2022 INTEGRATED RESOURCE PLAN

EAST KENTUCKY POWER COOPERATIVE

A Touchstone Energy® Cooperative

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Noted	807 KAR 5:058 Section 1(1)	General Provisions. This administrative regulation shall apply to electric utilities under commission jurisdiction except a distribution company with less than $10,000,000 annual revenue or a distribution cooperative organized under KRS Chapter 279.
Noted	807 KAR 5:058 Section 1(2)	**Each electric utility shall file triennially with the commission an integrated resource plan. The plan shall include historical and projected demand, resource, and financial data, and other operating performance and system information, and shall discuss the facts, assumptions, and conclusions, upon which the plan is based and the actions it proposes.**
Noted	807 KAR 5:058 Section 1(3)	**Each electric utility shall file ten (10) bound copies and one (1) unbound, reproducible copy of its integrated resource plan with the commission.**
N/A	807 KAR 5:058 Section 3	**Waiver. A utility may file a motion requesting a waiver of specific provisions of this administrative regulation. Any request shall be made no later than ninety (90) days prior to the date established for filing the integrated resource plan. The commission shall rule on the request within thirty (30) days. The motion shall clearly identify the provision from which the utility seeks a waiver and provide justification for the requested relief which shall include an estimate of costs and benefits of compliance with the specific provision. Notice shall be given in the manner provided in Section 2(2) of this administrative regulation.**
15	807 KAR 5:058 Section 4(1)	**Format: 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.**
15	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.
807 KAR 5:058 Section 5		Plan Summary. The plan shall contain a summary which discusses the utility's projected load growth and the resources planned to meet that growth. The summary shall include at a minimum:
1-3	807 KAR 5:058 Section 5(1)	Description of the utility, its customers, service territory, current facilities, and planning objectives;

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69	807 KAR 5:058 Section 5(2)	Description of models, methods, data, and key assumptions used to develop the results contained in the plan;
63-65, 70-71	807 KAR 5:058 Section 5(3)	Summary of forecasts of energy and peak demand, and key economic and demographic assumptions or projections underlying these forecasts;
157	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;
9	807 KAR 5:058 Section 5(5)	Steps to be taken during the next three (3) years to implement the plan;
10 - 13	807 KAR 5:058 Section 5(6)	Discussion of key issues or uncertainties that could affect successful implementation of the plan.
16 - 25	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 changes.
807 KAR 5:058 Section 7		**Load Forecasts. The plan shall include historical and forecasted information regarding loads.**
(a) 84 (b) 84 (c) 84 (d) 85 (e) 86 (f) 1 (g) 67 - 68	807 KAR 5:058 Section 7(1)	**The information shall be provided for the total system and, where available, disaggregated by the following customer classes:** **(a) Residential heating;** **(b) Residential nonheating;** **(c) Total residential (total of paragraphs (a) and (b) of this subsection);** **(d) Commercial;** **(e) Industrial;** **(f) Sales for resale;** **(g) Utility use and other.** **The utility shall also provide data at any greater level of disaggregation available.**

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(a) 84 - 89 (b) 74 (c) 74 (d) 74 (e) 75 (f) 68 (g) 66, 111 - 121 (h) 23, 24, 73, 75	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.**
84 - 93	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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(a) 67 - 68 (b) 65 (c) 77 (d) 66, 115 - 119 (e) 89	807 KAR 5:058 Section 7(4)	The following information shall be filed for each forecast: (a) Annual energy sales and generation for the system and sales disaggregated by class as defined in subsection (1) of this section; (b) Summer and winter coincident peak demand for the system; (c) If available for the first two (2) years of the forecast, monthly forecasts of energy sales and generation for the system and disaggregated by class as defined in subsection (1) of this section and system peak demand; (d) The impact of existing and continuing demand-side programs on both energy sales and system peak demands, including utility and government sponsored conservation and load management programs; (e) Any other data or exhibits which illustrate projected changes in load or load characteristics.
75	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:
N/A	807 KAR 5:058 Section 7(5)(a)	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: 1. Recorded and weather normalized annual energy sales and generation; 2. Recorded and weather-normalized coincident peak demand in summer and winter.
N/A	807 KAR 5:058 Section 7(5)(b)	For each of the fifteen (15) years succeeding the base year: 1. Forecasted annual energy sales and generation; 2. Forecasted summer and winter coincident peak demand.
69	807 KAR 5:058 Section 7(6)	A utility shall file all updates of load forecasts with the commission when they are adopted by the utility.
807 KAR 5:058 Section 7(7)		The plan shall include a complete description and discussion of:
69 - 70	807 KAR 5:058 Section 7(7)(a)	All data sets used in producing the forecasts;

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70 - 71 78 - 83	807 KAR 5:058 Section 7(7)(b)	Key assumptions and judgments used in producing forecasts and determining their reasonableness;
69 - 70, LF Technical Appendix	807 KAR 5:058 Section 7(7)(c)	The general methodological approach taken to load forecasting (for example, econometric, or structural) and the model design, model specification, and estimation of key model parameters (for example, price elasticities of demand or average energy usage per type of appliance);
90 - 93	807 KAR 5:058 Section 7(7)(d)	The utility's treatment and assessment of load forecast uncertainty;
1. 81 2. 78 3. 70 4. 111	807 KAR 5:058 Section 7(7)(e)	The extent to which the utility's load forecasting methods and models explicitly address and incorporate the following factors: 1. Changes in prices of electricity and prices of competing fuels; 2. Changes in population and economic conditions in the utility's service territory and general region; 3. Development and potential market penetration of new appliances, equipment, and technologies that use electricity or competing fuels; and 4. Continuation of existing company and government sponsored conservation and load management or other demand-side programs.
70	807 KAR 5:058 Section 7(7)(f)	Research and development efforts underway or planned to improve performance, efficiency, or capabilities of the utility's load forecasting methods; and
94 - 95	807 KAR 5:058 Section 7(7)(g)	Description of and schedule for efforts underway or planned to develop end-use load and market data for analyzing demand-side resource options including load research and market research studies, customer appliance saturation studies, and conservation and load management program pilot or demonstration projects. Technical discussions, descriptions, and supporting documentation shall be contained in a technical appendix.
157 - 190	807 KAR 5:058 Section 8(1)	Resource Assessment and Acquisition Plan. (1) The plan shall include the utility's resource assessment and acquisition plan for providing an adequate and reliable supply of electricity to meet forecasted electricity requirements at the lowest possible cost. The plan shall consider the potential impacts of selected, key uncertainties and shall include assessment of potentially cost-effective resource options available to the utility.
807 KAR 5:058 Section 8(2)		The utility shall describe and discuss all options considered for inclusion in the plan including:
123 - 141	807 KAR 5:058 Section 8(2)(a)	Improvements to and more efficient utilization of existing utility generation, transmission, and distribution facilities;
N/A	807 KAR 5:058 Section 8(2)(b)	Conservation and load management or other demand-side programs not already in place;

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N/A	807 KAR 5:058 Section 8(2)(c)	Expansion of generating facilities, including assessment of economic opportunities for coordination with other utilities in constructing and operating new units; and
163 - 166	807 KAR 5:058 Section 8(2)(d)	Assessment of nonutility generation, including generating capacity provided by cogeneration, technologies relying on renewable resources, and other nonutility sources.
175	807 KAR 5:058 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.
219	807 KAR 5:058 Section 8(3)(a)	A map of existing and planned generating facilities, transmission facilities with a voltage rating of sixty-nine (69) kilovolts or greater, indicating their type and capacity, and locations and capacities of all interconnections with other utilities. The utility shall discuss any known, significant conditions which restrict transfer capabilities with other utilities.
100 - 103	807 KAR 5:058 Section 8(3)(b)	A list of all existing and planned electric generating facilities which the utility plans to have in service in the base year or during any of the fifteen (15) years of the forecast period, including for each facility: 1. Plant name; 2. Unit number(s); 3. Existing or proposed location; 4. Status (existing, planned, under construction, etc.); 5. Actual or projected commercial operation date; 6. Type of facility; 7. Net dependable capability, summer and winter; 8. Entitlement if jointly owned or unit purchase; 9. Primary and secondary fuel types, by unit; 10. Fuel storage capacity; 11. Scheduled upgrades, deratings, and retirement dates;

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104 - 110	807 KAR 5:058 Section 8(3)(b)(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).
25, 167	807 KAR 5:058 Section 8(3)(c)	Description of purchases, sales, or exchanges of electricity during the base year or which the utility expects to enter during any of the fifteen (15) forecast years of the plan.
173 - 174	807 KAR 5:058 Section 8(3)(d)	Description of existing and projected amounts of electric energy and generating capacity from cogeneration, self-generation, technologies relying on renewable resources, and other nonutility sources available for purchase by the utility during the base year or during any of the fifteen (15) forecast years of the plan.
1. 113 2. 114 3. 115 - 119 4. 120 5. 121	807 KAR 5:058 Section 8(3)(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; 2. Expected duration of the program; 3. Projected energy changes by season, and summer and winter peak demand changes; 4. Projected cost, including any incentive payments and program administrative costs; and 5. Projected cost savings, including savings in utility's generation, transmission and distribution costs.

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1. 65 2. 170 3. N/A 4. N/A 5. N/A 6. 161 7. N/A 8. N/A 9. 166 10. 170 11. 171	807 KAR 5:058 Section 8(4)(a)	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; 6. Reductions or increases in peak demand from new conservation and load management or other demand-side programs; 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.
1. 174 2. 174 3. 174 4. 173 5. 161	807 KAR 5:058 Section 8(4)(b)	On planned annual generation: 1. Total forecast firm energy requirements; 2. Energy from existing and planned utility generating resources disaggregated by primary fuel type; 3. Energy from firm purchases from other utilities; 4. Energy from firm purchases from nonutility sources of generation; and 5. Reductions or increases in energy from new conservation and load management or other demand-side programs;
174	807 KAR 5:058 Section 8(4)(c)	For each of the fifteen (15) years covered by the plan, the utility shall provide estimates of total energy input in primary fuels by fuel type and total generation by primary fuel type required to meet load. Primary fuels shall be organized by standard categories (coal, gas, etc.) and quantified on the basis of physical units (for example, barrels or tons) as well as in MMBtu.

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807 KAR 5:058 Section 8(5)		The resource assessment and acquisition plan shall include a description and discussion of:
160 - 162	807 KAR 5:058 Section 8(5)(a)	General methodological approach, models, data sets, and information used by the company;
161, 163	807 KAR 5:058 Section 8(5)(b)	Key assumption and judgments used in the assessment and how uncertainties in those assumptions and judgments were incorporated into analyses;
121	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;
170	807 KAR 5:058 Section 8(5)(d)	Criteria used in determining the appropriate level of reliability and the required reserve or capacity margin, and discussion of how these determinations have influenced selection of options;
95	807 KAR 5:058 Section 8(5)(e)	Existing and projected research efforts and programs which are directed at developing data for future assessments and refinements of analyses;
177 - 216	807 KAR 5:058 Section 8(5)(f)	Actions to be undertaken during the fifteen (15) years covered by the plan to meet the requirements of the Clean Air Act amendments of 1990, and how these actions affect the utility's resource assessment; and
169	807 KAR 5:058 Section 8(5)(g)	Consideration given by the utility to market forces and competition in the development of the plan. Technical discussion, descriptions and supporting documentation shall be contained in a technical appendix.
217	807 KAR 5:058 Section 9	Financial Information. The integrated resource plan shall, at a minimum, include and discuss the following financial information: 1. Present (base year) value of revenue requirements stated in dollar terms; 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.

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Noted	807 KAR 5:058 Section 10	Notice. Each utility which files an integrated resource plan shall publish, in a form prescribed by the commission, notice of its filing in a newspaper of general circulation in the utility's service area. The notice shall be published not more than thirty (30) days after the filing date of the report.
Noted	807 KAR 5:058 Section 11(1)	Procedures for Review of the Integrated Resource Plan. (1) Upon receipt of a utility's integrated resource plan, the commission shall develop a procedural schedule which allows for submission of written interrogatories to the utility by staff and intervenors, written comments by staff and intervenors, and responses to interrogatories and comments by the utility.
Noted	807 KAR 5:058 Section 11(2)	The commission may convene conferences to discuss the filed plan and all other matters relative to review of the plan.
Noted	807 KAR 5:058 Section 11(3)	Based upon its review of a utility's plan and all related information, the commission staff shall issue a report summarizing its review and offering suggestions and recommendations to the utility for subsequent filings.
27-62	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.)

SECTION 1.0

EXECUTIVE SUMMARY

SECTION 1.0

EXECUTIVE SUMMARY

1.1 General Overview

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

East Kentucky Power Cooperative Inc. ("EKPC") is a not-for-profit, member-owned generation and transmission cooperative located in Winchester, Kentucky. EKPC provides electricity to 16 owner-member distribution cooperatives (owner-members) with more than 550,000 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 the John Sherman Cooper Station in Pulaski County (341 MW) and the Hugh L. Spurlock Station in Mason County (1,346 MW). EKPC owns and operates gas-fired generation at the J.K. Smith Station in Clark County (989 MW winter rating) and Bluegrass Generation Station in Oldham County (567 MW winter rating). EKPC also owns and operates Landfill Gas to Energy renewable generation facilities in Boone County (4.6 MW), Laurel County (3.0 MW), Barren County (0.9 MW), Greenup County (2.3 MW), Hardin County (2.3 MW) and Pendleton County (3.0 MW). EKPC owns an 8.5 MW solar generation facility in Clark County.

EKPC purchases 170 MW of hydropower from the Southeastern Power Administration ("SEPA") on a long-term basis, generated from the Cumberland River hydropower system. Laurel Dam (70 MW) historically has been a reliable resource.

In total, EKPC owns and/or purchases 3,438 MW (winter rating) or 3,136 MW (summer rating) of generation. EKPC operates within the PJM Interconnection, Inc. ("PJM"), which has more than 180,000 MW of generation capacity.

EKPC owns and operates a 2,968-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 77 normally closed free-flowing interconnections with its neighboring utilities.

EKPC is concerned about future reliability of the interconnected electric system and believes that conventional generation resources will continue to be required to facilitate the transition to renewable and low/no carbon emitting resources. Conventional generation resources will be required to maintain reliability as the transition occurs.

One of EKPC's strategic objectives is to actively manage its current and future asset portfolio to safely deliver reliable, affordable and sustainable energy from appropriately diversified resources, and work with federal and state stakeholders to ensure high reliability and economic viability while mitigating evolving regulatory challenges including possible carbon emissions reduction mandates and penalties. EKPC will accomplish this objective by actively managing its current and future asset portfolio to maintain high reliability of electric service to its owner-members and economically diversify its energy resources, including market purchases, fossil fuels, renewables, storage, demand management and energy efficiency programs, and partnering opportunities.

Another strategic objective is to continue to ensure reliability and affordability of electric service while supporting beneficial electrification and thoughtfully responding to growing pressures to decarbonize. EKPC will continue to manage for reliability and minimize negative financial impacts to end consumers while supporting beneficial electrification that could generate exponential load growth, particularly through continuing penetration of electric vehicles, electrification of industrial processes, and electrification of residential and commercial heating applications. EKPC will also work with state, federal, regional, and PJM stakeholders to respond to the legal, regulatory, and industry pressures to decarbonize the fleet through solutions based on science and engineering that ensure electric service continues to be highly reliable and available at an acceptable cost to the public.

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 distribution system 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, sustainability planning and financial forecasting.

The forecast indicates that for the period 2022 through 2036, total energy requirements will increase on average 1.1 percent per year. Winter and summer net peak annual demand will increase by 0.6 percent and 0.8 percent, respectively, on average.

EKPC notes that PJM prepares a load forecast for the full PJM geographic region, including the utility zones in Kentucky that are part of the PJM region. That forecast is used in PJM's long-term transmission expansion planning process and in the PJM Reliability Pricing Model, which are both discussed in later in this IRP. The forecast of is used to drive transmission projects EKPC must construct and EKPC's capacity obligation in PJM's Reliability Pricing Model (RPM) capacity market. EKPC contributes to the analysis by highlighting any anticipated load changes that might impact PJM's forecast.

1.3 Demand Side Management (DSM)

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

For this 2022 IRP, EKPC has contracted with GDS Associates, Inc. ("GDS") to conduct an updated and enhanced study of energy efficiency (EE) and demand response (DR) savings potential. For this study, a cost-effectiveness screening of a comprehensive set of measures using the Total Resource Cost test from the California standard was performed.

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 scenario described as $3 million energy efficiency ("EE") budget from the GDS potential study to develop energy efficiency participation estimates for the DSM programs.

1.4 PJM Membership

EKPC integrated its operations into the PJM market on June 1, 2013. PJM membership continues to drive significant beneficial operation changes and significant cost savings for EKPC's owner-members. 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 180,000 MW) which has significantly affected EKPC's electric power procurement and energy accounting practices. As expected, EKPC's total power supply costs to its owner-members have decreased subsequent to integration due to the economies of scale of a much larger system dispatch (i.e., diversity of supply resources and diversity of load needs across the PJM region). EKPC identified substantial net savings realized through May 31, 2021, as documented in its annual reports to the Executive Director of the Kentucky Public Service Commission ("Commission").

In addition to the daily energy market participation, EKPC participates in the ancillary services markets providing regulation service and synchronized reserves.

EKPC also participates in PJM's capacity market, called Reliability Pricing Model, and Financial Transmission Rights auctions

EKPC's obligation to PJM for capacity is defined by the RPM. PJM establishes a Variable Resource Requirement against which all supply resources clear, establishing the clearing price for committed capacity resources. The Variable Resource Requirement incorporates the reserve requirement established for the particular delivery year. Among other factors, the reserve requirement incorporates PJM's summer peak load forecast, forced outage rates of resources and, an expectation of resources the PJM region might receive from other regions during emergency conditions. The calculated reserve requirement for the delivery year June 1, 2022 through May 31, 2023 is 14.9% installed reserve margin, established in 2021. All EKPC capacity resources that clear in the market are committed to the PJM region to ensure resource adequacy; all committed resources are responsible to perform when PJM needs them to ensure regional reliability. All also must offer into the Day Ahead Energy Market.

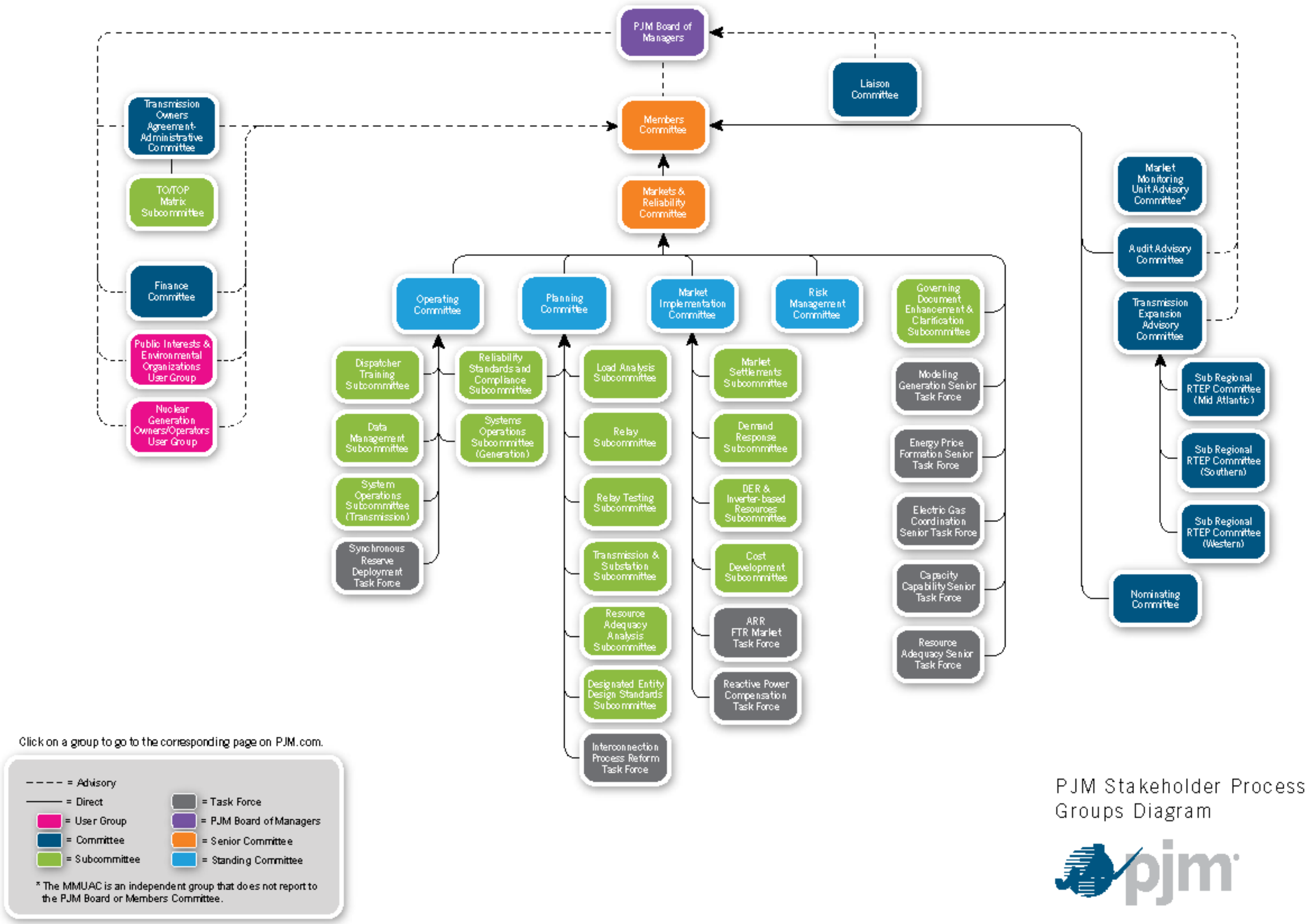
The commitment of capacity resources to be available to produce electricity in a future delivery year, however, does not lock in energy market prices for that future delivery year. The only way to guarantee a maximum cost on energy is to secure enough resources or energy contracts to hedge the prices that may result from the real time conditions and fuel prices in the energy market. EKPC takes measures to hedge its energy price exposure through 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), four additional Standing Committees (Market Implementation, Operating, Planning, and Risk Management Committees), Subcommittees or Working Groups created by these six Committees, and User Groups established in accordance with PJM's Operating Agreement.

Proposals to revise PJM governing documents and business practice manuals are considered in a hierarchical committee process. Proposed changes move from the subcommittees and working groups to their "parent" Standing Committee and from there to the "parent" Senior Committee. Proposals approved by this Stakeholder Process then move from the Senior Committee to the PJM Board of Directors for consideration or approval. Any changes to PJM governing documents must be submitted to the Federal Energy Regulatory Commission ("FERC") for approval.

EKPC is represented on each of the Senior and Standing Committees. EKPC is also represented on key Subcommittees and Working Groups that address matters of importance to EKPC. The EKPC representatives to the PJM Committees, Subcommittees, and Working Groups share what they have heard regarding the issues and policy development within the PJM Stakeholder Process and report to EKPC's Senior Executives. Additionally EKPC representatives advocate for interests through the subcommittees. Please see the PJM committee organizational chart on the following page or visit the following link
https://www.pjm.com/-/media/committees-groups/committee-structure-diagram.ashx


PJM Board of Managers
Members Committee
Markets & Reliability Committee
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
Operating Committee
Planning Committee
Market Implementation Committee
Risk Management Committee
Dispatcher Training Subcommittee
Data Management Subcommittee
System Operations Subcommittee (Transmission)
Synchronous Reserve Deployment Task Force
Reliability Standards and Compliance Subcommittee
Systems Operations Subcommittee (Generation)
Load Analysis Subcommittee
Relay Subcommittee
Relay Testing Subcommittee
Transmission & Substation Subcommittee
Resource Adequacy Analysis Subcommittee
Designated Entity Design Standards Subcommittee
Interconnection Process Reform Task Force
Market Settlements Subcommittee
Demand Response Subcommittee
DER & Inverter-based Resources Subcommittee
Cost Development Subcommittee
ARR FTR Market Task Force
Reactive Power Compensation Task Force
Governing Document Enhancement & Clarification Subcommittee
Modeling Generation Senior Task Force
Energy Price Formation Senior Task Force
Electric Gas Coordination Senior Task Force
Capacity Capability Senior Task Force
Resource Adequacy 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
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

1.5 EKPC Sustainability Plan

In 2018, EKPC's Board of Directors approved an update to the Mission Statement that now reads: EKPC exists to serve its member-owned cooperatives by safely delivering reliable, affordable and sustainable energy and related services. Then EKPC staff embarked on creating a sustainability plan to support the mission statement. Five (5) staff member teams were created to develop a better understanding of the changes taking place in and around the energy industry, changes that will affect EKPC for decades to come. The teams developed a sustainability plan that was approved by the EKPC Board of Directors in 2020. The sustainability plan and individual team initiatives are found at https://www.ekpc.coop/ekpc-planning-future.

1.6 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 beneficially 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, 2021, as described in its annual reports to the Commission. EKPC's existing resource portfolio adequately meets its power supply requirements for the next several years. EKPC continuously evaluates its resource portfolio compared to its forecasted load profile and considers how best to hedge its energy market price exposure and future load needs. EKPC has sufficient capacity resources to meet its forecasted summer load peaks through the IRP study period. It expects to utilize Power Purchase Agreements ("PPAs") to cover the future winter period needs for a hedge against energy price exposure and solar PPAs to meet its sustainability goals on an economic basis.

1.7 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-member Cooperatives by safely delivering reliable, affordable and sustainable energy and related services. EKPC's objective of the power supply plan is to develop an economic, reliable and sustainable 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 EKPC's long term plans.

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

- Continue to monitor economic and load growth conditions including distributed generation;
- Continue to develop and promote cost-effective DSM programs;
- Monitor sustainable energy resources and obtain resources through Power Purchase Agreements as needed to meet strategic and load driven directives;
- Continue to evaluate energy price hedges for winter seasons 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.
- Advocate for rules and policies that resolve the current PJM interconnection queue backlog.

1.8 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. Below are the risks and uncertainties identified by EKPC.

- *Continue to monitor economic and load growth conditions including distributed generation.* 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, as well as distributed generation being installed behind the meter throughout the system, 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 customers will ultimately determine the amount of energy savings and capacity that is avoided. EKPC uses California tests to cost justify its DSM tariffs. The California tests compare DSM programs to the avoided costs of capacity and energy. EKPC is pursuing DSM programs that pass the Total Resource Cost ("TRC") tests. EKPC has re-evaluated all of its DSM programs for cost-effectiveness. Some programs have been 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.

- *Monitor sustainable energy resources and obtain resources through Power Purchase Agreements as needed to meet strategic and load driven directives.* EKPC has developed a sustainability plan that indicates EKPC will need to obtain additional green energy resources to meet its goals. EKPC's owner-members are receiving more requests from their large consumers to provide green energy options for their power supply. EKPC will seek to secure the requested power supply alternatives. EKPC's Wholesale Renewable Energy tariff, frequently called the Green Energy Tariff, has been developed in direct response to these requests. Because EKPC is not a taxable entity, it has been more economic for EKPC to purchase power from an entity that can take full advantage of the federal tax savings than to develop its own solar projects. EKPC plans to advocate for policies that would allow non-taxable entities such as cooperatives and municipals to receive similar financial incentives as renewable developers that are taxable.

- *Continue to evaluate energy price hedges for winter seasons and review against market and owned-generation options.* The PJM capacity obligation EKPC must satisfy is based on the summer peak load forecast. EKPC has sufficient capacity resources in its portfolio to satisfy summer peak load requirements. Providing adequate capacity does not ensure energy prices. EKPC must continually review its available resources compared to its energy needs on an on-going basis to provide an adequate price hedge for its energy needs throughout the year. EKPC's owned generation resources and long term contracts provide adequate energy price hedges for all but the coldest winter months. EKPC continually reviews its options for supplying adequate energy price hedges for the winter season and thus far, has determined that securing firm energy purchases from third parties for specific months is its most economic option. EKPC's experiences in January of 2014 and February of 2015 highlighted the need to secure price hedges for its winter energy. Based on the results of the studies described in Section 8 of this IRP, EKPC intends to purchase PPAs to cover its future winter energy price hedges. EKPC will seek to find the most economic alternative to meet its power supply requirements while also ensuring satisfaction of state and federal environmental requirements.

- *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 savings that accrued to its members from June 1, 2013 through May 31, 2021 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. EKPC provides continuing education to its System Operators to keep them certified to operate within the PJM system, and provides training 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, affordable and sustainable energy from appropriately diversified fuel sources to its owner-members. EKPC supports the deployment of renewable and other no/low carbon emitting generation resources onto the transmission grid. However, EKPC is concerned about future reliability of the interconnected electric system and believes that conventional generation resources will continue to be required to facilitate the transition to renewable and low/no carbon emitting resources. Conventional generation resources will be required to maintain reliability as the transition occurs.

- *Advocate for rules and policies that resolve the current PJM interconnection queue backlog.* All generation resources seeking to connect to the PJM transmission system, including EKPC's transmission system, must be studied by PJM to ensure any necessary upgrades to the system are made to reliably support the injection of power and delivery to load across the PJM system. PJM has become significantly delayed in finalizing the study results of hundreds of projects in the study queue. Unless the generation project is in the last steps of the study process, it is unlikely that the project will be able to move forward to construction in the next few years. Neither EKPC nor any other generation developer will be able to construct a project not currently in the queue for several years as PJM works through the backlog of project studies PJM and stakeholders have developed a proposed solution to address this issue and expect to file the proposal with the Federal Energy Regulatory Commission in May 2022. At this time EKPC does not expect a reliability issue to materialize from the backlog, but because of the significant delay that any new project will experience, a concern could arise if a generator needed to deactivate or repower and its replacement is delayed. Delays also may challenge the achievement of decarbonization or other sustainability goals. Green Power Tariff requests as well as projects desired to meet sustainability goals, may face delays in project development. EKPC will stay actively involved in PJM policy and rules development in an effort to advance its ability to meet future energy and capacity needs. More details are included in section 6.0 of this IRP.

1.9 EKPC Demand Side Management and Renewable Energy Collaborative (Collaborative 2.0)

EKPC re-engaged the public interest groups and other interested parties in 2021 and established the EKPC Sustainability Collaborative. A new charter for the Collaborative was created with its primary purpose of promoting participation in demand side management, energy efficiency, renewable energy, and beneficial electrification programs offered by EKPC and EKPC's owner-member cooperatives. The following table identifies the organizations participating in the Collaborative.

EKPC | SUSTAINABILITY COLLABORATIVE

Company/Organization	
East Kentucky Power Cooperative	Bluegrass GreenSource
Big Sandy RECC	Kentucky Conservation Committee
Blue Grass Energy Cooperative	Kentuckians for the Commonwealth
Clark Energy Cooperative	Kentucky Interfaith Power and Light
Cumberland Valley Electric	Frontier Housing
Farmers RECC	Kentucky Industrial Utility Customers
Fleming-Mason Energy Cooperative	Mountain Association
Grayson RECC	Nucor/Gallatin Steel
Inter-County Energy Cooperative	Kentucky Association of Manufacturers
Jackson Energy Cooperative	Kentucky Chamber of Commerce
Licking Valley RECC	**Non-voting Members and Observers (Invited)**
Nolin RECC	**Company/Organization**
Owen Electric Cooperative	Center for Applied Energy Research
Salt River Electric Cooperative	Energy and Environment Cabinet
Shelby Energy Cooperative	
South Kentucky RECC	
Taylor County RECC	

The Collaborative met four (4) times in 2021. Meeting minutes are included in Exhibit 8 of the Technical Appendix, Volume 2, Demand Side Management.

1.10 Organization of the 2022 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
Denise Foster Cronin, Vice President of Federal and RTO Regulatory Affairs
Fernie Williams, Manager of Power Supply Analytics
Darrin Adams, Director of Transmission Planning and Protection
Jena McNeil, Director of Legislative and Government Relations
Scott Drake, Manager of Corporate Technical Services
Robin Hayes, Director of Financial Planning and Analysis
Jacob Watson, Sr. Load Forecast Analyst
Mark Mefford, Sr. Load Forecast Analyst
Chris Adams, 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 2022 IRP is organized in accordance with the sequencing of the planning process, while clearly cross-referencing the appropriate citation to 807 KAR 5:058.

EKPC used the PSC Staff Report of the 2019 IRP as a starting point in the analysis underlying this IRP. The PSC Staff Report recommendations, along with the basic requirements of the Commission's regulations, are the foundation for this Integrated Resource Plan.

1.11 Significant Changes from 2019

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

EKPC Changes Mission Statement and Develops a Sustainability Plan

In 2018, EKPC's Board of Directors approved an update to the Mission Statement that now reads: EKPC exists to serve its member-owned cooperatives by safely delivering reliable, affordable and sustainable energy and related services. Then EKPC staff embarked on creating a sustainability plan to support the mission statement. Five (5) staff based teams were created to develop a better understanding of the changes taking place in and around the energy industry, changes that will affect EKPC for decades to come. The five (5) teams are:

- Owner-Members
- Employees
- Energy and Environment
- Electric Grid
- Financial Health

Generally, sustainability plans center around the Environmental, Social, and Governance ("ESG") responsibility of a corporation. Each of the five (5) teams developed the team's purpose, guiding principles, and initiatives for long-term success. Collectively, the team's individual plans formed the EKPC Sustainability Plan. In 2020, EKPC's Board of Directors approved the EKPC Sustainability Plan.

EKPC, led by each team, is actively engaged and working to achieve the initiatives of the sustainability plan. Most notable are EKPC's effort to reduce carbon dioxide emissions and pursue renewable resources while also ensuring reliability and cost effectiveness for its owner-members.

The sustainability plan and individual team initiatives are found at https://www.ekpc.coop/ekpc-planning-future.

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 13,204 MWh in 2021.

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 EE and DR potential study for residential and commercial/industrial customers.

The findings this time were very similar to the earlier 2018 study. There were only minor differences in the list of measures that proved to be cost-effective. EE potential as a percentage of forecasted sales remained steady (26.0% versus 26.6 % for economic potential).

EKPC is proposing no significant changes to its portfolio of DSM programs. No new programs are proposed in this IRP.

DSM Carbon Cases

For this IRP, EKPC hired Guidehouse consultants to assess the impact of potential future decarbonization policies and their impact on energy market prices. EKPC used the market energy prices from the different decarbonization scenarios to evaluate the cost-effectiveness of EE programs.

EKPC had GDS evaluate cost-effectiveness under four (4) economic scenarios using the Guidehouse decarbonization energy price forecasts:

- Base Case – EKPC's avoided costs for energy and capacity from PJM
- Low Carbon – Base case plus $3.49 per MWh adder for carbon costs based on the Regional Greenhouse Gas Initiative ("RGGI")
- Mid Carbon – Base case plus $23.41 per MWh adder for carbon costs based on a Biden Administration proposal
- High Carbon – Base case plus $65.24 per MWh adder for carbon costs based on the social cost of carbon in New York. Information regarding the social cost of carbon in New York can be found at https://www.dec.ny.gov/press/122070.html.

While EKPC does not anticipate in the near term being required by a federal or state law to pay the Mid or High Carbon cost adder, the added carbon costs versus DSM program impacts sensitivity analyses were evaluated. As the price of energy increases, resulting from decarbonization, more EE programs become cost effective.

EKPC directed GDS to estimate energy and demand impacts for four annual EE scenarios corresponding to four economic scenarios. The economics scenario levels were chosen to represent reasonable expected spend for each scenario.
EKPC prepared DSM plans for each of four scenarios.

The increased energy cost associated with the Mid and High carbon cases show two (2) additional EE programs (the ENERGY STAR® Appliance rebate program, and the Small Business Lighting program) are cost-effective. EKPC does not anticipate a requirement for a carbon adder to apply to generation resources, therefore EKPC is not adopting the mid and high carbon cases.

These are the projected cumulative energy and demand savings in 2036 for each of these four scenarios:

Scenario	Annual MWh	Winter Peak MW	Summer Peak MW
Base	110,151	30	49
LOW carbon	171,896	49	56
MID carbon	251,474	64	70
HIGH carbon	407,873	127	97

DSM Differences

Table 1-1 presents the differences between the 2019 DSM plan and the 2022 DSM plan. The 2019 plan impacts are adjusted for a 2021 base year to match the base year of the current plan.

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

Table 1-1
Comparing DSM Impact projections from the 2019 IRP with the 2022 IRP

	2019 IRP			2022 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)
2022	9,942	2	2	7,508	2	3
2023	19,664	4	4	15,016	4	7
2024	28,976	5	6	22,523	6	10
2025	38,405	7	8	30,031	8	13
2026	47,835	8	10	37,539	10	16
2027	56,045	10	12	44,800	12	20
2028	64,189	11	14	52,061	14	23
2029	72,334	13	15	59,323	16	26
2030	80,478	15	17	66,584	18	29
2031	88,623	16	19	73,845	20	33
2032	96,768	18	20	81,106	22	36
2033	104,912	19	22	88,368	24	39

Discussion of differences between 2022 IRP Load Forecast and the 2019 IRP Load Forecast

The most significant differences are the base year energy and customers, the expansion of an industrial customer and DSM impacts. In 2022, total energy requirements by 2032 are a little over 500,000 MWh lower than the previous IRP, 15-year growth rates are slightly lower (1.1 vs 1.4 percent). Similarly, residential customers in 2022 are just over 400 less than the previous IRP and the growth rate is slightly lower (0.7 vs 0.8 percent).

Growth in use-per-customer 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 decline in mining. Others are seeing new commercial and industrial growth, as well as subdivision development. Table 1-2 displays comparisons between the 2019 IRP and 2022 IRP load forecasts.

Table 1-2 Forecast Comparison 2022 IRP Versus 2019 IRP				
		2022 IRP	2019 IRP	Difference
Residential Sales, MWh	2022	7,241,094	7,207,766	33,328
	2027	7,391,408	7,532,016	(140,608)
	2032	7,665,895	7,863,946	(198,051)
Total Commercial and Industrial Sales, MWh	2022	6,337,822	6,910,612	(572,789)
	2027	7,333,281	7,385,968	(52,686)
	2032	7,641,367	7,743,812	(102,446)
Residential Customers	2022	521,049	521,474	(425)
	2027	540,328	541,620	(1,292)
	2032	559,802	561,901	(2,099)
Net Winter Peak, MW	2022	3,309	3,349	(40)
	2027	3,427	3,468	(41)
	2032	3,520	3,568	(47)
Net Summer Peak, MW	2022	2,500	2,448	52
	2027	2,651	2,545	106
	2032	2,726	2,664	62
Total Requirements, MWh	2022	14,421,062	15,241,723	(820,661)
	2027	15,604,583	16,012,368	(407,785)
	2032	16,227,680	16,752,464	(524,784)

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 participation levels for DSM assumed for this IRP:

Table 1-3
DSM Impacts

2022 IRP	Energy (MWh)	Winter Peak (MW)	Summer Peak (MW)
Year 1	7,508	2	3
Year 2	15,016	4	7
Year 3	22,523	6	10
Year 4	30,031	8	13
Year 5	37,539	10	16
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

Figure 1-1

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

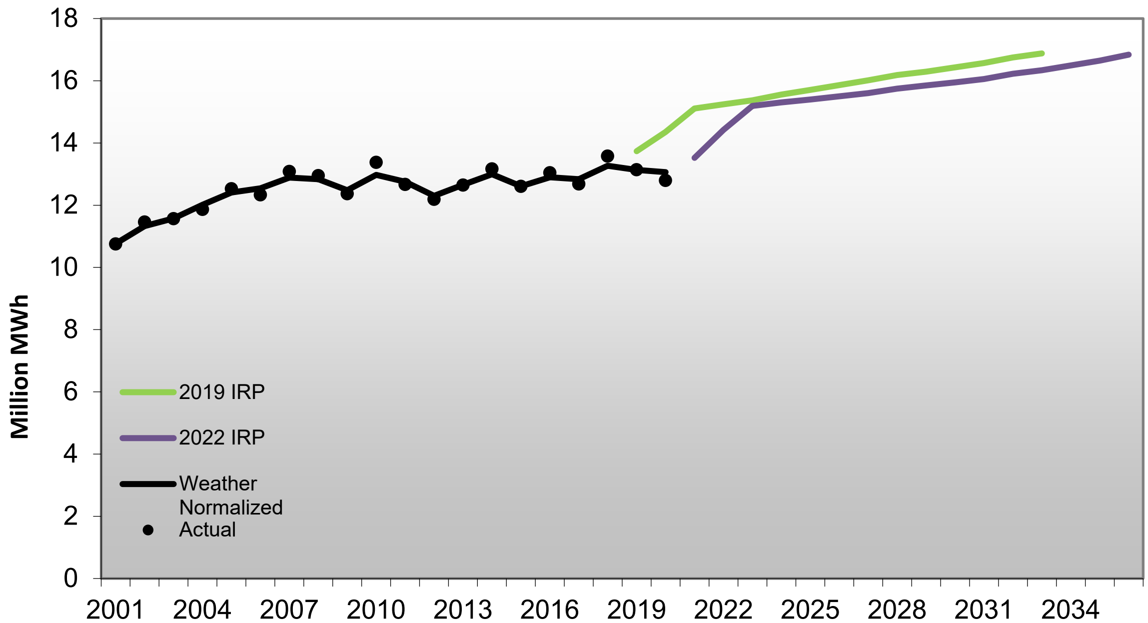


Figure 1-2

Comparisons of Load Forecasts
Winter Peak Demand Projections (MW)

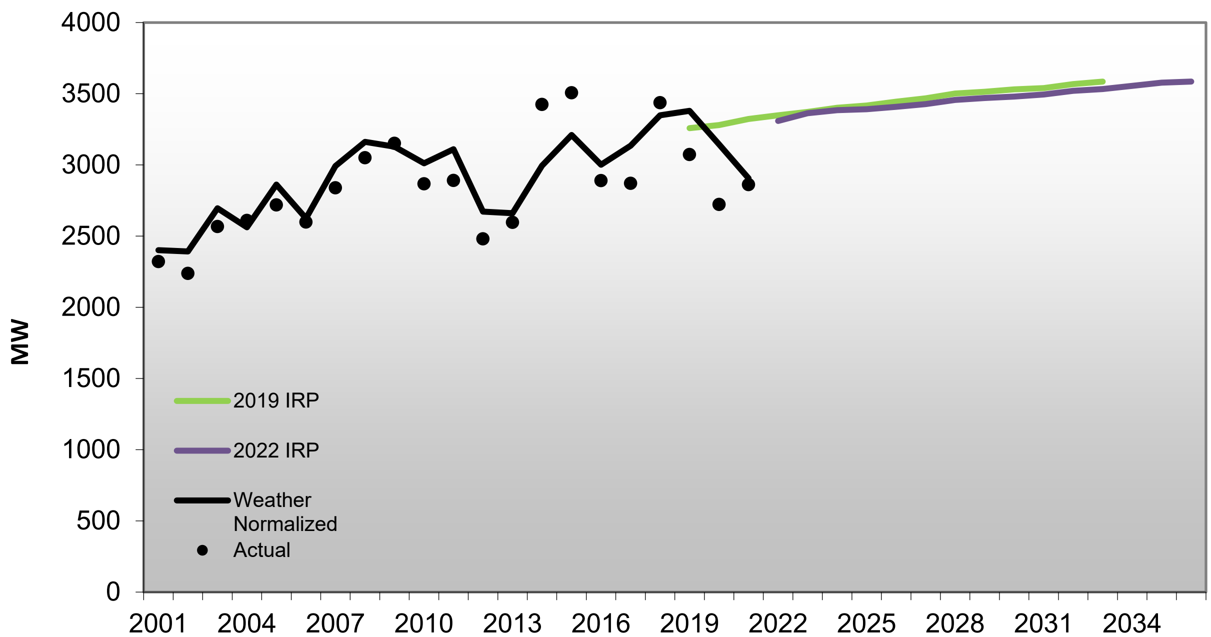
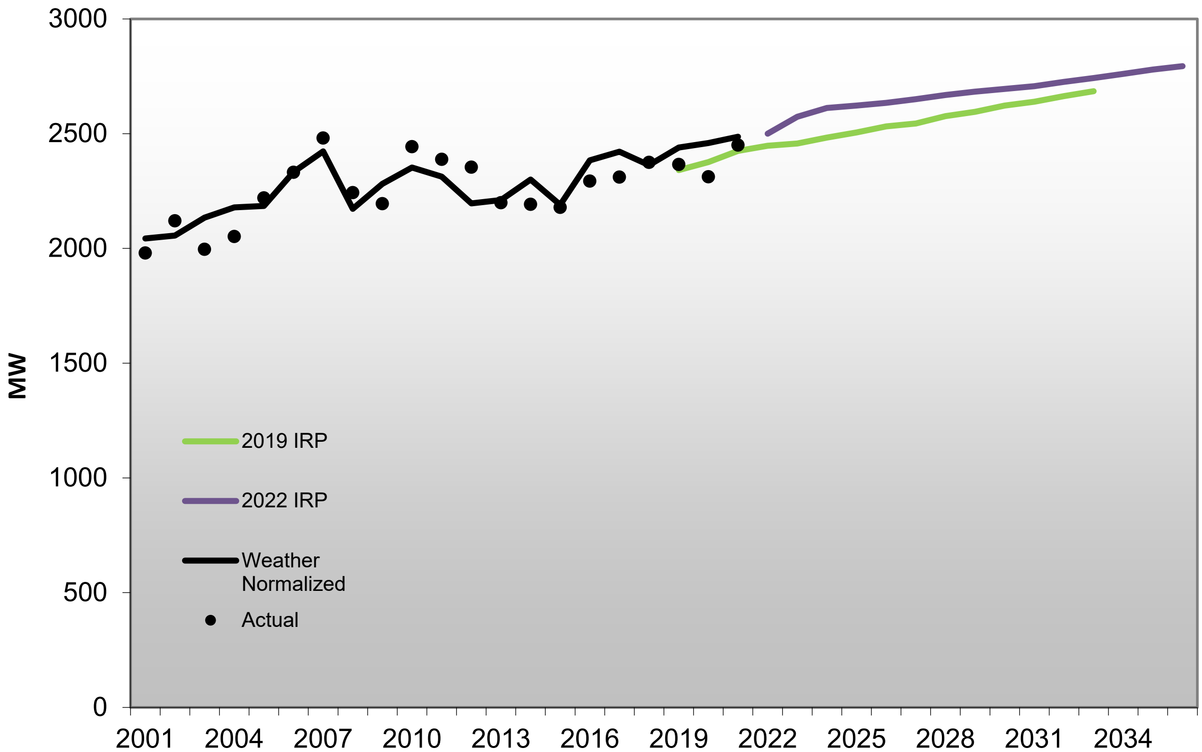


Figure 1-3

Comparison of Load Forecasts
Summer Peak Demand Projections (MW)



<u>Difference between 2022 Expansion Plan and 2019 Expansion Plan</u>

In comparison to the 2019 IRP, the projected capacity needs in the 2022 IRP are 73 MWs lower by the year 2032. EKPC joined PJM on June 1, 2013 and its future capacity requirements changed accordingly. PJM bases its members' capacity requirements on summer peak loads. However, EKPC continues to need to economically supply energy for its winter load requirements in addition to the PJM summer capacity requirements. The preparation process for the 2019 and 2022 IRPs considered similar renewable options in the resource planning process. Prices for solar, wind, and storage were used similarly for the creation of the least cost expansion plan to meet the required capacity requirements. The 2022 IRP preparation however added an additional external step to ensure EKPC's ability to meets its sustainability goal of 15% of new renewable energy in 2035, driven by the growing consumer and industry interest in green power in Kentucky. The load forecast for energy in 2035 provided a target and solar PPAs were added to meet the sustainability goal. The solar PPAs defined in Table 8-2 were used to layer in non-carbon energy to meet the intermediate sustainability step of 10% in 2030, and the final goal of 15% in 2035. EKPC's sustainability initiative results in additional renewable energy to meet our goal of 15% new renewable by 2035. This goal will be met in an economical manner.

Table 1-4
EKPC Projected Major Capacity Additions

	2019 IRP Capacity Available on January 1 – Winter Season Capacity				2022 IRP Capacity Available on January 1 – Winter Season Capacity		
Year	Baseload Capacity	Peaking/ Intermediate Capacity	Cumulative Capacity Additions	Year	Baseload Capacity	Peaking/ Intermediate Capacity	Cumulative Capacity Additions
	(MW)				(MW)		
2019				2019			
2020				2020			
2021				2021			
2022				2022			
2023				2023			
2024				2024			
2025				2025			
2026				2026			
2027				2027			
2028				2028			
2029				2029			
2030				2030			
2031				2031			
2032				2032		225 Simple Cycle CT	225
2033				2033			225
2034				2034			225
2035				2035			225
2036				2036			225
2037				2037			225

2019 IRP showed 2-100 MW Winter Call Options; these should have been denoted as energy hedges only, not capacity.

SECTION 2.0

COMMISSION REPORT ON THE 2019 IRP RECOMMENDATIONS

SECTION 2.0

COMMISSION STAFF RECOMMENDATIONS TO EKPC'S 2019 IRP

2.1 Introduction

EKPC submitted its 2019 IRP (Case No. 2019-00096) to the Commission on April 1, 2019. The report submitted by EKPC provided its plan to meet the power requirements of its 16 owner-members over the period 2019 to 2033. On November 23, 2020, EKPC received the Commission Staff's Report on EKPC's 2019 IRP. The purpose of the report was to review and evaluate EKPC's 2019 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 2019 and EKPC's responses.

Load Forecasting

- **EKPC has appropriately sought to place forecast boundaries around its Base Case scenarios with its extreme Low Case and High Case scenarios, which, arguably, is the point of the sensitivity analysis. However, additional insights might be gained by varying fewer variables at an extreme level or combinations of low and high variables. For example, only weather varies from its base case assumptions or weather remains normal and economic conditions change. EKPC should conduct and report on additional sensitivity analyses to investigate alternate variations in input assumptions.**

  EKPC hired Guidehouse consultants to prepare several carbon price forecasts to use in its sensitivity cases.

- Base Case – Prices and forecasts used in this IRP as the base case
- Low Carbon – Base case plus a per MWh adder for carbon costs based on the RGGI
- Mid Carbon – Base case plus a per MWh adder for carbon costs based on a Biden Administration proposal
- High Carbon – Base case plus a per MWh adder for carbon costs based on the social cost of carbon in New York. Information regarding the social cost of carbon in New York can be found at https://www.dec.ny.gov/press/122070.html.

Under the Mid and High carbon cases, additional EE measures became cost-effective. The Mid case resulted in about 30% more measures being cost-effective. EKPC is not proposing change to programs based on these cases.

- **EKPC should include the addition and loss of a major industrial load in its sensitivity analyses, as well as the possible effects of an extreme event, such as a pandemic, whose immediate impact may last more than one year.**

EKPC's goal with sensitivity analysis is to determine reasonable upper and lower bounds for its peak and energy forecasts based on varying assumptions such as economic and weather inputs. The loss of an industrial customer falls within the lower bound of the scenarios prepared. The effects of an extreme event, such as a pandemic, also fall within the lower bound of the scenarios prepared. The effects of shifting loads from other fuel sources to electric for decarbonization is also a scenario that could occur and has been considered to be bounded by the high load forecast.

- **EKPC should discuss participation in regional economic development efforts, the extent to which it assists the owner-members in recruiting or retaining industrial customers, and the seemingly growing importance of being able to offer renewable energy to satisfy corporate sustainable energy goals as a facet of economic development efforts. In addition, the extent to which the existing industrial parks/development sites are certified and move-in ready should be discussed.**

EKPC is recognized by global site selectors, real estate professionals and corporate managers as the lead organization for Kentucky's Touchstone Energy Cooperatives. EKPC and its owner-members work hard to provide competitively priced, reliable, sustainable and accessible electric service to over one million Kentuckians and many of Kentucky's largest companies. EKPC supports leading statewide agencies and organizations with recruitment, expansion and retention of businesses that enhance the quality of life and employment across our commonwealth. EKPC partners routinely with global, national and state affiliations that include the Kentucky Cabinet for Economic Development, industrial authorities, economic development councils and government officials. EKPC staff supports and serves as board and committee members on many leading regional, state, national and global economic development organizations.

EKPC and its owner-members are eager to provide personnel assistance for recruitment, retention and expansion needs across our service territories. The sixteen (16) owner-member Cooperatives have each identified a staff member with a focus on economic development across their service territories. The EKPC team works closely with this staff to enhance education, networking and ultimately business recruitment, retention and expansion success.

From 2015 through 2021, EKPC assisted many partners and communities in securing 332 announced economic development projects that will invest over $8.6 billion and create over 17,000 jobs within our distribution cooperative service territories. 128 or 39% of these announced projects represented new facilities to Kentucky investing over $4.7 Billion and creating over 11,000 jobs.

EKPC also provides cutting edge technology and beneficial economic development tools. For over a decade, the sixteen (16) owner-member cooperatives have supported EKPC's development and implementation of various award winning economic development tools and programs. EKPC takes pride in providing the best and latest technology to better serve its clients and members. That is why EKPC created its targeted GPS-based mobile app called PowerMap https://dataispower.org/powermap. A first of its kind application that puts the power of locational knowledge in the hands of site selectors, economic developers and service providers. PowerMap provides users with detailed service territory maps for all 87 counties served by EKPC and owner-member Cooperatives. This award winning app uses a mobile device's GPS capabilities to determine if the user is in one of the 16 cooperatives' service territories. Users can pinpoint the exact location of interest, related industrial and business park information and determine which local electric cooperative provides direct service.

The owner-members and EKPC are also making site analysis and development easier than ever before. EKPC provides site selectors with an expanding list of Kentucky's top industrial properties, known as PowerVision Sites. This uses the latest drone technologies to provide an aerial showcase of available commercial and industrial tracts located across areas served by owner-member Cooperatives. With the PowerVision Site Advantage, site selectors have access to data, downloadable files and aerial videos. Users can conduct virtual site visits, create custom building renderings and more without leaving the comfort of home or office. During the time of global shut down and travel these tools have allowed the continued promotion of EKPC owner-member service territories and the commonwealth for global projects interested in Kentucky.

StateBook is another tool EKPC and its owner-members provide at no cost to the eighty seven (87) counties and territories served. StateBook provides trusted, sourced data to improve location analysis. 63,000 data points of information allows clients to better compare locations and identify the most strategic opportunities for investment, confirm project viability, and mitigate risk across disparate data sources, multiple geography levels and over time. Over 250 global site selection firms use StateBook in their decision making process.

EKPC's commitment to assisting new and expanding companies is further enhanced through financial programs designed to encourage new industrial growth. In addition to being knowledgeable on state and local incentives, the owner-members offer incentives to qualifying projects. Programs such as the Economic Development Rider reduces electric rates over a set period of time. Owner-Members also promote low-interest loans and grant options available through the USDA Rural Economic Development Loan and Grant Program ("REDLG").

The Cooperative commitment to an active role in developing a skilled workforce pipeline is unwavering. This dedication includes helping to shape the next generation of employees with STEM education. Through proactive involvement in numerous education and workforce initiatives, EKPC owner-members are working to deliver real-world workforce solutions that meet current and future demands. The communities are proving they have the vision, collaboration and workforce quality to surpass any employer's goals. Nearly 80 percent of the region has been state-certified as either a Work Ready or a Work Ready in Progress Community. EKPC routinely encourages and assists its service regions in obtaining this important certification that projects the communities are committed to providing the highly skilled workforce of today, and future, that meets industry needs.

The majority of large client projects entertained today are seeking options for renewable energy access, which is a key driver for EKPC's sustainable energy goals. EKPC and its owner-member Cooperatives have access to electricity generated from a variety of sources, including conventional and renewable sources. As sustainable and renewable energy sources become more and more available, local cooperatives are plugged in and ready to deliver energy in the way members and clients want at the lowest costs available. EKPC has embraced a diverse energy portfolio. One example of this commitment is the Cooperative Solar Farm One, one of the largest solar projects in Kentucky. Located in Winchester, Kentucky, the 60-acre farm features 32,300 solar panels producing enough electricity for 1,000 Kentucky homes. Additionally, EKPC operates six plants that generate renewable power from methane gas at landfills. EKPC also purchases hydropower from the federal Southeastern Power Administration through their Cumberland River dam system.

EKPC currently does not offer funding for site certifications programs. A highly respected national site selector firm recently informed EKPC they do not accept site certifications in their process. They have found many times certifications are misleading and inaccurate. EKPC has seen recent examples of certifications performed on Eastern Kentucky sites proven inaccurate. Two different companies announced projects that were cancelled as they performed enhanced core drilling and environmental phases for construction. EKPC prefers at this time, to work closely with property owners and provide tools like PowerVision, PowerMap, Statebook etc. that give companies a wide range of resources to make informed decisions.

Demand Side Management

- **EKPC should continue to report, annually, on its DSM programs' energy savings and peak demand deductions.**

  EKPC produces a DSM Program Annual Report each year containing energy and demand impacts per program. Please find the DSM Annual Reports for 2019, 2020, and 2021 in the technical appendices of this filing.

- **EKPC should continue to scrutinize the results of each existing DSM program measure's cost-effectiveness test and provide those results in future DSM cases, along with detailed support for future DSM program expansions and additions. EKPC should also be mindful of the increasing saturation of EE products, and be watchful for the opportunity to scale back on programs offering incentives for behavior that may be dictated by factors other than the incentives.**

  EKPC analyzes DSM measures and programs using both qualitative and quantitative criteria. These criteria include customer acceptance, measure applicability, savings potential, and cost-effectiveness. The cost-effectiveness of DSM resources is analyzed in a rigorous fashion using the California tests for cost-effectiveness. For any DSM program expansion or additions, EKPC will provide detailed support including cost-effectiveness results. Because of the GDS Energy Efficiency and Demand Response Potential Report and interactive meetings with the EKPC Sustainability Collaborative, EKPC is considering only minor changes to the existing DSM programs to improve program operations.

- **The commission recommends that EKPC continue the stakeholder process through the collaborative and strive to include recommendations and inputs from the stakeholders. These meetings should be more than informational, and entail fluid**

dialog between all vested parties. Any changes to the DSM program must be discussed in full, including a transparent analysis of the cost and benefits inputs.

EKPC re-engaged the public interest groups and other interested parties in 2021 and established the EKPC Sustainability Collaborative. A new charter for the Collaborative was created with its primary purpose of promoting participation in demand side management, energy efficiency, renewable energy, and beneficial electrification programs offered by EKPC and EKPC's owner-member cooperatives. The table in section 1.9 identifies the organizations participating in the Collaborative.

- **As required by the IRP regulation, 807 KAR 5:058, Section 7(4)(d), EKPC should continue to define and improve procedures to evaluate, measure, and verify both actual costs and benefits of energy savings based on the actual dollar savings and energy savings.**

For the GDS Energy Efficiency and Demand Response Potential Study along with more detailed California tests performed at a program level by consultant John Farley, EKPC DSM program inputs were based on actual energy and demand savings along with associated costs.

- **EKPC should continue to report on updates to bidding its peak savings from DSM programs into the PJM capacity markets.**

EKPC continues to evaluate options for monetizing the energy efficiency DSM programs in the PJM wholesale markets. Energy Efficiency is eligible to participate only in the RPM capacity market. At maximum, Energy Efficiency may receive compensation for four delivery years of capacity value if it were planned and not yet implemented before the start of the first delivery year for which it would clear in the market. For EKPC, participation in the RPM capacity market would not provide monetary value to offset any implementation costs. Because EKPC territory is a single zone in the PJM region, and no other load serving entities serve load in our zone, we would derive no financial compensation from our Energy Efficiency clearing in the market. To be able to treat Energy Efficiency (a load reducer) as a supply resource that competes against generation, PJM scales up the load in the zone. Effectively, the energy efficiency would be an offset to the load allocated to us. Moreover, participation could be a cost because PJM has established measurement and verification requirements to ensure that the Energy Efficiency provides the capacity value for which it would be paid. Those requirements are complex, and EKPC would incur a cost to produce the required evaluation and reports.

Supply-side and Demand-Side Resource Assessment

- **EKPC should continue to stay abreast of changes in Federal regulations and rule changes within PJM that have or could impact EKPC's operations and participation in PJM markets and services. In its next IRP, EKPC should report on any changes at the federal level and at PJM that have or could potentially affect EKPC since the last IRP filing and how it has or plans to respond.**

EKPC works extensively to plan for and mitigate current and future risks present in the federal policy space that could impact its operations and stays abreast of developments and changes to the federal landscape that could impact its participation in PJM. Since the filing of EKPC's last IRP in 2019, the federal landscape has shifted significantly with a changeover in presidential administrations and a shift in power in the United States Congress, both of which have impacted federal policy posture towards the electric power sector. This is most apparent in a renewed increased push towards decarbonization of electric power, including a pledge by President Biden to reduce greenhouse gas emissions by 50 percent by 2030 and 100 percent by 2050; as well as increased emphasis on deployment of renewables, and a move toward greater expansion of electric vehicles ("EV") with associated investments in EV infrastructure.

Currently, there are two large federal legislative initiatives that should be discussed in the context of impacts to EKPC:

- **Federal Infrastructure Package.** On November 15, 2021, Congress passed and the president signed into law the Infrastructure Investment and Jobs Act. This legislation contains $1 billion dollars dedicated to infrastructure improvements and investments throughout the United States, a significant portion of which is tabbed for renewable energy projects and energy efficiency measures, as well as substantial investments in EV infrastructure.

Electric Vehicle investments. The bill specifies $7 billion for EV infrastructure. Even in the absence of federal policy investments in coming years, the U.S. electric vehicle market is expanding rapidly and there will be increased infrastructure demand in Kentucky particularly along highway corridors within EKPC territory. This, plus any associated demand for EV infrastructure by Kentuckians, will take careful planning to adapt for future load growth. While projected adoption of EVs is predicted to be slower in Kentucky in comparison to other states (and in particular EKPC territory), EKPC recognizes that even modest increases in EV load in concentrated areas could provide challenges and opportunities for EKPC and its owner-members. We are closely monitoring and planning, in consultation with other utilities and the Kentucky Energy and Environment Cabinet, for this potential new load to minimize peak demands on EKPC and its owner-member systems.

Energy efficiency. The infrastructure law also contains numerous provisions related to energy efficiency including monies to state energy offices, local energy efficiency and conservation block grants, monies for efficiency improvements at small manufacturing plants, and millions of other dollars aimed at increasing energy efficiency. It also includes $3.5 billion for low-income home weatherization. Kentucky, and Kentucky-based recipients are likely to receive a portion of these federal monies. While EKPC supports energy efficiency improvements, as the law is implemented and monies distributed, EKPC will continue to monitor how this could impact load.

Resources for grid modernization. The bill contained $5 billion for resiliency grants to supplement existing grid hardening efforts and to promote grid resiliency, as well as a separate pot of money for cybersecurity for electric cooperatives. EKPC is still awaiting additional information as to how these resources will be distributed and for what specific purposes the dollars can be used.

EKPC continues to work with its owner-members, as well as other electric cooperatives within the state, and with the Kentucky Cabinet on Energy and Environment and the Kentucky Legislature, as to which opportunities to seek out and which projects make the most sense to invest in within our Integrated Resource Plan ("IRP"), as well as how monies distributed throughout the state will have an impact on EKPC and its owner-members' operations. EKPC is in the process of contracting with a dedicated consultant to help understand these opportunities fully and to provide strategic guidance to best take advantage of the resources provided under the law.

- **Build Back Better Framework.** In 2020, President Joe Biden put forth a framework entitled Build Back Better which was the outline for federal legislation to further, among other efforts, the administration's climate goals. Early legislative iterations of the Build Back Better plan had embraced the concept of a Clean Electricity Payment Plan ("CEPP"). In initial draft form, the CEPP would have created a carrot and stick regime to further incentivize investments in non-coal/non-natural gas sources of renewable energy. The CEPP would have required percentage based increases in incorporation of carbon-free energy sources, with payments provided for utilities that met the goals. If a utility failed to meet this goal, the utility would be required to make a payment at a cost per MWh.

EKPC has expressed concerns to federal policymakers that proposals like the CEPP are challenging because an overly aggressive timeframe of renewable integration in terms of both technological challenges and supply chain concerns greatly jeopardizes our ability to provide reliable power. For instance, the significant downward pressure by the federal government to replace our coal assets comes at a time when we are finding a renewed emphasis on our coal assets. With natural gas prices at an all-time high, we anticipate a future need for coal generation and programs like CEPP would incentivize the decreasing availability of coal which is compounded by the ongoing supply chain and workforce crisis associated with COVID-19, as well as the continued challenges associated with too-heavy reliance on non-dispatchable, non-storable energy sources like solar and wind that have been demonstrated in recent years in states like California.

In recent bill iterations, the CEPP language was dropped from the bill, with wind and solar production tax credits (with direct pay language) and monies for clean power projects for electric cooperatives staying in the bill. However, while there was significant negotiation in late 2021 on the Build Back Better plan, these talks have stalled and it is unclear what might happen legislatively on the energy front before the mid-term elections. The White House has said that it will seek to reinvigorate talks on the bill in coming weeks. Regardless, White House climate adviser Gina McCarthy said in July 2021 that "we have lots of regulatory authority that we intend to use, regardless, and we'll move forward with those efforts to try to tackle the climate crisis." Subsequently, we expect an associated increase in agency rulemaking aimed at administratively working to get the goals of the CEPP accomplished in the absence of a bill becoming law. Deeply concerning is that if the White House seeks to accomplish the goals of the CEPP through the regulatory process, it will likely lack the financial incentives that might have been available under a congressionally appropriated incentives package, which could have helped ease the transition towards the President's clean energy goals.

Any future regulatory efforts to accomplish the decarbonization goals require significant analysis of reliability and cost implications. It is critical for PJM, the regional grid operator and wholesale market administrator, to provide that important analysis. EKPC, therefore, continues to engage with policymakers and PJM to ensure that integration of renewables does not compromise grid reliability.

Additionally, EKPC continues to move forward to meet the increased demand for clean energy products among the owner-members of EKPC's owner-member distribution cooperatives. EKPC sustainability plan ensures appropriate focus on reliability and cost-effectiveness in supporting the adoption of clean energy resources into its energy supply portfolio.

Going Forward. While the political dynamics could shift in coming years, creating conflicting and uncertain policy messaging which makes devising a long-term outlook difficult, we expect the focus on renewables and decarbonization of the power sector as a nation and within PJM to continue, particularly given state policy evolution (among the 13 states and District of Columbia within the PJM region) and continued emphasis on carbon reductions by corporations and businesses seeking to invest in Kentucky and elsewhere in the PJM region. EKPC will continue to actively work with other electric utilities, businesses and industry, and regulators and lawmakers to manage EKPC's compliance strategies while minimizing costs to EKPC's owner-members, and continuing to provide the reliable power Kentuckians rely on.

- **EKPC should continue to stay abreast of changes in Federal regulations and rule changes within PJM that have or could impact EKPC's operations and participation in PJM markets and services. In its next IRP, EKPC should report on any changes at the federal level and at PJM that have or could potentially affect EKPC since the last IRP filing and how it has or plans to respond.**

  Additional information for the above recommendation is included with the recommendation below.

- **EKPC should continue to stay abreast of Federal Energy Regulatory Commission (FERC) Orders. In its next IRP, EKPC should discuss the impact of recent FERC Orders regarding battery storage and distributed energy resources**.

  There have been numerous changes completed or initiated to PJM's market, operations and transmission planning rules, and the FERC has issued orders and completed or initiated numerous relevant rulemakings. Additionally, NERC is beginning to evaluate whether additional assessments should be performed and/or whether standards developed to enhance reliability or to address resilience. Below EKPC focuses on those most significant for EKPC's operations and market participation.

I. Introduction

Federal and state policy developments and economics are driving a transition of the U.S. electric grid. The PJM region has already undergone a significant change in its generation portfolio, and more change is expected on the horizon. EKPC actively engages in the PJM stakeholder process, and the FERC dockets related to those PJM stakeholder process matters (and occasionally federal court dockets), when EKPC believes those matters will have an impact on EKPC's generation and transmission operations or otherwise are fundamental to good market design or reliable operations and transmission planning.

Additionally, the FERC has identified a variety of wholesale electricity market -related items that it believes must be addressed (1) to ensure the markets provide non-discriminatory access for new technologies, and (2) to ensure the markets continue to provide appropriate compensation and price signals. The organized wholesale markets exist to ensure reliability, and FERC is focused on ensuring that the markets incent resource investment (maintenance of existing and development of new assets) to preserve reliability into the future. The FERC also is exploring questions around extreme weather, climate change and resilience in a rulemaking docket.

As KY PSC Staff noted in response to EKPC's 2019 IRP, the FERC has directed organized wholesale markets like PJM to revise market rules to encourage storage resource participation and to create opportunities for aggregated distributed energy resources. Even though EKPC has not and, as discussed in this IRP, is not currently planning to develop storage resources, certain merchant developers siting projects within EKPC's territory intend to develop "hybrid" resources, or what PJM calls "combination" resources – solar + battery storage. Moreover, the FERC has initiated a rulemaking that has the potential to make sweeping changes to transmission planning and cost allocation. It is too soon to know which elements of the FERC's ANOPR may proceed through the rulemaking process and become obligations for PJM and the Transmission Owners like EKPC. Any changes to transmission expansion planning and generation interconnection will impact EKPC's operations and likely costs will be borne by our owner-members.

The KY PSC Staff guidance did not address NERC. NERC's current focus on enhanced reliability or resilience may lead to future market and operational rule changes that will impact the PJM region and EKPC. EKPC notes that the NERC has recently begun to consider whether additional assessments should be performed or additional standards developed to address anticipated challenges to the ability of the nation's generation portfolio to assure reliability and to provide a measure of resilience. It is too early in the process for EKPC to provide details of this effort. However, EKPC is encouraged that the body responsible for ensuring the reliability of the bulk electric system for North America is delving into what may be required to ensure reliable delivery of power in all hours of the day and all seasons of the year. The evolving generation portfolio in PJM and across the U.S. will necessitate a change to the requirements intended to assure reliability. It is EKPC's view that its baseload generation resources and natural gas peaking units will continue to be valuable assets providing reliability and resilience attributes the grid needs now and into the future.

EKPC will factor in any additional guidance stemming from FERC's rulemaking and from NERC's efforts in future IRP submittals.

II. Wholesale Electricity Markets and Generation Operations

EKPC participates in every PJM administered wholesale electricity market: energy, capacity and various ancillary services markets.

EKPC provides the current status of PJM's capacity market and reserve market rule changes addressed by PJM stakeholders and the FERC. Also, described is the current PJM stakeholder process initiative to consider other market rule changes that may be needed to ensure future reliability with the evolving PJM generation portfolio in what has been called "Phase 2" of the capacity market discussions. This work is at the early stages and will be informed by PJM analysis, including the report PJM issued in December 2021, as well as any future developments in FERC rulemakings or NERC initiatives.

Additionally, to respond to KY PSC's specific request for an update on the FERC orders on storage and distributed energy resources, below are summaries of the relevant FERC orders and updates on related PJM implementation efforts.

A. **PJM Capacity Market & Phase 2 Initiative**

1. Capacity Market Minimum Offer Price Rule

PJM's capacity market includes a provision called the Minimum Offer Price Rule ("MOPR") to ensure that the capacity prices resulting from the auctions are just and reasonable and not affected by an exercise of buyer-side market power. When the MOPR is applied, it acts as a floor on the price level at which a specific resource may be offered into the auction; the offer cannot be set at a price lower than the MOPR established level. PJM and the PJM Independent Market Monitor review and approve the price floors for all capacity resources. Prior to December 2019, an electric cooperative like EKPC was exempt from the application of MOPR so long as its capacity resource portfolio was within specific net long/net short bounds when compared to its load serving capacity obligation. EKPC was able to offer its resources into the market without risk that its offers would be mitigated to a higher level (the price floor), creating a risk that the resources may not clear in the market which would leave EKPC unable to hedge the price exposure for its load serving capacity obligation.

The FERC's December 2019 order dramatically changed the MOPR provisions. Relevant to its application to EKPC, the FERC determined that capacity resource offers of electric cooperatives must be subject to the MOPR and provided a limited exemption for electric cooperative resources that had previously cleared a capacity market auction. Under this order, any resource (owned or under contract) that did not previously clear in a capacity market auction would be subject to the MOPR.

EKPC actively defended its interests in the FERC docket and initiated appeals of the various FERC orders issued in the docket. The appeals were consolidated with other parties' appeals in the 7th Circuit Court of Appeals. The appeal has been held in abeyance at the parties' agreement to allow PJM and the all stakeholders, including the parties, to consider holistic reform of the MOPR initiated in the PJM stakeholder process.

The PJM stakeholder process, using expedited rules of procedure, resulted in a proposal (narrowed MOPR) that achieved sufficient stakeholder support to file with the FERC. The proposal fully addressed EKPC's concerns, so EKPC voted for it in the stakeholder process as well as submitted comments (jointly with Buckeye and SMECO) and expert testimony in support of it at the FERC.

The four sitting FERC Commissioners were divided in their vote on the filing. Since the filing was made pursuant to Section 205 under the Federal Power Act, it went into effect by operation of law on the date by which FERC statutorily needed to act upon it -- September 29, 2021. A few parties have filed requests to FERC seeking rehearing and court appeals. EKPC intervened in the court appeal. Both the appeals of the earlier FERC orders and the appeals of the September 2021 FERC action are pending. On November 29, 2021 the FERC denied by operation of law the rehearing requests of the narrowed MOPR and parties have appealed that FERC action. The federal courts are going to allow the appeals of the recent FERC orders to be considered first, as any decision may moot the need for the court to consider the earlier line of cases.

PJM proposed an updated timeline for the 2023/24 Base Residual Auction ("BRA") and subsequent auctions to the FERC on January 21, 2022. On February 22, 2022, the FERC approved the proposal. The BRA for the 2023/2024 delivery year will take place on June 8, 2022. Ultimately, the approved timeline will allow PJM to return to a three-year-forward BRA beginning with the May 2024 BRA for the 2027/2028 delivery year. The need to delay the auctions resulted from a Dec. 2021 FERC order reversing most of the changes FERC previously approved for PJM's reserve markets. (There is an interplay between the capacity market and energy and ancillary service markets.) Additionally, PJM will need to update various parameters used in conducting the auctions, and market seller offers will need to be updated.

2. Capacity Market Phase 2 Initiative

After addressing MOPR reform, PJM initiated stakeholder discussions to address various items that affect resource adequacy in PJM. The PJM Board and stakeholders had identified a list of items that should be addressed in this initiative. Most of the items will be considered in a new task force, the Resource Adequacy Senior Task Force ("RASTF"), but other items fit more appropriately in the scope of other established PJM stakeholder groups, including the Market Implementation Committee, the Load Analysis Subcommittee, and the Operating Committee. PJM intends to communicate stakeholder progress on all items through the RASTF, and the RASTF will provide periodic reports to the Markets and Reliability Committee.

For many of these topics, the timeline for completion will be determined during the stakeholder discussion. Given the forward nature of the Base Residual Auction and the 60 day timeline for FERC to act on filings pursuant to Section 205 of the Federal Power Act, it is likely that the issues will be sequenced and addressed through multiple FERC filings should stakeholders determine changes to address the items are necessary. It is likely that the sequencing of potential filings will prioritize items that should be resolved prior to a particular future Delivery Year.

At a high level, the various items roll up into a holistic review evaluating aspects of resource adequacy assurance answering these broad questions:

- What is the appropriate reliability target?
- How do the various resources contribute to achieving the reliability target?
- What are the performance expectations of resources committed to provide capacity?
- Can the market facilitate the procurement of clean resources to satisfy state policies?
- Will any changes to RPM require changes to the Fixed Resource Requirement rules?

EKPC has not elected to satisfy its load serving capacity obligation with the Fixed Resource Requirement ("FRR"); rather it participates in the RPM capacity market. The PJM market rules require EKPC to offer all of its generation resources into the capacity market; EKPC also offers demand response into the market. The load EKPC is required to serve is included in the PJM load represented by the Variable Resource Requirement Curve, against which all the offered generation resources clear. As a Self-Supply Entity, EKPC does not actually make a market purchase to serve it load obligation. Instead, mechanically the auction accounts for EKPC's capacity supply resources that satisfy its load obligation, which is based on the load forecast and calculated reserve requirement for the delivery year, and then compensates EKPC for any additional capacity supply resources that clear in the auction. All EKPC capacity supply resources committed to serve its load obligation and any additional resources that clear in the market are committed to the PJM region to ensure resource adequacy; all committed resources are responsible to perform and produce energy when PJM needs them to ensure regional reliability. All also must offer into the Day Ahead Energy Market.

EKPC has an interest in ensuring, (1) that the reserve requirement is set appropriately to ensure reliability, (2) that its capacity supply resources are valued appropriately given their contribution to reliability assurance, and (3) that the clearing price resulting in the various capacity markets (Base Residual Auction and associated Incremental Auctions) are just and reasonable and not the result of market power. EKPC's generation and demand response assets provide a hedge against the price exposure for satisfying its load serving capacity obligation from the market. To the extent EKPC remains winter peaking and PJM remains summer peaking, EKPC has a potential to earn revenue to offset other costs of providing full requirements service to its owner-member distribution cooperatives.

The current FRR rules are an option for EKPC to satisfy its load serving capacity obligation. Initially upon integration into PJM, EKPC utilized the FRR rules the delivery years for which a Base Residual Auction had already run. EKPC has an interest in ensuring that the FRR rules are not modified in a manner that limits its ability to use them for the benefit of its owner-members should the PJM capacity market rules change in a manner that is counter to its owner-members' interests.

3. FERC Rulemaking

In early 2021, the FERC initiated a rulemaking docket focused on "modernizing electricity market design in the organized wholesale electricity markets, like PJM.[1] The FERC convened Commissioner-led technical conferences to discuss the role of the capacity market constructs in PJM, ISO New England Inc., and New York Independent System Operator, Inc. in an environment where state policies increasingly affect resource entry and exit. With respect to PJM, the FERC focused on implications of retaining the expanded minimum offer price rule (Expanded MOPR) in the PJM capacity market, as well as prospective alternative MOPR approaches. EKPC submitted comments to FERC expressing concern that the pace of change in the generation resource mix is likely to surpass the current market structures such that PJM may not have the resources available to produce energy, or reduce load, in real time with the operating characteristics that it needs to maintain reliability 24 hours a day, 7 days a week, 365 days a year. EKPC cautioned that generators with those necessary characteristics could prematurely retire if the market undervalues their contribution, just as new resources with the desired operational attributes may not enter if their attributes are not appropriately valued. EKPC also advocated in support of MOPR rules that respected the self-supply business model of electric cooperatives like EKPC.

The FERC has not issued a final rule addressing capacity market design; however, as noted above, the FERC has already considered changes to the MOPR rules in PJM's capacity market.

B. <u>PJM Reserve Market</u>

Reserves are resources that either are not currently producing energy but may turn on quickly, or are producing energy but may increase their energy production. (10 minute/30 minute response) Because PJM was concerned about its ability to maintain real-time

[1] Modernizing Electricity Market Design, Docket No. AD21-10-000 (2021).

operational reliability into the future with increasing uncertainties of load (due to the growth of Behind the Meter generation resources) and generation supply (due to the increased penetration of intermittent resources), it proposed changes to the reserve market. PJM was concerned that it did not have all the appropriate reserve products and that the market was not appropriately incentivizing resources to provide reserves when the system most needed them.

EKPC agreed that market reform was necessary to ensure future reliability. All of EKPC's available generation resources are offered into the reserve markets and provide reserves if PJM commits them or otherwise requests that they provide reserves.

After failing to achieve sufficient stakeholder approval of reforms to address PJM's concerns, PJM filed a proposal with the FERC under Section 206 of the Federal Power Act. At a high level, PJM's proposal:

(1) adjusted the reserve products so that all will be compensated, and aligned day ahead and real time products

(2) established curves that are used in establishing the clearing price which are downward sloping; the curves have a portion that prices reserves based on the probability of experiencing shortage of that reserve product in real time

The FERC approved PJM's filing in May 2020, subject to certain compliance directives. Following the experience of winter storm Uri in February 2021 and the price escalation that occurred in ERCOT, several PJM stakeholders, including EKPC, sought to ensure that the that the PJM reserve and energy markets do not result in elevated and/or sustained prices when resources participating in those markets may not be able to react to such pricing. PJM's Energy Price Formation Senior Task Force was charged with considering that possibility and developing potential market rule changes designed to prevent sustained high prices in PJM, or what some have called a "circuit breaker."

Several parties filed appeals of the various FERC orders in the PJM reserve market docket. In late summer 2021, upon the FERC's request, the court remanded the matter back to FERC. In December 2021, the FERC reversed most of the previously approved changes. Specifically, the FERC affirmed alignment of the day ahead and real time reserve products but reversed its approval of changes to the operating reserve demand curves used in establishing the clearing price of the various reserve products. That order did not specifically address some important details of the market design, such as whether the price capping provisions would be in effect. The Commission further explained that because the Remand Order affirmed "adopt[ion of] a new 30-minute Reserve Requirement and Secondary Reserve product, PJM may propose revised reserve price caps to reflect the addition of this new product."11

In response to PJM's request for clarification, the FERC in February 2022 clarified, among other things, that the December 2021 remand order did not remove certain price capping provisions applicable to PJM's reserve markets. Additionally, the FERC indicated that because the FERC approved the adoption of a new 30-minute reserve product, PJM may propose a price cap applicable to this new product. On February 22, PJM submitted its compliance filing, which included a proposed price cap for the new product, and retaining the price caps applicable to the other reserve products. The FERC has not yet issued an order on PJM's compliance filing.

It is unclear at the moment what these developments will mean for the future work efforts of the Energy Price Formation Senior Task Force.

C. **<u>FERC Rulemaking on Energy and Ancillary Services</u>**

The FERC expanded its focus beyond capacity markets in organized wholesale markets to energy and ancillary service markets in its "Modernizing Electricity Market Design" rulemaking noted above.[2] The FERC Staff issued a paper on potential reforms to these markets to better address changing system needs, which formed the basis of technical conferences held in the fall of 2021. EKPC has not submitted comments in that docket but notes it generally supports the comments PJM submitted in January describing how the changing energy landscape is driving a need for new market products that add flexibility.

[2] Modernizing Electricity Market Design, Docket No. AD21-10-000 (2021).

The FERC has not issued a final rule addressing energy and ancillary services.

D. <u>Storage</u>

1. FERC Order 841 and PJM's Implementation

The FERC's Order No. 841 required PJM to remove barriers to participation for energy storage resources in the wholesale electricity markets. At the time the order was issued, PJM was substantially compliant with two of the four requirements in Order 841, specifically:

- Energy storage resources already have full access to PJM's technology-neutral Energy, capacity and Ancillary Services markets. Batteries represent, on average, more than 80 percent of fast-responding frequency regulation resources.
- PJM has already established a low size threshold of 100 kilowatts for all resources (including energy storage) to participate in the wholesale markets.

  PJM proposed enhancing its market rules to meet the remaining two elements of the order:

- Energy storage resources can be dispatched by the grid operator and can set the wholesale market clearing price as buyers (they can already do this as sellers).
- PJM's proposal gives energy storage operators new tools to participate in markets while accounting for the physical and operational characteristics of their resources, including fast ramp times, the ability to quickly switch between charging and discharging states, and range of state of charge between charging and discharging states and continuous mode.

As part of PJM's Order No. 841 compliance filing, PJM established rules on how storage resources, including batteries, can participate in PJM's capacity market. These resources must be available to provide energy when needed in system emergencies. This is consistent with FERC's requirement that markets be resource-neutral and open to participation by batteries – or any other resource – according to its "technical capability" to provide the service in question.

The FERC largely approved PJM's compliance filing, however, it found that PJM did not satisfactorily address the capacity accreditation of storage resources. At the same time PJM needed to re-evaluate the appropriate capacity accreditation for storage resources, it was needing to consider the appropriate capacity accreditation for variable resources (e.g., solar and wind). Thus, PJM worked with stakeholders to develop an "Effective Load Carrying Capability" method of determining the capacity accreditation for storage and variable resources.

2. Effective Load Carrying Capability

As the deployment of renewable and storage resources increase throughout the electrical grid, PJM recognized the need to reconsider its methodology for establishing the accredited capacity value for these resources to account for their actual contribution to reliability when the grid needs their energy output. These resources have variable energy output or may only be able to inject energy into the grid for a limited duration of time. PJM sought to accurately measure whether the energy output to the grid aligned with when load most needed that output - during peak electricity usage periods. The approach adopted is called Effective Load Carrying Capability ("ELCC") and it relies on an "adjusted class average" approach to determining the accredited capacity value for such resources. "Class" refers to the specific technology types, which includes technologies such as solar, hydropower, wind, landfill, and battery storage. The adjusted class average approach measures the contribution to reliability of all the portfolio of resources in that class; it assigns a capacity value associated with the portfolio's contribution to meeting the PJM loss of load expectation ("LOLE") standard. The new capacity accreditation methodology also recognizes the diminishing return associated with greater levels of deployment of these resource types, ensuring that the RTO does not become over-dependent on a single resource type whose physical capabilities have inherent limitations.

The ELCC approach to capacity accreditation sets a cap or upper limit on the amount of unforced capacity that renewable and storage resources can offer to provide to the Capacity Market in any one delivery year. As penetration of ELCC Resources increase, the class ratings will decline.

The capacity value will be adjusted yearly. As more of these resources are introduced into the capacity market, the accredited capacity value for individual resources in the class will be reduced such that the entire portfolio of resources in the class does not exceed the calculated capacity value cap determined for that class. PJM will begin relying on the accreditation values that result from applying this new methodology for the 2023/2024 delivery year.

Looking ahead, some PJM stakeholders seek to apply an ELCC-type methodology to the calculation of accredited capacity values for thermal generation resources, so EKPC anticipates this will be a topic in PJM's phase 2 capacity market/resource adequacy construct discussions described above.

3. Capacity Interconnection Rights (CIRs) for ELCC resources

During the stakeholder discussions creating an ELCC methodology for storage and variable resources, it was noted that the Capacity Interconnection Rights ("CIRs") associated with such resources could be impacted should the ELCC capacity accreditation reduce their capacity value. Therefore, the stakeholders agreed to consider the impacts to CIRs in a stakeholder process at the conclusion of the ELCC stakeholder deliberations.

When PJM studies wind and solar generation resources in the generation interconnection process, its analysis is focused on the average resource outputs over the summer period consistent with the capacity accreditation methodology that preceded the use of the ELCC methodology. As a result, the associated assignment of CIRs and the design of the transmission system only support these average output levels. Moving to the ELCC capacity accreditation methodology necessitates a change in the deliverability analysis PJM must do when it studies such resources for interconnection. The potential change is under discussion in the PJM Planning Committee. Both the level of CIRs awarded and the transmission enhancement that is needed to reliably connect the ELCC resources are likely to be impacted as a result of that effort, should the FERC approve what PJM ultimately files.

E. **Distributed Energy Resource (DER) Aggregation**

FERC Order No. 2222 seeks to harness the operational and market efficiency benefits of Distributed Energy Resources ("DER") in organized wholesale electricity markets. The order recognizes individual resources do not meet the minimum size threshold for market participation, but aggregation of them would. FERC defines DERs as any resource located on the distribution system, any subsystem thereof or behind a customer meter. FERC did not prescribe which resource types may comprise an aggregation but has identified that electric storage, distributed generation, demand response, energy efficiency, thermal storage, and electric vehicles and their supply equipment may be among those aggregators that may seek to combine in aggregations for wholesale market participation. Additionally, FERC required Regional Transmission Organizations ("RTO") like PJM to ensure there were no barriers for DER aggregation participation in any market for which those aggregations may satisfy the operational requirements for participation (energy, ancillary services, and capacity).

Much of the detail about how the Electric Distribution Companies ("EDC"), including electric distribution cooperatives, and DER Aggregators coordinate and share operational information with each other and PJM, as well as the registration and review of individual DER resources and aggregations by the EDC were not addressed by Order 2222. FERC left those details to the RTO to address in their compliance filings. Additionally, the FERC left certain aspects to the retail regulator, such as the safe, reliable interconnection of DERs.[3]

[3] *Id* at ¶ 44 ("[T]he Commission recognizes a vital role for state and local regulators with respect to retail services and matters related to the distribution system, including design, operations, power quality, reliability, and system costs. As in Order No. 841, we reiterate that nothing in this final rule preempts the right of states and local authorities to regulate the safety and reliability of the distribution system and that all distributed energy resources must comply with any applicable interconnection and operating requirements.")

Order No. 2222 does not automatically apply to all distribution utilities. EKPC supported the inclusion of an "opt in" provision that would operate to not impose the Order 2222 requirement on small distribution utilities – those distribution utilities whose annual electricity usage is less than 4 million MWh. Such a provision recognizes the operational challenges and overall economic burden imposed by Order 2222. At present and for the foreseeable future, each of EKPC's owner-member distribution cooperatives meets the size threshold to be considered a small utility eligible for the "opt in."

PJM made its compliance filing on February 1, 2022. PJM requested that the rules not go into effect until 2026, in order to provide it sufficient time to ready its systems and processes to accommodate the new rules. PJM also requested that the DER aggregations be permitted to participate in the capacity market Base Residual Auction held in 2023, for the delivery year that coincides with the effective date they requested. The FERC extended the deadline for comments on PJM's compliance filing to April 2022.

Several parties have asked the FERC to hold a technical conference to evaluate Order 222 implementation across the RTOs. Not all RTOs have submitted their compliance filings, and FERC has not issued an order addressing the requests for a technical conference.

III. Transmission Expansion Planning

A discussion of PJM and FERC developments associated with transmission expansion planning and generation interconnection is important for a consideration of future changes that may impact EKPC's IRP. These developments are at an early stage, so EKPC has not made specific accommodation of these in this IRP. Rather, EKPC includes reference to these developments because they will have an impact in the future that EKPC intends to reflect in future IRP submittals.

PJM has the responsibility to develop a long-term, regional transmission expansion plan, and the PJM Transmission Owners, including EKPC, have an obligation to construct certain facilities included in that plan. The PJM planning process ensures reliability and seeks to mitigate transmission congestion, which is important to ensure we can deliver power reliably and economically to our owner-members.

Additionally, EKPC is required to interconnect generators that seek to connect to EKPC's transmission facilities. Thus, EKPC is impacted by the interconnection requirements.

The FERC has initiated a rulemaking that is evaluating whether changes should be made to the long-term, regional transmission expansion and local planning processes, and whether changes are merited to the interconnection process. Because the PJM interconnection queue has been significantly backlogged, PJM and its stakeholders have undertaken an effort to reform the process. Below is an update on both the broad FERC rulemaking and the PJM stakeholder process queue reform efforts.

The developments around hybrid resources and ELCC resources noted above include transmission planning implications. EKPC does not repeat those here.

A. ANOPR

In July 2021, FERC issued an Advance Notice of Proposed Rulemaking ("ANOPR") seeking comments on potential reform of regional and inter-regional electric transmission planning processes, generator interconnection processes, and transmission cost allocation. EKPC submitted comments in October 2021, focused on the FERC's specific inquiries into holistic approaches to planning -- including planning to address local system needs, anticipated future generation, and renewable energy zones – as well as associated cost allocation considerations.

Of most relevance to EKPC's IRP, EKPC highlighted in its FERC comments that it is an electric cooperative whose owner-members drive the need for and ultimately approve any EKPC investment in projects to address local transmission needs. As such, EKPC cautioned that any changes to how such projects are identified and approved going forward may create challenges to EKPC's ability to control the cost and implementation timing of needed projects.

Additionally, EKPC's FERC comments addressed the ANOPR's inquiry into approaches that could support the development of renewable generation more holistically than FERC perceived the ability of the current approach to generation interconnection. The current approach is based on specific generation development projects coming forth and entering the queue for study; those individual generators bear the cost of any necessary transmission enhancements to enable the power they produce to be deliverable to load in the PJM region. The ANOPR is questioning whether there may be a proactive approach to building out the transmission system in anticipation of generation projects coming forward in the future (but with no specific obligation for any such project to come forth), and whether the interconnecting generator should bear less than the full cost of the necessary transmission reinforcements. EKPC raised concerns with the suggestion that generation interconnection would be more efficient if transmission could be built out in a proactive manner in areas where certain renewable resources may eventually locate (assuming wind/solar profiles in the location). EKPC also pointed out that the ANOPR is silent on how the regions should ensure resource adequacy should there be a preference for renewable generation. The grid will need to rely on generation fueled by means other than the sun and wind for the foreseeable future and the transmission expansion policy should not create an uneven playing field for those needed resources. A renewable energy zone policy may create an unintended resource adequacy or operational reliability challenge if other resources are discouraged from interconnecting because of the market impacts associated with the preferred renewable resources.

Additionally, EKPC raised a variety of concerns related to cost allocation but does not elaborate here as they are not germane to this IRP.

Last, the ANOPR sought comments on reforms to improve the timeliness and efficiency of the process for evaluating generators connecting to the transmission system, as well as on potential changes to cost responsibility for network upgrades needed to reliably connect new generators to the transmission system. EKPC's comments agreed there are opportunities to reform the interconnection process and urged FERC to allow regions like PJM that were already in the midst of stakeholder discussions considering such reforms to move forward and not wait for the outcome of the rulemaking process to achieve important, necessary reforms. EKPC describes that PJM stakeholder process below.

B. Generation Interconnection Queue Reform at PJM

PJM made an information report filing with FERC in February 2022 providing an update on the status of its efforts to address the backlogged interconnection queue. [4] In that report, PJM indicated that it has been experiencing an increase in the number of New Service Requests received each year leading to a record-high volume of projects under study, which directly impacts, on a cascading basis, PJM's study process and timing. PJM reported that as of January 31, 2022, it has 2,494 active projects at various points in the study process representing approximately 226.5 GW.

This backlog was the impetus for PJM and stakeholders to tackle reforming the queue process. The stakeholders' goals were to: decrease each project's time in the PJM queue; provide actionable analysis results; and increase customer cost certainty relative to the existing process and any required upgrades. At a high-level, the proposed changes are focused on moving PJM from a first-in, first-out serial interconnection process to a first-ready, first-serve cycle/phase interconnection process. East Kentucky has supported this effort and these potential changes, and has supported PJM and stakeholders working toward a solution ahead of any further action FERC may take in the context of the ANOPR.

That stakeholder initiative is drawing to a close. It appears that there is sufficient stakeholder support for both the changes to the process and requirements imposed on the interconnection applicant as well for a proposal to manage the backlog through the transition to the end state new process. Stakeholder are anticipating voting on these changes in April 2022, and PJM is anticipating filing them with FERC in May 2022.

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[4] PJM Interconnection, L.L.C., Docket No. ER19-1958-003 Informational Report on Interconnection Study Performance Metrics (February 14, 2022).

At this time EKPC does not expect a reliability issue to materialize from the backlog, but because of the significant delay that any new project will experience, a concern could arise if a generator needed to deactivate or repower and its replacement is delayed. Delays also may challenge the achievement of decarbonization or other sustainability goals. This backlog has created a delay in EKPC being able to transact with a third party solar developer to install a project specifically requested by a large industrial customer via the Green Power Tariff. Additional Green Power Tariff requests, along with any projects desired to meet sustainability goals, will face similar delays in project development. EKPC will stay actively involved in PJM policy and rules development in an effort to advance its ability to meet future energy and capacity needs.

- **EKPC should provide greater transparency in and discussion of its sources of data, and how that data is used and manipulated to introduce uncertainty into the model.**

EKPC has provided all of its data and the sources of that data in the appropriate sections throughout the IRP. EKPC has also discussed its view of uncertainty in appropriate sections throughout the IRP. EKPC acknowledges that market and fuel prices levels at the end of March 2022 are significantly higher than they were in the Fall 2021, when EKPC developed the price assumptions for this study. The bulk of the differences would impact the short term operations, but the market is expected to eventually turn back towards the price assumptions used in the study.

- **EKPC should provide greater support for and discussion of the rationale of its choices of alternative assumptions (such as different weather assumptions in the demand and supply-side forecasts), constraints, and decision parameters programed into the RTSim production cost and optimization models. As one example, Table 8-2 on page 136 presents nine resource options offered into the RTSim production cost model. There should be a more robust detailed discussion as to why these particular options were chosen (such as cost, performance attributes, technology development, current and expected market characteristics) and why specifically other optional resources were rejected. In addition, EKPC should provide more explicit explanations for what**

environmental cost elements and uncertainties are included in the models. EKPC should include the potential effects of carbon regulation and how that could affect fuel and emission prices on the supply-side and ultimately the price of electricity on the load forecast.

EKPC has provided all of its data and the sources of that data in the appropriate sections throughout the IRP. EKPC has also discussed its view of uncertainty in appropriate sections throughout the IRP.

EKPC hired Guidehouse to prepare several carbon price forecasts.

EKPC had GDS evaluate and measure cost-effectiveness of DSM and EE programs under four (4) economic scenarios:

- Base Case – EKPC's avoided costs for energy capacity from PJM
- Low Carbon – Base case plus a per MWh adder for carbon costs based on the RGGI
- Mid Carbon – Base case plus a per MWh adder for carbon costs based on a Biden Administration proposal
- High Carbon – Base case plus a per MWh adder for carbon costs based on the social cost of carbon in New York.

Under the Mid and High carbon cases, additional EE measures became cost-effective. The Mid case resulted in about 30% more measures being cost-effective.

- **EKPC should provide more robust and detailed explanations of the modeling results between the demand side and supply-side modeling. For example, as brought out in the Hearing, the differences between the peak load demand forecasts in Table 3-19 and those used as supply-side inputs in Table 8-6, are well reasoned, but not obvious. In addition, there should be more discussion of specific steps taken by the models to ultimately obtain a preferred least cost plan, the interactions between the RTSim models, and tying results listed in tables to discussions more closely.**

EKPC has provided all of its data and the sources of that data in the appropriate sections throughout the IRP. EKPC has also discussed its view of uncertainty in appropriate sections throughout the IRP. The RTSim model is discussed in the Integrated Resource Planning section.

- **If not addressed above, EKPC should provide more detailed explanations of the renewable energy resource options offered into the RTSim models. Any available production tax credit, investment tax credit, financing, or any other incentive (current or expiring should be included appropriately and explained in the model.**

The renewable options initially considered included wind, solar, and battery storage. Solar energy, via PPAs, was the preferred resource due to cost and availability. Investment Tax Credits ("ITC") make self-build options less attractive due to the advantages a taxable entity is offered with the ITC. Wind was excluded from the screening due to the lack of significant wind resources in the EKPC zone, as noted on NREL wind speed maps, and the cost of a PPA with wind resources located in other areas of the PJM region. The transmission costs and impact of settling the PPA at the PJM AEP-Dayton Hub ("AD-Hub") and then at the EKPC zone, was cost prohibitive as compared to solar located in the EKPC zone. Battery storage has been considered for potential pilot applications, but the limited duration and initial cost has excluded batteries at this time. As the technology continues to develop and mature, EKPC anticipates further research and possible consideration of battery capacity as part of the resource portfolio.

Solar PPAs were based on expected costs from a recent RFP for solar energy. The PPAs were allowed to annually enter into the model throughout the study period of the capacity expansion study. This allowed solar energy to be compared with market purchases and natural gas resources.

- **There are multiple pending merchant solar facilities being considered for construction and interconnection with EKPC's transmission system. EKPC should consider and discuss both the short and long-term effects of the output from the facilities on: (1) any changes in the demand for energy (and capacity if applicable) within its service territory; (2) possible changes in interest in or the expansion of the**

solar share program; (3) any effects on EKPC's and Owner-Member Distribution Cooperative's (OMDC) transmission and distribution system brought out through interconnection studies; and (4) how the sustainability goals of large customers affects EKPC's transmission and generation planning, if at all.

(1) The merchant solar facilities are not being built to serve EKPC load. However, EKPC may seek to secure via contract the output of certain of these resources in order to hedge its load position, hedge the potential for energy price volatility, and otherwise achieve its sustainability goals, as described in this IRP. These facilities may require station service power at times; however, EKPC does not anticipate a meaningful increase in energy or capacity needs as a result of the addition of merchant solar facilities.

(2) EKPC continually monitors the solar share program and the interest in that program. Based on participation to date, EKPC does not anticipate expanding that program within the planning horizon of this IRP.

(3) Regarding any effects on EKPC's and its OMDC's combined transmission and distribution systems brought out through interconnection studies, the PJM study process as described in the PJM Operating Agreement, Schedule 6, and the PJM Open Access Transmission Tariff, Parts IV and VI, is utilized by PJM, and supported by EKPC, to determine the impacts of potential newly-interconnected generation facilities on the EKPC transmission system.[5]

For each requested interconnected facility, EKPC assesses the transmission infrastructure required for:

- direct connection to the EKPC system (which is typically either a new transmission substation or expansion of an existing transmission substation)
- non-direct connection needs to attach to the EKPC system (typically includes transmission line modifications near the point of interconnection, system protective

[5] If EKPC were not in PJM, it anticipates it would have seen an increased interest in solar development in Kentucky as it currently is experiencing because the interest is largely influenced by federal policies, including PURPA.

relay upgrades at existing substations in the vicinity, and establishment of communications pathways to the point of interconnection)

- network system upgrades needed to attach to the EKPC system (infrastructure additions and/or modifications to address overloaded EKPC transmission facilities due to increased power flows caused by the interconnected generation facility)

The facilities that are identified by EKPC for each generation interconnection are required to be constructed prior to the facility beginning commercial operations in the PJM market. This process evaluates the impacts of each project and ensures that the necessary facilities are installed to maintain a reliable and adequate EKPC transmission system while the generating facility is operating.

To assess longer-term impacts, both PJM and EKPC include interconnection queue projects with executed Interconnection Service Agreements in the long-term planning models that are used for evaluation of the transmission system through various planning studies. This ensures that any additional changes to the transmission system that are necessary to maintain adequacy and reliability are identified as the overall system changes in the future, while ensuring that the system is not overbuilt to accommodate generation projects that may not be developed.

To date, all solar generation facilities that have requested interconnection within the EKPC system have specified connection to the EKPC transmission system. Therefore, no impacts on the distribution systems of the EKPC owner-members have been identified. EKPC and its owner-members are beginning to assess general requirements for interconnection of facilities at the distribution level in anticipation of future interest by developers for smaller-scale projects with low interconnection costs. The assessment of these types of interconnection requests will evaluate both the immediate requirements and the longer-term impacts of the interconnected facilities.

(4) Regarding how the sustainability goals of large customers affects EKPC's transmission planning, EKPC has not made any changes to our process. The existing PJM study process provides a robust evaluation that covers potential dedicated renewable energy delivery to industrial customers served by EKPC owner-members. The PJM studies consider

deliverability of output of each potential interconnected facility in the PJM footprint to each load deliverability area, including EKPC. This ensures that necessary transmission infrastructure is identified and constructed to allow delivery of any generation in the PJM market to the EKPC load zone. Therefore, EKPC utilizes the existing PJM study process to determine specific infrastructure additions and modifications necessary to deliver energy from potential interconnected generation facilities to customers within the PJM zone. Furthermore, as described in the response to part (3) above, EKPC includes all generation facilities with executed Interconnection Service Agreements in our long-term planning models in order to identify any additional infrastructure requirements as the system continues to evolve, which ensures continued deliverability to EKPC customers for these facilities.

The sustainability goals of large customers can impact EKPC's generation planning. If large customers desire a specific green energy resource, EKPC will look to provide that resource to the customer as long as the specific customer incurs any additional costs associated with the request. EKPC will supply the green energy requests so long as the remainder of EKPC's customers are held harmless from any additional costs associated with the request.

EKPC, in concert with its owner-member cooperatives, developed programs and resulting tariffs to support those efforts. The Renewable Energy Program tariff was expanded to include two (2) new renewable energy options targeted to the commercial and industrial ("C&I") end-use members:

- Option B – Long-term Renewable Resources
- Option C – C&I RECs

The goal of the new program is to offer C&I end-use members renewable resources and/or Renewable Energy Credits ("RECs") to achieve their sustainability goals without cross-subsidization from or to non-participants. The Commission approved both Option B and Option C of the Renewable Energy Program tariff.

EKPC and its owner-member cooperatives have discussed the program with several large C&I end-use members. To date, one has already agreed to participate in the long-term renewable energy program. EKPC is working to secure the renewable resource as defined in the agreement. Another large C&I end-use member has agreed to a REC-only purchase. That business is offsetting 10% of its monthly consumption through RECs.

- **EKPC should continue to provide short descriptions of federal and state environmental rules and requirements that apply to it. Additionally, EKPC should clearly distinguish between: (1) rules and requirements with which EKPC is already in compliance; (2) expected changes to rules and requirements that would have a material effect on EKPC's operations and how its operations would be affected; and (3) rules and requirements with which EKPC is not yet in compliance.**

  (1) See Section 9.1.

  (2) and (3) In Section 9.2 EKPC has identified future rules from the EPA and Whitehouse Unified Agenda pending further action by the United States Executive Branch, Office of Management Budgets ("OMB") and the federal Environmental Protection Agency ("EPA"). The future rules could have a material impact to the generation and transmission assets but the rules have not been publicized nor have they appeared in the federal registry. Therefore, EKPC is not in compliance nor is it required to comply with the future rules just yet.

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 Rural Utilities Service ("RUS")-approved Load Forecast Work Plan ("Work Plan"). EKPC's "2021 - 2035 Load Forecast" was prepared pursuant to its Work Plan, which was approved by RUS in December 2019. The Work Plan details the methodology used to develop the forecasts. The EKPC Load Forecasting Department works with the staff of each owner-member to prepare sixteen (16) owner-member forecasts and then aggregates the resulting forecasts, adds projections of use of EKPC facilities and transmission losses, incorporates energy efficiency and demand response impacts resulting in EKPC's total system forecast. The load forecast was approved by the EKPC Board in December of 2020 and RUS in January 2021. Owner-Members use their load forecasts as input 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.

Due to the pandemic in 2020, this load forecast was produced later in the year than typical. SARS-CoV-2 ("COVID-19") began impacting Kentucky's economy in March of 2020. In an effort to better understand the near and longer-term impacts of the pandemic, EKPC opted to wait until updated economic forecasts became available. IHS Global Insight, Inc. ("IHS") released an updated outlook in June 2020. EKPC's load experienced its greatest reduction in April 2020 at an estimated 14%, weather normalized. Business and school closings and other government-imposed restrictions continued to impact the load in 2020. Having actual energy data for most of 2020, energy for 2020 was estimated outside of the construct of the model using insights from the owner-members and analysis of recent impacts due to COVID-19. To prevent skewing the growth rates, 2020 has been excluded from the calculations.

EKPC's load forecast projects total energy requirements to increase from 14.4 to 16.8 million MWh, an average of 1.1 percent per year over the 2022 through 2036 period. Net winter and summer peak demands will increase by approximately 277 MW or 0.6 percent and 294 MW or 0.8 percent respectively over weather-normalized 2022 to 2036. Annual load factor projections are increasing from 50 percent to approximately 54 percent from 2022 to 2036. Energy projections for the residential, small commercial, and large commercial classifications indicate that during the 2022 through 2036 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 1.9 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

	2022 - 2036
Net Total Energy Requirements	1.1%
Residential Energy Sales	0.7%
Commercial and Industrial ≤ 1000 KVA Energy Sales	0.8%
Commercial and Industrial > 1000 KVA Energy Sales	1.9%
	2022 - 2036
Net Winter Peak Demand	0.6%
Net Summer Peak Demand	0.8%

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 in preparing the forecast include: national, regional, and local economic performance; population and housing trends; service area industrial development; electric prices; 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 (%)
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	13,576,581	45.1%
2018 - 19	3,073	2019	2,366	2019	13,140,304	48.8%
2019 - 20	2,723	2020	2,312	2020	12,786,403	53.5%
2020 - 21	2,862	2021	2,450	2021	13,529,377	54.0%
2021 - 22	3,309	2022	2,500	2022	14,421,062	49.8%
2022 - 23	3,363	2023	2,574	2023	15,191,270	51.6%
2023 - 24	3,384	2024	2,612	2024	15,304,776	51.5%
2024 - 25	3,391	2025	2,623	2025	15,397,278	51.8%
2025 - 26	3,409	2026	2,634	2026	15,500,370	51.9%
2026 - 27	3,427	2027	2,651	2027	15,604,583	52.0%
2027 - 28	3,457	2028	2,669	2028	15,747,490	51.9%
2028 - 29	3,470	2029	2,684	2029	15,849,209	52.1%
2029 - 30	3,480	2030	2,695	2030	15,945,207	52.3%
2030 - 31	3,494	2031	2,707	2031	16,058,087	52.5%
2031 - 32	3,520	2032	2,726	2032	16,227,680	52.5%
2032 - 33	3,533	2033	2,742	2033	16,339,247	52.8%
2033 - 34	3,556	2034	2,761	2034	16,491,095	52.9%
2034 - 35	3,578	2035	2,780	2035	16,647,000	53.1%
2035 - 36	3,586	2036	2,794	2036	16,838,980	53.5%

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

Year	Energy (MWH)	Winter Peak (MW)	Summer Peak (MW)
2022	-35,631	-238	-237
2023	-41,647	-239	-238
2024	-47,662	-240	-238
2025	-53,678	-241	-239
2026	-59,432	-242	-240
2027	-65,186	-243	-240
2028	-70,940	-244	-241
2029	-75,579	-245	-241
2030	-80,218	-246	-241
2031	-84,857	-246	-242
2032	-89,496	-247	-242
2033	-94,135	-248	-243
2034	-98,774	-249	-243
2035	-103,413	-249	-243
2036	-101,652	-249	-243

A separate DSM plan was developed for inclusion in the capacity plan as a resource that includes new participants in new and 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 (MWh)	Large Comm. Sales (MWh)	Public Street and Highway Lighting (MWh)	Total Retail Sales (MWh)
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	6,502,113	534	1,896,475	36,578	3,395,430	9,325	11,840,456
2018	7,324,079	621	1,962,505	41,142	3,425,613	8,796	12,762,756
2019	7,036,916	663	1,925,821	39,829	3,314,391	8,770	12,326,390
2020	6,915,401	662	1,791,061	34,187	3,251,726	8,771	12,001,809
2021	7,205,739	744	1,967,078	39,064	3,546,763	8,707	12,768,095
2022	7,241,094	787	2,015,313	39,744	4,322,510	8,714	13,628,162
2023	7,250,544	830	2,043,245	39,984	5,044,551	8,724	14,387,878
2024	7,284,706	875	2,062,484	40,066	5,097,698	8,751	14,494,581
2025	7,302,221	921	2,079,718	40,009	5,149,693	8,788	14,581,351
2026	7,342,156	970	2,097,729	40,027	5,187,514	8,817	14,677,212
2027	7,391,408	1,024	2,108,594	40,062	5,224,687	8,845	14,774,619
2028	7,466,896	1,079	2,125,152	40,080	5,266,542	8,872	14,908,621
2029	7,507,069	1,126	2,142,182	40,010	5,303,801	8,898	15,003,086
2030	7,543,995	1,172	2,153,353	39,979	5,345,551	8,923	15,092,974
2031	7,583,918	1,222	2,170,018	39,974	5,394,473	8,949	15,198,554
2032	7,665,895	1,274	2,188,051	40,009	5,453,316	8,974	15,357,518
2033	7,710,245	1,325	2,204,658	39,993	5,495,901	8,999	15,461,120
2034	7,797,053	1,374	2,215,933	40,003	5,550,228	9,024	15,613,616
2035	7,876,640	1,427	2,236,079	40,019	5,596,044	9,049	15,759,257
2036	7,991,693	1,487	2,256,693	40,086	5,640,411	9,074	15,939,443

Note: Owner-Members' Form 7 data for 2021 were not available.

Table 3-4 continued
Total Sales and Requirements

Year	Total Retail Sales (MWh)	Owner-Member Office Use (MWh)	Average Distribution Losses (%)	Average Distribution Losses (MWh)	Sales to Owner-Members (MWh)	EKPC Facilities Use (MWh)	Transmission Losses (%)	Average Transmission Losses (MWh)	Net Total Requirements (MWh)
2010	12,233,507	10,401	4.4%	567,997	12,811,906	8,654	4.3%	555,732	13,376,292
2011	11,809,733	9,742	3.8%	469,596	12,289,071	10,146	3.0%	367,781	12,666,998
2012	11,407,734	9,120	4.4%	526,552	11,943,406	8,811	2.0%	237,853	12,190,070
2013	11,892,868	9,977	4.0%	498,059	12,400,903	8,270	1.9%	235,416	12,644,590
2014	12,357,874	10,497	4.1%	530,031	12,898,402	8,246	2.0%	256,868	13,163,516
2015	11,768,687	10,008	4.3%	524,746	12,303,441	8,190	2.3%	293,311	12,604,942
2016	12,143,355	10,270	4.1%	520,618	12,674,244	8,203	2.7%	357,506	13,039,953
2017	11,840,456	9,992	4.0%	490,346	12,340,793	8,374	2.5%	330,944	12,680,111
2018	12,762,756	10,647	3.5%	465,363	13,238,766	8,451	2.4%	329,364	13,576,581
2019	12,326,390	10,232	3.6%	462,149	12,798,772	7,891	2.5%	333,641	13,140,304
2020	12,001,809	9,444	3.9%	488,649	12,499,902	9,444	2.1%	277,057	12,786,403
2021	12,768,095	10,408	3.8%	449,737	13,228,240	8,250	2.4%	292,887	13,529,377
2022	13,628,162	10,408	3.8%	475,329	14,113,899	8,250	2.3%	298,913	14,421,062
2023	14,387,878	10,408	3.8%	481,691	14,879,977	8,250	2.3%	303,043	15,191,270
2024	14,494,581	10,408	3.8%	481,307	14,986,296	8,273	2.3%	310,207	15,304,776
2025	14,581,351	10,408	3.8%	485,187	15,076,946	8,250	2.3%	312,082	15,397,278
2026	14,677,212	10,408	3.8%	490,330	15,177,950	8,250	2.3%	314,170	15,500,370
2027	14,774,619	10,408	3.8%	495,025	15,280,053	8,250	2.3%	316,280	15,604,583
2028	14,908,621	10,408	3.8%	501,016	15,420,045	8,273	2.3%	319,172	15,747,490
2029	15,003,086	10,408	3.8%	506,231	15,519,725	8,250	2.3%	321,234	15,849,209
2030	15,092,974	10,408	3.8%	510,397	15,613,779	8,250	2.3%	323,178	15,945,207
2031	15,198,554	10,408	3.8%	515,412	15,724,373	8,250	2.3%	325,464	16,058,087
2032	15,357,518	10,408	3.8%	522,585	15,890,511	8,273	2.3%	328,896	16,227,680
2033	15,461,120	10,408	3.8%	528,312	15,999,840	8,250	2.3%	331,157	16,339,247
2034	15,613,616	10,408	3.8%	524,589	16,148,613	8,250	2.3%	334,232	16,491,095
2035	15,759,257	10,408	3.8%	531,696	16,301,361	8,250	2.3%	337,389	16,647,000
2036	15,939,443	10,408	3.8%	539,581	16,489,432	8,273	2.3%	341,275	16,838,980

Note: Owner-Members' Form 7 data for 2021 were not available. Distribution and Transmission losses exclude direct serve customers.

3.2 Load Forecast

3.2.1 Introduction

The forecast used in the IRP was approved December 2020 by the EKPC Board of Directors and by RUS in January 2021. It was prepared pursuant to its "2021 - 2035 Load Forecast Work Plan," which was approved by RUS in December 2019. Where available, actual data replaced forecasted values. For instance, 2020 total requirements, peaks and energy and 2021 peaks are examples of situations where actual data replaced forecasted values. Adjustments have been made to reflect more current assumptions. Specifically, the expansion of an industrial customer has been delayed over a year. The general steps followed in developing the load forecast include:

1. Develop regional economic projections: EKPC subscribes to IHS, in order to analyze regional economic performance. IHS provides county-level projections for population, employment, income as well as other variables. EKPC further analyzes the data to appropriately reflect the owner-members' individual service territories.
2. Perform analysis and construct models: EKPC prepares a preliminary forecast for each of its owner-members for each classification as reported on the RUS Form 7, which contains retail sales data for owner-members. These classes include: residential, seasonal, small commercial, public buildings, large commercial, and public 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 developed using historical normalized peaks and seasonal load factors.
3. Collect insights from the owner-members: 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. Revise the forecasts: The preliminary forecast is revised based on the mutual agreement of EKPC staff and owner-member's President/CEO and staff. This final forecast is approved by the Board of Directors of each owner-member.
5. Develop the system load forecast: The EKPC forecast is the summation of the forecasts of its sixteen (16) owner-members with demand response, energy efficiency, transmission losses and EKPC facilities' use incorporated.

There is close collaboration and coordination between EKPC and its owner-members throughout this process. This working relationship is essential because EKPC has no retail customers. Input from owner-members relating to industrial development, subdivision growth, and other specific service area information is crucial to the development 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 assumptions used in developing the EKPC and owner-member load forecasts are:

1. EKPC's owner-members will add almost 54,000 residential customers 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 0.7 percent per year through the forecast period. Included in the Load Forecast Appendix is a report from IHS describing the short-term outlook for Kentucky.

3. As of 2020, approximately 76 percent of all new households have electric heat and about 86 percent of all new households have electric water heating. Nearly all new homes will have electric air conditioning, either central or room.

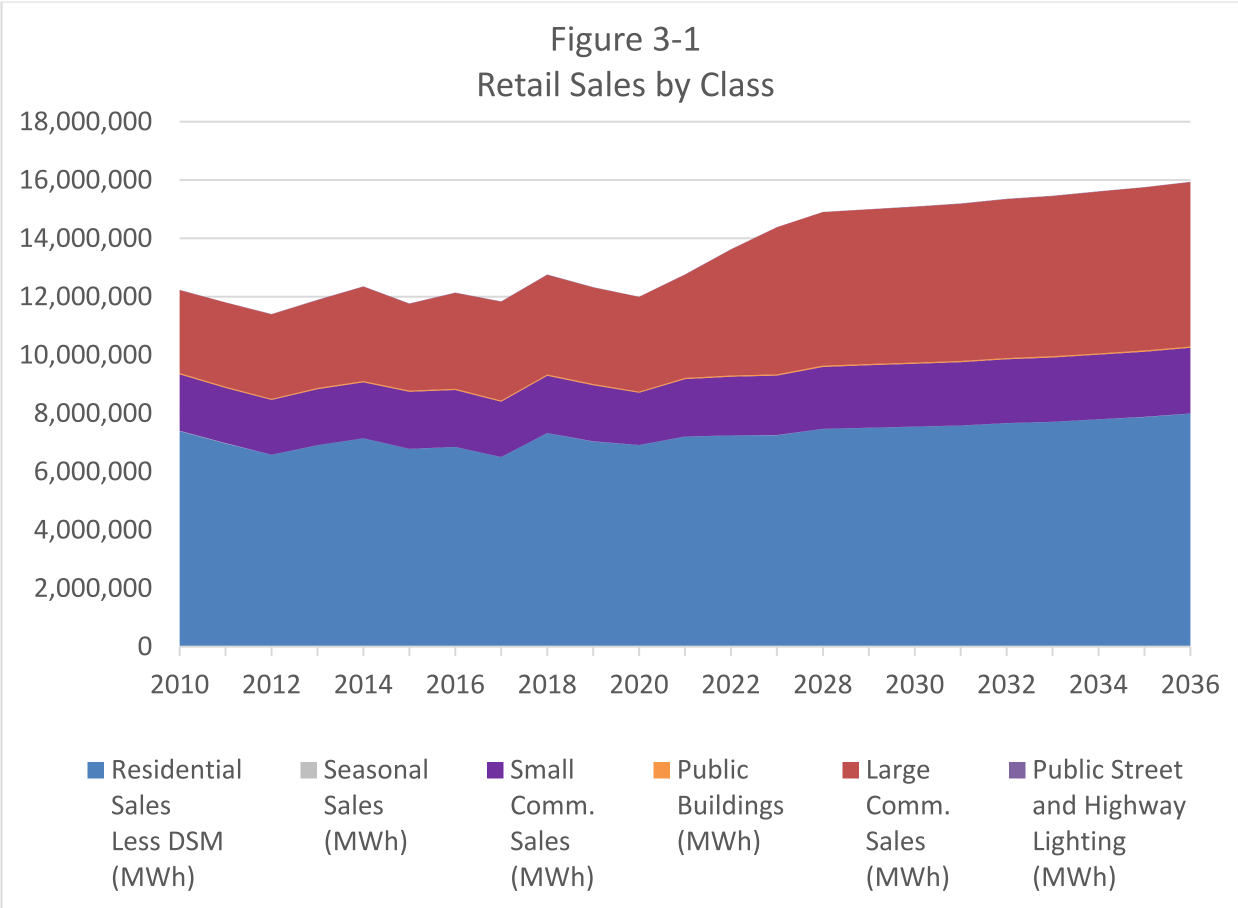
4. Over the forecast period, naturally occurring appliance efficiency improvements will have a dampening effect on residential retail sales. In addition to lighting, appliances particularly affected are heating and cooling.

5. Residential customer 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 (2000 – 2019). Seven different stations are used depending on geographic location of the owner-member. These stations include; Lexington ("LEX"), Louisville ("SDF"), Covington ("CVG"), Jackson ("JKL"), Somerset ("SME"), Bowling Green ("BWG"), and Huntington West Virginia ("HTS").

3.2.3 Discussion of Service Area

In EKPC's service area, electricity is the primary method for water heating and home heating. Around 86 percent of all homes have electric water heating, and about 63 percent use electricity as a primary fuel for heating. In 2020, nearly 58 percent of EKPC's owner-member retail sales were to the residential class and residential customer use averaged 1,121 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 Cincinnati contains a growing number of retail trade and service jobs. Mining has seen strong decreases due to regulatory changes as well as decreased gas prices, the most notable impacts being in the 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. 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 customer 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 2016 through 2020. 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 2016 through 2020.

Table 3-5
EKPC Recorded Annual Energy Sales (MWh) and Energy Requirements (MWh)
2016 - 2020

	2016	2017	2018	2019	2020
Total Residential	6,847,090	6,502,113	7,324,079	7,036,916	6,915,401
Residential Seasonal	416	534	621	663	662
Small Commercial	1,951,787	1,896,475	1,962,505	1,925,821	1,791,061
Large Commercial/ Industrial	3,296,495	3,395,430	3,425,613	3,314,391	3,251,726
Public Authorities	37,627	36,578	41,142	39,829	34,187
Public Street and Highway Lighting	9,940	9,325	8,796	8,770	8,771
Total Sales	12,143,355	11,840,456	12,762,756	12,326,390	12,001,809
Office Use	10,270	9,992	10,647	10,232	9,444
Distribution % Loss	4.1%	4.0%	3.5%	3.6%	3.9%
EKPC Sales to Owner-Members	12,674,244	12,340,793	13,238,766	12,798,772	12,499,902
EKPC Office Use	8,203	8,374	8,451	7,891	9,444
Transmission Loss (%)	2.7%	2.5%	2.4%	2.5%	2.1%
Net Total Requirements	13,039,953	12,680,111	13,576,581	13,140,304	12,786,403

Note: ***Owner-Members' Form 7 data for 2021 were not available.***

Table 3-6
Weather Normalized Coincident Peak Demands

Year	Season	Actual Peak MW	Adjusted Peak MW
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
2019	Winter	3,073	3,380
	Summer	2,366	2,440
2020	Winter	2,723	3,144
	Summer	2,312	2,459

Table 3-7
EKPC Weather Normalized Annual Energy Sales (MWh) and Energy Requirements (MWh)
2016 - 2020

	2016	2017	2018	2019	2020
Total Retails Sales by Owner-Member System					
Recorded	12,143,355	11,840,456	12,762,756	12,326,390	12,001,809
Weather Normalized	12,533,452	12,495,139	12,937,696	12,792,825	12,762,891
EKPC					
Recorded	13,039,953	12,680,111	13,576,581	13,140,304	12,786,403
Weather Normalized	12,895,262	12,838,462	13,267,758	13,134,522	13,064,550

Note: ***Owner-Members' Form 7 data for 2021 were not available. Data is not normalized by class.***

Table 3-8
Energy Sales and Firm Coincident Demand

	2016	**2017**	**2018**	**2019**	**2020**	**2021**
Energy Sales (MWh)*	12,674,244	12,340,793	13,238,766	12,798,772	12,499,902	NA
Coincident Peak Demand (MW)**	2,783	2,760	3,323	2,927	2,611	2,726

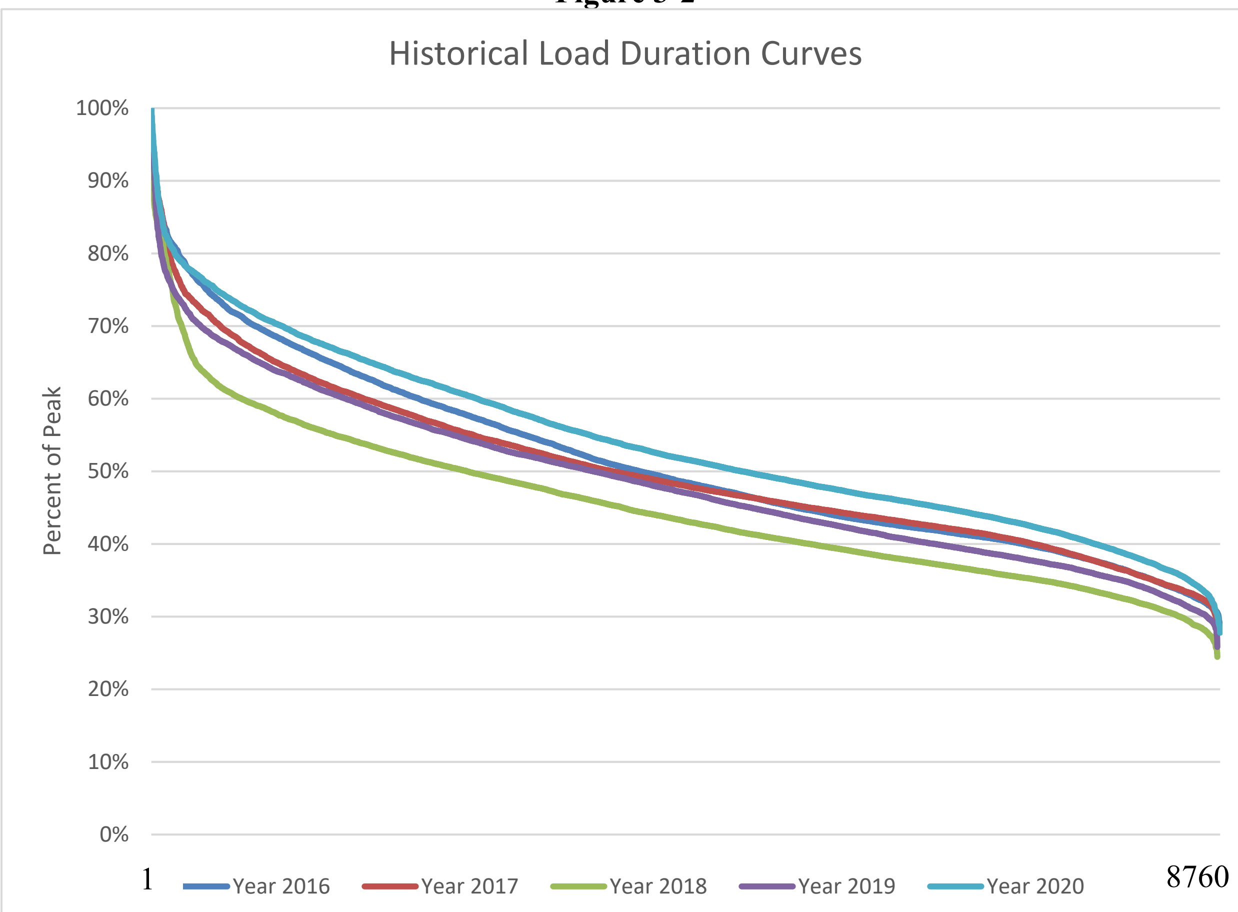
* Total sales to owner-members.
** Firm peak demand.

Table 3-9
Energy Sales and Non-Firm Demand

	2016	2017	2018	2019	2020	2021
Energy Sales (MWh)*	NA	NA	NA	NA	NA	NA
Coincident Peak Demand (MW)	107	111	114	146	112	136

* 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.

Customer 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
2022-2036

	Residential	Seasonal Residential	Commercial and Industrial ≤ 1000 KVA	Commercial and Industrial > 1000 KVA	Public Street and Highway Lighting	Other Public Authorities	Total
Customers	0.7%	4.6%	0.8%	1.3%	0.3%	0.5%	0.7%
Sales	0.7%	4.6%	0.8%	1.9%	0.3%	0.01%	1.1%

Table 3-11
Monthly Class Energy Sales Forecasts
2022 – 2023

		Sales (MWH)							Peak Demand (MW)
Year	Month	Residential	Seasonal	Small Commercial	Public Buildings	Large Commercial & Industrial	Public Street & Highway Lighting	Total Retail	System Coincident
2022	1	867,693	49	172,646	3,769	360,565	738	1,405,460	3,309
	2	775,770	46	164,226	4,173	333,029	736	1,277,980	3,080
	3	635,116	42	158,717	3,672	358,428	726	1,156,703	2,716
	4	484,407	34	156,549	3,250	355,821	716	1,000,777	2,175
	5	448,990	64	157,956	2,738	369,851	716	980,314	2,097
	6	523,540	108	169,433	3,028	367,235	712	1,064,056	2,446
	7	608,550	106	182,450	3,003	373,893	711	1,168,714	2,500
	8	622,138	105	189,555	3,265	382,170	715	1,197,948	2,391
	9	514,404	76	177,538	3,585	369,132	722	1,065,456	2,498
	10	454,610	57	163,230	3,159	365,576	731	987,362	2,251
	11	554,877	48	157,548	2,860	339,056	745	1,055,135	2,681
	12	751,000	52	165,464	3,241	347,753	747	1,268,259	3,013
Total		7,241,094	787	2,015,313	39,744	4,322,510	8,714	13,628,162	
2023	1	861,513	53	174,882	3,781	420,758	738	1,461,725	3,363
	2	796,922	50	168,761	4,185	388,644	737	1,359,299	3,190
	3	657,082	47	162,657	3,715	418,243	727	1,242,471	2,860
	4	503,927	36	158,478	3,266	415,358	717	1,081,782	2,315
	5	449,767	66	159,893	2,759	431,610	717	1,044,811	2,244
	6	508,610	112	171,463	3,049	428,555	712	1,112,500	2,574
	7	590,515	110	184,531	3,026	436,362	712	1,215,257	2,474
	8	609,790	109	191,708	3,287	445,937	716	1,251,548	2,410
	9	509,410	78	179,526	3,604	430,747	723	1,124,087	2,517
	10	458,427	60	165,014	3,179	426,582	731	1,053,993	2,259
	11	556,660	52	159,154	2,879	395,846	746	1,115,336	2,697
	12	747,921	56	167,178	3,255	405,909	748	1,325,068	2,997
Total		7,250,544	830	2,043,245	39,984	5,044,551	8,724	14,387,878	

3.3 Details of Assumptions

3.3.1 Regional Economic Model

EKPC combines county-level forecasts from IHS's county-level economic forecasts released in the second quarter of 2020, 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

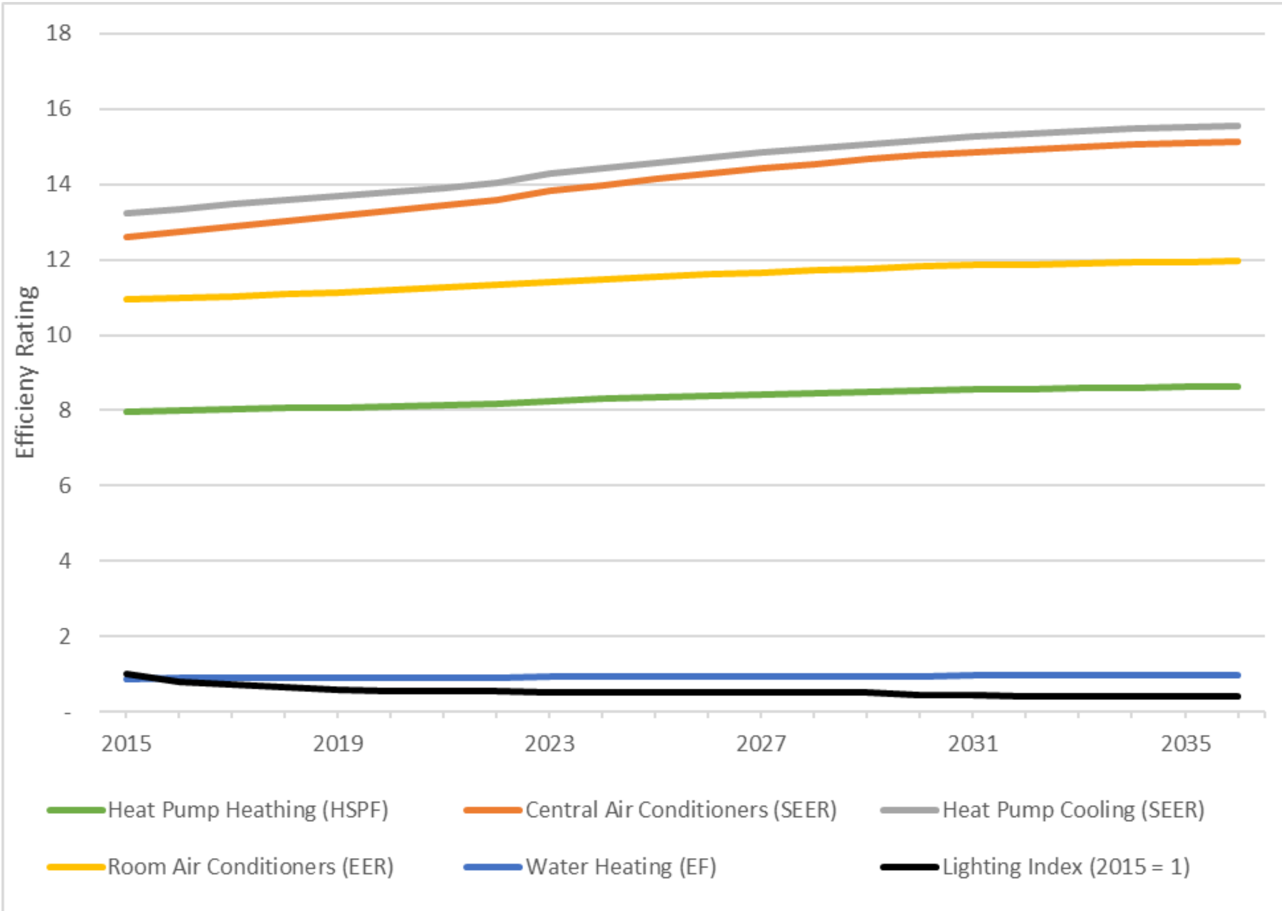
Every 2-3 years since 1981, EKPC has surveyed its owner-members' residential customers to gather information on electric appliance saturation and other factors affecting electricity demand. EKPC projects these saturations for each owner-member. Input from owner-members and other EKPC departments is sought during the development of the survey instrument. This year questions regarding ownership of electric vehicles and interest in purchasing one were included. The "2020 Load Forecast" incorporates appliance saturations into the models. The major drivers are:

- 63 percent of EKPC customers have electric as a primary fuel for heat.
- 98 percent of EKPC customers have some type of air conditioning.
- 86 percent of EKPC customers 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 Energy Information Administration ("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 "2020 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 ("NOAA") weather stations located at seven airports in or near the EKPC system. Normal weather data for owner-members are based on the historic 20-year values (2000-2019). EKPC uses the following weather stations:

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

3.4 Discussion of Models

3.4.1 Forecast Model Summary

Models are used to develop the load forecast for each owner-member for each class reported to RUS. Model specifications are included in the Load Forecast Technical Appendix.

3.4.1.1 Residential Sales

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

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

3.4.1.2 Small Commercial Sales

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

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

3.4.1.3 Large Commercial and Industrial Sales

EKPC models the monthly large commercial and industrial customers 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 customers and are generally aware of current production and future expansion plans, so they project energy sales for existing customers and identified expected new customers in this class for the next 3 years.

3.4.1.4 Seasonal Sales

Seasonal sales are made to customers with seasonal accounts such as vacation homes and weekend retreats and camps. Seasonal sales are relatively small and, as of 2020, only one owner-member reports seasonal residential customers.

3.4.1.5 Public Building Sales

Public Building sales include sales to accounts such as government buildings and libraries. The sales are relatively small and, as of 2020, only two owner-members report public building customers.

3.4.1.6 Public Street and Highway Lighting Sales

This class is relatively small and is projected as a function of residential sales. There are 11 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 2020, residential customers account for 58 percent of total energy sales at the EKPC system level. The average number of residential customers served by EKPC's owner-members is expected to increase from approximately 521,000 in 2022 to 575,000 in 2036. Sales to the residential class are expected to grow 0.7 percent per year during the forecast period. Projected average monthly use per customer 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 Customers 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
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	500,260	2,457	0.5	1,083	-63	-5.5	6,502,113	-344,977	-5.0
2018	505,379	5,119	1.0	1,208	125	11.5	7,324,079	821,967	12.6
2019	508,475	3,096	0.6	1,153	-54	-4.5	7,036,916	-287,163	-3.9
2020	514,043	5,568	1.1	1,121	-32	-2.8	6,915,401	-121,515	-1.7
2021	517,009	2,966	0.6	1,161	40	4	7,205,739	290,338	4.2
2022	521,049	4,040	0.8	1,158	-3	0	7,241,094	35,355	0.5
2023	524,917	3,868	0.7	1,151	-7	-1	7,250,544	9,450	0.1
2024	528,726	3,809	0.7	1,148	-3	0	7,284,706	34,162	0.5
2025	532,583	3,857	0.7	1,143	-6	0	7,302,221	17,516	0.2
2026	536,459	3,876	0.7	1,141	-2	0	7,342,156	39,935	0.5
2027	540,328	3,869	0.7	1,140	-1	0	7,391,408	49,252	0.7
2028	544,224	3,896	0.7	1,143	3	0	7,466,896	75,488	1.0
2029	548,114	3,890	0.7	1,141	-2	0	7,507,069	40,174	0.5
2030	551,999	3,885	0.7	1,139	-2	0	7,543,995	36,925	0.5
2031	555,873	3,874	0.7	1,137	-2	0	7,583,918	39,923	0.5
2032	559,802	3,929	0.7	1,141	4	0	7,665,895	81,977	1.1
2033	563,721	3,919	0.7	1,140	-1	0	7,710,245	44,350	0.6
2034	567,644	3,923	0.7	1,145	5	0	7,797,053	86,809	1.1
2035	571,512	3,868	0.7	1,149	4	0	7,876,640	79,586	1.0
2036	575,437	3,925	0.7	1,157	9	1	7,991,693	115,054	1.5

Note: Owner-Members' Form 7 data for 2021 were not 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. Customers whose annual peak demand is less than 1 MW are classified as small commercial customers and customers whose annual peak demand is greater than or equal to 1 MW are classified as large commercial/industrial customers. In 2020, there were more than 34,000 small commercial customers on the system. Customers are projected to grow to approximately 39,000 by 2036. As of 2020, small commercial customers account for 15 percent of total energy sales at the EKPC system level. Table 3-14 displays the results of the 2020 Load Forecast for the small commercial class.

Table 3-14
Small Commercial Class
Historical and Projected Customers 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
2010	32,553	173	0.5	59	4	7.3	1,935,479	148,367	8.3
2011	32,653	100	0.3	58	-1	-1.7	1,892,090	-43,389	-2.2
2012	33,069	416	1.3	57	-1	-1.7	1,883,241	-8,850	-0.5
2013	33,287	218	0.7	58	1	1.8	1,917,730	34,489	1.8
2014	33,670	383	1.2	57	-1	-1.7	1,919,198	1,468	0.1
2015	34,117	447	1.3	57	0	0.0	1,958,109	38,912	2.0
2016	34,252	135	0.4	57	0	0.0	1,951,787	-6,322	-0.3
2017	34,494	242	0.7	55	-2	-3.5	1,896,475	-55,312	-2.8
2018	34,199	-295	-0.9	57	2	3.6	1,962,505	66,030	3.5
2019	34,517	318	0.9	56	-1	-1.8	1,925,821	-36,684	-1.9
2020	34,741	224	0.6	52	-4	-7.1	1,791,061	-134,760	-7.0
2021	35,054	304	0.9	56	4	7.7	1,967,078	168,316	9.4
2022	35,341	287	0.8	57	1	1.8	2,015,313	48,234	2.5
2023	35,644	303	0.9	57	0	0.0	2,043,245	27,932	1.4
2024	35,929	285	0.8	57	0	0.0	2,062,484	19,239	0.9
2025	36,211	282	0.8	57	0	0.0	2,079,718	17,234	0.8
2026	36,507	296	0.8	57	0	0.0	2,097,729	18,011	0.9
2027	36,805	298	0.8	57	0	0.0	2,108,594	10,866	0.5
2028	37,093	288	0.8	57	0	0.0	2,125,152	16,558	0.8
2029	37,374	281	0.8	57	0	0.0	2,142,182	17,030	0.8
2030	37,658	284	0.8	57	0	0.0	2,153,353	11,171	0.5
2031	37,945	287	0.8	57	0	0.0	2,170,018	16,665	0.8
2032	38,240	295	0.8	57	0	0.0	2,188,051	18,033	0.8
2033	38,535	295	0.8	57	0	0.0	2,204,658	16,607	0.8
2034	38,827	292	0.8	57	0	0.0	2,215,933	11,275	0.5
2035	39,122	295	0.8	57	0	0.0	2,236,079	20,146	0.9
2036	39,423	301	0.8	57	0	0.0	2,256,693	20,614	0.9

Note: Owner-Members' Form 7 data for 2021 were not available. Beginning in 2018 there is a reclassification from Small Commercial to Residential.

3.5.3 Large Commercial and Industrial Sales Forecast

As of 2020, large commercial and industrial customers account for 27 percent of total energy sales at the EKPC system level. In 2020, there were 165 retail customers classified as large commercial and industrial customers. Approximately half of EKPC's large commercial customers are manufacturing plants, which like the small commercial class, support the automotive industry. Table 3-15 displays the results of the 2020 Load Forecast for the large commercial and industrial class.

Table 3-15
Large Commercial and Industrial Class
Historical and Projected Customers 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
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	153	4	2.7	22,390	-398	-1.7	3,425,613	30,183	0.9
2019	157	4	2.6	21,111	-1,279	-5.7	3,314,391	-111,222	-3.2
2020	165	8	5.1	19,707	-1,403	-6.6	3,251,726	-62,665	-1.9
2021	169	4	2.4	20,987	1,279	6.5	3,546,763	295,038	9.1
2022	173	4	2.4	24,986	3,999	19.1	4,322,510	775,746	21.9
2023	178	5	2.9	28,340	3,355	13.4	5,044,551	722,041	16.7
2024	180	2	1.1	28,321	-20	-0.1	5,097,698	53,147	1.1
2025	183	3	1.7	28,140	-180	-0.6	5,149,693	51,995	1.0
2026	185	2	1.1	28,041	-100	-0.4	5,187,514	37,821	0.7
2027	187	2	1.1	27,940	-101	-0.4	5,224,687	37,173	0.7
2028	189	2	1.1	27,865	-74	-0.3	5,266,542	41,855	0.8
2029	191	2	1.1	27,769	-97	-0.3	5,303,801	37,259	0.7
2030	193	2	1.0	27,697	-71	-0.3	5,345,551	41,750	0.8
2031	196	3	1.6	27,523	-174	-0.6	5,394,473	48,922	0.9
2032	199	3	1.5	27,404	-119	-0.4	5,453,316	58,843	1.1
2033	202	3	1.5	27,207	-196	-0.7	5,495,901	42,585	0.8
2034	204	2	1.0	27,207	0	0.0	5,550,228	54,327	1.0
2035	207	3	1.5	27,034	-173	-0.6	5,596,044	45,816	0.8
2036	208	1	0.5	27,117	83	0.3	5,640,411	44,367	0.8

Note: Owner-Members' Form 7 data for 2021 were not available.

3.5.4 Seasonal Sales Forecast

This class includes seasonal accounts such as vacation homes, weekend retreats, and camps. As of 2020, only one owner-member reports seasonal residential customers, 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 2020 Load Forecast for the seasonal sales class.

Table 3-16
Seasonal Class
Historical and Projected Customers 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
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	144	3	2.1	360	44	14.0	621	88	16.4
2019	150	6	4.2	368	8	2.3	663	41	6.6
2020	161	11	7.3	343	-25	-6.9	662	-1	-0.1
2021	170	10	6.3	365	14	4.1	744	71	10.6
2022	180	10	5.9	364	-1	-0.2	787	43	5.7
2023	191	11	6.1	362	-2	-0.6	830	43	5.5
2024	203	12	6.3	359	-3	-0.8	875	45	5.5
2025	214	11	5.4	359	-1	-0.2	921	46	5.2
2026	225	11	5.1	359	1	0.2	970	49	5.3
2027	238	13	5.8	358	-1	-0.3	1,024	53	5.5
2028	251	13	5.5	358	0	-0.1	1,079	55	5.4
2029	262	11	4.4	358	0	0.0	1,126	47	4.4
2030	273	11	4.2	358	0	-0.1	1,172	46	4.1
2031	284	11	4.0	358	1	0.2	1,222	50	4.2
2032	295	11	3.9	360	1	0.4	1,274	52	4.3
2033	307	12	4.1	360	0	-0.1	1,325	51	4.0
2034	317	10	3.3	361	2	0.4	1,374	49	3.7
2035	329	12	3.8	361	0	0.0	1,427	53	3.8
2036	340	11	3.3	364	3	0.8	1,487	60	4.2

Note: Owner-Member Form 7 data for 2021 was not available. As of 2012, one owner-member ceased reporting residential seasonal customers.

3.5.5 Public Building Sales Forecast

Public Building sales include sales to accounts such as government buildings and libraries. As of 2020, 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 2020 Load Forecast for the public building sales class.

Table 3-17
Public Building Class
Historical and Projected Customers 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
2010	1,046	48	4.8	3,172	207	7.0	39,809	4,301	12.1
2011	1,084	38	3.6	2,957	-214	-6.8	38,468	-1,341	-3.4
2012	1,096	12	1.1	2,676	-281	-9.5	35,194	-3,274	-8.5
2013	1,109	13	1.2	2,796	121	4.5	37,215	2,021	5.7
2014	1,117	8	0.7	2,966	169	6.1	39,753	2,537	6.8
2015	1,132	15	1.3	2,871	-95	-3.2	38,996	-757	-1.9
2016	1,137	5	0.4	2,758	-113	-3.9	37,627	-1,369	-3.5
2017	1,156	19	1.7	2,637	-121	-4.4	36,578	-1,049	-2.8
2018	1,165	9	0.8	2,943	306	11.6	41,142	4,563	12.5
2019	1,166	1	0.1	2,847	-96	-3.3	39,829	-1,313	-3.2
2020	1,174	8	0.7	2,427	-420	-14.7	34,187	-5,642	-14.2
2021	1,178	7	0.6	2,763	210	8.2	39,064	3,178	8.9
2022	1,184	6	0.5	2,797	34	1.2	39,744	680	1.7
2023	1,190	6	0.5	2,800	3	0.1	39,984	240	0.6
2024	1,197	7	0.6	2,789	-11	-0.4	40,066	82	0.2
2025	1,203	6	0.5	2,771	-18	-0.6	40,009	-58	-0.1
2026	1,209	6	0.5	2,759	-12	-0.5	40,027	18	0.0
2027	1,216	7	0.6	2,745	-13	-0.5	40,062	35	0.1
2028	1,222	6	0.5	2,733	-12	-0.4	40,080	18	0.0
2029	1,228	6	0.5	2,715	-18	-0.7	40,010	-70	-0.2
2030	1,235	7	0.6	2,698	-17	-0.6	39,979	-30	-0.1
2031	1,241	6	0.5	2,684	-13	-0.5	39,974	-5	0.0
2032	1,247	6	0.5	2,674	-11	-0.4	40,009	34	0.1
2033	1,254	7	0.6	2,658	-16	-0.6	39,993	-16	0.0
2034	1,260	6	0.5	2,646	-12	-0.5	40,003	10	0.0
2035	1,266	6	0.5	2,634	-12	-0.4	40,019	15	0.0
2036	1,273	7	0.6	2,624	-10	-0.4	40,086	67	0.2

Note: Owner-Members Form 7 data for 2021 were not available.

3.5.6 Public Street and Highway Lighting Sales Forecast

This class represents street lighting. As of 2020, 11 owner-members report public street and highway lighting customers, which account for 0.07 percent of total energy sales at the EKPC system level. Table 3-18 displays the results of the 2020 Load Forecast for the other sales class.

Table 3-18
Public Street and Highway Lighting Class
Historical and Projected Customers 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
2010	423	-1	-0.2	22	-1,759	-98.7	9,503	438	4.8
2011	416	-7	-1.7	24	1	5.3	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	412	4	1.0	24	0	-1.2	9,890	-26	-0.3
2016	402	-10	-2.4	25	1	3.0	9,940	50	0.5
2017	381	-21	-5.2	24	0	-1.0	9,325	-615	-6.2
2018	390	9	2.4	23	-2	-7.9	8,796	-530	-5.7
2019	409	19	4.9	21	-1	-4.9	8,770	-25	-0.3
2020	432	23	5.6	20	-1	-5.3	8,771	1	0.0
2021	431	2	0.5	20	0	-0.4	8,707	4	0.0
2022	433	2	0.5	20	0	-0.4	8,714	8	0.1
2023	436	3	0.7	20	0	-0.6	8,724	9	0.1
2024	438	2	0.5	20	0	-0.1	8,751	27	0.3
2025	440	2	0.5	20	0	0.0	8,788	37	0.4
2026	441	1	0.2	20	0	0.1	8,817	28	0.3
2027	442	1	0.2	20	0	0.1	8,845	28	0.3
2028	444	2	0.5	20	0	-0.1	8,872	27	0.3
2029	445	1	0.2	20	0	0.1	8,898	26	0.3
2030	446	1	0.2	20	0	0.1	8,923	26	0.3
2031	447	1	0.2	20	0	0.1	8,949	25	0.3
2032	449	2	0.4	20	0	-0.2	8,974	25	0.3
2033	450	1	0.2	20	0	0.1	8,999	25	0.3
2034	451	1	0.2	20	0	0.1	9,024	25	0.3
2035	452	1	0.2	20	0	0.1	9,049	25	0.3
2036	454	2	0.4	20	0	-0.2	9,074	25	0.3

Note: Owner-Members' Form 7 data for 2021 were not 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 for both weather and economic scenarios. 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 20 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).

3. Residential customers: In the EKPC base case, the residential growth rate is 0.7%. The basic approach to preparing high and low case scenarios for the future number of residential customers 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% was used to produce the high case and 0.3% was used for the low case.

4. Small and Large Commercial customer and energy: Small commercial customer growth is correlated to residential customer 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 customer forecasts which in turn results in different energy and demand forecasts.

The results for Net Total Energy Requirements are shown in Table 3-19 for the following cases:

- Pessimistic Economics Mild Weather - Pessimistic economic assumptions with mild weather
- Pessimistic Economics Normal Weather - Pessimistic economic assumptions with normal weather
- Base Case - Most probable economics assumptions with normal weather
- Optimistic Economics Normal Weather - Optimistic economic assumptions with normal weather
- Optimistic Economics Extreme Weather - Optimistic economic assumptions with extreme weather

Table 3-19
Net Total Energy Requirements (GWh)
By Economic and Weather Scenario

Year	Pessimistic Economics Mild Weather	Pessimistic Economics Normal Weather	**BASE CASE**	Optimistic Economics Normal Weather	Optimistic Economics Extreme Weather
2022	13,455	14,243	**14,421**	14,768	15,643
2023	14,147	14,936	**15,191**	15,736	16,610
2024	14,169	14,957	**15,305**	16,035	16,909
2025	14,170	14,958	**15,397**	16,317	17,191
2026	14,180	14,968	**15,500**	16,614	17,489
2027	14,191	14,979	**15,605**	16,918	17,792
2028	14,238	15,026	**15,747**	17,269	18,143
2029	14,245	15,033	**15,849**	17,580	18,454
2030	14,245	15,034	**15,945**	17,889	18,764
2031	14,262	15,050	**16,058**	18,223	19,097
2032	14,330	15,118	**16,228**	18,626	19,500
2033	14,343	15,131	**16,339**	18,969	19,844
2034	14,392	15,180	**16,491**	19,365	20,240
2035	14,444	15,233	**16,647**	19,773	20,647
2036	14,523	15,309	**16,839**	20,245	21,116

The results for Net Winter Peak Demand are shown in Table 3-20 for the following cases:

- Pessimistic Economics Mild Weather - Pessimistic economic assumptions with mild weather
- Pessimistic Economics Normal Weather - Pessimistic economic assumptions with normal weather
- Base Case - Most probable economics assumptions with normal weather
- Optimistic Economics Normal Weather - Optimistic economic assumptions with normal weather
- Optimistic Economics Extreme Weather - Optimistic economic assumptions with extreme weather

Table 3-20
Net Winter Peak Demand (MW)
By Economic and Weather Scenario

Year	Pessimistic Economics Mild Weather	Pessimistic Economics Normal Weather	**BASE CASE**	Optimistic Economics Normal Weather	Optimistic Economics Extreme Weather
2021 - 22	2,902	3,297	**3,309**	3,414	3,824
2022 - 23	2,904	3,300	**3,363**	3,476	3,893
2023 - 24	2,904	3,300	**3,384**	3,538	3,962
2024 - 25	2,893	3,287	**3,391**	3,586	4,016
2025 - 26	2,890	3,284	**3,409**	3,646	4,083
2026 - 27	2,889	3,283	**3,427**	3,708	4,153
2027 - 28	2,896	3,291	**3,457**	3,783	4,236
2028 - 29	2,890	3,284	**3,470**	3,841	4,301
2029 - 30	2,882	3,275	**3,480**	3,897	4,364
2030 - 31	2,876	3,268	**3,494**	3,957	4,431
2031 - 32	2,880	3,272	**3,520**	4,032	4,515
2032 - 33	2,873	3,265	**3,533**	4,093	4,584
2033 - 34	2,874	3,266	**3,556**	4,167	4,667
2034 - 35	2,875	3,267	**3,578**	4,241	4,750
2035 - 36	2,863	3,253	**3,586**	4,302	4,816

The results for Net Summer Peak Demand are shown in Table 3-21 for the following cases:

- Pessimistic Economics Mild Weather - Pessimistic economic assumptions with mild weather
- Pessimistic Economics Normal Weather - Pessimistic economic assumptions with normal weather
- Base Case - Most probable economics assumptions with normal weather
- Optimistic Economics Normal Weather - Optimistic economic assumptions with normal weather
- Optimistic Economics Extreme Weather - Optimistic economic assumptions with extreme weather

Table 3-21
Net Summer Peak Demand (MW)
By Economic and Weather Scenario

Year	Pessimistic Economics Mild Weather	Pessimistic Economics Normal Weather	**BASE CASE**	Optimistic Economics Normal Weather	Optimistic Economics Extreme Weather
2022	2,236	2,541	**2,500**	2,631	2,947
2023	2,221	2,524	**2,574**	2,659	2,978
2024	2,240	2,546	**2,612**	2,729	3,057
2025	2,236	2,541	**2,623**	2,772	3,105
2026	2,233	2,537	**2,634**	2,816	3,154
2027	2,233	2,538	**2,651**	2,866	3,210
2028	2,235	2,540	**2,669**	2,919	3,269
2029	2,234	2,539	**2,684**	2,969	3,325
2030	2,230	2,534	**2,695**	3,016	3,378
2031	2,227	2,531	**2,707**	3,064	3,432
2032	2,229	2,533	**2,726**	3,121	3,495
2033	2,229	2,533	**2,742**	3,176	3,557
2034	2,231	2,535	**2,761**	3,234	3,622
2035	2,233	2,537	**2,780**	3,293	3,688
2036	2,231	2,534	**2,794**	3,351	3,752

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 more than 407 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 35 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 16 load profile meters installed and collecting data.
3. Medium Commercial & Industrial: Includes retail members whose peak demands are between 50kW and 350kW. There are 21 load profile meters installed and collecting data.
4. Large Power: Includes retail members whose peak demands are greater than 350kW. There are 335 meters installed and collecting data.

3.7.2 Research and Development

EKPC and its 16 owner-member cooperatives are actively engaged with the Energy and Environment Cabinet and the Kentucky Department of Transportation in the effort to determine locations for the EV public charging network throughout Kentucky.

EKPC and its 16 owner-member cooperatives are reviewing funding opportunities resulting from the Infrastructure Investment and Jobs Act. EKPC is working with the owner-member cooperatives to identify funding opportunities to improve electric service to the Kentuckians served.

In 2020, EKPC and two (2) owner-members offered a smart home pilot to 50 residential members of each cooperative. The goals of the pilot include the evaluation of energy and demand savings along with gauging customer acceptance. Participants utilize the Powerley App to access their usage data every 15 seconds, as well as manage energy consumption of appliances in the home. The pilot is still operational.

SECTION 4.0

EXISTING AND COMMITTED CAPACITY RESOURCES SUMMARY

SECTION 4.0

EXISTING AND COMMITTED CAPACITY RESOURCES SUMMARY

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 and includes a firm purchase power agreement with the Southeastern Power Administration. Fuel sources include coal, natural gas, landfill gas, solar, and hydro.

Coal Fired Units

Cooper Station

John Sherman Cooper Station located near Somerset on Lake Cumberland. The station has one 116 MW unit that became operational on February 9, 1965, and one 225 MW unit that began operating commercially on October 28, 1969. Both units are pulverized coal units. A pollution control system was added to the Cooper 2 unit and began commercial operation in summer 2012. A duct reroute project, which routes the flue gas from unit one into the unit two pollution control system, was completed in 2016.

Spurlock Station

Hugh L. Spurlock Station situated near Maysville, Kentucky on the Ohio River. The station consists of four units. The first one is a 300 MW unit that began commercial operation on September 1, 1977. Unit 2 is a 510 MW unit that began operating on March 2, 1981. Both of these units are conventional pulverized coal units with FGD technology. Spurlock 1 and 2 have had extensive modification and enhancements to comply with coal combustion residuals and effluent limitation guidelines.

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

Steam Load

International Paper has a corrugated paper recycling facility adjacent to EKPC's Spurlock Station. The facility has an expected peak electrical load of approximately 35 MW and an equivalent of 29 MW in steam. The steam is supplied from Spurlock Unit 2 on a normal basis but can also be supplied from Spurlock Unit 1 when needed. On average, International Paper operates 99 percent of the time and Spurlock 2 operates at an average of 510 MW.

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 Station 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 73 MW and a winter rating of 88 MW (93MW for Unit 4). The ABB and GE turbines are all capable of firing with fuel oil as a secondary fuel supply. The two LMS 100 turbines became operational in 2010. Unit 9 has a summer rating of 75 MW and Unit 10 has a summer rating of 74 MW. They both have a winter rating of 103 MW.

EKPC expanded the peaking fleet in 2015 with the acquisition of the Bluegrass Generation Station in Oldham County. The three Siemens 501FD-2 units were commercial in 2002. The winter rating for each unit is 189 MW and the summer rating is 167 MW. In 2020, all three units were retrofitted for fuel oil as a secondary fuel supply.

Southeastern Power Administration ("SEPA")

EKPC purchases 170 MW of hydropower from SEPA on a long-term basis. Laurel Dam (70MW) has historically been a reliable resource and continues to be reliable. EKPC purchases a 100% of the energy generated at Laurel Dam. The remaining 100 MW is supplied from the Cumberland River system of hydropower projects. The Nashville District Corps of Engineers Hydropower

Program has developed a Capital Improvement Plan that covers non-routine maintenance, rehabilitation or modernization of the Cumberland River hydropower system over approximately the next 20 years. During this time, the system capacity could be less than the marketed capacity for the Cumberland customer groups as the units are taken out of service and are unavailable for generation. Reductions to capacity are reconciled through the SEPA invoicing process through providing capacity credits. Until such rehabilitation is completed to provide a total system capacity to support the customer allocations, scheduling capacities will continue to be reduced on a weekly basis according to the available system capacity.

Renewable Sources

Landfill Gas

EKPC owns and operates 16.1 MW of landfill gas capacity generated at 6 sites throughout Kentucky.

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. As of year-end 2021 there were 242 subscribers with 1,492 panels.

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

	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 4-2
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 (MW)	104 Sum 142 Win	104 Sum 142 Win	104 Sum 142 Win	73 Sum 93 Win	73 Sum 88 Win	73 Sum 88 Win	73 Sum 88 Win
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 4-3
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 (MW)	75 Sum 103 Win	74 Sum 103 Win
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 4-4
Generating Plant Data

Landfill Gas

	Bavarian	Green Valley	Laurel Ridge	Hardin Co.	Pendleton Co.	Glasgow
Location	Boone County, KY	Greenup County, KY	Laurel County, KY	Hardin County, KY	Pendleton County, KY	Barren County, KY
Status	Existing	Existing	Existing	Existing	Existing	Existing
Commercial Operation	9/22/03	9/9/03	9/15/03	1/30/06	2/1/07	12/1/15
Type	Gas	Gas	Gas	Gas	Gas	Gas
Net Dependable Capability	4.6 MW	2.3 MW	3.0 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 4-5
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 (MW)	167 Sum 189 Win	167 Sum 189 Win	167 Sum 189 Win
Entitlement (%)	100	100	100
Primary Fuel Type	Natural Gas	Natural Gas	Natural Gas
Secondary Fuel Type	Fuel Oil	Fuel Oil	Fuel Oil
Fuel Storage (Gallons)	1 million total	1 million total	1 million total

Table 4-6
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).

Cooper 1	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Capacity Factor	0.19	0.43	0.18	0.14	0.08	0.04	0.03	0.02	0.02	0.02	0.02	0.01	0.01	0.00	0.00	0.01
Availability Factor	0.73	0.91	0.91	0.91	0.91	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94
Average Heat Rate (Btu/kWh)	11,301	10,827	10,853	10,859	10,937	10,985	10,981	10,920	11,003	11,045	11,114	11,017	11,014	11,016	11,154	11,294
Fuel Cost ($/MMBtu)	3.22	3.22	3.20	3.20	3.36	3.43	3.53	3.66	3.69	3.61	3.66	3.80	3.92	4.05	4.16	4.21
Variable O&M ($/MWh)	4.99	9.03	9.22	9.34	9.48	9.64	9.79	9.97	9.85	9.83	9.97	10.25	10.46	10.63	10.99	10.59
Fixed O&M ($/kW/Yr)	45.60	60.62	62.07	63.56	65.09	66.65	68.25	69.89	71.57	73.28	75.04	76.84	78.69	80.58	82.51	84.49
Variable Production Cost ($/MWh)	35.47	45.55	45.72	45.91	48.89	50.45	51.74	52.46	54.36	54.37	56.06	56.43	57.92	59.56	63.04	66.79
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

	ACTUAL															
Cooper 2	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Capacity Factor	0.22	0.62	0.29	0.22	0.14	0.10	0.08	0.07	0.06	0.06	0.06	0.03	0.02	0.01	0.02	0.01
Availability Factor	0.82	0.81	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91
Average Heat Rate (Btu/kWh)	11,004	10,167	10,210	10,222	10,233	10,292	10,319	10,313	10,342	10,344	10,364	10,407	10,296	10,263	10,306	10,463
Fuel Cost ($/MMBtu)	3.22	3.24	3.21	3.21	3.38	3.45	3.55	3.66	3.72	3.66	3.71	3.81	3.98	4.10	4.23	4.30
Variable O&M ($/MWh)	3.80	5.75	5.87	5.97	6.07	6.16	6.26	6.40	6.50	6.58	6.70	6.79	6.99	7.04	7.20	7.25
Fixed O&M ($/kW/Yr)	45.60	52.97	54.24	55.54	56.88	58.24	59.64	61.07	62.54	64.04	65.57	67.15	68.76	70.41	72.10	73.83
Variable Production Cost ($/MWh)	35.47	39.76	40.17	40.40	42.49	44.19	45.79	47.06	48.28	47.85	48.89	50.86	50.74	51.74	53.95	57.99
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

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	ACTUAL															
Spurlock 1	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Capacity Factor	0.77	0.83	0.74	0.80	0.73	0.76	0.72	0.61	0.67	0.67	0.60	0.54	0.45	0.36	0.38	0.38
Availability Factor	0.89	0.86	0.78	0.86	0.86	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89
Average Heat Rate (Btu/kWh)	10,688	10,203	10,227	10,245	10,334	10,319	10,353	10,376	10,375	10,395	10,402	10,411	10,462	10,495	10,485	10,498
Fuel Cost ($/MMBtu)	1.96	1.92	1.97	2.06	2.43	2.51	2.59	2.67	2.58	2.63	2.72	2.70	2.78	2.83	2.91	2.99
Variable O&M ($/MWh)	4.62	2.52	2.57	2.61	2.78	2.72	2.79	2.79	2.78	2.82	2.82	2.84	2.88	2.89	2.91	2.92
Fixed O&M ($/kW/Yr)	10.84	38.82	39.75	40.70	41.68	42.68	43.71	44.76	45.83	46.93	48.06	49.21	50.39	51.60	52.84	54.11
Variable Production Cost ($/MWh)	20.38	22.18	22.83	23.81	28.01	28.77	29.75	30.72	29.78	30.41	31.38	31.23	32.46	33.18	33.95	34.88
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

	ACTUAL															
Spurlock 2	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Capacity Factor	0.86	0.84	0.82	0.81	0.77	0.79	0.71	0.76	0.76	0.76	0.75	0.74	0.72	0.70	0.70	0.71
Availability Factor	0.85	0.83	0.82	0.82	0.82	0.86	0.78	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86	0.86
Average Heat Rate (Btu/kWh)	10,452	9,906	9,921	9,938	9,997	10,008	10,035	10,056	10,044	10,052	10,067	10,086	10,120	10,152	10,149	10,142
Fuel Cost ($/MMBtu)	1.96	1.89	1.94	2.03	2.40	2.48	2.57	2.65	2.56	2.60	2.69	2.68	2.77	2.82	2.90	2.98
Variable O&M ($/MWh)	4.81	2.44	2.47	2.51	2.65	2.69	2.75	2.80	2.77	2.79	2.82	2.87	2.94	3.02	3.01	3.00
Fixed O&M ($/kW/Yr)	10.84	33.37	34.17	34.99	35.83	36.69	37.57	38.47	39.40	40.34	41.31	42.30	43.32	44.36	45.42	46.51
Variable Production Cost ($/MWh)	20.38	21.69	22.28	23.23	27.20	28.04	28.98	29.90	28.94	29.48	30.46	30.37	31.46	32.14	32.94	33.71
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

	ACTUAL															
Gilbert Unit	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Capacity Factor	0.80	0.83	0.83	0.82	0.72	0.78	0.76	0.76	0.76	0.76	0.75	0.74	0.72	0.71	0.71	0.72
Availability Factor	0.82	0.87	0.87	0.87	0.79	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88	0.88
Average Heat Rate (Btu/kWh)	9,506	9,741	9,753	9,766	9,820	9,850	9,886	9,900	9,888	9,903	9,918	9,936	9,969	10,001	9,994	9,979
Fuel Cost ($/MMBtu)	1.96	1.78	1.84	1.93	2.35	2.43	2.51	2.59	2.50	2.55	2.64	2.62	2.71	2.76	2.84	2.92
Variable O&M ($/MWh)	7.63	3.15	3.18	3.21	3.33	3.40	3.48	3.51	3.48	3.51	3.55	3.59	3.66	3.73	3.71	3.68
Fixed O&M ($/kW/Yr)	10.84	40.99	41.98	42.98	44.02	45.07	46.15	47.26	48.40	49.56	50.75	51.96	53.21	54.49	55.80	57.14
Variable Production Cost ($/MWh)	20.38	20.72	21.41	22.30	26.65	27.59	28.55	29.41	28.47	29.04	30.01	29.90	30.97	31.63	32.40	33.13
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

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	ACTUAL															
Spurlock 4	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Capacity Factor	0.85	0.80	0.80	0.79	0.77	0.77	0.76	0.76	0.70	0.76	0.75	0.75	0.74	0.73	0.73	0.73
Availability Factor	0.88	0.85	0.85	0.85	0.85	0.86	0.86	0.86	0.78	0.86	0.86	0.86	0.86	0.86	0.86	0.86
Average Heat Rate (Btu/kWh)	9,926	9,779	9,786	9,795	9,832	9,846	9,858	9,872	9,862	9,871	9,880	9,891	9,911	9,932	9,925	9,925
Fuel Cost ($/MMBtu)	1.96	1.77	1.84	1.93	2.34	2.42	2.50	2.58	2.49	2.54	2.63	2.61	2.70	2.75	2.83	2.91
Variable O&M ($/MWh)	6.02	3.21	3.23	3.25	3.34	3.37	3.40	3.43	3.41	3.43	3.45	3.48	3.52	3.57	3.56	3.56
Fixed O&M ($/kW/Yr)	10.84	34.33	35.15	36.00	36.86	37.75	38.65	39.58	40.53	41.50	42.50	43.52	44.56	45.63	46.73	47.85
Variable Production Cost ($/MWh)	20.38	20.93	21.61	22.49	26.78	27.64	28.49	29.36	28.42	28.97	29.91	29.77	30.77	31.39	32.15	32.94
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

	ACTUAL															
Smith CT1	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Capacity Factor	0.06	0.07	0.03	0.04	0.03	0.02	0.01	0.02	0.01	0.02	0.02	0.01	0.01	0.01	0.00	0.01
Availability Factor	1.00	0.95	0.98	0.98	0.98	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96
Average Heat Rate (Btu/kWh)	13,550	12,129	12,111	12,086	12,145	12,159	12,063	12,053	12,044	12,092	12,119	12,124	12,014	12,070	12,013	12,238
Fuel Cost ($/MMBtu)	4.43	4.79	4.13	3.82	3.65	3.58	3.75	3.79	3.88	3.67	3.64	3.72	3.92	3.91	4.23	4.19
Variable O&M ($/MWh)	0.45	10.62	10.79	10.93	11.49	11.83	11.63	11.85	12.08	12.64	13.10	13.43	13.10	13.75	13.74	15.50
Fixed O&M ($/kW/Yr)	31.78	10.45	10.70	10.95	11.22	11.49	11.76	12.04	12.33	12.63	12.93	13.24	13.56	13.89	14.22	14.56
Variable Production Cost ($/MWh)	55.49	72.99	65.10	61.25	60.31	60.02	60.86	61.67	63.25	61.61	62.27	64.00	64.73	66.40	69.06	73.49
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

	ACTUAL															
Smith CT2	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Capacity Factor	0.07	0.04	0.01	0.02	0.02	0.01	0.00	0.01	0.00	0.01	0.01	0.00	0.00	0.00	-	0.00
Availability Factor	0.97	0.93	0.96	0.96	0.96	0.94	0.95	0.94	0.94	0.94	0.94	0.95	0.95	0.94	0.94	0.94
Average Heat Rate (Btu/kWh)	13,832	12,088	12,052	12,061	12,049	12,100	12,012	12,013	12,013	12,100	12,117	12,013	12,015	12,013	-	12,179
Fuel Cost ($/MMBtu)	4.43	4.91	4.28	3.86	3.81	3.67	3.83	3.86	3.94	3.65	3.69	3.87	3.93	3.99	-	4.27
Variable O&M ($/MWh)	0.45	10.44	10.52	10.82	11.02	11.54	11.36	11.64	11.92	12.70	13.09	12.79	13.10	13.42	-	15.14
Fixed O&M ($/kW/Yr)	31.78	9.99	10.23	10.48	10.73	10.98	11.25	11.52	11.79	12.08	12.37	12.66	12.97	13.28	13.60	13.92
Variable Production Cost ($/MWh)	55.49	76.59	68.86	64.26	63.76	63.25	63.95	65.25	66.55	64.87	66.44	67.13	69.12	69.57	-	77.68
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

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	ACTUAL															
Smith CT3	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Capacity Factor	0.06	0.03	0.01	0.01	0.01	0.01	0.00	0.00	-	0.01	0.00	0.00	0.00	-	-	0.00
Availability Factor	0.85	0.90	0.93	0.93	0.93	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91
Average Heat Rate (Btu/kWh)	13,685	12,034	12,057	12,064	12,062	12,133	12,012	12,013	-	12,133	12,167	12,013	12,015	-	-	12,179
Fuel Cost ($/MMBtu)	4.27	5.06	4.26	3.89	3.80	3.62	3.83	3.86	-	3.61	3.64	3.87	3.93	-	-	4.27
Variable O&M ($/MWh)	0.45	10.19	10.54	10.84	11.08	11.72	11.36	11.64	-	12.88	13.37	12.79	13.10	-	-	15.14
Fixed O&M ($/kW/Yr)	31.78	9.75	9.99	10.23	10.47	10.72	10.98	11.24	11.51	11.79	12.07	12.36	12.66	12.96	13.27	13.59
Variable Production Cost ($/MWh)	55.49	78.41	70.16	65.71	65.19	64.64	65.27	66.57	-	66.53	68.53	68.71	70.91	-	-	79.79
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

	ACTUAL															
Smith CT4	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Capacity Factor	0.08	0.16	0.10	0.11	0.08	0.08	0.07	0.06	0.06	0.06	0.06	0.05	0.05	0.03	0.03	0.03
Availability Factor	0.89	0.93	0.97	0.97	0.97	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Average Heat Rate (Btu/kWh)	13,841	11,535	11,547	11,513	11,518	11,528	11,543	11,518	11,503	11,527	11,523	11,523	11,534	11,485	11,467	11,500
Fuel Cost ($/MMBtu)	4.43	4.49	3.83	3.61	3.52	3.47	3.47	3.55	3.65	3.47	3.49	3.58	3.61	3.75	4.05	4.25
Variable O&M ($/MWh)	0.45	8.03	8.28	8.32	8.54	8.79	9.08	9.17	9.31	9.66	9.88	10.10	10.40	10.38	10.50	10.93
Fixed O&M ($/kW/Yr)	31.78	10.15	10.39	10.64	10.90	11.16	11.43	11.70	11.98	12.27	12.57	12.87	13.18	13.49	13.82	14.15
Variable Production Cost ($/MWh)	55.49	61.24	53.97	51.35	50.54	50.30	50.79	51.72	52.93	51.37	51.82	53.10	53.95	55.17	58.83	62.13
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

	ACTUAL															
Smith CT5	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Capacity Factor	0.07	0.18	0.12	0.12	0.10	0.10	0.08	0.06	0.08	0.09	0.08	0.07	0.06	0.05	0.04	0.03
Availability Factor	0.95	0.94	0.97	0.97	0.97	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Average Heat Rate (Btu/kWh)	13,506	11,542	11,575	11,527	11,538	11,554	11,582	11,544	11,536	11,545	11,553	11,541	11,540	11,506	11,528	11,529
Fuel Cost ($/MMBtu)	4.27	4.47	3.77	3.58	3.49	3.42	3.41	3.53	3.60	3.44	3.46	3.54	3.60	3.72	3.94	4.20
Variable O&M ($/MWh)	0.45	8.05	8.39	8.37	8.62	8.91	9.25	9.28	9.45	9.74	10.00	10.18	10.42	10.46	10.81	11.07
Fixed O&M ($/kW/Yr)	31.78	10.40	10.65	10.90	11.17	11.43	11.71	11.99	12.28	12.57	12.87	13.18	13.50	13.82	14.16	14.50
Variable Production Cost ($/MWh)	55.49	60.61	53.05	50.61	49.97	49.51	49.97	51.13	52.19	50.61	51.25	52.37	53.26	54.63	57.81	61.19
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

	ACTUAL															
Smith CT6	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Capacity Factor	0.07	0.17	0.10	0.10	0.08	0.08	0.07	0.06	0.06	0.07	0.06	0.05	0.05	0.03	0.04	0.03
Availability Factor	0.97	0.90	0.94	0.94	0.94	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92
Average Heat Rate (Btu/kWh)	13,016	11,536	11,537	11,510	11,518	11,533	11,544	11,521	11,508	11,535	11,521	11,520	11,538	11,486	11,486	11,502
Fuel Cost ($/MMBtu)	4.43	4.48	3.86	3.62	3.52	3.45	3.47	3.55	3.64	3.45	3.50	3.59	3.60	3.74	4.02	4.26
Variable O&M ($/MWh)	0.45	8.04	8.24	8.31	8.54	8.81	9.08	9.18	9.33	9.71	9.86	10.09	10.42	10.38	10.62	10.96
Fixed O&M ($/kW/Yr)	31.78	10.49	10.74	11.00	11.26	11.53	11.81	12.09	12.38	12.68	12.98	13.29	13.61	13.94	14.28	14.62
Variable Production Cost ($/MWh)	55.49	61.44	54.42	51.61	50.85	50.55	51.10	51.99	53.23	51.52	52.18	53.53	54.32	55.44	59.13	62.51
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

	ACTUAL															
Smith CT7	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Capacity Factor	0.08	0.16	0.10	0.10	0.07	0.07	0.06	0.05	0.06	0.06	0.05	0.05	0.04	0.03	0.03	0.03
Availability Factor	0.98	0.95	0.98	0.98	0.98	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96
Average Heat Rate (Btu/kWh)	13,262	11,537	11,532	11,502	11,504	11,535	11,536	11,510	11,505	11,499	11,503	11,499	11,515	11,473	11,466	11,489
Fuel Cost ($/MMBtu)	4.43	4.50	3.87	3.63	3.55	3.45	3.49	3.56	3.64	3.51	3.52	3.62	3.64	3.76	4.05	4.29
Variable O&M ($/MWh)	0.45	8.04	8.22	8.27	8.48	8.83	9.04	9.13	9.32	9.52	9.77	9.98	10.31	10.31	10.50	10.89
Fixed O&M ($/kW/Yr)	31.78	10.39	10.64	10.89	11.15	11.42	11.70	11.98	12.26	12.56	12.86	13.17	13.49	13.81	14.14	14.48
Variable Production Cost ($/MWh)	55.49	62.00	54.89	52.09	51.33	50.93	51.60	52.50	53.65	52.21	52.72	54.05	54.91	55.98	59.71	63.18
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

	ACTUAL															
Smith CT 9	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Capacity Factor	0.22	0.40	0.30	0.29	0.25	0.23	0.19	0.19	0.19	0.23	0.22	0.17	0.15	0.12	0.13	0.11
Availability Factor	0.64	-	-	0.96	0.96	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92
Average Heat Rate (Btu/kWh)	10,373	8,800	8,811	8,813	8,806	8,813	8,809	8,819	8,819	8,817	8,810	8,821	8,824	8,816	8,830	8,833
Fuel Cost ($/MMBtu)	4.43	4.19	3.62	3.39	3.37	3.30	3.39	3.40	3.50	3.31	3.37	3.42	3.53	3.61	3.82	4.08
Variable O&M ($/MWh)	0.62	7.78	8.01	8.22	8.38	8.62	8.80	9.06	9.28	9.49	9.68	9.98	10.23	10.43	10.76	11.03
Fixed O&M ($/kW/Yr)	31.78	12.10	12.39	12.68	12.99	13.30	13.62	13.95	14.28	14.62	14.97	15.33	15.70	16.08	16.46	16.86
Variable Production Cost ($/MWh)	55.49	45.74	41.08	39.28	39.26	38.93	39.95	40.42	41.60	40.12	40.77	41.72	43.01	43.92	46.21	48.91
Capital Cost Escalation		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation		0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

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	ACTUAL															
Smith CT 10	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Capacity Factor	0.24	0.42	0.31	0.30	0.26	0.24	0.21	0.20	0.19	0.24	0.22	0.17	0.16	0.13	0.13	0.11
Availability Factor	0.81	0.91	0.99	0.99	0.99	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Average Heat Rate (Btu/kWh)	10,479	8,797	8,811	8,812	8,808	8,817	8,818	8,819	8,822	8,816	8,808	8,825	8,824	8,825	8,834	8,834
Fuel Cost ($/MMBtu)	4.43	4.22	3.62	3.38	3.37	3.31	3.36	3.40	3.52	3.29	3.39	3.43	3.52	3.61	3.82	4.07
Variable O&M ($/MWh)	0.63	7.77	8.01	8.22	8.39	8.63	8.85	9.06	9.30	9.49	9.67	9.99	10.23	10.48	10.78	11.04
Fixed O&M ($/kW/Yr)	31.78	11.31	11.58	11.86	12.14	12.43	12.73	13.03	13.35	13.67	14.00	14.33	14.68	15.03	15.39	15.76
Variable Production Cost ($/MWh)	55.49	45.83	40.91	39.09	39.13	38.92	39.62	40.27	41.58	39.78	40.79	41.62	42.75	43.80	46.13	48.65
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

	ACTUAL															
Bluegrass CT1	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Capacity Factor	0.07	0.06	0.06	0.06	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.03	0.03	0.02	0.02	0.02
Availability Factor	0.86	0.85	0.84	0.85	0.84	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92
Average Heat Rate (Btu/kWh)	10,663	10,597	10,618	10,616	10,604	10,617	10,618	10,606	10,612	10,604	10,611	10,613	10,614	10,594	10,605	10,612
Fuel Cost ($/MMBtu)	5.00	4.90	4.16	3.88	3.83	3.70	3.73	3.87	3.96	3.83	3.85	3.82	3.96	4.09	4.31	4.56
Variable O&M ($/MWh)	0.54	12.94	13.46	13.78	13.96	14.47	14.82	14.99	15.41	15.69	16.15	16.62	16.98	17.06	17.60	18.16
Fixed O&M ($/kW/Yr)	82.52	7.93	8.12	8.31	8.51	8.71	8.92	9.14	9.36	9.58	9.81	10.05	10.29	10.54	10.79	11.05
Variable Production Cost ($/MWh)	56.44	67.29	60.48	57.80	57.46	56.92	57.88	59.39	61.08	59.43	60.25	61.08	62.53	64.28	67.87	70.53
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

	ACTUAL															
Bluegrass CT2	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Capacity Factor	0.06	0.06	0.05	0.04	0.04	0.03	0.02	0.02	0.02	0.03	0.03	0.01	0.02	0.01	0.00	0.01
Availability Factor	0.86	0.84	0.84	0.84	0.84	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92
Average Heat Rate (Btu/kWh)	10,632	10,620	10,627	10,619	10,602	10,618	10,622	10,606	10,619	10,610	10,623	10,604	10,603	10,617	10,633	10,601
Fuel Cost ($/MMBtu)	5.00	4.86	4.26	4.06	4.04	3.87	3.96	4.06	4.21	3.99	4.01	4.03	4.15	4.35	4.52	4.63
Variable O&M ($/MWh)	0.54	13.24	13.57	13.79	13.90	14.44	14.83	14.96	15.43	15.74	16.27	16.45	16.79	17.34	17.95	17.98
Fixed O&M ($/kW/Yr)	82.52	7.93	8.12	8.31	8.51	8.71	8.92	9.14	9.36	9.58	9.81	10.05	10.29	10.54	10.79	11.05
Variable Production Cost ($/MWh)	56.44	68.20	62.46	60.07	59.97	59.57	60.29	61.58	63.46	61.74	62.41	63.00	64.69	66.21	69.92	73.12
Capital Cost Escalation		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation		0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

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	ACTUAL															
Bluegrass CT3	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Capacity Factor	0.01	0.06	0.06	0.06	0.05	0.05	0.05	0.04	0.05	0.05	0.04	0.03	0.03	0.02	0.02	0.02
Availability Factor	0.86	0.83	0.83	0.83	0.83	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91
Average Heat Rate (Btu/kWh)	10,650	10,592	10,608	10,608	10,605	10,620	10,623	10,607	10,618	10,617	10,606	10,616	10,610	10,602	10,610	10,603
Fuel Cost ($/MMBtu)	5.00	4.91	4.17	3.87	3.80	3.66	3.72	3.84	3.93	3.71	3.80	3.81	3.91	4.02	4.28	4.53
Variable O&M ($/MWh)	0.54	12.87	13.34	13.67	13.97	14.50	14.86	15.00	15.48	15.89	16.08	16.64	16.94	17.19	17.68	18.02
Fixed O&M ($/kW/Yr)	82.52	7.93	8.12	8.31	8.51	8.71	8.92	9.14	9.36	9.58	9.81	10.05	10.29	10.54	10.79	11.05
Variable Production Cost ($/MWh)	56.44	62.77	53.45	45.68	43.32	32.47	26.66	34.81	27.56	40.99	47.35	24.05	37.14	29.97	21.33	49.65
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

	ACTUAL															
Landfill Gas Projects	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Capacity Factor	0.73	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70
Availability Factor	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98	0.98
Average Heat Rate (Btu/kWh)	11,824	11,907	11,907	11,907	11,907	11,907	11,907	11,907	11,907	11,907	11,907	11,907	11,907	11,907	11,907	11,907
Fuel Cost ($/MMBtu)	0.72	0.70	0.71	0.71	0.72	0.72	0.73	0.73	0.73	0.74	0.74	0.75	0.75	0.76	0.76	0.77
Variable O&M ($/MWh)	21.72	28.23	28.91	29.60	30.32	31.04	31.79	32.55	33.33	33.33	33.33	33.33	33.33	33.33	33.33	33.33
Fixed O&M ($/kW/Yr)	7.50	106.41	108.97	111.58	114.26	117.00	119.81	122.69	125.63	128.65	131.73	134.90	138.13	141.45	144.84	148.32
Variable Production Cost ($/MWh)	22.66	36.62	37.35	38.09	38.85	39.63	40.43	41.25	42.08	42.14	42.19	42.25	42.31	42.37	42.43	42.50
Capital Cost Escalation (%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M Escalation (%)		0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

	ACTUAL															
Future SCGT	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Capacity Factor												0.47	0.43	0.38	0.35	0.30
Availability Factor												0.99	0.99	0.99	0.99	0.99
Average Heat Rate (Btu/kWh)												10,660	10,667	10,669	10,671	10,682
Fuel Cost ($/MMBtu)												3.87	3.93	3.99	#DIV/0!	4.27
Variable O&M ($/MWh)												4.06	4.17	4.15	4.09	4.09
Fixed O&M ($/kW/Yr)												0.00	0.00	0.00	0.00	0.00
Variable Production Cost ($/MWh)												41.72	43.01	43.92	46.21	48.91
Capital Cost Escalation (%)												-	-	-	-	-
O&M Escalation (%)												2.4	2.4	2.4	2.4	2.4

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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 customer needs and resource planning objectives in a cost- effective manner. EKPC analyzes DSM measures and programs using both qualitative and quantitative criteria. These criteria include customer acceptance, measure applicability, savings potential, and cost-effectiveness. The cost-effectiveness of DSM resources is analyzed in a rigorous fashion using the 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. l O (Ky. P.S.C. July 24, 2012).

5.2 DSM Planning Process

For the 2022 IRP, EKPC GDS to prepare an updated study of EE and DR savings potential. 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).

In this 2022 IRP, EKPC has again set participation levels for its DSM programs consistent with historical experience.

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

Guided by the findings in the GDS Potential Report, EKPC review the 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 the 2022 IRP includes seven (7) energy efficiency programs and one (1) demand response program.

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: Classes and End-uses

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 Bring Your Own Thermostat ("BYOT") [6] [7]	Residential	Space Cooling

[6] The tariff allows small commercial customers to participate. However, EKPC is not projecting to have any small commercial participants in this IRP.
[7] The Residential Direct Load Control ("DLC") program will continue to enroll both switches and thermostats. In this IRP, the savings and the costs are based on the BYOT option.

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 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. These load changes have been accounted for in the Load Forecast. 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)
2022	280	-568	-0.4	-0.1
2023	560	-1,136	-0.9	-0.3
2024	840	-1,703	-1.3	-0.4
2025	1,120	-2,271	-1.8	-0.5
2026	1,400	-2,839	-2.2	-0.7
2027	1,680	-3,407	-2.6	-0.8
2028	1,960	-3,974	-3.1	-0.9
2029	2,240	-4,542	-3.5	-1.1
2030	2,520	-5,110	-4.0	-1.2
2031	2,800	-5,678	-4.4	-1.3
2032	3,080	-6,245	-4.8	-1.5
2033	3,360	-6,813	-5.3	-1.6
2034	3,640	-7,381	-5.7	-1.7
2035	3,920	-7,949	-6.1	-1.9
2036	4,200	-8,516	-6.6	-2.0

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)
2022	375	-1,686	-0.5	-0.2
2023	750	-3,371	-1.0	-0.5
2024	1,125	-5,057	-1.5	-0.7
2025	1,500	-6,743	-2.0	-1.0
2026	1,875	-8,428	-2.5	-1.2
2027	2,250	-10,114	-3.0	-1.5
2028	2,625	-11,799	-3.5	-1.7
2029	3,000	-13,485	-4.0	-2.0
2030	3,375	-15,171	-4.5	-2.2
2031	3,750	-16,856	-5.0	-2.5
2032	4,125	-18,542	-5.5	-2.7
2033	4,500	-20,228	-6.0	-3.0
2034	4,875	-21,913	-6.5	-3.2
2035	5,250	-23,599	-7.0	-3.5
2036	5,625	-25,285	-7.4	-3.7

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)
2022	450	-3,456	0.0	-0.2
2023	900	-6,913	0.0	-0.3
2024	1,350	-10,369	0.0	-0.5
2025	1,800	-13,825	0.0	-0.7
2026	2,250	-17,282	0.0	-0.8
2027	2,700	-20,738	0.0	-1.0
2028	3,150	-24,194	0.0	-1.1
2029	3,600	-27,650	0.0	-1.3
2030	4,050	-31,107	0.0	-1.5
2031	4,500	-34,563	0.0	-1.6
2032	4,950	-38,019	0.0	-1.8
2033	5,400	-41,476	0.0	-2.0
2034	5,850	-44,932	0.0	-2.1
2035	6,300	-48,388	0.0	-2.3
2036	6,750	-51,845	0.0	-2.5

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)
2022	340	-1,025	-0.9	-0.2
2023	680	-2,049	-1.9	-0.5
2024	1,020	-3,074	-2.8	-0.7
2025	1,360	-4,098	-3.8	-0.9
2026	1,700	-5,123	-4.7	-1.1
2027	2,040	-6,147	-5.7	-1.4
2028	2,380	-7,172	-6.6	-1.6
2029	2,720	-8,196	-7.6	-1.8
2030	3,060	-9,221	-8.5	-2.0
2031	3,400	-10,246	-9.5	-2.3
2032	3,740	-11,270	-10.4	-2.5
2033	4,080	-12,295	-11.4	-2.7
2034	4,420	-13,319	-12.3	-2.9
2035	4,760	-14,344	-13.3	-3.2
2036	5,100	-15,368	-14.2	-3.4

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)
2022	50	-203	0.0	0.0
2023	100	-406	-0.1	0.0
2024	150	-609	-0.1	-0.1
2025	200	-812	-0.2	-0.1
2026	250	-1,015	-0.2	-0.1
2027	300	-1,218	-0.3	-0.1
2028	350	-1,421	-0.3	-0.2
2029	400	-1,624	-0.4	-0.2
2030	450	-1,827	-0.4	-0.2
2031	500	-2,030	-0.5	-0.2
2032	550	-2,233	-0.5	-0.3
2033	600	-2,436	-0.6	-0.3
2034	650	-2,639	-0.6	-0.3
2035	700	-2,842	-0.7	-0.3
2036	750	-3,045	-0.7	-0.4

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)
2022	500	-247	-0.1	-0.1
2023	1,000	-493	-0.2	-0.1
2024	1,500	-740	-0.2	-0.2
2025	2,000	-986	-0.3	-0.2
2026	2,500	-1,233	-0.4	-0.3
2027	2,500	-1,233	-0.4	-0.3
2028	2,500	-1,233	-0.4	-0.3
2029	2,500	-1,233	-0.4	-0.3
2030	2,500	-1,233	-0.4	-0.3
2031	2,500	-1,233	-0.4	-0.3
2032	2,500	-1,233	-0.4	-0.3
2033	2,500	-1,233	-0.4	-0.3
2034	2,500	-1,233	-0.4	-0.3
2035	2,500	-1,233	-0.4	-0.3
2036	2,500	-1,233	-0.4	-0.3

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)
2022	5,000	-252	0.0	0.0
2023	10,000	-504	-0.1	-0.1
2024	15,000	-756	-0.1	-0.1
2025	20,000	-1,008	-0.2	-0.1
2026	25,000	-1,260	-0.2	-0.1
2027	30,000	-1,512	-0.2	-0.2
2028	35,000	-1,764	-0.3	-0.2
2029	40,000	-2,016	-0.3	-0.2
2030	45,000	-2,268	-0.3	-0.2
2031	50,000	-2,520	-0.4	-0.3
2032	55,000	-2,772	-0.4	-0.3
2033	60,000	-3,024	-0.5	-0.3
2034	65,000	-3,276	-0.5	-0.4
2035	70,000	-3,528	-0.5	-0.4
2036	75,000	-3,780	-0.6	-0.4

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)
2022	2,000	-72	0.0	-2.4
2023	4,000	-144	0.0	-4.8
2024	6,000	-216	0.0	-7.2
2025	8,000	-288	0.0	-9.6
2026	10,000	-360	0.0	-12.0
2027	12,000	-432	0.0	-14.4
2028	14,000	-504	0.0	-16.8
2029	16,000	-576	0.0	-19.2
2030	18,000	-648	0.0	-21.6
2031	20,000	-720	0.0	-24.0
2032	22,000	-792	0.0	-26.4
2033	24,000	-864	0.0	-28.8
2034	26,000	-936	0.0	-31.2
2035	28,000	-1,008	0.0	-33.6
2036	30,000	-1,080	0.0	-36.0

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 5% discount rate. Owner-Member rebates are paid to retail member participants. More details on program costs and cost-effectiveness can be found in the DSM Technical Appendix.

Table 5-3
DSM Program Costs

	Program costs present value, 2022 $ using a 5% discount rate			
Program	**Owner-Member Admin**	**EKPC Admin**	**Rebates[8]**	**Member Investment**
Button-Up Weatherization	$1,091,976	$66,644	$1,762,366	$4,357,192
CARES Low Income	$9,746,701	$262,257	$0	$4,012,531[9]
Heat Pump Retrofit	$1,221,809	$130,820	$3,239,644	$15,466,986
Touchstone Energy (TSE) Home	$1,909,230	$65,410	$3,147,083	$6,067,156
ENERGY STAR® Manufactured Home	$30,854	$229,552	$709,636	$709,636
Residential Energy Audit	$0	$1,641,420	$0	$370,245
Residential Efficient Lighting	$0	$65,410	$555,368	$449,231
Direct Load Control-Residential: AC Bring Your Own Thermostat	$0	$13,473,350	$8,972,995	$2,468,300
Totals	$14,000,569	$15,934,863	$18,387,092	$33,901,277

[8] Rebates are not included in the TRC test.
[9] The member costs for the CARES Low Income program 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 Total Resource Cost test. Cost values are the present value of the future stream of costs using a 5% discount rate.

Table 5-4
DSM Program Cost Savings

		present value 2022 $
Program		**Projected Cost Savings**
Button-Up Weatherization		**$9,251,697**
CARES – Low Income		**$16,059,558** [10]
Heat Pump Retrofit		**$26,955,443**
Touchstone Energy (TSE) Home		**$16,870,385**
ENERGY STAR® Manufactured Home		**$1,575,665**
Residential Energy Audit		**$906,126**
Residential Efficient Lighting		**$2,020,012**
Direct Load Control-Residential: AC Bring Your Own Thermostat		**$34,634,303**
Total		**$108,273,189**

The Total Resource Cost test for the entire portfolio yields a benefit-cost ratio of **1.70.**

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 7-8 and 13-15 in the DSM technical appendix.

All DSM programs are evaluated using the standard California cost-effectiveness tests.

[10] 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;

<u>**Transmission System**</u>

<u>**Introduction**</u>

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 2,968 circuit miles of line at voltages of 69, 138, 161, and 345 kV, and includes 77 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 lists each of EKPC's free-flowing interconnections.

EKPC integrated into the PJM Regional Transmission Organization ("RTO") 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 demands with simultaneous outages of a transmission facility and a generating unit during peak conditions in both summer and winter.

Membership in PJM

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 electric energy market and capacity market and 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 transmission planning activities for the EKPC system through a bottom-up/top-down approach. EKPC and PJM share responsibility for planning of the EKPC transmission system to adhere to both PJM and EKPC transmission planning criteria. The PJM criteria includes both its criteria to maintain the reliability of the Bulk Electric System ("BES") as well as criteria EKPC has established to address certain local reliability needs and which has documented in FERC Form 715. All projects addressing FERC Form 715 criteria needs must be reviewed and approved by PJM.

PJM performs all required assessments of the entire BES for its footprint to ensure conformance with its planning criteria. Transmission projects are identified throughout the RTO footprint as needed to address potential violations of these criteria. These projects are then incorporated into the transmission plans of the applicable transmission owner, thereby ensuring that these plans are considered by the transmission owner in the development of their local transmission plans. PJM thereby ensures that an appropriate transmission expansion plan, called the Regional Transmission Expansion Plan ("RTEP"), 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.

With respect to local transmission plans, EKPC has established criteria to meet local planning needs not addressed by the PJM criteria or its FERC Form 715 criteria. All projects resulting from these local planning criteria are provided to PJM for inclusion in the RTEP. These are called supplemental projects. PJM verifies the need for these projects and ensures that they may reliably be incorporated into the RTEP. Moreover, the PJM planning process ensures transparency – that all projects, including local projects, are made known to the PJM stakeholder community. The local plans of EKPC and other PJM member systems are therefore rolled up into the overall regional plan.

Membership in SERC Reliability Corporation ("SERC")

EKPC is a member of SERC. SERC is one of six regional entities in North America that is responsible for ensuring the reliability and security of the interconnected electric grid. SERC has been delegated by the North American Electric Reliability Corporation ("NERC") to perform certain functions 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 630,000 square miles. The regional entities and all members of NERC work to safeguard the reliability of the BPS throughout North America. NERC has been certified by the FERC as the Electric Reliability Organization for North America. NERC has established Reliability Standards that the electric utilities operating in North America must adhere to. There are presently 93 mandatory Reliability Standards that are in effect and subject to enforcement. EKPC is required to comply with 44 of these standards based upon its responsibility for various functions. PJM is responsible for 37 other standards on EKPC's behalf based on PJM's registration for NERC-defined reliability functions. PJM and EKPC have joint compliance responsibilities for 12 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.

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 two new interconnections, a 69 kV interconnection with LG&E/KU at a new 69 kV switching station in Shelby County (July 2021), and a 161 kV interconnection with TVA at the Fox Hollow substation (January 2022). These new interconnections are needed to improve the reliability of the electric system in the area, and will have minimal power transfer benefits.

Transmission Expansion (2019-2021)

From 2019-2021, EKPC implemented various transmission projects, summarized as follows:

- Transmission station modifications
  - Two 161 kV circuit switcher additions
  - One 138 kV circuit switcher addition
  - One 161 kV breaker addition
  - Four 69 kV breaker additions
  - One 138-69 kV transformer upgrade
  - One 161 kV station upgrade
  - One 138 kV reactor upgrade
  - Addition of a 161 kV station expansion at an existing 69 kV substation
  - Addition of one 69 kV switching station
- Rebuild of existing line using larger (lower impedance, higher capacity) conductor
  - 89.73 miles – 69 kV
- Construction of 12.83 miles of new 69 kV transmission lines
- Construct 0.55 miles of new 138 kV transmission lines
- Construct 1.05 miles of new 161 kV transmission lines (2 new lines with lengths of 0.8 mile and 0.25 mile)
- High temperature upgrades of 69 kV transmission lines (6.52 miles)
- High temperature upgrades of 161 kV transmission lines (3.96 miles)

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 primarily due to the age and condition of older transmission lines in the EKPC system. EKPC's line rebuild projects typically increase conductor 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 to 400 MWh per year when transmission line conductors are upgraded for any particular transmission line.

Future Transmission Expansion

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 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 2022 to 2036 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 is 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 2022 to 2024 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 2022 to 2024 are summarized as follows:

- Upgrade of one existing 138-69 kV transformer
- Addition of three new 69 kV switching stations
- Upgrade of one existing 69 kV switching station
- Three 69 kV breaker additions
- Two 138 kV breaker additions
- Rebuild of 135.8 miles of 69 kV line
- Construction of 20.6 miles of new 69 kV line
- Construction of 0.6 miles of new 161 kV line

The analysis used to develop the plan beyond the first three years is typically less detailed than that used to develop the work plan for the first three years. The assumed system conditions are less certain than those used for the first three years of analysis. Many of the projects beyond the first three-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 2022-2036 period is included as Table 6-2 through Table 6-11. This 15-year expansion plan includes 266.1 miles of existing line 69 kV rebuilds, 31.1 miles of new 69 kV line construction, 0.6 miles of new 161 kV line construction, and 9.8 miles of high-temperature conductor upgrades. It also includes the addition and/or upgrade of 2 transmission stations, 4 new 69 kV switching stations, the upgrade of 1 138-69 kV autotransformer, and the addition or upgrade of facilities at 7 transmission stations. It also includes the addition of 73.5 MVARs of new transmission capacitor bank capability.

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 31.1 miles of new 69 kV line in the 2022-2036 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 and improve system protection schemes.

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.

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.

Generation Related Transmission

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 Open Access Transmission Tariff requirements. Only those projects necessary for firm (committed) generation resources (existing and future) are identified in EKPC's transmission expansion plan. This includes merchant generation facilities that have completed the PJM generation interconnection study process and have subsequently executed Interconnection Service Agreements with PJM/EKPC. Once a valid application for interconnection has been submitted to PJM, the proposed generation facility begins the PJM queue study process. This process involves three study phases (Feasibility Study, System Impact Study, and Facilities Study) that include power-flow analysis, short-circuit analysis, and stability analysis to determine impacts of the requested generator interconnection on the PJM transmission system. The Facilities Study also includes engineering review to develop the scope, estimated cost, and implementation schedule for the transmission-system upgrades necessary to connect the proposed project to the PJM system. EKPC works in conjunction with PJM on these studies, particularly with regard to providing the necessary transmission system upgrades to address impacts identified during the PJM study process.

As of January 1, 2022, there were a total of 103 active merchant-generation facilities in the PJM queue that had requested interconnection to the EKPC transmission system. The total maximum output of these facilities was 8,736 MW. All of these projects are either stand-alone solar generation facilities or hybrid solar/battery storage facilities. Of these 103 total projects, six (6) projects have reached the final-agreement phase – i.e., these facilities have an executed Interconnection Service Agreement. EKPC is in process of performing engineering, procurement, and preparing for construction for these six generation facilities. EKPC will need to construct various facilities required for direct connection of the generation facilities to the EKPC transmission system, as well as perform necessary upgrades on certain transmission facilities to accommodate the expected power flows with these projects connected. The necessary facilities are summarized as follows:

- Construction of one new 138 kV switching station
- Construction of three new 69 kV switching stations
- Expansion of one existing 161/138 kV substation
- High-temperature conductor upgrades of 19.9 miles of 69 kV transmission line

Additionally, EKPC will install overhead optical ground wire ("OPGW") for communications purposes on various line sections, and perform various protective-relay upgrades to accommodate these projects. All EKPC costs associated with the infrastructure needed to accommodate connection of generation projects to the EKPC transmission system are fully reimbursed by the generation-project developers. EKPC has not included any transmission projects in its transmission expansion plan for future generation interconnection other than those projects with executed Interconnection Service Agreements.

Import Capability

EKPC routinely assesses the ability to import power from external sources into the EKPC load zone. Import capability is assessed from regions to the north and to the south of the EKPC system 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 1,628 MW in 2018 during real-time operations 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.

PJM ensures generation in PJM may be deliverable to load throughout PJM. As such, PJM ensures that transmission constraints do not prevent power from effectively flowing to load. 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 each load-deliverability zone within PJM (including EKPC) can meet extreme demand levels with other PJM resources (external to each zone being studied) 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 2021 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 2019-2021 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 2019-2021, EKPC implemented various distribution substation projects, summarized as follows:

- Construction of 6 new distribution substations
- Upgrades of 9 existing distribution substations/transformers

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.

Further improvements are planned for EKPC's distribution substation delivery points for the 2022-2025 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 2022-2025 period are summarized as follows:

- Construction of 4 new distribution substations
- Rebuild and/or upgrade of 32 existing distribution substations

These distribution substation enhancements will improve system efficiency and utilization as described above. EKPC's 15-year expansion plan for the 2022-2036 period is included as Table 6-5 through Table 6-11.

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	170	170	170	170
2	Argentum	Grays Branch	69	42	42	54	54
3	Falcon	Falcon	69	34	34	34	34

No.	From (EKPC)	To	Voltage kV	Ratings in MVA			
				Summer		Winter	
				Normal	Emergency	Normal	Emergency
4	Helechawa	Lee City	69	52	52	52	52
5	Leon	Leon	69	55	66	69	69
6	Morgan County	Morgan County	69	69	69	69	69
7	Thelma	Thelma	69	71	71	90	90
AEP Total:				545	542	611	619
DP&L							
8	Spurlock	Stuart	345	1240	1532	1684	1792
DP&L Total:				1240	1532	1684	1792
Duke Energy-OHIO/KENTUCKY (DEOK)							
9	Boone	Long Branch	138	254	284	363	387
10	Hebron	Hebron	138	229	255	332	348
11	Spurlock	Meldahl Dam	345	1274	1421	1848	1894
12	Webster Road	Webster Road	138	96	117	121	139
13	Hebron	Hebron	69	89	98	128	134
DEOK Total:				1991	2229	2862	2975
LG&E/KU							
14	Avon	Loudon Avenue	138	203	203	286	287
15	Baker Lane	Baker Lane Tap	138	215	251	279	304
16	Beattyville	Beattyville	69	94	119	144	159
17	Beattyville	Beattyville Tap	161-69	84	84	84	84
18	Beattyville-Powell Co.	Delvinta	161	219	223	239	239
19	Bekaert	West Shelby	69	89	98	128	134
20	Bonnieville	Bonnieville	69-138	89	109	112	129
21	Boonesboro Tap	Boonesboro North	138	166	210	256	283
22	Bracken Co.	Carntown	69	36	36	72	72
23	Bracken Co.	Sharon	69	53	66	81	89
24	Bullitt Co	Bullitt Tap	161	267	298	351	362
25	Bullitt Co	Cedar Grove Industrial	161	219	277	336	371
26	Central Hardin	Hardin County	138	208	265	287	287
27	Central Hardin	Blackbranch	138	229	290	352	391
28	Clay Village	Clay Village Tap	69	49	54	70	73
29	Cooper	Elihu	161	219	277	279	305
30	Duncannon Lane Tap	Fawkes	69	89	98	128	134
31	East Bardstown	Bardstown Ind.	69	67	67	86	89
32	Fawkes	Fawkes	138	229	296	287	370
33	Fawkes	Fawkes Tap	138	229	284	355	387
34	Gallatin Co.	Ghent	138	229	255	287	287
35	Garrard Co.	Lancaster	69	90	115	141	156
36	Goldbug	Wofford	69	42	46	60	63
37	Green Co.	Greensburg	69	103	108	113	116
38	Green Hall Jct.	Delvinta	161	219	251	251	251
39	Hodgenville	Hodgenville	69	73	76	86	89
40	Hodgenville	New Haven	69	73	76	86	89
41	Kargle	Elizabethtown	69	89	98	128	134
42	Laurel Co.	Hopewell	69	119	124	141	145
43	Liberty Church Tap	Farley	69	66	76	88	94

No.	From (EKPC)	To	Voltage kV	Ratings in MVA			
				Summer		Winter	
				Normal	Emergency	Normal	Emergency
44	Marion Co.	Lebanon	138	192	220	264	272
45	Murphysville	Kenton	69	53	66	66	68
46	Murphysville	Sardis	69	53	66	81	89
47	Nelson Co.	Nelson Co Tap	69-138	144	152	172	178
48	North London	North London	69	73	76	86	89
49	North Springfield	Springfield	69	49	54	64	66
50	Owen Co.	Bromley	69	49	49	94	94
51	Owen Co.	Owen Co. Tap	138	194	200	219	225
52	Paris Tap	Paris	138	239	289	312	340
53	Penn	Scott Co.	69	77	90	95	100
54	Pittsburg Tap	Pittsburg	161-69	112	120	120	120
55	Renaker	Cynthiana Sw.	69	53	66	81	89
56	Rogersville Jct.	Rogersville	69	114	127	166	174
57	Rowan Co.	Rodburn	138	143	200	143	203
58	Sewellton	Union Underwear	69	77	90	95	100
59	Shelby Co.	Shelby Co. Tap	69	89	98	122	126
60	Somerset	Ferguson South	69	139	152	172	178
61	Somerset	Somerset South	69	129	133	129	133
62	South Anderson (624)	Bonds Mill (644)	69	89	98	128	134
63	South Anderson (634)	Bonds Mill (634)	69	83	98	128	134
64	Spurlock	Kenton	138	240	291	329	337
65	Stephensburg	Eastview	69	53	57	64	66
66	Taylor Co. Junction	Taylor Co.	161	159	200	167	265
67	Tharp Jct.	Elizabethtown	69	103	124	137	151
68	Union City	Lake Reba Tap	138	240	306	371	412
69	West Garrard	West Garrard	345	1290	1504	1589	1669
LG&E/KU Total:				8392	9756	10987	11785
TVA							
70	Fox Hollow	East Glasgow Tap	161	267	298	387	406
71	McCreary Co.	Jellico	161	267	298	384	394
72	McCreary Co.	Wayne Co.	161	267	298	384	394
73	McCreary Co.	Winfield	161	574	638	710	763
74	Russell Co. Tap	Wolf Creek	161	267	298	387	406
75	Summer Shade	Summer Shade	161	267	298	387	406
76	Summer Shade Tap	Summer Shade	161	396	461	468	501
77	Wayne Co.	Wayne Co.	161	127	131	127	131
TVA Total:				2501	2798	3329	3501
Grand Total:				14499	16669	19229	20418

Table 6-2

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2022 – 2036)	
A. New Transmission Lines	**Needed In-Service Date**
Construct a new Floyd-Woodstock 69kV line section using 556 ACSR (7 miles)	10/2023
Construct a new Coburg-EKPC Campbellsville 69kV line section using 556 ACSR (9.3 miles)	12/2026

Table 6-3

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2022 – 2036)	
B. New Transmission Substations & Transmission Substation Upgrades **Project Description**	**Needed In-Service Date**
Rebuild the 69 kV Tyner Switching Station	10/2023
Build a new 69kV substation where the KU Bluegrass-Berea North line intersects Hickory Plains-Crooksville Tap	12/2035

Table 6-4

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2022– 2036)	
C. New Transmission Switching Stations **Project Description**	**Needed In-Service Date**
Build a new Patriot Parkway 69kV (Switching Station	2/2022
Build a new Penn 69 kV Switching Station	12/2022
Build a new Norwood Junction 69kV Switching Station	11/2023
Build a new Coburg Junction 69kV Switching Station	12/2026

Table 6-5

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2022 – 2036)	
D. Transmission Transformer Upgrades **Project Description**	**Needed In-Service Date**
Upgrade the existing West Berea 138-69 kV 100 MVA autotransformer to 150 MVA	11/2022

Table 6-6

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2022 – 2036)	
E. Terminal Facility Upgrades & Additions **Project Description**	**Needed In-Service Date**
Add a new 69 kV breaker at Boone Switching for service to the Boone Distribution substation	10/2022
Add a new 138 kV breaker at Fawkes 138 kV for protection of the Fawkes-Fawkes KU interconnection	12/2022
Add a new 69 kV breaker at Elizabethtown	12/2022
Replace the relay at Argentum, and add a new 138 kV breaker for the existing line to Greenup Hydro	6/2023
Add a new breaker at Magoffin County for the existing 69 kV line to Falcon	12/2023
Add a new breaker at Rowan County for the existing 69 kV line to Elliotville	12/2026
Upgrade the CT associated with the Elizabethtown EK1-Elizabethtown EK2 69kV line section	12/2033

Table 6-7

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2022 – 2036)	
F. Transmission Line Rebuilds **Project Description**	**Needed In-Service Date**
Rebuild the 4/0 Hodgenville - Magnolia 69kV line section using 556 ACSR (8.49 miles)	5/2022
Rebuild the 4/0 Boone-Bullittsville 69kV line section using 556 ACSR (6.4 miles)	5/2022
Rebuild the 4/0 Brodhead-Three Links Junction 69 kV line section using 556 ACSR (8.2 miles)	10/2022
Rebuild the 3/0 Goddard-Oak Ridge 69kV line section using 556 ACSR (8.04 miles)	6/2023
Rebuild the 3/0 Beattyville Distribution-Booneville 69kV line section using 556 ACSR (9 miles)	7/2023
Rebuild the 4/0 Three Links - Three Links Junction 69kV line section using 556 ACSR (9.3 miles)	8/2023
Rebuild the 4/0 Summersville - Magnolia 69kV line section using 556 ACSR (15 miles)	12/2023
Rebuild the 4/0 Boone-Williamstown 69 kV line section using 556 ACSR (28.5 miles)	12/2023
Rebuild the 3/0 Booneville-South Fork 69kV line section using 556 ACSR (5.48 miles)	5/2024
Rebuild the 3/0 Oak Ridge-Charters 69kV line section using 556 ACSR (8.95 miles)	9/2024
Rebuild the 3/0 Fall Rock-Manchester 69kV line section using 556 ACSR (5.83 miles)	12/2024
Rebuild the 3/0 Stephensburg-Vertrees 69kV line section using 556 ACSR (8.7 miles)	12/2024
Rebuild the 556 Duncannon Lane-Fawkes 69kV line section using 795 ACSR (7.48 miles)	12/2024
Rebuild the 4/0 KU Carrollton – EK Bedford 69kV line section using 556 ACSR (22.1 miles)	12/2025
Rebuild the 3/0 Liberty Junction-Peyton's Store 69kV line section using 556 ACSR (14.2 miles)	6/2025
Rebuild the 4/0 Headquarters-Millersburg 69kV line section using 556 ACSR (5.12 miles)	12/2025

Rebuild the 4/0 Norwood Junction-Shopville 69kV line section using 556 ACSR (6.3 miles)	6/2026
Rebuild the 3/0 KU Wofford-McCreary Co. Junction 69kV line section using 556 ACSR (20.7 miles)	12/2027
Rebuild the 266.8 Budd-Logan Tap 69kV line section using 556 ACSR (0.48 miles)	6/2027
Rebuild the 3/0 Headquarters - Murphysville 69kV line section using 556 ACSR (19.9 miles)	7/2027
Rebuild the 4/0 Maytown - West Liberty 69kV line section using 556 ACSR (12.3 miles)	11/2028
Rebuild the 3/0 South Fork - Tyner 69kV line section using 556 ACSR (14.9 miles)	12/2028
Rebuild the 266.8 Dale-Newby 69 kV Double-Circuit line section using 556 ACSR (11.1 miles)	12/2028
Rebuild the 266.8 Bekaert-Budd 69kV line section using 556 ACSR (0.76 miles)	6/2030
Rebuild the 556 Tharp Tap-Elizabethtown KU 69kV line section using 954 ACSR (2.1 miles)	12/2034

Table 6-8

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2022 – 2036)	
G. Transmission Line High Temperature Upgrades **Project Description**	**Needed In-Service Date**
Increase the conductor maximum operating temperature of the Laurel Co-North London 266 ACSR 69kV line section from 167°F to 212°F (3.12 miles)	6/2029
Increase the conductor maximum operating temperature of the Tharp Tap-KU Elizabethtown 69kV 556 ACSR line section from 280°F to 302°F (2.1 miles)	12/2030
Increase the conductor maximum operating temperature of the Plumville-Rectorville 266 ACSR 69kV line section from 167°F to 212°F (2.9 miles)	6/2031
Increase the conductor maximum operating temperature of the Elizabethtown EK2-Tharp Tap 69kV 556 ACSR line section from 212°F to 280°F (1.7 miles)	12/2033

Table 6-9

EKPC 15-YEAR TRANSMISSION EXPANSION SCHEDULE (2022 – 2036)	
H. Capacitor Bank Additions **Project Description**	**Needed In-Service Date**
Install a new 28 MVAR, 69 kV capacitor bank at Liberty Junction substation	12/2026
Increase the size of the Coburg 69kV Capacitor Bank from 7.1 to 17 MVARs	12/2026
Increase the size of the Green River Plaza 69kV Capacitor Bank from 20.4 to 27 MVARs	12/2026
Install a new 20.5 MVAR, 69 kV capacitor bank at Bullitt County substation	12/2031
Install a new 8.5 MVAR cap bank at Elliottville substation	12/2031

Table 6-10

EKPC FOUR-YEAR DISTRIBUTION EXPANSION SCHEDULE (2022 – 2025)	
I. New Distribution Substations and associated Tap Lines Project Description	**Needed In-Service Date**
Construct a new Speedwell Road 69-25 kV 18/24/30 MVA Distribution Substation and associated 69 kV tap line to Crooksville (4.79 miles)	4/2022
Construct a new Dahl Rd 69-12.5 kV 12/16/20 MVA Distribution Substation, tapping the existing Asahi Motor Wheel-Shopville 69kV line section (0.1 miles)	6/2022
Construct a new Mineola Pike 69-12.5 kV 12/16/20 MVA Distribution Substation and associated 69 kV tap line to the Hebron 69 kV substation (8 miles)	12/2024
Construct a new Wieland 69-25 kV 18/24/30 MVA Distribution Substation by looping it into the existing Bekaert-Budd 69 kV line section (1.2 miles)	12/2025

Table 6-11

EKPC FOUR-YEAR DISTRIBUTION EXPANSION SCHEDULE (2022 – 2025)	
J. Distribution Substation Upgrades Project Description	**Needed In-Service Date**
Rebuild the 69 kV Miller's Creek Distribution Substation to 161-13.2 kV 12/16/20 MVA, tapping the Powell County-Beattyville 161 kV line (New Location) (0.6 miles)	4/2022
Rebuild and upgrade the Lees Lick 69-12.47 kV Distribution Substation to 12/16/20 MVA	5/2022
Rebuild the East Bernstadt Distribution Substation to 69-13.2kV 12/16/20 MVA	5/2022
Rebuild and upgrade the Thelma Distribution Substation to 69-13.2 kV 12/16/20 MVA	6/2022
Rebuild and upgrade the existing Highland 69-25 kV Distribution Substation and tap to 12/16/20 MVA (New Location) (0.3 miles)	9/2022
Rebuild and upgrade the Balltown Distribution Substation to 69-13.2kV 12/16/20 MVA	9/2022
Rebuild and upgrade the Munk 69-12.47 kV Distribution Substation	11/2022
Rebuild and upgrade the Redbush Distribution Substation to 69-13.2 kV 12/16/20 MVA	12/2022
Rebuild and upgrade the Penn Distribution Substation to 69-13.2 kV 12/16/20 MVA	12/2022
Rebuild and upgrade the Newfoundland 69kV Distribution Substation to 69-13.2kV 12/16/20	1/2023
Rebuild and upgrade the Rice Distribution Substation to 69-13.2 kV 12/16/20 MVA	1/2023
Rebuild the Griffin 69 kV Distribution Substation and tap line (6.4 miles)	6/2023
Rebuild and upgrade the Rockholds Distribution Substation to 69-13.2 kV 12/16/20 MVA	7/2023

Rebuild the Frenchburg Distribution Substation to 69kV-25kV 11.2 MVA	7/2023
White Oak 69-13.2 kV 12/16/20 MVA Distribution Substation & Tap and Retirement of the South Fork Distribution Substation (New Location) (0.1 miles)	8/2023
Rebuild and upgrade the Three Links Distribution Station to 69/13.2kV 12/16/20	8/2023
Rebuild and upgrade the Albany Distribution Substation to 69-13.2 12/16/20 MVA	9/2023
Rebuild the Shopville 69kV Distribution Substation to 69-13.2kV	10/2023
Rebuild the 69 kV Taylorsville Distribution Substation to 161-13.2kV (New Location) (0.2 miles)	11/2023
Rebuild and relocate the Tyner 69 kV Distribution Substation in the Tyner 161 kV yard (0.1 miles)	11/2023
Rebuild and upgrade the Brodhead Substation to 69-13.2kV 12/16/20 MVA	11/2023
Rebuild and upgrade the Oakdale Distribution Substation to 69-13.2 kV 12/16/20 MVA	12/2023
Upgrade the 3M #1 Transformer to 15/20/25 MVA	12/2023
Rebuild and upgrade the Nicholasville Substation to 69-13.2kV 12/16/20 MVA	3/2024
Rebuild and upgrade the Salt Lick Distribution Substation to 138-13.2 kV 12/16/20 MVA	9/2024
Rebuild and upgrade the Newby Substation to 69-12.5kV 12/16/20 MVA	12/2024
Rebuild and upgrade the Campbellsburg Distribution Substation 69-13.2 kV 12/16/20 MVA	12/2024
Rebuild and upgrade the Greensburg Distribution Substation 69-13.2 kV 12/16/20 MVA	12/2024
Rebuild and upgrade the North Springfield Distribution Substation to 69-13.2 kV 12/16/20 MVA	12/2024
Rebuild and upgrade the Elizabethtown #1 Distribution Substation to 69-13.2 kV 12/16/20 MVA	12/2024
Rebuild and upgrade the Whitley City Distribution Substation to 69-26.4 kV 12/16/20 MVA	12/2024
Rebuild the Homestead Lane Distribution Substation to 69-13.2 kV 18/24/30 MVA	12/2025

SECTION 7.0

PLANS FOR EXISTING GENERATING UNITS

SECTION 7.0

PLANS FOR EXISTING GENERATING UNITS

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. Please also see the discussion in Section 1.6, Power Supply Actions, in the Executive Summary of this IRP.

Maintenance of Existing EKPC Generating Units

Current facilities were brought online 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 Station, with three combustion turbine units that started operating in 2002, was purchased by EKPC on December 29, 2015. Each of EKPC's generating plants was state-of-the-art at the time of their construction and designed to operate under conditions and regulations 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 that takes into account costs, timing, risks, 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 internal review and approval process but do not require board approval.

Current Five-Year Major Projects Study

This plan covers the period from 2022 through 2026. Table 7-1 through Table 7-5 list 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
Generator Inspections	OC01-03	2022
Relocate GSU Protection Panel	OC00	2022
Enclosure Doors	OC00	2023
Demin Tank- Strip and Re-coat interior	OC00	2023
Stack Repair	OC01-02	2023
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
Temporary Landfill Cap	CP00	2022
ABB Symphony Plus Operations Rev. Upg	CP01	2022
ABB Symphony Plus Operations Rev. Upg	CP02	2022
U2 AQCS FD Fan Hub Swap	CP02	2022
U1 Boiler Economizer Tubes Installation	CP01	2023
Boiler Economizer Tubes Matl Purchase	CP01	2023
U1 Boiler Weld Overlay In Firebox	CP01	2023
1A Hyd Turb Rebuild	CP01	2023
Turbine Valve Rebuild	CP01	2025
High Energy Piping Assessment	CP01	2025
PJFF Bag Replacement	CP02	2025
Boiler Assessment	CP01	2026
C.W.P. And Motor Rebuild A	CP01	2026
CP00 - Common		
CP01 - Cooper 1		
CP02 - Cooper 2		

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

Description	Operating Unit	Date
Resurface Existing Blacktop	SP00	2022
Painting Structural Steel - Select Areas	SP00	2022
Ash Haul Bridge Repairs	SP00	2022
Add Concrete Pad At Rock Pile	SP00	2022
Clean & Inspect River Intake	SP00	2022
Clean , Test & Repair Well Pumps	SP00	2022
Water Services Building Piping Replacement	SP00	2022
Clean & Inspect River Intake	SP00	2022
Boiler Ignition Fuel Oil Tank Repairs	SP00	2022
Overhaul (4) Pulverizers	SP01	2022
Outage Boiler & Air heater Repair	SP01	2022
Outage Boiler & Air heater Inspection	SP01	2022
High Energy Piping Assessment	SP01	2022
Air Heater Wash (2)	SP01	2022
Refractory Repairs Boiler	SP01	2022
Expansion Joint Repairs	SP01	2022
1A BFP 5Yr Overhaul	SP01	2022
BFW-Medium Piping Assessment	SP01	2022
Tube Alignment Castings	SP01	2022
ID Fan Outlet Duct SS Overlay	SP01	2022
ID Fan Outlet Duct Expansion Joints D6-A & D6-B Replacement	SP01	2022
Sootblowing Air Receiver Tank 5 Year Inspection (Scafffold,Insulation,Nde,Painting)	SP01	2022
DA Tank Internal Repairs And Shell NDE	SP01	2022
HMI Operators S+ Upgrade - Comp/Software/Graphics	SP01	2022
Outage Boiler & Air heater Inspection And Repair	SP02	2022
Boiler Deslags-2	SP02	2022
Air Heater Wash 2 (TR)	SP02	2022
High Energy Piping Assessments	SP02	2022
Replace 2A BWCP Heat Exchanger	SP02	2022
Pulverizer Overhauls	SP02	2022
Rebuild Pulverizer Journals (3)	SP02	2022
Expansion Joint Repairs	SP02	2022
FD Fan Rotor Replacement	SP02	2022

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

Description	Operating Unit	Date
2B FD Fan Rotor Rebuild	SP02	2022
BFP Rotating Element Rebuild	SP02	2022
ID Fan Rebuild	SP02	2022
Condensate Pump Rebuild	SP02	2022
BFP Rebuild	SP02	2022
Lower Waterwall Remediation	SP02	2022
BFW-Medium Piping Assessment	SP02	2022
RH Leading Edge Replacement	SP02	2022
Amstar Flame Spray Repairs	SP03	2022
Boiler & Air heater Inspection	SP03	2022
Boiler & Air heater Repairs	SP03	2022
13.8 Switchgear Block I/O Replacement	SP03	2022
Plenum Expansion Joint Repairs	SP03	2022
SRD Constant Support Hanger Replacement	SP03	2022
Power Roof Exhauster Complete Replacement	SP04	2022
Amstar Flame Spray Repairs	SP04	2022
Boiler & Air heater Repairs	SP04	2022
4A Voith Drive Rebuild 5 Yr PM	SP04	2022
Plenum Expansion Joint Repairs	SP04	2022
Rebuild Limestone Mill Journals	SP03	2022
Refractory	SP03	2022
Rebuild Limestone Mill Journals	SP04	2022
Refractory (MP)	SP04	2022
SH & RH Floors	SP04	2022
SH & RH Walls	SP04	2022
Outage- Precipitator Inspection And Repairs	SP01	2022
Outage- Precipitator Inspection And Repairs	SP02	2022
Tube Sheet Modules / Wall Repair	SP03	2022
Replace Baghouse Bags/Filters	SP04	2022
Replace The Cone Liners In The UC4 Surge Bin	SP04	2022
Install Actuators On Coal Slide Inlet Chute Isolation Valves	SP01	2022
Overhaul U3 Crushers	SP03	2022
Replace The Chain And Sprockets On SR#3	SP03	2022

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

Description	Operating Unit	Date
Replace The Rotor In U3 Crusher	SP03	2022
Install Dust Suppression On PC3 And BC3 Conveyors	SP03	2022
Overhaul U4 Crushers	SP04	2022
Install Dust Suppression on PC4 and BC4 Conveyors	SP04	2022
SCR Catalyst Replacement	SP01	2022
SCR Inlet Expansion Joint D10-F Replacement	SP01	2022
Lagoon / Coal Pile Runoff Cleaning	SP00	2022
Reagent Line Replacement	SP20	2022
Filter Feed Line	SP20	2022
Scrubber Inlet Duct Repairs	SP21	2022
WESP SIRS Clean/Inspect/Repair	SP21	2022
Replace Kirk Keys	SP21	2022
WESP - Collecting Plate Replacement	SP21	2022
WESP SIRS Clean/Inspect/Repair	SP22	2022
2A Vacuum Pump - Refurbishment	SP22	2022
WESP - Collecting Plate Replacement	SP22	2022
FWH7 Extraction Steam NRV Relocation/Replacement	SP01	2022
Extraction Steam Secondary NRV Inspection	SP01	2022
Unit 1 MCC Essential 1A and 1B	SP01	2022
Asbestos Abatement for Condenser Water Boxes/Piping	SP01	2022
Turbine Valves	SP02	2022
Circ water line repair	SP02	2022
Bottle Replacement for Switchgear	SP02	2022
Cooling Tower Inspection & Repair	SP03	2022
Unit 3 Cooling Tower Fill Replacement - 3 cells	SP03	2022
Turbine and Exciter Controls	SP03	2022
Cooling Tower Inspection & Repair	SP04	2022
Cooling Tower Rain Zone Repair	SP04	2022
Turbine and Exciter Controls	SP04	2022
Spurlock 1 / 2 Bottom Ash Silo Elevator	SP01/02	2022
Air Heater Wash Water Pumping System	SP00	2022
Ash Pond Closure - CCR / ELG Compliance	SP00	2022

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

Description	Operating Unit	Date
CCR/ELG Compliance WMB Pond	SP00	2022
Ignition Fuel Oil Pipe Replacement	SP00	2022
Landfill - Area D Phase 2 Construction	SP00	2022
Landfill - Area D Phase 1 Construction	SP00	2022
Landfill Area D Construction - Ponds and Stream Mitigation	SP00	2022
SSR-2 Compressor Replacement	SP00	2022
Unit 1 Blowdown Flash Tank	SP01	2022
Unit 1 Condenser Retube	SP01	2022
Unit 1 Superheat Outlet Replacement	SP01	2022
Unit 2 Cooling Tower Replacement Project	SP02	2022
Unit 3 Blowdown Flash Tank	SP03	2022
Unit 3 Boiler Turn-Down Modifications	SP03	2022
Unit 4 Blowdown Flash Tank	SP04	2022
WWT and Ash System Platforms and Foggers	SP00	2022
Well 2R	SP00	2022
Resurface Existing Blacktop	SP00	2023
Chiller Replacement - 3rd of 3	SP00	2023
Day/Night Lighting Control	SP00	2023
Structural Painting	SP00	2023
Ash Haul Bridge Repairs	SP00	2023
Clean & Inspect River Intake	SP00	2023
Clean , Test & Repair Well Pumps	SP00	2023
Water Services Building Piping Replacement	SP00	2023
PLC to DCS RO and Pretreatment	SP00	2023
Transfer Tower 2 & 3 Controller Replacement	SP00	2023
4A IAC Overhaul	SP04	2023
4B IAC Overhaul	SP04	2023
Boiler Ignition Fuel Oil Tank Repairs	SP00	2023
Overhaul (4) Pulverizers	SP01	2023
Outage Boiler & Air heater Repair	SP01	2023
Outage Boiler & Air heater Inspection	SP01	2023
High Energy Piping Assessment	SP01	2023
Air Heater Wash (2)	SP01	2023

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

Description	Operating Unit	Date
Boiler Chemical Clean	SP01	2023
Expansion Joint Repairs	SP01	2023
Condensate Pump 1B Rebuild	SP01	2023
BFW-Medium Piping Assessment	SP01	2023
HMI Operators S+ Upgrade - Comp/Software/Graphics - Finalize	SP01	2023
Pulverizer Maintenance	SP02	2023
Outage Boiler & Air heater Inspection and Repair	SP02	2023
Misc. Scaffolding Boiler	SP02	2023
Boiler Deslags-2	SP02	2023
Air Heater Wash 2 (TR)	SP02	2023
FD Fan Rotor Rebuild	SP02	2023
High Energy Piping Assessments	SP02	2023
Pulverizer Overhauls	SP02	2023
Rebuild Pulverizer Journals (6)	SP02	2023
Boiler Chemical Clean	SP02	2023
Expansion Joint Repairs	SP02	2023
HMI Operators S+ Upgrade - Comp/Software/Graphics - Finalize	SP02	2023
U2 Pulverizer Inching Drive	SP02	2023
GECKO UT Inspection of Boiler Tubing	SP02	2023
2A ID Fan - Hydraulic Unit and Feedback Changeout	SP02	2023
ID Fan Stall Protection System	SP02	2023
Amstar Flame Spray Repairs	SP03	2023
Robotic Ut Inspection	SP03	2023
Boiler & Air heater Inspection	SP03	2023
Boiler & Air heater Repairs	SP03	2023
Boiler Chemical Clean	SP03	2023
3A FP volute replacement (2014 last)	SP03	2023
NO. 1 Sector Plate Replacement (Hot PA to GAS)	SP03	2023
Buy & install new condensate pump then rebuild for spare	SP03	2023
Air Preheater Sensorless Leakage Control System Upgrade (SLCS)	SP03	2023
CCW Heat Exchanger 5 yr PM	SP04	2023
Amstar Flame Spray Repairs	SP04	2023
Robotic Ut Inspection	SP04	2023
Boiler & Air heater Inspection	SP04	2023
Boiler & Air heater Repairs	SP04	2023
Air Preheater Sensorless Leakage Control System Upgrade (SLCS)	SP04	2023
Rebuild Limestone Mill Journals	SP03	2023
Refractory	SP03	2023

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

Description	Operating Unit	Date
Rebuild Limestone Mill Journals	SP04	2023
Refractory (MP)	SP04	2023
Outage- Precipitator Inspection And Repairs	SP01	2023
Outage- Precipitator Inspection And Repairs	SP02	2023
Tube Sheet Modules / Wall Repair	SP03	2023
Baghouse bag/filter membrane replacement	SP03	2023
Inspect & Repair Cells	SP00	2023
Dredge River around Unloading Cells	SP00	2023
Inspect & Repair Cells	SP00	2023
Dredge River around Unloading Cells	SP00	2023
Paint Barge Unloader	SP00	2023
Paint CH Structural Steel	SP00	2023
Overhaul U3 Crushers	SP03	2023
Overhaul U4 Crushers	SP04	2023
#3 Dozer Powertrain Rebuild	SP00	2023
Ammonia Tuning Grid Pipe Replacement	SP02	2023
Lagoon / Coal Pile Runoff Cleaning	SP00	2023
WMB Pond Dredging	SP00	2023
Replace Horizontal Run of NUVALY Piping	SP01	2023
Replace Horizontal Run of NUVALY Piping	SP02	2023
HMI Operators S+ Upgrade - Comp/Software/Graphics	SP20	2023
Scrubber Inlet Duct Repairs	SP21	2023
WESP SIRS Clean/Inspect/Repair	SP21	2023
WESP SIRS Clean/Inspect/Repair	SP22	2023
Brine Concentrator Tube cleaning	SP20	2023
Chemical Clean Evaporator Heat Exchanger	SP20	2023
Replace Filter Press Cloths	SP20	2023
Insulation/Heat Trace	SP20	2023
Electrical Instrumentation	SP20	2023
DSI Building Electrical Upgrade	SP21	2023
DSI Building Electrical Upgrade	SP22	2023
MCC Essential Service Upgrade	SP01	2023
Unit 1 Generator Relay Panel Replacement	SP01	2023
Stator Leak Monitoring System Replacement	SP02	2023
Cooling Tower Inspection & Repair	SP03	2023
Turbine valve repairs	SP03	2023
CT Lilly Pads	SP03	2023

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

Description	Operating Unit	Date
Unit 3 Cooling Tower Fill Replacement	SP03	2023
Cooling Tower Inspection & Repair	SP04	2023
Cooling Tower Rain Zone Repair	SP04	2023
CCR/ELG Compliance WMB Pond	SP00	2023
Ignition Fuel Oil Pipe Replacement	SP00	2023
Landfill - Area D Phase 2 Construction	SP00	2023
Unit 1 Condenser Retube	SP01	2023
Unit 1 Superheat Outlet Replacement	SP01	2023
Unit 3 Boiler Turn-Down Modifications	SP03	2023
Boiler Assessment	SP01	2024
"B" Feed Pump 5yr PM	SP01	2024
Boiler Assessment	SP02	2024
"B" Feed Pump 5yr PM	SP02	2024
FD Fan Overhaul A	SP02	2024
Boiler Assessment	SP03	2024
"B" Feed Pump 9yr PM	SP03	2024
"B" Voith Drive 5yr PM	SP03	2024
Limestone Mill 3-4yr PM	SP03	2024
Boiler Assessment	SP04	2024
Turbine Valves 5yr PM	SP04	2024
Baghouse filter replacement 2yr PM	SP04	2024
Ash Pond Closure - CCR / ELG Compliance	SP00	2024
Boiler Assessment	SP01	2025
"A" Feed Pump 5yr PM	SP01	2025
Boiler Assessment	SP02	2025
"A" Feed Pump 5yr PM	SP02	2025
ID Fan Overhaul B	SP02	2025
Boiler Assessment	SP03	2025
Major Turbine 10yr PM	SP03	2025
Generator Field & Stator	SP03	2025
Baghouse filter replacement 2yr PM	SP03	2025
Boiler Assessment	SP04	2025
Ash Pond Closure - CCR / ELG Compliance	SP00	2025
Boiler Assessment	SP01	2026
C.W.P. and Motor Rebuild A	SP01	2026

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

Description	Operating Unit	Date
Boiler Assessment	SP02	2026
C.W.P. and Motor Rebuild A	SP02	2026
ID Fan Overhaul A	SP02	2026
Boiler Assessment	SP03	2026
Boiler Assessment	SP04	2026
"A" Voith Drive 5yr PM	SP04	2026
Limestone Mill 3-4yr PM	SP04	2026
Baghouse filter replacement 2yr PM	SP04	2026
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
Structure Painting- Units 2 and 4 and bay	SM52/54	2022
Structure Painting- Units 1 and 3	SM51/53	2022
Site Blacktop repair	SM50	2022
U1-3 Camera replacement	SM51-53	2022
Rebuild liquid fuel pump- #1 (Unit 2)	SM52	2022
15 Yr Breaker Maintenance Units 1 & 3	SM51/53	2022
Retrofit ABB AdVac Breakers	SM50	2022
Unit No. 6 CI	SM56	2022
Unit No. 6 Parts Refurbishment	SM56	2022
Unit No. 7 CI Inspection	SM57	2022
Unit 10 Row 3-5 HPC Blade	SM60	2022
Gas Line Inspection from Bybee to Plant	SM50	2022
Intake Fan PLC Replacements on U1, 2, & 3	SM51-53	2022
Unit 1 Exhaust Repairs	SM51	2022
Waterwash CO or NOX	SM50	2022
Restack catalyst for LMS	SM50	2022
J.K. Smith Electrical Infrastructure Upgrades	SM50	2022
Smith New Water Intake	SM50	2022
Rebuild liquid fuel pump- #1 (Unit 1)	SM51	2023
Gas Compressor Overhaul	SM50	2023
Gas Compressor Overhaul	SM50	2023
Retrofit 5000A 13.8 KV Generator Breakers 4-7	SM54-57	2023
Unit No. 7 Parts Refurbishment	SM57	2023
Waterwash CO or NOX	SM50	2023
Restack catalyst for LMS	SM50	2023
Smith New Demineralized Water Storage Tank	SM50	2023
Smith New Water Intake	SM50	2023

Table 7-4 (continued)
Smith CTs - Station

Description	Operating Unit	Date
Generator Ckt Bkr 12 yr Maintenance	SM60	2024
Catalyst Replace	SM60	2025
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- Major Overhaul- Unit 2	LF01	2022
Laurel Ridge- Fuel skid upgrade	LF02	2022
Laurel Ridge - Major Overhaul- Unit 1	LF02	2022
Bavarian- Major Overhaul- Unit 4	LF03	2022
Pendleton- Major Overhaul- Unit 3	LF05	2022
Glasgow- Major Overhaul- Unit 1	LF07	2022
Green Valley- Major Overhaul- Unit 2 & 3	LF01	2023
Bavarian- Major Overhaul- Unit 1 & 3	LF03	2023
Hardin- Major Overhaul- Unit 2	LF04	2023
Pendleton- Major Overhaul- Unit 1 & 4	LF05	2023
Laurel Ridge - Major Overhaul- Unit 4	LF02	2024
Hardin- Major Overhaul- Unit 3	LF04	2024
Laurel Ridge - Major Overhaul- Unit 2	LF02	2025
Bavarian- Major Overhaul- Unit 2	LF03	2025
Laurel Ridge - Major Overhaul- Unit 3	LF02	2026
Pendleton- Major Overhaul- Unit 4	LF05	2026

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 member-owned cooperatives 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 high reliability and economic viability while mitigating evolving regulatory challenges including possible carbon emissions reduction mandates and penalties. To meet this strategic objective, EKPC will actively manage its current and future asset portfolio to maintain high reliability of electric service to its owner-members and economically diversify its energy resources, including market purchases, fossil fuels, renewables storage, demand management and energy efficiency programs, and partnering opportunities. 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 our owner-members.

EKPC is concerned about future reliability of the interconnected electric system and believes that conventional generation resources will continue to be required to facilitate the transition to renewable and low/no carbon emitting resources. Conventional generation resources will be required to maintain reliability as the transition occurs.

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 a Request for Proposals process ("RFP"). The RFP process ensures that EKPC has adequately surveyed available resources in the market for delivery to serve the EKPC 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 2020. This forecast was approved by the EKPC Board of Directors in December, 2020, and was approved by the Rural Utilities Service ("RUS"). The load forecast was updated to reflect known conditions in 2020 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. Fuel and market cost assumptions and projections were developed in the Fall 2021 in order to have adequate time to robustly evaluate integrated resource plan alternatives. These assumptions appear to be low in the near term as compared to prices and projections in March 2022. EKPC continually monitors its planning assumptions and will adjust its plans as needed. Based on this input data, then 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 determined no additional substantial unit modifications were required to meet current or predicted regulations.

8.3 Load Requirements to be Served

The forecast indicates that for the period 2022 through 2036, total energy requirements will increase by an average of 1.1 percent per year. Winter and summer net peak demand will increase by 0.6 percent and 0.8 percent, respectively.

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)
2022	-7,508	-2.0	-3.3
2023	-15,016	-4.1	-6.6
2024	-22,523	-6.1	-9.8
2025	-30,031	-8.2	-13.1
2026	-37,539	-10.2	-16.4
2027	-44,800	-12.2	-19.6
2028	-52,061	-14.2	-22.8
2029	-59,323	-16.2	-26.1
2030	-66,584	-18.1	-29.3
2031	-73,845	-20.1	-32.5
2032	-81,106	-22.1	-35.7
2033	-88,368	-24.0	-38.9
2034	-95,629	-26.0	-42.2
2035	-102,890	-28.0	-45.4
2036	-110,151	-29.9	-48.6

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 forced outages, unit ramp rates, and unit startup characteristics. The RTSim model uses a Monte Carlo simulation to capture the statistical variations of unit forced outages and deratings, load uncertainty, market price uncertainty, and fuel price uncertainty. Monte Carlo simulation requires repeated simulations (iterations) of the time period analyzed to simulate system operation under different outcomes of unit forced outages and deratings, load uncertainty, market price uncertainty, and fuel price uncertainty. The production cost model is simulating the actual operation of the power system in supplying the projected customer loads using a statistical range of inputs.

For this study, the model used the statistical load methodology. There is one set of load data in the model, which was created from the EKPC Load Forecast. 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:

Traditional Resources

Table 8-2

Resource	Capacity Type	Capacity (MW)	Primary Fuel	Projected Capital Cost (2020$) * $/kW	$M
LMS100 CT	Peaking	100	Natural Gas	1169	117
7F SCGT	Peaking	225	Natural Gas	709	160
Combined Cycle	Peaking/Intermediate	418	Natural Gas	1082	452
Solar	Intermittent	150	Solar	1778	267
Solar	Power Purchase	100	Solar	$40/MWh	
PPA - Winter Seasonal Market	Power Purchase	100	n/a	$50/MWh	

* Capital Costs Source: National Renewable Energy Laboratory ("NREL") Annual Technology Baseline ("ATB") 2021
Capital Costs Source: Energy Information Administration ("EIA") Annual Energy Outlook ("AEO") 2021
Market Cost Source: NRCO Power Marketing Forecast, November 2021

Renewable and Partnering Opportunities

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/Member Cooperative service territory. A member system is pursuing hydro-generation facilities via a power purchase agreement with a local developer. One facility rated at 2.64 MW was completed in 2021 and a similar second facility rated 3.04 MW is projected to be online in 2022.

EKPC currently has six landfill gas-to-energy ("LFGTE") facilities and continues to strive to improve performance at each of these facilities. 2021 generation from the existing EKPC facilities was approximately 99,977 MWh down from 101,207 MWh in 2017 and 90,220 MWh in 2016. EKPC developed the City of Glasgow Landfill into a LFGTE project, and it went online in December 2015.

In 2021 EKPC purchased 1,357 MWh from its one contracted cogeneration facility. Prominent barriers to new combined heat and power projects include 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. Two additional facilities recently received contractual approval for solar facilities. These solar installations total 425kWac of capacity. Small scale solar has a continuing interest and EKPC routinely answers questions regarding cogeneration/small power producer options.

EKPC, along with its sixteen owner-member cooperatives, implemented a community solar project in order to offer renewable solar energy to end users within the owner-member cooperative's service territories. This project is a result of the Demand-Side and Renewable Energy Collaborative group's efforts. The 8.5MWac 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 13,204 MWh in 2021.

There are currently approximately 9,023 kW of solar voltaic installations within the EKPC service territory taking advantage of the member cooperatives' net metering tariff. This number continues to grow as solar voltaic prices continue to decrease. There also are approximately 24 kV of small wind turbine installations taking advantage of owner-member cooperative's net metering tariff.

Recently, several industrial end-use members contacted their respective distribution cooperative about securing renewable energy resources or Renewable Energy Certificates ("RECs"). Those industrial end-use members indicated they have a corporate interest in acquiring RECs through their cooperative.

EKPC, in concert with its owner-member cooperatives, developed programs and resulting tariffs to support those efforts. The Renewable Energy Program tariff was expanded to include two (2) new renewable energy options targeted to the commercial and industrial ("C&I") end-use members:

- Option B – Long-term Renewable Resources
- Option C – C&I RECs

The goal of the new program is to offer C&I end-use members' renewable resources and/or RECs to achieve their sustainability goals without cross-subsidization from or to non-participants. The Commission approved both Option B and Option C of the Renewable Energy Program tariff.

EKPC and its owner-member cooperatives have discussed the program with several large C&I end-use members. To date, one has already agreed to participate in the long-term renewable energy program. EKPC is working to secure the renewable resource as defined in the agreement. Another large C&I end-use member has agreed to a REC-only purchase. That business is offsetting 10% of its monthly consumption through RECs.

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

Year	Energy Additions	Base Load Capacity Additions		Peaking/ Intermediate Cap. Additions		Total Capacity		Reserve Requirements[11]		Reserve Margin	
		Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum
2022	100					3,434	3,136	0	75	4%	25%
2023	110					3,434	3,198	0	77	2%	22%
2024	200					3,434	3,318	0	78	2%	20%
2025						3,434	3,318	0	78	2%	20%
2026	200					3,534	3,438	0	79	1%	19%
2027	200					3,534	3,558	0	79	1%	19%
2028						3,534	3,558	0	80	0%	18%
2029						3,534	3,558	0	80	0%	17%
2030						3,534	3,558	0	80	0%	17%
2031	200					3,534	3,678	0	81	0%	16%
2032[12]	200			225	170	3,659	3,968	0	81	5%	22%
2033						3,659	3,968	0	82	5%	21%
2034						3,659	3,968	0	82	4%	20%
2035						3,659	3,968	0	83	4%	19%
2036						3,659	3,968	0	83	3%	19%

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.

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[11] Based on PJM reserve requirements
[12] Only generation added for the purpose of covering summer peak load capacity obligations is considered "capacity" additions. All other intermittent or seasonal purchases are made to hedge the energy price exposure to the EKPC system and not to supply "capacity" to its portfolio or the PJM system.

The Resource Optimizer constructs expansion plans to meet certain criteria, then simulates each plan and calculates the present value of each plan as compared to doing nothing. Some of the inputs needed by the Resource Optimizer are the minimum and maximum future capacity needs, resource alternatives, the annualized fixed cost of the resource alternatives, and the potential in-service dates for the alternatives. The resource alternatives are modeled with the same detail as the existing and committed units in the model. In development of this IRP, the Resource Optimizer was set to try up to 2500 unique expansion plans, with each of those simulated with 5 iterations. Each iteration varies loads, fuel and market prices, and forced outages. The Resource Optimizer was run for the time period 2022 through 2036. The results in the following table, Table 8.4, show the five lowest cost plans out of 2,500 plans simulated.

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
Peaking Resource	1-1-2032
Case 2	
Seasonal Purchase	1- 1-2022
Seasonal Purchase	1- 1-2035
Peaking Resource	1-1-2033
Intermittent Resource	1-1-2029
Intermittent Resource	1-1-2031
Intermittent Resource	1-1-2031
Intermittent Resource	1-1-2033
Case 3	
Seasonal Purchase	1- 1-2022
Peaking Resource	1- 1-2034
Intermittent Resource	1-1-2035
Case 4	
Seasonal Purchase	1- 1-2022
Seasonal Purchase	1- 1-2033
Peaking Resource	1-1-2032
Peaking Resource	1-1-2036
Intermittent Resource	1-1-2031
Intermittent Resource	1-1-2033
Case 5	
Seasonal Purchase	1- 1-2022
Seasonal Purchase	1- 1-2024
Peaking Resource	1- 1-2033
Peaking Resource	1- 1-2036
Intermittent Resource	1-1-2028
Intermittent Resource	1-1-2030
Intermittent Resource	1-1-2034
Intermittent Resource	1-1-2034

Table 8-5
Resource Optimizer Plan Summary

Cumulative Min Power Supply	Incremental Power Supply	Year	Type	Plan 1	Plan 2	Plan 3	Plan 4	Plan 5	Final Plan
-112	0	2022	Peaking						
			Intermediate						
			Renewable						
			Seasonal PPA	100	100	100	100	100	**100**
-182	-70	2023	Peaking						
			Intermediate						
			Renewable						**110**
			PPA						
-237	-55	2024	Peaking						
			Intermediate						
			Renewable						**200**
			Seasonal PPA					100	
-288	-51	2025	Peaking						
			Intermediate						
			Renewable						
			PPA						
-325	-37	2026	Peaking						
			Intermediate						
			Renewable						**200**
			Seasonal PPA						
-348	-23	2027	Peaking						
			Intermediate						
			Renewable						**200**
			Seasonal PPA	100					
-346	2	2028	Peaking						
			Intermediate						
			Renewable					100	
			Seasonal PPA						
-334	12	2029	Peaking						
			Intermediate						
			Renewable		100				
			Seasonal PPA						
-314	21	2030	Peaking						
			Intermediate						
			Renewable					100	
			Seasonal PPA						
-285	28	2031	Peaking						
			Intermediate						
			Renewable		200		100		**200**
			Seasonal PPA						
-228	57	2032	Peaking	225			225		**225**
			Intermediate						
			Renewable						**200**
			Seasonal PPA						
-170	58	2033	Peaking		225			225	
			Intermediate						
			Renewable		100		100		
			Seasonal PPA				100		
-93	77	2034	Peaking			225			
			Intermediate						
			Renewable					200	
			Seasonal PPA						
3	95	2035	Peaking						
			Intermediate						
			Renewable			100			
			Seasonal PPA		100				
105	102	2036	Peaking				225	225	
			Intermediate						
			Renewable						
			Seasonal 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.

Since energy 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.

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 to meet its PJM capacity resource requirements as well as plans 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		Reserves		Total Requirements		Existing Resources		Capacity Needs	
	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum
2022	3,315	2,498	0	75	3,315	2,573	3,434	3,132	-119	-559
2023	3,360	2,568	0	77	3,360	2,645	3,434	3,132	-75	-487
2024	3,376	2,605	0	78	3,376	2,683	3,434	3,132	-58	-449
2025	3,380	2,613	0	78	3,380	2,691	3,434	3,132	-54	-441
2026	3,395	2,622	0	79	3,395	2,701	3,434	3,132	-40	-431
2027	3,410	2,636	0	79	3,410	2,715	3,434	3,132	-24	-417
2028	3,437	2,652	0	80	3,437	2,732	3,434	3,132	2	-401
2029	3,447	2,668	0	80	3,447	2,748	3,434	3,132	12	-384
2030	3,456	2,680	0	80	3,456	2,760	3,434	3,132	22	-372
2031	3,464	2,698	0	81	3,464	2,779	3,434	3,132	30	-353
2032	3,495	2,698	0	81	3,495	2,779	3,434	3,132	61	-353
2033	3,496	2,726	0	82	3,496	2,808	3,434	3,132	62	-324
2034	3,516	2,743	0	82	3,516	2,825	3,434	3,132	82	-308
2035	3,535	2,764	0	83	3,535	2,847	3,434	3,132	101	-285
2036	3,543	2,777	0	83	3,543	2,860	3,434	3,132	109	-273

Notes:
1. Reserve requirement based on EKPC's pro-rata share of the PJM Summer reserve requirements. EKPC seeks to hedge its winter energy exposure for price stability, but has no winter capacity obligation to satisfy its PJM load serving oblication.

Table 8-7 below shows the expected capacity and energy price hedge additions based on the 2021 IRP plan.

Table 8-7
EKPC Projected Additions and Reserves
(MW)

Year	Energy Additions	Base Load Capacity Additions		Peaking/ Intermediate Cap. Additions		Total Capacity		Reserve Requirements[13]		Reserve Margin	
		Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum
2022	100					3,434	3,136	0	75	4%	25%
2023	110					3,434	3,198	0	77	2%	22%
2024	200					3,434	3,318	0	78	2%	20%
2025						3,434	3,318	0	78	2%	20%
2026	200					3,534	3,438	0	79	1%	19%
2027	200					3,534	3,558	0	79	1%	19%
2028						3,534	3,558	0	80	0%	18%
2029						3,534	3,558	0	80	0%	17%
2030						3,534	3,558	0	80	0%	17%
2031	200					3,534	3,678	0	81	0%	16%
2032[14]	200			225	170	3,659	3,968	0	81	5%	22%
2033						3,659	3,968	0	82	5%	21%
2034						3,659	3,968	0	82	4%	20%
2035						3,659	3,968	0	83	4%	19%
2036						3,659	3,968	0	83	3%	19%

EKPC will work with Federal and State stakeholders to ensure the economic viability of future and existing resources to meet the challenges and opportunities surrounding climate change. 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.

EKPC is concerned about future reliability of the interconnected electric system and believes that conventional resources will continue to be required as the system shifts to renewable and clean

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[13] Based on PJM reserve requirements
[14] Only generation added for the purpose of covering summer peak load capacity obligations is considered "capacity" additions. All other intermittent or seasonal purchases are made to hedge the energy price exposure to the EKPC system and not to supply "capacity" to its portfolio or the PJM system.

energy resources. These conventional resources will continue to be needed to maintain reliability through the transition and into the future.

Table 8-8

Power Transactions (GWH)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Power Purchases	180	153	150	146	142	143	143	145	142	145	147	145	145	156	174
Market Purchase	14,318	15,208	15,657	15,966	16,283	16,818	17,177	17,277	17,370	17,695	18,294	18,621	18,770	18,924	19,105
SEPA	257	257	258	260	257	257	257	256	259	260	258	257	257	256	262
Total Purchases	16,777	17,642	18,089	18,398	18,707	19,246	19,605	19,708	19,800	20,131	20,731	21,056	21,206	21,372	21,577
Market Power Sales	13,320	11,703	11,973	11,104	11,405	11,120	11,224	11,226	11,454	11,389	11,703	11,420	10,851	10,853	10,870

Table 8-9

Non-Utility Generation (GWH)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
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 8.(3)(b) and 8.(4)(c).

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

Table 8-10

Forecast Energy	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Requirements (GWh) (as modeled)	14,421.1	15,192.8	15,306.0	15,397.3	15,498.3	15,600.6	15,741.5	15,840.9	15,933.8	16,043.6	16,209.6	16,318.5	16,467.8	16,621.1	16,802.3
Generation (GWH)															
Coal	11,406.6	10,171.3	10,084.6	9,183.5	9,380.1	8,795.6	8,701.7	8,719.4	8,822.5	8,575.2	8,302.3	7,875.5	7,476.2	7,537.7	7,604.9
Natural Gas	1,650.5	1,150.2	1,170.2	982.4	875.1	740.7	720.9	705.4	828.6	794.4	949.9	876.5	707.3	647.6	592.1
Landfill Gas	95.2	95.1	95.3	95.1	95.1	95.1	95.4	95.1	95.1	95.1	95.3	95.1	95.1	95.1	95.3
Solar	13.8	132.0	467.1	685.3	900.2	1,333.5	1,552.0	1,551.6	1,551.6	1,766.6	2,200.0	2,418.0	2,418.0	2,417.9	2,418.2
Total	13,166.2	11,548.5	11,817.3	10,946.3	11,250.4	10,964.9	11,069.8	11,071.5	11,297.8	11,231.3	11,547.5	11,265.1	10,696.5	10,698.3	10,710.5
Purchases (GWH)															
Firm Purchases-SEPA	256.9	256.9	258.4	260.2	257.0	257.5	257.2	256.5	258.9	260.2	257.8	256.9	256.9	256.5	261.8
Purchases-PJM Market	179.9	153.3	149.8	146.1	142.0	143.1	142.6	145.5	141.8	145.2	147.2	144.8	144.8	156.3	174.2
Firm Purchases-Non-Utilities	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	436.8	410.3	408.3	406.3	398.9	400.5	399.8	402.0	400.6	405.4	405.0	401.7	401.7	412.7	436.0

Table 8-11

Fuel Input (1,000s MBTU)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Coal	113,802	101,261	100,516	91,994	94,010	88,351	87,468	87,635	88,754	86,316	83,629	79,504	75,602	76,194	76,851
Natural Gas	16,928	11,649	11,932	9,962	8,849	7,487	7,250	7,101	8,333	7,976	9,753	9,013	7,251	6,603	6,068
Total	130,730	112,910	112,448	101,956	102,860	95,838	94,718	94,736	97,086	94,291	93,382	88,518	82,853	82,797	82,920
Fuel Input (Physical Units)															
Coal (1,000s Tons)	4,984	4,455	4,426	4,054	4,147	3,901	3,862	3,868	3,918	3,812	3,696	3,516	3,346	3,372	3,401
Natural Gas (1,000s mcf)	16,685	11,482	11,760	9,819	8,722	7,380	7,146	6,999	8,213	7,861	9,612	8,884	7,146	6,508	5,981

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 state of Kentucky.

SECTION 9.0

COMPLIANCE PLANNING

SECTION 9.0

COMPLIANCE PLANNING

9.1 Introduction

EKPC works diligently to be a proactive and forward thinking prudent electric utility and has taken several actions as listed below to comply with the Clean Air Act ("CAA"), Clean Water Act ("CWA"), Resource Conservation and Recovery Act ("RCRA").

EKPC is currently in compliance with the following CAA rules:

- New Source Performance Standards ("NSPS");
  - NSPS 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);
- Cross State Air Pollution Rule ("CSAPR");
- National Ambient Air Quality Standards ("NAAQS") for Sulfur Dioxide ("SO_2"), Nitrogen Dioxide ("NO_2"), 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 (vacated by the D.C. Circuit);

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

- Clean Water Act ("CWA");
  - Section 316(a) and (b)
  - Effluent Limitations Guidance ("ELG")
  - Waters of the United States ("WOTUS")
- Resource Conservation and Recovery Act ("RCRA")
  - Coal Combustion Rule ("CCR");

EKPC is in compliance with the existing Environmental Protection Agency ("EPA") rules. As a prudent utility, we survey the environmental waterfront for future rules, in draft, proposed and final form. The Biden Administration has announced goals that depart from the prior Trump Administration's focus on cooperative federalism. The new Administration's goals are generally at odds with coal-fired power generation. Specifically, the Administration has put forth a goal of carbon-free electrical generation by 2035 (Executive Order ("EO") 14008). While the desire to reduce coal from the generating mix is clear, the timing and regulatory approach for implementing this policy is less clear. Regulations and guidance implementing these policies are forthcoming.

The existing infrastructure and transmission grid will not support a carbon-free goal in the power sector by 2035 and a net zero economy by 2050. Furthermore, this goal may not be achievable without some type of technology that includes rotating generation equipment. Coal generation would need to be replaced, which requires the commissioning of new assets and new technologies to maintain grid resiliency and reliability. This takes time for technology maturation, project planning, permitting, financing and construction. EKPC and the power industry are working with several groups including the Electric Power Research Institute ("EPRI") to develop reasonable and practicable timelines. The power industry is evaluating and anticipating changes based on the Biden Administration's agenda. For instance, the Biden Administration has already issued a list of final environmental rules that it will be reconsidering, which are discussed herein.

The EPA issued a draft 2018-2026 Strategic Plan on October 1, 2021 (EPA Plan) that provides highlights of the Biden EPA's new initiatives. The EPA Plan adds tackling climate change and environmental justice to the existing general categories of focus, which are enforcement and compliance of existing laws and regulations, improvement of outdoor and indoor air quality, ensuring clean and safe water for all communities, safeguard and revitalize communities, and ensure safety of chemicals for people and the environment.

Environmental justice is a particular focus of the Biden Administration. President Biden released an EO on *Advancing Racial Equity and Support for Underserved Communities Through the Federal Government* on January 20, 2021. This EO established a comprehensive approach to advancing equity across the federal government, including an assessment of certain agency programs to assess whether underserved communities face systemic barriers in accessing benefits and opportunities and whether new policies, regulations or guidance documents may be necessary to advance equity in agency actions and programs. On April 7, 2021, EPA Administrator Michael Regan responded to the Biden EO by announcing new EPA measures to:

1. Strengthen enforcement of violations of cornerstone environmental statutes and civil rights laws in communities overburdened by pollution.

2. Take immediate and affirmative steps to incorporate environmental justice considerations into their work, including assessing impacts to pollution-burdened, underserved, and Tribal communities in regulatory development processes and to consider regulatory options to maximize benefits to these communities.

3. Take immediate and affirmative steps to improve early and more frequent engagement with pollution-burdened and underserved communities affected by agency rulemakings, permitting and enforcement decisions, and policies. Following President Biden's memorandum on strengthening the Nation-to-Nation relationship with Tribal Nations, EPA staff should engage in regular, meaningful, and robust consultation with Tribal officials in the development of federal policies that have Tribal implications.

4. Consistent with the Administration's Justice 40 initiative, consider and prioritize direct and indirect benefits to underserved communities in the development of requests for grant applications and in making grant award decisions, to the extent allowed by law.

EKPC's service area includes a significant number of end users in economically distressed communities. As such, there may be opportunities for increased funding directed toward bringing energy and efficiency programs to those areas, through RUS electric programs.

EKPC is complying with the current rules of environmental law. A description of each rule appears below and lays out what impacts are expected.

I. NSR

EKPC dedicates ongoing legal, operations, and environmental resources to the review of outage projects under its NSR compliance program. EKPC remains in compliance with the conditions of the 2007 Consent Decrees that were designed to survive termination through EKPC's air permits. Congress and the EPA considered reforms to the NSR rules that would have created a bright line test to determine whether a project requires a PSD permit. However, the Trump EPA did not accomplish any regulatory changes to this effect and legislation stagnated. In 2021, the Biden EPA has not made any significant changes to the NSR Program. However, on October 12, 2021, the EPA disclosed plans to initiate a rulemaking process to consider revisions to NSR regulations. EKPC will monitor future developments.

II. EGU Mercury Air Toxics Standards

On March 16, 2011, EPA issued the proposed EGU MACT rule to reduce emissions of toxic air pollutants from new and existing coal- and oil-fired EGUs. EPA 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 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.

Since the MATS rule is a Section 112 rule, other provisions in § 112 are relevant. Namely, Section 112(d)(6) requires EPA to "review and revise as necessary emission standards promulgated under this section no less often than every 8 years." Also, Section 112(f) states, among other things, "if standards promulgated pursuant to subsection (d) and applicable to a category or subcategory of sources emitting a pollutant (or pollutants) classified as a known, probable or possible human carcinogen do not reduce lifetime excess cancer risks to the individual most exposed to emissions from a source in the category or subcategory to less than one in one million, the Administrator shall promulgate standards under this subsection for such category." Taken together, these two provisions constitute what is called EPA's Risk and Technology Reviews ("RTR").

On December 27, 2018, EPA proposed to revise the Supplemental Cost Finding for MATS and the Clean Air Act required RTR. EPA promulgated the MATS RTR Final Rule on May 22, 2020. The Rule dictates that MATS remain in place although it concluded that it was not "appropriate and necessary" to regulate HAPs for EGUs. The Rule found that the costs of regulation outweigh the benefits of HAP emissions reductions. No change in the MATS Rule occurred as a result of this rulemaking. The MATS RTR Final Rule is on the Biden Administration's list of rules to be reconsidered. In response, EPA has reconsidered the Final Rule. Presently, the Office of Budget and Management ("OMB") is reviewing EPA's proposal entitled, "NESHAP: Coal- and Oil-Fired Electric Utility Steam Generating Units--Reconsideration of Supplemental Cost Finding and Residual Risk and Technology Review." The content of the rulemaking has not been released.

EKPC continues to comply with the MATS Rule using a combination of strategies. The pollution control upgrades on Spurlock 1 and 2 and Cooper 2 as part of the NSR Consent Decrees, 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. The dry scrubbed units in the EKPC coal-fired fleet have achieved low emitting EGU ("LEE") status for HCl. EKPC is currently in compliance with MATS requirements and monitors its units to assure ongoing compliance.

III. <u>Cross-State Air Pollution Rule</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 NAAQS. The rule called for the first phase emission reduction compliance to begin January 1, 2012 for annual SO_2 and NO_X and May 1, 2012 for ozone season NO_X. 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, EPA asked 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 did not affect the SO_2 allocations or the NOx allocations for 2015 and 2016. The D.C. Circuit in *Wisconsin v. EPA*, 938 F.3d 303 (D.C. Cir. 2019) found that CSAPR II only partially addressed downwind contributions from upwind states by the 2018 moderate ozone nonattainment NAAQS attainment date. The court remanded the rulemaking back to EPA. In response to the remand, the EPA Administrator signed the final CSAPR Update Rule on March 15, 2021 (the 2021 CSAPR Update).

EPA adopted substantial emission reductions for electric generating units ("EGUs") in 12 states beginning in the 2021 summer ozone season, with diminishing reductions in 2022-2023 that reduce NOx seasonal allowance allocation budgets and current banked allocations held by EGUs. State-wide NOx Ozone Season Emission Budgets reduce allocations based on optimization of existing SCRs and SNCRs. Kentucky is included among the 12 states that must participate in a new CSAPR NOx Ozone Season Group 3 Trading Program similar to the Group 2 Trading Program. EPA justified further reducing emissions from these states because it found that the states' projected 2021 emissions contribute at or above a threshold of 1% of the NAAQs (0.75 ppb) to the identified nonattainment and/or maintenance problems in downwind states.

The 2021 CSAPR Update made meaningful material reductions in the allocation budgets of the EKPC fleet. EKPC will be closely monitoring its ozone season NOx emissions to determine whether its allocations will continue to cover the NOx tons emitted. EKPC's state-of-the-art NOx controls are already optimized with little headroom for improvement. Therefore, EKPC would be required to address any shortfall via purchase of NOx allowances, projected at a premium cost, or unit curtailment since EPA significantly reduced the banked allowances earned as super compliance.

EKPC filed comments in the federal rulemaking docket for the 2021 CSAPR Update as did other utilities and the Midwest Ozone Group ("MOG"), of which EKPC is a member. MOG has challenged the 2021 CSAPR Update Rule in the D.C. Circuit in *Midwest Ozone Group v. EPA and Administrator Regan*. MOG argues that EPA undertook inappropriate "shortcuts," in computer modeling, procedurally, carved out banked allowances without notice and otherwise when addressing the D.C. Circuit's remand of the rule. A decision is not expected until mid to late 2022.

CSAPR is due for an update, even though the 2021 CSAPR Update was just issued. The 2021 CSAPR Update is based on the 2008 Ozone NAAQS standard of 0.075 ppm. EPA will update CSAPR to align with the 2015 Ozone NAAQS standard of 0.070 ppm. It is likely that EPA will propose the reduction of allocations beyond the tightened budgets in place for 2021-2023 due to the more stringent 2015 Ozone NAAQS standard. We project this change to take effect in 2023, or thereafter.

IV. <u>GHG Tailoring Rule</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_{2e}, EKPC must have obtained an NSR permit for the modification including the installation of 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. On October 3, 2016, EPA responded to the Court's action by issuing a Proposed Rule that sets the GHG significant emissions rate at 75,000 tons per year or more of CO_2. But until EPA issues a Final Rule, the GHG threshold will not be set. EKPC is tracking these developments.

V. <u>National Ambient Air Quality Standards ("NAAQS")</u>

If a county or counties is designated to be in nonattainment for a NAAQS, the Cabinet will work with major sources contributing to nonattainment to implement 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. <u>CO</u>

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 31, 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. SO_2

EPA revised the primary SO2 NAAQS in June 2010 to a one-hour standard of 75 ppb. The current secondary 3-hour SO_2 standard is 0.5 ppm. On March 18, 2019, EPA issued a Final Rule to keep the existing one-hour primary standard of 75 parts ppb of SO_2 after weighing potential changes, including altering the formula for how the agency determines whether an area is attaining or violating the NAAQS. This rulemaking is one of the rulemakings to be reconsidered by EPA under a Biden EO entitled *Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis*, dated January 20, 2021. However, this action did not appear in the list of agency actions to be reviewed in the non-exclusive list published on that same date.[15] It also does not appear in the most recent 2021 Unified Agenda under the list of EPA actions to be reconsidered.[16]

In 2011, Jefferson County, adjacent to Oldham County where Bluegrass Station is located, was designated as a non-attainment area. However, it has been converted to a maintenance area. A gas-fired facility can control SO_2 using low sulfur fuels. EKPC's coal-fired units are located in areas in attainment with the SO2 NAAQS. EKPC will continue to monitor future developments, should the Biden Administration attempt to lower the SO_2 NAAQS either in the normal statutory course of NAAQS five-year reviews (CAA, Section 109) by the Clean Air Scientific Advisory Committee ("CASAC") or by reconsideration of the 2019 final rule.

C. NO_2

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

[15] *Fact Sheet: List of Agency Actions for Review*, www.whitehouse.gov (Jan. 20, 2021).

[16] 2021 EPA Unified Agenda (07/30/2021), https://www.federalregister.gov/documents/2021/07/30/2021-14882/spring-2021-unified-agenda-of-regulatory-and-deregulatory-actions.

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. On April 18, 2018, EPA finalized its periodic review of the NO_2 NAAQS one-hour standard of 100 ppb and the annual standard of 53 ppb to determine if these existing standards are protective of public health and welfare. EPA retained both standards without revision.

D. Ozone

On December 20, 2017, EPA provided notice to Governor Bevin of 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 ppm to 0.070 ppm. On December 31, 2020, EPA finalized its review of the Ozone NAAQS and decided to maintain the current standard (0.070 ppm). However, the Biden Administration has opted to reconsider this rulemaking. It is also subject to the CRA. *See* 85 Fed. Reg. 87256 (Dec. 31, 2020).

The 2015 NAAQS Ozone Standard designations affect Bluegrass Station, 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. The 2017-2019 three-year average was below the level of the standard for all Kentucky sites except for Cannons Lane (Jefferson County), although Oldham County remains designated marginal nonattainment. EKPC will follow developments and assess any impacts on Bluegrass Station.

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

In 1997, EPA adopted the 24-hour fine particulate NAAQS ("$PM_{2.5}$") of 65 μg/m^3 and an annual standard of 15 μg/m3. In 2006, EPA revised this standard to 35 μg/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 μg/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 non-attainment. EKPC does not have facilities in these counties. On December 18, 2020, EPA finalized its review of the PM NAAQS and decided to maintain the current standard. However, the Biden Administration has opted to reconsider this rulemaking. It is also subject to the Congressional Review Act ("CRA"). *See* 85 Fed. Reg. 82684 (Dec. 18, 2020).

On October 8, 2021, EPA published a draft Policy Assessment paper that provides the scientific basis and recommendation to make the $PM_{2.5}$ NAAQS more stringent. The magnitude of any decrease may impact EKPC facilities in other counties. At present, Kentucky reports in its Annual Report for 2021 that the $PM_{2.5}$ values in Kentucky have decreased over time from 1999 to present with a current state-wide average lower than the present standard of 12 μg/m3 (below 10 μg/m3). *See* Kentucky's Air, Kentucky Division for Air Quality, 2021. Emission values remain the highest in counties near the Louisville metropolitan area. It is uncertain whether EPA can justify a reduction to the degree that it will impact counties outside of the Louisville area.

F. Lead

In October 2008, EPA strengthened the primary lead NAAQS from 1.5 μg/m^3 to 0.15 μg/m^3 in a three month period averaging time. EPA has designated the Commonwealth as unclassifiable/attainment for the lead NAAQS. EPA retained this standard on October 18, 2016 in a Final Rule.

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 on April 8, 2019. 84 Fed. Reg. 13800 (Apr. 8, 2019). EKPC installed SO_2, NOx and PM controls on Spurlock 1 and 2 and Cooper 2 to comply with the NSR Consent Decrees, the Regional Haze rule, MATS, CSAPR and any NAAQS requirements. At this point, Spurlock and Cooper Stations' compliance with CSAPR equals Regional Haze Rule/BART compliance. EPA re-affirmed that CSAPR compliance is sufficient to meet Regional Haze criteria. 85 Fed. Reg. 40286 (July 6, 2020). EKPC's coal-fired fleet has remained in compliance with BART since its compliance date of April 2017 and is in compliance with the BART provisions in its Title V permits. The Program requires reasonable progress reports every five years and revised Regional Haze Plans every 10 years. The next plan revision is due in 2028.

Regional Haze goals could become more stringent, if EPA determines in the future that CSAPR no longer satisfies BART compliance goals. It is also possible that EPA could alter the BART analysis using differing modeling inputs, visibility benefits, and cost analysis (e.g., with the addition of social costs) to require a more stringent BART Plan. In this way, EPA could choose to use BART as a mechanism to seek future NOx and SO2 reductions from the power sector. At present, changes to the BART program are uncertain.

VII. <u>New Source Performance Standards Under Sections 111(b) and 111(d) for Carbon Dioxide Emissions</u>

Regulation of carbon dioxide emissions under the New Source Performance Standards (NSPS) in the CAA have fluctuated considerably in the last five years. EPA has attempted to put in place NSPS requirements for CO_2 that apply to new sources (Section 111(b)) and existing sources (Section 111(d)), which has become a politically charged issue. This section briefly summarizes past efforts and the current status of regulations.

A. Clean Power Plan

The Obama Administration promulgated the final CPP in 2015. 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 Supreme Court stayed the CPP on February 9, 2016.

On March 28, 2017, President Trump signed EO 17833, entitled *Promoting Energy Independence and Economic Growth*, directing the 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 on 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. Rather than finalizing this Proposed Rule, EPA opted to repeal the CPP in the ACE rulemaking, discussed *infra*.

This repeal positively impacted EKPC. The prior rule assumed an unrealistic improvement in efficiency from coal units. EKPC is a leader in heat rate improvement measures and has some of the best performing units. Most of the feasible efficiency improvements have been made and any additional requirements may unfairly penalize EKPC for having made these improvements.

B. Affordable Clean Energy Rule

EPA issued the Proposed (ACE Rule to replace the CPP on August 21, 2018. EPA's general approach to the rule was to clarify the federal and state roles in rulemaking known as cooperative federalism, with particular emphasis on granting states more authority to make decisions about how to implement the ACE. EPA published the Final ACE Rule on July 8, 2019. The ACE Final Rule repealed and replaced the CPP. EPA sets BSER and provides guidance to the states on how to apply BSER. States apply BSER on a unit basis to set standards of performance (short term CO_2 emissions rate limits CO_2 lbs./MWh). States are charged with examining potential technologies and operation and maintenance practices that could potentially improve the efficiency of individual coal units and result in a reduction in CO_2 emissions. The units will combust less coal but generate the same amount of electricity. All resulting limits must be set based on the CO_2 emissions rate from a unit (pounds of CO_2 emitted per megawatt hour generated). States have three years to prepare a plan implementing the Rule. EKPC worked on the implementation process in 2020 to provide information to Kentucky in preparation for its plan submittal. The Kentucky Division of Air Quality ("DAQ") granted an extension to the EGUs in Kentucky until Spring of 2021.

The Final ACE Rule was challenged in the D.C. Circuit by numerous ENGOs and public health organizations, with states and industry participation in amicus curiae briefing in *American Lung Ass'n v. EPA*. On January 19, 2021, the D.C. Circuit vacated ACE, the CPP Repeal Rule and the challenged timing provisions within the implementing regulations, and remanded the actions to EPA for further proceedings consistent with its opinion.[17] The Court did not expressly reinstate the CPP. EPA has followed up in a memorandum to the EPA Regions to clarify that states do not have any current obligations under the CPP or ACE. DAQ postponed their requirement indefinitely for EGUs to submit ACE plans.

To summarize, there is currently no Section 111(d) rule in place for existing power plants. Leadership in the Biden Administration indicates that the CPP will not be reinstated. Rather, industry anticipates EPA to develop and propose a new Section 111(d) rule to reduce carbon dioxide emissions from existing coal-fired EGUs as well as other significant industrial sources (transportation, oil and gas industry) post-oral arguments and a hearing of WV v. EPA by the Supreme Court that began February 28, 2022. To the extent the Biden EPA has made any decisions regarding how to proceed in developing Section 111(d) rules, no specifics have been made public. EPA could pursue a specific carbon emission limit, plant-wide caps, technology requirements, a trading program, or a combination thereof. EKPC will continue to monitor regulatory developments and their impact on their fleet.

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[17] *American Lung Ass'n v. EPA*, 2021 WL 162579 (D.C. Cir. Jan. 19, 2021).

C. CO2 NSPS for New Utility Coal and Natural Gas units (Section 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 determines 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 highly efficient subcritical units. The resulting emissions limits (Table 1) apply to new and reconstructed EGU and are a floor for modified EGUs. Coal refuse EGUs have a slightly higher limit.

Table 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 CO2/MWh-gross for sources with heat input > 2,000 MMBtu/h** **2. 2,000 lb CO2/MWh-gross for sources with heat input ≤ 2,000 MMBtu/h or** **3. 2,200 lb CO2/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 CO2 emission rate (from 2002 to the date of the modification); the emission limit will be no more stringent than** **1. 1,900 lb CO2/MWh-gross for sources with heat input > 2,000 MMBtu/h** **2. 2,000 lb CO2/MWh-gross for sources with heat input ≤ 2,000 MMBtu/h** **or** **2,200 lb CO2/MWh-gross for coal refuse-fired sources**

There is no change to new unit limits for combustion turbines, including NGCC units. These limits are:

1. 1,000 lb CO2/MWh-g or 1,030 lb CO2/MWh-n for base load natural gas-fired units.
2. 120 lb CO2/MMBtu for non-base load natural gas-fired units.
3. 120 to 160 lb CO2/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 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. No Final Rule has been issued.

However, EPA did issue a *Pollutant-Specific Significant Contribution Finding for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units, and Process for Determining Significance of Other New Source Performance Standards Source Categories*, 86 Fed. Reg. 2542 (Jan. 13, 2021). This final rule provides criteria for making a significant contribution finding for GHG emissions from a source category, for the purpose of regulating those emissions under Section 111(b) of the CAA. The framework sets an emissions threshold of 3 percent of total gross United States GHG emissions from a stationary source category as the primary criterion in making a pollutant-specific significance determination. This rulemaking is on the Biden Administration's list of rulemakings to be reconsidered, although EPA has not acted on this final rule to-date.

NON-CAA RULES WITH REGULATORY CHANGES

For completeness EKPC is providing a summary of new CWA rules and Proposed Rules to change portions of the CCR rule.

A. CWA Section 316(a)

The CWA, Section 316(a) applies to point sources with thermal discharges. It authorizes the NPDES permitting authority – the Kentucky Division of Water ("KDOW") – to impose alternative thermal effluent limitations in lieu of the requirements that would be required under Sections 301 and 306 of the CWA. To obtain an alternative effluent thermal limitation, the permittee must demonstrate that the thermal limit is stringent enough to assure protection and propagation of a balanced, indigenous population ("BIP") in and on the body of water into which the discharge is made.

Cooper Station currently has an alternative thermal effluent limit (daily maximum limit of 100 degrees F) under Section 316(a) at Outfall 003, which handles once-through cooling water. Condition 5.7 of Cooper Station's KPDES permit requires that EKPC request continuation of this limitation in its next KPDES permit renewal application, which is due by December 31, 2022. EKPC plans to request that KDOW renew this alternative limit.

EKPC is in the process of developing a thermal plan study to support the renewal of this alternative thermal limit. The demonstration will include consideration of the following key elements, which is consistent with EPA Region 4 guidance:

- biotic community typically characterized by diversity;
- the capacity to sustain itself through cyclic seasonable changes;
- presence of necessary food chain species; and
- lack of domination of pollution-tolerant species.

In addition, EKPC will follow the KDOW guidance issued in 2019 for permittees seeking thermal variances under Section 316(a). EKPC met with KDOW in June 2019 to discuss EKPC's demonstration plan. KDOW concurred with EKPC's plan. EKPC is preparing the demonstration to apply for renewal of the alternative thermal limitation.

B. **CWA 316(b) Rule**

The Clean Water Act, Section 316(b) regulates cooling water intake structures ("CWIS") at existing facilities. 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.

EKPC is currently in compliance with Section 316(b) at its two active coal-fired facilities subject to the Rule: Spurlock and Cooper Stations. These plants hold a Kentucky Pollutant Discharge Elimination System ("KPDES") permit. KDOW has the discretion to determine the plant-specific entrainment mortality mitigation requirements each time the KPDES permit comes up for renewal and to set a schedule for implementation of any new controls.

Spurlock Station's KPDES permit was issued by KDOW 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. EKPC does not anticipate additional future requirements given the cooling water system, metrics, and lack of threatened or endangered species in the Ohio River.

With respect to Cooper Station, its KPDES permit has 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. KDOW must make an entrainment BTA determination under §125.98(f). EKPC will provide the Director with the relevant information to support the BTA decision with its Section 316(b) information submittal. EKPC believes that its current system is BTA for impingement and entrainment.

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

On November 3, 2015, EPA published the ELG final rule to regulate the quality of the wastewater that can be discharged from power plants. The ELG rule identifies effluent limits for arsenic, mercury, selenium, and nitrogen discharged from wet scrubber systems and zero discharge of pollutants in ash transport water. The original rule identified compliance between 2018 and 2023, depending upon a plant's NPDES permitting deadlines. The ELG rule was challenged in the United States Court of Appeals for the Fifth Circuit, which has resulted in further changes to the ELG rule as remanded by the court to EPA as to legacy wastewater and combustion residual leachate. On October 13, 2020, EPA promulgated the 2020 ELG Reconsideration final rule that establishes effluent limits for flue gas desulfurization ("FGD") wastewater and for bottom ash ("BA") transport water applicable to existing steam electric power generators, exclusively and did not revise any other waste streams. 85 Fed. Reg. 64650 (Oct. 13, 2020). The Biden Administration has identified this Rule in the list to be reconsidered and, on June 26, 2021, EPA announced decision to reconsider the stringency of the ELG regulations, promulgated under the Trump EPA. EPA plans to issue rulemaking by fall of 2022 and final rule in 2023.

Although ELG is a regulatory driver for many facilities, EKPC is well-positioned for compliance. Spurlock Station is installing a wastewater treatment system to handle wastewater prior to solid clarification and discharge (the Wastewater Treatment Project). The resulting effluent will be compliant with ELG BAT limitations. EKPC anticipates completion of the Wastewater Treatment Project prior to expiration of the Spurlock KPDES permit in September 2023.

D. **Waters of the United States**

WOTUS is a term that delineates federal jurisdiction over "navigable waters" under the Clean Water Act. It defines the scope of Clean Water Act programs such as water quality standards, oil spill prevention and preparedness, impaired waters and total maximum daily loads, NPDES permitting (discussed *supra* in the context of the ELG and Section 316 regulations), and permitting discharges of dredged or fill material. EKPC must comply with many of these Clean Water Act programs, which requires tracking any changes to the definition of WOTUS. Since EKPC borrows money from RUS, the National Environmental Policy Act is applicable to all EKPC capital projects. Capital projects are vetted through the 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 WOTUS, the permit applicant must submit a mitigation plan and/or pay the mitigation fees, bank or self-mitigate the project.

The definition and scope of WOTUS has undergone political shifts lately, similar to the Section 111 air regulations. The Obama Administration released the 2015 WOTUS Rule that more broadly construed WOTUS than the prior Regulatory Definition of "Waters of the United States" from 1986/1988. On January 23, 2020, EPA, under the Trump Administration, and the Department of Army issued the Final Navigable Waters Protection Rule (the Navigable Waters Rule), which completed the two steps involved to rescind the 2015 Rule and revise the regulatory definition of WOTUS, which was published on April 21, 2020. 85 Fed. Reg. 22250 (Apr. 21, 2020). The Final Rule became effective on June 22, 2020 but was subject to federal district courts challenges across the country. On August 30, 2021, the federal district court in Arizona in *Pascia Yaqui Tribe v. EPA* vacated and remanded the Navigable Waters Rule to EPA. Based on this court order, EPA halted implementation of the Navigable Waters Rule. EPA is presently interpreting WOTUS using the "pre-2015 definition." However, EPA is working toward replacing the Navigable Waters Rule. On November 18, 2021, EPA released a pre-publication version of a proposed rule to revise WOTUS. The proposed rule calls for the reinstatement of the pre-2015 definition of WOTUS with updates to reflect relevant Supreme Court decisions. Kentucky previously utilized the pre-2015 definition for WOTUS and waters of the Commonwealth, therefore EKPC has experience with this interpretation.

E. **Coal Combustion Residual Rule**

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 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. Pursuant to the WIIN Act, EPA proposed to establish a federal CCR permit program for CCR management units. 85 Fed. Reg. 9940 (Feb. 20, 2020). The public comment period has concluded. No final rule has been promulgated. At this juncture, only Texas, Oklahoma, and Georgia have approved CCR state programs.

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. EPA published a final rule extending certain CCR compliance deadlines on July 30, 2018, known as Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; Amendments to the National Minimum Criteria (Phase One, Part One), 83 Fed. Reg. 36435 (July 30, 2018). This Rule is on the list of rules to be reconsidered by the Biden Administration.

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 *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.

In 2019, EPA published proposed rules that provided for substantial changes to the CCR federal regulatory scheme, many of which were in response to the *USWAG* decision and finalized some of these rules in 2020. These proposed and final rules include:

- Proposed Rule: Enhancing Public Access to Information; Reconsideration of Beneficial Use Criteria and Piles, 84 Fed. Reg. 403 53 (Oct. 15, 2019) (Some of the proposals were finalized in the Closure Part A Rule).
- Proposed Rule: Federal CCR Permit Program.
- Final Rule: Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; A Holistic Approach to Closure Part A: Deadline To Initiate Closure, 85 Fed. Reg. 53516 (Aug. 28, 2020) (Closure Part A).

- Final Rule: Hazardous and Solid Waste Management System: Disposal of CCR; A Holistic Approach to Closure Part B: Alternate Demonstration for Unlined Surface Impoundments, 85 Fed. Reg. 72506 (Nov. 12, 2020) (Closure Part B).

Although in each of these rulemakings, EPA has suggested significant changes and additions to the CCR Rule provisions for beneficial use, reporting, website posting, and impoundment liners, the Final Rules concerning closure have the most impact on EKPC's CCR compliance strategy.

On August 28, 2020, EPA issued revisions to the CCR Rule that require all unlined surface impoundments to cease receipt of CCR and non-CCR waste and initiate closure by April 11, 2021, unless an alternative deadline is requested and approved. 40 CFR § 257.101(a)(1), (b)(1) (85 Fed. Reg. 53516 (Aug. 28, 2020)), known as *Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; A Holistic Approach to Closure Part A: Deadline To Initiate Closure* (Closure Part A.) Specifically, owners and operators of a CCR surface impoundment may seek and obtain an alternative closure deadline by demonstrating that there is currently no alternate capacity available on or off-site and that it is not technically feasible to complete the development of alternative capacity prior to April 11, 2021. 40 CFR § 257.103(f)(1). To make this demonstration, the facility is required to provide detailed information regarding the process the facility is undertaking to develop the alternative capacity by November 30, 2020. 40 CFR § 257.103(f)(1). Any extensions granted under this Section cannot extend past October 15, 2023, except an extension can be granted until October 15, 2024, if the impoundment qualifies as an "eligible unlined CCR surface impoundment" as defined by the rule. 40 CFR § 257.103(f)(1)(vi). Regardless of the maximum time allowed under the rule, EPA explains in the preamble to the Part A rule that each impoundment "must still cease receipt of waste as soon as feasible, and may only have the amount of time [the owner/operator] can demonstrate is genuinely necessary." 85 Fed. Reg. at 53546.

Prior to *USWAG*, facilities that are not considered lined by the CCR Rule but are not impacting groundwater were not subject to closure, such as the impoundment at Spurlock Station. To mitigate from this harsh outcome for sufficiently protective lined CCR Units, EPA made further revisions, promulgating *Hazardous and Solid Waste Management System: Disposal of CCR; A Holistic Approach to Closure Part B: Alternate Demonstration for Unlined Surface Impoundments* (Closure Part B) on November 12, 2020. 85 Fed. Reg. 72506 (Nov. 12, 2020). The Closure Part B Rule finalized a process for unlined impoundments to operate with an alternate liner approved by EPA or a Participating State Director as part of an Alternate Liner Demonstration ("ALD"). *Id*. Specifically, owners and operators of a CCR surface impoundment may submit an ALD to the Administrator or the Participating State Director to demonstrate that, based on the construction of the unit and surrounding site conditions, there is no reasonable probability that continued operation of the surface impoundment will result in adverse effects to human health or the environment. 85 Fed. Reg. at 72539-42 (adding 40 CFR § 257.71(d)). To make this demonstration, applications were due on November 30, 2020, although the effective date of the Closure Part B Rule is December 14, 2020. If the application is approved, facilities perform field work and analysis to prepare a comprehensive final ALD package no later than November 30, 2021. The Biden Administration has listed both the Closure Part A and Closure Part B rules for reconsideration.

The EKPC facilities are in compliance with the CCR Rule. Spurlock Station has three regulated CCR units (1 surface impoundment and 2 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. Therefore, the Spurlock surface impoundment is EKPC's only surface impoundment regulated by the CCR Rule.

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. However, the Spurlock surface impoundment is unlined per the CCR Rule. The Final Closure Part A Rule dictates that EKPC cease placement of CCR material in the impoundment by April 11, 2021 due solely to the lack of a compliant liner.

EKPC has proactively pursued a CCR compliance plan, which has been under development for more than three years. In 2018, EKPC obtained approval by the Public Service Commission for its Clean Closure Plan to close the Spurlock Station surface impoundment by removal. To achieve this clean closure, the Wastewater Treatment Project will divert the handling of certain CCR streams away from the impoundment and, instead, to solids clarification, evaporation, and finally to a permitted CCR landfill. EKPC estimates that the Wastewater Treatment Project will be complete by 2023, the timing depending on a number of factors, such as construction timing, equipment availability, and weather. EKPC has no other alternative capacity options for CCR storage in the interim. EKPC has applied for an extension pursuant to the Closure Part A Rule. EKPC timely submitted its extension request by November 20, 2020. EKPC's bottom ash and fly ash flows can be rerouted prior to April 11, 2021, but EKPC requires an extension for other CCR and non-CCR flows until November 30, 2022. Fifty-seven (57) facilities requested an extension past April 11, 2021. Of the fifty-seven (57) applications submitted, EPA determined that four applications were incomplete, one application is ineligible and the rest are complete. EPA issued four decisions on the complete applications, including three proposed denials, and one proposed conditional approval for EKPC H.L. Spurlock Station. The remaining applications were deemed complete but will come at a later date post closure of the commentary period February 23, 2022. EKPC and three other facilities requested a 60-day extension. EPA granted a 30-day extension to the public commentary period that effectively closes March 25, 2022. Due to early planning and execution, EKPC has placed itself in a favorable compliance position by pursuing its CCR compliance strategy before many of its utility counterparts.

9.2 Future Compliance

As noted in Section 2.0, EKPC has identified the following future rules listed below from the EPA and Whitehouse Unified Agenda pending further action by the United States Executive Branch, Office of Management Budgets ("OMB") and the federal Environmental Protection Agency ("EPA"). The following future rules could have a material impact to the generation and transmission assets but the rules have not been publicized nor have they appeared in the federal registry. Therefore, EKPC is not in compliance nor is it required to comply with the following future rules just yet.

Particulate Matter NAAQS Updates

Proposed Rule: August 2022 **Final Rule: Expected March 2023**

EPA has begun to reconsider the Trump EPA's final rule to retain the national ambient air quality standard ("NAAQS") for fine particulate matter (PM2.5). Notably, EPA staff is recommending in the supplemental science assessment to tighten the annual $PM_{2.5}$ standard and is examining lowering the $PM_{2.5}$ standard from 12 μg/m^3 to 11 or even 10 μg/m^3. EPA's review of the $PM_{2.5}$

standard is scheduled to be completed by Spring 2023. If EPA decides to tighten the $PM_{2.5}$ annual NAAQS (as most expect), this more stringent standard will require further source-specific SO_2 and NO_x emission controls from coal-fired power plants and other major stationary sources of these two air pollutants. These additional controls could be imposed by states for addressing local nonattainment problems through state implementation plans ("SIPs") or by EPA in order to address downwind nonattainment problems in other states through a new federal interstate transport rule. A change in the $PM_{2.5}$ NAAQS will create many additional non-attainment areas. Additionally, EKPC plants (coal-fired power plants specifically) may not meet the lower NAAQS standards. State agencies may require modeling to show compliance or EKPC facilities may be modeled by others and noncompliance may be shown.

Source: Unified Agenda, RIN 2060-AV52,
https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202110&RIN=2060-AV52

Ozone NAAQS Updates

Proposed Rule: December 2023 **Final Rule: EPA TBD**

EPA announced its decision to conduct an expedited review of the Trump's decision not to tighten the ozone NAAQS. EPA will fast track the review of the ozone NAAQS by supplementing the formal Trump EPA rulemaking review with analysis of additional scientific studies and thereby complete its review by December 2023 instead of taking the full five years. Based on initial reports, the ozone standard could be tightened from 70 parts per billion ("ppb") to 65 or 60 ppb. Such a tightening of the ozone standard would likely result in the imposition of addition SIP control measures from major sources of NOx emissions, including coal-fired power plants, in order to achieve the more stringent ozone NAAQS in many parts of the country. These additional NOx emissions controls could be imposed by states for addressing local nonattainment problems through SIP control measures or by EPA in order to address downwind nonattainment problems in other states through a new federal interstate transport rule. A change in the ozone NAAQS would create many additional non-attainment areas.

Source: Unified Agenda, RIN: 2060-AV33
https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202110&RIN=2060-AV33

Social Cost of Carbon

Proposed Rule: August 2022 **Final Rule: Expected March 2023**

The White House has established an interagency working group that will establish new metrics for the social cost of carbon ("SCC"). As a general matter, EPA and other federal agencies are using the SCC as a benchmark for estimating the damages associated with incremental increases in Greenhouse Gas ("GHG") emissions and the benefits of reducing GHG emissions under regulatory programs. CO2 abatement costs below the SCC benchmark could thereby be used to justify the imposition of those control requirements under that particular regulatory program. The Biden administration has increased the SCC metric from $8 to $51 per ton of CO2 as the new "interim" value for the SCC. This SCC value is likely to increase further – most likely to a value substantially over $100 per ton of CO2 – once the Biden administration completes its re-assessment of the SCC metric sometime in 2022. The SCC will be instrumental in the development of the ACE Rule replacement. The SCC will determine the cost of controls that may be justified under the proposed rule so the higher the SCC, the more cost of control that may be justified.

Source: Technical Support Document, https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf

Mercury and Air Toxics Standards (MATS or NESHAP for Coal- and Oil-Fired Electric Utility Steam Generating Units)

Notice of Proposed Rulemaking: June 2022 **Final Rule: Expected mid-2024**

On January 31, 2022, EPA issued a proposed rule to undertake several regulatory actions under the Mercury and Air Toxics Standards ("MATS") rule. The first change is to reinstate some language that was removed but has no practical effect on coal utilities since the MATS emissions limitations for coal-fired power plants were maintained in the MATS rule, and these sources have already complied with the MATS rule.

The second change includes an EPA request for the submission of additional information on new technologies, techniques, and measure that could justify tightening the current MATS limitations in the future. This information request effectively opens the door for EPA to tighten the current MATS limitations. EPA could attempt to justify the adoption of those tighter HAP limitations based on additional technical and cost information on controlling HAP emissions from coal-fired power plants along with the new information that EPA has just now developed on the health benefits of controlling HAPs emission under the MATS rule. The tightening of the MATS limitations could have major regulatory impacts on a significant portion of the coal fleet. Since this regulatory effort would require EPA to initiate an entirely new notice and comment rulemaking, the promulgation of a final rule by EPA to tighten the MATS limitations under an updated technology review would most likely not occur until sometime in 2024.

Additionally, the regulatory agenda for the EPA describes that the Agency will issue the MATS rule pursuant to section 610 of the Regulatory Flexibility Act (5 U.S.C. 610) to determine if the provisions that could affect small entities should be continued without change or should be rescinded or amended to minimize adverse economic impacts on small entities. As part of this review, EPA is considering comments on: 1) The continued need for the rule; 2) the nature of complaints or comments received concerning the rule; 3) the complexity of the rule; 4) the extent to which the rule overlaps, duplicates, or conflicts with other Federal, State, or local government rules; and 5) the degree to which the technology, economic conditions or other factors have changed in the area affected by the rule.
Source: Unified Agenda, RIN: 2060-AV12, 2060-AV53, 2060-AV08,
https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202110&RIN=2060-AV12
https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202110&RIN=2060-AV53
https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202110&RIN=2060-AV08

Cross-State Air Pollution Rule (CSAPR) 3.0 implementing 2015 Ozone NAAQs
Proposed Rule: Expected February 28, 2022 Final Rule: Expected December 15, 2022
EPA issued in March 2021 a revised Cross-State Air Pollution Rule ("CSAPR") that imposed a more stringent set of NOx control requirements for fossil-fueled power plants located in 12 states in the eastern half of the United States. The EPA is now shifting its focus to the development of an ozone interstate transport for meeting the 2015 NAAQs standard. Although still in the early stages, this transport rule is expected to impact the electric power sector (including coal-fired power plants) in two ways. First, it could require the installation of NOx SCR control systems on any remaining coal-fired power plants without these state-of-the-art controls. Second, it could

require additional NOx reduction on those coal-fired power plants with SCR control systems by requiring enhanced catalysts and performance optimizations of these existing SCR control systems.

Source: Unified Agenda, RIN 2060-AS74,

https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202110&RIN=2060-AS74

https://www.epa.gov/csapr/nox-ozone-season-group-3-trading-program-under-revised-cross-state-air-pollution-rule-csapr

https://www.epa.gov/sites/default/files/2021-03/documents/revised_csapr_update_factsheet_for_final_rule.pdf

Replacement of the ACE Rule

Notice of Proposed Rulemaking: Expected July 2022 Final Rule: Expected July 2023

EPA has an obligation to adopt a new rule that would set performance standards to limit CO_2 emissions from existing fossil-fueled power plants under section 111(d) of the CAA. This new rule will replace the Affordable Clean Energy ("ACE") rule that the D.C. Circuit invalidated last January along with the Clean Power Plan ("CPP") rule that EPA repealed during the Trump Administration. The rulemaking schedule for EPA's development of an ACE replacement rule is uncertain at this time although the most recent unified regulatory agenda indicates that a proposed rule is expected by July 2022 and a final rule by July 2023. Uncertainty also exists on the framework of stringency of any future replacement rule that EPA may adopt. Further clarity on these important substantive rulemaking matters will largely be addressed by the Supreme Court in the pending ACE/CPP litigation. In particular, the Supreme Court will likely rule on the extent of EPA's authority to regulate CO_2 emissions from coal-fired power plants under section 111(d) of the CAA – specifically, whether EPA has authority to set CO2 performance standards based on "beyond the fence control measures," such as generation shifting from coal-fired to renewable energy generation.

Source: Unified Agenda, RIN: 2060-AV10

https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202110&RIN=2060-AV10

https://www.epa.gov/stationary-sources-air-pollution/electric-utility-generating-units-advance-notice-proposed

Electric Generating Unit GHG New Source Performance Standard

Notice of Proposed Rulemaking: Expected June 2022 Final Rule: Expected June 2023

On October 23, 2015, the EPA finalized Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Generating Units, found at 40 CFR Part 60, subpart TTTT. On December 20, 2018, the EPA proposed to revise the standards of performance in 40 CFR Part 60, subpart TTTT. The EPA proposed to amend the previous determination that the best system of emission reduction (BSER) for newly constructed coal-fired steam generating units (i.e., EGUs) is partial carbon capture and storage, and replace it with a determination that BSER for this source category is the most efficient demonstrated steam cycle (e.g., supercritical steam conditions for large units and subcritical steam conditions for small units) in combination with the best operating practices. The EPA is undertaking a comprehensive review of the NSPS for greenhouse gas emissions from EGUs, including a review of all aspects of the 2018 proposed amendments and requirements in the 2015 Rule that the Agency did not propose to amend in the 2018 proposal. More to come in 2022.

Source: Unified Agenda, RIN 2060-AV09 and 2060-AV10

https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202110&RIN=2060-AV09

Emissions Monitoring and Reporting Requirements for Fossil EGUs

Notice of Proposed Rulemaking: Expected July 2022 Final Rule: Expected after July 2022

On January 19, 2021, the D.C. Circuit Court issued an opinion vacating the Affordable Clean Energy Rule (found at 40 CFR part 60, subpart UUUUa) – the previously applicable emission guidelines for GHG emissions from existing electric generating units ("EGUs"). The EPA is working on a new set of emission guidelines for states to follow in submitting state plans to establish and implement standards of performance for greenhouse gas emissions from existing fossil fuel-fired EGUs.

PSD and NNSR: Reconsideration of Fugitive Emissions Rule

Notice of Proposed Rulemaking: Scheduled June 2022 Final Rule: TBD

The EPA is reconsidering the final rule titled "Prevention of Significant Deterioration ("PSD") and Nonattainment New Source Review ("NSR"): Reconsideration of Inclusion of Fugitive

Emissions; Reconsideration." Through a letter signed on April 24, 2009, the EPA granted reconsideration on a petition submitted by the Nation Resources Defense Council ("NRDC"), as well as an administrative stay of the Fugitive Emissions Rule provisions. On March 30, 2011, the EPA issued an interim rule that stayed the Fugitive Emissions Rule by reverting the text of the affected sections of the Code of Federal Regulations back to the prior rule language. This stay will remain in effect until the EPA completes its reconsideration and undertakes any associated rulemaking. The final fugitive emissions rule required fugitive emissions to be included in determining whether a physical or operational change results in a major modification only for sources in industries that have been designated as major.

Source: Unified Agenda, RIN 2060
https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202110&RIN=2060-AQ47
https://www.epa.gov/sites/default/files/2015-12/documents/20100204stayfs.pdf)

Regional Haze

States Submit Plans: 07/31/2021 **Final Rule: TBD**

States have an obligation to develop and submit their regional haze plans for addressing visibility impairment in Class I areas during the second implementation period. On July 8, 2021, EPA issued guidance that attempts to limit the broad discretion and flexibility that states have in the development of their regional haze plans. Similarly, the EPA regions also have begun to take narrow interpretation of states' discretion in how they achieve their reasonable progress goals when reviewing states' regional haze plans for the second planning period. The intended overall effect of this new interpretation is to require the installation of SO_2 scrubbers and NO_x SCR control systems on the last remaining coal-fired power plants that are not currently operating with those SO_2 and NO_x control systems. Although the deadline for state submitting their regional haze plans was July 31, 2021, most states, including Kentucky, are still in the process of developing their plans and will not be ready to submit their plans until sometime later this year.

Source: https://www.epa.gov/system/files/documents/2021-07/clarifications-regarding-regional-haze-state-implementation-plans-for-the-second-implementation-period.pdf

Regulation of Coal Combustion Residuals

On July 9, 2021, EPA announced that it plans to implement several of Trump EPA rules for the regulations of coal combustion residuals ("CCR") without any changes in the current regulations. According to the Agency, no changes are necessary based on its determination that current CCR regulations provide "the most environmentally protective course of action." Although EPA will not be initiating a rulemaking to reconsider the current rules on the mandatory closure of existing unlined surface impoundments, EPA has initiated an effort to impose a new rigorous and overly prescriptive interpretation of the current federal CCR requirements on coal-fired power plants. This is reflected by EPA's proposed decisions not to approve many of the closure extension requests based on the coal-fired electric utilities' failure to comply with the applicable CCR requirements, as now being interpreted by the EPA. Spurlock has received a proposed conditional approval and will continue compliance efforts in accordance with that proposal. The overall purpose and effect of EPA's CCR initiative is to increase the stringency of the closure and remediation requirements and, in many cases to require the removal of the CCR from existing unlined impoundments (which EKPC is already doing). Finally, EPA has underway several other rulemakings that will establish new federal CCR requirements regarding permitting, legacy surface impoundments, and beneficial use of CCR products. All of these new requirements could increase stringency of the current federal CCR requirements on the management and disposal of CCR material by coal-fired electric utilities.

Source: Unified Agenda, RIN: 2050-AH14 and 2050-AH18

https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202110&RIN=2050-AH14

https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202110&RIN=2050-AH18

CCR Holistic Part A

Proposed Rule: **Final Rule: 8/28/2020**

Deadline to Initiate Closure and Enhanced Public Access to Web information went final July 29, 2020. Revised date for closure is April 11, 2021 unless extension is granted by EPA. EKPC submitted a Demonstration to EPA on November 30, 2020 in support of a request for an extension of the deadline to initiate closure of the Spurlock Impoundment until November 30, 2022. On January 11, 2022, EPA issued a proposed decision to approve EKPC's request with conditions. EKPC must submit a response to EPA's proposed decision by March 25, 2022. If the request is ultimately denied, EKPC would be required to cease all waste streams to the Spurlock Impoundment and initiate closure within 135 days of EPA's final decision.

CCR Holistic Part B

Proposed Rule: 03/03/2020 **Final Rule: 12/14/2020**

Alternative Demonstration for unlined surface impoundments and implementation of closure was proposed in federal register on March 03, 2020. It allows our Industry to use procedures to line ponds, two co-proposed options to close ponds, removal or in place with a cap, and requirements for annual progress reports. Pre-publication copy appeared in the federal register on October 15, 2020 that is under internal review. Had little to no impact to EKPC.

2020 Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category

Proposed Rule: **Final Rule: 12/14/2020**

EPA is reconsidering the 2020 reconsideration rule and evaluating the technologies available to the industry for FGD wastewater treatment, bottom ash transport water (specifically purge water), landfill leachate, and legacy wastewater, among other waste streams. EKPC (specifically at Spurlock) has already implemented projects to eliminate bottom ash transport water and provide for zero discharge of FGD wastewater (other than a potential intermittent high-quality distillate stream). Depending on the outcome of EPA's review (expected rulemaking in Q4 2022), additional limits may be added on other waste streams that could require treatment solutions or additional monitoring at the remaining coal units.

Regulation of CO_2 as a Criteria Air Pollutant through the SIP process

Proposed Rule: TBD- Longterm Review **Final Rule: TBD- Longterm Review**

EPA announced in March 2021 its withdrawal of the Trump EPA's denial of a petition by the Center for Biological Diversity to set a NAAQS for CO_2 under the CAA. If EPA were to adopt a NAAQS for CO_2, each state would then be required to adopt climate change SIP that would regulate all major sources of CO_2 (including coal-fired power plants) within its jurisdiction. If any state fails to adopt and implement a SIP in a timely fashion, EPA then has the authority and responsibility to adopt a federal implementation plan for regulating CO_2 emissions from power plants and other sources within the state. The EPA has not made the threshold decision on whether to regulate CO_2 as a criteria pollutant under the CAA, let alone set any timeline for doing so.

Regulation of GHGs as International Air Pollution

Proposed Rule: TBD- Longterm Review **Final Rule: TBD- Longterm Review**

EPA is reportedly examining its authority to regulate GHG emissions as "international pollution" under section 115 of the CAA. EPA has the authority to require states to regulate GHG emissions within their jurisdiction upon making the following two findings: (1) GHG emissions from any state "may reasonably be anticipated to endanger public health or welfare in a foreign country;" and (2) the foreign country being impacted by the GHG emissions "has given the United States essentially the same rights with respect to the prevention or control of air pollution occurring in that country as is given that country by [section 115]." Although in existence since 1977, this provision has been only used twice for regulating emissions causing acid rain pollution prior to the enactment of 1990 CAA amendments. The EPA has not made the threshold decision on whether to initiate a rulemaking to regulate GHG emissions under CAA section 115, let alone set any timeline for doing so.

Source: EPA Regulations Impacting the Coal Fleet Feb 7 2022.pdf.

Implementation of the 2008 NAAQS for Ozone: SIP Requirements Update

Proposed Rule: **Final Rule: CSAPR 2.0 March 2021**

This proposed rulemaking would update the final State Implementation Plan ("SIP") Requirements Rule for the 2008 Ozone NAAQS (80 FR 12264, March 6, 2015) to reconcile regulatory provisions that were vacated as part of the decision in South Coast Air Quality Management District v. EPA, 882 F.3d 1138 (D.C. Cir. 2018) (South Coast II) with those listed in part 51 of the Code of Federal Regulations. The 2008 SIP Requirements Rule governs attainment planning requirements that apply to areas designated nonattainment for the 2008 ozone NAAQS, and states in the Ozone Transport Region, as well as anti-backsliding requirements for areas once designated nonattainment for the revoked ozone NAAQS. This proposed action would clarify national policy by updating affected provisions in the 2008 ozone SIP Requirements Rule to reflect the outcome

of South Coast II and ensure that states understand the requirements that apply to them for continued implementation of the ozone NAAQS.
Source: Unified Agenda, RIN: 2060-AU88
https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202110&RIN=2060-AU88

Reclassification of Major Sources as Area Sources Under Section 112 of the Clean Air Act
Proposed Rule: Expected June 2022 **Final Rule: Scheduled June 2023**
The Reclassification of Major Sources as Area Sources Under section 112 of the Clean Air Act (Major MACT to Area-MM2A final rule) was promulgated on November 19, 2020, and became effective on January 19, 2021. This rule provides that a major source can be reclassified to area source status at any time upon reducing to its potential to emit ("PTE") hazardous air pollutants ("HAPs") to below the major source thresholds of 10 tons per year of any single HAP and 25 tpy of any combination of HAP. On January 20, 2021, President Biden issued Executive Order 13990 "Protecting Public Health and the Environment and Restoring Science to Take the Climate Crisis." The EPA has identified the MM2A final rule as an action being considered pursuant to section (2)(a) of Executive Order 13990. Under this review, EPA will publish for comment a notice of proposed rulemaking either suspending, revising, or rescinding the MM2A final rule.
Source: Unified Agenda, RIN: 2060-AV20
https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202110&RIN=2060-AV20

Petition to Delist Stationary Combustion Turbines From the List of Categories of Major Sources of Hazardous Air Pollutants
Propose Rule: Expected April 2022 **Final Rule: TBD**
The Clean Air Act section 112(c)(9) requires EPA to consider petitions to add or remove source categories. EPA reviews a petition to determine whether it provides adequate data and can be determined complete. If EPA decides that information is not adequate, the Administrator may use any authority available to him to acquire such information. Once the petition is determined to be complete, EPA must, within 12 months from the last receipt of information from the petitioners, either grant or deny the petition. On August 28, 2019, EPA received a petition to remove the Stationary Combustion Turbines source category from the list of categories of major sources. On November 19, 2019, December 2, 2020, and March 15, 2021, EPA received supplements to the

petition. The EPA is currently evaluating the petition for completeness and will issue a notice to notify the petitioners and the public of its determination of whether the petition will be granted (a proposed rulemaking) or denied.
Source: Unified Agenda, RIN: 2060-AU78
https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=202110&RIN=2060-AU78

New Source Review
Proposed Rule: **Final Draft: 11/24/2020**
Final Guidance/Memorandum
August 5, 2020 - EPA issued NSR guidance on August 5, 2020 to help Industry use plant wide applicability limitations ("PALs") as a path forward in permitting projects as minor NSR projects. Unfortunately, PALs must be renewed and risk termination. PALs offer some possibilities but present risk.

Draft Guidance
March 25, 2020 issued draft guidance to help industry and its regulators interpret and understand preconstruction and construction penalties under this program.
December 2, 2019 – EPA issued ambient air guidance to the Industry and States. Thus, the EPA's revised ambient air policy, consistent with its discretion available under the regulatory definition of ambient air, is that the atmosphere over land owned or controlled by the stationary source may be excluded from ambient air where the source employs measures, which may include physical barriers, that are effective in precluding access to the land by the general public.

EPA Proposed Action on "Project Emissions Accounting" occurred on August 1, 2019. EPA proposed to clarify the process for evaluating whether the NSR permitting program would apply to proposed projects at existing air pollution sources. This proposal would make it clear that both emissions increases and decreases from a major modification at an existing source are to be considered during Step 1 of the two-step NSR applicability test. This process is known as project emissions accounting (previously referred to as project netting.)
EKPC is advocating using the hourly maximum emissions from a source as the baseline by which NSR going forward should use to incorporate efficiencies gained under the Affordable Clean

Energy Rule. Thus, NSR would not prevent the Industry from performing efficiency projects that may result in enforcement action under the current NSR policy for title V of Clean Air Act and PSD.

WOTUS

Proposed Rule: December 7, 2021 **Final Rule: TBD, Anticipated in 2023**

EPA and the Army Corps of Engineers have initiated proposed rulemaking to again revise the definition of waters of the United States. EPA notes there will be two phases to the rulemaking. The first phase, for which a proposed rule was published in the Federal Register on December 7, 2021, would restore the pre-2015 definition of WOTUS, "updated to reflect consideration of Supreme Court decisions." The public comment period on that proposed rule closed on February 7, 2022. The date of a final rule is uncertain but may be sometime in late 2022. The second phase, for which a proposed rule is expected sometime in 2022, would make further revisions to the definition based on input from states, tribes, local governments, and a broad array of stakeholders. On February 24, 2022, EPA announced the selection of ten geographically varied roundtables to facilitate discussion on implementation of the WOTUS rule, to be conducted virtually over the Spring and Summer 2022. The date of a proposed or final rule on the second phase of rulemaking is uncertain but a final rule is not anticipated until 2023. [RIN: 2040-AG13 and RIN: 2040-AG19].

These rulemaking actions followed a federal court decision on August 30, 2021 which vacated the January 2020 revisions to the definition of WOTUS (which had significantly reduced the scope of federal jurisdiction). On January 24, 2022, the US Supreme Court announced it would review a lower court ruling (*Sackett v. EPA*, 9th Circuit) that applied the definition of WOTUS established in the 2006 Supreme Court case, *Rapanos v. United States*. This review may resolve ambiguities in the definition of WOTUS and the extent of federal laws and permitting authority by giving the Supreme Court an opportunity to revisit its *Rapanos* decision.

NEPA

Phase 2 Proposed Rule: June 2022 **Final Rule: TBD**

Council on Environmental Quality ("CEQ") – CEQ published a Notice of Proposed Rulemaking on October 7, 2021 to modify regulations for implementing the procedural provisions of the National Environmental Policy Act ("NEPA") to "generally restore regulatory provisions that were in effect for decades before being modified in 2020". The proposed rule would "restore provisions addressing the purpose and need of a proposed action, agency NEPA procedures for implementing CEQ's NEPA regulations, and the definition of 'effects'". The public comment period closed on November 22, 2021 and review continues for a final rulemaking in 2022. [RIN: 0331-AA07]

USACE Implementing Regulations

Proposed Rule: Anticipated September 2023 **Final Rule: TBD**

NEPA – Following final actions by CEQ, the Corps will propose to update the NEPA implementing procedures applicable to all of the Corps' Regulatory and Civil Works Programs. [RIN: 0710-AB20]

Dept. of Interior, Fish & Wildlife Service

Proposed Rule: TBD **Final Rule: TBD**

Monarch Butterfly Status - On December 17, 2020, the U.S. Fish and Wildlife Service ("USFWS") completed its 12-month finding on the petition to list the monarch butterfly under the Endangered Species Act ("ESA"). It determined that listing the monarch under the ESA is warranted but precluded at this time by higher-priority listing actions. As a part of this finding, it determined that an emergency listing was not necessary because of ongoing conservation measures. Although USFWS has stated a 2024 timeframe for the monarch, the agency may choose to make significant progress on its listing backlog and, hence, expedite the listing of the monarch. This listing may have implications for EKPC in its land management activities in right-of-way corridors (e.g., use of herbicides, invasive species control, brush and tree management, mowing, and revegetation), substations, and development projects. [RIN: 1018-BE30]

Proposed Rule: Anticipated September 2022 **Final Rule: TBD**

Northern Long-eared Bat – On March 1, 2021 the U.S. District Court for the District of Columbia issued an order directing the USFWS to issue a new listing determination under the ESA for the northern long-eared bat ("NLEB") by a date certain. The USFWS must issue a new proposed rule and final listing decision within 18 months of completing the joint Species Status Assessment ("SSA") for the NLEB, tri-colored bat, and little brown bat (each has a broad, multi-state range). Potentially affects development and maintenance of transmission corridors. [RIN: 1018-BG14]

Migratory Bird Treaty Act

Proposed Rule: May 6, 2021 **Final Rule: Anticipated April 2022**

The USFWS published a proposed rule to revoke the Trump-era final rule that codified the Migratory Bird Treaty Act ("MBTA") does not prohibit incidental take. The USFWS will return to implementing the MBTA as prohibiting incidental take and applying enforcement discretion. USFWS is proposing three options for its proposed permitting program: individual permits, general permits, and permit exclusions. It appears USFWS favors a general permitting structure. [RIN: 1018-BD76]

CWA Effluent Limitation Guidelines

Proposed Rule: Anticipated Fall 2022 **Final Rule: TBD**

Effluent Limitations Guidelines ("ELGs") – Following its review of the 2020 Steam Electric Reconsideration Rule, EPA has initiated a supplemental rulemaking for certain discharge limits in the Steam Electric Power Generating category (40 CFR Part 423). Several of the limits under review may result in more stringent limits and potentially impact EKPC's current efforts to comply with the 2015 and 2020 rules. As part of this supplemental rulemaking, EKPC received a Clean Water Act ("CWA") Section 308 information request letter on January 7, 2022 with an extensive list of items that to be submitted to EPA no later than February 20, 2022. EKPC is working diligently to respond to the request and has received a 60-day extension from EPA (until April 21, 2022) to submit. Notice of Proposed Rulemaking Initiative published August 3, 2021. [RIN: 2040-AG11]

Proposed Rule: Anticipated September 2022 **Final Rule: TBD**

EPA/State 401 Certification - EPA revised the 401 regulations, entitled "Clean Water Act section 401 Certification Rule", in June 2020 which among other things included limits on the timing and scope of state 401 certifications of federally licensed or permitted projects. EPA has completed its review of the June 2020 regulation and determined that it will propose revisions to the rule through a new rulemaking effort. NPRM anticipated March 2022. [RIN: 2040-AG12]

USACE Implementing Regulations

Proposed Rule: TBD **Final Rule: TBD**

401 Certification – In response to any forthcoming final EPA water quality certification regulation, the Corps would propose to amend its regulations for the Regulatory Program to ensure consistency with that EPA rule. [RIN: 0710-AB21]

KDOW Triennial Review of Water Quality Standards

Proposed Rule: Anticipated August 2022 **Final Rule: Anticipated Summer 2023**

KDOW is currently undertaking the triennial review of its water quality standards (WQS) mandated by Congress. Changes made in the WQS will ultimately be included in EKPC's discharge permits. The review includes public participation, which KDOW began with a public listening session in June 2021. Public notice of proposed changes to the WQS is tentatively scheduled for August 2022, with a public hearing in September. Following administrative review, KDOW will submit its proposed revisions for EPA approval in mid-2023.

SECTION 10.0

FINANCIAL PLANNING

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 the 2022 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 February 28, 2022 multiplied by a 1.50 TIER.

TABLE 10-1

EAST KENTUCKY POWER COOPERATIVE, INC.

REVENUE REQUIREMENTS AND AVERAGE SYSTEM RATES

Year	Sales to Members (MWh)	Total From Members Nominal $ ($000)	Total From Members Real 2022$ * ($000)	Total From Members Present Value ($000)	Nominal Cents per kWh	Real Cents per kWh Real 2022$*
2022	14,332,986	1,032,812	$ 1,032,812	$ 1,032,812	7.2058	7.2058
2023	15,099,064	1,057,635	$ 1,028,228	$ 1,005,739	7.0046	6.8099
2024	15,205,983	961,803	$ 909,061	$ 869,731	6.3252	5.9783
2025	15,296,033	999,699	$ 918,607	$ 859,642	6.5357	6.0055
2026	15,397,037	1,012,425	$ 904,433	$ 827,867	6.5755	5.8741
2027	15,499,140	1,027,598	$ 892,464	$ 799,043	6.6300	5.7581
2028	15,639,732	1,046,592	$ 883,687	$ 773,880	6.6919	5.6503
2029	15,738,812	1,055,878	$ 866,738	$ 742,437	6.7088	5.5070
2030	15,832,866	1,061,699	$ 847,285	$ 709,900	6.7057	5.3514
2031	15,943,460	1,083,206	$ 840,412	$ 688,741	6.7940	5.2712
2032	16,110,198	1,113,797	$ 840,119	$ 673,442	6.9136	5.2148
2033	16,218,927	1,137,369	$ 834,045	$ 653,951	7.0126	5.1424
2034	16,367,700	1,154,684	$ 823,199	$ 631,329	7.0546	5.0294
2035	16,520,448	1,182,655	$ 819,697	$ 614,894	7.1587	4.9617
2036	16,709,120	1,213,714	$ 817,834	$ 600,079	7.2638	4.8945
			** PV =	$ 11,483,486		

* Assumes an annual inflation rate of 2.86%

** Present value of revenue requirements using EKPC's discount rate of 5.16%

SECTION 11.0

SYSTEM MAP

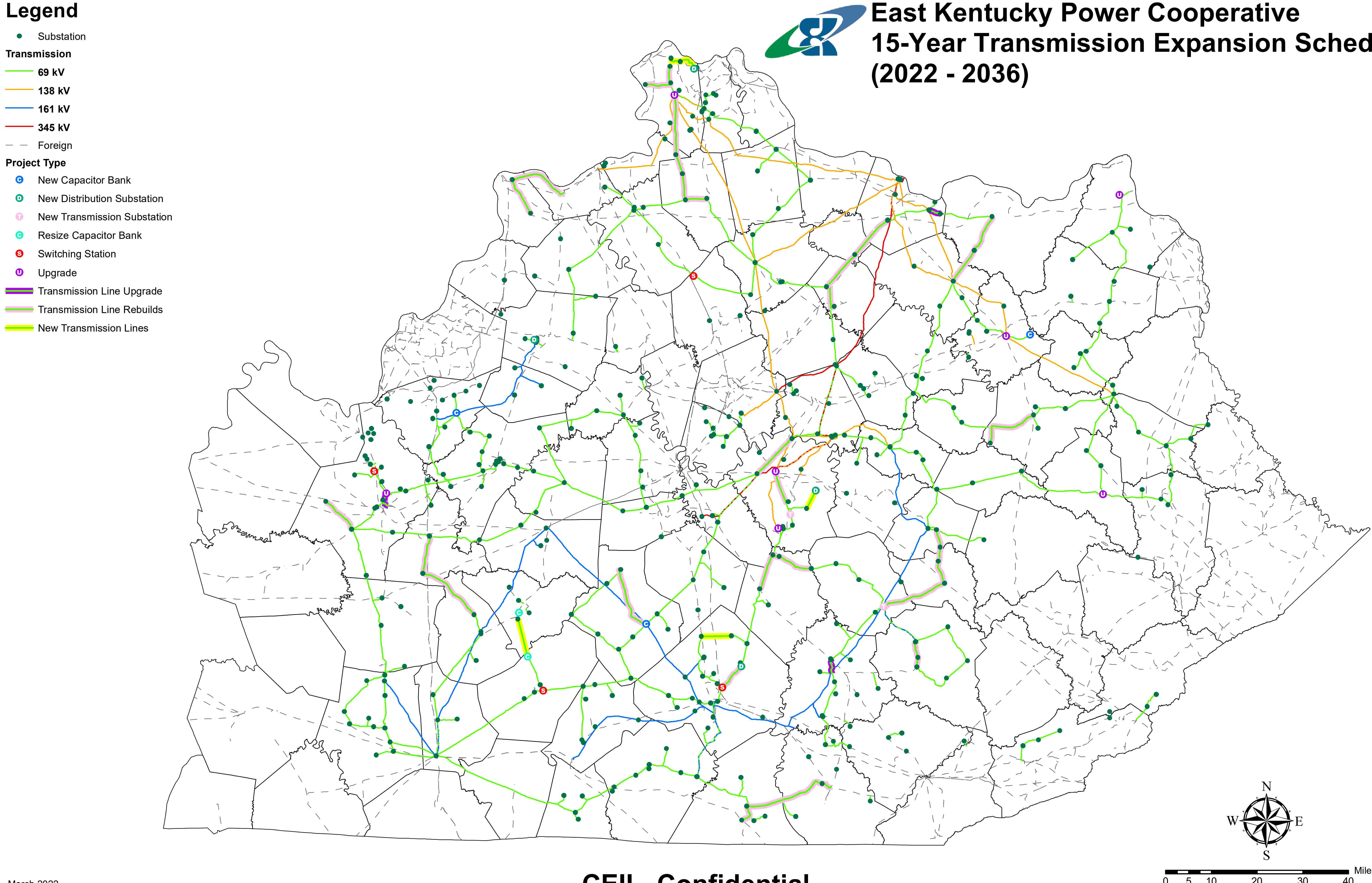
SECTION 11.0

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.

East Kentucky Power Cooperative 15-Year Transmission Expansion Schedule (2022 - 2036)



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