COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF: ELECTRONIC 2016	**)**	
INTEGRATED RESOURCE PLANNING REPORT OF	**)**	**CASE NO. 2016-00413**
KENTUCKY POWER COMPANY TO THE	**)**	
PUBLIC SERVICE COMMISSION OF KENTUCKY	**)**	

JIM WEBB AND SIERRA CLUB'S COMMENTS ON KENTUCKY POWER COMPANY'S 2016 INTEGRATED RESOURCE PLANNING REPORT

I. INTRODUCTION

Intervenors Jim Webb and Sierra Club hereby comment on Kentucky Power Company's ("KPC" or "Company") 2016 Integrated Resource Planning Report ("IRP"). Under the Preferred Plan identified in the IRP, KPC would take a number of important steps towards diversifying the Company's energy portfolio by increasing its investment in renewable energy and demand side management ("DSM"). Such steps include:

- Investing in solar energy resources, starting with 10 MWs in 2019 and ramping up to 130 MWs by 2031;
- Adding 75 MWs (nameplate capacity) of wind energy resources per year in 2018 through 2021, for a total of 300 MWs of wind capacity;
- Extending KPC's current level of cost-effective investments in energy efficiency through 2024, with additional energy efficiency starting in 2023;
- Adding a combined heat and power facility in 2022, and battery storage in 2025.

Notably, the IRP shows that these steps will save money for customers, with average monthly bills declining by $13.30 by 2031 under the Preferred Plan in comparison to what they would be under a "do-nothing" plan that relies only on existing resources. In other words, the IRP shows that KPC can start adjusting to fundamental changes in today's energy markets and seizing the opportunities presented by the growing availability of DSM and renewable energy resources, while also saving money for its customers.

Despite this progress, KPC's IRP is fundamentally flawed as it assumes the continued operation of all of the Company's existing generation resources without ever testing whether such an approach is the least-cost, least-risk option for customers. In particular, the IRP never compares the economics of continued operation of existing resources versus replacing some of those resources with other alternatives, such as renewable energy and DSM. Instead, renewables and DSM are arbitrarily limited and relegated to the role of potential add-ons to the Company's existing fleet, with increased levels of those resources never evaluated. Because of such arbitrary assumptions and limits, KPC's IRP fails to reflect the type of thorough and reasonable planning that can lead to a least-cost and least-risk energy future for customers. Instead, the fundamental resource planning questions of whether it is in the best interest of customers for KPC to continue to rely on its Rockport and Mitchell coal plants through 2031, or whether increased pursuit of renewables and DSM to replace some of those resources would be best for customers, are not even raised, much less answered, by the IRP.

The result of this fundamentally flawed approach is an overall resource portfolio in 2031 that would look quite similar to the current fleet. In 2031, KPC would still be obtaining the vast majority of its capacity and energy from its 50% share of the Mitchell coal plant and its 15% share of the Rockport coal plant, with the Big Sandy Unit 1 gas plant providing most of the rest. 71% of KPC's capacity and 82% of KPC's energy in 2031 would be from coal; levels which are only marginally lower than the 80% of capacity and 94.92% of energy today. (IRP at 18-19, Figures ES-2 to ES-5). It is also a portfolio that has significantly more capacity than is needed, as under the Preferred Plan, KPC would have excess capacity over its PJM obligation of 136 MWs in 2017 and well over 300 MWs in every year from 2021 through 2030 (IRP at 20, Figure ES-6).

Maintaining such excess capacity is an unnecessary expense for KPC customers who already face significant economic challenges. Especially given that KPC's IRP forecasts significantly lower load, and capacity, energy, and gas prices, than were forecast in the 2013 IRP, KPC should have carefully evaluated whether maintaining all of its existing capacity is the best option for customers. And the IRP should have assessed whether the pursuit of increased levels of cost-effective energy efficiency, wind energy, etc. could have further reduced costs for customers, at least in part by enabling KPC to further reduce the amount of existing capacity its customers would be paying to maintain under the Preferred Plan. As such, the Commission Staff should find the IRP inadequate and require KPC to address each of these shortcomings in all future resource planning and decision making.

It is important to keep in mind that the review of KPC's IRP is not just an academic exercise. Instead, as the only public resource planning process for Kentucky utilities, IRPs play an important role in determining whether utilities such as KPC will continue a business as usual approach of over-reliance on aging fossil fuel generation with renewables and efficiency relegated to the role of add-ons, or whether they will actively move towards a modern energy portfolio that prioritizes lower-cost and clean renewables and energy efficiency. It is becoming increasingly clear that the latter approach is the one that a growing number of major commercial and industrial customers in Kentucky want. For example, Toyota recently decided that by 2050 all of its operations, all around the world, should be zero-carbon.[1] Kevin Butt, Toyota's regional environmental sustainability director, who is charged with finding ways to power Toyota with

[1] *See Big Business Pushes Coal-Friendly Kentucky To Embrace Renewables* by Jennifer Ludden, *available at* http://www.npr.org/2017/04/17/523763826/big-business-pushes-coal-friendly-kentucky-to-embrace-renewables

clean energy, noted that one of the hardest places to do that is at the automaker's sprawling plant in central Kentucky, a state where nearly 90 percent of electricity still comes from coal. *Id*. Toyota is not alone; in Kentucky, General Motors, Ford, Walmart, L'Oréal and others also have big goals to reduce emissions. *Id*. Even the state's beloved bourbon makers are starting to look at renewables. *Id*. If Kentucky Power and other utilities don't start offering more renewable energy in their portfolios, industrial and commercial customers will look for other sources. *Id*. "There's not enough renewable energy being manufactured right now for all of us to do what we say we want to do," Kevin Butt says. "They either have to put it in their system," he says, "or people will be looking at alternate ways to get that energy in a renewable form." *Id*.

II. IRP Standards

The IRP process in Kentucky is governed by 807 K.A.R 5:058, which requires KPC to submit every three years a plan that discusses historical and projected demand, resource options for satisfying that demand, and the financial and operating performance of KPC's system.[2] Core elements of the filing include:

- A base load forecast that is "most likely to occur and, to the extent available, alternate forecasts representing lower and upper ranges of expected future growth of the load on its system."[3]

- A "resource assessment and acquisition plan for providing an adequate and reliable supply of electricity to meet forecasted electricity requirements at the lowest possible cost," and that includes consideration of "key uncertainties" and an "assessment of potentially cost-effective resource options available to the utility."[4]

- The revenue requirements and average system rates resulting from the plan set forth in the IRP.[5]

As the Commission Staff stated in reviewing KPC's 2013 IRP filing, the Commission's goal in establishing the IRP requirement:

> was to ensure that all reasonable options for the future supply of electricity were being examined and pursued, and that ratepayers were being provided a reliable supply of electricity at the lowest possible cost.[6]

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[2] 807 K.A.R. 5:058 Section 1(2).

[3] 807 K.A.R. 5:058 Section 7(3).

[4] 807 K.A.R. 5:058 Section 8(1).

[5] 807 K.A.R. 5:058 Section 9.

[6] Kentucky PSC, Staff Report on the 2013 Integrated Resource Plan of Kentucky Power Company, Case No. 2013-00475 (Nov. 2014), at 2 (hereinafter "2013 IRP Staff Report").

The Staff has further explained that, in reviewing an IRP, its goals are to ensure that:

1. All resource options are adequately and fairly evaluated;

2. Critical data, assumptions, and methodologies for all aspects of the plan are adequately documented and are reasonable; and

3. The report also includes an incremental component, noting any significant changes from Kentucky Power's most recently filed IRP.[7]

Evaluation of an IRP should also be guided by the overall requirement that utility rates are "fair, just, and reasonable."[8] As the Commission has explained, it has long been recognized that "'least cost' is one of the fundamental principles utilized when setting rates that are fair, just, and reasonable."[9] A utility's rates will almost certainly not be fair, just, and reasonable if they do not result from planning processes that seek to identify a resource plan that is low cost and low risk for customers.

It is with these standards in mind that the Sierra Club offers the following comments.

III. The IRP Fails to Consider a Reasonable Range of Resource Portfolio Options

One of the central requirements of the IRP process is that a utility provide a plan "for providing an adequate and reliable supply of electricity to meet forecasted electricity requirements at the lowest possible cost."[10] To achieve this goal, a utility must "describe and discuss all options considered for inclusion in the plan," including an assessment of existing generation sources, potential new generation sources, and nonutility generation options.[11] The resource plan must also "consider the potential impacts of selected, key uncertainties and shall include assessment of potentially cost-effective resource options available to the utility."[12] Implicit within that requirement is the notion that a utility will not limit itself to a single resource portfolio, but will instead consider alternative portfolios so "that all reasonable options for the future supply of electricity were being examined and pursued."[13]

KPC's 2016 IRP filing fails to meet these requirements because it simply assumes that the vast majority of the Company's energy and capacity needs will be satisfied by existing resources for the entire planning period, rather than testing whether those resources are the

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[7] *Id*. at 2-3.

[8] KRS § 278.030(1); KRS § 278.040; *Kentucky Public Service Com'n v. Com. ex rel. Conway*, 324 S.W.3d 373, 377 (Ky. 2010).

[9] *In the Matter of: Application of Kentucky Power Co.*, Case No. 2009-00545, 2010 WL 2640998 (Ky. P.S.C. 2010).

[10] 807 KAR 5:058 Section 8; *see also id.* Section 8(4).

[11] *Id.* Section 8(2).

[12] *Id.* KAR 5:058 Section 8.

[13] 2009 IRP Staff Report at 1.

lowest cost option for customers. In particular, the IRP takes as a given the continued reliance on KPC's 50% share of the Mitchell Plant,15% share of the Rockport plant, and (through 2030) 100% of the Big Sandy Unit 1 gas plant. By doing so, the IRP relegates renewable and energy efficiency resources to the role of minor add-ons to an existing fleet, rather than resources that could replace some of the existing resources that the IRP takes as a given. In short, rather than evaluate "all reasonable options for the future supply of electricity," the IRP presents a fait accompli with only modest levels of renewable and energy efficiency add-ons.

KPC's fundamentally flawed approach to existing resources in the IRP is especially unreasonable for two reasons. First, the IRP acknowledges changed market conditions regarding market commodity prices and load that will significantly impact the economics of KPC's existing resources. Second, KPC has an easy out from the Rockport Plant, which faces significant capital costs over the planning period. Namely, if KPC were to determine that Rockport is no longer a low cost resource option for its customers, the Company can simply decline to renew the Unit Power Agreement ("UPA") with the plant when it terminates in 2022. Such an approach, however, would be far easier if KPC began planning for it now.

For all of these reasons, the IRP's analysis of the costs and risks of its preferred resource portfolio and its comparison of its preferred portfolio with alternatives fails to live up to the requirements of the IRP rules. Sierra Club therefore respectfully requests that the Commission Staff note these deficiencies in its report on the Company's IRP and call on KPC to engage in resource planning that looks at a wide range of resource options.

A. The Resource Portfolios Evaluated in the IRP all Consist of Virtually the Same Mix of Generating Assets.

As noted above, one of the central purposes of the IRP process is to consider a variety of resource portfolios and evaluate how they perform under different future conditions.[14] A robust analysis of different resource alternatives helps ensure that a utility will meet the overarching goal of providing a reliable supply of electricity at the lowest possible cost. KPC's IRP fails this requirement because all of the resource portfolios considered in the IRP involve virtually the same set of generating resources.

In the IRP, the Company developed its preferred portfolio by examining four commodity pricing scenarios and two load scenarios:

- a mid-case based on implementation of the Mercury and Air Toxics ("MATS") rule in 2015, relatively lower natural gas price due to the emergence of shale gas plays, and the imposition of a price on CO_2 starting in 2024;
- a low case assuming lower than expected gas prices;
- a high case assuming higher than expected gas prices;
- a scenario assuming no price on CO_2;

[14] 807 KAR 5:058 Section 8(2).

- a low-load scenario, which used the mid-case commodity pricing scenario with a low-load forecast; and
- a high-load scenario, which used the mid-case commodity pricing scenario with a high-load forecast.

(IRP at 102-103, 135). Any potential differences in the impacts of these commodity pricing scenarios, however, were obscured by the fact that each of the resource portfolios modeled under the scenarios were virtually identical. In particular, all of the portfolios considered in the IRP assume that KPC will rely on the same existing generation assets – namely 50% of the Mitchell coal-fired power plant, 100% of Big Sandy Unit 1, and 15% of the Rockport plant – throughout the planning period. (IRP at 13). And, as discussed more fully below, every modeled portfolio capped utility renewable wind resources at no more than 75 MW per year starting in 2018, with a maximum of 300 MW available throughout the planning period, and capped utility renewable solar resources at 40 MW per year starting in 2018. (IRP at 126, 134). No portfolios were modeled in which Rockport and/or Mitchell were retired before 2031, or in which higher levels of renewables and energy efficiency could be pursued.

In short, the IRP failed to consider a broad mix of "potentially cost-effective resource options," thereby limiting the Company's ability to evaluate different resource portfolios and identify the least-cost, least-risk plan for the future.[15] Instead, the IRP created a fait accompli in which the preferred resource plan identified by KPC was essentially pre-determined. Indeed, the IRP explicitly acknowledges as such, stating that "The key initial assumptions in developing this plan are for Kentucky Power to: continue operation of the Mitchell Plant (KPCo share 780 MW); continue operation through 2030 of Big Sandy Unit 1 (285 MW) which was converted to burn natural gas instead of coal; and continue to receive power under the Unit Power Agreement (UPA) from the Rockport Units (393 MW)".) (IRP at 13). Given that the Company can "meet its customers' requirements with these existing sources" with only "modest" additional investments, the Company predetermined that all portfolios would contain the Mitchell, Big Sandy 1, and Rockport plants. (IRP at 14-15). But the point of an IRP process is to evaluate alternative portfolios and scenarios in order to assess whether or in what circumstances a utility should be taking a different resource approach in the future than it is today. By assuming KPC's resource portfolio that is currently in place would remain so for the entire fifteen year planning period, the Company short-circuited such assessment and undercut the primary reason for carrying out an IRP to begin with. Thus, KPC's "key initial assumptions in developing this plan" undercut the required analysis and the validity of the plan.

KPC's approach here was especially problematic because the available evidence suggests a more robust evaluation of resource options may have led to a different preferred resource portfolio. In particular, in every single one of the six scenarios that were evaluated by the Company, the model always added the amount of renewable wind energy that it could add (75 MW a year starting in 2018, with no more than 300 MWs throughout the planning period). (IRP

[15] 807 KAR 5:058 Section 8.

at 21, 136, 137). So even under the "no carbon" scenario and the "low-load" scenario the model selected to add all of the wind power that the Company would allow it to select. (*Id*.)

The Company found that even these modest additions of renewable energy had a significant impact because it lowered customers' bills, reduced the revenue requirements for the Company, and reduced the risk of rate volatility. (IRP at 140, 147). With regards to customer bills, the IRP states:

> Under the Do Nothing Plan [when no renewables or increased energy efficiency programs are added to the Portfolio], the monthly bill will rise due to the assumed annual escalation in the non-energy portion of the bill, in addition to the increased cost in the energy component for coal, natural gas, carbon allowances, PJM market energy prices and incremental investments in existing resources. <u>In the Preferred Plan, these same costs are present, but because many of the resource additions provide energy at lower than PJM market prices, the PJM Market Energy Revenue offsets a portion of the resource costs and provides a reduction in the total monthly bill</u>. As a result, over the planning period (by 2031), the <u>Preferred Plan results in a monthly bill that is $13.30 less than for the Do Nothing Plan</u>.

(IRP at 140). Moreover, based on its risk modeling, the Company determined that "the additional revenue requirement associated with the Preferred Plan is over $100 million lower than the Do Nothing Plan" and "also reduces the risk of rate volatility as well." (IRP at 146-147). Such results suggest that portfolios with increased levels of wind, solar, distributed generation (DG), and energy efficiency, and/or reduced levels of coal-fired generation could have been even lower cost and lower risk. But the IRP never even investigates such a portfolio.

Because the IRP did not consider any resource portfolios without all of the existing generating assets, KPC failed to fully "consider the potential impacts of selected, key uncertainties and [] include assessment of potentially cost-effective resource options available to the utility."[16] This means that the Commission, and KPC's customers, cannot be ensured that KPC is pursuing a least-cost, least-risk resource plan. The Staff should address this shortcoming by calling on KPC to evaluate and model resource portfolios that assume a range of options regarding coal plants, renewable resources, and DSM, rather than simply assuming the continued operation of existing resources for the entire planning period.

B. The IRP Forecasts Substantially Lower Energy and Capacity Market Prices and Loads, which Should Have Led the Company to Reevaluate Its "Key Initial Assumptions" to Continue to Operate Its Existing Capacity.

In addition to running contrary to the fundamental purpose of an IRP, KPC's key assumption that it would continue relying on all of its existing capacity for the entire planning

[16] 807 KAR 5:058 Section 8; *see also id.* KAR 5:058 Section 8I ("The utility shall describe and discuss all options considered for inclusion in the plan including . . . .").

period is also unreasonable given the significant market changes that have occurred since the 2013 IRP. In particular, the Company's analysis revealed four red flags that should have caused the Company to rethink these "key initial assumptions" – substantially lower forecasted energy, capacity, and gas prices than the 2013 IRP[17] and a load forecast that is 12.6% lower in 2028 than was forecast in the 2013 IRP. (IRP at 32, 55).

The fact that KPC is forecasting substantially lower forecasted energy, capacity, and gas prices is critical to how much customers would need to pay to keep the Mitchell and Rockport plants operating. This is because any costs (capital costs and fixed operation and maintenance costs) that are not covered by revenues from the energy and capacity markets have to be covered by KPC's customers. Each of these lower forecasted prices will significantly impact how much revenue the Company will get from the PJM marketplace, which will in turn significantly impact how much KPC's customers are on the hook to pay.

KPC is also forecasting significantly lower PJM energy market prices than it did in its 2013 IRP. In 2013, the Company predicted PJM energy prices from 2017 to 2031 to average \$53.92 and \$38.27 for on-peak and off-peak, respectively. (IRP at 32). In 2016, the Company predicted PJM energy prices from 2017 to 2031 to average \$38.04 and \$29.29 for on-peak and off-peak, respectively. (*Id.*) This represents a decrease of 29% and 21.4% from the 2013 forecast to the 2016 for on-peak and off-peak energy prices, respectively. (*Id.*). This decline in price, if realized, will significantly reduce the revenue to all of the Company's fossil fuel fired generators.

Generators often do not receive sufficient revenue to recover fixed costs through the PJM energy market alone, but can recoup some or all of those fixed costs through the PJM capacity market. The Company's most current forecast of PJM capacity prices demonstrates that this source of revenue is also expected to go down considerably. In 2013, the Company predicted PJM capacity prices from 2017 to 2031 to average \$215.84. (IRP at 32.) In 2016, the Company predicted PJM capacity prices from 2017 to 2031 to average \$41.60. (IRP at 32). This represents a decrease of 80.7% from the 2013 forecast to the 2016 for capacity prices. (*Id.*) As noted, revenues from the capacity market helps cover fixed costs of production (such as capital costs and fixed operation and maintenance costs). Given the most up-to-date information from the Company, the significantly reduced forecasted energy and capacity prices would significantly impact the ability of the Company to pay the fixed costs of production for the Mitchell and Rockport Plants – fixed costs to keep the Rockport plant operating are discussed in detail below – from the revenues it generates from the PJM energy and capacity market.

There are other forecasts that also would impact the ability of these plants to generate revenue. For instance, in the 2016 IRP, the Company forecasted that load would be 12.6% lower

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[17] The AEP Fundamental Analysis group prepares the Long-Term North American Energy Market Forecast ("Fundamentals Forecast") with support from the proprietary AURORAxmp Energy Market Model. (IRP at 99). AURORAxmp is a long-term fundamental production cost-based energy and capacity price forecasting tool that is driven by comprehensive, user-defined commodity input parameters. For example, nearer-term unit-specific fuel delivery and emission allowance price forecasts, based upon actual transactions, which are established by AEP Fundamental Analysis and AEP Fuel, Emissions and Logistics, are input into AURORAxmp. Estimates of longer-term natural gas and coal pricing are provided by AEP Fundamental Analysis in conjunction with input received from consultants, industry groups, trade press, governmental agencies, and others. (*Id.*) The Fundamental Forecast was completed in October of 2016. (IRP at 101).

in 2028 than was forecast in the 2013 IRP. (IRP at 55). The Company also forecasted from 2017 through 2031 that natural gas prices would be 24.5% lower and the Powder River Basin coal, which the Rockport plant burns, would be 24.9% higher under the 2016 IRP than under the 2013 IRP. (IRP at 32). Given how each of these significantly lower forecasted prices (energy, capacity, and gas), lower forecasted demand, and higher forecasted costs for Powder River Basin coal would significantly reduce the economics of the Mitchell and Rockport plants, the Company should not simply have assumed that these two plants would continue to operate through the planning period, but rather allowed the Plexos model to select the most cost-effective resource options available to the utility.

C. The Company Should Have Evaluated Scenarios in which it Does Not Renew the Lease on the Rockport Power Plant after 2022.

KPC's failure to evaluate portfolios with different mixes of generation resources skews, among other things, the IRP's treatment of the Rockport Plant. All of the resource scenarios considered in the IRP, including the preferred portfolio, assume that KPC will continue to purchase 15% of the Rockport plant's power – representing 393 MW of capacity – throughout the entire 15-year planning period. (IRP at 13, 14; *see also id.* at 13 ("While KPCo is assuming, for purposes of this IRP, that the UPA will be renewed and continue through the planning period, the actual decision to extend the UPA will be made in the future. KPCo is currently committed to this purchase through 2022, and there remains much uncertainty with regard to load growth, carbon regulations, commodity pricing, and the future UPA cost.")). In addition to maintaining its current agreement to purchase 15% of the Rockport plant's output, the IRP assumed that KPC would renew this purchase agreement, such that KPC would continue to rely on the Rockport plant beyond the IRP planning period. (*Id.* at 15 ("Although the IRP planning period is limited to 15 years (through 2031), the Plexos® modeling was performed through the year 2035, so as to properly consider various cost-based 'end-effects' for the resource alternatives being considered.")) Although KPC's continued reliance on Rockport is an assumption that undergirds the IRP planning process, KPC's resource portfolio fails to evaluate whether it is the least-cost, least-risk option given the significant known capital costs investments needed at this plant and the forecasted decreased PJM energy and capacity market prices.

Rather than assume continued purchases of Rockport for the next 15 years, the Company should be evaluating, and planning for resource scenarios that do not include energy or capacity from Rockport after the UPA terminates at the end of 2022. These steps are necessary to ensure that KPC has identified the least-cost least-risk resource plan, because Rockport faces significant known environmental compliance costs, and reduced revenues from the PJM energy and capacity markets than previously forecasted, as discussed above.

1. The Company Punted Any Analysis of Whether to Renew the Rockport Lease to a Future Point in Time.

One of the "key initial assumptions" of the 2016 IRP was the continued operation of the Rockport plant through the planning period, even though the Company's current lease for the plant expires in December 2022. (IRP at 12). There was zero analysis underpinning this assumption. The Company explicitly stated that it has "not performed any analyses of the continued operation of Rockport 2." (KPC Response to SC 1-1). The Company claims that it did no assessment of whether to continue the lease (the UPA) because there is too much uncertainty associated with the various planning criteria. (*Id.*) KPC claims that it would be "premature" to consider options for replacing Rockport before new lease terms are available. (*See* KPC Response to SC 2-5; 2-1). The only abbreviated review that the Company did was to review Indiana & Michigan's 2015 IRP which was filed before the Indiana Utility Regulatory Commission. (KPC Response to SC 2-3).

The Company's arguments are unpersuasive. Uncertainty is always present with all resource planning and there are ample planning tools to help address the risk around uncertainty. For instance, no utility knows what future commodity or market prices will be but they use forecasts to reasonably work with these uncertainties. Utilities can compare these forecasts to other forecasts and historical data as a way to evaluate their reasonableness. In addition, the Company could utilize a stochastic, or "Monte Carlo" modeling technique where input variables are randomly selected from a universe of possible values, given certain standard deviation constraints and correlative relationships. This allows a utility to "test" a plan over a distributed range of key variables or uncertainties. The output is, in turn, a distribution of possible outcomes, providing insight as to the risk or probability of a higher cost (revenue requirement) relative to the expected outcome. Each of these tools are standard planning tools to deal with uncertainty and were actually utilized by the Company in other elements of this IRP.

Moreover, uncertainty cuts both ways. Uncertainty impacts a decision extend the lease on the Rockport plant just as much as a decision to allow the lease to terminate. So it is unreasonable to take such a one-sided approach to the underlying uncertainty.

The Company's claim that it would be "premature" to consider options for replacing Rockport until new lease terms are available is also unpersuasive. By actually evaluating the cost and benefits of the Rockport plant as a possible element of the Company's portfolio it could help determine under what lease conditions it would be a least-cost, least-risk option for the Company.

The Company states that it "anticipates addressing an extension of the Rockport UPA coincident with the filing of the Company's 2019 Integrated Resource Plan." (KPC Response to SC 1-1; *see also* KPC Response to SC 2-11). The Commission should put little stock in this statement as the Company made a similar promise in the 2013 IRP process. In KPC's response to Sierra Club and Jim Webb's comments on the 2013 IRP, the Company punted the analysis of whether to extend the Rockport lease to the 2016 IRP, stating "[a]s the Company discussed during the informal conference on April 15, 2014, any decisions about future contractual relationships relating to the Rockport plant will be better addressed in the Company's next (2016) IRP filing when there is likely to be more certainty about key variables, notably potential restrictions on greenhouse gas emissions." (KPC Response to Sierra Club and Jim Webb's Comments on 2013 IRP at 5).

2. The Company is Facing Significant Capital Costs Associated with the NSR Consent Decree and Existing Regulations, Including Costs that will be Incurred in the Near Future.

As the IRP acknowledged, Rockport will face substantial environmental compliance costs in the coming years due to the terms of AEP's New Source Review ("NSR") consent decree and numerous environmental regulations. To comply with these mandates, the Rockport plant must be retrofitted with an array of pollution equipment, including:

- By April 16, 2015, the Rockport units were retrofitted with dry sorbent injection ("DSI") technology and an associated landfill to control SO_2 emissions. (IRP at 69);

- By December 31, 2017 and December 31, 2019, the Rockport units must be retrofitted with selective catalytic reduction ("SCR") systems to control NO_X emissions. (IRP at 69);

- By December 31, 2025, and December 31, 2028, the Rockport units must be retrofitted with flue gas desulfurization ("FGD") systems to control SO_2 emissions. (IRP at 69);

- By 2023, the wet bottom ash handling system at the Rockport plant will need to be converted to dry ash handling system to comply with Effluent Limitation Guidelines and the Coal Combustion Residuals Rule. (IRP at 66-67); and

- The Company anticipates that flow monitoring equipment will need to be installed at the Rockport plant to comply with the Clean Water Act 316(b) Rule.

Under the consent decree, the Rockport units are also subject to an annual SO_2 cap, in which SO_2 emissions from the plant must be steadily decreased over the IRP planning period. Thus, for example, whereas Rockport will be subject to an annual cap of 28,000 tons of SO_2 starting in 2016, that limit will drop to 22,000 tons starting in 2020, and 18,000 tons starting in 2026. (IRP at 70).

Collectively, the costs of these pollution control requirements will be significant. The NSR consent decree alone is expected to cost KPC nearly $[redacted] million in capital investments during the planning period. (*See* KPC Response to SC 1-17, Attachment 1). Specifically, KPC estimates that it will be responsible for $[redacted] in compliance costs over 2017-19 due to the installation of SCRs. (*Id.*). These compliance costs will likely pale in comparison to the cost of installing FGD systems at the Rockport in 2025 and 2028. Installing an FGD at Rockport is expected to cost over $1.4 billion per unit, and Rockport needs two of them. *Wilmington Trust Co. v. AEP Generating Co.*, Case No. 16-3496 (6th Cir. Apr. 14, 2017). Even though KPC's share of the Rockport plants is only 15%, the Company's share would be a significant sum of money at $[redacted] million. (*See* KPC Response to SC 1-17, Attachment 1).

Existing environmental regulations would also lead to capital costs. The Company is projecting that it would need to spend $[redacted] on [redacted] and $[redacted] million on [redacted] to comply with the Effluent Limitation Guidelines and Coal Combustion Residuals Rule. (*Id.*).[18] KPC assumed that the capital costs necessary to comply with the Effluent Limitation Guidelines would be completed in 2019. (*See* KPC Response to SC 1-7 and SC 2-6). Finally, the Company estimates that it might cost $[redacted] million to install flow monitoring equipment at the Rockport plant to comply with the Clean Water Act 316(b) Rule. (*See* KPC Response to SC 1-17, Attachment 1).

Moreover, KPC pays a Return on Equity ("ROE") of 12.6% under the Rockport UPA. (*See* KPC Response to AG 1-4). Since the Company is projecting $[redacted] million to comply with the Consent Decree and existing regulations, this would add another $[redacted] million of costs to KPC's customers.

The fact that compliance with the Consent Decree alone would lead to significant costs for fixed capital improvements – approximately $[redacted] after ROE is taken into account – and that KPC's most up-to-date forecasts project significantly lower PJM energy and capacity market prices and lower load, the Company should have not simply assumed that Rockport would continue to operate throughout the planning period but rather analyzed whether extension or renewal of the Rockport UPA beyond 2022 is really part of a least-cost portfolio.

3. The Company Should Begin to Evaluate Now Whether to Renew the Rockport Lease or to Pursue Other Lower-Cost Options.

The Commission Staff should ensure that future options regarding KPC's share of the Rockport plant are fully evaluated by calling on the Company to fully analyze whether the continued operation of this plant is reasonably part of a least-cost, least-risk portfolio.

If the Company did not renew its lease for the Rockport plant, it would face a capacity shortfall of 120 MWs to 140 MWs in years 2023 through 2030. (*See* KPC Response to PSC 1-1). This is not a significant capacity shortfall. If KPC begins planning now it will have ample time to evaluate all of the available alternatives and come up with a portfolio that fills this capacity need with a lower revenue requirement and a lower risk to rate volatility.

It is important that the Commission ask the Company to begin this analysis now. The Rockport plant is facing significant environmental compliance costs, many of which will be incurred before 2019 including costs to comply with the Effluent Limitation Guidelines and the installation of SCRs to comply with the Consent Decree. By requiring the Company to begin this analysis now it will have a suite of alternatives available for consideration.

[18] The Mitchell power plant is also expected to incur costs to comply with the Effluent Limitation Guidelines; these costs would be incurred from 2018-2022. (*See* KPC Response to SC 1-6.)

A bedrock principle of resource planning is that the plan must "consider the potential impacts of selected, key uncertainties and shall include assessment of potentially cost-effective resource options available to the utility" to determine what portfolio is the least-cost, least-risk option. *See, e.g.,* KAR 5:058 Section 8; *In the Matter of: Application of Kentucky Power Co.*, Case No. 2009-00545, 2010 WL 2640998 (Ky. P.S.C. 2010). The Company should not have simply assumed with no underlying analysis that it would continue to get power from the Rockport plant. This plant is facing significant capital costs. In fact, compliance with the Consent Decree alone would lead to significant costs for fixed capital improvements – approximately $[redacted] after ROE is taken into account. The Company's ability to generate enough money from the PJM energy and capacity market to cover all of the fixed costs of the plant will be significantly degraded under the most up-to-date PJM energy and capacity price forecasts and the projected decrease in load.

IV. KPC's Load Forecast Likely Overestimates Future Demand from the Coal Mining Sector.

One of the central requirements of an IRP is that it provides an accurate forecast of the load expected over the 15-year planning period.[19] Accurate load forecasts are not only an express requirement of the IRP rules, but they are also necessary to ensure that the utility's resource portfolio addresses customers' needs in a cost effective manner. Overestimating a utility's load could skew the IRP modeling, prompting a utility to maintain more generating capacity than necessary and exposing customers to unnecessary costs.

The IRP very likely overestimates future energy demand from the coal mining sector by forecasting that such demand will remain essentially flat from 2017 through 2031 rather than continuing the decline that has been experienced in recent years. The IRP acknowledges that such decline has been occurring, noting that between 2000 and 2015, coal mine production in Eastern Kentucky has fallen 72%, from almost 105 million tons per year to approximately 29 million tons per year. (IRP at 41). This decline has translated into falling mine energy sales, from 979 GWhs in 2010 to 537 GWhs in 2015, (SC 1-5 Attachment 1) which is a decline of 45%. As a result, mine power energy sales have dropped from 12.4% of KPC's total energy sales in 2010 to 7.9% in 2015. (*Id.*).

KPC's IRP forecasts that the sharp decline in mine power energy sales will essentially halt in 2017 and that annual sales will decrease by only 19 GWhs over the planning period, from 469 GWhs in 2017 to 450 GWhs in 2031. (SC 1-5 Attachment 1). KPC contends that it used "professional judgment" to derive that sales forecast from a forecast of Eastern Kentucky coal

[19] *See* 807 KAR 8:058 Section 7(3) (for each year of the planning period, utility must "provide a base load forecast it considers most likely to occur and, to the extent available, alternate forecasts representing lower and upper ranges of expected future growth of the load on its system"); *see also id.* Section (7)(d) (forecast must discuss "[t]he utility's treatment and assessment of load forecast uncertainty"); Section (7)(e)2 (forecast must discuss the extent to which the utility considered "[c]hanges in population and economic conditions in the utility's service territory and general region").

production of 27,755,266 tons in 2017, declining to 24,298,238 tons in 2031. (SC 2-5(c) and SC 2-5 Attachment 1). According to KPC, that Eastern Kentucky coal production forecast "is tied to the Energy Information Administration's forecast for Central Appalachian coal." (SC 2-5(c)). While KPC did not identify in SC 2-5(c) which EIA forecast it was referring to, it is presumably the EIA's 2015 Annual Energy Outlook, which KPC claims was the "most current, long-term outlook from EIA" available for use in the IRP. (KPSC 2-11(b)). KPC offers as further support for its mine power energy sales forecast the claim that such sales have "stabilized and shown slight growth in recent months since the sharp declines in 2015 and early 2016." (KPSC 2-11; KPSC 1-20). In addition, KPC asserts that the EIA's 2017 Annual Energy Outlook does not project significant declines in Central Appalachian coal mining over the 2017 through 2031 planning period. (KPSC 2-11(b)).

KPC's forecast of mine power energy sales in the 469 to 450 GWhs per year range throughout the planning period is unreasonable for at least three reasons. First, actual sales and coal production in 2016 were already well below the levels that KPC contends they would stabilize at over the planning period. In particular, KPC's mine power energy sales in 2016 were 365.7 GWhs, which is 22% below the level of sales that KPC forecasted for 2017. (SC 2-5(a)). And actual Eastern Kentucky coal production in 2016 was 16,689,541 tons,[20] nearly 40% below the 27,755,266 tons that KPC's forecasts for 2017. Even if Eastern Kentucky coal production and mine power energy sales have stabilized, no reason has been provided to think that they would do so at the 2017 levels forecast by KPC rather than at the actual 2016 levels.[21]

Second, KPC's reliance on EIA forecasts of coal production fails because those forecasts are for the entire Central Appalachian region, rather than only Eastern Kentucky. To the extent that such forecasts are relevant, they do not support KPC's forecast. For one thing, the 2015 forecast cited by KPC is of coal supply, not coal production.[22] Meanwhile, the 2017 EIA forecast of Central Appalachian coal production shows a decline in annual production of 23% from 2017 to 2031.[23] By contrast, KPC forecasted only a 12% decline in coal production from 2017 to 2031. (SC 2-5 Attachment 1).

Third, KPC took a very similar approach to forecasting mine power energy sales in its 2013 IRP, which has proven to be way off. In particular, such sales declined 35% from 2009

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[20] Kentucky Energy and Environment Cabinet, *Kentucky Quarterly Coal Report for October to December 2016* (Jan. 1, 2017) at 5, *available at* http://energy.ky.gov/Coal%20Facts%20Library/Kentucky%20Quarterly%20Coal%20Report%20(Q4-2016).pdf

[21] Given that KPC did not file its IRP until December 20, 2016, the Company could and should have incorporated actual coal production and mine power energy sales for a significant portion of 2016 in to the IRP forecast of mine power energy sales.

[22] *See* https://www.eia.gov/outlooks/aeo/data/browser/#/?id=95-AEO2015.

[23] *See* https://www.eia.gov/outlooks/aeo/data/browser/#/?id=95-AEO2017&region=0-0&cases=ref2017&start=2015&end=2050&f=A&linechart=~ref2017-d120816a.7-95-AEO2017&ctype=linechart&sourcekey=0, which shows 2017's forecasted production of 52.1 million tons declining to 40 million tons in 2031. The 2016 EIA showed an even larger Central Appalachian coal production decline of 33% over the planning period, mostly because it forecast a higher 2017 production level of 66.2 million tons.

through 2013, but KPC forecasted that those sales would stabilize in 2014 through the end of the planning period in the 671 GWhs to 688 GWhs per year range. (Case No. 2013-00475, KPSC 1-5 Attachment 1). Instead, such sales continued to decline to a 2016 level of 367.5 GWhs of actual sales that is nearly 45% lower than what KPC forecasted.

In short, even after considerably missing the mark with its 2013 IRP mine power energy sales forecast, KPC utilized in its 2016 IRP the exact same assumption that coal production and, hence, mine power energy sales, in Eastern Kentucky are about to stabilize. But there is no reason to believe that that assumption is any more likely to prove accurate this time around and, in fact, the available evidence of actual sales and mine production in 2016 shows that KPC's forecast in this IRP is almost certainly already over-inflated. The Commission Staff should note these deficiencies in its report on the IRP filing, and recommend that KPC's next IRP provide a more accurate forecast of the coal mining sector's future demand.

V. KPC's 2016 IRP Does Not Adequately Evaluate DSM, or Fully Account for its Ability to Save Customers Money.

The 2016 IRP falls short on evaluating the ability of DSM to help reduce costs for customers. DSM programs are the least-cost, least-risk system resource. With an average national levelized cost of roughly 2-3 cents per KWh, no fuel or emission costs, and the ability to reduce the amount of energy generation (and, therefore, the capacity needed to generate such energy) that is needed, DSM programs are a critical part of a cost-effective resource portfolio that can lower system costs and risk, and reduce customer bills.

KPC's Preferred Plan laudably includes a continuation of its current level of annual investment in energy efficiency through 2024, and an increase in its energy efficiency efforts starting in 2023. Those are important first steps towards developing a resource plan that is least-cost and least-risk for customers. But KPC's own potential study, and the results achieved by utilities throughout the country, show that far more energy efficiency savings are readily and cost-effectively achievable. This IRP is not the forum for resolving the cost recovery, program design, and program evaluation issues that will presumably be addressed in the investigatory docket that the Commission recently opened regarding KPC's current DSM programs and in the Company's future DSM program filings. But an IRP is an important forum for fully assessing a range of potential levels of DSM in order to identify the level that best minimizes costs and risk for customers. KPC's IRP fails to do so, which is a shortcoming that the Commission should ensure is addressed in future resource planning and decision making.

A. The Commission Has Long Recognized the Importance of DSM Resources, and the Need to Fully Evaluate such Resources in the Resource Planning Context.

The Commission has long recognized DSM as critical resources for reducing costs to customers. Since at least 2009, the Commission has noted its belief that "energy efficiency and DSM programs are very important and such programs will become more cost-effective as additional restrictions are placed on on coal-fired generation."[24] The Commission has made similar statements on numerous occasions since then,[25] and as recently as last fall explained in a case involving a different utility that:

> The Commission continues to believe that conservation, energy efficiency, and DSM, generally, will become increasingly important as more constraints are likely to be placed upon utilities whose main source of supply is coal-based generation. The Commission recognizes Kenergy's efforts regarding DSM-program offerings but believes that it is appropriate to continue to encourage Kenergy and all other electric providers to expand their efforts to offer cost-effective DSM and other energy-efficiency programs.[26]

Similarly, in a 2015 decision involving another utility, the Commission noted that:

> [It] commends Blue Grass Energy for its DSM/EE programs and encourages it to aggressively pursue new or expanded programs of that nature
>
> . . . . .
>
> Although Blue Grass Energy has a number of DSM/EE programs in place, the Commission believes that it is appropriate to encourage Blue Grass Energy, and all other electric energy providers, to make a greater effort to offer cost-effective DSM/EE programs.[27]

Such Commission encouragement for DSM has extended to KPC, which the Commission in 2012 "strongly encourage[d] . . . to promote its DSM programs, educate applicable customers who would qualify for DSM program participation, and work to increase participation levels in its DSM programs."[28]

In Kentucky, a primary forum for evaluating what levels of "greater" and "expand[ed]" efforts on DSM a utility should pursue is the IRP process, Specifically, the rules governing that process provide that utilities must identify and describe existing DSM programs and estimate their load impact; account for existing and continuing DSM programs for each load forecast; describe DSM resources that are not already in place and are considered for inclusion in the plan; provide detailed information about each new DSM program, including the energy and peak savings and cost savings; and describe the criteria used to screen each resource alternative, including DSM.[29] Moreover, the Commission has adopted an IRP standard that requires each

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[24] *In re Owen Elec. Co-op, Inc.*, Case No. 2008-00154, PSC Order at 23 (June 25, 2009).

[25] *See, e.g.*, Case No. 2010-00204, PSC Order at 14 (Sept. 30, 2010); *see also* Case No. 2010-00222, PSC Order at 15 (Feb. 17, 2011); Case No. 2008-00408, PSC Order at 22 (Oct. 6, 2011).

[26] *In re Kenergy Corp.*, Case No. 2015-00312, PSC Order at 20-21 (Sept. 15, 2016).

[27] *In re Blue Grass Energy Cooperative Corp.*, Case No. 2014-00339, PSC Order at 6-7 (May 29, 2015).

[28] *In re Application of Kentucky Power Co.*, Case No. 2011-00300, PSC Order at 9 (Jan. 23, 2012).

[29] 807 KAR 5:05(7), (8).

electric utility to “integrate energy efficiency resources into its plans and [] adopt policies establishing cost-effective energy efficiency resources with equal priority as other resource options” and, in each IRP, “fully explain its consideration of cost-effective energy efficiency resources as defined in the Commission’s IRP regulation (807 KAR 5058).”[30]

B. KPC Should Evaluate and Model Higher Levels of Energy Savings from DSM in its Resource Planning.

As noted, KPC’s Preferred Plan includes a continuation of its current level of annual investment in energy efficiency through 2024, and an increase in its energy efficiency efforts starting in 2023. (IRP at 148). According to the IRP, “overall EE savings” will reduce energy demand by nearly 7% by 2031. (IRP at 138-39 and Figure 29). That 7% figure includes savings attributable to federal codes and standards in addition to the energy efficiency programs that KPC includes in the Preferred Plan. While specific numerical data is not provided for Figure 29, it appears from the figure that approximately half of the 7% savings – i.e., 3.5% total - comes from KPC’s programs rather than federal codes and standards. It is important to keep in mind, however, that those figures are based only on residential and commercial load. With industrial load factored in, KPC’s total energy demand is approximately 6,500 GWhs per year. (IRP at 152, Figure 38). Given that KPC has no industrial efficiency programs, the savings from the energy efficiency programs included in the Preferred Plan would be approximately 1.8% of KPC’s total load by 2031. Averaged over the 15-year planning period, the annual incremental energy savings amounts to roughly 0.23% of residential and commercial demand per year, or 0.12% of total demand. The IRP does not model or evaluate any other level of savings from DSM.

That these levels of savings from DSM are well below what is cost-effectively achievable becomes evident upon review of the results of the 2015 market potential study carried out by the Applied Energy Group that KPC itself commissioned (“AEG Study”). That study assessed the technical, economic, and achievable levels of energy savings for KPC’s residential, commercial, and industrial loads. After screening technically feasible energy efficiency programs for cost effectiveness (by screening programs for a total resource cost (“TRC”) benefit-cost ratio higher than one) (IRP at 214), the AEG Study found an achievable potential savings for KPC ranging from 1% to 2.5% of total energy demand by 2018. (IRP at 202). By 2025, the achievable potential savings range from 4% to 9%, and by 2035, the savings range from 7% to 17%. (*Id.*) These levels of achievable savings are significantly higher than the savings included in the Preferred Plan. Yet the IRP does not even evaluate, much less model, such levels of savings that its own market potential study identifies as cost-effectively achievable.

The shortcoming in KPC’s approach here is compounded by the fact that a wide array of real-world experience with DSM at utilities throughout the country show that higher levels of savings than included in the Preferred Plan or identified in the AEG Study are *cost-effectively* achievable. For example:

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[30] *In re Consideration of the New Fed. Standards of the Energy Indep. and Sec. Act of 2007,* Case No. 2008-00408, PSC Order at 10 (July 24, 2012).

- From 2009 to 2011, KPC's sister utility in the neighboring state of Ohio, AEP Ohio, achieved 2.4% savings, or 0.5%, 0.8%, and 1.1% incrementally, at a cost of approximately 1 cent per kWh.[31]

- In Michigan, electric utilities have, on average, exceeded the state's energy efficiency standard, which escalated from 0.3% savings in 2009 to 1% savings in 2012 and each year thereafter, in each of those years.[32] In 2015, the Michigan utilities achieved savings that were 121% of the 1% standard, at a cost of $0.014per kWh of energy saved which, as the report notes, "is significantly lower than the cost of supply side options."[33] Each dollar of Michigan utility spending on energy efficiency in 2015 is expected to lead to $4.35 of benefits to customers, with $262 million of spending in 2015 expected to result in lifecycle savings to customers of $1.08 billion.[34]

- In 2015, 16 states – including Arizona, Illinois, Iowa, Maine, Michigan, Minnesota, and Oregon - achieved incremental energy savings of 1% or more in their electric sectors from efficiency programs.[35]

By contrast, KPC projects that in the 15-year planning period at issue here, the Company's energy efficiency programs will achieve an average of only 1/5 to 1/8 of the 1% savings that is regularly being achieved or exceeded by utilities and states throughout the country. No explanation has been offered for why KPC purportedly cannot achieve similar levels of savings as those of other utilities and states. But part of the reason is likely because KPC has never tried to evaluate whether it could do so and, if so, whether doing so would provide similar net benefits to customers as it does for other utilities and states.

The resource planning process is the ideal forum in which to evaluate the feasibility, benefits, and costs of such increased levels of DSM, yet KPC has failed to do so. The Commission should ensure that KPC remedies this deficiency in all future resource planning and decision making.

[31] Max Neubauer *et al.*, Ohio's Energy Efficiency Resource Standard: Impacts on the Ohio Wholesale Electricity Market and Benefits to the State, p.14, ACEEE (Apr. 2013), *available at* http://www.aceee.org/sites/default/files/publications/researchreports/e138.pdf.

[32] Michigan Public Service Commission, 2016 Report on the Implementation of P.A. 295 Utility Energy Optimization Programs (Nov. 30, 2016), at 12, *available at* http://www.michigan.gov/documents/mpsc/2016_Energy_Optimization_Report_to_the_Legislature_with_Appendix_Nov_30_543919_7.pdf.

[33] *Id*. at 1.

[34] *Id*.

[35] ACEEE, 2016 Spending Savings Tables, *available at* http://database.aceee.org/sites/default/files/docs/spending-savings-tables.pdf.

C. KPC Should Evaluate Industrial Efficiency Programs as part of its Resource Planning.

One way that KPC should increase the level of DSM savings evaluated in its resource planning is to factor in cost-effective industrial programs that the utility could pursue. The industrial sector represents roughly 43% of the load in KPC's service territory. (Compare SC 2-8(e) with IRP at 139, Figure 29). Yet, KPC does not currently offer any programs to its industrial customers and does not plan to offer any during the IRP planning period. This is a significant missed opportunity, as industrial energy efficiency generally has the most cost-effective potential of all of the sectors. Specifically, industrial efficiency resources can be half the cost of resources in other sectors, in terms of dollars per kWh saved, and offer higher benefit-to-cost ratios than measures in the residential and commercial sectors.[36] As such, industrial energy efficiency programs should play an important role in any resource planning process that is focused on developing lowest cost portfolios for customers.

KPC's failure to even evaluate industrial efficiency programs as part of its resource planning process is especially unreasonable given that the AEG Study identifies significant levels of savings that are achievable in the industrial sector. As that study found, "The industrial sector has significant untapped savings potential, specifically with regard to applying variable speed drives to the motor end uses." (IRP at 201). In addition, AEG found that "there are significant opportunities for savings in interior lighting measures (screw in and occupancy sensors), process timers and controls, and space heating." (*Id*. at 220). The AEG Study concluded that achievable potential savings for the industrial sector is between 0.7% and 2.8% by 2018, between 2.8% and 9.9% by 2025, and between 4.8% and 16.5% by 2035. (IRP at 88, Table 12).

KPC declines to consider industrial efficiency programs in its resource planning on the grounds that industrial customers will purportedly "self-invest in EE measures based on customer-specific economic evaluation regardless of the existence of utility-sponsored energy efficiency programs." (SC 1-14). But KPC cannot identify any study or analysis supporting its position, and has no data regarding the levels of "self-investment" in efficiency or resulting levels of energy saved by industrial customers in past years, or that can be expected in any year of the planning period. (SC 2-8(b), (c)). And, regardless, the AEG Study found significant levels of untapped energy savings potential in the industrial sector. (IRP at 88, 201, 220).

KPC also contends that it is appropriate for it to ignore industrial efficiency programs in its resource planning because its customers are not interested in such programs. (SC 1-14). The only real world experience, however, upon which this claim is based is an industrial audit and incentive program that KPC spent less than $76,000 on in 1996 through 1998. (SC 2-8(d)). KPC's contention that it has not received any requests to reinstate two lightly funded programs from twenty years ago (SC 1-14) hardly provides a reasonable basis to conclude a complete lack

[36] Anna Chittum, Follow the Leaders: Improving Large Customer Self-Direct Programs, ACEEE, at 5 (2011), *available at* http://www.aceee.org/research-report/ie112.

of interest among industrial customers for utility energy efficiency and DSM programs. At the very least, KPC should consider such programs in its IRP.

D. The Lack of Forecasted Load Growth in KPC's Service Territory Does Not Justify KPC's Failure to Evaluate Increased Levels of Cost-Effective DSM.

Finally, it is important to note that the fact that KPC is projected to experience declining, rather than increasing, energy demand over the planning period should not excuse the Company's failure to evaluate increased levels of cost-effective DSM. If, as is typically the case with DSM, it is cheaper to avoid the need for a kWh of electricity than it is to purchase that kWh, that cost savings benefit will accrue to a customer regardless of whether their total electricity needs are otherwise increasing or decreasing. As such, there is no basis to question the importance of DSM resources in the present scenario of declining demand.

It is true that DSM programs have typically been considered as ways to hold down costs in a scenario of projected rising demand. Energy efficiency may seem especially urgent when faced with projected demand increases because customers would likely be facing rising electricity bills to pay for both the increased number of kWhs that they would need and for the construction or purchase of additional generation capacity to serve increasing demand. In that scenario, DSM programs can save customers money by tamping down the number of kWhs of electricity a customer needs to purchase, and by staving off the need for additional generation capacity.

The opposite scenario of declining demand may appear to pose a less compelling case for increased energy efficiency and other DSM, but any such appearance is deceiving. In reality, the economic logic is the same in both scenarios. It is just that in the declining demand scenario, the DSM is benefitting customers by replacing higher priced existing capacity that the utility is already paying for, rather than capacity that the utility might have to acquire in the future.

For example, as discussed above, in part because of decreasing demand, KPC may be able to decline to renew or extend its lease for a 15% share of the Rockport plant beyond its 2022 termination date, thereby relieving customers of the cost of that resource. In a scenario where KPC were instead faced with increasing demand, the Company could have, hypothetically, been faced with the question of whether to pursue more of Rockport. In the latter situation, few would question the advisability of pursuing more DSM if it is a lower cost way to stave off any such need for more of Rockport. Similarly, in the former scenario of declining demand, increased DSM would benefit customers by helping to put KPC in the position to be able to stop paying for its current 15% share of Rockport after 2022. By not evaluating such increased levels of energy efficiency and other DSM, however, KPC effectively and unjustifiably excluded that critical benefit from its evaluation of DSM.

VI. While the IRP Proposes Some Important Progress on Wind Power, it also Unreasonably Limits the Pursuit of this Low Cost Renewable Resource.

KPC has long been a laggard when it comes to wind resources. The United States has more than 82,000 MWs of installed wind capacity,[37] and KPC's parent company – AEP – has more than 3,000 MWs of wind in its portfolio.[38] AEP affiliate Appalachian Power Company, with a service territory right across the border from KPC in West Virginia, recently signed a 20-year wind PPA that brings its wind capacity up to 495 MWs.[39] Yet in 2017, KPC has zero wind capacity or energy in its resource portfolio. (IRP at 149-150, Figures 33 and 35).

The IRP proposes to pursue 75 MWs (nameplate capacity) of wind per year from 2018 through 2021, which would result in the utility having 300 MWs of wind capacity within a little over four years. (IRP at 149). This 300 MWs of wind capacity was selected by KPC's Plexos modeling in all five market pricing scenarios that the Company modeled. (IRP at 136, Table 19). As KPC explained in a response to a data request, such result demonstrates that:

> The model selected wind energy because it lowers customers' costs over the wind project lifecycle; that is, the cost of wind energy is projected to be less than the cost of energy from the PJM market. As such, it is the least cost option.

(AG 1-2(b)). Sierra Club urges KPC to pursue this least cost resource as expeditiously as possible.

The fact that the model selected the full 300 MWs of wind capacity in every pricing scenario, however, also suggests that KPC should be pursuing more wind resources more quickly than proposed in the IRP, or at the very least evaluating a further scale up of this low cost resource. A review of the IRP and KPC's responses to data requests demonstrates that the IRP fails to recommend additional wind because KPC limited the level of this least cost resource that the model would select in several ways. As described below, these constraints are unreasonable and unsupported.

First, in all of its evaluated scenarios, the Company capped the amount of wind that could be selected to no more than 75 MW per year. (IRP at 127). KPC contends that such cap is necessary because of the Company's limited "ability to plan, manage and develop either the construction or the procurement of these resources." (*Id*.). KPC suggests that it has a learning curve with regards to wind, noting that "as KPCo gains experience with wind installations, this limit would likely be modified (for example, it may be lower earlier and greater later)." (*Id*.). This purported learning curve is questionable at best, given that KPC should have access to all of the knowledge and expertise that its parent company, AEP, has with acquiring more than 3,000

[37] http://apps2.eere.energy.gov/wind/windexchange/wind_installed_capacity.asp

[38] https://www.aep.com/environment/climatechange/renewableenergy.aspx

[39] https://www.appalachianpower.com/info/news/viewRelease.aspx?releaseID=1999

MWs of wind fleet wide. At a minimum, one would expect any such learning curve to be overcome quickly, yet KPC kept this annual 75 MW limit throughout the entire planning period. At a minimum, the Company should have had its annual cap limit increasing over the whole planning period.

Second, the Company capped the total amount of wind capacity that could be selected over the entire planning period. The description of this cap is inconsistent, as the IRP refers to it as a "300 MW cap," (*Id*.) but then in the very next sentence states that the cap "allows the model to select up to 30% of generation capacity resources as wind-powered by 2031." (*Id*.). The latter description does not match the IRP results, under which wind accounts for only "18.15%" of the "2031 KPCo Nameplate Capacity Mix." (IRP at 17, Fig. ES-3). Given that the Preferred Plan (like all evaluated scenarios) included the maximum amount of wind capacity allowed in each year, wind should have been 30% of nameplate capacity in the 2031 KPCo Nameplate Capacity Mix. Given that KPC has nearly 1,400 MWs of installed capacity in almost every year of the planning period, the 30% cap should have allowed for approximately 400 MWs of wind capacity, not 300 MWs. Regardless, the planning period cap itself, at either the 300 MW or 400 MW level, is unsupported. Instead, KPC contends only that the U.S. Department of Energy's Wind Vision Report "suggests that transmission grids should be able to support 20% to 30% of intermittent resources in the 2020 to 2030 timeframe." (IRP at 127). In support, KPC cites to Figure 1.5 in the Wind Vision Report, which simply notes that various studies have evaluated wind penetration rates of 20% to 30% by between 2026 and 2030.[40] Nowhere in the report does DOE contend that 20% to 30% integration is the limit for wind integration; in fact, the study explains that:

> Experience with the transmission, integration, and delivery of this electricity has verified the conclusions of numerous integration studies: No technical limits or obstacles have been identified that would prevent wind-generated electricity from meeting even greater portions of electricity demand in the United States. There may be a need for institutional or operational practice to change in some areas, however, so that wind power can be integrated successfully at increasing penetrations.[41]

In short, what the DOE report calls for is not a hard cap on the amount of wind that can be modeled in a long term integrated resource plan, but instead an evaluation of the steps needed to enable integration of increasing amounts of wind, along with the costs of such steps.[42] KPC, however, has not performed or identified any such analysis of what level of wind can be integrated into its existing system, or of what steps can be taken to overcome any obstacles that might serve to hinder higher levels of integration. Given the potential for renewable energy to dramatically decrease customers' bills, to reduce revenue requirements, and to decrease the risk of rate volatility, the Company should have done a specific analysis of its transmission grids to

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[40] DOE Wind Vision report at 12, *available at* https://www.energy.gov/sites/prod/files/WindVision_Report_final.pdf

[41] DOE Wind Vision Report at 83.

[42] *See generally*, DOE Wind Vision Report Chapter 2.

determine what level of renewable energy penetration is possible, not placed an arbitrary cap on a resource that is a least cost option for customers.

A third way that the IRP underestimates the competitiveness of wind is by assuming that no further declines in the cost of wind energy will occur. In particular, the IRP assumes a levelized cost of energy ("LCOE") for wind of $47/MWh in 2017, escalating to more than $70/MWh by 2024 as the Production Tax Credit ("PTC") phases out, and then continuing to increase after that to almost $80/MWh by 2031. (IRP at 127). Even assuming the reasonableness of the $47/MWh LCOE for 2017 and that the PTC phases out, KPC's wind cost projection is unreasonable because it fails to account for the fact that, leaving aside the PTC, most experts expect wind costs to continue to decline by approximately 10% to 20% by 2020, and 20% to 40% through 2030.[43] Such expected cost declines would offset at least some of the increased cost that would result from a phase out of the PTC. Yet KPC's wind energy cost forecast apparently assumes that the continued technological advances of wind power will not have any downward pressure on the cost of wind resources. Such an assumption is unsupported and unreasonable.

Finally, KPC's assignment of only a 5% capacity value to wind in the IRP, which is a little more than 1/3 of the capacity value that PJM assigns to wind, requires further justification. (IRP at 108). In response to a data request from Staff, KPC contends that the 5% capacity value reflects the risks under PJM's Capacity Performance Product to an intermittent resource such as wind. (KPSC 1-35). KPC, however, was unable to provide any explanation for how it arrived at a 5% capacity value, instead just vaguely referring to "management's judgment." (*Id.*) Some actual analysis is needed before it can be deemed reasonable for KPC to discount the capacity value of wind energy resources in this manner.

VII. While the IRP Proposes an Increase in Utility-Scale Solar, KPC Continues to Constrain the Resource and Assumes Very Low Levels of DG.

The IRP recognizes the steady decline in the cost of solar, as well as other attributes that make solar a prudent part of a utility resource mix. (IRP at 122). The Preferred Plan starts with 10 MWs of utility-scale solar in 2019 and ramps up to 130 MWs by 2031. (*Id.* at 148). This is progress.

However, similar to its consideration of wind resources, KPC limits the amount of this renewable energy resource that the model could select. Large scale solar resources were capped at 40 MW per year (nameplate capacity). (*Id.* at 122-23). KPC asserts that this annual cap is needed because "as solar costs continue to decrease relative to the market price of energy there will come a point where the optimization model will theoretically pick an unlimited amount of solar resources." (*Id.* at 123). But the fact that the model could choose more solar based on declining costs is not a sufficient reason to constrain the resource to 40 MW per year.

[43] Lawrence Berkeley National Labs, National Renewable Energy Laboratory, and IEA Wind, Forecasting Wind Energy Costs & Cost Drivers: The Views of the World's Leading Experts, LBNL-1005717 (June 2016) at 13, *available at* https://www.ieawind.org/task_26_public/PDF/062316/lbnl-1005717.pdf

KPC also states that the cap recognizes a practical limit with regards to the number of large scale solar plants that could be "identified, permitted, constructed and interconnected by KPCo in a given year." (*Id.* at 123). However, such a limitation is premised on a build-only option. Regardless of their merits, such constraints do not apply to purchases from existing solar resources, which KPC should also evaluate.

As in the case of wind, KPC notes that "as KPCo gains experience with solar installations, this limit would likely be modified (for example, it may be lower earlier and greater later)." (*Id.* at 123). But the 40 MW cap is not lifted or increased during any part of the planning period. At a minimum, the Company should have had its annual cap limit increasing over the planning period.

Finally, KPC's assumptions with regards to DG raises significant concerns. KPC recognizes that the price of residential rooftop solar continues to drop and the "economics of DG, particularly solar, continue to improve." (IRP at 79). However, the Company assumes that DG capacity will total only 1.1 MW (nameplate) by 2031. (IRP at 16). KPC states that this significant reduction in estimated DG capacity from the last IRP is "based on current trends." (IRP at 33). However, given the economic trends that KPC identified—namely those that have contributed to an increase in DG across the country—KPC's assumption should be reevaluated.

VIII. Conclusion

KPC's IRP proposes a number of important first steps to begin diversifying the Company's almost entirely coal-based portfolio. The rest of KPC's analysis, however, is fundamentally flawed because it assumes rather than evaluates the Company's continued reliance on its existing generation fleet and treats renewable energy and DSM as an arbitrarily limited "add-on" to KPC's existing fleet rather than resource options for helping to replace some of that aging capacity. The Commission should require KPC to correct these errors in the next IRP, and to address the identified flaws in any future resource planning and decision making,

Respectfully submitted,

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CERTIFICATE OF SERVICE

This is to certify that the foregoing copy of **JIM WEBB AND SIERRA CLUB'S COMMENTS ON KENTUCKY POWER COMPANY'S 2016 INTEGRATED RESOURCE PLANNING REPORT** in this action is a true and accurate copy of the document being filed in paper medium; that the electronic filing was transmitted to the Commission on April 21, 2017; that there are currently no parties that the Commission has excused from participation by electronic means in this proceeding; and that a copy of the filing in paper medium is being sent to the Commission via Federal Express.

/s/ Joe F. Childers_____________
Joe F. Childers