COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY POWER COMPANY FOR APPROVAL OF (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	)	CASE NO. 2025-00175

<u>O R D E R</u>

On June 30, 2025, Kentucky Power Company (Kentucky Power) filed an application requesting an order granting: (1) a certificate of public convenience and necessity (CPCN) authorizing the Company to make the capital investments necessary to continue taking 50 percent of the capacity and energy from the Mitchell Generating Station (Mitchell Plant or Mitchell) after December 31, 2028; (2) approval of its 2025 Environmental Compliance Plan; (3) approval of amendments to its Tariff Environmental Surcharge (Tariff ES) to reflect its 2025 Environmental Compliance Plan and amended environmental cost recovery surcharge; (4) deferral authority for about $20.1 million in environmental costs that have been charged to West Virginia customers; and (5) all other required approvals and relief. The Attorney General of the Commonwealth of Kentucky, by and through the Office of Rate Intervention (Attorney General); Kentucky Industrial Utility Customers, Inc. (KIUC); and Sierra Club intervened in this proceeding. Kentucky

Power, the Attorney General, and KIUC responded to written requests for information; the Attorney General, KIUC, and Sierra Club filed written testimony in response to the Application; and Kentucky Power filed rebuttal testimony. On November 13, 2025, Kentucky Power filed a settlement agreement to which KIUC agreed and to which the Attorney General indicated it had no objection without explicitly agreeing (Settlement Agreement), along with a motion to approve the settlement agreement. A hearing was conducted in this proceeding on November 18, 2025. Kentucky Power responded to post-hearing requests for information, and the parties filed post-hearing briefs. This matter stands submitted for a decision by the Commission.

LEGAL STANDARD

CPCN Standard

Pursuant to KRS 278.020(1), no utility may construct or acquire any facility to be used in providing utility service to the public until it has obtained a CPCN from this Commission. To obtain a CPCN, the utility must demonstrate a need for such facilities and an absence of wasteful duplication.[1]

"Need" requires

> [A] showing of a substantial inadequacy of existing service, involving a consumer market sufficiently large to make it economically feasible for the new system or facility to be constructed or operated.
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> [T]he inadequacy must be due either to a substantial deficiency of service facilities, beyond what could be supplied by normal improvements in the ordinary course of business; or to indifference, poor management or disregard of the rights of consumers, persisting over such a period of time as to

[1] *Kentucky Utilities Co. v. Pub. Serv. Comm'n*, 252 S.W.2d 885 (Ky. 1952).

> establish an inability or unwillingness to render adequate service.[2]

"Wasteful duplication" is defined as "an excess of capacity over need" and "an excessive investment in relation to productivity or efficiency, and an unnecessary multiplicity of physical properties."[3] To demonstrate that a proposed facility does not result in wasteful duplication, the Commission has held that the applicant must demonstrate that a thorough review of all reasonable alternatives has been performed.[4] The selection of a proposal that ultimately costs more than an alternative does not necessarily result in wasteful duplication.[5] All relevant factors must be balanced.[6]

Environmental Surcharge Mechanism Standard

KRS 278.183 provides that a utility shall be entitled to the current recovery of its costs to comply with the federal Clean Air Act, as amended, and those federal, state, or local environmental requirements that apply to coal combustion wastes and by-products from facilities utilized for the production of energy from coal.

Pursuant to KRS 278.183(2), a utility seeking to recover its environmental compliance costs through an environmental surcharge must first submit to the Commission a plan that addresses compliance with the applicable environmental

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[2] *Kentucky Utilities Co. v. Public Service Commission*, 252 S.W.2d 885, 890 (Ky. 1952).

[3] *Kentucky Utilities Co. v. Public Service Commission*, 252 S.W.2d 885, 890 (Ky. 1952).

[4] Case No. 2005-00142, *Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for the Construction of Transmission Facilities in Jefferson, Bullitt, Meade, and Hardin Counties, Kentucky* (Ky. PSC Sept. 8, 2005).

[5] See *Kentucky Utilities Co. v. Pub. Sew. Comm'n*, 390 S.W.2d 168, 175 (Ky. 1965). *See also* Case No. 2005-00089, *Application of East Kentucky Power Cooperative, Inc. for a Certificate of Public Convenience and Necessity for the Construction of a 138 kV Electric Transmission Line in Rowan County, Kentucky* (Ky. PSC Aug. 19, 2005).

[6] Case No. 2005-00089, August 19, 2005 Order at 6.

requirements. The plan must also include the utility's testimony concerning a reasonable return on compliance-related capital expenditures and a tariff addition containing the terms and conditions of the proposed surcharge applied to individual rate classes.

Within six months of submission, the Commission must render a decision that considers and, if the plan and rate surcharge are found reasonable and cost-effective for compliance with the applicable environmental requirements, approves the compliance plan and rate surcharge. The Commission must also establish a reasonable return on compliance-related capital expenditures and approve the application of the surcharge.

BACKGROUND

Kentucky Power is a public utility principally engaged in the provision of electricity to Kentucky retail consumers. Kentucky Power serves approximately 163,000 retail customers located in Boyd, Breathitt, Carter, Clay, Elliott, Floyd, Greenup, Johnson, Knott, Lawrence, Leslie, Letcher, Lewis, Magoffin, Martin, Morgan, Owsley, Perry, Pike, and Rowan counties.[7] Kentucky Power stated that in 2024 its peak winter demand was 1,288 megawatts (MW) and that its peak summer demand was 980 MW.[8] Kentucky Power is a Fixed Resource Requirement (FRR) member of PJM Interconnection, LLC (PJM), a regional transmission organization.

Kentucky Power's Request

Kentucky Power's application in this matter requests:

1. A CPCN for capital investments allegedly necessary to continue taking capacity and energy from Mitchell Plant after December 31, 2028;

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[7] Application at 2.

[8] Application at 2.

2. To amend Kentucky Power's environmental compliance plan to add a new Project 23 (ELG Project) allegedly necessary to comply with the Environmental Protection Agency's (EPA) 2020 Effluent Limitations Guidelines standards (2020 ELG Rules), and amend Kentucky Power's Tariff ES to recover costs related to the ELG Project, including capital costs and about $665 million in annual operation and maintenance (O&M) expenses; and

3. To defer the costs necessary to reimburse Wheeling Power Company (Wheeling Power) customers for prior recoveries of the 50 percent of the ELG Project costs not presently allocated to Kentucky Power and not recovered from Kentucky Power customers through December 31, 2025, and to include the recovery of that regulatory asset in the Tariff ES rates.[9]

In support of the application, Kentucky Power, among other things, argued that continuing to operate Mitchell Plant beyond 2028 is the reasonable, least cost option for serving its customers and meeting its capacity obligations.[10]

Current Generating Resources

Kentucky Power owns all or portions of two generating plants—Mitchell Plant and Big Sandy Plant. Mitchell Plant is located in West Virginia on the Ohio River and includes two pulverized coal-fired baseload generating units. Mitchell Plant is operated by Wheeling Power, which co-owns Mitchell Plant along with Kentucky Power.[11] Mitchell Unit 1 has a nameplate capacity of 770 MW and Mitchell Unit 2 has a nameplate capacity

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[9] Application at 1.

[10] Application at 9.

[11] Application at 2–3.

of 790 MW, for a total nameplate capacity of 1,560 MW.[12] Kentucky Power's 50 percent undivided share of the Mitchell Plant consists of 780 MW of nameplate capacity.[13]

Big Sandy Plant is located near Louisa, Kentucky and currently has a single operating unit with nameplate generating capacity of 295 MW.[14] Big Sandy Unit 1 was originally placed in service in 1963 and operated as a 278 MW coal-fired generating unit through mid-November 2015.[15] Big Sandy Plant was converted to a natural gas-fired unit at that time and returned to service May 31, 2016.[16]

Load and Capacity Requirements

Kentucky Power indicated that PJM currently establishes the capacity requirements for load serving entities based on the those entities' summer peak because PJM peaks in the summer.[17] However, Kentucky Power indicated that PJM has initiated a process to review and potentially revise how winter capacity is accounted for in its accreditation methodology, including adding a winter capacity requirement, beginning in the 2029/2030 delivery year.[18] Kentucky Power also indicated that it understands that the Commission expects electric utilities to plan to meet their maximum customer demand, which would require Kentucky Power, as a winter peaking utility, to plan to serve

[12] Application at 2.

[13] Application at 2–3.

[14] Application at 3.

[15] Application at 3.

[16] Application at 3.

[17] Direct Testimony of Tanner Wolfram (Wolfram Direct Testimony) (filed June 30, 2025) at 13.

[18] Wolfram Direct Testimony at 13.

its winter peak.[19] Kentucky Power projected that its PJM capacity requirement would be 828 MW of Unforced Capacity (UCAP) in the 2028/2029 delivery year based on its summer peak and that its PJM capacity requirement would be 1,223 MW UCAP in 2028/2029 if PJM adopted a capacity requirement based on winter peak.[20]

Kentucky Power also indicated that PJM recently made changes to its methodology for accrediting generation resources to meet PJM capacity requirements and now uses an Effective Load Carrying Capability (ELCC) methodology to determine the capacity to assign to generation resources.[21] Using that methodology, Kentucky Power indicated that Big Sandy Plant would have a UCAP capacity credit of 243 MW in the 2028/2029 delivery year and that a 50 percent share of Mitchell Plant would have a UCAP capacity credit of about 600 MW in the 2028/2029 delivery period.[22] Thus, Kentucky Power asserted that it would need the capacity from Mitchell Plant, or some alternative generation, to satisfy even PJM's current capacity requirements and that additional capacity would be needed if planning was conducted to serve its winter peak.[23]

<u>Requested Mitchell Investments</u>

Kentucky Power asserted that in order for Mitchell Plant to continue operating beyond 2028 that it had been necessary to build wastewater treatment and related

[19] Wolfram Direct Testimony at 13.

[20] Wolfram Direct Testimony at 14.

[21] Wolfram Direct Testimony at 13, footnote 9.

[22] Wolfram Direct Testimony at 14–15.

[23] Wolfram Direct Testimony at 13–15.

facilities to comply with the EPA's 2020 ELG Rule, i.e. the ELG Project.[24] Kentucky Power noted that, in Case No. 2021-00004, the Commission denied Kentucky Power's request for a CPCN for the ELG Project.[25] However, Kentucky Power indicated that the West Virginia Public Service Commission, which regulates Wheeling Power, approved the facilities.[26]

As a result of the decisions from the Kentucky and West Virginia commissions, Kentucky Power indicated that, consistent with the West Virginia Public Service Commission's orders, and this Commission's orders in Case No. 2021-00004 and Case No. 2021-00421,[27] it and Wheeling Power approved, through the Mitchell Operating Committee, the September 1, 2022 Written Consent Action of the Mitchell Operating Committee, in which the Mitchell Operating Committee agreed to provide for, among other things, asymmetrical capital investment at Mitchell Plant.[28] Kentucky Power stated that "the Written Consent Action ensured that, other than certain costs incurred in developing and evaluating [2020 ELG Rule] compliance options that Kentucky Power was permitted to recover, only Wheeling Power paid for the ELG Project."[29] Kentucky Power indicated that the Written Consent Action "also allocated a higher ratable share of all other capital

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[24] Application at 6. Notably, the ELG Project consists of a new FGD biological treatment system with ultrafiltration, and associated supporting equipment, such as valves, pumps, piping, and tanks.

[25] 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 July 15, 2021), Order at 6-9, 25.

[26] Application at 4-5.

[27] Case No. 2021-00421, *Electronic Application of Kentucky Power Company for Approval of Affiliate Agreements Related to the Mitchell Generating Station* (Ky. PSC May 3, 2022).

[28] *See* Application at 5; Wolfram Direct Testimony at 9, Exhibit TSW-1 at 28-32.

[29] Application at 5.

investments necessary to continue operating the Mitchell Plant after December 31, 2028, to Wheeling Power."[30]

In this case, Kentucky Power stated that it seeks approval to continue taking 50 percent of the energy and capacity from Mitchell Plant after December 31, 2028, by making the necessary investment to reflect a continued 50 percent share of the Mitchell Plant costs.[31] Kentucky Power asserted that the necessary investments required for it to reflect its full 50 percent share of the costs of Mitchell Plant beyond December 31, 2028, include two components: (a) investments to reflect a full 50 percent share of the ELG Project (ELG Investments); and (b) the capital investments necessary to reflect Kentucky Power's 50 percent share of non-environmental capital projects that were asymmetrically allocated to Wheeling Power because they had useful lives beyond 2028 (Non-ELG Investments).[32]

Kentucky Power indicated that the required ELG Investments would be $77.86 million, including 50 percent of the net plant balances for the ELG Project, estimated to be $57.8 million as of December 31, 2025, and 50 percent of the costs West Virginia customers have paid and will pay through December 31, 2025, for the ELG Project, estimated to be $20.1 million.[33] Kentucky Power indicated that Non-ELG Investments would be $60.38 million,[34] reflecting the changes in capital investments necessary to reflect a 50 percent allocation for non-ELG capital projects allocated

[30] Application at 5.

[31] Application at 6.

[32] Application at 7.

[33] Application at 7.

[34] Application at 7.

asymmetrically to Wheeling Power beginning in September 2022 through April 2025, calculated to be $49.0 million, and changes necessary to reflect a 50 percent allocation for non-ELG capital projects projected to be completed from April 2025 through December 31, 2025, estimated to be $11.40 million.[35]

On October 10, 2025, Kentucky Power supplemented its application in this matter. The supplemental information indicated that in the course of completing work on the cooling tower for Mitchell Unit 2 that was described in direct testimony filed with the application, more substantial structural work that was necessary was identified. The additional work warranted consideration of various alternatives.[36] Kentucky Power indicated at the time of that filing that it had identified several potential alternatives to the cooling tower work, including shortening the existing tower and constructing a new tower. However, while it recognized that additional work on the cooling tower might affect the decision in this case, Kentucky Power indicated that it was not requesting approval for work on the cooling tower in this case.[37]

<u>Short-Term Alternatives and Absence of Wasteful Duplication</u>

Kentucky Power stated that it considered multiple reasonable alternatives for meeting its upcoming energy and capacity needs.[38] Kentucky Power indicated that it evaluated three alternatives for providing capacity and energy to its customers for the years 2029 through 2031—Investment in Mitchell Plant (Alternative 1), Purchase Power

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[35] Direct Testimony of Joshua D. Snodgrass (Snodgrass Direct Testimony) (filed June 30, 2025) at 7–8, Figure JDS-3.

[36] Kentucky Power's Motion to Amend the Procedural Schedule (filed Oct. 10, 2025) at 2–3.

[37] Kentucky Power's Post Hearing Brief (filed Dec. 10, 2025) at 18, footnote 66.

[38] Application at 9.

Agreements (PPAs) (Alternative 2), and Capacity and Energy Market Purchases (Alternative 3). Kentucky Power asserted that it did not consider new build resources as part of the short-term analysis because "construction of new build resources would not be completed in time to meet the Company's capacity needs that would result from the loss of the Mitchell Plant."[39]

Kentucky Power asserted that of the options considered in the short-term, Alternative 1 which includes investing in and continuing to operate Mitchell Plant, is the most reasonable, least cost option.[40] Without reflecting the cost of additional cooling tower work or increases in capacity market prices, Kentucky Power indicated that Alternative 1 results in a cumulative cost of service during the period from 2029 to 2031 that is approximately $136.00 million less than Alternative 2, the PPA option, and approximately $560.00 million less than Alternative 3, the market purchase option.[41] Kentucky Power also asserted that if the PJM capacity price is increased based on the results of the most recent PJM Base Residual Auction (BRA) price of $329.17/MW-day, then Alternative 1 has a cumulative cost of service that is approximately $160.00 million less than Alternative 2 and approximately $640.00 million less than Alternative 3.[42]

Kentucky Power stated that, even including the cost for the cooling tower identified in supplemental testimony, the cumulative costs of Alternative 1 in 2029 to 2031 are

[39] Kentucky Power's Post Hearing Brief at 15; *see also* Vaughan Direct Testimony at 7.

[40] Kentucky Power's Post Hearing Brief at 15.

[41] Kentucky Power's Post Hearing Brief at 17.

[42] Kentucky Power's Post Hearing Brief at 17.

significantly lower than those of Alternative 2 and 3. Specifically, Kentucky Power identified four options for addressing the cooling tower:

1. Option 1: Expand and extend the exterior shell reinforcement project.

2. Option 2: Retire Unit 2 and partially demolish the existing Unit 2 cooling tower.

3. Option 3: Construct a new mechanical draft cooling tower and partially demolish the existing Unit 2 cooling tower.

4. Option 4: Reduce the height of the existing Unit 2 cooling tower and continue with a reduced scope of exterior shell reinforcement.[43]

Kentucky Power asserted that Options 3 and 4 for addressing the cooling tower issue would increase the cumulative cost of service of Option 1 by about $40,000,000 and $20,000,000, respectively.[44] Thus, Kentucky Power argued that the cumulative cost of service from 2029 to 2031 of Alternative 1 would be less than the cumulative cost of service from 2029 to 2031 of Alternatives 2 and 3 and that Alternative 1 would remain the reasonable, least cost option even with the increase in costs associated with the cooling tower.[45]

Long-Term Alternatives and Absence of Wasteful Duplication

While Kentucky Power indicated that it is not seeking approval to make further investments beyond those for the ELG Project and for non-ELG projects that are expected to be completed by 2025, Kentucky Power indicated that under current law the Mitchell

[43] Supplemental Direct Testimony of Alex E. Vaughan (Vaughan Supplemental Testimony) (filed Oct. 10, 2025) at 2.

[44] Kentucky Power's Post Hearing Brief at 18.

[45] Kentucky Power's Post Hearing Brief at 18-20.

Plant cannot continue to operate as a coal plant beyond December 31, 2031.[46] Specifically, Kentucky Power indicated that in May 2024 the EPA published Section 111 Greenhouse Gas Standards (GHG Rule), which require Mitchell Plant to either (a) retire by 2032, (b) convert to a 40 percent gas co-fire and retire by 2039, or (c) convert to 100 percent gas with no set retirement date.[47] Kentucky Power also indicated that in May 2024 that the EPA published revised Steam Effluent Limitation Guidelines (2024 ELG Rule) that require the installation of a zero liquid discharge system (ZLD System) by (a) December 31, 2029, or (b) by December 31, 2034, if the facility installed bioreactors to meet 2020 ELG Rule.[48] Kentucky Power acknowledged that the EPA has taken initial steps to repeal the GHG Rule and to extend deadlines for complying with 2024 ELG Rule. However, Kentucky Power asserted that the rules currently remain in effect such that under current law Kentucky Power is not able to operate Mitchell Plant beyond 2031 without further investments.[49] Thus, Kentucky Power indicated that it generally considered post-2031 alternatives based on compliance with those regulations.

Specifically, Kentucky Power looked at the following alternatives as part of its long-term analysis:

1. Alternative E1 – convert to 40 percent gas co-fire to comply with the GHG Rule, do not install a ZLD System to comply with the 2024 ELG Rule, and retire by December 31, 2034;

[46] Vaughan Direct Testimony at 8-9.

[47] Vaughan Direct Testimony 9.

[48] Vaughan Direct Testimony at 9.

[49] Kentucky Power's Post Hearing Brief at 21.

2. Alternative E2 – convert to a 40 percent gas co-fire to comply with the GHG Rule, install a ZLD System to comply with the 2024 ELG Rule, and retire by January 1, 2039;

3. Alternative E3 – convert to 100 percent gas to comply with the GHG Rule conversion, install a ZLD System to comply with the 2024 ELG Rule, and no retirement deadline (assumed 20-year life); or

4. Alternative E4 – construct a new build combined cycle gas plant to replace the Mitchell Plant.[50]

Kentucky Power also evaluated a fifth alternative, Alternative E5, in which it continued operating Mitchell Plant as a coal plant based on the assumption that the compliance deadlines for the relevant environmental regulations were extended to a point beyond Mitchell Plant's current assumed retirement date of 2040.[51]

Kentucky Power stated that it conducted a cost of service analysis to compare long-term alternatives that:

> Accounted for recovering the remaining net book value of the Mitchell Plant over the remaining life of the compliance alternative, included the incremental capital investment and operation and maintenance expense levels for each compliance alternative, included other operating expenses such as taxes, applied an estimated unit dispatch analysis based on the operating characteristics of each compliance alternative, and included market purchases for the compliance alternatives with shorter assumed lifespans to ensure an apples to apples comparison.[52]

[50] Vaughan Direct Testimony at 10.

[51] Vaughan Direct Testimony at 10.

[52] Kentucky Power's Post Hearing Brief at 22 *citing* Vaughan Direct Testimony at 11–12.

Kentucky Power provided the results of that analysis in Confidential Table AEV-2, as part of Alex Vaughn's Direct Testimony.[53] Kentucky Power asserted that those results demonstrated that "making the investment now that would allow Kentucky Power to continue with its undivided 50% interest in capacity and energy from the Mitchell Plant provides the Company and its customers with multiple reasonable cost options to meet its capacity and energy obligations after 2031."[54]

Kentucky Power indicated that it conducted a "break-even" analysis after it determined that additional cooling tower investment was required to determine the level of capital investment in the Mitchell Plant at which the Mitchell Plant would no longer be the lower-cost option as compared to Alternative E4, a new natural gas combined cycle (NGCC) plant.[55] Kentucky Power indicated that the "break-even" analysis demonstrated that the level of additional capital investment necessary to make the long-term continued operation of Mitchell Plant more costly than a NGCC was significantly higher than the estimated cost of certain cooling tower options.[56] Thus, Kentucky Power asserted that making the investments necessary for it to continue to receive capacity and energy from the Mitchell Plant past December 31, 2028, is the reasonable, least cost alternative for Kentucky Power to serve its customers, and provides the most viable options post-2031.[57]

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[53] Vaughan Direct Testimony at 13.

[54] Kentucky Power's Post Hearing Brief at 22; Vaughan Direct Testimony at 13.

[55] Vaughan Supplemental Testimony at 10.

[56] Kentucky Power's Post Hearing Brief at 24 *citing* Vaughan Supplemental Testimony at 10–11, Confidential Table AEV-SD3.

[57] Kentucky Power's Post Hearing Brief at 24.

2025 Environmental Compliance Plan, ES Rate, and Settlement

Kentucky Power requested that the Commission approve its 2025 Environmental Compliance Plan and Surcharge Rate as modified by the Settlement Agreement. Kentucky Power asserted that:

> Construction of the ELG Project at the Mitchell Plant was required to comply with federal environmental regulations that "apply to coal combustion wastes and by-products from facilities utilized for production of energy from coal," in order for the plant to continue to operate after April 11, 2021. Simply put, if Wheeling Power had not undertaken and paid for the work necessary to comply with the ELG Rule, then the Mitchell Plant would have been required to shut down.[58]

Thus, Kentucky Power indicated that the 2020 ELG Rule is among the environmental requirements described in KRS 278.183 such that the costs of such compliance are properly recoverable through the environmental surcharge.[59]

Kentucky Power asserted that its proposal in the application to recover the regulatory asset portion of the ELG Investment through 2031 and the remainder of the ELG Investment through 2040 was reasonable, and would have had about a $3.68 bill impact on the average residential customer using 1,189 kWh per month.[60] However, Kentucky Power asserted that the Settlement Agreement brings additional relief to customers.[61]

Kentucky Power indicated that the Settlement Agreement makes two adjustments to Kentucky Power's as-filed Application. First, it changed the amortization period for the

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[58] Kentucky Power's Post Hearing Brief at 25 (internal citations omitted).

[59] Kentucky Power's Post Hearing Brief at 25.

[60] Kentucky Power's Post Hearing Brief at 26.

[61] Kentucky Power's Post Hearing Brief at 26.

regulatory asset portion of the ELG Investment from 2031 to 2040. Second, it changed the depreciation rate for the CCR project approved in Case No. 2021-00004 to be recovered through 2040 instead of 2028 as previously authorized.[62] Kentucky Power indicated those changes would reduce the monthly rate increase in the ES rate proposed in this matter to $2.33 per month for residential customers with average usage of 1,189 kWh.[63] Kentucky Power stated that the Settlement Agreement reflects a reasonable compromise to ensure that Kentucky Power is able to continue to serve customers with a substantial amount of capacity and energy after December 31, 2028, at a reasonable cost, and argued that it should be approved.[64]

<u>Intervenor Testimony</u>

KIUC and the Attorney General jointly presented the testimony of Lane Kollen (Kollen) in support of their positions in this matter. Kollen recommended that the Commission approve Kentucky Power's request for a CPCN for both the ELG Investments and the Non-ELG Investments, because Kentucky Power needs the capacity and energy beyond December 31, 2028, and Kollen contended that Mitchell Plant is the reasonable least cost option for meeting that need.[65] Kollen generally recommended that the Commission approve the ES tariff and proposed changes to the Environmental Compliance Plan, with some modifications related to the depreciation rates for capital investments approved in Case No. 2021-00004 and with an increase to the amortization

[62] Kentucky Power's Post Hearing Brief at 27.

[63] Kentucky Power's Post Hearing Brief at 27.

[64] Kentucky Power's Post Hearing Brief at 28.

[65] Direct Testimony of Lane Kollen (Kollen Direct Testimony) (filed Oct. 3, 2025) at 6.

period for the regulatory asset portion of the ELG Investment.[66] Lastly, Kollen recommended that the Commission direct Kentucky Power to pursue the savings that could be available to customers through securitization financing, not only for the capital investments at issue in this case but also for the entire net book value of the Mitchell Plant.[67]

Sierra Club presented testimony of Devi Glick (Glick), Senior Principal at Synapse Energy Economics, Inc., in support of its position in this matter. Glick's primary findings were that:

> 1. With the updated cooling tower replacement and repair costs, Kentucky Power's analysis does not support its original claim that continuation of its 50 percent share of Mitchell beyond the required termination date of December 31, 2028, is the least-cost option for the Company regardless of environmental compliance options.
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> 2. Kentucky Power's own analysis shows that converting Mitchell to operate on gas is lower cost over the long term (beyond 2031) than replacing the cooling tower and continuing to operate the plant on coal.
>
> 3. Conversion of Mitchell to operate 100 percent on gas would avoid the need to invest in repairing or replacing the cooling tower and would also avoid the need to invest in expensive pollution control technology to comply with the 2024 Effluent Limitations Guidelines (ELG) Rule.
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> 4. For the 2028–2031 time period, Kentucky Power does not appear to have considered all alternatives, including entering into a short-term agreement with Wheeling Power Company to buy power from Mitchell.

[66] Kollen Direct Testimony at 5–6.

[67] Kollen Direct Testimony at 6, 10–13.

> 5. The analysis that the Company prepared to support its claims in both its direct and supplemental testimony was piecemeal, at times confusing, and did not follow industry best practices for evaluating resource costs and alternatives.

Glick recommended that the Commission deny Kentucky Power's request to continue its 50 percent ownership share in Mitchell beyond December 31, 2028, in the current docket based on a finding that Kentucky Power failed to present sufficient analysis and evidence in this case "that retaining ownership of Mitchell beyond 2028 and continuing to operate it on coal is the lowest cost option for its ratepayers."[68] Glick recommended that Kentucky Power robustly evaluate its near-term alternatives by pursuing negotiations with Wheeling Power for a short-term PPA or other agreement to buy power from Mitchell Plant in the near term.[69] Glick also recommended that Kentucky Power should provide industry-standard production cost and capacity expansion modeling to support its requests to build new resources or invest in existing resources in this and future CPCN applications.[70]

<u>Post-Hearing Briefs</u>

Kentucky Power Briefs

In its post-hearing brief, Kentucky Power made arguments consistent with its application and testimony such as those mentioned above. Kentucky Power also argued that the points made by Glick in the testimony filed by Seirra Club do not justify denying Kentucky Power's application.[71]

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[68] Direct Testimony of Devi Glick (Glick Direct Testimony) (filed Nov. 6, 2025) at 5.

[69] Glick Direct Testimony at 5.

[70] Glick Direct Testimony at 5.

[71] Kentucky Power's Post-Hearing Brief at 30.

Kentucky Power noted that Glick proposed in her testimony that instead of making the proposed investments that Kentucky Power should explore the option of entering into an agreement with Wheeling Power to buy power from Mitchell Plant for 2028 through 2031. Kentucky Power argued that proposal ignores how a PPA would be priced and the fact that entering into a PPA with Wheeling Power would be functionally the same as Kentucky Power's Alternative 1.[72] Kentucky Power stated that Glick's proposal ignored affiliate transaction statutes in both Kentucky and West Virginia and the prior orders of the Kentucky and West Virginia commissions.[73] Kentucky Power also asserted that such a hypothetical PPA option would not be realistic and argued that Glick acknowledged that fact on cross examination.[74] Kentucky Power noted that Sierra Club's proposal also would not give Kentucky Power access to Mitchell Plant post-2031.[75] Kentucky Power asserted that even Sierra Club's witness Glick indicated at the hearing that she was not aware of how realistic a PPA for the capacity and energy from Mitchell Plant would be.[76] Kentucky Power asserts that Sierra Club's position that Kentucky Power should have considered a PPA with Wheeling Power for Mitchell Plant for 2029 through 2031 also relies on an incorrect standard which would require Kentucky Power to consider all alternatives as opposed to all reasonable alternatives.[77]

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[72] Kentucky Power's Post Hearing Brief at 30–31.

[73] Kentucky Power's Post Hearing Brief at 32.

[74] Kentucky Power's Post Hearing Brief at 30–32.

[75] Kentucky Power's Post Hearing Brief at 32; *see also* Kentucky Power's Post Hearing Response Brief (filed Dec. 16, 2025) at 5-11 (arguing the Sierra Club's 3-year PPA alternative is unreasonable and that it considered all reasonable alternatives).

[76] Kentucky Power's Post Hearing Response Brief at 7.

[77] Kentucky Power's Post Hearing Response Brief at 2-4.

In response to Glick's assertion that Kentucky Power could avoid the cooling tower investment and the investment in the ZLD system by converting Mitchell Plant to 100 percent gas, Kentucky Power asserted that Mitchell Plant would still require a cooling tower and some level of ZLD expenditures even if it were converted to a 100 percent gas plant.[78] Specifically, Kentucky Power noted that a gas conversion would simply convert the plant from a coal fired boiler to a natural gas fired boiler, but that a safe and reliable cooling tower would be required under any full or partial conversion to gas.[79] Kentucky Power asserted that this was confirmed by Kentucky Power's witness Vaughan at the hearing.[80] Similarly, Kentucky Power stated that, as explained by Kentucky Power's witness Vaughan, a ZLD system would be needed to comply with the 2024 ELG Rule for discharges from existing ash ponds even if Mitchell Plant is converted to gas.[81]

Attorney General Brief

In its post-hearing brief, the Attorney General stated that it supports Kentucky Power's request and the continued ownership and operation of Mitchell Plant.[82] The Attorney General explained that it opposed the ELG investment in Case No. 2021-00004 based on the circumstances at the time, including the intended sale of Kentucky Power.[83] The Attorney General argued that the circumstances have changed, namely that Kentucky Power was not sold and that replacement resources were not obtained in the

[78] Kentucky Power's Post Hearing Brief at 32–33.

[79] Kentucky Power's Post Hearing Brief at 32–33.

[80] Kentucky Power's Post Hearing Brief at 33.

[81] Kentucky Power's Post Hearing Brief at 34.

[82] Attorney General's Post-Hearing Brief (filed Dec. 10, 2025) at 1.

[83] Attorney General's Post-Hearing Brief at 3.

interim period.[84] The Attorney General averred that Kentucky Power's failure to secure alternative resources in 2021 has led to increased prices in those resources due to decreased available units in general.[85] The Attorney General stated that it is undisputed that without Mitchell Plant Kentucky Power would have a capacity deficit;[86] however, the Attorney General contended that the current request is due to the failure of Kentucky Power to correctly plan for and actually acquire alternative resources.[87]

The Attorney General argued that continued ownership of Mitchell Plant is the most cost-effective option at this time because reliance on the market is not feasible.[88] The Attorney General argued that even if converting Mitchell Plant to natural gas was ultimately the least cost option, Kentucky Power must continue its ownership interest in Mitchell Plant in order to receive the benefit of the capacity whether it is coal or natural gas fired.[89] The Attorney General also stated that the possibility to securitize some portion of the Mitchell Plant costs would also favor continued ownership.[90]

KIUC Brief

KIUC supported the Settlement Agreement, stating that Mitchell Plant is necessary to meet Kentucky Power's load requirements beyond 2028 and Mitchall Plant is the least

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[84] Attorney General's Post-Hearing Brief at 4.

[85] Attorney General's Post-Hearing Brief at 5.

[86] Attorney General's Post-Hearing Brief at 5.

[87] Attorney General's Post-Hearing Brief at 5–6.

[88] Attorney General's Post-Hearing Brief at 7.

[89] Attorney General's Post-Hearing Brief at 8.

[90] Attorney General's Post-Hearing Brief at 9.

cost option through at least 2031.[91] KIUC argued that the cost to invest in Mitchell Plant is significantly lower than acquiring an alternative resource and that new generation could not be built before 2029.[92] KIUC argued that continuing ownership in Mitchell Plant also gives Kentucky Power the flexibility to change fuel sources in the future.[93] KIUC stated that increasing load growth, generation retirements, and the rise in PJM capacity prices all point to continued ownership of Mitchell Plant being necessary and cost effective for Kentucky Power.[94] KIUC further argued that the Settlement Agreement also provides benefits to customers through the increased amortization period for the deferred ELG costs and the remaining plant balance of the CCR project.[95] KIUC also stated that Kentucky Power agreed to encourage legislation that would allow Kentucky Power to securitize Mitchell Plant for significant savings.[96]

Sierra Club Briefs

Sierra Club recommended that the Commission only extend the ownership of Mitchell Plant through 2031 to avoid the long-term commitment to an aged coal plant and to provide additional time to evaluate alternative resources.[97] Sierra Club also argued

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[91] KIUC's Post-Hearing Brief (filed Dec. 10, 2025) at 4.

[92] KIUC's Post-Hearing Brief at 5.

[93] KIUC's Post-Hearing Brief at 5.

[94] KIUC's Post-Hearing Brief at 5.

[95] KIUC's Post-Hearing Brief at 6.

[96] KIUC's Post-Hearing Brief at 6.

[97] Sierra Club's Post-Hearing Brief (filed Dec. 10 2025) at 4.

that Kentucky Power's proposed plan favors shareholders and Wheeling Power at the expense of Kentucky customers.[98]

Sierra Club argued that Kentucky Power failed to consider all reasonable alternatives in the near-term.[99] Sierra Club stated that there is a need to evaluate a scenario in which Kentucky Power entered into a short term PPA with Wheeling Power to take power from Mitchell Plant through 2031 and that option was not explored.[100]

Sierra Club stated that the short-term and long-term analysis create divergent results.[101] Sierra Club argued that, beyond 2031, Kentucky Power's analysis does not support the continued operation of Mitchell Plant.[102] Sierra Club stated that long-term costs could be avoided by converting Mitchell to burn gas.[103] Sierra Club argued that the cost of compliance with environmental regulations is significantly higher if Mitchell Plant continues to be coal fired.[104] Sierra Club further argued that sunk costs in ELG upgrades for ash impoundments should not be considered in the economic analysis because they will be incurred regardless of whether Mitchell Plant remains coal fired or if it converts to partially or fully burn gas, but that other ELG costs, those necessary to comply with the 2024 ELG Rules, could be avoided by converting Mitchell Plant to burn gas.[105]

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[98] Sierra Club's Post-Hearing Reply Brief (filed Dec. 16, 2025) at 4.

[99] Sierra Club's Post-Hearing Brief at 6–8.

[100] Sierra Club's Post-Hearing Brief at 3 and 7–8.

[101] Sierra Club's Post-Hearing Brief at 4.

[102] Sierra Club's Post-Hearing Brief at 8.

[103] Sierra Club's Post-Hearing Brief at 9–10.

[104] Sierra Club's Post-Hearing Brief at 3–4.

[105] Sierra Club's Post-Hearing Reply Brief at 4–5.

DISCUSSION AND FINDINGS

Request for a CPCN

There is no dispute that Kentucky Power needs to maintain its 50 percent share of Mitchell Plant or to obtain some alternative generation to serve its customers' projected load and meet PJM capacity requirements from 2029 to 2031 and beyond. Further, while there were many concerning flaws in Kentucky Power's planning and analysis, as discussed in more detail below, the Commission finds that the evidence presented in this case established that making the investments proposed to continue taking capacity and energy from Mitchell Plant after 2028 is the most reasonable, least cost option for serving customers based on the relative costs of the alternatives, the long-term options Mitchell Plant offers, and the risks of relying heavily on the market in the current environment. In short, while there are few good options when faced with additional investments that will ultimately raise rates that are often already difficult for customers to afford, the Commission finds that continuing to take capacity and energy from Mitchell Plant is the least bad option at this time for serving customers, at least through 2031, because it is either competitive or least cost from a cost perspective, depending on the period and assumptions considered, provides the most economic options in the long-term in an environment in which energy and capacity are likely to be short, and limits customers exposure to capacity and energy markets. Thus, having reviewed the record and being otherwise sufficiently advised, the Commission finds that Kentucky Power's request for a CPCN should be granted in this matter, though the Commission also finds that additional requirements are necessary to protect customers, as discussed in more detail below.

<u>Need for CPCN Investments</u>

Load Serving Entities (LSEs) in PJM, like Kentucky Power, are responsible for ensuring that they have sufficient generating capacity available to serve their load. LSEs may do this either by building resources directly, entering into bilateral contracts to purchase the capacity, or obtaining capacity from PJM's Reliability Pricing Model auctions, though FRR members, like Kentucky Power, are generally limited to the first two options.[106] Generally speaking, PJM determines the capacity an LSE must have in each year based on the LSE's expected contribution to PJM's summer peak and generally accredits generation capacity obtained based on the expected availability of that capacity at system peak.[107] PJM assigns both an LSE's capacity requirement and the capacity credits for generation capacity using various statistical analyses intended to ensure a system with a loss of load expectation (LOLE) equal to or less than one day in ten years,[108] which is a standard commonly used by utilities for resource adequacy

[106] *See* PJM Manual 18: PJM Capacity Market, Revision 61 (effective July 23, 2025), Section 7, pages 159-165 (discussing the capacity requirements for RPM members and how they are determined); PJM Manual 18: PJM Capacity Market, Revision 61 (effective July 23, 2025), Section 11, pages 212-234 (discussing capacity requirements for FRR members and how they are determined).

[107] *See* PJM Manual 18: PJM Capacity Market, Revision 61, Section 7, pages 159-165; PJM Manual 18: PJM Capacity Market, Revision 61, Section 11, pages 212-234; *see also* PJM Manual 21B: PJM Rules and Procedures for Determination of Generating Capability, Revision 4 (effective Dec. 17, 2025) (discussing how resources area accredited in PJM); Wolfram Direct Testimony at 13-14 (discussing how PJM currently establishes resource requirements based on summer load but that it is discussing using winter load).

[108] *See* PJM Manual 20A: PJM Adequacy Analysis, Revision 2 (effective December 17, 2025), Section 1.1-1.5, pages 8-10 (providing an overview of the various criteria, studies, and methodologies employed by PJM to ensure resource adequacy, and indicating that "[t]he RTO-wide Resource Adequacy Criteria is a LOLE criterion of 1 day in 10 years, or 0.1 days per year").

planning.[109] Based on that analysis, capacity requirements and credits within PJM are expressed in terms of Unforced Capacity (UCAP).[110]

The undisputed evidence presented in this case indicates that Kentucky Power is slightly short on capacity necessary to meet its PJM capacity requirement even with Mitchell Plant and Big Sandy Unit 1. For instance, in the 2027/2028 PJM delivery year, Kentucky Power estimated that its 50 percent share of Mitchell Plant would be assigned a 600 MW UCAP capacity credit by PJM and that Big Sandy Unit 1 would be assigned a 239 MW UCAP capacity credit by PJM for a total of 839 MW UCAP, whereas Kentucky Power estimated that its PJM capacity requirement during the same period would be 844 MW UCAP based on its projected load.[111] Kentucky Power estimated similar PJM capacity credits and requirements for the 2028/2029 through 2030/2031 delivery years.[112] Further, those projected credits and requirements are based on and consistent with Kentucky Power's recent capacity credits and requirements and the analysis in its most recent Integrated Resource Plan.[113] Kentucky Power's projected capacity requirements and credits from existing units have also not been challenged by any party. Thus, the

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[109] *See* Case No. 2022-00402, *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan and Approval of Fossil Fuel-Fired Generating Unit Retirements* (Ky. PSC Nov. 6, 2023), Order at 69, footnote 258 (citing to testimony indicating that a 1 in 10 LOLE is a commonly used reliability planning target).

[110] PJM Manual 18: PJM Capacity Market, Revision 61, Section 7, pages 159-165; PJM Manual 18: PJM Capacity Market, Revision 61, Section 11, pages 212-234; PJM Manual 21B: PJM Rules and Procedures for Determination of Generating Capability, Revision 4 (all discussing the use of UCAP for capacity requirements and credits).

[111] Wolfram Direct Testimony at 14, Figure TSW-2.

[112] Wolfram Direct Testimony at 14, Figure TSW-2.

[113] *See* Wolfram Direct Testimony at 14, Figure TSW-2 (showing actual and projected capacity requirements and credits from 2025/2026 through 2030/2031).

Commission finds that Kentucky Power needs its 50 percent share of Mitchell Plant or some replacement generation of at least the same capacity to meet its PJM capacity requirement and serve load without significant energy market exposure.[114]

The evidence in this case similarly indicates that the ELG Project and the non-ELG projects through 2025, with the exception of cooling tower work that was not completed, were necessary for Mitchell Plant to continue operation beyond 2028. As an initial matter, the necessity of the ELG Project to comply with the 2020 ELG Rule was not the basis of the Commission's denial of the ELG Project in Case No. 2021-00004.[115] Kentucky Power argued in this case that the ELG Project was necessary to comply with the 2020 ELG Rule if Mitchell Plant would remain open after December 31, 2028.[116] Further, while Sierra Club raised questions regarding Kentucky Power's consideration of alternatives to Mitchell Plant and about the applicability of the 2024 ELG Rules to Mitchell Plant in the event that it is converted to a natural gas fired generator, no party disputed that the ELG Project was necessary for Mitchell Plant's continued operation as a coal plant beyond

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[114] Since Kentucky Power is a winter peaking utility and PJM is a summer peaking system, Kentucky Power's PJM capacity requirement is actually significantly lower than Kentucky Power's winter/system peak, meaning that Kentucky Power currently has insufficient native generation or contract capacity to meet its peak demand. While PJM has not historically seen this as causing a reliability issue because other LSEs have a lower load during this period such that the expectation has been that capacity would be available. However, Kentucky Power noted that PJM is considering using both summer and winter peak to establish capacity requirements, which would significantly increase Kentucky Power's capacity requirement. Further, as noted by Kentucky Power, the Commission has previously suggested that KRS Chapter 278 adequacy obligations may require utilities to plan to serve their peak load notwithstanding lower requirements established by Regional Transmission Organizations (RTOs). Thus, Kentucky Power arguably has or will have insufficient generating capacity even with Mitchell Plant, though it is not necessary to address that issue to resolve this case, as Kentucky Power needs Mitchell Plant to meet even its current PJM capacity requirements.

[115] Case No. 2021-00004, July 15, 2021 Order at 23–24.

[116] Wolffram Direct Testimony at 8; Kentucky Power's Post Hearing Brief at 25.

2028. Thus, the Commission finds that the ELG Project is necessary for Mitchell Plant to continue operating post-2028.

With respect to the Non-ELG Investment, the projects were generally small relative to Kentucky Power's overall plant in service and would have been completed in the ordinary course of business and allocated on 50 percent basis absent the initial denial of the ELG Project and the asymmetrical sharing arising from the Written Consent Action of the Mitchell Operating Committee. In fact, portions of many of the projects are already included in Kentucky Power's plant in service—they are just divided between Kentucky Power and Wheeling Power asymmetrically based on the Written Consent Action.[117] Kentucky Power's witness Joshua D. Snodgrass (Snodgrass) also generally identified and explained the basis or need for the projects.[118] For example, Snodgrass explained that the Air Heater Baskets on Mitchell Units 1 and 2 were replaced at a cost of about $3.8 million each because they had reached the end of their useful lives and were beginning to deteriorate; that welding was completed at a cost of about $1.4 million to thicken certain tube walls to address corrosion; and various parts were replaced, among other things, because they reached the end for their useful lives or were necessary for Mitchell Plant's continued operation.[119] The Commission also notes that, other than the cooling tower work, no party questioned that the Non-ELG projects and related investments were necessary for Mitchell Plant's continued operation. Thus, with the exception of cooling tower work that was not completed, the Commission finds that the

[117] *See* Snodgrass Direct Testimony at 7–8, Figure JDS-3.

[118] Snodgrass Direct Testimony at 8-10.

[119] Snodgrass Direct Testimony at 8-10.

Non-ELG projects that were split on a prorated basis through the end of 2025 were necessary for Mitchell Plants continued operation both before and after 2028.

The Commission notes that Kentucky Power indicated that it must make the ELG Investment and Non-ELG Investments in order for it to maintain its right to 50 percent of the capacity and energy at Mitchell Plant after December 31, 2028. Kentucky Power indicated that premise is based on the May 3, 2022 Order in Case No. 2021-00004[120] and the May 3, 2022 Order in Case No. 2021-00421,[121] "dictating that Kentucky Power was not authorized to make the ELG investment necessary for the Mitchell Plant to continue operating after December 31, 2028."[122] The Commission disagrees with Kentucky Power's characterization of those orders, which discuss the termination of Kentucky Power's share of Mitchell in dicta. However, no party has supported an argument that Kentucky Power can maintain its current 50 percent interest in the capacity and energy from Mitchell Plant without making the ELG Investment and the Non-ELG Investments or entering into a PPA, which is discussed below as an alternative to the proposed

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[120] 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 Mitchell Generating Station, An Amended Environmental Compliance Plan, and Revised Environmental Surcharge Tariff Sheets* (Ky. PSC May 3, 2022), Order.

[121] Case No. 2021-00421, *Electronic Application of Kentucky Power Company for Approval of Affiliate Agreements Related to the Mitchell Generating Station* (Ky. PSC May 3, 2022), Order.

[122] *See* Kentucky Power's Response to Commission Staff's Post-Hearing Request (Staff's Post-Hearing Request) (filed Dec. 16, 2025), Item 2(a) ("The premise that Kentucky Power is not currently entitled to energy and capacity from the Mitchell Plant after December 31, 2028, is based on the Commission's prior orders, specifically those referenced and provided in the Company's response to KPSC 1-1. . . . There are no explicit provisions within the Mitchell Plant Operating Agreement concerning the disposition of Kentucky Power's 50% ownership interest in the Mitchell Plant, but the aforementioned Commission orders require the Company's interest in the energy and capacity from the Mitchell Plant to terminate after December 31, 2028.")

investment.[123] Thus, based on the evidence presented in this matter and the Settlement Agreement, the Commission finds that the ELG Investment and the Non-ELG Investment in Mitchell Plant, other than cooling tower work that was not completed, or some alternative PPA arrangement, discussed below, are needed for Kentucky Power to continue to receive its 50 percent share of the capacity and energy from Mitchell Plant post-2028 or that some alternative generation is needed.

However, in making the finding in the preceding paragraph, the Commission notes that the finding is limited to the ELG Investment and the Non-ELG Investments through 2025 for which approval was specifically requested in this case. Nothing in this Order should be construed as limiting the Commission's prudency review of any future investments in Mitchell Plant. In fact, in response to post-hearing requests, Kentucky Power generally indicated that it did not take the position that the Commission's plenary authority and discretion to disapprove costs at Mitchell Plant in a manner consistent with its statutory authority would be eliminated as a result the approval of this application.[124] The Commission notes that its approval in this matter is based, in part, on that representation. Thus, in unwinding the Written Consent Action and otherwise moving back towards symmetrical cost sharing, Kentucky Power should take care not to obligate its customers to future costs without regard to the prudency of those costs or the Commission's authority to review the prudency of those cost.

[123] Sierra Club suggested that a PPA with Wheeling Power as an alternative consideration. However, while a PPA might be a possibility that possibility would be different from Kentucky Power's current interest in Mitchell Plant. Thus, it is discussed separately below with respect to the consideration of alternatives.

[124] Kentucky Power's Response to Staff's Post-Hearing Request, Item 2(b) – (d).

Absence of Wasteful Duplication

The Commission agrees, at least in part, with the testimony of Sierra Club's witness Glick that there are flaws in Kentucky Power's methodology and that Kentucky Power's analysis was not conducted with the level of rigor that the Commission would expect to see for a decision of this magnitude. However, despite those issues, the evidence presented in this case ultimately does indicate that authorizing Kentucky Power to make investments necessary for it to continue taking 50 percent of the capacity and energy from Mitchell Plant after December 31, 2028, is the reasonable least-cost alternative due to the relative projected costs of alternatives, the long-term options offered by maintaining a 50 percent share of Mitchell Plant, and the risks of relying too heavily on third parties and markets. Thus, as discussed in more detail below, the Commission finds that the investment for which Kentucky Power requests approval will not result in wasteful duplication, and therefore, finds that the request for a CPCN should be granted in this matter, though the Commission also finds that additional reporting and oversight requirements discussed below are necessary to protect customers from potential additional incremental costs.

Kentucky Power sought to establish the absence of wasteful duplication by looking at the expected cost of short-term (2029 to 2031) and long-term (post-2031) alternatives. A two-part analysis of this nature may be appropriate if, as Kentucky Power indicated was the case here, the short-term and long-term options for serving load differ due, for instance, to the timing of the need and limits on the ability to obtain certain alternative resources in the short-term, e.g. new generation cannot be built in the short term. Further, Kentucky Power could establish that continuing to rely on Mitchell Plant is the most reasonable, least cost option in the short-term based on only the incremental costs of alternatives in the short-term or by looking at the combined short-term and long-term incremental costs. Thus, Kentucky Power's use of a two-part analysis was not necessarily unreasonable.

Sierra Club's witness Glick testified that Kentucky Power failed to consider all short-term options and specifically suggested that Kentucky Power should have considered a short-term PPA with Wheeling Power to continue taking capacity and energy from Mitchell from 2029 through 2031 and suggested that Kentucky Power should update PPAs from third parties, including PPAs that included solar and battery storage.[125] With respect to the short-term PPAs for capacity and energy from Mitchell Plant, the Commission does believe that the best practice would have been for Kentucky Power to do more to investigate the possibility of a PPA with Wheeling Power and more broadly that Kentucky Power should investigate potential PPAs and partnerships for generation sources with other Kentucky utilities as contemplated by the Integrated Resource Planning regulation.[126] However, in this case, the Commission does not believe that the failure to consider those generation resources justifies finding that Kentucky Power failed to consider all reasonable alternatives or denying Kentucky Power's CPCN, because Kentucky Power did consider RFP responses for PPAs for thermal generation as an alternative to Mitchell Plant. As discussed in more detail below, those RFP responses were effectively used as proxies for the PPA market. If Wheeling Power and Kentucky

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[125] Glick Direct Testimony at 16.

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

Power had engaged in serious discussions regarding a PPA, Wheeling Power likely would have demanded what the market would pay, which ultimately would have likely been consistent with the prices obtained from third parties for PPAs. For that reason, Kentucky Power's consideration of the thermal PPAs reviewed in this matter provided a reasonable proxy for the likely costs of a PPA with Wheeling Power.[127] Moreover, even if Wheeling Power did provide capacity and energy from Mitchell Plant at below likely market rates, for instance if it provided it purely at the cost of service for 2029 through 2031 and that cost of service was below market rates, then Kentucky Power customers would not have any right to capacity and energy from Mitchell post-2031, when as discussed below, it will likely be the most economic option. Thus, while further consideration of more options is always beneficial, the Commission finds that additional consideration of a PPA for capacity and energy from Mitchell Plant was not necessary for Kentucky Power to support its CPCN.

With respect to Sierra Club's recommendation that Kentucky Power rebid the PPAs, including those for solar and batteries, the Commission notes, as discussed below with respect to the cost of Alternative 2, that Kentucky Power's witness Vaughan credibly testified that rebidding the PPAs would likely only increase the cost of the PPAs,[128] and

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[127] For instance, Kentucky Power's calculation of the annual cost of service for Mitchell in 2029 through 2031 included significant positive margins based on an assumption that revenue from Mitchell would exceed the variable cost of operation. While such margins are not necessarily consistent with past performance, they are consistent with Mitchell's actual margins so far in 2025. *See* Kentucky Power's response to Staff's Post-Hearing Request, Item 11, Attachment 2 (reflecting revenues exceeding variable costs in 2025 by tens of millions of dollars). If Wheeling Power expected such margins to continue, it would presumably charge a premium on any energy PPA given those margins. Moreover, as discuss below, capacity costs in PJM are increasing significantly, and in entering into PPAs, Wheeling Power would have an obligation to obtain the most it can from a PPA in the short term to cover the investments in made in Mitchell. Thus, the other thermal PPAs should offer a reasonable proxy for what a PPA for Mitchell Plant would look like.

[128] Hearing Video Transcript (HVT) of the November 18, 2025 hearing at 06:00:02–06:00:46.

Sierra Club's witness Glick acknowledged the same.[129] Further, Kentucky Power's RFP responses, which were updated in May 2024,[130] were just over a year old when this case was filed. While updated responses would provide better information, they too would be somewhat stale by the time Kentucky Power refiled an application and an order was issued. Additionally, as Kentucky Power noted, the Commission rejected the solar PPA from the 2023 RFP that Kentucky Power determined was most cost effective based on a finding that the solar PPA was not cost effective,[131] so it is unlikely that additional updated solar PPAs would be cost effective replacements of Mitchell Plant. Additionally, as Kentucky Power's witness Vaughan indicated in rebuttal, due to the lower capacity credits for solar in PJM, it would have taken about 8,391 MW of installed solar capacity to obtain the equivalent UCAP capacity credits offered by 50 percent of Mitchell,[132] which the Commission agrees would be impractical to obtain under the current timelines and would

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[129] HVT of the November 18, 2025 hearing at 07:41:35–07:41:40.

[130] *See* Kentucky Power's Response to Staff's Post-Hearing Request, Item 10, PublicAttachment 1 (reflecting the date on which the updated responses were provided).

[131] Case No. 2024-00243, *Electronic Application of Kentucky Power Company for (1) An Order Approving the Terms and Conditions of the Renewable Energy Purchase Agreement for Solar Energy Resources Between Kentucky Power Company and Bright Mountain Solar, LLC; (2) Authorization to Enter into the Agreement; (3) Recovery of Costs Through Tariff P.P.A; (4) Approval of Accounting Practices to Establish a Regulatory Asset; and (5) All Other Required Approvals and Relief* (Ky. PSC Mar. 31, 2025), Order at 13 ("[T]he Commission finds that Kentucky Power failed to carry its burden of proof that the proposed REPA with Bright Mountain satisfies Kentucky Power's need and will not result in wasteful duplication because it did not put forth sufficient evidence that the proposed agreement is reasonable and cost-effective.")

[132] Vaughan Rebuttal Testimony at R8.

likely not be cost effective.[133] Thus, the Commission finds that obtaining updated RFP responses was not necessary for Kentucky Power to consider all reasonable alternatives.

As noted by the Attorney General, the primary issue with Kentucky Power's consideration of short-term alternatives was its delay in the consideration of alternatives, which limited the options that could be considered. Specifically, Kentucky Power indicated that the reason that it did not consider self-build options was that those options could not be completed by 2028.[134] Rather, Kentucky Power indicated that the first date on which it could possibly complete new build replacement generation for Mitchell would be 2031.[135] However, if Kentucky Power had taken action more quickly after the final Order in Case No. 2021-00004, new build options would have been a possibility even in 2028.[136]

There were some legitimate reasons for Kentucky Power's delay. For instance, Kentucky Power was in the process of being sold by its parent company when the final Order was issued in Case No. 2021-00004, and shortly thereafter, the GHG Rules were proposed, which created uncertainty regarding what would be the best options. Further, Kentucky Power did conduct an RFP for new generation during this period and engaged

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[133] *See* Vaughan Rebuttal Testimony at R8 ("In addition to the issues previously discussed with these resource options, the size of the project required to achieve the same level of accredited capacity of the Mitchell Plant would cause rate impact and affordability issues. It also could be challenging to implement in the real world. Finally, given the current dynamics of generation resource additions in the PJM market, it is unclear, and unlikely, that the Company could procure that much accredited capacity by 2029.")

[134] Vaughan Direct Testimony at 7.

[135] *See* Vaughan Direct Testimony at 7 ("It is estimated that a new build generation resource could not be placed in-service until at least 2031.").

[136] *See* Case No. 2022-00402, November 6, 2023 Order (in which other utilities received approval for a new NGCC unit with an expected in-service date of 2027)

with counter parties to procure generation.[137] However, Kentucky Power could have acted more quickly as others did during this time frame.[138] Further, Kentucky Power's failure to plan in a timely manner ignores its obligation to provide adequate, efficient, and reasonable service pursuant to KRS 278.030(2), and the necessity to engage in appropriate and timely planning to ensure that it is able to do so. Thus, while there are no other reasonable short-term options to consider under the circumstances, in the future, Kentucky Power should investigate resource options in a more-timely manner to not artificially limit the options available as occurred here.

The Commission is also concerned about Kentucky Power's consideration of long-term alternatives. For instance, other than the continued operation of Mitchell Plant, in some form, the only long-term option that Kentucky Power considered was a 1,200 MW NGCC unit.[139] The Commission is concerned that Kentucky Power indicated that it plans to request a CPCN for a 450 MW simple cycle combustion turbine (SCCT) next year,[140] and yet, it did not analyze that as a resource option here. Additionally, the Commission notes that a resource assessment step is generally important in resource planning as alleged by Sierra Club's witness Glick, because it helps to ensure that alternative resource options are considered.

However, if Kentucky Power were only going to consider one alternative for its long-term analysis, then an NGCC unit is likely the best unit for it to consider as a

[137] HVT of the November 18, 2025 hearing at 01:29:18–01:29:56.

[138] *See, e.g.* Case No. 2022, November 6, 2023 Order.

[139] Vaughan Direct Testimony at 13.

[140] *See* Kentucky Power's Response to Commission Staff's First Request for Information (filed Aug. 25, 2025), Item 5b.

replacement for Mitchell Plant—numerous other utilities in Kentucky have determined that NGCC units are the most competitive base load units when a utility is considering a new build, and the Commission has approved several CPCNs for such units in the last few years.[141] Additionally, Kentucky Power is not requesting a CPCN in this matter for projects to operate Mitchell Plant post-2031. Rather, Kentucky Power relied on its more limited long-term analysis for the purpose of establishing that the continued availability of Mitchell Plant provides some of the lowest cost options post-2031 but it did not request a CPCN for those options.[142] Thus, the Commission does not believe that Kentucky Power's consideration of long-term options justifies finding that it failed to consider all reasonable alternatives in this case, though the result would likely be different if Kentucky Power were requesting a CPCN for post-2031 options.[143]

With respect to Kentucky Power's consideration of the costs, the primary flaw in Kentucky Power's analysis was that it only considered the incremental revenue requirement effects in 2029 through 2031 for the short-term options. This methodology does not accurately reflect the incremental cost increases customers would experience from the short-term alternatives and would tend to unreasonably favor Alternative 1 over Alternatives 2 and 3, because Alternative 1 would increase the costs to customers in 2026 through 2028 and after 2031 whereas Alternatives 2 and 3 would not necessarily do so.

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[141] *See, e.g.* Case No. 2022-00402, November 6, 2023 Order; Case No. 2024-00370, *Electronic Application of East Kentucky Power Cooperative, Inc. for (1) Certificates of Public Convenience and Necessity to Construct 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* (Ky. PSC July 3, 2025), Order.

[142] *See* Vaughan Direct Testimony at 8-9.

[143] Further, as noted above, the Commission would caution against waiting to make a decision regarding Mitchell Plant post-2031 in a way that would limit the options available for consideration.

For instance, Kentucky Power requested that the Commission approve ES rates in this matter effective January 1, 2026, to reflect the rate effects of the ELG Investments and the ELG Project, which Kentucky Power indicated would result in a revenue requirement increase of $13,103,816; $12,640,738; and $12,081,291; and in 2026, 2027, and 2028,[144] respectively. Similarly, Kentucky Power acknowledged that the Non-ELG Investment, if approved, would also likely have a revenue requirement effect in 2026, 2027, and 2028 of about $5,701,413; $6,019,525; and $5,909,054, respectively.[145] Thus, based on Kentucky Power's calculations, this would add about $55,445,837 in nominal costs to Alternative 1 as reflected in the updated table below.[146]

Table 1: Nominal Revenue Requirement Effects in 2026-2028 With Table AEV 1 Costs

	2026	**2027**	**2028**	
Alternative 1	$18,805,229	$18,660,263	$17,990,345	
Alternative 2	$ -	$ -	$ -	
Alternative 3	$ -	$ -	$ -	

	2029	**2030**	**2031**	**Total**
Alternative 1	$86,378,348	$113,272,572	$135,755,059	$390,861,816
Alternative 2	$157,901,093	$156,809,674	$156,729,376	$471,440,143
Alternative 3	$344,365,656	$294,411,638	$256,527,951	$895,305,244

Moreover, when calculating the revenue requirement effects for Alternative 1, Kentucky Power depreciated the additional plant in service associated with the expected incremental investments based on an expected 2040 retirement date such that a

[144] Application, Exhibit LMK-4, 08_KPCO_Exhibit_LMK-4.xlsx, Tab ELG Rev Req; *see also* Wolfram Settlement Testimony, Exhibit_TSW-S2.xlsx, Tab ELG Rev Req (indicating that the ELG revenue requirement after the settlement would be $11,244,570; $10,905,683; and $10,470,428; and in 2026, 2027, and 2028, respectively).

[145] Kentucky Power's Response to Staff's Post-Hearing Requests, Item 13, KPCO_R_KPSC_PHDR_13_Attachment1.xlsx, Tab 3.10.

[146] The costs for years 2029 through 2031 reflect the amounts included with Kentucky Power's Application. *See* Vaughn Direct Testimony, at 8, Table AEV-1. The costs for Alternative 1 for years 2026 through 2028 reflect the annual sum of the amounts included in the paragraph above.

significant portion of the incremental investment that Kentucky Power projected would be made at Mitchell Plant through 2031, including the investment for which it seeks approval herein, will not be fully depreciated by the end of 2031. Specifically, based on the schedules provided by Kentucky Power, the remaining net plant in service associated with the incremental investments identified by Kentucky Power would be about $179,383,123 as of December 31, 2031,[147] not including any additional investment that

[147] This amount is based on the schedules Kentucky Power used to calculate the revenue requirement effects of Alternative 1 in Table AEV 1 and reflects the sum of the following amounts from the sources referenced below:

1. $163,239,075 representing the estimated difference, as provided by Kentucky Power, in the net book value allocated to Kentucky Power as of December 31, 2028, if it is authorized to continue to take energy and capacity from Mitchell Plant post-2028 as compared to if it is not. *See* Kentucky Power's response to Attorney General's First Request for Information (Attorney General's First Request) (filed Aug. 25, 2025), Item 1, 03_ KPCO_R_AG_1_1_PublicAttachment1.xlsx, Tab 2029 NBV Starting Point; *see also* Nov. 18, 2025 Hearing Video Transcript (H.V.T.) at 6:17:26–6:19:00 (in which Kentucky Power Witness Vaughan indicated that the rate base used in KPCO_R_AG_1_1_Attachment2.xlsx, which reflects that from KPCO_R_AG_1_1_PublicAttachment1.xlsx, was inclusive of plant in service additions related to the ELG and Non ELG investments at issue in this case).

2. $62,076,000 in plant additions that Kentucky Power projected would be added to Kentucky Power's share of Mitchell Plant in 2029 through 2031. *See* Kentucky Power's response to Attorney General's First Request, Item 1, 04_ KPCO_R_AG_1_1_Attachment2.xlsx, Tab Rate Base – coal (reflecting $18,455,284, $24,552,683, and $19,067,787 in annual capital expenses in 2029, 2030, and 2031, respectively).

3. $(45,931,706) in additional accumulated depreciation, calculated as reflected below based on Kentucky Power's calculation of annual depreciation expense for the full plant balance in 04_ KPCO_R_AG_1_1_Attachment2.xlsx, Tab Rate Base – coal, including Kentucky Power's assumed depreciation rate of 8.33 percent:

	2029	2030	2031
Cumulative Incremental Plant*	$181,694,359	$206,247,042	$225,314,829
Annual Depreciation Expense on Incremental Plant (Cumulative Incremental Plant * 8.33%)	$13,603,256	$15,141,197	$17,187,254
Incremental Accumulated Depreciation	$13,603,256.25	$28,744,452.86	$45,931,706.37
Incremental Net Plant in Service	$168,091,103	$177,502,589	$179,383,123

*Kentucky Power's workpaper calculated the depreciation expense in 2029 by taking the sum of the net plant in service as of December 31, 2028, and then adding the projected plant additions in 2029 and might be necessary due to the cooling tower work identified in the supplemental testimony filed by Kentucky Power. Kentucky Power would presumably seek to recover that remaining net plant balance as a sunk cost even if Mitchell Plant is only operated through 2031 such that Alternative 1 would result in an incremental increase in costs to customers post-2031 even if Mitchell Plant is closed at that time.

Kentucky Power's failure to consider the incremental cost of Alternative 1 from 2026 to 2028, and to a lesser extent the incremental costs post-2031,[148] when comparing the expected costs to customers of the short-term alternatives was unreasonable, because in doing so, it failed to consider a material portion of the incremental costs that would be incurred for Alternative 1. An analysis of just the short-term alternatives should have considered the incremental revenue requirement impacts in 2026 through 2028 and the post-2031 revenue requirement impacts in addition to the revenue requirement impacts in 2029 to 2031. Moreover, a net present value analysis of the annual revenue requirement impacts of Alternatives 1, 2, and 3, including all incremental costs, would have allowed Kentucky Power to consider all costs and the time value of money, i.e. the difference between the value of a dollar today and a dollar in the future, and compare the costs the costs on an apples to apples basis.[149]

multiplying that by 8.33 percent. To stay consistent with Kentucky Power's methodology, the above table similarly uses the net plant as of December 31, 2028, as the starting place but removes what Kentucky Power estimated the net plant would be on December 31, 2028, if Kentucky Power planned to cease taking energy and capacity from the plant on December 31, 2028, to get the estimated incremental changes only.

[148] The failure to include the post-2031 costs is less problematic because the post-2031 costs should be included in the relevant analyses of the long-term alternatives such that when combining the short and long-term costs they would be included. However, to truly compare the costs of just the short-term options, as Kentucky Power purported to do, it would be necessary to include all of the incremental costs of each option including the pre-2029 and post-2031 costs of Alternative 1.

[149] *See* Case No. 2022-00402, November 6, 2023 Order at 108-111 (discussing the importance of NPVRR in comparing resource options).

Kentucky Power's witness Vaughan indicated that he disagreed that a net present value revenue requirement (NPVRR) analysis of the short-term alternatives that included the pre-2029 and post-2031 costs of Alternative 1 was necessary to assess the costs to customers of the alternatives. When asked about whether such an analysis could be used to assess the cost of the short-term alternatives, he stated:

> I mean, that could be your opinion. I don't necessarily agree with you. I think what we've done here is the right way to evaluate this for customers for the time frame in question. And trying to put all these options on an apples to apples basis is what we did. We -- we have included the costs for the environmental surcharge and the Environmental Compliance Plan in – in this filing. So, I guess we have to agree to disagree there. There -- there's no material -- there's no material revenue requirement impacts that change the answer, I guess is -- is my testimony.[150]

Kentucky Power's witness Vaughan also indicated that he felt that average revenue requirement was the best metric for assessing the cost of generation, stating:

> Q. Okay. What's the purpose of, I guess, looking at the net present value revenue requirement [as part of the long-term analysis]?
>
> A. Mostly because people like seeing them. I -- I personally think the important one is the average revenue requirement, because that is what hits customer bills. You know, when you look at NPVs or present values for -- for, one, live assets, they can be heavily influenced by commodity curves that are 20 to 30 years out. And our customers, you know, frankly don't care about what happens 20 years from now, they're worried about their bills in the short term; what is going to happen to them. . . .[151]

[150] HVT of the November 18, 2025 hearing at 06:29:51–06:30:22.

[151] HVT of the November 18, 2025 hearing at 06:26:55–06:27:23.

As an initial matter, the Commission disagrees with Vaughan regarding the importance of average revenue requirement, because average revenue requirement would not account for the timing of the revenue requirement impacts and would treat a dollar paid by customers today the same as a dollar paid by customers in 10 or 20 years,[152] which would generally be unreasonable given the opportunity cost of having to pay early, e.g. the inability to earn interest on the money or pay down credit card debt. Conversely, there is some validity to Vaughan's position that there is more uncertainty with long-term analyses the further you get into the future, and while such uncertainty would not justify abandoning a long-term analyses of the costs of alternatives in resource planning,[153] it would be appropriate to consider it in certain circumstances, including as a risk factor in the analysis. However, neither uncertainties in the long-term term analyses nor a desire to focus purely on the short-term costs to customers would justify Kentucky Power's failure to include the pre-2029 costs of Alternative 1, and to a lesser extent the post-2031 costs of Alternative 1, as part of its short-term cost analysis.

The 2026 to 2028 revenue requirement effects of Alternative 1 are not distant or uncertain. Kentucky Power proposed, as part of the Application, a rate increase to be

[152] For example, a resource option that is expected to cost $100 million annually for ten years and then $50 million annually for the next ten years would have the same average revenue requirement as a resource option that is expected to cost $50 million annually in the first ten years and $100 million annually for the next ten years. Conversely, a NPVRR analysis of the same alternatives would account for the value of lower costs in the short-term by discounting future years relative to past years and would appropriately reflect that the first option is significantly more expensive than the second option based on the time value of money.

[153] New generation resources will generally have a significantly higher initial capital investment than maintaining an existing resource but new resources are often more efficient and require less ongoing maintenance and additional capital expenditures than older existing units. This means that new resources may be more costly in the earlier years due to the carrying costs on the significant capital investment. However, as the initial capital investment is depreciated, the cost savings from the increased efficiency of the new generation should eventually exceed any additional carrying cost. Thus, if an analysis comparing an existing unit to a new unit focuses only on a short period of time, it is likely to favor the existing as compared to a new unit even if the new unit would be cheaper in the mid- or long-term.

effective January 1, 2026, to reflect the revenue requirement effects of the ELG Project[154] and has filed a general rate adjustment with a proposed effective date of March 1, 2026, that would include the revenue requirement effects of the Non-ELG Investments.[155] Similarly, there is no material uncertainty with respect to the post-2031 costs, because assuming that Mitchell Plant is taken out of service in 2032, the incremental post-2031 costs would generally consist of only the return on and return of the net plant balance associated with the incremental investment made through 2031 to retain Mitchell after 2028, and that incremental net plant balance was effectively calculated by Kentucky Power when it calculated the revenue requirement effect through 2031.[156] Thus, there is no reasonable basis to exclude the 2026 to 2028 revenue requirement effects from Kentucky Power's short-term analysis, and if Kentucky Power was relying solely on its short-term analysis to establish that Alternative 1 is the reasonable, least cost alternative, there would be no reasonable basis to exclude the post-2031 costs from the analysis.

Looking only at costs as reflected in Kentucky Power's application, the inclusion of the pre-2028 and post-2031 incremental revenue requirement effects for Alternative 1 would make Alternative 1 more costly than Alternative 2 on a nominal basis. As noted above, including those costs would add $55,445,837 to the revenue requirement through 2028 and an estimated $179,383,123 in additional sunk cost as of December 31, 2031. Conversely, Kentucky Power's Application indicated that Alternative 1 would be about

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[154] *See* Application at 16.

[155] *See* Application at 7 (indicating that Kentucky Power will include the cost of the non-ELG capital projects in its next base rate case); *see also* Kentucky Power's Response to Staff's Post-Hearing Request, Item 13 (calculating the expected revenue requirement effects of the Non-ELG Investments in 2026 through 2028).

[156] *See* footnote 143, *supra*.

$136 million cheaper than Alternative 2 when considering only the 2029 through 2031 costs.[157] Based on those numbers, even assuming no carrying costs on the return of the sunk costs, Alternative 1 would be nearly $100 million more than Alternative 2 on a nominal basis assuming no change in the costs of Alternative 2.

Using essentially the same methodology and discount rate that Kentucky Power used to calculate the NPVRR for its long-term alternatives[158] and annual costs for the short-term alternatives from 2026 through 2031 as reflected on Table 1 above, the NPVRR of Alternative 1, Alternative 2, and Alternative 3 through 2031 would be $287,710,896; $339,299,704; and $648,434,096, respectively. Assuming Mitchell Plant is taken out of service in 2031 and the incremental net plant in service is $179,383,123 as discussed above, the NPVRR effect of that remaining balance, if it is allowed to be recovered, would be about $127,260,895 assuming a 2040 amortization period for the

[157] Vaughan Direct Testimony at 8,Table AEV-1 (indicating the estimated cost of Alternative 1 to be $335,405,979 and the estimated costs of Alternative 2 to be $471,440,143)

[158] Kentucky Power simply used the Excel NPV function with a discount rate of 6.834 percent to calculate the NPVRR of the long-term alternatives. The only difference between Kentucky Power's methodology and the methodology used here is that Kentucky Power began discounting in 2030, the first year in which its longer-term analysis included a revenue requirement. *See, e.g.* Kentucky Power's response to AG First Requests, Item 1, KPCO_R_AG_1_1_ConfidentialAttachment5.xlsx, Tab OPCO Rev Reg (showing Kentucky Power's NPVRR calculation for Alternative E3). Conversely, the NPVRRs for Alternatives 1 through 3 were discounted beginning in 2026 regardless of whether there was a revenue requirement effect in that year.

resulting regulatory asset, declining rate base recover of the regulatory asset, a weighted average cost of capital of 8.22 percent, and a discount rate of 6.834 percent.[159]

The NPVRR effects of the various short-term alternatives would tend to indicate that Alternative 1 is more costly than Alternative 2 based purely on the costs assumed in the Application and assuming that Mitchell Plant only operates through 2031,[160] as operation beyond 2031 could affect the relative costs as discussed below. The cooling tower work, which Kentucky Power's analysis indicated would have a NPVRR effect of about [redacted] if Option 3 is selected,[161] would only further increase the cost of Alternative 1 relative to Alternative 2. However, the evidence in this case also supports a finding that Alternative 2 would be more costly than Kentucky Power originally assumed.

First, evidence of tightening capacity and energy markets generally and within PJM indicate that the cost of Alterenative 2 will likely increase relative to the amounts included

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159 The calculation of the annual revenue requirement amounts and the NPVRR for each year and cumulatively is included in the table attached as an Appendix. Notably, the NPVRR was calculated using the same method used by Kentucky Power in its longer analysis except that the table in the Appendix begins discounting in 2026 to be consistent with the NPVRR analysis for the pre-2031 costs of Alternative 1. The revenue requirement of the net remaining plant balance was generally calculated in the same manner Kentucky Power used to calculate the revenue requirement on Tab Amortize to 2040 of KPCO_R_AG_1_1_PublicAttachment1.xlsx. The Commission notes that there are some slight differences in the manner that Kentucky Power and the Attorney General's witness calculated the amortization of the reg assets arising from the closure of a plant. The Commission notes that the general use of Kentucky Power's methodology here was to remain consistent due to this discussion's primary reliance on Kentucky Power's schedules. It was not intended to resolve any differences between the calculation of the Attorney General's witness and Kentucky Power.

160 A NPVRR effect of about $414.97 million as compared to $339.29 million. It should be noted that the nominal cost used to calculate both of these amounts included carrying costs and the depreciation/amortization of net plant in service that has already be incurred in the amount of about $75 million per year. Thus, a significant portion of the costs for both alternatives is not tied to incremental investments in Mitchell Plant.

161 Kentucky Power's response to Staff's Post-Hearing Request, Item 6, Confidential Attachment 1 at 75. Notably, that attached indicated that the Option 3 would have an overall NPVRR from 2027 through 2038 of [redacted], which is consistent with other similar calculations in this matter and is a reasonable estimate based the projected capital cost for the project, declining rate base recovery, and a discount rate based on the weighted average cost of capital. However, only 50% would be allocated to Kentucky customers if that project moves forward.

in the application. Specifically, Kentucky Power estimated the cost of Alternative 2 based on responses it received to a 2023 RFP from thermal generators, which were initially provided in or about November 2023 and were updated in May 2024.[162] Because the PPAs offered less capacity than would be offered by Mitchell Plant, Kentucky Power estimated the cost of make-up capacity for the difference between Mitchell and the PPAs to compare Mitchell Plant and the PPAs on an apples to apples basis, at least from a capacity perspective. Kentucky Power estimated the cost of that make-up capacity based on estimated PJM BRA prices of between $203.18/MW Day to $215.30/MW Day.[163] However, the 2026/2027 PJM BRA, which took place in July 2025 after Kentucky Power filed this application,[164] resulted in a clearing price of $329.17/MW-day, which was actually the temporary price cap for that delivery year.[165]

Given the results of the BRA for the 2026/2027 delivery year and the application of the price cap, there is a strong likelihood that BRA prices in 2029 through 2031 will be at least in the range that they were for the 2026/2027 delivery year and likely higher. If the cost of the make-up capacity for Alternative 2 was recalculated based on a $329.17/MW-day capacity price, then the cost of Alternative 2 would increase by

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[162] *See* Kentucky Power's Response to Staff's Post-Hearing Request, Item 10, PublicAttachment 1 (reflecting the date on which the updated responses were provided); Kentucky Power's response to Staff's First Request, Item 16 (providing the original RFP responses, which generally indicate the dates on which they were provided).

[163] Kentucky Power's Response to Attorney General's First Request for Information (Attorney General's First Request) (filed Aug. 25 2025), Item 1, KPCO_R_AG_1_1_PublicAttachment1.xlsx, Tab Market.

[164] *See* PJM, *2026/2027 Base Residual Auction Report* (dated July 22, 2025) <https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2026-2027/2026-2027-bra-report.pdf> (last accessed Dec. 29, 2025) (providing the results of the 2026/2027 BRA).

[165] HVT of the November 18, 2025 hearing at 04:41:01–04:4121; *see also* Kentucky Power's Response to Staff's Post-Hearing Request, Item 15.

$9,184,453, $9,066,583, and $8,888,274 in 2029, 2030, and 2031, respectively,[166] or a total of $27,139,310 on a nominal basis. Thus, it would be reasonable to assume that the cost of Alternative 2 would increase by that amount on a nominal basis, which would result in about a $19.54 million increase in the NPVRR of Alternative 2.[167]

Kentucky Power's witness Vaughan also indicated that Kentucky Power would have to rebid the RFPs if it wanted to rely on them to serve load, and argued that if Kentucky Power did so that the prices would likely increase based on the tightening capacity and energy markets.[168] The Commission agrees that the PPAs would likely increase given the current state of the market, assuming that PPAs or similar resources would even be available for contract. While the BRA does not reflect the market within PJM as a whole, the significant increases in the BRA prices reflect the broader need for generation within PJM such that PPA prices within PJM would likely increase along with capacity and energy prices in PJM markets. In fact, even Sierra Club's witness Glick acknowledged that PPA prices would likely increase if they were rebid.[169]

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[166] In Kentucky Power's Response to the Attorney General's Post-Hearing Request for Information (Attorney General's Post-Hearing Request) (filed Dec. 5, 2025), Kentucky Power provided an updated calculation of the annual costs of Alternative 2 with the cost of the make-up capacity calculated using the $329.17/MW-day cost. It reflected a difference $9,184,453 and $9,066,583 in 2029 and 2031 when compared to Kentucky Power's original filing. However, for 2031, it reflected a lower difference than that referenced herein, because the calculation of the make-up capacity for one of the RFPs still referenced a value of $215.30/MW-day. When that reference is corrected, the difference in 2031 becomes $8,888,274. *See* Kentucky Power's Response to the Attorney General's Post-Hearing Request, Item 1, KPCO_R_AG_PHDR_1_ConfiodentialAttachment1.xlsx, Tab Market; Kentucky Power's response to AG First Requests, Item 1, KPCO_R_AG_1_1_ConfidentialAttachment1.xlsx, Tab Market..

[167] The NPVRR was again calculated using the Excel function used by Kentucky Power for the long-term analysis, except that 2026 was the first discount year.

[168] HVT of the November 18, 2025 hearing at 01:09:45–01:10:03.

[169] HVT of the November 18, 2025 hearing at 07:41:21–07:41:40; *see also* Kentucky Power's Response to Staff's Post-Hearing Request, Item 11, Attachment 2 (reflecting significantly higher margins so far in 2025 due in large part to higher revenues from energy sales, indicating Mitchell is likely becoming more competitive in the current environment).

It is difficult to estimate specifically how increases in the BRA prices would affect the PPA prices, because the PPAs that Kentucky Power relied on were for energy and capacity and because the pricing may be affected by numerous factors.[170] However, the Commission notes that in the years preceding the responses to the PPAs, the BRA prices were generally below $100/MW-day and were as low as $28.92/MW-day in the 2024/2025 delivery year before they jumped to $269.92/MW-day for the 2025/2026 delivery year shortly after the counterparties updated their RFP responses in May 2024.[171] The BRA closing price then jumped to the temporary cap of $329.17/MW-day for the 2026/2027 delivery year in July 2025. Thus, given the BRA pricing before the bids were submitted and the more recent $329.17/MW-day closing price for the 2026/2027 delivery year, there would likely be a significant increase in the costs of the PPAs related to the increased cost of capacity if the PPAs were rebid.

An increase in the capacity pricing in the PPAs equivalent to a $100/MW-day increase would result in an increase of about $14.57 million for Alternative 2 in each year Kentucky Power relies on the PPAs,[172] or $43.72 million in total nominal costs for the

[170] The RFP responses often include separate capacity and energy charges. However, it is apparent that capacity charges in a capacity and energy PPA include other costs, [redacted]. Thus, it is not necessarily possible to simply compare the capacity cost in the PPA to the BRA prices.

[171] *See* Kentucky Power's Response to Staff's Post-Hearing Request, Item 15 (indicating the capacity costs in each delivery year)

[172] Based on Tab PPAs of KPCO_R_AG_1_1_PublicAttachment1.xlsx, Kentucky Power indicated that the PPAs it relied on had a UCAP of 374 and 425 MW, respectively. Using those values, the estimated effect of a $100/MW-day increasing in the capacity pricing included in the PPAs was calculated as follows:

374 MW x $100/MW-day x 365 days = $13,632,750.

425 MW x $100/MW-day x 365 days = $15,512,500.

($13,632,750 + $15,512,500)/2 = $14,572,625.

period from 2029 through 2031. This would result in a NPVRR increase for Alternative 2 of about $31.46 million using the methodology discussed above. It would be reasonable to assume such a price escalation in the capacity pricing for the PPAs if the PPAs were rebid given the market conditions and age of the PPAs.

Additionally, energy prices within PJM, though variable, are likely to increase on average along with capacity prices, especially in peak periods, for the same reason that capacity costs are increasing. Though difficult to quantify, such energy price increases are likely to further increase the cost of any rebid of the PPAs, because the right to the energy from PPAs generally acts as a hedge against significant energy prices in peak periods to the extent of the capacity of the unit or portion of the unit contracted for in the PPA.

Based solely on the costs quantified above, Alternative 1, not including the additional cooling tower costs, would have a NPVRR of about $414.97 million whereas Alternative 2 would have a NPVRR of about $390.30 million.[173] As noted above, the cooling tower work would only further increase the cost of Alternative 1 relative to Alternative 2.

However, the NPVRR of $390.30 million for Alternative 2 assumes that the PPA would only be necessary for three years until alternative generation to replace Mitchell Plant could be brought online. There is a significant risk of that wholly new generation will be delayed in the current environment given the high demand for new generation. Such a delay would likely increase the cost of Alternative 2 relative to Alternative 1,

[173] It should be noted that for the years 2029 through 2031 that both of those number include about $75 million per year representing the return of and the return Mitchell Plant's existing net plant in service such that those NPVRR amounts represent more than is at issue in this case.

because there is a strong possibility that the GHG Rules will also be delayed, which would allow Mitchell Plant to continue operating through 2034 without material additional environmental controls,[174] and because a significant portion of the incremental cost of Alternative 1 is capital investment that would have to be paid beyond 2032 regardless of whether it ceases operation whereas the incremental cost of Alternative 2 is annual O&M that is paid in each year that the PPA is utilized. Thus, any delay in constructing replacement generation would likely make Alternative 2 more expensive relative to Alternative 1 even if the plan were to replace Mitchell Plant with new generation, such as an NGCC unit, in 2032.

In fact, the Commission notes that Kentucky Power estimated an annual difference between the cost of Alternatives 1 and 2 of $71.5, $43.5, and $21.0 million in 2029, 2030, and 2031, respectively, in testimony filed with its Application.[175] With the estimated changes in the make-up capacity costs based on a BRA of $329.17/MW-day discussed above, Alternative 2 would be about $80.8, $52.7, and $29.9 million more expensive than Alternative 1 in 2029, 2030, and 2031, respectively. Thus, it would be fair to estimate that a delay in the completion of alternative generation to replace Mitchell Plant would cost ratepayers at least $30 to $40 million more on an annual basis if Kentucky Power were

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[174] *See* Wolfram Direct Testimony, at 29, Exhibit TSW-3 (indicating that if the GHG Rules are repealed or delayed that Mitchell Plant could continue to operate under current regulations until 2034 without constructing additional environmental controls).

[175] *See* Vaughn Direct Testimony, at 8, Table AEV-1 (indicating the annual costs of Alternative 1 and 2 from which the differences can be determined).

relying on Alternative 2 as compared to Alternative 1, which would quickly close the gap in cost between Alternative 1 and Alternative 2.[176]

Further, with respect to the long-term costs, Kentucky Power's long-term analysis primarily compared the continued operation of Mitchell Plant in various forms against replacement generation in the form of a NGCC unit. Those results indicated that Alternative E3 and Alternative E5 (converting Mitchell Plant to 100 percent natural gas to comply with GHG Rules and continuing to operate Mitchell Plant as a coal plant through 2040 in the event that the GHG Rules are repealed) have the lower PVRR than Alternative E4 (building a new 1,200 MW NGCC).[177]

	Alternative E1	Alternative E2	Alternative E3	Alternative E4	Alternative E5
	40% Co-Fire Only Retire by 12/31/2034	40% Co-Fire, + ELG, Retire by 1/1/2039	100% Gas Conversion,+ ELG, No Set Retirement Date	New Build 1200 MW CC	Delayed Environmental, Retire 12/31/2040
Levelized Cost of Energy ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Present Value Revenue Requirement (Millions of Dollars)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Avg Annual Revenue Requirement (Millions of Dollars)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average Capacity Factor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Up-Front Capital Cost (Millions of Dollars)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

However, to properly assess Kentucky Power's long-term options, it is necessary to include the short-term cost of reaching those options. For Alternatives E3 and E5, it would generally be necessary to select Alternative 1 in which Mitchell Plant continues to

[176] There are also additional items that could make Alternative 1 more cost effective such as securitization or a grant from the federal government for the cooling tower work.

[177] Errata Direct Testimony of Alex E. Vaughan (Vaughan Errata Direct Testimony) (filed June 30, 2025) at 13, Confidential Table AEV-2 (which slightly modified Table AEV-2 to correct the cost of Alternative E3),.

operate and Kentucky Power retains the ability to take capacity and energy from Mitchell Plant. For Alternative E4, any of the short-term options could be used as a bridge until a new NGCC can be built, but it makes sense to combine Alternative E4 with Alternative 2 when comparing it to the continued operation of Mitchell Plant, because it is lower cost or less risky than Alternative 3.[178] Further, Kentucky Power's long-term analysis was conducted for 100 percent of Mitchell Plant and a unit that it determined was comparable to all of Mitchell Plant. For that reason, to combine the short-term and long-term costs, it is necessary to use only 50 percent of the PVRR for the long-term alternatives.

As noted above, the NPVRR of Alternative 1 through 2031 is $287,710,896; the NPVRR of the Option 3 cooling tower work is about [redacted]; the NPVRR of the post-2031 costs is $127,260,895, and the NPVRR of 50 percent of percent of Alternative E3 is about [redacted]. Conversely, the NPVRR of Alternative 3 even before any increase related to higher capacity costs discussed above is $339,299,704, and the NPVRR of 50 percent of Alternative E4 is [redacted]. Based on those numbers, the combined short and long-term NPVRR of Alternative 1 and Alternative E3 is about [redacted] whereas the combined short and long-term NPVRR of Alternative 2 and Alternative E4 is about [redacted].[179] Thus, the evidence in this matter indicates

[178] Even if the evidence showed that Alternative 1 was plainly lower cost in the short-term when accounting for all incremental costs, it would not be logic to combine Alternative 1 with Alternative E4. When looking at the long-term costs, we are necessarily assuming that the short-term cost alone could not establish that Mitchell Plant is the least cost option.

[179] The long-term NPVRR's calculated by Kentucky Power were discounted from 2031 and to combine them appropriately with the short-term costs they should have been discounted from 2026. However, recalculating those NPVRR's would not materially change the cost differences. It would reduce the NPVRR of all the long-term options in a relatively proportional manner and any change that might occur would not affect which alternative is cheaper based on Kentucky Power's modeling.

Additionally, it should not have been necessary to include the post-2031 costs from the short-term analysis as part of the combined short and long-term analysis, because the incremental cost of continuing that continuing to operate Mitchell Plant as a converted gas unit is the lower cost option of those considered in the event that the GHG Rules remain in place.

Similarly, the NPVRR of Alternative 1 through 2031 is $287,710,896; the NPVRR of the Option 3 cooling tower work is about [redacted]; the NPVRR of the post-2031 costs are $127,260,895, and the NPVRR of 50 percent of percent of Alternative E5 is about [redacted]. Additionally, the NPVRR of Alternative 3 even before any increase related to higher capacity costs discussed above is $339,299,704, and the NPVRR of 50 percent of Alternative E4, assuming that the GHG Rules are eliminated or delayed, is [redacted].[180] However, the NPVRR for the modified Alternative E4 is based on 20 years whereas the NPVRR for Alternative E5 is based on only 11 years of operations based on the assumption that Mitchell Plant would cease operating as a coal unit in 2040. While not perfect, to compare Alternative E5 and the modified Alternative E4 on more equal footing, the Commission used Kentucky Power's methodology to calculate a new NPVRR for the Alternative E4 based only on 11 years of operation, which resulted in a NPVRR for the modified version of Alternative E4 of [redacted] of which 50 percent would be [redacted]. Based on those numbers, the combined short and long-term NPVRR of Alternative 1 and Alternative E5 is about [redacted] whereas the combined short and long-term NPVRR of Alternative 2 and the modified Alternative E4 to

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to take capacity and energy from Mitchell Plant should have generally only been included in the long-term option in which Mitchell Plant continues to operate. However, Kentucky Power used the same net plant balance for Mitchell Plant as of 2029 in both Alternative E3 and Alternative E4, which had the effect of assuming that the incremental investment in Mitchell would be made in either case. To address that issue, the Commission included the cost of the incremental investment post-2031 in the combined Alternative 1 and Alternative E3.

[180] *See* Kentucky Power's Response to Staff's Post-Hearing Request, Item 14, KPCO_R_KPSC_14_ConfidentialAttachment1.xlsx, Tab OPCO Rev Req.

removed limits related to the GHG Rules is about [redacted] (even before any escalation of the costs to reflect the increased capacity costs for the PPAs).[181] Thus, at least through 2040, the evidence in this matter indicates that continuing to operate Mitchell Plant performs favorably against alternative generation resources.

Notably, the Sierra Club argued that Alternative E3, switching Mitchell Plant to 100 percent gas, was the most cost effective option presented by Kentucky Power and that it would actually be more cost effective than Kentucky Power reflected, because Kentucky Power included excessive ZLD investments in Alternative E3 to comply with the 2024 ELG Rules that would not be necessary if Mitchell Plant was converted to a 100 percent gas fired unit. However, as the Attorney Generally pointed out in its briefing, a reduction in the cost of ZLD investments for Alternative E3 would actually support the CPCN requested in this case, because the investments here would be necessary to have access to Mitchell Plant, and therefore, take energy and capacity from the converted plant. Thus, the Sierra Club's concern regarding the level of ZLD investment included in the long-term analysis of Alternative E3 would not justify denying the CPCN in this case.

[181] The long-term NPVRR's calculated by Kentucky Power were discounted from 2030 and to combine them appropriately with the short-term costs they should have been discounted from 2026. However, recalculating those NPVRR's would not materially change the cost differences. It would reduce the NPVRR of all the long-term options in a relatively proportional manner and any change that might occur would not affect which alternative is least cost overall given the cost differences indicated herein.

Additionally, it should not have been necessary to include the post-2031 costs from the short-term analysis as part of the combined short and long-term analysis, because the incremental cost of continuing to take capacity and energy from Mitchell Plant should have generally only been included in the long-term option in which Mitchell Plant continues to operate. However, Kentucky Power used the same net plant balance for Mitchell Plant as of 2029 in both Alternative E3 and Alternative E4, which had the effect of assuming that the incremental investment in Mitchell would be made in either case. To address that issue, the Commission included the cost of the incremental investment post-2031 in the combined Alternative 1 and Alternative E3.

Kentucky Power's analysis is not as robust as it could have been, as discussed above. The Commission's concerns regarding the analysis in this case should be carefully noted in Kentucky Power's ongoing planning efforts. However, the Commission ultimately finds that Mitchell Plant will at least be cost competitive in the short-term and will limit potentially significant market exposure in the short-term even if it only operates through 2031. Moreover, the Commission finds that maintaining Mitchell Plant as an option for the post-2031 period is important, because the evidence indicates that it would be the least cost option in the next 10 to 20 years when long-term costs are included. Maintaining Mitchel Plant is also important because even if Kentucky Power's long-term assumptions fail and it is ultimately not selected as a mid- or long-term option, maintaining access to Mitchell Plant will provide a hedge against long-term market and other risks at a cost that is at least likely to be competitive with other short-term alternatives.

Notably, the market for generation capacity is tightening at all levels from the ability to obtain new generators for generating facilities to the availability of PPAs for energy and capacity and limited excess supplies in energy and capacity markets such as those operated by PJM. In that environment, the Commission is reluctant to place Kentucky Power's customers at the mercy of merchant or other third party generators, or energy markets for a significant majority of their load until Kentucky Power is able to build new generation or contract for long-term generation on favorable terms. More importantly, the Commission does not believe that the costs here—which are likely competitive in the short-term and favorable in the long-term—justify the risk to customers of ceasing to take capacity and energy from Mitchell Plant after 2028. Thus, the Commission finds that Kentucky Power's 50 percent share of Mitchell Plant is the most reasonable, least cost alternative to continue providing service at this time, and therefore, finds that Kentucky Power's Application for CPCN should be granted.

However, in granting Kentucky Power's CPCN, the Commission notes that the CPCN is limited to those investments through 2025 identified in the Application—specifically, the ELG and Non-ELG Investments—that Kentucky Power indicated were necessary to unwind the asymmetrical cost sharing that arose after Case Nos. 2021-00004 and 2021-00471.[182] To the extent additional investments are needed in Mitchell Plant, Kentucky Power should request a CPCN for such investments when required by KRS 278.020(1). Conversely, when a CPCN is not required for such investments, Kentucky Power may complete such projects subject to KRS Chapter 278 and 807 KAR Chapter 5, but this order should not be construed as approving those projects. Rather, the Commission notes that the costs associated with those projects, will be subject to review when Kentucky Power seeks to include them in rates in the same manner as other capital costs incurred in the ordinary course of business.

In fact, the Commission notes that Kentucky Power indicated in the application that a decision regarding Mitchell Plant's post-2031 operation has not yet been made and specifically indicated that this case was not about Mitchell Plant's post-2031 operation. As such, the Commission would caution Kentucky Power against making investments in Mitchell Plant that are not necessary for it to continue operating past 2031. The Commission understands that a certain level of ongoing investment is appropriate to keep a plant operating, but it would likely be unreasonable to make investments that are not

[182] While Kentucky Power would presumably not read it as such, this grant of a CPCN would not pertain to Non-ELG Investments that were not completed including the amounts identified in Post-Hearing requests as being unspent on the cooling tower due to the discovery of the need for additional work.

necessary for Mitchell Plant's continued short-term operation when a decision regarding its long-term operation has not been made.

The Commission will review such investments to determine if they were prudent and should be recoverable in future proceedings consistent with to KRS Chapter 278 and 807 KAR Chapter 5. However, to monitor and mitigate the risk of a significant additional increase in capital investment between now and 2031 that Kentucky Power would likely seek to recover from customers even if Mitchell Plant is taken out of service in 2031, the Commission finds that Kentucky Power should be required to file a report by February 1 of each year, beginning in 2026 and ending in 2031, (1) identifying each capital project that was completed at Mitchell Plant in the preceding calendar year, identifying the cost of the project and whether it was on or over budget, and briefly explaining the need for the project; (2) identifying any material projects expected in the calendar year in which the report is filed, identifying the cost of the project, and briefly explaining the need for the project; and (3) providing the most recent ten-year capital budget for Mitchell Plant and any capital budget variance reports for Mitchell Plant prepared for management pertaining to the preceding calendar year.

The Commission is also concerned about Kentucky Power's diligence in presenting resource decisions to the Commission. As noted above, the short-term options available to serve Kentucky Power's customers in this matter were limited, at least in part, because of when Kentucky Power filed the Application in relation to its need. Moreover, the Commission is concerned about issues with Kentucky Power's least cost analysis, particularly its failure to include the obvious revenue requirement effects for Alternative 1 in the short-term analysis, its failure to consider additional alternatives, and its failure to conduct resource assessment modeling to identify other potential portfolios before conducting the production cost and financial modeling used to calculate revenue requirements. While those failures do not justify denying the Application in this matter for the reasons discussed above, the Commission is concerned that this is part of a broader pattern in which Kentucky Power, whether intentionally or not, has made poor resource decisions, likely including purchasing Mitchell Plant in the first place in 2012,[183] and has placed the Commission in a position of having to accept a resource decision proposed by Kentucky Power to prevent a worse outcome.

To ensure that the Commission remains informed regarding Kentucky Power's plans for Mitchell Plant, the Commission finds that as part of the annual reporting required above that Kentucky Power should be required to identify its current and future plans for Mitchell Plant based on Kentucky Power or its affiliates internal resource planning, including its post-2031 plans for Mitchell Plant, and explain each basis for the resource decisions. Moreover, since Kentucky Power's analysis indicated that the Mitchell gas conversion was least cost if the GHG Rules remain in place, the Commission finds that in Kentucky Power's next integrated resource plan filing, that it should include the 100 percent conversion of Mitchell Plant to gas as a resource option in scenarios both with and without the GHG Rules. Finally, while the Commission will not prejudge any application, the Commission would strongly encourage Kentucky Power to conduct

[183] *See* Case No. 2012-00578, *Application of Kentucky Power Company for (1) A Certificate of Public Convenience and Necessity Authorizing the Transfer to the Company of an Undivided Fifty Percent Interest in the Mitchell Generating Station and Associated Assets; (2) Approval of the Assumption by Kentucky Power Company of Certain Liabilities in Connection with the Transfer of the Mitchell Generating Station; (3) Declaratory Ruling; (4) Deferral of Costs Incurred in Connection with the Company's Efforts to Meet Federal Clean Air Act and Related Requirements; and (5) All Other Required Approvals and Relief* (Ky. PSC Oct. 7, 2013), Order (approving Kentucky Power's acquisition of Mitchell Plant).

resource assessment modeling, consider and discuss any potential alternatives, and include all costs in support of any future application for a CPCN to construct new generation.

DEFERRAL AUTHORITY, AMORTIZATION, AND DEPRECIATION RATES

For the reasons discussed above, the Commission finds that Kentucky Power's request to defer the costs necessary to reimburse Wheeling Power customers for prior recoveries of the 50 percent of the ELG Project costs not presently allocated to Kentucky Power or not recovered from Kentucky Power customers through December 31, 2025, be granted, which will result in the creation of a regulatory asset in the amount of about $20.1 million to be amortized and recovered through Tariff ES along with the rest of the ELG Investment. The Commission further finds that amortizing that regulatory asset through 2040 as proposed in the Settlement Agreement is reasonable and should be approved, because it aligns with the current depreciation rates for Mitchell Plant and because it provides an additional opportunity for savings in the event Kentucky Power seeks to securitize the ELG Investment. The Commission similarly finds that depreciating the remaining net plant balance of the CCR investment over the same period as proposed in the Settlement Agreement is reasonable and should be approved for the same reason.

SURCHARGE MECHANISM AND CALCULATION

Kentucky Power proposed amendments to its Tariff ES. Tariff ES is intended to provide Kentucky Power a method of recovering the cost of certain approved environmental projects through a customer environmental surcharge. In the event that the total monthly environmental costs to Kentucky Power exceed those already recovered in base rates, then customers are charged the difference through the environmental surcharge.

The changes to Tariff ES include the addition of the ELG Project and related ELG Investments. Kentucky Power updated the list of environmental equipment at the Mitchell Plant to include Project 23, the ELG Project, and updated the list of environmental costs for the total company to include those related to the ELG project, including the recovery of the regulatory asset portion of the ELG Investment. Kentucky Power requested that a return on equity of 9.65 percent that was established in Case No. 2023-00159 be applied. Pursuant to the Settlement Agreement, Kentucky Power changes to its Tariff ES rates to reflect the amortization of the regulatory asset portion of the ELG Investment through 2040 and the depreciation of the net plant balance of the CCR project through 2040.

The Commission has reviewed Kentucky Power's proposed changes to its Tariff ES, as modified by the Settlement Agreement, and finds that the updates to Tariff ES should be approved, as modified by the Settlement Agreement.

SECURITIZATION

The Commission notes that the Attorney General and KIUC's witness Kollen proposed that the Commission direct Kentucky Power to engage with the legislature to modify current statutes to allow for securitization of Mitchell Plant. Further, the Settlement Agreement stated:

> The Signatory Parties agree that securitizing the ELG and non-ELG cost described in this settlement along with the remaining net book value of the Mitchell Plant and continuing to operate the Plant after securitization is in the best interests of Kentucky Power's customers and could potentially lower customer bill impacts. The Signatory Parties therefore agree to make good faith efforts to encourage the passing of such new securitization legislation. However, the terms of the

> Settlement Agreement are not contingent upon the legislature ultimately passing securitization legislation because Kentucky Power receiving 50% of the capacity and energy from the Mitchell Plant after December 31, 2028, is the least cost, reasonable alternative regardless of whether the costs are securitized.

The Commission acknowledges that additional securitization has the potential to reduce costs under the right circumstances. Further, the Commission commends the parties for seeking innovative solutions to reduce rates. However, the Commission does not believe that this Order is the appropriate forum for it to take a position on potential or proposed legislative changes. Thus, while generally approving the settlement, such approval should not be taken as support for any specific legislative changes or as direction from the Commission that the parties engage with the legislature regarding this issue.

OUTSTANDING PROCEDURAL ISSUE

At the hearing in this matter, it was noted that Kentucky Power's July 25, 2025 motion for a partial deviation from 807 KAR 5:011, Section 8(2)(b), related to inadvertent errors made by several newspapers in failing to publish the notice for three consecutive weeks as required by the regulation. The Commission indicated at the hearing the motion for a deviation would be granted. Consistent with that determination, the Commission, having reviewed the record and being otherwise sufficiently advised finds that Kentucky Power established good cause for a deviation in its July 25, 2025 motion, and therefore, that the motion should be granted, because the errors were minor and were not caused by Kentucky Power, and were mitigated through subsequent publications by the newspapers at issue.

SUMMARY

Having reviewed the record and being otherwise sufficiently advised, the Commission finds that Kentucky Power's proposed investment to continue to take capacity and energy from Mitchell Plant is necessary and will not result in wasteful duplication and therefore finds that the CPCN should be granted in this matter. However, the Commission finds that additional reporting requirements, as discussed in more detail above, regarding capital expenditures at Mitchell Plant and planning with respect to Mitchell Plant are necessary to protect customers. The Commission further finds that Kentucky Power's proposed changes to its Tariff ES and its ES rates, as modified by the Settlement Agreement, are reasonable and should be approved. Finally, the Commission finds that the Settlement Agreement between KIUC and Kentucky Power, which the Attorney General signed as not objecting, should be approved, to the extent the Settlement Agreement does not conflict with this Order.

IT IS THEREFORE ORDERED that:

1. Kentucky Power's request for a CPCN for the ELG Investment and the Non-ELG Investment is approved as set forth herein.

2. Kentucky Power's request for deferral authority for the costs necessary to reimburse Wheeling Power customers for prior recoveries of the 50 percent of the ELG Project costs not presently allocated to Kentucky Power or not recovered from Kentucky Power customers through December 31, 2025 be granted.

3. Kentucky Power's motion to approve the Settlement Agreement is granted, to the extent the Settlement Agreement does not conflict with this Order.

4. Kentucky Power's Tariff ES, as modified by the Settlement Agreement, is approved for service rendered on and after January 1, 2026.

5. By February 1 of each year from 2026 to 2031, Kentucky Power shall file a report:

a. Identifying each capital project that was completed at Mitchell Plant in the preceding calendar year, identifying the cost of the project and whether it was on or over budget, and briefly explaining the need for the project;

b. Identifying any material projects expected in the calendar year in which the report is filed, identifying the cost of the project, and briefly explaining the need for the project;

c. Providing the most recent ten-year capital budget for Mitchell Plant and any capital budget variance reports for Mitchell Plant prepared for management pertaining the proceeding calendar year; and

d. Identifying its current and future plans for Mitchell Plant based on Kentucky Power or its affiliates internal resource planning, including its post-2031 plans for Mitchell Plant, and explaining each basis for the resource decisions.

6. Any documents filed in the future pursuant to ordering paragraph 5 shall reference this case number and shall be retained in the post-case correspondence file.

7. The Executive Director is delegated authority to grant reasonable extensions of time for filing any documents required by ordering paragraph 5 of this Order upon Kentucky Power's showing of good cause for such extension.

8. In Kentucky Power's next integrated resource plan filing, it shall include the 100 percent conversion of Mitchell Plant to natural gas as a resource option in any

resource assessment modeling, and in production cost and financial modeling scenarios both with and without the GHG Rules.

9. Within 20 days of the date of this Order, Kentucky Power shall file with the Commission, using the Commission's electronic Tariff Filing System, its revised Tariff ES as set forth in this Order reflecting that it was approved pursuant to this Order.

10. Kentucky Power's July 25, 2025 motion for a deviation is granted.

11. This case is now closed and removed from the Commission's docket.

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PUBLIC SERVICE COMMISSION

Chairman

Commissioner

Commissioner

ATTEST:

Linda Bridwell RP

Executive Director

ENTERED

DEC 30 2025 jdc

KENTUCKY PUBLIC
SERVICE COMMISSION

APPENDIX

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2025-00175 DATED DEC 30 2025

	NPVRR of Incremental Net Plant Post-2031 (Not Including Post-2025 Cooling Tower Work)										
	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Original Reg Asset Balance	$ -	$ 179,383,123	$ 179,383,123	$ 179,383,123	$ 179,383,123	$ 179,383,123	$ 179,383,123	$ 179,383,123	$ 179,383,123	$ 179,383,123	$ 179,383,123
Annual Amortization	$ -	$ -	$ (19,931,458)	$ (19,931,458)	$ (19,931,458)	$ (19,931,458)	$ (19,931,458)	$ (19,931,458)	$ (19,931,458)	$ (19,931,458)	$ (19,931,458)
Accumulated Amortization	$ -	$ -	$ (19,931,458)	$ (39,862,916)	$ (59,794,374)	$ (79,725,832)	$ (99,657,291)	$ (119,588,749)	$ (139,520,207)	$ (159,451,665)	$ (179,383,123)
Net Reg Asset Balance	$ -	$ 179,383,123	$ 159,451,665	$ 139,520,207	$ 119,588,749	$ 99,657,291	$ 79,725,832	$ 59,794,374	$ 39,862,916	$ 19,931,458	$ -
Rate Base Effect	$ -	$ 179,383,123	$ 159,451,665	$ 139,520,207	$ 119,588,749	$ 99,657,291	$ 79,725,832	$ 59,794,374	$ 39,862,916	$ 19,931,458	$ -
Carrying Costs	$ -	$ -	$ 14,738,515	$ 13,100,902	$ 11,463,289	$ 9,825,676	$ 8,188,064	$ 6,550,451	$ 4,912,838	$ 3,275,225	$ 1,637,613
Revenue Requirement Effect	$ -	$ -	$ 34,669,973	$ 33,032,360	$ 31,394,747	$ 29,757,134	$ 28,119,522	$ 26,481,909	$ 24,844,296	$ 23,206,684	$ 21,569,071
Annual NPVRR Effect	$ -	$ -	$ 21,826,649	$ 19,465,416	$ 17,316,957	$ 15,363,714	$ 13,589,502	$ 11,979,410	$ 10,519,700	$ 9,197,721	$ 8,001,826
Cummulative NPVRR Effect	$ -	$ -	$ 21,826,649	$ 41,292,065	$ 58,609,023	$ 73,972,737	$ 87,562,239	$ 99,541,649	$ 110,061,348	$ 119,259,069	$ 127,260,895

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