COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Application of Kentucky Power Company for Approval of	)	
its Environmental Compliance Plan, Approval of its Amended	)	**CASE NO. 2011-00401**
Environmental Cost Recovery Surcharge Tariffs, and for the	)	
Grant of Certificates of Public Convenience and Necessity	)	
for the Construction and Acquisition of Related Facilities	)	

TOM VIERHELLER, BEVERLY MAY, AND SIERRA CLUB'S POST HEARING BRIEF

RECEIVED
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PUBLIC SERVICE COMMISSION

LIST OF ACRONYMS

AEP	American Electric Power
AEP GENCO	AEP Generating Company
AFUDC	Allowance for Funds During Construction
CAPP	Central Appalachian
NGCC	Natural Gas Combined Cycle Plant
CPCN	Certificate for Public Convenience and Necessity
CPW	Cumulative Present Worth
CSAPR	Cross State Air Pollution Rule
DSM	Demand Side Management
FGD	Flue Gas Desulfurization
GWh	Gigawatt Hours
KPCo	Kentucky Power Company
MATS	Mercury and Air Toxics Standard Rule
NAPP	Northern Appalachian
NGCC	Natural Gas Combined Cycle Plant
OSS	Off System Sales
RFP	Request for Proposals
RRaR	Revenue Requirement at Risk

This proceeding boils down to a simple question – should the most impoverished communities in Kentucky have their electricity rates raised by as much as 35.2% in order to finance a nearly $1 billion retrofit of the 43-year-old Big Sandy Unit 2 coal plant. The answer to this question is plainly no, as Kentucky Power Company's ("KPCo" or "the Company") own filing shows that lower cost, newer options for meeting the company's energy needs and compliance requirements are available. KPCo, however, did not even look for such other resources, submitted highly flawed economic modeling that failed to account for a reasonable range of costs, and hid a potential $202 million additional cost to its ratepayers if Big Sandy Unit 2 were required to retire in 2030 instead of operating through 2040, even while taking steps to protect KPCo's shareholders from that same risk. In short, KPCo has not come close to satisfying its burden of showing that its 35.2% rate increase is just, reasonable, or part of a least cost option. As such, the Commission should deny the Certificate of Public Convenience and Necessity ("CPCN") so that KPCo can pursue lower cost market, natural gas, energy efficiency, and renewable energy resources.

I. FACTUAL BACKGROUND

A. KPCo's Surprising Announcement to Retrofit Big Sandy Unit 2 and Seek a 15-Year Depreciation on the Project.

On December 5, 2011, KPCo, a subsidiary of American Electric Power ("AEP"), submitted an application for a CPCN and to install flue gas desulfurization system ("FGD" or "scrubber") on its 816 megawatt ("MW") Big Sandy Unit 2 coal-fired power plant. This modification is needed to comply with the Cross State Air Pollution Rule, the Mercury and Air Toxic Standards Rule, and a consent decree KPCo entered into over 5 years ago if the unit is to continue operating beyond 2015. (McManus Dir. Test. at 6-8). KPCo projects the capital cost of this retrofit project is $940 million. (Application at 8.)

KPCo's proposed retrofit directly contradicts the course of action publicly announced by AEP on June 9, 2011, when it stated that it planned to retire the Big Sandy unit in December 31, 2014 and replace that capacity with a 640MW natural gas combined cycle ("NGCC") plant. In fact, up through October 2011, AEP was still telling shareholders that it intended to retire Big Sandy 2 as it was not economic to install a FGD system.[1] One month later, however, KPCo indicated to investors that it would retrofit the Big Sandy 2, not retire it.[2] In at least six presentations from November through December 2011, including some after the KPCo had requested nearly $1 billion from this Commission in this CPCN application, AEP continued to tell investors that the retrofit would cost $525 million.[3]

In the face of these inconsistencies, KPCo is requesting $940 million to install the FGD system. Although KPCo claims that this retrofitted unit will have a 25-year operating life, (Weaver Dir. Test. at 15), the Company is requesting that the Commission grant it a15-year depreciation on these capital costs and return on equity because there is a risk that "future environmental regulations, particularly carbon legislation," could cause operation of this unit "not to be economically feasible in the future." (Wohnhas Dir. Test. at 15). The Company states that there is a "medium risk" that this will occur. (Hearing Ex. SC-3, KPCo Response to Staff 1-91; Hearing, Witness Wohnhas, April 30, 2012, 13:54:32-13:55:09.) The Company is requesting this accelerated depreciation to protect its shareholders (as opposed to the ratepayers) from

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[1] Attachment to response to Sierra Club DR 1-1."ISI Meeting Handout" (October 6, 2011) slide 11, and response to Sierra Club DR 2-11. "Although the Company was still reviewing all of the alternatives as of this date [Oct 6, 2011], Big Sandy Unit 2 was then being shown as a retirement."

[2] Attachment to response to Sierra Club DR 1-1."Morgan Stanley Office Visit" (November 17, 2011) slide 22, and response to Sierra Club DR 2-12. "In November 2011, installation of a DFGD on Big Sandy Unit 2 was the alternative that had been chosen by the Company."

[3] Attachment to response to Sierra Club DR 1-1 "2011 Fact Book 46th EEI Financial Conference" (Nov. 6, 2011); "46th EEI Financial Conference Handout" (Nov 7-8, 2011); "Morgan Stanley Office Visit" (Nov. 17, 2011); "Utilities Week Investor Meeting Handout New York" (Nov. 29-30,2011); "Wells Fargo 10th Annual Pipeline, MLP & Energy Symposium Handout" (Dec 7, 2011); "Goldman Sachs 6th Annual Clean Energy & Power Conference" (Dec. 9, 2011).

facing $370 million in stranded investments. (Hearing, Witness Wohnhas, April 30, 2012, 14:08:37-14:12:50; *see also* Hearing Ex. SC-6, KPCo Response to SC 1-17j, Att. 2.) In fact, this risk is so pronounced that the Company even considered a more accelerated, 10-year depreciation on this retrofit. (Hearing, Witness Wohnhas, April 30, 2012, 13:58:37-14:02:50; Hearing Ex. SC-5, KPCo Response to KIUC's 1-28, att.) Despite this acknowledged risk and request for special shareholder protection, the Company justified this project as the supposed least-cost option based on modeling that assumed Big Sandy Unit 2 would operate for at least 25 years after the proposed retrofit. (Weaver Dir. Test. at 15).

B. The Company Only Considered a Limited Range of Alternatives.

The Company only considered four alternatives: (1) retrofitting the 43-year old Big Sandy Unit 2 with a FGD system; (2) retire Big Sandy Units 1 and 2 and replace them with a 762MW (904MW for peaking purposes) new combined cycle natural gas plant ("CC"); (3) repower Big Sandy Units 1 and 2 with a 745MW (780MW for peaking purposes) NGCC; and (4) retire Big Sandy Units 1 and 2 and replace both units with energy and capacity purchases on the market for either five or ten years. (Weaver Dir. Test. at 11-12.)

There are many alternatives that KPCo never considered. The Company never issued a Request for Proposals ("RFP") to identify the full range of fossil, renewable and efficiency resources available to replace Big Sandy Unit 2, including fractional or co-ownership in either new or existing resources. (Hearing, Witness Wohnhas, April 30, 2012, 15:16:46-15:17:38, KPCo Response to Staff 1-65(c); KPCo Responses to Sierra Club 1-51 and 2-21.) According to the Company, it did not need to issue an RFP as its identified alternatives represented an accurate proxy for bids it would have received.

The Company also never considered whether it could acquire AEP assets in Ohio. AEP is going through a corporate restructuring in Ohio in which distribution utilities are going to be separated from generation utilities. As a result, AEP's generation assets in Ohio will be available for sale or transfer. In December 2011, the Ohio Public Utility Commission initially approved this corporate separation plan. Then AEP Generating Company ("AEP GENCO") proposed in a FERC filing that certain of its generating units would be transferred to AEP affiliates at net book value. In an Ohio Public Utility Commission docket, AEP submitted a list of the generation assets that it planned to transfer to AEP GENCO. This list of assets includes the Waterford and Lawrenceburg NGCC plants, which each have a net book value of less than one-quarter of the cost for NGCC assumed in modeling Options 2 and 3. KPCo never inquired at AEP whether it could acquire all or a portion of these plants at net book value.

The Company also never did a market potential study to determine what demand-side management ("DSM") or energy efficiency programs are available to cost-effectively reduce energy and capacity demand. (Hearing, Witness Wohnhas, April 30, 2012, 15:17:40.)

Finally, KPCo never considered a portfolio approach. Instead, the Company considered an all-or-nothing approach – either full ownership of a large coal unit, full ownership of a large natural gas CC plant, or full procurement through the market. KPCo did not explore a portfolio approach consisting of one or more alternative mixes of various types and sizes of resources, including renewable sources, energy efficiency or demand response. (KPCo Responses to Sierra Club 1-52, Sierra Club 1-62.) The Company could have used Strategist, its primary modeling tool, to evaluate a much broader range of supply-side and demand-side resource options. The Company had the ability to enter a broad range of available options into Strategist and to let the model choose the portfolio with the optimal, i.e., least-cost, mix of capacity and energy from that inventory of resource options. (Wilson Direct Test. at 3.) The Company did not use Strategist as an optimization model; instead it placed so many constraints on the model that it reduced Strategist to a production cost model rather than resource optimization model. (Wilson Direct Test. at 3-4.)[4]

C. The Proposed Project, or Even Retirement of Big Sandy Unit 2, Would Only Have a Negligible Impact on Coal Mining in Eastern Kentucky.

The current environmental permits limit Big Sandy's possible fuel options to consuming only Central Appalachian ("CAPP") low sulfur coal. (Wohnhas Dir. Test. at 10.) The Big Sandy power plant currently purchases only 30% of its CAPP coal from sources within Kentucky. (Hearing Ex. KIUC- 2, KPCo's Resp. to SC 1-16.) The proposed modification would allow Big Sandy to expand its fuel options to include higher sulfur coals from the Northern Appalachian ("NAPP") and Illinois Basin and would easily allow Big Sandy to consume a 50/50 blend of higher sulfur coal with lower sulfur coal. (Wohnhas Dir. Test. at 10.) As a result, the Big Sandy Unit 2 retrofit could enable KPCo to reduce its purchases of coal from sources within Kentucky to 15%. This reduction in Kentucky coal purchases, or even a complete elimination of such purchases, would have a negligible impact on eastern Kentucky coal mining sales as Big Sandy currently consumes only about 1% of the coal mined in eastern Kentucky. (Hearing, Witness Wohnhas, April 30, 2012 at 11:38:00 – 11:40:30).

D. The Proposed Big Sandy Retrofit would Dramatically Raise Rates Again on an Impoverished Part of Kentucky and KPCo Acknowledges that More Rate Hikes are Expected.

KPCo provides power to twenty counties in eastern Kentucky. These counties are some of the most impoverished parts of Kentucky as thirteen of the counties[5] in the service territory

[4] The Company did not rebut this portion of Ms. Wilson's Direct Testimony.
[5] Lewis, Rowan, Elliott, Morgan, Martin, Magoffin, Floyd, Pike, Breathitt, Owsley, Perry, Leslie, and Clay Counties.

have a poverty rate[6] of between 26.5% – 45.4% and six of the counties[7] have a poverty rate of between 18.7% - 26.4%. (Hearing Ex. AG-3, Counties in AEP Service Area Percent of Persons in Poverty 2010).

These impoverished customers have already seen dramatic rate increases in the past few years. From 2003 to 2011, residential, commercial, and industrial customers have seen their rates nearly double from 5.09 to 9.66¢/kWh, from 5.25 to 9.82¢/kWh, and from 3.23 to 6.03¢/kWh, respectively. These rate increases mean that residential, commercial, and industrial rates have increased 89.7%, 87.05%, and 86.6%, respectively, since 2003. (Hearing Ex. KIUC-1, Kentucky Power FERC Form 1 Data).

According to KPCo's application, the proposed Big Sandy 2 retrofit would raise rates by an additional 29.49%, which amounts to an average of $39.39/month or $472.70/year. (Revised Ex. LPM-13 (Lila P. Munsey) provided in KPCo's Resp. to Staff 1-20; Hearing, Witness Wohnhas, April 30, 2012 at 10:58:00 – 11:02:48.)[8] Kentucky Industrial Utility Customers ("KIUC") witness Mr. Lane Kollen predicts that the proposed Big Sandy Unit 2 retrofit would actually increase residential bills by approximately 35.2% in 2016 (Kollen Dir. at 9), which would mean bills of $47.17/month or $566.04/year in 2016.[9] This projected rate increase, given the impoverished nature of this area, will severely impact the KPCo customers serviced in this area. These financial stresses are going to get worse as KPCo acknowledged throughout the

[6] According to the U.S. Census Bureau, the weighted average poverty thresholds in 2010 by size of family are:

One person	$11,139
Two people	$14,218
Three people	$17,374
Four people	$22,314
Five people $	$26,439

See, U.S. Census Bureau, Income, Poverty, and Health Insurance Coverage in the United States in 2010, available at http://www.census.gov/prod/2011pubs/p60-239.pdf.

[7] Carter, Boyd, Lawrence, Johnson, Knott, Letcher Counties.

[8] This estimate was actually based on 29.39% increase. If the additional 0.10% is added, rates would rise by $39.52/month and $474.24/year.

[9] 35.2% increase on a monthly bill of $134.04 = $47.17/month and $47.17 x 12 months = $566.04/year

hearing that it will need to request additional rate hikes related to the expected retrofit of the Rockport power plant and acquisition of a share of the Mitchell Power Station, and expected future environmental regulations related to coal combustion waste, the Clean Water Act, and greenhouse gas regulation of existing electric generating units. (Hearing, Witness Wohnhas, April 30, 2012, 15:12:30-15:16:45; Witness McManus, May 1, 2012, 11:46:30-12:08:58.)

E. Sierra Club, KIUC, and the Attorney General's Intervention and Testimony

On January 9, 2012 Sierra Club, on behalf of their thousands of Kentucky members, moved to intervene in this proceeding. On January 19, 2012, the Commission granted the intervention motion. The Kentucky Attorney General and KIUC also intervened in the proceeding.

On January 13, 2012 and February 8, 2012, Sierra Club filed requests for information regarding key assumptions and analyses used by the Company to support its application. Specifically, Sierra Club requested all model input and output files (both Strategist and Aurora) in workbooks that have the formulae intact. The Company's responses to discovery were so deficient that Sierra Club had to file a motion to compel on February 17, 2012. Even after this motion was filed, the Company only grudgingly turned over partial responses to many important data requests that were needed to fully audit the Company's analysis. (*See, e.g.*, Fisher Dir. at 51-52, 65; Wilson Dir. at 5-6; and Hearing, Witness Becker, May 2, 2012, 9:41:27-10:19:47).

On March 13, 2012, Sierra Club filed expert testimony from Dr. Jeremy Fisher, Mr. James Richard Hornby, and Ms. Rachel Wilson. Fisher[10] testified that KPCo currently allocates 40% of off system sales (OSS) revenue to shareholders, not ratepayers. (Fisher Rev. Supp. Dir. at

[10] Dr. Fisher holds a Ph.D. from Brown University in geological sciences, which he received in 2006. After graduating For the past five years, Dr. Fisher has worked at Synapse Energy Economics, where he has worked as a scientist on energy related matters including estimating the compliance costs for environmental regulations; developing alternate energy plans for municipalities, states, and regions; and estimating the price impacts of carbon policy on electricity generators and consumers. See Dr. Fisher Testimony, Ex. JIF-1.

15). In the current modeling structure, the Company appears to have allocated all OSS revenues back to ratepayers, rather than splitting these revenues with shareholders. (Fisher Rev. Supp. Dir. at 15-16). Adjusting for this error, the cumulative present worth ("CPW") of Option 1 rises by close to $100 million, while the other scenarios rise by approximately $80 million. Ultimately, the net effect is to narrow the gap between Option 1 and the other alternatives – and makes the market purchase options more attractive. (Fisher Supp. Rev. Dir. at 16; *see also* Ex. JIF-S3A).

Fisher testified that the capital costs used in the Strategist model appear to be incorrect as the full capital cost of the FGD is not included in the upfront capital costs and that there is a stream of fixed O&M costs in Option 1 (the retrofit case) that drops markedly from 2030 to 2031 by about $36 million per year and maintains at this lower value through the remainder of the analysis period. *See* Fisher Dir. at 16-26.

Fisher testified that the risk sensitivities used in the Strategist model were inadequate as they would not result in dramatically different results. (Fisher Supp. Rev. Dir. at 29.) The main problem with sensitivities is that commodity prices were correlated, when gas prices rise so did coal prices rendering the sensitivities insensitive to any reasonable tradeoffs between gas and coal use. The assumption is problematic as natural gas and coal have historically not been correlated (in real dollar terms). (Fisher Supp. Rev. Dir. at 31.) This assumption is also contrary to the way that the Aurora model treats commodity prices, where coal and natural gas prices are not correlated. (Fisher Supp. Rev. Dir. at 30-31.)

Fisher testified that the Company's CO_2 price forecast was unreasonable. (Fisher Rev. Supp. Dir. at 31-35.) In fact, KPCo's CO_2 price is inconsistent with CO_2 prices used by utilities across the nation in that it starts later in time, at a lower value, and is flat in real dollar terms. (Fisher Rev. Supp. Dir. at 31-36.) Simply shifting the CO_2 price forecast to a low-range forecast consistent with the low end of forecasts from other utilities and organizations renders the retrofit of the Big Sandy 2 unit essentially equivalent with the NGCC replacement in 2016 (Option 2) and far less economic than market purchases to 2020 (Option 4A). (Fisher Rev. Supp. Dir. at 37.) Fisher testified that if we adjust the off-system sales revenue to reflect 40% sharing with shareholders as currently allocated from KPCo and include this with a more reasonable carbon price, then Option 2 is only $9 million more and Option 4A becomes $231 million less than the proposed alternative. *See* Fisher Supp. Rev. Dir. at 38, table 6.

Fisher also testified about numerous concerns with the Aurora model. First, Fisher testified to concerns about how the results of the Aurora model differ dramatically from the results generated out of the Strategist model, and how the differences cannot be reasonably attributed to differences identified by the Company in discovery responses. (Fisher Supp. Rev. Dir. at 44-51.) Second, Fisher testified that the Company's responses to discovery responses were not transparent since it refused to turn over workbooks with formulae intact so neither the Commission nor any of the intervenors could audit the Company's analysis. This lack of transparency is problematic because, while the Aurora model is only a small part of the overall modeling performed by the Company, it is used by the Company to reject two Options – one of which is, by the Company's own estimate, more cost effective than maintaining the Big Sandy 2 unit. (Fisher Supp. Rev. Dir. at 52-53, 66-67.) Third, Fisher testified that the correlations between variables that the Company claims were used in the Aurora Monte Carlo analysis are derived from inadequate data, contain fundamental errors, are not represented in the model, and have inappropriately introduced bias into the analysis. (Fisher Supp. Rev. Dir. at 54-66.) Finally, Fisher testified that it is unclear how the stated correlations were actually used in the Aurora Monte Carlo analysis. Conceptually, these correlations should play an important role in how different variables "move" in relation to one another and are critical in determining the financial risk in each scenario – the purpose of the Aurora analysis. However, Dr. Fisher found that the correlations in files supplied by the Company did not match the Company's stated correlations.[11] *Id.*

Hornby testified that the Company did not evaluate the full range of alternatives available since it did not issue an RFP and did not explore a portfolio approach consisting of one or more alternative mixes of various types and sizes of resources, including renewable sources, energy efficiency or demand response. (Hornby Supp. Rev. Dir. at 11-12.) Hornby testified that given the magnitude of the investment under consideration this limited review of alternatives is especially egregious. Hornby testified that if the Commission approves this project the Company will be entirely dependent on base-load coal through 2024, and possibly longer if the Company also acquires a share of the Mitchell plant. (Hornby Supp. Rev. Dir. at 14.) Hornby also testified that there are advantages to diversifying your energy portfolio to withstand future uncertainties. (Hornby Supp. Rev. Dir. at 13-14.)

Hornby testified that the Company is asking the ratepayer to bear the majority of the financial risk. Hornby noted that if the Commission approved the project with a 15-year depreciation and the Company retired the plant in 2030 as Mr. Wohnhas predicts is a "medium" possibility, the Company's shareholder would have recovered its full investment in Big Sandy Unit 2, including a return on equity, and would bear no financial risk. (Hornby Dir. at 23.) In contrast, ratepayers would bear all the financial risk as they would have paid the revenue requirements associated with Big Sandy Unit 2 under the assumption that it was the most cost-effective option through 2040, but will have to pay the revenue requirements associated with the replacement capacity and energy from 2030 to 2040. (Hornby Dir. at 23-24.)

[11] This finding was not rebutted by the Company.

Wilson testified that Strategist, if used properly, is capable of selecting the least-cost mix of capacity and energy to meet a utility's projected peak demand and annual energy over a long-term planning horizon. (Wilson Dir. at 3.) Wilson testified that KPCo did not use the optimization capabilities of Strategist because it "locked in" specific resources options for specific years, rather than letting the model select the least-cost mix from the range of supply- and demand-side resources. (Wilson Dir. at 3-4.) Wilson also testified that the model files provided by the Company were incomplete and that, weeks after the files were delivered, the Company told her that one had to make changes to the files in order to reproduce the Company's results. (Wilson Dir. at 5-6.) Wilson testified that after imputing these requisite changes, she had concerns about the Strategist results. Wilson testified that Strategist, which forecasts emission rates for pollutants, showed that the Big Sandy 2 would emit mercury emissions above the MATS' limit for every year of operation. (Wilson Dir. at 9.) Wilson testified that this shows that additional pollution control is probably needed at the Big Sandy plant to control mercury emissions. (Wilson Dir. at 9.) Wilson also testified that she performed her own Strategist modeling that created a scenario using the Synapse low carbon price forecast. (Wilson Dir. at 10.)

On March 6, 2012, Kentucky Industrial Utility Customers submitted direct testimony from Lane Kollen, Stephen G. Hill and Stephen J. Baron and, on March 12, 2012, the Kentucky Attorney General submitted direct testimony from Dr. J. Randall Woolridge. Each witness's testimony detailed errors and inadequacies with KPCo's application.

F. The Company's Rebuttal Testimony

On April 16, 2012, the Company filed rebuttal testimony from Scott C. Weaver, Mark A. Becker, Karl R. Bletzacker, William E. Avera, Robert L. Walton, John McManus, and Ranie K.

Wohnhas. Weaver testified that he had made two changes to the Aurora model as a result of errors identified in Fisher's Testimony. (Weaver Reb. at 24). Weaver testified that a 20% demand toggle was erroneously left on, which meant that demand was increased by 20% over the forecasted demand. The magnitude of this error is demonstrated by Rebuttal Exhibit SCW-6. Having the 20% demand toggle on caused KPCo to overestimate the amount needed for energy purchases under Option 1 by $1 billion; under Options 2 and 3 by $2 billion; and Option 4b by $2 billion.

Becker testified that the upfront capital costs associated with the Big Sandy retrofit that would accrue from January 1, 2016 through June 1, 2016, were treated as O&M costs for the first fifteen years of operating life rather than as upfront capital costs in the PROVIEW module.

G. The Hearing

Starting on April 30, 2012, the Commission held a 3-day long hearing regarding KPCo's application. At the hearing, the Companies entered the testimony of nine witnesses, all of whom were cross-examined by the parties. Sierra Club entered the testimony of Fisher, Wilson and Hornby. KIUC entered the testimony of Kollen, Hill, and Baron. Kentucky Attorney General entered the testimony of Woolridge. The Company briefly cross-examined Fisher and Hill and declined to cross-examine Wilson, Hornby, Kollen, and Baron. The Commission and Staff briefly questioned Fisher and Wilson and declined to question Hornby. Of the many key points of testimony came out at the hearing, the most significant was that the Company revealed for the first time that on October 7, 2011 (two months before it filed its application), it had run a Strategist model with Option 1 retiring in 2030 and that this increased the revenue requirement for Option 1 by $202 million.

II. LEGAL BACKGROUND

Under Kentucky law, KPCo cannot install the scrubber on the aging Big Sandy Unit 2 until it receives a certificate that "public convenience and necessity require the service or construction." KRS § 278.020(1). Before the Commission can grant such a certificate for a facility, it must determine that there is both a need for the facility and "an absence of wasteful duplication resulting from the construction of the new system or facility." *Kentucky Utilities Co. v. Public Service Com'n*, 252 S.W.2d 885, 890 (Ky. 1952). This standard requires more than just a showing that there is a need for new generation, as the statutory mandate to avoid "wasteful duplication" forecloses "excessive investment in relation to productivity or efficiency, [or] an unnecessary multiplicity of physical properties." *Id.* In reviewing a CPCN application, the Commission has the authority to "issue or refuse to issue the certificate, or issue it in part and refuse it in part." KRS § 278.020(1).

Commission decision-making is guided by the overall requirement that utility rates are "fair, just, and reasonable." 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). This standard is satisfied if a utility has the "lowest reasonable rate" that allows it to "operate successfully, to maintain its financial integrity, to attract capital and to compensate its investors for the risks assumed even though they might produce only a meager return on the so-called 'fair value' rate base." *Com. ex rel. Stephens v. South Central Bell Tel. Co.*, 545 S.W.2d 927, 931 (Ky. 1976). As the Commission recently 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." *In the Matter of: Application of Kentucky Power Co.*, Case No. 2009-00545, 2010 WL 2640998 (Ky. P.S.C. 2010).

It is well established that in a CPCN proceeding the applicant bears the burden of proving that the statutory standards of public convenience and necessity, and of fair, just, and reasonable rates, have been satisfied. *See Energy Regulatory Comm'n v. Kentucky Power Co.*, 605 S.W.2d 46, 50 (Ky.App. 1980) ("Applicants before an administrative agency have the burden of proof."). Where an applicant has not carried its burden of proof, the Commission must deny the application even in the absence of evidence specifically refuting the applicant's claims. *Id.* at 50-51.

III. KPCO'S OWN FILING DEMONSTRATES THAT THE PROPOSED BIG SANDY UNIT 2 RETROFIT IS NOT THE LEAST COST OPTION.

The Commission must reject the CPCN because KPCo's own filing demonstrates that the Big Sandy Unit 2 retrofit is not the least cost option. As noted in Section II above, "least cost' is one of the "fundamental foundations utilized" when setting rates that are fair, just, and reasonable. *In the Matter of: Joint Application of Louisville Gas & Electric and Kentucky Utilities Co.*, Case No. 2011-00375 (Ky. PSC 2012); *In the Matter of: Application of Kentucky Power Co.*, Case No. 2009-00545, 2010 WL 2640998 (Ky. P.S.C. 2010). According to KPCo's application, Option 4B has a $47 million lower revenue requirement for ratepayers than does Option 1. In addition, KPCo modeling, first disclosed at the hearing, showed that the retirement of Big Sandy Unit 2 in 2030, which the Company says there is a "medium risk" of occurring, would increase the revenue requirement for Option 1 by at least $202 million. Finally, an option involving the transfer of 770MW of the already scrubbed Mitchell Plant, which is currently owned by AEP affiliate Ohio Power Company, would have a more than $338 million lower revenue requirement than Option 1.

It is reasonable to assume that KPCo's application would set forth the strongest possible case in favor of the Company's desired Big Sandy Unit 2 retrofit. As detailed in expert testimony submitted by KIUC and Sierra Club and discussed below, the case set forth in KPCo's application was highly flawed in numerous ways that skewed the analysis in favor of KPCo's desired outcome over other options. But even leaving aside all of those flaws and taking KPCo's modeling on its face, the Big Sandy Unit 2 retrofit does not satisfy the least cost standard required for issuance of a CPCN.

A. KPCO's application and witness testimony acknowledge that Option 4B has a revenue requirement that is at least $47 million lower than the proposed Big Sandy Unit 2 retrofit.

KPCo's application is not approvable as it shows that Option 4B would be a lower cost option than the proposed retrofit project. KPCo used the Strategist modeling program to calculate the current present worth revenue requirement over a thirty-year period for the Big Sandy Unit 2 retrofit and four other options under each of five different commodity price scenarios. That modeling concluded that under the Base Case scenario evaluated by KPCo, Option 4B would be $47 million less costly to ratepayers than Option 1. (Weaver Dir. at Ex. SCW-4). Under two other scenarios, Option 4B would be even more cost effective – by $119 million under the Lower Band alternative, and by $115 million under the early CO2 regulation scenario. (*Id.*). In short, as KPCo witness Weaver acknowledged (Hearing, Witness Weaver, May 1, 2012, 15:33:28 to 15:35:50), the Strategist modeling runs by the Company demonstrate that the proposed Option 1 retrofit is not the least-cost alternative required by law.

KPCo attempts to dismiss this shortcoming by claiming that the economics of Options 1 and 4B are a "near wash." (Weaver Dir. at p. 37 line 23; Hearing, Witness Weaver, May 1, 2012, 15:39:00 to 15:39:20). This contention is apparently based on an averaging of the cost differentials between Options 1 and 4B over the five scenarios that were modeled. (earing, Witness Weaver, May 1, 2012, 15:39:20 to 15:39:50). The contention fails, however, for two reasons. First, even if the results of the five scenarios are averaged equally, Option 4B still has an $8.4 million[12] advantage over Option 1 – i.e., Option 4B is still the least cost alternative. Second, KPCo did not identify estimated probabilities for each scenario. As such, there is no basis upon which to weigh or average the revenue requirement differentials for each scenario that KPCo modeled. Instead, the record shows only that KPCo considers the Base Scenario, under which Option 4B is $47 million cheaper than Option 1, the most likely to occur. (Weaver Dir. at Ex. SCW-4; Hearing, Witness Weaver, May 1, 2012, 14:48:00-15:15:00.) While the Company attempts to minimize that cost savings, in the most impoverished part of Kentucky a $47 million savings is significant.

KCPo contends that Option 4B should be rejected, however, because it is purportedly more risky than Option 1. Such purported risk takes two forms. First, through the use of an economic model known as Aurora, KPCo concluded that more ratepayer money is at risk through the potential for higher than estimated costs for Option 4B than for Option 1. (Weaver Dir. at p. 47 line 7 to page 48 line 9). Second, KPCo contends that Option 4B presents risks related to relying on the energy markets that justify rejecting that option. (*Id.* at 38-39). But, as detailed in Section VII below, the Aurora modeling carried out by KPCo is so flawed as to be worthless. As for the energy market risks, which are discussed in detail in Section VI below, KPCo has failed to quantify, document, or model those risks, and KPCo's affiliates Ohio Power Company and Indiana Michigan Power Company have submitted contemporaneous testimony with the Ohio and Indiana utility commissions explaining that reliance on market purchases is not a risky proposition. The illusory risks of Option 4B conjured up by KPCo do not provide a ground to justify rejection of that least cost option.

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[12] This figure was derived by adding the differential between Option 1 and Option 4B identified for each scenario - - $47, +$192, -$119, +$47, and -$115 – and then dividing by five.

B. KPCO modeling not disclosed until the hearing demonstrates that the revenue requirement for retrofitting Big Sandy Unit 2 increases by at least $202 million if Unit 2 ends up retiring in 2030, rather than after 2040.

On glaring inconsistency in KPCo's application stems from the date by which the Company assumes Big Sandy Unit 2 would retire if the plant were retrofitted. KPCo seeks to recover the full cost of the $940 million proposed scrubber over 15 years (Wohnas Dir. at p. 15 lines 1-5), which serves to protect shareholders from what KPCo has referred to as the "medium risk" that Big Sandy Unit 2 would retire in 2030. (KPCo Resp. to Staff DR 1-91). But in modeling the economic impact of the Big Sandy Unit 2 retrofit on ratepayers, KPCo assumed that Unit 2 would continue operating through at least 2040, which is the end of the 30-year study period used by the Company. (Weaver Dir. 15, lines 14-18.) As a result, KPCo excluded from its calculation of the CPW revenue requirement for Option 1 the cost of replacing Big Sandy Unit 2 if that unit were retired in 2030. In other words, when it came to shareholders, the Company took steps to ensure that they were protected from the risk of a 2030 retirement for Big Sandy Unit 2, but when it came to ratepayers, the Company's application did not even mention such risk.

The egregiousness of this inconsistency is escalated by the fact that the available evidence shows that KPCo knew that a 2030 Big Sandy Unit 2 retirement posed at least a $202 million risk to ratepayers but failed to disclose that risk to the Commission, Staff, or parties until the hearing. At the hearing KPCo witness Weaver testified that the Company had run a Strategist model that assumed that Big Sandy Unit 2 would retire in 2030. (Hearing, Witness Weaver, May 1, 2012, 14:54:17-14:56:45). That October 2011 Strategist modeling, the results of which were entered into evidence as KIUC Ex. 11, was not included in KPCo's December 2011 application or in any discovery responses despite being requested.[13] The results showed that the Big Sandy Unit 2 retrofit option would have a CPW revenue requirement that is $202 million higher than reported in KPCo's application if Unit 2 retired in 2030 rather than continuing operation through 2040. (KIUC Ex. 11.)[14]

At hearing, KPCo witness Weaver tried to justify ignoring this additional $202 million cost for the Big Sandy Unit 2 retrofit on the grounds that he was confident that the unit would continue operating through 2040. (Hearing, Witness Weaver, May 1, 2012, 14:49:40-14:56:12.) But such a claim is not credible when the Company has proposed that it be able to recover the retrofit cost based on a 2030 retirement date in order to avoid the "medium risk" to its shareholders of stranded investment. (Wohnas Dir. at 15 lines 1-5; KPCo Resp. to Staff 1-91.) In fact, in earlier analyses run by KPCo, the Company assumed a 10-year recovery period for purposes of "addressing future environmental-driven recovery risk," (KPCo Resp. to KIUC 1-28, Attachment 1, pp. 1-3), and the Company's December 2008 depreciation study assumed that Big Sandy Unit 2 would retire in 2029. (KPCo Resp. to Staff 2-27, Attachment 2, at pp. 17-21.) Given KPCo's consistent assumption for purposes of shareholder cost recovery and depreciation that Big Sandy Unit 2 would retire in 2030 or earlier, that same retirement assumption should be evaluated in determining the least cost option for ratepayers.

[13] Weaver's claim to the contrary notwithstanding (Hearing, Witness Weaver, May 1, 2012, 14:53:40-15:00:00), the October 2011 Strategist modeling assuming a 2030 Big Sandy Unit 2 retirement date was responsive to KIUC data request 1-28, which sought "all analyses, e-mails, and all other documents that support, source, and/or otherwise address the assumptions used in the analyses presented by Mr. Weaver in his Direct Testimony . . . includ[ing] . . . any alternative assumptions that were considered but not used in the analyses." Plainly, a 2030 retirement date instead of Big Sandy Unit 2 operating through 2040 was an "alternative assumption" that was considered but not used in KPCo's analyses.

[14] The October 2011 Strategist modeling also appears to underestimate the cost impact of a 2030 Big Sandy Unit 2 retirement by assuming that the 816MW Big Sandy Unit 2 would be replaced with a 578MW NGCC plant, rather than a larger plant. By contrast, in the "NGCC Replacement" and "Market to 2025" options, KPCo assumed that a 904MW NGCC plant would be needed to replace Big Sandy Unit 2. (KIUC Ex. 11 at 1). Unfortunately, due to KPCo's late disclosure of this modeling and the inability of KPCo witnesses Weaver and Becker to answer questions regarding the details of the October 2011 Strategist modeling, the details of that modeling could not be explored.

KPCo also tries to dismiss this issue by contending that a longer recovery period would have a similar Option 1 CPW revenue requirement as does a 15-year recovery period. (Weaver Dir. at p. 36 lines 8-11). But the cost differential here results not from a different recovery period, but rather from the extra cost to ratepayers of Option 1 if the "medium risk" of a 2030 Big Sandy Unit 2 retirement occurs. KPCo's October 2011 Strategist modeling shows that such early retirement raises the CPW revenue requirement of the retrofit option by at least $202 million due to the need to replace the energy and capacity from Big Sandy Unit 2. (KIUC Ex. 11 at 1.) And that impact, in turn, significantly changes the relevant economics of the various options evaluated by KPCo. For example, in Table 1 below, we have revised KPCo Exhibit SCW-4 to reflect the CPW revenue requirement differentials of Options 2 through 4B in comparison to the Big Sandy Unit 2 retrofit assuming a 2030 retirement date.

Table 1: Comparative CPW Revenue Requirements From Exhibit SCW-4 Revised to Reflect $202 Million Impact to Option 1 of 2030 Big Sandy Unit 2 Retirement

Scenario	Option 2	Option 3	Option 4A	Option 4B
Base	34	50	(123)	(249)
Higher Band	235	256	64	(10)
Lower Band	(25)	(19)	(181)	(321)
No Carbon	113	132	(36)	(155)
Early Carbon	(22)	(12)	(182)	(317)

(*see also* Hearing, Witness Weaver, May 1, 2012, 15:37:00 to 15:39:04). As demonstrated in Table 1, using the same 2030 Big Sandy Unit 2 retirement assumption that KPCo did in protecting its shareholders demonstrates that Option 4B is the least cost option under all scenarios, that Option 4A is lower cost than Option 1 under the Base case and three out of four scenarios, and that Options 2 and 3 are both lower cost than Option 1 under two out of five scenarios.

The October 2011 Strategist modeling provides further evidence that the Big Sandy Unit 2 retrofit is not the least cost option. For example, the "Market to 2025" option identified in KIUC Ex. 11 appears to be quite similar to Option 4B in KPCo's application. But while the Company's application suggests that Option 4B has a $47 million lower CPW revenue requirement than Option 1 (Weaver Dir., Ex. SCW 4), the October 2011 Strategist modeling reports that the Market to 2025 option has revenue requirement that is $140 million lower than Option 1, and $342 million lower than Option 1 with a 2030 Big Sandy Unit 2 retirement date. (KIUC Ex. 11 at 1.) In addition, the October 2011 Strategist modeling reports a "Market Only" option, which appears to have not been included in KPCo's application, with a revenue requirement that is $238 million lower than Option 1 and $440 million lower than Option 1 assuming a 2030 Big Sandy Unit 2 retirement date. (*Id.*)

Due to KPCo's late disclosure of the October 2011 Strategist modeling and the inability of the Company witnesses Weaver and Becker to answer questions at the hearing about the details of that modeling (Hearing, Witness Weaver, May 1, 2012, 14:50:30-14:58:00; Witness Becker, May 2, 2012, 10:20:55-10:21:15), further exploration of the options was not possible. But the record is clear that KPCo's own October 2011 Strategist modeling shows that there are a number of options that are lower cost than the Company's proposed Big Sandy Unit 2 retrofit. As such, the Commission must deny the CPCN.

C. KPCO's additional January 2012 analysis found that an option involving acquiring a 770MW share of the already-scrubbed Mitchell Plant has a revenue requirement that is [redacted] less than the retrofit of Big Sandy Unit 2

A third set of modeling carried out by KPCo demonstrated yet another lower cost option than the proposed Big Sandy Unit 2 retrofit. In January 2012, KPCo evaluated the cost impact of either acquiring or entering into a purchase power agreement for 770MW of the Mitchell Plant in

Moundsville, West Virginia to replace Big Sandy Unit 2. (KPCo Resp. to Sierra Club DR 1-52a). The 1,560MW Mitchell Plant is currently owned by AEP affiliate Ohio Power Company and already has a scrubber and other environmental controls. In January 2012, the Ohio Public Utility Commission ("Ohio PUC") had approved a corporate separation plan under which Ohio Power was to transfer its generating assets to the unregulated AEP Generation Company ("AEP GENCO"), and AEP GENCO was proposing to transfer 20% of the Mitchell Plant to KPCo at net book value. (Hearing, Witness Weaver, May 1, 2012, 14:37:20-14:47:30). While that 20% represented only 312MW, KPCo also requested an evaluation of acquiring 770MW of the plant. (KPCo Resp. to Sierra Club 1-52a). [redacted]

KPCo provided no explanation in its discovery response as to why it rejected this lower cost option, instead stating only that the January 2012 Strategist modeling did not "change the results and recommendations of the filing." (KPCo Resp. to Sierra Club 1-52b.) At hearing, KPCo witness Weaver contended that acquiring Mitchell is not a viable option right now because the Ohio PUC ended up rescinding the order approving Ohio Power Company's corporate restructuring. (Hearing, Witness Weaver, May 1, 2012, 14:41:00-14:46:35.) But this fact does not explain why KPCo failed to pursue the Mitchell Plant as part of a lower cost option when its application was filed in December 2011 or when the additional analysis was submitted in January 2012, as at those times the corporate separation proposal was moving forward. In addition, Ohio Power Company has resubmitted its proposed corporate restructuring plan for

Ohio PUC approval. In support of that submission, Ohio Power Company witness Philip Nelson testified that the company is still planning to transfer 20% of the Mitchell Plant to KPCo, with the remaining 80% being transferred to AEP-affiliate Appalachian Power Company. (Hearing Ex. SC-15, Testimony of Phillip Nelson at p. 5, lines 8-14). At hearing, KPCo's witnesses were unable to state whether the Company had requested a greater than 20% share of the Mitchell Plant or whether such larger acquisition of Mitchell is possible. Regardless, the January 2012 Strategist modeling shows that the Mitchell Plant is a potentially available option that KPCo's own modeling demonstrates would be a lower cost option to retrofitting Big Sandy Unit 2.

IV. KPCO FAILED TO EVALUATE NUMEROUS AVAILABLE AND LIKELY LOWER COST OPTIONS.

The record shows that KPCo did not make a serious attempt to even identify, much less evaluate, other available and lower cost resources than the narrow set of options assessed in the Company's application. In particular, KPCo failed to pursue known generating sources, such as the Riverside Generating Station and Ohio Power Company's Waterford NGCC, that would have likely been lower cost options to the Big Sandy Unit 2 retrofit. In addition, KPCo did not use the tools at its disposal – such as a Request for Proposals ("RFP") process, Strategist modeling, and an energy efficiency potential study – for creating a least cost energy portfolio.

Instead of a careful evaluation of the range of available energy resources, KPCo limited its assessment of the options for replacing Big Sandy Unit 2 to acquiring the same quantity of capacity from one of three basic categories of resources – base load coal, NGCC, or market purchases. And the result of the Company's limited assessment is a resource plan that would continue KPCo's status of having a generating fleet that is 100% base load coal through at least 2024. KPCo witnesses could not identify any other utility in Kentucky or in the US as a whole that is 100% dependent on base load coal units. (Hearing, Witness Weaver, May 1, 2012, 17:50:23-17:50:39, Hornby Exhibit_(JRH-2)).What is clear is that KPCo's failure to even look for lower cost alternatives provides further evidence that the Company has not satisfied the least-cost standard necessary for the issuance of a CPCN.

A. KPCO Ignored or Overlooked Numerous Available and Potentially Lower Cost Generating Resources in Kentucky and Surrounding States.

KPCo's application does not explain how it chose to limit its analysis to coal retrofit, NGCC, or market purchases, instead simply saying that those "alternative options were assumed to be available." (Weaver Dir. at p. 11, lines 7-9.) The evidence is clear, however, that numerous other resource options were also available, but were improperly ignored or dismissed.

For example, only 1.5 miles from the Big Sandy plant is the Riverside Generating Station ("Riverside"), which consists of five natural gas-fired combustion turbines with a combined nameplate capacity of approximately 900MW that began operation in 2001 or 2002. [redacted]

[redacted]

KPCo also made no attempt to determine whether it could acquire all or portions of the Waterford NGCC unit that is currently owned by AEP affiliate Ohio Power Company. Waterford is an 821MW plant in southeast Ohio that began commercial operation in August 2003. (SC Hearing Ex. 11, KPCo Resp. to AG DR 2-6). AEP purchased the plant in 2005 for $220 million (*id.*), and it has a [redacted]

Waterford is one of the Ohio Power Company generating assets that the company is proposing to transfer to the unregulated AEP GENCO at net book value as part of the corporate restructuring plan discussed in Section III.C above. (Hearing Ex SC-15, Testimony of Phillip Nelson at Ex. PJN-4, p. 4). Yet KPCo made no attempt to determine whether it could acquire all or some of the Waterford NGCC plant as a lower cost option to the Big Sandy Unit 2 retrofit. (Hearing, Witness Weaver, May 1, 2012, 14:33:00-14:34:05).

In short, KPCo has several options for acquiring 600 MW of NGCC including purchase of one of the gas units that Ohio Power Company expects to transfer to AEP GENCO at net book value, purchasing all or a portion of an existing NGCC from a third-party or building a new NGCC to be co-owned with another Kentucky utility that also needs such capacity. These options should have been pursued as part of identifying a least cost option for KPCo.

B. KPCO Failed to Use Available Tools to Identify Resources For a Least Cost Energy Portfolio

A primary flaw in KPCo's identification of resource options to evaluate is that the Company appears to have made no effort to identify an optimal least cost energy portfolio or to determine what cost effective resources might be available for such a portfolio. KPCo's failure to attempt to craft a least cost energy portfolio is especially egregious given that the Company has the tools at its disposal to do so in the form of an RFP process, Strategist modeling, and an energy efficiency potential study. KPCo's failure to use any of those tools before proposing to ask the most impoverished ratepayers in Kentucky to finance a $940 million retrofit of a 43-year-old power plant further demonstrates that KPCo's CPCN application cannot be approved.

1. KPCO failed to carry out an RFP process, which would have assisted the Company in determining exactly what energy resources were available to it and at what cost.

It is axiomatic that if you do not ask a question, you are unlikely to find out the answer. Yet when it came to determining what options were available to KPCo for replacing Big Sandy Unit 2, and at what price, the Company never asked the question. One primary way of asking would have been for KPCo to issue an RFP seeking proposals for the sale of various energy resources. Such an RFP process would have helped KPCo determine whether any of the natural gas units identified in Section IV.A above could have been part of a lower-cost portfolio than then Big Sandy Unit 2 retrofit, or whether there are other companies willing to sell generating assets or guaranteed energy or capacity from NGCC, natural gas combustion turbine, wind, solar, hydroelectric, biogas, or other energy resources that are either existing or being developed.

Instead, KPCo decided not to issue an RFP on the assumption that any energy resources that were available would cost the Company the same or more than simply building such resource itself. (Hearing, Witness Wohnhas, April 30, 2012, 15:16:46-15:17:38, KPCo Response to Staff 1-65(c); KPCo Responses to Sierra Club 1-51 and 2-21.) KPCo, however, took no steps to substantiate or test that assumption. The Company's failure to engage an RFP process provides yet further proof that KPCo has not satisfied its burden of showing that the $940 million retrofit of a 43-year-old coal plant is somehow the least cost option available.

2. KPCO failed to use Strategist to select an optimal resource plan for satisfying the energy and capacity demands currently served by Big Sandy Unit 2.

KPCo also could have, but did not, use its Strategist model to select an optimal, least cost resource plan. As Sierra Club witness Rachel Wilson testified:

> STRATEGIST should have been used to select the optimal resource plan from a variety of options, including construction of coal and natural-gas fired generation, a purchase-power agreement (PPA) for energy and capacity, and energy efficiency, demand response and renewable generating resources.

(Wilson Dir. at p. 4, lines 17-20). Instead, the Company constrained its Strategist modeling to only evaluate the resource options 1, 2, 3, 4A, and 4B that KPCo pre-selected before the model was run. As Wilson opined:

> The number of resource portfolios evaluated by STRATEGIST was so tightly constrained that it is possible, and even likely, that a lower cost resource portfolio exists that would have been identified by the model had it been allowed to perform long-term resource optimization.

(*Id.* at lines 11-15). This testimony from Wilson was not rebutted by the Company, and provides additional support for the fact that KPCo did not engage in a serious attempt to identify the least cost approach in this proceeding.

3. KPCO failed to carry out an energy efficiency potential study in order to determine what role energy efficiency could play in meeting part of the energy and capacity demand currently served by Big Sandy Unit 2.

KPCo's application is also silent on the role that increased energy efficiency, demand side management, and demand response (referred to collectively here as "energy efficiency") could play in reducing the energy and capacity needs currently served by Big Sandy Unit 2. This silence is inconsistent with the Commission's recognition of the importance of utilities implementing energy efficiency programs to reduce electricity costs for ratepayers. For example, in an order issued last October, the Commission explained that it:

> Recognizes the importance of greater deployment of energy efficiency initiatives to Kentucky's electric generating utilities due to the reliance on low cost coal-fired base load generation. Even though there has been no legislative mandate to adopt its goals, Kentucky's 7-Point Strategy for Energy Independence (Kentucky's Energy Plan) issued in November 2008 includes specific goals for energy efficiency as well as renewables and biofuels by 2025. The Commission also notes that Kentucky's reliance on coal-fired generation will face increasing pressure as costs are incurred to meet proposed and potential new federal environmental regulations.
>
> In several administrative cases, the Commission has noted its support for energy efficiency. In addition, in recent cases where utilities were requesting a general increase in base rates, the Commission has questioned utilities regarding their conservation and energy efficiency efforts. In those cases, the Commission has stated its belief that conservation, energy efficiency and demand-side management will become more important and cost-effective as there will likely be more constraints placed upon utilities whose main source of supply is coal-based generation. As a result, the Commission has encouraged all electric energy providers to make a greater effort to offer cost-effective demand-side management and other energy efficiency programs.

In re: Consideration of the New Federal Standards of the Energy Independence and Security Act of 2007, KPSC Case No. 2008-00408, Oct. 6, 2011 Order, at pp. 21-22 (citations omitted).

KPCo does have in place some energy efficiency programs that were approved in a previous docket. But that approval does not relieve the Company from the need to evaluate further cost-effective energy savings that could be achieved when the Company is proposing nearly $1 billion in capital expenditures to be paid for by ratepayers in the most impoverished part of Kentucky. Instead, the Commission has made clear that "the CPCN authority provided the Commission pursuant to KRS 278.020 also effectively treats cost-effective energy efficiency as a priority resource." *In re Consideration of New Federal Standards*, Order at p. 21. In addition, the "least cost" approach that is a "fundamental principle[] utilized when setting rates that are fair, just, and reasonable," *In re Application of Kentucky Power Co.*, 2010 WL 2640998, cannot be achieved unless all cost-effective and available resources, including energy efficiency, are evaluated in developing a least-cost portfolio. As such, a utility seeking a CPCN must evaluate cost-effective energy efficiency opportunities in order to ensure that any plan the Commission approves is least-cost.

The most effective way to determine the amount of energy savings that can be achieved through energy efficiency, and to identify the programs to cost effectively achieve such savings is through an energy efficiency potential study. *See, e.g.*, *In the Matter of : Joint Application of Louisville Gas & Electric and Kentucky Utilities Co.*, Case No. 2011-00375, slip op. at 17-18 (Ky. PSC 2012). KPCo, however, has not carried out such a study (*see, e.g.*, Hearing, Witness Wohnhas, April 30, 2012, 15:16:46-15:17:38), even as other AEP affiliates have done so. (Hearing, Witness Wohnhas, April 30, 201214:34:30-14:35:35.) Having failed to even consider the potential of replacing a portion of Big Sandy Unit 2 with additional cost-effective energy efficiency programs, KPCo cannot credibly claim that its proposed $940 million retrofit represents the least cost option for its ratepayers.

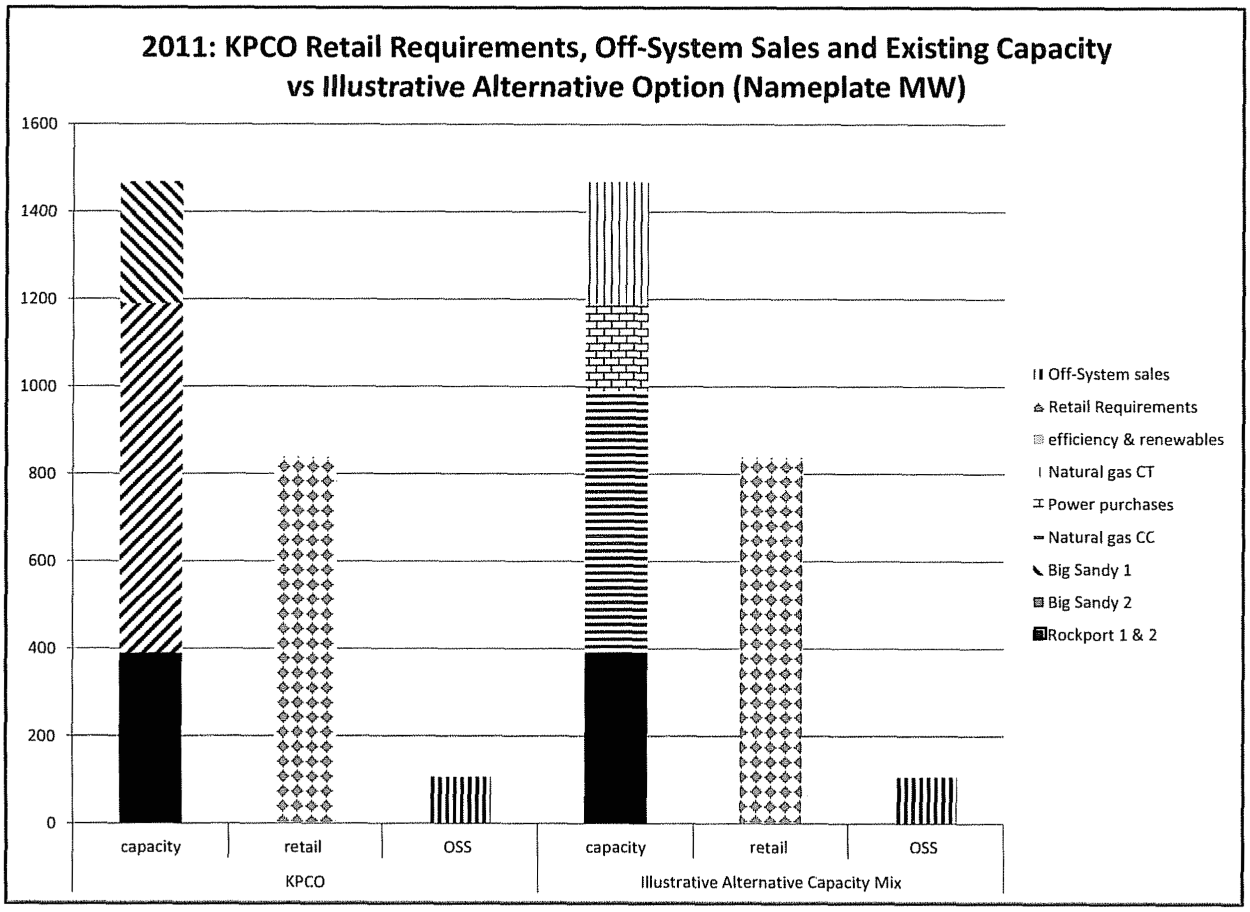
B. A Portfolio Approach Would Provide KPCO and its Ratepayers With Greater Flexibility Than the Company's 100% Base Load Coal Plan in Meeting Future Energy Needs

As a stand-alone company, KPCo is currently 100% dependent on base load coal units for capacity and annual generation, i.e., Big Sandy Unit 1, Big Sandy Unit 2 and a unit agreement for capacity and energy from Rockport 1 and Rockport 2. KPCo witnesses could not identify another utility in KY, or the US, that is 100% dependent on base load coal units (Hearing, Witness Weaver, May 1, 2012, 17:50:23-17:50:39; *see also* Hornby Exhibit___(JRH-2)). Yet the result of KPCo's proposal would be that the Company would remain 100% base load coal dependent through at least 2024. This problematic outcome was reached because KPCo limited its evaluation to acquiring "all or nothing" quantities of base load coal, NGCC, or market purchases while failing to evaluate the many other mixes of resource types and acquisition approaches available to the utility. The following three charts, based on the data that Sierra Club witness James Richard Hornby used to create Exhibit_(JRH-2) and Exhibit _(JRH-3), illustrate alternative mixes of resource types and acquisition approaches that KPCo failed to evaluate.[15]

Chart 1 compares KPCo's 2011 capacity, 100% baseload coal units, to a much more diverse alternative option consisting of 27% baseload coal (the Rockport unit agreement), 41% gas CC (600 MW0, 14% market purchases (200 MW) and 19% gas CT (278 MW). This illustrates just one of the many possible alternative options that KPCo could, and should, have evaluated for replacing Big Sandy Units 1 and 2 starting in 2016.

[15] KPCo did not issue a discovery request for the work papers underlying Mr. Hornby's Exhibits, did not rebut those Exhibits and did not cross-examine Mr. Hornby regarding those Exhibits.

Chart 1



Charts 2 and 3 demonstrate the potential benefit to KPCo of evaluating and choosing an alternative option that provides it flexibility to respond to changes in its requirements and other market conditions. Chart 2 compares KPCo's 2022 capacity under Option 1, approximately 73% base load coal units and 27% gas CC, to a continuation of the more diverse alternative option presented in Chart 1.[16] (During the hearing KPCo stated its intent to acquire a portion of the Mitchell coal instead of a adding a gas CC, which would continue KPCo's 100% dependence on coal base load units). KPCo's mix under the alternative option would be 24% coal (the Rockport

[16] Under Option 1 KPCo plans to add 424 MW gas CC in 2024 not 2022. This does not affect the illustration.

unit agreement), 38% gas CC, 21% market purchase and 17% gas CT. This alternative would continue to provide KPCo the flexibility of its 2016 Alternative Option.

Chart 2

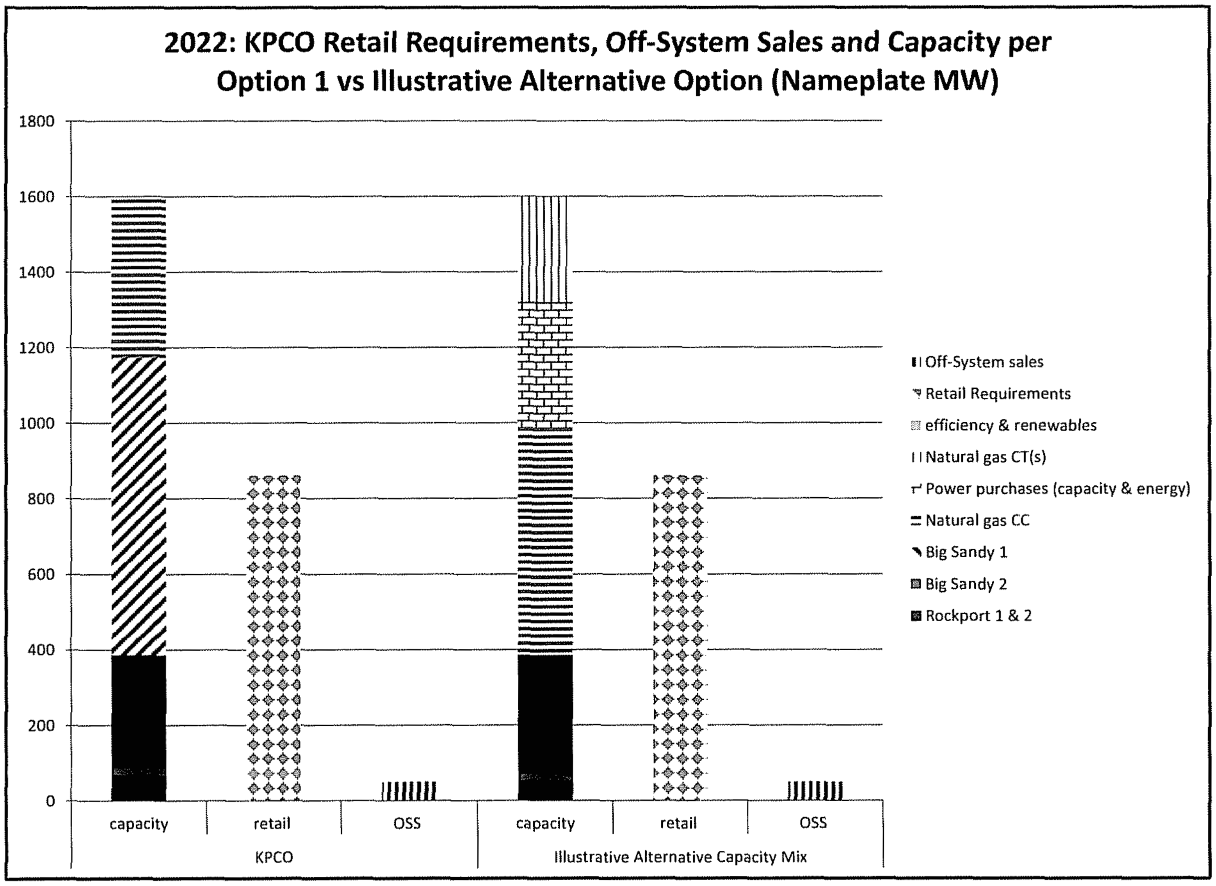
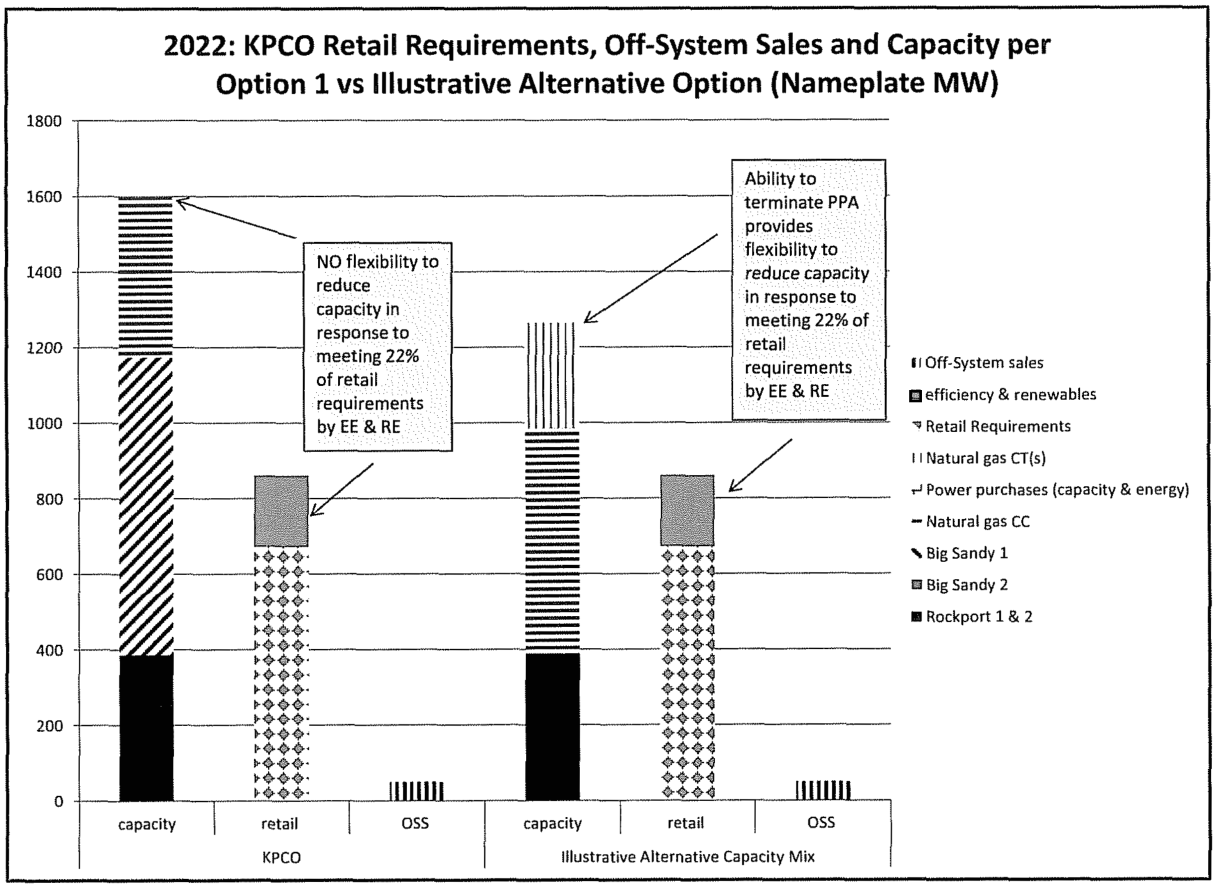


Chart 3 illustrates the benefit of having some flexibility to respond to changes in market conditions using the example that Hornby presented in Exhibit___(JRH-4), which assumes KPCo has to meet 22% of its retail requirements with efficiency and renewables in 2022. Chart 3 indicates that, under Option 1 KPCo would be stuck holding, and recovering the fixed costs of, considerable excess capacity if its retail requirements were 22% less than it had projected. In contrast, under the Alternative Option, KPCo would be able to terminate is market purchases and thereby reduce its excess capacity and associated fixed costs.

Chart 3



In summary, the available evidence demonstrates that there are likely a number of energy resources – including NGCC, combustion turbines, wind, solar, and energy efficiency – that could have been used to craft a lower cost and more flexible portfolio for KPCo and its ratepayers. But the Company declined to even look for such options and, instead, have proposed to continue to be 100% base load coal through at least 2024 by charging its ratepayers $940 million to retrofit a 43-year-old coal plant. Such a limited approach is unreasonable on its face, and fails to demonstrate compliance with the least cost principle at the core of ensuring that electric rates are just and reasonable. As such, the Commission must reject KPCo's CPCN application.

V. KPCO'S STRATEGIST MODELING UNDERESTIMATED THE COST OF OPTION 1, OVERESTIMATED THE COST OF OTHER OPTIONS, AND FAILED TO ENGAGE IN A MEANINGFUL SENSITIVITY ANALYSIS.

A. The Company's Strategist Sensitivity Runs Were Meaningless Because They Were Based on Price Correlations That Essentially Ensured That the Sensitivities Would Not Differentiate Between Various Options.

Good modeling practice requires that the modeler evaluate the confidence of the model, possibly assessing the uncertainties associated with the modeling process and with the outcome of the model itself. A sensitivity analysis determines if modeling results still hold true under a range of reasonable future scenarios and either give credence or cause to reject conclusions from a modeling exercise. If conclusions drawn from a modeling analysis depend on assumptions made about an uncertain future, a reasonably executed sensitivity analysis will show those conclusions to be weak, or non-robust. If fundamental conclusions do not change with reasonable variations in assumptions (i.e. are insensitive to those assumptions), the outcome of a model is non-robust. Thus, a useful sensitivity stress-tests conclusions with reasonable forecasts or assumptions.

There are three requirements for a reasonable sensitivity analysis: (a) stress-testing important or key variables, (b) a reasonable range of forecast assumptions for those key variables, and (c) using a reasonable combination of those key variables. By failing to test the correct variables or use a reasonable range for those variables, sensitivities may not capture likely stresses and thereby create undue risk. By failing to use a reasonable combination of those key variables, a sensitivity can either artificially mask or artificially inflate uncertainty. If key variables in a sensitivity analysis are perfectly correlated – i.e., when the system is stressed, all of the variables shift in the same direction – then the sensitivity analysis may mask certain important outcomes.

In the case of KPCo, the Company attempted to test the confidence of its Strategist model by running the model through four risk sensitivities: (1) a "higher" band of prices in which both the cost of gas and coal are increased by 16-20% and CO_2 prices are effectively unaltered; (2) a "lower" band of prices in which both the cost of gas and coal are decreased by 11-12% and CO_2 prices are effectively unaltered; (3) an "early carbon" scenario in which carbon prices start in 2017 instead of 2022 but are only about 80¢ higher (real 2011$); and (4) a "no carbon" scenario in which there is no carbon price and fuel prices are effectively unchanged (gas prices are reduced by 6%). (Fisher Rev. Supp. Dir. at 29; *see also*, Hearing, Witness Weaver, May 1, 2012, 15:07:40-15:28:30).

For both the "high band" and "low band" sensitivities, coal and natural gas prices move in the same direction almost perfectly. (Fisher Rev. Supp. Dir. at 29-30; Hearing, Witness Weaver, May 1, 2012, 15:18:04 – 15:28:30, Weaver Dir. at Ex. SCW-2). For example, under the Higher Band, natural gas, coal, energy, capacity, and CO2 prices are all higher than in the Base case and, under the Lower Band, all of those commodity prices except CO2 are lower than in the Base Case. Having all of these commodities move in the same direction violates the third requirement of a sensitivity analysis given above. The choice to move gas and coal prices together exclusively means that the range of outcomes between a gas and coal alternative would be artificially masked. Given that the Company was choosing between base load coal, NGCC, and market purchases, the assumption that natural gas, coal, energy, and capacity prices are all correlated means that it is very unlikely that any of the sensitivity analyses would lead to results that are different than those found in the base case. Instead, as Fisher testified, he "would not expect any of the sensitivities evaluated by the Company to result in dramatically different results." (Fisher Dir. at p. 28, line 20.) That testimony from Fisher was not rebutted by the Company. (Hearing, Witness Weaver, May 1, 2012, 15:28:00-15:28:50.)

The Company did not model any Strategist runs in which natural gas and coal prices moved in different directions. (Hearing, Witness Weaver, May 1, 2012, 15:23:40-15:28:30.) Since their fuel inputs were correlated, the Strategist modeling performed by the company did not determine if its results would change if one or more of the commodity price forecasts changed significantly. Essentially, the sensitivity analysis could not differentiate between the risks of each scenario. The Strategist model's perfect correlation between fuel prices is especially problematic because the price of natural gas and coal are not actually correlated in real dollar terms. (Fisher Rev. Supp. at 30). In fact, Weaver treats natural gas and coal prices as uncorrelated in his Aurora analysis.[17]

B. The Company Improperly Treated Off-System Sales in Its Strategist Modeling.

Fisher and Hornby testified that the Company improperly treated off-system sales ("OSS") in its Strategist modeling. (Fisher Sup. Rev. Dir at 15-18; Hornby Sup. Rev. Dir. at 18-19.) The Company credited 100% of the OSS revenues back to ratepayers, rather than splitting these revenues with shareholders.[18] (Fisher Sup. Rev. Dir at 15-16.) This treatment is inconsistent with the Company's current System Sales Clause, under which KPCo shareholders retain 40% of margin from OSS. (Fisher Sup. Rev. Dir at 15-16; Hornby Sup. Rev. Dir. at 18.)

Since the Company is presenting the Big Sandy 2 retrofit as the least-cost alternative for ratepayers rather than for shareholders, one would presumably review the benefit for ratepayers – not the Company. Fisher tested how the split in OSS revenues would affect the outcome of this

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[17] *See* Exhibit SCW-1, Table 1-4, which shows a correlation of 0.09 between natural gas and coal prices, *see also* Hearing, Witness Weaver, May 1, 2012, 15:22:10-15:27:50.

[18] EEI Fact Book pg. 69 (Nov. 2011), Attached to KPCo's response to Sierra 1-1 (the Company reminds investors that Kentucky has an OSS sharing mechanism allocating 60% of OSS to ratepayers).

analysis. (Fisher Sup. Rev. Dir at 16-18.) Using the Strategist output of market sales by KPCo,[19] Fisher deducted 40% of the market sales (net of the variable cost of production) from the KPCo system on an annual basis, and, following the Company's method for calculating the total cumulative present worth (CPW), subtracted the remaining revenues from the stream of costs and calculated a new CPW. (Fisher Sup. Rev. Dir at 16-18.)

The result of allocating 40% of OSS revenues to shareholders drives up the cost seen by ratepayers – but drives it up faster in those scenarios where KPCo has greater off-system sales, in this case Option 1. (Fisher Sup. Rev. Dir at 16.) The CPW of Option 1 rises by about $100 million, while the other scenarios rise by about $80 million. (Fisher Sup. Rev. Dir at 16.) Ultimately, the net effect is to narrow the gap between Option 1 and the other alternatives – and makes the market purchase options more attractive. (Fisher Sup. Rev. Dir at 16, *see also* Ex. JIF-S3A.) Option 4B (market purchases to 2025) continues to remain less expensive than Option 1. (Fisher Sup. Rev. Dir at 17.) These changes are reflected below.

Cumulative present worth of revenue requirements (M 2011$): Reanalysis with adjusted off-system sales[20]

Cumulative Present Worth of Revenue Requirements (M 2011$)
Re-Analysis with Adjusted Off System Sales

	Option #1 Retrofit Big Sandy 2 w/ FGD	Option #2 NGCC Replacement	Option #3 BS1 Repower	Option #4A Market to 2020; NGCC in 2020	Option #4B Market to 2025; NGCC in 2025
Company Assumptions					
CPW	6,839	7,075	7,091	6,918	6,791
Net benefit of retrofit (CPW)		236	252	78	(48)
Adjusted Off System Sales					
CPW	6,943	7,154	7,171	6,993	6,862
Net benefit of retrofit (CPW)		211	228	49	(81)

Weaver's rebuttal testimony agrees with Fisher's calculations regarding OSS. *See* Weaver Reb. at 19 ("[T]he Company is in agreement with his [Fisher's] ultimate 'Net Benefit Retrofit (CPW)' calculations as those figures now essentially match the qualified Company

[19] Generation and Fuel Module System Report from Strategist, line "Econ Energy Sales" in KPCo section.
[20] *See* Fisher Sup. Rev. Dir at 18, Ex. JIF-S3A.

derived results.") This OSS correction increases Option 4B's revenue requirement advantage over Option 1 to $81 million in the base case scenario. Weaver attempted to marginalize this error by claiming that "in all years modeled, … OSS margins as determined under Tariff S.S.C. were generally below that margin threshold, hence no adjustment was necessary in any event." However, at the hearing, Weaver conceded that the margin threshold is more frequently exceeded than not. (Hearing, Witness Weaver, May 1, 2012, 14:48:57-14:55:00.)

C. The Company Used an Unreasonable Carbon Cost that Remains Flat in Real Dollars Over Time and Is Far Below Costs Used by Other Utilities.

KPCo used an unreasonable carbon cost that actually remains flat in real dollars over time, which indicates that the carbon price is just a "token" price not meant to curb greenhouse gas emissions. This carbon price is far below what other utilities are using for a carbon price because it starts later in time, starts at a lower introductory price, and remains flat rather than increasing. The Company's attempt to gloss over its inconsistency with industry standards is not convincing because it would require treating carbon allowances differently than other pollutant allowances, which is an unsupported proposition. Moreover, if the Company had adequately accounted for the risks associated with future carbon costs, it would not need to request a 15-year depreciation to protect it from a "medium risk" that it will need to retire this unit in 2030 because of carbon regulation.

In the base case, the Company's CO_2 "Base" price starts at about $15 per metric tonne in 2022[21] and escalates by approximately 1.3%, which is slower than inflation. (Fisher Rev. Supp. at 31). Since this carbon cost escalates slower than inflation, this cost actually decreases in real dollars over time. (Fisher Rev. Supp. Exhibit 7b.) KPCo considered two other carbon costs in its

[21] Hearing, Witness Bletzacker, May 1, 2012, 20:09:08-20:09:40.

sensitivity analysis: (1) a no carbon cost case; and (2) an "early carbon case" starts five years earlier and is about 80¢ cents higher than the base case in real 2010$. (Fisher Rev. Supp. at 32.)[22]

The Company's carbon price is the lowest non-zero price used by other utilities. Fisher reviewed 22 different utility IRP and utility docket documents from a very diverse set of utilities operating all over the U.S.[23] (Fisher Rev. Supp. at 32.) These IRPs, all published in 2010 or 2011, all provide estimates for CO_2 prices at some time within the 2012-2040 planning horizon used by AEP. *See* Fisher Rev. Supp. at 32. With the exception of two IRPs that did not use a CO_2 price at all (i.e. a "zero price"),[24] all of the reference CO_2 price forecasts used by other utilities are higher than that of the Company. Indeed, there are no other utility forecasts that fall in real terms. For instance, Duke Energy filed IRPs in the latter half of 2011 in North Carolina, Indiana, and Ohio that used a reference CO_2 price that started at $12/ton in 2016 and increased to $42/ton in 2031. *See* Ex. SC-23 at pg. 101. Tennessee Valley Authority's ("TVA") Integrated Resource Plan from March 2011 used a reference CO2 price that started at $15/ton in 2013 and increased to $56/ton in 2030. (Hearing Ex. SC- 24 at pg. 97.)

The Company's analysis is so disjointed from how other utilities are treating the risk of future carbon costs that Bletzacker testified that he thought TVA was "imprudent" for using such a carbon price. (Hearing, Witness Bletzacker, May 1, 2012, 20:19:25-20:20:05.) Bletzacker further stated that he was "uncomfortable"[25] with the way all of the other utilities charted in Fisher Exhibit 7b treated carbon costs. (Hearing, Witness Bletzacker, May 1, 2012, 20:21:38-20:23:10.)

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[22] The Company did not rebut this point.
[23] See Exhibit JIF-5E for references
[24] Platte River Power Authority (Colorado, 2012) calculated a carbon mitigation curve (i.e. prices at which carbon reductions could be obtained by changing or building different resources), but did not provide an explicit price forecast. KU/LGE in KPSC Case No. 2011-00140 (2011) did not utilize a CO_2 price forecast.
[25] Bletzacker said that he didn't like the term "imprudent," but would easily say that he was uncomfortable with the way other utilities treated the cost. (Hearing, Witness Bletzacker, May 2, 2012, 20:21:45-20:23:10.)

The other utilities are using carbon price trajectories that assume a particular purpose – i.e. the mitigation of greenhouse gas emissions to prevent or slow the pace of climate change. *See* Fisher Rev. Supp. at 32-33. The basis of such prices is the concept that in order to eventually reach lower levels of CO_2 emissions, the effective price on CO_2 would have to rise over time, obtaining cumulative reductions in emissions by providing an incentive to mitigate at the lowest cost – essentially slowly moving up the supply curve of emissions reductions potential. (Fisher Rev. Supp. at 33.)

In contrast, the Company's price forecast appears to reflect a fairly cynical view that while a government entity might eventually impose a fee on carbon emissions, the political will to either increase or cease the fee will leave the price at a stalemate and thus achieve very little at all. This assumption is not shared by other utilities. (Fisher Rev. Supp. at 33.)

In fact, AEP's August 2011 (just four months before this CPCN application was filed), is starkly different than the one assumed by the utility in the preliminary analysis of Big Sandy 2. In that analysis, [redacted]

Fisher testified that Wilson conducted a re-analysis of the Company's Strategist base commodity price run, substituting the lowest Synapse CO_2 price forecast, which has a carbon price start at $15/ton (2010$/short ton) in 2020 and climb to $45/ton by the end of the 2040 analysis period. *See* Fisher Rev. Supp. at 35-36. The Synapse Low forecast does <u>not</u> represent the Mid, or expected case, according to the Synapse paper. Rather, it represents what the organization considers the lowest reasonable bound for a CO_2 price forecast (both low in price and late in start). *See* Fisher Rev. Supp. at 36. The Synapse Low case is, for example, consistent with forecasts from Ameren (MO) in 2011 and Duke (SC) in 2011, but is below TVA's estimates, and well below estimates from Nebraska, Kansas, Delaware, Idaho, and Oregon. *See* Fisher Rev. Supp. at 36.

Using a reasonable Low CO_2 price forecast substantively changes the outcome of KPCo's analysis. Simply shifting the CO2 price forecast to a low-range forecast consistent with the low end of forecasts from other utilities and organizations renders the retrofit of the Big Sandy 2 unit comparatively equal to the NGCC replacement in 2016 (Option 2) and far less economic than market purchases to 2020 (Option 4A). *See* Fisher Rev. Supp. at 36.

Cumulative present worth of revenue requirements (M 2011\$): Reanalysis with Synapse Low CO_2 price

Cumulative Present Worth of Revenue Requirements (M 2011\$) Re-Analysis with Synapse Low CO_2			
	Option #1 Retrofit Big Sandy 2 w/ FGD	**Option #2** NGCC Replacement	**Option #4A** Market to 2020; NGCC in 2020
Company Assumptions			
CPW	6,839	7,075	6,918
Net benefit of retrofit (CPW)		236	78
Synapse Low CO2 Price			
CPW	7,643	7,665	7,412
Net benefit of retrofit (CPW)		22	(230)

When the reasonable Low CO_2 price forecast is combined with the OSS corrections, the cost-effectiveness is again substantively changed. These numbers are shown below. (Fisher Rev. Supp. at 39.)[26]

[26] Even if one accepted KPCo's projections of the costs of each of the four options it evaluated at face value, its position that Option 1 is its least cost option through 2040 would not be accepted by the average citizen if it was described in everyday terms. KPCo maintains that investing over \$1 billion to retrofit Big Sandy Unit 2, a coal unit that is over 40 years old, in order to run it for 25 more years is preferable to investing a similar amount in a brand new gas-fired unit because KPCo projects the cumulative present worth of the retrofit over that period will be about 3.5% less than investing in the new gas unit (Hornby Rev. Supp. Direct, chart on pg 17, Exhibit___(JRH-6)). A very simple everyday analogy would be a husband trying to convince his wife that investing \$30,000 in their 15 year-old car in order to keep it running for 15 more years was a better choice than buying a new car for \$30,000 because the retrofit option would be 3.5% less expensive over the fifteen years. We doubt that many wives would accept that logic, especially when the husband adds that he expects her to pay the \$30,000 and bear the risk of the accuracy of his projections.

Cumulative Present Worth (CPW) under Company CO_2 assumptions and Synapse Low CO_2 price, capital cost corrected and adjusted for off-system sales sharing (revised 2)

Cumulative Present Worth of Revenue Requirements (M 2011$) Re-Analysis with Synapse Low CO2 & Adj. Off-System Sales			
0	**Option #1** Retrofit Big Sandy 2 w/ FGD	**Option #2** NGCC Replacement	**Option #4A** Market to 2020; NGCC in 2020
CPW	6,839	7,075	6,918
Net benefit of retrofit (CPW)		236	78
Synapse Low CO2 Price & Adjusted Off-System Sales			
CPW	7,694	7,702	7,462
Net benefit of retrofit (CPW)		9	(231)

Bletzacker attempts to diffuse this inconsistency with industry practice by stating that free allowances would double its carbon price. Specifically, Bletzacker states if the ultimate legislation that does pass contains a 50% free allocation of allowances, for example, then the effective cost of our KPCo modeling proxy of $15 per ton which is applied to all tons in the analysis is equivalent to a CO2 price of $30 per ton which is a very aggressive price." (Bletzacker Reb. at 8.)

The manner in which Bletzacker treats CO2 allowances is completely inconsistent with how Wohnhas states that NOx and SO2 allowances are treated. Wohnas stated that "What determines the price of allowances under CSAPR if they are allocated at zero cost?" "The price of an allowance under the CSAPR is determined by the cost at which companies are willing to sell their excess allowances, versus the cost that companies are willing to pay to earn the right to increase emissions." (Wohnhas Dir. at 17.) Under Wohnhas's theory of allowances, which is consistent with standard economic principles, the scenario by Bletzakcer would use $15 per ton, which is the market cost of CO2 allowance under his hypothetical. Bletzacker cites to no empirical studies or sources that indicate that a CO_2 market would no generally abide by the same economic principles as the NOx and SO_2 markets.

Bletzacker further attempts to justify the Company's carbon price that is starkly different than industry standards by claiming that carbon legislation is not likely to occur and that "alternative clean energy requirements or clean energy standards" are more likely to garner political support. (Bletzacker Reb. at 11.) The problem with this theory is that the Company did not model the carbon cost that would be associated with these renewable energy and energy efficiency standards. For instance, on March 1, 2012, Senator Bingaman introduced the Clean Energy Standard Act of 2012, which, if enacted, would require utilities to hold "clean energy" credits. (Hearing Ex. SC-25 at 9.) The U.S. Energy Information Administration recently modeled the price of those credits and determined they would start in 2015 at about $38 million per kWh, which translates to $38/MWh, in the base case. (Hearing Ex. SC-27 at pg. 143.)

Despite all of the Companies attempts to gloss over this issue as irrelevant, there is one fact that truly undermines their assertions. If the Company had adequately accounted for the risks associated with future carbon costs, it would not need to request a 15-year depreciation to protect it from a "medium risk" that it will need to retire this unit in 2030 because carbon regulation will make it uneconomic to run.

VI. KPCO'S AURORA MODELING WAS SO RIDDLED WITH ERRORS AS TO BE MEANINGLESS.

After completing its Strategist modeling, KPCo undertook a sensitivity analysis through use of a modeling program known as Aurora by which the Company estimated the revenue requirement at risk ("RRaR") of each option under consideration. The modeling involved one-hundred runs testing the impacts of six different input variables – load, construction costs, and the prices of coal, natural gas, energy prices, and CO2 allowances. (Weaver Dir. at Ex. SCW-1,

p. 10). The modeling runs then would produce estimated costs for each option at different probability levels, with the difference between each option of the revenue at risk at the 50th percentile versus the 95th percentile being used to determine which option posed the least risk. (*Id.* at p. 11). Such sensitivity analyses are supposed to help ensure that "none of the plans had outcomes that were economically-exposed – versus the other plans – under an array of input variables." (Weaver Dir. at Ex. SCW-1 p. 10).

Aurora and other models can be useful for analyzing such "long-term risks of alternative portfolios of resources." (Hornby Dir. at p. 23 lines 1-7). But KPCo's use of the Aurora model was so flawed that the results do not provide a reliable basis for such analysis. Those flaws fall into two categories – the use of inconsistent and inaccurate input variable correlations, and the erroneous use of a 20% demand vector or toggle in the modeling.

A. KPCo Used Input Variable Correlations in Aurora That Were Inconsistent With Those Used in Strategist and/or that Were Erroneous.

Aurora modeling is designed to evaluate how various resource options perform under different planning projections for important inputs variables. As such, in order for the Aurora modeling results to be worthwhile, the modeling needs to start with a reasonable set of assumptions regarding correlations between those variables. The correlations used by KPCo, however, are inconsistent and flawed and, therefore, do not provide a reasonable basis for the Aurora modeling.

The first major flaw with KPCo's sensitivity modeling is that the correlations by the Company in the Aurora modeling are contrary to the correlations used by the Company in the Strategist modeling discussed in Section V.A above. For example, in the Strategist modeling, KPCo assumed a significant positive correlation between coal and natural gas prices. As the Company explained in a discovery response, "coal and natural gas prices have historically been correlated, that is, coal and natural gas prices rise and fall in unison." (KPCo Resp. to KIUC DR 2-3). By contrast, in the Aurora modeling, the Company assumed that natural gas and coal prices had a correlation of only 0.09 (Weaver Dir. at Ex. SCW-1, p. 11, Table 1-4, *see also* Hearing, Witness Weaver, May 1, 2012, 15:22:10-15:27:50), which means virtually no correlation was assumed. Plainly, not both of these assumptions can be reasonable.

A similar correlation inconsistency can be seen with regards to the impact of CO2 prices on coal and natural gas prices. In the Strategist modeling, KPCo assumed that higher CO2 allowance prices would drive natural gas prices higher and coal prices lower. (May 1 Hearing Tr. at 15:18:50 to 15:21:06; Weaver Dir. at Ex. SCW-2). For the Aurora modeling, however, KPCo assumed that CO2 prices have a positive 0.69 correlation with coal prices and a negative 0.22 correlation with natural gas prices. (May 1 Hearing Tr. at 15:21:10 to 15:23:15; Weaver Dir. at Ex. SCW-1, p. 11, Table 1-4). This means that for Aurora, the Company assumed that higher CO2 prices would drive coal prices higher and would drive natural gas prices mildly lower. In other words, the Company assumed the exact opposite correlations between CO2, coal, and natural gas prices in Aurora as it did in Strategist. Plainly, not both sets of correlation assumptions can be reasonable.

In addition to these inconsistencies, there is strong evidence that the correlations used in the Aurora modeling are flawed for the various reasons that Fisher identifies in his testimony. (Fisher Dir. at p. 56 line 3 to p. 65 line 11). Most obviously, the Company assumed a positive correlation between demand and coal prices of 0.74. (Weaver Dir. at Ex. SCW-1, p. 11, Table 1-4). As Fisher explains, however, that correlation was based on an erroneous comparison between coal tonnage and demand, rather than coal prices and demand. (Fisher Dir. at p. 61 lines 10-15). When that error is corrected, the correlation changes to 0.08, which means that coal prices and demand are virtually uncorrelated. (*Id.*). KPCo did not rebut Fisher's testimony regarding the correlation of demand and coal prices. With regards to the rest of the errors identified by Fisher, Weaver does not directly challenge Fisher's analysis, but instead simply notes that KPCo "stands behind" its correlation estimates as "reasonable," contends that Fisher is merely "picking around the edges" on this issue, and attempts to dismiss the impact of potential errors in the correlations as "merely noise." (Weaver Rebuttal at p. 35 lines 6-7, p. 36 lines 12-16).

B. KPCo's Aurora Modeling Overestimated Energy Demand by 20%

KPCo's Aurora modeling was also unreliable because it overestimated expected energy demand by 20%. This overestimate occurred because a "demand vector" or "demand toggle" that allows the user of the Aurora model to test higher energy demand scenarios was left on for the initial Aurora modeling presented by Weaver in KPCo's application. (Weaver Rebuttal at p. 27 line 1 to p. 28 line 2). As a result, KPCo's total energy demand was escalated by 1,500 to 1,600 gigawatt hours ("GWh") per year in the Aurora modeling from the actual 2011 demand of approximately 7,600 GWh. (*Id.* at p. 28 lines 3 to 10). In other words, the model was assuming that KPCo would need to supply or purchase 1,500 to 1,600 GWhs more energy than actually needed each year.

This 20% demand vector overestimation had a significant impact on the revenue requirements calculated by the Aurora model, with impacts to market purchase Option 4B far larger than those to Option 1. Those impacts are illustrated in Weaver Rebuttal Ex. SCW-6, which charts the energy purchases or sales for Options 1, 2, and 4B under the Strategist modeling, the Aurora modeling with the 20% demand vector turned on, and the Aurora modeling with the 20% demand vector turned off. For Option 1, Strategist had net energy sales of more than $600 million, while Aurora had more than $1.5 billion in purchases with the demand vector on and $500 million in purchases with the demand vector off. So, having the 20% demand vector on caused KPCO to overestimate in Aurora the amount it would spend on energy purchases under Option 1 by $1 billion. For Option 4B, Strategist had net energy purchases of approximately $750 million, while Aurora had nearly $3.5 billion in purchases with the demand vector on, and less than $1.5 billion in purchases with the demand vector off. So having the 20% demand vector on caused KPCO to overestimate in Aurora the amount it would spend on energy purchases under Option 4B by $2 billion. Combined with the inconsistent and erroneous correlations, this $1 billion impact on Option 4B versus Option 1 raises serious questions about the reliability of the Aurora modeling performed by KPCo in this proceeding. Amazingly, KPCo witness Weaver did not acknowledge that overestimating demand by 20% was an error, but instead attempted to defend the 20% demand vector as a reasonable assumption and termed its corrected modeling as simply a "re-casting" of the analysis. (Weaver Rebuttal at p. 28 lines 11-16). Given the lack of support for assuming a 20% increase in energy demand and the large difference between the Aurora modeling with the 20% demand vector on versus with it off, terming the correction a simple "re-casting" strains credulity.

C. KPCo's Aurora Modeling Overstated the Purported Risk Benefit of Option 1 Over Option 4B By As Much as 118%.

The unreliability of KPCo's Aurora modeling is important because that modeling played an important role in the rejection of Option 4B in comparison to Option 1. KPCo tries to claim that the Aurora modeling simply "confirms the results and recommendations established by the Strategist modeling process that determined that the Option #1 (Big Sandy 2 DFGD Retrofit) was the least-cost alternative as set forth in Exhibit SCW-4." (Weaver Dir. at p. 48, lines 3-6). But, as discussed in Section III above, it is incorrect to say that the Strategist modeling showed

Option 1 to be the "least cost alternative." Instead, the Strategist modeling showed Option 4B to be the least cost, with a $47 million savings under the base scenario and an $81 million savings once off-system sales are properly accounted for. This basic error in KPCo's application strongly suggests that the Aurora modeling served as a basis for rejecting Option 4B, rather than simply confirming the results of Strategist.

As such, it is critical to note that the 20% demand vector error alone caused Aurora to overestimate the relative risk reduction benefit of Option 1 by 118%. As illustrated in the graph on Weaver Rebuttal Exhibit SCW-7R, the initial modeling with the 20% demand vector turned on reported that Option 1 had a little over $800 million of revenue at risk at the 95th percentile, while Option 4B had nearly $1.2 billion of revenue at risk, for a net difference of $363 million between the two options. With the model re-run with the 20% demand vector turned off, the differential between Option 1 and Option 4B shrinks considerably. Under that modeling, Option 1 has a revenue at risk of a bit over $600 million, while Option 4B had less than $800 million of revenue at risk, for a net difference of $166 million. (Weaver Rebuttal Ex. SCW-7R). As such, the Aurora modeling upon which KPCo based its application overstated the relative revenue at risk of Option 4B compared to Option 1 by 118%.[27] (May 1 Hearing Tr. at 16:47:15 to 16:49:20, 16:54:50 to 16:55:18).

In short, the significant changes that KPCo had to make to its initial modeling demonstrates that the errors that were identified were not "merely noise" or "picking around the edges," but instead demonstrate that the Aurora modeling carried out by KPCo is so unreliable as to be meaningless for purposes of this proceeding.

[27] $363,000,000 - $166,000,000 = $197,000,000/$166,000,000 = 1.18 or 118%.

VII. KPCO IMPROPERLY REJECTED LOWER COST OPTION 4B ON THE BASIS OF SUBJECTIVE MARKET RISKS THAT ARE CONTRADICTED IN AEP TESTIMONY IN OTHER STATES AND THAT KPCO DID NOT DOCUMENT, QUANTIFY, OR MODEL

Despite being anywhere from $47 million to hundreds of millions of dollars less costly to ratepayers than Option 1, KPCo rejected Option 4B largely because that option's reliance on market purchases for ten years "potentially subjects KPCo and its customers to additional pricing and performance risks." (Weaver Dir. at p. 38, lines 12-13). For purposes of this discussion, market purchases means KPCo purchasing capacity and energy through the PJM Reliability Pricing Model ("PJM-RPM") auction process, under which companies bid energy and capacity into a market three years in advance. With regards to "performance risk," Weaver notes that "the Company has no assurances that any future capacity required by PJM will be built as a result of the PJM-RPM construct." (Weaver Dr. at p. 38 lines 18-20). Weaver surmises that, as a result of such potential inadequacies, market capacity and energy prices could end up being higher than projected in the Strategist modeling that identified Option 4B as the least cost option. (*Id.* at p. 39 line 3 to p. 40 line 10). As a result, Weaver concludes, AEP Service Corporation continues to believe that AEP's affiliates are "economically advantaged" by remaining in a Fixed Resource Requirement ("FRR") construct rather than participating in the PJM-RPM auction process. (Weaver Dir. at p. 38 lines 13-18, Ex. SCW-1, p. 5).

A. In testimony filed with the Ohio PUC, AEP Ohio has rejected the type of concerns about reliance on PJM market energy and capacity purchases that KPCO is raising in this proceeding.

Weaver's testimony regarding reliance on the PJM-RPM market should be rejected by the Commission because it is directly contrary to the position being taken by AEP affiliate AEP Ohio in that company's pending corporate separation filing pending before the Ohio PUC. In that proceeding, AEP Ohio is proposing, effective June 1, 2015, to end its FRR approach and to begin acquiring all of the capacity and energy required to serve its customers through a competitive bid process with adequate capacity being assured through PJM. In support of that proposal, AEP Ohio offered the testimony of Robert Powers, who is an Executive Vice President at AEP Service Corporation, which is the same entity that employs KPCo witness Weaver. Powers explained that, as part of its proposed corporate restructuring, AEP Ohio would rely on PJM to assure adequate capacity, testifying as follows:

> **Q. HOW WILL THE PLANNED RETIREMENTS NTS OF AEP OHIO GENERATION ASSETS IMPACT THE AVAILABILITY OF ADEQUATE CAPACITY FOR OHIO CUSTOMERS?**
>
> A. The current AEP Ohio generation asset portfolio will have no direct relationship to the AEP Ohio load, once the transition to corporate separation, Pool Agreement elimination, and market-based capacity/energy procurement is complete. Therefore, any retirements would ultimately be offset by existing capacity or new capacity additions in PJM that could be built by other market participants.
>
> **Q. PLEASE EXPLAIN HOW AEP OHIO INTENDS TO ENSURE ADEQUATE CAPACITY ON AN ONGOING BASIS.**
>
> A. As outlined above, once the Pool Agreement is eliminated and corporate separation is complete, there will be a SSO Contract between the Genco and AEP Ohio over the ESP II term. To further support the Commission's intent to encourage competition in an expedited manner, from January 1, 2015-May 31, 2015, AEP Ohio will auction the energy component of SSO load. Effective June 1, 2015, AEP Ohio will use a CBP for supply of capacity and energy supporting SSO load in the same manner as other Ohio electric utilities do today. <u>The assurance of adequate capacity will become a function and obligation of PJM.</u> Please see the testimony of Company witness Graves who details PJM's RPM process.

(Hearing Ex. SC-17, Mar. 30, 2012, Testimony of Robert Powers at p. 23 lines 1-19) (emphasis added). The testimony of Frank Graves, referenced to by Powers, specifically rejected the type of performance risks identified by KPCo witness Weaver in the present proceeding with regards to reliance on the PJM-RPM market. Graves' written testimony submitted in the pending AEP Ohio proceeding explained:

> **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**
>
> I will explain why it is reasonable for the PUCO and the customers of Columbus Southern Power Company (CSP) and Ohio Power Company (OPCo) (also referred to as AEP Ohio) to be confident of the supply adequacy of their power supply when these AEP companies switch from being Fixed Resource Requirement (FRR) suppliers of capacity to relying on capacity supplied via PJM's Reliability Pricing Model (RPM) auctions.
>
> . . . .
>
> **Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND OPINIONS.**
>
> A. The PJM capacity markets have been functioning effectively since 2007. During that time, they have brought forward a large amount of new capacity resources, and have done so at prices generally below the annualized Net Cost of New Entry (Net CONE) in most regions of PJM, including the region in which CSP and OPCo are located. These auctions are designed to assure that there is an adequate supply reserve margin three years forward, and in that regard they have succeeded very well. This result has been achieved by eliciting the participation of many kinds of capacity resources, including demand response, plant life extensions, transmission expansions, and new generation stations.
>
> Despite likely coal plant retirements over the next few years (due to low gas prices and environmental retrofit obligations), it does not appear that there is any reason to fear a supply adequacy problem. PJM has more than target reserves at present and likely retirements are partly offset by announced new entry. Furthermore, the RPM auctions occur far enough in advance that even if a pending shortfall appeared likely, there would be sufficient time for new resources to be developed.

(Hearing Ex. SC-18, Mar. 30, 2012 Testimony of Frank Graves at p. 1 lines 6-11 and p. 2 line 14 to p. 3 line 60). In short, AEP Ohio is telling the Ohio PUC to disregards the exact same concerns about PJM and market purchases that KPCo witness Weaver is using as a basis for rejecting the lower cost Option 4B.

B. In testimony filed in Indiana, AEP affiliate Indiana Michigan Power Company has testified that market risks are similar to the risks associated with non-market options.

AEP affiliate Indiana Michigan Power Company ("IMPC") has similarly rejected the concerns about the market purchase risks that were relied on by Weaver in this proceeding. In a November 2011 Integrated Resource Plan filing with the Indiana Utility Regulatory Commission, IMPC evaluated three options for its generating fleet in Indiana – retrofitting coal units at the Rockport and Tanners Creek plants, retiring Tanners Creek Unit 4 and replacing it with a natural gas combined cycle facility, or retiring Tanners Creek Unit 4 and replacing it with market purchases. (Hearing SC-16, Nov. 1, 2011 Integrated Resource Plan at Exec. Summary p. 1). After running both Strategist and Aurora modeling of the three scenarios, IMPC concluded:

> the effects of market risk are similar to the risks associated with construction costs and fuel prices. This reinforces the conclusions from the *Strategist®* optimization analysis – that there is no particular advantage or disadvantage between the Base, Gas and Market portfolios

(*Id.* at 8-15). In other words, IMPC's analysis, just like AEP Ohio's, rejected the conclusion posited by KPCo Weaver to this Commission that a market purchase option presents some additional performance and pricing risks that justify dismissing such option.

C. KPCO has not quantified, documented, or modeled the market risks that it used to reject Option 4B.

In addition to being contradicted by AEP Ohio and IMPC filings in Ohio and Indiana, KPCo's claims that market risks justify rejecting the lower cost Option 4B are unavailing because the Company has not quantified, documented, or modeled those purported risks. It is important to keep in mind that the pricing risks that Weaver discusses on pages 38 and 39 of his direct testimony as a basis for rejecting Option 4B are "over and above" the range of market capacity and energy prices that were included in the different scenarios that KPCo evaluated in its Strategist modeling. (Hearing, Witness Weaver, May 1, 2012, 17:18:00 to 17:18:12, 17:21:20

to 17:21:30). KPCo's Strategist modeling used inputs from AEP's Fundamentals group projecting that PJM capacity prices would, under the Base scenario, increase more that twelve-fold by 2018 in comparison to 2012, and then nearly double again by 2030. (Weaver Dir. at SCW-2; Hearing, Witness Weaver, May 1, 2012, 17:18:50 to 17:19:32). The modeling also included four other scenarios with different ranges of projected PJM capacity and energy prices. (*Id.*). And that modeling, with the various capacity and energy prices factored in, showed that Option 4B was lower cost than Option 1 under the Base scenario and under most of the alternative scenarios that were modeled, as discussed in Sections III and V.B above.

At hearing it became clear that KPCo is seeking to reject the lower cost Option 4B on the basis of "other pricing risks that were not necessarily manifested in" the range of capacity and energy prices developed by AEP Fundamentals. (Hearing, Witness Weaver, May 1, 2012, 17:17:45 to 17:18:12). Yet KPCo acknowledges that it did not quantify or document such purported additional pricing risk. (Hearing, Witness Weaver, May 1, 2012, 17:18:35 to 17:18:45, 17:21:29 to 17:21:43). In addition, despite evaluating six "key risk factors" in its Aurora modeling, KPCo did not evaluate the purported additional capacity price risk in that model. (Hearing, Witness Weaver, May 1, 2012, 17:18:12 to 17:18:21). In essence, the Company is asking the Commission to reject a lower cost option on the basis of a subjective concern that KPCo affiliates have disavowed before other public utility commissions. Such amorphous, unsubstantiated, and ultimately unreviewable "risks" cannot provide a reasonable basis for rejecting a lower cost option, especially given that KPCo could have, but did not, quantify, document, or model such risks.

VIII. KPCO FAILED TO DISCLOSE RELEVANT EVIDENCE AND ONLY GRUDGINGLY RESPONDED TO DISCOVERY REQUESTS.

In CPCN proceedings, the Commission, its staff, and intervenors attempt to validate the veracity of an applicant's conclusions. This audit process requires parties to examine key assumptions and analyses of the applicant to determine if they are reasonable, meaning that an auditor could reasonably follow key assumptions and derivations, analysis mechanisms, and conclusions drawn from those analyses. If the assumptions and/or analyses are flawed, then the resulting conclusions are typically not reasonable. In a typical CPCN case involving a retrofit, a reasonable audit should be able to review: (1) the company's estimate (or bid) for their environmental upgrade and the estimate (or bid) for replacement capacity; (2) a logically structured modeling analysis in which the Commission or interveners may examine both input assumptions and output results; (3) sensitivity analyses that demonstrate robust conclusions, including explicit sensitivity inputs and outputs; (4) a clearly defined analytical framework for comparing the results of model runs; and (5) a justification of the project based on model results.

Transparency on the part of the applicant is an essential element of this audit process. A applicant must disclose information regarding input and output results, the modeling and analytical structure utilized, and which sensitivities were used, including inputs and outputs, how those sensitivities were selected. Without transparency regarding these issues it is impossible for the Commission or any party to verify, much less rely on, the applicant's assumptions and conclusions.

As part of the audit process of this CPCN application, Commission staff, Sierra Club, KIUC, and the Kentucky Attorney General propounded specific discovery so that it could either review and verify or reject KPCo's analyses and conclusions. However, KPC's responses to such requests for information were obstructive, evasive, and incomplete. The Commission should deny the Company's request for CPCN because this systematic and obfuscation.

A. The Company Failed to Disclose Strategist Modeling that Revealed a Medium Risk Identified by the Company Itself would Result in the Proposed Option Not Being the Least Cost Option.

The Company is requesting that the Commission grant it a15-year depreciation on these capital costs and return on equity associated with the Big Sandy retrofit because there is a risk that "future environmental regulations, particularly carbon legislation," could cause operation of this unit "not to be economically feasible in the future." (Wohnhas Dir. Test. at 15.) The Company states that there is a "medium risk" that this will occur. (KPCo Response to Staff 1-91; *see also* Hearing, Witness Wohnhas, April 30, 2012, 13:54:32-13:55:09.) The Company is requesting this accelerated depreciation to protect its shareholder (as opposed to the ratepayers) from facing $370 million in stranded investments. (Hearing, Witness Wohnhas, April 30, 2012, 14:08:37-14:12:50; *see also* KPCo Response to SC 1-17j, Att. 2.) In fact, this risk is so pronounced that the Company even considered a more accelerated, 10-year depreciation on this retrofit. (Hearing, Witness Wohnhas, April 30, 2012, 13:58:37-14:02:50; KPCo Response to KIUC's 1-28, att.)

The Company, however, justified the investment in Big Sandy Unit 2 as being the lowest-cost option based on his assumption Big Sandy Unit 2 will operate to 2040, not on any analyses that the Company might retire this unit earlier than 2040. Weaver Dir. at 15. Sierra Club and the Commission asked the Company, during cross examination, if the Company had ever modeled whether the proposed project is the lowest cost option if the plant only operates for 15 years. (*See*, *e.g.*, Hearing, Witness Wohnhas, April 30, 2012, 14:13:27-14:15:37.) Through cross examination, Sierra Club expressed concern that the ratepayers would bear all the financial risk as they would have paid the revenue requirements associated with Big Sandy Unit 2 under the assumption that it was the most cost-effective option through 2040, but will have to pay the revenue requirements associated with the replacement capacity and energy from 2030 to 2040. (*See*, *e.g.*, Hearing, Witness Wohnhas, April 30, 2012, 14:07:45-14:15:37.)

On the stand, Weaver admitted that the Company had modeled how retiring Big Sandy Unit 2 in 15 years impacted the least-cost analysis. (*See*, *e.g.*, Hearing, Witness Weaver, May 1, 2012, 14:50:32-14:54:30.) On October 7, 2011 (two months before it filed its application), the Company had run a Strategist model with Option 1 retiring in 2030 and that this indicated that Option 1 (the Big Sandy retrofit) would increase in price by $202 million and that Option 4B would be $238 million less expensive than the proposed retrofit.

The "medium risk" that this plant will need to retire in 2030, motivated the Company to take action to protect its shareholders. However, it did not afford the Commission or intervenors access to the same information to which it was privy until numerous witnesses were explicitly questioned about this issue on the stand. Since KPCo is requesting a CPCN that will cost an impoverished community $1 billion, it is shameful that KPCo should work so hard to protect its shareholders, while hiding information that impacts the bottom line from ratepayers who are struggling to pay their bills. This is far afield from the transparency that the Commission and intervenors deserve.

B. The Companies Failed to Provide Information Regarding the Strategist Model and Operating & Maintenance Costs.

The Company gave Sierra Club faulty Strategist files weeks after discovery responses were due, only acknowledged and rectifying these errors after Sierra Club filed a Motion to Compel, and refused to answer questions propounded in discovery requests to reconcile capital costs with O& M costs based on the advice of counsel. The Company's evasive and incomplete answers have undermined other parties' participation in these proceedings.

On January 13, 2012, Sierra Club propounded discovery on the Company that specifically requested the Strategist input and output files in a machine readable format. *See* SC 1-37. In the Company's response on January 27, 2012 to this information request, the Companies did not provide these files stating that permission was needed from Ventyx, as this is proprietary information. *See* KPCo's Response to SC 1-37. On February 1, Wilson spoke with Eric Hughes from Ventyx and Hughes stated that he asked AEP to provide the Strategist files as Synapse was a licensed user. On February 7, 2012, Sierra Club finally received the Strategist input files.[28]

However, the input files provided to Sierra Club were faulty. When these input files were used, the model correctly reproduced runs for Options 3, 4a, and 4b, but generated an error message that said, "no feasible combination of alternatives can be found in 2015," for Options 1 and 2. When the Company provided the input files on February 7, 2012, it did not indicate that corrections were needed to the input files in order to execute the runs produced.

On February 17, 2012, Sierra Club filed a Motion to Compel noting that the input files were defective and that the Company had not provided any output files, without which one cannot you are correctly replicating the Company's Strategist runs. On February 22, 2012, KPCo responded to Sierra Club's Motion to Compel and agreed to make Becker available to Sierra Club's experts to resolve this issue.

On February 24, 2012, Becker spoke with Wilson and Fisher and informed them that they had to change certain input files provided to interveners so that the model would produce the same results generated by KPCo in this analysis. (Hearing, Witness Becker, May 2, 2012,

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[28] Since the Company is fully aware that is takes four weeks to rerun Strategist, see Hearing, Witness Becker, May 2, 2012, 9:43:15-9:47:10, it fully understand that by delaying in getting the files to Sierra Club its was hindering its ability to audit the modeling process.

9:59:15-9:59:45.) One of the required changes that Wilson had to make was to extend the operating life of Big Sandy to 30 years as the Strategist model on its own kept retiring this unit. (Hearing, Witness Becker, May 2, 2012, 9:59:45-10:00:40.)

Wilson and Fisher then asked Becker to reconcile how capital costs and O&M costs were used in the Strategist model. (Hearing, Witness Becker, May 2, 2012, 10:01:24-10:01:40.) In response to a question Becker stated that capital expenditures were include in the O&M category. (Hearing, Witness Becker, May 2, 2012, 10:01:51-10:02:04.) Becker told Wilson and Fisher, however, that these capital expenditures were for ongoing costs and not an upfront investment. (Hearing, Witness Becker, May 2, 2012, 10:02:04-10:02:08.) Wilson and Fisher then asked follow-up questions to try to reconcile what these ongoing capital expenditures covered. Becker stated that he could not answer this question based on the advice of counsel. (Hearing, Witness Becker, May 2, 2012, 10:02:09-10:03:33.)

The Company's refusal to answer this question was especially egregious as Sierra Club had already propounded discovery on this matter. On February 8, 2012, Sierra Club filed its second request for information and specifically asked that the "Company clearly define and reconcile the major groups of capital costs used in the Strategist model with those described in witness testimony, e.g. costs of DFGD, costs of boiler modification, costs of life extensions, etc." *See* SC 2-34. In response to this data request, the Company stated that the capital costs of the four alternative options is defined in the PROVIEW module of Strategist, which has a single capital cost variable consisting of the Base cost without AFUDC ($/kw). This answer, however, was incomplete because Becker's rebuttal testimony finally clarified that not all capital costs associated with the retrofit projects were represented in the PROVIEW module and some were incorporated into ongoing capital expenditure. (*See* Becker Reb. at 8-10.)

In order for the Company to split the upfront capital costs into the carrying costs, which were used in fixed O&M category, the Company had to perform certain calculations.[29] (Hearing, Witness Becker, May 2, 2012, 10:10:55-10:12:31.) The Company has still not provided those calculations to the Commission or any party, hindering all parties' ability to verify them. (Hearing, Witness Becker, May 2, 2012, 10:11:05-10:11:19.)

C. The Companies Failed to Provide Requested Information Regarding the Aurora Model is so Egregious that the Commission Should Disregard the Aurora Model Entirely.

It is important for the Commission and independent evaluators, such as the interveners in this and other proceedings, to be able to examine how the Company uses modeling to support their conclusions – particularly if the basis of a decision rests so heavily on a modeled outcome, as in this CPCN. The Aurora model, while apparently only a small part of the overall modeling performed by the Company, is used by the Company to reject two Options – one of which is, by the Company's own estimate, more cost effective than maintaining the Big Sandy 2 unit. Given the weight the Company places on this Aurora model, it is extremely important that the Company provide transparent answers to allow the Commission and other parties to do a robust audit of the model's results. Unfortunately, the Company was evasive and opaque regarding the Aurora model.

Sierra Club repeatedly requested the input and output files from the Aurora model[30] to understand how the Company was using this platform, and if the inputs and process were

[29] The Company should have used the CER module as Ventyx recommends to avoid human error in performing the calculations.

[30] *See* SC 1-69 "provide all assumptions and workbooks, in electronic format and with all calculations operational and formulate intact, used to prepare SCW-1 through SCW-4, including output files from the Aurora model;" *see* SC 2-34 requesting "(1) all inputs to the Aurora model, in machine readable format; (2) the distribution assumed for each of the six key risk factors considered by the Aurora model, in machine readable format; and (3) the rationale supporting each of the distributions assumed for each of the six key risk factors;" *see* SC 2-35 requesting (1) all inputs to the Aurora model in operational, electronic format; (2) all outputs from the Aurora model, by year, in

consistent with other Company assumptions.[31] In response to Sierra Club's First Data Request, the Company provided only a list of 100 CPW values – with no component costs, no formulae, and no basis. (*See* KPCo Response to SC 1-69; *see also* Fisher Rev. Sup. Dir. at 52.) After filing a Motion to Compel, the Company provided a series of worksheets that break down the 100 CPW values into their component costs over time – but these worksheets arrived without formulae and the supporting workbooks were simply pasted values from another source. (*See* KPCo Response to SC 2-35(a) and (b); *see also* Fisher Rev. Sup. Dir. at 52.) In fact, it appears that formulae were purposefully disabled in this worksheet. (*See* Fisher Rev. Sup. Dir. at 52.)

Despite this lack of transparency, Fisher was able to reconstruct some components of the Aurora outcomes,[32] but Fisher had no mechanism to be able to rectify those outcomes with input data, or even sufficiently trace which input data actually went into the Aurora analysis. From the aspects that Fisher was able to review, he found inconsistencies between the Aurora and Strategist models. Fisher found that the Aurora model estimates that the (median) net benefit of retrofitting the Big Sandy 2 is anywhere from $350 to $609 million more than the Strategist model's output – or anywhere from double the benefit to well over ten times the benefit; results that simply don't hold water – particularly as they are examined more closely. (*See* Fisher Supp. Rev. at 42, 43-50.)

As a result of Fisher's testimony, Weaver testified that he had made two changes to the Aurora model. (*See* Weaver Reb. at 24.) One problem, Weaver testified was that a 20% demand toggle was erroneously left, which meant that demand was increased by 20% over the forecasted

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operational, electronic format; (3) all inputs used to prepare Exhibit SCW-5, by year, in operational, electronic format; and (5) all work papers used to prepare Exhibit SCW-5 in operational, electronic format.

[31] Other intervenors also requested this information. *See* KIUC 1-28.

[32] Hearing, May 1, 2012, Fisher Witness, 11:00:29-11:02:06 (Fisher testified that he does a lot of model building and model running. He noted that although he had not previously worked with the Aurora model be frequently works with dispatch models. Fisher stated that he does not need to fully understand the Aurora mechanisms to understand how the inputs would impact the model. In addition, he noted that reviewing the model outputs in conjunction with these inputs were indicative of problems with the model).

demand. *See* Weaver Reb. at 27-28. The magnitude of this error is demonstrated by Rebuttal Exhibit SCW-6. Having the 20% demand toggle on caused KPCo to overestimate the amount needed for energy purchases under Option 1 by $1 billion; under Options 2 and 3 by $2 billion; and Option 4b by $2 billion. (*See* Weaver Reb. at 29-30, Rebuttal Exhibit SCW-6R; *see also*, Hearing, Witness Weaver, May 1, 2012, 16:28:26-16:38:26.)

Weaver also acknowledged that the correlation issue identified by Fisher was corrected. See Weaver Reb. at 24. KPCo ran 100 runs of the Aurora model to estimate the revenue requirements of each option under various projected values for six key input variables. *See* Weaver Dir., SCW-1, page 10. Fisher testified that many of these correlations were incorrect and offered alternative correlations. As a result of Fisher's Testimony, Weaver testified that they reran the Aurora model to correct these correlations. (*See* Weaver Reb. at 24.) Once the 20% demand toggle was turned off and the correlations were removed from the model, the difference between the RRaR for Option 1 and for Option 4B became closer to $50 million once the 20% demand toggle is turned off and correlations removed, rather than the $364 million initially predicted by Weaver. (Hearing, Witness Weaver, May 1, 2012, 16:52:01-16:54:40.) The Company had used the Aurora model to rank the relative Revenue Requirement at Risk (RRaR)[33] profile for each option. This correction led to an approximately 86% reduction in the RRaR difference between Option 4B and Option 1. (Hearing, Witness Weaver, May 1, 2012, 16:48:55-16:49:37.)

Based only on the limited information the Company's provided regarding Aurora, intervenrors were able to identify two glaring errors. Based on this small sliver of transparency, the Aurora model is more likely erroneous – and potentially biased – then actually useful.

[33] The difference in RRaR represents a difference in risk, not absolute outcomes. *See* Hearing, Witness Weaver, May 1, 2012, 16:46:02-16:47:29.

Moreover, the Commission and interveners were not able to robustly analyze the Aurora model as the Company refused to turn over specifically requested information. The Company could have used arbitrary, or even biased, input data for this model and it would be impossible to know based on the information provided by the Company in this proceeding. Based on all of this information, the Commission should disregard the Aurora analysis in its entirety.