BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 48

In the Matter of PORTLAND GENERAL ELECTRIC 2009 Integrated Resource Plan	)))))))))

COMMENTS

OF THE

CITIZENS' UTILITY BOARD OF OREGON

May 19, 2010

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I. Introduction

PGE ("the Company") filed its IRP last November and filed a subsequent update in April. The update significantly changes PGE's proposed action plan related to the closure of the Company's Boardman coal plant. The Boardman closure has been the primary issue of concern in this IRP process and will be the focus of most of CUB's comments. Additional issues will also be addressed herein, including wind integration costs and the Cascade Crossing Transmission investment. CUB has not completed its analysis of these issues, but will offer a few thoughts on these non-Boardman issues here, with the expectation that additional comments will follow in response to Staff's proposed order.

II. Wind Integration.

CUB continues to be concerned about the Company's proposed wind integration costs. NWEC and RNP put forth a good critique of the wind integration study in their October 5, 2009 letter to PGE. CUB continues to believe that the use of these studies for ratemaking purposes in PGE's AUT and PacifiCorp's TAM gives utilities an incentive to inflate forecasted wind integration costs. Once these costs are established, we are unable to backcast and confirm whether the forecast was accurate, leaving the costs essentially unverified. CUB remains concerned about using a non-ratemaking planning docket to establish a significant ratemaking cost, with no way to verify the cost. This creates an incentive to inflate the forecasted cost, which will not only raise customer rates in future ratemaking dockets, but can also lead the Company to choose a portfolio that is not least cost/least risk. Customers can end up paying both higher than necessary rates for wind integration and higher than necessary rates overall.

III. Cascade Crossing.

CUB has concerns about Cascade Crossing, though we are not recommending against acknowledgement of the project at this time. We offer the following concerns and hope that the Company addresses them as we go forward in this docket:

A. Why does the expected closure of Boardman not affect Cascade Crossing? Closing Boardman, as PGE is proposing, will remove a significant amount of load from the proposed transmission line, but does not affect the need for the transmission facility. CUB understands that PGE expects to conduct an RFP for Boardman replacement resources, which suggests that the Boardman replacement resource may not be located at Boardman and/or may not purchase transmission from PGE.

B. CUB is not convinced that BPA cannot provide the transmission services that are necessary to serve PGE's network. CUB has heard arguments that relate to cost and reliability. CUB continues to be concerned that Cascade Crossing could cost customers more than BPA's transmission services. CUB remains unconvinced that BPA is not a reliable transmission provider.

C. CUB is concerned about the cost projections for the project. PGE does not have a great deal of recent experience managing transmission projects. Significant cost overruns could make this project uneconomical.

D. CUB is concerned that new transmission capacity may not be the top priority for investment. PGE is anticipating a great deal of new investments in the coming years, from new renewable resources, to replacing Boardman, to AMI meters and the promises of a smart grid.

> To keep costs under control for customers, it is critical that costs be managed and investments prioritized.

IV. Boardman.

A. Role of Current IRP.

The first objective of CUB's comments is to identify the issues related to Boardman that need to be acknowledged in this IRP, i.e. how Boardman relates to the current action plan. There has already been significant discussion in this IRP cycle over issues that are not ripe for acknowledgement. We will begin with CUB's view of what is ripe for review in this proceeding with regards to Boardman.

The purpose of the IRP process is "resource planning," or examining what mix of resources in the future will best meet the expected load. Utilities file IRPs every other year. While the planning looks out over 20 years or longer, the primary concerns are the resource decisions that will be made during the short term—the 5-year action plan. These are the investments, RFPs, and other resource decisions that utilities will soon need to act upon. Beyond that 5-year period, the IRP identifies resources that can be considered "placeholders," with the specifics of the investments guaranteed to be reviewed in future IRPs before the investment will be completed.

With respect to Boardman, there are critical decisions that will take place during this planning horizon (5-year action plan) that will affect the life of the plant. Those decisions need to be seriously considered in this acknowledgement process. However, those decisions, while affecting the closure date, are unlikely to predetermine the plant's closure. For example, if the PUC were to acknowledge the clean air investments through 2017, based on an analysis that says the plant will run through 2040, the plant may or may not run until 2040. If the Commission were to choose not to acknowledge those investments based on an analysis that says the plant will run through 2020, the plant may shut down before 2020 (for example, it is not difficult to imagine circumstances, such as a significant outage in the years leading up to any planned closure date, that would cause the plant to shut early). While there will be a great deal of discussion about closure dates, CUB believes that this process is not about picking the closure date but is about trying to identify which investment path related to Boardman provides the best mix of costs and risks.

B. Least Cost/Least Risk Standard

The IRP considers investments and actions on a least cost/least risk basis. This means that the Company is attempting to find the path that provides the best balance between the least costly alternative and the riskiest alternative. Because the least risky investment is almost never the least costly, this process involves a great deal of analysis and professional judgment. Because different stakeholders may have a different view of the risk of a particular investment or have a different expectation about the cost of a particular investment, stakeholders can have different views of the least cost/least risk path.

While utilities attempt to model costs and risks in a manner that allows them to be quantified and compared, CUB believes that the IRP review goes beyond picking the option with the highest score. Often the differences in scores over 20 years are relatively small, and any one of a set of low scoring paths could be considered reasonable.

CUB views the Boardman decision a little differently than PGE. Rather than define Boardman option based on closure dates, we define them based on the investments decisions that are required for each option. We see four Boardman paths associated with the 5-year action plan. While these paths have different life expectancies, we view them not based on the life expectancy of the plant (which is a forecast of the expected life and, like all forecasts, may be wrong), but on the actions within the action plan.

Option 1: Make no additional investment in Boardman

Option 2: Make the 2011/2012 investments, but not the 2014 or 2017 investments

Option 3: Make the 2011/2012 and 2014 investments but not the 2017 investments

Option 4: Make the 2011/2012, 2014 and 2017 investments

Each of these options requires significantly different investments over the next few years, has significantly different cost and risk profiles, and creates different potential life expectancies for the plant.

Two of these scenarios, Option 1 and Option 3, score poorly from both cost and risk perspectives and can easily be discarded. We believe the primary Boardman-related issue in this IRP is the determination of which of the other two options, based on current information, is the better path from a least cost/least risk analysis. The critical difference between these paths is simple: should we make additional clean air investment in 2014 and 2017?

C. The investments in 2014 and 2017 are not least cost/least risk.

In this case, PGE's filing shows that the 2014 and 2017 investments are not least cost/least risk. PGE identifies the preferred portfolio as one that does not include those investments and allows the plant to run until 2020. Under this scenario, PGE is asking DEQ to change the rule relating to Regional Haze and allow Boardman to run until 2020 without the 2014 and 2017 investments.

CUB, RNP and NWEC sent a letter[1] to the Company last fall to request the analysis of a portfolio where the 2014 and 2017 clean air investments were not made and the plant ran until 2020. This was based on CUB's reading of the DEQ BART rule as requiring those investments if the plant were to run until 2040, but that DEQ was open to revising the rule if the plant was scheduled to close at an earlier date.

PGE ran the portfolio we requested and it shows clearly that the 2014 and 2017 investments are neither least cost nor least risk. We commend PGE for running this analysis, even though it required the Company to reconsider its plans to run the plant until 2040. Boardman is a reasonably reliable, relatively inexpensive, significantly-sized resource. We have no doubt that agreeing to consider closing the plant was difficult for PGE and facing future demand without it worries power managers. But the scoring is very clear. It shows that not making the 2014 and 2017 investments reduces expected costs, while at the same time keeps the risks down to a reasonable level.

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[1] See CUB Attachment 1.

D. PGE's backup plan: allow clean air investment

PGE has complicated this issue by requesting acknowledgement of the clean air investments in the case, where DEQ, EPA, or some other entity requires the Company to do something that is different from its proposal to avoid the investment and run the plant through December 31, 2020.

CUB does not believe that such acknowledgement is possible. It is clear that the 2014 and 2017 clean air investments are not least cost/least risk if the plant is operated until 2020 on the terms that PGE is proposing. It is not clear that the investment would become least cost/least risk under another set of terms that have not been identified or modeled. Without knowing what those terms are, it is impossible to evaluate them and determine what is least cost/least risk.

Acknowledging the 2014 and 2017 clean air investment as a contingency in case environmental regulators offer PGE a different set of conditions than PGE's preferred approach will create significant regulatory risk as the process to close Boardman moves forward. Because this contingency acknowledgement would not be based on evaluating the actual conditions that are being offered by the environmental regulators, it would provide little comfort and little support for the investment. This scenario would mean that the prudence review of the 2014 and 2017 investments after those investments were made would be the venue to compare what the environmental regulators offered to PGE versus PGE's contingency plan. This approach puts both customers and shareholders at risk.

PGE is correct that the options for Boardman may not be what are proposed in this case. The DEQ may not accept PGE's proposed BART rule and might offer a different alternative. EPA regulators may require clean air investments under a different schedule. Clean air investment requirements might change, and the date for closure might change. We could end up with a choice that includes higher clean air investment costs versus an earlier closure date.

CUB believes that rather than trying to model and consider all possible (or even likely) contingencies, it makes more sense to look at what we do know about the particular investments that are likely to be put in the action plan. Based on what we currently know, CUB is unable to say that the 2014 and 2017 clean air investments are least cost/least risk. As such, those investments should not be acknowledged. If, due to actions of regulatory agencies or some other events, PGE believes the clean air investments will become least cost/least risk, then the Company should file an update to the IRP which identifies the events that have caused the analysis to change, how those events changed the analysis, and the new path that PGE believes is least cost/least risk. To the degree that the clock is ticking and investment decisions need to be made, it is far better to take the time to get the decision right (even if this means mothballing a plant) than to rush ahead and potentially spend hundreds of millions of dollars on an investment that the Company will later regret. While this delay does not create a great deal of certainty in the process, customers (and shareholders) will be taking a much smaller risk if we can ensure the proper analysis. Even if this study causes a delay in an investment, the benefits of ensuring that PGE is making wise least cost/least risk investments is well worth it.

E. MACT Standards.

A great deal of discussion has taken place in this proceeding concerning regulations from EPA that will not be issued until next year. These regulations, which are expected to require Maximum Achievable Control Technology [MACT] on coal plants, could require investments that are similar to the BART clean air investments. These regulations may not, however, have the flexibility to adjust for a plant that is being closed.

Some point to the MACT rules as proof that Boardman needs to be closed earlier than 2020. Others point to the MACT rules as proof that PGE will need to make these investments and keep running the plant. CUB believes that it is wise not to overreact to rules that have not been developed, but that PGE needs to recognize that it may have to update its plans to account for the rule.

CUB Attachment B is an analysis of the MACT rules that was referred to at the April 26 PUC Public Meeting by Steve Weiss of NWEC. It identifies more than 1,100 coal generating units and estimates that the MACT rules will lead to the closure of 24% of the United State's coal generation capacity, while requiring scrubbers to be installed on 29% of the total capacity. Assuming that the rules come out in late 2011 and have a four year deadline (3 years, plus a one-year extension), the deadline for complying would be late 2015.

Before assuming that these rules will require the same investment as BART but by the end of 2015, we should ask and answer some basic questions which get to the heart of whether these rules will be implemented:

> A. Is it actually possible to install pollution control equipment on more than 300 coal units between the issuance of the regulation (Fall 2011) and the deadline (Fall 2015)? Are there enough scrubbers and pollution control equipment being manufactured for all plants to be refurbished simultaneously? Are there enough trained crews to install the equipment?
>
> B. Is it possible to shut down 29% of the US coal generation while equipment is being installed without causing reliability problems in coal-dependent parts of the electric grid?
>
> C. Is it possible to close 24% of the US coal generation capacity as a result of the implementation of this regulation without causing reliability problems in coal dependent parts of the electric grid?
>
> D. At a cost of $420/kW, the cost of responding to this rule may be in the tens of billions of dollars. Most states do not have a "not presently used" statue that applies to upgrades of existing plants, so costs will begin to flow to customers when they are incurred, not when the pollution control equipment becomes used and useful. This means that billions of dollars in costs will begin to hit electric bills in 2012, an election year. What effect will the politics of rising electric bills have on the implementation of the new regulations?

CUB does not have the answers to these questions, but these questions get to the heart of whether the regulations will be in place by the end of 2015 or be delayed in some manner (such as Congressional action). To the degree that the regulations are impossible to implement, or threaten the reliability of the electric grid, or have a price that is too large for an election year, then it would seem reasonable to expect delays, and/or exemptions to the 2015 deadline.

CUB believes that the MACT regulations are something that all Oregonians will have to deal with, since coal plants that are implicated by the regulations generate significant amounts of electricity that is consumed in Oregon. However, because the regulations and the political response to the regulations are not yet known, it would not be wise to base decisions in this IRP on the expected effects of the regulations. Instead, CUB believes that PGE should file an update to this IRP if the new regulations that are issued require changing the IRP action plan. Only at that point can a rational approach to the MACT be taken.

F. Carbon Risk/Coal Risk

An important part of the Boardman analysis is PGE's analysis of the carbon risk. CUB generally supports the Company's approach to modeling carbon costs based on the expected costs associated with proposals to address carbon. Carbon regulation is coming. The primary question is when and how much it will cost PGE and other utilities to conform to carbon regulations.

PGE's approach probably overstates carbon compliance costs in the short run and understates those costs in the long run. PGE assumes that the costs will begin in 2013, which is earlier than likely given the current pace of Congress. At the same time, PGE assumes that the initial carbon regulatory program will continue for the long term without significant expansion. We tend to believe that carbon regulations will be established and will expand over time as the consequences of climate change become more pronounced. As sea levels rise and other changes become apparent, there will be additional costs placed on carbon emissions. In addition, CUB believes that additional regulatory pressure will come to bear on coal plants. The MACT standards may be a manifestation of this trend. Coal has a target on its back. There will likely be additional regulatory actions taken which raise the cost of coal-fired generation, from coal mining regulations to coal ash regulations. There will likely be federal and state legislative proposals that are designed to reduce or eliminate coal use. Finally, Oregon's initiative process will likely be used to target coal-fired generation, just as it was used to target nuclear power plants. Over the next 30 years there will be regulatory costs associated with coal plants that are not considered in PGE's IRP analysis.

V. CUB Recommendations

CUB commends PGE for updating its IRP and including a portfolio that includes the 2011/2012 clean air investments but avoids hundreds of millions of dollars in clean air investments in 2014 and 2017. CUB recommends that the PUC acknowledge the 2011/2012 investment in Boardman clean air controls, but not acknowledge the 2014 and 2017 investments.

Respectfully Submitted,
May 19, 2010

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September 23, 2009

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Dear Brian,

While we always appreciate the tremendous volume of analysis that goes into a utility's IRP, we are concerned that PGE's IRP analysis is based on assumptions that ultimately may undermine the analysis. Particularly, the analysis related to Boardman is based on two critical assumptions that are not well supported:

1. The assumption that PGE has no flexibility with regard to regional haze rules is not consistent with DEQ's position. This is critical because PGE's analysis on Boardman had earlier concluded that a 2020 phase out was the least cost approach. We believe that PGE should continue to examine a 2020 phase out and should pursue this path with DEQ if it finds this path continues to be the least cost portfolio.

2. We are concerned that PGE's analysis of Boardman does not include any sensitivity analysis around an early shut down due to carbon regulation. Dr. James Hanson, a leading climate scientist has been widely quoted saying that the US must phase out all pulverized coal plants over the next 20 years. PGE makes the assumption that if the company (or its customers) pays to install pollution control equipment, the plant will be allowed to operate until 2040. We believe that as Oregon's largest source of greenhouse gas emissions, Boardman will be a target for closure and that PGE should consider what happens if the Company is required to shut down the plant before 2040 (we would suggest conducting a sensitivity analysis on the portfolios with Boardman running until 2040 by forcing a premature shut down in 2030 and in 2035).

1. Keeping the 2020 phase out on the table.

In the draft IRP, PGE summarizes the DEQ Boardman decision as completely rigid, with criminal sanctions if PGE strays from the DEQ decision:

> *Under these rules, PGE has the following options*:
>
> *Install all of the controls: LNB/MOFA by July 2011, scrubbers/fabric filter by July 2014 and SCR by July 2017 and operate Boardman through 2040 or beyond.*
>
> *Install LNB/MOFA and scrubbers and cease Boardman operations in 2017; do not make the SCR investment.*
>
> *Install LNB/MOFA only and cease Boardman operations in 2014.*
>
> *Cease Boardman operations in July 2011 with no obligation to install additional controls.*
>
> *Non-compliance with the Oregon Regional Haze Plan (and also Oregon Utility Mercury Rule) is, however, not an option. The plant must meet emissions requirements by either installation of controls or by ceasing operations. Failure to comply with the plan can result in significant penalties, equitable remedies, and possibly criminal sanctions.*[1]

However, PGE has an additional option. It can conduct its Boardman analysis, and based on that analysis ask DEQ to consider extending the deadlines for controls based on an earlier shut down of the plant. For example, it could request that DEQ consider allowing the plant to be phased out by 2020.

According to DEQ's description of its rulemaking, it will consider such a plan on an expedited basis:

> *On December 17, 2008, DEQ received comments from PGE requesting that two "decision points" be added to the proposed rules, which would allow PGE to consider in 2012 and 2015 whether or not to close the Boardman plant by 2020 or 2029, rather than install the controls that DEQ had proposed. After careful consideration, DEQ decided not to include PGE's proposal in the final recommendation to the commission, but instead added provisions in the Regional Haze Plan that allow PGE to request a rule change if a decision is made in the future to close the plant. This will allow operation of the plant for a limited time without installing one or more of the controls proposed by DEQ, and thus help ensure that investments made at Boardman are cost-effective for rate payers. DEQ will make every effort to expedite this request.*[2]

We read the above statement as the DEQ inviting PGE to propose a closing date that is earlier than 2040 with DEQ willing to "allow operation of the plant for a limited time without installing one or more of the controls proposed by DEQ." This is a far cry from threatening criminal penalties.

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[1] PGE draft IRP, chapter 12
[2] http://www.deq.state.or.us/aq/haze/pge.htm

While we recognize that PGE is not guaranteed that DEQ would allow a 2020 phase out of the plant, we do not think such a guarantee is necessary for PGE to conduct analysis around this date. We note that PGE includes a portfolio in its analysis that includes a new nuclear power plant. We believe the siting and permitting risks associated with a new nuclear power plant may be greater than the regulatory risk that DEQ would deny a 2020 phase out of Boardman.

2. Considering how an early shut down due to CO2 will affect the plant.

PGE's modeling of carbon risks has greatly improved in recent years, and this IRP generally does a good job of considering the costs of carbon regulation. However, the modeling fails to adequately address the risk to Boardman's operations on a going forward basis. The carbon related risk of a coal plant is not limited to a dollar per ton regulatory "tax" on carbon emissions, but the risk that the utility will actually have to reduce its carbon emissions, including scenarios where coal fired power plant use will be severely curtailed or will be shut down.

PGE and PacifiCorp both model carbon costs, but do not model scenarios that reduce emissions or require a single pulverized coal plant being closed due to carbon regulations in their IRPs. This is not rational, as one goal of carbon regulatory policy is to reduce greenhouse emissions to sustainable levels, and many scientists agree with Dr. Hanson that this will require closing coal plants. Based on our current knowledge of climate change, we do not believe that it makes sense to model coal plants operating indefinitely into the future. While we are hesitant to predict the future life of Boardman (and Colstrip), we believe that the IRP should consider the possibility that the Company's emissions must be reduced significantly and pulverized coal plants will be shut down in the future. We suggest that PGE consider the affect on all portfolios of what happens if Boardman is required to close in 2030 (20 years) and 2035 (25 years).

Thank you for allowing us to take this opportunity to respond to your draft IRP. We look forward to discussing the assumptions underlying your analysis at the stakeholder meeting on Friday, September 25th and plan to provide additional thoughts and comments before your October 5 deadline.

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U.S. Utilities: A Visit to Washington Finds Utility Lobbyists & Environmentalists Agreeing on the Grim Outlook for Coal

Ticker	Rating	CUR	3/1/2010 Closing Price	Target Price	TTM Rel. Perf.	EPS 2009A	EPS 2010E	EPS 2011E	P/E 2009A	P/E 2010E	P/E 2011E	Yield
AEP	M	USD	33.94	39.00	-30.8%	2.97	3.06	3.26	11.4	11.1	10.4	4.8%
D	M	USD	38.30	38.00	-24.9%	3.27	3.28	3.21	11.7	NM	11.9	4.1%
DUK	M	USD	16.49	15.00	-29.4%	1.22	1.26	1.32	13.5	13.1	12.5	5.6%
EIX	M	USD	33.32	37.00	-29.4%	3.25	3.37	3.48	10.3	9.9	9.6	3.7%
EXC	M	USD	44.46	45.00	-57.6%	4.12	3.79	4.25	10.8	11.7	10.5	4.7%
FE	O	USD	39.07	49.00	-60.0%	3.77	3.45	4.43	10.4	11.3	8.8	5.6%
FPL	M	USD	47.38	51.00	0.0%	4.05	4.27	4.28	11.7	11.1	11.1	4.0%
PCG	O	USD	42.04	49.00	-41.8%	3.21	3.42	3.68	13.1	12.3	11.4	4.0%
SPX			1115.71			61.49	79.19	95.66	18.1	14.1	11.7	2.0%

O – Outperform, M – Market-Perform, U – Underperform, N – Not Rated

Highlights

- On a trip to Washington yesterday to meet with regulators, politicians, utility lobbyists and environmental groups, we found consensus on one point: EPA regulation of mercury and other air toxics will drive rapid and far-reaching changes within the utility sector, far outstripping the impact of regulatory standards for other air pollutants, including CO2, SO2 and NOx.
- The Edison Electric Institute (EEI), the power industry trade group, and the Natural Resources Defense Council (NRDC), a prominent environmental group, agree that EPA regulation of mercury and acid gases could require the installation of costly flue gas desulfurization equipment (SO2 scrubbers) across the coal fired fleet, potentially forcing the early retirement of a significant portion of U.S. coal fired capacity.
- In October 2009 the EPA submitted to a consent decree that requires, first, that by March 2011 it publish proposed emissions standards for hazardous air pollutants from coal and oil fired power plants and, second, that by November 2011 it issue final emissions standards.
- Within three years of issuance of the final rule (i.e., by November 2014), the Clean Air Act stipulates that sources of hazardous air pollutants must comply with MACT standards. While one-year extensions may be granted on a case-by-case basis, 2015 may be thought as the year by which all U.S. coal fired fleet power plants must have installed maximum achievable control technology for hazardous air pollutants.
  - Referred to as "air toxics," these hazardous air pollutants include mercury and other toxic metals, such as arsenic, lead and selenium; acid gases such as hydrogen chloride, hydrogen fluoride, and hydrogen cyanide; and organic air pollutants including organic hydrocarbons and volatile organic compounds.
- The Clean Air Act limits the EPA's flexibility in setting MACT standards for hazardous air pollutants. Specifically, Section 112(d) of the Act stipulates that MACT standards shall not be less stringent than "the average emission limitation achieved by the best performing 12 percent of existing sources" of the hazardous pollutant.
  - Some of the highest levels of mercury emissions reductions have been achieved at coal fired power plants that have installed expensive flue gas desulfurization equipment (SO2 scrubbers), a selective

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catalytic reduction system for NOx control, and a fabric filter for particulate matter. The EPA may find that this combination of expensive emissions controls constitutes MACT for mercury.

- EEI and NRDC agree that a similar configuration of pollution controls is very likely to be deemed MACT for acid gases.

- The Electric Power Research Institute, a research institute sponsored by the power industry, estimates the cost of installing only an SO2 scrubber at a typical 500 MW Midwestern plant to be some $420/kW – approximately the cost per kW of building a new gas turbine peaker.

Investment Conclusion

We have argued elsewhere (see our March 5, 2010 *Bernstein Commodities and Power Blast*, "Dark Days Ahead for Coal Clear the Skies for Gas") that the cost of installing scrubbers will be prohibitive at certain coal fired power plants, particularly those older, less efficient units whose high operating costs, consequently limited hours of operation, and short remaining useful lives make it impossible to recover the capital cost of a scrubber out of the future cash flows of the plant. Based on a comparison of the present value of future gross margin at these units with the capital cost of installing scrubbers, we estimate that such a requirement would likely result in the retirement of coal fired power plants that today generate 452 million MWh (24% of U.S. coal fired generation), while forcing plants that generate an additional 537 million MWh (29% of total) to install SO2 scrubbers.

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Details

On a trip to Washington yesterday to meet with regulators, politicians, utility lobbyists and environmental groups, we found consensus on one point: EPA regulation of mercury and other air toxics will drive rapid and far-reaching changes within the utility sector, far outstripping the impact of regulatory standards for other air pollutants, including CO2, SO2 and NOx.

Our trip to Washington included visits with the Edison Electric Institute (EEI), the power industry trade group; Mr. Robert Meyers, former head of the EPA's Office of Air and Radiation and currently senior counsel at the law firm Crowell & Moring; the legislative assistants for energy policy to Senators Lindsay Graham (R-SC) and Lamar Alexander (R-TN); and John Walke, Senior Attorney and Clean Air Director at the Natural Resources Defense Council (NRDC). This note will summarize our findings.

Air Toxics

EEI and NRDC were in surprising agreement on one critical issue: that EPA regulation of air toxics could require the installation of costly flue gas desulfurization equipment (SO2 scrubbers) across the coal fired fleet, potentially forcing the early retirement of a significant portion of U.S. coal fired capacity.

Air toxics include three categories of hazardous air pollutants: mercury and other toxic metals, such as arsenic, lead and selenium; acid gases such as hydrogen chloride, hydrogen fluoride, and hydrogen cyanide; and organic air pollutants including organic hydrocarbons and volatile organic compounds.

In 2000, the EPA determined that emissions of mercury and other hazardous air pollutants from coal and oil fired power plants should be regulated. The Clean Air Act requires all sources of hazardous air pollutants to install "maximum achievable control technology," or MACT, and directs the EPA to promulgate the applicable MACT standards.

To date, however, the EPA has failed to stipulate MACT standards for the air toxics. This failure led the Natural Resources Defense Council and other environmental organizations to sue the EPA in December 2008. This suit was settled in October 2009 when the EPA submitted to a consent decree that requires, first, that by March 2011 it publish proposed emissions standards for hazardous air pollutants from coal and oil fired power plants and, second, that by November 2011 it issue final emissions standards.

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Within three years of issuance of the final rule (i.e., by November 2014), the Clean Air Act stipulates that sources of hazardous air pollutants must comply with MACT standards. Although a one-year extension may be granted on a case-by-case basis, 2015 may be thought as the year by which all U.S. coal fired fleet power plants must have installed maximum achievable control technology for air toxics.

The Clean Air Act limits the EPA's flexibility in setting MACT standards for hazardous air pollutants. Specifically, Section 112(d) of the Act stipulates that MACT standards shall not be less stringent than "the average emission limitation achieved by the best performing 12 percent of existing sources" of the hazardous pollutant. According to the United States General Accountability Office (GAO), "EPA 1999 data, the most recent available, indicate that about one-fourth of the industry achieved mercury reductions of 90 percent or more as a co-benefit of other pollution control devices," specifically a combination of a scrubber for sulfur dioxide control, a selective catalytic reduction system for nitrogen oxides control, and a fabric filter for particulate matter control. Under the Clean Air Act, therefore, this array of expensive emissions control devices may be deemed to be maximum achievable control technology for mercury. EEI and NRDC agree that a similar configuration of pollution controls is likely to be deemed MACT for acid gases. Because the Clean Air Act requires that all sources of hazardous air pollutants deploy maximum achievable control technology, a finding by the EPA that MACT for air toxics involves such a combination of pollution control devices would require all coal and oil fired power plants in the country to deploy such controls by 2015.

To secure relief from what are likely to be onerous EPA regulations, EEI supports a legislative amendment of the Clean Air Act. Senators Carper (D-DE) and Alexander (R-TN) have introduced such a bill, entitled the Clean Air Act Amendments of 2010, which would codify the regulation of SO2, NOx and mercury emissions from utility boilers. As it now stands, however, the Carper-Alexander bill offers little relief to the industry, as it calls for mercury emissions to be reduced by 90% by 2015. By engaging with Senators Carper and Alexander to craft the legislation, however, EEI hopes to mitigate the impact on the industry of the EPA's regulation of air toxics. The bill could be used, for example, to amend the Clean Air Act to remove acid gases from the list of hazardous air pollutants.

Surprisingly, given its potential impact, EEI is aware of no comprehensive analysis of the impact on the coal fired fleet of EPA regulation of air toxics, and particularly the requirement that the full range of pollution control devices (i.e., scrubbers, SCRs and baghouses) be deployed to control them. Within this group of required pollution controls, scrubbers are the critical component. The Electric Power Research Institute, a research institute sponsored by the power industry, estimates the cost of installing an SO2 scrubber at a typical 500 MW Midwestern plant to be some $420/kW – approximately the cost per kW of building a new gas turbine peaker. We have argued elsewhere (see our March 5, 2010 *Bernstein Commodities and Power Blast*, "Dark Days Ahead for Coal Clear the Skies for Gas") that the cost of installing scrubbers will be prohibitive at certain coal fired power plants, particularly those older, less efficient units whose high operating costs, consequently limited hours of operation, and short remaining useful lives make it impossible to recover the capital cost of a scrubber out of the future cash flows of the plant. Based on a comparison of the present value of future gross margin at these units with the capital cost of installing scrubbers, we estimate that such a requirement would likely result in the retirement of coal fired power plants that today generate 452 million MWh (24% of U.S. coal fired generation), while forcing plants that generate an additional 537 million MWh (29% of total) to install SO2 scrubbers.

SO2 and NOx

From our discussions with EEI and NRDC, it was clear that the EPA regulation likely to have the most radical effect on the power industry would be a universal requirement to install SO2 scrubbers as the maximum achievable control technology for mercury or acid gases. Even in the absence of this threat, however, the industry will likely face significant challenges from new EPA regulations governing SO2. Both the EEI and the NRDC expect that by April or May the EPA will propose new regulatory standards for SO2 and NOx. These standards will replace the Clean Air Interstate Rule (CAIR), a set of regulations issued by the EPA in March 2005 to limit SO2 and NOx emissions in 25 states in the eastern U.S.

NOx contributes to the formation of ground-level ozone, a precursor of smog, and SO2 and NOx contribute to the formation of fine airborne particles. Inhaling these fine particles can cause or worsen respiratory diseases, such as emphysema, bronchitis, and asthma, and can aggravate existing heart disease, leading to increased hospitalization and premature death among at-risk populations, particularly the elderly. The EPA therefore adopted stringent National Ambient Air Quality Standards for fine particulate matter in 1997. Many areas remained in violation of the standard, however, so in March 2005 the EPA issued the Clean Air Interstate Rule. Compared with 2003 levels, CAIR mandated cuts in regional SO2 emissions of 45% by 2010 and 57% by 2015. NOx emissions were subject to cuts of 53% by 2009 and 61% by 2015, again measured against 2003 levels.

To achieve its targeted reduction in regional emissions, CAIR implemented a cap and trade scheme under which the EPA issued allowances to emit SO2 and NOx up to the targeted levels, and allocated these allowances to the coal fired power plants in the region. The recipients were free to trade the allowances; consequently, while the aggregate amount of allowances declined over time, individual generators could emit at or above historical levels provided they purchased the allowances necessary to cover their emissions. In July 2008, however the D.C. Circuit Court of Appeals vacated the Clean Air Interstate Rule (*North Carolina v. EPA*). The Court of Appeals found that CAIR's regional cap-and-trade system violated the "Good Neighbor Provision" of the Clean Air Act, which prohibits "any...type of emissions activity [that] contribute[s] significantly to nonattainment in, or interfere[s] with maintenance by, any other state with respect to any [National Ambient Air Quality Standard]" [42 U.S.C. Sec. 7410(a)(2)(D)]. Contrary to the Good Neighbor Provision, the Court found, CAIR permitted power plants in upwind states to continue to emit SO2 and NOx, provided they purchased the allowances to do so, and thus to contribute to air quality deterioration in downwind states. The Court therefore remanded the rule to the EPA, requiring it to measure each upwind state's contribution to downwind states' nonattainment of the air quality standards stipulated under the CAA, and to promulgate a revised regulation that would eliminate these contributions.

To comply with the Court's ruling, the EPA's new regulations must curtail the use of SO2 and NOx emissions allowances so as to ensure that the emissions of upwind states do not contribute to air quality deterioration in downwind states. As a result, generators will likely face significant constraints on their ability to comply with emissions limits through the purchase of allowances. To meet the new standards, therefore, it will likely be necessary for a larger number of coal fired generating units to install SO2 scrubbers.

In other respects, however, the EPA's new SO2 and NOx regulations are likely to resemble the rule they replace. EEI expects that EPA will maintain a 2015 target date in its revised regulations. In part this reflects the implementation schedule for the EPA's regulation of air toxics, under which 2015 is likely to be the first full year that utility boilers will be required to comply with the new emissions standards. Robert Meyers, former head of the EPA's Office of Air and Radiation and currently senior counsel at the law firm Crowell & Moring, also expects CAIR's 2015 target date to be preserved, likewise expecting that the EPA will seek to conform its schedule for SO2 emissions cuts to that for the air toxics. Finally, EPA is expected to continue to focus its regulations on the eastern United States, although Meyers believes that two additional states could be added to the western edge of the 25 state CAIR region.

Under CAIR, permitted emissions of SO2 were to be cut to 3.7 million tons in 2010 and 2.6 million tons in 2015 – the 2015 target representing a 50% reduction from 2008 levels of some 5.3 million tons. As discussed in our March 5, 2010 *Bernstein Commodities and Power Blast*, "Dark Days Ahead for Coal Clear the Skies for Gas," we estimate that to achieve the CAIR target of limiting SO2 emissions in the eastern United States to 2.6 million tons by 2015 it will be necessary (i) to retire unscrubbed coal fired power plants that today generate some 431 million MWh, or 23% of U.S. of coal-fired net generation, and (ii) to install

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SO2 scrubbers at power plants that today generate 254 million MWh, or a further 14% of U.S. coal fired generation. Given the age profile of the U.S. coal fired fleet, most of the retirements required to meet CAIR's SO2 target for 2015 are likely to occur through the natural attrition of older coal fired power plants over the next five years.

It is possible, however, that the EPA's regulations will be more stringent. Meyers believes it likely that the EPA will cut allowed emissions of SO2 in the CAIR states by a further 1.0 million tons, to 1.6 million tons in 2015, or 70% below 2008 levels. Such a regional target would imply a cut of approximately 50% in national emissions of SO2.

Even more stringent cuts in permitted emissions of SO2 are under consideration in Congress. As noted above, Senators Carper and Alexander have introduced a bill (the Clean Air Act Amendments of 2010) that would set national rather than regional emissions limits for SO2 and NOx and create a national cap and trade program for the two pollutants. Specifically, the bill would seek to cut national emissions of SO2 by 80 percent (from 7.6 million tons in 2008 to 1.5 million tons in 2018) and cut NO_X emissions by 53 percent (from 3 million tons in 2008 to 1.6 million tons in 2015). The Carper-Alexander bill would also require mercury emissions to be cut by 90% no later than 2015. Cap and trade would not be allowed in respect of this pollutant, however; rather, utilities would be required to implement the maximum achievable control technology. The Carper-Alexander bill would thus do little to modify the EPA's current approach to the regulation of mercury. The bill's 80% target reduction in emissions of SO2, moreover, would imply almost as stringent a requirement for the installation of SO2 scrubbers as is likely to result from the implementation of the EPA's air toxics rule.

In summary, whether through the EPA's regulation of SO2 or through its regulation of air toxics, we estimate that power plants generating between 14% and 29% of the nation's coal fired generation will likely be required to install SO2 scrubbers. More importantly, we estimate that power plants accounting for a further 23% of U.S. coal fired generation are likely to be retired. Legislative action such as that contemplated by the Carper-Alexander bill seems unlikely to change this result.

McCarthy Dialogue On Reliability (2)

40%

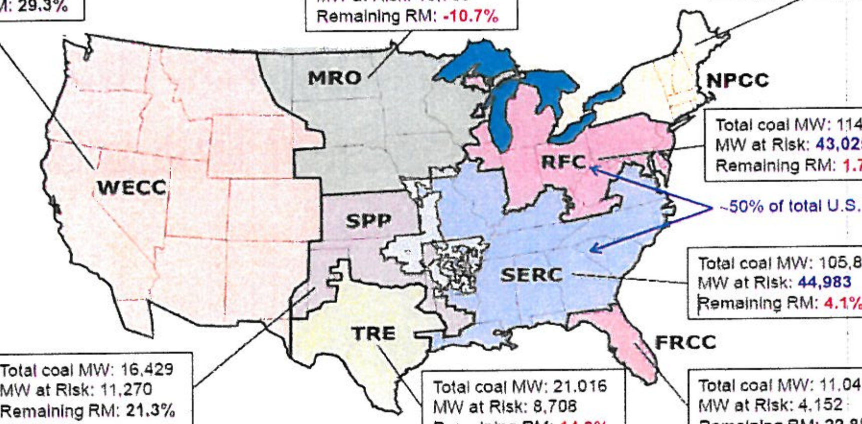
Taking Reliability Risk Seriously

Total US coal MW: 333,018
MW at Risk*: **137,248**

Remaining regional reserve margin (RM) if MW at risk* are unavailable

*MW at risk: MW without both an FGD and an SCR

MW that may be unavailable either because of a) retirement or b) the inability to add controls or replacement generation before the required compliance period.



INFORMATION FOR ILLUSTRATIVE PURPOSES ONLY. DOES NOT REPRESENT A MULTIPLE DECISION TREE INCLUDING CCBs, CO2, & WATER.

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Sources. NERC Summer Reliability Assessment 2008, EIA (www.eia.doe.gov/cneaf/electricity/page/capacity/existingunitsbs2008.xls), CAMD (http://camddataandmaps.epa.gov/gdm/) through 2nd Q 2009.

U.S. Coal Fleet Demographics

- Size
  - Over 75 GW that are <250 MWs
- Age
  - Over 45 GW >50 years old today
  - Another 67 GW between 40 and 50 years old
- Environmental Controls
  - Over 190 GW do not have FGD
  - Over 190 GW do not have SCR or SNCR
  - Over 280 GW do not have FF
  - Only 9 GW have all three installed-- FGD,SCR/SNCR,FF
  - 38% (275 GW) of fossil fuel fired units at risk of cooling towers retrofits
  - 169 GW with wet ash handling/disposal of CCBs[1]

Notes:
*Coal Unit Data: Energy Information Administration (www.eia.doe.gov/cneaf/electricity/page/capacity/existingunitsbs2008.xls)
*Air Emission Control Data: EPA Clear Air Markets Division (http://camddataandmaps.epa.gov/gdm/)
[1]EIA 767 data, 2005

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Coal Fleet Transition – Preliminary Data

Coal Units by Age, Capacity and Emissions

U.S. Generating Units, 10 Year Increments

Age of Units*	Generating Units		Total Nameplate Capacity		Total Net Generation Year 2008		Total CO_2 Emissions Year 2008		Total SO_2 Emissions Year 2008		Total NO_x Emissions Year 2008	
	#	Percent of Total	GW	Percent of Total	GWH	Percent of Total	MTons	Percent of Total	Tons	Percent of Total	Tons	Percent of Total
0-10 Years	16	1.4%	5.3	1.6%	19,788	1.1%	28.7	1.4%	18,083	0.2%	13,779	0.5%
11-20 Years	64	5.8%	14.9	4.5%	78,261	4.2%	78.1	3.8%	137,803	1.9%	108,115	3.8%
21-30 Years	186	16.7%	86.1	26.1%	541,408	29.0%	615.0	29.6%	1,336,033	18.0%	763,207	26.9%
31-40 Years	238	21.4%	122.5	37.1%	724,206	38.8%	780.7	37.6%	2,750,025	37.1%	1,053,259	37.1%
41-50 Years	270	24.3%	60.8	18.4%	316,029	16.9%	352.2	16.9%	1,879,152	25.4%	533,038	18.8%
51-60 Years	304	27.3%	39.3	11.9%	187,473	10.0%	220.7	10.6%	1,265,388	17.1%	356,902	12.6%
61-70 Years	30	2.7%	0.9	0.3%	1,166	0.1%	2.5	0.1%	19,223	0.3%	6,554	0.2%
> 70 Years	4	0.4%	0.0	0.01%	5	0.0003%	0.1	0.004%	87	0.001%	484	0.02%
Coal Unit Totals	1,112	100.0%	329.95	100.0%	1,868,336	100.0%	2077.9	100.0%	7,405,794	100.0%	2,835,339	100.0%

Source: Ventyx, Inc.—EV Suite
MTon = million tons
* Does not include units that came online in 2009

LC 48 – CERTIFICATE OF SERVICE

I hereby certify that, on this 19th day of May, 2010, I served the foregoing **OPENING COMMENTS OF THE CITIZENS' UTILITY BOARD** in docket LC 48 upon each party listed in the LC 48 OPUC Service List by email and, where paper service is not waived, by U.S. mail, postage prepaid, and upon the Commission by email and by sending 2 copies by U.S. mail, postage prepaid, to the Commission's Salem offices.

(W denotes waiver of paper service)

(C denotes service of Confidential material authorized)

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