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PUBLIC SERVICE
COMMISSION

October 24, 2011

RE: ***The 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

The Application of Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Approval of Its 2011 Compliance Plan for Recovery by Environmental Surcharge
Case No. 2011-00162

Dear Mr. DeRouen:

Enclosed please find an original and fifteen (15) copies of Kentucky Utilities Company's (KU) and Louisville Gas and Electric Company's (LG&E) Rebuttal Testimony for each of the above-referenced dockets.

This filing includes:

- Lonnie E. Bellar's Rebuttal Testimony and Exhibit,
- John N. Voyles's, Jr. Rebuttal Testimony,
- Gary H. Revlett's Rebuttal Testimony and Exhibits,
- David S. Sinclair's Rebuttal Testimony and Exhibits,
- Charles R. Schram's Rebuttal Testimony and Exhibits,
- Daniel K. Arbough's Rebuttal Testimony and Exhibits, and
- William E. Avera's Rebuttal Testimony and Exhibits.

Also enclosed for each of the above-referenced dockets are an original and fifteen (15) copies of a Joint Petition for Confidential Protection regarding certain information contained in the Rebuttal Testimonies and Exhibits of Mr. Schram and Mr. Sinclair.

Also enclosed for each of the above-referenced dockets are an original and fifteen (15) copies of a Joint Motion to Deviate from Requirement Governing Filing of Copies. As noted in the Joint Motion to Deviate, enclosed for each of the above-referenced dockets is one paper copy of Mr. Schram's Appendix A and Mr. Sinclair's Appendix B.

Should you have any questions concerning the enclosed, please do not hesitate to contact me.

Sincerely,

Robert M. Conroy

cc: Parties of Record

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

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 ENVIRONMENT SURCHARGE	)	CASE NO. 2011-00161

In the Matter of:

THE APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	)	CASE NO. 2011-00162

**REBUTTAL TESTIMONY OF
LONNIE E. BELLAR
VICE PRESIDENT, STATE REGULATION AND RATES
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY**

Filed: October 24, 2011

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Lonnie E. Bellar**, being duly sworn, deposes and says that he is Vice President, State Regulation and Rates for Louisville Gas and Electric Company and Kentucky Utilities Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Lonnie E. Bellar
Lonnie E. Bellar

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 20th day of October 2011.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2014

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

A. My name is Lonnie E. Bellar. I am the Vice President of State Regulation and Rates for Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, "Companies"). I am employed by LG&E and KU Services Company, which provides services to LG&E and KU. My business address is 220 West Main Street, Louisville, Kentucky, 40202.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address certain of the arguments presented by intervenors in this proceeding. Specifically, I will respond to portions of the testimony filed by the Kentucky Industrial Utility Customer's ("KIUC") witnesses, Lane Kollen, Stephen Baron, and Stephen Hill; the testimony of William Steinhurst, a witness for the Environmental Intervenors; as well as the testimony filed by Cathy Hinko on behalf of the Metropolitan Housing Coalition ("MHC") and the testimony of Jack Burch filed on behalf of the Community Action Council ("CAC"). Specifically, I will respond to the issues Mr. Kollen presents regarding the finality of the Environmental Protection Agency's proposed Hazardous Air Pollutants Rule, the financing costs and capitalization rate treatment, and securitization. As to Mr. Hill, I will respond to his argument that the Companies should be awarded a rate of return on the low end of the reasonable range. With regard to Mr. Baron's testimony, I will respond to the arguments he presents regarding the revenue allocation associated with the ECR surcharge. I will address Ms. Hinko's recommendation regarding a waiver or reduction of the ECR surcharge for low-income customers. Finally, I will also explain the Companies' continuing efforts to address the impact of rate increases on its low-income customers, to respond to Ms. Hinko and Mr. Burch.

Q. Please list the other persons filing rebuttal testimony of behalf of the Companies.

A. In addition to my testimony, Daniel K. Arbough, Chuck R. Schram, John N. Voyles, Jr., Gary H. Revlett, and Dr. William E. Avera are each filing rebuttal testimony to respond to the arguments presented in the intervenors' testimony. Dr. Avera's rebuttal testimony responds to the arguments presented by both the Attorney General and the KIUC's witnesses on the return on equity.

<u>Environmental Protection Agency's Hazardous Air Pollutants Regulation</u>

Q. Do you agree with Mr. Kollen's argument that LG&E's and KU's ECR plans should not include projects that are based on regulations that are not yet final?

A. No. As demonstrated in the Companies' direct testimony and responses to discovery requests, the regulations the Environmental Protection Agency ("EPA") requiring the projects for which the Companies are seeking approval, with one exception, are now final. As noted by Mr. Kollen, the only regulation currently not final is the Hazardous Air Pollutants ("HAPs") Rule.[1] The final HAPs Rule must be issued by December 16, 2011. Mr. Kollen's speculation that the proposed regulation may never be adopted is without support. The December 16, 2011 deadline is required under the terms of the October 21, 2011 Stipulation between EPA and the plaintiffs filed with the United States District Court for the District of Columbia.[2]

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[1] Direct Testimony of Lane Kollen, p. 7.

[2] *AMERICAN NURSES ASS'N, et al., Plaintiffs v. LISA JACKSON, in her official capacity as Administrator, U.S. Environmental Protection Agency, et al. Defendants*, Civil Action No. 1:08-cv-2139 (RMC), United States District Court for the District of Columbia.

Mr. Kollen's contention that the final HAPs Rule may be more lenient than currently proposed is conjecture. There is no reason to expect that the HAPs Rule will not be final by December 16, 2011, in essentially the same form as proposed.. And, as explained in the rebuttal testimony of Mr. Voyles, the final HAPS rule would have to differ very significantly from the proposed rule for the Companies' proposals to be affected- and there is no reason to believe that EPA will issue a much more lenient HAPs regulation.

Further Examination of the Compliance Plans

Q. Are additional analyses of LG&E's and KU's proposed environmental compliance plans necessary before the Commission can approve them?

A. No further analysis is necessary. Notwithstanding the exhaustive evidentiary records in these proceedings, the Environmental Intervenors have demanded the Commission direct the Companies to file more studies and analyses to support the proposed pollution control facilities.

In past proceedings, the Commission has rejected similar demands made for the purpose of achieving tactical delays, declined to encourage potentially endless analysis, and made sound decisions based on the best information then available. For example, when LG&E and KU sought Commission approval to terminate their Regional Transmission Owner membership, the Midwest Independent Transmission System Operator, Inc. ("MISO") sought to delay the essential decision by seeking to extend the proceeding for additional analysis of energy market data after extensive analysis was already in the record. In its order on rehearing in that proceeding, the Commission declined to grant rehearing to entertain more analysis and projections, determining that the evidence in the record was sufficient to support its final order approving LG&E's and KU's departure from MISO.[3]

I respectfully submit the same circumstance exists here. LG&E and KU supported their applications with thorough cost-benefit analyses demonstrating the cost-effectiveness and need to build the environmental controls in their proposed environmental compliance plans. The course of discovery has only strengthened that position. The Commission's application of the known and measureable standard has led the Commission to make sound and reasonable decisions. The Commission possesses all the evidence needed to approve LG&E's and KU's applications and Plans as the most cost-effective and robust means of continuing to provide customers with safe, reliable, and low-cost electric service while complying with all applicable environmental regulations.

Q. Please discuss the Environmental Intervenors' tactics in delaying the Companies' compliance with applicable environmental regulations.

A. The Environmental Intervenors' apparent goal in these proceedings is to cause the retirement of as many of the Companies' coal-fired generating plants as possible. This is in accord with the stated goals of one of the Environmental Intervenors, the Sierra Club, which has publicly provided its goals regarding the retirement of coal-fired generating plants. This information is provided as Rebuttal Exhibit LEB-1.[4] The Environmental Intervenors' purpose is evident based upon their tactics in this proceeding, which is to provide no discernable recommendation regarding the Companies' Plans, but instead assert that the Companies have not performed enough

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[3] Case No. 2003-00266, Order at 3-4 (July 6, 2006).
[4] Sierra Club Climate Recovery Partnership, http://www.sierraclub.org/crp/

analyses[5] and should conduct additional analyses to be filed in the Companies' pending, and entirely separate, IRP proceeding.[6] Cumulatively, these efforts do nothing more than attempt to delay the resolution of these proceedings. The Companies have explained that the ECR cases were instituted so that final orders would be issued by the Commission in time for the Companies to comply with the regulations. In delaying the resolution of these proceedings by providing no actual recommendations other than to suggest additional work for the Companies to perform, the Environmental Intervenors are seeking denial of the applications by default, meaning that these actions will be delayed so as to prevent the Companies from complying with the regulations, forcing the Companies to shut down the power plants for non-compliance. This tactic should not be allowed to succeed; the Environmental Intervenors have provided no sound basis to deny or modify the Companies' Plans.

Maximum Use of Short Term Debt

Q. Please address KIUC's argument that the Companies should maximize the use of short-term debt during construction.

A. Much of Mr. Kollen's testimony argues that the overall cost of the Companies' proposed projects could be reduced if the Companies maximize the use of short-term debt during the construction process. While the rebuttal testimony of Mr. Arbough will address the critical deficiencies in Mr. Kollen's position in greater detail, it is

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[5] Direct Testimony of Jeremy Fisher, PhD, p. 40 (Arguing that the Companies should perform analyses to test each unit's cost effectiveness against the "no retirements" case); *see also* Environmental Intervenors' Responses Nos. 2, 4 of LG&E and KU.
[6] Direct Testimony of William Steinhurst, p. 3.

important to understand that Mr. Kollen's position is not only untenable, it could also have an adverse impact on customers.

Mr. Kollen's testimony suggests that the Companies should devote all of its short-term debt to financing the projects in its ECR Plans because the cost of short-term debt is often lower than other forms of financing. This appears to be the same argument Mr. Kollen made to the Commission ten years ago in environmental surcharge proceedings. Specifically, Mr. Kollen testified:

> I recommend that the Commission apply a weighted average actual cost of capital to the rate base investment in new ECR projects approved by the Commission. This actual cost of capital should be computed on a monthly basis and first apply all outstanding short term debt, including the Company's accounts receivable financing, to these new capital costs. [7]
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> ****
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> ...the actual rate of return on the incremental environmental capital costs should reflect first the issuance of these various types of short term debt, especially during construction when the Company includes Construction Work in Progress ("CWIP") in its environmental rate base.[8]
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> *****
>
> ...the Company's approach fails to properly assign short-term debt first to the new environmental control costs. The Company's approach instead assumed that this short term debt is allocated between its existing non-environmental rate base, existing environmental rate base, and the new environmental rate base, with only a small fraction of the short term debt allocated to the new environmental rate base.[9]

In deciding the issue, the Commission observed:

> KIUC further argues that the rate of return applied to the 2001 Plan rate base should reflect the issuance of the various types of short-term

[7] *See* Testimony of Lane Kollen (Case No. 2000-439) p. 4.
[8] *Id.* at p. 13.
[9] *Id.* at p. 16.

> debt, especially during the construction period when [the Company] includes CWIP in the surcharge rate base. KIUC contends that only when the 2001 Plan rate base exceeds [the Company's] short-term debt should an overall rate of return be applied, with the rate adjusted to remove short-term debt[10]

There, as here, the Companies disagreed with KIUC's proposal and demonstrated there, as here, that the compliance plan will be funded with all sources of capital, not exclusively with short-term debt, and that the applied rate of return should reflect this fact.

The Commission rejected KIUC's arguments, stating:

> The Commission is not persuaded by KIUC's arguments. Pursuant to KRS 278.183(1), among the costs recoverable through the surcharge is a reasonable return on construction and other capital expenditures. KRS 278.183(2) (b) requires that the Commission establish a reasonable return on compliance-related capital expenditures. Given this requirement, the Commission believes that a reasonable return on capital expenditures included in the surcharge constitutes part of the total actual costs incurred by a utility.[11]

Thus, for more than ten years, the Commission has followed its decisions in Case Nos. 2000-439 and 2000-386. KIUC has presented no persuasive evidence demonstrating why the Commission should not continue to follow and apply the decisions from its prior orders. Then, as now, LG&E and KU do not finance construction projects with any one form of debt or equity. Instead, LG&E and KU, consistent with sound financial practices, finance their construction projects utilizing all sources of capital: short-term debt, long-term debt and equity. In relying on different forms of capital, LG&E and KU are able to prudently obtain the most suitable form of financing based upon the market conditions at that time. The

[10] Case No. 2000-439, Order page 21 (April 18, 2001); Case No. 2000-386, Order page 22 (April 18, 2001).
[11] Case No. 2000-439, Order page 22 (April 18, 2001); Case No. 2000-386, Order page 23-24 (April 18, 2001).

Commission should reject KIUC's claim to use all of the Companies' short-term debt to financing their projects in its ECR Plans.

Q. Is the Commission's decision to permit utilities to earn a rate of return based upon numerous sources of capital consistent with KRS 278.183?

A. Yes. KRS 278.183(1) states that a utility is entitled to the current recovery of its cost of complying with federal, state and local environmental requirements. These costs include "a reasonable return on construction and other capital expenditures and reasonable operating expenses for any plant, equipment, property, facility, or other action to be used to comply with applicable environmental requirements set forth in this section."[12] Notably, KRS 278.183 does not provide the Commission with any authority to require a utility to utilize a particular form of financing, instead reiterating that utilities shall be awarded a reasonable return on "capital expenditures" associated with complying with the applicable environmental requirements.

Mr. Kollen's testimony overstates the Commission's history of modifying and refining the rate of return established in ECR proceedings.[13] While Mr. Kollen notes that in KU's first ECR proceeding the Commission, at KU's request, established a rate of return based upon the Company's 1993 tax-exempt debt issue. That proposed rate of return was expressly qualified with the caveat that the return should be increased after its next general rate case to the return authorized in that rate case. At the time of the 1993 environmental surcharge case, KU's last rate case, and therefore

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[12] KRS 278.183(1).

[13] Direct Testimony of Lane Kollen, p. 15-16.

last authorized rate of return, was established in 1983.[14] It is significant to note that no party in the 1993 environmental surcharge case proposed an alternative return.

Mr. Kollen, while mentioning Case No. 2000-00439, fails to address the fact that in the final order in the proceeding, the Commission rejected the very same arguments the KIUC has advanced in this case. While the Commission certainly trues-up the ECR surcharge at review periods, the rate of return has been based upon numerous sources of capital, including both debt and equity, without deviation for over a decade.

Q. Since the 2000 proceeding, have the Companies' rate of return for ECR projects been based upon the use of numerous sources of debt and capital?

A. Yes, for over a decade the Companies' rate of return for ECR projects has been based upon a mixture of different forms of debt and equity, as the Companies have, without deviation, financed construction projects in this manner. That accounts for over fifteen consecutive compliance and review proceedings involving the Companies in which the rate of return has been based upon utilization of numerous sources of capital. Since unsuccessfully arguing that the return to which KU is entitled should be limited to the short-term debt rate in 2000, the KIUC has not contested the methodology employed by the Companies and approved by the Commission.

Q. Why do Mr. Kollen's and Mr. Hill's proposals produce no net gain to customers?

A. Mr. Kollen's and Mr. Hill's proposals do not result in net savings to customers because the proposals, as opposed to reducing the costs of compliance, simply shift

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[14] *See In the Matter of: General Adjustment of Electric Rates of Kentucky Utilities Company* (Case No. 8624) March 18, 1983 Order.

the costs between ECR rates and base rates. If the Commission accepts any of the special allocations Mr. Kollen and Mr. Hill have proposed, in the Companies' next base rate cases, the Companies will seek recovery of the higher cost elements of the capital structure through base rates. Mr. Kollen admits this in response to a data request by the Commission, in which he states that under his proposal there "would be differentiated returns to reflect the larger share of short-term and tax-exempt debt in the rate of return applied to the ECR rate base compared to the rate of return applied to the base rate capitalization."[15] Quite simply, dollars are fungible. Shifting the cost from one mechanism to another does not reduce the overall costs the Companies must incur. Their proposal is like suggesting that one end of a balloon can be squeezed without the other end expanding.

If the Commission accepts these recommendations, it will require the Companies to create a fiction that LG&E and KU project finance the costs of specific assets, which is simply inaccurate. The allocations proposed by Mr. Kollen and Mr. Hill do not lower the costs of the projects, but instead will require the Companies to devote significant effort in tracking the allocation of the costs. Because these efforts do not benefit customers, and in fact, prevent customers from understanding the true costs associated with the ECR projects, Mr. Kollen's and Mr. Hill's recommendations should be denied.

The traditional rate case adjustment to the Companies' capital structures (i.e., the pro forma adjustment to remove the cost of the environmental surcharge rate base from the capital structure) from the last rate case does not reflect Mr. Kollen's and Mr. Hill's proposed reallocation. Their proposals, if adopted, would cause an

[15] *See* KIUC's Response to Data Request No. 4(b) of the Commission.

immediate disallowance of a portion of the cost of both debt and equity until LG&E and KU can change their base rates in 2013 because the base rates assume a pro rata allocation of all costs of capital between the environmental surcharge rate base and the traditional rate base. And their proposals, if adopted, will cause base rates to be higher than base rates would be under the current balance between ECR and base rates. As a result, there is no meaningful benefit to customers.

Tax-Exempt Financing

Q. Does Mr. Kollen argue that tax-exempt financing be incorporated into the rate of return calculation for the ECR?

A. Yes. Mr. Kollen argues that all new tax-exempt financing should be allocated "in its entirety to the debt component"[16] of the rate of return used in the ECR revenue requirement. Mr. Kollen likewise takes issue with the Companies' alleged reticence in describing how it plans to reflect tax-exempt debt in the rate of return for the ECR. As explained at length with regard to Mr. Kollen's position regarding the use of short-term debt, the Companies use all forms of debt and equity, including tax-exempt financing, based upon which forms of financing are reasonably cost-effective at the time.

As with his argument regarding short-term debt, Mr. Kollen again advocates for the creation of an artificial calculation to separate ECR-related debt from non ECR-related debt based upon the type of debt utilized. This is an overly complex and burdensome endeavor that results in no benefit to customers. This proposal, like the recommendation with regard to short-term debt, does not reduce the overall cost of the construction projects, but simply shifts costs between ECR rates and base rates.

[16] Direct Testimony of Lane Kollen, p. 16.

LG&E and KU have repeatedly explained that they do not project finance the costs of specific assets, and to create the fiction that such a structure exists for ratemaking is inappropriate. Creation of such a structure directly conflicts with the Commission's Order in Case No. 2000-00439, which recognizes that a utility prudently relies upon various forms of capital during the construction process. Moreover, there is no authority in KRS 278.183, express or otherwise, that authorizes the Commission to order or otherwise limit the forms of financing the utility employs, so long as the overall cost of the project is reasonable.

Q. Mr. Kollen makes several arguments based upon the financial condition of LG&E's and KU's parent company, LG&E and KU Energy, LLC ("LKE"). Are these arguments relevant?

A. No. While Mr. Arbough will respond to each of the arguments Mr. Kollen presents on this issue, it is important to consider that these proceedings are limited in scope to the reasonableness of LG&E's and KU's projects and the need for same. It is not a proceeding in which the overall financial condition of LG&E and KU – much less that of its parent company – is under review. The Commission affirmed the limited scope of this proceeding in its September 1, 2011 Order in this action which largely denied the KIUC's motion to compel. After the KIUC had submitted a data request to LG&E and KU involving the financial condition of PPL, the Companies objected to the request in reliance on a prior decision by the Kentucky Supreme Court that held that the overall financial condition of a utility is not relevant in an ECR proceeding.

The Commission denied the motion to compel with regard to the request involving the Companies' parent company, finding it "not relevant to any issue in this case and does not appear to be calculated to lead to the discovery of relevant information."[17] This Order reaffirmed that the financial condition of LG&E's and KU's parent company is not relevant to this proceeding. Thus, the arguments Mr. Kollen presents regarding LKE and PPL are inapposite to the resolution of this proceeding.

Securitization

Q. Please explain Mr. Kollen's recommendation regarding securitization.

A. Mr. Kollen recommends that LG&E and KU be required to pursue the maximum securitization financing possible. Securitization, as noted in Mr. Kollen's testimony, is a form of asset-based financing that involves the use of government-sponsored bonds as a substitute for the debt and equity mix that is typically used to finance investor-owned utility capital requirements. Because of the government's involvement with the process, securitization is only available as a form of financing in states that have enacted enabling legislation. In Kentucky, no securitization legislation has been introduced or enacted. As such, it is currently unavailable as a form of financing and cannot be employed in this proceeding.

Q. Is the approach Mr. Kollen has advocated regarding maximum-mandatory-securitization consistent with the approaches taken by states that have enacted securitization legislation?

A. No. Mr. Kollen's position, which requires LG&E and KU to "pursue the maximum securitization financing possible,"[18] is extreme. No state that has enacted

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[17] *In the Matter of: Application of Louisville Gas and Electric Company for Certificates of Convenience and Necessity and Approval of Its 2011 Compliance Plan for Recovery by Environmental Surcharge* (Case No. 2011-00162) Order, September 1, 2011.

[18] Direct Testimony of Lane Kollen, p. 13.

securitization legislation has required utilities to utilize this form of financing to the maximum extent possible. To the contrary, in the states where the legislation has been enacted, the legislation is permissive and does not mandate maximum use of this form of financing.

Q. When has securitization typically been utilized in other jurisdictions?

A. Securitization has been employed primarily in jurisdictions as a method to finance stranded costs resulting from the transition to retail competition. Another typical use of securitization financing is to assist a utility's efforts in dealing with catastrophic losses, such as the losses accompanying a hurricane or similar significant weather event. In either case, the cost is non-recurring or one-time in nature, and known, fixed and certain. Only in one state, West Virginia, was securitization used to finance the construction costs associated with environmental control projects, and then only for financially distressed, sub-investment grade utility subsidiaries of Allegany Energy that were unable to raise capital in the markets due to poor credit ratings. While Mr. Kollen states that Wisconsin has also authorized the use of securitization as a form of financing for operating assets,[19] no transactions have been completed utilizing this method of financing in that state. Moreover, in states with securitization, maximum use is not mandatory.

Q. Would the use of securitization alter the Commission's review of ECR costs?

A. Yes. If LG&E and KU employed securitization to finance all or part of the construction costs in future ECR proceedings, the Commission would lose the ability to use the six-month and two-year reviews for the projects finance with securitization

[19] *See* KIUC's Response to Data Request No. 17 of LG&E and KU.

bonds. When projects are securitized, the revenues resulting from the securitization charge passed along to customers serves as the primary collateral for the bonds. The charge is explicitly deemed to be irrevocable, in an attempt to ensure that any future efforts to rescind or circumvent this obligation will be unsuccessful. The Commission thus has no opportunity to review the prudency of the costs incurred from the use of the proceeds raised through securitized debt, because the debt must be repaid to the bondholders. This varies from the current process, under which the Commission reviews the costs that have already been incurred for reasonableness. Due to the expected lives of these operating assets, some of which exceed twenty years, the Commission will be unable to review the reasonableness of the costs for a substantial period of time.

Return on Equity

Q. Is Mr. Hill correct in asserting that the Companies should be awarded an ROE on the low end of the reasonable range because there is less risk associated with the ECR surcharge?

A. No. KRS 278.183 provides that a utility shall be entitled to a "reasonable return on its construction and other capital expenditures." The statute does not state, nor have Commission decisions interpreting the statute held, that the recovery of costs pursuant to the mechanism limits the Companies to an ROE at the low-end of the reasonable range simply because the costs are assessed through the ECR surcharge. Moreover, there is a fundamental misconception in Mr. Hill's position because there are significant risks associated with costs passed through the ECR mechanism in the form of the statutorily mandated six-month and two-year review proceedings. During both of these reviews, the Commission retroactively examines the prudency and reasonableness of the costs recovered through the mechanism and consequently may disallow certain of those costs. In contrast, when rates are set in a base rate case, there are no mandatory review proceedings in which the Commission retrospectively reviews the costs. Setting the rate of return at the low end of the range of the return on equity in the face of the risks associated with these ongoing and retrospective review periods is unreasonable and not supportable. For years, absent a stipulation or a settlement agreement, the Commission has used the midpoint of the range of returns on common equity when determining revenue requirements. Using the midpoint of range on returns on common equity mitigates the risk of basis and results-oriented judgment when determining the ROE value to be used to calculate a revenue requirement. Using the midpoint within the range to determine the ECR calculation in these cases also balances the risks of the six-month and two-year reviews with the operation of the mechanism. KIUC's witness has failed to present any new evidence or demonstrate a change in circumstances supporting the departure from over ten years of consistent application of the ECR mechanism.

<u>Revenue Allocation</u>

Q. Please describe the modified rate allocation KIUC witness Stephen Baron has recommended.

A. Mr. Baron has recommended an alternative rate allocation of the ECR surcharge such that the ECR recovery factor for commercial and industrial ("C&I") customers is determined by recovering the ECR revenue requirement on the basis of non-fuel base revenues.[20] Mr. Baron states that his alternative allocation only affects business customers on General Service ("GS"), Power Service and various industrial rates of the Companies.

Q. How does this alternative allocation differ from the current methodology and how would the alternative allocation affect other customers?

A. The Companies have requested to recover the ECR surcharge based upon total revenues (including base rate, fuel adjustment clause, and demand-side management revenues) consistent with past practice. The alternative rate allocation Mr. Baron has proposed is different from the total revenues methodology the Companies have adhered to in accordance with Commission precedent. It uses two different allocation plans, depending on the class to which the costs are being allocated. Mr. Baron includes the Companies' rate schedules with demand charges, along with GS, in one allocation class (C&I Group), and the remainder of the customers in another allocation class (Non-C&I Group). The Non-C&I Group would continue to use a total revenue allocator for the allocation of environmental costs. The C&I Group would use a net revenue allocator to assign costs among customers in those rate classes. LG&E and KU are concerned about using different allocation plans for different customer classes.

Q. How does the alternative allocation affect customers?

A. Mr. Baron's proposed allocation methodology has no impact on the Non-C&I Group of customers because it continues to allocate costs using total revenue. However, the modified allocation methodology does have an effect on the C&I Group of customers. Using KIUC's proposed allocator will generally shift costs away from high load

[20] Direct Testimony of Stephen J. Baron, p. 12-13.

factor C&I customers with demand charges to low load factor C&I customers with demand charges. Unlike other Rate Schedules for C&I customer, Rate GS does not have a demand charge. In addition, Rate GS is an extremely heterogeneous rate class, consisting of customers that use electric energy for a wide variety of purposes. Because Rate GS consists of only a basic service charge (customer charge) and an energy charge, high load factor customers served under this rate schedule will be particularly impacted under Mr. Baron's proposal. Because Rate GS does not include a demand charge, Mr. Baron's proposal largely results in a kWh allocator for Rate GS. Therefore, a high load factor customer under Rate GS will be disadvantaged twice under Mr. Baron's proposal – first, as a result of a larger percentage of ECR costs being allocated to Rate GS as a whole; and, second, because a high load factor customer under Rate GS would receive a greater allocation of ECR costs within the class due to the absence of a demand charge.

Q. What is the Companies' recommendation?

A. If a net revenue allocation is adopted, the Companies would propose that this approach be used for *all* current and future ECR plans and not just for the 2011 Compliance Plans, because it is simply not administratively practicable for the Companies to bill different ECR plans using different billing methodologies. If the Commission concludes that it is appropriate to use different allocation methods, the two groups should be rate schedules with demand charges and rate schedules without demand charges.[21]

Integrated Resource Plan

[21] The rate schedules without a demand charge will be the same as the KIUC's non-C&I group, except for the inclusion of Rate GS.

Q. **Did William Steinhurst, a witness for the Environmental Intervenors, recommend that the Commission intertwine the ECR proceeding with the Integrated Resource Plan ("IRP") proceeding?**

A. Yes. As part of a larger recommendation, Mr. Steinhurst requested that the Commission consider whether the Companies should be granted certificates of public convenience and necessity in connection with its review of a separate Commission proceeding, Case No. 2011-00140, which is the Companies' pending IRP case.[22] Specifically, Mr. Steinhurst has recommended that LG&E and KU file analyses involving perceived "resource challenges" in the IRP proceeding.[23] It is inappropriate, as a matter of Commission policy, for a witness in a proceeding to recommend that the Commission order the utility to take action in an entirely separate proceeding. The Commission should maintain the separateness of these proceedings and disregard Mr. Steinhurst's recommendation. Contrary to Mr. Steinhurst's contention, as the Companies' stated in their IRP filing, the

> Integrated Resource Plan represents a snapshot of an ongoing resource planning process using current business assumptions. The planning process is constantly evolving and may be revised as conditions change and as new information becomes available. Before embarking on any final strategic decisions or physical actions, the Companies will continue to evaluate alternatives for providing reliable energy while complying with all regulations in a least-cost manner. Such decisions or actions will be supported by specific analyses and will be subject to the appropriate regulatory approval processes.[24]

The Commission's review of a utility's IRP is a triennial proceeding mandated by 807 KAR 5:058. An IRP proceeding is markedly different than an ECR

[22] Direct Testimony of William Steinhurst, p. 3-4.
[23] *Id.*
[24] *In the Matter of: The 2011 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company* (Case No. 2011-00140) Application filed April 21, 2011.

proceeding as the IRP case concludes with a Staff report, as opposed to the evidentiary hearing that will be held and final order that will be issued by the Commission in this case.

Low Income Concerns

Q. Did Cathy Hinko, witness for the MHC, offer a similar recommendation regarding the Companies' pending demand-side management ("DSM") case?

A. Yes. After providing information regarding the use of DSM programs in the Louisville area, Ms. Hinko recommended that the Commission "entwine the plan for the Demand Side Management case, with the assessment of impact of the Environmental Surcharge."[25] As with the IRP proceeding, the DSM case that is currently pending is a separate case that does not relate to this action. While LG&E acknowledges that ECR, IRP and DSM cases are pending before the Commission at the same time, it is simply coincidental and not indicative of the interrelatedness of the proceedings. It is thus inappropriate, as with the IRP proceeding, for the DSM proceeding to impact this action. The reasonableness of LG&E's ECR Plan and the corresponding surcharge must be evaluated on the basis of the standards set forth in KRS 278.183.

Q. Please describe Ms. Hinko's recommendation with regard to an ECR surcharge waiver or reduction.

A. Ms. Hinko has recommended that the Commission "urge LGE/KU to explore the implementation of an environmental surcharge fee waiver or reduction for qualified low-income households and/or a credit for those households to offset rate

[25] Direct Testimony of Cathy Hinko, p. 10.

increases."[26] Ms. Hinko supports her recommendation by listing utilities that operate in jurisdictions outside Kentucky that have different forms of fee waivers and reductions.

Q. Does LG&E believe it has the regulatory authority to implement a program similar to that recommended by Ms. Hinko?

A. No. KRS 278.170(1) states that no utility "shall, as to rates or service, give any unreasonable preference or advantage to any person or subject any person to any unreasonable prejudice or disadvantage, or establish or maintain any unreasonable difference between localities or between classes of service for doing a like and contemporaneous service under the same or substantially the same conditions." This statute prevents LG&E from implementing a program that would provide customers, including low-income customers, with a waiver or reduction of the ECR surcharge. For example, when a water utility proposed to implement a program that would reduce the meter charge by twenty-five percent for residential customers whose annual income was equal to or below the federal poverty level, the Commission denied the proposal stating that the proposed discount was a "unreasonable preference or advantage to a class of customers" prohibited by KRS 278.170.[27] Thus, any program LG&E sought to implement that reduced or waived the ECR surcharge for customers on the basis of income would likely be rejected for violation of KRS 278.170, as well.

Q. Please respond to the concerns addressed in the testimony of Mr. Burch on behalf of the CAC and Ms. Hinko on behalf of the MHC.

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[26] *Id.* at 6.
[27] *In the Matter of: Adjustment of the Rates of Kentucky-American Water Company* (Case No. 2004-00103) Order, February 28, 2005.

A. Mr. Burch's testimony presents concerns regarding the impact of an increase in the bills of low-income customers as a result of the heightened costs of complying with environmental regulations. The Companies certainly appreciate the impact of rate increases on its customers, especially during these difficult economic times. It is important to understand that the Companies are required to comply with environmental regulations by the date set forth in the rules; compliance simply is not optional.

In developing the projects for which approval is sought in this proceeding, LG&E and KU closely considered the costs of the projects and based its decisions, in part, on which methods of compliance could be effectuated at a reasonable cost. Complying with ever-tightening environmental regulations unfortunately cannot occur without increasing the ECR surcharge during the construction process. It is important to consider that several of the alternatives proposed by intervenors to this proceeding would increase the expected cost of compliance, consequently resulting in a greater impact to low-income customers.

LG&E and KU continue to expand their efforts to assist low-income customers. For example, as MHC is aware, the Companies are currently before the Commission seeking approval to expand the suite of demand-side management and energy-efficiency programs.[28] These programs enable customers, including low-income customers, to better understand and consequently control their energy consumption. Additionally, LG&E and KU continue to contribute, through

[28] *In the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Review, Modification, and Continuation of Existing, and Addition of New, Demand-Side Management and Energy-Efficiency Programs* (Case No. 2011-00134).

shareholder contributions, to programs that provide assistance to customers that have difficulty meeting their financial obligations with regard to their heating costs during the winter season.

Q. Are the Companies amenable to working with low-income groups such as MHC to further develop discussion of their concerns?

A. Certainly. LG&E and KU will continue to work with low-income groups in different forums to further develop the discussion of their concerns. The Companies are committed to addressing the concerns of its customers, including those of its low-income customers. LG&E and KU remain receptive to non-discriminatory methods by which to assist its low-income customers.

Recommendation

Q. What is your recommendation to the Commission?

A. My recommendation is that the Commission approve the projects in LG&E's and KU's ECR Plans, in addition to issuing certificates of public convenience and necessity for the projects that require the same. The Companies have worked to develop ECR Plans that include reasonable and effective measures of complying with the applicable environmental regulations that have quickly approaching compliance timelines. The recommendations advanced by the KIUC and the Environmental Intervenors, if accepted, would unduly complicate the administration of the ECR surcharge without producing any net gain to customers. Because these recommendations do not improve upon the ECR Plans the Companies have submitted, it is my recommendation that the Commission approve LG&E's and KU's as-filed ECR Plans and issue the requisite certificates of public convenience and necessity.

Q. Does this conclude your testimony?

A. Yes, it does.

Rebuttal Testimony
Exhibit LEB-1

CLIMATE RECOVERY PARTNERSHIP SIERRA CLUB

Partner Spotlight:
National Advancement Council

CRP Campaigns

Beyond Coal

Beyond Oil

Resilient Habitats

Protecting America's Waters

Beyond Coal
Defending against the most polluting energy source on earth, and clearing the way for clean energy solutions like solar and wind.

The Climate Recovery Partnership fosters:

- A reduction in carbon emissions of at least 80% by 2050;
- U.S. energy independence;
- A thriving, clean energy economy -- supporting smarter industries, construction, and transportation; and
- Natural environments and threatened communities protected from the consequences of global warming.

Looking Ahead

Our 2010 achievements positioned us well for our progress in 2011. Here are a few examples of where we are focusing our strengths:

- Launch nationwide campaign to retire and replace all existing coal plants by 2030.
- End mountaintop removal mining and block oil drilling in Alaska and other pristine wilderness.
- Advocate for adoption of high-performing building codes in 10 states.
- Establish 5-7 renewable energy zones in the Western United States.
- Promote strong Pavley 2 standards and an effective Zero Emissions Vehicle program to drive technology forward and influence national guidelines.
- Support initiatives that increase transportation choices and improve community planning.
- Reinforce protection for wildlife migration corridors.
- Uphold and strengthen the roadless rule for all national forests.

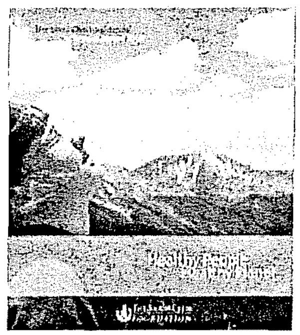
Campaign Updates

7.21.11
D.C. Mayor Echoes Club Concerns
Concerned about toxic air pollution from a coal-fired power plant in nearb...
read more

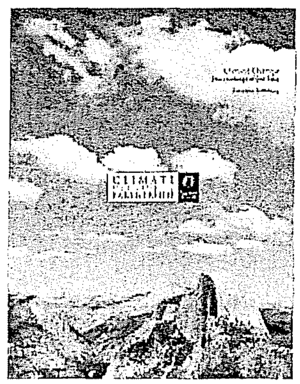
7.20.11
Report Proves Mining Facility is Draining Region's Water Supply
The Sierra Club and its partners, Black Mesa Water Coalition, Dine CARE, T...
read more

7.20.11
Knocking on the EPA's Door
Last Sunday in Boston, the Sierra Club and a coalition of more than 200 he...
read more

Campaign Highlights



Download our 2010 Annual Report (PDF)



Download our CRP Executive Summary (PDF)

SHARE

CLIMATE RECOVERY PARTNERSHIP

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE 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**

In the Matter of:

THE APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	)	**CASE NO. 2011-00162**

REBUTTAL TESTIMONY OF
JOHN N. VOYLES, JR.
VICE PRESIDENT, TRANSMISSION AND GENERATION SERVICES
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: October 24, 2011

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **John N. Voyles, Jr.**, being duly sworn, deposes and says that he is Vice President, Transmission and Generation Services for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

John N. Voyles, Jr.

John N. Voyles, Jr.

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 20th day of October 2011.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2014

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

A. My name is John N. Voyles, Jr. I am the Vice President of Transmission and Generation Services for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E"), and I am an employee of LG&E and KU Services Company, which provides services to LG&E and KU (collectively "the Companies"). My business address is 220 West Main Street, Louisville, Kentucky, 40202.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to the criticisms of the Companies' 2011 Environmental Cost Recovery ("ECR") Plans that Dr. Jeremy Fisher (on behalf of Sierra Club and related parties, "Environmental Interveners") and Lane Kollen (on behalf of the Kentucky Industrial Utility Customers, Inc., "KIUC") made in their direct testimonies. More specifically, I address Mr. Kollen's testimony concerning the National Emission Standards for Hazardous Air Pollutants rule for electric generating units ("HAPs Rule") and Dr. Fisher's testimony concerning compliance with the proposed cooling water intake rule promulgated under the federal Clean Water Act § 316(b).

HAPs Rule Compliance

Q. Mr. Kollen asserts in his direct testimony that the Companies' 2011 Plans should include projects to address only environmental regulations that have become final,[1] which he subsequently said applied only to the HAPs Rule.[2] Should the Companies delay taking any action concerning HAPs Rule compliance until the rule is final?

[1] *See* Kollen Testimony at 6-8.
[2] *See* KIUC's Oct. 14, 2011 Response to Commission Staff's DR No. 1(a).

A. Absolutely not. To do so would be imprudent. As Gary Revlett describes in his rebuttal testimony, there has been no indication that the U.S. Environmental Protection Agency ("EPA") intends to do anything other than issue the final HAPs Rule on or before December 16, 2011; indeed, EPA has affirmatively stated its intent to issue the final rule by then. The Companies will have only four years at most to comply with the final HAPs Rule which will require installing, on several of the Companies' generating units, the Particulate Matter Control Systems I described in my direct testimony, which are included in the Companies' 2011 environmental compliance plans ("2011 Plans"). Much of the utility industry operates coal-fired generating units and will therefore be engaged in the procurement and installation of similar equipment at the same time. It would have been irresponsible for the Companies to have delayed undertaking preliminary engineering studies to understand the scope and magnitude of the compliance work to be done, just as it would have been irresponsible for the Companies to have delayed bringing this matter to the Commission's attention by filing the applications in these proceedings. And I respectfully submit it would not be in our customers' best interests for the Commission to delay the Companies' ability to begin working on the compliance facilities in the 2011 Plans by denying the Companies' applications in these proceedings, as Mr. Kollen effectively proposes concerning HAPs Rule compliance.

Q. Mr. Kollen has also expressed concern that the final HAPs Rule could differ from the proposed rule.[3] How significantly would the proposed rule have to

[3] *See* KIUC's Oct. 14, 2011 Response to Commission Staff's DR No. 1(c).

differ from the final HAPs Rule to alter the Companies' HAPs Rule compliance proposals?

A. The final rule would have to differ very significantly from the proposed rule for the Companies' proposals to be affected. Although it is difficult to be precise, the proposed particulate emission surrogate (0.03 lbs/mmBtu filterable and condensable particulates) and mercury emission limits (1.2 lbs/TBtu or slightly above 90% removal) that will apply to the Companies' units would have to be much more lenient before changes to the Companies' proposed Particulate Matter Control Systems would be prudent. For the Companies' units, and design fuels, the mercury emission limit would have to be changed to only 80% removal (which would imply doubling the proposed limit to a 2.4 lbs/TBtu limit), rather than the 90% removal level as proposed, before a change would be warranted in the required technologies. However, any change in the mercury emission limit must be considered in parallel with the particulate emission surrogate limit. The particulate surrogate limit would need to be relaxed by at least two times for some units, and an even higher multiplier for others units, to change the proposed controls. Importantly, several states across the U.S. have established mercury regulations in their programs already. In most cases, the existing states which already mandate a statewide reduction in mercury require at least a 90% reduction in mercury emissions, so the Companies presently have no reason to believe EPA will alter its proposed standard in the final rule, and certainly not by such great factors. For that reason, I believe Mr. Kollen's concern is misplaced.

In the unlikely event of EPA's issuing a significantly less stringent mercury emission standard than the one proposed, the Companies will promptly notify the Commission and take appropriate action. And in no event will the Companies spend money on environmental compliance not justified by then-existing environmental requirements; the Companies are asking for authority to build certain facilities and to recover the costs thereof, but will not use such authority to make imprudent investments.

Q. What would be the likely effect of delaying the Companies' efforts to comply with the HAPs Rule?

A. Delaying construction of the systems required for compliance with the HAPs Rule increases the risk that some of the Companies' lower-cost generating units would not be available for supplying energy to the customers. As I stated in my direct testimony, attempting to install Particulate Matter Control Systems on twelve units at four different generating stations at the same time is not feasible from the viewpoint of outage scheduling, equipment supply, or construction labor. Additionally, at some stations, the construction schedule must be optimized by sequentially performing the work (e.g., Mill Creek Unit 3's fabric filter is planned to be built on the same footprint where the unit's current flue-gas-desulfurization system resides, which can only occur after Mill Creek Unit 4's new air control systems are placed in service). By proceeding now, the Companies will be able to achieve timely compliance and maximize the opportunity to do such at the most competitive prices. Also, the Companies will be able to coordinate construction around scheduled unit outages to the extent it is feasible to do so. Staying ahead of the coming demand wave for equipment and labor is, in the Companies' view, the prudent thing to do to best control the cost impact for our customers. Lastly, any significant delay of the projects will seriously impact the Companies' ability to meet the compliance deadlines.

Water Intake Structure Rule Compliance

Q. Dr. Fisher states that complying with the Water Intake Structure Rule (Clean Water Act § 316(b) Rule) at Mill Creek Unit 1 could cost $70 million, the cost to build a cooling tower for the unit.[4] Do you agree that compliance with the rule for Mill Creek Unit 1 will cost $70 million?

A. No. The Companies do not agree that the cost to comply with the rule will be $70 million, nor have the Companies concluded compliance requirements would include the installation of cooling towers. The best technology available, which is what the proposed rule would require, is to be determined on a case-by-case basis. Building a cooling tower on Mill Creek Unit 1 would likely be the most expensive technology that could be installed on the unit, and it is not at all clear that such a facility will be required after the rule becomes final and the appropriate studies required by the rule are performed.

Q. Do the Companies have any recent experience with building cooling towers in the event a cooling tower would be necessary to comply? If so, does that experience support your assertion that the cost of compliance would likely be much lower than the cost that Dr. Fisher asserts?

A. Yes, the Companies have recent experience with building cooling towers. LG&E built a new mechanical draft cooling tower for Trimble County Unit 1, which was placed in service in 2007. The total cost of the cooling tower, which included the

[4] Fisher Direct Testimony at 15-17.

equipment, foundations, fans, circulating piping, pumps, labor, and engineering, was $19 million. (The amount placed on LG&E's books was 75% of that amount, $14.3 million.) Trimble County Unit 1 is a 546 MW unit, significantly larger than Mill Creek Unit 1, which is a 330 MW unit. Therefore, the Companies would expect the cost of a cooling tower for Mill Creek Unit 1, in the event one is required, to be $19 million or less, even after taking into account market price changes since 2007 and the different site challenges and opportunities at Mill Creek versus Trimble County.

Q. Why is Dr. Fisher's cooling-tower-cost estimate so much higher than the Companies'?

A. The answer is simple: our recent cooling tower construction experience. Dr. Fisher came to his cost estimate by multiplying the nameplate capacity of the unit by a dollar amount he took from a NERC report.[5] The Companies, on the other hand, have, with assistance from outside firms, actually designed and built cooling towers (along with all our other recent experiences building generating units, environmental controls, transmission lines, distribution systems, and a host of other structures and facilities needed to run an electric utility). Clearly, with the work the Companies completed on our Trimble County Unit 1 cooling tower and the knowledge the Companies have of Mill Creek Unit 1, as well as all of our sites and their unique characteristics, our cost estimate is more reliable than Dr. Fisher's.

Recommendation

Q. What is your recommendation to the Commission?

A. I recommend that the Commission approve the Companies' proposed 2011 Plans, cost recovery for the plans through the Companies' environmental surcharge

[5] *See* Environmental Interveners' Oct. 14, 2011 Response to Companies' DR No. 1(a).

mechanism, and the requested certificates of public convenience and necessity. The regulatory timelines for the generating units in the 2011 Plans to maintain compliance with applicable environmental requirements necessitate that the Companies take swift action to begin contracting for and constructing the facilities.

Q. Does this conclude your testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE 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

In the Matter of:

THE APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	))))))	CASE NO. 2011-00162

REBUTTAL TESTIMONY OF
GARY H. REVLETT
DIRECTOR, ENVIRONMENTAL AFFAIRS
LG&E AND KU SERVICES COMPANY

Filed: October 24, 2011

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Gary H. Revlett**, being duly sworn, deposes and says that he is Director – Environmental Affairs for LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Gary H. Revlett
Gary H. Revlett

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 20th day of October 2011.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2014

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

A. My name is Gary H. Revlett. I am the Director of Environmental Affairs for LG&E and KU Services Company, which provides services to Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively "the Companies"). My business address is 220 West Main Street, Louisville, Kentucky, 40202.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to the criticisms of the Companies' 2011 Environmental Cost Recovery ("ECR") Plans that Dr. Jeremy Fisher (on behalf of Sierra Club and related parties) and Lane Kollen (on behalf of the Kentucky Industrial Utility Customers, Inc.) made in their direct testimonies. After addressing their criticisms, I conclude by recommending that the Commission approve the Companies' 2011 Plans as filed because it remains the most cost-effective means of complying with applicable environmental requirements.

Q. Do you agree with Mr. Kollen's argument that the finality of the regulations identified in LG&E's and KU's ECR plans are in doubt?

A. No, The Clean Air Transport Rule (now called the Cross-State Air Pollution Rule ("CSAPR")) is now final and in effect and the United States Environmental Protection Agency ("EPA") must issue the final National Emission Standards for Hazardous Air Pollutants Rule pertaining to electric generating units ("HAPs Rule" or "Utility MACT Rule") no later than December 16, 2011.

<u>Clean Air Transport Rule</u>

Q. What is the status of CSAPR?

A. The EPA issued the final Transport Rule (CSAPR) on July 6, 2011. Insofar as the rule will affect the Companies, the final rule is materially the same as the proposed rule.

In sum, the rule became effective on October 7, 2011, with the first phase of SO_2 and annual NO_X compliance requirements becoming effective on January 1, 2012. A second, more stringent phase of SO_2 compliance obligations will go into effect on January 1, 2014. The rule's ozone-season NO_X emission limits will become effective on May 1, 2012.

On October 6, 2011, EPA released technical adjustments to CSAPR.[1] These changes included adjustments to the allowance allocation amounts for Kentucky sources. The change was the result of EPA's comparing CSAPR allocations to previously signed consent decrees and concluding that TVA's Kentucky Electric Generating Units ("EGUs") had been assigned too many SO_2 allowances. The Kentucky statewide SO_2 budget remained the same, so these additional SO_2 allowances, which were to become available in 2013 and 2018, were redistributed to the remaining EGUs in amounts proportional to their original allocations. The increased SO_2 allocations for the Companies are approximately 2% in 2013 and 2% in 2018. The EPA's technical adjustments produced no change in the Companies' ozone-season NO_X allocations and only a very slight increase in the Companies' annual NO_X allocations in 2018.

Q. How has CSAPR affected emission allowances?

[1] *See* Companies' Supplemental Response to Commission Staff's DR Nos. 1-50(LG&E) and 1-49 (KU) (Oct 12, 2011).

A. On October 14, 2011, EPA effectively erased all allowances issued under the Clean Air Interstate Rule ("CAIR") for the year 2012 and beyond. On the basis of the allocations discussed above, EPA began issuing replacement CSAPR allowances for 2012 on October 17, 2011, and allowances for subsequent years will be issued thereafter.

Consistent with what I described in my direct testimony concerning the proposed Transport Rule, the final CSAPR permits unlimited intrastate trading of SO_2 and NO_X allowances, but there are significant constraints on interstate trading. EPA's rationale for this trading regime is that constraining interstate trading of allowances will ensure the states subject to CSAPR will achieve the physical emissions reductions the rule intends.

Q. Do the Companies' 2011 ECR Plans contain facilities necessary to comply with CSAPR?

A. Yes. As I described in my direct testimony, the Companies' 2011 Plans contain elements to reduce NO_X emissions. Specifically, KU proposes to address NO_X emissions by modifying facilities at Ghent Units 1, 3, and 4 to expand the generating-unit-operating range at which the units' Selective Catalytic Reduction facilities ("SCRs") can remain in service to effectively reduce NO_X emissions. LG&E proposes to build two new flue-gas desulfurization units ("FGDs"), one to serve Mill Creek Units 1 and 2 and another to serve Mill Creek Unit 4, and to tie Mill Creek Unit 3 into the existing FGD serving Unit 4 after installing performance upgrades to the FGD. (LG&E proposes to remove the existing FGDs for Mill Creek Units 1, 2, and 3.) Also, LG&E proposes to address NO_X emissions by modifying facilities at

Mill Creek Units 3 and 4 to expand the generating-unit-operating range at which the units' Selective Catalytic Reduction facilities ("SCRs") can remain in service to effectively reduce NOx emissions, and by upgrading the Mill Creek Unit 4 SCR.

Now that EPA has issued the final CSAPR, these facilities remain necessary for the Companies to comply with the rule in the most cost-effective way.

HAPs Rule

Q. What is the status of the HAPs Rule or Utility MACT Rule?

A. EPA is currently finalizing the HAPs Rule. The comment period ended on August 4, 2011. In my direct testimony, I described how EPA was bound by a Consent Decree entered by the United States District Court for the District of Columbia ("Court") providing that by no later than November 16, 2011, EPA must sign a notice of final rulemaking setting forth EPA's final emission standards for coal- and oil-fired electric utility steam generating units pursuant to Clean Air Act section 112(d).[2] On October 21, 2011, EPA and the plaintiffs to that case filed a stipulation with the Court, providing EPA a short 30-day extension in which to issue the final HAPs Rule by no later than December 16, 2011. In the stipulation, the plaintiffs expressly reserved their right to object to any further extension of the Consent Decree deadline.

Q. Are there facilities in the Companies' 2011 ECR Plans to comply with the HAPs Rule?

A. Yes. As I described in my direct testimony, concerning the particulate matter and mercury emissions limits imposed by the HAPs Rule, KU proposes to install Particulate Matter Control Systems to serve all of its Brown and Ghent units, and

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[2] *AMERICAN NURSES ASS'N, et al., Plaintiffs v. LISA JACKSON, in her official capacity as Administrator, U.S. Environmental Protection Agency, et al. Defendants*, Civil Action No. 1:08-cv-2139 (RMC).

LG&E proposes to install Particulate Matter Control Systems to serve all of its Mill Creek units and Trimble County Unit 1. Each Particulate Matter Control System comprises a pulse-jet fabric filter ("baghouse") to capture particulate matter, a Powdered Activated Carbon ("PAC") injection system to capture mercury, a lime injection system to protect the baghouses from the corrosive effects of sulfuric acid mist ("SAM"), and balance-of-plant modifications to accommodate the baghouse.

Q. **Mr. Kollen asserts in his direct testimony that the Companies' 2011 Plans should include projects to address only environmental regulations that have become final,[3] which he subsequently said would exlcude only the HAPs Rule.[4] Has there been any indication from the EPA that the issuance of the final HAPs Rule could be delayed beyond December 16, 2011?**

A. No,. In fact, EPA and others have repeatedly stated that the HAPs Rule will become final as planned. For example, on the same day EPA and the plaintiffs filed their stipulation with the Court, EPA also filed its opposition to a motion filed by a group representing the utility industry requesting the Court to modify the Consent Decree to postpone EPA's deadline until November 16, 2012.[5] In that filing, EPA represented to the Court that the utility industry's motion "should be denied because EPA does not at this time require any additional relief from its obligations under the Consent Decree beyond the 30-day extension reflected in the Consent Decree Parties' stipulation. EPA is on track to meet the revised December 16, 2011, deadline [...] and

[3] *See* Kollen Testimony at 6-8.
[4] *See* KIUC's Oct. 14, 2011 Response to Commission Staff's DR No. 1(a).
[5] *AMERICAN NURSES ASS'N, et al., Plaintiffs v. LISA JACKSON, in her official capacity as Administrator, U.S. Environmental Protection Agency, et al. Defendants*, Civil Action No. 1:08-cv-02198 (RMC), EPA's Opposition to Defendant-Intervenor's Motion for Equitable Relief from Judgment or Order Pursuant to Fed. R. Civ. P. 60(b)(5) filed on October 21, 2011 ("EPA's Opposition").

EPA is best positioned to determine and advise this Court whether it can meet that deadline."[6] In support of its filing, EPA submitted the Declaration of Regina McCarthy, EPA's Assistant Administrator for the Office of Air and Radiation, who testified that "EPA has made substantial progress towards establishing final section 112(d) emission standards ... and is currently on track to meet the December 16, 2011 Consent Decree deadline." (Copies of the EPA's Stipulation, Opposition and supporting Declaration are attached collectively hereto as Rebuttal Exhibit GHR-1.) In a September 22, 2011 memorandum, EPA Assistant Administrator Gina McCarthy stated: "EPA will continue to move forward with implementation and development of federal rules that reduce emissions of pollutants that contribute to smog and threaten public health. These actions include ... the Mercury and Air Toxics Standards (MATS) for power plants ...."[7] (A copy of the memorandum is attached hereto as Rebuttal Exhibit GHR-2.) And perhaps most notably, President Obama himself recently said, "[M]y commitment and the commitment of my administration to protecting public health and the environment is unwavering," citing the HAPs Rule as an example of that commitment.[8] (A copy of the President's full statement is attached hereto as Rebuttal Exhibit GHR-3.) It therefore continues to appear quite likely that the HAPs Rule will become final on or before the December 16, 2011 deadline.

[6] EPA's Opposition at p. 2.
[7] http://www.epa.gov/airquality/ozonepollution/pdfs/OzoneMemo9-22-11.pdf at 2.
[8] *See* http://www.whitehouse.gov/the-press-office/2011/09/02/statement-president-ozone-national-ambient-air-quality-standards.

Q. If the HAPs Rule is issued on time, when will the Companies' facilities have to comply with the rule's requirements?

A. Barring presidential intervention, a maximum of four years is all the time utilities will have to comply with the HAPs Rule, which is a very short time to build all the control facilities the industry will need. Delaying obtaining firm contracts to build such facilities could result in having to pay higher prices for labor and materials as those resources become increasingly demanded in the scramble to comply. For that reason, it is prudent for the Companies to begin to act now to ensure timely compliance. But the Commission, the interveners in this proceeding, and all of the Companies' customers can be assured that neither KU nor LG&E will spend any amounts that are not necessary to comply with the final HAPs Rule or any other environmental requirement.

<u>National Ambient Air Quality Standards</u>

Q. Dr. Fisher states in his direct testimony that EPA's current and planned ozone National Ambient Air Quality Standards should cause the Companies to include Selective Catalytic Reduction facilities ("SCRs") in their modeling for certain units to determine whether to retire them, including Brown Units 1 and 2.[9] Do you agree with Dr. Fisher's assertion?

A. I do not agree with Dr. Fisher's assertions. Contrary to Dr. Fisher's testimony, all counties in the Companies' service territories are in compliance with the current ozone NAAQS, and the proposed revision to the ozone NAAQS was delayed by a direct request from the President. I therefore do not agree that it is necessary or prudent to model SCRs on the units Dr. Fisher proposes.

[9] *See* Fisher Direct Testimony at 23-29.

On September 2, 2011, President Obama asked EPA Administrator Lisa Jackson to refrain from issuing new ozone NAAQS until the scheduled reconsideration of the current standard in 2013.[10] On September 22, EPA Assistant Administrator Gina McCarthy issued a memorandum to the EPA's ten regional air division directors confirming that the current ozone NAAQS is 0.075 ppm (the standard issued in 2008), and that a future revision to the ozone NAAQS is currently expected to be proposed in October 2013, with a final rule expected to be in place by July 2014.[11] But it is important to bear in mind that the eventual reconsideration of the current standard does not require the issuance of a new, more stringent standard. It means only that each NAAQS must be reviewed every five years.

But even concerning the current ozone NAAQS, EPA does not plan to designate with finality which areas are not in compliance with the standard until mid 2012:

> Because we have states' 2009 recommendations and quality assured ozone data for 2008-2010, there is nothing that state or local agencies need to do until we issue the 120-day letters later this year, though of course, states are welcome to contact us to discuss specific issues at any time. We expect to finalize initial area designations for the 2008 ozone NAAQS by mid-2012.[12]

That notwithstanding, on September 22, 2011, the EPA released its initial classifications of areas not in compliance with the 2008 ozone NAAQS based on 2008-2010 data.[13] (The classification document is an appendix to the memorandum attached hereto as Rebuttal Exhibit GHR-2.) Of the 52 areas EPA listed, none of the

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[10] *See* Rebuttal Exhibit GHR-3.
[11] *See* Rebuttal Exhibit GHR-2.
[12] *Id.* at 2.
[13] *See* http://www.epa.gov/airquality/ozonepollution/pdfs/OzoneTable9-22-11.pdf.

areas—not even one—was served by the Companies. Indeed, the only area in Kentucky listed as not being in compliance was "Cincinnati-Hamilton, OH-KY-IN"; it had an ozone measure of 0.079 ppm, which EPA designated as "Marginal." As Assistant Administrator McCarthy put it in her September 22 memo:

> As you know, many of the mandatory measures under the Clean Air Act are not required for Marginal areas since they are expected to achieve attainment within 3 years. In addition, EPA's modeling indicates that approximately half of the 52 areas would attain the 0.075 ppm standard by 2015 (the expected attainment deadline for Marginal areas) as a result of the emission-reducing rules already in place.

Therefore, all of the counties in the Companies' service territories appear to be in compliance with the current ozone NAAQS, and the only area in Kentucky that the EPA has preliminarily found not to be in compliance will likely have to do nothing at all for three years to come into compliance (*contra* Dr. Fisher's testimony that any area found not to be in compliance "must *automatically* comply" with certain requirements).[14] So nothing about the current ozone NAAQS requires the Companies to add NO_X control equipment.

Q. Would the plans discussed for possible NOx emission reductions at some undetermined point in the future require the addition of SCRs on certain units?

A. No, they likely would not. As Dr. Fisher stated in his direct testimony, the proposed revised ozone NAAQS standard was somewhere in the range of 0.060 – 0.070 ppm.[15] What Dr. Fisher did not address in his testimony is that, according to a draft version of the final ozone NAAQS available on the EPA's website, the agency was planning to issue a final ozone NAAQS of 0.070 ppm before President Obama intervened to

[14] *See* Fisher Direct Testimony at 23 ln. 24-29 (emphasis in original).
[15] Fisher Direct Testimony at 24.

postpone the ozone NAAQS review process until 2013.[16] (A copy of the draft final rule is attached hereto as Rebuttal Exhibit GHR-4.) So although there is no new ozone NAAQS to determine what would be needed to comply therewith, and there will not be until 2014 at the earliest, it appears that the new standard that EPA was considering issuing would likely have required little action, if any, by the Companies.

Indeed, by Dr. Fisher's own account, it does not appear that such a standard would have required any action concerning Brown Units 1 and 2, much less the addition of SCRs, because both Fayette and Jessamine Counties are currently in compliance with a 0.070 ppm standard.[17] And that compliance data does not take into account the effect of the SCR currently under construction for Brown Unit 3, which SCR is not scheduled to go into service until spring of 2012.

But even if action were necessary at some point in the future under a more stringent ozone NAAQS, it would likely require statewide compliance efforts because multiple areas in Kentucky would be in non-attainment. In this scenario, the Companies would look first to place an SCR or other NO_X emission control technology on Ghent Unit 2, then Mill Creek Units 1 and 2. Those units are larger and are dispatched frequently, making them more cost-effective units to retrofit with NO_X controls to meet tighter emission limits. This is the scenario the Companies evaluated in section 2.3 of the 2011 Air Compliance Plan Supplemental Analysis. Based on this analysis, the Companies demonstrated the low likelihood of installing SCRs on Brown Units 1 and 2. Only after retrofitting Ghent Unit 2 and Mill Creek

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[16] *See* http://www.epa.gov/airquality/ozonepollution/pdfs/201107_OMBdraft-OzoneRIA.pdf ("Today's rule sets the ozone NAAQS at 0.070 ppm, based on this reconsideration of the evidence available at the time the last standard was set.").

[17] Environmental Interveners' Oct. 14, 2011 Response to Commission Staff DR No. 9(a).

Units 1 and 2 with SCRs would the Companies consider retrofitting Brown Units 1 and 2, and even then the Companies would consider using the less expensive (but less effective) Selective Non-Catalytic Reduction technology ("SNCR") if using such technology would be sufficient. If a purely local non-attainment issue required NO_X reductions at Brown, the Companies would, as required by the Commission, look for the most cost-effective means to comply, which would first include SNCR or other reasonable available control technology before considering SCR. And as Charles Schram has shown and argues in his rebuttal testimony, it is still cost-effective to add the environmental controls in KU's 2011 Plan to Brown Units 1 and 2 and add SCRs later if needed.

Dr. Fisher is therefore incorrect to assert that the Companies' models are flawed for not including the cost of SCRs on Brown 1 and 2, Mill Creek 1 and 2, and Ghent 2 to meet current and proposed ozone NAAQS. The Companies are complying today with the current standard, and it simply is not known at this time whether there will be a more stringent standard in the future, or what such a standard might be, though it is clear there will not be such a standard in place before July 2014.

Q. In addition to ozone NAAQS, Dr. Fisher asserts the Companies erred by overlooking proposed revisions to the particulate matter ("PM") and NO_2 NAAQS. Was that an error?

A. No, it was not. The NO_2 NAAQS was revised last year; based on the Clean Air Act five-year review cycle for NAAQS, there is no reason to believe the NO_2 NAAQS will change before 2015. EPA proposed a revised NO_2 Secondary NAAQS on July 12, 2011, but it proposed no change to the existing secondary standard (0.053 ppm averaged over a year), and proposed a new secondary standard that is identical to the existing primary 2010 NO_2 NAAQS (100 ppb (parts per billion) averaged over one hour). The $PM_{2.5}$ and PM_{10} NAAQS were scheduled to be reviewed and new proposals presented this year; however, it appears that this is now indefinitely delayed.

Not only does it appear that EPA will not issue any such heightened standards in the foreseeable future, it is also not clear that the Companies would need to take any additional steps to meet tighter standards. Baghouses of the kinds the Companies are proposing are the best available control technology for particulate matter, and the proposed projects for NO_X emission reductions could cause the Companies to comply with a tighter NO_2 emission requirement (though no such requirement now exists or has even been proposed).

Greenhouse Gas and Carbon Dioxide Regulations

Q. Dr. Fisher has stated that the Companies' proposed 2011 ECR Plans is flawed because the modeling of capacity requirements and unit retirement scenarios did not take into account current and possible future greenhouse gas regulations, particularly carbon dioxide regulations. What is the status of greenhouse gas regulations?

A. Dr. Fisher is correct that the Greenhouse Gas ("GHG") Tailoring Rule in effect today requires existing sources that undergo major modifications to implement the Best Available Control Technology ("BACT") for greenhouse gases. But Dr. Fisher is incorrect that any of the proposed projects in the Companies' 2011 Plan would be a "major modification" requiring new source review under prevention of significant deterioration rules. Therefore, it was perfectly reasonable for the Companies not to address the Tailoring Rule, not "completely unreasonable" as Dr. Fisher claims.

There is no other existing or proposed greenhouse gas or CO_2 regulation that would restrict the Companies' ability to emit such gases. As David Sinclair discusses at length in his rebuttal testimony, numerous attempts to impose national or regional standards have failed or are flagging, and the political will to impose such requirements appears to be waning, not waxing. In any event, merely hypothetical future standards are not known and measurable, and are therefore inappropriate to use in evaluating the Companies' 2011 Plans.

Q. Based on your previous response, is it reasonable to attach a particular price-per-ton for carbon dioxide emissions when modeling capacity costs and unit retirement scenarios?

A. For the reasons described above and in Mr. Sinclair's rebuttal testimony, I do not believe it is reasonable at this time to include a dollar-per-ton CO_2 cost in the Companies' modeling for the purposes of planning the Companies' environmental compliance strategy. In my view, large scientific, economic, and political shifts would have to occur before including such a pricing regime in the Companies' planning would be reasonable.

Moreover, it is not reasonable to use a CO_2 pricing regime in analyzing the Companies' 2011 Plans because such pricing is not and cannot be BACT for GHG emissions, as Dr. Fisher acknowledges.[18] Although Dr. Fisher believes the Companies have conflated CO_2 pricing and BACT for GHG, they have done nothing

[18] *See* Environmental Interveners' Oct. 14, 2011 Response to Companies' DR No. 22.

of the sort.[19] The purpose of asking Dr. Fisher whether CO_2 pricing is BACT for GHG was to elicit his admission that it is not, which is precisely why I believe it is unreasonable to use CO_2 pricing in the analyses at issue in these proceedings. The GHG regulation that actually exists requires BACT, not CO_2 pricing; as Dr. Fisher's response to the Companies' data request about what is BACT for GHG shows, there is currently no specific equipment or cost identified as BACT for GHG, making it impossible to analyze.[20] (As I said above, none of the actions the Companies plan to take concerning their units would constitute a major modification that would require BACT under the GHG Tailoring Rule.)

In sum, because the only regulation that addresses CO_2 for EGUs does not apply to the Companies' units and would require BACT, not CO_2 pricing, if it did apply, and because I believe there is not a reasonable prospect of a legislatively imposed CO_2 pricing scheme at the state or federal level in the foreseeable future, I believe it is inappropriate to consider a CO_2 pricing scheme at this time.

Recommendation

Q. What is your recommendation to the Commission?

A. My recommendation is the same as what I recommended in my direct testimony; namely, I respectfully recommend that the Commission approve the Companies'

[19] *Id.* ("Based on this question, it seems that the Companies conflated two separate arguments that I raised in my testimony.").

[20] *See* Environmental Interveners' Oct. 14, 2011 Response to Companies' DR No. 14 ("Given that BACT is an emission limit established on a case-by-case basis, it is impossible to state specifically cite "what is BACT." However, the EPA has produced guidance discussing the control technologies that ought to be considered for GHG BACT. EPA notes that BACT might include efficiency improvements to the physical plant to effectively reduce the emissions rate, fuel switching (to higher heat content fuels or lower emissions fuels), or carbon capture and sequestration."). Notice that Dr. Fisher does not give an example of what was determined to be BACT for GHG in a single concrete case.

proposed 2011 Plans as filed. Delaying work on the further planning, engineering, and construction needed to complete the projects in the 2011 Plans will likely serve only to increase costs for customers.

Q. Does this conclude your testimony?

A. Yes it does.

Rebuttal Testimony
Exhibit GHR-1

U.S. EPA Stipulation, Opposition and Supporting Affidavit dated October 21, 2011

UNITED STATES DISTRICT COURT FOR THE DISTRICT OF COLUMBIA

AMERICAN NURSES ASS'N, *et al.*,

Plaintiffs

v.

LISA JACKSON, in her official capacity as Administrator, U.S. Environmental Protection Agency, *et al.*

Defendants.

Civil Action No. 1:08-cv-2139(RMC)

STIPULATION

WHEREAS, on April 15, 2010, the Court entered a consent decree resolving the claims of Plaintiffs American Nurses Ass'n *et al.* ("Plaintiffs") against Defendant Lisa Jackson, in her official capacity as Administrator of the United States Environmental Protection Agency, *et al.* ("EPA");

WHEREAS, Paragraph 4 of the Consent Decree provides that by no later than November 16, 2011, EPA shall sign a notice of final rulemaking setting forth EPA's final emission standards for coal- and oil-fired electric utility steam generating units ("EGUs") pursuant to CAA section 112(d);

WHEREAS, the final emission standards required by Paragraph 4 are already 9 years overdue;

WHEREAS, the Agency seeks a 30-day extension of the deadline for completing the final emission standards for coal- and oil-fired EGUs to account for EPA's extension of the comment period for 30 days and to allow time for the Agency to complete its responses to the comments raised on the proposed rule;

WHEREAS, Paragraph 6 of the Consent Decree provides that any dates set forth in the Consent Decree may be extended by written agreement of the parties and notice to the court;

WHEREAS, Plaintiffs reserve their right to object to any further extension of the Consent Decree deadline, except as stipulated below;

NOW, THEREFORE, the parties agree as follows:

EPA shall have an extension until December 16, 2011, to sign a notice of final rulemaking setting forth EPA's final emission standards for coal- and oil-fired EGUs pursuant to CAA section 112(d). No other provisions of the Consent Decree are affected by this Stipulation.

So Agreed:

FOR THE DEFENDANTS:

IGNACIA S. MORENO
Assistant Attorney General
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Dated: October 21, 2011

/s/ Eric G. Hostetler

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IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF COLUMBIA

AMERICAN NURSES ASS'N, et al., Plaintiffs, v. LISA JACKSON, in her official capacity as Administrator, United States Environmental Protection Agency, et al., Defendants, UTILITY AIR REGULATORY GROUP, Defendant-Intervenor.	)	Civ. Action No. 1:08-cv-02198 (RMC)

EPA's OPPOSITION TO DEFENDANT-INTERVENOR'S MOTION FOR EQUITABLE RELIEF FROM JUDGMENT OR ORDER PURSUANT TO FED. R. CIV. P. 60(b)(5)

INTRODUCTION

Hazardous air pollutants from coal- and oil-fired electric utility steam generating units ("EGUs") contribute to adverse health and environmental effects. Pursuant to applicable provisions of the Clean Air Act ("CAA" or "the Act"), EPA had a nondiscretionary duty to promulgate emission standards for hazardous air pollutants from EGUs by no later than December 2002.

Plaintiffs brought this CAA citizen suit to compel EPA to promulgate final emission standards, and on April 15, 2010, this Court entered a consent decree ("the Consent Decree"). Dkt. No. 33. Under the original Consent Decree terms, EPA had until November 16, 2011, to sign a notice of final rulemaking setting forth EPA's final emission standards for EGUs. On October 21, 2011, pursuant to the modification provisions of the Consent Decree, the parties to the Consent Decree executed and filed a stipulation which provides EPA with an additional 30 days, or until December 16, 2011, to sign a notice of final rulemaking. Dkt. No. 48.

Industry Intervenor Utility Air Regulatory Group ("UARG"), representing the utility industry, has filed a motion pursuant to Fed. R. Civ. P. 60(b)(5), requesting that the Court modify the Consent Decree so as to provide EPA with a substantial additional period of time to promulgate final emission standards. Dkt. No. 37. Specifically, UARG requests that the Consent Decree be modified to postpone EPA's deadline until November 16, 2012. UARG's motion should be denied because EPA does not at this time require any additional relief from its obligations under the Consent Decree beyond the 30-day extension reflected in the Consent Decree Parties' stipulation. EPA is on track to meet the revised December 16, 2011, deadline (*see* attached Declaration of Regina McCarthy), and EPA is best positioned to determine and advise this Court whether it can meet that deadline.

UARG's general concerns regarding the adequacy of the period of time provided to EPA to conclude rulemaking were previously raised and considered by this Court prior to the Court's entry of the Consent Decree. *See* Dkt. Nos. 26, 31. To the extent UARG is now making substantive and procedural attacks on EPA's forthcoming final emission standards – the contents of which have yet to be determined – these attacks are premature and will be exclusively reviewable by the D.C. Circuit following the promulgation of final standards. This Court cannot properly modify a Consent Decree deadline for EPA to conclude rulemaking based on the regulated industry's assessment of the strength of its potential challenges to EPA's forthcoming final standards.

BACKGROUND

I. Statutory and Regulatory Background

The CAA, 42 U.S.C. §§ 7401-7671q, enacted in 1970 and extensively amended in 1977 and 1990, is intended to "protect and enhance the quality of the Nation's air resources so as to promote the public health and welfare." 42 U.S.C. § 7401(b)(1). The CAA sets up a comprehensive and detailed program for control of air pollution.

The CAA, in part, establishes a regulatory program to control emissions of hazardous air pollutants. 42 U.S.C. § 7412. In the 1990 Amendments to the CAA, Congress substantially modified this hazardous air pollutant program. Among other modifications, Congress directed EPA to conduct a study to evaluate the hazards to public health resulting from emissions of hazardous air pollutants from EGUs that would reasonably be anticipated to occur following imposition of the other requirements of the Act, and to report the results of such study to Congress by November 15, 1993. 42 U.S.C. § 7412(n)(1)(A). Congress then required EPA to determine whether regulation of EGUs under CAA section 112 was "appropriate and necessary," after considering the results of the study. *Id.*

On December 20, 2000, EPA made a finding under section 7412(n)(1)(A) "that regulation of [hazardous air pollutant] emissions from [EGUs] under section 112 is 'appropriate and necessary.'" 65 Fed. Reg. 79,825, 79,830 (Dec. 20, 2000). Based on this finding, EPA added EGUs to the CAA section 112(c) list of source categories to be regulated under section 112.

Section 112(c)(5), in relevant part, provides that EPA must promulgate emission standards for newly listed source categories within two years after the date of listing. 42 U.S.C. § 7412(c)(5). Section 112(d) standards must require "the maximum degree of reduction in emissions of" hazardous air pollutants that the Administrator determines is achievable. *Id.* § 7412(d)(2). Section 112 also specifies the minimum degree of emission reductions that sources must achieve, and that minimum level is based on the emissions level achieved in practice by the best performing sources in the category or subcategory. *Id.* § 7412(d)(3). Section 112 emission standards are exclusively reviewable in the United States Court of Appeals for the District of Columbia. 42 U.S.C. § 7607(b). Likewise, any alleged procedural errors associated with EPA's emission standards are exclusively reviewable in the D.C. Circuit. 42 U.S.C. § 7607(d)(8). On December 18, 2008, environmental and public health organizations filed the instant citizen suit against EPA alleging that EPA had failed to perform a nondiscretionary duty to promulgate final emission standards for hazardous air pollutants from EGUs within two years of listing EGUs on the CAA section 112(c) list of source categories to be regulated. UARG, representing the utility industry, intervened as a defendant.

On April 15, 2010, this Court approved and entered the Consent Decree at issue between Plaintiffs and EPA. UARG opposed entry of the Consent Decree alleging, among other things, that the agreement provided insufficient time for EPA to conclude rulemaking. This Court rejected intervenor UARG's objections, explaining:

> Should haste make waste, the resulting regulations will be subject to successful challenge. If EPA has correctly estimated the speed with which it can do the necessary data gathering and analyses, harmful emissions will be reduced sooner. If EPA needs more time to get it right, *it* can seek more time.

Dkt. No. 31 at 4 (emphasis added).

Paragraph 3 of the Consent Decree required EPA to sign, by March 16, 2011, a notice of proposed rulemaking setting forth EPA's proposed emission standards for EGUs. EPA met this deadline. Paragraph 4 of the Consent Decree required EPA sign, by November 16, 2011, a notice of final rulemaking. On October 21, 2011, the parties to the Consent Decree executed a stipulation that provides EPA with an additional 30 days, or until December 16, 2011, to sign a notice of final rulemaking.[1] EPA is on track to meet the revised deadline. *See* Declaration of Regina McCarthy ¶ 8 (attached hereto as Ex. 1). Accordingly, EPA is not at this time seeking any further modification of the Consent Decree. *Id.*

II. Rule 60(b)

Federal Rule of Civil Procedure 60(b) provides that "[o]n motion and just terms, the court may relieve a party or its legal representative from a final judgment, order, or proceeding." Modification of a consent decree "'is an extraordinary remedy, as would be any device which allows a party . . . to escape commitments voluntarily made and solemnized by a court decree.'" *NLRB v. Harris Teeter Supermarkets*, 215 F.3d 32, 35 (D.C. Cir. 2000) (quoting *Twelve John Does v. District of Columbia*, 861 F.2d 295, 298 (D.C. Cir. 1988)). Thus, "[r]equests to modify consent decrees are to be approached with caution." *United States v. Caterpillar*, 227 F. Supp. 2d 73, 80 (D.D.C. 2002).

The party seeking modification of a consent decree bears the burden of showing that there has been a significant change in facts or law that warrants revision of the decree and that the proposed modification is suitably tailored to the changed circumstances. *Rufo v. Inmates of*

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[1] The Consent Decree provides that the parties to the Consent Decree may modify any provision of the Consent Decree by written stipulation, with notice to the Court. Consent Decree ¶ 6.

Suffolk County Jail, 502 U.S. 367, 383, 393 (1992). Rule 60(b)(5) does not authorize relief just because "it is no longer convenient to live with the terms of a consent decree." *Id.* at 383. Nor ordinarily should modification be granted "where a party relies upon events that actually were anticipated" when the decree was entered. *Id.* at 385.

This Court earlier this year addressed the showing that must be made by EPA to obtain an opposed modification of a court-ordered judgment in the specific context here – a request for modification of a judgment imposing a deadline for EPA to perform a nondiscretionary duty under the CAA to promulgate CAA Section 112 hazardous air pollutant emission standards. *Sierra Club v. Jackson ("Sierra Club")*, Case No. 1:01-1537(PLF), 2011 WL 181097 (D.D.C. Jan. 20, 2011) (attached hereto as Ex. 2). In *Sierra Club*, Judge Friedman, relying on D.C. Circuit precedent, held that before the Court could appropriately modify a judgment imposing a deadline on EPA to promulgate Section 112 CAA emission standards, EPA must meet a "heavy burden" of demonstrating that it would be "impossible" to meet that deadline. *Id.* at *5-6 (citing *Sierra Club v. Johnson*, 444 F. Supp. 2d. 46, 53, 58 (D.D.C. 2006); *NRDC v. Train*, 510 F.2d 692, 713 (D.C. Cir. 1974) ("The sound discretion of an equity court does not embrace enforcement through contempt of a party's duty to comply with an order that calls him 'to do an impossibility.'") (citation omitted); *Alabama Power Co. v. Costle*, 636 F.2d 323, 359 (D.C. Cir. 1979) (agency bears "heavy burden to demonstrate the existence of an impossibility")).

The Court explained in *Sierra Club* that "[w]hen Congress expresses its intent that regulations be promulgated by a date certain," "that intent is of utmost importance; a court considering a claim of impossibility must not 'order a remedy that would . . . completely neutralize the mandatory nature of the statutory directive." 2011 WL 181097, at *6 (quoting

Sierra Club v. Johnson, 444 F. Supp. 2d at 53. Accordingly, "[a]lthough EPA, like all agencies, should always strive to develop the most effective and sound regulations, 'that quest must give ground in favor of expedition where Congress expressly directs the Administrator to establish standards promptly.'" *Id.* at *7 (quoting *State v. Gorsuch,* 554 F. Supp. 1060, 1065 (S.D.N.Y. 1983)).

In considering EPA's motion for relief from a judgment in *Sierra Club*, the Court further explained that it lacked any authority "to address the content of EPA's conduct" or "issue substantive determinations of its own" on promulgated regulations. *Id.* (quoting *Sierra Club v. Johnson*, 444 F. Supp. 2d at 60). Thus, the Court determined that it could not "embroil [itself] in an assessment of the substance of EPA's actions or omissions" in evaluating a request for extension of time. *Id. (*quoting *Sierra Club v. Browner*, 130 F. Supp. 2d 78, 90 (D.D.C. 2001), *aff'd*, 285 F.3d 63 (D.C. Cir. 2002)).[2]

DISCUSSION

There has been no significant change in circumstances that warrants the extraordinary relief requested by intervenor UARG. To begin with, it is unclear that UARG, as a nonparty to the Consent Decree, is even eligible under Rule 60(b)(5) to move to relieve EPA from *the Agency's* obligations under the Consent Decree. But to the extent UARG may seek such relief, its burden under Rule 60(b)(5) should be at least as great as the burden EPA would have to meet to obtain the same relief. It would be incongruous for a nonparty to be able to modify consent

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[2] The Court found that where EPA's motion for an extension of time focused, in part, on the substantive quality of EPA's rules, the Court could give deference to *EPA's* ultimate conclusion on the substantive merit of its rules without running afoul of the exclusive grant of jurisdiction to the court of appeals at 42 U.S.C. § 7607(b), but even granting such deference, the Court found that EPA had not met its heavy burden of proving impossibility in that case. *Id.*

decree terms more readily than a party itself.

Applying the principles set forth by this Court recently in *Sierra Club,* UARG must meet the "heavy burden" of demonstrating that it would be "impossible" for EPA to promulgate hazardous air pollutant emission standards for EGUs by the revised December 16, 2011, Consent Decree deadline. 2011 WL 181097, at *6 (quoting *Alabama Power Co. v. Costle*, 636 F.2d at 359). UARG does not meet this heavy burden.

I. EPA Is Not Seeking Relief From the Consent Decree.

In the first place, EPA alone is positioned to determine and advise this Court whether it is possible for the Agency to meet its own rulemaking obligations pursuant to the Consent Decree. As set forth in the attached declaration of EPA Assistant Administrator Regina McCarthy, EPA has made substantial progress towards establishing final emission standards for hazardous air pollutants from EGUs, and EPA believes that it can meet the revised December 16, 2011, deadline. McCarthy Decl. ¶ 8.[3] EPA is considering the comments that have been submitted on its proposed standards, along with other pertinent materials. EPA intends to promulgate final standards that comport with the requirements of the CAA. *Id.* Thus, EPA does not at this time believe any additional modification of the Consent Decree is necessary.

EPA's considered judgment on its ability to comply with the Consent Decree, and its ability to promulgate standards that will comport with the requirements of the Act, should be afforded deference. *Cf. Sierra Club*, 2011 WL 181097, at *7 (deference must be granted to

[3] Pursuant to Paragraph 6 of the Consent Decree, EPA sought and obtained from Plaintiffs a stipulated 30-day extension of the original November 16, 2011 deadline. Dkt. No. 48. This extension accounts for EPA's 30-day extension of the comment period and provides additional time for the Agency to complete its responses to comments. McCarthy Decl. ¶ 6.

EPA's conclusions on the substantive merit of its rules in evaluating a request for modification of a judgment establishing a deadline to promulgate standards). If EPA were to determine that it needed additional time to meet the revised deadline, EPA would, of course, promptly seek additional relief pursuant to the modification procedures set forth in Paragraphs 6 and 7 of the Consent Decree.

II. UARG's General Concerns Regarding the Period for Rulemaking Were Considered Prior to Entry of the Consent Decree, and This Court Lacks Jurisdiction to Opine on Alleged Errors in EPA's Forthcoming Final Standards.

UARG's Rule 60(b)(5) motion generally raises concerns regarding the adequacy of the time available for EPA to conclude rulemaking. But UARG's general concerns regarding the amount of time provided to EPA to conclude this rulemaking were previously raised and considered by this Court prior to entry of the Consent Decree. *See* Dkt. Nos. 26, 31. This Court's central conclusions set forth when it entered the Consent Decree remain equally valid today:

> Should haste make waste, the resulting regulations will be subject to successful challenge. If EPA has correctly estimated the speed with which it can do the necessary data gathering and analysis, harmful emissions will be reduced sooner. If EPA needs more time to get it right, *it* can seek more time.

Dkt. No. 31 at 4 (emphasis added).

Inasmuch as UARG's motion raises concerns that were fully anticipated by UARG and brought to this Court's attention at the time the Consent Decree was entered, UARG's motion for a substantial period of additional time to conclude rulemaking should be denied. *See Rufo*, 502 U.S. at 385 (holding modification under Rule 60(b)(5) should not ordinarily be granted when moving party relies upon events that were anticipated when decree was entered).

UARG also contends that EPA should be provided with additional time so that EPA can correct various alleged "procedural and substantive errors" in its standards. UARG Mem. at 28. Essentially, UARG urges the Court to engage in speculation as to how EPA will respond to comments on its proposed standards in the forthcoming final rule, and then, based on this speculation, assess whether EPA's final standards will meet the requirements of the CAA. But this Court lacks jurisdiction to evaluate the substantive and procedural merits of EPA's forthcoming Section 112 emission standards. *See Sierra Club*, 2011 WL 181097, at *7.

As the Court recognized in *Sierra Club*, under 42 U.S.C. § 7607 the D.C. Circuit has exclusive authority to review the merits of emission standards promulgated by EPA and alleged procedural errors. *Id.* This means that in the context of considering a request for modification of a judgment establishing a deadline for EPA actions under the CAA, the CAA "does not allow district courts to address the content of EPA's conduct" or to "embroil [themselves] in an assessment of the substance of EPA's actions or omissions." *Id.* (citations omitted). Furthermore, EPA is entitled to a presumption that it will respond appropriately to comments submitted on its proposed emission standards. *See Hercules, Inc. v. EPA*, 598 F.2d 91, 123 (D.C. Cir. 1978) (presumption of regularity afforded administrative agency decisionmakers).[4/]

UARG further has a statutory remedy to the extent it concludes – following promulgation of final emission standards – that it was impracticable to raise an objection of central relevance to the outcome of the standards within the public comment period. Specifically, UARG can

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[4/] EPA strongly disputes UARG's characterization that EPA is engaging in a "shoddy rulemaking" process (UARG Mem. at 2). The instant motion is, however, not the appropriate forum for EPA to attempt to respond to comments submitted on EPA's proposed rule or to attempt to litigate potential attacks on EPA's final rule – the contents of which have yet to be determined. Any such attempt would be premature and in the wrong court.

petition EPA for reconsideration of the final standards, and if it can demonstrate that it was, in fact, impracticable for it to raise an objection of central relevance to the outcome of the rule within the public comment period, then EPA must convene a reconsideration proceeding pursuant to 42 U.S.C. 7607(d)(7)(B).[5]

III. Delaying Promulgation of Emission Standards for Hazardous Air Pollutants Would Not Be in the Public Interest.

Contrary to UARG's suggestion, it would not be in the public interest for EPA to further delay promulgation of emission standards for hazardous air pollutants from EGUs for a period of almost one additional year. Hazardous air pollutants from EGUs contribute to adverse health and environmental effects. Congress plainly directed EPA to promulgate emission standards for hazardous air pollutants from EGUs within two years of their inclusion, in December 2000, on the list of source categories to be regulated. 42 U.S.C. § 7412(c)(5). *See* 65 Fed. Reg. 79,825 (Dec. 20, 2000). It has already been almost nine years since the date-certain deadline for promulgation set forth by Congress.

The additional modification of the Consent Decree sought by UARG would frustrate Congress' intent inasmuch as it would potentially result in a further delay of the promulgation of emission standards intended to protect public health and welfare beyond the 2002 date-certain

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[5] UARG and amici specifically contend, among other things, that EPA should be provided with more time to promulgate final standards so as to further consider the impact of emission standards on reliable electric service. As noted above, EPA is considering comments on its proposed standards and intends to promulgate standards by the Consent Decree deadline that are consistent with the requirements set forth in the CAA. *See* McCarthy Decl. ¶ 8. To the extent that UARG and amici contend following promulgation of final emission standards that such final standards fail to appropriately take into account issues related to reliable electric service, these issues may be raised in challenges to the final standards, or in petitions for reconsideration of the final standards.

deadline. As this Court explained in *Sierra Club*, "[w]hen Congress expresses its intent that regulations be promulgated by a date certain," "*that intent is of utmost importance*; a court considering a claim of impossibility must not 'order a remedy that would . . . completely neutralize the mandatory nature of the statutory directive.'" *Sierra Club*, 2011 WL 181097, at *6 (quoting *Sierra Club v. Johnson*, 444 F. Supp. 2d at 53) (emphasis added).

CONCLUSION

WHEREFORE, for the reasons set forth above, UARG's motion should be denied.

Respectfully submitted,

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October 21, 2011

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EXHIBIT 1

UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF COLUMBIA

AMERICAN NURSES ASS'N, *et al.*,

Plaintiffs,

v.

LISA JACKSON, in her official capacity as Administrator, United States Environmental Protection Agency, *et al.*,

Defendants,

UTILITY AIR REGULATORY GROUP,

Defendant-Intervenor.

Civ. Action No. 1:08-cv-02198 (RMC)

DECLARATION OF REGINA McCARTHY

I, Regina McCarthy, under penalty of perjury, affirm and declare that the following statements are true and correct to the best of my knowledge and belief and are based on my own personal knowledge or on information contained in the records of the United States Environmental Protection Agency (EPA) or on information supplied to me by EPA employees under my supervision and employees in other EPA offices.

1. I am the Assistant Administrator for the Office of Air and Radiation of the United States Environmental Protection Agency, a position I have held since June 2009. The Office of Air and Radiation (OAR) is the EPA office that develops national programs, technical policies, and regulations for controlling air pollution. OAR's assignments include the protection of public health and welfare, pollution prevention, air

quality, industrial air pollution, pollution from vehicles and engines, toxic air pollutants, acid rain, stratospheric ozone depletion, and climate change.

2. Prior to joining EPA, I served as the Commissioner of the Connecticut Department of Environmental Protection. I have worked at both the state and local levels on critical environmental issues and helped coordinate policies on economic growth, energy, transportation and the environment. I have a B.A. in Social Anthropology from the University of Massachusetts at Boston and a joint M.S. in Environmental Health Engineering and Planning and Policy from Tufts University.

3. As part of my duties as Assistant Administrator of the Office of Air and Radiation, I oversee the development of regulations under section 112 of the Clean Air Act (CAA), the national emission standards for hazardous air pollutants (NESHAP) program, including development of the NESHAP for coal- and oil-fired electric utility steam generating units ("EGUs") that is the subject of the Consent Decree in this matter.

4. The above-captioned case was filed on December 18, 2008. Plaintiffs and EPA subsequently negotiated a Consent Decree that would require EPA to sign a notice of proposed rulemaking by March 16, 2011, and a notice of final rulemaking by November 16, 2011. On February 24, 2010, EPA moved to enter the Consent Decree. UARG objected. On April 15, 2010, the Court granted EPA's motion to enter the Consent Decree.

5. On March 16, 2011, consistent with the Consent Decree, EPA signed proposed CAA section 112(d) emission standards for coal- and oil-fired EGUs. EPA posted the signed proposed rule on its website on March 16, 2011, and, within a few days thereafter, posted many of the documents supporting the proposed rule. On May 3, 2011,

the proposed rule was published in the Federal Register, and EPA provided a 60-day comment period. In response to requests for an extension of the comment period, EPA extended the comment period by 30 days. The comment period closed on August 4, 2011. The public, therefore, had an official 90-day comment period and an additional period of about 45 days prior to publication of the proposed rule in the Federal Register to review the proposed rule and many of the supporting documents.

6. On October 21, 2011, pursuant to Paragraph 6 of the Consent Decree, the Parties to the Consent Decree signed a stipulation, extending the final rule deadline in Paragraph 4 of the Decree to December 16, 2011. That stipulation was filed with the Court on October 21, 2011, consistent with Paragraph 6 of the Decree. The Agency sought this short extension to account for the 30-day extension of the comment period, as described above, and to allow time for the Agency to complete its responses to the comments raised on the proposed rule.

7. EPA received over 900,000 comments on the proposed rule and approximately 22,000 unique comments. While this number is significant, many of the unique comments raise similar or the same issues.

8. EPA has made substantial progress towards establishing final section 112(d) emission standards for coal- and oil-fired EGUs and is currently on track to meet the December 16, 2011 Consent Decree deadline. The Agency has committed substantial resources so as to be able to comply with that deadline. Among other things, we have a cross-agency team that is working daily to complete the rulemaking. I have approximately 75 members of my staff reviewing and responding to comments on the proposed rule and conducting other work in support of the final rule. This number does

not include staff from other offices around the Agency that are supporting the Agency's efforts to comply with the requirements of the Consent Decree. We have also committed contractor resources to reviewing and summarizing the comments received and providing other rulemaking support. EPA intends to issue a final rule that is consistent with the requirements of the Clean Air Act.

SO DECLARED:

REGINA McCARTHY

Dated: 10/21/11

EXHIBIT 2

Slip Copy, 2011 WL 181097 (D.D.C.)
(Cite as: 2011 WL 181097 (D.D.C.))

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Only the Westlaw citation is currently available.

United States District Court,
District of Columbia.
SIERRA CLUB, Plaintiff,
v.
Lisa P. JACKSON, Administrator, United States Environmental Protection Agency,[FN1] Defendant.

FN1. Under Rule 25(d)(1) of the Federal Rules of Civil Procedure, EPA Administrator Lisa P. Jackson has been substituted as the defendant for former Administrator Stephen L. Johnson.

Civil Action Nos. 01-1537 (PLF), 01-1548, 01-1558, 01-1569, 01-1578, 01-1582, 01-1597.
Jan. 20, 2011.

James S. Pew, Earthjustice, Washington, DC, for Plaintiff.

Eileen T. Mcdonough, Angeline Purdy, U.S. DOJ - Environmental Defense Section, Washington, DC, for Defendant.

OPINION

PAUL L. FRIEDMAN, District Judge.

***1** "This case concerns defendant EPA's failure to discharge fully its duty under the 1990 Clean Air Act amendments to promulgate regulations governing the discharge of certain hazardous air pollutants." *Sierra Club v. Johnson,* 444 F.Supp.2d 46, 47 (D.D.C.2006). By Order of March 31, 2006, this Court entered judgment for plaintiff, finding that EPA's admitted failure to promulgate emission standards pursuant to the Clean Air Act constituted "a failure of the Administrator to perform any act or duty under this chapter that is not discretionary with the Administrator" within the meaning of Section 304(a)(2) of the Clean Air Act, 42 U.S.C. § 7604(a)(2). *See* Order at 1, Mar. 31, 2006. The Court ordered EPA to fulfill its statutory duties regarding the promulgation of emission standards under Sections 112(c)(3) and (k)(3)(B), Section 112(c)(6), and Section 183(e) on a prescribed schedule. *See id.* at 1-3. The Court explained the reasoning underlying its March 31, 2006 Order in its August 2, 2006 Opinion. *See Sierra Club v. Johnson,* 444 F.Supp. at 46.

Pursuant to the schedule established by the Court's Order, EPA was to have fully discharged all of its statutory duties by June 15, 2009. *See* Order at 3, Mar. 31, 2006; *Sierra Club v. Johnson,* 444 F.Supp.2d at 48. Since 2006, however, the Court has granted a number of EPA's motions to extend the deadlines in its March 31, 2006 Order, all without opposition from plaintiff. Thus, as amended, the Court's March 31, 2006 Order now requires, in relevant part, that EPA fully discharge its statutory duties under Sections 112(c)(3) and (k)(3)(B), and Section 112(c)(6) of the Clean Air Act by January 21, 2011. *See* Order at 1-2, Sept. 20, 2010; Order at 1, Jan. 12, 2011. EPA now requests an extension of this January 21, 2011 deadline-but this time its request is opposed.[FN2]

FN2. The parties' papers refer to a deadline of January 16, 2011. Because that date was a Sunday and January 17, 2011 was a federal holiday, the Court, with the agreement of the parties, extended this January 16, 2011 deadline to January 21, 2011, pending a decision on EPA's motion. *See* Order at 1, Jan. 21, 2011. The Court thus refers throughout this Opinion to January 21, 2011 as the applicable deadline.

This matter is before the Court on EPA's motion to amend paragraphs 1(i) and 3 of the Court's March 31, 2006 Order to allow EPA additional time to promulgate regulations governing emission standards for certain hazardous air pollutants. Six intervenors have collectively filed a response in support of EPA's motion. Plaintiff opposes the motion. Upon consideration of the parties' and intervenors' arguments, the applicable legal standards, and the entire record in this case, the Court will deny *in part and grant in part* EPA's motion. FN3

FN3. The papers reviewed in connection with the pending motion include the following: EPA's corrected motion to amend Order of March 31, 2006 ("Mot."); Exhibits 1 through 6 to Mot., including the Declaration of Panagiotis E. Tsirigotis (attached as Exhibit 6 to Mot.) ("Tsirigotis Decl."); plaintiff's opposition to EPA's motion to amend Order of March 31, 2006 ("Opp."); Exhibits A through I to Opp.; response by intervenors to EPA's motion to amend Order of March 31, 2006 ("Intervenors' Response"); the six Declarations attached to Intervenors' Response; plaintiff's reply to response by intervenors ("Pl.'s Reply to Intervenors"); EPA's reply ("Reply"); the Supplemental Declaration of Panagiotis E. Tsirigotis (attached to Reply) ("Tsirigotis Supp. Decl."); and plaintiff's surreply ("Surreply"). The Court also reviewed the parties' summary judgment papers.

I. BACKGROUND

A. The Clean Air Act and the 1990 Amendments

The Clean Air Act ("CAA" or "the Act") regulates hazardous air pollutants ("HAPs"). The first federal attempt to regulate these HAPs, enacted in 1970, "worked poorly." *See* S. REP. NO. 101-228, at 128 (1989). Indeed, from 1970 until 1990, "EPA ... listed only eight substances as hazardous air pollutants ... and ... promulgated emissions standards for seven of them." *See* H.R. REP. NO. 101-490, pt. 1, at 322 (1990). Accordingly, on November 15, 1990, Congress enacted sweeping revisions to the Act. *See* PUB.L. NO. 101-549, 104 STAT. 2399. The purpose of these revisions was to "entirely restructure the existing law, so that toxics might be adequately regulated by the Federal Government." S. REP. NO. 101-228, at 128 (1989). In place of the prior "risk-based approach," Congress imposed a technology-based emission-control scheme that limited EPA's discretion and that set strict requirements and deadlines for the promulgation of emission standards. *See NRDC v. EPA ("NRDC II")*, 489 F.3d 1364, 1368 (D.C.Cir.2007).

***2** As the Court previously described:

> Title III of the revised statute created a complex scheme for the regulation of 189 specified [HAPs], and directed EPA to identify the sources of those pollutants and to promulgate regulations governing the emission of HAPs from those sources. Congress by statute added to the Clean Air Act the list of pollutants to be regulated, minimum stringency requirements, and *(most important for this case) regulation deadlines*. It did so because it believed that EPA had failed to regulate enough HAPs under previous air toxics provisions.

Sierra Club v. Johnson, 444 F.Supp.2d at 48 (emphasis added). Title III recognizes and directs EPA to identify and regulate two basic kinds of sources of air pollutants: (1) major sources; and (2) area sources. *Id.* These two types of sources are distinguished by the amount of their respective HAP emissions. *See id.; see also* 42 U.S.C. §§ 7412(a)(1), (2). At issue in this case are the following two requirements regarding both area sources and major sources:

1. Regulate area sources of the thirty most dangerous HAPs: Sections 112(c)(3) and (k)(3)(B) of the Act, 42 U.S.C. §§ 7412(c) (3) and (k)(3)(B), require EPA (1) to "identify not less than 30 hazardous air pollutants which, as the result of emissions from area sources, present the greatest threat to public health in the largest number of urban areas"; (2) to identify the categories or subcategories of sources "accounting for 90 per centum or more of the aggregate emissions of each of the 30 identified hazardous air pollutants" by November 15, 1995; and (3) to issue emission standards for those area source categories by November 15, 2000. *Sierra Club v. Johnson*, 444 F.Supp.2d at 49. The emission standards must be based on one of three types of pollution control mechanisms: (1) maximum achievable control technologies ("MACTs"); (2) health-based standards; or (3) generally available control technologies. *See* 42 U.S.C. §§ 7412(d)(2), (d)(4), and (d)(5). As of 2006, EPA had fulfilled the first two of its duties under Sections 112(c)(3) and (k)(3)(B). EPA had failed, however, to fulfill its third duty: by 2006, it had promulgated emission standards for only fifteen of seventy area source categories. *Sierra Club v. Johnson,* 444 F.Supp.2d at 49.

2. Regulate sources of seven statutorily-specified HAPs: Section 112(c)(6) of the Act calls for EPA to regulate the sources of seven specific HAPs, without regard to whether those sources are major sources or area sources and without regard to their inclusion on EPA's list of sources of the thirty most dangerous HAPs. *See* 42 U.S.C. § 7412(c)(6); *Sierra Club v. Johnson,* 444 F.Supp.2d at 49. EPA's duties and deadlines with respect to Section 112(c)(6) are identical to its duties with respect to the thirty most dangerous HAPs under Sections 112(c)(3) and (k)(3)(B). *See* 42 U.S.C. § 7412(c)(6). The only difference is that EPA emission standards promulgated pursuant to Section 112(c)(6) cannot be based on generally available control technologies. Rather, the emission standards must be either (1) MACTs or (2) health-based standards. *See* 42 U.S.C. §§ 7412(d)(2) and (d)(4).

*3 As the Court explained in *Sierra Club v. Johnson,* because one source may emit numerous pollutants, there is the potential for EPA to satisfy its Section 112(c)(3) and (k)(3)(B) requirements and its Section 112(c)(6) requirements simultaneously. *See Sierra Club v. Johnson,* 444 F.Supp.2d at 48 n. 3. In other words, EPA may not need to promulgate regulations directly under Section 112(c) (6), because regulations it promulgates under other sections of the Act may suffice to "account[ ] for 90 per centum or more of the aggregate emissions" of the pollutants listed in that section. *Id.* at 59. Nevertheless, as of 2006, EPA had failed to promulgate emission standards under Section 112(c)(6) for five source categories. *Id.* at 49. These five source categories were also among the fifty source categories that were required to be regulated under Sections 112(c)(3) and (k)(3)(B). *Id.* at 50.

B. History of This Litigation

In 2001, plaintiff filed seven different complaints against EPA, each seeking relief for EPA's failure to discharge a different aspect of its regulatory duties under the Act. These cases were consolidated, and the parties entered into a partial consent decree on May 22, 2003. Other issues could not be resolved, however, and the parties eventually filed cross-motions for summary judgment. EPA did not contest the issue of liability: it admitted that it had failed to promulgate regulations by the statutory deadline of November 15, 2000. Accordingly, the only matter before the Court was to fashion an appropriate equitable remedy.

On March 31, 2006, the Court issued its Order denying EPA's motion for summary judgment and granting summary judgment in favor of plaintiff. The Court ordered EPA to fulfill its statutory duties under Sections 112(c)(3) and (k)(3)(B), Section 112(c)(6), and Section 183(e) on a prescribed schedule that would "best preserve the intent of Congress in enacting the 1990 Clean Air Act Amendments, without calling upon defendants to do the impossible." *See Sierra Club v. Johnson,* 444 F.Supp.2d at 61. That Order required, in relevant part, that EPA "promulgate standards under CAA Section 112(d) for those area source categories listed by EPA pursuant to CAA Section 112(c)(3) and (k)(3)(B) as source categories that are necessary to meet the 90 percent statutory threshold identified in Section 112(c)(3) and (k)(3)(B), and for which it has not yet issued standards" on a set schedule to be completed in full by June 15, 2009. *See* Order at 2, Mar. 31, 2006; *Sierra Club v. Johnson,* 444 F.Supp.2d at 48, 61. That Order further required that "[n]o later than December 15, 2007, EPA shall promulgate emission standards assuring that source categories accounting for not less than ninety percent of the aggregate emissions of each of the hazardous air pollutants enumerated in Section 112(c)(6) are subject to emission standards under Section 112(d)(2) or (d)(4)." Order at 3, Mar. 31, 2006; *Sierra Club v. Johnson,* 444 F.Supp.2d at 48, 61.

*4 After March 31, 2006, EPA moved for a number of unopposed extensions of time to complete its obligations. *See* Order at 1-2, Nov. 13, 2008; Order at 1-2, June 30, 2009; Order at 1-2, Sept. 10, 2009; Order at 1, Apr. 13, 2010. On August 31, 2010, EPA requested, without opposition from plaintiff, that the Court amend paragraphs 1(i) and 3 so as to extend its deadline from December 16, 2010 to January 16, 2011. *See* Unopposed Mot. to Amend Order at 1, Aug. 31, 2010. On September 20, 2010, the Court granted EPA's request, and the Court has since extended the deadline to January 21, 2011. *See supra* n. 2. Accordingly, as amended, the March 31, 2006 Order provides, in relevant part:

> 1. EPA shall promulgate emission standards under section 112(d) assuring that area sources representing ninety percent of the area source emissions of the 30 urban hazardous air pollutants identified pursuant to section 112(k)(3) are subject to emissions standards as follows:
>
> * * * *
>
> (i) EPA shall promulgate emission standards under section 112(d) or section 129 assuring that area sources representing ninety percent of the area source emissions of the 30 urban hazardous air pollutants are subject to emissions standards by January 21, 2011.
>
> * * * *
>
> 3. No later than December 16, 2010, the Agency shall promulgate emission standards for one additional category pursuant to section 112(c)(6). No later than January 21, 2011, the Agency shall promulgate emission standards assuring that sources accounting for not less than ninety percent of the aggregate emissions of each of the hazardous air pollutants enumerated in Section 112(c)(6) are subject to emission standards under Section 112(d)(2) or (d)(4).

See Order at 1-2, Sept. 20, 2010; Order at 1, Jan. 12, 2011. As required by paragraph 3, on December 16, 2010, EPA signed the final rule "National Emission Standards for Hazardous Air Pollutants: Gold Mine Ore Processing and Production Area Source Category; and Addition to Source Category List for Standards." *See* Def.'s Notice of Subsequent Event, Dec. 21, 2010. Still at issue, however, is the January 21, 2011 deadline in both paragraph 1(i) and paragraph 3. EPA now requests that this deadline be extended. *See* Mot. at 1-4.

C. EPA's Proposed Schedule

As EPA explains, the key for each of its remaining obligations "is reaching the ninety percent threshold." Mot. at 2. Since 2006, EPA has promulgated final rules establishing emission standards for forty-eight area source categories pursuant to paragraph 1, and EPA has promulgated emission standards for two source categories pursuant to paragraph 3. *See* Tsirigotis Decl. ¶¶ 9, 10. With respect to paragraph 3, in order to reach the required ninety percent threshold, EPA asserts that it needs to complete additional emission standards for (1) certain area source boilers, (2) major source boilers, and (3) commercial and institutional solid waste incineration ("CISWI") units (collectively, "the Three Air Rules"). *Id.* ¶¶ 11 & n. 2, 41. With respect to paragraph 1, in order to reach the required ninety percent threshold, EPA asserts that it needs to complete additional emission standards for (1) area source boilers, and (2) sewage sludge incineration ("SSI") units. *Id.* ¶¶ 9, 42.

*5 *Paragraph 3:* On April 29, 2010, the EPA Administrator signed proposed emission standards for the Three Air Rules. Tsirigotis Decl. ¶ 23. These proposed rules were then published in the Federal Register on June 4, 2010. *Id.* ¶ 25. Although the public comment period was originally to close on July 19, 2010, given the significant public interest in these rules, EPA granted extensions until August 23, 2010. *Id.* ¶¶ 29, 30. EPA received over 4,800 individual comments in response to those proposed rules. *Id.* ¶¶ 32-34. EPA now asserts that those comments "may materially affect important decisions relating to source categorizations and coverage for the final emission standards ." Mot. at 2. Thus, "EPA believes that the purpose of section 112(c)(6) and the public interest will be best served if the Agency's deadline in [p]aragraph 3 is extended ... to April 13, 2012, so that EPA can re-propose the rules for further public comment to ensure that the final rules are logical outgrowths of the proposals." *Id.* at 3; *see* Tsirigotis Decl. ¶¶ 4, 34-37. In the alternative, EPA requests an extension until June 15, 2011 to allow EPA time to fully respond to the 4,800 individual comments it received. Mot. at 4; Tsirigotis Decl. ¶¶ 5, 40.

Paragraph 1: Because the standards for certain area source boilers are necessary for EPA to complete its obligations under both paragraphs 1(i) and 3, EPA requests that the deadline for it to complete all emission standards required under both paragraphs 1(i) and 3 be extended to the same date-April 13, 2012. As to the one remaining area source category relevant to paragraph 1(i), SSI units, the EPA Administrator signed a proposed rule on September 30, 2010. Tsirigotis Decl. ¶ 47. The public comment period closed on November 29, 2010. *Id.* EPA received over eighty individual comments in response to its SSI proposal. *Id.* ¶ 48. EPA does not request an extension of time to re-propose this rule; rather, EPA requests an extension until July 15, 2011, so that it can fully respond to the individual comments it received. Mot. at 4; Tsirigotis Decl. ¶¶ 6, 49.

II. DISCUSSION

A. Standard of Review

Despite the complexity of the statutory scheme at issue, the Court is again presented with a single question for review: whether EPA has met the "heavy burden" of demonstrating that it would be impossible to comply with the current January 21, 2011 deadline for the promulgation of the remaining emission standards. *See Sierra Club v. Johnson,* 444 F.Supp.2d at 53, 58. The principles discussed in *Sierra Club v. Johnson* guide the Court's decision on the matter before it now. *See NRDC v. Train,* 510 F.2d 692, 713 (D.C.Cir.1974) ("Similar considerations apply after the issuance of an order when the defendant petitions for modification or the court considers the propriety of resorting to contempt to coerce compliance."). The Court, however, elaborates on several points.

*6 First, it is established that where, as here, "an agency has failed to meet a statutory deadline for a nondiscretionary act, the [C]ourt may exercise its equity powers 'to set enforceable deadlines both of an ultimate and an intermediate nature[.]' " *Sierra Club v. Johnson,* 444 F.Supp.2d at 52 (quoting *NRDC v. Train,* 510 F.2d at 705). Although a court may appropriately decline to impose a deadline that would call on an agency to do the impossible, the "heavy burden" of proving such an impossibility rests squarely on the agency. *Id.* at 52-53 (quoting *Alabama Power Co. v. Costle,* 636 F.2d 323, 359 (D.C.Cir.1979)).

As a general rule, "[f]lexibility rather than rigidity has distinguished equity jurisprudence." *NRDC v. Train,* 510 F.2d at 713 (internal quotations and citation omitted). Nevertheless, the court of appeals has cautioned that a district court must scrutinize carefully claims of impossibility, and must "separate justifications grounded in the purposes of the Act from the footdragging efforts of a delinquent agency." *Id.* "When Congress expresses its intent that regulations be promulgated by a date certain"-in this case, November 15, 2000, more than ten years ago-"that intent is of utmost importance; a court considering a claim of impossibility must not 'order a remedy that would ... completely neutralize the mandatory nature of the statutory directive.' " *Sierra Club v. Johnson,* 444 S. Supp.2d at 53 (quoting *Sierra Club v. Browner,* 130 F.Supp.2d

78, 95 (D.D.C.2001)).

To prove impossibility, "it is insufficient for the agency to demonstrate only that it has proceeded in good faith; it also must demonstrate 'utmost diligence' in its efforts to comply with the statute." *See Sierra Club v. Johnson,* 444 F.Supp.2d at 53. Because a "court's injunction should serve like adrenalin, to heighten the response and to stimulate the fullest use of resources," *NRDC v. Train,* 510 F.2d at 712, it is of course not the case than an agency can fail to act with "the fullest use of resources" and then claim, at the last minute, that compliance is impossible. Instead, although an agency's current position may be relevant to a court's ultimate conclusion on whether action is impossible, a court will examine all of the agency's actions and inactions following the initial injunction or other court order in determining whether an extension of a deadline is appropriate. *See id.* at 712-13; *Sierra Club v. Johnson,* 444 F.Supp.2d at 52-53. Here, the statutory mandates and court-ordered deadline at issue relate to the promulgation of emission standards for certain HAPs by a date certain. Thus, in order for EPA to demonstrate the existence of an impossibility for purposes of its pending motion, EPA must prove to the Court that it has in good faith exercised utmost diligence in its efforts to promulgate the required emission standards pursuant to paragraphs 1(i) and 3 by the Court's deadline of January 21, 2011.

*7 One final point requires discussion. Although EPA, like all agencies, should always strive to develop the most effective and sound regulations, "that quest must give ground in favor of expedition where Congress expressly directs the Administrator to establish standards promptly." *See State v. Gorsuch,* 554 F.Supp. 1060, 1065 (S.D.N.Y.1983). In light of Congress' express directive on the deadline for the promulgation of HAP regulations, the focus must be on "substantively adequate regulations"-*not* perfect regulations. *See Sierra Club v. Johnson,* 444 F.Supp.2d at 56 ("[C]ourts evaluating claims of impossibility when an agency has failed to meet a mandatory deadline generally have rejected claims that additional time is needed to ensure substantively adequate regulations."); *see also NRDC v. Train,* 510 F.2d at 712 (describing the necessary "formulation of adequate guidelines"); *Sierra Club v. Thomas,* 658 F.Supp. 165, 175 (N.D.Cal.1987) ("[T]he Court would extend EPA's time to compensate for its footdragging if it were convinced that doing so was necessary for the promulgation of workable regulations."). So the question remains: has EPA met its "heavy burden" of demonstrating that it would be impossible to promulgate "substantively adequate regulations" pursuant to paragraphs 1(i) and 3 of the Court's March 31, 2006 Order by January 21, 2011?

Answering this question presents a complication for this Court: the Clean Air Act " 'does not allow district courts to address the content of EPA's conduct' " or " 'issue substantive determinations of its own' " on promulgated regulations. *Sierra Club v. Johnson,* 444 F.Supp.2d at 60 (quoting *Sierra Club v. Browner,* 130 F.Supp.2d at 90). "[S]uch substantive judicial review is expressly reserved for the appropriate court of appeals." *Sierra Club v. Browner,* 130 F.Supp.2d at 90. Since the Court cannot "embroil [itself] in an assessment of the substance of EPA's actions or omissions," *id.* at 90, the Court must be cautious where, as here, EPA's motion for an extension of time focuses, in part, on the substantive quality of its rules. The only way for this Court simultaneously to comply with 42 U.S.C. § 7607(b) and the court of appeals' guidelines in *NRDC v. Train* is to give deference to EPA's ultimate conclusion on the substantive merit of its rules. As discussed below, however, even granting such deference, the Court finds that EPA has not met its heavy burden of proving impossibility.

B. The Substantive Concern-Re-Proposing the Three Air Rules

EPA requests an extension of time to re-propose the Three Air Rules. These rules relate to EPA's requirements under both Section 112(c)(6), and Sections 112(c)(3) and (k)(3)(B). In light of the comments received after EPA proposed these rules on April 29, 2010, EPA contends that "[a] re-proposal would result in standards that are more defensible and will yield environmental benefits earlier, because the final standards will more likely withstand substantive review." Mot. at 20-21; *see* Tsirigotis Decl. ¶¶ 34, 37. According to EPA: "On balance, given the broad impact these rules will have, EPA believes that the overall public interest is best served by allowing EPA to re-propose the rules so that [it] will be able to issue emission standards that are based upon a thorough consideration of all available data and reduce potential litigation risks." Mot. at 14; *see* Tsirigotis Decl. ¶¶ 34, 37.

***8** In support of its motion, EPA filed a declaration from Panagiotis E. Tsirigotis, the Director of the Sector Policies and Programs Division within the Office of Air Quality Planning and Standards, Office of Air and Radiation at EPA. Mr. Tsirigotis provides background on the rulemaking process for the Three Air Rules and explains why EPA only proposed these rules on April 29, 2010, just nine months short of the court-ordered deadline at the time, December 16, 2010. *See* Tsirigotis Decl. ¶¶ 12-24. In short, during the spring and summer of 2007, the court of appeals issued three decisions that "substantially impacted how [EPA] sets MACT emission standards" under the Act. *Id.* ¶¶ 13, 15; *see Sierra Club v. EPA*, 479 F.3d 875, 882-83 (D.C.Cir.2007); *NRDC v. EPA ("NRDC I")*, 489 F.3d 1250, 1257-61 (D.C.Cir.2007); *NRDC II*, 489 F.3d at 1374-75. Although EPA asserts that all three decisions had an impact on EPA's MACT methodology, EPA explains that *NRDC I* directly related to EPA's requirements for purposes of satisfying Section 112(c)(6), because in that case the court of appeals vacated emission standards for major source boilers and vacated a rule regarding the definition of CISWI units. *See* Tsirigotis Decl. ¶ 14.

Following these three decisions, EPA "determined that it needed additional information from data and major industrial, commercial and institutional boilers and process heaters and CISWI units in order to set defensible MACT emission standards" under the Act. Tsirigotis Decl. ¶ 16. EPA prepared an information collection request, which triggered a complicated but, EPA contends, necessary set of time-consuming processes, involving (1) Office of Management and Budget ("OMB") approval for its information collection request, (2) public comment on its information collection request, and (3) a two-phased information collection process. *See id.* ¶¶ 16-23. The first phase required facilities to submit existing information, and the second phase required certain facilities "to conduct a suite of stack tests to evaluate their emissions of hazardous air pollutants and certain other pollutants, such as particulate matter and carbon dioxide." *Id.* ¶ 17.

After this entire process was complete, on April 29, 2010, the EPA Administrator signed the proposed Three Air Rules. Tsirigotis Decl. ¶ 23. These rules were published in the Federal Register on June 4, 2010. *Id.* ¶ 25. Although the comment period was originally to close on July 19, 2010, given the significant public interest in these rules, EPA granted extensions until August 23, 2010. *Id.* ¶¶ 29, 30.

EPA explains that it received a significant number of public comments in response. Mot. at 2; Tsirigotis Decl. ¶¶ 32-34. Specifically, EPA received over 4,800 individual comments, and Mr. Tsirigotis now asserts that "[t]hese comments raise several significant issues and provide new information and data." Tsirigotis Decl. ¶ 34. Mr. Tsirigotis explains that "there were a number of significant issues raised in the comments that may result in certain changes to the proposed rules that, [EPA] believe[s], could change the direction from the proposals sufficiently to make additional notice and comment advisable." *Id.* ¶ 34. Thus, according to Mr. Tsirigotis: "Based on the comments and new information and data, ... a re-proposal of the major source boilers, area source boilers and CISWI rules would significantly bolster the strength of the final rules." *Id.* "[T]he re-proposal approach will result in standards that are more defensible and will yield environmental benefits earlier, because the final standards will more likely withstand substantive review." *Id.* ¶ 37. EPA therefore provides what it contends is "an achievable, but very aggressive schedule for a re-proposal," Mot. at 3, and requests that its deadline be extended until April 13, 2012. FN4

FN4. Intervenors' response in support of EPA's motion largely mirrors EPA's briefing, except that intervenors' position goes beyond what EPA argues, contending that the Three Air Rules are "fundamentally flawed .... hence re-proposals are in order." Intervenors' Response at 3. The Court's focus, however, is on EPA's view of its rules-not intervenors, who are free to seek substantive review of the rules in the court of appeals. *See* 42 U.S.C. § 7607(b).

*9 In response, plaintiff argues that EPA fails to meet the standard for impossibility, and that the Court therefore should deny EPA's requested extension. Among other things, plaintiff contends that EPA "adopted a rulemaking approach involving extensive discretionary delay." Opp. at 9. According to plaintiff, EPA's decision to collect information in two separate phases was a wholly discretionary decision that caused the information collection process to go on for more than two years. *Id.* Moreover, plaintiff contends, EPA failed to ask OMB to expedite its review of EPA's information collection request pursuant to 44 U.S.C. § 3507(j)(1)(B)(iii), which is permitted when the normal review process "is reasonably likely to cause a statutory or court-ordered deadline to be missed." Opp. at 9; *see* 44 U.S.C. § 3507(j)(1) (B)(iii). Plaintiff then notes that EPA failed to provide any discussion of how it has allocated its resources for purposes of attempting to comply with the Court's Order: "Neither EPA nor Mr. Tsirigotis indicates how many employees or contractors are working on the job and whether more could be deployed." Opp. at 11.

Finally, plaintiff asserts that EPA's central argument is one the Court clearly rejected in *Sierra Club v. Johnson:* that additional time will result in more defensible rules. *See* Opp. at 14 (citing *Sierra Club v. Johnson,* 44 F.Supp.2d at 53, 57). Plaintiff points out that EPA has merely suggested that "it might choose to make changes to the final rule that might not be logical outgrowths from the proposal." *Id.* EPA does not, however, "claim that it needs to make such changes or will make them." *Id.* And EPA has failed to consider Section 307(d)(7)(B) of the Act, a provision that provides for administrative reconsideration of a rule without necessarily postponing the effectiveness of that rule. *Id.* at 15; *see* 42 U.S.C. § 7607(d)(7)(B). Thus, plaintiff contends, EPA's concerns about the merits of its rules could be addressed under Section 307(d)(7)(B), obviating any purported need for re-proposal and further delay. *See* Opp. at 15.

The Court agrees with plaintiff. First, although much of the time-consuming rulemaking process for the Three Air Rules may have been appropriate under normal circumstances, the Court concludes that EPA engaged in discretionary delay in the face of a congressional directive. As an example, it appears to the Court that the OMB review process took between six and eight months. *See* Tsirigotis Decl. ¶¶ 16-21; Surreply at 5 n. 3. EPA could have requested expedited OMB authorization for its information collection request; such expedited authorization is expressly permitted when "the use of normal clearance procedures is ... reasonably likely to cause *a statutory or court ordered deadline* to be missed." 44 U.S.C. § 3507(j)(1)(B)(iii) (emphasis added). EPA asserts that, in the fall of 2007, at the time it was preparing the information collection request, it "could not have reasonably anticipated how prolonged the ... process would become." Reply at 17-18; *see* Tsirigotis Suppl Decl. ¶ 14. By statute, however, EPA's emission standards were already seven years overdue-and EPA's court-ordered deadline was soon approaching. Given these deadlines, it should have been clear to EPA that proceeding through the normal OMB process was "reasonably likely to cause a statutory or court ordered deadline to be missed." *See* 44 U.S.C. § 3507(j)(1)(B)(iii).

**10* Defending its information collection process, EPA also contends that, "[g]iven the public interest in the rules and the number and variety of facilities that would be regulated, it was important to secure public input ... to ensure that the necessary information would be obtained." Reply at 18. But like the four-phase regulatory process proposed and rejected at the summary judgment stage, EPA's determination was "indicative of 'a level of thoroughness and scientific certainty not within the contemplation of Congress at the time it mandated the regulation of hazardous air pollutants.' " *Sierra Club v. Johnson,* 444 F.Supp.2d at 56 (quoting *Sierra Club v. Gorsuch,* 551 F.Supp. 785, 788-89 (N.D.Cal.1982)). "Although in most circumstances the Court defers to agency expertise about appropriate rulemaking procedures, such deference is inappropriate where Congress has unambiguously expressed its intent that these regulations be promulgated by a date certain and the agency manifestly has failed to fulfill this statutory obligation." *Id.*

EPA's past actions aside, what is most important is that EPA has failed to establish that it would be impossible to promulgate substantively adequate rules by January 21, 2011. As stated in *Sierra Club v. Johnson,* "courts evaluating claims of impossibility when an agency has failed to meet a mandatory deadline [established by Congress] generally have rejected claims that additional time is needed to ensure substantively adequate regulations." *Sierra Club v. Johnson,* 444 F.Supp.2d at 56 (citing *Sierra Club v. Ruckelshaus,* 602 F.Supp. 892, 899 (N.D.Cal.1984); *State v. Gorsuch,* 554 F.Supp. at 1065). Although EPA urges the Court to "carefully consider the time needed for EPA to ensure that standards are not seriously flawed before final rules are issued," Reply at 5, EPA itself has not actually asserted that its proposed rules are flawed or inadequate. Instead, EPA has simply expressed the concern that there is a risk these rules will be challenged. Mr. Tsirigotis states: "[T]here were a number of significant issues raised in the comments that *may result* in certain changes to the proposed rules that, [EPA] believe [s], *could change* the direction from the proposals *sufficiently* to make additional notice and comment *advisable.*" Tsirigotis Decl. ¶ 34 (emphasis added); *see also* Tsirigotis Suppl. Decl. ¶ 26 (The Office of Air and Radiation has "recommended changes" to the Administrator "that could significantly change the direction of the proposals ...."). These concerns, expressed in conditional language, do not cast doubt on the conclusion that EPA will be able to promulgate substantively adequate rules by January 21, 2011.

Finally, EPA suggests that because the rules at issue "affect almost 200,000 boilers and 176 CISWI units across the United States, and are complex and inter-related," it is appropriate to avoid any risk of error. Mot. at 20. "On balance, given the broad impact these rules will have, EPA believes that the overall public interest is best served by allowing EPA to re-propose the rules so that the Agency will be able to issue emission standards that are based upon a thorough consideration of all available data and reduce potential litigation risks." *Id.* at 14. EPA acknowledges that Section 307(d)(7)(B) "would provide an avenue for addressing some of the complications that have developed as these rulemakings have proceeded," but contends that "[i]n these particular circumstances ... reconsideration is not as effective as a re-proposal in addressing the problems presented." Reply at 11; *see* Mot. at 20 (Although Section 307(d)(7)(B) "could provide a path for remedying some of the issues that are causing EPA to conclude that re-proposal is advisable,.... EPA does not believe it is the appropriate path to pursue here.").

**11* The policy arguments EPA raises have no place in a case where Congress has mandated expedition, and its statutorily-mandated deadlines have long since passed. Unfortunately for EPA, the impossibility test is not concerned with whether-as a matter of policy-re-proposal will produce more effective rules and thus is preferable to reconsideration under Section 307(d)(7)(B). "It is emphatically not within an agency's authority to set regulatory priorities that clearly conflict with those established by Congress." *Sierra Club v. Johnson,* 444 F.Supp.2d at 58. While EPA's view on the importance of its rules and the preferable course of conduct may have merit, at this stage EPA's (and intervenors') "remedy lies with Congress, not the courts." *Id.* at 57. " '[T]he [C]ourt's role is to enforce the legislative will when called upon to do so.' " *Id.* at 54 (quoting *State v. Gorsuch,* 554 F.Supp. at 1062-63). Because EPA has not met its heavy burden of demonstrating that it would be impossible to promulgate substantively adequate regulations pursuant to paragraphs 1(i) and 3 of the Court's March 31, 2006 Order by January 21, 2011, the Court denies EPA's request for an extension of time until April 13, 2012 so that EPA can re-propose the Three Air Rules.

C. The Procedural Concern-Responding to "Significant" Public Comments

Under Section 307(d)(6)(B) of the Act, a promulgated rule "shall ... be accompanied by a response to each of the significant comments, criticisms, and new data submitted in written or oral presentations during the comment period." 42 U.S.C. § 7607(d)(6)(B). EPA thus presents to the Court an alternative request: "[S]hould the Court deny EPA time to re-propose" the emission standards for the Three Air Rules, "EPA requests that the deadline for completing its obligations under [p]aragraph 3 [and paragraph 1(i)] be extended until June 15, 2011, to allow the Agency time to fully respond to the 4,800 individual comments received in response to the proposals ...." Mot. at 4. EPA also requests that the Court extend the deadline for completing its obligations under paragraph 1(i) as to the SSI units rule to July 15, 2011, "so that EPA can fully respond" to the comments to that proposed rule. *Id.*

As noted, EPA received over 4,800 individual comments concerning the proposed Three Air Rules. EPA explains that it is "concerned that it may not be able to adequately" respond to these comments by January 16, 2011-now January 21, 2011. Mot. at 21. Mr. Tsirigotis' declaration is more definitive: "The Agency cannot currently respond in full to all of the significant comments submitted on the major source, area source, and CISWI proposed rules and prepare a final rule for the Administrator's signature that is consistent with those comments by January 16, 2011." Tsirigotis Decl. ¶ 40; *see* Tsirigotis Suppl. Decl. ¶ 25. Mr. Tsirigotis contends that an extension until June 15, 2011 will "enable the Agency to develop responses to all significant comments received and to prepare fuller and more defensible response to those comments, which would enhance the defensibility of the final standards." Tsirigotis Decl. ¶ 40.

***12** With respect to the SSI unit rule, EPA received over eighty individual comments in response. Mot. at 22. EPA explains that the comment period closed on November 29, 2010, only forty-five days before the current deadline. *Id.* EPA expresses "serious concerns" whether the agency could fully respond to these comments-all of which EPA in its motion papers describes as "significant"-by January 21, 2011. *See* Mot. at 22. Again, Mr. Tsirigotis' declaration is more definitive, though he expresses no such claim that all eighty comments are in fact significant: "The Agency cannot ... currently respond in full to all of the significant comments submitted on the proposed sewage sludge incinerators by January 16, 2011." Tsirigotis Decl. ¶ 48; *see* Tsirigotis Suppl. Decl. ¶ 32. EPA contends that an extension until July 15, 2011 would "ensure that it has fully responded to all significant comments ... thereby improving the defensibility of the rule." Mot. at 22; *see* Tsirigotis Decl. ¶ 49; Tsirigotis Suppl. Decl. ¶ 34.

Plaintiff responds that Mr. Tsirigotis' declaration "provides only the unexplained and unsupported assertion that the agency needs more time to complete its response to comments." Opp. at 10. Plaintiff contends that Mr. Tsirigotis "does not say how much of the response to comments process is still unfinished and provides no reason to believe that process cannot be completed by January 16." *Id.* Plaintiff also points out that neither EPA nor Mr. Tsirigotis addresses the question of resource allocation-there is no discussion of how many employees or contractors are working on the responses or whether more could be deployed. *Id.* at 11. Then, describing EPA's responses with respect to other rules and findings, plaintiff asserts that completing the comment process by the Court's deadline is well within EPA's capability. *Id.* at 11-12.[FN5] Finally, plaintiff asserts that EPA has provided no information as to why it would take approximately five more months to respond to an undefined number of the 4,800 individual comments on the Three Air Rules that EPA considers "significant," and six more months to respond to an undefined number of the eighty individual comments on the SSI unit rule that are "significant." *Id.* at 12-13. In sum, plaintiff contends that EPA has failed to demonstrate that it is impossible for EPA to comply with the January 21, 2011 deadline.

> FN5. For example, plaintiff notes that "EPA responded to more than 400,000 comments including approximately 19,000 individual comments on its greenhouse gases tailoring rule in four and one half months between the close of its comment period on December 28, 2009 and the signature of its final rule on May 13, 2010." Opp. at 12. "Similarly, EPA responded to more than 380,000 comments including 11,000 individual comments on its greenhouse gases endangerment finding in a period of five and one half months between the close of the comment period on June 23, 2009 and promulgation on December 6, 2009." *Id.*

In *Sierra Club v. Johnson,* the Court stressed the importance of resource allocation and rejected EPA's argument that " 'other mandatory obligations' preclude its compliance with plaintiff's proposed schedule." *Sierra Club v. Johnson,* 444 F.Supp.2d at 57. The Court stated that "[t]he will of Congress, as expressed in the Act, is that the promulgation of standards according to ... mandatory deadlines should take precedence over all other rule-making that EPA has not been expressly ordered to complete by Congress, as well as (arguably) over mandatory rulemaking for which the authorizing statute does not set a date certain." *Id.* The same analysis necessarily must also apply to the less substantive responsibility of the agency to respond in writing to "significant comments." Although " '[a]n equity court can never exclude claims of inability to render absolute performance,' " such claims must be supported with facts and the Court " 'must scrutinize such claims carefully ....' " *Id.* at 53 (quoting *NRDC v. Train,* 510 F.2d at 713).

*13 Mr. Tsirigotis' first declaration claims that EPA cannot respond in full to the comments on the Three Air Rules and the SSI unit rule by January 21, 2011 without providing any information concerning (1) what EPA has been doing since it received the comments; (2) how much of the response process is still unfinished; (3) how EPA has chosen to allocate its resources so as to attempt to comply with the court-ordered deadline; or (4) which of the 4,800 comments on the Three Air Rules or the eighty comments on the SSI unit rule genuinely are "significant." *See Lead Indus. Ass'n v. EPA,* 647 F.2d 1130, 1167 (D.C.Cir.1980) (noting that it "borders on the ludicrous" to suggest that all comments "rise to the level of a comment which required a response from the Administrator"). Although EPA and Mr. Tsirigotis assert that EPA has received over 4,800 individual comments in response to the Three Air Rules and over eighty comments in response to the SSI unit rule, there is no discussion whatsoever of how many of these comments EPA in fact considers "significant." With respect to the 4,800 comments to the Three Air Rules, the Court finds EPA's lack of discussion on the matter especially telling, given that EPA asserts that it has performed an "initial review of the significant comments." *See* Mot. at 2; *see also* Tsirigotis Decl. ¶ 34 ("The Agency has spent considerable time reviewing the over 4,800 individual comments received ...."). By now, EPA surely must know how many are "significant" if the agency has been working as diligently as it says it has been. With respect to the eighty comments to the SSI unit rule, although EPA in its motion papers describes them all as significant, tellingly Mr. Tsirigotis, on penalty of perjury, makes no such claim. *Compare* Mot. at 2 ("EPA has serious concerns ... as to whether it can fully respond to the over 80 significant comments ...."), with Tsirigotis Decl. ¶ 48 ("[W]e have received over 80 individual comments .... The Agency cannot, however, currently respond in full to all of the significant comments submitted ....").

Plaintiff pointed out some of these flaws in its opposition, and Mr. Tsirigotis then submitted a supplemental declaration in reply. This supplemental declaration still lacks specificity on the most crucial issues. Mr. Tsirigotis now states that, once the comment period closed, EPA "immediately began reviewing the comments and other information, including the data." Tsirigotis Supp. Decl. ¶ 21. Mr. Tsirigotis provides more detail on the work left to be done and asserts that EPA "has been fully embroiled in the working on the final standards at issue in this matter since the close of the comment period." *Id.* ¶¶ 24, 30-34. Both EPA and Mr. Tsirigotis remain silent, however, on whether EPA is acting with "the fullest use of [its] resources." *See NRDC v. Train,* 510 F.2d at 712. And neither EPA nor Mr. Tsirigotis makes any attempt to segregate for the Court the significant comments from the insignificant. Finally, there is no discussion as to why EPA needs until June 15, 2011 to respond to the Three Air Rules comments that are significant and until July 15, 2011 to respond to the significant SSI unit rule comments.

*14 While there is no support for EPA's requests for extensions until June 15, 2011 and July 15, 2011, respectively, the Court has no reason to doubt Mr. Tsirigotis' unequivocal statements that EPA "cannot currently respond in full to all of the significant comments"-however many there may be-to the Three Air Rules and the SSI unit rule by January 21, 2011. *See* Tsirigotis Decl. ¶¶ 40, 48. The Court therefore finds that there is no reasonable possibility that EPA will be able to comply with its mandatory duty under Section 307(d)(6)(B) of the Act to respond "to each of the significant comments, criticisms, and new data submitted in written or oral presentations during the comment period" by January 21, 2011. 42 U.S.C. § 7607(d)(6)(B). "Rather than order the defendant to do what is likely an impossibility," *Sierra Club v. Johnson,* 444 F.Supp.2d at 59, the Court therefore will extend slightly the deadline for EPA to respond to the significant comments regarding the Three Air Rules and the SSI unit rule. EPA has not justified its request for an extension until June 15 and July 15, 2011. Nor has EPA even attempted to show that a more expeditious schedule would be impossible. Indeed, EPA's own papers make clear to the Court that its requested extensions would not reflect a schedule of "utmost diligence." FN6 Accordingly, the Court rejects EPA's proposed schedule and prescribes a more expeditious one. *See Sierra Club v. Johnson,* 444 F.Supp.2d at 52-53. The January 21, 2011 deadlines in paragraphs 1(i) and 3 are extended to February 21, 2011.

FN6. In fact, some of the work contemplated appears duplicative: although EPA asserts that it has already performed an "initial review of the significant comments" to the Three Air Rules, Mot. at 2, Mr. Tsirigotis indicates that EPA is apparently planning on reviewing again "all of the 4,800 comments ... to ensure that [EPA] ha[s] fully considered all of the issues," Tsirigotis Supp. Decl. ¶ 30(a).

CONCLUSION

For the foregoing reasons, defendant EPA's motion to amend the Court's March 31, 2006 Order [Dkt. No. 136] is DENIED in part and GRANTED in part.

An Order consistent with this Opinion shall issue this same day.

SO ORDERED.

D.D.C.,2011.
Sierra Club v. Jackson
Slip Copy, 2011 WL 181097 (D.D.C.)

END OF DOCUMENT

Rebuttal Testimony
Exhibit GHR-2

U.S. EPA Memorandum dated Sept. 22, 2011

Implementation of the Ozone National Ambient Air Quality Standard

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

September 22, 2011

OFFICE OF
AIR AND RADIATION

MEMORANDUM

TO: Air Division Directors, Regions 1 – 10

FROM: Gina McCarthy
Assistant Administrator

SUBJECT: Implementation of the Ozone National Ambient Air Quality Standard

The purpose of this memorandum is to clarify for state and local air agencies the status of the ozone National Ambient Air Quality Standard (NAAQS) and to outline implementation steps moving forward. With the recent decision on the reconsideration of the ozone NAAQS, the current ozone NAAQS is 0.075 ppm. This standard will provide additional public health and welfare protection until the next regular review is completed, and EPA fully intends to implement this current standard as required under the Clean Air Act.[1]

As I will describe below in more detail, EPA is moving ahead with certain required actions to implement the 2008 standard, but will do so mindful of the President's and Administrator's direction that in these challenging economic times EPA should reduce uncertainty and minimize the regulatory burdens on state and local governments. EPA is also continuing to implement and develop federal rules and other programmatic actions to reduce emissions that contribute to smog and improve air quality and public health across the nation.

Area Designations

EPA is proceeding with initial area designations under the 2008 standard, starting with the recommendations states made in 2009 and updating them with the most current, certified air quality data. We expect to issue our proposed changes to the states' recommendations (the "120-day letters") later this fall. We will quickly initiate and complete a rulemaking to establish nonattainment area classification thresholds so that we can finalize the designations. While we intend to take into consideration all comments we receive on the proposed rule, we note that we used a "percent above the standard" approach for classification under the 1997 ozone standard and believe that remains a reasonable approach.

[1] Note that the 2008 standard is under legal challenge. EPA has recently indicated to the Court that it does not object to the establishment of a briefing schedule in that litigation and has provided a schedule for the Court to consider.

Based on our initial review of ozone air quality data from 2008-2010, 52 areas monitor air quality that exceeds the 0.075 ppm standard. This preliminary review shows considerably fewer areas not meeting the 2008 standard than the number identified in 2009 when states made their recommendations. Using the "percent above the standard" classification approach, 43 of the 52 areas would fall into the Marginal category. As you know, many of the mandatory measures under the Clean Air Act are not required for Marginal areas since they are expected to achieve attainment within 3 years. In addition, EPA's modeling indicates that approximately half of the 52 areas would attain the 0.075 ppm standard by 2015 (the expected attainment deadline for Marginal areas) as a result of the emission-reducing rules already in place.

Because we have states' 2009 recommendations and quality assured ozone data for 2008-2010, there is nothing that state or local agencies need to do until we issue the 120-day letters later this year, though of course, states are welcome to contact us to discuss specific issues at any time. We expect to finalize initial area designations for the 2008 ozone NAAQS by mid-2012. However, we note that EPA currently faces litigation with respect to the timing of the designations and expects that the resolution of the litigation may well affect the precise timing of the schedule for designations.

Planning Requirements and Other Required Submissions
We will begin an expedited rulemaking to outline the implementation requirements for the 2008 standard in the very near future. The rule will be as straightforward and simple as we can make it. As you know, the Clean Air Act provides several years for states to develop their State Implementation Plans (SIPs) and to implement any mandatory measures. However, several deadlines for some state submissions have already passed, including the infrastructure SIPs and interstate transport SIPs. There are few requirements for Marginal areas beyond those SIPs.

EPA does not intend to penalize states for the passage of time, but we may also face litigation on these issues. In negotiating schedules for expeditious completion of required elements, we will seek to minimize any administrative burden on states associated with these requirements. To the extent that states are already engaged or would like to get started with clean air programs to address the standard, we will provide assistance with guidance and model language on rules or other programs, such as energy efficiency.

Federal Actions to Reduce Emissions
EPA will continue to move forward with implementation and development of federal rules that reduce emissions of pollutants that contribute to smog and threaten public health. These actions include recently promulgated rules that lower NOx and VOC emissions such as the Cross-State Air Pollution Rule (CSAPR), the Portland Cement Rule, and Light and Heavy Duty Vehicle standards. They also include rules under development such as the Maximum Achievable Control Technology (MACT) standards for Boilers, the Mercury and Air Toxics Standards (MATS) for power plants, the New Source Performance Standards (NSPS) for Commercial Incinerators/Solid Waste Incinerators (CISWI) and the Oil/Gas sector, and the Tier 3 vehicle and fuel standards. These federal actions will ensure steady forward progress to clean up the nation's air and protect the health of American families, while minimizing and in many cases eliminating the need for states to use their scarce resources on local actions.

The Next Ozone Review
The next regular review of the health and welfare science is well underway. EPA will propose any appropriate revisions in the fall of 2013 and finalize any revisions to the standard in 2014. Attached to this memorandum is a schedule that lays out the upcoming steps in that review.

I hope this memorandum has answered some of the most immediate questions. Please distribute this memo to state and local air agencies in your Region. We will be providing opportunities for further discussion and questions with state and local officials in the coming weeks.

Attachment

September 22, 2011

Ozone NAAQS Review Schedule

Stage of review	Major milestones	Schedule
Integrated Science Assessment (ISA)	1st Draft ISA	Mar 2011
	CASAC and public review 1st Draft ISA	May 19-20, 2011
	2nd Draft ISA	Sept 2011
	CASAC and public review of 2nd Draft ISA	Dec 15-16, 2011
	Final ISA	Feb/Mar 2012
Risk/Exposure Assessments (REAs)	Scope and Methods Plans	Apr 2011
	CASAC consultation and public review of Scope and Methods Plans	May 19-20, 2011
	1st Draft REAs	Feb/Mar 2012
	CASAC and public review 1st Draft REAs	May 2012
	2nd Draft REAs	Nov 2012
	CASAC and public review 2nd Draft REAs	Jan/Feb 2013
	Final REAs	Apr 2013
Policy Assessment (PA) and Rulemaking	1st Draft PA	Apr 2012
	CASAC and public review 1st Draft PA	May 2012
	2nd Draft PA	Dec 2012
	CASAC and public review 2nd Draft PA	Jan/Feb 2013
	Final PA	May 2013
	Proposed Rule	**Oct 2013**
	Final Rule	**July 2014**

September 22, 2011

EPA has done a preliminary review of ozone air quality data from 2008-2010. Below is EPA's initial estimate of areas exceeding the 2008 ozone standard of 0.075 ppm, based on those data. Of the 52 areas listed below, 44 areas are current nonattainment or maintenance areas that already have taken significant steps to address ozone pollution and 8 areas would be new to the process. The actual nonattainment areas will be determined through the designations process, which will include extensive input and review by the states and an opportunity for public comment.

Area*	Design Value 2008-2010 (ppm)	Potential Classification under 0.075 ppm ozone standard**	Current Designation Status for 1997 ozone NAAQS
Los Angeles South Coast Air Basin, CA	0.112	Serious	Nonattainment
San Joaquin Valley, CA	0.104	Serious	Nonattainment
Sacramento Metro, CA	0.102	Serious	Nonattainment
Los Angeles-San Bernardino Cos (W Mojave), CA	0.099	Moderate	Nonattainment
Riverside Co, (Coachella Valley), CA	0.095	Moderate	Nonattainment
Baltimore, MD	0.089	Moderate	Nonattainment
San Diego, CA	0.088	Moderate	Nonattainment
Dallas-Fort Worth, TX	0.086	Moderate	Nonattainment
Ventura Co, CA	0.086	Moderate	Nonattainment
San Luis Obispo-Paso Robles, CA	0.084	Marginal	Attainment
Houston-Galveston-Brazoria, TX	0.084	Marginal	Nonattainment
Nevada Co. (Western Part), CA	0.084	Marginal	Nonattainment
New York-N. New Jersey-Long Island,NY-NJ-CT	0.084	Marginal	Nonattainment
Amador and Calaveras Cos (Central Mtn), CA	0.083	Marginal	Nonattainment
Kern Co (Eastern Kern), CA	0.083	Marginal	Nonattainment
Mariposa and Tuolumne Cos (Southern Mtn), CA	0.083	Marginal	Nonattainment
Philadelphia-Wilmington-Atl. City, PA-NJ-MD-DE	0.083	Marginal	Nonattainment
Charlotte-Gastonia-Rock Hill, NC-SC	0.082	Marginal	Nonattainment
Pittsburgh-Beaver Valley, PA	0.081	Marginal	Nonattainment
Washington, DC-MD-VA	0.081	Marginal	Nonattainment
Red Bluff, CA	0.080	Marginal	Attainment
San Francisco Bay Area, CA	0.080	Marginal	Nonattainment
Atlanta, GA	0.080	Marginal	Nonattainment
Chico, CA	0.079	Marginal	Nonattainment
Cincinnati-Hamilton, OH-KY-IN	0.079	Marginal	Maintenance
Reading, PA	0.079	Marginal	Maintenance
Greater Connecticut, CT	0.079	Marginal	Nonattainment
Boston-Lawrence-Worcester (E. Mass), MA	0.078	Marginal	Nonattainment
Imperial Co, CA	0.078	Marginal	Nonattainment
Sublette County, WY - COUNTY	0.078	Marginal	Attainment
Baton Rouge, LA	0.078	Marginal	Nonattainment
Denver-Boulder-Greeley-Ft Collins-Love., CO	0.078	Marginal	Nonattainment
Sheboygan, WI	0.078	Marginal	Nonattainment
Columbus, OH	0.077	Marginal	Maintenance

Area*	Design Value 2008-2010 (ppm)	Potential Classification under 0.075 ppm ozone standard**	Current Designation Status for 1997 ozone NAAQS
Knoxville, TN	0.077	Marginal	Maintenance
Lancaster, PA	0.077	Marginal	Maintenance
Phoenix-Mesa, AZ	0.077	Marginal	Nonattainment
Springfield (Western MA), MA	0.077	Marginal	Nonattainment
Cleveland-Akron-Lorain, OH	0.077	Marginal	Maintenance
Jamestown, NY	0.077	Marginal	Nonattainment
St. Louis, MO-IL	0.077	Marginal	Nonattainment
Allentown-Bethlehem-Easton, PA	0.076	Marginal	Maintenance
Greensboro--Winston-Salem--High Point, NC	0.076	Marginal	Attainment
Greenville-Spartanburg-Anderson, SC	0.076	Marginal	Attainment
Gulfport-Biloxi-Pascagoula, MS	0.076	Marginal	Attainment
Las Vegas, NV	0.076	Marginal	Nonattainment
Memphis, TN-AR	0.076	Marginal	Maintenance
Nashville-Davidson-Murfreesboro-Columbia, TN	0.076	Marginal	Attainment
Richmond-Petersburg, VA	0.076	Marginal	Maintenance
Santa Barbara-Santa Maria-Goleta, CA	0.076	Marginal	Attainment
Sutter Co (Sutter Buttes), CA	0.076	Marginal	Nonattainment
Providence (All RI), RI	0.076	Marginal	Nonattainment

*Generally, the area descriptions in this table refer to metropolitan areas. Precise area boundaries will be established through the designations process.

**EPA will establish classification thresholds through notice-and-comment rulemaking. Listed in this table are the classifications that would result from the "percent-above-standard" approach EPA used for the 1997 NAAQS. These thresholds are: Marginal 0.076 up to 0.086 ppm; Moderate 0.086 up to 0.100 ppm; Serious 0.100 up to 0.113 ppm; Severe 0.113 up to 0.175; and Extreme 0.175 ppm and up.

Rebuttal Testimony
Exhibit GHR-3

Statement by the President on Ozone National Ambient Air Quality Standards dated September 2, 2011

The White House

Office of the Press Secretary

For Immediate Release September 02, 2011

Statement by the President on the Ozone National Ambient Air Quality Standards

Over the last two and half years, my administration, under the leadership of EPA Administrator Lisa Jackson, has taken some of the strongest actions since the enactment of the Clean Air Act four decades ago to protect our environment and the health of our families from air pollution From reducing mercury and other toxic air pollution from outdated power plants to doubling the fuel efficiency of our cars and trucks, the historic steps we've taken will save tens of thousands of lives each year, remove over a billion tons of pollution from our air, and produce hundreds of billions of dollars in benefits for the American people

At the same time. I have continued to underscore the importance of reducing regulatory burdens and regulatory uncertainty, particularly as our economy continues to recover. With that in mind, and after careful consideration, I have requested that Administrator Jackson withdraw the draft Ozone National Ambient Air Quality Standards at this time. Work is already underway to update a 2006 review of the science that will result in the reconsideration of the ozone standard in 2013 Ultimately, I did not support asking state and local governments to begin implementing a new standard that will soon be reconsidered

I want to be clear: my commitment and the commitment of my administration to protecting public health and the environment is unwavering I will continue to stand with the hardworking men and women at the EPA as they strive every day to hold polluters accountable and protect our families from harmful pollution. And my administration will continue to vigorously oppose efforts to weaken EPA's authority under the Clean Air Act or dismantle the progress we have made

BLOG POSTS ON THIS ISSUE

October 17, 2011 9:10 AM EDT

A Physician, Scientist and Mother Clears the Air

A physician, scientist and mother "clears the air" of the myth that restrictions on air polluters are too intrusive, too expensive and too burdensome

October 12, 2011 6:30 PM EDT

America's Great Outdoors: Results for American Communities

Today, the Administration released a progress report on President Obama's America's Great Outdoors Initiative (AGO) that shows on-the-ground results for American communities

October 07, 2011 2:16 PM EDT

The Link Between American Energy and Prosperity

October is Energy Action Month, a national effort to highlight the tremendous potential of clean energy technologies to create new American jobs and industries, and underscore the importance of investing in American innovation to lead the 21st century global clean energy economy

VIEW ALL RELATED BLOG POSTS ▸

Rebuttal Testimony
Exhibit GHR-4

U.S. EPA DRAFT Final Rule

Regulatory Impact Analysis -

Final National Ambient Air Quality Standard for Ozone

dated July 2011

Regulatory Impact Analysis

Final National Ambient Air Quality Standard for Ozone

July 2011

U.S. Environmental Protection Agency
Office of Air and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, NC 27711

DOCKET NUMBER

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Summary of the Supplemental Regulatory Impact Analysis (RIA) for the Reconsideration of the 2008 Ozone National Ambient Air Quality Standard (NAAQS)

On September 16, 2009, EPA committed to reconsidering the ozone NAAQS standard promulgated in March 2008. Today's rule sets the ozone NAAQS at 0.070 ppm, based on this reconsideration of the evidence available at the time the last standard was set. Today's rule also includes a separate secondary NAAQS, for which this RIA provides only qualitative analysis due to the limited nature of available EPA guidance for attaining this standard

This supplement to the RIA contains an updated illustrative analysis of the potential costs and human health and welfare benefits of nationally attaining a new primary ozone standard of 0.070 ppm. The basis for this updated economic analysis is the RIA published in March 2008 with changes. These changes reflect some significant methodological improvements to air pollution benefits estimation, which EPA has adopted since the ozone standard was last promulgated. These significant changes include the following:

- We have adopted several key methodological updates to benefits assessment since the 2008 Ozone NAAQS RIA. These updates have already been incorporated into previous RIAs for the Portland cement NESHAP, NO_2 NAAQS RIA, and Category 3 Marine Diesel Engine Rule, and are therefore now incorporated in this analysis. Significant updates include:
  - We removed the assumption of no causality for ozone mortality, as recommended by the National Academy of Science (NAS).
  - We included two more ozone multi-city studies, per NAS recommendation.
  - We revised the Value of a Statistical Life (VSL) to be consistent with the value used in current EPA analyses.
  - We removed thresholds from the concentration-response functions for $PM_{2.5}$, consistent with EPA's Integrated Science Assessment for Particulate Matter.

The other elements of the illustrative analysis included in the March 2008 RIA were not changed for this supplemental analysis. The March 2008 RIA was based on the best available air quality modeling available and reflected emission reductions expected from federal rules promulgated and proposed at that time. Because of the fundamental similarities between the original and more recent air quality modeling simulations, EPA has elected not to update the original analysis of emissions reductions needed to attain the ozone NAAQS as described in

Chapter 4 of the 2008 RIA. See section S1.3 below for discussion of the air quality baseline used in this supplemental analysis.

Structure of this Updated RIA

As part of the ozone NAAQS reconsideration, this RIA supplement takes as its foundation the 2008 ozone NAAQS RIA. Detailed explanation of the majority of assumptions and methods are contained within that document and should be relied upon, except as noted in this summary.

This supplement itself consists of four parts:

- Section 1 provides an overview of the changes to the analysis and summary tables of the illustrative cost and benefits of obtaining a revised standard and alternatives of 0.065 ppm and 0.075 ppm.
- Section 2 contains a supplemental benefits analysis outlining the adopted changes in the methodology, updated results for the final NAAQS of 0.070 ppm and standard alternatives of 0.065 and 0.075 ppm using the revised methodology and assumptions.
- Section 3 contains supplemental evaluation of a separate secondary ozone NAAQS of 13 ppm-hr, as well as a less stringent alternative of 15 ppm-hr and a more stringent alternative of 11 ppm-hr. This supplemental includes an explanation of the complexities associated with quantifying the costs and benefits of a secondary standard at this time. In addition, we have incorporated an assessment of which counties would have an additional requirement to reduce ozone concentrations to meet a secondary standard beyond the reductions needed to meet the primary standard, the qualitative benefits of reducing ozone exposure on vegetation, and maps of biomass/yield loss avoided by attaining the primary and secondary ozone standards.

S1.1 Results of Benefit-Cost Analysis

This updated RIA consists of multiple analyses, including an assessment of the nature and sources of ambient ozone; estimates of current and future emissions of relevant ozone precursors; air quality analyses of baseline and alternative control strategies; illustrative control strategies to attain the standard alternatives in future years; estimates of the incremental costs and benefits of attaining the final standard and three alternative standards, together with an examination of key uncertainties and limitations; and a series of conclusions and insights gained from the analysis. It is important to recall that this RIA rests on the analysis done in 2008; no new air quality modeling or other assessments were completed except those outlined above.

The supplement includes a presentation of the benefits and costs of attaining various alternative ozone National Ambient Air Quality Standards in the year 2020. These estimates only include areas assumed to meet the current standard by 2020. They do not include the costs or benefits of attaining the alternate standards in the San Joaquin Valley and South Coast air basins in California, because we expect that nonattainment designations under the Clean Air Act for these areas would place them in categories afforded extra time beyond 2020 to attain the ozone NAAQS.

[Hold for reference to Addendum]

In Table S1.1 below, the individual row estimates reflect the different studies available to describe the relationship of ozone exposure to premature mortality. These monetized benefits include reduced health effects from reduced exposure to ozone, reduced health effects from reduced exposure to $PM_{2.5}$, and improvements in visibility. The ranges within each row reflect two PM mortality studies (i.e. Pope and Laden).

Ranges in the total costs column reflect different assumptions about the extrapolation of costs as discussed in Chapter 5 of the 2008 Ozone NAAQS RIA. The low end of the range of net benefits is constructed by subtracting the highest cost from the lowest benefit, while the high end of the range is constructed by subtracting the lowest cost from the highest benefit. The presentation of the net benefit estimates represents the widest possible range from this analysis.

Table S1.2 presents the estimate of total ozone and $PM_{2.5}$-related premature mortalities and morbidities avoided nationwide in 2020 as a result of this regulation.

Table S1. 1: Total Monetized Costs with Ozone Benefits and $PM_{2.5}$ Co-Benefits in 2020 (in Billions of 2006$) [A]

	Ozone Mortality Function	Reference	Total Benefits [B]		Total Costs [C]	Net Benefits	
			3%	7%	7%	3%	7%
0.075 ppm	Multi-city	Bell et al. 2004	$6.9 to $15	$6.4 to $13	$7.6 to $8.8	$-1.9 to $7.4	$-2.4 to $5.4
		Schwartz 2005	$7.2 to $16	$6.8 to $13	$7.6 to $8.8	$-1.6 to $8.4	$-2.1 to $5.4
		Huang 2005	$7.3 to $16	$6.9 to $13	$7.6 to $8.8	$-1.5 to $8.4	$-2.0 to $5.4
	Meta-analysis	Bell et al. 2005	$8.3 to $17	$7.9 to $14	$7.6 to $8.8	$-0.50 to $9.4	$-1.0 to $6.4
		Ito et al. 2005	$9.1 to $18	$8.7 to $15	$7.6 to $8.8	$0.30 to $10	$-0.20 to $7.4
		Levy et al. 2005	$9.2 to $18	$8.8 to $15	$7.6 to $8.8	$0.40 to $10	$-0.10 to $7.4
0.070 ppm	Multi-city	Bell et al. 2004	$13 to $29	$11 to $24	$19 to $25	$-12 to $10	$-14 to $5.0
		Schwartz 2005	$15 to $30	$12 to $25	$19 to $25	$-10 to $11	$-13 to $6.0
		Huang 2005	$15 to $30	$13 to $26	$19 to $25	$-10 to $11	$-12 to $7.0
	Meta-analysis	Bell et al. 2005	$18 to $34	$16 to $29	$19 to $25	$-7.0 to $15	$-9.0 to $10
		Ito et al. 2005	$21 to $37	$18 to $31	$19 to $25	$-4.0 to $18	$-6.0 to $12
		Levy et al. 2005	$21 to $37	$18 to $31	$19 to $25	$-4.0 to $18	$-6.0 to $12
0.065 ppm	Multi-city	Bell et al. 2004	$22 to $47	$19 to $40	$32 to $44	$-22 to $15	$-25 to $7.0
		Schwartz 2005	$24 to $49	$21 to $42	$32 to $44	$-20 to $17	$-23 to $9.0
		Huang 2005	$25 to $50	$22 to $42	$32 to $44	$-19 to $18	$-23 to $10
	Meta-analysis	Bell et al. 2005	$31 to $56	$27 to $48	$32 to $44	$-13 to $24	$-17 to $16
		Ito et al. 2005	$36 to $61	$32 to $53	$32 to $44	$-8.0 to $29	$-13 to $20
		Levy et al. 2005	$36 to $61	$32 to $53	$32 to $44	$-7.0 to $29	$-12 to $20

[A] All estimates rounded to two significant figures. As such, they may not sum across columns. Only includes areas required to meet the current standard by 2020; does not include San Joaquin and South Coast areas in California.

[B] Includes ozone benefits, and $PM_{2.5}$ co-benefits. Range was developed by adding the estimate from the ozone premature mortality function to estimates from the $PM_{2.5}$ premature mortality functions from Pope et al. and Laden et al. Tables exclude unquantified and nonmonetized benefits.

[C] Range reflects lower and upper bound cost estimates. Data for calculating costs at a 3% discount rate was not available for all sectors, and therefore total annualized costs at 3% are not presented here. Additionally, these estimates assume a particular trajectory of aggressive technological change. An alternative storyline might hypothesize a much less optimistic technological trajectory, with increased costs, or with decreased benefits in 2020 due to a later attainment date.

Table S1.2: Summary of Total Number of Ozone and $PM_{2.5}$-Related Premature Mortalities and Premature Morbidity Avoided: 2020 National Benefits [A]

Combined Estimate of Mortality		0.075 ppm			0.070 ppm			0.065 ppm		
NMMAPS	Bell et al. (2004)	760	to	1,900	1,500	to	3,400	2,500	to	5,600
	Schwartz	800	to	1,900	1,600	to	3,600	2,700	to	5,800
	Huang	820	to	1,900	1,700	to	3,600	2,800	to	5,900
Meta-analysis	Bell et al. (2005)	930	to	2,000	2,000	to	4,000	3,500	to	6,600
	Ito et al.	1,000	to	2,100	2,400	to	4,300	4,000	to	7,200
	Levy et al.	1,000	to	2,100	2,400	to	4,300	4,100	to	7,200

Combined Estimate of Morbidity	0.075 ppm	0.070 ppm	0.065 ppm
Acute Myocardial Infarction [B]	1,300	2,200	3,500
Upper Respiratory Symptoms [B]	9,900	19,000	31,000
Lower Respiratory Symptoms [B]	13,000	25,000	41,000
Chronic Bronchitis [B]	470	880	1,400
Acute Bronchitis [B]	1,100	2,100	3,400
Asthma Exacerbation [B]	12,000	23,000	38,000
Work Loss Days [B]	88,000	170,000	270,000
School Loss Days [C]	190,000	600,000	1,100,000
Hospital and ER Visits	2,600	6,600	11,000
Minor Restricted Activity Days	1,000,000	2,600,000	4,500,000

[A] All estimates rounded to two significant figures. Only includes areas required to meet the current standard by 2020; does not include San Joaquin Valley and South Coast air basins in California. Includes ozone benefits, and $PM_{2.5}$ co-benefits. Mortality incidence range was developed by adding the estimate from the ozone premature mortality function to estimates from the $PM_{2.5}$ premature mortality functions from Pope et al. (2002) and Laden et al. (2006).

[B] Estimated reduction in premature morbidity due to $PM_{2.5}$ reductions only.

[C] Estimated reduction in premature morbidity due to ozone reductions only.

The following set of graphs is included to provide the reader with a richer presentation of the range of costs and benefits of the alternative standards. The graphs supplement the tables by displaying all possible combinations of net benefits, utilizing the six different ozone functions, the fourteen different PM functions, and the two cost methods. Each of the 168 bars in each graph represents a separate point estimate of net benefits under a certain combination of cost and benefit estimation methods. Because it is not a distribution, it is not possible to infer the likelihood of any single net benefit estimate. The blue bars indicate combinations where the net benefits are negative, whereas the green bars indicate combinations where net benefits are positive. Figures S1.1 through S1.3 shows all of these combinations for all standards analyzed. Figure S1.4 shows the comparison of total monetized benefits with costs using the two benefits anchor points based on Pope/Bell 2004 and Laden/Levy.

Figure S1.1:

Net Benefits for an Alternate Standard of 0.075 ppm (7% discount rate)

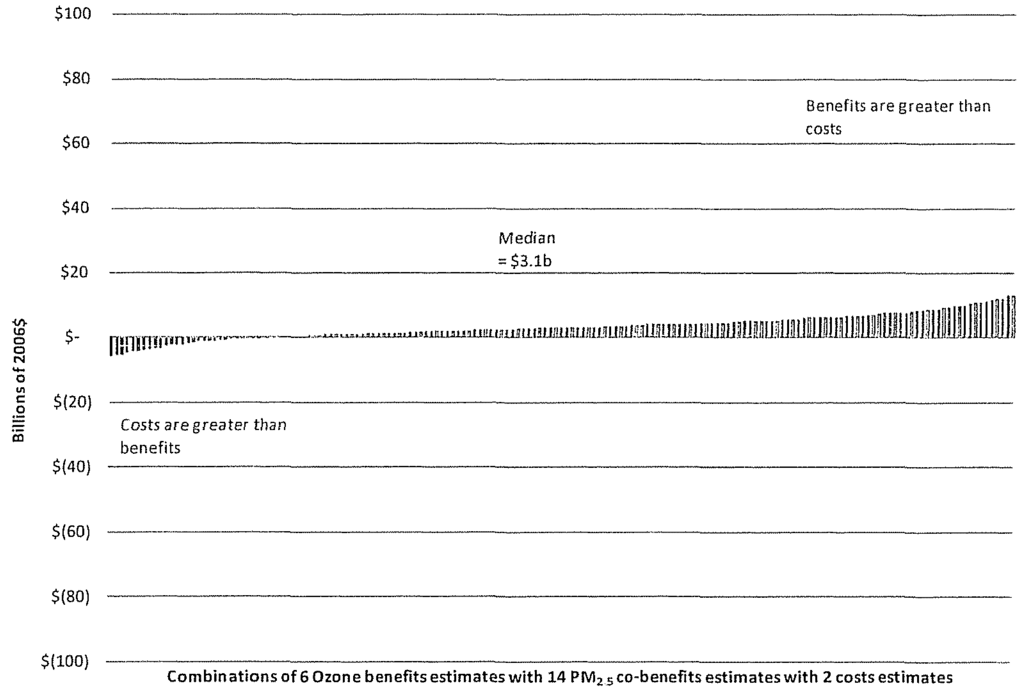
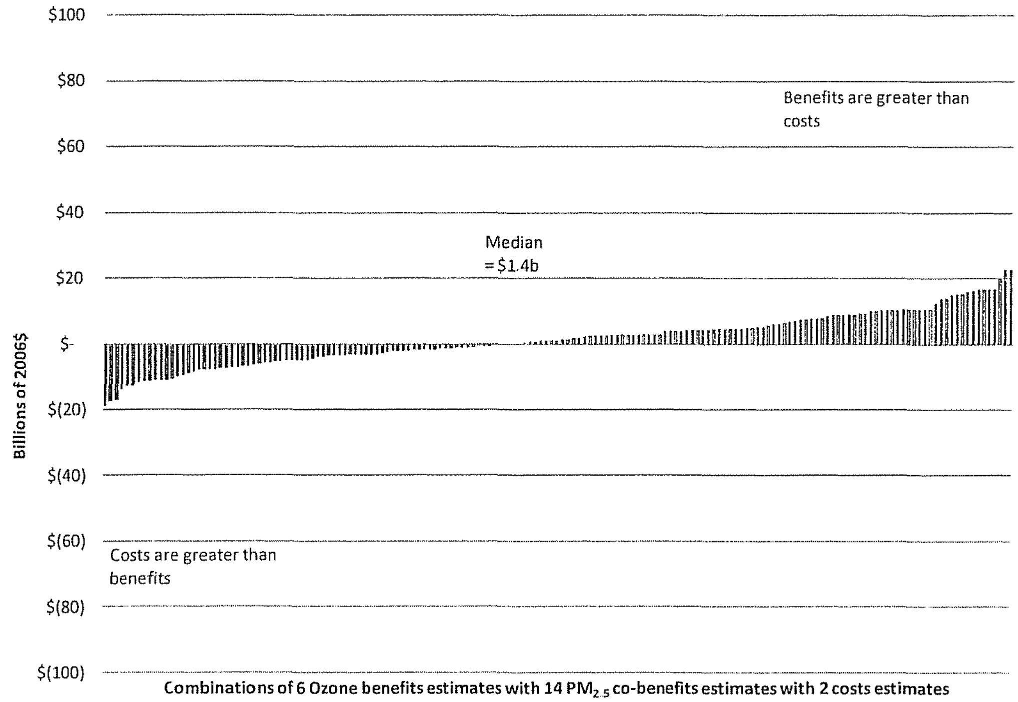


Figure S1.2:

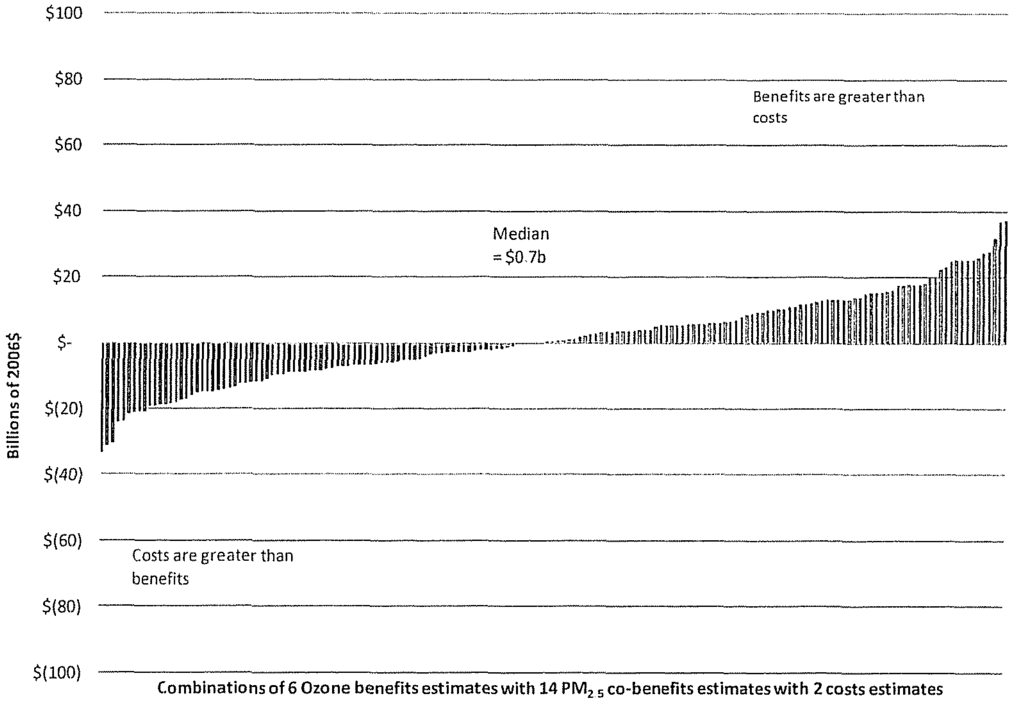
Net Benefits for an Alternate Standard of 0.070 ppm (7% discount rate)



These graphs show all 168 combinations of the 6 different ozone mortality functions and assumptions, the 14 different PM mortality functions, and the 2 cost methods. These combinations do not represent a distribution.

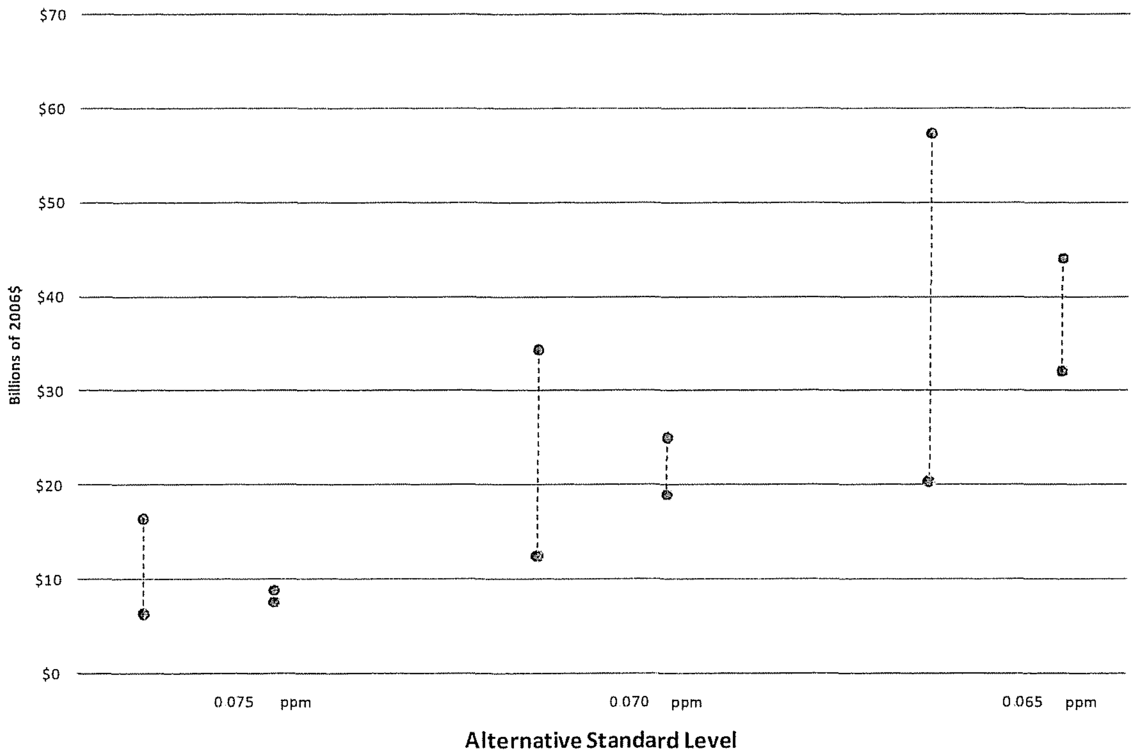
Figure S1.3:

Net Benefits for an Alternate Standard of 0.065 ppm (7% discount rate)



These graphs show all 168 combinations of the 6 different ozone mortality functions and assumptions, the 14 different PM mortality functions, and the 2 cost methods. These combinations do not represent a distribution.

Figure S1.4:
Comparison of Total Monetized Benefits to Costs for Alternative Standard Levels in 2020 (Updated results, 7% discount rate)



The low benefits estimate is based on Pope/Bell 2004 and the high benefits estimate is based on Laden/Levy. The two cost estimates are based on two different extrapolated cost methodologies. These endpoints represent separate estimates based on separate methodologies. The dotted lines are a visual cue only, and these lines do not imply a uniform range between these endpoints.

S1.2 Analysis of the Proposed Secondary NAAQS for Ozone

Exposure to ozone has been associated with a wide array of vegetation and ecosystem effects in the published literature. Sensitivity to ozone is highly variable across species, with over 65 plan species identified as "ozone-sensitive", many of which occur in state and national parks and forests. These effects include those that damage or impair the intended use of the plant or ecosystem. Such effects are considered adverse to the public welfare and can include reduced growth and/or biomass production in sensitive plant species, including forest trees, reduced crop yields, visible foliar injury, reduced plant vigor (e.g., increased susceptibility to harsh weather, disease, insect pest infestation, and competition), species composition shift, and changes in ecosystems and associated ecosystem services.

This secondary NAAQS standard for ozone is the first secondary standard to be promulgated with a form, averaging time, and level that is distinct from the health-based primary standard apart from the PM and SO_2 regulations originally set in the early 1970s. The index would be cumulated over the 12-hour daylight window (8:00 a.m. to 8:00 p.m.) during the consecutive 3-month period during the ozone season with the maximum index value (hereafter, referred to as W126). After reviewing the scientific evidence and public comments, the Administrator selected a secondary ozone NAAQS at a level of 13 ppm-hrs, using the W126 form, calculated as a 3-year average of the annual sums.

Quantifying the costs and benefits of attaining a secondary NAAQS is an exceptionally complex task, including unresolved issues related to the RIA analysis, air quality projection, monitoring expansion, and implementation.[1] Because of these complexities as well as limited time and resources within the expedited schedule, we are limited in our ability to quantify the costs and benefits of attaining a separate secondary NAAQS for ozone for this proposal. However, we have incorporated an assessment of which counties would have an additional requirement to reduce ozone concentrations to meet a secondary standard beyond the reductions needed to meet the primary standard, the qualitative benefits of reducing ozone exposure on vegetation, and maps of biomass/yield loss avoided by attaining the primary and secondary ozone standards. Using a cumulative seasonal secondary standard (i.e., W126), we evaluated alternate standard levels at 11, 13, and 15 ppm-hours. Figure S1.5 shows the counties projected to exceed a primary standard at 0.070 ppm and/or a secondary standard at 13 ppm-hrs in the 2020 baseline.

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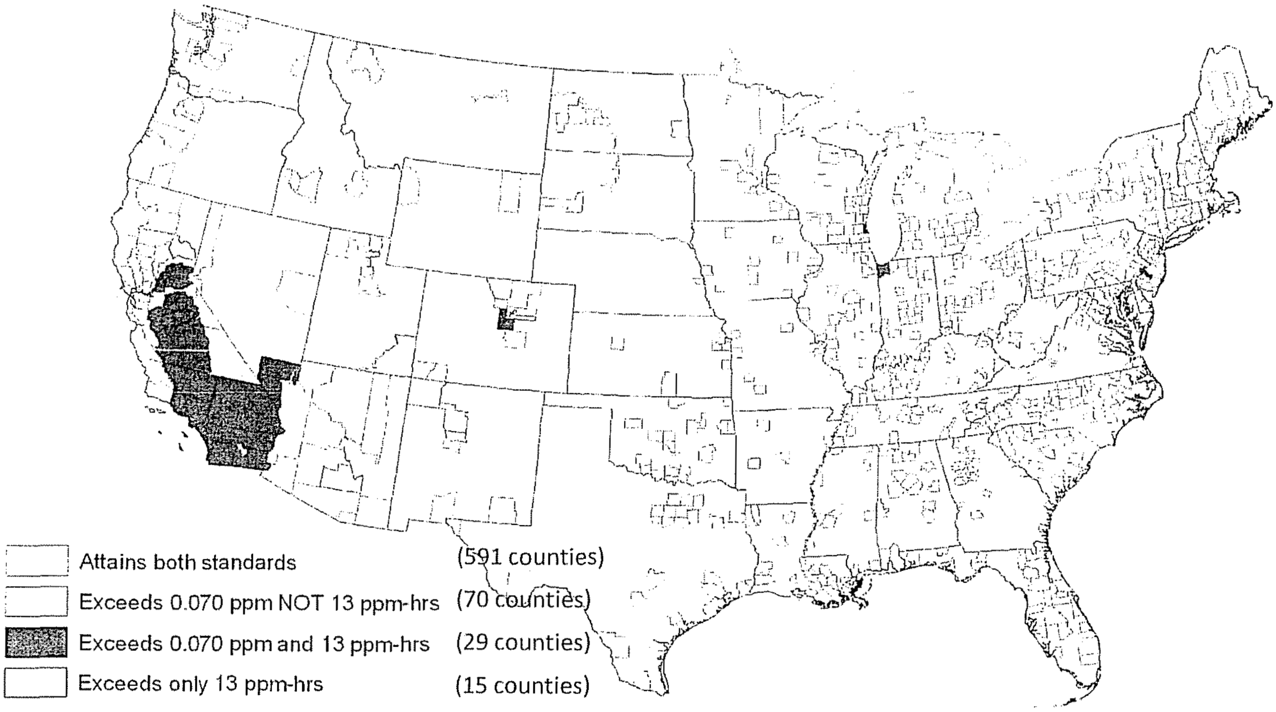
[1] These complexities are described in detail in Section S3.3.

Figure S1.5: Counties Projected to Exceed the Selected Primary and Secondary Standards in the Baseline in 2020*



* Many of the counties projected to exceed are in the South Coast and San Joaquin areas of California, which are not required to attain the primary standards by 2020.

S1.3 Baseline Emissions Inventory

EPA expects that the emissions reductions needed to attain the new ozone primary standard may be less than what EPA originally predicted in the March 2008 RIA. Recent updates to the emission and air quality modeling platform suggest that future baseline air quality will be better than what was projected in the 2008 RIA. If the more recent projections are better estimates of future ozone nonattainment in these areas, then the costs and benefits of attaining the ozone NAAQS incremental to the current standard will likely be less than what was projected as part of the 2008 RIA. However, there have also been a few rules promulgated since the 2008 RIA baseline was developed that significantly affect ozone precursor emissions. It is difficult to assess retroactively the net emissions impacts of these rules and how they would likely affect total costs and benefits of the ozone NAAQS if they had been included in the baseline. We discuss each of these baseline issues below.

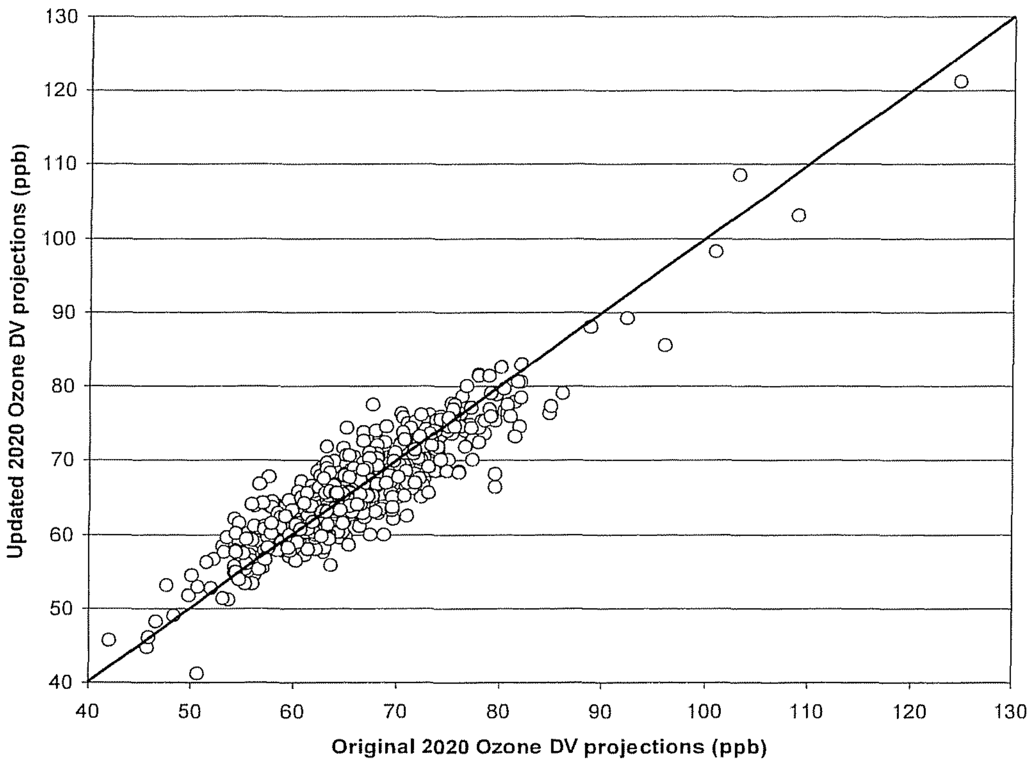
Modeling Platform

In March 2008, EPA completed a regulatory impacts analysis (RIA) that estimated the potential costs and benefits of attaining a 0.075 ppm standard as well as several alternatives. This illustrative analysis was based on the best available air quality modeling available at the time of the original analysis. As described in Chapter 2 of the 2008 RIA, EPA used the Community Multiscale Air Quality (CMAQ) model with inputs from a 2002 base year to project: a) ozone concentrations in the future (i.e., 2020) and b) the amount of emissions reductions that would be necessary to meet specified ozone targets. Since the original analysis, the CMAQ model has been updated with several new science algorithms (Foley et al., 2010) and the base year platform has been updated to include 2005 ambient data and model inputs. As part of this NAAQS reconsideration, EPA completed a quick analysis to determine if the updates to the air quality modeling system would substantially affect the original 2008 estimates of the control costs needed to attain the new ozone standard.

One of the key elements in determining the amount of controls needed to attain a particular ozone target is the estimate of how many areas will be above the chosen threshold in the future and by how much they will exceed the goal. Greater amounts of residual nonattainment will lead to greater amounts of needed emissions reductions which will lead to higher attainment costs and benefits attributable to the new standard.

EPA compared model projections of 2020 eight-hour ozone design values from the original RIA (based on the 2002 platform) against the same 2020 model projections from the latest air quality modeling simulations that use the current version of CMAQ and the more recent base year (2005). In general, the 2020 design value estimates were very similar between the two modeling exercises, as shown in Figure S1.6. For the 635 counties with eligible 2020 projections in both cases, the average difference between the most recent and the original analysis was -0.15 ppb. That is, the updated analysis estimated slightly cleaner ozone values in 2020 than what EPA previously estimated in the original RIA. However, the two sets of projections are very similar.

Figure S1.6: Comparison of projected 2020 eight-hour ozone design values over 635 counties in the U.S. from the original 2008 RIA air quality modeling (x-axis) and a more recent modeling analysis based on an updated model with updated model inputs (y-axis)



The majority of the cost in attaining a new ozone standard will come from meeting the target in the areas projected to be most polluted in the future. Limiting the analysis to only those 61 counties where the ozone design values are projected to exceed 0.070 ppm in 2020 after the implementation of the controls in the hypothetical RIA control scenario, we see that there is an even stronger tendency for the updated modeling to project cleaner conditions in the future. As discussed in the original RIA, these 61 counties are primarily located in four areas: California, Houston, the western Lake Michigan region, and the Northeast Corridor. For this subset of locations, the average 2020 projected design value difference was -3.3 ppb. In other words, the more recent EPA modeling predicts slightly cleaner ozone conditions (78.1 vs. 81.4 ppb) at the most polluted locations in the future. If the more recent projections are better estimates of future ozone nonattainment in these areas, then the costs and benefits of attaining the ozone NAAQS incremental to the current standard will likely be less than what was projected as part of the 2008 RIA.

Because of the fundamental similarities between the original and more recent air quality modeling simulations, EPA has elected not to update the original analysis of emissions reductions needed to attain the ozone NAAQS as described in Chapter 4 of the 2008 RIA. Based on the latest air quality modeling information, however, it is expected that the original RIA estimates of needed emissions reductions are greater than what is necessary to attain the new primary standard.

Federal Rulemakings Included in the Baseline

The starting point for this analysis is the "baseline", which represents what ambient air quality would be nationwide in 2020 absent the revised ozone NAAQS. (2020 is when the ozone NAAQS would be expected to be fully implemented in all areas except those with the most significant air quality problems. Our analysis recognizes that two areas in Southern California are not planning to meet the current standard by 2020.) The baseline for the revised ozone standard is calculated using emissions estimates that include emission controls that will be needed to attain the "current" standard by 2020. Since this rulemaking is a reconsideration of the 0.080 ppm NAAQS, for this analysis the "current" standard is considered to be 0.08 ppm (effectively 0.084 with rounding).

Two steps were used to develop the baseline for the March 2008 RIA. First, the reductions expected nationwide in ozone concentrations from Federal rules in effect or proposed at that time were included, as well as the controls applied as part of the PM2.5 NAAQS RIA analysis. The rules reflected in the modeling include:

- Clean Air Interstate Rule (EPA, 2005b)
- Clean Air Mercury Rule (EPA, 2005c)
- Regional Haze Regulations and Guidelines for Best Available Retrofit Technology Determinations (EPA, 2005d)
- Clean Air Nonroad Diesel Rule (EPA, 2004)
- Light-Duty Vehicle Tier 2 Rule (EPA, 1999)
- Heavy Duty Diesel Rule (EPA, 2000)
- Proposed rules for Locomotive and Marine Vessels (EPA, 2007a) and for Small Spark-Ignition Engines (EPA, 2007b)
- Proposed C3 Emission Control Area Rule (2009)
- State and local level mobile and stationary source controls identified for additional reductions in emissions for the purpose of attaining the current PM 2.5 and Ozone standards.

Second, since these reductions alone were not predicted to bring all areas into attainment with the current standard, we used a hypothetical control strategy to apply additional known controls. Additional control measures were used in four sectors to establish the baseline: Non-Electricity Generating Unit Point Sources (NonEGUs), Non-Point Area Sources (Area), Onroad Mobile Sources and Nonroad Mobile Sources.

Since the 2008 RIA was completed, a few other Federal rules significantly affecting ozone precursor emissions have been promulgated. Also since that time, the Clean Air Interstate Rule (CAIR) was remanded to EPA by the U.S. Court of Appeals for the D.C. Circuit and the Clean Air Mercury Rule (CAMR) was vacated by the Court. These new developments suggest that the baseline for this supplementary analysis does not reflect emission impacts expected from some recent rules, and that it does reflect emission impacts from some rules that are no longer in place.

Three major rules that were promulgated in 2010, and which affect large categories of NOx emissions, should be represented in the baseline but are not. These are the Renewable Fuel Standard (RFS2) and the Reciprocating Internal Combustion Engines (RICE) NESHAPs (2004 and 2010). It is difficult to assess retroactively how these rules would likely affect total costs of the ozone NAAQS if they had been included in the baseline. NOx emissions from the two RICE rules are estimated to have decreased by a total of about 165,000 tons per year in 2020. However, NOx emissions are expected to increase by 247,600 tons in 2020 as a result of RFS2.

It is difficult to quantify the emission implications of having CAIR in the baseline for the ozone analysis. In 2008, the U.S. Court of Appeals for the D.C. Circuit remanded CAIR to EPA. (See http://www.epa.gov/CAIR/ for more background on CAIR and the Court ruling.) On July 6, 2010, EPA proposed the Transport Rule as a replacement for CAIR. For NOx, the Transport Rule budget is lower in the near term and higher after 2015 relative to CAIR adjusting for differences in the spatial coverage of the two rules. On net, annual NOx emissions are higher than under CAIR once the replacement rule is in effect. Seasonal NOx emissions are lower with the replacement rule, but this is because of differences in baseline emissions and is not attributable to the replacement rule as emissions in the base case are lower than what is forecast with CAIR compliance. Table S1.3 below summarizes the modeled emissions under CAIR and the Transport Rule in various years.

Table S1.3. IPM Estimated Emissions Under CAIR and CAIR Replacement Rule (Transport Rule)

National NOx Annual Emissions (Million Tons)					
	2010	**2012**	**2015**	**2020**	**2025/2026**
CAIR baseline	3.6	NA	3.7	3.7	NA
CAIR	2.4	NA	2.1	2.1	NA

Transport Rule baseline	NA	3.0	3.0	3.1	3.1
Transport Rule main remedy	NA	2.2	2.2	2.3	2.3
CAIR-Region NOx Seasonal Emissions (Million Tons)					
	2010	**2012**	**2015**	**2020**	**2025/2026**
CAIR baseline	0.80	NA	0.80	0.80	NA
CAIR	0.70	NA	0.60	0.60	NA
Transport Rule baseline	NA	0.40	0.40	0.41	0.42
Transport Rule main remedy	NA	0.39	0.38	0.39	0.40

Source: CAIR results are taken from "EPA Base Case 2004" and "IPM Run CAIR 2004 Final" modeling output, available at: http://www.epa.gov/airmarkt/progsregs/epa-ipm/cair/index.html. Transport Rule results are taken from "TR Base Case" and "TR SB Limited Trading" modeling output, available at: http://www.epa.gov/airmarkets/progsregs/epa-ipm/transport.html

At this time we are unable to assess the relative emission reductions expected from the CAMR replacement rule relative to CAMR. In 2008, the U.S. Court of Appeals for the D.C. Circuit vacated the Clean Air Mercury Rule (CAMR). (See http://www.epa.gov/mercuryrule/ for more background CAMR and the Court ruling.) EPA intends to propose air toxics standards for power plants consistent with the D.C. Circuit's opinion regarding the CAMR by March 10, 2011 and finalize a rule by November 16, 2011.

S1.4 Caveats and Conclusions

Of critical importance to understanding these estimates of future costs and benefits is that they are not intended to be forecasts of the actual costs and benefits of implementing revised standards. There are many challenges in estimating the costs and benefits of attaining a tighter ozone standard, which are fully discussed in 2008 Ozone NAAQS RIA and the supplement to this analysis accompanying today's final rule.

There are significant uncertainties in both cost and benefit estimates for the full range of standard alternatives. Below we summarize some of the more significant sources of uncertainty common to all level analyzed in the 2008 ozone NAAQS RIA and this supplemental analysis:

- Benefits estimates are influenced by our ability to accurately model relationships between ozone and PM and their associated health effects (e.g., premature mortality).
- Benefits estimates are also heavily dependent upon the choice of the statistical model chosen for each health benefit.

- PM co-benefits are derived primarily from reductions in nitrates (associated with NOx controls). As such, these estimates are strongly influenced by the assumption that all PM components are equally toxic. Co-benefit estimates are also influenced by the extent to which a particular area chooses to use NOx controls rather than VOC controls.

- There are several nonquantified benefits (e.g., effects of reduced ozone on forest health and agricultural crop production) and disbenefits (e.g., decreases in tropospheric ozone lead to reduced screening of UV-B rays and reduced nitrogen fertilization of forests and cropland) discussed in this analysis in Chapter 6 of the 2008 Ozone NAAQS RIA.

- Changes in air quality as a result of controls are not expected to be uniform over the country. In our hypothetical control scenario some increases in ozone levels occur in areas already in attainment, though not enough to push the areas into nonattainment.

- As explained in Chapter 5 of the 2008 Ozone NAAQS RIA, there are several uncertainties in our cost estimates. For example, the states are likely to use different approaches for reducing NOx and VOCs in their state implementation plans to reach a tighter standard. In addition, since our modeling of known controls does not get all areas into attainment, we needed to make assumptions about the costs of control technologies that might be developed in the future and used to meet the tighter alternative. For example, for the 21 counties (in four geographic areas) that are not expected to attain 0.075 ppm[2] in 2020[3], assumed costs of unspecified controls represent a substantial fraction, of the costs estimated in this analysis ranging from 50% to 89% of total costs depending on the standard being analyzed.

    - As discussed in Chapter 5 of the 2008 Ozone NAAQS RIA, advice from EPA's Science Advisory Board has questioned the appropriateness of an approach similar to one of those used here for estimating extrapolated costs. For balance, EPA also applied a methodology recommended by the Science Advisory Board in an effort to best approximate the costs of control technologies that might be developed in the future.

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[2] Areas that do not meet 0.075 ppm are Chicago, Houston, the Northeastern Corridor, and Sacramento. For more information see chapter 4 section 4.1.1 of the 2008 Ozone NAAQS RIA.
[3] This list of areas does not include the San Joaquin and South Coast air basins who are not expected to attain the current 0.084 ppm standard until 2024.

- Both extrapolated costs and benefits have additional uncertainty relative to modeled costs and benefits. The extrapolated costs and benefits will only be realized to the extent that unknown extrapolated controls are economically feasible and are implemented. Technological advances over time will tend to increase the economic feasibility of reducing emissions, and will tend to reduce the costs of reducing emissions. Our estimates of costs of attainment in 2020 assume a particular trajectory of aggressive technological change. This trajectory leads to a particular level of emissions reductions and costs which we have estimated based on two different approaches, the fixed cost and hybrid approaches. An alternative storyline might hypothesize a much less optimistic technological change path, such that emissions reductions technologies for industrial sources would be more expensive or would be unavailable, so that emissions reductions from many smaller sources might be required for 2020 attainment, at a potentially greater cost per ton. Under this alternative storyline, two outcomes are hypothetically possible: Under one scenario, total costs associated with full attainment might be substantially higher. Under the second scenario, states may choose to take advantage of flexibility in the Clean Air Act to adopt plan with later attainment dates to allow for additional technologies to be developed and for existing programs like EPA's Onroad Diesel, Nonroad Diesel, and Locomotive and Marine rules to be fully implemented. If states were to submit plans with attainment dates beyond our 2020 analysis year, benefits would clearly be lower than we have estimated under our analytical storyline. However, in this case, state decision makers seeking to maximize economic efficiency would not impose costs, including potential opportunity costs of not meeting their attainment date, when they exceed the expected health benefits that states would realize from meeting their modeled 2020 attainment date. In this case, upper bound costs are difficult to estimate because we do not have an estimate of the point where marginal costs are equal to marginal benefits plus the costs of nonattainment. Clearly, the second stage analysis is a highly speculative exercise, because it is based on estimating emission reductions and air quality improvements without any information about the specific controls that would be available to do so.

Appendix S1.A: Reductions of Criteria Air Pollutants from Travel Efficiency Strategies

The RIA contains only a minimal analysis of travel efficiency strategies to reduce vehicle miles traveled, and thus reduce emissions of NOx and other pollutants. A recent report titled, *Moving Cooler: An Analysis of Transportation Strategies for Reducing Greenhouse Gas Emissions*[4], which EPA and US DOT helped to fund, analyzed the potential levels of emissions reductions from light-duty travel efficiency. Moving Cooler included six different bundles of strategies to reflect different potential groups of strategies that could be implemented. Using data from this report, EPA conducted an analysis of the air quality benefits of a subset of the travel efficiency strategies evaluated in the report. Below are preliminary results based on EPA's draft MOVES2009 Model.

For the purposes of EPA's analysis, we chose the "Low Cost" bundle because we believed that it represented the best combination of strategies based on cost, likelihood of success, and accuracy of the research results. This bundle included strategies like smart growth/transit, commuter strategies, system operations (e.g., eco-driving, ramp metering), pricing (e.g., parking taxes, congestion pricing, intercity tolls), speed limit restrictions, and multimodal freight strategies. Note that this bundle did not include a VMT tax or cap-and-trade assumptions.

Moving Cooler made assumptions about the geographic scope for which each strategy could be implemented, with certain strategies like transit being dependent on greater populations, while other strategies like speed limit restrictions could be implemented in both urban and rural areas. Adjustments were also made to operational and commuter strategies to account for induced demand impacts. Scenarios A and B represent aggressive and maximum deployment, respectively, of the "Low Cost" bundle of strategies in Moving Cooler.

Summary of Results

- Nationally, the modeled travel efficiency strategies would reduce exhaust $PM_{2.5}$, NOx, HC and CO from cars and light trucks by approximately 2% in 2020, to approximately 7% in 2045, under the "aggressive" Moving Cooler assumptions.
- The modeled travel efficiency strategies would reduce these emissions by approximately 5% in 2020, to approximately 11% in 2045, under the "maximum" Moving Cooler assumptions.

[4] Cambridge Systematics, Inc. (2009). Moving Cooler: An Analysis of Transportation Strategies for Reducing Greenhouse Gas Emissions. Urban Land Institute: Washington, D.C.

- Percent reductions would be larger in urban areas, where Moving Cooler VMT reductions are concentrated.

Detailed Results

U.S. Annual Ton Reductions from Moving Cooler Bundle 6

	"Maximum" Reductions							
	HC		NOx		PM2.5		CO	
	Tons	% LD	Tons	% LD	Tons	% LD	Tons	% LD
2010	3,437	0.2%	6,542	0.2%	116	0.2%	63,414	0.2%
2015	21,902	1.5%	44,447	1.4%	909	1.5%	486,532	1.4%
2020	50,756	5.2%	101,773	4.8%	2,881	5.2%	1,379,197	4.9%
2025	55,130	7.4%	109,888	6.9%	4,157	7.6%	1,848,978	7.1%
2030	55,569	8.5%	109,193	7.9%	5,039	9.0%	2,157,685	8.3%
2035	56,701	9.3%	111,183	8.7%	5,794	10.0%	2,401,437	9.2%
2040	62,517	10.1%	125,017	9.5%	6,659	10.9%	2,723,906	10.1%
2045	69,934	11.0%	142,747	10.3%	7,631	11.9%	3,088,375	11.0%

	"Aggressive" Reductions							
	HC		NOx		PM2.5		CO	
	Tons	% LD	Tons	% LD	Tons	% LD	Tons	% LD
2010	1,222	0.1%	2,325	0.1%	41	0.1%	22,536	0.1%
2015	6,345	0.4%	13,079	0.4%	265	0.4%	143,319	0.4%
2020	22,088	2.3%	44,291	2.1%	1,254	2.3%	600,223	2.1%
2025	30,592	4.1%	61,366	3.8%	2,301	4.2%	1,029,945	3.9%
2030	33,256	5.1%	65,633	4.8%	3,005	5.4%	1,292,924	5.0%
2035	35,727	5.8%	70,298	5.5%	3,638	6.3%	1,513,454	5.8%
2040	39,897	6.5%	80,020	6.1%	4,236	6.9%	1,738,288	6.5%
2045	45,181	7.1%	92,460	6.7%	4,916	7.6%	1,995,082	7.1%

1 SECTION 2: RE-ANALYSIS OF THE BENEFITS OF ATTAINING ALTERNATIVE OZONE STANDARDS TO INCORPORATE CURRENT METHODS

Synopsis

This chapter presents a benefits analysis of three alternate ozone standards updated to reflect key methodological changes that EPA implemented after publishing the 2008 Ozone NAAQS RIA. Since the completion of this analysis EPA has introduced several methodological improvements in other RIA's that are not incorporated in this analysis.[5] In this updated analysis we re-estimate the human health benefits of reduced exposure to ambient ozone and $PM_{2.5}$ co-benefits from simulated attainment with the selected daily 8hr maximum standard of 0.070 ppm and two alternate standards of 0.075 ppm and 0.065 ppm. For the selected standard of 0.070 ppm, EPA estimates the monetized benefits to be $13 to $37 billion (2006$, 3% discount rate) in 2020. For an alternative standard at 0.075 ppm, EPA estimates the monetized benefits to be $6.9 to $18 billion (2006$, 3% discount rate) in 2020.[6] For the alternative standard at 0.065 ppm, EPA estimates the monetized benefits to be $22 to $61 billion (2006$, 3% discount rate) in 2020. Higher or lower estimates of benefits are possible using other assumptions. These updated estimates reflect three key methodological changes we have implemented since the publication of the 2008 RIA that reflect EPA's most current interpretation of the scientific literature and include: (1) a no-threshold model for $PM_{2.5}$ that calculates incremental benefits down to the lowest modeled air quality levels; (2) removal of the assumption of no causality for the relationship between ozone exposure and premature mortality; (3) a different Value of Statistical Life (VSL). These benefits are incremental to an air quality baseline that reflects attainment with the 1997 ozone and 2006 $PM_{2.5}$ National Ambient Air Quality Standards (NAAQS). Methodological limitations prevented EPA from monetizing the benefits from several important benefit categories, including ecosystem effects.

S2.1 Background

In response to the recent court vacatur of the 2008 Ozone NAAQS, EPA is reconsidering this rulemaking. Consistent with EPA's decision to, in general, use the "existing record" for this reconsideration, we present a benefits analysis based on the same air quality modeling inputs as the 2008 analysis. However, we update this analysis to make the results consistent with an array of methodological updates that EPA has incorporated since the release of Regulatory Impact Analysis (RIA) for the 2008 Ozone NAAQS (U.S. EPA, 2008). Because the rulemaking period for the reconsideration is condensed, we only provide estimates associated with the promulgated standard level of 0.070 ppm and the two less stringent standard levels previously analysis (i.e.,

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[5] Such improvements include the use of more current baseline mortality and morbidity rates to calculate health impacts and the use of more recent PM health studies to calculate health impacts. The effect of these changes would be to reduce certain ozone and PM2.5-related health impacts reported in this RIA by a modest amount.

[6] Results are shown as a range from Bell et al. (2004) with Pope et al. (2002) to Levy (2005) with Laden et al. (2006). $PM_{2.5}$ co-benefits using a 7% discount rate would be approximately 9% lower.

0.065 ppm and 0.075 ppm). All benefits estimates in this analysis are incremental to the 1997 Ozone NAAQS standard at 0.08 ppm and the 2006 $PM_{2.5}$ NAAQS standard at 15/35 $\mu g/m^3$.

S2.2 Key updates to the benefits assessment

In this analysis, we update several aspects of our benefits assessment for the human health benefits of reducing exposure to ozone and $PM_{2.5}$.[7] Both ozone benefits and $PM_{2.5}$ co-benefits incorporate the updated population projections in BenMAP. In addition, both ozone benefits and $PM_{2.5}$ co-benefits reflect EPA's current interpretation of the economic literature on mortality valuation to use the value-of-a statistical life (VSL) based on meta-analysis of 26 studies.[8]

For ozone benefits, these updates are a response to recent recommendations from the National Research Council (NRC, 2008). In this analysis, we have incorporated three of NRC's recommendations:

1) We no longer include estimates of ozone benefits with an assumption of no causal relationship between ozone exposure and premature mortality.
2) We include two additional ozone mortality estimates, one based on the National Morbidity, Mortality and Air Pollution Study (NMMAPS) (Huang, 2005), and one 14-city study (Schwartz, 2005), placing the greatest emphasis on the multi-city studies, such as NMMAPS.
3) We present additional risk metrics, including the change in the percentage of baseline mortality attributable, and the number of life years lost due, to ozone-related premature mortality.

In addition to these recommendations, we modify the health functions used to estimate the number of emergency department visits for asthma avoided by reducing exposure to ozone. Specifically, we removed the Jaffe et al. (2003) function because the age range overlaps partially with Wilson et al. (2005) and Peel et al. (2005) functions. This change results in a slightly larger estimate of ozone-related emergency department visits as compared to the 2008 analysis.

For $PM_{2.5}$ co-benefits, this analysis is consistent with proposed Portland Cement NESHAP RIA (U.S. EPA, 2009a) and proposed NO_2 NAAQS RIA (U.S. EPA, 2009b). In this analysis, we incorporate four updates:

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[7] This analysis does not attempt to describe the overall methodology for estimating the benefits of reducing ozone and $PM_{2.5}$. For more information, please consult Chapter 6 of the 2008 Ozone NAAQS RIA (U.S. EPA, 2008).

[8] For more information regarding mortality valuation, please consult section 5.7 of the proposed NO_2 RIA (U.S. EPA, 2009b).

1) We removed assumed thresholds from the mortality and morbidity concentration-response functions for $PM_{2.5}$.[9] Removing the assumed 10 $\mu g/m^3$ threshold is a key difference between the method used in this analysis of $PM_{2.5}$-co benefits and the methods used in RIAs prior to Portland Cement, and we now calculate incremental benefits down to the lowest modeled $PM_{2.5}$ air quality levels. This change results in a larger estimate of PM-related premature mortality as compared to the 2008 analysis.
2) We now present the $PM_{2.5}$ co-benefits results using concentration-response functions for mortality from two cohort studies (Pope et al. (2002) and Laden et al. (2006)) instead of range between the minimum and maximum results from an expert elicitation of the relationship between exposure to $PM_{2.5}$ and premature mortality (Roman et al., 2008). This change produces a slightly narrower range of PM-related mortality estimates as compared to the 2008 analysis.
3) When adjusting the benefits of the modeled PM co-benefits for alternate standard levels, we apply $PM_{2.5}$ benefit per ton estimates calculated using a broader geographic area, which, when compared to the 2008 analysis, produces more reliable and generally larger PM-related benefits estimates.
4) We incorporated an updated methodology for quantifying the health incidences associated with the benefit-per-ton estimates. This change should produce more reliable estimates of PM-related health impacts.

In this analysis we estimate ozone-related premature mortality using risk coefficients drawn from short-term mortality studies. Two recent epidemiologic studies assessed the relationship between long-term exposure to ozone and premature mortality. Jerrett et al. (2009) utilized the ACS cohort with air quality data from 1977 through 2000 (April through September). Jarrett et al. reported a positive and statistically significant association between ambient ozone concentration and respiratory causes of death after controlling for $PM_{2.5}$ using co-pollutant models. Further examination of the association between ozone exposure and respiratory-related mortality revealed the association was increased by higher temperatures and geographic variation. In single pollutant models, long-term ozone exposure was also associated with cardiopulmonary, cardiovascular, and ischemic heart disease mortality, but the associations were not present in the co-pollutant model. Krewski et al. (2009) also utilized data from the ACS cohort with air quality data from 1980 (April through September) and observed a positive association between ozone exposure and all-cause and cardiopulmonary disease mortality. This association was robust to control for ecologic variables, but no association was

[9] For more information regarding thresholds in the $PM_{2.5}$ mortality relationship, please consult the proposed Portland Cement NESHAP RIA (U.S. EPA, 2009a).

observed with ischemic heart disease or lung cancer. In addition, Krewski et al. observed no association with year-round ozone exposure.

S2.3 Presentation of results

Tables S2.1 through S2.6 show the results of this updated analysis. Figures S2.1 and S2.2 show the breakdown of ozone benefits and $PM_{2.5}$ co-benefits by endpoint category using a single mortality study as an example. Figures S2.3 and S2.4 show the ozone benefits and $PM_{2.5}$ co-benefits by mortality study. Figures S2.5 and S2.6 show the breakdown of monetized benefits between ozone, PM, morbidity, mortality, and visibility. Figure S2.7 shows the results of this updated analysis graphically.

Table S2.1: Summary of Total Number of Ozone and $PM_{2.5}$-Related Premature Mortalities and Morbidity Incidences Avoided in 2020 [A]

Combined Estimate of Mortality		0.075 ppm	0.070 ppm	0.065 ppm
Multi-city	Bell et al. (2004)	760 to 1,900	1,500 to 3,400	2,500 to 5,600
	Schwartz	800 to 1,900	1,600 to 3,600	2,700 to 5,800
	Huang	820 to 1,900	1,700 to 3,600	2,800 to 5,900
Meta-analysis	Bell et al. (2005)	930 to 2,000	2,000 to 4,000	3,500 to 6,600
	Ito et al.	1,000 to 2,100	2,400 to 4,300	4,000 to 7,200
	Levy et al.	1,000 to 2,100	2,400 to 4,300	4,100 to 7,200
Combined Estimate of Morbidity		**0.075 ppm**	**0.070 ppm**	**0.065 ppm**
Acute Myocardial Infarction [B]		1,300	2,200	3,500
Upper Respiratory Symptoms [B]		9,900	19,000	31,000
Lower Respiratory Symptoms [B]		13,000	25,000	41,000
Chronic Bronchitis [B]		470	880	1,400
Acute Bronchitis [B]		1,100	2,100	3,400
Asthma Exacerbation [B]		12,000	23,000	38,000
Work Loss Days [B]		88,000	170,000	270,000
School Loss Days [C]		190,000	600,000	1,100,000
Hospital and ER Visits		2,600	6,600	11,000
Minor Restricted Activity Days		1,000,000	2,600,000	4,500,000

[A] *All estimates rounded to two significant figures.* Only includes areas required to meet the current standard by 2020; does not include San Joaquin Valley and South Coast air basins in California. Includes ozone benefits, and $PM_{2.5}$ co-benefits. Mortality incidence range was developed by adding the estimate from the ozone premature mortality function to estimates from the $PM_{2.5}$ premature mortality functions from Pope et al. (2002) and Laden et al. (2006).

[B] Estimated reduction in premature morbidity due to $PM_{2.5}$ reductions only.

[C] Estimated reduction in premature morbidity due to ozone reductions only.

Table S2.2: Summary of Total Monetized Benefits in 2020 (3% discount rate, in millions of 2006$)[A, B, C]

Combined Estimate of Mortality		0.075 ppm			0.070 ppm			0.065 ppm		
NMMAPS	Bell et al. (2004)	$6,900	to	$15,000	$13,000	to	$29,000	$22,000	to	$47,000
	Schwartz	$7,200	to	$16,000	$15,000	to	$30,000	$24,000	to	$49,000
	Huang	$7,300	to	$16,000	$15,000	to	$30,000	$25,000	to	$50,000
Meta-analysis	Bell et al. (2005)	$8,300	to	$17,000	$18,000	to	$34,000	$31,000	to	$56,000
	Ito et al.	$9,100	to	$18,000	$21,000	to	$37,000	$36,000	to	$61,000
	Levy et al.	$9,200	to	$18,000	$21,000	to	$37,000	$36,000	to	$61,000

[A] Does not reflect estimates for the San Joaquin and South Coast Air Basins

[B] All estimates rounded to two significant digits

[c] Includes Visibility benefits of $160,000

Table S2.3: Summary of Total Monetized Benefits in 2020 (7% discount rate, in millions of 2006$)[A, B, C]

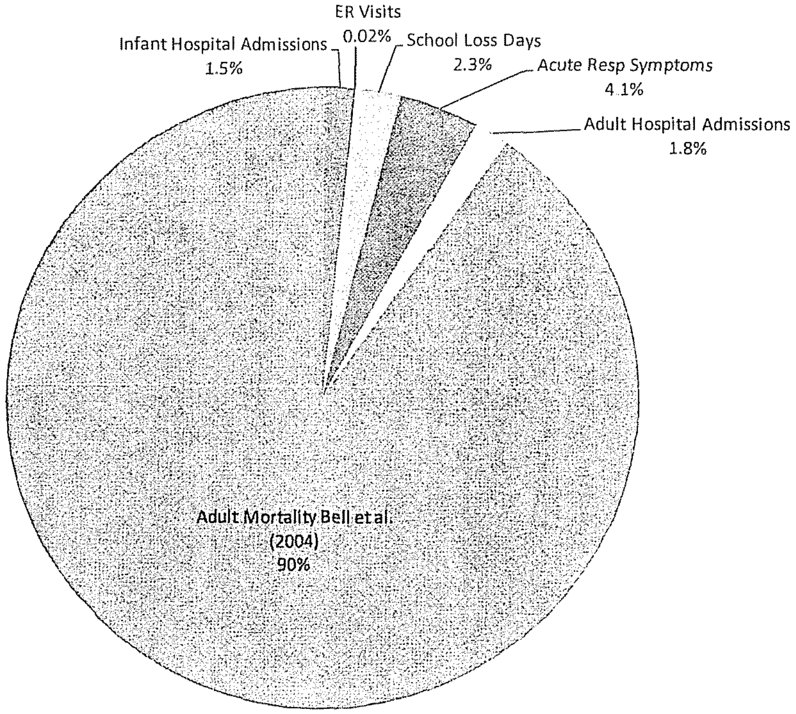
Combined Estimate of Mortality		0.075 ppm			0.070 ppm			0.065 ppm		
NMMAPS	Bell et al. (2004)	$6,400	to	$13,000	$11,000	to	$24,000	$19,000	to	$39,000
	Schwartz	$6,700	to	$13,000	$12,000	to	$25,000	$21,000	to	$41,000
	Huang	$6,800	to	$13,000	$13,000	to	$26,000	$21,000	to	$42,000
Meta-analysis	Bell et al. (2005)	$7,800	to	$14,000	$16,000	to	$29,000	$27,000	to	$48,000
	Ito et al.	$8,600	to	$15,000	$18,000	to	$31,000	$31,000	to	$52,000
	Levy et al.	$8,700	to	$15,000	$18,000	to	$31,000	$32,000	to	$52,000

[A] Does not reflect estimates for the San Joaquin and South Coast Air Basins

[B] All estimates rounded to two significant digits

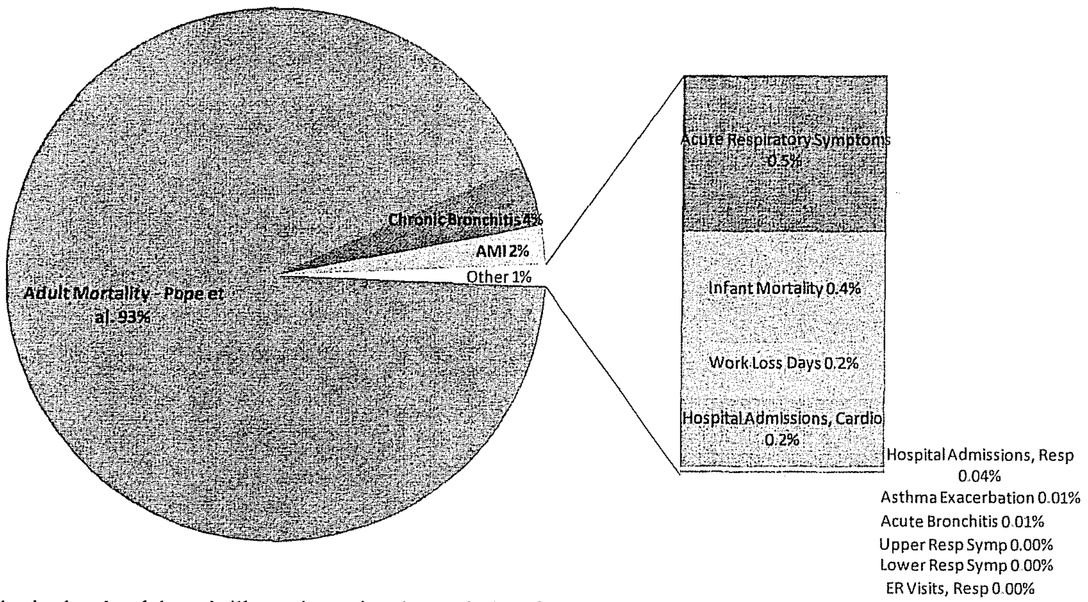
[c] Includes Visibility benefits of $160,000

Figure S2-1: Breakdown of Ozone Health Benefits (using Bell 2004)*



*This pie chart breakdown is illustrative, using the results based on Bell et al. (2004) as an example. Using the Levy et al. (2006) function for premature mortality, the percentage of total monetized benefits due to adult mortality would be 97%.

Figure S2-2: Breakdown of $PM_{2.5}$ Health Benefits (using Pope)*



*This pie chart breakdown is illustrative, using the results based on Pope et al. (2002) as an example. Using the Laden et al. (2006) function for premature mortality, the percentage of total monetized benefits due to adult mortality would be 97%. This chart shows the breakdown using a 3% discount rate, and the results would be similar if a 7% discount rate was used.

Table S2.4: Summary of National Ozone Benefits by Standard Level with 95th percentile confidence intervals (in millions of 2006$)[A, B, C]

Endpoint Group	Author	0.075 ppm Valuation	0.075 ppm Incidence	0.070 ppm Valuation	0.070 ppm Incidence	0.065 ppm Valuation	0.065 ppm Incidence
Infant Hospital Admissions, Respiratory		$11 ($5.7 -- $16)	550 (310 -- 830)	$17 ($8.5 -- $25)	1,700 (960 -- 2,600)	$30 ($15 -- $43)	3,000 (1,700 -- 4,500)
Emergency Room Visits, Respiratory		$0.11 (-$.21 -- $.35)	290 (-310 -- 930)	$0.36 (-$.71 -- $1.2)	990 (-890 -- 3,200)	$0.66 (-$1.3 -- $2.2)	1,800 (-1,600 -- 5,800)
School Loss Days		$17 ($7.5 -- $24)	190,000 (93,000 -- 280,000)	$53 ($23 -- $76)	600,000 (300,000 -- 880,000)	$96 ($42 -- $140)	1,100,000 (550,000 -- 1,600,000)
Acute Respiratory Symptoms		$30 ($12 -- $56)	510,000 (280,000 -- 790,000)	$96 ($37 -- $180)	1,600,000 (910,000 -- 2,500,000)	$170 ($68 -- $320)	2,900,000 (1,700,000 -- 4,500,000)
Hospital Admissions, Respiratory		$13 ($1.7 -- $22)	550 (130 -- 980)	$45 ($5.6 -- $77)	1,900 (550 -- 3,400)	$81 ($11 -- $140)	3,400 (1,000 -- 6,100)
Mortality	Bell et al. 2004	$660 ($54 -- $2,000)	74 (36 -- 120)	$2,200 ($180 -- $6,600)	250 (130 -- 410)	$4,000 ($330 -- $12,000)	450 (240 -- 730)
Mortality	Schwartz	$1,000 ($82 -- $3,000)	110 (54 -- 190)	$3,400 ($270 -- $10,000)	380 (190 -- 630)	$6,200 ($500 -- $19,000)	700 (350 -- 1,100)
Mortality	Huang	$1,100 ($95 -- $3,300)	130 (66 -- 200)	$3,800 ($320 -- $11,000)	420 (230 -- 670)	$6,800 ($580 -- $20,000)	770 (420 -- 1,200)
Mortality	Bell et al. 2005	$2,000 ($190 -- $6,100)	240 (140 -- 350)	$7,000 ($630 -- $21,000)	800 (490 -- 1,200)	$10,000 ($1,100 -- $37,000)	1,500 (910 -- 2,200)
Mortality	Ito et al.	$2,900 ($280 -- $8,200)	330 (230 -- 450)	$9,900 ($930 -- $28,000)	1,100 (790 -- 1,500)	$18,000 ($1,700 -- $50,000)	2,000 (1,400 -- 2,800)
Mortality	Levy et al.	$3,000 ($280 -- $8,200)	340 (260 -- 430)	$10,000 ($930 -- $28,000)	1,100 (870 -- 1,500)	$18,000 ($1,700 -- $50,000)	2,100 (1,600 -- 2,600)

[A] Does not reflect estimates for the San Joaquin and South Coast Air Basins

[B] Confidence intervals are not available for PM co-benefits because of methodological limitations when using benefit-per-ton estimates.

[C] All estimates rounded to two significant digits

Table S2.5: Summary of National Ozone Benefits and $PM_{2.5}$ Co-Benefits by Standard Level (in millions of 2006$ at a 3% discount rate)[A, B, C]

	Endpoint Group	Author	0.075 ppm Valuation	0.075 ppm Incidence	0.070 ppm Valuation	0.070 ppm Incidence	0.065 ppm Valuation	0.065 ppm Incidence
Ozone	Infant Hospital Admissions, Respiratory		$11	550	$17	1,700	$30	3,000
	Emergency Room Visits, Respiratory		$0.11	290	$0.36	990	$0.66	1,800
	School Loss Days		$17	190,000	$53	600,000	$96	1,100,000
	Acute Respiratory Symptoms		$30	510,000	$96	1,600,000	$170	2,900,000
	Hospital Admissions, Respiratory		$13	550	$45	1,900	$81	3,400
	Mortality	Bell et al. (2004)	$660	74	$2,200	250	$4,000	450
	Mortality	Schwartz	$1,000	110	$3,400	380	$6,200	700
	Mortality	Huang	$1,100	130	$3,800	420	$6,800	770
	Mortality	Bell et al. (2005)	$2,100	240	$7,100	800	$13,000	1,500
	Mortality	Ito et al.	$2,900	330	$9,900	1,100	$18,000	2,000
	Mortality	Levy et al.	$3,000	340	$10,000	1,100	$18,000	2,100
$PM_{2.5}$	Chronic Bronchitis		$230	470	$430	880	$700	1,400
	Acute Myocardial Infarction		$140	1,300	$240	2,200	$380	3,500
	Hospital Admissions, Respiratory		$2.5	180	$4.3	310	$6.8	490
	Hospital Admissions, Cardiovascular		$11	390	$18	670	$29	1,000
	Emergency Room Visits, Respiratory		$0.22	590	$0.39	1,100	$0.63	1,700
	Acute Bronchitis		$0.08	1,100	$0.15	2,100	$0.25	3,400
	Work Loss Days		$11	88,000	$20	170,000	$34	270,000
	Asthma Exacerbation		$0.64	12,000	$1.2	23,000	$2.0	38,000
	Acute Respiratory Symptoms		$31	520,000	$58	980,000	$95	1,600,000
	Lower Respiratory Symptoms		$0.24	13,000	$0.45	25,000	$0.75	41,000
	Upper Respiratory Symptoms		$0.29	9,900	$0.54	19,000	$0.89	31,000
	Infant Mortality		$22	3	$44	5	$73	8
	Mortality	Pope et al	$5,500	690	$10,000	1,200	$16,000	2,000
	Mortality	Laden et al	$14,000	1,800	$26,000	3,200	$41,000	5,100
	Mortality	Expert K	$1,900	230	$3,500	430	$5,700	700
	Mortality	Expert E	$19,000	2,300	$34,000	4,200	$55,000	6,800

[A] Does not reflect estimates for the San Joaquin and South Coast Air Basins

[B] Does not include confidence intervals

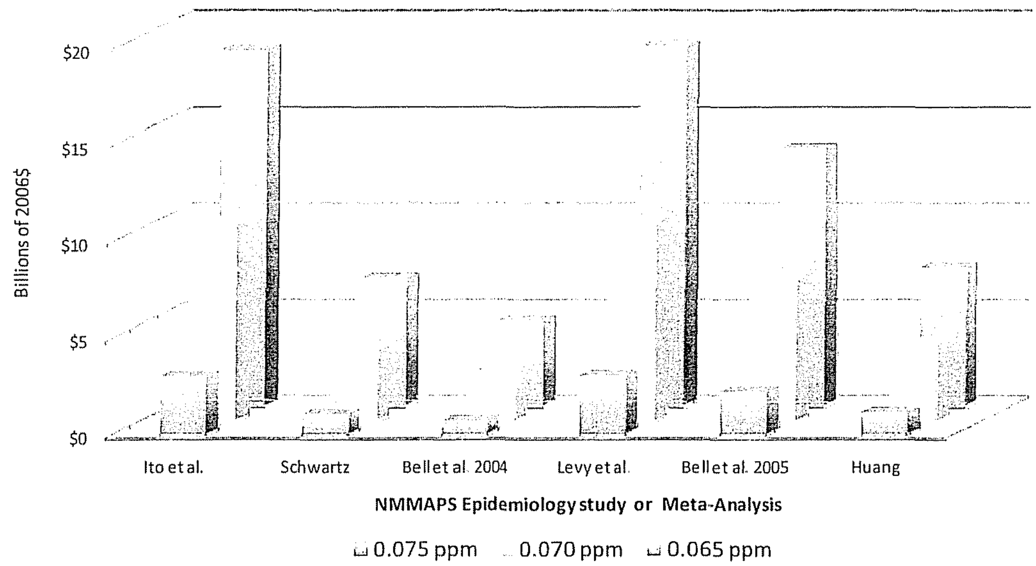
[c] All estimates rounded to two significant digits

Table S2.6: Summary of National Ozone Benefits and $PM_{2.5}$ Co-Benefits by Standard Level (in millions of 2006$ at a 7%

	Endpoint Group	Author	0.075 ppm Valuation	0.075 ppm Incidence	0.070 ppm Valuation	0.070 ppm Incidence	0.065 ppm Valuation	0.065 ppm Incidence
Ozone	Infant Hospital Admissions, Respiratory		$11	550	$17	1,700	$30	3,000
	Emergency Room Visits, Respiratory		$0.11	290	$0.36	990	$0.66	1,800
	School Loss Days		$17	190,000	$53	600,000	$96	1,100,000
	Acute Respiratory Symptoms		$30	510,000	$96	1,600,000	$170	2,900,000
	Hospital Admissions, Respiratory		$13	550	$45	1,900	$81	3,400
	Mortality	Bell et al. (2004)	$660	74	$2,200	250	$4,000	450
	Mortality	Schwartz	$1,000	110	$3,400	380	$6,200	700
	Mortality	Huang	$1,100	130	$3,800	420	$6,800	770
	Mortality	Bell et al. (2005)	$2.100	240	$7,100	800	$13,000	1,500
	Mortality	Ito et al.	$2,900	330	$9,900	1,100	$18,000	2,000
	Mortality	Levy et al.	$3,000	340	$10,000	1,100	$18,000	2,100
$PM_{2.5}$	Chronic Bronchitis		$230	470	$430	880	$700	1,400
	Acute Myocardial Infarction		$140	1,300	$240	2,200	$380	3,500
	Hospital Admissions, Respiratory		$2.5	180	$4.3	310	$6.8	490
	Hospital Admissions, Cardiovascular		$11	390	$18	670	$29	1,000
	Emergency Room Visits, Respiratory		$0.22	590	$0.39	1,100	$0.63	1,700
	Acute Bronchitis		$0.08	1,100	$0.15	2,100	$0.25	3,400
	Work Loss Days		$11	88,000	$20	170,000	$34	270,000
	Asthma Exacerbation		$0.64	12,000	$1.2	23,000	$2.0	38,000
	Acute Respiratory Symptoms		$31	520,000	$58	980,000	$95	1,600,000
	Lower Respiratory Symptoms		$0.24	13,000	$0.45	25,000	$0.75	41,000
	Upper Respiratory Symptoms		$0.29	9,900	$0.54	19,000	$0.89	31,000
	Infant Mortality		$22	3	$44	5	$73	8
	Mortality	Pope et al	$5,000	690	$9,000	1,200	$14,000	2,000
	Mortality	Laden et al	$13,000	1,800	$23,000	3,200	$37,000	5,100
	Mortality	Expert K	$1,700	230	$3,100	430	$5,100	700
	Mortality	Expert E	$17,000	2,300	$31,000	4,200	$49,000	6,800

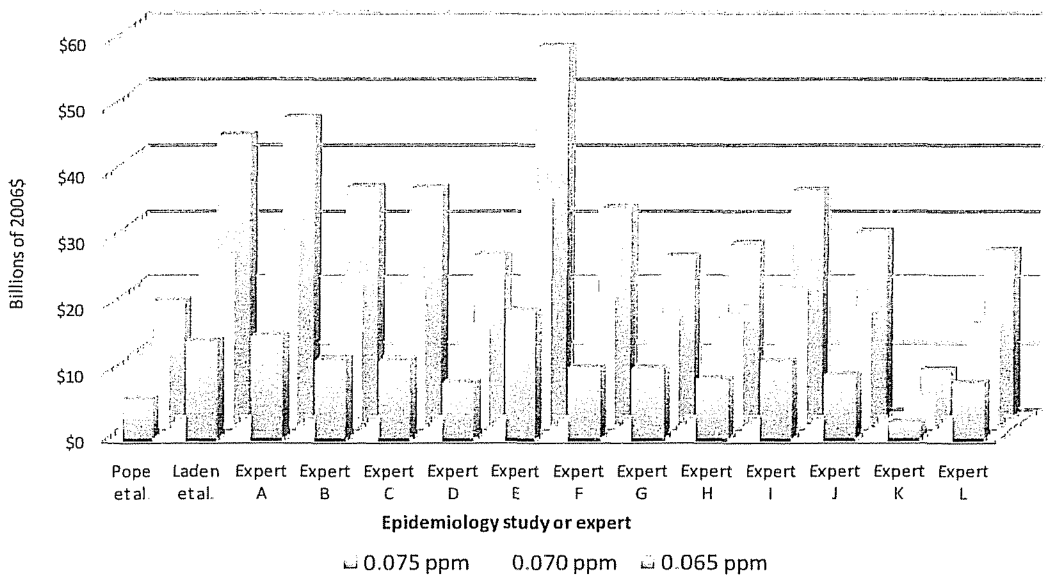
[A] Does not reflect estimates for the San Joaquin and South Coast Air Basins
[B] Does not include confidence intervals
[C] All estimates rounded to two significant digits

Figure S2.3: Ozone benefits for Alternate Standard Levels*



*This graph shows the estimated ozone benefits in 2020 using three NMMAPS-based epidemiology studies and three meta-analyses. The results shown are not the direct results from the studies; rather, the estimates are based in part on the concentration-response function provided in those studies. Because all ozone-related health effects are short-term, the discount rate does not affect the results.

Figure S2.4: $PM_{2.5}$ co-benefits for Alternate Standard Levels*



*This graph shows the estimated $PM_{2.5}$ co-benefits in 2020 using the no-threshold model at discount rates of 3% using effect coefficients using the Pope et al. study and the Laden et al study, as well as 12 effect coefficients derived from EPA's expert elicitation on PM mortality. The results shown are not the direct results from the studies or expert elicitation; rather, the estimates are based in part on the concentration-response function provided in those studies. Results using a 7% discount rate would be similar, but approximately 9% lower.

Figure S2.5: Breakdown of total monetized benefits for Alternate Standard Levels (Low)

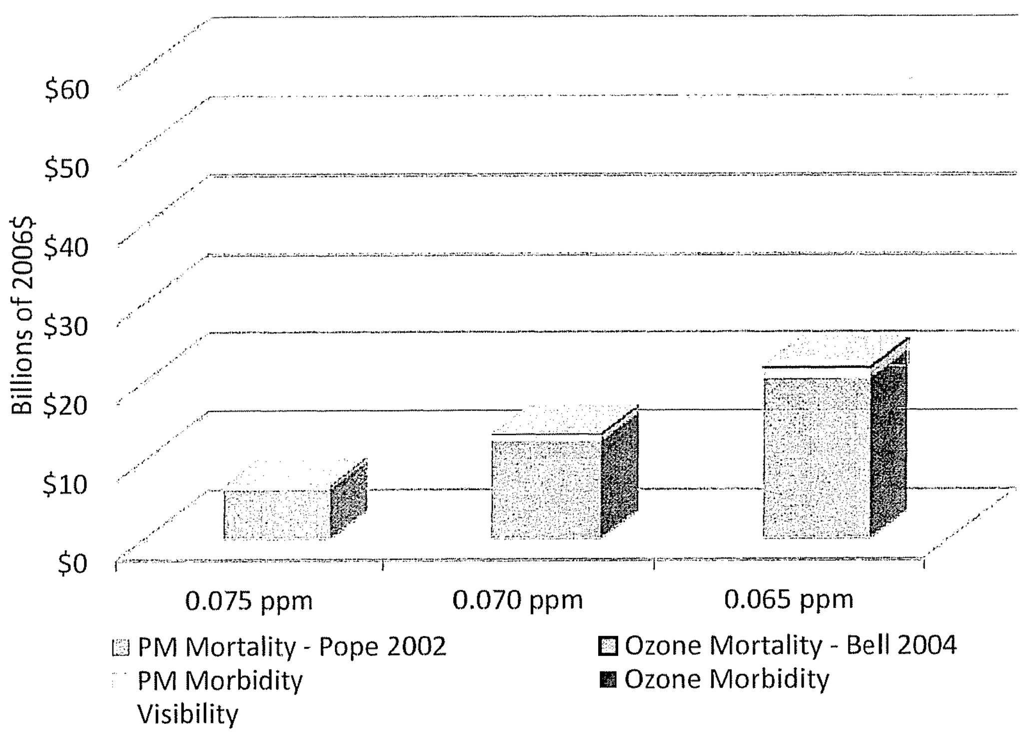


Figure S2.6: Breakdown of total monetized benefits for Alternate Standard Levels (High)

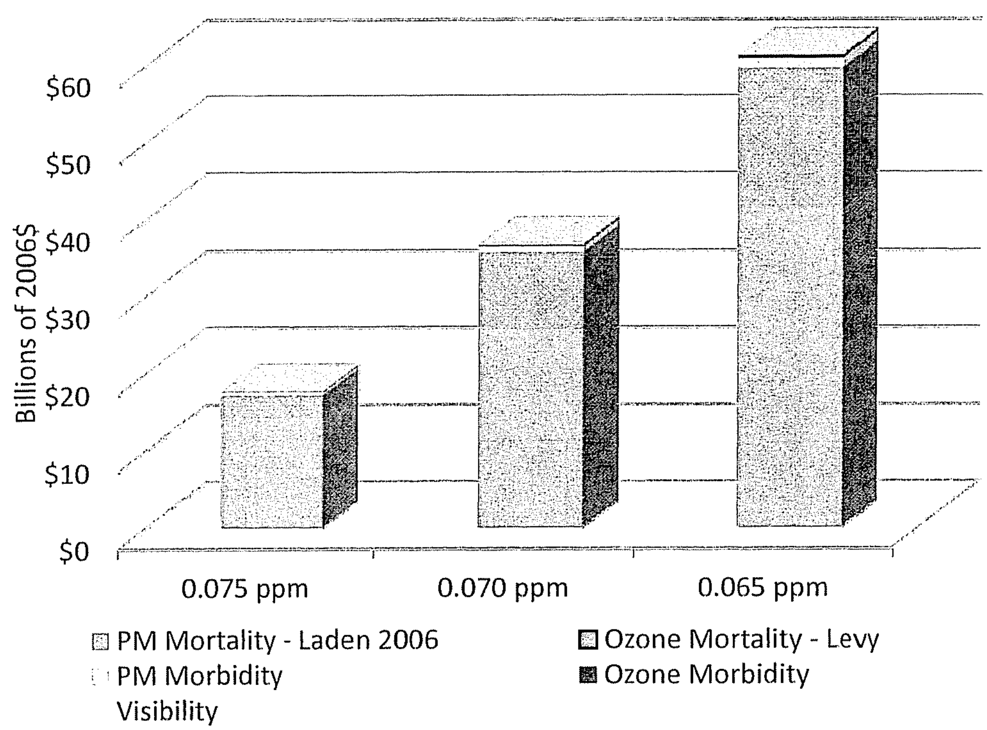
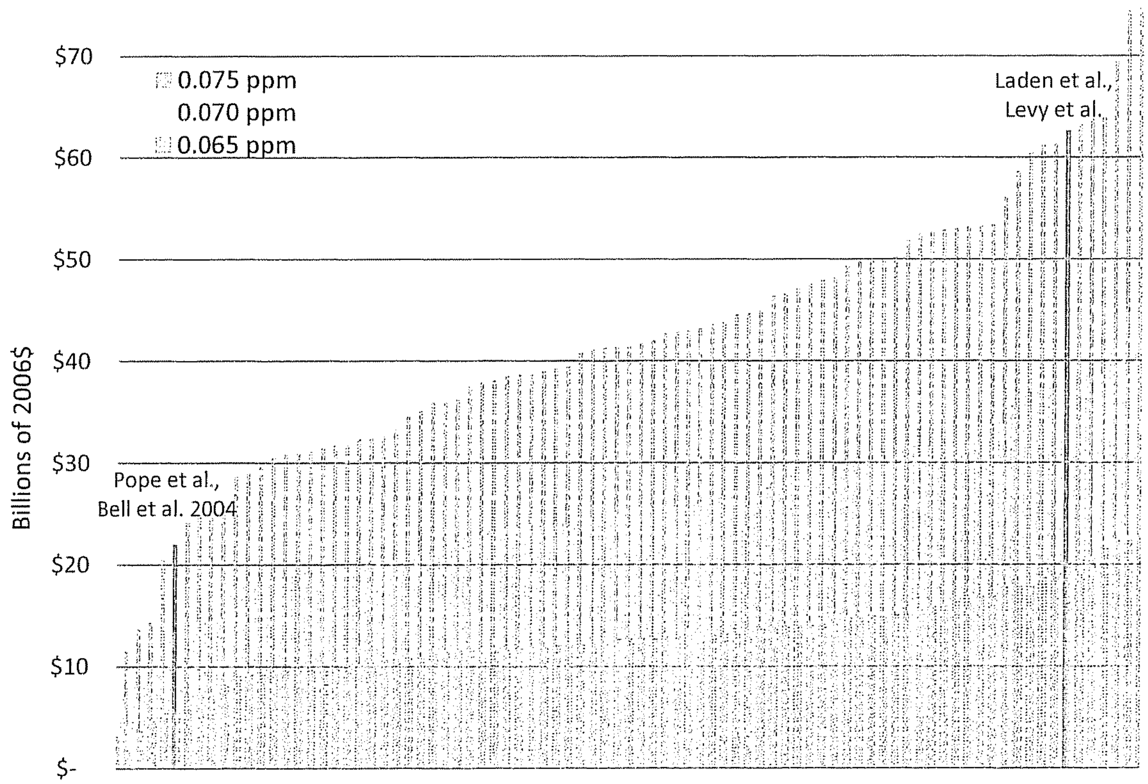


Figure S2.7: Total Monetized Benefits for Alternate Standard Levels*



*This graph shows the estimated total monetized benefits in 2020 using the no-threshold model at discount rates of 3% using effect coefficients derived from the 6 ozone mortality studies and PM co-benefits estimates using the Pope et al. study and the Laden et al study, as well as 12 effect coefficients derived from EPA's expert elicitation on PM mortality. The highlighted results represent the combined estimates from Bell et al. (2004) with Pope et al. (2002) and Levy (2005) with Laden et al. (2006). The results shown are not the direct results from the studies or expert elicitation; rather, the estimates are based in part on the concentration-response function provided in those studies. PM co-benefit results using a 7% discount rate would be similar, but approximately 9% lower.

In 2008, the National Research Council (NRC) evaluated the EPA's approach to estimating ozone-related mortality benefits. Among other recommendation, in its report the NRC indicated that "EPA should consider placing greater emphasis on reporting decrease in age-specific death rates and increases in life expectancy..." (NRC, 2008). As a first step in implementing this recommendation, below for two of the three scenarios, we present changes in the percentage of total cause-specific mortality attributable to ozone and the change in the number of life years.[10] Table 7 summarizes the estimated number of life years gained resulting from simulated attainment with the 0.065 ppm and 0.070 ppm standard alternatives. To simplify this presentation

[10] Here we omit the results for the 0.075 ppm alternative. We estimated the benefits of attaining this alternative through an interpolation approach that made subsequent estimation of life years and changes in death rates technically challenging.

we include results based on the estimates of ozone mortality reported in Levy et al. (2005) and Bell et al. (2004), which provide upper and lower-bound estimates, respectively.

Table S2.7: Estimated Reduction in Ozone-Related Premature Mortality in Terms of Life Years Gained from Increases in Life Expectancy

	Bell et al. (2004) mortality estimate		*Levy et al. (2005) mortality estimate*	
Age Range	0.070 ppm	0.065 ppm	0.070 ppm	0.065 ppm
25-29	75 (32—120)	130 (58—210)	660 (780—830)	1,200 (850—1,500)
30-34	66 (28—100)	120 (51—180)	580 (420—740)	1,000 (750—1,300)
35-44	260 (110—410)	460 (200—730)	1,600 (1,200—2,000)	2,800 (2,000—3,500)
45-54	520 (220—830)	930 (400—1,500)	2,600 (1,900—3,300)	4,500 (3,300—5,700)
55-64	1,000 (440—1,600)	1,800 (780—2,800)	4,600 (3,400—5,900)	8,100 (5,900—10,000)
65-74	1,200 (500—1,900)	2,100 (900—3,300)	5,200 (3,800—6,600)	9,100 (6,700—12,000)
75-84	810 (340—1,300)	1,400 (620—2,200)	3,500 (2,600—4,500)	6,200 (4,600—7,900)
85-99	400 (170—630)	720 (310—1,100)	1,800 (1,300—2,200)	3,100 (2,300—4,000)

Table S2.8 summarizes the percentage of total mortality attributable to ozone. As above, we include estimates based on the Bell et al. (2004) and Levy et al. (2005) risk coefficients.

Table S2.8: Percentage of Total Mortality Attributable to Ozone

	Bell et al. (2004) mortality estimate		*Levy et al. (2005) mortality estimate*	
Age Range	0.070 ppm	0.065 ppm	0.070 ppm	0.065 ppm
25-29	0.030%	0.054%	0.126%	0.224%
30-34	0.029%	0.052%	0.123%	0.217%
35-44	0.029%	0.051%	0.123%	0.217%
45-54	0.030%	0.052%	0.127%	0.224%
55-64	0.028%	0.050%	0.122%	0.212%
65-74	0.027%	0.047%	0.114%	0.200%
75-84	0.026%	0.046%	0.112%	0.197%
85-99	0.027%	0.048%	0.115%	0.206%

Based on our review of the current body of scientific literature, EPA estimated PM-related mortality without applying an assumed concentration threshold. EPA's Integrated Science Assessment for Particulate Matter (U.S. EPA, 2009c), which was recently reviewed by EPA's Clean Air Scientific Advisory Committee, concluded that the scientific literature consistently finds that a no-threshold log-linear model most adequately portrays the PM-mortality concentration-response relationship while recognizing potential uncertainty about the exact shape of the concentration-response function. Consistent with this finding, we have conformed the threshold sensitivity analysis to the current state of the PM science improved upon our previous approach for estimating the sensitivity of the benefits estimates to the presence of an assumed threshold by incorporating a new "Lowest Measured Level" (LML) assessment.

This approach summarizes the distribution of avoided PM mortality impacts according to the baseline $PM_{2.5}$ levels (i.e. those levels that exist prior to the implementation of the ozone attainment scenario) experienced by the population receiving the $PM_{2.5}$ mortality benefit (Figure S2.8 and S2.9). We identify on this figure the lowest air quality levels measured in each of the two primary epidemiological studies EPA uses to quantify PM-related mortality. This information allows readers to determine the portion of PM-related mortality benefits occurring above or below the LML of each study; in general, our confidence in the estimated PM mortality decreases as we consider air quality levels further below the LML in the two epidemiological studies. While the LML analysis provides some insight into the level of uncertainty in the estimated PM mortality benefits, EPA does not view the LML as a threshold and continues to quantify PM-related mortality impacts using a full range of modeled air quality concentrations.

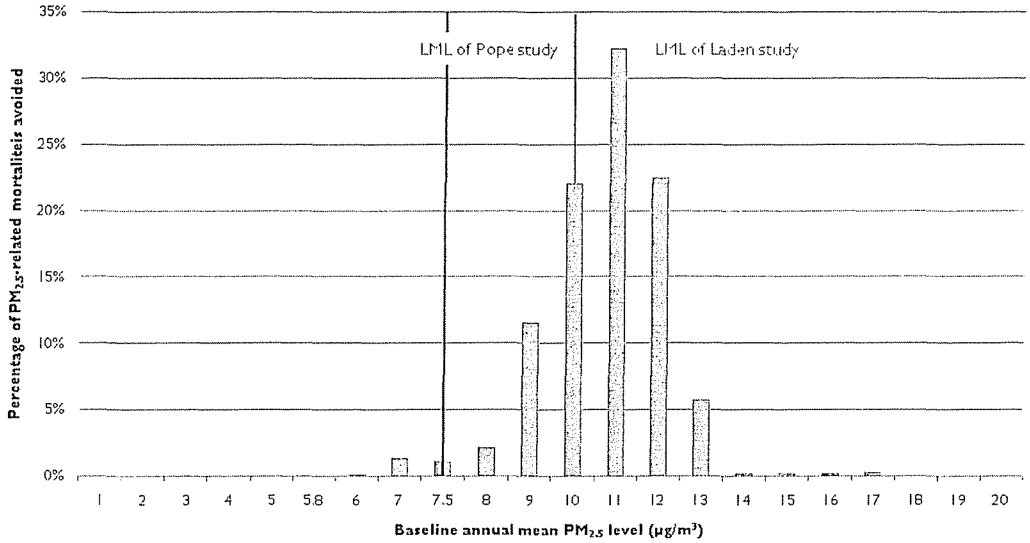
The very large proportion of the avoided PM-related impacts we estimate in this illustrative analysis occur among populations exposed at or above the LML of each study (Figures S2.8 and S2.9), increasing our confidence in the PM mortality analysis. Approximately 62% of the avoided impacts occur at or above an annual mean $PM_{2.5}$ level of 10 $\mu g/m^3$ (the LML of the Laden et al. 2006 study); about 97% occur at or above an annual mean $PM_{2.5}$ level of 7.5 $\mu g/m^3$ (the LML of the Pope et al. 2002 study). As we model mortality impacts among populations exposed to levels of $PM_{2.5}$ that are successively lower than the LML of each study our confidence in the results diminishes. However, the analysis above confirms that the great majority of the impacts occur at or above each study's LML.

Because time and resource limitations prevented EPA from performing air quality modeling of the $PM_{2.5}$-related co-benefits of the illustrative ozone attainment strategies, this LML analysis considers only a single air quality modeling scenario. This single scenario represents only a portion of $PM_{2.5}$ reductions we anticipate to occur as a result of the NOx emission reductions needed to attain a new standard of 0.065 ppm. As such, this LML analysis provides an incomplete representation of the distribution of avoided mortality impacts and reductions in $PM_{2.5}$ exposure that might occur under a air quality modeling scenario that simulated full attainment with the 0.065 ppm standard.

Finally, Figure S2.10 illustrates the percentage of population exposed to different levels of annual mean $PM_{2.5}$ levels in the baseline and after the implementation of the illustrative ozone attainment strategy in 2020. This strategy achieves fairly modest reductions of $PM_{2.5}$ as a co-benefit of the ozone attainment strategy. Much of this small benefit occurs among highly exposed populations and we find that prior to the implementation of this illustrative scenario, 83% of the population live in areas where $PM_{2.5}$ levels are projected to be above the lowest measured levels of the Pope study. Taken together, this information increases our confidence in the estimated mortality reductions for this rule.

While the LML of each study is important to consider when characterizing and interpreting the overall level PM-related benefits, as discussed earlier in this chapter, EPA believes that both cohort-based mortality estimates are suitable for use in air pollution health impact analyses. When estimating PM mortality impacts using risk coefficients drawn from the Laden et al. analysis of the Harvard Six Cities and the Pope et al. analysis of the American Cancer Society cohorts there are innumerable other attributes that may affect the size of the reported risk estimates—including differences in population demographics, the size of the cohort, activity patterns and particle composition among others. The LML assessment presented here provides a limited representation of one key difference between the two studies.

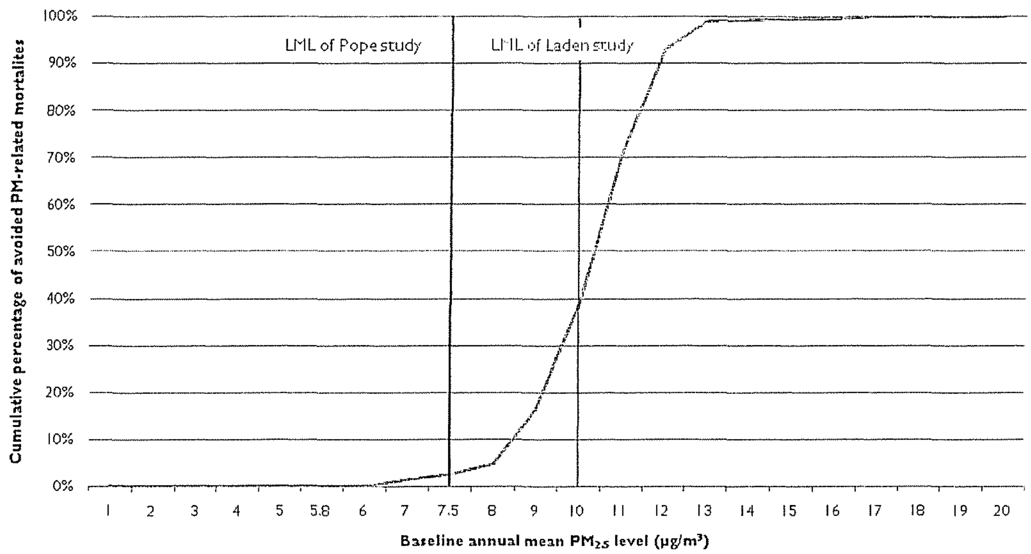
Figure S2.8: Percentage of PM-related mortalities avoided by baseline $PM_{2.5}$ air quality level



Of the total mortalities avoided:

97% occur among populations exposed to PM levels at or above the LML of the **Pope et al.** study.
62% occur among populations exposed to PM levels at or above the LML of the **Laden et al.** study.

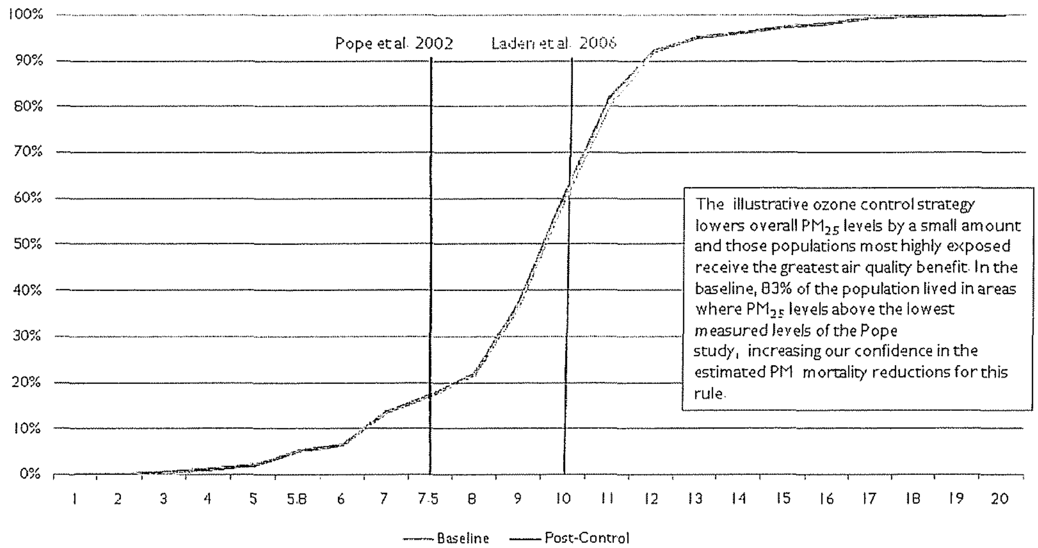
Figure S2.9: Cumulative percentage of total PM-related mortalities avoided by baseline $PM_{2.5}$ air quality level



Of the total mortalities avoided:

97% occur among populations exposed to PM levels at or above the LML of the **Pope et al.** study.
62% occur among populations exposed to PM levels at or above the LML of the **Laden et al.** study.

S2.10: Cumulative distribution of adult population at annual mean PM2.5 levels (pre- and post- policy scenario)



S2.4 Comparison of results to previous results in 2008 Ozone NAAQS RIA

The overall effect of incorporating the array of methodological changes was to increase the estimated benefits of attaining alternate ozone standards estimates presented in the 2008 Ozone NAAQS RIA. In general, the key update that had the largest effect on the valuation and the incidence results is removing the threshold from the PM concentration-response functions. Tables S2.9 and S2.10 show the total monetized benefits, costs, and net benefits for the 2008 Ozone RIA analysis and this updated analysis, respectively. Figure 6 shows a comparison of the range of net benefits estimates in this updated analysis compared to the net benefits presented in the 2008 Ozone NAAQS RIA.[11]

[11] Net benefits are total monetized benefits minus total monetized costs. Total monetized benefits include ozone health benefits, $PM_{2.5}$ health co-benefits, visibility benefits, but not other unquantified benefit categories.

Table S2.9: Total Monetized Costs with Ozone Benefits and $PM_{2.5}$ Co-Benefits in 2020 (in Billions of 2006$) [A] 2008 RIA

	Ozone Mortality Function	Reference	Total Benefits [B]		Total Costs [C]	Net Benefits	
			3%	7%	7%	3%	7%
0.075 ppm	NMMAPS and Multi-city	Bell et al. 2004	\$4.4 to \$8.5	\$4.1 to \$7.7	\$7.6 to \$8.8	\$-4.4 to \$0.9	\$-4.7 to \$0.1
		Schwartz 2005	N/A	N/A	N/A	N/A	N/A
		Huang 2005	N/A	N/A	N/A	N/A	N/A
	Meta-analysis	Bell et al. 2005	\$5.6 to \$9.7	\$5.3 to \$9.0	\$7.6 to \$8.8	\$-3.2 to \$2.1	\$-3.5 to \$1.4
		Ito et al. 2005	\$6.3 to \$10	\$5.9 to \$9.6	\$7.6 to \$8.8	\$-2.5 to \$2.7	\$-2.9 to \$2.0
		Levy et al. 2005	\$6.3 to \$10	\$6.0 to \$9.7	\$7.6 to \$8.8	\$-2.5 to \$2.8	\$-2.8 to \$2.1
0.070 ppm	NMMAPS and multi-city	Bell et al. 2004	\$8.8 to \$16	\$8.2 to \$15	\$19 to \$25	\$-16 to \$-2.8	\$-17 to \$4.1
		Schwartz 2005	N/A	N/A	N/A	N/A	N/A
		Huang 2005	N/A	N/A	N/A	N/A	N/A
	Meta-analysis	Bell et al. 2005	\$13 to \$21	\$13 to \$19	\$19 to \$25	\$-12 to \$1.5	\$-12 to \$0.2
		Ito et al. 2005	\$15 to \$23	\$15 to \$21	\$19 to \$25	\$-9.6 to \$3.8	\$-10 to \$2.5
		Levy et al. 2005	\$16 to \$23	\$15 to \$22	\$19 to \$25	\$-9.3 to 4.1	\$9.9 to \$2.7
0.065 ppm	NMMAPS and multi-city	Bell et al. 2004	\$15 to \$27	\$14 to \$24	\$32 to \$44	\$-29 to \$-5.4	\$-30 to \$-7.5
		Schwartz 2005	N/A	N/A	N/A	N/A	N/A
		Huang 2005	N/A	N/A	N/A	N/A	N/A
	Meta-analysis	Bell et al. 2005	\$22 to \$34	\$21 to \$32	\$32 to \$44	\$-22 to \$2.4	\$-23 to \$0.3
		Ito et al. 2005	\$27 to \$39	\$26 to \$36	\$32 to \$44	\$-17 to \$6.6	\$-18 to \$4.4
		Levy et al. 2005	\$27 to \$39	\$26 to \$37	\$32 to \$44	\$-17 to \$7.0	\$-18 to \$4.9

[A] All estimates rounded to two significant figures. As such, they may not sum across columns. Only includes areas required to meet the current standard by 2020; does not include San Joaquin and South Coast areas in California.

[B] Includes ozone benefits, and $PM_{2.5}$ co-benefits. Range was developed by adding the estimate from the ozone premature mortality function to estimates from the $PM_{2.5}$ premature mortality functions from Pope et al. and Laden et al. Tables exclude unquantified and nonmonetized benefits.

[C] Range reflects lower and upper bound cost estimates. Data for calculating costs at a 3% discount rate was not available for all sectors, and therefore total annualized costs at 3% are not presented here. Additionally, these estimates assume a particular trajectory of aggressive technological change. An alternative storyline might hypothesize a much less optimistic technological trajectory, with increased costs, or with decreased benefits in 2020 due to a later attainment date.

Table S2.10: Total Monetized Costs with Ozone Benefits and $PM_{2.5}$ Co-Benefits in 2020 (in Billions of 2006$) [A] Updated Analysis

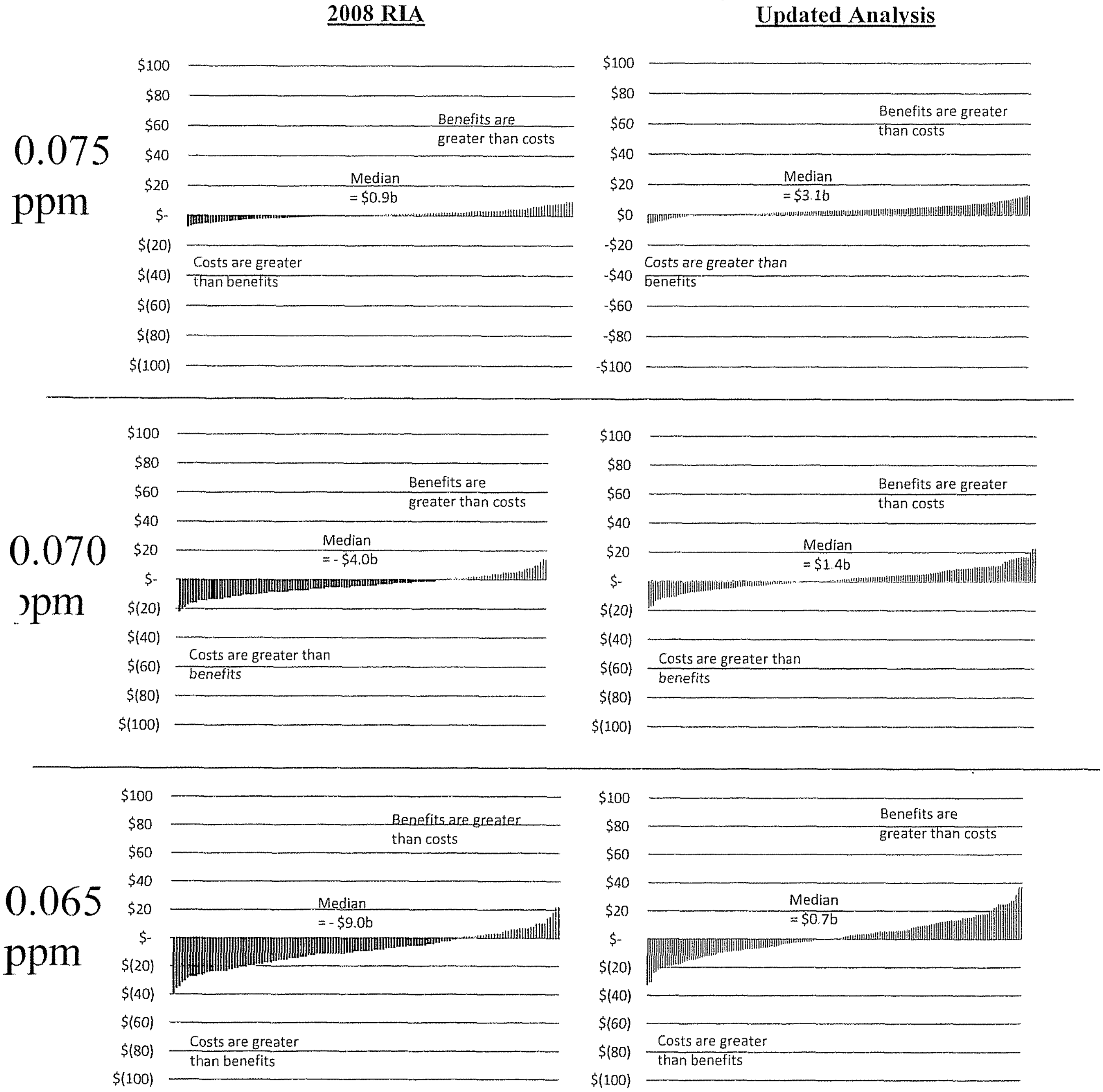
	Ozone Mortality Function	Reference	Total Benefits [B]		Total Costs [C]	Net Benefits	
			3%	7%	7%	3%	7%
0.075 ppm	NMMAPS and multi-city	Bell et al. 2004	$6.9 to $15	$6.4 to $13	$7.6 to $8.8	$-1.9 to $7.4	$-2.4 to $5.4
		Schwartz 2005	$7.2 to $16	$6.8 to $13	$7.6 to $8.8	$-1.6 to $8.4	$-2.1 to $5.4
		Huang 2005	$7.3 to $16	$6.9 to $13	$7.6 to $8.8	$-1.5 to $8.4	$-2.0 to $5.4
	Meta-analysis	Bell et al. 2005	$8.3 to $17	$7.9 to $14	$7.6 to $8.8	$-0.50 to $9.4	$-1.0 to $6.4
		Ito et al. 2005	$9.1 to $18	$8.7 to $15	$7.6 to $8.8	$0.30 to $10	$-0.20 to $7.4
		Levy et al. 2005	$9.2 to $18	$8.8 to $15	$7.6 to $8.8	$0.40 to $10	$-0.10 to $7.4
0.070 ppm	NMMAPS and multi-city	Bell et al. 2004	$13 to $29	$11 to $24	$19 to $25	$-12 to $10	$-14 to $5.0
		Schwartz 2005	$15 to $30	$12 to $25	$19 to $25	$-10 to $11	$-13 to $6.0
		Huang 2005	$15 to $30	$13 to $26	$19 to $25	$-10 to $11	$-12 to $7.0
	Meta-analysis	Bell et al. 2005	$18 to $34	$16 to $29	$19 to $25	$-7.0 to $15	$-9.0 to $10
		Ito et al. 2005	$21 to $37	$18 to $31	$19 to $25	$-4.0 to $18	$-6.0 to $12
		Levy et al. 2005	$21 to $37	$18 to $31	$19 to $25	$-4.0 to $18	$-6.0 to $12
0.065 ppm	NMMAPS and multi-city	Bell et al. 2004	$22 to $47	$19 to $40	$32 to $44	$-22 to $15	$-25 to $7.0
		Schwartz 2005	$24 to $49	$21 to $42	$32 to $44	$-20 to $17	$-23 to $9.0
		Huang 2005	$25 to $50	$22 to $42	$32 to $44	$-19 to $18	$-23 to $10
	Meta-analysis	Bell et al. 2005	$31 to $56	$27 to $48	$32 to $44	$-13 to $24	$-17 to $16
		Ito et al. 2005	$36 to $61	$32 to $53	$32 to $44	$-8.0 to $29	$-13 to $20
		Levy et al. 2005	$36 to $61	$32 to $53	$32 to $44	$-7.0 to $29	$-12 to $20

[A] All estimates rounded to two significant figures. As such, they may not sum across columns. Only includes areas required to meet the current standard by 2020; does not include San Joaquin and South Coast areas in California.

[B] Includes ozone benefits, and $PM_{2.5}$ co-benefits. Range was developed by adding the estimate from the ozone premature mortality function to estimates from the $PM_{2.5}$ premature mortality functions from Pope et al. and Laden et al. Tables exclude unquantified and nonmonetized benefits.

[C] Range reflects lower and upper bound cost estimates. Data for calculating costs at a 3% discount rate was not available for all sectors, and therefore total annualized costs at 3% are not presented here. Additionally, these estimates assume a particular trajectory of aggressive technological change. An alternative storyline might hypothesize a much less optimistic technological trajectory, with increased costs, or with decreased benefits in 2020 due to a later attainment date.

Figure S2.11: Comparison of Net Benefits in Updated Analysis to 2008 Ozone NAAQS RIA*



These graphs shows all combinations of the 6 different ozone mortality functions and assumptions, the 14 different PM mortality functions, and the 2 cost methods. These combinations do not represent a distribution.

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SECTION 3: SECONDARY OZONE NAAQS EVALUATION

1.1

1.2 Synopsis

This section contains an evaluation of the regulatory impacts associated with a distinct secondary NAAQS for ozone. The purpose of a secondary NAAQS is to protect the public welfare against the negative effects of criteria air pollutants, including decreased visibility, damage to animals, crops, vegetation, and buildings. Exposure to ozone has been associated with a wide array of vegetation and ecosystem effects, including those that damage or impair the intended use of the plant or ecosystem. Such effects are considered adverse to the public welfare. This secondary NAAQS standard for ozone is the first secondary standard to be promulgated with a form, averaging time, and level that is distinct from the health-based primary standard, apart from the PM and SO_2 regulations originally set in the early 1970s. Quantifying the costs and benefits of attaining a secondary NAAQS is an exceptionally complex task, including unresolved issues related to the RIA analysis, air quality projections, monitoring expansion, and implementation.[12] Because of these complexities as well as limited time and resources within the expedited schedule, we are limited in our ability to quantify the costs and benefits of attaining a distinct secondary NAAQS for ozone for this rule. However, we provide a semi-quantitative assessment in this analysis, including identifying which counties would have an additional requirement to reduce ozone concentrations to attain a secondary standard beyond the reductions needed to attain the primary standard, qualitative descriptions of available pollution control strategies, qualitative benefits of reducing ozone exposure on forests, crops, and ornamental plants, and maps of avoided biomass/yield loss for the currently monitor locations. The Administrator selected a secondary ozone NAAQS at a level of 13 ppm-hrs using the W126 form. Using a cumulative seasonal secondary standard (i.e., W126), we evaluated alternate standard levels at 11, 13, and 15 ppm-hours.

S2.6 Introduction

As defined by section 109(b)(2) of the Clean Air Act (CAA), the purpose of a secondary NAAQS is to protect the public welfare against any known or anticipated negative effects associated with criteria air pollutants. These welfare effects include, but are not limited to, "effects on soils, water, crops, vegetation, man-made materials, animals, wildlife, weather, visibility, and climate, damage to and deterioration of property, and hazards to transportation, as well as effects on economic values and on personal comfort and wellbeing."

The secondary NAAQS for ozone is focused on the negative effects on vegetation associated with direct ozone exposure. Exposure to ozone has been associated with a wide array

[12] These complexities are described in detail in Section S3.3.

of vegetation and ecosystem effects in the published literature (U.S. EPA, 2006). Sensitivity to ozone is highly variable across plant species, with over 65 plant species identified as "ozone-sensitive", many of which occur in state and national parks and forests.[13] These effects include those that damage or impair the intended use of the plant or ecosystem. Such effects are considered adverse to the public welfare and can include reduced growth and/or biomass production in sensitive plant species, including forest trees, reduced crop yields, visible foliar injury, reduced plant vigor (e.g., increased susceptibility to harsh weather, disease, insect pest infestation, and competition), species composition shift, and changes in ecosystems and associated ecosystem services.

Vegetation effects research has shown that seasonal air quality indices that cumulate peak-weighted hourly ozone concentrations are the best candidates for relating exposure to plant growth effects (U.S. EPA, 2006). Based on this research, the 2007 Ozone Staff Paper (hereafter, "the Staff Paper") concluded that the cumulative, seasonal index referred to as "W126" is the most appropriate index for relating vegetation response to ambient ozone exposures (U.S. EPA, 2007b). Based on additional conclusions regarding appropriate diurnal and seasonal exposure windows, the Staff Paper recommended a cumulative seasonal secondary standard, expressed as an index of the annual sum of weighted hourly concentrations (using the W126 form), set at a level in the range of 7 to 21 ppm-hours. The index would be cumulated over the 12-hour daylight window (8:00 a.m. to 8:00 p.m.) during the consecutive 3-month period during the ozone season with the maximum index value (hereafter, referred to as W126). After reviewing the recommendations in the Staff Paper, EPA's Clean Air Scientific Advisory committee (CASAC) agreed with the form of the secondary standard, but instead recommended a range of 7 to 15 ppm-hours (U.S. EPA-SAB, 2007). In January 2010, EPA's Administrator proposed a range of secondary standards based on the W126 index between 7 and 15 ppm-hrs (U.S. EPA, 2010). After reviewing the scientific evidence and public comments, the Administrator selected a secondary ozone NAAQS at a level of 13 ppm-hrs, using the W126 form, calculated as a 3-year average of annual sums.

To comply with Circular A-4 (OMB, 2003), this analysis includes the selected standard level as well as one more stringent and one less stringent alternative. Therefore, this analysis focuses on secondary standards at 13 ppm-hrs, as well as 15 ppm-hrs and 11 ppm-hrs.

S2.7 Air Quality Analysis

Ozone is a secondary pollutant formed by atmospheric reactions involving two classes of precursor compounds: nitrogen oxides (NOx) and volatile organic compounds (VOCs) (U.S. EPA,

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[13] Appendix S3A contains a list of plant species identified as "ozone-sensitive".

2007b). The W126 standard is a specific peak-weighted index that is summed over 12 hours per day during the maximum 3-month period within the ozone season and calculated as the 3-year average of the annual sums. An example of this calculation is described in more detail in Appendix S3-B of this RIA. The 3-year average provides increased stability due to large year-to-year variability. As described in the Staff Paper, using the highest PRB estimate of 0.035 ppm from Fiore et al. (2003) as a constant value would only add up to a 3-month 12-hr W126 of less than 1 ppm-hr (U.S. EPA, 2007b).

a. Ambient Monitoring Data (2007 – 2009)

The monitoring data for this analysis has been updated since the proposal. In addition to incorporating more recent monitoring data, we have also excluded monitoring data from CASTNET that cannot be used for nonattainment designations. Ozone concentrations were generally lower in 2009, and thus the 2007-2009 design values indicate fewer counties would violate the secondary standard compared to the counties shown in the proposal analysis. These monitoring data are limited to the existing monitoring network. It is important to note that nonattainment designations are likely to be based on 2008-2010 data, not 2007-2009 data. [14]

In this analysis, we considered the extent to which there is overlap between county-level air quality measured in terms of the 8-hour average form of the current standard and that measured in terms of the cumulative W126, seasonal form. Using monitoring data collected from 2007 to 2009, Table S3-1 shows the number of counties that exceed the alternate secondary standard levels in comparison to the number of counties that exceed the selected primary standard at 0.070 ppm. Figure S3-1 maps the counties that correspond with Table S3-1.

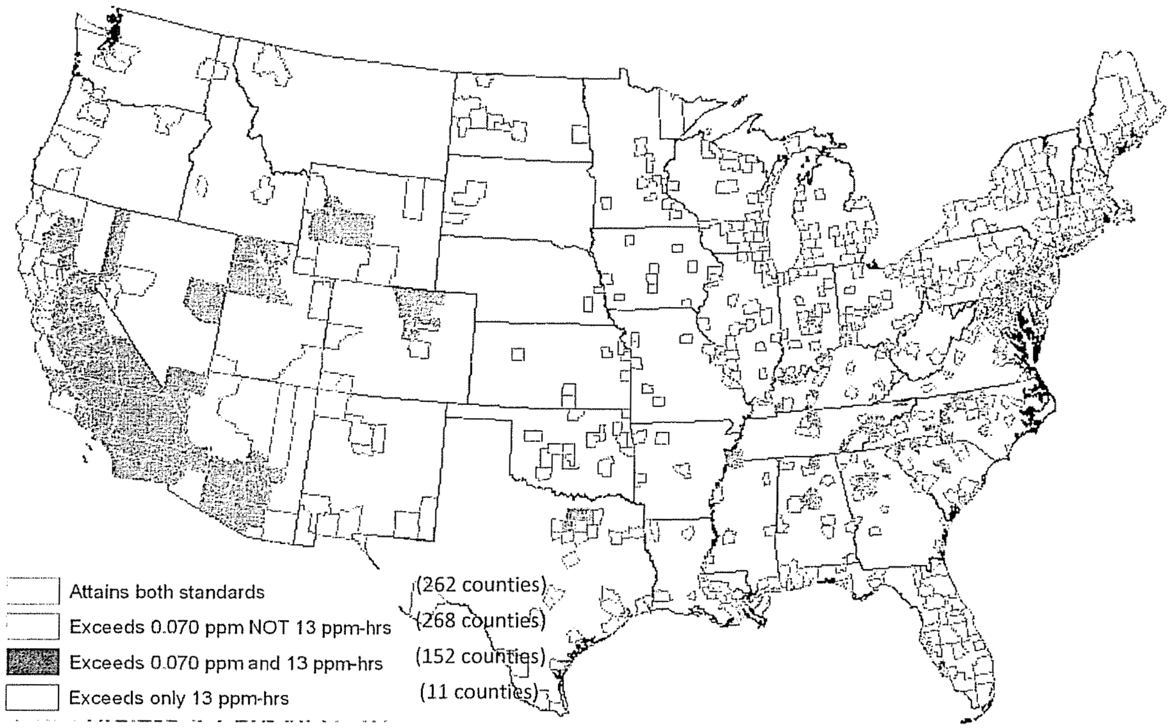
Table S3-1: Number of Counties Exceeding Alternate Secondary Standards (2007-2009 monitoring data)

Monitor Baseline	**15 ppm-hrs**	**13 ppm-hrs**	**11 ppm-hrs**
Attain primary (0.070 ppm) and secondary	270	262	257
Exceed only primary (0.070 ppm)	335	268	194
Exceed primary (0.070 ppm) and secondary	85	152	226
Exceed only secondary	3	11	16

* *As these estimates are limited to existing ozone monitoring data, there might be other non-monitored* areas after the monitoring network is expanded that would exceed the secondary standard. There are 693 currently monitored counties with sufficient data for this analysis.

[14] Monitoring data for 2010 is not yet available.

Figure S3-1: Counties exceeding Primary Standard at 0.070 ppm or Secondary Standard at 13 ppm-hours (based on 2007–2009 monitoring data)



b. Modeling Projection Data (2020)

In this analysis, we also projected W126 levels for two scenarios in 2020 developed as part of the 2008 analysis of the primary standard: the baseline scenario and the after hypothetical RIA controls scenario. The modeling methodology used to project W126 levels into the future utilizes the same approach as used to project design values of the primary standard, as described in EPA modeling guidance (U.S. EPA, 2007a). The 2020 baseline and hypothetical RIA control scenario are fully described in Chapter 3 of the 2008 Ozone NAAQS RIA (U.S. EPA, 2008a). The baseline includes current state and federal programs plus additional controls EPA estimated would be necessary to attain the previous ozone and $PM_{2.5}$ standards. For the hypothetical RIA control scenario, EPA applied additional known NOx and VOC controls in those specific geographic areas that were predicted to exceed an 0.070 ppm primary standard in 2020.[15]

Additionally, EPA estimated the counties that are projected to attain the primary standard in 2020 but would still exceed the alternate secondary standards. These data are listed in Table S3-2, and mapped in Figures S3-2 through S3-5. Because this projection approach is prefaced on

[15] It is important to note that the modeled hypothetical RIA controls did not fully attain the primary standard of 0.070 ppm, especially in Southern California, Houston, Eastern Lake Michigan, and the Northeast corridor.

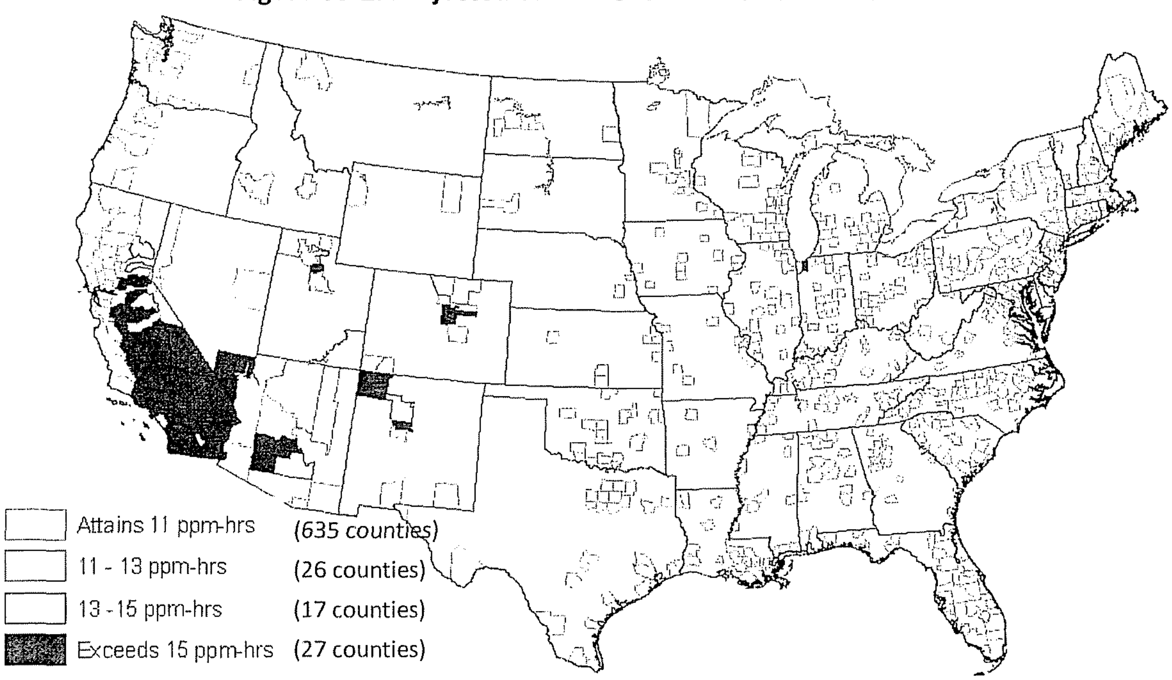
ambient data, projections can only be made for counties with ozone monitoring data for the base period. As a result, Table S3-2 and the associated figures may not capture other, currently unmonitored, locations.

Table S3-2: Number of Counties Projected to Exceed Alternate Secondary Standards in 2020*

2020 Baseline	**15 ppm-hrs**	**13 ppm-hrs**	**11 ppm-hrs**
Attain primary (0.070 ppm) and secondary	599	591	580
Exceed only primary (0.070 ppm)	79	70	55
Exceed primary (0.070 ppm) and secondary	20	29	44
Exceed only secondary	7	15	26
After Hypothetical RIA controls	**15 ppm-hrs**	**13 ppm-hrs**	**11 ppm-hrs**
Attain primary (0.070 ppm) and secondary	633	624	613
Exceed only primary (0.070 ppm)	48	41	36
Exceed primary (0.070 ppm) and secondary	17	24	29
Exceed only secondary	7	16	27

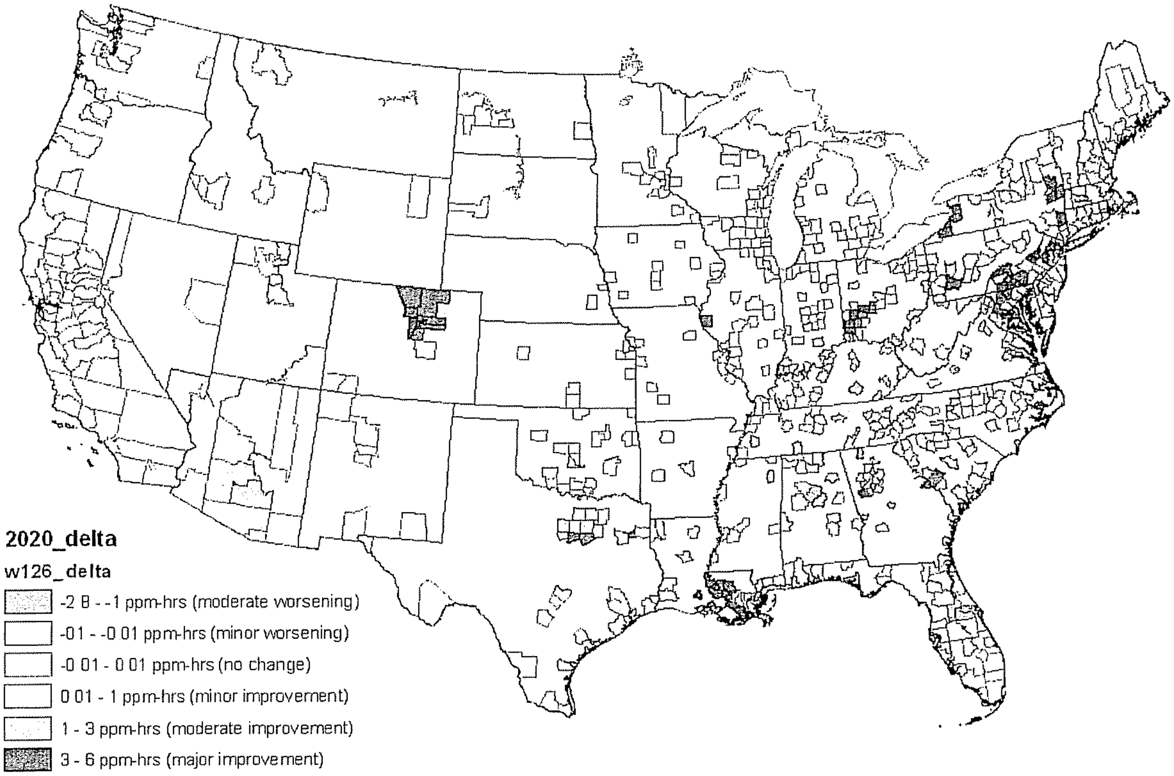
* As these projections are limited to counties with existing ozone monitoring data, there might be other non-monitored areas that would exceed the secondary standard while attaining the primary standard. There are 705 currently monitored counties with sufficient data for this analysis. It is important to note that the modeled hypothetical RIA controls did not fully attain the primary standard of 0.070 ppm, especially in Southern California, Houston, Eastern Lake Michigan, and the Northeast corridor. The number of counties that exceed only the secondary standard increase after the hypothetical RIA controls because those counties now attain the primary standard.

Figure S3-2: Projected W126 Levels in the Baseline in 2020*



* Many of the counties projected to exceed the alternate secondary standard levels are in the South Coast and San Joaquin areas of California, which are not required to attain the primary standards by 2020.

Figure S3-3: Change in Projected W126 Levels from the Hypothetical RIA controls in 2020*



*All of the counties projected to experience minor or moderate worsening due to the hypothetical RIA controls in 2020 are located in areas well below the alternate secondary standard levels. Because the hypothetical RIA controls were designed to reduce ozone concentrations in areas that exceeded the primary standard, those areas are also projected to experience minor to major improvements in W126 levels in 2020. It is important to note that the modeled hypothetical RIA controls did not fully attain the primary standard of 0.070 ppm, especially Southern California, Houston, Eastern Lake Michigan, and the Northeast corridor.

Figure S3-4: Counties Projected to Exceed the Selected Primary and Secondary Standards in the Baseline in 2020*

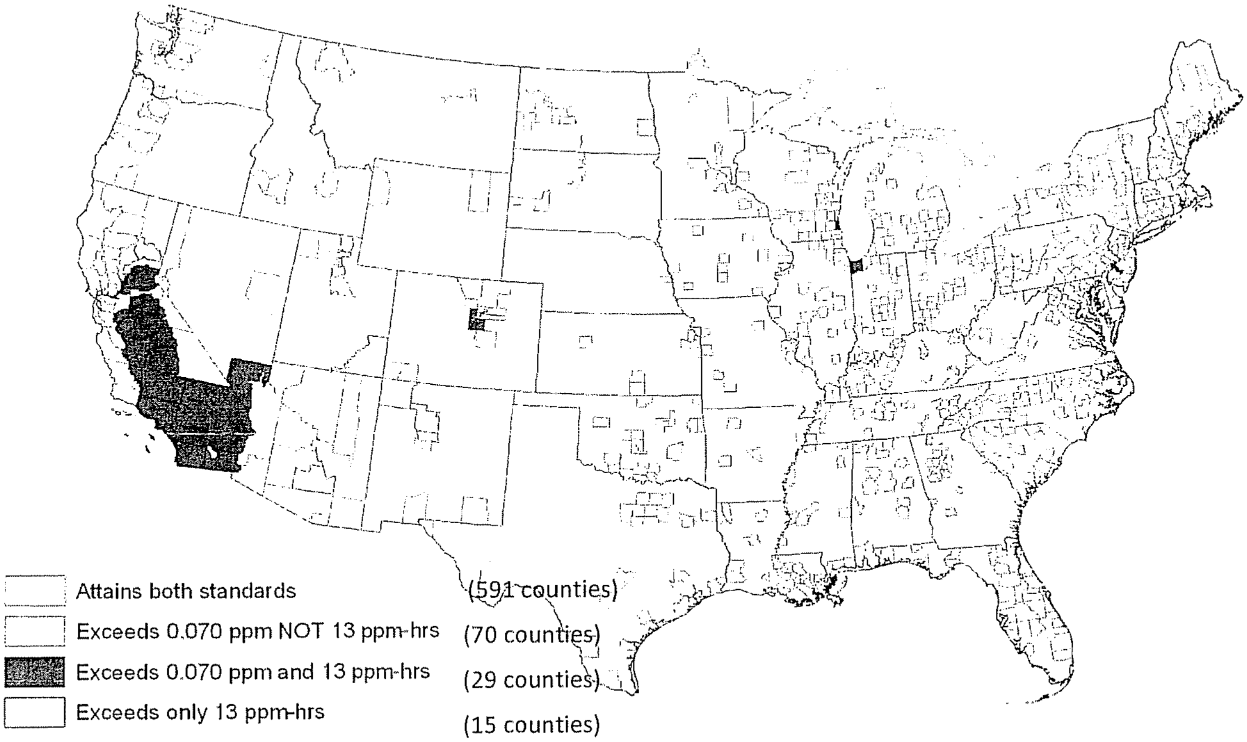
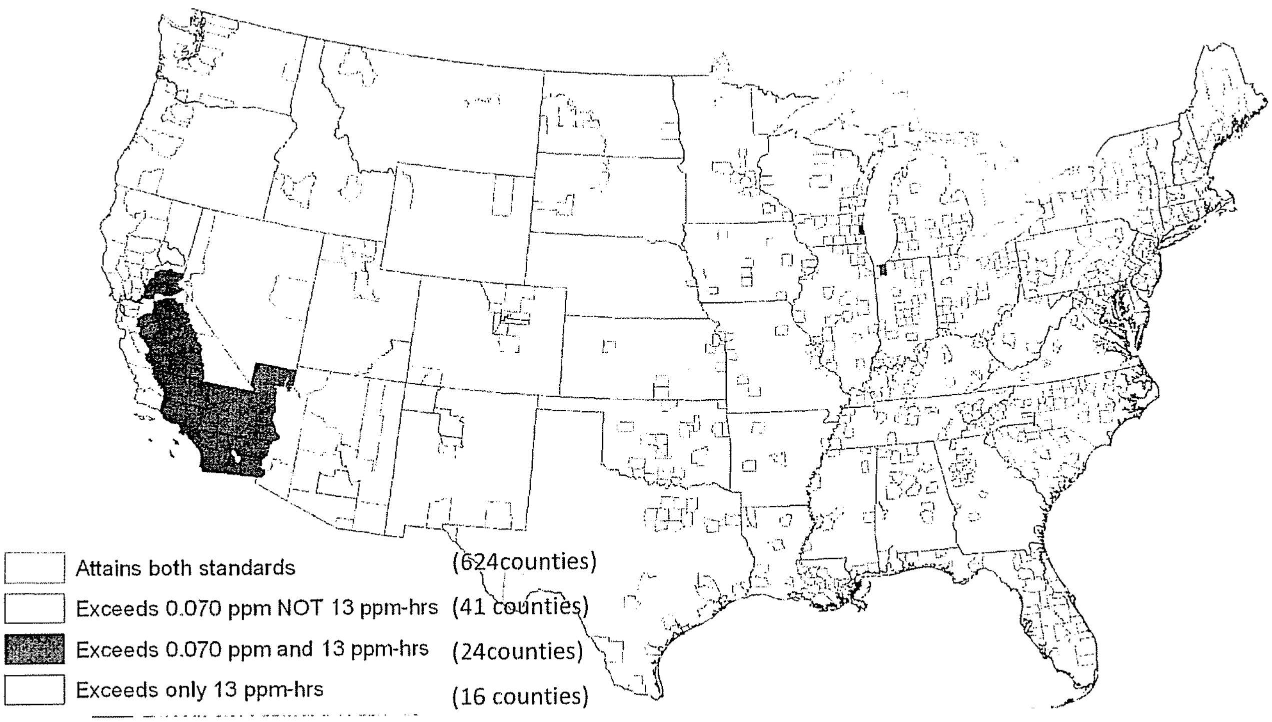


Figure S3-5: Counties Projected to Exceed the Selected Primary and Secondary Standards after Hypothetical RIA Controls in 2020*



* Many of the counties projected to exceed the secondary standard are in the South Coast and San Joaquin areas of California, which are not required to attain the primary standards by 2020. The number of counties that exceed only the secondary standard increase after the hypothetical RIA controls because those counties now attain the primary standard.

As noted above, this analysis only projected W126 levels in 2020 where ozone monitors currently exist. Due to the lack of more complete monitor coverage in many rural areas, this analysis might not be an accurate reflection of ozone concentrations in non-monitored, rural counties where sensitive vegetation, important ecosystems, or other areas of national public interest could be located. Many counties that contain high elevation, rural or remote sites tend to have flatter ozone concentration distributions. These areas may not reflect the typical urban and near-urban pattern of low morning and evening ozone concentrations with a high mid-day peak, but instead maintain relatively flat patterns with many concentrations in the mid-range (e.g., 0.05-0.09 ppm) for extended periods. Therefore, the potential for disconnect between 8-hour average and cumulative, seasonal form is greater. Additional rural, high elevation areas important for vegetation that are not currently monitored would likely experience similar ozone exposure patterns (U.S. EPA, 2007b). This is an important caveat because: (1) the biological database stresses the importance of cumulative, seasonal exposures in determining plant response; (2) plants have not been specifically tested for the importance of daily maximum 8-hour ozone concentrations in relation to plant response; and (3) the effects of attainment of a 8-hour standard in upwind urban areas on rural air quality distributions cannot be characterized with confidence due to the lack of monitoring data in rural and remote areas (U.S. EPA, 2007b).

Thus far, we have not expressly considered the question of whether it would be more difficult to attain the secondary standard than the primary or what levels of controls would be required to attain the secondary standard. Based on the existing air quality modeling from the 2008 Ozone NAAQS RIA, we have examined how W126 values might change in response to the hypothetical RIA control strategy designed to attain the primary standard. Based on projected W126 ozone levels before and after the implementation of the hypothetical RIA control strategy in 2020, there is some evidence that it may indeed be harder to attain the secondary standard in some areas. As an example, the hypothetical RIA control scenario reduces the number of counties exceeding a primary NAAQS of 0.070 ppm by about 34%; whereas the same control scenario reduces the number of counties exceeding a secondary NAAQS of 13 ppm-hours by only 9%.

The air quality modeling for the 2008 RIA focused on quantifying the impacts and costs of attaining the primary standard. Because the form of the secondary standard is calculated by summing the daily ozone concentrations over a three-month period, it is possible that mitigation strategies may be different for a secondary ozone standard than for the primary ozone standard. Initial ambient data analyses and future-year modeling suggest that it may be more difficult to attain the secondary standard in the western U.S. than in the eastern U.S for several reasons. First, ozone concentrations have less variability across days in the western U.S. Second, the meteorological parameters that generally result in lower daily ozone peaks (e.g., clouds, precipitation, frontal passages) occur less frequently in the western States. Lastly, the secondary standard may have larger implications for rural areas currently without monitors as opposed to the urban areas where the primary ozone standard is already a concern. Attainment of the secondary standard may involve more regional and national scale controls than the current local efforts to reduce peak concentrations.

S2.8 Complexities in Quantifying the Costs and Benefits of Attaining a Secondary Ozone NAAQS

Despite recent proposals, EPA has not promulgated a secondary NAAQS with a form, averaging time, and level that is distinct from the health-based primary standard, apart from the secondary NAAQS for PM and SO_2 originally set in the early 1970s. Therefore, prior to this rule, EPA has not conducted a regulatory analysis of a secondary NAAQS. Quantifying the costs and benefits associated with attaining a distinct secondary standard is an exceptionally complex task. We describe these complexities in detail below.

Because of these complexities as well as limited time, resources, and available data within the expedited schedule, we are limited in our ability to quantify the costs and benefits of attaining a distinct secondary NAAQS for ozone. However, we recognize that the regulatory impacts associated with this standard are of interest to many. Therefore, we provide a semi-quantitative assessment in this analysis, including identifying which counties would have an additional requirement to reduce ozone concentrations to attain a secondary standard beyond the reductions needed to attain the primary standard, qualitative descriptions of available pollution control strategies, qualitative benefits of reducing ozone exposure on forests, crops, and ornamental plants, and maps of avoided biomass/yield loss for the currently monitor locations.

S4.3.1 RIA complexities

There are two unresolved RIA issues that complicate a fully quantitative analysis of a secondary standard for ozone. First, it is unclear when an area would need to attain a secondary standard, which makes it difficult to choose an appropriate analysis year for the RIA. Whereas attainment dates for the primary NAAQS are explicitly designated in the CAA, the attainment dates for the secondary NAAQS are required "as expeditiously as practicable" after the nonattainment designation (42 USC §7502(a)(2)). As air quality improves over time from regulations already promulgated, an area would not need as many emission reductions for a later analysis year as the area would need for an earlier analysis year. Assuming an analysis year of 2020 as was assumed for the primary standard would substantially overestimate the costs and benefits associated with attaining the secondary standard. Even if we determined that it was most appropriate to choose an analysis year of 2030, 2040, or even 2050, we are limited to the available modeling data for

2020. Therefore, the choice of an analysis year has a significant effect on the magnitude of the costs and benefits of attaining a secondary standard.

Second, it is unclear whether it is appropriate to include emission reductions that occur as a result of implementing the primary standard in the baseline for the analysis of the secondary standard. This is a critical decision, as it would either improperly ascribe the costs and benefits of the primary NAAQS to the secondary NAAQS or it would violate the requirements of OMB's Circular A-4 to only include promulgated rules in the regulatory baseline. Most of the areas that exceed the secondary standard also exceed the primary standard. As shown in Table S3-2, the hypothetical RIA controls designed to attain the primary standard also reduce the number of counties that exceed the secondary standard. Furthermore, it is likely that full attainment of the primary standard in areas like Southern California or Eastern Lake Michigan would further reduce the number of counties that exceed the secondary standard.

S4.3.2 Air quality data complexities

In addition to unresolved RIA issues, we have limited information available from the available air quality modeling data to inform a secondary standard analysis. As shown in Table S3-2, several counties are projected to not to attain the alternate secondary standard levels in 2020 even after applying controls for the hypothetical RIA control scenario. Estimating the amount of additional reductions (extrapolated tons) needed to attain a secondary standard would require a better understanding of the relationship between emissions reductions and the W126 metric. Our long experience with the primary standard allows us to use simple impact ratios with some confidence in the extrapolated cost analysis for the primary standard. At present, it is not possible to reproduce a similar analysis for the secondary standard. Without the amount of emission reductions required to attain, it is not possible to identify the pollution control measures or the associated costs.

S4.3.3 Monitoring complexities

As described in Section S3.2, the current monitoring network was not designed to adequately reflect W126 levels in many areas of the country, especially the rural west. Therefore, we cannot extrapolate the concentrations beyond the currently monitored counties, and we cannot quantify the potential ozone vegetation impacts in many areas of high ecological value, such as National Parks, wilderness areas, or other areas of sensitive national vegetation and ecosystems. We note, however, that even if additional monitors were deployed, it may prove challenging to completely characterize ozone concentrations in some locations that have not traditionally been areas of focus for ozone network deployment.

S4.3.4 Implementation complexities

Other complexities related to implementation have yet to be resolved. For example, EPA has not yet issued guidance for States to recommend boundaries of nonattainment areas for a seasonal secondary ozone standard. The CAA requires that nonattainment areas include areas that violate the standard as well as nearby areas that contribute to a violation. Based on modeled projections of W126 levels in 2020, many of the areas that would exceed the secondary standard without exceeding the primary standard are located in rural areas. Many of those areas lack significant emission sources of ozone precursors within the area, so the cause of the violation is likely due to longer-range transport of ozone and precursors. Analyses of the origin of the contributing emissions in such areas are unavailable. It is unclear what the appropriate boundaries for these projected nonattainment areas would need to be such that the nearby sources that are contributing to the violation are included but the contributing sources that are not "nearby" are excluded. It is important to note that EPA intends to designate nonattainment areas for the 2011 secondary NAAQS for ozone in 2013 based on the recent air quality monitoring data at that time, not on the 2020 projected levels.

In addition, EPA is in the process of developing rules on how States should implement the secondary ozone standard. One issue that must be addressed from a legal stand point is whether planning for nonattainment areas must be done under the more prescriptive subpart 2 requirements of the CAA, which would require classification (as marginal, moderate, serious, etc) or under the less prescriptive subpart 1 of the CAA. For areas classified under subpart 2, there are certain specific control measures that States must adopt. The CAA language is unclear as to whether subpart 2 applies to nonattainment areas under a secondary standard (although it appears to be clear that the maximum statutory attainment dates in the classification table only apply to the "primary" standard). Therefore, it is unclear whether it is appropriate to include the subpart 2 mandatory measures in this analysis. The agency has never faced this issue in the past for ozone, so this will be addressed in the upcoming rules. Since most, if not all, of the areas that might be designated as nonattainment for the secondary standard would also be in nonattainment for the primary standard, it is unclear whether States would need to adopt additional control measures to attain the secondary standard.

S2.9 Pollution Control Strategies

The pollution control measures that might be adopted to attain the secondary standard overlap substantially with the control measures used to attain the primary standard. The air quality analysis showed that most areas that exceed the secondary standard would also exceed the primary standard. If there are areas that would need additional emission reductions to attain the secondary standard, we have included brief descriptions of some available NOx and VOC controls below.

S3.4.1 Point Source Control Measures

For electrical generating units (EGUs), the primary measures for controlling NOx emissions are selective catalytic reduction (SCR), selective noncatalytic reduction (SNCR), and low-NOx burners (LNB). SCR or SNCR can be applied along with a combustion control to further reduce NOx emissions.

Several types of NOx control technologies exist for nonEGU point sources: SCR, SNCR, natural gas reburn (NGR), coal reburn, and LNB. In some cases, LNB accompanied by flue gas recirculation (FGR) is applicable, such as when fuel-borne NOx emissions are expected to be of greater importance than thermal NOx emissions. When circumstances suggest that combustion controls do not make sense as a control technology (e.g., sintering processes, coke oven batteries, sulfur recovery plants), SNCR or SCR may be an appropriate choice. Finally, SCR can be applied along with a combustion control such as LNB with overfire air (OFA) to further reduce NOx emissions. All of these control measures are available for application on industrial boilers and other non-EGU point sources.

Besides industrial boilers, other nonEGU point source categories that could install controls include petroleum refineries, kraft pulp mills, cement kilns, stationary internal combustion engines, glass manufacturing, combustion turbines, and incinerators. NOx control measures available for petroleum refineries, particularly process heaters at these plants, include LNB, SNCR, FGR, and SCR along with combinations of these technologies. NOx control measures available for kraft pulp mills include those available to industrial boilers, namely LNB, SCR, SNCR, along with water injection (WI). NOx control measures available for cement kilns include those available to industrial boilers, namely LNB, SCR, and SNCR. Non-selective catalytic reduction (NSCR) can be used on stationary internal combustion engines. OXY-firing, a technique to modify combustion at glass manufacturing plants, can be used to reduce NOx at such plants. LNB, SCR, and SCR + steam injection (SI) are available measures for combustion turbines. Finally, SNCR is an available control technology at incinerators.

VOC controls include a variety of nonEGU point sources as defined in the emissions inventory. The first control is permanent total enclosure (PTE) applied to paper and web coating operations and fabric operations, and incinerators or thermal oxidizers applied to wood products and marine surface coating operations. A PTE confines VOC emissions to a particular area where can be destroyed or used in a way that limits emissions to the outside atmosphere, and an incinerator or thermal oxidizer destroys VOC emissions through exposure to high temperatures

(2,000 degrees Fahrenheit or higher). The second control is petroleum and solvent evaporation applied to printing and publishing sources as well as to surface coating operations.

S3.4.2 Area Source Control Measures

There are three control measures available for NOx emissions from area sources. The first is RACT (reasonably available control technology) to 25 tpy (LNB). This control is the addition of a low NOx burner to reduce NOx emissions. This control applies to industrial oil, natural gas, and coal combustion sources. The second control is water heaters plus LNB space heaters. This control is based on the installation of low-NOx space heaters and water heaters in commercial and institutional sources for the reduction of NOx emissions. The third control is switching to low sulfur fuel for residential home heating. This control is primarily designed to reduce sulfur dioxide, but has a co-benefit of reducing NOx.

An available control to reduce VOC emissions from area sources is CARB Long-Term Limits. This control, which represents controls available in VOC rules promulgated by the California Air Resources Board, applies to commercial solvents and commercial adhesives, and depends on future technological innovation and market incentive methods to achieve emission reductions. The next most frequently applied control was the use of low or no VOC materials for graphic art source categories. The South Coast Air District's SCAQMD Rule 1168 control applies to wood furniture and solvent source categories sets limits for adhesive and sealant VOC content. The OTC solvent cleaning rule control establishes hardware and operating requirements for specified vapor cleaning machines, as well as solvent volatility limits and operating practices for cold cleaners. The Low Pressure/Vacuum Relief Valve control measure is the addition of low pressure/vacuum (LP/V) relief valves to gasoline storage tanks at service stations with Stage II control systems. LP/V relief valves prevent breathing emissions from gasoline storage tank vent pipes. SCAQMD Limits control establishes VOC content limits for metal coatings along with application procedures and equipment requirements. Switching to Emulsified Asphalts control is a generic control measure replacing VOC-containing cutback asphalt with VOC-free emulsified asphalt. The equipment and maintenance control measure applies to oil and natural gas production. The Reformulation—FIP Rule control measure intends to reach the VOC limits by switching to and/or encouraging the use of low-VOC pesticides and better Integrated Pest Management (IPM) practices.

S3.4.3 Mobile Source Control Measures

The NOx control measures available to onroad mobile sources include retrofits of diesel engines, reduction of long duration heavy duty truck idling, continuous inspection and maintenance programs and commuter programs. For nonroad sources, retrofits of diesel engines and engine rebuilds are available. The VOC control measures available to onroad and nonroad mobile sources include the listed controls for NOx plus reduction of Reid vapor pressure in gasoline engines.

S3.4.4 Control Measures beyond the Identified Control Measures Database

Below is a list of controls beyond those in our identified control measures database that are under development and not widely available as yet. There are major uncertainties associated with each of these measures.

- *Enhanced LDAR for Fugitive Leaks: This control measure is a more stringent program to reduce leaks of fugitive VOC emissions from chemical plants and refineries that presumes that an existing LDAR program already is in operation.*
- *Flare Gas Recovery: This control measure is a condenser that can recover 98 percent of the VOC emitted by flares that emit 20 tons per year or more of the pollutant.*
- *Cooling Towers: This control measure is continuous monitoring of VOC from the cooling water return to a level of 10 ppb. This monitoring is accomplished by using a continuous flow monitor at the inlet to each cooling tower. There is not a general estimate of CE for this measure; one is to apply a continuous flow monitor until VOC emissions have reached a level of 1.7 tons/year for a given cooling tower.*[16]
- *Wastewater Drains and Separators: This control measure includes an inspection and maintenance program to reduce VOC emissions from wastewater drains and water seals on drains. This measure is a more stringent version of measures that underlie existing NESHAP requirements for such sources.*
- *Work Practices or Use of Low VOC Coatings: The control measure is either application of work practices (e.g., storing VOC-containing cleaning materials in closed containers, minimizing spills) or using coatings that have much lower VOC content. These measures, which are of relatively low cost compared to other VOC area source controls, can apply to a variety of processes, both for non-EGU point and area sources, in different industries and is defined in the proposed control techniques guidelines (CTG) for paper, film and foil coatings, metal furniture coatings, and large appliance coatings published by the US EPA in July 2007.*[17] *The estimated CE expected to be achieved by either of these control measures is 90 percent.*

[16] Bay Area Air Quality Management District (BAAQMD). Proposed Revision of Regulation 8, Rule 8: Wastewater Collection Systems. Staff Report, March 17, 2004.

[17] U.S. Environmental Protection Agency. Consumer and Commercial Products: Control Techniques Guidelines in Lieu of Regulations for Paper, Film, and Foil Coatings; Metal Furniture Coatings; and Large Appliance Coatings. 40 CFR 59. July 10, 2007. Available on the Internet at http://www.epa.gov/ttncaaa1/t1/fr_notices/ctg_ccp092807.pdf. It should be noted that this CTG became final in October 2007.

S2.10 Benefits of Reducing Ozone Effects on Vegetation and Ecosystems[18]

Air pollution can affect the environment and affect ecological systems, leading to changes in the ecological community and influencing the diversity, health, and vigor of individual species (U.S. EPA, 2006). Ozone causes discernible injury to a wide array of vegetation (U.S. EPA, 2006; Fox and Mickler, 1996). Sensitivity to ozone is highly variable across plant species, with over 65 plant species identified as "ozone-sensitive", many of which occur in state and national parks and forests.[19] In terms of forest productivity and ecosystem diversity, ozone may be the pollutant with the greatest potential for regional-scale forest impacts (U.S. EPA, 2006). Studies have demonstrated repeatedly that ozone concentrations commonly observed in polluted areas can have substantial impacts on plant function (De Steiguer et al., 1990; Pye, 1988).

When ozone is present in the air, it can enter the leaves of plants, where it can cause significant cellular damage. Like carbon dioxide (CO_2) and other gaseous substances, ozone enters plant tissues primarily through the stomata in leaves in a process called "uptake" (Winner and Atkinson, 1986). Once sufficient levels of ozone (a highly reactive substance), or its reaction products, reaches the interior of plant cells, it can inhibit or damage essential cellular components and functions, including enzyme activities, lipids, and cellular membranes, disrupting the plant's osmotic (i.e., water) balance and energy utilization patterns (U.S. EPA, 2006; Tingey and Taylor, 1982). With fewer resources available, the plant reallocates existing resources away from root growth and storage, above ground growth or yield, and reproductive processes, toward leaf repair and maintenance, leading to reduced growth and/or reproduction. Studies have shown that plants stressed in these ways may exhibit a general loss of vigor, which can lead to secondary impacts that modify plants' responses to other environmental factors. Specifically, plants may become more sensitive to other air pollutants, or more susceptible to disease, pest infestation, harsh weather (e.g., drought, frost) and other environmental stresses, which can all produce a loss in plant vigor in ozone-sensitive species that over time may lead to premature plant death. Furthermore, there is evidence that ozone can interfere with the formation of mycorrhiza, essential symbiotic fungi associated with the roots of most terrestrial plants, by reducing the amount of carbon available for transfer from the host to the symbiont (U.S. EPA, 2006).

This ozone damage may or may not be accompanied by visible injury on leaves, and likewise, visible foliar injury may or may not be a symptom of the other types of plant damage described above. Foliar injury is usually the first visible sign of injury to plants from ozone exposure and indicates impaired physiological processes in the leaves (Grulke, 2003). When visible

[18] It is important to note that these vegetation benefits are contingent upon the secondary standard being the controlling standard. In other words, if the primary standard is controlling in all areas, there would not be any additional vegetation benefits beyond those due to the primary standard.

[19] Appendix S3A contains a list of plant species identified as "ozone-sensitive".

injury is present, it is commonly manifested as chlorotic or necrotic spots, and/or increased leaf senescence (accelerated leaf aging). Visible foliar injury reduces the aesthetic value of ornamental vegetation and trees in urban landscapes and negatively affects scenic vistas in protected natural areas.

Ozone can produce both acute and chronic injury in sensitive species depending on the concentration level and the duration of the exposure. Ozone effects also tend to accumulate over the growing season of the plant, so that even lower concentrations experienced for a longer duration have the potential to create chronic stress on sensitive vegetation. Not all plants, however, are equally sensitive to ozone. Much of the variation in sensitivity between individual plants or whole species is related to the plant's ability to regulate the extent of gas exchange via leaf stomata (e.g., avoidance of ozone uptake through closure of stomata) and the relative ability of species to detoxify ozone-generated reactive oxygen free radicals (U.S. EPA, 2006; Winner, 1994). After injuries have occurred, plants may be capable of repairing the damage to a limited extent (U.S. EPA, 2006). Because of the differing sensitivities among plants to ozone, ozone pollution can also exert a selective pressure that leads to changes in plant community composition. Given the range of plant sensitivities and the fact that numerous other environmental factors modify plant uptake and response to ozone, it is not possible to identify threshold values above which ozone is consistently toxic for all plants.

Because plants are at the base of the food web in many ecosystems, changes to the plant community can affect associated organisms and ecosystems (including the suitability of habitats that support threatened or endangered species and below ground organisms living in the root zone). Ozone impacts at the community and ecosystem level vary widely depending upon numerous factors, including concentration and temporal variation of tropospheric ozone, species composition, soil properties and climatic factors (U.S. EPA, 2006). In most instances, responses to chronic or recurrent exposure in forested ecosystems are subtle and not observable for many years. These injuries can cause stand-level forest decline in sensitive ecosystems (U.S. EPA, 2006, McBride et al., 1985; Miller et al., 1982). It is not yet possible to predict ecosystem responses to ozone with certainty; however, considerable knowledge of potential ecosystem responses is available through long-term observations in highly damaged forests in the U.S. (U.S EPA, 2006).

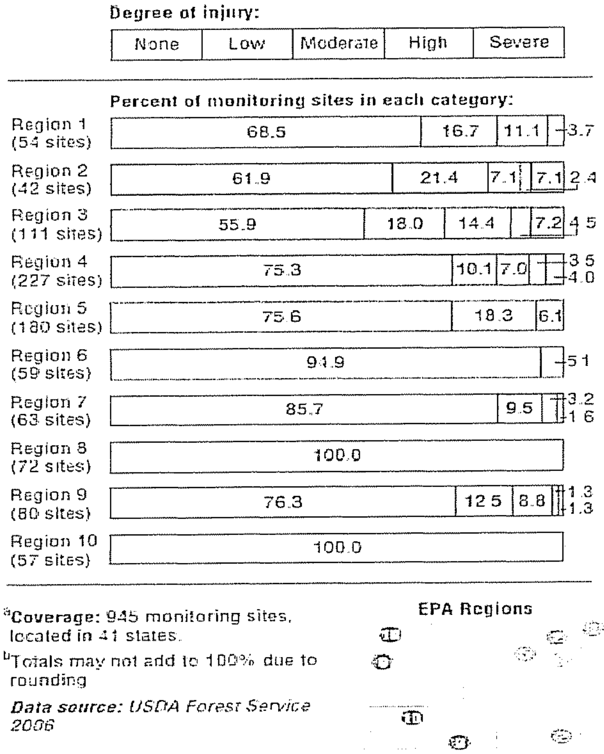
a. Ozone Effects on Forests

Ozone has been shown in numerous studies to have a strong, negative effect on the health of a variety of commercial and ecologically important forest tree species throughout the U.S. (U.S. EPA, 2007b). In the U.S., this data comes from the U.S. Department of Agriculture (USDA) Forest Service Forest Inventory and Analysis (FIA) program. As part of its Phase 3 program (formerly known as Forest Health Monitoring), FIA looks for visible foliar injury of ozone-sensitive forest plant species at each ground monitoring site across the country (excluding woodlots and urban trees) that meets certain minimum criteria. Because ozone injury is cumulative over the course of the growing season, examinations are conducted in July and August, when ozone concentrations and associated injury are typically highest.

Monitoring of ozone injury to plants by the U.S. Forest Service has expanded over the last 15 years from monitoring sites in 10 states in 1994 to nearly 1,000 monitoring sites in 41 states in 2002. Since 2002, the monitoring program has further expanded to 1,130 monitoring sites in 45 states. Figure S3-6 shows the results of this monitoring program for the year 2002 broken down by U.S. EPA Regions.[20] Figure S3-7 identifies the counties that were included in Figure S3-6, and provides the county-level data regarding the presence or absence of ozone-related injury. As shown in Figure S3-7, large geographic areas of EPA Regions 6, 8, and 10 were not included in the assessment. Ozone damage to forest plants is classified using a subjective five-category biosite index based on expert opinion, but designed to be equivalent from site to site. Ranges of biosite values translate to no injury, low or moderate foliar injury (visible foliar injury to highly sensitive or moderately sensitive plants, respectively), and high or severe foliar injury, which would be expected to result in tree-level or ecosystem-level responses, respectively (U.S. EPA, 2006; Coulston, 2004). The highest percentages of observed high and severe foliar injury, which are most likely to be associated with tree or ecosystem-level responses, are primarily found in the Mid-Atlantic and Southeast regions. While the assessment showed considerable regional variation in ozone injury, this assessment targeted different ozone-sensitive species in different parts of the country with varying ozone sensitivity, which contributes to the apparent regional differences. It is important to note that ozone can have other, more significant impacts on forest plants (e.g. reduced biomass growth in trees) prior to showing signs of visible foliar injury (U.S. EPA, 2006).

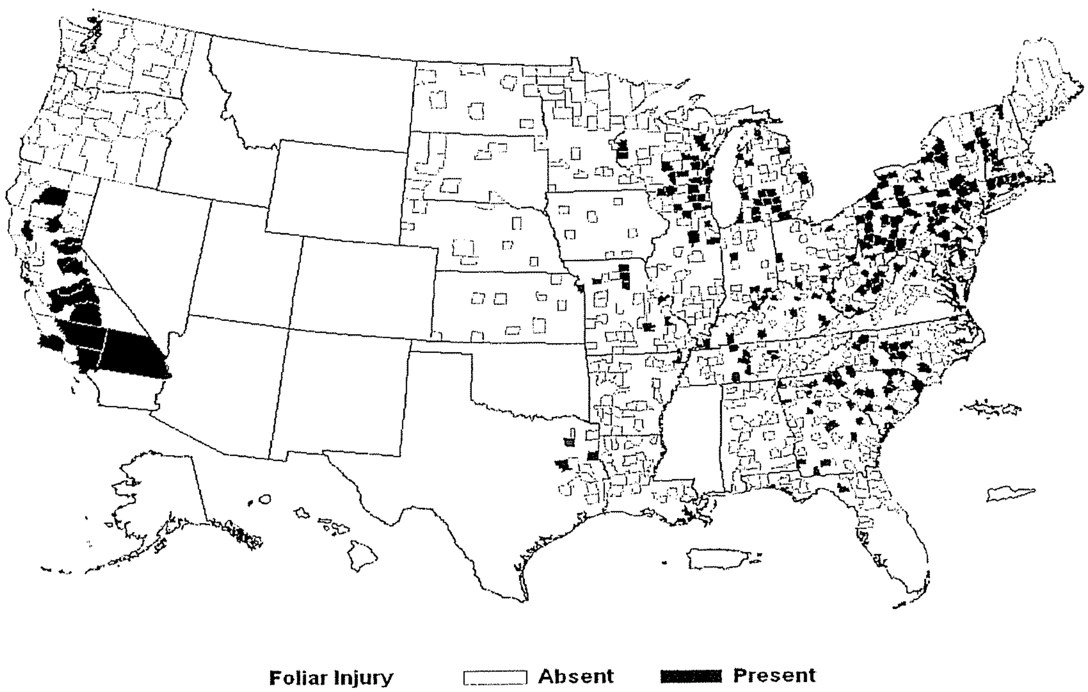
[20] The data are based on averages of all observations collected in 2002, which is the last year for which data are publicly available. For more information, please consult EPA's 2008 Report on the Environment (U.S. EPA, 2008d).

Figure S3-6: Visible Foliar Injury to Forest Plants from Ozone in U.S. by EPA Regions, 2002[a, b, c]



[c] ***Degree of Injury:*** These categories reflect a subjective index based on expert opinion. Ozone can have other, more significant impacts on forest plants (e.g. reduced biomass growth in trees) prior to showing signs of visible foliar injury.

Figure S3-7: Presence and Absence of Visible Foliar Injury, as measured by U.S. Forest Service, 2002 (U.S. EPA, 2007)

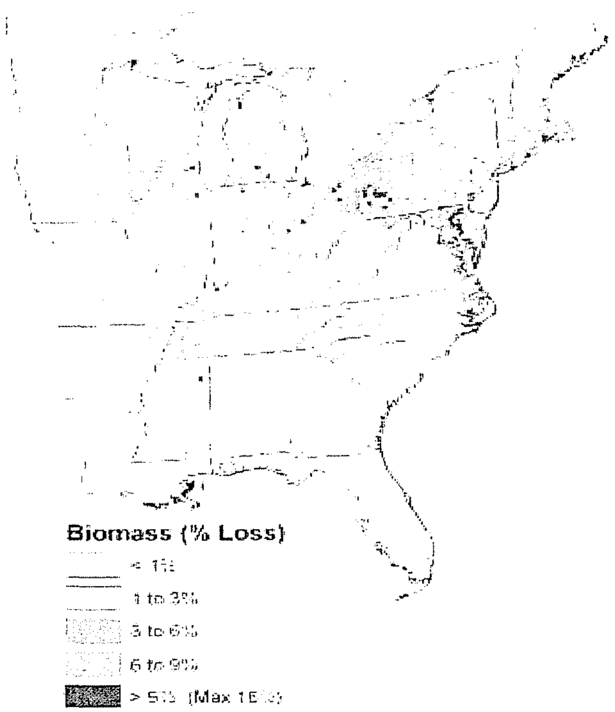


Assessing the impact of ground-level ozone on forests in the U.S involves understanding the risks to sensitive tree species from ambient ozone concentrations and accounting for the prevalence of those species within the forest. As a way to quantify the risks to particular plants from ground-level ozone, scientists have developed ozone-exposure/tree-response functions by exposing tree seedlings to different ozone levels and measuring reductions in growth as "biomass loss." Typically, seedlings are used because they are easy to manipulate and measure their growth loss from ozone pollution. The mechanisms of susceptibility to ozone within the leaves of seedlings and mature trees are identical, and the decreases predicted using the seedlings should be related to the decrease in overall plant fitness for mature trees, but the magnitude of the effect may be higher or lower depending on the tree species (Chappelka and Samuelson, 1998). In areas where certain ozone-sensitive species dominate the forest community, the biomass loss from ozone can be significant. Experts have identified 2% annual biomass loss as a level of concern, which would cause long term ecological harm as the short-term negative effects on seedlings compound to affect long-term forest health (Heck and Cowling, 1997).

Ozone damage to the plants including the trees and understory in a forest can affect the ability of the forest to sustain suitable habitat for associated species particularly threatened and endangered species that have existence value – a nonuse ecosystem service - for the public. Similarly, damage to trees and the loss of biomass can affect the forest's provisioning services in the form of timber for various commercial uses. In addition, ozone can cause discoloration of leaves and more rapid senescence (early shedding of leaves), which could negatively affect fall-color tourism because the fall foliage would be less available or less attractive. Beyond the aesthetic damage to fall color vistas, forests provide the public with many other recreational and educational services that may be impacted by reduced forest health including hiking, wildlife viewing (including bird watching), camping, picnicking, and hunting. Another potential effect of biomass loss in forests is the subsequent loss of climate regulation service in the form of reduced ability to sequester carbon and alteration of hydrologic cycles.

Some of the common tree species in the United States that are sensitive to ozone are black cherry (*Prunus serotina*), tulip-poplar (*Liriodendron tulipifera)*, and eastern white pine (*Pinus strobus)*. Ozone-exposure/tree-response functions have been developed for each of these tree species, as well as for aspen (*Populus tremuliodes*), and ponderosa pine (*Pinus ponderosa*) (U.S. EPA, 2007b). Other common tree species, such as oak (*Quercus* spp.*)* and hickory (*Carya* spp.), have not been studied for ozone sensitivity. Consequently, with knowledge of the range of sensitive species and the level of ozone at particular locations, it is possible to estimate the percentage of biomass loss for each species across their range. As shown in Figure S3-8, current ambient levels of ozone are associated with significant biomass loss across large geographic areas (U.S. EPA, 2009b). However, this information is unavailable for a future analysis year or incremental to a specified control strategy.

Figure S3-8: Estimated Biomass Loss for Black Cherry, Yellow Poplar, Sugar Maple, Eastern White Pine, Virginia Pine, Red Maple, and Quaking Aspen due to Ozone Exposure, 2006-2008 (U.S. EPA, 2009b)*



*This map does not include other tree species that are potentially sensitive to ozone.

According to the Staff Paper, the scientific consensus is that there is no threshold for exposures that cause effects on vegetation (Heck and Cowling 1997, U.S. EPA 2006). It is important to note that biomass loss in tree seedlings is not intended to be a surrogate for expected biomass loss in mature trees of the same species. Studies indicate that mature trees can be more or less sensitive than seedlings depending on the species. Sources of uncertainty include the ozone-exposure/plant-response functions, the tree abundance, and other factors (e.g., soil moisture). Although these factors were not considered in this assessment, they can affect ozone damage (Chappelka and Samuelson, 1998). EPA concluded in the Ozone Criteria Document that significant interactions with acid rain are unlikely (U.S. EPA, 2006).

Since the proposal, we have expanded the analysis of qualitative assessment of ozone impacts on forests. In this analysis, we include quantitative estimates of the tree biomass loss avoided by the primary and secondary standards across the range of the species. In this analysis, we estimate the biomass loss avoided for 6 tree species (i.e., ponderosa pine, red alder, black cherry, quaking aspen, yellow (tulip) poplar, and Virginia pine) in the continental U.S. These species were selected because they met two criteria: (1) the Staff Paper provided a W126-derived exposure-response function, and (2) the Staff Paper listed the species as an ozone-sensitive plant species (U.S. EPA, 2007b). To estimate the biomass loss avoided, we simply used the projected W126 design values in the exposure-response functions and subtracted the difference in biomass loss between the baseline and hypothetical RIA control scenarios. For mapping purposes, we assume that the W126 design value is representative of the W126 levels in the county. We then overlaid a map of the species range to focus on those areas where the species is likely to grow.[21] Though each map shows the geographical range for a species, it does not presume that an individual of that species would be found at every point within its range. Due to uncertainties in extrapolating W126 values, we have confined this analysis to the currently monitored counties. To calculated biomass loss associated with the secondary standard, we simply rolled back the W126 value in only the violating county to just attain the selected secondary standard.

Table S3-6 shows the exposure-response functions used to generate the tree maps. A full list of ozone-sensitive plant species from the Staff Paper is provided in Appendix S3A of this RIA. Figures S3-9 through S3-20 map the biomass loss avoided for each of the selected tree species by the hypothetical RIA controls for the primary standard and by the rollback to the secondary standard. It is important to note that the modeled hypothetical RIA controls did not fully attain the primary standard of 0.070 ppm, so this map underestimates the biomass loss avoided in several areas, especially Southern California, Houston, Eastern Lake Michigan, and the Northeast corridor. It is also important to note that the control strategy is likely to reduce W126 levels over a broader geographic area than just the violating county, so this map underestimates regional biomass loss avoided. Because we deliberately chose assumptions that underestimate tree biomass loss avoided, we have minimized potential uncertainty, and we have high confidence that the benefits are at least as high as those shown in the maps. Due to time and resource limitations, we were unable to monetize the benefits associated with avoiding tree biomass loss in this analysis. As mentioned above, these tree species provide several valuable ecosystem services, including timber, recreational/tourism, existence value, and climate and hydrologic regulation.

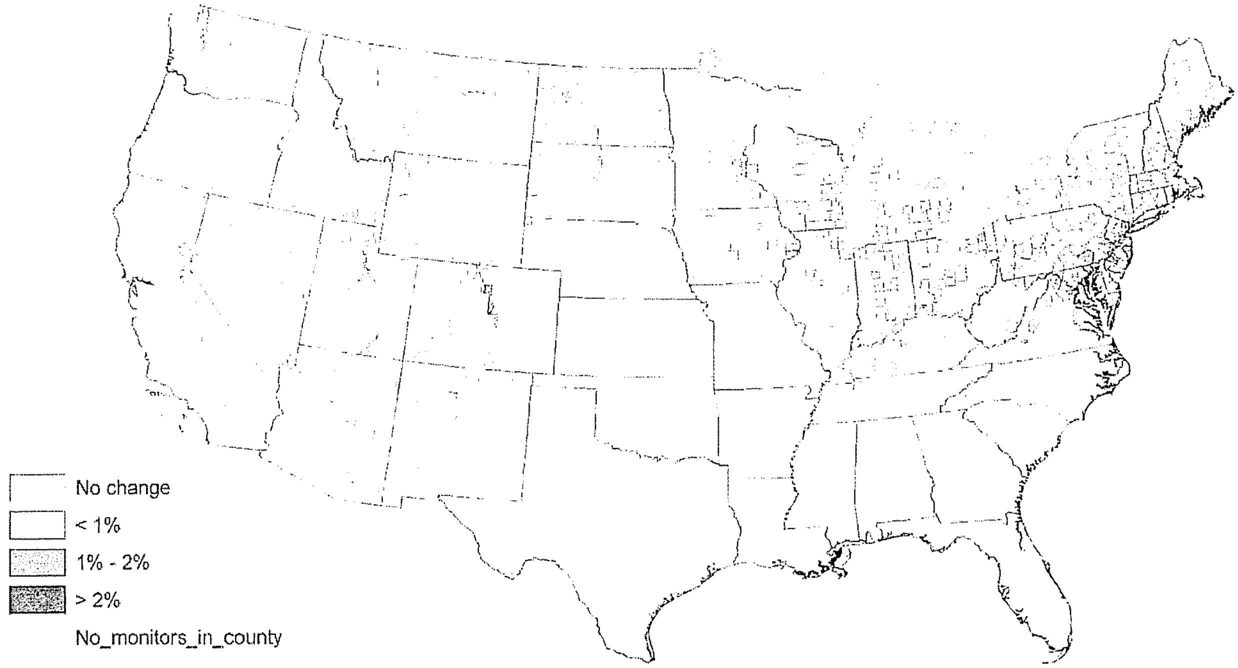
Table S3-6: Biomass Loss Functions for Trees

Species	Exposure-Response Function
Ponderosa Pine	1-exp(-1*(W126/159.63)^1.190)
Red Alder	1-exp(-1*(W126/179.06)^1.2377)
Black Cherry	1-exp(-1*(W126/38.92)^0.9921)
Quaking Aspen	1-exp(-1*(W126/109.81)^1.2198)
Virginia Pine	1-exp(-1*('W126/1714.64)^1)
Yellow (Tulip) Poplar	1-exp(-1*(W126/51.38)^2.0889)

*All functions are from Table 7F-3 of the Staff Paper (U.S. EPA, 2007b). Each function represents the median composite function for tree seedlings.

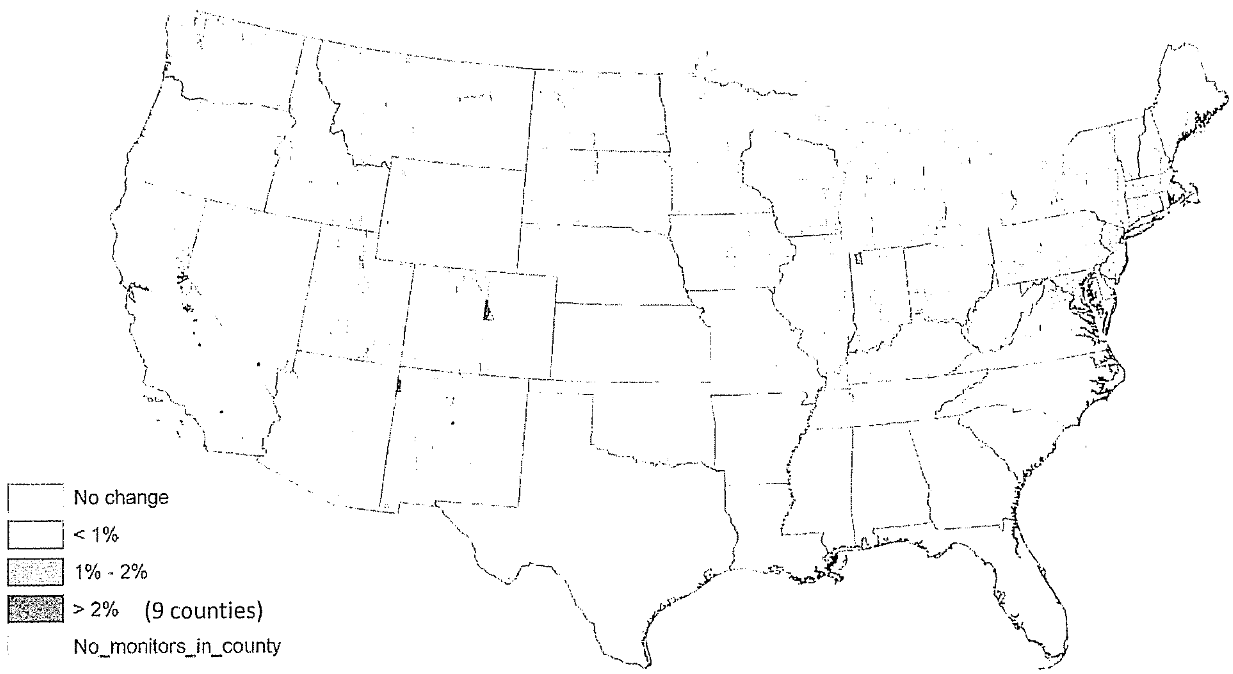
1.1 [21] The species geographic ranges are identical to those in the Staff Paper (U.S. EPA, 2007b)., and are from "Atlas of United States Trees" by Elbert L. Little, Jr, available on the Internet at http://esp.cr.usgs.gov/data/atlas/little/.

Figure S3-9: Biomass Loss Avoided by Primary Standard in 2020 for Quaking Aspen*



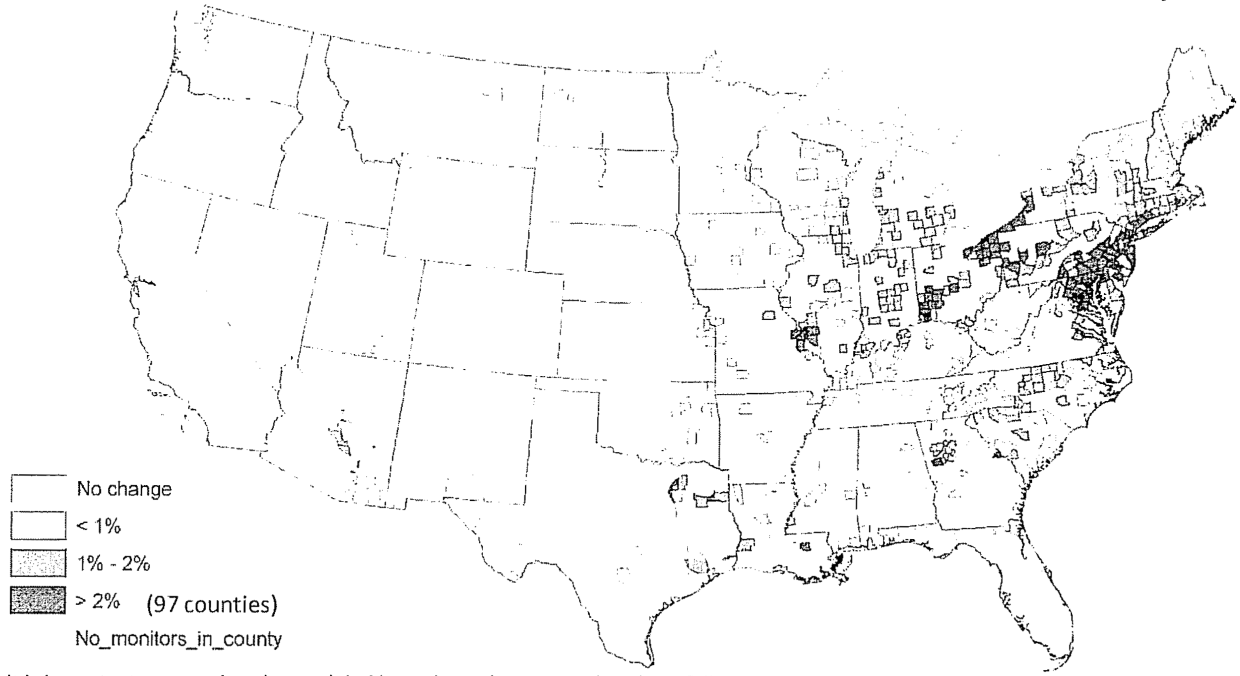
* It is important to note that the modeled hypothetical RIA controls did not fully attain the primary standard of 0.070 ppm, so this map underestimates the biomass loss avoided in several areas, especially Southern California, Houston, Eastern Lake Michigan, and the Northeast corridor. Experts have identified 2% annual biomass loss as a level of concern, which would cause long term ecological harm as the short-term negative effects on seedlings compound to affect long-term forest health. Though each map shows the geographical range for a species, it does not presume that an individual of that species would be found at every point within its range.

Figure S3-10: Additional Biomass Loss Avoided by Secondary Standard of 13 ppm-hrs in 2020 for Quaking Aspen*



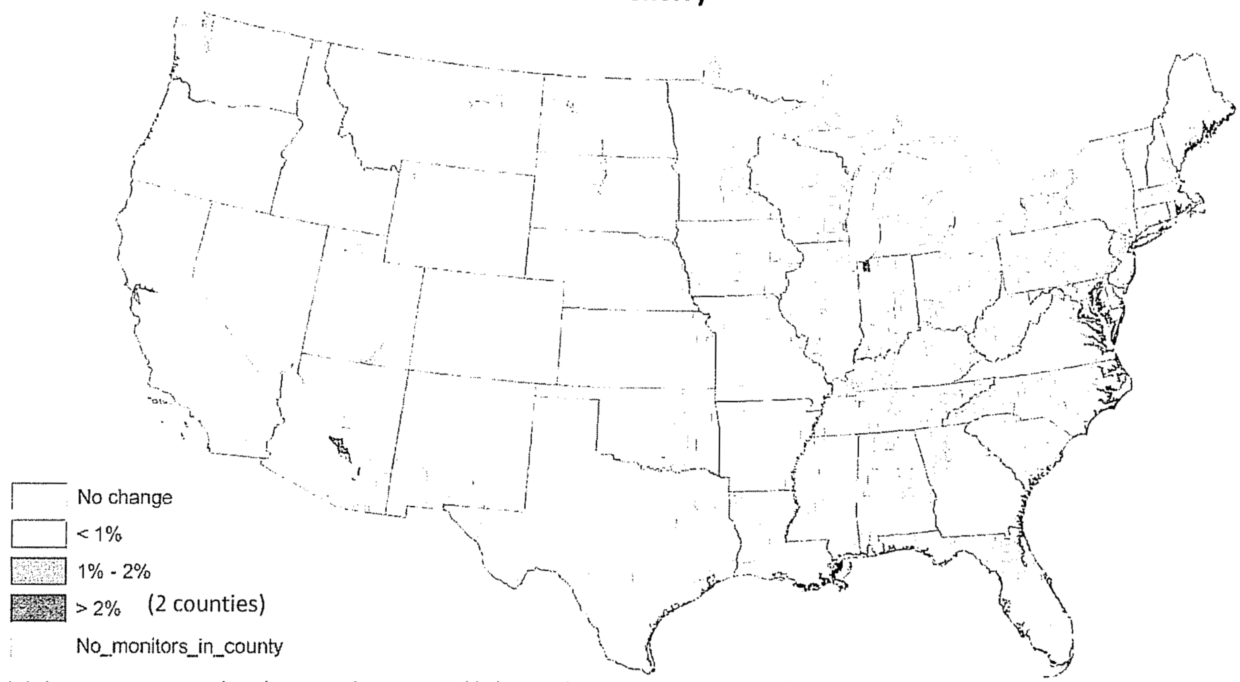
* It is important to note that the control strategy is likely to reduce W126 levels over a broader geographic area than just the violating county, so this map underestimates regional biomass loss avoided. Experts have identified 2% annual biomass loss as a level of concern, which would cause long term ecological harm as the short-term negative effects on seedlings compound to affect long-term forest health. Though each map shows the geographical range for a species, it does not presume that an individual of that species would be found at every point within its range.

Figure S3-11: Biomass Loss Avoided by Primary Standard in 2020 for Black Cherry*



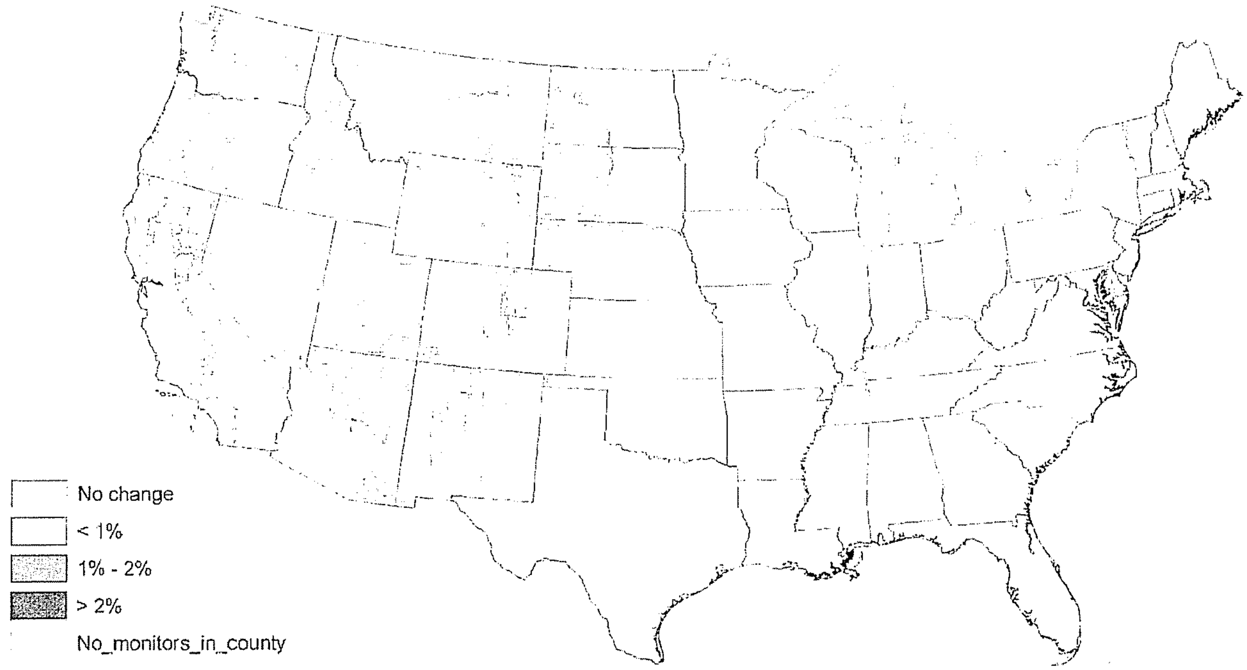
* It is important to note that the modeled hypothetical RIA controls did not fully attain the primary standard of 0.070 ppm, so this map underestimates the biomass loss avoided in several areas, especially Southern California, Houston, Eastern Lake Michigan, and the Northeast corridor. Experts have identified 2% annual biomass loss as a level of concern, which would cause long term ecological harm as the short-term negative effects on seedlings compound to affect long-term forest health. Though each map shows the geographical range for a species, it does not presume that an individual of that species would be found at every point within its range.

Figure S3-12: Additional Biomass Loss Avoided by Secondary Standard of 13 ppm-hrs in 2020 for Black Cherry*



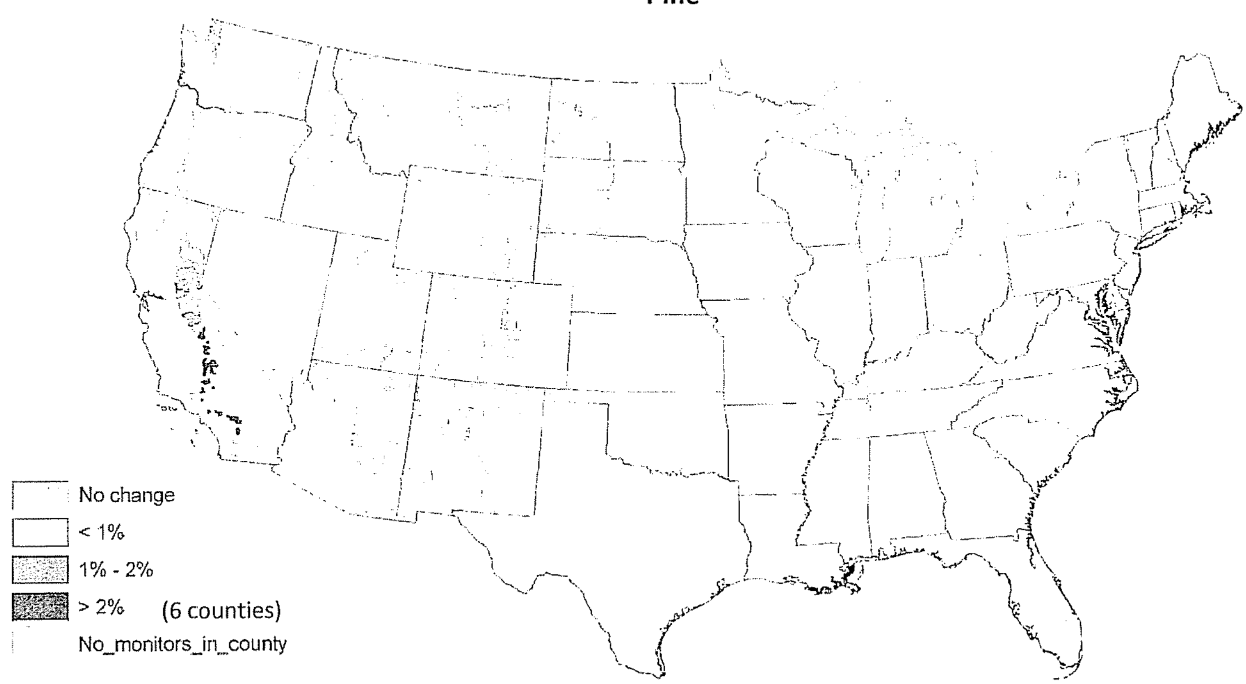
* It is important to note that the control strategy is likely to reduce W126 levels over a broader geographic area than just the violating county, so this map underestimates regional biomass loss avoided. Experts have identified 2% annual biomass loss as a level of concern, which would cause long term ecological harm as the short-term negative effects on seedlings compound to affect long-term forest health. Though each map shows the geographical range for a species, it does not presume that an individual of that species would be found at every point within its range.

Figure S3-13: Biomass Loss Avoided by Primary Standard in 2020 for Ponderosa Pine*



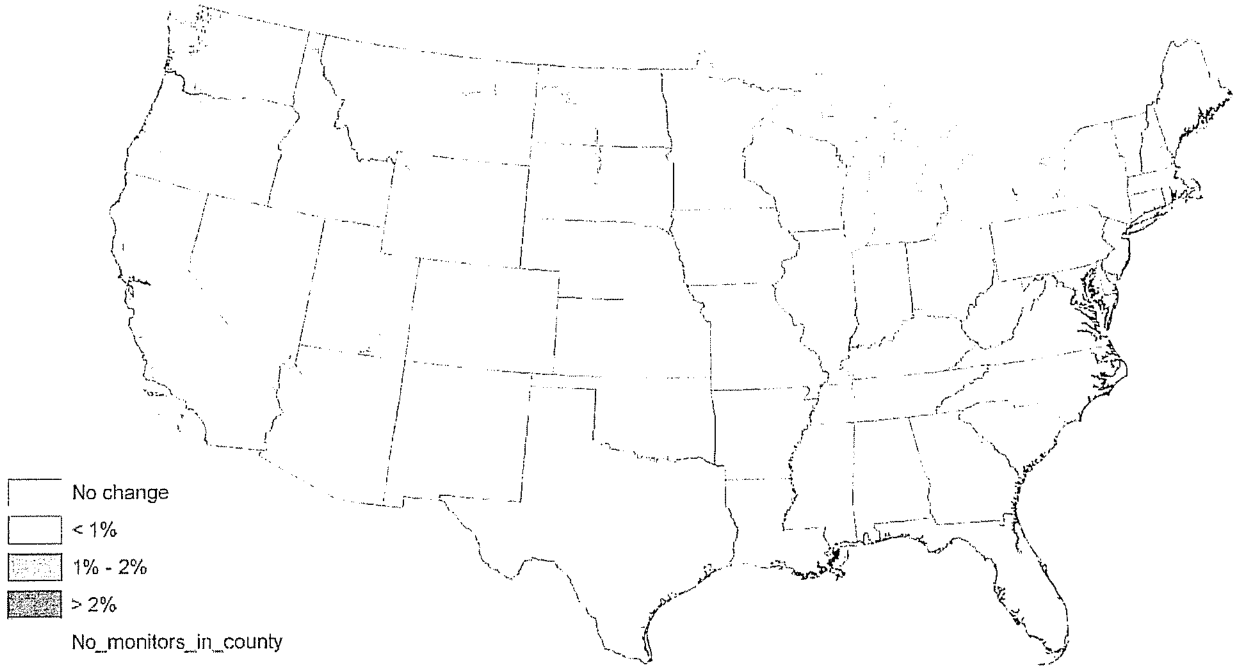
* It is important to note that the modeled hypothetical RIA controls did not fully attain the primary standard of 0.070 ppm, so this map underestimates the biomass loss avoided in several areas, especially Southern California, Houston, Eastern Lake Michigan, and the Northeast corridor. Experts have identified 2% annual biomass loss as a level of concern, which would cause long term ecological harm as the short-term negative effects on seedlings compound to affect long-term forest health. Though each map shows the geographical range for a species, it does not presume that an individual of that species would be found at every point within its range.

Figure S3-14: Additional Biomass Loss Avoided by Secondary Standard of 13 ppm-hrs in 2020 for Ponderosa Pine*



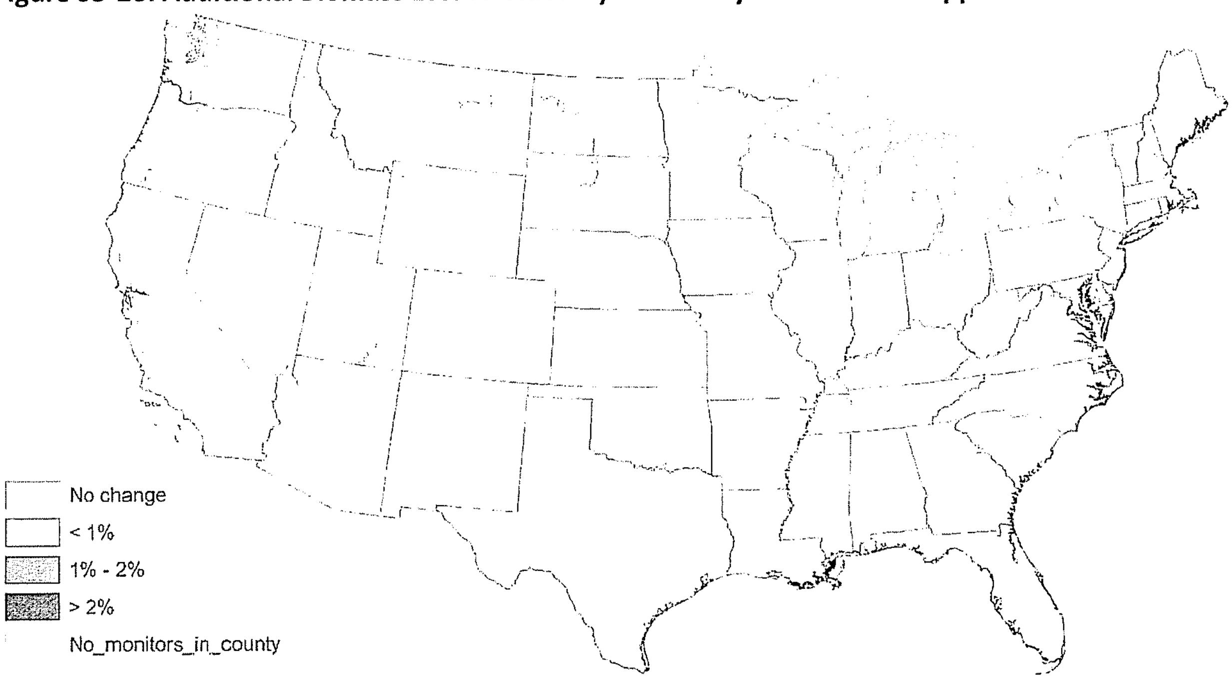
* It is important to note that the control strategy is likely to reduce W126 levels over a broader geographic area than just the violating county, so this map underestimates regional biomass loss avoided. Experts have identified 2% annual biomass loss as a level of concern, which would cause long term ecological harm as the short-term negative effects on seedlings compound to affect long-term forest health. Though each map shows the geographical range for a species, it does not presume that an individual of that species would be found at every point within its range.

Figure S3-15: Biomass Loss Avoided by Primary Standard in 2020 for Red Alder*



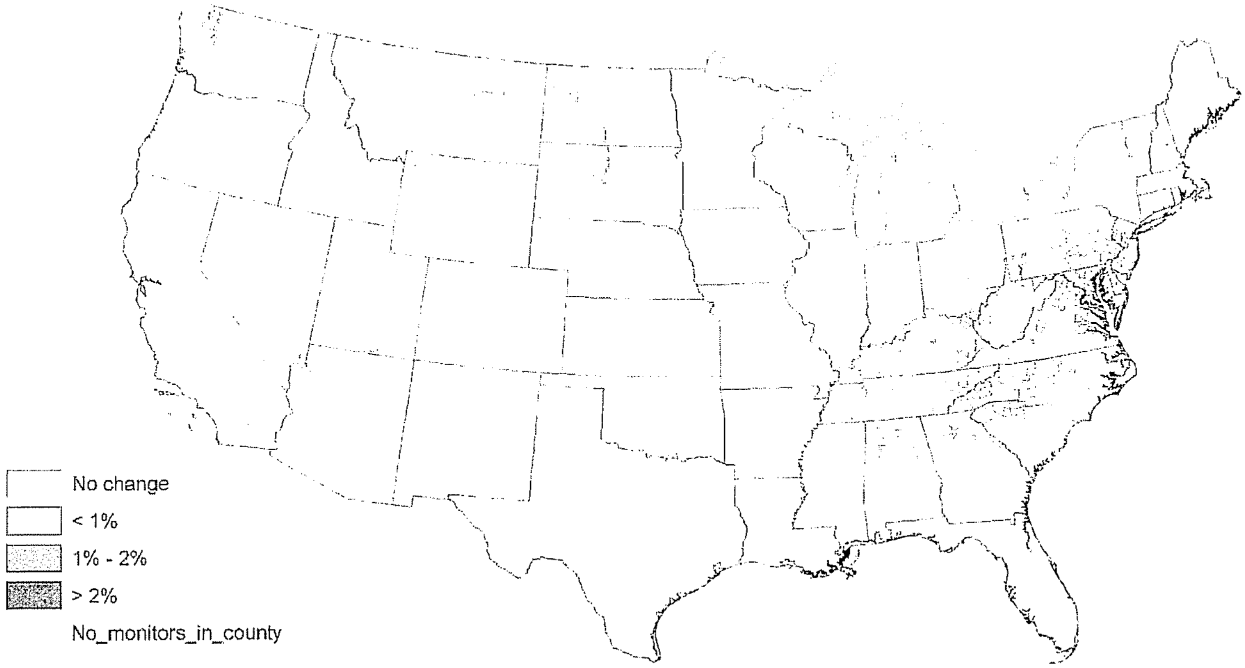
* It is important to note that the modeled hypothetical RIA controls did not fully attain the primary standard of 0.070 ppm, so this map underestimates the biomass loss avoided in several areas, especially Southern California, Houston, Eastern Lake Michigan, and the Northeast corridor. Experts have identified 2% annual biomass loss as a level of concern, which would cause long term ecological harm as the short-term negative effects on seedlings compound to affect long-term forest health. Though each map shows the geographical range for a species, it does not presume that an individual of that species would be found at every point within its range.

Figure S3-16: Additional Biomass Loss Avoided by Secondary Standard of 13 ppm-hrs in 2020 for Red Alder*



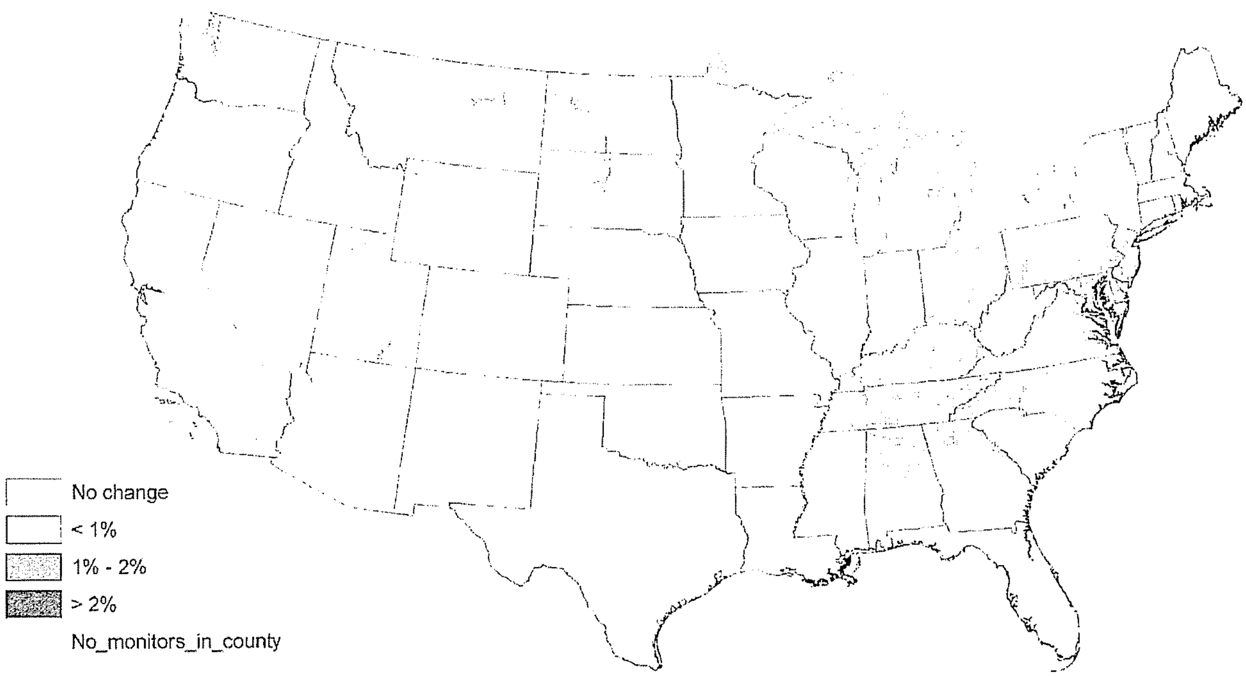
* It is important to note that the control strategy is likely to reduce W126 levels over a broader geographic area than just the violating county, so this map underestimates regional biomass loss avoided. Experts have identified 2% annual biomass loss as a level of concern, which would cause long term ecological harm as the short-term negative effects on seedlings compound to affect long-term forest health. Though each map shows the geographical range for a species, it does not presume that an individual of that species would be found at every point within its range.

Figure S3-17: Biomass Loss Avoided by Primary Standard in 2020 for Virginia Pine*



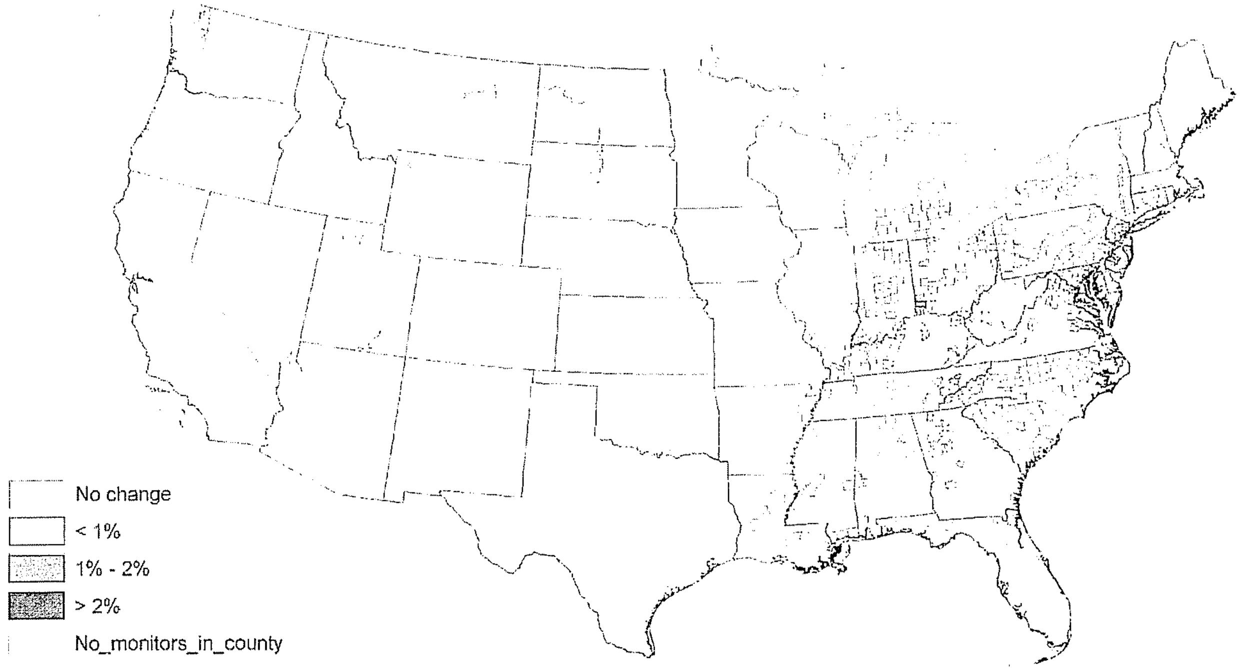
* It is important to note that the modeled hypothetical RIA controls did not fully attain the primary standard of 0.070 ppm, so this map underestimates the biomass loss avoided in several areas, especially Southern California, Houston, Eastern Lake Michigan, and the Northeast corridor. Experts have identified 2% annual biomass loss as a level of concern, which would cause long term ecological harm as the short-term negative effects on seedlings compound to affect long-term forest health. Though each map shows the geographical range for a species, it does not presume that an individual of that species would be found at every point within its range.

Figure S3-18: Additional Biomass Loss Avoided by Secondary Standard of 13 ppm-hrs in 2020 for Virginia Pine*



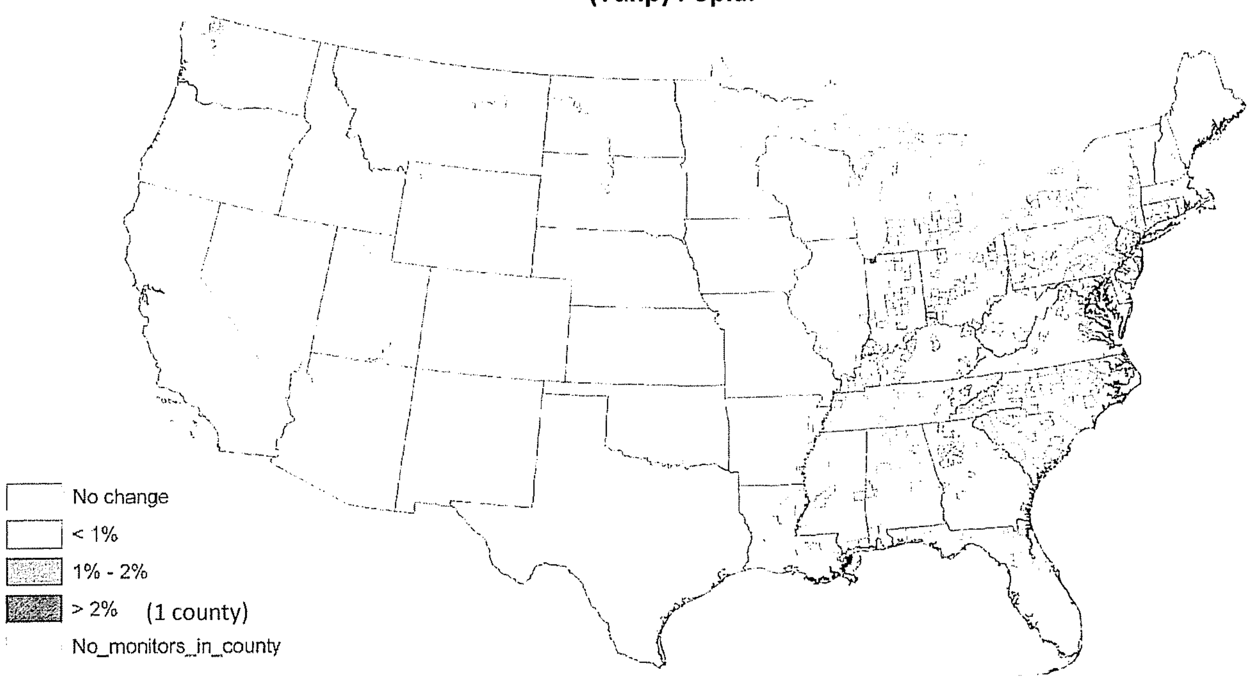
* It is important to note that the control strategy is likely to reduce W126 levels over a broader geographic area than just the violating county, so this map underestimates regional biomass loss avoided. Experts have identified 2% annual biomass loss as a level of concern, which would cause long term ecological harm as the short-term negative effects on seedlings compound to affect long-term forest health. Though each map shows the geographical range for a species, it does not presume that an individual of that species would be found at every point within its range.

Figure S3-19: Biomass Loss Avoided by Primary Standard in 2020 for Yellow (Tulip) Poplar*



* It is important to note that the modeled hypothetical RIA controls did not fully attain the primary standard of 0.070 ppm, so this map underestimates the biomass loss avoided in several areas, especially Southern California, Houston, Eastern Lake Michigan, and the Northeast corridor. Experts have identified 2% annual biomass loss as a level of concern, which would cause long term ecological harm as the short-term negative effects on seedlings compound to affect long-term forest health. Though each map shows the geographical range for a species, it does not presume that an individual of that species would be found at every point within its range.

Figure S3-20: Additional Biomass Loss Avoided by Secondary Standard of 13 ppm-hrs in 2020 for Yellow (Tulip) Poplar*



* It is important to note that the control strategy is likely to reduce W126 levels over a broader geographic area than just the violating county, so this map underestimates regional biomass loss avoided. Experts have identified 2% annual biomass loss as a level of concern, which would cause long term ecological harm as the short-term negative effects on seedlings compound to affect long-term forest health. Though each map shows the geographical range for a species, it does not presume that an individual of that species would be found at every point within its range.

b. Ozone Effects on Crops

Laboratory and field experiments have shown reductions in yields for agronomic crops exposed to ozone, including vegetables (e.g., lettuce) and field crops (e.g., cotton and wheat). Damage to crops from ozone exposures includes yield losses (i.e., in terms of weight, number, or size of the plant part that is harvested), as well as changes in crop quality (i.e., physical appearance, chemical composition, or the ability to withstand storage) (U.S. EPA, 2007b). The most extensive field experiments, conducted under the National Crop Loss Assessment Network (NCLAN) examined 15 species and numerous cultivars. The NCLAN results show that "several economically important crop species are sensitive to ozone levels typical of those found in the United States" (U.S. EPA, 2006). In addition, economic studies have shown reduced economic benefits as a result of predicted reductions in crop yields, directly affecting the amount and quality of the provisioning service provided by the crops in question, associated with observed ozone levels (Kopp et al, 1985; Adams et al., 1986; Adams et al., 1989). In addition, visible foliar injury by itself can reduce the market value of certain leafy crops (such as spinach, lettuce). According to the Staff Paper, there has been no evidence that crops are becoming more tolerant of ozone (U.S. EPA, 2007b). Using the Agriculture Simulation Model (AGSIM) (Taylor, 1994) to calculate the agricultural benefits of reductions in ozone exposure, U.S. EPA estimated that attaining a W126 standard of 13 ppm-hr would produce monetized benefits of approximately $400 million to $620 million (inflated to 2006 dollars) (U.S. EPA, 2007b).

According to the Staff Paper, the scientific consensus is that there is no threshold for exposures that cause effects on vegetation (Heck and Cowling 1997, U.S. EPA 2006). Sources of uncertainty include the ozone-exposure/plant-response functions, soil moisture/irrigation, fertilization, and other factors. Agricultural systems are heavily managed and vulnerable to adverse impacts from a variety of other factors (e.g., weather, insects, disease), which can overshadow the ozone-related effects. Additional research is needed to better understand the nature and significance of interactive effects of ozone with other plant stressors (U.S. EPA, 2007b).

Since the proposal, we have expanded the analysis of qualitative assessment of ozone impacts on crops. In this analysis, we include quantitative estimates of the crop yield loss avoided by the primary and secondary standards across the crop production areas for 3 crops (i.e., cotton, soybean, and winter wheat) in the continental U.S. These crops were selected because they met three criteria: (1) the Staff Paper provided a W126-derived exposure-response function, (2) the Staff Paper listed the crops as an ozone-sensitive plant species (U.S. EPA, 2007b), and (3) the Staff paper included maps of the crop production areas. To estimate the biomass loss avoided, we simply used the projected W126 design values in the exposure-response functions and subtracted the difference in yield loss between the two scenarios. For mapping purposes, we assume that the W126 design value is representative of the W126 levels in the county. We then overlaid a map of the crop production area to focus on those areas where the species is likely to be grown.[22] Due to uncertainties in extrapolating W126 values, we have confined this analysis to the currently monitored counties. To calculated biomass loss associated with the secondary standard, we simply rolled back the W126 value in only the violating county to just attain the selected secondary standard.

Table S3-6 shows the exposure-response functions used to generate the crop maps. A full list of ozone-sensitive crops from the Staff Paper is provided in Appendix S3A of this RIA. Figures S3-21 through S3-26 map the crop yield loss avoided for each of the selected crops by hypothetical RIA controls for the primary standard and by the rollback to the secondary standard. It is important to note that the modeled hypothetical RIA controls did not fully attain the primary standard of 0.070 ppm, so this map underestimates the crop yield loss avoided in several areas, especially Southern California, Houston, Eastern Lake Michigan, and the Northeast corridor. It is also important to note that the control strategy is likely to reduce W126 levels over a broader geographic area than just the violating county, so this map underestimates regional crop yield loss. Because we deliberately chose assumptions that underestimate crop yield loss, we have minimized potential uncertainty, and we have high confidence that the benefits are at least as high as those shown in the maps. Due to time and resource limitations, we were unable to monetize the benefits associated with avoiding crop yield loss in this analysis. As mentioned above, these crop species provide several valuable ecosystem services, including especially food and fiber production.

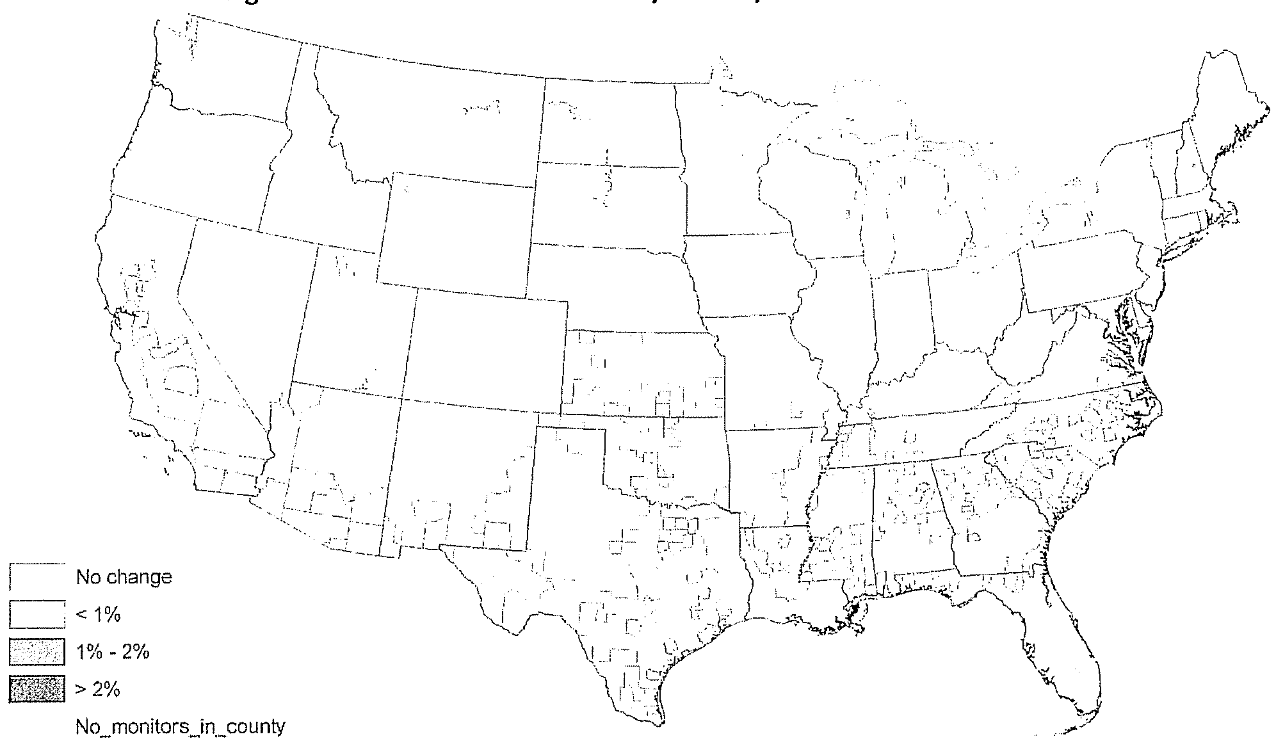
Table S3-6: Yield Loss Functions for Selected Crops

Crop	Exposure-Response Function
Cotton	1-exp(-1*(W126/96.1)^1.482)
Soybean	1-exp(-1*(W126/110.2)^1.359)
Winter Wheat	1-exp(-1*(W126/53.4)^2.367)

*All functions are from Table 7F-1 of the Staff Paper (U.S. EPA, 2007b). Each function represents the median function.

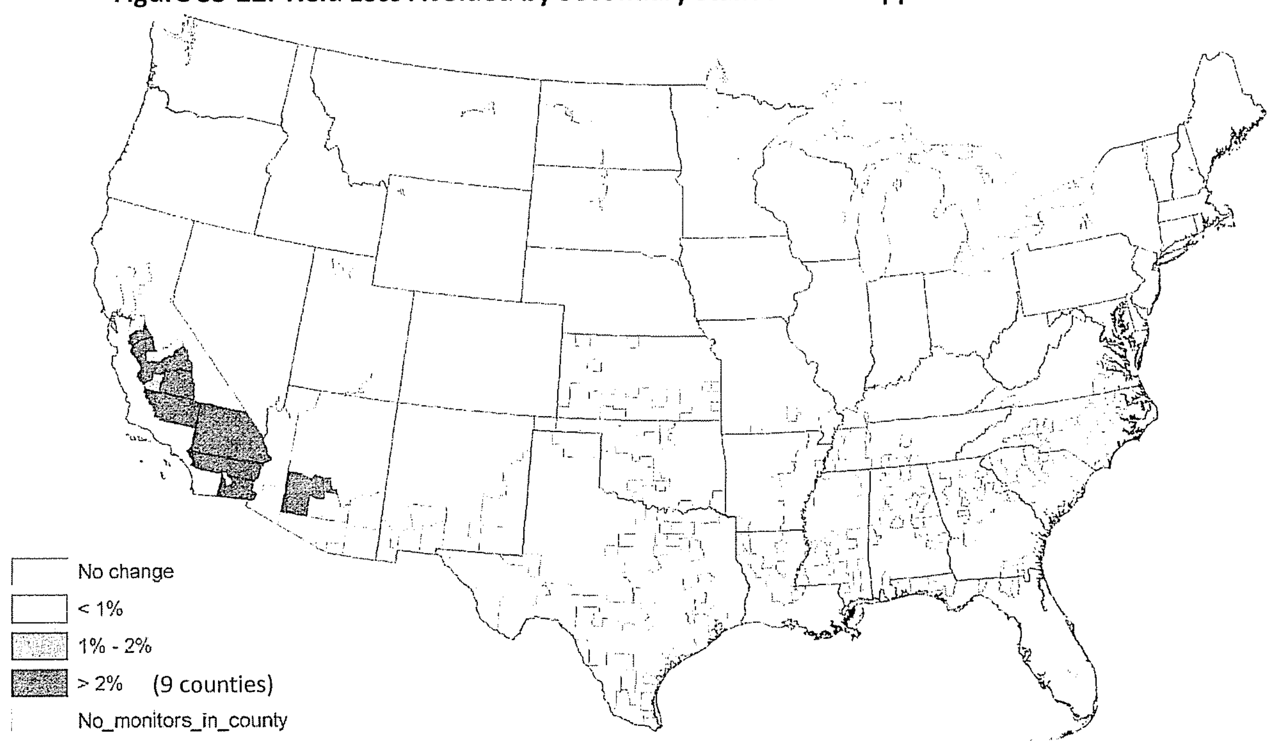
[22] Crop production areas are identical to those in the Staff Paper (U.S. EPA, 2007b) and were derived from the 2002 Census of Agriculture and from NASS 2001 County Crop Data. For more details on the crop production areas, please consult U.S. EPA (2007c).

Figure S3-21: Yield Loss Avoided by Primary Standard in 2020 for Cotton*



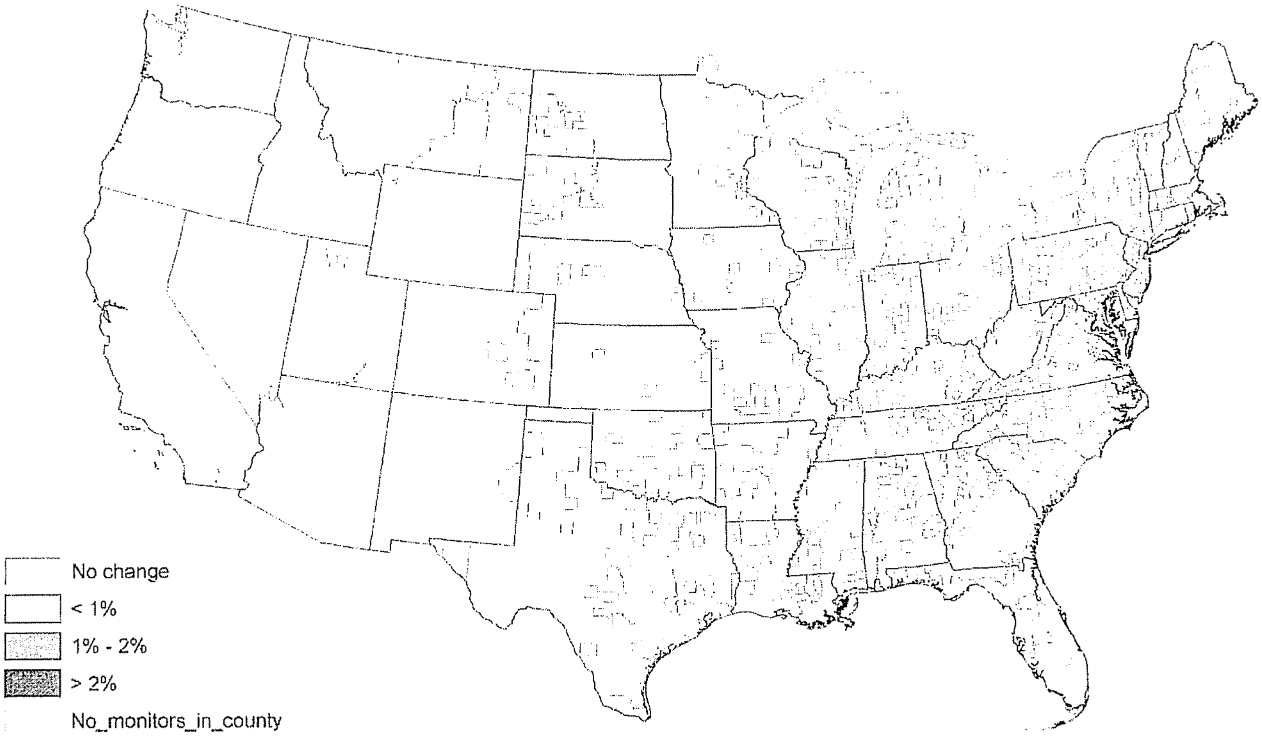
*It is important to note that the modeled hypothetical RIA controls did not fully attain the primary standard of 0.070 ppm, so this map underestimates the yield loss avoided in several areas, especially Southern California, Houston, Eastern Lake Michigan, and the Northeast Corridor.

Figure S3-22: Yield Loss Avoided by Secondary Standard of 13 ppm-hrs in 2020 for Cotton*



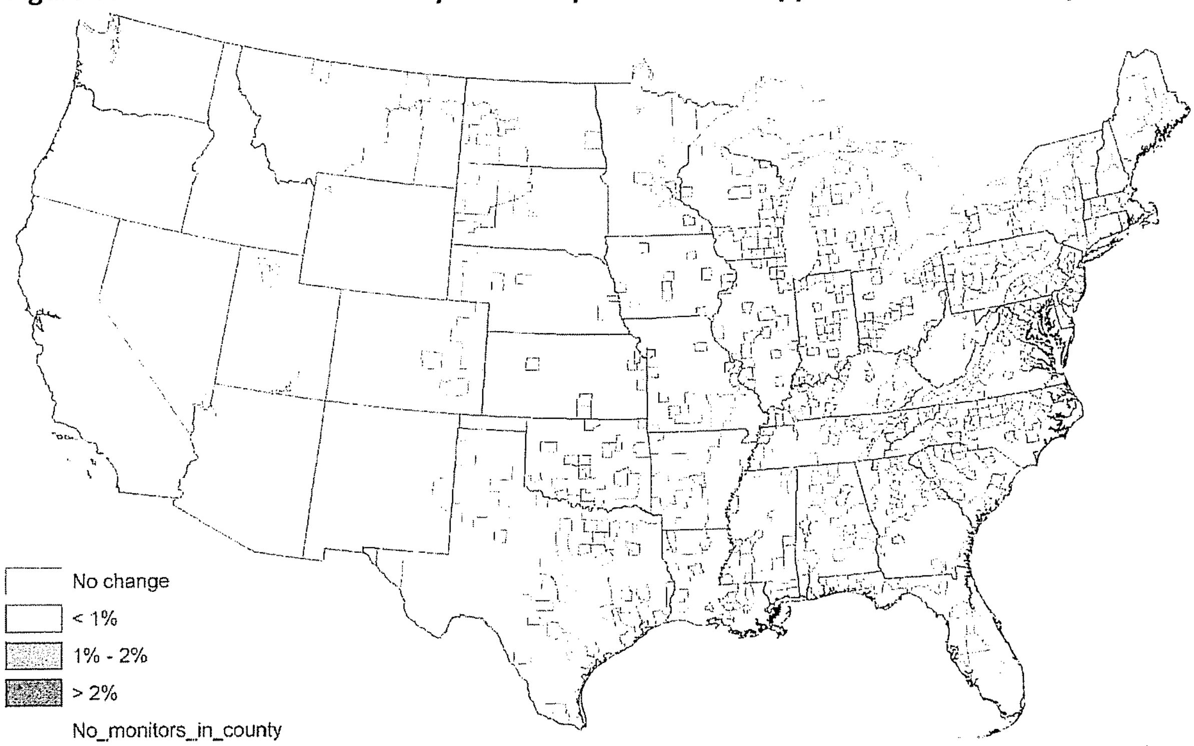
*It is important to note that the control strategy is likely to reduce W126 levels over a broader geographic area than just the violating county, so this map underestimates the regional yield loss avoided.

Figure S3-23: Yield Loss Avoided by Primary Standard in 2020 for Soybean*



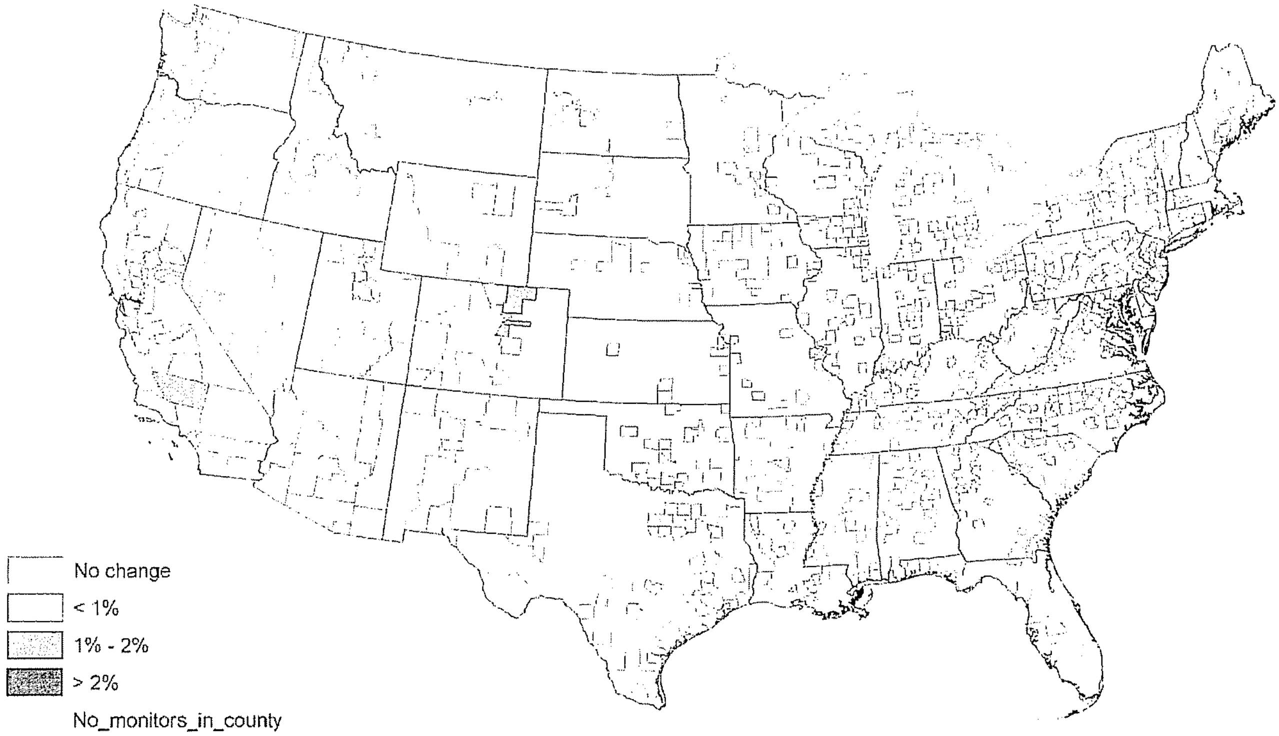
*It is important to note that the modeled hypothetical RIA controls did not fully attain the primary standard of 0.070 ppm, so this map underestimates the yield loss avoided in several areas, especially Southern California, Houston, Eastern Lake Michigan, and the Northeast Corridor.

Figure S3-24: Yield Loss Avoided by Secondary Standard of 13 ppm-hrs in 2020 for Soybean*



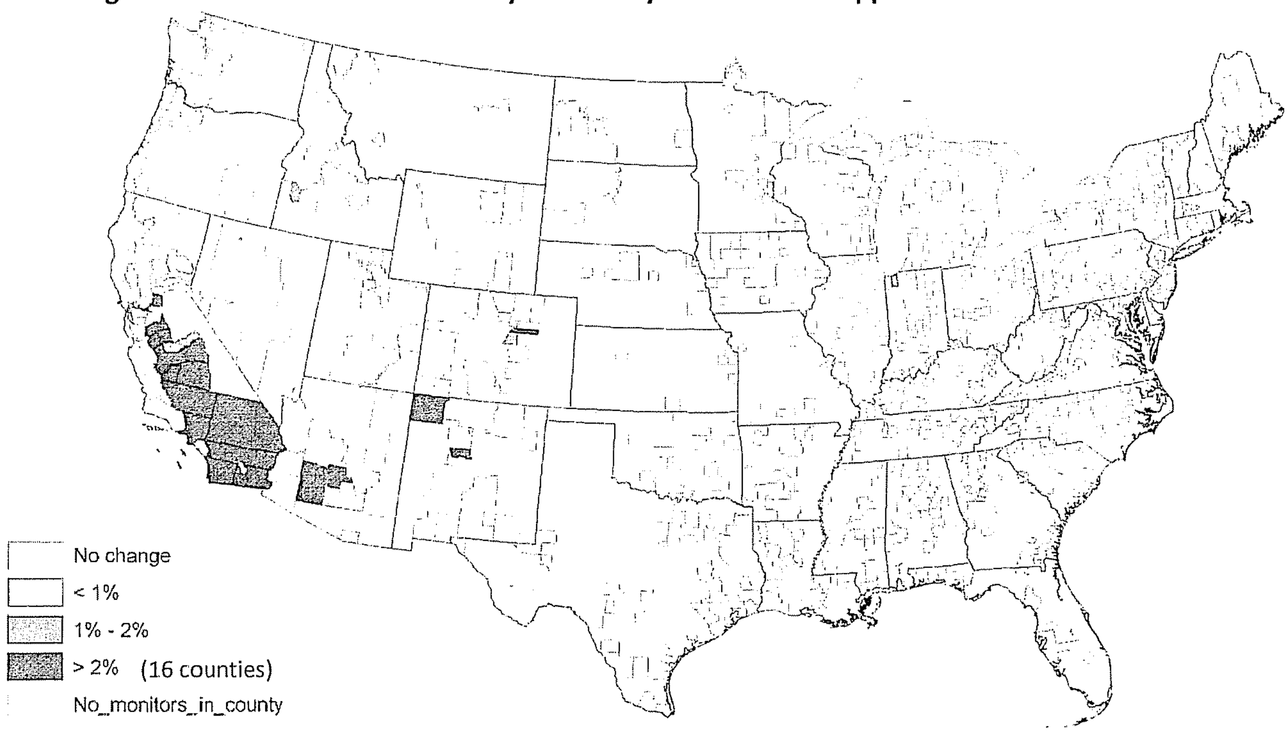
*It is important to note that the control strategy is likely to reduce W126 levels over a broader geographic area than just the violating county, so this map underestimates the regional yield loss avoided.

Figure S3-25: Yield Loss Avoided by Primary Standard in 2020 for Winter Wheat*



*It is important to note that the modeled hypothetical RIA controls did not fully attain the primary standard of 0.070 ppm, so this map underestimates the yield loss avoided in several areas, especially Southern California, Houston, Eastern Lake Michigan, and the Northeast Corridor.

Figure S3-26: Yield Loss Avoided by Secondary Standard of 13 ppm-hrs in 2020 for Winter Wheat*



*It is important to note that the control strategy is likely to reduce W126 levels over a broader geographic area than just the violating county, so this map underestimates the regional yield loss avoided.

c. Ozone Effects on Ornamental Plants

Urban ornamental plants are an additional vegetation category likely to experience some degree of negative effects associated with exposure to ambient ozone levels. A variety of ornamental species have been listed as sensitive to ozone (Abt Associates, 1995). Because ozone causes visible foliar injury, the aesthetic value of ornamental plants (such as petunia, geranium, and poinsettia) in urban landscapes would be reduced (U.S. EPA, 2007b). Sensitive ornamental species would require more frequent replacement and/or increased maintenance (fertilizer or pesticide application) to maintain the desired appearance because of exposure to ambient ozone (U.S. EPA, 2007b). In addition, many businesses rely on healthy-looking vegetation for their livelihoods (e.g., horticulturalists, landscapers, Christmas tree growers, farmers of leafy crops, etc.). The ornamental landscaping industry is a multi-billion dollar industry that affects both private property owners/tenants and governmental units responsible for public areas (Abt Associates, 1995). Preliminary data from the 2007 Economic Census indicate that the landscaping services industry, which is primarily engaged in providing landscape care and maintenance services and installing trees, shrubs, plants, lawns, or gardens, was valued at $53 billion (U.S. Census Bureau, 2010). Therefore, urban ornamentals represent a potentially large unquantified benefit category. This aesthetic damage may affect the enjoyment of urban parks by the public and homeowners' enjoyment of their landscaping and gardening activities. In addition, homeowners may experience a reduction in home value or a home may linger on the market longer due to decreased aesthetic appeal. In the absence of adequate exposure-response functions and economic damage functions for the potential range of effects relevant to ornamental plants, we cannot conduct a quantitative analysis to estimate these effects.

S2.11 Additional Co-benefits

1.3

1.4 In addition to the direct benefits on vegetation that the secondary ozone NAAQS is intended to produce, there are other co-benefits associated with reducing ambient ozone concentrations and ozone precursor pollutants. It is important to note that these additional benefits are contingent upon the secondary standard being the controlling standard. In other words, if the primary standard is controlling in all areas, there would not be any additional benefits beyond those attributable to implementation of the primary standard. For areas where additional control measures are needed to attain the secondary standard beyond those needed to attain the primary standard, there would be additional benefits associated with those emission reductions. These additional benefits are described below.

S4.6.1 Qualitative Human Health Co-benefits

1.4.1.1.1 Reducing ozone concentrations is associated with significant human health benefits, including avoiding mortality and respiratory morbidity. Researchers have associated ozone exposure with adverse health effects in numerous toxicological, clinical and epidemiological studies (U.S. EPA, 2006a). These health effects include respiratory morbidity such as fewer asthma attacks, hospital and ER visits, school loss days, as well as premature mortality.[23]

NOx is an ozone precursor, and reducing NOx emissions would also reduce health effects associated with NO_2 exposure. Following an extensive evaluation of health evidence from epidemiologic and laboratory studies, the Integrated Science Assessment (ISA) for Nitrogen Dioxide concluded that there is a likely causal relationship between respiratory health effects and short-term exposure to NO_2 (U.S. EPA, 2008b). Persons with preexisting respiratory disease, children, and older adults may be more susceptible to the effects of NO_2 exposure. The NO_2 ISA identified four short-term morbidity endpoints as a "likely causal relationship": asthma exacerbation, respiratory-related emergency department visits, and respiratory-related hospitalizations. The NO_2 ISA also concluded that the relationship between short-term NO_2 exposure and premature mortality was "suggestive but not sufficient to infer a causal relationship" because it is difficult to attribute the mortality risk effects to NO_2 alone. Although the NO_2 ISA stated that studies consistently reported a relationship between NO_2 exposure and mortality, the effect was generally smaller than that for other pollutants such as PM. The differing evidence and associated strength of the evidence for these different effects is described in detail in the NO_2 ISA.

1.4.1.1.2 Furthermore, NO_X and VOCs are precursors to $PM_{2.5}$ as well as ozone. Reducing exposure to $PM_{2.5}$ is associated with significant human health benefits, including avoiding mortality and respiratory morbidity.[24] Researchers have associated $PM_{2.5}$- exposure with adverse health effects in numerous toxicological, clinical and epidemiological studies (U.S. EPA, 2009). These health effects include premature mortality for adults and infants, cardiovascular morbidity such as heart attacks, hospital admissions, and respiratory morbidity such as fewer asthma attacks, bronchitis, hospital and ER visits, work loss days, restricted activity days, and respiratory symptoms.[25]

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[23] See Chapter 6 of the 2008 Ozone RIA, the updated benefits analysis in Section 3 of this supplemental for additional information on the ozone-related health effects associated with attaining the primary standard.

[24] See Chapter 6 of the 2008 Ozone RIA, the updated benefits analysis in Section 3 of this supplemental for additional information on the $PM_{2.5}$-related health effects associated with attaining the primary standard.

[25] See Chapter 6 of the 2008 Ozone RIA, the updated benefits analysis in Section 3 of this supplemental for additional information on the ozone-related health effects associated with attaining the primary standard.

S4.6.2 Qualitative Welfare Co-benefits

In addition to impacts on vegetation, ozone can also impact other welfare categories, including damage to certain manmade materials (e.g., elastomers, textile fibers, dyes, paints, and pigments) and climate interactions. The amount of damage to actual in-use materials and the economic consequences of that damage are poorly characterized, however, and the scientific literature contains very little new information to adequately quantify estimates of materials damage from photochemical oxidants (U.S. EPA, 2007b). Ozone is a well-known greenhouse gas, and the overall body of scientific evidence suggests that high concentrations of ozone on the regional scale could have a discernable influence on climate, leading to surface temperature and hydrological cycle changes (U.S. EPA, 2006).

1.4.1.1.3

1.4.1.1.4 NOx is an ozone precursor, and reducing NOx emissions would also reduce adverse welfare effects from acidic deposition, nutrient enrichment, and visibility impairment. Deposition of nitrogen causes acidification, which can cause a loss of biodiversity of fishes, zooplankton, and macro invertebrates in aquatic ecosystems, as well as a decline in sensitive tree species, such as red spruce (*Picea rubens*) and sugar maple (*Acer saccharum*) in terrestrial ecosystems. In the northeastern United States, the surface waters affected by acidification are a source of food for some recreational and subsistence fishermen and for other consumers and support several cultural services, including aesthetic and educational services and recreational fishing. Biological effects of acidification in terrestrial ecosystems are generally linked to aluminum toxicity, which can cause reduced root growth, which restricts the ability of the plant to take up water and nutrients. These direct effects can, in turn, increase the sensitivity of these plants to stresses, such as droughts, cold temperatures, insect pests, and disease leading to increased mortality of canopy trees. Terrestrial acidification affects several important ecological services, including declines in habitat for threatened and endangered species (cultural), declines in forest aesthetics (cultural), declines in forest productivity (provisioning), and increases in forest soil erosion and reductions in water retention (cultural and regulating). (U.S. EPA, 2008c)

Deposition of nitrogen is also associated with aquatic and terrestrial nutrient enrichment. In estuarine waters, excess nutrient enrichment can lead to eutrophication. Eutrophication of estuaries can disrupt an important source of food production, particularly fish and shellfish production, and a variety of cultural ecosystem services, including water-based recreational and aesthetic services. Terrestrial nutrient enrichment is associated with changes in the types and number of species and biodiversity in terrestrial systems. Excessive nitrogen deposition upsets the balance between native and nonnative plants, changing the ability of an area to support biodiversity. When the composition of species changes, nonnative grasses can fuel more frequent and more intense wildfires. (U.S. EPA, 2008c)

Reducing NOx and the secondary formation of $PM_{2.5}$ would reduce visibility impairment throughout the U.S. Fine particles with significant light-extinction efficiencies include sulfates, nitrates, organic carbon, elemental carbon, and soil (Sisler, 1996). These suspended particles and gases degrade visibility by scattering and absorbing light. Higher visibility impairment levels in the East are due to generally higher concentrations of fine particles, particularly sulfates, and higher average relative humidity levels. Visibility has direct significance to people's enjoyment of daily activities and their overall sense of wellbeing. Good visibility increases the quality of life where individuals live and work, and where they engage in recreational activities.

S2.12 References

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2 APPENDIX S3A: OZONE SENSITIVE PLANTS (FROM U.S. EPA, 2007)

Allegheny blackberry *Rubus allegheniensis*
American elder *Sambucus canadensis*
American hazelnut *Corylus americana*
American sycamore *Platanus occidentalis*
Basswood *Tilia Americana*
Big-leaf aster *Aster macrophyllus*
Black cherry *Prunus serotina*
Black huckleberry *Gaylussacia baccata*
Black locust *Robinia pseudoacacia*
Black poplar *Populus balsamifera trichocarpa*
Blue elderberry *Sambucus mexicana*
Box elder *Acer negundo*
California black oak *Quercus kelloggii*
Chokecherry *Prunus virginiana*
Common milkweed *Asclepias syriaca*
Cottonwood *Populus deltoids*
Crown-beard *Verbesina occidentalis*
Cutleaf coneflower *Rudbeckia laciniata*
Dogbane, Indian hemp *Apocynum cannibinum*
Evening primrose *Oenothera elata*
Goldenrod *Solidago altissima*
Gooding's willow *Salix goodingii*
Green ash *Fraxinus pennsylvanica*
Groundnut *Apios americana*
Huckleberry *Vaccinium membranaceum*
Jack pine *Pinus banksiana*
Jeffrey pine *Pinus jeffreyi*
Loblolly pine *Pinus taeda*
Maleberry *Lyonia ligustrina*
Monterey pine *Pinus radiata*
Mountain dandelion *Krigia montana*
Mugwort *Artemisia douglasiana*
Ninebark *Physocarpus capitatus*
Northern fox grape *Vitis labrusca*
Ohio Buckeye, Horse chestnut *Aesculus glabra*
Pacific ninebark *Physocarpus malvaceum*
Paper birch *Betula papyrifera*
Pinus ponderosa *Pinus ponderosa*
Pitch pine *Pinus rigida*
Poke milkweed *Asclepias exaltata*
Ponderosa pine *Pinus ponderosa*
Quaking aspen *Populus tremuloides*
Red alder *Alnus rubra*
Red elderberry *Sambucus racemosa*
Redbud *Cercis Canadensis*
Saskatoon serviceberry *Amelanchier alnifolia*
Sassafras *Sassafras albidum*
Scouler's willow *Salix scouleriana*
Serviceberry *Amelanchier alnifolia*
Silver wormwood *Artemisia ludoviciana*
Single-leaf ash *Fraxinus anomala*
Skunkbush *Rhus trilobata*
Smooth cordgrass *Spartina alterniflora*
Snowberry *Symphoricarpos albus*
Speckled alder *Alnus rugosa*
Spreading dogbane *Apocynum androsaemifolium*
Swamp milkweed *Asclepias incarnata*
Sweet mock orange *Philadelphus coronarius*
Sweetgum *Liquadambar styraciflua*
Table-mountain pine *Pinus pungens*
Tall milkweed *Asclepias exaltata*
Thimbleberry *Rubus parviflorus*
Thornless blackberry *Rubus canadensis*
Tree-of-heaven *Ailanthus altissima*
Twinberry *Lonicera involucrata*
Virgin's bower *Clematis virginiana*
Virginia creeper *Parthenocissus quinquefolia*
Virginia pine *Prunus virginiana*
White ash *Fraxinus americana*
White snakeroot *Eupatorium rugosum*
White stem blazingstar *Mentzelia albicaulis*
Whorled aster *Aster acuminatus*
Winged sumac *Rhus copallina*
Yellow-poplar *Liriodendron tulipifera*

Ozone Sensitive Crops

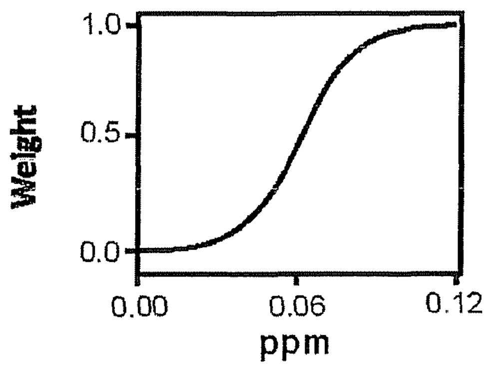
Cotton
Peanuts
Potatoes
Soybeans
Tobacco
Winter Wheat

Sand blackberry *Rubus cuneifolius*

3 APPENDIX S3B: CALCULATING THE W126 INDEX

Steps in calculating W126 value for a particular site:

1. Measure O_3 concentrations for each hour within 12-hour daylight period (8 am to 8 pm)
2. Weight each hourly O_3 concentration to get a W126 value: lower concentrations receive less weight than higher concentrations
3. Add the 12 weighted hourly W126 values to calculate daily W126 value for each day
4. Sum daily W126 values within each month to get a monthly W126 value
5. Identify the consecutive 3-month period whose sum of monthly W126 values produces the highest W126 index value. This maximum consecutive 3-month sum = seasonal W126 value for that site (in ppm-hrs)



Example of weighting over 5-hour period:

Hourly O_3 (primary)	Weight	W126 (ppm-hrs)
0.03	0.01	0.00
0.05	0.11	0.01
0.06	0.30	0.02
0.08	0.84	0.07
0.10	1.0	0.10
	SUM:	**0.20**

Daily value = sum of values over 12 daylight hours

Pt. 2 - Volume 1

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE 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

In the Matter of:

THE APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	)	CASE NO. 2011-00162

REBUTTAL TESTIMONY OF
CHARLES R. SCHRAM
DIRECTOR, ENERGY PLANNING, ANALYSIS AND FORECASTING
LG&E AND KU SERVICES COMPANY

Filed: October 24, 2011

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **Charles R. Schram**, being duly sworn, deposes and says that he is Director – Energy Planning, Analysis and Forecasting for LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Charles R. Schram

Charles R. Schram

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 21st day of October 2011.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2014

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

A. My name is Charles R. Schram. I am the Director, Energy Planning, Analysis and Forecasting for LG&E and KU Services Company, which provides services to Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively "the Companies"). My business address is 220 West Main Street, Louisville, Kentucky, 40202.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address a number of criticisms raised by Dr. Jeremy Fisher and Dr. William Steinhurst, witnesses for the Sierra Club and related parties ("Environmental Interveners"). More specifically, Dr. Fisher raised eight criticisms in his direct testimony, of which I will address six and David Sinclair will address two, and I will address Dr. Steinhurst's sole criticism. Dr. Fisher's and Dr. Steinhurst's assertions and a summary of Mr. Sinclair's and my responses are below (for convenience, I have used Dr. Fisher's names for the errors he claims the Companies made):

- **Natural gas price correction:** Dr. Fisher argued that the Companies used a "highly inflated" natural gas price forecast. Mr. Sinclair shows that Dr. Fisher and his colleagues at Synapse made a fundamental, elementary mistake by using their real-dollar gas price forecast along with the Companies' gas price forecast in nominal-dollar terms. Mr. Sinclair further shows that Synapse erred by treating all of the Companies' Strategist inputs as being in real dollars, when they were actually in nominal dollars. Mr. Sinclair corrects these errors and shows that the

Companies' gas price forecast falls within other forecasts Synapse believes to be mainstream, and shows that the corrected Synapse analysis (using Synapse's gas price forecast) produces the same retire-or-retrofit decisions as does the Companies' analysis.

- **SCR cost:** Dr. Fisher asserts that the Companies should have included selective catalytic reduction systems ("SCRs") for certain generating units in their modeling. I show that the Companies did indeed consider the possible future need for SCRs on certain units, and that there is only a small likelihood that present or proposed regulations would require SCRs on units that would affect the Companies' retire-or-retrofit analysis.
- **CO_2 price risk:** Dr. Fisher asserts that the Companies should have included unknown and unknowable future CO_2 pricing in their analysis in these proceedings. Mr. Sinclair shows that Dr. Fisher has incorrectly treated CO_2 pricing at some level as essentially inevitable, and has ignored the value of creating the real option of addressing the greenhouse gas issue in the future.
- **Oversized replacement capacity:** Dr. Fisher claims that the Companies' modeling uses "oversized" capacity additions. I rebut that claim by showing that the capacity additions result from an overall cost optimization process that considered possible capacity additions as small as 5 MW.
- **Utility modeled in isolation:** Dr. Fisher argues that the Companies should have modeled greater amounts of transfer capability with the Eastern

Interconnection. I demonstrate the flawed thinking in this criticism by pointing out that the Companies are engaged in capacity planning, and cannot assume that abundant quantities of cost-effective energy will be available at all times in the future; given the Companies' obligation to reliably serve their customers, any such assumption would be imprudent. Also, I show that there are often significant transmission constraints that hamper the Companies' ability to import energy from neighboring systems, further contradicting Dr. Fisher's assertion.

- **Emergency generation purchases:** Dr. Fisher contends that the Companies used too high a cost for emergency energy in their modeling. I refute that contention by showing that even using a significantly lower cost of emergency energy does not affect the retire-or-retrofit results, and argue that Dr. Fisher again misunderstands the difference between a utility's planning for future capacity to serve native load over the long term—the project in which the Companies are engaged—and optimizing dispatch on the basis of existing generating sources across a broader footprint.
- **NO_X and SO_2 Prices:** Dr. Fisher asserts that the Companies used incorrect emission allowance prices. I explain that the Companies conducted their analyses on the assumption that limited allowance trading could lead to an emissions allowance market with uncertain liquidity, and that physical compliance, consistent with allocated allowances, is a prudent strategy for the Companies.

- **Order of Retirement:** Dr. Fisher asserts that the Companies chose a "semi-arbitrary" order in which to consider units in their retire-or-retrofit analysis, and that changing the order could result in a more optimal solution. I show that the order of unit retirement is not relevant to the Companies' recommendations; there was nothing arbitrary about the order in which the Companies conducted their analysis; and that considering the units Dr. Fisher believes should be retired but the Companies propose to retrofit (Brown Units 1 and 2) leads to a less optimal and more costly portfolio than what the Companies have proposed.
- **Need for New Resource Analysis:** Dr. Steinhurst asserts that the Commission should deny the Companies' applications in their entirety and require the Companies to perform an entirely new resource analysis before making any retire-or-retrofit decisions. I argue that the Companies' proposals in these proceedings are the result of a thorough resource analysis process that has served the Commission, the Companies, and customers well for decades; therefore, there is no need for another analysis or delay that could prove to be costly to customers.

In addition to the points above, I concede Dr. Fisher's correction to the Companies' landfill costs, which, as Dr. Fisher noted, actually supports the Companies' retrofit proposals in these proceedings. I end my testimony by concluding that, *contra* Drs. Fisher and Steinhurst, the Commission should approve the Companies' applications as filed.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Rebuttal Exhibit CRS-1	OASIS Transmission Information
Rebuttal Exhibit CRS-2	Emergency Energy Cost
Rebuttal Exhibit CRS-3	LG&E and KU 2011 Reserve Margin Study

In addition, a complete collection of source documents and work papers are provided in Appendix A in electronic form on CD.

Modeling Possible Future SCRs

Q. How do you respond to Dr. Fisher's criticism that, based on current and proposed National Ambient Air Quality Standards ("NAAQS") for ozone, the Companies erred by not including in their modeling the cost of possible future selective catalytic reduction systems ("SCRs") for certain coal-fired generating units?[1]

A. As Gary Revlett discusses in his rebuttal testimony, the Companies' decision not to include SCRs in their modeling for the retire-or-retrofit analysis supporting their applications was reasonable. The entirety of Kentucky (with the exception of the area abutting Cincinnati, which the Companies do not serve) is in compliance with the current ozone NAAQS. As Mr. Revlett further describes, there appears to be little, if anything, the Companies would have to do to comply with the final rule the U.S. Environmental Protection Agency was drafting before President Obama asked EPA to put aside the rulemaking until 2013 (with a final rule to be issued no earlier than 2014). In particular, it appears that Brown Units 1 and 2 would not be affected by the

[1] Fisher Direct Testimony at 23-29.

draft-final (but now delayed) ozone NAAQS. So Dr. Fisher's criticism is without merit.

Moreover, the Companies did consider the cost of potential future SCRs, as Dr. Fisher acknowledges.[2] Section 2.3 of the 2011 Air Compliance Plan Sensitivity Analysis, filed July 12, 2011, considers the economic impact of potential SCRs on Brown Units 1 and 2, Ghent Unit 2, and Mill Creek Units 1 and 2. This was further discussed in the Companies' supplemental analysis filed on September 15, 2011. Those discussions show that all of the above-listed units could have SCRs installed and still be net beneficial to retrofit with controls as the Companies have proposed based on the Companies' base fuel forecast. Using the updated fuel forecasts the Companies provided on September 15, Ghent Unit 2 and Mill Creek Units 1 and 2 still remain net beneficial to retrofit with controls if SCRs had to be installed. And it is important to remember that according to Dr. Fisher's own data, Brown Units 1 and 2 likely would not require any NO_X control technology under the draft-final ozone NAAQS—which has now been shelved—even before taking into account the NO_X reductions of the under-construction Brown Unit 3 SCR.[3]

But the primary reason Dr. Fisher's criticism is incorrect is methodological. The Companies do not and have not planned their systems on the basis of what merely could happen; rather, they prudently make investment decisions on the basis of what is known and measurable. Dr. Fisher, on the other hand, would have the Commission evaluate the Companies' applications as though things that are merely possible are certain based upon his value judgments. At this time, nobody, not even

[2] Fisher Direct Testimony at 26-27.

[3] Environmental Interveners' Oct. 14, 2011 Response to Commission Staff DR No. 9(a).

Dr. Fisher, knows what the revised ozone NAAQS will be when it is issued no earlier than 2014, if there is any revision at all. Yet that has not prevented Dr. Fisher from asserting his belief that "*when* EPA implements this NAAQS, the operational plants that do not have SCR *will* require this control technology (Brown Units 1 & 2, Ghent 2, and Mill Creek 1 &2), to meet local attainment,"[4] notwithstanding that Dr. Fisher admits that he did not model the impact that the Brown Unit 3 SCR will have when it goes into service next year.[5] This sort of an approach to modeling is result-oriented and is fundamentally at odds with the Commission's tried-and-true approach to system planning analysis.

<u>Modeling Smaller and More Frequent Capacity Additions</u>

Q. Dr. Fisher's testimony (and his subsequent correction thereof) criticizes the Companies for not modeling smaller and more frequent capacity additions, calling the capacity additions produced by the Companies' modeling "oversized."[6] Is this a valid criticism?

A. No. Dr. Fisher provided no quantifiable support for his initial premises (i.e., smaller additions are more economical). His initial premise is contrary to the well-established premise of economies-of-scale in the electric utility industry. The capacity replacement options the Companies used in their modeling were found to be the most economical capacity expansion options in the Companies' 2011 Integrated Resource Plan ("IRP") process. That process considered a wide array of capacity options of all sizes and types—including a unit as small as a 5 MW landfill gas unit—

[4] Fisher Direct Testimony at 26, as corrected in his response to Commission's DR No. 9.
[5] *See* Environmental Interveners' Oct. 14 responses to the Companies' DR No. 13.
[6] Fisher Direct Testimony at 8; Environmental Interveners' Oct. 14 responses to the Companies' DR No. 9.

and included renewable resources. The Companies used the Strategist model in the IRP to evaluate which options were most economical over the planning horizon. The output of the Strategist model is designed to represent the least-cost expansion plan on a revenue-requirements basis. Consistent with this goal and reasonable resource-planning methodology, the tool aims to optimize the addition of resources across a long-term horizon. The model ultimately selected relatively larger combined-cycle gas units as the most economical means of meeting the Companies' capacity and energy requirements. As Dr. Fisher noted, the Companies took three capacity options from the IRP planning process—the most economical three out of many considered—and used them in the analysis for these proceedings. The three options varied significantly in size: about 200, 600, and 900 MW. In the ECR analysis, Strategist again selected relatively larger capacity additions in the near-term as it optimized the factors discussed above. So the capacity options considered were, in effect, far more than three, and the additions the model selected were not "oversized," but optimal. His criticism of the Companies for not modeling smaller and more frequent capacity additions is without merit.

Q. Did Dr. Fisher attempt to quantify the effect of this criticism in any way?

A. No, as Dr. Fisher candidly admitted, he did not.[7]

<u>Constrained Transfer Capacity</u>

Q. Dr. Fisher states that the Companies erred by failing to model transfers with the Eastern Interconnection.[8] Is this a valid criticism?

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[7] *See* Fisher Direct Testimony at 10.
[8] *See* Fisher Direct Testimony at 9.

A. No. Although it is true that the Companies did not model market interactions with the Eastern Interconnection, Dr. Fisher's criticism is misplaced. The Companies do not plan their system on the assumption that significant amounts of market energy will be available to serve native load on a day-ahead or real-time basis; indeed, to do so would be imprudent and also inconsistent with NERC Reliability Standard IRO-006, which recognizes that non-firm transmission capacity is subject to hourly curtailment. The Companies have an obligation to provide to their customers safe, reliable, and lowest-reasonable-cost service. To meet that obligation, the Companies must have firm, dispatchable capacity sufficient to meet peak load plus a reserve margin (currently targeted at 16%). The Companies do not have to own all the capacity they need to meet that requirement, but they do have to be able to call on it; that is why the Companies evaluate long-term power purchase contracts alongside other capacity options when determining how to meet their next resource need (e.g., during the Companies' request-for-proposals process). But it would be unreliable and possibly expensive for customers if the Companies planned to meet their service obligations by reaching out into the markets on a daily basis, at least for more than non-trivial amounts of energy.

That is not to say that there is never a time to model day-ahead or real-time market interactions. Such an analysis would be appropriate to determine how most economically to dispatch existing units at a given time; indeed, such analyses are what the Companies and regional transmission organizations run on a real-time basis to optimize dispatch across their footprints. But it would be neither necessary nor appropriate for a utility with an obligation to serve native load to model such market interactions when conducting long-term capacity optimization planning.

Q. Why would it be imprudent for the Companies to assume for modeling purposes that they can obtain energy and capacity requirements subject only to limited transmission constraints?

A. Contrary to Dr. Fisher's apparent belief that the Companies have ample transfer capacity because they are interconnected to multiple systems owned by other entities,[9] the Companies' available transfer capacity can be rather constrained. As shown in Rebuttal Exhibit CRS-1 attached hereto, it is not reasonable for long-term resource planning to assume unfettered access to market power if the Companies are to continue reliably supplying power to customers. Regardless of the existing physical interconnections within the transmission grid and the assumption of available power in other areas, the power still has to be moved to the Companies' system. For example, the Companies reviewed Open-Access Same-time Information System data for firm transmission capacity from PJM and MISO for November 2011 – October 2012. Zero firm capacity is available in four of the next twelve months, including the peak months of July and August, for both PJM and MISO. Furthermore, a review of historical daily firm transmission capacity from April through September 2011 revealed that for 65 days there was zero firm transmission capacity from both PJM and MISO. Without available transfer capacity, the Companies could not import power regardless of the ability to purchase power generated elsewhere.

[9] *See* Fisher Direct Testimony at 36-37; Environmental Interveners' Oct. 14 responses to the Companies' DR No. 23.

The Companies believe that reliability would be jeopardized if modeling simply assumed that energy and capacity were broadly available and assumed only predictable and limited transmission constraints between the Companies and other parts of the Eastern Interconnection. Real-time data indicates that transmission constraints are unpredictable, frequent, and significant. Furthermore, modeling such large capacity and energy requirements as market purchases without a formal RFP process to assess the market is risky. There is no assurance that large amounts of capacity and energy are firmly available. In summary, relying on the ability to import power at any time does not support reliable and effective long-term resource planning and would be inconsistent with NERC reliability standards.

Q. What did the Companies' recent request-for-proposals process for capacity options show concerning the cost-effectiveness of purchased-power alternatives to building or buying generating units?

A. The RFP process resulted in the Companies' recommendation to meet the replacement capacity and energy requirements by building a new combined-cycle gas unit and purchasing three simple-cycle combustion turbines from Bluegrass Generation Company, LLC in Lagrange, Kentucky. Purchased-power alternatives were thoroughly evaluated along with other assets offered for sale, but ultimately were not the least-cost solution.

Q. Did Dr. Fisher attempt to quantify the effect of this criticism in any way?

A. No. Dr. Fisher only raised the issue as a concern with no further support.

<u>Emergency Energy</u>

Q. Dr. Fisher suggests in his testimony that the Companies used an unreasonably high emergency energy cost in their modeling. Is this criticism valid?

A. No. Dr. Fisher offered no quantifiable support for his criticism. The Companies' resulting resource expansion plan is not significantly influenced by this cost of emergency energy. Modeled unserved energy volume is 0-0.01% of total energy requirements and 0-3% of total costs in any given year. As shown in Rebuttal Exhibit CRS-2, reducing the emergency energy cost from $16,600/MWh to $100/MWh does not affect the Companies' recommendations. This is not surprising, since the same value for emergency energy is used consistently throughout the retire and retrofit portfolios.

As discussed previously, the 2011 Plan analysis did not base the resulting resource plans on the availability of purchased power from the market. Therefore, consistent with the Companies' 2011 IRP, the emergency energy cost was assumed to equal the Companies' cost of unserved energy to ensure that the system is not short of generation due to dependence on market capacity and energy that may not be available. That is why Dr. Fisher's assertion that emergency energy is not the same as unserved energy is incorrect for the purpose of the Companies' analysis.[10] In other words, because the Companies' analysis is designed to ensure there is sufficient cost-effective capacity, the Companies did not model emergency energy *per se*; rather, the Companies used the emergency energy input in Strategist to model the cost of unserved energy as part of making appropriate capacity decisions.

Q. On what did the Companies base the value of unserved energy they used in their modeling?

[10] *See* Environmental Interveners' Oct. 14 responses to the Companies' DR No. 3(a).

A. The Companies used the same value contained in the 2011 IRP. This value was developed through work with Astrape Consulting on the optimal reserve margin and is further described in the 2011 IRP. (A copy of the Astrape Consulting report is attached hereto as Rebuttal Exhibit CRS-3.) The unserved energy value is intended to represent the amount customers would, in the aggregate, be willing to pay to obtain a marginal MWh of energy that would otherwise be unavailable.

Q. Did Dr. Fisher attempt to quantify the effect of this criticism in any way?

A. No. Again, Dr. Fisher only raised the issue as a concern with no further support.

Allowance Prices

Q. Dr. Fisher argues that one of the flaws of the Companies' modeling is the assumption that allowance values decline to zero by 2014.[11] What is your view of Dr. Fisher's criticism?

A. The Companies' modeling associated with their 2011 ECR Plans assumed that allowance values associated with the existing Clean Air Interstate Rule decline to zero by 2014 because of the then-existing uncertainty with the Cross-State Air Pollution Rule ("CSAPR") regulation. At the time the Companies conducted the modeling Dr. Fisher criticizes, CSAPR was not final, so it was not clear what compliance route EPA would take in the final rule. As Mr. Revlett noted in his rebuttal testimony, although EPA ultimately chose a limited allowance trading regime for the final rule, the notice of proposed rule-making included consideration of an alternative that would have driven allowance prices to zero (or very close thereto), namely directing restrictions on generating plant emissions with some emissions averaging permitted. The regime EPA ultimately chose allows intrastate trading and

[11] Fisher Direct Testimony at 39.

only limited interstate trading, making the market availability of such allowances uncertain at best. The Companies' planning philosophy in the face of such uncertainty is to assume physical compliance, consistent with allotted allowances, will be necessary. This approach allows the Companies to use their allotted allowances advantageously if opportunities arise while ensuring the Companies remain able to meet their service obligations. Therefore, it was prudent for the Companies not to assume high-priced or readily available allowances.

Q. Did Dr. Fisher attempt to quantify the effect of this criticism in any way?

A. No. Once again, Dr. Fisher only raised the issue as a concern with no further support.

<u>Retirement Order</u>

Q. Dr. Fisher suggests that changing the order in which the Companies analyze retiring units could change the decision whether to retire certain units,[12] and attempted to demonstrate the veracity of his suggestion by running a retire-or-retrofit analysis for each unit alone, i.e., as though it were going to be the only unit retired.[13] Does Dr. Fisher's approach show that the Companies' proposed 2011 Plans are sub-optimal?

A. No. Dr. Fisher's comparison of the order of unit consideration in which only a single unit is retired is nonsensical and misleading. Claiming that the Companies' plan is "not the optimal plan" is not supported by his demonstration, which ignores the overall cost of various generation portfolios. Instead, Dr. Fisher has only demonstrated that the difference in net present value revenue requirement ("NPVRR") between building controls and retiring a specific unit can change

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[12] Fisher Direct Testimony at 40.
[13] *See* Environmental Interveners' Oct. 14 responses to the Companies' DR No. 4(b).

depending on the starting point. However, it is the ending point – the total cost of the generating portfolio – that affects costs for customers.

Unlike Dr. Fisher, the Companies approached this complex problem in a prudent, reasonable, and logical way that resulted in the lowest-reasonable-cost portfolio of generating units, including new units and existing units outfitted with the required environmental controls. Clearly, one approach to the problem involves developing a portfolio cost for every possible combination of units and choosing the least cost portfolio on an NPVRR basis. This universe of possible combinations would include even cases where Trimble County Unit 1 is retired, but Tyrone 3 is retained and retrofitted with controls. However, the Companies did not choose to examine these extreme cases because a more reasonable approach was to acknowledge that the higher-variable-cost units with significant environmental retrofit costs were the obvious retirement candidates.

To further illustrate the portfolio costs, considering that there is no challenge from the Environmental Interveners about the Companies' plan to retire the Tyrone, Green River, and Cane Run units, the Companies constructed a portfolio that retires these units, then considers the merits of retaining (and building controls on) or retiring Brown Units 1 and 2. As seen below, the portfolio cost (NPVRR) of the Companies' proposed generating portfolio ("Portfolio A"), which includes the retention of Brown Units 1 and 2 with the proposed controls is $32.8 billion (as noted on page 4 of Exhibit CRS-1 in the Companies' 2011 Compliance Plan), which compares favorably to a more expensive "Portfolio B" with Brown Units 1 and 2 retired at $33.1 billion. Clearly, the Companies' plan to retain and build controls on

Brown Units 1 and 2 is supported by the $296 million lower cost (NPVRR) portfolio.[14]

Portfolio A	
Retired/Replaced Units	
Tyrone 3	
Green River 3	
Green River 4	
Cane Run 4	
Cane Run 5	
Cane Run 6	
Retrofitted Units	
Brown 1-2	
Brown 3	
Ghent 1	
Ghent 2	
Ghent 3	
Ghent 4	
Mill Creek 1-2	
Mill Creek 3	
Mill Creek 4	
Trimble County 1	
Portfolio cost (NPVRR $M)	**$32,811**

Portfolio B	
Retired/Replaced Units	
Tyrone 3	
Green River 3	
Green River 4	
Cane Run 4	
Cane Run 5	
Cane Run 6	
Brown 1-2	
Retrofitted Units	
Brown 3	
Ghent 1	
Ghent 2	
Ghent 3	
Ghent 4	
Mill Creek 1-2	
Mill Creek 3	
Mill Creek 4	
Trimble County 1	
Portfolio cost (NPVRR $M)	**$33,107**

This portfolio analysis supports the Companies' contention that their proposed 2011 Plans will result in being able to serve customers at the lowest reasonable cost, and that their retire-or-retrofit proposals are not sub-optimal.

Furthermore, while the Companies do not agree with the premise of Dr. Fisher's individual retirement concept, the Companies also found an error in Dr.

[14] Trimble County Unit 2 is also part of the generating unit portfolios, but does not require retrofitted controls.

Fisher's results.[15] In the case of Brown Units 1 and 2, the Companies' modeling results in a difference of NPVRR between the retire-or-retrofit cases of $212 million (favorable to retrofitting) versus $137 million in Dr. Fisher's table. The computation for retiring only Brown Units 1 and 2 should be the difference in NPVRR between (1) a generation portfolio with controls on all units and (2) a generation portfolio with controls on all units except Brown Units 1 and 2, since Brown Units 1 and 2 are retired in 2016. Instead, it appears that Dr. Fisher's second portfolio includes the operating costs associated with the Brown Units 1 and 2 controls in 2014-15 (unnecessarily, since Brown Units 1 and 2 are retired in his table) and fails to include operating costs for the retrofitted Tyrone 3 controls (which are required on all non-retired units) throughout the analysis period. The failure to include the operating costs for the Tyrone 3 controls significantly reduces the cost of the second portfolio so that the difference between the two portfolios is significantly lower. This is clearly an error. The Companies did not attempt to discover the presence of other errors in Dr. Fisher's analysis of individual retirements, since the future of the Brown Units 1 and 2 is the primary focus.

Landfill Costs

Q. Do you agree with Dr. Fisher's assertion that the Companies erred in calculating landfill costs in their models?[16]

A. Yes. The Companies acknowledge that a minor spreadsheet error affected the landfill costs.

[15] The Environmental Interveners provided the results of their Strategist runs in an Excel workbook in their Oct. 14 response to the Companies' DR No. 4(b). The Companies used these files to determine the error and precisely replicate the Environmental Interveners' result for Brown Units 1 and 2.

[16] Fisher Direct Testimony at 10-11.

Q. What impact does this error have on the Companies' retrofit-versus-retire analysis?

A. The error resulted in slightly advantaging the Companies' unit retrofit proposals in the filing. The minor correction does not materially affect the results or affect the Companies' recommendations for building the controls in the 2011 Compliance Plan or retiring the Cane Run, Green River, and Tyrone units.

<u>Resource Analysis</u>

Q. Does the current Integrated Resource Planning process enable appropriate long-term resource planning?

A. Yes. Kentucky's IRP requirements, in place since 1991, encourage prudent, consistent, professional, and effective long-term resource planning. The frequency, every three years, is appropriate considering the long-term nature and intent of the plan. The IRP process is not a request for approval of actionable items, nor is it designed to result in firm commitments for resource requirements on a short-term or long-term basis. Rather, it is a forum to provide a long-term view of resource needs based on a snapshot of current conditions and future expectations. Firm commitments for new resources are handled through the Certificate of Public Convenience and Necessity ("CPCN") process, which thoroughly considers the alternatives, including market opportunities and self-build options, to meet particular resource needs as they arise.

Q. Dr. Steinhurst has recommended that the Commission should deny the Companies' applications in these proceedings in total and require the

Companies to perform a complete resource assessment by a date certain.[17] Do you agree that the Companies should perform such an assessment?

A. No. The Companies believe that the resource assessment contained in the 2011 Plans is complete and reasonable, and is based on the thorough resource assessment the Companies conducted in their 2011 IRP. The Companies' 2011 Plans are the result of that assessment and the analyses in these proceedings. Calling for yet another resource analysis is a delay tactic, an invitation to unending analyses and never making a decision (except by default, which would likely result in significant financial harm to customers).

And that is perhaps the real concern the Companies have with the Environmental Interveners' approach in these proceedings. They have leveled criticisms—all of which the Companies have refuted—but proposed no solutions. Indeed, when challenged to provide what they believe are satisfactory solutions to the problems they have posited, the Environmental Interveners have refused to provide solutions or alternatives, preferring instead to give variations on the assertion that it is the Companies' responsibility to support their application, and the Companies' job to put forward alternatives.[18] Although that is true, it is not helpful or constructive merely to say what one thinks is wrong when one is unwilling to say what one thinks is right. For that reason, Dr. Steinhurst's recommendation that the Commission deny the Companies' applications and start all over again sounds like a call for indefinite delay.

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[17] Steinhurst Direct Testimony.

[18] *See* Environmental Interveners' responses to Commission Staff DR Nos. 2(a), 3, and 9(b); Environmental Interveners' responses to Companies' DR Nos. 2, 15, and 29.

Recommendation

Q. What is your recommendation to the Commission?

A. I recommend that the Commission approve the Companies' proposed 2011 Plans, cost recovery for the plans through the Companies' environmental surcharge mechanism, and the requested certificates of public convenience and necessity. The Companies believe their analysis supports their plans for these facilities and is the least-cost solution to comply with the revised NAAQS requirements, the CSAPR, and the HAPs Rule.

Q. Does this conclude your testimony?

A. Yes it does.

APPENDIX A

Please see the folder titled Schram Workpapers on attached CD for a complete collection of source documents and workpapers provided in electronic format, except for those documents for which an internet link has been provided.

Rebuttal Testimony
Exhibit CRS-1

Reservations | Sys Data | Offerings | Resale | NITS/NLS | Reductions | Data | Company | Home | Help | Logout

Ancillary | Offerings | Security | Deals | CG Deals | Schedules | Notices | User | Bulletin | Options | Auction

dbarker 10-18 05:58 EST

LGE

OASIS Archive

Transmission Offering Summary for: LGEE

TP LGEE * Incr MONTHLY Peri ALL POR PJM * Path

Sell ALL * Class FIRM Win ALL POD LGEE * Daylight Savings ☐ Show Active Data ☑

Ref Type POINT_TO_POINT Sub ALL Time Start Today forward Enter

New Posting | User Range | Columns | Hourly Summary | Save Query

ATC/TTC Monitor | Spreadsheet | Download CSV | Upload CSV

Selected time range: **2011-10-18 00:00 ES to 2099-12-31 23:59 ES**

Provider	POR	POD	Start Time ↓	Stop Time	Capacity	Increment	Class	Offer Price	Ceiling Price	Path	
LGEE	PJM	LGEE	2011-11-01 01:00:00 ES	2011-12-01 01:00:00 ES	0	MONTHLY	FIRM	0.0000	0.0000	P/LGEE/PJM-LGEE//	MONTHLY,FI
LGEE	PJM	LGEE	2011-12-01 01:00:00 ES	2012-01-01 01:00:00 ES	776	MONTHLY	FIRM	0.0000	0.0000	P/LGEE/PJM-LGEE//	MONTHLY,FI
LGEE	PJM	LGEE	2012-01-01 01:00:00 ES	2012-02-01 01:00:00 ES	776	MONTHLY	FIRM	0.0000	0.0000	P/LGEE/PJM-LGEE//	MONTHLY,FI
LGEE	PJM	LGEE	2012-02-01 01:00:00 ES	2012-03-01 01:00:00 ES	776	MONTHLY	FIRM	0.0000	0.0000	P/LGEE/PJM-LGEE//	MONTHLY,FI
LGEE	PJM	LGEE	2012-03-01 01:00:00 ES	2012-04-01 01:00:00 ES	0	MONTHLY	FIRM	0.0000	0.0000	P/LGEE/PJM-LGEE//	MONTHLY,FI
LGEE	PJM	LGEE	2012-04-01 01:00:00 ES	2012-05-01 01:00:00 ES	0	MONTHLY	FIRM	0.0000	0.0000	P/LGEE/PJM-LGEE//	MONTHLY,FI
LGEE	PJM	LGEE	2012-05-01 01:00:00 ES	2012-06-01 01:00:00 ES	640	MONTHLY	FIRM	0.0000	0.0000	P/LGEE/PJM-LGEE//	MONTHLY,FI
LGEE	PJM	LGEE	2012-06-01 01:00:00 ES	2012-07-01 01:00:00 ES	590	MONTHLY	FIRM	0.0000	0.0000	P/LGEE/PJM-LGEE//	MONTHLY,FI
LGEE	PJM	LGEE	2012-07-01 01:00:00 ES	2012-08-01 01:00:00 ES	0	MONTHLY	FIRM	0.0000	0.0000	P/LGEE/PJM-LGEE//	MONTHLY,FI
LGEE	PJM	LGEE	2012-08-01 01:00:00 ES	2012-09-01 01:00:00 ES	0	MONTHLY	FIRM	0.0000	0.0000	P/LGEE/PJM-LGEE//	MONTHLY,FI
LGEE	PJM	LGEE	2012-09-01 01:00:00 ES	2012-10-01 01:00:00 ES	640	MONTHLY	FIRM	0.0000	0.0000	P/LGEE/PJM-LGEE//	MONTHLY,FI
LGEE	PJM	LGEE	2012-10-01 01:00:00 ES	2012-11-01 01:00:00 ES	640	MONTHLY	FIRM	0.0000	0.0000	P/LGEE/PJM-LGEE//	MONTHLY,FI

Total: 12 Transofferings

Transmission Offering Summary for: LGEE

TP LGEE *	Incr MONTHLY	Peri ALL	POR MISO *	Path			
Sell ALL *	Class FIRM	Win ALL	POD LGEE *	Daylight Savings ☐	Show Active Data ☑		
Ref	Type POINT_TO_POINT	Sub ALL	Time Start	Today forward	Enter		

New Posting | User Range | Columns | Hourly Summary | Save Query

ATC/TTC Monitor | Spreadsheet | Download CSV | Upload CSV

Selected time range: **2011-10-18 00:00 ES** to **2099-12-31 23:59 ES**

Provider	POR	POD	Start Time ↓	Stop Time	Capacity	Increment	Class	Offer Price	Ceiling Price	Path	
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LGEE	MISO	LGEE	2011-12-01 01:00:00 ES	2012-01-01 01:00:00 ES	1351	MONTHLY	FIRM	0.0000	0.0000	P/LGEE/MISO-LGEE//	MONTHLY,FI
LGEE	MISO	LGEE	2012-01-01 01:00:00 ES	2012-02-01 01:00:00 ES	1571	MONTHLY	FIRM	0.0000	0.0000	P/LGEE/MISO-LGEE//	MONTHLY,FI
LGEE	MISO	LGEE	2012-02-01 01:00:00 ES	2012-03-01 01:00:00 ES	936	MONTHLY	FIRM	0.0000	0.0000	P/LGEE/MISO-LGEE//	MONTHLY,FI
LGEE	MISO	LGEE	2012-03-01 01:00:00 ES	2012-04-01 01:00:00 ES	0	MONTHLY	FIRM	0.0000	0.0000	P/LGEE/MISO-LGEE//	MONTHLY,FI
LGEE	MISO	LGEE	2012-04-01 01:00:00 ES	2012-05-01 01:00:00 ES	0	MONTHLY	FIRM	0.0000	0.0000	P/LGEE/MISO-LGEE//	MONTHLY,FI
LGEE	MISO	LGEE	2012-05-01 01:00:00 ES	2012-06-01 01:00:00 ES	963	MONTHLY	FIRM	0.0000	0.0000	P/LGEE/MISO-LGEE//	MONTHLY,FI
LGEE	MISO	LGEE	2012-06-01 01:00:00 ES	2012-07-01 01:00:00 ES	933	MONTHLY	FIRM	0.0000	0.0000	P/LGEE/MISO-LGEE//	MONTHLY,FI
LGEE	MISO	LGEE	2012-07-01 01:00:00 ES	2012-08-01 01:00:00 ES	0	MONTHLY	FIRM	0.0000	0.0000	P/LGEE/MISO-LGEE//	MONTHLY,FI
LGEE	MISO	LGEE	2012-08-01 01:00:00 ES	2012-09-01 01:00:00 ES	0	MONTHLY	FIRM	0.0000	0.0000	P/LGEE/MISO-LGEE//	MONTHLY,FI
LGEE	MISO	LGEE	2012-09-01 01:00:00 ES	2012-10-01 01:00:00 ES	1379	MONTHLY	FIRM	0.0000	0.0000	P/LGEE/MISO-LGEE//	MONTHLY,FI
LGEE	MISO	LGEE	2012-10-01 01:00:00 ES	2012-11-01 01:00:00 ES	1810	MONTHLY	FIRM	0.0000	0.0000	P/LGEE/MISO-LGEE//	MONTHLY,FI

Total: 12 Transofferings

Daily Firm ATC - PJM to LGEE - Apr 1 2011 to Sept 27 2011

Posting Ref	Provider	Path	POR	POD	Start Time	Stop Time	Capacity	Increment	Class	Type	Ferc Priority
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50863364	LGEE	P/LGEE/PJM	PJM	LGEE	2011-04-02 0	2011-04-03 0	0	DAILY	FIRM	POINT_TO_F	7
50863206	LGEE	P/LGEE/PJM	PJM	LGEE	2011-04-03 0	2011-04-04 0	0	DAILY	FIRM	POINT_TO_F	7
50863218	LGEE	P/LGEE/PJM	PJM	LGEE	2011-04-04 0	2011-04-05 0	0	DAILY	FIRM	POINT_TO_F	7
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50863439	LGEE	P/LGEE/PJM	PJM	LGEE	2011-04-06 0	2011-04-07 0	0	DAILY	FIRM	POINT_TO_F	7
50863615	LGEE	P/LGEE/PJM	PJM	LGEE	2011-04-07 0	2011-04-08 0	0	DAILY	FIRM	POINT_TO_F	7
50863620	LGEE	P/LGEE/PJM	PJM	LGEE	2011-04-08 0	2011-04-09 0	0	DAILY	FIRM	POINT_TO_F	7
50863896	LGEE	P/LGEE/PJM	PJM	LGEE	2011-04-09 0	2011-04-10 0	0	DAILY	FIRM	POINT_TO_F	7
50863902	LGEE	P/LGEE/PJM	PJM	LGEE	2011-04-10 0	2011-04-11 0	0	DAILY	FIRM	POINT_TO_F	7
50863704	LGEE	P/LGEE/PJM	PJM	LGEE	2011-04-11 0	2011-04-12 0	0	DAILY	FIRM	POINT_TO_F	7
50863945	LGEE	P/LGEE/PJM	PJM	LGEE	2011-04-12 0	2011-04-13 0	0	DAILY	FIRM	POINT_TO_F	7
50863747	LGEE	P/LGEE/PJM	PJM	LGEE	2011-04-13 0	2011-04-14 0	0	DAILY	FIRM	POINT_TO_F	7
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50864023	LGEE	P/LGEE/PJM	PJM	LGEE	2011-04-15 0	2011-04-16 0	0	DAILY	FIRM	POINT_TO_F	7
50863799	LGEE	P/LGEE/PJM	PJM	LGEE	2011-04-16 0	2011-04-17 0	0	DAILY	FIRM	POINT_TO_F	7
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51912563	LGEE	P/LGEE/PJM	PJM	LGEE	2011-06-06 0	2011-06-07 0	82	DAILY	FIRM	POINT_TO_F	7
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51969010	LGEE	P/LGEE/PJM	PJM	LGEE	2011-06-08 0	2011-06-09 0	0	DAILY	FIRM	POINT_TO_F	7
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52059509	LGEE	P/LGEE/PJM	PJM	LGEE	2011-06-11 0	2011-06-12 0	613	DAILY	FIRM	POINT_TO_F	7
52087196	LGEE	P/LGEE/PJM	PJM	LGEE	2011-06-12 0	2011-06-13 0	640	DAILY	FIRM	POINT_TO_F	7
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52440776	LGEE	P/LGEE/PJM	PJM	LGEE	2011-06-24 0	2011-06-25 0	640	DAILY	FIRM	POINT_TO_F	7
52469739	LGEE	P/LGEE/PJM	PJM	LGEE	2011-06-25 0	2011-06-26 0	640	DAILY	FIRM	POINT_TO_F	7
52497869	LGEE	P/LGEE/PJM	PJM	LGEE	2011-06-26 0	2011-06-27 0	640	DAILY	FIRM	POINT_TO_F	7
52527032	LGEE	P/LGEE/PJM	PJM	LGEE	2011-06-27 0	2011-06-28 0	640	DAILY	FIRM	POINT_TO_F	7
52556431	LGEE	P/LGEE/PJM	PJM	LGEE	2011-06-28 0	2011-06-29 0	640	DAILY	FIRM	POINT_TO_F	7
52586434	LGEE	P/LGEE/PJM	PJM	LGEE	2011-06-29 0	2011-06-30 0	354	DAILY	FIRM	POINT_TO_F	7
52614803	LGEE	P/LGEE/PJM	PJM	LGEE	2011-06-30 0	2011-07-01 0	640	DAILY	FIRM	POINT_TO_F	7
52646234	LGEE	P/LGEE/PJM	PJM	LGEE	2011-07-01 0	2011-07-02 0	461	DAILY	FIRM	POINT_TO_F	7
52675285	LGEE	P/LGEE/PJM	PJM	LGEE	2011-07-02 0	2011-07-03 0	573	DAILY	FIRM	POINT_TO_F	7
52703342	LGEE	P/LGEE/PJM	PJM	LGEE	2011-07-03 0	2011-07-04 0	640	DAILY	FIRM	POINT_TO_F	7
52733132	LGEE	P/LGEE/PJM	PJM	LGEE	2011-07-04 0	2011-07-05 0	640	DAILY	FIRM	POINT_TO_F	7
52761618	LGEE	P/LGEE/PJM	PJM	LGEE	2011-07-05 0	2011-07-06 0	640	DAILY	FIRM	POINT_TO_F	7
52790743	LGEE	P/LGEE/PJM	PJM	LGEE	2011-07-06 0	2011-07-07 0	640	DAILY	FIRM	POINT_TO_F	7
52823836	LGEE	P/LGEE/PJM	PJM	LGEE	2011-07-07 0	2011-07-08 0	640	DAILY	FIRM	POINT_TO_F	7
52852230	LGEE	P/LGEE/PJM	PJM	LGEE	2011-07-08 0	2011-07-09 0	576	DAILY	FIRM	POINT_TO_F	7
52880867	LGEE	P/LGEE/PJM	PJM	LGEE	2011-07-09 0	2011-07-10 0	640	DAILY	FIRM	POINT_TO_F	7
52913903	LGEE	P/LGEE/PJM	PJM	LGEE	2011-07-10 0	2011-07-11 0	640	DAILY	FIRM	POINT_TO_F	7
52942789	LGEE	P/LGEE/PJM	PJM	LGEE	2011-07-11 0	2011-07-12 0	462	DAILY	FIRM	POINT_TO_F	7
52971049	LGEE	P/LGEE/PJM	PJM	LGEE	2011-07-12 0	2011-07-13 0	0	DAILY	FIRM	POINT_TO_F	7
53000443	LGEE	P/LGEE/PJM	PJM	LGEE	2011-07-13 0	2011-07-14 0	610	DAILY	FIRM	POINT_TO_F	7
53031761	LGEE	P/LGEE/PJM	PJM	LGEE	2011-07-14 0	2011-07-15 0	640	DAILY	FIRM	POINT_TO_F	7
53059680	LGEE	P/LGEE/PJM	PJM	LGEE	2011-07-15 0	2011-07-16 0	640	DAILY	FIRM	POINT_TO_F	7
53088326	LGEE	P/LGEE/PJM	PJM	LGEE	2011-07-16 0	2011-07-17 0	640	DAILY	FIRM	POINT_TO_F	7
53118956	LGEE	P/LGEE/PJM	PJM	LGEE	2011-07-17 0	2011-07-18 0	640	DAILY	FIRM	POINT_TO_F	7
53146162	LGEE	P/LGEE/PJM	PJM	LGEE	2011-07-18 0	2011-07-19 0	640	DAILY	FIRM	POINT_TO_F	7
53176710	LGEE	P/LGEE/PJM	PJM	LGEE	2011-07-19 0	2011-07-20 0	0	DAILY	FIRM	POINT_TO_F	7
53203773	LGEE	P/LGEE/PJM	PJM	LGEE	2011-07-20 0	2011-07-21 0	0	DAILY	FIRM	POINT_TO_F	7
53235718	LGEE	P/LGEE/PJM	PJM	LGEE	2011-07-21 0	2011-07-22 0	0	DAILY	FIRM	POINT_TO_F	7
53264358	LGEE	P/LGEE/PJM	PJM	LGEE	2011-07-22 0	2011-07-23 0	0	DAILY	FIRM	POINT_TO_F	7
53292722	LGEE	P/LGEE/PJM	PJM	LGEE	2011-07-23 0	2011-07-24 0	640	DAILY	FIRM	POINT_TO_F	7
53320743	LGEE	P/LGEE/PJM	PJM	LGEE	2011-07-24 0	2011-07-25 0	640	DAILY	FIRM	POINT_TO_F	7
53350423	LGEE	P/LGEE/PJM	PJM	LGEE	2011-07-25 0	2011-07-26 0	103	DAILY	FIRM	POINT_TO_F	7
53379380	LGEE	P/LGEE/PJM	PJM	LGEE	2011-07-26 0	2011-07-27 0	0	DAILY	FIRM	POINT_TO_F	7
53407579	LGEE	P/LGEE/PJM	PJM	LGEE	2011-07-27 0	2011-07-28 0	0	DAILY	FIRM	POINT_TO_F	7
53439500	LGEE	P/LGEE/PJM	PJM	LGEE	2011-07-28 0	2011-07-29 0	0	DAILY	FIRM	POINT_TO_F	7

53468582	LGEE	P/LGEE/PJM	PJM	LGEE	2011-07-29 0	2011-07-30 0	255	DAILY	FIRM	POINT_TO_F 7
53497757	LGEE	P/LGEE/PJM	PJM	LGEE	2011-07-30 0	2011-07-31 0	640	DAILY	FIRM	POINT_TO_F 7
53568912	LGEE	P/LGEE/PJM	PJM	LGEE	2011-07-31 0	2011-08-01 0	640	DAILY	FIRM	POINT_TO_F 7
53605889	LGEE	P/LGEE/PJM	PJM	LGEE	2011-08-01 0	2011-08-02 0	0	DAILY	FIRM	POINT_TO_F 7
53639805	LGEE	P/LGEE/PJM	PJM	LGEE	2011-08-02 0	2011-08-03 0	0	DAILY	FIRM	POINT_TO_F 7
53673408	LGEE	P/LGEE/PJM	PJM	LGEE	2011-08-03 0	2011-08-04 0	0	DAILY	FIRM	POINT_TO_F 7
53706183	LGEE	P/LGEE/PJM	PJM	LGEE	2011-08-04 0	2011-08-05 0	0	DAILY	FIRM	POINT_TO_F 7
53743094	LGEE	P/LGEE/PJM	PJM	LGEE	2011-08-05 0	2011-08-06 0	0	DAILY	FIRM	POINT_TO_F 7
53776182	LGEE	P/LGEE/PJM	PJM	LGEE	2011-08-06 0	2011-08-07 0	0	DAILY	FIRM	POINT_TO_F 7
53809297	LGEE	P/LGEE/PJM	PJM	LGEE	2011-08-07 0	2011-08-08 0	98	DAILY	FIRM	POINT_TO_F 7
53841851	LGEE	P/LGEE/PJM	PJM	LGEE	2011-08-08 0	2011-08-09 0	0	DAILY	FIRM	POINT_TO_F 7
53873640	LGEE	P/LGEE/PJM	PJM	LGEE	2011-08-09 0	2011-08-10 0	0	DAILY	FIRM	POINT_TO_F 7
53907753	LGEE	P/LGEE/PJM	PJM	LGEE	2011-08-10 0	2011-08-11 0	0	DAILY	FIRM	POINT_TO_F 7
53941235	LGEE	P/LGEE/PJM	PJM	LGEE	2011-08-11 0	2011-08-12 0	116	DAILY	FIRM	POINT_TO_F 7
53977702	LGEE	P/LGEE/PJM	PJM	LGEE	2011-08-12 0	2011-08-13 0	52	DAILY	FIRM	POINT_TO_F 7
54010137	LGEE	P/LGEE/PJM	PJM	LGEE	2011-08-13 0	2011-08-14 0	507	DAILY	FIRM	POINT_TO_F 7
54044065	LGEE	P/LGEE/PJM	PJM	LGEE	2011-08-14 0	2011-08-15 0	370	DAILY	FIRM	POINT_TO_F 7
54077946	LGEE	P/LGEE/PJM	PJM	LGEE	2011-08-15 0	2011-08-16 0	640	DAILY	FIRM	POINT_TO_F 7
54110653	LGEE	P/LGEE/PJM	PJM	LGEE	2011-08-16 0	2011-08-17 0	588	DAILY	FIRM	POINT_TO_F 7
54143119	LGEE	P/LGEE/PJM	PJM	LGEE	2011-08-17 0	2011-08-18 0	640	DAILY	FIRM	POINT_TO_F 7
54178443	LGEE	P/LGEE/PJM	PJM	LGEE	2011-08-18 0	2011-08-19 0	286	DAILY	FIRM	POINT_TO_F 7
54216670	LGEE	P/LGEE/PJM	PJM	LGEE	2011-08-19 0	2011-08-20 0	0	DAILY	FIRM	POINT_TO_F 7
54252942	LGEE	P/LGEE/PJM	PJM	LGEE	2011-08-20 0	2011-08-21 0	0	DAILY	FIRM	POINT_TO_F 7
54286568	LGEE	P/LGEE/PJM	PJM	LGEE	2011-08-21 0	2011-08-22 0	0	DAILY	FIRM	POINT_TO_F 7
54320874	LGEE	P/LGEE/PJM	PJM	LGEE	2011-08-22 0	2011-08-23 0	414	DAILY	FIRM	POINT_TO_F 7
54352639	LGEE	P/LGEE/PJM	PJM	LGEE	2011-08-23 0	2011-08-24 0	0	DAILY	FIRM	POINT_TO_F 7
54386707	LGEE	P/LGEE/PJM	PJM	LGEE	2011-08-24 0	2011-08-25 0	0	DAILY	FIRM	POINT_TO_F 7
54423416	LGEE	P/LGEE/PJM	PJM	LGEE	2011-08-25 0	2011-08-26 0	0	DAILY	FIRM	POINT_TO_F 7
54457183	LGEE	P/LGEE/PJM	PJM	LGEE	2011-08-26 0	2011-08-27 0	229	DAILY	FIRM	POINT_TO_F 7
54490397	LGEE	P/LGEE/PJM	PJM	LGEE	2011-08-27 0	2011-08-28 0	0	DAILY	FIRM	POINT_TO_F 7
54524352	LGEE	P/LGEE/PJM	PJM	LGEE	2011-08-28 0	2011-08-29 0	640	DAILY	FIRM	POINT_TO_F 7
54559205	LGEE	P/LGEE/PJM	PJM	LGEE	2011-08-29 0	2011-08-30 0	302	DAILY	FIRM	POINT_TO_F 7
54594930	LGEE	P/LGEE/PJM	PJM	LGEE	2011-08-30 0	2011-08-31 0	0	DAILY	FIRM	POINT_TO_F 7
54627326	LGEE	P/LGEE/PJM	PJM	LGEE	2011-08-31 0	2011-09-01 0	114	DAILY	FIRM	POINT_TO_F 7
54664606	LGEE	P/LGEE/PJM	PJM	LGEE	2011-09-01 0	2011-09-02 0	34	DAILY	FIRM	POINT_TO_F 7
54701401	LGEE	P/LGEE/PJM	PJM	LGEE	2011-09-02 0	2011-09-03 0	0	DAILY	FIRM	POINT_TO_F 7
54734514	LGEE	P/LGEE/PJM	PJM	LGEE	2011-09-03 0	2011-09-04 0	410	DAILY	FIRM	POINT_TO_F 7
54768508	LGEE	P/LGEE/PJM	PJM	LGEE	2011-09-04 0	2011-09-05 0	433	DAILY	FIRM	POINT_TO_F 7
54802633	LGEE	P/LGEE/PJM	PJM	LGEE	2011-09-05 0	2011-09-06 0	640	DAILY	FIRM	POINT_TO_F 7
54836073	LGEE	P/LGEE/PJM	PJM	LGEE	2011-09-06 0	2011-09-07 0	263	DAILY	FIRM	POINT_TO_F 7
54868147	LGEE	P/LGEE/PJM	PJM	LGEE	2011-09-07 0	2011-09-08 0	640	DAILY	FIRM	POINT_TO_F 7
54906229	LGEE	P/LGEE/PJM	PJM	LGEE	2011-09-08 0	2011-09-09 0	640	DAILY	FIRM	POINT_TO_F 7
54942556	LGEE	P/LGEE/PJM	PJM	LGEE	2011-09-09 0	2011-09-10 0	183	DAILY	FIRM	POINT_TO_F 7
54972588	LGEE	P/LGEE/PJM	PJM	LGEE	2011-09-10 0	2011-09-11 0	183	DAILY	FIRM	POINT_TO_F 7
55007310	LGEE	P/LGEE/PJM	PJM	LGEE	2011-09-11 0	2011-09-12 0	433	DAILY	FIRM	POINT_TO_F 7
55040389	LGEE	P/LGEE/PJM	PJM	LGEE	2011-09-12 0	2011-09-13 0	640	DAILY	FIRM	POINT_TO_F 7
55075006	LGEE	P/LGEE/PJM	PJM	LGEE	2011-09-13 0	2011-09-14 0	0	DAILY	FIRM	POINT_TO_F 7
55108029	LGEE	P/LGEE/PJM	PJM	LGEE	2011-09-14 0	2011-09-15 0	640	DAILY	FIRM	POINT_TO_F 7
55145440	LGEE	P/LGEE/PJM	PJM	LGEE	2011-09-15 0	2011-09-16 0	640	DAILY	FIRM	POINT_TO_F 7
55179665	LGEE	P/LGEE/PJM	PJM	LGEE	2011-09-16 0	2011-09-17 0	640	DAILY	FIRM	POINT_TO_F 7
55214604	LGEE	P/LGEE/PJM	PJM	LGEE	2011-09-17 0	2011-09-18 0	640	DAILY	FIRM	POINT_TO_F 7
55247959	LGEE	P/LGEE/PJM	PJM	LGEE	2011-09-18 0	2011-09-19 0	640	DAILY	FIRM	POINT_TO_F 7
55282233	LGEE	P/LGEE/PJM	PJM	LGEE	2011-09-19 0	2011-09-20 0	640	DAILY	FIRM	POINT_TO_F 7
55315611	LGEE	P/LGEE/PJM	PJM	LGEE	2011-09-20 0	2011-09-21 0	640	DAILY	FIRM	POINT_TO_F 7
55348842	LGEE	P/LGEE/PJM	PJM	LGEE	2011-09-21 0	2011-09-22 0	640	DAILY	FIRM	POINT_TO_F 7
55385838	LGEE	P/LGEE/PJM	PJM	LGEE	2011-09-22 0	2011-09-23 0	640	DAILY	FIRM	POINT_TO_F 7
55420117	LGEE	P/LGEE/PJM	PJM	LGEE	2011-09-23 0	2011-09-24 0	640	DAILY	FIRM	POINT_TO_F 7
55455683	LGEE	P/LGEE/PJM	PJM	LGEE	2011-09-24 0	2011-09-25 0	640	DAILY	FIRM	POINT_TO_F 7
55487073	LGEE	P/LGEE/PJM	PJM	LGEE	2011-09-25 0	2011-09-26 0	640	DAILY	FIRM	POINT_TO_F 7
55520034	LGEE	P/LGEE/PJM	PJM	LGEE	2011-09-26 0	2011-09-27 0	640	DAILY	FIRM	POINT_TO_F 7
55553324	LGEE	P/LGEE/PJM	PJM	LGEE	2011-09-27 0	2011-09-28 0	640	DAILY	FIRM	POINT_TO_F 7

Daily Firm ATC - MISO to LGEE - Apr 1 2011 to Sept 27 2011

Posting Ref.	Provider	Path	POR	POD	Start Time	Stop Time	Capacity	Increment	Class	Type	Nerc Priority
50863141	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-04-01 0	2011-04-02 0	0	DAILY	FIRM	POINT_TO_F	7
50863188	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-04-02 0	2011-04-03 0	0	DAILY	FIRM	POINT_TO_F	7
50863190	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-04-03 0	2011-04-04 0	0	DAILY	FIRM	POINT_TO_F	7
50863235	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-04-04 0	2011-04-05 0	0	DAILY	FIRM	POINT_TO_F	7
50863236	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-04-05 0	2011-04-06 0	0	DAILY	FIRM	POINT_TO_F	7
50863452	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-04-06 0	2011-04-07 0	0	DAILY	FIRM	POINT_TO_F	7
50863455	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-04-07 0	2011-04-08 0	0	DAILY	FIRM	POINT_TO_F	7
50863627	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-04-08 0	2011-04-09 0	0	DAILY	FIRM	POINT_TO_F	7
50863892	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-04-09 0	2011-04-10 0	0	DAILY	FIRM	POINT_TO_F	7
50863907	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-04-10 0	2011-04-11 0	0	DAILY	FIRM	POINT_TO_F	7
50863699	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-04-11 0	2011-04-12 0	0	DAILY	FIRM	POINT_TO_F	7
50863717	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-04-12 0	2011-04-13 0	0	DAILY	FIRM	POINT_TO_F	7
50863742	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-04-13 0	2011-04-14 0	0	DAILY	FIRM	POINT_TO_F	7
50863757	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-04-14 0	2011-04-15 0	0	DAILY	FIRM	POINT_TO_F	7
50864019	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-04-15 0	2011-04-16 0	0	DAILY	FIRM	POINT_TO_F	7
50863804	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-04-16 0	2011-04-17 0	0	DAILY	FIRM	POINT_TO_F	7
50864058	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-04-17 0	2011-04-18 0	0	DAILY	FIRM	POINT_TO_F	7
50864075	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-04-18 0	2011-04-19 0	0	DAILY	FIRM	POINT_TO_F	7
50864185	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-04-19 0	2011-04-20 0	0	DAILY	FIRM	POINT_TO_F	7
50864486	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-04-20 0	2011-04-21 0	0	DAILY	FIRM	POINT_TO_F	7
50864492	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-04-21 0	2011-04-22 0	0	DAILY	FIRM	POINT_TO_F	7
50864528	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-04-22 0	2011-04-23 0	0	DAILY	FIRM	POINT_TO_F	7
50864534	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-04-23 0	2011-04-24 0	0	DAILY	FIRM	POINT_TO_F	7
50864327	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-04-24 0	2011-04-25 0	0	DAILY	FIRM	POINT_TO_F	7
50864332	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-04-25 0	2011-04-26 0	0	DAILY	FIRM	POINT_TO_F	7
50864369	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-04-26 0	2011-04-27 0	0	DAILY	FIRM	POINT_TO_F	7
50864617	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-04-27 0	2011-04-28 0	0	DAILY	FIRM	POINT_TO_F	7
50864416	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-04-28 0	2011-04-29 0	0	DAILY	FIRM	POINT_TO_F	7
50864655	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-04-29 0	2011-04-30 0	0	DAILY	FIRM	POINT_TO_F	7
50864688	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-04-30 0	2011-05-01 0	0	DAILY	FIRM	POINT_TO_F	7
50864703	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-05-01 0	2011-05-02 0	0	DAILY	FIRM	POINT_TO_F	7
50876355	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-05-02 0	2011-05-03 0	1934	DAILY	FIRM	POINT_TO_F	7
50919994	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-05-03 0	2011-05-04 0	0	DAILY	FIRM	POINT_TO_F	7
50947833	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-05-04 0	2011-05-05 0	0	DAILY	FIRM	POINT_TO_F	7
50977131	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-05-05 0	2011-05-06 0	0	DAILY	FIRM	POINT_TO_F	7
51004387	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-05-06 0	2011-05-07 0	1063	DAILY	FIRM	POINT_TO_F	7
51031247	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-05-07 0	2011-05-08 0	920	DAILY	FIRM	POINT_TO_F	7
51066964	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-05-08 0	2011-05-09 0	911	DAILY	FIRM	POINT_TO_F	7
51097247	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-05-09 0	2011-05-10 0	754	DAILY	FIRM	POINT_TO_F	7
51126543	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-05-10 0	2011-05-11 0	558	DAILY	FIRM	POINT_TO_F	7
51153782	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-05-11 0	2011-05-12 0	416	DAILY	FIRM	POINT_TO_F	7
51183651	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-05-12 0	2011-05-13 0	102	DAILY	FIRM	POINT_TO_F	7
51211508	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-05-13 0	2011-05-14 0	706	DAILY	FIRM	POINT_TO_F	7
51240086	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-05-14 0	2011-05-15 0	1324	DAILY	FIRM	POINT_TO_F	7
51268169	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-05-15 0	2011-05-16 0	1251	DAILY	FIRM	POINT_TO_F	7
51297498	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-05-16 0	2011-05-17 0	1966	DAILY	FIRM	POINT_TO_F	7
51326696	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-05-17 0	2011-05-18 0	1716	DAILY	FIRM	POINT_TO_F	7
51353678	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-05-18 0	2011-05-19 0	2005	DAILY	FIRM	POINT_TO_F	7
51382988	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-05-19 0	2011-05-20 0	1652	DAILY	FIRM	POINT_TO_F	7
51411159	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-05-20 0	2011-05-21 0	1259	DAILY	FIRM	POINT_TO_F	7
51440412	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-05-21 0	2011-05-22 0	1160	DAILY	FIRM	POINT_TO_F	7
51469369	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-05-22 0	2011-05-23 0	1288	DAILY	FIRM	POINT_TO_F	7
51503832	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-05-23 0	2011-05-24 0	1676	DAILY	FIRM	POINT_TO_F	7
51539221	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-05-24 0	2011-05-25 0	2096	DAILY	FIRM	POINT_TO_F	7
51566463	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-05-25 0	2011-05-26 0	1379	DAILY	FIRM	POINT_TO_F	7
51596942	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-05-26 0	2011-05-27 0	1297	DAILY	FIRM	POINT_TO_F	7
51627855	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-05-27 0	2011-05-28 0	2593	DAILY	FIRM	POINT_TO_F	7
51657212	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-05-28 0	2011-05-29 0	2629	DAILY	FIRM	POINT_TO_F	7
51686201	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-05-29 0	2011-05-30 0	2590	DAILY	FIRM	POINT_TO_F	7

51705669	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-05-30 0	2011-05-31 0	1254	DAILY	FIRM	POINT_TO_F	7
51733622	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-05-31 0	2011-06-01 0	0	DAILY	FIRM	POINT_TO_F	7
51762901	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-06-01 0	2011-06-02 0	0	DAILY	FIRM	POINT_TO_F	7
51794000	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-06-02 0	2011-06-03 0	0	DAILY	FIRM	POINT_TO_F	7
51822391	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-06-03 0	2011-06-04 0	219	DAILY	FIRM	POINT_TO_F	7
51851054	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-06-04 0	2011-06-05 0	514	DAILY	FIRM	POINT_TO_F	7
51883295	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-06-05 0	2011-06-06 0	724	DAILY	FIRM	POINT_TO_F	7
51912562	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-06-06 0	2011-06-07 0	869	DAILY	FIRM	POINT_TO_F	7
51940295	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-06-07 0	2011-06-08 0	0	DAILY	FIRM	POINT_TO_F	7
51969009	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-06-08 0	2011-06-09 0	0	DAILY	FIRM	POINT_TO_F	7
51999411	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-06-09 0	2011-06-10 0	0	DAILY	FIRM	POINT_TO_F	7
52030011	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-06-10 0	2011-06-11 0	0	DAILY	FIRM	POINT_TO_F	7
52059509	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-06-11 0	2011-06-12 0	441	DAILY	FIRM	POINT_TO_F	7
52087195	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-06-12 0	2011-06-13 0	1319	DAILY	FIRM	POINT_TO_F	7
52117393	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-06-13 0	2011-06-14 0	908	DAILY	FIRM	POINT_TO_F	7
52145558	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-06-14 0	2011-06-15 0	454	DAILY	FIRM	POINT_TO_F	7
52174376	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-06-15 0	2011-06-16 0	0	DAILY	FIRM	POINT_TO_F	7
52207711	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-06-16 0	2011-06-17 0	403	DAILY	FIRM	POINT_TO_F	7
52235222	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-06-17 0	2011-06-18 0	557	DAILY	FIRM	POINT_TO_F	7
52263943	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-06-18 0	2011-06-19 0	710	DAILY	FIRM	POINT_TO_F	7
52292637	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-06-19 0	2011-06-20 0	670	DAILY	FIRM	POINT_TO_F	7
52321693	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-06-20 0	2011-06-21 0	0	DAILY	FIRM	POINT_TO_F	7
52352016	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-06-21 0	2011-06-22 0	0	DAILY	FIRM	POINT_TO_F	7
52379541	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-06-22 0	2011-06-23 0	0	DAILY	FIRM	POINT_TO_F	7
52410728	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-06-23 0	2011-06-24 0	0	DAILY	FIRM	POINT_TO_F	7
52440775	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-06-24 0	2011-06-25 0	633	DAILY	FIRM	POINT_TO_F	7
52469738	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-06-25 0	2011-06-26 0	1874	DAILY	FIRM	POINT_TO_F	7
52497868	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-06-26 0	2011-06-27 0	2038	DAILY	FIRM	POINT_TO_F	7
52527031	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-06-27 0	2011-06-28 0	293	DAILY	FIRM	POINT_TO_F	7
52556430	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-06-28 0	2011-06-29 0	177	DAILY	FIRM	POINT_TO_F	7
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52614802	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-06-30 0	2011-07-01 0	500	DAILY	FIRM	POINT_TO_F	7
52646234	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-07-01 0	2011-07-02 0	401	DAILY	FIRM	POINT_TO_F	7
52675272	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-07-02 0	2011-07-03 0	495	DAILY	FIRM	POINT_TO_F	7
52703341	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-07-03 0	2011-07-04 0	564	DAILY	FIRM	POINT_TO_F	7
52733131	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-07-04 0	2011-07-05 0	0	DAILY	FIRM	POINT_TO_F	7
52761618	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-07-05 0	2011-07-06 0	0	DAILY	FIRM	POINT_TO_F	7
52790742	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-07-06 0	2011-07-07 0	0	DAILY	FIRM	POINT_TO_F	7
52823835	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-07-07 0	2011-07-08 0	521	DAILY	FIRM	POINT_TO_F	7
52852229	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-07-08 0	2011-07-09 0	495	DAILY	FIRM	POINT_TO_F	7
52880902	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-07-09 0	2011-07-10 0	992	DAILY	FIRM	POINT_TO_F	7
52913903	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-07-10 0	2011-07-11 0	953	DAILY	FIRM	POINT_TO_F	7
52942788	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-07-11 0	2011-07-12 0	0	DAILY	FIRM	POINT_TO_F	7
52971048	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-07-12 0	2011-07-13 0	0	DAILY	FIRM	POINT_TO_F	7
53000442	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-07-13 0	2011-07-14 0	0	DAILY	FIRM	POINT_TO_F	7
53031760	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-07-14 0	2011-07-15 0	605	DAILY	FIRM	POINT_TO_F	7
53059679	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-07-15 0	2011-07-16 0	461	DAILY	FIRM	POINT_TO_F	7
53088325	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-07-16 0	2011-07-17 0	535	DAILY	FIRM	POINT_TO_F	7
53118955	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-07-17 0	2011-07-18 0	508	DAILY	FIRM	POINT_TO_F	7
53146161	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-07-18 0	2011-07-19 0	0	DAILY	FIRM	POINT_TO_F	7
53176710	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-07-19 0	2011-07-20 0	0	DAILY	FIRM	POINT_TO_F	7
53203772	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-07-20 0	2011-07-21 0	0	DAILY	FIRM	POINT_TO_F	7
53235718	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-07-21 0	2011-07-22 0	0	DAILY	FIRM	POINT_TO_F	7
53264357	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-07-22 0	2011-07-23 0	0	DAILY	FIRM	POINT_TO_F	7
53292721	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-07-23 0	2011-07-24 0	177	DAILY	FIRM	POINT_TO_F	7
53320742	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-07-24 0	2011-07-25 0	559	DAILY	FIRM	POINT_TO_F	7
53350422	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-07-25 0	2011-07-26 0	0	DAILY	FIRM	POINT_TO_F	7
53379379	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-07-26 0	2011-07-27 0	0	DAILY	FIRM	POINT_TO_F	7
53407578	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-07-27 0	2011-07-28 0	0	DAILY	FIRM	POINT_TO_F	7
53439499	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-07-28 0	2011-07-29 0	0	DAILY	FIRM	POINT_TO_F	7
53468581	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-07-29 0	2011-07-30 0	189	DAILY	FIRM	POINT_TO_F	7

53497756	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-07-30 0	2011-07-31 0	714	DAILY	FIRM	POINT_TO_F 7
53568911	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-07-31 0	2011-08-01 0	744	DAILY	FIRM	POINT_TO_F 7
53605888	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-08-01 0	2011-08-02 0	0	DAILY	FIRM	POINT_TO_F 7
53639804	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-08-02 0	2011-08-03 0	0	DAILY	FIRM	POINT_TO_F 7
53673408	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-08-03 0	2011-08-04 0	0	DAILY	FIRM	POINT_TO_F 7
53706182	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-08-04 0	2011-08-05 0	0	DAILY	FIRM	POINT_TO_F 7
53743087	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-08-05 0	2011-08-06 0	0	DAILY	FIRM	POINT_TO_F 7
53776181	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-08-06 0	2011-08-07 0	0	DAILY	FIRM	POINT_TO_F 7
53809296	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-08-07 0	2011-08-08 0	482	DAILY	FIRM	POINT_TO_F 7
53841850	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-08-08 0	2011-08-09 0	0	DAILY	FIRM	POINT_TO_F 7
53873639	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-08-09 0	2011-08-10 0	0	DAILY	FIRM	POINT_TO_F 7
53907753	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-08-10 0	2011-08-11 0	0	DAILY	FIRM	POINT_TO_F 7
53941234	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-08-11 0	2011-08-12 0	106	DAILY	FIRM	POINT_TO_F 7
53977701	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-08-12 0	2011-08-13 0	419	DAILY	FIRM	POINT_TO_F 7
54010136	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-08-13 0	2011-08-14 0	1745	DAILY	FIRM	POINT_TO_F 7
54044064	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-08-14 0	2011-08-15 0	2136	DAILY	FIRM	POINT_TO_F 7
54077945	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-08-15 0	2011-08-16 0	24	DAILY	FIRM	POINT_TO_F 7
54110652	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-08-16 0	2011-08-17 0	0	DAILY	FIRM	POINT_TO_F 7
54143118	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-08-17 0	2011-08-18 0	0	DAILY	FIRM	POINT_TO_F 7
54178442	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-08-18 0	2011-08-19 0	244	DAILY	FIRM	POINT_TO_F 7
54216669	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-08-19 0	2011-08-20 0	248	DAILY	FIRM	POINT_TO_F 7
54252941	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-08-20 0	2011-08-21 0	1228	DAILY	FIRM	POINT_TO_F 7
54286567	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-08-21 0	2011-08-22 0	1716	DAILY	FIRM	POINT_TO_F 7
54320873	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-08-22 0	2011-08-23 0	49	DAILY	FIRM	POINT_TO_F 7
54352639	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-08-23 0	2011-08-24 0	0	DAILY	FIRM	POINT_TO_F 7
54386706	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-08-24 0	2011-08-25 0	0	DAILY	FIRM	POINT_TO_F 7
54423415	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-08-25 0	2011-08-26 0	0	DAILY	FIRM	POINT_TO_F 7
54457182	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-08-26 0	2011-08-27 0	303	DAILY	FIRM	POINT_TO_F 7
54490396	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-08-27 0	2011-08-28 0	1529	DAILY	FIRM	POINT_TO_F 7
54524351	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-08-28 0	2011-08-29 0	1474	DAILY	FIRM	POINT_TO_F 7
54559204	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-08-29 0	2011-08-30 0	61	DAILY	FIRM	POINT_TO_F 7
54594929	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-08-30 0	2011-08-31 0	0	DAILY	FIRM	POINT_TO_F 7
54627325	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-08-31 0	2011-09-01 0	18	DAILY	FIRM	POINT_TO_F 7
54664605	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-09-01 0	2011-09-02 0	29	DAILY	FIRM	POINT_TO_F 7
54701401	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-09-02 0	2011-09-03 0	0	DAILY	FIRM	POINT_TO_F 7
54734513	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-09-03 0	2011-09-04 0	355	DAILY	FIRM	POINT_TO_F 7
54768507	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-09-04 0	2011-09-05 0	778	DAILY	FIRM	POINT_TO_F 7
54802632	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-09-05 0	2011-09-06 0	696	DAILY	FIRM	POINT_TO_F 7
54836072	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-09-06 0	2011-09-07 0	554	DAILY	FIRM	POINT_TO_F 7
54868146	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-09-07 0	2011-09-08 0	1015	DAILY	FIRM	POINT_TO_F 7
54906228	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-09-08 0	2011-09-09 0	373	DAILY	FIRM	POINT_TO_F 7
54942555	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-09-09 0	2011-09-10 0	658	DAILY	FIRM	POINT_TO_F 7
54972587	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-09-10 0	2011-09-11 0	539	DAILY	FIRM	POINT_TO_F 7
55007310	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-09-11 0	2011-09-12 0	2020	DAILY	FIRM	POINT_TO_F 7
55040388	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-09-12 0	2011-09-13 0	762	DAILY	FIRM	POINT_TO_F 7
55075005	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-09-13 0	2011-09-14 0	504	DAILY	FIRM	POINT_TO_F 7
55108028	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-09-14 0	2011-09-15 0	612	DAILY	FIRM	POINT_TO_F 7
55145439	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-09-15 0	2011-09-16 0	1633	DAILY	FIRM	POINT_TO_F 7
55179664	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-09-16 0	2011-09-17 0	1928	DAILY	FIRM	POINT_TO_F 7
55214604	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-09-17 0	2011-09-18 0	1399	DAILY	FIRM	POINT_TO_F 7
55247958	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-09-18 0	2011-09-19 0	1434	DAILY	FIRM	POINT_TO_F 7
55282232	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-09-19 0	2011-09-20 0	377	DAILY	FIRM	POINT_TO_F 7
55315610	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-09-20 0	2011-09-21 0	389	DAILY	FIRM	POINT_TO_F 7
55348841	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-09-21 0	2011-09-22 0	459	DAILY	FIRM	POINT_TO_F 7
55385837	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-09-22 0	2011-09-23 0	1457	DAILY	FIRM	POINT_TO_F 7
55420117	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-09-23 0	2011-09-24 0	2298	DAILY	FIRM	POINT_TO_F 7
55455683	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-09-24 0	2011-09-25 0	2625	DAILY	FIRM	POINT_TO_F 7
55487073	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-09-25 0	2011-09-26 0	2625	DAILY	FIRM	POINT_TO_F 7
55520033	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-09-26 0	2011-09-27 0	350	DAILY	FIRM	POINT_TO_F 7
55553323	LGEE	P/LGEE/MIS(	MISO	LGEE	2011-09-27 0	2011-09-28 0	370	DAILY	FIRM	POINT_TO_F 7

Rebuttal Testimony
Exhibit CRS-2

REBUTTAL EXHIBIT CRS-2

	NPVRR Delta at Varying Emergency Energy Cost ($/MWh)				
	100	1,000	5,000	10,000	Compliance Plan (16,600)
TY	4	4	2	1	-1
GR3	-26	-28	-39	-52	-69
BR3	525	530	548	572	603
CR4	-166	-162	-142	-119	-87
CR6	8	8	9	10	11
BR1-2	205	207	213	220	230
CR5	-66	-65	-63	-60	-57
GH3	888	890	898	908	921
GH1	752	754	766	781	800
GR4	-96	-96	-95	-95	-94
MC4	803	806	820	837	859
TC1	930	933	949	969	996
GH4	1,100	1,104	1,118	1,137	1,161
MC3	705	708	720	736	756
GH2	1,095	1,098	1,110	1,126	1,146
MC1-2	942	946	965	990	1,022

Note: The values above reflect the correction of the landfill cost error identified by Dr. Fisher and the error identified by the Companies' in response to Supplemental Requests for Information of Rick Clewett, Raymond Barry, Sierra Club and the Natural Resource Defense Council dated August 18, 2011, Question No. 8(b). The impact of these errors is insignificant.

Rebuttal Testimony
Exhibit CRS-3

2011

LG&E and KU 2011 Reserve Margin Study

Astrape Consulting
4/8/2011

Contents

Executive Summary

The purpose of this study is to determine the optimum planning reserve margin for the Louisville Gas & Electric Company and Kentucky Utilities (the "Companies") based on estimated total costs and risks to customers. Customers generally expect power to be available 24 hours a day, 365 days a year, but due to excessive costs it is imprudent for a load serving entity to hold enough reserves to always meet this expectation. Therefore, it is necessary for utilities to understand their risks relative to resource adequacy by determining the expected frequency and cost of reliability events. As a load serving entity increases its planning reserve margin, the total cost of carrying reserves rises while the costs related directly to reliability events decrease. The optimal planning reserve margin is the reserve margin where the cost of carrying reserves plus the cost of reliability events (or reliability energy) is minimized.

In determining the optimum reserve margin, SERVM[1] (Strategic Energy and Risk Valuation Model) was used to model the uncertainty in weather, unit performance, load growth, and import capability from interconnected regions. Other key inputs include the value of unserved energy, the cost of expensive market purchases, and the cost of new peaking capacity[2]. As additional peaking capacity is installed, the Companies can expect to reduce the following:

- Cost of Unserved Energy Events
- Cost of Expensive Purchased Power
- Cost of Dispatching Expensive Peaking Resources

In this analysis, these costs are collectively referred to as "reliability energy costs". When using SERVM, reliability energy costs were computed over thousands of scenarios and various reserve margin levels (from 10 to 24 percent) to determine how these costs decrease as reserves increase.

[1] SERVM has been used extensively by large utilities in the south-eastern U.S. for economic reserve margin studies, demand side resource evaluation, cost of intermittent or energy limited resources, and the economic and reliability value of tie line capacity to neighboring power systems.

[2] In this study, the cost of new peaking capacity is the cost of a new combustion turbine.

The reliability energy costs are then added to the cost of carrying reserves and the point at which these total reliability costs are minimized is the optimal reserve margin.

The resulting distributions of reliability energy costs and cost of carrying reserves were utilized to determine the optimal reserve margin level. Figure ES1 plots the distributions of reliability energy costs while Figure ES2 plots the cost for carrying reserves. Both are plotted at varying reserve margin levels. It is seen that reliability energy costs are extremely volatile across scenarios while the cost of carrying reserves is fixed. Reliability energy costs are relatively small in 50% of all scenarios. However, when combinations of extreme events such as generation outages, severe weather, load forecast error, and low import capability occur, these costs can be substantial. For a 12% reserve margin level, reliability energy costs can range from 200 thousand dollars to 900 million dollars for a single year. As illustrated in Figure ES2, the cost of carrying reserves increase as reserve margin increases. These costs are fixed across all scenarios because additional capacity can be constructed or purchased through a bilateral contract effectively locking in that cost for many years.

Figure ES1. Distribution of Reliability Energy Costs

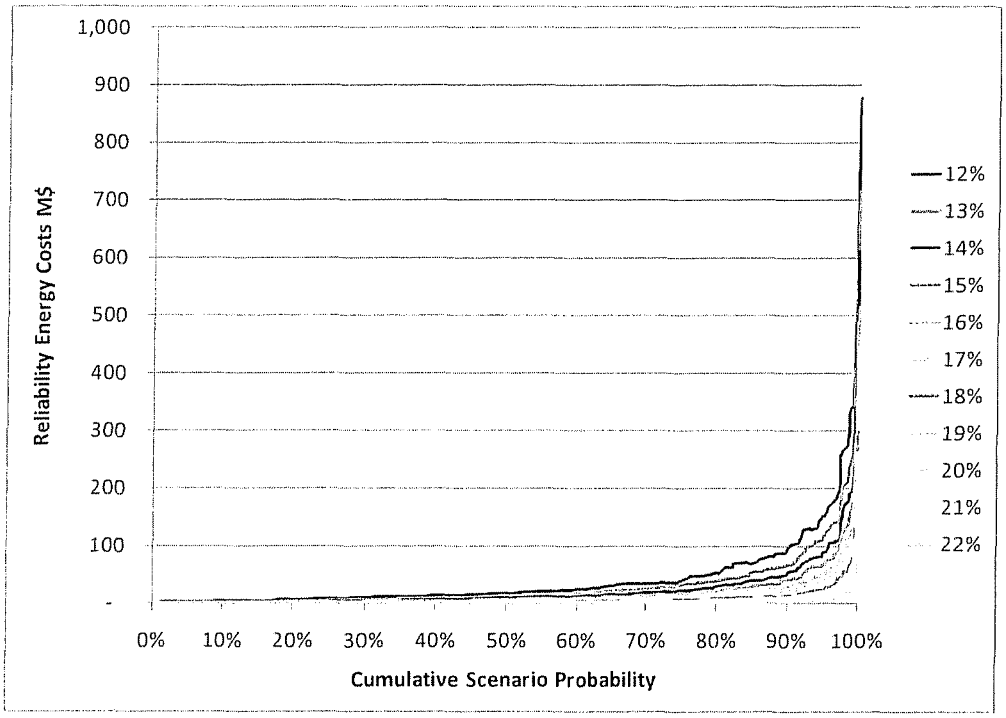
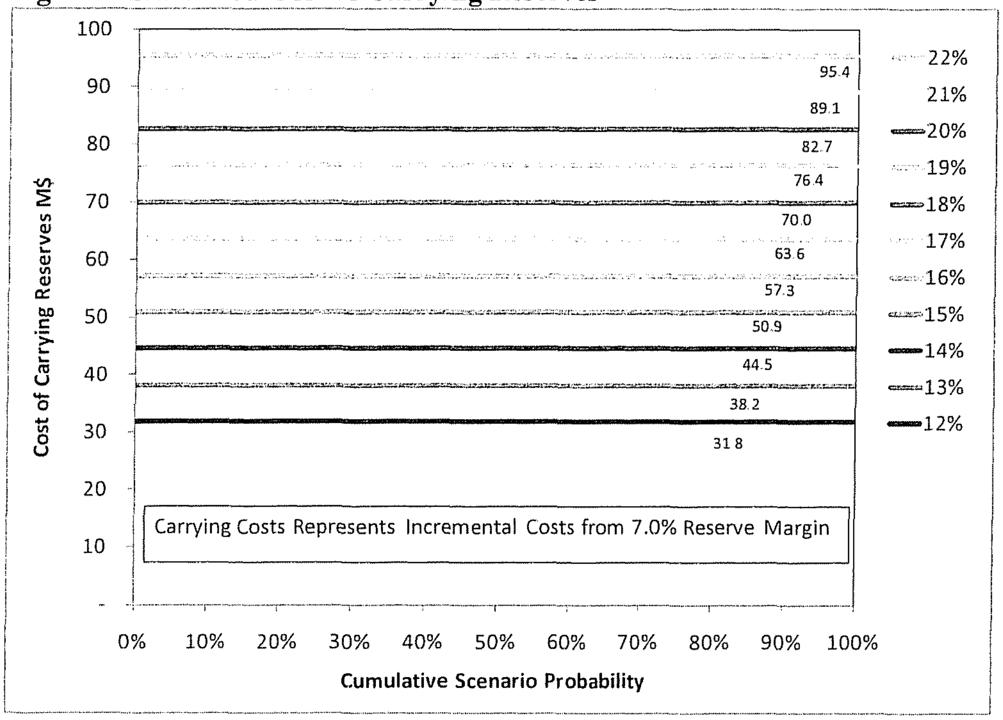
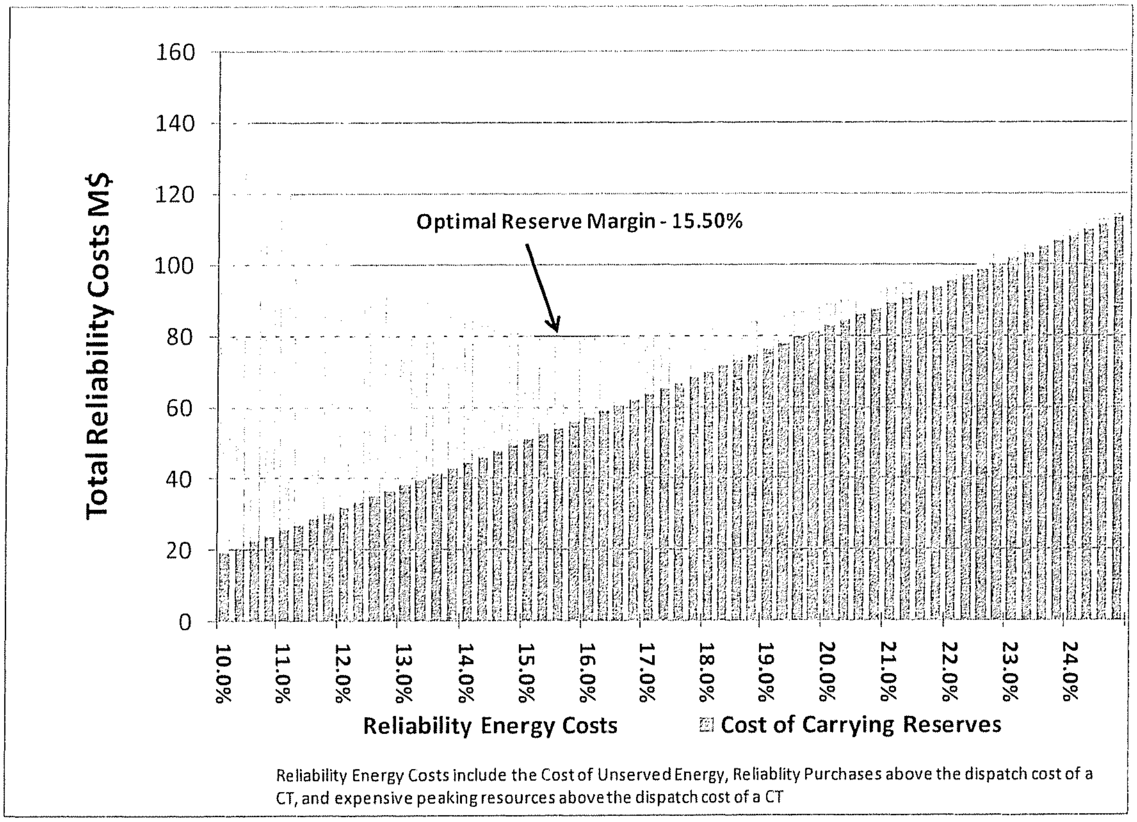


Figure ES2. Fixed Cost of Carrying Reserves



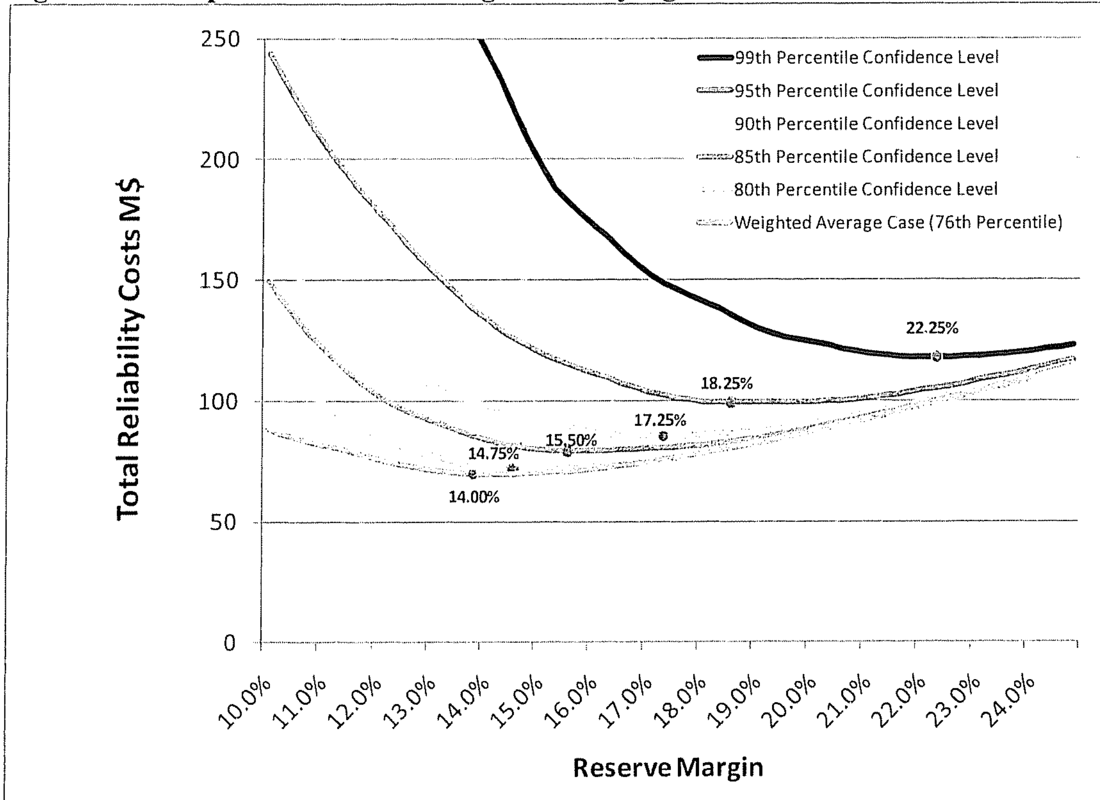
The optimal reserve margin is where the sum of the cost of reliability energy costs (Distributions from ES1) and the cost of carrying reserves (Distributions from ES2) is minimized. However, since reliability costs are extraordinarily volatile but capacity costs are fixed, a conversion is necessary to put the two on the same basis. The casualty insurance industry faces a similar issue in computing a fixed premium for which it can viably accept the risk associated with potentially volatile casualty payouts. In this industry, the premium that best mitigates the company's exposure to the distribution of casualty payouts is typically computed as a value between the 85th and 95th percent confidence levels on this distribution. Therefore, in this example, if an insurance company were assuming the risks shown in Figure ES1, then an approximate premium would equal the 85th - 95th confidence level of the distribution. Astrape Consulting recommends a similar risk adjustment using reliability energy costs at the 85th to 90th confidence level range based on its experience in performing reserve margin studies for other jurisdictions within the southeast because these levels have resulted in the lowest cost resource plans that also avoid unreasonable risk for utilities, regulators, and customers. Figure ES3 summarizes total reliability costs assuming reliability energy costs at the 85th percentile. As reserve margin increases, reliability energy costs decrease and the cost of carrying reserves increase. With this assumption, total reliability costs are minimized at a reserve margin of 15.50%.

Figure ES3. Optimal Reserve Margin with Reliability Energy Costs at 85th Percentile Confidence Level



Next, total reliability costs were calculated assuming reliability energy costs at various confidence levels to understand how the least cost reserve margin is impacted by this assumption. Figure ES4 displays these results without the individual components being shown.

Figure ES4. Optimal Reserve Margin at Varying Confidence Intervals



	Weighted Average (76th Percentile)	85% Confidence Level	90% Confidence Level	95% Confidence Level	99% Confidence Level
Optimal Reserve Margin	14.00%	15.50%	17.25%	18.25%	22.25%

The recommended range of reserve margin assuming the 85th and 90th confidence levels of reliability energy costs is between 15.50% and 17.25%. The weighted average case assumes the reliability energy costs are weighted based on the probability of each scenario which happens to fall out at the 76th percentile point on the distribution. However, it is Astrape Consulting's experience that assuming this as a long term planning reserve margin provides more risk than utilities and regulators are willing to take in a given year even though it may minimize average costs in the long run. Based on Figure ES1, a 14.00% reserve margin results in a risk that in 5% of all scenarios reliability energy costs would exceed 90 million dollars and 1% of the time they would exceed $200 million dollars. A 15.50% reserve margin lowers this exposure to 60 million dollars and 140 million dollars respectively. In contrast, the 99 percentile confidence level reserve margin of 22.25% eliminates almost all risk but puts an unreasonable amount of cost on customers as shown in Figure ES4.

It is recognized that many inputs used to set the target reserve margin could vary more than expected introducing more reliability events. Several sensitivities were performed to understand how major assumptions impact the results. These sensitivities included varying the cost of carrying reserves, varying the cost of expected unserved energy, removing all tie assistance, increasing unit forced outage rates, decreasing neighbor reserve capacity, decreasing transmission limits, and increasing market prices during scarce conditions. Table ES5 shows the sensitivity of the minimum cost reserve margin to various input assumptions at several confidence levels of reliability energy costs. It is seen that the cost of EUE has little impact on the overall results. This is due to the fact that unserved energy events are short and infrequent events. The remaining sensitivities are discussed in greater detail in the full report.

Table ES5. Sensitivity Analysis

	Weighted Average	85% Confidence Level	90% Confidence Level	95% Confidence Level
EUE = $5,000/MWh	13.75%	15.50%	17.00%	18.00%
Base Case Optimal Reserve Margin (EUE = $16,600/MWh)	**14.00%**	**15.50%**	**17.25%**	**18.25%**
EUE = $30,000/MWh	14.25%	16.00%	17.75%	18.75%
Cost of Capacity - $110/kW-yr	13.25%	15.25%	16.50%	18.00%
Base Case Optimal Reserve Margin (Cost of Capacity = $88.42/kW-yr)	**14.00%**	**15.50%**	**17.25%**	**18.25%**
Cost of Capacity - $70/kW-yr	14.75%	17.25%	18.50%	20.75%

	Weighted Average (76th Percentile)	85% Confidence Level	90% Confidence Level	95% Confidence Level
Optimal Reserve Margin	14.00%	15.50%	17.25%	18.25%
Scarcity Pricing Sensitivity - Increase by 50%	15.25%	17.50%	19.00%	20.25%
EFOR Sensitivity - Increase by 50%	17.00%	19.00%	21.25%	22.75%
Neighbor Reserve Margin Sensitivity - 15% RM to 12% RM	16.00%	18.00%	20.25%	22.00%
Transmission Sensitivity - Decrease by 50%	15.00%	16.75%	18.25%	19.50%
Island Sensitivity - No Interconnection Ties	21.75%	23.75%	24.75%	26.00%

In conclusion, the simulation results demonstrate the Companies' potential risk due to lower planning reserve margins and show that low probability, high impact cost exposures exist at all reserve margin levels. No system is 100% reliable and this reliability assessment has quantified the frequency and duration of major events and their economic impact on customers under a full distribution of weather years, unit performance, and load forecast uncertainty. The study also demonstrates the value of capacity reserve margins to the extent they protect customers from extreme, high cost outcomes. Based on the simulations and sensitivities, the precedent set by other industries, and experience in other jurisdictions, Astrape Consulting recommends that the Companies set a long-term target reserve margin using the 85th to 90th percentile of reliability energy costs which results in reserve margins between 15% and 17%.

I. List of figures

II. List of tables

III. Input Assumptions

A. Study Year

The selected study year is 2016. The year was chosen because it typically takes a utility 4 to 5 years to develop and install capacity once a decision to build new generation is confirmed. This process includes necessary regulatory approvals, air permits, engineering and design, construction, and startup and testing. Due to changing load forecasts, load shapes, outage data, resource mix, and other factors, the study results should be updated periodically.

B. Load Modeling

Table 1. 2016 Load Forecast

Month	Energy (MWh)	Peak Demand (MW)	Peak Demand (MW)*
1	3,692,991	7269	7144
2	3,332,365	6962	6726
3	3,217,290	6205	6205
4	2,913,918	5297	5297
5	2,785,636	5611	5611
6	3,231,899	6592	6528
7	3,539,916	7011	6886
8	3,627,576	7196	7070
9	2,947,541	6536	6471
10	2,766,808	5103	5103
11	2,736,902	5186	5186
12	3,191,820	6061	6061

*Assumes Reduction For Interruptible Loads

Table 1 displays the monthly peak and energy forecast for 2016 under normal weather conditions. To model the effects of weather uncertainty, 35 synthetic load shapes based on 35 years of historical weather were created to reflect the impact of weather on load. The frequency and duration of severe weather has a significant impact on load shape and therefore reliability simulations. Based on the last seven years of historical weather and load, a neural network program was used to develop relationships between weather observations, such as temperature, and load. This relationship was then used to develop 35 unique load shapes based on the last 35 years of weather. The synthetic load shapes were then scaled so that the average summer and winter peaks are equivalent to the 2016 forecasted summer and winter peaks. Equal probabilities were given to each of the 35 load shapes in the simulation. Table 2 summarizes the 35 synthetic weather year peaks (not reduced by interruptible load). It is seen that in the most severe weather conditions, the summer peak can be 7% higher than normal weather conditions whereas the most extreme winter peak is only 5% higher than normal weather conditions. The last section of the table represents the distribution of annual energy values seen over the last 35 years.

Table 2. 2016 Peak Load Rankings for All Weather Years

Summer Peaks (MW)

Max	7,729	107%
Average	7,196	
Min	6,699	93%

Rank	Year	Peak (MW)
1	1983	7,729
2	1999	7,727
3	2007	7,648
4	1995	7,555
5	2005	7,503
6	1980	7,480
7	1990	7,474
8	1988	7,473
9	1978	7,401
10	1991	7,376
11	2002	7,374
12	2006	7,373
13	1993	7,323
14	1977	7,270
15	1987	7,232
16	1994	7,223
17	1979	7,154
18	1998	7,150
19	1997	7,134
20	2000	7,132
21	1981	7,109
22	1996	7,080
23	1986	7,061
24	2001	7,049
25	1989	7,044
26	2008	7,024
27	1976	7,004
28	1975	6,979
29	2003	6,934
30	2009	6,877
31	1992	6,849
32	1985	6,839
33	1984	6,806
34	2004	6,763
35	1982	6,699

Winter Peaks (MW)

Max	7,621	105%
Average	7,269	
Min	6,714	92%

Rank	Year	Peak (MW)
1	1977	7,621
2	2003	7,557
3	2009	7,556
4	1982	7,514
5	1978	7,489
6	1981	7,484
7	1992	7,469
8	2000	7,463
9	1984	7,460
10	2004	7,440
11	1994	7,436
12	1995	7,429
13	1979	7,416
14	1997	7,399
15	1987	7,393
16	1999	7,335
17	1976	7,323
18	2001	7,319
19	2005	7,299
20	2008	7,254
21	2007	7,220
22	1989	7,199
23	1983	7,190
24	1998	7,169
25	1991	7,144
26	1980	7,102
27	2006	7,098
28	1986	7,090
29	1985	7,081
30	1988	7,040
31	1993	6,980
32	2002	6,941
33	1996	6,911
34	1975	6,884
35	1990	6,714

Annual Energy (GWh)

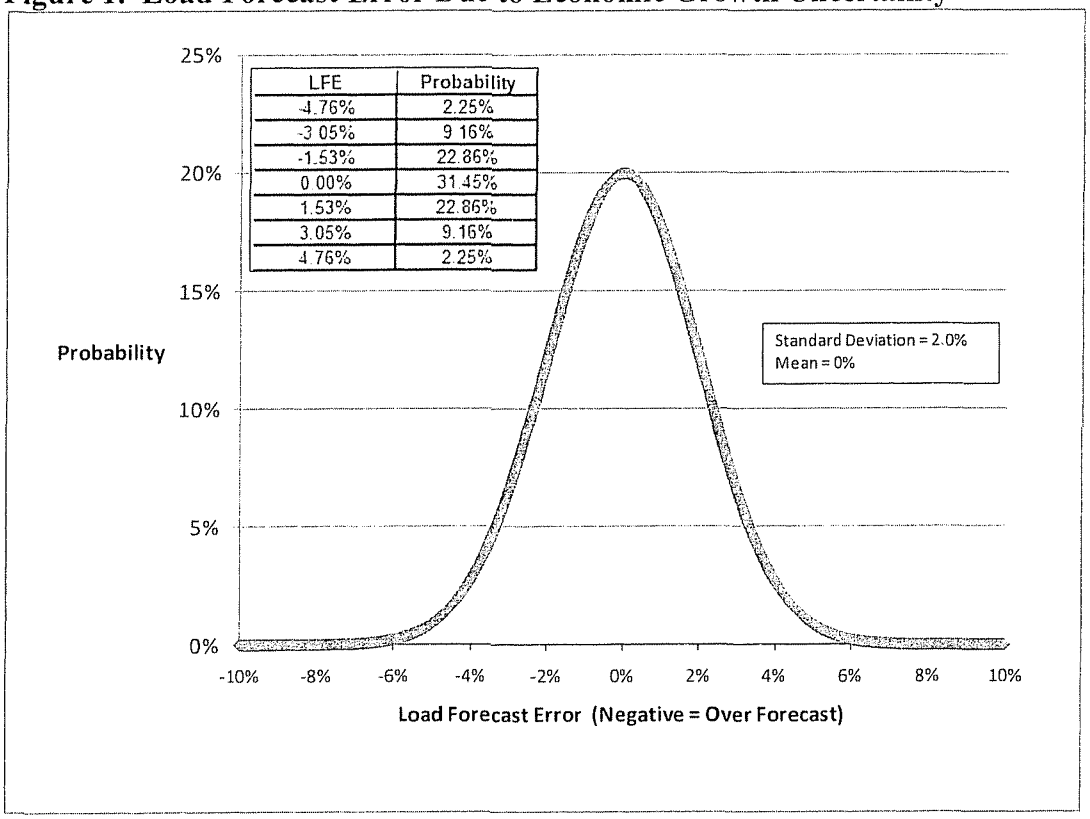
Max	39,102	103%
Average	37,925	
Min	36,822	97%

Rank	Year	Energy (GWh)
1	1977	39,102
2	1978	38,814
3	1980	38,757
4	2007	38,693
5	2002	38,670
6	1983	38,597
7	1988	38,542
8	2008	38,457
9	1995	38,356
10	2005	38,205
11	1991	38,140
12	1993	38,041
13	1989	38,018
14	1987	38,004
15	1981	37,994
16	1986	37,994
17	1979	37,974
18	1999	37,963
19	1985	37,896
20	1996	37,844
21	2000	37,801
22	1975	37,753
23	1994	37,675
24	2003	37,663
25	1984	37,624
26	1982	37,615
27	2001	37,539
28	1998	37,496
29	1997	37,404
30	2009	37,305
31	2004	37,296
32	2006	37,276
33	1976	37,163
34	1990	36,868
35	1992	36,822

C. *Load Forecast Error due to Economic Growth Uncertainty*

Based on the observed load forecast error using 4 and 5 year load forecasts compared to normalized peak loads for the same periods, the following distribution was created to represent load forecast error relative to economic growth uncertainty. The continuous normal distribution was converted into a discrete distribution with the 7 points shown in the table below for use in determining discrete scenarios to be modeled. In the most extreme cases modeled, load can be as much at 4.76% higher than the 5 year forecast due to economic growth assumptions. This scenario has a 2.25% probability of occurring.

Figure 1. Load Forecast Error Due to Economic Growth Uncertainty



SERVM utilized each of the 35 weather years and applied each of these 7 load forecast error points to create 245 different load scenarios. Given that SERVM matches load and generation perfectly, every MW of load above the available capacity is calculated as EUE, but no adjustment is made for shedding more load than is required. In actual practice, load would be curtailed in large blocks and would be off longer than necessary. This limitation was offset by adding 50 MW of load to each hour in the study above the load forecast error assumption.

D. Resources

The resources and assumed monthly capacities for the 2016 study are shown in the following tables. For the simulation, the amounts of peaking units were varied to achieve different reserve margin levels. Once all existing peaking resources were utilized, a generic combustion turbine was used which is documented in Part J of the input section.

Table 3. Summary of Resources

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Base Load and Intermediate Capacity	5,688	5,688	5,658	5,599	5,599	5,568	5,568	5,568	5,599	5,658	5,656	5,686
Peaking Capacity	2,341	2,341	2,166	2,238	2,238	2,115	2,115	2,115	2,238	2,166	2,166	2,341
Hydro Capacity	130	130	130	130	130	130	130	130	130	130	130	130
Total	8,159	8,159	7,954	7,967	7,967	7,813	7,813	7,813	7,967	7,954	7,952	8,157

Table 4. Base load and Intermediate Capacity

Base Load and IntermediateCapacity	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Brown.1	107	107	107	105	105	105	105	105	105	107	107	107
Brown.2	167	167	167	165	165	165	165	165	165	167	167	167
Brown.3	407	407	407	403	403	403	403	403	403	407	407	407
Ghent.1	481	481	481	488	488	488	488	488	488	481	481	481
Ghent.2	476	476	476	486	486	486	486	486	486	476	476	476
Ghent.3	480	480	465	465	465	449	449	449	465	465	465	480
Ghent.4	491	491	487	487	487	483	483	483	487	487	487	491
Mill.Creek.1	300	300	300	300	300	300	300	300	300	300	298	298
Mill.Creek.2	296	296	296	298	298	298	298	298	298	296	296	296
Mill.Creek.3	393	393	393	387	387	387	387	387	387	393	393	393
Mill.Creek.4	487	487	487	472	472	472	472	472	472	487	487	487
Trimble.County.1	381	381	381	378	378	378	378	378	378	381	381	381
Trimble.County.2	571	571	560	560	560	549	549	549	560	560	560	571
Tyrone.3	0	0	0	0	0	0	0	0	0	0	0	0
Combined.Cycle.2016 (2x1)	651	651	651	605	605	605	605	605	605	651	651	651
Total	5,688	5,688	5,658	5,599	5,599	5,568	5,568	5,568	5,599	5,658	5,656	5,686

Table 5. Peaking Capacity

Peaking Capacity	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Brown.10	129	129	116	116	116	102	102	102	116	116	116	129
Brown.11	129	129	116	116	116	102	102	102	116	116	116	129
Brown.5	131	131	122	122	122	112	112	112	122	122	122	131
Brown.6	163	163	155	155	155	146	146	146	155	155	155	163
Brown.7	163	163	155	155	155	146	146	146	155	155	155	163
Brown.8	129	129	116	116	116	102	102	102	116	116	116	129
Brown.9	129	129	116	116	116	102	102	102	116	116	116	129
Cane.Run.11	14	14	14	14	14	14	14	14	14	14	14	14
Haefling	42	42	42	36	36	36	36	36	36	42	42	42
Paddys.Run.11T	13	13	13	12	12	12	12	12	12	13	13	13
Paddys.Run.12T	28	28	28	23	23	23	23	23	23	28	28	28
Paddys.Run.13T	175	175	167	167	167	158	158	158	167	167	167	175
Trimble.Co.05T	180	180	165	165	165	160	160	160	165	165	165	180
Trimble.Co.06T	180	180	165	165	165	160	160	160	165	165	165	180
Trimble.Co.07T	180	180	165	165	165	160	160	160	165	165	165	180
Trimble.Co.08T	180	180	165	165	165	160	160	160	165	165	165	180
Trimble.Co.09T	180	180	165	165	165	160	160	160	165	165	165	180
Trimble.Co.10T	180	180	165	165	165	160	160	160	165	165	165	180
Zorn.1	16	16	16	14	14	14	14	14	14	16	16	16
Brown.ICE.Units	0	0	0	86	86	86	86	86	86	0	0	0
Total	2,341	2,341	2,166	2,238	2,238	2,115	2,115	2,115	2,238	2,166	2,166	2,341

Table 6. Hydro Capacity

Hydro	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Ohio.Falls	100	100	100	100	100	100	100	100	100	100	100	100
Dix.Dam	30	30	30	30	30	30	30	30	30	30	30	30
Total*	130	130	130	130	130	130	130	130	130	130	130	130

*Expected Capacity Available during Summer Peak hours is 94 MW

E. Unit Outage Data

Generating units typically operate for a period of time, fail and are repaired, and then operate again. SERVM uses historical outage events for each unit representing both full outages and partial outages. SERVM then randomly selects operating events from the historical events to determine generator availability. For every hour, each unit will be on reserve shutdown, operating, partially failed, completely failed, or on scheduled maintenance. GADS data was available for all units and data from 2007 – 2010 was used for this study to accurately represent the frequency and duration of full and partial outages. An example of the outage data input into SERVM is below.

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Table 7. Full Outage Example

		Summer Time to Fail Hours	Summer Time to Repair Hours	Winter Time to Fail Hours	Winter Time to Repair Hours	Off Peak Time to Fail Hours	Off Peak Time to Repair Hours
Ghent 1		[redacted]					
Ghent 1		[redacted]					
Ghent 1		[redacted]					
Ghent 1		[redacted]					

Table 8. Partial Outage Example

		Summer Time to Fail Hours	Summer Time to Repair Hours	Summer Derate %	Winter Time to Fail Hours	Winter Time to Repair Hours	Winter Derate %	Off Peak Time to Fail Hours	Off Peak Time to Repair Hours	Off Peak Derate %
Ghent 1		[redacted]								
Ghent 1		[redacted]								
Ghent 1		[redacted]								
Ghent 1		[redacted]								

The following Equivalent Forced Outage Rates were targeted for each unit.

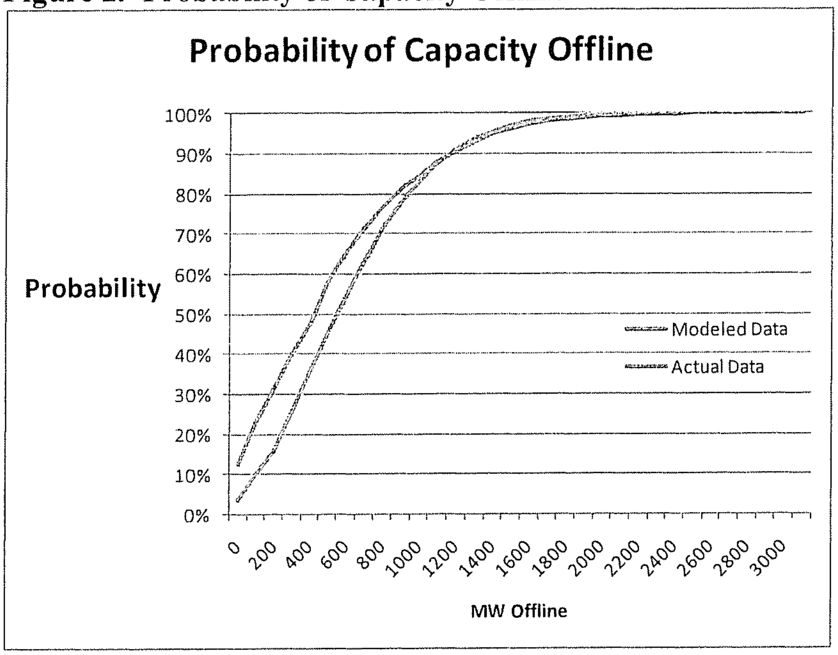
Table 9. Equivalent Forced Outage Rate

Unit	EFOR
Brown 5	[redacted]
Brown 6	[redacted]
Brown 7	[redacted]
Brown 8	[redacted]
Brown 9	[redacted]
Brown 10	[redacted]
Brown 11	[redacted]
Trimble Co 5	[redacted]
Trimble Co 6	[redacted]
Trimble Co 7	[redacted]
Trimble Co 8	[redacted]
Trimble Co 9	[redacted]
Trimble Co 10	[redacted]
Paddy's Run 13	[redacted]
Cane Run 11	[redacted]
Haefling 1	[redacted]
Haefling 2	[redacted]
Haefling 3	[redacted]
Paddy's Run 11	[redacted]
Paddy's Run 12	[redacted]
Zorn 1	[redacted]

Unit	EFOR
Brown 1	[redacted]
Brown 2	[redacted]
Brown 3	[redacted]
Ghent 1	[redacted]
Ghent 2	[redacted]
Ghent 3	[redacted]
Ghent 4	[redacted]
Mill Creek 1	[redacted]
Mill Creek 2	[redacted]
Mill Creek 3	[redacted]
Mill Creek 4	[redacted]
Trimble County 1	[redacted]
Trimble County 2	[redacted]
Tyrone 3	[redacted]

Figure 2 shows the total capacity offline as a percentage of total time. The chart compares the actual 2007 – 2010 data to the simulated distribution created within SERVM. This comparison demonstrates the ability of the model to accurately predict the frequency and duration of generator outages based on history to ensure that the tails of the distribution are reasonable. It is seen that approximately 20% of the time, there are at least 1,000 MW offline due to generator outages or 80% of the time that there are less than 1,000 MW offline.

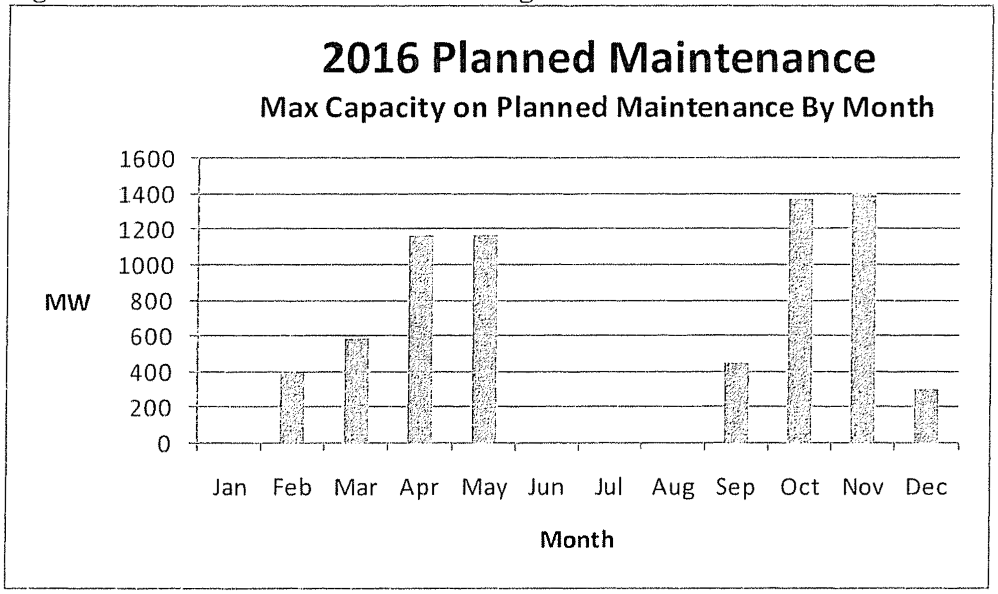
Figure 2. Probability of Capacity Offline



F. Planned Outage Data

The planned outage schedule for 2016 was incorporated into the analysis. Figure 3 shows the planned outages modeled in the simulation.

Figure 3. Planned Maintenance Outages



G. Hydro Modeling

Based on upgrades planned at Ohio Falls and Dix Dam, it is expected that 130 MW of hydro capacity will exist in 2016. However, it is not expected that all 130 MW of hydro capacity will be available on peak and based on operator input, the units were only dispatched up to 94 MW on peak. SERVM has the ability to divide the hydro energy into run or river, scheduled energy with minimum flow requirements, and emergency energy. Ohio Falls and Dix Dam were modeled as scheduled energy and allowed to be optimally dispatched to peak load while only allowing 94 MW of capacity to be utilized across the peak. Given the small amount of hydro on the system, it unlikely the assumptions regarding hydro would be extremely material.

H. Load Management

A total of 126 MWs of load management were modeled in the simulation to be called upon given a reliability event similarly to a generating resource. These resources are called after all peaking resources are utilized. SERVM takes into account the user input constraints on load

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management and dispatches accordingly. These constraints include a market price threshold before the interruptible contracts are called, a maximum number of hours per day, days per week, and hours per year. Because most of the company's load management contracts force them to dispatch all existing resources first, the dispatch price was set at $500/MWh. Table 10 summarizes the load management modeling.

Table 10. Load Management Representation

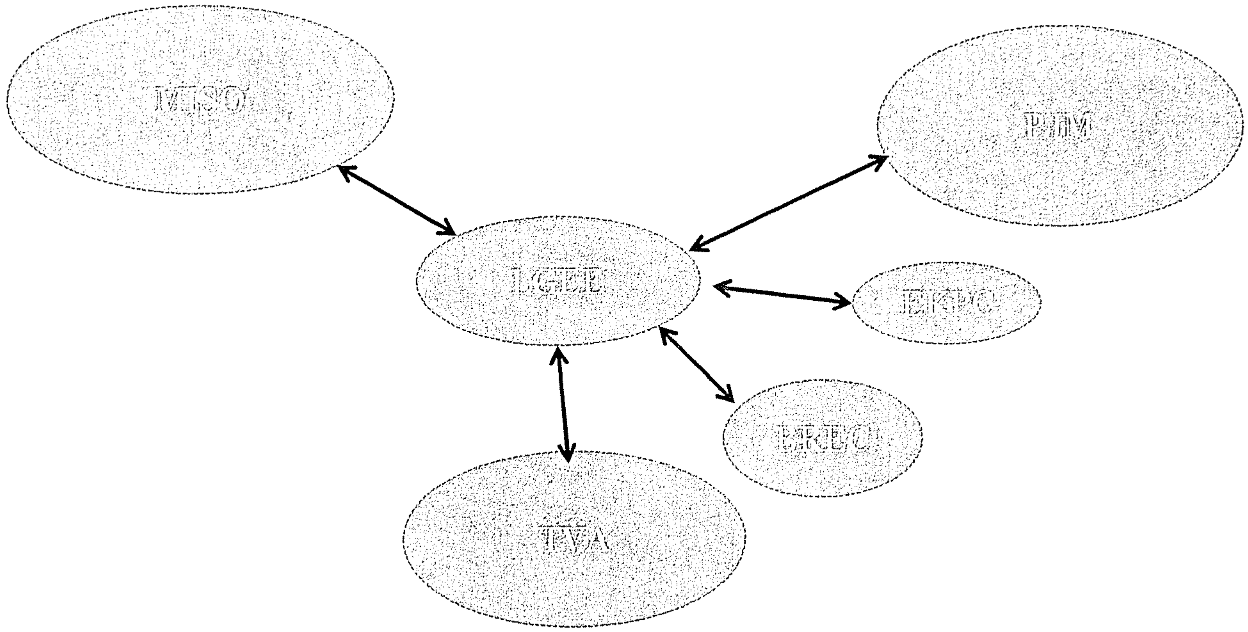
	Capacity	Dispatch Constraints			
Interruptible Contracts	MW	Hours Per Year	Hours Per Day	Days Per Week	Dispatch Price $/MWh*
[redacted]		100	14	7	500
		200	14	7	0
		100	14	7	500
		100	14	7	500
		150	14	7	0
		100	14	7	500
Total	125.6				

*$500 /MWh was chosen to ensure that interruptibles were called after all resources and market purchases were dispatched. The contracts that have a $0 dispatch price are called after the last CT is called.

I. Neighbor Representation and Reliability Purchase Modeling

The purpose of the market purchase modeling is to ensure that in a reliability event, SERVM takes into account the ability of a utility to purchase capacity from its neighbors if capacity and transmission are available. It is expected that if a utility is in a reliability event due to high load conditions or extreme weather, then surrounding neighbors will likely be experiencing similar conditions causing capacity to be scarce. SERVM calculates on an hourly basis, the expected capacity that is available in surrounding regions, the expected amount of import capability, and the scarcity premium that will be charged for the reliability purchase. Figure 4 displays the representation of interconnected neighbors.

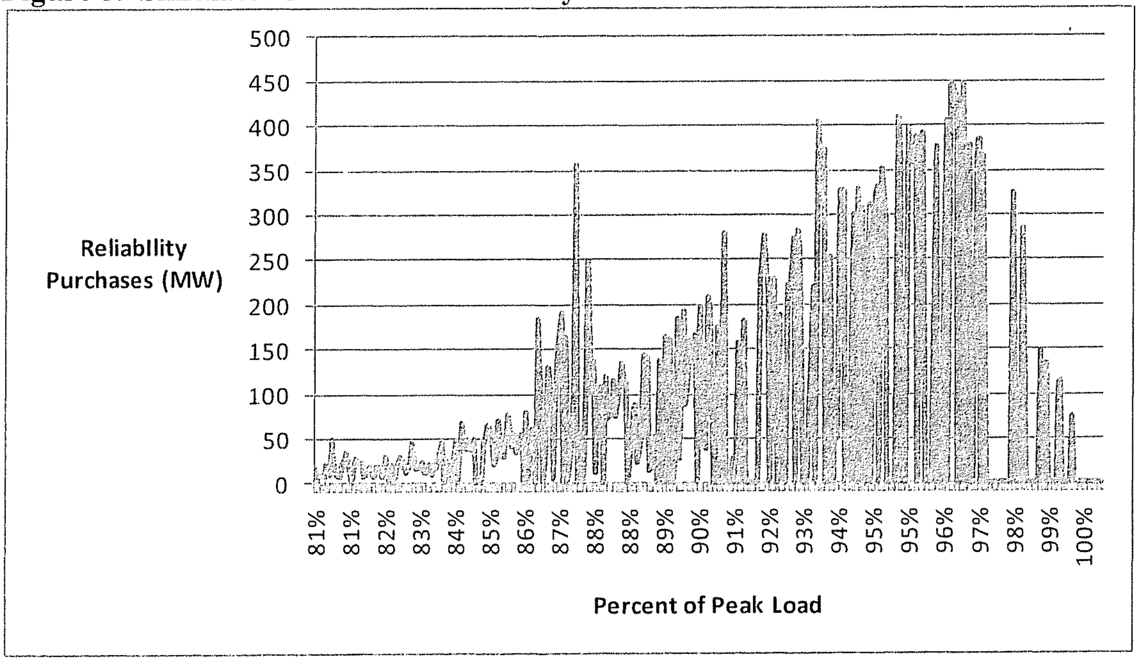
Figure 4. Neighbor Summary



Area	Reference for Capacity	Capacity	Peak Load	Reserve Margin
PJM	PJM 2009 Reserve Margin Study	184,000	160,000	15%
MISO	MISO LOLE Update for 2010, 2014, 2019	125,776	109,370	15%
EKPC	EIA 860 Forms	3,592	3,123	15%
TVA	EIA 860 Forms	40,226	34,979	15%
BREC	EIA 860 Forms	1,971	1,714	15%

The surrounding neighbor capacity information is based on publicly available information and engineering judgment. It was assumed that by 2016, surrounding areas will carry a 15% reserve margin level. Each neighbor's capacity is dispatched to load to determine the hourly available generation at each interface. SERVM is a transportation model in which transmission interface limits are input and varied hourly across each import interface. Historical hourly import capability was analyzed to establish a distribution that was representative of available transmission capacity. Astrape Consulting calibrated the amount of purchases predicted by the model based on historical purchases during high load periods. The amount of purchases that are occurring on average by load level in the simulations can be seen in Figure 5. As load increases, reliability purchases increase but then decrease as the peak load is approached due to overall scarcity in the region.

Figure 5. Simulated Market Purchases by Load Level



The scarcity cost curves in Figure 6 represent the pricing that was assumed for purchases in the model. The prices represent the additional premium for energy above the cost of a CT. As reserve margins in the region for a given year are low and capacity shortages occur, the premium for energy in those hours is substantially higher than in conditions when reserves in the region are high. Reliability purchases are called upon after peaking resources have been dispatched in the system. It should be noted that these curves do not determine whether or not capacity is available, instead the curves are only used for the price if capacity and import capability from another region is available. These curves are based on actual company purchases over the last 6 years and extrapolated to tighter conditions and capped at the cost of unserved energy. As part of the modeling process, Astrape Consulting calibrated the model results to recent years to ensure that SERVM is predicting reliability purchase costs reasonably.

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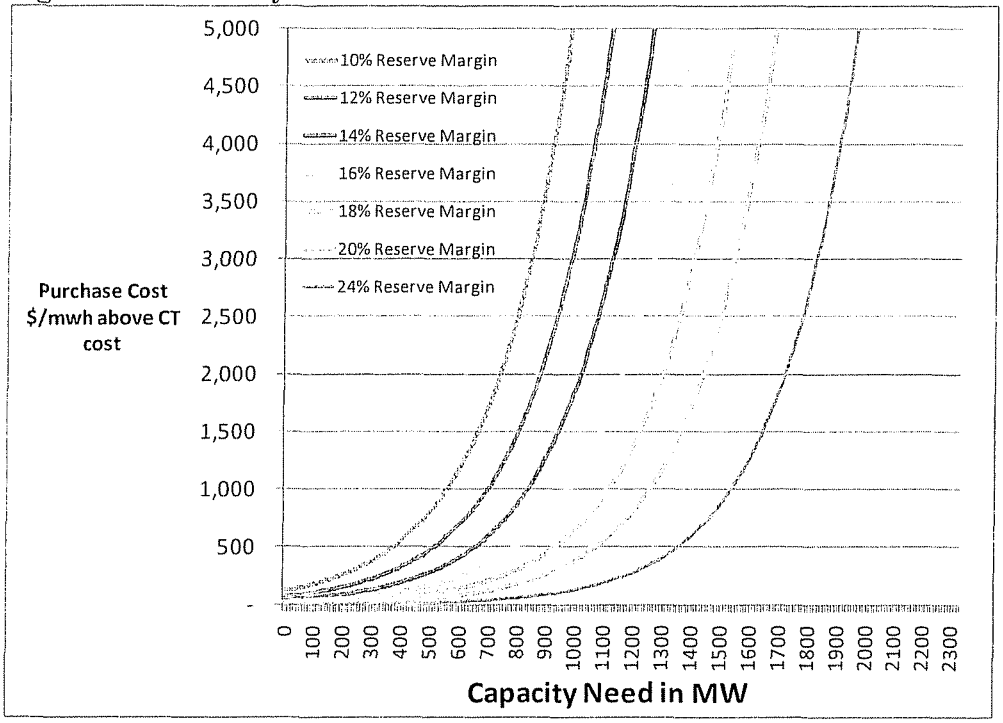
Figure 6. Reliability Purchase Price Model



J. Carrying Cost of Reserves

The cost of carrying incremental reserves was based on the capital and fixed O&M of a new combustion turbine with the following characteristics.

Table 11. Generic Combustion Turbine Characteristics

Marginal Combustion Turbine

Fixed Charge Rate	10.38%
Capital Cost - 2010 $/kW-yr	[redacted]
Fixed O&M 2010$ $/kW-yr	6.12
Escalation Assumption	2.50%
Discount Rate	6.96%
Variable O&M 2010 $/MWh	25.38
Heat Rate btu/kWh	10,446

For this study additional reserves cost $[redacted]/kW-yr as shown in Table 12.

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Table 12. Carrying Cost of Reserves

	Capital Cost	Fixed O&M	
	$/kW-yr	$/kW-yr	$/kW-yr
2016	[redacted]	$ 7.10	[redacted]

K. Operating Reserve Requirements

The total operating reserve requirement assumed in the study is 287 MW. The spinning reserve requirement is 212 MW. Within the simulation, it is assumed that the company would shed firm load in order to maintain operating reserve requirements.

L. Cost of Unserved Energy (Value of Lost Load)

Some of the impacts of outages on business and residential customers include loss of productivity, interruption of a manufacturing process, lost product, potential damage to electrical services, and inconvenience or discomfort due to loss of cooling, heating, or lighting. While the value of lost load is important to understand, the risk of paying expensive market purchases in the market place impacts results more than the assumption for the value of lost load. For this study, unserved energy costs were derived based on information from four publicly available studies. Two of the studies were performed by the Berkeley National Laboratory for the Department of Energy in 2003 and 2009 respectively. All studies split customers into residential, commercial, and industrial classes which is a typical breakdown of customers in the electric industry. After escalating the costs from each study to 2010 dollars and weighting the cost based on LG&E and KU customer class weightings across all four studies, the cost of unserved energy costs was calculated to be $14.97/kWh. Table 13 shows how the numbers were derived. The range for residential customers varied from $1.1/kWh to $2.82/kWh. The range for commercial customers varied from \$20.22/kWh to \$29.94/kWh while industrial customers varied from \$10.48/kWh to \$24.31/kWh. It is expected that commercial and industrial customers would place a much higher value on reliability given the impact of lost production and/or product. The total system cost variance across the four studies was approximately \$6,000/MWh. As part of the reserve margin study, an additional sensitivity was performed to analyze how the cost of unserved energy assumption impacts the optimal planning reserve margin. Optimum reserve margins using a range of lost load value from \$5000 to \$30000/MWh only varied from 0.50% to 0.75% due to the rarity of outage events.

Table 13. Costs of Unserved Energy

	Customer Class Mix	2003 DOE Study \$/kWh	2009 DOE Study \$/kWh	Christian Associates Study \$/kWh	Billinton and Wacker Study \$/kWh
Residential	34%	1.32	1.12	2.82	2.47
Commercial	36%	29.94	27.20	20.22	21.01
Industrial	30%	17.27	24.31	10.48	21.01
System Cost of Unserved Energy		16.37	17.46	11.35	14.71

	Customer Class Mix	Min \$/kWh	Mean \$/kWh	Max \$/kWh	Variance \$/kWh
Residential	34%	1.12	1.93	2.82	1.69
Commercial	36%	20.22	24.59	29.94	9.72
Industrial	30%	10.48	18.27	24.31	13.83
Average System Cost of Unserved Energy \$/kWh			14.97		
All Values Scaled to 2010\$					

IV. Simulation Methodology

Since most reliability events are high impact, low probability events, a large number of scenarios must be considered in order to capture these events. Simply constructing worst case scenarios will not give an accurate representation of the operation of any system during such an event, nor would it provide the likelihood of such a scenario. By utilizing 35 years of historical weather, a robust distribution of load shapes will be considered. For each load shape, 7 load growth multipliers are used to represent the uncertainty in the growth of the economy. For each of these 245 cases (35 load shapes * 7 economic forecast uncertainty points), 400 iterations of unit performance were simulated to allow for results to converge in each case resulting in 98,000 hourly simulations for each reserve margin level. From this analysis, an expected reliability energy costs can be calculated and compared to the cost of adding additional reserves which is equal to the carrying cost of a generic CT.

A. Case Probabilities

The probabilities given for each case are shown in Table 14. It is assumed that each weather year is given equal probability and each weather year is multiplied by the probability of each load forecast error point to calculate the overall case probability.

Table 14. Case Probabilities

Weather Year	Weather Year Probability	LDF Errors	LDF Probability	Case Probability	Weather Year	Weather Year Probability	LDF Errors	LDF Probability	Case Probability
1975	2.9%	-4.76%	2.2%	0.1%	1983	2.9%	-4.8%	2.2%	0.1%
1975	2.9%	-3.05%	9.2%	0.3%	1983	2.9%	-3.0%	9.2%	0.3%
1975	2.9%	-1.53%	22.9%	0.7%	1983	2.9%	-1.5%	22.9%	0.7%
1975	2.9%	0.00%	31.5%	0.9%	1983	2.9%	0.0%	31.5%	0.9%
1975	2.9%	1.53%	22.9%	0.7%	1983	2.9%	1.5%	22.9%	0.7%
1975	2.9%	3.05%	9.2%	0.3%	1983	2.9%	3.0%	9.2%	0.3%
1975	2.9%	4.76%	2.2%	0.1%	1983	2.9%	4.8%	2.2%	0.1%
1976	2.9%	-4.8%	2.2%	0.1%	1984	2.9%	-4.8%	2.2%	0.1%
1976	2.9%	-3.0%	9.2%	0.3%	1984	2.9%	-3.0%	9.2%	0.3%
1976	2.9%	-1.5%	22.9%	0.7%	1984	2.9%	-1.5%	22.9%	0.7%
1976	2.9%	0.0%	31.5%	0.9%	1984	2.9%	0.0%	31.5%	0.9%
1976	2.9%	1.5%	22.9%	0.7%	1984	2.9%	1.5%	22.9%	0.7%
1976	2.9%	3.0%	9.2%	0.3%	1984	2.9%	3.0%	9.2%	0.3%
1976	2.9%	4.8%	2.2%	0.1%	1984	2.9%	4.8%	2.2%	0.1%
1977	2.9%	-4.8%	2.2%	0.1%	1985	2.9%	-4.8%	2.2%	0.1%
1977	2.9%	-3.0%	9.2%	0.3%	1985	2.9%	-3.0%	9.2%	0.3%
1977	2.9%	-1.5%	22.9%	0.7%	1985	2.9%	-1.5%	22.9%	0.7%
1977	2.9%	0.0%	31.5%	0.9%	1985	2.9%	0.0%	31.5%	0.9%
1977	2.9%	1.5%	22.9%	0.7%	1985	2.9%	1.5%	22.9%	0.7%
1977	2.9%	3.0%	9.2%	0.3%	1985	2.9%	3.0%	9.2%	0.3%
1977	2.9%	4.8%	2.2%	0.1%	1985	2.9%	4.8%	2.2%	0.1%
1978	2.9%	-4.8%	2.2%	0.1%	1986	2.9%	-4.8%	2.2%	0.1%
1978	2.9%	-3.0%	9.2%	0.3%	1986	2.9%	-3.0%	9.2%	0.3%
1978	2.9%	-1.5%	22.9%	0.7%	1986	2.9%	-1.5%	22.9%	0.7%
1978	2.9%	0.0%	31.5%	0.9%	1986	2.9%	0.0%	31.5%	0.9%
1978	2.9%	1.5%	22.9%	0.7%	1986	2.9%	1.5%	22.9%	0.7%
1978	2.9%	3.0%	9.2%	0.3%	1986	2.9%	3.0%	9.2%	0.3%
1978	2.9%	4.8%	2.2%	0.1%	1986	2.9%	4.8%	2.2%	0.1%
1979	2.9%	-4.8%	2.2%	0.1%	1987	2.9%	-4.8%	2.2%	0.1%
1979	2.9%	-3.0%	9.2%	0.3%	1987	2.9%	-3.0%	9.2%	0.3%
1979	2.9%	-1.5%	22.9%	0.7%	1987	2.9%	-1.5%	22.9%	0.7%
1979	2.9%	0.0%	31.5%	0.9%	1987	2.9%	0.0%	31.5%	0.9%
1979	2.9%	1.5%	22.9%	0.7%	1987	2.9%	1.5%	22.9%	0.7%
1979	2.9%	3.0%	9.2%	0.3%	1987	2.9%	3.0%	9.2%	0.3%
1979	2.9%	4.8%	2.2%	0.1%	1987	2.9%	4.8%	2.2%	0.1%
1980	2.9%	-4.8%	2.2%	0.1%	1988	2.9%	-4.8%	2.2%	0.1%
1980	2.9%	-3.0%	9.2%	0.3%	1988	2.9%	-3.0%	9.2%	0.3%
1980	2.9%	-1.5%	22.9%	0.7%	1988	2.9%	-1.5%	22.9%	0.7%
1980	2.9%	0.0%	31.5%	0.9%	1988	2.9%	0.0%	31.5%	0.9%
1980	2.9%	1.5%	22.9%	0.7%	1988	2.9%	1.5%	22.9%	0.7%
1980	2.9%	3.0%	9.2%	0.3%	1988	2.9%	3.0%	9.2%	0.3%
1980	2.9%	4.8%	2.2%	0.1%	1988	2.9%	4.8%	2.2%	0.1%
1981	2.9%	-4.8%	2.2%	0.1%	1989	2.9%	-4.8%	2.2%	0.1%
1981	2.9%	-3.0%	9.2%	0.3%	1989	2.9%	-3.0%	9.2%	0.3%
1981	2.9%	-1.5%	22.9%	0.7%	1989	2.9%	-1.5%	22.9%	0.7%
1981	2.9%	0.0%	31.5%	0.9%	1989	2.9%	0.0%	31.5%	0.9%
1981	2.9%	1.5%	22.9%	0.7%	1989	2.9%	1.5%	22.9%	0.7%
1981	2.9%	3.0%	9.2%	0.3%	1989	2.9%	3.0%	9.2%	0.3%
1981	2.9%	4.8%	2.2%	0.1%	1989	2.9%	4.8%	2.2%	0.1%
1982	2.9%	-4.8%	2.2%	0.1%	1990	2.9%	-4.8%	2.2%	0.1%
1982	2.9%	-3.0%	9.2%	0.3%	1990	2.9%	-3.0%	9.2%	0.3%
1982	2.9%	-1.5%	22.9%	0.7%	1990	2.9%	-1.5%	22.9%	0.7%
1982	2.9%	0.0%	31.5%	0.9%	1990	2.9%	0.0%	31.5%	0.9%
1982	2.9%	1.5%	22.9%	0.7%	1990	2.9%	1.5%	22.9%	0.7%
1982	2.9%	3.0%	9.2%	0.3%	1990	2.9%	3.0%	9.2%	0.3%
1982	2.9%	4.8%	2.2%	0.1%	1990	2.9%	4.8%	2.2%	0.1%

Weather Year	Weather Year Probability	LDF Errors	LDF Probability	Case Probability	Weather Year	Weather Year Probability	LDF Errors	LDF Probability	Case Probability
1991	2.9%	-4.8%	2.2%	0.1%	1999	2.9%	-4.8%	2.2%	0.1%
1991	2.9%	-3.0%	9.2%	0.3%	1999	2.9%	-3.0%	9.2%	0.3%
1991	2.9%	-1.5%	22.9%	0.7%	1999	2.9%	-1.5%	22.9%	0.7%
1991	2.9%	0.0%	31.5%	0.9%	1999	2.9%	0.0%	31.5%	0.9%
1991	2.9%	1.5%	22.9%	0.7%	1999	2.9%	1.5%	22.9%	0.7%
1991	2.9%	3.0%	9.2%	0.3%	1999	2.9%	3.0%	9.2%	0.3%
1991	2.9%	4.8%	2.2%	0.1%	1999	2.9%	4.8%	2.2%	0.1%
1992	2.9%	-4.8%	2.2%	0.1%	2000	2.9%	-4.8%	2.2%	0.1%
1992	2.9%	-3.0%	9.2%	0.3%	2000	2.9%	-3.0%	9.2%	0.3%
1992	2.9%	-1.5%	22.9%	0.7%	2000	2.9%	-1.5%	22.9%	0.7%
1992	2.9%	0.0%	31.5%	0.9%	2000	2.9%	0.0%	31.5%	0.9%
1992	2.9%	1.5%	22.9%	0.7%	2000	2.9%	1.5%	22.9%	0.7%
1992	2.9%	3.0%	9.2%	0.3%	2000	2.9%	3.0%	9.2%	0.3%
1992	2.9%	4.8%	2.2%	0.1%	2000	2.9%	4.8%	2.2%	0.1%
1993	2.9%	-4.8%	2.2%	0.1%	2001	2.9%	-4.8%	2.2%	0.1%
1993	2.9%	-3.0%	9.2%	0.3%	2001	2.9%	-3.0%	9.2%	0.3%
1993	2.9%	-1.5%	22.9%	0.7%	2001	2.9%	-1.5%	22.9%	0.7%
1993	2.9%	0.0%	31.5%	0.9%	2001	2.9%	0.0%	31.5%	0.9%
1993	2.9%	1.5%	22.9%	0.7%	2001	2.9%	1.5%	22.9%	0.7%
1993	2.9%	3.0%	9.2%	0.3%	2001	2.9%	3.0%	9.2%	0.3%
1993	2.9%	4.8%	2.2%	0.1%	2001	2.9%	4.8%	2.2%	0.1%
1994	2.9%	-4.8%	2.2%	0.1%	2002	2.9%	-4.8%	2.2%	0.1%
1994	2.9%	-3.0%	9.2%	0.3%	2002	2.9%	-3.0%	9.2%	0.3%
1994	2.9%	-1.5%	22.9%	0.7%	2002	2.9%	-1.5%	22.9%	0.7%
1994	2.9%	0.0%	31.5%	0.9%	2002	2.9%	0.0%	31.5%	0.9%
1994	2.9%	1.5%	22.9%	0.7%	2002	2.9%	1.5%	22.9%	0.7%
1994	2.9%	3.0%	9.2%	0.3%	2002	2.9%	3.0%	9.2%	0.3%
1994	2.9%	4.8%	2.2%	0.1%	2002	2.9%	4.8%	2.2%	0.1%
1995	2.9%	-4.8%	2.2%	0.1%	2003	2.9%	-4.8%	2.2%	0.1%
1995	2.9%	-3.0%	9.2%	0.3%	2003	2.9%	-3.0%	9.2%	0.3%
1995	2.9%	-1.5%	22.9%	0.7%	2003	2.9%	-1.5%	22.9%	0.7%
1995	2.9%	0.0%	31.5%	0.9%	2003	2.9%	0.0%	31.5%	0.9%
1995	2.9%	1.5%	22.9%	0.7%	2003	2.9%	1.5%	22.9%	0.7%
1995	2.9%	3.0%	9.2%	0.3%	2003	2.9%	3.0%	9.2%	0.3%
1995	2.9%	4.8%	2.2%	0.1%	2003	2.9%	4.8%	2.2%	0.1%
1996	2.9%	-4.8%	2.2%	0.1%	2004	2.9%	-4.8%	2.2%	0.1%
1996	2.9%	-3.0%	9.2%	0.3%	2004	2.9%	-3.0%	9.2%	0.3%
1996	2.9%	-1.5%	22.9%	0.7%	2004	2.9%	-1.5%	22.9%	0.7%
1996	2.9%	0.0%	31.5%	0.9%	2004	2.9%	0.0%	31.5%	0.9%
1996	2.9%	1.5%	22.9%	0.7%	2004	2.9%	1.5%	22.9%	0.7%
1996	2.9%	3.0%	9.2%	0.3%	2004	2.9%	3.0%	9.2%	0.3%
1996	2.9%	4.8%	2.2%	0.1%	2004	2.9%	4.8%	2.2%	0.1%
1997	2.9%	-4.8%	2.2%	0.1%	2005	2.9%	-4.8%	2.2%	0.1%
1997	2.9%	-3.0%	9.2%	0.3%	2005	2.9%	-3.0%	9.2%	0.3%
1997	2.9%	-1.5%	22.9%	0.7%	2005	2.9%	-1.5%	22.9%	0.7%
1997	2.9%	0.0%	31.5%	0.9%	2005	2.9%	0.0%	31.5%	0.9%
1997	2.9%	1.5%	22.9%	0.7%	2005	2.9%	1.5%	22.9%	0.7%
1997	2.9%	3.0%	9.2%	0.3%	2005	2.9%	3.0%	9.2%	0.3%
1997	2.9%	4.8%	2.2%	0.1%	2005	2.9%	4.8%	2.2%	0.1%
1998	2.9%	-4.8%	2.2%	0.1%	2006	2.9%	-4.8%	2.2%	0.1%
1998	2.9%	-3.0%	9.2%	0.3%	2006	2.9%	-3.0%	9.2%	0.3%
1998	2.9%	-1.5%	22.9%	0.7%	2006	2.9%	-1.5%	22.9%	0.7%
1998	2.9%	0.0%	31.5%	0.9%	2006	2.9%	0.0%	31.5%	0.9%
1998	2.9%	1.5%	22.9%	0.7%	2006	2.9%	1.5%	22.9%	0.7%
1998	2.9%	3.0%	9.2%	0.3%	2006	2.9%	3.0%	9.2%	0.3%
1998	2.9%	4.8%	2.2%	0.1%	2006	2.9%	4.8%	2.2%	0.1%

Weather Year	Weather Year Probability	LDF Errors	LDF Probability	Case Probability
2007	2.9%	-4.8%	2.2%	0.1%
2007	2.9%	-3.0%	9.2%	0.3%
2007	2.9%	-1.5%	22.9%	0.7%
2007	2.9%	0.0%	31.5%	0.9%
2007	2.9%	1.5%	22.9%	0.7%
2007	2.9%	3.0%	9.2%	0.3%
2007	2.9%	4.8%	2.2%	0.1%
2008	2.9%	-4.8%	2.2%	0.1%
2008	2.9%	-3.0%	9.2%	0.3%
2008	2.9%	-1.5%	22.9%	0.7%
2008	2.9%	0.0%	31.5%	0.9%
2008	2.9%	1.5%	22.9%	0.7%
2008	2.9%	3.0%	9.2%	0.3%
2008	2.9%	4.8%	2.2%	0.1%
2009	2.9%	-4.8%	2.2%	0.1%
2009	2.9%	-3.0%	9.2%	0.3%
2009	2.9%	-1.5%	22.9%	0.7%
2009	2.9%	0.0%	31.5%	0.9%
2009	2.9%	1.5%	22.9%	0.7%
2009	2.9%	3.0%	9.2%	0.3%
2009	2.9%	4.8%	2.2%	0.1%

For this study, total reliability costs are defined as the following:

a. Reliability Energy Costs
   i. Cost Unserved Energy Events – The value of lost load to customers.
   ii. Cost of Expensive Purchased Power – defined as the costs of any purchases at prices higher than the generic CT costs
   iii. Cost of Dispatching Expensive Peaking Resources – defined as any costs of the system's physical generation above the dispatch cost of the new capacity resource. This includes the dispatch of higher-cost generators such as oil-fired turbines and old natural gas turbine units.

b. Cost of Carrying Reserves – The carrying cost of adding additional capacity in \$/kW-yr.

These components are calculated for each of the above cases weighted based on probability.

B. Reserve Margin Definition

For this study, reserve margin is defined as the following:

- (Resources – Demand) / Demand *100%
    - Resources including Interruptible Capacity
    - Demand is the August Peak Load including Interruptible Load. August Peak Load was chosen because that is the month in which reserves are the lowest since capacity for most thermal resources is much higher in winter months compared to summer months.

V. Base Case Results and Risk Analysis

Figure 7 shows the resulting distribution of reliability energy costs across varying reserve margins. The components include the cost EUE, cost of reliability purchases, and production costs above a CT. As reserve capacity is added, these reliability energy costs are reduced. As seen, more than 70% of the time, the utility is going to pay more in capacity costs than for reliability energy because the reliability energy is concentrated in a few extreme cases when the combination of severe generator outages, weather, and load forecast error, and low import capability occur. It is the risk on the tail end of the distribution that forces a utility to carry reserves. Some years these costs may be close to zero while other years those costs may be orders of magnitude higher than the incremental cost of carrying additional reserves. Assuming a 12% reserve margin level, reliability energy costs can range from 200 thousand dollars to 900 million dollars for a single year.

Figure 7. Distribution of Reliability Energy Costs

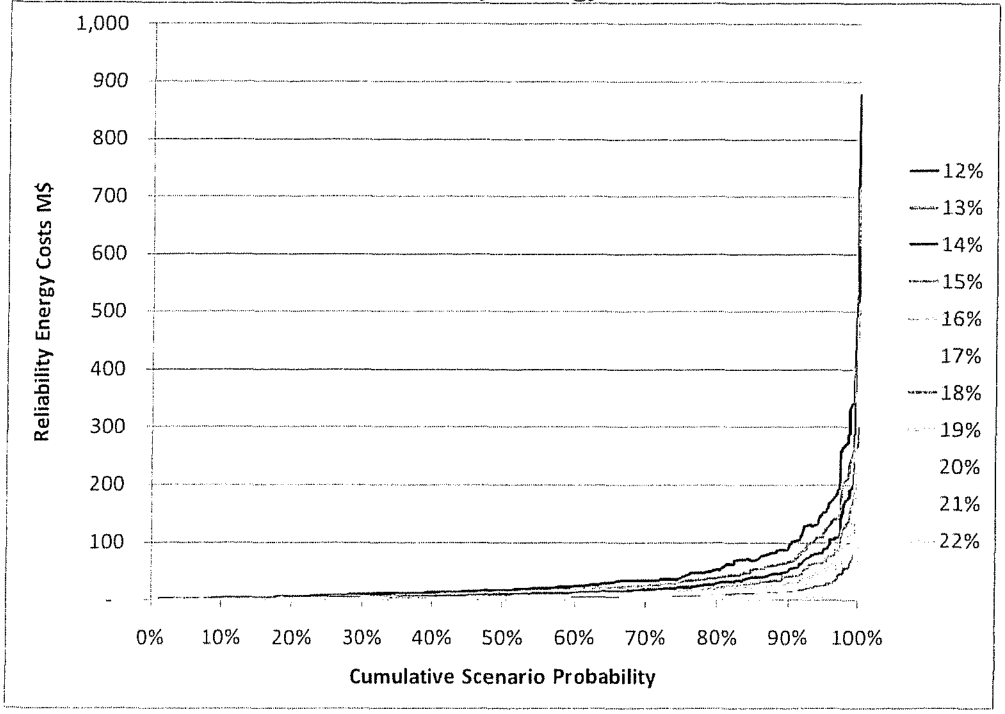
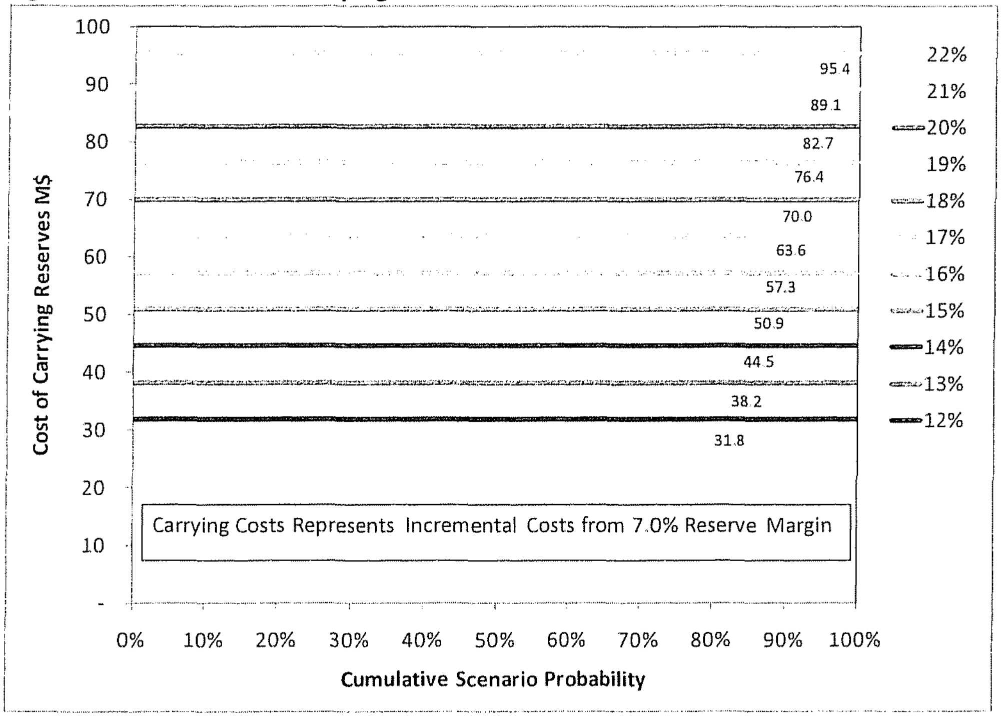


Figure 8 shows the cost of carrying reserves at varying reserve margin levels. As reserve margin increases, the cost of carrying reserves increases. The cost of carrying reserves is fixed for all scenarios because capacity can be constructed or purchased through a bilateral contract which will effectively lock that cost for many years.

Figure 8. Fixed Cost of Carrying Reserves



The optimal reserve margin is where the sum of the cost of reliability energy costs (Distributions from Figure 7) and the cost of carrying reserves (Distributions from Figure 8) is minimized. However, since reliability costs are extraordinarily volatile but capacity costs are fixed, a conversion is necessary to put the two on the same basis. Otherwise, the comparison would inappropriately consider two very different cost structures. The casualty insurance industry faces a similar issue of how to compare fixed premiums with volatile casualty payouts. The typical solution is to remove the risk from the casualty distributions by selecting the 85th to 95th percent costly long-term scenario for comparing to fixed premiums. In other words, premiums are frequently set using anywhere between 85 to 95 percent confidence levels that the insurance company will be covered in the long-term. Therefore, in this example, if an insurance company were assuming the risks shown in Figure 7, then an approximate premium would equal the 85th -

95^{th} confidence level of the distribution. Astrape Consulting recommends a similar risk adjustment using reliability energy costs at the 85^{th} to 90^{th} confidence level range based on its experience in performing reserve margin studies for other jurisdictions within the southeast because these levels have resulted in the lowest cost resource plans that also avoid unreasonable risk for utilities, regulators, and customers. Figure 9 summarizes total reliability costs assuming reliability energy costs at the 85^{th} percentile. As reserve margin increases, reliability energy costs decrease and the cost of carrying reserves increase. With this assumption, total reliability costs are minimized at a reserve margin of 15.50%.

Figure 9. Optimal Reserve Margin with Reliability Energy Costs at 85^{th} Percentile Confidence Level

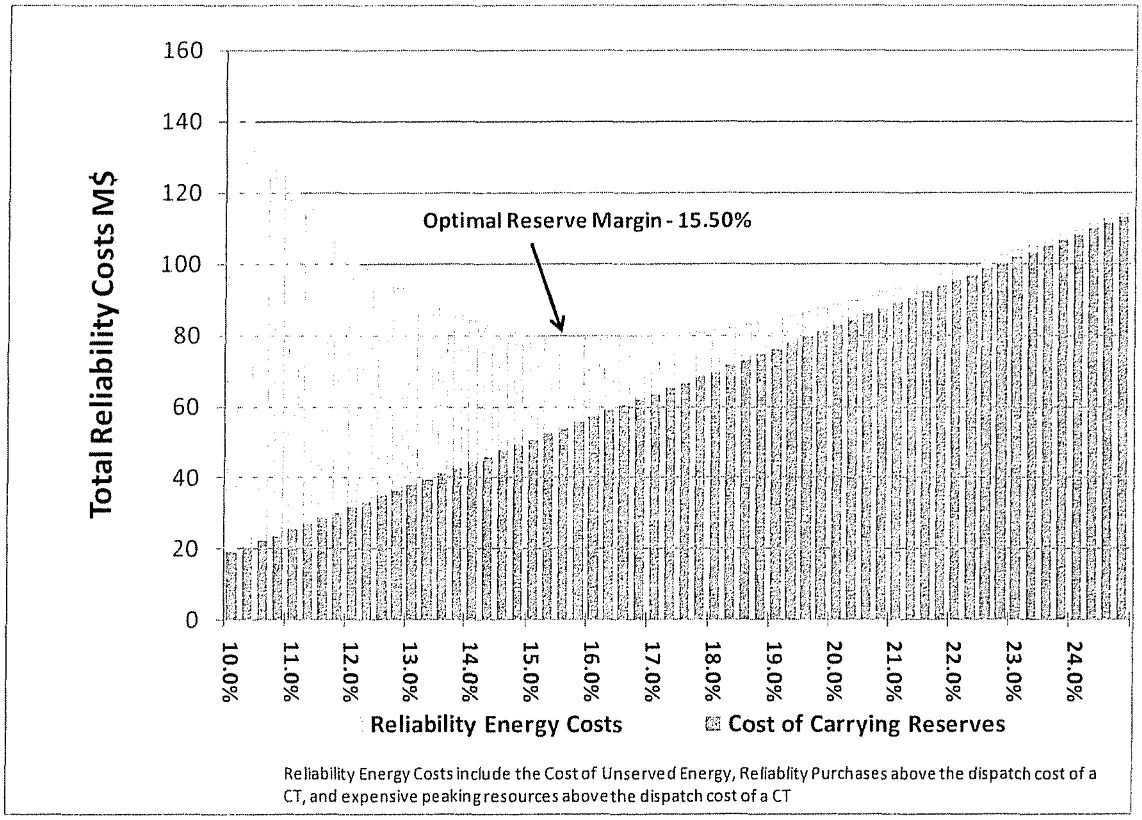
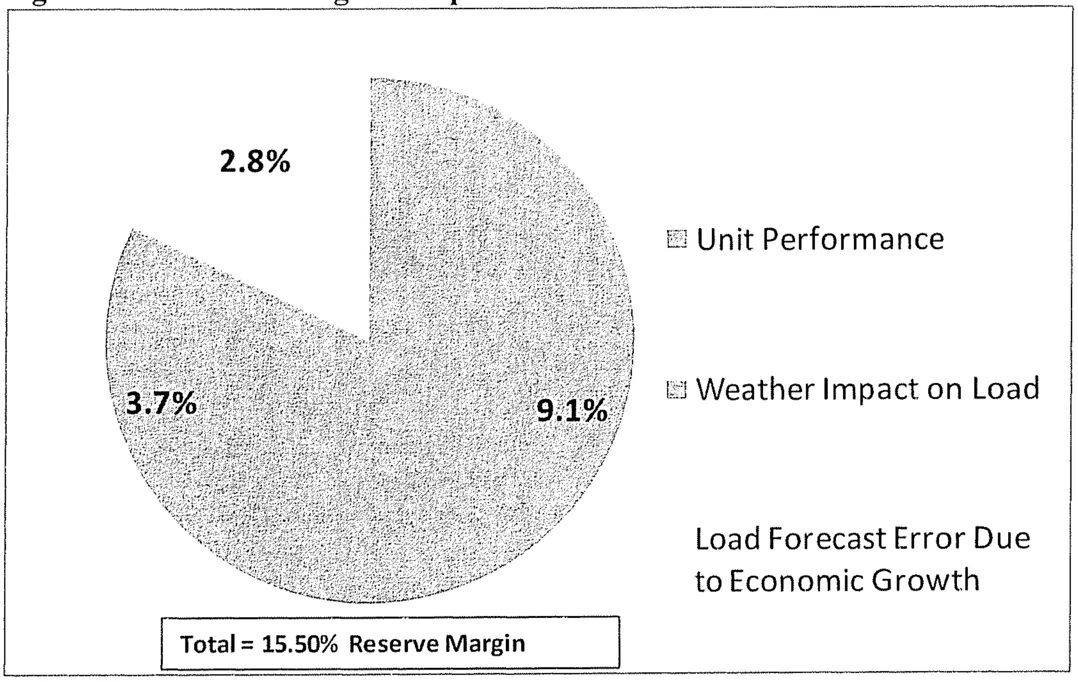


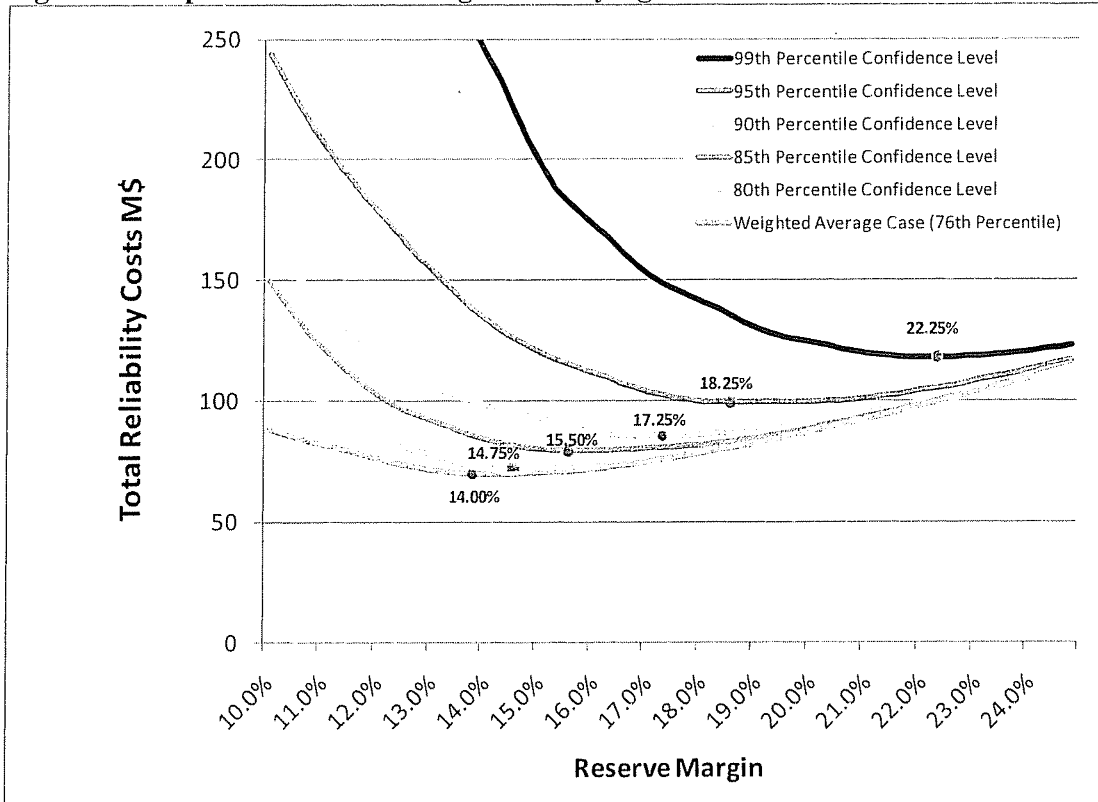
Figure 10 supplies a breakdown of the optimal reserve margin into three components: Unit Performance, Weather Impact on Load, and Load Forecast Error Due to Economic Growth. The largest component is unit performance which is not surprising given the fact that 1,000 MW of capacity are on outage 20% of the time as shown in Figure 2 of the Input Section.

Figure 10. Reserve Margin Components at 85th Percentile Confidence Interval



Next, total reliability costs were calculated assuming reliability energy costs at various confidence levels to understand how the least cost reserve margin is impacted by this assumption. Figure 11 displays these results. The study was performed at the weighted average (76th percentile), 80th, 85th, 90th, 95th, and 99th confidence levels.

Figure 10. Optimal Reserve Margin at Varying Confidence Intervals



	Weighted Average (76th Percentile)	85% Confidence Level	90% Confidence Level	95% Confidence Level	99% Confidence Level
Optimal Reserve Margin	14.00%	15.50%	17.25%	18.25%	22.25%

The recommended range of reserve margin assuming the 85th and 90th confidence levels of reliability energy costs is between 15.50% and 17.25%. The weighted average case assumes the reliability energy costs are weighted based on the probability of each scenario which happens to fall out at the 76th percentile point on the distribution. However, it is Astrape Consulting's experience that assuming this as a planning reserve margin provides more risk than utilities and regulators are willing to take in a given year even though it may minimize average costs in the long run. Based on Figure 7, a 14.00% reserve margin results in a risk that in 5% of all scenarios reliability energy costs would exceed 90 million dollars and 1% of the time they would exceed

$200 million dollars. A 15.50% reserve margin lowers this exposure to 60 million dollars and 140 million dollars respectively. Also, even if the weighted average case is assumed, the increase in total reliability costs between the 14.00% reserve margin and the 15.50% reserve margin is only 1.2 million dollars. In contrast, the 99 percentile confidence level reserve margin of 22.25% eliminates almost all risk but puts an unreasonable amount of cost on customers as shown in Figure 10.

VI. Sensitivity Analysis

In addition to the base case analysis, several sensitivities were performed to test the major assumptions in the base case. These sensitivities included varying the cost of unserved energy, varying the cost of carrying additional capacity reserves, removing all tie assistance, increasing unit forced outage rates, decreasing neighbor capacity, decreasing transmission limits, and increasing market prices during scarce conditions.

Table 15. Sensitivities – Cost of EUE and Carrying Cost of Reserves

	Weighted Average	85% Confidence Level	90% Confidence Level	95% Confidence Level
EUE = $5,000/MWh	13.75%	15.50%	17.00%	18.00%
Base Case Optimal Reserve Margin (EUE = $16,600/MWh)	**14.00%**	**15.50%**	**17.25%**	**18.25%**
EUE = $30,000/MWh	14.25%	16.00%	17.75%	18.75%
Cost of Capacity - $110/kW-yr	13.25%	15.25%	16.50%	18.00%
Base Case Optimal Reserve Margin (Cost of Capacity = $88.42/kW-yr)	**14.00%**	**15.50%**	**17.25%**	**18.25%**
Cost of Capacity - $70/kW-yr	14.75%	17.25%	18.50%	20.75%

As the cost of reserves decreases, it is more economic for the system to carry additional capacity and vice versa if the cost of capacity increases. As shown in the results, the 85th percentile confidence level reserve margin ranges from 15.25% to 17.25% by varying the cost of capacity from \$110/kW-yr to \$70/kW- yr. Because the risk exposure to reliability energy is exponential and not linear across reserve margins, there is a lesser effect of raising the cost of reserves than there is when lowering the cost of capacity as shown in the results.

As the cost of unserved energy decreases, it is more economic for the system to carry less capacity reserves. Due to the fact that the majority of reliability energy costs come from events in which reliability purchases occurred, the value for the cost of EUE is not a major driver in the analysis. For this sensitivity, the cost of EUE was varied from as much as \$5000/MWh to \$30,000/MWh and the 85th percentile confidence level reserve margin ranges from 15.50% to 16.00%.

Table 16 shows the results of the remaining sensitivities that were performed individually off of the Base Case.

Table 16. Other Sensitivities

	Weighted Average (76th Percentile)	85% Confidence Level	90% Confidence Level	95% Confidence Level
Optimal Reserve Margin	14.00%	15.50%	17.25%	18.25%
Scarcity Pricing Sensitivity - Increase by 50%	15.25%	17.50%	19.00%	20.25%
EFOR Sensitivity - Increase by 50%	17.00%	19.00%	21.25%	22.75%
Neighbor Reserve Margin Sensitivity - 15% RM to 12% RM	16.00%	18.00%	20.25%	22.00%
Transmission Sensitivity - Decrease by 50%	15.00%	16.75%	18.25%	19.50%
Island Sensitivity - No Interconnection Ties	21.75%	23.75%	24.75%	26.00%

The effect of increasing the scarcity pricing by 50% increased the 85th percentile confidence level reserve margin by 2.00% to 17.50%. However, increasing the unit forced outage rates (FOR) by 50% had a much larger impact of 3.50% resulting in a 19.00% reserve margin. This is logical as increasing the FOR is effectively removing available capacity resulting in not only higher market prices but also more reliability energy. Increasing the scarcity pricing is only increasing the cost of the reliability energy for a specific, but does not affect the energy available.

Market conditions were varied by assuming less reserve margins from existing neighbors (15% reserve margin to 12% reserve margin) and a 50% reduction in transmission import capability. The 85^{th} percentile confidence level reserve margin shifts from 15.50 % to 18.00% for the reserve margin sensitivity and to 16.75% for the transmission reduction sensitivity.

Finally, the 85^{th} percentile confidence level reserve margin point rises to 23.75% if the company is assumed to be an island without any emergency assistance from its neighbors. In this scenario, all reliability purchases are shifted to unserved energy which causes reliability costs to increase substantially. This sensitivity shows the importance that interconnected regions have on the Companies' reliability.

These sensitivities illustrate the potential change in reserve margin due to significant assumptions. Excluding the island sensitivity, the reserve margins only shift by a few percentage points even with significant changes in major inputs.

VII. Conclusions/Recommendations

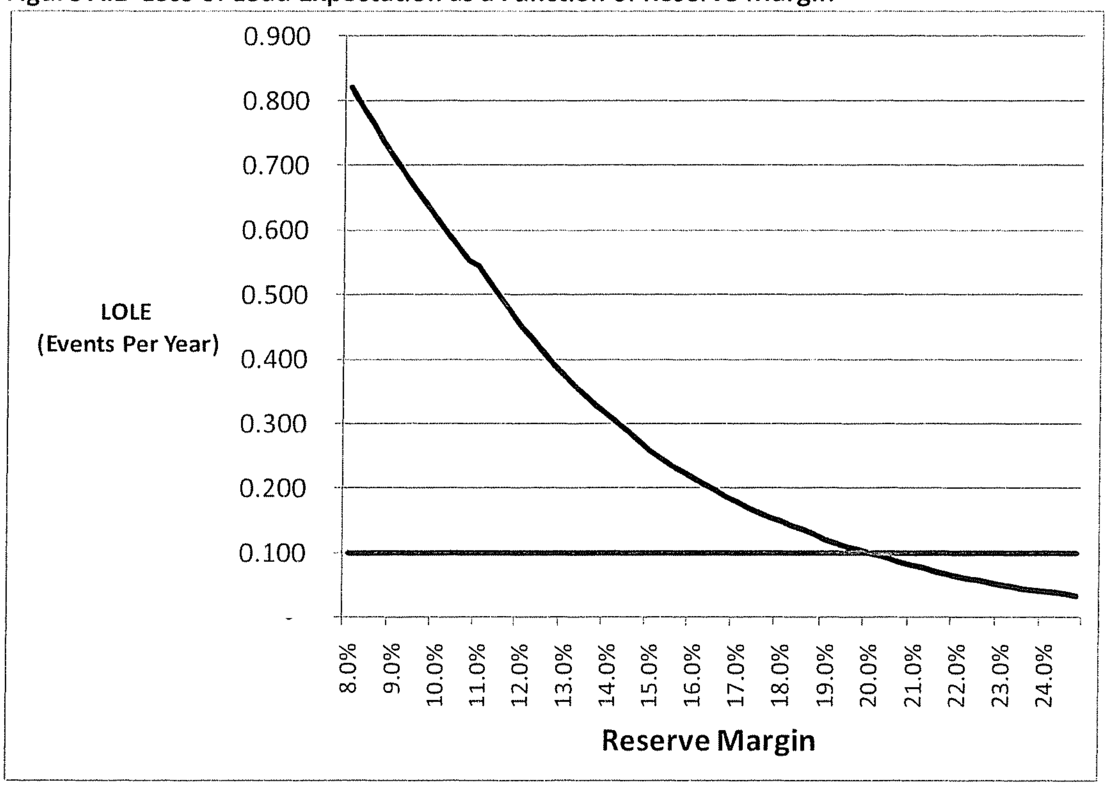
In conclusion, the simulation results demonstrate the Companies' risk due to lower planning reserve margins and show that low probability, high impact cost exposures exist at all reserve margin levels. No system is 100% reliable and this reliability assessment has quantified the frequency and duration of major events and their economic impact on customers under a full distribution of weather years, unit performance, and load forecast uncertainty. The study also demonstrates the value of capacity reserve margins to the extent they protect customers from extreme, high cost outcomes. Based on the simulations and sensitivities, the precedent set by other industries, and experience in other jurisdictions, Astrape Consulting recommends that the Companies set a long-term target reserve margin using the 85^{th} to 90^{th} percentile of reliability energy costs which results in reserve margins between 15% and 17%.

Appendix

Physical Reliability Metrics

Loss of Load Expectation (LOLE) is a common physical reliability metric used when looking at resource adequacy studies. An LOLE of 0.1 events per year or "1 day in 10 years" is a criterion that is used in many jurisdictions. Below is a figure showing the LOLE curve for the base case of this study. The 1 day in 10 year metric occurs at a 20% reserve margin level. For customers to achieve this level of reliability, costs would need to increase substantially which would lead to an inefficient level of reserves. LOLE metrics, especially for relatively smaller systems (less than 10,000 MW) do not always translate to the most economic reserve margin as shown below. Based on the recommended reserve margin Of 15% - 17%, it is expected that there would be on average approximately 2 events every 10 years.

Figure A.1 Loss of Load Expectation as a Function of Reserve Margin



COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE 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

In the Matter of:

THE APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	)	CASE NO. 2011-00162

REBUTTAL TESTIMONY OF
DAVID S. SINCLAIR
VICE PRESIDENT, ENERGY MARKETING
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: October 24, 2011

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **David S. Sinclair**, being duly sworn, deposes and says that he is Vice President, Energy Marketing for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

David S. Sinclair

David S. Sinclair

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 21st day of October 2011.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2014

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

A. My name is David S. Sinclair. I am Vice President, Energy Marketing for Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, "Companies") and an employee of LG&E and KU Services Company, which provides services to LG&E and KU. My business address is 220 West Main Street, Louisville, Kentucky, 40202. A complete statement of my education and work experience is attached to this testimony as Appendix A.

Q. Please describe your responsibilities as Vice President of Energy Marketing.

A. I have four primary areas of responsibility: (i) fuel procurement (coal and natural gas) for the power stations and coal combustion by-product marketing, (ii) optimizing the real time dispatch of our generating stations to meet load (including buying and selling of electricity), (iii) sales and market analysis and generation planning and (iv) business information support of the generation business. As these responsibilities pertain to this proceeding, the Generation Planning group, under the direction of Charles R. Schram, performed the analysis of the impact of U.S. Environmental Protection Agency ("EPA") regulations on the Companies' future generation.

Q. Have you previously testified before this Commission?

A. Yes. I previously testified before this Commission in Case No. 2004-00507 in which the Companies sought and received approval for the expansion of the Trimble County Generating Station and in Case No. 2003-00266, the investigation into the Companies' membership in the Midwest Independent Transmission System Operator. I recently submitted testimony in Case No. 2011-00375, the joint application of the Companies for a Certificate of Public Convenience and Necessity and Site Compatibility Certificate for the construction of a combined-cycle combustion turbine at the Cane Run Generating Station and the purchase of existing simple-cycle combustion turbine facilities from Bluegrass Generation Company, LLC in La Grange, Kentucky.

Q. What is the purpose of your testimony?

A. Dr. Jeremy Fisher, a witness for Sierra Club and related parties ("Environmental Interveners"), states in his testimony that "the company has used a series of input assumptions in their retire/retrofit model that are not realistic"[1] and that "the entire analytical basis for the Companies' proposed resource analysis is fundamentally flawed due to erroneous assumptions and methodologies."[2] His opinion is that the Companies' analysis contains eight errors. I will address two of Dr. Fisher's issues regarding natural gas prices and CO_2 price risk. Mr. Schram's testimony will address the remaining six issues. In my testimony, I will: (i) show that, as Dr. William Steinhurst states, "grave errors were made in the cost benefit analysis of retrofit versus retirement for the company's coal fired generating units,"[3] but that they were not made by the Companies, but rather by his colleagues Dr. Fisher and Rachel Wilson in their modeling of gas prices; ii) demonstrate the reasonableness and robustness of the natural gas forecast used by the Companies as compared to the one proposed by Dr. Fisher; and iii) rebut Dr. Fisher's proposed methodology for incorporating greenhouse gas ("GHG") regulation uncertainty into the decision to install environmental controls.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

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[1] Direct testimony of Dr. Fisher, page 41, lines 14-15.
[2] Direct testimony of Dr. Fisher, page 42, lines 23-24.
[3] Direct testimony of Dr. William Steinhurst, page 6, lines 4-6.

Rebuttal Exhibit DSS-1 Portfolio Revenue Requirements with Dr. Fisher's Recommended Gas Price Forecast

Rebuttal Exhibit DSS-2 Synapse's Range of Gas Prices

Rebuttal Exhibit DSS-3 Gas Price Forecast Comparison and Ranges

Rebuttal Exhibit DSS-4 Sierra Club Policy on Natural Gas Fracturing

Rebuttal Exhibit DSS-5 Gas Price Forecast Comparisons with Threshold

Rebuttal Exhibit DSS-6 CO_2 Pricing Legislation Proposals

Rebuttal Exhibit DSS-7 International Greenhouse Gas Summits

Rebuttal Exhibit DSS-8 Annual Nominal Savings/(Costs)

Rebuttal Exhibit DSS-9 Cumulative Nominal Savings/(Costs)

Rebuttal Exhibit DSS-10 "Transforming America's Energy Future", Sierra Club

Rebuttal Exhibit DSS-11 Excerpt from Companies' "Carbon Footprint" Presentation

Rebuttal Exhibit DSS-12 Synapse's CO_2 Price Forecasts

In Appendix B, a complete collection of source documents and workpapers is provided in electronic format, except for those documents for which an internet link has been provided.

<u>Summary of Conclusions</u>

Q. What are your conclusions regarding the base case natural gas forecasts used by the Companies and the one being proposed by Dr. Fisher?

A. Dr. Fisher significantly erred in assessing the reasonableness of the Companies' base case natural gas forecast. In Figures 1 and 2 of his testimony, Dr. Fisher compared the Companies' <u>nominal</u> gas price forecast to several forecasts that were presented in <u>real</u> dollars and concluded that the Companies' forecast was "highly inflated." Because real forecasts do not reflect the impact of general inflation on prices, they are almost always lower than nominal forecasts. Dr. Fisher's comparison of real and nominal gas price forecasts is not appropriate. In addition, when Dr. Fisher re-analyzed the Companies' retire-or-retrofit decisions in Strategist with his recommended gas price, he used his gas price forecast (expressed in real terms) along with the Companies' other inputs expressed in nominal terms. These simple mistakes make the results of his analysis nonsensical and misleading. When the Companies' and Dr. Fisher's forecasts are presented on the same basis, the difference between the forecasts narrows substantially. In fact, converting Dr. Fisher's real gas price forecast to a nominal forecast and re-running the Strategist model produces the same the retire-or-retrofit decisions as the Companies' recommendations to install controls on Brown Units 1 & 2 and Mill Creek Units 1 & 2.

Q. What conclusions do you have regarding the reasonableness of the natural gas price forecasts used by the Companies as compared to the one proposed by Dr. Fisher?

A. After adjusting for the real-versus-nominal difference, it is my opinion that both forecasts are reasonable forecasts of future natural gas prices. However, in the context of the decision facing the Companies regarding whether to install controls on Brown Units 1 & 2 and Mill Creek Units 1 & 2 or retire and replace them with natural gas-fired generation, the base forecast used by the Companies results in a far more robust decision than using Dr. Fisher's forecast.[4] This is important because my review of the source documents for Dr. Fisher's forecast revealed that there is little potential for prices to go much lower than

[4] Note that Dr. Fisher stated in response to the Companies' Data Request Question No. 5(b) that he is not recommending "retiring specific units" but rather not approving the controls recommended by the Companies. In the context of this analysis and this case, that is a distinction without a difference. Throughout my testimony, I will refer to the decision as retrofit or retire.

his base case forecast but that there are numerous "material" upside price risks.[5] Based on Synapse's own risk analysis, Dr. Fisher's forecast is skewed to the lower end of the range of possible future gas prices. It is my opinion that the economic analysis that supports major decisions such as retiring a power station should be robust under many possible futures and should balance both the upside and downside risks.

Q. What are your conclusions regarding Dr. Fisher's view that there will be a CO_2 price in the U.S. beginning in 2018?

A. Dr. Fisher's judgment that there will be a price on CO_2 beginning in 2018 appears to be based on his biased interpretation of events, not on any facts or analysis of national and international events related to climate change regulation. As I will explain, international efforts to establish globally binding greenhouse gas limits continue to flounder, efforts to pass national GHG legislation have all but ceased, and existing state-level initiatives are being curtailed. This is all occurring against a backdrop of increasing American skepticism of anthropogenic climate change since the 2009 Climategate scandal, increasing concern regarding the cost of environmental regulations in general and international and domestic economic weakness.

Q. Is Dr. Fisher recommending a reasonable analytical approach to addressing the uncertainty surrounding future GHG regulations?

A. No. As I will demonstrate, his view that unknown and unknowable future GHG regulations must be included in the analysis of compliance options for National Ambient Air Quality Standards ("NAAQS") and Hazardous Air Pollutants ("HAPs") regulations is at best simplistic and at worst misleading. I will demonstrate that the Companies'

[5] *Avoided Energy Supply Costs in New England: 2011 Report*, Synapse Energy Economic, Inc., July 21, 2011, Amended August 11, 2011, pages 1-23 and 1-24, http://www.synapse-energy.com/Downloads/SynapseReport.2011-07.AESC.AESC-Study-2011.11-014.pdf.

recommended course of action is more likely to result in lower costs for customers because it preserves the real option to address the uncertainty surrounding the GHG issue in the future by not requiring the Companies and their customers to commit today to a GHG compliance plan as Dr. Fisher's analytical approach seems to suggest.

Error: Real vs. Nominal Gas Price Forecasts

Q. Do you have any concerns regarding Dr. Fisher's assessment of the reasonableness of the natural gas price forecast used by the Companies?

A. Yes. In Figure 1 on page 21 of Dr. Fisher's testimony he attempts to compare the natural gas price forecast used by the Companies to other forecasts. Though this is a useful exercise, he made, in the words of Dr. Steinhurst, a "grave error." According to the data in Dr. Fisher's Figure 1, all of these forecasts are supposed to be in real 2010 dollars, meaning they have been adjusted to remove the effects of general inflation. But the forecast used by the Companies and depicted on Dr. Fisher's chart are in nominal dollars, not real dollars which means they have been escalated to reflect the effects of general inflation. It is nonsensical to compare forecasts in real and nominal dollars as Dr. Fisher does. This error is especially puzzling because the Companies clearly stated in response to the Environmental Interveners' supplemental data request Question No. 33(b) that the Companies' fuel forecasts were in nominal dollars.

Q. How would Dr. Fisher's comparison be affected if he had properly converted the natural gas price forecast used by the Companies to 2010 dollars?

A. Converting the forecast used by the Companies to 2010 dollars (to maintain consistency with Dr. Fisher's graph) reduces it substantially. Figure 1 demonstrates that when compared appropriately, the difference between the gas price forecast used by the

Companies and Dr. Fisher's recommended forecast is not at all as portrayed in his testimony. As one can see, the forecast used by the Companies falls within the range of other forecasts that Dr. Fisher implies are "mainstream," which is not surprising because the forecast was prepared by PIRA Energy Group ("PIRA"), an independent professional energy consulting firm.

Figure 1: Gas Price Forecast Comparison

[redacted]

Q. What are your conclusions regarding Dr. Fisher's re-analysis of the Companies' retire-or-retrofit decisions using his recommended gas price?

A. Dr. Fisher states in his response to the Commission Staff's First Request for Information, "It is unlikely that a re-analysis or closer examination of the risks to Brown Units 1 & 2 would result in a different outcome for these units."[6] But Dr. Fisher's erroneous use of a real gas price forecast in combination with the Companies' other inputs in nominal terms

[6] Commission Staff's First Request for Information Question No. 1-3(a), page 6.

creates nonsensical results. The conclusions that he draws from the results of this elementary mistake must be rejected entirely.

Q. How did you conclude that Dr. Fisher used a real gas price along with the Companies' other inputs expressed in nominal terms?

A. My group reviewed the Strategist input files that Dr. Fisher provided in response to the Companies' Data Request Question No. 10. In Strategist, the user can input prices in either real or nominal terms. If the prices are entered in real terms, the user must also enter an inflation factor to inflate the real values. The fuel cost and inflation factor inputs are clearly described in the Strategist user manual. The Companies chose to use nominal prices with no inflation factor; because the Companies' values were nominal, no inflation factor was needed. Dr. Fisher and his colleagues at Synapse input the real prices from their "Avoided Energy Supply Costs in New England: 2011 Report" ("AESC 2011 Report") and did not enter an inflation factor.[7]

Q. Did you correct his mistake?

A. Yes. My group converted Dr. Fisher's recommended forecast into nominal dollars using the same general inflation assumption the Companies used for the base case PIRA gas price forecast, then ran the Strategist model. The results showed (see Rebuttal Exhibit DSS-1) that even using Dr. Fisher's recommended forecast, installing controls as the Companies have proposed, and installing them on Brown Units 1 & 2 and Mill Creek Units 1 & 2 in particular, are part of the least-cost portfolio to reliably meet the future energy needs of our customers.[8]

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[7] July 21, 2011, Amended August 11, 2011, http://www.synapse-energy.com/Downloads/SynapseReport.2011-07.AESC.AESC-Study-2011.11-014.pdf.

[8] Determining the least-cost portfolio is independent of their ordering, as suggested by Dr. Fisher, and depends solely on their relative present value revenue requirements.

<u>Reasonableness of Natural Gas Price Forecasts</u>

Q. Do you agree with Dr. Fisher's conclusion that the natural gas price forecast used by the Companies is an "error" or is "non-realistic" or "highly inflated"?

A. No. By definition one cannot know ahead of time whether any forecast will come true so it is impossible to state that the use of any particular forecast is an error, is unrealistic, or is inflated. I suggest that the appropriate standard to judge a forecast is "reasonableness."

Q. Please describe what in your opinion makes a forecast "reasonable."

A. To evaluate reasonableness, it is important to consider the models used by the forecaster, the quality of the assumptions that went into the models, and the sensibleness of the results produced by the combination of the models and the assumptions. The quality of the last step, reviewing the results, is further enhanced by the experience and capabilities of the forecaster. A forecast that is deficient in any of these areas may be suspect. Conversely, a forecast that was prepared by experienced analysts using great care in the use of models, choice of assumptions, and review of results will likely be reasonable.

Q. Is the natural gas price forecast used by the Companies reasonable?

A. Yes. The natural gas price forecast used by the Companies is based through 2015 on market forward gas prices and in the long-term on subscription information from PIRA. PIRA is an international energy-consulting firm specializing in global energy market research, analysis and intelligence. PIRA evaluates international supply-and-demand fundamentals for key energy commodities and issues that impact the behavior and performance of the industry and its various markets and sectors.[9] The Companies rely on forecast data from third-party consultants such as PIRA because of their independence, expertise, and experience in forecasting commodity prices.

[9] PIRA's corporate website, http://www.pira.com.

Q. Do you have any other thoughts regarding Dr. Fisher's recommended use of the AESC natural gas price forecast?

A. Yes. I reviewed Synapse's AESC 2011 Report which is the source document for the AESC forecast. It states, "The AESC 2011 Base Case forecast draws upon…the AEO 2010 High Shale case as a reasonable estimate based on long-term market fundamentals." The AEO case, which was developed by the U.S. Energy Information Administration, reflects a scenario in which shale gas is abundantly available, is extracted at low cost, and there is little regulation or restriction placed on its development.

Q. Does Synapse's forecast consider any uncertainties regarding the future of shale gas development?

A. Yes. Synapse states, "There is considerable uncertainty regarding projections of shale production quantities and costs," and "Concerns have been raised regarding the need for additional regulation of hydraulic fracturing in order to minimize its environmental impacts on groundwater, surface water, and air emissions."[10] The nature of these risks would imply more upside price risk than downside price risk from their base case, which depends on an abundant and low cost supply of shale gas. Furthermore, the U.S. Energy Information Administration's natural gas price forecast, which forms the basis of the AESC forecast, does not include any future GHG regulations. Such regulations would likely put further upward pressure on U.S. natural gas prices.

Q. Does Synapse consider a range of future natural gas prices?

A. Yes. They developed both a High Price and Low Price case as well as a statistical high-and-low range of prices based on historical price volatility as shown in Rebuttal Exhibit DSS-2.

[10] AESC 2011 Report, p. 1-22.

Q. How does the natural gas price forecast used by the Companies compare to the Synapse High Price and Low Price cases and the statistical high-and-low range?

A. Although Dr. Fisher failed to present this comparison Rebuttal Exhibit DSS-3 (shown in 2011 dollars to maintain consistency with Synapse's graph) demonstrates that the forecast used by the Companies (when converted to 2011 dollars) falls within the range developed by Synapse.[11] The gas price forecast used by the Companies is between Synapse's Base Case and High Price case in the near to medium term (through 2021) and is similar to Synapse's High Price case in the longer term, refuting the argument that Dr. Fisher makes regarding an "error" or "non-realistic" or "highly inflated" gas price assumptions on the part of the Companies.

Q. Do you have any other observations regarding Synapse's Base Case forecast?

A. Yes. I note that Synapse's Base Case forecast is not much different from their Low Price case and that the High Price case is significantly higher than the Base Case. In other words, Synapse seems to indicate that the risk around their Base Case is not symmetrical, with there being much greater risk of price increases than price decreases. This is not surprising given their assumptions regarding future shale gas development. In my opinion, they essentially assume that future shale gas development must proceed in a very favorable way for their Base Case to occur. Synapse itself seems to acknowledge the riskiness of this assumption: "Given the uncertainty associated with projections of shale gas resource availability, production quantities, regulations, and costs, there is certainly a possibility that *material* changes in the long-term outlook for shale gas production and

[11] Dr. Fisher, NRDC, and Sierra Club refused to provide the underlying AESC data for Exhibit 3-15 in the AESC 2011 Report in response to the Companies' data request, Question No. 27(b)(ii). Therefore, several of the AESC values are estimated as indicated.

cost may occur after the completion of AESC 2011 and before the initiation of AESC 2013."[12]

Q. How is shale gas being extracted?

A. Shale gas is being extracted by a process known as "fracking." Fracking is the fracturing of shale rock formations to release natural gas trapped within the rock. Water, other fluids, and sand are injected into the rock at high pressure to crack and hold open the rock, allowing the gas to flow out of the rock, through the well, and out of the ground.

Q. What are the public positions of the Natural Resources Defense Council ("NRDC") and the Sierra Club concerning fracking?

A. NRDC states, "Although drilling can create jobs and income, many fear the effects of drilling on their health, land and quality of life. Current laws need to be changed to catch up with the drilling explosion."[13] They go on to say, "We can and must get safeguards on the books to protect against the impacts of fracking-gone-wrong that we are watching unfold across the country."[14]

Sierra Club's policy on fracking (or "frac'ing"), as declared by its Board of Directors on December 21, 2009,[15] and shown in Rebuttal Exhibit DSS-4, states that the Sierra Club opposes any frac'ing projects that meet any of the following criteria:

- "The identity and volume of frac'ing fluids are not fully disclosed to the public."
- The frac'ing fluids used pose "unacceptable toxic risks."

[12] AESC 2011 Report, pages 1-23 and 1-24, emphasis added.
[13] "Don't Get Fracked!", NRDC, http://www.nrdc.org/health/drilling/default.asp.
[14] *Id.*
[15] Sierra Club Board of Directors, "Natural Gas Fracturing" http://www.sierraclub.org/policy/conservation/NaturalGasFracturing.pdf.

- The project does not "properly treat, manage, and account for frac'ing fluids, drilling muds, and produced water."
- The project endangers "water supplies or critical watersheds, seriously damage important wildland resources, significantly increase habitat fragmentation, imperil human health, or otherwise violate the Club's land conservation policies."
- The project would cause violations of air quality standards, individually or cumulatively.
- The project does not "comply with best management practices, even in regions where state or federal law may permit lower standards of environmental management."

This policy also states, "Chapters are encouraged to press for effective regulatory frameworks to control the impacts of deep shale gas and may oppose specific projects that are inappropriately sited or that fail to comply with best management practices." Consistent with this policy, Sierra Club has protested natural gas pipeline expansion and Marcellus Shale development.[16] The New Jersey chapter has called for a ban on fracking, while the Pennsylvania chapter has called for a moratorium on new Marcellus shale drilling permits.[17, 18]

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[16] Sean Sullivan, "CNYOG's MARC I Project Becomes Battleground for Marcellus Shale Opponents," SNL Energy, July 13, 2011.
[17] Bryan Schutt, "Advocacy Group: Fracking Makes Natural Gas 'Bridge to Nowhere,'" SNL Energy, June 13, 2011.
[18] Bryan Schutt, "Pa. Chapter of Sierra Club Calls for Moratorium on New Marcellus Drilling Permits," SNL Energy, September 13, 2010.

Q. **Is there an inconsistency between NRDC's and Sierra Club's positions on fracking and the assumptions regarding fracking regulations in Dr. Fisher's proposed gas price forecast?**

A. Yes. Although the NRDC and the Sierra Club are champions of fracking regulation, Dr. Fisher's gas price forecast explicitly excludes assumptions for any costs related to more stringent regulations of hydraulic fracturing. It is difficult to reconcile this inconsistency.

Q. **If Sierra Club succeeds in its efforts concerning fracking, what will be the likely effect on natural gas prices?**

A. Their efforts would likely reduce the supply of shale gas and increase the cost to produce shale gas. Both of these effects would increase natural gas prices, likely resulting in higher prices than those in the AESC 2011 Base Case forecast.

Q Has any regulation regarding fracking already been proposed?

A. Yes. On October 20, 2011, EPA announced a schedule to develop standards for wastewater discharges produced by natural gas extraction from underground coalbed and shale formations.[19] On September 28, 2011, the New York Department of Environmental Conservation released proposed regulations on fracking and will accept public comments until December 12, 2011.[20] These regulations echo several of the points outlined by the Sierra Club policy regarding fracking fluids and water monitoring, but go further to specify a number of permitting and operating guidelines. In addition, the governor of Pennsylvania has proposed a fee on natural gas wells of as much as $160,000 per well as well as requirements for the minimum proximity of wells to water sources.[21]

[19] http://yosemite.epa.gov/opa/admpress.nsf/0/91E7FADB4B114C4A8525792F00542001

[20] New York State Department Of Environmental Conservation, High Volume Hydraulic Fracturing Proposed Regulations, http://www.dec.ny.gov/regulations/77353.html.

[21] "Drill Fee Proposed For Pennsylvania," *Wall Street Journal*, October 4, 2011, p. A6.

Robustness of Natural Gas Price Forecasts

Q. You previously stated that the natural gas price forecast used by the Companies is reasonable. Can you say the same about the Synapse forecast?

A. Yes. Despite their Base Case forecast being skewed to the low side, it appears that the forecast meets all of the same reasonableness criteria I applied to the forecast used by the Companies.

Q. Is the Commission required to determine whether a particular gas price forecast is more reasonable than another to grant the Companies' applications in these cases?

A. No. In my opinion, the issue is not whether the Synapse or the PIRA gas price forecast is more reasonable than the other, particularly because both support the decision to install controls at Brown Units 1 & 2 and Mill Creek Units 1 & 2. Rather, the real issue is how the forecast is used in the decision analysis to retrofit or retire and replace a generating unit and how robust that decision is under alternative possible futures for natural gas prices. As demonstrated in Figure 1 in the Companies' "2011 Air Compliance Plan Supplemental Analyses," a breakeven "HH - Threshold" forecast of natural gas prices was calculated that results in no difference between the present value revenue requirement for the installation of controls compared to retirement of Brown Units 1 & 2 (note that the breakeven threshold price would even lower for Mill Creek Units 1 & 2).[22] As seen in Rebuttal Exhibit DSS-5 (shown in 2011 dollars to maintain consistency with Synapse's graphs), this HH - Threshold forecast is well below the Compliance Plan gas

[22] KU's Supplemental Response to Commission Staff's July 12, 2011 DR No. 20(b) (Sept. 15, 2011); LG&E's Supplemental Response to Commission Staff's July 12, 2011 DR No. 18(b) (Sept. 15, 2011).

price forecast used by the Companies, and is below even the AESC 2011 Low Price case presented by Synapse.[23]

Q. In your opinion, does the natural gas price forecast used by the Companies result in a robust recommendation?

A. Yes. Future natural gas prices could turn out to be significantly lower than the base forecast used by the Companies, the AESC Base Case proposed by Dr. Fisher, and even the AESC Low Price case, and still the optimal decision would be to install controls on Brown Units 1 & 2 and Mill Creek Units 1 & 2. The fact that installing controls is the least-cost solution for our customers under such a wide range of possible natural gas prices gives me confidence that the Companies' recommendation is robust.

Potential for CO_2 Pricing

Q. Please describe your experience and responsibilities as it relates to climate change issues.

A. I first became involved in climate change issues around 2005. At that time, the Companies were owned by E.ON AG, a multi-national German-based energy company. As part of my responsibilities for energy market analysis, I was asked to represent the U.S. business on an E.ON-wide project to develop an overall corporate position on climate change that reflected the unique circumstances of each country where E.ON had major operations. Since that time, I have participated in and directed numerous analyses related to potential climate change regulations and laws and their impact on the Companies.

[23] Dr. Fisher, NRDC, and Sierra Club refused to provide the underlying AESC data for Exhibit 3-15 in the AESC 2011 Report in response to the Companies' data request, Question No. 27(b)(ii). Therefore, several of the AESC values are estimated as indicated.

Q. What was your involvement in the 2008 and 2011 Integrated Resource Plans ("IRPs")?

A. As Vice President, Energy Marketing, both the sales forecast and the resource plan were prepared under my direction.

Q. What was the assumption regarding CO_2 regulation in the 2008 IRP?

A. Dr. Fisher states in his testimony (page 31, line 9) that the Companies included CO_2 pricing in the 2008 IRP modeling. Actually, no CO_2 regulation was assumed in the base analyses of the 2008 IRP; rather, the Companies evaluated the impact of potential CO_2 regulation in two aspects of the 2008 IRP.

First, in the Supply Side Screening analysis in which the least cost supply-side technology options are evaluated, two sensitivity cases for CO_2 emissions prices were evaluated:

- "Intermediate" CO_2 emission prices starting in 2012 at $4.61 per short ton and increasing to $21.10 per short ton in 2036 in nominal dollars. The result of this was no change to the least-cost technology choices.
- "High" CO_2 emission prices starting in 2012 at $40.71 per short ton and increasing to $87.20 per short ton in 2036 in nominal dollars. This resulted the addition of "new hydroelectric" to the list of potential least-cost technology options. Ultimately, it was not included in the final set of potential options due to the scarcity of available sites.

Second, a least-cost expansion plan was developed assuming the intermediate CO_2 prices analysis. This sensitivity did not result in a change to the base case least-cost expansion plan, which assumed no CO_2 pricing.

Q. Why did the Companies perform these analyses in the 2008 IRP?

A. When the 2008 IRP was developed during the fall of 2007 and early 2008, support for CO_2 regulation was on the rise. In Congress, legislative climate efforts were escalating, with many proposals making it out of subcommittee. Examples of such proposed legislation included the Lieberman-Warner bill, which proposed to establish a market-based cap-and-trade system for GHG emissions that would reduce emissions 71% below 2005 levels by 2050, and the Bingaman-Specter bill, which also would have established a cap-and-trade system with GHG emissions reduced to 1990 levels by 2030.[24, 25] Bipartisan compromises were being fostered regarding allowance allocations, cost-containment measures, regulation points, and the use of offsets. It was logical to assume that a national CO_2 trading system for the U.S. could be enacted in the 2013-2014 timeframe. However, because no CO_2 legislation had been enacted, allowance prices associated with CO_2 regulation were considered only in sensitivity studies and not in the base analyses of the 2008 IRP.

Q. How did the Companies' assumptions regarding the potential for CO_2 regulation change in the 2011 IRP?

A. No costs for CO_2 were included in the base studies or sensitivity analyses in the 2011 IRP.

Q. Why was this change made?

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[24] America's Climate Security Act of 2007, S.2191, http://www.gpo.gov/fdsys/pkg/BILLS-110s2191rs/pdf/BILLS-110s2191rs.pdf.

[25] Low Carbon Economy Act, S.1766, http://www.gpo.gov/fdsys/pkg/BILLS-110s1766is/xml/BILLS-110s1766is.xml.

A. When the 2011 IRP was developed, no market was anticipated for CO_2 emissions allowances due to currently proposed regulations. National and international support for global warming rules has declined and CO_2 regulation appears far less likely.

Q. Please explain recent attempts by Congress to regulate CO_2 emissions.

A. By late 2009, in the absence of Congressional passage of economy-wide climate legislation, EPA began exercising its authority under the Clean Air Act to regulate GHG emissions. By 2011, no legislative proposals to price carbon were filed in Congress, while EPA vigorously pursued its ability to develop and enforce new GHG regulations. CO_2 pricing legislation proposals for carbon taxes or cap-and-trade plans began in 2005, peaked in 2009 with passage in the House of Representatives of Waxman-Markey, and appears to have declined to none so far in 2011, as shown in Rebuttal Exhibit DSS-6.

Q. What national legislation has been introduced recently to avert GHG regulations?

A. Several bills were filed in 2011 to nullify EPA's "endangerment finding" that classified GHG emissions as dangerous air pollutants under the Clean Air Act, and to block or delay EPA's plans to limit GHG emissions from power plants, large manufacturers and refineries under the Clean Air Act. Senator John Barrasso's *Defending America's Affordable Energy and Jobs Act* and Rep. Fred Upton's *Energy Tax Prevention Act*, explicitly nullify the endangerment finding. Barrasso's bill was referred to the Senate Committee on Environment and Public Works, as was Upton's after it passed the House in April 2011. Rep. Marsha Blackburn's *Free Industry Act* and Rep. Ted Poe's *Ensuring Affordable Energy Act* prohibit EPA from regulating GHGs. Both were referred to the House Committee on Energy and Commerce. Although none of these bills have been signed into law, they demonstrate that there is legislative opposition to GHG regulation.

Q. In the absence of federal legislation, what progress have the states made in regulating CO_2 emissions?

A. The states have made very little progress. Regional cap-and-trade programs such as the Regional Greenhouse Gas Initiative ("RGGI"), Midwest Greenhouse Gas Accord ("MGGA"), and Western Climate Initiative ("WCI") have faltered. RGGI is the nation's first mandatory GHG cap-and-trade program. It originally included 10 northeastern states although New Jersey is withdrawing this year, and another, New Hampshire, reportedly has considered withdrawal.[26] The goal of RGGI is to stabilize GHG emissions at an initial level from 2009-2014, then reduce GHG emissions 2.5% per year from 2015 to 2018 for a total 10% reduction. Between 2009 and 2010, emissions increased 10.9%.[27] RGGI allowance prices have fallen steadily since auctions began in September 2008; RGGI's allowances now are at the $1.89 "minimum reserve price," due to the fact that the RGGI emissions cap is too high to result in market prices much above the minimum reserve price.[28]

MGGA, which comprised Illinois, Iowa, Kansas, Michigan, Minnesota, Wisconsin, and Manitoba, disbanded in 2009, one year after releasing design recommendations for its cap-and-trade program.

WCI began in 2007, when its original eight members proposed to reduce greenhouse gas emissions in the West to 15% below 2005 levels by 2020. But its proposed 2012 start date has been delayed until 2013 due to New Mexico's withdrawal,

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[26] Bradley Carlson, "New Jersey to Leave RGGI," New Hampshire Public Radio, May 26, 2011, http://www.nhpr.org/new-jersey-leave-rggi.
[27] "RGGI Emission Trends," Environment Northeast, May 2011, http://www.env-ne.org/public/resources/pdf/ENE_RGGI_Emissions_Report_110502_FINAL.pdf.
[28] http://rggi.org/market/co2_auctions/results

Oregon's and Washington's failure to pass necessary implementation laws, and the delayed start of California's, British Columbia's, and Quebec's cap-and-trade programs.[29]

To date, Kentucky has taken no substantive actions to regulate CO_2 emissions beyond the implementation of the EPA Tailoring Rule and GHG emission inventory requirements.

Q. Why do you think that legislative efforts for CO_2 regulation in the U.S. are diminishing?

A. Gallup polls show that Americans are less concerned about global warming than they were in the past, with 51% saying they worry a great deal or fair amount about the problem, a level of worry that compares with 66% just three years ago, and is only one percentage point higher than the low Gallup measured in 1997.[30] Polling indicates that the plurality of Americans continue to believe the seriousness of global warming is generally exaggerated in the news (43%) rather than generally correct (26%) or generally underestimated (29%). Such public opinion is unlikely to spur political action to price carbon. This decline in public support is coincident with the "Climategate" controversy in which emails purportedly reveal scientists manipulating climate data and suppressing their critics, and acknowledged errors by the Intergovernmental Panel on Climate Change in its 4th Assessment Report regarding, among other things, sea level in the Netherlands and its projected date of melting Himalayan glaciers.[31]

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[29] Cora Zeeman, "California delays start of Cap and Trade until 2013," Canadian Energy Law, July 6, 2011, http://www.canadianenergylaw.com/2011/07/articles/climate-change/california-delays-start-of-cap-and-trade-until-2013/.

[30] http://www.gallup.com/poll/146606/Concerns-Global-Warming-Stable-Lower-Levels.aspx

[31] Jeffrey Ball and Keith Johnson, "Climate Group Admits Mistakes", *Wall Street Journal*, February 10, 2010, http://online.wsj.com/article/SB10001424052748704182004575055703697897576.html

Q. If the U.S. has not made any progress in pricing CO_2, what is the status of international efforts to address climate change?

A. In the European Union, the Emission Trading Scheme ("ETS") is on shaky ground and whether it survives in its current form, given its equivocal effectiveness, is a fair question.[32, 33] Allowance prices have dropped this year from $22 to $16 per metric ton due to an oversupply of allowances in the ETS market, which is expected to continue through 2020.[34] As the global economy recovers from the recent downturn, GHG emissions are increasing commensurately; the European Union "is about to set a record for the biggest yearly hike in carbon emissions in twenty years."[35] The ETS faces many administrative challenges as it moves from Phase II to Phase III at the end of 2012, including a general shift from free allocations to auctions, major restrictions on the use of offsets, and the coverage of new sectors and industries, such as aviation.

The Kyoto Protocol's first commitment period is set to expire at the end of 2012. It seems likely that a failure to extend or replace the commitment period would see the Kyoto Protocol effectively discontinued, according to Christiana Figueres, Director of the UN Framework Convention on Climate Change.[36] Recent United Nations meetings regarding a successor to the Kyoto Protocol have not produced a legally binding agreement. The United States has not historically supported an agreement under the Kyoto Protocol paradigm, which requires only developed nations to cut emissions without requiring similar commitments from China or India. Rebuttal Exhibit DSS-7

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[32] Arnold Mulder, "The EU Emission Trading Scheme: designed by committee," April 18, 2011.
[33] Allesandro Torello, "EU Weighs Pullback on Cutting Emissions", *Wall Street Journal*, October 19, 2011.
[34] Arnold Mulder, "The EU Emission Trading Scheme: designed by committee," April 18, 2011.
[35] "EU Emissions Show Biggest Annual Increase in 20 Years," Eenews.net, October 11, 2011.
[36] "Fate of Kyoto Pact Likely to be Determined This Year," Eenews.net, May 13, 2011.

summarizes the major international summits regarding GHGs since 1992 and highlights the fact that true international support for GHG limits has failed to coalesce.

Based on the International Energy Agency's ("IEA's") projections, China is expected to continue its use of fossil fuels, particularly coal. According to the IEA's 2010 World Energy Outlook "[F]ossil fuels—oil, coal, and natural gas—remain the dominant energy sources in 2035 [in all of its scenarios]."[37] "Natural gas is set to play a central role in meeting the world's energy needs for at least the next two-and-a-half decades. It is the only fossil fuel for which demand is higher in 2035 than in 2008 in all scenarios."[38] IEA states:

> If countries act upon Copenhagen Accord commitments in a cautious manner, as we assume in the New Policies scenario, rising demand for fossil fuels would continue to drive up energy-related CO_2 emissions. The goal of limiting the increase in global temperature to two degrees Celsius above pre-industrial levels can only be achieved with vigorous implementation of commitments in the period to 2020 and much stronger action thereafter.[39]

EIA's 2011 International Energy Outlook agrees with this view and demonstrates an expectation for a continued increase in coal and natural gas demand for electricity production through 2035 both globally and in the U.S., reflecting the assumption for an "absence of national policies and/or binding international agreements that would limit or reduce greenhouse gas emissions."[40]

Q. So what should one conclude from the international activities on climate change?

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[37] "World Energy Outlook 2010," International Energy Agency, p.4, http://www.iea.org/Textbase/npsum/weo2010sum.pdf.
[38] *Id.* at 7.
[39] *Id.* at 11.
[40] "International Energy Outlook 2011," U.S. Energy Information Administration, September 19, 2011, http://205.254.135.24/forecasts/ieo/more_highlights.cfm#world.

A. It is my opinion that there will continue to be much discussion about climate change just as there has been for the last 20 years. I agree with the EIA's 2011 International Energy Outlook that the world's growing energy needs are likely to be largely met by fossil fuels because they are the least-cost technologies to reliably meet this demand, thus making it very difficult to meet the targeted CO_2 levels suggested by many, including Dr. Fisher.[41]

Q. How has Dr. Fisher's employer Synapse changed its view on CO_2 regulation?

A. Over the past five years, Synapse has made material changes to its assumption regarding the onset of CO_2 pricing in the U.S. In a 2006 document, "Forecasting and Using Carbon Prices in a World of Uncertainty," Synapse assumed a CO_2 price beginning in 2010.[42] But two years later, in its "2008 CO_2 Price Forecasts" document, it delayed the start of CO_2 pricing to 2013, stating, "This is a reasonable assumption since it is likely that climate change legislation will be passed by the next Congress."[43] In fact, Congress did not act, forcing Synapse to once again revise the starting date for CO_2 pricing; in Synapse's "2011 Carbon Dioxide Price Forecast," CO_2 pricing is assumed to begin five years later, in 2018, because, "Congress has lagged behind the states and executive branch in developing a policy response to the science of climate change."[44] As Synapse states in its 2011 report, "[P]rospects for legislation establishing an economy-wide emissions cap seem dim [in the 112th Congress.]"[45] Therefore, it would appear that their

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[41] Dr. Fisher's response to Companies' Data Request Question No. 26(c).
[42] "Forecasting and Using Carbon Prices in a World of Uncertainty," Synapse, January 2006, http://www.synapse-energy.com/Downloads/SynapsePresentation.2006-01.EUEC.Forecasting-and-Using-Carbon-Prices-in-a-World-of-Uncertainty.S0021.pdf.
[43] "2008 CO2 Price Forecasts," Synapse, July 2008, http://www.synapse-energy.com/Downloads/SynapsePaper.2008-07.0.2008-Carbon-Paper.A0020.pdf.
[44] "2011 Carbon Dioxide Price Forecast," Synapse, February 2011, http://www.synapse-energy.com/Downloads/SynapsePaper.2011-02.0.2011-Carbon-Paper.A0029.pdf
[45] *Id.* at 3.

assumption of a 2018 starting date for CO_2 pricing could be subject to further revision in the future.

Q. Does Synapse's 2011 CO_2 report evaluate the risk around CO_2 pricing?

A. Yes. It presents both high and low cases for CO_2 prices based on a wide range of possible future policy initiatives. Their report seems to recognize the difficulty of projecting CO_2 prices under such uncertainty when it states, "The range of prices we have shown is recommended for planning purposes, but it is certainly possible that the actual price will fall outside of this range."[46] I would agree that it is very difficult to forecast the actions of Congresses and Presidents that have yet to be elected.

Q. Does the EPA's current regulation of CO_2 result in a price on CO_2 emissions?

A. No. As Gary Revlett explains in his rebuttal testimony, under certain conditions, EPA's current CO_2 regulation requires the installation of Best Available Control Technology ("BACT"), which has not been defined. Dr. Fisher agrees that specifics on BACT technology are currently undefined, stating in his response to the Companies' Data Request Question No. 14, "[I]t is impossible to state specifically cite [sic] 'what is BACT.'"

Q. Are the CO_2 price forecasts contained in the Synapse "2011 Carbon Dioxide Price Forecast" report relied upon by Dr. Fisher based upon EPA's BACT regulation?

A. No. Dr. Fisher states in his response to the Companies' Data Request Question No. 22, "[B]oth legislative action implementing a greenhouse gas mechanism <u>or</u> regulatory action by the EPA (including promulgated rules) 'could reasonably impose a cost on the emissions of CO_2.'" But this statement is not supported by the source document for his

[46] *Id.* at 16.

recommended CO_2 prices as it makes no mention of EPA regulations as the justification for a particular CO_2 price forecast.[47]

Incorporating CO_2 Pricing Uncertainty into Investment Decision Analysis

Q. In your opinion, is Dr. Fisher's position that the Companies should assume a U.S. CO_2 price beginning in 2018 reasonable?

A. No. Though anything is possible, the likelihood is clearly decreasing that the existing national and international issues that have prevented a CO_2 pricing scheme from being established in the U.S. will be resolved anytime soon or that public support in the U.S. for such regulations will strengthen.

Q. Do you agree with Dr. Fisher's statement in response to the Companies' Data Request Question No. 22 that it is "unreasonable" for the Companies to assume zero compliance costs related to GHG emissions?

A. No. This proceeding and the analysis performed by the Companies to support it are about the lowest-reasonable-cost means for the Companies to comply with known or knowable EPA regulations for SO_2, NO_x, and HAPs. The issues at hand are not about unknown and unknowable CO_2 regulations. Dr. Fisher's analytical approach is premised on his value judgment that GHG regulations will occur and that only the precise timing and degree of costs are a bit uncertain. If the GHG regulations in fact were known and measureable, and only the precise timing and costs slightly uncertain, then merely running a couple of simple sensitivities on timing and the level of CO_2 prices as he suggests might be adequate. However, there are much better and more sophisticated methods of analyzing uncertainty.

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[47] *Id.* at 15-18.

Q. What are some alternative methods that could be employed to evaluate the uncertainty?

A. There are a number of methods to aid a decision maker when evaluating uncertainty such as Monte Carlo simulation and decision trees. But both of these techniques require the analyst to know something about the probability distributions of the variables being evaluated in order for these techniques to provide meaningful information. For example, because there is a long history of experience with natural gas prices (both historical and forward), one could reasonably build a Monte Carlo simulation model that would provide a representative statistical distribution of possible future prices. Similarly, decision trees rely upon having a reasonable means to estimate the probability of occurrence of various branches on the tree.

As it relates to the GHG issue, we have neither the historical market price information to develop a future statistical price distribution to perform a Monte Carlo analysis nor a means of assessing with any reliability the probability of future courses of events such as the timing, method, and degree of GHG regulation to construct a meaningful decision tree.

A better tool to use in this circumstance where no reliable data is obtainable is to determine the value of the real options available to the Companies and choose the alternative that maximizes that option value for customers.

Q. Please explain what you mean by a real option.

A. First, any option involves the right or ability to take a future action. Because of the flexibility afforded the option owner, finance theory tells us that one should never exercise an option until it is about to expire. A real option is simply the ability to make, abandon, expand, or contract a capital investment. As it relates to the GHG issue, Dr. Fisher is arguing that the Companies, and therefore our customers, must exercise their rights (option) to comply with these unknown and unknowable GHG regulations now and forgo the future ability to see what, if any, regulations occur, as well as the future technological options that will be available to meet such regulations in the least-cost way. These real options have significant value to customers and are ignored by Dr. Fisher's simplistic analytical approach to evaluating the uncertainty surrounding GHG regulations.

Q. Did you estimate the value of this real option to customers?

A. Yes. I evaluated the real option value of deferring the decision to retire Brown Units 1 & 2 and Mill Creek Units 1 & 2 by installing the Companies' recommended controls. To do this, I compared the revenue requirements of the Companies' recommended generation portfolio (including the cost of proposed controls) with an alternative generation portfolio wherein Brown Units 1 & 2 and Mill Creek Units 1 & 2 were retired and replaced with new generating resources, consistent with Dr. Fisher's implied recommendation. My group calculated revenue requirements for three possible CO_2 worlds (no CO_2 prices, Synapse's Mid Case, and Synapse's Low Case) for each of the two generation portfolios using Dr. Fisher's base case gas price forecast.[48]

Q. What factors were not quantified in this analysis?

A. It was assumed that the Companies could take no further action regarding retirement or installation of CO_2 emissions controls at Brown Units 1 & 2 and Mill Creek Units 1 & 2. Also, I did not consider future technology advancements that might occur regarding CO_2

[48] Dr. Fisher's prices were adjusted for inflation to be consistent with the Companies' other Strategist inputs. Note that we adjusted Synapse's CO_2 prices for inflation even though Dr. Fisher failed to do this in his testimony and this would lead to increased revenue requirements.

control or capture, renewable technologies, or efficiency improvements to existing units. Although GHG regulations would likely result in higher gas prices, I did not quantify the extent to which higher gas prices would increase the value of the real option.[49]

Q. What were the results of this analysis?

A. The analysis showed that there is significant value created for customers related to the GHG issue as a result of installing SO_2, NO_x, and HAPs controls on Brown Units 1 & 2 and Mill Creek Units 1 & 2. Table 1 below shows the savings/(costs) in present value revenue requirements ("PVRR") over different time periods to customers as a result of the decision to install SO_2, NO_x, and HAPs controls on these units under the three possible CO_2 worlds. If Dr. Fisher is correct and GHG regulations occur according to the Mid CO_2 case, then customers are risking approximately $0.2 billion in PVRR through 2040 by not retiring Brown Units 1 & 2 and Mill Creek Units 1 & 2 in 2016. Alternatively, if Dr. Fisher is wrong, customers, by not retiring Brown Units 1 & 2 and Mill Creek Units 1 & 2, will save at least $1.3 billion if GHG regulations never occur or at least $0.4 billion in the Low CO_2 price case.

Table 1: PVRR Savings/(Costs) by Installing Controls on Brown Units 1 & 2 and Mill Creek Units 1 & 2

	Cash Flows from 2011 through:			
2011 PVRR $ million	**2020**	**2025**	**2030**	**2040**
No CO_2	136	354	659	1,298
Low CO_2	111	164	257	391
Mid CO_2	46	15	(20)	(168)

[49] Dr. Fisher's own sources indicate that the costs of GHG emission restrictions on electric generating units would likely increase natural gas costs. For example, compare the "Navigant GHG As-is" and "Navigant GHG Plus" gas price forecast curves shown in Figure 1 of Dr. Fisher's direct testimony at page 21. The Navigant report Dr. Fisher cites explains the Navigant GHG Plus case at pages 27-30. *See* http://www.navigant.com/~/media/Site/Insights/Energy/Cheniere_LNG_Export_Report_Energy.ashx.

It is interesting to note that in the Mid CO_2 price case customers would see a positive option value through 2025 if the Companies install the recommended controls, thereby affording the Companies the opportunity to evaluate future technological developments to address CO_2 emissions that could be lower cost than today's technology. Furthermore, the $168 million PVRR cost through 2040 in this case is the result of the high CO_2 costs that are forecasted to occur beyond 2030. It appears that the CO_2 prices that Dr. Fisher used in Strategist for years after 2030 are extrapolated linearly from the CO_2 prices forecasted in the 2011 Synapse CO_2 report. In this proceeding, the Companies face decisions that are far too important to rely on Dr. Fisher's simple straight-line guesses for future CO_2 prices. It is extremely difficult to forecast the price for any good or service twenty-plus years in the future, but it is nearly impossible to forecast the price for something that is solely a creation of government policy like a right to emit a ton of CO_2. This is another reason why the real option created by the decision to install controls on Brown Units 1 & 2 and Mill Creek Units 1 & 2 is so valuable.

It is also important to look at the nominal impact on annual customer costs to better understand the potential real option value. Rebuttal Exhibit DSS-8 and Rebuttal Exhibit DSS-9 show the annual and cumulative (respectively) savings/(costs) by year to customers as a result of the decision to install SO_2, NO_x, and HAPs controls on Brown Units 1 & 2 and Mill Creek Units 1 & 2. These graphs confirm that in the No CO_2 and the Low CO_2 cases, customers would prefer the Companies' compliance plan. In the Mid CO_2 case, customers would be indifferent between the two plans through 2026, allowing another fifteen years to investigate the gamut of developing CO_2 reduction options.

Q. What conclusions have you drawn from this analysis?

A. This analysis demonstrates there is real option value to customers by installing SO_2, NO_x, and HAPs controls and deferring the decision to react to unknown and unknowable GHG regulations compared to Dr. Fisher's plan to force our customers to invest now in hopes that his speculation regarding GHG regulation comes true. The potential upside savings possibilities of $1.3 billion with no CO_2 prices and $0.4 billion with the Low CO_2 case far outweigh the $0.2 billion at risk in Dr. Fisher's Mid CO_2 price case even without considering all of the qualitative factors that would further increase the real option value. Contrary to Dr. Fisher's insistence that it is "unreasonable" to assume zero compliance costs for GHG emissions and that "there will be no choice but to find mechanisms to reduce CO_2 emissions," I contend that it would be imprudent to simply assume a compliance cost for unknown and unknowable government policies and to ignore the very real option value that is created by the Companies' recommended compliance plan.

Dr. Fisher states in his response to the Commission Staff's Data Request Question No. 9(b), "[T]he Company may be able to structure a "no regrets" compliance plan such that it is minimally exposed to both large magnitude capital costs and yet meets environmental requirements." With this rebuttal analysis, I have demonstrated that the Companies' compliance plan significantly limits the risks to our customers as compared to following Dr. Fisher's recommendation. Although there is always a chance that an option will expire out of the money, the relatively low cost of that risk in this instance is more than offset by the savings potential of deferring any decisions on GHG regulations until they become known or knowable.

Q. Why do you think Dr. Fisher insists that it is unreasonable not to include GHG emission compliance costs in a decision analysis that is being precipitated by SO_2, NO_x, and HAPs regulations and not CO_2 regulations?

A. As can be seen in Rebuttal Exhibit DSS-10, Dr. Fisher's client, the Sierra Club, has stated, "By 2030, we plan to shut down all conventional – not carbon sequestered – coal plants."[50] To meet that goal, the cost of compliance with CO_2-only regulations would need to be significantly greater than the price forecasts suggested by Dr. Fisher. To economically justify retiring an existing coal plant and replacing it with a new combined cycle gas turbine, CO_2 prices would need to be in the range of $50 to $60 per ton.[51] As can be seen in Rebuttal Exhibit DSS-12, it will be many years before the CO_2 prices forecasted by Synapse (adjusted to nominal dollars) would approach that level. Therefore, I can only conclude that Dr. Fisher's insistence that the Companies and their customers address GHG issues now in this proceeding is related to the goal of his client to shut down all coal plants by 2030, not what is in the best interest of customers. The economic realities of replacing existing coal generation with new technology appear to drive the need for Dr. Fisher and Sierra Club to attempt to piggyback the GHG issue onto the SO_2, NO_x, and HAPs compliance plan to significantly reduce the economic threshold that GHG emission reductions would otherwise have to meet. Dr. Fisher's approach to the unknown and unknowable GHG issue in this proceeding is at best simplistic and at

[50] *Transforming America's Energy Future*, Sierra Club, http://www.sierraclub.org/crp/downloads/SierraClub-CRP-CleanTech-Mrkt-Opps.pdf.

[51] In 2009, the Companies performed an analysis that was included with the attachments with the Companies' response to the Metro Housing Coalition's Data Request Question No. 1-6 that showed the relative costs of reducing CO_2 emissions with different technologies. Rebuttal Exhibit DSS-11 is an excerpt from that presentation that shows the levelized all-in production cost of various technologies. Calculating the dollars per ton CO_2 price that would make one indifferent between retiring an existing coal plant and installing a combined cycle gas turbine requires taking the difference (without the carbon tax) between the all-in levelized production cost of a new combined cycle gas turbine and an existing coal unit, converting from cents/kWh to $/ton (based on a typical coal plant's CO_2 emission rate of one ton per MWh). These values would not have changed significantly in the last two years.

worst an attempt to mislead the Commission, and to follow his approach would be imprudent.

Q. What is your recommendation?

A. Dr. Fisher's claim that the Companies' "analysis is fundamentally flawed due to erroneous input assumptions and methodologies" is not correct.[52] I have demonstrated that (i) Dr. Fisher made a fundamental error in modeling natural gas prices, (ii) the natural gas price forecast utilized by the Companies is reasonable and supports a robust decision, and (iii) the Companies' assumptions regarding future GHG regulations are also reasonable, support a robust decision, and create significant real option value for customers. The Companies' plan continues to represent the lowest-reasonable-cost option for complying with EPA regulations and reliably meeting the Companies' future load obligations. Therefore, I recommend that the Commission approve the issuance of all CPCNs and rate treatment for retrofitting the Companies' coal units as originally requested.

Q. Does that conclude your testimony?

A. Yes.

[52] Direct testimony of Dr. Fisher, page 42, lines 23-25.

APPENDIX A

David S. Sinclair

Vice President, Energy Marketing
LG&E and KU Energy, LLC
220 West Main Street
Louisville, Kentucky 40202
(502) 627-4653

Education

Arizona State University, M.B.A. – 1991
Arizona State University, M.S. in Economics – 1984
University of Missouri, Kansas City, B.A. in Economics – 1982

Professional Experience

LG&E and KU Energy, LLC
- 2008-present – Vice President, Energy Marketing
- 2000-2008 – Director, Energy Planning, Analysis and Forecasting

LG&E Energy Marketing, Louisville, Kentucky
- 1997-1999 – Director, Product Management
- 1997-1997 (4th Quarter) – Product Development Manager
- 1996-1996 – Risk Manager

LG&E Power Development, Fairfax Virginia
- 1994-1995 – Business Developer

Salt River Project, Tempe, Arizona
- 1992-1994 – Analyst, Corporate Planning Department

Arizona Public Service, Phoenix, Arizona
- 1989-1992 – Analyst, Financial Planning Department
- 1986-1989 – Analyst, Forecasts Department

State of Arizona, Phoenix, Arizona
- 1983-1986 – Economist, Arizona Department of Economic Security

APPENDIX B

Please see the folder titled Sinclair Workpapers on the attached CD for a complete collection of source documents and workpapers provided in electronic format, except for those documents for which an internet link has been provided.

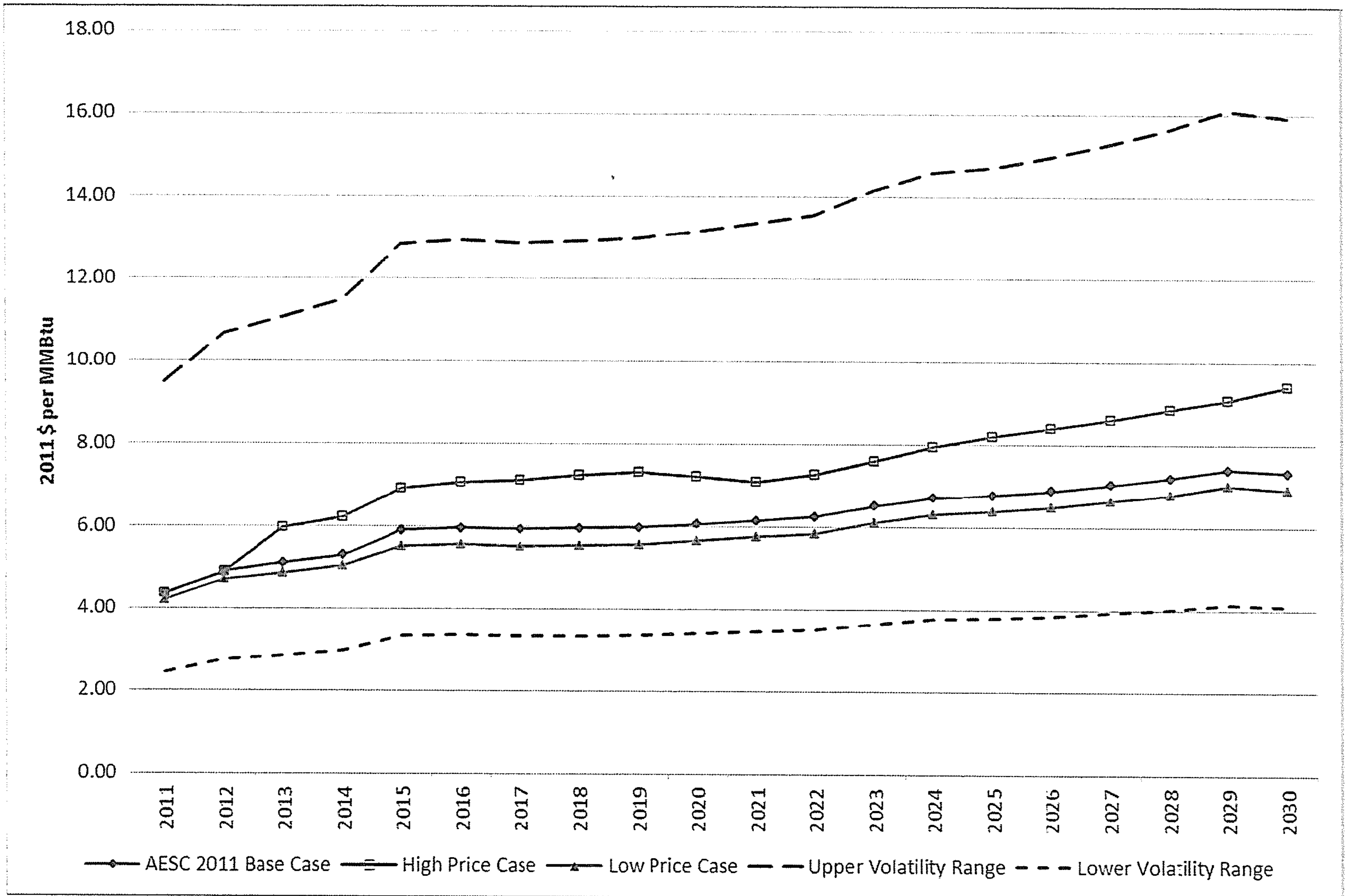
Rebuttal Exhibit DSS-1: Portfolio Revenue Requirements with Dr. Fisher's Recommended Gas Price Forecast[53]

Coal Units in Portfolio

Trimble County 2	Trimble County 1	Mill Creek 3	Mill Creek 4	Ghent 1	Ghent 2	Ghent 3	Ghent 4	Brown 3	Mill Creek 1-2	Brown 1-2	Green River 4	Cane Run 5	Cane Run 6	Cane Run 4	Green River 3	Tyrone 3	Portfolio PVRR 2011 to 2040 ($Million)
X	X	X	X	X	X	X	X	X	X	X							32,671
X	X	X	X	X	X	X	X	X	X	X	X						32,737
X	X	X	X	X	X	X	X	X	X	X	X	X					32,811
X	X	X	X	X	X	X	X	X	X	X	X	X	X				32,819
X	X	X	X	X	X	X	X	X	X								32,909
X	X	X	X	X	X	X	X	X	X	X	X	X	X	X			32,968
X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X		32,997
X	X	X	X	X	X	X	X	X	X		X	X					33,044
X	X		X	X	X	X	X	X	X	X							33,345
X	X	X		X	X	X	X	X	X	X							33,401
X	X	X	X		X	X	X	X	X	X	X						33,479
X	X	X	X	X	X	X	X		X	X	X	X	X	X			33,491
X	X	X	X	X	X	X	X	X		X							33,546
X	X	X	X	X	X		X	X	X	X	X						33,575
X		X	X	X	X	X	X	X	X	X							33,581
X	X	X	X	X		X	X	X	X	X							33,686
X	X	X	X	X	X	X		X	X	X							33,697
X	X	X	X	X	X	X	X	X									33,969

53 The values above reflect the correction of the landfill cost error identified by Dr. Fisher and the error identified by the Companies in response to Supplemental Requests for Information of Rick Clewett, Raymond Barry, Sierra Club and the Natural Resources Defense Council dated August 18, 2011, Question No. 8(b). These errors had insignificant impacts on the results.

Rebuttal Exhibit DSS-2: Synapse's Range of Gas Prices[54]



[54] AESC 2011 Report, Exhibit 3-15, page 3-34

Rebuttal Exhibit DSS-3: Gas Price Forecast Comparison and Ranges CONFIDENTIAL INFORMATION REDACTED

[redacted]

Rebuttal Exhibit DSS-4: Sierra Club Policy on Natural Gas Fracturing

Natural Gas Fracturing

All natural gas production, including deep shale gas, should be governed by a robust and effective regulatory structure: all gas should be produced using rigorous best management practices to limit environmental damage.

The Club opposes all coalbed methane extraction because it poses unacceptable risks to water quality in shallow aquifers. The following provisions apply to deep shale gas:

First, the Sierra Club opposes frac'ing projects if the identity and volume of frac'ing fluids are not fully disclosed to the public.

Second, the Club opposes any projects using frac'ing fluids that pose unacceptable toxic risks.

Third, the Club opposes any projects that do not properly treat, manage, and account for frac'ing fluids, drilling muds, and produced water. Frac'ing should not be permitted unless it can be demonstrated that drinking water aquifers and surface waters are adequately protected from contamination.

Fourth, the Club opposes frac'ing projects that would endanger water supplies or critical watersheds, seriously damage important wildland resources, significantly increase habitat fragmentation, imperil human health, or otherwise violate the Club's land conservation policies.

Fifth, the Club opposes any frac'ing projects that would cause violations of air quality standards, individually or cumulatively.

Finally, as the industry matures, a series of best management practices will emerge, some already identified, some evolving with time. These best management practices should, to the maximum extent possible, be swiftly incorporated into regulatory requirements as they are developed. The Club opposes any unconventional or conventional drilling projects that do not comply with best management practices, even in regions where state or federal law may permit lower standards of environmental management.

The Club will use these standards as a yardstick for any regulatory reform efforts it undertakes or supports, and to judge which new drilling projects, if any, cause unacceptable environmental damage and warrant opposition.

Chapters are encouraged to press for effective regulatory frameworks to control the impacts of deep shale gas and may oppose specific projects that are inappropriately sited or that fail to comply with best management practices.

Board of Directors, December 21, 2009

Rebuttal Exhibit DSS-5: Gas Price Forecast Comparisons with Threshold CONFIDENTIAL INFORMATION REDACTED

[redacted]

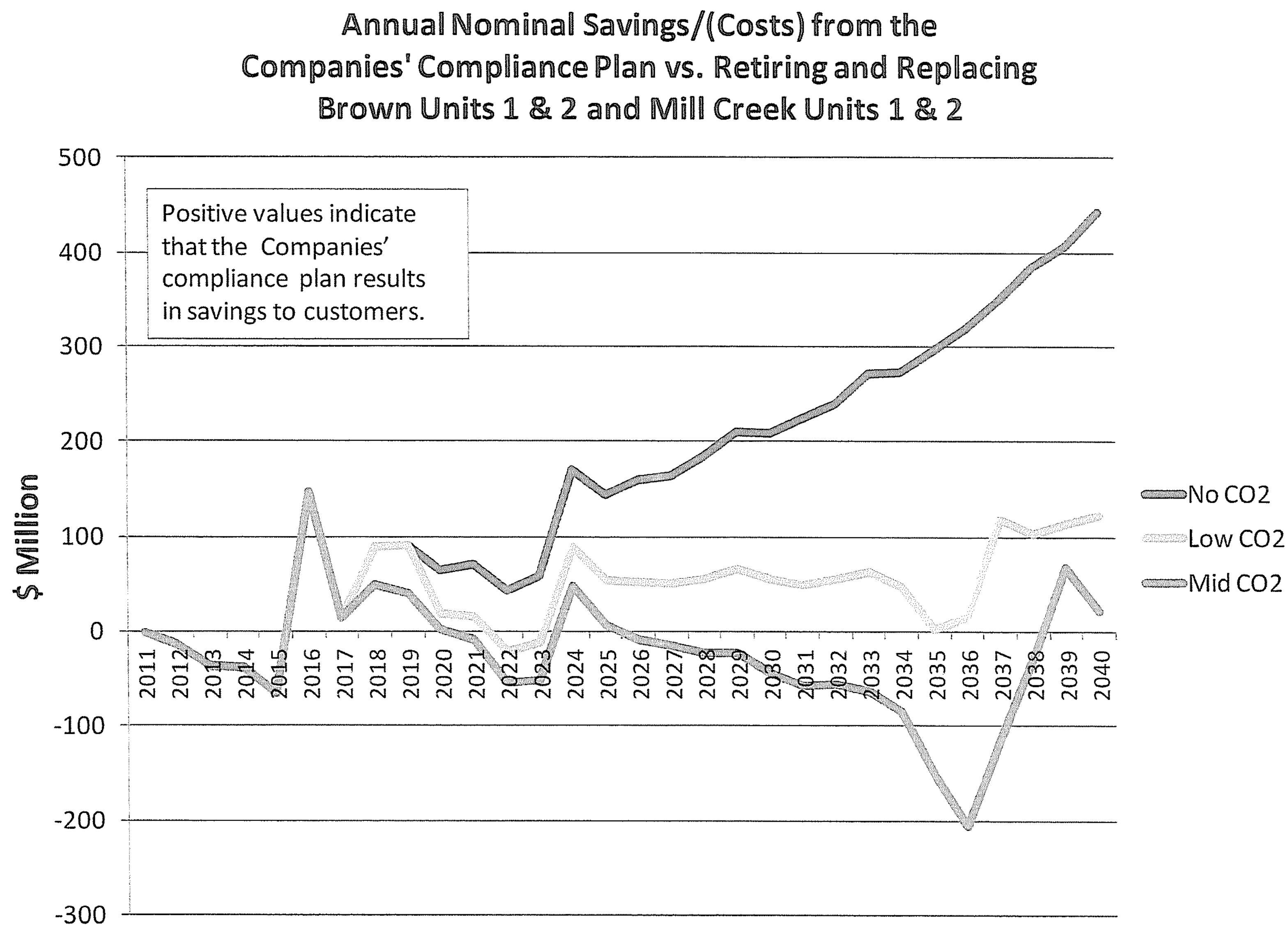
Rebuttal Exhibit DSS-6: CO_2 Pricing Legislation Proposals

2005	Bingaman *discussion draft* McCain-Lieberman "*Climate Stewardship and Innovation Act*"
2006	Udall-Petri "*Keep America Competitive Global Warming Policy Act*" Feinstein *discussion draft* Kerry-Snowe "*Global Warming Reduction Act*" Waxman "*Safe Climate Act*" Jeffords-Boxer "*Global Warming Pollution Reduction Act*"
2007	Bingaman-Specter "*Low Carbon Act*" Lieberman-Warner "*Climate Security Act*" Sanders-Boxer "*Global Warming Pollution Reduction Act*" McCain-Lieberman "*Climate Stewardship and Innovation Act*"
2008	Markey "*Investing in Climate Action and Protection Act*" Dingell-Boucher *discussion draft*
2009	Waxman-Markey "*American Clean Energy & Security Act (ACES)*" Kerry-Boxer "*Clean Energy Jobs & American Power* Act" Cantwell "*Carbon Limits and Energy for America's Renewal Act (CLEAR)*" Stark "*Save Our Climate Act*" Larson "*America's Energy Security Trust Fund Act*" Inglis "*Raise Wages, Cut Carbon Act*"
2010	Kerry-Lieberman-Graham *discussion draft*
2011	None

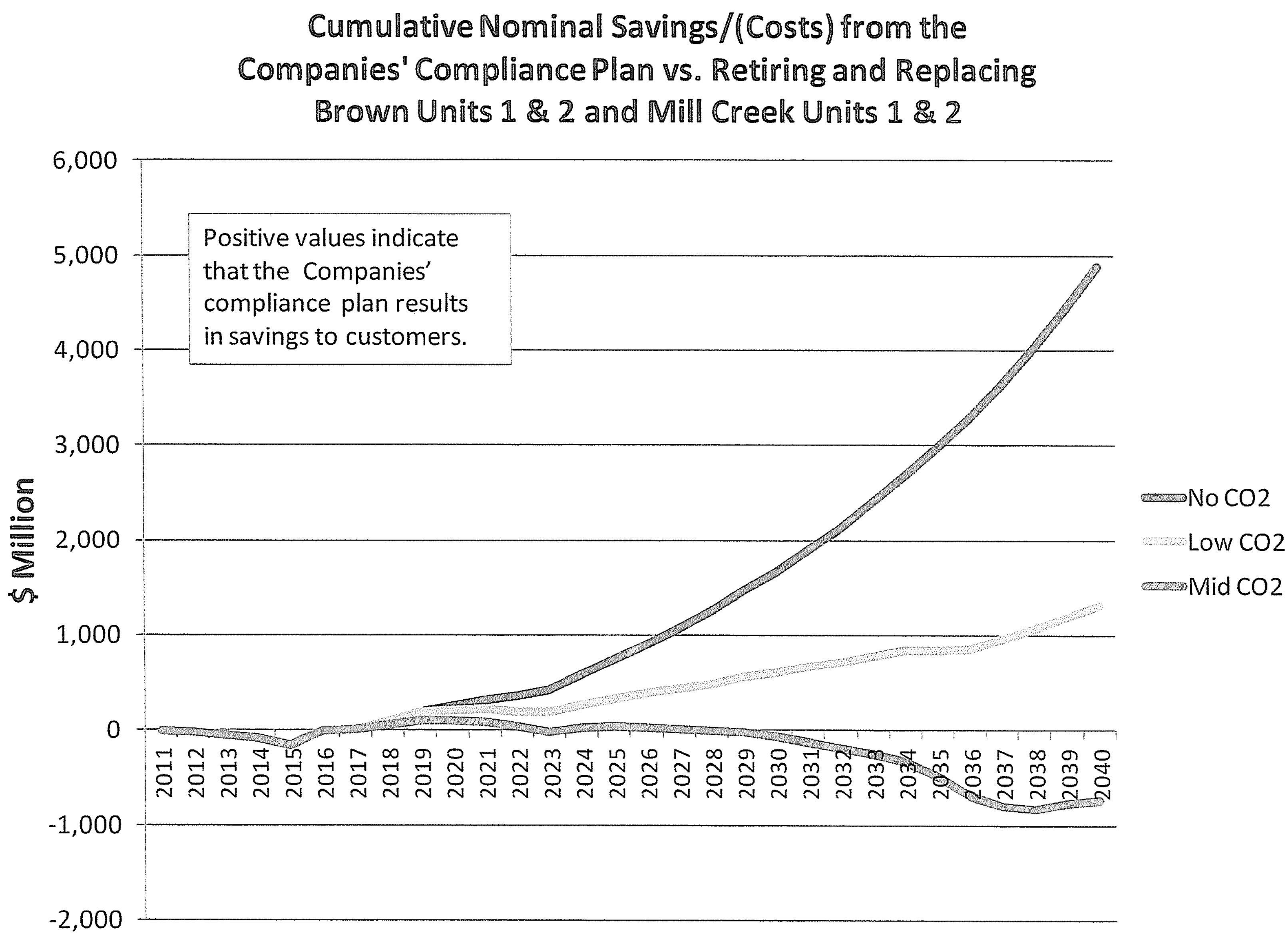
Rebuttal Exhibit DSS-7: International Greenhouse Gas Summits

Year, Location	Event
1992, Rio de Janeiro	Negotiations start with completion of U.N. Framework Convention on Climate Change (UNFCCC). Countries agree to voluntarily reduce emissions with "common but differentiated responsibilities."
1995, Berlin	The first annual Conference of the Parties to the framework, known as a "COP." Sets up a two-year negotiation schedule. U.S. agrees to exempt developing countries from binding obligations.
1997, Kyoto	COP-3 diplomats approve the Kyoto Protocol. Mandates developed countries to cut greenhouse gas emissions. U.S. is required to cut total emissions 7 percent below 1990 levels.
1998, Buenos Aires	COP-4 sets two-year plan for Kyoto implementation in 2000.
2000, The Hague	Outgoing Clinton administration and Europeans differ on some COP-6 terms. Talks collapse.
2001, Bonn	An extended session of the COP-6 talks sets up terms for compliance and adaptation, but the Bush administration rejects a treaty, claiming it is "flawed."
2004, Buenos Aires	U.S. blocks formal negotiations on post-Kyoto treaty. COP-10 diplomats try informal talks.
2007, Bali	COP-13 diplomats approve schedule for post-Kyoto negotiations to end in 2009. This time, as presidential candidates warm to the subject of climate change, U.S. agrees.
2009, Copenhagen	President Obama and small group of world leaders produce the Copenhagen Accord, where countries make promises to cut carbon emission but with key decisions still remaining on how they will follow through. Also calls for the immediate launch of a forest carbon market and a "mechanism" to help countries develop and deploy clean energy technology.
2010, Cancun	140 countries "associate" themselves with the Copenhagen Accord, despite widespread concerns about the way it was created. Nations meet in Cancun to expand upon the political agreement and work toward a possible new binding treaty in 2011.

Rebuttal Exhibit DSS-8: Annual Nominal Savings/(Costs)



Rebuttal Exhibit DSS-9: Cumulative Nominal Savings/(Costs)

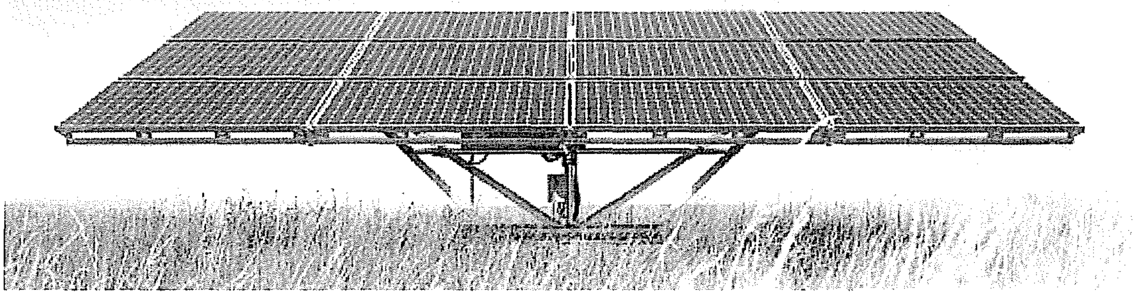


Rebuttal Exhibit DSS-10: "Transforming America's Energy Future", Sierra Club

CLIMATE RECOVERY PARTNERSHIP — SIERRA CLUB

Transforming America's Energy Future

Powerful Partnerships for Economic & Environmental Recovery



Opportunities for Clean Tech Innovators

Sierra Club's Climate Recovery Partnership is focused on fundamentally transforming the energy sector of the U.S. economy. We will level the playing field between the coal and oil of the past and the renewables, energy performance, and efficiency of the future. *We will close major loopholes and eliminate hundreds of billions of dollars of giveaways — including direct cash subsidies — to the high carbon incumbents, and provide financial certainty via affordable capital and markets to low carbon, clean energy innovators.*

Campaign Deliverables

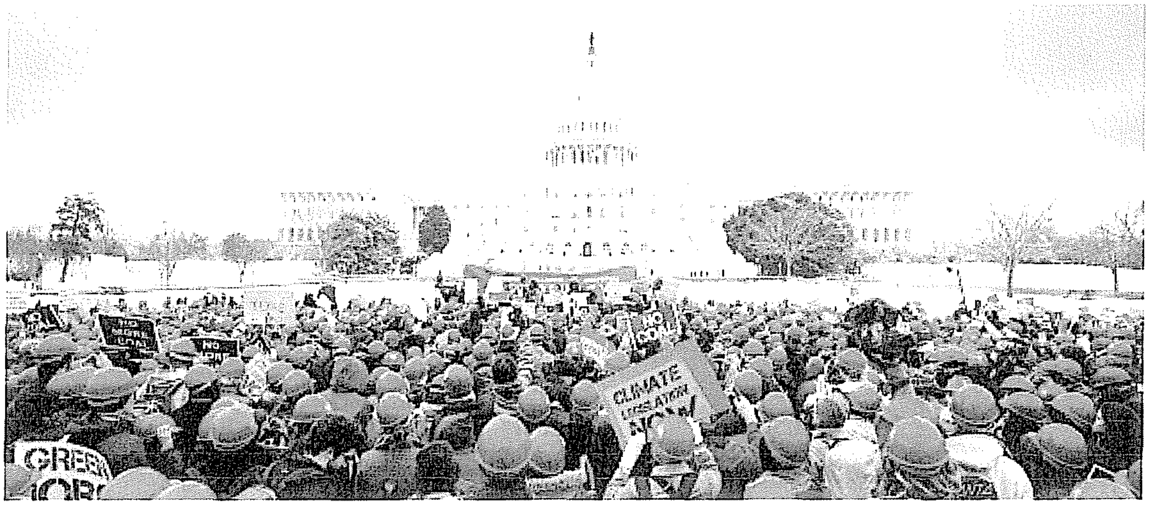
Sierra Club will measure our success against a series of mid- and long-term deliverables and benchmarks. These benchmarks will be measured in terms of reduced pollution from the U.S. economy and in the increasing scale of the clean energy market opportunity we are helping to create:

- By 2020, the U.S. will generate 500 TWH of low carbon electricity, and sell 3 million grid-ready vehicles (electrics and plug-in hybrids). We want the majority of new capital investments in this space to go to innovative renewable energy and storage technologies and efficiency companies.

- By 2030, we must phase out coal and oil as the backbones of the electricity and transportation sectors, thereby generating a new market for 2,000 TWH of low carbon electricity, with the majority coming from renewable energy; and eliminate 12 million barrels of oil a day, replacing petroleum powered vehicles with a combination of vehicle electrification, biofuels, and natural gas.

SIERRA CLUB BY THE NUMBERS:

- ✓ 1.4 million members and supporters
- ✓ 65 chapters across the United States and 400 groups worldwide
- ✓ 32,000 grassroots volunteers
- ✓ 1.8 million activist emails per year sent to state and federal legislators
- ✓ 35-member legal team with 20 staff attorneys
- ✓ More than 100 energy organizers in 40 states



A Formula for Linking Market Opportunities

BC (Beyond Coal) + CE (Clean Electricity) + VE (Vehicle Electrification) = Energy Independence + Climate Protection

Electrification of cars and rail means greater demand for electricity. Increased demand is compatible with our climate goals only *if we decarbonize the electric sector. Energy independence in the transportation sector thus requires success in* getting to 500, and then 2,000 TWH of clean electricity. Integrated state and federal campaigns to level the policy playing field have already dramatically changed America's energy trajectory. But progress so far is only a downpayment. Getting the job done requires new partnerships between environmentalists and entrepreneurs and innovators in the clean tech sector.

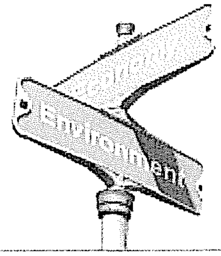
Opportunity #1: A Clean, Low-Carbon Electricity Sector

In the electric sector, we must create market space for new clean energy by blocking the misguided residual rush to build 150 GW of new coal power. We expect to have won the fight against this coal rush by the end of 2012.

But stopping new coal is not enough.

To truly open a major market for clean energy, we must shut down the existing coal fleet. Our Beyond Coal Campaign is positioned to force the phase-out of 25% of current coal electricity by 2020 (500 TWH). By 2030, we plan to shut down all conventional - not carbon sequestered - coal plants (2,000 TWH).

This vision is practical, but coal will be replaced by low-carbon energy only if we coordinate a simultaneous transition. Sierra Club is leveraging our ubiquitous, state "Beyond Coal" campaigns with geographically-coordinated synchronized advocacy for enhanced market access and finance for affordable, clean energy.



Opportunity #2: An All-American Transport Sector

The strategy for an All American Transportation system envisions the phase out of all reliance on oil - using largely available but still-to-be-perfected technologies:

- Cars to the grid - plug in hybrid or electric
- Planes to biofuels
- Trucks to biofuels or natural gas
- A freight, passenger, and urban rail system as good as those in Europe

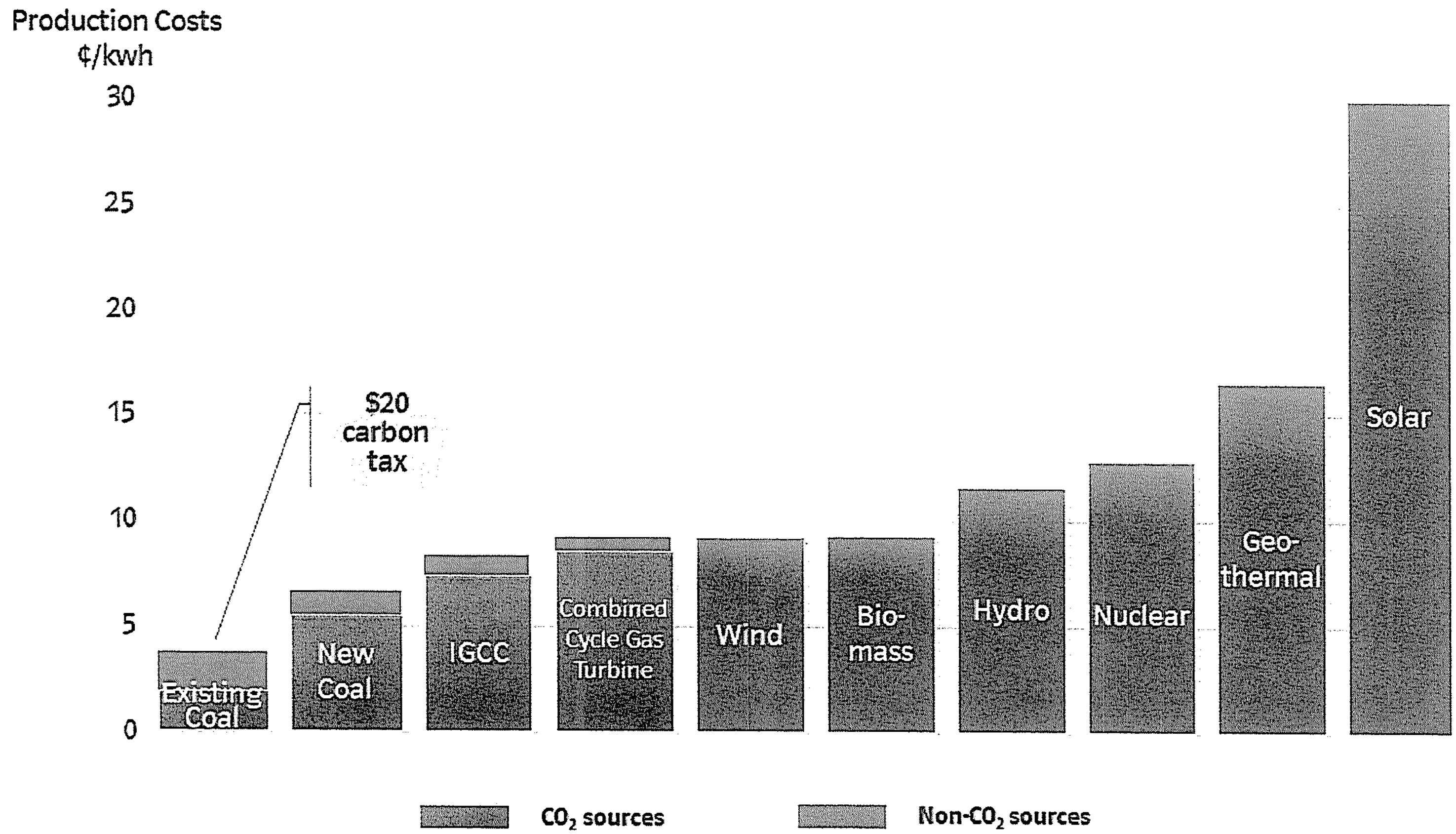
Sierra Club celebrated an early success when 17 states adopted California's proposed clean car standards, cutting oil consumption and CO_2 pollution from cars by 40%. Following our lead, the Obama Administration issued lower emission policies for cars and trucks nationwide.

In light of the BP disaster, we have a unique opportunity to build on this momentum and move America beyond oil in the next two decades.

To learn more about Sierra Club's energy programs contact Jesse Simons at *jesse.simons@sierraclub.org* or (415) 977 5537
Sierra Club • 85 Second Street, 2nd Floor • San Francisco, CA 94105 • *ClimateRecoveryPartnership.org*

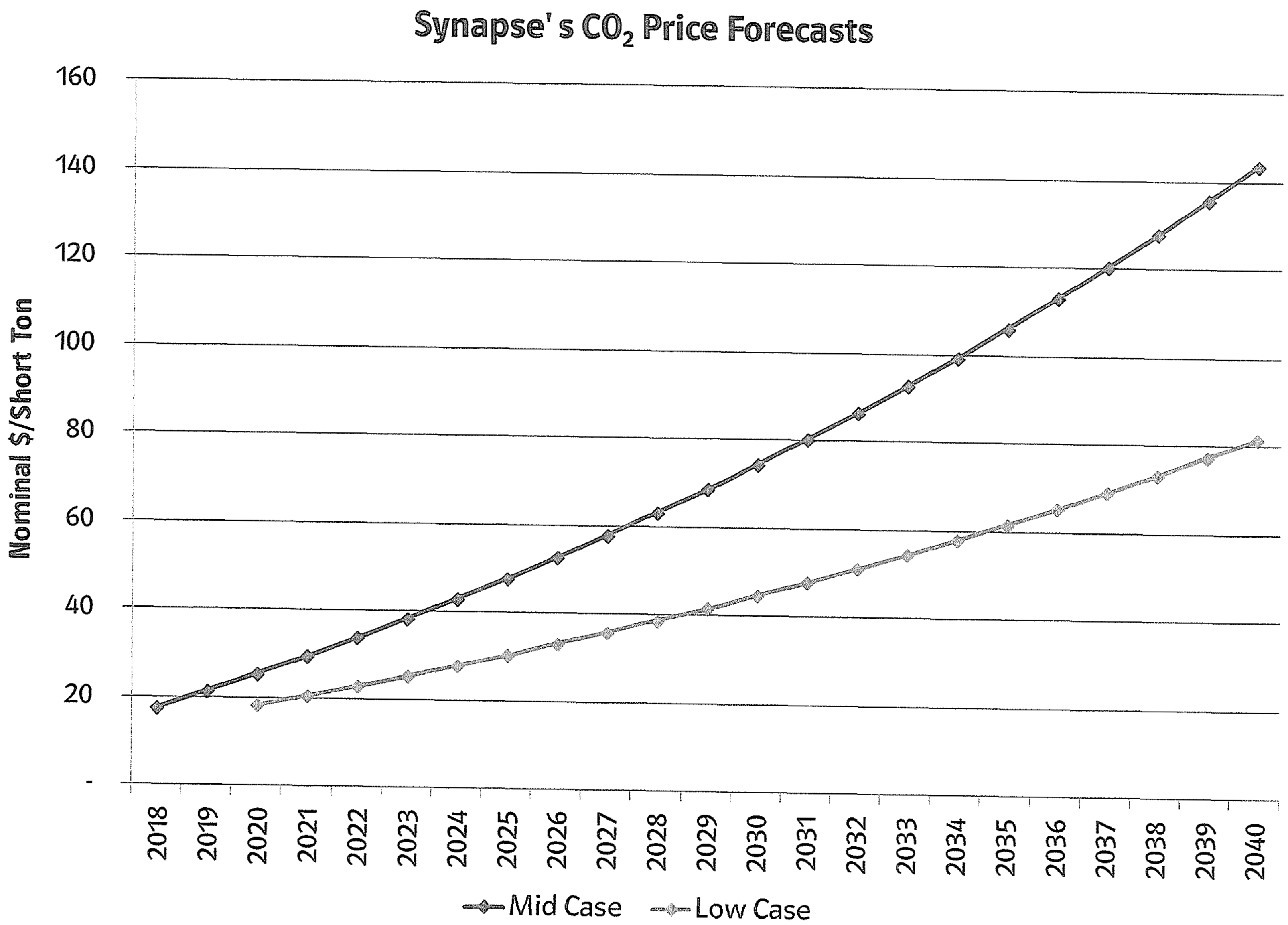
Rebuttal Exhibit DSS-11: Excerpt from Companies' "Carbon Footprint" Presentation

Cap & trade — incentive or tax?



LG&E KU

Rebuttal Exhibit DSS-12: Synapse's CO_2 Price Forecasts



COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

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 ENVIRONMENT SURCHARGE	))))))	CASE NO. 2011-00161

In the Matter of:

THE APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	))))))	CASE NO. 2011-00162

REBUTTAL TESTIMONY OF
DANIEL K. ARBOUGH
TREASURER
KENTUCKY UTILITIES COMPANY
LOUISVILLE GAS AND ELECTRIC COMPANY AND
LG&E AND KU SERVICES COMPANY

Filed: October 24, 2011

VERIFICATION

COMMONWEALTH OF KENTUCKY	)	
	)	**SS:**
COUNTY OF JEFFERSON	)	

The undersigned, **Daniel K. Arbough**, being duly sworn, deposes and says that he is Treasurer for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Daniel K. Arbough

Daniel K. Arbough

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 21st day of October 2011.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2014

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

A. My name is Daniel K. Arbough. I am the Treasurer for Louisville Gas and Electric Company ("LG&E"), Kentucky Utilities Company ("KU") (collectively, "the Companies"), and LG&E and KU Services Company, which provides services to LG&E and KU. My business address is 220 West Main Street, Louisville, Kentucky, 40202.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to the arguments presented by Kentucky Industrial Utility Customers, Inc.'s ("KIUC") witnesses, Lane Kollen and Stephen Hill. Mr. Kollen and Mr. Hill have recommended various proposals regarding how the Environmental Cost Recovery ("ECR") costs are allocated and the forms of debt the Companies should be permitted to utilize that are not only contrary to Commission orders, but would have a serious negative impact on the Companies if adopted by the Commission. My testimony will also address Mr. Kollen's recommendation regarding the use of securitization as a form of financing the construction projects.

<u>Use of Short-Term Debt and Tax-Exempt Debt During Construction</u>

Q. Please provide an overview of Mr. Kollen's position regarding the use of short-term debt.

A. Mr. Kollen's testimony states that he "recommend[s] that the Commission direct the Companies to maximize the use of low-cost short term debt during construction."[1] Mr. Kollen has made this recommendation because the cost of short-term debt is often less expensive than other forms of debt. Mr. Kollen asserts that because the

[1] Direct Testimony of Lane Kollen, p. 4.

Companies maintain several sources of liquidity that total $1.05 billion, allocating all of the available short-term debt to the ECR construction projects will result in savings to customers and lower the overall cost of construction.

Q. Is it prudent for the Commission to adopt Mr. Kollen's recommendation?

A. Absolutely not. Mr. Kollen's recommendation is not only imprudent, if adopted it would have a substantially detrimental effect on the financial condition of the Companies. While Mr. Kollen is correct that the Companies maintain liquidity totaling $1.05 billion, there are two principal reasons why these amounts cannot be fully utilized to finance the construction of the ECR projects.

First, the Companies are required to adhere to Federal Energy Regulatory Commission's ("FERC") requirements regarding short-term debt. Currently, pursuant to a FERC limitation, KU and LG&E may each maintain only $400 million in short-term debt. Both KU and LG&E have applied to increase their short-term borrowing limit to $500 million, but approval has not yet been given by FERC.[2] In any event, there are limitations on the amount of short-term debt that each Company may maintain, which prevent KU and LG&E from utilizing the substantial amounts of short-term equity Mr. Kollen has recommended.

Second, rating agencies require KU and LG&E to maintain, dollar for dollar, available revolving credit facilities for any outstanding commercial paper. For example, if KU or LG&E has $250 million in commercial paper outstanding, the utility would have to maintain at least $250 million in a revolving credit facility available to repay the outstanding commercial paper. Rating agencies require the

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[2] KU's application is available at: http://elibrary.ferc.gov/idmws/File_list.asp?document_id=13957380; LG&E's application is available at: http://elibrary.ferc.gov/idmws/File_list.asp?document_id=13957381.

revolving credit facility availability to protect investors if the utility has difficulty issuing replacement paper when the outstanding commercial paper reaches maturity.

As noted in Mr. Kollen's testimony, KU and LG&E are preparing to create a $250 million commercial paper program by the end of the year. When the commercial paper is issued, KU and LG&E must have an available reserve at least equal to the amount of outstanding commercial paper in revolving credit facilities. Thus, KU and LG&E cannot simply utilize all of their available short-term debt facilities to finance the construction of the ECR projects. Mr. Kollen's position is in direct conflict with the requirements and limitations imposed on the Companies with regard to short-term debt.

Q. Has the Commission recognized that utilities do not construct projects utilizing only one type of capital?

A. Yes. KRS 278.183(1) permits utilities to earn a "reasonable return on construction and other capital expenditures." For over a decade, the Commission has recognized that the reasonable rate of return includes both debt and equity. This is in accordance with how the Company finances the construction of all projects, ECR-related or otherwise, by relying on all sources of capital as appropriate. The Commission's final orders in the KU and LG&E ECR proceedings in 2000 affirmed the reasonableness of the Companies' financing sources and corresponding rate of return in rejecting the very same argument presented by the KIUC in this proceeding: "...the Commission believes that a reasonable return on the capital expenditures included in the surcharge constitutes part of the total actual costs incurred by the utility. Concerning the financing of utility plant, *it has long been recognized in the utility* *industry that capital expenditures are financed by numerous sources of capital, and that it is generally not possible to match a capital expenditure with a specific source of capital. KIUC has acknowledged that neither it nor KU stated that the 2001 Plan capital expenditures will be financed exclusively with short-term debt.*"[3]

This decision, which rejected the KIUC's argument that the rate of return to which KU is entitled should be based on KU's short-term debt rate, establishes that the Companies, consistent with utility industry standards, finance construction utilizing numerous sources of capital and the reasonable rate "on construction and capital expenditures" to which the Companies are entitled pursuant to KRS 278.183 must reflect the same. The Commission's Order is well reasoned, as it ensures that a utility's rate of return on ECR-related projects actually corresponds with how the Companies finance the construction.

Q. Does Kollen's recommendation, if accepted, expose the Companies to risk in refinancing?

A. Yes. Under Mr. Kollen's approach, the Companies would be attempting to place significant amounts of long-term first mortgage bonds to replace the short-term debt once the projects in the ECR Plans are fully completed. If debt rates are high at the time of the transaction, LG&E's and KU's customers would be faced with excessively high rates in the years following the transaction.

The recent financial crisis provides an illustrative example of when such refinancing risks can occur. In late 2008, in the midst of the economic downturn, the commercial paper market for companies with short-term debt rating comparable to

[3] *In the Matter of: The Application of Kentucky Utilities Company for Approval of an Amended Compliance Plan for Purposes of Recovering the Costs of New and Additional Pollution Control Facilities and to Amend its Environmental Surcharge Tariff* (Case No. 2000-439) Order, April 18, 2001 (emphasis added).

KU's and LG&E's ratings of A-2/P-2/F-2 was limited, with bank market capacity nearly impossible to obtain. Long-term first mortgage bonds could have been issued but at very wide spreads. If the Companies had been heavily exposed to the short-term market at that time, the Companies could have been forced to issue very expensive long-term bonds to avoid a default. The more prudent approach for the Companies to follow is to place debt in smaller amounts throughout the construction cycle, which allows the Companies to appropriately diversify their debt issuances and take advantage of favorable market conditions for particular forms of debt at the time. This diversified practice has successfully been used for years to mitigate the risks and volatility of the financial markets.

Q. **Is Mr. Kollen's approach consistent with how the Companies finance construction expenses?**

A. No. When KU and LG&E finance construction projects, they utilize various sources of debt and equity. As noted earlier in my rebuttal testimony, the Commission has recognized that the standard in the utility industry is to rely upon numerous sources of capital. If the Commission accepted Mr. Kollen's recommendation and required the Companies to finance all of the compliance costs with short-term debt, not only would KU and LG&E be greatly harmed, the Commission would likewise be departing from its well-established and sound policy.

Q. **Have witnesses proposed that special allocations of certain portions of the capital structure be made to the ECR costs?**

A. Yes, there are several proposals recommending these special allocations. For example, Mr. Kollen has recommended that any new tax-exempt pollution control debt financing be used only to finance ECR construction projects and should be "allocated in its entirety to the debt component of the ROR [rate of return] used in the ECR revenue requirement."[4] Mr. Kollen has a similar proposal with regard to the allocation of short-term debt.[5] Mr. Hill's testimony concurs, stating, "KIUC's primary recommendation with regard to the return to be included in the environmental surcharge is that the Commission utilize a short-term debt rate because that will be the manner in which the construction will actually be financed."[6]

Q. Do you agree with Mr. Kollen's and Mr. Hill's assertion that Companies use all of the available short-term debt to only finance the construction of the ECR projects?

A. No. Both Mr. Kollen and Mr. Hill imply that the Companies will predominantly devote its available short-term debt to construction of the ECR projects. This is inaccurate because the Companies utilize short-term debt for purposes other than financing projects under construction. For example, short-term debt is utilized for seasonal fluctuations in working capital, such as accounts receivable and is used to finance inventory changes such as the annual injection of natural gas into storage in anticipation of high winter usage. Other examples include payment of a wide variety of taxes, interest expense, and payroll. Mr. Kollen conceded that his statement that short-term debt is generally not used to finance plant-in-service was not based on his

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[4] Direct Testimony of Lane Kollen, p. 16.
[5] *Id.* at 19-20.
[6] Direct Testimony of Stephen G. Hill, p. 29.

experience with LG&E or KU, or even based on his experience with proceedings before this Commission.[7]

Moreover, in calculating the alleged savings resulting from predominant use of short-term debt, Mr. Kollen utilized a short-term debt rate of 0.16%, which is the money pool rate provided by the Companies in a data response. The money pool is in the process of being modified to more accurately reflect the current costs of borrowing on a short-term basis using the current short-term ratings of A-2/P-2 because the current money pool is based on outdated Company ratings.[8] The current A-2/P-2 borrowing rate is 0.36%. Thus, in using the 0.16% rate, Mr. Kollen overstates the savings available by using only short-term debt to finance construction.

Q. In addition to the limitations discussed above, are there financial risks associated with financing the ECR costs using only short-term debt?

A. Yes. The capital structure of the Companies would be greatly altered if the Companies utilized only short-debt to finance the compliance costs and construction projects. Based upon the June 30, 2011 balance sheets (with goodwill adjusted out), if KU added $1.114 billion in short-term debt, its debt to total capital ratio would increase from 46.7% to 58.4%. Likewise, if LG&E added $1.392 billion in short-term debt, its debt to total capital ratio would increase from 45.2% to 65.0%. Obviously, the resulting difference in these ratios is substantial. It is almost a certainty that the resulting levels of leverage, which would be extremely high for both

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[7] *See* KIUC's Response to Data Request No. 18 of LG&E and KU ("This statement is based on Mr. Kollen's experience in multiple ratemaking proceedings, including claims made by utilities, such as Atmos Energy Corp., and precedent by various state commissions, including the Public Utilities Commission of Ohio…").
[8] *See* PUE-2011-00110.

Companies, would lead to a downgrade of the bond ratings, likely by multiple notches.

Q. What leads you to believe that a significant increase in short-term debt could lead to a downgrade?

A. Liquidity is one of the key elements the rating agencies consider when determining a company's bond rating. S&P published its methodology for evaluating liquidity in an article entitled "Methodology and Assumptions: Liquidity Descriptors for Global Corporate Issuers" dated September 28, 2011. This article is attached as Rebuttal Exhibit DKA-1. The article describes a calculation that results in a ratio of liquidity sources/liquidity uses. All debt which matures within a year is included as a use of liquidity as are expected capital expenditures. To maintain an investment grade issuer credit rating, a company must be deemed to have "Adequate" liquidity which requires a ratio of liquidity sources being at least 1.2X the liquidity uses as noted in item 30 on page 6 of the Exhibit. If LG&E had short-term debt of $1.25 billion, expected capital expenditures of $250 million, and funds from operations of $250 million, its **undrawn, available** bank lines of credit maturing beyond 12 months would need to total over $1.5 billion. Similarly, if KU had $1 billion in short-term debt and expected capital expenditures of $400 million, and funds from operations of $350 million, its **undrawn, available** bank lines of credit maturing beyond 12 months would need to total more than $1.25 billion.

Given the size of the Companies, I do not believe banks would be willing to commit to facilities of the size mentioned above. Consequently, I strongly disagree with and dispute Mr. Kollen's statement in his response to the Commission's data request number 2 wherein he states that he "does not believe that there will be negative effects on the Companies' secured debt ratings if the utilities increase their use of short-term debt by several hundred million during construction over the next five years."[9]

Q. Is it important that the Companies maintain their credit ratings?

A. Yes, it is important. KU's and LG&E's current capital structures are established in accordance with the independent criteria set forth by Standard and Poor's, an independent credit rating agency, to achieve a rating in the "A" range. Standard and Poor's adopted a business risk/financial risk matrix structure in 2007. A copy of an article entitled "*Key Credit Factors: Business and Financial Risks in the Investor-Owned Utilities Industry*" dated March 11, 2010, which explains the Standard and Poor's current methodology is attached as Rebuttal Exhibit DKA-2. Table 1 from that article shows the relationship of Standard and Poor's assessments of the business and the financial risks for purposes of determining the credit rating of an investor-owned utility. In addition to the updated table 1 contained in the March 11, 2010 article Standard and Poor's published new indicative ratio guidelines in a May 27, 2009 article entitled "*Criteria Methodology: Business Risk/Financial Risk Matrix Expanded*" which is attached as Rebuttal Exhibit DKA-3. These two publications, taken together, represent Standard and Poor's current view on financial risk profile metrics for determining the credit ratings of investor owned utilities.

The Companies' financial risk profile, according to Standard and Poor's assessment, fits the category between "Significant" and "Highly Leveraged," known

[9] *See* KIUC's Response to Data Request No. 2 of the Commission.

as the "Aggressive" category. Standard and Poor's recommends a debt to total capital range of 50 percent to 60 percent to remain in this category. KU's and LG&E's target capital structures are based on achieving a rating in the "A" range rather than the current BBB. Table 1 in the same article shows KU and LG&E must achieve the "Intermediate" risk profile to achieve an A rating, and a "Significant" risk profile to achieve an A- rating. To reach the Intermediate financial risk profile, the Companies must maintain a maximum debt/capital ratio of 45% as measured by Standard & Poor's, and a maximum of 50% to achieve the "Significant" risk profile. Given Standard & Poor's assessment that the Companies meet the "Excellent" business risk profile, KU and LG&E target a maximum debt/total capital ratio of 48% as measured by Standard and Poor's.

Based on these criteria, KU and LG&E target an adjusted equity to total capital ratio (including imputed debt for purchased power, leases, pensions, and other adjustments) of 52% – equivalent to 48% adjusted debt to total capital ratio. If Mr. Kollen's recommendation is accepted by the Commission and the Companies are required to incur sufficient short-term debt to finance all of the costs associated with the projects in the Companies' ECR Plans, KU's debt will be 10.4% above the target 48% and LG&E's debt will be 17% above the target. If the Companies are forced to become this highly levered, the rating agencies will likely downgrade the utilities.

LG&E's and KU's Capital Structure

Q. Does Mr. Hill's testimony allege that LG&E's and KU's capital structures have too much equity?

A. Yes. Mr. Hill takes issue with the fact that at March 31, 2011, KU was capitalized with 53.4% common equity capital and LG&E was capitalized with 54.91% common equity.[10] Mr. Hill then asserts that LKE "has a utilized a more cost-effective capital structure that contains far less common equity" because at March 31, 2011, common equity was roughly 44% of total capital.[11] Mr. Hill then states that PPL was capitalized with roughly 34% of equity following the acquisition of LG&E and KU.[12]

Q. Do LG&E's and KU's capital structures have too much equity?

A. No. As explained above, KU's and LG&E's current capital structures are established in accordance with the independent criteria set forth by Standard and Poor's, an independent credit rating agency, to achieve a rating in the "A" range. In order to achieve this rating, based upon the controlling criteria, KU and LG&E target an adjusted equity to total capital ratio (including imputed debt for purchased power, leases, pensions, and other adjustments) of 52%. KU's and LG&E's equity ratios at June 30, 2011, were 51.1% and 50.6% respectively. The Companies have repeatedly explained that its target capital structures are intended to achieve an "A" rating so that it can access attractively priced capital. Mr. Hill's statements that the Companies have too much equity is incorrect, as the amount of equity Mr. Hill has deemed reasonable for the Companies would likely render it impossible for LG&E and KU to achieve an "A" rating.

Q. Have customers benefited from the current capital structures and credit ratings of LG&E and KU?

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[10] Direct Testimony of Stephen G. Hill, p. 19.
[11] *Id.* at 20.
[12] *Id.* at 21.

A. Yes. The current capital structure has allowed the Companies to have very low debt costs that benefit customers. In November 2010, following the PPL Corporation acquisition of LG&E and KU Energy LLC, the Companies issued first mortgage bonds at very attractive rates. LG&E issued $535 million at an average yield of 3.56% and KU issued $1.5 billion at an average yield of 3.98%. These transactions allow the companies to have all in debt costs of below 4% - one of the lowest in the country.

Irrelevance of the Parent Company and the Use of the Stand-Alone Methodology

Q. Are Mr. Kollen's statements regarding how LG&E and KU Energy, LLC ("LKE") finances its investment in the common equity of LG&E and KU correct?

A. No. Mr. Kollen's statement that "nearly half of the common equity of KU and LG&E is financed through long-term debt issued by LKE" is incorrect and based upon a flawed analysis. First, Mr. Kollen states that LKE's capitalization at June 30, 2011, consisted of $3,991 million in common equity and $3,825 million in long-term debt. The debt amounts Mr. Kollen lists are the consolidated capitalization numbers for LKE – meaning that the debt amounts include all of the debt of LG&E and KU, not just that of LKE. In fact, only $872 million of the $3,825 million debt that Mr. Kollen cites is at the LKE level or other affiliates. As to LG&E's and KU's equity, the vast majority is comprised of retained earnings or equity raised in years prior through the sale of stock. Equity owners have reinvested a significant portion of the earnings of the utilities to fund investment in the growth of LG&E and KU. As made evident in the 2009 financial statements of the utilities, equity contributions from LKE accounted for only $84 million of LG&E's total equity, and $316 million of KU's total equity, which are in stark contrast to the $755 million in retained earnings at LG&E and $1.32 billion at KU. Thus, Mr. Kollen has greatly overstated the amount of common equity LKE has invested in LG&E and KU, and has misrepresented the financing structure of LKE.

Q. Mr. Kollen describes LG&E, KU and LKE as "inextricably interrelated" for purposes of this proceeding. Is this accurate?

A. No. Mr. Kollen builds upon his flawed analysis regarding the role of LKE in LG&E's and KU's equity and debt totals to argue that the Companies' return on rate base and income taxes are overstated because the "computations do not consider all three companies together, as they should be."[13] Mr. Kollen states that the Companies' "income tax expense is overstated because it does not reflect the reduction in income tax expense from the interest expense deductions on the debt used by LKE, the intermediate holding company that owns LG&E and KU, to finance LKE's investment in the common equity of LG&E and KU."[14] Mr. Kollen's ultimate recommendation is that the Commission "refine" its computation of income tax expense to reflect the reduction in income tax expense resulting from the "use by LKE of debt to finance its investments in the KU and LG&E common equity."[15]

First, the Commission has recently affirmed that LG&E's and KU's income tax expense is to be calculated on a stand-alone basis, rejecting the argument that income tax expense should be determined using the consolidated method. The stand-alone method is based upon the following three closely related accounting and

[13] Direct Testimony of Lane Kollen, p. 23.
[14] *Id.* at 25.
[15] *Id.* at 26.

regulatory principles: (1) cost causation; (2) the benefits-burden relationship; and (3) prevention of cross-subsidies of, or by, affiliates. In other words, a utility's rates are set to recover the just and reasonable costs of actually providing utility service. In LG&E's and KU's most recent rate case proceedings, the Commission affirmed the stand-alone method of computing tax expense as the rate-making principle the Commission "has long employed," and the consolidated tax method "would result in cross subsidization of [the Companies] and its ratepayers by its unregulated affiliates."[16] In arguing that LG&E's and KU's income tax expense with regard to its ECR costs are overstated, Mr. Kollen is requesting that the Commission ignore its clear rejection of the consolidated tax method.

Q. Do you agree with Mr. Kollen's recommendation at pages 25-26 of his testimony that KU's, LG&E's and LKE's returns on rate base and income tax expense be considered together rather than separately?

A. Absolutely not. This recommendation, if adopted, would represent a radical and abrupt departure from twenty years of the Commission's well-established, sound, and balanced policy prohibiting affiliate cross-subsidization.[17] The Commission should continue its long-standing practice of using the stand-alone method for the direct assignment of costs, income tax expense and revenue requirements that are part of a holding company organization.

Q. Would you please explain the source of the Commission's the stand-alone requirements?

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[16] *See In the Matter of: Application of Kentucky Utilities Company for an Adjustment of Base Rates*, Case No. 2009-00548, Order (July 30, 2010).

[17] *See In the Matter of: Application of Louisville Gas and Electric Company for an Order Approving an Agreement and Plan of Exchange and to Carry Out Certain Transactions in Connection Therewith*, Case No. 89-374, Order (May 25, 1990).

A. Yes. In its May 25, 1990 Order in Case No. 89-374, *Application of Louisville Gas and Electric Company for an Order Approving an Agreement and Plan of Exchange and to Carry Out Certain Transactions in Connection Therewith*, the Commission approved LG&E's proposed reorganization and creation of a holding company structure. The consummation of this transaction resulted in LG&E Energy Corp. becoming the parent corporation of LG&E. As part of its application, LG&E proposed its Corporate Policies and Guidelines for Intercompany Transactions for the purpose of expressly establishing the affiliate transaction regulation of LG&E and its affiliates, including its parent corporation. The Commission's May 25, 1990 Order states in part:

> 11. LG&E and each related company shall comply with LG&E's Corporate Policies and Guidelines for Intercompany Transactions.[18]

These Corporate Polices and Guidelines for Intercompany Transactions require the following:

> 1. Separation of costs between utility and non-utility activities will be maintained.
>
> Distinct and separate accounting and financial records will be maintained and fully documented for each entity. All costs, which can be specifically identified and associated with an activity, will be directly assigned to that activity. Indirect costs, which provide a benefit to more than one activity, will be allocated to the activities that receive a benefit.
>
> *****
>
> 4. Financial Reporting.
>
> ...Holding will file consolidated Federal and State income tax returns which will include LG&E's and any other subsidiaries'

[18] *In the Matter of: Application of Louisville Gas and Electric Company for an Order Approving an Agreement and Plan of Exchange and to Carry Out Certain Transactions in Connection Therewith*, Case No. 89-374, Order at 20 (May 25, 1990).

> taxable income. The "stand alone" method will be used to allocate the income tax liabilities of each entity. Payment transfers for tax liabilities or tax benefits will be made on the dates established for the payment of Federal estimated income taxes.[19]

LG&E thus is obliged by the Commission's May 25, 1990 Order to comply with these requirements.

Q. Did the Commission adopt a similar requirement for KU?

A. Yes. The Commission approved an identical requirement (i.e., use of the stand-alone method to allocate the income tax liabilities of each entity) when KU proposed a similar corporate reorganization and holding company structure in Case No. 10296, *In the Matter of: Application of Kentucky Utilities Company for an Order Approving an Agreement and Plan of Exchange and to Carry Out Certain Transactions in Connection Therewith.*[20] The Commission required KU and KU Energy Corporation to adhere to similar Corporate Policies and Guidelines, which contained a similar stand-alone requirement as LG&E.

Thus, the Commission required both companies to adopt and implement similar Guidelines to protect their customers and the utilities themselves from the risks associated with non-utility activities. These Guidelines were intended to ensure that there would be no cross-subsidization between unregulated activities and the utilities or their customers in part by the requirement to follow the stand-alone method for computing income tax expense and revenue requirements.

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[19] Corporate Policies and Guidelines for Intercompany Transactions (LG&E Holding) at 4-5.
[20] Corporate Policies and Guidelines for Intercompany Transactions (KU Holding) at 3.

Q. When the Commission approved LG&E's and KU's reorganizations into holding companies, did the Commission foresee the possibility that their unregulated activities could cause substantial losses?

A. Yes. The Commission clearly anticipated the risk that such unregulated activities might entail, including the possibility of significant losses. This is shown by the requirement in the orders that each holding company, as a condition of approval, be willing to divest the utility in the event that losses on the unregulated side became so great that they posed a risk to the utility operations.[21]

Q. Did the Commission approve new <u>Guidelines</u> that include the stand-alone requirement in connection with the approval of the LG&E and KU merger?

A. Yes. In its Order of September 12, 1997, in Case No. 97-300, *In the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of Merger*, the Commission ordered as follows:

> LG&E, KU and each related company shall, after the merger, comply with LG&E Energy's *Corporate Policies and Guidelines for Intercompany Transactions.*

Order, p. 39. LG&E Energy's <u>Corporate Policies and Guidelines for Intercompany Transactions</u> expressly state:

> 1. <u>Separation of costs between utility and non-utility activities will be maintained</u>.
>
> Distinct and separate accounting and financial records will be maintained and fully documented for each entity. All costs, which can be specifically identified and associated with an activity, will be directly assigned to that activity. Indirect

[21] *In the Matter of: Application of Louisville Gas and Electric Company for an Order Approving an Agreement and Plan of Exchange and to Carry Out Certain Transactions in Connection Therewith*, Case No. 89-374, Order at 13-14, 21 (May 25, 1990); *In the Matter of: Application of Kentucky Utilities Company to Enter into an Agreement and Plan of Exchange and to Carry Out Certain Transactions in Connection Therewith*, Case No. 10296, Order at 12-13,18 (Oct. 6, 1988).

> costs, which provide a benefit to more than one activity, will be allocated to the activities that receive a benefit.
>
> *****
>
> 4. <u>Financial Reporting</u>.
>
> ...Holding will file consolidated Federal and State income tax returns which will include LG&E's and any other subsidiaries' taxable income. The "stand alone" method will be used to allocate the income tax liabilities of each entity. Payment transfers for tax liabilities or tax benefits will be made on the dates established for the payment of Federal estimated income taxes.[22]

Rebuttal Exhibit DKA-4 contains an accurate copy of the LG&E, KU, and LG&E/KU Guidelines.

Q. Did the Commission require LG&E and KU to continue to follow the <u>Guidelines</u> as a condition of approving the PowerGen merger with LG&E Energy Corp.?

A. Yes. In its Order of May 15, 2000, in Case No. 2000-095, *In the Matter of: Joint Application of PowerGen plc, LG&E Energy Corp., Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of a Merger*, in Appendix B the Commission ordered as follows:

> LG&E and KU should continue to comply with their <u>Corporate Policies and Guidelines for Intercompany Transactions</u> as well as employing other procedures and controls related to sales, transfers and cost allocation to ensure and facilitate the full review by the Commission and protection against cross-subsidization.

Thus, again, the Commission affirmed the <u>Guidelines</u> and the stand-alone method requirement therein.

Q. Did the Commission require LG&E and KU to continue to follow the <u>Guidelines</u> as a condition to the approval of the E.ON acquisition of PowerGen?

[22] Corporate Policies and Guidelines for Intercompany Transactions (LG&E Energy) at 5.

A. Yes. In its August 6, 2001 Order in Case No. 2001-104, *In the Matter of: Joint Application for Transfer of Louisville Gas and Electric Company and Kentucky Utilities Company in Accordance with E.ON AG's Planned Acquisition of PowerGen plc*, the Commission required as a condition of its approval of the acquisition and transfer of ownership and control of LG&E and KU the acceptance of the following Commitment and assurance:

> E.ON, Powergen, LG&E Energy, LG&E and KU shall adhere to the conditions described in the Commission's Orders in Case Nos. 10296, 89-374, 97-300 and 2000-095 to the extent those conditions are not superseded by KRS 278.2201 through 278.2219 or the jurisdiction of the SEC or FERC. These conditions, restated in Appendix B to the Commission's May 15, 2000 Order in Case No. 2000-095, concern protection of utility resources, monitoring the holding company and the subsidiaries and reporting requirements.

Order (May 6, 2001), Appendix A - No. 1.

Q. Did the Commission require LG&E and KU to continue to follow the <u>Guidelines</u> as a condition to the approval of the PPL Corporation acquisition of LKE?

A. Yes. In its September 30, 2010 Order in Case No. 2010-00204, *In the Matter of: Joint Application of PPL Corporation, E.ON A.G, E.ON US Investments Corp., E.ON U.S. LLC, Louisville Gas and Electric Company, and Kentucky Utilities Company For Approval Of An Acquisition Of Ownership And Control Of Utilities*, the Commission required as a condition of its approval of the acquisition and transfer of ownership and control of LG&E and KU the acceptance of the following Commitment and assurance:

> Except to the extent expressly superseded by KRS 278.2201 through 278.2219, the jurisdiction of the Federal Energy Regulatory Commission ("FERC") or the findings and conditions set forth in this Order of the Kentucky Public Service Commission ("Commission"), PPL Corporation (PPL),

> E.ON US LLC ("E.ON US"), Louisville Gas and Electric Company ("LG&E), and Kentucky Utilities Company ("KU") shall adhere to the conditions described in the Commission's Orders in Case Nos. 10296, 89-374, 97-300, 2000-00095, and 2001-00104. The conditions, restated in Appendix B to the Commission's May 15, 2000 Order in Case No. 2000-00095 and incorporated by reference into the Commission's August 6, 2001 Order in Case No. 2001-00104, concern protection of utility resources, monitoring the holding company and the subsidiaries, and reporting requirements.

Order (September 30, 2010), Appendix C - No. 1.

Q. Please explain the principle preventing cross-subsidies between Commission-regulated and unregulated businesses, and how KIUC's proposed approach to consolidate KU's, LG&E's and LKE's returns on rate base and income tax expense would violate it.

A. The Commission has permitted the holding company of LG&E and KU to pursue unregulated businesses; however, there has always been a requirement that there should be no cross-subsidization between regulated and unregulated businesses. If a utility's returns on rate base and income tax expense are not calculated on a stand-alone method, but instead are adjusted using consolidated financings and capital amounts, the separation between a utility and its affiliates will be completely compromised. Imposing such an adjustment creates a mathematical certainty that changes in the operations of unregulated affiliates will have the capacity to alter utility rates. If unregulated capital structures change, utility rates will change accordingly. The imposition of this adjustment will drag the activities of unregulated affiliates into the regulatory arena, contrary to the long-standing principle of utility insulation. In order to prevent cross-subsidies, all regulated and unregulated members of holding company structure should be treated separately and independently.

Q. Would acceptance of KIUC's recommendation jeopardize the ability of LG&E and KU to achieve their authorized rates of return?

A. Yes. KIUC's recommendation would preclude LG&E and KU from achieving their authorized rates of return because the recommendation would result in an imputed, as opposed to an actual, benefit. The only effect of the adjustment is to reduce revenues with no offsetting benefit. If all other revenue and expense items remain the same, diminished revenues will result in a rate of return that is necessarily less than authorized. LG&E and KU would not have a meaningful opportunity to earn a reasonable return on their capital invested in pollution control facilities to serve customers. The impact of such an adjustment could also affect LG&E and KU's ability to raise capital at reasonable and cost-effective rates because investors would view the adjustment as an effective discount to the allowed rate of return.

Q. Do you agree with Mr. Kollen's contention that his proposal is consistent with the stand-alone method because he does not believe that LKE holds investments in unregulated affiliates?[23]

A. No. While LKE is not structured to own and operate PPL Corporation's unregulated business or regulated business in Pennsylvania, LKE is structured to own and operate both regulated business like LG&E and KU and unregulated businesses like Western Kentucky Energy Corporation. Since the 1990s, LKE has held numerous investments in unregulated affiliates and continues to own the inactive Western Kentucky Energy Corporation. Moreover, LKE can invest in additional

[23] KIUC's Response to Data Request No. 5 of the Commission.

unregulated activity in Kentucky at any time. In "superimposing" LKE's financial structure on the Companies as Mr. Kollen has suggested, there is certainly a risk of cross-subsidization of, or by, the regulated utilities.

Moreover, if the overall financial condition of the Companies' affiliates is not to be considered as part of a base rate proceeding in computing tax expense, it is certainly irrelevant to this case because the Commission has recognized that an ECR proceeding is limited in scope. As the Commission recognized in its earlier orders in these proceedings, the overall financial condition of the utilities themselves are irrelevant to a surcharge proceeding[24] certainly then the financial condition of its affiliates and parent company is irrelevant. Mr. Kollen has provided no basis to depart from the protections of the stand-along methodology or the recognition of the limited scope of this proceeding.

Second, KRS 278.183(1) permits utilities such as KU and LG&E to recover its actual costs in complying with environmental regulations. If the Commission accepted Mr. Kollen's recommendation and considered the Companies' affiliates and consequently authorized a lower rate of return than would otherwise be awarded based upon an adjustment in the Companies' income tax expense, certainly, then, the Companies would not be recovering their actual costs of compliance. Mr. Kollen's recommendation cannot be accepted without violating KRS 278.183.

Q. Does the rule Mr. Kollen references from Florida have any bearing on this proceeding?

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[24] *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) Order, September 1, 2011.

A. No. Mr. Kollen cites a Florida administrative rule regarding the effect of parent debt on federal corporate income tax. This rule is obviously not binding on the Companies or the Commission. If the rule, in fact, requires the utility to reduce income tax expense for ratemaking purposes by the tax effect of interest expense incurred by a parent company on debt used to finance their equity investments in utility companies as Mr. Kollen asserts, then it directly conflicts with the Commission's orders over the last 20 years and its continuous adherence to the stand-alone methodology. Mr. Kollen stated in a data response that he is not aware of other state commissions that have adopted this approach.[25] The fact that another commission has adopted a contrary position is of no import where this Commission has repeatedly held otherwise.

Q. Please respond to Mr. Kollen's recommendation that the Commission should authorize LG&E and KU to earn a rate of return on the low end of the range because of LKE's financing of equity in LG&E and KU.

A. As I explained in detail above, Mr. Kollen has substantially overstated LKE's investment in the equity of the Companies. The figures on which Mr. Kollen relies in arguing that LKE is inextricably intertwined with the Companies are simply inaccurate and consequently undercut the arguments Mr. Kollen has made. Even if Mr. Kollen's statements were accurate, if the Commission considered the financial condition of LKE, or that any of the utilities' affiliates or parent company, not only would LG&E and KU be deprived of recovering their actual costs of compliance, but the Commission would also depart from its well-established position regarding the

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[25] KIUC's Response to Data Request No. 5 of the Commission ("Mr. Kollen is only aware of the FPSC's Rule due to this experience in FPSC rate proceedings. He hasn't researched other state commissions to determine if they have similar rules or precedents.").

separateness of regulated utilities from its non-regulated affiliates and parent company. As such, Mr. Kollen's arguments provide no sound reason to award the Companies a lower rate of return.

Q. Do you agree with Mr. Hill's contention that the Commission should consider the capital structure of KU's and LG&E's parent when determining the return on common equity for LG&E and KU?

A. No. While Mr. Hill concedes that the Commission has a well-established practice of utilizing the book capital structure of the utilities within its jurisdiction for determining the overall cost of capital to include in rates,[26] Mr. Hill nevertheless argues that "the Commission should examine not only the capital structure of the regulated subsidiary but also the capital structure of the parent company." [27] Mr. Hill concludes by stating the use of KU's and LG&E's book capital structures are only reasonable if the allowed return on equity recognizes the low financial risk of that capital structure.[28] As established in my earlier testimony, his recommendation, like Mr. Kollen's recommendation, if adopted, would represent a radical and abrupt departure from twenty years of the Commission's well-established, sound, and balanced policy prohibiting affiliate cross-subsidization.[29] In order to prevent cross-subsidies, all regulated and unregulated members of holding company structure should be treated separately and independently. Mr. Hill's recommendation asks the

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[26] *Id.* at 21-22.
[27] *Id.* at 24.
[28] *Id.* at 29.
[29] *See e.g., In the Matter of: Application of Louisville Gas and Electric Company for an Order Approving an Agreement and Plan of Exchange and to Carry Out Certain Transactions in Connection Therewith*, Case No. 89-374, Order (May 25, 1990).

Commission to engage in a selective process of considering the capital structures of LG&E's and KU's parents for the purpose of achieving cross-subsidization.

Securitization

Q. Please address Mr. Kollen's recommendations regarding the use of securitization.

A. Mr. Kollen recommends that if securitization legislation is enacted the Commission should *require* the Companies to pursue the *maximum* securitization financing possible.[30] As explained in Mr. Bellar's testimony, no state that has enacted securitization as a form of financing has mandated that utilities use that form of financing to the maximum extent possible. Mandating the use of securitization in the manner presented in Mr. Kollen's testimony would be viewed negatively by credit markets and credit rating agencies. Because securitization legislation permits utilities in other jurisdictions to use this form of financing in limited circumstances, requiring this form of financing to the maximum extent possible would be viewed as quite extreme.

Currently, the Kentucky regulatory environment is seen as credit supportive by rating agencies and the larger financial community. Imposition of any securitization financing structure will be viewed as highly intrusive. While the financial markets are currently comfortable with the existing regulatory construct in Kentucky, an aggressive mandate such as the one Mr. Kollen proposes, or even a permissive authorization for financing of new plant the utility would own and operate, will undoubtedly cause the financial community to reconsider the

[30] Direct Testimony of Lane Kollen, p. 13.

attractiveness of the Kentucky regulatory regime. Mr. Hill, another witness for the KIUC, acknowledged that rating agencies consider the impact of regulation in evaluating a utility's risks.[31] As a necessary consequence, the credit ratings and credit risk of the bonds issues by any utility within the Commission's jurisdiction – not just LG&E's and KU's – will likewise be reconsidered. As noted above, S&P has evaluated the Companies' business risk profile (which is largely a function of the regulatory environment) as "Excellent". As shown in the table on page 2 of Rebuttal Exhibit DKA-2, if S&P were to reduce its business risk profile to "Strong" a downgrade of the Companies to a sub-investment grade level would be implied.

Q. Is Mr. Kollen's contention that LG&E's customers would realize annualized savings of $97 million and KU's customers would realize annualizes savings of $75 million if the Companies LG&E finances the entirety of their capital expenditures with securitization financing correct?

A. No. While I acknowledge there is a difference in the cost of the carrying charge between equity and debt, Mr. Kollen's calculation of the purported savings is over-simplified. In response to a data request of the Companies, Mr. Kollen provided the worksheets he utilized to create the savings. In examining the calculation, several critical deficiencies became apparent. For example, the calculation simply assumes a lower cost of capital, leaving all of the other elements of the calculation the Companies provided to the KIUC in a data response unchanged. This is an inaccurate means by which to calculate the savings. The debt service for securitization bonds includes both principal and interest on each payment date and the principal amortization will be more rapid than the book depreciation that is included in the

[31] *See* KIUC's Response to Data Request No. 24 of LG&E and KU.

model provided by the KIUC. The accelerated repayment of the principal will increase the cost of securitization compared to what is shown in the model.

Recommendation

Q. What is your recommendation to the Commission?

A. My recommendation is that the Commission reject the various proposals Mr. Kollen and Mr. Hill have advanced. The argument that the Companies only use short-term debt to finance ECR costs is neither practical nor prudent and would have a substantially detrimental effect on the credit ratings of the Companies. Likewise, the proposals that would allocate certain portions of the capital structure to ECR costs would only result in administrative difficulty and decreased rate transparency, while having no positive effect to customers. Mr. Hill's assertion that LG&E and KU have too much equity ignores the fact that the Companies' capital structures are premised upon achieving an "A" rating. Mr. Kollen's and Mr. Hill's attempts to urge the Commission to consider the financial conditions of LKE and PPL in computing the rate of return and income tax expense is contrary to the stand-alone methodology, KRS 278.183, and the Commission's Orders in this proceeding. Finally, the securitization recommendation Mr. Kollen has made would greatly impact how the financial markets and rating agencies view the regulatory framework in Kentucky to the detriment of all utilities operating in the state.

Q. Does this conclude your testimony?

A. Yes.

Rebuttal Testimony
Exhibit DKA-1

S&P Global Credit Portal

Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers

dated September 28, 2011

STANDARD & POOR'S

Global Credit Portal
RatingsDirect®

September 28, 2011

Criteria | Corporates | General:

Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers

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Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers

1. Standard & Poor's Ratings Services is refining its methodology for its liquidity analysis used when determining issuer credit ratings (ICRs) on global corporate issuers. We are publishing this article to help market participants better understand our approach to reviewing corporate liquidity. This article supersedes our criteria article "Methodology And Assumptions: Standard & Poor's Standardizes Liquidity Descriptors For Global Corporate Issuers," published July 2, 2010, on RatingsDirect. The article, "Principles Of Credit Ratings," published Feb. 16, 2011, forms the basis of these criteria.

SCOPE OF THE CRITERIA

2. These criteria apply to the analysis of corporate issuers globally. They do not apply to project finance ratings, because of the contractual cash management protections in place for those credits, nor to issuers with characteristics of finance companies, such as equipment leasing companies.

SUMMARY OF CRITERIA UPDATE

3. The methodology for scoring corporate liquidity addresses the liquidity factors used as a component of the analysis of corporate issuers. The quantitative analysis focuses on the monetary flows--the sources and uses of cash--that are the key indicators of a company's liquidity cushion. The analysis also assesses the potential for a company to breach covenant tests related to declines in earnings before interest, taxes, depreciation, and amortization (EBITDA). The methodology incorporates a qualitative analysis that addresses such factors as the ability to absorb high-impact, low-probability events, the nature of bank relationships, the level of standing in credit markets, and the degree of prudence of the company's financial risk management.

4. The methodology focuses on the standardization of liquidity descriptors into a five-point scale and a characterization of the features associated with each of the descriptors. The methodology also describes the impact of the criteria on ICRs.

UPDATES TO EXISTING CRITERIA

5. This article supersedes our criteria article "Methodology And Assumptions: Standard & Poor's Standardizes Liquidity Descriptors For Global Corporate Issuers." It clarifies previous criteria by stating that, to receive an ICR of 'BBB-' or higher, a company's liquidity must be scored as "adequate," as we define the term, or stronger. Companies with a score that is "less than adequate," as we define the term, will not receive an ICR higher than 'BB+'; those with a "weak" score, as we define the term, will not receive an ICR higher than 'B-'. In addition, the characteristics of adequate liquidity have been amended for companies with an ICR of 'BBB-' or higher to use a shorter time horizon when assessing the effects of undrawn committed bank lines and debt maturities (see "Criteria Methodology: Business Risk/Financial Risk Matrix Expanded," published May 27, 2009).

IMPACT ON OUTSTANDING RATINGS

6 We expect only a small number of rating changes after publishing these criteria.

EFFECTIVE DATE AND TRANSITION

7 These criteria are effective Sept. 28, 2011, for all new and outstanding corporate ICRs. We expect to update our ratings over a period of up to six months.

METHODOLOGY

8. Liquidity is an important component of financial risk across the entire rating spectrum (see "2008 Corporate Ratings Criteria: Analytical Methodology," published April 15, 2008, under the Liquidity section). Unlike most other rating factors within an issuer's risk profile, a lack of liquidity could precipitate the default of an otherwise healthy entity. Accordingly, liquidity is an independent characteristic of a company, measured on an absolute basis, and the assessment is not relative to industry peers or other companies in the same rating category.

9. The descriptors for liquidity are:

- Exceptional;
- Strong;
- Adequate;
- Less than adequate; and
- Weak.

10 Adequate liquidity is rating-neutral. To avoid the risk of default, a company's liquidity must be sufficiently robust to absorb a moderate level of stress. Accordingly, for a company to receive a rating of 'BBB-' or higher, its liquidity must be scored adequate or stronger.

11 The benchmarks to achieve "strong" and "exceptional" liquidity, as we define the terms, are intended to meet stress scenarios, but all investment-grade companies must have at least adequate liquidity. Strong and exceptional liquidity, by definition, exceed the norm. Excess liquidity can help bolster an ICR and differentiate between issuers in a given rating category; however, the basis for the projected continuation of such liquidity is rooted in other credit strengths. Therefore, these strengths must be considered in combination with strong or exceptional liquidity in order to have a higher ICR.

12. By contrast, less than adequate and weak liquidity are very likely to weigh on the ICR. As noted above, whatever a company's underlying performance, a lack of liquidity could precipitate a default, and ratings should reflect that risk.

13. Short-term ratings are highly correlated to long-term ICRs. However, to the extent that, for a given long-term rating, two short-term ratings are possible, liquidity is an important differentiating consideration. Accordingly, the assessment of a company's liquidity could translate directly into a higher or lower short-term rating.

14 For companies with ICRs based on their stand-alone credit profiles (SACPs), with ratings benefitting from potential extraordinary intervention from a parent, affiliate or governmental entity, the criteria assess liquidity at the SACP

level. Any relationship between the liquidity assessment and the ICR, as stated in the criteria, corresponds to a similar relationship between the liquidity assessment and the SACP.

15. When assessing a company's banking relationships, the criteria consider the history of the specific relationship (including periods when the company's credit quality was under stress); the variety of lending facilities in place; the degree of legal commitment involved in each facility; the tenor of existing facilities; the amounts involved, relative to bank lending limits; and the concentration/diversification of ties with various banks. (See "2008 Corporate Ratings Criteria: Analytical Methodology," and "2008 Corporate Ratings Criteria: Commercial Paper.")

Key Quantitative Measures

16. The key indicators of a company's liquidity cushion are:

- A/B: Liquidity sources (A) divided by uses (B); and
- A-B: Liquidity sources (A) minus uses (B).

17. Monetary flows within sources and uses of cash, for this purpose, refer to amounts generated or used over the next six to 24 months, with the timeframes identified by each of the liquidity descriptors. The amounts used in the calculations conform to an anticipated base case, assuming no refinancing for the company in question, and include both internal and external components. The analysis of monetary flows excludes the sources and uses of cash from captive finance operations (see "Assumptions: Analytical Adjustments For Captive Finance Operations," published June 27, 2008).

Sources

18. The criteria consider the following liquidity sources:

- Cash and liquid investments;
- Forecasted funds from operations (FFO), if positive;
- Forecasted working capital inflows, if positive;
- Proceeds of asset sales (when confidently predictable);
- The undrawn, available portion of committed bank lines maturing beyond the next 12 months; and
- Expected ongoing cash injections from a government or corporate group members, as appropriate.

19. Cash and liquid investments are netted against debt. This is the same approach used for surplus cash (see "Corporate Criteria: Ratios And Adjustments," under "Surplus cash"). If a company holds cash to satisfy upcoming, short-term obligations, the criteria net these to avoid the appearance of liquidity dilution. This may include hedged or presold commodity trading inventories.

20. Forecasted FFO will fluctuate with economic and business cycles. This effect is not smoothed, because the cyclical low point is where most cyclical companies experience liquidity problems. Management's expectation that a cyclical shortage of liquidity and the effectiveness of its measures to counter this risk may affect the calculation of FFO.

21. A contracted sale of a subsidiary or other asset to a creditworthy counterparty is included as a source of cash. Alternatively, the criteria do not include a potential sale of a subsidiary or property as a source of cash.

22. Undrawn portions of committed seasonal bank lines are also considered. If covenants are present, there must be a comfortable cushion or headroom.

23 Cash injections are considered based on a proven track record or an explicit guarantee provided by a government for the support of a government-related entity (GRE). This source of liquidity also includes similar ongoing support made to corporate subsidiaries by their parent companies or identified group members. The potential for extraordinary support (usually occurring in times of stress) is excluded from this source of liquidity.

Uses

24 The criteria consider the following uses of cash:

- Forecasted funds from operations, if negative;
- Expected capital spending;
- Forecasted working capital outflows, if negative;
- All debt maturities (either recourse to the company or which it is expected to support);
- Any required cash-based, postretirement employee benefit top-up needs;
- Credit puts that cause debt acceleration or new collateral posting requirements in the event of a ratings downgrade of up to three notches; and
- Contracted acquisitions and expected shareholder distributions under a stress scenario, including expected share repurchases.

25 Expected capital spending includes estimated maintenance spending, plus expansion project spending with a long lead time that will likely proceed even in a downturn, or that have been contractually committed.

26 To assess forecasted working capital outflows in companies with material intra-year working capital requirements (e.g., those companies in seasonal businesses), forecasted cumulative peak working capital outflows are used. In cases where working capital changes are positive over a given period because of large seasonal inflows that more than offset outflows, the criteria use the cumulative peak working capital outflows forecasted over the period.

27 Collateral posting requirements related to derivative contracts are not considered under liquidity uses. Potential uses in stress-case scenarios related to derivative contracts are analyzed separately (see "Analyzing The Liquidity Adequacy Of U.S. Energy Marketing And Trading Operations," published May 4, 2004).

Liquidity Categories

Exceptional

28 Companies with exceptional liquidity should be able to withstand severe adverse market conditions over the next two years while still having sufficient liquidity to meet their obligations. To have exceptional liquidity, an entity would have to meet the ratio test for A/B and at least four of the other supportive characteristics listed below. Few companies qualify for this category. The first three characteristics reference quantitative measures that apply in most industries. In exceptionally stable or volatile industries, however, the relevant "Key Credit Factors" article may specify different standards. Characteristics of a company with exceptional liquidity include:

- A/B of 2x or more projected each year over the next two years.
- Positive A-B, even if forecasted EBITDA were to decline by 50%.
- Few covenants. If covenants are present, headroom under these is such that forecasted EBITDA could fall by 50% without the company breaching covenant test measures; and debt at 30% below any covenant limits.
- The likely ability to absorb, without refinancing, high-impact, low-probability events (such as market turbulence, sovereign risk, or the activation of material-adverse-change clauses).

- Well-established and solid relationships with banks.
- A generally high standing in credit markets. This can be assessed from equity, debt, and credit default swap (CDS) trading data relative to peers and market averages.
- Very prudent financial risk management. To meet this assessment, the company needs to show evidence that its management anticipated potential setbacks and took the necessary actions to ensure continued strong liquidity (see "2008 Corporate Criteria: Analytical Methodology," under "How Company Management Influences Business Risk And Financial Risk").

Strong

29 Companies with strong liquidity should be able to withstand substantially adverse market circumstances over the next 24 months while still having sufficient liquidity to meet their obligations. To have strong liquidity, an entity must meet the ratio test for A/B and demonstrate at least four of the other supportive characteristics listed below. The first three characteristics reference quantitative measures that apply in most industries. In exceptionally stable or volatile industries, however, the relevant "Key Credit Factors" article may specify different standards. Characteristics of a company with strong liquidity include:

- A/B for the upcoming 12 months of 1.5x or more. Even when measured over the next 24 months, the measure remains above 1.0x.
- Positive A-B, even if forecasted EBITDA declines by 30%.
- Sufficient covenant headroom for forecasted EBITDA to decline by 30% without the company breaching coverage tests, and debt is 25% below covenant limits.
- The likely ability to absorb, without refinancing, high-impact, low-probability events.
- Well-established, solid relationships with banks.
- A generally high standing in credit markets. This can be assessed from equity, debt, and CDS trading data relative to peers and market averages.
- Generally very prudent financial risk management. To meet this assessment, the company needs to show evidence that its management anticipated potential setbacks and took the necessary actions to ensure continued strong liquidity.

Adequate

30 Companies with adequate liquidity should be able to withstand adverse market circumstances over the next 12 months while maintaining sufficient liquidity to meet their obligations. Adequate liquidity is ratings-neutral, rather than an enhancing or detracting characteristic. To have adequate liquidity, an entity must meet the ratio test for A/B and demonstrate at least four of the other supportive characteristics listed below. The first three characteristics reference quantitative measures that apply in most industries. In exceptionally stable or volatile industries, however, the relevant "Key Credit Factors" article may specify different standards. Characteristics of a company with adequate liquidity include:

- A/B of 1.2x or more. In particular, any upcoming maturities should be manageable.
- Positive A-B, even if forecasted EBITDA declines by 15%.
- Sufficient covenant headroom for forecasted EBITDA to decline by 15% without the company breaching coverage tests, and debt is 15% below covenant limits (or, if not, the related facilities are not material).
- The likely ability to absorb high-impact, low-probability events, with limited need for refinancing. Liquidity is supplemented by the perceived flexibility to lower capital spending or sell assets, among other actions.
- Sound relationships with banks.

- A generally satisfactory standing in credit markets. This can be assessed from equity, debt, and CDS trading data relative to peers and market averages.
- Generally prudent financial risk management. To meet this assessment, the company needs to show evidence that its management anticipated potential setbacks and took the necessary actions to ensure continued adequate liquidity.

31 For the purposes of calculating adequate liquidity, the debt maturities and the undrawn, available portion of committed bank lines are based on a six-month time horizon for companies with certain strong credit characteristics. The A/B and A-B tests for the adequate category use debt maturities within the next six months as a use of liquidity and include the undrawn, available portion of committed bank lines that matures beyond the next six months as a source of liquidity when:

- The company's issuer credit rating is at least 'BBB-', and
- All three of the following qualitative characteristics--normally associated with strong liquidity--apply: (1) Well-established and solid relationships with banks; (2) A generally high standing in credit markets. This can be assessed from equity, debt, and CDS trading data relative to peers and market averages; and (3) Generally very prudent financial risk management. To meet this assessment, the company needs to show evidence that its management anticipated potential setbacks and took the necessary actions to ensure continued adequate liquidity.

32 If the A/B and A-B tests do not meet the requisite levels outlined in paragraph 30, using a six-month time horizon, but a company meets all other characteristics outlined in paragraph 31, it may still receive a liquidity score of adequate. A company's liquidity may still receive a score of adequate, if it has a credible plan to within three months address the lack of liquidity that would cause the A/B and A-B tests to increase to the levels outlined in paragraph 30. However, in this event, the ICR on the company will be no higher than in the 'A' category. Characteristics of credible plans generally include advanced discussions with lending groups or bond underwriters with clear timetables for proposed refinancings or new issues, which would not extend beyond the next three months.

Less than adequate

33 A company with less than adequate liquidity has an ICR no higher than 'BB+'. To have a level of liquidity that is less than adequate, an entity would have one or more of the negative characteristics described below or would not qualify for an adequate or weak liquidity assessment. Characteristics of a company with less than adequate liquidity include:

- A/B of less than 1.2x. This level offers scant protection against unexpected adverse developments.
- A-B of about zero or below.
- Covenant headroom so tight that coverage tests could be breached if forecasted EBITDA were to decline by just 10%. (A covenant breach on any related facilities would likely have a significant impact, because the debt containing the covenants in question could not easily be repaid.)
- The likelihood of the company not being able to absorb low-probability adversities, even factoring in capital-spending cuts, asset sales, and cuts in shareholder distributions.
- No particular core bank relationship and indications of a poor standing in credit markets, such as wide CDS trades for several consecutive weeks or share price declines.

Weak

34 Weak liquidity represents an overarching credit risk. In all cases, such an assessment will translate into an ICR of 'B-' or lower. To have weak liquidity, an entity would display the first characteristic listed below and typically one

or both of the two subsequent characteristics. Characteristics of a company with weak liquidity include:

- A/B or A-B reflecting a material deficit over the next 12 months.
- The likelihood that covenants will be breached unless there is a very credible plan to avert such a breach in a timely fashion or lenders appear likely to provide a covenant waiver or amendment (assuming that the related facilities are material). Only low-probability, unforeseen positive events would allow the company to regain a level of liquidity better than weak.
- Indications of a poor standing in credit markets, such as very wide CDS trades or a serious share price decline.

RELATED CRITERIA AND RESEARCH

- Principles Of Credit Ratings, Feb. 16, 2011
- Criteria Methodology: Business Risk/Financial Risk Matrix Expanded, May 27, 2009
- Assumptions: Analytical Adjustments For Captive Finance Operations, June 27, 2008
- Corporate Ratings Criteria 2008, April 15, 2008
- Analyzing The Liquidity Adequacy Of U.S. Energy Marketing And Trading Operations, May 4, 2004

These criteria represent the specific application of fundamental principles that define credit risk and ratings opinions. Their use is determined by issuer- or issue-specific attributes as well as Standard & Poor's Ratings Services' assessment of the credit and, if applicable, structural risks for a given issuer or issue rating. Methodology and assumptions may change from time to time as a result of market and economic conditions, issuer- or issue-specific factors, or new empirical evidence that would affect our credit judgment.

Rebuttal Testimony
Exhibit DKA-2

S&P Global Credit Portal

Key Credit Factors: Business and Financial Risks in the Investor-Owned Utilities Industry

dated March 22, 2010

STANDARD
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Global Credit Portal
RatingsDirect®

March 11, 2010

Criteria | Corporates | Utilities:

Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry

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Criteria | Corporates | Utilities:

Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry

(Editor's Note: Table 1 in this article is no longer current. It has been superseded by the table found in "Criteria Methodology: Business Risk/Financial Risk Matrix Expanded," published May 27, 2009, on RatingsDirect. For our latest comments on regulated utility subsidiaries, please see "Methodology: Differentiating The Issuer Credit Ratings Of A Regulated Utility Subsidiary And Its Parent," published March 11, 2010, on RatingsDirect.)

Standard & Poor's Ratings Services' analytic framework for companies in all sectors, including investor-owned utilities, is divided into two major segments: The first part is the fundamental business risk analysis. This step forms the basis and provides the industry and business contexts for the second segment of the analysis, an in-depth financial risk analysis of the company.

An integrated utility is often a part of a larger holding company structure that also owns other businesses, including unregulated power generation. This fact does not alter how we analyze the regulated utility, but it may affect the ultimate rating outcome because of any higher risk credit drag that the unregulated activities may have on the utility. Such considerations include the freedom and practice of management with respect to shifting cash resources among subsidiaries and the presence of ring-fencing mechanisms that may protect the utility.

Relationship Between Business And Financial Risks

Prior to discussing the specific risk factors we analyze within our framework, it is important to understand how we view the relationship between business and financial risks. Table 1 displays this relationship and its implications for a company's rating.

Table 1

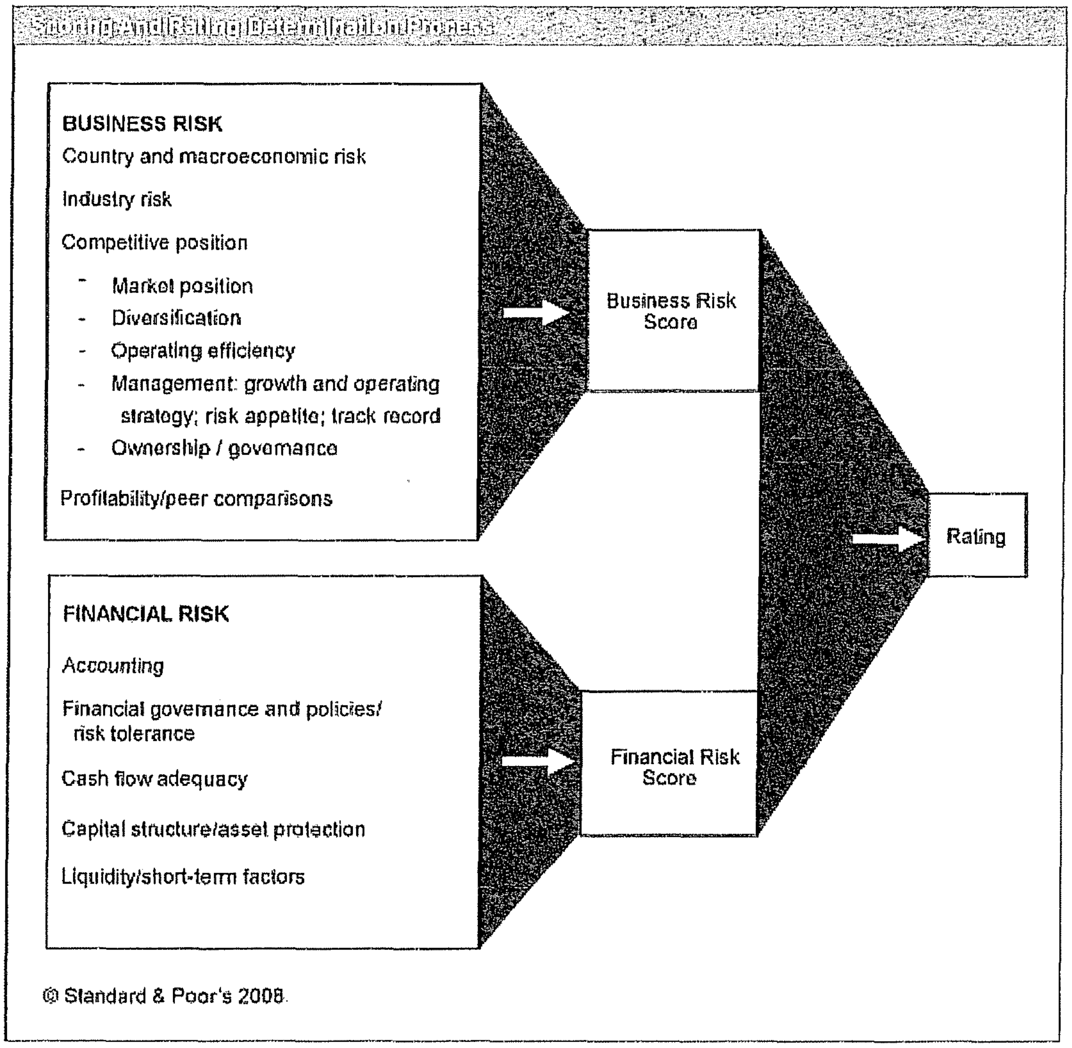
Business And Financial Risk Profile Matrix

		Financial Risk Profile				
Business Risk Profile		Minimal	Modest	Intermediate	Aggressive	Highly leveraged
		(AAA/AA)	(A)	(BBB)	(BB)	(B)
Excellent	(AAA/AA)	AAA	AA	A	BBB	BB
Strong	(A)	AA	A	A-	BBB-	BB-
Satisfactory	(BBB)	A	BBB+	BBB	BB+	B+
Weak	(BB)	BBB	BBB-	BB+	BB-	B
Vulnerable	(B)	BB	B+	B+	B	B-

These rating outcomes are shown for guidance purposes only Other qualitative and quantitative rating factors may override these measures

Chart 1 summarizes the ratings process.

Chart 1



Part 1--Business Risk Analysis

Business risk is analyzed in four categories: country risk, industry risk, competitive position, and profitability. We determine a score for the overall business risk based on the scale shown in table 2.

Table 2

Business Risk Measures

Description	Rating equivalent
Excellent	AAA/AA
Strong	A
Satisfactory	BBB
Weak	BB
Vulnerable	B/CCC

Analysis of business risk factors is supported by factual data, including statistics, but ultimately involves a fair amount of subjective judgment. Understanding business risk provides a context in which to judge financial risk, which covers analysis of cash flow generation, capitalization, and liquidity. In all cases, the analysis uses historical experience to make estimates of future performance and risk.

In the U.S., regulated utilities and holding companies that are utility-focused virtually always fall in the upper range (Excellent or Strong) of business risk profiles. The defining characteristics of most utilities--a legally defined service territory generally free of significant competition, the provision of an essential or near-essential service, and the presence of regulators that have an abiding interest in supporting a healthy utility financial profile--underpin the business risk profiles of the electric, gas, and water utilities.

1. Country risk and macroeconomic factors (economic, political, and social environments)

Country risk plays a critical role in determining all ratings on companies in a given national domicile. Sovereign-related stress can have an overwhelming effect on company creditworthiness, both directly and indirectly.

Sovereign credit ratings suggest the general risk local entities face, but the ratings may not fully capture the risk applicable to the private sector. As a result, when rating a corporation, we look beyond the sovereign rating to evaluate the specific economic or country risks that may affect the entity's creditworthiness. Such risks pertain to the effect of government policies and other country risk factors on the obligor's business and financial environments, and an entity's ability to insulate itself from these risks.

2. Industry business and credit risk characteristics

In establishing a view of the degree of credit risk in a given industry for rating purposes, it is useful to consider how its risk profile compares to that of other industries. Although the industry risk characteristic categories are broadly similar across industries, the effect of these factors on credit risk can vary markedly among industries. Chart 2 illustrates how the effects of these credit-risk factors vary among some major industries. The key industry factors are scored as follows: High risk (H), medium/high risk (M/H), medium risk (M), low/medium risk (L/M), and low risk (L).

Chart 2

Key Industry Characteristics And Drivers Of Credit Risk

	Utilities regulated	Competitive power	Oil & gas downstream	Autos	Airlines
Industry dynamics and competitive environment					
Industry cyclicality	M	H	H	H	H
Ease of entry	L	M/H	H	M/H	M/H
Product cycle/obsolescence	L	L	L	H	L
Level of product quality	L	L	M	H	M
Disintermediation/substitution	L	L	L	L/M	L
Competition/commoditization	L/M	H	M	H	H
Pricing inflexibility	M	H	M	H	H
Business model stability	M	M/H	L	L/M	M
Demographic trends	L	L	M	H	L
Growth and profitability					
Growth outlook	M	M	L	M/H	L/M
Profit margin pressure/outlook	M	M/H	M	M/H	H
Earnings volatility	M	M/H	H	H	H
Operating considerations and costs					
Technological risk/change	L	L	L/M	L/M	L/M
Cost efficiency/pressures	M	H	M	H	H
Operating leverage	M/H	H	H	H	H
R&D costs	L	L	L	H	L
Energy cost sensitivity	H	H	H	H	H
Raw material cost sensitivity	H	H	H	H	L
Labor costs	M	M	M	H	H
Labor inflexibility/unrest	L	L	M	H	H
Pension costs/contingents	M	L	L/M	H	M/H
Environmental impact/costs	H	L	H	H	M/H
Marketing costs	L	L	M	H	L/M
Customer concentration	L	M	L	L	L
Supplier concentration	H	H	H	M	M
Risk management	M	H	M	M	M
Asset/plant quality and age/upkeep	M	H	H	M	M/H
Event risk sensitivity	M/H	H	H	M/H	H
Financial market volatility/sensitivity	M	M/H	L	M	M
Fashion/fad/design sensitivity	L	L	L	H	L/M
Capital and financing characteristics					
Capital intensity	H	H	H	H	H
Borrowing requirement	H	H	L/M	H	H
Interest rate sensitivity	L/M	L/M	L/M	H	L/M
Government, regulatory, and legal environments					
Regulation/deregulation	H	H	M	M/H	H
Government microeconomic and social policies	H	H	H	H	M/H
Litigiousness/legal risk	L	H	M	M	M

Industry strengths:

- Material barriers to entry because of government-granted franchises, despite deregulatory trends;
- Strategically important to national and regional economies; key pillar of the consumer and commercial economy;
- Improving management focus industry-wide on operating efficiency in recent years; and
- Cross-border growth opportunities in Europe and industrializing emerging markets.

Industry challenges/risks:

- Maturity, with a weak growth outlook in developed countries;
- Highly politicized and burdensome regulatory (i.e., rate setting and investment recovery) process; and
- Risks of "legacy cost drag" as wholesale and retail markets move toward greater deregulation.

Major global risk issues facing the utilities industry:

- Increased volatility in the regulatory environment and competitive landscape leading to greater uncertainty regarding adequacy of pricing and return on capital;
- Longer-term impact of, and ability to absorb, significant secular upturn in fuel costs, which is the industry's major operating expense;
- Ability to recover massive investment costs that will likely be necessary to replace aging industry infrastructure in a harsher cost and regulatory environment; and
- The debate over global warming will continue far beyond 2008. What the ultimate outcome will be is unclear, but growing legislation addressing carbon emissions and other greenhouse gases is probable in the near future. Utilities' ability to recover environmentally mandated costs in authorized rates and consumers' willingness to pay them could impact the industry's future credit strength.

Industry business model and risk profile in transition

Regulated utilities are in many developed countries transitioning away from quasi-monopolies toward more open competitive environments.

The level of business and credit risk associated with the investor-owned regulated utilities has historically proven in most countries to be lower (risk) than for many other industries. This has been because of the existence of government policy and related regulation that created significant barriers to entry limiting competition, and regulatory rate setting designed to provide an opportunity to achieve a specific level of profitability. The credit quality of most vertically integrated utilities in developed countries has historically been, and remains, solidly investment grade. This, to reiterate, is primarily a function of the existence of protective regulation.

The risks of, and rationale for, deregulation

The traditional protected and privileged utilities industry business model with its marked monopolistic characteristics is in many countries undergoing transition to a more competitive and open framework. This transition process, known as deregulation or liberalization, is weakening the business and credit risk profile of the industry. While the impact of these changes may prove positive in the longer term for more efficient industry players, it is important to bear in mind that economic history is littered with the vestiges of industries and enterprises that once flourished under the protection of government-created barriers and other protections. The shift is being driven by introduction in many countries of policies to encourage the entrance of new competitors and to reduce the traditional regulatory protections and privileges enjoyed by incumbents. Historically, the regulated investor-owned utilities were usually granted exclusive franchises. Because of the significant risks associated with the capital-intense nature of the utility investment, including massive sunk/fixed costs and long-term break-even horizons, governments in many countries created legal and regulatory frameworks that granted exclusivity to one operator in a given geographic area. To offset the monopolistic pricing power this exclusivity created, a system of heavy regulation was typically developed, which included the setting of pricing. The model often set pricing on a "cost-plus-basis", i.e., the margin over cost allowing for a perceived fair return to shareholders of investor-owned utilities. One major weakness of this system is that it created little incentive for utilities to efficiently manage costs. In recent years as many governments have adopted more liberal open market economic philosophies and related policies focused on the creation of greater competition—in an effort to foster improved economic growth and pricing efficiency throughout the economy—the traditional utility models in many countries have come under increasing political scrutiny and pressure.

A major public policy and political risk, as well as a credit risk, associated with deregulation of protected industries, is that existing incumbents often experience significant challenges in readjusting their management strategies, cultures, and expense basis to be able to compete effectively in the new environment.

The turmoil and bankruptcies in the U.S. in the nonregulated power marketing and trading arena between 2000 and 2002 arose subsequent to a major government initiative to deregulate the wholesale market. These failures, as well as other high-profile problems arising from deregulation elsewhere in the world, have given governments pause as to the desirability of a headlong rush into deregulation. In the U.S., for example, there is currently little impetus to carry deregulation any further.

Regulation and deregulation in the U.S.

While considerable attention has been focused on companies in states that deregulated in the late 1990s and the early part of this decade, and the related consequences of disaggregation and nonregulated generation, 27 states (plus four that formally reversed, suspended, or delayed restructuring) have retained the traditional regulated model. For utilities operating in those states, the quality of regulation and management loom considerably larger than markets, operations, and competitiveness in shaping overall financial performance. Policies and practices among state and federal regulatory bodies will be key credit determinants. Likewise, the quality of management, defined by its posture towards creditworthiness, strategic decisions, execution and consistency, and its ability to sustain a good working relationship with regulators, will be key. Importantly, however, it is virtually impossible to completely segregate each of these characteristics from the others; to some extent they are all interrelated.

Fragmentation of original model emerges in the U.S.

- Traditional regulated, vertically integrated utilities (generation, transmission, and distribution);
- Transmission and distribution;
- Diversified;
- Transmission; and
- Merchant generation.

We view a company that owns regulated generation, transmission, and distribution operations as positioned between companies with relatively low-risk transmission and distribution operations and companies with higher-risk diversified activities on the business profile spectrum. What typically distinguishes one vertically integrated utility's business profile score from another is the quality of regulation and management, which are the two leading drivers of credit quality.

Deregulation in the U.S. creates a new volatile industry subsector

The birth of large-scale, nonregulated power generators created the opportunity--and the need--for companies to market and broker power. Power marketers, independent power producers, and unregulated subsidiaries of utility companies offer power-supply alternatives to other utilities in the wholesale market as well as to large industrial customers. Power marketing operations have been formed by energy companies (many with experience in marketing natural gas), utility subsidiaries, and independents. As with the gas industry, electric power marketers expected to develop an efficient market by straddling the gulf between electricity generators and their customers, who have become "free agents" in the newly competitive environment.

Deregulation creates tiering of industry, business and credit risk profiles in Europe

The regional differences in market liberalization across Western Europe result in material variations in industry and business risk profiles for the utilities industry at the national level. The U.K. and Nordic markets, in particular, are substantially deregulated and open, and consequently present higher risks than other markets that are less open, including France and the Iberian market. Ratings therefore generally are lower in these more deregulated markets. The less-liberalized markets may face more regulatory risk going forward, particularly if efforts by the EU to advance the internal market by increasing the extent of market liberalization across the EU continue.

Legal action against companies that infringe on competition laws should be expected--particularly against those that move to prevent new entry and limit customer choice (for example, through the tying of markets and capacity hoarding) or collude with other incumbents to do so. The European Commission (EC) can fine companies that have violated antitrust laws up to 10% of their global annual turnover and, under certain conditions, impose structural remedies. Particular emphasis would be placed on increasing the effective unbundling of network and supply activities and on diminishing market concentration and barriers to entry.

The EC has publicly stated is intention to pursue, as a priority, abuses of the dominant position of vertically integrated companies (called vertical foreclosure). Behavioral remedies, such as energy release programs, are expected to be imposed by the EC for which such abuses, or collusion, are proved. The commission could also enforce structural measures when behavioral remedies are deemed insufficient.

3. Company competitive position and keys to competitive success

In analyzing a company's competitive position, we consider the following:

- Regulation;
- Markets;
- Diversification;
- Operations;
- Management, including growth strategy;
- Governance; and
- Profitability.

We are most concerned about how these elements contribute individually and in aggregate to the predictability and sustainability of financial performance, particularly cash flow generation relative to fixed obligations.

Regulation. Critical success factors include:

- Consistency and predictability of decisions;
- Support for recovery of fuel and investment costs;
- History of timely and consistent rate treatment, permitting satisfactory profit margins and timely return on investment; and
- Support for a reasonable cash return on investment.

Regulation is the most critical aspect that underlies regulated integrated utilities' creditworthiness. Regulatory decisions can profoundly affect financial performance. Our assessment of the regulatory environments in which a utility operates is guided by certain principles, most prominently consistency and predictability, as well as efficiency and timeliness. For a regulatory process to be considered supportive of credit quality, it must limit uncertainty in the recovery of a utility's investment. They must also eliminate, or at least greatly reduce, the issue of rate-case lag, especially when a utility engages in a sizable capital expenditure program.

Our evaluation encompasses the administrative, judicial, and legislative processes involved in state and national government regulation, and includes the political environment in which commissions render decisions. Regulation is assessed in terms of its ability to satisfy the particular needs of individual utilities. Rate-setting actions are reviewed case by case with regard to the potential effect on credit quality.

Evaluation of regulation focuses on the ability of regulation to provide utilities with the opportunity to generate cash flow and earnings quality and stability adequate to:

- Meet investment needs;
- Service debt and maintain a satisfactory rating profile; and
- Generate a competitive rate of return to investors.

To achieve this, regulation must allow for:

- Timely recognition of volatile cost components such as fuel and satisfactory returns on invested capital and equity;
- Ability to enter into long-term arrangements at negotiated rates without having to seek regulatory approval for each contract; and
- Ability to recover costs in new investment over a reasonable time frame.

Because the bulk of a utility's operating expenses relate to fuel and purchased power, of primary importance to rating stability is the level of support that state regulators provide to utilities for fuel cost recovery, particularly as gas and coal costs have risen. Utilities that are operating under rate moratoriums, or without access to fuel and purchased-power adjustment clauses, or face significant regulatory lag, also are subject to reduced operating margins, increased cash flow volatility, and greater demand for working capital. Companies that are granted fuel true-ups may be required to spread recovery over many years to ease the pain for the consumer. In addition to fuel cost recovery filings, regulators will have to address significant rate increase requests related to new generating capacity additions, environmental modifications, and reliability upgrades. Current cash recovery and/or return by means of construction work in progress support what would otherwise sometimes be a significant cash flow drain and reduces the utility's need to issue debt during construction.

Markets/market position. Critical success factors include:

- A healthy and growing economy;
- Growth in population and residential and commercial customer base;
- An attractive business environment;
- An above-average residential base; and
- Limited bypass risk.

The importance of diversification and size. Critical success factors include:

- Regional and cross-border market diversification (mitigates economic, demographic, and political risk concentration);
- Industrial customer diversification;
- Fuel supplier diversification;

- Retail, compared with wholesale;
- Regulatory regime diversification; and
- Generating facility diversification.

Operations (operating strategy, capability, and performance efficiency). Critical success factors include:

- Low cost structure;
- Well-maintained assets;
- Solid plant performance;
- Adequate generating reserves, and compliance with environmental standards; and
- Limited environmental exposures.

Management evaluation. Utilities are complex specialized businesses requiring experienced and successful management teams to have a strong mix of the aforementioned disciplines. Critical elements of management success include:

- Commitment to credit quality;
- Operating efficiency and cost control;
- Maintaining a competitive asset base, i.e., power plant construction project management, and plant upkeep and renovation;
- Regulatory track record, process, and relationship management;
- M&A experience in successfully identifying, executing, and integrating acquisitions;
- Credibility and strong corporate governance;
- Conservative financial policies, especially regarding non-regulated activities; and
- Ability and track record in repositioning and transforming business to not just survive, but prosper in a more open market environment.

Management is assessed for its ability to run and expand the business efficiently, while mitigating inherent business and financial risks. The evaluation also focuses on the credibility of management's strategy and projections, its operating and financial track record, and its appetite for assuming business and financial risk.

The management assessment is based on tenure, turnover, industry experience, financial track record, corporate governance, a grasp of industry issues, and knowledge of regulation, the impact of deregulation, of customers, and their needs. Management's ability and willingness to develop workable strategies to address system needs, and to execute reasonable and effective long-term plans are assessed. Management quality is also indicated by thoughtful balancing of multiple priorities; a record of credibility; and effective communication with the public, regulatory bodies, and the financial community.

We also focus on management's ability to achieve cost-effective operations and commitment to maintaining credit quality. This can be assessed by evaluating accounting and financial practices, capitalization and common dividend objectives, and the company's philosophy regarding growth and risk-taking.

4. Profitability/peer comparison

Regulated. Traditionally, the lower levels of risk in utilities because of the highly regulated environment has resulted in lower profitability and return on capital than in many other industrial sectors. In the regulated marketplace the level and margin of profitability has often primarily been a function of regulatory leeway, with the contribution of operating efficiency and revenue growth taking more of a back seat.

Deregulated/liberalized environments. In deregulated markets, cost efficiency and flexibility, and internal growth, are the major profitability drivers. The development of a robust risk management culture and infrastructure are also keys to creating stability of earnings, because the company no longer has recourse to the regulator to cover costs or losses—a recourse that usually protects from downside earnings surprises in the regulated sector.

Whether generated by the regulated or deregulated side of the business, profitability is critical for utilities because of the need to fund investment-generating capacity, maintain access to external debt and equity capital, and make acquisitions. Profit potential and stability is a critical determinant of credit protection. A company that generates higher operating margins and returns on capital also has a greater ability to fund growth internally, attract capital externally, and withstand business adversity. Earnings power ultimately attests to the value of the company's assets, as well. In fact, a company's profit performance offers a litmus test of its fundamental health and competitive position. Accordingly, the conclusions about profitability should confirm the assessment of business risk, including the degree of advantage provided by the regulatory environment.

Part 2—Financial Risk Analysis

Having evaluated a company's competitive position, operating environment, and earnings quality, our analysis proceeds to several financial categories. Financial risk is portrayed largely through quantitative means, particularly by using financial ratios.

We analyze five risk categories: accounting characteristics; financial governance/policies and risk tolerance; cash flow adequacy; capital structure and leverage; and liquidity/short-term factors. We then determine a score for overall financial risk using the following scale:

Table 3

Financial Risk Measures

Description	Rating equivalent
Minimal	AAA/AA
Modest	A
Intermediate	BBB
Aggressive	BB
Highly leveraged	B

The major goal of financial risk analysis is to determine the quality of cash resources from operations and other major sources available to service the debt and other financial liabilities, including any new debt. An integral part of this analysis is to form an understanding of the debt structure, including the mix of senior versus subordinated, fixed versus floating debt, as well as its maturity structure. It is also important to analyze and form an opinion of management's financial policy, accounting elections, and risk appetite. Using cash flow analysis as a building block, it is further necessary to establish the company's liquidity profile and flexibility. While closely interrelated, the analysis of a company's liquidity differs from that of its cash flow as it also incorporates the evaluation of other sources and uses of funds, such as committed undrawn bank facilities, as well as contingent liabilities (e.g., guarantees, triggers, regulatory issues, and legal settlements).

1. Accounting characteristics

Financial statements and related footnotes are the primary source of information about a company's financial condition and performance. The analysis begins with a review of accounting characteristics to determine whether ratios and statistics derived from the statements adequately measure a company's performance and position relative to those of both its direct peer group and the universe of industrial companies. This assessment is important in providing a common frame of reference and in helping the analyst determine the quality of disclosure and the reliability of the reported numbers. We focus on the following areas:

- Analytical adjustments and areas of potential concern;
- Significant transactions and notable events that have accounting implications.
- Significant accounting and financial reporting policies and the underlying assumptions.
- History of nonoperating results and extraordinary charges or adjustments and underlying accounting treatment, disclosure, and explanation.

2. Financial governance/policies and risk tolerance

The robustness of management's financial and accounting strategies and related implementation processes is a key element in credit risk evaluation. We attach great importance to management's philosophies and policies involving financial risk.

Financial policies are also important because companies with more conservative balance sheets and the credit capacity to pursue the necessary investments or acquisitions gain an advantage. Overly aggressive capital structures can leave very little capacity to absorb unexpected negative developments and will certainly leave little capacity to make future strategic investments. Companies with the credit capacity to support strategic investments will be better positioned to both evolve with industry change and to withstand inevitable downturns.

Understanding management's strategy for raising its share price, including its financial performance objectives, e.g., return on equity, can provide invaluable insight about the financial and business risk appetite.

3. Cash flow adequacy

Cash-flow analysis is one of the most critical elements of all credit rating decisions. Although there usually is a strong relationship between cash flow and profitability, many transactions and accounting entries affect one and not the other. Analysis of cash-flow patterns can reveal a level of debt-servicing capability that is either stronger or weaker than might be apparent from earnings. Focusing on the source and quality/volatility of cash flow is also important (e.g., regulated/deregulated; generation/transmission/trading).

A review of cash flow historically, as well as needs on a forward-looking basis, should take into account levels of capital expenditures for new generation plants. In periods where elevated new construction occurs in anticipation of a rise in power demand, cash outflows will be high.

It is particularly important to evaluate capital-intensive businesses, such as utility companies, on the basis of how much cash they generate and absorb. Debt service is an especially important use of cash flow.

Cash-flow ratios. Ratios show the relationship of cash flow to debt and debt service, and also to the company's needs. Because there are calls on cash flow other than repaying debt, it is important to know the extent to which those requirements will allow cash to be used for debt service or, alternatively, lead to greater need for borrowing. The most important cash flow ratios we look at for the investor-owned utilities are:

- Funds from operations (FFO)/Total debt;
- FFO/Income;
- Funds from operations/Total debt (adjusted for off-balance-sheet liabilities);

- EBITDA/Interest; and
- Net cash flow/Capital spending requirements.

4. Capital structure and leverage

For utilities, the long-term nature of capital commitments and extended breakeven periods on investment, make the type of financing required by these companies to finance these needs to be similar in many ways to the financing needs of other long-term asset-intensive businesses. Our analysts review projections of future CAPEX, debt, and FFO levels to make a determination of the likely level of leverage and debt over the medium term, and the companies' ability to sustain them. The valuation of the debt amortization scheduled is tied into projections of profitability breakeven, and the underlying assets becoming cash-flow-positive, are key components of the combined cash flow and leverage analysis.

Capitalization ratios. When analyzing a utility's balance sheet, a key element is analysis of capitalization ratios. The main factors influencing the level of debt are the level of capital expenditures, particularly construction expenditures, and the cost of debt. Companies with strong balance sheets will have more flexibility to further reduce their debt, and/or increase their dividends. The following are useful indicators of leverage:

- Total debt*/total debt + equity; and
- Total debt* + off-balance-sheet liabilities/total debt + off-balance-sheet liabilities + equity.

*Power purchase agreement-adjusted total debt. Fully adjusted, historically demonstrated, and expected to consistently continue.

Debt leverage, and interest and amortization coverage ratios are the key drivers of the financial risk score.

5. Liquidity/working capital/short-term factors:

Our liquidity analysis starts with operating cash flow and cash on hand, and then looks forward at other actual and contingent sources and uses of funds in the short term that could either provide or drain cash under given circumstances.

A key source of liquidity is bank lines. Key factors reviewed are total amount of facilities; whether they are contractually committed; facility expiration date(s); current and expected usage and estimated availability; bank group quality; evidence of support/lack of support of bank group; and covenant and trigger analysis. Financial covenant analysis is critical for speculative-grade credits. We request copies of all bank loan agreements and bond terms and conditions for rated entities, and review supplemental information provided by issuers for listing of financial covenants and stipulated compliance levels. We review covenant compliance as indicated in compliance certificates, as well as expected future compliance and covenant headroom levels. Entities that have already tripped or are expected to trip financial covenants need to be subject to special scrutiny and are reviewed for their ability to obtain waivers or modifications need to be subject to special scrutiny and are reviewed for their ability to obtain waivers or modifications to covenants. Tripping covenants can have a double negative effect on a company's liquidity. It may preclude it from borrowing further under its credit line, and may also lead to a contractual acceleration of repayment and increased interest rates.

Rebuttal Testimony
Exhibit DKA-3

S&P Global Credit Portal

Criteria Methodology: Business Risk/Financial Risk Matrix Expanded

dated May 27, 2009

STANDARD
&POOR'S

Global Credit Portal
RatingsDirect®

May 27, 2009

Criteria | Corporates | General:

Criteria Methodology: Business Risk/Financial Risk Matrix Expanded

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Criteria | Corporates | General:

Criteria Methodology: Business Risk/Financial Risk Matrix Expanded

(Editor's Note: In the previous version of this article published on May 26, certain of the rating outcomes in the table 1 matrix were missated. A corrected version follows.)

Standard & Poor's Ratings Services is refining its methodology for corporate ratings related to its business risk/financial risk matrix, which we published as part of 2008 Corporate Ratings Criteria on April 15, 2008, on RatingsDirect at www.ratingsdirect.com and Standard & Poor's Web site at www.standardandpoors.com.

This article amends and supersedes the criteria as published in Corporate Ratings Criteria, page 21, and the articles listed in the "Related Articles" section at the end of this report.

This article is part of a broad series of measures announced last year to enhance our governance, analytics, dissemination of information, and investor education initiatives. These initiatives are aimed at augmenting our independence, strengthening the rating process, and increasing our transparency to better serve the global markets.

We introduced the business risk/financial risk matrix four years ago. The relationships depicted in the matrix represent an essential element of our corporate analytical methodology.

We are now expanding the matrix, by adding one category to both business and financial risks (see table 1). As a result, the matrix allows for greater differentiation regarding companies rated lower than investment grade (i.e., 'BB' and below).

Table 1

Business And Financial Risk Profile Matrix

Business Risk Profile	Financial Risk Profile					
	Minimal	Modest	Intermediate	Significant	Aggressive	Highly Leveraged
Excellent	AAA	AA	A	A-	BBB	--
Strong	AA	A	A-	BBB	BB	BB-
Satisfactory	A-	BBB+	BBB	BB+	BB-	B+
Fair	--	BBB-	BB+	BB	BB-	B
Weak	--	--	BB	BB-	B+	B-
Vulnerable	--	--	--	B+	B	CCC+

These rating outcomes are shown for guidance purposes only. Actual rating should be within one notch of indicated rating outcomes.

The rating outcomes refer to issuer credit ratings. The ratings indicated in each cell of the matrix are the midpoints of a range of likely rating possibilities. This range would ordinarily span one notch above and below the indicated rating.

Business Risk/Financial Risk Framework

Our corporate analytical methodology organizes the analytical process according to a common framework, and it divides the task into several categories so that all salient issues are considered. The first categories involve fundamental business analysis; the financial analysis categories follow.

Our ratings analysis starts with the assessment of the business and competitive profile of the company. Two companies with identical financial metrics can be rated very differently, to the extent that their business challenges and prospects differ. The categories underlying our business and financial risk assessments are:

Business risk

- Country risk
- Industry risk
- Competitive position
- Profitability/Peer group comparisons

Financial risk

- Accounting
- Financial governance and policies/risk tolerance
- Cash flow adequacy
- Capital structure/asset protection
- Liquidity/short-term factors

We do not have any predetermined weights for these categories. The significance of specific factors varies from situation to situation.

Updated Matrix

We developed the matrix to make explicit the rating outcomes that are typical for various business risk/financial risk combinations. It illustrates the relationship of business and financial risk profiles to the issuer credit rating.

We tend to weight business risk slightly more than financial risk when differentiating among investment-grade ratings. Conversely, we place slightly more weight on financial risk for speculative-grade issuers (see table 1, again). There also is a subtle compounding effect when both business risk and financial risk are aligned at extremes (i.e., excellent/minimal and vulnerable/highly leveraged.)

The new, more granular version of the matrix represents a refinement--not any change in rating criteria or standards--and, consequently, holds no implications for any changes to existing ratings. However, the expanded matrix should enhance the transparency of the analytical process.

Financial Benchmarks

Table 2

Financial Risk Indicative Ratios (Corporates)

	FFO/Debt (%)	Debt/EBITDA (x)	Debt/Capital (%)
Minimal	greater than 60	less than 1.5	less than 25
Modest	45-60	1.5-2	25-35
Intermediate	30-45	2-3	35-45
Significant	20-30	3-4	45-50
Aggressive	12-20	4-5	50-60
Highly Leveraged	less than 12	greater than 5	greater than 60

How To Use The Matrix--And Its Limitations

The rating matrix indicative outcomes are what we typically observe--but are not meant to be precise indications or guarantees of future rating opinions. Positive and negative nuances in our analysis may lead to a notch higher or lower than the outcomes indicated in the various cells of the matrix.

In certain situations there may be specific, overarching risks that are outside the standard framework, e.g., a liquidity crisis, major litigation, or large acquisition. This often is the case regarding credits at the lowest end of the credit spectrum--i.e., the 'CCC' category and lower. These ratings, by definition, reflect some impending crisis or acute vulnerability, and the balanced approach that underlies the matrix framework just does not lend itself to such situations.

Similarly, some matrix cells are blank because the underlying combinations are highly unusual--and presumably would involve complicated factors and analysis.

The following hypothetical example illustrates how the tables can be used to better understand our rating process (see tables 1 and 2).

We believe that Company ABC has a satisfactory business risk profile, typical of a low investment-grade industrial issuer. If we believed its financial risk were intermediate, the expected rating outcome should be within one notch of 'BBB'. ABC's ratios of cash flow to debt (35%) and debt leverage (total debt to EBITDA of 2.5x) are indeed characteristic of intermediate financial risk.

It might be possible for Company ABC to be upgraded to the 'A' category by, for example, reducing its debt burden to the point that financial risk is viewed as minimal. Funds from operations (FFO) to debt of more than 60% and debt to EBITDA of only 1.5x would, in most cases, indicate minimal.

Conversely, ABC may choose to become more financially aggressive--perhaps it decides to reward shareholders by borrowing to repurchase its stock. It is possible that the company may fall into the 'BB' category if we view its financial risk as significant. FFO to debt of 20% and debt to EBITDA 4x would, in our view, typify the significant financial risk category.

Still, it is essential to realize that the financial benchmarks are guidelines, neither gospel nor guarantees. They can vary in nonstandard cases: For example, if a company's financial measures exhibit very little volatility, benchmarks may be somewhat more relaxed.

Moreover, our assessment of financial risk is not as simplistic as looking at a few ratios. It encompasses:

- a view of accounting and disclosure practices;
- a view of corporate governance, financial policies, and risk tolerance;
- the degree of capital intensity, flexibility regarding capital expenditures and other cash needs, including acquisitions and shareholder distributions; and
- various aspects of liquidity--including the risk of refinancing near-term maturities.

The matrix addresses a company's standalone credit profile, and does not take account of external influences, which would pertain in the case of government-related entities or subsidiaries that in our view may benefit or suffer from affiliation with a stronger or weaker group. The matrix refers only to local-currency ratings, rather than foreign-currency ratings, which incorporate additional transfer and convertibility risks. Finally, the matrix does not apply to project finance or corporate securitizations.

Related Articles

Industrials' Business Risk/Financial Risk Matrix--A Fundamental Perspective On Corporate Ratings, published April 7, 2005, on RatingsDirect.

Rebuttal Testimony
Exhibit DKA-4

Corporate Policies and Guidelines for Intercompany Transactions

LG&E/LG&E Energy

KU/KU Energy

LG&E/KU

LG&E/LG&E Energy

Corporate Policies and Guidelines for Intercompany Transactions

Corporate Policies and Guidelines for Intercompany Transactions

These Policies and Guidelines have been established to set forth business practices to be observed in transactions between Louisville Gas and Electric Company (LG&E), its proposed Holding Company ("Holding") and any nonutility subsidiary created by Holding. As nonutility subsidiaries are created by Holding, these policies and guidelines will be revised and expanded to ensure that the non-regulated activities are not subsidized by LG&E's ratepayers. Updated policies and guidelines will be filed with the Public Service Commission on an annual basis.

Policies and Guidelines

1. Separation of costs between utility and non-utility activities will be maintained.

Distinct and separate accounting and financial records will be maintained and fully documented for each entity. All costs, which can be specifically identified and associated with an activity, will be directly assigned to that activity. Indirect costs, which provide a benefit to more than one activity, will be allocated to the activities that receive a benefit.

Although initially there will be a sharing of resources between LG&E and Holding, to the extent practicable, each subsidiary of Holding will acquire and maintain its own facilities, equipment, staff and financing.

2. Intercompany transactions shall be structured to ensure that non-regulated activities are not subsidized by the regulated utility.

Separate accounting and financial records will be maintained to ensure that intercompany transactions related to non-utility activities will not have an adverse impact on the utility or its customers.

Transfers or sales of assets will be priced at the greater of cost or fair market value for transfers or sales from LG&E to Holding or other subsidiaries and at the lower of cost or fair market value for transfers or sales made to LG&E from Holding or any of its subsidiaries. Settlement or transfer of liabilities will be accounted for in the same manner. Through this policy, the utility will receive the full benefit from intercompany transfers or sales.

LG&E shall furnish a report to the PSC annually of each transfer of utility assets between LG&E and Holding or any of its subsidiaries, which has a value of $250,000 or more. Transfers having a value of less than $250,000 will be grouped and reported by specific categories, such as transportation equipment, power operated equipment, etc.

Transfers or sales of nonutility assets, payment of dividends and normal recurring transactions are expressly excluded from this reporting requirement.

All good or services provided by the utility to Holding or any of its subsidiaries will be billed at cost, including the proper assignment of all indirect costs.

LG&E will utilize its automated responsibility accounting system to accumulate and allocate costs among the various companies. To the extent possible, specific activities or projects will be directly recorded in the accounting and financial records of the appropriate company. Transactions affecting more than one entity will be allocated among the affected companies by reference to some reasonable, objective standard related to the facts and circumstances of the transaction (i.e., number of employees, number of transactions, etc.)

Billings for intercompany transactions shall be issued on a timely basis with documentation sufficient to provide for subsequent audit or regulatory review. Payments for intercompany transactions shall be made within thirty (30) days of receipt of the invoice. If payment is not made by the due date, late charges will be assessed by the billing company.

3. <u>Strict internal controls will be maintained to provide reasonable assurance that intercompany transactions are accounted for in accordance with management's policies and guidelines</u>.

Accounting policies and procedures for intercompany transactions will be fully documented and provided to all entities.

Intercompany transactions will be fully documented in sufficient detail to enable verification of the relevant information. Periodic audits will be made of intercompany transactions and transfer prices to ensure that these policies and guidelines are being observed. Any detected deviations from these policies and guidelines shall be reported to management and such deviations shall be corrected in a timely manner.

4. Financial Reporting.

Holding and all subsidiaries shall prepare and have available monthly and annual financial information required to compile financial statements and to comply with other reporting requirements. The financial information shall be accumulated and prepared in accordance with Generally Accepted Accounting Principles. In addition, the accounting information prepared and maintained by LG&E shall conform to the requirements of the Public Service Commission of Kentucky and the Federal Energy Regulatory Commission's uniform system of accounts.

All intercompany transactions shall be reported and the nature and terms of the transactions should be fully described and explained.

Holding will file consolidated Federal and State income tax returns which will include LG&E's and any other subsidiaries' taxable income. The "stand alone" method will be used to allocate the income tax liabilities of each entity. Payment transfers for tax liabilities or tax benefits will be made on the dates established for the payment of Federal estimated income taxes.

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KU/KU Energy

Corporate Policies and Guidelines for Intercompany Transactions

CORPORATE POLICIES AND GUIDELINES FOR INTERCOMPANY TRANSACTIONS

PURPOSE

The purpose of this statement is to establish Policies and Guidelines to govern transactions between Kentucky Utilities Company ("KU"), its proposed Holding Company ("Holding") and any other non-utility subsidiary of Holding that may be created. The guidelines have been established to ensure that the following policies are adhered to with respect to inter-party transactions:

I. A distinct separation of costs between utility and non-utility activities will be maintained.

II. Intercompany transactions will be structured, and reimbursement made, in such manner that such transactions do not have an adverse impact on utility customers.

III. Strict internal controls will be maintained with respect to inter-party transactions to ensure that these polices are observed and to provide for adequate and effective regulatory oversight of KU's electric utility operations.

IV. All books and records of KU and all affiliates will be maintained in accordance with Generally Accepted Accounting Principles and, in addition, the books and records of KU will continue to comply with the requirements of the Uniform System of Accounts.

GUIDELINES

I. A distinct separation of costs between utility and non-utility activities will be maintained.

In order to achieve the maximum level of efficiency it is anticipated that there will be sharing of corporate resources. In those instances the costs of such resources will be allocated to the party receiving the benefit.

II. Intercompany transactions will be structured, and reimbursement made, in such manner that such transactions do not have an adverse impact on utility customers.

Prompt and fair reimbursement will be made with respect to any sale or transfer of assets, liabilities, or services between the parties. Separate accountability of management and records will be maintained to assure that transactions involving non-utility activities will not have an adverse impact on the utility or its customers.

Sales or transfer of assets are to be settled by cost or fair market value, whichever is greater when transfers or sales are made by KU to Holding, or other parties, and such transfers or sales are to be settled by cost or fair market value, whichever is lower when transfers are made to KU from Holding or other parties. Settlement or transfer of liabilities are to be treated in the same manner. These guidelines will insure that the utility will not be negatively impacted by an inter-party transaction.

Sales or provisions of services fall into two broad categories; continuing services (such as payroll) and special or periodic services (such as sale of common stock). For continuing services KU already has in place a responsibility accounting system, which will be used as the basis for cost allocation. For each responsibility area, which provides continuing services, an objective measure of the services provided (i.e., number of employees) will be determined and used to allocate the costs of that responsibility to Holding or any other subsidiary based on that measure.

The special or periodic services will be assigned a project number for each project, all direct costs accumulated and, with assignment of proper overheads, billed to Holding or any other subsidiary as appropriate.

The foregoing cost allocation methods will be reviewed at least annually and modifications made to reflect current operating conditions to ensure that all costs incurred for each party are assigned to that party.

Inter-party billings shall be issued on a timely basis with sufficient detail attached to assure an adequate audit trail and to provide for adequate and effective regulatory review. Payment shall be due upon receipt and past due 30 days after receipt of invoice. Late charges will be assessed by the billing company on past due amounts.

III. Strict internal controls will be maintained with respect to inter-party transactions to ensure that these policies are observed and to provide for adequate and effective regulatory oversight of KU's electric utility operations.

These policies and guidelines will be adopted by KU, by Holding and by each other subsidiary of Holding. Intercompany transactions will be documented in a consistent manner and in sufficient detail to develop an adequate audit trail. Intercompany transactions will be periodically audited and reports given to management as to compliance with these policies and guidelines.

Internal controls will be designed to ensure proper accountability by (1) recognizing all intercompany transactions, (2) establishing appropriate value, and (3) recording each transaction properly.

IV. <u>All books and records of KU and all affiliates will be maintained in accordance with Generally Accepted Accounting Principles and, in addition, the books and records of KU will continue to comply with the requirements of the Uniform System of Accounts</u>.

Holding and all subsidiaries are expected to provide timely financial information necessary to compile the required financial statements and to comply with other reporting requirements. All books and records will be maintained in accordance with Generally Accepted Accounting Principles and, in addition, the books and records of KU must meet the requirements of the Uniform System of Accounts. Audited financial statements are to be accompanied by notes summarizing significant accounting policies and other required disclosures.

It is anticipated that KU and Holding will file consolidated Federal and State income tax returns. Holding will receive and disburse payments between parties, which result from the "stand alone" method of computing income tax liabilities. The payment transfers will include quarterly installment responsibilities.

<u>MODIFICATION</u>

These guidelines will be modified from time to time as experience may require to ensure that the costs of all inter-company transactions are properly allocated, recorded and reimbursed.

0097522.01

LG&E/KU

Corporate Policies and Guidelines for Intercompany Transactions

Corporate Policies and Guidelines
for Intercompany Transactions

These Policies and Guidelines have been established to set forth business practices to be observed in transactions between Louisville Gas and Electric Company ("LG&E"), Kentucky Utilities Company ("KU"), their Holding Company, LG&E Energy Corp. ("LG&E Energy") and any non-utility subsidiary created by LG&E Energy. As nonutility subsidiaries are created by LG&E Energy, these policies and guidelines will be revised and expanded to ensure that the non-regulated activities are not subsidized by LG&E's or KU's ratepayers. Updated policies and guidelines will be filed with the Public Service Commission on an annual basis.

Policies and Guidelines

1. Separation of costs between utility and non-utility activities will be maintained.

Distinct and separate accounting and financial records will be maintained and fully documented for each entity. All costs, which can be specifically identified and associated with an activity, will be directly assigned to that activity. Indirect costs, which provide a benefit to more than one activity, will be allocated to the activities that receive a benefit.

Although initially there will be a sharing of resources between LG&E, KU and LG&E Energy, to the extent practicable, each subsidiary of LG&E Energy will acquire and maintain its own facilities, equipment, staff and financing.

2. <u>Intercompany transactions shall be structured to ensure that non-regulated activities are not subsidized by the regulated utility</u>.

Separate accounting and financial records will be maintained to ensure that intercompany transactions related to non-utility activities will not have an adverse impact on the utilities or their customers.

Transfers or sales of assets will be priced at the greater of cost or fair market value for transfers or sales from LG&E or KU to LG&E Energy or other subsidiaries and at the lower of cost or fair market value for transfers or sales made to LG&E or KU from LG&E Energy or any of LG&E Energy's non-utility subsidiaries. Transfers or sales of assets between LG&E and KU will be priced at cost. Settlement or transfer of liabilities will be accounted for in the same manner. Through this policy, the utilities will receive the full benefit from intercompany transfers or sales.

LG&E or KU shall furnish a report to the PSC annually of each transfer of utility assets between themselves or between LG&E or KU and LG&E Energy or any of its non-utility subsidiaries, which has a value of $250,000 or more. Transfers having a value of less than $250,000 will be grouped and reported by specific categories, such as transportation equipment, power operated equipment, etc.

Transfers or sales of nonutility assets, payment of dividends and normal recurring transactions are expressly excluded from this reporting requirement.

All goods or services provided by LG&E or KU to LG&E Energy or any of its non-utility subsidiaries will be billed at cost, including the proper assignment of all indirect costs.

LG&E and KU will utilize their automated responsibility accounting system to accumulate and allocate costs among the various companies. To the extent possible, specific activities or projects will be directly recorded in the accounting and financial records of the appropriate company. Transactions affecting more than one entity will be allocated among the affected companies by reference to some reasonable, objective standard related to the facts and circumstances of the transaction (i.e., number of employees, number of transactions, etc.)

Billings for intercompany transactions shall be issued on a timely basis with documentation sufficient to provide for subsequent audit or regulatory review. Payments for intercompany transactions shall be made within thirty (30) days of receipt of the invoice. If payment is not made by the due date, late charges will be assessed by the billing company.

3. <u>Strict internal controls will be maintained to provide reasonable assurance that intercompany transactions are</u>

accounted for in accordance with management's policies and guidelines.

Accounting policies and procedures for intercompany transactions will be fully documented and provided to all entities. Intercompany transactions will be fully documented in sufficient detail to enable verification of the relevant information. Periodic audits will be made of intercompany transactions and transfer prices to ensure that these policies and guidelines are being observed. Any detected deviations from these policies and guidelines shall be reported to management and such deviations shall be corrected in a timely manner.

4. Financial Reporting.

LG&E Energy and all subsidiaries shall prepare and have available monthly and annual financial information required to compile financial statements and to comply with other reporting requirements. The financial information shall be accumulated and prepared in accordance with Generally Accepted Accounting Principles. In addition, the accounting information prepared and maintained by LG&E and KU shall conform to the requirements of the Public Service Commission of Kentucky and the Federal Energy Regulatory Commission's uniform system of accounts.

All intercompany transactions shall be reported and the nature and terms of the transactions should be fully described and explained.

LG&E Energy will file consolidated Federal and State income tax returns which will include LG&E's, KU's and any other subsidiaries' taxable income. The "stand alone" method will be used to allocate the income tax liabilities of each entity. Payment transfers for tax liabilities or tax benefits will be made on the dates established for the payment of Federal estimated income taxes.

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