SIERRA CLUB
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September 16, 2011

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SEP 19 2011

PUBLIC SERVICE COMMISSION

Jeff Derouen
Cases Nos. 2011-161, 162
Kentucky Public Service Commission
211 Sower Blvd.
Frankfort, KY 40601

Dear Mr. Derouen:

Our local counsel, Ed Zuger, was filing these when he ran into printer problems. I am, therefore, submitting one original and ten copies of the filing in color on his behalf.

Sincerely,

Andrea Sanchez
Program Assistant
Environmental Law Program

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

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SEP 19 2011

PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN AMENDED ENVIRONMENTAL COMPLIANCE PLAN, A REVISED SURCHARGE TO RECOVER COSTS, AND CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION OF NECESSARY ENVIRONMENTAL EQUIPMENT	)	**CASE NO. 2011-00162**

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	)	**CASE NO. 2011-00161**

JOINT NOTICE THAT DREW FOLEY, JANET OVERMAN, GREGG WAGNER, RICK CLEWETT, RAYMOND BARRY, SIERRA CLUB, THE NATURAL RESOURCES DEFENSE COUNCIL WILL FILE SUPPLEMENTAL TESTIMONY

On September 14, 2011, less than 48 hours before the Rick Clewett, Raymond Barry, Drew Foley, Janet Overman, Gregg Wagner, Sierra Club, and the Natural Resources Defense Counsel's (collectively "Environmental Intervenors") testimony was due in these dockets, Louisville Gas and Electric Company and Kentucky Utilities Company (collectively, the "Companies") served supplemental discovery responses. *See* Exhibit 1 (email from Kendrick Riggs to Kristin Henry), attached hereto. This supplemental discovery response was in reply to Staff Discovery Request 20(b), which was filed on July 12, 2011. This supplemental discovery response included a "Supplemental Analysis," which is an entirely new and substantively different analysis supporting the Companies' conclusions than was originally produced.

Serving this Supplemental Analysis less than 48 hours before testimony is due substantially prejudices the Environmental Intervenors. The direct testimonies that Environmental Intervenors prepared consist of a thorough and reasoned critique of the Companies original analysis and conclusions based on that analysis. These testimonies parse out different assumptions and/or inputs in the original analysis, discuss why those assumptions and/or inputs were unreasonable and re-run the Companies' Strategist model with the more reasonable assumptions and inputs to determine how it would alter the decision to retire or retrofit certain units. Environmental Intervenors then make recommendations to the Commission based on this analysis. It is simply impossible for Environmental Intervenors, in 48 hours, to re-run the Strategist Model with the new information contained in the Supplemental Analysis, which requires creating different model runs based on changes to individual or multiple parameters, and analyze how those new model runs impact the decision to retire or retrofit each unit in the Companies' fleet. While the Supplemental Analysis, actually endorses Environmental Intervenors' analysis in some ways, it essentially voids the analysis done by Environmental Intervenors, thus prejudicing our ability to participate these proceedings.

To ensure that Environmental Intervenors are not unduly prejudiced by the Companies' actions, Environmental Intervenors are going to file their direct testimony (which reflects a critique of the Companies' Original analysis) on September 16, 2011 and file supplemental testimony (which will discuss how the late-breaking information released by the Companies changes our original critique) on September 23, 2011. The Companies do not object to the Environmental Intervenors' plans to file supplemental testimony related to this updated information by September 23, 2011. *See* Exhibit 2 (email from Kendrick Riggs to Kristin Henry), attached hereto.

Respectfully submitted,

Kristin A. Henry

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Dated: September 16, 2011

CERTIFICATE OF SERVICE

I certify that I mailed a copy of this Petition For Full Intervention by first class mail on September 16, 2011 on the following:

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Kristin A. Henry

Kristin A. Henry
Counsel for Movants

KPSC: ECR Cases: Supplemental Response to KU KPSC-1 20(b) / LGE KPSC-1 18(b)
Riggs, Kendrick R.
to:
David C. Brown, David J. Barberie, Dennis G. Howard II, Edward George Zuger III, Faith B. Burns, Iris G. Skidmore, Kristin Henry, Kurt J. Boehm, Lawrence W. Cook, Leslye M. Bowman, Michael L. Kurtz, Quang D. Nguyen, Richard G. Raff, Robert A. Ganton, Scott E. Handley, Shannon Fisk, Tom FitzGerald
09/14/2011 01:54 PM
Cc:
"Sturgeon, Allyson"
Show Details

History: This message has been forwarded.

Dear Counsel,

Enclosed you will find the supplemental responses to KU KPSC-1 20(b) / LGE KPSC-1 18(b).

The original and 15 copies of each filing will be filed with the KPSC tomorrow. Hard copies will be mailed to all parties tomorrow as well.

Under seperate cover, I will send the confidential portion of the filing to those parties who have signed confidentiality agreements.

Regards,

Kendrick R. Riggs
Stoll Keenon Ogden PLLC
2000 PNC Plaza
500 West Jefferson Street
Louisville, Kentucky 40202
Direct Dial: (502) 560-4222
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Lexington | Louisville | Frankfort | Henderson | Morganfield | **skofirm.com**

From: Schroeder, Andrea [mailto:Andrea.Schroeder@lge-ku.com]
Sent: Wednesday, September 14, 2011 3:20 PM
To: Riggs, Kendrick R.; Crosby, W. Duncan; Sturgeon, Allyson
Cc: Conroy, Robert; Bellar, Lonnie; Braun, Monica; Henry, Joan; Elzy, Tammy
Subject: ECR Supplemental Response to KU KPSC-1 20(b) / LGE KPSC-1 18(b)
Importance: High

ATTORNEY-CLIENT COMMUNICATION
CONFIDENTIAL & PRIVILEGED

Kendrick,

Attached are PDFs of the PUBLIC versions of the supplemental response to KU KPSC-1 20(b) / LGE KPSC-1 18(b) that are ready to be provided electronically to the parties in the ECR Plan cases. Also attached are PDFs of the CONFIDENTIAL pages from the attachment and the Petition for Confidential Protection.

The original and 15 copies of each filing will be filed with the KPSC tomorrow, September 15. Hard copies will be sent by US Mail to all parties tomorrow (9/15).

Please let me know if you have any questions.

Thanks,
Andrea

Andrea Schroeder
LG&E and KU
State Regulation and Rates
502-627-3651
502-627-3213 (fax)

KPSC Case Nos. 2010-00161 and 2010-00162
Riggs, Kendrick R.
to:
Kristin Henry
09/15/2011 01:59 PM
Show Details

Kristen,

I am writing to confirm our phone conversation this afternoon.

I understand the Sierra Club and other environmental intervenors plan to file testimony tomorrow along with a motion for leave to file supplemental testimony by September 23, 2011 addressing the information provided in the supplemental responses to KU KPSC-1 20(b) / LGE KPSC-1 18(b), distributed in my email of September 14, 2011.

KU and LG&E do not object to the motion of the Sierra Club and other environmental intervenors to file supplemental testimony related to this updated information by next Friday, September 23, 2011. You have my permission to represent this position in your motion.

Regards,

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Lexington | Louisville | Frankfort | Henderson | Morganfield | **skofirm.com**

Commonwealth of Kentucky

RECEIVED
SEP 19 2011
PUBLIC SERVICE COMMISSION

Before the Public Service Commission

In the Matter of:

THE APPLICATION OF KENTUCKY UTILITIES COMPANY FOR CERTIFICATES OF PUBLIC CONVIENENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMETNAL SURCHARGE	)))))))	Case No. 2011-00161

In the Matter of:

THE APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR CERTIFICATES OF PUBLIC CONVIENENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMETNAL SURCHARGE.	)))))))	Case No. 2011-00162

Direct Testimony of Jeremy Fisher, Ph.D.

On Behalf of Sierra Club and Natural Resources Defense Council

PUBLIC VERSION

September 16, 2011

Table of Contents

1. Introduction and Qualifications

Q Please state your name, business address and position.

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

Q Please describe Synapse Energy Economics.

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

Q Please summarize your work experience and educational background.

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

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

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

My full curriculum vitae is attached as **Exhibit JIF-1.**

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of Sierra Club and the Natural Resources Defense Council.

Q Have you testified previously before the Kentucky Public Service Commission?

A No, I have not.

Q What is the purpose of your testimony?

A My testimony reviews Louisville Gas & Electric and Kentucky Utilities' (collectively "the Companies") modeling approach used to determine which units to retire and which to retrofit. I have assessed some of the key variables assumed by the Companies as inputs to their model and, with my colleague Ms. Wilson, have re-run the Companies' planning model and retire/retrofit spreadsheet model to determine if the analysis would change based on more mainstream assumptions. In this testimony, I will present the results of this re-analysis. My testimony demonstrates that the Companies have chosen a non-economic solution to meet impending environmental requirements for certain coal-fired units and assesses the risk that these units pose to the Companies and their ratepayers.

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

A In addition to Applications for Certificates of Public Convenience and Necessity (CPCN) and Approval of its 2011 Compliance Plan for Environmental Surcharge with their accompanying witness testimonies and appendices in these cases, I have reviewed the following documents and data prepared by the Companies:

- Integrated Resource Plan (IRP) ("2011 IRP") submitted April 21, 2011
- Selected input and output data from the Strategist Model as used by the Companies in this docket;
- The Companies' retire/retrofit spreadsheet analysis.

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

A Unfortunately, no, because the Companies filed a very late-breaking supplemental discovery response to Staff's Question 20(b), dated September 14, 2011 ("2011 Air Compliance Plan Supplemental Analysis"). This supplemental included an entirely new and substantively different set of analyses that are highly apropos to the testimony I am delivering today. As this information was received only 36 hours before my testimony was due, I have not had adequate time to assess the Companies' new analysis or its implications. I intend to file supplemental testimony that will review the Companies' latest changes.

Q Are there any other changes to this testimony that you intend on filing with the supplemental testimony?

A Yes. Coincident with the late filing by the Companies, my colleague Ms. Wilson and I discovered an error in our gas price input to the Strategist model. When we examined this error, we found that we had input prices into the model that were 1.6% to 8.3% too high. We have not had the opportunity to re-run the model as of this filing, but I believe that a corrected price will not substantively change our conclusions and may, in fact, reinforce our findings. We already intend to re-run the Strategiest model because the Companies included new natural gas price estimates in their supplemental discovery filed on September 14, 2011, so I will correct this seasonal price error with the model re-runs and address this issue with the supplemental testimony.

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:** Net Present Value Revenue Requirement of Installing Controls vs. Retiring and Replacing Capacity: Companies' Results and Re-Analysis Results
- **Exhibit JIF-3:** Natural gas price forecast comparisons.
- **Exhibit JIF-4:** 2011 Carbon Dioxide Price Forecast from Synapse Energy Economics, Inc.

2. Summary and Conclusions

Q **In your opinion and according to the documents you have reviewed, have the Companies adequately shown that the coal plants seeking environmental upgrades in these CPCN/ Environmental Surcharge dockets merit the capital expenditures requested?**

A No, they have not. While the Companies created a generally reasonable framework for the evaluation of their existing resources and resource requirements in the face of new and emerging environmental regulations, some of the inputs into this analysis are flawed; thus tainting the analysis and ultimately the decision to maintain and retrofit units of the existing coal fleet.

In this testimony, I will describe the environmental obligations facing the Companies and briefly summarize the Companies approach to their retire/retrofit decisions in the face of those regulations. I will then discuss large-scale flaws in the input assumptions and modeling framework, results of an analysis conducted by Synapse to re-evaluate the Companies' decisions under their same framework but with revised assumptions, and the serious doubt these results cast on the Companies' request for CPCN and environmental surcharges. I will show that several of the Companies' key assumptions are outliers and that simply using more reasonable assumptions results in a very different outcome. Finally, I will discuss additional concerns with the Companies' analysis and how these concerns might influence the ultimate retire/retrofit decisions.

Q Please describe the Companies' framework for the evaluation of existing resources and resource requirements.

A The Companies reasonably anticipate that existing and pending environmental regulations will require significant capital and operating expenditures at their coal fleet – expenses that could render units in the fleet non-economic to maintain. They therefore created a framework in which to evaluate the economic merit of each of their coal assets given these new expenses.

Briefly, the framework uses the Ventyx Strategist model to evaluate the net present value revenue requirement (NPVRR) of a series of retrofit and retirement scenarios. The initial baseline case estimates the NPVRR of retrofitting the entire fleet to meet environmental standards, and building new "optimal" capacity to meet requirements over a long analysis period. The Companies then estimate the NPVRR of this same scenario with the added assumption that their least economic coal unit retires in 2016, thereby avoiding the cost of expensive environmental retrofits. If the NPVRR of the case in which the unit is retired, the Companies find that it is more economic to retire the unit rather than retrofit it, and the unit's retirement is assumed in the baseline.

The Companies test each of their coal assets in this method sequentially, from the most expensive operating unit to the least. Each time a unit is found to be non-meritorious, the unit is assumed to be retired and taken out of the baseline.

The Companies use this modeling process to justify environmental upgrades at KU's units Brown 1-3 and Ghent 1-4, and LG&E's units Mill Creek 1-4 and Trimble County 1. The Companies also find that it is reasonable to retire, rather than retrofit, six of their least economic units: Tyrone 3, Green River 3 & 4, and Cane Run 4, 5, & 6.

Q **Which elements of this analysis have been incorrectly characterized?**

A The Companies have created a reasonable and transparent framework for analyzing the economic merit of retiring versus retrofitting their coal assets and have correctly characterized many of the costs faced by their fleet. However, I have found significant errors in the Companies' modeling assumptions and framework, which when corrected significantly change the outcome of this analysis, ultimately rendering at least two additional units (Brown 1 & 2) deeply non-economic and which cast serious doubt on the economic viability of another two units (Mill Creek 1 & 2).

It is my opinion that the Companies' analysis contains the following errors, each of which I will discuss in further detail later:

- **Natural gas price correction:** The assumed future price of natural gas is highly inflated by the Companies;
- **SCR cost:** The Companies have inappropriately dismissed the risk that some of its units may require selective catalytic reduction (SCR) to meet emissions limits for oxides of nitrogen (NO_x) under both promulgated and proposed ozone standards;
- **CO_2 price risk**: The Companies have assumed that there is no chance that the federal government will regulate carbon dioxide (CO_2) emissions anytime in the future, thereby exposing ratepayers to a very real financial risk;
- **Oversized replacement capacity:** The Companies assume that replacement generation is only available from three types of natural gas plants, ranging in size from 493 to 907 MW, forcing the model to only evaluate unduly expensive alternatives that present potentially non-optimal solutions.

- **Utility modeled in isolation:** The model used by the Companies assumes that they have no interactions with the Eastern Interconnection, which forces the model into unrealistic solutions.
- **Emergency generation purchases:** The model uses a very high cost for emergency generation with an unreasonably high frequency, resulting in very high costs with no apparent basis.
- **NO_x and SO_2 Prices:** The Companies have assumed that the trading price of NO_x and sulfur dioxide (SO_2) will diminish to zero in two years, in contradiction to EPA estimates; thereby denying the Companies the opportunity cost of avoiding these emissions through retirement or emissions controls.
- **Order of Retirement:** The Companies have chosen a semi-arbitrary order in which to test the retire/retrofit decision without regard to the impact that this order imposes on the modeled economic merit of each unit. Simply changing this order could result in a more optimal solution and retire/retrofit decisions.

Q Have you evaluated how the Companies' optimal solution might change if some of these assumptions are corrected?

A Yes, my colleague Ms. Rachel Wilson re-ran the Strategist model with the Companies' assumptions and then produced alternate outcomes by correcting the Companies natural gas price forecast and testing the impact of a mid-level CO_2 price forecast. I then used the Companies analysis worksheet to re-construct the decision the Companies might have made if they had:

1) used a mainstream natural gas price forecast,

2) evaluated the avoided cost of applying an SCR at several units, and

3) evaluated the risk of CO_2 regulation through a mid-level CO_2 price starting in 2018.

I calculated the outcomes of each correction both individually and in concert. I will discuss the background and results of these analyses in greater detail below. I have included these results in **Exhibit JIF-2**. The results of changing individual variables are shown in Boxes 3-5 and the results of changing multiple variables in the same scenario are shown in Boxes 6-8.

Q Did you fix all of the assumptions that you believe are flawed?

A I did not. Due to time constraints and limited information available at this time, we did not evaluate anticipated NO_x and SO_2 prices, the impact of including appropriately-sized capacity expansion options, the effect of including electricity purchases and sales outside of the LG&E/KU system as an option, or a more optimal retirement order.

Q Did you find any other errors in the Companies' analysis?

A Yes. In the Companies' analysis workbook,[1] the avoided cost of mitigating landfill waste or coal combustion residuals (CCR) appears to incorrectly reference the year after the year of interest. I have assumed that this is in error, and corrected the formula in my re-analysis, resulting in small benefits towards the retrofit decision in some scenarios ($0-$7 million). I have propagated this correction through the remainder of my re-analysis.

Q What was the outcome of your re-analysis?

A Under each of the three scenarios listed above, the relative economic merit of the coal units declines markedly. Using the Companies' retirement order framework but using *either* a more realistic gas price *or* evaluating the cost of SCR *or* utilizing a CO_2 price makes the retirement/retrofit decision of Brown 1 & 2 essentially a break-even decision ($2, $34, or $18 million NPVRR, respectively – found in **Exhibit JIF-2** Boxes 3-5). Using the corrected gas price in concert with anticipated costs of SCR strongly favors the retirement of Brown 1 & 2 (a loss of

[1] 20110517_LAK_2011IRPRetirementStudies_MC1-2CombinedFGD_Laye.xlsx

\$193 million NPVRR relative to the non-retirement option – found in **Exhibit JIF-2** Box 6).

While there are significant uncertainties associated with the future of CO_2 regulation, including shifting political climates and continued delays of meaningful national legislation, the possibility of CO_2 regulation poses a marked risk to the Companies' coal assets slated for retrofit. In concert with corrected gas prices and SCR risk, a preliminary assessment would suggest marked economic risk at all units except the Trimble County and Ghent 4 units. A more detailed analysis of this risk would evaluate the effects of a CO_2 price across the wider region electrical system, as well as ripple effects through other fuel costs.

Q What is your conclusion?

A I find that the decision to continue to invest in the Brown 1 & 2 units is not justified when the Companies' analysis is corrected and in particular when the reasonable risk of NO_x reductions through SCR is considered. Further, I believe that the economic merit of retrofitting Mill Creek units 1 & 2 is called into question in light of the new gas price and SCR risk. Both of these sets of units, and others, pose a significant economic liability for the Companies under a carbon constraint.

Q What is your recommendation to this commission?

A I recommend that the commission deny CPCN and environmental surcharge for the Brown 1 & 2 units and require the Companies to further analyze the financial risks posed in retrofitting Mill Creek 1 & 2 prior to granting CPCN on these units.

3. Environmental Regulations Faced by LG&E/KU

Q Is the Companies' coal fleet subject to federal laws protecting human health and the environment?

A Yes it is. The Companies' 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 rules directly affect the LG&E/KU coal fleet?

A There are a number of regulatory areas under the CAA that directly affect the Companies' coal fleet today and in the near future, including:

- The recently finalized Cross State Air Pollution Rule (CSAPR), limiting NO_x and SO_2 emissions that contribute to poor air quality in neighboring states;
- The proposed air toxics rule for utility steam generating units ("MACT"), designed to protect human health 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 SO_2 and the proposed strengthening of NAAQS for ozone (O_3), particulates ($PM_{2.5}$), and nitrogen dioxide (NO_2) designed to protect human health, reduce premature mortality, and reduce environmental harms from emissions.

Q Which Clean Water Act rules directly affect the LG&E/KU coal fleet?

A There are two CWA regulations, currently being finalized by the EPA, that the Companies should reasonably expect to affect the LG&E/KU coal fleet:

- the proposed cooling water intake structures rule, designed to protect fisheries and aquatic organisms from being trapped by cooling water screens, or uptake into cooling systems,
- and the expected effluent limitation guidelines, restricting toxic releases into waterways from steam power plant structures and effluent ponds.

Q Which Resource Conservation and Recovery Act rules directly affect the LG&E/KU coal fleet?

A The EPA is expected to finalize a rule regulating the disposal and storage of coal combustion residuals (CCR) including ash and other wastes to prevent toxic releases into ground and surface waters.

Q Have the Companies reasonably accounted for the impact of existing and proposed environmental regulations on its coal fleet?

A Yes, with a few critical exceptions.

Q Are there circumstances where you believe the Companies have correctly accounted for environmental requirements?

A There are. Assuming that the Companies are able to meet permitted emissions limits, I believe that they are correct in anticipating that all of the retrofits stipulated in KU projects 29, 34, & 35 (KU JNV-1) and LG&E projects 26 and 27 (LG&E JNV-1) would be needed to comply with environmental regulations in order to remain operational. While those controls are required if the units are going to continue to operate, they are *not necessarily sufficient.*

Q How will these projects help the Companies meet environmental requirements?

A After accounting for expected retirements, the Companies anticipate retrofitting their remaining partially-controlled units (Brown 1-3, Ghent 1-4, Mill Creek 1-4, and Trimble County 1) with flue gas desulfurization (FGD), which can presumably meet SO_2 compliance obligations under both CSAPR and SO_2 NAAQS. FGD are also considered a maximum achievable control technology (MACT) for the control of acid gases under the toxics rule, have ancillary benefits in mercury control also under the toxics rule, and benefit secondary particulate control under the $PM_{2.5}$ NAAQS. The combination of fabric filter baghouses with activated carbon injection (ACI) at all of these units is also generally considered MACT for the control of mercury emissions under the toxics rule.

The proposed coal waste rule may require conversion to dry storage from wet impoundments and is likely to require the lining and closure of unlined CCR impoundments. It appears that the Companies has taken this rule into account by estimating new ongoing landfill expenditures associated with its existing coal fleet.

While not stipulated in the projects listed previously, the Companies appear to have estimated the potential costs of effluent limitation guidelines in their forward modeling as well. As noted in a discovery response to the Environmental Groups, the Companies explain that the analysis "contains the revenue requirements associated with future capital costs for complying with effluent guidelines scheduled to be proposed in late 2012." [2] These costs are apparent in the Companies' retire/retrofit model.

Q How are the projects anticipated in this docket "required [but] ***not necessarily sufficient*****?"**

A What I mean is that while the Companies would need to implement these projects in order to keep the plants operational, these units will face additional environmental compliance costs on top of the ones considered. Critically, the Companies have failed to anticipate the impact of **both** the current (2008) and impending ground-level ozone NAAQS. Witness Revlett discusses SO_2 NAAQS and the Clean Air Transport Rule (CATR), the precursor to the current CSAPR rule, but makes no mention of the impending ozone NAAQS.

Q Why are the ozone NAAQS important in this analysis?

A It is widely believed that the ozone NAAQS are one of the most important EPA regulations in regards to the impact this standard could have on the existing coal fleet by requiring selective catalytic reduction (SCR) on numerous coal plants. It is my opinion that in failing to account for the cost of SCR, the Companies inappropriately expose customers to a known and likely environmental cost. The SCR cost risk affects several units that are requesting CPCN and environmental surcharges in these dockets, including Brown 1 & 2, Ghent 2, and Mill Creek 1 & 2.

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[2] Response to the Supplemental Requests for Information, August 18th 2011. Question 4

Q Have you examined the implications of SCR on the cost effectiveness of those units?

A I have. I'll describe this analysis and the results later in this testimony. However, suffice it to say that the cost of SCR is high enough to render a completely different retire/retrofit decision on the Brown 1 & 2 units and significantly impact the economics of the Mill Creek 1 & 2.

Q Are there other environmental regulations that the company has not taken into account in this analysis?

A Yes. I believe that current and pending EPA regulations on greenhouse gas emissions were insufficiently addressed in this CPCN, and I will be discussing a feasible remedy later in my testimony. In addition, the company has made no mention of the cooling water intake structures rule which could impose significant costs on units that use once-through cooling.

Q What is the cooling water intake structures 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. [33 U.S.C. § 1326.] 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.

Q Are there any plants in the Companies' fleet that would be subject to this rule?

A Large units that use once-through cooling are likely to violate the 125 MGD limit. According to information reported by the Companies to the US Department of Energy (DOE) Energy Information Administration (EIA) in 2009 (Form 860), the Tyrone 3, Cane Run 4-6 units, and Mill Creek 1 unit all use once-through cooling. The company plans to retire Tyrone 3 and the Cane Run units regardless, but the Mill Creek 1 unit would still be a concern for this rule.

According to independent research at the National Renewable Energy Laboratory (NREL),[3] once-through coal-fired units withdraw between 20,000 to 50,000 gallons per MWh of energy. According to information supplied by the company in discovery,[4] Mill Creek will output upwards of 2,200 GWh on an annual basis through the end of the analysis period. At this output, I would estimate that the unit would withdrawal between 120 and 300 MGD. I assume that the company has access to data to know if the unit would be subject to the more stringent entrainment guideline.

Q If Mill Creek 1 were subject to the entrainment guidelines of this cooling water rule, how might that affect their economic merit?

A The cooling water intake rule is designed to reduce impacts associated with once-through cooling. It is likely that the compliance mechanism for high withdrawal units will require retrofits to cooling towers as the "best technology available" where feasible. These cooling towers can be expensive. Using cost assumptions from a North American Reliability Council (NERC), I estimate the cost of a cooling tower for Mill Creek unit 1 at around $70 million. However, it is my

[3] National Renewable Energy Laboratory. March, 2011. A Review of Operational Water Consumption and Withdrawal Factors for Electricity Generating Technology. http://www.nrel.gov/docs/fy11osti/50900.pdf

[4] Confidential Attachment to Response to KU KPSC-1 Question No. 37, p3

opinion that it is incumbent on the Companies evaluate the risk that the unit will be subject to the rule and estimate the cost of compliance.

4. Synapse Retire/Retrofit Re-Analysis

Q How have the Companies determined which units to retrofit with environmental controls?

A The Companies have made the overarching assumption, appropriately, that they should consider the economic merit of retiring some coal units rather than retrofitting them to meet stringent environmental regulations. The Companies determined that all coal units operating after 2016 would have a broad set of environmental obligations (and therefore costs). From an economic perspective, it would be most efficient to operate the existing coal fleet up to the first high-cost compliance deadline, and then retire any units which are non-economic at that time.

To determine whether to retrofit or retire each unit in its fleets, the Companies examined the net present value revenue requirement (NPVRR) of maintaining and retrofitting each unit versus retiring the unit in the year 2016 and replacing the capacity with natural gas fired generation.

Q How do the Companies determine the NPVRR of each case?

A The Companies uses the Ventyx Strategist model to determine a reasonable build-out through 2040 under each of their test cases. The model is first run for a case in which all existing coal units are retrofited as required to remain operational (the "no retirements" case). The net production and new unit capital cost from this run is compared against a case in which a high-variable cost coal unit is retired in 2016. If the total NPVRR of the no-retirement case is higher than the retirement case (including avoided capital costs),[5] then the retirement case is considered more efficient and the Companies assumes that they will retire the unit.

[5] The retirement cases include the avoided costs of the environmental capital expenditures and fixed O&M, and a single-year cost adder to decommission retiring units.

Otherwise, the Companies assume that they will retrofit the unit under consideration. If the unit is retired, the new base case (by which the next unit is tested) includes the previous unit's retirement.

Q Were you able to replicate the Companies' modeling results?

A We were. Synapse obtained the Strategist model inputs from the Companies and the Companies' spreadsheet-based analysis. My colleague Ms. Wilson licensed an identical build of the Strategist model as used by the Companies from Ventyx and re-ran the model with the same inputs. We were able to obtain the same results as the Companies.

The Companies results are shown in **Exhibit JIF-1**, Box 1. These values are also found in the Companies' direct testimony in Exhibit CRS-1, Table 2, in the column entitled "Difference (A)-(B)."[6] These values are the NPVRR difference, relative to a no retirement scenario of retiring each unit in a cumulative fashion as described above and in the Companies' direct testimony.

The Companies find that it is economically efficient to retire the units with negative NPVRR values relative to a "no retirement" scenario. These units include Tyrone 3, Green River 3 & 4, and Cane Run 4 & 5. The Companies determined that, although the NPVRR value is marginally above zero, retrofitting Cane Run 6 presents too high of a risk and has opted to retire this unit as well.

In **Exhibit JIF-2** Box 2, we have corrected a formula error in the Companies analysis that references an incorrect year, as described in the summary of this testimony. This correction is maintained through the re-analysis results, and favors the retrofit decision by $0-$7 million.

Q Does the Companies analysis have any flaws?

A As I identified in the summary section, the analysis had a number of flaws, some of which are unquestionably significant enough to completely change the analysis

[6] As noted in a commission staff discovery request, this column should be labeled "Difference (B) – (A)"

outcome. Therefore, it was important to conduct a re-analysis with corrected assumptions to estimate how retire/retrofit decisions would change.

Q How did you perform a re-analysis?

A As noted above, we used the Companies' build of Strategist and model inputs provided in discovery (Environmental Groups DR 3) to re-run the analysis. We used the Companies broad arching assumption of the order in which units are tested for economic merit, but *for internal consistency with the Companies, did not pull any additional units out of the analysis if they were deemed non-economic.*

The re-analysis examined three fundamental aspects of the Companies' analysis:

- **First,** we corrected the Companies' natural gas price forecast to reflect a more mainstream estimate;
- **Second,** we added the Companies estimated capital and operating costs of SCR at the Brown 1 & 2, Ghent 2, and Mill Creek 1 & 2 units into the avoided cost analysis;
- **Third,** we tested the impact of a mid-range CO_2 price on the decision to retire or retrofit.

We examined each of these adjustments *independently* and in concert.

The method and justification for each of these changes is described in detail in the sections below.

5. Gas Price Correction

Q Is the Companies' gas price forecast consistent with forecasts?

A No. In recent years, the price of natural gas has dropped dramatically with the discovery of new plays and, while there is continued uncertainty about the future of natural gas prices, most analysts believe that the price will rise slowly over the next two decades. In contrast, the Companies estimate that the price will XXXXX in a decade. The Companies' forecast as used in the Strategist model falls well-above other analysts' estimates and rises more rapidly than others expect.

In Figure 1, below (and in **Exhibit JIF-3**, page 1), we show the Companies' estimate of the Henry Hub (HH) price in red triangles, [7] and a variety of publicly available forecasts for the HH price,[8, 9, 10,11,12,13,14,15] as well as our recommended correction in black circles.

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[7] Found in Attachment to Response to SC/NRDC Production of Documents Question No. 16. *2011 Air Compliance Plan Sensitivity Analysis. July 2011*

[8] US DOE Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2010 Reference Case

[9] US DOE Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2011 Reference Case

[10] Northwest Power and Conservation Council (NWPCC), August 2011. Update to Council's Forecast of Fuel Prices (pg 6-7)

[11] Globex Futures from CME Group Henry Hub Natural Gas Futures, Trade Date 9/12/2011 (2011-2023) Settlement Price. http://www.cmegroup.com/trading/energy/natural-gas/natural-gas_quotes_globex.html

[12] Eastern Interconnection Planning Collaborative (EIPC). Working Draft of MRN-NEEM Modeling Assumptions and Data Sources for EIPC Capacity Expansion Modeling. December 22, 2010. Charles River Associates. Hi Gas Henry Hub Price.

[13] Navigant Consulting, August 2010. Market Analysis for Sabine Pass LNG Export Project. http://www.navigant.com/~/media/Site/Insights/Energy/Cheniere_LNG_Export_Report_Energy.ashx

[14] RGGI and EPA prices extracted from EIPC Fuel and Emission Prices Subteam January 12 Report.

[15] Avoided Energy Supply Component (AESC) Study Group, July 2011. Avoided Energy Supply Costs in New England: 2011 Report. http://www.synapse-energy.com/Downloads/SynapseReport.2011-07.AESC.AESC-Study-2011.11-014.pdf

[CONFIDENTIAL FIGURE REMOVED]

Figure 1. Henry Hub Natural Gas Price Comparisons: Companies Estimate, Other Analyst Forecasts, and Re-Analysis Forecast (AESC 2011)

Q Which natural gas price forecast did you use in the re-analysis?

In our re-analysis, we have used an HH forecast from the Avoided Energy Supply Component (AESC) Study Group in 2011. The AESC report is sponsored by a group of electric utilities, gas utilities, and other efficiency program administrators throughout New England and was written by consultants at Synapse Energy Economics, Inc, as well as other experts. The report reviews gas price forecasts and the underlying fundamentals, including changes in supply, and ultimately settles on a gas price forecast near the midline of AEO's 2010 and 2011 forecasts. It is my understanding that this forecast represents the outcome of both expert analysis, as well as consensus amongst a large number of utilities and service providers.

The delivered price of gas for electric utilities has an adder or differential above the HH price. In this case, we have estimated the adder used by the Companies in their modeling by comparing the Companies' HH price forecast to the input in the Strategist model (shown in red in **Figure 2,** below and in **Exhibit JIF-3**, page 2).

We used this same adder [CONFIDENTIAL MATERIAL REMOVED] through 2025, and then held it constant thereafter. The corrected re-analysis gas price is in black in Figure 2, below.

[CONFIDENTIAL FIGURE REMOVED]

Figure 2 Burner Tip Natural Gas Price Comparisons: Companies' Estimate and Re-Analysis Forecast (AESC 2011) plus KY Delivery Adder

As I noted in the introduction to my testimony, we recently discovered an error in the way we translated our HH estimate into the Strategist model. As a result, the costs we input into the model were anywhere from 1.6% to 8.3% too high. We have not had the opportunity to re-run the Strategist model since discovering this error, but we do not anticipate that correcting this error will change our findings. We will plan on submitting a revised answer in supplemental testimony.

Q Did adjusting the gas price forecast make a difference in the re-analysis of the Companies' results?

A Yes. Simply correcting the natural gas price forecast to a reasonable mid-line estimate made the relative benefit of maintaining any of the coal units diminish significantly, but is particularly notable at Brown 1 & 2. As shown in **Exhibit JIF-2** in Box 3, the NPVRR benefit of maintaining Brown 1 & 2 falls to $2 million, below the threshold at which the Companies decided to retire Cane Run 6 and well within the region of model noise.

In other words, the re-analysis with a corrected gas price would suggest that Brown 1 &2 are very high risk for continued operation and, according to the Companies' own stated risk preference, they should retire these units.

6. Costs for SCR at Brown 1 & 2, Ghent 2, and Mill Creek 1 & 2

Q In the summary, you stated that the Companies has not anticipated the impact of the impending ground-level ozone NAAQS. Does this shortcoming have an impact in the Companies assessment of the retire/retrofit decision?

A Absolutely. By ignoring the impact of both current and proposed ozone NAAQS, the Companies ignore the high cost of mitigating ozone; costs that the companies reasonably face in the near future. One of the most effective mechanisms for reducing ozone pollution is by controlling NO_x emissions at stationary sources through installing Selective Catalytic Reduction (SCR) technology. This technology has a high price tag, and, if required, could feasibly alter the retire/retrofit decision at some of the Companies' coal-fired units .

Q What are the ozone NAAQS?

A EPA promulgates NAAQS pursuant to the authority granted by Clean Air Act § 109 (42 U.S.C. §7409). EPA sets primary NAAQS to protect public health and secondary NAAQS protect public welfare. The NAAQS are supposed to be evaluated and revised, if necessary to protect public health and welfare, at five year intervals. New standards for ozone (and other criteria pollutants) will trigger the process for designating areas as either in "attainment" or "nonattainment" with the new standards. In nonattainment areas, sources must *automatically* comply with emission reduction requirements known as "Reasonably Available Control Technology" (RACT), and new sources, including major modifications at existing sources, must comply with very strict emissions reductions consistent with "lowest achievable emissions reductions" (LAER), as well as obtain emission offsets.

Q Are Kentucky counties likely to be in "nonattainment" with respect to the ozone NAAQS?

A The current ozone standard, promulgated on March 12, 2008 (73 Fed. Reg. 16,436 (March 27, 2008)) set the ozone NAAQS at 0.075 parts per million (ppm). According to estimates released in January 6, 2010, thirteen counties in Kentucky violated the current standard between 2006-2008.[16]

The EPA proposed a stringent new ozone standard on January 19, 2010 (75 Fed. Reg. 2,938 (Jan. 19, 2010)), reducing the standard from 0.075 ppm to between 0.060 and 0.070 ppm, a move which could cause 25 counties in Kentucky to violate the new standard, according to 2006-2008 data.[17]

Q Will EPA promulgate the new ozone NAAQS this year?

A Although EPA was due to finalize the new ozone NAAQS by July 29, 2011, this was pushed back by an executive review. On September 9th, 2011, the EPA announced that it was holding off on the promulgation of this rule until 2013. This delay will likely face a court challenge.

It is my opinion that the rule will be delayed by two years, either due to the impending legal obstacles or by administrative fiat, but must ultimately EPA will promulgate the new ozone NAAQS due to the EPA's legal responsibility to protect public health.

Q **Is this a reasonable opinion given EPA's recent action?**

Yes. The law unequivocally requires EPA to review the NAAQS standards every five years to ensure that they provide adequate health and environmental protection, and to update those standards as necessary to protect public health. EPA is set to review the ozone NAAQS standard in 2013. If EPA has not promulgated a standard by then, it must certainly do so then as the Clean Air

[16] US EPA. 2010. Counties Violating the Primary Ground-level Ozone Standard, 2006-2008. http://www.epa.gov/glo/pdfs/CountyPrimaryOzoneLevels0608.pdf

[17] US EPA. 2010. Counties Violating the Primary Ground-level Ozone Standard, 2006-2008. http://www.epa.gov/glo/pdfs/CountyPrimaryOzoneLevels0608.pdf

Scientific Advisory Committee found that a standard between 0.060 to 0.070 ppm is absolutely needed to protect public health. The CAA does not authorize EPA to consider the cost of achieving a NAAQS in establishing the standard. Therefore, my opinion that EPA will promulgate a new ozone NAAQS in the near future is quite reasonable.

Q. How will a new ozone NAAQS impact the LG&E/KU fleet?

Of particular importance to the LG&E/KU fleet, the four coal plants which are anticipated to continue operation (Ghent, Trimble County, Mill Creek, and Brown) are all either in, or immediately adjacent to counties which violate even the least rigorous of the proposed standards (see Figure 1, below)

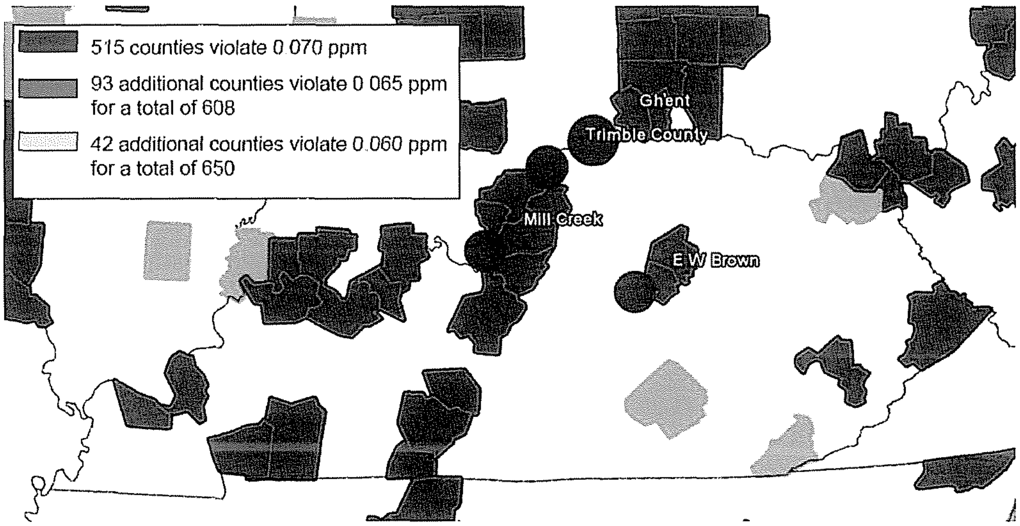

Figure 3. Counties With Monitors Violating Primary 8-hour Ground-level Ozone Standards 0.060 - 0.070 parts per million (based on 2006-2008 Air Quality Data). Kentucky detail, Modified from EPA.[18]

While there is no guarantee that these counties will still violate the standard when the rule is promulgated, these regions are so far out of compliance that it will require significant reductions to meet the more stringent limit. Also, it is often the case that air quality managers find the most cost effective air quality reductions by controlling large, uncontrolled stationary sources – such as coal plants.

[18] US EPA, 2010. http://www.epa.gov/glo/pdfs/20100104maps.pdf

Ozone is a secondary pollutant formed from NO_x emissions and other ambient volatile compounds. One of the most cost-effective methods of reducing ozone pollution by requiring large-scale NO_x reductions at large power plants through the implementation of SCR.

I believe that when EPA implements this NAAQS, the operational plants that do not have SCR will require this control technology (Brown 1 & 2, Ghent 2, and Mill Creek 1 &2), to meet local attainment.

Q What action should the Companies take in regards to the ozone NAAQS?

A The Companies should evaluate the costs and reasonable risk of SCR at these units in their forward modeling.

Q Have the Companies evaluated the cost of SCR at the uncontrolled units?

A In April 2010, the Companies comprehensively examined the environmental regulations faced by their coal fleet, including that of the ozone NAAQS. In the E.On US Fleetwide Assessment (attached to Exhibit JNV-2 as Appendix A, the file "Complete Appendix A" therein), the Companies notes both ozone revised NAAQS as well as new NO_x NAAQS standards impending shortly that could impact the fleet. Indeed, in regards to Brown 1 &2, for example, the Companies stated as part of the full report (p 4-3) filed in April that

> to meet the identified pollutant emissions limits, new AQC technologies are required for Brown Unit 2. These AQC technologies include the installation of new SCR and PAC injection.... The new SCR system can reduce NOx emissions to 0.11 lb/MMBtu or lower.

The Companies similarly stated that Ghent 2 and Mill Creek 1 & 2 would also require SCR (p 4-16, and 4-28, respectively).

As part of this analysis, the Companies evaluated the costs of SCR at Brown 1 & 2, Ghent 2, and Mill Creek 1 & 2, and had decided by May 2010 to pursue SCR as part of the suite of environmental controls required at their units. In the

Environmental Air Compliance Strategy Summary (Exhibit JNV-1, p3), the Companies state:

> Installing SCRs was the most cost effective, reliable and efficient option for B&V to estimate. Low NOx burner and OFA [overfire air] installations have already been installed on most of these units on past projects. The small gains in burner technology since these past modifications were installed would impact NO_x emissions, *but not at a level that would consistently meet the requirements of pending regulations.* [emphasis added]

However, in "late 2010", "the Companies' Energy Planning, Analysis and Forecasting department's first round of modeling indicated that the SCR's…identified in the Phase I and II studies would not be necessary to meet the CATR NO_x emissions reductions for the generating fleet." (Exhibit JNV-1 p8). This claim is repeated in Witness Voyles direct testimony, that simple modifications to existing infrastructure "defer[s] the need for additional SCR installations and support[s] least-cost compliance with the proposed CATR, which will impose stricter NO_x emissions requirements on LG&E and KU."

The stipulation that the CATR (the Transport Rule) is the only pending regulation which will require NO_x reductions is flawed because, as noted above, I believe that the ozone NAAQS will require SCR on the Companies coal plants.

The Companies examined this possibility in the 2011 Air Compliance Plan Sensitivity Analysis (p6), stating:

> Because more stringent NO_x emission reduction requirements in the future could require the construction of SCRs on some or all of these units, the Companies considered the cost of potential future controls and whether these costs could be incurred without changing the Companies' current recommendation.

Q Did the Companies provide the costs of SCR at their uncontrolled plants?

A Yes. The Companies provided their estimated streams of capital and operating expenses for SCR at Brown 1 & 2, Ghent 2, and Mill Creek 1 & 2 in discovery, and we were able to incorporate these costs into the Companies' modeling structure as part of the re-analysis, as if the SCR came online in 2018.

Q What is the result of the re-analysis examining the additional cost of SCR at these stations?

A In our re-analysis, only the three unit blocks of Brown 1 & 2, Ghent 2, and Mill Creek 1 & 2 are affected by the decision to add SCR, or more specifically realize a significant avoided cost of SCR by retiring, rather than retrofitting these units. The results of this analysis are shown in **Exhibit JIF-2,** Box 4. The NPVRR of retrofitting Brown 1 & 2 shrinks from $230 million to $34 million, and both Ghent 2 and Mill Creek 1 & 2 move from over a billion dollars of benefit to about $800 million benefit each.

The $34 million net benefit remaining at Brown 1 & 2 once SCR is required—assuming the company's gas price is correct— is a fine margin upon which to base a decision to retrofit and maintain this unit. At about 1% of the total NPVRR of the total system cost, this narrow window could easily be violated by uncertainties in the model, forecast fuel and emissions prices, or capital requirements.

This component of the re-analysis alone should cause the Companies to reconsider their decision to retrofit the Brown 1 & 2 units.

Q What is the result of the re-analysis examining the additional cost of SCR *and* the corrected gas price at these stations?

A Combining the corrected gas price re-analysis and the avoided cost of not building SCR at these stations has a dramatic impact on the retire/retrofit decision. The results of this analysis are shown in **Exhibit JIF-2**, Box 6. Our re-analysis indicates that retrofitting Brown 1 & 2 would result in a NPVRR *loss* of $193 million to the Companies, and is an inefficient solution.

The Ghent 2 and Mill Creek 1 & 2 units are also diminished in benefit to $377 and $137 million NPVRR relative to a retirement decision, significantly down from the billion dollar benefit suggested by the Companies' original analysis (Box 1).

7. Carbon Mitigation Risk

Q Does the Companies' model address the risk of carbon dioxide emissions mitigation?

A No. The Companies make no reference to recent legislative proposals to mitigate carbon dioxide (CO_2) emissions or to the existing Greenhouse Gas Tailoring Rule, finalized in May 2010, which requires that projects that increase GHG emissions substantially would require air permits. These actions could reasonably impose a cost on the emissions of CO_2.

Q Are any of the carbon dioxide risks currently applicable or is future legislative action required before the risk exists?

A Current regulations impose a risk on the Companies' fleet of coal-fired power plants. Under the Greenhouse Gas Tailoring Rule, if a modification to a power plant will cause an increase in greenhouse gas emissions of 75,000 tons per year and the total emissions from the plant exceed 100,000 tons, then the plant must control its greenhouse gas emissions with the best available control technology (BACT). The Companies anticipate in the "no retirements" Strategist run that some of their coal units—units that are receiving major environmental modifications—would increase GHG emissions beyond this threshold in the next few years. Therefore, it was completely unreasonable for the Companies to not address this regulation.

Q Why does the Companies' lack of a CO_2 price represent a risk to ratepayers?

A The vast majority of scientists who study climate change and climate change impacts, 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 will be required 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), or pay others to do so in their stead. Power producers will likely realize these regulations as a cost imposed on CO_2 emissions.

Due to the increasingly contentious politics associated with regulating CO_2 and other greenhouse gases, it is uncertain when such regulatory or legislative actions might occur. However, if the weight of evidence does eventually prevail, it is my opinion that there will be no choice but to find mechanisms to reduce CO_2 emissions; those actions would almost certainly impose costs on sources with large CO_2 emissions, such as coal-fired power plants.

The Companies' failure to address CO_2 risk results in no carbon price at all. It is my opinion that this is an extremely unlikely scenario, and this failure to plan for a likely significant future costs poses a major regulatory risk for LG&E/KU customers.

Q Have you evaluated how a reasonable CO_2 cost could impact the Companies' decision to retrofit versus retire units of their coal fleet?

Yes. I have conducted a re-analysis of the Companies' plan implementing a mid-range CO_2 price as forecast by my firm, Synapse Energy Economics, attached as **Exhibit JIF-4**. The Synapse forecast was produced in February of 2011, and represents the marked uncertainty in how and when greenhouse gas prices might apply. The forecast is a public document explaining background, state and regional initiatives, analytical estimates, and the recommended Synapse 2011 CO_2 price forecast for planning purposes.

For the purposes of this case, I have tested the re-analysis with the Mid, or Expected, CO_2 Price Forecast. This CO_2 price starts at $15/ton (2010$/short ton) in 2018 and climbs to $50/ton in 2030. The levelized cost is $26/ton over the period 2015-2030.

Sierra Club witness Ms. Wilson extrapolated the straight line estimate through 2040 and incorporated the published CO_2 prices into the re-analysis.

Q Are the CO_2 prices you used in the re-analysis similar to CO_2 prices utilized by the Companies in the past?

A Yes. In the Companies' 2008 IRP they included CO_2 pricing in their modeling. The Companies utilized an intermediate and high carbon price, similar in magnitude to our price estimate. The Companies noted that it needed to account for these costs because of risks associated with future regulation or legislation.

Q What are the results of implementing the CO_2 price on the retire/retrofit decision?

A As with the corrected gas price analysis, a CO_2 price tends to favor gas replacement relative to coal, therefore drawing down the NPVRR benefit of maintaining any units in the coal fleet. **Exhibit JIF-2,**, Box 5 shows the effect of using *only* the Synapse Mid CO_2 price on the NPVRR of each retire/retrofit decision, leaving the Companies' gas and SCR assumptions intact. Unto itself, the CO_2 price used here does not necessarily result in retirements, depending on the risk threshold one is prepared to accept. However, the NPVRR of retrofitting the Brown 1 & 2 units again is diminished down to $18 million, suggesting a very high risk by choosing to retrofit. This $18 million benefit is likely within the uncertainty of the model as constructed.

When the Companies' gas price is corrected and the CO_2 price risk is imposed on the fleet, the retrofit/retire decision changes for much of the fleet under consideration – barring Trimble County 1, Ghent 4, and Ghent 2, all of the other units are rendered non-economic relative to the Strategist replacement options (see **Exhibit JIF-2,**, Box 7).[19]

Finally, applying all three revised assumptions to the model results in an apparent non-economic performance of all but the Trimble County 1 and Ghent 4 units (see **Exhibit JIF-2,**, Box 8).

8. Re-Analysis Findings

Q Would you summarize your re-analysis findings?

A I stipulate that while the Companies have constructed a reasonable and thoughtful approach to evaluating the retrofit/retire decision for each of their coal units, basic fundamental inputs into the Companies' model are deeply flawed, tainting the analysis and ultimately exposing ratepayers to unnecessary risk. Correcting any one of those three flaws—gas price forecast, SCR requirements, or the risk of a CO_2 price—demonstrates that some of the units for which LG&E/KU is requesting CPCN and an environmental surcharge, are not economic.

Using any two of these corrections in concert dramatically changes the Companies' decision to retrofit *at least* the Brown 1 & 2 units, and calls into serious question the cost-effectiveness of upgrading other coal units as well.

The risk that the Companies will be exposed to by a CO_2 price is by no means *de minimis,* and yet in this analysis, the Companies has failed to review this risk – much less assess how it could change the forward-going economics of their coal fleet.

I find that the Brown 1 & 2 unit retrofit is *not economically justifiable* using any series of reasonable assumptions. In addition, I conclude that the Mill Creek 1 & 2 units pose a marked financial risk to the Companies, and that the Commission

[19] By the same virtue that the net benefit of maintaining Brown 1 & 2 with an SCR only assumption (Box 4) might be considered a solution "in the noise" at $34 million NPVRR, the retirement of Ghent 3 and Mill Creek 3 in this scenario (at -$24 and -$43 million, respectively) might also be considered "in the noise". Clearly, should a CO_2 price be implemented, the regional impact would be significant and thus these retirements should be considered within the context of regional changes as well.

should require the Companies to evaluate these units in more detail prior to authorizing retrofit and rate recovery.

9. Additional Analytical Concerns

Q Are there other problems or concerns that you've identified in the Companies' modeling in this case?

A There are. I have concerns with:

- the large-block capacity additions,
- the lack of transactions with other companies,
- emergency energy costs,
- the order in which units are chosen for retirement, and
- the Companies' assumed SO_2 and NO_x prices.

Q Please explain what you mean by "large-block" capacity additions, and why that is a concern.

A Central station power plants are constructed in discrete sizes. This can present challenges for system planners, in that capacity additions may result in excess capacity for some period of time, and related challenges in terms of planning analysis and modeling.

In this case, the gas combined cycle plant that is called upon in the Strategist model in or around 2016 is roughly 1000 MW in capacity. This is quite large for a system the size of LG&E/KU, which has an annual peak demand of about 7000 MW.

The graph shown in **Figure 4**, below, illustrates the "large-block" issue in two different cases – in red, the case in which there are no retirements and in green, the "maximum" retirement case where Tyrone 3, Green River 3 & 4, and Cane Run 4-6 are all retired in 2016.[20]

- In the "no retirements" case, a single 1000 MW 3x1 unit is built in 2017, exceeding the capacity requirement by 700 MW in the first year, and leaving an overbuilt system through at least 2022.
- In the Companies' "maximum retirements" case,[21] the total capacity of retired units works out to exactly the rated capacity of the 3x1 gas unit, and thus there is nearly a perfect replacement in 2016. Thereafter, the supply echoes the "no retirements" scenario, offset by one year.

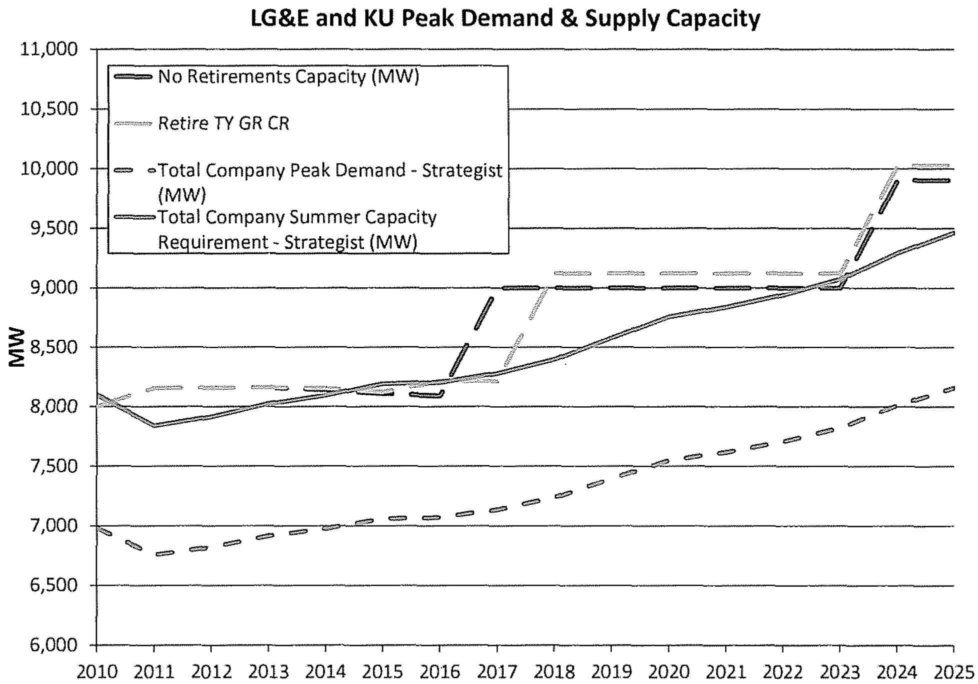

Figure 4. Peak demand, summer capacity requirement (assuming 16% target reserve margin), and supply in two retire/retrofit cases.

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[20] Scenario using Companies assumptions.

[21] Not named as such by the Company, but the scenario in which Tyrone 3, Green River 3 & 4, and Cane Run 4-6 are all retired.

The Companies' chosen modeling constraints that require the system to be overbuilt by large margins is what I mean by "large-block" problem.

Q How does the "large-block" issue impact the retire/retrofit decision?

A There is a large mismatch between the size of the commonly chosen 3x1 gas CC and the coal units available for potential retirement. One of the confounding circumstances that occurs is when a small unit is retired, or considered for retirement, but there are only large units available for replacement.

For example, take the case of the "maximum retirements" case above, where the combination of six retiring units in 2016 works out to exactly the size of a 3x1 gas CC, and thus a "perfect" replacement. The next unit that the Companies analyze is Mill Creek 4, which is 544 MW. The model chooses to build two 3x1 CCs in 2016 to make up the gap, overbuilding by 363 MW, and advancing a large capital expenditure forward by two years (from 2018 to 2016), which would inflate the NPVRR of this scenario unnecessarily.

Q What can be done about this "large-block" issue in modeling, and in actual system expansion?

A In conducting utility system planning it makes sense generally for the capacity addition options to have a resemblance in size to the particular capacity decisions being made, and to maximize flexibility where feasible in the system. In other words, if the focus of the analysis is upon coal units sized at about 100 MW then you can minimize the large-block problems by offering the model replacement capacity additions available in 100 MW size. Also, it is informative to look at capacity increments in terms relative to annual load growth. In this case, the annual load growth projected by the Companies, and input to Strategist, is about 100 to 200 MW per year. So capacity additions of 1000 MW represent anywhere from five to 10 years of load growth. It is, in my opinion, more reasonable for modeling purposes to have multiple additions that represent two or three years of load growth, so that the model results are smoother and less subject to erratic noise caused by the large additions of unneeded capacity in a particular year.

In the actual system expansion, adding more reasonably sized increments of capacity can help to avoid having customers pay for excess capacity for long periods of time, and the rate shock and economic issues that it can engender. One way that utilities can avoid these problems (in modeling and in actuality) is to share capacity additions. If a 1000 MW combined cycle plant truly offered significant efficiencies or economies of scale, then perhaps two companies could partner and co-own the construction project of such a plant. Indeed, there are likely many utilities across Kentucky and the larger region that are facing similar, if not identical, retrofit/retire decisions as the Companies, and on the same timescale.

Q Are there other issues of concern with the large replacement units available in the Strategist model?

A Yes. The model inputs suggest that the 3x1 CC units are rated at 1009 MW, but provide only peak capacity of 907 MW, an unusually large de-rating for a new and ostensibly quite efficient unit.

Also, results from the Strategist model, provided by my colleague Ms. Wilson, suggest that these very large CC units are run at extremely low capacity factors – 25% to 33%, or well below what is expected from a baseload-capable unit. While we have not had the opportunity to explore these issues yet in greater depth, intuitively it seems as if a combination of fewer gas CC units and either peakers or additional demand response (or both) could provide a more cost-effective capacity and energy replacement.

Q What do you mean when you say that there is a problem with a "lack of transactions with other companies"?

A Well, the problem is really that the Companies' Strategist model treats its system in nearly complete isolation from neighboring utilities and other generators in the region. In reality, the Companies are very well interconnected with their neighbors and the investment in the transmission that makes that possible is in rates that their customers pay.

Q How would participation in the broader regional system influence the economics of retiring specific coal-fired power plants?

A In general, the availability of purchasing energy from others, either bilaterally or through MISO markets, would present additional resources that could play a part in the energy mix replacing the generation that would otherwise have come from the retired units over *at least* short periods of time or for fairly limited capacity requirements. By modeling its system in isolation in Strategist the Companies have unrealistically restricted the range of potential sources of replacement energy, therefore encumbering the model artificially in regards to efficient retirement.

Q What is your concern with emergency energy costs in the model?

A In the Strategist model, the Companies have included an extremely expensive source of power purchases, emergency power. Typically, emergency power is regarded as exactly that, a resource of last resort when nothing else is available. The Companies have assumed that the cost of this energy is $16,600 per MWh - or several hundred times as expensive as typical power sources.

This very high "emergency energy" price represents the costs incurred or reported by customers who suffer interruptions in service. In fact, there are numerous other lower cost measures that can be, and are, called upon before interrupting service. These include purchases from other companies, calls for demand response, and various emergency operating procedures. These do not appear to be adequately represented in the Companies' model.

In the model results, emergency energy represents only a fraction of the total system energy – anywhere from 80 MWh to 5,400 MWh per year, or something like 0.001% to 0.01% of total energy requirements in the LG&E/KU system – and yet the total costs of this energy reaches up to $90 million in some years and cases.

Q These costs seem fairly small relative to the total operating and capital costs required to run the LG&E/KU system. Why are emergency generation costs a concern in this analysis?

Costs of $10-$90 million can pale in comparison to the total production and new unit capital costs seen in this model on an annual basis (between 0.5% and 4%), but where these values become extremely important is in the difference between the Strategist runs. It is unclear what threshold the Companies would require in order to determine retirement versus retrofit is the better option, and the difference between the NPVRR of the emergency power might, in some cases, exceed the cost difference between two scenario runs. Therefore, it is quite critical to get this value correct and justified.

Q Are you able to give an example where the cost of emergency energy could tip the balance in this analysis?

A Yes. In the 2011 Air Compliance Plan (Exhibit CRS-1), the explanation next to the Cane Run 6 analysis explains that even though the NPVRR favors retrofit, the difference is quite small – only $8 million. The Companies explain (Section 4.2.5) that:

> If the Companies install controls on Cane Run 6 and the PVRR of a future expenditure not contemplated in this analysis exceeds $8 million, installing controls is not the least cost option. Because the possibility of this occurring is considered high, the Companies do not recommend installing environmental controls on Cane Run 6. Cane Run 6 will be retired when the air regulations take effect.

In contrast, under the section "Future Environmental Costs" in the Sensitivity (Section 2.3), the Companies explain that:

> Because more stringent NO_x emission reduction requirements in the future could require the construction of SCRs on some or all of these units, the Companies considered the cost of potential controls and whether these costs could be incurred without changing the Companies' current recommendation.

The Companies goes on to explain that the net value of Brown 1 & 2 in their analysis is $228 million, and the NPV of installing SCRs on these units is $195 million. The net difference, $33 million is, according the Companies, sufficiently large enough to justify the continued use of the units.

However, the NPVRR differences between scenarios due to the "emergency power cost" can quickly the $33 million dollar value and feasibly change the results of the analysis.

Q What is your concern with the Companies' SO_2 and NO_x prices?

A In the concurrent 2011 IRP, the Companies show its forecast of SO_2 and NO_x prices. These prices start at $19 and $460/ton of pollutant, and drop to zero by 2014 – remaining at zero thereafter.

The Companies will have the opportunity to trade SO_2 and NO_X allowances within the state via the CSAPR rule, and should therefore carefully evaluate the opportunities and opportunity costs associated with selling excess allowances through retirement or retrofit or purchasing allowances if plants are not retrofited. The Companies should incorporate these costs into the Strategist model.

Q So why are the Companies' SO_2 and NO_x prices a concern?

A They are much lower than the prices predicted by the EPA. In its Regulatory Impact Assessment for the CSAPR rule, the EPA predicts that SO_2 prices in the Group 1 Trading Program (of which Kentucky is a member) at approximately $1000/ton in 2012 and $1,100 in 2014, while NO_x prices in the ozone season trading program (of which Kentucky is also a participant) will reach up to $1,500 in 2014 – a far cry from zero.

While I have not produced a prediction of SO_2 and NO_x trading prices after 2014, I believe it is incumbent on the Companies to carefully assess those costs and opportunities, as they have the potential to change the Companies' retire/retrofit calculus.

Q Do you also have a concern with the order of retirement stipulated by the Companies?

A Yes. I understand that the Companies evaluate the cost efficacy of maintaining their fleet on a unit-by-unit basis. Each time a unit is found to be non-economic in the retire/retrofit analysis, it is assumed to be retired in year 2016, as part of the base case. In this stepwise system, units which are analyzed early are compared to a "no retirements" or at least few retirements scenario, while units which are analyzed late are compared against a numerous retirements scenario. Each time a unit is retired, the remaining units, by virtue of being in a "closed" system, increase in capacity factor and therefore look marginally more economic.

By the time we examine the last units in this system, those units may look far more economic than if they were considered first.

Q What would you recommend the Companies do to rectify this problem?

A I understand that there is a legitimate question raised by retirement, in which remaining units may indeed have to make up some of the energy lost by retiring other units; therefore, I do not fundamentally object to this sort of test. However, I would suggest that the Companies should test each unit's cost effectiveness against the "no retirements" case, determine which units will be least cost effective *going forward* rather based on current operations and choose to retire the least economic units first. This sort of re-ordering of the analysis should happen in parallel with the evaluation of the emergency energy price, more mid-sized unit replacement (or large unit shares) options, and realistic connections between LG&E/KU and neighboring utilities. Alternatively, given the immense dollar amounts at stake and minor expense of computer time and analysis labor, as well as the multi-decade length of the commitments involved, the company could feasibly find more optimal retirement solutions.

I believe that these types of adjustments would make for a less noisy and more realistic solution by which to judge the retire/retrofit decision.

Q Have you corrected these Strategist problems for your testimony in this case?

No. We have had to prioritize the efforts of this re-analysis given that we had a limited period of time in which to complete it. We chose to focus only on the most pressing concerns, described in the re-analysis sections.

Q Are there issues and errors in the company's use of Strategist beyond those that you've identified in this testimony?

A There may be other issues and errors. I have presented in this testimony all of the problems and concerns that I have identified at this point in time. That does not, of course, mean that there aren't other problems with the inputs or methodology that have gone unnoticed. System modeling is a complicated matter, and it should be done carefully and thoughtfully.

10. CONCLUSIONS

Q What are your conclusions?

In my opinion, the company has used a series of input assumptions in their retire/retrofit model that are not realistic. In addition, I have identified a number of concerns with the company's modeling framework and assumptions, but have not had the opportunity to assess how much these problems impact the retire/retrofit decision. Basing resource decisions on those non-realistic assumptions and methodologies would burden the Companies' ratepayers with substantial and unnecessary costs and risks.

By correcting the company's natural gas price forecast, a move that the company appears to be endorsing in its late-breaking "Supplemental Analysis" filed on September 14th, the economic merit of retrofitting the company's coal-fired units diminishes significantly. A simple correction to the gas price should result in the decision to retire Brown 1 & 2, rather than expend additional dollars on retrofitting these units.

The Companies' assessment of the requirement for SCR requirements at Brown 1 & 2, Ghent 2, and Mill Creek 1 & 2 is inaccurate and understates the significant risk that these units will require rigorous NO_x controls to comply with both current and pending ozone rules. Even accepting the company's gas price forecast, the risk to Brown 1 & 2 should result in the choice to retire, rather than retrofit these units. When the corrected gas price forecast is utilized, Brown 1 & 2 are clearly non-economic when SCR is required, therefore posing a marked risk to ratepayers. The Mill Creek 1 & 2 units remain marginally economic, but would certainly be considered high risk under this circumstance and that is *only* if all the other erroneous assumptions and methodologies are ignored.

Finally, I believe that the lack of a CO_2 price (or a range of CO_2 forecasts) in the Companies' model inappropriately exposes the Companies and their ratepayers to substantial costs for carbon regulatory risk. Indeed, applying a mid-range CO_2 price to the forecast results in the marked reduction in cost-effectiveness of all of the Companies' coal units. Applying both the CO_2 price and the adjusted natural gas price makes much of the KU/LGE fleet appear non-economic.

Q What are your recommendations to the Commission?

A I recommend that the commission deny CPCN and rate treatment for retrofitting the Brown 1 & 2 units. I also recommend that Commission deny CPCN and rate treatment for retrofitting the Mill Creek 1 & 2 units as their marginal or negative cost effectiveness place their economics in a very uncertain range. The Commission may wish to require the company to assess, in greater detail and with a greater range of uncertainty, the risks posed in retrofitting the Mill Creek 1 & 2 units.

Furthermore, as the entire analytical basis for the Companies' proposed resource analysis is fundamentally flawed due to erroneous assumptions and methodologies, the Commission should deny CPCNs and rate treatment for any upgrades to the Companies' coal units at this time.

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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

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

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

Teaching

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

Fellowships

2007 Visiting Fellow, Watson Institute for International Studies, Brown University

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

UNIVERSITY SERVICE

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

PROFESSIONAL ASSOCIATIONS

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

Net Present Value Revenue Requirement (NPVRR) of Installing Controls vs. Retiring and Replacing Capacity (Million 2010$)

Original KU/LG&E Analysis

KU / LG&E Assumptions — Box 1: Original (CPCN Results)	
Tyrone 3	-13
Green River 3	-80
Brown 3	601
Cane Run 4	-88
Cane Run 6	8
Brown 1-2	228
Cane Run 5	-58
Ghent 3	914
Ghent 1	794
Green River 4	-110
Mill Creek 4	859
Trimble County 1	993
Ghent 4	1,155
Mill Creek 3	756
Ghent 2	1,139
Mill Creek 1-2	1,022

KU / LG&E Assumptions — Box 2: Original, Formula Corrected (CPCN Results, Landfill Year Corrected)	
Tyrone 3	-13
Green River 3	-80
Brown 3	603
Cane Run 4	-87
Cane Run 6	11
Brown 1-2	230
Cane Run 5	-57
Ghent 3	921
Ghent 1	800
Green River 4	-110
Mill Creek 4	859
Trimble County 1	996
Ghent 4	1,161
Mill Creek 3	756
Ghent 2	1,146
Mill Creek 1-2	1,022

Key	
If NPVRR relative to no retirement scenario	
≥ $40 M, retrofit	100
< $40 M & ≥ $0 M, high risk retrofit	20
< $0 M, retire	-80

Synapse Re-Analysis Single Variable Correction

Synapse Re-Analysis — Box 3: A (Corrected Gas Price)	
Tyrone 3	-64
Green River 3	-69
Brown 3	309
Cane Run 4	-230
Cane Run 6	-135
Brown 1-2	2
Cane Run 5	-223
Ghent 3	489
Ghent 1	363
Green River 4	-132
Mill Creek 4	384
Trimble County 1	602
Ghent 4	661
Mill Creek 3	375
Ghent 2	665
Mill Creek 1-2	397

Synapse Re-Analysis — Box 4: B (SCR at Brown 1 & 2, Ghent 2, and Mill Creek 1 & 2)	
Tyrone 3	-13
Green River 3	-80
Brown 3	603
Cane Run 4	-87
Cane Run 6	11
Brown 1-2 (+SCR)	34
Cane Run 5	-57
Ghent 3	921
Ghent 1	800
Green River 4	-110
Mill Creek 4	859
Trimble County 1	996
Ghent 4	1,161
Mill Creek 3	756
Ghent 2 (+SCR)	858
Mill Creek 1-2 (+SCR)	762

Synapse Re-Analysis — Box 5: C (Synapse Mid CO2 Price)	
Tyrone 3	-59
Green River 3	-100
Brown 3	249
Cane Run 4	-268
Cane Run 6	-260
Brown 1-2	18
Cane Run 5	-257
Ghent 3	323
Ghent 1	262
Green River 4	-128
Mill Creek 4	290
Trimble County 1	563
Ghent 4	550
Mill Creek 3	340
Ghent 2	576
Mill Creek 1-2	299

Synapse Re-Analysis Multiple Variable Correction

Synapse Re-Analysis — Box 6: A + B (Corrected Gas Price + SCR)	
Tyrone 3	-64
Green River 3	-69
Brown 3	309
Cane Run 4	-230
Cane Run 6	-135
Brown 1-2 (+SCR)	-193
Cane Run 5	-223
Ghent 3	489
Ghent 1	363
Green River 4	-132
Mill Creek 4	384
Trimble County 1	602
Ghent 4	661
Mill Creek 3	375
Ghent 2 (+SCR)	377
Mill Creek 1-2 (+SCR)	137

Synapse Re-Analysis — Box 7: A + C (Corrected Gas Price + CO2 Price)	
Tyrone 3	-72
Green River 3	-112
Brown 3	-144
Cane Run 4	-414
Cane Run 6	-457
Brown 1-2	-222
Cane Run 5	-440
Ghent 3	-24
Ghent 1	-104
Green River 4	-175
Mill Creek 4	-171
Trimble County 1	155
Ghent 4	79
Mill Creek 3	-43
Ghent 2	80
Mill Creek 1-2	-329

Synapse Re-Analysis — Box 8: A + B + C (Corrected Gas Price + SCR + CO2 Price)	
Tyrone 3	-72
Green River 3	-112
Brown 3	-144
Cane Run 4	-414
Cane Run 6	-457
Brown 1-2 (+SCR)	-417
Cane Run 5	-440
Ghent 3	-24
Ghent 1	-104
Green River 4	-175
Mill Creek 4	-171
Trimble County 1	155
Ghent 4	79
Mill Creek 3	-43
Ghent 2 (+SCR)	-208
Mill Creek 1-2 (+SCR)	-590

Synapse
Energy Economics, Inc.

2011 Carbon Dioxide Price Forecast

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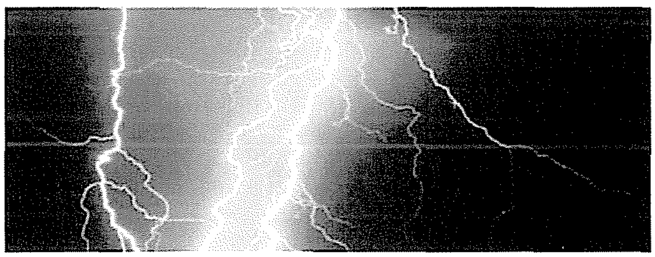

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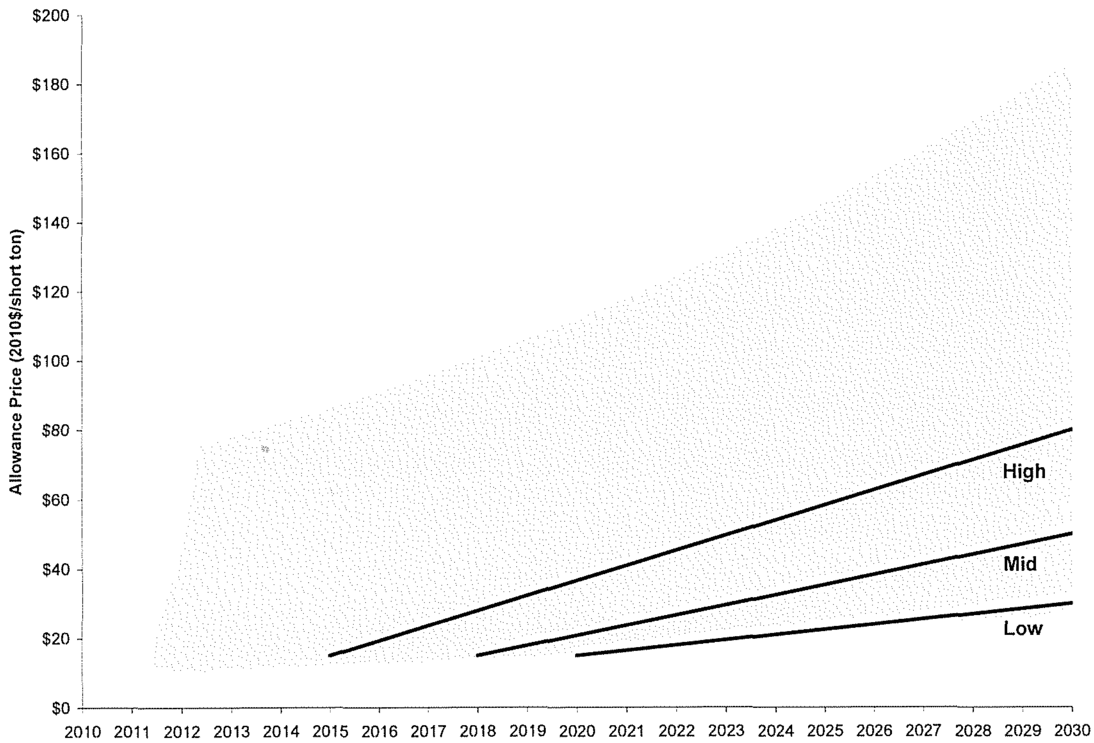
1. Executive Summary

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

Figure ES-1: Synapse price forecast



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

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

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

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

2. Introduction

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

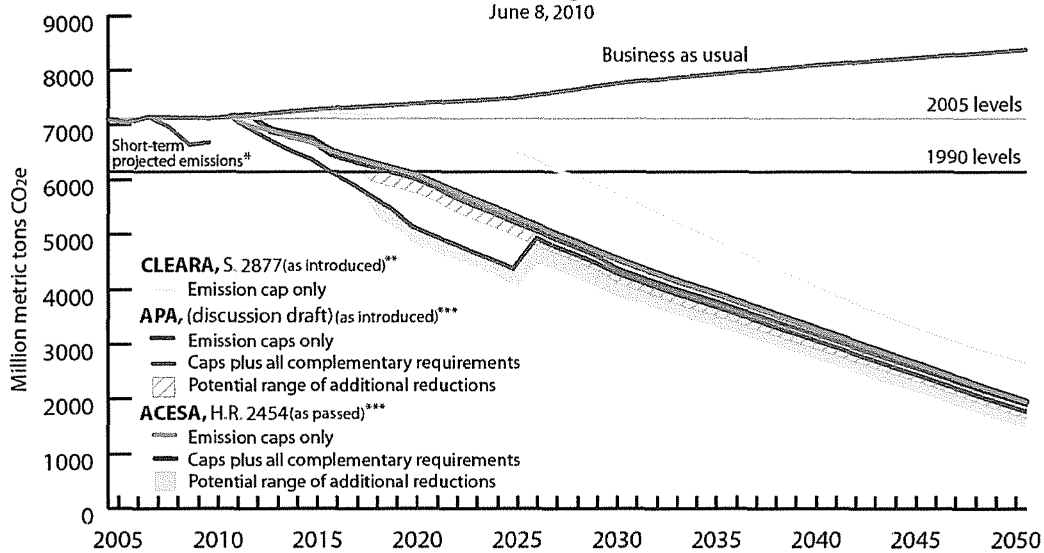
3. Policy Context

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

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

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

June 8, 2010



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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.

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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.

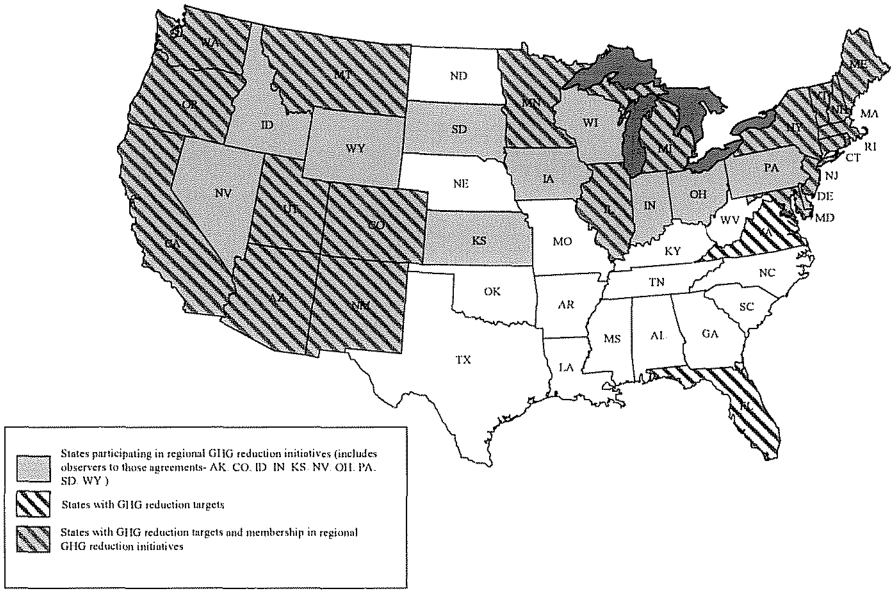
The map below shows states with emission targets and those participating in, or observing, regional climate initiatives as of January 2011. States that have adopted emissions targets and/or that are participating actively in regional climate initiatives comprise 44.4% of US electrical generation, 48.3%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

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

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

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

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

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

4. Elements in a price projection

A. Difficulty of price projection under uncertainty

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

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

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

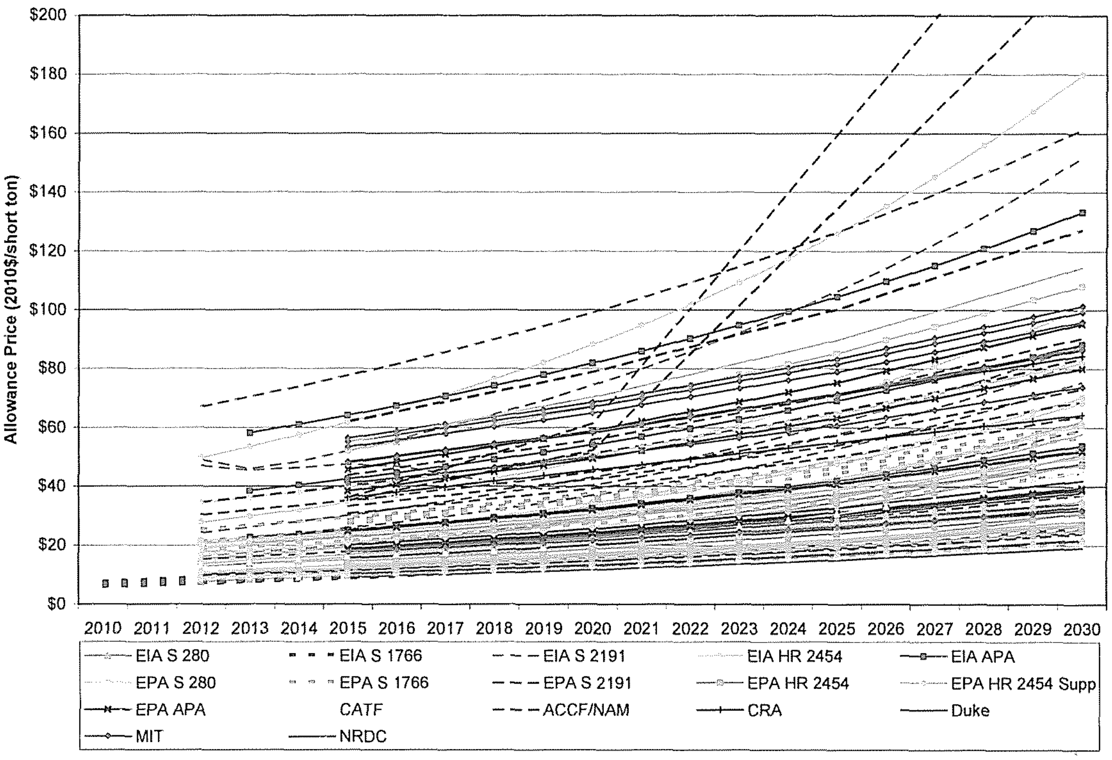
[12] Information is available at http://www.pewclime.org/copenhagen-accord

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

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

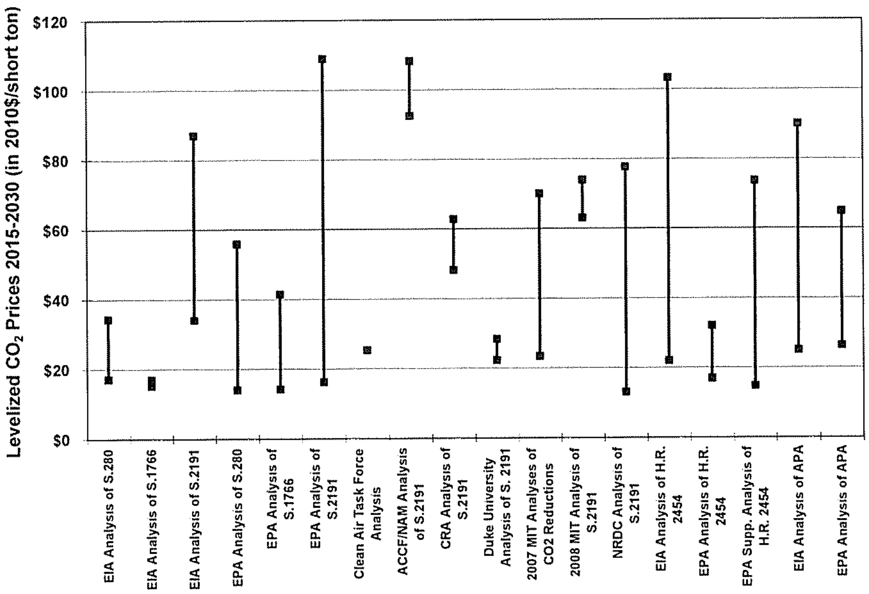
The graph below shows the results of all the scenarios from multiple analyses in the past several years. The studies that are incorporated into this graph are identified in Appendix A.

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



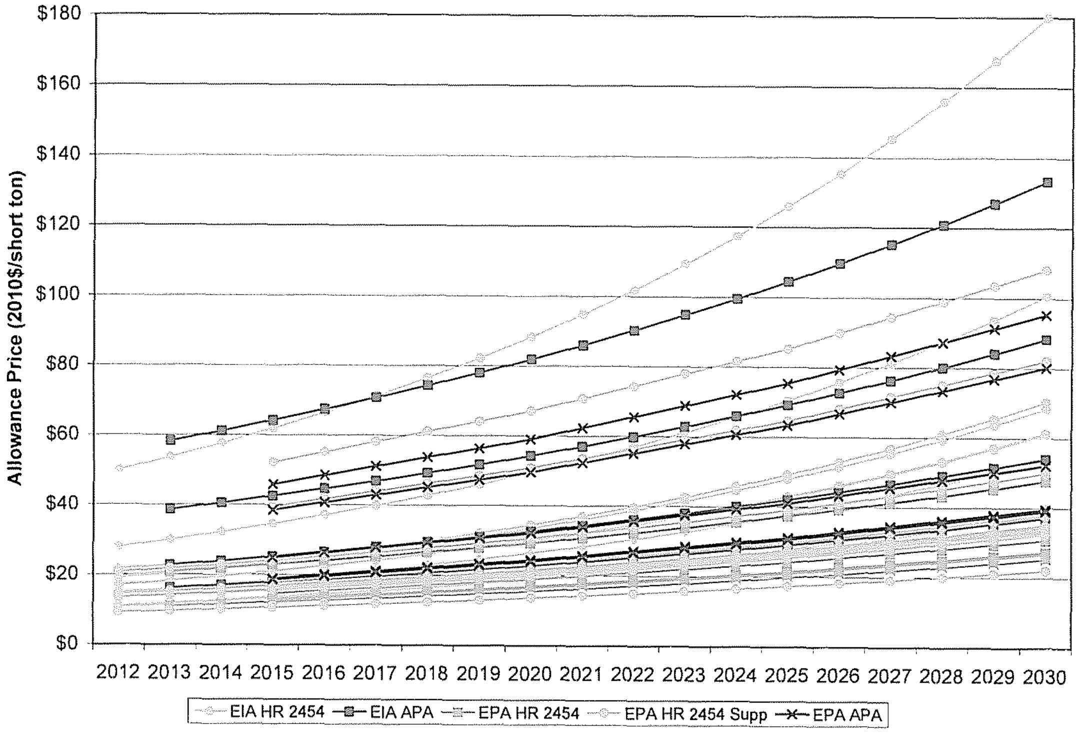
The results of these same analyses are represented in Figure 4, below, as ranges of levelized costs.

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



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

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



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

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

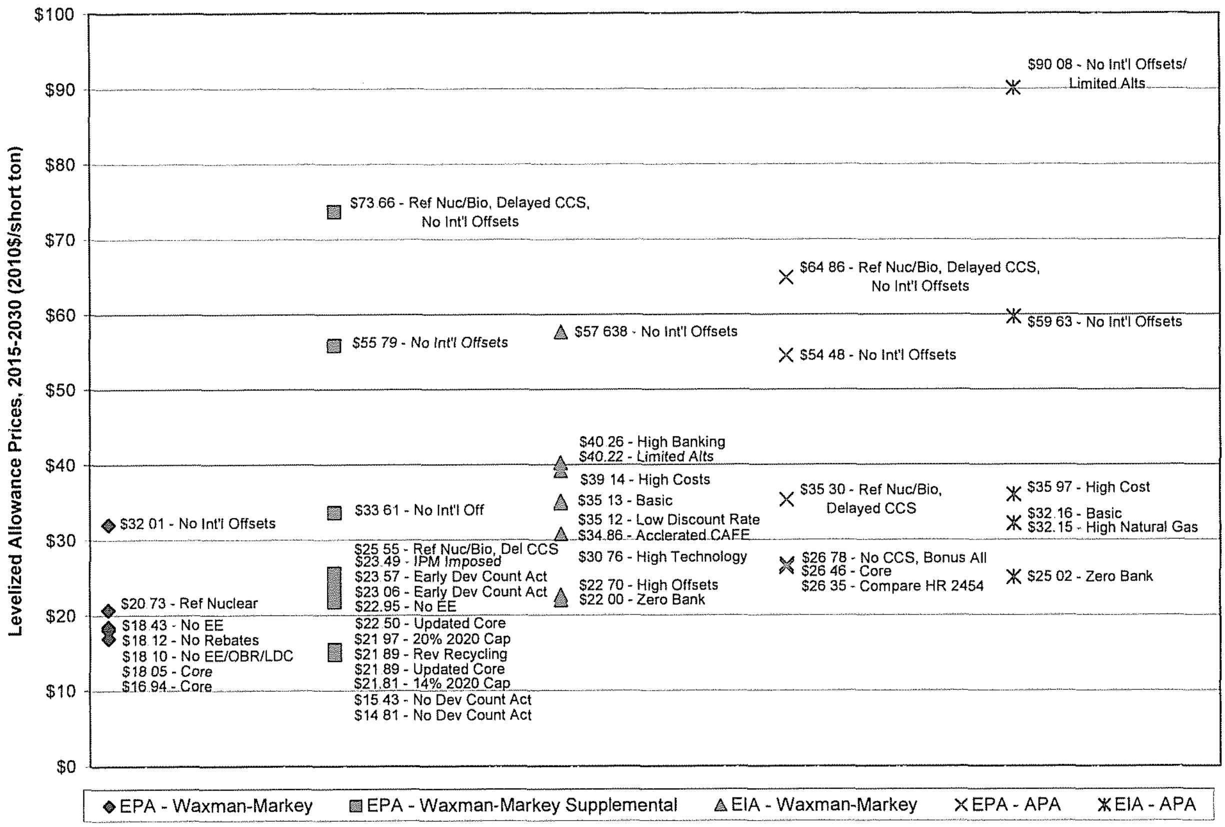
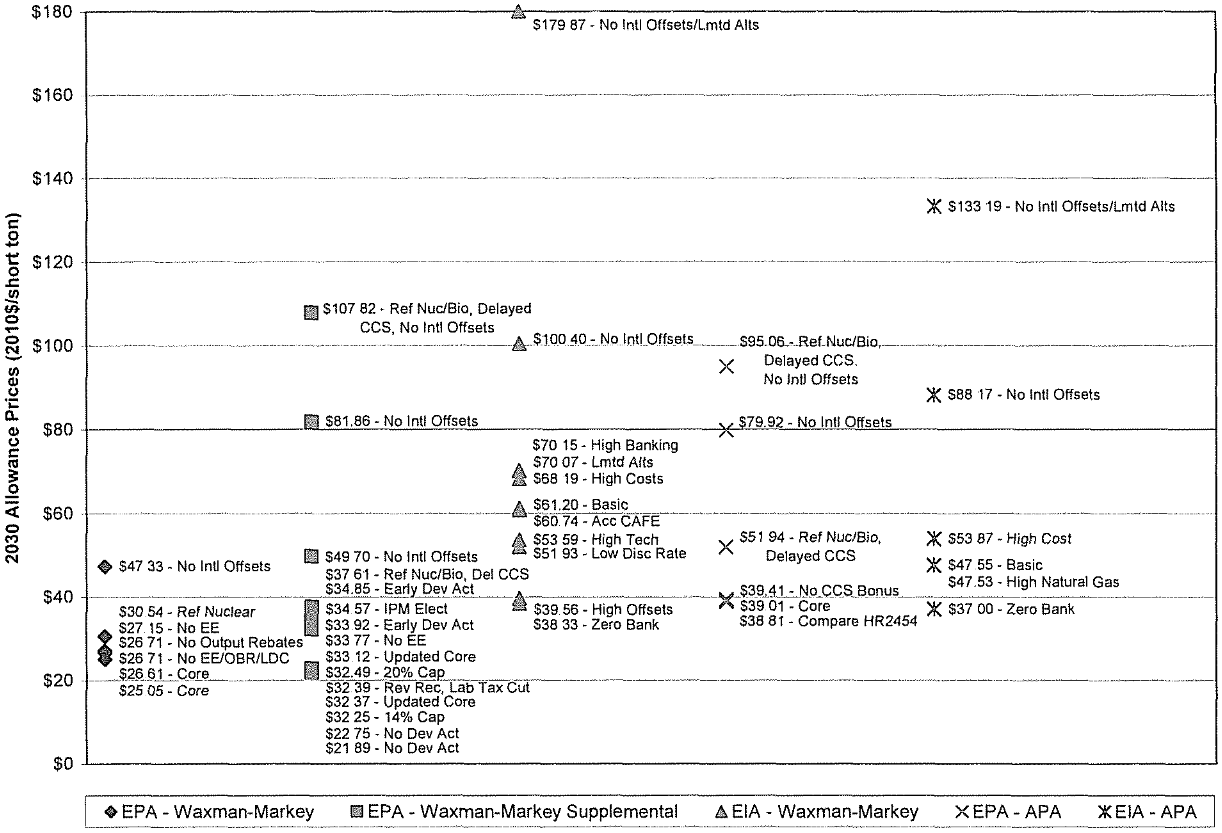


Figure 7: 2030 Greenhouse gas allowance price projections for HR 2454 and APA 2010



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

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

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

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

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

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

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

C. Other forecasts

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

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

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

5. Synapse's Recommended February 2011 CO_2 Price Forecast

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

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

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

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

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

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

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

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

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

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

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

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

Figure 8: 2011 Forecast Values

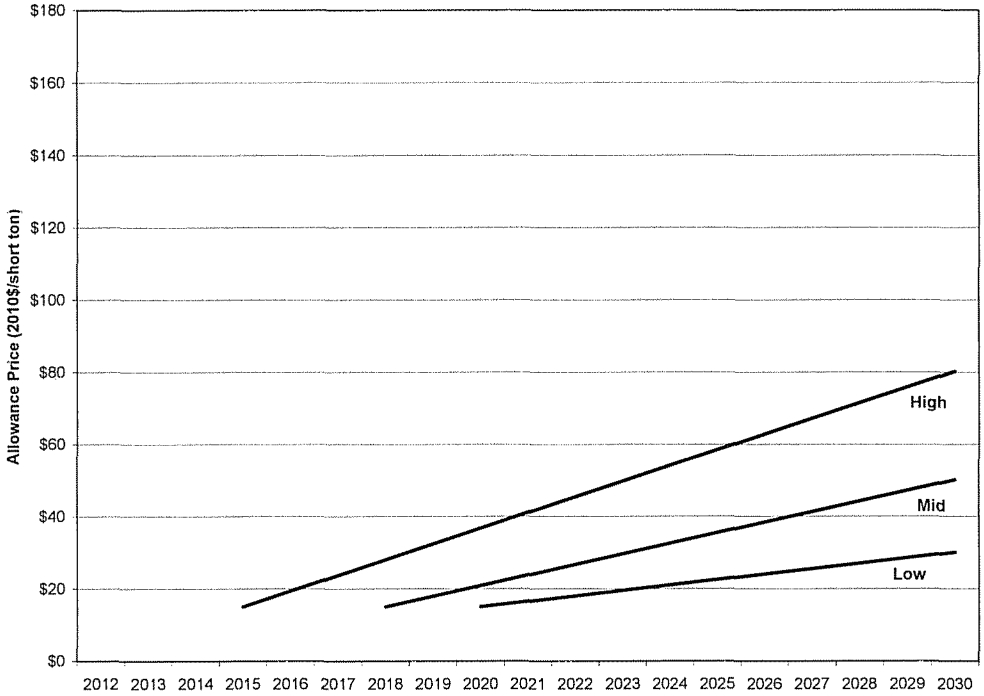
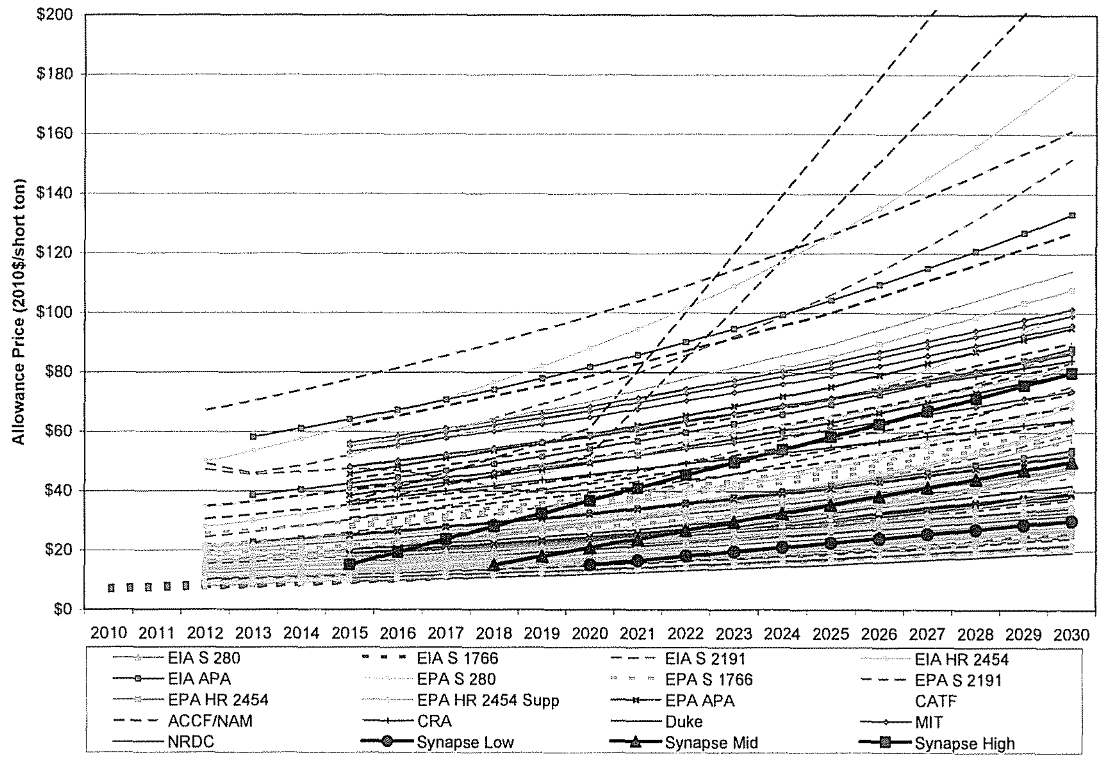


Table 3: 2011 Synapse Low, Mid, and High CO_2 Allowance Price Forecasts (2010$/short ton)

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

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

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



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

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

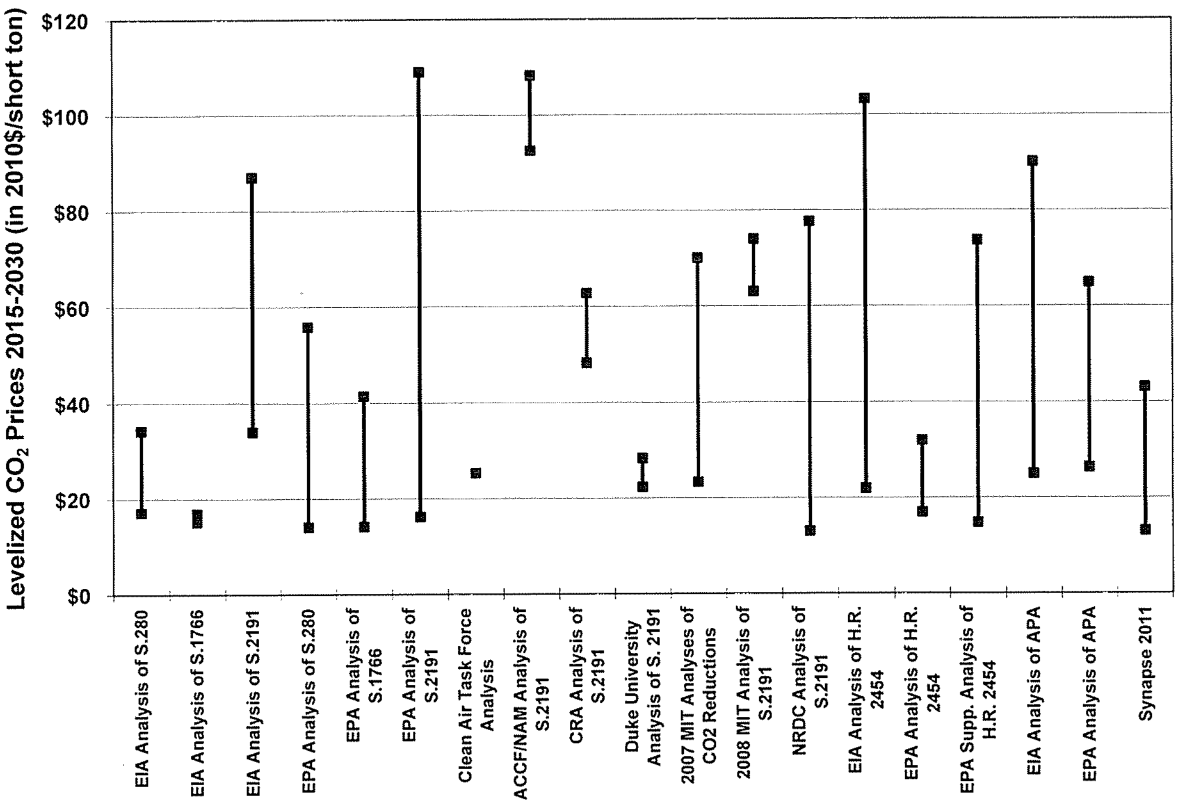


Figure 11: Synapse CO_2 trajectories and greenhouse gas allowance price projections for HR 2454 and APA 2010

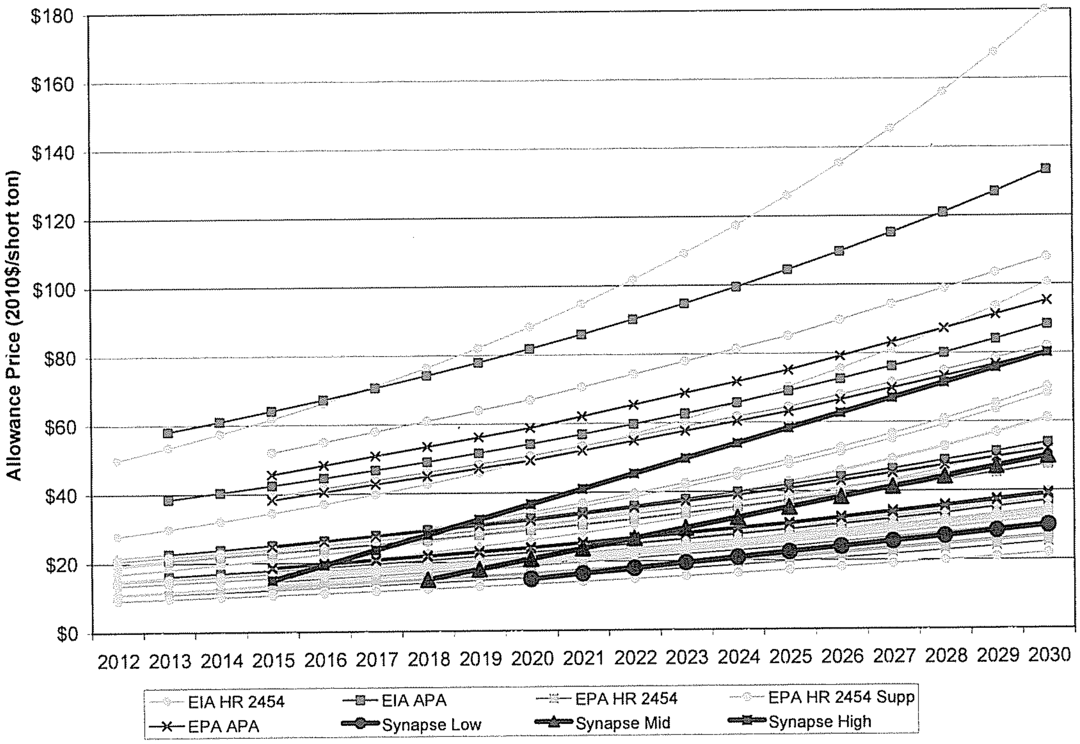


Figure 12: Synapse CO_2 trajectories and greenhouse gas allowance price projections for HR 2454 and APA 2010- levelized 2015-2030

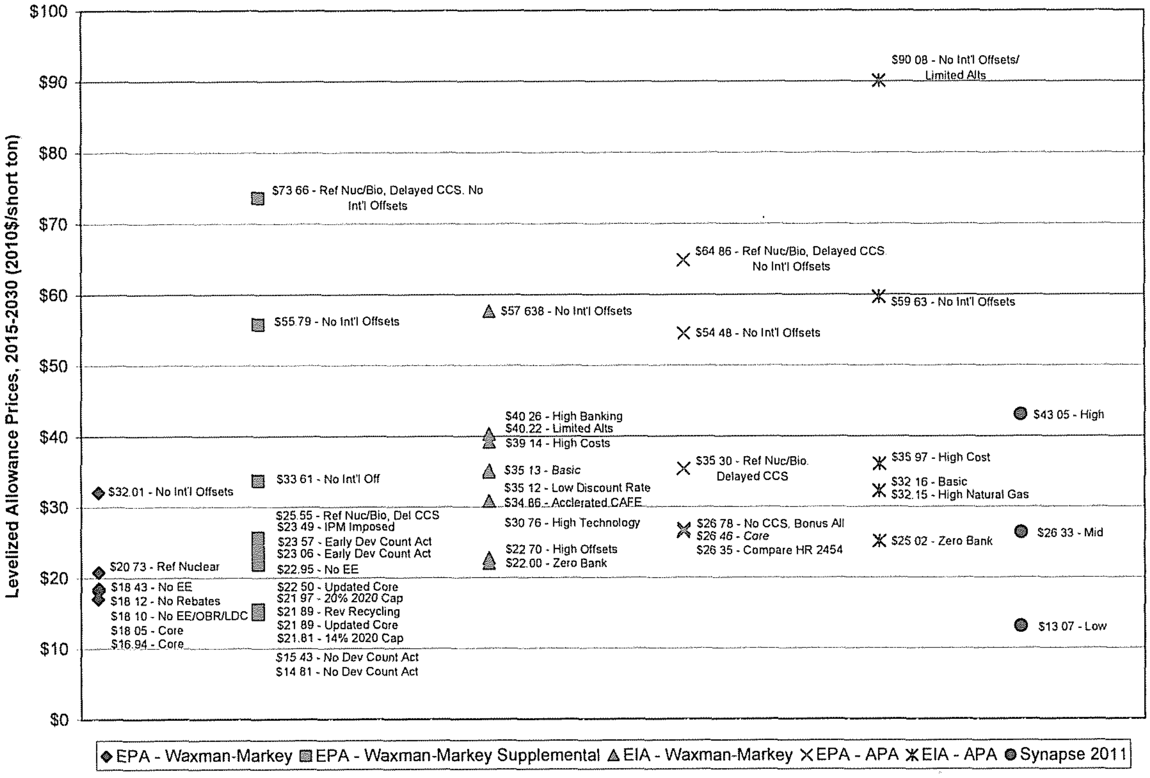
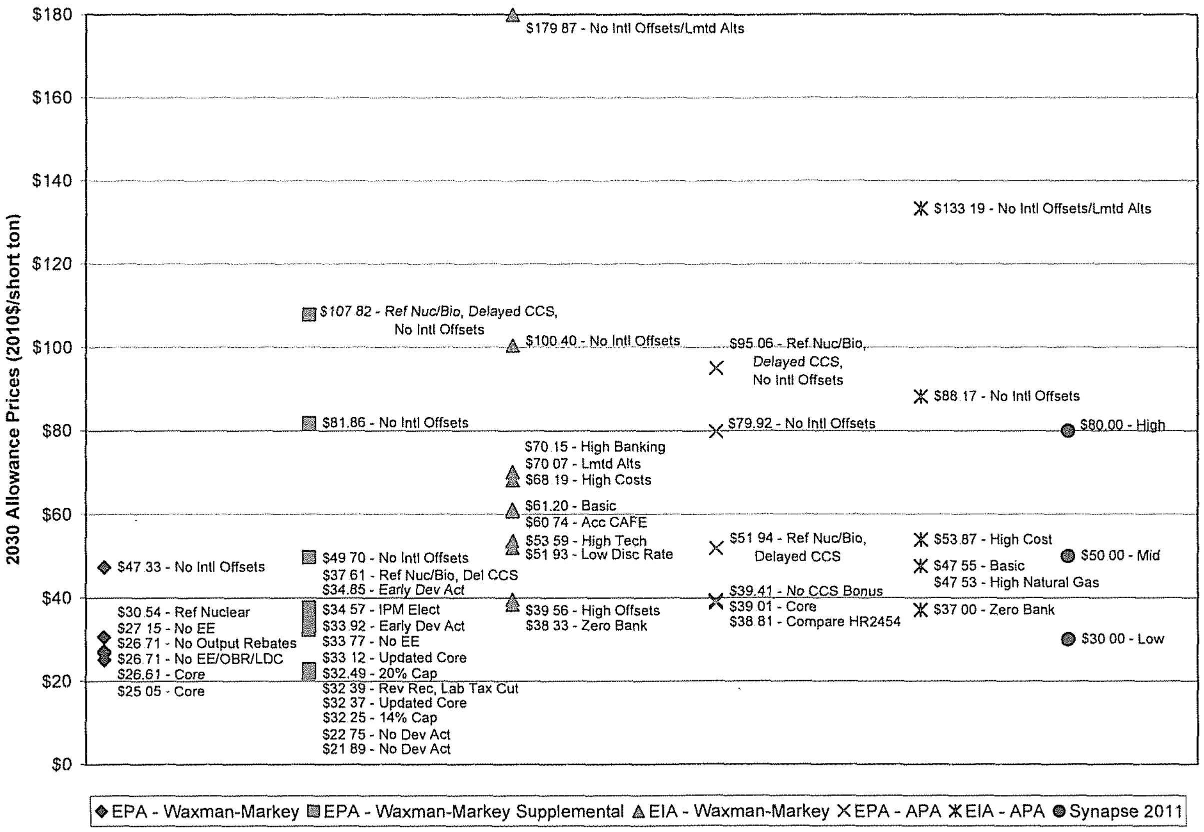


Figure 13: 2030 Synapse CO_2 prices and greenhouse gas allowance price projections for HR 2454 and APA 2010



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

6. Conclusion

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

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PUBLIC SERVICE
COMMISSION

Commonwealth of Kentucky

Before the Public Service Commission

In the Matter of:	)	
	)	
THE APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR CERTIFICATES OF PUBLIC CONVIENENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMETNAL SURCHARGE.	)	Case No. 2011-00162

In the Matter of:	)	
	)	
APPLICATION OF KENTUCKY UTILITIES FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	)	CASE NO. 2011-00161

Direct Testimony of
William Steinhurst, Ph.D.

On Behalf of
Sierra Club and
Natural Resources Defense Council

September 16, 2011

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 Vermont Department of Public Service, the Vermont Attorney-General's Office, the Delaware Public Utilities Commission, the Regulatory Assistance Project, National Association of Regulatory Utility Commissioners (NARUC), National Regulatory Research Institute (NRRI), American Association of Retired Persons (AARP), The Utility Reform Network (TURN), Union of Concerned Scientists, Northern Forest Council, Nova Scotia Utility and Review Board, U.S. EPA, Conservation Law Foundation, Sierra Club, Southern Alliance for Clean Energy, Oklahoma Sustainability Network, Natural Resources

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to consider certain environmental upgrades proposed by Kentucky Utilities (KU) and Louisville Gas and Electric (LG&E), both of PPL Company ("the Companies"), and whether the Kentucky PSC should grant Certificates of Public Convenience and Necessity (CPCN) and allow prospective rate recovery for those upgrades. I also address the question of whether the Commission should approve the Companies' integrated resource plan (IRP).

2. CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your primary conclusions and recommendations.

A. My primary conclusions are summarized as follows:

(1) At this time, the Commission should deny the requested CPNCs for the proposed environmental upgrades at the Companies' coal fired generating stations (the Proposed Retrofits) because further upgrades to those units are not cost effective.

(2) For the same reason, the Commission should deny the rate recovery requested for those upgrades at this time.

(3) The Commission should examine these same issues in its ongoing proceeding regarding the Companies' IRP.

(4) Given the resource challenges identified by witness Fisher, and in order to ensure future least cost service to ratepayers, the Commission should direct the Companies to develop resource alternatives that address the concerns identified in the prefiled testimony of witness Fisher and to file it by a single date certain along with supporting workpapers and documentation sufficient for the Commission and intervenors to fully evaluate the analytical basis for the alternatives. The Commission may wish to require that filing be made in its proceeding on the Companies' IRP. If so, it should not simply wait for the next triennial IRP since many of the options that

the Company for seeking to perform the correct analyses and for establishing a good foundation on which to correct these problems in the future. The Commission needs a comprehensive and consistent process for considering utility proposals for major investments in 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.

The Companies have started down that path, and the Commission should encourage and require them and other Kentucky utilities to continue down it as they plan for Kentucky's electric energy future. I would encourage the Commission and the Companies to continue exploring a broad array of alternative resources and to further develop methods for analyzing the risk and uncertainty of resource portfolios in addition to their expected costs.

Q. Does this conclude your testimony?

A. Yes, it does. However, as noted in the prefiled testimony of witness Fisher, further evaluation is necessary to determine whether and how the just-produced supplemental discovery responses impacts the points made and conclusions reached in our direct testimonies. We will address issues related to this in our supplemental testimonies.

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA.
Senior Consultant, July 2003 to Present
Consulting services to state and provincial energy regulators and public advocates, state provincial and national energy departments, and non-governmental organizations on regulatory policy, power supply procurement, electric industry restructuring, portfolio management, rate setting and rate design, economic impacts of efficiency and renewable generation programs, and other utility and energy topics. Expert witness services and litigation advice. Co-authored reports, journal articles and conference presentations on portfolio management, energy efficiency programs, and electric reliability.

Vermont Department of Public Service, Montpelier, VT.
Director for Regulated Utility Planning, 1986-2003
Preparation of long range policy plans in the areas of electric utilities, energy and telecommunications, including oversight of research, modeling, public input processes, policy analysis and writing. Development of policy positions and drafting of legislation and rules concerning utility resource planning, power supply acquisition, generation and transmission permitting, environmental costing, energy efficiency and alternative generation, utility restructuring and retail choice, distributed utility planning, rate setting and rate design, mergers, financing and acquisitions, decision analysis, power contract restructuring, Qualifying Facility contracts and permits, net metering, and other critical regulatory issues. Extensive expert testimony on those matters, as well as utility bankruptcy, prudence reviews, and critical utility policy matters. Extensive legislative testimony.

Planning Econometrician, 1981-1986
Energy demand forecasting, economic and demographic projections, economic and policy impact analysis, avoided cost estimates, and other quantitative analysis for utility and energy policy making. Development of State's basic policies regarding least cost planning and resource selection, including methods for evaluation of and program design for generation, transmission and demand-side options. Implementation of utility energy efficiency program requirements.

Vermont Agency of Human Services, Montpelier, VT.
Director of Planning, 1979-1981

Vermont Department of Social and Rehabilitation Services, Waterbury, VT.
Director of Planning and Evaluation, 1977-1979
Acting Deputy Commissioner, 1977

Vermont Department of Corrections, Montpelier, VT.
Director of Planning and Research, 1974-1977
Chief of Research and Statistics, 1973-1974

Continuing Education

Seminar in Electricity and Telecommunications Demand, 1981
Advanced Workshop in Regulation and Public Utility Economics, June, 1982 and
June, 1983, Rutgers University
Transmission Reliability Assessment, Power Technologies, Inc., 1986
Regional Forecasting and Simulation Modeling, January, 1991, U. Massachusetts-Amherst

TESTIMONY, EXPERT REPORTS and AFFIDAVITS

Vermont Public Service Board

On behalf of the Vermont Department of Public Service:

Docket 4661 - Green Mountain Power Rate Increase

Dockets 5009/5112 - Vt. Electric Coop. Rate Increase

Dockets 5108/5109 - Vt. Marble Co. Small Power Rate

Docket 5133 - Moretown Hydro Energy Co. Small Power Rate

Docket 5202 - VPPSA Refinancing

Docket 5248 - DPS Ontario Hydro Power Purchase

Docket 5270 - Least Cost Planning and Demand-Side Management

Docket 5270-GMP-1 - Highgate Apartments Fuel Switching

Docket 5270-CV-1&3 - Demand-Side Management Preapproval and Ratemaking Principles

Docket 5270-CV-4 - IRP

Docket 5270-VGS-1 - Demand-Side Management Preapproval

Docket 5270-WEC-1 - Demand-Side Management Preapproval

Dockets 5270-BRTN-1, 5270-CUC-3, 5270-HDPK-1, 5270-JHNS-1, 5270-JKSN-1,
5270-LDLW-1, 5270-LYND-1, 5270-MRSV-1, 5270-ORLN-1, 5270-RDSB-1,
5270-ROCH-1, 5270-STOW-1, 5270-SWNT-1, 5270-VMC-1 - IRP's

Docket 5270-VGS-2 - Demand-Side Management Preapproval

Docket 5277 - DPS Ontario Hydro Transactions Agreement

Docket 5330A - Hydro Quebec Power Purchase

Docket 5330E - Hydro Quebec Power Purchase, Waiver and Amendment

Docket 5372 - CVPSC Rate Increase

Docket 5491 - CVPSC Rate Increase

Docket 5630/32 - VEC Debt Restructuring & Rate Increase

Docket 5634 - NET Toll Dialing Plan

Docket 5638 - CVPSC Mack Molding*

Docket 5664 - EPACT Standards

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Docket 5826 - Vermont Marble Electric Division - IRP - externalities

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------- and G. Backus. "Application of System Dynamics to an Integrated Economic and Environmental Policy Assessment." In D. F. Andersen, et al., *System Dynamics '90, Proc. of the 1990 International System Dynamics Conf.*, Boston, MA., pp. 1060-1074.

------- and W. Merten. "Statistical Analysis of Thermal Shock Tests." *Statistics in Manufacturing*, S. G. Kapoor and M. R. Martinez, eds., ASME Proc., PED-9 (83), 51-56.

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Resume dated September 15, 2011.

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PUBLIC SERVICE COMMISSION

Commonwealth of Kentucky

Before the Public Service Commission

In the Matter of:

THE APPLICATION OF KENTUCKY UTILITIES COMPANY FOR CERTIFICATES OF PUBLIC CONVIENENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMETNAL SURCHARGE	)	Case No. 2011-00161

In the Matter of:

THE APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR CERTIFICATES OF PUBLIC CONVIENENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMETNAL SURCHARGE.	)	Case No. 2011-00162

Direct Testimony of
Rachel S. Wilson

On Behalf of
Sierra Club and Natural Resources Defense Council

September 16, 2011

Table of Contents

1. INTRODUCTION AND QUALIFICATIONS

Q Please state your name, business address and position.

A My name is Rachel Wilson and I am an Associate with Synapse Energy Economics, Inc. (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.

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

Q Please summarize your work experience and educational background.

At Synapse, I conduct research and assist in writing testimony and publications, focusing on a variety of issues relating to electric utilities, including: federal and state clean air policies; emissions from electricity generation; environmental compliance technologies, strategies, and costs; integrated resource planning; valuation of environmental externalities from power plants; and the nexus between water and energy.

I also provide project support through modeling-related analysis of electric power systems. I am proficient in the use of optimization and electricity dispatch models, including STRATEGIST, PROMOD, and PROSYM/Market Analytics, to conduct analyses of utility service territories and regional energy markets. I have participated in in-house trainings for STRATEGIST and also attended an advanced training session at the Atlanta headquarters of Ventyx, an ABB Company.

Prior to joining Synapse in 2008, I worked for Analysis Group, Inc., an economic and business consulting firm, where I focused on issues relating to energy and the electric industry. I was also a Research Assistant at the Yale Center for Environmental Law and Policy and was responsible for collecting and processing data on corporate and environmental strategy, as well as environmental performance data on a country-by-country basis.

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 Exhibit RW-1.

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of Sierra Club and the Natural Resources Defense Council.

Q Have you testified previously before the Kentucky Public Service Commission?

A No, I have not.

Q What is the purpose of your testimony?

A My testimony describes the Strategist modeling I performed in these dockets.

2. Description of Modeling Analysis

Q Please describe your modeling analysis.

A It was my responsibility, using the STRATEGIST databases provided by Kentucky Utilities (KU) and Louisville Gas & Electric (LG&E), collectively "the Companies," to execute modeling runs with revised input assumptions.

Prior to executing any modeling runs with changes to the inputs, I executed the runs performed by the Companies presented in these CPCN dockets, in order to verify that STRATEGIST was performing as expected. I was able to exactly reproduce the Companies' results. The "set" of STRATEGIST scenarios performed by the Companies include the following:

- No Retirements
- Retire Tyrone 3
- Retire Tyrone 3 and Green River 3
- Retire Tyrone 3, Green River 3, and Brown 3
- Retire Tyrone 3, Green River 3, and Cane Run 4
- Retire Tyrone 3, Green River 3, Cane Run 4, and Cane Run 6
- Retire Tyrone 3, Green River 3, Cane Run 4, Cane Run 6, and Brown 1-2
- Retire Tyrone 3, Green River 3, and Cane Run 4-6
- Retire Tyrone 3, Green River 3, Cane Run 4-6, and Ghent 3
- Retire Tyrone 3, Green River 3, Cane Run 4-6, and Ghent 1
- Retire Tyrone 3, Green River 3-4, and Cane Run 4-6
- Retire Tyrone 3, Green River 3-4, Cane Run 4-6, and Mill Creek 4
- Retire Tyrone 3, Green River 3-4, Cane Run 4-6, and Trimble County 1
- Retire Tyrone 3, Green River 3-4, Cane Run 4-6, and Ghent 4
- Retire Tyrone 3, Green River 3-4, Cane Run 4-6, and Mill Creek 2
- Retire Tyrone 3, Green River 3-4, Cane Run 4-6, and Ghent 3
- Retire Tyrone 3, Green River 3-4, Cane Run 4-6, and Mill Creek 1-2

I then constructed three new sets of STRATEGIST runs made up of the scenarios listed above using: 1) a revised gas price; 2) a price for carbon dioxide emissions; and 3) a revised gas price and a price for carbon dioxide emissions. These modified input assumptions were provided to me by Dr. Jeremy Fisher.

Dr. Fisher then used the results from my model runs in his retirement analysis.

Q After you performed your modeling analysis, did you subsequently find any errors in that analysis?

A Yes. I realized that the Companies' gas price inputs to the STRATEGIST model represent an annual maximum price. The Companies applied seasonal price adjustment factors to these annual maximum prices which results in gas prices that vary from month to month. The revised gas price input that I used in my modeling was intended to represent an average annual price. When the Companies seasonal price adjustment factors were applied, the resulting gas price was incorrect. I did not have the opportunity to re-run the STRATEGIST model after discovering this error before filing this direct testimony. However, I intend to re-run the STRATEGIST model for my supplemental testimony because the Companies included new natural gas price estimates in their supplemental discovery filed on September 14, 2011. I will correct this seasonal price error with the model re-runs and in my supplemental testimony, but believe that using a corrected gas price will not substantively change the findings of Dr. Fisher.

Q Does that conclude your testimony at this time?

A Yes.

Rachel Wilson

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. Associate, 2010 – present, Research Associate, 2008 – 2010.
Performs consulting, conducts research, and assists in writing testimony and reports on a wide range of issues relating to electric utilities, including federal and state clean air policies; emissions from electricity generation; environmental compliance technologies, strategies, and costs; integrated resource planning; valuation of environmental externalities from power plants; and the nexus between water and energy. Uses optimization and electricity dispatch models, including Strategist, PROMOD, and PROSYM/Market Analytics, 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 and 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.

CERES, Boston, MA. Student Consultant, Spring 2006.
As part of a four-person team, made strategic recommendations on all aspects of messaging and engagement to encourage corporate directors to act on the issue of climate change. First strategic recommendation was sustainable governance forums, which were profiled in New York Times article "Global Warming Subject for Directors at Big Companies" on September 21, 2006.

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, Master of Environmental Management, New Haven, Connecticut, 2007.
Concentration in Law, Economics, and Policy with a focus on energy issues and markets.

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

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

SKILLS AND ACCOMPLISHMENTS

Microsoft Office Suite, Lexis-Nexis, Platts Energy Database, Strategist, PROMOD, and PROSYM/Market Analytics, some SAS and STATA.
Competent in oral and written Spanish.
Hold the Associate in Risk Management (ARM) professional designation.

PUBLICATIONS AND PRESENTATIONS

Hornby, R., P. Chernick, C. Swanson, D. White, J. Gifford, M. Chang, N. Hughes, M. Wittenstein, R. Wilson, and B. Biewald. *Avoided Energy Supply Costs in New England: 2011 Report.* Prepared for the Avoided-Energy-Supply-Component (AESC) Study Group. July 21, 2011.

Wilson, R. and Paul Peterson. *A Brief Survey of State Integrated Resource Planning Rules and Requirements*. Prepared for the American Clean Skies Foundation. April 28, 2011.

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

Fisher, J., R. Wilson, N. Hughes, M. Wittenstein, and B. Biewald. *Benefits of Beyond BAU: Human, Social, and Environmental Damages Avoided Through the Retirement of the US Coal Fleet*. Prepared for the Civil Society Institute. January 25, 2011.

Peterson, P., V. Sabodash, R. Wilson, and D. Hurley. *Public Policy Impacts on Transmission Planning*. Prepared for Earthjustice, December 21, 2010.

Fisher, J., S. Levy, Y. Nishioka, P. Kirshen, R. Wilson, M. Chang, J. Kallay, and C. James. *Co-Benefits of Energy Efficiency and Renewable Energy in Utah*. Prepared for the State Energy Office of Utah, March 2010.

Wilson, R. "The Energy-Water Nexus: Interactions, Challenges, and Policy Solutions." Presented at the National Drinking Water Symposium 2009, October 2009.

Fisher, J., C. James, L. Johnston, D. Schlissel, R. Wilson, *Energy Future: A Green Alternative for Michigan*. Prepared for Natural Resources Defense Council and Energy Foundation, August 2009.

Schlissel, D., R. Wilson, L. Johnston, D. White, *An Assessment of Santee Cooper's 2008 Resource Planning*. April 2009.

Schlissel, D., A. Smith, R. Wilson, *Coal-Fired Power Plant Construction Costs*. July 2008.

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