station will need to submit the information outlined in §§122.21(r)(2)-(8) unless the Director uses his authority under §125.95(a)(3) to waive some or all of the §122.21(r) reports in a "manmade lake or reservoir" with "fisheries [that] are stocked and managed by a State or Federal natural resources agency or equivalent." This provision could potentially apply since Lake Cumberland has no federally-listed T&E species and is currently stocked by the Kentucky Department of Fish and Wildlife Resources with walleye and striped bass, is considering stocking of shell cracker, and is implementing a recovery program to reintroduce lake sturgeon.

EKPC will need to discuss the basis of its selected IM compliance approach based on maximum design through-screen velocity less than 0.5 fps in the submittal for §122.21(r)(6). As previously discussed, the summary of the biological resources in the source water under §122.21(r)(4) will be important to provide the basis for the determination of EM BTA and gain concurrence by the services. Compliance for IM following the pre-approved 0.5 fps intake design through-screen velocity will eliminate the need for IM monitoring requirements following the Director's decision on IM BTA.

The applicable monitoring provisions for entrainment will vary with the determination of whether Cooper Station's AIF is less than or greater than 125 MGD. If greater than 125 MGD, a two-year entrainment characterization study will need to be implemented and included with the reports required under §§122.21(r)(9)-(13). Beyond this initial two year period, the rule provides the Director the discretion to determine the monitoring frequency, including for potential monitoring that occurs after the EM BTA finding. The rule allows, but does not require, post-entrainment mortality monitoring. It is likely that such a mortality assessment would not be beneficial to the overall assessment strategy and compliance approach.

The final KPDES permit for Cooper Station was issued with an effective date of July 1, 2018. The permit includes a condition to prepare and submit a 316(b) demonstration for the Division "to establish impingement mortality and entrainment BTA requirements as applicable under 40 CFR 125.94(c) and (d)." This demonstration is to be included with the next KPDES permit renewal application due 180 days prior to permit expiration (approximately December 31, 2022). While the actual intake flow at Cooper is <125 MGD and therefore the submittals for entrainment BTA under 40 CFR 122.21 (r)(9) through (13) are not required, based on EKPC's review of the draft permit for Spurlock Station the Division is closely looking at its requirement to assess BTA for entrainment on a best professional judgment basis. This could result in close scrutiny of using the existing cooling towers at Cooper Station and/or the installation of fine mesh wedge wire screens to comply with Section 316(b).

II. Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category

A. Background

The EPA published the Effluent Limitations Guidelines (ELG) final rule on November 3, 2015. The ELG governs the quality of the wastewater that can be discharged from power plants. The Rule phases in more stringent effluent limits for arsenic, mercury, selenium, and nitrogen discharged from wet scrubber systems and zero discharge of pollutants in ash transport water. As initially issued, power plants must comply between 2018 and 2023, depending upon when new Clean Water Act (CWA) permits are required for each respective plant.

EPA is reviewing the ELG Rule and reconsidering a number of issues. EPA issued a final rule, September 18, 2017, postponing the compliance dates for FGD wastewater and bottom ash transport water ELG requirements. In the United States Court of Appeals for the Fifth Circuit, environmental non-governmental organizations (eNGOs) are challenging the ELG postponement as well as the ELG Rule's "best available technology" (BAT) determinations as to legacy wastewater and combustion residual leachate. EPA met with the industry, including G&Ts, to seek input on the content of a future proposed rule addressing these requirements. EPA originally projected that a proposed rule would be issued in December of 2018 and a final rule by the end of 2019; however, these projections have been delayed by the government shutdown in December 2018-January 2019. Compliance with the Rule is not expected to be required before 2023.

B. Potential ELG Requirements for Spurlock Station

Wastewaters at Spurlock Station are generated from several sources, including ash transport waters, ash pond overflow, low volume waste, coal pile runoff, cooling tower blowdown, FGD scrubber blowdown, metal cleaning wastes, and storm water. The ash pond receives clarifier solids and other wastewaters from the pretreatment area and boiler bottom ash water in addition to effluent from the material handling storage pond. Flows from the primary lagoon and ash pond are directed to the secondary lagoon, along with FGD scrubber blowdown from FGD Units 1 and 2. Cooling tower blowdown can be directed to either the primary or secondary lagoons. Chemical precipitation is used to treat chemical metal cleaning wastes.

C. Potential ELG Requirements for Cooper Station

Wastewaters at Cooper Station are generated from several sources and include once-through cooling water, cooling tower blowdown, metal cleaning wastes, coal pile runoff, CCR landfill leachate, and storm water. Cooper Station already utilizes dry handling for fly ash and bottom ash and, therefore, no impacts on these activities are expected from the final ELGs. Similarly, Cooper Station already employs sedimentation through an impoundment for treatment of CCR leachate from the landfill, so no impacts are expected from the ELG unless more stringent standards are adopted in the final rule. Cooper Station does not operate a wet FGD.

Depending on the requirements of the final rule with respect to non-chemical metal cleaning wastes, the final rule could have some impact on the manner in which such wastewater streams are handled. However, the potential exists for the same exemption that exists under the current KPDES Permit for non-chemical metal cleaning wastes, which are discharged to the coal pile runoff pond and are treated in a physical chemical wastewater treatment plant prior to being discharged.

III. Waters of the United States (WOTUS)

On February 28, 2017, the President of the United States issued an Executive Order directing EPA and the Department of the Army to review and rescind or revise the 2015 Clean Water Rule. The agencies are in the process of reviewing the 2015 Rule and considering a revised definition of WOTUS consistent with the Executive Order and the 1986/1988 Regulatory Definition of WOTUS as defined below:

40 CFR 230.3(s) The term waters of the United States means:

1. All waters which are currently used, or were used in the past, or may be susceptible to use in interstate or foreign commerce, including all waters which are subject to the ebb and flow of the tide;
2. All interstate waters including interstate wetlands;
3. All other waters such as intrastate lakes, rivers, streams (including intermittent streams), mudflats, sandflats, wetlands, sloughs, prairie potholes, wet meadows, playa lakes, or natural ponds, the use, degradation or destruction of which could affect interstate or foreign commerce including any such waters:
    a. Which are or could be used by interstate or foreign travelers for recreational or other purposes; or
    b. (From which fish or shellfish are or could be taken and sold in interstate or foreign commerce; or
    c. Which are used or could be used for industrial purposes by industries in interstate commerce;
4. All impoundments of waters otherwise defined as waters of the United States under this definition;
5. Tributaries of waters identified in paragraphs (s)(1) through (4) of this section;
6. The territorial sea;
7. Wetlands adjacent to waters (other than waters that are themselves wetlands) identified in paragraphs (s)(1) through (6) of this section; waste treatment systems, including treatment ponds or lagoons designed to meet the requirements of CWA (other than cooling ponds as defined in 40 CFR 423.11(m) which also meet the criteria of this definition) are not waters of the United States.

WOTUS does not include prior converted cropland. Notwithstanding the determination of an area's status as prior converted cropland by any other federal agency, for the purposes of the Clean Water Act, the final authority regarding Clean Water Act jurisdiction remains with EPA. The EPA and the Army continue to review the U.S. District Court for the District of South Carolina's decision to vacate and nationally enjoin the agencies' final Rule that added an applicability date to the 2015 Clean Water Rule. Pursuant to the Court's order, the 2015 Clean Water Rule is now in effect in 22 states, the District of Columbia, and the U.S. territories. While the litigation continues, the agencies are complying with the District Court's order and implementation issues that arise are being handled on a case-by-case basis.

The definition of WOTUS currently applicable in 28 states is the definition promulgated in 1986/1988, implemented consistent with subsequent Supreme Court decisions and guidance documents.

The agencies recognize the uncertainty this decision has created and are committed to working closely with states and stakeholders to provide updated information on an ongoing basis regarding which rules are in place in which states.

Kentucky, currently, utilizes the pre-2015 definition for the Waters of the United States and Commonwealth. Since EKPC borrows money from RUS, the National Environmental Policy Act is applicable to all EKPC capital projects. All the capital projects are vetted and go through RUS NEPA process for RUS Environmental and Engineering permitting and approval. Should any capital projects impact WOTUS, the NEPA process resultant report is reviewed and approved by RUS via the NEPA process which includes public participation. As a cooperating regulatory federal agency the United States Army Corp of Engineers (USACE) reviews the environmental report or environmental assessment for their permit purposes and issues a Finding of No Significant Impact (FONSI), or an Environmental Assessment (EA) as authorization of the project. Should the USACE identify impacts to the WOTUS, the permit applicant must submit a mitigation plan and/or pay the mitigation fees, bank or self-mitigate the project.

IV. Coal Combustion Residual Rule (CCR)

On June 21, 2010, EPA published the Proposed Rule for Disposal of Coal Combustion Residuals (CCRs) from Electric Utilities. EPA provided two co-proposals for public comment: regulation of CCRs as a hazardous, or "special," waste under RCRA subtitle C and regulation of CCRs as a solid waste under RCRA subtitle D. EPA stated that it supports and has endeavored to maintain beneficial reuse of CCRs under both proposed rules. The Subtitle C alternative has extensive repercussions and there are serious questions as to whether the industry could comply with these requirements.

On April 17, 2015, the EPA published a final rule regulating management of CCR under the Resource Conservation and Recovery Act. The CCR Rule became effective on October 14, 2015. The final Rule applies to landfills and surface impoundments that contain CCRs. The CCR Rule establishes minimum national criteria for the safe disposal of CCR. The criteria address a wide spectrum of activities related to CCR. Areas addressed include location restrictions, structural integrity requirements, liner design criteria, operations, groundwater monitoring, closure and post-closure requirements. CCR includes fly ash, bottom ash, boiler slag and flue gas desulfurization materials.

The requirements in the final Rule do not apply to:

(1) CCR landfills that ceased receiving CCR prior to the effective date of the rule
(2) CCR units at facilities that have ceased producing electricity prior to the Rule being effective
(3) CCR generated at facilities that are not part of an electric utility or independent power producer, such as manufacturing facilities, universities and hospitals
(4) fly ash, bottom ash, boiler slag, and flue gas desulfurization generated primarily from the combustion of fuels other than coal (unless the fuel burned consists of more than fifty percent coal on a total heat input or mass input basis) whichever results in the greater mass feed rate of coal
(5) CCR that is beneficially used
(6) CCR placement at active or abandoned underground or surface coal mines or
(7) municipal solid waste landfills that receive CCR

The final CCR Rule applies to owners and operators of landfills and surface impoundments and establishes minimum national criteria for the safe disposal of solid waste CCR. The criteria address a wide spectrum of activities related to CCR solid waste disposal. Areas addressed include location restrictions, structural integrity requirements, liner design criteria, operations, groundwater monitoring, closure and post-closure requirements. The closure and post-closure requirements resulted in the Cooperative revising its asset retirement obligations. Additionally, the CCR Rule sets out recordkeeping and reporting requirements, as well as the requirement for each facility to establish and post specific information to a publicly-accessible website. In 2016, the Cooperative established a website for CCR postings, as required by the CCR Rule.

The Water Infrastructure Improvements for the Nation (WIIN) Act became effective law on December 16, 2016. Overall, the WIIN Act is comprehensive legislation that aims to improve the United States' water resources infrastructure. The WIIN Act also includes an amendment to the CCR Rule. Specifically, the WIIN Act allows for a state permit program for CCR management that is at least as protective as the federal coal combustion residual rule. The WIIN Act also granted the EPA authority to directly enforce the implementation of the CCR Rule and an approved state permit program. In the absence of an approved state program, the WIIN Act requires EPA to put its own program in place.

Certain provisions of the CCR Rule were remanded back to EPA by the D.C. Circuit of Appeals for further action on June 14, 2016. On March 15, 2018, EPA proposed a rule to address these remanded issues. The key issue for the Remand Rule is for EPA to delay future CCR compliance deadlines. A final Rule extending certain CCR compliance deadlines was published on July 30, 2018.

The final Rule provides for the following:

- Delayed the deadlines for CCR Units that have detected a statistically significant increase in a covered pollutant or cannot comply with aquifer requirements to close from six months to until October 31, 2020.
- Allows the suspension of groundwater monitoring for up to ten years where there is no potential for migration of CCR constituents to groundwater.
- Adds limits for cobalt, lithium, molybdenum, and lead.
- Allows State Directors of approved programs to approve compliance measures instead of a third party professional engineer.

On August 22, 2018, the United States District Court for the District of Columbia issued an opinion in the *USWAG v. EPA*. The Court found that unlined impoundments are likely to leak, that contamination is likely to create an unacceptable risk to human health and the environment, and that only twice-yearly monitoring would allow leaks to go undetected. The Court found that clay-lined impoundments are similarly insufficiently protective. The Court further found that RCRA provides authority to regulate both active and inactive units and rejected the exemption for legacy ponds (described as a subset of inactive impoundments) as arbitrary and capricious. EPA is in the process of revising the CCR Rule to address the issues identified by the Court. In the meantime, the current CCR Rule stays in place. NRECA, with USWAG representatives, have met with EPA to discuss the agency's plans for complying with the decision. EPA is expected to issue a proposed rule sometime in 2019.

EKPC facilities are in compliance with the CCR Rule. Spurlock Station has three regulated CCR units (one surface impoundment and two landfills); Cooper Station has a regulated CCR unit (landfill); and Smith Station has a regulated CCR unit (landfill). The Dale Station ash ponds are not subject to the CCR Rule because the facility did not generate electricity after October 19, 2015. The ponds have been closed by removal in accordance with a closure plan approved by the Kentucky Division of Waste Management. EKPC's CCR units are presently in detection monitoring, except for the Spurlock Station surface impoundment, which is in assessment monitoring. None of the constituents in the CCR units have been detected at statistically significant levels above the groundwater protection standards established under the CCR Rule. Therefore, no corrective action is required. In addition, EKPC is moving forward with a compliance plan, approved by the Public Service Commission, to proactively close the Spurlock Station surface impoundment by removal. This plan will place EKPC in a favorable compliance position should EPA's response to the DC Circuit opinion mandate closure of unlined ponds.

SECTION 10.0

FINANCIAL PLANNING

REDACTED

SECTION 10.0

FINANCIAL PLANNING

807 KAR 5:058 Section 9(1-4). The integrated resource plan shall, at a minimum, include and discuss the following financial information: (1) Present (base year) value of revenue requirements stated in dollar terms; (2) Discount rate used in present value calculations; (3) Nominal and real revenue requirements by year; and (4) Average system rates (revenues per kilowatt hour) by year.

Table 10-1 provides the Present (base year) value of revenue requirements stated in dollar terms for this IRP and the Nominal and Real Revenue Requirements (in $millions) from the owner-members. The Average Rate for each of the forecasted years included in the plan is defined as the Nominal Revenue Requirements divided by the total Sales to Members (in cents/kWh) and is also included in Table 10-1 below.

The discount rate used in present value calculations is the weighted average cost of EKPC's outstanding long-term debt as of December 31, 2018 multiplied by a [redacted] TIER.

Table 10-1
Revenue Requirements and Average System Rates

Year	Sales to Members (MWh)	Total From Members Nominal $ ($000)	Total From Members Real 2019$ * ($000)	Total From Members Present Value ($000)	Nominal Cents per kWh	Real Cents per kWh Real 2019$
2019	[redacted]					
2020	[redacted]					
2021	[redacted]					
2022	[redacted]					
2023	[redacted]					
2024	[redacted]					
2025	[redacted]					
2026	[redacted]					
2027	[redacted]					
2028	[redacted]					
2029	[redacted]					
2030	[redacted]					
2031	[redacted]					
2032	[redacted]					
2033	[redacted]					
			** PV =	[redacted]		

* Assumes an annual inflation rate of [redacted]

** Present value of revenue requirements using EKPC's discount rate of [redacted] and a base date of 12/31/2018.

SECTION 11.0

SYSTEM MAP

SECTION 11.0

SYSTEM MAP

807 KAR 5:058 Section 8.(3)(a) The following information regarding the utility's existing and planned resources shall be provided. A utility which operates as part of a multistate integrated system shall submit the following information for its operations within Kentucky and for the multistate utility system of which it is a part. A utility which purchases fifty (50) percent or more of its energy needs from another company shall submit the following information for its operations within Kentucky and for the company from which it purchases its energy needs. (a) A map of existing and planned generating facilities, transmission facilities with a voltage rating of sixty-nine (69) kilovolts or greater, indicating their type and capacity, and locations and capacities of all interconnections with other utilities. The utility shall discuss any known, significant conditions which restrict transfer capabilities with other utilities.

Please see system map on the following page.

System Map

Confidential protection of the system map has been requested in the form of a motion for confidential treatment.