COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

AN APPLICATION Of EAST KENTUCKY POWER COOPERATIVE, INC. FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR ALTERATION OF CERTAIN EQUIPMENT AT THE COOPER STATION AND APPROVAL OF A COMPLIANCE PLAN AMENDMENT FOR ENVIRONMENTAL SURCHARGE COST RECOVERY	**)))))))))**	**CASE NO. 2013-00259**

Direct Testimony of Tyler Comings

Public Version

On Behalf of Sonia McElroy and Sierra Club

November 27, 2013

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1. INTRODUCTION AND PURPOSE OF TESTIMONY

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

A My name is Tyler Comings. I am an Associate with Synapse Energy Economics, Inc. (Synapse), which is located at 485 Massachusetts Avenue, Suite 2, in Cambridge, Massachusetts.

Q Please summarize your work experience and educational background.

A I have eight years of experience in economic research and consulting. At Synapse, I have worked extensively on the energy planning sector including economic impact analyses for Vermont Energy Efficiency programs for the Vermont Department of Public Service, a proposed Renewable Portfolio and Efficiency Standard in Kentucky for Mountain Association for Community Economic Development (MACED), a "Beyond Business as Usual" energy future for the U.S. for Civil Society Institute (CSI) and a proposed carbon standard for Natural Resources Defense Council (NRDC). I have worked on several cases involving coal and gas plant economics. I have provided consulting services for various other clients including: U.S. Department of Justice, District of Columbia Office of the People's Counsel, New Jersey Division of Rate Counsel, West Virginia Consumer Advocate Division, Illinois Attorney General, Nevada State Office of Energy, Sierra Club, Earthjustice, Citizens Action Coalition of Indiana, Consumers Union, Energy Future Coalition, American Association of Retired Persons, and Massachusetts Energy Efficiency Advisory Council.

Prior to joining Synapse, I performed research in consumer finance for Ideas42 and economic analysis of transportation and energy investments at Economic Development Research Group.

I hold a B.A. in Mathematics and Economics from Boston University and a M.A. in Economics from Tufts University.

My full resume is attached as Exhibit TFC-1.

Q Please describe Synapse Energy Economics.

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

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

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of Sonia McElroy and Sierra Club.

Q Have you submitted testimony in other recent regulatory proceedings?

A Yes, I submitted testimony regarding Indianapolis Power & Light's Certificate of Public Convenience and Necessity Application before the Indiana Utility Regulatory Commission (Cause 44339).

Q Have you testified in front of the Kentucky Public Service Commission previously?

A No, I have not.

Q What is the purpose of your testimony?

A I was retained by the Sierra Club to review the application of the East Kentucky Power Cooperative (EKPC or the Company) for a Certificate of Public Convenience and Necessity (CPCN) for re-ducting of Cooper unit 1 to meet compliance requirements under the federal Mercury and Air Toxics Standard (MATS).

My testimony focuses on the assumptions used in the Company's supporting market analysis, performed by Brattle Group. I also discuss the Company's capacity and energy outlook, potential compliance costs of future environmental regulations, alternative proposals that may be more economically beneficial than the Cooper unit 1 project, the risks put on ratepayers if this CPCN is approved, and critical information that has not been provided by the Company in this case.

Q Has the Company provided all information needed for a full evaluation of its proposal?

A No. The Company has not provided key evidence that is necessary to properly evaluate the economic viability of the Cooper unit 1 project. Further detail on this is provided in Section 8 of my testimony. Thus, my conclusions and analysis are based on the provision of limited information and data from the Company.

Q How much is the Company proposing to spend on the retrofit for Cooper unit 1?

A The capital cost of the project is estimated at $14.95 million.[1] The estimated annual operations and maintenance (O&M) cost for the project is $2.6 million.[2]

Q What is the Company proposing for Cooper unit 1?

A The Company determined that, in order to comply with MATS, it would need to retire or retrofit with environmental controls both Dale and Cooper unit 1.[3] Company witness Jerry Purvis describes that by ducting flue gasses from Cooper unit 1 through a flue gas desulfurization (FGD) unit and fabric filter baghouse already installed at Cooper 2, the Company will be able to meet MATS limits on filterable particulate matter (PM), acid gases, and mercury.[4]

[1] EKPC Application, p. 9
[2] EKPC Application, p. 8
[3] EKPC Application, p. 4
[4] Direct Testimony of Jerry Purvis, p. 7 lines 3-5

Q **How did the Company justify the investment in Cooper unit 1?**

A First, the Company identified a need of approximately 300 MW of new capacity in its 2012 Integrated Resource Plan (IRP)—the maximum need would occur if it were to retire the Dale plant (200 MW) and Cooper unit 1 (116 MW). Second, the Company issued an RFP on June 8, 2012 for replacement resources and hired Brattle Group to administer and evaluate the responses from both outside parties (termed "bids") as well as issued by the Company itself (termed "proposals"). Finally, the Company and Brattle Group determined that the Company's Cooper unit 1 proposal "clearly provided the most reasonable, least-cost option."[5] This proposal is estimated to provide 116 MW of capacity by keeping Cooper unit 1 on-line. The Company states that it is "actively negotiating" to fill the remaining capacity need.[6]

Q **How did the Company and Brattle group determine that the Cooper unit 1 project was the "most reasonable" option?**

A The Brattle Group performed a market valuation for each bid and proposal by estimating the net present value (NPV) over each project's life, or term. This valuation is equivalent to that which might be performed by a merchant generator: the costs of providing capacity and energy to the PJM market are deducted from the projected revenue the Company would receive from selling capacity and energy on the PJM market--the net difference is the value of each project. The Brattle Group also considered intermittency, specific strategic goals (e.g. resource mix), exposure to future risks (e.g. self-build risks), and other factors when evaluating the viability of the each option. Brattle Group concluded that Cooper unit 1 provided the highest value to the Company.[7] The Brattle Group's analysis is discussed in Exhibit 1a, Exhibit 1b, and the Direct Testimony of James Read.

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[5] EKPC Application, p. 5

[6] EKPC Application, p. 7

[7] Exhibit 1b, p. 2

Q **What are your findings regarding the Company's application?**

A The Company's application provides insufficient justification for the retrofit of Cooper unit 1 in the following ways:

1. The Company acknowledges that it no longer needs to procure additional capacity even if both Cooper unit 1 and the Dale Station are retired;
2. The market valuation analysis likely overestimates the value of the project;
3. The Company received a bid with a higher value than the project;
4. The Company's analysis does not account for future environmental regulations and associated compliance costs;
5. The Company's analysis does not account for potential carbon regulations and associated compliance costs;
6. The project puts unnecessary risk on captive distributors and their ratepayers; and
7. The Company has not provided sufficient information for the Commission and Intervenors to fully evaluate EKPC's application.

Q **What are your recommendations to this Commission?**

A I recommend that the Company's application for CPCN to retrofit Cooper unit 1 be denied. The Company has failed to show a need for the project and failed to provide reasonable economic justification for the project. I believe that the project is likely to pose a net liability to EKPC's members and ratepayers, rather than provide a benefit, for the reasons for which I will lay out subsequently in my testimony.

Q **Did you perform any adjusted analysis for the Company's results?**

A Yes, I have estimated a market valuation of the Cooper unit 1 project using an adjusted energy price forecast. In addition, I have updated the actual PJM capacity prices to compare against the Company's forecast, and reviewed a range of environmental regulatory costs that are likely to be imposed on Cooper unit 1 within the next several years. Finally, I have reviewed the benefits of one of the renewable PPAs offered to the Company, should the Company require additional energy resources.

Q Are PJM market energy and capacity prices key determinants of the market valuation of the EKPC bids and proposals?

A Yes. On June 1, 2013, EKPC joined the PJM regional transmission organization (RTO).[8] As a member of the RTO, the Company's generation resources would be centrally dispatched by PJM, and the Company would sell both its capacity and energy into the regional market. In turn, it would purchase energy and capacity from the regional market on behalf its members and distributors. As such, the generation arm of EKPC acts similarly to a merchant generator, relying on energy and capacity margins to support operations; unlike a merchant generator however, any net profits (or presumably, losses) would be netted as a benefit or liability to EKPC's members and ratepayers.

The Company assumed that energy and capacity from each bid and proposal (including the Cooper unit 1 project) would be sold into the PJM market. The Company and Brattle Group relied on energy and capacity price forecasts to estimate the revenue each bid would collect over its economic life, or term. These results are highly sensitive to energy and capacity price forecasts—as my analysis will show.

Q What changes did you make to the Company's market energy and capacity price forecasts?

A The Company's market energy price forecasts [redacted]. I will discuss this [redacted] later in my testimony. I have substituted the Company's energy price forecasts with a more reasonable forecast based on the relationship of the Company's broker values for energy from 2013 through 2017 compared to its

[8] Application for EKPC to join PJM addressed in KY PSC case 2012-00169. Also, see http://www.pjm.com/~/media/committees-groups/committees/mc/20130328/20130328-item-03-ekpc-integration.ashx

projected natural gas prices for that period. This adjusted forecast also matches closely with the Company's actual bid prices for energy from 2013 through 2017.

I have also updated EKPC's assumed capacity price of $[redacted] per MW-day for the 2016/2017 delivery year to the actual PJM RTO 2016/2017 Base Residual Auction (BRA) clearing price of $59.37 per MW-day.[9]

Q What were the results of your analysis?

A The Company originally estimated a 25-year market valuation of $[redacted] NPV for the project. However, substituting the up-to-date capacity price and an adjusted energy price forecast shrinks this result to a $[redacted] NPV—shown in Figure 1. This represents a [redacted]% decrease in the project's value compared to the Company's estimate over the 25-year period.

The Company and Brattle Group cite the positive market valuation of the project after 10 years.[10] The Company's original estimate for 10-year market valuation is $[redacted] in NPV, whereas the valuation with adjusted market prices for the same period is [redacted] in NPV for the project. This represents an [redacted]% decrease in the project's value compared to the Company's estimate over the 10-year period. My results also show the project not "breaking even" until [redacted]

[9] Actual PJM RTO prices are found here: http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2016-2017-base-residual-auction-report.ashx
[10] See EKPC Application, p.6 and Exhibit 1a, p. 12: "Over a ten-year time horizon…the retrofit has an NPV of over $50 million."

[redacted]

Figure 1: Adjusted Cumulative NPV Estimate for Cooper Unit 1 Project [11]

Q Are there key elements that are unaccounted for in these adjusted results?

A Yes. This adjusted estimate does not account for the costs of compliance with future environmental regulations (which I will discuss further in my testimony) and it does not include any changes in the capacity factor that would result from lower energy market prices. If the market valuation were to properly account for these factors, the value of the Cooper unit 1 project would decrease further.

2. <u>THE COMPANY NO LONGER NEEDS TO PROCURE ADDITIONAL CAPACITY</u>

Q On what basis does the Company claim it has a capacity need?

A Company Witness Julia Tucker explains that the Company conducted the 2012 IRP on a "'business as usual' basis" which meant assuming the Company would be short on capacity in 2015 (i.e. meeting its winter peak load plus a reserve

[11] "Company's 25-year NPV" is produced annually by changing the "Lifetime of New Facility" field in PSC 5 - CONFIDENTIAL_Proposal Evaluation_Energy Production.xls; "Adjusted 25-year NPV" is calculated in the same way in PSC 5 - CONFIDENTIAL_Proposal Evaluation_Energy Production - Synapse alt.xls

margin).[12] The Company's filing in this current case discusses a "capacity need" and "capacity shortfall" of 300 MW.[13]

Q Have the Company's capacity and energy obligations changed since the 2012 IRP was issued?

A Absolutely. The Company joined PJM in June 2013. It now sells all of its capacity and energy on the respective PJM markets and separately buys energy and capacity to serve its distributors' load from those markets. The Company still has a capacity obligation to PJM; however, this obligation does not have to come from the Company's own fleet. Of key importance, the Company's obligation is now based on summer peak load instead of winter peak load.[14] Witness Tucker explains that this recent change "significantly impacts the amount of capacity that East Kentucky Power must either supply or purchase in the market within PJM."[15] In particular, by taking advantage of reserve sharing with PJM, EKPC would require a far smaller planning reserve requirement.[16]

Q Does the Company still need Cooper unit 1 to satisfy its own capacity requirements?

A No. Witness Tucker explains that "it is possible that the 300 MW could be retired without replacement capacity" and that "the replacement capacity became strictly an economic issue when EKPC joined PJM."[17] Witness James Read states that "constructing or acquiring additional generation resources is an option for EKPC, not a requirement."[18]

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[12] Direct Testimony of Julia Tucker, p.4 lines 5-8.
[13] EKPC Application, p.7
[14] Direct Testimony of Julia Tucker, p.4 lines 11-12
[15] Direct Testimony of Julia Tucker, p.4 lines 14-15
[16] See EKPC Application in Docket 12-00169, p. 15-16: "Due to the fact that EKPC is a winter peaking system and PJM as a whole is summer peaking, EKPC has the unique opportunity to monetize this diversity through the reduction of its own peak reserve requirements to match those of PJM. Thus, instead of maintaining the current 12% planning reserve requirement in both the winter and summer seasons, EKPC would only be required to maintain a 2.8% installed planning reserve for EKPC's summer peak as a fully participating member of PJM's Reliability Pricing Model (''RPM")."
[17] Direct Testimony of Julia Tucker, p.4 lines 16-19
[18] Direct Testimony of James Read, p.7 lines 18-19

Q Does the Company have sufficient capacity to meet its obligations to PJM absent the Cooper unit 1 project?

A Yes. In response to PSC Staff Data Request 13b, the Company claimed it "would have just under 400 MW of excess capacity as compared to its PJM capacity obligation, assuming no existing capacity was retired" for the 2015/2016 delivery year. This means that even if Dale (200 MW) and Cooper unit 1 (116 MW) were to retire, the Company would still have enough capacity to meet its obligations to PJM.[19] Witness Jeffrey Loiter also discusses this issue in his direct testimony.

Q Why is the Company pursuing the Cooper unit 1 project if it does not need the capacity?

A The Company appears to be attempting to maximize net revenues from energy and capacity markets rather than focusing on meeting its own capacity and energy requirements. Such a strategy relies on EKPC's projections that the sale of capacity and energy from Cooper unit 1 to the PJM market would more than offset the costs of the project and continued operation of the unit. In this way, the Company is making a decision very much like a merchant generator, except that captive ratepayers are "on the hook" if EKPC's market projections are incorrect.

Q Has the Company provided the historical and projected costs of operating Cooper unit 1 with the project, which are necessary to analyze the market value of the unit?

No. In responses to Intervenors' Supplemental Data Request 5 and 6, the Company claimed that this data was not relevant to this case. I discuss this issue, among other omissions, in Section 8 of my testimony.

Q What are the implications if capacity and energy prices do not generate enough revenue to offset the costs of continuing to operate Cooper unit 1?

A If PJM market capacity and energy prices are not sufficient to support the investment and continued operation of Cooper unit 1, then the Company and its ratepayers would have been better served by not pursuing the project. Table 1,

[19] Excess capacity of exactly 400 MW minus 200 MW (Dale) and 116 MW (Cooper unit 1) would result in 84 MW excess.

below, illustrates a decision matrix for this project, depending on if the utility actually requires the capacity to meet its requirements, and if the market prices ultimately support the investment. If Cooper unit 1 is not required to meet the Company's capacity obligations, the Company is acting like a merchant generator with respect to this project (i.e. producing power for profit, rather than to serve obligations). If market prices do not support this and other required investments, ratepayers would be better off buying from the market. In the worst case (if Cooper unit 1 is not dispatched sufficiently to cover its own costs), ratepayers will also be stuck with stranded investments. In the next section, I discuss the Company's projections of energy and capacity revenue from the Cooper unit 1 project.

Table 1: Decision Matrix for Investment

	Company requires project capacity	**Company <u>does not</u> require project capacity**
Market prices support investment	Company acts as vertically integrated utility, hedges against market prices.	Company acts as merchant generator, passes profits to ratepayers.
Market prices <u>do not</u> support investment	Company acts as vertically integrated utility, captive ratepayers pay above market rates for energy and/or capacity.	Company acts as merchant generator, ratepayers pay above market prices <u>and</u> stranded investment.

3. <u>THE MARKET VALUATION ANALYSIS LIKELY OVERESTIMATES THE VALUE OF THE PROJECT</u>

Q Is the valuation of each project dependent on the assumed PJM market energy price forecasts?

A Yes. The Company now sells all of its energy into the PJM wholesale market. The amount of generation of the Company's fleet (for each option) multiplied by the energy price determines the energy revenue provided by that option. The Company calculates the total energy revenue minus the total costs of generation to arrive at a gross margin. It then compares this gross margin for each proposal or bid to a "base case" where Cooper unit 1 and the Dale plant are assumed to be retired and not replaced. This “energy margin” represents the incremental profits (compared to retiring Cooper unit 1 and Dale) from energy sales for each option.[20]

Q Are the energy price forecasts used in estimating the “energy margin” reasonable?

[redacted] No. Figure 2 below shows the average annual assumptions for all-hours energy prices assumed by the Company. There is a sharp increase in energy [redacted]

This figure shows [redacted]

This [redacted] appears unreasonable and arbitrary.

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[20] This calculation is shown in the “Energy Margins” tab in PSC 5 - CONFIDENTIAL_Proposal Evaluation_Energy Production.xls

[21] The annual average all-hours price in 2020 is $[redacted] ($2012) compared to $[redacted] in 2017. Real prices in 2012 dollars were derived using a [redacted]% inflation rate assumption.

[redacted]

Figure 2: EKPC Annual Average Energy Price Forecast[22]

Q Where does the Company obtain its energy market price forecasts?

A The energy price forecast is produced by ACES Power Marketing ("ACES"), an "energy marketing agent" owned by EKPC and other cooperatives. EKPC President and CEO, Mr. Anthony Campbell, serves as a board member of ACES.[23] It is notable that in the docket wherein EKPC requested membership in PJM (Case No. 2012-00169), the Company noted that an independent auditor (Liberty Consulting Group) "recommended that 'EKPC should hire an independent consultant to determine the costs and benefits of ISO membership,'"

[22] The forecasts were provided in the"Energy Prices" tab in PSC 5 - CONFIDENTIAL_Proposal Evaluation_Energy Calculated. Annual average calculations are shown in CONFIDENTIAL Synapse Price Analysis.xls.
[23] See: http://www.acespower.com/about/board-of-managers/. Accessed November 21, 2013.

and further “expressed some concern in its report that ACES may not be sufficiently independent.”[24]

Q What do you propose as an adjusted energy price forecast to that provided by ACES?

A I believe that the [redacted]% price jump (after inflation) in [redacted] in the ACES energy market price forecast is unreasonable and unlikely. The long-term Wood Mackenzie forecast (used from 2020 onward) is [redacted] than the trend shown from broker values. To the extent that the broker prices received by the Company or ACES indicate actual market expectations of real sellers, I assume that these prices are moderately reliable. Therefore, I calculated an implied marginal heat rate from the Company’s natural gas price forecast compared to the broker values for [redacted] and applied this heat rate to natural gas prices going forward. This methodology assumes that the energy prices in the future will continue to track with natural gas prices in a similar manner. The average ratio of broker value energy prices ($/MWh) to natural gas prices ($/MMBtu) for this period is [redacted]—an implicit heat rate (MMBtu/MWh) for the average marginal energy resource.[25] Applying this ratio to the Company’s base case natural gas price forecast from [redacted] onward provides [redacted] energy price than what the Company is assuming—shown in Figure 3.

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[24] Direct Testimony of Anthony Campbell, KY PSC Case No. 2012-00169, page 4 line 13 through page 5 line 4.

[25] Based on a five-year average of the ratio of the broker price to the Company’s natural gas price forecast. The calculation is shown in CONFIDENTIAL Synapse Price Analysis.xlsx

[redacted]

Figure 3: EKPC Annual Average Energy Price Forecast Compared to Applying the Ratio of Broker Values to EKPC Natural Gas Price Forecast[26]

Q **Is it reasonable to assume that energy and natural gas prices are closely related?**

A Yes, in recent years, energy and natural gas prices have been correlated. Given the [redacted] in energy prices shown in the Company's energy price forecast, one would expect a [redacted] in natural gas prices or a major policy change—such as the addition of a carbon policy.

Q **Do the Company's natural gas price forecasts show a [redacted] in the same period as its energy price forecasts?**

A No. The Company's natural gas price forecasts show a slower, steady increase through 2032 when compared to its energy price forecasts—shown in Figure 4.

[26] The forecasts were provided in the "Energy Prices" tab in PSC 5 - CONFIDENTIAL_Proposal Evaluation_Energy Calculated. Annual average calculations for the Company and for the Adjusted Prices are shown in CONFIDENTIAL Synapse Price Analysis.xls

[redacted]

Figure 4: EKPC Monthly Natural Gas Price Forecast[27]

Q Does the energy price forecast [redacted]?

A [redacted] The name of the forecast in the workbook provided is "[redacted]."[28] In response to Intervenors' Data Request 54b, the Company claimed that it "assumed that the market has taken a view of the likely costs associated with complying with proposed environmental rules and that those costs are appropriately reflected in future expected market prices." In fact, the Company has chosen to use a forecast that [redacted] Therefore, given the [redacted] and the inconsistencies between the Company's long-term energy price and natural gas forecasts, the adjusted energy price forecast is reasonable.

[27] #13c ii and iii - Input data for 2012 RFP.xls. Adjusted to 2012 dollars assuming 2.5% inflation.
[28] Shown in "Energy Prices" tab in PSC 5 - CONFIDENTIAL_Proposal Evaluation_Energy Calculated.xls

I will discuss the impacts of potential carbon regulations or policies on the Company's fleet later in my testimony.

Q How does the adjusted energy price change the energy margin recovered by the Project?

A The adjusted energy price forecast reduces the energy margin significantly—as shown in Figure 5. The average annual energy margin with the adjusted energy price forecast is $[redacted] compared to $[redacted] using the Company's forecast.

The Company assumed that the Cooper unit 1 project would provide modest margins for the first three years of the project: $[redacted] in 2016, $[redacted] in 2017 and $[redacted] in 2018. However, the energy margin [redacted] as the [redacted] This energy price increase affects the energy margins in two ways: 1) the revenue per unit of energy increases with the price; and 2) Cooper unit 1 would generate more often with higher prices because the unit would be more economic to run.

[redacted]

Figure 5: Adjusted Energy Margin Estimate for Cooper Unit 1 Project [29]

Q Why are the energy margins [redacted]?

A The workbook models the energy margin as being [redacted].[30] This essentially means that the energy prices after 2031 have no effect on the dispatch of the plant since the energy margin is [redacted] at 2031 levels.

Q What was the estimate of the market valuation for the project with the adjusted energy price forecast?

A The Company originally estimated a 25-year market valuation of [redacted] for the project. However, substituting the up-to-date capacity price and a more reasonable energy price forecast changes this result to a valuation of [redacted]

[29] "Company's Energy Margin estimate" from PSC 5 - CONFIDENTIAL_Proposal Evaluation_Energy Production.xls; "Adjusted Energy Margin estimate" is calculated in PSC 5 - CONFIDENTIAL_Proposal Evaluation_Energy Production - Synapse alt.xls

[30] See "Energy Margins" tab in PSC 5 - CONFIDENTIAL_Proposal Evaluation_Energy Production.xls

[redacted]—shown in Figure 6, below. This represents a [redacted] decrease in the valuation compared to the Company's estimate.

The Company and Brattle Group cite the positive market valuation of the project after 10 years. The original estimate for 10-year market valuation is $[redacted] in NPV, whereas the valuation with adjusted market prices for the same period is $[redacted] in NPV for the project. This represents an[redacted]% decrease in the project's value compared to the Company's estimate over the 10-year period. My results also show the project not "breaking even" [redacted]

[redacted]

Figure 6: Adjusted Cumulative NPV Estimate for Cooper Unit 1 Project [31]

[31] "Company's 25-year NPV" is produced annually by changing the "Lifetime of New Facility" field in PSC 5 - CONFIDENTIAL_Proposal Evaluation_Energy Production.xls; "Adjusted 25-year NPV" is calculated in the same way in PSC 5 - CONFIDENTIAL_Proposal Evaluation_Energy Production - Synapse alt.xls

Q Is this adjusted valuation meant to replace the results provided by the Company?

A Yes, although it is still incomplete. The valuation presented here simply substitutes an adjusted set of energy prices that are lower than the Company's forecasts after 2018 and up-to-date capacity prices for 2016/2017 delivery year (as I will discuss later in this section). The adjusted valuation does not account for future environmental compliance costs (which I will discuss in the Sections 5 and 6) and does not account for the change in dispatch of Cooper unit 1 that would occur due to the energy price.

Q Why would the dispatch of Cooper unit 1 be affected by the market energy price?

A Cooper unit 1 and the rest of the Company's fleet are subject to economic dispatch among other plants in PJM. Generally, the PJM energy price must be sufficient to cover the operating cost of each unit for it to operate. The adjusted energy prices would mean Cooper unit 1 would get dispatched less often than with the Company's energy price forecast, further decreasing the valuation of the project.

Q Were you able to review the historical and projected operating costs for Cooper unit 1?

A Yes, but not the assumptions that are being used in the filing. There is variable O&M and fuel cost information in the Company's 2012 IRPs which, for Cooper unit 1, only exists through 2015 since the unit is assumed to be retired. When asked by Intervenors for historical and projected variable operation and maintenance (O&M) costs, the Company responded that this data had "no bearing on determining the reasonableness of the Cooper unit 1 project."[32] The Company provided forecast fuel costs for Cooper unit 1 in the form of coal price forecasts (in $/MMBtu),[33] but did not provide historic fuel costs or procurements for comparison.

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[32] Response to Intervenors' Supplemental Data Request 5 and 6.
[33] #13 c ii and iii – Input data for 2012 RFP.xls

Q **Why would you have needed projected variable O&M costs for Cooper unit 1 in this docket?**

A Because the dispatch of Cooper unit 1 is based on how its marginal costs of operating (fuel and variable O&M) compare against expected market prices. Since the Company refused to provide the projected variable O&M costs, I was unable to determine if Cooper unit 1 was or will dispatch economically against market energy prices.

Q **Could you back operational costs out of the analysis provided by the Company?**

A No. The Company provided "thermal total cost" values aggregated to annual, fleet wide numbers.[34] I assume that these numbers include both fuel and O&M costs, and are thus non-separable. A breakdown of these costs was provided for the Company's base case but that does not include the operation of Cooper unit 1 after 2015.

Q **Were you able to review the projected generation for Cooper unit 1?**

A Yes, but the values provided by the Company were inconsistent with the results of the economic analysis. The Company provided capacity factors for Cooper unit 1 but the generation does not match the implied generation between the Cooper unit 1 retrofit case and the base case in the Brattle Group's valuation as shown in Figure 7.

The capacity factor provided by the Company in Supplemental Response to Intervenors' Request 15 implies that Cooper unit 1 is dispatched only [redacted] Similarly, the implied generation from the Brattle analysis implies that Cooper unit 1 is [redacted] until [redacted]. The implied generation for

[34] See "Energy Data" tab in PSC 5 - CONFIDENTIAL_Proposal Evaluation_Energy Production.xls
[35] Supplemt #15d Cooper1-retro-capacity factors.xls

Cooper unit 1 is also [redacted] than the highest historical average generation for Cooper unit 1 in 2008.[36]

[redacted]

Figure 7: Cooper Unit 1 Generation Assumptions[37]

Q Are the assumptions for total generation from the fleet under the Company's base case consistent throughout the filing?

A No. The Company has only provided a breakdown of the expected generation by unit in the "base case" which assumes Cooper unit 1 and Dale are retired. When comparing the base case thermal generation in the market valuation to the inputs provided in data responses, the totals do not match—as shown in Figure 8. Without detailed underlying information that the Company has refused to provide, no explanation is readily evident for why the projections in separate parts of the

[37] "Cooper Gen based on Capacity Factor provided" is from Supplemt #15d Cooper1-retro-capacity factors.xls; "Implied Gen from Cooper 1 Retrofit Case vs. Base Case" is the difference between "Thermal Generation (MWH)" of "BASE 6-A" and "BASE" cases found in PSC 5 - CONFIDENTIAL_Proposal Evaluation_Energy Production.xls, "Cooper 1 Historical Generation" is based on annual gross generation from US EPA Air Markets Program Data, found here: http://ampd.epa.gov/ampd/

Company's filing are different.

[redacted]

Figure 8: Base Case Thermal Generation Assumptions[38]

Q How were capacity revenues estimated in the market valuation analysis?

A Brattle Group projected the present value of capacity for each proposal or bid based on the length of the term, the amount of capacity available and the projected capacity price.

Q What was the basis for the capacity price projection?

A Brattle Group used actual PJM RTO clearing prices through the 2015/2016 delivery year then applied a [redacted]% escalation rate for each subsequent year to the actual 2015/2016 clearing price of $136 per MW-day.

[38] "Base Case thermal gen in market valuation model" is "Thermal Generation (MWH)" from the base case found in PSC 5 - CONFIDENTIAL_Proposal Evaluation_Energy Production.xls; "Base Case thermal gen from inputs provided" is from #13c vii and xii - RFP-Unit-data – CONFIDENTIAL.xls

Q Is the 2015/2016 clearing price the most recent capacity auction in PJM?

A No. Since the Brattle Group's analysis was complete there has been another PJM capacity auction for the 2016/2017 delivery year. These results were announced on May 24, 2013, several months before the Company's filing.

Q Was the 2016/2017 clearing price close to the price forecast by Brattle Group at the time of its analysis?

A No. The Brattle Group used the much higher 2015/2016 price as a basis which led them to project a capacity price of $[redacted] per $MW-day in 2016/2017. The actual clearing price for that auction was $59 per MW-day—[redacted]% lower than the price assumed by Brattle Group.

[redacted]

Figure 9: Capacity Price Forecasts[39]

[39] "Capacity Prices" tab in PSC 5 - CONFIDENTIAL_Proposal Evaluation_Energy Production; Actual PJM RTO prices are found here: http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2016-2017-base-residual-auction-report.ashx

Q Have you updated the capacity price projections to reflect this?

A Yes, my adjusted market valuation estimates for the project reflect the most recent PJM auction results for 2016/2017.

Q Have you updated the capacity price projections for any other years in the future?

A No. Although it is possible that capacity prices will not follow a similar trajectory to what Brattle has assumed, I have kept the prices the same as the Company's forecast for delivery years after 2016/2017.

4. <u>THE COMPANY RECEIVED A BID WITH A HIGHER VALUE THAN THE PROJECT</u>

Q Were there any bids the Company received that had a similar or improved market valuation compared to the Cooper unit 1 project?

A Yes, several bids were of similar or better market valuation in terms of net present dollars per MW-year (which adjusts for the size of the unit). For instance, the Company evaluated a Power Purchase Agreement (PPA) for a natural gas combined-cycle (CC) plant with a 25-year market value of $[redacted] per MW-year (compared to $[redacted] per MW-year for the Cooper unit 1 project).[40]

The Company also received a bid for a PPA for wind from [redacted] for a cost of $[redacted] per MWh escalating at [redacted]% per year, starting in 2015. The 20-year market value for this project was estimated at of $[redacted] per MW-year ([redacted]% higher than the comparable measure for Cooper unit 1).[41]

Q Is this wind PPA economically attractive for the Company given its assumptions in this case?

A Yes, the cost of energy from the wind PPA is [redacted] relative to the Company's all-hours energy price forecast (and [redacted] than the adjusted

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[40] "PPA Summary" and "Facility Summary" tabs in PSC 5 - CONFIDENTIAL_Proposal Evaluation_Energy Production.xls

[41] This compares the 20-year valaution of both projects, based on the term of the wind PPA: $[redacted] per MW-day for the wind PPA and $[redacted] for Cooper Unit 1 (Cooper Unit 1's 25-year valuation is [redacted] than the 20-year valuation in terms of dollars per MW-year). The wind PPA costs are based on information on bid [redacted] in "Proposals Analysis" tab in PSC 5 - CONFIDENTIAL_Proposal Evaluation_Energy Calculated.xls

forecast presented in my testimony). Thus the wind PPA provides an attractive hedge against the energy market.

[redacted]

Figure 10: Energy Forecasts Compared to Wind PPA Energy Cost[42]

Q What are the key risks and benefits associated with the wind PPA?

A The wind PPA carries the risk that energy market prices will be even lower than the cost of energy quoted in the PPA (see Figure 10, above). However, the energy cost of the wind remains lower than even my adjusted all-hours energy price forecast; therefore this risk is low.

The Company did not select the wind PPA because it [redacted][43]

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[42] Calculations of "Wind PPA Energy Costs" are based on information on bid [redacted] in "Proposals Analysis" tab in PSC 5 - CONFIDENTIAL_Proposal Evaluation_Energy Calculated.xls. The wind PPA energy costs [redacted]

[43] Exhibit 1a, p.12.

But EKPC has not supported this statement; the Company has not provided any analysis in the record that supports the conclusion that a 200 MW PPA is too large to add to EKPC's existing supply portfolio of nearly 3000 MW.[44] Intermittency should not be an issue if the project is being used as a financial hedge and the capacity is not needed.

The wind PPA provides key benefits in the form of protection from risks of fuel price volatility and environmental compliance costs. The wind project also goes towards diversifying the Company's resource mix which the Brattle Group raised as a concern.[45] The Company should take these benefits into account when evaluating the viability of the wind PPA.

Q What are the key risks associated with the Cooper unit 1 project?

A The Cooper unit 1 project carries several key risks including: 1) that market prices will not be sufficient to justify operating the unit (i.e. the unit is not dispatched), 2) that market prices will not provide sufficient revenue to cover the fixed costs of the retrofit and other future capital (i.e. the Company will have stranded investments), 3) that significant incremental costs will be required for the unit to comply with future environmental regulations, and 4) that, because the dispatch price of Cooper is highly dependent on fuel costs, that the cost of coal may rise faster than expected by the Company.

In general, the Brattle Group discusses the risks associated with the Company's reliance on coal generation in its resource mix, claiming that "shifting the EKPC supply portfolio towards gas-fired generation would be desirable from the standpoint of hedging its members' exposures to market risks."[46]

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[44] See 2012 IRP, p. 54.
[45] Exhibit 1a, p.9
[46] *Id.*

Q In general, are there risks associated with a self-build option compared to procurement with a third party (as in a PPA)?

A Yes. Brattle Group's memo to the Company summarizing the proposals discusses the various risks involving the self-build option, concluding that:

> If EKPC chooses a self-build option, then it will run the risk that the cost to complete the project will exceed the amount estimated by PC&E, that it will take more time to complete and/or that is will fail to perform as anticipated. In contrast, if EKPC pursues a contract with a third party, it can seek to negotiate contract provisions that provide protection from the consequences of these events. Thus, there is a drawback to self-build options: EKPC cannot bind itself to itself. It must self-insure against this class of risks. This means a self-build proposal must have a higher expected value than an otherwise comparable proposal from a third party.[47]

5. <u>THE COMPANY FAILED TO EVALUATE POTENTIAL ENVIRONMENTAL COMPLIANCE COSTS</u>

Q How are impending environmental regulations important to the case at hand?

A In addition to the regulation of greenhouse gases (discussed in the next section), a suite of final and proposed EPA regulations will require coal-burning power plants to install pollution controls.[48] The environmental retrofits at issue in this case are required for compliance with the MATS (Mercury and Air Toxics Standards) rule, one of multiple rules expected in the next few years. Just as the MATS rule imposes costs on the existing coal fleet, as made apparent by the retrofits at issue in this docket, other pending rules are also expected to have moderate to significant impacts on the costs of operating and owning coal units.

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[47] Exhibit 1a, p.11

[48] Note: a proposed rule from the EPA is a draft version of the rule made available for public comment, and is usually a strong indicator that a final rule with similar provisions will follow.

Q Aside from the MATS, are future environmental rules reflected in the economic analysis conducted by the Company?

A No. According to the Company, "no additional costs to make Cooper unit 1 compliance with undetermined environmental rules were included."[49] I assume that by "undetermined," the Company means "non-finalized."

With the exception of dealing with MATS, the Company has neglected important costs of compliance with proposed and pending environmental regulations, effectively assigning them a zero cost. In the current case, the Company neither addresses nor examines the likelihood of future compliance obligations.

Forthcoming environmental regulations will impose significant costs on the Company's coal-fired assets. While tying Cooper unit 1 into Cooper unit 2's dry flue gas desulfurization (DFGD) and fabric filter baghouse may mitigate some future environmental concerns for Cooper unit 1, it by no means settles the balance of risk for these future costs. By neglecting pending environmental regulations, the Company biases its economic analysis towards those projects that will likely incur future costs, unnecessarily putting its members at risk.

Q Is the Company aware of the environmental risks to which you refer?

A Yes. It is clear that the Company has been tracking environmental rules and regulations. In the Company's 2012 Integrated Resource Plan (IRP), filed April 20, 2012, it discusses each of the rules to which I will refer.[50] The IRP pre-dates this application by over a year; therefore the Company is well aware of these rules. The relevant section of the 2012 IRP is attached as Exhibit TFC-2.

Q Which environmental regulations has the Company ignored in this analysis?

A Rules governing air quality, water quality, and coal combustion residual disposal are all expected to impose moderate to significant costs at existing coal-fired facilities. These rules include:

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[49] See Response to Intervenors Supplemental Request 39c.

[50] See EKPC 2012 IRP, Section 9: Compliance Planning. Pages 170-186. Exhibit TFC-2.

- finalized and emerging National Ambient Air Quality Standards (NAAQS),
- the re-issuance of the Cross State Air Pollution Rule (CSAPR),
- the proposed rules governing the disposal of Coal Combustion Residuals (CCR),
- provisions of the Clean Water Act governing cooling water intake structures under section 316(b) of that act, and
- proposed Clean Water Act effluent limitation guidelines (ELG) for scrubber and ash handling wastewater at steam electric generating units.

I'll describe each of these rules in turn, and the expected impact of the rule on Cooper unit 1.

Q Why did the Company ignore the impact of these rules on its evaluation?

A The Company generally claimed that since the rules were not yet finalized, identifying regulatory compliance options would be speculative.[51] Although, in a presentation to its board, when referring to "[redacted]" the Company claimed that the Cooper unit 1 project would provide "[redacted]"

Q Have any parties reviewed the potential compliance costs with proposed and emerging rules such as the NAAQS, CSAPR, CCR, ELG, or 316(b) rule?

A Yes. Since 2010, at least a dozen organizations have reviewed the potential impact of one or more of these rules on the domestic coal fleet, examining compliance options, costs, and differing levels of stringency.[53] The U.S. EPA has

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[51] See EKPC Responses to Intervenors' Supplemental Requests 31a, 32a & d, 33a & d, 35c, 36a & b, and 38b.

[52] #30 - RFP 2012 SI Board Presentation.pptx, slide 11

[53] Organizations include Bernstein Research (2010), Brattle Group (2010), Charles River Associates (2010) Credit Suisse (2010), Deutsche Bank (2010), Edison Electric Institute (2011), ICF (2010), MJ Bradley and Analysis Group (2011), National Economic Research Associates (NERA, 2011), North American Electric Reliability Corporation (NERC, 2010), US Department of Energy (2011), and Synapse Energy Economics (2013).

produced a series of regulatory impact assessments (RIAs) that explicitly explore the implications, capital, and operational costs of proposed and promulgated rules.

Q Can the impact of these rules be known with absolute certainty?

A No. Until each rule is finalized, and until the state and EPA determine compliance mechanisms for electric generating units that violate these rules, the exact timing and impact of these rules is unknown. However, the Company should have evaluated proxy costs for reasonable bounding cases based on lenient or strict implementation of the rules especially given that draft rules are already available in many instances.

Q Why is it not sufficient for the Company to determine the cost-effectiveness of the retrofits under the MATS rule only?

A Such an evaluation would be incomplete, as it ignores relevant planning information that the Company's management knows or should know, and could put ratepayers at risk for the costs of capital expenditures that, when considered as part of a whole, might not be cost-effective. Instead, the Company is pursuing a piecemeal approach— requesting cost recovery for a single upcoming cost (i.e., MATS) rather than considering the full costs to ratepayers of continuing to operate the units. Without factoring in the full-range of known and likely costs that ratepayers would have to bear, it is not possible to assert that Cooper unit 1 produces low-cost generation, or that the costs associated with the instant case will not be stranded well before the assets have fully depreciated. Nor is it possible to properly compare the various bids and proposals evaluated by the Company, given this omission.

Q Please briefly describe the purpose and impact of National Ambient Air Quality Standards (NAAQS).

A NAAQS set minimum air quality standards that must be met at all locations across the nation. Compliance with the NAAQS can be determined through air quality monitoring stations, which are located throughout the U.S., or through air quality dispersion modeling. If an area is found to be violating a particular

NAAQS, the state is required to adopt a plan with enforceable requirements to reduce emissions from sources contributing to the violation such that the NAAQS are attained and maintained.

EPA has established short-term and/or annual NAAQS for six pollutants: sulfur dioxide (SO_2), nitrogen dioxides (NO_2), carbon monoxide (CO), ozone, particulate matter (measured as particulate matter less than or equal to 10 micrometers in diameter (PM_{10}) and particulate matter less than or equal to 2.5 micrometers in diameter ($PM_{2.5}$)), and lead. EPA is required to periodically review and evaluate the need to strengthen the NAAQS if necessary to protect public health and welfare. For example, EPA is currently evaluating the NAAQS for ozone and is likely to make that standard more stringent based on the latest science regarding health effects.

Q: Which NAAQS are most likely to impact the Company's solid-fueled assets at issue in this case?

A The 8-hour Ozone NAAQS and the $PM_{2.5}$ NAAQS are likely to have the greatest impacts on Cooper unit 1 due to the cost of the controls that may be required to help meet compliance obligations.

Q Please briefly describe the 8-hour Ozone NAAQS.

A In March 2008, EPA strengthened the 8-hour ozone standard from 84 ppb (parts per billion) to 75 ppb. On September 16, 2009, EPA announced that because the 2008 standard was not as protective as recommended by EPA's panel of science advisors, it would reconsider the 75 ppb standard. In January 2010, EPA proposed lowering the 75 ppb primary ozone standard to between 60 and 70 ppb.

On September 2, 2011, however, the Administration announced that EPA would not finalize its proposed reconsideration of the 75 ppb standard ahead of the Agency's normal 5-year NAAQS review cycle. The next 5-year review for 8-hour ozone was due in 2013, though EPA has indicated that it needs more time to conduct additional analyses.[54]

If EPA were to propose a standard in the 60 to 70 ppb range (as it did in 2010), it is likely that additional areas in Kentucky would be designated as non-attainment for the new standard.[55] Pulaski County, where the Cooper plant is located, would have violated a 60 ppb standard based on 2006-2008 data, and other nearby counties would have violated a more lenient 70 ppb standard.[56] A more stringent ozone standard could drive significant additional NO_X emission reduction requirements.

Q Please briefly describe the $PM_{2.5}$ NAAQS.

A In 1997, the EPA established the first ever annual and 24-hour $PM_{2.5}$ NAAQS at 15 micrograms per cubic meter ($\mu g/m^3$) and 65 $\mu g/m^3$, respectively. In 2006, the EPA lowered the 24-hour $PM_{2.5}$ standard to 35 $\mu g/m^3$ and retained the 15 $\mu g/m^3$ annual standard. The 2006 $PM_{2.5}$ standards were primary drivers behind the EPA's 2005 CAIR and 2011 CSAPR rules, which were designed to lower NO_X and SO_2 emissions from electric generating units in affected states that significantly contributed to $PM_{2.5}$ non-attainment areas in other states.

In December 2012, EPA lowered the annual $PM_{2.5}$ standard from 15 $\mu g/m^3$ to 12 $\mu g/m^3$ and retained the 24-hour standard at 35 $\mu g/m^3$. EPA will make final area designations for the new standard by December 2014, at which time states with non-attainment areas will have three years to develop a state implementation plan (SIP) outlining how they will reduce pollution to meet the standard by 2020.

Particulate matter is made up of primary particles, which are emitted directly from a source, as well as secondary particles, which are formed through reactions in the

[54] See Memorandum from Lydia Wegman, Director, Health and Environmental Impacts Division Office of Air Quality Planning and Standards, to Holly Stallworth, Designated Federal Officer, Clean Air Scientific Advisory Committee (CASAC) EPA Science Advisory Board Staff Office, dated November 5, 2013.
[55] See US EPA, 2010. Counties Violating the Primary Ground-level Ozone Standard: http://www.epa.gov/airquality/ozonepollution/pdfs/CountyPrimaryOzoneLevels0608.pdf
[56] *Id.*

atmosphere of chemicals such as SO_2 and NOx.[57] The $PM_{2.5}$ NAAQS, therefore, requires control of not just directly emitted particles but also of SO_2 and NOx – the precursors of secondary particles.

Q Please briefly describe the purpose and impact of the Cross State Air Pollution Rule.

A The Cross State Air Pollution Rule (CSAPR), finalized in 2011, established the obligations of each affected state to reduce emissions of NO_X and SO_2 that significantly contribute to another state's $PM_{2.5}$ and ozone non-attainment problems. CSAPR was vacated by the U.S. Court of Appeals for the District of Columbia on August 21, 2012. In June 2013, the U.S. Supreme Court announced that it would review that decision, creating the possibility it could reinstate CSAPR. Even if EPA fails to salvage CSAPR through the courts, the Agency must still promulgate a replacement rule to implement Clean Air Act requirements to address the transport of air pollution across state boundaries. When the D.C. Circuit vacated CSAPR, it ordered EPA to continue to implement the 2005 Clean Air Interstate Rule (CAIR) in CSAPR's place to address those "good neighbor" obligations. CAIR was previously struck down by the D.C. Circuit for not being stringent enough, but was left in place while EPA developed a replacement rule (what would become CSAPR).

As it awaits a decision from the Supreme Court, EPA has continued to work on a replacement for CSAPR that meets the D.C. Circuit's requirements.

Q How will the Ozone and $PM_{2.5}$ NAAQS, and next iteration of CSAPR impact Cooper unit 1?

A NO_X is a precursor to both $PM_{2.5}$ and ozone, meaning that areas that are not in attainment for these two pollutants will seek the most effective source controls for precursors. Since large emissions sources – such as coal-fired generating stations – contribute disproportionately to emissions of these precursors and are effectively controlled with post-combustion controls such as SCR (selective

[57] EPA Particulate Matter website: http://www.epa.gov/air/particlepollution/basic.html

catalytic reduction), I assume that if areas of Kentucky within the dispersion area of Cooper are found to be in non-attainment for the ozone or $PM_{2.5}$ standards, the state and EPA could require rigorous NOx controls at these units to meet the standards.

Similarly, if the next version of the interstate transport rule finds that NOx sources in Kentucky contribute to ozone or $PM_{2.5}$ pollution in downwind states (as did the vacated version), then large sources in Kentucky could either be required to install controls or purchase NOx allowances at high prices. Based on the promulgation of new, lower $PM_{2.5}$ NAAQS and the expected tightening of the ozone NAAQS, I'd expect that the next version of CSAPR will be more stringent than the vacated version.

These rules could entail the addition of new NOx emissions controls at Cooper unit 1. The re-ducting proposed by the Company in this docket would bypass the selective catalytic reduction (SCR) facility at Cooper unit 2, and thus not be able to take advantage of that control. Cooper unit 1 could require either a selective non-catalytic reduction (SNCR) units, or possibly a more expensive SCR. Roughly, I estimate the capital cost of SCR at Cooper unit 1 at about $27 million (2012$).[58] At the lenient end of a compliance obligation, an SNCR could be required at Cooper unit 1. I estimate the capital cost of SNCR at Cooper unit 1 to be roughly $6 million (2012$).[59]

Q If designations for $PM_{2.5}$ are made next year, and a new ozone standard is promulgated in 2015, a SIP requiring additional NOx controls could be finalized as early as 2018. Please briefly describe the purpose and impact of the proposed Coal Combustion Residuals rule.

A Coal-fired power plants generate a tremendous amount of ash and other residual wastes, which are commonly placed in dry landfills or slurry impoundments; regulations governing the structural integrity and leakage from these installations

[58] Synapse calculation based on EPA estimates. See "Documentation for EPA Base Case v.4.10" for the Proposed Transport Rule. Available at http://www.epa.gov/airmarket/progsregs/epa-ipm/BaseCasev410.html

[59] Synapse calculation based on IPM Model – Revisions to Cost and Performance for APC Technologies, SNCR Cost Development Methodology, Sargent & Lundy, August 2010.

vary. On June 21, 2010, EPA proposed regulation of ash and flue gas desulphurization (FGD) wastes, or "coal combustion residuals" (CCR) as either a Subtitle C "hazardous waste" or Subtitle D "solid waste" under the Resource Conservation and Recovery Act (RCRA).[60]

Under a Subtitle C designation, the EPA would regulate siting, liners, run-on and run-off controls, groundwater monitoring, fugitive dust controls, and any corrective actions required; in addition, the EPA would also implement minimum requirements for dam safety at impoundments.

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

The EPA is currently evaluating which regulatory pathway will most effectively protect human health and the environment without resulting in unintended consequences or resulting in unnecessarily burdensome requirements. On October 29, 2013, the U.S. District Court for the District of Columbia gave EPA until December 29, 2013 to submit a plan for finalizing its delayed CCR rule. This suggests that a final CCR rule is forthcoming.

A number of parties have estimated costs associated with compliance with the CCR rule, including the Electric Power Research Institute (EPRI), Edison Electric Institute (EEI), and the EPA in the Regulatory Impact Assessment (RIA) of the proposed rule. Compliance costs are fairly specific to the circumstances and current disposal practices of each facility. However, major incremental costs generally include improved groundwater monitoring, bottom lines, leachate collection, and conversion to dry-waste handling. In addition, the EPA estimates costs for mitigating leakage in karstic geology (i.e. where natural caverns or gaps form in the underlying bedrock); according to the EPA's RIA, Cooper sits in this type of terrain.

[60] 75 Fed. Reg. 35127. June 21, 2010.

The EPA's RIA reviews engineering estimates from Tennessee Valley Authority (TVA) on conversion from wet-ash handling to dry ash handling, and estimates an annual capital cost of $43.70/ton of ash per year. According to EIA records, Cooper produces 117,100 tons of ash per year (which could increase with the addition of other environmental controls)[61]; at TVA's costs this would amount to $5.1 million per year, or $1.7 million attributable to Cooper unit 1—$34 million over 20 years (2005$).[62] In addition, the EPA estimates $4.1 million of one-time mitigation costs to create leakage barriers in karstic geology (therefore $1.3 million attributable to Cooper unit 1). While I do not have specific engineering knowledge of the conditions at Cooper unit 1, I assume that compliance with the CCR rule at Cooper unit 1 would cost approximately $41 million (2012$), assuming conversion to dry ash handling will be required.[63] EPA could issue a final CCR rule that selects another option, such as the subtitle D option, which would cost less, or the subtitle D prime option, which would cost the least. I made the very conservative assumption of no costs for the most lenient scenario; this is conservative because even if EPA selected the least stringent option, subtitle D prime, EKPC is still likely to incur some compliance costs.

Q Please briefly describe the purpose and impact of the proposed Effluent Limitation Guidelines (ELG).

A The Clean Water Act requires EPA to develop "effluent limitation guidelines" (ELGs) – standards for what large industrial sources of water pollution can discharge into nearby waters.[64] These standards must be based on the best-performing technology in the industry that is technically and economically achievable across the industry, and must be updated at least once every five years

[61] EIA 923, Schedule 8A. Found here: http://www.eia.gov/electricity/data/eia923/

[62] Regulatory Impact Analysis for EPA's Proposed RCRA Regulation of Coal Combustion Residues (CCR) Generated by the Electric Utility Industry, US EPA Office of Resource Conservation and Recovery, April 30, 2010, p.85

[63] It is unclear from the EIA Form 923 how much the Company uses dry disposal. If it needed to completely convert from wet to dry disposal then the calculation of compliance costs would be as follows: (117,100 tons*$43.70/ton*20 years*Cooper 1 share) + $1.3 million = $35.3 million (2005$). Using the Consumer Price Index to adjust to 2012 dollars equates to $41.47 million.

[64] See 33 U.S.C. § 1311; 40 C.F.R. Part 423 (current ELGs for steam electric generating unit source category).

to reflect improving treatment technology and move towards the Clean Water Act's goal of eliminating water pollution.

On June 7, 2013, EPA proposed standards for bottom ash and fly ash handling water, impoundment and landfill leachate, wastewater from wet FGD systems, flue gas mercury control systems, regeneration of the catalysts used for SCR, among other waste streams.[65]

EPA's proposed rule contains several different compliance options. Nearly all of these options require zero discharge of fly ash and bottom ash handling waters, either through conversion to dry ash handling or implementation of closed loop wet ash handling system. Likewise, most options will require at least chemical precipitation, and some options will require additional biological treatment, of any wastewater generated by a wet FGD system. EPA is required by a consent decree to finalize the ELG rulemaking by May 2014.

Based on cost estimates developed by EPA, a strict implementation of the ELG rule could cost $9 million (2012$) for advanced waste handling, and bottom ash water treatment at Cooper unit 1. At the lenient end, advanced waste handling might cost around $2 million in capital costs for the unit. These costs do not include the fixed costs of maintaining these new structures.

Q Please briefly describe the purpose and impact of the proposed Cooling Water Intake Rule.

A On March 28, 2011, the EPA proposed a long-expected rule implementing the requirements of Section 316(b) of the Clean Water Act at existing power plants.[66] Section 316(b) requires "that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact." Under this new rule, EPA set new standards reducing the impingement and entrainment of aquatic organisms from cooling water intake structures at new and existing electric generating facilities.

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[65] Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (Proposed Rule), 78 Fed. Reg. 34,432. June 7, 2013.
[66] 33 U.S.C. § 1326.

The proposed rule provides that:

- Existing facilities that withdraw more than two million gallons per day (MGD) would be subject to an upper limit on fish mortality from impingement and must implement technology to either reduce impingement or slow water intake velocities. Facilities with intake velocities above 0.5 feet per second (fps) would be required to reduce intake speeds or provide other mitigation measures.

- Existing facilities that withdraw at least 125 MGD would be required to conduct an entrainment characterization study for submission to the Director to establish a "best technology available" for the specific site.

After an extensive comment period, the EPA expects to release the final rule by January 14, 2014.[67]

EKPC's 2012 IRP discusses the proposed 316(b) requirements and the impacts of this rule on the Company's power stations.[68] The intake structure for Cooper station has a design intake flow of 208 MGD, above the threshold for entrainment mortality. However, due to low water levels in Lake Cumberland (from repairs at the Wolf Creek dam), the Company installed temporary floating pump houses and cooling towers at Cooper 2, dramatically reducing the water requirements of the larger unit when the cooling towers are in operation (from 119 MGD to 3 MGD).[69] This retrofit does not currently appear to be linked to Cooper unit 1, which still utilizes once-through cooling. The 2012 IRP notes that Cooper unit 1 currently has an intake flow of 7.2 fps at end of the intake pipe, but only 0.3 fps at fish exclusion screens in the pumphouse. In the 2012 IRP, the Company interprets the proposed 316(b) rule as requiring slow velocities at the exclusion screens, not at the actual intake pipe. While the exact nature of the final rule is yet unknown, based on the language in the draft rule, I expect that the high velocity end-of-pipe intake at Cooper unit 1 could be unacceptable under a reasonable final rule.

[67] See http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/. Last reviewed Nov 21, 2013.
[68] EKPC 2012 IRP, p.176-185. Exhibit TFC-2.
[69] EKPC 2012 IRP, p.181. Exhibit TFC-2.

It is unknown if final implementation of the rule will effectively require "open cycle" cooling (i.e. those that withdraw from and discharge hot water directly to rivers or lakes) to retrofit with "closed cycle" cooling towers, or if advanced fish screens will prove sufficient. At the strict end of the spectrum, the rule could require Cooper unit 1 to install a cooling structure commensurate with the Cooper 2 tower, at a cost of about $16 million. At the lenient end, Cooper unit 1 could meet requirements with low-cost modifications to its screen structure.

Q How do these proposed and impending environmental rules change the economic picture for Cooper unit 1?

A Overall, the implementation of the rules I have described here has a significant impact on the outcome of the Company's analysis. Today, the Company requests about $15 million for retrofits at Cooper to meet MATS obligations. Under lenient to strict environmental regimes, the Company could see capital compliance obligations of anywhere from $8 to $92 million or more at Cooper unit 1,[70] in addition to costs to comply with carbon regulations issued under the Section 111(d) rule expected to be proposed next year. None of these anticipated costs were taken into account by the Company.

In my adjusted economic evaluation, I estimate that the Company's project does not [redacted], and only achieves a net benefit of $[redacted] by 2025 and [redacted] by 2040 (see Figure 1 on page 7). It is likely then that any additional costs for compliance with environmental regulations would render this project non-economic relative to the PJM market, and therefore a liability for EKPC's members.

It is my opinion that a reasonable mid-level estimate of future obligations is the more lenient implementation of environmental rules, along with the Synapse mid-case CO_2 price; however, the Company and this Commission should review the risks of a more stringent environmental regime as well.

[70] Lenient: $6 million (SNCR) + $2 million (ELG) = **$8 million**.
Strict: $26 million (SCR) + $41 million (CCR) + $9 million (ELG) + $16 million (cooling) = **$92 million**

6. THE COMPANY FAILED TO EVALUATE A COST FOR THE MITIGATION OF CARBON DIOXIDE POLLUTION

Q Did the Company consider the potential for costs associated with carbon dioxide emissions in its economic evaluations?

A No. The likelihood of an actual or imputed price on emissions of carbon dioxide (CO_2) has all but been dismissed by the Company. Two Company witnesses, Julia Tucker and James Read, acknowledge that carbon regulation poses a direct economic risk to the proposed project.[71,72] Nonetheless, the Company failed to actually review the impact of this risk on its decision-making process and adamantly dismissed the idea that the risk of carbon regulation should play any role in its decision-making process.[73]

Q Is it reasonable to assume that emissions of CO_2 will remain cost and risk-free?

A No. A baseline forecast of no CO_2 price is an unreasonable assumption for the time horizon of the Cooper unit 1 project. It is quite likely that either the U.S. Environmental Protection Agency (EPA), or eventually Congress, will regulate CO_2 emissions well within the 25-year span of the analysis conducted by the Company. For example, as I discuss below, the President of the United States has directed the EPA to propose standards regulating carbon emissions from existing power plants by June 1, 2014 and issue a final rule by June 1, 2015. Depending on the implementation of this rule, the effects could take place within ten years (when the Company is claiming the Cooper unit 1 project will be largely

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[71] Direct Testimony of Julia Tucker, p.10 lines 10-15: "The Project does leave EKPC with 116 MW more coal-fired capacity than it would have if Cooper 1 was retired, and thus with that much more capacity exposed to coal market price risk and the potential for a carbon tax and/or carbon regulations."
[72] Direct Testimony of James Read, p.9 lines 13-17: "As a result, over 80 percent of its energy supply is coal-based. … [O]ver the long term, gas-fired generation is less exposed than coal to the possibility that carbon emissions will be priced or taxed. Therefore, shifting the EKPC supply portfolio towards gas-fired generation would be desirable from the standpoint of hedging its members' exposures to market risks."
[73] See Responses to Intervenors Request 10, Intervenors Request 13c.v, Intervenors Supplemental Request 22c, Intervenors Supplemental Request 34, and Intervenors Supplemental Request 38b.

profitable). Various compliance options are currently being explored by the Commonwealth of Kentucky, as I will discuss later.[74]

Q Do other Commissions expect utilities to examine CO_2 costs in resource planning?

A Yes. For example, the Arkansas Public Service Commission recently ordered utilities to assign a non-zero avoided regulatory cost for carbon emissions as part of energy efficiency cost-effectiveness analysis.[75] The Indiana Utility Regulatory Commission, citing the risk of carbon regulation to the economic viability of a coal unit, determined that the costs of environmental compliance would not be recoverable by a utility should carbon regulation render the unit non-economic.[76] Similarly, the Idaho Public Utilities Commission recently ordered PacifiCorp to increase its levels of cost-effective DSM and "devote more focus on the development of alternative energy resources" stating that, with regards to carbon pricing, "it seems more likely than not that the EPA will move forward and enact additional regulations of fossil fuels under the federal Clean Air Act."[77]

Q Why has the Company dismissed the potential for costs associated with CO_2 emissions in its economic evaluations?

A The Company states that "given the uncertainty of the final CO_2 requirements, determining realistic future CO_2 costs, taxes, and emission allowance prices is difficult at best. Consequently, EKPC has not prepared or had prepared any forecasts or projections of future CO_2 costs, taxes, or emission allowance prices…"[78]

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[74] Letter to Administrator Gina McCarthy US EPA, Kentucky Energy and Environment Cabinet, October 22, 2013 and attachment "Greenhouse Gas Policy Implications for Kentucky under Section 111(d) of the Clean Air Act." Both are attached as Exhibit TFC-3.

[75] See Arkansas PSC, Docket 13-002-U, In the Matter of the Continuation, Expansion, and Enhancement of Public Utility Energy Efficiency Programs in Arkansas, Order No. 1, at p.19.

[76] Indiana Utility Regulatory Commission. August 14, 2013. Verified Petition of IPL for Approval of Clean Energy Projects…etc.. Cause 44242. Final Order. Page 36. http://www.in.gov/iurc/files/44242order_081413.pdf

[77] Idaho Public Utilities Commission. September 11, 2013. In the Matter of PacifiCorp dba Rocky Mountain Power's 2013 Integrated Resource Plan. Case PAC-E-13-05. Order 32890. Attached as Exhibit TFC-4.

[78] See Response to Intervenors Request 10.

Q Has the Company evaluated the potential for costs associated with CO_2 emissions in previous economic evaluations?

A Yes. In a discovery response issued by the Company in KY PSC Case 2012-00149, the 2009 IRP included a price on carbon emissions – at least in the consideration of demand-side management (DSM) programs. According to the Company, "at the time the 2009 IRP was done, a value was set at $40/ton for use in the Societal Cost test as an estimate for what future allowance prices could be in a marketplace with a cap and trade program for carbon."[79] However, the response explains that the Company has since withdrawn consideration of a carbon price:

> Given there has been no legislation passed dealing with carbon, the cost of complying with environmental regulation is reflected in the avoided capacity and energy costs, and therefore, for the 2012 IRP the value for the Societal Cost test was set at $0/MWh.[80]

This explanation apparently still holds true for the Company today. In its comments on the 2012 IRP's treatment of environmental regulation, Commission Staff stated the following:

> EKPC included no CO_2 costs in the supply side evaluation and did not specifically address CO_2 issues in its compliance planning. Although EKPC provided what it believed was appropriate rationale for not doing so, the Staff believes that EKPC should have made some attempt to evaluate the impact of potential CO_2 rules. Staff views the exclusion of CO_2 from the IRP as a shortcoming and therefore recommends that EKPC provide a complete discussion of compliance actions and plans relating to

[79] Response to Movants' Initial Requests for Information Dated 06/08/12, Request 43, in KY PSC Docket 2012-00149. Attached as Exhibit TFC-5.
[80] *Id*.

current and pending environmental regulations within the next resource plan.[81]

Q Has anything changed since the submission of the Company's 2012 IRP?

A Yes. On June 25, 2013, two months prior to the submission of this application, the President announced a series of initiatives to start regulating carbon emissions from new and existing fossil fuel fired electricity generators. Earlier, in May 2013, the Administration also released a new series of estimates for the "social cost of carbon" (SCC), a monetized estimate of the damage caused to society by global climate change.[82] Together, these two announcements signal a strong intent by the current Administration to reduce carbon emissions from new and existing sources.

Q What was entailed in the President's June 2013 announcement?

A In conjunction with a public announcement, the White House released a memorandum containing several directives.[83] Referring to the EPA, the memo stated (in part):

> Section 1. (b) Carbon Pollution Regulation for Modified, Reconstructed, and Existing Power Plants. To ensure continued progress in reducing harmful carbon pollution, I direct you to use your authority under sections 111(b) and 111(d) of the Clean Air Act to issue standards, regulations, or guidelines, as appropriate, that address carbon pollution from modified, reconstructed, and existing power plants and build on State efforts to move toward a cleaner power sector. In addition, I request that you:
>
> (i) issue proposed carbon pollution standards, regulations, or guidelines, as appropriate, for modified, reconstructed, and existing power plants by no later than June 1, 2014;

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[81] Kentucky Public Service Commission Staff Report on the 2012 Integrated Resource Plan of East Kentucky Power Cooperative, Case No. 2012-00149, p.50.
[82] See Exhibit TFC-6
[83] See Exhibit TFC-7

(ii) issue final standards, regulations, or guidelines, as appropriate, for modified, reconstructed, and existing power plants by no later than June 1, 2015; and

(iii) include in the guidelines addressing existing power plants requirement that States submit to EPA the implementation plans required under section 111(d) of the Clean Air Act and its implementing regulations by no later than June 30, 2016.

Q Is it clear what would happen under a Section 111(d) standard to regulate carbon dioxide emissions from existing power plants?

A Not yet. Under Section 111(b) of the Clean Air Act, EPA is required to propose new source performance standards (NSPS) for new sources of greenhouse gas pollution. Section 111(d) of the Act requires that, once these standards have been set for new sources, EPA must prescribe regulations establishing a procedure for states to set standards of performance for greenhouse gases from existing sources. On September 20, 2013, EPA released a draft NSPS for greenhouse gases (i.e., CO_2) at new sources. The draft NSPS would require all new fossil generation to emit CO_2 at a level no greater than 1,100 lbs of CO_2 per MWh (for coal plants and small natural gas plants) or 1,000 lbs of CO_2 per MWh (for large natural gas plants); new coal plants would effectively have to use carbon capture and sequestration (CCS) to pass this threshold.[84] EPA also announced that it will issue a proposal for CO_2 at existing sources under Section 111(d) by mid-2014.[85] At this point, I do not believe that there is any resolution on exactly what standards EPA will propose for existing units, though EPA has made clear that carbon capture and sequestration will not be required.

Unit-specific emission rates standards—such as the proposed CO_2 NSPS for new sources—are one of several plausible options. Unit-specific standards could categorize power plants by fuel and technology type, each with its own maximum

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[84] See EPA, 2013. EPA Proposes Carbon Pollution Standards for New Power Plants/Agency takes important step to reduce carbon pollution from power plants as part of President Obama's Climate Action Plan. http://yosemite.epa.gov/opa/admpress.nsf/0/da9640577ceacd9f85257beb006cb2b6!OpenDocument
[85] *Id.*

emission rate.[86] Other regulatory design options for existing units covered under Section 111(d) include maintaining a state-wide average maximum emission rate, or market-based (e.g. cap-and-trade) approaches.

On August 5, 2013, ICF International, a primary consultant for EPA responsible for modeling the impact of environmental regulations, released a whitepaper exploring options available to the EPA.[87] This paper discusses a number of non-flexible options, such as requiring specific heat-rate improvements or certain retirement deadlines, as well as flexible options, such as standard based cap-and-trade mechanisms.

While it is unclear which mechanism will be proposed as of yet, it is increasingly certain that any proposal will effectively impose either a real or effective cost on carbon emissions—such as through cap-and-trade or performance standard. In the current regulatory environment, it is inappropriate to still consider a zero cost as a reasonable baseline, much less the only option examined.

Q Is the Company aware of the President's June 2013 memorandum directing the EPA to issue carbon regulations under Section 111(d)?

A Yes. The Company acknowledges the President's announcement,[88] and the existence of the memorandum.[89] Nonetheless, the Company dismisses the President's directive for the EPA to comply with federal law and regulate carbon emissions from existing power plants expediently, and claims that identifying any compliance costs would be "speculative."[90]

[86] Units that are out of-compliance could undertake upgrades to improve efficiency, although these kinds of upgrades are expensive and can only achieve small, one-time changes to emission rates.
[87] Attached as Exhibit TFC-8.
[88] See Response to Intervenors Request 1-34
[89] See Response to Intervenors Request 1-38
[90] See Response to Intervenors Request 1-38: "Since the directive at this time is only a memorandum and final regulations for existing sources will not be forthcoming until after 2015, EKPC objects to identifying any level of compliance costs as it requires speculation concerning the future of rulemaking."

Q Has the Company discussed the potential impacts of Section 111(d) elsewhere, publicly?

Yes. The Company's President and CEO, Anthony Campbell recently testified before the United States Congress regarding "EPA's Proposed Greenhouse Gas Standards for Electric Power Plants."[91] Mr. Campbell claims that "EKPC's greatest concern relates to regulations for existing sources."[92] He proceeds to claim that:

> Even if we ignore the economic devastation that will result from an adverse existing source rule, Congressional action is also necessary to prevent Section 111(d) from being used to regulate GHG emissions from existing power plants.[93]

If Mr. Campbell is correct that such a regulation would have costly consequences and that legislation would be required to prevent it from happening, then the Company must (at the very least) plan for the prospect of that regulation occurring.

Q Is the government of the Commonwealth of Kentucky preparing for compliance with Section 111(d)?

A Yes. The Kentucky Energy and Environment Cabinet, Governor Beshear, and Administrator Gina McCarthy (U.S. EPA) have discussed the impacts of Section 111(d) on Kentucky.[94] The Cabinet has developed a detailed analysis of the impacts of the rule and proposed solutions for the Kentucky going forward. The possible compliance options for Kentucky include: improving units' efficiency, increasing demand-side resources, increasing renewable energy, switching to

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[91] Testimony of Anthony S. "Tony" Campbell, Subcommittee on Energy and Power, Committee on Energy and Commerce, United States House of Representatives, November 14, 2013. Attached as Exhibit TFC-9.
[92] *Id*. p.5
[93] *Id*. p.5
[94] Letter to Administrator Gina McCarthy US EPA, Kentucky Energy and Environment Cabinet, October 22, 2013 and attachment "Greenhouse Gas Policy Implications for Kentucky under Section 111(d) of the Clean Air Act." Both are attached as Exhibit TFC-3.

natural gas, replacing 800 MW with carbon capture and sequestration (CCS), and reforesting.[95]

Q Is assuming that there will be no cost for future carbon emissions a valid mechanism for handling the risk to EKPC from these regulations?

A Not at all. In fact, ignoring the economic impact of the impending rules ascribes them a value of exactly zero dollars – i.e. the Company speculates that there will be no cost at all to comply.[96] I am quite certain that, unless EPA is prevented from implementing a regulation on carbon, a real or imputed cost will be established for emissions of CO_2 from existing sources, including from EKPC's coal-fired generating units. The Commonwealth of Kentucky is taking the prospect of Section 111(d) seriously, and the Company should do so in this filing.

Q Do you have an opinion regarding a reasonable carbon price forecast for use in cases such as this?

A Yes. Synapse tracks the state of CO_2 policy and regulation, and utility views of regulatory initiatives, which we make available to the public. Synapse has recently released an updated carbon price discussion paper and forecast, attached as Exhibit TFC-10. The carbon price presented in the paper is meant to be a proxy for the costs of compliance with "near-term regulatory measures to reduce greenhouse gas emissions, coupled with longer-term cap-and-trade or carbon tax legislation."[97]

Synapse breaks the forecast into a bounded region of likely prices, all starting in 2020. The mid-case starts at \$15/ton in 2020 and rises to \$60/ton by 2040 (2012\$); this case represents our best estimate of a reasonable base case. The

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[95] *Id.* p.13

[96] Since the Company does not review a range of risk for any factor, much less environmental regulations, the analysis must represent the Company's base set of assumptions, or average outcome. By setting the price of CO_2 at zero, the Company, in fact, speculates on a <u>very</u> certain outcome: that there will be absolutely no CO_2 cost in the future. For example, if the base price were a non-zero dollar value, the Company might explain that it could be higher, or it could be zero – but the average outcome is somewhere in between. Since it is unlikely that the Company will be paid to emit CO_2, an average price of zero means that there is no chance that the price could be greater than zero.

[97] Synapse Energy Economics, 2013 Carbon Dioxide Forecast, November 1, 2013. Attached as Exhibit TFC-10.

attached discussion paper details the background and assumptions underlying the forecast.

Q Were you able to modify the Company's workbooks to review a different CO_2 price forecast?

A No. As I discussed previously, the Company did not provide nearly enough information to calculate the impact of a CO_2 price on its decision-making process. Such a price would clearly influence dispatch decisions and the market price of electricity, but because the electricity price forecast is likely incorrect and the Company has withheld critical information about the function and cost of its units, I cannot provide a reasonable alternative analysis with a CO_2 price forecast intact.

However, using Cooper 2 as a proxy for Cooper unit 1,[98] it is notable that according to the Company's own estimates, the dispatch costs [redacted][99] implying that under the PJM construct, EKPC loses money [redacted] Presuming, as I discussed earlier, that the market energy price will not [redacted], Cooper unit 1 is likely to remain on or nearly marginal for the indefinite future. The addition of a carbon price or regulatory restriction would likely increase costs at Cooper unit 1 to a greater degree than market energy prices due to the carbon-intensity of coal generation compared to that of natural gas generation (assuming a mix of both resources are setting the marginal price). Therefore, I would expect that under a carbon price – even a fairly low carbon price – Cooper unit 1 would be non-economic much of the year.

[98] The Company did not provide sufficient information to characterize the all-in dispatch cost of Cooper unit 1, despite the key importance of this unit to the instant proceeding.

[99] On-peak energy prices produced in "Energy Prices" tab in PSC 5 - CONFIDENTIAL_Proposal Evaluation_Energy Calculated.xlsx. Peak 5x16 market energy prices rise from [redacted] MWh in 2013 to [redacted] /MWh in 2015. Cooper 2 variable cost from #13c vii and xii - RFP-Unit-data - CONFIDENTIAL.xlsx is [redacted] /MWh in 2013 and $[redacted] MWh in 2015.

7. <u>THE PROJECT PUTS UNNECESSARY RISK ON DISTRIBUTORS AND RATEPAYERS</u>

Q If a utility makes a poor decision, what options are available to utility customers in an RTO construct?

A Generally, if there is retail choice available to customers, or if large industrial customers are able to procure directly from the wholesale market, consumers or distributors will find alternative suppliers, or turn directly to the wholesale market (see Table 1).

Q Do the Company's distributors have the option of leaving EKPC to purchase from the PJM market directly?

A No, it appears that they do not have this option. According to Fitch Ratings:

> EKPC supplies wholesale power to its distribution members **pursuant to long-term, take-or-pay contracts, extending through Jan. 1, 2051**, requiring members to purchase nearly all of their power requirements from EKPC to meet distribution system needs (emphasis added).[100]

Thus distributors and their ratepayers are bound to the Company's decisions through 2051—past the expected life of the Cooper unit 1 project.

Q What are the financial risks for distributors and ratepayers if the Commission approves the CPCN?

A If the Commission approves the CPCN for Cooper unit 1, the investment will be recovered from ratepayers through the Company's distributors whether the project is economically viable or not. If the Cooper Unit 1 project does not generate a positive value—after all costs are accounted for—then ratepayers will be paying more than they would have paid by relying on the market or through another option. However, as explained above, this option will not be available to them.

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[100] See: http://www.businesswire.com/news/home/20131025005890/en/Fitch-Upgrades-East-Kentucky-Coops-Revenue-Bonds. Attached as Exhibit TFC-11.

8. THE COMPANY HAS NOT PROVIDED SUFFICIENT INFORMATION IN THIS CASE

Q Has the Company produced all of the information needed to thoroughly review and evaluate its application?

A No. The Company has not been forthcoming with all relevant information in this case, as I have noted throughout my testimony. In both the first and supplemental round of data requests, Intervenors posed critical modeling and operational questions for which responses were absent or massively incomplete. In many cases, we asked follow-up questions to seek clarity on questions that were highly relevant to the case at hand. Several examples include:

- The Company failed to provide historical costs for Cooper unit 1 and other key units.[101] The historical costs of Cooper unit 1 and other EKPC units are absolutely relevant to the case. The historical performance of the unit in question provides an indication for how much it will cost in the future.
- The Company failed to produce projected costs for Cooper unit 1.[102] The projected cost of operating Cooper unit 1 is at the very heart of this case since the project is being compared to other bids and proposals on a cost basis.
- The Company failed to produce past operations of Cooper unit 1 and other key units.[103] The past performance of the Company's plants is indeed relevant in examining how the Company is planning on running them in the future, among other aspects of the analysis.

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[101] The response to Intervenors' Supplemental Data Request 5 for historical annual costs of the Company's plants states: "the historical annual costs for the plants have no bearing on determining the reasonableness of the project."

[102] The response to Intervenors' Supplemental Data Request 6 for projected annual costs of the Company's plants states: "the projected annual costs for the plants have no bearing on determining the reasonableness of the Cooper Unit 1 project." The costs of running the Company's fleet were provided in Intervenors' First Set Data Request 13c.vii and 13c. xii., however, this was only provided for the Company's "base case" which assumes that Cooper unit 1 is retired.

[103] The response to Intervenors' Supplemental Data Request 12a for historical annual generation of the Company's plants states: "the historical annual generation for the plants has no bearing on determining the reasonableness of the Cooper Unit 1 project."

- The Company will not provide descriptions or cost breakdowns for its own proposals except for the Cooper unit 1 project.[104] Several Company self-build options are listed in Brattle Group's analysis but these are not described in testimony and sufficient information on these other options has not been provided. Again, the heart of the case is comparing the costs of various projects to one another.

- The Company's plans for the future of the Dale plant are unclear.[105] The retirement of the Dale plant is not explicitly mentioned in the Company's direct testimony [redacted] The Company's planned operation of its fleet is important in evaluating the future role of Cooper unit 1.

- The Company will not provide the information it reviewed on potential costs of future environmental regulations.[106] Potential future costs of environmental regulations are important in evaluating whether to invest more in the Cooper plant. Projects should be evaluated against one another only after taking environmental risks and costs into account.

Q Has sufficient evidence been provided to justify the Cooper unit 1 project?

A No. The issues listed above are all important in evaluating whether the Cooper unit 1 project is the best option for the Company. As a result, the Commission and

[104] The response to Intervenors' Supplemental Data Request 14c for descriptions and breakdowns of costs for all of the Company's self-build options that were evaluated states: "EKPC objects to providing detailed descriptions of any proposal other than the selected alternative. The process was designed to treat all proposals equally and fairly and this request segregates the self-build options thus placing them on a separate platform. In order to preserve the integrity of the bidding process, now and in the future, EKPC will not disclose the details of any proposal other than the one selected."
[105] The response to PSC Staff Second Set Data Request 2b for the Company's plans for retiring any of its units states: "EKPC does not have any plans to retire any of its units at this time."
[106] The responses to Intervenors' Supplemental Data Requests 31a, 32a, and 33a asking for the Company's documents reviews on the potential Cooper Units 1 and/or Unit 2 costs for compliance with Clean Water Act 316(b), Resource Conservation and Recovery Act, and Clean Water Act ELG's, respectively, all include the statement: "EKPC rejects this request on the grounds that it is overly broad and will not result in relevant evidence concerning the reasonableness of the proposed Cooper Unit 1 project."

other parties involved are being denied the opportunity to properly scrutinize the Company's analysis and results.

9. <u>FINDINGS</u>

Q What are your findings?

A I conclude that the Company has failed to provide adequate justification for the investment in Cooper unit 1 for the following reasons:

1) <u>The Company no longer needs to procure additional capacity.</u> At the time the RFP for capacity was issued, the Company was a load balancing authority and was procuring most of its own capacity and energy. However, it is now part of the PJM market and, therefore, does not need to supply its own capacity and energy. The Company has also stated that it anticipates a surplus compared to its PJM capacity obligation.

2) <u>The market valuation analysis likely overestimates the value of the project.</u> The Company's energy price forecasts are unreasonable given that [redacted] in energy prices that leads to large "energy margins" for the project. Using an adjusted energy price based on the Company's trajectory of natural gas prices leads to significantly lower valuation of the project—an [redacted]% reduction in the project's original NPV after 10 years and a [redacted]% reduction after 25 years.

3) <u>The bids received by the Company included alternatives that have a similar or higher value than the project.</u> The construct set up by the Brattle Group to evaluate responses to the RFP valued a bid for wind energy higher than the Cooper unit 1 retrofit project--$[redacted] for the 20-year valuation of the wind project compared to $[redacted] for the Cooper unit 1 project over the same period. The wind PPA valuation was also higher in

terms of dollars per MW-year. The PPA includes an energy cost of $[redacted]/MWh, which should be attractive to the Company.[107]

4) The Company's analysis does not account for other future environmental regulations and associated compliance costs. The Company has ignored the risks of impending environmental regulations and its potential costs to Cooper unit 1. The costs and risks that new regulations pose are simply too large to neglect, especially altogether. I estimate that the associated capital costs could range from $8 million under lenient regulations and $92 million for strict regulations.

5) The Company's analysis does not account for potential greenhouse gas regulation and associated compliance costs. The Company has acknowledged the possibility of carbon regulation in the future yet has not included the potential costs of such a regulation. It is effectively assuming an unreasonable carbon cost of $0.

6) The project puts unnecessary risk on the Company's distributors and their ratepayers. The Company's distributors and their ratepayers are contractually bound by decisions made by the Company. Even if the PJM market for energy or capacity should become more attractive than what is provided by the Cooper unit 1 project, the distributors will not have the option to buy off the PJM market themselves.

7) The Company has not provided sufficient information in this case. Unfortunately, the Company has not provided enough supporting evidence for this case—in some instances after being asked several times by the Intervenors. In my opinion, the Company is leaving the Commission and Intervenors without the necessary tools to fully evaluate the Company's application.

[107] 20-year NPV for project "[redacted]" in PSC 5 - CONFIDENTIAL_Proposal Evaluation_Energy Production.xls and "[redacted]" in PSC 5 - CONFIDENTIAL_Proposal Evaluation_Energy Calculated.xls

Q **What are your recommendations for this Commission?**

A For the reasons listed above, I recommend that the Company's application for CPCN for Cooper unit 1 be denied in this case.

Q **Does this conclude your testimony?**

A It does.

CERTIFICATE OF SERVICE

I certify that I had filed with the Commission and served via U.S. Mail and electronic mail the foregoing Direct Testimony of Tyler Comings (Public Version) to East Kentucky Power Cooperative on November 27, 2013 to the following:

Mark David Goss
Goss Samford, PLLC
2365 Harrodsburg Road, Suite B325
Lexington, KY 40504

Patrick Woods
East Kentucky Power Cooperative, Inc.
4775 Lexington Road
P. O. Box 707
Winchester, KY 40392-0707

Michael L. Kurtz
Kurt J. Boehm
Boehm, Kurtz & Lowry
36 East Seventh Street, Suite 1510
Cincinnati, OH 45202

Anthony Raduazo

Tyler Comings

Associate
Synapse Energy Economics
485 Massachusetts Ave., Suite 2, Cambridge, MA 02139
(617) 453-7050 • fax: (617) 661-0599
www.synapse-energy.com
tcomings@synapse-energy.com

PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. Associate, July 2011 – present.
Provides consulting services, conducts research, and performs economic impact analysis of renewable energy and energy efficiency investments. Recent work includes developing economic impacts of energy efficiency programs in Vermont and a scenario of clean energy investments for the U.S.

Ideas42, Boston, MA. Senior Associate, 2010 – 2011.
Organized studies analyzing behavior of consumers regarding finances, and worked with top researchers in behavioral economics. Managed implementation and data analysis for a study of mitigation of default for borrowers that were at-risk of delinquency. Performed case studies for World Bank on financial innovations in developing countries.

Economic Development Research Group Inc., Boston, MA. Research Analyst, Economic Consultant, 2005 – 2010.
Performed economic impact modeling and benefit-cost analyses using IMPLAN and REMI for transportation and renewable energy projects, including support for Federal stimulus applications. Performed statistical modeling, including results on the timing of effects of highway construction on economic growth in Appalachia. Developed a unique Web-tool for the National Academy of Sciences on linkages between economic development and transportation, and presented findings to state government officials around the country. Created economic development strategies and improvements to company's economic development software tool.

Harmon Law Offices, LLC., Newton, MA. Billing Coordinator, Accounting Liaison, 2002 – 2005.
Allocated IOLTA and Escrow funds, performed bank reconciliation and accounts receivable. Projected legal fees and costs for cases at the firm.

Massachusetts Department of Public Health, Boston, MA. Data Analyst (contract), 2002.
Designed statistical programs using SAS based on data taken from health-related surveys. Extrapolated trends in health awareness and developed benchmarks for performance of clinics and other healthcare facilities for statewide assessment.

EDUCATION

Tufts University, Medford, MA, MA Economics, 2007.

Graduate work in micro- and macroeconomics, econometrics, development economics, and international finance (Fletcher School of Law and Diplomacy).

Boston University, Boston, MA, BA Mathematics and Economics, 2002. *Cum Laude*, Dean's Scholar.

ADDITIONAL SKILLS

Software: MS Office, STATA, SPSS, SAS, REMI, IMPLAN, Mathematica
Programming: C++
Languages: Conversant in French

RELEVANT REPORTS

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Resume dated August 2013.

SECTION 9.0

COMPLIANCE PLANNING

9.1 Introduction

807 KAR 5:058 Section 8(5)(f) The resource assessment and acquisition plan shall include a description and discussion of: (f) Actions to be undertaken during the fifteen (15) years covered by the plan to meet the requirements of the Clean Air Act amendments of 1990, and how these actions affect the utility's resource assessment.

EKPC is currently in compliance with the following CAA rules:

- New Source Performance Standards (NSPS);
- New Source Review (NSR);
- Title IV of the CAA and the rules governing pollutants that contribute to Acid Deposition (Acid Rain program);
- Title V operating permit requirements (Title V);
- Summer ozone trading program requirements promulgated after EPA action on Section 126 petitions and the Ozone SIP Call (Summer Ozone program);
- Clean Air Interstate Rule (CAIR).

On January 28, 2004, the United States filed a complaint alleging that EKPC was out of compliance with the Prevention of Significant Deterioration provisions in Part C of Subchapter I of the Act, 42 U.S.C. §§ 7470-92 (NSR); NSPS, Title V and the federally-enforceable State Implementation Plan ("SIP") developed by the Commonwealth of Kentucky. EKPC and the United States settled this action and entered into a Consent Decree memorializing the terms of the settlement which was entered by the Court on September 27, 2007 (NSR CD).

On June 30, 2006, the United States and the Commonwealth of Kentucky filed a complaint alleging that EKPC was in violation of the Acid Rain Program and Title V. This matter was also settled and the Consent Decree capturing the terms of the settlement was entered by the Court on November 30, 1997 (Acid Rain CD).

EKPC in partnership with the Environmental Protection Agency and the Kentucky Environmental Cabinet has worked diligently to implement the requirements of these two Consent Decrees and is in compliance with each. The relevant provisions of these CDs are in the process of being added to EKPC's Title V permits for Spurlock, Cooper and Dale stations.

New CAA Rules

Looking forward to the 15 years covered by this plan, EKPC anticipates complying with the following future rules or existing CAA rules that will generate future rules or requirements:

- Green House Gas (GHG) Tailoring Rule revisions to NSR;
- Cross-State Air Pollution Rule (CSAPR) promulgated by EPA on remand of CAIR with the goal of replacing CAIR;
- Electric Generating Unit Maximum Achievable Control Technology rule. EPA named this rule the Mercury and Air Toxics Standards (MATS) when the final rule was issued in December of 2011;
- National Ambient Air Quality Standards (NAAQS) for Sulfur Dioxide (SO_2), Nitrogen Dioxide (NO2), Carbon Monoxide (CO), Ozone, Particulate Matter (PM), Particulate Matter 2.5 microns or less (PM 2.5) and Lead;
- Clean Air Visibility (Regional Haze) rule to protect National Parks and pristine areas designated as Class I areas by EPA.

MATS Rule

On March 16, 2011, EPA issued the proposed EGU MACT rule to reduce emissions of toxic air pollutants from new and existing coal- and oil-fired EGUs. EPA finalized the MATS rule on December 16, 2011 to reduce emissions of heavy metals, including mercury (Hg), arsenic, chromium, and nickel, and acid gases, including hydrogen chloride (HCl) and hydrogen fluoride (HF). The MATS allows sources to control surrogate emissions to demonstrate control of HAP metals and HAP acid gases. Non-Hg metallic toxic air pollutants are represented by PM emission limits because these metals travel in particulate form in boiler gas paths. HCL and /or SO_2 are surrogates for all acid gas HAPs since they are controlled by the same mechanisms.

Under MATS mercury emissions are subject to limits and units must measure mercury emissions directly to demonstrate compliance. EGUs must comply with the mercury, SO_2 or HCL, and PM limits in the MATS beginning in the Spring of 2015. If units are in the process of installing additional pollution control equipment and cannot complete the work by this initial compliance date, an additional year to begin compliance can be granted by Kentucky Cabinet.

EKPC has conducted emissions testing of its units to determine the best way to achieve compliance with the MATS rule. This testing is ongoing and is being conducted as part of an extensive engineering effort to ensure that EKPC's units comply with this rule. The pollution control upgrades on Spurlock 1 and 2 and Cooper 2 as part of NSR CD compliance place EKPC's units ahead of most EGU units for MATS compliance. Likewise, EKPC's new units (Spurlock 3 and 4) are equipped with Best Available Control Technology (BACT) and are likely to meet the MATS rule limits without additional controls.

The Cross-State Air Pollution Rule

On July 6, 2011 the EPA finalized CSAPR to require 27 states (Kentucky included) and the District of Columbia to significantly improve air quality by reducing power plant emissions that contribute to ozone and fine particle pollution in other states. This rule replaces EPA's 2005 CAIR rule that was remanded to EPA by the U.S. District Court of Appeals. CSAPR requires significant reductions in SO_2 and nitrogen oxides (NO_X) emissions that cross state lines. These pollutants react in the atmosphere to form fine particles and ground-level ozone and are transported long distances, making it difficult for other states to achieve the National Ambient Air Quality Standards (NAAQS). The rule called for the first phase emission reduction compliance to begin January 1, 2012 for annual SO_2 and NO_X and May 1, 2012 for ozone season NO_X. The second phase of SO_2 reductions was to begin January 1, 2014.

On December 30, 2011, CSAPR was stayed by the United States Court of Appeals for the District of Columbia in response to industry petitions challenging the rule. Briefing and oral argument in the appeal will be complete on April 13, 2012 and the Court will issue a decision sometime later in 2012. The Court has ordered EPA to continue to administer CAIR while CSAPR is stayed. The earliest that EKPC and other utilities may be subject to CSAPR is 2013 and it is likely to be later. CSAPR is likely to be remanded to EPA for revision which will further delay the CSAPR rule.

GHG Tailoring Rule

On May 13, 2010, the EPA issued a final rule that establishes emission thresholds for addressing GHG emissions from stationary sources under the CAA permitting programs. The GHG Tailoring rule sets GHG thresholds for applicability under the NSR rules and Title V program. GHGs are considered one pollutant for NSR, which is composed of the weighted aggregate of CO_2, N_2O, SF_6, HFCs, PFCs, and methane (CH_4) into a combined CO_2 equivalent (CO_{2e}).

If any of the stations undergo a modification that would result in a net increase of 75,000 tons per year or more of CO_2 equivalents (CO_{2e}), EKPC must obtain an NSR permit for the modification which includes the analysis of Best Available Control Technology (BACT) for GHGs and the implementation of BACT on the modified unit.

EKPC routinely analyzes all capital projects for the potential need to undergo pre-construction NSR permitting. This NSR review process has been expanded to include an analysis of GHG emissions. EKPC's NSR CD also includes a future covenant from EPA that allows EKPC some flexibility with respect to the NSR rules until December 31, 2015.

National Ambient Air Quality Standards (NAAQS)

EPA recently promulgated revisions to the NAAQS for fine particulate matter ($PM_{2.5}$), 1-hour SO_2 and 1-hour nitrogen dioxide (NO_2) that are substantially lower than the existing NAAQS. EPA and the Kentucky Cabinet will work together to determine whether the Commonwealth is in compliance with these standards, as well as existing NAAQS for Ozone, CO, Lead and PM, by analyzing data from monitors stationed across Kentucky that measure the concentration of these pollutants in the air and by computer models that estimate concentrations of these pollutants. If a county or counties are designated to be in nonattainment for a NAAQS, the Cabinet will work with major sources contributing to nonattainment to implement Reasonably Achievable Control Technology (RACT) retrofits to bring the areas into attainment. Further, no permits can be approved by the Cabinet without a NAAQS compliance demonstration which involves submitting computer modeling of emissions that shows that the Commonwealth will stay in attainment despite the permitted activity.

CO

In January 2011, EPA proposed to retain the current primary CO NAAQS of 9 ppm (8-hour) and 35 ppm (1-hour). This rule was finalized in August 2011. As of September 27, 2010, all CO areas have been designated as maintenance areas.

SO_2

EPA revised the primary SO_2 NAAQS in June 2010 to a one-hour standard of 75 ppb. On June 2, 2011, Kentucky made area designation recommendations for the new SO_2 standard. The State recommended that Jefferson County be designated as a non-attainment area and that the remainder of the state be designated as unclassifiable or attainment. Area designations for the new SO_2 standard are expected to be finalized in June 2012. The current secondary 3-hour SO_2 standard is 0.5 ppm. EPA proposed to retain both the SO_2 and NO_2 secondary standards in July 2011 and this rule has not yet been finalized.

NO_2

EPA revised the primary NO_2 NAAQS in January 2010. The new primary NAAQS for NO_2 is a one-hour standard of 100 ppb. EPA retained the existing primary and secondary annual standard of 53 ppb. On January 11, 2011, Kentucky made area designation recommendations for the new NO_2 standard and recommended that areas with monitors showing compliance be designated as in attainment and that the remainder of the state be designated as unclassifiable. On June 28, 2011, EPA responded indicating its intent to designate the entire country as unclassifiable/attainment due to the limited availability of monitoring data. On August 3, 2011, the state responded to EPA's proposed revision requesting that the areas that show compliance with area monitors be designated as attainment and that the remainder of the state be designated as unclassifiable/attainment. Area designations for the new NO_2 standard were expected to be finalized in January 2012 and remain outstanding. Under the new rule, a new monitoring system will be implemented to measure NO_2 concentrations. Three years after the new monitoring system is implemented, EPA will re-evaluate the existing data and re-designate areas as necessary (2016/2017). An initial compliance deadline of 2021/2022 is contemplated.

Ozone

Currently, the 1997 8-hour ozone NAAQS of 80 ppb is in place. In 2008, EPA finalized a revised rule, lowering the standard to 75 ppb. This standard was challenged in court, and as a result EPA undertook a voluntary review of the 2008 ozone NAAQS. The litigation challenging the 2008 standard was held in abeyance while the standard was re-evaluated. In January 2010, EPA proposed that the standard be lowered even further to a range within 60-70 ppb. At the same time, EPA proposed a new seasonal secondary standard in the range of 7 to 15 ppm. Ultimately, the proposed final rule was withdrawn by EPA at the request of President Obama. The standard will now be reviewed during the course of its normal five year review. As such, a new ozone standard is expected to be proposed in the fall of 2013 and finalized during the summer of 2014. In the interim, EPA has turned back to implementation of the 2008 standard and plans to make area designations by May 31, 2012. These area designations will be based on the recommendations made by states in 2009. In 2009, Kentucky recommended that a number of counties be designated as nonattainment. In 2011, Kentucky updated these recommendations and recommended that the entire state be designated as attainment or attainment/unclassifiable. In December 2011, EPA revised the state's recommendation and indicated its intent to designate Boone, Campbell and Kenton counties as non-attainment and the remainder of the state as unclassifiable/attainment.

Particulate Matter ($PM_{2.5}$)

In 1997, EPA adopted the 24-hour fine particulate NAAQS ($PM_{2.5}$) of 65 $\mu g/m^3$ and an annual standard of 15 ug/m3. In 2006, EPA revised this standard to 35 $\mu g/m^3$, and retained the existing annual standard. In December 2004, the following counties were designated as nonattainment under the 1997 standard: Boone, Campbell, Kenton, Boyd, Lawrence (partial), Bullitt, and Jefferson. This was modified in April 2005 and in October of 2009, the entire state of Kentucky was designated as unclassifiable/attainment under the 2006 standard.

Lead

In October 2008, EPA strengthened the primary lead NAAQS from 1.5 $\mu g/m^3$ to 0.15 $\mu g/m^3$. EPA has designated the state of Kentucky as unclassifiable/attainment for the lead NAAQS.

Currently, EKPC's units are not located in any areas that are predicted to be in nonattainment. EKPC anticipates that existing controls on its coal generation and new controls and compliance strategies adopted to comply with the MATS rule and CSAPR will ensure that the fleet will also comply with any future NAAQS requirements.

Regional Haze Rule

The Regional Haze Rule has triggered the first in a series of once-per-decade reviews of impacts on visibility at pristine areas such as national parks, with a focus in the first review on large emission sources put into operation between 1962 and 1977. This first review, just now being completed, targets Best Available Retrofit Technology (BART) controls for SO_2, NO_x, and PM emissions. The threshold for being exempt from BART review is very stringent, such that coal-fired electrical generating stations are almost universally subject to BART.

A BART assessment includes an evaluation of SO_2 controls and post-combustion NO_x controls. Cooper Units 1 and 2 are the only EKPC units subject to BART. EKPC has submitted its Regional Haze compliance plans to the Cabinet and the Cabinet submitted the plan for the Commonwealth to EPA who has proposed to adopt it formally into Kentucky's State Implementation Plan (SIP). EKPC is in the process of installing SO_2, NOx and PM controls on Cooper 2 to comply with the NSR CD, the Regional Haze rule, MATS, CSAPR and any NAAQS requirements. EKPC has committed in the Regional Haze compliance plan to install parallel controls on Cooper 1.

Additional Non-CAA New Rules

For completeness EKPC is providing a summary of new Clean Water Act (CWA) rules and the proposed Coal Combustion Residuals (CCR) rule.

New CWA 316(b) rule

EPA published its proposed rule to regulate cooling water intake structures (CWIS) at existing facilities on April 20, 2011. The rule is scheduled to be finalized in July 2012 and will include several implementation milestones. The proposed rule will set requirements that establish Best

Technology Available (BTA) for minimizing adverse environmental impact from impingement mortality and entrainment mortality due to operation of the CWIS.

Impingement mortality results from impingement of aquatic organisms on the cooling water intake structure, typically traveling water screens used to prevent debris from entering the cooling water circulating pumps and the steam condenser tubes. Entrainment mortality results when organisms that are entrained through the cooling water intake structure die due to the combined effects of mechanical stress from the pumps, thermal stresses from the heat transferred from the condensers, and application of any biocides.

Impingement Mortality

The rule requires that all facilities with existing traveling screens retrofit them with "fish-friendly" Ristroph modifications, consisting of smooth screen mesh, fish buckets installed at the base of each screen panel, low-pressure washes for fish located before the high pressure wash for debris, separate collection troughs for fish and debris with guard rails or barriers, and a fish return system. Continuous rotation of the traveling screens is not required by the proposed rule but this technology may be necessary in the event that numerical impingement mortality standards are relevant to a site.

The intake velocity then dictates the path for compliance with the impingement mortality portion of the rule. For facilities with traveling screens, intake velocity is generally interpreted to be equivalent to the through-screen velocity; otherwise it is the velocity at the point of withdrawal. Facilities that can demonstrate that design intake velocities are equal to or less than 0.5 feet per second (fps) are not subject to the numeric impingement mortality performance standards and are not required to conduct impingement monitoring. Facilities must operate and maintain their intake screen such that no more than 15 percent of the surface area is occluded by debris, and they must ensure that impingeable fish have the means to escape or be returned to the source waterbody. Facilities that cannot demonstrate that the design intake velocity is no more than 0.5 fps must conduct compliance monitoring for intake velocity to demonstrate the actual intake velocity remains below 0.5 fps.

Facilities that have through-screen velocities in excess of 0.5 fps must conduct bi-weekly impingement monitoring and are required to achieve impingement mortality rates of less than 12 percent on an annual basis and less than 31 percent on a monthly basis. The rule indicates that the numerical impingement mortality performance standards apply to "species of concern" but is ambiguous on the definition of this term. There is some question as to whether these performance standards will be included in the final rule.

Entrainment Mortality

Under the proposed rule, facilities that are equipped with closed cycle cooling, including wet or dry cooling towers or closed loop cooling ponds, most likely will be considered to be BTA for entrainment, but the permitting authority will still need to make that determination. Facilities not so equipped must determine if their actual intake flow is greater than 125 million gallons per day (MGD). Under the proposed rule, facilities that have withdrawn an average of over 125 MGD over the last three years would have to prepare four documents evaluating the feasibility, costs, and benefits of potential measures to reduce entrainment and entrainment mortality. The proposed rule does not have a blanket requirement to mitigate entrainment but leaves the decision to require such measures to the permitting authority (e.g., the Kentucky Cabinet). The studies required for facilities with actual intake flows greater than 125 MGD include:

- An Entrainment Characterization Study (proposed at 40 CFR 122.21(r)(9) of the draft rule);
- A Comprehensive Technical Feasibility and Cost Evaluation Study (proposed at 40 CFR 122.21(r)(10));
- A Benefits Evaluation Study (proposed at 40 CFR 122.21(r)(11)); and
- A Non-Water Quality and Other Environmental Impacts Study (proposed at 40 CFR 122.21(r)(12)).

The proposed rule would require that at least two technologies (closed cycle cooling and the use of fine mesh panels on the traveling screens) be evaluated for cost, feasibility, effectiveness, monetized and non-monetized benefits. The Entrainment Characterization Study must be submitted to the permitting authority for review and approval. Under the proposed rule, each of the studies also requires peer review by a third party. Based on the findings of these four studies, the permitting authority establishes BTA on a case-by-case basis. Facilities with actual intake flows less than 125 MGD are not required to perform the studies but are still subject to a BTA determination by the permitting authority. Under the proposed rule, new units placed into service at existing facilities would be required to reduce entrainment mortality to levels commensurate with the use of closed cycle cooling. Retrofitting with closed cycle cooling at an existing facility will be very expensive and will likely result in a very adverse cost-to-monetized benefit ratios. On the other hand, achieving levels of entrainment mortality reduction commensurate with closed cycle cooling using other technologies may be very difficult.

Potential Spurlock Station 316(b) Requirements

Spurlock Station Cooling Water System Description

The cooling system consists of four evaporative mechanical draft cooling towers with a combined makeup water requirement of 21.6 MGD. Spurlock Station withdraws water for cooling tower makeup and other purposes from the Ohio River. The station's CWIS consists of two submerged passive wedgewire intake screens, an intake sump, and three vertical makeup water pumps. The screens consist of welded Type 304 stainless steel wedgewire strainer elements with circumferential 1/8 inch slot construction. They each have a design capacity of 14,050 gallons per minute (gpm) and a maximum through-slot velocity 0.5 fps at design flow. The calculated velocity through the strainer elements is 0.466 fps. Debris collected in the screen is periodically cleaned by a compressed air backwash system which is capable of producing a backwash pressure of 150 pounds per square inch (psi).

Makeup water is withdrawn through the two submerged intake screens by gravity and flows into the intake sump. Each pump is rated for 5,000 gpm at 141.5 feet of head and is driven by a 250 hp/1.15 service factor, 1,180 rpm motor manufactured by General Electric. The cooling water intake structure does not employ traveling water screens.

Spurlock Station Compliance Options

Spurlock Station is not equipped with traveling screens and therefore is not required to retrofit with Ristroph modifications to its CWIS. The station's passive screens have a maximum design through-screen velocity of 0.5 fps and a calculated through-screen velocity of 0.466 fps; therefore under the proposed rule the station would not be required to perform impingement monitoring or be subject to the impingement mortality performance standards. The station would need to submit documentation of meeting the through-screen velocity threshold (i.e., the

Impingement Mortality Reduction Plan required under Section 122.21(r)(6)), which would include velocity monitoring records and documentation of the technologies and operational measures taken to ensure actual intake velocity does not exceed 0.5 fps.

Both the design intake flow (21.6 MGD) and actual intake flow (5.9 MGD for the period January 2008 through December 2010) are significantly less than the 125 MGD actual intake flow threshold that would require the station to conduct the Entrainment Characterization Study and other analyses described in Section 2.1.2. It is still subject to a site-specific determination of BTA for entrainment by the Kentucky Cabinet on a Best Professional Judgment basis. It is unlikely that additional controls for entrainment mortality will be necessary because:

- The facility uses closed cycle cooling which is considered to achieve high levels of reduction in cooling water flow and entrainment rates;
- The cooling water intake structure would be compliant with the requirements of the 316(b) Phase I rule for new facilities;
- The quantity of cooling water relative to the Ohio River discharge is very small indicating that entrainment losses from the ecosystem will be minimal; and
- Passive wedgewire screens were classified as a pre-approved BTA technology in prior EPA rulemakings.

Potential Cooper Station 316(b) Requirements

Cooper Station Cooling Water System Description

The cooling system at the Cooper Station consists of two condensers equipped with once-through cooling systems. The permanent intake structures are located in Lake Cumberland approximately 25 feet from the shoreline and withdraw water at an elevation of 671 feet mean sea level (MSL), which under full pool conditions (723 feet MSL) is approximately 52 feet below the water surface. Ongoing repairs at Wolf Creek Dam which controls the water level in Lake Cumberland required that the lake elevation be lowered to 680 feet MSL, resulting in higher intake temperatures due to the closer proximity of warmer surface waters at the intake. A floating barge intake structure is currently in place during the drawdown period, but no information was available to describe its configuration or operation. A cooling tower was also retrofitted to Unit 2 and brought online in 2009, and is operated during warm water months due to these elevated intake temperatures. For the purposes of planning for Section 316(b) compliance, EKPC anticipates that the reservoir level will return to approximately full pool following the conclusion of dam repairs in 2013.

The once-through cooling water system at Cooper Station has a design intake flow of approximately 208 MGD. Unit 1's intake has a design capacity of 89.2 MGD and consists of two 42-inch intake pipes, two hydraulic turbine pumps to lift water to the elevated screen house, two conventional traveling screens, two 32,000 gallon per minute (gpm) circulating water pumps, and a fish return system. The conventional traveling screens are 10 feet wide, have 3/8-inch screen openings, and a minimum maintained wetted screen depth of 30 feet. The estimated through-screen velocity at design flow is 0.34 fps. The estimated velocity at the two 42 inch intakes located in the lake at design flow is 7.2 fps.

Unit 2's intake has a design capacity of 118.9 MGD and consists of two 48-inch intake pipes, two hydraulic turbine pumps to lift water to the elevated screen house, two conventional traveling screens, two 40,000 gpm circulating water pumps, and a fish return system. The traveling screens are 10 feet wide, have 3/8-inch screen openings, and a minimum maintained wetted screen depth of 30 feet. The estimated through-screen velocity at design flow is 0.45 fps. The estimated through-pipe velocity at the two 48 inch intakes located in the lake at design flow is 7.3 fps.

An 8-cell cooling tower was also retrofitted to Unit 2 in 2007 and brought online in 2009, and is operated during warm water months to offset the elevated intake temperatures at the surface due to the lower lake levels. When operating, the cooling tower has an average makeup water demand of 3.25 MGD, substantially reducing the cooling water supply requirement for Unit 2 and the overall demand for the station. The estimated through-pipe velocity at the Unit 2 intakes drops to 0.2 fps during cooling tower operation and the through-screen velocity drops to an estimated 0.012 fps.

The traveling screens are typically manually operated twice per day but may operate more frequently when the debris loads are high and increased differential pressure across the screens triggers automatic operation. Fish and debris are washed into a trough below the traveling screens and then conveyed through a pipe which releases fish back into the river.

Cooper Station Compliance Options

Impingement Mortality

Cooper Station is equipped with traveling screens and therefore is required by the draft rule to retrofit with Ristroph modifications to its CWIS. The calculated through-screen velocities are less than the 0.5 fps threshold; therefore the station would not be required to comply with the proposed impingement mortality restrictions (if retained in the final rule) unless the definition of "intake velocity" is changed in the final rule to include the inlet pipes.

Entrainment Mortality

Cooper Station has measured the actual intake flow (AIF) for the past three years (2008 through 2010) to be 110 MGD. These actual flows are less than the 125 MGD actual intake flow threshold that would require the station to conduct the Entrainment Characterization Study and other analyses. However, it should be noted that the AIF is likely reduced by operation of the cooling towers for Unit 2 during warmer months and its reduced cooling water requirements (3.25 MGD), substantially less than the once-through design flow of 118.9 MGD.

Potential Dale Station 316(b) Requirements

Dale Station Cooling Water System Description

The cooling system at the Dale Power Station consists of once-through cooling systems using water withdrawn from the east bank of the Kentucky River at river mile 177.5. The CWIS has a total design capacity of 219 MGD and consists of a stop log and trash rack structure, a screen well, six traveling screens, and six circulating water pumps. The trash rack is located at the river bank, while the traveling screens are located approximately 500 feet from the bank.

River water is withdrawn through the stop log and trash rack structure into two 72-in diameter pipes at an intake invert elevation of 557 feet mean sea level (MSL). Based on available river profiles from the U.S. Army Corps of Engineers (USACE) Louisville District, the normal pool elevation at this point in the Kentucky River (Pool 10) is approximately 567.6 feet MSL. This normal pool elevation results in a typical water depth at the inlets of approximately 10 feet.

The pipes convey river water into the screen well at the screen house structure. The screen house structure contains the screen well, traveling screens, and circulating water pumps for all four operating units. Two screens with respective pumps provide cooling water for Units 1 and 2. The remaining four screens and pumps provide cooling water for Units 3 and 4. The conventional traveling screens have 3/8-inch mesh, a wetted depth of 13 feet, and are equipped with high-pressure washes and troughs that flow into an open channel that flows back into the river.

Units 1 and 2 circulating water pumps have a capacity of 22,000 gpm (31.7 MGD) each. Based on a screen width of 4 feet, 13-foot wetted depth, and a 68 percent open area, the estimated through-screen velocity for Units 1 and 2 is 1.39 feet per second (fps). Unit 3 and 4 circulating water pumps each have a capacity of 27,000 gpm (38.9 MGD). Based on a screen width of 9 feet, 13-foot wetted depth, and a 68 percent open area, the estimated through-screen velocity is 0.76 fps.

The circulating water pumps for Units 1 and 2 operate when the units are in operation. Since they discharge to a common header, either pump can be used when only one unit is operating. If both screens are used when only one unit is operating, the through-screen velocity is halved (approximately 0.7 fps). The four circulating water pumps for Units 3 and 4 also discharge to a common header, and all four pumps are typically used for approximately six months of the year. During the colder months of the year, three pumps are sufficient to meet the heat rejection requirements for Units 3 and 4, resulting in a 25 percent reduction in flow across the four traveling screens serving Units 3 and 4 and a through-screen velocity of 0.57 fps.
The screens are operated automatically based on head-loss triggers and typically rotate two hours per day. During periods when debris loads are high the screens may operate continuously. A trough below each traveling screen conveys fish and debris washed from the screens into a pipe which leads from the screenhouse to a trough which returns fish to the Kentucky River through an open, rip-rap lined channel.

Dale Station Compliance Options

Impingement Mortality

Dale Station is equipped with traveling screens and therefore is required to retrofit with Ristroph modifications to its CWIS. The through-screen velocities also exceed the 0.5 fps threshold; therefore the station will be required to comply with the proposed impingement mortality restrictions (if retained in the final rule) unless these intake velocities can be reduced.

Potential options to decrease intake velocities include:

- Additional once-through traveling screens or retrofit with dual flow traveling screens to increase the screen area of the traveling screens;
- Reduce approach velocity at intake inlets in the river;
- Installation of wedgewire screens; and
- Flow reduction through retrofit of cooling towers.

Entrainment Mortality

Dale Station has measured the actual intake flow (AIF) for the past three years (2008 through 2010) to be 148 MGD. These actual flows are greater than the 125 MGD threshold that would require the station to conduct the Entrainment Characterization Study and other analyses. With intake flows greater than 125 MGD, the studies required under 40 CFR 122.21(r)(9) through (12) would need to be undertaken and BTA for entrainment mortality established for Dale Station on a site-specific basis. There are three potential technology-based compliance scenarios for reducing entrainment mortality at the station. The station could install fine-mesh traveling water screens with a fish return system, install wedgewire screens with a mesh fine enough to protect fish eggs and larvae, or retrofit cooling towers.

Entrainment rates during the 2006 to 2007 studies at Dale Station were low and the most frequently entrained species was gizzard shad and unidentified clupeids and unidentified eggs. Based on the timing of the collection of the unidentified eggs and larvae, these unidentified eggs and larvae were also most likely gizzard shad. Given the robust population of gizzard shad in the Kentucky River and the very low entrainment rates of sport fish larvae, white bass and sunfish species, it may be possible to not install entrainment protection equipment at Dale Station based on a cost-benefit analysis.

New CWA Effluent Standards

EPA is expected to issue a draft rule proposing new standards for effluent discharges from electric generating units by November 2012 with final action by January 2014. It is expected that EPA will propose to regulate all effluent streams including fly ash- and bottom ash-derived wastewaters, flue gas desulfurization (FGD) wastewater, and leachate and runoff from coal piles and land-filled or impounded coal combustion residuals (fly ash, bottom ash, boiler slag, and FGD solids).

New CCR Rule

On June 21, 2010, EPA published the Proposed Rule for Disposal of Coal Combustion Residuals (CCRs) from Electric Utilities. EPA provided two co-proposals for public comment: regulation of CCRs as a hazardous, or "special," waste under RCRA subtitle C and regulation of CCRs as a solid waste under RCRA subtitle D. EPA stated that it supports and has endeavored to maintain beneficial reuse of CCRs under both proposed rules. The Subtitle C alternative has extensive repercussions and there are serious questions as to whether the industry could comply with these requirements.

Given the challenges that would accompany Subtitle C regulation of CCRs, the Subtitle D alternative seems like the most likely course for EPA. This is further supported by recent legislative actions that have been directed towards a state-run Subtitle D approach.

Under the proposed regulations for the Subtitle D approach, EPA is proposing to establish dam safety requirements to address the structural integrity of surface impoundments. Within one year of the effective date of the regulations, all surface impoundments are required to be in compliance with groundwater monitoring and demonstrate locational criteria requirements to continue to accept waste. All impoundments that are not in compliance with the liner requirements of the subtitle D are required to cease accepting waste within five years of the effective date of the regulations. If there were no alternatives for CCR disposal, the five years in which the impoundment must have completed closure may be extended for an additional two years.

Under the proposed regulations, there would be no liner requirement deadline for existing landfills (those that are constructed or substantially constructed), but groundwater monitoring would be required. All new landfills or lateral expansions will be required to have composite liner systems, leachate collection systems, and groundwater monitoring networks.

EXHIBIT TFC-3

STEVEN L. BESHEAR
GOVERNOR

LEONARD K. PETERS
SECRETARY

ENERGY AND ENVIRONMENT CABINET
OFFICE OF THE SECRETARY
500 MERO STREET
12TH FLOOR, CAPITAL PLAZA TOWER
FRANKFORT, KY 40601
TELEPHONE: (502) 564-3350
FACSIMILE: (502) 564-3354
www.eec.ky.gov

October 22, 2013

Gina McCarthy, Administrator
US Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

Dear Administrator McCarthy:

First, thank you and your staff for meeting with Governor Beshear and me last month to discuss several issues of mutual concern.

As you know, Kentucky has numerous problems and concerns with the EPA's proposed rule on CO_2 emissions relating to new power plants, and we will be further voicing those concerns as that process unfolds.

In regard to the upcoming proposed rule concerning existing power plants, on behalf of Governor Beshear, I am providing a white paper for discussion of compliance options under Section 111 (d) of the Clean Air Act. As you indicated during our September 19, 2013 meeting, states will be an integral part of the EPA's process to develop guidelines for the existing source rule under Section 111 (d).

A framework such as the one outlined in the attached document provides needed flexibility, and yet is an effective, equitable, and cost-effective approach. It considers the vast differences among states in their resource potential and current generation portfolio; and more importantly for states like Kentucky, it does not lead to an all-out replacement of coal-fired generation with natural gas generation, as we contend would occur under a less flexible approach.

Since President Obama's goal is to reduce carbon dioxide emissions, and not simply favor one fossil fuel over another, compliance options that take into account demand and supply-side energy efficiency and renewable and other low-carbon generation sources must be allowed. This sample framework includes these options. Furthermore, our analyses demonstrate that greater emissions reductions can occur under such a flexible, mass-emissions approach (reducing total average emissions) when compared with a rigid standard that simply places an emissions threshold of tons per unit of energy on electric generating facilities. For national energy and economic security purposes, electric generation resource diversity is crucial, and the only way to ensure such diversity while reducing emissions is to avoid a rigid target.

Kentucky is committed to reducing its greenhouse gas emissions, but we will not put our citizens and industries in the untenable position of having to forego economic prosperity to achieve these reductions. We are also committed to working with you and your staff in the coming weeks and months as you develop guidelines in advance of the June 2014 deadline. Our framework is not a formal proposal, *per se*—it is meant to guide our discussions with you and to demonstrate that we can achieve reductions to meet President Obama's goals in a meaningful manner that does not jeopardize our state's economy.

As the state most-dependent on coal-fired generation and one with the most energy-intensive manufacturing economy, Kentucky has much at stake if national policies do not take into account the variations among the states in establishing existing source guidelines. We look forward to discussing the framework we have outlined at your earliest convenience. We truly appreciate your sincerity and willingness to consider a broad array of options to meet Section 111(d) guidelines.

Sincerely yours,

L K Peters

Leonard K. Peters
Secretary

LKP:wh
Enclosure

cc: Robert Perciasepe, Deputy Administrator
US Environmental Protection Agency

Gwen Keyes-Fleming, Chief of Staff
US Environmental Protection Agency

Janet McCabe, Acting Assistant Administrator for the Office of Air and Radiation
US Environmental Protection Agency

EXHIBIT TFC-3

Greenhouse Gas Policy Implications for Kentucky under Section 111(d) of the Clean Air Act

Commonwealth of Kentucky
Energy and Environment Cabinet

October 2013

Technical Contacts

Several individuals contributed to this document; the principal authors are:
Kenya Stump, Division for Air Quality, Department for Environmental Protection; Aron Patrick, Department for Energy Development and Independence; and Karen Wilson, Energy and Environment Cabinet.

Correspondence regarding the contents of this document may be addressed to:
John Lyons
Email: John.lyons@ky.gov

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PREFACE

As a cornerstone of his Climate Action Plan, President Barack Obama has directed the U.S. Environmental Protection Agency to establish carbon dioxide emission standards for new and existing power plants. EPA has indicated it is seeking state input in developing these standards under Section 111(d) of the Clean Air Act for existing power plants. In response, Kentucky presents the following framework, developed through extensive analysis and economic modeling. This framework complies with the legal provisions of Section 111(d) while ensuring Kentucky can reduce emissions in the most cost-effective manner.

"The flexibility afforded to states under Section 111(d) is crucial to crafting greenhouse gas regulations and policies that enable strong state economies while capitalizing on diversity among the states."

By comparing two divergent approaches to an emissions reduction program—a rate-based versus a mass emissions—our analyses demonstrate why the latter is not only more effective at achieving stated goals for reducing emissions but does so in a more equitable manner considering the differences among states with their existing generating portfolios. The flexibility afforded to states under Section 111(d) is crucial to crafting greenhouse gas regulations and policies that enable strong state economies while capitalizing on diversity among the states. The framework details strategies that reduce greenhouse gas (GHG) emissions to meet the President's goals through a combination of demand-side energy efficiency and conservation, electric generating unit (EGU) process upgrades and improvements, fuel switching and EGU diversification, and carbon offsets.

Kentucky's position urging EPA to adopt a mass-emissions approach over a rate-based approach arises from a thorough analysis of how variations in states' generating portfolios, energy intensity and leading economic sectors are intricately linked. Each state and its economy are different and unique. One way of measuring these differences is through the amount of electricity required to generate a dollar of state gross domestic product (SGDP). It is intuitive that manufacturing states and those with a substantial industrial component will be higher by this measure. Consumer states without a significant manufacturing base will benefit from those energy expenditures in states with a strong manufacturing base, and these more service-oriented states will have lower state electricity generation and consumption.

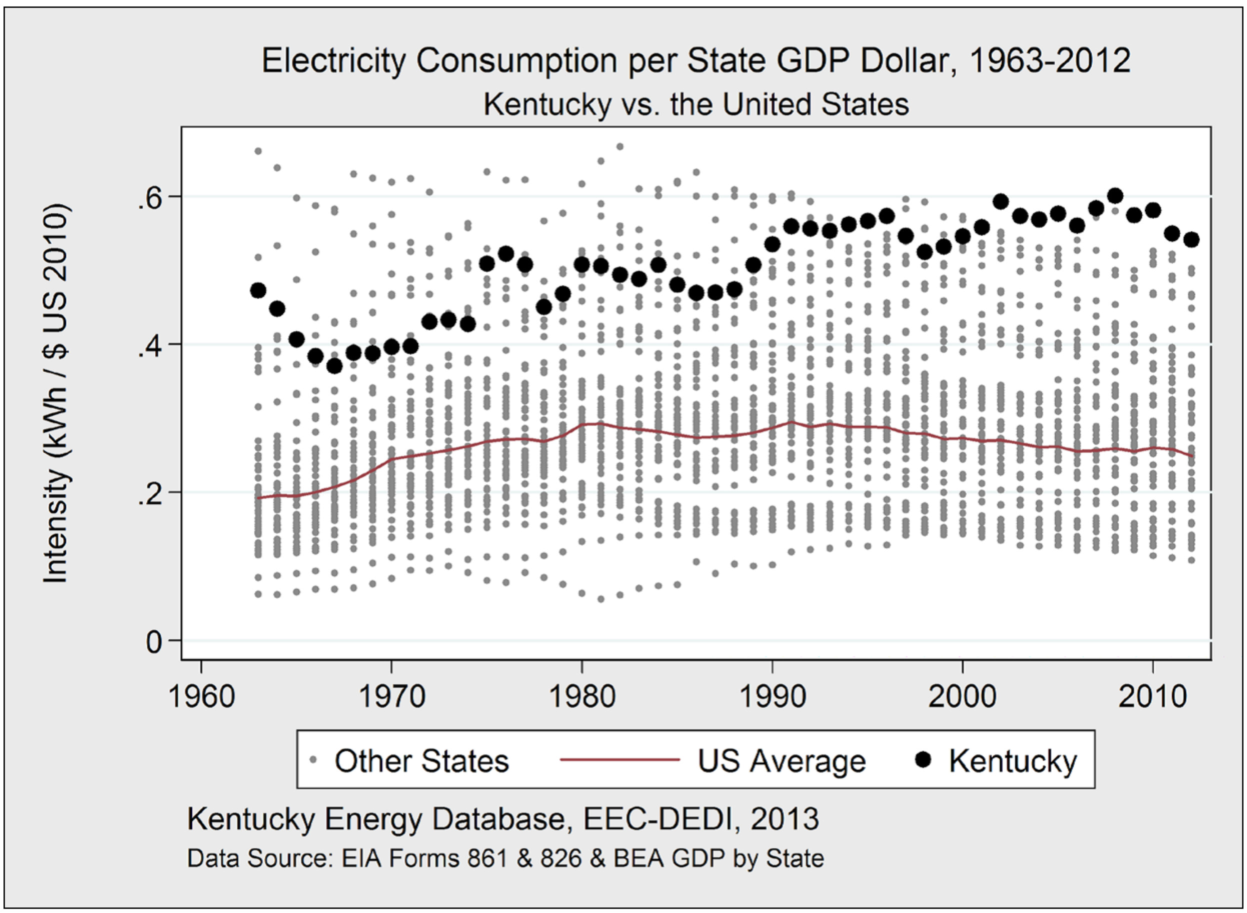
These differences among producer and consumer states have resulted from numerous historic factors, and they illustrate how states have developed based on their geographic and natural resource strengths. Kentucky is an example of this—with vast coal resources allowing for low-cost and reliable electricity and with the geographic accessibility to major population centers, energy-intensive industries have located within the state. These industries provide a large share of the manufactured products used throughout the country. A state like New York has thrived through a more service-oriented economy. Each state's strengths provide benefits nationally, and actions that are detrimental to an economic engine in one state can have negative impacts throughout the country.

Figure 1 and Table 1 (on Pages 2 and 3) show this aspect of individual state economies over several decades. In Figure 1, each dot represents the kilowatt hour per dollar of SGDP (kw-h/$SGDP) for each state in each year. This measure varies more than four-fold from the highest to the lowest. Producer states like Kentucky cluster on the high end at about 0.5 kw-h/$SGDP, while primarily consumer states like New York and California are on the low end at about 0.13 kw-h/$SGDP.

It is a likely corollary that if these producer states did not have low electricity rates there would be even less manufacturing in the U.S. today. It is incumbent that, as federal policies for greenhouse gas (GHG) emissions reductions are proposed and implemented, these differences among the states be an essential element of the discussions and deliberations. Given President Obama has stressed rejuvenating the nation's manufacturing economy, which must rely heavily on reliable, affordable electricity, these considerations align with the overall objectives of the administration.

Kentucky's historically low and stable electricity prices have fostered the most electricity-intensive manufacturing economy in the United States, making Kentucky particularly vulnerable to future electricity price increases. A 2012 study predicted a 25 percent increase in electricity prices would be associated with a net loss of 30,000 full-time jobs, primarily in the manufacturing sector. [1] Greater increases in electricity prices would have even greater impacts on job losses.

Figure 1: Electricity Consumption per State GDP Dollar



1 Kentucky Energy and Environment Cabinet. (2012). *The Vulnerability of Kentucky's Manufacturing Economy to Increasing Electricity Prices.* Department for Energy Development and Independence, Frankfort.
http://energy.ky.gov/Programs/Documents/Vulnerability%20of%20Kentucky's%20Manufacturing%20Economy.pdf

Table 1: Electricity Intensity by State, 2012

Rank	State	**Electricity Intensity** *kWh of Electricity Consumption per Real GDP*	Rank	State	**Electricity Intensity** *kWh of Electricity Consumption per Real GDP*
1	Kentucky	0.541	27	Nevada	0.277
2	Mississippi	0.503	28	Texas	0.274
3	Alabama	0.496	29	Michigan	0.274
4	West Virginia	0.468	30	Washington	0.260
5	South Carolina	0.467	31	Virginia	0.259
6	Wyoming	0.465	32	Pennsylvania	0.253
7	Arkansas	0.449	33	United States	0.249
8	Idaho	0.424	34	Oregon	0.247
9	Oklahoma	0.386	35	Minnesota	0.240
10	Indiana	0.368	36	Utah	0.240
11	Tennessee	0.368	37	Maine	0.227
12	Louisiana	0.366	38	Illinois	0.216
13	Montana	0.359	39	Vermont	0.212
14	Missouri	0.336	40	Colorado	0.207
15	North Dakota	0.334	41	Maryland	0.205
16	Georgia	0.320	42	Delaware	0.185
17	Nebraska	0.318	43	New Hampshire	0.177
18	Iowa	0.316	44	Rhode Island	0.159
19	Ohio	0.314	45	New Jersey	0.157
20	New Mexico	0.304	46	Massachusetts	0.142
21	Kansas	0.304	47	Hawaii	0.140
22	Florida	0.296	48	California	0.136
23	North Carolina	0.296	49	Connecticut	0.135
24	Arizona	0.296	50	Alaska	0.130
25	South Dakota	0.294	51	New York	0.124
26	Wisconsin	0.277	52	District of Columbia	0.108

INTRODUCTION

In developing our proposed framework, we analyzed the potential implications on Kentucky and other states for addressing carbon dioxide emissions from existing power plants using various policy options, with the assumptions that:

- Each major GHG emissions sector will contribute proportionately to any overall emissions reduction strategy.
- Greenhouse gas emissions from transportation sources will be handled through federal regulations such as Corporate Average Fuel Economy (CAFE) standards.
- Proportionate GHG emissions from other non-electric generating unit (EGU) emitting sources will be handled under other EPA-proposed regulations.
- EGU-equivalent emission reductions in Kentucky will be met through emission reductions at the source, reductions through efficiency and conservation, and carbon offsets.

"The transition to lower emission sources should not be a sole trade-off between one type of carbon fuel (coal) for another (natural gas)."

As with other landmark environmental policies, greenhouse gas regulations for the electricity generating sector will be a pivotal point for many states as they transition to cleaner sources of energy. However, the transition to lower emission sources should not be a sole trade-off between one type of carbon fuel (coal) for another (natural gas). Our proposed framework avoids such a scenario as it encompasses flexible mechanisms that ultimately favor a diverse energy portfolio that will include renewable and other low-carbon sources and energy efficiency.

Kentucky, as with many other states, is already implementing policies and programs that lead to reduced greenhouse gas emissions across sectors. These activities include a substantial emphasis on energy efficiency as it is the least-cost method for reducing emissions across end-use sectors. For example, Kentucky's stated goal of meeting 18 percent of electricity demand through energy efficiency by the year 2025 is well on target. Our proposal builds upon these activities and aligns them with Section 111(d) regulatory obligations. In addition to programs and policies, electricity market forces combined with regulations on other air emissions are moving Kentucky's generation portfolio toward reduced greenhouse gas emissions.

With these combined factors, Kentucky and many other states are positioned to achieve the President's stated greenhouse gas emission reduction goals when combined with what we urge are flexible, achievable standards through requirements for existing plants under Section 111(d). From 2005 emission levels, Kentucky's fossil fueled power plants have achieved 7 percent reductions as of 2012 (see Appendix B). A mass-emission reduction standard affords all states the maximum flexibility to use each state's unique current and future energy resources to support the economies of each state.

Clean Air Act Section 111(d)

Section 111(d) obligates EPA to prescribe regulations for a state to submit a plan to establish standards of performance for any existing sources. Under Section 111(d), EPA sets guidelines for these standards, but the states have the responsibility to apply the requirements for existing sources. States have broad flexibility to implement Section 111(d) standards; however, EPA retains approval authority and the ability to regulate if a state fails to submit a satisfactory plan. To ensure flexibility is afforded in establishing standards, Section 111(d)(1)(B) states that EPA shall allow the state to take into consideration, among other factors, the remaining useful life of the existing source when applying a standard of performance. Ultimately, the state-specific plan is submitted as a State Implementation Plan (SIP) to EPA for approval.

A key element to Section 111 is the definition for "standard of performance."

The term "standard of performance" means a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the administrator determines has been adequately demonstrated. (CAA Section 111(a))

"While Carbon Capture and Sequestration (CCS) technology is critical to the reduction of CO_2 levels from fossil fuel-based power plants, it is not yet commercially proven in the primary large-scale application for which it is envisioned—electric power plants fueled by coal or natural gas."

Of note are the terms "achievable" and "adequately demonstrated." For greenhouse gases under Section 111(d), any control technology requirements proposed by EPA would have to meet these conditions, and EPA would have to provide justification on why it believes technology exists to allow the sector to meet a particular standard.

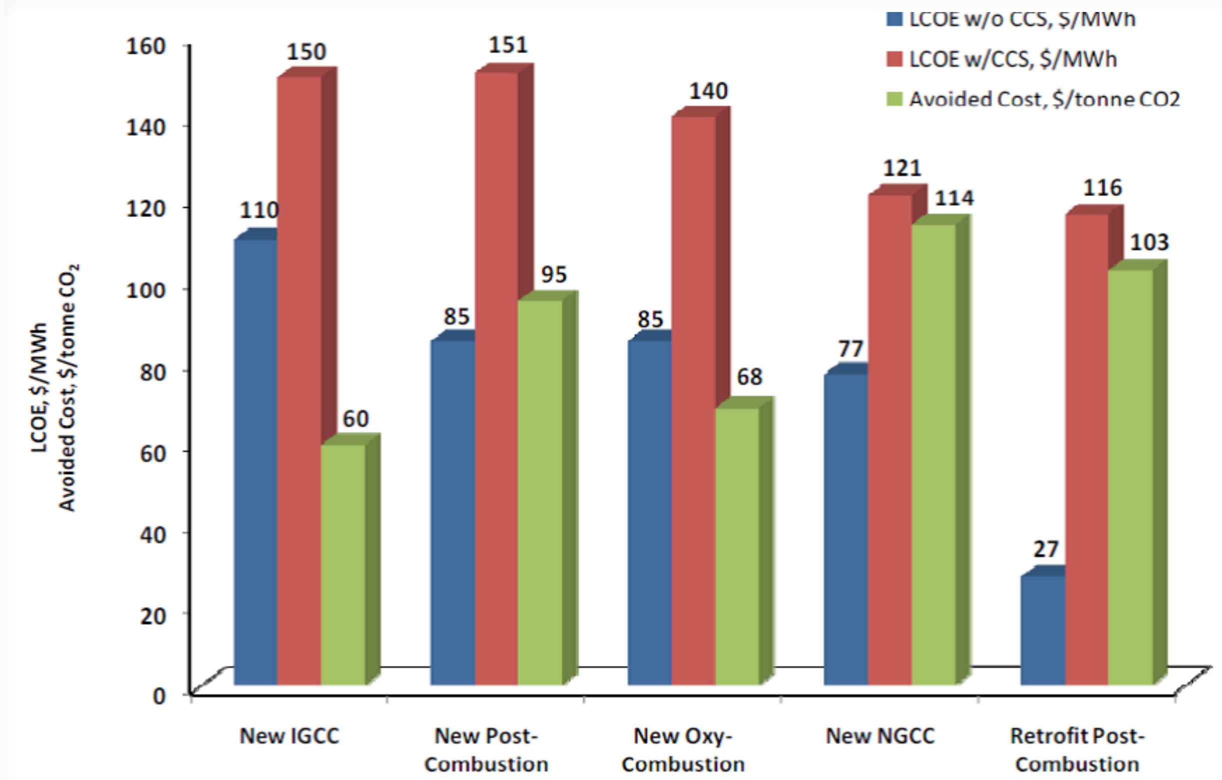
Of concern is whether the technologies to capture and sequester CO_2 from existing sources will be deemed achievable and adequately demonstrated by the EPA in establishing the Section 111(d) standards. While Carbon Capture and Sequestration (CCS) technology is critical to the reduction of CO_2 levels from fossil fuel-based power plants, it is not yet commercially proven in the primary large-scale application for which it is envisioned—electric power plants fueled by coal or natural gas. See Appendix C for the status of current carbon capture projects in the United States.

The energy requirements of current CO_2 capture systems are roughly 10 to 100 times greater than those of other environmental control systems employed at a modern electric power plant. For existing power plants, such as those in Kentucky, the feasibility and cost of retrofitting CO_2 capture systems depend heavily on site-specific factors such as the plant size, age, efficiency, type and design of existing air pollution control systems, and availability of space to accommodate a capture unit. To obtain comparable GHG emission reductions, the cost of retrofitting an existing power plant with CCS technology is higher than the cost of a new NGCC without CCS ($116 per MWh versus $77 per MWh) (Figure 2).

Rate-Based versus Mass Emissions Strategies

Traditional performance standards have been technology-based and ultimately tied to achieving the National Ambient Air Quality Standard (NAAQS) for a pollutant. In the case of CO_2 and existing coal electricity generating units, there is no NAAQS or readily available technology to guide any CO_2 performance standard. In the absence of a NAAQS, much discussion is focused on a rate-based approach, with emission levels from a natural gas combined cycle unit (which are one-half the emissions of a typical coal unit) serving as a surrogate target.

Figure 2: CCS Cost Variation Among Different Generating Sources [2]



LCOE--Levelized Cost of Electricity is a cost of generating elecricity for a particular system. It is an economic assessment of the cost of the energy-generating system including all the costs over its lifetime: initial investment, operations and maintenance, cost of fuel, cost of capital.

An emission rate standard is one where the emission level is established in relationship to a raw material input or production output. An example of this approach is one where the rate-based standard is expressed as allowable CO_2 emissions per unit of electricity generation output (MW-h) as has been done with the recently proposed NSPS for new EGUs. These types of standards are in comparison to the second option of a mass-emission reduction standard. A mass-emission standard establishes a quantity or mass of pollutant to be reduced from a baseline level. Mass-emissions standards are often expressed as a percent reduction of the mass (tons) of pollutant (CO_2).

Our analyses (see details in Appendix A), using benchmarks established in the Natural Resources Defense Council's (NRDC) 2013 report Closing the Power Plant Carbon Pollution Loophole, show that Kentucky's economy would be negatively affected by a traditional rate-based emissions threshold, and more importantly, we will have not achieved the level of emissions reductions that could occur through a more flexible mass-emissions reduction strategy. Kentucky is not alone in this regard. Therefore, we urge EPA to examine the results of this analysis and consider the implications in its rulemaking for existing sources.

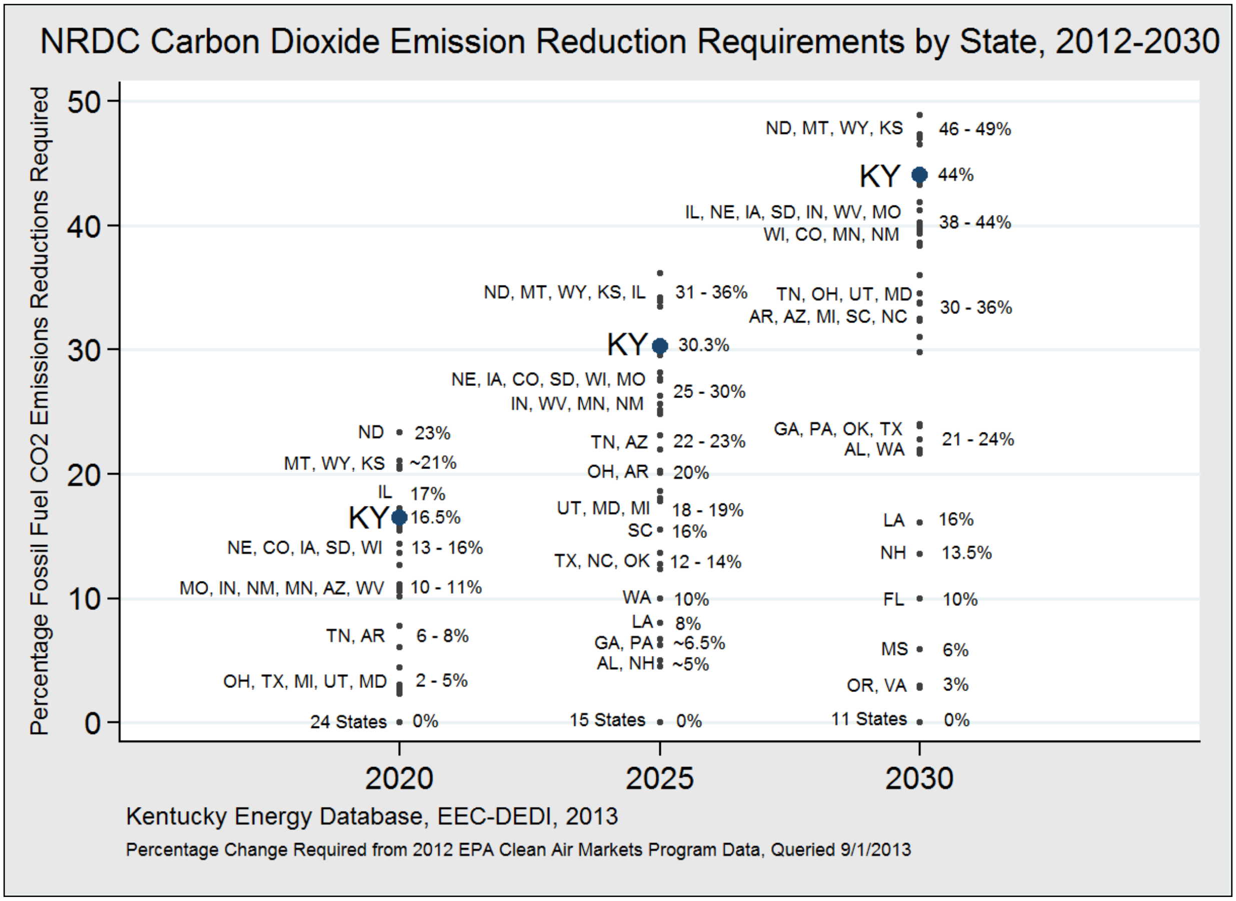
The traditional rate-based approach would likely force Kentucky's utilities to retire their coal units—which currently provide more than 90 percent of Kentucky's electricity—and build new natural gas fired generation. Kentucky would simply go from being primarily dependent on one fossil energy source (coal)

[2] Report of the Interagency Task Force on Carbon Capture and Storage, August 2010.

to being primarily dependent on another fossil energy source (natural gas). The costs for ratepayers would be high, renewable and efficiency opportunities would not achieve their full potential, and the amount of greenhouse gas emission reductions achieved in the aggregate would be less than that specified by the President's goal.

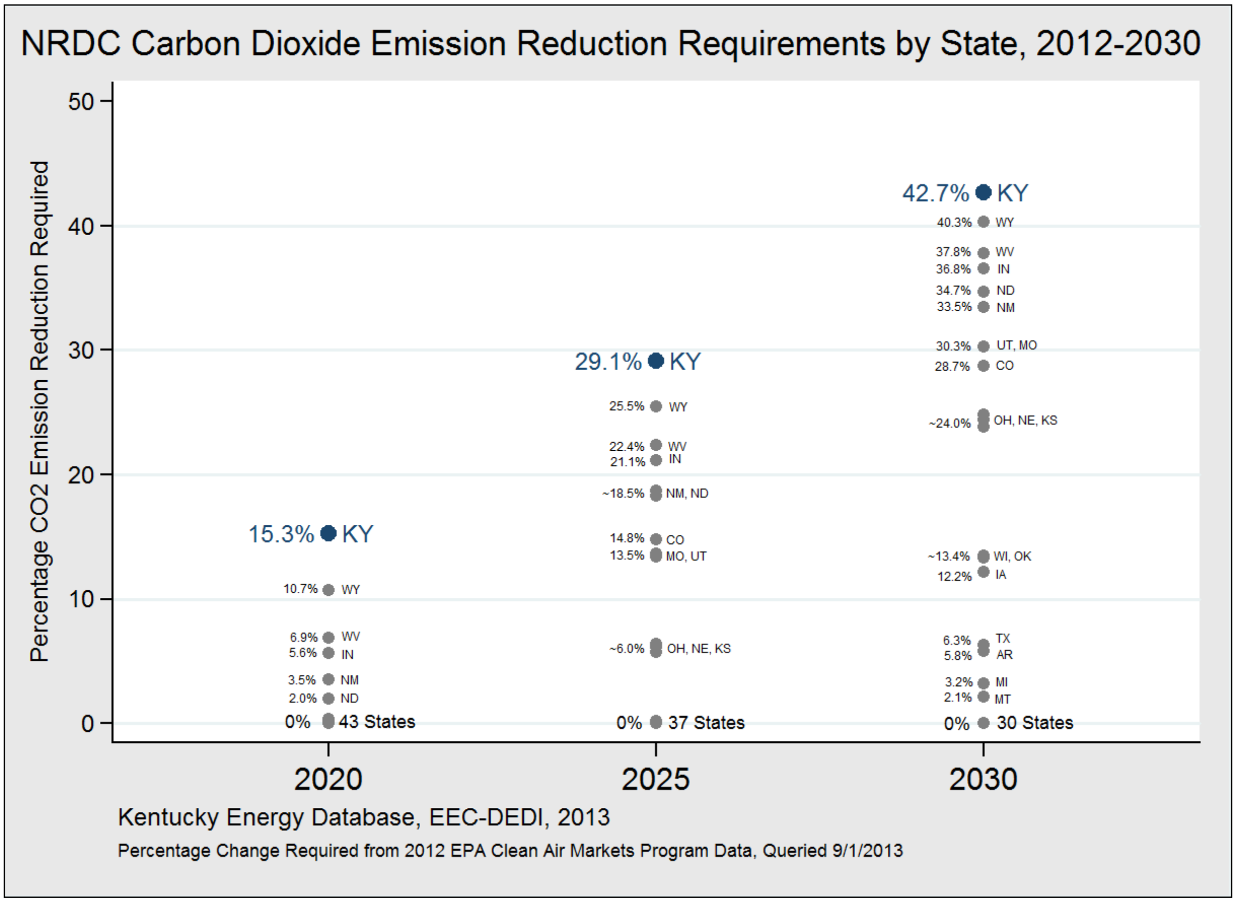
Our analyses also show that Kentucky and a few other states carry a disproportionate burden relative to other states. The charts are based on benchmarks applied to the fossil-fuel portion of a state's electricity generation fleet (Figure 3) and to an entire fleet, including renewables (Figure 4).

Figure 3: Emission Reductions Based on NRDC Benchmarks, Fossil Fleet Only [3]



[3] Figure 3 illustrates the approximate minimum percentage reduction of total simple carbon dioxide emissions from utility-scale electricity generation in 2012 required for each state to be able to achieve the emission rates proposed by the NRDC in each benchmark year from 2020 to 2030 and beyond. Emissions data for 2012 were collected by state and year from the Continuous Emissions Monitoring Systems available in the EPA Clean Air Markets Program Database. The effective NRDC emission rates benchmarks for each state were calculated using the formula specified in Appendix A and 2005 net electricity generation data from fossil fuel units (coal, natural gas, and petroleum) per the Power Plant Operations Report available in the U.S. Energy Information Administration, Form EIA-923. Alaska and Hawaii were excluded from this analysis because comparable 2012 emissions data were not available for these states from the EPA Clean Air Markets Program Database.

Figure 4: Emission Reduction Requirements by State Based on NRDC $C0_2$ Emission Benchmarks, Total Fleet



"While natural gas is currently relatively inexpensive, locking ourselves into a single-fuel economy poses significant risks in the future as natural gas prices increase, as they would be expected to do with a substantial increase in demand from the utility sector."

States should not be placed in a position of choosing between energy efficiency and renewable energy versus a fossil fueled fleet that becomes dependent on yet another single source of fuel, natural gas. In either of the rate-based approaches depicted in Figures 3 and 4, Kentucky is faced with significant challenges in meeting the 2020, 2025 and 2030 target fossil fleet rates.

Such an approach is not realistic because it is not feasible or appropriate to assume that coal facilities would be in a position to cost effectively add on control equipment to reduce adequately the pounds of CO_2 generated per MW-h produced or have the means to sequester those emissions. Furthermore, a rate-based standard that uses natural gas—specifically combined cycle systems—as a surrogate for add-on CO_2 control technologies is one that unfairly advocates for a single fuel economy. This approach would force coal plant conversions to natural gas in the absence of available proven technology.

As shown, a rate-based standard can either be a force for electric generating unit efficiency upgrades or a push to an alternative fuel. At this time, the market favors the fuel of choice being natural gas. While natural gas is currently relatively inexpensive, locking ourselves into a single-fuel economy poses significant risks in the future as natural gas prices increase, as they would be expected to do with a substantial increase in demand from the utility sector.

These scenarios not only have significant implications for the nation's manufacturing economy, but they also place a burden on many states that continue to struggle with a slow economic recovery. As the nation is only slowly emerging from a severe economic recession, such a regulatory scheme would not be in the best interests of the nation and does not offer states the amount of flexibility necessary to successfully implement Section 111(d).

KENTUCKY'S PROPOSED FRAMEWORK

Kentucky proposes an equitable and cost-effective approach that provides the needed flexibility to comply with a Section 111(d) plan. In the absence of control technology for existing EGUs, compliance options include offsets, demand-side energy efficiency, renewables and other low-carbon fuels, and supply-side efficiency improvements. Our proposed framework will diversify Kentucky's electricity generating portfolio, reduce emissions, and benefit the economy.

Kentucky has identified the following objectives for the framework outlined below:

- Utilize mass-emission reductions from the fossil fueled electricity generating sector as the primary mechanism for addressing greenhouse gases in Kentucky.
- Ensure that the fossil fueled electricity generating sector has the time and resources necessary to transition to a cleaner fleet when necessary and appropriate.
- Provide that the fossil fueled electricity generating sector has the flexibility to choose the least-cost method of achieving reductions.
- Encourage diversity for Kentucky's electricity generation fleet.

A mass-emission reduction standard provides state flexibility under Section 111(d) guidelines that encourage CO_2 reduction from multiple pathways, achieves sustained greenhouse gas reductions, and encourages economic growth until the commercial availability of CCS technology has been demonstrated as feasible and cost effective on a large scale for the power sector. Such an approach also allows a state to take advantage of emission reductions achieved through coal-plant retirements and fuel-switching based on other existing Clean Air Act regulations.

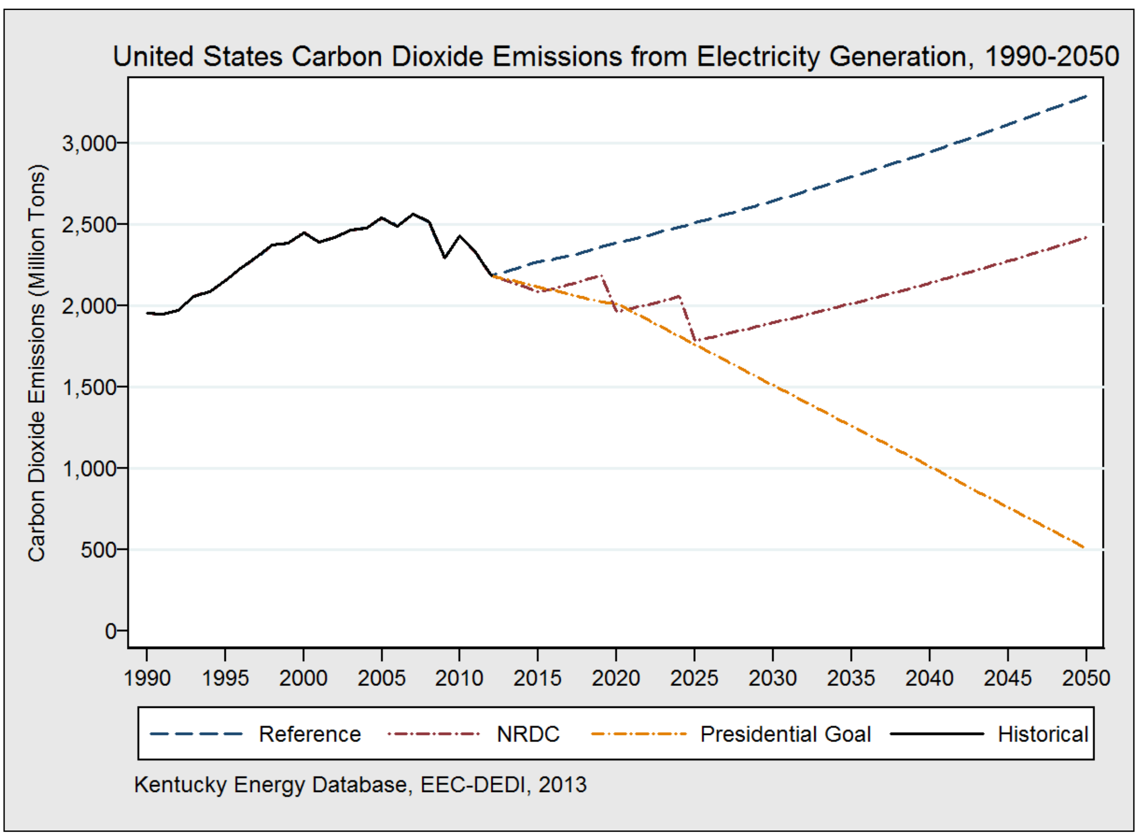
In a typical scenario, the EPA would set a NAAQS for greenhouse gases, and states would have at least three years to develop state implementation plans to demonstrate how they will attain and meet the NAAQS. These plans give states the flexibility to devise regulations to control sources within their own state. However, greenhouse gases, which are emitted from multiple sectors, including the transportation and industrial sectors, are unlike other pollutants where NAAQS have been established. Just as a NAAQS does not logically apply to regulating greenhouse gas emissions, a traditional rate-based regulatory framework has its limitations.

In the absence of a NAAQS, EPA is faced with calculating the amount of emission reductions required from the electricity generating sector to be protective of public health and the environment under 111(d), taking into account other emission reduction sources and contributors. To date the only levels of overall emission reductions stated by the President have been a 17 percent reduction from 2005 levels by 2020 with an 80 percent reduction by 2050. EPA would still be in a position under 111(d) to demonstrate that these mass-emission reductions stabilize or reduce CO_2 concentration in the atmosphere.

Given the difficulty of this task and as an alternative, EPA could allow states the flexibility to determine emission reductions that are appropriate given each state's own fossil fuel portfolio mix, existing life of affected electricity generating units, market conditions, and renewable energy potential along with any quantifiable energy efficiency gains. This approach would help mitigate the potential adverse economic and social impacts to states that have a strong manufacturing base and allow a path forward to develop a plan that can ensure diversity in energy sources, cleaner sources of energy, as well as economic stability.

Figure 5 illustrates that a mass-emission reduction standard is one that achieves sustainable reductions for the future, is not disproportionate among states, and can offer the tools for the development of state-specific programs considering state resources and economic conditions. Figure 5 juxtaposes the forecasted sum of state-level simple carbon dioxide emissions from electricity generation under the following three cases. The Reference case assumes that electricity generators in each state continue to emit CO_2 at 2012 emissions rates, with anticipated growth, as calculated from the EPA Clean Air Markets

Figure 5: U.S. $C0_2$ Emission Forecasts, 1990-2050



Program Database. The NRDC case assumes that fossil fuel generating stations in each state emit carbon dioxide at the maximum rate proposed by the NRDC benchmarks using a 2005 baseline, while holding constant the proportion of each state's generating portfolio derived from fossil fuels to 2050. The Presidential Goal case assumes that each state achieves a 17 percent reduction by 2020, and 80 percent by 2050, in simple carbon dioxide emissions from electricity generation from 2005 levels.

Kentucky's framework contains the following provisions:

1. Establish a statewide baseline CO_2 level using the CO_2 emission from fossil fueled electric generating units from 2005.
2. Establish the following baseline CO_2 reduction targets for 2020 (17 percent reduction), 2025 (28 percent reduction), and 2030 (38 percent reduction). Beyond 2020, state-specific data as well as energy portfolio trends would be used to set additional reductions beyond 2020 achievable through demand-side and supply-side efficiencies, renewable and other low-carbon energy potential, offsets, and any control technology gains. The 2050 target is the 80 percent reduction goal proposed by President Obama.
3. Obtain credit for CO_2 reductions that have occurred from the baseline established in item 1, thereby allowing states to comply with baseline reduction targets established in item 2.
4. Allow a suite of compliance options that would enable Kentucky to implement the least-cost method of meeting reduction targets. These compliance options would include, but not be limited to:
   - Demand-side energy efficiency
   - Supply-side conservation or efficiency programs
   - Transmission upgrades
   - Renewable and other low-carbon energy projects at the affected source or at the consumer level
   - Carbon Capture and Sequestration (CCS) technology
   - Fuel switching to lower emitting fuels
   - Quantifiable and verifiable offsets
   - Participation in regional or national market-based CO_2 credit-trading programs
5. Establish an enforcement and monitoring mechanism whereby the state would be responsible for review, verification of emission estimates and reductions, and approval of the compliance options above. In addition, the state would be responsible for tracking statewide trends and projects.

Compliance Options

Potential compliance options available under Kentucky's 111(d) framework are outlined using findings from the Kentucky Climate Action Plan Council's (KCAPC) final report. [4] The analyses used in developing the KCAPC report were conducted in partnership with the Center for Climate Strategies, and although some of the underlying assumptions have changed, the relative impact of various options' ability to reduce greenhouse gases and their relative cost are useful in understanding the benefits of a mass emission-based standard over a rate-based standard. Kentucky's Energy and Environment Cabinet is in

[4] Final report of the Kentucky Climate Action Plan Council, November 2011. http://energy.ky.gov/carbon/pages/default.aspx

the process of developing the Kentucky Electricity Portfolio Model that will enable the agency to better understand the impact of changes to the state's electricity portfolio. Whether changes are driven by environmental regulations, state or federal policies, or economic market conditions, the cabinet will soon be able to determine the impact of the changes on price, fuel consumption, and ultimately jobs.

Demand and Supply-Side Energy Efficiency

Energy efficiency remains an essential element to Kentucky's framework because it is a cost-effective tool for reducing greenhouse gas emissions. When paired with more costly compliance strategies, the savings from energy efficiency can mitigate the cost of supply-side diversification. A standard that does not include efficiency as a primary compliance tool increases the compliance burden, as demonstrated in Table 2. Kentucky has a number of active energy-efficiency initiatives and has received broad stakeholder support for demand-side energy efficiency through its Stimulating Energy Efficiency in Kentucky (SEE-KY) program. As a result of this initiative, Kentucky, through the co-operation of utility and other stakeholders, is committed to reducing electricity generation by 1 percent annually between 2015 and 2020.

"Kentucky has a number of active energy-efficiency initiatives and has received broad stakeholder support for demand-side energy efficiency through its Stimulating Energy Efficiency in Kentucky (SEE-KY) program."

Renewable Electricity and Fuel Switching

Kentucky can realistically and cost-effectively increase its renewable electricity generation to 15 percent by 2030. Assuming Kentucky achieves just a third of this goal (5 percent) by 2020 and relies on mostly out-of-state wind along with some in-state hydro, wind, solar, and landfill gas-generated electricity, the state can avoid 7.4 MMt CO_2e at a cost per ton of $11.

Kentucky is already experiencing retirements of coal units, with much of the lost capacity being replaced by new natural gas combined cycle units. This level of fuel switching is realistic, even without stringent rate-based emissions standards. The table also includes estimated reductions of 800 MW of traditional coal generation were to be replaced with supercritical coal generation with 90 percent carbon capture and storage.

Carbon Offsets

Analyses on carbon sequestration through reforestation indicate this would be an achievable and affordable emission-reduction strategy. Reforestation of 22,700 acres of previously mined land by 2020 would avoid 0.02 MMt CO_2e. An additional 142,000 acres of other (non-mined) land could be reforested in Kentucky by 2020 avoiding 0.55 MMt CO_2e by 2020. These reforestation estimates are conservative. We have initiated discussions with volunteer-driven organizations for reforesting 2 million acres over a 15 to 20 year time period, with an estimated 2 to 3 tons of carbon dioxide capture per acre.

Table 2 summarizes estimated emissions reductions and cost, based on analyses performed through the KCAP process, for each of these possible compliance options.

Table 2: Total Emissions Reductions Estimated Through Possible Compliance Options by 2020

Strategy	**MMt CO_2e Avoided**	**Cost/t CO_2e ($2009)**
Supply-Side Efficiency	1.6	$8.0
Demand-Side Efficiency	6.0	-$20
Switch to 5% Renewable Electricity	7.4	$11
Switch to 20% gas	8.7	$17
Replace 800 MW with supercritical with CCS	2.3	$33
Reforest Mine and Other Lands	1.6	$3.7
Total	27.6	$9.3

"Kentucky is positioned to spend less money while reducing more greenhouse gases using a suite of compliance options that include efficiency and carbon offsets."

These strategies demonstrate that a more holistic and less costly approach could be implemented to reduce overall greenhouse gas emissions, and offer a more effective tool than a rate-based emissions standard to help Kentucky achieve the President's stated emission reduction goals. In fact, a strategy that omits the benefits of supply and demand-side efficiency and carbon offsets results in approximately 30 percent less CO_2e reduced. Kentucky is positioned to spend less money while reducing more greenhouse gases using a suite of compliance options that include efficiency and carbon offsets.

Identified EPA Opportunities for State Flexibility

The framework outlined by Kentucky presents many opportunities for emissions reductions. The following discussion outlines areas of concern whereby EPA should provide flexibility under Section 111(d).

NSR/PSD Regulatory Issues

By establishing a flexible emission reduction framework, regulated entities are given an incentive to find the least-cost method to achieve compliance. Sources might invest in efficiency upgrades that would normally trigger PSD/NSR review.

Kentucky is recommending that EPA consider implementing a mechanism for sources that opt to invest in efficiency upgrades and are not precluded from doing so by NSR/PSD permitting requirements, if those efficiency improvements are consistent with meeting Section 111(d) guidelines and do not jeopardize violation of an existing National Ambient Air Quality Standard.

Regional or National Market Based CO_2 Programs

Kentucky's proposed framework sets a statewide mass-emission limit that could be the foundation for an allocation program. If it is determined that allocating allowances is the best path forward in Kentucky, state authorities will have within its discretion to define if allowances will be sold (auctioned) or offered freely to the affected sources. In this program, holding of the allowances and credits becomes the *de-facto* method of demonstrating compliance. In this policy scenario, sources that did not acquire sufficient auction allowances would be required to use the compliance options outlined to make up the difference between their auction allowances purchased and those allocated.

Once the allowances are allocated to the source either via auction or free allocation, trading between the sources would be at the discretion of state authorities. Kentucky does not see an obvious benefit of a state-only trading program but believes that a federal or regional program potentially could provide added incentive for reductions among the sector.

Kentucky's recommendation allows affected sources to participate in market-based programs. An EPA designed regional or national auction, banking, or trading program could help with state SIP development; however, Kentucky would encourage EPA to allow:

- Offsets or credits within state boundaries that are consistent with the President's Climate Action Plan and the GHG Reporting Rule;
- The ability to set a price floor on auction allowances;
- The ability to determine a price ceiling on offsets; and
- The ability of commonly owned affected sources to borrow credits among those under common ownership.

Verification and Quantification of Energy Efficiency

Kentucky's framework allows "credit" for energy efficiency programs. For approval of source compliance strategies as well as Section 111(d) SIP development, a more detailed approach on how to account for energy efficiency gains and how to translate them into CO_2 reductions must be developed. With no explicit guidance on how to accomplish this from EPA and no prior SIPs approved by EPA that include these measures, Kentucky would face significant hurdles in developing a strategy in the limited time between the final rule date of June 1, 2015, and the proposed June 30, 2016, SIP submittal date.

Any strategy included in a proposal translates into a more formalized program to document, track and translate energy efficiency gains. For many states, this type of knowledge is not within state air quality programs. To lessen this gap, Kentucky is requesting EPA to develop specific approved methodologies for quantification and verification of energy efficiency program results. Without such methodologies, states are burdened with developing methods that may not be consistent nationwide.

CONCLUSIONS

Without the flexibility afforded under the Clean Air Act Section 111(d) for a mass-emissions approach, Kentucky and other heavy manufacturing states will face serious economic impacts and job losses. We welcome the opportunity to engage the EPA with a framework that ensures Kentucky's economy and energy portfolios are not crippled by an unachievable, rigid performance standard and presents opportunities for a level playing field under Section 111(d).

The market can be a powerful tool and provides needed flexibility for a sector that is faced with a lack of control options; however, market-based approaches can be labor intensive to operate and monitor in terms of the state's capacity to implement such a program. There is also great variability in market programs due to changing market conditions (technology advancement, price of fuels, renewable subsidies, etc.) which may yield unexpected results. These results ultimately may not be in line with state targets or goals.

"It is imperative that EPA allow ample time and work in collaboration with states to design programs that are 111(d) compliant but provide states the needed flexibility to ensure economic stability."

For Kentucky, this lends itself to a framework that places a priority on the flexibility of market systems such as declining caps, auctions, banking, trading, and offsets coupled with the enforceability of a mass-based emission limit both statewide and at the source. In the absence of control technology for existing EGUs, compliance options include offsets, energy efficiency, renewables, and supply-side efficiency improvements. It is our expectation that this framework will yield results of increased diversity in Kentucky's electricity generating portfolio, a cleaner environment, and a thriving economy.

However, in order to successfully implement the framework outlined, Kentucky also identifies that significant state resources must be utilized and that EPA guidance and flexibility on key issues would allow for a SIP development that is not overly burdensome on state agencies. It is imperative that EPA allow ample time and work in collaboration with states to design programs that are 111(d) compliant but provide states the needed flexibility to ensure economic stability.

APPENDIX A

Kentucky's Current CO_2 Performance Status

Given that target emission rates are developed by including a state's baseline generation mix, the first task is to establish Kentucky's baseline fossil fuel generation. Table 3 represents what is currently operating (Year 2012) and does not include any speculation as to closures or fuel switching.

Table 3: Kentucky Fossil Fuel Baseline Generation, 2012

Fuel Type	Generation MW-h	% MW-h
Coal	92,793,081	97.15%
Diesel Oil	12,827	0.01%
Pipeline Natural Gas	2,713,143	2.84%
Total	**95,519,051**	**100.00%**

The second task is to calculate Kentucky's fossil fleet average target emission rates using the NRDC proposal as a guideline. Table 4 shows Kentucky's NRDC emission target rates for 2020 and beyond 2025. Table 5 shows the weighted average for each fuel type in 2012. Table 5 also illustrates the best performing units in Kentucky by fuel type. For coal-based utilities, the best performing plant achieves 1,743 pounds of CO_2 per MW-h. For natural gas, the best performer achieves 1,094 pounds of CO_2 per MW-h.

Table 4: Kentucky Fossil Fleet Target Emission Rate under NRDC Proposal

NRDC Kentucky 2015-2019 Target Emission Rate* (lbs CO_2/MW-h)	NRDC Kentucky 2020-2024 Target Emission Rate*(lbs CO_2/MW-h)	NRDC Kentucky 2025 & Beyond Target Emission Rate*(lbs CO_2/MW-h)
1,777	1,485	1,194
* Using a 2012 current fleet split of 97% Coal and 3% NG/Oil by MW-h generated		

Table 5: Kentucky Current CO_2 Emission Rate Profile

Fuel Type	Min (lbs CO_2/MW-h)	Max (lbs CO_2/MW-h)	2012 Actual Fleet Averages* (lbs CO_2/MW-h)	2020 NRDC Target Emission Rate (lbs CO_2/MW-h)	2025 NRDC Target Emission Rate (lbs CO_2/MW-h)
Coal	1,743	2,472	1,969	1,500	1,200
Natural Gas	1,094	1,836	1,316	1,000	1,000
Oil	1,595	1,661	1,641	1,000	1,000
Fleet Average			1,951	1,485	1,194
			*Weighted average based on MW-h generated		

Proposed Kentucky Fossil Fleet Changes

Given what is known about future power plant retirements and speculative conversion, Table 6 updates Table 3 and shows projected fleet generation mix by fuel type. Table 7 builds upon the fossil fleet generation changes in Table 6 and shows the projected CO_2 emission rates by fuel type as compared to the NRDC targets. Table 4 calculated a baseline Kentucky fleet average of 1,950 pounds of CO_2 per MW-h. The fleet average in Table 7 of 1,800 pounds of CO_2 per MW-h shows improvements; however, when compared to NRDC targets, a significant gap still remains.

Table 6: Projected Fossil Fleet Generation Changes

Fuel Type	% of MW-h
Coal	83.02%
Diesel Oil	0.01%
Pipeline Natural Gas	16.96%
Grand Total	**100.00%**

Table 7: Kentucky Projected Fleet CO_2 Profile compared to NRDC Proposal

Fuel Type	Projected Averages (lbs CO_2/MW-h)	2020 NRDC Target Emission Rate (lbs CO_2/MW-h)	2025 NRDC Target Emission Rate (lbs CO_2/MW-h)
Coal	1,961	1,500	1,200
Diesel Oil	1,641	1,000	1,000
Pipeline Natural Gas	1,011	1,000	1,000
Fleet Average	1,800	1,485	1,194

APPENDIX B

Kentucky's Current and Future Estimates of Fossil Fleet CO_2 Mass Emission Reductions

	2005	2012	Scenario #1* 2020	Scenario #2* 2025	Scenario #3** 2030
Million Tons of CO_2 Emission data from CAMD Acid Rain Database	100.2	93.2	80.30	72.94	62.11
% Reduction from 2005		-6.99%	-19.83%	-27.23%	-38.00

*Speculative changes in electricity generating portfolio based on internal discussions with stakeholders
** Kentucky 111(d) framework target benchmark based on President's goal

Analyses

This paper utilizes NRDC's benchmarks to analyze a rate-based approach for analysis purposes. Under the rate-based approach analyzed, there is a statewide target fossil fleet average emission rate with specific benchmarks for coal and oil/gas units. States like Kentucky with more carbon-intensive fleets would have higher target emission rates but a greater differential between starting emission rates and their targets.

The NRDC benchmarks for state fossil fuel generation fleets established for 2015 to be met by 2020 include 1,800 pounds of CO_2 per MW-h for coal units and 1,035 pounds of CO_2 per MW-h for natural gas and oil units. By 2025, the benchmarks are 1,500 pounds of CO_2 per MW-h for coal units and 1,000 pounds of CO_2 per MW-h for natural gas and oil units. By 2030, fleet coal units must achieve 1,200 pounds of CO_2 per MW-h and the natural gas benchmarks remain the same. The formula for calculating the state target emission rate is given below:

1. For 2015–2019, state/regional rate = [1,800 lbs/MW-h] × [baseline coal generation share of state region] + [1,035 lbs/MW-h] × [baseline oil/gas generation share of state/region]
2. For 2020–2024, state/regional rate = [1,500 lbs/MW-h] × [baseline coal generation share of state region] + [1,000 lbs/MW-h] × [baseline oil/gas generation share of state/region]
3. For 2025 and thereafter, state/regional rate = [1,200 lbs/MW-h] × [baseline coal generation share of state/region] + [1,000 lbs/MW-h] × [baseline oil/gas generation share of state/region]

For 2020, state/regional target emission rate:

= [1,500 lbs/MW-h] × [baseline coal generation share of state/region] + [1,000 lbs/MW-h] × [baseline oil/gas generation share of state/region]
= (1500 lbs/MW-h * 0.97) + (1000 lbs/MW-h *0.03)
= 1455 lbs/MW-h + 30 lbs/MW-h
= 1,485 lbs/MW-h

For 2025 and thereafter, state/regional rate target emission rate:

= [1,200 lbs/MW-h] × [baseline coal generation share of state/region] + [1,000 lbs/MW-h] × [baseline oil/gas generation share of state/region]
= [1,200 lbs/MW-h] × [baseline coal generation share of state/region] + [1,000 lbs/MW-h] × [baseline oil/gas generation share of state/region]
= (1200 lbs/MW-h * 0.97) + (1000 lbs/MW-h *0.03)
= 1164 lbs/MW-h + 30 lbs/MW-h
= 1,194 lbs/MW-h

Table 5 Calculations

The weighted mean of a set of data $\{x_1, x_2, \ldots, x_n\}$ with non-negative weights $\{w_1, w_2, \ldots, w_n\}$, is represented by the formula below

$$\bar{x} = \frac{\sum_{i=1}^{n} w_i x_i}{\sum_{i=1}^{n} w_i},$$

which translates to the following formula:

$$\bar{x} = \frac{w_1 x_1 + w_2 x_2 + \cdots + w_n x_n}{w_1 + w_2 + \cdots + w_n}.$$

For Table 5 calculations, the formula uses the MW-h for each fuel as the weight (W) and the individual fuel's lbs CO_2/MW-H is the value (X) in the formula. This is illustrated with the 2012 data shown on Table 8 on Page 21. For Table 7, the process is repeated using revised electricity generating fleet data to reflect shutdowns and conversions to natural gas.

Table 8: 2012 MW-h and CO_2 Emissions by Fuel Type

Column Identifier	A	B	C	D=(A+B+C)	E	F	G	H = (E+F+G)
	MW-h from Coal	MW-h from Oil	MW-h from NG	Total MW-h	lbs of CO_2 from Coal	lbs of CO_2 from Oil	lbs of CO_2 from NG	Total lbs of CO_2
	92,793,081	12,827	2,713,143	95,519,051	182,744,159,958	21,043,885	3,570,824,993	186,336,028,836

Row Identifier	Description	Formula	Result from 2012 Data (lbs of CO_2/MW-h)
I	2012 Fleet CO_2 lbs/MW-h from Coal	=E/A	=1,969
J	2012 Fleet CO_2 lbs/MW-h from Oil	=F/B	=1,641
K	2012 Fleet CO2 lbs/MW-h from NG	=G/C	=1,316
	2012 Weighted Total Fleet lbs CO2/MW-h	$=\frac{(A*I)+(B*J)+(C*K)}{D}$ =(A/D)*I + (B/D)*J + (C/D)*K =(coal lbs/MW-h × % of electricity generated that is coal) + (oil lbs/MW-h × % of electricity generated that is oil) + (NG lbs/MW-h × % of electricity generated that is NG) **= (0.9715*1969) + (0.0001 *1641) + (0.0284*1316)**	=1,951

APPENDIX C

Current Large-Scale CCS Projects

Project Name	Leader	Feedstock	Size MW	Capture Process	CO_2 Fate	Status	Location
USA							
Kemper County	Southern	Coal	582	Pre	EOR	Under Construction	Mississippi
TCEP	Summit Power	Coal	400	Pre	EOR	Planning	Texas
WA Parish	NRG Energy	Coal	240	Post	EOR	Planning	Texas
HECA	SCS	Petcoke	400	Pre	EOR	Planning	California
FutureGen	FutureGen Alliance	Coal	200	Oxy	Saline	Planning	Illinois
Canada							
Project Name	**Leader**	**Feedstock**	**Size MW**	**Capture Process**	**CO_2 Fate**	**Status**	**Location**
Boundary Dam	SaskPower	Coal	110	Post	EOR	Under Construction	Saskatchewan
Bow City	BCPL	Coal	1000	Post	EOR	Planning	Alberta

European Union							
Project Name	**Leader**	**Feedstock**	**Size MW**	**Capture Process**	**CO_2 Fate**	**Status**	**Location**
Ferrybridge	SSE	Coal	500	Post	Depleted Oil	Construction of Pilot	UK
ROAD	E.ON	Coal	250	Post	Saline	Planning	Netherlands
Compostilla	ENDESA	Coal	323	Oxy	Saline	Planning	Spain
Getica	Turceni Energy	Coal	330	Post	Saline	Planning	Romania
Peterhead	Shell and SSE	Gas	385	Post	Depleted Gas	Planning	UK
Don Valley Power Project	2Co Energy	Coal	920	Pre	EOR	Planning	UK
Teesside Low Carbon	Progressive	Coal	400	Pre	Depleted Oil	Planning	UK
Killingholme	C.GEN	Coal	430	Pre	Saline	Planning	UK
White Rose	Capture Power	Coal	426	Oxy	Saline	Planning	UK
Porto Tolle	ENEL	Coal	250	Post	Saline	Planning	Italy
Captain	Summit Power	Coal	400	Post	Depleted Oil	Planning	UK
Magnum	Nuon	Various	1200	Pre	EOR/ EGR	Planning	Netherlands

Norway							
Project Name	**Leader**	**Feedstock**	**Size MW**	**Capture Process**	**CO_2 Fate**	**Status**	**Location**
Mongstad	Statoil	Gas	350	Post	Saline	Operational May 2012	Norway
Longyearbyen	Unis CO2	Coal	N/A	N/A	Saline	Planning	Norway
Rest of the World							
Project Name	**Leader**	**Feedstock**	**Size MW**	**Capture Process**	**CO_2 Fate**	**Status**	**Location**
Daqing	Alstom & Datang	Coal	350	Oxy	EOR	Planning	China
HPAD	Masdar	Gas	400	Pre	EOR	Planning	UAE
GreenGen	GreenGen	Coal	250/400	Pre	Saline	Planning	China

Source: http://sequestration.mit.edu/tools/projects/index_capture.html
Oxy = Oxyfuel Combustion Capture; Pre = Pre Combustion Capture; Post = Post Combustion Capture ; EOR = Enhanced Oil Recovery; EGR = Enhanced Gas Recovery; Saline = Saline Formation; Depleted Gas = Depleted Gas Reservoir; Depleted Oil = Depleted Oil Reservoir; TBD = To Be Decided

Office of the Secretary
Service Date
September 11, 2013

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF PACIFICORP DBA ROCKY MOUNTAIN POWER'S 2013 INTEGRATED RESOURCE PLAN	)))))	**CASE NO. PAC-E-13-05** **ORDER NO. 32890**

On April 30, 2013, PacifiCorp dba Rocky Mountain Power ("Rocky Mountain" or "Company") filed its 2013 Integrated Resource Plan (IRP) with the Commission pursuant to the Commission's Rules and in compliance with the biennial IRP filing requirements mandated in Order No. 22299.

On May 30, 2013, the Commission issued a Notice of Filing establishing a 28-day comment deadline and a 7-day intervention deadline. *See* Order No. 32819. Thereafter, the Commission granted intervention to Idaho Conservation League ("ICL"), Snake River Alliance ("SRA"), Monsanto Company ("Monsanto"), and Renewable Energy Coalition ("REC"). *See* Order Nos. 32827, 32876.

Upon Motion by ICL, the Commission extended the public comment period until August 8, 2013. *See* Order No. 32838.

ROCKY MOUNTAIN'S INTEGRATED RESOURCE PLAN

Rocky Mountain's 2013 IRP is its 12^{th} plan submitted to state regulatory commissions. The Company states that its IRP was developed with participation from numerous public stakeholders, including regulatory staff, advocacy groups, and other interested parties. The 2013 IRP focuses on a 10-year period, 2013-2022.

The Company states that its projected load forecast in the 2013 IRP is down in relation to projected loads used in the 2011 IRP and 2011 IRP Update. The Company cites industrial self-generation and load cancellation requests in Utah and Wyoming as significant drivers of this decreased load estimate. The reduced load forecast has greatly mitigated but not eliminated the Company's need for new resources.

Rocky Mountain also noted that base case wholesale power and natural gas prices are down significantly from the 2011 IRP and 2011 IRP Update. Rocky Mountain states the proliferation of shale gas exploration in North America has led to these favorable market conditions.

The Company identified three goals for its IRP process: (1) determine resource needs focused on the first ten years; (2) identify the preferred portfolio of incremental supply and demand-side resources to meet this need; and (3) develop an action plan for the next two to four years required to implement the plan.

The Company indicated a system capacity deficit of 824 MW starting in 2013 that increases to 2,308 MW in 2022. The Company's load obligation takes into account a 1.2% yearly system coincident-peak load growth rate. This average yearly load forecast is 11.3% lower than the load forecast used in the 2011 IRP. According to the Company, the decreased load forecasts are driven in part by increased self-generation by industry taking advantage of low natural gas prices and by load cancellations. Existing resource capacity has also been adjusted down by an annual average 113 MW between 2013 and 2076 and approximately 200 MW in years 2017 and beyond. When taking into account lower load growth rates and small reductions in existing capacity, the annual load and resource balance deficit has decreased dramatically ranging from 1925 MW in year 2013 to 3852 MW in year 2020 when compared to the 2011 IRP, thus eliminating the need for major resource acquisitions in the first ten years of the planning horizon.

From an energy perspective, PacifiCorp does not experience any deficits throughout the first ten years of the planning horizon during off-peak hours. Minor deficits begin to occur during on-peak hours in 2018 and become increasingly frequent beyond the 2022 time frame.

The Idaho and system retail sales growth that drives resource needs is depicted in the table below. Compared to system sales growth, the Company predicts Idaho residential and commercial growth will exceed the system average while industrial sales growth will be less. PacifiCorp also predicts irrigation sales will decline overall for the system, with a higher rate of reduction in Idaho. Overall, the forecast shows a 0.89% growth rate across the planning horizon's first ten years, with Idaho's growth lagging below the system average at 0.57%.

PacifiCorp identified 19 core cases with different combinations of fuel price, Carbon Dioxide (C02) price, renewable portfolio standard (RPS) requirements, demand-side management (DSM) assumptions, and targeted resources. Each core case was modeled across five different scenarios of the Energy Gateway project implementing various combinations of transmission line segments. Overall, PacifiCorp ran 94 core-case simulations with each generating a unique resource portfolio and an associated net present value revenue requirement

(PVRR) over a 20-year period. A summary of the core cases is included as Attachment A to the Plan.

The Company selected its preferred resource portfolio after performing risk analysis on 37 of the portfolios. The final selection was based primarily on the performance of risk adjusted PVRR, projected cumulative carbon dioxide emissions, and supply reliability measures.

Incremental resources within the first ten years include: 12 MW of combined heat and power resources, 953 MW of Class 2 DSM, 149 MW of solar, and between 650 MW and 1333 MW of annual market power purchases. PacifiCorp identified 23 action items as a result of developing the plan and from feedback received from public participants. Details of these action items are listed in Attachment C to the Plan.

ICL COMMENTS

ICL believes that Rocky Mountain's IRP is flawed and incomplete. ICL is critical of Rocky Mountain's forecast of future carbon costs, its rejection of "the top performing accelerated DSM Portfolio," and the Company's assumption that the utility pays the capital costs associated with distributed PV systems. ICL believes that over the planning horizon it is reasonable to assume that there will be a price attached, legislatively or administratively, to future carbon emissions. ICL forecasts that low, mid and high carbon prices beginning in 2020 will be $15, $20, and $30 and escalate to $25, $42.50, and $70 by 2030, while "RMP assumes a low, mid, and high prices of $0, $16, and $26."

ICL believes that an "arbitrary and unexplained discounting of future carbon prices can expose customers to substantial risk." ICL suggests that the Commission require the Company to estimate resource capacity deficits by both size (MW) and timeframe. ICL believes the Company should identify concrete methods to increase DSM acquisition.

ICL cites the Company's failure to "discuss how changes to transmission scheduling will affect future resource needs, costs, or system operations." Finally, ICL believes that Rocky Mountain does not accurately account for the compliance costs and risks of future coal plant upgrades, nor do they adequately consider reasonable alternatives "to compete against coal."

MONSANTO COMMENTS

Monsanto stated that the Commission should, as it has for previous IRP filings, accept the Company's filing as non-binding. In its comments, Monsanto addressed four issues: (1) inconsistent and unexplained changes to the capacity contribution at system peak for existing interruptible resources; (2) the Company's reliance on its newly developed System Operational and Reliability Benefits Tool ("SBT" or "model") as an analytical model designed to measure incremental economic benefits of specific transmission projects; (3) double counting in the Energy Balance Account; and (4) the complexity of the Company's IRP process.

Monsanto remarked that the Company has cut its forecast of interruptible contract resources at system peak from 281 MW in the 2011 IRP to 141 MW in this IRP filing. According to Monsanto, this is implausible because on page 95 of the filing Rocky Mountain cites the availability of "324 MW of load interruption capability at time of system peak."

Monsanto believes the Company's SBT model is "untested" and its results are "unverified" by "third parties and stakeholders." Monsanto states the model may have potential "adverse consequences" to the MSP's allocation of costs to Idaho. Nonetheless, Monsanto cites as "positive features" in the Company's IRP: (1) the use of planning criteria in the IRP based on achieving a 13% planning reserve margin associated with summer peak loads; (2) forecasted energy shortages and the importance to the PacifiCorp system of the differences between on-peak and off-peak consumption of electricity; and (3) the role of the state renewable

Portfolio Standards ("RPS") in the IRP process, including the newly-developed "RBS scenario maker" which was included in the IRP to identify and isolate the costs associated with the state's specific RPS requirements.

Monsanto believes that the Company's updated "Energy Balance Determination" is not consistent with the updated "Capacity Balance Determination." According to Monsanto, the Company includes "interruptibles" in its Existing Resources, and Sales are deducted. Sales are also included in the Obligation equation. This double counts Sales as both reducing resources and increasing load obligation.

Finally, Monsanto cites to its "renewed effort to actively participate" in the IRP process. As a result, Monsanto states that it has become clear that Rocky Mountain has intentionally designed the IRP process to be overly complex so as to discourage participation. Monsanto believes the Company's IRP process should be overhauled and suggested Rocky Mountain more closely emulate the IRP process implemented by Idaho Power.

REC COMMENTS

REC states that the organization "is a large group of primarily existing hydroelectric Public Utility Regulatory Policies Act (PURPA) qualifying facilities (QF) located in

PacifiCorp's multi-state service areas." REC's comments focus on a single issue: the year of resource deficiency cited in Rocky Mountain's 2013 IRP filing.

REC remarks that the Company often refers to the "next avoidable resource as a 2024 CCCT." REC believes that Rocky Mountain's decision of how or when to fill a resource deficit, whether from purchased power, DSM or a new generating facility, does not negate the reality of a specific capacity deficit in 2013, which grows significantly each year of the planning horizon (*see* PacifiCorp 2013 IRP Volume 1, page 99, Table 5.1,2). REC states that it has several members that have existing and long-standing PURPA contracts with Rocky Mountain. Contracts expiring and needing replacement could be impacted by avoided cost pricing based upon the year of deficit being established as 2024.

SRA COMMENTS

Snake River Alliance is an Idaho-based non-profit organization, established in 1979 to address Idahoans' concerns about nuclear waste and safety issues. In 2007, SRA expanded the scope of its mission by launching its Clean Energy Program. SRA believes the Company provided stakeholders reasonable opportunities to provide input into the IRP process.

SRA questions the Company's efforts to upgrade and retrofit its coal plants. SRA believes the Company relies too heavily on uncertain market transactions in lieu of a timely renewable resource acquisition plan. According to SRA, Rocky Mountain has adopted an unrealistic and conservative forecast of future carbon regulation. SRA is critical of the Company's participation in multi-utility effort to combat the EPA's implementation of new regulations under the Clean Air Act. SRA believes the Company should conduct a full "coal plant analysis" that accounts for the total costs of "anticipated emission-control upgrades."

SRA questions the Company's commitment to renewable energy resources. SRA believes the Company's wind resource additions are the minimum amount required under the utility's Oregon RPS obligations. SRA advocates an accelerated deployment of energy efficiency and demand response programs.

SRA highlighted the Company's acknowledgment of lower annual system load growth and believes the Commission should defer acceptance of the IRP filing until the Company can cure some of the flaws and concerns referenced in SRA's comments.

STAFF COMMENTS

Staff recommended the Commission acknowledge the Company's 2013 IRP. Staff believes the Company performed extensive analyses, gave reasonably equal consideration of supply- and demand-side resources, and provided acceptable opportunities for public input, resulting in an IRP that satisfies the Commission established requirements.

Staff's analysis focused on two main issues: (1) Load and Resource Balance – Issues related to the load forecast and planning reserve margin; and (2) Resource Portfolio Selection – Company's rationale for selecting its final preferred resource portfolio; issues related to RPS, market risk, and near term investments in transmission and coal plant emission controls.

Load Resource Balance

Staff noted that existing resource capacity net of system load obligation shows a positive reserve margin of 4.4% in 2013 becoming negative starting in year 2016. This is far short of the Company's goal of maintaining a 13% planning reserve margin.

The large reductions in load forecasts compared to the Company's 2011 IRP is largely attributable to load reductions in the industrial sector. Staff examined electricity forecasts in the Energy Information Agency (EIA) 2011 and 2013 Annual Energy Outlook for the Mountain West and Pacific regions. According to Staff, the percentage decrease in projected energy use across the same ten-year period was comparable (5-6% reduction) to the percent change in the energy forecast of this year's IRP with the 2011 IRP Update.

Staff believes the Company's load forecasts in its 2011 IRP were overly optimistic. Given the reduction to the 2013 IRP load forecast, comparable reductions relative to EIA forecasts, and the methodology changes the Company has adopted, Staff believes the Company's latest forecasts are more reasonable and in-line with current circumstances.

Staff believes that the Company's 13% target for planning reserves is reasonable. A planning reserve margin between 12 and 15% does not increase system costs in a significant manner. Staff noted that the Company also establishes incremental planning reserves within the Northwest Power Pool and its participation in the California Independent System Operator (CISO) energy imbalance market.

Resource Portfolio Selection

Staff highlights the Company's decision to defer the addition of a major generation resource until 2024, when the Company expects to add a 423 MW CCCT gas plant and 432 MW of wind generation. The Company plans to use unbundled renewable energy credits (REC) to meet Washington RPS requirements prior to 2024.

Rocky Mountain selected the second highest ranked portfolio (EG2-C07) as its preliminary preferred portfolio. Staff believes this was reasonable for two reasons. First, the preliminary preferred portfolio and the accelerated DSM portfolio are nearly identical during the first ten years. The only difference is that the accelerated DSM portfolio has an increased amount of DSM Class 2 resources in lieu of firm market purchases.

Staff believes the Company's rejection of the accelerated DSM portfolio was reasonable. Given that the Company does not have confidence that the ramp rates are achievable, passing on the accelerated DSM portfolio and choosing the next highest ranked portfolio would carry less risk. This gives the Company several IRP cycles to determine if the ramp rates are feasible. However, modeling accelerated DSM ramp rates gave the Company insight as to the positive effect cost-effective DSM has on risk-adjusted PVRR of a given portfolio prompting the Company to identify several action items to attempt to accelerate its Class 2 DSM programs.

Second, by not making selections based on model results alone, the Company is demonstrating that it is using its decision support tools appropriately. Rocky Mountain augmented its preliminary preferred portfolio so that wind resources needed to meet Washington RPS requirements were replaced with unbundled RECs. The results reflect a $116 million to $232 million reduction in risk-adjusted PVRR compared to the preliminary preferred portfolio. Staff supports this refinement to significantly reduce revenue requirements while allowing the Company to comply with Washington State regulatory requirements.

Staff's position is that requirements imposed by a jurisdiction that drives incremental cost above the comparable resource cost should generally not be imposed on Idaho ratepayers. The Company developed several portfolios with and without RPS requirements to understand its effect. Depending on the specific case, those model runs with no RPS requirements include very little or no incremental wind, biomass, or geothermal generation resources. This indicates, most likely due to low capacity contribution rates, that renewables are not cost-effective when compared to other resources System Optimizer can choose to meet peak loads.

Staff does not believe that the increase in the incremental firm market purchases in the 2013 preferred portfolio is unreasonable. However, Staff is concerned that the apparent increase in customer exposure to electricity price risk will occur if large market anomalies occur even though the Company has accurately evaluated market price risk through modeling variable electricity prices. Additionally, there is no guarantee that the energy will be available for sale in the market if a geographically widespread peak event occurs. Staff believes resource adequacy studies by the Northwest Power Planning Council and the Western Electricity Coordinating Council, as well as the inclusion of a 13% planning reserve margin, provide reasonable protection. Nevertheless, the potential for over-reliance on the market exists.

Staff is encouraged by the Company's development of a System Benefit Tool (SBT) to measure transmission benefits not captured by other IRP models. Staff believes SBT benefits can be reported with appropriate caveats but should not be rolled into the overall IRP analysis until the error of the calculation is well understood and sufficiently small. Construction of the remaining segments of the Energy Gateway Transmission Project after 2020 will enable more accurate analysis in future IRP's.

Staff commented that the lowest mean PVRR across all CO2 levels was a portfolio that assumes no additional thermal base load capacity, accelerated DSM ramp rates, and no Populous to Winstar transmission line (Segment D). Staff recommended the Company further explore these alternatives to offset the need for the new line. In the interim, Staff does not object to the Company continuing the permit procurement process for Segment D.

Again, Staff emphasizes that the system benefits of transmission investments seem to disproportionately favor states with RPS standards. Given that Idaho does not have an RPS, Staff believes increased documentation and support are required when the allocation of cost are not proportional to the jurisdictional benefit.

Staff remarked that Rocky Mountain is faced with making large coal plant emission control investments in order to comply with federal environmental regulations. The Company claims that its efforts to either shut down or convert some of its coal fleet to natural gas is complicated because it is bound by shared ownership agreements and legal compliance requirements in combination with the fact it is not the majority owner or operator of either plant.

Staff believes that Rocky Mountain's analysis of the alternative that retires coal plant units on the compliance date did not take into account the location of alternate resources that could reduce the need for additional transmission capacity. For example, Staff believes that if the Company's Jim Bridger units were shutdown early and replaced with generation closer to major load centers, a significant amount of existing transmission capacity could become available lessening and/or delaying the need for the Segment D. Staff believes an analysis should be done and, if warranted, transmission implementation plans should be adjusted and any cost savings should be included in coal plant emission control investment decisions.

PUBLIC COMMENTS

On June 21, 2013, the Commission received a joint letter from SRA, ICL, Sierra Club, HEAL Utah and the Powder River Basin Resource Council (hereinafter collectively referred to as "organizations"). The organizations expressed concern regarding the scope of PacifiCorp's IRP across its multi-state jurisdictions. Specifically, the organizations referenced the pollution controls made necessary by the EPA's implementation of the Regional Haze Rule in Wyoming. The organizations believe the Company's IRP and coal study "completely missed the mark" by not adequately accounting for the costs of the foreseeable pollution control requirements. Accordingly, they have asked the Commission to defer acceptance of the IRP filing until the Company addresses these concerns.

On August 8, 2013, the Commission received a comment from NW Energy Coalition ("NWEC"). NWEC states that its overarching concern is that the Company continues to focus and rely on outdated coal plants that are becoming increasingly expensive to operate – coupled with a lack of appreciation for the reduced risk and cost offered by demand-side resources and newer resource options such as demand response, distributed generation and renewables.

NWEC criticizes the Company's lack of documentation to substantiate its assumptions that the accelerated DSM in its least cost/risk portfolio is not reliably achievable. NWEC stated that Rocky Mountain's explanations of its action plan to achieve accelerated Class 2 DSM targets are too vague. NWEC cited key parts of the Company's 2011 IRP action plan that were not implemented. According to NWEC, an analysis of the Company's DSM achievements since 2011 suggests the Company is being too conservative in setting its 2013 IRP targets for DSM. NWEC recommended the Commission urge Rocky Mountain to continue its progress on Class 2 DSM achievements that match those identified in the least cost/least risk portfolio Case EGO2-C15.

NWEC is pleased with the Company's efforts in improving its analysis of the costs and risks associated with upgrades to its coal fleet. These improvements notwithstanding, the

Coalition maintains that the Company is still underestimating the cost and risk of continued reliance on coal generation.

NWEC believes that the Company's base case modeling assumptions utilize a CO2 price (zero cost through 2022) that is too low and, second, the Company underestimates the likely requirements, and therefore costs, from known and unknown future environmental regulations that impose pollution control investments. NWEC recommended that prior to Commission approval or acknowledgment of any coal plant upgrades contained in the 2013 IRP Action Plan, the Company be required to perform a revised coal unit analysis that incorporates a broader range of current and future compliance scenarios that can be evaluated for economic and regulatory risk.

NWEC believes that load control and demand response are undervalued in the 2013 IRP. NWEC recommended close Commission scrutiny of the underlying model assumptions in the 2013 IRP of Class 1 DSM. NWEC also recommended the Commission encourage Rocky Mountain to improve its analysis regarding demand response and other load control tools in its next IRP.

NWEC is critical of the Company's failure to increase or maintain its commitment to renewable energy resources. NWEC believes the IRP starts with too high a current cost for solar PV and does not incorporate the likely decline in costs over both the short and long term. NWEC recommended the Commission closely review the solar price projections for Idaho and encourage the Company to look for ways to close the gap between technical potential and achievable technical potential in distributed solar resources. NWEC also recommended the Commission urge the Company to review and improve its methodology for including natural gas price uncertainty and risk in IRP modeling in the next IRP.

Finally, NWEC cited the Company's efforts to assess the effects of transmission upgrades on the planning process. NWEC recommended the Commission seek out a process, workshops, to develop a broader transmission assessment into the IRP.

On August 8, 2013, the Renewable Northwest Project ("Renewable Northwest" or "RNP") submitted a public comment on Rocky Mountain's 2013 IRP. Renewable Northwest commended the Company on the inclusion of stakeholders and what it called "a robust public process."

Renewable Northwest states that Rocky Mountain is investing in the past, not the future. Approving this IRP gives PacifiCorp a green light to make long-term investments at four coal units and to delay the acquisition of new clean energy resources until 2022.

Renewable Northwest opined that, since fall of 2012, the landscape of federal energy policy has shifted further than any time in the last five years. Renewable Northwest believes EPA regulations will add costs to the operation of coal units, and may not allow the Company's facilities to operate at today's level of output. The organization believes that Rocky Mountain's resource strategy stands in sharp contrast to that of its utility peers. Thus, Renewable Northwest recommended the Commission review this IRP and action plan in light of the potential for EPA regulation of carbon and under the high CO2 price, rather than the base CO2 assumption on which many of the Company's investment decisions are based.

Renewable Northwest is critical of the Company's failure to choose the IRP's highest performing portfolio featuring accelerated energy efficiency and the use of cheaper gas peaking units rather than large combined cycle units. The results clearly demonstrate that accelerating the acquisition of energy efficiency throughout the Company's service territory saves ratepayers money and reduces their exposure to volatility in the natural gas and wholesale power market.

Renewable Northwest believes the Company did not provide evidence that the energy efficiency measures could not be accelerated. Renewable Northwest recommended the Commission communicate to Rocky Mountain that it expects the Company to clarify what definitive and quantifiable actions will be taken to implement an aggressive energy efficiency program.

Renewable Northwest believes the Company's flawed assumptions and analysis of renewable energy resources led to their lack of inclusion in the 2013 IRP. Rocky Mountain uses a simpler but less accurate methodology that simply considers the likelihood that renewables will be generating during the "super-peak" period. The result is to credit renewable resources with less capacity value, which makes portfolios with renewables appear more expensive due to excess capacity resources.

Renewable Northwest commends Rocky Mountain for their improved transmission analysis. The methodological improvements were ambitious and increased the IRP's complexity, but RNP considers the results impressive. Renewable Northwest agrees with the

Company that the System Benefit Tool used in this IRP is preliminary and there remains considerable flexibility as to how these benefits should be measured.

COMMISSION FINDINGS AND DECISION

The Commission has reviewed the filings of record in Case No. PAC-E-13-05, including Rocky Mountain's 2013 Integrated Resource Plan, appendices and addendums, and related comments. We find that the Company's 2013 IRP is in the appropriate format and contains the necessary information outlined by the Commission in Order No. 22299. The Commission accepts Rocky Mountain's 2013 IRP filing.

In so doing, the Commission reiterates that a standard IRP is merely a plan, not a blueprint. An IRP is a utility planning document that incorporates many assumptions and projections at a specific point in time. It is the ongoing planning process that we acknowledge, not the conclusions or results. The Commission offers no opinion or ruling regarding the prudency of the Company's election of its preferred resource portfolio.

The Commission acknowledges the comments and criticisms of the intervenors and other interested parties, including but not limited to Monsanto and ICL. The Commission appreciates the Company providing a meaningful process and venue to enable the parties' active participation in the IRP process. Engagement by multiple interested parties is a prerequisite to the development of a comprehensive and useful IRP.

The Commission also acknowledges that recent history has demonstrated that attempts by energy analysts to predict carbon pricing is fraught with failure and uncertainty. However, it seems more likely than not that the EPA will move forward and enact additional regulations of fossil fuels under the federal Clean Air Act. In light of this contingency, it appears to be in the best interest of the Company and its customers to continue to evaluate and devote more focus on the development of alternative energy resources.

The Commission directs the Company to increase its efforts toward achieving higher levels of cost-effective DSM. Instituting cost-effective energy efficiency measures that reduce customer demand benefits everyone. Such measures can obviate the need for new generation resources and thereby decrease the constant upward pressure on energy pricing. Cost-effective reductions in customer demand, particularly in peak hours and months, are almost always preferable to the construction of a new natural gas plant or purchases on the wholesale power market. Therefore, the Commission will be attentive to Rocky Mountain's efforts toward DSM programs. In future IRP and DSM filings, the Commissions directs the Company to present clear and quantifiable metrics governing its actions regarding decisions to implement or decline to implement energy efficiency programs.

Finally, several parties, including the Company, Monsanto and Staff, commented on the Company's new model for measuring transmission benefits, the System Benefit Tool (SBT). As is always the case regarding utility planning models, the reliability of the SBT will be borne out over time. The Commission anticipates that the usefulness of the SBT will become clearer upon the construction of the remaining segments of the Energy Gateway Transmission Project.

CONCLUSIONS OF LAW

The Idaho Public Utilities Commission has jurisdiction over PacifiCorp dba Rocky Mountain Power, an electric utility, pursuant to Title 61 of the Idaho Code and the Commission's Rules of Procedure, IDAPA 31.01.01.000 *et seq*.

ACCEPTANCE OF FILING

Based upon our review, we find it reasonable to accept and acknowledge Rocky Mountain's filed 2013 Electric IRP. Our acceptance of Rocky Mountain's 2013 IRP should not be interpreted as an endorsement of any particular element of the plan, nor does it constitute approval of any resource acquisition contained in the plan.

O R D E R

IT IS HEREBY ORDERED that PacifiCorp's 2013 Integrated Resource Plan is accepted for filing. Acceptance of the 2013 IRP should not be interpreted as an endorsement of any particular element of the plan, nor does it constitute approval of any resource acquisition or proposed action contained in the plan.

THIS IS A FINAL ORDER. Any person interested in this Order may petition for reconsideration within twenty-one (21) days of the service date of this Order with regard to any matter decided in this Order. Within seven (7) days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. *See Idaho Code* § 61-626.

DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 11th day of September 2013.

PAUL KJELLANDER, PRESIDENT

MACK A. REDFORD, COMMISSIONER

MARSHA H. SMITH, COMMISSIONER

ATTEST:

Barbara Barrows
Assistant Commission Secretary

O:PAC-E-13-05_np3

EAST KENTUCKY POWER COOPERATIVE, INC.

PSC CASE NO. 2012-00149

FIRST REQUEST FOR INFORMATION RESPONSE

MOVANTS' INITIAL REQUESTS FOR INFORMATION DATED 06/08/12

REQUEST 43

RESPONSIBLE PERSON: Scott Drake

COMPANY: East Kentucky Power Cooperative, Inc.

Request 43. Refer to p. 15 of the DSM Report found in Technical Appendix Volume 2. Explain the basis for the claim that $0/MWh is the "likely value placed on carbon dioxide over the 15 year planning period," and produce any documents supporting that claim.

Response 43. At the time the 2009 IRP was done, a value was set at $40/ton for use in the Societal Cost test as an estimate of what future allowance prices could be in a marketplace with a cap and trade program for carbon. Given there has been no legislation passed dealing with carbon, the cost of complying with environmental regulation is reflected in the avoided capacity and energy costs, and therefore, for the 2012 IRP the value for the Societal Cost test was set at $0/MWh.

EXHIBIT TFC-6

Technical Support Document: -
Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis -
Under Executive Order 12866 -

Interagency Working Group on Social Cost of Carbon, United States Government

With participation by

Council of Economic Advisers
Council on Environmental Quality
Department of Agriculture
Department of Commerce
Department of Energy
Department of Transportation
Environmental Protection Agency
National Economic Council
Office of Management and Budget
Office of Science and Technology Policy
Department of the Treasury

May 2013

Executive Summary

Under Executive Order 12866, agencies are required, to the extent permitted by law, "to assess both the costs and the benefits of the intended regulation and, recognizing that some costs and benefits are difficult to quantify, propose or adopt a regulation only upon a reasoned determination that the benefits of the intended regulation justify its costs." The purpose of the "social cost of carbon" (SCC) estimates presented here is to allow agencies to incorporate the social benefits of reducing carbon dioxide (CO_2) emissions into cost-benefit analyses of regulatory actions that impact cumulative global emissions. The SCC is an estimate of the monetized damages associated with an incremental increase in carbon emissions in a given year. It is intended to include (but is not limited to) changes in net agricultural productivity, human health, property damages from increased flood risk, and the value of ecosystem services due to climate change.

The interagency process that developed the original U.S. government's SCC estimates is described in the 2010 interagency technical support document (TSD) (Interagency Working Group on Social Cost of Carbon 2010). Through that process the interagency group selected four SCC values for use in regulatory analyses. Three values are based on the average SCC from three integrated assessment models (IAMs), at discount rates of 2.5, 3, and 5 percent. The fourth value, which represents the 95th percentile SCC estimate across all three models at a 3 percent discount rate, is included to represent higher-than-expected impacts from temperature change further out in the tails of the SCC distribution.

While acknowledging the continued limitations of the approach taken by the interagency group in 2010, this document provides an update of the SCC estimates based on new versions of each IAM (DICE, PAGE, and FUND). It does not revisit other interagency modeling decisions (e.g., with regard to the discount rate, reference case socioeconomic and emission scenarios, or equilibrium climate sensitivity). Improvements in the way damages are modeled are confined to those that have been incorporated into the latest versions of the models by the developers themselves in the peer-reviewed literature.

The SCC estimates using the updated versions of the models are higher than those reported in the 2010 TSD. By way of comparison, the four 2020 SCC estimates reported in the 2010 TSD were \$7, \$26, \$42 and \$81 (2007\$). The corresponding four updated SCC estimates for 2020 are \$12, \$43, \$65, and \$129 (2007\$). The model updates that are relevant to the SCC estimates include: an explicit representation of sea level rise damages in the DICE and PAGE models; updated adaptation assumptions, revisions to ensure damages are constrained by GDP, updated regional scaling of damages, and a revised treatment of potentially abrupt shifts in climate damages in the PAGE model; an updated carbon cycle in the DICE model; and updated damage functions for sea level rise impacts, the agricultural sector, and reduced space heating requirements, as well as changes to the transient response of temperature to the buildup of GHG concentrations and the inclusion of indirect effects of methane emissions in the FUND model. The SCC estimates vary by year, and the following table summarizes the revised SCC estimates from 2010 through 2050.

EXHIBIT TFC-6

Revised Social Cost of CO_2, 2010 – 2050 (in 2007 dollars per metric ton of CO_2)

Discount Rate Year	5.0% Avg	3.0% Avg	2.5% Avg	3.0% 95th
2010	11	33	52	90
2015	12	38	58	109
2020	12	43	65	129
2025	14	48	70	144
2030	16	52	76	159
2035	19	57	81	176
2040	21	62	87	192
2045	24	66	92	206
2050	27	71	98	221

I. Purpose

The purpose of this document is to update the schedule of social cost of carbon (SCC) estimates from the 2010 interagency technical support document (TSD) (Interagency Working Group on Social Cost of Carbon 2010).[1] E.O. 13563 commits the Administration to regulatory decision making "based on the best available science."[2] Additionally, the interagency group recommended in 2010 that the SCC estimates be revisited on a regular basis or as model updates that reflect the growing body of scientific and economic knowledge become available.[3] New versions of the three integrated assessment models used by the U.S. government to estimate the SCC (DICE, FUND, and PAGE), are now available and have been published in the peer reviewed literature. While acknowledging the continued limitations of the approach taken by the interagency group in 2010 (documented in the original 2010 TSD), this document provides an update of the SCC estimates based on the latest peer-reviewed version of the models, replacing model versions that were developed up to ten years ago in a rapidly evolving field. It does not revisit other assumptions with regard to the discount rate, reference case socioeconomic and emission scenarios, or equilibrium climate sensitivity. Improvements in the way damages are modeled are confined to those that have been incorporated into the latest versions of the models by the developers themselves in the peer-reviewed literature. The agencies participating in the interagency working group continue to investigate potential improvements to the way in which economic damages associated with changes in CO_2 emissions are quantified.

Section II summarizes the major updates relevant to SCC estimation that are contained in the new versions of the integrated assessment models released since the 2010 interagency report. Section III presents the updated schedule of SCC estimates for 2010 – 2050 based on these versions of the models. Section IV provides a discussion of other model limitations and research gaps.

II. Summary of Model Updates

This section briefly summarizes changes to the most recent versions of the three integrated assessment models (IAMs) used by the interagency group in 2010. We focus on describing those model updates that are relevant to estimating the social cost of carbon, as summarized in Table 1. For example, both the DICE and PAGE models now include an explicit representation of sea level rise damages. Other revisions to PAGE include: updated adaptation assumptions, revisions to ensure damages are constrained by GDP, updated regional scaling of damages, and a revised treatment of potentially abrupt shifts in climate damages. The DICE model's simple carbon cycle has been updated to be more consistent with a more complex climate model. The FUND model includes updated damage functions for sea level rise impacts, the agricultural sector, and reduced space heating requirements, as well as changes to the transient response of temperature to the buildup of GHG concentrations and the inclusion of indirect effects of

[1] In this document, we present all values of the SCC as the cost per metric ton of CO_2 emissions. Alternatively, one could report the SCC as the cost per metric ton of carbon emissions. The multiplier for translating between mass of CO_2 and the mass of carbon is 3.67 (the molecular weight of CO_2 divided by the molecular weight of carbon = 44/12 = 3.67).
[2] http://www.whitehouse.gov/sites/default/files/omb/inforeg/eo12866/eo13563_01182011.pdf
[3] See p. 1, 3, 4, 29, and 33 (Interagency Working Group on Social Cost of Carbon 2010).

methane emissions. Changes made to parts of the models that are superseded by the interagency working group's modeling assumptions – regarding equilibrium climate sensitivity, discounting, and socioeconomic variables – are not discussed here but can be found in the references provided in each section below.

Table 1: Summary of Key Model Revisions Relevant to the Interagency SCC

IAM	Version used in 2010 Interagency Analysis	New Version	Key changes relevant to interagency SCC
DICE	2007	2010	Updated calibration of the carbon cycle model and explicit representation of sea level rise (SLR) and associated damages.
FUND	3.5 (2009)	3.8 (2012)	Updated damage functions for space heating, SLR, agricultural impacts, changes to transient response of temperature to buildup of GHG concentrations, and inclusion of indirect climate effects of methane.
PAGE	2002	2009	Explicit representation of SLR damages, revisions to damage function to ensure damages do not exceed 100% of GDP, change in regional scaling of damages, revised treatment of potential abrupt damages, and updated adaptation assumptions.

A. DICE

DICE 2010 includes a number of changes over the previous 2007 version used in the 2010 interagency report. The model changes that are relevant for the SCC estimates developed by the interagency working group include: 1) updated parameter values for the carbon cycle model, 2) an explicit representation of sea level dynamics, and 3) a re-calibrated damage function that includes an explicit representation of economic damages from sea level rise. Changes were also made to other parts of the DICE model—including the equilibrium climate sensitivity parameter, the rate of change of total factor productivity, and the elasticity of the marginal utility of consumption—but these components of DICE are superseded by the interagency working group's assumptions and so will not be discussed here. More details on DICE2007 can be found in Nordhaus (2008) and on DICE2010 in Nordhaus (2010). The DICE2010 model and documentation is also available for download from the homepage of William Nordhaus.

Carbon Cycle Parameters

DICE uses a three-box model of carbon stocks and flows to represent the accumulation and transfer of carbon among the atmosphere, the shallow ocean and terrestrial biosphere, and the deep ocean. These parameters are "calibrated to match the carbon cycle in the Model for the Assessment of Greenhouse

Gas Induced Climate Change (MAGICC)" (Nordhaus 2008 p 44).[4] Carbon cycle transfer coefficient values in DICE2010 are based on re-calibration of the model to match the newer 2009 version of MAGICC (Nordhaus 2010 p 2). For example, in DICE2010, in each decade, 12 percent of the carbon in the atmosphere is transferred to the shallow ocean, 4.7 percent of the carbon in the shallow ocean is transferred to the atmosphere, 94.8 percent remains in the shallow ocean, and 0.5 percent is transferred to the deep ocean. For comparison, in DICE 2007, 18.9 percent of the carbon in the atmosphere is transferred to the shallow ocean each decade, 9.7 percent of the carbon in the shallow ocean is transferred to the atmosphere, 85.3 percent remains in the shallow ocean, and 5 percent is transferred to the deep ocean.

The implication of these changes for DICE2010 is in general a weakening of the ocean as a carbon sink and therefore a higher concentration of carbon in the atmosphere than in DICE2007, for a given path of emissions. All else equal, these changes will generally increase the level of warming and therefore the SCC estimates in DICE2010 relative to those from DICE2007.

Sea Level Dynamics

A new feature of DICE2010 is an explicit representation of the dynamics of the global average sea level anomaly to be used in the updated damage function (discussed below). This section contains a brief description of the sea level rise (SLR) module; a more detailed description can be found on the model developer's website.[5] The average global sea level anomaly is modeled as the sum of four terms that represent contributions from: 1) thermal expansion of the oceans, 2) melting of glaciers and small ice caps, 3) melting of the Greenland ice sheet, and 4) melting of the Antarctic ice sheet.

The parameters of the four components of the SLR module are calibrated to match consensus results from the IPCC's Fourth Assessment Report (AR4).[6] The rise in sea level from thermal expansion in each time period (decade) is 2 percent of the difference between the sea level in the previous period and the long run equilibrium sea level, which is 0.5 meters per degree Celsius (°C) above the average global temperature in 1900. The rise in sea level from the melting of glaciers and small ice caps occurs at a rate of 0.008 meters per decade per °C above the average global temperature in 1900.

The contribution to sea level rise from melting of the Greenland ice sheet is more complex. The equilibrium contribution to SLR is 0 meters for temperature anomalies less than 1 °C and increases linearly from 0 meters to a maximum of 7.3 meters for temperature anomalies between 1 °C and 3.5 °C. The contribution to SLR in each period is proportional to the difference between the previous period's sea level anomaly and the equilibrium sea level anomaly, where the constant of proportionality increases with the temperature anomaly in the current period.

[4] MAGICC is a simple climate model initially developed by the U.S. National Center for Atmospheric Research that has been used heavily by the Intergovernmental Panel on Climate Change (IPCC) to emulate projections from more sophisticated state of the art earth system simulation models (Randall et al. 2007).
[5] Documentation on the new sea level rise module of DICE is available on William Nordhaus' website at: http://nordhaus.econ.yale.edu/documents/SLR_021910.pdf.
[6] For a review of post-IPCC AR4 research on sea level rise, see Nicholls et al. (2011) and NAS (2011).

The contribution to SLR from the melting of the Antarctic ice sheet is -0.001 meters per decade when the temperature anomaly is below 3 °C and increases linearly between 3 °C and 6 °C to a maximum rate of 0.025 meters per decade at a temperature anomaly of 6 °C.

Re-calibrated Damage Function

Economic damages from climate change in the DICE model are represented by a fractional loss of gross economic output in each period. A portion of the remaining economic output in each period (net of climate change damages) is consumed and the remainder is invested in the physical capital stock to support future economic production, so each period's climate damages will reduce consumption in that period and in all future periods due to the lost investment. The fraction of output in each period that is lost due to climate change impacts is represented as one minus a fraction, which is one divided by a quadratic function of the temperature anomaly, producing a sigmoid ("S"-shaped) function.[7] The loss function in DICE2010 has been expanded by adding a quadratic function of SLR to the quadratic function of temperature. In DICE2010 the temperature anomaly coefficients have been recalibrated to avoid double-counting damages from sea level rise that were implicitly included in these parameters in DICE2007.

The aggregate damages in DICE2010 are illustrated by Nordhaus (2010 p 3), who notes that "…damages in the uncontrolled (baseline) [i.e., reference] case … in 2095 are $12 trillion, or 2.8 percent of global output, for a global temperature increase of 3.4 °C above 1900 levels." This compares to a loss of 3.2 percent of global output at 3.4 °C in DICE2007. However, in DICE2010, annual damages are lower in most of the early periods of the modeling horizon but higher in later periods than would be calculated using the DICE2007 damage function. Specifically, the percent difference between damages in the base run of DICE2010 and those that would be calculated using the DICE2007 damage function starts at +7 percent in 2005, decreases to a low of -14 percent in 2065, then continuously increases to +20 percent by 2300 (the end of the interagency analysis time horizon), and to +160 percent by the end of the model time horizon in 2595. The large increases in the far future years of the time horizon are due to the permanence associated with damages from sea level rise, along with the assumption that the sea level is projected to continue to rise long after the global average temperature begins to decrease. The changes to the loss function generally decrease the interagency working group SCC estimates slightly given that relative increases in damages in later periods are discounted more heavily, all else equal.

B. FUND

FUND version 3.8 includes a number of changes over the previous version 3.5 (Narita et al. 2010) used in the 2010 interagency report. Documentation supporting FUND and the model's source code for all versions of the model is available from the model authors.[8] Notable changes, due to their impact on the

[7] The model and documentation, including formulas, are available on the author's webpage at http://www.econ.yale.edu/~nordhaus/homepage/RICEmodels.htm.

[8] http://www.fund-model.org/. This report uses version 3.8 of the FUND model, which represents a modest update to the most recent version of the model to appear in the literature (version 3.7) (Anthoff and Tol, 2013). For the purpose of computing the SCC, the relevant changes (between 3.7 to 3.8) are associated with improving

SCC estimates, are adjustments to the space heating, agriculture, and sea level rise damage functions in addition to changes to the temperature response function and the inclusion of indirect effects from methane emissions.[9] We discuss each of these in turn.

Space Heating

In FUND, the damages associated with the change in energy needs for space heating are based on the estimated impact due to one degree of warming. These baseline damages are scaled based on the forecasted temperature anomaly's deviation from the one degree benchmark and adjusted for changes in vulnerability due to economic and energy efficiency growth. In FUND 3.5, the function that scales the base year damages adjusted for vulnerability allows for the possibility that in some simulations the benefits associated with reduced heating needs may be an unbounded convex function of the temperature anomaly. In FUND 3.8, the form of the scaling has been modified to ensure that the function is everywhere concave and that there will exist an upper bound on the benefits a region may receive from reduced space heating needs. The new formulation approaches a value of two in the limit of large temperature anomalies, or in other words, assuming no decrease in vulnerability, the reduced expenditures on space heating at any level of warming will not exceed two times the reductions experienced at one degree of warming. Since the reduced need for space heating represents a benefit of climate change in the model, or a negative damage, this change will increase the estimated SCC. This update accounts for a significant portion of the difference in the expected SCC estimates reported by the two versions of the model when run probabilistically.

Sea Level Rise and Land Loss

The FUND model explicitly includes damages associated with the inundation of dry land due to sea level rise. The amount of land lost within a region is dependent upon the proportion of the coastline being protected by adequate sea walls and the amount of sea level rise. In FUND 3.5 the function defining the potential land lost in a given year due to sea level rise is linear in the rate of sea level rise for that year. This assumption implicitly assumes that all regions are well represented by a homogeneous coastline in length and a constant uniform slope moving inland. In FUND 3.8 the function defining the potential land lost has been changed to be a convex function of sea level rise, thereby assuming that the slope of the shore line increases moving inland. The effect of this change is to typically reduce the vulnerability of some regions to sea level rise based land loss, thereby lowering the expected SCC estimate. [10]

Agriculture

consistency with IPCC AR4 by adjusting the atmospheric lifetimes of CH4 and N2O and incorporating the indirect forcing effects of CH4, along with making minor stability improvements in the sea wall construction algorithm.

[9] The other damage sectors (water resources, space cooling, land loss, migration, ecosystems, human health, and extreme weather) were not significantly updated.

[10] For stability purposes this report also uses an update to the model which assumes that regional coastal protection measures will be built to protect the most valuable land first, such that the marginal benefits of coastal protection is decreasing in the level of protection following Fankhauser (1995).

In FUND, the damages associated with the agricultural sector are measured as proportional to the sector's value. The fraction is bounded from above by one and is made up of three additive components that represent the effects from carbon fertilization, the rate of temperature change, and the level of the temperature anomaly. In both FUND 3.5 and FUND 3.8, the fraction of the sector's value lost due to the level of the temperature anomaly is modeled as a quadratic function with an intercept of zero. In FUND 3.5, the coefficients of this loss function are modeled as the ratio of two random normal variables. This specification had the potential for unintended extreme behavior as draws from the parameter in the denominator approached zero or went negative. In FUND 3.8, the coefficients are drawn directly from truncated normal distributions so that they remain in the range $[0,\infty)$ and $(-\infty,0]$, respectively, ensuring the correct sign and eliminating the potential for divide by zero errors. The means for the new distributions are set equal to the ratio of the means from the normal distributions used in the previous version. In general the impact of this change has been to decrease the range of the distribution while spreading out the distributions' mass over the remaining range relative to the previous version. The net effect of this change on the SCC estimates is difficult to predict.

Transient Temperature Response

The temperature response model translates changes in global levels of radiative forcing into the current expected temperature anomaly. In FUND, a given year's increase in the temperature anomaly is based on a mean reverting function where the mean equals the equilibrium temperature anomaly that would eventually be reached if that year's level of radiative forcing were sustained. The rate of mean reversion defines the rate at which the transient temperature approaches the equilibrium. In FUND 3.5, the rate of temperature response is defined as a decreasing linear function of equilibrium climate sensitivity to capture the fact that the progressive heat uptake of the deep ocean causes the rate to slow at higher values of the equilibrium climate sensitivity. In FUND 3.8, the rate of temperature response has been updated to a quadratic function of the equilibrium climate sensitivity. This change reduces the sensitivity of the rate of temperature response to the level of the equilibrium climate sensitivity, a relationship first noted by Hansen et al. (1985) based on the heat uptake of the deep ocean. Therefore in FUND 3.8, the temperature response will typically be faster than in the previous version. The overall effect of this change is likely to increase estimates of the SCC as higher temperatures are reached during the timeframe analyzed and as the same damages experienced in the previous version of the model are now experienced earlier and therefore discounted less.

Methane

The IPCC AR4 notes a series of indirect effects of methane emissions, and has developed methods for proxying such effects when computing the global warming potential of methane (Forster et al. 2007). FUND 3.8 now includes the same methods for incorporating the indirect effects of methane emissions. Specifically, the average atmospheric lifetime of methane has been set to 12 years to account for the feedback of methane emissions on its own lifetime. The radiative forcing associated with atmospheric methane has also been increased by 40% to account for its net impact on ozone production and stratospheric water vapor. All else equal, the effect of this increased radiative forcing will be to increase the estimated SCC values, due to greater projected temperature anomaly.

C. PAGE

PAGE09 (Hope 2013) includes a number of changes from PAGE2002, the version used in the 2010 SCC interagency report. The changes that most directly affect the SCC estimates include: explicitly modeling the impacts from sea level rise, revisions to the damage function to ensure damages are constrained by GDP, a change in the regional scaling of damages, a revised treatment for the probability of a discontinuity within the damage function, and revised assumptions on adaptation. The model also includes revisions to the carbon cycle feedback and the calculation of regional temperatures.[11] More details on PAGE09 can be found in Hope (2011a, 2011b, 2011c). A description of PAGE2002 can be found in Hope (2006).

Sea Level Rise

While PAGE2002 aggregates all damages into two categories – economic and non-economic impacts -, PAGE09 adds a third explicit category: damages from sea level rise. In the previous version of the model, damages from sea level rise were subsumed by the other damage categories. In PAGE09 sea level damages increase less than linearly with sea level under the assumption that land, people, and GDP are more concentrated in low-lying shoreline areas. Damages from the economic and non-economic sector were adjusted to account for the introduction of this new category.

Revised Damage Function to Account for Saturation

In PAGE09, small initial economic and non-economic benefits (negative damages) are modeled for small temperature increases, but all regions eventually experience economic damages from climate change, where damages are the sum of additively separable polynomial functions of temperature and sea level rise. Damages transition from this polynomial function to a logistic path once they exceed a certain proportion of remaining Gross Domestic Product (GDP) to ensure that damages do not exceed 100 percent of GDP. This differs from PAGE2002, which allowed Eastern Europe to potentially experience large benefits from temperature increases, and which also did not bound the possible damages that could be experienced.

Regional Scaling Factors

As in the previous version of PAGE, the PAGE09 model calculates the damages for the European Union (EU) and then, assumes that damages for other regions are proportional based on a given scaling factor. The scaling factor in PAGE09 is based on the length of a region's coastline relative to the EU (Hope 2011b). Because of the long coastline in the EU, other regions are, on average, less vulnerable than the EU for the same sea level and temperature increase, but all regions have a positive scaling factor. PAGE2002 based its scaling factors on four studies reported in the IPCC's third assessment report, and allowed for benefits from temperature increase in Eastern Europe, smaller impacts in developed countries, and higher damages in developing countries.

[11] Because several changes in the PAGE model are structural (e.g., the addition of sea level rise and treatment of discontinuity), it is not possible to assess the direct impact of each change on the SCC in isolation as done for the other two models above.

Probability of a Discontinuity

In PAGE2002, the damages associated with a "discontinuity" (nonlinear extreme event) were modeled as an expected value. Specifically, a stochastic probability of a discontinuity was multiplied by the damages associated with a discontinuity to obtain an expected value, and this was added to the economic and non-economic impacts. That is, additional damages from an extreme event, such as extreme melting of the Greenland ice sheet, were multiplied by the probability of the event occurring and added to the damage estimate. In PAGE09, the probability of discontinuity is treated as a discrete event for each year in the model. The damages for each model run are estimated either with or without a discontinuity occurring, rather than as an expected value. A large-scale discontinuity becomes possible when the temperature rises beyond some threshold value between 2 and 4°C. The probability that a discontinuity will occur beyond this threshold then increases by between 10 and 30 percent for every 1°C rise in temperature beyond the threshold. If a discontinuity occurs, the EU loses an additional 5 to 25 percent of its GDP (drawn from a triangular distribution with a mean of 15 percent) in addition to other damages, and other regions lose an amount determined by the regional scaling factor. The threshold value for a possible discontinuity is lower than in PAGE2002, while the rate at which the probability of a discontinuity increases with the temperature anomaly and the damages that result from a discontinuity are both higher than in PAGE2002. The model assumes that only one discontinuity can occur and that the impact is phased in over a period of time, but once it occurs, its effect is permanent.

Adaptation

As in PAGE2002, adaptation is available to help mitigate any climate change impacts that occur. In PAGE this adaptation is the same regardless of the temperature change or sea level rise and is therefore akin to what is more commonly considered a reduction in vulnerability. It is modeled by reducing the damages by some percentage. PAGE09 assumes a smaller decrease in vulnerability than the previous version of the model and assumes that it will take longer for this change in vulnerability to be realized. In the aggregated economic sector, at the time of full implementation, this adaptation will mitigate all damages up to a temperature increase of 1°C, and for temperature anomalies between 1°C and 2°C, it will reduce damages by 15-30 percent (depending on the region). However, it takes 20 years to fully implement this adaptation. In PAGE2002, adaptation was assumed to reduce economic sector damages up to 2°C by 50-90 percent after 20 years. Beyond 2°C, no adaptation is assumed to be available to mitigate the impacts of climate change. For the non-economic sector, in PAGE09 adaptation is available to reduce 15 percent of the damages due to a temperature increase between 0°C and 2°C and is assumed to take 40 years to fully implement, instead of 25 percent of the damages over 20 years assumed in PAGE2002. Similarly, adaptation is assumed to alleviate 25-50 percent of the damages from the first 0.20 to 0.25 meters of sea level rise but is assumed to be ineffective thereafter. Hope (2011c) estimates that the less optimistic assumptions regarding the ability to offset impacts of temperature and sea level rise via adaptation increase the SCC by approximately 30 percent.

Other Noteworthy Changes

Two other changes in the model are worth noting. There is a change in the way the model accounts for decreased CO_2 absorption on land and in the ocean as temperature rises. PAGE09 introduces a linear feedback from global mean temperature to the percentage gain in the excess concentration of CO_2, capped at a maximum level. In PAGE2002, an additional amount was added to the CO_2 emissions each period to account for a decrease in ocean absorption and a loss of soil carbon. Also updated is the method by which the average global and annual temperature anomaly is downscaled to determine annual average regional temperature anomalies to be used in the regional damage functions. In PAGE2002, the scaling was determined solely based on regional difference in emissions of sulfate aerosols. In PAGE09, this regional temperature anomaly is further adjusted using an additive factor that is based on the average absolute latitude of a region relative to the area weighted average absolute latitude of the Earth's landmass, to capture relatively greater changes in temperature forecast to be experienced at higher latitudes.

III. Revised SCC Estimates

The updated versions of the three integrated assessment models were run using the same methodology detailed in the 2010 TSD (Interagency Working Group on Social Cost of Carbon 2010). The approach along with the inputs for the socioeconomic emissions scenarios, equilibrium climate sensitivity distribution, and discount rate remains the same. This includes the five reference scenarios based on the EMF-22 modeling exercise, the Roe and Baker equilibrium climate sensitivity distribution calibrated to the IPCC AR4, and three constant discount rates of 2.5, 3, and 5 percent.

As was previously the case, the use of three models, three discount rates, and five scenarios produces 45 separate distributions for the global SCC. The approach laid out in the 2010 TSD applied equal weight to each model and socioeconomic scenario in order to reduce the dimensionality down to three separate distributions representative of the three discount rates. The interagency group selected four values from these distributions for use in regulatory analysis. Three values are based on the average SCC across models and socio-economic-emissions scenarios at the 2.5, 3, and 5 percent discount rates, respectively. The fourth value was chosen to represent the higher-than-expected economic impacts from climate change further out in the tails of the SCC distribution. For this purpose, the 95th percentile of the SCC estimates at a 3 percent discount rate was chosen. (A detailed set of percentiles by model and scenario combination and additional summary statistics for the 2020 values is available in the Appendix.) As noted in the 2010 TSD, "the 3 percent discount rate is the central value, and so the central value that emerges is the average SCC across models at the 3 percent discount rate" (Interagency Working Group on Social Cost of Carbon 2010, p. 25). However, for purposes of capturing the uncertainties involved in regulatory impact analysis, the interagency group emphasizes the importance and value of including all four SCC values.

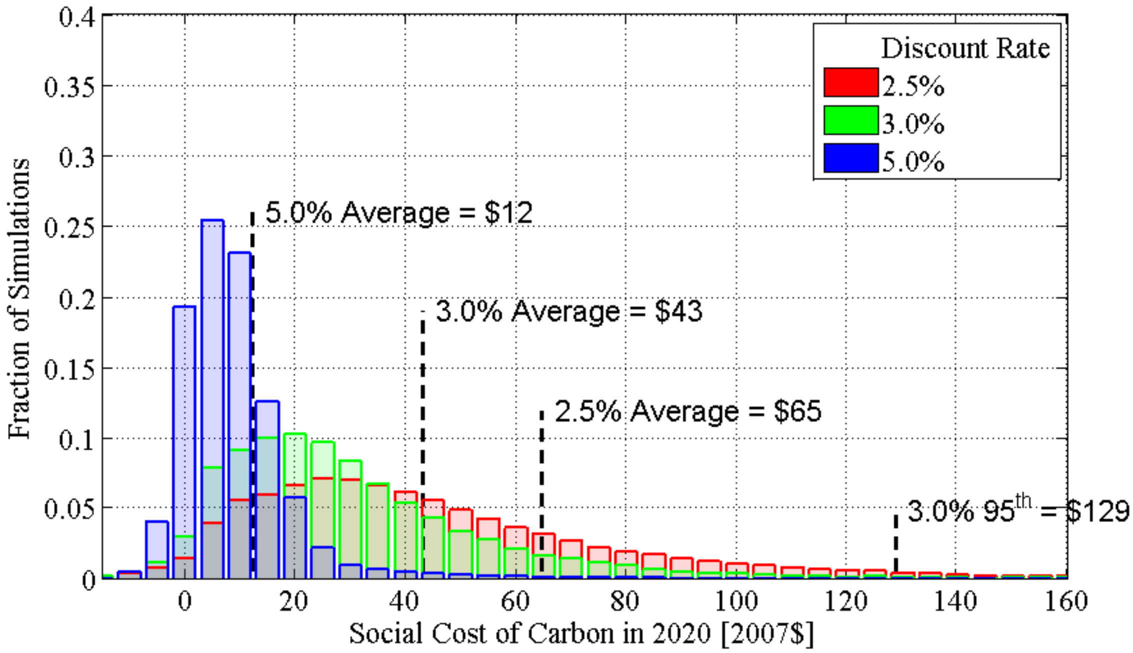
Table 2 shows the four selected SCC estimates in five year increments from 2010 to 2050. Values for 2010, 2020, 2030, 2040, and 2050 are calculated by first combining all outputs (10,000 estimates per model run) from all scenarios and models for a given discount rate. Values for the years in between are calculated using linear interpolation. The full set of revised annual SCC estimates between 2010 and 2050 is reported in the Appendix.

Table 2: Revised Social Cost of CO_2, 2010 – 2050 (in 2007 dollars per metric ton of CO_2)

Discount Rate Year	5.0% Avg	3.0% Avg	2.5% Avg	3.0% 95th
2010	11	33	52	90
2015	12	38	58	109
2020	12	43	65	129
2025	14	48	70	144
2030	16	52	76	159
2035	19	57	81	176
2040	21	62	87	192
2045	24	66	92	206
2050	27	71	98	221

The SCC estimates using the updated versions of the models are higher than those reported in the 2010 TSD due to the changes to the models outlined in the previous section. By way of comparison, the 2020 SCC estimates reported in the original TSD were $7, $26, $42 and $81 (2007$) (Interagency Working Group on Social Cost of Carbon 2010). Figure 1 illustrates where the four SCC values for 2020 fall within the full distribution for each discount rate based on the combined set of runs for each model and scenario (150,000 estimates in total for each discount rate). In general, the distributions are skewed to the right and have long tails. The Figure also shows that the lower the discount rate, the longer the right tail of the distribution.

Figure 1: Distribution of SCC Estimates for 2020 (in 2007$ per metric ton CO_2)



As was the case in the 2010 TSD, the SCC increases over time because future emissions are expected to produce larger incremental damages as physical and economic systems become more stressed in response to greater climatic change. The approach taken by the interagency group is to compute the cost of a marginal ton emitted in the future by running the models for a set of perturbation years out to 2050. Table 3 illustrates how the growth rate for these four SCC estimates varies over time.

Table 3: Average Annual Growth Rates of SCC Estimates between 2010 and 2050

Average Annual Growth Rate (%)	5.0% Avg	3.0% Avg	2.5% Avg	3.0% 95th
2010-2020	1.2%	3.2%	2.4%	4.3%
2020-2030	3.4%	2.1%	1.7%	2.4%
2030-2040	3.0%	1.8%	1.5%	2.0%
2040-2050	2.6%	1.6%	1.3%	1.5%

The future monetized value of emission reductions in each year (the SCC in year *t* multiplied by the change in emissions in year *t*) must be discounted to the present to determine its total net present value for use in regulatory analysis. As previously discussed in the 2010 TSD, damages from future emissions should be discounted at the same rate as that used to calculate the SCC estimates themselves to ensure internal consistency – i.e., future damages from climate change, whether they result from emissions today or emissions in a later year, should be discounted using the same rate.

Under current OMB guidance contained in Circular A-4, analysis of economically significant proposed and final regulations from the domestic perspective is required, while analysis from the international perspective is optional. However, the climate change problem is highly unusual in at least two respects. First, it involves a global externality: emissions of most greenhouse gases contribute to damages around the world even when they are emitted in the United States. Consequently, to address the global nature of the problem, the SCC must incorporate the full (global) damages caused by GHG emissions. Second, climate change presents a problem that the United States alone cannot solve. Even if the United States were to reduce its greenhouse gas emissions to zero, that step would be far from enough to avoid substantial climate change. Other countries would also need to take action to reduce emissions if significant changes in the global climate are to be avoided. Emphasizing the need for a global solution to a global problem, the United States has been actively involved in seeking international agreements to reduce emissions and in encouraging other nations, including emerging major economies, to take significant steps to reduce emissions. When these considerations are taken as a whole, the interagency group concluded that a global measure of the benefits from reducing U.S. emissions is preferable. For additional discussion, see the 2010 TSD.

IV. Other Model Limitations and Research Gaps

The 2010 interagency SCC TSD discusses a number of important limitations for which additional research is needed. In particular, the document highlights the need to improve the quantification of both non-catastrophic and catastrophic damages, the treatment of adaptation and technological change, and the way in which inter-regional and inter-sectoral linkages are modeled. While the new version of the models discussed above offer some improvements in these areas, further work remains warranted. The 2010 TSD also discusses the need to more carefully assess the implications of risk aversion for SCC estimation as well as the inability to perfectly substitute between climate and non-climate goods at higher temperature increases, both of which have implications for the discount rate used. EPA, DOE, and other agencies continue to engage in research on modeling and valuation of climate impacts that can potentially improve SCC estimation in the future.

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Appendix

Table A1: Annual SCC Values: 2010-2050 (2007$/metric ton CO_2)

Discount Rate Year	5.0% Avg	3.0% Avg	2.5% Avg	3.0% 95th
2010	11	33	52	90
2011	11	34	54	94
2012	11	35	55	98
2013	11	36	56	102
2014	11	37	57	106
2015	12	38	58	109
2016	12	39	60	113
2017	12	40	61	117
2018	12	41	62	121
2019	12	42	63	125
2020	12	43	65	129
2021	13	44	66	132
2022	13	45	67	135
2023	13	46	68	138
2024	14	47	69	141
2025	14	48	70	144
2026	15	49	71	147
2027	15	49	72	150
2028	15	50	73	153
2029	16	51	74	156
2030	16	52	76	159
2031	17	53	77	163
2032	17	54	78	166
2033	18	55	79	169
2034	18	56	80	172
2035	19	57	81	176
2036	19	58	82	179
2037	20	59	84	182
2038	20	60	85	185
2039	21	61	86	188
2040	21	62	87	192
2041	22	63	88	195
2042	22	64	89	198
2043	23	65	90	200
2044	23	65	91	203
2045	24	66	92	206
2046	24	67	94	209
2047	25	68	95	212
2048	25	69	96	215
2049	26	70	97	218
2050	27	71	98	221

Table A2: 2020 Global SCC Estimates at 2.5 Percent Discount Rate (2007$/metric ton CO_2)

Percentile	1st	5th	10th	25th	50th	Avg	75th	90th	95th	99th
Scenario[12]	PAGE									
IMAGE	6	11	15	27	58	129	139	327	515	991
MERGE	4	6	9	16	34	78	82	196	317	649
MESSAGE	4	8	11	20	42	108	107	278	483	918
MiniCAM Base	5	9	12	22	47	107	113	266	431	872
5th Scenario	2	4	6	11	25	85	68	200	387	955
Scenario	DICE									
IMAGE	25	31	37	47	64	72	92	123	139	161
MERGE	14	18	20	26	36	40	50	65	74	85
MESSAGE	20	24	28	37	51	58	71	95	109	221
MiniCAM Base	20	25	29	38	53	61	76	102	117	135
5th Scenario	17	22	25	33	45	52	65	91	106	126
Scenario	FUND									
IMAGE	-17	-1	5	17	34	44	59	90	113	176
MERGE	-7	2	7	16	30	35	49	72	91	146
MESSAGE	-19	-4	2	12	27	32	46	70	87	135
MiniCAM Base	-9	1	8	18	35	45	59	87	108	172
5th Scenario	-30	-12	-5	6	19	24	35	57	72	108

Table A3: 2020 Global SCC Estimates at 3 Percent Discount Rate (2007$/metric ton CO_2)

Percentile	1st	5th	10th	25th	50th	Avg	75th	90th	95th	99th
Scenario	PAGE									
IMAGE	4	7	10	18	38	91	95	238	385	727
MERGE	2	4	6	11	23	56	58	142	232	481
MESSAGE	3	5	7	13	29	75	74	197	330	641
MiniCAM Base	3	5	8	14	30	73	75	184	300	623
5th Scenario	1	3	4	7	17	58	48	136	264	660
Scenario	DICE									
IMAGE	16	21	24	32	43	48	60	79	90	102
MERGE	10	13	15	19	25	28	35	44	50	58
MESSAGE	14	18	20	26	35	40	49	64	73	83
MiniCAM Base	13	17	20	26	35	39	49	65	73	85
5th Scenario	12	15	17	22	30	34	43	58	67	79
Scenario	FUND									
IMAGE	-14	-3	1	9	20	25	35	54	69	111
MERGE	-8	-1	3	9	18	22	31	47	60	97
MESSAGE	-16	-5	-1	6	16	18	28	43	55	88
MiniCAM Base	-9	-1	3	10	21	27	35	53	67	107
5th Scenario	-22	-10	-5	2	10	13	20	33	42	63

[12] See 2010 TSD for a description of these scenarios.

Table A4: 2020 Global SCC Estimates at 5 Percent Discount Rate (2007$/metric ton CO_2)

Percentile	1st	5th	10th	25th	50th	Avg	75th	90th	95th	99th
Scenario					PAGE					
IMAGE	1	2	2	5	10	28	27	71	123	244
MERGE	1	1	2	3	7	17	17	45	75	153
MESSAGE	1	1	2	4	9	24	22	60	106	216
MiniCAM Base	1	1	2	3	8	21	21	54	94	190
5th Scenario	0	1	1	2	5	18	14	41	78	208

Scenario					DICE					
IMAGE	6	8	9	11	14	15	18	22	25	27
MERGE	4	5	6	7	9	10	12	15	16	18
MESSAGE	6	7	8	10	12	13	16	20	22	25
MiniCAM Base	5	6	7	8	11	12	14	18	20	22
5th Scenario	5	6	6	8	10	11	14	17	19	21

Scenario					FUND					
IMAGE	-9	-5	-3	-1	2	3	6	11	15	25
MERGE	-6	-3	-2	0	3	4	7	12	16	27
MESSAGE	-10	-6	-4	-1	2	2	5	9	13	23
MiniCAM Base	-7	-3	-2	0	3	4	7	11	15	26
5th Scenario	-11	-7	-5	-2	0	0	3	6	8	14

Table A5: Additional Summary Statistics of 2020 Global SCC Estimates

Discount rate:	5.0%				3.0%				2.5%			
Statistic:	Mean	Variance	Skewness	Kurtosis	Mean	Variance	Skewness	Kurtosis	Mean	Variance	Skewness	Kurtosis
DICE	12	26	2	15	38	409	3	24	57	1097	3	30
PAGE	22	1616	5	32	71	14953	4	22	101	29312	4	23
FUND	3	560	-170	35222	21	22487	-85	18842	36	68055	-46	13105

EXHIBIT TFC-7

THE PRESIDENT'S CLIMATE ACTION PLAN

Executive Office of the President

June 2013

THE WHITE HOUSE
WASHINGTON

EXHIBIT TFC-7

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EXHIBIT TFC-7

PRESIDENT OBAMA'S CLIMATE ACTION PLAN

"We, the people, still believe that our obligations as Americans are not just to ourselves, but to all posterity. We will respond to the threat of climate change, knowing that the failure to do so would betray our children and future generations. Some may still deny the overwhelming judgment of science, but none can avoid the devastating impact of raging fires and crippling drought and more powerful storms.

The path towards sustainable energy sources will be long and sometimes difficult. But America cannot resist this transition, we must lead it. We cannot cede to other nations the technology that will power new jobs and new industries, we must claim its promise. That's how we will maintain our economic vitality and our national treasure -- our forests and waterways, our croplands and snow-capped peaks. That is how we will preserve our planet, commanded to our care by God. That's what will lend meaning to the creed our fathers once declared."

-- President Obama, Second Inaugural Address, January 2013

THE CASE FOR ACTION

While no single step can reverse the effects of climate change, we have a moral obligation to future generations to leave them a planet that is not polluted and damaged. Through steady, responsible action to cut carbon pollution, we can protect our children's health and begin to slow the effects of climate change so that we leave behind a cleaner, more stable environment.

In 2009, President Obama made a pledge that by 2020, America would reduce its greenhouse gas emissions in the range of 17 percent below 2005 levels if all other major economies agreed to limit their emissions as well. Today, the President remains firmly committed to that goal and to building on the progress of his first term to help put us and the world on a sustainable long-term trajectory. Thanks in part to the Administration's success in doubling America's use of wind, solar, and geothermal energy and in establishing the toughest fuel economy standards in our history, we are creating new jobs, building new industries, and reducing dangerous carbon pollution which contributes to climate change. In fact, last year, carbon emissions from the energy sector fell to the lowest level in two decades. At the same time, while there is more work to do, we are more energy secure than at any time in recent history. In 2012, America's net oil imports fell to the lowest level in 20 years and we have become the world's leading producer of natural gas – the cleanest-burning fossil fuel.

While this progress is encouraging, climate change is no longer a distant threat – we are already feeling its impacts across the country and the world. Last year was the warmest year ever in the contiguous United States and about one-third of all Americans experienced 10 days or more of 100-degree heat. The 12 hottest years on record have all come in the last 15 years. Asthma rates have doubled in the past 30 years and our children will suffer more asthma attacks as air pollution gets worse. And increasing floods, heat waves, and droughts have put farmers out of business, which is already raising food prices dramatically.

These changes come with far-reaching consequences and real economic costs. Last year alone, there were 11 different weather and climate disaster events with estimated losses exceeding $1 billion each across the United States. Taken together, these 11 events resulted in over $110 billion in estimated damages, which would make it the second-costliest year on record.

In short, America stands at a critical juncture. Today, President Obama is putting forward a broad-based plan to cut the carbon pollution that causes climate change and affects public health. Cutting carbon pollution will help spark business innovation to modernize our power plants, resulting in cleaner forms of American-made energy that will create good jobs and cut our dependence on foreign oil. Combined with the Administration's other actions to increase the efficiency of our cars and household appliances, the President's plan will reduce the amount of energy consumed by American families, cutting down on their gas and utility bills. The plan, which consists of a wide variety of executive actions, has three key pillars:

1) **Cut Carbon Pollution in America:** In 2012, U.S. carbon emissions fell to the lowest level in two decades even as the economy continued to grow. To build on this progress, the Obama Administration is putting in place tough new rules to cut carbon pollution – just like we have for other toxins like mercury and arsenic – so we protect the health of our children and move our economy toward American-made clean energy sources that will create good jobs and lower home energy bills.

2) **Prepare the United States for the Impacts of Climate Change:** Even as we take new steps to reduce carbon pollution, we must also prepare for the impacts of a changing climate that are already being felt across the country. Moving forward, the Obama Administration will help state and local governments strengthen our roads, bridges, and shorelines so we can better protect people's homes, businesses and way of life from severe weather.

3) **Lead International Efforts to Combat Global Climate Change and Prepare for its Impacts:** Just as no country is immune from the impacts of climate change, no country can meet this challenge alone. That is why it is imperative for the United States to couple action at home with leadership internationally. America must help forge a truly global solution to this global challenge by galvanizing international action to significantly reduce emissions (particularly among the major emitting countries), prepare for climate impacts, and drive progress through the international negotiations.

Climate change represents one of our greatest challenges of our time, but it is a challenge uniquely suited to America's strengths. Our scientists will design new fuels, and our farmers will grow them. Our engineers to devise new sources of energy, our workers will build them, and our businesses will sell them. All of us will need to do our part. If we embrace this challenge, we will not just create new jobs and new industries and keep America on the cutting edge; we will save lives, protect and preserve our treasured natural resources, cities, and coastlines for future generations.

What follows is a blueprint for steady, responsible national and international action to slow the effects of climate change so we leave a cleaner, more stable environment for future generations. It highlights progress already set in motion by the Obama Administration to advance these goals and sets forth new steps to achieve them.

EXHIBIT TFC-7

CUT CARBON POLLUTION IN AMERICA

In 2009, President Obama made a commitment to reduce U.S. greenhouse gas emissions in the range of 17 percent below 2005 levels by 2020. The President remains firmly committed to achieving that goal. While there is more work to do, the Obama Administration has already made significant progress by doubling generation of electricity from wind, solar, and geothermal, and by establishing historic new fuel economy standards. Building on these achievements, this document outlines additional steps the Administration will take – in partnership with states, local communities, and the private sector – to continue on a path to meeting the President's 2020 goal.

I. *Deploying Clean Energy*

Cutting Carbon Pollution from Power Plants: Power plants are the largest concentrated source of emissions in the United States, together accounting for roughly one-third of all domestic greenhouse gas emissions. We have already set limits for arsenic, mercury, and lead, but there is no federal rule to prevent power plants from releasing as much carbon pollution as they want. Many states, local governments, and companies have taken steps to move to cleaner electricity sources. More than 35 states have renewable energy targets in place, and more than 25 have set energy efficiency targets.

Despite this progress at the state level, there are no federal standards in place to reduce carbon pollution from power plants. In April 2012, as part of a continued effort to modernize our electric power sector, the Obama Administration proposed a carbon pollution standard for new power plants. The Environmental Protection Agency's proposal reflects and reinforces the ongoing trend towards cleaner technologies, with natural gas increasing its share of electricity generation in recent years, principally through market forces and renewables deployment growing rapidly to account for roughly half of new generation capacity installed in 2012.

With abundant clean energy solutions available, and building on the leadership of states and local governments, we can make continued progress in reducing power plant pollution to improve public health and the environment while supplying the reliable, affordable power needed for economic growth. By doing so, we will continue to drive American leadership in clean energy technologies, such as efficient natural gas, nuclear, renewables, and clean coal technology.

To accomplish these goals, President Obama is issuing a Presidential Memorandum directing the Environmental Protection Agency to work expeditiously to complete carbon pollution standards for both new and existing power plants. This work will build on the successful first-term effort to develop greenhouse gas and fuel economy standards for cars and trucks. In developing the standards, the President has asked the Environmental Protection Agency to build on state leadership, provide flexibility, and take advantage of a wide range of energy sources and technologies including many actions in this plan.

Promoting American Leadership in Renewable Energy: During the President's first term, the United States more than doubled generation of electricity from wind, solar, and geothermal sources. To ensure America's continued leadership position in clean energy, President Obama has set a goal to double renewable electricity generation once again by 2020. In order to meet this ambitious target, the Administration is announcing a number of new efforts in the following key areas:

- **Accelerating Clean Energy Permitting:** In 2012 the President set a goal to issue permits for 10 gigawatts of renewables on public lands by the end of the year. The Department of the Interior achieved this goal ahead of schedule and the President has directed it to permit an additional 10 gigawatts by 2020. Since 2009, the Department of Interior has approved 25 utility-scale solar facilities, nine wind farms, and 11 geothermal plants, which will provide enough electricity to power 4.4 million homes and support an estimated 17,000 jobs. The Administration is also taking steps to encourage the development of hydroelectric power at existing dams. To develop and demonstrate improved permitting procedures for such projects, the Administration will designate the Red Rock Hydroelectric Plant on the Des Moines River in Iowa to participate in its Infrastructure Permitting Dashboard for high-priority projects. Also, the Department of Defense – the single largest consumer of energy in the United States – is committed to deploying 3 gigawatts of renewable energy on military installations, including solar, wind, biomass, and geothermal, by 2025. In addition, federal agencies are setting a new goal of reaching 100 megawatts of installed renewable capacity across the federally subsidized housing stock by 2020. This effort will include conducting a survey of current projects in order to track progress and facilitate the sharing of best practices.

- **Expanding and Modernizing the Electric Grid:** Upgrading the country's electric grid is critical to our efforts to make electricity more reliable, save consumers money on their energy bills, and promote clean energy sources. To advance these important goals, President Obama signed a Presidential Memorandum this month that directs federal agencies to streamline the siting, permitting and review process for transmission projects across federal, state, and tribal governments.

Unlocking Long-Term Investment in Clean Energy Innovation: The Fiscal Year 2014 Budget continues the President's commitment to keeping the United States at the forefront of clean energy research, development, and deployment by increasing funding for clean energy technology across all agencies by 30 percent, to approximately $7.9 billion. This includes investment in a range of energy technologies, from advanced biofuels and emerging nuclear technologies – including small modular reactors – to clean coal. To continue America's leadership in clean energy innovation, the Administration will also take the following steps:

- **Spurring Investment in Advanced Fossil Energy Projects:** In the coming weeks, the Department of Energy will issue a Federal Register Notice announcing a draft of a solicitation that would make up to $8 billion in (self-pay) loan guarantee authority available for a wide array of advanced fossil energy projects under its Section 1703 loan guarantee program. This solicitation is designed to support investments in innovative technologies that can cost-effectively meet financial and policy goals, including the avoidance, reduction, or sequestration of anthropogenic emissions of greenhouse gases. The proposed solicitation will cover a broad range of advanced fossil energy projects. Reflecting the Department's commitment to continuous improvement in program management, it will take comment on the draft solicitation, with a plan to issue a final solicitation by the fall of 2013.

- **Instituting a Federal Quadrennial Energy Review:** Innovation and new sources of domestic energy supply are transforming the nation's energy marketplace, creating economic opportunities at the same time they raise environmental challenges. To ensure that federal energy policy meets our economic, environmental, and security goals in this changing landscape, the Administration will conduct a Quadrennial Energy Review which will be led by the White House Domestic Policy Council and Office of Science and Technology Policy, supported by a Secretariat established at the Department of Energy, and involving the robust engagement of federal agencies and outside stakeholders. This first-ever review will focus on infrastructure challenges, and will identify the threats, risks, and opportunities for U.S. energy and climate security, enabling the federal government to translate policy goals into a set of analytically based, clearly articulated, sequenced and integrated actions, and proposed investments over a four-year planning horizon.

II. Building a 21st-Century Transportation Sector

Increasing Fuel Economy Standards: Heavy-duty vehicles are currently the second largest source of greenhouse gas emissions within the transportation sector. In 2011, the Obama Administration finalized the first-ever fuel economy standards for Model Year 2014-2018 for heavy-duty trucks, buses, and vans. These standards will reduce greenhouse gas emissions by approximately 270 million metric tons and save 530 million barrels of oil. During the President's second term, the Administration will once again partner with industry leaders and other key stakeholders to develop post-2018 fuel economy standards for heavy-duty vehicles to further reduce fuel consumption through the application of advanced cost-effective technologies and continue efforts to improve the efficiency of moving goods across the United States.

The Obama Administration has already established the toughest fuel economy standards for passenger vehicles in U.S. history. These standards require an average performance equivalent of 54.5 miles per gallon by 2025, which will save the average driver more than $8,000 in fuel costs over the lifetime of the vehicle and eliminate six billion metric tons of carbon pollution – more than the United States emits in an entire year.

Developing and Deploying Advanced Transportation Technologies: Biofuels have an important role to play in increasing our energy security, fostering rural economic development, and reducing greenhouse gas emissions from the transportation sector. That is why the Administration supports the Renewable Fuels Standard, and is investing in research and development to help bring next-generation biofuels on line. For example, the United States Navy and Departments of Energy and Agriculture are working with the private sector to accelerate the development of cost-competitive advanced biofuels for use by the military and commercial sectors. More broadly, the Administration will continue to leverage partnerships between the private and public sectors to deploy cleaner fuels, including advanced batteries and fuel cell technologies, in every transportation mode. The Department of Energy's eGallon informs drivers about electric car operating costs in their state – the national average is only $1.14 per gallon of gasoline equivalent, showing the promise for consumer pocketbooks of electric-powered vehicles. In addition, in the coming months, the Department of Transportation will work with other agencies to further explore strategies for integrating alternative fuel vessels into the U.S. flag fleet. Further, the Administration will continue to work with states, cities and towns through the Department of Transportation, the Department of Housing and Urban Development, and the Environmental Protection Agency to improve transportation options, and lower transportation costs while protecting the environment in communities nationwide.

III. Cutting Energy Waste in Homes, Businesses, and Factories

Reducing Energy Bills for American Families and Businesses: Energy efficiency is one of the clearest and most cost-effective opportunities to save families money, make our businesses more competitive, and reduce greenhouse gas emissions. In the President's first term, the Department of Energy and the Department of Housing and Urban Development completed efficiency upgrades in more than one million homes, saving many families more than $400 on their heating and cooling bills in the first year alone. The Administration will take a range of new steps geared towards achieving President Obama's goal of doubling energy productivity by 2030 relative to 2010 levels:

- **Establishing a New Goal for Energy Efficiency Standards:** In President Obama's first term, the Department of Energy established new minimum efficiency standards for dishwashers, refrigerators, and many other products. Through 2030, these standards will cut consumers' electricity bills by hundreds of billions of dollars and save enough electricity to power more than 85 million homes for two years. To build on this success, the Administration is setting a new goal: Efficiency standards for appliances and federal buildings set in the first and second terms combined will reduce carbon pollution by at least 3 billion metric tons cumulatively by 2030 – equivalent to nearly one-half of the carbon pollution from the entire U.S. energy sector for one year – while continuing to cut families' energy bills.

- **Reducing Barriers to Investment in Energy Efficiency:** Energy efficiency upgrades bring significant cost savings, but upfront costs act as a barrier to more widespread investment. In response, the Administration is committing to a number of new executive actions. As soon as this fall, the Department of Agriculture's Rural Utilities Service will finalize a proposed update to its Energy Efficiency and Conservation Loan Program to provide up to $250 million for rural utilities to finance efficiency investments by businesses and homeowners across rural America. The Department is also streamlining its Rural Energy for America program to provide grants and loan guarantees directly to agricultural producers and rural small businesses for energy efficiency and renewable energy systems.

  In addition, the Department of Housing and Urban Development's efforts include a $23 million Multifamily Energy Innovation Fund designed to enable affordable housing providers, technology firms, academic institutions, and philanthropic organizations to test new approaches to deliver cost-effective residential energy. In order to advance ongoing efforts and bring stakeholders together, the Federal Housing Administration will convene representatives of the lending community and other key stakeholders for a mortgage roundtable in July to identify options for factoring energy efficiency into the mortgage underwriting and appraisal process upon sale or refinancing of new or existing homes.

- **Expanding the President's Better Buildings Challenge:** The Better Buildings Challenge, focused on helping American commercial and industrial buildings become at least 20 percent more energy efficient by 2020, is already showing results. More than 120 diverse organizations, representing over 2 billion square feet are on track to meet the 2020 goal: cutting energy use by an average 2.5 percent annually, equivalent to about $58 million in energy savings per year. To continue this success, the Administration will expand the program to multifamily housing – partnering both with private and affordable building owners and public housing agencies to cut energy waste. In addition, the Administration is launching the Better Buildings Accelerators, a new track that will support and encourage adoption of State and local policies to cut energy waste, building on the momentum of ongoing efforts at that level.

IV. Reducing Other Greenhouse Gas Emissions

Curbing Emissions of Hydrofluorocarbons: Hydrofluorocarbons (HFCs), which are primarily used for refrigeration and air conditioning, are potent greenhouse gases. In the United States, emissions of HFCs are expected to nearly triple by 2030, and double from current levels of 1.5 percent of greenhouse gas emissions to 3 percent by 2020.

To reduce emissions of HFCs, the United States can and will lead both through international diplomacy as well as domestic actions. In fact, the Administration has already acted by including a flexible and powerful incentive in the fuel economy and carbon pollution standards for cars and trucks to encourage automakers to reduce HFC leakage and transition away from the most potent HFCs in vehicle air conditioning systems. Moving forward, the Environmental Protection Agency will use its authority through the Significant New Alternatives Policy Program to encourage private sector investment in low-emissions technology by identifying and approving climate-friendly chemicals while prohibiting certain uses of the most harmful chemical alternatives. In addition, the President has directed his Administration to purchase cleaner alternatives to HFCs whenever feasible and transition over time to equipment that uses safer and more sustainable alternatives.

Reducing Methane Emissions: Curbing emissions of methane is critical to our overall effort to address global climate change. Methane currently accounts for roughly 9 percent of domestic greenhouse gas emissions and has a global warming potential that is more than 20 times greater than carbon dioxide. Notably, since 1990, methane emissions in the United States have decreased by 8 percent. This has occurred in part through partnerships with industry, both at home and abroad, in which we have demonstrated that we have the technology to deliver emissions reductions that benefit both our economy and the environment. To achieve additional progress, the Administration will:

- **Developing an Interagency Methane Strategy:** The Environmental Protection Agency and the Departments of Agriculture, Energy, Interior, Labor, and Transportation will develop a comprehensive, interagency methane strategy. The group will focus on assessing current emissions data, addressing data gaps, identifying technologies and best practices for reducing emissions, and identifying existing authorities and incentive-based opportunities to reduce methane emissions.

- **Pursuing a Collaborative Approach to Reducing Emissions:** Across the economy, there are multiple sectors in which methane emissions can be reduced, from coal mines and landfills to agriculture and oil and gas development. For example, in the agricultural sector, over the last three years, the Environmental Protection Agency and the Department of Agriculture have worked with the dairy industry to increase the adoption of methane digesters through loans, incentives, and other assistance. In addition, when it comes to the oil and gas sector, investments to build and upgrade gas pipelines will not only put more Americans to work, but also reduce emissions and enhance economic productivity. For example, as part of the Administration's effort to improve federal permitting for infrastructure projects, the interagency Bakken Federal Executive Group is working with industry, as well as state and tribal agencies, to advance the production of oil and gas in the Bakken while helping to reduce venting and flaring. Moving forward, as part of the effort to develop an interagency methane strategy, the Obama Administration will work collaboratively with state governments, as well as the private sector, to reduce emissions across multiple sectors, improve air quality, and achieve public health and economic benefits.

Preserving the Role of Forests in Mitigating Climate Change: America's forests play a critical role in addressing carbon pollution, removing nearly 12 percent of total U.S. greenhouse gas emissions each year. In the face of a changing climate and increased risk of wildfire, drought, and pests, the capacity of our forests to absorb carbon is diminishing. Pressures to develop forest lands for urban or agricultural uses also contribute to the decline of forest carbon sequestration. Conservation and sustainable management can help to ensure our forests continue to remove carbon from the atmosphere while also improving soil and water quality, reducing wildfire risk, and otherwise managing forests to be more resilient in the fact of climate change. The Administration is working to identify new approaches to protect and restore our forests, as well as other critical landscapes including grasslands and wetlands, in the face of a changing climate.

V. Leading at the Federal Level

Leading in Clean Energy: President Obama believes that the federal government must be a leader in clean energy and energy efficiency. Under the Obama Administration, federal agencies have reduced greenhouse gas emissions by more than 15 percent – the equivalent of permanently taking 1.5 million cars off the road. To build on this record, the Administration is establishing a new goal: The federal government will consume 20 percent of its electricity from renewable sources by 2020 – more than double the current goal of 7.5 percent. In addition, the federal government will continue to pursue greater energy efficiency that reduces greenhouse gas emissions and saves taxpayer dollars.

Federal Government Leadership in Energy Efficiency: On December 2, 2011, President Obama signed a memorandum entitled "Implementation of Energy Savings Projects and Performance-Based Contracting for Energy Savings," challenging federal agencies, in support of the Better Buildings Challenge, to enter into $2 billion worth of performance-based contracts within two years. Performance contracts drive economic development, utilize private sector innovation, and increase efficiency at minimum costs to the taxpayer, while also providing long-term savings in energy costs. Federal agencies have committed to a pipeline of nearly $2.3 billion from over 300 reported projects. In coming months, the Administration will take a number of actions to strengthen efforts to promote energy efficiency, including through performance contracting. For example, in order to increase access to capital markets for investments in energy efficiency, the Administration will initiate a partnership with the private sector to work towards a standardized contract to finance federal investments in energy efficiency. Going forward, agencies will also work together to synchronize building codes – leveraging those policies to improve the efficiency of federally owned and supported building stock. Finally, the Administration will leverage the "Green Button" standard – which aggregates energy data in a secure, easy to use format – within federal facilities to increase their ability to manage energy consumption, reduce greenhouse gas emissions, and meet sustainability goals.

PREPARE THE UNITED STATES FOR THE IMPACTS OF CLIMATE CHANGE

As we act to curb the greenhouse gas pollution that is driving climate change, we must also prepare for the impacts that are too late to avoid. Across America, states, cities, and communities are taking steps to protect themselves by updating building codes, adjusting the way they manage natural resources, investing in more resilient infrastructure, and planning for rapid recovery from damages that nonetheless occur. The federal government has an important role to play in supporting community-based preparedness and resilience efforts, establishing policies that promote preparedness, protecting critical infrastructure and public resources, supporting science and research germane to preparedness and resilience, and ensuring that federal operations and facilities continue to protect and serve citizens in a changing climate.

The Obama Administration has been working to strengthen America's climate resilience since its earliest days. Shortly after coming into office, President Obama established an Interagency Climate Change Adaptation Task Force and, in October 2009, the President signed an Executive Order directing it to recommend ways federal policies and programs can better prepare the Nation for change. In May 2010, the Task Force hosted the first National Climate Adaptation Summit, convening local and regional stakeholders and decision-makers to identify challenges and opportunities for collaborative action.

In February 2013, federal agencies released Climate Change Adaptation Plans for the first time, outlining strategies to protect their operations, missions, and programs from the effects of climate change. The Department of Transportation, for example, is developing guidance for incorporating climate change and extreme weather event considerations into coastal highway projects, and the Department of Homeland Security is evaluating the challenges of changing conditions in the Arctic and along our Nation's borders. Agencies have also partnered with communities through targeted grant and technical-assistance programs—for example, the Environmental Protection Agency is working with low-lying communities in North Carolina to assess the vulnerability of infrastructure investments to sea level rise and identify solutions to reduce risks. And the Administration has continued, through the U.S. Global Change Research Program, to support science and monitoring to expand our understanding of climate change and its impacts.

Going forward, the Administration will expand these efforts into three major, interrelated initiatives to better prepare America for the impacts of climate change:

I. Building Stronger and Safer Communities and Infrastructure

By necessity, many states, cities, and communities are already planning and preparing for the impacts of climate change. Hospitals must build capacity to serve patients during more frequent heat waves, and urban planners must plan for the severe storms that infrastructure will need to withstand. Promoting on-the-ground planning and resilient infrastructure will be at the core of our work to strengthen America's communities. Specific actions will include:

Directing Agencies to Support Climate-Resilient Investment: The President will direct federal agencies to identify and remove barriers to making climate-resilient investments; identify and remove counterproductive policies that increase vulnerabilities; and encourage and support smarter, more resilient investments, including through agency grants, technical assistance, and other programs, in sectors from transportation and water management to conservation and disaster relief. Agencies will also be directed to ensure that climate risk-management considerations are fully integrated into federal infrastructure and natural resource management planning. To begin meeting this challenge, the Environmental Protection Agency is committing to integrate considerations of climate change impacts and adaptive measures into major programs, including its Clean Water and Drinking Water State Revolving Funds and grants for brownfields cleanup, and the Department of Housing and Urban Development is already requiring grant recipients in the Hurricane Sandy–affected region to take sea-level rise into account.

Establishing a State, Local, and Tribal Leaders Task Force on Climate Preparedness: To help agencies meet the above directive and to enhance local efforts to protect communities, the President will establish a short-term task force of state, local, and tribal officials to advise on key actions the federal government can take to better support local preparedness and resilience-building efforts. The task force will provide recommendations on removing barriers to resilient investments, modernizing grant and loan programs to better support local efforts, and developing information and tools to better serve communities.

Supporting Communities as they Prepare for Climate Impacts: Federal agencies will continue to provide targeted support and assistance to help communities prepare for climate-change impacts. For example, throughout 2013, the Department of Transportation's Federal Highway Administration is working with 19 state and regional partners and other federal agencies to test approaches for assessing local transportation infrastructure vulnerability to climate change and extreme weather and for improving resilience. The Administration will continue to assist tribal communities on preparedness through the Bureau of Indian Affairs, including through pilot projects and by supporting participation in federal initiatives that assess climate change vulnerabilities and develop regional solutions. Through annual federal agency "Environmental Justice Progress Reports," the Administration will continue to identify innovative ways to help our most vulnerable communities prepare for and recover from the impacts of climate change. The importance of critical infrastructure independence was brought home in the Sandy response. The Federal Emergency Management Agency and the Department of Energy are working with the private sector to address simultaneous restoration of electricity and fuels supply.

Boosting the Resilience of Buildings and Infrastructure: The National Institute of Standards and Technology will convene a panel on disaster-resilience standards to develop a comprehensive, community-based resilience framework and provide guidelines for consistently safe buildings and infrastructure – products that can inform the development of private-sector standards and codes. In addition, building on federal agencies' "Climate Change Adaptation Plans," the Administration will continue efforts to increase the resilience of federal facilities and infrastructure. The Department of Defense, for example, is assessing the relative vulnerability of its coastal facilities to climate change. In addition, the President's FY 2014 Budget proposes $200 million through the Transportation Leadership Awards program for Climate Ready Infrastructure in communities that build enhanced preparedness into their planning efforts, and that have proposed or are ready to break ground on infrastructure projects, including transit and rail, to improve resilience.

Rebuilding and Learning from Hurricane Sandy: In August 2013, President Obama's Hurricane Sandy Rebuilding Task Force will deliver to the President a rebuilding strategy to be implemented in Sandy-affected regions and establishing precedents that can be followed elsewhere. The Task Force and federal agencies are also piloting new ways to support resilience in the Sandy-affected region; the Task Force, for example, is hosting a regional "Rebuilding by Design" competition to generate innovative solutions to enhance resilience. In the transportation sector, the Department of Transportation's Federal Transit Administration (FTA) is dedicating $5.7 billion to four of the area's most impacted transit agencies, of which $1.3 billion will be allocated to locally prioritized projects to make transit systems more resilient to future disasters. FTA will also develop a competitive process for additional funding to identify and support larger, stand-alone resilience projects in the impacted region. To build coastal resilience, the Department of the Interior will launch a $100 million competitive grant program to foster partnerships and promote resilient natural systems while enhancing green spaces and wildlife habitat near urban populations. An additional $250 million will be allocated to support projects for coastal restoration and resilience across the region. Finally, with partners, the U.S. Army Corps of Engineers is conducting a $20 million study to identify strategies to reduce the vulnerability of Sandy-affected coastal communities to future large-scale flood and storm events, and the National Oceanic and Atmospheric Administration will strengthen long-term coastal observations and provide technical assistance to coastal communities.

II. Protecting our Economy and Natural Resources

Climate change is affecting nearly every aspect of our society, from agriculture and tourism to the health and safety of our citizens and natural resources. To help protect critical sectors, while also targeting hazards that cut across sectors and regions, the Administration will mount a set of sector- and hazard-specific efforts to protect our country's vital assets, to include:

Identifying Vulnerabilities of Key Sectors to Climate Change: The Department of Energy will soon release an assessment of climate-change impacts on the energy sector, including power-plant disruptions due to drought and the disruption of fuel supplies during severe storms, as well as potential opportunities to make our energy infrastructure more resilient to these risks. In 2013, the Department of Agriculture and Department of the Interior released several studies outlining the challenges a changing climate poses for America's agricultural enterprise, forests, water supply, wildlife, and public lands. This year and next, federal agencies will report on the impacts of climate change on other key sectors and strategies to address them, with priority efforts focusing on health, transportation, food supplies, oceans, and coastal communities.

Promoting Resilience in the Health Sector: The Department of Health and Human Services will launch an effort to create sustainable and resilient hospitals in the face of climate change. Through a public-private partnership with the healthcare industry, it will identify best practices and provide guidance on affordable measures to ensure that our medical system is resilient to climate impacts. It will also collaborate with partner agencies to share best practices among federal health facilities. And, building on lessons from pilot projects underway in 16 states, it will help train public-health professionals and community leaders to prepare their communities for the health consequences of climate change, including through effective communication of health risks and resilience measures.

Promoting Insurance Leadership for Climate Safety: Recognizing the critical role that the private sector plays in insuring assets and enabling rapid recovery after disasters, the Administration will convene representatives from the insurance industry and other stakeholders to explore best practices for private and public insurers to manage their own processes and investments to account for climate change risks and incentivize policy holders to take steps to reduce their exposure to these risks.

Conserving Land and Water Resources: America's ecosystems are critical to our nation's economy and the lives and health of our citizens. These natural resources can also help ameliorate the impacts of climate change, if they are properly protected. The Administration has invested significantly in conserving relevant ecosystems, including working with Gulf State partners after the Deepwater Horizon spill to enhance barrier islands and marshes that protect communities from severe storms. The Administration is also implementing climate-adaptation strategies that promote resilience in fish and wildlife populations, forests and other plant communities, freshwater resources, and the ocean. Building on these efforts, the President is also directing federal agencies to identify and evaluate additional approaches to improve our natural defenses against extreme weather, protect biodiversity and conserve natural resources in the face of a changing climate, and manage our public lands and natural systems to store more carbon.

Maintaining Agricultural Sustainability: Building on the existing network of federal climate-science research and action centers, the Department of Agriculture is creating seven new Regional Climate Hubs to deliver tailored, science-based knowledge to farmers, ranchers, and forest landowners. These hubs will work with universities and other partners, including the Department of the Interior and the National Oceanic and Atmospheric Administration, to support climate resilience. Its Natural Resources Conservation Service and the Department of the Interior's Bureau of Reclamation are also providing grants and technical support to agricultural water users for more water-efficient practices in the face of drought and long-term climate change.

Managing Drought: Leveraging the work of the National Disaster Recovery Framework for drought, the Administration will launch a cross-agency National Drought Resilience Partnership as a "front door" for communities seeking help to prepare for future droughts and reduce drought impacts. By linking information (monitoring, forecasts, outlooks, and early warnings) with drought preparedness and longer-term resilience strategies in critical sectors, this effort will help communities manage drought-related risks.

Reducing Wildfire Risks: With tribes, states, and local governments as partners, the Administration has worked to make landscapes more resistant to wildfires, which are exacerbated by heat and drought conditions resulting from climate change. Federal agencies will expand and prioritize forest and rangeland restoration efforts in order to make natural areas and communities less vulnerable to catastrophic fire. The Department of the Interior and Department of Agriculture, for example, are launching a Western Watershed Enhancement Partnership – a pilot effort in five western states to reduce wildfire risk by removing extra brush and other flammable vegetation around critical areas such as water reservoirs.

Preparing for Future Floods: To ensure that projects funded with taxpayer dollars last as long as intended, federal agencies will update their flood-risk reduction standards for federally funded projects to reflect a consistent approach that accounts for sea-level rise and other factors affecting flood risks. This effort will incorporate the most recent science on expected rates of sea-level rise (which vary by region) and build on work done by the Hurricane Sandy Rebuilding Task Force, which announced in April 2013 that all federally funded Sandy-related rebuilding projects must meet a consistent flood risk reduction standard that takes into account increased risk from extreme weather events, sea-level rise, and other impacts of climate change.

III. Using Sound Science to Manage Climate Impacts

Scientific data and insights are essential to help government officials, communities, and businesses better understand and manage the risks associated with climate change. The Administration will continue to lead in advancing the science of climate measurement and adaptation and the development of tools for climate-relevant decision-making by focusing on increasing the availability, accessibility, and utility of relevant scientific tools and information. Specific actions will include:

Developing Actionable Climate Science: The President's Fiscal Year 2014 Budget provides more than $2.7 billion, largely through the 13-agency U.S. Global Change Research Program, to increase understanding of climate-change impacts, establish a public-private partnership to explore risk and catastrophe modeling, and develop the information and tools needed by decision-makers to respond to both long-term climate change impacts and near-term effects of extreme weather.

Assessing Climate-Change Impacts in the United States: In the spring of 2014, the Obama Administration will release the third U.S. National Climate Assessment, highlighting new advances in our understanding of climate-change impacts across all regions of the United States and on critical sectors of the economy, including transportation, energy, agriculture, and ecosystems and biodiversity. For the first time, the National Climate Assessment will focus not only on dissemination of scientific information but also on translating scientific insights into practical, useable knowledge that can help decision-makers anticipate and prepare for specific climate-change impacts.

Launching a Climate Data Initiative: Consistent with the President's May 2013 Executive Order on Open Data – and recognizing that freely available open government data can fuel entrepreneurship, innovation, scientific discovery, and public benefits – the Administration is launching a Climate Data Initiative to leverage extensive federal climate-relevant data to stimulate innovation and private-sector entrepreneurship in support of national climate-change preparedness.

Providing a Toolkit for Climate Resilience: Federal agencies will create a virtual climate-resilience toolkit that centralizes access to data-driven resilience tools, services, and best practices, including those developed through the Climate Data Initiative. The toolkit will provide easy access to existing resources as well as new tools, including: interactive sea-level rise maps and a sea-level-rise calculator to aid post-Sandy rebuilding in New York and New Jersey, new NOAA storm surge models and interactive maps from the National Oceanic and Atmospheric Administration that provide risk information by combining tidal data, projected sea levels and storm wave heights, a web-based tool that will allow developers to integrate NASA climate imagery into websites and mobile apps, access to the U.S. Geological Survey's "visualization tool" to assess the amount of carbon absorbed by landscapes, and a Stormwater Calculator and Climate Assessment Tool developed to help local governments assess stormwater-control measures under different precipitation and temperature scenarios.

LEAD INTERNATIONAL EFFORTS TO ADDRESS GLOBAL CLIMATE CHANGE

The Obama Administration is working to build on the actions that it is taking domestically to achieve significant global greenhouse gas emission reductions and enhance climate preparedness through major international initiatives focused on spurring concrete action, including bilateral initiatives with China, India, and other major emitting countries. These initiatives not only serve to support the efforts of the United States and others to achieve our goals for 2020, but also will help us move beyond those and bend the post-2020 global emissions trajectory further. As a key part of this effort, we are also working intensively to forge global responses to climate change through a number of important international negotiations, including the United Nations Framework Convention on Climate Change.

I. Working with Other Countries to Take Action to Address Climate Change

Enhancing Multilateral Engagement with Major Economies: In 2009, President Obama launched the Major Economies Forum on Energy and Climate, a high-level forum that brings together 17 countries that account for approximately 75 percent of global greenhouse gas emissions, in order to support the international climate negotiations and spur cooperative action to combat climate change. The Forum has been successful on both fronts – having contributed significantly to progress in the broader negotiations while also launching the Clean Energy Ministerial to catalyze the development and deployment of clean energy and efficiency solutions. We are proposing that the Forum build on these efforts by launching a major initiative this year focused on further accelerating efficiency gains in the buildings sector, which accounts for approximately one-third of global carbon pollutions from the energy sector.

Expanding Bilateral Cooperation with Major Emerging Economies:
From the outset, the Obama Administration has sought to intensify bilateral climate cooperation with key major emerging economies, through initiatives like the U.S.-China Clean Energy Research Center, the U.S.-India Partnership to Advance Clean Energy, and the Strategic Energy Dialogue with Brazil.

We will be building on these successes and finding new areas for cooperation in the second term, and we are already making progress: Just this month, President Obama and President Xi Jinping of China reached an historic agreement at their first summit to work to use the expertise and institutions of the Montreal Protocol to phase down the consumption and production of HFCs, a highly potent greenhouse gas. The impact of phasing out HFCs by 2050 would be equivalent to the elimination of two years' worth of greenhouse gas emissions from all sources.

Combatting Short-Lived Climate Pollutants: Pollutants such as methane, black carbon, and many HFCs are relatively short-lived in the atmosphere, but have more potent greenhouse effects than carbon dioxide. In February 2012, the United States launched the Climate and Clean Air Coalition to Reduce Short-Lived Climate Pollution, which has grown to include more than 30 country partners and other key partners such as the World Bank and the U.N. Environment Programme. Major efforts include reducing methane and black carbon from waste and landfills. We are also leading through the Global Methane Initiative, which works with 42 partner countries and an extensive network of over 1,100 private sector participants to reduce methane emissions.

Reducing Emissions from Deforestation and Forest Degradation: Greenhouse gas emissions from deforestation, agriculture, and other land use constitute approximately one-third of global emissions. In some developing countries, as much as 80 percent of these emissions come from the land sector. To meet this challenge, the Obama Administration is working with partner countries to put in place the systems and institutions necessary to significantly reduce global land-use-related emissions, creating new models for rural development that generate climate benefits, while conserving biodiversity, protecting watersheds, and improving livelihoods.

In 2012 alone, the U.S. Agency for International Development's bilateral and regional forestry programs contributed to reducing more than 140 million tons of carbon dioxide emissions, including through support for multilateral initiatives such as the Forest Investment Program and the Forest Carbon Partnership Facility. In Indonesia, the Millennium Challenge Corporation is funding a five-year "Green Prosperity" program that supports environmentally sustainable, low carbon economic development in select districts.

The Obama Administration is also working to address agriculture-driven deforestation through initiatives such as the Tropical Forest Alliance 2020, which brings together governments, the private sector, and civil society to reduce tropical deforestation related to key agricultural commodities, which we will build upon.

Expanding Clean Energy Use and Cut Energy Waste: Roughly 84 percent of current carbon dioxide emissions are energy-related and about 65 percent of all greenhouse gas emissions can be attributed to energy supply and energy use. The Obama Administration has promoted the expansion of renewable, clean, and efficient energy sources and technologies worldwide through:

- Financing and regulatory support for renewable and clean energy projects
- Actions to promote fuel switching from oil and coal to natural gas or renewables
- Support for the safe and secure use of nuclear power
- Cooperation on clean coal technologies
- Programs to improve and disseminate energy efficient technologies

In the past three years we have reached agreements with more than 20 countries around the world, including Mexico, South Africa, and Indonesia, to support low emission development strategies that help countries to identify the best ways to reduce greenhouse gas emissions while growing their economies. Among the many initiatives that we have launched are:

- The U.S. Africa Clean Energy Finance Initiative, which aligns grant-based assistance with project planning expertise from the U.S. Trade and Development Agency and financing and risk mitigation tools from the U.S. Overseas Private Investment Corporation to unlock up to $1 billion in clean energy financing.

- The U.S.-Asia Pacific Comprehensive Energy Partnership, which has identified $6 billion in U.S. export credit and government financing to promote clean energy development in the Asia-Pacific region.

Looking ahead, we will target these and other resources towards greater penetration of renewables in the global energy mix on both a small and large scale, including through our participation in the Sustainable Energy for All Initiative and accelerating the commercialization of renewable mini-grids. These efforts include:

- **Natural Gas.** Burning natural gas is about one-half as carbon-intensive as coal, which can make it a critical "bridge fuel" for many countries as the world transitions to even cleaner sources of energy. Toward that end, the Obama Administration is partnering with states and private companies to exchange lessons learned with our international partners on responsible development of natural gas resources. We have launched the Unconventional Gas Technical Engagement Program to share best practices on issues such as water management, methane emissions, air quality, permitting, contracting, and pricing to help increase global gas supplies and facilitate development of the associated infrastructure that brings them to market. Going forward, we will promote fuel-switching from coal to gas for electricity production and encourage the development of a global market for gas. Since heavy-duty vehicles are expected to account for 40 percent of increased oil use through 2030, we will encourage the adoption of heavy duty natural gas vehicles as well.

- **Nuclear Power.** The United States will continue to promote the safe and secure use of nuclear power worldwide through a variety of bilateral and multilateral engagements. For example, the U.S. Nuclear Regulatory Commission advises international partners on safety and regulatory best practices, and the Department of Energy works with international partners on research and development, nuclear waste and storage, training, regulations, quality control, and comprehensive fuel leasing options. Going forward, we will expand these efforts to promote nuclear energy generation consistent with maximizing safety and nonproliferation goals.

- **Clean Coal.** The United States works with China, India, and other countries that currently rely heavily on coal for power generation to advance the development and deployment of clean coal technologies. In addition, the U.S. leads the Carbon Sequestration Leadership Forum, which engages 23 other countries and economies on carbon capture and sequestration technologies. Going forward, we will continue to use these bilateral and multilateral efforts to promote clean coal technologies.

- **Energy Efficiency.** The Obama Administration has aggressively promoted energy efficiency through the Clean Energy Ministerial and key bilateral programs. The cost-effective opportunities are enormous: The Ministerial' s Super-Efficient Equipment and Appliance Deployment Initiative and its Global Superior Energy Performance Partnership are helping to accelerate the global adoption of standards and practices that would cut energy waste equivalent to more than 650 mid-size power plants by 2030. We will work to expand these efforts focusing on several critical areas, including: improving building efficiency, reducing energy consumption at water and wastewater treatment facilities, and expanding global appliance standards.

Negotiating Global Free Trade in Environmental Goods and Services: The U.S. will work with trading partners to launch negotiations at the World Trade Organization towards global free trade in environmental goods, including clean energy technologies such as solar, wind, hydro and geothermal. The U.S. will build on the consensus it recently forged among the 21 Asia-Pacific Economic Cooperation (APEC) economies in this area. In 2011, APEC economies agreed to reduce tariffs to 5 percent or less by 2015 on a negotiated list of 54 environmental goods. The

APEC list will serve as a foundation for a global agreement in the WTO, with participating countries expanding the scope by adding products of interest. Over the next year, we will work towards securing participation of countries which account for 90 percent of global trade in environmental goods, representing roughly $481 billion in annual environmental goods trade. We will also work in the Trade in Services Agreement negotiations towards achieving free trade in environmental services.

Phasing Out Subsidies that Encourage Wasteful Consumption of Fossil Fuels: The International Energy Agency estimates that the phase-out of fossil fuel subsidies – which amount to more than $500 billion annually – would lead to a 10 percent reduction in greenhouse gas emissions below business as usual by 2050. At the 2009 G-20 meeting in Pittsburgh, the United States successfully advocated for a commitment to phase out these subsidies, and we have since won similar commitments in other fora such as APEC. President Obama is calling for the elimination of U.S. fossil fuel tax subsidies in his Fiscal Year (FY) 2014 budget, and we will continue to collaborate with partners around the world toward this goal.

Leading Global Sector Public Financing Towards Cleaner Energy: Under this Administration, the United States has successfully mobilized billions of dollars for clean energy investments in developing countries, helping to accelerate their transition to a green, low-carbon economy. Building on these successes, the President calls for an end to U.S. government support for public financing of new coal plants overseas, except for (a) the most efficient coal technology available in the world's poorest countries in cases where no other economically feasible alternative exists, or (b) facilities deploying carbon capture and sequestration technologies. As part of this new commitment, we will work actively to secure the agreement of other countries and the multilateral development banks to adopt similar policies as soon as possible.

Strengthening Global Resilience to Climate Change: Failing to prepare adequately for the impacts of climate change that can no longer be avoided will put millions of people at risk, jeopardizing important development gains, and increasing the security risks that stem from climate change. That is why the Obama Administration has made historic investments in bolstering the capacity of countries to respond to climate-change risks. Going forward, we will continue to:

- Strengthen government and local community planning and response capacities, such as by increasing water storage and water use efficiency to cope with the increased variability in water supply

- Develop innovative financial risk management tools such as index insurance to help smallholder farmers and pastoralists manage risk associated with changing rainfall patterns and drought

- Distribute drought-resistant seeds and promote management practices that increase farmers' ability to cope with climate impacts.

Mobilizing Climate Finance: International climate finance is an important tool in our efforts to promote low-emissions, climate-resilient development. We have fulfilled our joint developed country commitment from the Copenhagen Accord to provide approximately $30 billion of climate assistance to developing countries over FY 2010-FY 2012. The United States contributed approximately $7.5 billion to this effort over the three year period. Going forward, we will seek to build on this progress as well as focus our efforts on combining our public resources with smart policies to mobilize much larger flows of private investment in low-emissions and climate resilient infrastructure.

II. Leading Efforts to Address Climate Change through International Negotiations

The United States has made historic progress in the international climate negotiations during the past four years. At the Copenhagen Conference of the United Nations Framework Convention on Climate Change (UNFCCC) in 2009, President Obama and other world leaders agreed for the first time that all major countries, whether developed or developing, would implement targets or actions to limit greenhouse emissions, and do so under a new regime of international transparency. And in 2011, at the year-end climate meeting in Durban, we achieved another breakthrough: Countries agreed to negotiate a new agreement by the end of 2015 that would have equal legal force and be applicable to all countries in the period after 2020. This was an important step beyond the previous legal agreement, the Kyoto Protocol, whose core obligations applied to developed countries, not to China, India, Brazil or other emerging countries.
The 2015 climate conference is slated to play a critical role in defining a post-2020 trajectory. We will be seeking an agreement that is ambitious, inclusive and flexible. It needs to be ambitious to meet the scale of the challenge facing us. It needs to be inclusive because there is no way to meet that challenge unless all countries step up and play their part. And it needs to be flexible because there are many differently situated parties with their own needs and imperatives, and those differences will have to be accommodated in smart, practical ways.

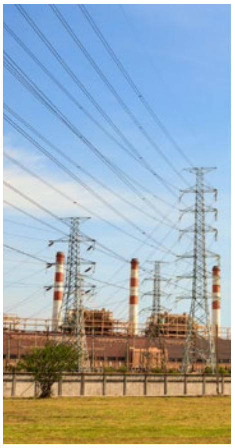
At the same time as we work toward this outcome in the UNFCCC context, we are making progress in a variety of other important negotiations as well. At the Montreal Protocol, we are leading efforts in support of an amendment that would phase down HFCs; at the International Maritime Organization, we have agreed to and are now implementing the first-ever sector-wide, internationally applicable energy efficiency standards; and at the International Civil Aviation Organization, we have ambitious aspirational emissions and energy efficiency targets and are working towards agreement to develop a comprehensive global approach.

EXHIBIT TFC-8

WHITE PAPER

President Obama's Climate Action Plan: What It Could Mean for the Power Sector

By Steve Fine and Chris MacCracken, ICF International



Summary

*For the first time, the U.S. Environmental Protection Agency (EPA) is moving forward with a clear timeline to regulate CO2 from existing power plants. The regulations are likely to be transformative for the energy industry, redefining prospective winners and losers, power prices, and capital allocation. But **how** the regulations will transform the industry is an open question that will be determined as each regulation is developed.*

In this paper, we discuss one of the most important factors affecting the transformation: the stringency and form of the regulations. Depending on the stringency and form (i.e., unit-specific emission standards or state- and regional-based emission standards), the level of reductions achieved and the implications for individual assets and the power sector as a whole could be dramatically different. Under relatively modest unit-specific emissions standards, the economics for non-emitting sources such as renewables and energy efficiency may only minimally be affected in the early phases of the regulation. Compliance costs for a subset of plants within each category (e.g., the top-performing coal plants from an emissions perspective) may be effectively negligible for a period of time (i.e., these plants require no or little further modifications initially and potentially limited modifications over time). In contrast, under more stringent standards that provide for a state- and regional-based standard that allows some form of trading or averaging, all coal plants possibly would incur more substantial compliance costs right from the start of the regulation. Here, potential also exists for the universe of facilities participating in a trading scheme to include non-emitters that could potentially realize emission credits and associated revenue.

The design of these programs and their implications on power prices, fuel switching, and retirements must be understood, as they will impact the economics of existing assets as well as investment decision making around new assets. New CO2 standards, even if they are not likely to take effect for several years, will become part of the equation of compliance and investment decisions today. They may result in incremental unit retirements beyond those already planned. Such retirements, along with expectations of power price impacts, will influence reliability considerations and decision making. They will shape investments in new capacity and affect the need for transmission upgrades or additions.

Overview of the Climate Action Plan and EPA Authority

President Obama's Climate Action Plan,[1] released on June 25, 2013, reignites the debate over regulating new and existing power plants under the Clean Air Act. In the plan, the President directed EPA to effectively reissue a proposal to regulate CO_2 emissions from new power plants through the establishment of New Source Performance Standards (NSPS). And for the first time, the President, under existing law, also directed EPA to issue "standards, regulations, or guidelines" to regulate CO_2 emissions from existing power plants. The timing, form, and stringency of the existing source rule have the potential to make it a transformative regulation for the U.S. power sector with wide-ranging impacts on power, fuel, and emissions markets. Depending on its structure, the regulation has the potential to redefine the winners and losers in the energy industry.

The rule for existing units would be established under the authority granted EPA by Section 111(d) of the Clean Air Act to "Establish a procedure…under which each State shall submit to the Administrator a

[1] FACT SHEET: President's Climate Action Plan. June 25, 2013. Retrieved July 26, 2013, from http://www.whitehouse.gov/the-press-office/2013/06/25/fact-sheet-president-obama-s-climate-action-plan.

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plan which establishes standards of performance for any existing source for any air pollutant." In 2007, the Supreme Court ruled in *Massachusetts v. EPA*[2] that the agency not only had the authority to regulate greenhouse gases under Section 111 but also the responsibility to do so. In a subsequent settlement agreement with state and environmental petitioners, EPA consented to use its power under the Clean Air Act to establish emissions guidelines for greenhouse gas emissions from existing sources.

Under the Clean Air Act's guiding principle of "cooperative federalism," EPA will set the process for states to establish the standards but allow states themselves to determine how they will achieve them. It also may issue a "model rule" that would effectively allow states to opt in to a program preapproved by EPA. EPA will require that each state respond to its final rule with a State Implementation Plan (SIP) detailing how the state will comply. EPA may accept a SIP or return it to the state for revision. In cases where EPA and the state cannot agree on a final SIP, EPA may impose a Federal Implementation Plan on the state with a prescribed implementation approach. The President's proposed schedule for this rulemaking process appears in Figure 1.

Figure 1: Proposed Deadlines for New and Existing Source Rulemaking

Rulemaking	Stage	Proposed Deadline
New Sources	Reissue Proposal	September 20, 2013
	Final	"In a timely fashion after considering all public comments"
Existing Sources	Proposed Standards from EPA	June 1, 2014
	Final Standards from EPA	June 1, 2015
	State Implementation Plans submitted by states to EPA	June 30, 2016

The form EPA takes with the regulation will be an important determinant of its impact on power markets. However, what form the rule will take is not clear. EPA has used 111(d) to control conventional pollutant emissions from municipal waste incinerators, pulp and paper facilities, petroleum refiners and others, but not for power generation more broadly and not for CO_2. EPA also used Section 111(d) in its Clean Air Mercury Rule (CAMR), finalized in 2005, that would have established a national cap-and-trade program for mercury. The court vacated CAMR for other reasons before it could rule on the appropriateness of using Section 111(d) for a trading-based program. As a result, very limited precedent exists on what type of requirement EPA may develop to control CO_2 emissions from existing sources and to what extent any proposed approach would withstand legal challenge.

One option for EPA is setting unit-specific emission rate standards, similar to the approach used for waste combustors under Section 111(d). These standards, likely expressed on an output basis in tons per megawatt-hour, could be set for categories of technology types (e.g., sub- or super-critical steam boiler or combined cycle) and fuels (coal by rank, natural gas, or oil) based on the performance of the existing fleet. For example, EPA may specify a standard for coal-fired generators burning subbituminous coals based on the median emission rate for units in that category. An existing unit that did not already meet the standard would be required to undertake upgrades to improve its emission rate through improvements in its heat rate (efficiency). Or, the unit could potentially co-fire with less carbon-intensive

[2] Massachusetts, et al. v. Environmental Protection Agency, et al., 549 US 497 (2007). Retrieved July 26, 2013, from http://www.supremecourt.gov/opinions/06pdf/05-1120.pdf.

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fuels or retire by a specific date. Although straightforward and requiring little interpretation, compliance costs at the program level for this type of requirement may be higher than alternatives achieving the same level of reductions.

> *NRDC's proposal would establish state-specific emission rate standards that are a function of each state's historical fossil generation levels and fuel-specific emission rate "benchmarks" defined by EPA.*

Following the President's guidance on the use of flexibility mechanisms, EPA also may develop a rule allowing credit trading among affected units in a fashion similar to the model rule issued around the NO_X SIP Call.[3] The added flexibility in the program may allow for more stringent standards to be achieved at the same or less cost than less flexible alternatives. However, these flexibility measures also may incur additional legal challenges that could impact the schedule in Figure 1. To provide the greatest degree of flexibility to the states, EPA may offer both unit-specific and trading programs as options and possibly other options between those two, with the final choice made by the individual states (subject to EPA review).

NRDC Proposal for Existing Sources

The Natural Resource Defense Council (NRDC) recently released what is so far the only public proposal for establishing an existing source standard that would include such flexibility mechanisms. Its approach would create state-specific emission rate standards around which affected sources could trade compliance credits. NRDC's proposed standards would be a function of each state's historical fossil generation levels and fuel-specific emission rate "benchmarks" defined by EPA that would decline over time. Under this type of program:

> *To promote cost-effective emission reductions, the President's directive included language directing the EPA to "develop approaches that allow the use of market-based instruments, performance standards, and other regulatory flexibilities."*

- Fossil sources emitting above the state standard would buy credits equal to the difference in their emission rates and the state standards;
- Fossil sources emitting below the standard would generate credits for sale to buyers in an amount equal to the difference between their rates and the standards; and
- Non-emitting sources, including energy efficiency and renewables to the extent they are allowed under the program, would generate credits for sale at the full state standard rate.

Figure 2 shows the net credit positions for representative generators of different types. The demand and supply for these credits would balance around a credit price, likely expressed in dollars per ton of CO_2. Greater demand for credits by higher-emitting units would lead to higher credit prices. Such prices would impose greater dispatch costs, leading the units to potentially reduce their levels of operation or potentially retire.

The credit prices would vary by state, consistent with each state's generation mix and its availability of lower-emitting options, including renewable resources, energy efficiency potential, and available generation capacity. States with an existing supply of under-used lower-emitting gas combined cycle (CC) units, for example, may realize lower credit prices than states dominated by coal with few generation

[3] EPA. NO_X Budget Trading Program/NOx SIP Call, 2003-2008. Retrieved July 26, 2013, from http://www.epa.gov/airmarkets/progsregs/nox/sip.html.

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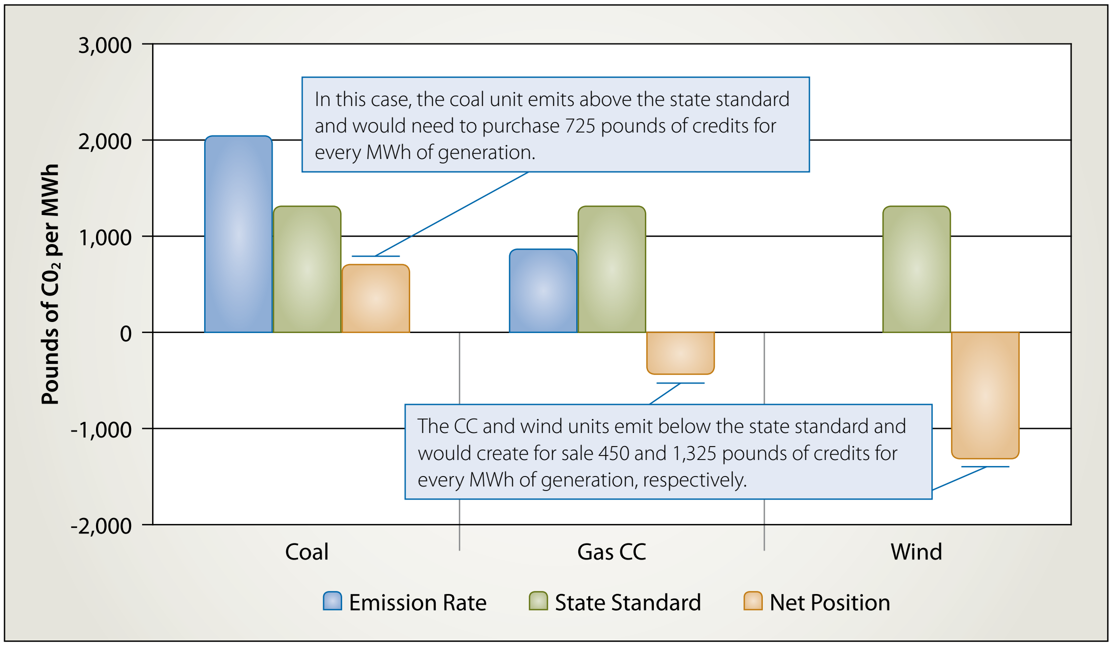
or efficiency alternatives. NRDC suggested that regional credit trading zones also may be a possibility to broaden the range of options for credit supply, potentially reducing compliance costs for these more constrained states.

Figure 2: Net CO2 Credit Positions for a Representative State Standard and Generating Units Under NRDC's Proposed Approach



Standard-Based Regulation vs. Traditional Cap-and-Trade Program

The mechanics of the standard-based approach, such as proposed by NRDC, would differ from those expected of a more traditional cap-and-trade program. Under a standard-based program, EPA would not place a limit on total CO_2 emissions. Instead, actual emissions would be based on the standard and the level of activity (generation) by affected sources. The programs also would differ in that credit allocations would not necessarily be a matter for discussion. Whereas allocations among sectors and generators were hotly debated in the development of the Waxman-Markey[4] and related cap-and-trade legislative proposals, a standard-based program builds an allocation into the program itself through the state standard. Under the standard-based program, generators that emit above the standard pay only on the difference between their emission rates and their states' standards, as discussed above, so they are implicitly "allocated" at the level of the state standard. Similarly, generators that emit below the standard would generate credits for sale, much as if they had been granted allocations in excess of their emissions under a cap-and-trade program.

The impact of the state-based standard also would differ from a cap-and-trade program. Under previous cap-and-trade proposals, generators would pay for credits based on their total emissions, regardless of their relative emission levels. Figure 3 shows how a CO_2 allowance price of $10 per ton would translate into dispatch costs for three representative unit types. Although allocations granted under such a program may offset some of the total cost of allowances to the generators, the price signal to the market, at least in

[4] H.R. 2454 (111th): American Clean Energy and Security Act of 2009. Retrieved July 26, 2013, from http://www.govtrack.us/congress/bills/111/hr2454/text.

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competitive markets, would likely have been based on the equivalent CO_2 dispatch cost shown in the table. This cost would translate into higher power prices.

Figure 3: Dispatch Cost for Illustrative Generators Under Cap-and-Trade Program

Generator Type	Illustrative Emission Rate (lbs/MWh)	Illustrative State Standard (lbs/MWh)	Net Position Relative to Standard (lbs/MWh)	Illustrative CO_2 Price ($/Ton)	Equivalent CO_2 Dispatch Cost ($/MWh)
Coal	2,050	N/A	2,050 (short)	$10	$10.3 (cost)
Gas CC	875	N/A	875 (short)	$10	$4.4 (cost)
Non-emitting	0	N/A	N/A	$10	N/A

Figure 4 illustrates how the dispatch cost effects could differ under a standard-based trading program. The same $10 per ton CO_2 credit price would translate into a lower dispatch cost to coal units. The gas and non-emitting units would receive an incremental revenue stream under the program. In this case, the impact on power prices is less certain. Although the incremental cost to coal units would put upward pressure on coal prices, the revenues to gas and non-emitting generators resulting from the program may push power prices downward. Those generators would need less from the energy market to cover their costs and make their necessary returns. The trading system also would result in a transfer of funds from coal-fired generators to gas and renewable generators as credits are exchanged. To the extent that the program could generate credits for and incentivize energy efficiency projects—thus reducing demand for generation, power prices could face additional downward pressure. However, other offsetting and second-order impacts could occur, including pressure on natural gas prices and capacity prices.

Figure 4: Dispatch Cost for Illustrative Generators Under Standard-Based Trading Program

Generator Type	Illustrative Emission Rate (lbs/MWh)	Illustrative State Standard (lbs/MWh)	Net Position Relative to Standard (lbs/MWh)	Illustrative CO_2 Price ($/Ton)	Equivalent CO_2 Dispatch Cost ($/MWh)
Coal	2,050	1,325	725 (short)	$10	$3.6 (cost)
Gas CC	875	1,325	450 (long)	$10	$2.3 **(revenue)**
Non-emitting	0	1,325	1,325 (long)	$10	$6.6 **(revenue)**

Conclusions

Regardless of the form (or forms) that EPA's standards take, they will have impacts on the power sector. Many coal unit compliance decisions, including retirement, already have been made, and are continuing to be made, in the face of a 2015/2016 compliance deadline for EPA's Mercury and Air Toxics Standards. These decisions also are occurring in combination with expected final rules from EPA governing coal ash handling, effluent guidelines, and water intake structures. A new lower gas price regime, relatively low energy demand growth, and the Supreme Court's recent decision to review the Cross-States Air

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Pollution Rule decision[5] only further complicate the uncertainty facing coal units and the sector as a whole. New CO_2 standards, even if they are not likely to take effect for several years, will become part of the equation of those compliance decisions today. They may result in incremental unit retirements beyond those already planned. Those retirements, along with expectations of power price impacts, will influence reliability considerations and decision making. They also will shape investments in new capacity and the need for transmission upgrades or additions.

EPA will conclude the rulemaking process for NSPS for new electric generating units in the coming months. Stakeholders will begin discussions in earnest over the potential look and feel of performance standards for existing units. Opportunities to shape the discussions and understand the implications of an EPA ruling under Section 111(d) are apparent. In particular, compliance costs will vary drastically based on the form of the standards. If a state plan resembles NRDC's proposal, a range of factors will determine the ultimate compliance costs and the resulting financial positions of the companies impacted. These factors include the rates set for fossil resources and the crediting mechanisms for renewable energy, energy efficiency, and potentially even new nuclear generation. State leaders and agencies also will serve an important role in this process, because the exact design of the performance standard could change depending on what flexibility EPA grants states in shaping implementation plans. Stakeholders must sift through these uncertainties and analyze the potential impacts on their assets in the near future.

ICF continues to be at the forefront of working with our clients to help them understand and evaluate the potential regulatory options and the impact on generation assets and on the power and fuel markets.

To discuss this further, please contact Steve Fine at Steve.Fine@icfi.com or +1.703.934.3302.

[5] EPA. Cross-State Air Pollution Rule (CSAPR). Retrieved July 26, 2013, from http://www.epa.gov/crossstaterule/.

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About ICF International

Since 1969, ICF International (NASDAQ:ICFI) has been serving government at all levels, major corporations, and multilateral institutions. With more than 60 offices and more than 4,500 employees worldwide, we bring deep domain expertise, problem-solving capabilities, and a results-driven approach to deliver strategic value across the lifecycle of client programs.

At ICF, we partner with clients to conceive and implement solutions and services that protect and improve the quality of life, providing lasting answers to society's most challenging management, technology, and policy issues. As a company and individually, we live this mission, as evidenced by our commitment to sustainability and carbon neutrality, contribution to the global community, and dedication to employee growth.

About the Authors

Steve Fine, Vice President, ICF International

An expert on environmental markets, Steve Fine has led numerous multistakeholder engagements, including the Edison Electric Institute, U.S. Climate Action Partnership, Regional Greenhouse Gas Initiative (RGGI), and Clean Energy Group. His work has concentrated on evaluating the economics of conventional and renewable energy resources within the context of developing environmental regulations.

Mr. Fine was an invited panelist to a U.S. Senate Roundtable discussion on the future of 3P and 4P legislation conducted by Senators Carper and Alexander. He has a B.A. from the University of California, Santa Cruz, and an M.A. in Economics from the Johns Hopkins School of Advanced International Studies.

Chris MacCracken, Principal, ICF International

Chris MacCracken has more than 15 years of experience in energy and economic modeling and assessing the potential impacts of environmental policies on the energy sector. He has directed a number of studies examining the impacts of environmental regulation on emission, power and fuel markets, compliance planning, and electric generating unit valuations for electric utilities, independent power producers (IPPs), industry associations, and nonprofit policy organizations. He is lead author of the Emission Markets chapter in ICF International's quarterly Integrated Energy Outlook publication.

Prior to joining ICF in 2000, Mr. MacCracken worked with the Global Climate Change Group at Battelle-Pacific Northwest National Laboratory. He modeled the impacts of climate change policy and the role of advanced technologies in mitigating climate change.

Testimony of Anthony S. "Tony" Campbell
President & CEO
East Kentucky Power Cooperative

November 14, 2013

SUMMARY

EKPC is a generation and transmission cooperative based in Winchester, KY. Our mission is to provide safe, reliable, affordable electric power to the 16 electric distribution cooperatives that own EKPC. Nationwide, not for profit electric cooperatives serve 42 million people in 47 states.

We do not believe Congress ever intended for the Clean Air Act to regulate greenhouse gas emissions from power plants.

The proposed Section 111 regulations have already had a chilling impact on electricity generation in the U.S. When that proposed rule was issued, approximately 15 coal-fired power plants had received a PSD permit, but had not yet commenced construction. By the time the rule was withdrawn and re-proposed in 2013, most of those plants had been scrapped due to regulatory uncertainty, despite the exemption EPA included in the proposed rule.

In recent years electric utilities have faced a daunting array of environmental regulations on all fronts – air, water, and waste – that have contributed to widespread unit retirements. Coal-fired generation is essential to ensure energy diversity and to keep electricity prices low. Although natural gas prices are currently low, recent data from the United States Energy Information Administration ("EIA") shows that natural gas prices have increased by more than 50% since April 2012.

In addition to the realities and risks of rising natural gas prices, it is not feasible for the nation's existing coal-fired generating capacity to be transitioned to natural gas. Natural gas generation requires transportation from natural gas wells to power plants via an intricate network of interstate pipelines and compressor stations. These requirements raise infrastructure and national security concerns.

EKPC's greatest apprehension relates to regulations for existing sources. EKPC operates three baseload power plants fueled by coal and one plant operated by natural gas-fired combustion turbines. EKPC has invested almost $1 billion in retrofitting existing coal-fired power plants with modern air pollution control equipment. Further, EKPC spent another $1 billion to construct two of the cleanest coal units in the country. An existing source rule that requires CCS would leave EKPC, with no choice but to convert these units to natural gas, essentially wasting the extensive capital investments that have been made to lower pollutants from the coal-fired units.

EKPC is very worried about the supply of electricity to its rural cooperative members and its cost. There is a lack of technology that would allow EKPC to control GHG emissions, and a lack of demonstrated benefits to the environment. Most if not all coal-fired units will be forced to retire as a result of the regulation of GHG emissions, which would astronomically increase electricity rates and ultimately cause further job losses.

TESTIMONY OF ANTHONY S. "TONY" CAMPBELL
PRESIDENT & CHIEF EXECUTIVE OFFICER
EAST KENTUCKY POWER COOPERATIVE

BEFORE THE
SUBCOMMITTEE ON ENERGY AND POWER
COMMITTEE ON ENERGY AND COMMERCE
UNITED STATES HOUSE OF REPRESENTATIVES

REGARDING

EPA'S PROPOSED GREENHOUSE GAS STANDARDS FOR ELECTRIC POWER PLANTS

November 14, 2013

A. Introduction

Chairman Whitfield, Ranking Member Rush and members of the Subcommittee, thank you for the opportunity to appear before you today. My name is Anthony S. "Tony" Campbell. I am the President and CEO of East Kentucky Power Cooperative ("EKPC"), and I have served in that position since 2009. I have previously served as CEO of Citizens Electric Cooperative in Missouri, and my career has also included positions at Corn Belt Energy and Soyland Power Cooperative, both in Illinois. I have a Bachelor's degree in Electrical Engineering from Southern Illinois University and a Master's degree in Business Administration from the University of Illinois.

Nationwide, not for profit electric cooperatives serve 42 million people in 47 states. While about 12 percent of the nation's meters are members of a rural electric cooperative, those co-ops own and maintain 42 percent of the nation's electric distribution lines, covering three quarters of the nation's landmass. Electric cooperatives employ about 70,000 people nationwide.

EKPC is a generation and transmission cooperative based in Winchester, Ky. Our mission is to provide safe, reliable, affordable electric power to the 16 electric distribution cooperatives that own EKPC. EKPC generates electricity at three baseload power plants fueled by coal and one peaking plant fueled by natural gas. More than 90 percent of the power we generate is fueled by coal. EKPC's total generating capacity is about 3,000 megawatts, and that power is delivered over a network of high-voltage transmission lines totaling about 2,800 miles. EKPC employs about 700 people.

More than 1 million Kentucky residents and businesses in 87 counties depend on the power we generate. Our 16 owner-member cooperatives serve mainly rural areas in the Eastern and Central two-thirds of Kentucky. EKPC and its member cooperatives exist only to serve their members. Our electric cooperatives serve some of the most remote parts of Kentucky. The terrain in this region varies from rolling farmland in Central Kentucky to mountains in the eastern portion. On average, our cooperatives have about 9 consumers per mile of power line, while investor-owned utilities average 37 consumers per mile and municipal utilities average 48 consumers. We also serve some of the neediest Kentuckians. The household income of Kentucky cooperative members is 7.4 percent below the state average, and 22 percent below the national average.

B. Use of the Clean Air Act to Regulate Greenhouse Gases from Electric Utility Units

Congress never intended for the Clean Air Act to regulate greenhouse gas emissions ("GHG") from power plants. This fact is illustrated by EPA's attempts to promulgate GHG new source performance standards ("NSPS") under Section 111. The Administration's proposed GHG NSPS, first issued in April 2012, demonstrated unequivocally that the Administration seeks to end new coal generation through regulation. In that proposal EPA chose not to establish a separate standard for coal-fired units; instead, it lumped coal units together with natural-gas fired units into a new NSPS subcategory, and established a GHG emission limit that only some natural gas combined cycle units can achieve. These proposed Section 111 regulations have already had a chilling impact on electricity generation in the U.S. When that proposed rule was issued, approximately 15 coal-fired power plants had received a PSD permit but had not yet commenced construction. By the time the rule was withdrawn and re-proposed in 2013, most of those plants had been scrapped due to regulatory uncertainty, despite the exemption EPA included in the proposed rule. The impact of the proposed GHG NSPS on already permitted new coal plants was fully realized when EPA did not finalize the proposed GHG NSPS rule within a year after proposing it, and instead, re-proposed the rule in September without any exemption for transitional sources. EPA recognized in the preamble to the rule that there are only three new coal units under development that would not include carbon capture and sequestration ("CCS"), the proposed Wolverine project in Michigan, the Washington County project in Georgia, and the Holcomb project in Kansas.

Just last month the Supreme Court agreed to hear a challenge to EPA's regulations requiring major sources to obtain permits for GHG emissions along with traditional pollutants. The specific issue for which the Court granted certiorari is "whether the Agency's regulation of GHGs from new motor vehicles triggered permitting requirements under the Clean Air Act for stationary sources." This case, *Utility Air Regulatory Group v. EPA*, tests EPA's authority to use the Endangerment Finding and the determination that GHGs from new motor vehicles must be regulated to protect public health and welfare as the basis to require PSD permits for new major sources of GHGs and major modifications to existing major sources of GHGs. Although this appeal will likely not directly address the regulations EPA is developing under Section 111 of the Clean Air Act, the real possibility that EPA's regulation of GHG emissions under the PSD permitting program may be struck down by the Supreme Court underscores the importance of Congressional guidance in this area.

While the current low price of natural gas has contributed to the decline in coal-fired electricity generation and the resurgence of natural gas-fired units, EPA's new regulations are an equally important factor in this trend. In recent years electric utilities have faced a daunting array of environmental regulations on all fronts – air, water, and waste – that have contributed to widespread unit retirements. According to the American Coalition for Clean Coal Electricity, EPA's rules have contributed to the closure of some 300 existing coal-fired units in 33 states.

Coal-fired generation is essential to ensure energy diversity and to keep electricity prices low. Although natural gas prices are currently low, recent data from the United States Energy Information Administration ("EIA") shows that natural gas prices have increased by more than 50% since April 2012. EIA's Annual Energy Outlook for 2013 projects that natural gas prices for the electric power sector will continue to increase by about 3.7% each year until 2040, and that total electricity demand will increase by 28% by 2040.[1] These estimates underscore the need for a diverse fuel mix that includes coal to meet these energy demands.

In addition to the realities and risks of rising natural gas prices, it is simply not feasible for the nation's entire existing coal-fired generating capacity to be transitioned to natural gas. Natural gas generation requires transportation from natural gas wells to power plants via an intricate network of interstate pipelines and compressor stations that allow the gas to be constantly pressurized. These requirements raise not only infrastructure concerns but also safety and national security concerns. If a key compressor station were to fail or be targeted in a terrorist attack, the nation's electric grid would be placed in jeopardy. When these natural gas supply requirements are contrasted with coal which is plentiful in supply, can be stockpiled at a 30-45 day supply, and can be transported via several different methods without the use of interstate pipelines, it makes no sense to require wholesale conversions from coal-fired generation to natural gas, particularly in areas of the country that are rich in coal resources and are not located in close proximity to natural gas wells.

Further regulations limiting GHG emissions from fossil fuel electric generating units are unnecessary and unreasonable. Coal-fired power plants in the U.S. contribute only approximately 4% to global GHG emissions.[2] The U.S. power fleet has already reduced CO_2 emissions by 16% below 2005 levels, with CO_2 from coal-fired power plants reduced by almost 25%.[3] These reductions are a result of the utility sector's shift to natural gas generation. EPA should allow coal-fired power plants to continue to make these reductions in a reasonable manner and in response to market pressures, instead of by regulatory fiat. Furthermore, the regulations at issue will not have a meaningful impact on global climate change. The minimal impact that these regulations will have on the environment further underscores the need for all GHG regulations to be economically achievable. Currently, EPA is developing GHG regulations for new and existing power plants without adequate input from coal states. None of EPA's listening sessions are located in Kentucky or any other coal state. Congressional action is necessary to keep EPA from regulating all coal-fired electricity generation out of existence.

C. The Whitfield-Manchin Discussion Draft Bill

EKPC supports the bipartisan Whitfield-Manchin discussion draft bill as common-sense legislation that provides important guidelines and parameters for EPA to follow in developing GHG regulations for new and existing power plants without causing irreparable harm to the U.S. economy. The Whitfield-Manchin discussion draft is different from many of the other bills and

[1] EIA, *Annual Energy Outlook 2013*, April 2013, http://www.eia.gov/forecasts/aeo/.
EPA *Greenhouse Gas Reporting Program Data*, available at http://epa.gov/ghgreporting/ghgdata/reported/powerplants.html and Ecofys, *World GHG Emissions Flow Chart 2010*, available at http://www.ecofys.com/files/files/asn-ecofys-2013-world-ghg-emissions-flow-chart-2010.pdf.
[3] EIA, *Monthly Energy Review*, October 2013.

legislative riders that have been introduced in recent years, in that it does not seek to strip EPA entirely of its authority to regulate GHGs under the Clean Air Act. It narrowly responds to only one regulatory initiative by EPA – EPA's proposed regulation of GHG emissions from power plants under Section 111 of the Clean Air Act. This bipartisan bill is badly needed to ensure EPA does not promulgate a rule that jeopardizes the country's energy future, puts electricity reliability at risk, and severely harms the economy.

Although EPA's re-proposed GHG NSPS rule purportedly addressed many of the concerns raised in comments to the 2012 proposal, there are still many troubling aspects of the rule that require Congressional action. First, the proposed rule assumes that no new traditional coal-fired units will be built in the future and considers only IGCC and synfuel units in the rule's Best System of Emission Reduction (BSER) analysis for new coal-based unit CO_2 limits. Second, the proposed rule eliminated the 30-year compliance option that would have allowed utilities time to phase in use of carbon capture and storage (CCS). Instead, at least partial CCS is required to be implemented in new coal-fired power plants if new coal units are to achieve the BSER CO_2 limits. EPA identifies CCS projects that are currently being developed as evidence that CCS technology has been adequately demonstrated. However, none of the U.S. projects involve traditional coal units. Three of those projects are IGCC facilities that can more readily sequester CO_2 than conventional coal-fired power plants, and one project is a demonstration project at the Boundary Dam power station in Saskatchewan, Canada. In addition, EPA points to the Great Plains Synfuels project and a pilot CCS project that was operated at American Electric Power's Mountaineer Station in 2009 but subsequently cancelled, as examples of projects that have successfully implemented CCS. None of the generation projects are complete or currently operational and the synfuels project should not be used as a comparison for the electric generation industry.

All of the four CCS projects identified by EPA as currently under development[4] have received government funding. The Kemper IGCC project, which received a $270 million federal grant and $412 million in federal tax credits, recently announced that it will miss its May 2014 completion deadline. Delays at the Kemper IGCC project have contributed to an almost $5 billion cost that is almost double the original estimated cost of around $2.8 billion.[5] In addition, the Boundary Dam project recently announced a $115 million cost overrun despite receiving $240 million in funding from the Canadian government.[6] All of the four projects plan to sell captured CO_2 for enhanced oil recovery. EPA has not considered the taxpayer-funded portion of these project costs and does not appear to have accounted for cost overruns in its BSER analysis.

Any GHG emissions limit under Section 111 must reflect "the application of the best system of emission reduction which … the Administrator determines has been adequately demonstrated." EPA has not presented any real evidence that CCS is adequately demonstrated. EKPC supports

[4] EPA identified Southern Company's Kemper County Energy Facility, SaskPower's Boundary Dam CCS Project, Summit Power Group's Texas Clean Energy Project (recipient of a $450 million federal grant), and Hydrogen Energy California, LLC's proposed IGCC facility (recipient of a $408 million federal grant).

[5] Associated Press, *Kemper County power project cost approaches $5 billion with latest rise* (updated Oct. 29, 2013 at 10:19 pm), http://blog.gulflive.com/mississippi-press-business/2013/10/kemper_county_power_project_co.html.

[6] Bruce Johnstone, *SaskPower CEO says ICCS project $115M over budget*, Regina Leader-Post (Oct. 18, 2013), http://www.leaderpost.com/business/energy/SaskPower+says+ICCS+project+115M+over+budget/9055206/story.html.

the language in the draft bill that would prevent EPA from imposing any GHG emission standard on new coal-fired units until such limit has been achieved by representative coal-fired units for at least a year, because EPA's determination that CCS has been adequately demonstrated does not reflect reality.

EKPC's greatest concern relates to regulations for existing sources. As stated earlier, EKPC operates three baseload power plants fueled by coal and one plant operated by natural gas-fired combustion turbines. Pursuant to a consent decree with EPA, EKPC has invested almost $1 billion in retrofitting existing coal-fired power plants with modern air pollution control equipment. Further, EKPC spent another $1 billion to construct two of the cleanest coal units in the country. An existing source rule that requires CCS would leave EKPC with no choice but to convert these units to natural gas, essentially wasting the extensive capital investments that have been made to lower pollutants from the coal-fired units. This would result because there is no demonstrated technology that would be able to control GHG emissions. In addition, EKPC has already expended all of its investment capital on pollution controls under the consent decree and has no additional funds to invest in new, expensive technologies such as CCS. The costs associated with such a transition would represent a devastating and unfair impact to our rural members who have already paid for pollution control upgrades to EKPC's existing generating units, only to deal with much higher electricity rates. Higher electricity rates would further harm Kentucky's economy, where coal production has decreased by 64% since 2000. Recent coal mining employment figures released by the Kentucky Energy and Environment Cabinet show only an estimated 12,342 individuals employed in Kentucky coal mines – the lowest level recorded since 1927 when the Commonwealth began keeping mining employment statistics.[7] With higher rates, manufacturing jobs would also disappear, further compounding the impact to the economy from the loss of mining jobs. These dire figures demonstrate that Congressional action is sorely needed to ensure that coal-fired generation can continue in states like Kentucky.

These concerns extend to Governor Beshear's Kentucky Climate Action Plan which proposes significant GHG emissions reductions from the electric generating sector beginning in 2020. Reductions at this level will result in the shutdown of EKPC's coal units for which hundreds of millions dollars have been spent on pollution controls to ensure that the units could comply with EPA's many new environmental regulations. EKPC, instead, favors an approach like the one that the Whitfield-Manchin discussion draft bill contemplates, which we believe will foster more flexible, creative approaches to reducing GHGs from new and existing sources.

Even if we ignore the economic devastation that will result from an adverse existing source rule, Congressional action is also necessary to prevent Section 111(d) from being used to regulate GHG emissions from existing power plants. It is EKPC's view that the discussion draft bill does not go far enough, since the bill seems to assume that Section 111(d) is an appropriate vehicle for regulating GHG emissions from existing stationary sources. The discussion draft bill requires only that Congress set an effective date for any standard of performance for existing sources under Section 111(d) and that such rules or guidelines may not take effect unless the Administrator has submitted to Congress a report containing:

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[7] Kentucky Energy and Environment Cabinet, *Kentucky Quarterly Coal Report*, Q2 2013, http://energy.ky.gov/Coal%20Facts%20Library/Kentucky%20Quarterly%20Coal%20Report%20(Q2-2013).pdf

(1) the text of such rule or guidelines;
(2) the economic impacts of such rule or guidelines, including potential effects on economic growth, competitiveness and jobs, and on electricity ratepayers; and
(3) the amount of GHG emissions that such rule or guidelines are projected to reduce as compared to overall GHG emissions.

While this may have the result of delaying indefinitely any regulations that EPA may promulgate under Section 111(d), EKPC supports a more permanent solution that clarifies that Section 111(d) cannot be used to regulate GHG emissions from existing power plants. Regardless of whether the utility sector may eventually succeed in challenging these regulations, Congress should put an end to the regulatory uncertainty surrounding existing power plants and clarify that Section 111(d) and, in fact, Section 111 as a whole, is not the appropriate mechanism for regulating GHG emissions from electric generating units.

C. Conclusion

EKPC appreciates the work of this Committee and the opportunity to present our views on EPA's regulation of GHGs from power plants. To summarize, EKPC's main concern is for our rural cooperative members. There is a lack of technology that would allow EKPC to control GHG emissions, and a lack of demonstrated benefits to the environment. Most if not all coal-fired units will be forced to retire as a result of the regulation of GHG emissions, which would astronomically increase electricity rates and ultimately cause further job losses. EKPC believes the transportation and national security concerns presented by natural gas pipelines and compressor stations, as well as the upward trend in natural gas prices make conversion to a gas-fired utility fleet much too risky for this country's energy security. I would like to reaffirm EKPC's support for the Whitfield-Manchin discussion draft bill. Congressional action is sorely needed to end the regulatory uncertainty surrounding the electric power sector and put the country back on a path toward full economic recovery.

2013 Carbon Dioxide Price Forecast

November 1, 2013

AUTHORS

Patrick Luckow
Elizabeth A. Stanton
Bruce Biewald
Jeremy Fisher
Frank Ackerman
Ezra Hausman

Synapse Energy Economics, Inc.

485 Massachusetts Avenue, Suite 2
Cambridge, Massachusetts 02139

617.661.3248 | www.synapse-energy.com

CONTENTS

1. EXECUTIVE SUMMARY

Prudent planning requires electric utilities and other stakeholders in carbon-intensive industries to use a reasonable estimate of the future price of carbon dioxide (CO_2) emissions when evaluating resource investment decisions with multi-decade lifetimes. However, forecasting a CO_2 price can be difficult. While several bills have been introduced in Congress, the federal government has yet to legislate a policy to reduce greenhouse gas emissions in the United States.

Although this lack of a defined policy that sets a price on carbon poses a challenge in CO_2 price forecasting, an assumption that there will be no CO_2 price in the long run is not, in our view, reasonable. The scientific basis for attributing climatic changes to human-driven greenhouse gas emissions is irrefutable, as are the type and scale of damages expected to both infrastructure and ecosystems. The need for a comprehensive U.S. effort to reduce greenhouse gas emissions is clear. Any policy requiring or leading to greenhouse gas emission reductions will result in higher costs to the electricity resources that emit CO_2.

The Synapse 2013 CO_2 price forecast is designed to provide a reasonable range of price estimates for use in utility Integrated Resource Planning (IRP) and other electricity resource planning analyses. The current forecast updates Synapse's 2012 CO_2 price forecast, published in October 2012.[1] Our 2013 forecast incorporates new data that have become available since 2012, in order to provide useful CO_2 price estimates for utility resource planning purposes.

1.1. Key Assumptions

Synapse's 2013 CO_2 price forecast reflects our expert judgment that near-term regulatory measures to reduce greenhouse gas emissions, coupled with longer-term cap-and-trade or carbon tax legislation passed by Congress, will result in significant pressure to decarbonize the electric power sector. The key assumptions of our forecast include:

- A federal program establishing a price for greenhouse gases is the probable eventual outcome, as it allows for a least-cost path to emissions reduction.
- Initial climate-focused policy actions are more likely to take a regulatory approach, e.g. Section 111(d) of the Clean Air Act. In the longer-term, federal legislation setting a price on emissions through a cap-and-trade policy or a carbon tax will likely be prompted by one or more of the following factors:
    - New technological opportunities that lower the cost of carbon mitigation;

[1] Wilson et al., "2012 Carbon Dioxide Price Forecast," October 2012. http://www.synapse-energy.com/Downloads/SynapseReport.2012-10.0.2012-CO2-Forecast.A0035.pdf.

- A patchwork of state policies that achieve state emission targets for 2020, spurring industry demands for federal action;
- A series of executive actions taken by the President that spur demand for Congressional action;
- A Supreme Court decision that permits nuisance lawsuits, making it possible for states to sue companies within their boundaries that own high-carbon-emitting resources, and creating a financial incentive for energy companies to act; and
- Mounting public outcry in response to increasingly compelling evidence of human-driven climate change.

Given the growing interest in reducing greenhouse gas emissions by states and municipalities throughout the nation, a lack of timely, substantive federal action will result in the enactment of diverse state and local policies. Heterogeneous—and potentially incompatible—sub-national climate policies would present a challenge to any company seeking to invest in CO_2 emitting power plants, both existing and new. Historically, there has been a pattern of states and regions leading with energy and environmental initiatives that have in time been superseded at the national level. It seems likely that this will be the dynamic going forward: a combination of state and regional actions, together with federal regulations, that are eventually eclipsed by a comprehensive federal carbon price.

We expect that federal regulatory measures together with regional and state policies will lead to the existence of a cost associated with greenhouse gas reductions in the near term. Prudent utility planning requires that utilities take this cost into account when engaging in resource planning, even before a federal carbon price is enacted.

1.2. Study Approach

To develop the 2013 CO_2 price forecast, Synapse reviewed several key developments that have occurred over the past year. These include:

- Proposed federal regulatory measures to limit CO_2 emissions from new power plants and administrative initiatives to advance regulation for existing units;
- Updates to the U.S. carbon price used to assess the climate benefit of federal rulemakings;
- Revisions to the Northeast's Regional Greenhouse Gas Initiative (RGGI) CO_2 policy and the first allowance auctions under California's AB 32 Cap-and-Trade program;
- The results of a multi-year Energy Modeling Forum (EMF) research effort on the costs of U.S. emissions abatement from nine integrated assessment modeling teams; and
- Carbon price forecasts from the most recent IRP efforts of 28 utilities.

1.3. Synapse's 2013 CO_2 Price Forecast

Based on analyses of the sources described in sections 3 through 9, and relying on our own expert judgment, Synapse developed Low, Mid, and High case forecasts for CO_2 prices from 2013 to 2040. Figure ES-1 (below) shows the range covered by the Synapse forecasts. These projections assume that state and regional policies will combine with federal regulatory measures to put economic pressure on carbon-emitting resources in the next several years such that the costs of operating a high-carbon-emitting plant increase—followed later by a broader federal, market-based policy. In states other than the RGGI region[2] and California, we assume a zero carbon price for the next several years; by 2020, we expect that federal regulatory measures will begin to put economic pressure on carbon-emitting power plants throughout the United States. All annual carbon prices are reported in 2012 dollars per short ton of CO_2.[3]

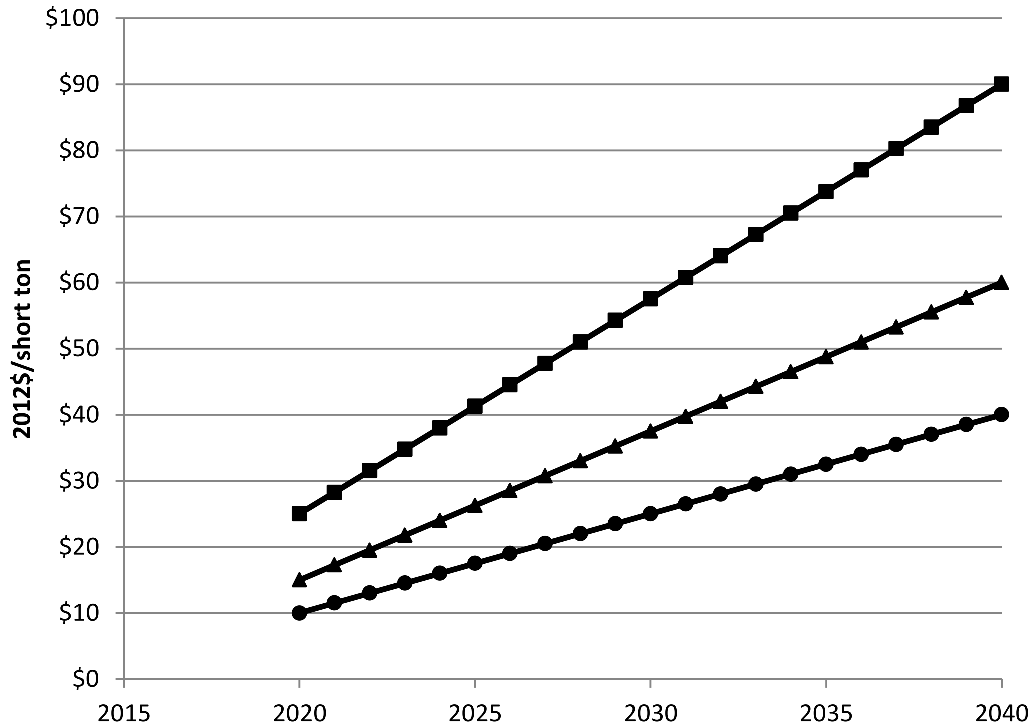
Each of the forecasts shown in Figure ES-1 represents a different level of political will for reducing carbon emissions, as described below.

- The **Low case** forecasts a carbon price that begins in 2020 at $10 per ton, and increases to $40 per ton in 2040, representing a $22 per ton levelized price over the period 2020-2040. This forecast represents a scenario in which federal policies—either regulatory or legislative—exist but are not very stringent.
- The **Mid case** forecasts a carbon price that begins in 2020 at $15 per ton, and increases to $60 per ton in 2040, representing a $34 per ton levelized price over the period 2020-2040. This forecast represents a scenario in which federal policies are implemented with significant but reasonably achievable goals.
- The **High case** forecasts a carbon price that begins in 2020 at $25 per ton, and increases to approximately $90 per ton in 2040, representing a $52 per ton levelized price over the period 2020-2040. This forecast is consistent with the occurrence of one or more factors that have the effect of raising carbon prices. These factors include somewhat more aggressive emissions reduction targets; greater restrictions on the use of offsets; restricted availability or high cost of technological alternatives such as nuclear, biomass, and carbon capture and sequestration; more aggressive international actions (thereby resulting in fewer inexpensive international offsets available for purchase by U.S. emitters); or higher baseline emissions.

[2] Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont.

[3] Results from public modeling analyses were converted to 2012 dollars using price deflators taken from the U.S. Bureau of Economic Analysis, and are available at: http://www.bea.gov/national/nipaweb/SelectTable.asp. Consistent with U.S. Energy Information Administration and U.S. Environmental Protection Agency modeling analyses, a 5 percent real discount rate was used in all levelization calculations.

ES- 1: Synapse 2013 CO_2 Price Trajectories



2. STRUCTURE OF THIS REPORT

This report presents Synapse's 2013 Low, Mid and High CO_2 price forecasts, along with the evidence assembled to inform these forecasts:

- Section 3 discusses broader concepts of CO_2 pricing.
- Sections 4 through 8 discuss existing state and federal legislation, potential future legislation, recent cap-and-trade results from the research community, and a range of current CO_2 price forecasts from utilities.
- Section 9 presents Synapse's 2013 Low, Mid, and High CO_2 price forecast, along with a comparison to recent utility forecasts.

Unless otherwise indicated, all prices are in 2012 dollars and CO_2 emissions are given in short tons.

3. WHAT IS A CARBON PRICE?

There are several co-existing meanings for the term “carbon price” or “CO_2 price”: each of these meanings is appropriate in its own context. Here we give a brief introduction to five common types of carbon prices, along with a quick guide to which of the carbon price estimates reviewed in this report are based on which of these meanings. (Note that the definition of an additional term—the “price of carbon”—is ambiguous because it can at times mean several of the following.)

Carbon allowances (sometimes called credits or certificates, and best known for their use in policies called “cap and trade”): Allowances are certificates that give their holder the right to emit a unit of a particular pollutant. A fixed number of carbon allowances are issued by a government, some sold and, perhaps, some given away.[4] Subsequent trade of allowances in a secondary market is common to this policy design. The price that firms must pay to obtain allowances increases their cost of doing business, thereby giving an advantage to firms with cleaner, greener operations, and creating an incentive to lower emissions whenever it can be done for less than the price of allowances. The number of allowances—the “cap” in the cap-and-trade system—reflects the required society-wide emission reduction target. A greater reduction target results in a lower cap and a higher price for allowances. In the field of economics, pricing emissions is called “internalizing an externality”: The external (not borne by the polluting enterprise) cost of pollution damages is assigned a market price (thus making it internal to the enterprise).

In this report: The Northeast’s RGGI and California’s Cap-and-Trade Program are both carbon allowance trading systems. In addition, the Kerry-Lieberman, Waxman-Markey, and Cantwell-Collins bills all proposed policy measures that included carbon allowance trading.

Carbon tax: A carbon tax also internalizes the externality of carbon pollution, but instead of selling or giving away rights to pollute (the allowance approach), a carbon tax creates an obligation for firms to pay a fee for each unit of carbon that they emit. In theory, if the value of damages were known with certainty, a tax could internalize the damages more accurately, by setting the tax rate equal to the damages; in practice, the valuation of damages is typically uncertain. In contrast to the government issuance of allowances, with a carbon tax there is no fixed amount of possible emissions (no “cap”). A cap-and-trade system specifies the amount of emission reduction, allowing variation in the price; a tax specifies the price on emissions, allowing variation in the resulting reductions. In both cases there is an incentive to reduce emissions whenever it can be done for less than the prevailing price. In both cases there is the option to continue emitting pollution, at the cost of either buying allowances or paying the tax. While some advocates have claimed that a tax is administratively simpler and reduces bureaucratic, regulatory, and compliance costs, a general aversion to new taxes has meant that no carbon tax proposals have received substantial support in recent policy debate.

[4] Whether or not allowances are initially given away for free or sold, they represent an opportunity cost of emissions to the holder.

Effective price of carbon (sometimes called the notional, hypothetical, or voluntary price): Carbon allowances and carbon taxes internalize the climate change externality by making polluters pay. However, many other types of climate policies work not by making polluting more expensive per se, but instead by requiring firms to use one technology instead of another, or to maintain particular emission limitations in order to avoid legal repercussions. Non-market-based emission control regulatory policies are called “command and control.” For any such non-market policy there is an “effective” price: a market price that—if instituted as an allowance or tax—would result in the identical emission reduction as the non-market policy. An effective price may be used internally within a firm, government agency, or other entity to represent the effects of command and control policies for the purpose of improved decision making. Renewable Portfolio Standards, energy efficiency measures, and other policies designed to mitigate CO_2 emissions impose an effective price on carbon.

In this report: Utility carbon price forecasts are effective prices used for state-required IRPs and internal planning purposes. The U.S. Environmental Protection Agency’s (EPA’s) proposed carbon pollution standard for new sources of electric generation is a non-market-based policy that would represent an effective price.

Marginal abatement cost of carbon: An abatement cost refers to an estimate of the expected cost of reducing emissions of a particular pollutant. Estimation of a marginal abatement cost requires the construction of a “supply curve”: all of the possible solutions to controlling emissions (these may be technologies or policies) are lined up in order of their cost per unit of pollution reduction. Then, starting from the least expensive option, one tallies up the pollution reduction from various solutions until the desired total reduction is almost achieved, and then asks: what would it cost to reduce emissions by one more unit to achieve the target? The answer is the “marginal” cost of that level of pollution reduction; a greater reduction target would have a higher marginal cost. The marginal abatement cost of carbon is not a market price used to internalize an externality. Rather, it is a method for estimating the price that, if it were applied as a market price, would have the effect of achieving a given emission reduction target. In a well-functioning cap-and-trade system, the allowance price would tend towards the marginal abatement cost of carbon.

In this report: We do not analyze any marginal abatement costs in this report—see the *2012 Synapse Carbon Dioxide Price Forecast* for further information. McKinsey & Company has been a consistent producer of this type of analysis, an example being their 2010 report *Impact of the Financial Crisis on Carbon Economics: Version 2.1 of the Global Greenhouse Gas Abatement Cost Curve*.

Social cost of carbon: Whereas the marginal abatement cost estimates the price of stopping pollution, the social cost of carbon estimates the cost, per unit of emissions, of allowing pollution to continue. The social cost of carbon is the societal cost of current and future damages related to climate change from the emission of one additional unit of pollutant. Estimating the uncertain costs of uncertain future damages from uncertain future climatic events is, of course, a tricky business. If enough information were available, a marginal abatement cost for each level of future emissions (the supply of emission reductions) could be compared to a social cost of carbon for each level of future emissions (the demand for emission reductions) to determine an “optimal” level of pollution (such that the next higher unit of emission reduction would cost more to achieve than its value in reduced damages). More commonly, the social cost of carbon is used as part of the calculation of benefits of emission-reducing measures.

In this report: The U.S. federal government's internal carbon price for use in policy making is estimated as the social cost of carbon.

4. FEDERAL CLIMATE ACTION IS INCREASINGLY LIKELY

In the near term, comprehensive federal climate legislation appears unlikely to come out of a divided Congress. The Executive Branch, however, is moving forward with regulatory actions to limit greenhouse gas emissions. Following a directive issued by President Obama, EPA released revised CO_2 performance standards for new power plants on September 20, 2013.[5] In June 2013, President Obama also instructed EPA to use its Clean Air Act authority to propose CO_2 standards for existing power plants by June 2014 and to finalize these standards by June 2015.[6] While this report is focused on electric sector CO_2 policies, similar regulatory measures have been proposed for the transportation, buildings, and industrial sectors; policies enacted in other sectors include vehicle efficiency standards set to rise to 54.5 miles per gallon by 2025 for new cars and light-duty trucks, and new energy efficiency standards for federal buildings set to reduce energy consumption by nearly 20 percent.[7,8]

We continue to expect that a federal cap-and-trade program for greenhouse gases is the most likely policy outcome in the long term, because it permits reductions to come from sources that can mitigate emissions at the lower cost. While state and regional policies combined with federal regulatory actions appear to be more likely than a federal cap-and-trade policy in the near term, according to a WRI analysis these local measures are unlikely to be able to meet long-term goals of reducing total greenhouse gas emissions to 83 percent below 2005 levels by 2050, even in the most aggressive of scenarios.[9]

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[5] EPA. "2013 Proposed Carbon Pollution Standard for New Power Plants." Available at: http://www2.epa.gov/carbon-pollution-standards/2013-proposed-carbon-pollution-standard-new-power-plants.

[6] Memorandum from President Obama to Administrator of the Environmental Protection Agency, Power Sector Carbon Pollution Standards (June 25, 2013). Available at: http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards.

[7] Vlasic, Bill. "US Sets Higher Fuel Efficiency Standards." *The New York Times*. August 28th, 2012. Available at: http://www.nytimes.com/2012/08/29/business/energy-environment/obama-unveils-tighter-fuel-efficiency-standards.html.

[8] "Energy Efficiency Design Standards for New Federal Commercial and Multi-Family High-Rise Residential Buildings." A Rule by the Department of Energy. July 9th, 2013. Available at: https://www.federalregister.gov/articles/2013/07/09/2013-16297/energy-efficiency-design-standards-for-new-federal-commercial-and-multi-family-high-rise-residential#h-9.

[9] See WRI's analysis of these scenarios in the 2013 report "Can the U.S. Get There From Here?: Using Existing Federal Laws and State Action to Reduce Greenhouse Gas Emissions." Available at: http://www.wri.org/publication/can-us-get-there-from-here.

4.1. Regulatory Measures for Reducing Greenhouse Gas Emissions

Clean Air Act

As a result of the 2007 Supreme Court finding in *Massachusetts v. EPA*, greenhouse gas emissions were determined to be subject to the Clean Air Act and (in a later ruling) to contribute to air pollution anticipated to endanger public health and welfare. In 2009, EPA issued an "endangerment finding," obligating the agency to regulate emissions of greenhouse gases from stationary sources such as power plants.[10] EPA released draft New Source Performance Standards (NSPS) in April 2012 and revised NSPS standards on September 20, 2013. The revised standards limit CO_2 emissions from new fossil-fuel power plants to 1,000-1,100 pounds of CO_2 per MWh (lbs/MWh)—a level achievable by a new natural gas combined-cycle plant. The exact limit of CO_2 emissions within that range depend on the type of plant and period over which the emission rate would be averaged.[11]

Under Section 111(d) of the Clean Air Act, the EPA is required to propose standards for existing power plants by June 2014, but there remains substantial uncertainty over what form these regulations will take. Unit-specific emission rates standards, such as the NSPS for greenhouse gases, are only one of several plausible options. Unit-specific standards could apply to power plants based on categories by fuel type and technology type, each with its own maximum emission rate. Units that are not in compliance could undertake upgrades to improve efficiency; however, these kinds of upgrades can be expensive, can only achieve small, one-time changes to emission rates, and could trigger New Source Review/Prevention of Significant Deterioration (NSR/PSD) provisions, increasing the cost further.[12,13]

Other regulatory design options for existing plants under 111(d) include maintaining a state-wide average maximum emission rate, and market-based (e.g. cap-and-trade) approaches. More flexible mechanisms like these could lower the cost of compliance, but could also result in additional legal challenges as compared to a simpler but more rigid system of unit-specific regulation.[14] An Edison Electric Institute white paper on potential regulation of existing sources notes that "because of concerns about legal challenges to the guidelines, EPA may be reluctant to incorporate a wide range of

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[10] EPA. "Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the Clean Air Act." Available at: http://www.epa.gov/climatechange/endangerment/.

[11] EPA. "Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units." Available at: http://www2.epa.gov/sites/production/files/2013-09/documents/20130920proposal.pdf.

[12] EEI. "Existing Source GHGH NSPS White Paper," Page 5. Available at: http://online.wsj.com/public/resources/documents/carbon04232013.pdf.

[13] Tarr J., Monast J., Profeta T. "Regulating Carbon Dioxide under Section 111(d) of the Clean Air Act." The Nicholas Institute. January 2013. Available at: http://nicholasinstitute.duke.edu/sites/default/files/publications/ni_r_13-01.pdf.

[14] Fine, Steven and MacCracken, Chris. "President Obama's Climate Action Plan: What It Could Mean to the Power Sector." ICF International. August 2013. Available at: http://www.icfi.com/insights/white-papers/2013/president-obama-climate-action-plan.

compliance flexibility mechanisms in the guidelines, but may be more receptive to such mechanisms if proposed by the states in compliance plans."[15]

End-use energy efficiency may be an important part of a comprehensive compliance strategy in a regulation that averages emission rates across states. States may be able to achieve emissions reductions at a lower cost through the structures of their existing energy efficiency resource standards.

Methods for demonstrating compliance with 111(d) may be similar to existing regulations: in a process similar to Section 110 of the Clean Air Act, under which EPA sets National Ambient Air Quality Standards (NAAQS), states will be required to submit State Implementation Plans (SIPs) that specify how they intend to comply with 111(d). EPA can then decide whether a proposed SIP meets the terms of the regulation; in the absence of an acceptable SIP, EPA can impose a Federal Implementation Plan (FIP). Under the schedule outlined by President Obama in his Climate Action Plan, regulations for existing sources under 111(d) will be finalized by June 2015, and states would be required to submit SIPs to the EPA by June 2016.

Performance standards for new and existing sources will affect decisions made by utilities regarding operation, expansion, and retirements. Enforcement of the Clean Air Act creates an opportunity cost of greenhouse gas abatement: prudent utilities will take Clean Air Act compliance into consideration in their planning, either explicitly as a maximum allowable emissions rate, or implicitly as an effective carbon price. An NRDC analysis of the impacts of 111(d) implementation estimated compliance costs under this policy at $7.53 per ton of CO_2 avoided.[16]

Other regulatory measures put economic pressure on carbon-intensive power plants

A suite of current and proposed EPA regulations require pollution-intensive power plants to install environmental controls for compliance. The cost of complying with environmental regulations reduces the profitability of the worst polluters, sometime rendering them uneconomic. These policies demonstrate momentum towards appropriately regulating or pricing environmentally harmful activities in the electric sector. To the extent that plants with high emissions of other pollutants also have high carbon emissions, these policies would tend to *lower* the future CO_2 price necessary to achieve a given reduction; as more pollution-intensive plants retire in response to other EPA regulations, the necessary carbon price is reduced. Specific regulatory measures include:

- *National Ambient Air Quality Standards (NAAQS)* set maximum air quality limitations that must be met at all locations across the nation. EPA has established NAAQS for six pollutants: sulfur dioxide (SO_2), nitrogen dioxides (NO_2), carbon monoxide (CO), ozone, particulate matter—measured as particulate matter less than or equal to 10

[15] Edison Electric Institute. "Existing Source GHG NSPS White Paper," Page 2. Available at: http://online.wsj.com/public/resources/documents/carbon04232013.pdf.

[16] Natural Resources Defense Council. "Closing the Power Plant Carbon Pollution Loophole: Smart Ways the Clean Air Act Can Clean Up America's Biggest Climate Polluters," March 2013. Available at: http://www.nrdc.org/air/pollution-standards/files/pollution-standards-report.pdf.

micrometers in diameter (PM10) and particulate matter less than or equal to 2.5 micrometers in diameter (PM2.5)—and lead.

- *The Cross State Air Pollution Rule (CSAPR)*, finalized in 2011, establishes the obligations of each affected state to reduce emissions of NO_x and SO_2 that significantly contribute to another state's PM2.5 and ozone non-attainment problems. CSAPR was vacated by the U.S. Court of Appeals for the District of Columbia on August 21, 2012. In June 2013, the U.S. Supreme Court announced that it would review CSAPR. Even if EPA fails to salvage CSAPR through the courts, the Agency must still promulgate a replacement rule to implement Clean Air Act requirements to address the transport of air pollution across state boundaries. In the meantime, the court left the requirements of the 2005 Clean Air Interstate Rule in place.
- *Mercury and Air Toxics Standards (MATS)*: The final MATS rule, approved in December 2011, sets stack emissions limits for mercury, other metal toxins, organic and inorganic hazardous air pollutants, and acid gasses. Compliance with MATS is required by 2015, with a potential extension to 2016. Many utilities have already committed to capital improvements at their coal plants to comply with the standard.
- *Coal Combustion Residuals (CCR) Disposal Rule:* On June 21, 2010, EPA proposed to regulate CCR for the first time either as a Subtitle C hazardous waste or Subtitle D solid waste under the Resource Conservation and Recovery Act. Under a Subtitle C designation, the EPA would regulate siting, liners, run-on and run-off controls, groundwater monitoring, fugitive dust controls, and any corrective actions required. In addition, the EPA would implement minimum requirements for dam safety at impoundments. Under a solid waste Subtitle D designation, the EPA would require minimum siting and construction standards for new coal ash ponds, compel existing unlined impoundments to install liners, and require standards for long-term stability and closure care.
- *Steam Electric Effluent Limitation Guidelines (ELGs):* On June 7, 2013, EPA released eight regulatory options for new, proposed steam-electric ELGs to reduce or eliminate the release of toxins into U.S. waterways. A final rule is required by May 22, 2014.[17] New requirements will be implemented in 2014 to 2019 through the five-year National Pollutant Discharge Elimination System permit cycle.[18]

Other regulations which may raise costs for carbon-intensive resources include Regional Haze rules and cooling water rules under the Clean Water Act.

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[17] See U.S. Environmental Protection Agency website. Accessed February 21, 2013. Available at: http://water.epa.gov/scitech/wastetech/guide/steam-electric/amendment.cfm.

[18] See U.S. Environmental Protection Agency. Steam Electric ELG Rulemaking. UMRA and Federalism Implications: Consultation Meeting. October 11, 2011. http://water.epa.gov/scitech/wastetech/guide/upload/Steam-Electric-ELG-Rulemaking-UMRA-and-Federalism-Implications-Consultation-Meeting-Presentation.pdf.

4.2. Proposed Cap-and-Trade Legislation

Over the past decade, there have been several Congressional proposals to legislate cap-and-trade programs, with the goal of reducing greenhouse gas emissions by up to 83 percent below recent levels by 2050 through a federal cap. Such programs would allow trading of allowances to promote least-cost reductions in greenhouse gas emissions.

Comprehensive climate legislation was passed by the House in the 111th Congress: the American Clean Energy and Security Act of 2009, also known as Waxman-Markey or H.R. 2454. However, the Senate did not vote on either of the two climate bills before it in that session (Kerry-Lieberman APA 2010 and Cantwell-Collins S. 2877). Waxman-Markey was a cap-and-trade program that would have required a 17 percent reduction in emissions from 2005 levels by 2020, and an 83 percent reduction by 2050.[19] Further analysis of these proposals is provided in Synapse's 2012 Carbon Dioxide Price Forecast.

Congressional interest in climate policy has been ongoing. In March 2012, Senator Bingaman introduced the Clean Energy Standard Act of 2012 (S. 2146), which would have required larger utilities to meet a percentage of their sales with electric generation from sources that produce less greenhouse gas emissions than a conventional coal-fired power plant. Credits generated by these clean technologies would have been tradable with a market price. In February 2013, Senators Sanders and Boxer introduced new comprehensive climate change legislation, the Climate Protection Act of 2013. This bill proposed a carbon fee of $20 per ton of CO_2 or CO_2 equivalent content of methane, rising at 5.6 percent per year over a ten-year period. The bill has not yet been brought to a vote.

We expect that federal cap-and-trade legislation will eventually be enacted but that it is unlikely to happen in the near term. In contrast, federal carbon regulations are in effect or under development today, and the economic pressure—or opportunity cost—that they create may be represented as an effective price of greenhouse gas emissions. Regulatory measures may be successful in achieving near-term targets of 17 percent below 2005 levels by 2020, but according to a WRI analysis are unlikely to meet long-term goals of reducing total greenhouse gas emissions to approximately 80 percent below 2005 levels by 2050, even in the most aggressive of scenarios.[20] A broader approach will be increasingly attractive in order to meet these goals at lower costs, and our judgment indicates this is most likely to take the form of a federal cap-and-trade system.

[19] U.S. Energy Information Administration (EIA); Energy Market and Economic Impacts of the American Power Act of 2010 (July 2010). Available at http://www.eia.gov/oiaf/servicerpt/kgl/index.html. EIA; Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009 (August 2009). Available at http://www.eia.doe.gov/oiaf/servicerpt/hr2454/index.html.

[20] See WRI's analysis of these scenarios in their 2013 report "Can the U.S. Get There From Here?: Using Existing Federal Laws and State Action to Reduce Greenhouse Gas Emissions." Available at: http://www.wri.org/publication/can-us-get-there-from-here.

5. STATE AND REGIONAL CLIMATE POLICIES

Since the October 2012 release of our 2012 CO_2 price forecasts, there have been significant updates to the two existing regional and state cap-and-trade programs, the Northeast's RGGI and California's Cap-and-Trade Program under AB32. In addition, a total of 20 states plus the District of Columbia have set greenhouse gas emissions targets as low as 80 percent below 1990 levels by 2050.[21]

Recent Revisions to RGGI

RGGI is a cap-and-trade greenhouse gas program for power plants in the northeastern United States. Current participant states are Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. Pennsylvania, Québec, New Brunswick, and Ontario are official "observers" in the RGGI process. RGGI recently marked five years of successful CO_2 allowance auctions, with Auction 21 resulting in a clearing price of $2.67 per ton.[22] RGGI is designed to reduce electricity sector CO_2 emissions to at least 45 percent below 2005 levels by 2020.[23]

When RGGI was established in 2007, the expectation was that the CO_2 emissions allowance auction would generate revenues for consumer benefit programs such as energy efficiency, renewable energy, and clean energy technologies. While RGGI has provided significant revenues for consumer benefit, its allowance prices have generally remained near the statutory minimum price. External influences, including changes to fuel prices, caused a shift from coal and oil to lower-carbon natural gas generation. Compared to those external factors, the effect of the original RGGI cap requirements were relatively minor in meeting the goals of reducing CO_2 emissions in the power sector.[24]

In 2012 and 2013, the RGGI states evaluated a number of plans for tighter emissions caps with the goal of raising allowance prices. In February of 2013, participating states agreed to lower the CO_2 cap from 165 million to 91 million short tons in 2014, to be reduced by 2.5 percent each year from 2015 to 2020. RGGI analysis indicates that with these lower caps, allowance prices will rise to $4.16 per short ton in 2014, increasing to $10.40 per ton in 2020.[24]

California's Cap-and Trade-Program under AB32

With the goal of reducing the state's emissions to 1990 levels by 2020, California's Global Warming Solutions Act (AB32) has created the world's second largest carbon market, after the European Union's

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[21] "Greenhouse Gas Emissions Targets." Center for Climate and Energy Solutions. Accessed September 13, 2013. Available at: http://www.c2es.org/us-states-regions/policy-maps/emissions-targets.

[22] RGGI Auction 21 results available at: http://www.rggi.org/market/co2_auctions/results/Auction-21

[23] RGGI. "RGGI States Propose Lowering Regional CO_2 Emission Cap 45%, Implementing a More Flexible Cost-Control Mechanism." February 2013. Available at: http://www.rggi.org/docs/PressReleases/PR130207_ModelRule.pdf.

[24] Environment Northeast. "RGGI at One Year: An Evaluation of the Design and Implementation of the Regional Greenhouse Gas Initiative." February 2010. Available at: http://www.env-ne.org/public/resources/pdf/ENE_2009_RGGI_Evaluation_20100223_FINAL.pdf.

Emissions Trading System. The first compliance period for California's Cap-and-Trade Program began on January 1, 2013 and covers electricity generators, CO_2 suppliers, large industrial sources, and petroleum and natural gas facilities emitting at least 27,600 tons of CO_2e per year.[25,26] On August 16, 2013, the California Air Resources Board held its fourth quarterly allowance auction, resulting in a clearing price of $11.11 per ton.[27] This first phase of the program includes electricity generators and large industrials. Phase II, beginning in 2015, will also include transportation fuels and smaller industrial sources.

6. Assessment of Carbon Price for Federal Rulemaking

In 2010, the U.S. federal government began including a carbon cost in regulatory rulemakings to account for the climate damages resulting from each additional ton of greenhouse gas emissions;[28] updated values were released in 2013.[29] The 2013 Economic Report of the President acknowledges that these values will continue to be updated as scientific understanding improves.[30]

An Interagency Working Group on the Social Cost of Carbon—composed of members of the Department of Agriculture, Department of Commerce, Department of Energy, Environmental Protection Agency, and Department of Transportation, among others—was tasked with the development of a consistent value for the social benefits of climate change abatement. Four values were developed (see Section 3 for more explanation of the "social cost of carbon" methodology). These values--$11, $36, $55, and $101 per ton of CO_2 in 2013, rising over time— represent average (most likely) damages at three discount rates, along with one estimate at the 95th percentile of the assumed distribution of climate impacts.[31,32,33,34] While

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[25] "CO_2e" refers to CO_2-equivalent, the combination of CO_2 and an equivalent value for other greenhouse gases.

[26] CARB 2013a. "California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms to Allow for the Use of Compliance Instruments by Linked Jurisdictions." July 2013. Available at: http://www.arb.ca.gov/cc/capandtrade/ctlinkqc.pdf. Legislated value is 25,000 metric tons, converted here to short tons.

[27] CARB 2013b. "CARB Quarterly Auction 4, August 2013: Summary Results Report." August 21, 2013. Available at: http://www.arb.ca.gov/cc/capandtrade/auction/august-2013/results.pdf.

[28] Interagency Working Group on the Social Cost of Carbon, U. S. G. (2010). Appendix 15a. Social cost of carbon for regulatory impact analysis under Executive Order 12866. In Final Rule Technical Support Document (TSD): Energy Efficiency Program for Commercial and Industrial Equipment: Small Electric Motors. U.S. Department of Energy. URL http://go.usa.gov/3fH.

[29] Interagency Working Group on the Social Cost of Carbon (2013) Technical Support Document – Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12866. Available at: http://www.whitehouse.gov/sites/default/files/omb/inforeg/social_cost_of_carbon_for_ria_2013_update.pdf.

[30] 2013 Economic Report of the President (2013). Chapter 6. March 2013. Available at: http://www.whitehouse.gov/sites/default/files/docs/erp2013/ERP2013_Chapter_6.pdf.

[31] These values represent recently revised costs for the SCC. Originally, these values were $5, $21, $35, and $65 per metric tonne for the year 2010 in 2007 dollars.

[32] In a 2012 paper, Ackerman and Stanton modified the Interagency Working Group's assumptions regarding uncertainty in the sensitivity of temperature change to emissions, the expected level of damages at low and high greenhouse gas concentrations, and the assumed discount rate, and found values for the social cost of carbon ranging from the Working Group's level up to more than an order of magnitude greater. Similarly, Laurie Johnson and Chris Hope modified discount rates and methodologies and found results up to twelve times larger than the Working Group's central estimate.

subject to significant uncertainty, this multi-agency effort represents an initial attempt at incorporating the benefits associated with CO_2 abatement into federal policy.

As of May 2012, these estimates had been used in at least 20 federal government rulemakings, for policies including fuel economy standards, industrial equipment efficiency, lighting standards, and air quality rules.[35, 36] In the first rule in which the revised 2013 values were used—improving energy efficiency in microwave ovens—the net present value of benefits over a 30-year timeframe increased by $400 million as a result of the increase in effective carbon price.[37] While a carbon price for federal rulemaking assessments is a fundamentally different kind of cost metric than the others discussed in this report, it nonetheless represents a dollar value for greenhouse gas emissions currently in use by the U.S. federal government.

7. Recent CO_2 Price Forecasts from the Research Community

The Energy Modeling Forum (EMF), a working group of government and private modeling teams, has been convening to explore energy system issues since the late 1970s. The group recently completed its EMF 24 analysis with the objective of evaluating what CO_2 price trajectories are consistent with proposed emission reduction targets under different technology scenarios. This analysis also incorporated several complementary policies in a cap-and-trade proposal, including: transportation emissions reduction through vehicle gas mileage standards; renewable portfolio standards in the electric sector; and mandates that all new coal facilities employ carbon capture and storage (CCS) technology—a

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[33] Frank Ackerman and Elizabeth A. Stanton (2012). "Climate Risks and Carbon Prices: Revising the Social Cost of Carbon." *Economics: The Open-Access, Open-Assessment E-Journal*, Vol. 6, 2012-10. http://dx.doi.org/10.5018/economics-ejournal.ja.2012-10.

[34] Laurie T. Johnson, Chris Hope. "The social cost of carbon in U.S. regulatory impact analyses: an introduction and critique." *Journal of Environmental Studies and Sciences*, 2012; DOI: 10.1007/s13412-012-0087-7.

[35] Robert E. Kopp and Bryan K. Mignone (2012). "The U.S. Government's Social Cost of Carbon Estimates after Their First Two Years: Pathways for Improvement." Economics: The Open-Access, Open-Assessment E-Journal, Vol. 6, 2012-15. http://dx.doi.org/10.5018/economics-ejournal.ja.2012-15.

[36] See, for example, "Rulemaking for Microwave Ovens Energy Conservation Standard: Technical Support Document." May 2013. Available at: http://www1.eere.energy.gov/buildings/appliance_standards/rulemaking.aspx/ruleid/37

[37] Brad Blumer (2013). "The social cost of carbon is on the rise." The Washington Post, June 6th, 2013. Available at: http://articles.washingtonpost.com/2013-06-06/business/39789409_1_carbon-dioxide-emissions-obama-administration.

policy similar to EPA's proposed NSPS for coal plants. Nine modeling teams participated in this study.[38,39]

Results from the EMF 24 exercise show a range of CO_2 price trajectories depending on availability of new technologies, policy type, model baseline trajectories, and other more structural characteristics of the models. One question asked by this study that is of particular relevance to users of the Synapse CO_2 price forecast is: which economic sectors would emissions reductions come from in an economically efficient approach to emissions mitigation? Consistent with earlier EMF analyses, the electric sector was found to be the largest contributor to CO_2 emissions reductions across all models.

Under a cap-and-trade scenario designed to reduce energy system emissions 50 percent below 2005 levels by 2050, most of the EMF 24 models reduced electric sector emissions by 75 percent by 2050. Under an 80 percent emissions reduction scenario, most of the additional emissions reductions came from other sectors. Although CO_2 prices are higher under the 80 percent scenario, most electricity customers are not paying these prices, as the electricity sector is largely decarbonized before 2050.

CO_2 prices estimated by the EMF 24 models show substantial variation. While it is difficult to distinguish the roles of model structure and model assumptions in this variation, the results present a reasonable range across which prices may fall. Under the most optimistic technology assumptions, with low-cost renewables, high levels of energy efficiency, and availability of new nuclear and CCS, CO_2 prices in 2020 fell between \$10 per tCO_2 and \$40 per tCO_2. In contrast, prices fell between \$20 per tCO_2 to \$80 per tCO_2 under the most pessimistic assumptions. Complementary policies, such as renewable portfolio standards or fuel economy standards, reduce carbon prices, as indicated in Figure 1.

Universally, the models show that substantial emissions reductions are not achievable in the absence of a policy. Even in the most optimistic technology scenario, the most aggressive emissions reductions from any model in the absence of a policy was 0.19 percent per year, resulting in emissions 7 percent below 2005 levels in 2050.

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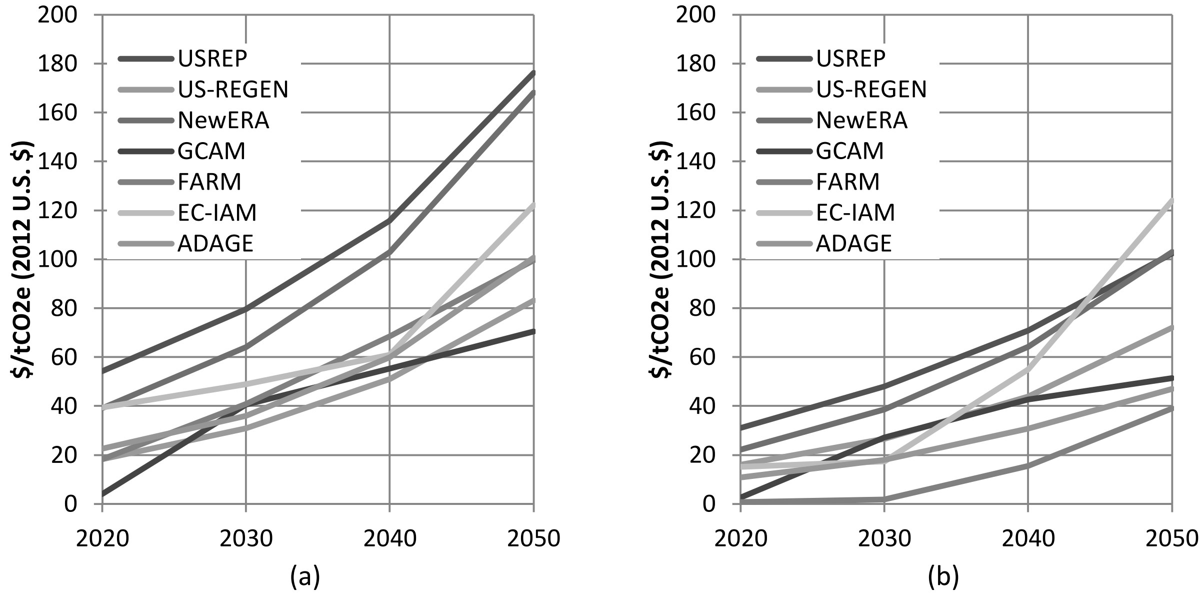
[38] Clarke, L.C., A.A. Fawcett, J.P. Weyant, V. Chaturvedi, J. MacFarland, Y. Zhou, "Technology and U.S. Emissions Reductions Goals: Results of the EMF 24 Modeling Exercise," (forthcoming). *The Energy Journal.*

[39] Fawcett, A.A., L.C. Clarke, S. Rausch, J.P. Weyant. "Overview of EMF 24 Policy Scenarios," (forthcoming). *The Energy Journal*.

Figure 1: Allowance prices from EMF study under (a) 50 percent cap-and-trade policy and with (b) the addition of several complementary policies (optimistic CCS/nuclear technology assumptions) [35,36]



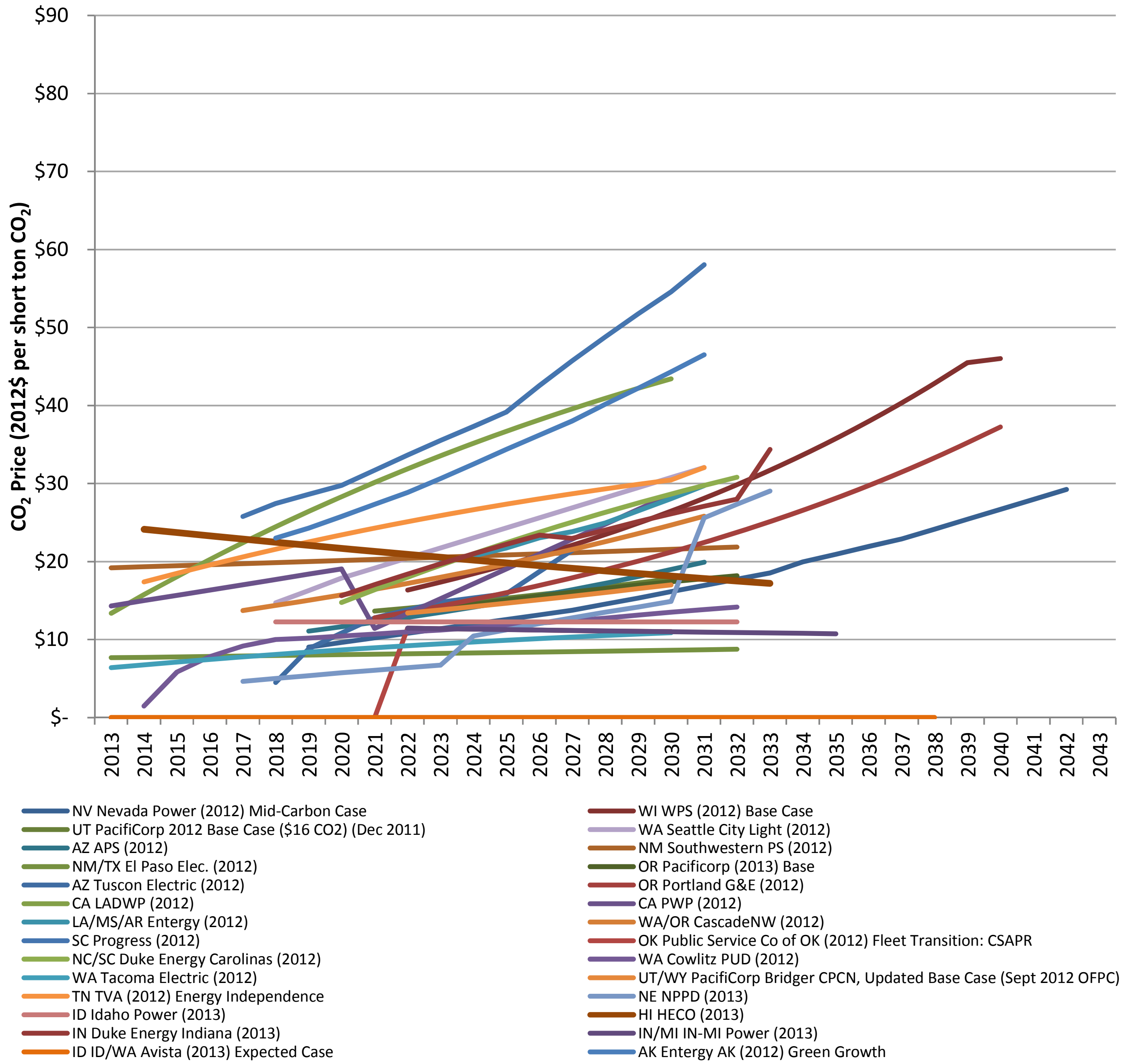
8. CO_2 PRICE FORECASTS IN UTILITY IRPS

A growing number of electric utilities include projections of the costs that will be associated with greenhouse gas emissions in their resource planning procedures. Figure 2 summarizes the reference case values (often described as their "mid" or "central" values) of publicly available forecasts used by utilities in resource planning over the past two years.[40]

Despite ongoing obstacles to a federally legislated CO_2 price and challenges in Congress to addressing climate or energy policy in a meaningful way, many utilities are including an effective price for carbon in their planning. The majority of utility reference case carbon price forecasts start in the 2015-2020 timeframe, and rise gradually (in real terms) throughout the study period.

[40] Where a utility has released multiple IRP or IRP updates in the past two years, we have included only the most recent value. The IRPs shown here represent those publicly available by internet as of the October 2013.

Figure 2: Utility Reference Case Forecasts from 2012 and 2013



9. OVERVIEW OF THE EVIDENCE FOR A FUTURE CO_2 PRICE

Our CO_2 price forecasts are developed based on the data sources and information presented above and reflect a reasonable range of expectations regarding future efforts to limit greenhouse gas emissions. The following items have guided the development of the Synapse forecasts:

- **Regulatory measures limiting CO_2 emissions from power plants will be implemented in the near term**. The EPA is required to propose emissions standards for existing power plants under Section 111(d) of the Clean Air Act by June 2014. Standards for new power plants were proposed on September 20, 2013. These actions represent an effective price that will affect utility planning and operational decisions.

- **State and regional action limiting CO_2 is ongoing and growing more stringent**. In the Northeast, the RGGI CO_2 cap has been tightened, resulting in higher CO_2 prices for electric generators in the region. California's Cap-and-Trade Program, which represents an even larger carbon market than RGGI, has held many successful allowance auctions, and has been successfully defended against numerous legal challenges.

- **A price for CO_2 is already being factored into federal rulemakings.** The federal government has demonstrated a commitment to considering the benefits of CO_2 abatement in rulemakings such as fuel economy and appliance standards.

- **Ongoing analysis of emissions caps suggests a wide range of possible prices.** Important factors include the stringency of any future climate policy, the existence of complementary policies, technology availability, and how quickly old capital stock can be phased out in favor of new technologies.

- **Electric suppliers continue to account for the opportunity cost of CO_2 abatement in their resource planning.** Prudent planning requires utilities to consider adequately the potential for future policies. The range of carbon prices reported in section 8 indicates that many utilities believe that by 2020 there will likely be significant economic pressure towards low-carbon electric generation.

10. SYNAPSE 2013 CO_2 PRICE FORECAST

Based on analyses of the sources described in sections 3 through 8 (above), and relying on our own expert judgment, Synapse has developed Low, Mid, and High case forecasts for CO_2 prices from 2013 to 2040. Figure 3 and Table 1 show the Synapse forecasts over this period.

Figure 3: Synapse 2013 CO_2 Price Trajectories

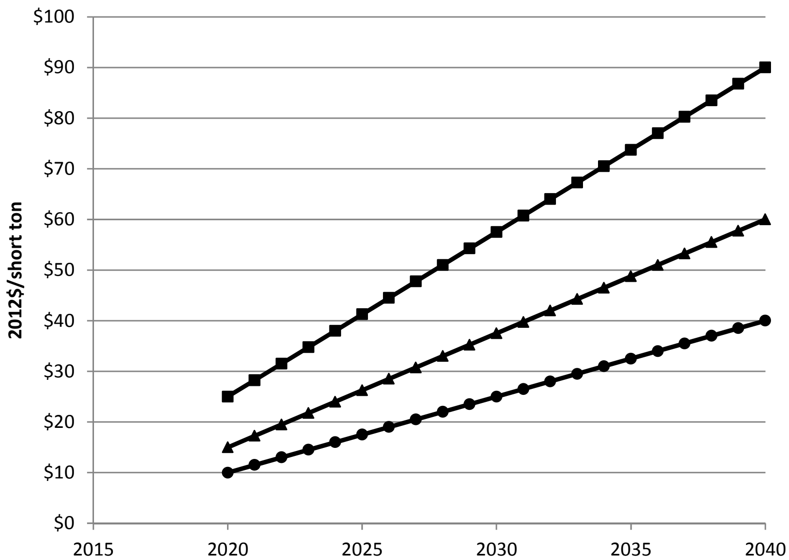


Table 1: Synapse 2013 CO_2 Allowance Price Projections (2012 dollars per ton CO_2)

Year	Low Case	Mid Case	High Case
2020	$10.00	$15.00	$25.00
2021	$11.50	$17.25	$28.25
2022	$13.00	$19.50	$31.50
2023	$14.50	$21.75	$34.75
2024	$16.00	$24.00	$38.00
2025	$17.50	$26.25	$41.25
2026	$19.00	$28.50	$44.50
2027	$20.50	$30.75	$47.75
2028	$22.00	$33.00	$51.00
2029	$23.50	$35.25	$54.25
2030	$25.00	$37.50	$57.50
2031	$26.50	$39.75	$60.75
2032	$28.00	$42.00	$64.00
2033	$29.50	$44.25	$67.25
2034	$31.00	$46.50	$70.50
2035	$32.50	$48.75	$73.75
2036	$34.00	$51.00	$77.00
2037	$35.50	$53.25	$80.25
2038	$37.00	$55.50	$83.50
2039	$38.50	$57.75	$86.75
2040	$40.00	$60.00	$90.00
Levelized 2020-2040	$22.36	$33.54	$51.79

In these forecasts, state and regional policies, together with federal regulatory measures, place economic pressure on CO_2 emitting resources in the next several years, such that it is relatively more expensive to operate a high-carbon-emitting power plant. These pressures are followed later by a broader federal policy, such as cap and trade. In any state other than the RGGI region and California, we assume a zero carbon price through 2019; beginning in 2020, we expect that federal regulatory measures will put economic pressure on carbon-emitting power plants throughout the United States. All annual allowance prices and levelized values are reported in 2012 dollars per short ton of carbon dioxide.

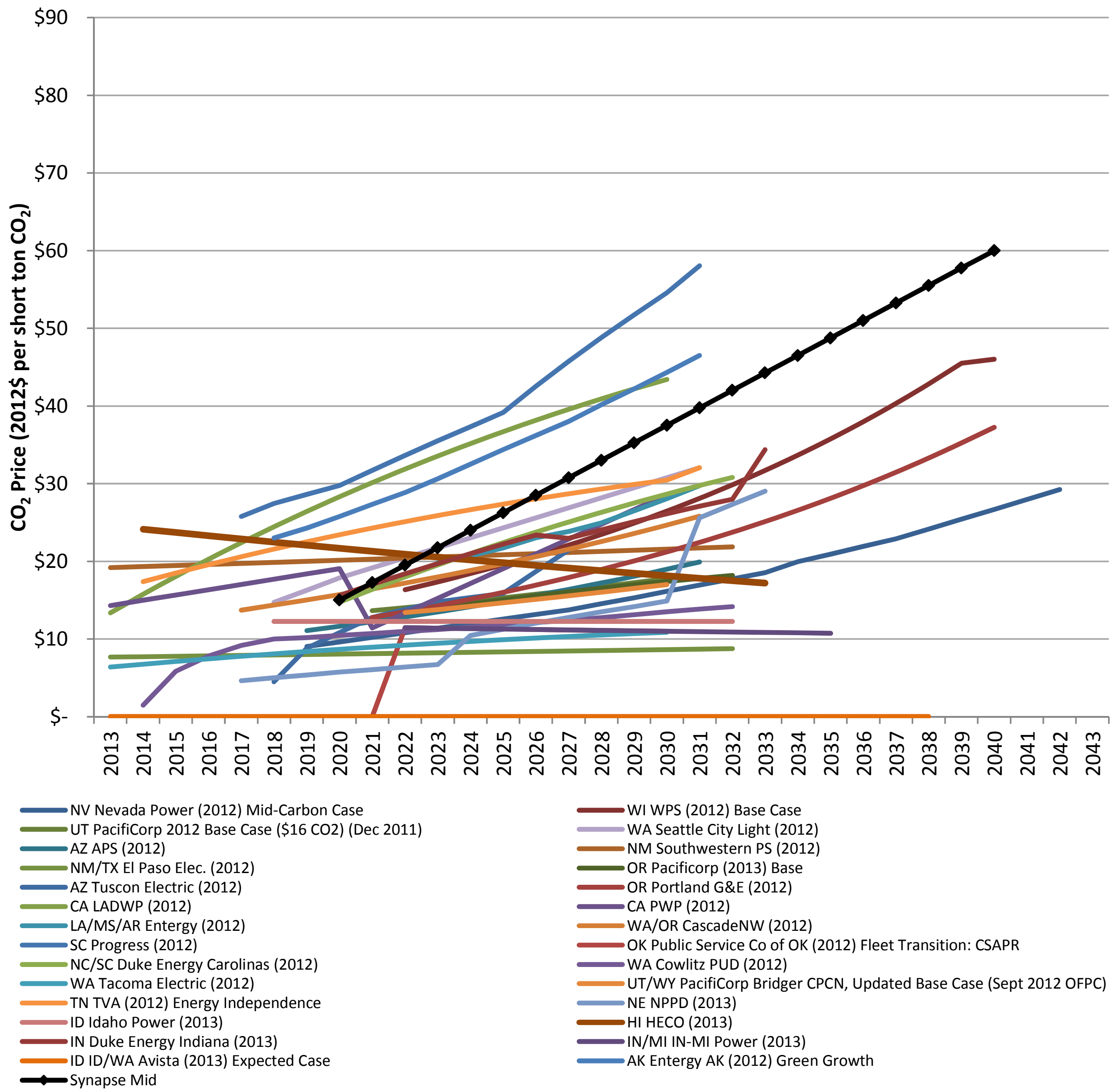
- The **Low case** forecasts a carbon price that begins in 2020 at $10 per ton, and increases to $40 per ton in 2040, representing a $22 per ton levelized price over the period 2020-2040. This forecast represents a scenario in which federal policies—either regulatory or legislative—exist but are not very stringent.
- The **Mid case** forecasts a carbon price that begins in 2020 at $15 per ton, and increases to $60 per ton in 2040, representing a $34 per ton levelized price over the period 2020-2040. This forecast represents a scenario in which federal policies are implemented with significant but reasonably achievable goals.
- The **High case** forecasts a carbon price that begins in 2020 at $25 per ton, and increases to approximately $90 per ton in 2040, representing a $52 per ton levelized price over the period 2020-2040. This forecast is consistent with the occurrence of one or more factors that have the effect of raising carbon prices. These factors include somewhat more aggressive emissions reduction targets; greater restrictions on the use of offsets; restricted availability or high cost of technology alternatives such as nuclear, biomass and carbon capture and sequestration; more

aggressive international actions (thereby resulting in fewer inexpensive international offsets available for purchase by U.S. emitters); or higher baseline emissions.

These price trajectories are designed for planning purposes, so that a reasonable range of emissions costs can be used to investigate the likely costs of alternative resource plans. We expect an actual CO_2 price to fall somewhere between the low and high estimates throughout the forecast period.

In Figure 4, the Synapse Mid forecast is shown in comparison to the reference case utility forecasts presented earlier. See Appendix A for comparisons to utilities' Low and High case forecasts.

Figure 4: Synapse Mid Forecast Compared to Recent Utility Mid Case Forecasts



In Figure 5, the Synapse forecasts are compared to the carbon price used in federal rulemaking. While the federal price starts out higher in 2020, the Synapse Mid forecast approaches this value at the end of the projected period. In Figure 6, the Synapse forecasts for 2020 are compared to several of the sources identified in this report: the carbon price used in federal rulemakings, EMF 24 study results, and recent utility forecasts. The high and low ends of these sources span a wide range, but the central values show less variation.

Figure 5: Synapse Forecast Compared to Carbon Price Used in Federal Rulemakings

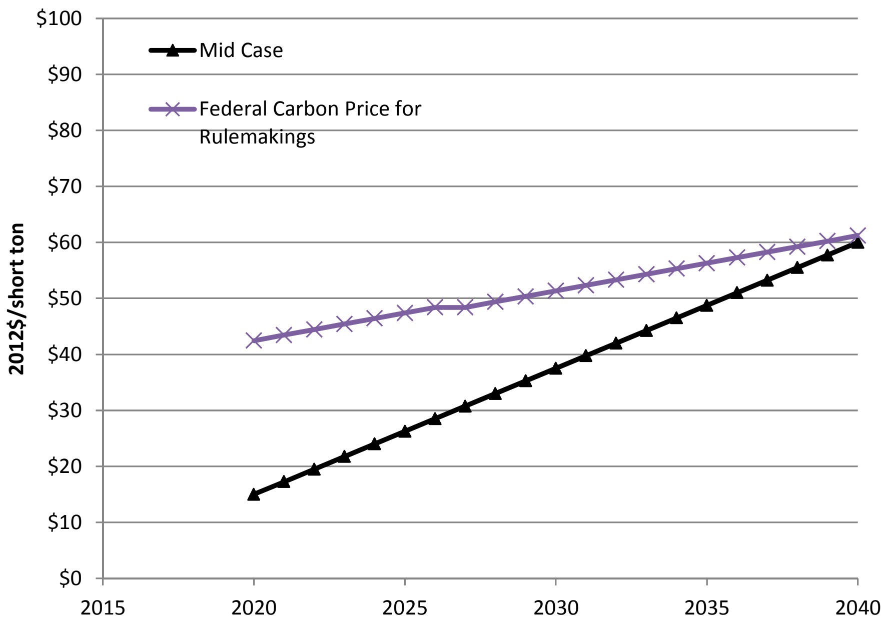
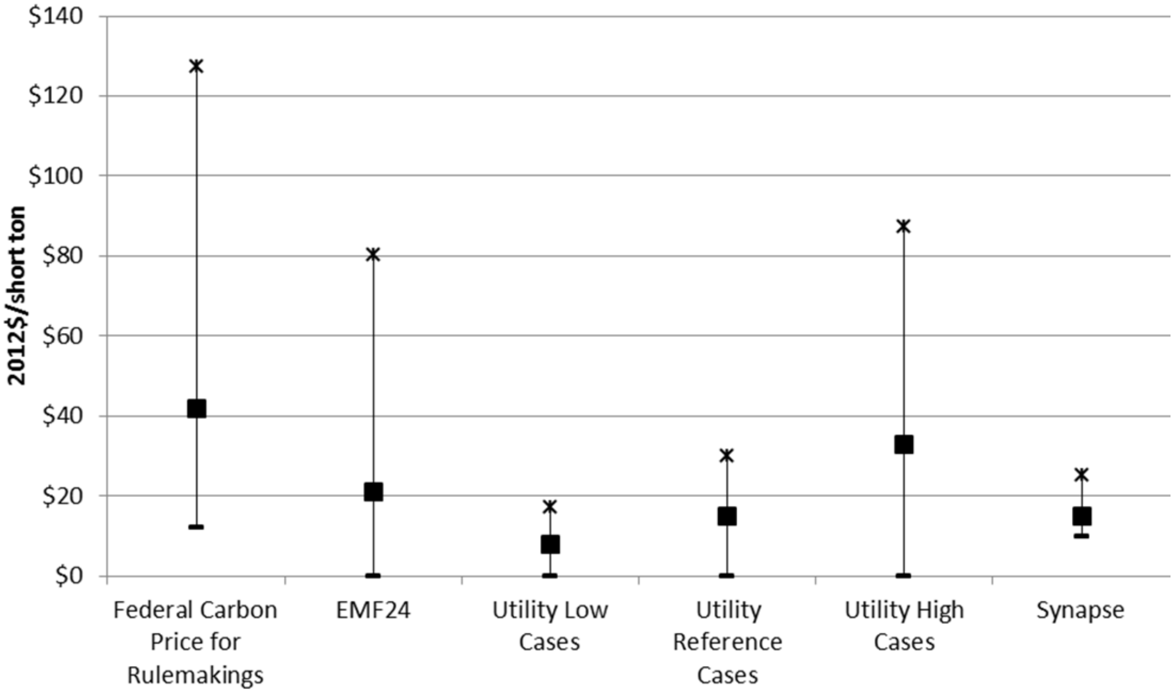


Figure 6: Synapse CO_2 Forecasts for 2020 Compared to Other Sources



Appendix A: Synapse Forecast Compared to Utility Forecasts

Figure 7: Synapse CO_2 Price Forecast Compared to Recent Utility Low-case Forecasts

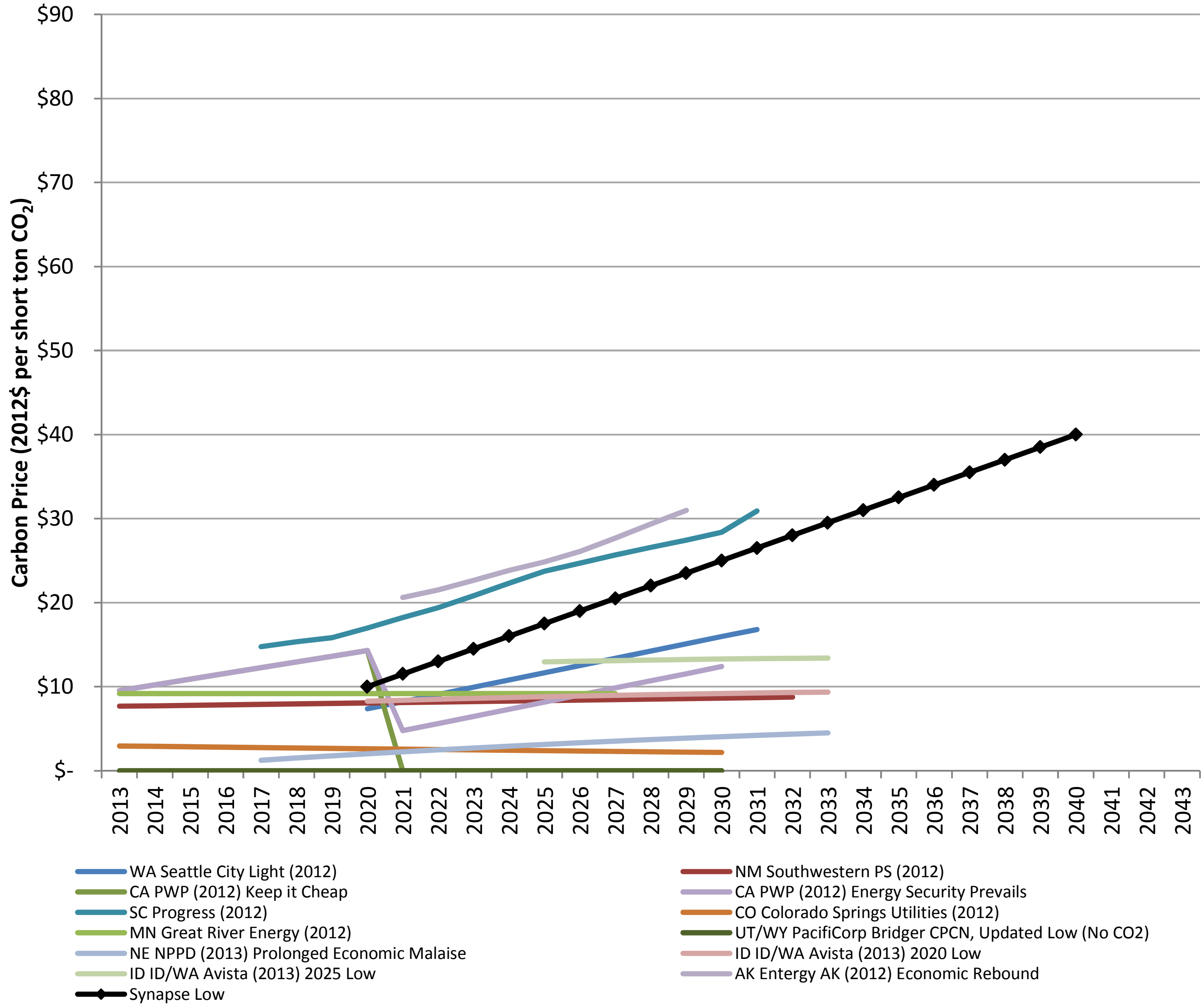
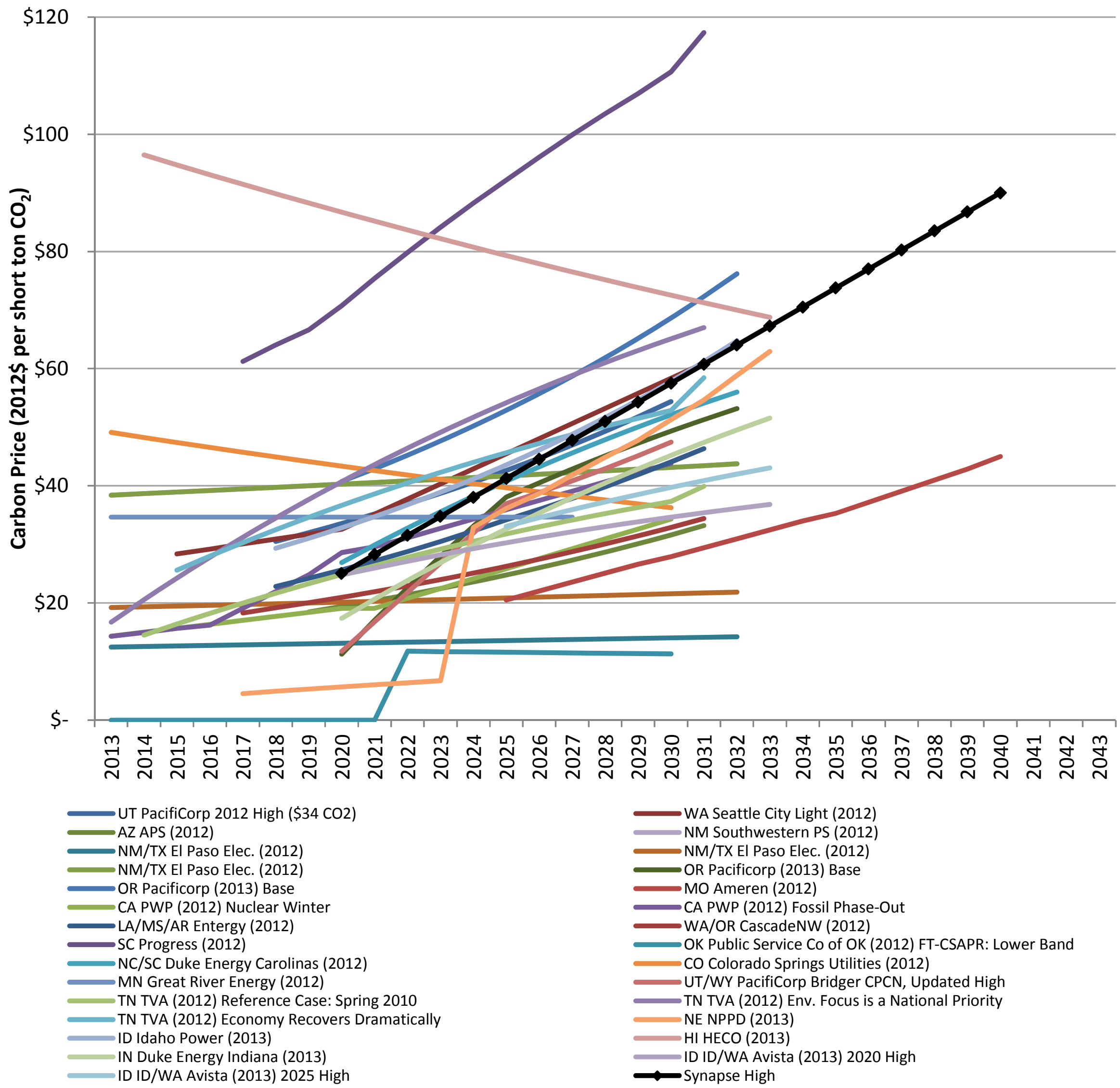


Figure 8: Synapse CO_2 Price Forecast Compared to Recent Utility High-case Forecasts



Fitch Affirms East Kentucky Power Cooperative's Sr. Secured Bonds at 'BBB'

October 29, 2012 11:41 AM Eastern Daylight Time

NEW YORK--(BUSINESS WIRE)--Fitch Ratings affirms the 'BBB' rating on the following East Kentucky Power Cooperative (EKPC) outstanding secured bonds:

--$25.9 million County of Mason, KY pollution control revenue bonds, series 1984B;

--$6.5 million Pulaski County, KY solid waste disposal revenue bonds, series 1993B.

In addition, Fitch affirms the rating of 'BBB' on EKPC's implied senior unsecured obligations. The rating takes into account $400.7 million of parity debt at Dec. 31, 2011.

The Rating Outlook is Stable.

SECURITY

The senior secured obligations are secured by a mortgage interest in substantially all of EKPC's tangible and certain of its intangible assets.

KEY RATING DRIVERS

GENERATION AND TRANSMISSION COOPERATIVE: EKPC supplies wholesale power to its 16 member-owner distribution cooperatives who serve predominantly rural territories in central and eastern Kentucky. The cooperative's generation fleet is geographically diverse; however, the vast majority of power is derived from the cooperative's coal-fired units.

SOLID UNDERLYING COOPERATIVE FUNDAMENTALS: EKPC supplies power to its members pursuant to long-term, take-or-pay contracts that extend through Jan. 1, 2051, and require members to purchase from EKPC nearly all of their power requirements to meet system needs. This contractual relationship, together with the diversity and financial wherewithal of the member distribution cooperatives are fundamental to the rating.

IMPROVING FINANCIAL PROFILE: EKPC's financial profile has stabilized in recent years following a series of operational challenges and financial distress during the period 2004-2006. A more defined and comprehensive strategic plan has been adopted by the new management team and board of directors, which appears to be on track and supports credit quality.

SUBJECT TO RATE REGULATION: The electric rates charged by EKPC and its members are regulated by the Kentucky Public Service Commission (KPSC), which could limit the cooperative's financial flexibility and may delay the timing or amount of necessary rate increases. Regulation by the KPSC to date has been largely supportive.

SUFFICIENT POWER SUPPLY RESOURCES: EKPC's current portfolio of power supply resources is generally sufficient to meet anticipated demand through 2018, obviating the need for significant construction activity or additional debt. The environmental compliance risks related to its coal-dominated portfolio are lessened by the presence of emissions control equipment at its most active units.

ACCEPTABLE FINANCIAL METRICS: Fitch-calculated financial metrics for 2011 include debt service coverage (DSC) of 1.25x and equity to capitalization of 10.2%, both of which are consistent with the rating category. Total debt to funds available for debt service (FADS) of 10.4x is weaker than comparable Fitch rated cooperatives but Fitch expects that EKPC's high leverage to moderate as equity builds up pursuant to the strategic plan.

WHAT COULD TRIGGER A RATING ACTION

EXECUTION OF STRATEGIC PLAN: Successful execution of the current strategic plan and achievement of the cooperative's financial objectives could trigger consideration for an upgrade.

RESTRICTIVE RATE REGULATION: Future regulatory decisions that prevent the cooperative from adequately recovering costs would likely result in downward pressure on the rating or Outlook.

CREDIT PROFILE

EKPC is a not-for-profit generation and transmission cooperative incorporated in 1941 and headquartered in Winchester, Kentucky. EKPC supplies wholesale energy, transmission and support services to its 16 member distribution cooperatives, who serve predominately rural territories throughout 87 counties in central and eastern Kentucky. In 2011, the EKPC membership provided retail electric service to more than 521,000 residences, farms and businesses. The rates and services provided by EKPC are regulated by the KPSC.

Adequate Power Supply Resources

EKPC owns and operates a portfolio of generating units with capacity totaling 2,929 MW. Nearly 64.3% of EKPC's generating capacity is coal-fired, but nine relatively new natural-gas fired units provide valuable peaking capacity, as well as fuel diversity. Additional capacity and energy supply to meet member load demand is derived from ownership of 15.2 MW of renewable landfill gas projects, its allocation of Southeastern Power Administration hydro-electric capacity, and modest amounts of purchased power. EKPC's existing resources are largely sufficient to meet forecasted demand over the near term. The cooperative has no plans for significant new construction prior to 2015.

EKPC has issued a request for proposals (RFP) to obtain up to 300 MW of generation resources with an online date between October 2015 and 2017. This capacity is planned to replace 200 MW of capacity from the Dale station as the unit approaches the end of its useful life in 2016, and potentially replace 100 MW of capacity from the Cooper unit 1. Power purchase agreements and facility ownership options are under consideration. Fitch does not evaluate the merits of owning versus purchasing power, but considers the costs and benefits to the entity of both scenarios.

Troubled Operating and Financial History

Over the past decade, EKPC has faced a series of circumstances which have challenged both the operational and financial performance of the cooperative. Beginning in 2004, alleged violations of environmental requirements, a forced outage at the cooperative's Spurlock Unit 1 generating facility and the determination that considerable new generating capacity would be required to meet anticipated load growth all contributed to higher operating expenses and capital requirements. At the same time, management's decision to forego timely rate increases produced negative net margins and severely strained cash flow. These events ultimately led to a period of financial distress.

Improved Performance Under New Leadership

In recent years a new leadership team has been assembled at the cooperative, which has worked to implement recommendations from a KPSC-ordered management audit, and draft a comprehensive strategic planning effort. Although the principal components of the strategic plan are still nascent, management's earlier initiatives have restored some stability to the cooperative's financial results and appear to have set the stage for continued improvement.

Fiscal 2011 results point to another year of stability and financial improvement, a result of KPSC's approved rate increase, healthier working capital, customer stability and fleet optimization. EKPC reported net margins of $55.8 million, an increase of 70% over the previous year. Fitch-calculated metrics for DSC and total debt to funds available for debt service were correspondingly stronger increasing to 1.25x and decreasing to 10.4x, respectively. EKPC reported a times interest earned ratio (TIER) of 1.48x, up from 1.28x in 2010.

Additional information is available at 'www.fitchratings.com'. The ratings above were solicited by, or on behalf of, the issuer, and therefore, Fitch has been compensated for the provision of the ratings.

Applicable Criteria and Related Research:

--'Revenue-Supported Rating Criteria', dated June 20, 2011;

--'U.S. Public Power Rating Criteria', dated March 28, 2011.

For information on Build America Bonds, visit www.fitchratings.com/BABs.

Applicable Criteria and Related Research:

Revenue-Supported Rating Criteria

http://www.fitchratings.com/creditdesk/reports/report_frame.cfm?rpt_id=681015

U.S. Public Power Rating Criteria

http://www.fitchratings.com/creditdesk/reports/report_frame.cfm?rpt_id=665815

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Contacts

Fitch Ratings
Primary Analyst:
Michael Mohammed Murad, +1-212-908-0757
Associate Director
Fitch, Inc.
One State Street Plaza
New York, NY 10004

or
Secondary Analyst:
Dennis M. Pidherny, +1-212-908-0738
Senior Director
or
Committee Chairperson:
Chris Hessenthaler, +1-212-908-0773
Senior Director
or
Elizabeth Fogerty, +1-212-908-0526
Media Relations, New York
elizabeth.fogerty@fitchratings.com