COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC 2025 INTEGRATED RESOURCE PLAN OF EAST KENTUCKY POWER COOPERATIVE, INC.	)))	CASE NO. 2025-00087

O R D E R

The Commission initiated this proceeding for its Commission Staff to conduct a review of the 2025 Integrated Resource Plan (IRP) filed by East Kentucky Power Cooperative, Inc. (EKPC), pursuant to 807 KAR 5:058. Attached as Appendix A to this Order is the Commission Staff's Report summarizing Commission Staff's review of the IRP. This Commission Staff's Report is being entered into the record of this case pursuant to 807 KAR 5:058, Section 11(3).

Based on the evidence of record, the Commission finds that the Commission Staff's Report represents the final substantive action in this matter. The final administrative action will be an Order closing the case and removing it from the Commission's docket. That Order will be issued after the period for comments on the Commission Staff Report has expired.

IT IS THEREFORE ORDERED that:

1. The Commission Staff's Report on EKPC's 2025 IRP represents the final substantive action in this matter.

2. Any party desiring to file comments regarding the Commission Staff's Report on EKPC's 2025 IRP shall do so on or before June 15, 2026.

3. An Order closing this case and removing it from the Commission docket shall be issued after the period for comments on the Commission Staff's Report has expired.

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Entered on this 1st day of June, 2026.

PUBLIC SERVICE COMMISSION

Angie Hatton
Chair

Mary Pat Regan
Commissioner

Andrew W. Wood
Commissioner

Barry L. Mayfield
Commissioner

ATTEST:

Linda C. Bridwell, PE
Executive Director

APPENDIX A

AN APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2025-00087 DATED JUN 01 2026

FIFTY SIX PAGES TO FOLLOW

Kentucky Public Service Commission

Commission Staff's Report on the

2025 Integrated Resource Plan of

East Kentucky Power Cooperative, Inc.

Case No. 2025-00087

June 1, 2026

SECTION 1

INTRODUCTION

In 1990, the Kentucky Public Service Commission (Commission) promulgated 807 KAR 5:058 to create an integrated resource planning process for review of the long-range resource plans of Kentucky's jurisdictional electric generating utilities by Commission Staff. The Commission's goal was to ensure that all reasonable options to meet projected load were being examined in order to provide ratepayers a reliable supply of electricity that is cost-effective.[1]

Each electric generating utility is required by 807 KAR 5:058, Section 2, to file an Integrated Resource Plan (IRP) every three years. This plan requires the utility to (1) forecast its load, or expected demand, for the following 15 years;[2] (2) identify existing and potential supply- and demand-side resources;[3] and (3) determine how to meet its demand in a way that minimizes cost while maintaining reliable service. The load forecast is compared to existing resource generation capacity, and the utility must establish a plan for meeting any capacity shortfall for each year. Modern generation planning involves complex software modeling systems in which the utility includes available resources as variables and the model is intended to output the most cost-effective[4] generation portfolio for each of several scenarios combining variables such as variance from forecasted load, fuel costs, changes to reserve margin requirements, changes in environmental regulation, and capital expenditures.

East Kentucky Power Cooperative, Inc. (EKPC) filed its 2025 Integrated Resource Plan (2025 IRP) on April 1, 2025.[5] EKPC is a not-for-profit, member-owned generation and transmission (G&T) cooperative located in Winchester, Kentucky.[6] EKPC supplies wholesale power to 16 Owner-Member distribution cooperatives serving approximately 570,000 retail consumers (approximately 1.1 million people) across 89 Kentucky counties and 4 counties in Tennessee; EKPC does not directly serve retail consumers.[7] Its Owner-Members include Big Sandy RECC; Jackson Energy Cooperative; Blue Grass Energy

[1] *See* Admin. Case No. 308, *An Inquiry into Kentucky's Present and Future Electric Needs and the Alternatives for Meeting Those Needs* (Ky. PSC Aug. 8, 1990), Order at 1–3. *See also* 807 KAR 5:058.

[2] 807 KAR 5:058, Section 7.

[3] 807 KAR 5:058, Section 8.

[4] Subject to the requirements that the utility provide adequate, efficient and reasonable service under KRS 278.030 and the rebuttable presumption against retirement of fossil fuel-fired electric generating units found in KRS 278.264.

[5] 2025 Integrated Resource Plan of East Kentucky Power Cooperative, Inc. (EKPC) (2025 IRP) (filed Apr. 1, 2025).

[6] 2025 IRP Section 1 at 2.

[7] 2025 IRP Section 1 at 2.

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; and Taylor County RECC.[8] EKPC's 2025 IRP reflects its resource plan for meeting Owner-Members' electricity requirements for the 2025 to 2039 planning period.[9]

EKPC reports net dependable capacity of approximately 2,963 MW (summer) and 3,265 MW (winter) from owned/operated resources and long-term entitlements (including SEPA hydro), plus 200 MW of interruptible load and approximately 28 MW of peak-reduction mechanisms. EKPC's record winter peak of 3,754 MW occurred on January 17, 2024.[10]

EKPC owns approximately 2,994 circuit-miles of high-voltage transmission and the necessary substations.[11] It maintains 77 normally closed free-flowing interconnections; its transmission is operated by PJM Interconnection, LLC (PJM), of which EKPC has been a fully integrated member since June 1, 2013. PJM operates the largest capacity/energy market in North America, coordinating more than 180,000 MW of generation.[12]

EKPC stated that it owns, operates, and/or has firm rights to approximately 3,435 MW (winter) across 25 generating units at 11 sites, with fuel sources including coal, natural gas, landfill gas, solar, and hydro.[13]

- Coal-Fired Generation
  - John Sherman Cooper Station (Pulaski Co.) - two pulverized-coal units (116 MW; 225 MW); major controls added in 2012; flue-gas reroute completed in 2016.[14]
  - Hugh L. Spurlock Station (Mason Co.) - four units: Spurlock 1 (300 MW) and 2 (510 MW) pulverized coal with flue gas desulfurization (FGD); Spurlock 3 and 4 (268 MW each) circulating fluidized bed units.[15]
- Natural Gas-Fired Generation

[8] 2025 IRP Section 1 at 2.

[9] 2025 IRP Section 1 at 14.

[10] 2025 IRP Section 1 at 2.

[11] 2025 IRP Section 1 at 2.

[12] 2025 IRP Section 1 at 2.

[13] 2025 IRP Section 4 at 82—83.

[14] 2025 IRP Section 4 at 83.

[15] 2025 IRP Section 4 at 83.

    - J.K. Smith Station (Clark Co.) - three ABB GT11N2 CTs (1999) and four GE 7EAs (2001/2005); two GE LMS100s (2010). Seasonal ratings shown in the IRP (e.g., LMS100s 75/74 MW summer, 103 MW winter).[16]
    - Bluegrass Generation Station (Oldham Co.) - three Siemens 501FD-2 CTs (commercial 2002; acquired 2015); each 167 MW summer / 189 MW winter; retrofitted in 2020 for fuel-oil backup.[17]
- Hydropower (SEPA)
    - Long-term purchases totaling 170 MW: Laurel Dam (70 MW) (100% of energy) and 100 MW from the Cumberland River system; the Corps' capital program may temporarily reduce marketed capacity during rehabilitation, reconciled via SEPA capacity credits.[18]
- Renewables & Other
    - Landfill Gas-to-Energy: 13.8 MW at five Kentucky sites.[19]
    - Solar: Cooperative Solar Farm One (Winchester) 8.5 MW (32,300 panels); Star Hill Farm (Maker's Mark, Loretto) 0.5 MWac online September 2024.[20]

EKPC stated that its strategic objectives are to actively manage its current and future asset portfolio to deliver reliable, competitive, and sustainable capacity and energy from appropriately diversified resources, and to work with federal, state, regional, and PJM stakeholders to maintain high reliability and economic viability while addressing decarbonization pressures and potential carbon-reduction mandates. EKPC indicated it will pursue these objectives by maintaining high reliability of service to Owner-Members; economically diversifying resources across market purchases, fossil fuels, renewables, demand management, and energy-efficiency programs; supporting beneficial electrification where cost-effective; and coordinating with stakeholders so that its fleet remains reliable and competitively priced.[21]

On April 10, 2025, an Order was entered establishing a procedural schedule for the review of EKPC's 2025 IRP.[22] The procedural schedule established a deadline for requesting intervention, two rounds of requests for information to EKPC, and an opportunity for parties to file written comments regarding the IRP and indicated that a hearing and additional comments from parties would be scheduled. On July 1, 2025, the

[16] 2025 IRP Section 4 at 83—84. *See also* unit ratings at 84—85.

[17] 2025 IRP Section 4 at 84.

[18] 2025 IRP Section 4 at 84—85.

[19] 2025 IRP Section 4 at 85.

[20] 2025 IRP Section 4 at 85.

[21] 2025 IRP Section 1 at 3.

[22] Order (Ky. PSC Apr. 10, 2025).

procedural schedule was amended to allow EKPC additional time to respond to requests for information.[23]

The Attorney General of the Commonwealth of Kentucky, by and through the Office of Rate Intervention (Attorney General),[24] and Sierra Club[25] were permitted to intervene in this matter pursuant to 807 KAR 5:001.

EKPC responded to two rounds of requests for information from intervenors[26] and three rounds of requests for information from Commission Staff.[27] Intervenors filed comments regarding EKPC's IRP on September 11, 2025,[28] and EKPC filed comments in response on September 19, 2025.[29] An in-person hearing was held on March 10, 2026. EKPC responded to one round of post-hearing data requests.[30] Intervenors filed post-hearing comments on April 13, 2026,[31] and EKPC filed comments in response on April 20, 2026.[32] The parties may file additional comments regarding this report on or before June 15, 2026.

The purpose of this report is to review and evaluate EKPC's 2025 IRP in accordance with 807 KAR 5:058, Section 11(3), which requires Commission Staff to issue a report summarizing its review of each IRP filing made with the Commission and make suggestions and recommendations to be considered by a utility in its next IRP filing.

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[23] Order (Ky. PSC July 1, 2025).

[24] Order (Ky. PSC Apr. 2, 2025).

[25] Order (Ky. PSC May 20, 2025).

[26] EKPC's Response to the Attorney General's First Request for Information (Attorney General's First Request) (filed June 6, 2025). EKPC's Response to the Attorney General's Second Request for Information (Attorney General's Second Request) (filed Aug. 28, 2025). EKPC's Response to Sierra Club's First Request for Information (Sierra Club's First Request) (filed June 6, 2025). EKPC's Response to Sierra Club's Second Request for Information (Sierra Club's Second Request) (filed Aug. 28, 2025).

[27] EKPC's Response to Staff's Amended First Request for Information (Staff's Amended First Request) (filed July 31, 2025). EKPC's Response to Staff's Second Request for Information (Staff's Second Request) (filed June 6, 2025). EKPC's Response to Staff's Third Request for Information (Staff's Third Request) (filed Aug. 28, 2025).

[28] Attorney General's Initial Comments (filed Sept. 11, 2025); Sierra Club's Initial Comments (filed Sep. 11, 2025).

[29] EKPC's Initial Reply Comments (filed Sept. 19, 2025).

[30] EKPC's Response to Commission Staff's Post-Hearing Request for Information (Staff's Post-Hearing Request) (filed Mar. 30, 2026); EKPC's Response to Sierra Club's Post-Hearing Request for Information (Sierra Club's Post-Hearing Request) (filed Mar. 30, 2026).

[31] Attorney General's Post-Hearing Comments (filed Apr. 13, 2026); Sierra Club's Post-Hearing Comments (filed Apr. 13, 2026).

[32] EKPC's Post-Hearing Reply Comments (filed Apr. 20, 2026).

Commission Staff recognizes that resource planning is a dynamic, ongoing process. Specifically, Commission Staff's goals are to ensure, among other things, the following:

- All resource options are adequately and fairly evaluated;
- Critical data, assumptions, and methodologies for all aspects of the plan are adequately documented and are reasonable; and
- The report includes an incremental component, noting any significant changes from EKPC's most recent IRP filed in 2022.

The remainder of this report is organized as follows:

- Section 2: Load Forecasting—reviews EKPC's projected load growth and load forecasting methodology.
- Section 3: Demand-Side Management and Energy Efficiency (DSM/EE)—summarizes EKPC's evaluation of DSM opportunities.
- Section 4: Supply-Side Resource Assessment—focuses on supply-side resources available to meet EKPC's load requirements and environmental compliance planning.
- Section 5: Integration—discusses EKPC's overall assessment of supply-side and demand-side options and their integration into an overall resource plan.
- Section 6: Reasonableness and Recommendations—discusses Commission Staff's position regarding the reasonableness of the IRP and its assumptions and includes Commission Staff's recommendations.

SECTION 2

LOAD FORECASTING

INTRODUCTION

This Section reviews and comments on the projected load growth for EKPC's systems and EKPC's load forecasting methodology. This section also reviews the parties' comments regarding EKPC's load and demand forecast. Commission Staff's discussion of and recommendations regarding EKPC's load and demand forecasting are discussed in Section 6 of this Report.

Calculating the energy consumption and peak demand forecast for each customer class and for the entire system is an important first step in the IRP process. It forms the basis for projecting how the generation fleet may evolve over time to meet projected customer demand, which in turn can affect long-term capital budgeting and investment decisions.

FORECASTING METHODOLOGY

EKPC works with each of the 16 Owner-Member cooperatives to prepare 16 individual forecasts.[33] Then, once all 16 forecasts are finalized, EKPC aggregates the forecasts and adds projections of facility and transmission losses, incorporates energy efficiency and demand-side management (DSM) impacts, and incorporates electric vehicle (EV) assumptions to configure EKPC's total system forecast.[34]

In preparation of the load forecast, EKPC considers national, regional, and local economic performance, population and housing trends, service area industrial development, electricity pricing, household income, appliance efficiencies and saturations, DSM programs, and weather.[35]

EKPC stated that consumer and energy models for each class are used to develop the load forecasts for each Owner-Member.[36] EKPC modeled and analyzed the regional economies, consumer and sales trends, energy efficiency and DSM impacts, appliance saturations, and weather impacts.[37]

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[33] 2025 IRP Technical Appendix, Vol. 1, Section 1.0 at 1.

[34] 2025 IRP Technical Appendix, Vol. 1, Section 1.0 at 1.

[35] 2025 IRP Technical Appendix, Vol. 1, Section 1.0 at 1 and Section 3.0 at 11.

[36] 2025 IRP Technical Appendix, Vol. 1, Section 3.0 at 12.

[37] 2025 IRP Technical Appendix, Vol. 1, Section 3.0 at 12.

In the regional economic model, EKPC divides the 16 Owner-Members' service areas into seven economic regions.[38] Regional forecasts for population, employment, and income are developed and used as variables within the consumer or energy models, as appropriate.[39] IHS Global Inc., an affiliate of S&P Global (IHS), historical and projected county-level economic forecast data is combined into the regional economic models based upon each Owner-Members' service territory boundaries.[40] The data includes North American Industry Classification System (NAICS) employment, personal income, real personal income, population, and household information.[41]

In EKPC's consumer and sales models, Owner-Member energy use per consumer was projected using a statistically adjusted end-use (SAE) model.[42] The SAE modeling utilized appliance saturation, appliance use, appliance efficiencies, household characteristics, weather, price elasticity and other demographic/economic data to determine projected residential usage, seasonal energy sales, and public building energy use.[43] EKPC stated that the number of residential consumers is projected using population or household variables at the Owner-Member level.[44] The results are summed to determine the total number of consumers and total class sales.[45]

Commercial and industrial accounts are classified into two groups; consumers 1,000 KVA or less are classified as small commercial and consumers over 1,000 KVA are classified as large commercial and industrial.[46] The number of small commercial consumers is forecasted by means of regression analysis on various regional economic data, including variables such as employment by sector and economic activity.[47] Energy use per consumer is calculated by dividing the energy sales forecast by the number of consumers.[48] Large commercial sales are projected utilizing specific knowledge on key accounts from the Owner-Members or EKPC's Economic Development staff in the short term.[49] For long term, EKPC projects new large loads based on history and the economy

[38] 2025 IRP Technical Appendix, Vol. 1, Section 3.0 at 12.

[39] 2025 IRP Technical Appendix, Vol. 1, Section 3.0 at 13.

[40] 2025 IRP Technical Appendix, Vol. 1, Section 3.0 at 13.

[41] 2025 IRP Technical Appendix, Vol. 1, Section 3.0 at 14.

[42] 2025 IRP Technical Appendix, Vol. 1, Section 3.0 at 15.

[43] 2025 IRP Technical Appendix, Vol. 1, Section 3.0 at 15.

[44] 2025 IRP Technical Appendix, Vol. 1, Section 3.0 at 16.

[45] 2025 IRP Technical Appendix, Vol. 1, Section 3.0 at 16.

[46] 2025 IRP Technical Appendix, Vol. 1, Section 3.0 at 16.

[47] 2025 IRP Technical Appendix, Vol. 1, Section 3.0 at 16.

[48] 2025 IRP Technical Appendix, Vol. 1, Section 3.0 at 16.

[49] 2025 IRP Technical Appendix, Vol. 1, Section 3.0 at 16.

of the Owner-Member service territory using regression analysis.[50] Demand of 1.5 MW and 70 percent load factor is assumed for new loads.[51]

EKPC stated that since public street and highway lighting sales are a small class, the number of consumers is correlated with residential consumers, and the energy sales are a known decrease due to high efficiency light bulbs.[52]

For DSM and energy efficiency related appliance saturations, projections of appliance efficiencies are sourced from the Energy Information Administration (EIA) Annual Energy Outlook.[53] EKPC is a member of Itron's Energy Forecasting Group, which further analyzes the EIA projections and incorporates them into the SAE framework.[54] These projections, combined with EKPC's End-Use Survey saturations, are used in the models.[55] EKPC projects each Owner-Members' electric appliance saturation, household characteristics, resident demographics, and other factors affecting electricity demand and usage as a function of time based on biennial or triennial survey data.[56] EKPC stated that increased appliance efficiency and lighting improvements will have a dampening effect on residential retail sales.[57]

Wholesale power costs are based on EKPC projections.[58] For the retail rate assumption, each Owner-Member provides a projection of the distribution adder used in the individual own-member models.[59]

EKPC normalized weather based on a historic 20-year proxy, from 2003 to 2023.[60] The Owner-Members are assigned weather stations that relate to each Owner-Members weather region.[61]

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[50] 2025 IRP Technical Appendix, Vol. 1, Section 3.0 at 16.

[51] 2025 IRP Technical Appendix, Vol. 1, Section 3.0 at 16.

[52] 2025 IRP Technical Appendix, Vol. 1, Section 3.0 at 17.

[53] 2025 IRP Technical Appendix, Vol. 1, Section 3.0 at 17.

[54] 2025 IRP Technical Appendix, Vol. 1, Section 3.0 at 17.

[55] 2025 IRP Technical Appendix, Vol. 1, Section 3.0 at 17.

[56] 2025 IRP Technical Appendix, Vol. 1, Section 3.0 at 17.

[57] 2025 IRP Technical Appendix, Vol. 1, Section 3.0 at 17.

[58] 2025 IRP Technical Appendix, Vol. 1, Section 3.0 at 17.

[59] 2025 IRP Technical Appendix, Vol. 1, Section 3.0 at 17.

[60] 2025 IRP Technical Appendix, Vol. 1, Section 3.0 at 17.

[61] 2025 IRP Technical Appendix, Vol. 1, Section 3.0 at 17.

EKPC's EV stock is a projection of owned EVs over time, utilizing number of consumers, the US Census, the U.S. Energy Information Administration (EIA) Annual Energy Outlook (2023), and the Bureau of Transportation Statistics.[62] EKPC stated that the overall trend in EV adoption and assumptions about vehicle useful lives are assumed consistent with EKPC's Owner-Members.[63] The number of vehicles per household and consumer growth are specific to each Owner-Member.[64]

EV energy sales are a determination of total energy sales from EVs based on the EV stock forecast and analysis of electrical consumption over time.[65] EKPC stated that EIA data on the share of passenger cars and light-duty vehicles is used to differentiate the stock.[66] Estimated typical miles driven per year and annual energy consumption per mile driven for charging are assumed and estimated by GDS Associates, Inc. (GDS).[67] The product of stock, miles driven, and kWh per mile results in cumulative EV energy sales for each Owner-Member.[68]

EKPC developed EV load profiles using the Alternative Fuels Data Center's (AFDC) EVI-Pro-Lite load profile tool and Lexington-Fayette County, Kentucky charging profiles. EKPC incorporated assumptions regarding seasonal temperatures, miles driven per day, EV type, charging access, and charging timing for EKPC consumers.[69]

KEY ASSUMPTIONS

Key regional economy assumptions stemmed from IHS Global Inc's February 2024 Kentucky state analysis.[70] The report stated that employment in Kentucky grew by over 2.6 percent by the third quarter of 2023, which is faster than the national average by 1.9 percent.[71] The unemployment rate stood equal to the pre-pandemic rate at approximately 4.2 percent.[72] IHS Global Inc. reported that Kentucky's labor market will expand at a

[62] 2025 IRP Technical Appendix, Vol. 1, Section 3.0 at 18.

[63] 2025 IRP Technical Appendix, Vol. 1, Section 3.0 at 18.

[64] 2025 IRP Technical Appendix, Vol. 1, Section 3.0 at 18.

[65] 2025 IRP Technical Appendix, Vol. 1, Section 3.0 at 19.

[66] 2025 IRP Technical Appendix, Vol. 1, Section 3.0 at 19.

[67] 2025 IRP Technical Appendix, Vol. 1, Section 3.0 at 19.

[68] 2025 IRP Technical Appendix, Vol. 1, Section 3.0 at 19.

[69] 2025 IRP Technical Appendix, Vol. 1, Section 3.0 at 19.

[70] 2025 IRP Technical Appendix, Vol. 1, Section 4.1 at 21.

[71] 2025 IRP Technical Appendix, Vol. 1, Section 4.1 at 21.

[72] 2025 IRP Technical Appendix, Vol. 1, Section 4.1 at 21.

compound annual rate of 0.3 percent across 2023-2028.[73] Households, employment, and overall population in Kentucky was shown to continue moderate growth.[74] Economic growth varied across Kentucky, with a range of -0.6 percent population decline in the east region to 0.6 percent population growth in the north region.[75] Household growth mirrored this by having a -0.2 percent decline in the east region and a 0.9 percent growth in the central north and north regions.[76] Total employment declines by -0.4 percent in the east region and 0.5 percent growth in the north.[77]

EKPC made energy and peak adjustment assumptions based on the impact of its DSM/EE plan.[78] EKPC stated that to avoid double counting, the impacts did not include energy efficiency measures installed prior to 2025.[79] The table below summarizes the impact of DSM/EE on EKPC's load forecast:[80]

Additional Effect of DSM/EE Programs			
Year	Energy (MWh)	Winter Peak (MW)	Summer Peak (MW)
2025	-5,232	-7	-24
2026	-18,177	-13	-29
2027	-31,129	-19	-33
2028	-44,127	-25	-37
2029	-56,761	-31	-41
2030	-69,792	-38	-45
2031	-82,852	-44	-49
2032	-96,103	-50	-54
2033	-108,663	-56	-58
2034	-121,091	-60	-56
2035	-133,857	-66	-60
2036	-147,802	-72	-64
2037	-160,175	-78	-67
2038	-173,082	-83	-71
2039	-185,729	-89	-74

[73] 2025 IRP Technical Appendix, Vol. 1, Section 4.1 at 21.

[74] 2025 IRP Technical Appendix, Vol. 1, Section 4.1 at 22.

[75] 2025 IRP Technical Appendix, Vol. 1, Section 4.2 at 24.

[76] 2025 IRP Technical Appendix, Vol. 1, Section 4.2 at 24.

[77] 2025 IRP Technical Appendix, Vol. 1, Section 4.2 at 24.

[78] 2025 IRP Technical Appendix, Vol. 1, Section 4.3 at 25.

[79] 2025 IRP Technical Appendix, Vol. 1, Section 4.3 at 26.

[80] 2025 IRP Technical Appendix, Vol. 1, Section 4.3 at 26.

In EKPC's service territory, approximately 62.1 percent of residential consumers utilize electric heating, 15.5 percent use natural gas, and 5.2 percent use wood or coal burning heating sources.[81] Ninety-six percent of residential consumers have some form of air conditioning system, of which 43.1 percent utilize electric central air and 11.9 percent as plug-in window units.[82]

EV assumptions resulted from a survey of residential consumers in the entire service territory.[83] According to the survey, 86.5 percent of the residential consumer survey population stated that they do not own an EV, nor plan on buying one in the near future.[84] Additionally, for those in the territory that do own an EV, the survey concluded that 55.3 percent of EV owners charge their vehicle between 10:00 PM and 6:00 AM.[85]

ENERGY FORECAST

EKPC's base load forecast projects total energy requirements to increase from 15.4 million MWh to 18.4 million MWh, which is an average of 1.3 percent per year through 2039.[86] EKPC's High Case scenario amplifies the impact to economic growth, utilizes a 30-year historical maximum degree days, and assumes stronger EV adoption and miles.[87] The High Case projected total energy requirements increased from 16.4 million MWh to 21.1 million MWh in 2039.[88] For the Low Case scenario, EKPC assumed slow economic growth, mild weather, and lower EV adoption and miles compared to the base case scenario.[89] The Low Case scenario projected total energy requirements to increase from 14.2 million MWh to 15.8 million MWh.[90] The table below presents EKPC's net total energy requirements starting with the summation of Owner-Member sales and accounting for office and facilities uses, distribution losses, transmission losses, EVs, and DSM/EE impacts.[91]

[81] 2025 IRP Technical Appendix, Vol. 1, Section 4.4 at 27.

[82] 2025 IRP Technical Appendix, Vol.1, Section 4.4 at 27.

[83] 2025 IRP Technical Appendix, Vol. 1, Section 4.4 at 28.

[84] 2025 IRP Technical Appendix, Vol. 1, Section 4.4 at 28.

[85] 2025 IRP Technical Appendix, Vol. 1, Section 4.4 at 28.

[86] 2025 IRP, Section 3.1 at 43.

[87] 2025 IRP, Section 3.6 at 72.

[88] 2025 IRP, Section 3.6, Table at 74.

[89]2025 IRP, Section 3.6 at 73.

[90] 2025 IRP, Section 3.6, Table at 74

[91] 2025 IRP, Section 3.1, Table 3—4 at 48

Year	Total Retail Sales(MWh)	Owner-Member Office Use (MWh)	Sales to Owner-Members (MWh)	EKPC Facilities Use (MWh)	EV Base Case (MWh)	DSM/EE Impacts (MWh)	Net Total Requirements (MWh)
2024	13,723,049	8,596	14,228,124	7,514	76,377	0	14,597,314
2025	14,435,540	8,596	14,954,336	7,514	99,859	-5,232	15,356,328
2026	15,072,250	8,596	15,602,661	7,514	127,704	-18,177	16,032,547
2027	15,335,351	8,596	15,870,588	7,514	159,643	-31,129	16,324,831
2028	15,512,403	8,596	16,053,804	7,514	196,255	-44,127	16,535,333
2029	15,661,424	8,596	16,204,972	7,514	235,825	-56,761	16,716,466
2030	15,744,831	8,596	16,291,658	7,514	280,009	-69,792	16,836,043
2031	15,851,839	8,596	16,402,956	7,514	328,278	-82,852	16,984,780
2032	16,003,722	8,596	16,560,979	7,514	381,999	-96,103	17,186,440
2033	16,062,202	8,596	16,622,110	7,514	437,727	-108,663	17,291,964
2034	16,158,433	8,596	16,722,102	7,514	498,516	-121,091	17,442,321
2035	16,278,058	8,596	16,846,686	7,514	563,466	-133,857	17,621,587
2036	16,468,243	8,596	17,044,352	7,514	634,362	-147,802	17,880,165
2037	16,553,341	8,596	17,133,164	7,514	705,928	-160,175	18,029,950
2038	16,683,861	8,596	17,279,360	7,514	783,352	-173,082	18,243,593
2039	16,820,333	8,596	17,411,162	7,514	864,886	-185,729	18,446,924

Net winter and summer peak demands were projected to increase by approximately 416 MW or 0.8 percent per year and 411 MW or 1.1 percent per year, respectively in the base forecast.[92]

	Winter Peak (MW)[93]			Summer Peak (MW)[94]		
Year	Low	Base	High	Low	Base	High
2024-25	3,148	3,517	3,984	2,222	2,530	2,845
2025-26	3,197	3,627	4,155	2,223	2,588	2,960
2026-27	3,231	3,677	4,217	2,263	2,641	3,024

[92] 2025 IRP, Section 3.1 at 43.

[93] 2025 IRP, Section 3.6, Table at 76.

[94] 2025 IRP, Section 3.6, Table at 78.

2027-28	3,258	3,712	4,272	2,269	2,664	3,054
2028-29	3,258	3,727	4,298	2,286	2,688	3,096
2029-30	3,259	3,743	4,331	2,289	2,703	3,124
2030-31	3,262	3,760	4,362	2,297	2,723	3,160
2031-32	3,277	3,788	4,406	2,305	2,749	3,196
2032-33	3,270	3,793	4,425	2,308	2,766	3,228
2033-34	3,275	3,811	4,458	2,321	2,792	3,271
2034-35	3,283	3,832	4,493	2,332	2,818	3,312
2035-36	3,307	3,870	4,546	2,351	2,853	3,365
2036-37	3,307	3,882	4,574	2,361	2,878	3,408
2037-38	3,319	3,908	4,615	2,377	2,910	3,459
2038-39	3,331	3,933	4,655	2,391	2,941	3,509

RESPONSES TO PREVIOUS COMMISSION STAFF'S RECOMMENDATIONS

1. EKPC should strive to present internally consistent data and to explain any differences in similar data such as the different load forecasts based on the original and updated IHS Global Insight data.

Response: When preparing the 2022 IRP, EKPC's most recently completed long-term load forecast was prepared in 2020. In an effort to use a more current vintage, EKPC updated DSM projections and assumptions for its largest industrial consumer's expansion plan. In doing so, the long-term load forecast tables included in the IRP did not match the tables in the 2020 Long-Term Load Forecast Report included as a technical appendix with the 2022 IRP. The differences in tables and forecast vintage caused notable confusion. The 2025 IRP is based on EKPC's 2024 Long-Term Load Forecast without alteration or updated assumptions. The tables in the 2025 IRP match the 2024 Long-Term Load Forecast report included as a technical appendix with the 2025 IRP.

2. EKPC did not include any DSM/EE program impacts beyond those in the current approved suite of programs. As discussed above and below, EKPC should analyze DSM/EE programs and generation resources together as resources that may be selected in the same modeling runs to meet projected load, using the same cost and other inputs, to ensure that new DSM/EE programs and generation resources are assessed on equal footing. However, if EKPC is not able to assess new DSM/EE programs using the modeling software, EKPC should at minimum project the effect of new cost-effective DSM/EE programs on load during the planning period and explain how it did so.

Response: The primary model used in developing the resource plan is RTSim from Simtec, Inc., of Madison, Wisconsin. RTSim's Resource Optimizer optimizes the generation resource plan. The Resource Optimizer sets up and runs the RTSim production cost model to perform simulations of a large number of supply side resource plans to determine the optimal plan.

For this 2025 IRP, EKPC included new DSM/EE program impacts beyond the current approved suite of programs. EKPC filed new DSM tariffs for four new DSM/EE programs.

EKPC uses modelling tools for DSM/EE that are designed specifically to assess these resources. These programs proved cost-effective based on the major tests in the California standard. EKPC used the DSMore software to perform these calculations. DSMore accounts for detailed program-specific assumptions for kW and kWh savings, program costs and program incentives. DSMore also accounts for the avoided costs per kW for generation and T&D and avoided cost per kWh for energy.

EKPC projected the effect of new DSM/EE programs on load during the planning period. Each program is modelled using 48-daytype hourly load profiles for the savings. The program impacts are then aggregated. The aggregate impacts are mapped into the annual hourly load forecast by day, type and year. This ensures that peak savings are applied to peak days in the load forecast, near-peak savings are applied to the near-peak days in the load forecast, and so on.

INTERVENOR AND RESPONSE COMMENTS

In Sierra Club's initial comments, it criticized EKPC's lack of modeling for hypothetical data center load.[95] Sierra Club also suggested that EKPC should assess the likelihood of data center load being added to EKPC's service territory. In post-hearing comments, Sierra Club reiterated the need for transparency with regards to the process for EKPC potentially partnering with data centers.[96] Sierra Club noted that Commission's approval of EKPC's Data Center Power tariff (filed after the commencement of the present case) included instructions that EKPC "proactively address community concerns through an engagement program that includes early intervention, transparent communication . . . and being upfront about potential impacts includes aesthetics and noise abatement programs."[97] Sierra Club was concerned that non-disclosure agreements (NDAs) during the negotiation phase leads to a too-secretive approach to an arrangement that may significantly affect EKPC's Owner-Members.[98]

EKPC responded in initial reply comments that it was committed to bringing forward a resource portfolio plan for any data center over 250 MW as evidenced by its

[95] Sierra Club's Initial Comments at 2.

[96] Sierra Club's Post-Hearing Comments at 1—2.

[97] Sierra Club's Post-Hearing Comments at 2, citing Case No. 2025-00140, *Electronic Tariff Filing of East Kentucky Power Cooperative, Inc. to Establish a New Tariff for Data Center Power* (Ky. PSC Oct. 30, 2025), Order at 23.

[98] Sierra Club's Post-Hearing Comments at 1—2.

Data Center Power tariff filing.[99] EKPC stated that any special contract with a data center customer would necessitate a special contract approved by the Commission, with appropriate intervenors being permitted to participate.[100] EKPC also indicated that it was dedicated to engaging with the public in multiple ways regarding data centers, but warned that NDAs were necessary, as lack of confidentiality during negotiation, including disclosure of possible locations of a new development could jeopardize a customer locating within the service territory.[101]

[99] EKPC's Initial Reply Comments at 9. *See* Case No. 2025-00140, *Electronic Tariff Filing of East Kentucky Power Cooperative, Inc. to Establish a New Tariff for Data Center Power* (Ky. PSC May 23, 2025), opening Order.

[100] EKPC's Post-Hearing Reply Comments at 2—3.

[101] EKPC's Post-Hearing Reply Comments at 4—5.

SECTION 3

DEMAND-SIDE MANAGEMENT AND ENERGY EFFICIENCY

INTRODUCTION

Depending on the circumstances, the IRP regulation permits demand-side resources to be assessed as options that could be selected to meet projected load or based on their projected effects on load.[102] This section briefly describes EKPC's existing DSM/EE programs, summarizes how existing programs were reflected in the IRP, and discusses DSM/EE programs EKPC reviewed to meet projected load. This section also reviews EKPC's response to Commission Staff's recommendations regarding DSM/EE in its 2022 IRP..

CURRENT DSM/EE PROGRAMS

EKPC analyzed its DSM/EE program plans for 2025 by including qualitative and quantitative research, which includes data regarding member acceptance, measure applicability, savings potential, and cost-effectiveness.[103] The DSM portfolio includes seven energy efficiency programs and three demand response programs. Three of the energy efficiency programs are new, as well as two of the demand response programs since EKPC's last IRP. EKPC's DSM/EE portfolio includes the following programs:[104]

1. Button-Up Weatherization Program: This program is designed to incentivize participants with poor energy-performing homes to improve the energy efficiency of the home's shell and ductwork. The program encourages homeowners to improve the thermal envelope of their home through improved insulation, upgraded windows and doors, and air-sealing. An incentive is paid based on heat loss reduction which is then measured in British thermal units per hour (Btuh). Homes must be greater than two years old and the primary source of heat must be electric for customers to be eligible for this program.
2. Customer Assistance Residential Energy Support (CARES) Low-Income Weatherization: Working with Kentucky Community Action Agencies (CAA), the CARES program provides an incentive to enhance the weatherization and energy efficiency of low-income customers' homes. The program provides installation of weatherization including insulation, air sealing, duct sealing, and water heater blankets to single family or multi-

[102] *See* 807 KAR 5:058, Section 7(3).

[103] 2025 IRP, Executive Summary, Section 1.3 at 4.

[104] 2025 IRP Technical Appendix, Vol. 2, Exhibit DSM-5.

family homes. Customers with and without a heat pump are eligible for the program and the maximum incentive per household is $3,000.

3. Heat Pump Retrofit Program: This program provides an incentive to customers to replace their old heat sources such as electric furnaces, ceiling cable heat, baseboard heat, or electric thermal storage with more energy efficient heat pumps. The program provides a rebate incentive for both centrally ducted systems and mini-split systems. The rebates range from $500 to $1,000 depending on the type of equipment installed.
4. Touchstone Energy Home Program: This program is designed to encourage new homes to be built to higher standards for thermal integrity and equipment efficiency. New residential homes must undergo a variety of inspections and specifications before approval, receive greater than or equal to a score of 75 on the Home Energy Rating System (HERS), and pass the 2009 International Energy Conservation Code. Homes must be located within the EKPC service territory of a participating Owner-Member system in order to be eligible.
5. High Efficiency Heat Pump Program: This program is designed to incentivize participants to install an air source heat pump (ASHP) that meets or exceeds the current ENERGY STAR requirements, or a heat pump that has received the EPA cold climate air source heat pump (ccASHP) designation. The program is targeted towards single or multi-family homes that meet the specific eligibility requirements. The participant will receive an incentive of $250 to $1,000 depending on the equipment installed.
6. Commercial Advanced Lighting Program: This program is designed to incentivize non-residential customers to install high-efficiency LED lighting. The program offers four prescriptive measures with an incentive ranging from $10 to $37 per fixture. Incentives are capped at up to $5,000 annually per facility. Businesses that do not exceed 3,000,000 kWh of energy usage per year are eligible.
7. Commercial & Industrial Thermostat Program: This program is designed to promote energy efficiency among commercial and industrial customers by upgrading to self-learning thermostats. The thermostats reduce heating and cooling costs by adjusting temperature settings to optimize energy use. The program offers a $100 incentive per installed thermostat to eligible non-residential customers.
8. Direct Load Control Program, Residential Air Conditioners and Water Heaters (Switches and Bring Your Own Thermostat (BYOT)): This program is designed to reduce peak demands to provide load relief to the grid by load control of air conditioners, heat pumps, and water heaters. EKPC will not be installing new switches; however, all new enrollments will have wi-fi

enabled thermostats for load control. Customers may receive incentives of $10 per year for each water heater and $20 per year for each air conditioner or heat pump controlled by EKPC.

9. Residential Electric Vehicle Off-Peak Charging Program: The program is designed to reduce the growth in peak demand due to the adoption of electric vehicles in EKPC's service territory. The program offers a monthly incentive to all participants for charging that occurs during off-peak hours.
10. Backup Generator Control Program: The program is designed to incentivize residential users, who own backup generators, to participate in EKPC's demand response initiatives. Generators must meet certain eligibility requirements and have the capability to carry the entire load of the residence at any time of the year. The generator must also have the capability to be controlled by EKPC.

DSM/EE IMPACTS ON DEMAND

The following table provides the annual energy, winter peak demand, and summer peak demand reductions of the existing DSM/EE programs:[105]

Year	Impact on Energy Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2025	-5,232	-7	-24
2026	-18,177	-13	-29
2027	-31,129	-19	-33
2028	-44,127	-25	-37
2029	-56,761	-31	-41
2030	-69,792	-38	-45
2031	-82,852	-44	-49
2032	-96,103	-50	-54
2033	-108,663	-56	-58
2034	-121,091	-60	-56
2035	-133,857	-66	-60
2036	-147,802	-72	-64
2037	-160,175	-78	-67
2038	-173,082	-83	-71
2039	-185,729	-89	-74

[105] 2025 IRP, Section 5.4, Table at 114 and 123.

The following tables provide the summer peak demand and winter peak demand load impact of each individual existing DSM/EE programs:[106] Negative values indicate a reduction in load.

Impact on Summer Peak (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Button-up Weatherization	0.0	-0.5	-1	-1.5	-1.9	-2.4	-2.9	-3.4	-3.8	-4.3	-4.8	-5.3	-5.8	-6.2	-6.7
CARES Low-Income	-0.2	-0.4	-0.7	-0.9	-1.1	-1.3	-1.5	-1.7	-2.0	-2.2	-2.4	-2.6	-2.8	-3.0	-3.3
Heat Pump Retrofit	0.0	-0.1	-0.2	-0.2	-0.3	-0.4	-0.4	-0.5	-0.6	-0.6	-0.7	-0.8	-0.8	-0.9	-1.0
Touchstone Energy Home	-0.4	-0.9	-1.3	-1.8	-2.2	-2.7	-3.1	-3.6	-4.0	-4.4	-4.9	-5.3	-5.8	-6.2	-6.7
High Efficiency Heat Pump	0.0	-0.4	-0.8	-1.3	-1.7	-2.1	-2.5	-3.0	-3.4	-3.8	-4.2	-4.7	-5.1	-5.5	-5.9
Commercial Advanced Lighting	0.0	-0.6	-1.2	-1.7	-2.3	-2.9	-3.5	-4.0	-4.6	-5.2	-5.8	-6.3	-6.9	-7.5	-8.1
Commercial & Industrial Thermostat	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1
Direct Load Control - Residential Switches and BYOT	-23.6	-24.6	-25.7	-26.7	-27.8	-28.8	-29.9	-30.9	-32.0	-27.1	-28.2	-29.2	-30.3	-31.3	-32.4
Residential Electric Vehicle Off-Peak Charging	0.0	-0.50	-1	-1.5	-2.0	-2.5	-3.00	-3.5	-4.0	-4.5	-5.0	-5.0	-5.0	-5.0	-5.0
Backup Generator Control	0.0	-0.3	-0.6	-0.9	-1.2	-1.5	-1.8	-2.1	-2.4	-2.7	-3.0	-3.0	-3.0	-3.0	-3.0

[106] 2025 IRP, Section 5.4 at 117-122.

Impact on Winter Peak (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Button-up Weatherization	-0.1	-1.2	-2.3	-3.4	-4.5	-5.6	-6.7	-7.8	-8.9	-10.0	-11.1	-12.3	-13.4	-14.5	-15.6
CARES Low-Income	-0.5	-1.0	-1.5	-2.0	-2.5	-3.0	-3.5	-4.0	-4.5	-5.1	-5.6	-6.1	-6.6	-7.1	-7.6
Heat Pump Retrofit	-0.4	-0.9	-1.5	-2.1	-2.6	-3.2	-3.7	-4.3	-4.8	-5.4	-6.0	-6.5	-7.1	-7.6	-8.2
Touchstone Energy Home	-1.2	-2.3	-3.5	-4.7	-5.8	-7.0	-8.2	-9.3	-10.5	-11.7	-12.9	-14.0	-15.2	-16.4	-17.5
High Efficiency Heat Pump	0.0	-1.3	-2.7	-4.0	-5.3	-6.7	-8.0	-9.3	-10.7	-12.0	-13.3	-14.7	-16.0	-17.3	-18.7
Commercial Advanced Lighting	0.0	-0.4	-0.8	-1.2	-2.6	-2.0	-2.4	-2.8	-3.2	-3.6	-4.0	-4.5	-4.9	-5.3	-5.7
Commercial & Industrial Thermostat	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
Direct Load Control - Residential Switches and BYOT	-4.5	-4.5	-4.5	-4.5	-4.5	-4.5	-4.5	-4.5	-4.5	-2.5	-2.5	-2.5	-2.5	-2.5	-2.5
Residential Electric Vehicle Off-Peak Charging	0.0	-0.1	-0.2	-0.3	-0.3	-0.4	-0.5	-0.6	-0.7	-0.8	-0.9	-0.9	-0.9	-0.9	-0.9
Backup Generator Control	0.0	-0.50	-1	-1.5	-2.0	-2.5	-3.00	-3.5	-4.0	-4.5	-5.0	-5.0	-5.0	-5.0	-5.0

DSM/EE PROGRAM COST-EFFECTIVENESS AND ENERGY SAVINGS

EKPC stated that it selects DSM/EE programs based on customer needs and resource planning objectives in a cost-effective manner.[107] EKPC stated that it guided its decisions on its DSM/EE program portfolio based on the findings of the GDS 2024 Potential Report.[108] EKPC did not suggest any changes to its DSM programs except for those proposed in Case No. 2024-00370.[109]

EKPC utilized the "DSMore" software to evaluate the cost-effectiveness of each DSM/EE program offered by EKPC.[110] EKPC calculated the cost-effectiveness of its DSM/EE programs by applying the California Standard Tests, which include the Total Resource Cost (TRC), Participant Cost Test (PCT), Ratepayer Impact Measurement (RIM), and Utility Cost Test (UTC) analyses.[111] The values listed below are the benefits

[107] 2025 IRP, Section 5.1 at 111.

[108] 2025 IRP, Section 5.1 at 112.

[109] Case No. 2024-00370, *Electronic Application of East Kentucky Power Cooperative, Inc. for 1) Certificates of Public Convenience and Necessity to Construct a New Generation Resources; 2) For a Site Compatibility Certificate Relating to the Same; 3) Approval of Demand-Side Management Tariffs; and 4) Other General Relief* (filed Nov. 11, 2024).

[110] 2025 IRP Technical Appendix, Vol. 2, Exhibit DSM-6 at 2.

[111] 2025 IRP Technical Appendix, Vol. 2, Exhibit DSM-6 at 1.

in the TRC test[112] and are the present value of the future stream of costs and benefits using a five percent discount rate:[113]

Program Name	TRC Cost-Benefit Ratio	TRC Program Cost	TRC Program Benefits
Button-Up Weatherization	2.41	$20,746,682	$49,900,671
CARES Low-Income	3.46	$5,999,401	$20,768,273
Heat Pump Retrofit	6.23	$6,138,157	$38,264,737
Touchstone Energy Home	3.36	$15,616,713	$52,414,097
High Efficiency Heat Pump	2.43	$34,909,217	$84,883,874
Commercial Advanced Lighting	1.25	$23,043,922	$28,829,365
Commercial & Industrial Thermostat	1.86	$65,297	$121,405
Direct Load Control – Residential Switches and BYOT	1.74	$20,557,281	$35,669,595
Residential Vehicle Off-Peak Charging	1.55	$5,394,081	$8,361,172
Backup Generator Control	5.96	$1,040,343	$6,200,391
Total Portfolio	**2.44**	**$133,511,094**	**$325,413,580**

As shown above, the TRC test for the entire portfolio yields a benefit-cost ratio of 2.44.

RESPONSES TO PREVIOUS COMMISSION STAFF'S RECOMMENDATIONS

1. EKPC should identify and assess all potential cost-effective DSM options.

Response: Please reference the Exhibit DSM-1 of the DSM Technical Appendix for the 2024 Potential Study prepared by GDS Associates, Inc.

2. Any changes to the DSM portfolio should be discussed in full including a transparent analysis of the cost and benefits inputs.

Response: Please reference the DSM Technical Appendix that discusses all changes to the DSM portfolio and includes cost and benefit inputs. Specific DSM program descriptions including program changes are provided in Exhibit DSM-5 of the DSM Technical Appendix. Cost and benefit inputs are provided in Exhibit DSM-3 of the DSM Technical Appendix. EKPC requested DSM tariff approvals for changes to the DSM portfolio, or DSM plan, as identified in EKPC Case 2024- 000370.

[112] A TRC score of over one is generally considered cost-effective.

[113] 2025 IRP, Section 5.4 at 126.

3. EKPC should describe and discuss all new DSM programs that they considered, and if a program was considered but ultimately not included in any model or format, EKPC should explain each basis for excluding the program.

Response: EKPC considered and developed the cost-effective DSM/EE programs recommended by the DSM/EE experts at EKPC and the Owner-Member cooperatives.

4. EKPC should continue the stakeholder process through the EKPC DSM Collaborative meetings and strive to include recommendations and inputs from the stakeholders in its DSM assessment.

Response: Please reference Exhibit DSM-7 of the DSM Technical Appendix.

5. EKPC should consider making AMI usage data that is more closely aligned to real-time data available to customers.

Response: EKPC, in partnership with Nolin RECC and Shelby Energy, conducted a pilot project that provided near real-time energy consumption data to a small test group of residential end-use members. Although some in the test group thought the near real-time data was “cool”, the pilot project resulted in very little energy and demand impacts. Most importantly, EKPC, Nolin RECC and Shelby Energy struggled just to find enough residential end-use members willing to participate in the pilot project. Thus, the pilot project was terminated due to lack of interest.

6. EKPC should consider pilot programs, peak time rebate programs, time-of-use rates and prepay options for AMI customers.

Response: As noted above, EKPC, in partnership with its Owner-Member cooperatives, conducts pilot projects. Additionally, as noted in Exhibit DSM-5, the Residential Electric Vehicle Off-Peak Charging Program is a pilot program approved by the Commission. Time-of Use and prepay programs tend to be distribution cooperative rates and service offerings instead of DSM/EE rebate programs.

7. 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.

Response: Please reference Exhibit DSM-3 of the DSM Technical Appendix that identifies deemed energy and demand savings and associated voided costs. EKPC utilizes deemed savings from Technical Resource Manuals of nearby states to forego the extremely expensive evaluations, measurement, and verification programs.

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

Response: Please reference Exhibit DSM-8 of the DSM Technical Appendix.

9. EKPC should thoroughly examine and fully discuss the cost-saving possibilities involved in the proliferation of C&I interruptible rate options.

Response: EKPC has a robust portfolio of commercial and industrial demand response programs that maximize monetary benefit from the PJM capacity and energy markets. EKPC and its Owner-Member cooperatives' "interruptible" rate is being utilized by over 20 commercial and industrial accounts and continues to grow. Participants are provided with a demand credit for participation. Although the program is complex, EKPC leverages a sophisticated distributed energy resource management system, and works diligently with the member systems and the interruptible participants to ensure that they understand how to manage their risk for both economic (AKA optional) and reliability (AKA mandatory) interruptions.

Participants are subjected to economic interruptions when the Locational Marginal Pricing (LMP) values exceed a threshold, allowing EKPC to forego high energy market expenses. Participants are given the option to either interrupt their load, avoiding higher energy charges for the specified time, or they can buy through at the LMP market costs.

Participants that are subjected to PJM's capacity market interruptions, although rare, require a mandatory load reduction. The MWs of interruptible load is a capacity resource and EKPC receives the financial payment from the PJM capacity market for the interruptible MW participation. The winter load drop capability is close to 10 percent of EKPC's total generation fleet.

SECTION 4

SUPPLY-SIDE RESOURCE ASSESSMENT

INTRODUCTION

In this Section, Commission Staff reviews, summarizes, and comments on EKPC's evaluation of existing and future supply-side resources. Commission Staff's discussion of and recommendations regarding EKPC's supply-side resource assessment forecasting are in Section 6 of this Report.

SUMMARY OF EXISTING AND PLANNED CAPACITY AND RESOURCES

EKPC's stated total power capacity at the time it filed its 2025 IRP was approximately 2,963 megawatts (MW) of net summer generating capacity and 3,265 MW of net winter generating capacity.[114] EKPC explained that it currently owns, operates, and/or has firm rights to approximately 3,435 MW of winter capacity, located at 11 separate sites with a total of 25 generating units, including a firm purchase power agreement with the Southeastern Power Administration (SEPA).[115] EKPC's existing resources include:

- Coal-fired generation production at John S. Cooper Station (Cooper Station) totaling 341 MW.[116] Cooper Station includes two pulverized coal units, one with generation capacity of 116 MW and one with generating capacity of 225 MW, which became operational on February 9, 1965, and October 28, 1969, respectively;[117]

- Coal-fired generation production at Hugh L. Spurlock Station (Spurlock Station) totaling 1,346 MW.[118] Spurlock Station includes two pulverized coal units with FGD technology, one is a 300 MW unit that began commercial operation on September 1, 1997, and one is a 510 MW unit that began operating on March 2, 1981.[119] Additionally, Spurlock Station includes two circulating fluidized bed boiler technology, 268 MW units, which became operational on March 1, 2005, and April 1, 2009, respectively.;[120]

[114] 2025 IRP at 1—2.

[115] 2025 IRP at 82.

[116] 2025 IRP at 1—2.

[117] 2025 IRP at 82.

[118] 2025 IRP at 1—2.

[119] 2025 IRP at 82.

[120] 2025 IRP at 82.

- Natural gas/fuel oil fired generation at J. K. Smith Station (Smith Station), including nine combustion turbines totaling 753 MW of summer capacity and 989 MW of winter capacity;[121]

- Natural gas/fuel oil fired generation at Bluegrass Generating Station (Bluegrass Station), including three CT units totaling 501 MW of summer capacity and 567 MW of winter capacity, which were retrofitted for fuel oil as a secondary fuel supply in 2020;[122]

- 13.8 MW of landfill gas generation which EKPC owns and operates at five sites throughout Kentucky;[123]

- 8.5 MW of solar power from the Cooperative Solar Farm One facility which was placed into operation on November 12, 2017 and features 32,300 solar panels. As of year-end 2024 there were 293 subscribers with 1,827 panels;[124]

- 500 kWac of solar power from the Star Hill Farm which became operational on September 17, 2024;[125]

- 170 MW hydroelectric power which EKPC purchases from SEPA on a long-term basis;[126]

- A corrugated paper recycling facility owned by International Paper which has an expected peak electrical load of approximately 35 MW and an equivalent of 29 MW in steam, for which the steam is supplied from the Spurlock Station;[127]

- 200 MW interruptible load;[128] and

- 28 MW in peak reduction mechanisms.[129]

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[121] 2025 IRP at 83.

[122] 2025 IRP at 83.

[123] 2025 IRP at 84.

[124] 2025 IRP at 84.

[125] 2025 IRP at 84.

[126] 2025 IRP at 83.

[127] 2025 IRP at 83.

[128] 2025 IRP at 1—2.

[129] 2025 IRP at 1—2.

EKPC has also received CPCNs for the following generation projects to be constructed:

- 136.5 MW of solar power from three proposed solar farms;[130]
- 214 MW in Reciprocating Internal Combustion Engine (RICE) generators;[131] and
- 745 MW natural gas-fired Combined Cycle Gas Turbine (CCGT) at Cooper Station, along with natural gas co-fire conversion of existing coal-fired generating units including Spurlock Units 1 through 4 and Cooper Unit 2,[132] which according to EKPC does not change the capacity value of Spurlock or Cooper Stations.[133]

EKPC plans to construct, but has not yet obtained CPCNs for, an additional 321 MW of solar power accredited for 80 MW of capacity during summer and no capacity value for winter.[134] EKPC also included in its IRP 300 MW of (energy-only) hydroelectric power purchase agreement (PPA) that terminated on December 31, 2025 and will not be renewed.[135]

SUMMARY OF NEW GENERATION CONSIDERED

PJM will require a reserve margin of 17.8 percent for 2025/2026.[136] To meet the capacity required to meet the needs indicated by the load forecast plus the reserve margin, the RTSim modeling system must consider new generation options.

[130] Approval of one solar farm, granted in Case No. 2024-00129, *Electronic Application of East Kentucky Power Cooperative, Inc. for Certificates of Public Convenience and Necessity and Site Compatibility Certificates for the Construction of a 96 MW (Nominal) Solar Facility in Marion County, Kentucky and a 40MW (Nominal) Solar Facility in Fayette County, Kentucky and Approval of Certain Assumptions of Evidence of Indebtedness Related to the Solar Facilities and Other Relief* (Ky. PSC Dec. 26, 2024), Order at 34, is on appeal to Franklin Circuit Court, Case No. 25-CI-00044, *Lexington Fayette Urban County Gov't, et al. v. Kentucky Public Svc. Comm., et al*.

[131] Case No. 2024-00310, *Electronic Application of East Kentucky Power Cooperative, Inc. For 1) a Certificate of Public Convenience and Necessity to Construct a New Generation Resource; 2) a Site compatibility Certificate; and 3) Other General Relief* (Ky. PSC May 20, 2025), Order at 60.

[132] Case No. 2024-00370, *Electronic Application of East Kentucky Power Cooperative, Inc. for 1) Certificates of Public Convenience and Necessity to Construct a New Generation Resource; 2) for a Site Compatibility Certificate Relating to the same; 3) Approval of Demand-Side Management Tariffs; and 4) Other General Relief* (Ky. PSC July 3, 2025), Order at 80.

[133] Case No. 2024-00370, Application (filed Nov. 20, 2024), Exhibit BY-2 at 1—5 and Exhibit BY-3 at 1-5.

[134] 2025 IRP at 13.

[135] EKPC's Response to Commission Staff's First Request for Information, Item 5(a).

[136] 2025 IRP at 6.

For modeling purposes, EKPC assumed all of the above-referenced existing and planned generation, with no retirements due to the need for additional capacity.[137] The model was permitted to select the following generation resources:[138]

- 100 MW 7EA Simple Cycle Gas Combustion Turbine (CT)
- 282 MW 7F Simple Cycle Gas CT
- 745 MW Natural Gas Combined Cycle Unit (CC)
- 214 MW RICE Unit
- 278 MW Small Modular Reactor (SMR) Nuclear
- 325 MW Pumped Hydroelectric Power
- 400 MW Battery Energy Storage System (BESS)
- 50/100 MW Winter PPA

TRANSMISSION AND DISTRIBUTION SYSTEM PLANNING

Since PJM manages the transmission of electricity across 13 states and the District of Columbia, EKPC coordinates closely with PJM regarding transmission planning. PJM establishes transmission criteria, identifies areas of need, and assesses planned transmission projects.[139] EKPC performs additional analysis to identify projects to meet local transmission-system needs not addressed by the PJM planning criteria.[140]

Between 2022 and 2024, EKPC upgraded four transmission stations, constructed two new switching stations, rebuilt 134.63 miles of transmission line to higher capacity line, constructed 14.16 miles of new transmission lines, performed high temperature upgrades of 0.6 miles of transmission lines, and reconductored aging lines.[141]

EKPC's plans for transmission system improvements through 2027 includes a rebuild of 176.7 miles of 69 kV line and construction of four new 69 kV switching stations, 42.9 miles of new 69 kV line, and 3.2 miles of new 161 kV line.[142]

ENVIRONMENTAL COMPLIANCE

EKPC stated that it evaluates proposed, draft, and final federal environmental rules on an ongoing basis to maintain a forward-looking compliance plan. However, EKPC clarified at hearing that it always models based on existing, enforceable environmental regulations, and does not speculate as to the success or failure of potential changes until

[137] EKPC's Response to Staff's First Request, Item 10.

[138] 2025 IRP at 180.

[139] 2025 IRP at 131.

[140] 2025 IRP at 132.

[141] 2025 IRP at 133—134.

[142] 2025 IRP at 135.

pending regulations are finalized.[143] Section 9 of the IRP provides the current compliance narrative and identifies the major air, water, and waste programs applicable to EKPC's fleet.[144] EKPC indicates it is presently in compliance with applicable Clean Air Act (CAA), Clean Water Act (CWA), and Resource Conservation and Recovery Act (RCRA) requirements discussed below.[145]

Clean Air Act (CAA)

- New Source Review/Prevention of Significant Deterioration (NSR/PSD)
  - EKPC reports it maintains an internal NSR/PSD review program for outage and project work and remains in compliance with its 2007 Consent Decrees as incorporated into air permits.[146] EKPC also filed a PSD application on September 20, 2024 for the proposed Wärtsilä RICE facility near Liberty, Kentucky.[147]
- Section 111 Greenhouse Gas (GHG) Rules for Existing Coal Units
  - EPA finalized the GHG standards of performance for existing coal-fired units (Subpart UUUUb) on May 9, 2024. The rule requires long-term operating commitments (retire/repower by date-certain or meet emission-rate standards via controls or co-firing). EKPC summarized the final rule and key compliance pathways and timelines in the IRP.[148] EPA also issued a companion "Implementation Rule" describing state plan milestones and federal plan contingencies, which EKPC is monitoring.[149]
- Mercury and Air Toxics Standards (MATS)
  - EPA completed its 2024 MATS review, tightening filterable particulate matter (PM) (as a surrogate for non-Hg metals) and other limits; EKPC discusses the final action and compliance implications for its units.[150]
- Cross-State Air Pollution Rule (CSAPR) / Good Neighbor Plan
  - EPA's recent "Good Neighbor Plan" revisions for ozone transport tightened seasonal NO_x budgets in multiple phases. EKPC's IRP discusses

[143] Hearing Video Transcript (HVT) of March 10, 2026 Hearing, Hearing Testimony of Jerry Purvis (Purvis Hearing Testimony) at 11:47:55—11:51:31; HVT of March 10, 2026 Hearing, Hearing Testimony of Julia Tucker (Tucker Hearing Testimony) at 15:38:02—15:39:06.

[144] 2025 IRP at 193.

[145] 2025 IRP at 196—197.

[146] 2025 IRP at 196.

[147] 2025 IRP at 196—197.

[148] 2025 IRP at 206—209.

[149] 2025 IRP at 210—211.

[150] 2025 IRP at 199.

continuing obligations under CSAPR/Good Neighbor and notes ongoing monitoring of program adjustments.[151]

- National Ambient Air Quality Standards (NAAQS)
    - EPA's NAAQS program continues to evolve. EKPC summarizes current standards and the then-recent revision activity, including the 2024 particulate matter reconsideration and associated state implementation planning timelines that could affect permitting and operations.[152]

Clean Water Act (CWA)

- Section 316(a) Thermal Variances and 316(b) Cooling Water Intake
    - EKPC outlines compliance with thermal variance requirements (316(a)) and entrainment/impingement controls for cooling water intakes (316(b)) at its generating stations, including applicable monitoring and best technology available determinations.[153]
- Steam Electric Effluent Limitations Guidelines (ELGs)
    - EPA's Steam Electric Effluent Limitations Guidelines (ELGs) were revised in 2023–2024 for bottom ash transport water, FGD wastewater, and related waste streams. EKPC summarizes applicability and compliance pathways/timelines for its coal units and indicates it is tracking rule reconsideration activity and associated implementation schedules.[154]

Resource Conservation and Recovery Act (RCRA) — Coal Combustion Residuals (CCR)

- CCR Rule (2015) and Subsequent Actions
    - The IRP recounts the CCR program's framework (location restrictions, structural integrity, liner, groundwater monitoring, closure and post-closure), the WIIN Act's federal/state permitting provisions, and the D.C. Circuit's *USWAG v. EPA* decision that precipitated later CCR amendments.[155] EKPC reports that all regulated CCR units at Spurlock, Cooper, and Smith are presently meeting groundwater monitoring requirements with no statistically significant exceedances of groundwater protection standards and no corrective action required.[156]
- 2024 CCR "Legacy" Rule
    - EPA's May 8, 2024 Legacy Rule extends certain CCR requirements to (i) legacy CCR surface impoundments (LSIs) and (ii) CCR management units

[151] 2025 IRP at 200—201.

[152] 2025 IRP at 201—203.

[153] 2025 IRP at 210—211.

[154] 2025 IRP at 212.

[155] 2025 IRP at 217—218.

[156] 2025 IRP at 219—220.

(CCRMu). EKPC summarizes the rule and lists key deadlines: for LSIs, install monitoring and begin detection/assessment monitoring by May 10, 2027 and initiate closure by May 8, 2028; for CCRMus, begin monitoring by May 8, 2028 and initiate closure by May 8, 2029.[157] EKPC identifies 11 facilities that may have LSIs/CCRMus, has engaged third-party engineering firms to support inventories and compliance planning, and states it is monitoring EPA's pending "technical corrections" while evaluating obligations to meet all future deadlines.[158]

RELIABILITY

EKPC's stated strategic objectives included balancing resources in a way that maintains reliable capacity while navigating environmental regulation, transitioning to more sustainable resources, and mitigating cost for ratepayers.[159] PJM also seeks to ensure reliability within its service territory, in part, by requiring its member load serving entities to maintain a summer reserve margin capacity requirement.[160]

For its 2025 IRP, EKPC established a 7 percent winter reserve margin,[161] in part in response to specific reliability issues arising from Winter Storm Elliott outages and derates resulting in over $13 million in performance penalties.[162] The inclusion of a winter reserve margin was a recognition of two risks: higher than anticipated demand during extreme cold weather and generator unit outages.[163]

EKPC noted that as technology develops to allow for a "lower carbon future," fossil fuels and nuclear power will bridge the gap and maintain reliability until storage technology and cost improvements permit renewable energy sources to provide greater capacity. Coal and natural gas resources with dual fuel backup secure dispatchability via on-site fuel storage. This provides a significant reliability advantage over resources without access to on-site fuel storage.[164] Renewables, primarily solar power, provide little to no capacity value during winter heating season and especially during winter peaks. PJM also noted that "[solar] ... only met or exceeded its capacity expectations during a few hours each afternoon, which was not coincident with the peak electric demand

[157] 2025 IRP at 218—219 (deadlines summarizing Legacy Rule).

[158] 2025 IRP at 219—220.

[159] 2025 IRP at 2-3.

[160] 2025 IRP at 6, 17.

[161] 2025 IRP at 11, 39. EKPC did not utilize a winter reserve margin for its 2022 IRP.

[162] 2025 IRP at 10—11.

[163] 2025 IRP at 11.

[164] EKPC's Response to Attorney General's First Request for Information, Item 1(c-d) and Item 2(b)(i-iii).

periods."[165] At present, renewables, specifically solar, though not anticipated to provide winter capacity, provide cost-effective energy which is anticipated to offset economic energy purchases from the PJM energy market.[166]

The Attorney General's comments, discussed below, aptly note the balance that must be struck between reliability and affordability. Unfortunately, reliability and affordability are inversely proportional. For example, EKPC's plan to adopt a winter reserve margin unquestionably raises reliability of the grid during the winter, but it also unquestionably raises costs to ratepayers. The Commission will be tasked with weighing these two factors in future generation CPCN cases alongside FERC guidelines for reliability and the requirements of KRS 278.264, which favors maintaining fossil fuel generation resources over least-cost principles.

RESPONSES TO PREVIOUS COMMISSION STAFF'S RECOMMENDATIONS

1. EKPC should provide a more robust discussion of potentially viable supply-side resources and should assess all potentially cost-effective resources using the resource expansion modeling software.

Response: EKPC provided a robust discussion of potentially viable supply-side resources to meet the immediate supply need from 2025 through 2030. EKPC modeled this need using the expansion modeling software RTSim. The supply-side resources are also the subject of one recent, two pending, and one anticipated CPCN cases.

2. EKPC should describe and discuss all supply-side resources that were considered, including variations of the same resource (e.g., NGCC with and without CCS), and if a resource was considered but ultimately not included in the model, EKPC should explain each basis for excluding the resource, including the specific information used to support each basis such as engineering concerns that resulted in a resource being excluded based on a determination that it is not feasible.

Response: EKPC provided in this IRP all reasoning for including or excluding supply-side resources.

3. EKPC should consider interconnection costs and the cost of necessary network upgrades to the extent possible when assessing resources both in and outside its service territory and should describe and discuss how such costs were considered, whether and how such costs were included in the modeling software, uncertainties associated with how such costs were considered and, if applicable, why such costs could not be included in the modeling software.

[165] EKPC's Response to the Attorney General's First Request, Item 2 and b(i-v).

[166] EKPC Response to Attorney General's First Request, Item 2b(iii).

Response: EKPC did not consider interconnection costs with regards to the resource expansion modeling performed as part of this IRP. The optimal plan did not include the addition of generation to the EKPC system beyond what is included in Case No. 2024-00310 and Case No. 2024-00370 currently being considered by the Commission; and therefore, it was not beneficial to model or compare interconnection costs. EKPC will, when applicable, consider interconnection costs for new resources.

4. EKPC should consider and discuss savings, if any, that could be achieved by obtaining resources owned and operated through partnerships with other utilities.

Response: When EKPC issues public Request for Proposals (RFPs), all other utilities can answer. At the request of the Kentucky Economic Development Cabinet, EKPC discussed the possibility of jointly serving future large industrial loads.

5. EKPC should consider and discuss opportunities, or the lack thereof, to partner with nearby utilities to gain experience with or access to new generation resources.

Response: When EKPC issues public Request for Proposals (RFPs), all other utilities are able to answer.

6. EKPC should generally be in communication with other Kentucky electric utilities and review their IRPs when conducting planning.

Response: EKPC is in general communication with other Kentucky utility companies and reviews each IRP filed at the Commission.

7. To the extent possible, EKPC should consider whether transmission options would allow it to serve load at a lower cost, including whether additional transmission capacity could lower locational marginal pricing within EKPC's PJM zone in a way that will reduce costs to customers or could provide access to additional energy from other PJM zones, when necessary, at a lower cost than constructing or maintaining additional reserve generation.

Response: PJM studies market efficiency projects through its Regional Transmission Expansion Planning (RTEP) process. Market efficiency projects are intended to lower overall energy costs throughout the PJM system and bring greater efficiency to energy delivery within the RTO.

8. In its next IRP, EKPC should provide a discussion of each cause of any reliability issues that arose on its system during Elliott; how EKPC could improve its current generation and transmission facilities to address reliability issues in a cost effective manner; the risks presented by multiple Kentucky utilities relying on the same natural gas transmission network and how they can be mitigated; and how EKPC changed its assessment of resources based on Elliott, e.g. whether it increased the risk of forced outages for certain resource for planning purposes. EKPC should also discuss long-term and short-term options to improve reliability if it is not able to run gas generators coupled

with the possibility of not being able to import power, including whether it would be reasonable to plan for such a scenario. To the extent EKPC has any bilateral contracts to provide or receive power during an emergency, the discussion should include whether the contracts protect EKPC if it is unable to provide backup power and what obligation the counterparty has to provide power to EKPC.

Response: EKPC discusses the impacts of Winter Storm Elliott to its planning throughout the IRP and discusses specific events of Winter Storm Elliott in Section 1.6.

INTERVENOR AND RESPONSE COMMENTS

The Attorney General's comments focused largely on reliability and affordability. These comments cautioned against what the Attorney General perceives as a national trend towards "prematurely shuttering fossil fuel baseload generation resources."[167] The Attorney General noted "the intermittent nature of renewable resources such as wind and solar inherently carries reliability risks" and that EKPC's generation portfolio includes planned renewable resources.[168] Nonetheless, the Attorney General appears to have approved of EKPC's resource balance between dispatchable resources and renewables, stating "EKPC appears to share the Attorney General's reliability concerns with the electric grid" and "EKPC further states that conventional generation resources will be required to maintain the reliability of the grid. The conventional generation EKPC refers to as being required to maintain reliability is fossil fuel generation (e.g., coal, natural gas, and oil), as well as nuclear generation."[169] (citations omitted)

The Attorney General also expressed concerns regarding the impact of changes in federal environmental and energy policy on reliability, resource planning, and energy costs.[170]

Sierra Club commented that the Commission should reject EKPC's IRP due to its "lack of exploration of other alternatives at the Company's coal units and other replacement alternatives to the new natural gas combined cycle plant (NGCC) at the Cooper coal plant site."[171] Sierra Club asserted that EKPC understated the costs of natural gas-fueled generation and overstated the cost of battery storage in its modeling.[172]

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[167] Attorney General's Initial Comments at 3—4.

[168] Attorney General's Initial Comments at 3—4.

[169] Attorney General's Initial Comments at 5.

[170] *See* Case No. 2024-00129, *Electronic Application of East Kentucky Power Cooperative, Inc. for Certificates of Public Convenience and Necessity and Site Compatibility Certificates for the Construction of a 96 MW (Nominal) Solar Facility In Marion County, Kentucky and a 40 MW (Nominal) Solar Facility in Fayette County, Kentucky and Approval of Certain Assumptions of Evidences of Indebtedness Related to the Solar Facilities and Other Relief* (Ky. PSC Dec. 26, 2024), Order at 35.

[171] Sierra Club's Initial Comments at 1.

[172] Sierra Club's Initial Comments at 1—2, 11.

Sierra Club also criticized predetermination of major resource decisions.[173] Sierra Club believed that EKPC should have considered full gas conversion or retirement of coal units.[174] Sierra Club reiterated in post-hearing comments that EKPC should have allowed the model to allow for full-gas conversion of gas/coal co-firing units and retirement of coal plants.[175]

EKPC's response comments noted that the recent removal of renewables tax credits eliminated several planned solar projects that may have saved ratepayers on energy costs.[176]

EKPC responded to Sierra Club's modeling comments by explaining that EKPC chose to model the co-fire conversion of the existing coal fleet (with exception of Cooper 1), Liberty RICE, and Cooper NGCC as assumptions because these assets were critical to EKPC's portfolio within the IRP's 2025-2039 planning horizon.[177] EKPC did not model full conversion to natural gas because, this would put EKPC in full reliance on natural gas suppliers and eliminate the ability to hedge exposure to gas price increases.[178] EKPC did not include retirement of generation in its modeling due to its capacity shortfall, as well as the strong likelihood that environmental deregulation would eliminate economic benefits of retirement.[179]

Regarding battery storage options, EKPC stated that battery storage was modeled but not selected by the resource optimizer.[180] EKPC further responded that "NREL capital cost estimates for BESS were derived from a 4-hour BESS as the default resource. EKPC chose to use the default resource as it is the most reasonable estimate available."[181]

[173] Sierra Club's Initial Comments at 1—2.

[174] Sierra Club's Initial Comments at 4.

[175] Sierra Club's Post-Hearing Comments at 2—5. Commission Staff notes that although Sierra Club references "six remaining coal units" besides two at Cooper Stations and four at Spurlock Station, EKPC only operates the six total coal units at Cooper and Spurlock stations.

[176] EKPC's Initial Response Comments at 3.

[177] EKPC's Initial Response Comments at 4—5.

[178] EKPC's Initial Response Comments at 5.

[179] EKPC's Initial Response Comments at 6—7.

[180] EKPC's Initial Response Comments at 8.

[181] EKPC's Initial Response Comments at 9.

SECTION 5

INTEGRATION

INTRODUCTION

A goal of the IRP process is to integrate supply-side and demand-side options to achieve an optimal resource plan. This section will discuss the integration process and the resulting EKPC's plan. Commission Staff's discussion of and recommendations regarding EKPC's integration are in Section 6 of this Report.

Optimizing and Modeling

EKPC uses the RTSim model to develop its future resource plans. The RTSim production cost model calculates the hour-by-hour operation of all EKPC's generation including unit hourly generation, commitment, power purchases, and sales (economic and day ahead transactions in the PJM energy market and daily and monthly options using Monte Carlo simulations).[182] Generation inputs include expected outages, Monte Carlo forced outages, unit ramp rates, and unit startup characteristics. The Monte Carlo simulations capture statistical variations of unit forced outage and derates, load uncertainty, market price uncertainty, and fuel price uncertainty, all in an effort to simulate the actual operation of a power system to supply projected customer loads.[183] Each Monte Carlo simulation uses one set of load data based on EKPC's load forecast and four additional load data sets, creating a statistical range of high and low load forecasts. Each Monte Carlo iteration will draw on a few days from different forecasts to simulate changing weather patterns and then use actual and forecasted market prices, natural gas prices, coal prices, and emission costs correlated to the load data. Five hundred iterations are used in the model simulations.[184]

EKPC uses the RTSim Resource Optimizer (Optimizer) module to perform the optimization of the resource plans. The Optimizer automatically sets up and runs the RTSim production cost module to perform simulations of a large number of potential resource plans to determine the optimal plan.[185] Data inputs include but are not limited to: minimum and maximum future capacity needs, resource alternatives, resource alternative annual fixed costs and variable costs of alternative resources, and alternative resource potential in-service dates.[186] The Optimizer uses the same data and analysis in production cost simulations, except that future generation units are set as resource option

[182] 2025 IRP at 179.

[183] 2025 IRP at 179.

[184] 2025 IRP at 179.

[185] 2025 IRP at 179.

[186] 2025 IRP at 184.

alternatives. These are set up with several potential in-service dates. Annualized fixed capital costs and variable costs associated with particular resources are included.[187]

The Optimizer module was set up to run 2,500 different expansion plans with five iterations for each alternate plan. Each iteration varied load, fuel and market prices and forced outages. As a result of EKPC essentially hard-coding the amount of and timing of its existing generation, it's to-be-filed generation CPCNs, and its yet-to-be-filed generation CPCNs, the Optimizer was run for the 2025-2030 period only; the years within the study period for which additional capacity was needed. The production cost and Optimization modeling was not allowed to choose these resources in conjunction with the potential resources over the study period to comprehensively evaluate whether they would have been selected in a least cost expansion plan in the same manner that they had been hard coded into EKPC's preferred expansion plan. EKPC's rationale was that the IRP represented a snapshot in time and the capacity resources included in the modeling were based on the information and its generation plan as of November 2024.[188] Table 8-5 Resource Optimization Plan Summary (listed below) contains the five lowest cost resource portfolios and EKPC's preferred final plan:[189]

Year	Type	Plan 1	Plan 2	Plan 3	Plan 4	Plan 5	Final Plan
2025	Peaking		282	282	282	282	
	Intermediate						
	Renewable						
	Seasonal PPA	50	50	80	90		**50**
2026	Peaking						
	Intermediate						
	Renewable						
	Seasonal PPA	100	110	90		180	100
2027	Peaking						
	Intermediate						
	Renewable						
	Seasonal PPA	50	60				**50**
2028	Peaking						
	Intermediate						
	Renewable						
	Seasonal PPA	50			60		**50**
2029	Peaking						
	Intermediate						

[187] 2025 IRP at 180.

[188] IRP, Section 1.6 Footnote 5 at 13.

[189] IRP, Section 8 Table 8-5 page 186, select years. *See also* EKPC's Response to Staff's Second Request for Information, Item 28b Attachment. Staff notes that the seasonal PPA additions are listed in EKPCs as capacity purchases in EKPC's IRP2025 Expansion Plan – ELCC Adjusted Summer table.

	Renewable						
	Seasonal PPA						
2030	Peaking						
	Intermediate						
	Renewable						
	Seasonal PPA				180		

EKPC selected the lowest cost portfolio which called for winter seasonal capacity purchases annually for the 2025-2029 period. Subsequently at the hearing, EKPC indicated that the Hydro PPA and the four solar PPAs had been removed from the expansion plan and replaced with four separate 100 MW PPAs backed by nuclear power from Constellation Energy.[190] The table below shows EKPC's most complete up-to-date representation of its preferred expansion plan with projected additions, deletions and reserves.[191]

Table 8-3 (w/o Hydro PPA, w/o Solar Farms 5-8, w/ Nuclear PPAs)
EKPC Projected Additions and Reserves (MW)

Year	Capacity Additions** / Retirements*		Current PPAs***		Seasonal Energy Additions		Long-Term Load Forecast		Reserve Requirements		Capacity Required		Total Capacity & Peak Energy		Reserve Margin (Target 7%)	
	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum
2025					50		3517	2530	246	177	3763	2707	3,777	3,452	0%	27%
2026			200	200	250		3627	2588	254	181	3881	2769	3,877	3,352	0%	21%
2027			100	100	450		3677	2641	257	185	3934	2826	3,977	3,286	1%	16%
2028			100	100	450		3712	2664	260	186	3972	2850	3,977	3,286	0%	15%
2029	214	214			400		3727	2688	261	188	3988	2876	4,039	3,398	1%	18%
2030					400		3743	2703	262	189	4005	2892	4,030	3,389	1%	17%
2031	745	725					3760	2723	263	191	4023	2914	4,375	4,114	9%	41%
2032	-116	-16					3788	2749	265	192	4053	2941	4,259	3,998	5%	36%
2033							3793	2766	266	194	4059	2960	4,259	3,998	5%	35%
2034							3811	2792	267	195	4078	2987	4,259	3,998	4%	34%
2035							3832	2818	268	197	4100	3015	4,259	3,998	4%	33%
2036							3870	2853	271	200	4141	3053	4,259	3,998	3%	31%
2037							3882	2878	272	201	4154	3079	4,259	3,998	3%	30%
2038							3908	2910	274	204	4182	3114	4,259	3,998	2%	28%

[190] HVT of March 10, 2026 Hearing, Hearing Testimony of Christopher Adams (Adams Hearing Testimony) at 02:22:00–02:22:59. *See also* EKPC's Response to Staff's Post-Hearing Data Request Item 5, Attachment PSC_PHDR_Response_5_-_Table_8-3_(Updated).pdf.

[191] EKPC's Response to Staff's Post-Hearing Data Request Item 5, Attachment PSC_PHDR_Response_5_-_Table_8-3_(Updated).pdf. Note that the base load and peaking / intermediate capacity columns have been combined.

2039							3933	2941	275	206	4208	3147	4,259	3,998	1%	27%

* Cooper 1 begins Mothball status Jan 2032

** Liberty RICE addition in Dec 2028 and Cooper 3 CCGT in Dec 2030.

*** Current PPAs include four separate 100 MW PPAs with Constellation Energy.

Two 100 MW PPAs for 2026, one 100 MW PPA for 2027, and one 100 MW PPA for 2028.

RESPONSES TO PREVIOUS COMMISSION STAFF'S RECOMMENDATIONS

1. The Preferred Plan was not determined by the production cost/optimization model (RTSimm). EKPC's Sustainability Goals were layered by committee consensus in on the top least cost plan (Plan 1). If EKPC reflects its sustainability goals in the next IRP, EKPC should at minimum identify and explain each of its sustainability goals, explain each assumption or assessment that formed its basis for adopting those goals, and explain in detail how those sustainability goals were used to develop the final plan.

Response: EKPC discussed its sustainability goals within this IRP. The goals represent a target for greater diversity in energy supply at competitive costs.

2. As an alternative for comparison purposes and clarity, the sustainability goals, or rather the basis for the sustainability goals, should be given to RTSimm and the model should be allowed to determine the least-cost way to achieve the goals. EKPC could then develop and discuss a final plan based on the relative costs of the various plans produced by the model in scenarios with and without the sustainability goals and EKPC's analysis of the relative likelihood of the various scenarios.

Response: EKPC included solar and hydro resources within its modeling based on expected service dates for each resource as included in EKPC's RUS New ERA application.

3. Carbon prices were excluded from load forecasting but were included in DSM modeling. EKPC should consistently include or exclude carbon prices or any other carbon limitation across different modeling methods.

Response: EKPC did not include carbon prices in any capacity, forecasting, DSM model in this IRP.

4. EKPC should spend additional time discussing the likelihood of the regulatory risks it identified and how those risks would affect existing and potential resources if they occurred. Further, as above, the modeling software should be used to the extent possible to assess resource options and potential scenarios that are likely to materially affect the resources selected, e.g., a scenario that assessed the costs of upgrading existing units to comply with the potential revision to the Cross-State Air Pollution Rule. EKPC could then develop and discuss a final plan based on the relative costs of the various plans produced by the model in scenarios with and without the potential regulation and EKPC's analysis of the relative likelihood of the various scenarios.

Response: EKPC discussed potential regulatory risks and how those risks would affect existing resources. EKPC did not identify any potentially new resources within this IRP for which to discuss regulatory risks.

5. EKPC should use the full functionality of RTSimm, or its chosen modeling software, to examine the economic and practical viability of available and near-market-ready resources, including: Economic addition or retirement of generation resources; Behind the meter DERs and other customer owned generation; Cogeneration opportunities to the extent these exist or can be anticipated and modeled; and DSM/EE programs: To the extent possible, EKPC should analyze generation resources and DSM/EE programs together as resources that may be selected in the same modeling runs to meet projected load, using the same cost and other inputs, to ensure that new DSM/EE programs and new generation resources are assessed on equal footing.

Response: EKPC has no current plans to retire any generation units given its need for additional capacity within the 2025 through 2030 period. Therefore, the model was not used to predict retirement of any generation. The model employed the economic addition of generation or supply resources as discussed in this IRP.

Behind the meter DERs, end-use member-owned generation, cogeneration and small power producer generation is included within the base forecast assumptions, along with all DSM and EE projections, as offsets to demand and energy. They are not explicitly modeled as resources within the model. This is because EKPC cannot guarantee the construction, availability or output of these resources. EKPC encouraged these types of resources through its DSM and Cogeneration tariffs.

6. If EKPC is not able assess the adoption of customer owned generation using its modeling software, EKPC should project the extent to which its customers will adopt customer owned resources, including qualifying facilities, customer owned solar and other customer owned DERs, during the planning period of its next IRP and should project the effects those resources are likely to have on load, and EKPC should fully explain the methodology and assumptions used to make those projections.

Response: EKPC did not forecast increases in customer-owned generation, QFs, customer-owned solar or other DERs. EKPC encouraged these types of resources through its net metering DSM and Cogeneration tariffs.

7. Each of the five lowest cost plans and the optimal plan had multiple additions of solar PPAs in various years. For the next IRP, if a similar pattern emerges which includes EKPC's sustainability goals, there needs to be a discussion of how each of EKPC's generation resources will operationally function such that the overall resource mix as determined by the RTSimm models is the least-cost plan.

Response: EKPC did not discuss this as there is no such pattern within this IRP.

8. EKPC should consider the likelihood of PJM changing its solar capacity credit as a variable in future modeling.

Response: EKPC utilized PJM's ELCC forecasts for fixed-panel solar assets to assess the total annual capacity contribution of solar.

INTERVENOR AND RESPONSE COMMENTS

The Attorney General commented regarding concerns that EKPC's planning strategy is too reliant on purchases from the PJM market to make up EKPC's forecasted energy shortage.[192]

EKPC filed response comments, echoing the Attorney General's need for balance to be achieved between reliability and cost. EKPC noted that PJM market purchases prevent EKPC from running "out-of-the-money" generation to meet its load requirements,[193] and argued that seasonal PPAs can hedge against the cost of PJM market purchases.[194] However, EKPC also acknowledged that the Attorney General's desire for EKPC to have more native generation to serve its native load was the best hedge against PJM market uncertainty.[195]

[192] Attorney General's Initial Comments at 11.

[193] EKPC's Initial Response Comments at 1—2.

[194] EKPC's Initial Response Comments at 2.

[195] EKPC's Initial Response Comments at 2.

SECTION 6

REASONABLENESS AND RECOMMENDATIONS

INTRODUCTION

Many aspects of EKPC's 2025 IRP, including some of the methodologies and assumptions used to produce the IRP, are reasonable and consistent with 807 KAR 5:058. However, there are areas in which EKPC could improve its IRPs going forward, including issues with certain methodologies and assumptions that affected the reasonableness of the 2025 IRP. This section discusses the reasonableness of EKPC's 2025 IRP and the issues and areas for improvement and makes recommendations for EKPC's next IRP in 2028.

LOAD FORECAST

Data Centers

The development of data centers as a major source of future load is likely to continue for the foreseeable future and led Commission Staff to consider whether all electric generating utilities should include a hypothetical data center load in their load forecasts and modeling. EKPC did not initially model a hypothetical data center load; However, in response to Staff's First Amended Request, EKPC modeled the addition of a one-gigawatt load with a 95 percent load factor, the results of which included the addition of two 745 MW 2-on-1 F-class NGCC units as the least cost solution.[196] The unique nature of large load data centers means that even the addition of a single customer has the potential to overwhelm EKPC's traditional load forecast (especially in the short to medium term) favoring constructing additional generation in historically atypical fashion without the proven stability embedded in traditional system growth rates, risking unnecessary or less economically efficient capital investments in favor of satisfying a single customer's immediate business needs. Sierra Club argued in favor of transparency and communication with the public regarding details of any planned data center in EKPC's territory.

During the time the electric industry experienced slow to moderate growth, triennial IRP filings provided Commission Staff with relevant information regarding the status of the utility's current and planned generation portfolio and load forecast. However, the rapid introduction of data centers and other high load factor customers has created significantly more uncertainty, with the introduction of extremely high demand, high load factor customers, the rapid increase in power demand, greater competition and lead times for generation equipment, and increasing costs. While IRPs are necessarily a snapshot in time for the utility (as with any long range forecasting study), the new realities of utilities participating in a dynamic electric industry has eroded the usefulness of the current IRP

[196] *See* EKPC's Response to Staff's Amended First Request for Information, and Staff_DR1_R1_-_Large_Load_Test_Case_Expansion_Plan.pdf (filed July 31, 2025).

process in terms of understanding the status of utilities' expansion plan and having a utility's IRP serve as a point of reference for future generation and transmission CPCN filing. Understanding the changing dynamics of utility expansion planning, transmission development, and related CPCN filings has value for staff and the Commission and aids in evaluating CPCN filings with relatively short timelines.

Recommendation: Commission Staff notes that EKPC's tariff Rate DCP (Data Center Power), filed subsequent to the start of the present case,[197] represents EKPC's effort to shield its Owner-Members from any costs associated with the location of a significant data center load within its service territory. As such, EKPC would hold the data center apart and completely separate from its native Owner-Member load, which is the basis for it not including or modeling data center loads in its load forecast. At the hearing, EKPC stated that EKPC would keep analysis of data center load separate from native load.[198]

Under the EKPC model of holding data centers apart and completely separate from native Owner-Members, excluding data centers taking service under EKPC's tariff Rate DCP from its native Owner-Member load forecasts and the resulting effects on resource assessments and least cost production cost modeling and preferred least cost expansion plans is reasonable.

In the interest of transparency, and assuming that EKPC continues to adhere to its current framework of holding Rate DCP qualifying data centers completely separate, EKPC's next IRP should include information corresponding to any data center on its system at the time of filing. This information should be presented in its own IRP section, and should include, but not be limited to, the number and load size of each data center, status of and any changes in status of generation (including capacity factors) and transmission assets serving each data center. The data center section should also include a status update on any changes in EKPC's tariffs or federal or state regulations affecting the data center(s) that could affect EKPC or its Owner-Members. Examination of the effects of data center and dedicated generation siting, including the factors that Sierra Club is concerned with, should be addressed in other cases. Financial factors would be addressed in the special contract case and environmental, and logistical concerns would be addressed in the subsequent CPCN/siting case.

Regarding the usefulness of IRPs as the generation landscape becomes increasingly dynamic, for EKPC's next IRP, it should comment on how IRP filings can be made more relevant in terms of explaining its generation and transmission expansion plan and whether the linkages between the IRP and CPCN filings should be strengthened and, if so, explain how the current process could be changed.

Winter Reserve Margin

[197] Tariff Rate DCP (Data Center Power) was approved by the Commission in Case No. 2025-00140 on October 30, 2025.

[198] HVT of March 10, 2026 Hearing, Tucker Hearing Testimony at 15:15:15.

Commission Staff welcomes the evaluation of a winter reserve margin as opposed to treating PJM reserve margin guidelines (with no winter reserve margin) as the maximum necessary margin. EKPC also should continue to evaluate in future IRP's whether the proposed winter reserve margin is adequate to meet peak load based on existing weather data, or whether it is excessive. Lack of cost data to compare the status quo with the proposed margin makes the proposal difficult for the Commission to evaluate.[199]

Recommendation: Commission Staff recognizes the additional production cost and financial modeling effort that would be required to determine the additional cost necessary to meet the proposed seven percent winter reserve margin. However, when EKPC ultimately files a CPCN application seeking generation capacity, this difference will be at the heart of the Commission's evaluation. The Commission must weigh whether the additional cost to ratepayers is worth the improved reliability expected from the establishment of a seven percent winter reserve margin.

SUPPLY SIDE RESOURCES AND MODELING ASSUMPTIONS

Environmental Regulation

Due to administration changes at the federal level, litigation, and technological limitations and advancements, environmental compliance challenges always include an element of uncertainty as to predicting how regulations will affect generation resource selection modeling. EKPC did an excellent and thorough job of summarizing developments in the complex and rapidly changing environmental regulation landscape. EKPC also clarified at the hearing that it always models based on existing, enforceable environmental regulations, and does not speculate as to the success or failure of potential changes until pending regulations are finalized.[200] However, the IRP is not completely clear as to what environmental compliance assumptions were utilized, because it was not always immediately clear what regulations EKPC considered to be in effect or how the effects of those regulations were modeled.

Commission Staff also does not disagree with EKPC excluding environmental compliance costs and requirements from modeling except for regulations in effect at the time, at least for base case scenarios. However, as with other projections and assumptions, potential regulatory changes, whether through the repeal of an existing regulation or the adoption of a new regulation, do present a risk to long-term models that should not be wholly ignored when developing a plan. For instance, if two portfolios would have approximately the same cost in base case scenarios that only include current environmental regulations, then EKPC should consider the effects of expected or probable changes in environmental regulations on those portfolios, because if one such

[199] *See* EKPC's Response to Commission Staff's Second Request, Item 3(b).

[200] HVT of March 10, 2026 Hearing, Purvis Hearing Testimony at 11:47:55—11:51:31; HVT of March 10, 2026 Hearing, Tucker Hearing Testimony at 15:38:02—15:39:06.

portfolio performs significantly better in the face of such changes, EKPC may be able to mitigate a future risk at no or limited additional cost.

Commission Staff also notes that as of the issuance of this report EKPC has removed its sustainability goals from the webpage linked from its IRP.[201] However, at hearing, EKPC witness Julia Tucker stated that with regards to any rollback of existing compliance measures, "it's hard to imagine going backwards."[202] Thus, there is some uncertainty regarding the status of EKPC's sustainability goals, if any, and how environmental deregulation affects EKPC's sustainability goals

Recommendation: EKPC should make clear in future IRPs how each environmental regulation and policy assumption was treated for purposes of modeling and resource selection, including whether certain regulations were assumed to remain in effect, be modified, or have no material effect on resource planning outcomes. For example, if EKPC assumes that proposed or potentially changing environmental regulations will not materially affect future resource planning, the IRP should clearly identify those assumptions and explain the basis for them.

While Commission Staff understands it is not possible to predict all future regulations, EKPC should also consider, discuss, and model (or discuss why modeling would not be useful for) likely future environmental regulation changes, including at minimum proposed changes pending when the report is prepared, in addition to any base case scenarios that only include current environmental regulations in order to stress test portfolios selected in the base case. Commission Staff generally also agrees with Sierra Club that all feasible options should be included in modeling, such as gas conversion and coal plant retirements, though the sweeping deregulation described by EKPC makes these options potentially unnecessary for inclusion, as they would not result in least-cost selections.

Future IRPs should also (1) explain if and why sustainability goals have changed or been abandoned, (2) if not abandoned, whether and how these goals are considered as post-modeling qualitative factors affecting selection of a preferred plan, and (3) consider whether full-gas conversion and coal plant retirements should be included in the model as selections under a sustainability scenario so stakeholders and the Commission can assess the cost of sustainability measures.

INTEGRATION

Internal Consistency of Data

[201] 2025 IRP at 9. *See* https://www.ekpc.coop/ekpc-planning-future. A copy of archived versions of the main "Sustainability" webpage and linked pages under the "Energy & Environment" heading are attached hereto as Attachment 1. https://www.ekpc.coop/ekpc-planning-future. (last accessed April 18, 2025).

[202] Tucker Hearing Testimony, March 10, 2026, HVT at 15:35:33—15:36:18.

In the original 2025 IRP, Tables 8-3 and 8-6 contained inconsistent data when comparing winter Total Capacity in Table 8-3 with winter Existing Resources in Table 8-6. Table 8-3 Total Capacity included all capacity additions in its existing expansion plan including existing resources and resources that had not yet been approved by the Commission. Between the two tables, the amounts for summer capacity match. The amounts for winter capacity in Table 8-3 for 2025-2029 make sense only when the winter capacity purchases (Preferred Plan) in Table 8-5 are added to the Existing Resources winter amounts column in Table 8-6. For 2030-2031, when the 214 MW winter capacity addition in Table 8-3 is added to the Existing Resources in Table 8-6, the resulting amount does not equal the Total Capacity amounts in Table 8-3.

In EKPC's response to Staff's Second Request, Item 27(b), it revised Table 8-3 to include resources that had inadvertently been omitted: 300 MW of summer and winter hydroelectric capacity in 2026 and an additional 80 MW of seasonal energy purchase in 2030. Commission Staff notes that the way hydroelectric PPA is presented is confusing. EKPC had a 300 MW energy-only contract and was in negotiations for both energy and capacity, which at the time of the IRP filing was included in the expansion plan. However, Table 8-3 (Revised) lists the 300 MW as summer and winter capacity, but which appears to have no effect on the amount of total capacity. EKPC explained that it had signed a PPA "for 100 MW of around-the-clock energy physically backed by several nuclear assets located in PJM."[203] With these revisions, EKPC's total winter capacity was consistent only in Tables 8-3 (Revised) and Table 8-6 when the seasonal PPAs in Table 8-5 (the preferred expansion plan) were added to total capacity, though they are not listed as capacity. In EKPC's response to Staff's Third Request, Item 8, it explained that the capacity additions represented in the winter capacity column were intended to be one or more physically delivered, energy-only PPAs. Moreover, EKPC explained that "[i]t is accurate to list these purchases as energy as shown in Table 8-3 (Revised). They are listed under the "CAPACITY ADDITIONS" column in the resource expansion plan, as these purchases would be physical, not financial, purchases on an annual or seasonal basis which would hedge the load at a known quantity and price. The purchases would not provide a PJM Reliability Pricing Model (RPM) capacity benefit as they would be energy-only. The intent was to procure enough capacity and/or energy resources to meet EKPC's peak load plus planning reserves until capacity can be built."[204]

In response to Staff's Post-Hearing Request, EKPC filed a final updated table 8-3: Table 8-3 (w/o Hydro PPA, w/o Solar Farms 5-8, w/ Nuclear PPAs). Even though EKPC made clear that the seasonal and around-the-clock energy purchases were energy-only, not counted as PJM accredited capacity, but are being counted as capacity by EKPC, the table still appears to be internally inconsistent for the 2025-2028 period. The Seasonal Energy Additions column appears to be cumulative, but how the energy additions from the preferred plan in Table 8-5 and the energy additions in the Current PPA column are

[203] EKPC's Response to Staff's Third Request, Item 8b.

[204] EKPC's Response to Staff's Third Request, Item 8.

included is not clear. Also, the annual capacity additions in the Total Capacity & Peak Energy column do not appear to match the energy/non-PJM accredited additions.

Recommendation: For the next IRP, EKPC should take pains to ensure that the data presented in tables is accurate, consistent, and make logical sense both within the table and across tables.

EKPC's counting energy-only PPAs as non-PJM accredited capacity could have been better explained. Having around-the-clock energy is tantamount to having a physical generation unit being continuously dispatched on EKPC's system, which is akin to having capacity. This was a novel approach. However, with this realization, Commission Staff understood EKPC's rationale for counting the energy purchases as capacity. In EKPC's next IRP, if it plans to maintain the format used in the various versions of Table 8-3 including energy additions and corresponding capacity additions, EKPC needs a very clear explanation of and distinction between which energy purchases are to be counted as non-PJM accredited capacity and which are not.[205] Additionally, EKPC should label the type of capacity (ICAP, UCAP, ELCC) in its tables.

Hard-Coded Supply-Side Modeling

EKPC filed three successive CPCN cases prior to filing the present IRP case: Case Nos. 2024-00129, 2024-00310, and 2024-00370. Though the Commission had not yet approved each of these cases when the IRP was filed, EKPC included these along with other potential generation assets for which a CPCN had yet to be filed (its then current generation plan), in its modeling base case as if they had already been approved. From a planning perspective, this is not an unreasonable assumption. However, including potential generation resources for which no CPCN had been filed is less reasonable. Commission Staff had the benefit of examining EKPC's production cost modeling and optimization results in 2024-00310 and 2024-00370. However, this was not necessarily the case for all resources. In addition, the final resolution of EKPC's efforts in its pursuit of the hydroelectric PPA to include both energy and capacity through the pendency of this case underscores the new realities of an evolving electric industry. Also, it highlights the diminished usefulness of taking a triennial status snapshot of a utility's generation planning. Costs, lead times, contract negotiations, and other variables can change which could affect the resource selection and the timing of when resources are added to EKPC's portfolio. There is value in allowing the production cost and optimization modeling to take a holistic evaluation of EKPC's energy and capacity requirements over the entire planning period if for no other reason than validation of EKPC's final expansion plan. This is especially true since the Commission had not approved or seen all of the necessary CPCNs or been aware of all energy PPAs.

Recommendation: For the next and successive IRPs, EKPC should run the RTSim production cost and Optimizer to evaluate and select resources over the entire planning period as opposed to selecting and including resources *a priori*.

[205] See EKPC's Response to Staff's Third Request Item 8.

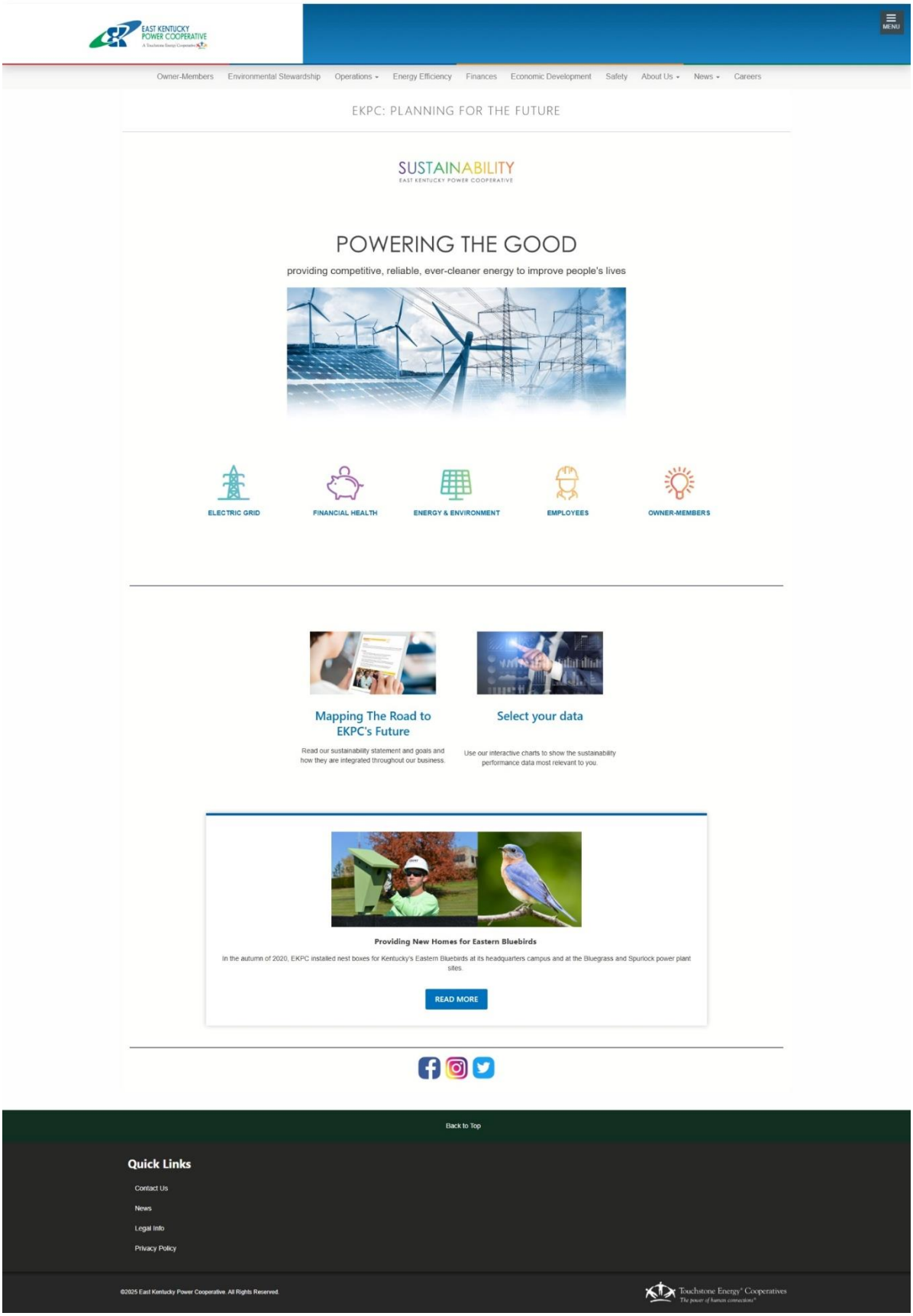
REASONABLENESS

Commission Staff believes that EKPC's preferred resource selection plan for maintaining necessary capacity standards is reasonable. Commission Staff perceives no significant problems with EKPC's load forecast. The selected plan appears to be the least-cost reasonable alternative to meet that forecasted load. The timing of EKPC's IRP filing as required by regulation greatly simplified the process—EKPC had already obtained approval for multiple native generation projects, including making its case for establishing a specific winter reserve margin. In addition, the significant deregulation currently occurring eliminates the numerous scenarios other generation utilities were required to navigate in their IRPs.

However, Commission Staff shares the Attorney General's concern that relying too heavily on PJM capacity market purchases to cover capacity shortfalls exposes EKPC to price volatility risk, although overbuilding generation may likewise result in net losses if PJM market prices fall.

Commission Staff agrees with EKPC's position regarding modeling environmental compliance variables. EKPC has generally modeled based on laws in effect at the time the IRP was generated but has clearly included continuing developments in environmental regulation as evidenced by its thorough analysis of applicable law and potential changes.

Attachment 1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Read our sustainability statement and goals and how they are integrated throughout our business.
Select your data
Use our interactive charts to show the sustainability performance data most relevant to you.
Providing New Homes for Eastern Bluebirds
In the autumn of 2020, EKPC installed nest boxes for Kentucky's Eastern Bluebirds at its headquarters campus and at the Bluegrass and Spurlock power plant sites.
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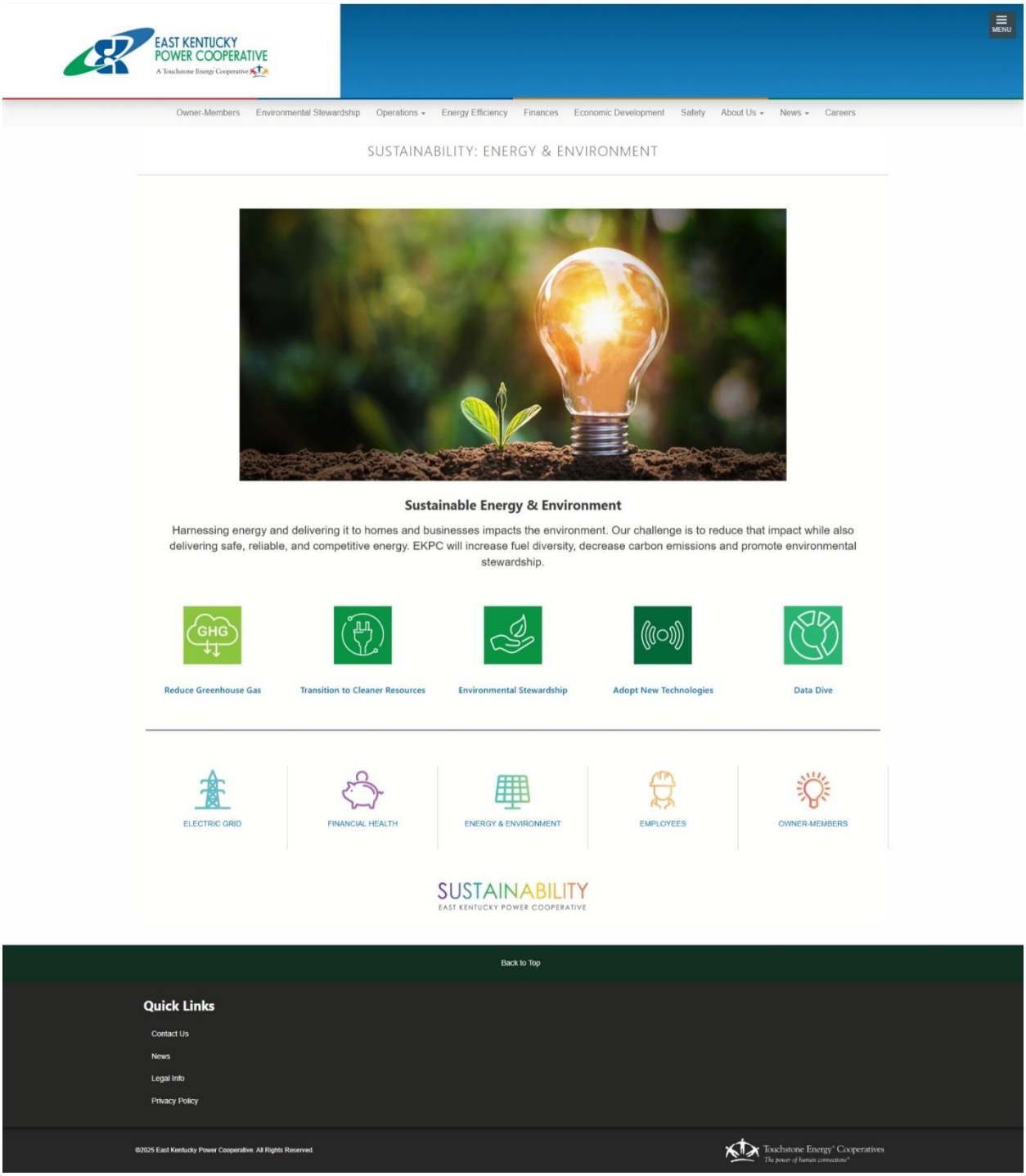
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REDUCE GREENHOUSE GAS

EKPC's Commitment to Reducing Greenhouse Gas

EKPC is committed to reducing its greenhouse gas emissions in a deliberate, responsible manner while recognizing the impact of sustainability, reliability and affordability of energy on the 1.1 million Kentucky residents and businesses that use the energy EKPC provides.

EKPC is committed to:

- 35% reduction in total carbon dioxide emissions by 2035.*
- 70% reduction in total carbon dioxide emissions by 2050.*

* Reductions based on 2010 emissions.

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TRANSITION TO CLEANER RESOURCES

Transition to Cleaner Resources in a Responsible Manner

EKPC recognizes the necessity of transitioning to cleaner energy resources in a responsible manner. Decisions regarding deployment of energy-generation technologies and energy-mix strategies must account for the sustainability, reliability and affordability of those technologies and strategies, with particular attention to the impact on the people who will use the energy.

EKPC is committed to providing:

- 10% energy from new renewables by 2030.*
- 15% energy from new renewables by 2035.*

* Does not include renewable assets as of 2019.

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PROMOTE ENVIRONMENTAL STEWARDSHIP

Sponsor and Promote Environmental Stewardship

EKPC recognizes its operations affect the environment beyond the impact of the fuel used to make energy. Every day, EKPC and its employees make choices that have implications for consumption and disposal. EKPC is exploring ways to make better decisions, facilitated by a commitment to reducing, reusing and recycling where it makes sense.

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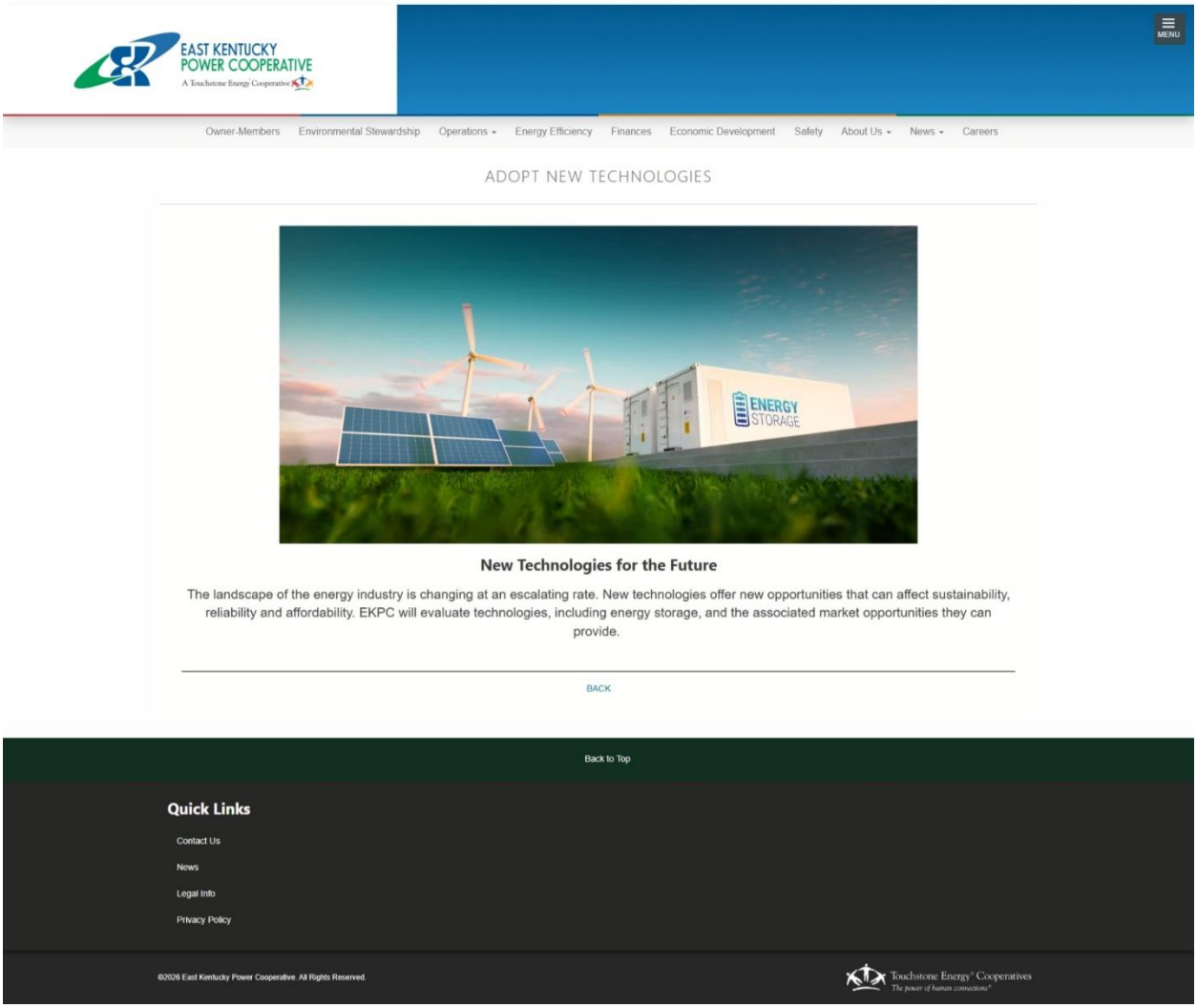
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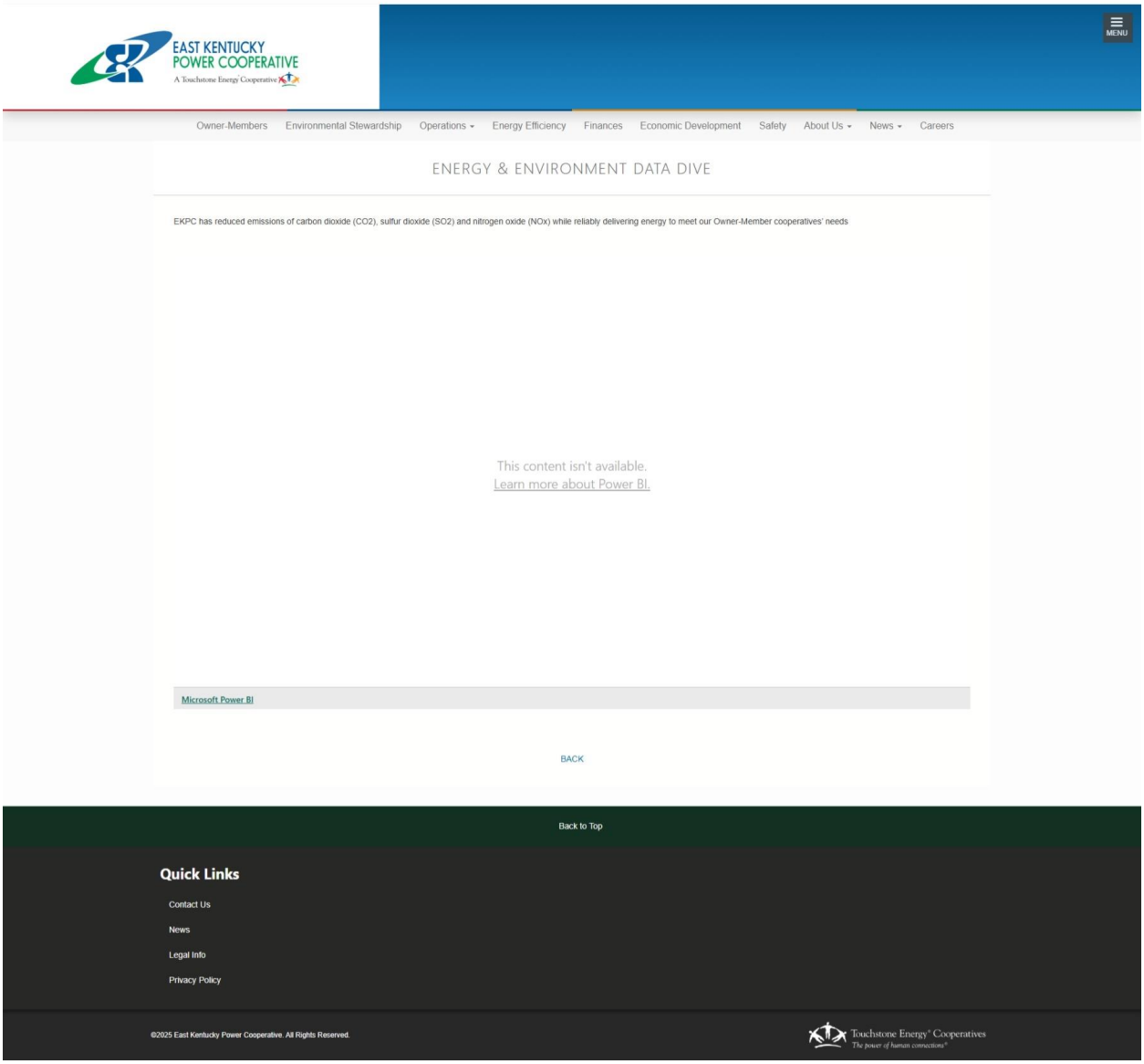
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