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Witness:	Rachel S. Wilson
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Case No.:	ER-2014-0370
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BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

IN THE MATTER OF KANSAS CITY POWER & LIGHT COMPANY'S REQUEST FOR AUTHORITY TO IMPLEMENT A GENERAL RATE INCREASE FOR ELECTRIC SERVICE	))))	**Case No. ER-2014-0370**

Direct Testimony of Rachel S. Wilson

On Behalf of Sierra Club

April 2, 2015

**** Denotes Highly Confidential Information ****

PUBLIC

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1. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and position.

A. My name is Rachel Wilson and I am a Senior Associate with Synapse Energy Economics, Incorporated ("Synapse"). My business address is 485 Massachusetts Avenue, Suite 2, Cambridge, Massachusetts 02139.

Q. Please describe Synapse Energy Economics.

A. Synapse 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.

Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government agencies, and utilities.

Q. Please summarize your work experience and educational background.

A. At Synapse, I conduct research and write testimony and publications that focus on a variety of issues relating to electric utilities, including: integrated resource planning; federal and state clean air policies; emissions from electricity generation; environmental compliance technologies, strategies, and costs; electrical system dispatch; and valuation of environmental externalities from power plants.

I also perform modeling analyses of electric power systems. I am proficient in the use of spreadsheet analysis tools, as well as optimization and electricity dispatch models to conduct analyses of utility service territories and regional energy markets. I have direct experience running the Strategist, PROMOD IV, PROSYM/Market Analytics, PLEXOS, and PCI Gentrader models, and have reviewed input and output data for a number of other industry models.

Prior to joining Synapse in 2008, I worked for the Analysis Group, Inc., an economic and business consulting firm, where I provided litigation support in the form of research and quantitative analyses on a variety of issues relating to the electric industry.

I hold a Master of Environmental Management from Yale University and a Bachelor of Arts in Environment, Economics, and Politics from Claremont McKenna College in Claremont, California.

A copy of my current resume is attached as Schedule RSW-1.

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

A. I am testifying on behalf of the Sierra Club.

Q. Have you testified previously before the Missouri Public Service Commission?

A. No, I have not.

Q. What is the purpose of your testimony in this proceeding?

A. My testimony details and evaluates components of Kansas City Power & Light's (the "Company" or "KCP&L") analysis supporting its application, specifically the economic justifications for the environmental retrofits at the La Cygne Generating Station for which capital recovery is requested in this case. I find that KCP&L's original analysis of the La Cygne retrofits was imprudent, and that market conditions changed significantly in the electric sector in 2011 and 2012, warranting a reevaluation of that analysis.

Q. Please identify the documents and filings on which you base your opinions regarding KCP&L's proposed rate increase.

A. I have reviewed the Company witnesses' testimonies and discovery responses in this case, which include but are not limited to: 1) KCP&L's original application for predetermination presented to the Kansas Corporation Commission in 2011 in Docket No. 11-KCPE-581-PRE; 2) the original MIDAS modeling files and associated work papers; and 3) the monthly status reports on the La Cygne environmental retrofits provided to the Missouri Public Service Commission ("MPSC"). I have reviewed documents related to Planning Prudence and Rates that intervenors submitted to the MPSC in 2012 in Case No. ER-2012-0174. Finally, I have also reviewed KCP&L's 2012 Integrated Resource Plan (IRP) and intervenor comments submitted to the MPSC under File No. EO-2012-0323, as well as the 2013 Integrated Resource Plan Update.

2. OVERVIEW OF TESTIMONY AND CONCLUSIONS

Q. In your opinion, do the facts and evidence presented in this case support the Company's proposed rate increase?

A. No, they do not. I believe that KCP&L's original analysis was flawed, and that the inclusion of specific elements that were missing from the original analysis would have changed the results. I also believe that conditions in the electric sector changed substantially after KCP&L completed its analysis of the La Cygne retrofits, such that those retrofits were even less economic, and certainly not in the best interest of ratepayers.

Q. What is the basis for your objection to the proposed rate increase?

A. KCP&L's original analysis of the La Cygne retrofits was imprudent. There were many elements missing from the Company's calculations that would have raised the costs to retrofit and to continue to operate La Cygne Units 1 and 2. These elements were brought to KCP&L's attention by various intervenors in the Kansas docket for predetermination of the retrofits, 11-KCPE-581-PRE, and KCP&L was aware of these criticisms.

Electric utilities have an obligation to conduct prudent planning with regard to all investments for which they intend to seek rate recovery. This is especially true for major capital additions, such as the La Cygne environmental retrofits at issue in this case, due to the magnitude and risk of these expenditures. Conditions in the electric sector can change quickly, and thus the obligation for prudent planning does not end when the initial decision to proceed with a major capital addition is made, but is instead ongoing during the construction period for as long as costs are avoidable.

Market conditions in the electric sector changed significantly during 2011 and 2012 such that increasing numbers of coal-fired power plants across the country have become uneconomic to operate. I find that there were several decision points during this time period at which KCP&L should have revisited its original analysis and arrived at different conclusions with respect to the La Cygne retrofits. The available record in this case indicates that the Company chose not to do so. Proper consideration of market conditions would have shown the retrofits at La Cygne to be uneconomic when compared to retirement and replacement options. Inclusion of the additional elements that were missing from the original analysis would have caused the retrofits to be even more costly.

As of 2011, a number of environmental regulations had recently been proposed by the United States Environmental Protection Agency ("EPA") to govern a variety of pollutants emitted by coal-fired generating units, which would require significant investment in environmental control technologies. Owners and operators of these units had to analyze the costs associated with the installation of pollution control retrofits at their units compared to the cost of retiring and replacing the units with alternative generation options.

Natural gas prices declined significantly in 2011 and 2012, as did future forecasts of natural gas price trajectories and wholesale prices for electricity. In April 2011, the Energy Information Administration ("EIA") released its Annual Energy Outlook ("AEO") 2011 data, which showed a significant drop in natural gas prices from the previous year's forecast. If this forecast had been used in place of KCP&L's initial natural gas price forecast, the benefits from the Company's preferred plan to install emission controls at La Cygne 1 and 2 would have been eliminated. Forecasts from the EIA in January 2012 and June 2012 showed declines in natural gas prices that were even more significant, and at either of these two dates it would have been clear that the retirement of one or both of the units was the more economic choice.

Taking only the gas prices as a cue, KCP&L should have significantly reconsidered and re-evaluated its decision to retrofit La Cygne 1 and 2 in April 2011, and likely should have taken serious action to suspend retrofit operations and sought to retire one or both of the La Cygne units by January 2012, avoiding expensive pollution control retrofits, the cost of which ratepayers are being asked to bear in this proceeding.

3. OVERVIEW OF KCP&L ANALYSIS

Q. What is KCP&L seeking in this docket, and what were the regulatory drivers that prompted the Company's decision?

KCP&L is seeking rate recovery for emissions control retrofits at its La Cygne generating plant for Units 1 and 2. These retrofits are budgeted at $1.23 billion and are intended to bring the units into compliance with the following environmental regulations: the Regional Haze Rule, the Mercury and Air Toxics Standards, the Cross-State Air Pollution Rule, the National Ambient Air Quality Standards, and the Acid Rain Program.[1] KCP&L installed 1) low nitrogen oxide ("NO_x") burners and selective catalytic reduction technologies on Unit 2 to remove NO_x; 2) scrubbers on both Units 1 and 2 to remove sulfur dioxide ("SO_2"); 3) additional and/or upgraded particulate removal equipment and sorbent injection systems on both Units 1 and 2; and 4) various other associated support equipment, including but not limited to, a new dual flue stack, induced draft fans,

[1] Direct Testimony of Paul Ling. MPSC Case No. ER-2014-0370. October, 2014. Page 3, lines 21-23.

an emergency generator and pump, and ash, gypsum and limestone storage and handling equipment.[2]

Q. Have other jurisdictions had the opportunity to review KCP&L's analysis of the environmental retrofits at La Cygne?

A. Yes. On February 23, 2011, KCP&L filed a Petition for Predetermination with the Kansas Corporation Commission ("KCC"), asking the KCC to determine rate-making principles and treatment to recover in rates the cost to make environmental upgrades to La Cygne Units 1 and 2. KCP&L submitted the same analysis in that docket (11-KCPE-681 PRE) that was submitted in this proceeding.

Q. Please describe the analysis performed by KCP&L to support its conclusion that La Cygne should receive emissions control retrofits.

A. KCP&L's analysis addressed the question of whether it was more economic to install pollution control retrofits at La Cygne Units 1 and 2, or to avoid those emissions control costs by retiring one or both units. The Company did this through a modeling analysis that examined different configurations of environmental retrofits and unit retirement and replacement with either natural gas combustion turbines ("CTs") or combined cycle ("NGCC") units. These combinations were examined for La Cygne Units 1 and 2 and Montrose Units 1-3. As Mr. Crawford described in his testimony in the Kansas predetermination proceeding, KCP&L created 14 different resource plans and four sensitivity plans during an initial "resource screening process."[3] These 18 resource plans addressed varying scenarios under which different combinations of retrofits and retirements at La Cygne Units 1 and 2 and Montrose Units 1-3 were evaluated. The original

[2] Direct Testimony of Paul Ling. MPSC Case No. ER-2014-0370. October, 2014. Page 7, lines 19-23 and page 8, lines 1-2.
[3] Direct Testimony of Burton Crawford. KCC Docket No. 11-KCPE-581-PRE. February 1, 2011. Page 9, lines 4-6.

14 plans include KCP&L's estimate of base demand-side management measures ("DSM") while the four sensitivity plans examine increased levels of DSM.

The alternative resource plans were then evaluated using the MIDAS model, a production cost model that calculates an expected 25-year (from 2010-2034) net present value of revenue requirement ("PVRR") for each plan. These calculations were performed under 64 risk scenarios, which were developed to "gauge the risk associated with identified critical uncertain factors."[4] These factors included natural gas prices, coal prices, load growth, construction costs, financing costs, and carbon dioxide ("CO_2") emission allowance prices.[5] KCP&L applied a weighting to each of the 64 risk scenarios, and then calculated a single weighted average PVRR value for each of its 18 resource plans.[6]

Q. Please describe the outcome of the Company's modeling as presented to the Kansas Corporation Commission in 2011.

A. Of the 14 resource plans in its base analysis, the Company had identified the case where ** ______________________________ ______________________________ **.[7] This informed the Company's decision to retrofit La Cygne 1 and 2.

The case in which ** ______________________________ ______________ ** exceeded the preferred resource plan by

[4] Direct Testimony of Burton Crawford. KCC Docket No. 11-KCPE-581-PRE. February 1, 2011. Page 5, lines 10-11.
[5] Direct Testimony of Burton Crawford. KCC Docket No. 11-KCPE-581-PRE. February 1, 2011. Page 7, lines 15-18.
[6] Direct Testimony of Burton Crawford. KCC Docket No. 11-KCPE-581-PRE. February 1, 2011. Page 7, lines 3-9.
[7] Direct Testimony of Burton Crawford. KCC Docket No. 11-KCPE-581-PRE. February 1, 2011. Confidential Schedule BLC2011-12.

$**_ ** million, or less than **__**% of the $1.23 billion in environmental retrofit cost contemplated in this case.[8]

It is also important to note that KCP&L's preferred plan, KP05B, was not the least-cost plan under all scenarios. In his direct testimony in the Kansas docket, Mr. Crawford stated that the retrofits were part of the low cost plan in about 73 percent of the scenarios analyzed, and "[t]he scenarios where the retrofits were not selected generally include both the low gas price scenarios and the high CO_2 price scenarios."[9] He also acknowledges this in his testimony in this proceeding.[10]

Q. Was KCP&L's analysis subject to any criticism in the predetermination proceeding (11-KCPE-581-PRE)?

A. Yes, it was subject to several criticisms from a number of intervenors. Certain major critiques are summarized here:

- *Dr. William Steinhurst, testifying for Sierra Club*: Dr. Steinhurst testified that the Company's analysis and justification for the retrofit of the La Cygne units did not meet the standard for pre-approval in Kansas, and asked that the pre-approval request be denied without prejudice. He found that the Company had failed to consider a reasonable level of cost effective energy efficiency, and did not consider renewable energy above that of the then existing RPS. Dr. Steinhurst recommended that the KCC require KCP&L to assess all relevant resource options, including a range of supply and demand-side measures, and develop a plan that

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[8] Direct Testimony of Burton Crawford. KCC Docket No. 11-KCPE-581-PRE. February 1, 2011. Confidential Schedule BLC2011-12.
[9] Direct Testimony of Burton Crawford. KCC Docket No. 11-KCPE-581-PRE. February 1, 2011. Page 14, lines 19-21.
[10] Direct Testimony of Burton Crawford. MPSC Case No ER-2014-0370. October 2014. Page 24, lines 15-18.

appropriately manages cost and risk in the face of considerable market and regulatory uncertainty.[11]

- *Dr. Ezra Hausman, testifying for Sierra Club*: Dr. Hausman stated that KCP&L's analysis supporting its decision to retrofit La Cygne was overly constrained, and did not include a full range of options for addressing regulations such as non-gas supply options, or demand-side resources. Dr. Hausman found that the net benefit of the Company's preferred plan did not meaningfully exceed other plans considered by the Company.[12]
- *Dr. Jeremy Fisher, testifying for Sierra Club*: Dr. Fisher testified that KCP&L had correctly identified the range of environmental regulations that were likely to impact their fleet, but had failed to assess or model costs for the then impending coal combustion residuals ("CCR") rule and still pending effluent limitation guidelines ("ELGs"), thereby ignoring the risk of substantial control costs at existing coal units.[13]
- *Mr. David Schlissel, testifying for the Great Plains Alliance for Clean Energy*: Mr. Schlissel testified that KCP&L's analysis relied on natural gas price forecasts that were more than 13 months out-of-date, and that revised forecasts had been issued that were significantly lower than the earlier forecast on which KCP&L relied. He stated that a "Company does have a responsibility to re-examine the economics of a proposed project when at least one of the forecasts on which the Company is relying for

[11] Direct Testimony of Dr. William Steinhurst. KCC Docket No. 11-KCPE-581-PRE. June 3, 2011. Attached as Schedule RSW-2.
[12] Direct Testimony of Dr. Ezra Hausman. KCC Docket No. 11-KCPE-581-PRE. June 3, 2011. Attached as Schedule RSW-3.
[13] Direct Testimony of Dr. Jeremy Fisher. KCC Docket No. 11-KCPE-581-PRE. June 3, 2011. Page 7, lines 3-12. Attached as Schedule RSW-4.

> one of the most critical input assumptions, in this case natural gas prices, changes by a significant amount."[14]

Q. What was the outcome of the Kansas predetermination proceeding (11-KCPE-581-PRE)?

A. The KCC found that the plan selected by KCP&L to retrofit La Cygne Units 1 and 2 was reasonable, efficient, and reliable under the Kansas statutes that govern predetermination. The Order granting predetermination states that the Commission finds that the La Cygne retrofits were:

> "(P)rudent at the time the determination was made as reflected in the record. But the Commission cautions that it recognizes events change…Thus the issue of prudence does not end with a finding by this Commission that, at the time its determination was made, KCP&L made a prudent decision that the La Cygne Project was the least cost option. While implementing the La Cygne Project, KCP&L will need to continue to be careful, use caution, be attentive, and use good judgment in addressing ongoing changes that arise and in making decisions regarding the La Cygne Project to make sure its decision remains prudent."[15]

This Order was issued on August 19, 2011.

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[14] Direct Testimony of Mr. David Schlissel. KCC Docket No. 11-KCPE-581-PRE. June 3, 2011. Page 18, lines 18-21. Attached as Schedule RSW-5.

[15] State Corporation Commission of the State of Kansas. Order Granting KCP&L Petition for Predetermination of Rate-Making Principles and Treatment. KCC Docket No. 11-KCPE-581-PRE. August 19, 2011. Page 35.

4. CONDITIONS IN THE ELECTRIC SECTOR CHANGED SUBSTANTIALLY IN 2012 AND WARRANTED A REEVALUATION OF KCP&L'S RETROFIT ANALYSIS

Q. Can you describe the conditions in the electric sector in 2011, at the time KCP&L requested predetermination in Kansas for the retrofits at La Cygne, and immediately after in 2012?

At the time of KCP&L's Kansas request for predetermination, a number of environmental regulations had recently been proposed by the EPA to govern a variety of pollutants emitted by coal-fired generating units, including SO_2, NOx, mercury, and CCR, as well as cooling water intake. Owners and operators of these units were faced with a decision to either install pollution control retrofits at their units or retire and replace them with alternative generation options.

In February 2012, KCP&L filed a rate case with this Commission, Case No. ER-2012-0174. KCP&L was not yet seeking recovery of any expenditures related to the La Cygne environmental retrofits in that case, but construction of the retrofits was ongoing at that time. My colleague, Mr. Bruce Biewald, submitted testimony to this Commission in that case concerning the need for KCP&L to evaluate the prudence of the La Cygne environmental retrofits on an ongoing basis, and to adequately document that evaluation. In that testimony, Mr. Biewald stated the following about how changing conditions in the electric sector were causing an increasing number of utility company decisions to retire their coal-fired generating units instead of investing in costly and risky retrofits:

> "The decisions to retire existing coal-fired generating capacity are being made based on the economics. A combination of factors is causing the economic value of continued operation to be negative. These factors include the investments required to comply with environmental regulations, the risks of further regulations, aging and degradation of plant equipment, declining market prices for natural gas and wholesale

electricity, and an increasingly broad and attractive range of alternative resources including renewable energy and energy efficiency."[16]

Q. Mr. Biewald recommended before this Commission in Case No. ER-2012-0174 that KCP&L review the prudence of continuing the La Cygne Environmental Projects. What was Mr. Biewald's specific recommendation to the Commission?

Mr. Biewald noted that the IRP process within Missouri was not necessarily well aligned with the decision-making process required of KCP&L, but that the Company nonetheless had a continuing obligation to review their ongoing investments. Mr. Biewald stated:

> "I recommend that the Missouri Commission make it clear to KCP&L that any additional investment in La Cygne and Montrose will not be recoverable from Missouri customers unless the prudence of making those investments is justified in economic terms in a proper planning analysis, subject to ongoing examination. I understand that construction has begun on some of the retrofit projects, but that does not mean that the decision to continue that construction in light of changing market conditions and expectations should not be reevaluated. Indeed, market conditions have changed so substantially in the last year or two that the initial decisions to begin construction must be reevaluated frequently, in order to determine whether it is prudent and reasonable to proceed with the projects…Any eventual rate recovery of the investment should be contingent upon KCP&L conducting and demonstrating prudent planning with regard to spending at these existing coal plants."[17]

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[16] Direct Testimony of Bruce Biewald. MPSC Case No. ER-2012-0174. August 2, 2012. Page 7, lines 14-20.

[17] Direct Testimony of Bruce Biewald. MPSC Case No. ER-2012-0174. August 2, 2012. Page 4, lines 16-24 and Page 5, lines 3-5.

Q. When did Mr. Biewald make this recommendation?

A. On August 2, 2012.

Q. Did Mr. Biewald have any additional recommendations?

A. Yes. In his surrebuttal testimony Mr. Biewald stated that:

> "(I)t would be useful, especially in light of the significantly changed conditions in natural gas prices and energy markets since KCP&L began its $1.23 billion retrofit project, for the Missouri Commission to indicate that it intends to take a close look at the prudence of KCP&L emission control investments."[18]

Mr. Biewald further recommended that:

> "(T)he issue of emissions control investments compared with retirement of the existing coal units be prioritized within the IRP, and examined on an accelerated schedule, or that a separate process be initiated to examine the emission control investments in an inclusive, transparent, comprehensive, and timely manner."[19]

Q. When did Mr. Biewald make these recommendations?

A. On October 8, 2012.

Q. What was this Commission's finding with regards to Mr. Biewald's recommendation?

A. This Commission acknowledged that retiring existing units could benefit ratepayers under certain conditions, and set forth conditions that might precipitate such a consideration:

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[18] Surrebuttal Testimony of Bruce Biewald. MPSC Case No. ER-2012-0174. October 8, 2012. Page 1, lines 22-26.

[19] Surrebuttal Testimony of Bruce Biewald. MPSC Case No. ER-2012-0174. October 8, 2012. Page 4, lines 8-11.

> "When running a power plant costs more than the revenue it generates, it is time to consider retiring the plant. Retirement of coal-fired plants is common for several reasons. The cost to comply with environmental regulations is rising. Market prices for natural gas and wholesale electricity are declining. The availability of alternative resources like renewable energy and energy efficiency are growing. Those trends make sales of electricity off-system less profitable."[20]

Q. Did the Company re-evaluate its investments in La Cygne after either Mr. Biewald's recommendation or this Commission's acknowledgement that changing energy prices could render a decision uneconomic?

A. Nothing in the record suggests that KCP&L re-evaluated its decision to retrofit La Cygne subsequent to Kansas Docket 11-KCPE-581-PRE. That application was filed in February of 2011.

Q. Mr. Crawford asserts on p. 25 of his Direct Testimony that KCP&L reevaluated its 2011 analysis of La Cygne in subsequent Missouri IRP dockets. Did KCP&L's 2012 IRP adequately reevaluate the prudence of the La Cygne retrofits?

A. No, it did not. KCP&L's 2012 IRP was subject to the same major criticism raised in the 2011 Kansas predetermination proceeding and at issue here: the Company's analysis relied on outdated natural gas price forecasts and failed to account for an electricity market that had changed significantly in 2011 and 2012 such that coal plant economics were affected. Sierra Club's Comments submitted in the IRP docket EO-2012-0323 state that "it is unreasonable for KCP&L to continue to rely in its April 2012 IRP on projections from December 2010 and mid-to-late

[20] MPSC Case No. ER-2012-0174 and ER-2012-0175. Report and Order. January 9, 2013.

2011."[21] These forecasts were at least six months and as many as 17 months out-of-date.

KCP&L might argue that these types of resource planning dockets take a significant amount of time because the Company must collect and vet various input assumptions and forecasts, run modeling analyses, check those analyses for quality assurance, and draft an application or a resource plan. While it is true that these processes take time, prudent planning requires resource decisions to be evaluated outside of these regularly scheduled planning processes, as well as within them. Mr. Crawford stated in his testimony that he was aware that low natural gas price scenarios led to changed results, and that the retrofits of La Cygne were no longer economic under KCP&L's low gas price forecast, making retirement of the units the least-cost option.[22] Thus, even the suggestion of falling gas prices should have led KCP&L to drop a lower natural gas forecast into its modeling analysis as a test case in order to determine if it should perform further analysis.

As an electric system modeler, this is the sort of exercise that I frequently perform. It is a simple exercise to input a new natural gas forecast into a production simulation model like MIDAS and generate new PVRR values for resource portfolios that have already been modeled, and prudent planning dictates that KCP&L should have done that exact exercise at several different decision points from August 2011 to October 2012.

Q. Were there substantial changes in the energy market subsequent to February 2011?

A. Yes. As this Commission is no doubt aware, natural gas prices fell steeply in 2012. While prices had hovered around $4-$5/MMbtu from 2010 through about

[21] Comments of Sierra Club In the Matter of the Resource Plan of Kansas City Power & Light Company. MPSC Case No. EO-2012-0323. September 6, 2012. Page 9.
[22] Direct Testimony of Burton Crawford. KCC Docket No. 11-KCPE-581-PRE. February 1, 2011. Page 14, lines 19-21.

mid-2011,[23] prices declined steadily through 2012, bottoming out below \$2/MMbtu in early 2012. This steady decline in gas prices dropped energy prices, briefly inverted the dark/spark spread, and caused many coal units to significantly reduce their dispatch. The dark spread is the gross margins (on a \$/MWh basis) that could be commanded by a theoretical coal-fired unit relative to market prices. The spark spread refers to the same for a gas-fired unit. The difference between the dark and the spark spread simply indicates which units dispatch preferentially, and can be calculated as the difference between the variable cost of a theoretical gas-fired unit and a theoretical coal-fired unit. Historically, coal units have dispatched before natural gas units; however, in 2012, the average gas-fired combined cycle unit was less expensive than the average coal-fired unit by \$3.06/MWh, causing gas units to be dispatched before coal units and inverting the traditional dark/spark spread.[24]

Not only did gas prices fall, the long-term outlook for natural gas prices fell dramatically. As new gas extraction techniques started to become commonplace, forecasts predicted that gas prices (and thus energy prices) would remain suppressed for years to come.

In its 2011 analysis, KCP&L created its natural gas price forecast in part from a forecast from the EIA AEO that was dated April 2010.[25] In the Kansas Docket, Mr. Schlissel testified that this forecast was outdated, and that the EIA had issued a revised natural gas price forecast in **______________________________

[23] Henry Hub prices. US Department of Energy, Energy Information Administration (EIA). http://www.eia.gov/dnav/ng/hist/rngwhhdW.htm

[24] Based on a national average heat rate of 10.15 MMbtu/MWh for coal and 7.97 MMbtu/MWh for gas (from EPA Clean Air Markets Division, Air Markets Program Data 2012); annual average fuel prices of \$2.38/MMBtu (coal) and \$2.75 (gas) from DOE Energy Information Administration Short Term Energy Outlook historic prices for 2012; and variable O&M costs of \$4.25/MWh (coal) and \$3.43/MWh (gas) from Annual Energy Outlook, 2012.

[25] Direct Testimony of Mr. David Schlissel. KCC Docket No. 11-KCPE-581-PRE. June 3, 2011. Page 19, line 11.

____________________________________ **.[26] This **______ ___ ** forecast was EIA's AEO 2011 Early Release. In April 2011, after KCP&L had submitted its petition for predetermination, the EIA released its AEO 2011 data with another updated natural gas price forecast that was lower still.

In June of 2012, the EIA published its 2012 AEO, projecting ongoing low gas prices through the end of the analysis period in 2035, not exceeding $5/MMBtu (nominal$) until 2018.[27] Subsequent AEO forecasts have likewise continued to project low gas prices.[28]

Q. Do you believe that other utilities were aware of these changes and making decisions based on these new conditions?

A. Yes, I do. During this period, utilities across the country were undertaking similar retrofit versus retirement evaluations in order to determine the best way to comply with environmental regulations. These energy sector changes would have had a similar effect on their analyses, and in fact we see that the number of announced retirements increases in the United States between 2009 and 2011, as shown in Table 1.

Table 1. Announced coal retirements in the United States, from EIA 860 2009-2012.

	EIA 2009	EIA 2010	EIA 2011
Planned coal retirements in the U.S. (GW)	5.1	12.4	30.1
Original release date	*Jan 2011*	*Nov 2011*	*Sep 2012*

[26] Direct Testimony of Mr. David Schlissel. KCC Docket No. 11-KCPE-581-PRE. June 3, 2011. Page 19, lines 11-14.
[27] Annual Energy Outlook 2012. Page 62, Table 19. http://www.eia.gov/forecasts/aeo/pdf/0383%282012%29.pdf. Also, Data Table 62. Lower 48 Natural Gas Production and Wellhead Prices by Supply Region, Reference case. Line 25.
[28] Annual Energy Outlook 2013 and Annual Energy Outlook 2014.

The data release dates align with major dates in the KCP&L timeline: January 2011 is close to the time at which KCP&L filed for predetermination in Kansas; November 2011 is just after KCP&L began spending money on the La Cygne retrofits; and September 2012 is yet another point at which I argue that KCP&L should have revisited its analysis, and given that it had not already done so, suspended construction and taken actions to retire one or both of the La Cygne units, as discussed later in this testimony.

5. REEVALUATION OF LA CYGNE ENVIRONMENTAL RETROFIT PROJECTS

Q. Were you able to evaluate how the Company's analysis would have looked in light of new natural gas price forecasts in 2011 and 2012?

A. Yes. As Mr. Crawford described in his Kansas testimony in the predetermination proceeding (11-KCPE-581-PRE), KCP&L had developed 64 risk scenarios to "gauge the risk associated with identified critical uncertain factors."[29] These factors included both natural gas prices and CO_2 emission allowance price forecasts, amongst other variables.[30] The Company tested fourteen different resource plans with base DSM and four sensitivity plans with increased DSM. These plans included different combinations of La Cygne 1 and 2 and Montrose 1-3 retrofit or replaced with CTs or NGCC units. For each resource plan, the Company established a single weighted average PVRR. To get to the single weighted average PVRR, the Company applied a weighting to each of the 64 risk scenarios.

[29] Direct Testimony of Burton Crawford. KCC Docket No. 11-KCPE-581-PRE. February 1, 2011. Page 5 at 10-11.

[30] Direct Testimony of Burton Crawford. KCC Docket No. 11-KCPE-581-PRE. February 1, 2011. Page 7 at 15-18.

While the Company only chose to examine the central weighted average and the range of results in their 64 risk scenarios, I examined each of the resulting risk scenarios independently.

Of the 64 risk scenarios, nine examined every permutation of low, mid, and high natural gas and CO_2 price forecasts envisioned by the Company while all other factors were at the "mid" level. Predictably, the PVRR outcomes of the scenarios are extremely highly correlated with the natural gas and carbon prices. In fact, holding all else constant, natural gas and CO_2 predict, on average, over 99.7% of the variance in the scenarios when other factors are held at a "mid" level.

Although I cannot substitute a 2011 or 2012 gas price forecast or an updated CO_2 price forecast from 2012 into the Company's 2011 analysis without running the Company's model, a rough proxy method may be used to determine the break-even cost of gas or CO_2 required to change the Company's analysis results (a method first used by PacifiCorp for this same purpose, as far as I am aware).[31]

Q. For which of KCP&L's resource portfolios did you apply this analysis?

A. Of the fourteen resource plans, I was particularly interested in the resource plan in which **____
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______ **.

In 2011, KCP&L had identified that the least-cost alternative on a weighted average PVRR basis had an expected value of $**_____ ** million.[32] The case in

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[31] Utah Docket 12-035-92. "In the Matter of: the Voluntary Request of Rocky Mountain Power for Approval of Resource Decision to Construct Selective Catalytic Reduction Systems on Jim Bridger Units 3 and 4." Direct Testimony of PacifiCorp witness Rick Link. Page 22. August 24, 2012.
[32] Direct Testimony of Burton Crawford. KCC Docket No. 11-KCPE-581-PRE. February 1, 2011. Confidential Schedule BLC2011-12.

which **____ ** had an expected value of $**_____ ** million, or $**__ ** million more than the lower-cost plan. On this basis, the retirement of La Cygne and Montrose was rejected.

However, as I noted previously, each of KCP&L's fourteen alternate resource plans contained nine risk scenarios with every combination of low, mid, and high natural gas and CO_2 price forecasts envisioned by the Company. I used that information to determine a "break-even" price of natural gas at which the **____________________ ** would have been preferable to the Company's plan.

Q. Please describe how you determined a break-even price for natural gas.

A. To start, I took the three cases from the Company's 2011 analysis in which CO_2 and all other factors, aside from gas, were at the "mid" level. I levelized the Company's cost of natural gas in the "high," "mid," and "low" cases from 2010 through 2035. When the difference in present value of revenue requirements (PVRR(d)) between the Company's plan and the "retire all" plan are plotted against the levelized cost of natural gas, it becomes clear that the overall cost of the portfolio is heavily dependent on the price of gas, and that the relationship is fairly linear.

Confidential Figure 1, below, shows three data points with PVRR(d) between KCP&L's 2011 preferred resource plan and the case in which all units are retired, plotted against levelized natural gas prices. At the "mid" case, where gas is around $**_**/MMBtu, the Company's plan is preferred by $**__ ** million; however, at the lower price of gas, the Company's plan is a liability of -$**__ ** million (net present value).

[redacted]

Confidential Figure 1. Breakeven analysis for natural gas price. PVRR(d) between Company preferred resource plan and "retire all" plan with all other variables at "mid."

This analysis shows that the difference (PVRR(d)) crosses the zero line at about $**__ **/MMBtu, just $**__ **/MMBtu less than the Company's mid case, or expected value. The pertinent question then is whether there was a reasonably foreseeable chance that gas price forecasts had fallen by more than this value – if so, the Company should have revisited its analysis.

Q. Was there evidence in 2011 and early 2012 that reasonable projections of gas prices had fallen substantially?

A. Yes. In April 2011, EIA published natural gas price forecasts in its AEO 2011 that were equal to $6.16/MMBtu on a levelized basis. This value is $**__ **/MMBtu lower than the $**__ **/MMBtu "break even" level shown in Confidential Figure 1, and should have indicated to KCP&L in the middle of the Kansas predetermination proceeding that there was essentially no difference in PVRR between installing emission control retrofits at La Cygne and retiring both units.

In January 2012, EIA published the Early Release version of AEO 2012, with natural gas prices substantially below AEO 2011 levels ($5.78/MMBtu, or $0.37/MMBtu lower than AEO 2011 on a levelized basis).

The final version of AEO 2012, released in June 2012, forecast even lower forward prices for natural gas $0.52/MMBtu below 2011 levels – at $5.64/MMBtu – a drop significant enough to readily surpass the break-even level.

Confidential Figure 2 shows the AEO 2011, AEO 2012ER, and AEO 2012 forecasts of natural gas prices plotted against the forecasts used by KCP&L in its analysis. The forecast produced by EIA in April 2011 during the Kansas predetermination proceeding drops below **______________________________ ____________________ **. One can see that the AEO's 2012 forecasts are approximately **__________ ** lower than KCP&L's Mid Gas forecast through 2030, and in fact **____ ___________________________________ **.

[redacted]

Confidential Figure 2. KCP&L Natural Gas Price Forecast Used in Kansas Docket 11-KCPE-581-PRE Compared to AEO 2011 (dated April 2011), AEO 2012 Early Release (dated January 2012) and AEO 2012 (dated June 2012).

Confidential Figure 3 shows the levelized version of Henry Hub prices in AEO 2012ER (solid red box) and AEO 2012 (empty red box), well below the break-even.

HC

[redacted]

Confidential Figure 3. Breakeven analysis for natural gas price. PVRR(d) plus AEO 2012ER and AEO 2012 natural gas price levelizations.

Substituting in AEO 2012ER prices indicates that the PVRR of the plan that retired the La Cygne units was $**__ ** million lower than the Company's preferred resource plan that installed emissions control retrofits at Units 1 and 2. Substituting in the AEO 2012 prices, the Company's analysis would have indicated in June 2012 that retiring La Cygne 1 and 2 would result in a PVRR value that was $**__ ** million lower than the portfolio that retrofit both of these units.

Q. Was KCP&L aware that a drop in the price of natural gas had the potential to change the outcome of its modeling process?

Yes. In his testimony in the Kansas predetermination proceeding (11-KCPE-581-PRE), Mr. Crawford states that "[t]he scenarios where the retrofits were not selected generally include both the low gas price scenarios and the high CO_2 price scenarios."[33] Looking at the AEO 2011 and AEO 2012 forecasts of natural gas prices should have provided a clear indication to KCP&L that it needed to revisit its analysis of the economics of the retrofits at La Cygne 1 and 2.

Taking only the gas prices as a cue, KCP&L should have significantly reconsidered and re-evaluated its decision to retrofit La Cygne in April 2011, and by January 2012 likely should have begun to take serious actions to suspend expenditures on the retrofits and plan for an orderly retirement of one or both of the La Cygne units.

Q. What was the Company's CO_2 price analysis in 2011?

A. The Company's "mid" case estimated that CO_2 prices would begin at a modest level in **____ **. This forecast may have been based off of an expectation that the U.S. legislature would regroup on a bill similar to the American Clean Energy and Security (ACES, also known as "Waxman-Markey") bill of 2008 that subsequently failed to reach the Senate in 2009. By 2012 it would have been quite clear that a legislative bill requiring a CO_2 price could not reasonably be expected by **____ **.

My firm, Synapse Energy Economics, produces a publicly available CO_2 price forecast on a regular basis, tracking regulatory and legislative developments in the states, on a regional level, and on a national level, as well as utility expectations. In February of 2011, we had revised earlier expectations (from 2008) outwards to capture a likely start of regulations between 2015 and 2020, with a reference case at 2018. As of October 2012, just a few days before my colleague Mr. Biewald submitted testimony before this Commission in Case No. ER-2012-0174 asking KCP&L to revisit its analysis of the prudence of the La Cygne retrofits, Synapse

[33] Direct Testimony of Burton Crawford. KCC Docket No. 11-KCPE-581-PRE. February 1, 2011. Page 14, lines 19-21.

published its 2012 CO_2 price forecast showing CO_2 prices starting in 2020.[34] By pushing the start date backwards, we effectively forecasted a lower impact of CO_2 prices in our present-day analyses.

From the perspective of a utility revising its analysis in October 2012, it would have been appropriate to both use a revised (and later) CO_2 price forecast in conjunction with the lower gas price levels.

Q. Were you able to determine the outcome of the Company's analysis effective as of October 2012 and adjusting for a later onset CO_2 price and using the lower gas price?

A. Yes. Of the 64 risk scenarios contemplated by the Company, nine offered all feasible permutations of low, mid, and high CO_2 and gas prices. As such, I was able to use the Company's expected PVRR outcomes for all nine scenarios and the levelized gas and CO_2 prices in a least squares regression. A two-dimensional least squares regression seeks to solve a simple equation, where I know the PVRR of each scenario and I know the gas and CO_2 prices:

$$PVRR = x(gasprice) + y(CO2price) + b$$

These elements are enough to solve for *x*, *y*, and *b* (a constant). Using this information, and presuming the equation is both linear and readily solved, I can then substitute in new gas and CO_2 prices and determine estimated PVRR values under different circumstances. In other words, I can re-create what the Company should have known in late 2012.

The equation here is readily solved for each of the Company's 14 resource scenarios, and in each case the gas and CO_2 prices describe more than 98.9% of the variation in the PVRRs (the r^2 value). In some cases, CO_2 and gas prices

[34] Synapse, 2012. 2012 Carbon Dioxide Price Forecast. http://www.synapse-energy.com/sites/default/files/SynapseReport.2012-10.0.2012-CO2-Forecast.A0035.pdf. Attached as Schedule RSW-6.

describe more than 99.99% of the variance in prices. Based on this information, I can state that the equation is linear and readily describes the variation in plan costs with respect to gas and CO_2 prices.

Q. What is the outcome of the Company's modeling if you use gas and CO_2 price forecasts that were available in October 2012?

A. My re-analysis of the Company's 2011 results indicates that under the lower levelized CO_2 price as revised by Synapse in October 2012, the plan in which **____** would still have been the least cost plan by about $**_** million relative to the case in which **______________________________** is retired. This result of course also depends on all of the other assumptions of KCP&L's 2011 planning framework being reasonable. As I discuss below, this was not the case. Limitations in KCP&L's 2011 planning framework likely skewed the modeling results in favor of retrofitting La Cygne, and correcting those limitations would likely result in the plan in which **______________________________ ____**.

6. TIMELINE OF SPENDING FOR LA CYGNE RETROFITS

Q. On what date did the Kansas Corporation Commission grant predetermination to KCP&L for the environmental retrofits at La Cygne 1 and 2?

A. Predetermination was granted in Kansas on August 19, 2011.

Q. When did KCP&L begin to spend money on the environmental retrofits at La Cygne 1 and 2?

A. According to the monthly status reports provided to the MPSC Staff, and provided under the discovery response to SC-15, the Company began to spend money on the retrofits in **__________**.

Q. Have you been able to assemble a schedule of spending from the monthly status reports?

A. I have. As of January 2012, the time of the AEO 2012 Early Release, KCP&L had spent approximately **________ ** of the total cost of the La Cygne retrofits. By December 2012, KCP&L had spent approximately **________ ** of the total cost. A timeline of Company spending is shown in Confidential Figure 4.

[redacted]

Confidential Figure 4. Timeline of KCP&L spending on La Cygne environmental retrofits.

Q. You identify several dates at which KCP&L could have reexamined its analysis of the La Cygne retrofits. What was the total spending as of each of those dates?

A. The dates at which KCP&L should have reexamined its analysis are shown in Confidential Table 2, along with the condition that had changed to make that date relevant. Confidential Table 2 also shows the spending that had been incurred by KCP&L as of that date, and the costs of the retrofits that still could have been avoided if KCP&L had halted construction at that point.

Confidential Table 2. Total spending incurred at KCP&L "decision points."

Date	Change in Conditions	Total spent (million$)	Cost avoided (million$)
Apr-11	AEO 2011	[redacted]	[redacted]
Jan-12	AEO 2012 Early Release	[redacted]	[redacted]
Jun-12	AEO 2012	[redacted]	[redacted]
Aug-12	Biewald testimony	[redacted]	[redacted]
Oct-12	Synapse CO2 forecast	[redacted]	[redacted]
Jan-13	MPSC Order	[redacted]	[redacted]

Note that the estimates of costs that could have been avoided simply subtract the spending incurred from the total cost of the retrofits. KCP&L may only have been able to avoid some percentage of these costs due to the specific cancellation clauses contained in their contracts for equipment. Due to time limitations, I was unable to obtain and review all of the Company's individual cancellation clauses and did not evaluate the penalties that might have been incurred due to cancellation.

Confidential Table 2 shows that if KCP&L had been actively monitoring conditions in the electric sector and been willing to reevaluate its original analysis at the first signs of changed forecasts in April 2011, it could have avoided all of the costs associated with the retrofits at La Cygne Units 1 and 2. If KCP&L had reexamined its analysis as of January 2012, it could have avoided almost **_ _____ ** of the costs of the La Cygne environmental retrofits. By January 2013, KCP&L had been subject to various requests by third parties to update its analysis, as well as myriad new data forecasts and reports, which were totally ignored by the Company. Had KCP&L instead chosen to revise its analysis at this point in time, it could still have avoided over **_________** of the costs of the La Cygne retrofits.

Q. What has happened to natural gas prices since the AEO 2012 forecast?

A. Subsequent AEO forecasts predicted natural gas prices that were even lower than AEO 2012. Those prices are shown against KCP&L's mid and low gas price forecasts from the 2011 Kansas proceeding in Confidential Figure 5. Use of these forecasts in KCP&L modeling would reinforce the conclusion that it was uneconomic to retrofit the La Cygne units.

[redacted]

Confidential Figure 5. KCP&L Natural Gas Price Forecast Used in Kansas Docket 11-KCPE-581-PRE Compared to AEO 2012, AEO 2013 and AEO 2014.

7. DEVELOPMENT OF A LEAST-COST PORTFOLIO

Q. You already stated that KCP&L's modeling approach was subject to criticism in the predetermination proceeding (11-KCPE-581-PRE). In your opinion, does the Company's 2011 preferred resource plan represent a reasonable outcome?

A. No, it does not. I agree with Dr. Hausman's assessment that the types of available resource alternatives that the Company evaluated in 2011 were unreasonably restricted. KCP&L created 14 base capacity expansion plans it its analysis, but limited the range of alternatives that could replace the capacity from La Cygne 1 and 2 and the Montrose units to new fossil-fueled resources only, in the form of new coal, new natural gas CCs, or new natural gas CTs.

I also agree with Dr. Fisher that KCP&L failed to assess or model costs for the then impending CCR rule and still pending ELGs in the 2011 Kansas proceeding, thereby ignoring the risk of substantial control costs at existing coal units.

Q. Why does it matter that KCP&L did not examine DSM and renewables as part of a preferred resource portfolio?

A. While DSM, combined heat and power ("CHP"), and renewable energy may not be able to replace a coal-fired generating unit on a per MW basis at a reasonable cost, the combination of these resources would serve to reduce customer loads and provide additional capacity and energy. Had it evaluated these resources, KCP&L may have been able to build fewer combustion turbines or a smaller, less expensive NGCC when conducting its portfolio analysis. Inclusion of these types of resources may have allowed for the displacement of certain resources that were selected by KCP&L in its planning analysis, namely the environmental retrofits at one or both of La Cygne 1 and 2.

Q. What additional resources should KCP&L have considered in formulating resource portfolios?

A. The Company should have considered additional DSM measures, as well as CHP resources and renewable resources.

Q. Why should KCP&L have considered additional DSM?

A. As stated in the 2011 direct testimony of Dr. William Steinhurst, energy efficiency measures offer a number of non-energy benefits, are less risky and more cost-effective than supply-side alternatives, and decrease both consumer energy bills and wholesale electric prices. Dr. Steinhurst states that KCP&L's analysis limited DSM options to "certain pre-defined quantities that are far below what can be expected from aggressive pursuit of all cost-effective and reasonably achievable energy efficiency resources, even though the company (has) indicated that higher levels of DSM would reduce the cost of service. This is a serious omission and does a significant disservice to ratepayers."[35]

In its 2012 IRP, KCP&L included a DSM portfolio achieving 0.5 percent energy savings per year and stated that portfolios achieving 1.0 percent savings or greater were not realistically achievable. In fact, data from the American Council for an Energy Efficient Economy (ACEEE) show that at least 15 states had set goals of at least 1.0 percent savings per year, with some having set goals of 2 - 2.5 percent energy savings per year.[36] KCP&L had not completed a DSM potential study as of the 2011 predetermination docket in Kansas, nor had it done one for the 2012 IRP in Missouri, although it did finally complete such a study in 2013.[37] The results of such a study, if the Company had completed it in a more timely manner, could have contributed to a different outcome in KCP&L's analysis of the La Cygne environmental retrofits.

While KCP&L's sensitivity analysis did include increased levels of DSM, and while PVRR results for these resource portfolios are lower than in the Company's preferred plan, KCP&L gives no indication that it considered these results in any meaningful way.

Q. Why should KCP&L have considered additional CHP?

A. Comments of the Sierra Club on KCP&L's 2012 IRP, submitted in File No. EO-2012-0323, stated that KCP&L failed to evaluate CHP resources as part of a DSM

[35] Direct Testimony of Dr. William Steinhurst. KCC Docket No. 11-KCPE-581-PRE. June 3, 2011. Page 11.
[36] ACEEE. Energy Efficiency Resource Standards: A Progress Report on State Experience. June 2011. Available at: http://aceee.org/sites/default/files/publications/researchreports/u112.pdf
[37] Kansas City Power & Light Company. Integrated Resource Plan: 2013 Annual Update. June 2013.

portfolio. Missouri's technical potential for CHP is approximately 16 times as much as the 227 MW of total installed CHP capacity as of 2012.[38]

Q. Why should KCP&L have considered additional renewable resources?

A. KCP&L failed to consider additional wind resources despite their attractive costs and pervasive availability in the region in which KCP&L operates. In 2012 the wind industry was growing at a rapid pace, and the US established a new record for wind additions in a single year with 13.1 GW, nearly double the amount of capacity added in 2011, and greater than capacity added in 2010 and 2011 combined.[39] Declining costs of wind turbines and power purchase agreements ("PPAs") prompted growth in the manufacturing of turbines and components throughout the country.[40] The average installed cost of wind projects in Kansas dropped to $1,760 per kW and prompted growth in wind resources from 11 percent of state-wide generation capacity to over 20 percent.[41] Nationally, PPAs averaged $40/MWh in 2012, but prices in the Interior fell to nearly $30/MWh, and appeared set to drop even further in following years.[42] Mr. Crawford shows that wind resources examined by KCP&L in its initial resource screening have a **_ ** percent capacity factor and a nominal utility cost of $**____ **/MWh. While expected wind performance is adequately reflected in this estimate, the Company's numbers in early 2011 did not reflect the reasonable expectation that wind prices will decline over time.

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[38] Bradbury, et al. Midwest Manufacturing Snapshot: Missouri. World Resources Institute. February 2012. Available at: http://www.wri.org/publication/midwest-manufacturing-snapshot

[39] U.S. Department of Energy. 2012 Wind Technologies Market Report. August 2013. Page 3. Available at: http://www1.eere.energy.gov/wind/pdfs/2012_wind_technologies_market_report.pdf

[40] U.S. Department of Energy. 2012 Wind Technologies Market Report. August 2013. Page 17.

[41] U.S. Department of Energy. 2012 Wind Technologies Market Report. August 2013. Page 9.

[42] U.S. Department of Energy. 2012 Wind Technologies Market Report. August 2013.Pages 50-51.

Q. What effect will regulations on coal combustion residuals and wastewater effluent have on La Cygne 1 and 2?

A. In its 2013 IRP Update, KCP&L assumes that CCR and wastewater effluent compliance obligations could be satisfied by ceasing wet sluicing of ash and converting to dry handling, and that doing so would require a $22.3 million capital expenditure and raise fixed O&M by $0.60/kW (in 2012$).[43] Inclusion of these costs in the original analysis would have negatively affected the economics of La Cygne Units 1 and 2 relative to natural gas-fired generation, which is not subject to these rules. KCP&L did model the addition of cooling towers at the La Cygne units, even though 316(b) rules had not yet become final in 2011. At the very least, KCP&L should have included costs of technologies that it deemed reasonable for compliance with CCR regulations and the effluent guidelines in its modeling analysis.

8. CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your conclusions.

A. Resource planning in the electric sector used to be much simpler. Fuel prices were highly stratified, there were fewer types of cost-effective demand- and supply-side resource technologies, environmental regulations were more limited in scope, and technologies to meet these regulations were almost all command-and-control. Utilities were vertically-integrated and operated to serve customers in their service territories rather than to sell their generation into a wholesale energy market. It was not necessary to update forecasts and assumptions as frequently because conditions simply did not change that quickly. In many ways, KCP&L seems to still be operating in this type of planning environment. In this proceeding and others mentioned in my testimony, the Company uses forecasts and assumptions in its analyses that are vastly out-of-date and limits its resource

[43] Kansas City Power & Light Company. Integrated Resource Plan: 2013 Annual Update. June 2013. Page 129.

choices to conventional fossil-fueled generation – coal or natural gas CTs and NGCCs.

In Case No. ER-2012-0174, this Commission acknowledged that market prices for natural gas and wholesale energy are declining, costs to comply with environmental regulations are rising, and the availability of energy efficiency and renewable energy is growing. These variables all have the ability to change the economics of coal-fired power plant operation, and may lead to plant retirement.

Based on my review of the record available to me in this proceeding, I conclude that KCP&L's original analysis submitted in Kansas Docket No. 11-KCPE-581-PRE in February 2011 was not prudent. KCP&L should have revisited that analysis as early as April 2011. If the Company had updated its PVRR analysis with a new natural gas forecast at that time, it would have found that the environmental retrofits at La Cygne Units 1 and 2 were no longer the least-cost plan. An analysis done with gas prices that were forecast in January 2012 or as late as June 2012 would have revealed that PVRR costs of the plan that retrofit the La Cygne units were much higher than the PVRR costs of a plan that retired the units.

In addition, if the Company had included capital expenditures to comply with coal combustion residuals and wastewater effluent regulations, that would have lowered the benefits of continued operation of the La Cygne units by an even larger margin. Inclusion of a greater range of resource types in resource expansion portfolios may have revealed a less-costly mix of resources that would have allowed KCP&L to meet energy and capacity needs over the planning period. Intervenors repeatedly voiced concerns on each of these issues, but the Company chose not to acknowledge these concerns. A new analysis could have kept KCP&L from making significant capital investments in emission control retrofits at La Cygne Units 1 and 2.

It is therefore my recommendation that this Commission should deny rate recovery for some or all of the capital costs associated with the environmental retrofit projects at La Cygne Units 1 and 2.

Q. Does this conclude your direct testimony?

A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service	)))	Case No. ER-2014-0370

County of Middlesex)
) ss
State of Massachusetts)

AFFIDAVIT OF RACHEL S. WILSON

Rachel S. Wilson, of lawful age, on her oath states: that she has participated in the preparation of this direct testimony in question and answer form consisting of 36 pages to be given as Direct Testimony in the above-named case; that the answers were given by her and that she has knowledge of the matters set forth in such answers; and that such matters are true to the best of her knowledge and belief.

Rachel Wilson
Rachel S. Wilson

In witness whereof I have hereunto subscribed by name and affixed my official seal this 2 day of April, 2015.

JANICE CONYERS
Notary Public
Commonwealth of Massachusetts
My Commission Expires
July 27, 2018

Rachel Wilson, Senior Associate

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Senior Associate*, 2013 – present, *Associate*, 2010 – June 2013, *Research Associate*, 2008 – 2010.

- Conducts research and writes testimony and reports on a wide range of issues relating to electric utilities, including: integrated resource planning; federal and state clean air policies; emissions from electricity generation; electric system dispatch; and environmental compliance technologies, strategies, and costs.
- Uses optimization and electricity dispatch models, including Strategist, PROMOD, PROSYM/Market Analytics, and PLEXOS to conduct analyses of utility service territories and regional energy markets.

Analysis Group, Inc., Boston, MA.

Associate, Energy Practice, 2007 – 2008.

- Supported an expert witness asked to opine on various topics in the electric industry as they applied to merchant generators and provided incentives for their behavior in the late 1990s and early 2000s.
- Analyzed data related to coal production on Indian land and contractual royalties paid to the tribe over a 25 year period to determine if discrepancies exist between these values for the purposes of potential litigation.
- Examined Canadian policies relating to carbon dioxide, and assisted with research on linkage of international tradable permit systems.
- Managed analysts' work processes and evaluated work products.

Senior Analyst Intern, Energy Practice, 2006 – 2007.

- Supported an expert witness in litigation involving whether a defendant power company could financially absorb a greater investment in pollution control under its debt structure while still offering competitive rates. Analyzed impacts of federal and state clean air laws on energy generators and providers. Built a quantitative model showing the costs of these clean air policies to the defendant over a 30 year period. Built a financial model calculating impacts of various pollution control investment requirements.
- Researched the economics of art; assisted in damage calculations in arbitration between an artist and his publisher.

Yale Center for Environmental Law and Policy, New Haven, CT. *Research Assistant*, 2005 – 2007.

- Gathered and managed data for the Environmental Performance Index, presented at the 2006 World Economic Forum. Interpreted statistical output, wrote critical analyses of results, and edited report drafts.
- Part of the team that produced *Green to Gold*, an award-winning book on corporate environmental management and strategy. Managed data, conducted research, and implemented marketing strategy.

Marsh Risk and Insurance Services, Inc., Los Angeles, CA. *Risk Analyst*, Casualty Department, 2003 – 2005.

- Evaluated Fortune 500 clients' risk management programs/requirements and formulated strategic plans and recommendations for customized risk solutions.
- Supported the placement of $2 million in insurance premiums in the first year and $3 million in the second year.
- Utilized quantitative models to create loss forecasts, cash flow analyses and benchmarking reports.
- Completed a year-long Graduate Training Program in risk management; ranked #1 in the western region of the US and shared #1 national ranking in a class of 200 young professionals.

EDUCATION

Yale School of Forestry & Environmental Studies, New Haven, CT
Masters of Environmental Management, concentration in Law, Economics, and Policy with a focus on energy issues and markets, 2007

Claremont McKenna College, Claremont, California
Bachelor of Arts in Environment, Economics, Politics (EEP), 2003. *Cum laude* and EEP departmental honors.

School for International Training, Quito, Ecuador
Semester abroad studying Comparative Ecology. Microfinance Intern – Viviendas del Hogar de Cristo in Guayaquil, Ecuador, Spring 2002.

ADDITIONAL SKILLS AND ACCOMPLISHMENTS

- Microsoft Office Suite, Lexis-Nexis, Platts Energy Database, Strategist, PROMOD, PROSYM/Market Analytics, and PLEXOS, some SAS and STATA.
- Competent in oral and written Spanish.

- Hold the Associate in Risk Management (ARM) professional designation.

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TESTIMONY

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Michigan Public Service Commission (Case No. U-17087): Direct testimony before the Commission discussing Strategist modeling relating to the application of Consumers Energy Company for the authority to increase its rates for the generation and distribution of electricity. On behalf of the Michigan Environmental Council and Natural Resources Defense Council. February 21, 2013.

Indiana Utility Regulatory Commission (Cause No. 44217): Direct testimony before the Commission discussing PROSYM/Market Analytics modeling relating to the application of Duke Energy Indiana for Certificates of Public Convenience and Necessity. On behalf of Citizens Action Coalition, Sierra Club, Save the Valley, and Valley Watch. November 29, 2012.

Kentucky Public Service Commission (Case No. 2012-00063): Direct testimony before the Commission discussing upcoming environmental regulations and electric system modeling relating to the application of Big Rivers Electric Corporation for a Certificate of Public Convenience and Necessity and for approval of its 2012 environmental compliance plan. On behalf of Sierra Club. July 23, 2012.

Kentucky Public Service Commission (Case No. 2011-00401): Direct testimony before the Commission discussing STRATEGIST modeling relating to the application of Kentucky Power Company for a Certificate of Public Convenience and Necessity, and for approval of its 2011 environmental compliance plan and amended environmental cost recovery surcharge. On behalf of Sierra Club. March 12, 2012.

Kentucky Public Service Commission (Case No. 2011-00161 and Case No. 2011-00162): Direct testimony before the Commission discussing STRATEGIST modeling relating to the applications of Kentucky Utilities Company, and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity, and approval of its 2011 compliance plan for recovery by environmental surcharge. On behalf of Sierra Club and Natural Resources Defense Council (NRDC). September 16, 2011.

Minnesota Public Utilities Commission (OAH Docket No. 8-2500-22094-2 and MPUC Docket No. E-017/M-10-1082): Rebuttal testimony before the Commission describing STRATEGIST modeling performed in the docket considering Otter Tail Power's application for an Advanced Determination of Prudence for BART retrofits at its Big Stone plant*.* On behalf of Izaak Walton League of America, Fresh Energy, Sierra Club, and Minnesota Center for Environmental Advocacy. September 7, 2011.

Resume dated March 2015

2011.06.03 16:50:01
Kansas Corporation Commission
/S/ Thomas A. Day

BEFORE THE STATE CORPORATION COMMISSION

OF THE STATE OF KANSAS

DIRECT

TESTIMONY

OF

WILLIAM STEINHURST

ON BEHALF OF SIERRA CLUB

Received on
JUN 03 2011
by
State Corporation Commission of Kansas

DOCKET NO. 11-KCPE-581-PRE

June 3, 2011

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1. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and occupation.

A. My name is William Steinhurst, and I am a Senior Consultant with Synapse Energy Economics (Synapse). My business address is 32 Main Street, #394, Montpelier, Vermont 05602.

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 over thirty years of experience in utility regulation and energy policy, including work on renewable portfolio standards and portfolio management practices for default service providers and regulated utilities, green marketing, distributed resource issues, economic impact studies, and rate design. Prior to joining Synapse, I served as Planning

Econometrician and Director for Regulated Utility Planning at the Vermont Department of Public Service, the State's Public Advocate and energy policy agency. I have provided consulting services for various clients, including the Connecticut Office of Consumer Counsel, the Illinois Citizens Utility Board, the California Division of Ratepayer Advocates, the D.C. and Maryland Offices of the Public Advocate, the Delaware Public Utilities Commission, the Regulatory Assistance Project, the National Association of Regulatory Utility Commissioners (NARUC), the National Regulatory Research Institute (NRRI), American Association of Retired Persons (AARP), The Utility Reform Network (TURN), the Union of Concerned Scientists, the Northern Forest Council, the Nova Scotia Utility and Review Board, the U.S. EPA, the Conservation Law Foundation, the Sierra Club, the Southern Alliance for Clean Energy, the Oklahoma Sustainability Network, the Natural Resource Defense Council (NRDC), Illinois Energy Office, the Massachusetts Executive Office of Energy Resources, the James River Corporation, and the Newfoundland Department of Natural Resources.

I hold a B.A. in Physics from Wesleyan University and an M.S. in Statistics and Ph.D. in Mechanical Engineering from the University of Vermont.

I have testified as an expert witness in approximately 30 cases on topics including utility rates and ratemaking policy, prudence reviews, integrated resource planning, demand side management policy and program design, utility financings, regulatory enforcement, green marketing, power purchases, statistical analysis, and decision analysis. I have been a frequent witness in legislative hearings and represented the State of Vermont, the Delaware Public Utilities Commission Staff, and several other groups in numerous collaborative settlement processes addressing energy efficiency, resource planning and distributed resources.

I was the lead author or co-author of Vermont's long-term energy plans for 1983, 1988, and 1991, as well as the 1998 report *Fueling Vermont's Future: Comprehensive Energy* Plan and Greenhouse Gas Action Plan, and also Synapse's study *Portfolio Management: How to Procure Electricity Resources to Provide Reliable, Low-Cost, and Efficient Electricity Services to All Retail Customers*. In 2008, I was commissioned by the National Regulatory Research Institute (NRRI) to write *Electricity at a Glance*, a primer on the industry for new public utility commissioners, which included coverage of energy efficiency programs. In 2011, NRRI commissioned a second edition of that work.

My resume is attached to this testimony as Exhibit SC-10 (WS-1).

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

A. I am testifying on behalf of the Sierra Club.

Q. Have you testified previously before the Kansas State Corporation Commission (the Commission)?

A. No, I have not.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to consider whether certain environmental upgrades (the preferred plan) proposed by Kansas City Power & Light Company (the company, KCP&L) and supported by Westar Energy, Inc., (Westar) should be preapproved under K.S.A. 66-1239 as requested by the company in its Application of February 23, 2011. XX I also address the question of coordination between the company's integrated resource plan (IRP) activities and its rate case requests. XX

Q. How is your testimony organized?

A. My testimony is organized as follows:

1. Introduction and Qualifications.
2. Summary of Conclusions and Recommendations.
3. The Context for Consideration of Preapproval
4. Critique of the Company's Proposal and Analyses
5. Recommendations

2. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your primary conclusions.

A. My primary conclusions are summarized as follows:

1. The standard for preapproval should, at a minimum, meet the requirements set out in the Sierra Club Initial Comments in the 492 docket and reiterated below in this prefiled testimony.

2. As explained by Dr. Fisher, the current and emerging environmental regulations considered in the Company's analyses were correct as far as they went, but were not sufficient to meet the above standard for preapproval because certain emerging environmental regulations were neglected and others were considered in too weak a manner.

3. As explained by Dr. Fisher, the range of environmental control options considered in the company's analyses were correct as far as they went, but were not sufficient to meet the above standard for preapproval because of certain shortcomings and omissions in the environmental standards assumed by the company.

4. As explained by Dr. Hausman, the general type of analysis conducted by the Company was sufficient to meet the above standard for preapproval, but the inputs and choice of specific scenarios was biased in favor of the proposed retrofits, so the results cannot be relied upon.

5. Taking into account the Company 's analyses of the upgrades proposed for both of the La Cygne units and the nature and extent of the biases involved in those analyses, the La Cygne units have not been shown to be cost effective or to meet the above standard for preapproval.

6. The retrofits that would be necessary for the Montrose units to meet current and emerging environmental regulations, while not the subject of the preapproval requested in this proceeding, are clearly not cost effective, even in the Company's biased analyses, andare not in the public interest.

7. Given the problems with the Company 's analyses, as set out in the prefiled testimony of Dr. Hausman and Dr. Fisher, the cost-effectiveness of the proposed retrofits for both of the La Cygne units is in doubt and certainly is not sufficiently well determined to warrant preapproval at this time.

Q. Please summarize your primary recommendations.

A. The Commission should

1. Adopt the preapproval standards set out in Sierra Club's Initial Comments and below in this prefiled testimony

2. Deny without prejudice preapproval for the proposed upgrades to both La Cygne units. The Commission should also direct the company to file a new study that corrects the deficiencies identified in the Sierra Club testimony so that the Commission can properly oversee the company's resource planning. It should also find that such a study will be an essential element for a proper preapproval filing in the future, for the La Cygne units or any other.

3. Find that upgrading the Montrose units to meet current and emerging environmental regulations is not cost-effective and direct the company to file a plan to retire those units. That plan should be required to identify and incorporate the long term, least cost resource alternatives to the Montrose units.

4. Require that the studies called for in items 2 and 3, above, comprehensively examine all alternatives, both supply- and demand-side, on a level playing field and also consider a sufficiently wide range of uncertainties and risks, properly documented and quantified and with the assumptions and methodologies made available to the Commission and intervenors

Without such an analysis, it is impossible for the Commission or any intervenor to fully assess whether the company's plans for the maintenance, upgrades, and operations of its fleet of plants is in keeping with least-cost principles, and whether the company's proposed investments represent a suitable use of ratepayer monies.

In addition, the Commission should take action now to ensure that all cost-effective and reasonably available energy efficiency and distributed energy resources are being acquired on an aggressive schedule. I will discuss this recommendation further below, but the reasoning behind it is quite simple. Energy efficiency and distributed energy resources are the least risky and most cost-effective alternative to investment in generation, but require considerable lead time if they are to be available when needed to actually be feasible alternatives. Therefore, now is the time to ensure those resources are being acquired so they will be on hand when needed.

3. THE CONTEXT FOR CONSIDERATION OF PREAPPROVAL

Q. Do you have a recommendation for how the Commission should approach preapproval decisions?

A. Yes. I recommend that the Commission adopt the preapproval approach and standard set out in Sierra Club's Initial Comments in the the Commission's Docket No. 11-GIME-492-GIE (the 492 docket) and recapped below.

Q. Can you succinctly paraphrase that standard?

A. As pointed out by Dr. Hausman in his prefiled testimony,

> If a proper analysis would suggest that the more prudent course would have been to retire La Cygne but the company chose to do otherwise, then the retrofits themselves would be part of an imprudent plan. As such they would represent imprudent expenditures. Ratepayers should not have to foot the bill to support an imprudent resource plan.

The logical implication is that the Commission should deny preapproval to retrofits that are not convincingly demonstrated to be part of comprehensive, long-term, least cost plan for meeting ratepayer needs.

Q. Please explain Sierra Club's recommendation regarding preapproval.

A. As explained in its Initial Comments filed in the 492 docket,

> The Sierra Club strongly urges the Commission to establish a comprehensive and consistent process for considering utility proposals for major investments in existing generating units. In general, the Commission's final guidelines must require:
>
> (1) a thorough inventory and description of all the relevant resource options, together with an assessment of their costs, benefits, uncertainties and risks, as well as the probabilities of those risks,
>
> (2) an objective analysis of how those uncertainties and risks affect the performance of various resource plans individually and in combination,
>
> (3) development of a plan relying on a portfolio of resources that manages risk and uncertainty to a reasonable level while delivering the lowest life cycle cost over the fullest possible range of plausible future scenarios.[1]

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[1] Docket No. 11-GIME-492-GIE, *Sierra Club Initial Comments*, ¶ 7.

Those Initial Comments go on to explain that

> Thus the scope of Commission consideration and guidelines should include all material factors that affect resource cost comparison and relative risk assessment. . . . In general, the scope of the Commission's consideration and the guidelines should include a comprehensive set of issues and factors and should reflect a multi-pollutant approach to evaluating the likely costs of continued operation and retrofit, rather than considering one regulation at a time.[2]

The main point is that the Commission should make preapproval decisions about coal plant retrofits only when it is satisfied that it is fully informed about the full, forward-going costs that utilities would incur to operate those plants over their remaining life. The scope of Commission consideration and guidelines should include all material factors that affect resource cost comparison and relative risk assessment applied to decisions between retrofit technologies and replacement or retirement. In fact, this observation applies to preapproval decisions generally, but is particularly crucial for existing coal plants because of the potential synergistic effects of existing and proposed environmental regulations and requirements applicable to those plants. The sheer number and wide coverage of these mandates make it essential for the Commission and the utilities to consider their potential impact in a cohesive, rather than singular, case-by-case basis for future utility planning.

Q. What resource alternatives should be considered in such a cohesive analysis?

A. The Commission should to think beyond a simple selection among alternative power plant retrofits to determine the optimal configuration for meeting regulatory requirements over the long term. As pointed out in Sierra Club's Initial Comments,

> When compared with the high cost of traditional retrofits, options such as new wind generation, demand-side management, energy efficiency, fuel switching at the existing units, and underutilized and/or new combined cycle natural gas capacity, in combination with coal-unit retirements, may present the "optimal" cost and risk configuration for complying with new environmental and public health-based requirements. Therefore it is important to consider this question in two ways: (1) what are the required retrofit configurations to meet

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[2] *Op. cit.*, ¶ 13.

regulatory requirements if retrofit is chosen; and (2) what is the optimal way to meet regulatory requirements including non-retrofit options.[3]

Commission consideration of a broad range of alternatives, particularly a range including acquisition of all cost-effective and reasonably achievable energy efficiency and renewables is especially vital in view of immense disparity between the portfolio risk profiles that would be imposed on ratepayers under the company's preferred plan and one that employs more aggressive acquisition of alternatives.

4. CRITIQUE OF THE COMPANY'S PROPOSAL AND ANALYSES

Q. What is the company's proposal and what analysis did it provide of that proposal and the alternatives to it?

A. Dr. Fisher's prefiled testimony lists the specific retrofits proposed in the company's preferred plan. Dr. Hausman's prefiled testimony describes the analyses performed and alternatives considered by the company.

Q. Has the company presented information sufficient for the Commission to preapprove the capital investments in pollution control in the company's preferred plan?

A. No. As explained by Dr. Fisher, the company has correctly anticipated and taken into account some but not all of the most expensive environmental regulations facing its coal fleet. On the other hand, the company provided no information or analysis concerning certain other requirements (e.g., coal combustion waste) and other requirements are omitted in some scenarios (e.g., CO_2 in certain model runs). In addition, as shown by Dr. Hausman, the company's justification for its preferred plan is inadequate to support preapproval, even if the range of environmental requirements had been complete and correct. Specifically, while the company considered many of the pollution controls that are likely to be required to comply with current and upcoming EPA rules, its estimates of the costs and benefits of the various alternatives are biased in favor of the preferred plan. Dr. Hausman summarizes that point as follows:

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[3] *Op. cit.*, ¶ 26.

> My overall conclusion is that the company's analysis of alternatives to their [preferred] resource plan was limited, inadequate, and biased towards the continued investment in and operation of their existing generating plants. Not only did they fail to consider a reasonable range of alternatives, they unreasonably truncated their analysis of possible future scenarios, thereby artificially limiting the apparent uncertainty in their results. Even given this truncated range of uncertainty, however, the [net benefit of the] company's preferred plan does not exceed in any meaningful sense [the net benefit of] a number of the other plans considered in terms of benefits for consumers. However, the company's preferred plan does entail significant risks of future costs for consumers that are not present in some of the alternative plans—and especially in alternative plans incorporating higher levels of demand-side resources and renewables that the company did not even consider.
>
> The company is requesting the opportunity to recover significant costs from ratepayers associated with the continued operation of its existing coal-fired power plants. The Commission should require the company to provide a comprehensive analysis of the full range of options for addressing those regulations, including both supply- and demand-side resources, as well as alternatives to continued operation such as retirement or repowering. *Instead, the company has provided a limited analysis of a very narrow set of options, specifically ruling out numerous options that their own analysis shows to be lower cost.*
>
> Because of these shortcomings, the company's plan cannot be deemed to be "reasonable, reliable, and efficient".
>
> My recommendation to the commission is thus that the company's petition for predetermination be denied, until and unless the company demonstrates through a full analysis of the costs and risks of the plan that it is unambiguously superior to all reasonable alternatives in terms of ratepayer benefits.[4]

It is critical for the company's planning and decision making to consider the proper set of alternatives and use unbiased assumptions in doing so.

Q. Were there any additional specific shortcomings in the company's choice of alternatives to consider?

A. Yes. The company did not consider a reasonable range of alternative resource plans because it considered only a very limited range of renewable energy and demand-side management alternatives. Renewable energy options were restricted to the minimum

[4] Xx citation

required by Renewable Portfolio Standard (RPS) rules. Demand-side management (DSM) options were limited to certain pre-defined quantities that are far below what can be expected from aggressive pursuit of all cost-effective and reasonably achievable energy efficiency resources, even though the company's indicated that higher levels of DSM would reduce the cost of service. This is a serious omission and does a significant disservice to ratepayers.

Q. Please explain why more emphasis is needed on DSM in the consideration of alternatives to the proposed upgrades.

A. Energy efficiency is the least expensive and least risky resource option for meeting ratepayer needs.

Q. Please explain the non-energy benefits of DSM?

A. DSM programs offer immense risk reduction benefits for ratepayers and utility stockholders, alike, when compared to supply-side resources, even in cases where implementation is not 100% successful. For example, energy efficiency can help reduce the risks associated with fossil fuels and their inherently unstable price and supply characteristics and avoid the costs of unanticipated increases in future fuel prices. It is well understood that fuel diversity is desirable, particularly when it reduces rate sensitivity to fuel costs. Generally, energy efficiency has zero sensitivity to fuel costs making it superior to generation in that regard. Energy efficiency can also reduce the risks associated with environmental impacts, by reducing a utility's environmental impacts and helping utilities and their ratepayers avoid the hard to predict costs of complying with potential future environmental regulations, such as CO_2 regulation. Of course, energy efficiency also reduces the risks associated with regulatory, liability and other costs associated with other environmental and health effects, such as those from mercury and other hazardous air pollutants, as well as the risks to the Commonwealth's economy from potential ozone non-attainment problems. Energy efficiency can improve the overall reliability of the electricity system by reducing peak demand at those times when reliability is most at risk and by slowing the rate of growth of electricity peak and energy demands and giving utilities more time and flexibility to respond to changing market conditions, while moderating the "boom-and-bust" effect of competitive market forces on generation supply.

Q. How is it that energy efficiency is less risky than supply-side alternatives?

A. Energy efficiency is generally less risky than supply-side alternatives because DSM programs are modular and easily adjustable as circumstances change. Plus, each measure installed delivers benefits beginning immediately, unlike power plants that deliver no benefits at all unless and until they are completely built; uncertainties in load forecasts, capital costs of new generation, permitting delays and so on are types of planning risk that burden supply-side options but not DSM resources. Utility witnesses often make much of their lack of certainty as to the amount of DSM they can actually harvest, but make no effort in their testimony to compare those uncertainties to the many risks, financial and otherwise, that generation alternatives carry with them. The important point here is that any difficulties that arise in DSM program delivery can be identified, addressed and remedied in as little as one calendar quarter, while a problem that crops up in the construction or operation of a new, large-scale fossil fueled or nuclear power plant can take a decade to surface and be irretrievable once identified.

The U.S. EPA sums up the situation nicely:

> ***Some Say:***
>
> Customers will pay more if utilities offer energy efficiency.
>
> **The Fact Is:**
>
> - Total bills can decrease 2% to 9% over a 10-year period.
> - Customer will pay more if new, more costly infrastructure is built to serve avoidable demand.
> - Lower demand from efficiency programs puts downward pressure on market prices.[5]

When acting to further the public interest, the Commission should consider the total life-cycle cost of service, external costs, risk reduction, equity in program availability, and protection of hard to reach customers. The bottom line is that all cost effective savings are in the public interest. Anything less means that ratepayers will see higher bills than necessary, shoulder huge unnecessary financial and other risks, and see a less vigorous overall economy in the Commonwealth.

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[5] *See,* U.S. EPA at http://www.epa.gov/cleanenergy/energy-programs/napee/index.html.

Q. How does your recommendation on demand-side management apply to low-income, small businesses, and other hard-to-reach customers?

A. Equity demands proper treatment of hard-to-reach customers, including those on limited incomes, small businesses, and others. These customers face higher and added barriers to implementing DSM on their own or participating in DSM programs. Specifically, the Commission should require that utility energy efficiency programs (or additional, special programs as needed) be designed and implemented so as to ensure that hard-to-reach customers' needs are met in ways the work for them, not just the average customer.

Q. Please explain why you make that recommendation.

A. In my experience, some utility program designs and implementation strategies lack sensitivity to hard-to-reach customers, so I recommend the Commission pay special attention to this issue in energy efficiency programs.

Q. What do you mean by "hard-to-reach" customers?

A. By hard-to-reach customers I mean:

1. Residential electricity users who rent their residences from persons other than kin (defined in a manner appropriate to state law and society), trusts operated by and for the benefit of the users, or the users' legal guardians;

2. Commercial electricity users who rent their business property from persons other than the users' owners, parent companies, subsidiaries of their parent companies, their own subsidiaries, or trusts operated by and for the benefit of the same;

3. Residential or commercial electricity users who traditionally fail to engage in energy efficiency or demand response programs because of one or more severe barriers beyond those experienced by average residential or commercial customers in a utility's service area.

By "barrier," I mean any physical or non-physical necessity, obligation, condition, constraint, or requisite that obstructs or impedes electricity user participation in energy efficiency or demand response programs. Barriers may include but are not limited to language, physical or mental disability, educational attainment, utility meter type, economic status, property status, or geography.

Q. What policy do you recommend to the Commission in regard to utility energy efficiency programs for hard-to-reach customers?

A. I recommend that the Commission policy be that utilities are required to address programs for limited-income customers and other hard-to-reach customers so as to assure proportionate energy efficiency programs are deployed in these customer groups despite higher barriers to energy efficiency investments. The Commission may wish to allow programs targeted to low-income or hard-to-reach customers to meet lower threshold cost-effectiveness results than other programs or be enhanced in other ways to ensure that those customers are not left out.

Q. Please summarize your critique of the company's application for preapproval.

A. The company is to be complimented for its serious consideration of current and emerging environmental regulations that affect its coal-fired power plants and for considering a range of appropriate technologies for controlling the emissions from those plants. However, its consideration of alternatives to such controls was inadequate, blinkered and severely tilted in favor of its preferred plan. Therefore, the company has not met its burden for justifying preapproval by any reasonable standard.

4. RECOMMENDATIONS

Q. What recommendations do you have for Commission?

A. I recommend that the Commission order the following:

1. Adopt the preapproval standards set out in Sierra Club's Initial Comments and below in this prefiled testimony
2. Deny without prejudice preapproval for the proposed upgrades to both La Cygne units. The Commission should also direct the company to file a new study that corrects the deficiencies identified in the Sierra Club testimony so that the Commission can properly oversee the company's resource planning. It should also find that such a study will be an essential element for a proper preapproval filing in the future, for the La Cygne units or any other.
3. Find that upgrading the Montrose units to meet current and emerging environmental regulations is not cost-effective and direct the company to file a plan to retire those units. That plan should be required to identify and incorporate the long term, least cost resource alternatives to the Montrose units.

4. Require that the studies called for in items 2 and 3, above, comprehensively examine all alternatives, both supply- and demand-side, on a level playing field and also consider a sufficiently wide range of uncertainties and risks, properly documented and quantified and with the assumptions and methodologies made available to the Commission and intervenors

Q. Do you have additional recommendations for the Commission?

A. Yes. I have two.

First, the Commission must take a proactive approach to ensure sound decision-making and to ensure that the Commission has sufficient information to evaluate company decisions that could result in significant costs to ratepayers. In particular, the Commission must consider establishing a comprehensive and consistent process for considering utility proposals for major investments in new or existing generating units. In general, the Commission's guidelines for such a process should require:

(1) A thorough inventory and description of all the relevant resource options, together with an assessment of their costs, benefits, uncertainties and risks, as well as the probabilities of those risks,

(2) An objective analysis of how those uncertainties and risks affect the performance of various resource plans individually and in combination,

(3) Development of a plan relying on a portfolio of resources that manages risk and uncertainty to a reasonable level while delivering the lowest life cycle cost over the fullest possible range of plausible future scenarios.

If the company fails to do so or fails to coordinate its rate requests with its IRP planning processes and principles, the Commission should consider imposing a penalty in the form of a reduction to the company's allowed rate of return.

Second, the Commission should take forceful action now to ensure that all cost-effective and reasonably available energy efficiency and distributed energy resources are being acquired on an aggressive schedule. As discussed above, energy efficiency and distributed energy resources are the least risky and most cost-effective alternative to investment in generation, but require considerable lead time if they are to be available when needed to actually be feasible alternatives. Therefore, now is the time for the Commission to act so that those resources will be on hand when needed.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

In the Matter of the Petition of Kansas City Power & Light Company("KCP&L") for Determination of the Ratemaking Principles and Treatment that Will Apply to the Recovery in Rates of the Cost to be Incurred by KCP&L for Certain Electric Generation Facilities Under K.S.A. 2003 SUPP. 66-1239	))))))))	Docket No. II-KCPE-__-PRE

AFFIDAVIT OF WILLIAM STEINHURST

STATE OF VERMONT)
) ss
COUNTY OF WASHINGTON)

William Steinhurst, being first duly sworn on his oath states:

1. My name is William Steinhurst. I work in Montpelier, Vermont, and I am employed by Synapse Energy Economics, Inc., as a Senior Consultant.
2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of Sierra Club consisting of 19 pages, having been prepared in written form for introduction into evidence in the above-captioned docket.
3. I have knowledge of the matters set forth therein. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded, including any attachments thereof, are true and accurate to the best of my knowledge, information and belief.

William Steinhurst
William Steinhurst

Subscribed and sworn before me this 3rd th day of June, 2011.

Notary Public

My commission expires:

ANNABEL L GONYAW
NOTARY PUBLIC, VERMONT
MY COMMISSION EXPIRES FEB. 10, 2015

2011.06.03 16:47:25
Kansas Corporation Commission
/S/ Thomas A. Day

BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

IN THE MATTER OF THE PETITION OF KANSAS CITY POWER & LIGHT COMPANY ("KCP&L")FORDETERMINATION OF THE RATEMAKING PRINCIPLESAND TREATMENT THAT WILL APPLY TO THE RECOVERYIN RATES OF THE COST TO BE INCURRED BY KCP&L FORCERTAIN ELECTRIC GENERATION FACILITIES UNDER K.S.A. 66-1239	)	Docket No. 11-KCPE-581-PRE

Received
on
'JUN 0 3 2011
by
State Corporation Commission
of Kansas

PUBLIC VERSION

Direct Testimony of

Ezra D. Hausman, Ph.D.

On Behalf Of

The Sierra Club

June 3, 2011

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EXHIBITS

Exhibit EDH-1:	Resume of Ezra D. Hausman Ph.D.
Exhibit EDH-2:	Synapse Energy Economics, *2011 Carbon Dioxide Price Forecast*, White Paper, February 2011.

1. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, title and business address.

A. My name is Ezra D. Hausman, Ph.D., and I am Vice President and Chief Operating Officer of Synapse Energy Economics (Synapse), located at 485 Massachusetts Avenue, 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.

Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government agencies, and utilities.A complete description of Synapse is available at our website, www.synapse-energy.com.

Q. Please summarize your relevant work experience and youreducational background.

A. I have been employed by Synapse since July of 2005, and I have served as vice president of Synapse since July 2009. During this time I have provided expert analysis and testimony in numerous cases involving electricity, generating capacity, and ancillary service markets, electricity price forecasting, resource planning, environmental compliance, and economic analysis. I have prepared reports on these and other related topics for clients including federal and state agencies; offices of consumer advocate; legislative bodies; cities and towns; non-governmental organizations; foundations; industry associations; and resource developers. I have also facilitated and served as an expert analyst for state-level stakeholder and legislative processes related to electricity resource planning and mitigation of greenhouse gas emissions.

From 1997 until 2005, I was employed as a Senior Associate with Tabors Caramanis & Associates (TCA), now part of CRA International, performing a wide range of electricity market and economic analyses and price forecast modeling studies.These included asset valuation studies, market transition cost/benefit studies, market power analyses, and litigation support. I have extensive personal experience with market simulation, production cost modeling, and resource planning methodologies and software.

I hold a B.A. from Wesleyan University, an M.S. in civil engineering from Tufts University, an S.M. in applied physics from Harvard University and a Ph.D. in atmospheric chemistry from Harvard University.

A copy of my current resume is attached as Exhibit EDH-1 to this testimony.

Q. On whose behalf are you appearing in this proceeding?

A. I am appearing on behalf of the Sierra Club.

Q. Have you testified previously before the Kansas State Corporation Commission (the Commission)?

A. No, I have not.

Q. Have you reviewed the testimony and discovery responses submitted in association with this docket?

A. Yes, to the extent possible. However, certain discovery responses were not available until very shortly before the filing deadline for this testimony, and indeed certain discovery requests, including some Sierra Club discovery requests, have not been addressed as of this writing. Therefore it is possible that as I have an opportunity to review this additional information, I will file amended testimony with the commission in this Docket.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address KCP&L's basis for selecting its preferred plan, which serves as the basis of its planned environmental upgrades for the La Cygne coal-fired power plant. Specifically, I have reviewed documents and data related to the company's scenario and sensitivity analysis to evaluate whether their selection of a preferred plan is justified.

Q. Why is the Company's approach toward the selection of a preferred plan germane to this predetermination proceeding?

A. The company's request for predetermination and its selection of a preferred plan are intimately related. The justification for the company'spetition for predetermination for environmental retrofits on La Cygne is that itsanalysis indicates that these units should be kept in service as part of the preferred plan. An alternative plan might have retired one or both La Cygne units, and in this case the retrofits would obviously be unnecessary. Conversely, were the company's plan to support maintaining the Montrose units, additional retrofits would be required.

However, I do not believe that the company has followed good utility practice in performing and interpreting this analysis. As I will discuss, there is ample reason to conclude that a more thorough and rigorous analysiswould suggest that an alternative plan has a better cost and risk profile. Very possibly, such a preferable alternative would involve the retirement of one or both La Cygne units, obviating the retrofits.If so, then the company has not followed good utility practice, and ratepayers should not have to foot the bill for the resultingexcessive expenditures.

Q. What are your overall conclusions and your recommendation to the commission?

A. My overall conclusion is that the company's analysis of alternatives to its resource plan was limited, inadequate, and biased toward the continued investment in, and operation of, its existing generating plants. Not only did the company fail to consider a reasonable range of alternatives, it unreasonably truncated its analysis of possible future scenarios, thereby artificially limiting the apparent uncertainty in its results. Even given this truncated range of uncertainty, however, the net benefit of the company's preferred plan does not exceed, in any meaningful sense,the net benefit of a number of the other plans considered in terms of benefits for consumers. However, the company's preferred plan does entail significant risks of future costs for consumers that are not present in some of the alternative plans—in particular, these risks would be reduced in alternative plans incorporating higher levels of investment in demand-side resources and renewables that the company did not even consider.

The company is requesting the opportunity to recover significant costs from ratepayers associated with the continued operation of its existing coal-fired power plants. The Commission should require that the company provide a comprehensive analysis of the full range of options for addressing those regulations, including both supply- and demand-side resources, as well as alternatives to continued operation such as retirement or repowering. Instead, the company has provided a limited analysis of a very narrow set of options, specifically ruling out numerous options that their own analysis shows to be lower cost to ratepayers.

Because of these shortcomings, the company's plan cannot be deemed "reasonable, reliable, and efficient" as required under K.S.A. 66-1239(c)(3). I therefore concur with and adopt the second and fourth recommendations of Sierra Club witness Dr. William Steinhurst, regarding recommended commission action on KCP&L's preapproval petition and standards for adequate consideration of alternatives and risks, respectively.

2. KCP&L'S PLAN SELECTION AND ANALYSIS PROCESS

Q. Can you describe briefly the company's approach that resulted in the selection of its preferred plan, including the environmental upgrades at issue in this proceeding?

A. I will to the best of my ability. However, the company's testimony and response to data requests provide scarce detail. Company witness Burton Crawford's overview of the process comprises less than two pages of his direct testimony. (Crawford pages 4-5) Additional details can be pieced together from a number of exhibits and discovery responses, and these, together with Mr. Crawford's testimony, form the basis of my understanding of the process.

Based on an initial "resource screening process" (Crawford 5 at 17) the company selected fourteen different resource plans and four additional sensitivity plans. (Crawford 9 at 4) The details of this screening process are unknown, except for the vague statement that "options that are more expensive to operate are barred from further consideration."(Crawford 5 at 20) The demand-side elements of the fourteen plans are all based on the company's "October 2010" DSM/EE activities,[1] while the sensitivities rely upon the somewhat more aggressive "September 2009" DSM/EE levels. (File "KCC_20110225-23-Att-KCC-Q23-La Cygne Retrofit NPVRR (2-11-11 Runs)_Filed Case.xls", provided in response to KCC Discovery Question 23)

To analyze the NPVRR associated with each of the company's 18 plans and sensitivities, the company considers a range of future scenarios, including variations in the following six unknown variables: (1) Load Growth; (2) Construction Costs, (3) Financing Costs; (4) CO_2 Emissions Price; (5) Natural Gas Price; and (6) Coal Price. (File "KCC_20110225-23-Att-KCC-Q23-Decision Tree_Filed Case.xlsx", provided in response to KCC Discovery Question 23) The company has defined a low, medium, and high value to go with each of these

[1] DSM = Demand Side Management. Energy Efficiency, or EE, is one form of DSM that focuses on reducing overall energy use. Demand Response, or DR, is another form of DSM that focuses on reducing peak-hour energy use. In this testimony I will refer to these resources generally as DSM.

variables, except for financing costs, for which they consider only the medium and high cases. Thus the total number of possible future scenarios is $2*3^5$, or 486 possible futures. However, in the interest of reducing required model runs, the companyanalyzed only 64 of these future scenarios for each of the plans and sensitivities. (Crawford page 5 at 10) Based on its assessment of the likelihood of the high, medium, and low outcomes for each variable, the company performs a calculation of the combined ("conditional") probability for each of the 64 scenarios considered.

The company then performed MIDAS™ model runs on each of the plans for each of the future scenarios, covering the years 2010-2034. The company then determines the NPVRR for each plan/scenario combination, using a real discount rate of 7.885%. (As seen in the file KCC_20110225-23-Att-KCC-Q23-La Cygne Retrofit NPVRR (2-11-11 Runs)_Filed Case.xls, e.g., provided in response to Data Request Set KCC_20110225, Question 23.)The "expected" NPVRR for each plan is then calculated as the average NPVRR for the plan averaged over all of the future scenarios, weighted by the conditional probabilities.

Q. In your opinion, did the company consider a reasonable range of alternative resource plans?

A. No. The company considered a very limited range of resource alternatives, all of which depend on various configurations of natural gas and coal generation to meet the utility's expected energy and capacity requirements over the planning period. (See response to Data Request Set KCC_20110330, Question 78.)None of the primary plans consider additional investment in demand-side resources as a low-cost, low-risk way of matching supply with demand. The company's own sensitivity cases suggest that higher levels of DSM lead to lower NPVRR values, yet the company relies on a lower level of DSM for all of its alternative plans, and never considers the benefits of aggressive investments in this area. As discussed in the direct testimony of Dr. William Steinhurst, this is a serious omission that does a significant disservice to ratepayers.

While the company considered a number of retirement and replacement scenarios, it omitted configurations that may well have proven superior had they been considered. The company did not consider any plans in which existing coal units would be replaced by higher levels of DSM, by harnessing Kansas' abundant wind power potential beyond the minimum required by the state RPS, or by relying on increased market purchases of energy and capacity. (See responses to Sierra Club Discovery Request Questions 20 and 21, respectively.) The company did analyze plans with modestly increased levels of DSM as "sensitivity" cases and found them to be lower cost, but apparently rejected them out of hand. The company did not analyze any scenarios includingwhat I would consider to be aggressive DSM, such as levels approaching a standard of "all cost-effective" DSM.

Replacing much of the existing coal capacity with a combination of DSM, new gas, and higher utilization of existing gas capacity, along with renewables, would likely have been found to be a competitive option. This direction should have been explored thoroughly. Yet while the company's analysis consistently showed that retiring Montrose is beneficial to ratepayers, the company has not evaluated the option of combining retirement of Montrose with retirement of other coal-fired resources, again replacing the energy and capacity with DSM, renewables, market purchases, and gas-fired resources. This clearly leaves important questions unanswered and promising options unexplored.

Q. Isn't it reasonable to perform an initial screening process to eliminate the more expensive plans?

A. Yes, but in this case so little information is provided on the screening process that Mr. Crawford's statement cannot be taken at face value. It is also unclear what Mr. Crawford means by "options that are more expensive to operate," which seems to imply that capital costs are not part of the screening criteria.

Q. Did the Sierra Club or any other intervener request additional details from KCP&L on the selection of the resource plans?

A. Yes. Sierra Club's Discovery Request Question No. 13 requested all work papers and analyses documenting this process. In addition, Michael Deupree of the KCC requested these materials in KCC's Discover Request Question No. 78, and CURB requested the same information in Data Request No. 81. KCP&L provided a general answer in response to Mr. Deupree's request No. 78 and referred other interveners to that response. However, the company's response contains no description of any analytical basis for their selection of the resource plans to be considered. This calls further into question the validity of Mr. Crawford's statement that the selection was based on operating cost, or any other rigorous analysis.

Q. In your opinion, did the company consider a reasonable range of alternative future scenarios?

A. No. I understand from personal experience that it is a cumbersome task to evaluate hundreds or thousands of future scenarios, but if the company is going to request over a billion dollars from ratepayers in this case, a thorough analysis is in order. Numerous approaches are available to reasonably limit computing requirements while still covering the range of future outcomes. Unfortunately, the method the company devised to reduce the number of runs resulted in an unduly restricted and biased assessment of the range of possible outcomes. Essentially, the company excluded from consideration any scenario that, according to its probability estimate, had less than a 0.5% chance of occurring (the company also considered the two least likely scenarios, but the company-assigned probability of theseis so slight that they had almost no effect on the outcome, and I will neglect them in my statements.) (Response to KCC Discovery Request Question 14)

While this might seem logical at first blush, it actually has the effect of removing from consideration a huge fraction of the possible future outcomes, considering only those that are, by definition, clustered in the middle of the possible range—because the company assigned a 50% probability to the "middle" value for each variable, and 25% for the "high" and "low" values. However, because there are many more values outside this range, some of which are almost as likely as those inside the range, it is actually more likely than not—about 60% likely—that the future would lie completely outside of the range considered by the company.[2]This is illustrated in Figure 1, below, showing possible outcomes divided into two groups—those the company rejected out of hand and those it did not. If you threw a dart at a random location in Figure 1,it would be more likely to hit the red area than the blue area—yet the company only considered the possibilities represented by the dart hitting the blue area.For this reason, among others, I believe that the company's analysis severely underestimated the uncertainty in the calculation of NPVRR.

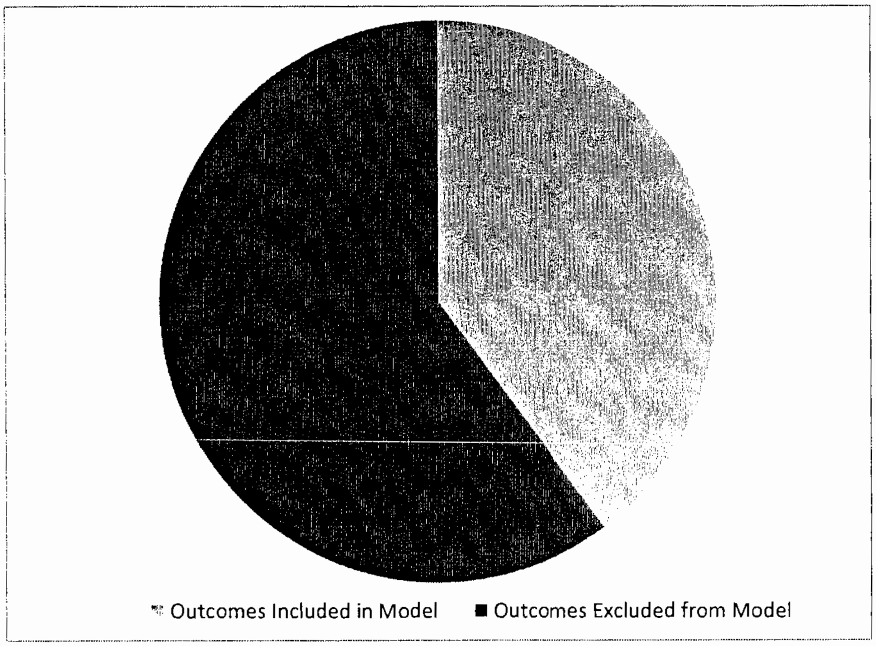

Figure 1. Combined likelihood of future scenarios considered vs. those not considered, represented proportionately.

[2] The company's approach also relies on the unstated assumption that the variables are uncorrelated and independent, which they most certainly are not. For example, it is likely that if fuel prices are high, construction costs will also increase. In my estimation, this further increases the likelihood of a future outside of the range considered by the company.

3. Robustness of the Company's NPVRR Estimations

Q. What is the company's estimate of the uncertainty in their NPVRR calculations?

A. Mr. Crawford did not report the company's estimate of uncertainty in testimony. However, in response to KCC's Data Request, the company did provide more detailed model output, including the NPVRR values for each of the runs. (KCC Discovery Request Response 23) As may be seen from Figure 2, based on these data, the uncertainty in the NPVRR for any given scenario is much larger than the differences among the scenarios.

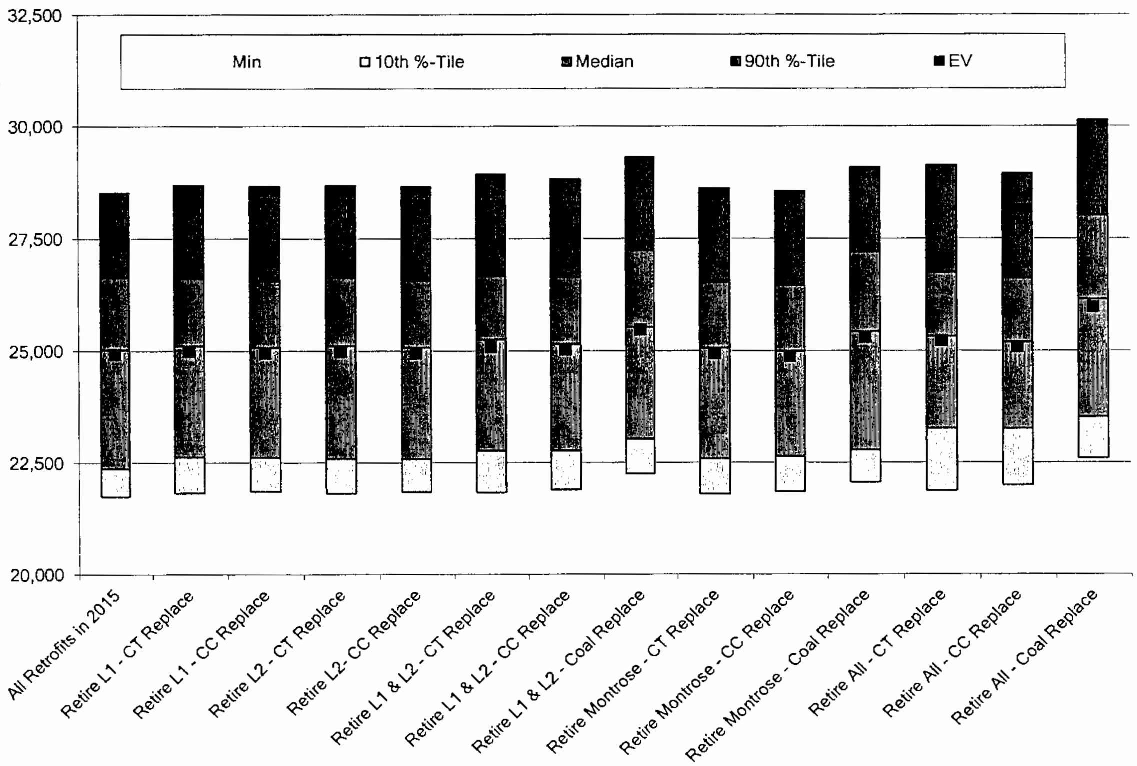

Figure 2. Range of NPVRR outcomes by scenario, as represented by KCP&L in response to KCC Data Request 23.

Q. Do you agree with the company's designation of percentiles in Figure 1?

A. For reasons described above, I believe that the actual ranges are much wider, and the true percentiles are much further from the median. It is impossible to estimate how much further, however,because the company only analyzed scenarios that they found close to the middle of the range.

Q. Putting aside the question of whether the Commission should have confidence in the company's analytical approach, was the company's selection of its preferred plan justified by its analysis?

A. No. The differences among the plans are extremely small—as small as 0.3% of the total NPVRR in some cases. This may be compared with the range of uncertainty—over 15% of NPVRR from the 10^{th} to 90^{th} percentile, even by the company's overly conservative estimate.

Further, the differences among the plans are not robust. By this I mean that a small change in expected conditions (that is, in what we assume about future events) could lead to a large change in the projected NPVRR differences between plans. For example, Figure 3shows that in the scenarios considered by the company, weighted by their assessment of the probability of each scenario, retiring all the coal units could be less costly than the company's preferred plan of retiring Montrose alone—as much as $400 million less on an NPVRR basis. In fact, even accepting *all* the company's assumptions there is a one in four chance that retiring all the coal plants will be cheaper than retiring just Montrose and spending over a billion dollars retrofitting La Cygne. Thus, the reported *average*NPVRR difference of $205 million between these cases masks a large range of uncertainty, including a significant likelihood that the "Retire All" case (KP06B) will actually be less costly than retiring Montrose alone (KP05B).

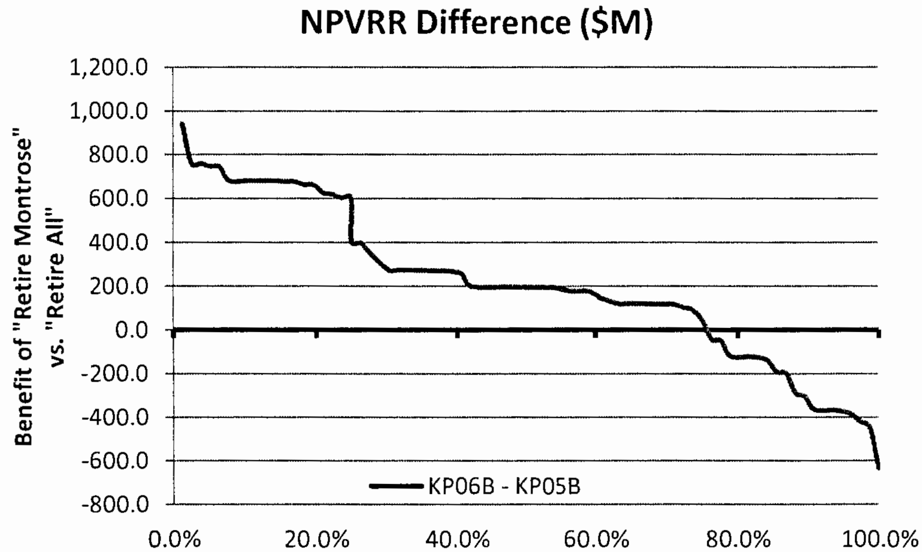

Figure 3. Cumulative probability distribution for the difference between scenarios KP06B ("Retire All – CC Replace") and KP05B ("Retire Montrose – CC Replace"). The differences between the scenarios for all 64 scenarios are shown, ordered from those that most favor KP05B to those that most favor KP06B, Negative values on the Y-axis indicate that KP06B is less costly. Based on detailed model results provided in response to KCC Data Request Question No. 23.

On this basis I conclude that the company's reported NPVRR differences are not meaningful, and are likely to be quite different under different future conditions. Under these circumstances, the company cannot reasonably conclude that its plan is superior to the others on the basis of projected NPVRR.

Q. Are you saying that NPVRR is irrelevant to the choice of a preferred plan?

A. No. The company should ensure that the selected plan is among those that have the lowest NPVRR. However, if there is no meaningful difference between the NPVRR values for two plans, then the company should take other considerations into account. For example, an important consideration is that of additional risks and costs associated with any given plan. The company did not compare plans on that basis, and thus, did not properly favor plans that have less risk of future unaccounted costs. As explained in Dr. Fisher's testimony, the La Cygne coal-fired power plant faces significant future risk due to environmental requirements.

Q. Are there any plans for which the differences in NPVRR appear to be robust?

A. Yes. The company considered four plans with higher DSM/EE levels, all of which resulted in NPVRR values significantly lower than the 14 primary plans considered. For example, Figure 4 shows the range of possible outcomes (again following the company's analysis) for the NPVRR difference of two scenarios in which La Cygne Unit 1 is retired, but with different levels of DSM spending. In this case I would say that the benefits of the higher-DSM plan are robust, because there is a persistent, $500 million plus benefit over almost all of the (probability-weighted) scenarios considered.

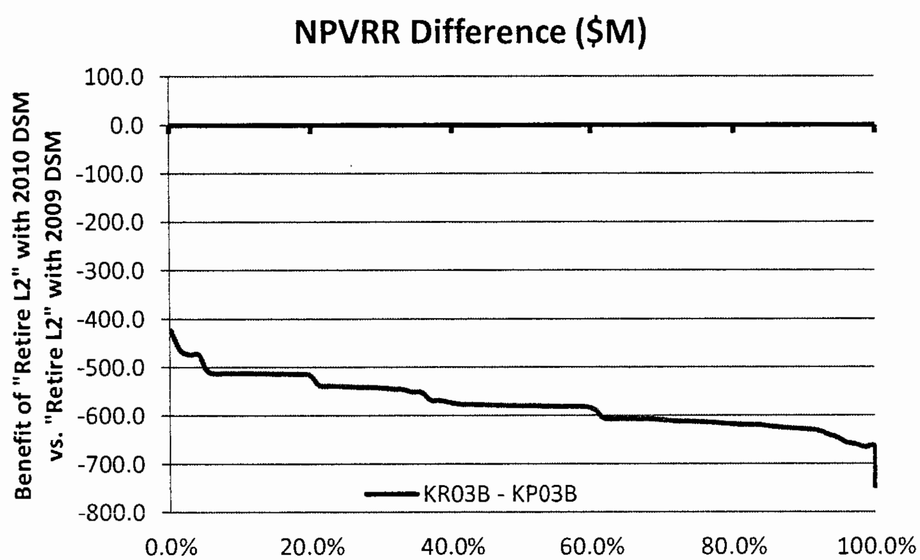

Figure 4. Cumulative probability distribution for the difference between scenarios KR03B and KP03B. Both scenarios are described as "Retire L2 – CC Replace"; however, KR03B assumes a higher level of DSM/EE activity. The differences between the scenarios for all 64 scenarios are shown, ordered from those that most favor KP03B to those that most favor KR03B. Negative numbers for all scenarios indicate that KR03B is less costly under all scenarios. Based on detailed model results provided in response to KCC Data Request Question No. 23.

Q. Do the results shown in Figure 4 include the extra cost of the more aggressive DSM plan?

A. That is unclear to me. There is a note in the response to KCC Data Request Question 23 that reads in part, "These runs do not include any costs changes [sic] for these different DSM/EE Levels." This note may mean that the costs of additional DSM are not included. However, I estimate the incremental NPV costs of the more aggressive DSM plan to be approximately $100 million -$130 million, which if netted from the benefits shown in Figure 4, would still leave a significant and robust several hundred million dollar benefit to the DSM plans.

Q. Would application of a higher level of DSM, such as that shown in the four DSM sensitivity plans or higher, make retirement of more coal units a low-cost scenario?

A. Very possibly. However, the company modeled very few plans under its more aggressive EE scenario, none of which considered retiring more than either Montrose alone or a single La Cygne unit. The company did not model *any* plans with what I would consider to be an aggressive DSM program, which would use a standard such as "all cost-effective" demand-side resources. Thus we cannot conclude based on the company's limited analysis whether investing in more DSM instead of retrofits would provide consumer benefits. However, I strongly suspect that it would, based on the limited analysis the company has provided.

4. UNQUANTIFIED RISKS OF THE COMPANY'S PLAN

Q. You noted earlier that if there is no meaningful difference between the NPVRR values for two plans, the company should take other factors into account. Can you elaborate?

A. Yes. A NPVRR analysis is forward-looking and therefore it necessarily involves uncertain projections and may omit important risks and costs. In the abstract,it is unreasonable to select a higher-cost plan when another plan is substantially and unambiguously less costly on an NPVRR basis.If a utility has properly anticipated and quantified the relevant future costs and revenues of those two plans, then it should select the lower cost plan, all other things being equal. However, in a case such as this where the preferred plan has an NPVRR that is not unambiguously better than alternatives, the relative riskiness of those plans their unquantified costs,benefits, and risks can and should play a larger role.

Q. What sort of risks should the company consider in this case?

A. There are a number of risks and unknowns associated with any resource plan. In this case, and as discussed in the testimony of company witness Paul Ling and Sierra Club witness Dr. Jeremy Fisher, the company appears to have done a comprehensive job of anticipating the costs of compliance with existing and likely future regulations for non-greenhouse gas air pollutants that will affect the generation fleet.However, there are significant environmental costs associated with continued operation of coal-fired power plants that were not adequately accounted for. These include the cost of managing coal combustion residuals (CCRs), mitigating effluent from generating stations and CCR impoundment ponds, and the cost of CO_2 emissions mitigation.

Q. Do you agree with witness Paul Ling that "KCP&L cannot determine the impacts of the EPA's proposed CCRs rule until an option is selected by the EPA and the final regulation is enacted?" (Ling page 24 at 11)

A. I understand that there issignificant uncertainty in this area. However, as discussed in Dr. Fisher's testimony, it is likely that provisions of the CCR rule will entail significant capital and operating investments. While these costs are not entirely avoidable at an existing plant, they will continue to mount as the plant continues operations.

Q. Why doesn't the company's treatment of carbon emissions costs adequately cover the risk of CO_2 emissions mitigation costs?

A. The vast majority of climate scientists, myself included, have concluded that unabated greenhouse gas emissions, particularly emissions of CO_2, pose an extraordinarily large risk to human societies and economies. These risks and costs will become increasingly obvious in the coming years and decades as the damages to communities, ecosystems, and species mount. This risk cannot be addressed without significant reductions in CO_2 emissions, a large share of which come from the power sector. Assuming federal policy will ultimately address this problem, at some point in the not-too-distant future coal-fired power plants such as La Cygne will be forced to either cease operations or make capital investments to capture and permanently store CO_2 emissions—using technology whose nature and cost are not known today.

KCP&L has considered a range of possible CO_2 emissions costs in its analysis. I believe the "mid" and "high" costs the company has considered (Confidential Exhibit WEB2011-14) [redacted]. The company also considered a "low-price" scenario which [redacted] the company's 2009 Missouri-filed IRP indicating a 100% "subjective probability" of future CO_2 regulations that would impose a price on greenhouse gas emissions. (GMO IRP Volume 4, p.33)This is an extremely unlikely scenario,and as a result the company's use of this scenario has biased the weighted average results in favor of carbon-intensive plans such as the chosen plan to retrofit La Cygne.

However, one must also consider the possibility of a scenario in which carbon regulation makes it simply impractical to operate coal plants without capturing the carbon they emit—as noted above, a requirement for any serious attempt to mitigate the risks associated with climate change. In my opinion, this risk is significant enough that the company should favor plans that reduce reliance on coal plants. This is certainly a reasonable consideration if the cost differences among the plans are small and non-robust. If the company can combine greenhouse gas emissions reductions with cost savings, as would be the case under a more DSM-based plan, this seems to me the obvious choice.

5. Overall Conclusions and Recommendations

Q. What are your overall conclusions and recommendations for the commission in this case?

A. My overall conclusion is that the company's analysis alternative resource plans was limited, inadequate, and biased towards the continued investment in, and operation of, the company's existing generating plants. Not only did the company fail to consider a reasonable range of alternatives, it unreasonably truncated the analysis of possible future scenarios, thereby artificially limiting the apparent uncertainty in the results. Even given this truncated range of uncertainty, however, the net benefit of the company's preferred plan does not exceed, in any meaningful sense, the net benefit of a number of the other plans considered in terms of benefits for consumers. However, the company's preferred plan does entail significant risks of future costs for consumers that are not present in some of the alternative plans—in particular, these risks would be reduced in alternative plans incorporating higher levels of investment in demand-side resources and renewables that the company did not even consider.

The company is requesting the opportunity to recover significant costs from ratepayers associated with the continued operation of its existing coal-fired power plants. The Commission should require that the company provide a comprehensive analysis of the full range of options for addressing those regulations, including both supply- and demand-side resources, as well as alternatives to continued operation such as retirement or repowering. Instead, the company has provided a limited analysis of a very narrow set of options, specifically ruling out numerous options that its own analysis shows to be lower cost to ratepayers.

Because of these shortcomings, the company's plan is not "reasonable, reliable, and efficient" as required under K.S.A. 66-1239(c)(3). I therefore concur with and adopt the second and fourth recommendations of Sierra Club witness Dr. William Steinhurst, regarding recommended commission action on KCP&L's

preapproval petition, and standards for adequate consideration of alternatives and risks, respectively.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

In the Matter of the Petition of Kansas City Power & Light Company("KCP&L") for Determination of the Ratemaking Principles and Treatment that Will Apply to the Recovery in Rates of the Cost to be Incurred by KCP&L for Certain Electric Generation Facilities Under K.S.A. 2003 SUPP. 66-1239	)	**Docket No. II-KCPE-581-PRE**

AFFIDAVIT OF Ezra D. Hausman, Ph.D.

STATE OF Massachusetts)
) ss
COUNTY OF Middlesex)

Ezra D. Hausman, being first duly sworn on his oath, states:

1. My name is Ezra D. Hausman. I work in Cambridge, Massachusetts, and I am employed by Synapse Energy Economics as a Vice President and Chief Operating Officer.
2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of Sierra Club consisting of twenty-one (21) pages, having been prepared in written form for introduction into evidence in the above-captioned docket.
3. I have knowledge of the matters set forth therein. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded, including any attachments thereof, are true and accurate to the best of my knowledge, information and belief.

Ezra D. Hausman

Ezra D. Hausman

Subscribed and sworn before me this 3rd day of June, 2011.

Notary Public

My commission expires:
October 8, 2015

REBECCA ANNE KEANE
Notary Public
COMMONWEALTH OF MASSACHUSETTS
My Commission Expires
October 8, 2015

Ezra Daskal Hausman, Ph.D.

Vice President and Chief Operating Officer
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ehausman@synapse-energy.com

SUMMARY

I have worked for over 14 years as an electricity market analyst with a focus on market design and market restructuring, environmental regulation in electricity markets, and pricing of energy, capacity, transmission, losses and other electricity-related services. I have performed market analysis, offered expert testimony, led workshops and working groups, made presentations and participated on panels, and provided other support to clients in a number of areas, including:

- Economic analysis, price forcasting, and asset valuation in electricity markets
- Electricity and generating capacity market design
- Integrated Resource Planning and portfolio analysis
- Economic analysis of environmental and other regulations, including cap-and-trade regulation of CO_2, in electricity markets
- Quantification of the economic and environmental benefits of displaced emmissions associated with energy efficiency and renewable energy initiatives
- Modeling and analysis of coordinated hydropower operations and water resource management on reservoir systems
- Regulation and mitigation of greenhouse gas emissions from the supply and demand sides of the U.S. electricity sector.

I have prepared reports and offered other expert services on these and other related topics for clients including federal and state agencies; offices of consumer advocate; legislative bodies; cities and towns; non-governmental organizations; foundations; industry associations; and resource developers.

I hold a Ph.D. in atmospheric science from Harvard University, an S.M. in applied physics from Harvard University, an M.S. in water resource engineering from Tufts University, and a B.A.degree from Wesleyan University.

PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA.
Chief Operating Officer, March 2011 – Present;
Vice President, July 2009 – Present;
Senior Associate, 2005-2009.
Conducting research, writing reports, and presenting expert testimony pertaining to consumer, environmental, and public policy implications of electricity industry regulation. Focus of work includes:

- Economic analysis of electricity industry regulation and restructuring

- Efficient pricing of generating and transmission capacity
- Long-term electric power system planning and market design
- Price forecasting and asset valuation
- Impact of air quality and environmental regulations on electricity markets and pricing
- Energy efficiency and renewable energy programs and policies, including avoided emissions analysis
- Market power and market concentration analysis in electricity markets
- Consumer and environmental protection
- Regulation and mitigation of greenhouse gas emissions.

Charles River Associates (CRA), Cambridge, MA. Senior Associate, 2004-2005
CRA acquired Tabors Caramanis & Associates in October, 2004.

Tabors Caramanis & Associates, Cambridge, MA. Senior Associate, 1998-2004
Modeling and analysis of electricity markets, generation and transmission systems. Projects included:

- Several market transition cost-benefit studies for development of Locational Marginal Price (LMP) based markets in US electricity markets
- Long-term market forecasting studies for valuation of generation and transmission assets,
- Valuation of financial instruments relating to transmission system congestion and losses
- Modeling and analysis of hydrologically and electrically interconnected hydropower system operations
- Natural gas market analysis and price forecasting studies
- Co-developed an innovative approach to hedging financial risk associated with transmission system losses of electricity
- Designed, developed and ran training seminars using a computer-based electricity market simulation game, to help familiarize market participants and students in the operation of LMP-based electricity markets.
- Developed and implemented analytical tools for assessment of market concentration in interconnected electricity markets, based on the "delivered price test" for assessing market accessibility in such a network
- Performed regional market power and market power mitigation studies
- Performed transmission feasibility studies for proposed new generation and transmission projects in various locations in the US
- Provided analytical support for expert testimony in a variety of regulatory and litigation proceedings, including breach of contract, bankruptcy, and antitrust cases, among others.

Global Risk Prediction Network, Inc., Greenland, NH. Vice President, 1997-1998
Developed private sector applications of climate forecast science in partnership with researchers at Columbia University. Specific projects included a statistical assessment of grain yield predictability in several crop regions around the world based on global climate indicators (Principal Investigator); a statistical assessment of road salt demand predictability in the United States based on global climate indicators (Principal Investigator); a preliminary design of a climate and climate forecast information website tailored to the interests of the business community; and the development of client base.

Hub Data, Inc., Cambridge, MA. Financial Software Consultant, 1986-1987, 1993-1997
Responsible for design, implementation and support of analytic and communications modules for bond portfolio management software; and developed software tools such as dynamic data

compression technique to facilitate product delivery, Windows interface for securities data products.

Abt Associates, Inc., Cambridge, MA. Environmental Policy Analyst, 1990-1991
Quantitative risk analysis to support federal environmental policy-making. Specific areas of research included risk assessment for federal regulations concerning sewage sludge disposal and pesticide use; statistical alternatives to Most-Exposed-Individual risk assessment paradigm; and research on non-point sources of water pollution.

Massachusetts Water Resources Authority, Charlestown, MA. Analyst, 1988-1990
Applied and evaluated demand forecasting techniques for the Eastern Massachusetts service area. Assessed applicability of various techniques to the system and to regional planning needs; and assessed yield/reliability relationship for the eastern Massachusetts water supply system, based on Monte-Carlo analysis of historical hydrology.

Somerville High School, Somerville, MA. Math Teacher, 1986-1987
Courses included trigonometry, computer programming, and basic math courses.

EDUCATION

Ph.D., Earth and Planetary Sciences. Harvard University, Cambridge, MA, 1997

S.M., Applied Physics. Harvard University, Cambridge, MA, 1993

M.S., Civil Engineering. Tufts University, Medford, MA, 1990

B.A., Wesleyan University, Psychology. Middletown, CT, 1985

FELLOWSHIPS, AWARDS AND AFFILIATIONS

President, Burr Elementary School Parent Teacher Organization, 2005-2007

UCAR Visiting Scientist Postdoctoral Fellowship, 1997

Postdoctoral Research Fellowship, Harvard University, 1997

Certificate of Distinction in Teaching, Harvard University, 1997

Graduate Research Fellowship, Harvard University, 1991-1997

Invited Participant, UCAR Global Change Institute, 1993

House Tutor, Leverett House, Harvard University, 1991-1993

Graduate Research Fellowship, Massachusetts Water Resources Authority, 1989-1990

Teaching Fellowships:

> **Harvard University:** *Principles of Measurement and Modeling in Atmospheric Chemistry; Hydrology; Introduction to Environmental Science and Public Policy; The Atmosphere.*
>
> **Wesleyan University:** *Introduction to Computer Programming; Psychological Statistics; Playwriting and Production.*

Professional affiliations

Member, American Association for the Advancement of Science

Member, American Economic Association

EXPERT SERVICES

Massachusetts Department of Energy Resources – 2009-2011
Served as expert analyst and modeling coordinator for analysis related to implementation of the Massachusetts Global Warming Solutions Act.

Iowa Office of Consumer Advocate – 2010-Present
Assisted Consumer Advocate in evaluating a proposed power purchase agreement for the output of the Duane Arnold nuclear power station.

Missouri Public Service Commission (Docket No. EW-2010-0187) – 2010
Expert participant on behalf of the Sierra Club in stakeholder process to develop a "demand side investment mechanism" in Missouri.

Louisiana Public Service Commission (Docket No. R-28271 Subdocket B) – 2009-2010
Expert participant on behalf of the Sierra Club in Renewable Portfolio Standard Task Force considering RPS for Louisiana.

Joint Fiscal Committee of the Vermont Legislature – 2008-2010
Serving as lead expert advising the Legislature on economic issues related to the possible recertification of the Vermont Yankee nuclear power plant.

Town of Littleton, NH – 2006-2010
Serving as expert witness on the value of the Moore hydroelectric facility.

Nevada Public Service Commission (Docket No. 08-05014) – August, 2008
Presented prefiled and live testimony on behalf of Nevadans for Clean Affordable Reliable Energy regarding the proposed Ely Energy Center and resource planning practices in Nevada.

Mississippi Public Service Commission (Docket No. 2008-AD-158) – August, 2008
Presented written and live testimony on behalf of the Sierra Club regarding the resource plans filed by Entergy Mississippi and Mississippi Power Company.

Kansas House of Representatives - Committee on Energy and Utilities – February, 2008
Presented testimony on behalf of the Climate and Energy Project of the Land Institute of Kansas on a proposed bill regarding permitting of power plants. Focus was on the risks and costs associated with new coal plants and on their contribute to global climate change.

Vermont Public Service Board (Docket No. 7250) – 2006-2008
Prepared report and testimony in support of the application of Deerfield Wind, LLC. For a Certificate of Public Good for a proposed wind power facility.

Iowa Utilities Board (Docket No. GCU-07-1) – October, 2007 – January, 2008
Presented wrtten and live testimony on behalf of the Iowa Office of Consumer Advocate regarding the science of global climate change and the contribution of new coal plants to atmospheric CO_2.

Nevada Public Service Commission (Docket No. 07-06049) – October, 2007
Presented prefiled direct testimony on behalf of Nevadans for Clean Affordable Reliable Energy regarding treatment of carbon emissions costs and coal plant capital costs in utility resource planning.

Massachusetts General Court, Joint Committee on Economic Development and Emerging Technologies – July 2007
Presented written and live testimony on climate change science and the potential benefits of a revenue-neutral carbon tax in Massachusetts.

Town of Rockingham, VT – 2006-2007
Served as expert witness on the value of the Bellows Falls hydroelectric facility.

South Dakota Public Utilities Commission (Case No EL05-22) – June 2006
Minnesota Public Utilities Commission (Docket TR-05-1275) – December 2006
Submitted prefiled and live testimony on the contribution of the proposed Big Stone II coal-fired generator to atmospheric CO_2, global climate change and the environment of South Dakota and Minnesota, respectively.

Arkansas Public Service Commission (Docket No. 06-070-U) – October 2006
Submitted prefiled direct testimony on inclusion of new wind and gas-fired generation resources in utility rate base.

Federal Energy Regulatory Commission (Docket Nos. ER055-1410-000 and EL05-148-000) – May-Sept 2006

- Participant in settlement hearings on proposed capacity market structure (the Reliability Pricing Model, or RPM) on behalf of State Consumer Advocates in Pennsylvania, Ohio and the District of Columbia
- Invited participant on technical conference panel on PJM's proposed Variable Resource Requirement (VRR) curve
- Filed Pre- and post-conference comments and affidavits with FERC
- Participated in numerous training and design conferences at PJM on RPM implementation.

Illinois Pollution Control Board (Docket No. R2006-025) – June-Aug 2006
Prefile and live testimony presented on behalf of the Illinois EPA regarding the costs and benefits of proposed mercury emissions rule for Illinois power plants.

Long Island Sound LNG Task Force – January 2006
Presentation of study on the need for and alternatives to the proposed Broadwater LNG storage and regasification facility in Long Island Sound.

Iowa Utilities Board (Docket No. SPU-05-15) – November 2005
Whether Interstate Power and Light's should be permitted to sell the Duane Arnold Energy Center nuclear facility to FPLE Duane Arnold, Inc., a subsidiary of Florida Power and Light.

PUBLICATIONS AND REPORTS

Johnston, L., E.D. Hausman, B. Biewald, R. Wilson, and D. White. "2011 Carbon Dioxide Price Forecast." Synapse White Paper, February 11, 2011.

Hausman, E.D., V. Sabodash, N. Hughes, and J. I. Fisher, "Economic Impact Analysis of New Mexico's Greenhouse Gas Emissions Rule." Prepared for New Energy Economy, February 9, 2011.

Hausman, E.D., J. Fisher, L. Mancinelli, and B. Biewald. "Productive and Unproductive Costs of CO_2 Cap-and-Trade: Impacts on Electricity Consumers and Producers." Prepared for National Association of Regulatory Utility Commissioners, National Association of State Utility Consumer Advocates, National Rural Electric Cooperative Association, and American Public Power Association, July 15, 2009.

Peterson, P., E. Huasman, R. Fagan, and V. Sabodash, Report to the Ohio Office of Consumer Counsel, on the value of continued participation in RTOs. Filed under Ohio PUC Case No. 09-90-EL-COI, May 26, 2009.

Schlissel, D., L. Johnston, B. Biewald, D. White, E. Hausman, C. James, and J. Fisher, "Synapse 2008 CO_2 Price Forecasts." July 2008.

Hausman, E.D., J. Fisher and B. Biewald, "Analysis of Indirect Emissions Benefits of Wind, Landfill Gas, and Municipal Solid Waste Generation." Report to the Air Pollution Prevention and Control Division, National Risk Management Research Laboratory, U.S. Environmental Protection Agency, July, 2008.

Hausman, E.D. and C. James, "Cap and Trade CO_2 Regulation: Efficient Mitigation or a Give-away?" Presentation to the ELCON Spring Workshop, June, 2008.

Hausman, E.D., R. Hornby and A. Smith, "Bilateral Contracting in Deregulated Electricity Markets." Prepared for the American Public Power Association, April, 2008.

Hausman, E.D., R. Fagan, D. White, K. Takahashi and A. Napoleon, "LMP Electricity Markets: Market Operations, Market Power and Value for Consumers." Prepared and delivered for the American Public Power Association's Electricity Market Reform Initiative (EMRI) symposium, *Assessing Restructured Electricity Markets"* in Washington, DC, February 5, 2007.

Hausman, E.D. and K. Takahashi, "The Proposed Broadwater LNG Import Terminal Response to Draft Environmental Impact Statement and Update of Synapse Analysis." Synapse Energy report on behalf of the Connecticut Fund for the Environment and Save The Sound, January 22, 2007.

Hausman, E.D., K. Takahashi, D. Schlissel and B. Biewald, "The Proposed Broadwater LNG Import Terminal: An Analysis and Assessment of Alternatives." Synapse Energy report on behalf of the Connecticut Fund for the Environment and Save The Sound, March 2, 2006.

Hausman, E.D., P. Peterson, D. White and B. Biewald, "RPM 2006: Windfall Profits for Existing Base Load Units in PJM: An Update of Two Case Studies" Synapse Energy report prepared on behalf of Pennsylvania Office of Consumer Advocate and the Illinois Citizens Utility Board, February, 2006.

Hausman, E.D., K. Takahashi, and B. Biewald, "The Glebe Mountain Wind Energy Project: Assessment of Project Benefits for Vermont and the New England Region" Report prepared on behalf of Glebe Mountain Wind Energy, LLC., February, 2006.

Hausman, E.D., K. Takahashi, and B. Biewald, "The Deerfield Wind Project: Assessment of the Need for Power and the Economic and Environmental Attributes of the Project" Report prepared on behalf of Deerfield Wind, LLC., January, 2006.

Hausman, E.D., P. Peterson, D. White and B. Biewald, "An RPM Case Study: Higher Costs for Consumers, Windfall Profits for Exelon" Synapse Energy report to the Illinois Citizens Utility Board, October, 2005.

Hausman, E.D. and G. Keith, "Calculating Displaced Emissions from Energy Efficiency and Renewable Energy Initiatives" Content for EPA website, 2005

Rudkevich, A., E.D. Hausman, R.D. Tabors, J. Bagnal and C Kopel, "Loss Hedging Rights: A Final Piece in the LMP Puzzle" *Hawaii International Conference on System Sciences, Hawaii,* January, 2005 *(accepted).*

Hausman, E.D. and R.D. Tabors, "The Role of Demand Underscheduling in the California Energy Crisis" *Hawaii International Conference on System Sciences, Hawaii,* January, 2004.

Hausman, E.D. and M.B. McElroy, The reorganization of the global carbon cycle at the last glacial termination, *Global Biogeochemical Cycles, 13*(2), 371-381, 1999.

Norton, F.L., E.D. Hausman and M.B. McElroy, "Hydrospheric transports, the oxygen isotope record, and tropical sea surface temperatures during the last glacial maximum" *Paleoceanography, 12,* 15-22, 1997.

Hausman, E.D. and M.B. McElroy, "Variations in the oceanic carbon cycle over glacial transitions: a time-dependent box model simulation" presented at the spring meeting of the American Geophysical Union, San Francisco, 1996.

PRESENTATIONS AND WORKSHOPS

NASUCA 2010 Annual Conference: "Addressing Climate Change while Protecting Consumers." November 2010.

NASUCA Consumer Protection Committee: Briefing on the Synapse report entitled, "Productive and Unproductive Costs of CO_2 Cap-and-Trade." September 2009.

NARUC 2009 Summer Meeting: Invited speaker on topic: "Productive and Unproductive Costs of CO_2 Cap-and-Trade." July, 2009.

NASUCA 2008 Mid-Year Meeting: Invited speaker on the topic, "Protecting Consumers in a Warming World, Part II: Deregulated Markets." June 2008.

Center for Climate Strategies: Facilitator and expert analyst on state-level policy options for mitigating greenhouse gas emissions. Serve as facilitator/expert for the Electricity Supply (ES) and Residential, Commercial and Industrial (RCI) Policy Working Groups in the states of Colorado and South Carolina. 2007-2008.

NASUCA 2007 Mid-Year Meeting: Invited speaker on the topic, "Protecting Consumers in a Warming World" June 2007.

ASHRAE Workshop on estimating greenhouse gas emissions from buildings in the design phase: Participant expert on estimating displaced emissions associated with energy efficiency in building design. Also hired by ASHRAE to document and produce a report on the workshop. April, 2007.

Assessing Restructured Electricity Markets An American Public Power Association Symposium: Invited speaker on the history and effectiveness of Locational Marginal Pricing (LMP) in northeastern United States electricity markets, February, 2007.

ASPO-USA 2006 National Conference: Invited speaker and panelist on the future role of LNG in the U.S. natural gas market, October, 2006.

Market Design Working Group: Participant in FERC-sponsored settlement process for designing capacity market structure for PJM on behalf of coalition of state utility consumer advocates, July-August 2006.

***NASUCA 2006 Mid-Year Meeting*:** Invited speaker on the topic, "How Can Consumer Advocates Deal with Soaring Energy Prices?" June 2006.

Soundwaters Forum, Stamford, CT: Participated in a debate on the need for proposed Broadwater LNG terminal in Long Island Sound, June 2006.

Energy Modeling Forum: Participant in coordinated academic exercise focused on modeling US and world natural gas markets, December 2004.

Massachusetts Institute of Technology (MIT): Guest lecturer in Technology and Policy Program on electricity market structure, the LMP pricing system and risk hedging with FTRs. 2002-2005.

LMP: The Ultimate Hands-On Seminar. Two-day seminar held at various sites to explore concepts of LMP pricing and congestion risk hedging, including lecture and market simulation exercises. Custom seminars held for FERC staff, ERCOT staff, and various industry groups. 2003-2004.

Learning to Live with Locational Marginal Pricing: Fundamentals and Hands-On Simulation. Day-long seminar including on-line mock electricity market and congestion rights auction, December 2002.

LMP in California. Series of seminars on the introduction of LMP in the California electricity market, including on-line market simulation exercise. 2002.

Synapse
Energy Economics, Inc.

2011 Carbon Dioxide Price Forecast

February 11, 2011

AUTHORS

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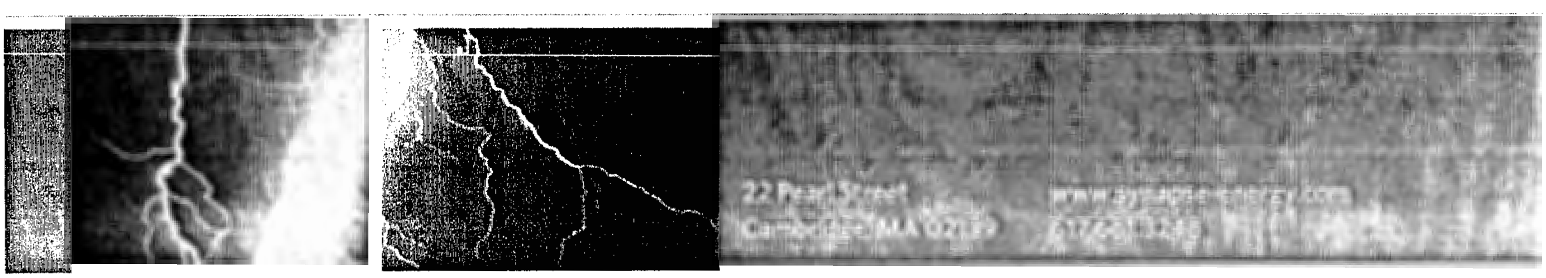
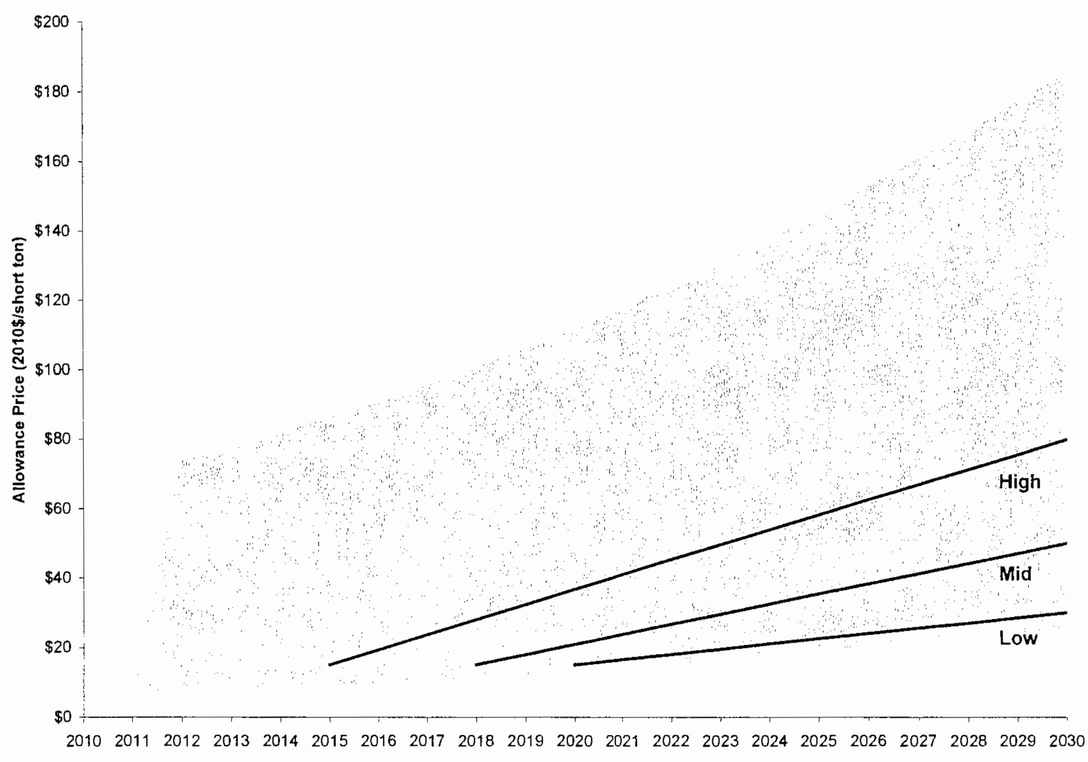


Table of Contents

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



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[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.

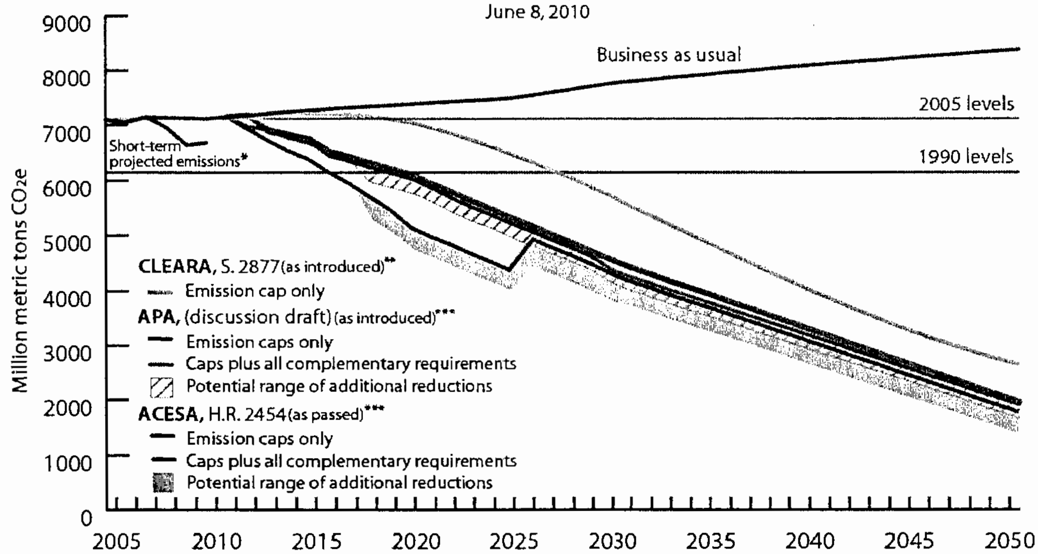
3. Policy Context

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



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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.

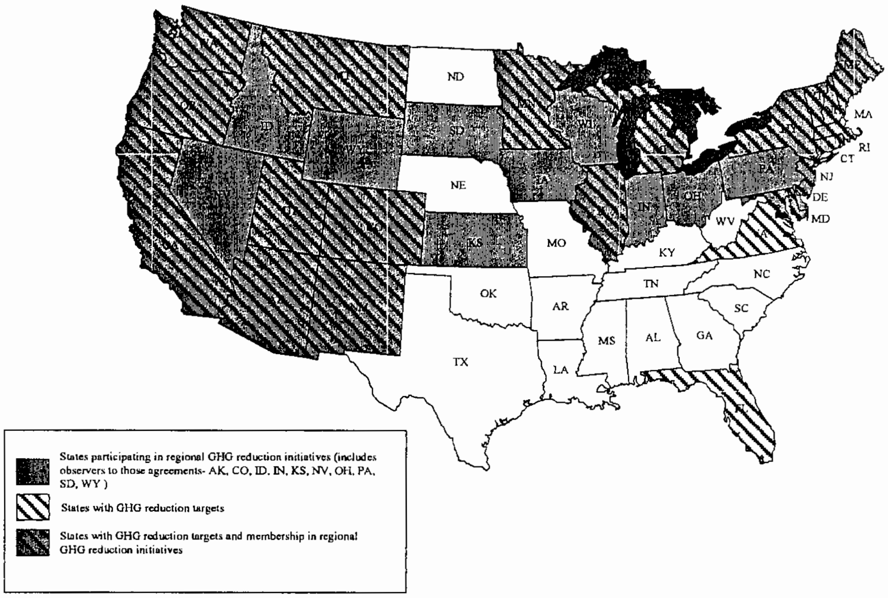
The map below shows states with emission targets and those participating in, or observing, regional climate initiatives as of January 2011. States that have adopted emissions targets and/or that are participating actively in regional climate initiatives comprise 44.4% of US electrical generation, 48.3%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

[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

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[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 the 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.

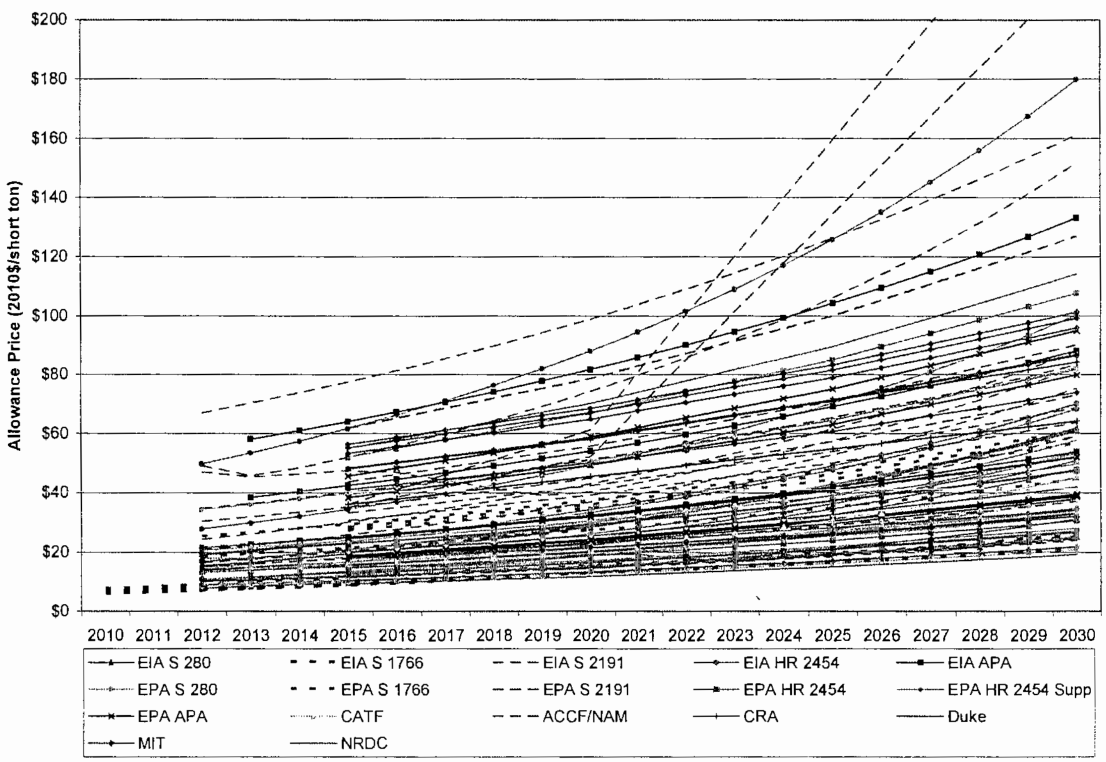
[12] Information is available at http://www.pewclime.org/copenhagen-accord

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.

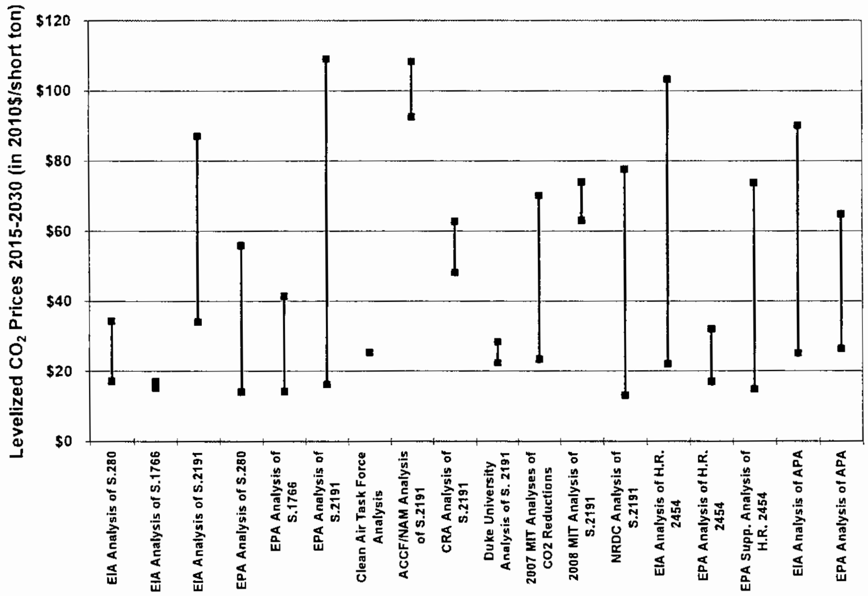
The graph below shows the results of all the scenarios from multiple analyses in the past several years. The studies that are incorporated into this graph are identified in Appendix A.

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



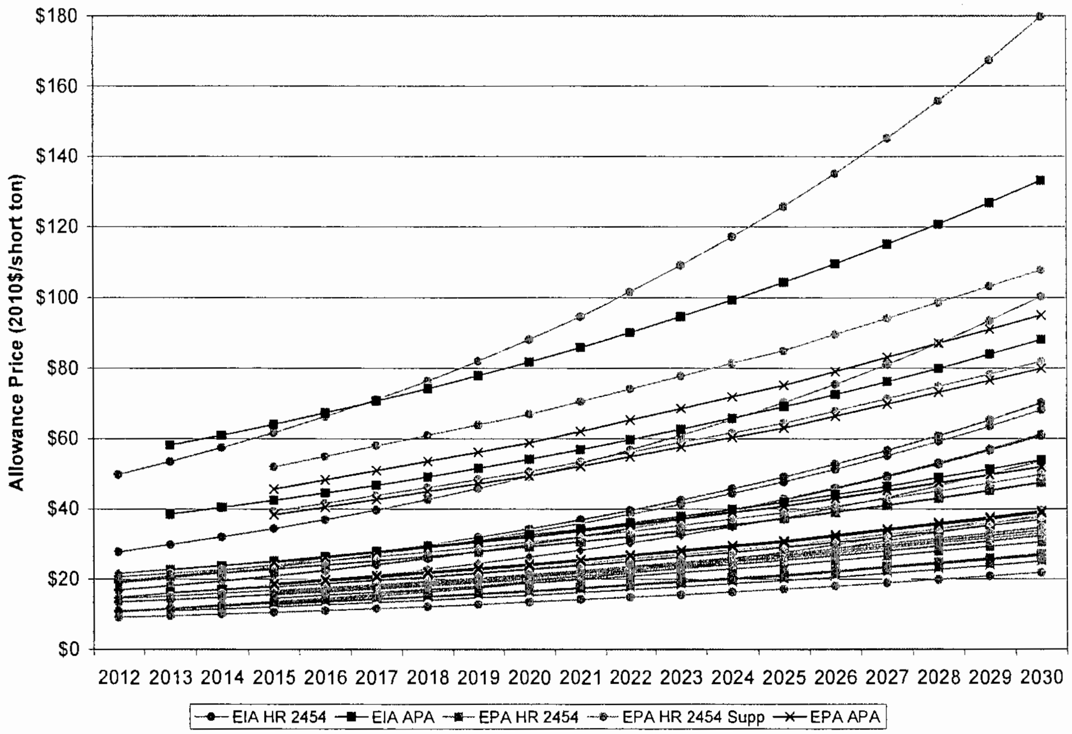
The results of these same analyses are represented in Figure 4, below, as ranges of levelized costs.

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

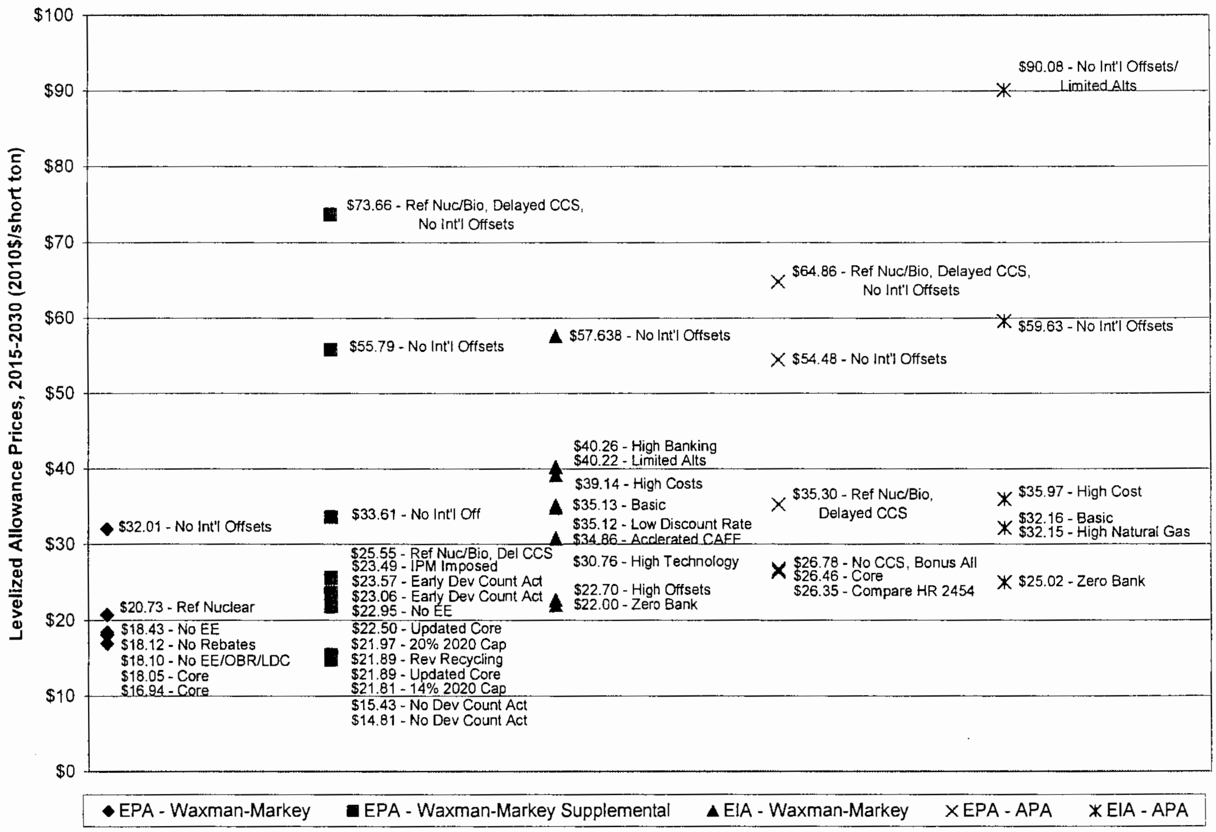
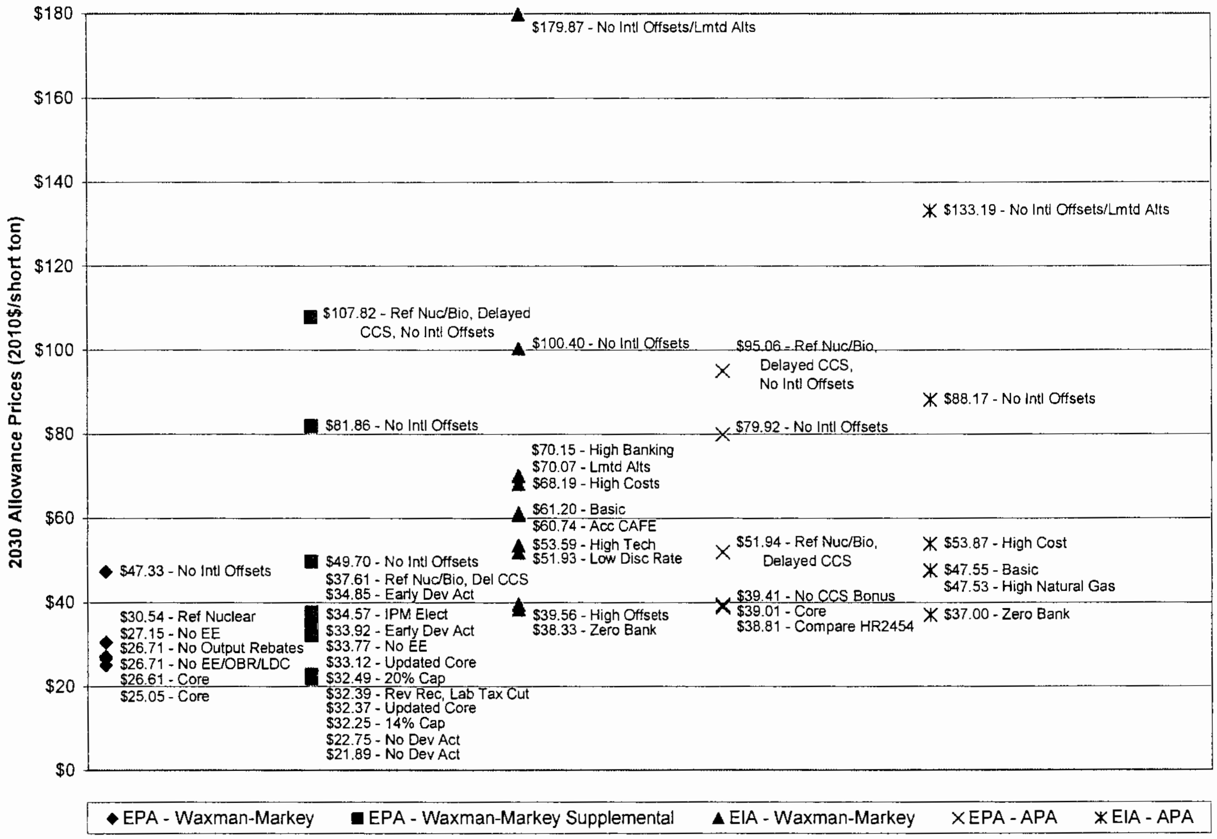


Figure 7: 2030 Greenhouse gas allowance price projections for HR 2454 and APA 2010



Our review of the more than 75 scenarios examined in the modeling analyses represented in Figure 3, 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.

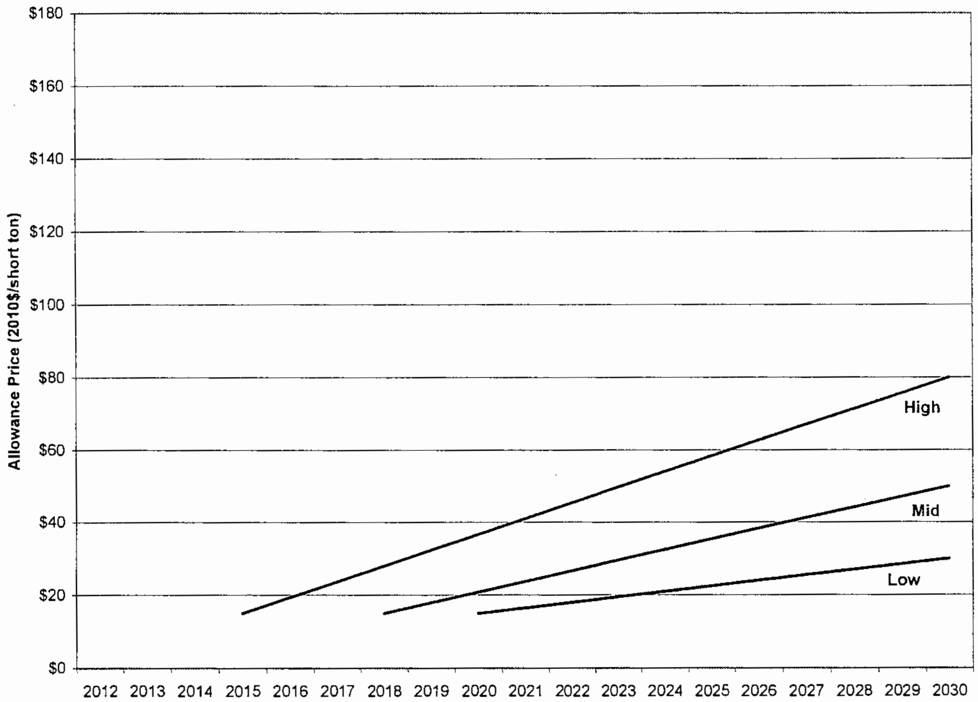
The factors could also include state actions to reduce emissions through aggressive energy efficiency and renewable actions, and/or a decision by Congress to adopt a set of aggressive complementary policies as part of a package to reduce CO_2 emissions. These complementary policies could include an aggressive 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 3 and Table 2 below:

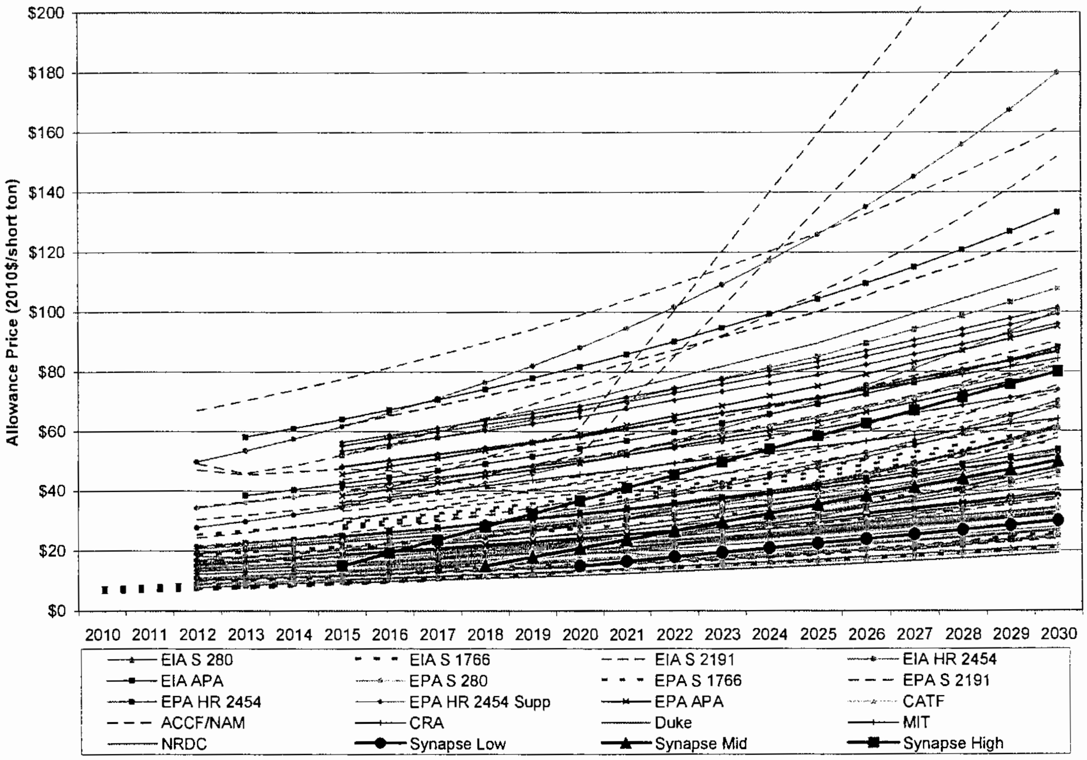
Figure 8: 2011 Forecast Values



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 \$24 and \$63. 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.

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

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



Schedule RSW-3

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

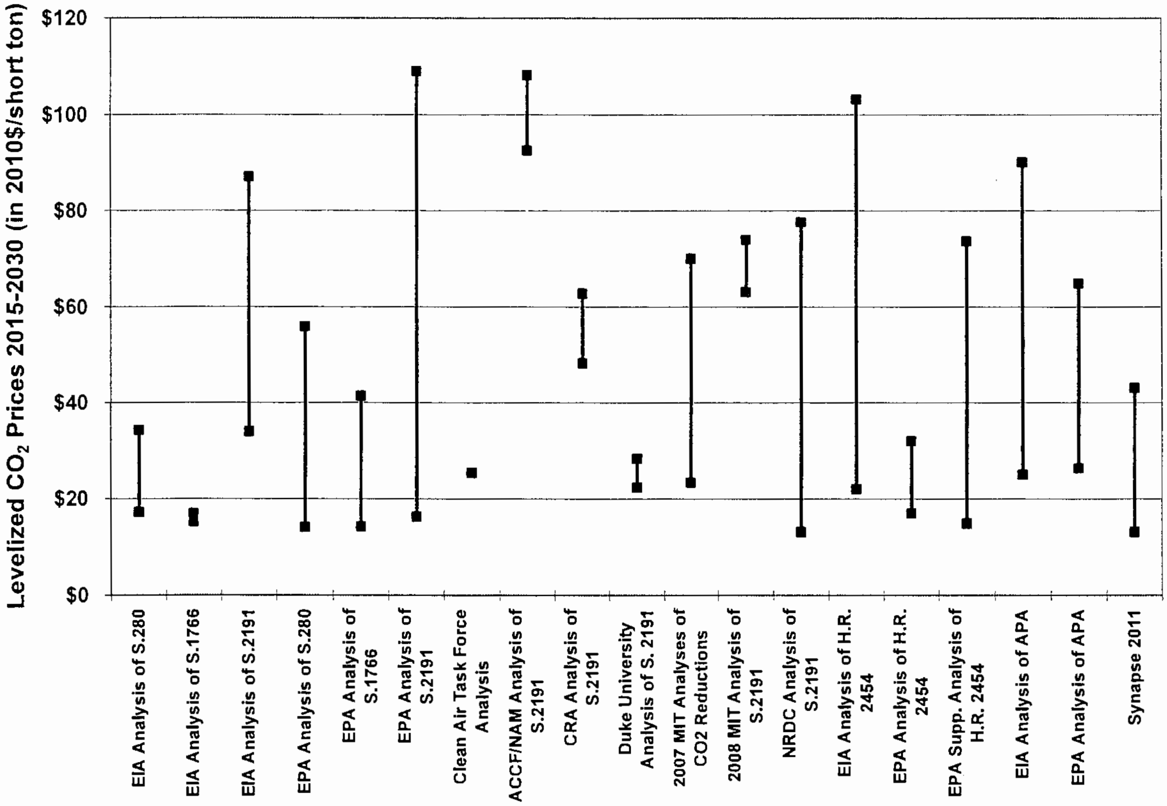


Figure 11: Synapse CO_2 trajectories and greenhouse gas allowance price projections for HR 2454 and APA 2010

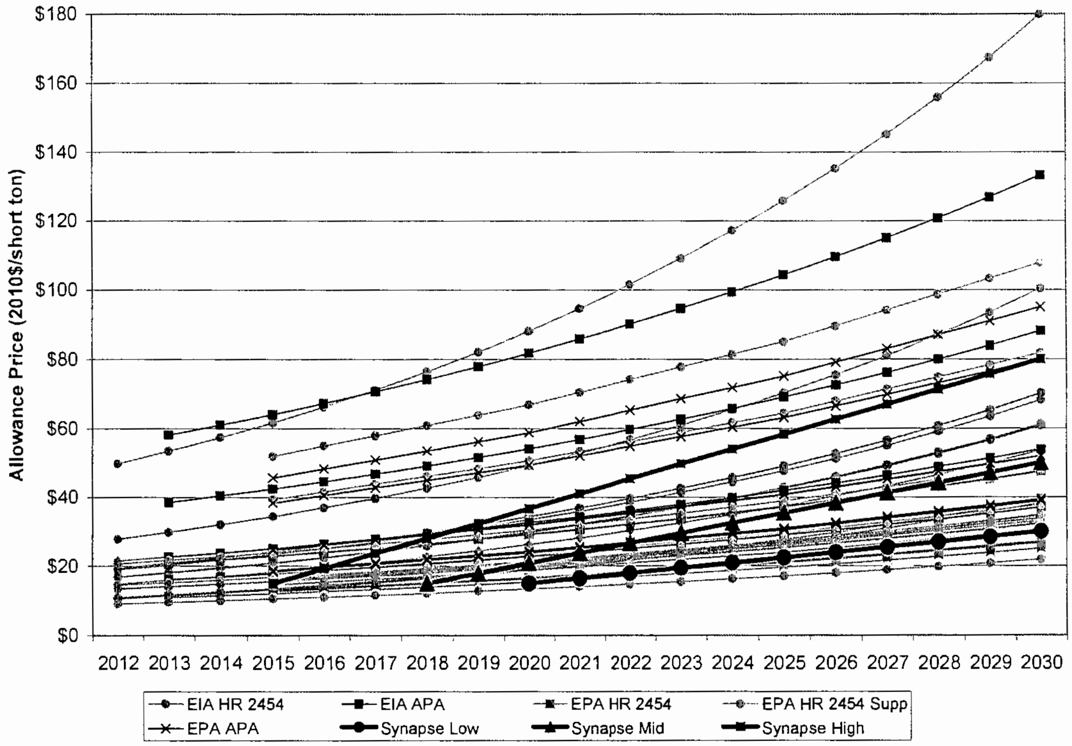
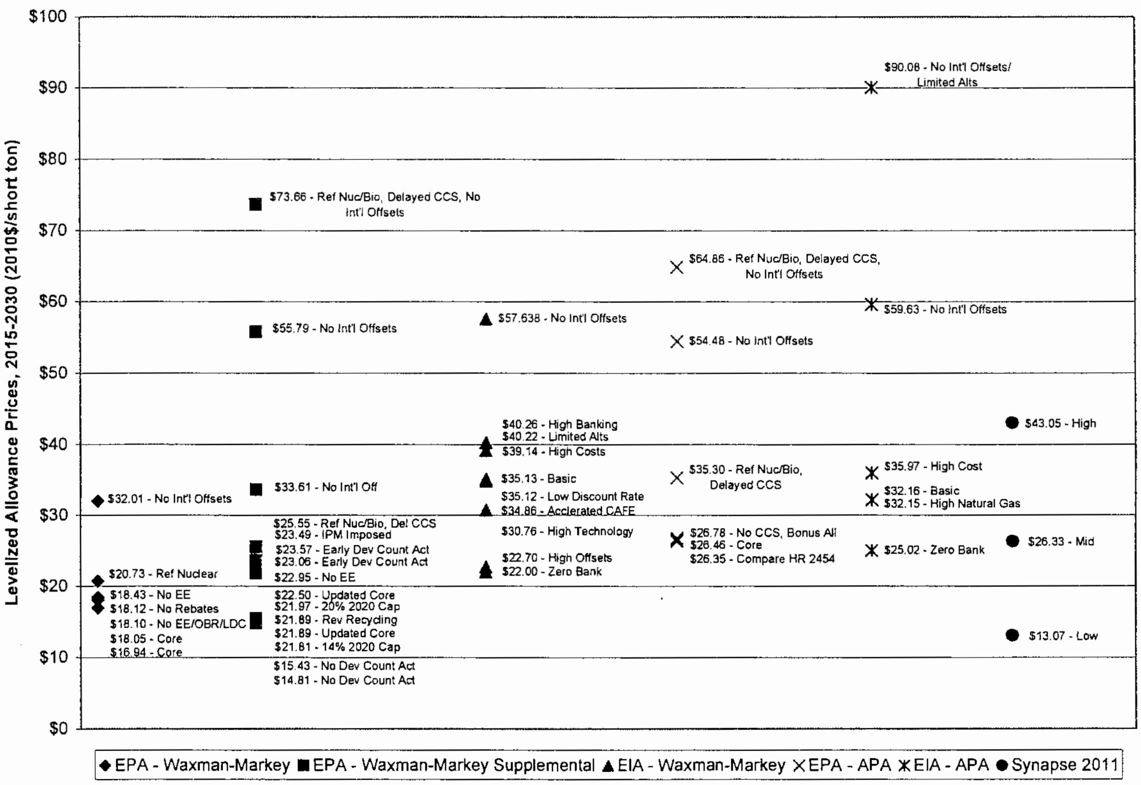
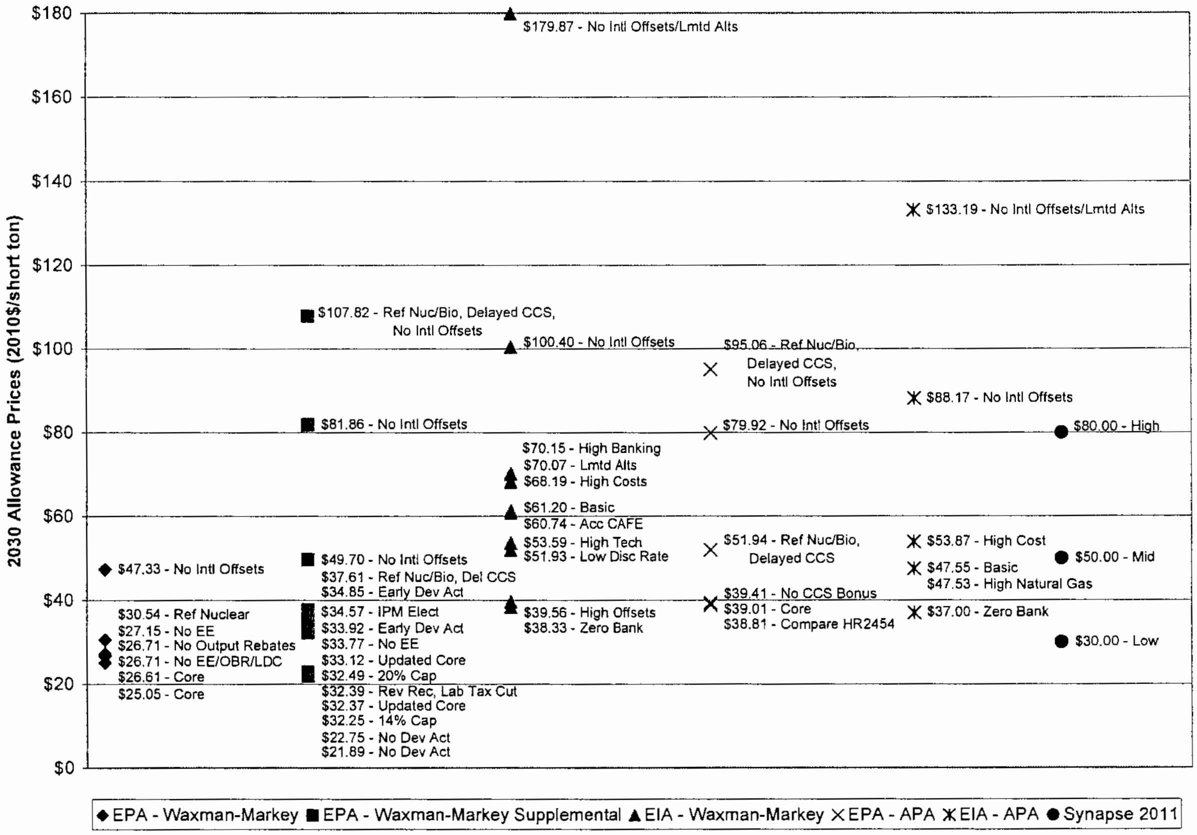


Figure 12: Synapse CO_2 trajectories and greenhouse gas allowance price projections for HR 2454 and APA 2010- levelized 2015-2030



Schedule RSW-3

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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- American Council for Capital Formation and the National Association of Manufacturers, NMA; Analysis of the Lieberman-Warner Climate Security Act (S. 2191) using the National Energy Modeling System (NEMS/ACCF/NAM) (March 2008).[33]

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28 Available at http://mit.edu/globalchange/www/MITJPSPGC_Rpt146_AppendixD.pdf.
29 Available at http://www.nicholas.duke.edu/institute/econsummary.pdf
30 Available at http://docs.nrdc.org/globalwarming/glo_08051401A.pdf
31 Available at http://lieberman.senate.gov/documents/catflwcsa.pdf .
32 Available at http://www.nma.org/pdf/040808_crai_presentation.pdf ....
33 Available at http://www.accf.org/pdf/NAM/fullstudy031208.pdf.

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Kansas Corporation Commission
/S/ Thomas A. Day

BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

IN THE MATTER OF THE PETITION OF KANSAS CITY POWER & LIGHT COMPANY ("KCP&L") FOR DETERMINATION OF THE RATEMAKING PRINCIPLES AND TREATMENT THAT WILL APPLY TO THE RECOVERY IN RATES OF THE COST TO BE INCURRED BY KCP&L FOR CERTAIN ELECTRIC GENERATION FACILITIES UNDER K.S.A. 66-1239	)	Docket No. 11-KCPE-581-PRE

Received
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by
State Corporation Commission
of Kansas

Direct Testimony of

Jeremy I. Fisher, Ph.D.

On Behalf Of

The Sierra Club

June 3, 2011

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1. Introduction and Qualifications

Q **Please state your name, business address and position.**

A My name is Jeremy Fisher, and I am a scientist with Synapse Energy Economics (Synapse). My business address is 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. 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), the National Rural Electric Cooperative Association (NRECA), the State of Alaska, the Western Grid Group, the Union of Concerned Scientists (UCS), the Sierra Club, the National Resources Defense Council (NRDC), the Environmental Defense Fund (EDF), the Stockholm Environment Institute (SEI), and the 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 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 the Sierra Club.

Q **Have you testified previously before the Kansas Corporation Commission?**

A No, I have not.

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

A The purpose of my testimony is to detail the current and likely upcoming federal environmental regulations that are likely to affect the operations and economics of the fleet of coal plants owned by the Kansas City Power and Light (KCP&L, or "the company"). I will support the company's assertion that the environmental retrofits requested in this docket are required if the coal units are to be kept operational in 2015 and beyond, and discuss shortcomings in the company's assumptions about emerging environmental regulations.

This testimony provides support for the modeling analysis performed by Sierra Club witness Dr. Hausman.

Q **On what KCP&L documents and filings do 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 company witness testimony and discovery responses, I have reviewed the following publicly available documents prepared by KCP&L:

- KCP&L 2009 Integrated Resource Plan (IRP) ("2009 IRP"), filed in Missouri (Docket EE-2009-0237);
- KCP&L Annual Statement (Form 10-K) to the Securities and Exchange Commission (SEC), filed on December 31, 2010;
- KCP&L Best Available Retrofit Technology (BART) Five Factor Analysis for La Cygne Generating Station, filed August 2007 with the Kansas Department of Health and Environment (KDHE);

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** Chart of EPA regulatory history for major classes of pollutants

Q How is your testimony organized?

A My testimony is organized as follows:

- Introduction and Qualifications
- Summary of Conclusions and Recommendations
- Environmental Regulations
- Clean Air Act Visibility Rule
- Clean Air Act Toxics Rule For Utility Steam Generating Units
- Clean Air Act National Ambient Air Quality Standards (NAAQS)
- Clean Water Act Cooling Water Intake Rule
- Clean Water Act Effluent Limitation Guidelines
- Resource Conservation and Recovery Act Coal Combustion Residuals Disposal Rule
- Closing

2. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q In your opinion and according to the documents you have reviewed, do the environmental retrofits proposed and modeled by KCP&L substantively address current and reasonably expected environmental regulations?

A Generally speaking, yes. The company has demonstrated that it is aware of and has planned for current and impending environmental regulations governing emissions of air pollutants which lead to the formation of harmful particulates, ground-level ozone, haze, acid rain, and emissions of hazardous air pollutants and mercury, as well as regulations governing water use for power plant cooling, and the management and disposal of coal combustion residuals. It is my opinion that the company's proposed retrofits could bring the La Cygne units into compliance with many of the existing and impending regulations that govern emissions of criteria pollutants and toxics, assuming these retrofits would meet emissions limitations contained in an enforceable permit. While the company has not proposed cooling towers for predetermination in this docket, the planning process has reasonably evaluated the costs of reaching compliance with likely cooling water withdrawal rules. Finally, the company has also evaluated the costs of bringing the Montrose coal units into compliance with existing and impending emissions regulations.

Where I disagree with the company's planning process in support of this docket pertains to three sets of important costs:

- Carbon dioxide (CO_2): For the purposes of this Predetermination docket, the company has unreasonably assumed that a "low" cost for CO_2 emissions is no cost at all. I find this proposal extremely improbable, and in disagreement with the company's stated expectation with "100%

probability" of a CO_2 cap and trade program, as stipulated in the 2009 IRP filed in the State of Missouri,[1] as well as earlier CO_2 price projections.

- Coal Combustion Residuals (CCR): The company has not taken into account proposed EPA regulations governing the transport and disposal of CCR, despite having similarly assigned this rule a "subjective probability" of 100% in the 2009 IRP.[2] According to the company's 2010 SEC filing, the rule could impose significant capital and operational costs on KCP&L coal-fired generators.[3]

- Effluent limitation guidelines: The company has not accounted for the potentially significant costs of complying with the Clean Water Act's requirement to meet effluent limitations that reflect standards set by state-of-the-art technologies.

Sierra Club witness Dr. Ezra Hausman discusses the implications of the company's failure to adequately address these likely future environmental costs on the company's plan submitted for this docket.

Q What is your recommendation to the Commission?

A I recommend that the commission adopt KCP&L's assumptions regarding the necessity of the proposed and modeled retrofits at the La Cygne and Montrose units, should the units remain in operation. However, I further recommend that the commission require the company to examine the set of scenarios in this docket assuming that the company will be required to meet impending environmental regulations governing the disposal of coal ash and the release of effluent waters from the site.

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[1] 2009 IRP, Volume 4 p33

[2] 2009 IRP, Volume 4 p33

[3] KCP&L SEC Form 10-K December 31, 2010, p15

I defer to recommendations of Sierra Club witness Dr. William Steinhurst regarding the proper mechanism for addressing current and impending regulations in utility resource planning, including in the plan submitted for this docket..

Q Will you provide the details of the environmental compliance obligations likely to be faced by KCP&L's fleet, and how they have been treated in this predetermination docket?

The following sections describe environmental regulations that can reasonably be expected to impact the KCP&L coal fleet. Due to the number of regulatory regimes and the evolving nature of the rules, and the fact that these rules can be and have been interpreted differently for different regions and resources depending on ambient conditions, plant type, fuels, economic viability, and other factors, this analysis can be quite intricate. However, a certain level of detail is required to present the whole picture of compliance costs that will ultimately be faced by ratepayers if KCP&L continues operating its coal fleet.

In my opinion, no reasonable decision can be made on the future viability of these plants without explicitly addressing all of these existing and impending regulations. The company has provided a similar discussion of these current and impending regulations in company witness Mr. Paul Ling's direct testimony.

3. Environmental Regulations

Q Is KCP&L's coal fleet subject to federal laws protecting human health and the environment?

A Yes. The company's coal units are subject to EPA regulations under the Clean Air Act (CAA), the Clean Water Act (CWA), and the Resource Conservation and Recovery Act (RCRA), among other statutes.

Q Which Clean Air Act requirements do you believe are most significant for KCP&L's fleet from a utility resource planning perspective?

A There are four regulatory areas under the Clean Air Act that directly affect the company's coal fleet, including:

- The existing Regional Haze rule, designed to improve visibility in National Parks and other Class 1 public lands;
- The Clean Air Transport rule, governing the emissions and transport of criteria pollutants states under the "good neighbor" provision of the Clean Air Act;
- The proposed Air Toxics rule for utility steam generating units, designed to protect human health and wellbeing by reducing emissions of hazardous air pollutants (HAPs) and mercury (Hg) from oil and coal-burning units; and
- The strengthening of National Ambient Air Quality Standards (NAAQS) for sulfur dioxide (SO_2), the proposed strengthening of the ozone (O3), and the imminent proposal to strengthen the standard for fine particulates ($PM_{2.5}$). These NAAQS are designed to protect human health, reduce premature mortality, and reduce environmental harms from emissions.

Q What Clean Water Act requirements do you believe are most significant for KCP&L's fleet from a utility resource planning perspective?

A There are two CWA regulations, currently being finalized by the EPA, with which KCP&L will need to comply:

- the proposed Cooling Water Intake Structures rule, designed to protect fisheries and aquatic organisms from the impacts of cooling water intake structures, and

- the updated Effluent Limitation guidelines for the steam industry, which will restrict the discharge of harmful pollution, such as arsenic, selenium, and mercury from KCP&L's power plants.

Q What Resource Conservation and Recovery Act ("RCRA") requirements do you believe are most significant for KCP&L's fleet from a utility resource planning perspective?

A The EPA is expected to release a rule under RCRA regulating the disposal and storage of coal ash to prevent toxic releases into ground and surface waters.

Q Why do you believe the above-mentioned Clean Air Act, Clean Water Act, and RCRA requirements are significant from a utility resource planning perspective?

The existing and impending regulations considered in this testimony represent significant investments on the part of the company, and form a partial basis for deciding if retrofitting the La Cygne units represents an economic choice for KCP&L. Alternatives could include retirement, repowering, or replacement with more cost-effective supply-side resources, as well as a greater use of demand-side resources. Indeed, a number of industry studies have found that, even with fairly conservative assumptions, numerous plants could be replaced more cost-effectively than they could be retrofit in order to meet existing and impending regulations. Similar conclusions have been reached by the North American Electric Reliability Corporation (NERC)[4], the Brattle Group,[5] and Credit Suisse[6].

The regulations considered in this testimony and by company witness Paul Ling, could conceivably require yet larger investments in La Cygne than are currently identified by the company in this docket. The failure to include all the associated

[4] North American Electric Reliability Corporation (NERC). October, 2010. 2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations.

[5] Brattle Group. December 8, 2010. Potential Coal Plant Retirements Under Emerging Environmental Regulations.

[6] Credit Suisse. September 23, 2010. Growth from Subtraction.

costs and risks associated with continued operation of the plant hinders the Commission and the other parties' analysis. It is incumbent on the company to show that the retrofits considered here and in resource planning represent a least cost solution. As discussed by Sierra Club witness Dr. William Steinhurst, "the Commission should deny preapproval to retrofits that are not convincingly demonstrated to be part of comprehensive, long-term, least cost plan for meeting ratepayer needs."

It is my opinion that the retrofits considered in this docket for the La Cygne plant will be necessary, but not sufficient, to meet existing and impending environmental regulations. As discussed by Sierra Club witness Dr. Ezra Hausman, maintaining the plants entails significant risks of future costs for consumers—costs which have not been considered by the company.

Q Is it reasonable for the Commission to require KCP&L to consider all of these environmental regulations?

A Yes. The environmental regulations under consideration have either been enacted or have been under consideration by the EPA for a number of years. While the specific form of likely regulations is still evolving, the likelihood that a suite of regulations would affect coal-fired power plants is and has been has been well known. The full suite of regulations discussed in this testimony has been generally expected by the industry since 2007, with some of the rules in the works since 1972. **Exhibit JIF-2** presents a chart, prepared by Synapse, showing when specific sets of regulations were announced, considered, proposed, and/or enacted. The chart suggests that utilities have had number of years to prepare for impending regulations. It is fully reasonable that KCP&L take into account the full suite of regulations noted in this testimony and by company witness Mr. Paul Ling.

4. CLEAN AIR ACT REGIONAL HAZE RULE

Q Please describe the Clean Air Act's Regional Haze Rule

A The Clean Air Act defines as a national goal the remedying of existing visibility impairment that results from manmade air pollution in all "Class I" areas (e.g., most national parks and wilderness areas). *See* 42 U.S.C. § 7491(a)(1). EPA's implementing rules require states to create plans to achieve natural visibility conditions by 2064 with enforceable reductions in haze-causing pollution from individual sources and other measures to meet "reasonable further progress" milestones. *See* generally 40 C.F.R. §51.308-309.

The Clean Air Act's Regional Haze Rule was promulgated in 1999, and revised in 2005. A key component of the haze rule is the imposition of air pollution controls on certain existing facilities that impact visibility in Class I areas. Specifically, the rules require emissions limits on haze-causing pollutants; these limits are represented by "best available retrofit technology" (BART). BART limits are established for air pollutants that impact visibility in our national parks and wilderness areas – namely, sulfur dioxide (SO_2), nitrogen oxides (NO_x), and particulate matter (PM).

Under the Clean Air Act, States have the primary responsibility for developing these requirements, but EPA must determine that a state's plan to achieve natural visibility, including its imposition of BART limits on certain sources, comply with the Clean Air Act's requirements. If EPA finds the plans do not fully meet its regulations, EPA must adopt a federal plan and BART requirements that comply with its regulations. Affected facilities must achieve BART emissions limitations as expeditiously as practicable, but no later than five years from the date EPA approves the state plan or adopts a federal plan.

Q Are the La Cygne units subject to BART under the Regional Haze Rule?

A Yes. The regional haze rule guidelines established by EPA define BART-eligible coal-fired units as those which began operation between August 1962 and August 1977, inclusive, and having the potential to emit more than 250 tons of haze-forming pollution per year. Both of the La Cygne units meet these criteria.

Q When is the compliance deadline for achieving BART emissions limits?

A BART limits must be met as expeditiously as practicable, but no later than five years after EPA approves the state's regional haze plan or adopts a federal plan. Kansas submitted a State Implementation Plan (SIP) for Regional Haze to the US EPA on October 26, 2009. Presuming that the EPA approves the SIP this year, we would expect a compliance deadline by 2016 according to statute.

Q Is the EPA likely to approve the Kansas Regional Haze SIP?

A Yes. The EPA submitted comments to KDHE in advance of the final SIP recommending improvements to the SIP, but generally finding that the BART determinations and regulatory actions proposed in the SIP were satisfactory.[7] I also understand that KDHE secured legally binding and enforceable consent agreements with KCP&L to the satisfaction of the US EPA. In this agreement, KCP&L committed to "install and operate BART as expeditiously as practical, but in no event later than 5 years after approval of the SIP or June 1, 2015, which ever date occurs first."[8] Therefore, even if the SIP is not ultimately approved by EPA, KCP&L must meet the legally binding June 1, 2015 deadline to achieve BART limits at La Cygne.

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[7] Kansas Regional Haze SIP, Appendix 2.1. Comments and Responses from First Comment Period (7/17/2008 – 8/20/2008)

[8] Regional Haze Agreement between KCP&L and KDHE, Nov 20, 2007. Amended Feb 18, 2009

Q How will KCP&L meet its BART emissions limits?

A The limits agreed within the consent agreement are more restrictive than the presumptive BART limits for NO_X and SO_2. If these units continue operating past June 1, 2015, KCP&L plans to install selective catalytic reduction (SCR) as well as pre-combustion controls such as low-NO_X burners at La Cygne 1 & 2 to meet the NO_x limits and wet flue gas desulfurization units to meet the the SO_2 limits. It is not clear if KCP&L is proposing to install baghouses to meet a BART limit for particulate matter.

Emissions compliance could also be met through the repowering, retirement, or replacement of the La Cygne units.

Q What compliance actions has KCP&L taken to date regarding the Regional Haze Rule and BART requirements?

A To my understanding, the SCR and FGD retrofits proposed by the company represent the company's compliance action to meet the BART requirements and the terms of the consent agreement at the La Cygne units.

5. Clean Air Act Toxics Rule for Utility Steam Generating Units

Q Please describe the proposed Clean Air Act Toxics Rule (Utility MACT)

A In 2000, after a lengthy study, EPA found it was necessary to regulate toxic air emissions (or hazardous air pollutants, HAPs) from utility steam electric generating units. As a result of that finding, EPA must adopt emission limitations for hazardous air pollutants that are based on the emissions of the cleanest existing sources.[9] These emission limitations are known as Maximum Achievable Control Technology (MACT). Although EPA was required to adopt MACT standards within two years after issuing its finding in 2000, the rules have been tied up in litigation.

[9] Clean Air Act §112(d)

On March 16, 2011, EPA proposed MACT emission limits for electric generating units. The final utility MACT rule will establish emission limits for various toxic pollutants including mercury, acid gases, and non-mercury metals. As required under the Clean Air Act, the EPA's emissions limitations for existing units will be based on emissions achieved at the lowest emitting 12% of electric generating units in the nation. The best-controlled units in the country use wet scrubbers (i.e., wet FGD systems), selective catalytic reduction (SCR) systems, and baghouses to control HAPs. In addition, activated carbon injection (ACI) may be required to control mercury.

In the proposed rule, EPA describes controls that will comply with a MACT rule, finding that combinations of existing control technologies, such as FGD scrubbers and SCR are useful in conjunction with baghouses and ACI for reducing mercury emissions:

> EPA projects that for acid, companies will likely use dry scrubbing and sorbent injection technologies rather than wet scrubbing. For non-Hg metal HAP controls, EPA has assumed that companies with ESPs [electrostatic precipitators] will likely upgrade them to FFs [fabric filter baghouses]. As a number of units that in the MACT floor for non-Hg HAP metals only had ESPs installed, this is likely a conservative assumption. For Hg, EPA projects that companies will comply either through the collateral reductions created by other controls (e.g. scrubber/SCR combination) or ACI. [proposed rule, p442]

EPA will finalize the MACT rule in late 2011, triggering a compliance deadline of 2015 for all sources subject to the rule to comply.

Q Are the La Cygne units subject to EPA's proposed MACT rule?

A Yes. The La Cygne units meet the §63.9982 statuary definition of "all existing coal- or oil-fired EGUs [electric generating units] as defined in §63.10042."[10]

[10] 76 FR 25102

Q Will the retrofits proposed by KCP&L in this docket meet compliance requirements of the Utility MACT rule?

A I believe, given the proper emissions limits in a permit, that the retrofits proposed in this predetermination docket, including the SCR, FGD, baghouse, and activated carbon injection (ACI) will either meet or support the requirements of EPA's final MACT rule. Company witness Paul Ling suggests that "the requirements of the final rule may require the proposed emission controls on La Cygne Generating Station if not already completed pursuant to other regulations discussed in this testimony." Paul Ling at p21.

6. Clean Air Act National Ambient Air Quality Standards (NAAQS)

Q Please describe the proposed Clean Air Act NAAQS

A EPA promulgates "National Ambient Air Quality Standards" (NAAQS) pursuant to the authority granted by Clean Air Act §109 (42 U.S.C. §7409). Primary NAAQS are set to protect public health and secondary NAAQS to protect public welfare. The NAAQS are supposed to be evaluated and revised if necessary to protect public health and welfare at five year intervals. EPA is currently working to improve NAAQS for sulfur dioxide (SO_2), nitrogen dioxide (NO_2), ozone, and fine particulate matter, known as $PM_{2.5}$.

When EPA sets new standards for these pollutants, states must review air quality data and designate areas as either in "attainment" or "nonattainment". In nonattainment areas, sources must automatically comply with emission reduction requirements known as "Reasonably Available Control Technology" (RACT), and "new sources", which includes major modifications at existing sources, must comply with very strict emissions reductions consistent with "lowest achievable emissions reductions" (LAER).

States containing areas that are designated nonattainment for any of the pollutants discussed above must develop a State Implementation Plan (SIP), to bring the air quality into compliance with the applicable NAAQS. Should counties in Kansas or Missouri violate the standards, the states would develop SIPS requiring emissions reductions. To the extent a large coal-fired power plant contributes to non-attainment, it will likely require controls to reduce overall emissions to help bring areas into attainment.

Q When are the new NAAQS expected, and what are the expected compliance deadlines?

- **SO_2**: EPA adopted a new one hour average NAAQS for SO_2 in 2010.[11] States have until June 3, 2011 to designate nonattainment areas. All areas must attain the standard by 2017.
- **NO_2**: EPA adopted a new one hour average NAAQS for NO_2 in 2011.[12] EPA expects to do initial nonattainment designations by January 2012 with additional areas designated based on the implementation of a new air monitoring network in 2016 or 2017. Compliance is required within five years of the final area designations.
- **Ozone**: The EPA has proposed a new standard, and a final rule is expected by July 29, 2011.[13] Final area designations will be due by late 2013 with attainment required by 2018.
- **$PM_{2.5}$**: the proposed rule is expected from EPA by mid-2011. States have one year from the time the standard is final to designate nonattainment areas, with one more year for EPA to finalize those areas. A compliance deadline could reasonably be expected in 2019.

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[11] 75 Fed. Reg. 35520 (June 22, 2010)

[12] 75 Fed.Reg. 6474 (February 9, 2010).

[13] 75 Fed. Reg. 2938 (Jan. 19, 2010).

Q Are areas in Kansas or Missouri expected to be in nonattainment in light of the new NAAQS?

A In 2009, both the KDHE and the Missouri Department of Natural Resources (MO DNR) submitted findings to the EPA indicating that several counties in both states were in nonattainment of 8-hour ozone standards, as revised in 2008, between the years 2006 and 2008. In the Kansas City area, two KS counties, Johnson and Wyandotte, and five MO counties, Platte, Clinton, Clay, Jackson, and Cass, were found to have violated the ozone standard. Both states recommended that these areas be given nonattainment status. To my understanding, the EPA has not yet acted on these recommendations.

As noted above, in July of 2011, the EPA is expected to pass a more stringent standard for the 8-hour ozone NAAQS, revising it downwards from 0.075 parts per million (ppm) to between 0.060 and 0.070 ppm. Based on monitoring data from 2006 to 2008, several counties in eastern Kansas and five counties in western Missouri have ambient air that violates the proposed standard.[14]

Linn county, where La Cygne is located, is amongst the KS counties with ambient air that violates the proposed ozone standard according to the 2006-2008 monitoring data. If the area is ultimately designated nonattainment, KDHE must consider control of La Cygne's emissions, including controls like SCR to meet stricter emissions limits.

Similarly, for stricter NAAQS on SO_2, NO_2, $PM_{2.5}$ the state could again require end-of-pipe controls or a consent decree requiring unit retirement to meet compliance limits.

[14] EPA. January 6, 2010. Proposed Revisions to National Standards for Ground-Level Ozone, Maps. January 6, 2010.

Q In your opinion, are the controls at issue in this docket adequate to reduce emissions at La Cygne to bring nonattainment areas into attainment for the new NAAQS?

A Probably. Ultimately, the states will need to take all steps necessary to ensure areas are brought into attainment. These controls are a good start, but it is not out of the question that additional measures may be needed, such as fuel switching or retirement, to further reduce emissions as deemed necessary by KDHE or EPA.

7. Clean Water Act Cooling Water Intake Rule

Q Please describe the proposed CWA Cooling Water Intake Structure rule

A On March 28, 2011, the EPA proposed a long-expected rule implementing the requirements of Section 316(b) of the Clean Water Act at existing power plants.[15] Section 316(b) requires "that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact." Under this new rule, EPA set new standards reducing the impingement and entrainment of aquatic organisms from cooling water intake structures at new and existing electric generating facilities.

The rule provides that:

- Existing facilities that withdraw more than two million gallons per day (MGD) would be subject to an upper limit on fish mortality from impingement, and must implement technology to either reduce impingement or slow water intake velocities.
- Existing facilities that withdraw at least 125 million gallons per day would be required to conduct an entrainment characterization study for submission to the Director to establish a "best technology available" for the specific site.

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[15] 33 U.S.C. § 1326.

Q Will the La Cygne units be required to comply with the proposed cooling water rule?

A Yes. Based on 2008 data submitted to the Energy Information Administration (EIA) by KCP&L and other operators, I expect that the La Cygne units will exceed the upper threshold of 125 million gallons per day.[16] The company will therefore be required to submit a plan, and potentially to install new technology, to reduce water withdrawals. It is likely that the compliance mechanism for such high withdrawal units will require retrofits to cooling towers where feasible.

Q What are the compliance deadlines for the new rule?

A EPA will finalize the rule in July, 2012, and the regulations will become effective within 60 days thereafter. EPA stipulates that "as proposed, facilities would have to comply with the impingement mortality requirements as soon as possible."[17] However, facilities would have five years, and up to eight years on appeal, to comply with the impingement mortality requirements; and up to eight years at the discretion of the Director to comply with the entrainment provisions. Therefore, I would expect an outer compliance deadline of 2017 for impingement, and 2020 for entrainment.

Q Has KCP&L taken the cooling water intake structures rule into account in this docket?

A Yes. The company anticipates that it will have to retrofit the La Cygne, Montrose, and other units. The expected costs of these retrofits are included in the expansion model.

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[16] I have calculated withdrawals based on data reported to the EIA in Form 860 (2008) on cooling water intake structures, as well as on generation data reported to the EIA in Form 923 (2008). I estimate that La Cygne units 1 & 2 withdrew approximately 445 and 300 gallons per day, respectively, in 2008.

[17] EPA. March 28, 2011. NPDES—Proposed Regulations to Establish Requirements for Cooling Water Intake Structures at Existing Facilities. EPA. p. 262

8. Clean Water Act Effluent Limitation Guidelines

Q Please describe the emerging effluent limitation guidelines under the Clean Water Act

A The Clean Water Act requires EPA to develop "effluent limitation guidelines" – clear rules for what large industrial sources of water pollution can discharge into nearby waters.[18] These rules must consider what is "economically achievable" and must be updated at least once every five years to keep up with improving treatment technology. Although EPA is supposed to update its rules regularly, the power plant rules were last updated in 1982, and are almost thirty years out of date.

On September 15, 2009, EPA announced an intent proceed with a rulemaking on effluent guidelines for wastewater discharges from steam electric plants, including nuclear and fossil-fired plants.

The EPA has identified wastewaters from flue gas mercury control systems, regeneration of the catalysts used for SCR, wastes from FGD units, and coal combustion residual storage ponds as waste streams that warrant attention. The new effluent limitation guidelines will address toxic releases from point sources, including coal ash ponds like those associated with KCP&L's coal-fired generating facilities.

Q When are the compliance deadlines for the new rule?

A A final rule is not expected until 2013, and requirements are expected on a permit-by-permit basis, which could take up to five years. Therefore, I would expect effluent limitations for steam electric plants to be in place between 2015 and 2018.

[18] *See* 33 U.S.C. § 1311; 40 C.F.R. 423.

Q Could KCP&L be required to comply with more stringent effluent limitations before 2018?

A Yes, permit writers are required by the Clean Water Act to use "best professional judgment" to set technology-based effluent limits in NPDES permits. Given the plan to install scrubbers at La Cygne, which would represent a new wastewater stream, the next NPDES renewal should require consideration of technology-based effluent limits for La Cygne.

Q Has KCP&L taken the emerging effluent limitation guidelines into account in the planning process for this docket?

A As far as I can tell, no. Company witness Mr. Paul Ling does discuss the effluent limitation guidelines currently under consideration by the EPA (Ling at 29), but does not opine on the impact that this rule could have on the La Cygne or Montrose units. Sierra Club issued a discovery request on this topic, but received a blank answer in response from the company. [19]

9. Resource Conservation and Recovery Act Coal Combustion Residuals Disposal Rule

Q Please describe the emerging coal combustion residuals (CCR) disposal rule under the Resource Conservation and Recovery Act (RCRA)

A Coal-fired power plants generate a tremendous amount of ash and other residual wastes, which are commonly placed in dry landfills or slurry impoundments. The risk associated with wet storage of CCR was dramatically revealed in the catastrophic failure of the ash slurry containment at the Kingston coal plant in Roane County, Tennessee in December 2008, releasing over a billion gallons of slurry and sending toxic sludge into tributaries of the Tennessee River.

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[19] Data Request – Set Sierra Club 20110512, Question No 49: "Please explain whether anticipated environmental regulations as described by witness Ling taken into account in modeling for this Docket, including updated "effluent limitation guidelines" for the steam industry under the Clean Water Act, and more stringent NAAQS for particulate matter. If yes, please provide a description and supporting documentation." Response, provided 5/26/2011 is blank.

On June 21, 2010, EPA proposed regulation of ash and FGD wastes, or "coal combustion residuals" (CCR) as either a Subtitle C "hazardous waste" or Subtitle D "solid waste" under the Resource Conservation and Recovery Act (RCRA).[20] The current rulemaking is 30 years overdue.

If the EPA classifies CCR as hazardous waste, a cradle-to-grave regulatory system would apply to CCR, requiring regulation of the entities that create, transport, and dispose of the waste. Under a Subtitle C designation, the EPA would regulate siting, liners, run-on and run-off controls, groundwater monitoring, fugitive dust controls, and any corrective actions required; in addition, the EPA would implement minimum requirements for dam safety at impoundments.

Under a "solid waste" Subtitle D designation, the EPA would require minimum siting and construction standards for new coal ash ponds, compel existing unlined impoundments to install liners, and require standards for long-term stability and closure care.

The EPA is currently evaluating which regulatory pathway will be most effective in protecting human health and the environment without resulting in unintended consequences or resulting in unnecessarily burdensome requirements. In 1999, the EPA released a series of technical papers to Congress documenting cases in which damages are known to have occurred from leakages and spills from coal ash impoundments.[21] In the current proposed rule, the EPA recognizes a substantial *increase* in the types and quantities of potentially toxic CCR from air pollution control equipment, including FGD, SCR, and ACI:

> Use of more advanced air pollution control technology reduces air emissions of metals and other pollutants in the flue gas of a coal-

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[20] 75 Fed. Reg. 35127. June 21, 2010

[21] EPA. March 15, 1999. Technical Background Document for the Report to Congress on Remaining Wastes from Fossil Fuel Combustion: Potential Damage Cases.

> fired power plant by capturing and transferring the pollutants to the fly ash and other air pollution control residues. The impact of changes in air pollution control on the characteristics of CCRs and the leaching potential of metals is the focus of ongoing research by EPA's Office of Research and Development (ORD).[22]

Q Do CCR impoundments at KCP&L plants currently present a hazard to either public safety or the environment?

A Yes. To inform the rulemaking process, in 2009, EPA requested information from specific facilities and impoundments at coal-fired power plants. KCP&L provided information on six of the company's coal-fired plants, including La Cygne, Lake Road, Sibley, Hawthorn, Iatan, and Montrose. Within the survey, the EPA requested information about the hazard rating of coal impoundments if a state or federal agency regulates the pond. KCP&L disclosed two "management" ponds at La Cygne, the first used for setting bottom ash and the second used to permanently store fly ash and residues from the existing FGD system. The second unit stores 11 million cubic yards of waste, twice as much as was lost in the TVA Kingston spill. According to the EPA survey this impoundment had three "unpermitted releases" of wastewater in 2007 and 2009 due to excessive rainfall.[23,24] Despite these releases, the company stated to the EPA that "there are no planned assessments or evaluation of this Management Unit in the future beyond the visual inspections."

According to company witness Mr. Paul Ling, "both the subtitle C and D regulatory options proposed would require: (i) liner systems for new landfills and surface impoundments; (ii) surface impoundment design, operation, and inspection programs; (iii) location restrictions for disposal facilities; and (iv)

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[22] 75 Fed. Reg. 35139 (June 21, 2010).

[23] KCP&L response to EPA request for information regarding bottom ash settling pond and scrubber sludge pond at La Cygne, May 15, 2009.

[24] In a discovery request to the company, Sierra Club requested information about leaks and spills from any impoundments, but the company only responded that "water from an ash impoundment discharged through an emergency spillway in 2007 and 2009 due to excess rain events."

groundwater monitoring." These regulations could entail both high costs for mitigating existing structures, and increased operational costs for improved disposal practices.

Q Will the La Cygne impoundments need to comply with coal ash disposal rules?

A Yes. If the EPA designates CCR as hazardous waste (Subtitle C), all of the coal units in KCP&L's coal fleet as well as the facilities that process wastes from the unit, could be subject to significant new oversight and regulation at all stages of waste creation, transportation, and disposal. If the EPA designates CCR as solid waste (Subtitle D), units that dispose waste into unlined impoundments would be required to renovate their disposal ponds to prevent leakage.

Q Has KCP&L taken into consideration the costs of compliance with the proposed CCR rule in this docket?

A As far as I can tell, no. It does not appear that the company has evaluated the cost of remediating CCR in this current docket or included any estimate of such costs in plan submitted for this predetermination docket. The company projects in their 2009 IRP that "landfills [will] be required to provide dry handling of CCP [(coal combustion products) with a] 100% probability"[25] and notes in their 2010 10-K SEC filing that, pertaining to the environmental risks of solid wastes,

> If enacted, any new laws and regulations, especially if CCRs are classified as hazardous waste, could have a material adverse effect on the Companies' results of operations, financial position and cash flows.[26]

Despite these cautionary notes, it is not clear that the company has taken these costs into consideration in this planning process. Sierra Club issued a discovery

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[25] 2009 IRP, volume 4 p33

[26] KCP&L SEC 10-K, Dec 31, 2010

request on this topic, but had not received an answer at the time of this writing regarding the company's consideration of the CCR rule in this planning process.

10. CLOSING

Q What do you conclude about KCP&L's treatment of expected costs of compliance with current and proposed environmental regulations in this predetermination docket?

A Based on the existing regulations and on my understanding of the emerging regulations, if the La Cygne unit is to continue operation, the company will be required to install a range of retrofits to meet environmental compliance obligations. These retrofits include flue gas desulfurization (FGD), low NO_X burners (LNB), selective catalytic reduction (SCR), fabric filter baghouses, activated carbon injection (ACI), coal ash remediation for coal combustion residuals (CCR), cooling towers and/or new water intake structures, and potentially liquid effluent controls.

I understand that the company has considered a number of environmental regulations in the planning process associated with this predetermination docket, and that the retrofits are designed to meet both current and emerging regulations. The company has also considered, and included in this analysis, the costs of retrofitting existing cooling systems to meet a reasonable interpretation of the emerging EPA cooling water standard.

However, the company's analysis falls short in accounting for the expected costs of mitigating coal combustion residuals (CCR) and effluent. The company has also unreasonably assumed a zero cost for carbon dioxide in a large number of the analyses, in contrast to expectations as articulated in their 2009 IRP.

The net effect of these omissions is that the company has likely underestimated the costs or risks entailed in maintaining the La Cygne units, as discussed in more detail by Sierra Club witness Dr. Ezra Hausman.

Q **Does this conclude your testimony?**

A Yes, it does.

Jeremy I. Fisher, PhD

Curriculum Vitae

Synapse Energy Economics
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Cambridge, MA 02139
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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

WHITE PAPERS

Fisher, J.I. , R. Wilson, N. Hughes, M. Wittenstein, B. Biewald. 2011. Benefits of Beyond BAU. White paper *for* Civil Society Institute. Synapse Energy Economics.

Fisher, J.I. and B. Biewald. 2011. Environmental Controls and the WECC Coal Fleet: Estimating the forward-going economic merit of coal-fired power plants in the West with new environmental controls.

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Bruce E. Biewald **Fisher, J.I.** C James. L. Johnston, D. Schlissel. R. Wilson. 2009. Energy Future: A Green Energy Alternative for Michigan. White paper *for* Sierra Club. Synapse Energy Economics.

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Hausman, E.D., **J.I. Fisher**, B. Biewald. **2008** Analysis of Indirect Emissions Benefits of Wind, Landfill Gas, and Municipal Solid Waste Generation. White paper *for* US. Environmental Protection Agency. Synapse Energy Economics.

Schlissel, D., **J.I. Fisher. 2008** A preliminary analysis of the relationship between CO_2 emission allowance prices and the price of natural gas. White paper *for* the Energy Foundation. Synapse Energy Economics.

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Fisher, J.I., B. Biewald. **2007** Electricity Sector. *in* E.A. Stanton and F. Ackerman. *Florida and Climate Change: The Costs of Inaction*. Tufts University.

Peer-Reviewed Publications

J. T. Morisette, A. D. Richardson, A. K. Knapp, **J.I. Fisher** , E. Graham, J. Abatzoglou, B.E. Wilson, D. D. Breshears , G. M. Henebry, J. M. Hanes and L. Liang. **2009**. Tracking the rhythm of the seasons in the face of global change: Challenges and opportunities for phenological research in the 21st Century. In Press at *Frontiers in Ecology.*

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Fisher, J.I. & J.F. Mustard. **2007** Cross-scalar satellite phenology from ground, Landsat, and MODIS data. *Remote Sensing of Environment* 109:261–273

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Fisher, J.I. & J.F. Mustard. **2004** High spatial resolution sea surface climatology from Landsat thermal infrared data. *Remote Sensing of Environment*. 90:293-307.

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Fisher, J.I. and S.J. Goetz. **2001** Considerations in the use of high spatial resolution imagery: an applications research assessment. *American Society for Photogrammetry and Remote Sensing (ASPRS) Conference Proceedings*, St. Louis, MO.

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Fisher, J.I. and J.F. Mustard. Constructing a climatology of Narragansett Bay surface temperature with satellite thermal imagery. *The Rhode Island Natural History Survey Conference.* Cranston, RI. March, 2003.

Fisher, J.I. and J.F. Mustard. Constructing a high resolution sea surface climatology of Southern New England using satellite thermal imagery. *New England Estuarine Research Society.* Fairhaven, MA. May, 2003.

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Fisher, J.I. and S.J. Goetz. Considerations in the use of high spatial resolution imagery: an applications research assessment. *American Society for Photogrammetry and Remote Sensing (ASPRS) Conference Proceedings*, St. Louis, MO. March, 2001.

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Fisher, J.I. E. Hausman, and C. James. Emissions Behavior in the Northeast from the EPA Acid Rain Monitoring Dataset. Northeast States for Coordinated Air Use Management (NESCAUM), Boston, MA. January 30, 2008.

Fisher, J.I. J.F. Mustard, and M. Vadeboncoeur. Climate and phenological variability from satellite data. Ecology and Evolutionary Biology, Tulane University. March 24, 2006.

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

EPA Regulatory Timeline for Air Pollutant Classes

Color Codes	Initial indication of likely regulation	First regulatory step- laying groundwork	Proposed regulation or regulatory action	Final regulatory action

	Regional Haze	Mercury and Hazardous Air Pollutants	Ozone National Ambient Air Quality Standards	PM2.5 National Ambient Air Quality Standards	SO2 National Ambient Air Quality Standards	NO2 National Ambient Air Quality Standards
<= 1995	1990 CAAA emphasis on visibility and haze 1991 EPA establishes Grand Canyon Visibility Transport Commission	1990 CAAA EPA given authority to control Hg and HAPS 1995 Settlement: Utility Air Toxics Study	EPA forms subcommittee on revised ozone and PM NAAQS, and regional haze	EPA forms subcommittee on revised ozone and PM NAAQS, and regional haze		
1996						
1997	[illegible]	EPA delivers Mercury Study Report to Congress	0.080 ppm Ozone NAAQS Promulgated			
1998		EPA "Utility Air Toxics Study" to Congress				
1999	Regional Haze Regulations; Final Rule [64 FR 35714]			[illegible]		
2000		"Appropriate and necessary" finding for Utility Hg [65 FR 79825]				
2001				PM2.5 NAAQS Risk Analysis Scoping Plan		
2002						
2003						
2004	[illegible]	[illegible]		PM2.5 Air quality criteria assessment [EPA/600/p-99/002aD]		
2005	EPA issues BART guidelines [70 FR 39104]	Clean Air Mercury Rule (CAMR) issued, proposed revision of "appropriate and necessary" finding [70 FR 62200]	[illegible]	[illegible]		Integrated science assessment for NO2 [70 FR 73236]
2006		[illegible]		35 µg/m3 PM2.5 NAAQS Promulgated [71 FR 61144]	Integrated science assessment for SO2 [71 FR 28023]	
2007			[illegible]	Integrated science assessment for PM2.5 [72 FR 35462]		
2008		Court of Appeals vacates EPA removal of power plants from CAA list of HAP sources.	0.075 ppm Ozone NAAQS Promulgated [73 FR 16436]		Risk and Exposure Assessment for SO2 [73 FR 42341]	Risk and Exposure Assessment for NO2 [73 FR 20045]
2009			EPA announces [illegible] strengthening [EPA Fact Sheet] / Clean Air Transport Rule Proposed		[illegible]	[illegible]
2010			[illegible]	Risk Assessment for PM2.5 [75 FR 4067]	75 ppb SO2 NAAQS Promulgated [75 FR 35520]	100 ppb NO2 NAAQS Promulgated [75 FR 6474]
2011		[illegible]	0.060 Ozone NAAQS Expected [DC Circuit No. 08-1200]	PM2.5 NAAQS Expected [EPA, Oct 5, 2010]		

EPA Regulatory Timeline for Non-Air Pollutants

Initial indication of likely regulation	First regulatory step- laying groundwork	Proposed regulation or regulatory action	Final regulatory action

	Coal Combustion Residuals	Cooling Water Use 316(b)	Effluent Limitation Guidelines
<= 1995		1995 Consent decree - EPA agrees to issue rules to implement Sec 316(b) of CWA	1982 Effluent guidelines for Steam EGUs
1996			
1997			
1998			
1999			
2000			
2001		EPA issues final rules for new facilities - Phase I	
2002		Consent decree establishing schedule for Phase II and Phase III	
2003			
2004		Phase II rules - existing generating units. [69 FR 41575] *Appealed*	
2005	Steam Generating Point Source study identifies CCR as effluent source		EPA Steam Electric Power Generating Point Source study identifies steam electric generating industry for study and review of effluent guidelines
2006		[illegible]	Effluent Guidelines Program Plan provides update on study
2007		Phase II rules suspended [72 FR 37107]	
2008	Kingston TVA spill		Effluent Guidelines Program Plan provides update on study
2009	EPA announces New Action to Prevent Coal Ash Releases, requests impoundment data from utilities	[illegible]	EPA announces decision to proceed with rulemaking revising effluent guidelines
2010	[illegible]	[illegible]	
2011		[illegible]	

BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

In the Matter of the Petition of Kansas City Power & Light Company("KCP&L") for Determination of the Ratemaking Principles and Treatment that Will Apply to the Recovery in Rates of the Cost to be Incurred by KCP&L for Certain Electric Generation Facilities Under K.S.A. 2003 SUPP. 66-1239	)	**Docket No. II-KCPE-581-PRE**

AFFIDAVIT OF Jeremy Fisher, Ph.D.

STATE OF Massachusetts)
) ss
COUNTY OF Middlesex)

Jeremy Fisher, being first duly sworn on his oath, states:

1. My name is Jeremy Fisher. I work in Cambridge, Massachusetts, and I am employed by Synapse Energy Economics as a Scientist.
2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of Sierra Club consisting of twenty-seven (27) pages, having been prepared in written form for introduction into evidence in the above-captioned docket.
3. I have knowledge of the matters set forth therein. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded, including any attachments thereof, are true and accurate to the best of my knowledge, information and belief.

Jeremy Fisher

Subscribed and sworn before me this 3rd day of June, 2011.

Notary Public

My commission expires:
October 8, 2015

REBECCA ANNE KEANE
Notary Public
COMMONWEALTH OF MASSACHUSETTS
My Commission Expires
October 8, 2015

2011.06.03 15:33:14
Kansas Corporation Commission
/S/ Thomas A. Day

PUBLIC VERSION

Confidential Materials Have Been Redacted

Received
on
JUN 03 2011
by
State Corporation Commission
of Kansas

**BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS**

DIRECT TESTIMONY OF

DAVID A. SCHLISSEL

**ON BEHALF OF
THE GREAT PLAINS ALLIANCE FOR CLEAN ENERGY**

**IN THE MATTER OF THE PETITION OF
KANSAS CITY POWER & LIGHT COMPANY ("KCP&L")
FOR DETERMINATION OF THE RATEMAKING PRINCIPLES
AND TREATMENT THAT WILL APPLY TO THE RECOVERY
IN RATES OF THE COST TO BE INCURRED BY KCP&L FOR
CERTAIN ELECTRIC GENERATION FACILITIES
UNDER K.S.A. 66-1239**

DOCKET NO. 11-KCPE-581-PRE

Q. Please state your name, occupation, and business address.

A. My name is David A. Schlissel. I am the President of Schlissel Technical Consulting, Inc. My business address is 45 Horace Road, Belmont, Massachusetts 02478.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the Great Plains Alliance for Clean Energy ("GPACE").

Q. Please summarize your educational background and recent work experience.

A. I graduated from the Massachusetts Institute of Technology in 1968 with a Bachelor of Science Degree in Engineering. In 1969, I received a Master of Science Degree in Engineering from Stanford University. In 1973, I received a Law Degree from Stanford University. In addition, I studied nuclear engineering at the Massachusetts Institute of Technology during the years 1983-1986.

Since 1983 I have been retained by governmental bodies, publicly-owned utilities, and private organizations in 38 states to prepare expert testimony and analyses on engineering and economic issues related to electric utilities. My recent clients have included the U.S. Department of Justice, the Attorney General and the Governor of the State of New York, state consumer advocates, and national and local environmental organizations.

I have filed expert testimony before state regulatory commissions in Arizona, New Jersey, California, Connecticut, Kansas, Texas, New Mexico, New York, Vermont, North Carolina, South Carolina, Maine, Illinois, Indiana, Ohio, Massachusetts, Missouri, Rhode Island, Wisconsin, Iowa, South Dakota, Georgia, Minnesota, Michigan, Florida, North Dakota, Mississippi, Maryland, Virginia, Arkansas, Louisiana, Colorado, New Mexico, Oregon and West Virginia and before an Atomic Safety & Licensing Board of the U.S. Nuclear Regulatory Commission.

A copy of my current resume is included as Exhibit DAS-1. Additional information about my work is available at www.schlissel-technical.com.

Q. Have you previously testified before the Kansas State Corporation Commission?

A. Yes. I have testified in Kansas State Corporation Commission Case 164,211-U.

Q. Please summarize your testimony.

A. Schlissel Technical Consulting was retained to investigate the reasonableness of the environmental retrofits of La Cygne Generating Station Units 1 and 2 being proposed by Kansas City Power & Light Company ("KCP&L" or "the Company") and Westar ("Companies"). This testimony presents the initial results of my analyses.

Q. What information did you review as part of your analysis?

A. I reviewed the Application and supporting testimony submitted by KCP&L and Westar. I also reviewed the Companies' responses to the data requests submitted by the KCC Staff, CURB, the Sierra Club and GPACE.

Q. Have you had a full opportunity to analyze the Companies' proposal to retrofit La Cygne Units 1 and 2?

A. No. The extremely short schedule in this proceeding does not allow a reasonable opportunity to fully review the Company's analyses and supporting data responses. Moreover, KCP&L has not posted a number of key data responses to requests from the KCC Staff, the Sierra Club and GPACE to its electronic data room and has withheld key fuel price and CO_2 price forecast information from intervening parties.

Q. Please summarize your conclusions.

A. My conclusions are as follows:

1. KCP&L is to be commended for considering uncertainty by examining ranges of values for some key input assumptions. However, the Company has failed to examine a number of potentially less expensive alternatives to the retrofitting of La Cygne Units 1 and 2 (such as purchasing capacity and energy from existing combined cycle units or converting one or more of its existing combustion turbines to combined cycle technology) and did not consider any uncertainty in another key input assumption – the future operating performance of La Cygne Units 1 and 2 as they age.

2. In addition, the results of KCP&L's modeling analyses also are biased in favor of the retrofitting of La Cygne Units 1 and 2 by the use of natural gas prices that KCP&L are based, at least in part, on public forecasts from the U.S. Department of Energy that are out-of-date and that have been replaced by significantly lower forecasts. The Company's modeling analyses also did not reflect a reasonable range of potential prices for coal.

3. Even with these biases, the resource plan in which all of the La Cygne and Montrose coal units would be retrofitted by 2015 [redacted]

4. An unbiased assessment might well show that retirement of La Cygne Units 1 and 2 would be a lower cost option than retrofitting.

5. KCP&L's customers would be exposed to significant risks if the Company proceeds with the proposed retrofitting of La Cygne Units 1 and 2. These include (1) that the cost of the retrofits will be higher than the Company now projects, (2) that the Units will not operate as well as the Company currently forecasts, (3) that coal prices will be higher than KCP&L assumes, (4) that CO_2 prices also will be higher, (5) that natural gas prices will be lower, (6) that plant operating costs will be higher, and/or (7) that one or both of the Units will be retired before 2034.

6. Westar's customers also would be exposed to these same risks.

7. KCP&L's fuel mix has been extremely heavily dependent on coal. The Company will continue to be heavily dependent on coal if it retrofits La Cygne Units 1 and 2. In fact, there is no evidence that KCP&L has any plan for reducing its current dependence on coal.

8. KCP&L's testimony overstates the market-related risk of natural gas.

9. KCP&L would not be heavily dependent on natural gas even if the La Cygne Units were retired and replaced by natural gas-fired combined cycle capacity.

10. The Company's testimony ignores significant economic risks of coal.

11. An increasing number of other utilities are retiring unscrubbed coal units in order to reduce their exposure to the risks associated with the continued operating of aging coal plants.

12. KCP&L does not appear to have a plan to significantly reduce its CO_2 emissions in the coming years.

13. There is no evidence that suggests that adoption of a CO_2 regulatory regime would lead to higher natural gas prices.

Q. Do you have any comments on KCP&L's overall analytic methodology for evaluating the relative economics of retrofitting La Cygne Units 1 and 2?

A. Yes. KCP&L is to be commended for considering uncertainty by examining ranges of values for key input assumptions such as [redacted]. However, the Company has failed to examine a number of potentially less expensive alternatives to the proposed retrofits (such as a long-term PPA, purchasing capacity in the market and converting one or more existing combustion turbines to combined cycle technology) and did not consider any potential uncertainty in another key input assumption – that is, the possibility that the future operating performance of La Cygne Units 1 and 2 may degrade as they age.

In addition, the natural gas prices that KCP&L used in its modeling analyses were based, at least in part, on public forecasts from the U.S. Department of Energy that are out-of-date and that have been replaced by significantly lower projected gas prices. Consequently, the Company's base, high and low natural gas prices are too high, a factor which biases the analyses against natural gas alternatives and in favor of continued operation of KCP&L's existing coal-fired units like La Cygne Units 1 and 2. At the same time, KCP&L did not reflect a significant range for the future escalation of coal prices. This too biased the results of the modeling analyses in favor of retrofitting La Cygne Units 1 and 2.

Q. Why are these biases important?

A. Even with the biases that I have just discussed, the resource plan in which all of the La Cygne and Montrose units would be retrofitted by 2015 [redacted], as shown in Figure 1, below:

Figure 1: NPVRR of Retrofit and Retirement Scenarios [REDACTED][1]

[redacted] Consequently, an unbiased assessment, that reflects more current natural gas prices and the risk that the performance of the La Cygne Units may degrade over time, as well as the potential for less expensive alternatives than

[1] Source Confidential Schedule BLC2011-12.

building new combined cycle units, might well show that retirement of these units would be a lower cost option than retrofitting.

Q. What is the NPVRR difference in KCP&L's modeling between the alternative plan in which both La Cygne Units are retired and the plan in which both units would be retrofitted?

[redacted]

Q. What are the main risks to which the Company's customers would be exposed if KCP&L proceeds with the retrofitting of La Cygne Units 1 and 2?

A. The Company's ratepayers are exposed to the risks that (1) the cost of the retrofits will be higher than KCP&L now projects, (2) the Units will not operate as well as KCP&L currently forecasts, (3) coal prices will be higher, (4) CO_2 prices will be higher, (5) natural gas prices will be lower, (6) plant operating costs will be higher and/or (7) one or both of the Units will be retired before 2034.

Q. Has KCP&L quantified all of these risks?

A. No. However, KCP&L has examined a high CO_2 price, low gas price scenario in which the retrofitting of La Cygne Units 1 and 2 is approximately [redacted] than retiring the units and adding replacement combined cycle capacity. However, this scenario does not represent a worst case because CO_2 prices could be higher than the Company's "high" case and it does not reflect the other risks I identified in my previous answer.

Q. Are Westar's customers exposed to the same set of risks as the customers of KCP&L?

A. Yes. In general, Westar's customers are exposed to the same risks as KCP&L's customers: (1) the cost of the retrofits will be higher than KCP&L now projects, (2) the Units will not operate as well as Westar currently forecasts, (3) coal prices will be higher, (4) CO_2 prices will be higher, (5) natural gas prices will be lower, (6) plant operating costs will be higher and/or (7) one or both of the Units will be retired before 2034.

Q. Do you have any comments on the weighing factors that KCP&L has applied to the different scenarios it has modeled?

A. I am concerned that the weighing factors that KCP&L has assigned to the different scenarios are very subjective and that even relatively modest changes to the weights given to different scenarios can affect the overall results. Yet, KCP&L has provided no evidence that I have seen that supports the specific weights it assigned.

Q. Do you agree with KCP&L witness Crawford that it is important for a company to maintain a balanced portfolio of generation resources?[2]

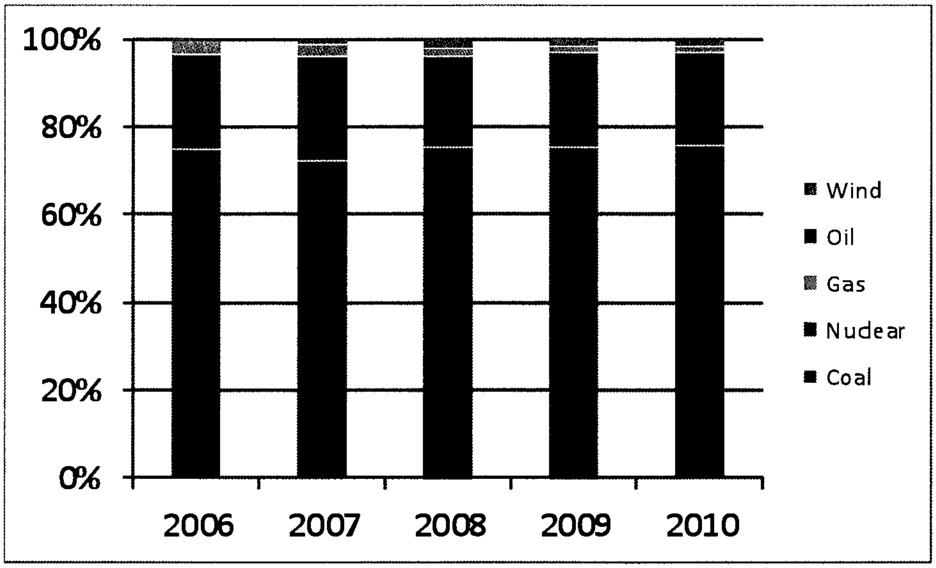
A. Yes. I agree it is important to maintain a diverse fuel mix.

Q. Does KCP&L currently have a balanced or diverse fuel mix?

A. No. As shown in Figure 2, below, KCP&L currently has a fuel mix that is extremely heavily dependent on coal and on a single nuclear power plant (Wolf Creek). Natural gas, oil and renewable resources represent only about 3 percent of the Company's generation.

2 Direct Testimony of Burton L. Crawford, at page 11, lines 5-6.

Figure 2: KCP&L Fuel Mix 2006-2010



Thus, KCP&L has been dependent on coal for approximately 75 percent of its generation and the Wolf Creek nuclear plant for another 21 percent.

Q. Does Figure 2 include purchased power as well as the generation at Company-owned power plants?

A. No. Figure 2 includes only the generation at Company-owned power plants.

Q. Does Figure 2 include all of KCP&L or only its power plants in Kansas?

A. Figure 2 represents the fuel mix for all of KCP&L.

Q. Is there any reason to expect that the Company generation mix will be even more heavily coal-fired in the near future?

A. Yes. The generation that forms the basis for Figure 2, above, only includes six months of operations in 2010 at the new Iatan 2 coal plant. It is reasonable to expect that the Company's fuel mix will be even more heavily coal dependent when this new unit operates for a full calendar year.

Q. Will the proposed environmental retrofit of La Cygne 1 and 2 diversify KCP&L's fuel mix?

A. No. The results of the Company's modeling analyses show that if KCP&L retrofits La Cygne Units 1 and 2, it will remain just as heavily dependent on coal throughout the study period.

Q. Is there any evidence in its resource plans that KCP&L intends to reduce its current heavy dependence on coal?

A. No. The Company apparently intends to continue to operate its existing baseload generation (coal and nuclear) and add new fossil-fired combustion turbines to provide peaking capacity. Consequently, unless KCP&L radically changes its resource plans, the Company's fuel mix will not change significantly through the 25 year study period.

In fact, the results of KCP&L's Base Case modeling analyses show that approximately [redacted] percent of the Company power would be generated at coal-fired facilities throughout the 2010-2034 study period.

Q. Do you agree with the testimony of KCP&L witness Blunk that "Placing a bet on natural gas as a primary fuel source has greater market-related risk than a similar commitment to coal?[3]

A. No. All fuel prices will exhibit some degree of price uncertainty and volatility – that is daily, weekly or monthly variations based on fluctuations in the relationships between supplies and demand, and weather. Of course, Commissions should be concerned about such volatility and should require utilities to take reasonable actions to hedge natural gas supplies in order to minimize volatility.

It is obvious that KCP&L's focus on natural gas price uncertainty and volatility is intended to taint the options of building a new gas-fired plant or purchasing power from

[3] Direct Testimony of Wm. Edward Blunk, at page 17, lines 1-3.

existing gas-fired units as reasonable alternatives to retrofitting La Cygne Units 1 and 2. However, Mr. Blunk overstates the risk that future natural gas prices will have the same degrees of uncertainty and volatility as has been experienced in the past. At the same time, he completely ignores the risk associated with the Company's continued heavy dependence on coal and its almost total avoidance of natural gas.

Q. Please explain how Mr. Blunk overstates the market-related risk of natural gas.

A. Mr. Blunk overstates the market-related risk of natural gas in several ways.

First, he has presented evidence on the historic uncertainty and volatility of natural gas prices and has given several examples of how fast, he believes, the natural gas market can swing from a supply-surplus to being supply limited.[4] Although, he does discuss the increased natural gas supplies now generally accepted to be available from shale gas deposits, he essentially ignores or dismisses the import of these increased supplies. Most particularly, Mr. Blunk cites a number of examples of supply disruptions after Hurricanes Katrina and Rita that simply are not relevant to today's natural gas supply situation. This is due both to (1) the dramatically increased supply of natural gas and (2) the fact that the overwhelming portion of this supply (and the related production) is on-shore and, therefore, relatively immune from long-term disruption by hurricanes.

In fact, the new supplies of natural gas that have been identified since 2008 have been described (by Entergy Corporation, for example) as a structural change and a "seismic shift" in the natural gas market. This structural change has two important impacts on the resource planning for companies like KCP&L: (1) As a result of the existing and expected supply glut, current and projected prices of natural gas have been reduced. (2) At the same time, the dramatically larger domestic supplies of natural gas should be able to accommodate any increased demands from any fuel switching due to federal regulation of greenhouse gas emissions without causing significant increases in natural gas prices.

[4] Id, at pages 11 and 12.

The structural change in the natural gas markets already has had a significant impact on utilities' resource planning. For example, in early 2009, Entergy Louisiana informed the Louisiana Public Service Commission of its intent to defer (and perhaps cancel) the proposed retirement of an existing gas-fired power plant and its replacement by a new coal-fired unit. Entergy explained that it no longer believed that a new coal plant would provide economic benefits for its customers due to its current expectation that future gas prices would be much lower than previously anticipated:

> Perhaps the largest change that has affected the Project economics is the sharp decline in natural gas prices, both current prices and those forecasted for the longer-term. The prices have declined in large part as a result of a structural change in the natural gas market driven largely by the increased production of domestic gas through unconventional technologies. The decline in the long-term price of natural gas has caused a shift in the economics of the Repowering Project, with the Project currently – and for the first time – projected to have a negative value over a wide range of outcomes as compared to a gas-fired (CCGT) resource.[5]
>
> 4. Recent Natural Gas Developments
>
> Until very recently, natural gas prices were expected to increase substantially in future years. For the decade prior to 2000, natural gas prices averaged below $3.00/mmBtu (2006$). From 2000 through May 2007, prices increased to an average of about $6.00/mmBtu (2006$). This rise in prices reflected increasing natural gas demand, primarily in the power sector, and increasingly tighter supplies. The upward trend in natural gas prices continued into the summer of 2008 when Henry Hub prices reached a high of $13.32/mmBtu (nominal). The decline in natural gas prices since the summer of 2008 reflects, in part, a reduction in demand resulting from the downturn in the U.S. economy.
>
> *   *   *   *
>
> However, the decline also reflects other factors, which have implications for long-term gas prices. During 2008, there occurred a seismic shift in the North American gas market. "Non-conventional gas" – so called because it involves the extraction of gas sources that previously were non-economic or technically difficult to extract – emerged as an economic source of long-term supply. While the existence of non-conventional natural gas deposits within North America was well established prior to this time, the ability to extract supplies economically in large volumes was not. The recent success of non-conventional gas exploration techniques

[5] *Report and Recommendation Concerning the Little Gypsy Unit 3 Repowering Project*, submitted by Entergy Louisiana to the Louisiana Public Service Commission, April 1, 2009, at pages 6-8.

> (e.g., fracturing, horizontal drilling) has altered the supply-side fundamentals such that there now exists an expectation of much greater supplies of economically priced natural gas in the long-run....
>
> *   *   *   *
>
> Of course, it should be noted that it is not possible to predict natural gas prices with any degree of certainty, and [Entergy Louisiana] cannot know whether gas prices may rise again. Rather, based upon the best available information today, it appears that gas prices will not reach previous levels for a sustained period of time because of the newly discovered ability to produce gas through non-traditional recovery methods...[6]

Entergy's conclusion that there has been a seismic shift in the domestic natural gas industry was confirmed in early June 2009 by the release of a report by the American Gas Association and an independent organization of natural gas experts known as the Potential Gas Committee, the authority on gas supplies. This report concluded that the natural gas reserves in the United States are 35 percent higher than previously believed. The new estimates show "an exceptionally strong and optimistic gas supply picture for the nation," according to a summary of the report.[7]

A Wall Street Journal Market Watch article titled "U.S. Gas Fields From Bust to Boom" similarly reported that huge new gas fields have been found in Louisiana, Texas, Arkansas and Pennsylvania and cited one industry-backed study as estimating that the U.S. now has enough natural gas to satisfy nearly 100 years of current natural gas-demand.[8] It further noted that

> Just three years ago, the conventional wisdom was that U.S. natural-gas production was facing permanent decline. U.S. policymakers were resigned to the idea that the country would have to rely more on foreign imports to supply the fuel that heats half of American homes, generates one-fifth of the nation's electricity, and is a key component in plastics, chemicals and fertilizer.
>
> But new technologies and a drilling boom have helped production rise 11% in the past two years. Now there's a glut, which has driven prices

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6 Id, at pages 17, 18 and 22.

7 *Estimate Places Natural Gas Reserves 35 percent Higher*, New York Times, June 9, 2009.

8 Available at http://online.wsj.com/article/SB124104598912705 85.html.

> down to a six-year low and prompted producers to temporarily cut back drilling and search for new demand.[9]

Q. Have other companies besides Entergy recognized that there has been a structural change or a seismic shift in the natural gas market?

A. Yes. The significant impact of the increased domestic reserves on natural gas prices, in particular, and resource planning, in general, has been widely recognized. For example, Xcel Energy explained in its 2010 Resource Plan that it filed with the Minnesota Public Utility Commission:

> Economically recoverable shale gas has been a major contributor to increasing reserves and declining natural gas prices.....
>
> *   *   *   *
>
> A long-term lower price for natural gas will produce significant benefits to our customers. It will reduce the production cost at both current and new resources. In addition to lowering the cost of energy from our natural gas-fired facilities, the lower cost of energy is expected to put downward pressure on wind prices, which are a close competitor. Lower natural gas production costs also reduce the integration costs of wind on our system since our ability to follow the wind with flexible gas generation becomes less expensive. Today's natural gas forecasts also predict reduced price volatility.
>
> The Commission has expressed concern in the past that more extensive use of natural gas for electric generation would hamper the supply and increase the cost of natural gas for residential heating customers. The substantial increase in supply due to the ability to economically recover shale gas may result in the ability to expand natural gas-fired generation while reducing the cost to all users of natural gas. Still, natural gas is a commodity that comes with some price volatility and the impacts of federal regulations on shale extraction will be a key factor in whether the same level of volatility that we have seen in the past decade returns.[10]

A recent report from the Bipartisan Policy Center and American Clean Skies Foundation's Task Force on Ensuring Stable Natural Gas Markets has similarly noted that:

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9 Id.

10 Xcel Energy Minnesota 2010 Resource Plan, at pages 2-5 to 2-7.

> Recent developments allowing for the economic extraction of natural gas from shale formations reduce the susceptibility of gas markets to price instability and provide an opportunity to expand the efficient use of natural gas in the United States.[11]

And:

> The currently understood and projected shale gas resource has allowed the United States to project a significant increase in economically recoverable gas resources for the first time in the last 15 years. And for the first time since the 1990s, it now appears that deliverability (i.e., available production) could be adequate to meet increasing gas demand, meaning that the United States will no longer be in the tight supply/demand regime that has historically made natural gas markets vulnerable to price instability.[12]

Q. Are there other actions that a utility can take to mitigate the risk of natural gas price uncertainty and volatility besides retrofitting aging coal-fired power plants?

A. Yes. Many utilities regularly limit their exposure to natural gas price uncertainty and volatility through financial or physical hedging.

In addition, energy efficiency (both for electricity and for natural gas) and renewable technologies are reasonable alternatives for limiting dependence on natural gas. Repowering older natural gas-fired units (in particular, older combustion turbines) with newer, more efficient combined cycle technology is another option.

Q. How dependent is KCP&L on natural gas?

A. As shown in Figure 2, above, KCP&L generates only about one percent of its power from gas-fired facilities.

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11 At page 67 of 76. Available at http://www.cleanskies.org/wp-content/uploads/2011/05/63704_BPC_web.pdf

12 Id, at page 45 of 76.

Q. How dependent on natural gas would KCP&L be if the generation from La Cygne Units 1 and 2 were replaced by generation from one or more natural gas-fired combined cycle units?

A. Using 2010 as an example, if the total generation from La Cygne Units 1 and 2 had been replaced by generation from natural gas-fired combined cycle units, KCP&L's fuel mix would still have been 55 percent coal, 21 percent nuclear and just 23 percent gas with a very minor contribution from oil and wind. Consequently, KCP&L would not have been unreasonably dependent on natural gas even if La Cygne had been retired before 2010.

Q. What economic risks related to coal does Mr. Blunk ignore?

A. Although Mr. Blunk does not mention them in his testimony, there are a number of potentially significant risks associated with KCP&L's proposed retrofitting of La Cygne Units 1 and 2.

First, the actual costs for adding emissions controls on La Cygne Units 1 and 2 could be higher than KCP&L currently estimates, as the Company recognizes in its capital cost sensitivity analyses.

Second, environmental regulations will likely become increasingly stringent over time, requiring additional controls on existing coal plants which could lead to increased capital investments, higher O&M costs and/or reduced operating performance. KCP&L's continued operation of the la Cygne plant (as well as its overall heavy dependence on coal) exposes it to greater regulatory uncertainty, as well as greater risk from future liabilities such as groundwater contamination, coal-ash cleanup, or other unidentified environmental hazards.

Third, the future costs of CO_2 could be higher than assumed by KCP&L. Relying on coal as a fuel source therefore includes significant risk because any future increases in CO_2 costs would have substantially greater impacts on coal-fired power plants compared to other resources.

Fourth, it is possible that the aging of plant equipment, structures and components will lead to higher capital investments and/or operating costs than KCP&L has assumed in its modeling analyses. Plant aging also could lead to diminished operating performance. KCP&L currently assumes that La Cygne Units 1 and 2 will continue to operate as efficient baseload units through the end of the planning period in 2034 at which time Unit 1 will be 61 years old and Unit 2 will be 57 years old. For example, KCP&L assumes that there will be no increases in unit forced outage rates, planned outage rates or heat rates during the planning period.[13] This is an extremely optimistic assumption. Indeed, given the large number of older, less efficient coal plants being retired around the nation (many of which are less than 60 years old), it is possible that La Cygne Units 1 and 2 might be forced into retirement before 2034.

Q. What capacity factors have La Cygne Units 1 and 2 achieved in recent years?

A. La Cygne Unit 1 achieved an average 69 percent annual capacity factor between 2000 and 2010. La Cygne Unit 2 achieved an average 80 percent annual capacity factor during this same period.

Q. What capacity factors does KCP&L project that La Cygne Units 1 and 2 will operate at if they are retrofitted?

A. The annual unit capacity factors for La Cygne Units 1 and 2 from KCP&L's KP01 Base Case modeling are shown in Figure 3, below. As can be seen, KCP&L is projecting that they will achieve [redacted] capacity factors as they age.

[13] For example, see KCP&L's Responses to Data Request KCC 23.

Figure 3: Projected La Cygne Unit 1 and Unit 2 Capacity Factors 2016-2034 [REDACTED]

Q. Is it possible that La Cygne Units 1 and 2 will sustain such sustained periods of excellent performance as they age?

A. KCP&L is proposing to make significant investments in life extension programs, modifications and maintenance at La Cygne.[14] It is possible that these investments will be completely successful and that the Units actually will achieve the high levels of performance that are assumed in KCP&L's modeling analyses. However, there is a risk that the performance of the La Cygne Units will deteriorate over time as they age, in spite of the large life extension investments KCP&L is planning. Unfortunately, the Company completely ignored this risk.

[14] See KCP&L's Responses to KCC Staff Data Requests Nos. 68 and 71.

Q. How should KCP&L have addressed this uncertainty surrounding the future performance of the La Cygne Units?

A. Instead of optimistically assuming that the performance of the La Cygne Units definitely will improve after the planned environmental retrofits and life extension investments, KCP&L should have examined sensitivity scenarios reflecting diminished plant performance (i.e., higher planned and forced outage rates and heat rates, and, consequently, lower capacity factors) and higher plant operating costs.

Q. Do you have any concerns about the natural gas prices that KCP&L used in its modeling analyses?

A. Yes. Even though KCP&L appears to have rerun its modeling analyses in mid-February of this year, it continued to rely, in part, on U.S. Department of Energy natural gas price forecasts that are, by now, more than thirteen months old. [redacted]

Q. Are you testifying that a utility like KCP&L has a responsibility to rerun its modeling analyses every time the value of an input assumption changes?

A. Not at all. What I am saying is that a Company does have a responsibility to re-examine the economics of a proposed project when at least one of the forecasts on which the Company is relying for one of the most critical input assumptions, in this case natural gas prices, changes by a significant amount.

Q. Please explain.

A. The Company developed the natural gas price forecasts from a review of a number of different sources (public and private) that Mr. Blunk lists at page 5, lines 12-15, of his testimony. Two of these sources are publicly available information: NYMEX natural gas futures prices and the long-term forecasts issued by the Energy Information Administration of the U.S. Department of Energy ("EIA").

Q. Have NYMEX natural gas futures prices changed significantly from the figures used by KCP&L to develop its composite natural gas price forecast?

A. No. Current NYMEX natural gas futures prices are only several percent below the figures used by KCP&L.

Q. Have the EIA's projected long term natural gas prices changed significantly from the figures used by KCP&L?

[redacted]

Figure 4: 2010 vs. 2011 EIA Natural Gas Price Forecasts [REDACTED]

[redacted]

Q. What impact would using the EIA's 2011 natural gas price forecast have on the composite natural gas prices that KCP&L used in its modeling analyses?

A. I have not had an opportunity to make that calculation.

Q. Are you concerned that any of the other natural gas price forecasts on which KCP&L relied also might be stale?

A. Yes. [redacted]

[redacted] has revised its natural gas price forecast in the 13 months since then.

Q. What is the significance of the fact that EIA and perhaps others have recently revised their natural gas price forecasts?

A. Natural gas prices are one of the most important inputs for a resource modeling analysis, along with projected retrofit costs, CO_2 prices, projected plant operating performance, and the forecast technical availability and economic feasibility of alternatives costs. This is especially true where, as here, there are only minor differences between the NPVRR of the various alternative resource plans.

Q. Have you seen any evidence that suggests that coal prices could be higher than KCP&L has assumed in its analyses?

A. Yes. A number of factors suggest there will be significant upward pressures on PRB and Colorado coal prices in coming years, as well as price volatility.

In particular, there is an increasing emphasis on exporting domestic U.S. coal at the very same time that traditional sources are being depleted. This is expected to lead to upward pressure on coal prices as Central Appalachian reserves are depleted and mining in the PRB is intensified due to rising domestic and international demands and reduced supplies at other sources.[15] A recent coal industry market commentary expressed a concern that appears to be felt by many in the industry: "If the near-term sense of helplessness against the tide of seemingly incurable market dilemmas portends longer-term problems, if a season of wild price volatility truly is a precursor to a more complex and domestically threatening energy environment, we might all be about to catch a falling knife."[16]

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15 See, for example, Scott Learn, *Mining companies aim to export coal to China through Northwest points,* The Oregonian, September 8, 2010. The most recent reporting on plans to ship PRB coal through the Pacific Northwest.

16 Energy Publishing, In, *Coal and Energy Price Report,* Volume 12, No.88, May 10, 2010.

For example, a presentation by John Drexler, Senior VP and CFO, Arch Coal, Inc., at the BMO Capital Markets 2011 Global Metals/Mining Conference in February 2011 noted the following:

> Even modest increases in export activity can have significant market implications:
>
> - Arguably the most significant driver in the 2008 market run-up was a 32 million ton increase in exports from 2006 to 2008.
> - U.S. exports appear to be in the midst of an even greater expansion at present.
> - The market implications of such an increase could prove dramatic.[17]

In addition, there are indications that intensified mining efforts will lead to rising costs of production in the Powder River Basin.[18] In 2008 the USGS issued a study of the PRB's Gillette coal beds. This study, which reflected forty years of USGS research on coal reserve methodology throughout the United States, concluded that the methods used by the United States government to calculate coal reserves had significantly overstated the amount of economically recoverable coal. The study explained that as existing mines and new mines in the area are more intensively exploited, production costs would rise substantially, perhaps to a level that could not be covered by the market price.[19] This is an important observation as the Gillette coal bed contains most of the coal produced in the Powder River Basin, and, overall, accounts for 37% of the nation's coal production.

Q. Do you have any comments regarding the comparisons between natural gas prices and delivered coal prices presented by Mr. Blunk?

A. Yes. Mr. Blunk's comparison is very misleading. You have to include all costs in order to meaningfully compare coal versus natural gas generation. In particular, natural gas combined cycle plants burn their fuel much more efficiently (that is, approximately 7,000

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17 In Slide No. 15.

18 United States Geological Survey, *Assessment of Coal Geology Resources and Reserves in the Gillette Coalfield River Basin, Wyoming,* Open-File Report – 2008-1202.

19 The study offers precise calculations for existing mines in the Gillette coal beds as well as cost curves based on various production levels. These models allow for a dynamic understanding of the relationship between rising costs of production and the need for higher coal prices in the market place.

btu/kwh) than coal plants (approximately 10-11,000 btu/kwh). That difference in heat rates eliminates much of the cost advantage that Mr. Blunk presents for coal.

In addition, when comparing natural gas to coal generation, it is important to include such other costs as constructions and capital additions expenditures, fixed and variable O&M costs and the costs of needed environmental upgrades. A graph such as Mr. Blunk's Schedule WEB2011-2 really offers no insight into the relative economics of gas and coal generation.

Q. Mr. Blunk's Schedules WEB2011-1, WEB2011-2 and WEB2011-3 suggest that coal prices have not exhibit very much volatility compared to natural gas prices. Is this an accurate representation of the volatility of coal prices?

A. No. Mr. Blunk's Schedules WEB2011-2 and WEB2011-3 actually present only Power River Basin coal prices ("PRB"). He ignores the extreme volatility that has been experienced in the prices of coal from other regions of the nation such as Central Appalachia. It is reasonable to expect that the prices of PRB coal may become more volatile in the future as its demand grows due to exports and switching by utilities in the eastern and southern U.S.

Q. What actions have other utilities taken to reduce their exposure to the risks associated with the continued operation of aging coal plants?

A. An increasing number of utilities have decided to retire their unscrubbed coal units and to replace the retired coal capacity with new combined cycle units. For example, Xcel Energy has replaced three of its coal-fired power plants with efficient new combined cycle capacity since 2002 and is now seeking permission from the Minnesota Public Utility Commission to repower another two coal units with combined cycle technology.[20] Other utilities, such as Progress Energy and Duke Energy are taken similar actions. As

[20] Xcel Energy Minnesota 2010 Resource Plan, at pages 6-2 and 6-3.

Progress Energy explained in its 2010 Integrated Resource Plan filing in North Carolina Utilities Commission Docket No. E-100, Sub 128:

> As stated in last year's plan, the current environment presents many significant challenges to deal with from a resource planning perspective, e.g., historic levels of fuel price volatility, tremendous economic uncertainty, potential federal environmental legislation dealing with regulation of carbon emissions, proposals for Federal renewable portfolio standards, the proposed new Environmental Protection Agency ("EPA") Transport Rule, the expected EPA Maximum Achievable Control Technology ("MACT") mercury rule, the potential consideration of coal ash as hazardous waste by EPA, and customer behavior and usage changes. What continues to be one of the most notable examples of such uncertainty is the potential for environmental and climate change legislation. Even though at the time of this filing there appears to be a temporary loss in legislative momentum with respect to climate change it is widely assumed there will ultimately be legislation of some form resulting in a mandate to reduce the carbon output from the Company's generation fleet. This potential legislation paired with proposed and expected EPA regulations regarding greenhouse gas emissions led to the Company's decision to retire three coal units at each of its Lee and Sutton facilities and construct new state of the art efficient natural gas combined cycle units at those sites.
>
> These same considerations have caused the Company to conclude that it should plan to retire its remaining uncontrolled coal units in North Carolina at the beginning of 2015. It should be noted that this projected date is still subject to movement pending the outcome of many of the legislative initiatives listed in the Company's Coal Retirement Plan approved by the North Carolina Utilities Commission as well as continued movement in underlying fuel prices. As a cumulative result of the new gas fired combined cycles being constructed at the Lee and Sutton sites and the associated retirement of eleven coal units at the Lee, Sutton, Weatherspoon and Cape Fear sites, the Company will have replaced approximately 1500 MWs of unscrubbed coal generation with 1500 MWs of state of the art gas fired generation. Benefits of this portfolio modernization include both environmental benefits, in the form of significant reductions in the output of SO_2, NO_x, mercury and CO_2, as well as fuel diversification benefits resulting from the addition of the new gas fired generation. [Progress Energy Carolinas] continues to evaluate the best course of action with regard to its South Carolina Robinson coal plant.[21]

[21] Progress Energy Carolinas *2010 Integrated Resource Plan – NCUC Docket No. E-100, Sub 128*, September 13, 2010, at page 3.

Q. Did KCP&L consider a reasonable range of alternatives to the retrofitting of La Cygne Units 1 and 2 in its modeling planning analyses?

A. No. KCP&L did not consider a number of feasible alternatives. In particular, the Company has acknowledged that:

- It did not consider increased release on market purchases of capacity in order to meet reserve margin requirements.[22]
- It has not conducted any studies of wholesale capacity availability.[23]
- It has not prepared any analyses since at least January 1, 2006 of the technical and/or economic feasibility of converting any of its existing combustion turbines to combined cycle technology.[24]
- Even though KCP&L is aware of a number of uncommitted generation facilities in the Southwest Power Pool (including hydro and nuclear capacity) and has had some discussions concerning those facilities, it did not analyze the potential purchase of any capacity from any of these units.[25]
- In its evaluation of new/replacement capacity costs, KCP&L considered only new builds and not any availability of existing Independent Power Producer or other utility capacity.[26]

Q. What evidence have you seen that suggests that there is be a significant amount of underutilized combined cycle capacity in the Southwest Power Pool?

A. Yes. Combined cycle units are generally considered to have the potential to operate at capacity factors on the order of 60 percent to 75 percent. I have seen several studies that show that the existing combined cycle units in the Southwest Power Pool have operated at an average capacity factor of significantly below this range. This suggests that there is significant capacity within the region to meet the needs of Kansas' electric ratepayers even if La Cygne Units 1 and 2 were retired as early as 2015.

22 KCP&L Response to Data Request SC 21.

23 KCP&L Response to Data Request SC 11(b).

24 KCP&L Response to Data Request GPACE 2-12.

25 KCP&L Responses to Data Requests GPACE 3-1, 3-2 and 3-3.

26 KCP&L Response to KCC Staff Data Request 76.

For example, an August 2010 study by the Analysis Group and M.J. Bradley & Associates, reported that the 12,051 MW of installed combined cycle units of larger than 500 MW operated at an average utilization of only 32 percent in 2008.[27] A fall 2010 analysis by Energy Ventures Analysis, Inc., similarly reported that the natural gas combined cycle units in the West South Central Region of the U.S. (excluding ERCOT) operated at an average 34 percent capacity factor in 2007, 35 percent in 2008 and 38 percent in 2009.[28]

Q. What are the potential benefits of converting one or more existing combustion turbines into combined cycle facilities?

A. Existing combustion turbines can be converted into combined cycle units at lower cost by using existing site equipment such as the combustion turbines and transmission facilities. In this way, a peaking combustion turbine that had a 12-14,000 btu/kwh heat rate can be repowered as a baseload or intermediate combined cycle unit with a heat rate of 7,000 btu/kwh.

Q. What have been KCP&L's annual CO_2 emissions over the past decade?

A. KCP&L's annual CO2 emissions are presented in Figure 5, below.

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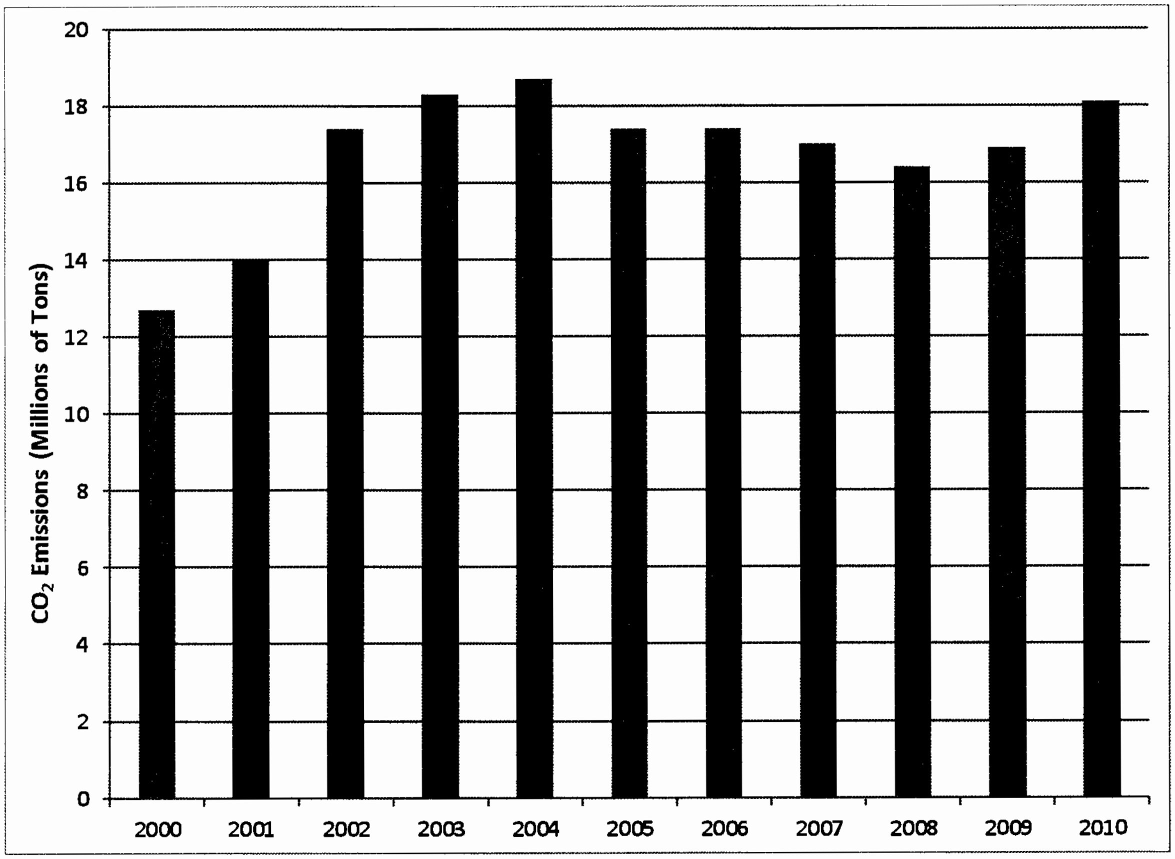
27 *Ensuring a Clean, Modern Electric Generating Fleet While Maintaining Electric System Reliability*, August 2010, at page 13. Available at http://www.mjbradley.com/documents/MJBAandAnalysisGroupReliabilityReportAugust2010.pdf.

28 *Outlook for Natural Gas Demand for 2010-2011 Winter*, at Exhibit A-5.

Figure 5: KCP&L Annual CO_2 Emissions 2000-2010



Thus, KCP&L's annual CO_2 emissions increased by approximately 42 percent between 2000 and 2010.

Q. Have you seen any evidence that KCP&L plans to significantly reduce its CO_2 emissions in the coming years?

A. No. In fact, its annual CO_2 emissions are likely to be higher in the short term as 2010 reflects only six months of operations of Iatan 2. Moreover, the Company's preferred plan in its most recent Integrated Resource Plan filing, included the continued operation of its existing baseload units and the addition of new combustion turbines to provide peaking capacity.[29] Consequently, there is no reason to believe that the Company's annual CO_2 emissions will be reduced in any meaningful way at any point in the foreseeable future.

[29] KCP&L Response to Data Request KCC 78.

Q. What do KCP&L's modeling analyses show that the Company's future CO_2 emissions will be if La Cygne Units 1 and 2 are retrofitted?

A. The results of KCP&L's modeling of its Base Case plan where all of the La Cygne and Montrose coal-fired units are retrofitted show that the Company's CO_2 emissions will [redacted]. These [redacted] CO_2 emissions will carry a significant regulatory and economic risk for KCP&L's ratepayers.

Figure 6: KCP&L's Projected CO_2 Emissions if La Cygne and Montrose Retrofitted [REDACTED]

Q. Do you have any comments on the CO_2 prices that KCP&L has used in its modeling analyses?

A. Yes. Unfortunately, I have not had time to fully examine the reasonableness of KCP&L's base and high CO_2 price forecasts. However, it is clear that KCP&L's low CO_2 price forecast, which assumes a [redacted] price throughout the 2010-2034 planning period is unreasonable as it assumes that there will be [redacted] regulation of CO_2 emissions at any time over the next 22 to 23 years. Although the current Congress is unlikely to act on climate change. I do not believe that it is reasonable to assume that the federal government (or state governments) will not act to reduce greenhouse gas emissions at any time in the next two decades – especially given the widespread support for such actions among the public, business leaders and utilities.

Q. Have you seen any evidence that suggests that adoption of a CO_2 regulatory regime would lead to higher natural gas prices?

A. No. It is possible that natural gas demand could be somewhat higher due to CO_2 emission regulations and, as a result, natural gas prices could be expected to be somewhat higher than otherwise would be the case. However, the effect is very complicated and will depend on a number of factors, such as how much new natural gas capacity is built as a result of the higher coal-plant operating costs due to the CO_2 emission allowance prices, how much additional DSM and renewable alternatives are added to the U.S. system, the levels and prices of any incremental natural gas imported into or developed in the U.S., and changes in the dispatching of the electric system. Indeed, depending on future circumstances there may be some periods in which the prices of natural gas may be lower as a result of CO_2 regulations. Thus it is very difficult to determine, at this time, the amount by which natural gas prices might increase, if at all, due to the regulation of CO_2 emissions.

In fact, the detailed modeling of proposed greenhouse gas legislation does not show that the price of natural gas would increase as a result of a federal program for regulating greenhouse gas emissions but reveals a much more complex dynamic.

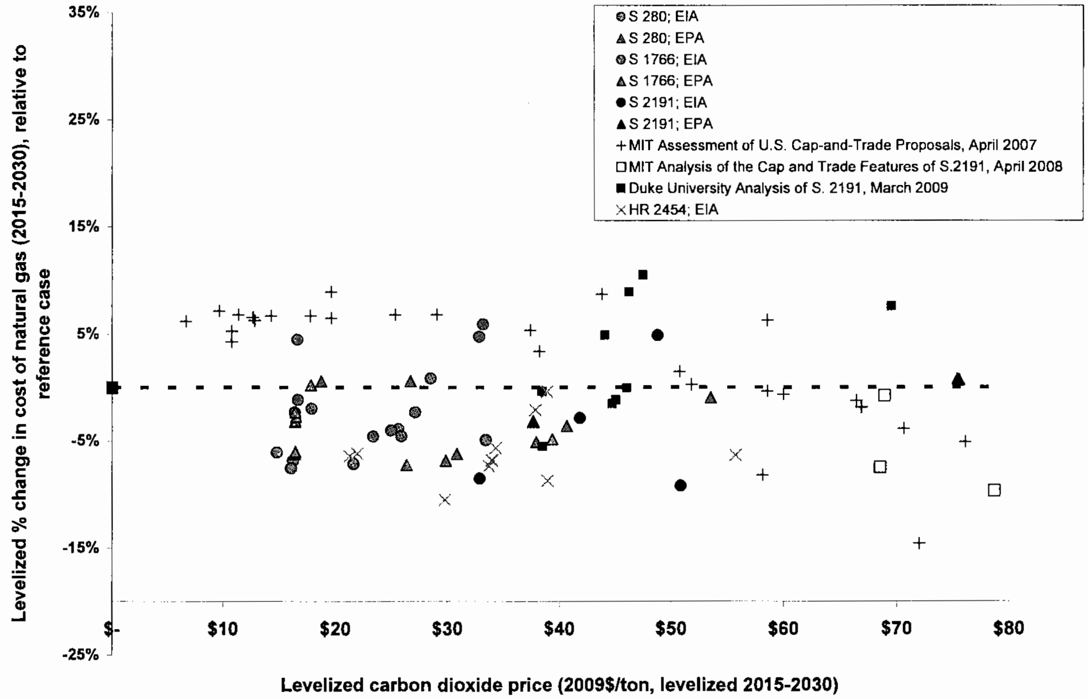
Q. Have you examined the impact that the enactment of CO_2 emissions regulations might have on natural gas prices?

A. Yes. While I worked with Synapse Energy Economics, we reviewed the publicly available modeling results concerning the impact that adoption and implementation of CO_2 regulatory legislation could have on natural gas prices. The results of our review are presented in Figures 7, 8, and 9, below.

Figure 7, below, shows the levelized percentage changes in natural gas prices (i.e., increases or decreases from the base case, which includes no regulation of greenhouse gas emissions) in a large number of scenarios from the major climate change proposals that have been introduced in the U.S. Congress in recent years. Each data point shown in Figure 7 reflects the levelized change in the natural gas prices in a modeled scenario and the levelized CO_2 price for that scenario.

The levelized CO_2 prices and natural gas price changes presented in Figure 7 have been developed from the results of modeling by the EIA of the Department of Energy, the U.S. EPA, and the Joint Program at MIT on the Science and Policy of Global Change, and cover multiple climate change proposals in the 110th U.S. Congress: Senate Bill S.280 (the McCain-Lieberman bill), Senate Bill S.1766 (the Bingaman-Specter bill), Senate Bill S.2191 (the Lieberman-Warner bill) and House Bill 2454 in the 111^{th} Congress (the American Clean Energy and Security Act of 2009, "Waxman-Markey").

Figure 7: The relationship between CO_2 emissions allowance prices and natural gas prices.



As shown clearly in Figure 7, *none* of the results of any of the independent modeling analyses support an assumption that regulation of CO_2 emissions will increase natural gas prices by any significant amount, especially not at very low CO_2 prices.

In fact, the results of the modeling of a substantial number of the CO_2 regulation scenarios represented in Figure 7 suggest that the adoption of greenhouse gas regulation could lead to lower natural gas prices as the demand for and the use of natural gas decline due to its greenhouse gas emissions. Thus, there is no credible modeling evidence to support any assumption that federal regulation of greenhouse gas emissions would inevitably lead to a significant increase in the price of natural gas, particularly at relatively low CO_2 prices.

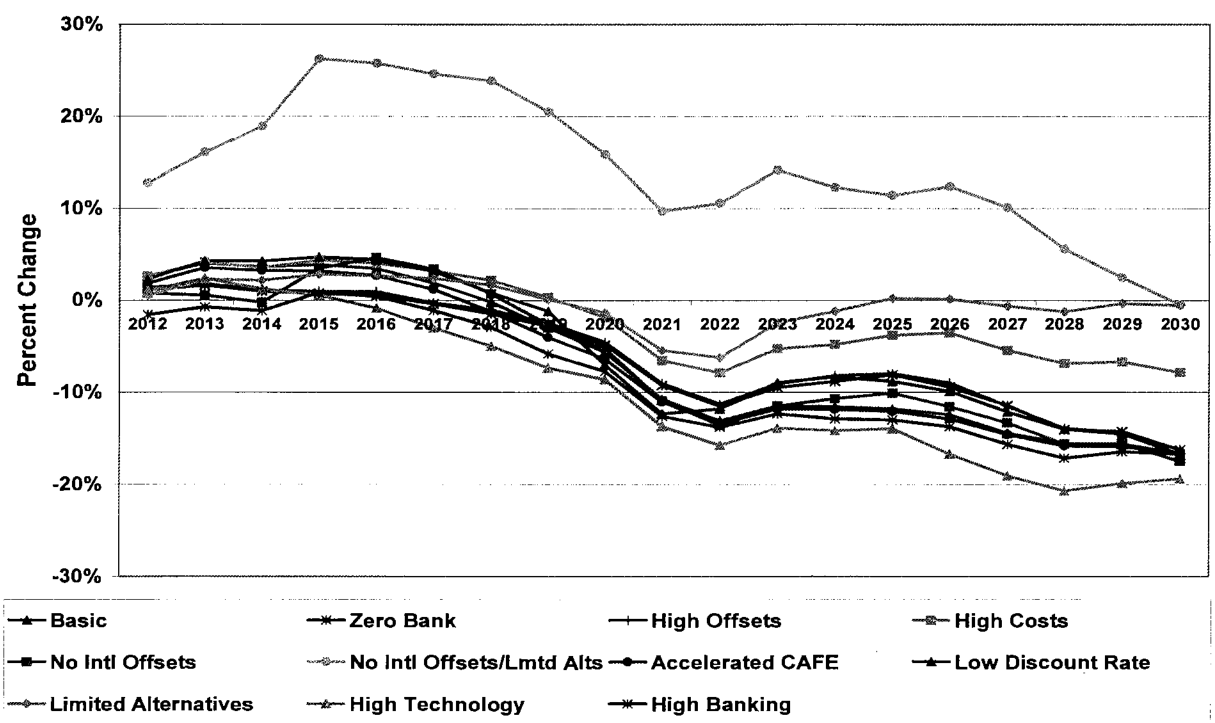
Q. Does Figure 7, above, include the modeling of the HR 2454, the Waxman-Markey legislation that was approved by the U.S. House of Representatives in 2010?

A. Yes. The results of the recent EIA modeling of the Waxman-Markey bill are included in Figure 7.

Q. Have you seen any other evidence that suggests that federal regulation of greenhouse gas emissions will not cause significant increases in natural gas prices?

A. Yes. Figure 8, below, presents the annual percentage changes in natural gas prices in each of the scenarios examined by the EIA in its recent modeling of the Waxman-Markey bill from the gas prices in the EIA's reference case without any regulation of CO_2 emissions. This information provides insight in the ranges of natural gas prices that could be expected from adoption of the Waxman-Markey bill.

Figure 8: Annual Changes in Natural Gas Prices from Reference Case in EIA Modeling of Proposed Waxman-Markey Legislation



As can be seen from Figure 8, under the Waxman-Markey bill that was passed by the House of Representatives, in almost all of the scenarios studied by the EIA, natural gas prices would increase somewhat for a few initial years except for a single scenario in which there would only be limited alternatives to using gas in place of coal and in which the use of international offsets would not be allowed. Indeed, in many of the cases studied by the EIA, natural gas prices would be expected to decrease over time as a result of the federal regulation of greenhouse gas emissions.

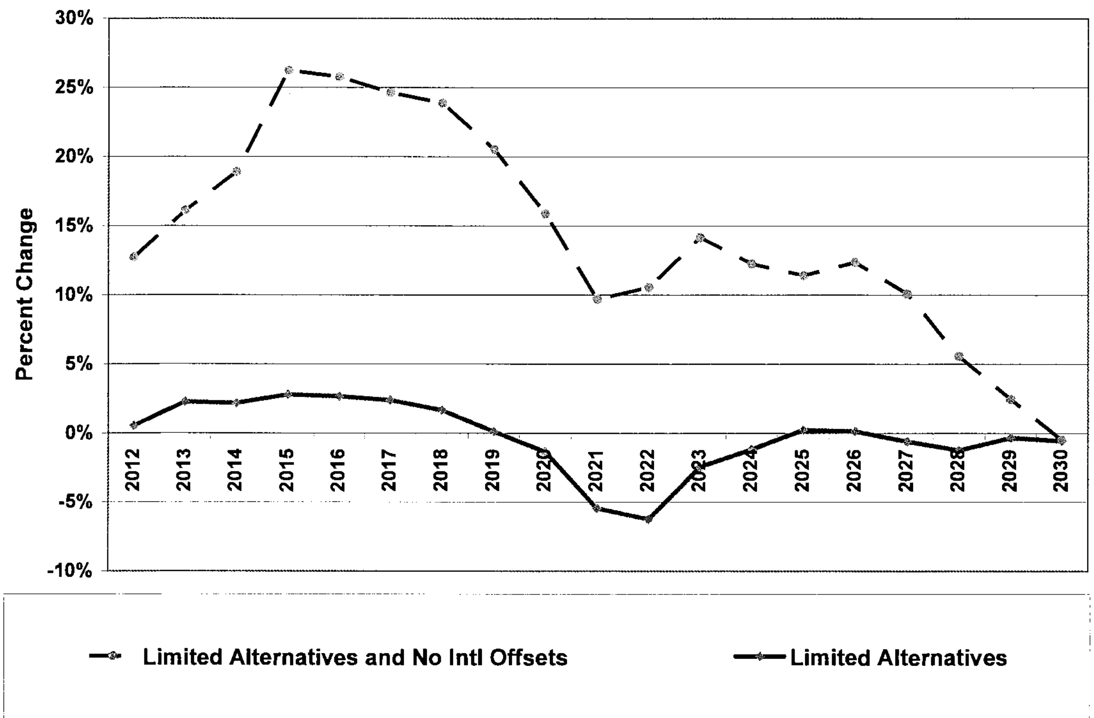
Q. Doesn't the EIA's modeling of H.R. 2454, the Waxman-Markey bill, show natural gas prices decreasing simply because most of the scenarios studied assume significant additions to the number of nuclear power plants in the U.S?

A. No. The EIA also modeled two "Limited Alternatives" scenarios in which the additions of nuclear capacity, dedicated biomass and coal plants with carbon capture and sequestration were constrained. In one of these "Limited Alternatives" scenarios, the use of international offsets also was prohibited.

Q. What impact did the proposed Waxman-Markey bill have on natural gas prices in these two Limited Alternatives scenarios?

A. The annual changes in natural gas prices in each of the two "Limited Alternatives" scenarios modeled by the EIA, as compared to the base case without any CO_2 regulation, are presented in Figure 9 below. This Figure presents the same information that was presented in Figure 8, above, except that all of the other scenarios modeled by the EIA other than the "Limited Alternatives" scenarios have been removed. These other scenarios assumed some large nuclear additions.

Figure 9: Changes from Base Case Natural Gas Prices in EIA "Limited Alternatives" Modeling Scenarios



As can be seen from Figure 9, natural gas prices did not increase very much, at all, as compared to the reference case prices in the EIA "Limited Alternatives" scenario that constrained new nuclear, biomass and coal plant with CCS additions.[30] In fact, over time natural gas prices were projected to decrease, as compared to the reference case, because of the cost of the fuel's CO_2 emissions.

Natural gas prices only increased significantly in the scenario which added a prohibition on the use of international offsets to the "Limited Alternatives" scenario.

Q. Would the use of international offsets have been prohibited under the Waxman-Markey bill?

A. No. The Waxman-Markey bill and the Kerry-Boxer legislation under consideration in the U.S. Senate both would allow significant use of international offsets. Therefore, the gas price impacts are more likely to track the lower line in Figure 9.

[30] The reference case examined by the EIA did not assume regulation of CO_2 emissions.

Q. But doesn't common sense suggest that regulating greenhouse gas emissions will lead to less coal-fired generation and more of a dependence on natural gas – thereby increasing the demand for and price of natural gas?

A. Not necessarily, especially over the mid-to-longer term. In fact, there are several reasons why federal regulation of greenhouse gas emissions may not lead to any meaningful increases in the price of natural gas. First, natural gas plants also emit CO_2. Thus, there will be incentives as a result of federal regulation of greenhouse gases to shift away from use of natural gas to more carbon neutral options such as energy efficiency and renewable resources. This will act to reduce the demand for natural gas as well as coal-fired generation.

It also is generally accepted that strategies for reducing our national greenhouse gas emissions will require implementing complementary policies adding large amounts of new wind and energy efficiency. Thus, legislative proposals for regulation of greenhouse gases, such as the Waxman-Markey bill also included increased investments in these areas. Consequently, carbon legislation, when coupled with increasing amounts of new wind and energy efficiency, actually may lead to decreases in the demand for and, consequently, reduced costs for natural gas over the long term, counter to what the Applicants have assumed.

For example, a recent study by the U.S. Department of Energy's National Renewable Energy Laboratory examined the costs and benefits of achieving 20 percent wind energy penetration by 2030.[31] One of the benefits that this DOE study found was that wind generation could displace up to 50 percent of the electricity that would be generated from natural gas – this, in turn, could translate into a reduction in national demand for natural gas of 11 percent.[32]

The substantially higher domestic U.S. natural gas supplies that have been identified within the past year, as I discussed earlier, also will reduce the impact that regulation of CO_2 emissions could have on natural gas prices.

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[31] *20 Percent Wind Energy by 2030*, available at http://www.20percentwind.org/20p.aspx?page=Report.

[32] Id, at pages 16 and 154.

Q. Does this complete your testimony?

A. Yes.

BEFORE THE STATE COPORATION COMMISSION
OF THE STATE OF KANSAS

In the Matter of the Petition of Kansas	**)**	
City power & Light Company ("KCP&L)	**)**	
For Determination of the Ratemaking	**)**	
Principles and Treatment that Will Apply	**)**	**Docket No. 11-KCPE-581-PRE**
To the Recovery in Rates of the cost to be	**)**	
Incurred by KCP&L for Certain Electric	**)**	
Generation Facilities Under K.S.A. 66-1239	**)**	

AFFIDAVIT OF DAVID A. SCHLISSEL

STATE OF MASSACHUSETTS)
) ss
COUNTY OF MIDDLESEX)

David A. Schlissel, appearing before me, affirms and states:

1. My name is David A. Schlissel. I work in Belmont, Massachusetts, and I am the President of Schlissel Technical Consulting, Inc.

2. Attached hereto and made a part hereof for all purposes is my Intervenor Direct Testimony on behalf of the Great Plains Alliance for Clean Energy consisting of thirty-six (36) pages, having been prepared in written form for introduction into evidence in the above-captioned docket.

3. I have knowledge of the matters set forth therein. I hereby affirm that my answers contained in the attached testimony to the questions therein propounded, including any attachments thereof, are true and accurate to the best of my knowledge, information, and belief.

David A. Schlissel
David A. Schlissel

Subscribed and affirmed before me this 3rd day of June 2011.

Juanita Hollis
Notary Public

My commission expires: 4/19/2013

JUANITA HOLLIS
Notary Public
Commonwealth of Massachusetts
My Commission Expires
April 19, 2013

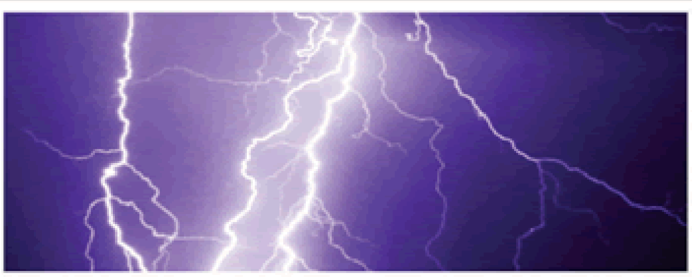
Schedule RSW-5

Synapse
Energy Economics, Inc.

2012 Carbon Dioxide Price Forecast

October 4, 2012

AUTHORS
Rachel Wilson, Patrick Luckow,
Bruce Biewald, Frank Ackerman,
and Ezra Hausman



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1. Executive Summary

Electric utilities and others should use a reasonable estimate of the future price of carbon dioxide (CO_2) emissions when evaluating resource investment decisions with multi-decade lifetimes. Estimating this price can be difficult because, despite several attempts, the federal government has not come to consensus on a policy (or a set of policies) to reduce greenhouse gas (GHG) emissions in the U.S.

Although this lack of a defined policy certainly creates challenges, a "zero" price for the long-run cost of carbon emissions is not a reasonable estimate. The need for a comprehensive effort in the U.S. to reduce GHG emissions has become increasingly clear, and it is certain that any policy requiring, or leading to, these reductions will result in a cost associated with emitting CO_2 over some portion of the life of long-lived electricity resources. Prudent planning requires a reasonable effort to forecast CO_2 prices despite the considerable uncertainty with regard to specific regulatory details.

This 2012 forecast seeks to define a reasonable range of CO_2 price estimates for use in utility Integrated Resource Planning (IRP) and other electricity resource planning analyses. This forecast updates Synapse's 2011 CO_2 price forecast, which was published in February of 2011. Our 2012 forecast incorporates new data that has become available since 2011, and extends the study period end-date to 2040 in order to provide recommended CO_2 price estimates for utilities planning 30 years out into the future.

A. Key assumptions

Synapse's 2012 CO_2 price forecast reflects our expectation that cap-and-trade legislation will be passed by Congress in the next five years, and the resultant allowance trading program will take effect in or around 2020. These assumptions are based on the following reasoning:

- We believe that a federal cap-and-trade program for GHGs is a key component of the most likely policy outcome, as it enables the reduction of significant amounts of GHGs while allowing those reductions to come from sources that can mitigate their emissions at the least cost.
- We believe that federal legislation is likely by the end of the session in 2017 (with implementation by about 2020) prompted by one or more of the following factors:
    - 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
    - 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 hodgepodge of state policies. This scenario is a challenge for any company that seeks to make investments in existing, modified, or new power plants. It would also lead to inefficient emissions decisions that are driven by inconsistent policies rather than economics. Historically, this pattern of states and regions initiating policies that are eventually superseded at a national level has been common for energy and environmental regulation in the U.S. It seems likely that this will be the dynamic that ultimately leads to federal action on greenhouse gases, as well.

In addition to the assumptions regarding a federal GHG program described above, we anticipate that regional and state policies will lead to costs associated with GHGs in the near-term (i.e., prior to 2020). Prudent planning requires that utilities take these costs into account when engaging in resource planning.

B. Study approach

To develop its 2012 CO_2 price forecast, Synapse reviewed more than 40 carbon price estimates and related analyses, including:

- McKinsey & Company's 2010 analyses of the marginal abatement costs and abatement potential of GHG mitigation technologies
- Analyses of the CO_2 allowance prices that would result from the major climate change bills introduced in Congress over the past several years, including analyses by the Energy Information Association (EIA) and the Environmental Protection Agency (EPA)
- The U.S. Interagency Working Group's estimates for the social cost of carbon
- Analyses of the factors that affect projections of allowance prices, including analyses by the EIA and Resources for the Future
- CO_2 price estimates used by utilities in a wide range of publicly available utility Integrated Resource Plans

Because we expect that a federal cap and allowance trading program will ultimately be adopted, analyses of the various Congressional proposals to date using this approach offer some of the most relevant estimates of costs associated with greenhouse gas emissions under a variety of regulatory scenarios. It is not possible to compare the results of all of these analyses directly, however, because the specific models and the key assumptions vary.

Synapse also considered the impact on CO_2 prices of regulatory measures outside of a cap-and-trade program—such as a federal Renewable Portfolio Standard—that could simultaneously help to achieve the emission-reduction goals of cap-and-trade. These "complementary policies" result in lower CO_2 allowance prices, since they would reduce the demand for CO_2 emissions allowances under cap-and-trade.

C. Synapse's 2012 CO_2 price forecast

Based on analyses of the sources described above, and relying on its own expert judgment, Synapse developed Low, Mid, and High case forecasts for CO_2 prices from 2020 to 2040. These cases represent different appetites for reducing carbon, as described below.

- The Low case forecast starts at $15/ton in 2020, and increases to approximately $35/ton in 2040.[1] This forecast represents a scenario in which Congress begins regulation of greenhouse gas emissions slowly—for example, by including a modest emissions cap, a safety valve price, or significant offset flexibility. This price forecast could also be realized through a series of complementary policies, such as an aggressive federal Renewable Portfolio Standard, substantial energy efficiency investment, and/or more stringent automobile CAFE mileage standards (in an economy-wide regulation scenario).
- The Mid case forecast starts at $20/ton in 2020, and increases to approximately $65/ton in 2040. This forecast represents a scenario in which a federal cap-and-trade program is implemented with significant but reasonably achievable goals, likely in combination with some level of complementary policies to give some flexibility in meeting the reduction goals. Also assumed in the Mid case is some degree of technological learning, i.e. assuming that prices for emissions reductions technologies will decline as greater efficiencies are realized in their design and manufacture and as new technologies become available.
- The High case forecast starts at $30/ton in 2020, and increases to approximately $90/ton in 2040. This forecast is consistent with the occurrence of one or more factors that have the effect of raising prices. These factors include somewhat more aggressive emissions reduction targets; greater restrictions on the use of offsets (nationally or internationally); restricted availability or high cost of technology alternatives such as nuclear, biomass and carbon capture and sequestration; or higher baseline emissions.

Table ES-1 presents Synapse's Low, Mid, and High case price projections for each year of the study period, as well as the levelized cost for each case.

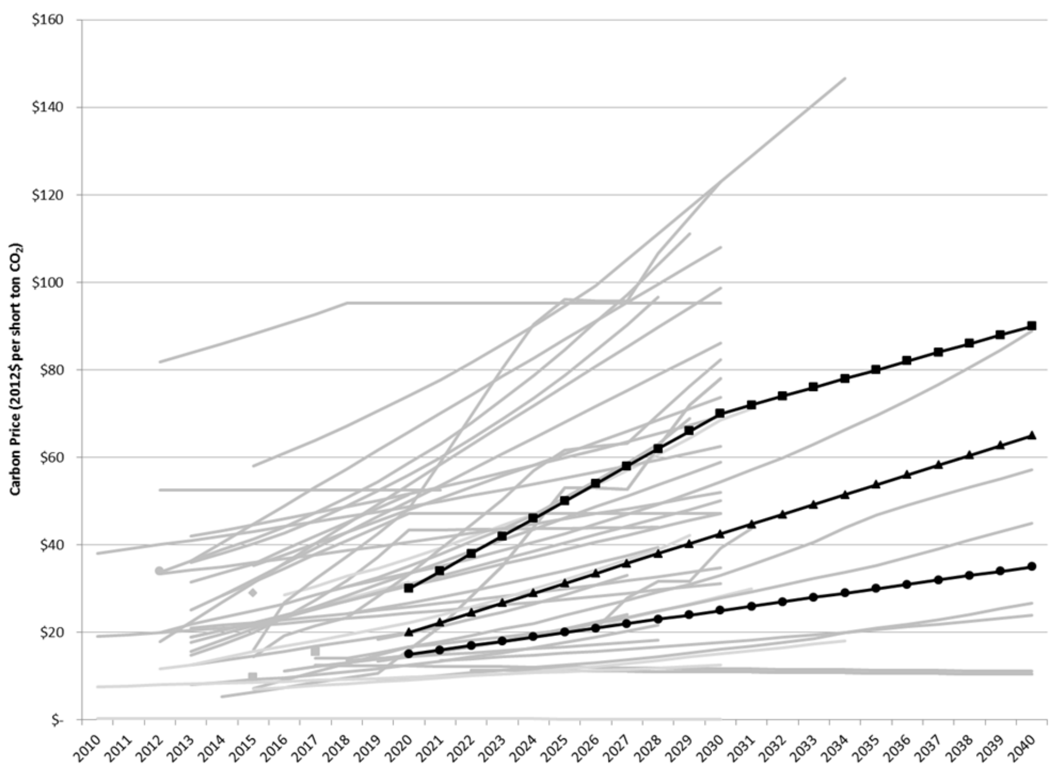
Figure ES-1 presents Synapse's Low, Mid, and High case forecasts as compared to a broad range of CO_2 allowance prices used by utilities in resource planning over the past three years. Synapse forecasts are represented by black lines, while utility forecasts are represented by grey.

[1] Throughout this report, CO_2 allowance prices are presented in $2012 per short ton CO_2, except in reference to a few original sources, where alternate units are clearly labeled. Results from other modeling analyses were converted to 2012 dollars using price deflators taken from the US Bureau of Economic Analysis. Because data were not available for 2012 in its entirety, values used for conversion were taken from Q2 of each year. Results originally provided in metric tonnes were converted to short tons by multiplying by a factor of 1.1.

Table ES-1: Synapse 2012 CO_2 allowance price projections (2012 dollars per ton CO_2)

Year	Low Case	Mid Case	High Case
2020	$15.00	$20.00	$30.00
2021	$16.00	$22.25	$34.00
2022	$17.00	$24.50	$38.00
2023	$18.00	$26.75	$42.00
2024	$19.00	$29.00	$46.00
2025	$20.00	$31.25	$50.00
2026	$21.00	$33.50	$54.00
2027	$22.00	$35.75	$58.00
2028	$23.00	$38.00	$62.00
2029	$24.00	$40.25	$66.00
2030	$25.00	$42.50	$70.00
2031	$26.00	$44.75	$72.00
2032	$27.00	$47.00	$74.00
2033	$28.00	$49.25	$76.00
2034	$29.00	$51.50	$78.00
2035	$30.00	$53.75	$80.00
2036	$31.00	$56.00	$82.00
2037	$32.00	$58.25	$84.00
2038	$33.00	$60.50	$86.00
2039	$34.00	$62.75	$88.00
2040	$35.00	$65.00	$90.00
Levelized	$23.24	$38.54	$59.38

Figure ES-1: Synapse forecasts compared to a range of utility forecasts



2. Structure of this Paper

This paper presents Synapse's assumptions, data sources, and estimates of reasonable future CO_2 prices for use in resource planning analyses. The report is structured as follows:

- Section 3 discusses the key assumptions behind Synapse's estimates
- Sections 4 through 8 present data from the sources reviewed by Synapse in developing its estimates of the future price of CO_2 emissions
- Section 9 presents Synapse's 2012 Low, Mid, and High CO_2 price forecasts, and compares these projections to a range of utility forecasts
- Appendix A provides a more detailed discussion of state and regional GHG initiatives. Collectively, these initiatives suggest that momentum is building toward federal GHG action

3. Discussion of Key Assumptions

A. Federal GHG legislation is increasingly likely

Congressional action in the form of cap-and-trade or clean energy standards 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. The states, the federal courts, and federal agencies are also grappling with the complex issues associated with climate change. Many of these efforts are proceeding simultaneously.

Nonetheless, we believe that a federal cap-and-trade program for GHGs is the most likely policy outcome, as it enables the reduction of significant amounts of GHGs while allowing those reductions to come from sources that can mitigate their emissions at the least cost. Several cap-and-trade proposals have been taken up by Congress in the past few years, though none yet have been passed by both houses. (More discussion of this topic is provided in Section 5 of this report.)

We further believe that federal action will occur in the near-term. This 2012 CO_2 price forecast assumes that cap-and-trade legislation will be passed by Congress in the next five years, and the resultant allowance trading program will take effect in 2020, prompted by one or more of the following factors:

- 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
- 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 hodgepodge of state policies. This scenario is a challenge for any company that seeks to make investments in existing, modified, or new power plants. It would also lead to inefficient emissions decisions driven by inconsistent policies rather than economics. Historically, this pattern of states and regions initiating policies that are eventually superseded at a national level has been common for energy and environmental regulation in the U.S. It seems likely that this will be the dynamic that ultimately leads to federal action on greenhouse gases, as well.

B. State and regional initiatives building toward federal action

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 wait for federal action, are already pursuing policies on their own or in regional groups. These policies are described below, and are discussed in more detail in Appendix A of this report.

Cap-and-trade programs

The Northeast/Mid-Atlantic region and the state of California have developed, or are in the last stages of developing, greenhouse gas caps and allowance trading. [2]

Under the Regional Greenhouse Gas Initiative (RGGI), ten Northeast and Mid-Atlantic 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.

Meanwhile, California's Global Warming Solutions Act (AB 32) has created the world's second largest carbon market, after the European Union's Emissions Trading System (EU ETS). The first compliance period for California's cap-and-trade program will begin on January 1, 2013, and will cover electricity generators, carbon dioxide suppliers, large industrial sources, and petroleum and natural gas facilities emitting at least 25,000 metric tons of CO_2e[3] per year. The initial cap is set at 162.8 million metric tons of CO_2e and decreases by 2% annually through 2015.

State GHG reduction laws

Massachusetts: In 2008, the Massachusetts Global Warming Solutions Act was signed into law. In addition to the commitments to power sector emissions reductions associated with RGGI, this law committed Massachusetts to reduce statewide emissions to 10-25% below 1990 levels by 2020 and 80% below 1990 levels by 2050. Following the development of a comprehensive plan on steps to meet these goals, the 2020 target was set at 25% below 1990 levels.[4] Rather than put a price on carbon in the years before 2020, this plan will achieve a 25% reduction through a combination of federal, regional, and state-level regulations applying to buildings, energy supply, transportation, and non-energy emissions.

Minnesota: In 2008, the Next Generation Energy Act was signed to reduce Minnesota emissions by 15% by 2015, 30% by 2025, and 80% by 2050.[5] While the law called for the development of an action plan that would make recommendations on a cap-and-trade system to meet these goals, the near-term goals will be met by a combination of an aggressive renewable portfolio standard and energy efficiency.

Connecticut: Also in 2008, the state of Connecticut passed its own Global Warming Solutions Act, establishing state level targets 10% below 1990 levels by 2020 and 80% below 2001 levels by 2050. In December 2010, the state released a report on mitigation options focused on regulatory mechanisms in addition to strengthening RGGI and reductions of non-CO_2 greenhouse gases.[6]

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[2] The Midwest Greenhouse Gas Reduction Accord was developed in 2007. Though the agreement has not been formally suspended, the participating states are no longer pursuing it.

[3] CO2e refers to carbon dioxide equivalent, a measure that includes both carbon dioxide and other greenhouse gases converted to an equivalent amount of carbon dioxide based on their global warming potential.

[4] Massachusetts Clean Energy and Climate Plan for 2020, Available at: http://www.mass.gov/green/cleanenergyclimateplan

[5] Minnesota Statutes 2008 § 216B.241

[6] See http://www.ctclimatechange.com for further details on CT plans for emissions mitigation.

Renewable portfolio standards and other initiatives

A renewable portfolio standard (RPS) or renewable goal specifies that a minimum proportion of a utility's resource mix must be derived from renewable resources. The standards range from modest to ambitious, and qualifying energy sources vary by state.

Currently, 29 U.S. states have renewable portfolio standards. Eight others have renewable portfolio goals. In addition, many states are pursuing other policy actions relating to reductions of GHGs. These policies include, but are not limited to: greenhouse gas inventories, greenhouse gas registries, climate action plans, greenhouse gas emissions targets, and emissions performance standards.

In the absence of a clear and comprehensive federal policy, many states have developed a broad array of emissions and energy related policies. For example, Massachusetts has a RPS of 15% in 2020 (rising to 25% in 2030), belongs to RGGI (requiring specific emissions reductions from power plants in the state), and has set in place aggressive energy efficiency targets through the 2008 Green Communities Act.

4. Marginal Abatement Costs and Technologies

This chapter presents key data related to marginal abatement costs for CO_2, which were reviewed by Synapse in developing its estimates of the future price of CO_2 emissions.

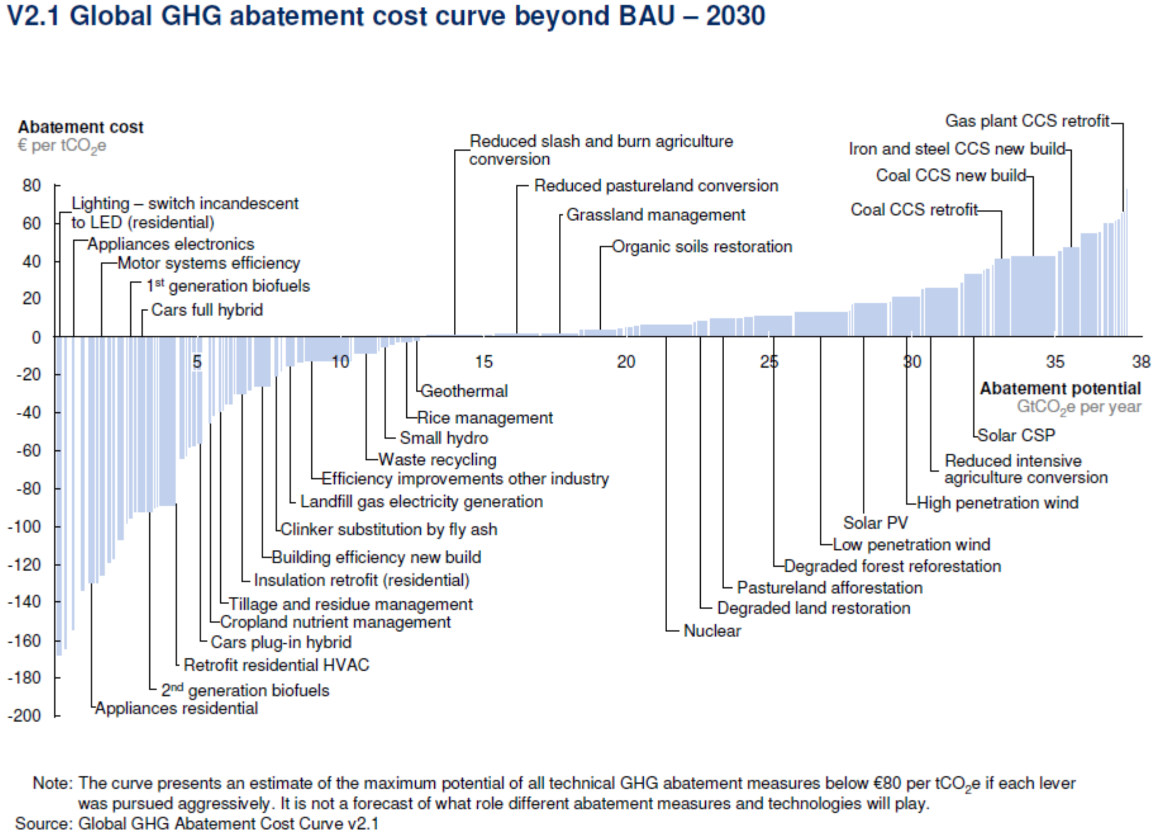
The long-run marginal abatement cost for CO_2 represents the cost of the control technologies necessary for the last (or most expensive) unit of emissions reduction required to comply with regulations. This cost depends on emission reduction goals: lower emissions reduction targets can be met by lower-cost technologies, while more stringent targets will require additional reduction technologies that are implemented at higher costs. The Copenhagen Agreement, drafted at the 15th session of the Conference of the Parties to the United Nations Framework Convention on Climate Change in 2009, recognizes the scientific view that in order to prevent the more drastic effects of climate change, the increase in global temperature should be limited to no more than 2° Celsius. Atmospheric concentrations of CO_2 would need to be stabilized at 450 ppm in order to limit the global temperature increase to no more than 2°C.[7]

In recent years, there have been several analyses of technologies that would contribute to emission reductions consistent with an increase in temperature of no more than 2°C. McKinsey & Company examined these technologies in a 2010 report entitled *Impact of the Financial Crisis on Carbon Economics: Version 2.1 of the Global Greenhouse Gas Abatement Cost Curve*. The CO_2 mitigation options identified by McKinsey and the costs of those options are shown in Figure 1. Global mitigation options are ordered from least expensive to most expensive, and the width of each bar represents the amount of mitigation likely at these costs. The chart represents a marginal abatement cost price curve, where cost of abatement is shown on the y-axis and cumulative metric tonnes of GHG reductions are shown on the x-axis. It is likely that the lowest cost reductions will be implemented first, but as reduction targets become more stringent and low-cost options are saturated, the cost of the marginal abatement technology is likely to increase.

The chart below, from the McKinsey report, provides a useful reference to the types of options and technologies that might be employed at specific CO_2 prices.

[7] IPCC, 2007: Summary for Policymakers. In: *Climate Change 2007: Mitigation. Contribution of Working Group III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change* [B. Metz, O.R. Davidson, P.R. Bosch, R. Dave, L.A. Meyer (eds)], Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA.

Figure 1: McKinsey & Company marginal abatement technologies and associated costs for the year 2030[8]



As shown in Figure 1, technologies for carbon mitigation that are available to the electric sector include those related to energy efficiency, nuclear power, renewable energy, and carbon capture and storage (CCS) for fossil-fired generating resources. McKinsey estimates CCS technologies to cost 50-60 €/metric tonne (2005€). Converted into current dollars, this is equivalent to $65 to $85/ton ($71.5 to $93.5/metric tonne, 2012$). According to the International Energy Agency (IEA), “in order to reach the goal of stabilizing global emissions at 450 ppm by 2050, CCS will be necessary.”[9] If this is true, it is reasonable to expect that a CO_2 allowance price will rise to $65/ton or higher under a GHG policy designed to limit the global temperature increase to no more than 2°C. However, if significant reductions could be accomplished with CCS at the high $65 to $85/ton CO_2 range, we would not expect CO_2 mitigation prices to significantly exceed the top of that range.

[8] McKinsey & Company. *Impact of the Financial Crisis on Carbon Economics: Version 2.1 of the Global Greenhouse Gas Abatement Cost Curve.* 2010. Page 8.
[9] International Energy Agency. *Technology Roadmap: Carbon Capture and Storage*. 2009. Page 4.

5. Analyses of Major Climate Change Bills

This chapter presents key data related to analyses of major climate change bills proposed in Congress over the past few years, which were reviewed by Synapse in developing its estimates of the future price of CO_2 emissions. Because we expect that a federal cap and allowance trading program will ultimately be adopted, analyses of these proposals offer some of the most relevant estimates of costs associated with greenhouse gas emissions under a variety of regulatory scenarios. It is not possible to compare the results of all of these analyses directly, however, because the specific models and the key assumptions vary.

A. Cap-and-trade proposals

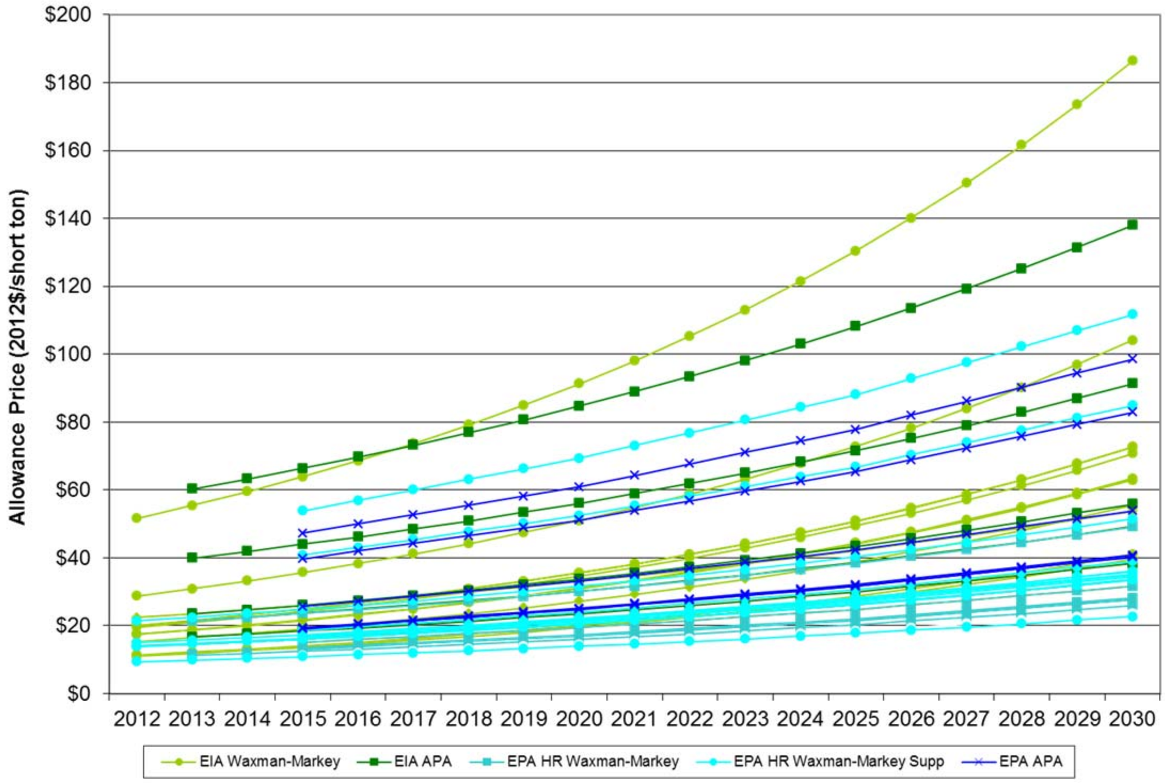
In the past decade, the expectation has been that action on climate change policy will occur at the Congressional level. Legislative proposals have largely taken the form of cap-and-trade programs, which would reduce greenhouse gas emissions through a federal cap, and would allow trading of allowances to promote reductions in GHG emissions where they are most economic. Legislative proposals and President Obama's stated target aim to reduce emissions by up to 80% from current levels by 2050.

Comprehensive climate legislation was passed in the House in the 111th Congress in the form of the American Clean Energy and Security Act of 2009 (ACES, also known as Waxman-Markey and HR 2454); however, the Senate ultimately did not take up climate legislation in that session. HR 2454 was a cap-and-trade program that would have required a 17% reduction in emissions from 2005 levels by 2020, and an 83% reduction by 2050. It was approved by the House of Representatives in June, 2009, but the Senate bill, known as the American Power Act of 2010 (APA, also known as Kerry-Lieberman), never came to a vote.

Figure 2 shows the results of EIA and EPA analyses of HR 2454 and APA. The chart shows the forecasted allowance prices in the central scenarios, as well as a range of sensitivities. Figure 3 shows these values as levelized prices for the time period 2015 to 2030.[10]

[10] Consistent with EIA and EPA modeling analyses, a 5% real discount rate was used in all levelization calculations.

Figure 2: Greenhouse gas allowance price projections for HR 2454 and APA 2010[11]



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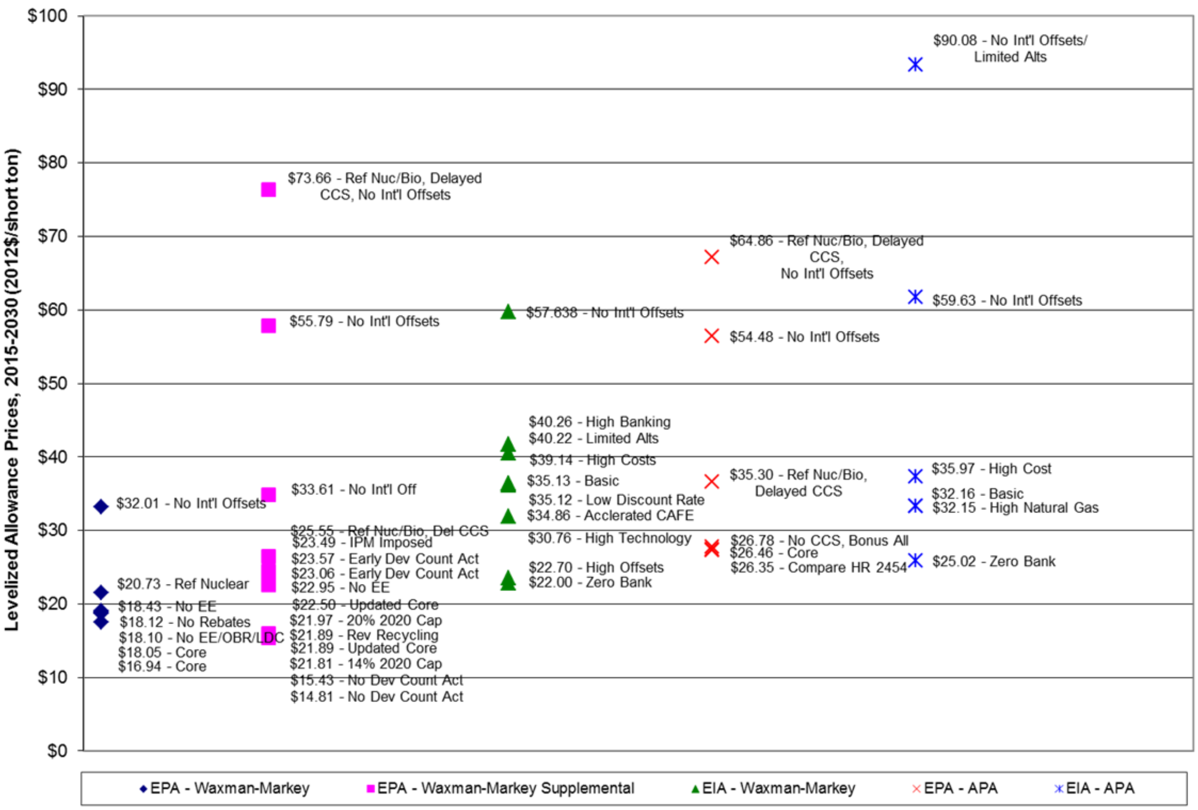
[11] Sources for Figure 2 include the following:
U.S. Energy Information Administration (EIA); *Energy Market and Economic Impacts of the American Power Act of 2010* (July 2010). Available at http://www.eia.gov/oiaf/servicerpt/kgl/index.html
EIA; *Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009* (August 2009). Available at http://www.eia.doe.gov/oiaf/servicerpt/hr2454/index.html
U.S. Environmental Protection Agency ("EPA"); *Analysis of the American Power Act of 2010 in the 111th Congress* (June 2010). Available at http://www.epa.gov/climatechange/Downloads/EPAactivities/EPA_APA_Analysis_6-14-10.pdf
EPA; *Supplemental EPA Analysis of the American Clean Energy and Security Act of 2009 (H.R. 2454)* (January 2010). Available at: Available at http://www.epa.gov/climatechange/economics/pdfs/HR2454_SupplementalAnalysis.pdf
EPA; *Analysis of the American Clean Energy and Security Act of 2009 (H.R. 2454)* (June 2009). Available at: http://www.epa.gov/climatechange/Downloads/EPAactivities/HR2454_Analysis.pdf

Figure 3: GHG allowance price projections for HR 2454 and APA 2010 - levelized 2015-2030



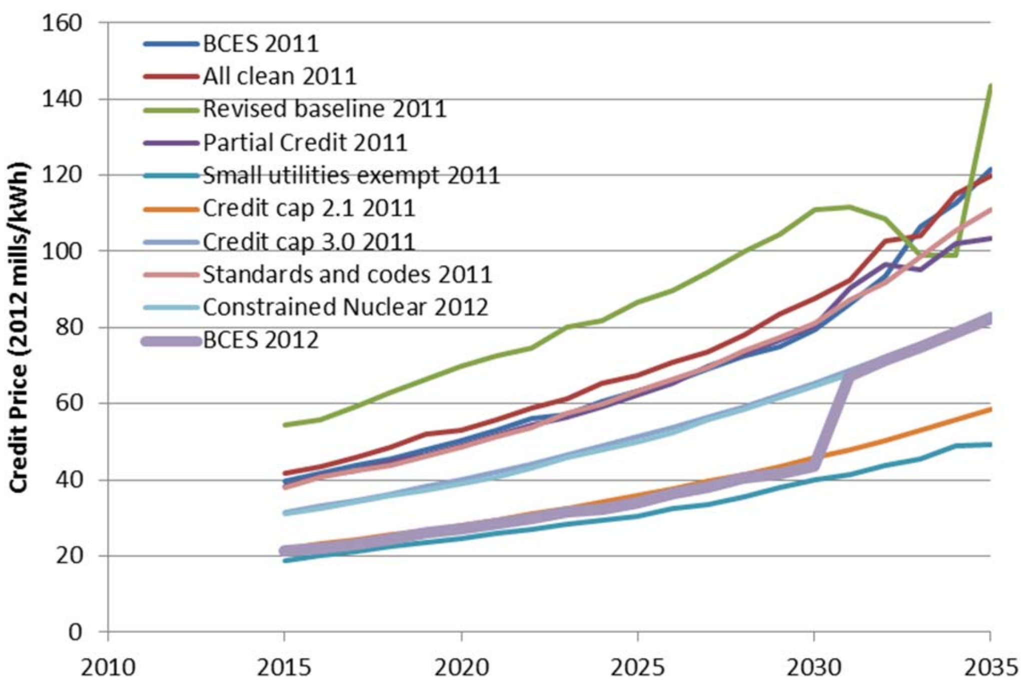
B. Clean Energy Standard

The 112th Congress chose not to revisit legislation establishing an economy-wide emissions cap, and instead focused on policies aimed at fostering technology innovation and developing renewable energy or clean energy standards. In March 2012, Senator Bingaman introduced the Clean Energy Standard Act of 2012 (S.2146), under which larger utilities would be required to meet a percentage of their sales with electric generation from sources that produce fewer greenhouse gas emissions than a conventional coal-fired power plant. All generation from wind, solar, geothermal, biomass, municipal solid waste, and landfill gas would earn a full CES credit, as would hydroelectric and nuclear facilities. Lower-carbon fossil facilities, such as natural gas and coal with carbon capture, would earn partial credits based on their CO_2 emissions. Generation owners would be required to hold credits equivalent to 24% of their sales beginning in 2015, and the CES requirement rises over time to 84% by 2035, creating demand for renewable energy and low-emissions technologies. The credits generated by these clean technologies would be tradable and have a value that would change depending on how costly the policy is to achieve. The Clean Energy Standard would apply to utilities with sales greater than 2 million MWh, and expand to include those with sales greater than 1 million MWh by 2025.

The EIA conducted analyses of a potential Clean Energy Standard in both 2011 and 2012.[12,13] All of these cases result in some level of increase in nuclear, gas, and renewable generation, typically at the expense of coal. The exact generation mix, as well as the resulting reduction in emissions, is highly dependent on both the technology costs and policy design. The resulting CES credit prices (Figure 4) vary widely, from 25 to 70 mills/kWh in 2020,[14] rising to 47 to 138 mills/kWh in 2035. The credit cap cases show a smaller rise in credit prices. When credit prices are capped at a specific value, clean energy deployment and emissions abatement is reduced.

An effective CO_2 allowance price can be calculated based on the fact that this policy gives existing gas combined cycle units 0.48 credits and existing coal units zero credits, and the emissions from an average gas unit are about 0.57 tCO_2/MWh and from an average coal unit 1.125 tCO_2/MWh.[15] For the BCES 2012 case, for example, this conversion would result in effective allowance prices of \$18.4/tCO_2 in 2015 and \$71.4/tCO_2 in 2035.

Figure 4: CES credit prices in EIA analyses of a U.S. Clean Energy Standard



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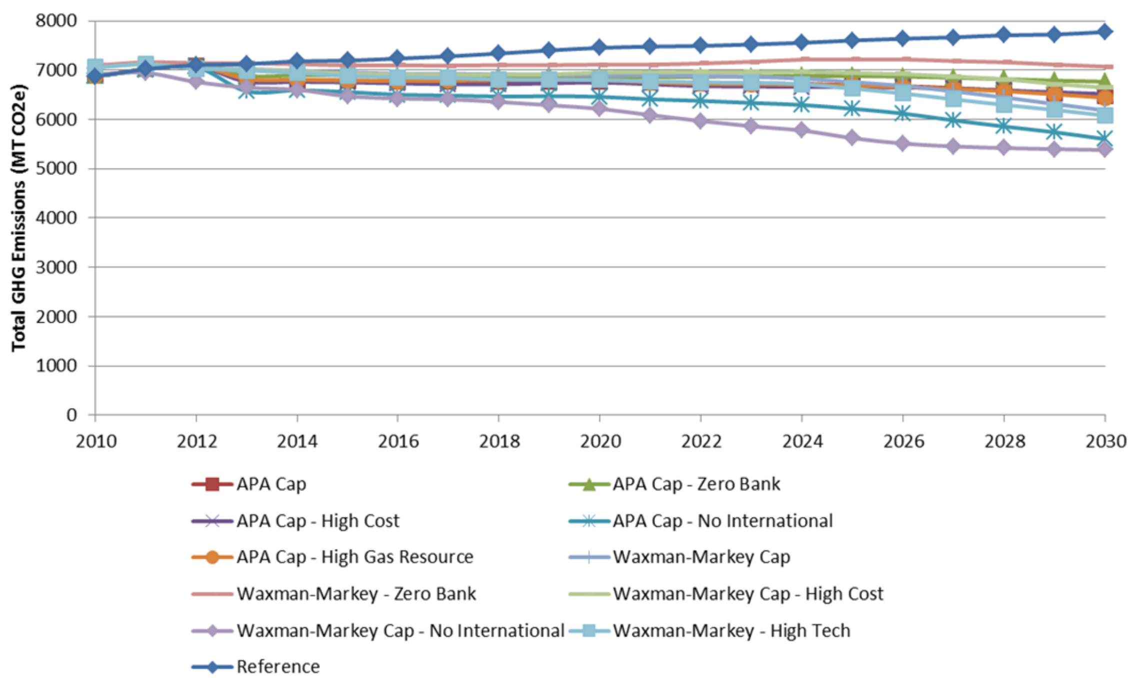
[12] US EIA. 2011. Analysis of Impacts of a Clean Energy Standard as requested by Chairman Bingaman. http://www.eia.gov/analysis/requests/ces_bingaman/.
[13] US EIA. 2012. Analysis of the Clean Energy Standard Act of 2012. http://www.eia.gov/analysis/requests/bces12/.
[14] A mill is one one-hundredth of a cent. Therefore, these CES prices in 2020 represent costs of 0.25 to 0.70 ¢/kWh, or \$2.5 to \$7/MWh.
[15] EPA Air Emissions Overview, Available at: http://www.epa.gov/cleanenergy/energy-and-you/affect/air-emissions.htm

6. Key Factors Affecting Allowance Price Projections

Dozens of analyses over the past several years have shown that there are a number of factors that affect projections of allowance prices under federal greenhouse gas regulation. Some of these factors derive from the details of policy design, while others pertain to the context in which a policy would be implemented.

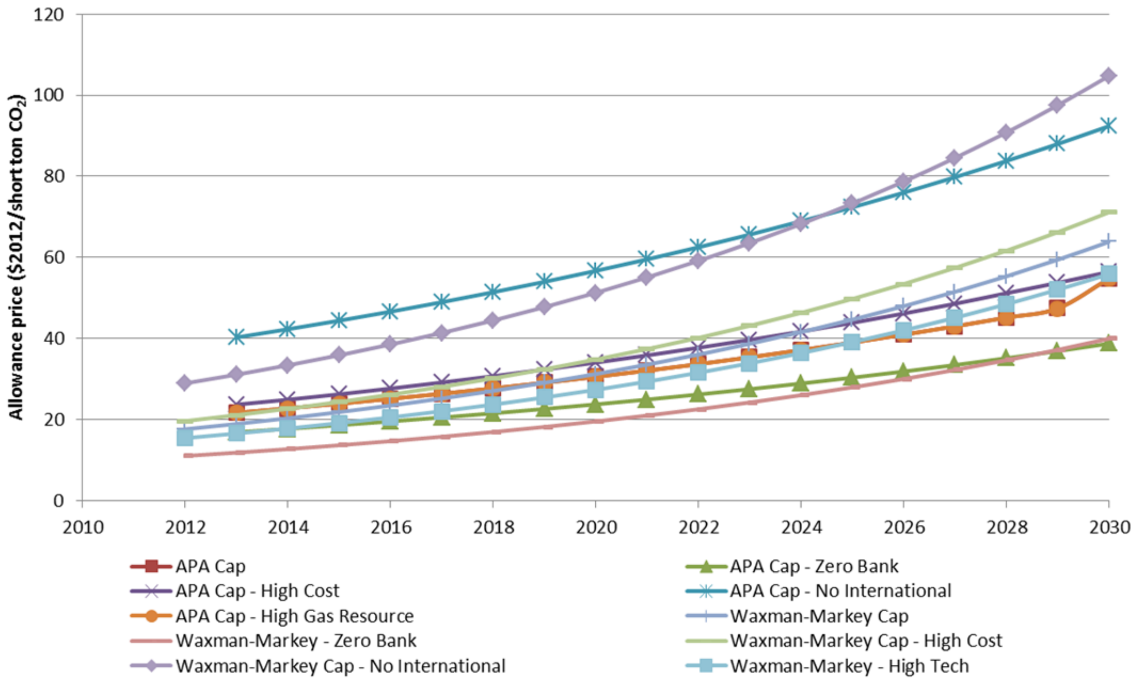
Factors in a forecast include: the base case emissions forecast; the reduction targets in each proposal; whether complementary policies such as aggressive investments in energy efficiency and renewable energy are implemented independent of the emissions allowance market; the policy implementation timeline; program flexibility regarding emissions offsets (perhaps including international offsets) and allowance banking; assumptions about technological progress; the presence or absence of a "safety valve" price; and treatment of emissions co-benefits. Figures 5 and 6 show the very significant ranges in emissions and allowance prices for the Waxman-Markey and APA federal cap-and-trade policies, as well as several associated sensitivities, including assumptions on banking, international offsets, technology cost and progress, and gas supply.

Figure 5: GHG Emissions in Waxman-Markey and APA policies and sensitivities[16]



[16] Sources for Figure 5 include the following:
U.S. Energy Information Administration (EIA); *Energy Market and Economic Impacts of the American Power Act of 2010* (July 2010). Available at http://www.eia.gov/oiaf/servicerpt/kgl/index.html
EIA; *Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009* (August 2009). Available at http://www.eia.doe.gov/oiaf/servicerpt/hr2454/index.html

Figure 6: Allowance prices in ACES and APA policies and sensitivities[17]



A. Assessing the potential impact of a natural gas supply increase

The recent shale gas boom has put substantial downward pressure on natural gas prices. Several factors could influence future gas prices, including the estimated ultimate recovery per well and regulations addressing the environmental impacts of hydraulic fracturing.[18] The impact of higher or lower gas prices on carbon prices is uncertain. In the near term, lower natural gas prices are likely to make emissions mitigation in the electric sector less expensive, as gas power plants can displace coal plants at lower cost. Conversely, as marginal electricity prices are frequently set by natural gas plants, lower gas prices will contribute to lower electricity prices, potentially increasing electricity consumption and associated emissions. Lower electricity prices also make it more difficult for renewable technologies with even lower emissions than gas to compete in electricity markets.

In 2010, Resources for the Future (RFF) used a version of the EIA's National Energy Modeling System (NEMS) energy model to test effects of increased gas supply from shale gas on the economics of energy policy. Under a moderate climate policy, the high gas scenario decreased the 2030 allowance price by less than 1%, from $61.1 to $60.8 per ton of CO_2.[19] The EIA showed

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[17] Sources for Figure 6 include the following:
U.S. Energy Information Administration (EIA); *Energy Market and Economic Impacts of the American Power Act of 2010* (July 2010). Available at http://www.eia.gov/oiaf/servicerpt/kgl/index.html
EIA; *Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009* (August 2009). Available at http://www.eia.doe.gov/oiaf/servicerpt/hr2454/index.html

[18] EIA (2012) "Projected natural gas prices depend on shale gas resource economics" http://www.eia.gov/todayinenergy/detail.cfm?id=7710

[19] Brown et al (2010). "Abundant Shale Gas Resources: Some Implications for Energy Policy". Available at: http://www.rff.org/RFF/Documents/RFF-BCK-Brownetal-ShaleGas.pdf

similar results in its analysis of the American Power Act: increased gas supply decreased the 2030 allowance price by less than 0.1%, from $49.80 to $49.78 per ton of CO_2.[20] In the policies studied by EIA and RFF, the result of an increased gas supply amounted to an inconsequential reduction in CO_2 prices. At this point it appears that, while a large shale gas resource may change how each policy is met, it is not a significant factor in the CO_2 cost that utilities should use for planning. Ongoing studies are expected to provide further insight into this issue.[21]

[20] EIA (2010) "Energy Market and Economic Impacts of the American Power Act of 2010". Available at: http://www.eia.gov/oiaf/servicerpt/kgl/index.html

[21] The Energy Modeling Forum will evaluate carbon constraints under cases of reference and high case supply levels in the EMF 26 study, which began in late 2011 and is ongoing (see http://emf.stanford.edu/research/emf_26/)

7. The U.S. Interagency Social Cost of Carbon

In 2010, the U.S. government began to use "social cost of carbon" values in an attempt to account for the damages resulting from climate change.[22] Four values for the social cost of carbon were initially provided by the Interagency Working Group on the Social Cost of Carbon, a group composed of members of the Department of Agriculture, Department of Commerce, Department of Energy, Environmental Protection Agency, and Department of Transportation, among others. This group was tasked with the development of a consistent value for the global societal benefits of climate change abatement. These values, $5, $21, $35, and $65 per metric tonne of CO_2 in 2007 dollars ($4.9, $20.7, $34.5, and $64.0 per ton in 2012 dollars), reflected three discount rates and one estimate of the high cost tail-end of the distribution of impacts. As of May 2012, these estimates have been used in at least 20 federal government rulemakings, for policies including fuel economy standards, industrial equipment efficiency, lighting standards, and air quality rules.[23]

The U.S. "social cost" values are the result of analysis using the DICE, PAGE, and FUND integrated assessment models. The combination of complex climate and economic systems with these reduced-form integrated assessment models leads to substantial uncertainties. In a 2012 paper, Ackerman and Stanton[24] explored the impact of specific assumptions used by the Interagency Working Group, and found values for the social cost of carbon ranging from the Working Group's level up to more than an order of magnitude greater. Despite limitations in the calculations for the social cost of carbon stemming from the choice of socio-economic scenarios, modeling of the physical climate system, and quantifying damages around the globe for hundreds of years into the future, this multi-agency effort represents an important initial attempt at incorporating consistent values for the benefits associated with CO_2 abatement in federal policy.

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[22] Interagency Working Group on the Social Cost of Carbon, U. S. G. (2010). Appendix 15a. Social cost of carbon for regulatory impact analysis under Executive Order 12866. In Final Rule Technical Support Document (TSD): Energy Efficiency Program for Commercial and Industrial Equipment: Small Electric Motors. U.S. Department of Energy. URL http://go.usa.gov/3fH.

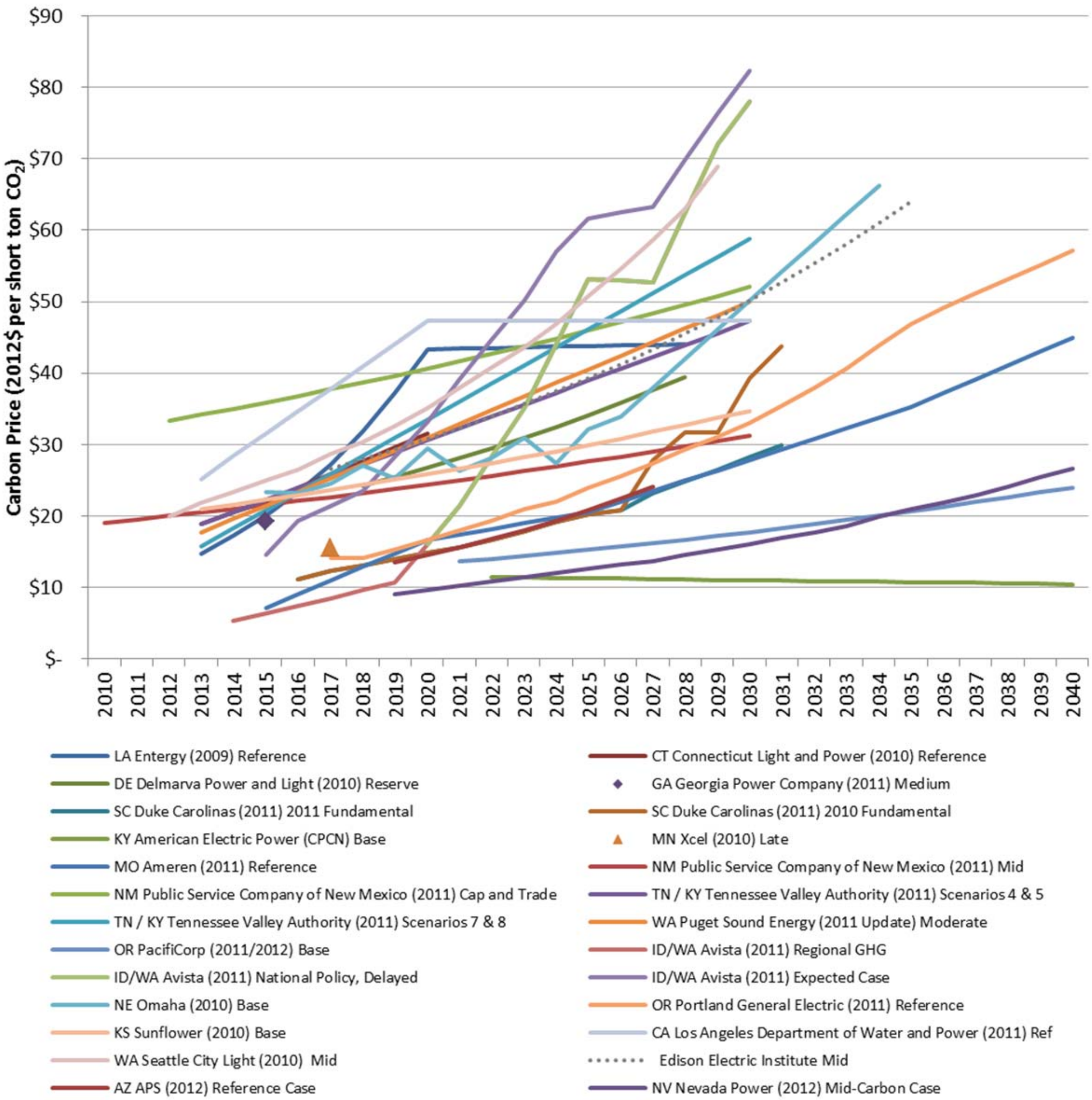
[23] Robert E. Kopp and Bryan K. Mignone (2012). The U.S. Government's Social Cost of Carbon Estimates after Their First Two Years: Pathways for Improvement. Economics: The Open-Access, Open-Assessment E-Journal, Vol. 6, 2012-15. http://dx.doi.org/10.5018/economics-ejournal.ja.2012-15

[24] Frank Ackerman and Elizabeth A. Stanton (2012). Climate Risks and Carbon Prices: Revising the Social Cost of Carbon. Economics: The Open-Access, Open-Assessment E-Journal, Vol. 6, 2012-10. http://dx.doi.org/10.5018/economics-ejournal.ja.2012-10

8. CO_2 Price Forecasts in Utility IRPs

A number of electric companies have included projections of costs associated with greenhouse gas emissions in their resource planning procedures. Figure 7 presents the mid-case values of publicly available forecasts used by utilities in resource planning over the past three years.

Figure 7: Utility Mid Case CO_2 Price Forecasts



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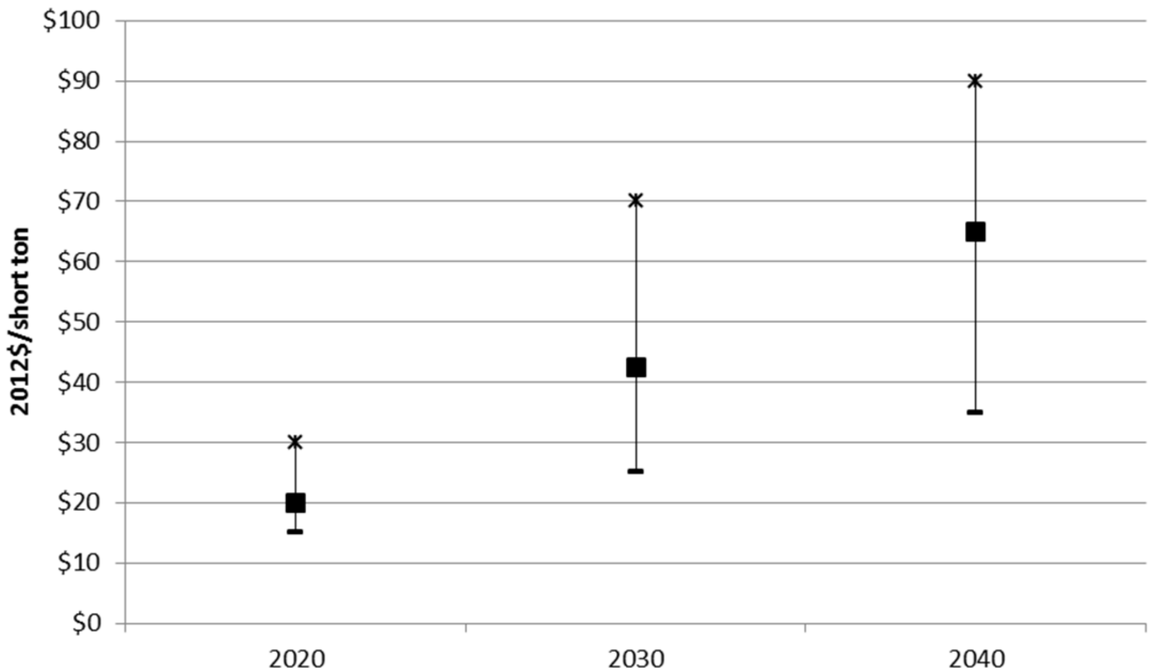
9. Recommended 2012 CO_2 Price Forecast

Based on analyses of the sources described in Sections 4 through 8, and relying on our own expert judgment, Synapse developed Low, Mid, and High case forecasts for CO_2 prices from 2020 to 2040. Figure 8 shows the range covered by the Synapse forecasts in three years: 2020, 2030, and 2040. These forecasts share the common assumption that a federal cap-and-trade policy will be passed sometime within the next five years, and will go into effect in 2020. All annual allowance prices and levelized values are reported in 2012 dollars per ton of carbon dioxide.[25]

Figure 8: Synapse 2012 Forecast Values



Each of the forecasts shown in Figure 8 represents a different appetite for reducing carbon, as described below.

- The Low case forecast starts at $15/ton in 2020, and increases to approximately $35/ton in 2040, representing a $23/ton levelized price over the period 2020-2040. This forecast represents a scenario in which Congress begins regulation of greenhouse gas emissions slowly—for example, by including a modest emissions cap, a safety valve price, or significant offset flexibility. This price forecast could also be realized through a series of complementary policies, such as an aggressive federal Renewable Portfolio Standard, substantial energy efficiency investment, and/or more stringent automobile CAFE mileage standards (in an economy-wide regulation scenario). Such complementary policies would

[25] All values in the Synapse Forecast are presented in 2012 dollars. Results from EIA and EPA modeling analyses were converted to 2012 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 2012 in its entirety, values used for conversion were taken from Q2 of each year. Consistent with EIA and EPA modeling analyses, a 5% real discount rate was used in all levelization calculations.

lead directly to a reduction in CO_2 emissions independent of federal cap-and-trade, and would thus lower the expected allowance prices associated with the achievement of any particular federally mandated goal.

- The Mid case forecast starts at $20/ton in 2020, and increases to approximately $65/ton in 2040, representing a $39/ton levelized price over the period 2020-2040. This forecast represents a scenario in which a federal cap-and-trade program is implemented with significant but reasonably achievable goals, likely in combination with some level of complementary policies to give some flexibility in meeting the reduction goals. These complementary policies would include renewables, energy efficiency, and transportation standards, as well as some level of allowance banking and offsets. Also assumed in the Mid case is some degree of technological learning, i.e. assuming that prices for emissions reductions technologies will decline as greater efficiencies are realized in their design and manufacture and as new technologies become available.
- The High case forecast starts at $30/ton in 2020, and increases to approximately $90/ton in 2040, representing a $59/ton levelized price over the period 2020-2040. This forecast is consistent with the occurrence of one or more factors 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.

Synapse's Low, Mid, and High case price projections for each year of the study period are presented in graphic and tabular form, below.

Figure 9: Synapse 2012 CO_2 Price Trajectories

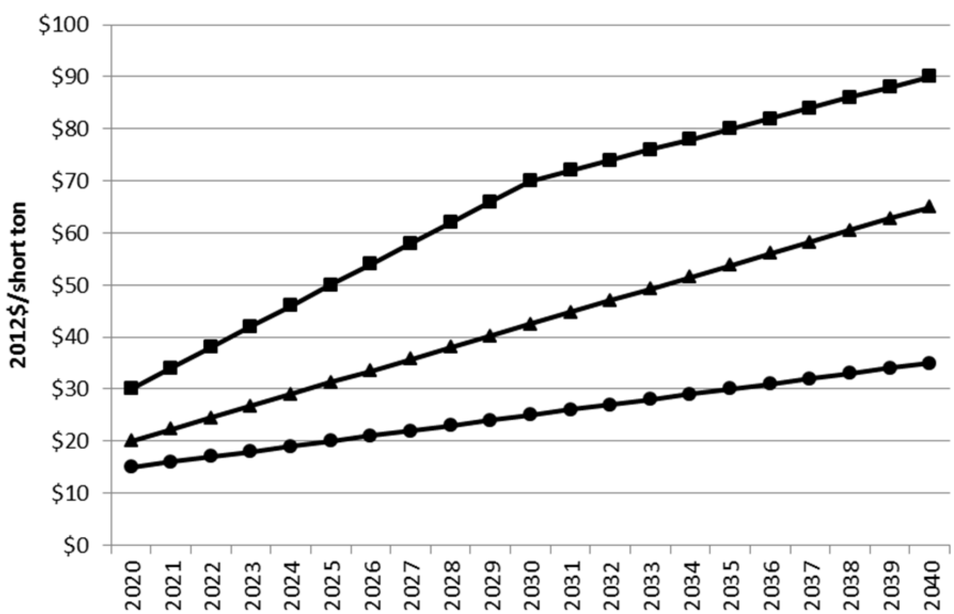


Table 1: Synapse 2012 CO_2 Allowance Price Projections (2012 dollars per ton CO_2)

Year	Low Case	Mid Case	High Case
2020	$15.00	$20.00	$30.00
2021	$16.00	$22.25	$34.00
2022	$17.00	$24.50	$38.00
2023	$18.00	$26.75	$42.00
2024	$19.00	$29.00	$46.00
2025	$20.00	$31.25	$50.00
2026	$21.00	$33.50	$54.00
2027	$22.00	$35.75	$58.00
2028	$23.00	$38.00	$62.00
2029	$24.00	$40.25	$66.00
2030	$25.00	$42.50	$70.00
2031	$26.00	$44.75	$72.00
2032	$27.00	$47.00	$74.00
2033	$28.00	$49.25	$76.00
2034	$29.00	$51.50	$78.00
2035	$30.00	$53.75	$80.00
2036	$31.00	$56.00	$82.00
2037	$32.00	$58.25	$84.00
2038	$33.00	$60.50	$86.00
2039	$34.00	$62.75	$88.00
2040	$35.00	$65.00	$90.00
Levelized	$23.24	$38.54	$59.38

The following charts compare the Synapse Mid, High, and Low case forecasts against various utility estimates. Data on utility estimates was collected from a wide range of available public Integrated Resource Plans (IRPs). We have excluded several IRPs with zero carbon prices or IRPs with no carbon price given, accounting for 9 of 65 collected.

Figure 10 shows 26 utility CO_2 price forecasts, with 2030 prices ranging from $10/t$CO_2$ to above $80/t$CO_2$. Due to the extended development period of many IRPs, some of these forecasts may not accurately reflect very recent years; a NM Public Service forecast, for example, begins in 2010, when there was no economy-wide CO_2 price. Nevertheless, IRPs do their best to represent accurate views of the future, in order to develop least-cost plans. The Synapse Mid forecast, beginning at $20/t$CO_2$ and rising to $65/t$CO_2$, lies well within the range of the mid-case forecasts shown here.

Figure 10: Synapse 2012 Mid forecast as compared to the Mid forecasts of various U.S. utilities (2010-2012)[26]

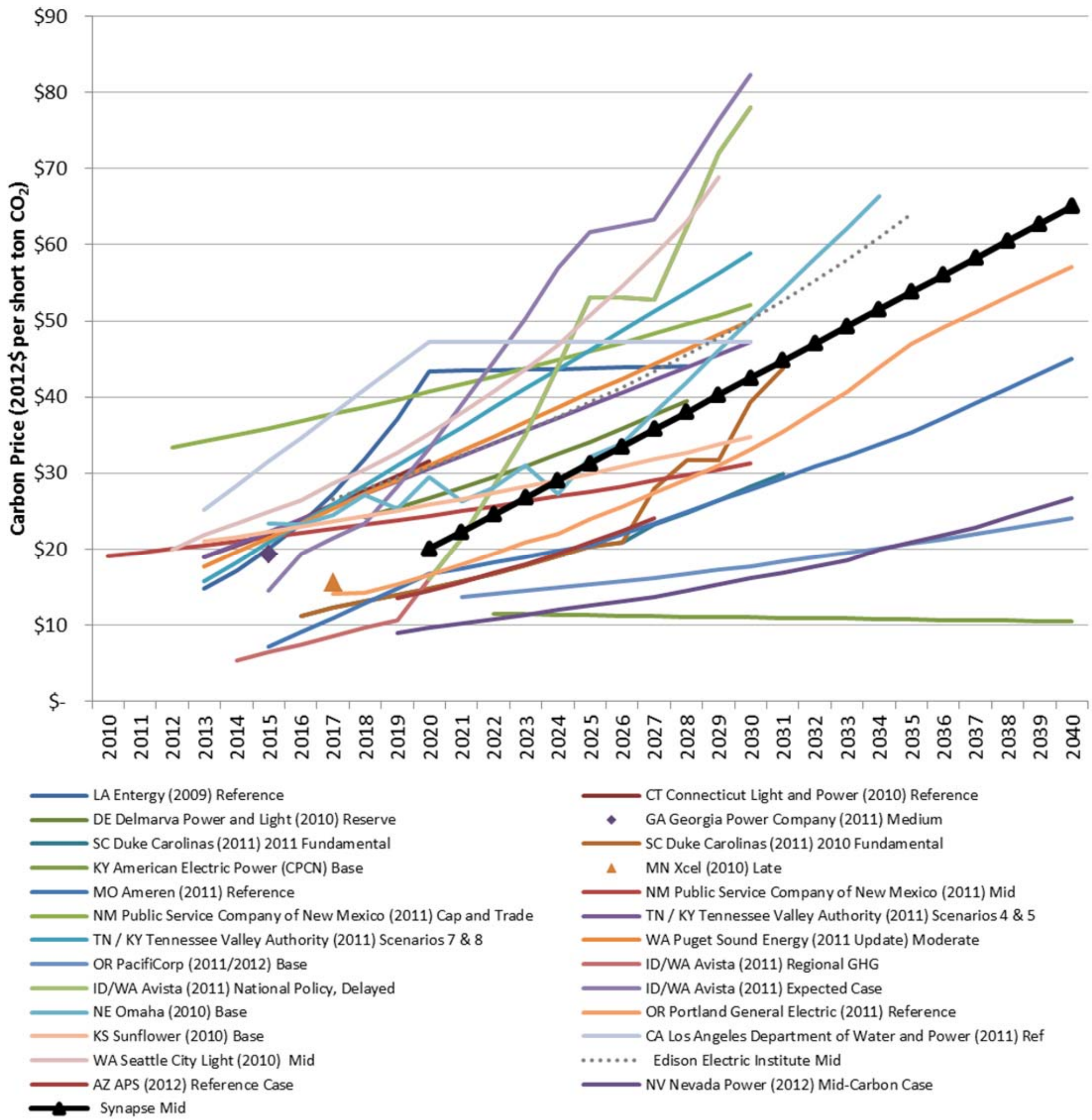


Figure 11 overlays the Synapse High case and the high case forecasts of many IRPs on top of the utility mid case forecasts shown in Figure 10 (now shaded in grey). Not all IRPs that provide mid-level forecasts also provide high forecasts. The high cases generally reflect a nearer-term policy start date, as well as a more rapid rate of increase in prices with time. The Synapse forecast starts later than most, and rises from $30/tCO_2$ in 2020 to $90/tCO_2$ in 2040.

[26] Legend given here is common to all subsequent utility price forecast charts. While scenario names may change, colors are constant for a given utility.

Figure 11: Synapse High forecast as compared to the High and Mid forecasts of various utilities (see legend in Figure 10)

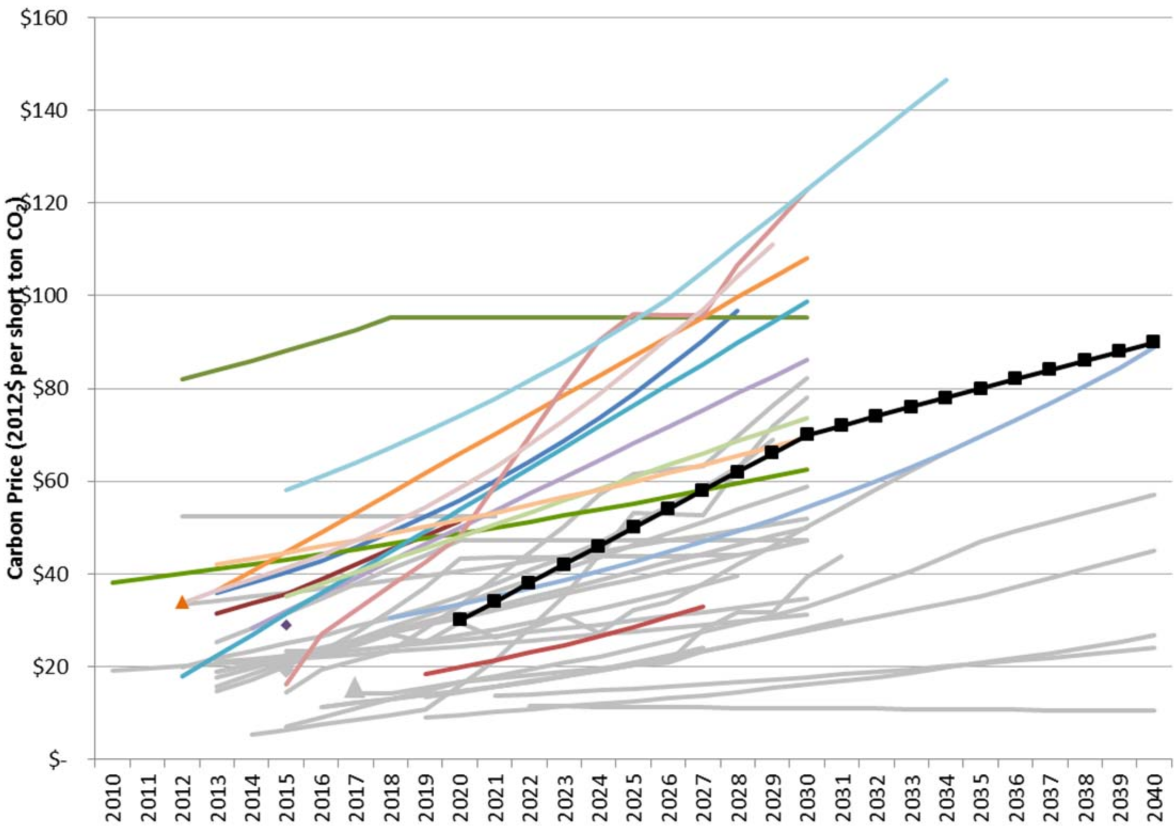


Figure 12 overlays the Synapse Low case and the low case forecasts of many IRPs on top of the utility mid case forecasts shown in Figure 10 (shaded in grey). The low case forecasts both start at substantially lower values (occasionally at zero values), and rise at slower rates. The Synapse forecast starts later than most and rises from $15/t$CO_2$ in 2020 to $35/t$CO_2$ in 2040.

Figure 12: Synapse Low forecast as compared to the Low and Mid forecasts of various utilities (see legend in Figure 10)

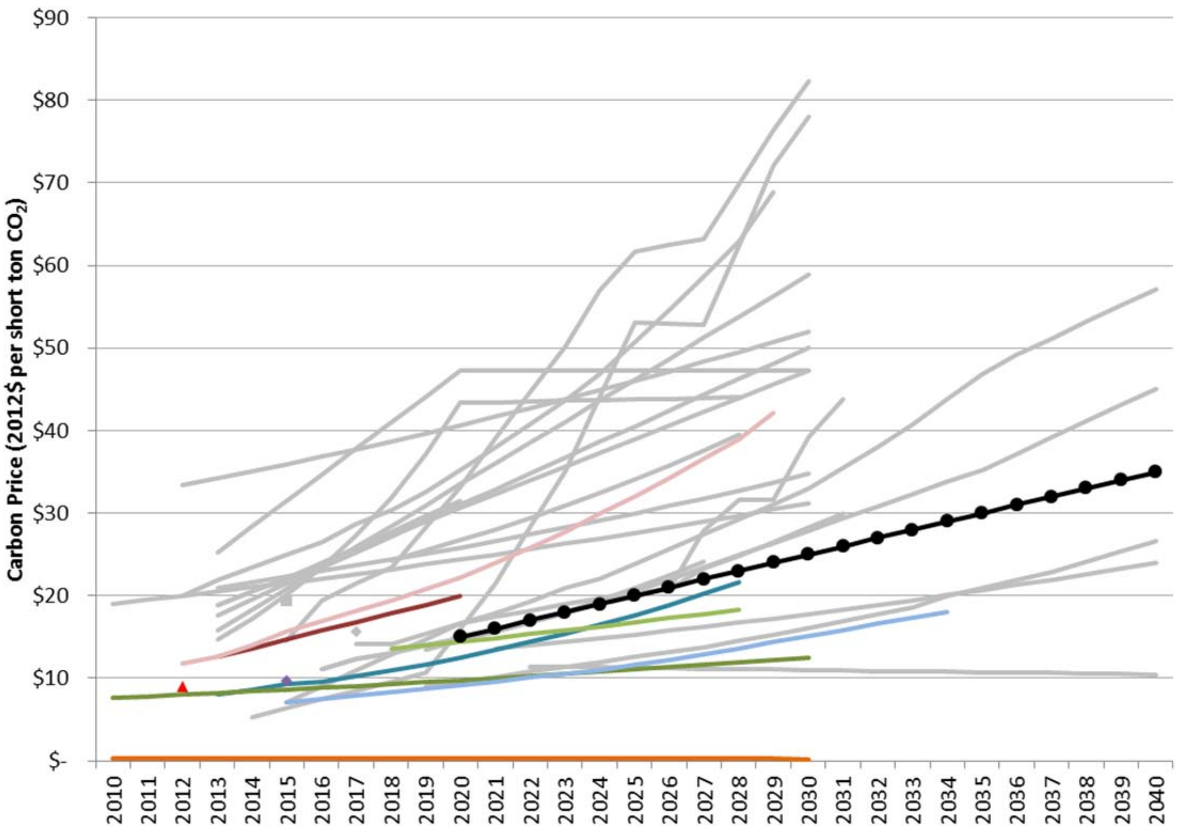


Figure 13 shows Synapse's Low, Mid, and High forecasts compared to the full range of utility forecasts shown above. The Synapse projections represent a plausible range of possible future costs. Using all three recommended price trajectories will facilitate sensitivity testing of long-term investment decisions in electric sector resource planning against likely federal climate policy scenarios.

Figure 13: Synapse forecasts compared to the range of utility forecasts

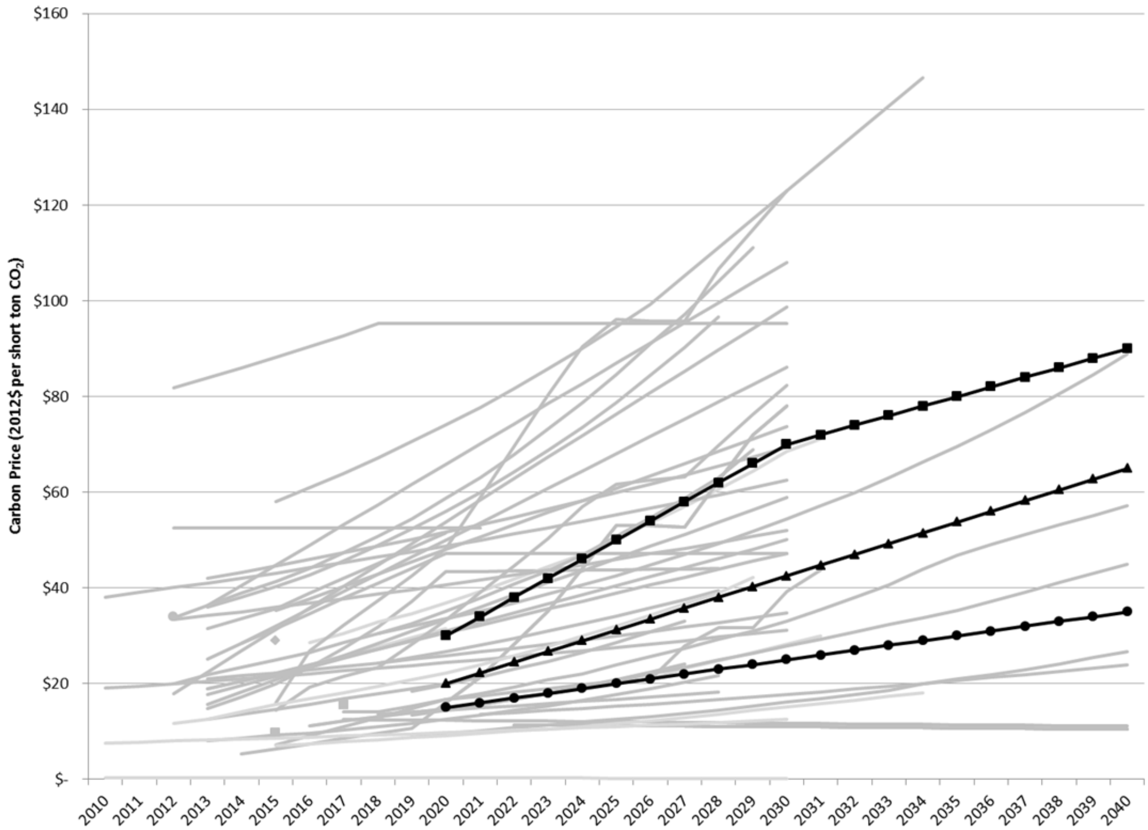
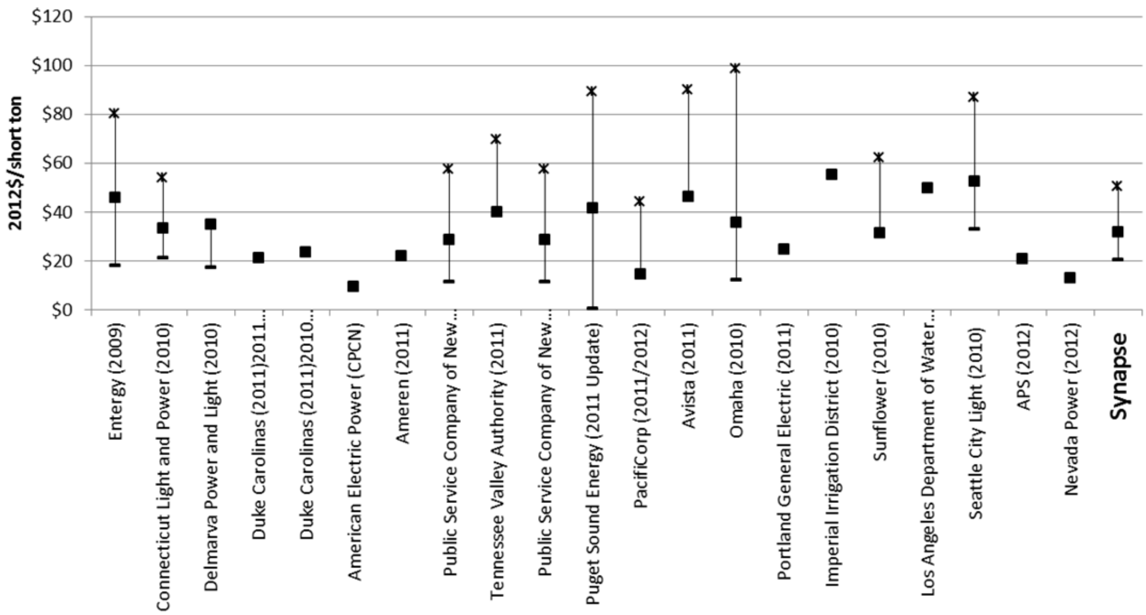


Figure 14 compares the levelized costs of Synapse's Low, Mid, and High cases to the levelized costs of utility estimates for 2020 through 2030, a period after the start and before the end of most forecasts. While levelizing between 2020 and 2030 results in different Synapse values than presented in Table 1 (where forecasts were levelized between 2020 and 2040), this approach allows for overlap and comparison with a broader range of utility estimates.

Figure 14: Levelized price of CO_2, 2020-2030, utilities and Synapse[27]



[27] All forecasts are levelized with a 5% discount rate based on CO_2 prices between 2020 and 2030. Forecasts with a price for only a single year excluded.

Appendix A: State and Regional GHG Initiatives

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.

This appendix provides a more thorough discussion of state and regional greenhouse gas (GHG) initiatives. Collectively, these initiatives suggest that momentum is building toward more comprehensive federal GHG action.

Cap-and-trade programs

The Northeast/Mid-Atlantic region and the state of California have developed, or are in the last stages of developing, greenhouse gas caps and allowance trading. [28]

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.[29] This is the first mandatory carbon trading program in the nation. Recently, allowance prices have been hitting the CO_2 price floor, as actual emissions are far below the budget of 188 mtons/year.

California: In 2006, the California Legislature passed the Global Warming Solutions Act (AB 32), which requires the state to reduce emissions of GHGs to 1990 levels by 2020. The California Air Resources Board (CARB) outlined more than a dozen measures to reduce carbon emissions to target levels in its 2008 *Scoping Plan*. Those measures include a renewable portfolio standard, a low carbon fuel standard, and a cap-and-trade program. Approximately 22.5% of the emissions reductions called for by AB 32 are estimated to occur under the cap-and-trade program. California will have the world's second largest carbon market, after the European Union's Emissions Trading System (EU ETS).

The first compliance period for the program will begin on January 1, 2013, and will cover electricity generators, carbon dioxide suppliers, large industrial sources, and petroleum and natural gas facilities emitting at least 25,000 metric tons of CO_2e per year. The second compliance period will run from 2015-2017, and the third compliance period will cover 2018-2020. During these periods, the cap-and-trade program will expand to cover suppliers of natural gas, distillate fuel oil, and liquefied petroleum gas if the combustion of their products would result in 25,000 metric tons of CO_2e or more.[30] The initial cap is set at 162.8 million metric tons of CO_2e and decreases by 2% annually through 2015. When additional sources are added, the cap increases to accommodate them, but then increases the percentage reductions in emissions to 3% in 2016, rising to 2.5% in 2020. The state plans to allocate the bulk of allowances for free in 2013, but will gradually auction

[28] The Midwest Greenhouse Gas Reduction Accord was developed in 2007. Though the agreement has not been formally suspended, the participating states are no longer pursuing it.
[29] 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
[30] §95812 (d)(1), page 48

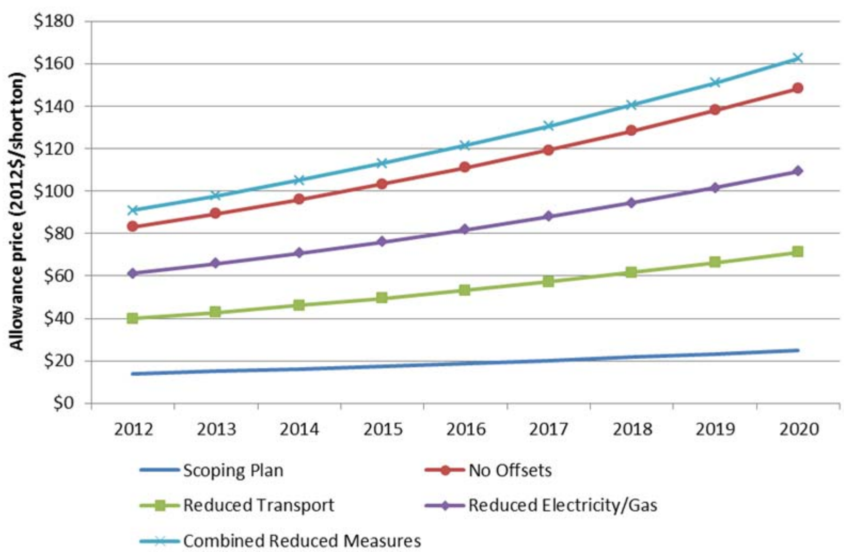
an increasing number of allowances between 2013 and 2020. Banking[31] and offsets[32] are both allowed under the California program.

The state of California has set a floor price for allowances beginning at $9.1/ton in 2013 ($10/metric tonne), and rising annually by 5% plus the rate of inflation.[33] In 2010 the Air Resources Board modeled the CO_2 allowance price trajectory that would enable reduction targets to be met under the following five cases:

1. Scoping Plan: Implements all of the measures contained in CARB's *Scoping Plan*
2. No Offsets: Does not allow offsets in the cap-and-trade program
3. Reduced Transport: Examines less effective implementation of the transportation-sector measures
4. Reduced Electricity/Gas: Examines less successful implementation of the electricity and natural gas measures
5. Combined Measures Reduced: Examines less successful implementation of transportation, electricity, and natural gas measures[34]

These five cases represent different scenarios of regulatory programs which, although different from the cap-and-trade program, can simultaneously help to achieve the goals of cap-and-trade. These regulatory measures are known as complementary policies. Figure A-1 shows the allowance price trajectories associated with those five cases.

Figure A-1: AB 32 Modeled Allowance Price Trajectories[35]



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[31] §95922 (a), page 151
[32] §95973 (a)(2)(C), page 156
[33] §95911 (b)(6), page 129
[34] California Air Resources Board. *Updated Economic Analysis of California's Climate Change Scoping Plan: Staff Report to the Air Resources Board.* March 24, 2010. Page ES-6.
[35] Id. Page 40.

As shown in Figure A-1, when the policies that are complementary to the cap-and-trade program are less effective, greater CO_2 reductions need to occur under the cap-and-trade program, and the allowance price is much higher. Similarly, the availability of offsets lowers the allowance price in the cap-and-trade program, as compliance with reduction targets can be met with offsets. This allows banking of allowances in the beginning of the program, which can keep allowance prices lower in later years.

California's first allowance auction is scheduled for November 14. A trial auction was completed on August 30, and more than 430 entities that will be regulated under the cap-and-trade program were invited to participate. CARB does not plan to release a settlement price, but on the date of the test auction, futures for December 2013 were trading at $14.77/ton, and forward contracts had sold for $14.77 and $14.82/ton.

State GHG reduction laws

Massachusetts: In 2008, the Massachusetts Global Warming Solutions Act was signed into law. In addition to the commitments to power sector emissions reductions associated with RGGI, this law committed Massachusetts to reduce statewide emissions to 10-25% below 1990 levels by 2020 and 80% below 1990 levels by 2050. Following the development of a comprehensive plan on steps to meet these goals, the 2020 target was set at 25% below 1990 levels.[36] Rather than put a price on carbon in the years before 2020, this plan will achieve a 25% reduction through a combination of federal, regional, and state level regulations applying to buildings, energy supply, transportation, and non-energy emissions.

Minnesota: In 2008, the Next Generation Energy Act was signed to reduce Minnesota emissions by 15% by 2015, 30% by 2025, and 80% by 2050.[37] While the law called for the development of an action plan that would make recommendations on a cap-and-trade system to meet these goals, the near-term goals will be met by a combination of an aggressive renewable portfolio standard and energy efficiency.

Connecticut: Also in 2008, the state of Connecticut passed its own Global Warming Solutions Act, establishing state level targets 10% below 1990 levels by 2020 and 80% below 2001 levels by 2050. In December 2010, the state released a report on mitigation options focused on regulatory mechanisms in addition to strengthening RGGI and reductions of non-CO_2 greenhouse gases.[38]

Renewable portfolio standards and other initiatives

A renewable portfolio standard (RPS) or renewable goal specifies that a minimum proportion of a utility's resource mix must be derived from renewable resources. These policies require electric utilities and other retail electric providers to supply a specified minimum amount—usually a percentage of total load served—with electricity from eligible resources. The standards range from modest to ambitious, and qualifying energy sources vary by state.

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[36] Massachusetts Clean Energy and Climate Plan for 2020, Available at: http://www.mass.gov/green/cleanenergyclimateplan

[37] Minnesota Statutes 2008 § 216B.241

[38] See http://www.ctclimatechange.com for further details on CT plans for emissions mitigation.

In general the goal of an RPS policy is to increase the development of renewable resources by creating a market demand. Increasing demand makes these technologies more economically competitive with other less expensive, but polluting, forms of electric generation. Many other policy objectives drive the adoption of an RPS or renewable goal, including climate change mitigation, job creation, energy security, and cleaner air.

The impact of an RPS on CO_2 emissions is dependent on factors such as:

- the types of resources that are eligible to meet the standard,
- the target level set by the RPS,
- the base quantity of electricity sales upon which the standard is set,
- how renewable energy credits (RECs) or attributes are tracked or counted,
- how RECs are assigned to different resources,
- banking, trading and borrowing of RECs,
- alternative compliance options, and
- coordination with other state and federal policies.

Currently, 29 US states have renewable portfolio standards. Eight others have renewable portfolio goals.

In addition, many states are pursuing other policy actions relating to reductions of GHGs. These policies include, but are not limited to: greenhouse gas inventories; greenhouse gas registries; climate action plans, greenhouse gas emissions targets, and emissions performance standards.

In the absence of a clear and comprehensive federal policy, many states have developed a broad array of emissions and energy related policies. For example, Massachusetts has a RPS of 15% in 2020 (rising to 25% in 2030), belongs to RGGI, requiring specific emissions reductions from power plants in the state, and has set in place aggressive energy efficiency targets through the 2008 Green Communities Act.

Hawaii, while not part of a regional climate initiative, has an even more aggressive RPS, seeking to achieve 40% renewable energy by 2030, coupled with an Energy Efficiency Portfolio Standard with the goal of reducing electricity use by 4,300 GWh by 2030. After 2013, 2% of electricity revenues in Hawaii will go towards a Public Benefit Fund, an independent entity tasked with promoting and incentivizing energy efficiency measures across the state.