COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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

REBUTTAL TESTIMONY OF

MARK A. BECKER

ON BEHALF OF KENTUCKY POWER COMPANY

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Mark A. Becker and my business address is 212 East Sixth Street, Tulsa, Oklahoma. I am employed by American Electric Power Service Corporation (AEPSC) as a Managing Director of Resource Planning.

Q. ARE YOU THE SAME MARK A. BECKER WHO OFFERED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. ARE YOU SPONSORING ANY REBUTTAL EXHIBITS?

A. I am sponsoring the following rebuttal exhibits

- Exhibit MAB-R1 – Sierra Club response to Kentucky Power discovery request 1-37
- Exhibit MAB-R2 – Kentucky Power's supplemental response to Sierra Club discovery request 1-16

II. PURPOSE OF REBUTTAL TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to the testimony of Sierra Club Witness Rachel Wilson and Office of the Attorney General of the Commonwealth of Kentucky and the Kentucky Industrial Utility Customers, Inc. (jointly "AG/KIUC") Witness Lane Kollen. In responding to Ms. Wilson's testimony, I explain that her analysis of the economic impacts of alternative resource plans contains numerous flaws, is based on

inconsistent assumptions, and should not be relied upon. More specifically, her cost of replacement resource additions, as well as her assumptions concerning the achievability of adding the level of resources needed are flawed and make her 2028 Mitchell retirement plans appear more economic than retiring Mitchell in 2040. Also, certain components of her new resource costs were either left out entirely or were understated. Similarly, her capacity factors and the energy value of resources included in her resource plans appear overstated. Important considerations such as energy market price effects, system reliability, credit rating considerations, land requirements, and transmission requirements of the future she envisions were not addressed at all. Some of these factors may be small individually, but combined they materially understate the costs and overstate the benefits of the portfolios of new resources she proposes to replace Mitchell with if it were to retire in 2028.

Q. WHAT ABOUT MR. KOLLEN'S TESTIMONY?

A. In responding to the testimony of Mr. Kollen, I will demonstrate that Mr. Kollen's suggested errors in Kentucky Power's replacement resource cost assumptions would not materially impact the Company's analysis.

III. REBUTTAL OF SIERRA CLUB WITNESS RACHEL WILSON

Q. PLEASE PROVIDE AN OVERVIEW OF THE SIERRA CLUB'S ANALYSIS AND ITS FLAWS.

A. Ms. Wilson's analysis was similar to mine in some respects, in that it was a comparison of the cost of a case in which CCR and ELG investments were made at the Mitchell units and they operated through 2040, and one in which only the CCR investments are made and the units retired in 2028. Ms. Wilson used the EnCompass model to produce alternative

resource plans and economic analysis of those two Mitchell retirement cases. Ms. Wilson produced resource plans that replaced the retiring units with a mix of only renewable resources, with the exception of a small gas-fired turbine to replace Big Sandy 1 when it is retired. In her analysis, she assumed the same market electricity prices used in my analysis in the Base with Carbon and Base No Carbon fundamentals forecasts. She also used the same assumptions as the Company regarding the capacity credit each renewable resource is expected to receive in the PJM market under the Effective Load Carrying Capability (ELCC) methodology. However, Ms. Wilson failed to include an analysis of the Mitchell options under the Low Band fundamentals forecast I included in my analysis.

Q. WHAT IS THE CONSEQUENCE OF MS. WILSON'S FAILURE TO USE THE LOW BAND FORECAST?

A. The lower market energy prices found in the Low Band forecast would have negatively impacted the economics of her renewable-focused Mitchell 2028 retirement plans, making them less economic compared to a case where Mitchell operated through 2040. As I will discuss later, a future that is based on a significant level of renewable resources would result in lower energy prices due to the large increase in zero variable cost resources being available at times of peak market energy prices. The Low Band fundamentals forecast is a better representation of market energy pricing in a heavy renewables future. By not performing the analysis using Low Band fundamentals, Ms. Wilson's analysis lacks the insight that the Kentucky Power's analysis provides regarding the sensitivity of the results of lower power prices.

Q. WHAT THINGS MUST YOU BELIEVE IN ORDER FOR MS. WILSON'S ECONOMIC ANALYSIS OF THE MITCHELL CCR AND ELG EXPENDITURES TO BE CREDIBLE?

A. To accept Ms. Wilson's analysis that the 2028 Mitchell retirement (Kentucky Power Case 2) is more economic than continuing to operate Mitchell until 2040 (Kentucky Power Case 1) the Commission must accept all of the following:

1. That Kentucky Power's generation fleet can contain up to approximately 3,600 MW of total nameplate capacity by 2050 (Wilson Direct Table 1 Synapse 2028 Retirement case, Base with Carbon), which is almost three times the current level of installed capacity. All of her new additions add up to a total cost of approximately $5.3 billion by 2050, which is a very large amount for a company the size of Kentucky Power. In addition, the Commission must accept that increased amount of capacity could be added without significant rate increases.
2. That owning approximately 3,600 MW of nameplate capacity, which is roughly four times Kentucky Power's 2050 projected peak load obligation of 900 MW, along with all of energy market exposure that comes with that capacity, is reasonable and necessary.
3. That Kentucky Power can receive approval for, and acquire, an average of 450 MW of new stand-alone solar resources every year for four years in a row beginning in 2026, while other utilities, large companies, and federal, state, and local governments with clean energy mandates and aspirations are competing for a limited number of available renewable projects.
4. That stand-alone solar will be available between 2026 and 2040 at an average cost without tax credits of approximately $26.00/MWh. I find this assumption particularly hard to believe given extreme demand for solar panel components, including metals such as copper, which has led to large increases in costs since the NREL cost estimates Ms. Wilson used were published.
5. That if solar is available to any utility, or renewable developer, at the $26/MWh cost just mentioned, that average PJM market energy prices including a CO_2 cost would remain at the

levels (~$45/MWh) forecasted by the Company, which assumed a much lower penetration of renewable energy. Such a market opportunity would cause wind and solar resources to be built well above the level in AEP's commodity price forecast and would cause market energy prices to decline sharply.

6. That no new transmission beyond basic interconnection costs will be required to enable the delivery of all of this new generation, and none of the new resources will incur any PJM congestion costs or be curtailed.
7. That sites occupying up to 15,000 acres of land for solar (7 acres per MW) and 7,800 acres for wind (6 acres per MW) required by the resources added in her 2028 Retirement case (Wilson Testimony Table 1) can be located.
8. While assuming that a small combustion turbine would replace Big Sandy 1 in all cases evaluated, the addition of new gas fired generation as a potential Mitchell replacement alternative should not be allowed.

There are other concerns that come from a more detailed examination of Ms. Wilson's analysis, but these high level points indicate how unrealistic and hard to achieve her results will be. I will discuss some of these points in more detail later in this testimony.

Q. IS THIS A PROPER WAY TO DO RESOURCE PLANNING?

A. No. In order to add enough capacity to meet the PJM minimum reserve margin requirement, Ms. Wilson's plan would require the Company to install levels of wind and solar generation that are approximately three times Kentucky Power's summer peak demand by 2028. This would create reserve margins in the 50 percent to almost 100 percent range in the 2026 to 2028 time period.

Q. WHAT WERE THE PRIMARY RESOURCES ADDED BY MS. WILSON BETWEEN NOW AND WHEN THE MITCHELL UNITS RETIRED IN THE 2028 MITCHELL RETIREMENT CASE?

A. Ms. Wilson's modeling added 400 MW of wind and 1,800 MW of solar by the time she assumed Mitchell would retire in the 2028 Mitchell retirement case. Because gas capacity was not available to replace Mitchell in her modeling, wind and solar were chosen as the primary replacement resources. In addition, the model continued to make wind and solar additions until those generation resources reached approximately 3,500 MW by the end of the analysis in 2050.

Q. ARE THERE OTHER CONCERNS ABOUT THE AMOUNT OF WIND AND SOLAR ADDITIONS IN MS. WILSON'S MODELING OF THE 2028 MITCHELL RETIREMENT CASE?

A. Yes. To add enough wind and solar capacity to meet the PJM minimum reserve margin requirement, Ms. Wilson's analysis would require Kentucky Power to install 400 MW to 500 MW of solar annually over a four year period from 2026 to 2029 and a total of 400 MW of wind prior to when the Mitchell units retire. The addition of these wind and solar resources will require capital investments of approximately $2.8 billion by 2029, which is much larger than the $67 million investment in CCR and ELG at Mitchell. At these extremely large levels, there is concern around the reasonableness of her plan and the ability to achieve those levels of wind and solar additions in such a short period of time.

Q. WHAT SOURCE DID MS. WILSON USE FOR THE COSTS AND CAPACITY FACTORS OF THE AVAILABLE RESOURCES?

A. Ms. Wilson relied on publicly available cost and capacity factor data from the National Renewable Energy Laboratory ("NREL") from the financial case it calls the "R&D Case" from its 2020 Annual Technology Baseline (ATB), published in July of 2020. The primary customer of the ATB is the US Department of Energy, but other industry participants use it as well. NREL's modeling and the information NREL publishes about electric generation resources are widely followed and respected, and are useful for their intended purpose. NREL's R&D case, as the name of the case suggests, is designed to allow users to evaluate how future research and development will affect the costs of various technologies under a common set of assumptions. The NREL cost data used by Ms. Wilson is prepared without influences of things like inflation, income tax expense, book depreciation expense, and tax credits, among other things. These assumptions could differ from one technology to another based on federal tax policy, supply chain issues, etc., and are therefore removed from the cost calculations. Users can see what NREL predicts will happen to the cost of energy from several technologies based simply on the technological aspects of each technology, which primarily consist of operating expenses and capital expenses. This can be useful information for its intended purposes of ranking technologies in terms of relative cost of each technology, but is not as informative about the absolute nominal cost of the resource.

Q. DO YOU TAKE ISSUE WITH THE WAY THE NREL DATA WAS USED AND PORTRAYED?

A. Yes. Ms. Wilson referred to it at page 19 lines 15 and 17 as "industry standard cost assumptions". The NREL R&D case cost of energy data is not "pricing" data for energy, especially when it comes to drawing a parallel between it and regulated utility cost of

service. She used a levelized cost of energy to price the energy produced by her new resources as if the energy were being purchased through a 30-year power purchase agreement (PPA) at a fixed price. While some of the underlying costs, such as projected capital costs, are used through the industry as useful building blocks for resource planning, it is a stretch to call the real dollar levelized cost of energy (LCOE) numbers published by NREL based on aggressive developer capital structures and low rates of return "standard pricing" for capacity and energy for 30-year PPAs.

Q. PLEASE DESCRIBE HOW MS. WILSON UNDERSTATED THE FIXED COSTS OF HER NEW RESOURCES.

A. Ms. Wilson understated the fixed costs of new resources through a combination of errors. I have attached to this testimony as MAB Exhibit MAB-R1 the Sierra Club's response to Kentucky Power's discovery request 1-37. It provides evidence that certain costs were omitted from the NREL analysis, and therefore were likewise omitted from Ms. Wilson's analysis. I am not criticizing NREL, which provides on its website the reasons why its R&D case analysis is prepared the way it is. While this request was related to a workpaper used by Ms. Wilson to do her calculations of solar costs, based on my review of her workpapers the same methodology also was used for wind resources.

Q. PLEASE EXPLAIN THE SPECIFIC SHORTCOMINGS OF THE MANNER IN WHICH MS. WILSON USED THE NREL DATA.

A. First, the response to subpart (h) of the response to the Company's discovery request confirms that NREL's underlying cost data relied upon by Ms. Wilson excluded depreciation, income taxes, property taxes, and general and administrative expenses. All of these should either be directly included in retail cost of service for owned assets, or

included in the PPA price charged by the developer. If a PPA is to be entered into for the entire 30 year life of a solar asset, depreciation must be reflected in the PPA price, or the developer would not recover its initial investment. I acknowledge that in the process of leaving out income tax effects in its R&D case NREL also excludes investment tax credits that would reduce the cost of solar for whatever years they are available. However, these credits are much smaller than the combination of all of the understatements of costs mentioned in this testimony, resulting in a large net understatement of cost.

Second, Exhibit MAB-R1 reveals that the capital recovery factor of 4.28% she used to apply carrying charges to solar was based on a real dollar weighted average cost of capital (WACC) of 1.69%. This 1.69% WACC was computed using NREL's calculation logic to deduct 2.5% inflation from NREL's nominal 4.24% after-tax WACC. Neither a PPA project developer nor Kentucky Power would ever price a PPA, or seek cost recovery in retail cost of service, based on a real dollar rate of return on a nominal dollar investment. Ms. Wilson acknowledged this and performed a calculation to convert the real return to nominal return, but she did so incorrectly, which understated the nominal WACC in her calculations. She simply added inflation to an LCOE calculated off of real dollar capital carrying costs. To do it correctly, Ms. Wilson should have used a nominal carrying charge rate to compute the LCOE to start with.

Third, fixed O&M was assumed by NREL, and thus by Ms. Wilson, to decline throughout the 30 year forecast period. Because NREL is forecasting capital costs to decline in real dollar terms, it is also assuming O&M will decline in real dollar terms. It makes sense why NREL is forecasting the up-front capital cost of solar and storage to decline in the next several years, as technology improvements, better materials and

economies of scale as the supply chain and manufacturing capacity expand to meet growing demand will bring capital costs down. However, fixed O&M contains significant costs that are unrelated to the actual technology costs. Costs like property taxes, land leases, insurance, and the wages of workers who will be performing the maintenance will not decline for the reasons capital costs could drop. In her solar cost calculations, Ms. Wilson assumes fixed O&M will drop from $19/KW-year in 2018 to $10/KW-year by 2030. A nearly 50% drop in O&M over that period is a very aggressive if not unrealistic assumption, and one that is unlikely to come to fruition.

Fourth, Ms. Wilson assumed the new solar resources would achieve a 28% or 29% capacity factor between now and 2031, and 30% or 31% thereafter, based on NREL's estimation of the capacity factor for solar sources in Missouri. In AEP's experience, based on numerous actual projects that have been evaluated in the PJM region, capacity factors of 22-24% are more likely in these time periods. Solar capacity factor is a very important assumption for two reasons. First because lower output means lower energy sales profits, and second because output in MWh is the denominator of the LCOE calculation. Ms. Wilson calculated an LCOE for solar every year of her analysis and used that to project the future cost of her solar resources. Lower capacity factors mean higher LCOEs and thus more costly resources as she modeled them. Ms. Wilson's results are very sensitive to this assumption based on calculations I performed using her workpapers. In my estimation, a change to a 23% capacity factor (the midpoint of the capacity factors expected by AEP) would increase the LCOE of her solar resources by $7-9 per MWh over the entire period from 2026 until 2040. This change, along with the lower energy output from the lower capacity factor, would greatly reduce the solar energy profits embedded in her resource

plans. These profits contribute heavily to the cost advantage she claims will result versus continued operation of Mitchell.

Q. IN EACH OF MS. WILSON'S SCENARIOS SHE MODELED SIGNIFICANTLY LARGER ADDITIONS OF LOW- OR NO-VARIABLE-COST ENERGY FROM RENEWABLE RESOURCES TO DISPLACE MORE EXPENSIVE FOSSIL GENERATION. DID MS. WILSON CONSIDER THE RESULTING IMPACT OF CHANGES ON PJM GENERATION FLEET COMPOSITION, FLEET DISPATCH, AND ENERGY PRICES IN THE PROJECTED COST SAVINGS PRESENTED?

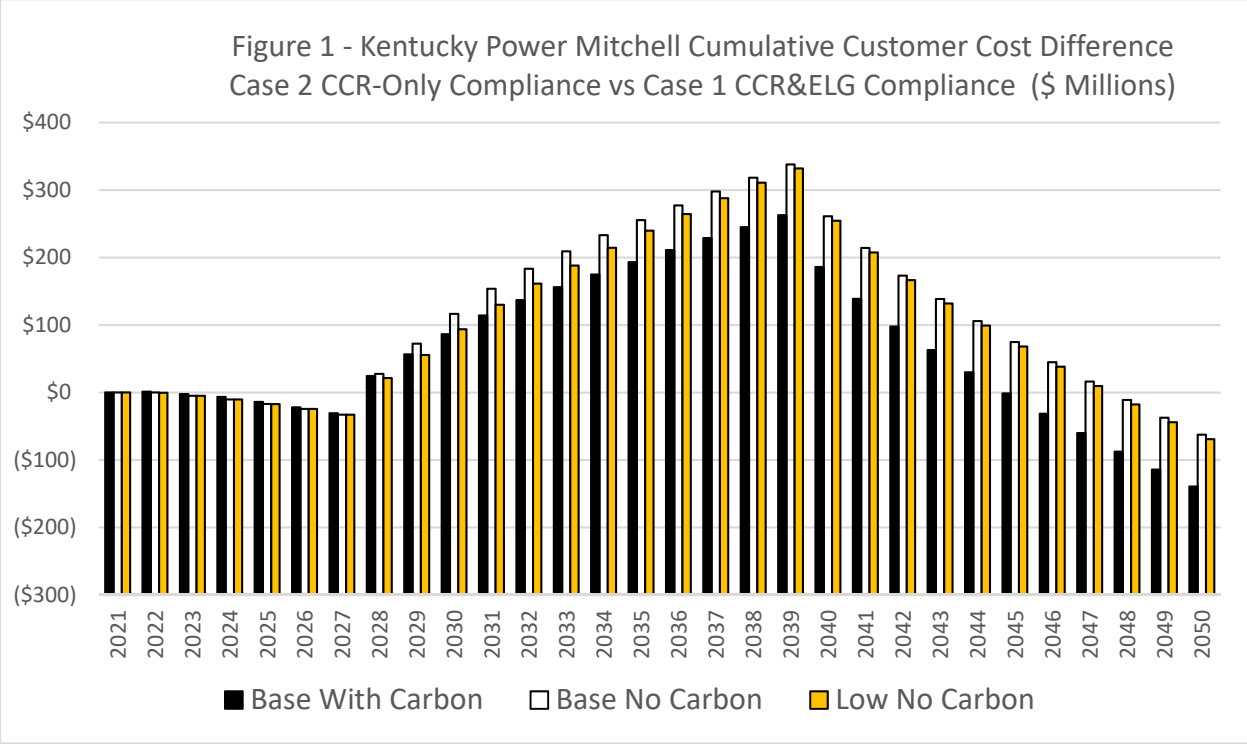
A. No. Ms. Wilson used the Company's Base No Carbon and Base with Carbon energy prices as the basis of her analysis for all scenarios. Those prices do not reflect the impact of significantly displacing fossil generation, which includes fuel and other variable costs, with renewables and storage that have zero or near zero variable costs. In PJM, generation is dispatched based on variable costs, with the marginal unit setting the price of energy for each hour. Ms. Wilson's analysis assumed no new gas resources were available. If that were the case, all else being equal, on-peak market prices (when solar would be producing energy and the storage would be expected to be discharged to meet load) would be expected to be lower in the future than what was incorporated in Company Witness Trecazzi's fundamental forecasts used by Ms. Wilson. Gas units would set the marginal price less often. As a result, the lower power prices reflected in the Low Band fundamental forecast would be expected to be closer to that future state. Ms. Wilson did not model that case as I did. Lower prices would translate to lower energy value for all of the solar and storage

resources added in her analysis, reducing the claimed cost advantage of her 2028 Retirement case compared to her Business As Usual case.

IV. REBUTTAL OF AG/KIUC WITNESS LANE KOLLEN

Q. DO YOU AGREE THAT THE QUANTITATIVE RESULTS OF THE MITCHELL CASES ARE "VERY CLOSE," AS MR. KOLLEN SUGGESTS?

A. As Figure 1 below indicates, over the next approximately 20 years, retirement of Mitchell in 2028 would be $260 million to $340 million ***more expensive*** on a nominal basis under all three fundamentals forecasts than continuing to operate the plant. Only when considering the full analysis period through 2050 do the costs converge.



Q. DO YOU AGREE WITH MR. KOLLEN THAT THE COMPANY WILL BE EXPOSED TO ECONOMIC RISK IF MITCHELL CONTINUES TO OPERATE?

A. No, I do not. Again, as shown in Figure 1, continuing to operate Mitchell over the next approximately 20 years, would be $260 million to $340 million less expensive on a nominal

basis than retiring the plant early in 2028. These significant savings clearly indicate that there is limited economic risk in the Mitchell plant's continued operation. If the $49 million ELG investment is made, the cost savings that customers will experience by delaying hundreds of millions of dollars of replacement capacity occur very quickly. Customers will not have to wait long to benefit from the ELG investment and the continued operation of Mitchell. After a slight cumulative net cost for the ELG investments prior to 2028, the continued operation of Mitchell begins to benefit customers in 2028. Without Mitchell, customers will incur approximately $500 million of replacement capacity costs in 2028 that would be delayed by over a decade by making the $49 million investment to comply with the ELG Rule.

Q. DO YOU AGREE WITH MR. KOLLEN'S COMPARISON OF THE 20 YEAR SOLAR PPAS WITH THE SOLAR PRICING USED BY THE COMPANY IN THEIR ANALYSIS?

A. No, I do not. The Company's modeling assumes 150 MW solar alternative with a 30 year operating life. Mr. Kollen compares the Company's solar alternative to a solar PPA with an operating life of only 20 years. In order to make a reasonable comparison of those two alternatives, the resources would need to be of a similar operating life. In this instance, the 20 year PPA would need to be replaced at some cost at the end of its 20 year life by a PPA with a 10 year life so that the Company and the PPA alternatives would have similar operating lives. During the 10 year period when additional resources have to be added after the expiration of the 20 year PPA, the 30 year owned resource would have depreciated by two-thirds of its original cost. That lower rate base would make the 30 year owned resource more affordable than a new asset for those last 10 years of the owned asset's life.

In addition, the solar PPAs that Mr. Kollen references are due to come on-line in 2023, several years before Kentucky Power would need the capacity to replace Mitchell if it were to retire in 2028.

Q. MR. KOLLEN INDICATES THAT, HAD KENTUCKY POWER USED PPAS AS HE DESCRIBES IN HIS TESTIMONY, THERE WOULD BE AN INCREASE IN THE SAVINGS OF MITCHELL RETIREMENT. DO YOU AGREE THAT THOSE ADDITIONAL SAVINGS ARE SIGNIFICANT?

A. No, I do not. If it were possible to acquire PPAs at the costs Mr. Kollen describes when Kentucky Power needed the capacity in 2028, the retirement savings only increases from $6 million to $14 million out a total cost of $4.3 billion over the 30 year analysis period

Q. DO YOU AGREE WITH MR. KOLLEN THAT THE 2028 MITCHELL RETIREMENT SAVINGS WOULD INCREASE IF THE MODEL WERE ALLOWED TO SELECT ADDITIONAL SOLAR ECONOMICALLY?

A. No, I do not. If the solar PPA pricing was assumed in the modeling as Mr. Kollen suggests, then the model could find it economic to add up to the same capacity levels in both the Mitchell continued operation case and the Mitchell retirement case. If this occurred, then there would be no cost savings attributable to the addition of solar resources.

Q. DO YOU AGREE WITH MR. KOLLEN THAT THE COMPANY ERRED BY NOT INCLUDING A 10% SOLAR INVESTMENT TAX CREDIT (ITC) FOR PROJECTS THAT GO IN SERVICE AFTER 2024?

A. Yes, but only in part. Mr. Kollen is correct that the ITC should have been extended for solar projects that go in service after 2024. However, the solar resources that are critical to this decision are those that are added prior to the potential retirement of Mitchell capacity

in 2028. Therefore, the solar pricing for those resources is only overstated by approximately 4% for the three years prior to the 2028 Mitchell retirement.

Q. DO YOU AGREE WITH MR. KOLLEN THAT THE COMPANY'S COMBUSTION TURBINE ESCALATION RATES USED IN THE ANALYSIS WERE IN ERROR?

A. No, but Mr. Kollen's testimony is premised but an incorrect response I provided to SC 1-16, Attachment 1. During the course of developing my rebuttal testimony, I discovered the original discovery response contained outdated information for the escalation of combustion turbine capital cost. These outdated costs were not used by Kentucky Power in the PLEXOS analysis. In fact, as evidenced by my supplemental response to SC 1-16, the combustion turbine escalation rates that were actually used in the model averaged 2.54% over the analysis period. This escalation rate is very close to Mr. Kollen's suggested 2.5% escalation rate. As a result, the combustion turbines selected by the model to replace a portion of Mitchell capacity in 2028 were constructed for approximately $800/kW. I have included the Company's supplemental discovery response as Exhibit MAB-R2.

Q. DO YOU AGREE WITH MR. KOLLEN THAT THE ANALYSIS RESULTS WOULD NOT BE IMPACTED SUBSTANTIALLY IF THE COMPANY MODEL THE RECENT CHANGES IN WIND PRODUCTION TAX CREDITS (PTCs)?

A. Yes, I do. The Company performed its economic analysis using the most current renewable tax laws at the time the analysis was prepared in October 2020. Subsequently, the law was amended. The important take away is, as Mr. Kollen suggests, that the addition of any new wind that might result for the extension of the PTCs should be viewed in light of wind's limited availability in the Commonwealth, low capacity factor, and the possible transmission investment required to bring wind energy to the Commonwealth.

Q. DO YOU AGREE WITH MR. KOLLEN THAT THE COMPANY NEEDS TO RERUN ITS PLEXOS ANALYSIS WITH HIS SUGGESTED CHANGES IN INPUT ASSUMPTIONS?

A. No, I do not. If the PLEXOS analysis was revised with Mr. Kollen's suggested changes in replacement resource cost assumptions, the results of the analysis would not be materially impacted.

V. CONCLUSION

Q. WHAT CONCLUSIONS HAVE YOU DRAWN FROM YOUR REVIEW OF INTERVENORS' TESTIMONY?

A. I have concluded that Ms. Wilson's analysis contains numerous questionable assumptions and that the results of her analysis should be discounted. In addition, Mr. Kollen's suggested errors in Kentucky Power's analysis would not materially impact the Company's analysis and do not change the Company's conclusions.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

Case No. 2021-00004
Sierra Club Response to KPC Request No. 37
Respondent: Rachel Wilson

Request No. 37

Refer to the fixed charge rate (labeled Capital Recovery Factor) of 4.279% in every year of Row 247 of the tab names ATB Utility Solar_SEE found in the file named Renewable LCOE.xlsx provided in Ms. Wilson's workpapers:

a. Please confirm if Ms. Wilson agrees with the statement that in general the use of a fixed charge rate in an analysis of regulated utility cost of service such as this one produced by Ms. Wilson is intended to produce an estimate of the annual nominal cost ratepayers would incur for a given capital investment by the utility. If she does not agree, please provide an explanation of the fixed charge rate in her analysis.
b. Please confirm that the 4.25% nominal WACC used by Ms. Wilson to develop the 4.279% fixed charge rate referenced here was ultimately sourced from row 776 of the WACC Calc tab in the 2020 ATB Data file provided to the Company with Ms. Wilson's workpapers.
c. Please confirm that the useful life which was assumed for the solar resource used in Ms. Wilson's analysis is 30 years.
d. Please explain why a nominal fixed charge rate on a 30-year investment such as this solar alternative should not be closer to the Company's 10.95% 30 year value found on page 3 of Ms. Wilson's direct testimony Exhibit RW-3.
e. Please confirm that the 4.279% fixed charge rate which ultimately led to the LCOE's used to forecast the costs of the solar resources in Ms. Wilson's analysis was based on the use of NREL's real WACC of 1.69% rather than NREL's nominal WACC of 4.24%, both of which were sourced from the "2020-ATB-Data" file.
f. Please confirm that in NREL's ATB source file "2020 ATB Data" the 4.24% nominal WACC is the same value every year from 2018-2050.
g. Please explain why, given that Ms. Wilson relied on NREL's real dollar capital recovery factor every year from 2018-2050 to prepare real dollar LCOE's on the LCOE Cost Summary worksheet in the Renewable LCOE workpaper file, that she did not also rely on NREL's nominal capital recovery factor every year from 2018 through 2050 when she converted real dollar LCOE's to the nominal dollar LCOE's presented in her testimony and used to forecast the solar resource costs.
h. Were depreciation expenses, income taxes, land leases, property taxes and general and administrative expenses included in the forecasted costs of the solar resources in Ms. Wilson's analysis? If so, provide workpapers that clearly show their inclusion. If not, please explain why not.
i. If the solar resources were assumed to be PPA resources in Ms. Wilson's analysis, would Ms. Wilson agree that a rational PPA counterparty offering a 30-year term for an asset with a 30-year useful life would seek to recovery some amount of depreciation, general and administrative expenses, and income taxes in the PPA price? If not, why not?

Response

Sierra Club, by and through counsel, insofar as it calls for legal conclusions. Subject to and without waiving that objection, Ms. Wilson responds:

a. According to the Financial Definitions tab of the NREL 2020-ATB-Data workbook, which provides the calculation of solar resource costs used in this analysis, the fixed charge rate is the "Amount of revenue per dollar of investment required that must be collected from customers to pay the carrying charges on that investment." This is the purpose of the fixed charge rate in the Synapse analysis. Contrary to KPC's statement that the fixed charge rate is labeled capital recovery factor, these are actually two distinct values. The fixed charge rate is calculated by multiplying the Capital Recovery Factor by the "Project Finance factor," which is calculated in the NREL 2020-ATB-Data workbook on the "Financial Definitions" tab as follows:

Project Finance factor	ProFinFactor = (1 - TR * PVD) / (1 - TR)	
	TR = combined state/federal tax rate	
	PVD = present value of depreciation = summation from y=1 to y=M+1 of (FD_y * f_y)	
	M = # years in MACRS depreciation schedule	
	FD_y = fraction of capital depreciated in year y	
	f_y = depreciation factor in year y	$f_y = 1/d^y$
	d = nominal discount rate (8.9%)	d = WACC * i
	i = inflation rate	

b. The 4.279% value referenced is the Capital Recovery Factor and not the fixed charge rate, but it is confirmed that the 4.25% nominal WACC was ultimately sourced from row 776 of the WACC Calc tab in the 2020 ATB Data file.
c. Confirmed.
d. KPC's 10.95% nominal fixed charge rate on a 30-year investment is calculated as the sum of Return (7.07%), Depreciation (1.81%), FIT (0.62%), and Property Taxes, General & Admin Expenses (1.45%). The Synapse Analysis assumes that solar resources will be developed via PPA and any of these values could and will likely be different for solar developers, or even other utilities.
e. It is confirmed that the 4.279% Capital Recovery Factor was based on the use of NREL's real WACC of 1.69% rather than NREL's nominal WACC of 4.24%, both of which were sourced from the "2020-ATB-Data" file.
f. Confirmed.
g. Ms. Wilson relied on NREL's real dollar LCOE's on the LCOE Cost Summary worksheet in the Renewable LCOE workpaper file, and then converted these values to nominal dollars for use in the EnCompass model.
h. Ms. Wilson's testimony presents an economic analysis of the forward-going costs associated with the continued operation of Mitchell until 2040 versus the early retirement of the plant in 2028. It is not an analysis of the cost of service for Kentucky Power and should not be considered as such. For that reason, there are components that are included in a cost of service analysis that are not included in Ms. Wilson's analysis, and that is true for all resources (existing and new) and all scenarios. Depreciation expenses, income taxes, land leases, property taxes, and general and administrative expenses associated with the Mitchell plant, for example, are also not included in Ms. Wilson's analysis.

i. Ms. Wilson has never worked for a renewable developer and thus does not know if or how they might seek to recover some amount of depreciation, general and admin expenses, and income taxes in their PPA prices. However, publicly available information from other jurisdictions point to evidence that renewable developers are submitting project bids well below KPC's assumed prices. The Public Service Company of Colorado's 2017 all-resource solicitation resulted in a median bid price for solar PV of $29.50/MWh. Northern Indiana Public Service Company's 2018 all-resource solicitation resulted in an average bid price for solar PV of $35.67. See: https://eta-publications.lbl.gov/sites/default/files/all_source_competitive_solutions_20210217_gmlc_format.pdf.

Kentucky Power Company
KPSC Case No. 2021-00004
Sierra Club's First Set of Data Requests
Dated March 12, 2021
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DATA REQUEST

SC 1_16 Refer to the Direct Testimony of Mark A. Becker, page 14, lines 1-10. For each type of fossil generation resource that was available to the PLEXOS model for selection, provide:
a. Technology type
b. Size (MW) on both an ICAP and UCAP basis
c. Assumed book life
d. Assumed operating life
e. Heat rate
f. Firm capacity value
g. Capital cost ($/kW), including annual increases/decreases, if applicable
h. Annual fixed O&M
i. Annual variable O&M
j. Interconnection costs
k. First year available
l. Annual minimum number of units
m. Annual maximum number of units
n. Cumulative maximum

RESPONSE

a and b- Please see the testimony of Company Witness Becker, Table 3 for the gas resource types and nameplate (ICAP). Coal and nuclear were not made available to the PLEXOS model. Please see the Company's response to KUIC-AG 1-29 (KPCO_R__KIUC_AG_1_029_Attachment2). See item f for UCAP.

c & d- 30 years

e-Please see KPCO_R_SC_1_016_Attachment2.

f- The gas options were assumed to receive 99% firm capacity credit for firm capacity (UCAP) purposes.

g-Please see KPCO_R_SC_1_016_Attachment1.

h and i- See the EIA study provided as KPCO_R__KIUC_AG_1_029_Attachment2 for the requested O&M information for the units listed in witness Martin's Table 3.

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j- The Company adopted EIA's assumption regarding interconnection costs, which were based on a one mile interconnection, sized to match the size of the resource. This is provided for each resource type in the Company's response to KUIC-AG 1-29 in KPCO_R__KIUC_AG_1_029_Attachment2.

k-Gas reciprocating internal combustion engine units (RICE) were available beginning in 2024. Frame CT's and CC's were available beginning in 2025.

l, m and n- No annual or cumulative minimum or maximum limits were placed on the fossil resource options.

MAY 28, 2021 SUPPLEMENTAL RESPONSE

g. Kentucky Power determined that the capital costs supplied in KPCO_R_SC_01_16_Attachment1 were outdated capital costs that were not used in connection with the Plexos modeling described in Company Witness Becker's testimony. Please see KPCO_SR_SC_01_16_SupplementalAttachment1 for the capital costs of fossil generation resources that were made available to the Plexos for selection in connection with the modeling described in Company Witness Becker's February 8, 2021 testimony. It should be noted that the capital costs of fossil generation resources made available to the model, and described in Company Witness Becker's February 8, 2021 testimony, escalate at an average annual rate of 2.54% between 2025 and 2050.

Witness: Mark A. Becker

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	overnight cost ($Millions)				overnight cost ($Millions)+ Overheads			
	240 MW CT	430 MW CC	1100 MW CC	20 MW Internal Combustion (RICE)	240 MW CT	430 MW CC	1100 MW CC	20 MW Internal Combustion (RICE)
2021								
2022								
2023								
2024				40.32				45.79
2025	171	485	1,087	41	194	550	1,235	47
2026	174	495	1,110	42	198	562	1,260	48
2027	179	507	1,137	43	203	575	1,291	49
2028	184	521	1,169	44	209	591	1,327	50
2029	189	535	1,201	45	214	608	1,364	52
2030	194	551	1,236	47	221	625	1,403	53
2031	200	566	1,270	48	227	643	1,443	55
2032	205	581	1,303	49	232	659	1,480	56
2033	210	595	1,335	51	238	676	1,517	57
2034	215	610	1,369	52	244	693	1,554	59
2035	220	624	1,401	53	250	709	1,591	60
2036	225	639	1,434	54	256	726	1,629	62
2037	231	654	1,467	56	262	742	1,666	63
2038	236	669	1,500	57	268	759	1,704	64
2039	241	684	1,535	58	274	777	1,744	66
2040	248	702	1,575	60	281	797	1,789	68
2041	254	720	1,616	61	288	818	1,835	69
2042	261	739	1,659	63	296	839	1,883	71
2043	268	759	1,703	64	304	862	1,934	73
2044	275	779	1,747	66	312	884	1,985	75
2045	281	798	1,791	68	320	907	2,034	77
2046	289	819	1,838	70	328	930	2,087	79
2047	296	840	1,885	71	336	954	2,141	81
2048	304	862	1,933	73	345	978	2,195	83
2049	311	883	1,981	75	354	1,003	2,250	85
2050	322	912	2,047	77	365	1,036	2,325	88

2021	
2022	
2023	
2024	0.97%
2025	2.05%
2026	2.08%
2027	2.44%
2028	2.79%
2029	2.77%
2030	2.90%
2031	2.79%
2032	2.57%
2033	2.50%
2034	2.49%
2035	2.38%
2036	2.36%
2037	2.28%
2038	2.26%
2039	2.35%
2040	2.58%
2041	2.59%
2042	2.64%
2043	2.66%
2044	2.64%
2045	2.51%
2046	2.60%
2047	2.57%
2048	2.55%
2049	2.50%
2050	3.30%

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E-Signature Summary

E-Signature 1: Mark A. Becker (MAB)
June 09, 2021 09:04:00 -8:00 [5B74A64F8254] [167.239.2.87]
mabecker@aep.com (Principal) (Personally Known)

E-Signature Notary: S. Smithhisler (SRS)
June 09, 2021 09:04:00 -8:00 [69D2FC0E09A5] [167.239.221.81]
srsmithhisler@aep.com
I, S. Smithhisler, did witness the participants named above electronically sign this document.

VERIFICATION

The undersigned, Mark A. Becker, being duly sworn, deposes and says he is a Managing Director of Resource Planning for American Electric Power Service Corporation, that he has personal knowledge of the matters set forth in the forgoing testimony, and the information contained therein is true and correct to the best of his information, knowledge and belief after reasonable inquiry.

Mark A. Becker
Signed on 2021/06/09 09:04:00 -8:00

Mark A. Becker

STATE OF OHIO)
) Case No. 2021-00004
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Mark A. Becker, on 06/09/2021.

NOTARY PUBLIC STATE OF OHIO
Sarah Smithhisler
Commission # 2019-RE-775042
Electronic Notary Public
State of Ohio
My Comm Exp. Apr 29, 2024
Notary Stamp 2021/06/09 09:04:00 PST 89D2FC0E09A5

S Smithhisler
Signed on 2021/06/09 09:04:00 -8:00

Notary Public

Notary ID Number: 2019-RE-775042