**COMMONWEALTH OF KENTUCKY**
**BEFORE THE PUBLIC SERVICE COMMISSION**

**In the Matter of:**

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|---|---|---|
| **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** | ) | **CASE NO. 2021-00004** |

# Direct Testimony of Rachel Wilson

## On Behalf of Sierra Club

*** PUBLIC, REDACTED VERSION***

May 12, 2021

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## 1. INTRODUCTION AND QUALIFICATIONS

**Q. Please state your name, business address, and position.**

A. My name is Rachel Wilson and I am a Principal Associate with Synapse Energy Economics, Incorporated (Synapse). My business address is 485 Massachusetts Avenue, Suite 3, Cambridge, Massachusetts 02139.

**Q. Please describe Synapse Energy Economics.**

A. Synapse is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government agencies, and utilities.

**Q. Please summarize your work experience and educational background.**

A. At Synapse, I conduct analysis and write testimony and publications that focus on a variety of issues relating to electric utilities, including: integrated resource planning; power plant economics; federal and state clean air policies; emissions from electricity generation; environmental compliance technologies, strategies, and costs; electrical system dispatch; and valuation of environmental externalities from power plants.

I also perform modeling analyses of electric power systems. I am proficient in the use of spreadsheet analysis tools, as well as optimization and electricity dispatch models to conduct analyses of utility service territories and regional energy markets. I have direct experience running the Strategist, PROMOD IV, PROSYM/Market Analytics, PLEXOS, EnCompass, and PCI Gentrader models, and have reviewed input and output data for several other industry models.

Prior to joining Synapse in 2008, I worked for the Analysis Group, Inc., an economic and business consulting firm, where I provided litigation support in the form of research and quantitative analyses on a variety of issues relating to the electric industry.

I hold a Master of Environmental Management from Yale University and a Bachelor of Arts in Environment, Economics, and Politics from Claremont McKenna College in Claremont, California.

A copy of my current resume is attached as Exhibit RW-1.

**Q. On whose behalf are you testifying in this case?**

A. I am testifying on behalf of Sierra Club.

**Q. Have you testified previously as an expert witness before the Kentucky Public Service Commission?**

A. Yes, several times: in Case Nos. 2011-00161 and 2011-00162, dockets in which Louisville Gas & Electric Company and Kentucky Utilities Company sought certificates of public convenience and necessity (CPCNs) for environmental compliance capital projects; in Case No. 2011-00401, another CPCN docket, filed by Kentucky Power Company (KPC, or the Company), related to environmental compliance capital projects; and in Case No. 2012-00063, another such docket, filed by Big Rivers Electric Corporation.

**Q. Have you testified previously as an expert witness in any formal hearings before other regulatory bodies?**

A. Yes, many times. I have submitted expert testimony in electric utility dockets in Minnesota, Indiana, Oklahoma, Missouri, Texas, Virginia, Washington, Georgia, Mississippi, Alabama, North Carolina, South Carolina, and West Virginia.

**Q. What is the purpose of your testimony in this proceeding?**

A. My testimony evaluates the application of KPC for a CPCN to undertake capital investments at the Mitchell power plant—a two-unit, 1,560 MW, coal-fired power plant located near Moundsville, West Virginia, of which KPC is a 50 percent owner. Mitchell's co-owner is Wheeling Power Company, one of KPC's fellow subsidiaries of American Electric Power Company (AEP). The capital projects for which KPC is seeking a CPCN are intended to make Mitchell compliant with respective deadlines coming up later this decade under the federal Coal Combustion Residuals (CCR) regulation as well as the Effluent Limitation Guidelines (ELG) regulation. With respect to the ELG compliance in particular, KPC is proposing to spend tens of millions on capital projects that would be needed to keep Mitchell running as a coal-fired plant past the year 2028—instead of the alternative ELG compliance option of retiring Mitchell's coal units by the end of that year.

In conjunction with my evaluation of KPC's application, I present the results of an alternative modeling analysis that compares two cases for the Mitchell plant, identified below. The Synapse analysis includes KPC's input assumptions but updates prices for solar, wind, and storage consistent with industry standard sources.

1) **Synapse BAU ("business as usual") –** This case features KPC investing in both CCR and ELG compliance projects at Mitchell and has the plant retiring on December 31, 2040, as proposed in the Company's application.

2) **Synapse 2028 Retirement –** This case features KPC investing in CCR compliance projects needed to keep Mitchell operating past 2023, but not the ELG projects, and has the plant retiring on December 31, 2028.

**Q. Are you involved in any other regulatory proceedings concurrently addressing Mitchell's compliance options under the CCR and ELG rules? Please explain.**

A. Yes. I am a testifying expert witness for Sierra Club in Case No. 20-1040-E-CN pending before the West Virginia Public Service Commission. In that case, Wheeling Power Company, filing jointly with sibling utility and AEP subsidiary Appalachian Power Company, is seeking a CPCN for capital projects at Mitchell meant for CCR and ELG compliance, as KPC is in this case. (There are two other plants at issue as well in that case, in addition to Mitchell, but they are not part of KPC's portfolio.) As detailed in my testimony filed in that case on May 6, 2021, I have concluded that Wheeling Power's plainly least-cost option for ELG compliance is to retire Mitchell in 2028, forgoing investments in the capital projects that KPC is proposing in parallel.

**Q. Please identify the sources of information on which you base your opinions in this case.**

A. My analysis and findings rely primarily upon the testimony, exhibits, and discovery responses of KPC and its witnesses. I also rely on certain industry publications and publicly available data sources.

**Q. Are you sponsoring any exhibits?**

A. Yes. I am sponsoring the following exhibits:

| Exhibit Number | Description of Exhibit | Protected Status |
|---|---|---|
| Exhibit RW-1 | Resume of Rachel S. Wilson | Non-Confidential |
| Exhibit RW-2 | KPC Response to KIUC-AG RFI 1-14, Confidential Attachment 2 | Confidential |
| Exhibit RW-3 | KPC Response to Sierra Club RFI 2-5, Attachment 1 | Non-Confidential |
| Exhibit RW-4 | KPC Response to Sierra Club RFI 2-6, Attachment 1 | Non-Confidential |
| Exhibit RW-5 | KPC Response to Sierra Club RFI 2-7, Attachment 1 | Non-Confidential |
| Exhibit RW-6 | *KPMG report: Outlook for what's ahead for energy tax incentives (updated)* | Non-Confidential |

## 2. OVERVIEW OF TESTIMONY AND CONCLUSIONS

**Q. Please summarize your primary conclusions.**

A. My independent modeling demonstrates that it is uneconomic, and not in the best interest of ratepayers, for KPC to invest in both CCR and ELG capital projects at

Mitchell and to continue operating the plant through 2040. The lesser-cost, better option is instead to invest in only the CCR projects, forgo the ELG investments, and retire the plant's two coal units by the end of 2028. My analysis shows that early retirement would save ratepayers *$194 million* under a Base case, even with No Carbon commodity price forecast. Further, when an effective price on carbon dioxide ($CO_2$) emissions is added to the analysis, ratepayer savings rise to more than *$341 million* when Mitchell forgoes ELG investments, retires at the end of 2028, and is replaced with an alternative resource portfolio. Notably, neither case factors in any new non-carbon regulations that could arise in the next twenty years and further challenge coal's competitiveness. A summary of the resource additions, retirements, and net present value of revenue requirements (NPVRR) for the year 2050, in the Synapse modeling, is shown below in Table 1.[1]

**Table 1. Summary of Synapse modeling results (2050)**

| | Base No Carbon | | Base With Carbon | |
|---|---|---|---|---|
| | Synapse BAU | Synapse 2028 Retirement | Synapse BAU | Synapse 2028 Retirement |
| NPVRR (2021-2050) | $2.9 | $2.7 | $2.8 | $2.5 |
| Solar (MW) | 2,240 | 2,200 | 2,160 | 2,160 |
| Wind (MW) | 0 | 0 | 2,000 | 1,300 |
| Storage (MW) | 36 | 0 | 12 | 0 |
| Gas (MW) | 125 | 125 | 125 | 125 |
| Coal (MW) | 0 | 0 | 0 | 0 |

1 Using the year 2050 for the NPVRR means that the Synapse analysis evaluates the annual revenue requirements over the analysis period from 2021 through 2050, discounting the results using KPC's weighted average cost of capital (WACC). KPC analyzed this same time period, although the Company's analysis also included what is known as an "end effects" period.

**Q. Please summarize your primary recommendations.**

A. Based on my findings, I recommend that the Commission grant the CPCN only for the proposed CCR compliance capital projects and deny the CPCN for the ELG projects. Using industry standard pricing for replacement resources, the most economic option for KPC customers is to forgo ELG project investments and retiring Mitchell in 2028, even under a base commodity forecast that does not include an effective price or constraint on future $CO_2$ emissions. Customer savings from early retirement would only increase—and substantially so—if an effective carbon price does materialize in the coming years, which a prudent utility should consider.

## 3. SUMMARY OF KPC'S APPLICATION

**Q. What is KPC requesting in its Application in this docket?**

A. KPC is requesting the Commission's approval of a CPCN for the CCR and ELG projects at Mitchell, approval of the Company's 2021 Environmental Compliance Plan, and an amended environmental compliance surcharge to provide cost recovery for the ELG and CCR compliance work.[2] The total cost of compliance with CCR and ELG for Mitchell is $133.5 million, with KPC's 50 percent share being $66.75 million.[3]

2 KPC Application, page 1.
3 KPC Application, page 7.

**Q. Did KPC present any analysis supporting its Application?**

A. Yes. According to his Direct Testimony, KPC witness Mark A. Becker prepared an economic analysis that compared two compliance cases:

- Case 1 assumes CCR and ELG investments at Mitchell, with a retirement date of December 31, 2040; and
- Case 2 assumes only CCR investments at Mitchell, with a retirement date of December 31, 2028.[4]

These analyses were done under three forecasted commodity price assumptions: Base No Carbon, Base With Carbon, and Low Band, which has a lower gas price forecast.

**Q. What were the results of KPC's analysis?**

A. According to KPC, its Case 1—investing in CCR and ELG technologies at Mitchell and retiring the plant in 2040—is the least-cost option, when comparing the net present value of revenue requirements (NPVRR). The revenue requirements for each case, under each commodity forecast, are shown below in Table 2 along with the change in costs (or the "delta") relative to Case 1.

4 Direct Testimony of Mark A. Becker at 3:5-3:13.

**Table 2. Comparison of net present value of revenue requirements, KPC modeled scenarios**

| | | NPVRR ($ Millions) | Delta from Case 1 ($ Millions) | Delta from Case 1 (Percent) |
|---|---|---|---|---|
| Case 1 | Base With Carbon | $4,331 | n/a | n/a |
| | Base No Carbon | $3,944 | n/a | n/a |
| | Low Band | $3,489 | n/a | n/a |
| Case 2 | Base With Carbon | $4,325 | ($6) | -0.14% |
| | Base No Carbon | $3,971 | $27 | 0.68% |
| | Low Band | $3,509 | $20 | 0.57% |

*Source: Exhibit MAB-1.*

The percentage differences between KPC's cases reflected above were calculated by Synapse. Notably, Case 2—in which the Mitchell units retire at the end of 2028—is already the least-cost option in the Company's modeling under the Base With Carbon case, and only less than one percent more expensive when a carbon price is excluded. Mr. Becker notes in his own testimony that there is a difference between cases of less than one percent of the total NPV of KPC's expected total energy production cost of service over the analysis period.[5] That differential is extremely small, and thus even a small adjustment to KPC's input assumptions that either increased the costs to continue to operate existing coal or lowered the cost of replacement resources (or both) could shift the results such that the 2028 retirement of Mitchell becomes the more economic option under all of KPC's cases, even under the Company's own analysis.

It is imperative to recognize that either (or both) of those are distinctly probable over the next twenty years. Indeed, it is reasonable to expect that long-term trends

[5] Direct Testimony of Mark A. Becker at 5:1-5:3.

such as increasing stringency of environmental regulations and increasing cost-effectiveness of renewable energy and storage technologies will continue to increase both the cost and risk of continued investment in coal-fired power plants.

**Q. How does KPC's analysis assume the Mitchell units will operate into the future?**

A. In Case 1, when Mitchell is assumed to operate until the end of 2040, KPC's results show thermal generation from Mitchell as well as the Company's Big Sandy gas-fired plant increasing between 2021 and 2028. After that point, however, generation falls quite steeply and stays low until all the units retire at the end of 2040. In all years of KPC's analysis, the Company relies heavily on imports from PJM, particularly after 2030. This pattern is shown below in CONFIDENTIAL Figure 1, generated from data that KPC provided in discovery.

**CONFIDENTIAL Figure 1. Generation in KPC's Case 1, No Carbon (Mitchell operates until 2040)**

[redacted]

*Source: KPC's Response to KIUC AG No. 1-2, Confidential Attachment KPC Base without Carbon – CCR&ELG Optimal Plan.xlsx*

**Q. In the scenario in which Mitchell retires in 2028, what sort of replacement capacity is selected in KPC's analysis?**

A. When Mitchell retires at the end of 2028, the PLEXOS model selects 480 MW of gas-fired combustion turbines and 200 MW of a capacity-only power purchase agreement (PPA).

Mr. Becker states in his direct testimony that the PLEXOS model chose the cheapest capacity options available to replace Mitchell, due to the low level of market energy prices in the AEP Fundamentals Forecast. Because energy from the PJM market is relatively inexpensive, the model did not choose thermal units with low heat rates, which might be expected to run more, or renewable resources, which

Mr. Becker says are less valuable when market prices are low.[6] Instead, KPC's plans "result in very heavy reliance on the PJM energy market for the energy needed to serve customers."[7] Even when Mitchell continues to operate until 2040, the PLEXOS model begins to select large volumes of imports beginning in 2030, as shown in CONFIDENTIAL Figure 1, above.

**Q. Can you draw any conclusions about KPC's input assumptions from that heavy reliance on imports from PJM?**

A. Yes. When making the decision about which resources to build, PLEXOS considers both the cost of capacity (in MW) and the cost of energy (in $/MWh) of different types of replacement resource. The calculation is complicated by KPC's ability to purchase from or sell to the PJM market. The PLEXOS model chose primarily capacity resources (*e.g.*, combustion turbines and the capacity-only PPA) in KPC's analysis rather than energy resources (*e.g.*, solar and wind), and instead relies on purchased energy from PJM to meet demand. This suggests that KPC's market energy price forecast is low, its renewable prices are high, or both.

**Q. What does KPC forecast for the performance of the Mitchell units in its Case 1?**

A. KPC projects the capacity factors of the Mitchell units to start quite low in the first year of the analysis period, increase in the near term, and peak in 2026-2028, with figures in the [redacted]. By 2032, the capacity factors are less than [redacted] at both

6 Direct Testimony of Mark A. Becker at 18:21–18:28.
7 *Id.* at 18:27–18:28.

Unit 1 and Unit 2. The Mitchell units, which were intended to operate as "baseload" generators with high levels of output, would be operating as if they were peaking units, under KPC's projections, if they continued to operate past the 2028 retirement date.

Annual capacity factor projections for the Mitchell units are shown below in CONFIDENTAL Table 3.

**CONFIDENTAL Table 3. Comparison of capacity factors at Mitchell under Case 1, Base No Carbon**

[redacted]

*Source: KPC Response to KIUC AG RFI 1-14, Confidential Attachment 2* [8]

**Q. Are these projections consistent with recent experience at the Mitchell plant?**

A. No. Mitchell has operated less in recent years as a result of declines in locational marginal prices (LMPs) in PJM. From 2019 to 2020, load weighted average real

8 Attached as Exhibit RW-2.

time LMPs fell 20.3 percent, from \$27.32/MWh to \$21.77/MWh.[9] As a result, capacity factors at Mitchell were just over 22 percent and 30 percent, for Units 1 and 2, respectively. Annual capacity factors from the last five years are shown below in Table 4.

**Table 4. Net capacity factor at the Mitchell units (%)**

| | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|
| Mitchell 1 | 52.07 | 46.50 | 38.12 | 35.97 | 22.43 |
| Mitchell 2 | 59.99 | 65.77 | 42.37 | 37.78 | 30.20 |

*Source: KPC Response to KIUC-AG RFI 1-14, Attachment 1*

Despite declining capacity factors at Mitchell over the last five years, KPC's forecast for some reason anticipates increasing generation by the plant over the next five years.

When we compare the operating costs of the Mitchell units, calculated from KPC's PLEXOS outputs as the sum of fuel, variable O&M, emissions costs, and start/shutdown costs, to the AEP Fundamentals Forecast for market energy, we see that Mitchell is uneconomic relative to both on- and off-peak market prices starting in 2031. A comparison of the operating costs of the Mitchell units relative to AEP's forecast of both on- and off-peak market energy prices is shown below in CONFIDENTIAL Figure 2.

9 Monitoring Analytics. March 29, 2021. *State of the Market Report for PJM*. Members Committee Briefing. Available at: https://www.pjm.com/-/media/committees-groups/committees/mc/2021/20210329-special/20210329-state-of-the-market-report-for-pjm-2020.ashx.

**CONFIDENTIAL Figure 2. Comparison of KPC's market energy forecast versus operating cost of its coal plants**

[redacted]

*Sources:* *Energy market prices come from KPC Response to KIUC-AG RFI 1-2, Attachment 17. Operating costs were calculated using KPC Response to KIUC-AG RFI 1-2, Confidential Attachment 8 – Case 1 CCR and ELG.*

In KPC's analysis, the Mitchell units offer capacity and energy value to its customers in the near-term but offer very little energy value (as evidenced by declining capacity factors) in the later part of the decade and beyond.

## 4. SYNAPSE MODELING METHODOLOGY

Q. **Do you present an alternative to the KPC modeling analysis?**

A. Yes, I did.

**Q. Which model did you use to perform your analysis?**

A. The Synapse analysis uses the EnCompass capacity optimization and dispatch model, developed by Anchor Power Solutions, to simulate resource choice impacts in the KPC's service territory.

**Q. Is EnCompass a widely accepted industry model?**

A. Yes. EnCompass was released in 2016 and several major utilities have transitioned to the model since that time. For example, the three investor-owned utilities in Minnesota (Minnesota Power, Otter Tail Power, and Xcel Energy) adopted the EnCompass model in 2019, along with Great River Energy, the largest of the state's electric cooperatives.[10] Duke Energy announced in 2020 that it had chosen EnCompass to expand its capabilities in resource planning.[11] Public Service New Mexico and Public Service Company of Colorado are two other IOUs that have adopted EnCompass in recent years.

**Q. What did Synapse model in its analysis?**

A. Synapse modeled two different scenarios in our analysis for the KPC plants:

1) **Synapse BAU** includes both CCR and ELG investments at the Mitchell plant and retires the plant on December 31, 2040;
2) **Synapse 2028 Retirement** includes only the CCR investments at the Mitchell plant, not the ELG investments, and retires the plant on December 31, 2028.[12]

A matrix of these scenarios is shown below in Table 5.

10 Anchor Power Solutions. December 2019. Available at: https://anchor-power.com/news/minnesota-plans-for-its-energy-future-with-encompass/.

11 Anchor Power Solutions. May 2020. Available at: https://anchor-power.com/news/duke-energy-implemented-encompass-software/.

12 As noted by KPC in its Application, CCR compliance will be required by October 17, 2023. ELG costs, however, can be avoided if a plant is shut down by 2028 (and KPC makes a commitment to do so by October 2021). Because of the short time necessary to comply with CCR regulations, and because it is not clear that all costs could be avoided even if a plant ceased operations, I have not considered a scenario where CCR costs were not included.

**Table 5. Matrix of Synapse KPC modeling scenarios**

| | | Synapse BAU | Synapse 2028 Retirement |
|---|---|---|---|
| Retrofit Technology | Mitchell | CCR/ELG | CCR |
| Retirement Date | Mitchell | 2040 | 2028 |

**Q. Do the input assumptions used in the Synapse analysis conform to KPC's assumptions?**

A. Largely, yes. To ensure a valid, apples-to-apples comparison, the Synapse analysis uses KPC's assumptions for peak and annual energy, load shape, reserve margin, unit retirements, commodity prices (fuel, $CO_2$, and energy market prices), and compliance costs for CCR/ELG at Mitchell under the 2028 and 2040 retirement dates. The sources for key input assumptions in the Synapse modeling are shown below in Table 6.

**Table 6. Sources of input assumptions in Synapse modeling**

| Assumption | Source |
|---|---|
| Load Forecast | KPC response to KIUC-AG RFI 1-2, Becker Workpapers |
| Load Shape | KPC response to SC RFI 1-7, Attachments 1 |
| Reserve Margin | Becker Direct Testimony |
| Coal Prices | KPC response to KIUC-AG 1-2, AEP Fundamentals Forecast |
| Gas Prices | KPC response to KIUC-AG 1-2, AEP Fundamentals Forecast |
| $CO_2$ Prices | KPC response to KIUC-AG 1-2, AEP Fundamentals Forecast |
| Market prices | KPC response to KIUC-AG 1-2, AEP Fundamentals Forecast |
| Solar Costs | NREL ATB 2020 Mid |
| Battery Costs | NREL ATB 2020 Mid |
| Onshore Wind Costs | NREL ATB 2020 Mid, Class 7 |
| Capacity Credit | KPC response to KIUC-AG 1-2, Becker Workpapers |
| Amos/Mountaineer Op Costs | KPC response to KIUC AG 1-2, Becker Workpapers |
| CCR/ELG Costs | KPC response to KIUC AG 1-2, Becker Workpapers |
| Transmission Costs | KPC response to KIUC AG 1-2, Becker Workpapers |

**Q. Did you have to adjust any of the Company's input assumptions?**

A. Yes, I had to adjust KPC's assumptions on pricing for solar, wind, and battery storage resources. The Company provided the annual cost values as they were input into the PLEXOS model in its Response to Sierra Club's Second Set of Discovery and indicated that the source of its pricing for these resources was the Energy Information Administration's (EIA) 2020 Annual Energy Outlook (AEO). However, EIA did not publish annual overnight capital cost projections for forward-looking years in this version of the AEO, so I was unable to confirm KPC's values. EIA did publish those values in AEO 2021, however, so I was able to compare KPC's data to a more recent version of AEO. For solar, KPC's assumed PPA price is $57.58/MWh in 2026.[13] This is much higher than the assumed levelized cost of energy from EIA in AEO 2021 for solar resources in 2026, which is $33.68/MWh.[14] KPC has stated that its cost assumptions come from EIA, but there is a substantial difference between EIA's values and those used by KPC in this analysis.

**Q. Are you able to determine the source of that difference?**

A. Only generally. KPC's assumptions regarding both the capital and fixed O&M component costs for solar are higher than those assumed by EIA. My expertise is not in utility financing or accounting, but KPC's underlying workpapers contain a

13 KPC Response to Sierra Club RFI 2-5, Attachment 1 (attached as Exhibit RW-3).

14 Energy Information Administration, *Levelized Costs of New Generation Resources in the Annual Energy Outlook 2021* (February 2021), available at https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf. This document shows a cost of $29.04 in 2020$. That value was converted to nominal dollars using KPC's assumed inflation rate of 2.5% from its Response to Sierra Club RFI 2-5, Attachment 1.

number of financial assumptions that appear to add to the costs of their replacement resources.[15] I have not seen the costs of replacement resources calculated in this way in previous utility dockets in which I have been involved.

**Q. Are there any other data points that lead you to believe that KPC's assumed new resource costs are unreasonably high?**

A. Yes. KPC's forecasts are higher than currently published PPA prices for both solar and wind. Solar PPA pricing in PJM in Q4 2020 was $37.50/MWh, while wind PPAs were priced at $35.50/MWh.[16] However, analysts note that both prices are an increase over prior years, because of disruptions due to COVID-19 as well as supply constraints that have arisen due to high demand.[17] Over the longer term, basic economics suggests that the market will respond to these supply constraints and that prices will stabilize lower.

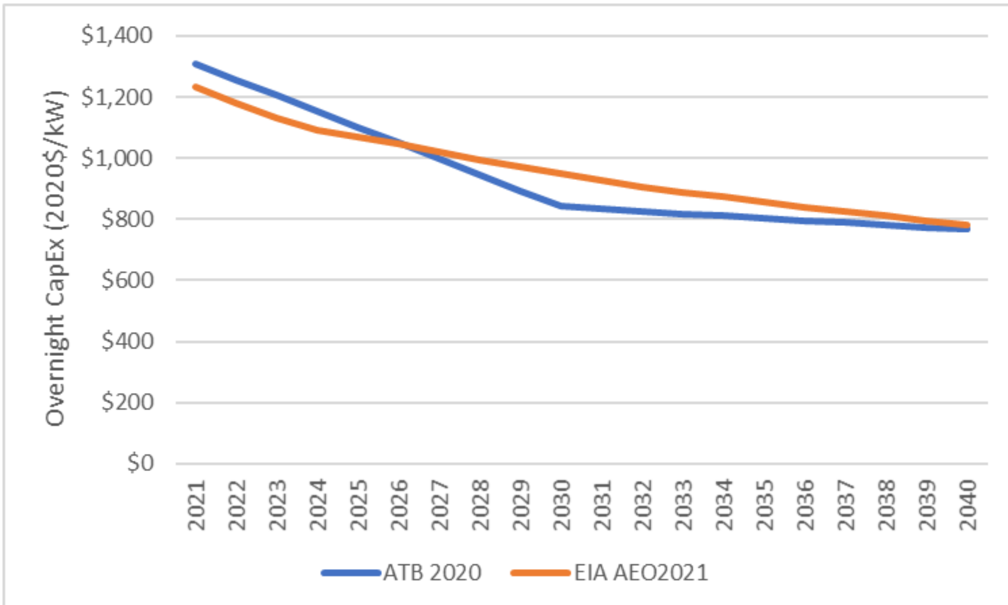
**Q. What source did the Synapse modeling analysis use as the basis for its assumptions around the cost of replacement resources?**

A. The Synapse modeling uses industry standard cost assumptions from the National Renewable Laboratory's (NREL) 2020 Advanced Technology Baseline (ATB) for utility-scale photovoltaic (PV) solar, onshore wind, and battery storage resources. NREL's ATB 2020 data is quite similar to the estimates of overnight capital costs

15 Exhibit RW-3.
16 Level 10 Energy. *North America, Q4 2020 LevelTen Energy PPA Price Index.* Available at: https://leveltenenergy.com/blog/ppa-price-index/q4-2020/
17 *Id.*

from EIA 2021. A comparison of the capital costs for solar PV from both sources is shown below in Figure 3.

**Figure 3. Comparison of overnight capital cost forecasts for solar PV, ATB 2020 and AEO 2021**

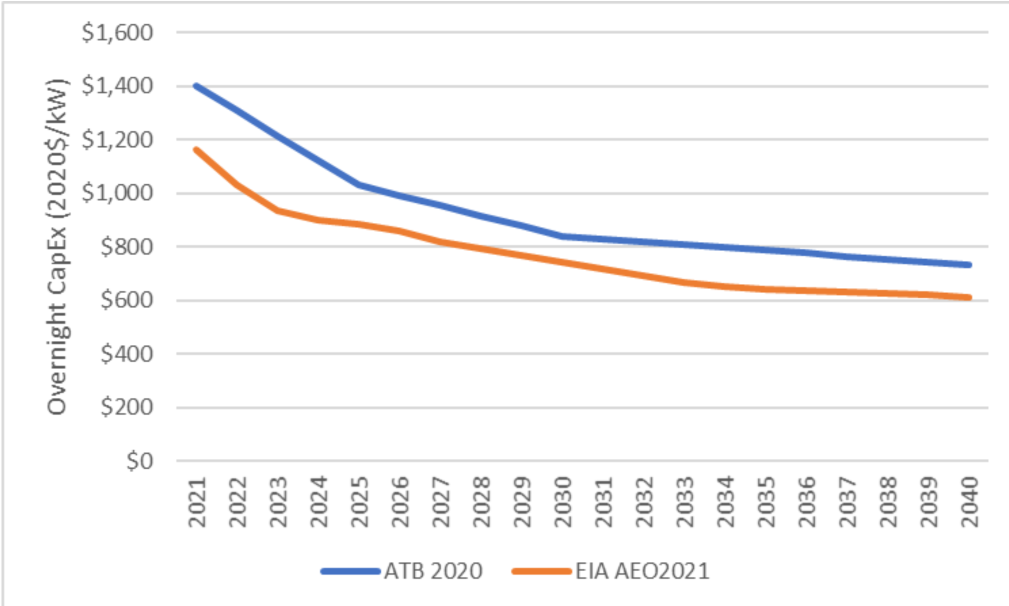



*Sources:* *National Renewable Energy Laboratory, Annual Technology Baseline (2020), available at:* https://atb.nrel.gov/electricity/2020/data.php*; Energy Information Administration, Annual Energy Outlook (2021) at Table 55, available at:* https://www.eia.gov/outlooks/aeo/data/browser/#/?id=123-AEO2021&cases=ref2021&sourcekey=0.

Battery storage costs are more conservative in NREL's ATB Moderate Case than in AEO 2021. Those overnight capital costs are shown below in Figure 4.[18]

18 A comparison of wind costs is not presented here because they are not directly comparable between sources, as AEO 2021 presents wind costs by region while NREL ATB presents costs by wind class. Synapse selected Class 7 to represent the wind resource that would be available to KPC for the purposes of this analysis.

**Figure 4. Comparison of overnight capital cost forecasts for battery storage, ATB 2020 and AEO 2021**




*Sources: National Renewable Energy Laboratory, Annual Technology Baseline (2020), available at:* https://atb.nrel.gov/electricity/2020/data.php*; Energy Information Administration, Annual Energy Outlook (2021) at Table 55, available at:* https://www.eia.gov/outlooks/aeo/data/browser/#/?id=123-AEO2021&cases=ref2021&sourcekey=0.

**Q. The capital costs you have shown from EIA are generally similar to, or lower than, ATB. Why are you suggesting that KPC's costs are too high?**

A. Costs for wind, solar, and battery storage have two major components: capital and fixed O&M. A comparison of these components between KPC and EIA for a solar PV resource coming online in 2026 shows that KPC's forecasts of both components are higher than those being used in AEO 2021.

**Table 7. Comparison of KPC solar PPA cost with EIA levelized solar costs, $/MWh**

| | Capital | Fixed O&M | Transmission | Tax Credit | Total |
|---|---|---|---|---|---|
| KPC | $44.65 | $12.93 | - | - | $57.58 |
| EIA 2021 | $26.21 | $6.87 | $3.22 | -$2.62 | $33.68 |

**Q. Why did Synapse choose to use NREL ATB 2020 as its source for new resource costs rather than EIA?**

A. As shown Figure 3 and Figure 4, above, the EIA and NREL overnight capital costs for solar and storage are actually quite similar. However, EIA's input costs are based on a single source: a report from Sargent & Lundy published in December 2019[19] and provided by KPC in responses to discovery.[20] The NREL ATB, on the other hand, incorporates several different sources, including analyses from both NREL and Oak Ridge National Laboratory, data from EIA, and information from a variety of published reports to arrive at its forecasts of generation technology cost and performance.[21]

NREL's ATB is a widely used source of renewable and storage pricing data. Detroit Edison used the 2018 ATB Mid costs in its 2019 Integrated Resource Plan, with some intervenors arguing that the costs were too conservative.[22] In its recent

19 Energy Information Administration. *Annual Energy Outlook 2021: Levelized Costs of New Generation Resources* (February 2021), available at https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf.

20 KPC Response to KIUC-AG RFI 1-29, Attachment 2, also available online at https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf.

21 National Renewable Energy Laboratory, *2020 Annual Technology Baseline: Electricity Data Now Available* (July 9, 2020), available at: https://www.nrel.gov/news/program/2020/2020-annual-technology-baseline-electricity-data-now-available.html.

22 *In re Application of DTE Electric Company for approval of its integrated resource plan pursuant to MCL 460.6t and for other relief*, Michigan Public Service Commission Case No. U-20471 (February 20, 2020), available at: https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000009jWc2AAE.

Integrated Resource Plan filing in Minnesota, Xcel Energy used ATB 2019 as the basis for its renewable and storage costs.[23]

Lastly, in order to accurately model these replacement resources, we need more than just the forecasted capital costs. We also need annual estimates of fixed O&M cost, which the AEO 2021 does not provide. NREL's ATB does provide these data, however, which, when combined with performance data, allows for a levelized cost calculation that utilizes data from a single source.

**Q. How do Synapse's modeled costs for wind and solar compare to KPC's?**

A. Prices used by both KPC and Synapse for wind and solar are shown below in Table 12.

23 *Xcel Energy's 2020-2034 Upper Midwest Resource Plan*, Minnesota Public Utilities Commission Docket No. E002/RP-19-368 (July 1, 2019), available at https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/The-Resource-Plan-No-Appendices.pdf.

**Table 8. Comparison of prices for new resources in KPC and Synapse modeling**

| | Solar | | Wind | |
|---|---|---|---|---|
| Year | KPC | Synapse | KPC | Synapse |
| 2021 | $57.60 | $33.63 | | |
| 2022 | $54.45 | $32.80 | $40.76 | |
| 2023 | $52.55 | $31.94 | $45.10 | $45.25 |
| 2024 | $56.25 | $31.05 | $40.51 | $45.00 |
| 2025 | $57.70 | $30.12 | $55.53 | $44.71 |
| 2026 | $57.58 | $29.15 | $56.30 | $44.39 |
| 2027 | $57.83 | $28.15 | $57.01 | $44.04 |
| 2028 | $57.90 | $27.10 | $57.83 | $43.65 |
| 2029 | $58.05 | $26.02 | $58.60 | $43.22 |
| 2030 | $58.24 | $24.90 | $59.35 | $42.76 |
| 2031 | $58.40 | $25.12 | $60.01 | $43.28 |
| 2032 | $58.59 | $25.33 | $60.63 | $43.80 |
| 2033 | $58.84 | $25.55 | $61.19 | $44.33 |
| 2034 | $59.08 | $25.77 | $61.73 | $44.85 |
| 2035 | $59.31 | $25.99 | $62.25 | $45.38 |
| 2036 | $59.50 | $26.21 | $62.79 | $45.91 |
| 2037 | $59.66 | $26.43 | $63.29 | $46.45 |
| 2038 | $59.86 | $26.64 | $63.77 | $46.98 |
| 2039 | $60.05 | $26.86 | $64.32 | $47.52 |
| 2040 | $60.29 | $27.08 | $64.91 | $48.05 |

*Sources: KPC Responses to Sierra Club RFI 2-5 and 2-6*

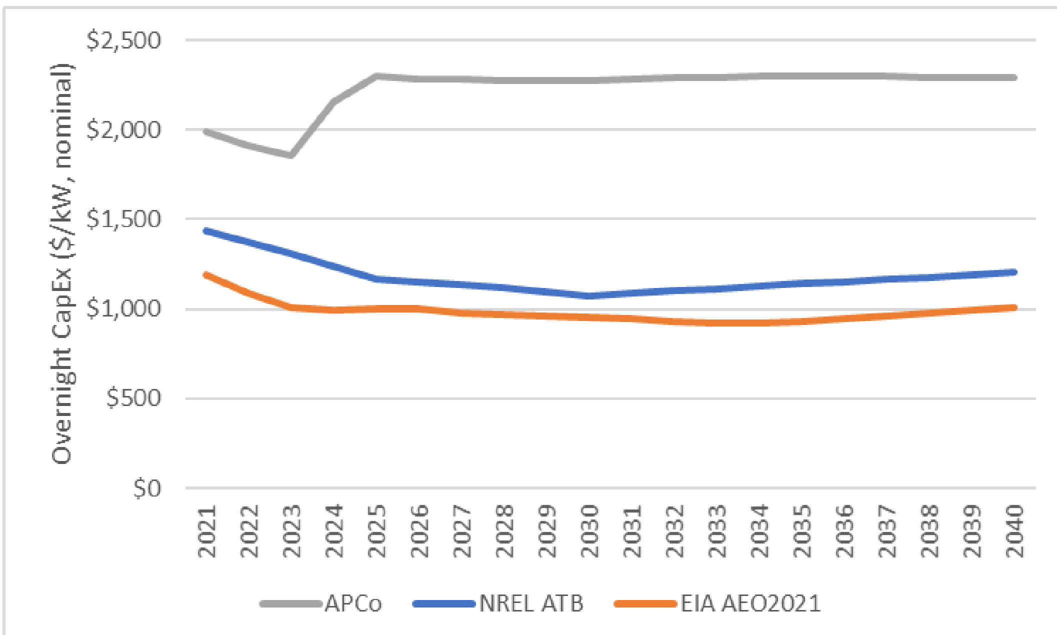
In 2028, KPC's solar PPA price is $57.90/MWh.[24] In contrast, the solar PPA price in the Synapse modeling is $27.10/MWh, which reflects the projection from NREL ATB 2020 that capital and fixed O&M for solar PV will both be lower than KPC's projections. Similarly, KPC's levelized cost for wind in 2028 is $57.83/MWh,[25] while Synapse's wind cost is $43.65/MWh. The Synapse modeled resources are much more cost-effective and competitive with KPC's forecasted on-peak market price of $34.87/MWh and the off-peak market energy price of $28.21/MWh.[26]

24 Exhibit RW-3.
25 KPC Response to Sierra Club RFI 2-6, Attachment 1 (attached as Exhibit RW-4).
26 KPC Response to KIUC-AG RFI 1-2, Attachment 17.

**Q. How do KPC's assumptions about battery storage costs compare to those from industry sources?**

A. KPC's modeling builds no battery storage resources because of the Company's high assumed build costs for these resources. The build costs used by KPC in the PLEXOS model in comparison to ATB and EIA are shown below in Figure 9.

**Figure 5. Comparison of overnight capital cost forecasts for battery storage, KPC, ATB 2020, and AEO 2021**




*Sources: National Renewable Energy Laboratory, Annual Technology Baseline (2020), available at:* https://atb.nrel.gov/electricity/2020/data.php*; Energy Information Administration, Annual Energy Outlook (2021) at Table 55, available at:* https://www.eia.gov/outlooks/aeo/data/browser/#/?id=123-AEO2021&cases=ref2021&sourcekey=0; *and KPC Response to Sierra Club RFI 2-7, Attachment 1, attached as Exhibit RW-5.*

## 5. SYNAPSE MODELING RESULTS

**Q. What were the results of the Synapse modeling analysis?**

A. In contrast to KPC's modeling analysis, Synapse's modeling found that Kentucky ratepayers save money under the 2028 Retirement scenario relative to the continued operation of Mitchell until 2040. When compared to the Synapse BAU, the retirement of Mitchell in 2028 would save ratepayers approximately $194 million.

The benefits to ratepayers from retirement grow under the Base With Carbon price forecast relative to the BAU, with the retirement of Mitchell in 2028 resulting in ratepayer savings of $341 million. The revenue requirements for each of the four Synapse scenarios, under KPC's Base No Carbon and Base With Carbon pricing forecasts, are shown below in Table 8.

**Table 9. Net present value of revenue requirements, Synapse modeling scenarios**

| | Base No Carbon | | Base With Carbon | |
|---|---|---|---|---|
| **Scenario** | **NPVRR ($Millions)** | **Delta from BAU ($Millions)** | **NPVRR ($Millions)** | **Delta from BAU ($Millions)** |
| Synapse BAU | $2,850 | n/a | $3,239 | n/a |
| Synapse 2028 Retirement | $2,656 | ($194) | $2,898 | ($341) |

**Q. Can the NPVRR values for the Synapse scenarios be compared directly to the NPVRR values from KPC's analysis?**

A. No. There are a few reasons why results would differ. The first key reason is that KPC used the PLEXOS model while Synapse used EnCompass. Each model has different optimization and dispatch algorithms and would produce different results even when using the same inputs. For this reason, Synapse always reproduces a utility's base case scenario, or BAU, to produce an NPVRR value to which we can compare results from alternative scenarios. In this case we updated the resource cost assumptions in the Synapse BAU as well as in our 2028 Retirement scenarios so that the BAU costs were not artificially high.

Second, Synapse is an independent consulting firm that is not afforded the same level of access to the details of KPC's electric system as is given to AEP's modelers. As a result, there may be certain inputs in KPC's analysis that are represented slightly differently in the Synapse analysis. The key, however, is that these elements are the same among all the modeled Synapse scenarios and are not therefore driving the differences in these scenarios. The only way that one can perfectly replicate a utility's analysis is to use the same model, version number, and exact input files. The models used by utilities often must be licensed by intervenors on a project basis and are cost prohibitive. While I am familiar with the PLEXOS model and have used it in previous work, there are limits to the extent to which one can reconstruct an analysis without the opportunity to spend time exploring a utility's database within the model's interface.

Finally, KPC's NPVRR values include an analysis period from 2021 to 2050 and include an end effects period, while the Synapse values only include the period from 2021 to 2050. The Synapse NPVRR values in all scenarios are not directly comparable to KPC's because they do not include a similar end effects period.

It is not the delta between the KPC scenarios and the Synapse scenarios that matters in this case, but rather the deltas between each entity's own set of modeled scenarios. For all of these reasons, the Synapse NPVRR values should be compared to each other and not compared directly to the KPC values.

**Q. What types and quantities of replacement resources are added in the Synapse scenarios?**

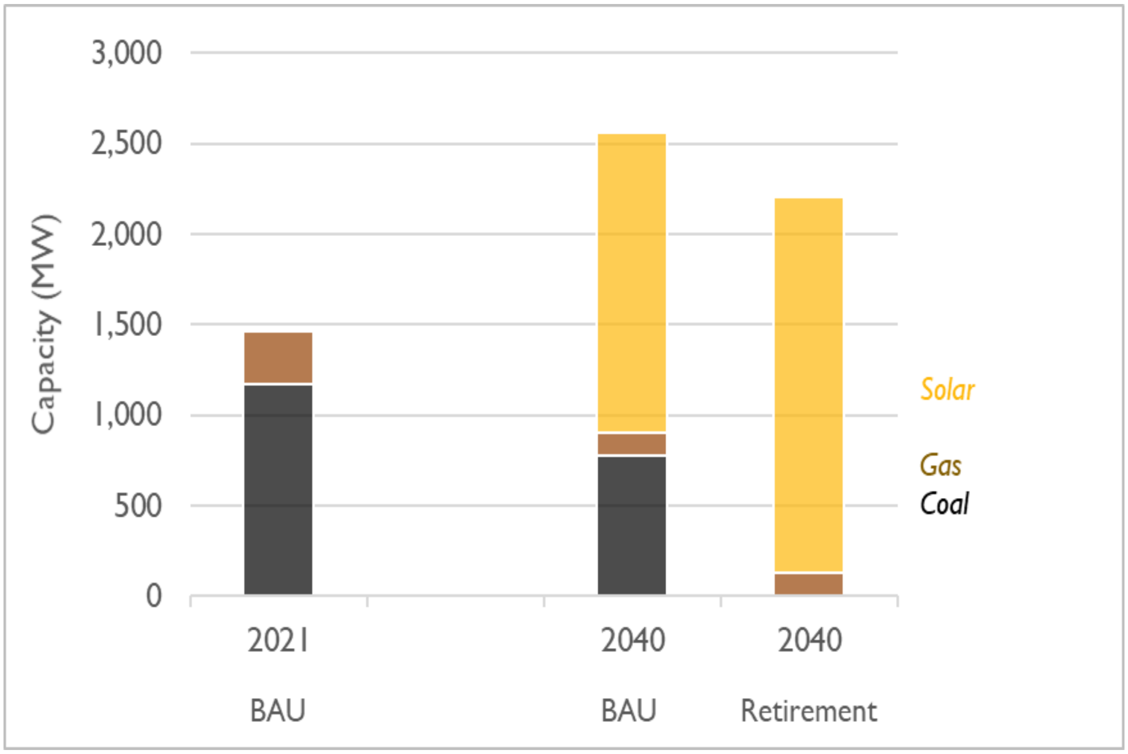
A. The EnCompass model was allowed to optimize the buildout of replacement resources for the retiring coal units beginning with wind in 2023 and with replacement solar PV and battery storage resources in 2024. Solar PV and battery storage were offered as both standalone and paired resources.[27]

Figure 5 below compares the capacity in 2021, which is the same in both scenarios, to the capacity in 2040 in the BAU and 2028 Retirement scenarios. In addition to what is shown in Figure 5, EnCompass also selects 50 MW of the Capacity Only PPA in 2040 in the 2028 Retirement scenario.[28]

27 Per the Kentucky Power 2019 IRP, a small combustion turbine is added in 2031 as a partial replacement for the Big Sandy unit. This resource is added in both scenarios.

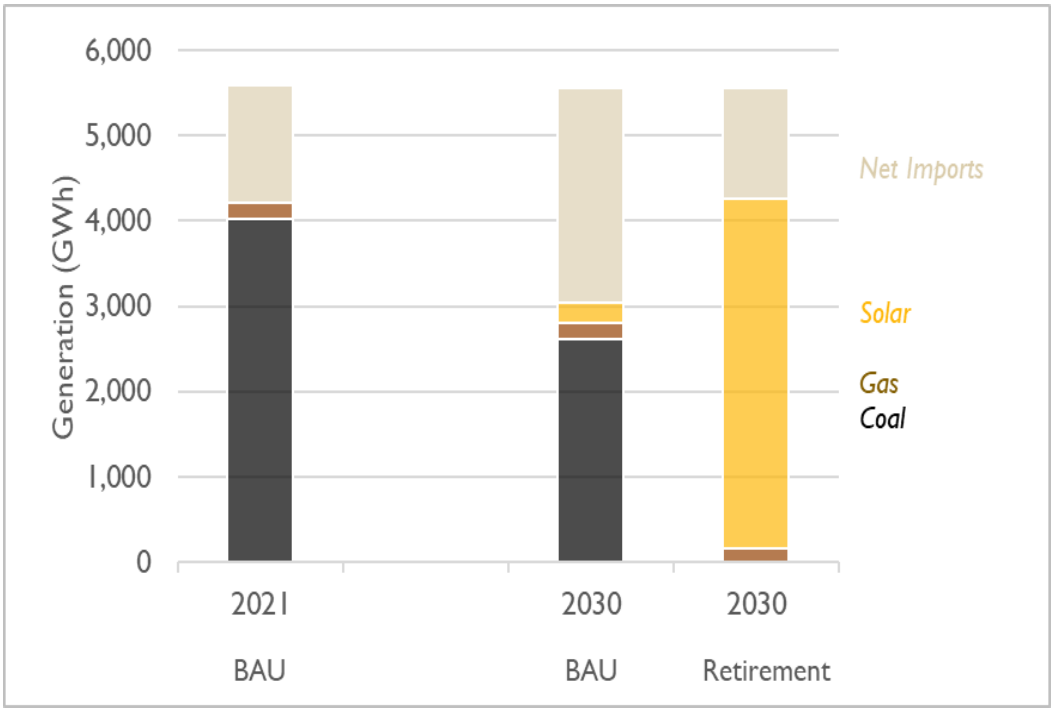
28 The Capacity Only PPA was included in KPC's modeling as a replacement resource option. It is available in 50-MW blocks, with an annual maximum of 400 MW, and is one year in duration. The Capacity Only PPA is priced at the capacity price forecast from the AEP Fundamentals Forecast.

**Figure 6. Comparison of nameplate capacity in Synapse modeled scenarios, Base No Carbon**




When we look at generation in 2030 under both scenarios, we see that coal generation has declined in the BAU, and imports have increased relative to 2021. In the 2028 Retirement scenario, KPC's generation is largely coming from solar resources with smaller amounts of imports. This comparison is shown below in Figure 6.

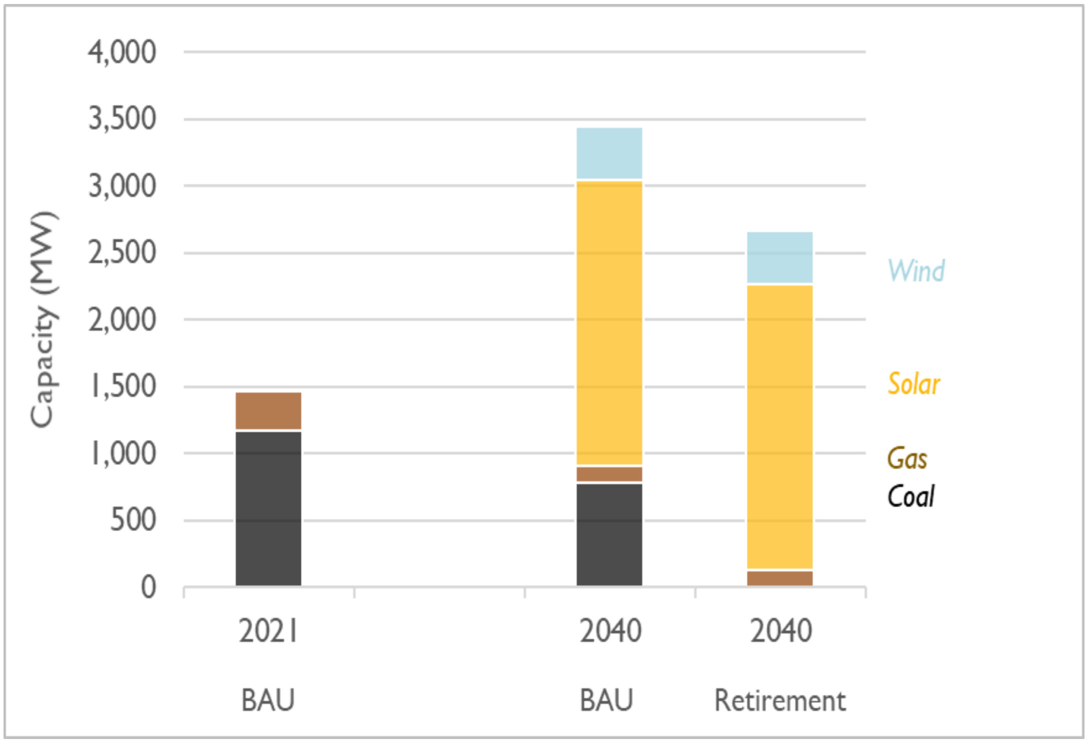
**Figure 7. Comparison of generation in Synapse modeled scenarios, Base No Carbon**




**Q. Does the resource portfolio look different when a price on $CO_2$ is included in the modeling?**

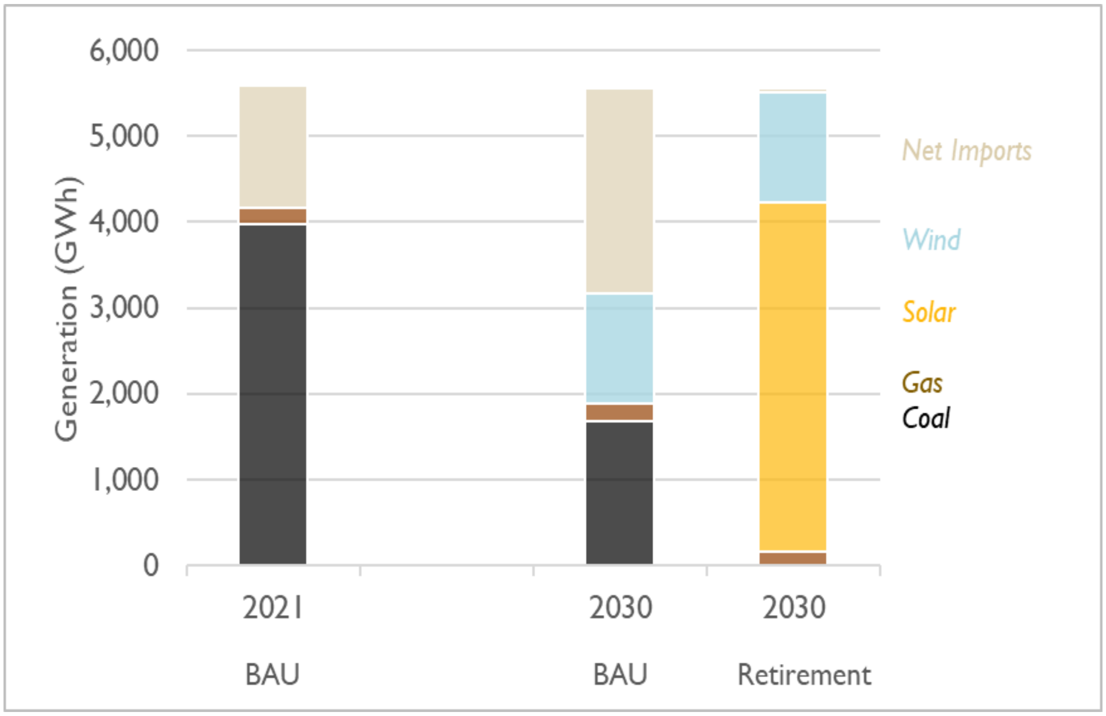
A. Yes. The addition of a price on $CO_2$ changes AEP's energy market price forecast such that the model finds it economic to also add new wind units to the resource portfolio. The capacity mix under the Base With Carbon commodity price forecast is shown below in Figure 7.

**Figure 8. Comparison of nameplate capacity in Synapse modeled scenarios, Base With Carbon**




Wind generation is often complementary to solar generation, producing energy in the early mornings, late evenings, and overnight when the sun is not shining. Below, Figure 8 shows the generation mix under the two resource portfolios when a $CO_2$ price is included. The addition of wind energy has displaced the majority of the imported energy in the 2028 Retirement scenario, such that KPC's reliance on imports in 2030 is shown to be minimal, particularly when compared to the fuel mix in the BAU scenario in that same year.

**Figure 9. Comparison of generation in Synapse modeled scenarios, Base With Carbon**




**Q. How do $CO_2$ emissions compare between the two Synapse scenarios?**

A. Emissions of $CO_2$ in the 2028 Retirement scenario fall dramatically relative to the BAU after the retirement of Mitchell at the end of 2028 under the Base No Carbon case. Emissions in 2021, 2030, and 2040 for these two scenarios are shown below in Table 9, under a No Carbon commodity price forecast.[29] By 2030, $CO_2$ emissions in the BAU have fallen by 68 percent relative to 2021, while emissions under the 2028 Retirement scenario have fallen by 97 percent.

**Table 10. Comparison of $CO_2$ emissions in the Synapse modeled scenarios, Base No Carbon**

| | 2021 | 2030 | 2040 |
|---|---|---|---|
| Synapse BAU | 4.0 | 2.7 | 2.4 |
| Synapse 2028 Retirement | 4.0 | 0.1 | 0.0 |

29 Note that these numbers do not include the emissions associated with PJM imports.

AEP, like many of its utility peers, has committed itself to net-zero $CO_2$ emissions by 2050, and has an interim goal to cut emissions 80 percent from 2000 levels by 2030, while adding more than 10,000 MW of regulated wind and solar.[30] While emissions drop in the Synapse BAU after the retirement of Mitchell in 2040, KPC's interim emissions reductions are must less than in the 2028 Retirement scenario.

**Q. What is the effect of including a $CO_2$ price in the Synapse modeling analysis?**

A. The difference in NPVRR for the BAU, which relies more heavily on coal, in a forecast that includes a carbon price versus one that does not is much greater than the difference between the Synapse 2028 Retirement scenarios. As shown below in Table 10, the $CO_2$ price adds $389 million to the cost of the BAU scenario, but only $242 million to the 2028 Retirement scenario. In other words, the risk of following the BAU path given the future uncertainties of carbon pricing is much greater than in a scenario in which Mitchell retires at the end of 2028.

**Table 11. Comparison of scenarios with and without a carbon price**

| Scenario | NPVRR ($Millions) No Carbon | NPVRR ($Millions) With Carbon | Delta |
|---|---|---|---|
| Synapse BAU | $2,850 | $3,239 | $389 |
| Synapse 2028 Retirement | $2,656 | $2,898 | $242 |

30 American Electric Power, *Clean Energy Future*, https://www.aep.com/about/ourstory/cleanenergy#:~:text=Achieving%20net%20zero%20carbon%20dioxide,billion%20in%20renewables%20through%202025 (last accessed April 29, 2021).

**Q. Are you suggesting that KPC rely almost exclusively on solar resources to make up a replacement resource portfolio if Mitchell were to retire in 2028?**

A. No. Under the pricing assumptions used in the Synapse analysis—which includes AEP's market and fuel price forecasts but updates the costs of renewables to be commensurate with NREL's ATB—solar is the cheapest resource. The EnCompass model adds solar resources to meet energy needs in the 2028 Retirement scenario, displacing as much of KPC's reliance on imported energy as it can in the hours it can, but relying on the PJM market to provide the rest. The reserve margin is met through the building of these resources to provide energy. KPC's replacement portfolio, on the other hand, consists entirely of combustion turbines and capacity-only PPAs, which are intended to provide capacity, but not energy. Neither portfolio might be expected to serve KPC's load in an extreme weather event similar to the one that occurred in Texas in February 2021 (blackouts and high prices resulted there from a complex set of reasons). However, KPC's current portfolio, with its reliance on two units at a single Mitchell plant, also might not be expected to meet reliability needs.

Under the Base With Carbon commodity price forecast, the Synapse 2028 Retirement scenario relies on a combination of wind and solar. This mix of resources is the one that is more likely actually to materialize, particularly as we see an extension, or even an increase, in the policies that increase the competitiveness of these technologies and make the operation of coal less economic. Given that the retirement of Mitchell would not occur until December

21, 2028, KPC would have several years and two more upcoming Integrated Resource Plans (in 2022 and 2025) to study the ideal replacement resource mix.

**Q. You indicated that you also filed testimony in West Virginia on the proposed compliance investments at Mitchell. What did those results show?**

A. My West Virginia analysis, set out in my direct testimony filed in WV PSC Case No. 20-1040-E-CN on May 6, 2021, showed a net benefit to Wheeling Power of $118 million with the 2028 retirement of Mitchell under a Base No Carbon forecast, relative to the Synapse BAU. Savings under a Base With Carbon scenario increased to $350 million.

**Q. What should this Commission conclude from the Synapse modeling analysis?**

A. There are several important takeaways from the Synapse modeling analysis.

First, the retirement of Mitchell in 2028 is the least-cost scenario and in the best interest of Kentucky ratepayers under the regulatory landscape in the electric sector as it exists today, saving $194 million. Those savings increase to $341 million under a scenario that models an effective price on $CO_2$. Moreover, if future additional environmental regulations not modeled here were to be implemented in the next 20 years that further constrained coal or coal-fired power plants, that could further increase the savings posed by retiring Mitchell in 2028.

Second, the Commission should note that it is in the economic interests of KPC's ratepayers to integrate additional renewable and storage capacity slightly ahead of the actual retirement year for Mitchell. This low-variable-cost energy both displaces more expensive fossil generation and/or imported energy and reduces KPC's reliance on the PJM market.

Lastly, the importance of KPC's forecasts for both replacement resources and market energy prices cannot be understated. These two sets of input assumptions, both separately and together, are the primary drivers of the revenue requirements in all modeled scenarios. Synapse used the Mid set of forecasts from ATB 2020, but as noted above, these have often been criticized as too conservative. The NREL ATB also includes Low and High cost forecasts for each technology, and KPC would be advised to model specific nascent resources, like battery storage, using the Low value to test the sensitivity of its results to changes in technology costs.

## 6. COAL-FIRED POWER PLANTS' INCREASINGLY UNECONOMIC FUTURE PROSPECTS

**Q. What does the future look like for coal-fired generating units in the United States?**

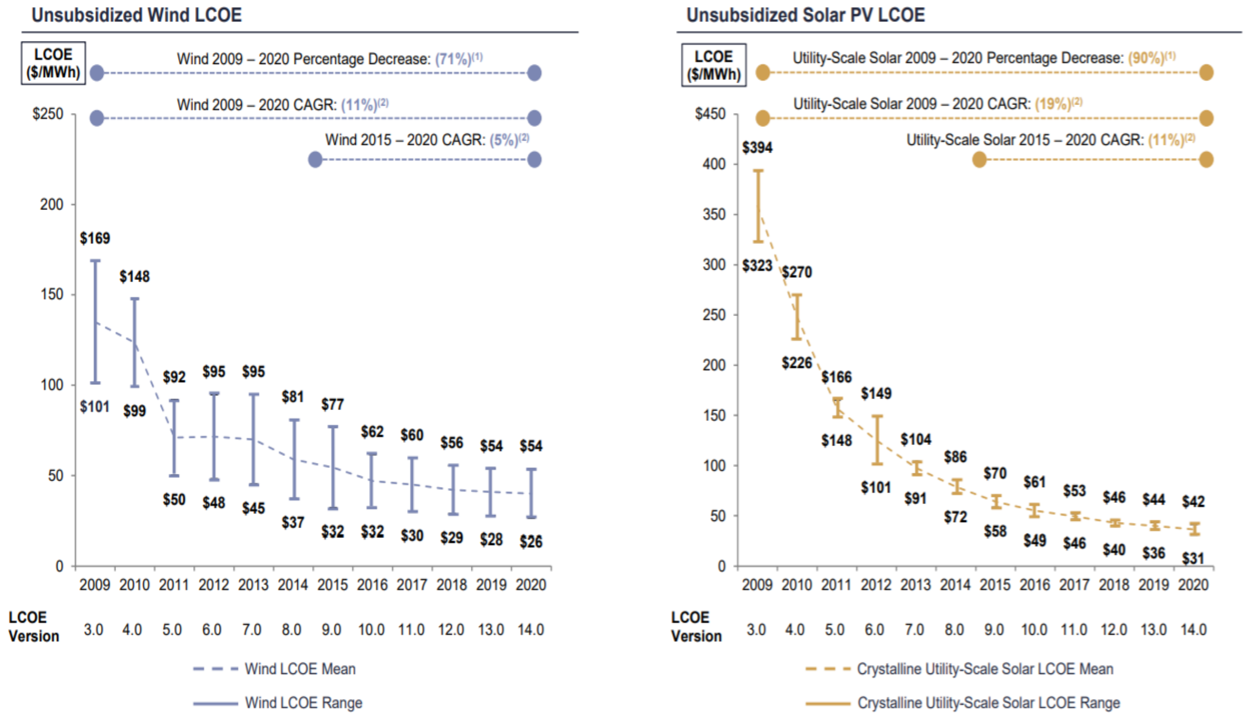
A. Existing coal-fired generating units will be become even less economic than they are today, because of economic and regulatory forces that will increase the costs of operation at coal units relative to other, cheaper types of generation and capacity. In addition, due to corporate trends and investor preferences beyond economics and legal constraints, the power sector is moving away from coal in response to widespread calls to reduce contributions to climate change. In the past five years, 48 GW of coal has retired in the United States, with an additional 2.7 GW scheduled to retire in 2021.[31]

**Q. What are the economic forces that affect the operation of existing coal units?**

A. The primary economic factor is the cost of clean generation technologies, which have fallen dramatically over the previous decade. On a levelized cost of energy (LCOE) basis, costs for wind are now 71 percent lower than the costs in 2009, with a compound annual rate of decline of 11 percent per year. Costs for solar are now 90 percent lower than in 2009, with a compound annual rate of decline of 19 percent per year. Those annual trends are shown below in Figure 10.

31 Energy Information Administration, *Nuclear and coal will account for majority of U.S. generating capacity retirements in 2021* (January 12, 2021), available at https://www.eia.gov/todayinenergy/detail.php?id=46436#:~:text=After%20substantial%20retirements%20of%20coal,of%20the%20U.S.%20coal%20fleet.

**Figure 10. Historic levelized cost of energy for wind and solar technologies**




*Source: Lazard, Levelized Cost of Energy Analysis 14.0 (2020), available at* https://www.lazard.com/media/451419/lazards-levelized-cost-of-energy-version-140.pdf

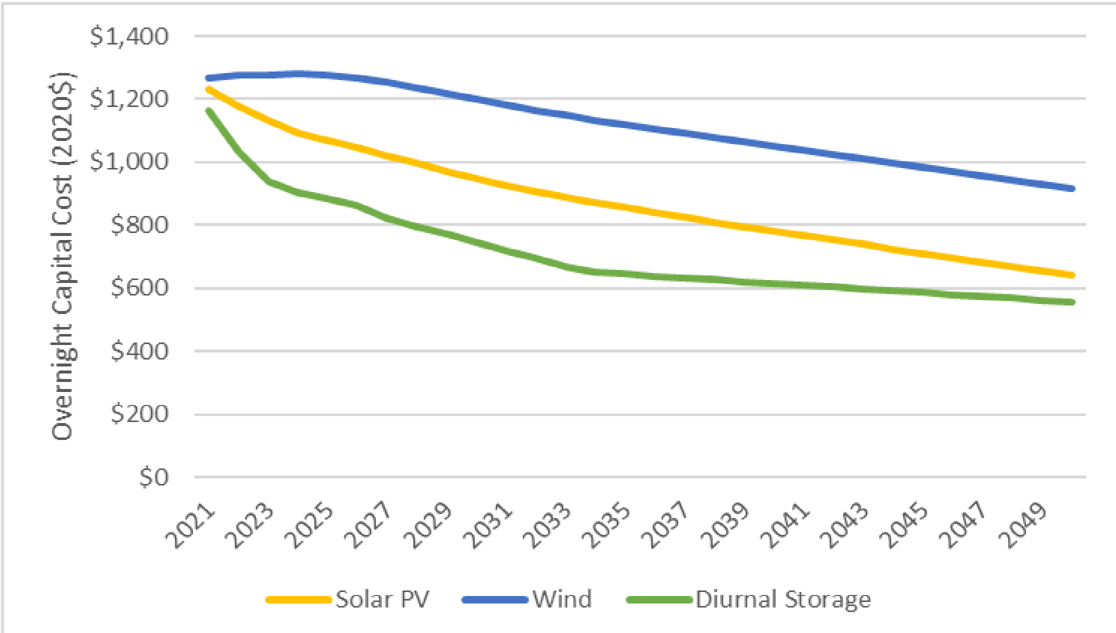
Battery storage technologies have experienced similar cost declines, but over a shorter period of time. Bloomberg New Energy Finance (BNEF) analyzed historical battery storage costs, finding that costs for lithium-ion batteries have fallen 76 percent between 2012 and the first half of 2019 and noting that these declines were the most striking of all observed energy technology cost trends.[32]

These three technologies—solar, wind, and storage—are predicted to continue to experience cost declines at varying rates. The US EIA's forecasts used in

32 HJ Mai, *Electricity costs from battery storage down 76 percent since 2012: BNEF*, UTILITY DIVE (March 26, 2019), available at: https://www.utilitydive.com/news/electricity-costs-from-battery-storage-down-76-since-2012-bnef/551337/.

developing AEO 2021 for solar PV, wind, and storage resources are shown below in Figure 11.

**Figure 11. Forecast of overnight capital costs for new solar, wind, and storage**




*Source:* *Energy Information Administration, Annual Energy Outlook (2021) at Table 55, available at:* https://www.eia.gov/outlooks/aeo/data/browser /#/?id=123-AEO2021&cases=ref2021&sourcekey=0

Given KPC's emphasis on inexpensive capacity in the form of new gas-fired combustion turbines as the primary resource selection in its own modeling,[33] battery storage costs warrant particular attention. The Synapse modeling uses KPC's values for firm capacity credit, with solar PV and wind receiving 40 percent and 12 percent, respectively, and battery storage resources given a higher amount of firm capacity of 80 percent. These firm capacity values, coupled with declining prices, make storage resources a cost-effective replacement resource for traditional peaking units. In fact, a 2018 report by GTM Research and Wood Mackenzie

33 Direct Testimony of Mark A. Becker at 18:21–18:28.

predicted that energy storage technologies will regularly compete head-to-head with new gas-fired peaking units by 2022, and that new gas peaking units will be rare by 2028.[34]

**Q. What are the regulatory forces that challenge the operation of existing coal units?**

A. One regulatory force is the increase to renewable portfolio standards (RPS) in neighboring states that also operate in the PJM market. The volume of zero-variable-cost resources on the grid in PJM will increase in future years as neighboring states increase their renewable energy targets, implement more stringent targets for carbon dioxide emissions reductions, or both. For example, in 2018, New Jersey increased its RPS to 50 percent by 2030.[35] In 2019, Maryland legislators passed a bill that also increases its RPS to 50 percent by 2030.[36] The District of Columbia increased its RPS to 100 percent renewable energy by 2040.[37] There are many other examples, including local/municipal clean energy pledges. The locational marginal price for energy will decline as a greater number of

34 Ravi Manghani, *Will Energy Storage Replace Peaker Plants?*, GREENTECH MEDIA (March 1, 2018), available at https://www.greentechmedia.com/webinars/webinar/will-energy-storage-replace-peaker-plants#gs.6JwDozs.

35 Energy Information Administration, *Today in energy: Updated renewable portfolio standards will lead to more renewable electricity generation* (2019), available at https://www.eia.gov/todayinenergy/detail.php?id=38492#:~:text=Under%20the%20previous%20target%2C%20the,35%25%20of%20sales%20by%202030.

36 Catherine Morehouse, *Maryland 50% RPS bill doubles offshore wind target, expands solar-carve out*, UTILITY DIVE (April 10, 2019), available at https://www.utilitydive.com/news/maryland-50-rps-bill-doubles-offshore-wind-target-expands-solar-carve-out/552421/.

37 Utility Dive, *DC eases path for renewable generators as it pursues 100% goal* (2019), available at https://www.utilitydive.com/news/dc-eases-path-for-renewable-generators-as-it-pursues-100-goal/548259/.

renewable generators come online, further lowering energy revenues earned by coal units.

**Q. Are there other relevant regulatory drivers?**

A. Yes, almost certainly, though we do not yet know what they will look like. President Biden has announced the goal of net-zero carbon dioxide emissions on the country's power grid by 2035. Policies are not yet in place that are explicitly intended to achieve this goal; however, it can be assumed that they will consist at least in part of a combination of incentives for zero-carbon energy and additional effective costs for fossil-fueled generators. Earlier this year, the U.S. Court of Appeals for the D.C. Circuit struck down President Trump's Affordable Clean Energy Rule, requiring the EPA to draft new regulations governing emissions of $CO_2$ from power plants. We can expect new regulations affecting the economics of coal plants from the EPA in the next four years.

Meanwhile, there have been different proposals put forth by members of the United States Congress to extend the production tax credit (PTC) and investment tax credit (ITC) for renewables and storage for a period of ten years. The proposals vary, but different provisions include an increased credit for resources cited in low-income areas, as well as the option for regulated utilities to opt out of tax normalization requirements.[38] Extensions of the PTC and ITC would lower the costs of replacement resources for KPC.

38 KPMG. *KPMG Report: Outlook for What's Ahead for Energy Tax Incentives (Updated)* (2021), available at https://assets.kpmg/content/dam/kpmg/us/pdf/2021/05/21197.pdf and enclosed as Exhibit RW-6.

**Q. Are there additional forces at play, beyond economic and regulatory levers?**

A. Concerns about climate change from consumers and investors, in addition to the scientific community, are likely only to continue to increase. In response to such concerns and popular pressure, corporate pledges to reduce carbon emissions are likely only to strengthen over time. As I noted above, AEP itself has committed to net-zero $CO_2$ emissions by 2050 and has an interim goal to cut emissions 80 percent from 2000 levels by 2030, while adding more than 10,000 MW of regulated wind and solar.[39] Both the general trend and AEP's current specific goals support the retirement of Mitchell in 2028. Similarly, they only enhance the risk, if KPC were to invest in the ELG capital projects, that Mitchell would become a stranded asset before 2040.

## 7. CONCLUSIONS AND RECOMMENDATIONS

**Q. Please summarize your conclusions.**

A. My independent modeling demonstrates that it is uneconomic, and not in the best interest of ratepayers, for KPC to invest in both CCR and ELG capital projects at Mitchell plant in order to continue operating the plant as coal-fired through 2040. The least-cost option, rather, is to invest in only the CCR projects (to keep Mitchell operating past 2023), but to forgo the ELG projects and to retire the coal units by the end of 2028. According to my analysis, retirement in 2028 results in ratepayer

39 American Electric Power, *Clean Energy Future*, https://www.aep.com/about/ourstory/cleanenergy#:~:text=Achieving%20net%20zero%20carbon%20dioxide,billion%20in%20renewables%20through%202025 (last accessed April 29, 2021).

savings of $194 million under a Base with No Carbon commodity price forecast, or $341 million when an effective carbon price is included. Again, that does not consider the substantial risk that additional non-carbon regulations could be promulgated over the next twenty years and further diminish the cost-competitiveness of coal-fired power plants.

**Q. Please summarize your recommendations.**

A. Based on my findings, I recommend that the Commission grant a CPCN for the CCR compliance projects at the Mitchell plant, but not for the ELG projects.

**Q. Does this conclude your pre-filed direct testimony?**

A. Yes.

# LIST OF EXHIBITS

TO THE DIRECT TESTIMONY OF RACHEL WILSON

ON BEHALF OF SIERRA CLUB

| Exhibit Number | Description of Exhibit | Protected Status |
|---|---|---|
| Exhibit RW-1 | Resume of Rachel S. Wilson | Non-Confidential |
| Exhibit RW-2 | KPC Response to KIUC-AG RFI 1-14, Confidential Attachment 2 (March 26, 2021) | Confidential |
| Exhibit RW-3 | KPC Response to Sierra Club RFI 2-5, Attachment 1 (May 5, 2021) | Non-Confidential |
| Exhibit RW-4 | KPC Response to Sierra Club RFI 2-6, Attachment 1 (May 5, 2021) | Non-Confidential |
| Exhibit RW-5 | KPC Response to Sierra Club RFI 2-7, Attachment 1 (May 5, 2021) | Non-Confidential |
| Exhibit RW-6 | KPMG. *KPMG Report: Outlook for What's Ahead for Energy Tax Incentives (Updated)* (2021), *available at* https://assets.kpmg/content/dam/kpmg/us/pdf/2021/05/21197.pdf | Non-Confidential |

# EXHIBIT RW-1

Resume of Rachel S. Wilson

## **Rachel Wilson,** Principal Associate

Synapse Energy Economics I 485 Massachusetts Avenue, Suite 3 I Cambridge, MA 02139 I 617-453-7044
rwilson@synapse-energy.com

## PROFESSIONAL EXPERIENCE

**Synapse Energy Economics Inc.**, Cambridge, MA. *Principal Associate*, April 2019 – present, *Senior Associate*, 2013 – 2019, *Associate*, 2010 – 2013, *Research Associate*, 2008 – 2010.

Provides consulting services and expert analysis on a wide range of issues relating to the electricity and natural gas sectors including: integrated resource planning; federal and state clean air policies; emissions from electricity generation; electric system dispatch; and environmental compliance technologies, strategies, and costs. Uses optimization and electricity dispatch models, including Strategist, PLEXOS, EnCompass, PROMOD, and PROSYM/Market Analytics to conduct analyses of utility service territories and regional energy markets.

**Analysis Group, Inc.**, Boston, MA.

*Associate*, 2007 – 2008, *Senior Analyst Intern*, 2006 – 2007.

Provided litigation support and performed data analysis on various topics in the electric sector, including tradeable emissions permitting, coal production and contractual royalties, and utility financing and rate structures. Contributed to policy research, reports, and presentations relating to domestic and international cap-and-trade systems and linkage of international tradeable permit systems. Managed analysts' work processes and evaluated work products.

**Yale Center for Environmental Law and Policy**, New Haven, CT. *Research Assistant*, 2005 – 2007.

Gathered and managed data for the Environmental Performance Index, presented at the 2006 World Economic Forum. Interpreted statistical output, wrote critical analyses of results, and edited report drafts. Member of the team that produced *Green to Gold*, an award-winning book on corporate environmental management and strategy. Managed data, conducted research, and implemented marketing strategy.

**Marsh Risk and Insurance Services, Inc.**, Los Angeles, CA. *Risk Analyst*, Casualty Department, 2003 – 2005.

Evaluated Fortune 500 clients' risk management programs/requirements and formulated strategic plans and recommendations for customized risk solutions. Supported the placement of $2 million in insurance premiums in the first year and $3 million in the second year. Utilized quantitative models to create loss forecasts, cash flow analyses and benchmarking reports. Completed a year-long Graduate Training Program in risk management; ranked #1 in the western region of the US and shared #1 national ranking in a class of 200 young professionals.

## EDUCATION

**Yale School of Forestry & Environmental Studies**, New Haven, CT
Master of Environmental Management, concentration in Law, Economics, and Policy with a focus on energy issues and markets, 2007

**Claremont McKenna College**, Claremont, California
Bachelor of Arts in Environment, Economics, Politics (EEP), 2003. *Cum laude* and EEP departmental honors.

**School for International Training**, Quito, Ecuador
Semester abroad studying Comparative Ecology. Microfinance Intern – Viviendas del Hogar de Cristo in Guayaquil, Ecuador, Spring 2002.

## ADDITIONAL SKILLS AND ACCOMPLISHMENTS

- Microsoft Office Suite, Lexis-Nexis, Platts Energy Database, Strategist, PROMOD, PROSYM/Market Analytics, EnCompass, and PLEXOS, some SAS and STATA.
- Competent in oral and written Spanish.
- Hold the Associate in Risk Management (ARM) professional designation.

## PUBLICATIONS

Bhandari, D., M. Chang, P. Eash-Gates, J. Frost, S. Letendre, J. Litynski, C. Roberto, A. Takasugi, J. Tabernero. R. Wilson. 2021. *Exelon Illinois Nuclear Fleet Audit*. Synapse Energy Economics for Illinois Environmental Protection Agency.

Wilson, R., E. Camp, N. Garner, T. Vitolo. 2020. *Obsolete Atlantic Coast Pipeline Has Nothing to Deliver: An examination of the dramatic shifts in the energy, policy, and economic landscape in Virginia and North Carolina since 2017 shows there is little need for new gas generation.* Synapse Energy Economics for Southern Environmental Law Center.

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Wilson, R., T. Comings, E. A. Stanton. 2015. *Analysis of the Tongue River Railroad Draft Environmental Impact Statement.* Synapse Energy Economics for Sierra Club and Earthjustice.

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Luckow, P., E. A. Stanton, S. Fields, B. Biewald, S. Jackson, J. Fisher, R. Wilson. 2015. *2015 Carbon Dioxide Price Forecast.* Synapse Energy Economics.

Stanton, E. A., P. Knight, J. Daniel, B. Fagan, D. Hurley, J. Kallay, E. Karaca, G. Keith, E. Malone, W. Ong, P. Peterson, L. Silvestrini, K. Takahashi, R. Wilson. 2015. *Massachusetts Low Gas Demand Analysis: Final Report.* Synapse Energy Economics for the Massachusetts Department of Energy Resources.

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Fagan, R., P. Luckow, D. White, R. Wilson. 2013. *The Net Benefits of Increased Wind Power in PJM.* Synapse Energy Economics for Energy Future Coalition.

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Fagan, R., M. Chang, P. Knight, M. Schultz, T. Comings, E. Hausman, R. Wilson. 2012. *The Potential Rate Effects of Wind Energy and Transmission in the Midwest ISO Region*. Synapse Energy Economics for Energy Future Coalition.

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Wilson, R. 2011. *Comments Regarding MidAmerican Energy Company Filing on Coal-Fired Generation in Iowa*. Synapse Energy Economics for the Iowa Office of the Consumer Advocate.

Hausman, E., T. Comings, R. Wilson, and D. White. 2011. *Electricity Scenario Analysis for the Vermont Comprehensive Energy Plan 2011*. Synapse Energy Economics for Vermont Department of Public Service.

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Fisher, J., C. James, L. Johnston, D. Schlissel, R. Wilson. 2009. *Energy Future: A Green Alternative for Michigan*. Synapse Energy Economics for Natural Resources Defense Council (NRDC) and Energy Foundation.

Schlissel, D., R. Wilson, L. Johnston, D. White. 2009. *An Assessment of Santee Cooper's 2008 Resource Planning*. Synapse Energy Economics for Rockefeller Family Fund.

Schlissel, D., A. Smith, R. Wilson. 2008. *Coal-Fired Power Plant Construction Costs*. Synapse Energy Economics.

## TESTIMONY

**West Virginia Public Service Commission (Case No. 20-1040-E-CN):** Direct testimony of Rachel Wilson evaluating the application of Appalachian Power Company and Wheeling Power Company for approval of a rate adjustment clause for capital investments and operations and maintenance expenses to comply with the federal Coal Combustion Residuals and Effluent Limitation Guidelines regulations in lieu of retirement of the Amos, Mountaineer, and Mitchell coal plants. On behalf of Sierra Club. May 6, 2021.

**Washington Utilities and Transportation Commission (Docket Nos. UE-200900 and UG-200901):** Direct testimony of Rachel Wilson evaluating Avista's treatment of the costs that it plans to incur for both integration with the Western Energy Imbalance Market (EIM) and ongoing operational support. On behalf of the Public Counsel Unit of the Washington Attorney General's Office. April 21, 2021.

**South Carolina Public Service Commission (Docket Nos. 2019-224-E and 2019-225-E):** Surrebuttal testimony of Rachel S. Wilson providing alternative resource modeling in the Duke Energy Carolinas and Duke Energy Progress Integrated Resource Planning dockets. On behalf of Carolinas Clean Energy Business Association, Natural Resources Defense Council, Sierra Club, Southern Alliance for Clean Energy, South Carolina Coastal Conservation League, and Upstate Forever. April 15, 2021.

**Virginia State Corporation Commission (Case No. PUR-2020-00258):** Direct testimony of Rachel Wilson evaluating the application of Appalachian Power Company for approval of a rate adjustment clause for capital investments and operations and maintenance expenses to comply with the federal Coal Combustion Residuals and Effluent Limitation Guidelines regulations in lieu of retirement of the Amos and Mountaineer. On behalf of the Sierra Club. April 9, 2021.

**West Virginia Public Service Commission (Case No. 20-0065-E-ENEC):** Direct testimony of Rachel Wilson evaluating coal unit commitment decisions by Monongahela Power Company and the impact on ratepayers. On behalf of Sierra Club. November 16, 2020.

**Virginia State Corporation Commission (Case No. PUR-2020-00035):** Direct testimony of Rachel Wilson evaluating Dominion's 2020 Integrated Resource Plan and providing independent capacity optimization modeling. On behalf of the Sierra Club. September 15, 2020.

**Virginia State Corporation Commission (Case No. PUR-2020-00015):** Direct testimony of Rachel Wilson examining the economics of the coal units owned by Appalachian Power Company as part of the rate case. On behalf of the Sierra Club. July 30, 2020.

**North Carolina Utilities Commission (Docket No. E-2, SUB 1219):** Direct testimony of Rachel Wilson examining the economics of the coal units owned by Duke Energy Progress as part of the rate case. On behalf of the Sierra Club. April 13, 2020.

**North Carolina Utilities Commission (Docket No. E-2, SUB 1219):** Direct testimony of Rachel Wilson examining the economics of the coal units owned by Duke Energy Carolinas as part of the rate case. On behalf of the Sierra Club. February 25, 2020.

**North Carolina Utilities Commission (Docket No. EMP-105, SUB 0):** Rebuttal testimony of Rachel Wilson evaluating the application of Friesian Holdings, LLC for a Certificate of Public Convenience and Necessity. On behalf of Friesian Holdings, LLC. December 12, 2019.

**Alabama Public Service Commission (Docket No. 32953):** Direct testimony of Rachel Wilson regarding Alabama Power Company's petition for a Certificate of Convenience and Necessity. On behalf of the Sierra Club. December 4, 2019.

**North Carolina Utilities Commission (Docket No. EMP-105, SUB 0):** Direct testimony of Rachel Wilson evaluating the application of Friesian Holdings, LLC for a Certificate of Public Convenience and Necessity. On behalf of Friesian Holdings, LLC. November 26, 2019.

**Georgia Public Service Commission (Docket No. 42516)**: Direct testimony of Rachel Wilson regarding coal ash spending in Georgia Power's 2019 Rate Case. On behalf of the Sierra Club. October 17, 2019.

**Mississippi Public Service Commission (Docket No. 2019-UA-116):** Direct testimony of Rachel Wilson regarding Mississippi Power Company's petition to the Mississippi Public Service Commission for a Certification of Public Convenience and Necessity for ratepayer-funded investments required to meet Coal Combustion Residuals regulations at the Victor J. Daniel Electric Generating Facility. On behalf of the Sierra Club. October 16, 2019.

**Georgia Public Service Commission (Docket No. 42310 & 42311):** Direct testimony of Rachel Wilson regarding various components of Georgia Power's 2019 Integrated Resource Plan. On behalf of the Sierra Club. April 25, 2019.

**Washington Utilities and Transportation Commission (Dockets UE-170485 & UG-170486):** Response testimony regarding Avista Corporation's production cost modeling. On behalf of Public Counsel Unit of the Washington Attorney General's Office. October 27, 2017.

**Texas Public Utilities Commission (SOAH Docket No. 473-17-1764, PUC Docket No. 46449):** Cross-rebuttal testimony evaluating Southwestern Electric Power Company's application for authority to change rates to recover the costs of investments in pollution control equipment. On behalf of Sierra Club and Dr. Lawrence Brough. May 19, 2017.

**Texas Public Utilities Commission (SOAH Docket No. 473-17-1764, PUC Docket No. 46449):** Direct testimony evaluating Southwestern Electric Power Company's application for authority to change rates to recover the costs of investments in pollution control equipment. On behalf of Sierra Club and Dr. Lawrence Brough. April 25, 2017.

**Virginia State Corporation Commission (Case No. PUE-2015-00075):** Direct testimony evaluating the petition for a Certificate of Public Convenience and Necessity filed by Virginia Electric and Power Company to construct and operate the Greensville County Power Station and to increase electric rates to recover the cost of the project. On behalf of Environmental Respondents. November 5, 2015.

**Missouri Public Service Commission (Case No. ER-2014-0370):** Direct and surrebuttal testimony evaluating the prudence of environmental retrofits at Kansas City Power & Light Company's La Cygne Generating Station. On behalf of Sierra Club. April 2, 2015 and June 5, 2015.

**Oklahoma Corporation Commission (Cause No. PUD 201400229):** Direct testimony evaluating the modeling of Oklahoma Gas & Electric supporting its request for approval and cost recovery of a Clean Air Act compliance plan and Mustang modernization, and presenting results of independent Gentrader modeling analysis. On behalf of Sierra Club. December 16, 2014.

**Michigan Public Service Commission (Case No. U-17087)**: Direct testimony before the Commission discussing Strategist modeling relating to the application of Consumers Energy Company for the authority to increase its rates for the generation and distribution of electricity. On behalf of the Michigan Environmental Council and Natural Resources Defense Council. February 21, 2013.

**Indiana Utility Regulatory Commission (Cause No. 44217)**: Direct testimony before the Commission discussing PROSYM/Market Analytics modeling relating to the application of Duke Energy Indiana for Certificates of Public Convenience and Necessity. On behalf of Citizens Action Coalition, Sierra Club, Save the Valley, and Valley Watch. November 29, 2012.

**Kentucky Public Service Commission (Case No. 2012-00063)**: Direct testimony before the Commission discussing upcoming environmental regulations and electric system modeling relating to the application of Big Rivers Electric Corporation for a Certificate of Public Convenience and Necessity and for approval of its 2012 environmental compliance plan. On behalf of Sierra Club. July 23, 2012.

**Kentucky Public Service Commission (Case No. 2011-00401)**: Direct testimony before the Commission discussing STRATEGIST modeling relating to the application of Kentucky Power Company for a Certificate of Public Convenience and Necessity, and for approval of its 2011 environmental compliance plan and amended environmental cost recovery surcharge. On behalf of Sierra Club. March 12, 2012.

**Kentucky Public Service Commission (Case No. 2011-00161 and Case No. 2011-00162)**: Direct testimony before the Commission discussing STRATEGIST modeling relating to the applications of Kentucky Utilities Company, and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity, and approval of its 2011 compliance plan for recovery by environmental surcharge. On behalf of Sierra Club and Natural Resources Defense Council (NRDC). September 16, 2011.

**Minnesota Public Utilities Commission (OAH Docket No. 8-2500-22094-2 and MPUC Docket No. E-017/M-10-1082)**: Rebuttal testimony before the Commission describing STRATEGIST modeling performed in the docket considering Otter Tail Power's application for an Advanced Determination of Prudence for BART retrofits at its Big Stone plant. On behalf of Izaak Walton League of America, Fresh Energy, Sierra Club, and Minnesota Center for Environmental Advocacy. September 7, 2011.

*Resume updated May 2021*

# EXHIBIT RW-2

KPC Response to KIUC-AG RFI 1-14, Confidential Attachment 2 (March 26, 2021)

***CONFIDENTIAL***

Kentucky Power Company
KPSC Case No. 2021-00004
KIUC-AG's First Set of Data Requests
Dated March 10, 2021

**DATA REQUEST**

**KIUC-AG_1_14** Provide the Mitchell Generating Station's Net Capacity Factor over the past five years. Compare that net capacity factor to the modeled or assumed factors of other potential replacement resources.

**RESPONSE**

Please see KPCO_R_KIUC_AG_1_14_Attachment1 for the net capacity factors for the last five years and KPCO_R_KIUC_AG_1_14_ConfidentialAttachment2 for the forecasted capacity factors.

Capacity factors are dependent on market energy and gas prices for dispatchable resource types such as coal or gas fired units. Capacity factor alone is not a good indicator of the overall value of a given resource. The most likely replacement resources for Mitchell would be some combination of solar, wind, or gas-fired resources. Generally speaking, solar resources in PJM experience capacity factors of around 20-25 percent. Wind resource capacity factors vary widely by location, but generally in areas of PJM suitable for wind development wind achieves between 30 percent and 40 percent capacity factors. Simple cycle gas fired peaking resources typically operate at under 10 percent capacity factors. Combined cycle gas-fired units experience capacity factors as high as 70-90 percent when gas prices are low as they have been in recent periods. The capacity factor is lower when gas prices are higher.

Witness: Mark A. Becker

Case 1 Base with Carbon Fundamental Scenario

| Description | Year | Mitchell 1 | Mitchell 2 |
|---|---|---|---|
| Capacity Factor | 2021 | [redacted] | |
| Capacity Factor | 2022 | | |
| Capacity Factor | 2023 | | |
| Capacity Factor | 2024 | | |
| Capacity Factor | 2025 | | |
| Capacity Factor | 2026 | | |
| Capacity Factor | 2027 | | |
| Capacity Factor | 2028 | | |
| Capacity Factor | 2029 | | |
| Capacity Factor | 2030 | | |
| Capacity Factor | 2031 | | |
| Capacity Factor | 2032 | | |
| Capacity Factor | 2033 | | |
| Capacity Factor | 2034 | | |
| Capacity Factor | 2035 | | |
| Capacity Factor | 2036 | | |
| Capacity Factor | 2037 | | |
| Capacity Factor | 2038 | | |
| Capacity Factor | 2039 | | |
| Capacity Factor | 2040 | | |

Case 1 Base No Carbon Fundamental Scenario

| Description | Year | Mitchell 1 | Mitchell 2 |
|---|---|---|---|
| Capacity Factor | 2021 | [redacted] | [redacted] |
| Capacity Factor | 2022 | [redacted] | [redacted] |
| Capacity Factor | 2023 | [redacted] | [redacted] |
| Capacity Factor | 2024 | [redacted] | [redacted] |
| Capacity Factor | 2025 | [redacted] | [redacted] |
| Capacity Factor | 2026 | [redacted] | [redacted] |
| Capacity Factor | 2027 | [redacted] | [redacted] |
| Capacity Factor | 2028 | [redacted] | [redacted] |
| Capacity Factor | 2029 | [redacted] | [redacted] |
| Capacity Factor | 2030 | [redacted] | [redacted] |
| Capacity Factor | 2031 | [redacted] | [redacted] |
| Capacity Factor | 2032 | [redacted] | [redacted] |
| Capacity Factor | 2033 | [redacted] | [redacted] |
| Capacity Factor | 2034 | [redacted] | [redacted] |
| Capacity Factor | 2035 | [redacted] | [redacted] |
| Capacity Factor | 2036 | [redacted] | [redacted] |
| Capacity Factor | 2037 | [redacted] | [redacted] |
| Capacity Factor | 2038 | [redacted] | [redacted] |
| Capacity Factor | 2039 | [redacted] | [redacted] |
| Capacity Factor | 2040 | [redacted] | [redacted] |

Case 1 Low No Carbon Fundamental Scenario

| Description | Year | Mitchell 1 | Mitchell 2 |
|---|---|---|---|
| Capacity Factor | 2021 | [redacted] | [redacted] |
| Capacity Factor | 2022 | [redacted] | [redacted] |
| Capacity Factor | 2023 | [redacted] | [redacted] |
| Capacity Factor | 2024 | [redacted] | [redacted] |
| Capacity Factor | 2025 | [redacted] | [redacted] |
| Capacity Factor | 2026 | [redacted] | [redacted] |
| Capacity Factor | 2027 | [redacted] | [redacted] |
| Capacity Factor | 2028 | [redacted] | [redacted] |
| Capacity Factor | 2029 | [redacted] | [redacted] |
| Capacity Factor | 2030 | [redacted] | [redacted] |
| Capacity Factor | 2031 | [redacted] | [redacted] |
| Capacity Factor | 2032 | [redacted] | [redacted] |
| Capacity Factor | 2033 | [redacted] | [redacted] |
| Capacity Factor | 2034 | [redacted] | [redacted] |
| Capacity Factor | 2035 | [redacted] | [redacted] |
| Capacity Factor | 2036 | [redacted] | [redacted] |
| Capacity Factor | 2037 | [redacted] | [redacted] |
| Capacity Factor | 2038 | [redacted] | [redacted] |
| Capacity Factor | 2039 | [redacted] | [redacted] |
| Capacity Factor | 2040 | [redacted] | [redacted] |

# EXHIBIT RW-3

KPC Response to Sierra Club RFI 2-5, Attachment 1 (May 5, 2021)

Kentucky Power Company
KPSC Case No. 2021-00004
Sierra Club's Second Set of Data Requests
Dated April 20, 2021

**DATA REQUEST**

**SC 2_5** For each solar resource offered to the PLEXOS model as part of the capacity optimization, for each of the years that resource is available as a resource option, provide the following exactly as input into the PLEXOS model:

a. The capital cost of that resource.

b. The fixed O&M associated with that resource, and the source of this assumption.

c. If neither (a) nor (b) are applicable, provide the levelized cost of that resource in $/MWh.

d. If none of the above are applicable, describe how capital and operating costs of each solar resource are input into PLEXOS and provide those data.

e. All workpapers that derive the cost of the resource, as input into PLEXOS, documenting original source data, with all cells unlocked and formulae intact

f. Any and all annual limits for additions of these resources.

g. Any and all cumulative limits for additions of these resources.

**RESPONSE**

a-e. Please see KPCO_R_SC_ 2_005_ Attachment1 for the PLEXOS inputs for the 150 MW utility-owned and PPA solar options. The capital cost input, which includes return on rate base, depreciation expense, and income taxes net of investment tax credits is provided in Column B of the Tier 2 Build Cost tab. The process used to compute the PLEXOS input value needed to produce levelized fixed carrying costs on invested capital that correspond to the expected levelized costs of electricity is shown on that tab. The Fixed O&M input is shown in Column Q of the Solar Prices tab.

f and g. 150 MW per year and 450 MW cumulative limits were applied to solar capacity additions.

Witness: Mark A. Becker

# Plexos Addition of 50 MW Utility Tier 2 Solar Capital Cost Calculation

| | Plexos Input Build Cost ($/kW) | Units Built | Maximum Capacity (MW) | Build Cost ($000) | WACC (%) | Inflation Rate (%) | Economic Life (Years) | Tax Rate (%) | Depreciation Method | SLD Method Annuity Calculation ($000) | Levelized Cost Annuity ($000) | SLD vs Levelized Annuity ($000) | SLD vs Levelized Annuity (%) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2022 | 1182 | 1 | 150.00 | 177,283 | 7.070% | 2.500% | 30 | 26.00% | SLD | 13,168 | 13,168 | 0 | 0 |
| 2023 | 1098 | 1 | 150.00 | 164,769 | 7.070% | 2.500% | 30 | 26.00% | SLD | 12,239 | 12,239 | 0 | 0 |
| 2024 | 1046 | 1 | 150.00 | 156,946 | 7.070% | 2.500% | 30 | 26.00% | SLD | 11,658 | 11,658 | 0 | 0 |
| 2025 | 1139 | 1 | 150.00 | 170,912 | 7.070% | 2.500% | 30 | 26.00% | SLD | 12,695 | 12,695 | 0 | 0 |
| 2026 | 1173 | 1 | 150.00 | 176,004 | 7.070% | 2.500% | 30 | 26.00% | SLD | 13,073 | 13,073 | 0 | 0 |
| 2027 | 1165 | 1 | 150.00 | 174,787 | 7.070% | 2.500% | 30 | 26.00% | SLD | 12,983 | 12,983 | 0 | 0 |
| 2028 | 1166 | 1 | 150.00 | 174,924 | 7.070% | 2.500% | 30 | 26.00% | SLD | 12,993 | 12,993 | 0 | 0 |
| 2029 | 1163 | 1 | 150.00 | 174,399 | 7.070% | 2.500% | 30 | 26.00% | SLD | 12,954 | 12,954 | 0 | 0 |
| 2030 | 1161 | 1 | 150.00 | 174,179 | 7.070% | 2.500% | 30 | 26.00% | SLD | 12,938 | 12,938 | 0 | 0 |
| 2031 | 1161 | 1 | 150.00 | 174,102 | 7.070% | 2.500% | 30 | 26.00% | SLD | 12,932 | 12,932 | 0 | 0 |
| 2032 | 1159 | 1 | 150.00 | 173,904 | 7.070% | 2.500% | 30 | 26.00% | SLD | 12,917 | 12,917 | 0 | 0 |
| 2033 | 1159 | 1 | 150.00 | 173,802 | 7.070% | 2.500% | 30 | 26.00% | SLD | 12,910 | 12,910 | 0 | 0 |
| 2034 | 1159 | 1 | 150.00 | 173,907 | 7.070% | 2.500% | 30 | 26.00% | SLD | 12,917 | 12,917 | 0 | 0 |
| 2035 | 1160 | 1 | 150.00 | 174,006 | 7.070% | 2.500% | 30 | 26.00% | SLD | 12,925 | 12,925 | 0 | 0 |
| 2036 | 1160 | 1 | 150.00 | 174,012 | 7.070% | 2.500% | 30 | 26.00% | SLD | 12,925 | 12,925 | 0 | 0 |
| 2037 | 1159 | 1 | 150.00 | 173,881 | 7.070% | 2.500% | 30 | 26.00% | SLD | 12,916 | 12,916 | 0 | 0 |
| 2038 | 1157 | 1 | 150.00 | 173,618 | 7.070% | 2.500% | 30 | 26.00% | SLD | 12,896 | 12,896 | 0 | 0 |
| 2039 | 1157 | 1 | 150.00 | 173,493 | 7.070% | 2.500% | 30 | 26.00% | SLD | 12,887 | 12,887 | 0 | 0 |
| 2040 | 1156 | 1 | 150.00 | 173,327 | 7.070% | 2.500% | 30 | 26.00% | SLD | 12,874 | 12,874 | 0 | 0 |
| 2041 | 1156 | 1 | 150.00 | 173,341 | 7.070% | 2.500% | 30 | 26.00% | SLD | 12,875 | 12,875 | 0 | 0 |
| 2042 | 1156 | 1 | 150.00 | 173,423 | 7.070% | 2.500% | 30 | 26.00% | SLD | 12,882 | 12,882 | 0 | 0 |
| 2043 | 1158 | 1 | 150.00 | 173,636 | 7.070% | 2.500% | 30 | 26.00% | SLD | 12,897 | 12,897 | 0 | 0 |
| 2044 | 1158 | 1 | 150.00 | 173,744 | 7.070% | 2.500% | 30 | 26.00% | SLD | 12,905 | 12,905 | 0 | 0 |
| 2045 | 1159 | 1 | 150.00 | 173,894 | 7.070% | 2.500% | 30 | 26.00% | SLD | 12,916 | 12,916 | 0 | 0 |
| 2046 | 1160 | 1 | 150.00 | 173,941 | 7.070% | 2.500% | 30 | 26.00% | SLD | 12,920 | 12,920 | 0 | 0 |
| 2047 | 1159 | 1 | 150.00 | 173,914 | 7.070% | 2.500% | 30 | 26.00% | SLD | 12,918 | 12,918 | 0 | 0 |
| 2048 | 1158 | 1 | 150.00 | 173,765 | 7.070% | 2.500% | 30 | 26.00% | SLD | 12,907 | 12,907 | 0 | 0 |
| 2049 | 1159 | 1 | 150.00 | 173,805 | 7.070% | 2.500% | 30 | 26.00% | SLD | 12,910 | 12,910 | 0 | 0 |
| 2050 | 1158 | 1 | 150.00 | 173,731 | 7.070% | 2.500% | 30 | 26.00% | SLD | 12,904 | 12,904 | 0 | 0 |

| | |
|---|---|
| Real Annuity Factor = | 12.322 |
| Nominal Annuity Factor = | 9.776 |
| SLD Factor = | 0.074278159 |

2020 KPCo CCR/ELG
Solar Alternative Pricing

| | | Column L | | | Column I | FO&M Charge | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Annual Levelized Capital Cost ($/MWh) | Annual Levelized Cost ($000) | | **$/kW** | Plexos $/KW-Yr | Input FOM | | | |
| COD EOY | Modeling YR | **EIA** | EIA | | FOM | | | FO&M Cos | Max Capacity (MW) | |
| 2021 | 2022 | $45.28 | 13,168 | | $23.74 | $32.08 | | 3563.1 | 150 | $0.01 |
| 2022 | 2023 | $42.09 | 12,239 | 0.93 | $23.81 | $32.18 | | 3574.2 | 150 | $0.02 |
| 2023 | 2024 | $40.09 | 11,658 | 0.95 | $24.01 | $32.44 | | 3606.253 | 150 | $0.03 |
| 2024 | 2025 | $43.66 | 12,695 | 1.09 | $24.25 | $32.78 | | 3640.8 | 150 | $0.02 |
| 2025 | 2026 | $44.96 | 13,073 | 1.03 | $24.55 | $33.18 | | 3685.2 | 150 | $0.02 |
| 2026 | 2027 | $44.65 | 12,983 | 0.99 | $24.93 | $33.68 | | 3740.7 | 150 | $0.01 |
| 2027 | 2028 | $44.68 | 12,993 | 1.00 | $25.33 | $34.23 | | 3806.601 | 150 | $0.05 |
| 2028 | 2029 | $44.55 | 12,954 | 1.00 | $25.73 | $34.76 | | 3862.8 | 150 | $0.03 |
| 2029 | 2030 | $44.49 | 12,938 | 1.00 | $26.13 | $35.31 | | 3918.3 | 150 | -$0.01 |
| 2030 | 2031 | $44.47 | 12,932 | 1.00 | $26.54 | $35.86 | | 3984.9 | 150 | $0.03 |
| 2031 | 2032 | $44.42 | 12,917 | 1.00 | $26.95 | $36.41 | | 4051.47 | 150 | $0.06 |
| 2032 | 2033 | $44.40 | 12,910 | 1.00 | $27.36 | $36.97 | | 4107 | 150 | $0.02 |
| 2033 | 2034 | $44.42 | 12,917 | 1.00 | $27.78 | $37.54 | | 4162.5 | 150 | -$0.03 |
| 2034 | 2035 | $44.45 | 12,925 | 1.00 | $28.21 | $38.12 | | 4229.1 | 150 | -$0.01 |
| 2035 | 2036 | $44.45 | 12,925 | 1.00 | $28.64 | $38.70 | | 4307.469 | 150 | $0.08 |
| 2036 | 2037 | $44.42 | 12,916 | 1.00 | $29.07 | $39.28 | | 4362.3 | 150 | $0.01 |
| 2037 | 2038 | $44.35 | 12,896 | 1.00 | $29.51 | $39.88 | | 4428.9 | 150 | $0.02 |
| 2038 | 2039 | $44.32 | 12,887 | 1.00 | $29.96 | $40.48 | | 4495.5 | 150 | $0.01 |
| 2039 | 2040 | $44.27 | 12,874 | 1.00 | $30.41 | $41.09 | | 4574.599 | 150 | $0.09 |
| 2040 | 2041 | $44.28 | 12,875 | 1.00 | $30.87 | $41.72 | | 4628.7 | 150 | -$0.01 |
| 2041 | 2042 | $44.30 | 12,882 | 1.00 | $31.34 | $42.35 | | 4695.3 | 150 | -$0.03 |
| 2042 | 2043 | $44.35 | 12,897 | 1.00 | $31.81 | $42.99 | | 4773 | 150 | $0.01 |
| 2043 | 2044 | $44.38 | 12,905 | 1.00 | $32.28 | $43.62 | | 4852.859 | 150 | $0.07 |
| 2044 | 2045 | $44.42 | 12,916 | 1.00 | $32.76 | $44.27 | | 4917.3 | 150 | $0.02 |
| 2045 | 2046 | $44.43 | 12,920 | 1.00 | $33.23 | $44.91 | | 4983.9 | 150 | -$0.01 |
| 2046 | 2047 | $44.42 | 12,918 | 1.00 | $33.71 | $45.56 | | 5061.6 | 150 | $0.03 |
| 2047 | 2048 | $44.39 | 12,907 | 1.00 | $34.19 | $46.20 | | 5142.25 | 150 | $0.09 |
| 2048 | 2049 | $44.40 | 12,910 | 1.00 | $34.67 | $46.85 | | 5205.9 | 150 | $0.03 |
| 2049 | 2050 | $44.38 | 12,904 | 1.00 | $35.15 | $47.51 | | 5272.5 | 150 | $0.00 |
| 2050 | 2051 | $44.32 | 12,888 | 1.00 | $35.64 | $48.16 | | | | |

| | Generic Solar |
|---|---|
| | **EIA** |
| Annual Energy (GWh) | 290.7882 |
| Capacity (MW) | 150 |
| Capacity Factor (%) | 22.1 |
| Inflation (%) | 1% |

Kentucky Power Company
Annual Investment Carrying Charges
For Economic Analyses
As of 12/31/2019

| | Investment Life (Years) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2 | 3 | 4 | 5 | 10 | 15 | 20 | 25 | 30 | 33 | 40 | 50 |
| Return (1) | 7.07 | 7.07 | 7.07 | 7.07 | 7.07 | 7.07 | 7.07 | 7.07 | 7.07 | 7.07 | 7.07 | 7.07 |
| Depreciation (2) | 49.04 | 31.91 | 23.32 | 18.19 | 8.04 | 4.78 | 3.23 | 2.35 | 1.81 | 1.57 | 1.18 | 0.85 |
| FIT (3) (4) | 1.06 | 0.77 | 0.82 | 0.68 | 0.64 | 0.77 | 0.80 | 0.69 | 0.62 | 0.59 | 0.54 | 0.49 |
| Property Taxes, General & Admin Expenses | 1.45 | 1.45 | 1.45 | 1.45 | 1.45 | 1.45 | 1.45 | 1.45 | 1.45 | 1.45 | 1.45 | 1.45 |
| Carrying Cost Per Year | 58.62 | 41.19 | 32.66 | 27.39 | 17.20 | 14.07 | 12.55 | 11.57 | 10.95 | 10.68 | 10.24 | 9.86 |

(1) Based on a 100% (as of 12/31/2019) and 0% incremental weighting of capital costs

(2) Sinking Fund annuity with R1 Dispersion of Retirements

(3) Assuming MACRS Tax Depreciation

(4) @ 21% Federal Income Tax Rate

| Project Name | OpCo | COD | Tier | Calc CF | Levelized CF | ITC % | Build Cost $/kW | Levelized O&M $/kW | Levelized O&M $/MWh | Levelized Cost of Energy $/MWh | Levelized Capital Cost $/MWH |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2021COD-KYP-Tier 2 | KYP | 2021 | Tier 2 | 23.23% | 22.13% | 30% | $1,353 | $23.74 | $12.32 | $57.60 | $45.28 |
| 2022COD-KYP-Tier 2 | KYP | 2022 | Tier 2 | 23.23% | 22.13% | 30% | $1,257 | $23.81 | $12.36 | $54.45 | $42.09 |
| 2023COD-KYP-Tier 2 | KYP | 2023 | Tier 2 | 23.22% | 22.13% | 30% | $1,198 | $24.01 | $12.46 | $52.55 | $40.09 |
| 2024COD-KYP-Tier 2 | KYP | 2024 | Tier 2 | 23.23% | 22.13% | 10% | $1,153 | $24.25 | $12.59 | $56.25 | $43.66 |
| 2025COD-KYP-Tier 2 | KYP | 2025 | Tier 2 | 23.23% | 22.13% | 0% | $1,122 | $24.55 | $12.74 | $57.70 | $44.96 |
| 2026COD-KYP-Tier 2 | KYP | 2026 | Tier 2 | 23.23% | 22.13% | 0% | $1,114 | $24.93 | $12.93 | $57.58 | $44.65 |
| 2027COD-KYP-Tier 2 | KYP | 2027 | Tier 2 | 23.22% | 22.13% | 0% | $1,115 | $25.33 | $13.14 | $57.83 | $44.68 |
| 2028COD-KYP-Tier 2 | KYP | 2028 | Tier 2 | 23.23% | 22.13% | 0% | $1,112 | $25.73 | $13.35 | $57.90 | $44.55 |
| 2029COD-KYP-Tier 2 | KYP | 2029 | Tier 2 | 23.23% | 22.13% | 0% | $1,110 | $26.13 | $13.56 | $58.05 | $44.49 |
| 2030COD-KYP-Tier 2 | KYP | 2030 | Tier 2 | 23.23% | 22.13% | 0% | $1,110 | $26.54 | $13.77 | $58.24 | $44.47 |
| 2031COD-KYP-Tier 2 | KYP | 2031 | Tier 2 | 23.22% | 22.13% | 0% | $1,109 | $26.95 | $13.98 | $58.40 | $44.42 |
| 2032COD-KYP-Tier 2 | KYP | 2032 | Tier 2 | 23.23% | 22.13% | 0% | $1,108 | $27.36 | $14.20 | $58.59 | $44.40 |
| 2033COD-KYP-Tier 2 | KYP | 2033 | Tier 2 | 23.23% | 22.13% | 0% | $1,109 | $27.78 | $14.41 | $58.84 | $44.42 |
| 2034COD-KYP-Tier 2 | KYP | 2034 | Tier 2 | 23.23% | 22.13% | 0% | $1,109 | $28.21 | $14.63 | $59.08 | $44.45 |
| 2035COD-KYP-Tier 2 | KYP | 2035 | Tier 2 | 23.22% | 22.13% | 0% | $1,109 | $28.64 | $14.86 | $59.31 | $44.45 |
| 2036COD-KYP-Tier 2 | KYP | 2036 | Tier 2 | 23.23% | 22.13% | 0% | $1,108 | $29.07 | $15.08 | $59.50 | $44.42 |
| 2037COD-KYP-Tier 2 | KYP | 2037 | Tier 2 | 23.23% | 22.13% | 0% | $1,107 | $29.51 | $15.31 | $59.66 | $44.35 |
| 2038COD-KYP-Tier 2 | KYP | 2038 | Tier 2 | 23.23% | 22.13% | 0% | $1,106 | $29.96 | $15.54 | $59.86 | $44.32 |
| 2039COD-KYP-Tier 2 | KYP | 2039 | Tier 2 | 23.22% | 22.13% | 0% | $1,105 | $30.41 | $15.78 | $60.05 | $44.27 |
| 2040COD-KYP-Tier 2 | KYP | 2040 | Tier 2 | 23.23% | 22.13% | 0% | $1,105 | $30.87 | $16.02 | $60.29 | $44.28 |
| 2041COD-KYP-Tier 2 | KYP | 2041 | Tier 2 | 23.23% | 22.13% | 0% | $1,105 | $31.34 | $16.26 | $60.55 | $44.30 |
| 2042COD-KYP-Tier 2 | KYP | 2042 | Tier 2 | 23.23% | 22.13% | 0% | $1,107 | $31.81 | $16.50 | $60.85 | $44.35 |
| 2043COD-KYP-Tier 2 | KYP | 2043 | Tier 2 | 23.22% | 22.13% | 0% | $1,108 | $32.28 | $16.74 | $61.12 | $44.38 |
| 2044COD-KYP-Tier 2 | KYP | 2044 | Tier 2 | 23.23% | 22.13% | 0% | $1,108 | $32.76 | $16.99 | $61.41 | $44.42 |
| 2045COD-KYP-Tier 2 | KYP | 2045 | Tier 2 | 23.23% | 22.13% | 0% | $1,109 | $33.23 | $17.24 | $61.67 | $44.43 |
| 2046COD-KYP-Tier 2 | KYP | 2046 | Tier 2 | 23.23% | 22.13% | 0% | $1,109 | $33.71 | $17.48 | $61.91 | $44.42 |
| 2047COD-KYP-Tier 2 | KYP | 2047 | Tier 2 | 23.22% | 22.13% | 0% | $1,108 | $34.19 | $17.73 | $62.12 | $44.39 |
| 2048COD-KYP-Tier 2 | KYP | 2048 | Tier 2 | 23.23% | 22.13% | 0% | $1,108 | $34.67 | $17.98 | $62.38 | $44.40 |
| 2049COD-KYP-Tier 2 | KYP | 2049 | Tier 2 | 23.23% | 22.13% | 0% | $1,107 | $35.15 | $18.23 | $62.61 | $44.38 |
| 2050COD-KYP-Tier 2 | KYP | 2050 | Tier 2 | 23.23% | 22.13% | 0% | $1,106 | $35.64 | $18.48 | $62.80 | $44.32 |

# EXHIBIT RW-4

KPC Response to Sierra Club RFI 2-6, Attachment 1 (May 5, 2021)

**DATA REQUEST**

**SC 2_6** For each wind resource offered to the PLEXOS model as part of the capacity optimization, for each of the years that resource is available as a resource option, provide the following exactly as input into the PLEXOS model:

a. The capital cost of that resource.

b. The fixed O&M associated with that resource, and the source of this assumption.

c. If neither (a) nor (b) are applicable, provide the levelized cost of that resource in $/MWh.

d. If none of the above are applicable, describe how capital and operating costs of each wind resource are input into PLEXOS and provide those data.

e. All workpapers that derive the cost of the resource, as input into PLEXOS, documenting original source data, with all cells unlocked and formulae intact

f. Any and all annual limits for additions of these resources.

g. Any and all cumulative limits for additions of these resources.

**RESPONSE**

a-e. Please see KPCO_R_SC_ 2_006_ Attachment1 for the PLEXOS inputs for the 200 MW wind option. The capital cost input, which includes return on rate base, depreciation expense, and income taxes net of production tax credits is provided in Column B of the Build Cost tab. The process used to compute the PLEXOS input value needed to produce levelized fixed carrying costs on invested capital that correspond to the expected levelized costs of electricity is shown on that tab. The Fixed O&M input is shown in Column N of the Wind Prices tab.

f and g. 200 MW per year and 600 MW cumulative limits were applied to wind capacity additions.

Witness: Mark A. Becker

# Plexos Addition of 150 MW Utility Tier 1 Wind Capital Cost Calculation

| **COD Dec** | **Plex Yr** | Plexos Input Build Cost ($/kW) | Units Built | Maximum Capacity (MW) | Build Cost ($000) | WACC (%) | Inflation Rate (%) | Economic Life (Years) | Tax Rate (%) | Depreciation Method | SLD Method Annuity Calculation ($000) | Levelized Cost Annuity ($000) | SLD vs Levelized Annuity ($000) | SLD vs Levelized Annuity (%) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2022 | 2023 | **917** | 1 | 200.00 | 183,406 | 7.070% | 2.500% | 30 | 26.00% | SLD | 13,623 | 13,623 | 0 | 0 |
| 2023 | 2024 | 1088 | 1 | 200.00 | 217,650 | 7.070% | 2.500% | 30 | 26.00% | SLD | 16,167 | 16,167 | 0 | 0 |
| **2024** | 2025 | 887 | 1 | 200.00 | 177,458 | 7.070% | 2.500% | 30 | 26.00% | SLD | 13,181 | 13,181 | 0 | 0 |
| **2025** | 2026 | 1495 | 1 | 200.00 | 299,041 | 7.070% | 2.500% | 30 | 26.00% | SLD | 22,212 | 22,212 | 0 | 0 |
| **2026** | 2027 | 1513 | 1 | 200.00 | 302,650 | 7.070% | 2.500% | 30 | 26.00% | SLD | 22,480 | 22,480 | 0 | 0 |
| 2027 | 2028 | 1530 | 1 | 200.00 | 305,903 | 7.070% | 2.500% | 30 | 26.00% | SLD | 22,722 | 22,722 | 0 | 0 |
| 2028 | 2029 | 1549 | 1 | 200.00 | 309,814 | 7.070% | 2.500% | 30 | 26.00% | SLD | 23,012 | 23,012 | 0 | 0 |
| 2029 | 2030 | 1567 | 1 | 200.00 | 313,435 | 7.070% | 2.500% | 30 | 26.00% | SLD | 23,281 | 23,281 | 0 | 0 |
| 2030 | 2031 | 1584 | 1 | 200.00 | 316,867 | 7.070% | 2.500% | 30 | 26.00% | SLD | 23,536 | 23,536 | 0 | 0 |
| 2031 | 2032 | 1598 | 1 | 200.00 | 319,641 | 7.070% | 2.500% | 30 | 26.00% | SLD | 23,742 | 23,742 | 0 | 0 |
| 2032 | 2033 | 1611 | 1 | 200.00 | 322,115 | 7.070% | 2.500% | 30 | 26.00% | SLD | 23,926 | 23,926 | 0 | 0 |
| 2033 | 2034 | 1621 | 1 | 200.00 | 324,185 | 7.070% | 2.500% | 30 | 26.00% | SLD | 24,080 | 24,080 | 0 | 0 |
| 2034 | 2035 | 1630 | 1 | 200.00 | 326,057 | 7.070% | 2.500% | 30 | 26.00% | SLD | 24,219 | 24,219 | 0 | 0 |
| 2035 | 2036 | 1639 | 1 | 200.00 | 327,718 | 7.070% | 2.500% | 30 | 26.00% | SLD | 24,342 | 24,342 | 0 | 0 |
| 2036 | 2037 | 1648 | 1 | 200.00 | 329,554 | 7.070% | 2.500% | 30 | 26.00% | SLD | 24,479 | 24,479 | 0 | 0 |
| 2037 | 2038 | 1655 | 1 | 200.00 | 331,039 | 7.070% | 2.500% | 30 | 26.00% | SLD | 24,589 | 24,589 | 0 | 0 |
| 2038 | 2039 | 1662 | 1 | 200.00 | 332,359 | 7.070% | 2.500% | 30 | 26.00% | SLD | 24,687 | 24,687 | 0 | 0 |
| 2039 | 2040 | 1670 | 1 | 200.00 | 334,098 | 7.070% | 2.500% | 30 | 26.00% | SLD | 24,816 | 24,816 | 0 | 0 |
| 2040 | 2041 | 1681 | 1 | 200.00 | 336,145 | 7.070% | 2.500% | 30 | 26.00% | SLD | 24,968 | 24,968 | 0 | 0 |
| 2041 | 2042 | 1690 | 1 | 200.00 | 338,058 | 7.070% | 2.500% | 30 | 26.00% | SLD | 25,110 | 25,110 | 0 | 0 |
| 2042 | 2043 | 1701 | 1 | 200.00 | 340,206 | 7.070% | 2.500% | 30 | 26.00% | SLD | 25,270 | 25,270 | 0 | 0 |
| 2043 | 2044 | 1714 | 1 | 200.00 | 342,766 | 7.070% | 2.500% | 30 | 26.00% | SLD | 25,460 | 25,460 | 0 | 0 |
| 2044 | 2045 | 1725 | 1 | 200.00 | 345,030 | 7.070% | 2.500% | 30 | 26.00% | SLD | 25,628 | 25,628 | 0 | 0 |
| 2045 | 2046 | 1737 | 1 | 200.00 | 347,333 | 7.070% | 2.500% | 30 | 26.00% | SLD | 25,799 | 25,799 | 0 | 0 |
| 2046 | 2047 | 1748 | 1 | 200.00 | 349,522 | 7.070% | 2.500% | 30 | 26.00% | SLD | 25,962 | 25,962 | 0 | 0 |
| 2047 | 2048 | 1758 | 1 | 200.00 | 351,684 | 7.070% | 2.500% | 30 | 26.00% | SLD | 26,122 | 26,122 | 0 | 0 |
| 2048 | 2049 | 1768 | 1 | 200.00 | 353,679 | 7.070% | 2.500% | 30 | 26.00% | SLD | 26,271 | 26,271 | 0 | 0 |
| 2049 | 2050 | 1780 | 1 | 200.00 | 355,917 | 7.070% | 2.500% | 30 | 26.00% | SLD | 26,437 | 26,437 | 0 | 0 |
| 2050 | 2051 | | | | | | | | | | | | | |
| 2051 | | | | | | | | | | | | | | |

Real Annuity Factor = 12.322
Nominal Annuity Factor = 9.776
SLD Factor = 0.074278159

2019 KPCo IRP
Wind Alternative Pricing
Column J
**35%**

Output Check

| **COD Dec** | Annual Levelized Capital Cost ($/MWh) 35 CF | Annual Levelized Cost ($000) 35 CF | | Screening FOM $/kW | FOM $/kW | Plex Year | Generation (GWh) | FO&M Cost ($000) | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | 0 | 0 | | |
| 2022 | $22.22 | 13,623 | | 56.90 | 76.90 | 2023 | 613.2062 | 11381.2 | 56.906 | 0.00 |
| 2023 | $26.36 | 16,167 | 1.19 | 57.50 | 77.70 | 2024 | 616.3852 | 11531.11 | 57.65553 | 0.16 |
| 2024 | $21.50 | 13,181 | 0.82 | 58.34 | 78.84 | 2025 | 613.2062 | 11668.32 | 58.3416 | 0.00 |
| 2025 | $36.22 | 22,212 | 1.69 | 59.25 | 80.06 | 2026 | 613.2062 | 11848.88 | 59.2444 | 0.00 |
| 2026 | $36.66 | 22,480 | 1.01 | 60.26 | 81.43 | 2027 | 613.2062 | 12051.64 | 60.2582 | 0.00 |
| 2027 | $37.05 | 22,722 | 1.01 | 61.25 | 82.78 | 2028 | 616.3852 | 12285.01 | 61.42503 | 0.17 |
| 2028 | $37.53 | 23,012 | 1.01 | 62.29 | 84.18 | 2029 | 613.2062 | 12458.64 | 62.2932 | 0.00 |
| 2029 | $37.97 | 23,281 | 1.01 | 63.32 | 85.57 | 2030 | 613.2062 | 12664.36 | 63.3218 | 0.00 |
| 2030 | $38.38 | 23,536 | 1.01 | 64.35 | 86.95 | 2031 | 613.2062 | 12868.6 | 64.343 | 0.00 |
| 2031 | $38.72 | 23,742 | 1.01 | 65.34 | 88.29 | 2032 | 616.3852 | 13102.72 | 65.5136 | 0.18 |
| 2032 | $39.02 | 23,926 | 1.01 | 66.31 | 89.61 | 2033 | 613.2062 | 13262.28 | 66.3114 | 0.00 |
| 2033 | $39.27 | 24,080 | 1.01 | 67.27 | 90.91 | 2034 | 613.2062 | 13454.68 | 67.2734 | 0.00 |
| 2034 | $39.50 | 24,219 | 1.01 | 68.24 | 92.21 | 2035 | 613.2062 | 13647.08 | 68.2354 | 0.00 |
| 2035 | $39.70 | 24,342 | 1.01 | 69.20 | 93.52 | 2036 | 616.3852 | 13878.88 | 69.3944 | 0.19 |
| 2036 | $39.92 | 24,479 | 1.01 | 70.18 | 94.84 | 2037 | 613.2062 | 14036.32 | 70.1816 | 0.00 |
| 2037 | $40.10 | 24,589 | 1.00 | 71.17 | 96.17 | 2038 | 613.2062 | 14233.16 | 71.1658 | 0.00 |
| 2038 | $40.26 | 24,687 | 1.00 | 72.15 | 97.50 | 2039 | 613.2062 | 14430 | 72.15 | 0.00 |
| 2039 | $40.47 | 24,816 | 1.01 | 73.18 | 98.89 | 2040 | 616.3852 | 14675.82 | 73.37909 | 0.20 |
| 2040 | $40.72 | 24,968 | 1.01 | 74.22 | 100.30 | 2041 | 613.2062 | 14844.4 | 74.222 | 0.00 |
| 2041 | $40.95 | 25,110 | 1.01 | 75.27 | 101.72 | 2042 | 613.2062 | 15054.56 | 75.2728 | 0.00 |
| 2042 | $41.21 | 25,270 | 1.01 | 76.35 | 103.17 | 2043 | 613.2062 | 15269.16 | 76.3458 | 0.00 |
| 2043 | $41.52 | 25,460 | 1.01 | 77.45 | 104.66 | 2044 | 616.3852 | 15532.12 | 77.66059 | 0.21 |
| 2044 | $41.79 | 25,628 | 1.01 | 78.53 | 106.13 | 2045 | 613.2062 | 15707.24 | 78.5362 | 0.00 |
| 2045 | $42.07 | 25,799 | 1.01 | 79.63 | 107.61 | 2046 | 613.2062 | 15926.28 | 79.6314 | 0.00 |
| 2046 | $42.34 | 25,962 | 1.01 | 80.73 | 109.09 | 2047 | 613.2062 | 16145.32 | 80.7266 | 0.00 |
| 2047 | $42.60 | 26,122 | 1.01 | 81.83 | 110.58 | 2048 | 616.3852 | 16410.68 | 82.05339 | 0.22 |
| 2048 | $42.84 | 26,271 | 1.01 | 82.92 | 112.05 | 2049 | 613.2062 | 16583.4 | 82.917 | 0.00 |
| 2049 | $43.11 | 26,437 | 1.01 | 84.02 | 113.55 | 2050 | 613.2062 | 16805.4 | 84.027 | 0.00 |
| 2050 | $43.35 | 26,583 | 1.01 | 85.12 | 115.03 | 2051 | | | | |
| 2051 | $43.57 | 26,717 | 1.01 | 86.22 | 116.51 | 2052 | | | | |
| | | | | | | 2023 | | | | |

Generic Wind

| | |
|---|---|
| Annual Energy (GWh) | 613.2 |
| Capacity (MW) | 200 |
| Capacity Factor (%) | 35 |
| Inflation (%) | 1.0% |

Kentucky Power Company
Annual Investment Carrying Charges
For Economic Analyses
As of 12/31/2019

| | Investment Life (Years) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2 | 3 | 4 | 5 | 10 | 15 | 20 | 25 | 30 | 33 | 40 | 50 |
| Return (1) | 7.07 | 7.07 | 7.07 | 7.07 | 7.07 | 7.07 | 7.07 | 7.07 | 7.07 | 7.07 | 7.07 | 7.07 |
| Depreciation (2) | 49.04 | 31.91 | 23.32 | 18.19 | 8.04 | 4.78 | 3.23 | 2.35 | 1.81 | 1.57 | 1.18 | 0.85 |
| FIT (3) (4) | 1.06 | 0.77 | 0.82 | 0.68 | 0.64 | 0.77 | 0.80 | 0.69 | 0.62 | 0.59 | 0.54 | 0.49 |
| Property Taxes, General & Admin Expenses | 1.45 | 1.45 | 1.45 | 1.45 | 1.45 | 1.45 | 1.45 | 1.45 | 1.45 | 1.45 | 1.45 | 1.45 |
| Carrying Cost Per Year | 58.62 | 41.19 | 32.66 | 27.39 | 17.20 | 14.07 | 12.55 | 11.57 | 10.95 | 10.68 | 10.24 | 9.86 |

(1) Based on a 100% (as of 12/31/2019) and 0% incremental weighting of capital costs

(2) Sinking Fund annuity with R1 Dispersion of Retirements

(3) Assuming MACRS Tax Depreciation

(4) @ 21% Federal Income Tax Rate

| Scenario | OpCo | COD Year | CF | Build Cost ($/kW) | PTC Credit | Levelized O&M $/kW | Levelized O&M $/MWh | Levelized Cost of Energy $/MWh | Levelized Capital Cost $/MWH |
|---|---|---|---|---|---|---|---|---|---|
| 2022COD-KYP-0.35CF | KYP | 2022 | 35% | $1,329 | 60% | $56.90 | $18.54 | $40.76 | $22.22 |
| 2023COD-KYP-0.35CF | KYP | 2023 | 35% | $1,316 | 40% | $57.50 | $18.74 | $45.10 | $26.36 |
| 2024COD-KYP-0.35CF | KYP | 2024 | 35% | $1,322 | 60% | $58.34 | $19.01 | $40.51 | $21.50 |
| 2025COD-KYP-0.35CF | KYP | 2025 | 35% | $1,331 | 0% | $59.25 | $19.31 | $55.53 | $36.22 |
| 2026COD-KYP-0.35CF | KYP | 2026 | 35% | $1,347 | 0% | $60.26 | $19.64 | $56.30 | $36.66 |
| 2027COD-KYP-0.35CF | KYP | 2027 | 35% | $1,361 | 0% | $61.25 | $19.96 | $57.01 | $37.05 |
| 2028COD-KYP-0.35CF | KYP | 2028 | 35% | $1,379 | 0% | $62.29 | $20.30 | $57.83 | $37.53 |
| 2029COD-KYP-0.35CF | KYP | 2029 | 35% | $1,395 | 0% | $63.32 | $20.64 | $58.60 | $37.97 |
| 2030COD-KYP-0.35CF | KYP | 2030 | 35% | $1,410 | 0% | $64.35 | $20.97 | $59.35 | $38.38 |
| 2031COD-KYP-0.35CF | KYP | 2031 | 35% | $1,423 | 0% | $65.34 | $21.29 | $60.01 | $38.72 |
| 2032COD-KYP-0.35CF | KYP | 2032 | 35% | $1,433 | 0% | $66.31 | $21.61 | $60.63 | $39.02 |
| 2033COD-KYP-0.35CF | KYP | 2033 | 35% | $1,443 | 0% | $67.27 | $21.92 | $61.19 | $39.27 |
| 2034COD-KYP-0.35CF | KYP | 2034 | 35% | $1,451 | 0% | $68.24 | $22.24 | $61.73 | $39.50 |
| 2035COD-KYP-0.35CF | KYP | 2035 | 35% | $1,459 | 0% | $69.20 | $22.55 | $62.25 | $39.70 |
| 2036COD-KYP-0.35CF | KYP | 2036 | 35% | $1,467 | 0% | $70.18 | $22.87 | $62.79 | $39.92 |
| 2037COD-KYP-0.35CF | KYP | 2037 | 35% | $1,473 | 0% | $71.17 | $23.19 | $63.29 | $40.10 |
| 2038COD-KYP-0.35CF | KYP | 2038 | 35% | $1,479 | 0% | $72.15 | $23.51 | $63.77 | $40.26 |
| 2039COD-KYP-0.35CF | KYP | 2039 | 35% | $1,487 | 0% | $73.18 | $23.85 | $64.32 | $40.47 |
| 2040COD-KYP-0.35CF | KYP | 2040 | 35% | $1,496 | 0% | $74.22 | $24.19 | $64.91 | $40.72 |
| 2041COD-KYP-0.35CF | KYP | 2041 | 35% | $1,505 | 0% | $75.27 | $24.53 | $65.48 | $40.95 |
| 2042COD-KYP-0.35CF | KYP | 2042 | 35% | $1,514 | 0% | $76.35 | $24.88 | $66.09 | $41.21 |
| 2043COD-KYP-0.35CF | KYP | 2043 | 35% | $1,526 | 0% | $77.45 | $25.24 | $66.76 | $41.52 |
| 2044COD-KYP-0.35CF | KYP | 2044 | 35% | $1,536 | 0% | $78.53 | $25.60 | $67.39 | $41.79 |
| 2045COD-KYP-0.35CF | KYP | 2045 | 35% | $1,546 | 0% | $79.63 | $25.95 | $68.03 | $42.07 |
| 2046COD-KYP-0.35CF | KYP | 2046 | 35% | $1,556 | 0% | $80.73 | $26.31 | $68.65 | $42.34 |
| 2047COD-KYP-0.35CF | KYP | 2047 | 35% | $1,566 | 0% | $81.83 | $26.66 | $69.26 | $42.60 |
| 2048COD-KYP-0.35CF | KYP | 2048 | 35% | $1,574 | 0% | $82.92 | $27.02 | $69.87 | $42.84 |
| 2049COD-KYP-0.35CF | KYP | 2049 | 35% | $1,584 | 0% | $84.02 | $27.38 | $70.50 | $43.11 |
| 2050COD-KYP-0.35CF | KYP | 2050 | 35% | $1,593 | 0% | $85.12 | $27.74 | $71.09 | $43.35 |
| 2051COD-KYP-0.35CF | KYP | 2051 | 35% | $1,601 | 0% | $86.22 | $28.09 | $71.66 | $43.57 |

# EXHIBIT RW-5

KPC Response to Sierra Club RFI 2-7, Attachment 1 (May 5, 2021)

# Plexos Addition of 50 MW Storage Capital Cost Calculation

| | Plexos Input Build Cost ($/kW) | Units Built | Maximum Capacity (MW) | Build Cost ($000) | WACC (%) | Inflation Rate (%) | Economic Life (Years) | Tax Rate (%) | Depreciation Method | SLD Method Annuity Calculation ($000) | Levelized Cost Annuity ($000) | SLD vs Levelized Annuity ($000) | SLD vs Levelized Annuity (%) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2021 | 2061 | 1 | 50.00 | 103,059 | 7.070% | 2.500% | 10 | 26.00% | SLD | 12,325 | 12,325 | 0 | 0 |
| 2022 | 1982 | 1 | 50.00 | 99,106 | 7.070% | 2.500% | 10 | 26.00% | SLD | 11,852 | 11,852 | 0 | 0 |
| 2023 | 1921 | 1 | 50.00 | 96,026 | 7.070% | 2.500% | 10 | 26.00% | SLD | 11,484 | 11,484 | 0 | 0 |
| 2024 | 2155 | 1 | 50.00 | 107,775 | 7.070% | 2.500% | 10 | 26.00% | SLD | 12,889 | 12,889 | 0 | 0 |
| 2025 | 2267 | 1 | 50.00 | 113,354 | 7.070% | 2.500% | 10 | 26.00% | SLD | 13,556 | 13,556 | 0 | 0 |
| 2026 | 2252 | 1 | 50.00 | 112,578 | 7.070% | 2.500% | 10 | 26.00% | SLD | 13,463 | 13,463 | 0 | 0 |
| 2027 | 2246 | 1 | 50.00 | 112,295 | 7.070% | 2.500% | 10 | 26.00% | SLD | 13,429 | 13,429 | 0 | 0 |
| 2028 | 2243 | 1 | 50.00 | 112,144 | 7.070% | 2.500% | 10 | 26.00% | SLD | 13,411 | 13,411 | 0 | 0 |
| 2029 | 2240 | 1 | 50.00 | 112,017 | 7.070% | 2.500% | 10 | 26.00% | SLD | 13,396 | 13,396 | 0 | 0 |
| 2030 | 2240 | 1 | 50.00 | 112,016 | 7.070% | 2.500% | 10 | 26.00% | SLD | 13,396 | 13,396 | 0 | 0 |
| 2031 | 2246 | 1 | 50.00 | 112,278 | 7.070% | 2.500% | 10 | 26.00% | SLD | 13,427 | 13,427 | 0 | 0 |
| 2032 | 2254 | 1 | 50.00 | 112,695 | 7.070% | 2.500% | 10 | 26.00% | SLD | 13,477 | 13,477 | 0 | 0 |
| 2033 | 2259 | 1 | 50.00 | 112,938 | 7.070% | 2.500% | 10 | 26.00% | SLD | 13,506 | 13,506 | 0 | 0 |
| 2034 | 2262 | 1 | 50.00 | 113,113 | 7.070% | 2.500% | 10 | 26.00% | SLD | 13,527 | 13,527 | 0 | 0 |
| 2035 | 2261 | 1 | 50.00 | 113,053 | 7.070% | 2.500% | 10 | 26.00% | SLD | 13,520 | 13,520 | 0 | 0 |
| 2036 | 2263 | 1 | 50.00 | 113,134 | 7.070% | 2.500% | 10 | 26.00% | SLD | 13,530 | 13,530 | 0 | 0 |
| 2037 | 2261 | 1 | 50.00 | 113,044 | 7.070% | 2.500% | 10 | 26.00% | SLD | 13,519 | 13,519 | 0 | 0 |
| 2038 | 2258 | 1 | 50.00 | 112,881 | 7.070% | 2.500% | 10 | 26.00% | SLD | 13,500 | 13,500 | 0 | 0 |
| 2039 | 2257 | 1 | 50.00 | 112,832 | 7.070% | 2.500% | 10 | 26.00% | SLD | 13,494 | 13,494 | 0 | 0 |
| 2040 | 2259 | 1 | 50.00 | 112,944 | 7.070% | 2.500% | 10 | 26.00% | SLD | 13,507 | 13,507 | 0 | 0 |
| 2041 | 2257 | 1 | 50.00 | 112,833 | 7.070% | 2.500% | 10 | 26.00% | SLD | 13,494 | 13,494 | 0 | 0 |
| 2042 | 2258 | 1 | 50.00 | 112,903 | 7.070% | 2.500% | 10 | 26.00% | SLD | 13,502 | 13,502 | 0 | 0 |
| 2043 | 2260 | 1 | 50.00 | 112,990 | 7.070% | 2.500% | 10 | 26.00% | SLD | 13,513 | 13,513 | 0 | 0 |
| 2044 | 2259 | 1 | 50.00 | 112,971 | 7.070% | 2.500% | 10 | 26.00% | SLD | 13,510 | 13,510 | 0 | 0 |
| 2045 | 2259 | 1 | 50.00 | 112,953 | 7.070% | 2.500% | 10 | 26.00% | SLD | 13,508 | 13,508 | 0 | 0 |
| 2046 | 2259 | 1 | 50.00 | 112,971 | 7.070% | 2.500% | 10 | 26.00% | SLD | 13,510 | 13,510 | 0 | 0 |
| 2047 | 2260 | 1 | 50.00 | 112,983 | 7.070% | 2.500% | 10 | 26.00% | SLD | 13,512 | 13,512 | 0 | 0 |
| 2048 | 2259 | 1 | 50.00 | 112,928 | 7.070% | 2.500% | 10 | 26.00% | SLD | 13,505 | 13,505 | 0 | 0 |
| 2049 | 2257 | 1 | 50.00 | 112,856 | 7.070% | 2.500% | 10 | 26.00% | SLD | 13,497 | 13,497 | 0 | 0 |
| 2050 | 2273 | 1 | 50.00 | 113,655 | 7.070% | 2.500% | 10 | 26.00% | SLD | 13,592 | 13,592 | 0 | 0 |
| Real Annuity Factor = | | | | 7.001 | | | | | | | | | |
| Nominal Annuity Factor = | | | | 6.260 | | | | | | | | | |
| SLD Factor = | | | | 0.119591144 | | | | | | | | | |

2020 KPCo IRP
Storage Alternative Pricing

**50 MW size**

| | Modeling YR | T1 (No PTC) | Annual Levelized Cost ($/MWh) **EIA** T2 (w PTC) | Annual Levelized Cost ($000) EIA Storage | esc | **$/kW** FOM | | FO&M Charge Plexos $/KW-Yr | Input FOM | Scaled up to 50 MW ELCC has 40 MW |
|---|---|---|---|---|---|---|---|---|---|---|
| 2021 | 2021 | - | *$39.63* | 12,325 | | BAT 2021 | $25.28 | | $34.17 | $42.71 |
| 2022 | 2022 | - | *$38.11* | 11,852 | 0.96 | | $25.04 | 0.99 | $33.84 | $42.30 |
| 2023 | 2023 | - | *$36.93* | 11,484 | 0.97 | | $24.92 | 0.99 | $33.67 | $42.09 |
| 2024 | 2024 | - | *$41.45* | 12,889 | 1.122341 | | $25.11 | 1.01 | $33.94 | $42.42 |
| 2025 | 2025 | - | *$43.59* | 13,556 | 1.051771 | | $25.31 | 1.01 | $34.21 | $42.76 |
| 2026 | 2026 | - | *$43.29* | 13,463 | 0.993152 | | $25.49 | 1.01 | $34.45 | $43.06 |
| 2027 | 2027 | - | *$43.18* | 13,429 | 0.997485 | | $25.73 | 1.01 | $34.77 | $43.46 |
| 2028 | 2028 | - | *$43.13* | 13,411 | 0.998659 | | $25.98 | 1.01 | $35.11 | $43.88 |
| 2029 | 2029 | - | *$43.08* | 13,396 | 0.998866 | | $26.23 | 1.01 | $35.45 | $44.31 |
| 2030 | 2030 | - | *$43.08* | 13,396 | 0.999993 | | $26.50 | 1.01 | $35.81 | $44.76 |
| 2031 | 2031 | - | *$43.18* | 13,427 | 1.002335 | | $26.79 | 1.01 | $36.21 | $45.26 |
| 2032 | 2032 | - | *$43.34* | 13,477 | 1.003715 | | $27.11 | 1.01 | $36.63 | $45.79 |
| 2033 | 2033 | - | *$43.43* | 13,506 | 1.00216 | | $27.41 | 1.01 | $37.04 | $46.30 |
| 2034 | 2034 | - | *$43.50* | 13,527 | 1.001545 | | $27.70 | 1.01 | $37.44 | $46.79 |
| 2035 | 2035 | - | *$43.48* | 13,520 | 0.999469 | | $27.98 | 1.01 | $37.81 | $47.26 |
| 2036 | 2036 | - | *$43.51* | 13,530 | 1.00072 | | $28.27 | 1.01 | $38.21 | $47.76 |
| 2037 | 2037 | - | *$43.47* | 13,519 | 0.999207 | | $28.55 | 1.01 | $38.59 | $48.23 |
| 2038 | 2038 | - | *$43.41* | 13,500 | 0.998558 | | $28.83 | 1.01 | $38.96 | $48.70 |
| 2039 | 2039 | - | *$43.39* | 13,494 | 0.999562 | | $29.12 | 1.01 | $39.35 | $49.19 |
| 2040 | 2040 | - | *$43.43* | 13,507 | 1.000991 | | $29.44 | 1.01 | $39.78 | $49.72 |
| 2041 | 2041 | - | *$43.39* | 13,494 | 0.999017 | | $29.73 | 1.01 | $40.17 | $50.22 |
| 2042 | 2042 | - | *$43.42* | 13,502 | 1.000622 | | $30.04 | 1.01 | $40.59 | $50.74 |
| 2043 | 2043 | - | *$43.45* | 13,513 | 1.000774 | | $30.35 | 1.01 | $41.02 | $51.28 |
| 2044 | 2044 | - | *$43.44* | 13,510 | 0.999827 | | $30.66 | 1.01 | $41.44 | $51.80 |
| 2045 | 2045 | - | *$43.44* | 13,508 | 0.999839 | | $30.97 | 1.01 | $41.85 | $52.32 |
| 2046 | 2046 | - | *$43.44* | 13,510 | 1.000163 | | $31.29 | 1.01 | $42.28 | $52.85 |
| 2047 | 2047 | - | *$43.45* | 13,512 | 1.000106 | | $31.60 | 1.01 | $42.70 | $53.38 |
| 2048 | 2048 | - | *$43.43* | 13,505 | 0.99951 | | $31.91 | 1.01 | $43.12 | $53.90 |
| 2049 | 2049 | - | *$43.40* | 13,497 | 0.999369 | | $32.22 | 1.01 | $43.54 | $54.42 |
| 2050 | 2050 | - | *$43.71* | 13,592 | 1.007076 | | $32.61 | 1.01 | $44.07 | $55.09 |
| | | | *#REF!* | | | | | | | |

| Project Name | OpCo | Capacity MW | COD | Tier | Solar CF | Levelized CF | ITC % | Build Cost $/kW | Levelized O&M $/kW | Levelized O&M $/MWh | Levelized Cost of Energy $/MWh | Levelized Capital Cost $/MWH | 30 Year PPA Proxy (Upfront ITC) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2021COD-KYP-Tier 2-F2 | KYP | 150 | 2021 | Tier 2 | 23.23% | 22.13% | 30% | $1,179 | $38.44 | $19.92 | $59.55 | $39.63 | $51.24 |
| 2022COD-KYP-Tier 2-F2 | KYP | 150 | 2022 | Tier 2 | 23.23% | 22.13% | 30% | $1,134 | $38.09 | $19.73 | $57.85 | $38.11 | $49.85 |
| 2023COD-KYP-Tier 2-F2 | KYP | 150 | 2023 | Tier 2 | 23.22% | 22.13% | 30% | $1,099 | $37.90 | $19.64 | $56.57 | $36.93 | $48.82 |
| 2024COD-KYP-Tier 2-F2 | KYP | 150 | 2024 | Tier 2 | 23.23% | 22.13% | 10% | $1,093 | $38.20 | $19.79 | $61.24 | $41.45 | $57.71 |
| 2025COD-KYP-Tier 2-F2 | KYP | 150 | 2025 | Tier 2 | 23.23% | 22.13% | 0% | $1,088 | $38.51 | $19.95 | $63.55 | $43.59 | $62.12 |
| 2026COD-KYP-Tier 2-F2 | KYP | 150 | 2026 | Tier 2 | 23.23% | 22.13% | 0% | $1,080 | $38.79 | $20.10 | $63.39 | $43.29 | $61.97 |
| 2027COD-KYP-Tier 2-F2 | KYP | 150 | 2027 | Tier 2 | 23.22% | 22.13% | 0% | $1,078 | $39.15 | $20.28 | $63.47 | $43.18 | $62.06 |
| 2028COD-KYP-Tier 2-F2 | KYP | 150 | 2028 | Tier 2 | 23.23% | 22.13% | 0% | $1,076 | $39.53 | $20.48 | $63.61 | $43.13 | $62.20 |
| 2029COD-KYP-Tier 2-F2 | KYP | 150 | 2029 | Tier 2 | 23.23% | 22.13% | 0% | $1,075 | $39.92 | $20.68 | $63.76 | $43.08 | $62.35 |
| 2030COD-KYP-Tier 2-F2 | KYP | 150 | 2030 | Tier 2 | 23.23% | 22.13% | 0% | $1,075 | $40.33 | $20.90 | $63.97 | $43.08 | $62.56 |
| 2031COD-KYP-Tier 2-F2 | KYP | 150 | 2031 | Tier 2 | 23.22% | 22.13% | 0% | $1,078 | $40.78 | $21.13 | $64.31 | $43.18 | $62.90 |
| 2032COD-KYP-Tier 2-F2 | KYP | 150 | 2032 | Tier 2 | 23.23% | 22.13% | 0% | $1,081 | $41.26 | $21.38 | $64.72 | $43.34 | $63.30 |
| 2033COD-KYP-Tier 2-F2 | KYP | 150 | 2033 | Tier 2 | 23.23% | 22.13% | 0% | $1,084 | $41.71 | $21.62 | $65.05 | $43.43 | $63.62 |
| 2034COD-KYP-Tier 2-F2 | KYP | 150 | 2034 | Tier 2 | 23.23% | 22.13% | 0% | $1,086 | $42.16 | $21.85 | $65.35 | $43.50 | $63.92 |
| 2035COD-KYP-Tier 2-F2 | KYP | 150 | 2035 | Tier 2 | 23.22% | 22.13% | 0% | $1,085 | $42.59 | $22.07 | $65.54 | $43.48 | $64.12 |
| 2036COD-KYP-Tier 2-F2 | KYP | 150 | 2036 | Tier 2 | 23.23% | 22.13% | 0% | $1,086 | $43.03 | $22.30 | $65.81 | $43.51 | $64.38 |
| 2037COD-KYP-Tier 2-F2 | KYP | 150 | 2037 | Tier 2 | 23.23% | 22.13% | 0% | $1,085 | $43.46 | $22.52 | $66.00 | $43.47 | $64.57 |
| 2038COD-KYP-Tier 2-F2 | KYP | 150 | 2038 | Tier 2 | 23.23% | 22.13% | 0% | $1,083 | $43.89 | $22.74 | $66.15 | $43.41 | $64.73 |
| 2039COD-KYP-Tier 2-F2 | KYP | 150 | 2039 | Tier 2 | 23.22% | 22.13% | 0% | $1,083 | $44.34 | $22.97 | $66.36 | $43.39 | $64.95 |
| 2040COD-KYP-Tier 2-F2 | KYP | 150 | 2040 | Tier 2 | 23.23% | 22.13% | 0% | $1,084 | $44.82 | $23.22 | $66.66 | $43.43 | $65.23 |
| 2041COD-KYP-Tier 2-F2 | KYP | 150 | 2041 | Tier 2 | 23.23% | 22.13% | 0% | $1,083 | $45.26 | $23.45 | $66.84 | $43.39 | $65.42 |
| 2042COD-KYP-Tier 2-F2 | KYP | 150 | 2042 | Tier 2 | 23.23% | 22.13% | 0% | $1,084 | $45.74 | $23.70 | $67.12 | $43.42 | $65.70 |
| 2043COD-KYP-Tier 2-F2 | KYP | 150 | 2043 | Tier 2 | 23.22% | 22.13% | 0% | $1,084 | $46.23 | $23.95 | $67.40 | $43.45 | $65.98 |
| 2044COD-KYP-Tier 2-F2 | KYP | 150 | 2044 | Tier 2 | 23.23% | 22.13% | 0% | $1,084 | $46.70 | $24.20 | $67.64 | $43.44 | $66.22 |
| 2045COD-KYP-Tier 2-F2 | KYP | 150 | 2045 | Tier 2 | 23.23% | 22.13% | 0% | $1,084 | $47.17 | $24.44 | $67.88 | $43.44 | $66.45 |
| 2046COD-KYP-Tier 2-F2 | KYP | 150 | 2046 | Tier 2 | 23.23% | 22.13% | 0% | $1,084 | $47.65 | $24.69 | $68.13 | $43.44 | $66.71 |
| 2047COD-KYP-Tier 2-F2 | KYP | 150 | 2047 | Tier 2 | 23.22% | 22.13% | 0% | $1,084 | $48.14 | $24.94 | $68.39 | $43.45 | $66.97 |
| 2048COD-KYP-Tier 2-F2 | KYP | 150 | 2048 | Tier 2 | 23.23% | 22.13% | 0% | $1,084 | $48.61 | $25.18 | $68.61 | $43.43 | $67.19 |
| 2049COD-KYP-Tier 2-F2 | KYP | 150 | 2049 | Tier 2 | 23.23% | 22.13% | 0% | $1,083 | $49.08 | $25.43 | $68.83 | $43.40 | $67.40 |
| 2050COD-KYP-Tier 2-F2 | KYP | 150 | 2050 | Tier 2 | 23.23% | 22.13% | 0% | $1,091 | $49.69 | $25.74 | $69.45 | $43.71 | $68.01 |

Kentucky Power Company
Annual Investment Carrying Charges
For Economic Analyses
As of 12/31/2019

| | Investment Life (Years) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2 | 3 | 4 | 5 | 10 | 15 | 20 | 25 | 30 | 33 | 40 | 50 |
| Return (1) | 7.07 | 7.07 | 7.07 | 7.07 | 7.07 | 7.07 | 7.07 | 7.07 | 7.07 | 7.07 | 7.07 | 7.07 |
| Depreciation (2) | 49.04 | 31.91 | 23.32 | 18.19 | 8.04 | 4.78 | 3.23 | 2.35 | 1.81 | 1.57 | 1.18 | 0.85 |
| FIT (3) (4) | 1.06 | 0.77 | 0.82 | 0.68 | 0.64 | 0.77 | 0.80 | 0.69 | 0.62 | 0.59 | 0.54 | 0.49 |
| Property Taxes, General & Admin Expenses | 1.45 | 1.45 | 1.45 | 1.45 | 1.45 | 1.45 | 1.45 | 1.45 | 1.45 | 1.45 | 1.45 | 1.45 |
| Carrying Cost Per Year | 58.62 | 41.19 | 32.66 | 27.39 | 17.20 | 14.07 | 12.55 | 11.57 | 10.95 | 10.68 | 10.24 | 9.86 |

(1) Based on a 100% (as of 12/31/2019) and 0% incremental weighting of capital costs

(2) Sinking Fund annuity with R1 Dispersion of Retirements

(3) Assuming MACRS Tax Depreciation

(4) @ 21% Federal Income Tax Rate

# EXHIBIT RW-6

KPMG. *KPMG Report: Outlook for What's Ahead for Energy Tax Incentives (Updated)* (2021) *available at* https://assets.kpmg/content/dam/kpmg/us/pdf/2021/05/21197.pdf

KPMG

TaxNewsFlash

**United States**

No. 2021-197
May 3, 2021

# KPMG report: Outlook for what's ahead for energy tax incentives (updated)

Coming off year-end extensions, the tax incentives for various renewable and clean energy sources and technologies could see an additional boost from Congress in the coming months.

This report briefly describes the potential for additional extensions and enhancements as proposals from the Biden Administration and Congress take shape.

**Biden Administration plan**

President Biden has described a two-step plan for "rescue and recovery" in response to the coronavirus (COVID-19) pandemic health and economic crises. With enactment of the "American Rescue Plan Act of 2021" on March 11, 2021, the focus can now shift to recovery.

President Biden on March 31, 2021, announced the "recovery" portion of his two-step plan that focuses on infrastructure, energy, innovation, and other areas. The available information about the plan does not include detailed descriptions, but does include the following energy related tax provisions:

- 10-year extension and phase down of an expanded direct-pay investment tax credit and production tax credit for clean energy generation and storage (paired with strong labor and collective bargaining standards for jobs created by the credits)
- Investment tax credit to mobilize private capital for the buildout of at least 20 gigawatts of high-voltage capacity power lines
- Reform and expansion of section 45Q credit for carbon capture projects
- Tax incentives "to buy American-made" electric vehicles
- Extend and expand home and commercial energy-efficiency tax credits
- Extend section 48C advanced manufacturing tax credit
- Repeal fossil fuel subsidies and reinstate superfund payments

Another notable feature of the Biden plan that could be an interesting companion to the enhanced tax incentives is the plan to establish the "Energy Efficiency and Clean Electricity Standard" (EECES). There are few details about how the EECES would operate, but it could act as a nation-wide standard

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requiring utilities to source electricity from specified cleaner resources, similar to renewable portfolio standards currently enacted in several states.

Additional details of the Biden plan are still taking shape but for an indication of how many of these provisions may work it is useful to look to recently introduced legislative proposals. Comprehensive extensions, enhancements, and reforms to the energy tax incentives have recently been proposed in the both the House of Representatives and the Senate.

**The GREEN Act**

In February 2021, Representative Mike Thompson, (D-CA), a member of the U.S. House of Representatives Committee on Ways and Means reintroduced the "Growing Renewable Energy and Efficiency Now" (GREEN) Act. The Biden plan's proposals related to energy seem to track the GREEN Act in many ways, which may make the GREEN Act a good early indicator of how the Biden plan will translate into legislative language.

- ***ITC and PTC***

  The GREEN Act would reinstate and extend the solar investment tax credit (ITC) at 30% for projects that begin construction before 2026, then phase down to 26% for projects that begin construction in 2026, 22% for projects that begin construction in 2027 and 10% thereafter.

  For wind, the GREEN Act would extend the current 60% production tax credit (PTC) for wind facilities that begin construction before 2027.

  The GREEN Act would extend the ITC and PTC for other eligible technologies and expand the ITC to include energy storage technology and linear generators.

- ***Direct pay***

  A significant feature of the GREEN Act is its inclusion of a "direct pay" provision allowing taxpayers to elect to treat 85% of the ITC and PTC as a payment of tax, entitling them to a refund to the extent the payment exceeds available tax liability. The direct pay provision would apply to projects placed in service after the date of enactment.

- ***Electric vehicles***

  The GREEN Act also includes proposals related to electric vehicles, which is another priority area for the Biden Administration. The proposal would extend and expand the existing electric vehicle credit, specifically by increasing the phase-out threshold and permitting used and large vehicles to be eligible for the credit. The GREEN Act would also allow manufacturers that have already passed the existing 200,000 vehicle threshold to continue to benefit from the credit.

- ***Other notable provisions***

  - Extension of the section 45Q credit for carbon oxide sequestration facilities that begin construction before the end of 2026 and provide an 85% direct-payment option
  - Extension and modification of residential energy and energy efficiency incentives
  - Additional allocation of section 48C advanced manufacturing credit, with prevailing wage requirement
  - Extension of excise tax credit for alternative fuels
  - Extension of availability of publicly traded partnerships for renewable energy projects

**Senate Finance Chairman Wyden's proposals**

Senate Finance Committee Chairman Ron Wyden (R-OR) on April 21, 2021 introduced a bill—the "Clean Energy for America Act''—that would aim to create a simpler set of long-term, performance-based energy tax incentives with the goals of being technology-neutral and to promote clean energy in the United States.

- ***ITC and PTC***

  The bill would replace the current renewable energy tax incentives with a new clean electricity PTC and ITC. The bill would allow taxpayers to choose between a 30% ITC or a PTC equal to 2.5 cents per kilowatt hour. The credits would apply to facilities with zero or net negative carbon emissions placed in service after December 31, 2022. The Wyden bill would also extend current tax credit provisions through December 31, 2022.

  The credits are set to phase out when certain emission targets are achieved, specifically when the Environmental Protection Agency and the Department of Energy certify that the electric power sector emits 75 percent less carbon than 2021 levels.

  Qualifying transmission grid improvements also would be eligible for the 30% ITC including standalone energy storage property. Storage technologies eligible for the ITC would not be required to be co-located with power plants and include any technologies that can receive, store and provide electricity or energy for conversion to electricity. Transmission property would include transmission lines of 275 kilovolts (kv) or higher, plus any necessary ancillary equipment. Regulated utilities would have the option to opt-out of tax normalization requirements for purposes of the grid improvement credit. The bill does not, however, include a similar opt-out of the tax normalization provisions for ITC for other types of qualifying facilities.

  Under the bill, investments qualifying for the clean emission investment credit, grid credit or energy storage property credit that are located in qualifying low-income areas would qualify for higher credit rates.

- ***Carbon capture***

  The section 45Q tax credit would be extended until the power and industrial sectors meet certain emissions goals; however, the bill would make some significant modifications to the credit, in particular, enhanced oil and natural gas recovery projects would no longer qualify for the credit.

  In addition, the credit amounts for direct air capture facilities would be significantly enhanced, and the bill would also modify the minimum capture thresholds. Under the proposed modified thresholds, in order to qualify for the section 45Q tax credit, electric generating facilities would be required to capture at least 75% of the $CO_2$ that otherwise would be released into the atmosphere and industrial facilities would be required to capture at least 50% of the $CO_2$ which would otherwise be released into the atmosphere. These changes would be effective for projects on which construction begins after December 31, 2021.

- ***Direct pay***

  The Wyden bill would provide taxpayers with the option of treating the ITC, PTC, and section 45Q credit as payments of tax; those wishing to avail themselves of this election would have to inform the Treasury Department **before** the facility to which the election relates begins construction. Unlike the GREEN Act, the Wyden bill would not impose a 15% haircut on the amount of the direct pay amount. Also, note that in the Wyden bill, the direct pay election and resulting refund would be allowed at the partnership level. Finally, the new ITC and PTC created by the bill, including the direct pay feature, would be effective for projects that are placed in service after December 31,

2022. For section 45Q, the direct pay provision would apply to projects that begin construction after December 31, 2021.

- ***Electric vehicles***

  The Wyden bill would modify and enhance the incentives available for electric vehicles. Specifically, the bill would repeal the per-manufacturer vehicle cap and make the credit refundable for individuals. Commercial operators would be able to claim non-refundable credit worth 30% of the purchase of an electric vehicle. The credits would phase out when the electric vehicles represent more than 50% of annual vehicle sales.

- ***Other notable provisions***

  - Taxpayers receiving credits to pay wages at not less than local prevailing rates and use registered apprenticeship programs
  - PTC for production of clean fuels
  - Incentives for energy efficient homes and commercial buildings and for clean transportation technologies
  - Tax credit bonds for facilities producing clean electricity or clean transportation fuels
  - Repeal of certain incentives for fossil fuels, including immediate expensing for intangible drilling costs, percentage depletion, deductions for tertiary injectants and credits for enhanced oil recovery, coal gasification and advanced coal projects; also repeal of the special treatment of fossil fuels under the publicly traded partnership rules

**Table comparing various provisions**

| | **Biden Plan** | **GREEN Act** | **Wyden Plan** |
|---|---|---|---|
| ITC | 10 yr extension and phase down; no info on credit amount; direct pay but no additional info | Generally provides 30% ITC if construction begins before 2026, then phases down to 10% for construction beginning after 2027; 85% direct pay | Any technology can qualify for ITC the credits as long as emissions at or below zero; 30% credit rate; 100% direct pay; credits will phase out based on emissions targets |
| PTC | 10 yr extension and phase down; no info on credit amount; direct pay but no additional info | Generally extends PTC for projects beginning construction before 2026; credit rate at 60% of statutory rate; 85% direct pay | Any technology can qualify for PTC the credits as long as emissions at or below zero; 30% credit rate; 100% direct pay; credits will phase out based on emissions targets |
| Storage | Includes "storage" as part of credit proposal but no additional detail | ITC for storage; 85% direct pay | ITC for storage; Regulated utilities can elect out of tax normalization requirements; 100% direct pay |
| Transmission | ITC for buildout of at least 20 gigawatts of high-voltage capacity | Does not include transmission incentive | ITC for transmission investment; Regulated utilities can elect out tax normalization requirements; 100% direct |

| | | | |
|---|---|---|---|
| | power lines | | pay |
| Carbon capture | "Reform and expand" the 45Q tax credit; add direct pay | Extend 45Q for projects on which construction begins before 2027; 85% direct pay | Section 45Q tax credit would be extended until the power and industrial sectors meet emissions goals; EOR no longer eligible; higher credit for direct air capture; modified minimum capture thresholds; 100% direct pay |
| Electric vehicles | Provide "tax incentives" to buy American made EVs | Modifies current law credits by increasing phase out limits; creates new credits for used and large electric vehicles | Makes credit refundable for individuals; commercial operators can claim 30% non-refundable credit; credits phase out when EVs represent more than 50% of annual vehicle sales |
| Manufacturing | Extend 48C | Extend 48C | No incentive for manufacturing |
| Fossil Fuel Subsidies | "Eliminate tax preferences for fossil fuels" | No provisions related to fossil fuels | Repeal fossil fuel preferences |

**KPMG observation**

The common thread between the various proposals is the continued incentivization of clean energy development through the tax code. The tax credit regime has proven successful at encouraging new investment and the rules and the industry have evolved together. While the Biden Administration plan and the GREEN Act would mostly extend and enhance the existing tax credits, the Wyden bill—although still tax incentive-based—presents a departure of sorts.

Another common policy is the move toward making the tax credits refundable through a direct pay mechanism. It remains to be seen if and how refundability makes its way into law. Various justifications for direct pay include the limited tax liability of investors and the base erosion anti-abuse (BEAT) limitations on tax credits, but query whether potential higher tax rates and/or BEAT repeal make direct pay seem less necessary?

Finally, it will be interesting to monitor the development of some of the non-tax aspects of these proposals. Specifically will the inclusion of an EECES and strong labor standards become part of the ultimate package and, if so, how could that shape development going forward?

In terms of next steps, the Treasury Department will soon release a "Green Book" that will describe in more detail many of the proposals in the Biden plan. With that additional detail, larger negotiations will determine how the energy and tax portions of the ultimate legislative package take shape. The process is likely to be complicated and, of course, priorities could change during this time. That said, particularly in light of President Biden's recent commitment to reduce emissions by approximately half by 2030, the emphasis on clean energy is unlikely to subside.

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