COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

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PUBLIC SERVICE COMMISSION

**In the Matter of:**

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

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**AFFIDAVIT OF JAMES RICHARD HORNBY FOR DIRECT TESTIMONY (PUBLIC VERSION)**

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Commonwealth of )
Massachusetts )
)

James Richard Hornby, being first duly sworn, states the following: The prepared Direct Testimony (Public Version) and associated exhibits filed on Monday, March 12, 2012 constitute the direct testimony of Affiant in the above-styled cases. Affiant states that he would give the answers set forth in the Direct Testimony, Public Version, if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, his statements made are true and correct.

J R Hornby
James Richard Hornby

SUBSCRIBED AND SWORN to before me this 9 day of March 2012.

M M Schultz
Notary Public

My Commission Expires:

MELISSA SCHULTZ
Notary Public
Commonwealth of Massachusetts
My Commission Expires
July 27, 2018

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

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| In the Matter of: | ) | |
| | ) | |
| APPLICATION OF KENTUCKY POWER COMPANY | ) | |
| FOR APPROVAL OF ITS 2011 ENVIRONMENTAL | ) | |
| COMPLIANCE PLAN, FOR APPROVAL OF ITS | ) | |
| AMENDED ENVIRONMENTAL COST RECOVERY | ) | Case No. 2011-00401 |
| SURCHARGE TARIFF, AND FOR THE GRANT OF A | ) | |
| CERTIFICATE OF PUBLIC CONVIENENCE AND | ) | |
| NECESSITY FOR THE CONSTRUCTION AND | ) | |
| ACQUISITION OF RELATED FACILITIES | ) | |

**Direct Testimony of**
**J. Richard Hornby**

**On Behalf of**
**Sierra Club**

**March 12, 2012**

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## 1. INTRODUCTION

**Q. Please state your name and occupation.**

A. My name is J. Richard Hornby. I am a Senior Consultant at Synapse Energy Economics, 485 Massachusetts Avenue, Cambridge, MA 02139.

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

A. Synapse Energy Economics ("Synapse") is a research and consulting firm specializing in energy and environmental issues. Its primary focus is on electricity resource planning and regulation including computer modeling, service reliability, resource portfolios, financial and economic risks, transmission planning, renewable energy portfolio standards, energy efficiency, and ratemaking. Synapse works for a wide range of clients including attorneys general, offices of consumer advocates, public utility commissions, environmental groups, U.S. Environmental Protection Agency, Department of Energy, Department of Justice, Federal Trade Commission and National Association of Regulatory Utility Commissioners. Synapse has over twenty professional staff with extensive experience in the electricity industry.

## 2. BACKGROUND

**Q. Please summarize your educational background.**

A. I have a Bachelor of Industrial Engineering from the Technical University of Nova Scotia, now the School of Engineering at Dalhousie University, and a Master of Science in Energy Technology and Policy from the Massachusetts Institute of Technology (MIT).

**Q. Please summarize your work experience.**

A. I have over thirty years of experience in in the energy industry, primarily in utility regulation and energy policy. Since 1986, as a regulatory consultant I have provided expert testimony and litigation support on natural gas and electric utility resource planning, cost allocation and rate design issues in over 120 proceedings in the United States and Canada. During that period my clients have included utility regulators, consumer advocates, environmental groups, energy marketers, gas producers, and utilities. Prior to 1986 I served as Assistant Deputy Minister of

Energy for Nova Scotia where I helped prepare the province's first comprehensive energy plan and served on a federal-provincial board responsible for regulating exploration and development of offshore oil and gas reserves. I have also spent several years as a project engineer in the industrial sector.

I was the lead author of *Potential Impacts of a Renewable and Energy Efficiency Portfolio Standard in Kentucky* (January 2012) and of projections of long-term avoided energy supply costs in New England prepared 2007, 2009 and 2011. I was co-author of *Portfolio Management: How to Procure Electricity Resources to Provide Reliable, Low-Cost, and Efficient Electricity Services to All Retail Customers,* a 2006 report prepared for the National Association of Regulatory Utility Commissioners (NARUC).

My resume is attached to this testimony as Exhibit__(JRH-1).

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

A. I am testifying on behalf of Sierra Club.

**Q. Have you testified previously before the Kentucky Public Service Commission (Commission)?**

A. No, I have not.

## 3. PURPOSE OF TESTIMONY

**Q. What is the purpose of your testimony?**

A. The Sierra Club retained the Synapse team of Dr. Jeremy Fisher, Ms. Rachel Williams and me to assist in their review of the Kentucky Power Company's (KPCo or Company) application for a Certificate of Public Convenience and Necessity (CPCN) to retrofit Big Sandy Unit 2.

The purpose of my testimony is to provide an overview of our analysis of whether the Company's proposed CPCN for Big Sandy Unit 2 and associated Environmental Cost Recovery (ECR) surcharge are reasonable and cost-effective for complying with the environmental requirements the Company is facing. My testimony discusses the resource options KPCo evaluated, the range of future scenarios it used to evaluate those resource options, its projection of revenue requirements for each resource option under those future scenarios and its conclusions regarding the merits of its proposed CPCN based upon its projections and analyses.

Synapse witness Wilson describes her review of the Company's modeling of resource options using Strategist as well as her use of Strategist to model those resource options under an additional future scenario reflecting a different projection of carbon prices. Synapse witness Dr. Fisher describes his review of the Company's assumptions regarding the costs of certain resource options, certain future scenarios the Company tested in its Strategist modeling and the Company's modeling of those resource options using Aurora.

**Q. What data sources did you rely upon to prepare your review of the Company's request?**

A. My review relies primarily upon the direct testimonies and Exhibits of KPCo witnesses Wohnhas, Weaver and Munsey and their responses to various data requests. The specific responses I cite in this testimony are attached as Exhibit____(JRH-10). In addition I reviewed KRS 278.183, referred to as the Environmental Surcharge Statute, as well as materials regarding Kentucky's energy and environmental policies and regarding strategies that companies with coal units are using to comply with environmental regulations.

## 4. SUMMARY CONCLUSIONS AND RECOMMENDATIONS

**Q. Please summarize KPCo's request for a CPCN to install environmental control equipment on Big Sandy Unit 2 and for a rate increase to recover the costs of that investment.**

A. KPCo has requested approval for a CPCN to install environmental control equipment, primarily a Dry Flue Gas Desulfurization System ("DFGD"), on Big Sandy Unit 2 ("the Plant"). Concurrently it has requested an increase in its ECR surcharge in order to recover the cost of installing that equipment. The Company estimates the environmental control equipment, at a capital cost of $940 million, will have an annual revenue requirement of approximately $178 million and cause its retail rates to increase by more than 30 percent.

KPCo maintains that installing a DFGD on that Unit is in the long-term best interest of its customers. The Company's conclusion is based upon the results of Mr. Weaver's economic evaluation which indicates that, relative to the three other resource options it examined, retrofitting Big Sandy Unit 2 is the best option for complying with the environmental regulations the Company is facing.

**Q. Please summarize your major conclusions and recommendation regarding the Company's request.**

A. My first conclusion is that the Company has not demonstrated that its proposed CPCN for Big Sandy Unit 2 is reasonable and cost-effective for complying with the environmental requirements the Company is facing. That conclusion is based upon the results of our review which indicates that the Company has not evaluated the full range of resource options available to it, that its projections of revenue requirements for the resource options it did evaluate are not correct, that its evaluation of future scenarios does not include a reasonable projection of carbon prices and that its Monte Carlo risk analysis is flawed. My second, related, conclusion is that allowing KPCo to recover the costs of installing environmental control equipment on Big Sandy Unit 2 from ratepayers will not result in reasonable rates.

Based upon those two conclusions I recommend that the Commission not approve the Company's request for a CPCN for Big Sandy Unit 2.

**Q. Please summarize your conclusions and recommendations regarding ratemaking should the Commission decide to approve the CPCN.**

A. In the event that the Commission decides to approve the Company's request for a CPCN, I am sure it will limit the Company's recovery of actual costs to only the amounts it finds just and reasonable. My understanding of the ratemaking process under the Environmental Surcharge Statute is that the Commission will review the Company's actual costs every six months, and disallow actual amounts it finds that are not just and reasonable, and that it will shift recovery of amounts it does find reasonable from the surcharge into base rates every two years. However, my conclusion is that even with those measures, ratepayers will still bear the bulk of the financial risk resulting from

KPCo's decision to propose and pursue the CPCN since they will be paying the vast majority of, if not all, the revenue requirements resulting from KPCo's choice of that resource option.

Based on that conclusion, if the Commission decides to approve the CPCN, I recommend that the Commission require the Company to:

- recover its investment in environmental controls at Big Sandy Unit 2 based upon a depreciation rate consistent with generally accepted accounting principles, which would be a period of at least twenty years;
- modify its System Sales Clause to be consistent with the amount of off-system sales margin it assumed would flow to ratepayers under its modeling of the CPCN option; and
- bear the risk of carbon regulation costs in excess of the values the Company has assumed in its early carbon future scenario.

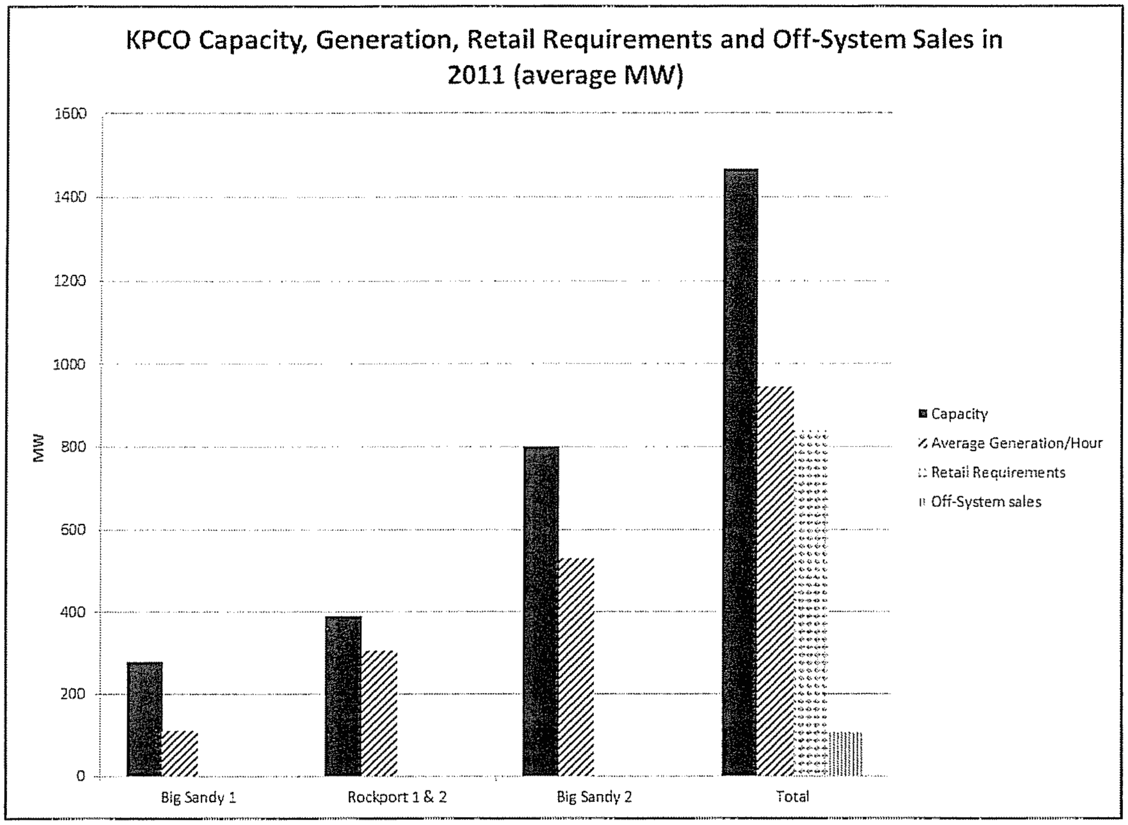
## 5. APPROACH TO REVIEW OF KPCO REQUEST

**Q. Please summarize KPCo's current mix of capacity and energy by resource.**

A. KPCo has modeled its future operations as if it will be operating as a stand-alone company rather than a member of the current AEP pool. As a stand-alone company KPCo is currently entirely dependent on coal units for capacity and annual generation, i.e., energy, to serve its retail load. It owns two coal fired units, Big Sandy Unit 1 and Big Sandy Unit 2. It acquires capacity and energy from two other coal-fired units, Rockport 1 and Rockport 2, through a long-term purchase power agreement which its modeling assumes will be renewed to continue through 2040

KPCo's mix of capacity and energy in 2011, as modeled by the Company in Strategist, is illustrated in the bar chart below from Exhibit___(JRH-2). In that year Big Sandy Unit 2 accounted for approximately 55% of the Company's total capacity and generation. In contrast, Big Sandy Unit 1 accounted for approximately 20% of the Company's capacity but provided only 12% of its annual energy. That Exhibit also indicates that the Company used approximately 10% of its total generation to make off-system sales. Under the

KPCo System Sales Clause, Tariff S.S.C., the Company retains forty percent of the margin revenue from off-system and credits retail customers with the remaining sixty percent.




**Q. Please summarize KPCo's current resource mix and the known and emerging environmental regulations it is facing.**

A. The Company is currently facing the following known and emerging environmental regulations: the Cross-State Air Pollution Rule (CSAPR), the Mercury and Air Toxics Standard, the Coal Combustion residuals rule, the Clean Water Act "316(b)" rule and expected Effluent Limitation Guidelines as well as the New Source Review consent decree. The Company expects that Big Sandy Unit1 and Big Sandy Unit 2 will need to comply with at least some of these environmental requirements by 2016.

**Q. Please summarize the economic evaluation KPCo conducted to evaluate its resource options for complying with those environmental requirements.**

A. According to Mr. Weaver's direct testimony, KPCo evaluated its resource options for complying with these environmental requirements in four major steps.

- First, it identified four resource options for complying with these environmental requirements.
- Second, it identified a Base Case and four additional discrete scenarios to evaluate the future conditions under which those resource options might operate.
- Third, the Company developed projections of the revenue requirements associated with each resource options over a 30-year period, 2011 to 2040, under each of the five discrete future scenarios. The Company developed those projections using the Strategist model, a computer simulation model, and a separate workbook to calculate the carrying charges of each resource option.
- Fourth, the Company used Aurora, another computer simulation model, to prepare a risk analysis of the four resource options.

Based upon his review of the revenue requirements of each resource option under each of the five scenarios, summarized in his Exhibit___(SCW-4), his review of the results from the Aurora model and other points in his direct testimony, Mr. Weaver concluded that retrofitting Big Sandy 2 with DFGD technology is in the long-term best interest of KPCo's customers.

**Q. Please describe the approach the Synapse team used to determine if the Company's proposed CPCN for Big Sandy Unit 2 and associated ECR surcharge were reasonable and cost-effective for complying with the environmental requirements the Company is facing.**

A. The Synapse team treated the Company's application as a request for rate relief and reviewed that request in the same level of detail as a base rate filing. Specifically we reviewed the validity of the key input assumptions underlying the Company's projection of revenue requirements for each resource option under each future scenario. Where applicable we also verified the mathematical accuracy of those revenue requirement projections.

We followed this rate-making proceeding approach based on the Commission's Order in Case No. 2011-00161 indicating that a proceeding under the Environmental Surcharge Statute is a rate-making alternative to a general rate case. Our approach is also based upon the Environmental Surcharge Statute requirement that the Commission must determine if the Company's proposed plan and rate surcharge are reasonable and cost-effective for complying with the environmental requirements it is facing.

**Q. Please contrast the magnitude of rate relief the Company is requesting in this proceeding with the rate relief it requested in its most recent general rate proceeding.**

A. The increase in rates the Company is requesting in this proceeding is much larger than the increase it requested in its most recent general rate proceeding. In this proceeding the Company is requesting an increase in annual revenues of $178.8 million, or over 30 percent. That amount is approximately fifty percent more than the increase of $123.6 million it requested in its 2009 general rate proceeding, Case No. 2009-00459, and approximately three times greater than the $63.7 million increase it ultimately agreed to in the settlement of that Case.

**Q. Is it more difficult to assess the reasonableness of its request in this proceeding than its request in a general rate proceeding?**

A. Yes. In order to determine the reasonableness of the revenue requirements a utility requests in any type of rate proceeding parties generally follow two basic steps. They review the Company's support for the input values it has used to calculate its revenue requirements and they review the mathematical accuracy of its calculation of revenue requirements based upon those input values. While I do not wish to minimize the time and effort that parties put into verifying the reasonableness of the revenue requirements in general rate proceedings, I consider it more difficult to execute those two steps in this type of rate proceeding. In a general rate case in Kentucky, parties review a projection of revenue requirements for a historical test year, thus many of the inputs are actual or close to actual costs, and the costs are limited to one year. In contrast, in this proceeding the parties must verify the Company's support for assumptions for 30 years as well as the mathematical accuracy of its calculations using those assumptions.

Given the uncertainty associated with the values of key input assumptions over that planning horizon it is particularly important that all parties have a clear understanding of the basis for the Company's key input assumptions regarding resource costs and of the range of future market and regulatory conditions it may face. It is particularly important to "stress test" those assumptions under a range of realistic possible future scenarios.

## 6. ASSESSMENT OF KPCO REQUEST FOR CPCN AND RATE INCREASE

**Q. Has your team been able to confirm the validity of all key input assumptions and verify the Company's calculations and projections based upon those inputs?**

A. No. Our review has found many aspects of the Company's filing unclear, particularly in terms of documentation of key input assumptions and transparency of calculations based upon those assumptions. Ms. Wilson and Dr. Fisher discuss the lack of clarity and inconsistencies in various aspects of the Company filing. As a result we do not claim to have confirmed the validity of all key input assumptions underlying the Company's projection of revenue requirements for each resource option under each future scenario, or to have verified the mathematical accuracy of all of its projections.

**Q. Please list the major problems the Synapse team has found with the Company's economic evaluation**

A. Our review has identified problems with four major aspects of the Company's economic evaluation. The four major problem areas are:

i. the limited range of pre-determined resource options the Company modeled in Strategist;

ii. certain of the Company's assumptions regarding the costs of the four resource options it did evaluate were unreasonable or inconsistent, and when corrected change the projected revenue requirements of those Options;

iii. the limited range of future scenarios the Company modeled using Strategist to evaluate the four resource options, in particular its failure to evaluate scenarios that are substantively different from each other or a scenario with a reasonable projection of carbon prices; and

iv. the risk analysis the Company prepared using Aurora.

**i. Limited Range of Pre-determined Resource Options**

**Q. Please summarize the four resource options the Company evaluated for complying with known and emerging environmental regulations at the Big Sandy plant.**

A. For Big Sandy Unit 1 the Company's proposed environmental compliance strategy is to retire it as a coal-fired unit effective January 1, 2015. For Big Sandy Unit 2, the Company decided to choose among four possible resource options in order to determine the best environmental compliance strategy. The four resource options it evaluated were:

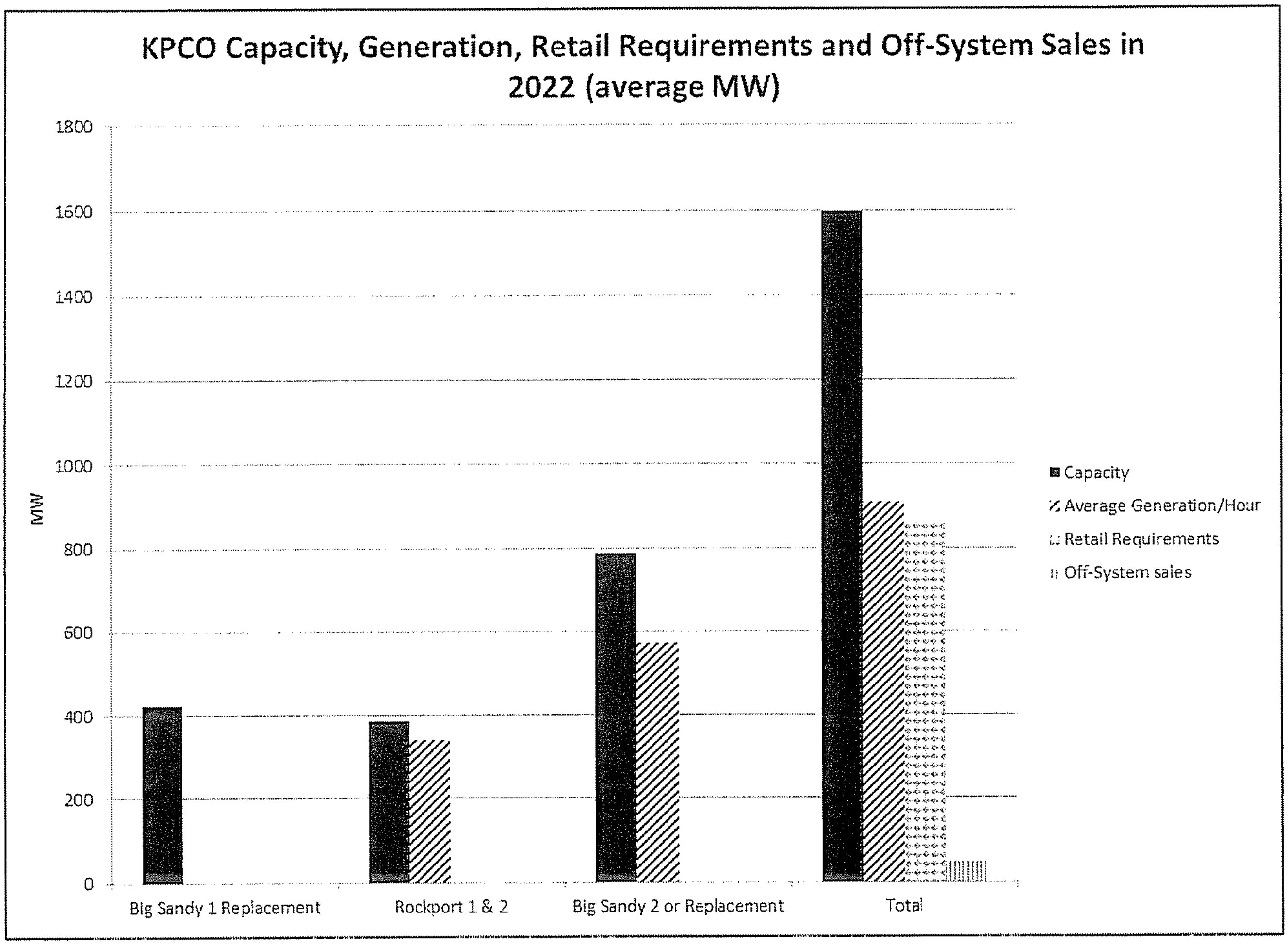
- Option 1, Retrofit Big Sandy Unit 2 with DFGD by June 2016 in order to allow it to continue operating at approximately 800 MW;
- Option 2, Retire Big Sandy Unit 2. Build a 762 MW natural gas-fired combined cycle unit (CC) by January 2016 at the Big Sandy plant site;
- Option 3, Retire Big Sandy Unit 2. Repower Big Sandy Unit 1 as a 745 MW natural gas-fired combined cycle unit (CC) by January 2016;
- Option 4, Retire Big Sandy Unit 2 and replace essentially all of its capacity and energy with purchases from the relevant PJM wholesale markets for a period of either 5 years (Option 4A) or 10 years (Option 4B) and then build or acquire replacement CC capacity.

**Q. Please comment on the Company's choice of those four options.**

A. I have three concerns with the Company's choice of those four options. First, it has not provided a formal analysis supporting its choice of those four options (Response to KIUC 1-29).

Second, the Company has in effect limited its evaluation to three resources, to be acquired in 2016 in "all or nothing" quantities under either full ownership or full procurement. Specifically KPCO has evaluated a single large coal unit ownership option, a single large natural gas CC ownership option (i.e., Options 2 and Option 3 are essentially the same) and an all market purchase option. The bar chart below, from Exhibit___(JRH-3), illustrates the extent to which the Company would be dependent on whichever of those single large resource options it implemented during the period 2017 through 2024. Using 2022 as a representative year, the bar chart indicates that Big Sandy

Unit 2 (Option 1), or its replacement, would account for approximately 49% of the Company's total capacity and approximately 63% of its annual energy.




Third, the Company's assessment of only four options is inconsistent with the wide range of FGD designs it evaluated (Exhibit SCW-3).

**Q. Do those four options represent all of major resource options available to KPCo?**

A. No. The Company did not evaluate all of the major resource options available to it. First, the Company 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 (Responses to Sierra Club 1-52, Sierra Club 1-62). Second, KPCo did not evaluate a variation on Option 4 under which it would acquire capacity and energy through a strategy consisting of purchases from the PJM wholesale markets, long-term power purchase agreements and other hedging strategies. (That approach would address the concerns the Mr. Weaver raises regarding the Company's exposure to cost uncertainty and price volatility variation under Option 4). Another approach that KPCo evaluated in its March 2011 analyses but not in this proceeding was a combination of a smaller gas CC, perhaps in the 600 MW range, plus market purchases (Response to Sierra Club 1-69). The Company maintains that Option 2 represents a proxy for the bids it would receive in response to a Request for Qualifications (RFQ) or a Request for Proposal (RFP) to buy existing gas-fired CC or CT units (Responses to Staff 1-65 and 2-29). However, the Company did not evaluate a "resource blind" RFP for capacity and energy to identify the full range of fossil, renewable and efficiency resources available to replace Big Sandy Unit 2, including fractional ownership (Responses to Sierra Club 1-51 and 2-21).

**Q. Did the Company have the ability to evaluate a much wider range of resource options?**

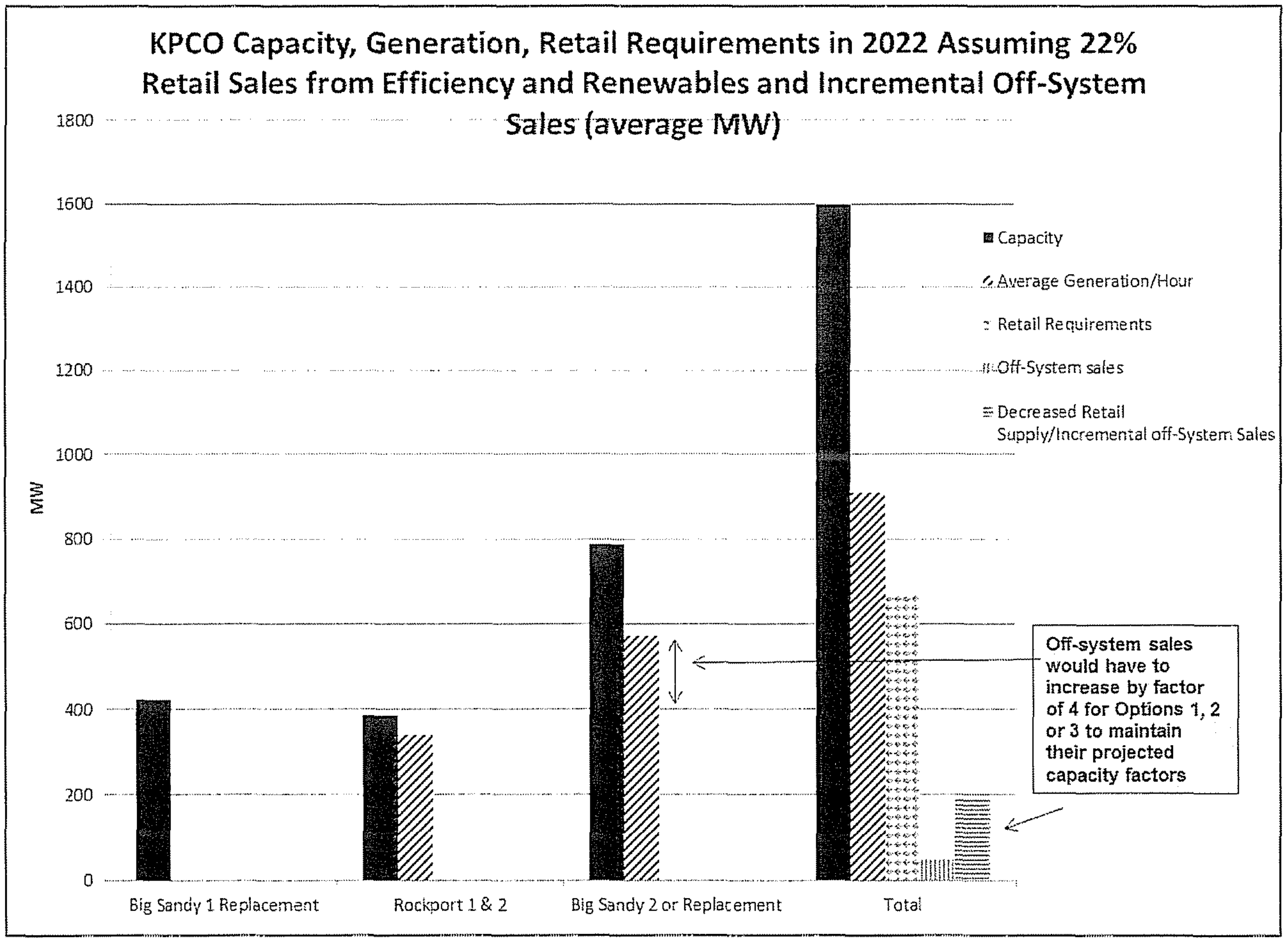
A. Yes. The Company could have used Strategist, its primary modeling tool, to evaluate a much broader range of supply-side and demand-side resource options. As Ms. Wilson explains, the Company had the ability to enter a broad range of available options into Strategist and to let the model choose the portfolio with the optimal, i.e., least-cost, mix of capacity and energy from that inventory of resource options.

**Q. Why is it so important for the Company to have evaluated a range of resource options?**

A. It is important for the Company to have evaluated a range of resource options given the magnitude of investment under consideration and the long-term risk associated with making such a large investment in one resource. As I noted earlier, there are significant uncertainties regarding how the future will unfold over the next ten years, let alone through 2040. There is tremendous value in maintaining some degree of flexibility to respond to changes in future regulatory and market conditions, and thus ensuring rates can remain reasonable as circumstances change. It is important to ensure that KPCo is not committing itself to a major investment in baseload capacity which it may not need to meet retail load in ten years or fifteen years due to major changes in the requirements of its retail customers, the relative costs of the resources available to it or future environmental regulations. Thus, it is essential that the Company demonstrate that it has thoroughly evaluated the resource portfolios which might provide it that flexibility.

**Q. Can you provide a simple illustration of one change in market conditions the Company may face?**

A. Yes. Legislation being introduced in the Kentucky General Assembly proposes to establish a Renewable and Energy Efficiency Portfolio Standard (REPS) for utilities in the states. Under that proposal, utilities would have to meet their retail load with increasing specific quantities of efficiency and renewables, reaching approximately 22% of their retail load by 2022. That change in energy requirements for retail load is illustrated in the bar chart in Exhibit___(JRH-4), using 2022 as the same representative year as in the bar chart from Exhibit___(JRH-3) shown earlier.



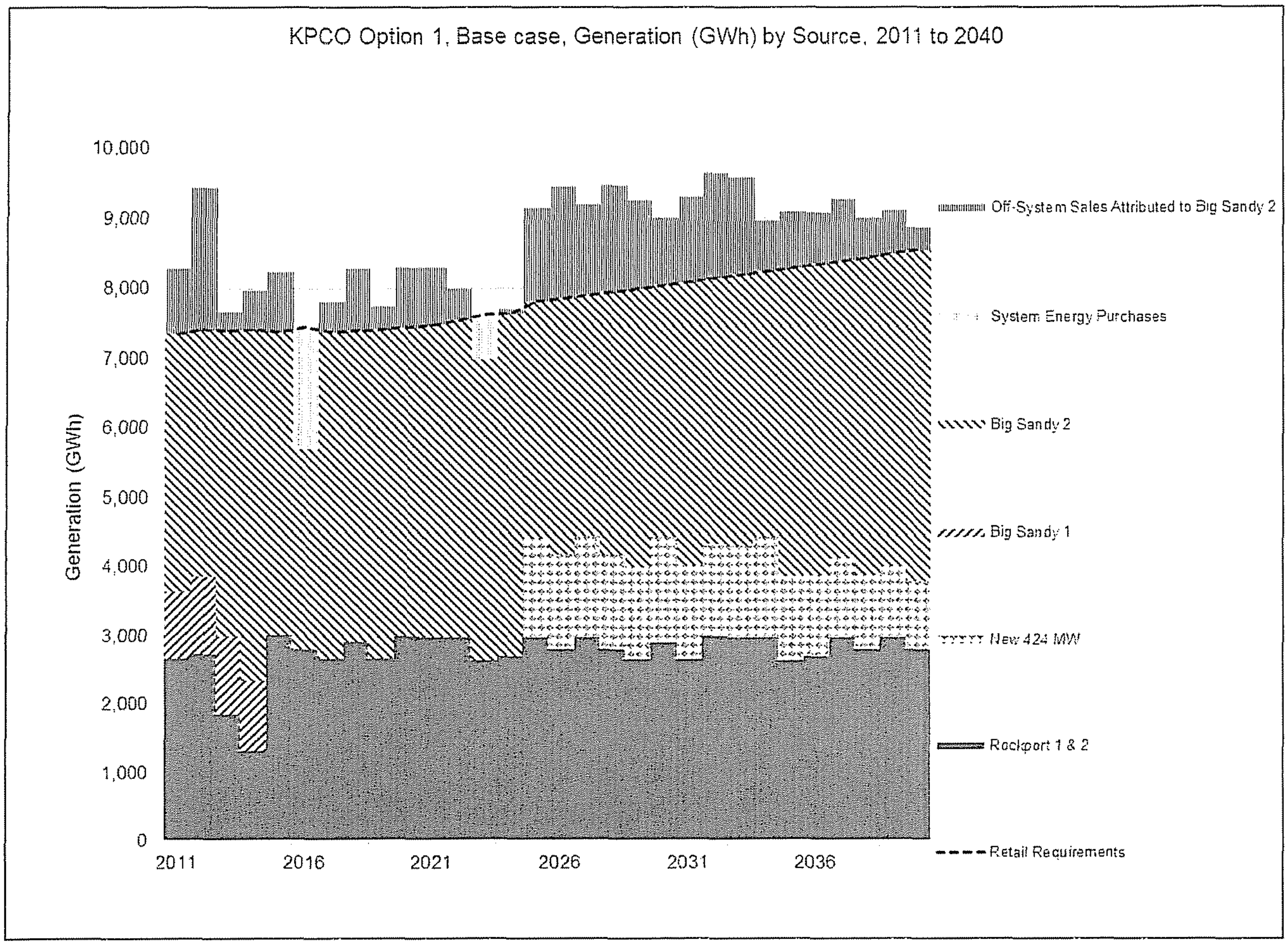

This simple illustration indicates that if KPCO implemented either of Options 1, 2 or 3 and its actual retail requirements from fossil generation in 2022 proved to be over twenty per cent less than it has modeled in this proceeding, it might not have the most cost-effective mix of capacity and energy. For example, it might have too much baseload capacity and not enough peaking capacity. Admittedly this simple, one-year snapshot does not reflect the potential the Company might have to not renew its power purchase agreement for one of its Rockport units, or to defer its proposed addition of 407MW of capacity in 2025. However, it does illustrate the type of substantial change in conditions the Company may face over a planning horizon through 2022, let alone through 2040.

**Q. Does the Company's evaluation of the four resource options it considered include a thorough analysis of the flexibility it will have to respond to changes in market conditions under each of the resource options?**

A. No. First, the Company has not evaluated its four resource options under a future scenario with much lower retail requirements from fossil generation (Response to Sierra Club 1 – 43 and 2-25). Second, Mr. Weaver refers to the importance of planning flexibility, adaptability to risk and other planning criteria on page 7 of his testimony. However he does not provide any metrics for those criteria nor any assessments beyond those presented in his Exhibits SCW 4 and SCW 5 (Responses to Sierra Club 1-33, 1-34, 1-57, 2-22 and 2-31). Finally, as I discuss later in my testimony, KPCo has not tested its four resource options against a sufficiently broad range of future scenarios.

**Q. Please describe the Company's projected mix of capacity and energy under the Base Case if Option 1 is approved.**

A. If Option 1 is approved, the Company will continue to be largely, if not entirely, dependent on coal units for its capacity and energy through 2040. KPCo's projected mix of capacity and energy under the Base Case if Option 1 is approved is illustrated in the chart below from Exhibit___(JRH-5). That Exhibit also indicates that the Company projects it will continue to use generation from Big Sandy Unit 2 to make off-system sales in addition to supplying its retail customers.




### ii. Resource Option Cost Assumptions and Resulting Revenue Requirements

**Q. Please summarize the Company's projection of revenue requirements for each resource option under each future scenario.**

A. The Company's projection of revenue requirements for each resource option is the sum of six major categories of projected costs. Those six categories of costs are:

i. Fuel and other variable production costs of all KPCo units, which include its entitlement share of Rockport Units 1 and 2;

ii. Emission allowance costs of all KPCo units;

iii. Sales or purchases of market energy by or for KPCo;

iv. Sales or purchases of market capacity by or for KPCo;

v. Fixed operation and maintenance (FOM) costs for all KPCo units; and

vi. Fixed carrying charges of major incremental KPCo capital investments in generation capacity.

The largest two categories of costs are variable production costs, in particular fuel, and fixed carrying charges.

**Q. Please summarize the models the Company used to calculate these revenue requirements.**

A. The Company used the Strategist model to project the first five categories of cost inputs to its revenue requirements, which I refer to as Net Production and FOM costs. It used only the economic dispatch and production costing functionality of the Strategist model to project theses costs. Strategist develops those projections based on the numerous inputs entered by the Company including projections of retail load, generating unit heat rates, fuel prices, emission prices, and capacity and energy prices in PJM wholesale markets.

The Company used a separate, spreadsheet model to project the fixed carrying charges and costs of capacity purchases associated with each resource option. Finally KPCo used a Strategist Compilation Workbook to calculate the revenue requirements of each resource option, i.e., to essentially add the Net Production and FOM costs from Strategist to the fixed carrying charges and purchased capacity costs.

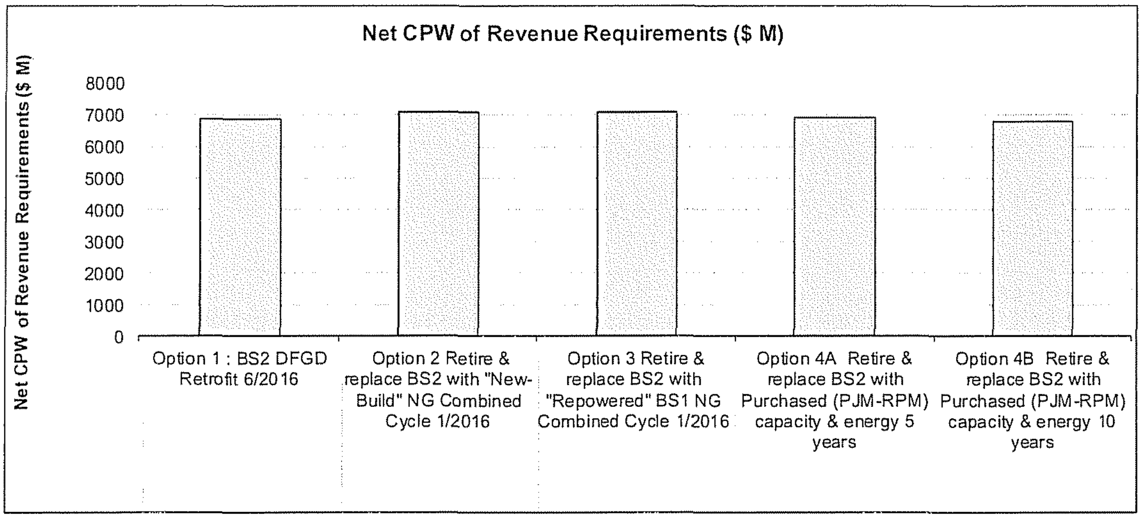
**Q. Did your team review the Company's estimate of net production and FOM costs using Strategist?**

A. Yes. Ms. Wilson began her review by obtaining the Company's inputs to Strategist for each of its 25 runs and using Strategist to independently reproduce and verify the Company projections for each of those runs. Ms. Wilson's testimony describes the problems she found with the Company's projections of net production and FOM costs using Strategist.

**Q. Please summarize the Company's projected revenue requirements for each of the resource options and future scenarios it considered.**

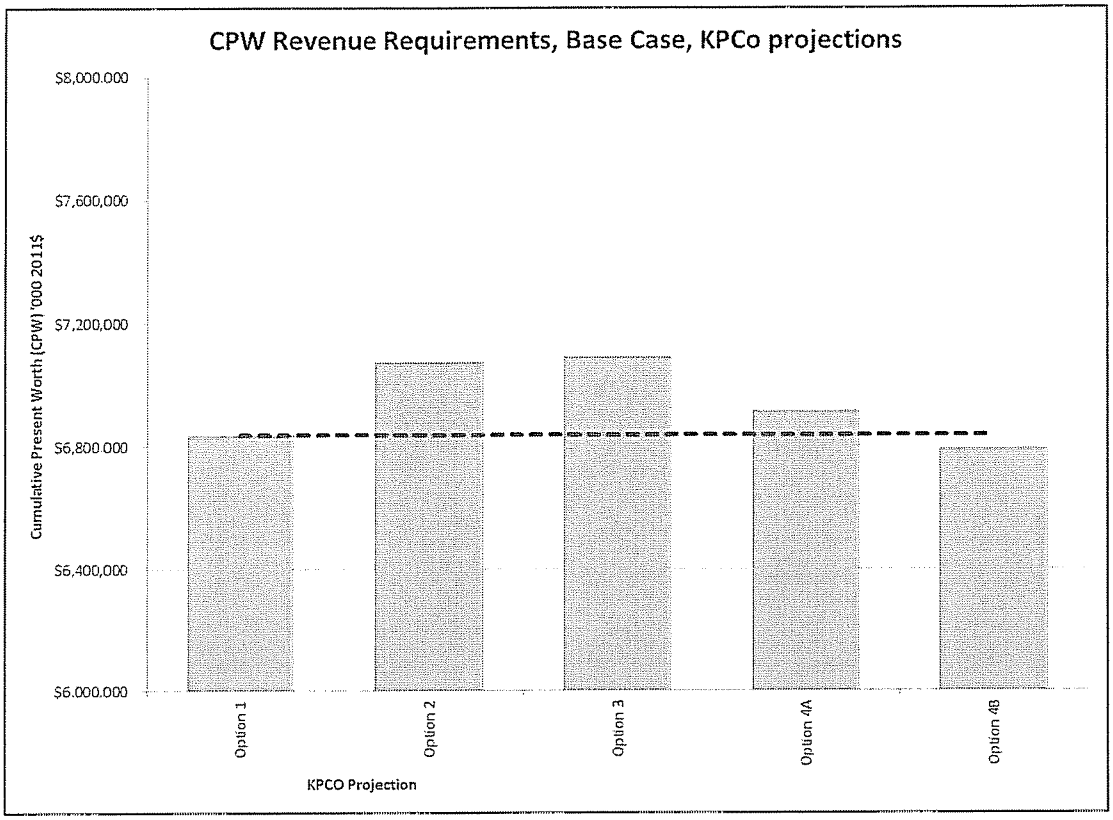
A. The cumulative present worth (CPW) values of the Company's projected revenue requirements for each resource option and future scenario, assuming a 15 year depreciation period for Option 1, are presented in Exhibit___ (JRH-6). That Exhibit also presents the difference in CPW by resource option, measured relative to Option 1, for each future scenario, in absolute and percentage terms.

The CPW of total revenue requirements for each resource option under the Base Case are very close, as indicated in the bar chart below taken from Exhibit___ (JRH-6).




| | | | | | |
|---|---|---|---|---|---|
| Net CPW of Revenue Requirements ($ M) | $ 6,839 | $ 7,075 | $ 7,091 | $ 6,918 | $ 6,792 |
| Delta of Net CPW from Option 1 ($ M) | N/A | $236 | $252 | $79 | -$47 |
| Delta of Net CPW from Option 1 (%) | N/A | 3.5% | 3.7% | 1.2% | -0.7% |

The fact that the CPWs of the resource options are relatively close may not be surprising, given the thirty year timeframe and the inclusion of costs common to all four resource options, i.e., the Rockport units and the 407 MW CC scheduled to be added in 2025. However, it does require one to focus on the differences in CPW by resource option for each future scenario as well as on other policy considerations in order to determine which resource option is cost-effective and reasonable. The differences in the CPW of total revenue requirements for each resource option under the Base Case are more apparent in the bar chart below, also taken from Exhibit___ (JRH-6).

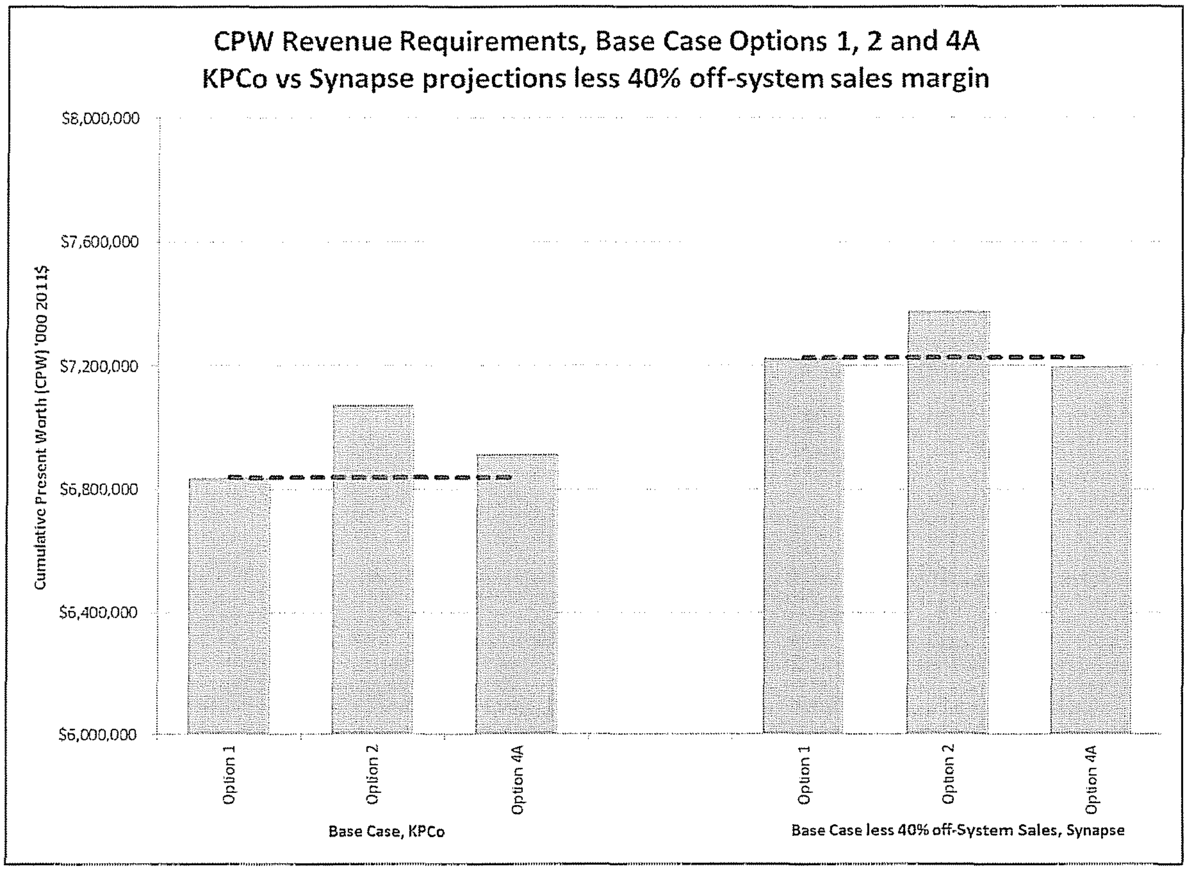



In the balance of my testimony, I use the Company's projections for Option 1, Option 2 and Option 4A under its Base Case to illustrate the problems we have found with its projections.

**Q. Please comment on the Company's treatment of margin from off-system sales in its projection of revenue requirements for each resource option.**

A. As discussed in more detail by Dr. Fisher, the Company appears to have credited 100% of the margin from projected off-system sales against the projected gross revenue requirements of each resource option when calculating net revenue requirements to be recovered from retail customers. We support this treatment, but note that it is not consistent with the Company's current System Sales Clause, under which KPCo shareholders retain 40% of margin from off-system sales.

If the Company's projection of revenue requirements reflected a continuation of the current System Sales Clause, and credited only 60% of the margin from off-system sales against gross revenue requirements, the difference in CPW between Option 1 and the other three Options is reduced substantially. Dr. Fisher quantifies that impact, which is illustrated in the bar chart from Exhibit ___(JRH-7).

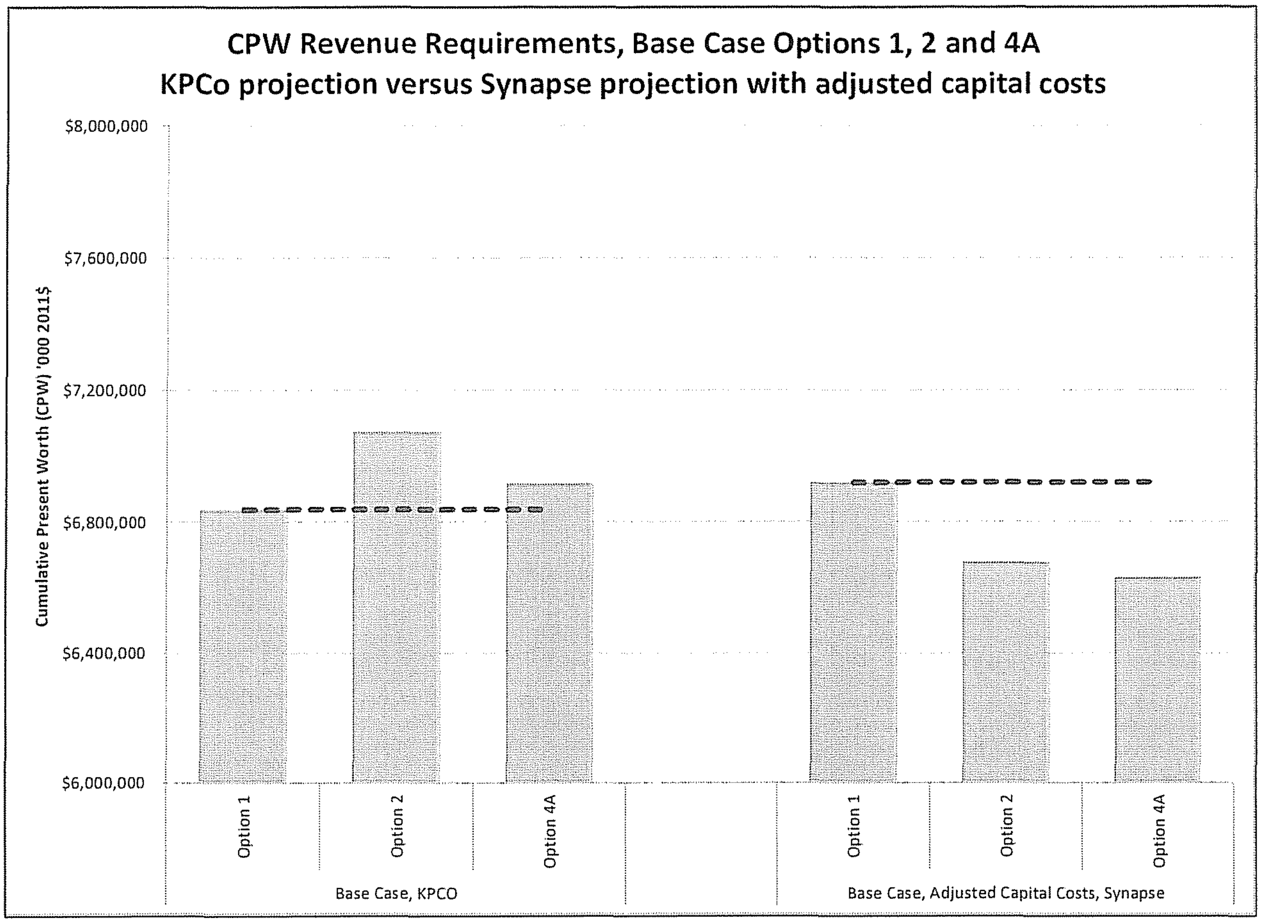



**Q. Has your team identified problems with any of the Company's cost assumptions for the four resource options it did evaluate?**

A. Yes. The reviews conducted by Ms. Wilson and Dr. Fisher indicate that the Company's estimate of capital costs for Option 1 is too low. Dr. Fisher's review indicates that estimates of capital costs for Options 2, 3 and 4 are too high. His analyses also indicate that the Company's estimate of annual fixed operation and maintenance costs (FOM) of Option 1 from 2031 onward are too low.

**Q. Have you prepared projections of revised revenue requirements based upon corrected assumptions for the four resource options?**

A. Yes. The bar chart below, from Exhibit ___(JRH-8), illustrates the impact on revenue requirements of correcting the capital cost assumptions identified by Dr. Fisher and Ms. Wilson. Those revised projections indicate that Option 1 would have the highest revenue requirement, and as such is neither reasonable nor cost-effective.




### iii. Limited Range of Future Scenarios without Reasonable Projection of Carbon Prices

**Q. Please summarize the five future scenarios the Company modeled in Strategist in order to evaluate the four resource options it considered.**

A. The Company evaluated its four resource options under a Base Case and four discrete sensitivity scenarios. The five future scenarios it modeled are:

1. Base Fleet Transition-CSAPR. This assumes natural gas prices at Henry Hub reach $6.52/MMBtu by 2020 and a carbon price starting at $15 per metric tonne in 2022, both in nominal dollars. The carbon price is based on assumption that carbon emissions from existing fossil generation will begin to be regulated in that year.
2. Fleet Transition-CSAPR: Higher Band. This tests sensitivity to higher prices for natural gas and coal, relative to Base Case levels, with no other change to Base Case assumptions.

3. Fleet Transition-CSAPR: Lower Band. This tests sensitivity to lower prices for natural gas and coal, relative to Base Case levels with no other change to Base Case assumptions.

4. Fleet Transition-CSAPR: No Carbon. This tests sensitivity to zero prices for carbon, with no other change to Base Case assumptions.

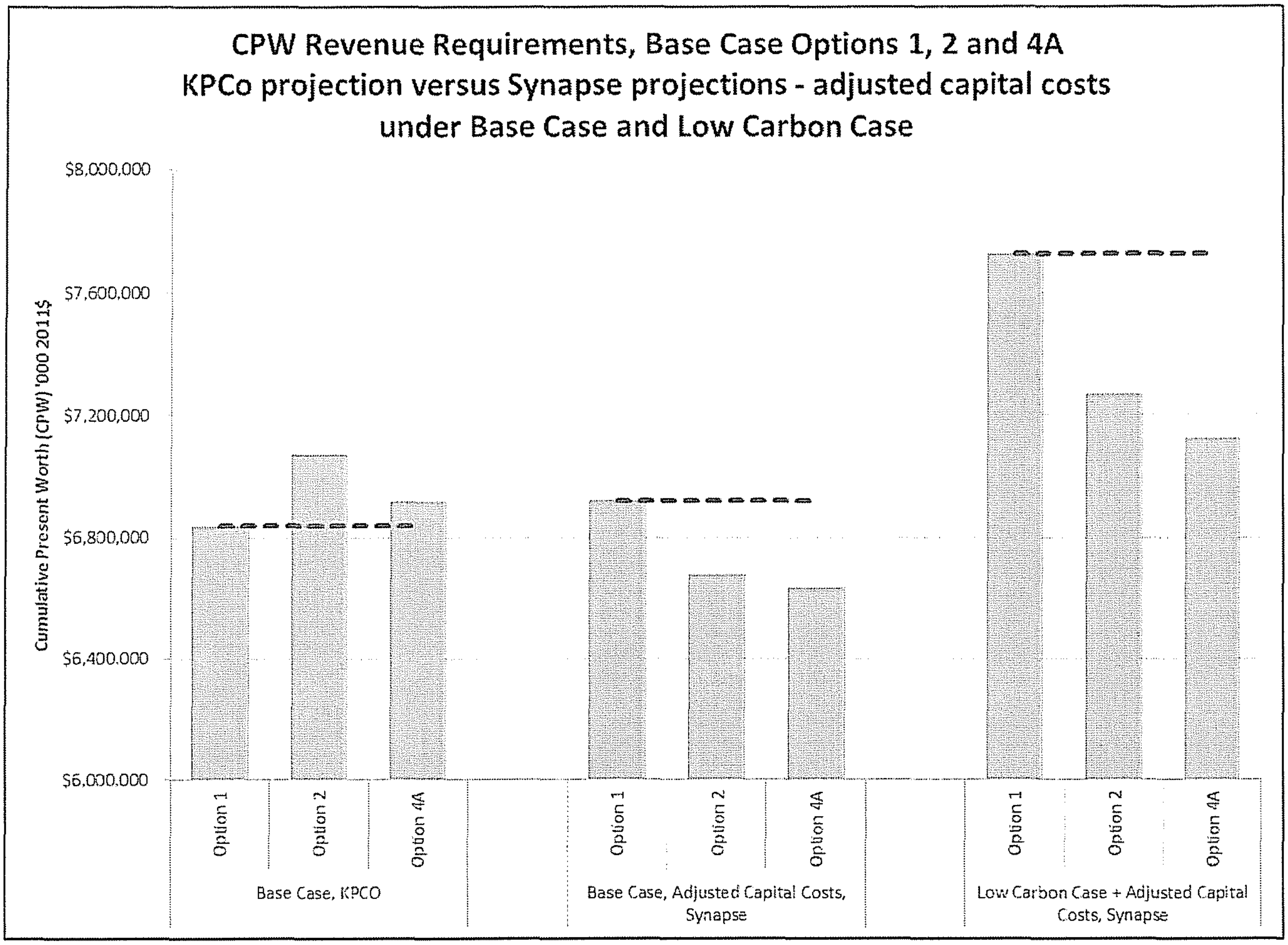
5. Fleet Transition-CSAPR Early Carbon. This tests sensitivity to prices for carbon starting at $15 per metric tonne in 2017, with no other change to Base Case assumptions.

**Q. Has your team identified problems with any of the Company's assumptions for those five future scenarios?**

A. Yes. Dr. Fisher's review indicates that the Company's assumption of carbon prices under its Base Case and each of its four other scenario are too low, including those in the Early Carbon scenario. In addition, his analysis indicates that the Company's assumptions regarding the relationship between natural gas and coal prices in its higher band and lower band scenarios are inconsistent with its assumption regarding the correlation of those prices in its Aurora runs. Also, as noted earlier, the Company did not test a scenario with a much lower level of retail requirements from fossil generation.

**Q. Have you prepared revised projections of revenue requirements using corrected assumptions for Options 1, 2 and 3 and a future scenario with a reasonable projection of carbon prices?**

A. Yes. Exhibit ___(JRH-9) presents projections of revised revenue requirements using corrected assumptions for options 1, 2 and 3 under the carbon scenario recommended by Dr. Fisher. Those revised projections indicate that Option 1 has the highest revenue requirement, and as such is not reasonable or cost-effective.




### iv. Risk Analysis Using Aurora

**Q. Please summarize why and how the Company used the Aurora model.**

A. As discussed, the Company used Strategist to quantify the risk associated with each resource option by testing the sensitivity of their projected revenue requirements under its Base Case to four discrete changes in assumptions about the future, i.e., higher fuel prices, lower fuel prices, higher carbon prices and zero carbon prices. The Company used the Aurora model in an attempt to further quantify the potential risks associated with each resource option by projecting their revenue requirements under 100 different future scenarios. The Aurora model created the 100 different futures based on the Company's input assumptions regarding the relationships, or correlations, between five key input assumptions using a "Monte Carlo" modeling technique or algorithm. The 100 futures reflect different combinations of five key input assumptions, i.e., coal prices, natural gas prices, carbon prices, wholesale power prices and retail demand.

**Q. In theory, does this type of modeling have the potential to provide useful information for resource planning decisions?**

A. Yes. For example, *Portfolio Management: How to Procure Electricity Resources to Provide Reliable, Low-Cost, and Efficient Electricity Services to All Retail Customers*, a 2006 report that Synapse prepared for the NARUC, notes the potential benefit of using computer models such as Aurora to analyze long-term risks of alternative portfolios of resources.

Q. **Does the Company's application of the Aurora model in this proceeding provide a useful assessment of the cost risk associated with each resource option?**

A. No. Dr. Fisher identifies numerous problems with the Company's risk modeling using the Aurora model. Given the extent of the problems he has identified, the results from the Company's risk modeling using the Aurora model do not provide a useful assessment of the cost risk associated with each resource option.

**v. Sharing of Financial Risk between Ratepayers and Shareholders**

**Q. Will ratepayers bear the majority of the financial risk under any resource strategy that the Company ultimately implements?**

A. Yes. Ratepayers bear the majority of the financial risk under any resource strategy the Company ultimately implements because their rates are based upon the revenue requirements that result from that strategy.

Consider the allocation of financial risk under the following hypothetical. The Commission decides to approve Big Sandy Unit 2 with a 15 year depreciation and by 2030 the scenario Mr. Wohnhas discusses in his testimony proves to be correct, i.e., future increased EPA standards cause operation of Big Sandy Unit 2 not to be economically feasible. Under that hypothetical KPCo would retire Big Sandy Unit 2 in 2030 and replace it with some other source of capacity and energy. Under this hypothetical the Company would have recovered its full investment in Big Sandy Unit 2, including a return on equity, by 2030 and will bear no financial risk. In contrast, ratepayers will bear all the financial risk. They will have paid the revenue requirements associated with Big Sandy Unit 2 through 2030, which was approved on the assumption it was the most cost-effective option through 2040, plus they will have to pay the revenue requirements associated with the replacement capacity and energy from 2030 to 2040.

**Q. Please comment on the financial risks that the Company should bear if the Commission decides to approve KPCo's request for a CPCN**

A. In the event that the Commission decides to approve the Company's request for a CPCN, ratepayers will bear the vast majority of the financial risk resulting from KPCo's decision to propose and pursue that option. Since the Company apparently believes this is the best approach, it is reasonable to expect them to bear a reasonable portion of the risk associated with this investment. The Company's only rationale for fifteen 15 year depreciation appears to be to avoid exposure to absorbing any stranded investment in the Big Sandy Unit 2 DFGD (Responses to Sierra Club 2-16 and 2-18). According to generally accepted accounting principles, an investment such as this should be depreciated over its useful life (Response to Sierra Club 1-17). For the DFGD this is twenty to thirty years according to the Company's witnesses and projections.

The Company's projection of revenue requirements for the CPCN option assumes a significant amount of off-system sales margins will flow to ratepayers. It is reasonable for the Commission to hold the Company to those projections. Thus, the Company should be required to modify its System Sales Clause to be consistent with the off-system sales margins it has assumed would flow to ratepayers under its modeling of the CPCN option.

Finally, the Company asserts that it has tested its four resource options against a realistic range of carbon prices. Again, since the Company apparently believes it has evaluated the full range of these prices, it is reasonable to expect them to bear the risk of carbon regulation costs that prove to be higher than the values the Company has assumed in its projections.

## 7. CONCLUSIONS AND RECOMMENDATIONS

**Q. Please summarize the major conclusions and recommendation from your review of the Company's request.**

A. My first conclusion is that the Company has not demonstrated that its proposed CPCN for Big Sandy Unit 2 is reasonable and cost-effective for complying with the environmental requirements the Company is facing. That conclusion is based upon the results of our review, which indicates that the Company has not evaluated the full range of resource options available to it, that its projections of revenue requirements for the resource options it did evaluate are not correct, that its evaluation of future scenarios does not include a reasonable projection of carbon prices and that its Monte Carlo risk analysis is flawed. My second, related, conclusion is that allowing KPCo to recover the costs of installing environmental control equipment on Big Sandy Unit 2 from ratepayers will not result in reasonable rates.

Based upon those conclusions my recommendation is that the Commission not approve the Company's request for a CPCN for Big Sandy Unit 2.

**Q. Please summarize your conclusions and recommendation regarding ratemaking in the event the Commission decides to approve the Company's request.**

A. In the event that the Commission decides to approve the Company's request for a CPCN, I am sure it will limit the Company's recovery of actual costs to only the amounts it finds just and reasonable. My understanding of the ratemaking process under the Environmental Surcharge Statute is that the Commission will review the Company's actual costs every six months, and disallow actual amounts it finds that are not just and reasonable, and that it will shift recovery of amounts it does find reasonable from the surcharge into base rates every two years. However, my conclusion is that even with those measures, ratepayers will still bear the bulk of the financial risk resulting from KPCo's decision to propose and pursue the CPCN.

Based on that conclusion, I recommend that the Commission require the Company to:

- recover its investment in environmental controls at Big Sandy Unit 2 based upon a depreciation rate consistent with generally accepted accounting principles, which would be a period of at least twenty years;
- modify its System Sales Clause to be consistent with the off-system sales margins the Company assumed would flow to ratepayers under its modeling of the CPCN option; and
- bear the risk of carbon regulation costs in excess of the values the Company has assumed in its early carbon future scenario.

**Q. Does this complete your Direct Testimony?**

A. Yes.

## LIST OF EXHIBITS


| | |
|---|---|
| Exhibit___(JRH-1) | Resume of James Richard Hornby |
| Exhibit___(JRH-2) | KPCo Capacity, Generation, Retail Requirements and Off-System Sales in 2011 |
| Exhibit___(JRH-3) | KPCo Capacity, Generation, Retail Requirements and Off-System Sales in 2022 |
| Exhibit___(JRH-4) | KPCo Capacity, Generation, Retail Requirements in 2022 assuming 22% Retail Sales from Efficiency and Renewables and Incremental Off-System Sales |
| Exhibit___(JRH-5) | KPCo Option 1, Base Case, Generation (GWH) by Source, 2011 to 2040 |
| Exhibit___(JRH-6) | KPCo – Cumulative Present Worth (CPW) of Revenue Requirements |
| Exhibit___(JRH-7) | CPW revenue requirements, Base Case, Options 1, 2, 4A – KPCO vs Synapse projections less 40% off-system sales margin |
| Exhibit___(JRH-8) | CPW revenue requirements, Base Case, Options 1, 2, 4A – KPCO vs Synapse projections with adjusted capital costs |
| Exhibit___(JRH-9) | CPW revenue requirements, Options 1, 2, 4A – KPCO vs Synapse projections - adjusted capital costs under Base Case and Low Carbon Case |
| Exhibit___(JRH-10) | Kentucky Power Company Responses to Selected Data Requests |

# James Richard Hornby

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## PROFESSIONAL EXPERIENCE

**Synapse Energy Economics, Inc.**, Cambridge, MA.
*Senior Consultant,* 2006 to present.

Provides analysis and expert testimony regarding resource planning and ratemaking issues in the electricity and natural gas industries. Resource planning related projects include evaluation of the potential impacts of a renewable and energy efficiency portfolio standard in Kentucky, evaluation of Oklahoma Gas & Electric wind power purchase agreements and associated transmission project and projections of long-term avoided costs of electricity and natural gas. Ratemaking projects include evaluation and testimony regarding proposals for advanced metering infrastructure (AMI or smart grid) and dynamic pricing in several states. Major projects regarding alignment of financial incentives with aggressive pursuit of energy efficiency by electric and gas utilities include testimony on the "save-a-watt" approach proposed by Duke Energy in North Carolina, Indiana and South Carolina.

**Charles River Associates (formerly Tabors Caramanis & Associates)**, Cambridge, MA.
*Principal,* 2004-2006, *Senior Consultant,* 1998–2004.
Expert testimony and litigation support in energy contract price arbitration proceedings and various ratemaking proceedings. Productivity improvement project for electric distribution companies in Abu Dhabi. Analyzed market structure and contracting issues in wholesale electricity markets.

**Tellus Institute**, Boston, MA.
*Vice President and Director of Energy Group*, 1997–1998.
*Manager of Natural Gas Program,* 1986–1997.
Presented expert testimony on rates for unbundled retail services, analyzed the options for purchasing electricity and gas in deregulated markets, prepared testimony and reports on a range of gas industry issues including market structure, strategic planning, market analyses, and supply planning.

**Nova Scotia Department of Mines and Energy**, Halifax, Canada.
*Member*, Canada-Nova Scotia Offshore Oil and Gas Board, 1983–1986.
*Assistant Deputy Minister of Energy* 1983–1986.
*Director of Energy Resources* 1982-1983
*Assistant to the Deputy Minister* 1981-1982

**Nova Scotia Research Foundation**, Dartmouth, Canada, *Consultant*, 1978–1981.
**Canadian Keyes Fibre**, Hantsport, Canada, *Project Engineer*, 1975–1977.
**Imperial Group Limited,** Bristol, England, *Management Consultant*, 1973–1975.

## EDUCATION

M.S., Technology and Policy (Energy), Massachusetts Institute of Technology, 1979.
B.Eng., Industrial Engineering (with Distinction), Dalhousie University, Canada, 1973

## TESTIMONY

| Jurisdiction | Company | Docket | Date | Issue |
|---|---|---|---|---|
| Nova Scotia | Heritage Gas | NG-HG-R-11 | September 2011 | Cost allocation and rate design |
| Arkansas | Oklahoma Gas & Electric | 10-109-U | May 2011 and June 2011 | advanced metering infrastructure (AMI) |
| Texas | Texas-New Mexico Power | PUC 38306 | April 2011 | advanced metering infrastructure (AMI) |
| Arkansas | Oklahoma Gas & Electric | 10-067-U | March 2011 | Windspeed transmission line |
| Pennsylvania | PECO Energy | M-2009-2123944 | December 2010 and January 2011 | Dynamic Pricing |
| Arkansas | Oklahoma Gas & Electric | 10-073-U | November 2010 | Wind power purchase agreement |
| Indiana | Vectren Energy Delivery of Indiana | Cause No. 43839 | July 2010 | Sales Reconciliation Adjustment |
| Alaska | Enstar Natural Gas | U-09-069 and U-09-070 | March 2010 | Rate Design |
| Pennsylvania | Allegheny Power | M-2009-2123951 | March 2010 and October 2009. | Smart meters / advanced metering infrastructure (AMI) |
| Massachusetts | All Massachusetts regulated electric and gas utilities | D.P.U. 09-125 et al. | December 2009 | Avoided Energy Supply Costs in New England |

| Jurisdiction | Company | Docket | Date | Issue |
|---|---|---|---|---|
| Pennsylvania | Metropolitan Edison Company | M-2009-2123950 | October 2009. | Smart meters / AMI |
| Maryland | Potomac Electric Power | No. 9207 | October 2009 and July 2011. | Smart meters / AMI |
| Maryland | Baltimore Gas and Electric | No. 9208 | October 2009 and July 2010. | Smart meters / AMI |
| New Jersey | Jersey Central Power & Light | EO08050326 and EO08080542 | July 2009 | Demand response programs |
| Minnesota | CenterPoint Energy | G-008/GR-08-1075 | June 2009. | Conservation Enabling Rider |
| South Carolina | Progress Energy Carolinas | 2008-251-E | January 2009. | Compensation for efficiency programs |
| North Carolina | Progress Energy Carolinas | No. E-2 sub 931 | December 2008. | Compensation for efficiency programs |
| Maine | Central Maine Power | 2007 – 215 | October 2008. | Smart meters / AMI |
| North Carolina | Duke Energy Carolinas | E-7 Sub 831 | June 2008 | Compensation for efficiency programs (save-a-watt) |
| Indiana | Duke Energy Indiana | No. 43374 | May 2008. | Compensation for efficiency programs (save-a-watt) |
| Pennsylvania | PECO Energy Company | P-2008-2032333 | June 2008. | Residential Real Time Pricing pilot |
| Arkansas | Entergy Arkansas | 06-152-U Phase II A | October 2007 | Interim tolling agreement and proposed allocation of Ouachita Power capacity |

| Jurisdiction | Company | Docket | Date | Issue |
|---|---|---|---|---|
| Washington | Avista Utilities | UE-070804 and UG-070805 | September 2007. | Cost allocation, rate design |
| Arkansas | Entergy Arkansas | 06-152-U | January 2007. | Need for load-following capacity |
| Michigan | Consumers Energy Company | U-14992 | December 2006. | Proposed sale of Palisades nuclear plant and associated power purchase |
| Connecticut | Connecticut Natural Gas Corporation | 06-03-04PH01 | November 2006. | Gas supply strategy and proposed rate recovery |
| Michigan | Consumers Energy Company | U-14274-R | October 2006. | Purchases from Midland Cogeneration Venture Limited Partnership |
| Illinois | WPS Resources and Peoples Energy Corporation | Docket No. 06-0540 | October and December 2006. | Service quality metrics and benchmarks |
| Arizona | Arizona Public Service | E-01345A-05-0816 | August 2006 and September 2006. | Hedging strategy and base fuel recovery amount |
| Ontario | Transalta Energy Corporation versus Bayer Inc. | Private arbitration | January 2006. | Price for steam under a 20-year contract |
| Nova Scotia | Nova Scotia Power vs Shell | Private arbitration | October 2005. | New natural gas price under a 10-year supply contract |
| New York | Consolidated Edison of New York, New York State Electric and Gas | Case 00-M-0504 | September and October 2002. | Rates for unbundled supply, distribution, metering and billing services |

| Jurisdiction | Company | Docket | Date | Issue |
|---|---|---|---|---|
| New Jersey | Public Service Electric and Gas | BPU Docket GM00080564 | April 2001. | Proposed transfer of gas contracts to an unregulated affiliate and supply contract associated with that transfer. |
| Nova Scotia | Sempra | NSUARB-NG-SEMPRA-SEM-00-08 | February 2001. | Proposed distribution service tariff rates including market-based rates |
| New Jersey | Generic proceeding | BPU Docket EX99009676 | March 2000. | Design and pricing of unbundled customer account services |
| United States of America | Bonneville Power Administration | BPA Docket WP-02 | November 1999. | Functionalization of communication plant |
| South Carolina | South Carolina Electric and Gas | 99-006-G | October 1999. | Purchased gas costs |
| New Jersey | Public Service Electric & Gas, South Jersey Gas, New Jersey Natural Gas and Elizabethtown Gas | GO99030122–GO99030125 | July and September 1999. | Service unbundling policies and rates |
| Maine | Northern Utilities Inc. | Docket 97-393 | September and December 1998. | Rate redesign and partial unbundling |
| Pennsylvania | Peoples Natural Gas | R-00984281; A-12250F0008 | May 1998. | Purchased gas costs and proposal to transfer production assets to affiliate |

| Jurisdiction | Company | Docket | Date | Issue |
|---|---|---|---|---|
| New Jersey | Rockland Electric Company | BPU E09707 0465<br>OAL PUC-7309-97<br>BPU E09707 0464<br>OAL PUC-7310-97 | January and March 1998. | Rate unbundling |
| New Jersey | Jersey Central Power & Light d/b/a GPU Energy. | BPU EO9707 0459<br>OAL PUC- 7308-97<br>BPU E09707 0458<br>OAL PUC-7307-97 | November 1997. | Rate unbundling |
| Pennsylvania | Equitable Gas Company | R-00963858 | June and July 1997. | Rate structure proposals |
| Pennsylvania | Peoples Natural Gas Company | R-00973896 and A-0012250F-0007 | May 1997. | Purchased gas costs, proposal to transfer producing assets to CNG Producing Company and proposed Migration Rider |
| South Carolina | South Carolina Pipeline Corporation | 97-009-G | April 1997. | Reasonableness of proposal to acquire additional pipeline capacity |
| FERC | Transcontinental Gas Pipeline | RP95-197-001; RP97-71-000 | March 1997. | Review of proposed rolled-in ratemaking for Leidy Line incremental facilities |
| Arkansas | Arkla | 95-401-U | September 1996. | Gas purchasing and transportation plan |
| Maine | Northern Utilities Inc. and Granite State Gas Transmission | 95-480; 95-481 | April 1996 | Precedent Agreement for LNG Storage Service and PNGTS Transportation Service |
| Rhode Island | ProvGas | 2025 | November 1995 | Settlement Agreement |

| Jurisdiction | Company | Docket | Date | Issue |
|---|---|---|---|---|
| Pennsylvania | T.W. Phillips Gas and Oil | R-953406 | October 1995 | Cost allocation, rate design |
| Illinois | Northern Illinois Gas | 95-0219 | August1995 | Cost allocation, rate design |
| Pennsylvania | Columbia Gas of Pennsylvania | R-953316 | May 1995 | Purchased gas costs |
| Pennsylvania | Peoples Natural Gas | R-943252 | May 1995 | Cost allocation, rate design |
| South Carolina | South Carolina Pipeline Corporation. | 94-007-G | April 1995 | 1994 purchased gas costs |
| Pennsylvania | National Fuel Gas Distribution Corp | R-943207 | March 1995 | 1995 Purchased Gas Adjustment filing |
| Pennsylvania | UGI Utilities | R-00943063 | December 1994 | FERC Order 636 transition cost tariff |
| South Carolina | South Carolina Electric and Gas Co. | 94-008-G | October 1994 | 1994 Purchased Gas Adjustment |
| Oklahoma | Public Service of Oklahoma | PUD 920 001342 | September and November 1994 | Gas supply strategy, transportation and agency services and rate mechanism |
| Pennsylvania | Pennsylvania Gas and Water | R-943078 | September 1994 | Market Sensitive Sales Service |
| Massachusetts | Generic proceeding | D.P.U. 93-141-A | September 1994 | Policies on interruptible transportation and capacity release |

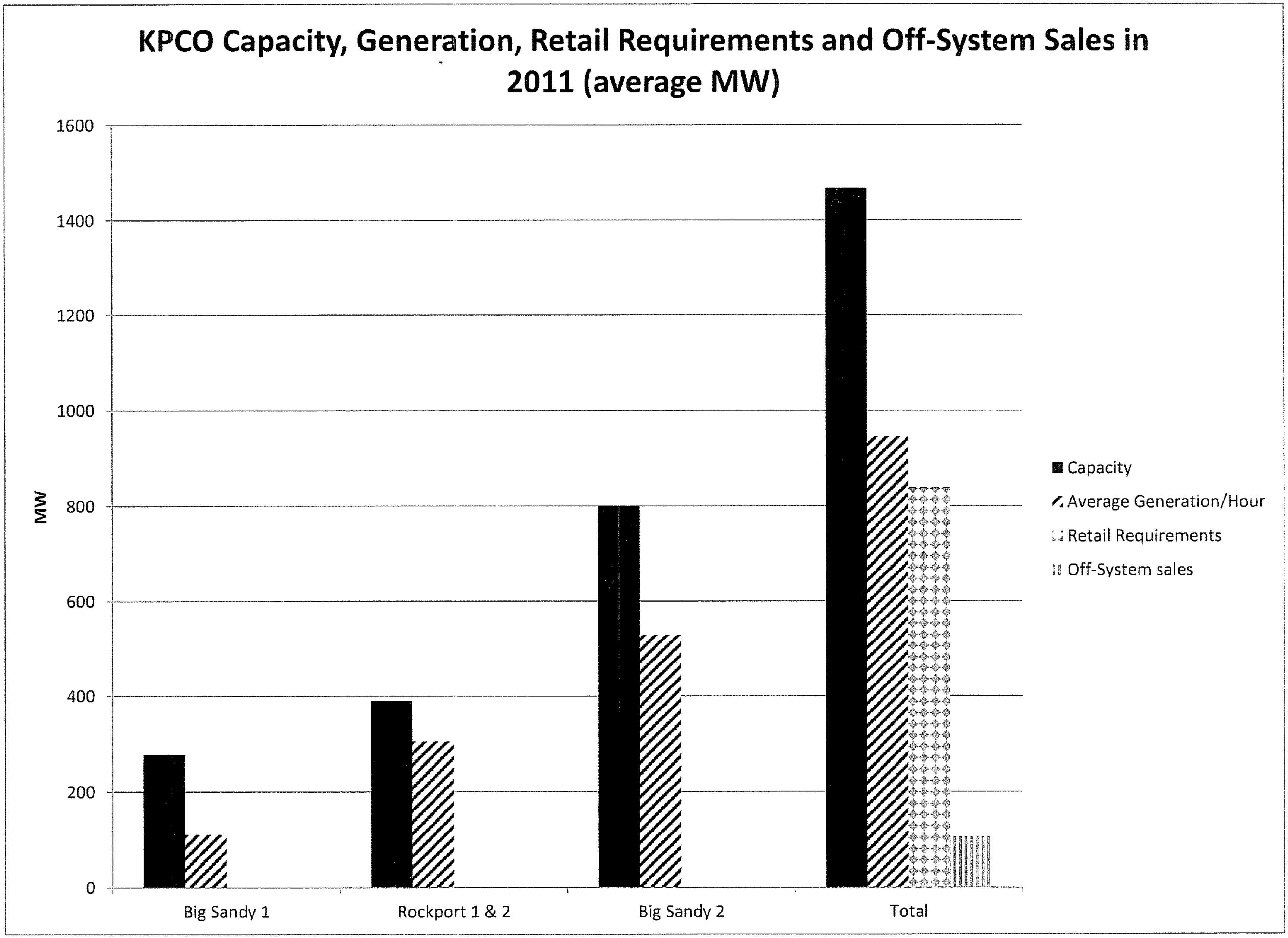
| Jurisdiction | Company | Docket | Date | Issue |
|---|---|---|---|---|
| Hawaii | HELCO | 7259 | August 1994 | DSM programs for competitive energy end-use markets, multi-attribute analysis |
| Pennsylvania | Pennsylvania Gas and Water | R-00943066 | July 1994 | 1994 Purchased Gas Adjustment |
| Pennsylvania | Pennsylvania Gas and Water | R-942993; R-942993 C0001-C0004 | May 1994 | Take-or-Pay Cost Recovery |
| Pennsylvania | Columbia Gas of Pennsylvania | R-943001 | May 1994 | Cost allocation, rate design |
| Pennsylvania | Columbia Gas of Pennsylvania | R-943029 | May 1994 | 1994 Purchased Gas Adjustment; Negotiated Sales Service |
| Pennsylvania | Peoples Natural Gas | R-932866; R-932915 | March 1994 | Cost allocation, rate design |
| Kansas | Generic proceeding | 180; 056-U | February 1994 | IRP rules for gas utilities |
| Arizona | Citizens Utility Company Arizona Gas Division | E-1032-93-111 | December 1993 | Cost allocation, rate design |
| Hawaii | HECO | 7257 | December 1993 | Residential sector water heating program |
| Hawaii | GASCO | 7261 | September 1993 | IRP |
| Pennsylvania | Pennsylvania Gas and Water | R-932655; R-932655 C001; R-932655 C002 | September 1993 | Balancing service |
| Pennsylvania | Pennsylvania Gas and Water | R-932676 | July 1993 | 1993 Purchased Gas Adjustment filing |

| Jurisdiction | Company | Docket | Date | Issue |
|---|---|---|---|---|
| Rhode Island | Providence Gas Company | 2025 | April 1993 | IRP |
| Pennsylvania | Equitable | I-900009; C-913669 | March 1993 | Charges for transportation service and cost allocation methods in general |
| Arkansas | Arkla Energy Resources, Arkansas Louisiana Gas | 92-178-U | August 1992 | Gas cost and purchasing practices |
| Colorado | Generic proceeding | 91R-642EG | August 1992 | Gas integrated resource planning rule |
| Pennsylvania | Pennsylvania Gas and Water | R-00922324 | July 1992 | 1992 Purchased Gas Adjustment filing |
| Pennsylvania | Peoples Natural Gas Company | R-922180 | May 1992 | Cost allocation, rate design |
| Michigan | Consumers Power Company | U-10030 | April 1992 | Gas Cost Recovery Plan, role of demand-side management as a resource in five-year forecast and supply plan |
| Pennsylvania | T.W. Phillips | R-912140 | March 1992 | 1992 Purchased Gas Adjustment |
| FERC | Columbia Gas Transmission and Columbia Gulf Transmission | RP91-161-000 et al RP91-160-000 et al. | February 1992 | Cost allocation, rate design |
| Arkansas | Arkla Energy Resources | 91-093-U | February 1992 | Base cost of gas |
| New Hampshire | Energy North Natural Gas | DR90-183 | January 1992 | Cost allocation, rate design |

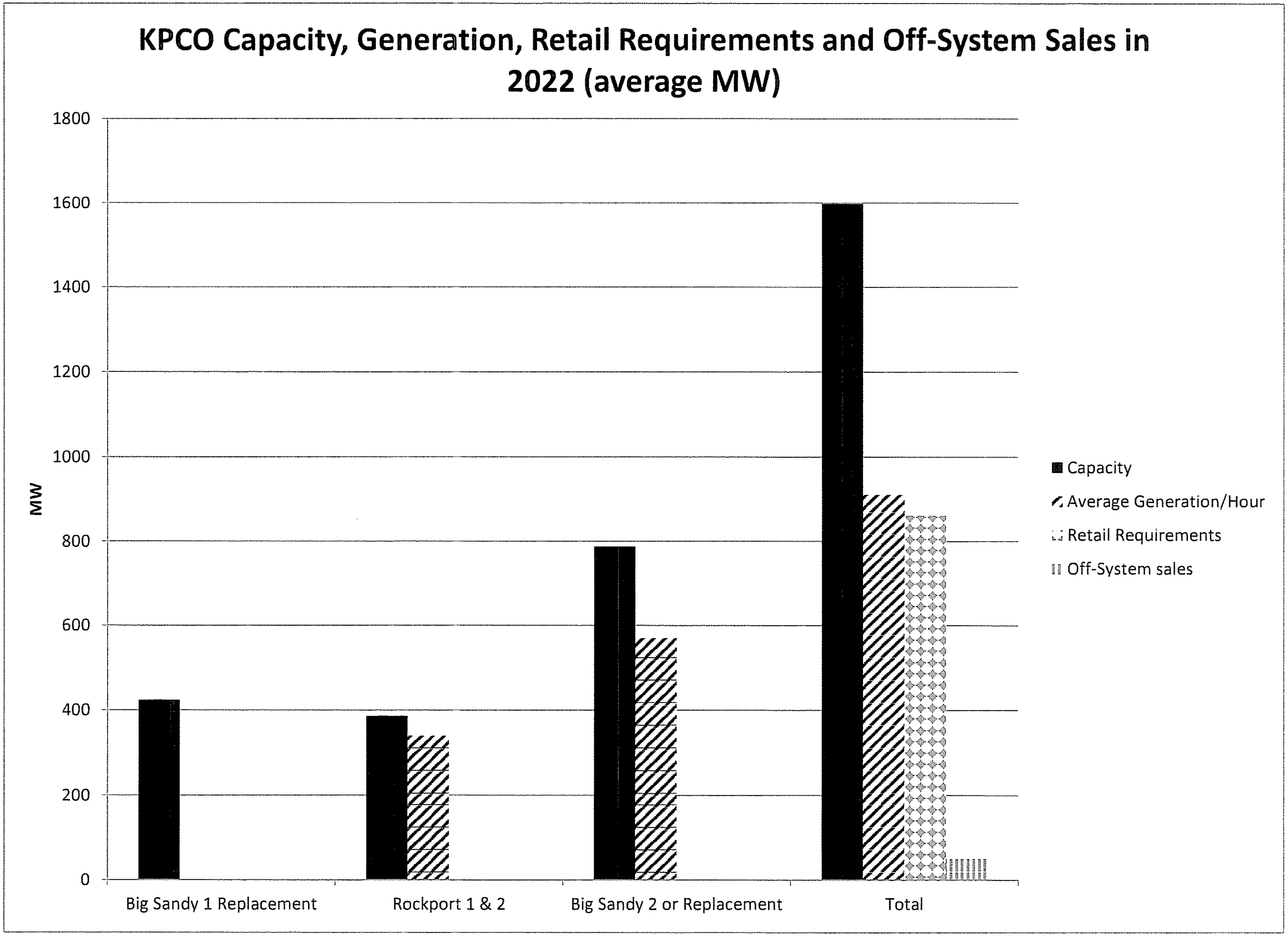
| Jurisdiction | Company | Docket | Date | Issue |
|---|---|---|---|---|
| Arizona | Southwest Gas Corporation | U-1551-89-102 & U-1551-89-103; U-1551-91-069 | September 1991 | Gas Procurement Practices and Purchased Gas Costs |
| Maryland | Baltimore Gas and Electric | 8339 | July 1991 | Cost allocation, rate design |
| Rhode Island | Bristol and Warren Gas | 1727 | June 1991 | Gas procurement |
| New Mexico | Gas Company of New Mexico | 2367 | June 1991 | Gas transportation policies |
| Pennsylvania | T.W. Phillips | R-911889 | March 1991 | Gas supply |
| Michigan | Michigan Gas Company | U-9752 | March 1991 | Gas Cost Recovery Plan |
| Arkansas | Arkla | 90-036-U | August and September 1990 | Gas supply contracts, including Arkla-Arkoma transactions |
| Arizona | Southern Union Gas | U-1240-90-051 | August 1990 | Cost Allocation and Rate Design |
| Utah | Mountain Fuel Supply | 89-057-15 | July1990 | Cost Allocation and Rate Design |
| Pennsylvania | Equitable Gas Company | R-901595 | June 1990 | Cost Allocation and Rate Design |
| West Virginia | APS | 90-196-E-GI ; 90-197-E-GI | May 1990 | Coal supply strategy |
| Pennsylvania | T.W. Phillips Gas and Oil Co. | R-891572 | March 1990 | Purchased Gas Costs |

| Jurisdiction | Company | Docket | Date | Issue |
|---|---|---|---|---|
| Colorado | Generic proceeding | 89R-702G | January 1990 | Policies and rules for gas transportation service |
| Arizona | Generic proceeding | U-1551-89-102 and U-1551-89-103 | October 1989 | Regulatory Oversight of Purchased Gas Costs |
| Rhode Island | Narragansett Electric Company | 1938 | October 1989 | Sales Forecast, Cost Allocation, rate design |
| Pennsylvania | Pennsylvania Gas and Water | R891293 | July 1989 | Purchased Gas Costs |
| Pennsylvania | Columbia Gas of Pennsylvania | R891236 | May 1989 | Take-or-Pay Cost Recovery |
| New Jersey | Elizabethtown Gas Company | GR 88081-019 | December 1988and February 1989 | Take-or-Pay Cost Recovery |
| Montana | Montana-Dakota Utilities | 87.7.33; 88.2.4; 88.5.10; 88.8.23 | December1988 | Gas Procurement, Transportation Service Gas Adjustment Clause |
| New Jersey | South Jersey Gas Company | GR 88081-019 and GR 88080-913- | November 1988 and February 1989 | Take-or-Pay Cost Recovery |
| New Jersey | Public Service Electric and Gas | GR 88070-877 | October 1988 and February 1989 | Take-or-Pay Cost Recovery |
| District of Columbia | District of Columbia Natural Gas | Formal Case 874 | September 1988 | Gas Acquisition, Gas Cost Allocation, take or pay-costs; Regulatory Oversight |

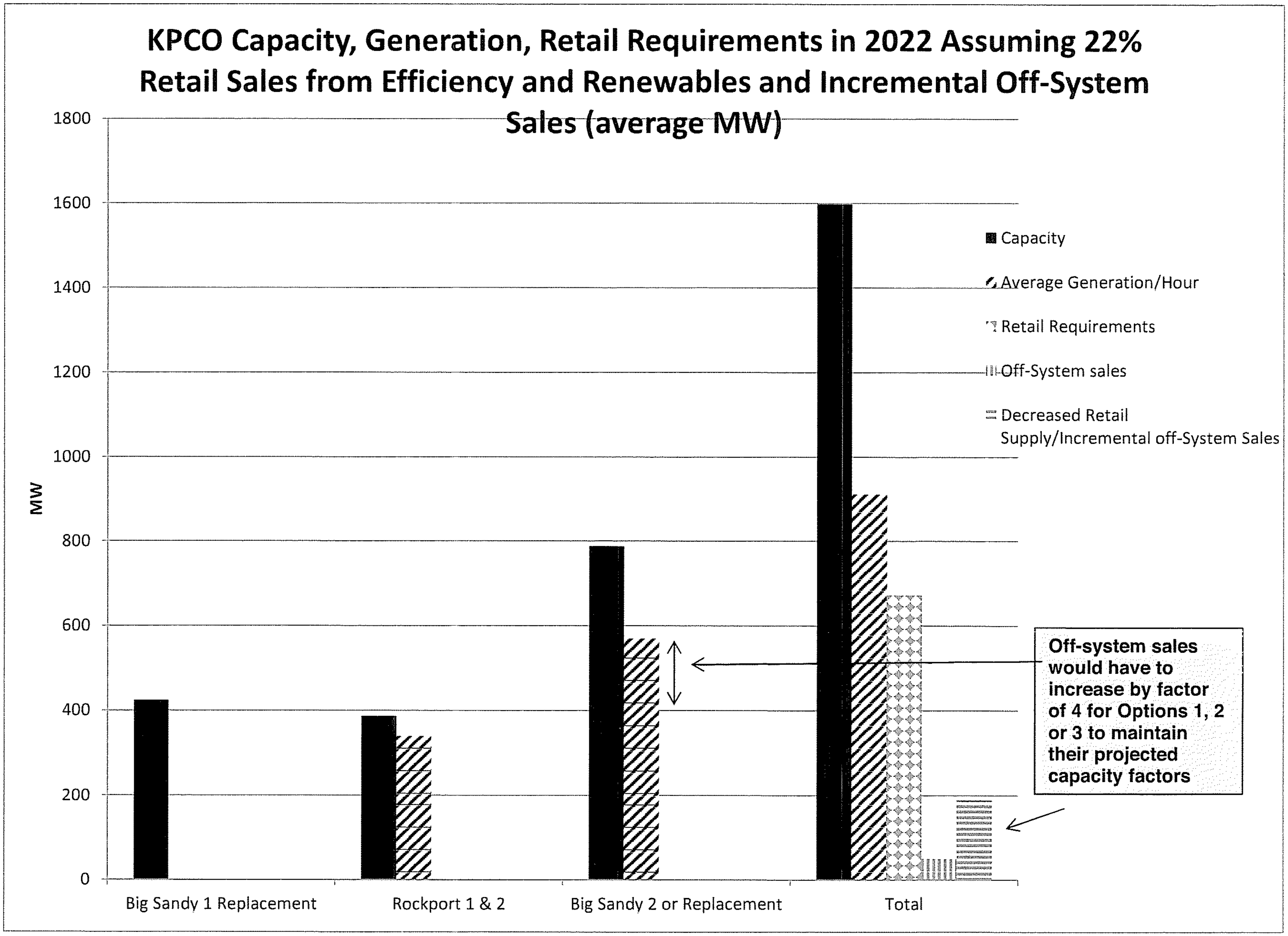
| Jurisdiction | Company | Docket | Date | Issue |
|---|---|---|---|---|
| Illinois | Generic proceeding | 88-0103 | July 1988 | Take-or-Pay Cost Recovery |
| West Virginia | Generic proceeding | 240-G | June 1988 | Gas Transportation Rate Design |
| Pennsylvania | Pennsylvania Gas & Water | R-880958 | June 1988 | Purchased Gas Adjustment |
| Utah | Mountain Fuel Supply | 86-057-07 | March 1988 | Gas Transportation Rate Design |
| South Carolina | South Carolina Electric and Gas | 87-227-G | September 1987 | Gas Supply and Rate Design |
| Arizona | | U-1345-87-069 | September 1987 | Fuel Adjustment Clause |




Source: *Workbook for Exhibits JRH-2 to JRH-5.xls*

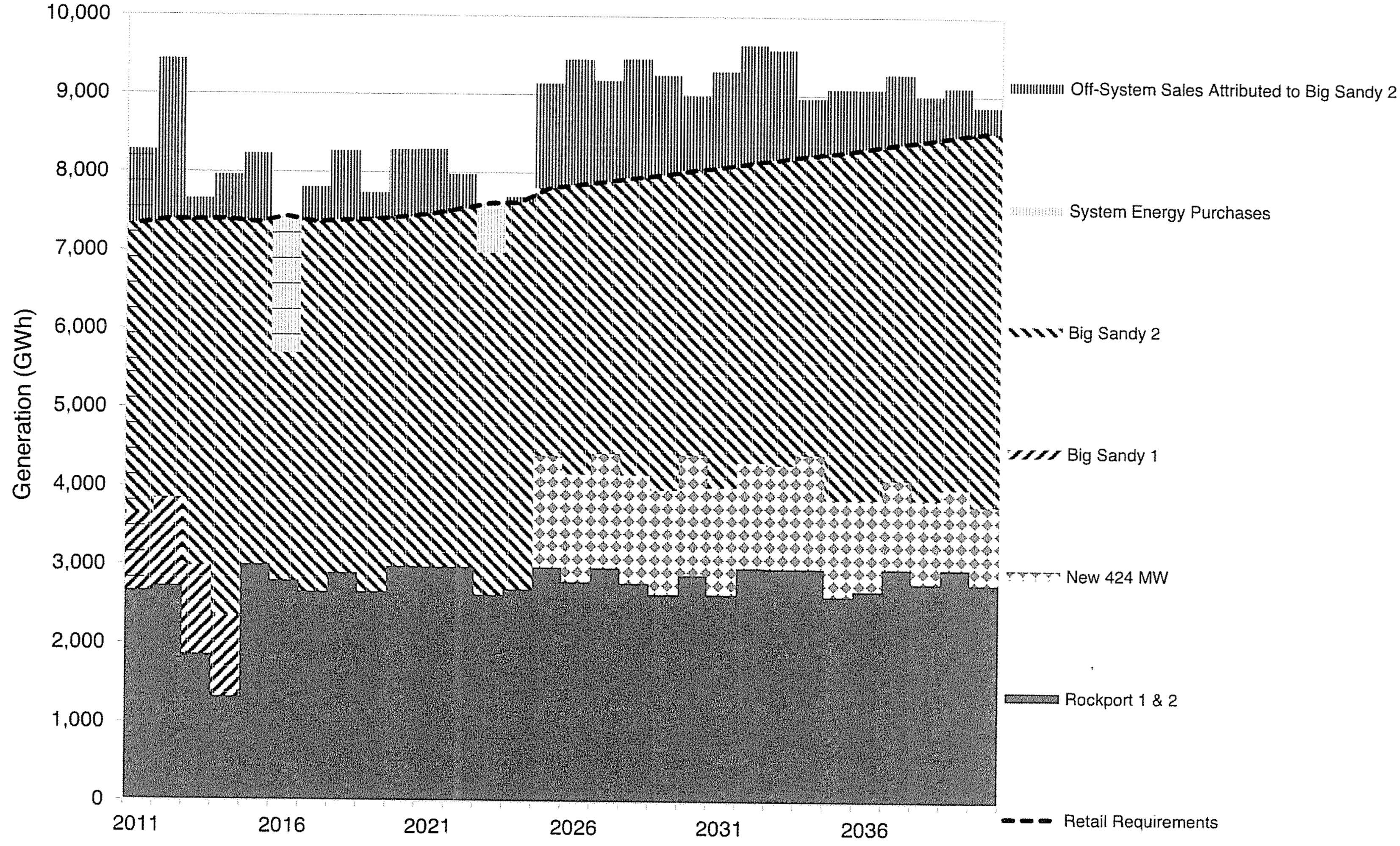



Source: *Workbook for Exhibits JRH-2 to JRH-5.xls*




Source: *Workbook for Exhibits JRH-2 to JRH-5.xls*

## KPCO Option 1, Base Case, Generation (GWh) by Source, 2011 to 2040




Source: Workbook for Exhibits JRH-2 to JRH-5

**KPCo - Cumulative Present Worth (CPW) of Revenue requirements (2011$), $000**

| Options | | 1 | 2 | 3 | 4 | |
|---|---|---|---|---|---|---|
| | | Option 1 : BS2 DFGD Retrofit 6/2016 | Option 2 Retire & replace BS2 with "New-Build" NG Combined Cycle 1/2016 | Option 3 Retire & replace BS2 with "Repowered" BS1 NG Combined Cycle 1/2016 | Option 4A Retire & replace BS2 with Purchased (PJM-RPM) capacity & energy 5 years | Option 4B Retire & replace BS2 with Purchased (PJM-RPM) capacity & energy 10 years |
| | | | | | | |
| **Scenarios** | | | | | | |
| 1 | Base | $ 6,838,879 | $ 7,075,297 | $ 7,091,182 | $ 6,917,767 | $ 6,791,587 |
| 2 | Higher band fuel prices | $ 7,290,000 | $ 7,727,148 | $ 7,748,132 | $ 7,556,049 | $ 7,481,637 |
| 3 | Lower Band fuel prices | $ 6,574,765 | $ 6,751,584 | $ 6,757,528 | $ 6,595,640 | $ 6,455,915 |
| 4 | No Carbon | $ 6,412,030 | $ 6,726,790 | $ 6,746,259 | $ 6,577,540 | $ 6,459,157 |
| 5 | Early Carbon | $ 7,207,670 | $ 7,388,101 | $ 7,397,994 | $ 7,227,961 | $ 7,092,447 |

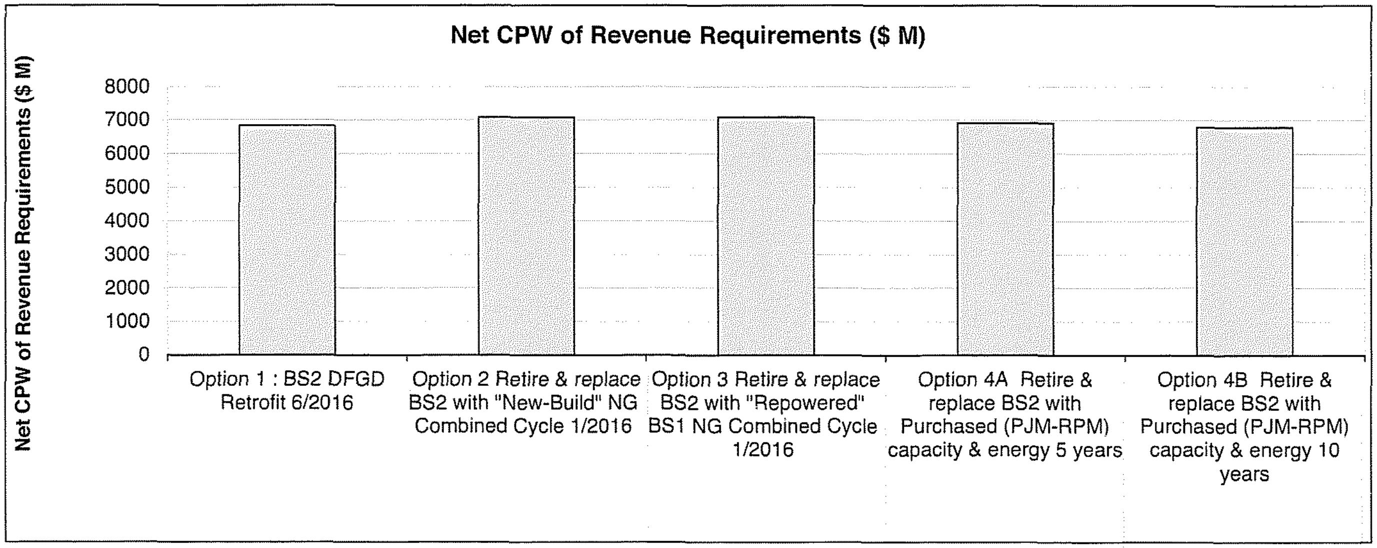
**KPCo - Comparative CPW of Revenue Requirements (2011$) vs Option 1, $million**

| | Option | 1 | 2 | 3 | 4A | 4B |
|---|---|---|---|---|---|---|
| **Scenario** | | | | | | |
| 1 | Base | $ - | $ 236 | $ 252 | $ 79 | $ (47) |
| 2 | Higher band fuel prices | $ - | $ 437 | $ 458 | $ 266 | $ 192 |
| 3 | Lower Band fuel prices | $ - | $ 177 | $ 183 | $ 21 | $ (119) |
| 4 | No Carbon | $ - | $ 315 | $ 334 | $ 166 | $ 47 |
| 5 | Early Carbon | $ - | $ 180 | $ 190 | $ 20 | $ (115) |

**KPCo - Comparative CPW of Revenue Requirements vs Option 1, %**

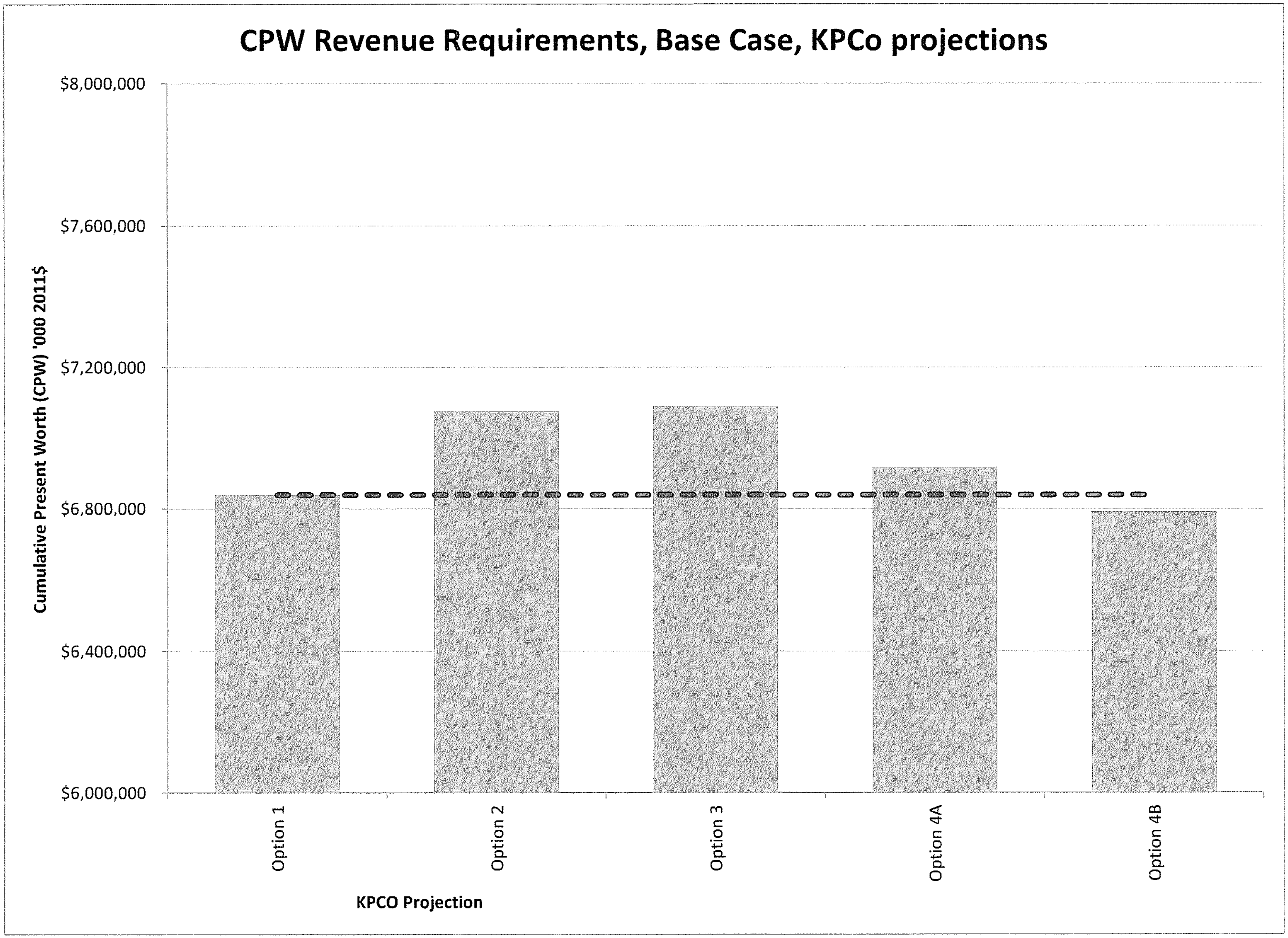
| | Option | 1 | 2 | 3 | 4A | 4B |
|---|---|---|---|---|---|---|
| **Scenario** | | | | | | |
| 1 | Base | n/a | 3.5% | 3.7% | 1.2% | -0.7% |
| 2 | Higher band fuel prices | n/a | 6.0% | 6.3% | 3.6% | 2.6% |
| 3 | Lower Band fuel prices | n/a | 2.7% | 2.8% | 0.3% | -1.8% |
| 4 | No Carbon | n/a | 4.9% | 5.2% | 2.6% | 0.7% |
| 5 | Early Carbon | n/a | 2.5% | 2.6% | 0.3% | -1.6% |

Source: *Workbook for Exhibits JRH-6 to JRH-9.xls*



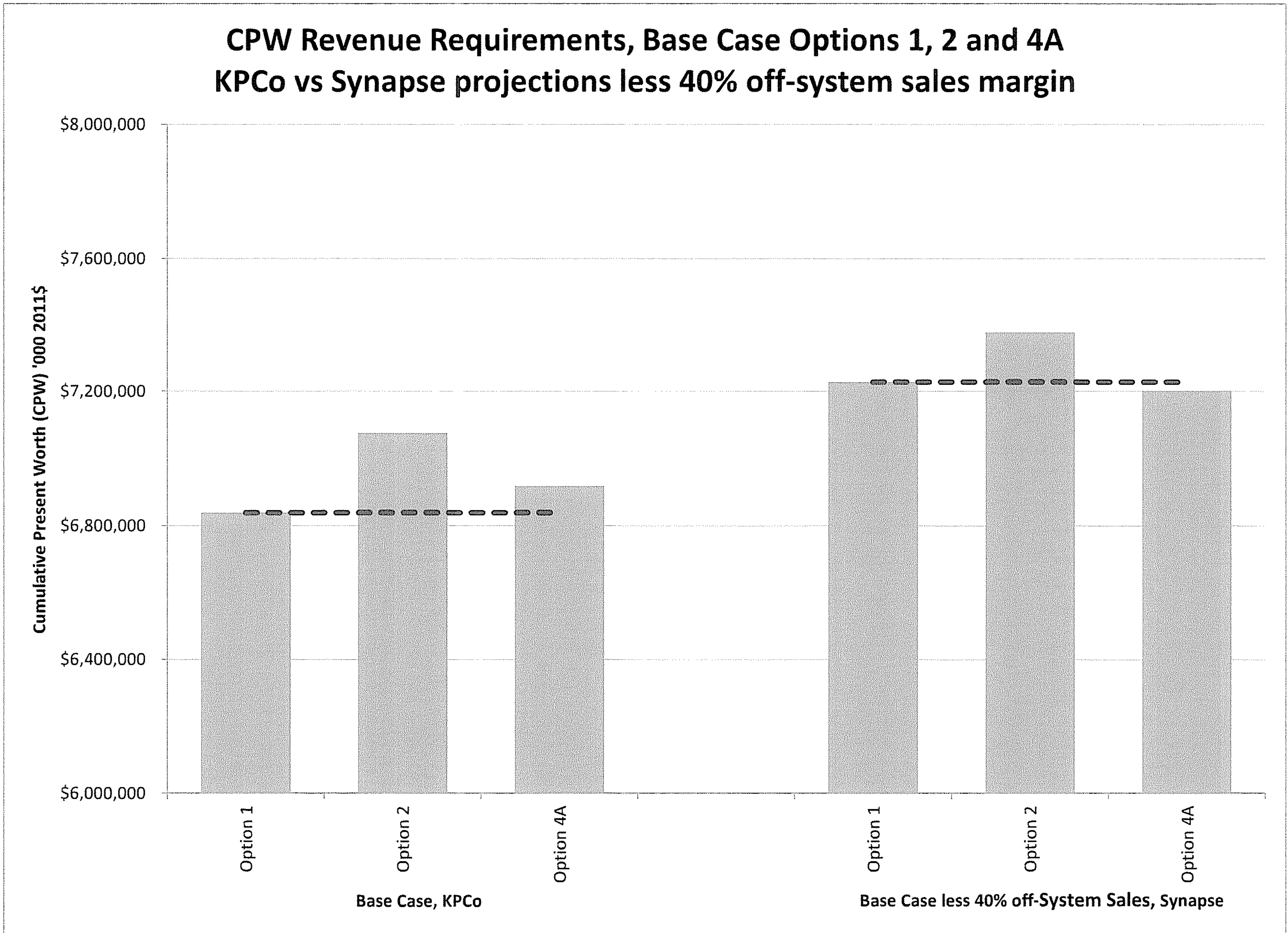

| | | | | | |
|---|---|---|---|---|---|
| **Net CPW of Revenue Requirements ($ M)** | $ 6,839 | $ 7,075 | $ 7,091 | $ 6,918 | $ 6,792 |
| **Delta of Net CPW from Option 1 ($ M)** | N/A | $236 | $252 | $79 | -$47 |
| **Delta of Net CPW from Option 1 (%)** | N/A | 3.5% | 3.7% | 1.2% | -0.7% |

Source: *Workbook for Exhibits JRH-6 to JRH-9.xls*



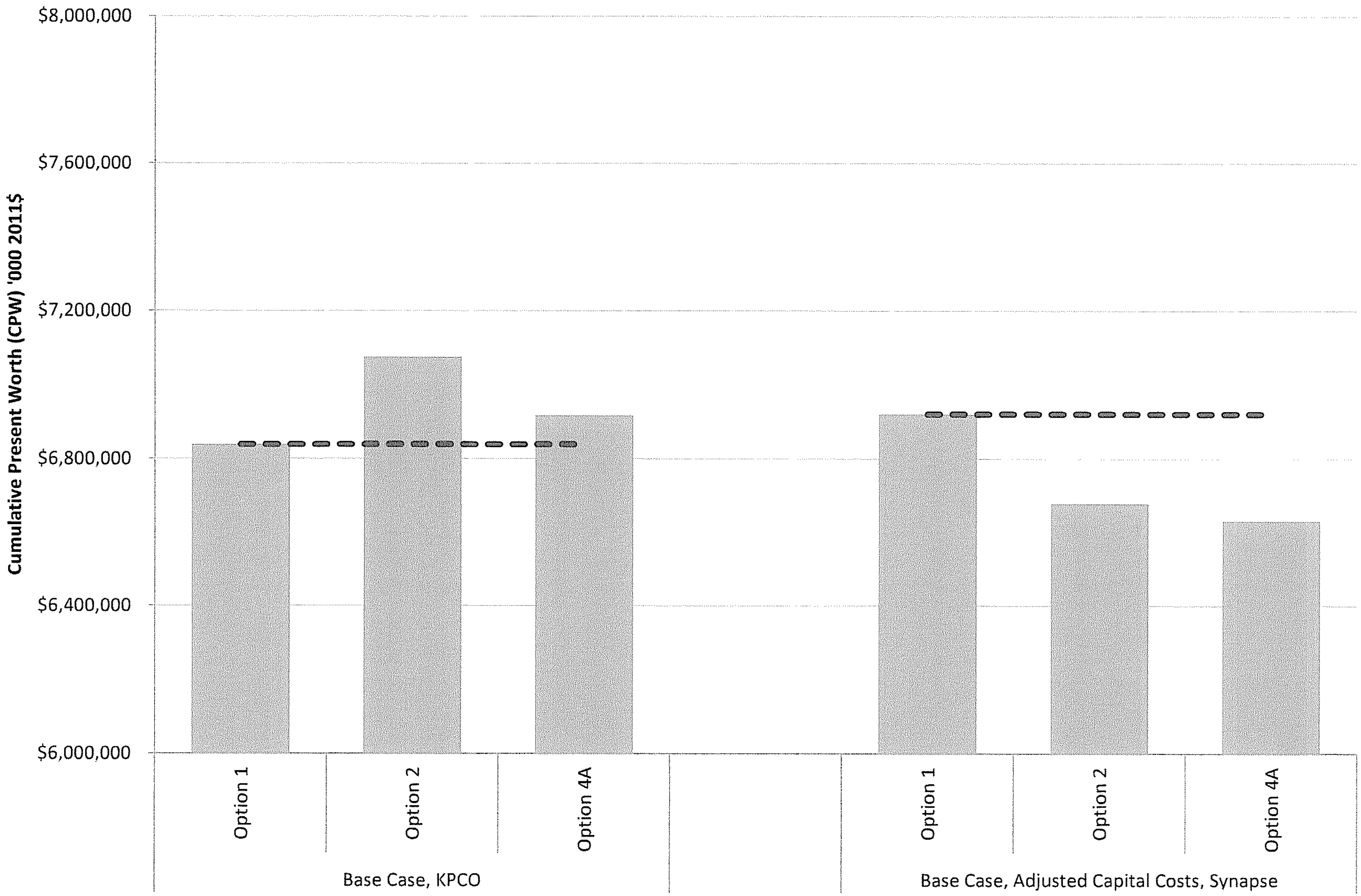

Source : *Workbook for Exhibits JRH-6 to JRH-9.xls*

Exhibit___(JRH-7)

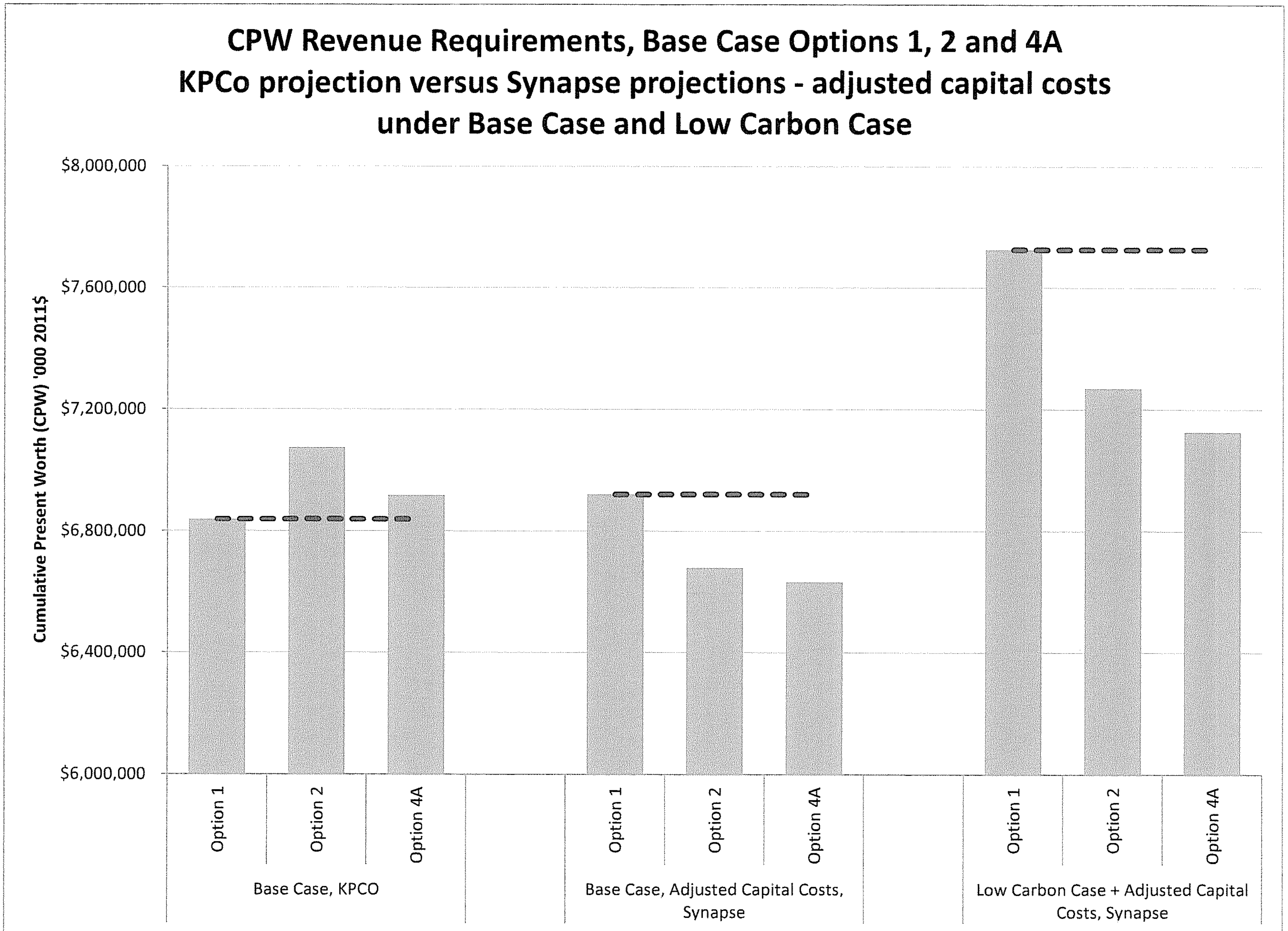



Source : *Workbook for Exhibits JRH-6 to JRH-9.xls*

**CPW Revenue Requirements, Base Case Options 1, 2 and 4A**
**KPCo projection versus Synapse projection with adjusted capital costs**




Source: *Workbook for Exhibits JRH-6 to JRH-9.xls*




Source: *Workbook for Exhibits JRH-6 to JRH-9.xls*

# Kentucky Power Company Responses to Selected Data Requests

Staff 1-65 and 2-29

KIUC 1-29

Sierra Club

- 1-17
- 1-33
- 1-34
- 1-43
- 1-51
- 1-52
- 1-62
- 2-16
- 2-18
- 2-21
- 2-22
- 2-25
- 2-31

# Kentucky Power Company

## REQUEST

Refer to pages 25-26 of the Weaver Testimony, regarding the discussion of Option #4, the "(Full) Capacity Replacement Purchase."

a. Explain whether a RFQ solicitation for capacity and energy was not also issued as an additional alternative to full reliance on the PJM market capacity and energy and pricing.

b. Explain the rationale for only considering full market participation in PJM for the purchase of power.

c. If a RFQ solicitation was issued, provide the analysis of the bids including the terms of the bids and why each bid received was not acceptable.

d. If a RFQ solicitation was not issued seeking capacity and energy, explain the rationale for not seeking such a solicitation.

## RESPONSE

a. For the reasons set out in the testimony of Mr. Weaver beginning on page 40, line 11, through page 42, line 3, an RFQ solicitation was not issued. In summary, based on input from AEP commercial experts with experience around such long-term (10-20 year) contractual arrangements, Option #2 (a Big Sandy 2 Replacement CC alternative) represented the alternative in which KPCo management believed would serve as a proxy for such a market solicitation for capacity beginning in that (2016) timeframe. Another critical factor established by KPCo management was the going-in desire that any long-term solution should maintain a generation presence in eastern Kentucky. "Market" Options #4A and #B (PJM-RPM market capacity & energy for 5 and 10 years, respectively... followed then by New-Build CCs in 2020 and 2025), were viewed as short-term or, effectively, "bridge" solutions until a long-term--preferably Kentucky-domiciled-- generation solution could be established.

b. See the response to part a. of this question.

c. No market solicitation was issued.

d. See the response to part a. of this question.

WITNESS: Scott C Weaver

# Kentucky Power Company

## REQUEST

Refer to Kentucky Power's response to the AG's First Request, Item 22, Attachment 8.

a. If AEP or Kentucky Power had purchased the Riverside Generating ("RG") natural gas plant in Zelda, Kentucky at the initial non-binding offer made on March 09, 2010, provide and describe the financial impact on Off-System Sales ("OSS"), pool capacity costs, and PJM capacity costs to:

(1) Kentucky Power as a member of the East Pool Agreement;

(2) The other members of the East Pool Agreement;

(3) The members of the contemplated three member pool; and

(4) The members of any other agreement between the AEP subsidiaries of the East Pool Agreement.

b. Provide a further explanation of why AEP or Kentucky Power did not purchase the RG natural gas plant considering the capability of conversion to a 2x1 combined cycle ("CC") and 3x1 CC which would enhance the capacity of the facility.

c. Prepare an analysis of the purchase of the RG natural gas plant as an option scenario and compare to Options 1 through 4, using the same modeling as used for those four options. Include revenues from OSS, pool capacity costs, PJM capacity costs, and the financial impact to the current East Pool Agreement and the proposed three member pool.

d. Explain whether AEP or Kentucky Power considered including other utilities in a possible purchase/conversion of the RG natural gas plant as a way to offset the excess capacity and mitigate costs.

## RESPONSE

a. The Company has not conducted such a study.

# Kentucky Power Company

## REQUEST

Please provide a copy of all analyses, emails, and all other documents that address the selection of supply side resource options in the analyses presented by Mr. Weaver in his Direct Testimony. This includes, but is not limited to, any alternative resources that were considered but not cited by Mr. Weaver in his Direct Testimony and/or not used in the analyses.

## RESPONSE

No such formal documents exist that specifically isolate or choose the "selection" of the unit disposition options analyzed. Rather, these options that were analyzed have been viewed by AEP and KPCo management as being the most typical, rational and logical set of options available when considering such a coal unit disposition decision.

However, in January of 2012, subsequent to the filing of this case, KPCo management requested the performance on an additional analysis. Please see the response to Sierra Club Item No. 52 part a., First Set, for a description of that additional analysis.

WITNESS: Scott C Weaver

# Kentucky Power Company

**REQUEST**

Direct Testimony of Ranie Wohnhas, pages 14 and 15.

a. Please identify the generally accepted accounting principles that apply to the determination of the time period over which the Company depreciates major capital investments, such as the capital cost of a FGD.

b. Please identify the time period over which the Company would propose to depreciate the cost of the FGD unit according to those generally accepted accounting principles and in the absence of any material risk of future environmental regulations.

c. Please identify cases in which the Public Service Commission of Kentucky has approved a 15 year time period for depreciation of a FGD.

d. Please identify cases in which the Public Service Commission of Kentucky has approved a time period for depreciation shorter than the one consistent with generally accepted accounting principles in order to reduce the risk of stranded investment.

e. Please identify cases in which the regulatory commissions in other states in which American Electric Power operates have approved a 15 year time period for depreciation of a FGD.

f. Please identify cases in which the which the regulatory commissions in other states in which AEP operates have approved a time period for depreciation shorter than the one consistent with generally accepted accounting principles in order to reduce the risk of stranded investment.

g. Please list the "increased EPA standards" that could cause operation of this unit not to be economically feasible in the future.

h. Please describe how the Company analyzed the risk associated with those "increased EPA standards" in its economic evaluation of resource alternatives.

i. Please explain how the Company would bear a portion of the risk of stranded investment if the Commission approves recovery through the environmental cost recovery surcharge, and describe the percent of the risk the Company would bear.

j. Please explain, with supporting illustrative calculations, how a 15 year depreciation period would reduce the risk of stranded investment that ratepayers will bear if the Commission approves recovery through the environmental cost recovery surcharge.

**RESPONSE**

a. The Generally Accepted Accounting Principle (GAAP) that applies to the determination of the time period over which the Company depreciates its investment is the matching principle. The matching principle requires that the asset's cost be allocated to depreciation expense over the life of the asset.

FASB 71 states that if a regulator prescribes a period of time to depreciate an asset that is shorter than the useful life of the asset then using the shorter life is consistent with GAAP.

b. The Company is not proposing a period other than the 15 years since is does not believe it is appropriate to assume an absence of any material risk of future environmental regulations. As stated in response to Staff 1-12, the expected life could reach 70 years and thus the depreciation life would be 25 years.

c. The Company is not aware of any cases in which the KPSC approved a 15 year time period for depreciation of a FGD.

d. The Company is not aware of any cases in which the KPSC approved a shorter time period to recover depreciation in order to reduce the risk of stranded investment.

e. The Company is not aware of any other regulatory commission in other states in which American Electric Power operates has approved a 15 year time period for depreciation of a FGD.

f. In Indiana & Michigan's CPCN filing for a scrubber on one of its Rockport Units in Cause No. 43636, they are asking for a 15 year depreciation period. Please see Attachment 1 to this response as the statutory authority to ask for this time frame..

g. The Company does not know what those future increased EPA standards will be at this time.

h. The Company did not attempt to analyze the risk associated with future unknown increased EPA standards.

i. The Company proposes to make the investment to provide service to its customers at the lowest cost and in accordance with federal law. Under these circumstances the Company should not bear any risk of stranded investment.

j. Attachment 2 to this response is an illustrative calculation comparing the depreciation of an asset over 15 years versus 25 years. You will notice that at the end of 15 years the asset being depreciated over 25 years still has $370M of undepreciated plant (net plant). If the Company were to retire that asset in year 15 (before the end of the 25 year depreciation period), the $370M of net plant is stranded investment. If the asset were to be retired prior to 15 years, both scenarios would have stranded investment, but the asset being depreciated over 15 years would have less stranded investment versus the asset being depreciated over 25 years. Thus, the amount at risk subject to stranded investment is much less.

**WITNESS:** Ranie K Wohnhas

**KPSC Case No. 2011-00401**
**Sierra Club Initial Set of Data Requests**
**Dated January 13, 2012**
**Item No. 33**
**Page 1 of 1**

# Kentucky Power Company

## REQUEST

Direct Testimony of Scott Weaver page 7, lines 3 to 21.

a. Please describe the metric that KPC uses to measure “planning flexibility” and the rationale for choosing that metric.

b. Please describe the metric that KPC uses to measure “optimum asset mix” and the rationale for choosing that metric.

c. Please describe the metric that KPC uses to measure “adaptability to risk” and the rationale for choosing that metric.

d. Please describe the metric that KPC uses to measure “affordability” and the rationale for choosing that metric.

## RESPONSE

a-d. The plan characteristics listed in this request are considered "other objectives" of a resource plan as defined by Kentucky statute. The primary objective, as defined by the statute, is to "assure the reliable, adequate and economical supply of electric power to the customer, in an environmentally compatible manner". KPCo does not use a quantitative metric to measure these "other objectives" of its resource plan. Rather, it would compare its chosen plan to other potential plans with respect to these objectives.

**WITNESS:** Scott C Weaver

**KPSC Case No. 2011-00401**
**Sierra Club Initial Set of Data Requests**
**Dated January 13, 2012**
**Item No. 34**


# Kentucky Power Company

## REQUEST

Direct Testimony of Scott Weaver page 7, lines 3 to 21 and pages 30 to 54.

a. Please provide the Company's assessment of the "planning flexibility" of each of the four alternative options it evaluated.

b. Please provide the Company's assessment of the "optimum asset mix" of each of the four alternative options it evaluated.

c. Please provide the Company's assessment of the "adaptability to risk" of each of the four alternative options it evaluated.

d. Please provide the Company's assessment of the "affordability" of each of the four alternative options it evaluated.

## RESPONSE

a-d. KPCo did not perform this assessment for the alternatives considered. Based on the analysis the Company did prepare, Exhibits SCW-4A through 4E provide a measure of "optimum asset mix" and "affordability", and Exhibit SCW-5, Figure 5-1 provides a measure of "adaptability to risk" and, to a lessor extent, "planning flexibility".

**WITNESS:** Scott C Weaver

# Kentucky Power Company

## REQUEST

Direct Testimony of Scott Weaver page 20 and Exhibit SCW-1, pages 4 to 7.

a. Did KPC test the sensitivity of its options to the possibility of the Kentucky General assembly passing clean energy legislation, such as the Clean Energy Opportunity Act (HB 67), which would require utilities such as KPC to achieve specified reductions from energy efficiency and to acquire specific quantities of generation from new renewable resources?

b. If yes, please explain how the Company evaluated this possibility.

c. If no, please explain why not.

## RESPONSE

a. No such sensitivity tests were performed

b. N/A

c. The legislation is not finalized. Therefore, KPCo has no obligation to commit to such programs and would likely not do so, until cost recovery assurances were received from the Commission. In fact, KPCo had previously sought to acquire 100 MW of renewable (wind) resources that would presumably achieve such "clean energy" attributes; however such costs associated with that potential wind renewable energy purchase agreement were denied recovery by the KPSC.

**WITNESS:** Scott C Weaver

# Kentucky Power Company

## REQUEST

Direct Testimony of Scott Weaver, Table 1 and pages 23 to 30

a. Please provide all analyses underlying the Company's decision to assume the four alternative options summarized in Table 1, as opposed to other possible alternative options.

b. Please explain why the Company did not choose to evaluate an alternative option in which it would retire Big Sandy units 1 and 2 and replace them with a mix of "steel in the ground" gas CC units and purchases, but starting with a lower initial quantity of new gas CC capacity coming into service January 2016, for example 350 MW, followed by a second addition on new gas CC capacity coming into service five years later?

c. Has the Company had any discussions with LG&E and KU regarding joint development of a gas CC unit to come into service in 2016 and an additional unit to come into service a few years later? If so, please document those discussions. If not, why not.

## RESPONSE

a. The four alternative options were viewed by KPCo's management as a reasonable basis for the performance of the Big Sandy disposition analysis. However, as identified beginning on page 40, line 11, through page 42, line 3, of Mr. Weaver's testimony, additional long-term "market" alternatives were effectively proxied by Option #2 (Replace with a [Brownfield] CC. Likewise, Options #4A and #4B (Replace with [Short-Term] PJM-Market Capacity & Energy... for 5 and 10 years, respectively; then replace with a CC) also has many of the same attributes as replacing with a Peaking Asset (i.e. natural gas Combustion Turbine units). Based on the fact that the AEP Fundamental Analysis group's long-term forecast of PJM capacity value used for that Option assessment are projected to approach the anticipated PJM Net Cost of New Entry value (Net CONE) --for which PJM utilizes the net cost of *peaking generation* to establish-- one could also then assert that this Options #4A and #4B very reasonably approximate a "peaking asset" alternative.

See also the response to KIUC Item No. 29, First Set.

b. The Company viewed an approximate 700-800 MW CC replacement (or, a size roughly equivalent to that of Big Sandy Unit 2 it would be replacing) set forth in Option #2, as being more appropriate for analysis purposes than multiple smaller, staggered, CC units. There are certain economies of scale that are created by exercising a combined cycle plant build option that would require a "2x2x1" (2 combustion turbine x 2 heat recovery steam generators [HRSG] x 1 steam turbine) design. A combined cycle unit in approximately the 350 MW size would typically be a "1x1x1" design having a higher relative installed cost per kW of capacity; as well as a higher heat rate (i.e., poorer thermal efficiency). Internal AEP estimates suggest that this $ per kW difference could be significant at over +20%, while the "full load" heat rate difference could be as much as +4% for a smaller, roughly 350 MW, 1x1 CC.

c. The Company has not had any discussions with LG&E/KU regarding a joint venture to develop a gas CC unit. A joint venture does not solve any issues or concerns relative to the cost impact to the customer.

**WITNESS:** Scott C Weaver, Toby Thomas

# Kentucky Power Company

## REQUEST

Direct Testimony of Weaver, Table 1 and pages 23 to 30. Has the Company considered any other alternatives aside from Options 1-4?

a. If so, please provide detailed descriptions of all other alternatives considered, the level to which they were considered (i.e. discussion only, analysis, modeling, etc...), and any analytical work, such that it exists, that examined the cost efficacy of these other alternatives.

b. If so, please provide any analytical work that supports the non-consideration of those alternatives in the final four options presented here.

c. If not, why not?

d. Has the Company considered the cost effectiveness of replacing Big Sandy with capacity-only replacement, such as combustion turbine without combined cycle capacity?

e. Has the Company considered the cost effectiveness of replacing Big Sandy with a mixture of capacity and energy resources, such as a mix of combustion turbines and combined cycle capacity?

f. Has the Company considered the cost effectiveness of replacing Big Sandy with any combination of fossil resources and renewable energy purchases in either the short or long-term (i.e. immediately, up to 5 years as in Option 4A, or up to 10 years as in Option 4B)?

g. Has the Company considered the cost effectiveness of replacing Big Sandy with any combination of fossil resources and energy efficiency, demand response, or other demand-side management acquisitions or programs?

h. If the answer to any of (d)-(e) is yes, and as not otherwise provided in answer to (a) or (b), please provide any workpapers showing the scenario considered, the expected costs of the scenario, and any model results from comparing the scenario against other alternatives.

**RESPONSE**

a. An additional evaluation was performed in January of 2012, after the filing of this case. This assessment focused on the possibility of either acquiring --or entering into a purchase power arrangement-- from affiliate Ohio Power Company for a portion of the Mitchell Unit 1 and/or Unit 2 facilities. These 770 MW and 790 MW, respective coal-fired units are located in Moundsville, West Virginia and have recently been environmentally-controlled with FGDs and SCRs. The timing of this alternative evaluation was based on the recent prospect that Ohio Power Company could become corporately separated and, with that, the generation assets of that company may no longer be regulated and, hence, may be available for sale/transfer.

One of these evaluations calls for the purchase of a 20% portion of the combined Mitchell Units 1 and 2 (or, a total of 312 MW) and is under consideration as a replacement for the proposed retirement of KPCo's Big Sandy Unit 1. This evaluation is intended to be introduced as a proposed component of the 'Section 205' filing with the FERC that AEP is intending to file in early 2012 that would seek to modify the AEP Interconnection (Pool) Agreement.

Additionally, KPCo management also requested that an additional analysis be performed under which Kentucky Power would seek to receive a greater portion from Mitchell Units 1 and 2 (ostensibly, one of the 'full' Mitchell units) that would serve to effectively be substituted for the like-sized Big Sandy 2. This evaluation also assumed that in lieu of retiring Big Sandy Unit 1, it would consider converting that unit to burn solely natural gas (i.e. it would become a "gas-steam" unit).

The attachment to this response is a summary of these indicative Strategist-based evaluations performed in January 2012.

b. As indicated in the response part a of this question, this assessment was performed after this KPCo filing, but does not change the results and recommendation of the filing.

c. N/A

d. The Company has not considered the replacement of Big Sandy 2 with a combustion turbine unit. If Big Sandy Unit 2 were to be retired, KPCo would be replacing a large "baseload" facility that has historically contributed significant amounts of generated energy. As such, if it were to replaced purely with peaking capability --in the form of natural gas combustion turbine (CT) units, or as a unit simply converted to burn natural gas (i.e., a gas-steam unit)--, the Company believes it could be exposed to unacceptable levels of market (energy) purchases and, with that, potential for price volatility for the long-term life of the CTs/gas conversion due to such facilities' would very likely have very low utilization/capacity factors.

e. No. However, this option is essentially captured by, particularly, Options #4A and #4B. See the response Sierra Club 1-51, part a, for an elaboration.

f. No. The Company believes that renewable energy purchases are not substitutable for, particularly, capacity planning purposes. For instance, the PJM RTO recognizes only 13% of the nameplate MW-capacity of wind generating sources for capacity planning purposes. Further, KPCo 2009 request to recover its costs under a proposed wind renewable energy purchase agreement (REPA) was denied by the Commission following opposition by KIUC and the Attorney General.

g. No. While as indicated on Table 1-2 of Exhibit SCW-1, KPCo is projected to achieve 41 MW of demand response (DR) resource by 2016, and at least 60 MW by 2020, such amounts would likely serve to merely adjunct KPCo's resource portfolio, rather than offer a major contribution. As with peaking resources, DR would not contribute much in the way of *energy* contribution. Likewise, that same Table 1-2 of Exhibit SCW-1 also indicates as much as nearly 100 GWh of (annual) energy efficiency contribution being projected for the Company by 2016. However, that level also represents a small (< 2%) percentage of KPCo's overall internal load estimate for that year.

h. N/A

**WITNESS:** Scott C Weaver

## Kentucky Power Company

REQUEST

Direct Testimony of Scott Weaver pages 11 and 12, Table 1.

a. Did KPC pursue fractional ownership of any new fossil fuel generation units proposed or iscussed by other nearby utilities as referenced in those companies' IRP, CPCN, or other planning documents?

b. Did KPC make any attempt to secure partners in the construction and operation of new fossil fuel generation units?

c. Should KPC pursue Option #4A or Option #4B, would KPC preserve the possibility of installing environmental upgrades on Big Sandy Unit 1 or Big Sandy Unit 2 at some future date (e.g. 2020, 2025, or some other date) if the assumptions related to coal prices, natural gas prices, installation costs of new generators or environmental controls, energy or peak load forecasts, the price of procurement of electricity on the PJM market, carbon prices, future environmental regulations, or any other model input or inputs proved inaccurate whereby a similar analysis performed then in fact did demonstrate that installing environmental controls was at that future date more economical than constructing new natural gas generation and/or acquiring replacement market capacity and energy from the PJM markets?

**RESPONSE**

a. No.

b. No.

c. While plausible, preserving that option would come at a potentially significant premium. For an elaboration, please see the first paragraph of the response to Sierra Club 1-67.

**WITNESS:** Scott C Weaver

# Kentucky Power Company

## REQUEST

Refer to the Company's response to Sierra Club initial data request 1-17b and 1-17h. Direct Testimony of Ranie Wohnhas, page 14 line 22 to page 15 line 5 refers to the possibility that future increased EPA standards could "...cause operation of this unit not to be economically feasible in the future". With reference to the possibility of such future increased EPA standards response 1-17b states that the Company "...does not believe it is appropriate to assume an absence of any material risk of future environmental regulations."

a. Please confirm that these two statements indicate that the Company believes it is appropriate to assume there is a material risk of future environmental regulations that could cause operation of the Big Sandy Unit 2 not to be economically feasible in the future. If the Company cannot confirm this interpretation please explain why not.

b. If the Company believes it is appropriate to assume there is a material risk of future environmental regulations that could cause operation of the Big Sandy Unit 2 not to be economically feasible in the future, please explain why the Company did not analyze that risk per response 1-17h.

## RESPONSE

a. The Company believes it is appropriate to assume there is risk of future environmental regulations that could cause operation of the Big Sandy Unit 2 not to be economically feasible in the future.

b. While the Company agrees it is appropriate to consider risk of future environmental regulations, it is difficult to quantify such risk from potential unknown requirements. However, the Company has proactively attempted to quantify such risk by including costs in analyses that are associated with current and potential EPA regulatory programs. In addition to the final CSAPR and MATS rules, analyses of Big Sandy Plant include potential cost implications related to the proposed 316(b) and CCR rules and the yet-to-be proposed Steam Electric Effluent Guidelines. Each of these programs could require installation of mitigation technology at Big Sandy Plant. In addition, the Company has for some time now included a carbon "tax" in its analyses as a proxy for some future regulation of greenhouse gas emissions. The timing of the applicability of such a proxy has changed as prospects for Green House Gas legislation have waned in the current US Congress.

WITNESS: Ranie K. Wohnhas

# Kentucky Power Company

## REQUEST

Refer to the Company's response to Sierra Club initial data request 1-17j. If the Company expects to recover the total amount of all revenue requirements associated with Big Sandy unit from ratepayers, including all stranded investment, why is it concerned about the number of years over which it recovers that amount? (We recognize that the net present value of the total amount the Company would ultimately collect from ratepayers would be less if it collected the revenue requirements and stranded investment over a shorter number of years rather than a longer number of years).

## RESPONSE

If the Company were allowed recovery of all costs associated with installing a DFGD on Big Sandy Unit 2 including any future stranded investment, then the Company would not be as concerned about the number of years in which it recovers those costs.

WITNESS: Ranie K Wohnhas

KPSC Case No. 2011-00401
Sierra Club Supplemental Set of Data Requests
Dated February 8, 2012
Item No. 21
Page 1 of 1

# Kentucky Power Company

## REQUEST

Refer to the Company's response to Sierra Club initial data requests 1-32c-d, 8 and 9.

a. Please provide the Company's most recent estimate of achievable potential for cost-effective reductions from energy efficiency in its service territory based upon the tests listed in response 32c-d. If the Company has not prepared, or commissioned, such an estimate, please explain why not.

b. Is it the Company's position that its current programs are capturing all achievable potential for cost-effective reductions from energy efficiency in its service territory? If yes, please provide the analyses supporting that position. If no, please explain why the Company is not capturing that full achievable potential.

## RESPONSE

a A single market potential study has not been commissioned for Kentucky Power Company. Detailed evaluation reports are completed for each DSM program and have been utilized to review the program cost effectiveness and program process including evaluation of market conditions and/or market potential. The Company completed evaluation of 7 DSM programs in 2011 and is currently evaluating the 5 other programs out of the total 12 programs currently included in the company's DSM portfolio. The Company has also purchased demographic data specific to the residential customer class which will further assist with planning the residential DSM programs.

b. No. The Company does not believe it has exhausted all cost-effective energy efficiency opportunities. Kentucky Power has operated energy efficiency programs continuously since 1996, and the Company recently expanded the DSM programs for both residential and commercial customers. In addition, the Company is testing a pilot load management program based on two-way cellular technology for customer home energy management and utility demand control of hvac and water heating equipment. Kentucky Power, in coordination with its collaborative and regulators has developed a portfolio of programs designed to help ratepayers use energy efficiently while balancing the impact on rates.

WITNESS: Ranie K Wohnhas

# Kentucky Power Company

## REQUEST

Refer to the Company's response to Sierra Club initial data requests 1-33 and 1-34 and Direct Testimony of Scott Weaver page 7, lines 3 to 21.

a. Please reconcile response 33 that the Company would compare its chosen plan to other potential plans with respect to these objectives with response 34 stating the Company did not perform this assessment for the alternatives considered.

b. Please provide the most recent analysis in which the Company compared its chosen plan to other potential plans using any or all of those metrics.

## RESPONSE

a. & b. As stated in response to Sierra Club 1-33, KPCo does not use a quantitative metric to measure these "other objectives" of its resource plan. Rather, it compares its chosen plan to other potential plans with respect to these objectives. Also, as stated in Sierra Club 1-34, Exhibits SCW-4A through 4E may provide a measure of "optimum asset mix" and "affordability," and Exhibit SCW-5, Figure 5-1 provides a measure of "adaptability to risk" and, to a lesser extent, "planning flexibility."

WITNESS: Scott C Weaver

KPSC Case No. 2011-00401
Sierra Club Supplemental Data Requests
Dated February 8, 2012
Item No. 31
Page 1 of 1

# Kentucky Power Company

## REQUEST

Refer to the Company's response to Sierra Club initial data request 1-57b and the Direct Testimony of Weaver, page 37, lines 4 to 6. Please confirm that, under Option 4, the Company would retain the flexibility to change its mix of owned capacity and purchased power in reaction to changes in load, gas prices, environmental regulations, availability, and cost of renewable resources and power prices between 2012 and 2040? If not, please explain why not.

## RESPONSE

The "flexibility" the Company would retain with Option 4 is questionable. Under Option 4 the Company would retire both Big Sandy Unit 1 and Unit 2 in 2015 and, therefore, must rely fully on market purchases to meet its customers' requirements during any interim period prior to a presupposed ultimate CC-build. Therefore, this would immediately eliminate coal from the Company's capacity (and energy) mix, and replace it with market purchases that would most likely emanate solely from gas-fired sources.

Contrastingly, Option 1 (as well as Options 2 and 3)--as indicated in the direct testimony of Mr. Weaver on page 52, line 1, through page 53, line 18--would offer a more reasonable "mix" of market purchase opportunities than Option 4 due to the need to replace the capacity and energy attributes of approximately 170-to-300 MW of retired KPCo generation.

WITNESS: Scott C Weaver