COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC 2022 INTEGRATED RESOURCE PLANNING REPORT OF KENTUCKY POWER COMPANY	)))	CASE NO. 2023-00092

O R D E R

The Commission initiated this proceeding for Commission Staff to conduct a review of the 2022 Integrated Resource Plan (IRP) filed by Kentucky Power Company (Kentucky Power), pursuant to 807 KAR 5:058. Attached as an Appendix 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's Report has expired.

IT IS THEREFORE ORDERED that:

1. The Commission Staff's Report on Kentucky Power's 2022 IRP represents the final substantive action in this matter.

2. Any party desiring to file comments regarding the Commission Staff's Report on Kentucky Power's 2022 IRP shall do so on or before October 15, 2025.

3. Kentucky Power may file comments, if any, with respect to the Commission Staff's Report and in response to Intervenor comments on or before November 14, 2025.

4. 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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PUBLIC SERVICE COMMISSION

Chairman

Commissioner

Commissioner

ATTEST:

Executive Director

ENTERED
SEP 12 2025
AB
KENTUCKY PUBLIC
SERVICE COMMISSION

APPENDIX

AN APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2023-00092 DATED SEP 12 2025

THIRTY-SEVEN PAGES TO FOLLOW

Kentucky Public Service Commission

Commission Staff's Report on the

2022 Integrated Resource Plan

of Kentucky Power Company

Case No. 2023-00092

September 2025

SECTION 1

INTRODUCTION

In 1990, the Kentucky Public Service Commission (Commission) promulgated 807 KAR 5:058 to create an integrated resource planning process to provide 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]

Kentucky Power Company (Kentucky Power) is an investor-owned utility company headquartered in Ashland, Kentucky. Kentucky Power is a subsidiary of American Electric Power Company, Inc. (AEP) and provides retail service to approximately 165,000 customers in Boyd, Breathitt, Carter, Clay, Elliott, Fleming, Floyd, Greenup, Johnson, Knott, Lawrence, Leslie, Letcher, Lewis, Magoffin, Martin, Morgan, Owsley, Perry, Pike, and Rowan counties.[2] Kentucky Power filed its 2022 Integrated Resource Plan (2022 IRP) on March 23, 2023.[3]

Kentucky Power's current supply side resources include 385 MW of Installed Capacity (ICAP) derived from its 50 percent undivided interest in the Mitchell Plant. When Kentucky Power prepared its 2022 IRP it remained on track to divest its 50 percent interest in the Mitchell Plant by the end of 2028 to Wheeling Power Company (Wheeling Power).[4] Consequently, Kentucky Power could not access that capacity for the 2028-2029 PJM delivery year. However, following an informal conference in Case No. 2021-00004, which the Commission granted at Kentucky Power's request, Commission Staff is aware that Kentucky Power intends to request approvals to assume certain environmental costs to maintain the Company's interest in the Mitchell Plant beyond 2028.[5] Finally, Kentucky Power also owns 285 MW ICAP at its Big Sandy Plant. Commission Staff

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[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] *Annual Report of Kentucky Power to the Public Service Commission for the Year Ending December 31, 2022* (2022 Annual Report) at 4–5.

[4] Kentucky Power provided notice of its intent to file a CPCN application seeking approval for investments required to continue to take service from the Mitchell Plant beyond 2028. *See* Case No. 2025-00175, *Electronic Application of Kentucky Power Company for Approval (1) a Certificate of Public Convenience and Necessity to Make the Capital Investments Necessary to Continue taking Capacity and Energy from the Mitchell Generating Station After December 31, 2028, (2) An Amended Environmental Compliance Plan, (3) Revised Environmental Surcharge Tariff Sheets, and (4) All Other Required Approvals and Relief* (filed June 30, 2025).

[5] Case No. 2021-00004, *Electronic Application of Kentucky Power Company for Approval of a Certificate of Public Convenience and Necessity for Environmental Project Construction at the Mitchell Generating Station, an Amended Environmental Compliance Plan, and Revised Environmental Surcharge Tariff Sheets* (Ky. PSC March 7, 2025), Memorandum of Informal Conference of March 6, 2025.

understands that, regardless of the circumstances surrounding Kentucky Power's other ongoing and impending cases before the Commission, the IRP represents a snapshot in time, and Commission Staff will continue to rely on the information provided in the IRP to inform this report.

Kentucky Power's application defined four objectives for the 2022 IRP: (1) customer affordability; (2) rate stability; (3) maintaining reliability; and (4) sustainability. The planning period for the report was 15 years, ending in 2037.[6]

Kentucky Power submitted its 2022 IRP to the Commission on March 20, 2023. On April 14, 2023, the Commission issued an Order establishing a procedural schedule for this proceeding. The procedural schedule established a deadline for requesting intervention, provided for two rounds of requests for information to Kentucky Power, an opportunity for intervenors to file written comments, and an opportunity for Kentucky Power to file a response to any intervenor comments. Additionally, a hearing to gather more information about the IRP was set in this matter and was held on June 12, 2024.

The following parties filed for, and were granted, intervention in this matter: (1) Attorney General of the Commonwealth of Kentucky, by and through the Office of Rate Intervention (Attorney General); (2) Kentucky Industrial Utility Customers (KIUC); (3) Mountain Association; (4) Appalachian Citizen's Law Center; (4) Kentuckians for the Commonwealth; (5) Kentucky Solar and Energy Society; and (6) LS Power Development LLC. Intervenor comments are due 30 days after the date of service of this Commission Staff's Report. In addition, a number of individuals and organizations filed public comments regarding the IRP. Commission Staff reviewed and considered the comments.[7]

The purpose of this report is to review and evaluate Kentucky Power's 2022 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. 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 Kentucky Power's most recent IRP filed in 2019.

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[6]IRP at 13.

[7] All comments are publicly available for this case at: https://psc.ky.gov/Case/ViewCaseFilings/2023-00092/Public.

The remainder of this report is organized as follows:

- Section 2: Load Forecasting—reviews Kentucky Power's projected load growth and load forecasting methodology.

- Section 3: Demand-Side Management and Energy Efficiency (DSM/EE)—reviews Kentucky Power's evaluation of DSM opportunities.

- Section 4: Supply-Side Resource Assessment—focuses on supply-side resources available to meet Kentucky Power's load requirements and environmental compliance planning and the selection of the preferred portfolio.

- Section 5: Integration—broadly discusses Kentucky Power's integration and selection of the preferred portfolio.

SECTION 2

LOAD FORECAST

INTRODUCTION

This Section reviews and comments on the projected load growth for Kentucky Power's systems and Kentucky Power's load forecasting methodology. This Section also reviews the parties' comments regarding Kentucky Power's load and demand forecast. Finally, this Section includes Commission Staff's discussion of and recommendations regarding Kentucky Power's load and demand forecasting.

FORECASTING METHODOLOGY AND ASSUMPTIONS

As in Kentucky Power's previous integrated resource plans (IRPs), its load forecasts are based on a combination of econometric and statistically adjusted end use (SAE) models. Short term econometric, autoregressive time series models are used to obtain monthly forecasts extending two years and employ both the latest energy sales and weather data.[8] In the short term, the stock of electric energy consuming equipment and appliances and other economic factors are assumed to be fixed. Key economic and demographic variables include monthly and seasonal binaries, time trends, and monthly heating and cooling degree days.[9]

The long-term econometric models produce monthly forecasts extending out 30 years. These models are designed to capture structural shifts and trends in the underlying economy as well as changes in equipment stocks and energy efficiency. These long-term models incorporate SAE modeling techniques which capture changes in energy efficiency that can drive changes in energy consumption.[10] Key structural economic and demographic variables include employment, population, housing stock, real personal income, number of households, electricity and natural gas prices, heating and cooling degree days, lagged dependent variables, and binary variables.[11]

The short term and long-term forecasts are blended together for each revenue class to produce a forecast. Energy class sales are summed and adjusted for energy

[8] IRP at 31.

[9] IRP. at 31.

[10] IRP at 29 and 32.

[11] IRP at 32 and 34-35.

losses to produce an internal[12] energy forecast.[13] Peak demand models are algorithms that allocate energy sales forecasts to forecast hourly demand. Forecast hourly demand is a function of blended revenue class sales, energy losses, weather, 24-hour load profiles and calendar information.[14]

Kentucky Power's load forecasts incorporate economic forecast data provided by Moody's Analytics, energy prices from the Federal Reserve, U.S. Department of Energy's (DOE) Energy Information Administration (EIA) and internal sources, industrial output from the Federal Reserve Board index of industrial production, weather data from the National Oceanographic and Atmospheric Administration and Itron.[15]

In addition to the customer class models, Kentucky Power developed two additional supporting models produce independent variable forecasts, which are used in other energy forecast models. Forecasted natural gas prices are obtained from a consumed natural gas pricing model based upon Kentucky Power's residential, commercial and industrial sector prices and forecasted prices from the EIA's 2022 Annual Energy Outlook. Though significantly diminished, coal mining continues to have a role in Kentucky Power's service territory.[16] A regional coal production model was used to forecast coal production for the mine power energy sales model. Key variables include EIA forecasts of Central Appalachian and US coal exports and binary variables.[17]

RESIDENTIAL ENERGY SALES

The residential energy sales forecast was the product of two separate forecasts the forecast number of residential customers buy the forecast kilowatt hours (kWh) usage per customer. Residential energy usage is forecast using a SAE linear regression model. Energy use is a function of Heating, Cooling and Other usage variables. The Heating variable is comprised of a heating index multiplied by a heating use variable. The heating index is a function of heating equipment saturation, heating equipment efficiency standards and trends, thermal integrity and home size. Heating use is a function of billing days, heating degree days, household size, personal income, gas prices and electricity

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[12] IRP. *See* footnote 3 at 27. Internal load is defined as "load that is directly connected to the utility's transmission and distribution system and that is provided with bundled generation and transmission service by the utility." And connected load is defined as including internal load and "directly connected load for which the utility serves only as a transmission provider."

[13] IRP. at 36-37 and exhibit C-1 at 197. Also, see Exhibit C-8 at 203 for an illustration of how the short term and long term forecasts are blended together.

[14] IRP at 37.

[15] IRP at 27-28 and 34-35.

[16] IRP. at 33. Between 2000 and 2021, Eastern Kentucky coal production declined from 105 million metric tons to 10.1 million metric tons, a decrease of about 90%. The forecast is for coal production to remain at about 10 million tons annually.

[17] IRP at 33.

prices.[18] Similarly, the Cooling variable is comprised of a cooling index multiplied by a cooling usage variable. The cooling index is a function of cooling equipment efficiency and saturation levels and trends and the thermal integrity and size of homes. Cooling usage is a function of billing days, cooling degree days, household size, personal income, electricity prices, and gas prices.[19] The Other variable estimates non-weather sensitive energy sales is a function of appliance and equipment saturation levels, the number of billing cycles each month, average household size, real personal income, and gas and electricity prices.[20] Historical appliance saturation levels were derived from Kentucky Power's 2021 residential customer survey.[21] Forecasts are based on EIA forecast and Itron analysis. Thermal integrity and home size are taken from DOE and Itron data.

Over the 2023-2037 forecast period (forecast period), Kentucky Power's population and number of customers is projected to decline 0.6 percent annually.[22] Similarly, residential energy sales are projected to decline at an average annual rate of 0.7 percent from 1,959 GWh to 1,765 GWh.[23]

COMMERCIAL ENERGY SALES

Similar to the residential revenue class, commercial energy sales are the product of the number of commercial customers and usage per customer. Commercial customer energy usage is estimated using SAE modeling techniques and is a function of equipment efficiencies, building square footage and equipment saturations in the East North Central Region, electric prices, economic factors, heating and cooling degree days, and billing cycle days. Heating, Cooling, and Other variables are derived in the SAE modeling

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[18] IRP at 34.

[19] IRP Also see Kentucky Power's response to Commission Staff's First Request for Information (Staff's First Request), Item 3. Normal weather is based on 30-year average heating and cooling degree days. Also see Kentucky Power's Response to Staff's First Request, Item 7. EIA uses a 30-year linear trend for its models where the warmer case had cooling degree days increasing by one percent annually. Kentucky Power's analysis utilized data taken from a Purdue University study, which had cooling degree-days increasing approximately two percent annually.

[20] See Kentucky Power's Response to Staff's First Request, Item 59, Attachment 1 for Itron's explanation and derivation of the Heating, Cooling and Other variables.

[21] IRP at 49.

[22] IRP at 27.

[23] IRP Exhibit C-1 at 197.

process.[24] In addition, Kentucky Power boosted the Commercial sales forecast due to the anticipated addition of a significant, large customer.[25]

With the anticipated addition of the significant large customer, Commercial energy sales are forecast to grow from 1,144 GWh to 1,220 GWh over the 2021-2023 period and then to in 1,657 GWh by 2024. Subsequently, Commercial energy sales are expected to decline slowly from 1,657 GWh to 1,612 GWh over the 2024-2037 forecast period. The large increase in sales provides for an average annual increase of 2.0 percent over the 2022-2037 forecast period.

INDUSTRIAL ENERGY SALES

Industrial energy sales are comprised of manufacturing and mine power sales. Manufacturing energy sales are a function of service area manufacturing employment, petroleum industrial production index, Kentucky industrial gas prices, service area electricity prices, and binary variables. In addition, based upon customer service engineer information, load may be added or subtracted from the forecast depending on customer plant load adjustments, plant openings and closures.[26]

Mine power energy sales are a function of regional coal production, service area mine power electricity prices and binary variables. In addition, based upon customer service engineer information, load may be added or subtracted from the forecast depending on mine load adjustments, mine openings and closures.[27]

Over the forecast period, Industrial energy sales are forecast to slowly decline from 2,032 GWh to 1,933 GWh. Overall, industrial sales, including the anticipated load addition, sales expected to decline slowly at an average annual rate of 0.2 percent.[28]

OTHER INTERNAL ENERGY SALES

Public street and highway lighting sales forecasts are a function of employment and binary variables.[29] Forecasted energy sales hold steady at 9 GWh over the forecast

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[24] IRP at 35.

[25] IRP at 35. Though unnamed in the IRP, Kentucky Power filed Case No. 2022-00387, *Electronic Tariff Filing of Kentucky Power Company for Approval of a Special Contract with Ebon International, LLC* (Filed Oct. 28, 2022). In the Cover Letter, Kentucky Power stated that Ebon International, LLC would require 80-100 MW of contract capacity in its operational Phase One and up to 250 MW of contract capacity (25 MW firm capacity) in operational Phase Two. The Commission denied the proposed contract in its Order dated August 8, 2023.

[26] IRP at 36.

[27] IRP at 36.

[28] IRP Exhibit C-1 at 197.

[29] IRP at 36.

period.[30] Wholesale customer sales forecasts are a modeled as a function of service area employment, population, heating and cooling degree days and binary variables. However, these contracts were set to expire beginning June 2025 when the IRP was filed and the wholesale customers had issued proposals for service after that date.[31] As a consequence, Kentucky Power removed wholesale customer sales from its energy sales and peak load forecasts.[32] Forecasted wholesale customer energy sales drop from 87 GWh in 2024 to zero in 2026.[33]

TOTAL INTERNAL ENERGY REQUIREMENTS

Including losses, Total Internal Energy requirements range from a high of 6,098 GWh in 2024 to 5,734 GWh in 2037.[34] The inclusion of the expected large industrial load in 2024 supports an overall average annual growth rate of 0.1 percent. However, from 2024 through the end of the forecast period, energy sales are in slow decline.[35]

SEASONAL PEAK INTERNAL DEMAND

The seasonal peak demand forecast is derived by allocating monthly internal energy sales forecasts to hourly demands. Hourly demand is a function of revenue class sales, energy loss multipliers, weather profiles, 24-hour load profiles and various calendar events. Weather profiles are based on 30 years of monthly profiles of average daily temperatures representing heating and cooling degree days. The 24-hour load profiles are based on historical company or jurisdictional load and end use or revenue class hourly load profile, which are a function of season, day type and average daily temperature ranges.[36]

Over the 2023-2037 forecast period, peak demand follows similar trends to forecast energy sales. Summer peak demand is expected to jump from 952 MW in 2023

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[30] IRP Exhibit C-1 at 197.

[31] IRP at 36.

[32] *See* Kentucky Power's Response to Commission Staff's Second Request for Information (Staff's Second Request), Item 26. Because the existing wholesale tariffs (Olive Hill, Ky. and Vanceburg, Ky. expire beginning June 2025, Kentucky Power stated that its obligation to serve these customers no longer exists. Therefore, it would not be prudent to include forecasts and planning for customers no longer served. However, the IRP is a long-range planning exercise and considering that Kentucky Power forecasts declining sales and customer growth, it appears to be highly implausible that it would not ensure that the contracts were renewed. Forecasted energy sales and peak demand could have been reasonably included beyond June 2025.

[33] IRP Exhibit C-1 at 197.

[34] *IRP* at 44. Note that the forecast, later referenced as the Base Case forecast, assumes no new Demand Side Management (DSM) programs.

[35] IRP Exhibit C-1 at 197.

[36] IRP at 37.

to 1,033 MW in 2024 with the addition of the expected industrial load and then declines slowly to 979 MW by 2037. Because of the large load addition, summer peak load grows at a 0.2 percent rate. Similarly, forecast winter peak demand declines from 1,289 MW to 1,178 MW at an average annual rate of negative 0.6.[37]

LOAD FORECAST SCENARIOS – SENSITIVITY ANALYSIS

Kentucky Power ran multiple scenarios by varying the assumptions applied to the Base Case forecast scenario. Assuming normal weather, the high and low economic growth forecasts taken from the EIA 20209 Outlook produced upper and lower bounds of all scenarios. Over the 2023-2037 forecast period, the high economic growth scenario for energy sales, summer, and winter peak demand forecasts are approximately 11 percent greater than the respective Base Case forecast. The low economic forecast growth scenario produced forecasts approximately 8.2 percent below the respective Base Case forecast.[38] The table below contains Kentucky Power's forecasted internal seasonal peak demand and energy (sales) requirements over the 2023-2037 forecast period.[39]

	Summer Peak Demands (MW)			Winter Peak Demands (MW)			Internal Energy Reqs. (GWH)		
Year	**Low Case**	**Base Case**	**High Case**	**Low Case**	**Base Case**	**High Case**	**Low Case**	**Base Case**	**High Case**
2023	926	952	986	1,248	1,289	1,343	5,488	5,643	5,841
2024	1,000	1,033	1,077	1,236	1,283	1,345	5,903	6,098	6,353
2025	992	1,030	1,080	1,203	1,256	1,323	5,835	6,060	6,351
2026	968	1,010	1,064	1,190	1,247	1,320	5,698	5,948	6,266
2027	961	1,006	1,065	1,176	1,235	1,313	5,649	5,918	6,263
2028	953	1,000	1,064	1,170	1,231	1,315	5,613	5,892	6,265
2029	947	997	1,065	1,158	1,223	1,311	5,578	5,872	6,271
2030	941	994	1,066	1,148	1,217	1,309	5,536	5,850	6,270
2031	935	992	1,067	1,135	1,206	1,303	5,500	5,832	6,275
2032	929	987	1,066	1,130	1,205	1,307	5,472	5,814	6,277
2033	927	988	1,071	1,118	1,198	1,306	5,437	5,795	6,286
2034	917	983	1,072	1,107	1,193	1,308	5,393	5,780	6,300
2035	911	982	1,076	1,094	1,185	1,307	5,349	5,765	6,319

[37] IRP. Exhibit C-2A-C-2B at 198-199 and C-5 at 201. Also see Kentucky Power's Response to Staff's Second Request, Item 23. The load forecast above was completed in June 2022. And see Case No 2022-00387, Kentucky Power's Response to Commission Staff's First Request for Information, Item 4, Attachment 2. The summer peak load forecast in 2022-00387 is approximately between 60 MW to 80 MW higher than in Table C-5 in the IRP, which reflects an updated forecast completed in September 2022. Even though the IRP was filed in March 20234, approximately six months after the September 2022 forecast update, Kentucky Power chose not to update its IRP load forecast and planning on the updated September forecast.

[38] IRP at 44

[39] IRP Exhibit C-9 at 203.

2036	903	978	1,079	1,086	1,183	1,313	5,308	5,750	6,340
2037	899	979	1,086	1,077	1,178	1,317	5,265	5,734	6,363
Average Annual Growth Rate %									
2023-2037	-0.2	0.2	0.7	-1.0	-0.6	-0.1	-0.3	0.1	0.6

The Base Case forecast is identical to the No New DSM scenario. Two appliance/equipment efficiency scenarios were run; one keeping 2022 energy efficiency levels held constant for residential and commercial equipment and one assuming energy efficiency levels progressed at a faster rate than in the Base Case. In the held constant case, load forecasts were slightly higher than Base Case forecasts. In the latter case, load forecasts were slightly below Base Case forecasts. The extreme weather scenario assumed higher average daily temperatures for both summer and winter seasons resulting in lower heating degree-days in winter and increased cooling degree days for summer. This scenario resulted in overall increased energy requirements, and increased summer load and decreased winter load.[40]

SIGNIFICANT CHANGES

Though Kentucky Power continues to evaluate each sector for changes in growth patterns to determine factors that may be affecting any such changes, it did not report any significant changes to its forecasting methodology. There are differences between the 2022 forecast and the 2019 forecast. Overall, the 2022 energy forecast is about five percent lower by 2034, though the average annual growth rate is higher. The Residential forecast is slightly lower due to the economy and continued reductions in the customer base. The Industrial forecast is off by 25.5 percent due to plant closures and the continuing decline in coal mining. Due to the expected addition of a single large customer, the 2022 Commercial forecast is up by 38.7 percent. In addition, because the wholesale customer contracts are expiring in 2025, that portion of Other Internal sales is off by 90.3 percent.[41]

INTERVENOR COMMENTS

The intervenors had no comments regarding Kentucky Power's load forecasts or methodology.

REASONABLENESS OF KENTUCKY POWER'S LOAD FORECAST

In Kentucky Power's prior IRP, Commission Staff recommended that Kentucky Power include in its load forecasting discussion and analysis of potential increases in the distributed energy resources (DER). Specifically, Commission Staff mentioned, behind the meter generation at residential, commercial, and industrial customer locations; and

[40] IRP at 44-45.

[41] IRP at 47-48.

that Kentucky Power review those resources both separately and cumulatively to understand the driving factors encouraging or discouraging the development of such resources. In response, Kentucky Power stated that while it expected electric vehicle and distributed energy resource adoption to grow during the planning window, neither was forecasted to significantly affect its energy sales.[42] In support of its position, Kentucky Power presented both Exhibits C-27 and C-28 which provide numerical support of its analysis. Staff believes that this analysis is too narrow, it does not materially address the pragmatic drivers and obstacles for adoption of such resources. Without the second order analysis, as recommended by Commission Staff in the prior IRP, evaluating the need for additional incentives, or other programs involving DER will be more difficult and may lead to incomplete conclusions. This is especially true because Kentucky Power is anticipating a declining rate base over the planning period and will need to be creative to protect its remaining customers at the least possible cost to all parties involved.

RECOMMENDATIONS FOR KENTUCKY POWER'S NEXT IRP

1. In the case of a significant addition to load or an extended length of time between when the forecast is finalized and when the IRP is filed, Kentucky Power should strive to include the most up-to-date forecast possible. In the present case, the anticipated addition of significant load growth most likely altered the timing and composition of new resources in the subsequent preferred long-range resource portfolio and the various scenarios. The Commission utilizes the load forecasts as reference benchmarks. When there are significant anticipated changes in future load, at a minimum, Kentucky Power should include load forecasts with and without that anticipated load in its scenario analyses. The failure to run the scenarios diminishes the value of the load forecasts as well as the subsequent timing of and the resource additions / retirements in the utility's preferred plan. This analysis should also account for the potential timeline of bringing new resources on-line, given the time and financial investment required to place steel in the ground.

2. With respect to Kentucky Power's wholesale customer contracts or any other significant load for whom the contract expiration date coincides with the IRP forecast period and Kentucky Power intends to retain the business going forward, regardless of whether actual negotiations have commended, the anticipated load should be included in the forecast scenarios if not in the Base Case. In the case of Olive Hill, KY and Vanceburg, KY, the load is not especially large, but it is not small either. The omission of this and any similar load further diminishes the validity of the forecasts and the preferred plan.

3. It is possible that there could be high economic growth and extreme weather over the forecast period. It is plausible that in such cases, that customers would respond by seeking to implement increased cost-effective DSM, behind-the-meter generation, and demand response programs. These plausible customer responses should be considered as potential secondary moderating effects in future high demand forecast scenarios.

[42] IRP at 53.

Such secondary effects could alter the timing and or composition of future resource additions and increase the validity of the Preferred Plan.

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.[43] This section briefly describes Kentucky Power's existing DSM/EE programs, summarizes how existing programs were reflected in the IRP, and discusses DSM/EE programs Kentucky Power's reviewed to meet projected load. This section also reviews Kentucky Power's response to Commission Staff's recommendations regarding DSM/EE in its 2022 IRP and the parties' comments specifically regarding Kentucky Power's DSM/EE programs.

SUMMARY DISCUSSION OF DSM-EE

As Kentucky Power stated in its IRP, DSM programs typically refer to energy efficiency (EE), demand reduction (DR), conservation voltage reduction (CVR), and Distributed Generation (DG). Currently, Kentucky Power has demand response agreements with the three customers totaling 6.2 MW of peak DR capability.[44] Additionally, Kentucky Power has 184 net metering installations, comprised of 156 residential systems, 27 commercial systems, and 1 industrial system making up roughly 2.5 MW of net metered DG.[45] Kentucky Power does not currently have any cogeneration/combined heat power (CHP) customers in its service territory.[46]

RESPONSES TO PREVIOUS COMMISSION STAFF'S RECOMMENDATIONS

In Case No. 2019-00443,[47] Kentucky Power's previous IRP, Commission Staff provided a series of DSM recommendations.[48] As part of its discussion regarding Kentucky Power's DSM programs, the Commission Staff's Report noted that, in Case No. 2017-00097,[49] the Commission, following an investigation, ordered Kentucky Power to eliminate all of its DSM/EE programs except for those that "target income-eligible

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

[44] IRP at 62.

[45] IRP at 63.

[46] IRP at 63.

[47] Case No. 2019-00443, *Electronic 2019 integrated Resource Planning Report of Kentucky Power Company* (Ky. PSC Feb. 15, 2021), Commission Staff's Report.

[48] Case No. 2019-00443, Commission Staff's Report at 16.

[49] Case No. 2017-00097, *Electronic Investigation of the Reasonableness of the Demand Side Management Programs and Rates of Kentucky Power Company*, (Ky PSC Jan. 18, 2018), Order.

residential customers until Kentucky Power's capacity position indicates a need for additional generation to serve its load."[50] Commission Staff's Report continued, noting that, consistent with the Order in Case No. 2017-00097, Kentucky Power's DSM portfolio consisted, at that time, of only the residential targeted energy efficiency (TEE) program.[51]

With that context in mind, Commission Staff's Report provided a series of actionable recommendations for Kentucky Power regarding its DSM/EE programs. Those recommendations were:

1. As required by the IRP regulation, 807 KAR 5:058, Kentucky Power 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. With the expiration of the Rockport UPA, the potential impact of new DSM programs will be much greater in the next IRP.

2. Kentucky Power should continue to scrutinize the results of each existing DSM program measure's cost-effectiveness test and provide those results in future DSM cases, along with detailed support for future DSM program expansions and additions after the Rockport UPA capacity is no longer available.

3. Kentucky Power should evaluate the marginal benefits and costs, including opportunity costs of VVO and DR programs.

4. Kentucky Power should examine additional low-income programs that allow for more participants and easier access to EE alternatives.

5. Kentucky Power should continue to monitor the DG additions.

As part of Kentucky Power's IRP in this case, the utility provided responses to the Commission's past recommendations. Specifically, Kentucky Power stated that it had initiated a market potential study "to identify energy efficiency programs beneficial to its territory."[52] However, consistent with its past position, Kentucky Power's only current DSM program is its TEE program, which is a low-income weatherization program. Regarding the Volt-VAR Optimization (VVO) recommendation, Kentucky Power stated that it currently has more than twenty circuits with VVO installed.

<u>INTERVENOR COMMENTS</u>

Joint intervenors' comments expressed approval of Kentucky Power's current approach to expanding DSM/EE program offerings. However, Joint Intervenors also stated that Kentucky Power's IRP did not specifically consider a program operating the

[50] Case No. 2019-00443, Commission Staff's Report at 13.

[51] Case No. 2019-00443, Commission Staff's Report at 14.

[52] IRP at 64.

Pay As You Save (PAYS) program standards. As Joint Intervenors explained, this program operates as the utility directly investing in EE and load control measures installed in customers' homes and businesses.[53] The program must include certain elements such as: (1) the investment being recovered through fixed monthly tariffed charge assigned to the meter; (2) the installed technology must be have verified energy and cost savings for the customer; and (3) the energy savings must exceed the monthly repayment of the utility's investment.[54]

DISCUSSION OF REASONABLENESS

Commission Staff believes that Kentucky Power has taken appropriate steps to reach its DSM/EE obligations. Commission Staff generally agrees that Kentucky Power has modeled and evaluated its DSM/EE programs in a reasonable and appropriate manner.

RECOMMENDATIONS

1. As required by the IRP regulation, 807 KAR 5:058, Kentucky Power 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. Kentucky Power projects being significantly capacity short beginning in 2028, and new DSM programs will potentially have greater impact moving forward.

2. Kentucky Power should conclude the Market Potential Study, identifying all programs which have the potential to be beneficial to its customers.

3. Kentucky Power should study, either independently, or as part of its ongoing Market Potential Study, the Pay As You Save program identified by Joint Intervenors' comments to determine whether such a program will be cost effective and beneficial to its customers.

4. Kentucky Power should continue to scrutinize the results of its current TEE program for cost-effectiveness and provide those results, along with the results of the finalized Market Potential Study, in future IRP filings.

5. Kentucky Power should continue to monitor DG additions.

6. Kentucky Power should give special attention to examining additional low-income programs that will allow for more of its customers to participate and/or provide easier access to EE alternatives.

[53] Joint Intervenors' comments at 5.

[54] Joint Intervenors' comments at 5.

SECTION 4

SUPPLY-SIDE RESOURCE ASSESSMENT AND INTEGRATION

INTRODUCTION

In this Section, Commission Staff reviews and summarizes Kentucky Power's current supply-side resources, its assessment of supply side resources, and its preferred portfolio. This section also discusses the reasonableness of, and recommendations regarding and related to Kentucky Power's supply side assessment.

SUMMARY OF EXISTING GENERATION RESOURCES

Subject to constraints, Kentucky Power utilized the AURORA energy market simulation (AURORA) model to assess the most cost-effective way various generation resource options satisfied its forecast energy and capacity requirements. This model iteratively generates zonal, not company specific long-term capacity expansion plans, annual energy dispatch, fuel burns and emission totals from inputs including fuel, load, emissions and capital costs.[55] As a starting point for the study, Kentucky Power assembled a list of current and potential resources that will be made available to the AURORA model to determine the most reasonable cost effective portfolio of resources to meet its future requirements.

Kentucky Power's current PJM accredited resources include the Big Sandy natural gas fired unit with 295 MW installed capacity (ICAP) and 285 MW unforced capacity (UCAP), Mitchell Unit 1 with 385 MW ICAP and 292 MW UCAP, and Mitchell Unit 2 with 395 MW ICAP and 357 MW UCAP.[56] Kentucky Power assumed that its share of the Mitchell Units' capacity will end after the 2027-2028 PJM Planning Year. The Big Sandy Plant is assumed to retire at the end of the 2030/2031 PJM Planning Year.[57] In addition, with the expiration of the Rockport UPA, Kentucky Power has a capacity deficit that is being made up with short-term capacity purchases and the addition of more resources. Finally, Kentucky Power reported that it was working toward the addition of 100 MW of solar generation that would come online in 2027.[58]

For purposes of determining going-forward capacity needs, Kentucky Power relied on and modeled the PJM Installed Reserve Margin (IRM) of 14.7 percent for the

[55] IRP at 116. In part, AURORA accesses an online database provided by ABB Velocity Suite, for information pertaining to markets, entities, transactions and operating characteristics of 25,000 generation facilities across North America and Baja, Mexico. *Id.* at 116-117.

[56] IRPTable 3, at 55. The stated capacities for Mitchell Units 1 and 2 reflect Kentucky Power's 50 percent ownership stake in the units.

[57] IRP. at 55.

[58] IRP at 56.

2024/2025 PJM Planning Year and remains at that level through the 2037/2038 Planning Year.[59] The ultimate reserve margin is determined from the PJM Forecast Pool Requirement (FPR), which considers the IRM and the PJM Pool-Wide Average Equivalent Demand Forced Outage Rate ($EFOR_D$).[60] The FPR is 8.9 percent for the 2024/2025 and remains at that level for the balance of the planning period. Because Kentucky Power is a Fixed Resource Requirement (FRR) entity within PJM, it is allowed to plan to a lower IRM as opposed to the 21.7 percent reserve margin requirement for Reliability Pricing Model (RPM) entities.[61]

SUMMARY OF NEW GENERATION CONSIDERED

The resource options considered in the IRP include base/intermediate alternatives, peaking alternatives, renewable alternatives, advanced generation alternatives, long-term storage alternatives and short-term market purchases. Initial technology cost and performance assumption data is based upon EIA's 2022 AEO. Technology cost and performance assumption changes over time are based upon the 2022 medium case National Renewable Energy Laboratory (NREL) Annual Technology Baseline report (NREL ATB 2022).[62]

For baseload / intermediate generation, coal generation is modeled with carbon capture and storage (CCS) technology only. Traditional nuclear generation is not included as a resource option.[63] Natural gas combined cycle (NGCC) is modeled in two variants: a 418 MW H class turbine single shaft and a 1,083 MW H class multi-shaft turbine. These resources are made available to the AURORA model beginning in 2029 corresponding the anticipated timeline for planning, siting and construction.[64] The AURORA model evaluates the evolution of generation capacity and prices across PJM by using an optimization technique to select the "least cost" set of resources that minimizes the cumulative present worth (CPW) subject to constraints with various market condition assumptions (scenarios) including load, fuel, and CO_2 prices, and reserve requirements. The various generation technology assumptions include capacity accreditation.[65]

[59] IRP at 54.

[60] IRP footnote 7 at 54. FPR = (1+IRM) * ($1-EFOR_D$), Reserve Margin = FPR – 1.

[61] IRP at 54.

[62] IRP at 86.

[63] IRP at 87.

[64] IRP at 87.

[65] IRP at 115 and 155. Specifically, the AURORA model iteratively generates zonal, but not company specific, long-term capacity expansion plans, annual energy dispatch, fuel burns, and emission totals from inputs including fuel, load, emissions, and capital costs. IRP at 116.

Peaking resources included various generation technologies. A single 240 MW F-class natural gas combustion turbine (CT) was made available to the AURORA model beginning in 2029. The model was constrained to an annual capacity addition of 480 MW and a cumulative total of 720 MW. The possibility of burning up to 30 percent hydrogen in the CT and retrofitting to burn 100 percent hydrogen was also modeled.[66] Aeroderivative (AD) generators were modeled in units of 105 MW with an annual capacity addition of 210 MW and were made available to the model beginning in 2029. They are more expensive than CTs but have faster start times.[67] Reciprocating Engines are modeled in 21 MW units and were made available to the model in 2029. The AURORA model was constrained to annual capacity additions of 105 MW. Lithium-ion batteries were modeled as a four-hour, limited duration energy storage resource. They were made available to the model in 50 MW units beginning in 2026 with an annual capacity addition of 200 MW and a cumulative total of 500 MW.[68] Investment tax credits for lithium-ion batteries were applied as a reduction to estimated capital costs. Capital costs were reduced by 30 percent for projects beginning service before the end of 2032, by 22.5 percent for projects entering service in 2033, and by 15 percent for projects in 2034 and zero thereafter.[69]

Renewable generation resources include both onshore wind and utility scale solar. Regardless of modeling scenario, only 75 percent of potential solar resources and no potential wind resources are assumed to be located inside Kentucky Power's service territory.[70] Two pricing tiers for wind are modeled in 100 MW units reflecting the possible range of response to a Request for Proposal (RFP). The maximum annual capacity addition for lower cost Tier 1 Wind sites is 100 MW and 300 MW for Tier 2 sites. The capacity credit attributed to wind is 16 percent in 2022 declining to 11 percent by 2037.[71] The model applied the full amount of a production tax credit (100 percent) to the estimated capital cost amounting to $25/MWh for projects beginning construction by 2032, 75 percent of the credit for projects beginning construction by 2033, 50 percent by 2034 and zero thereafter.[72] Solar is made available to the model in 50 MW units. Like wind, two pricing tiers are modeled based on potential RFP responses. The total annual capacity additions for Tier 1 sites are 150 MW and 300 MW for Tier 2. The cumulative maximum for solar is 1,800 MW. Solar's summer capacity credit is based on a percentage

[66] IRP at 89.

[67] IRP at 90.

[68] IRP at 92.

[69] IRP at 93.

[70] IRP at 169. In the IRP, Kentucky Power acknowledged the risks related to the availability of wind resources and the delivery of energy to its service territory.

[71] IRP at 94.

[72] IRP at 95.

of ICAP, currently at 54 percent and declining to 23-28 percent by 2037.[73] The same production tax credit structure and amounts for wind are modeled for solar.[74] In addition, the model was given the option of combining solar and lithium-ion battery storage as a potential resource.[75]

Kentucky Power modeled various advanced generation alternatives that are not commercially available currently but could be during the forecast horizon. These advanced alternatives included small modular nuclear reactors,[76] CCS technology applied to coal and NGCC generation units in both retrofit and new build options. Carbon storage and transportation costs were included with these technology options.[77] Two green, hydrogen -based generation options were made available to the model. The first is the utility owning both the polymer electrolyte membrane (PEM) electrolyzer and the hydrogen gas CT (H_2CT). The second option is a third party supplying the hydrogen and the utility owning the H_2CT. Hydrogen projects are eligible for a production tax credit of $3 per kg of hydrogen fuel produced using a process that is less than 0.45kg of CO_2-equivilent emissions.[78] Long duration storage technologies were also modeled. These technologies include pumped thermal energy storage, vanadium flow battery storage and compressed air energy storage. Investment tax credits similar to those of wind and solar, in both structure amounts and timing, are modeled for these technologies.[79] Finally, short-term market capacity resource purchases were modeled to allow the model to mitigate short-term capacity shortfalls. The model was allowed to choose up to 500 MW through 2026 and in 2028 and up to 235 MW in 2026, 2027, 2030, 2031, 2033, 2034, 2036 and 2037. The specific limits were established to act as a capacity bridge to allow Kentucky Power to work to acquire firm resources and to align with an approximate size of a CT resource.[80] The table below summarizes select modeling parameters / characteristics of each potential generation resource.[81]

Select Key Supply-Side Generation Resource Option Assumptions (a)(b)

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[73] IRP at 96

[74] IRP at 96.

[75] IRP at 96.

[76] IRP, see discussion and data sources at 97-99.

[77] IRP, see discussion and data sources at 99-101.

[78] IRP, see discussion and data sources at 102-105.

[79] IRP, see discussion and data sources at 105-110. Also, the IRP did not include pumped hydro storage as a potential resource based on the reasoning that its potential has largely been depleted.

[80] IRP at 110-111.

[81] IRP, Exhibit D at 218.

Type	Capacity (MW) Summer	Installed Cost (c) ($/kW)	Full Load Heat Rate (HHV,Btu/kWh)	Fuel Cost (d) ($/MBtu)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	LCOE (e) ($/MWh)
Base Load							
Small Modular Reactor	600	6,875	10,443	0.69	3.14	99.46	159
Coal USC with 90% Carbon Capture	650	6,601	12,507	2.47	11.49	62.34	265
NGCC H-Class Single Shaft with 90% Carbon Capture	377	3,000	7,124	2.88	6.11	28.89	193
NGCC H-Class Single-Shaft	418	1,194	6,431	2.88	2.67	14.76	70
NGCC H-Class Multi-Shaft	1083	1,037	6,370	2.88	1.96	12.77	64
Peaking							
NGCT F-Class 240 MW (f)	240	753	9,905	2.88	0.62	7.33	100
Aero-Derivative	105	1,242	9,124	2.88	4.92	17.06	141
Recip. Engine Farm	21	1,980	8,295	2.88	5.96	36.81	154
Hydrogen Electrolyzer + Hydrogen Gas CT (f)	240	3,295	30% (g)	n/a (h)	1.12	54.16	n/a
Hydrogen Gas Combustion Turbine (f)	240	1,576	9,655	10.77	0.62	7.33	n/a
4-Hour Lithium-Ion Battery	50	1,432	85% (g)	n/a	n/a	25.57	n/a
20-Hour Pumped Thermal Energy Storage	50	3,336	65% (g)	n/a	n/a	51.72	n/a
20-Hour Vanadium Flow Battery Storage	50	3,844	70% (g)	n/a	n/a	11.45	n/a
20-Hour Compressed Air Energy Storage	50	1,788	52% (g)	n/a	n/a	17.37	n/a
Renewable							
Utility-scale Onshore Wind Tier 1	100	1,411	n/a	n/a	n/a	27.57	46
Utility-scale Onshore Wind Tier 2	100	1,552	n/a	n/a	n/a	27.57	52
Utility-scale Solar Photovoltaic Tier 1	50	1,320	n/a	n/a	n/a	14.81	69
Utility-scale Solar Photovoltaic Tier 2	50	1,452	n/a	n/a	n/a	14.81	77
Utility-scale Solar + Storage (3:1)	50	1,721	n/a	n/a	n/a	33.67	114

Notes:

(a) Installed cost, capability and heat rate number have been rounded

(b) All costs in 2021 dollars

(c) Total Plant Investment Cost

(d) Average fuel price across study horizon

(e) First year LCOE based on capacity factors shown in table. Not shown for storage or for low dispatch

(f) Start cost of $79 / MW additional to VOM

(g) Denotes efficiency, (with power electronics)

(h) Fuel input is dependent on electricity price for electrolyzer

RESOURCE ASSESSMENT MODELING SCENARIOS AND RESULTS

Once the list of potential resources had been assembled, the AURORA model used those resources to create various generation resource portfolios based upon different economic and regulatory assumptions/constraints. Initially, five market scenarios were developed to test plausible, but different long-term views of fundamental external market conditions.

The Reference market scenario, which Kentucky Power considered to be the most likely, assumes that over the forecast period, demand for energy in PJM grows at the annual rate of 0.8 percent, summer and winter peak demand grow at the annual rates of 0.39 and 0.63 percent respectively.[82] Commodity prices including coal, gas and CO_2 emissions pricing represent the expected broader PJM market.[83] Gas price forecasts were based on the monthly Columbia Gas Transmission (TCO pool) prices. Coal price forecasts were based on Central Appalachian Basin (CAPP) prices, which is the coal predominately used by Kentucky Power. CO_2 prices were assumed to begin at approximately $11/ton and increase gradually throughout the forecast period. It is assumed that the CO_2 prices will increase the dispatch cost of all PJM fossil fired generation.[84] Under the Reference market scenario, the IRM is 14.7 percent adjusted for PJM wide average EFORd. The FPR pool requirement is approximately 9.0 percent. The capacity contribution of the various resource technologies will change over the forecast period depending on the associated ELCC of each resource.[85] In addition, where applicable, investment and production tax credits were applied to resource capital costs.[86]

The Reference High-Cost scenario (REF-HC) is similar to the Reference scenario, except that new unit costs for solar, wind and storage remain elevated relative to the Reference scenario.[87]

The Clean Energy Technology Advancement (CETA) scenario assumes that greenhouse gas (GHG) reductions are attained through increased incentives for clean supply side and demand side technology deployment. It also assumes an aggressive

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[82] IRP at 117.

[83] IRP at 117-118.

[84] IRP at 118-119.

[85] IRP at 120.

[86] IRP at 121.

[87] IRP at 123.

adoption of end use electrification technologies such as greater EV penetration. The end effect is an increased load forecast and changing consumption patterns.[88]

The Enhanced Carbon Regulation (ECR) scenario assumes that GHG reductions are attained through higher costs for emitting generation and restrictions on the future development of fossil fuels. Utilizing a cap-and-trade mechanism results in significant CO_2 prices and higher natural gas costs relative to the Reference scenario.[89]

The No Carbon Regulation (NCR) scenario assumes no carbon regulation over the forecast period and that gas prices remain low. Resulting market conditions are similar to recent history and tend to be more favorable to coal and gas resources relative to the Reference scenario.[90]

In response to stakeholder input, two additional portfolios were created. The Combined Cycle (CC) scenario was developed in response to stakeholder input since no other portfolio resulted in a combined cycle unit being constructed. The No Wind scenario was created reflecting the availability of wind resources in Kentucky Power's service territory and the potential challenges of siting or acquiring output from new wind projects.[91]

In addition to developing each market scenario, Kentucky Power performed a stochastic risk analysis to evaluate volatility and risk impacts to the generation portfolio that would not be assumed under either expected or normal weather deterministic forecasts. In these analyses, 250 combinations of stochastic gas prices, power prices and renewable outputs are used to specifically address portfolio performance and cost under various market dynamics and generation availability outcomes.[92] The AURORA model and the PERFORM financial model are utilized. The 95th and 50th percentile CPW among the set of portfolio cost realizations are identified to calculate the "Cost Risk" scorecard metric.[93]

Kentucky Power developed a scorecard to understand how the various portfolios performed relative to each other under various evaluation metrics. Kentucky Power established four overall objectives, each with its own set of performance indicators. Customer Affordability performance is measured by CPW, percentage of income, and Near-term rate impacts. Rate Stability is measured by scenario resilience, cost risk, and market exposure. Maintaining Reliability is measured by reserve margins and operational

[88] IRP at 123-124.

[89] IRP at 124.

[90] IRP at 124.

[91] IRP at 155.

[92] IRP at 137.

[93] IRP at 137-138.

flexibility. Local Impacts and Sustainability is measured by local impacts (new investment) and carbon emissions.[94] The table below represents select scorecard results for each of the portfolios under different objectives and metrics.[95]

[94] IRP Figure 67 at 145. Also, see a more detailed discussion at 145-152.

[95] IRP Figure 79 at 172. A detailed discussion of individual portfolio results and a summary can be found at 155-171. Also see IRP Appendix E2 at 219-304 for additional case and scenario study results.

	Customer Affordability		Rate Stability			Maintaining Reliability		Local Impacts & Sustainability	
Portfolio	*Short Term: 5-yr Cost CAGR, Reference Case*	*Long Term: 15-yr CPW, Reference Case*	*Scenario Range: High Minus Low Scenario Range, 15-yr CPW*	*Cost Risk: RR Increase In Reference Case (95th minus 50th percentile)*	*Market Exposure: Net Sales as % of Portfolio Load, Scenario Average*	*Planning Reserves: % Reserve Margin, scenario Average*	*Operational Flexibility: Dispatchable capacity*	*Local Impacts: New Nameplate MW & Total CAPEX Installed Inside service Territory*	*CO2 Emissions: Percent Reduction from 2005 Baseline - Reference case*
Year Ref	2023 - 2028	2023 - 2037	2023 - 2037	2037	2037	2023 - 2037	2027 I 2037	2023 - 2037	2027 I 2037
Units	%	$MM Levelized Rate	$MM Levelized Rate	$MM	Summer I Winter	Summer I Winter	MW	MW I $MM	% Reduction
Reference Portfolio	7.52	3,395 $62.1	438 $8.9	77.6	14% I 30%	11.3% I -22.7%	1,111 I 775	893 I $1,146	74% I 90%
Reference-High Cost Portfolio	8.53	3,435 $62.3	432 $8.7	72.2	10% I 26%	10.6% I -23.1%	1,111 I 775	855 I $1,134	74% I 90%
CETA Portfolio	9.16	3,504 $64.0	565 $11.6	87.1	31% I 39%	20.2% I -19.9%	1,111 I 825	1,205 I $1,511	74% I 90%
ECR Portfolio	8.21	3,605 $65.6	886 $15.1	95.8	28% I 26%	3.4% I -37.4%	1,111 I 490	1,465 I $1,942	74% I 96%
NCR Portfolio	7.91	3,517 $64.1	497 $13.3	37.9	-25% I -20%	10.2% I -20.8%	1,111 I 925	855 I $1,067	74% I 90%
CC Portfolio	8.78	3,516 $64.6	430 $9.3	56.8	24% I 21%	10.7% 1 -26.5%	1,111 I 763	993 I $1,528	74% I 86%
No Wind Portfolio	7.65	3,755 $68.4	684 $12.6	48.9	5% I -45%	10.6% I -37.1%	1,111 I 660	1,118 I $2,088	74% I 94%
Preferred Portfolio	**8.81**	**3,522 $64.8**	**501 $9.4**	**58.3**	**6% I 0%**	**14.6% I -23.5%**	**1,111 I 825**	**1,055 I $1,355**	**74% I 90%**

Kentucky Power selected its Preferred Plan based upon the portfolio scorecard results. The Preferred Plan pre-selects the 480 MW CT build from the optimized portfolio along with the 700 MW of new wind, 800 MW of new solar, and the 50 MW of battery storage resource selections from the CC Portfolio. The Preferred Plan also includes the life extension of the Big Sandy Unit to 2041 and Short-Term Market Purchases of up to 78 MW through 2026 and 407 MW in 2028.[96] The table below shows the capacity additions of the Preferred Plan.[97]

[96] IRP at 173 and Appendix E1 at 220-223.

[97] IRP at 174 and Appendix E1 at 223.

Utility Scale Incremental New Build By Addition Year (ICAP MW)

Year	Gas CT	Solar (T1/T2)	Wind (T1/T2)	Li-ion 4hr Battery Storage	Big Sandy Extension	Capacity Purchase	DSM Additions (MW)
2023						73	3
2024						78	8
2025						78	14
2026			100			78	24
2027		250	100/100				32
2028		150/300	100/100			407	38
2029	480	100					43
2030			100				47
2031					295		47
2032							48
2033							48
2034							48
2035				50			48
2036							47
2037							46
Total	480	800	700	50	295		

The table below show the results of the Preferred Portfolio as applied to the Reference Case (most likely) scenario set of set of assumptions. The results are presented on a UCAP MW basis.[98]

[98] IRP Appendix E2 at 240.

Year	Capacity MW	Peak + Reserves MW	Capacity Surplus MW	Reserve Margin %	Energy Surplus (GWh)
2023	1,019	1,014	5	9.5	556.0
2024	1,029	1,019	9	9.9	(1.0)
2025	1,032	1,002	29	12.1	(1,402.0)
2026	1,053	1,054	(1)	8.8	(1,503.0)
2027	1,111	1,050	61	15.3	(1,217.0)
2028	1,086	1,044	42	13.4	(1,186.0)
2029	1,105	1,040	64	15.7	1,072.0
2030	1,107	1,037	70	16.3	283.0
2031	1,110	1,035	74	16.8	102.0
2032	1,100	1,030	70	16.3	(124.0)
2033	1,095	1,031	64	15.7	(75.0)
2034	1,089	1,026	63	15.7	(277.0)
2035	1,118	1,025	94	18.9	(281.0)
2036	1,112	1,021	91	18.7	(20.0)
2037	1,105	1,022	83	17.8	(172.0)

INTERVENOR COMMENTS

The Attorney General asserted that Kentucky Power's IRP fails to demonstrate that it will provide an adequate and reliable supply of electricity. The Attorney General noted that Kentucky Power's preferred plan results in a 23.5 percent reserve margin deficit during the winter, and that Kentucky Power plans to meet its load need through membership in PJM during the winter peaking months. The Attorney General asserted that plan fails on its face at Kentucky Power's core requirement to provide adequate and reliable electricity to serve its clients.[99]

More specifically, the Attorney General asserted that intermittent resources, such as wind and solar on which Kentucky Power's preferred plan relies on heavily, are not reliable, because among other things, they cannot deliver power at any time due to their intermittent nature.[100] The Attorney General also stated that energy markets are increasingly volatile due to increased penetration of unreliable intermittent resources, and that the proliferation of heavily subsidized intermittent resources in energy markets has distorted price signals.[101] The Attorney General argued that Kentucky policy, including

[99] Attorney General's Comments at 5-10.

[100] Attorney General's Comments at 8-16.

[101] Attorney General's Comments at 17-26.

Senate Bill 4, favors dispatchable thermal resources over intermittent resources.[102] The Attorney General argued that the IRPs plan to add resources outside of Kentucky subjects ratepayers to additional risks than the location of resources in Kentucky, including higher transmission costs and to regulation by other jurisdictions.[103] The Attorney General also indicated that Kentucky Power's parent company has emissions targets that are driving IRP decisions increasing cost risks to customers.[104]

The Attorney General stated that Kentucky Power currently has 1,075 MW of dispatchable thermal generation—Big Sandy with 295 MW ICAP and Mitchell with 780 MW of ICAP—but that Kentucky Power only plans to have 331 MW of dispatchable generation in 2028. Then, the Attorney General asserted that once the new 480 MW CT is built Kentucky Power will have 825 MW of dispatchable generation. The Attorney General noted that there is an open question regarding whether the separation of Kentucky Power from the Mitchell Coal Plant will constitute the retirement of a fossil fuel-fired electric generating unit under Senate Bill 4 but asserted that at minimum it runs contrary to the intent of the bill.[105]

The Attorney General recommended that Commission Staff or the Commission:

1. Reiterate that Kentucky law requires utilities to replace existing thermal, dispatchable generation with thermal, dispatchable generation when replacement becomes necessary;
2. Make clear that membership in an RTO and compliance with the requirements of that RTO is insufficient resource planning;
3. Require Kentucky Power to investigate the feasibility of entering into purchase power agreements with LG&E/KU and/or EKPC to reduce or eliminate its capacity deficits;
4. Reject any plan for Kentucky Power to serve ratepayers through heavy dependence on unreliable, intermittent resources located outside the Commonwealth;
5. Require Kentucky Power to study whether changing market dynamics demand that ratepayers would be better served by avoiding increasingly costly market purchases and instead, directly generating the energy needed to serve ratepayers;

[102] Attorney General's Comments at 26-28.

[103] Attorney General's Comments at 31-32.

[104] Attorney General's Comments at 31-32.

[105] Attorney General's Comments at 26-28.

6. Require Kentucky Power to study the feasibility of fully meeting the generation needs of its ratepayers by producing power fully within the Commonwealth; and
7. Require Kentucky Power to engage in robust transmission planning for planned projects such that all costs are considered before a decision is made with respect to generation investments.[106]

KIUC asserted that Kentucky Power's proposed plan introduces several material risks for customers beginning in 2028. KIUC asserted that Kentucky Power's plan to rely on 407 MW of market capacity purchases beginning in 2028 introduces real questions about potential rate impacts. KIUC asserted that under a capacity only purchase that Kentucky Power would have no hedge, instead relying entirely upon the market for energy. KIUC also asserted that Kentucky Power's proposal to rely on out-of-state wind, solar, and new gas CT units to address its capacity shortfall beyond 2028 instead of considering purchases of existing resources is also risky. KIUC suggested that Kentucky Power consider leveraging existing resources, including exploring an agreement to purchase energy and capacity from the Mitchell units beyond 2022 and/or purchasing Kentucky Utility Company's 495 MW Ghent Unit 2.[107]

KIUC argued that Kentucky Power failed to properly model the inclusion of NGCC units. Specifically, in modeling the NGCC portfolio, KIUC stated that Kentucky Power assumed the addition of the wind and solar resources prior to the addition of the NGCC resource. KIUC stated that this choice reduced the capacity factor of the NGCC unit and undermined the need and economics of that portfolio. KIUC asserted that if the modeling had been conducted differently the recommended approach may have included an NGCC. KIUC asserted that Kentucky Power should be required to more fairly consider the NGCC alternative.[108]

Joint Intervenors asserted that the IRP failed to adequately consider distributed energy resources (DER) as a means of providing sufficient capacity. Joint Intervenors noted that it is unclear if and how the Company incorporated an evaluation of DERs into its IRP analysis to help avoid distribution upgrades. Joint Intervenors asserted that DERs, particularly solar and battery resources, serve as a low-cost resource that can supply capacity requirements, reduce fuel price volatility, improve reliability, increase resilience, and overcome barriers to deployment of new resources. Joint Intervenors argued that Kentucky Power did not t conduct a comprehensive analysis of DERs. Joint Intervenors recommended including an evaluation of potential supply side DERs and a DER forecast

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[106] Attorney General's Comments at 2-3.

[107] KIUC's Comments at 2-4.

[108] KIUC's Comments at 4-6.

in future IRPs. Joint Intervenors also asserted that Kentucky Power should show how these evaluations are incorporated into the IRP.[109]

More specifically, Joint Intervenors asserted that Kentucky Power's IRP limits its modeling on battery storage as a DER source. Joint Intervenors, citing to a report they commissioned for this matter, argued that Kentucky Power constrained its annual build limit on battery storage, limited the book life of battery storage resources, and did not model 8- or 10-hour lithium-ion battery storage and multiday storage as a resource.[110]

Joint Intervenors supported Kentucky Power's use of an all-source request for proposal (RFP) process but suggested some improvements to the process. Specifically, Joint Intervenors asserted that Kentucky Power unnecessarily limited the ability of battery storage projects to compete by restricting eligible storage projects to 10-year PPAs rather than a "more economic 15- or 20-year period" and "by apparently not allowing solar + storage hybrid projects to bid into the process."[111] Second, Joint Intervenors assert that the best practice for such RFP processes requires that they be administered by an independent third-party.[112] Third, Joint Intervenors asserted that Kentucky Power's process needs additional transparency.[113]

DISCUSSION OF REASONABLENESS

It is not clear, and the IRP did not adequately explain the meaning of modeling on an AEP / Zonal basis as opposed to modeling Kentucky Power on an individual standalone company basis. From AEP's perspective, such an approach has merit due to the manner in which its generation resources are managed and offered into the PJM markets. However, there is no discussion of how Kentucky Power's specific resource additions and retirements are obtained out of a zonal model optimization solution. The resource optimization analyses for the AEP Zonal model suggests that all AEP generation resources are optimized jointly and results in an AEP Zonal solution where each of the various AEP operating companies (OPCOs) would have its specific subset of resource additions and retirements according to the zonal optimized solution.

In the scenario of Kentucky Power being analyzed as a standalone company, the timing of and selection of resource additions and retirements could plausibly be quite different. Arguably, what is the least reasonable cost for Kentucky Power's ratepayers

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[109] Joint Intervenors' Comments at 9-13.

[110] Joint Intervenors' Comments at 13-19.

[111] Joint Intervenors' Comments at 23.

[112] Joint Intervenors' Comments at 24.

[113] Joint Intervenors' Comments at 25.

under a zonal optimization may not be reasonably least cost under a standalone optimization.

Looking at the specific scenario results for the Preferred Plan, per the Scorecard over the forecast period, every Portfolio produced a positive summer reserve margin ranging from 3.4 percent (ECR) to 20.2 percent (CETA) and a negative winter reserve margin ranging from -19.9 percent (CETA) to – 37.4 percent (ECR). Kentucky Power's Preferred Plan produces a summer and winter planning reserve margin of 14.6 percent and -23.5 percent, respectively. Implicit in Kentucky Power's results is that it will simply purchase any necessary energy during the winter heating season as opposed to having adequate capacity to fulfill its winter energy needs. If the energy is modeled as supplied from inside the AEP zone, then the evolution of how the other AEP OPCOs' resource portfolios change over time is relevant to Kentucky Power's resource optimization over time.

However, Commission Staff still believe that the goal of the IRP process is to identify a plan to provide adequate and reliable service to Kentucky Power customers with a reasonable, least-cost portfolio in a manner that complies with Kentucky law. Thus, the costs and effects on reliability of various resource divisions, including locating resources outside of Kentucky and relying on capacity and energy purchases through bilateral contracts or market purchases, should be considered and discussed in reaching a preferred plan.

While Kentucky Power's IRP included a number of reasonable assumptions and relied on some reasonable methodologies, particularly given when it was prepared, Commission Staff does ultimately question the reasonableness of Kentucky Power's preferred portfolio for reasons discussed in more detail in the recommendations sections above and below.

RECOMMENDATIONS FOR KENTUCKY POWER'S NEXT IRP

For the Next IRP, Kentucky Power should:

1. Explain how the AURORA model functions when the AEP Zonal resource optimization approach is taken to reach an optimized zonal solution. Include in the response how a zonal approach to Kentucky Power's future resource additions and retirements is affected by the other AEP East OPCOs' resource additions and retirements within the zonal optimized solution.

2. Present the zonal modeling results in total and broken out by each AEP East OPCOs separately.

3. Because of Kentucky Power's large winter capacity deficit, it would have been instructive to break up the energy sales and purchases on a seasonal (winter,

spring, summer and fall) basis. That would shed light on exactly how the large additions of solar (700 MW) and wind (800 MW) resources affect seasonal energy sales, purchases, reserve margins and whether the proposed CT (480 MW) remained the optimal choice versus the NGCC. For the next IRP, Kentucky Power should present energy sales, purchases, reserve margins and resource additions and retirements on an annual and on a seasonal basis.

4. If all the AEP East OPCOs greatly reduce base load generation in favor of intermittent and renewable resources in a fashion similar to Kentucky Power's preferred plan, that in turn could affect Kentucky Power's decisions regarding its own resource portfolio. In other words, a zonal model was used to initially forecast resource additions and retirements, but the zonal results are not presented. It is relevant to know what the other OPCOs' forecast choices would be and how that might affect Kentucky Power's ultimate resource decisions and interactions with the evolving zonal market conditions.

From a planning perspective, it is curious that Kentucky Power is purchasing capacity and energy (negative surplus) leading up to the time it divests itself of its share of the Mitchell Units and then only brings the CTs online the following year. Given that the forecast was completed in June of 2022 and the Mitchell divestiture occurred six years later in 2028, it is not clear why the timing of the CT addition in 2030 makes sense. There would appear to be sufficient time to plan for and construct the proposed CTs to coordinate with the Mitchell divestiture.

The IRP discusses how the Preferred Plan compares to the other scenario resource portfolios. However, there is not sufficient discussion regarding specific results from adopting the Preferred Plan. For example, Kentucky Power's surplus energy goes from 556.0 GWh in 2023 to negative 1,402 GWh in 2025. In 2028, energy surplus is negative 1,186 GWh and then increases to 1,072 GWh in 2029. For context, forecast Residential energy sales range from 1,959 GWh in 2023 and decrease to 1,848 GWh in 2029.[114] The Commercial class energy sales does reflect the addition of the anticipated cybersecurity load. For the next IRP, Kentucky Power should better explain the market drivers behind such large swings and the anticipated effects on ratepayers.

At the time the forecast was completed in June 2022, AEP was still moving forward with the sale of Kentucky Power. Consequently, Kentucky Power would have only temporarily relied on AEP personnel and assistance with PJM process through some form of contractual agreement. Since AEP was presuming a sale at the time of this IRP filing, conducting a long-term generation study with the assumption that Kentucky Power remained in the AEP system (for generation management, dispatch, and cost allocation) would not have yielded reliable results. While Commission Staff understands that Kentucky Power was required to conduct a long-term study to comply with 807 KAR 5:058, Section 7(3), there appears to be no rationale provided regarding the reasonableness of the assumptions associated with remaining a part of AEP for the duration of the IRP horizon. There is little to no basis upon which to rely on the planned

[114] IRP Exhibit C-1 at 197.

resource additions in the preferred plan (even if adjusted due to RFP responses) as being the most reasonably cost effective and timely for Kentucky Power when modeled as a standalone company and not remaining under the ambit of AEP's authority and resource planning. For example, when modeled as a standalone company and assuming that Kentucky Power remains in the AEP load zone subject to PJM allocations, not AEP transmission cost allocations, its transmission cost allocation certainly be different, and perhaps, even lower.

Moreover, Kentucky Power's future within the AEP system does not appear to be certain in the medium- to long-term. Therefore, for the next IRP, in addition to modeling Kentucky Power as an integrated part of the AEP system as in this IRP, it should be modeled as a standalone company, as if it were under new ownership and in the AEP Zone, but not part of AEP's transmission cost allocation formula. The resource selection and portfolio optimization results of modeling Kentucky Power both as a part of AEP and as a standalone company should be compared and contrasted to show how Kentucky Power's ratepayers are impacted over the IRP time horizon.

5. PJM seeks to ensure reliability within its service territory, in part, by imposing reserve margin capacity requirements upon its members, and Kentucky Power, like other utilities in an RTO, generally plans for reliability by planning to meet the reliability, or capacity requirements of the PJM. However, as the Attorney General argued, planning to simply meet PJM capacity requirements may not necessarily satisfy state adequacy requirements. Thus, although PJM plans for reliability at the regional level, Commission Staff believes that Kentucky Power should also independently examine the reliability of its preferred portfolio options and reasonable alternatives by considering the impact on the LOLE of the various portfolio options to the extent possible, and if not possible, the effect, if any, of portfolio options on the LOLE of the PJM zone in which Kentucky Power is located.

6. The Clean Air Act, Section 111 has been updated recently. However, the EPA recently announced its intent to focus heavily on deregulation.[115] While specific actions and timelines remain unclear, there appears to be considerable movement in the immediate term which has the potential to affect both Big Sandy and Mitchell's future. By the time the next IRP is filed, the regulatory landscape will have had a greater opportunity to stabilize, and Kentucky Power can make more informed medium- and long-term resource decisions. For the next IRP, Kentucky Power should incorporate all current and new environmental regulations into both its resource selection and its production cost / resource portfolio optimization analyses. For environmental regulations under a stay or court challenge, Kentucky Power should model portfolios with and without the specific regulation and provide a detailed explanation for not including any environmental regulation that is under court challenge if that particular rule is not incorporated into the analyses. Commission Staff recognizes that this process is more cumbersome than prior recommendations, but the rapidly changing regulatory landscape, coupled with the expected immediate demand growth in PJM broadly, and in Kentucky's other territories,

[115] https://www.epa.gov/newsreleases/epa-launches-biggest-deregulatory-action-us-history

necessitate the additional steps. State and Federal regulations are significant cost drivers, and uncertainty regarding Kentucky Power's, and all utilities', responsibilities have the potential to cause real harm to ratepayers as utilities struggle to make appropriate long-term decisions regarding their generation sources. This is especially true for Kentucky Power because of the expected capacity shortfall in 2028 and possible loss of Big Sandy as a resource in 2031.

7. The announcement of new, very large data centers has been in the news recently. These data centers will require significant amounts of power and the construction of additional transmission infrastructure. The costs of which Kentucky Power will be allocated a share as a part of the AEP East system but will arguably receive little benefit. For the next IRP, Kentucky Power should discuss and model the effect on Kentucky ratepayers of the new anticipated data centers in the AEP Zone, both as a part of the AEP system and in the AEP Zone, but not part of the AEP system.

8. Kentucky Power did not include long-term power purchase agreements (PPAs) as potential resource additions. For the next IRP, Kentucky Power should include PPAs as potential resources. In addition, it should look for and consider potential generation resources (intermittent or otherwise) in Kentucky. These resources could be acquired or contracted via PPAs.

9. When Kentucky Power files an application for a Certificate of Public Convenience and Necessity (CPCN) or for approval of a PPA, it should include an updated demand forecast and an updated supply side analysis (selection of potential resources and production cost / portfolio optimization) as a part of the application.

10. Kentucky Power should work to align the onboarding of new generation to coincide with the significant expected capacity shortfall beginning in 2028 and with the potential to grow by 2031.

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 Kentucky Power plan.

For the resource optimization step, capacity resources made available to the AURORA model must include current resources and anticipated capacity resource additions and retirements, current and anticipated environmental impacts, changes in appliance and equipment efficiencies, current DR and EE resources, capacity and transmission constraints and limitations, changes that can result from decisions surrounding unit deposition evaluations, overall load and peak demand, and PJM requirements regarding reserve margins and reliability. PJM capacity requirements are structured in such a way so that Kentucky Power's capacity requirements and margins are based on the utility's own internal forecasted demand at the projected PJM summer peaks. Kentucky Power is a winter peaking utility, but its IRP analyses is structured to meet PJM peak requirements and not its own peaking demand requirements. Of course, if PJM full transitions to a seasonal model, this will likely have a positive effect on Kentucky Power's own forecasted demands because the seasonal peaks could create an incentive for Kentucky Power to build and/or secure firm generation resources that matches its internal forecasts. However, Commission Staff believes that PJM's own forecasting model should not obviate the very real need of Kentucky Power to ensure that it is securing the necessary capacity that coincides with its own moments of greatest needs. If Kentucky Power fails in that, its customers are still at risk of paying exorbitant prices when the region is also experiencing extreme weather events, or responsible, through the PJM ecosystem for generation while other areas of the PJM footprint experience those weather events.

Turning first to the environmental matters, Kentucky Power modeled only the requirements which were in effect at the time of modeling.[116] As part of the IRP, Kentucky Power identified several key statutory schemes of which it was aware. Those included the National Ambient Air Quality Standards (NAAQS) standards, the Cross-State Air Pollution Rule (CSAPR), the Coal Combustion Residual Rule (CCR), and the Clean Water Act Regulations such as the Effluent Limitations Guidelines and Standards (ELG).[117] Commission Staff are cognizant of the constantly evolving regulatory landscape and the challenges of operating in such an environment. However, Kentucky Power should emphasize analysis which account for the uncertainty. Given the length-of-time involved in permitting, constructing, and operating a new generation resource, it is imperative that Kentucky Power takes a truly longitudinal approach to regulatory compliance.

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[116] IRP at 56.

[117] IRP at 56-58.

As Kentucky Power recognized in its IRP filing, there is the real possibility for a broad range of continuing action such as "Presidential Executive Orders, litigation, petitions for review, and [EPA] proposals" which "may delay the implementation of [rules] or alter the requirements set forth by these regulations."[118] Therefore, Kentucky Power should model a range of potential outcomes to review, and not focus in on only one of those possibilities. It is imperative for the Commission and the public to understand the range of potential outcomes and How Kentucky Power intends to address each possibility. It is also imperative that Kentucky Power does the same in order to ensure that it is making the appropriate decisions in an appropriate timeline to protect the interests of itself and its customers.

As stated previously, Kentucky Power is currently part of the AEP eastern transmission system which is located entirely within the Reliability First Corporation (RFC) geographic region. Additionally, because Kentucky Power is part of AEP's eastern zone it "participates PJM regional planning, operations[,] and market." As Kentucky Power noted in its IRP, this interconnection system requires incremental system upgrades including larger capacity transformers and circuit breaker replacements.[119] Kentucky Power also anticipates the need for additional "system enhancements" to match load growth and allow for the addition of large load customers and additional, or other, generation facilities.[120]

AEP, on behalf of Kentucky Power, works with PJM to coordinate all the planning of transmission system in the PJM footprint. As part of this coordination, AEP does its planning with an eye to satisfying its local system requirements while PJM, through the use of modeling assessment, ensures that the transmission needs of its entire footprint are met.[121] Under PJM's Regional Transmission Expansion Plan process (RTEP), PJM determines each member utility's share of costs and construction responsibilities required to implement its expansion plan.[122]

DISCUSSION OF REASONABLENESS

While Commission Staff is generally satisfied Kentucky Power's integration process, including its risk analysis and plan optimization, Commission Staff remains concerned that the plan as presented in this IRP was not designed to meet the individual needs of Kentucky ratepayers and the internal needs of Kentucky Power. This is because the preferred plan was clearly developed to meet PJM and AEP summer peaks. Commission Staff is aware that a tension exists between Kentucky Power's needs and

[118] IRP at 56.

[119] IRP at 66.

[120] IRP at 66.

[121] IRP at 67.

[122] IRP at 67.

those of AEP and PJM stemming from the fact that the latter two's generation and capacity needs peak in the summer, while Kentucky Power peaks in the winter. Indeed, this is the only way to properly understand the preferred plan's insistence on solar and wind energy, despite the sharp decline in generation of those resources during winter months. This concern is not new. In Kentucky Power's prior IRP, Commission Staff voiced identical concerns regarding Kentucky Power's need to think of its commitments to its own customers when evaluating resource and capacity options.[123]

Commission Staff is also not convinced by Kentucky Power's strategy to rely on large market purchases to fill its resource gap, especially given the loss of the Rockport UPA and the resulting massive capacity shortfall the utility is expecting beginning in 2028.[124] This extraordinary reliance on the market does not seem likely to help achieve Kentucky Power's goal of rate stability.[125] Indeed, as recently as December 2022, during Winter Storm Elliott, Kentucky Power's reliance on the PJM market meant that the utility paid a massive premium reaching above \$3,500/MWh.[126] Therefore, Commission Staff again stresses the need for Kentucky Power to ensure that it looks first to meet the needs of its native customer base first.

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[123] Case No. 2019-00443, Commission Staff's Report at 32.

[124] IRP at 13.

[125] IRP at 147.

[126] Case No. 2023-00145, *Electronic Application of Kentucky Power Company for an Order Approving Accounting Practices to Establish a Regulatory Asset Related to the Extraordinary Fuel Charges Incurred by Kentucky Power Company in Connection with Winter Storm Elliott in December 2022* (Ky. PSC June 23, 2023) Order at 5.

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