COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Application of Kentucky Power Company for Approval of its Environmental Compliance Plan, Approval of its Amended 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**

AFFIDAVIT OF DR. JEREMY FISHER FOR DIRECT TESTIMONY (PUBLIC VERSION)

Commonwealth of)
Massachusetts)
)

Dr. Jeremy Fisher, 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.

Dr. Jeremy Fisher

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

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

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 SURCHARGE TARIFF, AND FOR THE GRANTING OF A CERTIFICATE OF PUBLIC CONVIENENCE AND NECESSITY FOR THE CONSTRUCTION AND ACQUISITION OF RELATED FACILITIES.	)	Case No. 2011-00401

Direct Testimony of
Jeremy Fisher, Ph.D.

On Behalf of
Sierra Club

March 12, 2011

Public Version

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1. INTRODUCTION AND QUALIFICATIONS

Q Please state your name, business address and position.

A My name is Jeremy Fisher. I am a scientist with Synapse Energy Economics (Synapse), which is located at 485 Massachusetts Avenue, Suite 2, Cambridge Massachusetts 02139.

Q Please describe Synapse Energy Economics.

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

Q Please summarize your work experience and educational background.

A I have ten years of applied experience as a geological scientist, and four years of working within the energy planning sector, including work on integrated resource plans, long-term planning for states and municipalities, electrical system dispatch, emissions modeling, the economics of regulatory compliance, and evaluating social and environmental externalities. I have provided consulting services for various clients, including the U.S. Environmental Protection Agency (EPA), the National Association of Regulatory Utility Commissioners (NARUC), the California Energy Commission (CEC), the California Division of Ratepayer Advocates, the State of Utah Energy Office, the National Association of State Utility Consumer Advocates (NASUCA), National Rural Electric Cooperative Association (NRECA), the State of Alaska, the Western Grid Group, the Union of Concerned Scientists (UCS), Sierra Club, Natural Resources Defense Council (NRDC), Environmental Defense Fund (EDF), Stockholm Environment Institute (SEI), and Civil Society Institute.

Prior to joining Synapse, I held a post doctorate research position at the University of New Hampshire and Tulane University examining the impacts of Hurricane Katrina.

I hold a B.S. in Geology and a B.S. in Geography from the University of Maryland, and an Sc.M. and Ph.D. in Geological Sciences from Brown University.

My full curriculum vitae is attached as **Exhibit JIF-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?

A Yes, I have. On September 16, 2011 I filed direct testimony in the joint application of Kentucky Utilities/Louisville Gas &Electric for a CPCN in similar dockets (2011-00161 and 2011-00162).

Please identify the Company's documents and filings on which you base your opinion regarding the Company's expectations for and treatment of environmental compliance costs affecting its fleet of coal plants.

A In addition to the Application for Certificate of Public Convenience and Necessity (CPCN) with accompanying witness testimony and appendices in this case, I have reviewed the following data prepared by Kentucky Power Company (KPCo) and American Electric Power (AEP) (the "Company", collectively):

- Select input and output data from the Strategist model as used by the Company in this docket;
- Input and output data from the Aurora model to the extent made available by the Company;
- Numerous spreadsheet workpapers supplied by the Company in response to discovery requests by Sierra Club, Staff, and KIUC.

- Other discovery responses filed by the Company to both Sierra Club and other parties.

Q Have you based your findings and opinions on the complete set of filings submitted by the Company?

A Yes, however, the Company's failure to timely respond to Sierra Club's data requests hindered our ability to determine whether additional information relevant to the Company's filing exists. In particular, Sierra Club received incomplete responses to initial data requests and only received complete responses on February 27^{th} – four days prior to the original direct testimony deadline and more than two weeks <u>after</u> the filing deadline for supplemental discovery.[1] These initially withheld responses turned out to be quite crucial in our assessment of the Company's plan. It took the entirety of the last two weeks remaining to us to piece together how the Company arrived at its final conclusion. While the mechanism by which the Company arrived at its answer was eventually brought to light, the information in these files raises many more questions that should be fully explored. Without questioning motive, we have found numerous key assumptions obfuscated or incompletely explained. Therefore, I hesitate to say whether the information supplied by the Company to date presents a complete picture upon which the Commission and the parties can evaluate the Company's filing.

Q What is the purpose of your testimony?

A My testimony details and evaluates specific components of the Company's analysis supporting this CPCN application. My testimony reviews both inputs assumptions and the outcomes from two models used by the Company to support this filing: STRATEGIST ("Strategist") and Aurora^{xmp} ("Aurora"). I approach four significant areas of concern within the Strategist model and supporting

[1] The Company apparently filed the supplemental response to 1-69 "containing detailed back-up to Exhibit SCW-4A through SCW 4-E" on Wednesday, February 22^{nd}, but sent the files to Sierra Club analysts by second-day delivery. This mailing was not received until the start of business on Monday, February 27^{th}.

workpapers: which capital costs are utilized in the model, how fixed operating and maintenance costs are portrayed in the model, the treatment of off-system sales from KPCo, and the adequacy of the sensitivities explored using Strategist. For both the Strategist and Aurora models, I challenge the assumption that the Company's carbon dioxide (CO_2) price forecast represents a standard in the industry or a reasonable assessment of CO_2 price risk. Finally, I assess the utility of and assumptions behind the Aurora model, challenging internal inconsistencies between stated input assumptions and those actually used in the model, the derivation of fundamental assumptions and errors in those derivations, the output of the model as compared against the Company's other modeling mechanism, and the use of the model in this filing.

My testimony relies on Strategist modeling conducted by my colleague Ms. Rachel Wilson, who has also sponsored testimony in this docket, and supports the conclusions drawn by my colleague Mr. Hornby. The calculations that I present in this testimony are my own.

Q Are you filing any exhibits with this testimony?

A I have attached the following exhibits to this testimony:

- **Exhibit JIF-1:** Curriculum Vitae;
- **Exhibit JIF-2:** Relative cumulative present worth of Options 1, 2, and 4A under Company and corrected assumptions;
- **Exhibit JIF-3:** Tables indicating the CPW of Options 1-5 under Company assumptions and corrected assumptions;
- **Exhibit JIF-4:** Calculations on capital cost of replacement NGCC;
- **Exhibit JIF-5**: Streams of carrying charges in Options 1 & 2;
- **Exhibit JIF-6**: Total capital cost of FGD project and NGCC options from Weaver, Table 2 (plus AFUDC) versus from Strategist; and calculations of AFUDC;

- **Exhibit JIF-7**: Comparison of CO_2 price forecasts government entities, other electric utilities, industry groups, and Company;
- **Exhibit JIF-8**: Synapse CO2 price forecast paper, February 2011.
- **Exhibit JIF-9**: Company results from Strategist with ranges from Aurora model.
- **Exhibit JIF-10:** Differences between Aurora and Strategist outcomes; differences between Aurora and Strategist variables.
- **Exhibit JIF-11**: Comparison of CPW cost components between Strategist and Aurora.
- **Exhibit JIF-12**: Correlations for Aurora from Company in testimony, as used in Aurora, and as derived from US datasets.

2. SUMMARY AND CONCLUSIONS

Q In your opinion and according to the documents you have reviewed, does the Application submitted by the Company in this proceeding merit the requested Certificate of Public Convenience and Necessity and associated Environmental Surcharge?

A No, it does not. I have found numerous errors, inconsistencies, and flaws within the workbooks supporting the application rendering the Application inadequate and incomplete. The application does not support the Company's contention that the environmental retrofits at Big Sandy 2 are the least cost solution for ratepayers. In attempting to reconstruct the Company's analysis supporting its contention, I have found multiple circumstances where specific errors or flaws in the analysis or underlying assumptions have biased the results towards favoring the retrofits. Correcting these sometimes simple errors leads to the conclusion that retrofitting Big Sandy 2 is, by a fairly wide margin, the least economical choice for Kentucky Power Company's ratepayers.

In short, the Company has not demonstrated that the retrofit of the Big Sandy 2 unit is warranted given the availability of other, lower cost options for the Company.

Q Are you suggesting that the decision to retrofit the Big Sandy 2 unit is based on an erroneous analysis?

A In part, yes. My colleague Mr. Hornby briefly characterizes some of the changes made in the Company's analysis over the last few months of 2011. Up through October of 2011, the Company was still indicating to shareholders that the Big Sandy 2 unit would be retired because it was not economic to install a flue gas desulfurization (FGD or DFGD) system.[2] One month later, however, the Company indicated to investors that it would retrofit the Big Sandy 2, not retire it.[3] In at least six presentations from November through December 2011,[4] including some after the Company had requested nearly $1 billion from this Commission in this CPCN application,[5] the Company continued to tell investors that the retrofit would cost $525 million.[6] While the Company attributes at least one slide (and presumably the five others like it) to a "scrivener's error," errors of the same magnitude are found throughout the analysis underlying this application.

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

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

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

[5] Initial CPCN filing on Dec 5th, 2011.

[6] Attachment to response to Sierra Club DR 1-1. "Goldman Sachs 6th Annual Clean Energy & Power Conference" (December 9, 2011) slide 20, and response to Sierra Club DR 2-13. "In reviewing Slide 20 of the Goldman Sachs 6th Annual Clean Energy and Power Conference (December 9,2011), investors would have noted that the high end cost for the Big Sandy 2 FGD was stated to be $525 million."

In my assessment, the Company appears to have carried something akin to this "scrivener's error" through their supporting Strategist model, resulting in a surprisingly low capital cost for the FGD as portrayed in their fundamental Strategist analysis, while simultaneously inflating the expected capital cost of replacement options by 33-42% in the model relative to values presented in direct testimony.

Based on evidence provided by the Company, the cost of the FGD retrofit has remained unchanged since at least June 2011.[7] While the Company has not indicated when it received the estimated cost of replacement natural gas combined cycle (NGCC) from Sargent and Lundy (S&L), it appears that this estimate was available to the Company in mid-2011 as well.[8] Therefore, it is unclear how or why the Company's assessment of the relative economics of retrofitting or replacing the Big Sandy 2 unit changed just one month before this application was filed.

Other errors and inconsistencies in the Company's Strategist analysis, such as the allocation of all off-system sales for ratepayer benefit (rather than as currently split with shareholders), a surprising drop in fixed O&M costs for the FGD unit in 2030, and an extremely low "base" CO_2 price all appear to favor the Company's retrofit decision. Further, the sensitivity commodity prices used by the Company fail to allow for a reasonable exploration of actual risk.

Inputs into the Aurora analysis, used by the Company as a form of risk assessment, contain significant calculation errors and are inconsistent with direct testimony filed by the Company in this case.

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[7] See response to Sierra Club DR 2-10e.

[8] Information embedded in the file "Big Sandy CC Brownfield Build_Option 2 S&L Client Version DETAIL.xls" provided in response to Sierra Club DR 1-69 in supplemental response indicates that it was "last printed" in May of 2011.

Q What is your overall finding?

A When we correct knowable errors within the Company's fundamental Strategist analysis, each and every alternative explored by the Company – repowering Big Sandy 1 as a natural gas unit, replacing the Big Sandy 2 unit with a brownfield NGCC, or purchasing market power to 2020 to 2025 – are all more cost-effective than the FGD retrofit by a wide margin.

Figure 1 below (also **Exhibit JIF-2)** shows the total cumulative present worth (CPW) of Options 1, 2, & 4A under the Company's "BASE" assumptions on the left, and the gap that appears to render Option 1 least cost of these three options. On the right, I show the results of our analysis after correcting the Company's capital carrying costs, an allocation of off system sales (OSS) to shareholders, and running the model under a low-bound carbon dioxide cost (CO_2) representative of that used by other utilities and organizations.

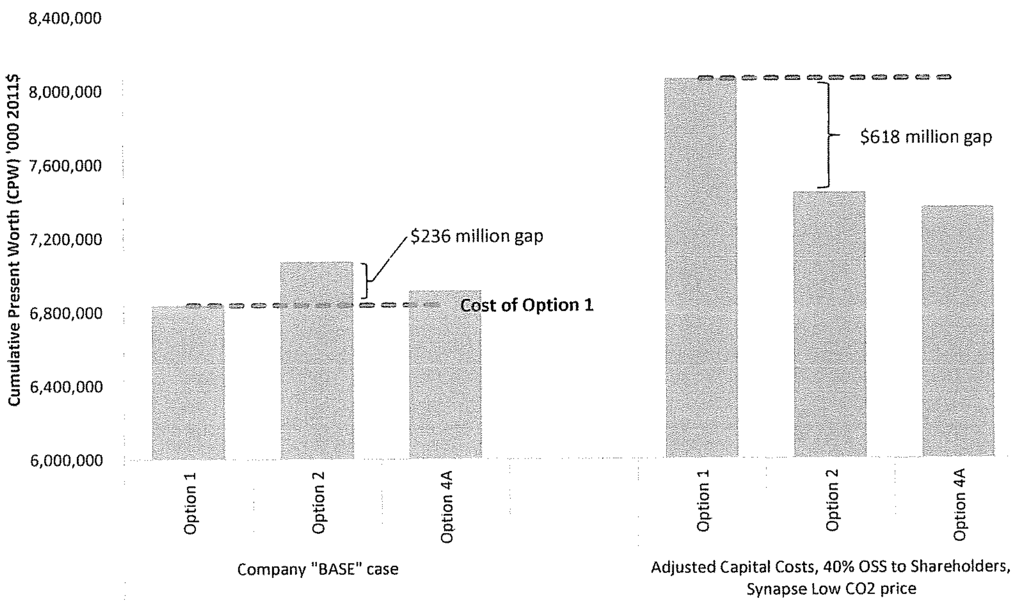


Figure 1. Cumulative present worth (CPW) of Options 1 (retrofit), 2 (NGCC replace in 2016), and 4A (market purchase to 2020) under Company Base assumptions (left) and Synapse revised assumptions and corrections (right). See text for details.

Q Would you give an overview your testimony structure?

A My testimony largely supports the overarching testimony of Mr. Hornby, and thus is divided into discrete segments exploring errors and uncertainty in both the Strategist model and the Aurora model.

- In **Sections** 3-7, I discuss a series of concerns with the Company's Strategist modeling, including assumed capital costs, fixed O&M costs, off-system sales, and the commodity pricing sensitivities used by the Company.
- In **Section 8,** I challenge the reasonableness and basis of the Company's CO_2 price forecast, and provide alternative options for consideration.
- In **Sections 9-13**, I examine the Company's Aurora model and its inputs, to the extent provided by the Company. I discuss my concerns with the overall Aurora results, the lack of transparency associated with the use of this Aurora model, errors and inconsistencies in the underlying correlations used in this analysis, and deep concerns about the use of this model to support this particular filing.
- Finally, **Section 14** summarizes my conclusions and recommendations.

3. STRATEGIST CONCERNS – OVERVIEW

Q Please describe how the Company has used Strategist to support this filing.

A An analysis based on output from the Strategist model forms the basis of the Company's decision to retrofit the Big Sandy 2 unit and directly support Exhibit SCW-4 in Mr. Scott Weaver's direct testimony. My colleague Ms. Wilson discusses in depth how the Company used the Strategist model itself in this proceeding. I have evaluated the post-model analysis conducted by the Company and discussed by Mr. Weaver.

My understanding is that the Company has developed a number of input assumptions used to drive the Strategist model. As Ms. Wilson describes, for the purpose of this filing, the Company does not appear to have used the optimization capability of Strategist, instead "locking in" all resource choices and, in effect, using Strategist as a production cost model. Certain outputs of the Strategist model, specific to the KPCo system, are then brought into what I will call the "Company Strategist Compilation Workbook," a separate analysis that calculates the cumulative present worth (CPW) of each option.[9] These CPW values are then used in Exhibit SCW-4.

The Strategist model is used to compute annual fuel costs, contract and market costs and revenues for *energy*, fixed and variable O&M costs, and total emissions costs. Although Mr. Weaver states in his direct testimony that fixed carrying charges and capacity sales/purchases are also "model outputs," this is not strictly the case. Both capital carrying charges and capacity sales/purchases, as used in this filing, are calculated completely externally to the Strategist model in the Company Strategist Compilation Workbook.

Also of note is that fixed O&M expenses are input into the Strategist model and passed, unaltered, out of the Strategist model; because the Strategist model does not optimize scenarios, these fixed O&M charges are effectively calculated completely externally to the Strategist model as well.

Q Which elements of the Strategist model, as used in this filing, are of concern?

A Ms. Wilson describes specific elements of the Company's use of the Strategist model that are of concern. I will focus on inputs to the model, the Company Strategist Compilation Workbook, and areas of concern that can be tested quickly through the Workbook. In particular, I have five areas of concern that are important in this CPCN application:

1. The treatment of off-system sales out of the KPCo system (Section 4)

[9] These workbooks were made available in supplemental discovery responses to Sierra Club DR 1-69. There is a separate workbook for each Option under each market commodity pricing scenario for a total of 25 workbooks (as used in this filing).

2. The treatment and magnitude of capital expenses and carrying costs in the Workbook (Section 5),
3. Inconsistent behavior or use of fixed O&M costs as input into the Strategist model (Section 6),
4. The appropriateness of the "commodity price" sensitivities used by the Company (Section 7) and
5. The Company's reference carbon dioxide (CO_2) price is far lower than reference prices used by any other source cited by the Company (Section 8)

It is my opinion that, had the Company correctly portrayed the current split in off-system sales between ratepayers and shareholders, used internally consistent capital cost expectations, used a CO_2 price consistent with other utilities, consultants, and agencies, or any combination thereof, the outcome of this analysis would have been very different, and not favorable to the retrofit.

4. STRATEGIST CONCERNS: OFF SYSTEM SALES

Q What is your concern with off-system sales as depicted in the Company Strategist Compilation Workbook?

A My colleague Mr. Hornby addresses whether off system sales revenues are appropriately allocated in this CPCN to the correct parties. As he notes, KPCo currently allocates 40% of off system sales (OSS) revenue to shareholders, not ratepayers. Presuming that the Company is presenting the Big Sandy 2 retrofit as the least cost alternative for ratepayers rather than for shareholders, one would presumably review the benefit for ratepayers – not the Company (i.e. shareholders). In the current modeling structure, the Company appears to have allocated all OSS revenues back to ratepayers, rather than splitting these revenues with shareholders.[10]

If the Company expects that the current 40-60 revenue split will continue through the analysis period, then the expectation of ratepayer benefit assumed in the modeling should be different.

Q To what extent would sharing off-system revenues with shareholders impact the net outcome of the Strategist analysis?

A I tested how the split in OSS revenues might affect the outcome of this analysis. Using the Strategist output of market sales out of KPCo,[11] I deducted 40% of the gross market sales from the KPCo system on an annual basis, and, following the Company's method for calculating the total cumulative present worth (CPW), subtracted the remaining revenues from the stream of costs and calculated a new CPW.

The result of allocating 40% of OSS revenues to shareholders drives up the cost seen by ratepayers – but drives it up faster in those scenarios where KPCo has greater off-system sales, in this case Option 1. The CPW of Option 1 rises by close to $400 million, while the other scenarios rise by $260-$300 million. Ultimately, the net effect is to narrow the gap between Option 1 and the other alternatives – and makes the market purchase options more attractive, even tipping the balance of Option 4A (market purchases to 2020) into a net benefit relative to the retrofit (see

[10] Received from the Company in response to Sierra DR 1-1, the 2011 EEI Fact Book (Nov. 2011) the Company reminds investors that Kentucky has an OSS sharing mechanism allocating 60% of OSS to ratepayers (p69).

[11] Generation and Fuel Module System Report from Strategist, line "Econ Energy Sales" in KPCO section.

Table 1 below; also in **Exhibit JIF-3A**). Option 4B (market purchases to 2025) continues to remain less expensive than Option 1.

Table 1. Cumulative present worth of revenue requirements (M 2011$): Reanalysis with adjusted off-system sales.

Cumulative Present Worth of Revenue Requirements (M 2011$) Re-Analysis with Adjusted Off System Sales	Option #1 Retrofit Big Sandy 2 w/ FGD	Option #2 NGCC Replacement	Option #3 BS1 Repower	Option #4A Market to 2020; NGCC in 2020	Option #4B Market to 2025; NGCC in 2025
Company Assumptions					
CPW	6,839	7,075	7,091	6,918	6,791
Net benefit of retrofit (CPW)		236	252	78	(48)
Adjusted Off System Sales					
CPW	7,228	7,377	7,394	7,201	7,055
Net benefit of retrofit (CPW)		149	166	(27)	(173)

5. STRATEGIST CONCERNS – CAPITAL EXPENSES AND CARRYING COSTS

Q What is problematic about capital expenses as used in the Company's model?

A I have identified two problems. First, values presented in Mr. Weaver's direct testimony in Table 2 (p24) are based on erroneous calculations and double-count AEP's 7% overhead in the cost of the replacement natural gas combined cycle (NGCC or CC) unit. Secondly, and more problematic, relative to values then stated in Mr. Weaver's Table 2 and associated discovery[12] the capital costs used in the Strategist model appear to be incorrect. After adjusting for Allowances for Funds Used During Construction (AFUDC), the Strategist carrying costs are:

- Depressed for the FGD retrofit project by about 11%
- Inflated for the replacement NGCC in Options 2, 4A, and 4B by about 43%, and
- Inflated for the capital cost of repowering in Option 3 by about 33%.

I have not corrected the first error leading to Mr. Weaver's values in Table 2, but I have corrected the Strategist carrying costs to be consistent with Mr. Weaver's Table 2. Correcting values back to those given by Mr. Weaver dramatically changes the final outcome of this analysis. In the Company's base case, the

[12] The values in Weaver Table 2 (p24) are presented as streams of capital expenses (DFGD, new build-NGCC, and repowered NGCC at Big Sandy 1) in Sierra DR 1-69 "Capital Cost of BS2 FGD and CC Alternatives used in *L-T Modeling.xls*"

retrofit of the FGD is non-economic relative to *all* other Options by anywhere from (-$49) to (-$229) M 2011$. The exact nature of this discrepancy is discussed further, below.

Capital Cost for NGCC inflated by 7% in Weaver, Table 2

Q The first problem you identified is that the capital costs of in Table 2 of Mr. Weaver's testimony appear to be overstated. Would you explain further?

A The values in Table 2 can be traced back to at least three separate work papers provided in response to Sierra DR 1-69 – each one starting where the last left off. The latter two both add in overhead costs for AEP and therefore overstate the cost of the NGCC. I trace through the following calculations in **Exhibit JIF-4**.

- The first paper appears to be a direct estimate summary from S&L and produces a "Total Project Cost" of $786 M (2011$).[13]
- The second paper is a summary of the total costs, plus additional costs, including an AEP Owner's Cost and the cost of interconnections.[14] The AEP Owner's cost amounts to nearly 7% of the total project cost and brings the total from $790 to $844 M (2011$).[15] Between the interconnection cost and escalating the cost to nominal dollars, the final value given here is $969 M (Nominal $).
- The third paper is a summary of the economic outcome of a retire/retrofit decision, conducted in August of 2011.[16] This paper *starts* with [redacted]

[13] Big Sandy CC Brownfield Build_Option 2 S&L Client Version DETAIL.xls

[14] Big Sandy CC Brownfield & U1 Repower S&L-based SUMMARY .xls

[15] Apparently the initial estimate was $790 M, revised down by S&L to $786. The higher value appears to propagate through the remainder of the estimate given in direct testimony.

[16] Confidential file "PRELIMINARY_Relative BS2 Unit Disposition Alt Economics_081711.xls"

[redacted]. The final value, $1,141 M is consistent with Mr. Weaver's Table 2.

The evidence suggests that redundant AEP overhead costs have been added to the total cost of the NGCC in Table 2 of Mr. Weaver's testimony.

Strategist Carrying Costs Inconsistent with Weaver, Table 2

Q In addition, you indicated that the values in Strategist are inconsistent with Table 2 in Mr. Weaver's testimony. Is this due to the same double-counting problem you identified above?

A No. Mr. Weaver has overstated the costs of the NGCC replacement unit in Table 2 of his testimony. However, even given these particular values, the capital costs of the NGCC and DFGD as portrayed in the Strategist analysis are incorrect. The costs of the NGCC are yet further overstated in the Strategist model, even relative to Table 2, and the costs of the DFGD are depressed.

As discussed below in my testimony, the Strategist model appears to have overinflated costs of the NGCC by approximately 43% relative to Table 2, and Table 2 inflated costs of the NGCC by about 7% relative to estimates from Sargent and Lundy, even including AEP overhead. So therefore, relative to the S&L estimates cited by the Company, the Strategist model uses costs that are about 50% higher for the NGCC than would be suggested by S&L.

Q How can you tell that the capital costs in Strategist are inconsistent with Table 2 in Mr. Weaver's testimony?

A I have looked closely at the stream of carrying charges that underlie the results in Exhibit SCW-4. Recalling that just about all other options are held constant between the Strategist runs, if we look at two sets of lines representing annual carrying charges between Option 1 (retrofit) and Option 2 (new NGCC) as in **Figure 2 (Exhibit JIF-5)**, below, we see that in 2016, the two lines both rise significantly and separate. In the Figure below, the solid black line is carrying charges of Option 1 – the Big Sandy 2 retrofit, and the grey dashed line is the carrying charges of Option 2 – the NGCC replacement.

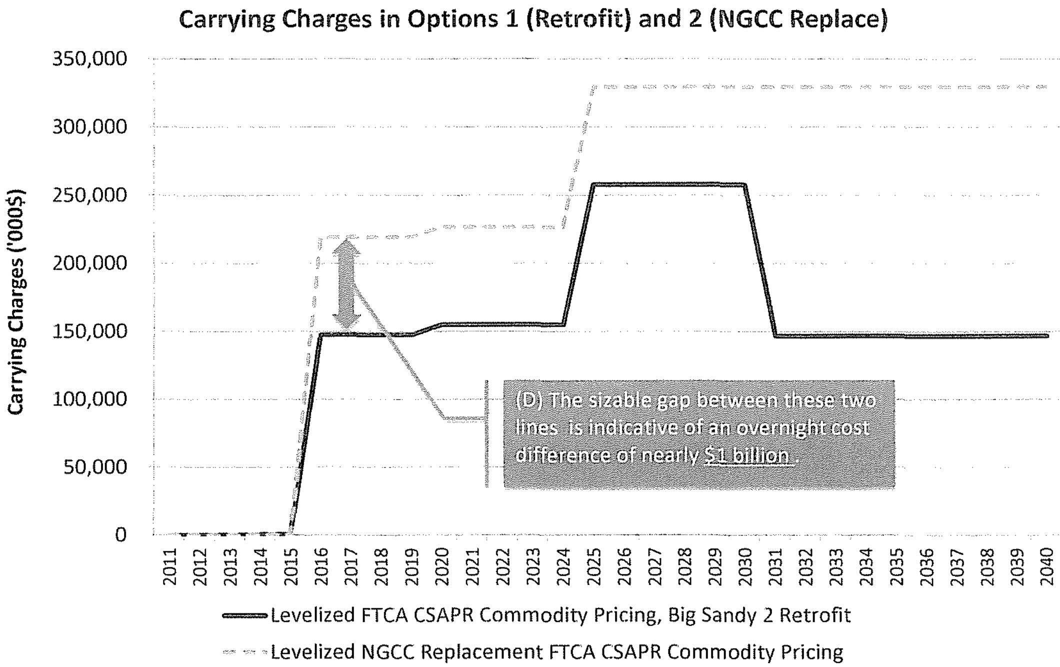


Figure 2. Streams of carrying charges in Options 1 and 2.

The two projects represented by the costs from 2016 to about 2019 (when the next capital cost is incurred) cost about $784 million (the FGD) and $1,057 million (NGCC),[17] and have book lives of 15 years and 30 years, respectively. Taking the expected annual payment of those two projects (not including AFUDC) over 15 and 30 years, we would expect the projects to have very similar carrying charges ($95 M and $100 M, respectively).[18] Yet the Strategist modeling used a much larger gap, as shown in Figure 1 above. In fact, the gap between the two lines suggests a capital cost difference of nearly $1 billion (2011$).

I believe that either one or both of these carrying charges are in error, or the company has used a non-disclosed financial model with very different assumptions for the retrofit and replacement NGCC units.

[17] Weaver Table 2, p24. 800 MW * $980/kW (coal + CCR projects, after owners cost) = $784 M; 904 MW * $1169/kW (NGCC) = ~1,057 M (2011$).

[18] Values calculated using the PMT function in Excel for (a) a 15 year loan on a $784M principal with an 8.64% ROE = $95.20M and (b) a 30 year loan on a $1,057M principal with an 8.64% ROE = $99.62M.

Tracing the basis of these changes requires a brief description of how capital expenses flow through the Strategist model, and how the Company portrays capital expenses.

Q Please describe how capital expenses flow through the Company's Strategist model.

A Briefly, capital expenses for new projects, including the FGD in Option 1 and the replacement NGCC units in the other options, are input into the Strategist model as overnight costs in real 2011$ per kW. The model calculates an allowance for funds used during construction (AFUDC) for the year the project is put in-service, and allocates a real levelized carrying charge across the project's book life. In an optimized run (i.e. when Strategist is allowed to choose the optimal portfolio), this carrying charge is considered part of the portfolio cost.

As discussed by Ms. Wilson, however, the Company has locked all options in place and taken the capital carrying charge equation outside of Strategist.

Q Where does the Company calculate carrying charges?

A The Company does a number of calculations in what I refer to as the "Company Strategist Compilation Workbook." At least in terms of the final outcome, the Company's mechanism for calculating carrying charges appears to be consistent with the mechanism used by Strategist (although the values used in both Strategist and the workbooks are incorrect). The Company appears to have generated a workbook for each of the 25 runs in this proceeding, made available to interveners as a supplemental response to Sierra DR 1-69.

A spreadsheet in each of those workbooks calculates the stream of carrying costs (spreadsheet "KPCO New Additions"). While the reasoning behind the formulae is not explained in the worksheet, it appears that the Company has calculated real levelized carrying charges for each new capital addition (including AFUDC) as if the project were to be started in any year of the analysis and depreciated over a given book-life - what we might think of as a "potential" levelized carrying charge. The potential levelized carrying charges are inflated over time with different inflation factors for some projects.

When a project is brought online, the potential levelized carrying charge for that year is carried down through the book life of the project or the end of the analysis period (whichever comes first). The sum of those carrying charges that are incurred over all projects are added together and flow back into the fundamental primary cost worksheet; this worksheet ultimately leads to the values given in Exhibit SCW-4, the economic justification for the Big Sandy 2 retrofit.

In this way, carrying charges for each individual project can be summed as required, and total cost streams can be broken down into their component parts.

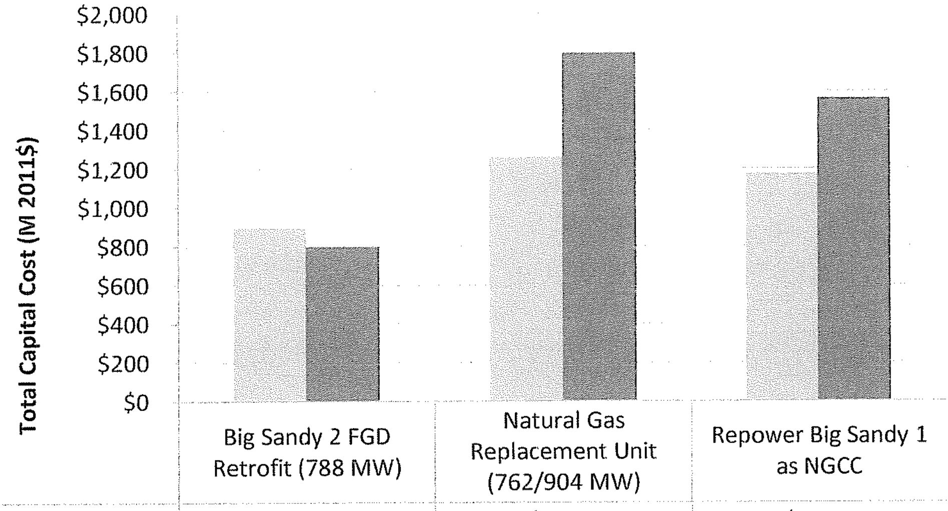
All-In Capital Cost Assumed in Strategist Model

Q Were you able to determine the principal that generates the Company's carrying cost estimate in the Company's Strategist Compilation Workbook?

A Yes, but indirectly. The Company's analysis ceases being traceable in the "KPCO New Additions" spreadsheet – the Company only presents a string of potential levelized carrying charges for each potential start year. However, using the 2011 potential levelized carrying charge as the equivalent of a non-inflated payment, I've estimated the capital associated with each project in the Company's planning horizon for KPCO. These values are in the second columns of the chart below, labeled "Strategist."

I've also estimated the total all-in 2011 capital costs of the retrofit and the natural gas replacement units from the values shown in Weaver Table 2, including AFUDC. I then compare these values against the capital costs derived from the Company's Strategist Compilation Workbook. These values the first columns of the chart below, labeled "Weaver, Table 2."

Figure 3 (also **Exhibit JIF-6A**) shows my estimate of the 2011 capital costs with AFUDC of the Big Sandy 2 FGD based on Weaver Table 2 (p24) and supporting discovery, and the estimated 2011 capital costs used in the Company Strategist Compilation Workbook (used to create Exhibit SCW-4).[19]



	Big Sandy 2 FGD Retrofit (788 MW)	Natural Gas Replacement Unit (762/904 MW)	Repower Big Sandy 1 as NGCC
Weaver, Table 2	$897	$1,260	$1,175
Strategist	$797	$1,795	$1,563

Figure 3. Total Capital Cost of FGD and replacement units, including AFUDC. Green bars are derived from Weaver, Table 2 (p24); blue bars are derived from carrying costs in Company Strategist Compilation Workbook.

<u>All-In Capital Cost Derived from Weaver, Table 2</u>

Q How did you estimate total all-in 2011 capital costs, including AFUDC, from Weaver, Table 2?

A I used example calculations provided by the Company to estimate AFUDC above the total dollar costs given by Weaver in Table 2.

The Company provided two spreadsheets – one with a stream of capital costs incurred for the FGD project and the new and repowered NGCC units,[20] and one with an example AFUDC calculation for the FGD project.[21] I followed the

[19] Calculation from worksheet values described below.

[20] Sierra DR 1-69: Capital Cost of BS2 FGD and CC Alternatives used in L-T Modeling.xls

[21] Sierra DR 1-69: BS2 DFGD AFUDC Calc for modeling.xls

AFUDC mechanism for the coal combustion residuals (CCR) that is part of the FGD retrofit, the replacement NGCC, and the repowered NGCC.[22] I then converted these nominal dollar values into real 2011$ using the 2.8% escalation factor assumed in the Company's AFUDC worksheet. The sum of these annual costs, including real 2011$ AFUDC became the all-in capital cost of the FGD and the NGCC units as shown in the Figure above. My calculations are shown in **Exhibit JIF-6B.**

Using the Company's worksheet, I calculated AFUDC of about 13% for the FGD and about 20% for the NGCC replacement and repowering options.

Comparing CPW Outcomes from Weaver, Table 2 Capital Costs

Q How did you incorporate capital costs from Weaver, Table 2 into the Company's Strategist Compilation Workbook?

A I copied the basic mechanism used in the Company's Strategist Compilation Workbook to incorporate capital costs, compile Strategist results from Ms. Wilson's runs and test other hypotheses about the Company's presented data. I will refer to my workbook at the "Synapse Strategist Compilation Workbook."

In my workbook, I calculated the required levelized carrying charges from the AFUDC-inflated capital costs from Weaver, Table 2 for the year 2011.[23] I then inflated this value through time at the same rate used by the Company for the same resources. I adopted the Company's mechanism to use the correct potential levelized carrying charge over the correct number of years, and carried this value through to the summed string of carrying charges. I then created an alternate version of the workpapers behind Exhibit SCW-4 with revised carrying charges, and evaluated the CPW outcomes of each Option, as well as the delta CPW between Options.

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[22] Used contingency-inflated price, and added AEP allocated of 9.1% for CCR and 7.1% for NGCC units. Assumed in-service date of 6/2016 for all projects. Streams of costs extend into 2016, rendering it impossible to use the Company estimated in-service date of January 2016 (see Weaver p51 at 22).

[23] Levelized carrying charges estimated using Excel PMT function on capital costs (including AFUDC, as shown in Figure 3) over Company-assumed book life at 8.64% ROE.

The following table illustrates the magnitude of the capital cost correction (also in **Exhibit JIF-3B**).

Table 2. Cumulative present worth of revenue requirements (M 2011$): Reanalysis with corrected capital costs.

Cumulative Present Worth of Revenue Requirements (M 2011$) Re-Analysis with Corrected Capital Costs	Option #1 Retrofit Big Sandy 2 w/ FGD	Option #2 NGCC Replacement	Option #3 BS1 Repower	Option #4A Market to 2020; NGCC in 2020	Option #4B Market to 2025; NGCC in 2025
Company Capital Costs					
CPW	6,839	7,075	7,091	6,918	6,791
Net benefit of retrofit (CPW)		236	252	78	(48)
Corrected Capital Costs					
CPW	6,921	6,679	6,790	6,632	6,610
Net benefit of retrofit (CPW)		(242)	(131)	(289)	(311)

In the first set of rows ("Company Capital Costs"), I show the outcome of the Company's Strategist run and capital carrying charges, and the net benefit of retrofit. These values are virtually identical to those found in Exhibit SCW-4A.[24]

In the second set of rows ("Corrected Capital Costs"), I show the outcome of the same Strategist runs with adjusted capital carrying charges as described above. The CPW of Option 1 is increased by nearly $100 million, while the other options fall by anywhere from $280 to $400 million. With these corrections, the net benefit of the retrofit evaporates – all other options are less expensive than the retrofit by a fairly wide margin.

When paired with the adjusted off-system sales, as discussed previously in my testimony, the net effect is that the Big Sandy retrofit is far less economic for ratepayers than any other Option examined by the Company (see table below; also in **Exhibit JIF-3C**).

[24] The values appear to differ slightly because of small differences in the Strategist runs. As described by Ms. Wilson, Synapse used Strategist input files provided by AEP and modified after a discussion with Mr. Mark. A. Becker, a modeler provided by AEP. According to AEP, these runs should have produced identical output to that used in this proceeding.

Table 3. Cumulative present worth of revenue requirements (M 2011$): Reanalysis with corrected capital costs and adjusted off-system sales.

Cumulative Present Worth of Revenue Requirements (M 2011$) Re-Analysis with Adjusted Off System Sales & Corrected Capital Costs	Option #1 Retrofit Big Sandy 2 w/ FGD	Option #2 NGCC Replacement	Option #3 BS1 Repower	Option #4A Market to 2020, NGCC in 2020	Option #4B Market to 2025; NGCC in 2025
Company Assumptions					
CPW	6,839	7,075	7,091	6,918	6,791
Net benefit of retrofit (CPW)		236	252	78	(48)
Corrected Capital Costs & Off System Sales					
CPW	7,310	6,981	7,093	6,916	6,874
Net benefit of retrofit (CPW)		(329)	(217)	(394)	(436)

Q Have you used any of your own capital or financial assumptions in creating these tables?

A I have not. I used capital assumptions from the direct testimony of Mr. Weaver and as presented in discovery, and financial assumptions copied directly from discovery and workpapers supporting Mr. Weaver's testimony.

6. STRATEGIST CONCERNS: FIXED O&M COSTS

Q What is your concern with the fixed operation and maintenance (O&M) costs used in the Company's model?

A The stream of fixed O&M costs in Option 1 (the retrofit case) drops markedly from 2030 to 2031 by about $36 million per year (nominal, or $27 M 2010$) and maintains at this lower value through the remainder of the analysis period.[25] We can trace this discrepancy back to the input (and output) for the Big Sandy 2 FGD from the Strategist model where fixed O&M costs for this single unit drop by $45 million (nominal, or $33 M 2010$) in 2030.

Q Would such a drop in fixed O&M costs be expected if the unit were continuing to operate in 2031 as it did in 2030?

A I can think of no reasonable explanation why fixed O&M costs, usually representing ongoing capital expenditures and maintenance activities, should decline so markedly in 2031.

[25] In the year 2040 fixed O&M appears to takes very high end-effects value as discussed by Ms. Wilson.

Q Is the drop in expected fixed O&M costs important in the outcome of the model?

A Yes. If the pre-2031 fixed O&M costs were carried through the end of the analysis period (2031-2039), we would expect the 2011 cumulative present value (CPW) of the retrofit to increase by about $69 million (2011$).

Q Can you explain why the fixed O&M costs may have this behavior?

A No, but I can put forward a hypothesis. I suspect that the Company has included a discrete 2016 capital expense as part of the fixed O&M stream of costs. A capital cost amortized over 15 years using the Company's levelized carrying charge mechanism would appear as a flat increase in nominal dollars over a 15 year period (i.e. ending in 2030). Comparing the stream of fixed O&M costs input into the Strategist model with fixed O&M costs apparently input into the Aurora model,[26] I note that the Strategist model assumes an additional $34 million each year (flat in nominal terms) from 2016 to 2030.

This discrepancy is somewhat corroborated by the Company's response to KIUC DR 2-2f with the statement that "a component of the fixed o&m [sic] is ongoing capital costs which are recovered through an annual carrying charge." While I believe that there is likely an additional capital cost "that is recovered through an annual carrying charge" for 15 years, I find it difficult to believe that this increase represents "ongoing capital costs" (emp. added) as those would likely carry through the full analysis period (presuming that the FGD remains in operation).[27]

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[26] From file Sierra DR 2-34a "sc_KPCo 2011 3 Plans Unit Data_10_10_11_confidential.xls"

[27] Company response to KIUC DR 2-2f indicates that one should "see the accompanying CD to the response to KIUC 2.2(a) for all assumptions and source documents." While the attached files are large, they does not present the breakdown of either variable or fixed O&M costs pertinent to KIUC's request, or the reasoning behind the changes in the fixed O&M values over time.

7. STRATEGIST CONCERNS: INSUFFICIENT FUEL PRICE SENSITIVITIES

Q Did the Company examine any risk sensitivities in the Strategist model?

A Ostensibly, yes, but the sensitivities used by the Company are not able to adequately explore a reasonable range of future price risks. The Company runs their model through four sensitivities, described very briefly below:

- A "higher" band of prices in which fuel costs (both gas and coal) are increased by 16-20% and CO_2 prices are effectively unaltered;[28]
- A "lower" band of prices in which fuel costs (both gas and coal) are decreased by 11-12% and CO_2 prices are effectively unaltered;
- An "early carbon" scenario in which carbon prices start in 2017 instead of 2022 but are only about 80¢ higher (real 2011$);
- A "no carbon" scenario in which there is no carbon price and fuel prices are effectively unchanged (gas prices are reduced by 6%).

Q What is problematic about these sensitivities?

A While I appreciate that the Company is attempting to examine both the impact of changing fuel prices and uncertainty in CO_2 prices, these alternative futures are insufficient sensitivities, particularly in stress-testing the effectiveness of continuing to operate a coal-fired power plant versus replacement with a natural gas portfolio. Useful sensitivities push to reasonably likely futures that are substantively different from each other. In this case, however, I would not expect any of the sensitivities evaluated by the Company to result in dramatically different results.

For example, for both the "high band" and "low band" options, coal and natural gas prices move in the same direction almost perfectly – meaning that we would generally expect the results of these analyses to show about the same level of

[28] CO2 prices are increased by 30¢ (in real 2010$)

differentiation from each other. In particular, when the all-in variable cost of a new natural gas fired CC is quite close to the all-in variable cost of the coal retrofit, as is the case here,[29] changes in the cost of coal and the cost of natural gas will not really differentiate the costs of the Options – if it is assumed that coal and natural gas prices will both move about the same amount in the same direction.

The "no carbon" scenario simply bolsters the Company's standing position. The "early carbon" scenario does impose new costs between 2017 and 2022 for five years of additional carbon pricing; but at the low prices assumed by the Company, these five years result in fairly small differentiations for such a significant policy.[30]

Q Has the Company explored more functionally useful sensitivities in Strategist?

A No, they have not. KIUC asked the Company in DR 2-3 if the Company had run a scenario in which lower prices for gas were run against higher prices for coal; the Company responded that it had not.

Q Why did the Company choose not to run low gas / high coal?

A The response to discovery, written by Mr. Karl Bletzacker, states that "the Company determined it was unnecessary to do so because coal and natural gas prices have historically been correlated, that is, coal and natural gas prices rise and fall in unison…" This statement appears to contradict the testimony of Mr. Scott Weaver, who shows explicitly in his Aurora "Assumed Variable Correlations" table (Exhibit SCW-1, Table 1-4) that prices for natural gas and

[29] In the base case, differentiated by about \$5-\$7/MWh in 2010\$

[30] For the first years of this analysis prior to the start of carbon pricing in 2022 (i.e. 2011-2021) the difference in CPW of Option 1 is about \$300 million between the early carbon and base commodity price scenarios. Conversely, the difference in CPW of Option 2 is about \$240 million over that same time period (between the early carbon and base scenarios). Pushing up the Company's carbon price by five years only results in a \$60 million dollar shift between Options.

coal are <u>not</u> correlated.[31] I agree that the price of natural gas and coal have not been correlated (in real dollar terms).

Q What is your recommendation?

A In evaluating this CPCN, running scenarios in which the price of fuels are not correlated would be an important and illuminating mechanism of evaluating the risk of either a retrofit or retire decision.

8. REASONABLENESS OF CO_2 PRICE AND RISK

Q Did the Company consider the potential for costs associated with carbon dioxide emissions?

A To a limited extent, yes. In the base case, and in four of five "pricing scenarios," the Company utilized a price for carbon dioxide (CO_2) emissions.

Q Why, then, are you concerned about the Company adequately accounting for potential carbon legislation?

A The price employed by the Company for CO_2 emissions does not represent any form of an effective or likely carbon policy but rather a token price that is never increased.

Q What do you mean by a "token price" for CO_2?

A I define a token price as a cost for no other purpose than simply imposing a cost – a price that neither changes dispatch decisions or build decisions – i.e. has no impact at either operational or build margins.

Q What has the Company used as a CO_2 price in this proceeding?

A In the base case, the Company's CO_2 "Base" price starts at about $15 per metric tonne and escalates about 1.3%, or slower than inflation. In real 2010$ per short

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[31] The non-relationship between historic movements of the price of natural gas and the price of coal is consistent between Mr. Weavers' table, US historic records and the UK futures examined by Mr. Weaver.

ton,[32] this price starts at \$10.82 and holds essentially flat. The "early carbon case" starts five years earlier and is about 80¢ cents higher than the base case in real 2010\$.

Exhibit SCW-2 shows a slightly higher value of CO_2 for the "high band" and "low band" sensitivities; a price difference that amounts to about 30¢ higher than the base case in both sensitivities. However, this is inconsistent with the data from the Strategist model. An examination of the data underlying SCW-4A[33]indicates that the CO_2 price in the higher and lower bands are identical to the base case.

Q How does this compare to other CO_2 price forecasts used by other utilities?

A Of the numerous recent CO_2 price forecasts that I have reviewed, this is the lowest I have seen used for "reference case" purposes.[34]

Synapse has collected 22 different utility IRP and utility docket documents from a very diverse set of utilities operating all over the U.S.[35] These IRPs, all published in 2010 or 2011, all provide estimates for CO_2 prices at some time within the 2012-2040 planning horizon used by AEP. With the exception of two IRPs and case documents that did not use a CO_2 price at all,[36] all of the reference CO_2 price forecasts used by other utilities are higher than that of the Company. Indeed, there are no other utility forecasts that fall in real terms.

Most other CO_2 price trajectories that I have reviewed assume a particular purpose – i.e. the mitigation of greenhouse gas emissions to prevent or slow the

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[32] About 1.1 short tons per metric tons; derived cumulative inflation rate from natural gas prices in nominal and real dollars as presented in Sierra DR 1-69 "Ex. SCW-2 (L-T Commodity Price Fcst).xls" to convert to real 2010\$.

[33] See Staff 1-48 "Staff_1-48_(Ex SCW-4B-High Pr Eval Detail).xls", "Staff_1-48_(Ex SCW-4C-Low Pr Eval Detail).xls", and files associated with the "detailed back up files for SCW-4", including e.g. FT-"Higher Band 2-Pgrs\Levelized Retrofit Under FT_CSAPR_HIGH_BAND.xls"

[34] With the exception of the zero price assumed by another Kentucky utility in Cases No. 2011-00161 & 00162.

[35] See Exhibit JIF-5E for references

[36] Platte River Power Authority (Colorado, 2012) calculated a carbon mitigation curve (i.e. prices at which carbon reductions could be obtained by changing or building different resources), but did not provide an explicit price forecast. KU/LGE in KPSC Case No. 2011-00140 (2011) did not utilize a CO_2 price forecast.

pace of climate change. The basis of such prices is the concept that in order to eventually reach lower levels of CO_2 emissions, the effective price on CO_2 would have to rise over time, obtaining cumulative reductions in emissions by providing an incentive to mitigate at the lowest cost – essentially slowly moving up the supply curve of emissions reductions potential.

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

Q Has the Company reviewed other CO_2 price forecasts?

A Sierra DR 1-45 states that the "carbon dioxide price (CO2)… reflect[s] a national carbon tax and an industry consensus view." The response then lists a wide variety of stakeholders that shape the Company's view of the long-term forecast.

Q How does the Company's forecast hold up against the views of other "stakeholders" as listed in the discovery response?

A Many of the stakeholders listed therein do not actually provide forecasts (such as the trade press Coal Daily or Coal Weekly, or even some of the key organizations listed (such as NERC and FERC). Of those that I am aware of that do produce CO_2 price forecasts, their CO_2 trajectories are universally higher than those used by the Company here. For example:

- **Industry Groups** – Edison Electric Institute: EEI produced an assessment of recently promulgated and proposed environmental regulations (January 2011)[37] and included two CO2 prices, both of which are significantly above the Company forecast (see **Exhibit JIF-7A**).

[37] Provided in response to AG discovery request 1-14 as Attachment 16. CO_2 assumptions on page 50.

- **Government Agencies** – EPA and the US DOE Energy Information Administration have both produced estimates of the carbon price that would be realized from proposed federal legislation. These are all significantly above the Company forecast prices (see **Exhibit JIF-7A**). To my knowledge, NERC and FERC do not produce CO_2 price forecasts.[38]

- **Energy Companies** – Reference case CO_2 prices from 20 electric utilities, including Duke (SC-2011), TVA (TN/KY-2011), Ameren (MO-2011), Southern Company (GA-2011)[39], and Sunflower (KS-2010) amongst others are charted in **Exhibit JIF-7B**. Each and every trajectory charted here is higher to significantly higher than the AEP/KPCo forecast.

- **Third Party Consultants** – There are numerous third party consultants who have produced forecasts for CO_2 prices. Synapse Energy Economics, my firm, produced a CO_2 price forecast in early 2011. I have produced these forecasts in **Exhibit JIF-7C** also showing the range (in the lighter bar) of reference forecasts used by other utilities. I have attached the paper supporting the Synapse CO_2 price forecasts in Exhibit **JIF-8**.

Q Why are there two different AEP trajectories plotted in Exhibit JIF-7C?

A The Company provided, in Sierra DR 1-69 a file that appears to have commodity price assumptions from August of 2011,[40] including a CO_2 price forecast. [redacted].

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[38] NERC specifically does not review the impact of CO2 regulations in its late 2010 reliability assessment (available as response to AG discovery request 1-14 in Attachment 9)

[39] The starting point for the Georgia reference case is public, but the trajectory is confidential.

[40] In August 2011 the Company was still announcing that the Big Sandy 2 unit would be retired.

Q Can you describe how the Company's CO_2 assumed reference and range of CO_2 prices compare to those of other electric utilities in the US?

A I have charted the low, high, and (if multiple forecasts were given) average levelized cost of CO_2 (2015-2030) from 16 utilities, Edison Electric Institute (EEI), the Eastern Interconnect Planning Collaborative (EIPC) and forecast prices from my firm Synapse, in the figure below (also attached as Exhibit **JIF-7D**).[41] The reference case in this CPCN (the last column) is the lowest non-zero price given and, aside from those utilities that only give a single value, just about the narrowest range of prices as well. The AEP (8/2011) price that is second to last represents the cost assumed by the utility in the preliminary analysis of Big Sandy 2 in August of 2011.

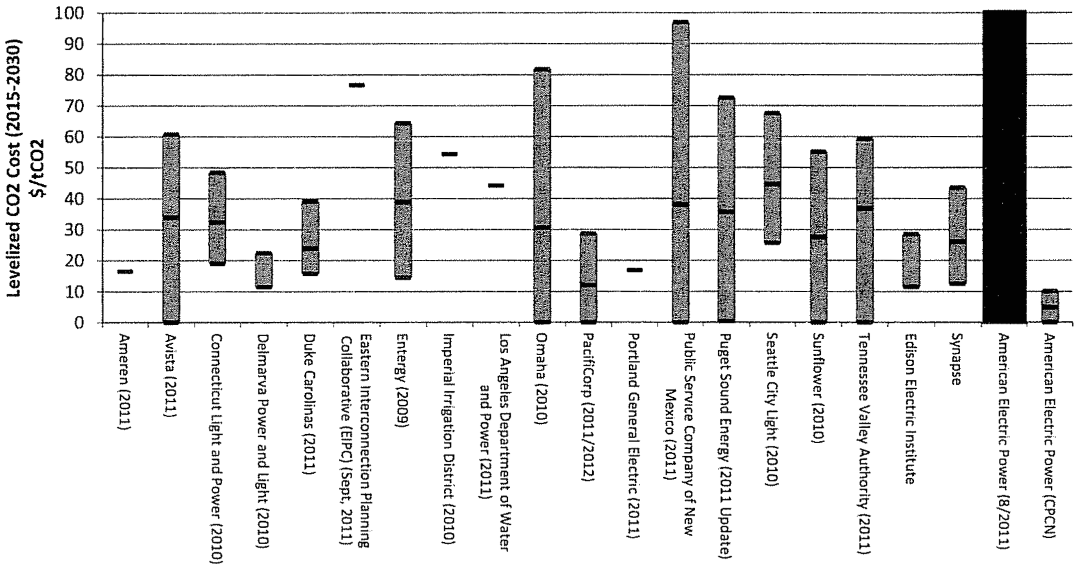

Figure 4. Low, high and average CO_2 prices given by different utilities in IRP & CPCN from 2010-2011. The AEP forecast for this CPCN is the final bar on this chart.

Q Have you evaluated how a more reasonable CO_2 price could impact the Company's decision to retrofit versus retire the Big Sandy unit?

Yes. Ms. Wilson conducted a re-analysis of the Company's Strategist base commodity price run, substituting the lowest CO_2 price forecast from my firm,

[41] Range given when a utility has produced or used more than one forecast. The average is given only if a utility has produced or used three or more forecasts.

Synapse (see **Exhibit JIF-7C and JIF-8)**. The Synapse forecast was produced in February of 2011, and represents the marked uncertainty in how and when greenhouse gas prices might apply.[42] The forecast is a public document explaining background, state and regional initiatives, analytical estimates, and the recommended Synapse 2011 CO_2 price forecast for planning purposes.

For the purposes of this case, Ms. Wilson tested three of the Options (retrofit [1], NGCC replacement [2], and market purchases to 2020 [4a]) using the Synapse Low CO_2 Price Forecast. This CO_2 price starts at $15/ton (2010$/short ton) in 2020 and climbs to $45/ton by the end of the 2040 analysis period.

The Synapse Low forecast does <u>not</u> represent the Mid, or expected case, according to the Synapse paper. Rather, it represents what the organization considers the lowest reasonable bound for a CO_2 price forecast (both low in price and late in start).

The Synapse Low case is, for example, consistent with forecasts from Ameren (MO) in 2011 and Duke (SC) in 2011, but is below TVA's estimates, and well below estimates from Nebraska, Kansas, Delaware, Idaho, and Oregon.

Q Does using a reasonable Low CO_2 price forecast substantively change the outcome of this analysis?

A Yes, it does. Simply shifting the CO_2 price forecast to a low-range forecast consistent with the low end of forecasts from other utilities and organizations renders the retrofit of the Big Sandy 2 unit essentially a wash with the NGCC replacement in 2016 (Option 2) and far less economic than market purchases to 2020 (Option 4A).[43] **Table 4**, below **(Exhibit JIF-3D)**, shows the difference between the Company's base case run and a modified CO_2 price run with other Company assumptions intact.

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[42] Early prices might be realized by rapid action starting after the next session of Congress, or if the EPA acts to regulate CO_2 emissions independently of legislative action. Late prices (2020) might represent an additional presidential term without either administrative or legislative action.

[43] We did not test, but assume that market purchases to 2025 (Option 4B) would continue to fare well in this analysis, and that Option 3 (repowering Big Sandy 1) would probably fare on par with Option 2.

Table 4. Cumulative present worth of revenue requirements (M 2011$): Reanalysis with Synapse Low CO_2 price

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

The results above assume that we accept the Company's erroneous carrying charges. If we also correct the carrying charges error in addition to the CO_2 price, as in **Table 5** below (**Exhibit JIF-3E**), both Option 2 and Option 4A fare significantly better than the retrofit.

Table 5. Cumulative Present Worth (CPW) under Company CO_2 assumptions and Synapse Low CO_2 price, capital cost corrected.

Cumulative Present Worth of Revenue Requirements (M 2011$) Re-Analysis with Synapse Low CO2 & Corrected Capital Costs	Option #1 Retrofit Big Sandy 2 w/ FGD	Option #2 NGCC Replacement	Option #4A Market to 2020; NGCC in 2020
Company Assumptions			
CPW	6,839	7,075	6,918
Net benefit of retrofit (CPW)		236	78
Synapse Low CO2 Price & Corrected Cap Costs			
CPW	7,725	7,269	7,127
Net benefit of retrofit (CPW)		(456)	(597)

If we adjust the off-system sales revenue to reflect 40% sharing with shareholders as currently allocated from KPCo, the answers adjust again and even further favors either Option 4A or Option 2, as shown in

Table 6 **(Exhibit JIF-3F)**, below.

Table 6. Cumulative Present Worth (CPW) under Company CO_2 assumptions and Synapse Low CO_2 price, capital cost corrected and adjusted for off-system sales sharing.

Cumulative Present Worth of Revenue Requirements (M 2011$) Re-Analysis with Synapse Low CO2, Corrected Cap Costs & Adj. Off-System Sales	Option #1 Retrofit Big Sandy 2 w/ FGD	Option #2 NGCC Replacement	Option #4A Market to 2020; NGCC in 2020
Company Assumptions			
CPW	6,839	7,075	6,918
Net benefit of retrofit (CPW)		236	78
Synapse Low CO2 Price, Corrected Capital Costs & Off System Sales			
CPW	8,063	7,445	7,367
Net benefit of retrofit (CPW)		(618)	(695)

Q What CO_2 price trajectory do you recommend?

A In large decisions where long-term CO_2 emissions are a tangible risk, it is incumbent on the Company to test a wide and reasonable range of CO_2 prices designed to bound the feasible risk faced by their ratepayers. As a reasonable starting point, I would recommend using the range provided in the Synapse 2011 CO_2 price forecast, using something akin to the Synapse Mid case as a reasonable reference. This price starts at \$15/tCO_2 in 2018 and rises (in real 2010\$) linearly to \$80 in 2041, and holds at that price indefinitely.[44] The "low" bound starts at \$15/tCO_2 in 2020 and rises at a slower pace, reaching \$60 in 2050, while the "high" bound also starts at \$15 but at 2015 and reaches the \$80 saturation point in 2030. It may be reasonable to explore a complete absence of CO_2 price as one possible scenario (representing an inability to muster the political will to mitigate climate change), but I think this outcome over the next three decades is extremely unlikely.

Recalling that we have only tested the very lowest bounds of CO_2 prices in this re-analysis, I would expect that any higher prices would result in an even further economic advantage for Options 2 and 4A over the Big Sandy 2 retrofit.

[44] Synapse has assumed that \$80 represents a broad-scale abatement price at which emerging technologies (such as carbon capture and sequestration) might become cost effective, thus potentially saturating the market.

9. AURORA CONCERNS: OVERVIEW

Q How did the Company use Aurora^{xmp} in this proceeding?

A In this proceeding, the Company has used Aurora to evaluate how uncertainty in several key variables, such as fuel and emissions prices, as well as demand and electricity market prices, might influence the relative risk of four options – retrofitting Big Sandy, replacing or repowering the unit in 2015 (Options 2 & 3, respectively) or replacing the unit in 2025 (Option 4b). The Company did not use Aurora to evaluate Option 4a, purchasing market power through 2020.

Because the Company used the model to drive a stochastic analysis, Aurora potentially offered the Company the opportunity to evaluate a range of uncertain futures simultaneously – in essence replacing the function of running Strategist through multiple pricing, or commodity, scenarios.

Q What results did the Company draw from the Aurora analysis in this proceeding?

A This is unclear. On pages 46-48 of his testimony, Mr. Weaver discusses <u>only</u> the metric of Revenue Requirement at Risk (RRaR), which is effectively the width of the uncertainty band around the middle, or median, answer. Mr. Weaver does not suggest in his written testimony that the differences between the median costs projected by the Aurora model should be used to evaluate the relative cost effectiveness of each option. In Sierra DR 1-68, Mr. Weaver appears to further re-enforce the statement that Aurora model is not designed to measure the relative economic merit of the options, but "is used to measure the relative risk inherent in a resource portfolio," by which I understand him to mean that it should be used to measure the relative risk inherent in any given resource portfolio, rather than the relative economic viability of the different scenarios. The relative economic viability measures an expected outcome, while the "risk inherent" measures the uncertainty associated with any given scenario.

Q Mr. Weaver cites Exhibit SCW-5 as an "optical and tabular summary of those results." What is your impression of this Exhibit?

A I read Figures 5-1 and 5-2 in SCW-5 very differently than described by Weaver in his written testimony. The first and most obvious point that stands out from this graphic is that the median of Option 1 appears to be much lower in "Cumulative Present Worth" than the other three Options modeled here. Indeed, the exhibit then shows, in tabular form, the "delta" (or difference) in alternative Option costs relative to Option 1, and suggests a consistently large benefit in pursuing the retrofit.

Q What do you recommend in regards to Mr. Weaver's Exhibit 5?

A Whether in error or purposefully, the Company misrepresents the point and potential value of the Aurora analysis, which is to estimate the uncertainty associated with the economic outcome of their various options, rather than the absolute outcome.

I recommend that, if the Company chooses to pursue the use of the Aurora model for uncertainty analysis, that the Company withdraw Exhibit 5 and replace it with an exhibit (graphical, tabular or both) that correctly represents the uncertainty bounds and RRaR, rather than absolute outcomes as shown here.

However, there are sufficient concerns with how the Aurora model has been used in this proceeding to warrant disregarding the Aurora analysis in its entirety.

Q Do you have a fundamental objection to the use of this type of model for planning purposes?

A No, I do not. Conceptually, there is value in being able to evaluate a wide range of uncertainties simultaneously. In particular, this type of evaluation could, and should, be used to determine just how much any Option differs from another – i.e. if a separation of millions of dollars in cumulative present worth (CPW) is significant or insignificant.

Generally speaking, I applaud the use of multiple models to converge on a robust answer, particularly in the face of uncertainty, and I would encourage the

Company to continue developing the use of other models to support decision-making.

However, I have significant concerns with the Company's choice to reject results from the Strategist model by citing the Aurora model, in this case, both based on the interpretation of results and fundamental problems within the Aurora analysis itself.

Q Where does the Company reject Strategist results on the basis of the Aurora model?

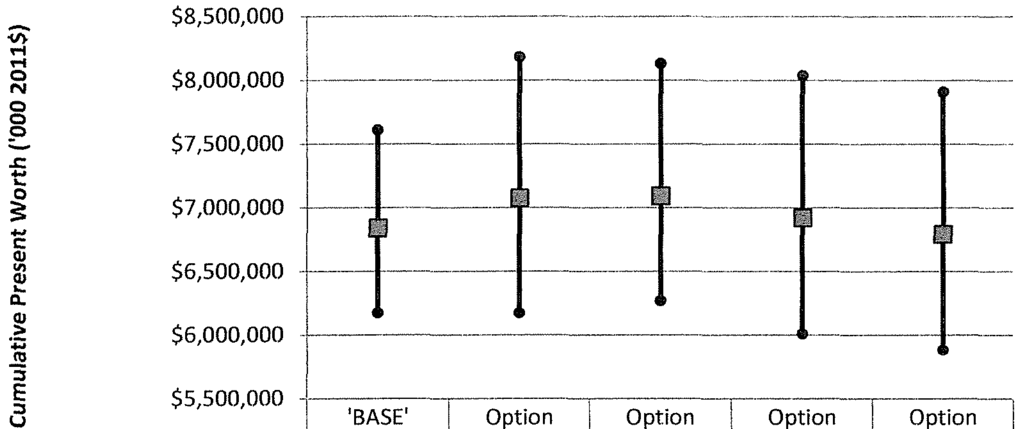
A In Mr. Weaver's testimony (p 47 at 15- p 48 at 2), he specifically states that "although the 'discrete' risk modeling results – shown on Exhibit SCW-4 – from the Strategist-based modeling point to this Option #4B as being a near 'wash' with a Big Sandy 2 DFGD retrofit solution, this additional Monte Carlo risk modeling indicates KPCo's customers would be potentially exposed to *significantly* greater cost-of-service/revenue requirement uncertainty in the future under that 'market' alternative." (emphasis in original)

If we take the Company's interpretation of the Aurora outcomes at face value, these model results would suggest that all other alternatives, market-based or no, should probably be rejected on the basis of its attendant risk (which is essentially identical for Options 2, 3, and 4b).

What Mr. Weaver does not state here is that while the Aurora model appears to show an apparent downside risk to natural gas purchases (market or steel-in-the-ground), the same results also show a large upside benefit as well– i.e. the model results would indicate that consumers have nearly as high a probability of coming out far better than far worse with a market replacement.

Indeed, simply drawing from the Company's data *with no alterations* to either Strategist or Aurora, we can re-cast the Strategist and Aurora results as the Company claims it intended. In **Figure 5** below (**Exhibit JIF-9**), I show the

"Base" scenario outcomes from the Strategist model,[45] plus error bars representing the Aurora uncertainty ranges at the 5th and 95th percentile.[46]



	'BASE' Option #1	Option #2	Option #3	Option #4A	Option #4B
95th % Aurora Risk	7,609,980	8,182,166	8,130,133	8,034,108	7,907,927
Strategist ("Base") Outcome	6,838,879	7,075,297	7,091,182	6,917,767	6,791,587
5th % Aurora Risk	6,171,648	6,172,690	6,268,489	6,008,162	5,881,981

Figure 5. Company results (unaltered) of cumulative present worth (CPW) of Options #1-#4B. Center points represent Strategist outcome in "Base" commodity scenario. Upper and lower bounds represent <u>range</u> of 95th and 5th percentile outcome from Aurora results. Assumes 4A has same risk profile as 4B.

What becomes immediately apparent in this graphic is that the error bounds (as used by the Company, and under Aurora assumptions used by the Company) swamp the differences between the scenarios as shown in Strategist models.

Q Do you have a concern with the Aurora model as used here, specifically?

A Yes, I do. I have five fundamental objections to Aurora model as presented in this hearing.

First, the results of the Aurora model differ dramatically from the results generated out of the Strategist model, and the differences cannot be reasonably attributed to differences identified by the Company in discovery responses.

[45] Directly from Exhibit SCW-4A

[46] Calculated from Sierra DR 2-35c-d (data behind graphs in SCW-5)

Second, the Aurora model as utilized and presented in both testimony and discovery responses is opaque and generally non-auditable.

Third, the correlations between variables that the Company claims were used in the Monte Carlo analysis are derived from inadequate data, contain fundamental errors, are not represented in the model, and have inappropriately introduced bias into the analysis.

Fourth, it is unclear how these correlations were actually used in the Monte Carlo analysis. Conceptually, these correlations should play an important role in how different variables "move" in relation to one another. However, in the files supplied, we are unable to find any mechanism that successfully replicates the stated correlations.

Fifth, the Company has not presented the Aurora model used thusly to this Commission in previous proceedings for independent evaluation, and has supplied inadequate information to allow this Commission to evaluate if the model has been utilized correctly in this proceeding.

Overall, it is my contention that the Aurora model is so poorly supported, so erroneous, and so fundamentally disparate from the more transparent Strategist model runs that <u>the Aurora model runs used for this proceeding should be disregarded in their entirety</u>.

I will discuss each of the above concerns individually.

10. <u>AURORA CONCERNS: CONTRASTING AURORA AND STRATEGIST OUTCOMES</u>

Q You have stated as your first objection that the results of the Aurora model differ from the Strategist model. Why is this important?

A As I state above, even though the Company discusses Aurora only in the context of revenue requirement at risk (RRaR), Exhibit SCW-5 shows the absolute outcomes of the Aurora model on a relative scale, leading to the very likely interpretation that the Aurora model independently estimates the complete CPW of each scenario in a comparable fashion to Strategist. This misinterpretation is compounded by a label in Exhibit SCW-5 that marks the values as CPW of " 'G' costs", or the total incremental revenue requirement of the scenario as used elsewhere in Mr. Weaver's testimony (i.e. p18 at 6 and p35 at 6).

Q What is so different about the results of the Strategist and Aurora models?

A Simply stated, the Aurora model estimates that the (median) net benefit of retrofitting the Big Sandy 2 is anywhere from $350 to $609 million *more* than the Strategist model's output – or anywhere from double the benefit to well over ten times the benefit; results that simply don't hold water – particularly as they are examined more closely.

The vast differences between the Aurora and Strategist runs are illustrated in the **Table 7 (Exhibit JIF-10A)** below. The differences, in millions 2011$ CPW are directly extracted from exhibits of Mr. Weaver.

Table 7. Differences in relative net benefit of retrofit versus other alternatives.

Net benefit of Big Sandy retrofit versus:	**Option 2:** Replace with NGCC	**Option 3:** Repowered BS1	**Option 4a:** Market until 2020 NGCC	**Option 4b:** Market until 2025 NGCC
Strategist Ex. SCW-4	$236 M	$252 M	$79 M	$(-47) M
Aurora Ex. SCW-5 (p1)	$586 M	$527 M	Not modeled	$562 M
Relative advantage conferred by Aurora	$350 M	$275	-	$609 M
% Difference	248%	209%	-	1,195%

For each of four options (1, 2, 3, and 4b), the Aurora model is run 100 times and subsequently returns 100 different results. However, because the baseline (median, in this case) input variables that go into the Aurora model are identical to the commodity prices in the Strategist "Base" case, we would reasonably expect that the median output from the Aurora model would replicate closely, if not exactly, the Strategist output. This is clearly not the case.

Q Does the Company have an explanation as to why these results are so different?

Mr. Weaver appears to concur that the differences are confounding. In Sierra DR 1-5f, he states that "the results vary … because the models are unique and thus have different internal dispatching logic that can result in absolute answers that are different" but that "given enough iterations of Aurora, one might reasonably expect that the median values of the Aurora approximately equal the Strategist solution, save for the inherent (and proprietary) differences in the model's internal logic."

Mr. Weaver poses two hypotheses in his explanation –

- **first**, that it is feasible that the Company did not run Aurora enough times to converge on a robust solution, and
- **second**, that the models would have resulted in disparate results because of logical differences in dispatch.

The first hypothesis can be rejected quickly. If the Company were truly uncomfortable with its modeling for a nearly one billion dollar retrofit project, I expect that they would have run the model through more iterations. However, for showing the differences between the model runs, the Company reports median (middle) values, which, from a statistical standpoint are fairly robust, so I do not expect that additional model runs would have resulted in substantively different results.[47]

The second hypothesis implies that dispatch logic alone is sufficient to explain these dramatic differences. I agree that dispatch dynamics are probably one element that is significantly different between these two models – but this alone does not explain the difference. In fact, comparing these two models (or at least

[47] One way of showing the robustness of the median here is by examining how tightly bound the value is within the range of potential answers. The median represents the 50th percentile answer – moving to the 40th percentile answer instead, the difference between it and the median is always less than 3% of the total span of answers. Even if the Company ran another 20 runs and each one came out lower than the 40th percentile answer, the new median would only shift to the 40th percentile – or by 3%.

the information supplied by the Company and used for their cost comparisons) suggests apples and oranges comparisons with respect to just about every material factor – and overwhelmingly large differences in how the models treat market purchases and sales, and capital expenses.

Q Why do you think that the models do not simply differ in dispatch dynamics, and why would you want to compare more than just CPW?

A While differences in the CPW are useful for final decision-making, how costs are assumed to expend over time is illustrative and critical for understanding the basis of the decision. In Sierra DR 2-35a-b, the Company finally supplied the detailed outputs from the Aurora results (the "Aurora workbooks").[48] These spreadsheets are comprised of matrices dimensioned by year and Aurora iterations. We can trace the final value used by the Company in Ex. SCW-5 back to component parts, and in turn, trace those component parts over time.

The Company also supplied what I will call the "Strategist compilation analysis," which appears to take cost component outputs from the Strategist model, as well as other data sources, and creates a stream of expected costs over time, the CPW of which were used for Ex. SCW-4. The worksheets for the Strategist Compilation Analysis were supplied in Staff DR 1-48, and formula-enabled versions with key underlying worksheets were supplied as a supplemental to Sierra DR 1-69 on February 22, 2012.

I compared the cost categories supplied in the Company's Aurora workbooks against the cost categories in the Company's Strategist compilation model.[49] The cost categories summed in each model are listed in the **Table 8 (Exhibit JIF-10B)** below.

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[48] Workbooks are IRP_XMP_DGTool_KPCO_BS_Retirement.xls, IRP_XMP_DGTool_KPCO_BS1_Repower.xls, IRP_XMP_DGTool_KPCO_BS2_Retrofit.xls, and IRP_XMP_DGTool_KPCO_NGCC_Replacement.xls

[49] The output of Strategist runs are apparently put through a compilation model, the bulk majority of which appears to have been delivered as a supplemental to Sierra DR 1-69 in response to a Motion to Compel. Formula-disabled versions of these worksheets were delivered to Staff in response to Staff DR 1-48.

Table 8. Cost Category names in Strategist and Aurora

Cost Categories	Strategist Compilation Analysis Name	Aurora Spreadsheets Name
Fuel Costs	Fuel Cost	Fuel Costs
Contract Purchases & Sales	Contract Revenue	Contract Revenue
Market Purchases & Sales	Market Revenue / (Cost)	Net Cost of Imports
Capital Expenditures	Carrying Charges	*Not in Aurora Analysis*
Variable O&M	Incremental O&M [and Base O&M]	Variable O&M
Fixed O&M		Fixed O&M
Emissions Allowances	Market Value of Allowances Consumed	Emissions Cost
Capacity Cost	Value of ICAP	ICAP

With one exception, that of capital expenditures, the category titles can generally be matched between the two analyses. As far as I am aware, capital expenditures, including the costs of the FGD or any replacement capacity, are completely absent from these analytical results. Unless these costs have been inexplicably pushed into the "Net Cost of Imports," it is entirely unclear if the Aurora analysis takes capital expenditures into account at all in the final results.

The similarities generally end with the name of the cost category. **Figure 6 (Exhibit JIF-11A)** below, shows the CPW (in '000 of 2011$) of Options 1, 2, and 4b, broken down by cost category for both the Strategist (base case) and Aurora models (median solution). As will be detailed below, to the extent that these two models appear to result in *total* CPW that are even within range of each other may be no more than coincidence; the degree to which any differences between options can be examined at face value is suspect.

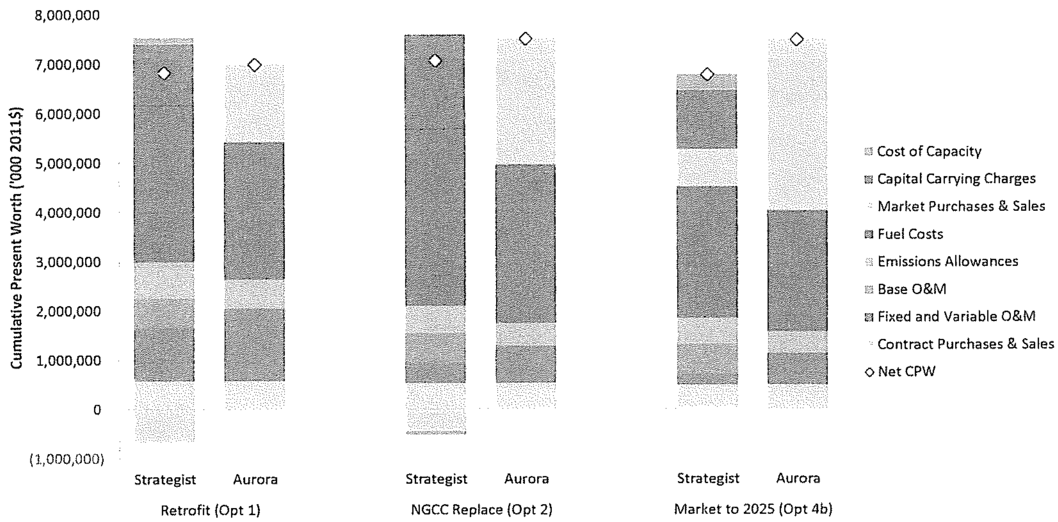

Figure 6. Comparison of CPW cost components between Strategist and Aurora models.

Each pair of columns represents the total CPW of an Option as portrayed by either Strategist or Aurora. Working from the bottom up:

- <u>Contract Revenues</u> (or in this case, costs in each model) are fixed in the Aurora model based on Strategist, so there is no discrepancy between these values.
- <u>O&M</u> values are moderately comparable, if Base O&M costs[50] are included, yet are still consistently 14-35% higher in the Strategist analysis across all options.
- The cost of <u>pollution allowances</u> are consistently 20-25% higher in the Strategist runs, representing both higher costs for near-term allowances (SO_2 and NOx) and long-term allowances (CO_2).
- <u>Total fuel costs</u>, the variable that I would expect to be most influenced by "different internal dispatching logic" is consistently higher by 9-14% in the Strategist model.

[50] Base O&M costs appear to be O&M associated with "another case with only those additions already present in 2011" (*see* response to Staff DR 2-2f) and are subtracted from all Options in the Strategist runs. The stream of Base O&M costs can be found in the supplemental response to Sierra DR 1-69 in any spreadsheet on the "O&M" tab W34:W63.

- Capital carrying charges do not appear to be represented in the Aurora model at all, meaning that important differences between the avoidable costs of construction (i.e. the FGD or replacement NGCC) and the uncertainty of those costs are not considered at all in this analysis.

- Market purchases are completely different between these two models, with Strategist predicting net market sales in Options 1-3, and Aurora predicting massive net market purchases in all cases. Figure 7 below (**Exhibit JIF-11B**) illustrates the massive discrepancies between market purchases in the Aurora and Strategist model, amounting to, for example a difference of over three billion dollars in Option 2 (NGCC replacement in 2015).

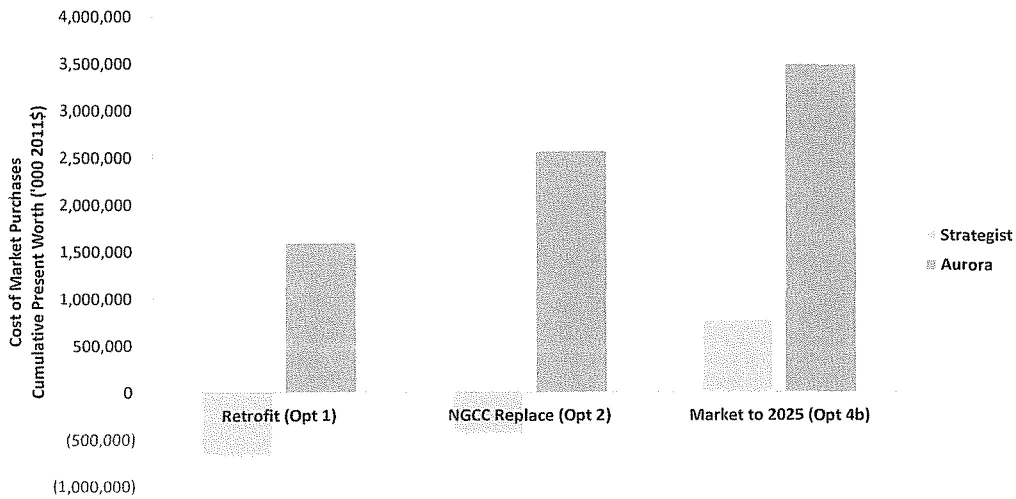

Figure 7. Contrasting market purchases between the Aurora and Strategist models in three scenarios.

- Capacity purchases, while a smaller component of the overall CPW, appear to have a similar, but inverted, relationship between the two models. Strategist often predicts net capacity purchases and Aurora predicting net capacity sales.

It is important to note that the Company is evaluating which option to pursue on the basis of the *difference* between net CPW costs in each model. These CPW differences are on the order of tens of millions to a maximum of about $500 million in the Strategist model (*see* Ex. SCW-4) – yet the differences between <u>components of the Strategist and Aurora models differ by up to three billion dollars CPW, in evaluating the same Option.</u>

I am unable to find a reasonable mechanism to rectify these disparate results.

Q Why are capital carrying charges not included in the Aurora analysis?

A It is not clear to me why capital charges are not included. A stochastic analysis like Aurora could be well suited to examine uncertainty in build costs as part of the total financial risk package.

The lack of capital carrying charges in this model is inconsistent with Mr. Weaver's Exhibit SCW-1 (p10) that states "the input variables…considered by Aurora XMP® within this analysis were [amongst other variables] construction costs (annual carrying costs) ($/kW-year)." This lack is also in stark contrast to the response of Mr. Weaver to Sierra DR 2-6a that states that amongst "the variables [that were] allowed to vary stochastically in the Monte Carlo analysis… [are] Construction Costs [as] implemented in the FOM variable." The fixed O&M (FOM) variable in Aurora appears to only represent FOM costs as implemented in Strategist – not the major capital expenditures (i.e. the FGD or new/repowered NGCC units). In addition, this variable is held almost perfectly constant. In the retrofit Aurora run (Option 1), the CPW of FOM costs displays less than a 0.1% variance – effectively held completely constant. Indeed, the only variance in the FOM variable occurs after 2025, possibly representing some level of uncertainty in the FOM of the small additional NGCC added in out-years.

11. Aurora Concerns: Lack of Transparency

Q You have stated as your second objection that the Aurora model as used in this proceeding is generally opaque and non-auditable. Please support that contention.

A Sierra Club repeatedly requested the input and output files from the Aurora model[51] to be able to better understand how the Company was using this platform, and if the inputs and process were consistent with other Company assumptions. From the first request (Sierra DR 1-69), we received only a list of 100 CPW values – with no component costs, no formulae, and no basis. From the second request (Sierra DR 2-35a-b) and a separate Motion to Compel, we received a series of worksheets that break down the 100 CPW values into their component costs over time – but these worksheets arrived without formulae and the supporting workbooks are simply pasted values from another source. It appears that formulae were purposefully disabled in this worksheet.

I have been able to reconstruct some components of the Aurora outcomes, but have no mechanism to be able to rectify those outcomes with input data, or even sufficiently trace which input data actually went into the Aurora analysis.

I contend that the Commission and interveners are unable to verify that the Company has provided a robust analysis in the Aurora model, and therefore cannot audit, much less rely upon the results of the Aurora analysis. As far as I am able to tell, the Company could have used arbitrary, or even biased, input data for this model and it would be impossible to know based on the information provided by the Company in this proceeding.

Q Are there examples of where the information provided by the Company in the Aurora analysis appears to be internally inconsistent?

A Yes, there are. One of the key components of this analysis the "risk factors," or ranges of uncertainty that six specific variables are allowed to take (*see* Exhibit

[51] Sierra DR 1-69 "provide all assumptions and workbooks, in electronic format and with all calculations operational and formulate intact, used to prepare SCW-1 through SCW-4, including output files from the Aurora model."

SCW-1, p10 at second paragraph under section A). In Sierra DR 2-34b, interveners requested "the distribution assumed for each of the six key risk factors considered." In response, the Company delivered a spreadsheet with the "risk factors" of 15 variables:

- one of which appears to represent the variance of demand,
- eight of which appear to represent coal distributions,
- two of which appear to represent natural gas price distributions
- one of which may represent market price distributions, and
- three of which are completely unlabeled ("Generic") and do not appear to correspond to any known variable – either CO_2 prices or construction cost risks.

We are unable to determine which of these variables, if any, are actually used in the Aurora model. As noted previously, the Company also supplied opaque "Aurora workbooks" that, if reconstructed, appear to be elements of the output from the Aurora model. Three worksheets in these workbooks correspond to natural gas prices (2025-2040), coal prices, and CO_2 prices. Theoretically, if the distributions provided in Sierra DR 2-34b have any relationship to the input represented in these workbooks, the pattern (if not the absolute value) of variable distributions should correspond well between these two data sources. As presented, the natural gas prices correspond perfectly, but the coal and CO_2 prices do not correspond.[52] Again, without a moderately linear analytical pathway, it is impossible to know what data was used by the Company in the Aurora analysis, and what the outputs represent.

[52] We can test the correspondence of the reported inputs in the distributions against the reported inputs in the Aurora workbooks by simply looking at how well a trendline fits the data. For the coal prices against the coal price distributions, the r^2 value is 0.46, meaning that 46% of the actual variance in coal prices can be described by the "coal price distributions". In the CO_2 tab, the r^2 value is effectively zero (0.01) meaning that the reported inputs have no relationship whatsoever to the Aurora reported model data.

12. AURORA CONCERNS: FAULTY CORRELATIONS

Q What is the purpose of the correlations as used in this proceeding?

A There are at least two ways of running a stochastic model - or a model that can handle a range of uncertainty. One way is to assume that all of the variables that are uncertain vary randomly, with no relation to one another; in that circumstance, one might have no information about how variables are related, or one might know for certain that they do not influence each other.

Another way of dealing with uncertain variables is to tie them together with correlations. In that case, one might know or have ample reason to believe that as one variable changes, another will change with it. For example, one might know that every time it gets hot, electricity consumption increases – these two variables move together. If one was going to run a model in which both future temperature and electricity consumption were uncertain, it might be beneficial to tie these two variables together such that they tend to follow one another. In this same way, the Company has introduced correlations between most of its driving variables in the Aurora analysis.

Q What is the effect of using a high correlation between two variables?

A Since variables that are highly correlated will tend to move together, variables with a high correlation may have an amplifying affect if those variables both represent a driver in the same direction. Take, for example, gas prices and power prices – if either of these variables increases, then the cost of a portfolio that includes both gas and market purchases will increase. If the variables are tied together via a correlation, then any time either one increases, the other will increase as well – and the total portfolio cost will increase. The correlation here would have an amplifying effect.

If these variables were not correlated, then the total price would be far less sensitive to fluctuations in the price of gas or market purchases. If these two variables were inversely correlated (i.e. a negative number approaching negative 1) then they'd have a dampening effect on each other – as the market price of power increases, the cost of gas decreases – and so total portfolio costs remain more stable.

Q How do you think the correlations used by the Company influenced the model outcome?

This is a difficult question because it is not apparent that the correlations presented by the Company in Exhibit SCW-1, Table 1-4 actually represent the values used in the Aurora model. I present the correlation values that it appears the Company used in the Aurora model later, in

Table 9 of my testimony.

Given the correlations, I believe were actually used in the model, I think the correlations deeply influenced the outcome, and may have unduly biased the results

As noted previously, the Company uses Aurora to look at the uncertainty bounds on total portfolio prices (via Revenue Requirement at Risk, or RRaR) using a model with explicit correlations, some of which are fairly high. In particular, it appears, based on Sierra DR 2-34b, that the Company imposed very high correlations between demand, market prices, and gas prices – but a very low correlation between demand and coal prices.

For a portfolio that is rich in gas or market purchases – such as Options 2, 3, or 4a/b – random upward shifts in demand (the "driving" variable) will tend to amplify not only the amount of power that is required, but also increase the price of that power if it is purchased from the market or a gas generator. This makes for a very expensive portfolio. Inversely, random downward shifts in demand will tend to create a very low cost for a gas or market-rich portfolio.

For a portfolio that is coal-heavy, such as Option 1, changes in demand shift market prices,[53] but do not impact coal prices at all, and thus the Option is very insensitive to changes in demand and market prices.

One would expect, looking at these correlations, that a gas or market-rich portfolio will tend to come out of the model with a very wide range of portfolio costs, while a coal-heavy portfolio will come out looking fairly stable. And in fact, that is exactly what we see in the final outcomes in Ex. SCW-5.

It is not at all surprising, based on these correlations, that the Company's examination of upside risk (RRaR at the 95th percentile) proves unfavorable for Options 2, 3, 4a or 4b. It is my belief that the RaRR found by the Company is

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[53] Increased market prices are favorable for the net off-system sales of Option 1.

largely a product of the correlations imposed by the Company, and I do not believe that those correlations are well founded, as I will describe below.

Q You have stated as your third objection a number of directed concerns with the correlations used in the Company's Aurora model. Can you briefly outline those concerns?

A I have reviewed the data that the Company used to derive the correlations in Sierra DR 1-61, and I am not satisfied that the correlations are either real or in any way accurate. The following concerns are fairly technical in their nature, but require documentation, for it is my understanding that using a different set of correlations would probably have resulted in very different Aurora results. Briefly:

- The correlations presented in Exhibit SCW-1, Table 1-4 do not represent the correlations actually used by the Aurora model.
- The Company has confounded temporal change, or change over time, with uncertainty;
- The Company has mixed correlations from historical and future data over very different time spans representing very different processes;
- The Company erroneously used a measure of amount instead of price when reviewing the historic cost of coal versus other factors;
- The data used to derive correlations in the future are non-robust, changing sign with the simple exclusion of incorrectly-used data;
- By introducing incorrect and large value correlations, the Company has inappropriately introduced bias into their analysis, a bias which favors Option 1 (the retrofit).

Q Why do you think that the correlations presented in SCW-1 Table 1-4 are not the same as actually used in the Aurora model?

A In Sierra DR 2-34b, Sierra Club requested the "distribution assumed for each of the six key risk factors considered in the Aurora model." In response, the Company provided a very long table of values that appear to contain "risk factors," which I interpret to be the expected variance on individual factors. I examined the correlation of these factors against each other[54] and arrived at a very different set of correlations than provided by Mr. Weaver in Table 1-4.

[54] Assumes that Demand represented Demand, KPCo_External_Supply represented the market price of electricity, AEP_FUEl_BIGS2 represented the variance on coal price at Big Sandy 2, AEP_FUEL_CC_KP represented the gas price variance, and that Distribution 28 represented CO_2 price variance (although the final correlation is insensitive to if Distribution 27, 28 or 29 are utilized).

Table 9 below (**Exhibit JIF-12A**) shows the correlations presented by Mr. Weaver in Table 1-4, the correlations I've derived from the data supplied by the Company in Sierra DR 2-34b, and the difference between the two sets.

Table 9. Comparison of correlations presented in testimony and derived from discovery.

Correlations provided by AEP in SCW-1, Table 1-4

	Natural Gas	Coal	Carbon	Power	Demand
Natural Gas	1.00	0.09	(0.23)	0.88	seasonal
Coal		1.00	0.69	0.19	0.74
Carbon			1.00	(0.14)	0.50
Power				1.00	0.75
Demand					1.00

Correlations derived from Sierra DR 2-34b

	Natural Gas	Coal	Carbon	Power	Demand
Natural Gas	1.00	0.09	0.45	0.88	0.66
Coal		1.00	0.05	0.10	0.08
Carbon			1.00	0.53	0.68
Power				1.00	0.76
Demand					1.00

*Assumes CO2 is Generic Distribution 28

Europe	US	Hypothesized

Difference

	Natural Gas Price	Coal Price	Carbon Price	Power Price	Demand
Natural Gas Price		0.00	(0.68)	0.00	
Coal Price			0.63	0.09	0.66
Carbon Price				(0.67)	(0.18)
Power Price					(0.01)
Demand					

Q Did the Company actually use the correlations reported in Sierra DR 2-34b or SCW-1 in the Aurora Model?

A It does not appear that they did. In response to Sierra DR 2-35a-b, the Company provided selected outputs from the Aurora model, including the CO_2, natural gas, and coal prices apparently used in each run and each year. Working from the actual values, I derived the variance of each of these commodities as used in the Model and compared the variance against the values reported in Sierra DR 2-34b.

The variance of natural gas prices matched nearly perfectly, but both coal and CO_2 were almost completely unrelated.[55]

After having tested numerous combinations and permutations of data provided by the Company, I can be fairly certain that I am reviewing the data correctly. Thus, I surmise that either the Company provided incorrect data in response to one or more requests, used inconsistent data in the model, or has misstated how (or if) the model uses the correlations provided by Mr. Weaver.

Q What do you mean that the "Company has confounded temporal change with uncertainty"?

A Simply stated, the purpose of the correlations is to examine how variables "move" relative to each other –

- high positive correlations mean that variables will move closer to in synch,
- high *negative* correlations mean that variables will move in synch in opposite directions, and
- low magnitude correlations mean that variables will move independently.

The Company has derived these correlations by looking at historic time series for some types of known variables (such as natural gas price and "demand" using U.S. generation as a proxy), and future time series for others derived from a UK futures market (ICE). The Company found correlations (or a lack thereof) between incremental changes in price from year to year. However, many of the variables that were examined (including the futures price for UK coal, UK gas, and EU carbon) are derived from nominal dollars, which introduces a positive correlation bias. Indeed, any long-term trends will introduce a positive bias into this analysis.[56]

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[55] It should be noted that the cross-correlation of these three variables also did not match either the correlation values given in Table 1-4 in SCW-1 or the correlations derived from Sierra DR 2-35a-b.

[56] If the Company were examining year-to-year uncertainty, which they are not, it could be argued that examining interannual changes without removing trends is appropriate; as used in Aurora here, the Company attempts to simulate uncertainty relative to an "average" behavior in each year independently, and thus introduces bias by using trended data.

Q Why is using correlations from future and historic data problematic?

A Within reason it should not be a problem to use recent history and reasonably expected futures data as required. However, in this analysis, the Company mixes correlations from a sparsely populated (data-wise) European futures market to 2014 for CO_2, coal and natural gas relationships[57] with correlations from U.S. data for coal and thermal generation stretching back five decades. There is little reason to think that these data represent anywhere near a similar process as each other – it is unlikely that 1950s vintage relationships between coal prices and demand represent processes that are still happening today.

Q What data did the Company use to derive the relationship between coal prices and demand?

A In the single use of actual U.S. data, the Company erroneously used coal <u>tonnage</u> instead of coal <u>prices</u> to create a correlation between demand and fuel price. Correcting this error changes the relationship from a very correlated 0.74 to a low value of 0.08.

Q What do you mean that the data used for the correlations are non-robust?

A Putting aside the question of if the correlations presented by Mr. Weaver were actually used in the Aurora model, the data that the Company has used can swing dramatically just from small changes in the way that they are used. Of the nine correlation values that Mr. Weaver presents in Exhibit SCW-1, Table 1-4, two are complete guesses (yet high values, nonetheless) and six are derived from very sparse data.

The Company wanted to provide some data to show a relationship between commodity prices (particularly gas and coal) and CO_2 prices. Because there is not yet an active national market for CO_2 in the US, the Company turned to Europe to represent an active carbon market, and used UK commodity prices to match. Examining changes in fuel, CO_2, and market prices, the Company used reviewed

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[57] These factors are feasibly the most important in this set.

exactly nine quarters of forward prices on the ICE market – between June 2011 and June 2013.[58] The futures report shifted to annual timesteps after June 2013, so the Company then added a nine-month step and an annual step, finishing with 11 data points in December 2014. First, changes over quarters may be quite different from changes over annual timesteps (i.e. seasonal gas swings vs. annual increments); second, the eleven data points are very scattered and very non-robust.

Simply removing the 9-month span and the annual span from the series makes the correlation between gas price and CO_2 drop from -0.23 to -0.52. Randomly removing any two datapoints from this series results in answers ranging from a correlation of +0.34 to -0.54.

Finally, the Company chose to use very sparse European data to determine a relationship between coal and gas, as well as between electricity market prices and those fuels. Without suggesting that adopting historic domestic data is any improvement or should be used instead, simply examining trends of U.S. retail rates and U.S. natural gas prices against U.S. coal and U.S. demand results in, again, a very different correlation.

In

[58] The Company used vintage data, hence the forward price start at June 2011.

Table 10, below (**Exhibit JIF-12B**), I've examined domestic gas, demand, and retail prices, removed the 9-month and 1-year span in the European data for carbon correlations and presented an alternate matrix to Ex. SCW-1, Table 1-4. This table is provided for illustrative contrasting purposes only. I do not believe that the statistics used by the Company (or presented here) are the correct mechanism to evaluate uncertainty correlations. I think that, in absence of robust and supportable information, I would suggest that no correlations be used in this particular uncertainty analysis.

Table 10. Comparison of correlations presented in testimony and derived from domestic data.

Correlations provided by AEP in SCW-1, Table 1-4

	Natural Gas	Coal	Carbon	Power	Demand
Natural Gas	1.00	0.09	(0.23)	0.88	seasonal
Coal	0.00	1.00	0.69	0.19	0.74
Carbon	0.00	0.00	1.00	(0.14)	0.50
Power	0.00	0.00	0.00	1.00	0.75
Demand	0.00	0.00	0.00	0.00	1.00

Synapse (for contrast only)

	Natural Gas Price	Coal Price	Carbon Price	Power Price	Demand
Natural Gas Price	1.00	0.11	(0.43)	0.41	(0.15)
Coal Price		1.00	0.67	0.32	0.11
Carbon Price			1.00	(0.43)	0.00
Power Price				1.00	(0.51)
Demand					1.00

Europe	US	Hypothesized

Difference (Company minus Synapse)

	Natural Gas Price	Coal Price	Carbon Price	Power Price	Demand
Natural Gas Price		-0.03	0.20	0.46	0.81
Coal Price			0.01	(0.14)	0.63
Carbon Price				0.30	0.50
Power Price					1.26
Demand					

Q Mr. Weaver supports the strongly positive correlation between demand and market price in Sierra DR 2-32b. Do you agree with his assessment?

A No, not at all. Sierra Club questioned if "the positive correlation of 0.75 means that the Company assumes that retail load will increase as wholesale power prices increase…" and Mr. Weaver responded that "in the shorter run, as demand increases … the cost of supplying that power increases as progressively more expensive units must be dispatched."

The general principles of economic dispatch over short time periods are not in dispute. However, this is not the question poised in the Aurora model or answered by these correlations. The uncertainty in the Aurora model appears to represent annual departures from a mean, not movement along a dispatch curve – that type of movement is not uncertain at all, and not only extremely well characterized by this dispatch model but completely endogenous. The model is already very well equipped to increase market prices in response to short term demand increases; this correlation asks for a representation of how demand shifts in response to price changes.

Indeed, if we look at annual changes in electricity sales (not de-trended) and average electricity prices[59] from the same dataset provided as the response to Sierra DR 2-32b[60] we see a fairly consistent negative correlation of about -0.36. This same correlation is repeated for Kentucky and Ohio consumers (-0.37) and (-0.33).

13. AURORA CONCERNS: USE OF AURORA TO SUPPORT THIS FILING

Q You have finally noted that the Company has not presented the Aurora model used in this manner to the Commission previously. Why is that important in this case?

A It is important for the Commission and independent evaluators, such as the interveners in this and other proceedings, to be able to examine how the Company uses modeling to support their conclusions – particularly if the basis of a decision rests so heavily on a modeled outcome, as in this CPCN. The Aurora model, while apparently only a small part of the overall modeling performed by the Company, is used by the Company to reject two Options – one of which is, by the Company's own estimate, more cost effective than maintaining the Big Sandy 2 unit. It is my belief that if the Company is willing to stand behind the results of this model as the basis for this billion-dollar decision, then the model should be robust, transparent, and well audited.

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[59] As used by Mr. Weaver in his testimony for coal and demand correlation in Ex. SCW-1, Table 1-4

[60] US DOE, Energy Information Administration. Data/Sales (consumption), revenue, prices & customers. Available at http://www.eia.gov/cneaf/electricity/page/sales_revenue.xls

To the best of my knowledge, I understand that this Commission has seen reference to the Aurora model from KPCo as the mechanism by which the Company determines commodity prices[61] and capacity prices,[62] but not as a decision-making tool unto itself.

Q What is your conclusion regarding the Aurora model as used in this proceeding?

A Although I am confounded by the lack of transparency into the model inputs and outputs provided by the Company, from the aspects that I have been able to review, I have found little consistency between the two models (Aurora and Strategist), between the filed testimony of Mr. Weaver and the inputs to the Aurora model, and between the correlations as stated (or used in the model) and correlations derived from a reasonable use of data.

I have found numerous errors and inconsistencies in the Aurora inputs and outputs; and with no ability to trace the use or genesis of the data (or errors), it is nearly impossible to state how influential these errors and inconstancies are in the final outcome. However, based on my observations of the data presented by the Company, it is my assessment that the Aurora model, as presented is more likely erroneous – and potentially biased – then actually useful.

It is my recommendation that the Commission disregard the Aurora analysis in its entirety.

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[61] See both AEP East 2009 IRP (p81) and 2010 IRP (p79): "The AEP-SEA long-term power sector suite of commodity forecasts are derived from the Aurora model. Aurora is a fundamental production-costing tool that is driven by inputs into the model, not necessarily past performance. AEP-SEA models the eastern synchronous interconnect and ERCOT using Aurora. Fuel and emission forecasts established by AEP Fuel, Emissions and Logistics, are fed into Aurora."

[62] See KPCo *response to Staff DR 2-16* in case 2007-04777.

14. CONCLUSIONS

Q What conclusions are you able to draw on the basis of your analysis of the Company's application for CPCN at the Big Sandy 2 unit?

A I conclude that the Company has not provided sufficient evidence that retrofitting the Big Sandy 2 unit with an FGD would be the best option for Kentucky ratepayers. The evidence that the Company has provided is internally inconsistent and ill-founded; when fundamental errors are corrected, the economic benefit found by the Company is removed and reversed.

I find that:

- if the Company expects to continue allocating a sizable portion of revenues from off-system sales to shareholders rather than ratepayers, the relative advantage of the FGD is greatly diminished;
- according to the Company's own analysis, using values for capital expenditure that are consistent with those reported by the Company in direct testimony, the FGD would be the least economic option of those examined;
- the Company's projected CO_2 price forecast is inconsistent with other utilities and the industry at large, and exposes ratepayers to significant regulatory risk. By correcting this value to even a reasonable low bound, the, the relative advantage of the FGD retrofit is eliminated;
- adjusting for off-system sales revenues, capital cost corrections, and a reasonable low bound CO_2 price reveals that the FGD is over \$600 million dollars (in cumulative present worth) more expensive than other options explored by the Company;
- the Company's risk analysis in Strategist are insufficient to elucidate a reasonable range of risks to consumers; and

- the Company's risk analysis in Aurora is internally inconsistent, erroneous, and non-transparent, leading us to question its utility and accuracy.

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Curriculum Vitae

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EMPLOYMENT

Scientist **2007-present**

Synapse Energy Economics

- Model and evaluation of avoided emissions from energy efficiency and renewable energy (Utah State, California Energy Commission, US EPA, State of Connecticut),
- Evaluation of heath, water, and social co-benefits of energy efficiency and renewable energy (Utah State, Civil Society Institute)
- Develop analysis of water consumption and withdrawals from electricity sector (Stockholm Environment Institute, Union of Concerned Scientists)
- Estimate of compliance costs for environmental regulations (Western Grid Group)
- Development of alternate energy plans for municipalities, states, and regions (Sierra Club Los Angeles, NRDC Michigan, Western Resource Advocates Nevada)
- Price impacts of carbon policy on electricity generators and consumers (NARUC, NASUCA, APPA, NRECA)
- Facilitate and provide energy sector modeling for stakeholder-driven carbon mitigation program in Alaska (Center for Climate Strategies)
- Estimate of greenhouse gas emissions reductions from energy efficiency, agricultural and forestry offsets for all US states (Environmental Defense Fund)
- Economic cost of climate change on energy sector in US and Florida (EDF, NRDC)
- Estimate full costs of nuclear waste decommissioning in West Valley site

Postdoctoral Research Scientist **2006-2007**

Tulane University, Department of Ecology and Evolutionary Biology

University of New Hampshire, Institute for the Study of Earth, Oceans, and Space

- Predicted forest mortality from wind damage using satellite data and ecosystem model
- Analyzed Gulf Coast ecosystem impacts of Hurricane Katrina
- Wrote and organized team synthesis review on causes of natural rainforest loss in the Amazon basin
- Redeveloped ecosystem model to explore carbon ramifications of long-term Amazon disturbance

Visiting Fellow **2007-2008**

Brown University, Watson Institute for International Studies

- Designed remote sensing study to examine migratory bird response to climate variability in Middle-East

Research Assistant **2001-2006**

Brown University, Department of Geological Sciences

- Used satellite data to track influence of local and global climate patterns on temperate forest seasonality
- Worked with West African collaborators to determine land-use impact on landscape degradation
- Investigated coastal power plant effluent through multi-temporal satellite data

Remote Sensing Analyst **2005-2006**

Consultant for Geosyntec. in Acton, Massachusetts

- Mapped estuary from hyperspectral remote sensing data to determine impact of engineered tidal system
- Developed suite of algorithms to correct optical and sensor error in hyperspectral dataset

Remote Sensing Specialist 2000
3Di, LLC. Remote Sensing Department. Easton, Maryland

Research Assistant 1999-2001
University of Maryland, Laboratory for Global Remote Sensing Studies
- Developed GIS tools for monitoring global ecological trends
- Created thermal model of continental ice properties from microwave satellite data

EDUCATION

Ph.D. Geological Sciences	**2006**	Brown University, Providence, Rhode Island
M.Sc. Geological Sciences	**2003**	Brown University, Providence Rhode Island
B.S. Geography	**2001**	University of Maryland, College Park, Maryland
B.S. Geology *(honors)*	**2001**	University of Maryland, College Park, Maryland

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Fisher, J.I., J.F. Mustard, and M. Vadeboncoeur. Anthropogenic and climatic influences on green leaf phenology: new observations from Landsat data. Ecosystems Center at the Marine Biological Laboratory. Woods Hole, MA. Seminar, September 27, 2005.

Fisher, J.I. and J.F. Mustard. High resolution phenological modeling in Southern New England. Woods Hole Research Center. Woods Hole, MA. Seminar, March 16, 2005.

Teaching

Teaching Assistant	**2005**	Global Environmental Remote Sensing, Brown University
Teaching Assistant	**2002 & 2004**	Estuarine Oceanography, Brown University
Laboratory Instructor	**2002**	Introduction to Geology, University of Maryland

Fellowships

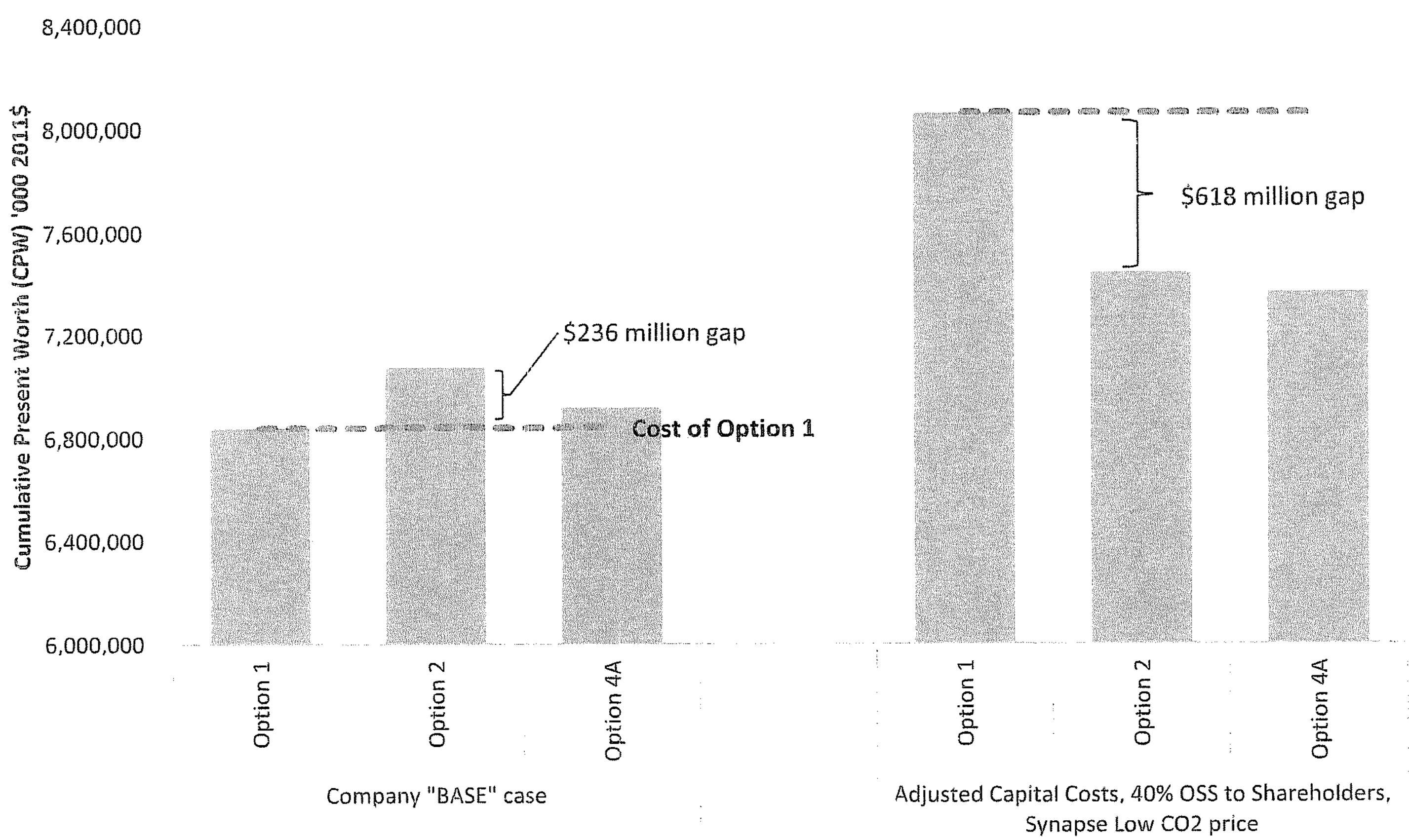
2007 Visiting Fellow, Watson Institute for International Studies, Brown University
2003 Fellow, National Science Foundation East Asia Summer Institute (EASI)
2003 Fellow, Henry Luce Foundation at the Watson Institute for International Studies, Brown University

University Service

Representative	**2005-2006**	Honorary Degrees Committee, Brown University
Representative	**2004-2006**	Graduate Student Council, Brown University

Professional Associations

American Geophysical Union; Geological Society of America; Ecological Society of America; Sigma Xi



Cumulative present worth (CPW) of Options 1 (retrofit), 2 (NGCC replace in 2016), and 4A (market purchase to 2020) under Company Base assumptions (left) and Synapse revised assumptions and corrections (right). See text for details.

Exhibit____JIF-3A

Cumulative Present Worth of Revenue Requirements (M 2011$) Re-Analysis with Adjusted Off System Sales	Option #1 Retrofit Big Sandy 2 w / FGD	Option #2 NGCC Replacement	Option #3 BS1 Repow er	Option #4A Market to 2020; NGCC in 2020	Option #4B Market to 2025; NGCC in 2025
Company Assumptions					
CPW	6,839	7,075	7,091	6,918	6,791
Net benefit of retrofit (CPW)		236	252	78	(48)
Adjusted Off System Sales					
CPW	7,228	7,377	7,394	7,201	7,055
Net benefit of retrofit (CPW)		149	166	(27)	(173)

Exhibit____JIF-3B

Cumulative Present Worth of Revenue Requirements (M 2011$) Re-Analysis with Corrected Capital Costs	Option #1 Retrofit Big Sandy 2 w / FGD	Option #2 NGCC Replacement	Option #3 BS1 Repow er	Option #4A Market to 2020; NGCC in 2020	Option #4B Market to 2025; NGCC in 2025
Company Assumptions					
CPW	6,839	7,075	7,091	6,918	6,791
Net benefit of retrofit (CPW)		236	252	78	(48)
Corrected Capital Costs					
CPW	6,921	6,679	6,790	6,632	6,610
Net benefit of retrofit (CPW)		(242)	(131)	(289)	(311)

Exhibit____JIF-3C

Cumulative Present Worth of Revenue Requirements (M 2011$) Re-Analysis with Adjusted Off System Sales & Corrected Capital Costs	Option #1 Retrofit Big Sandy 2 w / FGD	Option #2 NGCC Replacement	Option #3 BS1 Repow er	Option #4A Market to 2020; NGCC in 2020	Option #4B Market to 2025; NGCC in 2025
Company Assumptions					
CPW	6,839	7,075	7,091	6,918	6,791
Net benefit of retrofit (CPW)		236	252	78	(48)
Corrected Capital Costs & Off System Sales					
CPW	7,310	6,981	7,093	6,916	6,874
Net benefit of retrofit (CPW)		(329)	(217)	(394)	(436)

Cumulative Present Worth (CPW) under Company CO_2 assumptions and Alternate Assumptions.

Exhibit____JIF-3D

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

Exhibit____JIF-3E

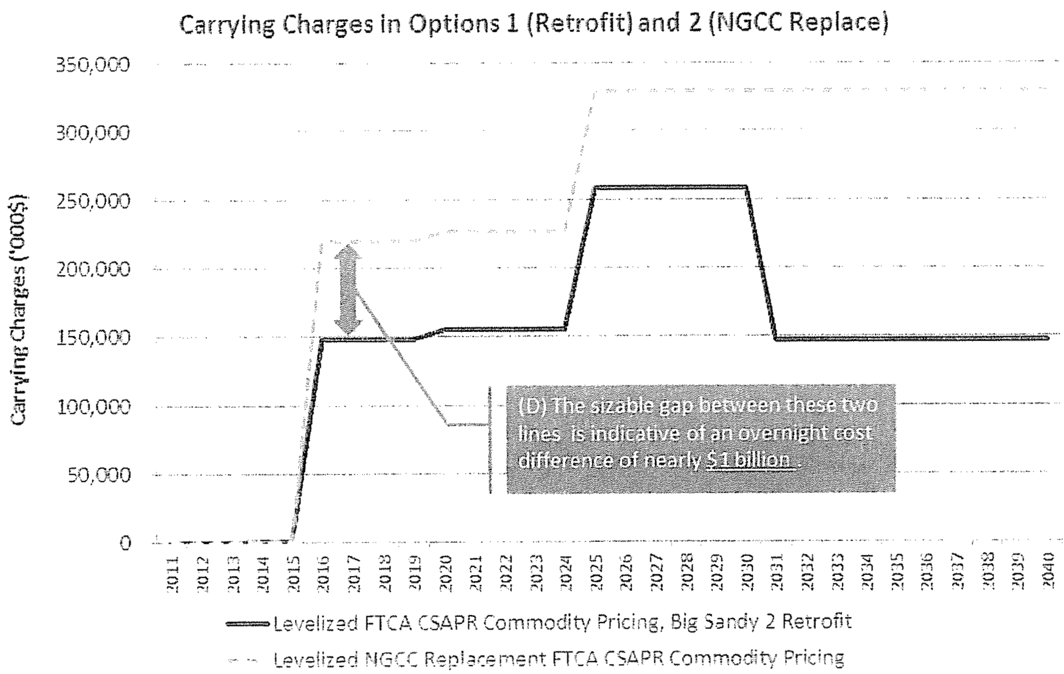
Cumulative Present Worth of Revenue Requirements (M 2011$)			
Re-Analysis with Synapse Low CO2 & Corrected Capital Costs			
	Option #1	**Option #2**	**Option #4A**
	Retrofit Big Sandy 2 w / FGD	NGCC Replacement	Market to 2020; NGCC in 2020
Company Assumptions			
CPW	6,839	7,075	6,918
Net benefit of retrofit (CPW)		236	78
Synapse Low CO2 Price & Corrected Cap Costs			
CPW	7,725	7,269	7,127
Net benefit of retrofit (CPW)		(456)	(597)

Exhibit____JIF-3F

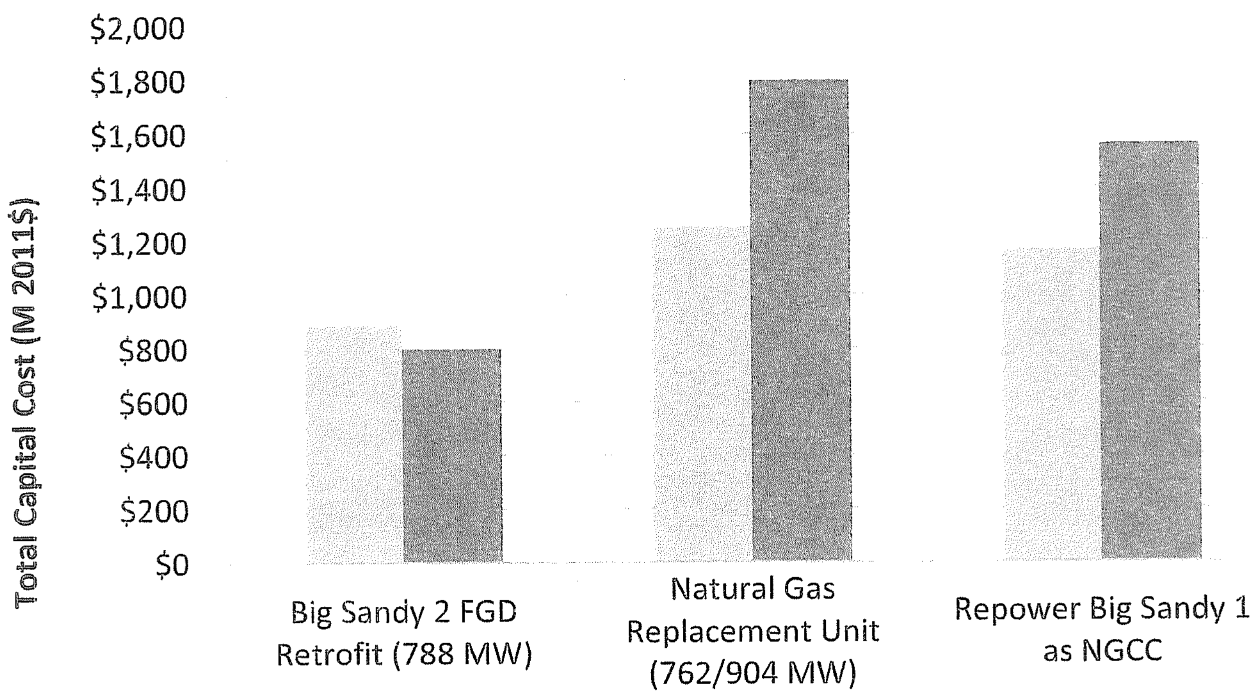
Cumulative Present Worth of Revenue Requirements (M 2011$)			
Re-Analysis with Synapse Low CO2 Corrected Cap Costs & Adj Off-System Sales			
	Option #1	**Option #2**	**Option #4A**
	Retrofit Big Sandy 2 w / FGD	NGCC Replacement	Market to 2020; NGCC in 2020
Company Assumptions			
CPW	6,839	7,075	6,918
Net benefit of retrofit (CPW)		236	78
Synapse Low CO2 Price, Corrected Capital Costs & Off System Sales			
CPW	8,063	7,445	7,367
Net benefit of retrofit (CPW)		(618)	(695)

Cumulative Present Worth (CPW) under Company CO_2 assumptions and Alternate Assumptions.

Sierra DR 1-69 "Big Sandy CC Brownfield & U1 Repower S&L-based SUMMARY.xls"				
BS (Brownfield) NGCC Cost Estimates - Preliminary *				
Option 2 - G Class				*Note:*
NGCC EPC Subtotal (from S&L)	$	790.2	M 2011$	
AEP Owners Costs (per EP&FS)	$	53.8	M 2011$	~ 7% increase
Total NGCC (2011$)	**$**	**844.0**	M 2011$	
Interconnections				
Natural Gas Supply (per FEL)	$	47.4	M 2011$	
Transmission /SWYD (per EP&FS)	$	4.4	M 2011$	
Total Interconn (2011$)	**$**	**51.8**	M 2011$	
Project total (2011$)	**$**	**895.8**	M 2011$	
S&L Escalation	$	73.2		*Real to nominal*
Project Total (As Spent)	**$**	**969.0**	**M Nom$**	
Sierra DR 1-69 "PRELIMINARY_Relative BS2 Unit Disposition Alt Economics_081711.xls"				
[redacted]				
Direct Testimony of Mr. Scott Weaver, Table 2 (p24)				
Option #2: Big Sandy Unit 2				
Replacement Option - **New-Build CC**	**$**	**1,141**	**M ("As Spent" $)**	



Streams of carrying charges in Options 1 and 2.



	Big Sandy 2 FGD Retrofit (788 MW)	Natural Gas Replacement Unit (762/904 MW)	Repower Big Sandy 1 as NGCC
Weaver, Table 2	$897	$1,260	$1,175
Strategist	$797	$1,795	$1,563

Total Capital Cost of FGD and replacement units, including AFUDC. Blue bars are derived from Weaver, Table 2 (p24); red bars are derived from carrying costs in Company Strategist Compilation Workbook.

Source: Sierra 1-69. File "BS2 DFGD AFUDC Calc for Modeling.xls"

Big Sandy Unit 2 DFGD Project Spend — Calculation of AFUDC

Estimated AFUDC Calculation Utilized in Alternative Economic Evaluations (i e., Initially Assuming No CWIP Treatment)

All Dollars in Millions

	Total Project Cost 'As Spent' S (Excl. AFUDC)		Year 1 2011	Year 2 2012	Year 3 2013	Year 4 2014	Year 5 2015	Year 6** 2016	TOTAL
DFGD *	1,046	Cash Cost + Overhd Allc *(inc. cont)*	3 0	35.8	107.2	179 4	261.2	252.8	*839*
		Annual CF %	*0.4%*	*4.3%*	*12.8%*	*21.4%*	*31.1%*	*30.1%*	*100%*
		(Avg) AFUDC Rate	*8.6%*	*8.6%*	*8.6%*	*8.6%*	*8.6%*	*8.6%*	
		AFUDC	0.1	1.8	8.1	21.1	41.8	28.1	101
		Total w/ AFUDC	3.1	37 6	115.3	200.5	303.0	280.9	940

* includes DFGD, Associated (Boiler) Projects, FGD Landfill
** assumes 6/2016 In-service

Big Sandy Unit 2 CCR Project — Calculation of AFUDC

All Dollars in Millions

	Total Project Cost 'As Spent' S (Excl. AFUDC)	Year 1 2011	Year 2 2012	Year 3 2013	Year 4 2014	Year 5 2015	Year 6 2016	Year 7 2017	TOTAL ("As Spent")
CCR	Cash Cost + Overhead Alloc***	-	-	-	1.9	10 5	23.6	12.3	*48*
	Annual CF %	*0.0%*	*0.0%*	*0.0%*	*4.0%*	*21.8%*	*48.9%*	*25.4%*	*100%*
	(Avg) AFUDC Rate	*8.6%*	*8.6%*	*8.6%*	*8.6%*	*8.6%*	*8 6%*	*8.6%*	
	AFUDC	-	-	-	0.1	0.6	2.1	3.9	7
	Total w/ AFUDC	-	-	-	2.0	11.1	25 7	16.1	55

Cash Cost Source: "Capital Cost of BS2 FGD and CC Alternatives used in L-T Modeling.xls")
**** assumes 9 1% AEP Allocated Costs*
***** Assumes end of year in-service date*

(Escalation Factor) 2.8%
Source: Sierra 1-69. File "BS2 DFGD AFUDC Calc for Modeling.xls"

Big Sandy Unit 2 Combined Coal Projects - Opt. 1 — Sum of Coal Project Costs at Big Sandy 2

Base Year: 2011

Nominal Dollar Calculation	2011	2012	2013	2014	2015	2016	2017	Total ("As Spent")
Big Sandy Unit 2 DFGD Project Spend (Nominal M$, w/ AFUDC)	3.1	37.6	115 3	200.5	303.0	280.9	-	940 3
Big Sandy Unit 2 CCR Project (Nominal M$ w/ AFUDC)	-	-	-	2.0	11.1	25.7	16.1	54.9
Big Sandy Unit 2 Combined Coal Projects - Opt. 1 (Nominal M$ w/ AFUDC)	**3.1**	**37.6**	**115.3**	**202.4**	**314.1**	**306.6**	**16.1**	**995.2**
Conversion to Real 2011$								**Total (M 2011$)**
Big Sandy Unit 2 DFGD Project Spend (M 2011$ w/ AFUDC)	3 1	36 6	109.1	184.5	271.3	244.7	-	849.2
Big Sandy Unit 2 CCR Projec (M 2011$ w/ AFUDC)	-	-	-	1.8	10.0	22.4	13.7	47.8
Big Sandy Unit 2 Combined Coal Projects - Opt. (M 2011$ w/ AFUDC)	**3.1**	**36.6**	**109.1**	**186.3**	**281.2**	**267.1**	**13.7**	**$ 897.06**

Project Size (MW) 800 MW — Project Cost (2011$/kW with AFUDC) $1121 / kW

New-Build CC (Brownfield @ BS Site) - Opt. 2 | Calculation of AFUDC

All Dollars in Millions

Total Project Cost 'As Spent' $ (Excl AFUDC)	Nominal $	*Year 1* 2011	*Year 2* 2012	*Year 3* 2013	*Year 4* 2014	*Year 5* 2015	*Year 6* 2016	TOTAL ("As Spent")
	Cash Cost + Overhead Alloc***	5.7	62.7	342.2	524.6	171.1	34.2	*1,141*
	Annual CF %	*0.5%*	*5.5%*	*30.0%*	*46.0%*	*15.0%*	*3.0%*	*100%*
	(Avg) AFUDC Rate	*8.6%*	*8.6%*	*8.6%*	*8.6%*	*8.6%*	*8.6%*	
	AFUDC	0.2	3.2	20.8	59.8	94.8	46.6	225
	Total w/ AFUDC (Nominal $)	5.9	65.9	363.0	584.5	265.9	80.8	1,366
New-Build CC (Brownfield @ BS Site) - Opt. 2 (M 2011$ w/ AFUDC)		**5.9**	**64.1**	**343.5**	**538.0**	**238.1**	**70.4**	$ 1,259.99
	Project Size (MW)	**904 MW w/ Duct Firing**		Project Cost (2011$/kW with AFUDC)				**$1394 / kW**

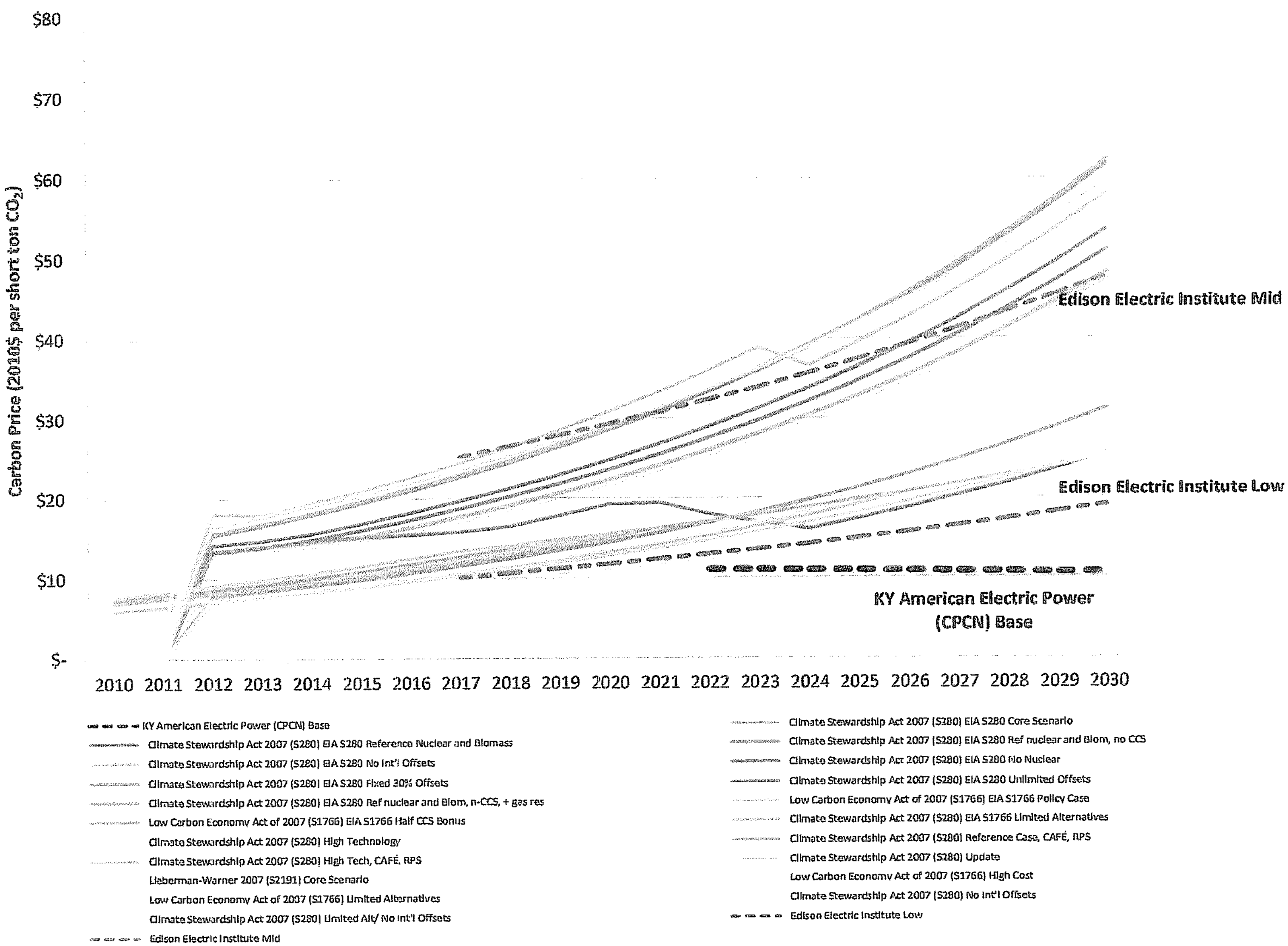
Cash Cost Source: "Capital Cost of BS2 FGD and CC Alternatives used in L-T Modeling.xls")
** assumes 6/2016 In-service
**** assumes 7.0% AEP Allocated Costs & includes 10% contingency as in source workbook*

(Big Sandy Unit 1) Repowered CC - Opt. 3 | Calculation of AFUDC

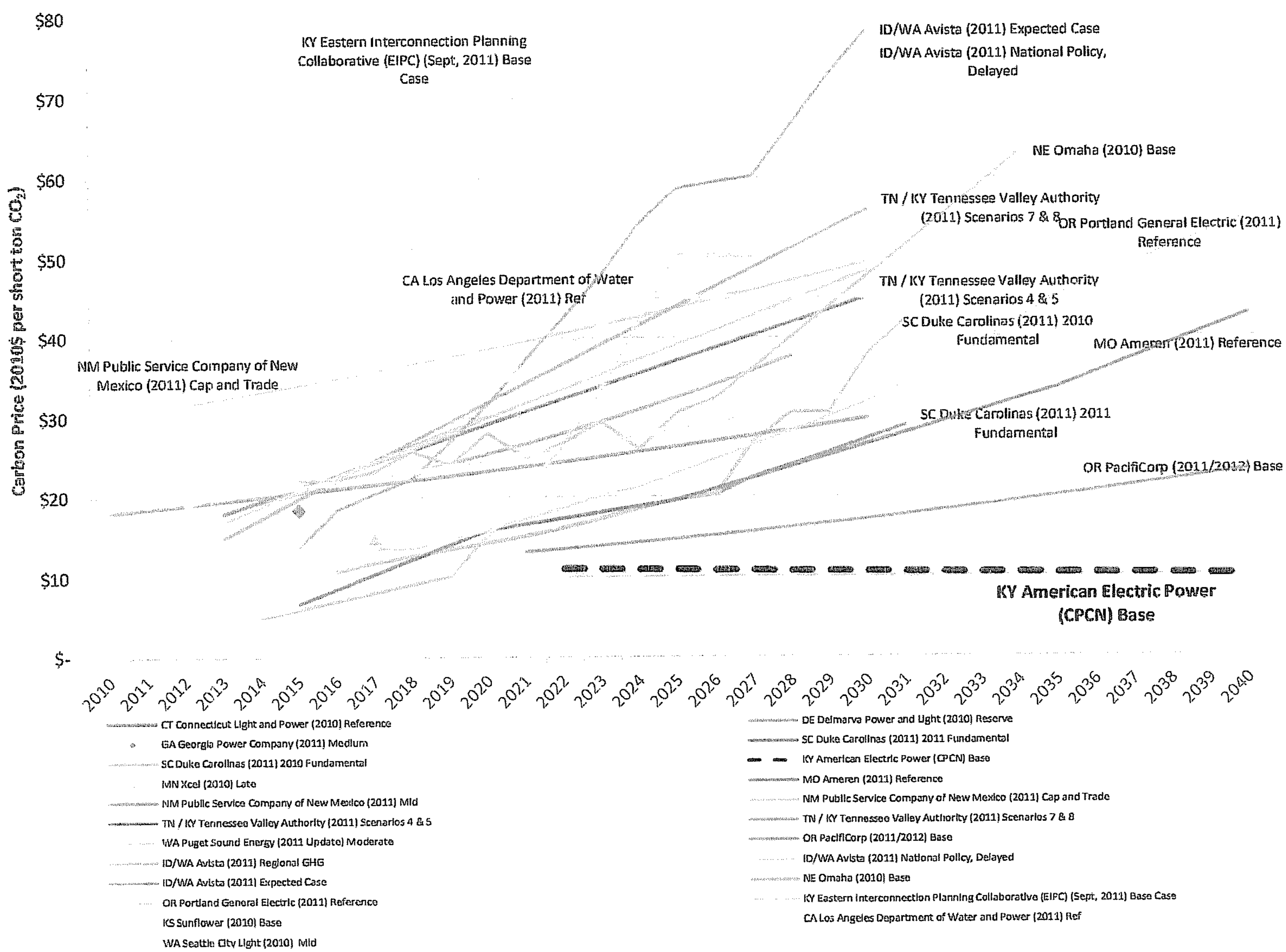
All Dollars in Millions

Total Project Cost 'As Spent' $ (Excl. AFUDC)	Nominal $	*Year 1* 2011	*Year 2* 2012	*Year 3* 2013	*Year 4* 2014	*Year 5* 2015	*Year 6* 2016	TOTAL ("As Spent")
	Cash Cost + Overhead Alloc***	5.3	58.5	319.0	489.1	159.5	31.9	*1,063*
	Annual CF %	*0.5%*	*5.5%*	*30.0%*	*46.0%*	*15.0%*	*3.0%*	*100%*
	(Avg) AFUDC Rate	*8.6%*	*8.6%*	*8.6%*	*8.6%*	*8.6%*	*8.6%*	
	AFUDC	0.2	3.0	19.4	55.8	88.4	43.4	210
	Total w/ AFUDC (Nominal $)	5.5	61.5	338.4	544.9	247.9	75.3	1,273
(Big Sandy Unit 1) Repowered CC - Opt. 3 (M 2011$ w/ AFUDC)		**5.5**	**59.8**	**320.2**	**501.6**	**221.9**	**65.6**	$ 1,174.67
	Project Size (MW)	**870 MW w/ Duct Firing**		Project Cost (2011$/kW with AFUDC)				**$1350 / kW**

Cash Cost Source: "Capital Cost of BS2 FGD and CC Alternatives used in L-T Modeling.xls")
** assumes 6/2016 In-service
**** assumes 7.0% AEP Allocated Costs & includes 20% contingency as in source workbook*

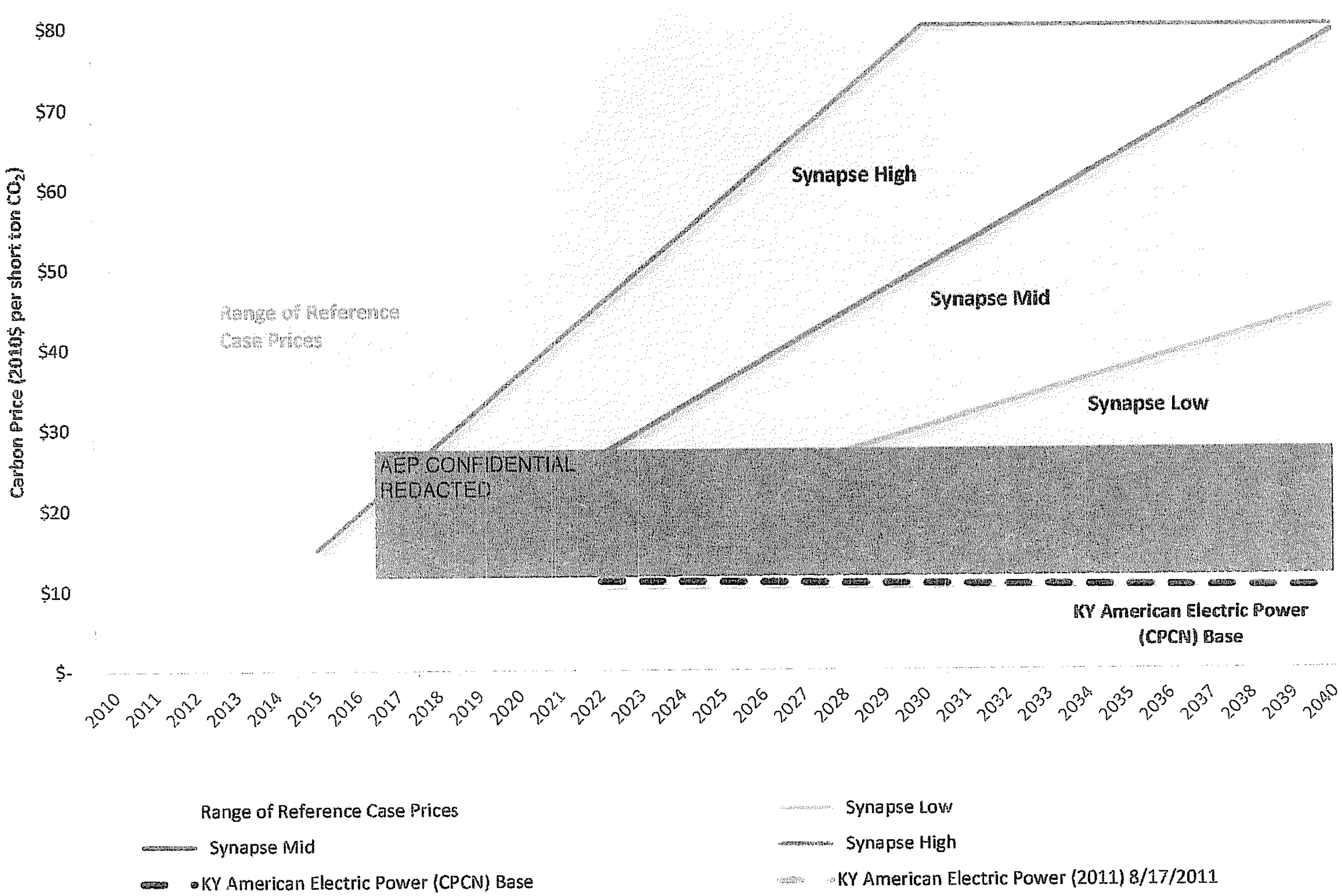


Exhibit____JIF-7A

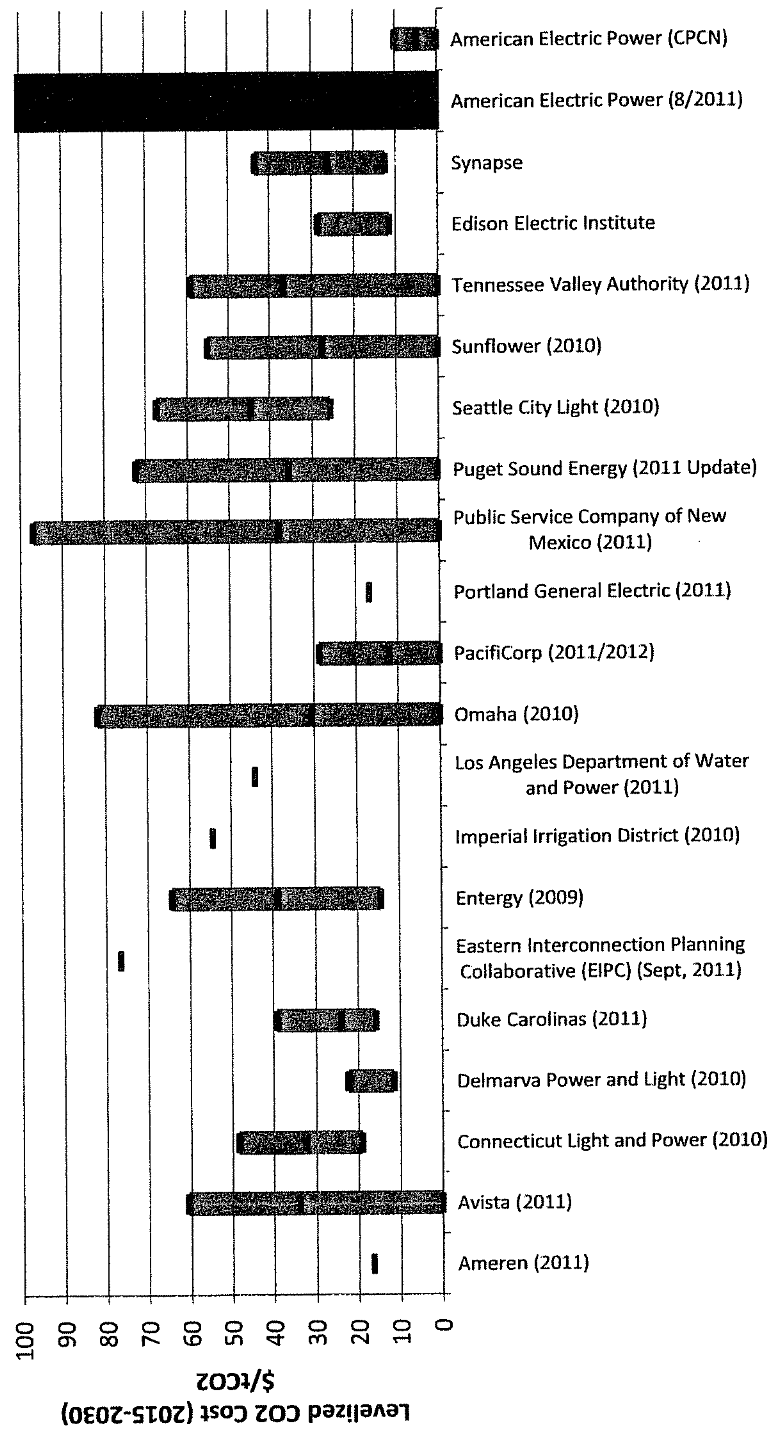


Reference case CO2 prices from other US utilities

Exhibit____JIF-7C



Reference case CO2 prices from other US utilities (green background). Synapse CO2 prices & Company assumed prices in August 2011 and in this case (CPCN).



Low, high and average CO_2 prices given by different utilities in IRP & CPCN from 2010-2011. The AEP forecast for this CPCN is the final bar on this chart.

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Synapse
Energy Economics, Inc.

2011 Carbon Dioxide Price Forecast

February 11, 2011

(Amended August 10, 2011)

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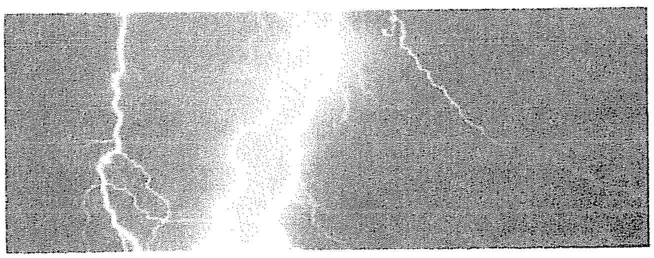

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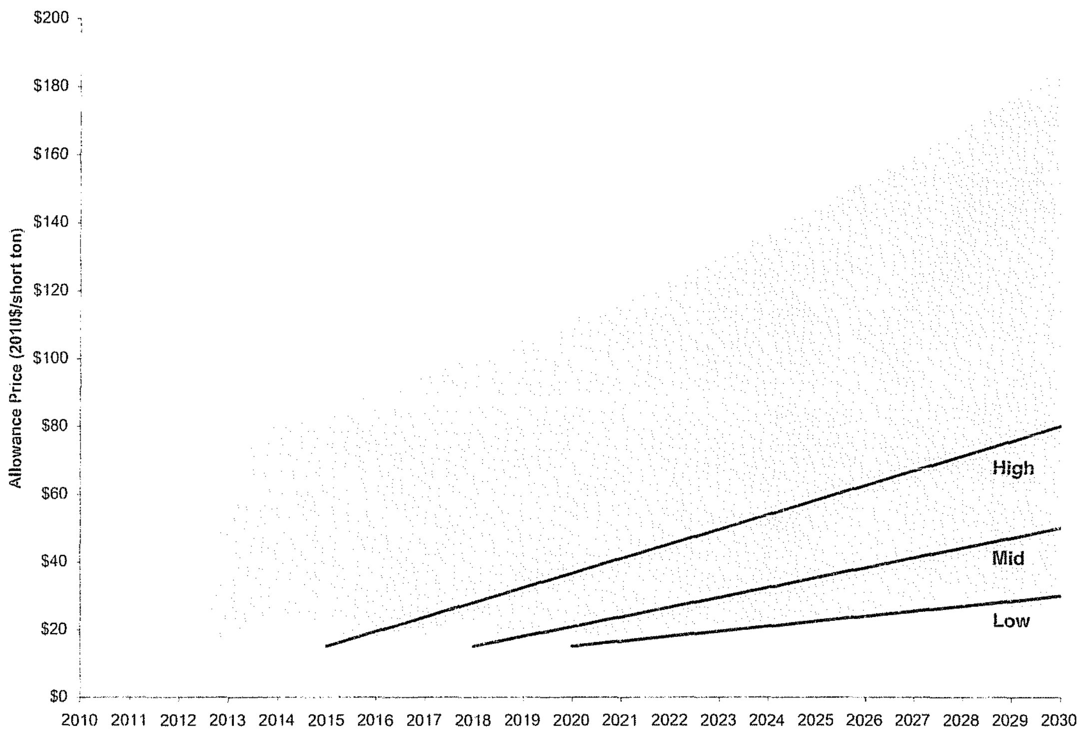
Table of Contents

1. Executive Summary

Synapse has prepared 2011 CO_2 price projections for use in Integrated Resource Planning (IRP) and other electricity resource planning analyses. Our projections of prices associated with carbon dioxide emissions reflect a reasonable range of expectations regarding the likelihood and the magnitude of costs for greenhouse gas emissions. Our high bound on our CO_2 Price Forecast starts at $15/ton in 2015, and rises to approximately $80/ton in 2030. This High Forecast represents a $43/ton levelized price over the period 2015-2030. The low boundary on the Synapse CO_2 price forecast starts at $15/ton in 2020, and increases to approximately $30/ton in 2030. This represents a $13/ton levelized price over the period 2020-2030. Synapse also has prepared a Mid CO_2 Price Forecast that starts a bit more slowly, but close to the low case, at $15/ton in 2018, but then climbs to $50/ton by 2030. The levelized cost of this mid CO_2 price forecast is $26/ton. All annual allowance price and levelized values are given in 2010 dollars per short ton of carbon dioxide.[1] Our forecast is presented below, in Figure ES-1. The shaded region shows a range of allowance prices forecasted by various analyses of legislative cap-and-trade proposals. Further details on these proposals are shown in later Figures.

Figure ES-1: Synapse price forecast



[1] All values in the Synapse Forecast are presented in 2010 dollars. Results from EIA and EPA modeling analyses were converted to 2010 dollars using price deflators taken from the US Bureau of Economic Analysis, and available at: http://www.bea.gov/national/nipaweb/SelectTable.asp Because data were not available for 2010 in its entirety, values used for conversion were taken from Q3 of each year. Consistent with EIA and EPA modeling analyses, a 5% real discount rate was used in all levelization calculations.

The future of climate change policy is unclear. While climate legislation was considered in the last Congress, and passed the House, it did not pass the Senate; currently, there are a range of actions that could be taken by federal entities in the legislative, executive and judicial branches of government, as well as by states individually and in regional organizations that will affect the competitiveness of resources with greenhouse gas emissions (these are described in more detail in the body of this report). The lack of clarity regarding the future of climate change policy in the United States presents a challenge, but is not justification for assuming there will be no cost associated with greenhouse gases, no effect on the competitiveness of resources based on their greenhouse gas emissions. Though we cannot predict specific policies that will develop between now and 2030, the end of our forecast period, we believe that current and emerging state, regional, and federal policies are all indications that greenhouse gas emissions will not be without cost impact on the emitter over the course of any investment in long-term resources. Indeed, it would be imprudent to make resource decisions today based upon an assumption that carbon emissions will be unregulated, or priced at zero, in the future.

The Synapse projections represent a range of possible future costs, recommended price trajectories, that are useful for testing range-sensitivity of various investment possibilities in resource planning in the electric sector. The projection does not represent a prediction of specific future price trajectories; there will be variability and volatility in prices following supply and demand dynamics, as there is with other cost drivers. We intend and anticipate that the CO_2 price projections presented here will be useful for planning in the face of uncertainty.

While reasonable people may argue about the ultimate timing and details of any policy, about the likelihood of various forms of federal policy, and about the costs of specific technologies, we believe our forecast represents a valuable tool for use in resource planning and selection and in investment decisions in the electric sector.

2. Introduction

Over the next several years the economics of power generation will change in a manner that makes sources with high greenhouse gas emissions less competitive relative to those with lower greenhouse gas emissions. This change in the competitiveness of resources will result from interactions among a variety of factors (including state policy actions, federal agency regulations, federal court decisions, federal legislative initiatives, technological innovation, and presidential administrations) not due to any single factor.

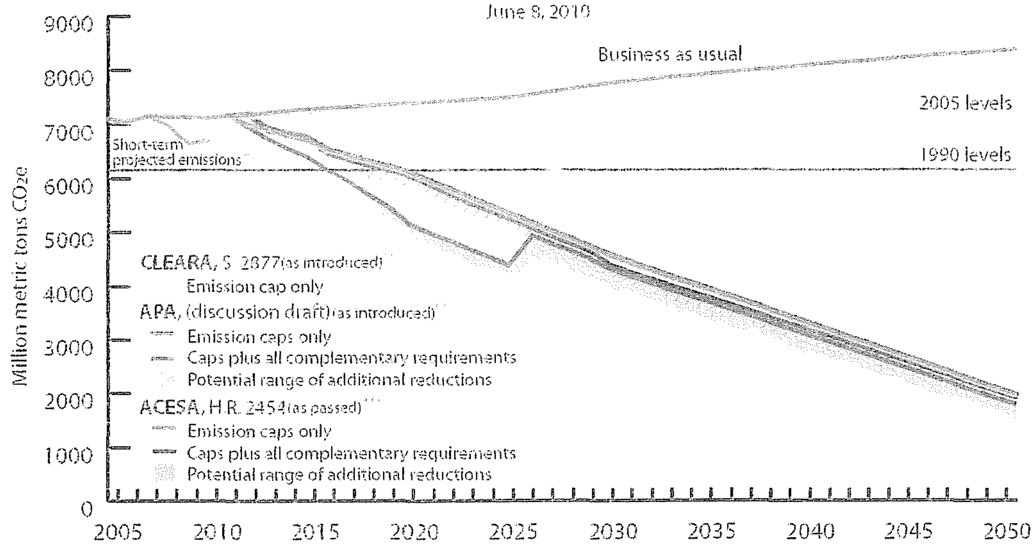
3. Policy Context

In the past few years, Congress has been a major focus for climate policy. Congress has considered enacting legislation that would reduce greenhouse gas emissions through a federal cap on greenhouse gas emissions and trading emissions allowances, or through other means. Legislative proposals and the President Obama's initiatives aim to reduce greenhouse gas emissions by approximately 80% from current levels by 2050.

Figure 1, below, shows the emissions reductions trajectories from recent legislative proposals (Waxman-Markey HR 2454, Kerry-Lieberman APA 2010, and Cantwell-Collins S. 2877).

Figure 1. Net Estimates of Emissions Reductions Under Pollution Reduction Proposals in the 111th U.S. Congress, 2005-2050

June 8, 2010



WORLD RESOURCES INSTITUTE

For a full discussion of underlying methodology, assumptions and references, please see http://www.wri.org/usclimatetargets.

* "Business as usual" emission projections are from EPA's reference case for its analysis of the Waxman-Markey bill. "Short-term projected emissions" represent EIA's most recent estimates of emissions for 2008-2010.

** The CLEARA sets economy-wide reduction targets beginning with a 20 percent reduction from 2005 levels by 2020. However, additional action by Congress would be required before these targets could be met. Reduction estimates do not include emissions increases above the cap that could occur if the safety-valve is triggered.

*** The APA and the ACESA allow offsets from emission reduction activities outside the cap to be used for a portion of compliance. If these offsets are not real, additional, verifiable and permanent, net emissions reductions would decrease proportionately

2

Despite passage of comprehensive climate legislation in the House in the 111th Congress, the Senate ultimately did not take up climate legislation in that session. On the other hand, the Senate did consider -- but did not pass – legislation that would have restricted the Environmental Protection Agency's ability to regulate greenhouse gases.

As the 112th Congress opens, prospects for legislation establishing an economy-wide emissions cap seem dim, and legislators seem instead likely to focus on policies that would foster technology innovation, and a possible multi-regulation approach to energy issues. The 112th Congress is opening with simultaneous promises to use Congressional authority to prevent or delay EPA's ability to issue regulations concerning greenhouse gas emissions, and increasing interest in developing renewable energy standards or clean energy standards. Congress is unlikely to take up an economy-wide cap and trade program in its new session; instead, legislators are likely to focus on policies that promote technological innovation.

In fact, Congressional action is only one avenue in an increasingly dynamic and complex web of activities that could result in internalizing a portion of the costs associated with emissions of greenhouse gases from the electric sector. As Congress wrestles with the issue, the states, the federal courts, and federal agencies also grapple with the complex issues associated with climate change. Many efforts are proceeding simultaneously.

The U.S. Environmental Protection Agency (EPA) intends to mandate emissions reductions following the Supreme Court's determination that the harms associated with climate change are serious and well-recognized, that greenhouse gases fit within the Clean Air Act's definition of "air pollutant", and that the EPA has the authority to regulate greenhouse gases.[2] As a first step, the EPA issued a finding that greenhouse gases endanger public health and welfare. The EPA has also developed regulations to limit any greenhouse gas emission permitting requirements to the largest industrial sources, as well as regulations that boost automobile and truck fuel efficiency and contain the first-ever greenhouse gas tailpipe standards for vehicles. On August 12, 2010, EPA proposed two rules to ensure that businesses planning to build new, large facilities or make major expansions to existing ones obtain New Source Review Prevention of Significant Deterioration (PSD) permits that address greenhouse gases (GHG). These rules became effective in early January 2011. EPA announced December 23, 2010 that it will issue greenhouse gas performance standards for new and modified electric generating units under section 111(b) of the Clean Air Act, and for existing electric generating units under section 111(d) with final regulations promulgated in May 2012 and December 2012, respectively.[3]

The states – individually and coordinating within regions - are leading the nation's policies to respond to the threat of climate change. In fact, several states, unwilling to postpone and wait for federal action, are pursuing policies specifically because of the lack of federal legislation.

States continue to be the innovative laboratories for climate policy, and they are pursuing a wide variety of policies across the country.

- Forty-three states have a greenhouse gas inventory,
- Forty-one states have a greenhouse gas registry,
- Thirty-six states have completed a climate action plan or have one in progress,
- Twenty-two states have greenhouse gas emissions targets,
- Eleven states have an electric sector cap and allowance trading,
- Five states have emissions performance standards.
- Twenty-one states are participating in the operation or development of regional emissions cap and allowance trading programs, with an additional nine states as official observers in those processes.
- Only Nebraska, North Dakota, and the District of Columbia appear not to be taking specific climate-related policy initiatives at this time.
- In general, states are also where the nitty-gritty decisions will be made about investments in new or existing power plants.

The map below shows states with emission targets and those participating in, or observing, regional climate initiatives as of January 2011. States that have adopted emissions targets and/or that are participating actively in regional climate initiatives comprise 44.4% of US electrical generation, 48.3% of retail electricity sales, and 58.1% of U.S. population. The observer states add

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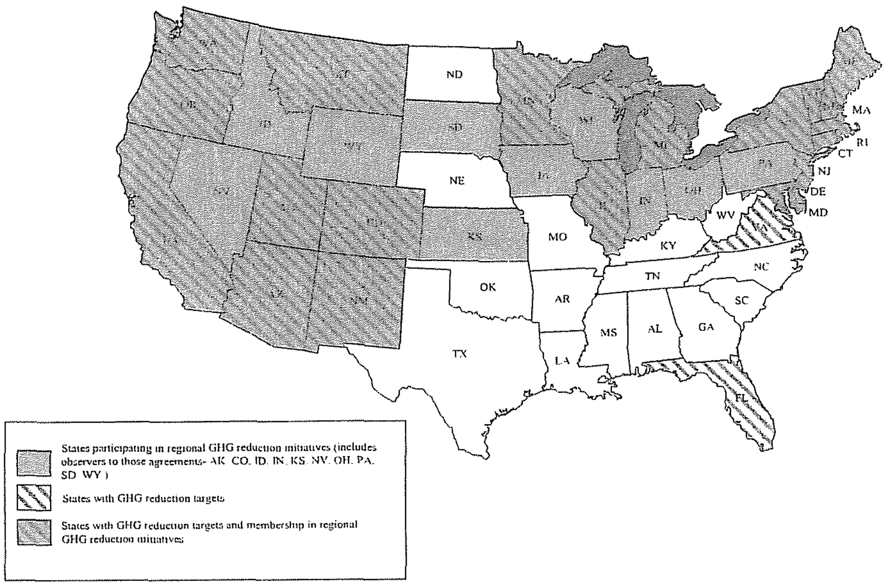
[2] Information on EPA's plans and regulations available from EPA website on climate change regulatory initiatives at http://www.epa.gov/climatechange/initiatives/index.html

[3] U.S. EPA, EPA to Set Modest Pace for Greenhouse Gas Standards, Press Release December 23, 2010. And U.S. EPA, Settlement Agreements to Address Greenhouse Gas Emissions from Electric Generating Units and Refineries - Fact Sheet, December 23, 2010. Available at http://www.epa.gov/airquality/pdfs/settlementfactsheet.pdf

an additional 17.3% of electrical generation, 16.1 % of retail electricity sales, and 14.5% of the U.S. population.

Figure 2: States in regional climate initiatives and/or with greenhouse gas targets



Source. Pew Center on Global Climate Change

Three regions in the country have developed, or are developing greenhouse gas caps and allowance trading:

Regional Greenhouse Gas Initiative: The Regional Greenhouse Gas Initiative (RGGI) is an effort of ten Northeast and Mid-Atlantic states to limit greenhouse gas emissions and is the first market-based CO_2 emissions reduction program in the United States. Participating states have agreed to a mandatory cap on CO_2 emissions from the power sector with the goal of achieving a ten percent reduction in these emissions from levels at the start of the program by 2018.[4] This is the first mandatory carbon trading program in the nation.

Western Climate Initiative: In 2007, Governors of five western states signed an agreement establishing the Western Climate Initiative (WCI), a joint effort to reduce greenhouse gas (GHG) emissions and address climate change.[5] Subsequently, two more states and four Canadian Provinces also joined the effort.[6] Fourteen states and provinces also are official observers of the process.[7] WCI members signed a Memorandum of Understanding agreeing to jointly set a regional emissions target and establish a market-based system—such as a cap-and-trade program covering

[4] The ten states are: Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont. Information on the RGGI program, including history, important documents, and auction results is available on the RGGI Inc website at www.rggi.org

[5] The five states are Arizona, California, New Mexico, Oregon and Washington.

[6] Utah, Montana, British Columbia, Manitoba, Ontario and Quebec.

[7] Alaska, Colorado, Idaho, Kansas, Nevada, and Wyoming, as well as the provinces of Nova Scotia and Saskatchewan and the Mexican states of Baja California, Chihuahua, Coahuila, Nuevo Leon, Sonora, and Tamaulipas.

multiple economic sectors—to aid in meeting this target. The WCI regional, economy-wide greenhouse gas emissions target is 15 percent below 2005 levels by 2020, or approximately 33 percent below business-as-usual levels. The WCI Partners released the Design for the WCI Regional Program in 2010.[8]

Midwest Greenhouse Gas Reduction Accord: In 2007, six states and one Canadian province established the Midwest Greenhouse Gas Reduction Accord (MGGRA).[9] Three additional states are official observers.[10] The members agree to establish regional greenhouse gas reduction targets, including a long-term target of 60 to 80 percent below current emissions levels, and develop a multi-sector cap-and-trade system to help meet the targets. The MGGRA Advisory Group presented final recommendations in May 2010.[11]

The Federal Courts have allowed common law nuisance actions to go forward against some of the nation's largest owners and operators of fossil fueled facilities. In those actions, plaintiffs successfully stated a cause of action for harm suffered as a result of defendants' carbon intensive activities that contributed to climate change. The Supreme Court is due to take up legality of "nuisance" lawsuits over greenhouse gas emissions in 2012. If nuisance lawsuits are allowed to go forward, the threat of climate change lawsuits could spur congressional action.

It is not likely that all of these initiatives will move forward and result in a cost to emitting greenhouse gases. It is also not likely that none of these initiatives or similar initiatives will move forward. Any of these will happen in the context of implementing other policies that, while not focusing directly on greenhouse gas emissions (e.g. renewable standards, efficiency standards, investment in new technologies etc.) will reduce greenhouse gas emissions.

In the absence of a comprehensive federal policy, efforts to address the climate issues will persist, albeit in a variety of forums. The multiple threats of EPA regulation, litigation (nuisance and plant by plant), and diverse state policies could very well create a strong demand for coordinated federal legislation. However, it is clear that the absence of federal legislation has not brought efforts to formulate policies addressing greenhouse gas emissions to a halt, and it is equally clear that these policies will affect the costs of operating resources with high levels of greenhouse gas emissions. Regulation of greenhouse gases will increase the cost of producing electricity from power sources that emit greenhouse gases, reflecting either the direct cost of reducing emissions or the cost of purchasing emissions allowances. Though it is certain that emission-related costs will increase, the nature, magnitude and timing of the cost increases are uncertain and thus introduce financial risk into decisions to invest in long-lived capital-intensive resources that use carbon-based fuels.

Meanwhile, negotiations for international coordination on initiatives to mitigate and adapt to climate change are on-going. Most recently, the 2009 Copenhagen Accord called on developed nations to submit quantified greenhouse gas emission reduction targets for 2020, and for developing nations to submit "nationally appropriate mitigation actions." The United States has said it will reduce

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[8] This summary is based on information available from Pew Center on Global Climate Change, www.pewclimate.org; and also from the WCI website, www.westernclimateinitiative.org.

[9] The states are Illinois, Iowa, Kansas, Michigan, Minnesota, and Wisconsin, as well as the Premier of the Canadian Province of Manitoba.

[10] Observers are Indiana, Ohio, and South Dakota.

[11] This summary is based on information available from Pew Center on Global Climate Change, www.pewclimate.org; and also from the MGGRA website, www.midwesternaccord.org

greenhouse gas emissions in the range of 17% below 2005 levels by 2020, which is a target consistent with anticipated climate and energy legislation.[12]

4. Elements in a price projection

A. Difficulty of price projection under uncertainty

Though the need for a comprehensive effort to reduce greenhouse gas emissions seems clear, the particular set of policies that will be adopted to bring about a low carbon economy are unknown. It is also likely that some policies will focus on adaptation rather than emissions reduction. Nevertheless, while state and federal policy-makers continue to struggle with the details and political challenges of such an effort, the need for a reliable and cost-effective electric sector does not diminish. Regardless of what the policy or policies ultimately look like, it is certain that any policy requiring, or leading to, greenhouse gas emission reductions will mean that there is a cost associated with emitting greenhouse gases over at least some portion of the life of a long-lived resource. Despite policy uncertainty, it is important to incorporate some reasonable consideration of a range of potential costs into long-term investment planning in the electric sector.

There are several types of information that are useful to consult in developing a reasonable forecast of the cost of carbon emissions for decision-making in the electric sector. Though none of this information can predict future costs, it is useful as a point of reference in developing a reasonable forecast. Information includes analyses of compliance costs under various federal cap and trade proposals, costs of low carbon technologies, projections of compliance costs under mandatory emission reduction programs other than cap and trade. For this forecast, we have focused primarily on analyses of federal cap and trade proposals since they present a well analyzed and comprehensive exploration of the possible costs associated with carbon dioxide emissions. But we have also taken into account other sources of information.

A large number of modeling analyses have been undertaken to evaluate the CO_2 allowance prices that would result from the major climate change bills introduced in Congress over the past several years. Though it is not certain that a federal cap and allowance trading program will ultimately be what is adopted, analyses of the various proposals to date are one of the sources of the most comprehensive estimates of costs associated with greenhouse gas emissions under a variety of regulatory scenarios. These estimates can be useful sources of information. It is not possible to compare the results of all of these analyses directly because the specific models and the key assumptions vary. Further, it is not certain that a federal cap and trade program will be the form that climate policy in the U.S. takes. While consistent federal rules would be the most efficient mechanism for climate policy, the costs are associated with emissions limits and other policy details, not with the source of the rules. Accordingly, the results of these analyses provide important insights into the ranges of possible future CO_2 allowance prices under a range of potential scenarios.

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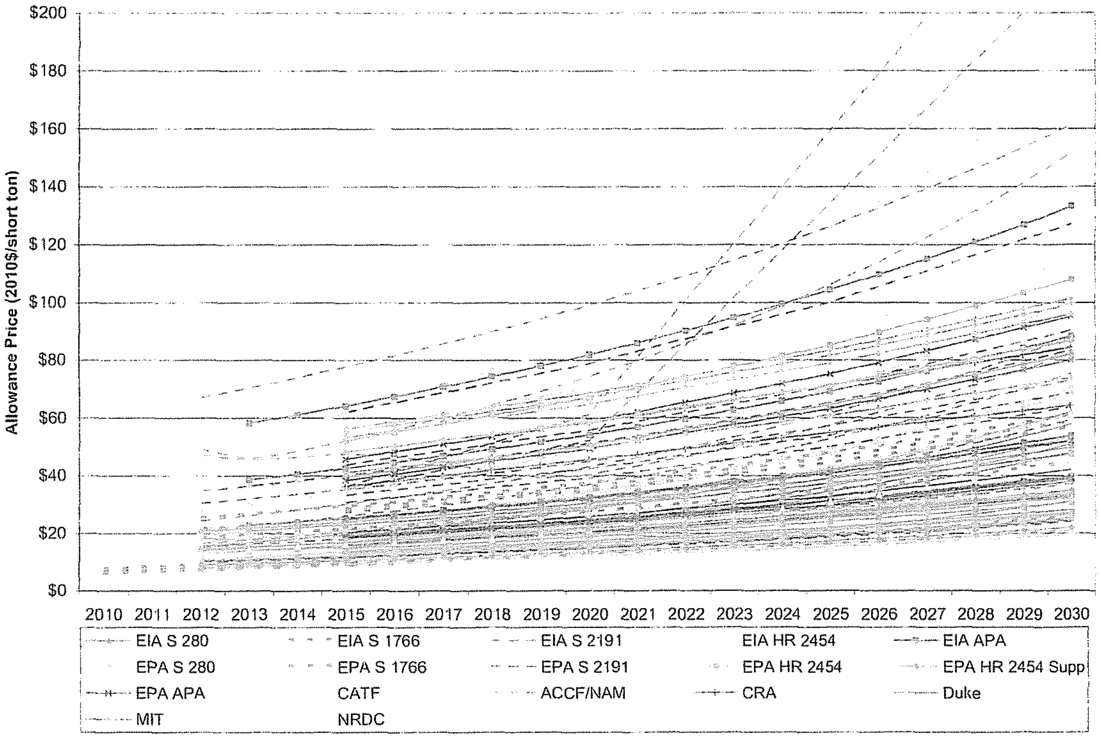
[12] Information is available at http://www.pewclime.org/copenhagen-accord

B. Analyses of compliance costs- and conclusions on effects of factors

The results of the dozens of analyses over the past several years show that there are a number of factors that affect projections of allowance prices under federal greenhouse gas regulation. Some of these derive from the details of policy design, some of them pertain to the outlook for the context in which a policy would be implemented. These include: the base case emissions forecast; the reduction targets in each proposal; whether complementary policies such as aggressive investments in energy efficiency and renewable energy are implemented, independent of the emissions allowance market; the policy implementation timeline; program flexibility regarding emissions offsets (perhaps international) and allowance banking; assumptions about technological progress; the presence or absence of a "safety valve" price; and emissions co-benefits.

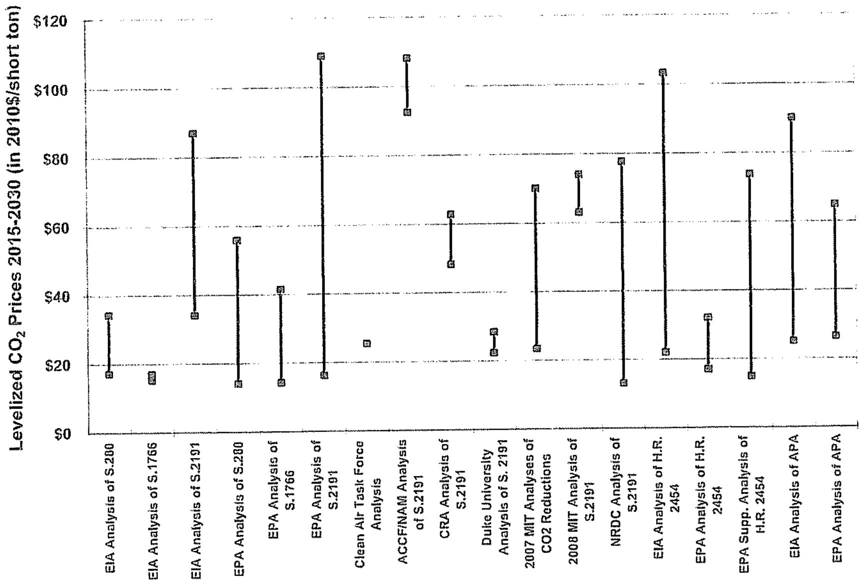
The graph below shows the results of all the scenarios from multiple analyses in the past several years. The studies that are incorporated into this graph are identified in Appendix A.

Figure 3: Greenhouse gas allowance price projections based on analyses of federal legislative proposals



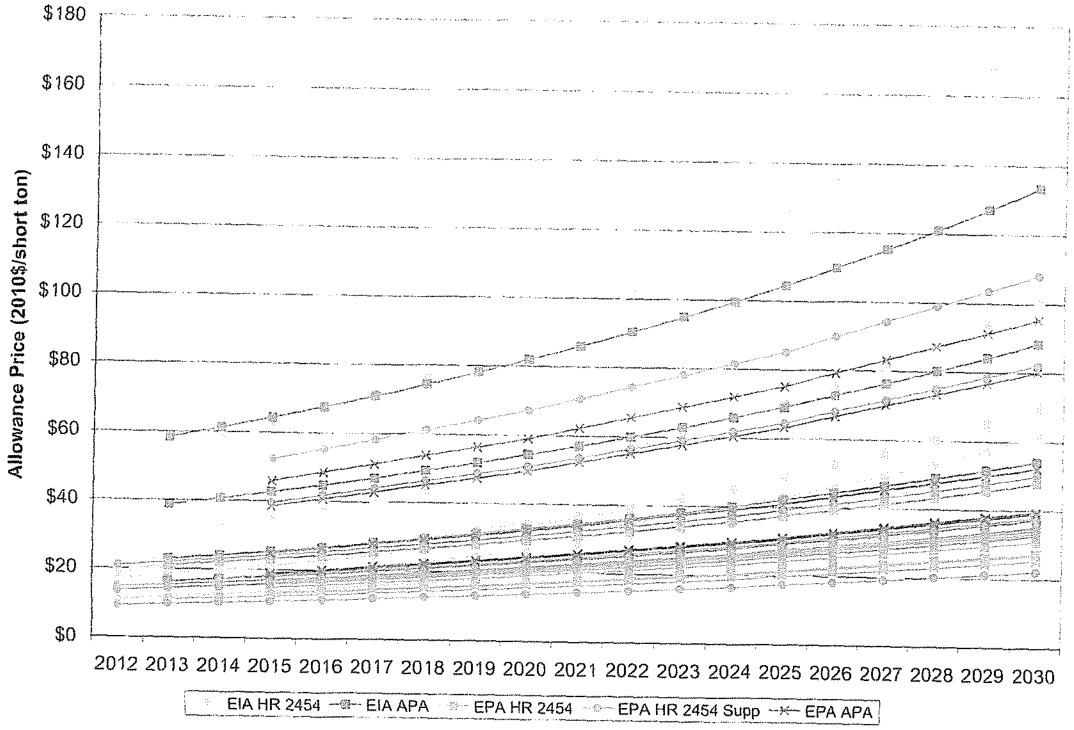
The results of these same analyses are represented in Figure 4, below, as ranges of levelized costs.

Figure 4: Greenhouse gas allowance price projections based on analyses of federal legislative proposals - levelized



We have looked in more detail at the EIA and EPA analyses of the three major legislative proposals in the 111th Congress. The results of these analyses span a similar range to earlier studies. The chart below shows the forecasted allowance prices in all of the scenarios of those analyses.

Figure 5: Greenhouse gas allowance price projections for HR 2454 and APA 2010



These values are shown as levelized prices for the time period 2015 to 2030 in Figure 6 below.

Figure 6: Greenhouse gas allowance price projections for HR 2454 and APA 2010- levelized 2015-2030

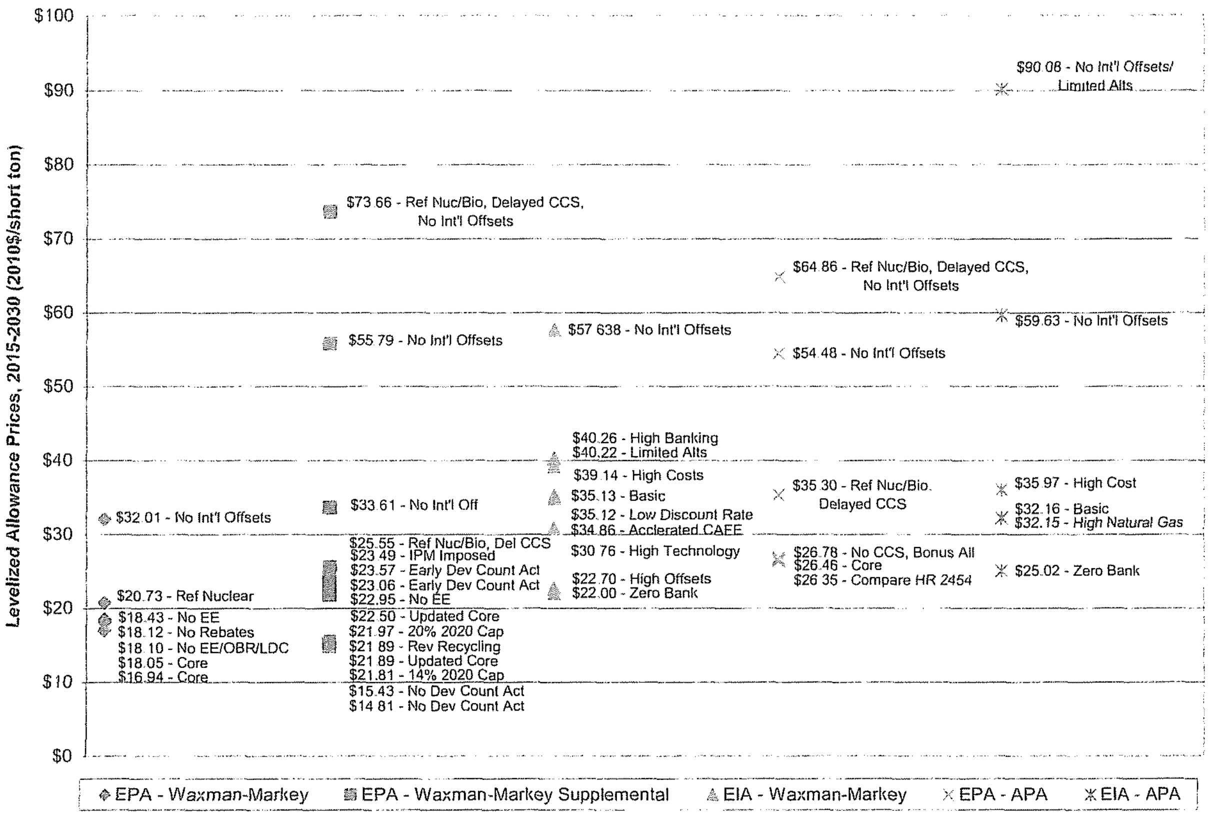
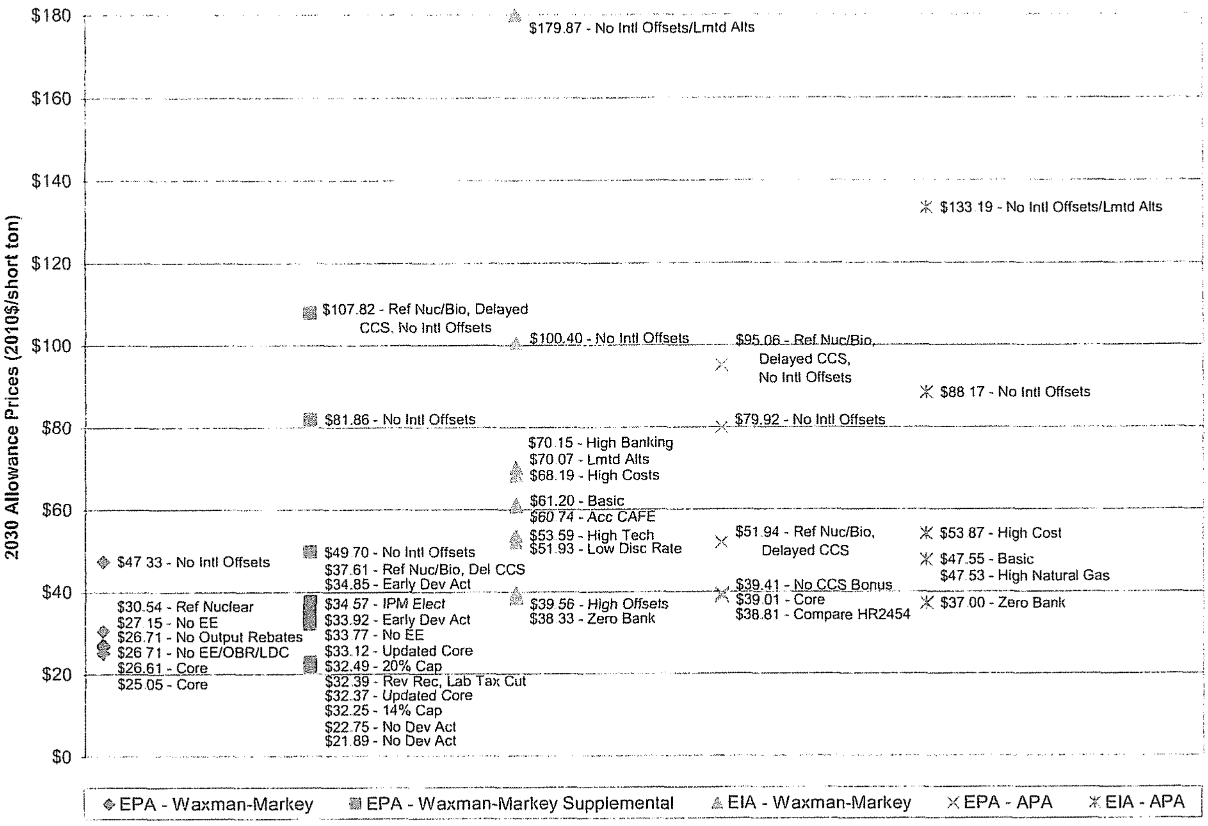


Figure 7: 2030 Greenhouse gas allowance price projections for HR 2454 and APA 2010



Our review of the more than 75 scenarios examined in the modeling analyses represented in Figure 7, above, as well as a closer examination of the most recent analyses of legislation considered in the 111th Congress indicates that:

1. Other things being equal, more aggressive emissions reductions will lead to higher allowance prices than less aggressive emissions reductions.

2. Greater program flexibility decreases the expected allowance prices, while less flexibility increases prices. This flexibility can be achieved through increasing the percentage of emissions that can be offset, by allowing banking of allowances or by allowing international trading.

3. The rate of improvement in emissions mitigation technology is a crucial assumption in predicting future emissions costs. For CO_2, looming questions include the future feasibility and cost of carbon capture and sequestration, and cost improvements in integrating carbon-free generation technologies. Improvements in the efficiency of coal burning technologies and in the costs of nuclear power plants could also be a factor. In general, those scenarios in the modeling analyses with lesser availability of low-carbon alternatives have the higher CO_2 allowance prices. When low carbon technologies are widely available, CO_2 allowance prices tend to be lower.

4. Complementary energy policies, such as direct investments in energy efficiency or policies that foster renewable energy resources are a very effective way to reduce the demand for emissions allowances and thereby lower their market prices. A policy scenario which includes aggressive energy efficiency and/or renewable resource development along with carbon emissions limits will result in lower allowance prices than one in which these resources are not directly addressed.

5. Most technologies which reduce carbon emissions also reduce emissions of other criteria pollutants, such as NO_x and SO_2, and mercury. Models which include these co-benefits will predict a lower overall cost impact from carbon regulations, as the cost of reducing carbon emissions will be offset by savings in these other areas. Adopting carbon reduction technology results not only in cost savings to the generators who no longer need criteria pollutant permits, but also in broader economic benefits in the form of reduced permit costs and consequently lower priced electricity. In addition, there are a number of co-benefits such as improved public health, reduced premature mortality, and cleaner air associated with overall reductions in power plant emissions which have a high economic value to society.

6. Projected emissions under a business-as-usual scenario (in the absence of greenhouse gas emission restrictions) have a significant bearing on projected allowance costs. The higher the projected emissions, the higher the projected cost of allowance to achieve a given reduction target.

C. Other forecasts

A number of electric companies include projections of costs associated with greenhouse gas emissions in their resource planning procedures. Table 2, below, summarizes the values used by utilities in their resource plans in the past two years.

Table 2: Values for carbon dioxide used by utilities in resource planning

Utility	Date of IRP (or equivalent)	Model Run	Description
Avista	2009	Base-case	Allowance cost is $46.14 (nominal) and $33.37 (2009 dollars), beginning in 2012. Reaches its high value in 2029.
Idaho Power	2009		$43/ton starting in 2012
LADWP	2010	Base Case	Base case assumes that GHG pricing starts at $20/short ton in 2012 and escalates to $40/short ton in 2020, then escalating at 2.6% annually through 2030. (nominal dollars)
		Low Case	The low case assumes that pricing starts at $15/short ton in 2012 and escalates to $30/short ton in 2020, then escalating at 2.6% annually through 2030. (nominal dollars)
		High Case	The high case assumes that pricing starts at $25/short ton in 2012 and escalates to $50/short ton by 2020 with continued escalation of 2.6% through 2030. (nominal dollars)
Minnesota Power	2010	Base Forecast	$22.11/short ton starting in 2015 and $47.03/short ton in 2024
		Low Forecast	No carbon costs
		High Forecast	$25.66/short ton starting in 2012 and $138.04/short ton in 2024
Nevada Power	2009	Low	Begins at about $10 in 2013 and rises to about $32 in 2039. (2009$/short ton)
		Mid	Begins at about $20 in 2013 and rises to about $70 in 2039. (2009$/short ton)
		High	Begins at about $39 in 2013 and rises to about $138 in 2039. (2009$/short ton)
NorthWestern	2009		Base Case assumes that regs begin in 2013 at $9.55/ton and rises to $80.41/ton in 2030 (2006$). Also cases for earlier and later action.
PacifiCorp	2011	Low	Starting at $12/ton (2015$) in 2015, with 5% annual escalation.
		Medium	Starting at $19/ton (2015$) in 2015, with 5% annual escalation.
		High	Starting at $25/ton (2015$) in 2015, with 7% annual escalation.
		Medium-High	Starting at $19/ton (2009$) in 2015, with 5% annual escalation through 2020; in 2020, escalating at 12% per year. Price reaches $75/ton by 2030.
PGE	2009	Base	Levelized cost of $30/short ton. (2009$)
		Sensitivity	Levelized costs of $12/short ton. (2009$)
		Sensitivity	Levelized costs of $20/short ton. (2009$)
		Sensitivity	Levelized costs of $45/short ton. (2009$)
		Sensitivity	Levelized costs of $65/short ton. (2009$)
PSCo	2010	Base	$20/ton starting in 2014 and escalating at 7% per year
		Sensitivity	$0/ton for all year
		Sensitivity	$40/ton starting in 2014 and escalating at 7% per year
PSE	2009	2007 Trends/2009 Trends	Assumes a CO2 charge of $37/ton starting in 2012, increasing to $130/ton by 2029.
		Green Worlds	CO2 emissiosn cost rise from $55/ton in 2012 to $150/ton in 2029.
		2007 BAU/2009 BAU	$1.60/ton for 20% of the CO2 emitted by plants producing greater than 250 MW. This equates to $0.32/ton, i.e. nearly zero.
Seattle City Light	2010	Basic	In 2007$ per ton. Begins at $20/ton in 2012 and increases to $64.80 in 2030.
		Low	In 2007$ per ton. Begins at $15/ton in 2012 and increases to $41.90 in 2030.
		High	In 2007$ per ton. Begins at $30/ton in 2012 and increases to $106.40 in 2030.
Sierra Pacific	2010		2009$/short ton. Low case begins at about $9 in 2014 and rises to about $31 in 2040. Mid case begins at about $19 in 2014 and rises to about $64 in 2040. High case begins at about $38 in 2014 and rises to about $132 in 2040.
Tri-State	2007	Low	$10/ton (2007$) starting in 2007, escalating at 3% per year
		Mid	$25/ton (2007$) starting in 2007, escalating at 3% per year
		High	$35/ton (2007$) starting in 2007, escalating at 3% per year
SPS (Xcel)	2009		Modeled at $8, $20, and $40 per metric ton, escalated at 2.5%/year consistent with New Mexico PUC Order.
Northern States Power Company (Xcel)	2010		A planning value of $17 per ton CO2 starting in 2012 and escalating at 1.9% per annum. MN Commission high and low externality values are incorporated as sensitivities.

5. Synapse's Recommended February 2011 CO_2 Price Forecast

Our forecast of prices associated with carbon dioxide emissions reflects a reasonable range of expectations regarding the `timing and magnitude of costs for greenhouse gas emissions. We considered what policy developments (e.g. regulation, regional coordination, federal legislation) would lead to costs in the near-term. Our forecast of the range for the mid-term is dominated by projections of legislative compliance costs since those are readily available, rigorous analyses of potential costs under a variety of reduction targets. These are informative even with current uncertainty about federal legislation since they represent the most comprehensive analysis of costs of achieving certain levels of reductions. In the long-term, beyond 2030, we anticipate that costs of emissions will be governed by the costs of marginal abatement technologies. However, our current forecast does not extend beyond 2030. All annual allowance price and levelized values are given in 2010 dollars per short ton of carbon dioxide.[13]

The Synapse February 2011 CO_2 price forecast begins in 2015. This assumption reflects the fact that Congress has lagged behind the states and executive branch in developing a policy response to the science of climate change. The earliest possible action that will affect power generation in all states will likely be regulations from EPA. EPA has agreed to issue final regulations by 2012. Implementation of the regulations, resulting in costs to generators, is likely to be in 2013-2015. That time frame is also consistent with the development of regional emissions cap and allowance trading programs in the West and the Midwest that will affect 13 states beyond the 10 that are already participating actively in the functioning Regional Greenhouse Gas Initiative in the Northeast.

The high bound on our CO_2 Price Forecast starts at $15/ton in 2015, and rises to approximately $80/ton in 2030. Taken as a single trajectory, this High Forecast represents a $43/ton levelized price over the period 2015-2030. This High CO_2 Price Forecast is consistent with the occurrence of one or more of the factors identified above that have the effect of raising prices. These factors include somewhat more aggressive emissions reduction targets, greater restrictions on the use of offsets, restricted availability or high cost of technology alternatives such as nuclear, biomass and carbon capture and sequestration, more aggressive international actions (thereby resulting in fewer inexpensive international offsets available for purchase by U.S. emitters), or higher baseline emissions.

The low boundary on the Synapse CO_2 price forecast starts at $15/ton in 2020, and increases to approximately $30/ton in 2030. Taken as a trajectory, this represents a $13/ton levelized price over the period 2015-2030. By the year 2020 there is likely to be a price on greenhouse gas emissions either related to achieving greenhouse gas reduction goals, or to adaptation initiatives. A price on carbon affecting power plants throughout the country could come as late as 2020 if legislators fail to act for the next three sessions of congress, and if the President in power is either unable or unwilling to drive federal climate policy. In our opinion, federal legislation is likely by the end of the session in 2018 (with implementation by 2020) spurred by one or more of the following factors:

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[13] All values in the Synapse Forecast are presented in 2010 dollars. Results from EIA and EPA modeling analyses were converted to 2010 dollars using price deflators taken from the US Bureau of Economic Analysis, and available at: http://www.bea.gov/national/nipaweb/SelectTable.asp Because data were not available for 2010 in its entirety, values used for conversion were taken from Q3 of each year. Consistent with EIA and EPA modeling analyses, a 5% real discount rate was used in all levelization calculations.

technological opportunity; a patchwork of state policies to achieve state emission targets for 2020 spurring industry demands for federal action; a Supreme Court decision to allow nuisance lawsuits to go ahead resulting in a financial threat to energy companies; and increasingly compelling evidence of climate change. Given the interest and initiatives on climate change policies in states throughout the nation, a lack of federal action will result in a hodge podge of state policies. This scenario is a nightmare for any company that seeks to make investments in existing, modified, or new power plants. Historically, just such a pattern of states and regions leading with initiatives that are eventually superseded at a national level is common for energy and environmental policy in the US. It seems likely that this will be the dynamic that ultimately leads to federal action on greenhouse gases, as well.

The low forecast boundary is consistent with the coincidence of one or more of the factors discussed above that have the effect of lowering prices. For example, this price boundary may represent a scenario in which Congress begins regulation of greenhouse gas emissions slowly by either:

1. including a very modest or loose cap, especially in the initial years,
2. including a safety valve price or
3. allowing for significant offset flexibility, including the use of substantial numbers of international offsets.

The factors could also include state actions to reduce emissions through aggressive energy efficiency and renewable actions, and/or a decision by Congress to adopt a set of aggressive complementary policies as part of a package to reduce CO_2 emissions. These complementary policies could include an aggressive federal Renewable Portfolio Standard, more stringent automobile CAFE mileage standards (in an economy-wide regulation scenario), and/or substantial energy efficiency investments. Such complementary policies would lead directly to a reduction in CO_2 emissions independent of federal cap-and-trade or carbon tax policies, and would thus lower the expected allowance prices associated with the achievement of any particular federally-mandated goal.

The range of prices we have shown is recommended for planning purposes, but it is certainly possible that the actual price will fall outside of this range. For example, there are some CO_2 price scenarios identified in recent analyses that are significantly higher than our Synapse High Price Forecast. These scenarios represent situations with limited availability of alternatives to carbon-emitting technologies and/or limited use of international and domestic offsets. We do not believe that the CO_2 prices characteristic of such scenarios are likely in the current political environment, given that there may be avenues available for meeting likely emissions goals that would mitigate costs to below these levels. However, the political context may change over time due to changes in technical, economic, and political circumstances, and/or developments in scientific evidence on the rate and impacts of a changing climate.

Synapse also has prepared a Mid or Expected CO_2 Price Forecast that starts a bit more slowly, but close to the low case, at $15/ton in 2018, but then climbs to $50/ton by 2030. The levelized cost of this mid CO_2 price forecast is $26/ton over the period 2015 to 2030.

The 2011 Synapse High, Mid and Low CO_2 Price Forecasts are shown in Figure 8 and Table 3 below:

Figure 8: 2011 Forecast Values

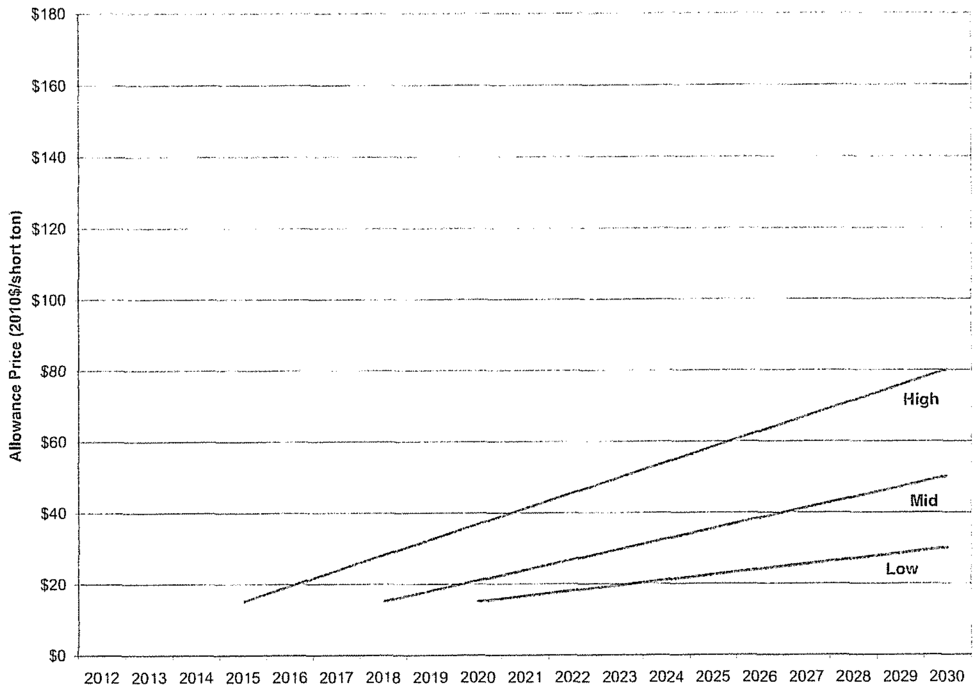
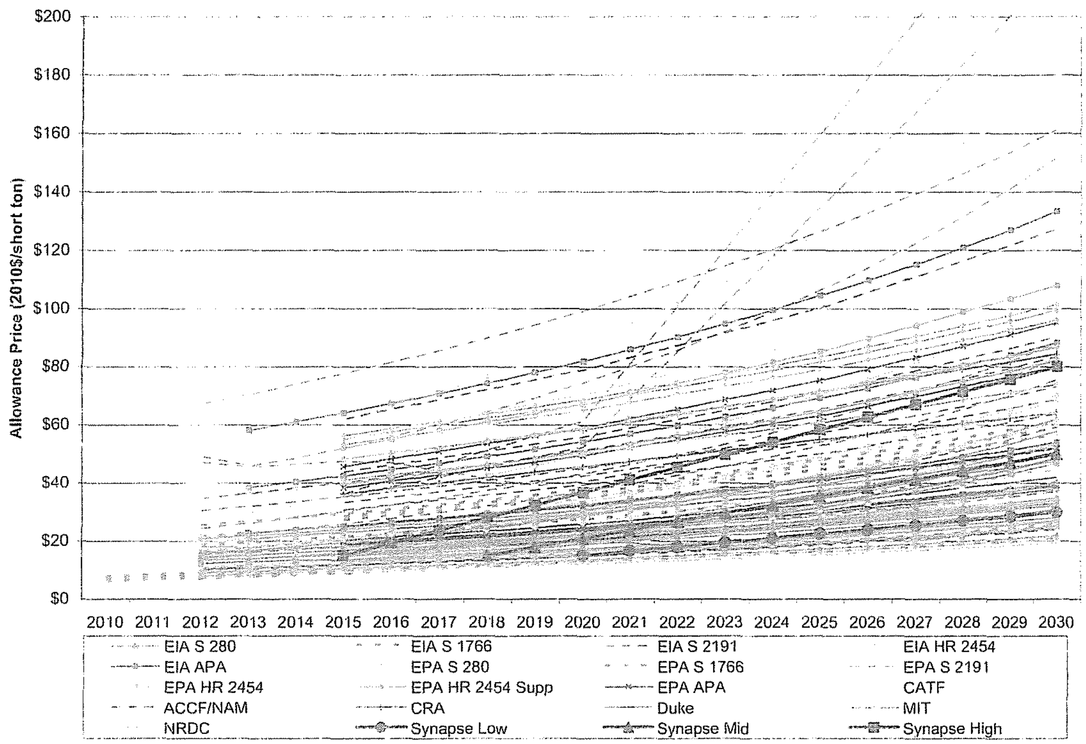


Table 3: 2011 Synapse Low, Mid, and High CO_2 Allowance Price Forecasts (2010$/short ton)

Year	Low Case	Mid Case	High Case
2015	N/A	N/A	$15.00
2016	N/A	N/A	$19.33
2017	N/A	N/A	$23.67
2018	N/A	$15.00	$28.00
2019	N/A	$17.92	$32.33
2020	$15.00	$20.83	$36.67
2021	$16.50	$23.75	$41.00
2022	$18.00	$26.67	$45.33
2023	$19.50	$29.58	$49.67
2024	$21.00	$32.50	$54.00
2025	$22.50	$35.42	$58.33
2026	$24.00	$38.33	$62.67
2027	$25.50	$41.25	$67.00
2028	$27.00	$44.17	$71.33
2029	$28.50	$47.08	$75.67
2030	$30.00	$50.00	$80.00

It is important to emphasize that these are price trajectories to use for planning purposes, so that a reasonable range of emissions costs can be incorporated to reflect likely costs of alternative resource plans, for example. We do not expect carbon prices to follow any single trajectory in our forecast. Rather, our forecast can be read as the expectation that in 2015 the price will be between $0 and $15 in 2010 dollars, and in 2025 it will be between $23 and $58. It is entirely possible that the price will start out quite low, as Congress "tests the waters" on carbon policy, and rise closer to our high case as the need for greater emissions reductions becomes increasingly evident, more technological options become available, and the economy and the electorate adjust to paying for carbon emissions. Just such a scenario was recently applied by Pacificorp in their proposed Integrated Resource Plan.[14] Their "Low to Very High" trajectory begins at $12/ton in 2015 (2015 dollars) and grows at only 3%/year in real terms until 2020, and then at 18% real escalation thereafter. Converted into 2010 dollars, this scenario has a levelized cost almost exactly the same as Synapse' "Mid" case presented here. Figures 9 through 13, below, place the Synapse February 2011 forecast in context. They present the Synapse February 2011 forecast alongside projections of greenhouse gas allowance prices associated with federal legislative proposals discussed in previous sections of this report.

Figure 9: Synapse CO_2 trajectories and greenhouse gas allowance price projections based on analyses of federal legislative proposals



[14] Pacificorp, "Portfolio Development Cases for the 2011 Integrated Resource Plan", December 7, 2010.

Figure 10: Synapse CO_2 trajectories and greenhouse gas allowance price projections based on analyses of federal legislative proposals – levelized

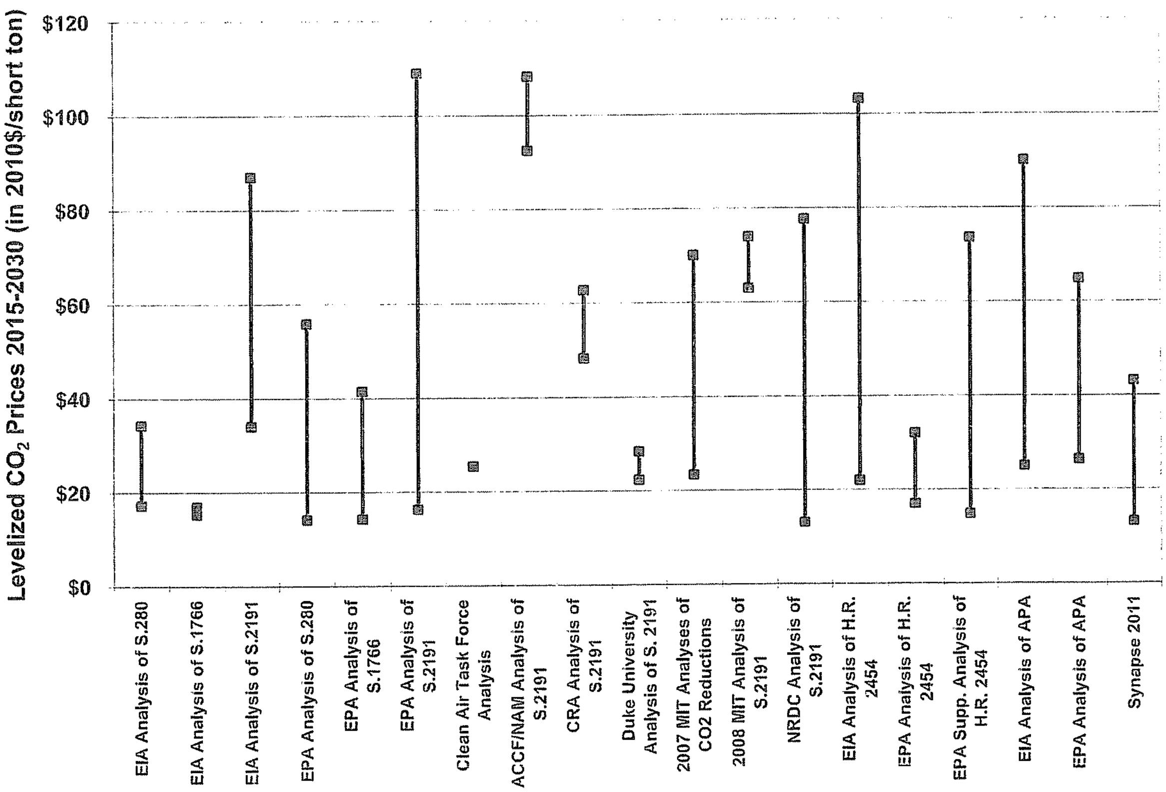


Figure 11: Synapse CO_2 trajectories and greenhouse gas allowance price projections for HR 2454 and APA 2010

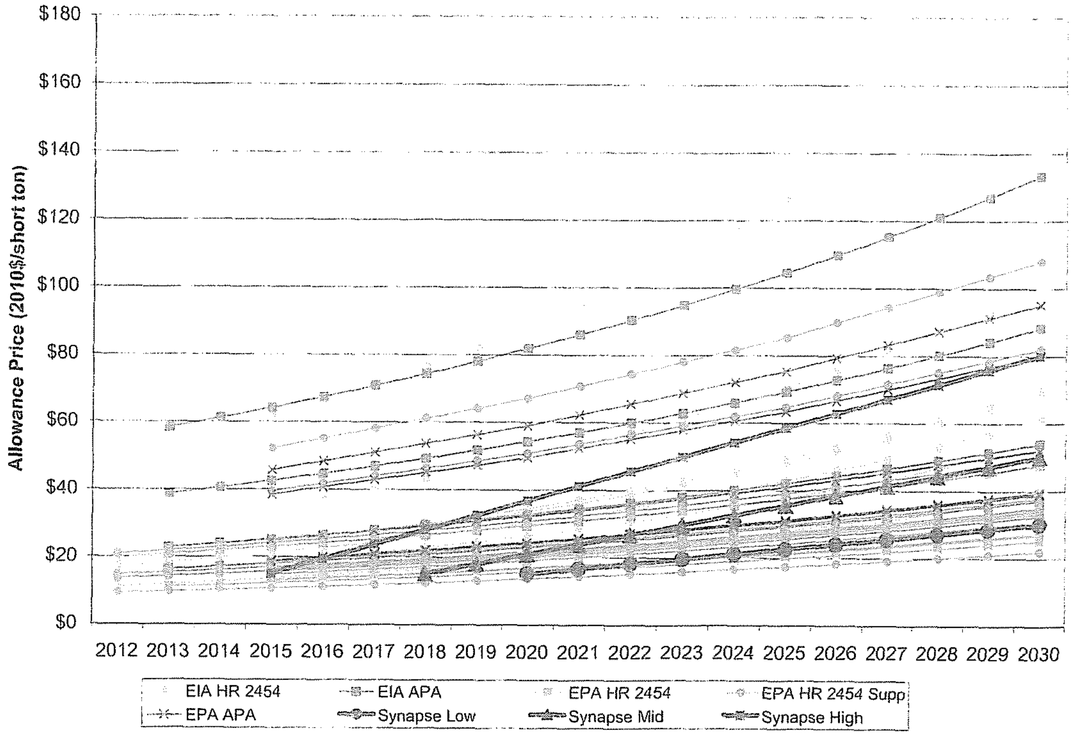


Figure 12: Synapse CO_2 trajectories and greenhouse gas allowance price projections for HR 2454 and APA 2010- levelized 2015-2030

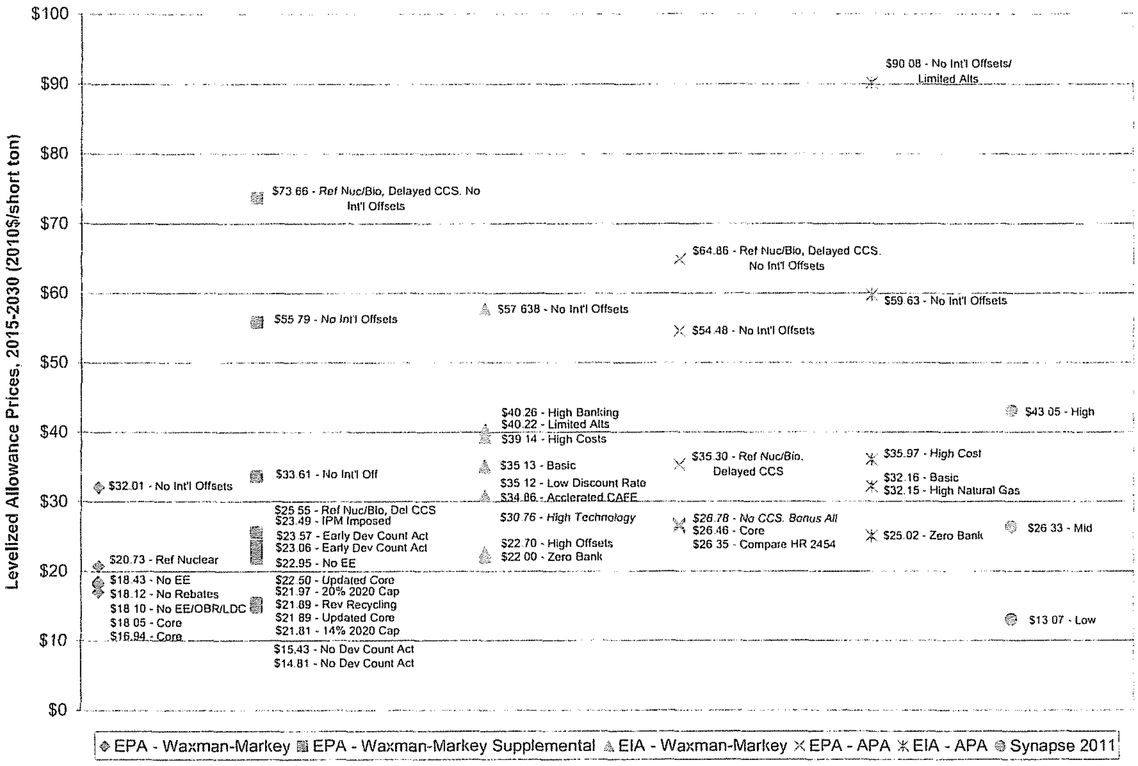
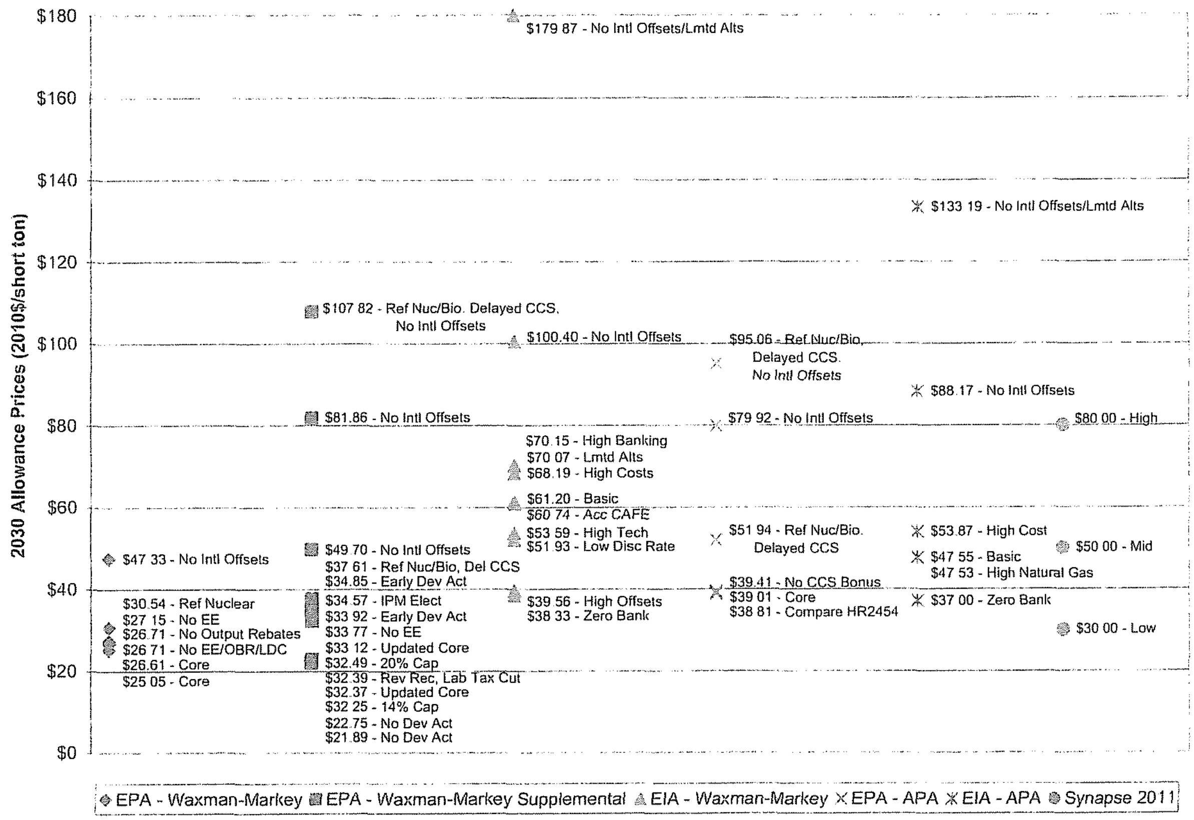


Figure 13: 2030 Synapse CO_2 prices and greenhouse gas allowance price projections for HR 2454 and APA 2010



The Synapse projections represent a range of possible future costs. These recommended price trajectories will be useful for testing range-sensitivity of various investment possibilities in resource planning in the electric sector. There will certainly be variability and volatility in prices following supply and demand dynamics, as there is with other cost drivers. Nonetheless, we intend and anticipate that the projections represent a useful price range for resource planning and policy analysis in the face of uncertainty.

6. Conclusion

The lack of clarity on the future of climate change policies in the United States does not diminish the importance of appropriate consideration of likely future emissions costs in electric resource planning. To the contrary, a reasonable projection of a range of costs is critical to investment decisions and the selection of least-cost resource plans that will be robust under a variety of circumstances. As the most comprehensive source of information on potential costs under a variety of emission reduction scenarios, analyses of recent legislative proposals provide useful insight in developing a reasonable emissions price projection. These analyses of legislative proposals provide information that is useful in considering a variety of policy futures – well beyond those that include a national emissions cap and allowance trading program. They explore the dynamic relationship between factors such as emission reductions, technology innovation, flexibility mechanisms (such as offsets), penetration of clean energy sources and efficiency, and others – all of which come into play under a variety of policy mechanisms. The Synapse February 2011 Carbon Forecast represents a reasonable range of values to use in investment decisions and resource selection. The range presented does not include the most extreme high or low values, which derive from a combination of factors that can reasonably be deemed unlikely to occur in combination. Rather, it represents a reasonable range to use for purposes of robust analysis of resource plans and policy options, recognizing that the future will always involve uncertainty.

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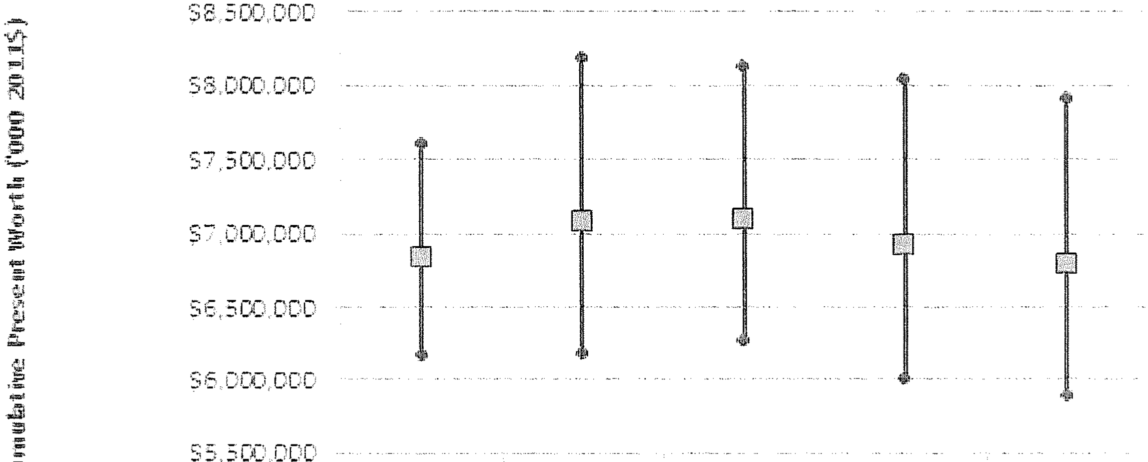
Exhibit____JIF-9



	'BASE' Option #1	Option #2	Option #3	Option #4A	Option #4B
95th % Aurora Risk	7,609,980	8,182,166	8,130,133	8,084,108	7,907,927
Strategist ("Base") Outcome	6,838,879	7,075,297	7,091,182	6,917,767	6,781,587
5th % Aurora Risk	6,171,648	6,172,690	6,268,489	6,008,152	5,881,981

Company results (unaltered) of cumulative present worth (CPW) of Options #1-#4B. Center points represent Strategist outcome in "Base" commodity scenario. Upper and lower bounds represent range of 95^{th} and 5^{th} percentile outcome from Aurora results. Assumes 4A has same risk profile as 4B.

Exhibit____JIF-10A

Net benefit of Big Sandy retrofit versus:	**Option 2:** Replace with NGCC	**Option 3:** Repowered BS1	**Option 4a:** Market until 2020 NGCC	**Option 4b:** Market until 2025 NGCC
Strategist Ex. SCW-4	\$236 M	\$252 M	\$79 M	\$(-47) M
Aurora Ex. SCW-5 (p1)	\$586 M	\$527 M	Not modeled	\$562 M
Relative advantage conferred by Aurora	\$350 M	\$275	-	\$609 M
% Difference	248%	209%	-	1,195%

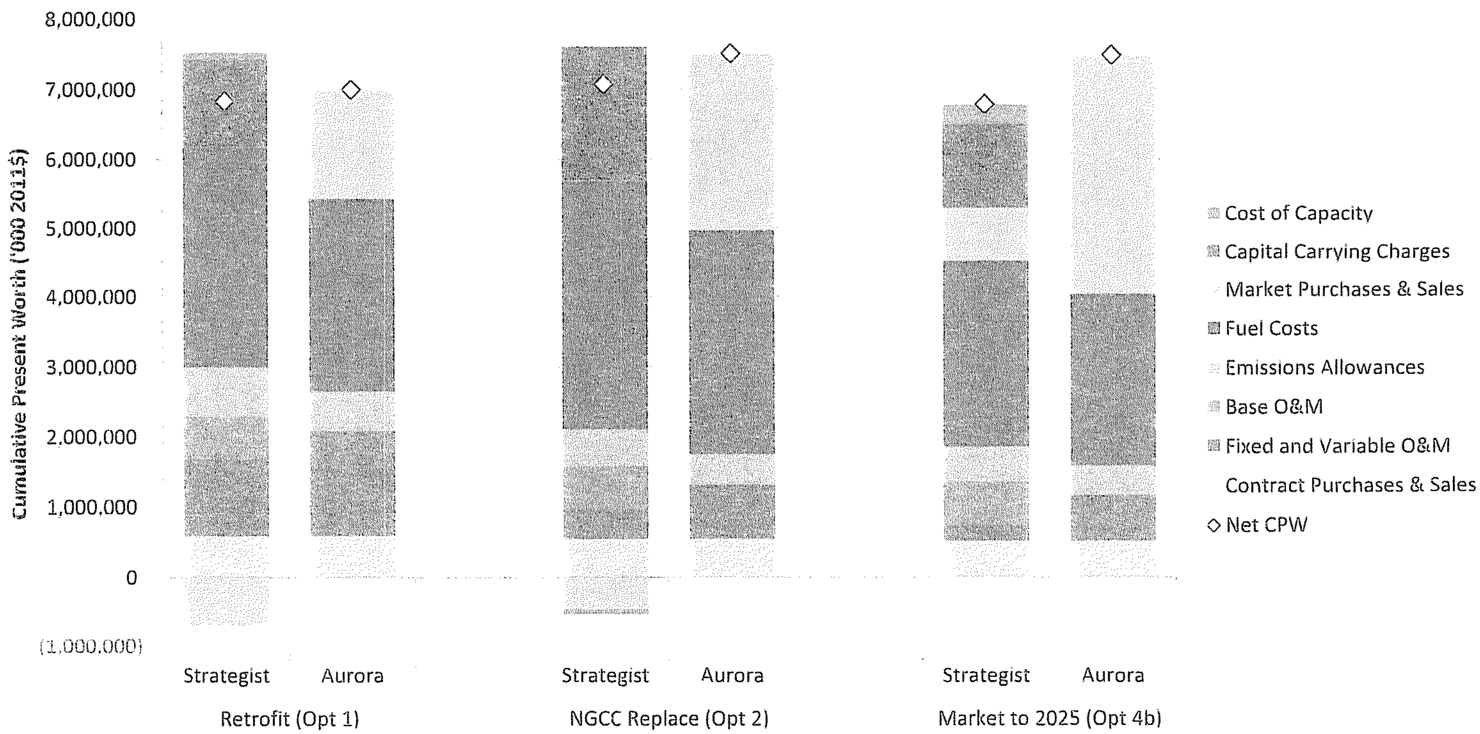
Differences in relative net benefit of retrofit versus other alternatives.

Exhibit____JIF-10B

Cost Categories	**Strategist Compilation Analysis Name**	**Aurora Spreadsheets Name**
Fuel Costs	Fuel Cost	Fuel Costs
Contract Purchases & Sales	Contract Revenue	Contract Revenue
Market Purchases & Sales	Market Revenue / (Cost)	Net Cost of Imports
Capital Expenditures	Carrying Charges	*Not in Aurora Analysis*
Variable O&M	Incremental O&M [and Base O&M]	Variable O&M
Fixed O&M		Fixed O&M
Emissions Allowances	Market Value of Allowances Consumed	Emissions Cost
Capacity Cost	Value of ICAP	ICAP

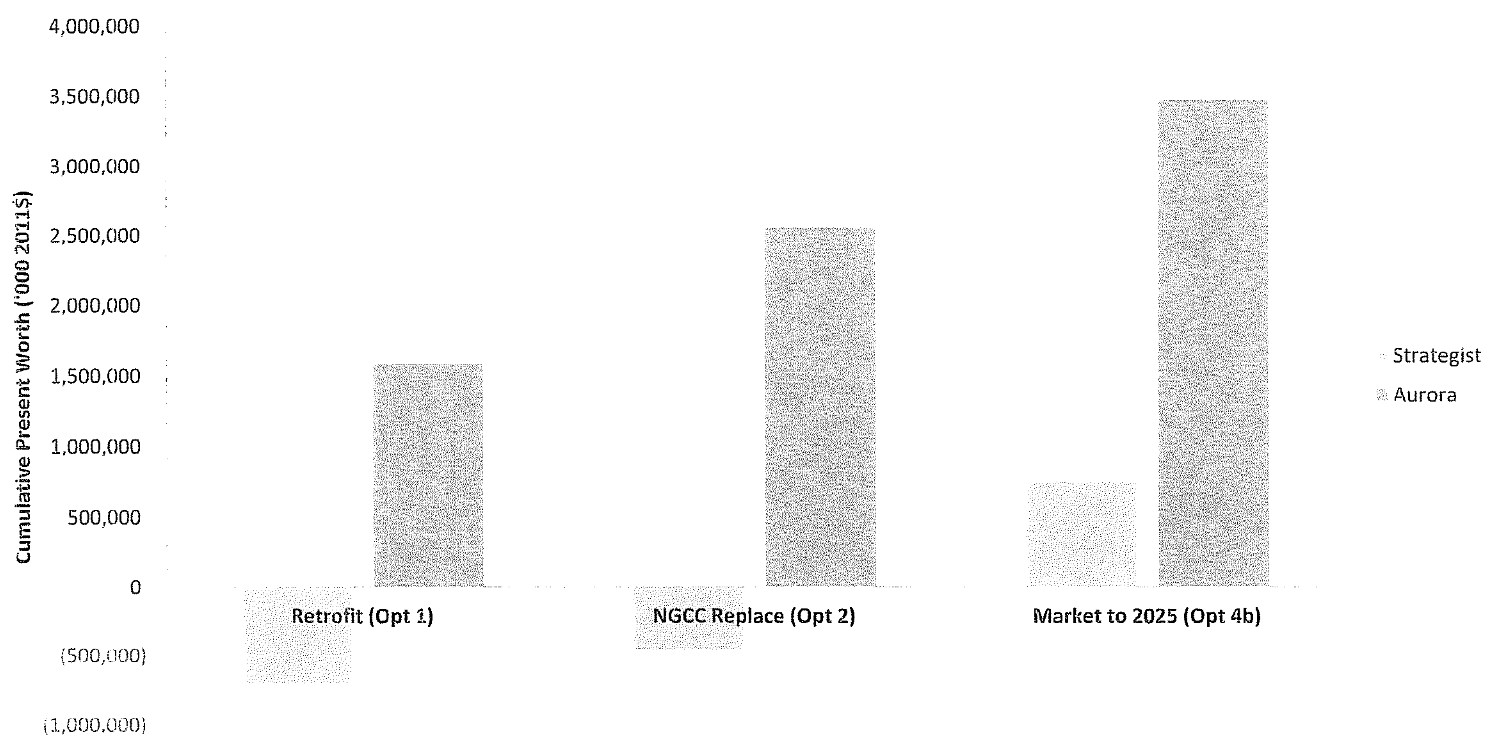
Cost Category names in Strategist and Aurora

Exhibit____JIF-11A



Comparison of CPW cost components between Strategist and Aurora models.

Exhibit____JIF-11B



Contrasting market purchases between the Aurora and Strategist models in three scenarios.

Correlations provided by AEP in SCW-1, Table 1-4

	Natural Gas Price	Coal Price	Carbon Price	Market Power Price	Demand (Load Req)
Natural Gas Price	1.00	0.09	(0.23)	0.88	seasonal
Coal Price		1.00	0.69	0.19	0.74
Carbon Price			1.00	(0.14)	0.50
Market Power Price				1.00	0.75
Demand (Load Req)					1.00

Correlations derived from Company Response to Sierra DR 2-34b

	Natural Gas Price	Coal Price	Carbon Price	Market Power Price	Demand (Load Req)
Natural Gas Price	1.00	0.09	0.45	0.88	0.66
Coal Price		1.00	0.05	0.10	0.08
Carbon Price			1.00	0.53	0.68
Market Power Price				1.00	0.76
Demand (Load Req)					1.00

**Assumes CO2 is Generic Distribution 28*

Data Source		
Europe	US	Hypothesized

Difference

	Natural Gas Price	Coal Price	Carbon Price	Market Power Price	Demand (Load Req)
Natural Gas Price		0.00	-0.68	0.00	
Coal Price			0.63	0.09	0.66
Carbon Price				-0.67	-0.18
Market Power Price					-0.01
Demand (Load Req)					

Comparison of correlations presented in testimony and derived from discovery.

Correlations provided by AEP in SCW-1, Table 1-4

	Natural Gas Price	Coal Price	Carbon Price	Market Power Price	Demand (Load Req)
Natural Gas Price	1.00	0.09	(0.23)	0.88	seasonal
Coal Price		1.00	0.69	0.19	0.74
Carbon Price			1.00	(0.14)	0.50
Market Power Price				1.00	0.75
Demand (Load Req)					1.00

Synapse Estimates

	Natural Gas Price	Coal Price	Carbon Price	Market Power Price	Demand (Load Req)
Natural Gas Price	1.00	0.11	(0.43)	0.41	(0.15)
Coal Price		1.00	0.67	0.32	0.11
Carbon Price			1.00	(0.43)	0.00
Market Power Price				1.00	(0.51)
Demand (Load Req)					1.00

Data Source		
Europe	US	Hypothesized

Difference

	Natural Gas Price	Coal Price	Carbon Price	Market Power Price	Demand (Load Req)
Natural Gas Price		-0.03	0.20	0.46	0.81
Coal Price			0.01	-0.14	0.63
Carbon Price				0.30	0.50
Market Power Price					1.26
Demand (Load Req)					

Comparison of correlations presented in testimony and derived from domestic data.