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November 2, 2011

Jeff Derouen
Executive Director
Public Service Commission
211 Sower Blvd.
P.O. Box 615
Frankfort, Kentucky 40602-0615

RECEIVED
NOV 3 2011
PUBLIC SERVICE
COMMISSION

In re: Kentucky Public Service Commission Cases #2011-00161, 2011-00162

Dear Mr. Derouen,

On behalf of Environmental Intervenors, please accept, and file in the matters above, the enclosed originals and appropriate copies of:

1. Joint Motion to Allow James Richard Hornby to Adopt Direct Testimony of William Steinhurst's, including (a) the Joint Motion; (b) the original Steinhurst testimony with minor edits and an errata sheet; (c) Hornby's affidavit of qualifications, and (d) Hornby's affidavit of testimony.
2. Joint Motion to File Corrected Testimony of Dr. Jeremy Fisher.
3. Confidential Corrected Testimony of Dr. Fisher, including (a) the Corrected Testimony; (b) a Confidential errata sheet; and (c) Dr. Fisher's affidavit of the Confidential Corrected Testimony.
4. Public Corrected Testimony of Dr. Fisher, (a) the Corrected Testimony; (b) a Public errata sheet; and (c) Dr. Fisher's affidavit of the Public Corrected Testimony.

Thank you, kindly, and have an excellent week.

Best Regards,

Edward George Zuger III, Esq
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enclosures

cc: Parties

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED

NOV 3 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 COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	)	**CASE NO. 2011-00161**

JOINT MOTION BY DREW FOLEY, JANET OVERMAN, GREGG WAGNER, RICK CLEWETT, RAYMOND BARRY, SIERRA CLUB, AND NATURAL RESOURCES DEFENSE COUNCIL TO ALLOW JAMES RICHARD HORNBY TO ADOPT DIRECT TESTIMONY OF WILLIAM STEINHURST

Rick Clewett, Raymond Barry, Drew Foley, Janet Overman, Gregg Wagner, Sierra Club and Natural Resources Defense Council's (collectively "Environmental Intervenors") move the Commission to allow James Richard Hornby to adopt the Direct Testimony of William Steinhurst.

On September 19, 2011, William Steinhurst filed Direct Testimony in support of Environmental Intervenors. At that time, Dr. Steinhurst planned on testifying at the hearing for these dockets but, unfortunately, has developed some health problems and his doctors have advised him not to travel.

Environmental Intervenors move to have James Richard Hornby adopt the Direct Testimony of William Steinhurst. Mr. Hornby is extremely qualified to testify about the same issues that Mr. Steinhurst intended to address. Mr. Hornby is a senior consultant at Synapse Energy Economics, the same firm that employs Mr. Steinhurst. Mr. Hornby has worked in the energy industry since 1976, as a regulatory consultant, senior civil servant, and project engineer. Since 1986 he has submitted testimony on electric and natural gas planning, pricing, and market restructuring issues in approximately 120 proceedings for gas producers, retail energy service providers, electric and gas utilities, regulators, and consumer advocates. He has testified in proceedings before regulators in Arkansas, Arizona, California, Colorado, the District of Columbia, Florida, Maine, Maryland, Michigan, Minnesota, New Hampshire, Massachusetts, Hawaii, Indiana, Illinois, New York, New Jersey, Pennsylvania, North Carolina, South Carolina, Oklahoma, Rhode Island, Montana, Utah, West Virginia and Nova Scotia. For a complete listing of Mr. Hornby's qualifications, please see his curriculum vitae attached as Exhibit 1.

Mr. Hornby has reviewed the 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, selected input and output data from the Strategist Model as used by the Companies and Dr. Fisher, the retire/retrofit spreadsheet analyses prepared by the Companies and Dr. Fisher, the testimonies of Dr. Jeremy Fisher, Rachel Wilson, and William Steinhurst. After reviewing this information, Mr. Hornby can fully endorse Mr. Steinhurst's analysis and conclusions and adopt his testimony. Environmental Intervenors will make Mr. Hornby available at the hearing, so that the Commission and all parties can cross-examine Mr. Hornby regarding his opinions and recommendations.

Attached to this motion is the corrected Direct Testimony of William Steinhurst, which is the same testimony previously submitted on behalf of William Steinhurst with a few minor corrections. These corrections do not reflect a difference in opinion between Mr. Hornby and Mr. Steinhurst, as Mr. Steinhurst would have made these corrections if he was going to continue to testify. An errata sheet is included, which provides a line-by-line identification of how the initial direct testimony was altered.

Dated: November 2, 2011

Respectfully submitted,

Edward George Zuger III

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Dated: November 2, 2011

CERTIFICATE OF SERVICE

I certify that I mailed a copy of this Motion to Adopt Steinhurst Testimony by first class mail on November 2, 2011 to the following:

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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

ERRATA
November 2, 2011

- Cover page – delete page number
- Cover page – insert (As modified on November 2, 2011)
- Page 1 of testimony – insert page numbers starting at 1
- Page 3 of testimony, line 11 – replace "CPNCs" with "CPCNs"
- Page 4 line 20 and 21 replace "The Commission must take a proactive approach to ensure sound decision-making and to ensure that the Commission…" with "The Commission should ensure that it …"

Commonwealth of Kentucky

Before the Public Service Commission

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

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

Direct Testimony of
William Steinhurst, Ph.D.

On Behalf of
Sierra Club and
Natural Resources Defense Council

September 16, 2011
(As modified on November 2, 2011)

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1. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and occupation.

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

Q. Please describe Synapse Energy Economics.

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

Q. Please summarize your work experience and educational background.

A. I have over thirty years of experience in utility regulation and energy policy, including work on renewable portfolio standards and portfolio management practices for default service providers and regulated utilities, green marketing, distributed resource issues, economic impact studies, and rate design. Prior to joining Synapse, I served as Planning Econometrician and Director for Regulated Utility Planning at the Vermont Department of Public Service, the State's Public Advocate and energy policy agency. I have provided consulting services for various clients, including the Connecticut Office of Consumer Counsel, the Illinois Citizens Utility Board, the California Division of Ratepayer Advocates, the D.C. and Maryland Offices of the Public Advocate, the 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

Defense Council (NRDC), Illinois Energy Office, Massachusetts Executive Office of Energy Resources, James River Corporation, and Newfoundland Department of Natural Resources.

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

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

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

My resume is attached to this testimony as Exhibit WS-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. 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 CPCNs 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 Companies should consider as alternatives to the Proposed Retrofits may require lead time to implement.[1]

Q. What are the reasons for denying the requested CPCNs?

A. As explained in the prefiled testimony of witness Fisher, grave errors were made in the cost benefit analysis of retrofit versus retirement for the company's coal fired generating units. As he demonstrated, correcting only one of those errors fundamentally alters the cost-effectiveness results concerning a number of those units, and correcting two or more of those errors overturns the entire cost-effectiveness analysis of the Companies' strategic approach to addressing future generation needs.

Q. Why is it in the public interest for the Commission to deny the requested CPCNs and rate recovery?

A. Ratepayers are entitled to service under efficient and economic management; anything less results in rates that are not just and reasonable. Least cost resource selection is an essential prerequisite for efficient and economic management of a public utility. The Proposed Retrofits are not least cost resources for meeting customer needs, as shown by witness Fisher's prefiled direct testimony. The Commission should not issue a CPCN for such projects. Nor should the Commission allow rate recovery, much less authorize it in advance for such projects.

Q. Do you have additional recommendations for the Commission?

A. Yes. The Commission should ensure that it has sufficient information to evaluate the Companies' decisions that could result in significant costs to ratepayers. While witness Fisher and I oppose the Proposed Retrofits for specific factual and analytical reasons, we commend the Company for seeking to perform the correct analyses and for establishing a

---

[1] 807 KAR 5:058, Sec. 2, provides different IRP filing cycles for LG&E and KU. Nevertheless, the circumstances of this proceeding, namely the filing of a single IRP by the company and reliance of both LG&E and KU on the same coal fired generating stations which require decisions affecting both retail companies, are such that the Commission should require a single filing date for the corrected IRP. This is permitted by Sec. 2(c) of that regulation. The Commission should also require simultaneous filing of the IRP's supporting data and analyses for administrative economy and to advance the resolution of those decisions in the public interest and because this proceeding has demonstrated that no party can properly assess the IRP without that information. Furthermore, for the same reasons and despite the provision in Sec. 11(4) of that regulation ("A utility shall respond to the staff's comments and recommendations in its next integrated resource plan filing."), the Commission should set a date certain for submission of a corrected IRP as soon as possible.

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.

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

AFFIDAVIT OF JAMES RICHARD HORNBY TO ADOPT DIRECT TESTIMONY OF WILLIAM STEINHURST

Commonwealth of Massachusetts)
)
)

James Richard Hornby, being first duly sworn, states the following:

1. I am James Richard Hornby. My business address is Synapse Energy Economics, Inc., 485 Massachusetts Avenue, Cambridge, Massachusetts 02139.

2. I am a Senior Consultant at Synapse Energy Economics. I have worked in the energy industry since 1976, as a regulatory consultant, senior civil servant, and project engineer.

4. I joined Synapse in 2006. In my current capacity, I focus on areas of planning, market structure, ratemaking and contracting in the electricity and natural gas industries. My resource planning cases have included testimony on behalf of Staff of the Arkansas Public Service Commission in several electric utility planning cases as well the development of long-term projections of avoided costs of electricity and natural gas in New England for a coalition of utility program administrators in 2007, 2009 and 2011.

5. Prior to joining Synapse, I was a Principal with CRA International where I provided expert testimony and litigation support in several energy contract price arbitration proceedings,

as well as in ratemaking proceedings in Ontario, New York, Nova Scotia, and New Jersey. During that time I managed a major productivity improvement and planning project for two electric distribution companies within the Abu Dhabi Water and Electricity Authority. Prior to CRA, from 1986 to 1998, I worked as a regulatory consultant with Tellus Institute, where I served in several capacities, most recently as the Director of their energy group. At Tellus, I presented expert testimony on rates for unbundled retail services, analyzed the options for purchasing electricity and gas in deregulated markets, prepared testimony and reports on a range of gas industry issues including market structure, strategic planning, market analyses, and supply planning. Prior to 1986, I held several positions within the Nova Scotia Department of Mines and Energy over a seven year period, most recently as the Assistant Deputy Minister of Energy and Member of the Canada-Nova Scotia Offshore Oil and Gas Board. In Nova Scotia, I directed the preparation of provincial energy plans and analyses of policies to improve energy efficiency and to develop Nova Scotia's natural gas, coal and renewable energy resources.

3. I have a Bachelor of Industrial Engineering degree from Dalhousie University (Nova Scotia, Canada) and a Master of Science in Technology and Policy degree from the Massachusetts Institute of Technology (Massachusetts, U.S.A.).

4. Since 1986 I have submitted testimony on electric and natural gas planning, pricing, and market restructuring issues in approximately 120 proceedings for gas producers, retail energy service providers, electric and gas utilities, regulators, and consumer advocates. I have testified in proceedings before regulators in Arkansas, Arizona, California, Colorado, the District of Columbia, Florida, Maine, Maryland, Michigan, Minnesota, New Hampshire, Massachusetts, Hawaii, Indiana, Illinois, New York, New Jersey, Pennsylvania, North Carolina, South Carolina, Oklahoma, Rhode Island, Montana, Utah, West Virginia and Nova Scotia. I have also testified in a gas pipeline proceeding at the Federal Energy Regulatory Commission and before gas supply contract arbitration panels in Nova Scotia and Ontario. I have presented papers on these topics at conferences organized by NARUC, NASUCA, the DOE, and ACEEE.

JR Hornby
James Richard Hornby

SUBSCRIBED AND SWORN to before me this 2 day of November 2011.

Notary Public

My Commission Expires:

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

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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

AFFIDAVIT OF JAMES RICHARD HORNBY FOR DIRECT TESTIMONY

Commonwealth of)
Massachusetts)
)

James Richard Hornby, being first duly sworn, states the following: The prepared Direct Testimony (Public Version) and associated exhibits filed on Monday, September 19, 2011 constitute the direct testimony of Affiant in the above-styled cases. Affiant states that he would give the answers set forth in the Direct Testimony, Public Version, if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, his statements made are true and correct.

James Richard Hornby
James Richard Hornby

SUBSCRIBED AND SWORN to before me this 3 / day of October 2011.

Notary Public

My Commission Expires:

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

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

Corrected Direct Testimony of
Jeremy Fisher, Ph.D.

On Behalf of
Sierra Club and Natural Resources Defense Council

PUBLIC VERSION

September 23, 2011
Updated November 2, 2011

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1. Introduction and Qualifications

Q Please state your name, business address and position.

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

Q Please describe Synapse Energy Economics.

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

Q Please summarize your work experience and educational background.

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

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

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

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

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

A I am testifying on behalf of Sierra Club 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 Company's (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.
- Companies' Discovery responses and rebuttal testimony

Q Is this document the same as your originally filed direct testimony?

A It is not. Significant new information has come to light since the original filing of my original direct testimony, and the Companies have changed at least one underlying set of assumptions, both of which concern forecast natural gas prices. Between the new information from the Companies and the new underlying assumptions, it seemed helpful to both correct my original direct testimony and modify my recommendations in light of the new information, submitting a singular, clean record. I will discuss these changes in more depth later in this testimony.

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

A To the best of my knowledge. In my original testimony, I noted that "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 response included an entirely new and substantively different set of analyses that are highly apropos to the testimony." The range of natural gas price forecasts explored by the Companies in that supplement appeared to support my contention that the Companies' gas prices were too high, but I was not given access to these new forecasts until October 17, 2011, nearly a month after I filed my 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-E2:** Net Present Value Revenue Requirement of Installing Controls vs. Retiring and Replacing Capacity: Companies' Results and Re-Analysis Results
- **Exhibit JIF-E3:** 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 inappropriately bias a retire/retrofit decision towards maintaining older coal units, and that simply using more mid-range 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 is lower than the NPVRR of the case in which the unit is retrofit, the Companies find that it is more economical 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 significant concerns with the Companies' modeling assumptions and framework. The outcome of this analysis hinges on these assumptions, such that by simply examining a reasonable mid-range set of assumptions renders at least two additional units (Brown 1 & 2) non-economic and casts serious doubt on the economic viability of another two units (Mill Creek 1 & 2).

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

- **Natural gas price correction:** The Companies' base-case natural gas price forecast appears to inappropriately represent the highest end of gas price assumptions;
- **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, a single-cycle turbine of 194 MW, and two combined cycle sized at 605 and 907 MW (summer capacity), respectively. These large-size combined cycle units are larger than many of the coal units under consideration, 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 using a mid-range 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 mid-range 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-range 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-E2**. 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.

[1] 20110517_LAK_2011IRPRetirementStudies_MC1-2CombinedFGD_Laye.xlsx

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 mid-range gas price *or* evaluating the cost of SCR *or* utilizing a CO_2 price makes the decision to retrofit Brown 1 & 2 anywhere from risky to a net loss ($49, $34, or -$157 million NPVRR, respectively – found in **Exhibit JIF-E2** Boxes 3-5). Using the mid-range gas price in concert with anticipated costs of SCR strongly favors the retirement of Brown 1 & 2 (a loss of $146 million NPVRR relative to the non-retirement option – found in **Exhibit JIF-E2,** 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. Utilizing a CO_2 price 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 either the Companies' gas or CO_2 forecasts are adjusted to mid-range values, or when the reasonable risk of an SCR at the units are considered. In general, the risk of carbon prices poses a significant economic liability for the Companies.

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, as described below.

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 The Brown 1-3 units have already installed a new flue gas desulfurization (FGD) system, and the Trimble County unit is already in possession of an FGD unit. Of the non-retiring units, the four units at Mill Creek are anticipated by the Companies to require new or retrofit FGD systems, which can presumably meet SO_2 compliance obligations under both CSAPR and SO_2 NAAQS. FGDs 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 have 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 is 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

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

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.

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 Companies have 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 Companies 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 exceed 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 Companies 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 withdraw between 120 and 300 MGD. I assume that the Companies have access to data to know if the unit would be subject to the more stringent entrainment guideline.

[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

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 opinion that it is incumbent on the Companies to 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 efficient to operate the existing coal fleet up to the first high-cost compliance deadline, and then take out of service any units which are non-economic at that time.

To determine whether to retrofit or retire each unit in their fleet, 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 use 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 retrofitted 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. 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 able to replicate the Companies' originally filed results. 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. Using identical input, we were able to obtain the same results as the Companies.

The Companies' originally filed results are shown in **Exhibit JIF-E2** 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.

[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.

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

In **Exhibit JIF-E2** 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 outcome. Therefore, it was important to conduct a re-analysis with corrected assumptions to estimate how retire/retrofit decisions would change under a reasonable set of assumptions.

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 mid-range estimate as provided by the Companies;
- **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 other forecasts?

A The Companies have presented a range of gas price forecasts throughout this proceeding. The original forecast supplied by the Companies was outside the bounds of natural gas prices reflected by most other analysts.

Q Have the Companies provided alternative fuel price forecasts?

A Quite recently, yes. On September 14th, the Companies provided Supplemental analyses exploring the retire/retrofit decision with three more recent and lower price forecasts from PIRA Group, Wood Mackenzie, and IHS CERA, but did not provide the fuel forecast values. On October 17th, the Companies finally supplied the gas price forecasts from these three sources. Finally, in rebuttal testimony filed October 24, the Companies provided definitive information that their original forecasts were presented in nominal dollars and definitive information about the expected inflation rate for fuel costs,[7] thus partially explaining a large deviation from mid-range estimates. We have assumed that this same inflation rate, amounting to approximately 2.18% per year, applies to the other fuel price forecasts as well.

Q Are the alternative gas price forecasts consistent with others' forecasts?

A Yes. When the 2.18% inflation rate is removed from the PIRA, Wood Mackenize, and CERA prices, the real value of these forecasts appears to fall within the range of other analysts' estimates. As shown in **Figure 1**, below (and in **Exhibit JIF-E3**, page 1), we show the Companies' original estimate of the Henry Hub (HH)

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[7] Annual deflators for fuel, as used by the Companies, are given in rebuttal witness Sinclair's workpapers. Converting from nominal to real dollar values; the net impact amounts to an annually compounding interest rate of approximately 2.18%. The Company appears to use 2.5% inflation rate for capital expenditures, 2% for variable O&M costs (and in the conversion of a provided CO_2 price) but does not inflate the emergency energy cost in the model, leaving it at $16,600 / MWh in each year.

price in red triangles,8 a variety of publicly available forecasts for the HH price,9, 10, 11,12,13,14,15,16, and the Companies' proprietary, alternative forecasts (PIRA, Wood Mackenzie, and CERA) in shades of orange.

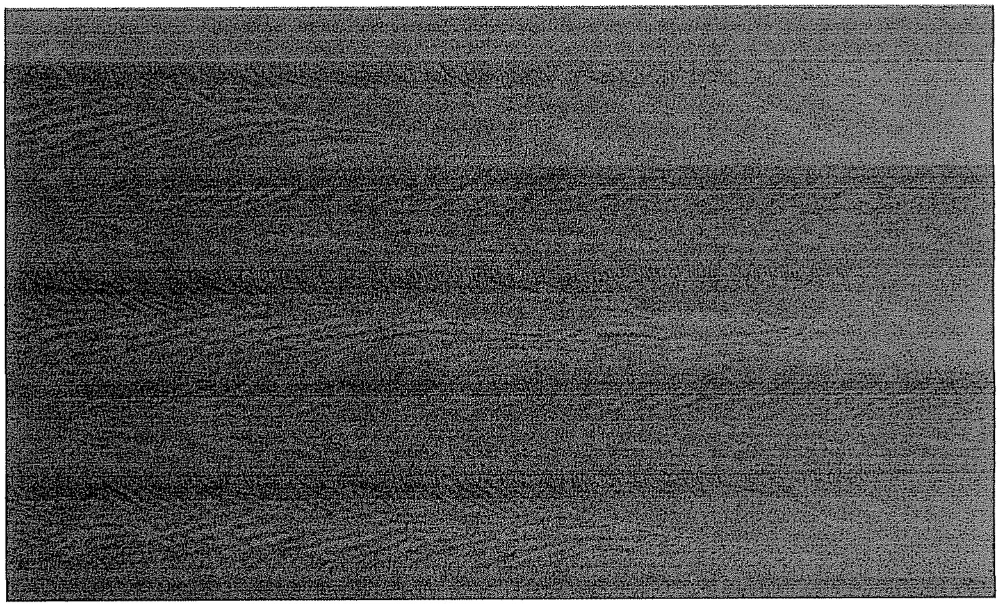

Figure 1. Henry Hub Natural Gas Price Comparisons: Companies Estimate, Other Analyst Forecasts, and Re-Analysis Forecast (AESC 2011)

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

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

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

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

[12] 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

[13] 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.

[14] 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

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

[16] 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

Expressed here in constant 2010$, the Companies' alternative forecasts appear to represent a reasonable range of high, mid, and low gas price forecasts.

Q Is it reasonable to use a high, mid, and low gas price forecast?

A It is. The use of a range of forecasts can help elucidate risk posed in an uncertain future. However, the Companies have chosen the highest of those prices to represent their "base case." It appears that the Companies' natural gas price forecast is at the high-end of the range of forecasts given by other public and private entities.

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

A In the initial form of this direct testimony, we had used a natural gas price 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 Companies released their alternative natural gas price forecasts in the October 17th Supplemental Analyses. Of the three alternatives presented, the Wood Mackenzie price is most consistent with the AESC baseline forecast, and appears to represent a reasonable mid-range forecast. Therefore, we have chosen to simplify the record by adopting the Wood Mackenzie price from the Companies' series of alternatives.

Q Would it still be reasonable to use the AESC forecast of natural gas prices as a mid-range forecast?

A Yes.

Q Please describe how you used the Wood Mackenzie natural gas price in the Strategist model.

A The Strategist model accepts natural gas prices in \$/MCF,[17] and in addition, it is apparent that the Companies have added a transportation or local price adjustment to the HH forecast and have set up the model to read gas prices as the highest annual monthly-average gas price. To adjust the Wood Mackenzie HH price to a burner-tip equivalent, we used a short conversion:

First, we converted Strategist input prices back to \$/MMBtu. Second, we extracted the seasonal gas price adjustment factors used by the Companies to adjust from the highest price month to monthly prices. We obtained the average of these factors on an annual basis (2010-2025), assuming that the average roughly represents the deflator from the highest price month to the annual average price. Next, we adjusted the "high" delivered price forecast (in \$/MMBtu) to the annual average price, and examined the difference between this price and the Companies' Henry Hub forecast (p. 4 of the Sensitivity Analysis[18]). We assumed the resulting \$0.35 to \$0.40 adder was the local price adjustment from HH. This cost is similar to the premium estimated by the EIA for electric generation in East South Central region (including KY) relative to HH in 2010.

We then reversed this process for the Wood Mackenzie HH price, adding the delivery charge, dividing by the seasonal adjustment factor, and converting back into \$/MCF. This revised value was exported back to the Strategist model.

Retaining consistency with the Companies' assumptions, we held the nominal price of the Wood Mackenzie HH forecast constant from 2025 through the end of the analysis period, as shown in the Wood Mackenzie line of **Exhibit JIF-E3**, on page 2.

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[17] The prices in the model, in \$/MCF, replicate those given in the "Attachment to Response to KPSC-1 Question No. 44" which are listed as fuel costs in \$/MMBtu. It is assumed that the units in model, rather than the discovery response, are correct.

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

Q Were you able to reproduce the results given by the Companies in the October 17th Supplemental Analyses?

A We were not able to replicate the results exactly. As shown in Table 1, below, we obtained similar, but not exact results. The tables below are similar to those shown in **Exhibit JIF-E2**, where each value represents the relative net present value of installing controls versus retiring and replacing capacity. The Companies' results, from the October 17th Supplemental Analyses are shown in the first box, while Synapse's re-analysis, using the same data, are shown in the middle box. The third box shows the difference between these two analytical results.

Table 1. Difference in NPVRR (2011$) between Companies' Supplemental Analysis and Synapse Re-Analysis using Wood Mackenzie 2011 price forecast.

KU/LGE Supplemental Analysis	
Table 5 - PVRR of Installing Controls vs. Retiring and Replacing Capacity	
Tyrone 3	-10
Green River 3	-88
Brown 3	357
Cane Run 4	-187
Cane Run 6	-145
Brown 1-2	39
Cane Run 5	-171
Ghent 3	520
Ghent 1	400
Green River 4	-140
Mill Creek 4	481
Trimble County 1	675
Ghent 4	750
Mill Creek 3	453
Ghent 2	755
Mill Creek 1-2	536

Synapse Re-Analysis	
Nominal Wood Mackenzie Gas Price*	
Tyrone 3	-59
Green River 3	-66
Brown 3	368
Cane Run 4	-240
Cane Run 6	-67
Brown 1-2	49
Cane Run 5	-193
Ghent 3	529
Ghent 1	430
Green River 4	-130
Mill Creek 4	484
Trimble County 1	654
Ghent 4	727
Mill Creek 3	423
Ghent 2	728
Mill Creek 1-2	530

Difference	
Synapse minus KU/LGE	
Tyrone 3	-49
Green River 3	22
Brown 3	11
Cane Run 4	-53
Cane Run 6	78
Brown 1-2	10
Cane Run 5	-22
Ghent 3	9
Ghent 1	30
Green River 4	10
Mill Creek 4	3
Trimble County 1	-21
Ghent 4	-23
Mill Creek 3	-30
Ghent 2	-27
Mill Creek 1-2	-6

We were not given the Companies workpapers, and so do not know why our results are not identical to the Companies, but it is possible that we may have adjusted the Henry Hub gas price to a local gas price using a different formulation than that of the Companies or used a different coal price than the Companies.[19] Regardless, there are no directional changes in our re-analysis, but there are changes in the magnitude of benefit realized through the retirement or retrofit of any given set of units.

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

A Yes. By adjusting the natural gas price forecast to a reasonable mid-range estimate, the relative benefit of maintaining any of the coal units diminishes significantly, but is particularly notable at Brown 1 & 2. As shown in **Exhibit JIF-E2** in Box 3, the NPVRR benefit of maintaining Brown 1 & 2 falls from $228 million to $49 million (or $39 million by the Companies' calculation).

In other words, the re-analysis with a mid-range gas price would suggest that Brown 1 & 2 are a high risk for continued operation. While a lower gas price alone does not *a priori* render these units non-economic, I believe that other faults

[19] Synapse maintained the original coal price forecast used by the Companies in the 2011 Compliance plan.

in Company assumptions quickly erode the remaining margin, including the inflated emergency energy cost assumptions (discussed later in my testimony).

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

Q In the summary, you stated that the Companies have 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.[20]

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.[21]

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 9, 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 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?**

A 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

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

[21] 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?

A 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)

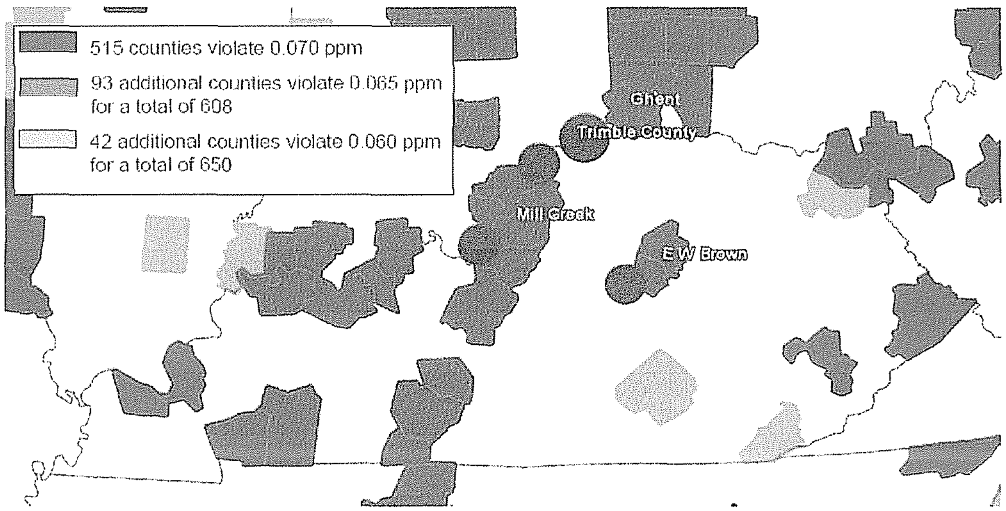

Figure 2. Counties With Monitors Violating Primary 8-hour Ground-level Ozone Standards 0.060 - 0.070 parts per million (based on 2006-2008 Air Quality Data). Kentucky detail, Modified from EPA.[22]

While there is no guarantee that these counties will still violate the standard when the rule is promulgated, these regions have poor air quality that 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.

[22] 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, there is a risk that 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 that these units will need to install SCRs to remain compliant with the law 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-E2,** 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 narrow 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 mid-range gas price at these stations?

A Combining the mid-range 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-E2**, Box 6. Our re-analysis indicates that retrofitting Brown 1 & 2 would result in a NPVRR *loss* of $146 million to the Companies, and is an inefficient solution.

The Ghent 2 and Mill Creek 1 & 2 units are also diminished in benefit to $441 and $270 million NPVRR relative to a retirement decision, significantly down from the billion dollar benefit suggested by the Companies' original analysis (**Exhibit JIF-E2**, 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 obtain air permits that regulate these emissions. 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 or regulatory 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.

I used a straight-line extrapolation to extend the Synapse Mid CO2 price through 2040, and adjusted the price from constant 2010$ to nominal dollars at the 2.18% inflation rate consistent with the Companies effective natural gas price inflation rate (see rebuttal witness Sinclair workpapers). Sierra Club witness Ms. Wilson incorporated these 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 CO2 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-E2,**, 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' original gas and SCR assumptions intact. Imposing the Synapse Mid CO_2 price results in an economic loss at Brown 1 & 2 of $157 million, at Mill Creek 1 & 2 of $20 million, and even Ghent 1 of $4 million.

Using a mid-range gas price provided by the Companies', and imposing a CO_2 price risk 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-E2,**, Box 7).[23]

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-E2,**, 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 flawed, tainting the analysis and ultimately exposing ratepayers to unnecessary risk. Any one of these 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 assessed how it could change the forward-going economics of their coal fleet.

I find that the Brown 1 & 2 unit retrofit is a high risk, and likely a net loss under reasonable mid-range assumptions, and that the Companies' gas price and CO2 assumptions overstate the benefit realized by maintaining these units.

[23] 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.

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 3**, 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.[24]

[24] Scenario using Companies assumptions.

- 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,[25] 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.

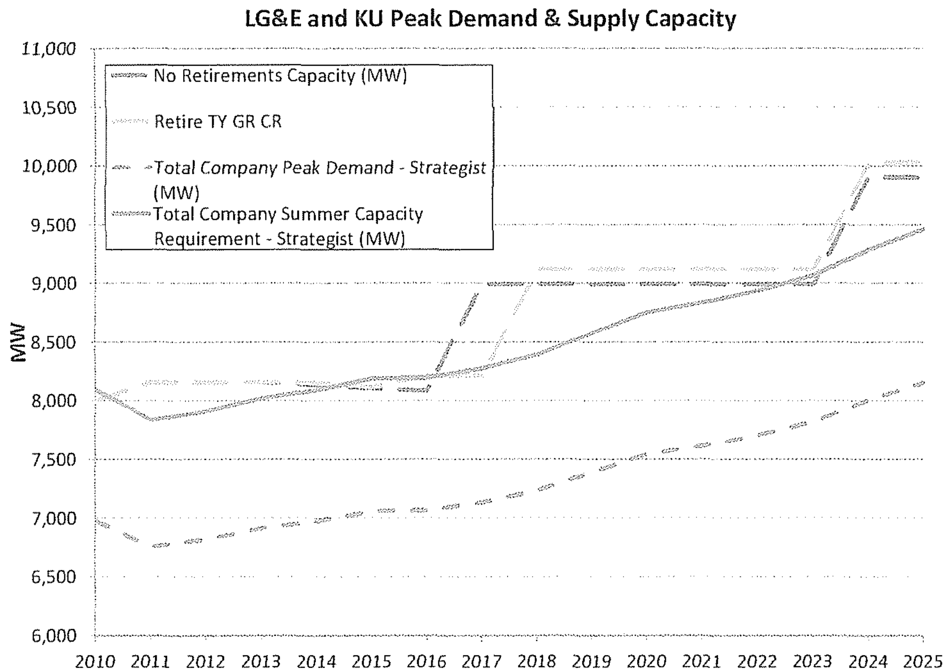

Figure 3. Peak demand, summer capacity requirement (assuming 16% target reserve margin), and supply in two retire/retrofit cases.

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

[25] 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.

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. In this case, the Companies should consider modeling incremental shares of a large, cost effective natural gas plant, as if it were to be a shared expense with other utilities in similar positions.

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[26] - 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.

[26] The $16,600 value remains constant throughout the study period, implying that the cost diminishes in real terms over the analysis period.

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?

A Costs of $10-$90 million are small 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, particularly for marginal units. It is unclear what threshold the Companies would require in order to determine if retirement or 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. For example, as indicated in Exhibit CRS-2 toWitness Schram's rebuttal testimony, high emergency energy costs consistently favors the retrofit decision. Of note, using a $16,600/MWh charge rather than, for example, a cost of $1,000/MWh favors the retrofit of Mill Creek by $76 million, and Brown 1 & 2 by $23 million. I conclude that, even for these forward-planning exercises, 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 diminish the $33 million dollar value and feasibly change the results of the analysis. Indeed, witness Shram's rebuttal testimony would suggest that this value could be only $10 million net benefit if the cost of emergency energy is closer to $1000/MWh rather than $16,600/MWh.

Q What is your concern with the Companies' SO2 and NOx prices?

A In the concurrent 2011 IRP, the Companies show their 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 and outside the state to a limited extent under 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 retrofitted. The Companies should incorporate these costs into the Strategist model.

Q So why are the Companies' SO2 and NOx 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 "many 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. 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/retrofit solutions.

I believe that these types of adjustments would make for a less noisy and more realistic solution by which to judge the merits of granting CPCN.

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

A 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?

A In my opinion, the company has used a series of input assumptions in their retire/retrofit model that do not adequately reflect ratepayer risk. In addition, I have identified a number of concerns with the Companies' 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 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 Companies appear to endorse as evidenced in their late-breaking "Supplemental

Analysis" filed on September 14, 2011', the economic merit of retrofitting the Companies' 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 of SCR at Brown 1 & 2 should result in the choice to retire, rather than retrofit these units. When the mid-range gas price forecast is utilized and under the circumstance that SCR is required, Brown 1 & 2 are clearly non-economic and pose 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 My recommendation is two-fold:

- First, under most reasonable assumptions, retrofitting and operating Brown Units 1 & 2 is anywhere from marginal to non-economic, relative to replacement with natural gas. Therefore, I recommend the Commission deny CPCN for these units. It is unlikely that a re-analysis of the risks to Brown Units 1 & 2 would result in a dramatically different outcome for these units.

- Second, a corrected gas price and mid-level CO_2 price appears to render much of the KU/LG&E fleet non-economic. However, in absence of more information about replacement capacity availability and transmission costs and availability, a specific course of action for these other units cannot be recommended at this time. Instead, it is incumbent on the Companies to assess these costs and risks comprehensively prior to requesting a CPCN.

The net impact of these considerations is that I recommend that, in this docket, the Commission deny the requested CPCNs.

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

Nominal Dollar Analysis & Wood Mackenzie Gas Prices - October 31, 2011

Original KU/LG&E Analysis

KU / LG&E Assumptions — Original — Box 1	
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 — Original, Formula Corrected — Box 2	
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

*Wood Mackenzie Gas and/or Synapse Mid CO2, Nominal

Synapse Re-Analysis Single Variable Correction

Synapse Re-Analysis — A — Box 3	
Nominal Wood Mackenzie Gas Price*	
Tyrone 3	-59
Green River 3	-66
Brown 3	368
Cane Run 4	-240
Cane Run 6	-67
Brown 1-2	49
Cane Run 5	-193
Ghent 3	529
Ghent 1	430
Green River 4	-130
Mill Creek 4	484
Trimble County 1	654
Ghent 4	727
Mill Creek 3	423
Ghent 2	728
Mill Creek 1-2	530

Synapse Re-Analysis — B — Box 4	
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 — C — Box 5	
Synapse Mid CO_2 Price*	
Tyrone 3	-87
Green River 3	-74
Brown 3	-70
Cane Run 4	-450
Cane Run 6	-384
Brown 1-2	-157
Cane Run 5	-329
Ghent 3	58
Ghent 1	-4
Green River 4	-234
Mill Creek 4	162
Trimble County 1	387
Ghent 4	422
Mill Creek 3	177
Ghent 2	438
Mill Creek 1-2	-20

Synapse Re-Analysis Multiple Variable Correction

Synapse Re-Analysis — A + B — Box 6	
Nominal Wood Mackenize Gas Price* + SCRs	
Tyrone 3	-59
Green River 3	-66
Brown 3	368
Cane Run 4	-240
Cane Run 6	-67
Brown 1-2 (+SCR)	-146
Cane Run 5	-193
Ghent 3	529
Ghent 1	430
Green River 4	-130
Mill Creek 4	484
Trimble County 1	654
Ghent 4	727
Mill Creek 3	423
Ghent 2 (+SCR)	441
Mill Creek 1-2 (+SCR)	270

Synapse Re-Analysis — A + C — Box 7	
Nominal WoodMac Gas + Synapse Mid CO_2*	
Tyrone 3	-118
Green River 3	-129
Brown 3	-475
Cane Run 4	-594
Cane Run 6	-621
Brown 1-2	-324
Cane Run 5	-386
Ghent 3	-347
Ghent 1	-357
Green River 4	-336
Mill Creek 4	-157
Trimble County 1	75
Ghent 4	96
Mill Creek 3	-121
Ghent 2	99
Mill Creek 1-2	-563

Synapse Re-Analysis — A + B + C — Box 8	
Nominal AESC Gas + Synapse Mid CO_2* + SCRs	
Tyrone 3	-118
Green River 3	-129
Brown 3	-475
Cane Run 4	-594
Cane Run 6	-621
Brown 1-2 (+SCR)	-519
Cane Run 5	-386
Ghent 3	-347
Ghent 1	-357
Green River 4	-336
Mill Creek 4	-157
Trimble County 1	75
Ghent 4	96
Mill Creek 3	-121
Ghent 2 (+SCR)	-189
Mill Creek 1-2 (+SCR)	-824

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

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

Commonwealth of Massachusetts)
)
)

Dr. Jeremy Fisher, being first duly sworn, states the following: The prepared Corrected Direct Testimony (Public Version) and associated exhibits filed on Wednesday, November 02, 2011 constitute the direct testimony of Affiant in the above-styled cases. Affiant states that he would give the answers set forth in the Corrected Direct Testimony, Public Version, if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, his statements made are true and correct.

____
Dr. Jeremy Fisher

SUBSCRIBED AND SWORN to before me this 2 day of November 2011.

____
Notary Public

My Commission Expires:

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

On page 2, update the Table of Contents page numbers to the following:

1. Introduction and Qualifications 3
2. Summary and Conclusions 6
3. Environmental Regulations Faced by LG&E/KU 12
4. Synapse Retire/Retrofit Re-Analysis 17
5. Gas Price Correction 20
6. Costs for SCR at Brown 1 & 2, Ghent 2, and Mill Creek 1 & 2 26
7. Carbon Mitigation Risk 32
8. Re-Analysis Findings 35
9. Additional Analytical Concerns 36
10. Conclusions 44

On page 5, insert a new text following line 11 that reads (in bulleted format):

- Companies' Discovery responses and rebuttal testimony.

On page 5, following the insertion above, insert new text that reads:

Q **Is this document the same as your originally filed direct testimony?**

A It is not. Significant new information has come to light since the original filing of my original direct testimony, and the Companies have changed at least one underlying set of assumptions, both of which regard forecast natural gas prices. Between the new information from the Companies and the new underlying assumptions, it seemed to be helpful to both correct my original direct testimony, and modify my recommendations in light of the new information, submitting a singular, clean record. I will discuss these changes in more depth later in this testimony.

On page 5 at line 14, strike "Unfortunately, no, because" and replace with "To the best of my knowledge. In my original testimony, I noted that"

On page 5 at line 14, insert a quotation mark before "the Companies"

On page 5 at line 16, insert "response" between "supplemental" and "included"

On page 5 at line 18, insert a period and a quotation mark after "the testimony"

On page 5 at line 18, strike "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

On page 5 at line 18, strike "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." Replace with: "The range of natural gas price forecasts explored by the Companies in that supplement appeared to support my contention that the Companies' gas prices were too high, but I was not given access to these new forecasts until October 17, 2011, nearly a month after I filed my testimony."

On page 5, strike lines 22 through 28.

On page 6, strike lines 1 and 2.

On page 6 at line 6, strike "Exhibit JIF-2" and replace it with "Exhibit JIF-E2"

On page 6 at line 9, strike "Exhibit JIF-3" and replace it with "Exhibit JIF-E3"

On page 6 at line 15, insert a space between "CPCN" and "/"

On page 7 at line 1, strike "are outliers" and replace with "inappropriately bias a retire/retrofit decision towards maintaining older coal units,"

On page 7 at line 2, strike "reasonable" and replace with "mid-range"

On page 7 at line 19, strike the comma after "unit is retired" and replace with "is lower than the NPVRR of the case in which the unit is retrofit, the"

On page 7 at line 20, strike "economic" and replace with "economical"

On page 8 at line 5, strike "found"

On page 8 at line 5, strike "errors in" and replace with "concerns with"

On page 8 at line 6, insert a period after "framework"

On page 8 at line 6, strike "which when corrected significantly change the outcome of this analysis, ultimately rendering" and replace with "The outcome of this analysis hinges on these assumptions, such that by simply examining a reasonable mid-range set of assumptions renders"

On page 8 at line 7, strike "deeply"

On page 8 at line 8, strike "which cast" and replace with "casts"

On page 8 at line 10, strike "contains the following errors," and replace with "incorrectly characterizes the following elements,"

On page 8 at line 12, strike "The assumed future price of natural gas is highly inflated by the Companies;" and replace with "The Companies' base-case natural gas price forecast appears to inappropriately represent the highest end of gas price assumptions;"

On page 8 at line 22, strike "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." And replace with "The Companies assume that replacement generation is only available from three types of natural gas plants, a single-cycle turbine of 194 MW, and two combined cycle sized at 605 and 907 MW (summer capacity), respectively. These large-size combined cycle units are larger than many of the coal units under consideration, forcing the model to only evaluate unduly expensive alternatives that present potentially non-optimal solutions."

On page 9 at line 20, strike "correcting the Companies'" and replace with "using a mid-range"

On page 9 at line 24, strike "mainstream" and replace with "mid-range"

On page 9 at line 26, strike "mid-level" and replace with "mid-range"

On page 10 at line 3, strike "JIF-2" and replace with "JIF-E2"

On page 10 at line 22, strike "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 $193 million NPVRR relative to the non-retirement option – found in **Exhibit JIF-2** Box 6)." And replace with "but using *either* a mid-range gas price or evaluating the cost of SCR or utilizing a CO_2 price makes the decision to retrofit Brown 1 & 2 anywhere from risky to a net loss ($49, $34, or -$157 million NPVRR, respectively – found in Exhibit **JIF-E2** Boxes 3-5). Using the mid-range gas price in concert with anticipated costs of SCR strongly favors the retirement of Brown 1 & 2 (a loss of $146 million NPVRR relative to the non-retirement option – found in **Exhibit JIF-E2**, Box 6)."

On page 11 at line 6, insert "Utilizing a CO_2 price" before "in concert with corrected"

On page 11 at line 13, insert "either" before "the Companies'"

On page 11 at line 13, strike "analysis is corrected and in particular when the reasonable risk of NO_x reductions through SCR is considered." and replace with "gas or CO_2 forecasts are adjusted to mid-range values, or when the reasonable risk of an SCR at the units are considered."

On page 11 at line 14, strike "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," and replace with "In general, the risk of carbon prices poses a significant economic liability for the Companies."

On page 11, strike lines 19 through 22.

On page 13 at line 3, insert ", as described below" after "exceptions"

On page 13 at line 14, strike "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)," and replace with "The Brown 1-3 units have already installed a new flue gas desulfurization (FGD) system, and the Trimble County unit is already in possession of an FGD unit. Of the non-retiring units, the four units at Mill Creek are anticipated by the Companies to require new or retrofit FGD systems,"

On page 15 at line 7, replace "company has" with "Companies have"

On page 15 at line 11, replace "company" with "Companies"

On page 16 at line 5, insert "exceed" after "are likely to"

On page 16 at line 13, replace "company" with "Companies"

On page 16 at line 16, replace "company has" with "Companies have"

On page 17 at line 11, strike "most"

On page 17 at line 12, strike "retire" and replace with "take out of service"

On page 17 at line 14, strike "its fleets" and replace with "their fleet"

On page 17 at line 19, strike "uses" and replace with "use"

On page 18 at line 5, insert "able to replicate the Companies' originally filed results" after "We were"

On page 18 at line 8, insert "Using identical input," before "we were able to obtain"

On page 18 at line 10, strike "The Companies results are shown in Exhibit JIF-1" and replace with "The Companies' originally filed results are showing in Exhibit JIF-E2"

On page 18 at line 20, strike "JIF-2" and replace with "JIF-E2"

On page 19 at line 2, insert "under a reasonable set of assumptions" after "would change"

On page 19 at line 12, strike "more mainstream" and replace with "mid-range"

On page 19 at line 12, insert "as provided by the Companies" after "estimate"

On page 19 at line 22, insert "others'" after "consistent with"

On page 19 at line 23, strike: "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 double 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." And replace with "The Companies have presented a range of gas price forecasts throughout this proceeding. The original forecast supplied by the Companies was outside the bounds of natural gas prices reflected by most other analysts."

On page 20, prior to line 3, insert a new question and answer, as follows: "Have the Companies provided alternative fuel price forecasts?" "Quite recently, yes. On September 14th, the Companies provided Supplemental analyses exploring the retire/retrofit decision with three more recent and lower price forecasts from PIRA Group, Wood Mackenzie, and IHS CERA, but did not provide the fuel forecast values. On October 17th, the Companies finally supplied the gas price forecasts from these three sources. Finally, in rebuttal testimony filed October 24, the Companies provided definitive information that their original forecasts were presented in nominal dollars and definitive information about the expected inflation rate for fuel costs,[footnote 7] thus partially explaining a large deviation from mid-range estimates. We have assumed that this same inflation rate, amounting to approximately 2.18% per year, applies to the other fuel price forecasts as well."

On page 20, insert footnote 7 as follows: "Annual deflators for fuel, as used by the Companies, are given in rebuttal witness Sinclair's workpapers. Converting from nominal to real dollar values; the net impact amounts to an annually compounding interest rate of approximately 2.18%. The Company appears to use 2.5% inflation rate for capital expenditures, 2% for variable O&M costs (and in the conversion of a provided CO2 price) but does not inflate the emergency energy cost in the model, leaving it at $16,600 / MWh in each year."

On page 20, prior to line 3, insert the new question: "Are the alternative gas price forecasts consistent with others' forecasts?"

On page 20 at line 3, insert "Yes. When the 2.18% inflation rate is remove from the PIRA, Wood Mackenize, and CERA prices, the real value of these forecasts appears to fall within the range of other analysts' estimates. As shown in" before "Figure 1"

On page 20 at line 3, strike "JIF-3" and replace with "JIF-E3"

On page 20 at line 4, insert "original" before "estimate"

On page 20 at line 5, strike "as well as our recommended correction in black circles" and replace with "and the Companies' proprietary, alternative forecasts (PIRA, Wood Mackenzie, and CERA) in shades of orange."

On page 21 at line 1, strike Figure 1 chart and replace it with this updated chart:

[redacted]

On page 21, prior to line 4, insert "Expressed here in constant 2010$, the Companies' alternative forecasts appear to represent a reasonable range of high, mid, and low gas price forecasts."

On page 21, prior to line 4, insert a new question and answer, as follows: "Is it reasonable to use a high, mid, and low gas price forecast?" "It is. The use of a range of forecasts can help elucidate risk posed in an uncertain future. However, the Companies have chosen the highest of those prices to represent their "base case". It appears that the Companies' natural gas price forecast is at the high end of the range of forecasts given by other public and private entities."

On page 21 at line 4, strike "the" and replace with "your"

On page 21 at line 5, strike "In our re-analysis, we have used an HH forecast" and replace with "In the initial form of this direct testimony, we had used a natural gas price forecast"

On page 21 at line 9, strike "The report reviews gas"

On page 21 at line 9, insert the following new text and Table following "as other experts."

> The Companies released their alternative natural gas price forecasts in the October 17th Supplemental Analyses. Of the three alternatives presented, the Wood Mackenzie price is most consistent with the AESC baseline forecast, and appears to represent a reasonable mid-range forecast. Therefore, we have chosen to simplify the record by adopting the Wood Mackenzie price from the Companies' series of alternatives.

Q Would it still be reasonable to use the AESC forecast of natural gas prices as a mid-range forecast?

A Yes.

Q Please describe how you used the Wood Mackenzie natural gas price in the Strategist model.

A The Strategist model accepts natural gas prices in $/MCF,[1] and in addition, it is apparent that the Companies have added a transportation or local price adjustment to the HH forecast and have set up the model to read gas prices as the highest annual monthly-average gas price. To adjust the Wood Mackenzie HH price to a burner-tip equivalent, we used a short conversion:

First, we converted Strategist input prices back to $/MMBtu. Second, we extracted the seasonal gas price adjustment factors used by the Companies to adjust from the highest price month to monthly prices. We obtained the average of these factors on an annual basis (2010-2025), assuming that the average roughly represents the deflator from the highest price month to the annual average price. Next, we adjusted the "high" delivered price forecast (in $/MMBtu) to the annual average price, and examined the difference between this price and the Companies' Henry Hub forecast (p4 of the Sensitivity Analysis [footnote 18]). We assumed the resulting

$0.35 to $0.40 adder was the local price adjustment from HH. This cost is similar to the premium estimated by the EIA for electric generation in East South Central region (including KY) relative to HH in 2010.

[1] The prices in the model, in $/MCF, replicate those given in the "Attachment to Response to KPSC-1 Question No. 44" which are listed as fuel costs in $/MMBtu. It is assumed that the units in model, rather than the discovery response, are correct.

We then reversed this process for the Wood Mackenzie HH price, adding the delivery charge, dividing by the seasonal adjustment factor, and converting back into $/MCF. This revised value was exported back to the Strategist model.

Retaining consistency with the Companies' assumptions, we held the nominal price of the Wood Mackenzie HH forecast constant from 2025 through the end of the analysis period, as shown in the Wood Mackenzie line of **Exhibit JIF-E3**, on page 2.

[footnote 18: Found in Attachment to Response to SC/NRDC Production of Documents Question No. 16. 2011 Air Compliance Plan Sensitivity Analysis. July 2011]

Q **Were you able to reproduce the results given by the Company in the October 17th Supplemental Analyses?**

We were not able to replicate the results exactly. As shown in Table 1, below, we obtained similar, but not exact results. The tables below are similar to those shown in Exhibit JIF-E2, where each value represents the relative net present value of installing controls versus retiring and replacing capacity. The Companies' results, from the October 17th Supplemental Analyses are shown in the first box, while Synapse's re-analysis, using the same data, are shown in the middle box. The third box shows the difference between these two analytical results.

Table 1. Difference in NPVRR (2011$) between Companies' Supplemental Analysis and Synapse Re-Analysis using Wood Mackenzie 2011 price forecast.

KU/LGE Supplemental Analysis	
Table 5 - PVRR of Installing Controls vs. Retiring and Replacing Capacity	
Tyrone 3	-10
Green River 3	-88
Brown 3	357
Cane Run 4	-187
Cane Run 6	-145
Brown 1-2	39
Cane Run 5	-171
Ghent 3	520
Ghent 1	400
Green River 4	-140
Mill Creek 4	481
Trimble County 1	675
Ghent 4	750
Mill Creek 3	453
Ghent 2	755
Mill Creek 1-2	536

Synapse Re-Analysis	
Nominal Wood Mackenzie Gas Price*	
Tyrone 3	-59
Green River 3	-66
Brown 3	368
Cane Run 4	-240
Cane Run 6	-67
Brown 1-2	49
Cane Run 5	-193
Ghent 3	529
Ghent 1	430
Green River 4	-130
Mill Creek 4	484
Trimble County 1	654
Ghent 4	727
Mill Creek 3	423
Ghent 2	728
Mill Creek 1-2	530

Difference	
Synapse minus KU/LGE	
Tyrone 3	-49
Green River 3	22
Brown 3	11
Cane Run 4	-53
Cane Run 6	78
Brown 1-2	10
Cane Run 5	-22
Ghent 3	9
Ghent 1	30
Green River 4	10
Mill Creek 4	3
Trimble County 1	-21
Ghent 4	-23
Mill Creek 3	-30
Ghent 2	-27
Mill Creek 1-2	-6

We were not given the Companies workpapers, and so do not know why our results are not identical to the Companies, but it is possible that we may have adjusted the Henry Hub gas price to a local gas price using a different formulation than that of the Companies or used a different coal price than the Companies.[footnote 19] Regardless, there are no directional changes in our re-analysis, but there are changes in the magnitude of benefit realized through the retirement or retrofit of any given set of units.

[footnote 19: Synapse maintained the original coal price forecast used by the Companies in the 2011 Compliance plan.]

On page 21, strike lines 10 through 18.

On page 22, strike lines 1 through 12.

On page 22 at line 15, strike "Simply correcting" and replace with "By adjusting"

On page 22 at line 15, strike "mid-line" and replace with "mid-range"

On page 22 at line 16, insert a comma after "estimate"

On page 22 at line 16, strike "made"

On page 22 at line 18, strike "JIF-2" and replace with ""JIF-E2"

On page 22 at line 18, strike "to $2 million, below the threshold at which the Companies decided to retire Cane Run 6 and well within the region of model noise." and replace with "from $228 million to $49 million (or $39 million by the Companies' calculation)."

On page 23 at line 3, strike "corrected" and replace with "mid-range"

On page 23 at line 4, strike "very" and replace with "a"

On page 23 at line 4, insert a period after "operation"

On page 23 at line 4, strike "and, according to the Companies' own stated risk preference, they should retire these units." And replace with "While a lower gas price alone does not *a priori* render these units non-economic, I believe that other faults in Company assumptions quickly erode the remaining margin, including the inflated emergency energy cost assumptions (discussed later in my testimony)."

On page 23 at line 7, strike "has" and replace with "have"

On page 25 at line 17, strike "Figure 3" and replace with "Figure 2"

On page 25 at line 21, strike "are so far out of compliance that it" and replace it with "have poor air quality that"

On page 26 at line 7, strike "the" and replace it with "there is a risk that"

On page 26 at line 11, strike "of SCR at these units" and replace with "that these units will need to install SCRs to remain compliant with the law"

On page 28 at line 13, strike "JIF-2" and replace with "JIF-E2"

On page 28 at line 18, strike "fine" and replace with "narrow"

On page 28 at line 26, strike "corrected" and replace with "mid-range"

On page 28 at line 27, strike "corrected" and replace with "mid-range"

On page 29 at line 1, strike "JIF-2" and replace with "JIF-E2"

On page 29 at line 2, strike "$193" and replace with "$146"

On page 29 at line 4, strike "$377" and replace with "$441"

On page 29 at line 5, strike "$137" and replace with "$270"

On page 29 at line 6, insert "Exhibit JIF-E2," before "Box 1"

On page 29 at line 14, strike "would require" and replace with "obtain"

On page 29 at line 14, insert "that regulate these emissions" between "air permits" and the period.

On page 31 at line 5, strike the paragraph beginning "Sierra Club witness Ms. Wilson" and replace with a new paragraph that reads: "I used a straight-line extrapolation to extend the Synapse Mid CO2 price through 2040, and adjusted the price from constant 2010$ to nominal dollars at the 2.18% inflation rate consistent with the Companies effective natural gas price inflation rate (see rebuttal witness Sinclair workpapers). Sierra Club witness Ms. Wilson incorporated these CO2 prices into the re-analysis."

On page 31 at line 17, strike "JIF-2" and replace with ""JIF-E2"

On page 31 at line 19, insert "original" after "the Companies'"

On page 31 at line 19, strike "Unto itself, the CO2 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." And replace with "Imposing the Synapse Mid CO_2 price results in an economic loss at Brown 1 & 2 of $157 million, at Mill Creek 1 & 2 of $20 million, and even Ghent 1 of $4 million."

On page 31 at line 25, strike "When the Companies' gas price is corrected and the" and replace it with "Using a mid-range gas price provided by the Companies', and imposing a"

On page 31 at line 25, strike "is imposed"

On page 32 at line 2, strike "JIF-2" and replace with "JIF-E2"

On page 32 at line 5, strike "JIF-2" and replace with "JIF-E2"

On page 32 at line 10, strike "deeply"

On page 32 at line 11, strike "Correcting any one of those" and replace with "Any one of these"

On page 32 at line 14, strike the comma after "surcharge"

On page 32 at line 22, strike "not economically justifiable using any series of" and replace with "a high risk, and likely a net loss under"

On page 32 at line 23, insert "mid-range" after "reasonable"

On page 32 at line 23, insert ", and that the Companies' gas price and CO_2 assumptions overstate the benefit realized by maintaining these units." after "assumptions"

On page 32 at line 23, strike "In addition, I conclude that the Mill Creek 1 & 2 units pose a marked financial risk to the Companies, and that the Commission should require the Companies to evaluate these units in more detail prior to authorizing retrofit."

On page 33 at line 22, strike "Figure 4" and replace with "Figure 3"

On page 34 at line 11, strike "Figure 4" and replace with "Figure 3"

On page 36 at line 10, insert a new sentence after "timescale." that reads: "In this case, the Companies should consider modeling incremental shares of a large, cost effective natural gas plant, as if it were to be a shared expense with other utilities in similar positions."

On page 37 at line 7, insert a comma after "Strategist"

On page 37 at line 15, insert a new footnote after "MWh" that reads: "The $16,600 value remains constant throughout the study period, implying that the cost diminishes in real terms over the analysis period."

On page 37 at line 17, strike the extra space before the word "This"

On page 38 at line 4, strike "can pale" and replace with "are small"

On page 38 at line 7, insert ", particularly for marginal units" after "Strategist runs"

On page 38 at line 8, insert "if" after "determine"

On page 38 at line 8, strike "versus" and replace with "or"

On page 38 at line 10, insert new text after "scenario runs." As follows: "For example, as indicated in Exhibit CRS-2 to Witness Schram's rebuttal testimony, high emergency energy costs consistently favors the retrofit decision. Of note, using a $16,600/MWh charge rather than, for example, a cost of $1000/MWh favors the retrofit of Mill Creek by $76 million, and Brown 1 & 2 by $23 million. I conclude that, even for these forward-planning exercises, it is quite critical to get this value correct and justified."

On page 38 at line 10, strike "Therefore, it is quite critical to get this value correct and justified."

On page 39 at line 6, insert "diminish" after "quickly"

On page 39 at line 7, insert a new sentence after "the analysis." As follows: "Indeed, witness Shram's rebuttal testimony would suggest that this value could be only $10 million net benefit if the cost of emergency energy is closer to $1,000/MWh rather than $16,600/MWh."

On page 39 at line 9, strike "its" and replace with "their"

On page 39 at line 13, strike "via" and replace with "and outside the state to a limited extent under"

On page 40 at line 7, insert quotation marks around the words "few retirements"

On page 40 at line 8, strike "numerous" and replace with "many"

On page 40 at line 8, insert quotation marks around the words "many retirements"

On page 40 at line 23, strike "Alternatively," and capitalize "given"

On page 40 at line 26, strike "retirement" and replace with "retirement/retrofit"

On page 40 at line 28, strike "retire/retrofit decision" and replace with "merits of granting CPCN"

On page 41 at line 15, strike "are not realistic" and replace with "do not adequately reflect ratepayer risk."

On page 41 at line 16, replace "company's" with "Companies'"

On page 41 at line 18, strike "non-realistic"

On page 41 at line 21, replace "company" with "Companies"

On page 41 at line 22, strike "endorsing in its" and replace with "endorse as evidenced in their"

On page 41 at line 23, insert "2011" after "September 14th,"

On page 41 at line 23, replace "company's" with Companies'"

On page 42 at line 3, strike "to" and replace with "of SCR at"

On page 42 at line 4, strike "corrected" and replace with "mid-range"

On page 42 at line 4, insert "and under the circumstance that SCR is required," after "utilized,"

On page 42 at line 5, strike "when SCR is required, therefore posing" and replace with "and pose"

On page 42, strike lines 16 through 26, and replace with the following new text:

"My recommendation is two-fold:

- First, under most reasonable assumptions, retrofitting and operating Brown Units 1 & 2 is anywhere from marginal to non-economic, relative to replacement with natural gas. Therefore, I recommend the Commission deny CPCN for these units. It is unlikely that a re-analysis of the risks to Brown Units 1 & 2 would result in a dramatically different outcome for these units.

- Second, a corrected gas price and mid-level CO2 price appears to render much of the KU/LG&E fleet non-economic. However, in absence of more information about replacement capacity availability and transmission costs and availability, a specific course of action for these other units cannot be recommended at this time. Instead, it is incumbent on the Companies to assess these costs and risks comprehensively prior to requesting a CPCN.

The net impact of these considerations is that I recommend that, in this docket, the Commission deny the requested CPCNs."