BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON
LC 52

In the Matter of	)	
	)	SIERRA CLUB'S PRELIMINARY
PACIFICORP	)	COMMENTS
	)	
2011 Integrated Resource Plan	)	
	)	

I. Introduction and Recommendations

Sierra Club respectfully submits these preliminary comments on PacifiCorp's 2011 Integrated Resource Plan (IRP). These comments are preliminary because as the company and Commission recognized at the August 19, 2011 public hearing, PacifiCorp must provide additional detailed analyses on significant current and anticipated compliance costs facing its coal-fired units. Therefore, at this stage, these comments focus on the company's basic obligations to meet Commission requirements such as selecting a "portfolio of resources with the best combination of expected costs associated risks and uncertainties."[1] And, in particular, including in the IRP "sensitivity analyses on a range of reasonably possible regulatory futures for nitrogen oxides, sulfur oxides, and mercury."[2]

The Sierra Club actively participated in the stakeholder input process during the development of the 2011 IRP, and raised many of the issues discussed herein. (See Exhibit 1.) The company did not respond to any requests for data related to the topics addressed in these comments, choosing instead to provide only a small amount of materials in the final draft, just days before the company submitted the final IRP.

The IRP's flaws stem from the omission of a series of environmental compliance costs and obligations in its least-cost planning analyses. Until the company discloses these costs and attendant regulatory risks, the very validity of the IRP will remain an open question that undermines most, if not all, of the planning exercises and the

[1] OR PUC Order 07-002 1(c).
[2] OR PUC Order 08-339 8(d).

resulting preferred scenario. Indeed, as demonstrated by the IRP's conspicuous lack of important environmental costs, and in evidence obtained in very recent rate cases throughout PacifiCorp's service territory, the company has established a pattern of omitting very real environmental costs in its forward planning efforts. The company's historic failure to disclose these costs and mechanisms as a component of its least-cost compliance strategy has already caused substantive damage to ratepayers. The company's failure to disclose these costs and present a least-cost strategy for meeting current and future compliance obligations in this IRP exposes ratepayers to extraordinary costs and regulatory risks, and is a serious shortcoming in this IRP.

Sierra Club requests that the Commission not acknowledge the 2011 IRP because on the filing fails to meet the most basic criteria of a reasonable planning document. We request that the Commission require that the company:

a) Present a thorough accounting of applicable current and reasonably foreseeable impending environmental regulations that may result in either substantial compliance costs or operational constraints on both the company's existing and proposed generating resources;
b) Evaluate feasible compliance mechanisms, the costs of those mechanisms (both capital and operational) on both existing and proposed generating resources, as well as evaluate the risk (i.e. probability) and timing of those regulations, and use these evaluations to produce a reference, high, and low trajectory of non-CO_2 environmental compliance costs for their generation fleet;
c) Develop "Continued Use and Operation" studies (CUO) for each applicable generating resource which will test whether ratepayers could be better served through the retirement or curtailment of generating resources with environmental compliance obligations;
d) Use the results of the CUO studies to inform both the IRP "core case" selection and preferred scenario selection; and
e) Provide a revised analysis as an update to the 2011 IRP, instead of considering these improvements in future IRPs. This last is critical given the timely nature of this IRP, current environmental obligations, and substantial company investments.

To be clear, the issue before the Commission, as addressed in these comments, does not concern specific error within the IRP; rather the central issue concerns egregious and repeated omission of critical data and analyses.

II. Mounting Environmental Costs for PacifiCorp's Coal Fleet

The U.S. coal fleet is facing mounting costs to comply with federal environmental regulations designed to protect human health and the environment. PacifiCorp is not immune to these costs. Indeed, according to documents filed with the Wyoming Department of Environmental Quality, "from 2005 through 2010 PacifiCorp has spent more than $1.2 billion in capital dollars [to reduce emissions at its existing coal-fueled generation units.]" (See Exhibit 2.) In 2011, PacifiCorp requested double-digit rate increases in Wyoming and Utah, a large fraction of which can be directly attributed to these mounting costs.

These costs will continue to impact PacifiCorp's fleet for years to come. According to the company:

> *It is anticipated that the total costs for all projects that have been committed to will exceed $2.7 billion by the end of 2022. The total costs (which include capital, O&M and other costs) that will have been incurred by customers to pay for these pollution control projects during the period 2005 through 2023, are expected to exceed $4.2 billion, and by 2030 the annual costs to customers for these projects will have reached $360 million per year.* (Id.)

These costs are not simply small incremental improvements to maintain the company's existing units, rather they are significant capital improvements which rival the net value of the coal plants they are meant to control. According to Senior Vice President of MEHC, Cathy Woollums:

> *PacifiCorp's fossil steam generation units currently have a cumulative net value (after depreciation) of approximately $3.38 billion. Just compare that current value – $3.38 billion – to the estimated $1.3 billion in additional environmental control project capital costs PacifiCorp will spend between now and 2022, and that gives you a relative sense of the cost of these emissions control devices to our customers.* (See Exhibit 3 Testimony of Cathy S. Woollums. Senior Vice President and Chief Environmental Counsel,

MidAmerican Energy Holdings Company, Testimony to U.S. Senate Committee on Environment and Public Works, June 15, 2011.)

Given these tremendous costs to customers, and the implications for the economic condition of the company's coal fleet, the company is responsible for fully describing these costs in its central planning document. Yet there is no mention that the company has current compliance obligations, much less future costs, in the 2011 IRP or its appendices.

III. Cleaning up the Coal Fleet

The Environmental Protection Agency ("EPA") has promulgated and proposed a series of rules that will directly affect the company's coal fleet. There are three categories of non-greenhouse gas rules that aim to curb air pollutant emissions:

- The ongoing EPA action on state **Regional Haze rules** ("BART"), designed to improve visibility in national parks and other Class 1 public lands;
- The proposed **air toxics rule** for utility steam generating units ("MACT"), designed to protect human health by reducing emissions of hazardous air pollutants (HAPs) and mercury (Hg) from oil and coal-burning units; and,
- The proposed strengthening of **National Ambient Air Quality Standards** (NAAQS) on **ozone** (O_3) **sulfur dioxide** (SO_2), **particulates** ($PM_{2.5}$), and **nitrogen dioxide** (NO_2) designed to protect human health, reduce premature mortality, and reduce environmental harms from emissions.

There are two sets of Clean Water Act rules proposed and expected that would impact the PacifiCorp fleet:

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

Finally EPA will issue a final rule regulating the disposal and storage of **coal combustion residuals** (CCR) including ash and other wastes to prevent toxic releases into ground and surface waters.

These environmental compliance obligations have a significant impact on the operation and economics of the coal fleet, and should play a significant role in planning. Several studies, released by major research and investment organizations, have indicated that numerous plants in the U.S. coal fleet could face retirement in the face of high environmental obligations. The North American Reliability Corporation (NERC) published a study on the impact of emerging EPA rules and regulations[3] at the end of 2010 predicting 6-25 GW of economic retirements given strict EPA regulations. The Brattle Group followed shortly after with a similar study[4] estimating 50-66 GW of retirements by 2020. Other financial sector assessments by Credit Suisse[5] and Bernstein Research[6] confirmed these findings with similar retirement expectations. A January, 2011 study of coal plants in the Western Electric Coordinating Council (WECC) found that, under a strict environmental control scenario, a full half of PacifiCorp's coal units would fall into the bottom 25% of least economic coal units in the WECC region.[7]

These studies, which estimated that the worst performing and most polluting coal plants in the country would retire under economic pressure, uniformly suffer from a single flaw: each study assumed that utilities actually examine the forward-going costs of operation under a rational planning framework. In the most fundamental planning document, an IRP, PacifiCorp has failed to disclose the costs its coal fleet faces, and failed to meaningfully examine the economic merit of its generating fleet.[8]

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[3] 2010 Special Reliability Assessment Scenario. November 29, 2010. NERC

[4] Potential Coal Plant Retirements Under Emerging Environmental Regulations. December 8, 2010. The Brattle Group. *http://www.brattle.com/_documents/UploadLibrary/Upload898.pdf*

[5] Growth From Subtraction. September 23, 2010. Credit Suisse. Available online at *http://epw.senate.gov/public/index.cfm?FuseAction=Files.View&FileStore_id=b42de70d-b814-4410-831d-34b180846a19*

[6] U.S. Utilities: Coal-Fired Generation Is Squeezed in the Vice of EPA Regulation; Who Wins and Who Loses? October, 2010. Bernstein Research. Available online at *http://207.114.134.6/coal/oh/downloads/bernstein-report.pdf*

[7] WECC Coal Plant Retirement Based on Forward-Going Economic Merit. January 10, 2011. Western Grid Group for WECC. http://www.wecc.biz/committees/BOD/TEPPC/TAS/SWG/10March2011/Lists/Minutes/1/WECC%20Coal%20Retirement%20Criteria%201-10-2011%20Final.pdf

[8] It can be argued that the company has not only failed to examine the economic merit of their existing fleet by comprehensively reviewing all environmental costs, but have engaged in an incremental or piecemeal approach to new capital expenditures, layering them over time such that the total effect is not made clear.

IV. 2011 IRP Coal Plant Utilization Study

PacifiCorp's 2008 IRP Update, published in 2010, acknowledged that impending environmental regulations will significantly impact coal generators:

> *There are currently a multitude of environmental regulations which are in various stages of being promulgated… Each of these regulations will have an impact on the utility industry and could affect environmental control requirements, limit operations, change dispatch, and could ultimately determine the economic viability of PacifiCorp's generation assets. The US Environmental Protection Agency has undertaken a multi-pronged approach to minimize air, land, and water-based environmental impacts. Aside from potential greenhouse gas regulation, no single regulation is likely to materially impact the industry; however, in concert they are expected to have a significant impact – especially on the coal fueled generating units that supply approximately 50% of the nation's electricity.*

Despite the company's own dire forecast, the 2011 IRP failed to examine the "significant impact" that these regulations could have on the economic merit of the PacifiCorp coal fleet.

The 2011 IRP proposes a series of "coal plant utilization sensitivity" cases that are "intended to pave the way for future refinement of the modeling approach" but are "<u>not</u> intended to draw conclusions on the disposition of individual generating units or desirability of specific strategies to respond to future regulatory developments." (2011 IRP p. 180) To the best of our understanding, these five cases are the only circumstances in which the company assigns any dollar cost for compliance with just two of the rules listed above, the regional haze rule (colloquially, BART) and the proposed air toxics rule (MACT). In these marginalized sensitivities, the company does not estimate the costs for coal ash remediation, cooling water intake or effluent mitigation, or any of the expected NAAQS.[9]

Indeed, even the company's 2011 IRP interpretation of federal regional haze rule requirements is fraught with errors and omissions. For example, there is evidence that the EPA will not accept Utah or Wyoming's regional haze plans, and will require

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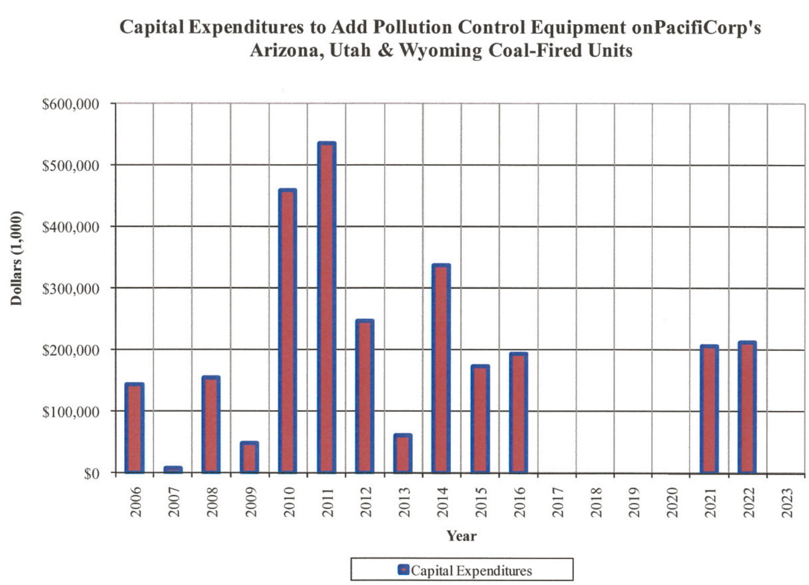
[9] Stakeholder phone call with the PacifiCorp IRP team confirmed that the costs in the 2011 IRP are similar, if not identical, to those in the Emissions Reduction Plan, presumably the same as filed in Wyoming and attached as **Exhibit A**.

additional costly selective catalytic reduction (SCR) systems on more of PacifiCorp's units. Ms. Woollums testified to this costly potential in her Senate testimony:

> *Unfortunately, recent discussions with the Utah and Wyoming Departments of Environmental Quality suggest that EPA Region 8 believes it may be necessary, for purposes of Regional Haze BART requirements, to install another five SCR in Wyoming and four SCR in Utah, combined with the five planned installations, within a five-year time period—potentially requiring 14 SCR by 2017 and an additional $1.7 billion to $2 billion in costs.* (Exhibit 3 at p. 10)

A correctly executed "coal plant utilization" study would evaluate the relative economic merit of maintaining a coal plant facing environmental compliance versus retiring the plant and replacing the power with either market purchases or new generation, as required. In fact, the PacifiCorp modeling framework is well equipped to examine exactly this question by evaluating the system cost and financial risk associated with maintaining any given plant, or a cohort of plants, versus retiring them *before environmental compliance deadlines*. Retiring *after* compliance deadlines results in unnecessary capital expenditures and unfortunate stranded costs for non-useful environmental controls.

The largest environmental deadlines looming are the final EPA approved regional haze rules and requirement to meet toxic air emissions limits. Indeed, the company's emissions planning document [Exhibit 2] suggests that PacifiCorp will make most of its environmental investments prior to these deadlines (see figure below).



The 2011 IRP, however notes that "Coal units are not specified with a shut-down date; in other words, the units are assumed to operate past 2030 unless the model chooses a replacement. System Optimizer is allowed to select the gas plant betterment option for any year after 2016." This artificial date restriction prevents the model from allowing any plant to retire in order to avoid large capital expenditures, and commits essentially all of the expenses.[10]

Unfortunately, there are other problems too. For example, it is unclear if the company's model adds capital expenses to the remaining plant balance, which would further provide a disincentive to retire coal plants with new capital expenditures. Despite an advanced modeling framework, the company only allows coal plants to be replaced by a "gas betterment option" rather than by the same type of portfolio choices which are available for new capacity – there is no reason to believe that a coal plant cannot be replaced by a combination of gas, DSM, renewable energy, market purchases, and even underutilized capacity in other coal plants, a combination which would likely be less expensive than a one-to-one gas replacement.[11]

According to recent company testimony in both the Wyoming and Utah general rate cases, these sensitivities have been developed to simply test the system, and the company may consider their use in the next IRP cycle. However, this is unacceptable because most of the environmental costs will be realized or committed by the next IRP in 2013/2014. Thus, these costs must be rationally considered now, in the 2011 IRP.

In summary, the coal plant utilization sensitivities are insufficient because:

1. The sensitivities are excluded, *a priori*, from consideration in the base cases, marginalizing their utility and effectively committing the utility to another 2-3 years of major investments without the benefit of regulatory or intervener oversight;
2. The sensitivities knowingly underestimate the compliance obligations faced by the company, both rationalizing that unknown costs must be zero costs;

[10] Sierra Club confirmed this fact on a stakeholder call with PacifiCorp.

[11] It is unclear if the "gas betterment option" is a rebuild of the existing plant with gas infrastructure, a replacement of the boiler to handle natural gas, or a completely new and efficient gas combined cycle unit.

3. The sensitivities fail to account for the risks of compliance obligations beyond those envisioned by the company, such as the newly recognized requirement for additional SCR to meet federally approved regional haze rules;
4. The sensitivities limit the replacement option for any retiring plant to be an ill-defined "gas betterment", rather than a potentially lower cost portfolio; and,
5. The sensitivities, by design, cannot avoid the vast majority of environmental obligation costs, undermining their potential utility.

In failing to take the risk that these environmental obligations pose to the coal fleet seriously, the company risks undercutting the validity of other parts of the IRP as well. For example, a coal plant retirement might require additional capacity, change off-system sales patterns, and modify transmission requirements. New capacity might be located closer to load centers than existing coal generators, thereby freeing transmission constraints or requirements for expensive new transmission. The IRP should provide the opportunity to examine all of these ramifications.

V. Recommendations

As described here, the 2011 IRP failed to examine important costs facing the existing coal fleet; costs that could fundamentally change the face of PacifiCorp generation. It is unclear why the company chosen to sideline these considerations. When asked in the recent Utah rate case whether the company had used the 2008 or 2011 IRPs to test the cost effectiveness of environmental upgrades, the company responded:

> *No specific cost-effectiveness analyses of the environmental upgrades at issue in this docket were performed by the company or external parties as part of the 2008 or 2011 IRPs. Consistent with current state IRP guidelines, the company's IRP process and associated system planning models have focused on the economics and risks of acquiring future resources rather than potential investments connected with existing assets.*[12]

Clearly, the company's view that its IRP is only a structure for investigating "future resources" is a flawed understanding of the utility of an IRP. The company is charged with finding a least-cost solution to meet customer demand. Ignoring solutions

[12] Discovery Response to Sierra Club 3.1, Utah Docket 10-035-124

which might involve the retirement or replacement of an existing generating asset does nothing to benefit ratepayers, public health and the environment.

Therefore, Sierra Club recommends that the Commission not acknowledge the 2011 IRP until the company agrees to:

- Transparent environmental compliance planning;
- Unit-by-unit Continued Use and Operation studies; and,
- Re-evaluate the preferred scenario, including new transmission initiatives.

A. Transparent Environmental Compliance Planning

- At the time of the IRP submission, the company must evaluate and disclose all applicable existing, proposed, and reasonably foreseeable environmental regulations.
- The company should both describe how each regulation may impact each of its generating units, to the extent known; and describe the compliance options available to meet those obligations.
- The company should characterize the risk of any given proposed or foreseeable regulation being promulgated in such a way that it would substantively impact the company's generating units, and characterize the costs which could be faced under such a ruling (both capital and operational).
- The company should create a reference obligation cost trajectory for each unit, as well as a "strict" (high cost) case and a "less restrictive" (low cost) case.
- The company must make the control cost assumptions and engineering considerations available for review to all parties.

B. Continued Use and Operation Studies

- The company should develop "Continued Use and Operation" studies (CUO) for each applicable generating resource.
- The CUO studies should test the economic merit of continued use with environmental retrofits against the retirement and *optimized portfolio* replacement of each unit or cohort of units subject to substantial environmental obligations.
- The CUO studies should evaluate the risk of retirement under the reference obligation cost trajectory, and high and low cost cases.

- The CUO studies should effectively allow feasible replacements as of the first year of the IRP analysis, or the earliest substantive environmental compliance deadline.

C. Re-Evaluate Preferred Scenario

- The company should use the results of the CUO studies to inform both the IRP "core case" selection and preferred scenario selection.
- The company should re-evaluate the requirement for additional transmission initiatives (i.e. Gateway) given the results of the CUO studies.

Given the timely nature of this IRP, current environmental obligations, and substantial company investments, the company must provide a revised analysis as an update to the 2011 IRP, rather than implementing such improvements in a future IRP.

We are confident that the company has already commenced some of this work. For example it supplied rudimentary retirement studies in the Wyoming rate case docket that simply tested the company's first-level assumption of costs, without taking into account the reasonably expected full range of costs expected at each plant. (See Exhibit 4.) The studies were flawed because they came much too late, failed to reasonably take into account future regulations, and other things, they nonetheless can serve as a starting point for a Boardman powerplant-type analysis for the Commission and parties.

IV. Conclusion

Sierra Club is encouraged that on August 19th the company committed to supplying individual coal unit analyses. We assume this additional analysis will include a continued use study for each unit which will evaluate costs and risks, rather than a simple test of company short-term incremental assumptions. Sierra Club looks forward to commenting on the IRP once the company provides the analyses necessary for the company itself, the regulators and the public to evaluate the enormous costs facing its coal-fired units.

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Dated: August 25, 2011

Respectfully submitted,

/s/

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Exhibit 1

SIERRA CLUB
FOUNDED 1892

To: PacifiCorp 2011 Integrated Resource Plan Team
From: Sierra Club
Date: March 8, 2011
Re: **Comments on Public Input Meetings 6 & 7, Jan 31 and Feb 23, 2011**

The Sierra Club respectfully submits comments, questions and data requests based on the presentations at the 6th and 7th Public Input Meetings (PIM) of PacifiCorp's 2011 Integrated Resource Plan (IRP), taking place on January 31st, 2011 and February 23rd, 2011, respectively.

The most significant comments fall under three umbrella categories, namely that

1. the public process, through which PacifiCorp is intended to share assumptions and respond substantively to public concerns, failed to provide transparency, presenting already enacted Company positions rather than seeking real input;

2. the IRP process, and IRP materials to date, fails to consider current and impending EPA regulations designed to improve public health and environmental impacts from the existing coal fleet;

3. in failing to analyze or examine a diversity of portfolios, the IRP created artificial barriers for finding a least cost portfolio, exposing PacifiCorp's ratepayers to unnecessary regulatory and financial risk;

4. the Company undermines any productive forward-planning by relying extensively on either ambiguous market capacity ("front office transactions") or undefined "growth resources", minimizing the value of the IRP.

While there are specific technical comments and recommendations based on materials presented in the two meetings, these questions are largely overshadowed by the concerns posed above. The following sections provide more detail and specific comments.

Public Process

The public input meeting process has consistently

(a) failed to deliver key materials to stakeholders until after substantive, and ostensibly irreversible, decisions have been made by the company (including resource cost assumptions, demand-side management (DSM) assumptions, portfolio definitions, model run outputs for most sensitivities, and preferred scenario choices, amongst others); and

(b) dismissed legitimate public concerns regarding Company assumptions on demand-side and supply-side options.

In the months preceding the choice of the "Preferred Portfolio Selection" (February 14 2011), requests from multiple parties were made to evaluate renewable energy assumptions, such as wind and solar PV costs, as well as DSM availability and cost assumptions, and mechanisms which would be used to determine "optimized" coal plant retirements in several run definitions.

As of the 7th and final PIM on February 23rd, 2011, the Company had not made available DSM cost or availability assumptions, or the assumptions which would be used to determine the "optimized" coal plant retirement schedule. Repeated requests by multiple PIM participants to evaluate wind costs, capacity factors, and availability assumptions garnered responses indicating that the Company was not open to altering these assumptions. Requested information was not made available during the input process.

Critical components of portfolio evaluation include changes in capacity (for reliability purposes), energy (for meeting demand from owned resources versus market purchases), bulk power and capital costs (to evaluate ratepayer impacts), as well as water use and emissions (to evaluate external environmental and economic impacts).

Despite repeated requests for all of these essential components, all of which are fundamental model outputs used by the Company for portfolio evaluation, public participants were only granted access to incremental capacity additions and 20-year net present value costs, largely meaningless without additional information (i.e. cost streams, near-term and long-term risk, or cost components such as fuel, emissions, and capital expenditures).

On January 28th, 2011, the Company presented results from only 19 "core" cases, of 51 potential resource portfolio runs, and asked public participants to evaluate these results in absence of the remaining 32 cases. After promising during the PIM meeting that results from these additional runs would be made available prior to the next meeting, on February 23rd, 2011, the Company selected a modified version of a core case as its preferred scenario. As discussed in the next section below, the core cases are essentially a cohort of equivalent runs for all practical purposes; therefore, there is little value in commenting on either the outcomes of the core cases or the preferred scenario in particular. With a notable, and potentially deliberate, lack of information, the PIM process disenfranchises public participants and erodes goodwill.

<u>Specific Comments:</u>

1. PacifiCorp should make DSM assumptions available for public inquiry, including costs and availability;

2. PacifiCorp should show and evaluate capacity, energy, emissions, and cost streams for all resources in <u>all</u> scenarios, not just incremental capacity and net present value for a pre-selected subset of scenarios;

3. PacifiCorp should construct an effective mechanism to allow substantive public input and transparency to "public input meetings" and "stakeholder process", rather than disregarding public input and concerns.[1]

Evaluate Existing Resources and Impending Regulatory Requirements

The existing coal fleet throughout the US faces a series of regulatory challenges over the next few years. EPA regulations designed to protect public health and environmental resources will tighten toxic gas, particulate, and mercury emissions standards, require cooling towers on power plants with excessive water use and thermal effluent, regulate the disposal and use of coal ash, and require greenhouse gas emissions reductions at either the state or national level. To comply with these rulings and reduce the external costs of combusting coal, many generating units in the US fleet will either have to retrofit with environmental controls, or choose to retire if it the economically expedient choice. These questions are faced by utilities and merchant operators around the US, and are not unique to the Intermountain West. However, PacifiCorp is unique amongst large coal-fired utilities in delaying serious evaluation of the merit of its existing coal fleet.

In recognition that PacifiCorp's ratepayers may be negatively impacted by a lack of forward planning at the utility, PacifiCorp agreed to run a series of buildout scenarios recognizing "optimized" coal plant retirements in the face of impending regulations. However, even as the Company settled on a "preferred" plan, these critical decisions were never made public.

Indeed, out of 51 resource plans, 32 cases are not available for either public scrutiny or selection as part of the preferred resource selection criteria.[2] Failing to account for impending regulations in consideration of future build out options places PacifiCorp ratepayers at unnecessary risk.

Specific Comments

1. PacifiCorp should include, as part of the IRP and build-out plan, a specific strategy to meet current and impending EPA regulations governing the existing coal fleet;

2. PacifiCorp should make criteria for selecting "optimized" coal plant retirements available for public scrutiny;

3. PacifiCorp should evaluate all (51) runs, including sensitivities, in net present value calculations and evaluation criteria for preferred resource plan;

Portfolio Diversity

The 19 core cases which were presented and from which a preferred scenario was selected offer a marked lack of diversity from which to make informed decisions; indeed, the analytical process

[1] There are numerous valid mechanisms for achieving a valid, inclusive, and transparent stakeholder process, many components of which have been violated in this process. However, because there multiple options, we withhold specific recommendations.

[2] The 32 cases are excluded with the explanation that "sensitivity cases serve to evaluate the impact of alternate planning assumptions on resource selection, fulfill resource study requirements mandated by the company's state utility commissions, and support development of the Company's IRP action plan."

chosen by PacifiCorp virtually guaranteed a specific outcome, undermining the purpose of an IRP process and exposing ratepayers to unnecessary risk.

The 19 core cases examine only new incremental additions to the PacifiCorp fleet, and are excluded, *a priori*, from replacing or retiring any elements of the existing fleet. Having locked in the existing fleet, the new capacity additions available for selection are multiple types of gas-fired turbines, DSM, wind, geothermal, storage, solar, and nuclear power. Within this selection grid, the range of potential answers is highly constrained:

- the levelized cost of energy from solar, storage, and nuclear, as assumed by the Company, are all restrictively high (between $130 and $250/MWh);

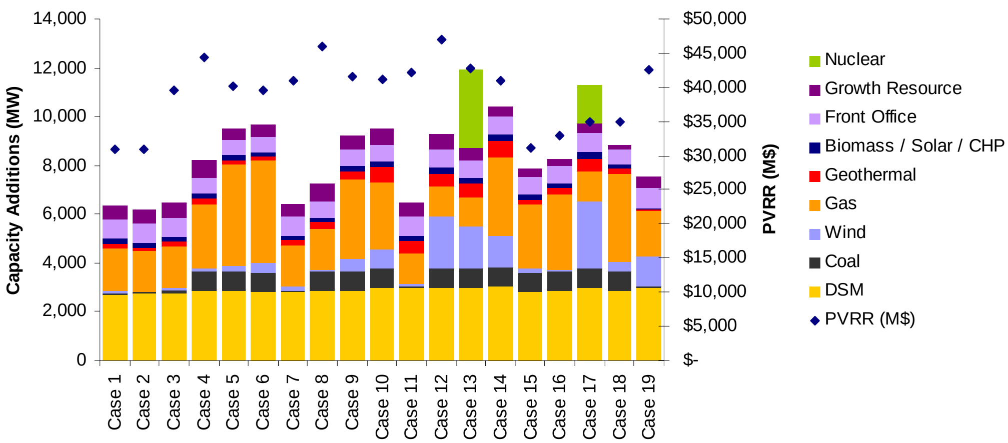
- the costs for DSM were never made public, but are assumed to almost always be cost-competitive;

- geothermal availability is restricted by company assumptions;

- the costs for wind and natural gas are nearly equivalent, depending on case-specific forecasts for natural gas and CO_2 prices, but wind is assumed to have a far lower capacity value.

Therefore, we would expect that, given no change in the existing resource profile, that the future load gaps for PacifiCorp will be primarily filled with DSM (when assumed available), and a combination of wind and gas-fired resources, with an emphasis on gas due to the low capacity factors for wind.

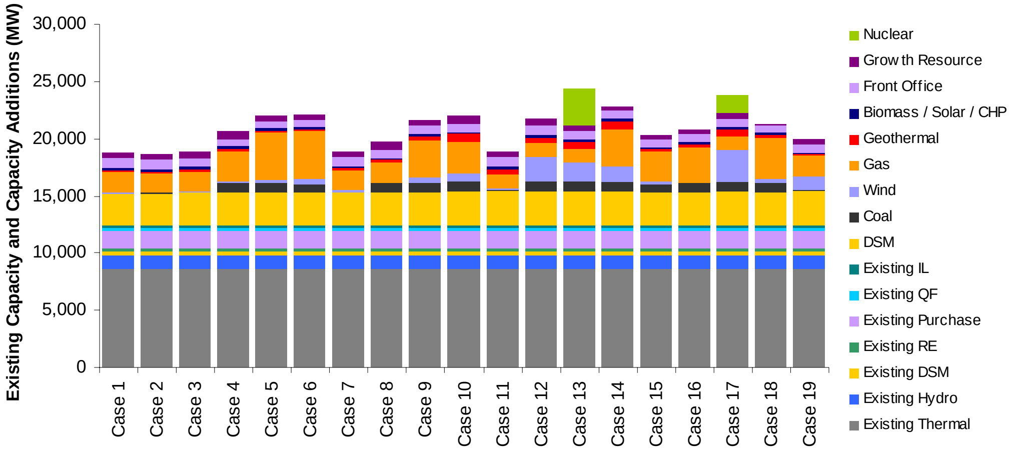
The 20-yr capacity additions, as shown in the "Portfolio Development Results" presentation from January 28, 2011, are shown in the figure below.



Indeed, the portfolios presented to stakeholders show extremely consistent results: a fixed amount of DSM made available in each core scenario (over 20 years, ~1,300 - ~1,500 MW in the

East and ~1,250 MW in the West),[3] little geothermal in near-term years, gas to meet capacity requirements in the near term, and variable amounts of wind in the longer-term. Most of the coal and nuclear additions only occur in the model in year 2030, neither substantively impacting model results nor the net present value.[4]The results are convoluted by the ambiguous "front office transactions" and "growth resources", which have undefined cost, energy implications, or emissions.

What these development scenarios do *not* show are the unchanging portfolios underlying the new capacity additions, now added into in the figure below.



By having left these resources intact in the only considered scenario runs, and not evaluating the forward-going costs of operating existing units on an economic basis, the Company needlessly exposes ratepayers to unnecessary financial and regulatory risk, such as required improved environmental controls on existing coal plants, a price on greenhouse gas emissions, and rising coal prices, all of which expose ratepayers in the existing fleet.

Finally, the Company has selected a preferred portfolio on the basis of a long-term net present value (PVRR) and a stochastic measure of the risk in PVRR. This PVRR is highly dependent on the timing of specific resources (such new gas combined cycle being built in 2015 or 2016), rather than the very real risks of high and low gas prices, or high or low CO_2 prices, or equally important, yet undervalued, external impacts of generation. It is critical that the company evaluate the risks present to the entire fleet (not just incremental capacity) by including a wider range of portfolios, and evaluating in the external environmental and economic costs of the scenarios.

Specific Comments

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[3] A fixed amount of DSM in each case suggests that the cost of DSM is extremely competitive in this analysis, and is only restricted by availability.

[4] It can be argued, that from an analytical standpoint, if nuclear capacity is not selected until 2030, and CCS is restricted in the model until 2030, that these options should be significantly discounted as unlikely portfolio options; to the extent that these resources are important players in the IRP, they should be evaluated as serious options, but a presence only in the last year of analysis, 2030, is an unnecessary convulsion rather than illustrative.

4. PacifiCorp should include all (51) runs, including sensitivities, in net present value calculations and evaluation criteria for preferred resource plan;

5. PacifiCorp should test alternate DSM availability criteria, assuming economic potential (i.e. utility test cost-benefit) in full resource territory;

6. PacifiCorp should provide and evaluate information on the external environmental and economic consequences of given portfolios.

Front Office Transactions and Growth Resources

In 2013, some build-outs require over 1,400 MW of Front Office Transactions (FOT), maintaining similar levels through 2020. These transactions appear to account for over 10% of PacifiCorp's capacity requirements in near term years; however, the price, risk profile, and emissions of these transactions are not made clear for the purposes of building the Portfolio Development Cases.

In the October 5th (2010) Portfolio Development Case definitions, it is stated that "the coal plant CO_2 emissions rate of 205 lbs/MMBtu is applied to balancing spot market transactions and firm market purchases (front office transactions) at the start of CO2 regulations." However there is little indication that the amount of FOT chosen in the scenarios reflect this CO_2 burden. The amount of FOT chosen, for example, does not significantly differ between Development cases based on high or low CO_2 prices. Ultimately the question needs to be addressed as to what resources PacifiCorp believes are available for firm transaction purchases through 2020, and how short and long-term contract prices are reflected in the risks for each scenario.

In later years, the Development cases, and indeed, the Preferred Scenario, rely heavily on "growth resources", which, like FOT are undefined for the public in price, risk, or emissions. It was suggested in the 7th PIM meeting that PacifiCorp seeks public input on the nature of these resources as gas, wind, or other renewable or thermal resources. We strongly recommend that these resources, in both the near and long-term should be regarded as capacity from renewable energy, demand response programs, and, if required, additional gas capacity. Increasing the portfolio use of wind capacity will reduce long-term fuel price and emissions risks.

Specific Comments

1. PacifiCorp should define a source, likely cost, and emissions profile for front office transactions and growth resources

2. PacifiCorp should model an increasing fraction of FOT and growth resources as wind and demand-side management.

SIERRA CLUB
FOUNDED 1892

To: PacifiCorp 2011 Integrated Resource Plan Team
From: Sierra Club
Date: March 24, 2011
Re: **Comments on Draft 2011 Integrated Resource Plan**

The Sierra Club respectfully submits comments based on the Draft 2011 Integrated Resource Plan, released March 7, 2011. As with our previous letters, these comments were prepared with the expert assistance of Synapse Energy Economics. Due to a compressed comment period, the comments here focus on one key provision, the incorrectly modeled "coal utilization" sensitivities, and resulting ratepayer exposure to inappropriate costs.

The Company should completely model coal plant utilization options, including retirement, for the purposes of determining a least cost solution for ratepayers. The determination of the most economically efficient choice requires a comprehensive and detailed assessment of the costs associated with a variety of options; limiting the scope of these options imposes a bias on the results, and may result in an unfair burden on consumers.

In the IRP, PacifiCorp has chosen to model a limited number of "coal plant utilization" sensitivities, which "<u>are not intended to draw conclusions</u> on the disposition of individual generating units or desirability of specific strategies to respond to future regulatory developments." (p151). By restricting the analysis from looking at economically favorable results, the Company unfairly and inappropriately skews the results of this IRP.

Further, in the limited cases in which existing coal plant utilization is examined, the company severely biases results by (a) failing to allow *any* environmental upgrade costs to be avoidable through coal plant retirement and (b) failing to take into account all reasonably expected environmental control costs.

To capture the avoided costs associated with environmental compliance upgrades, the Company should, in a modeling framework which includes sensitivities on natural gas and greenhouse gas prices:

1. Show <u>all</u> expected environmental compliance costs over the course of a reasonable analysis period (2011 – 2030);

2. Allow units to be retired or replaced as an environmental compliance mechanism, and evaluate the relative costs of these plans;

3. Allow all cost-effective resources, including efficiency, renewable energy, and gas resources to be utilized as "replacement" technologies for retiring units;

4. Evaluate costs to ratepayers and the company with and without full cost recovery for remaining plant balances on retiring units;

5. Remove contrived penalties associated with "coal contract liquidated damages".

The following points illustrate the significant shortcomings of the modeling exercise.

a) The IRP omits relevant information regarding the "incremental" environmental control costs for existing coal units that are considered in the model. Information on the estimated required environmental controls and the costs of these controls are important assumptions and factors underlying the model. The Company has steadfastly refused to discuss the exact EPA, state, and regional rules which it believes will impact its existing fleet, noting only the regulations which could be applicable, but not which ones are assumed to apply. During a stakeholder conference (March 22, 2010), requests for this information were turned down on the basis of confidentiality; however, the Company confirmed that the assumptions in the model were consistent with a November 2010 document entitled "PacifiCorp Emissions Reductions Plan", filed as a Technical Support Document (TSD) for the Wyoming Regional Haze 309(g) State Implementation Plan (SIP, January 7, 2011). [1] The reduction plan **estimates $4.2 billion in capital and operational expenses required to comply *only* with BART rules.** The plan states:

> "It is anticipated that the total costs for all projects that have been committed to will exceed $2.7 billion by the end of 2022. The total costs (which include capital, O&M and other costs) that will have been incurred by customers to pay for these pollution control projects during the period 2005 through 2023, are expected to exceed $4.2 billion, and by 2023 the annual costs to customers for these projects will have reached $360 million per year." - Reduction Plan, p1.

The Reduction Plan further notes that "…the rate increases for PacifiCorp customers associated with PacifiCorp's emission reduction strategy alone will be significant."

b) PacifiCorp has not estimated the costs of compliance with mercury or HAP MACT provisions. The Draft IRP states that:

> "The Company does, however, anticipate that additional state and federal environmental laws and regulations will necessitate further investment in pollution control and environmental compliance projects, as well as further evaluation of unit specific operational/dispatch impacts, especially with respect to pending greenhouse gas regulations and hazardous air pollutants maximum achievable control technology (HAPs MACT) requirements."

However, assuming that the modeling assumptions are consistent with the Reduction Plan, we can surmise that the model does not include mercury emissions and hazardous air pollutants (HAP) provisions under EPA's 2011 proposed Maximum Achievable Control Technologies (MACT) ruling. In the Reduction Plan, the Company notes that

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[1] Exhibit A – PacifiCorp's Emissions Reduction Plan. November, 2, 2010. Available online at http://deq.state.wy.us/aqd/308%20SIP/PacifiCorp%20Emissions%20Reductions%20Plan_11-2-10_Chap.%206.pdf

> "These cost increases do not include other costs expected to be incurred in the future to meet further emission reduction measures or address other environmental initiatives, including but not limited to: … 2. The addition of mercury control equipment under the requirements of the upcoming mercury MACT provisions." - Reduction Plan, p7.

Potential additional capital and operating expenditures to comply with these provisions could include new fabric filter baghouses, activated carbon injection (ACI), and selective catalytic reduction (SCR) for MACT compliance.

c) PacifiCorp has not estimated the costs of compliance with expected EPA rules on CCR. Both the Draft IRP and Reduction Plan do not estimate the anticipated costs of compliance with expected an EPA ruling on the proper disposal and management of coal combustion residuals (CCR) under the Resource Conservation and Recovery Act (RCRA). The Draft IRP states that:

> "Costs that have not been incorporated include potential plant regulatory compliance costs associated with the EPA's proposed rules for coal combustion residuals (CCR) and cooling water intake structures…"

The Reduction Plan notes that:

> "These cost increases do not include… 5. Regulations associated with coal combustion byproducts… It is anticipated that <u>the requirements under the final rule will impose significant costs</u> on PacifiCorp's coal-fueled facilities within the next eight to ten years." - Reduction Plan, p7.

d) PacifiCorp has not estimated the costs of compliance with expected EPA rules on cooling water intake structures. As stated above, the Draft IRP (and Reduction Plan) specifically excludes the anticipated costs of compliance with an expected EPA ruling on the use of cooling water intake structures (particularly once-through cooling) under the Clean Water Act (CWA) §316(b). The Company bears significant risk of compliance obligations at the once-through cooled Dave Johnson plant in Wyoming, as well as the open-water cooling pond structure at Cholla, in Arizona.

e) PacifiCorp has failed to appropriately estimate the costs and benefits of using coal plant retirement as an environmental compliance mechanism. A rational, forward-looking planning exercise, such as an IRP, should logically consider environmental compliance costs as part of the decision of if a plant should continue operations. The company, however, creates a model structure in which environmental <u>compliance costs cannot be avoided</u> through the retirement of coal units.

1. The Company has confirmed (in a March 22, 2011 stakeholder call) that the costs associated with these utilization runs are those set forth in the 2010 Reduction Plan. In keeping with EPA compliance deadlines, these costs are almost exclusively incurred prior to the year 2016 (see Reduction Plan, p5; Capital Expenditures graphic)

2. The model used by PacifiCorp specifically prohibits the retirement of any coal unit prior to the year 2016.[2]

3. The company has confirmed, in the same stakeholder call, that the environmental retrofit costs are unavoidable, i.e. that ratepayers will be compelled to pay for the retrofits regardless of if a lower cost plan would have retired the plant.

We conclude that PacifiCorp has excluded important potential least-cost plans, thereby dramatically increasing ratepayer exposure to regulatory risk, by failing to appropriately model both the existing fleet in addition to new fleet capacity additions.

[2] 2011 Draft IRP. p152. "System Optimizer is allowed to select the gas plant betterment option for any year after 2016."

Exhibit 2

November 2, 2010

Exhibit A

PacifiCorp's Emissions Reductions Plan

In connection with its Best Available Retrofit Technology ("BART") determinations and its other regional haze planning activities, the Wyoming Department of Environmental Quality, Air Quality Division ("AQD") asked PacifiCorp to provide additional information about its overall emission reduction plans through 2023. The purpose is to more fully address the costs of compliance on both a unit and system-wide basis. PacifiCorp is committed to reduce emissions in a reasonable, systematic, economically sustainable and environmentally sound manner while meeting applicable legal requirements. These legal requirements include complying with the regional haze rules which encompass a national goal to achieve natural visibility conditions in Class 1 areas by 2064

Summary

PacifiCorp owns and operates 19 coal-fueled generating units in Utah and Wyoming, and owns 100% of Cholla Unit 4, which is a coal-fueled generating unit located in Arizona. PacifiCorp is in the process of implementing an emission reduction program that has reduced, and will continue to significantly reduce emissions at its existing coal-fueled generation units over the next several years. From 2005 through 2010 PacifiCorp has spent more than $1.2 billion in capital dollars. It is anticipated that the total costs for all projects that have been committed to will exceed $2.7 billion by the end of 2022. The total costs (which include capital, O&M and other costs) that will have been incurred by customers to pay for these pollution control projects during the period 2005 through 2023, are expected to exceed $4.2 billion, and by 2023 the annual costs to customers for these projects will have reached $360 million per year.

Environmental benefits, including visibility improvements will flow from these planned emission reductions. PacifiCorp believes that the emission reduction projects and their timing appropriately balance the need for emission reductions over time with the cost and other concerns of our customers, our state utility regulatory commissions, and other stakeholders. PacifiCorp believes this plan is complementary to and consistent with the state's BART and regional haze planning requirements, and that it is a reasonable approach to achieving emission reductions in Wyoming and other states.

PacifiCorp's Long-Term Emission Reduction Commitment

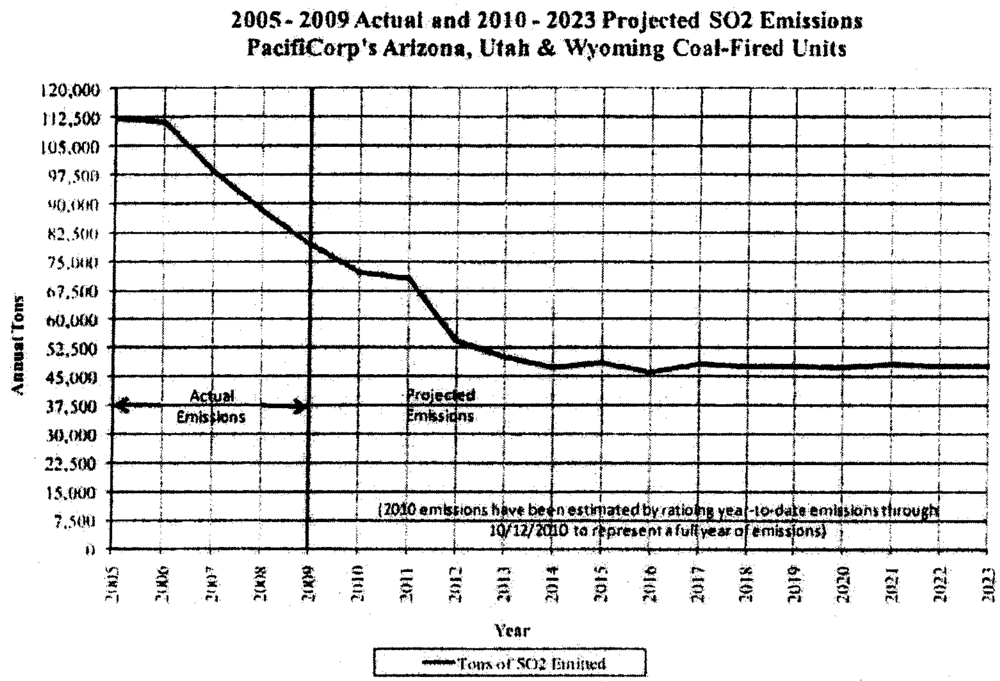
Table 1 below identifies the emission reduction projects and related construction schedules as currently included in PacifiCorp's reduction plan.

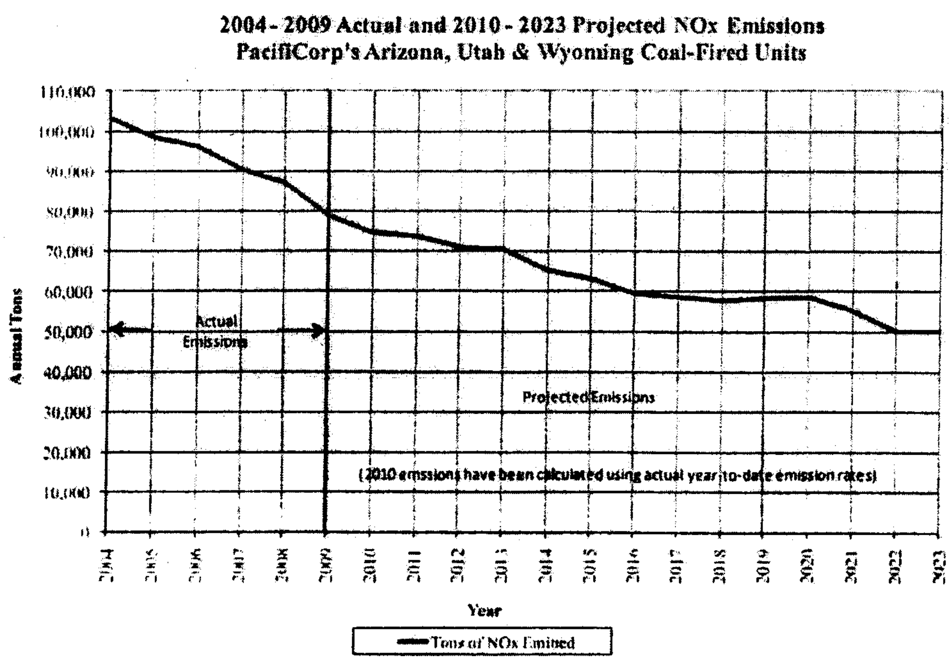
Table 1: Long-Term Reduction Plan

Plant Name	SO2 Scrubbers Installation - I Upgrades - U	Low NOx Burner Installations	Baghouse Installations	Status of SO2 / LNB / Baghouse Permitting	Selective Catalytic Reduction
Hunter 1	2014 - U	2014	2014	Permitted	
Hunter 2	2011 - U	2011	2011	Under Construction	
Hunter 3	Existing	2008	Existing	Completed	
Huntington 1	2010 - U	2010	2010	Under Construction	
Huntington 2	2007 - I	2007	2007	Completed	
Dave Johnston 3	2010 - I	2010	2010	Completed	
Dave Johnston 4	2012 - I	2009	2012	Under Construction	
Jim Bridger 1	2010 - U	2010		Completed	2022
Jim Bridger 2	2009 - U	2005		Completed	2021
Jim Bridger 3	2011 - U	2007		Permitted	2015
Jim Bridger 4	2008 - U	2008		Completed	2016
Naughton 1	2012 - I	2012		Under Construction	
Naughton 2	2011 - I	2011		Under Construction	
Naughton 3	2014 - U	2014	2014	Baghouse Permitted	2014
Wyodak	2011 - U	2011	2011	Under Construction	
Cholla 4	2008 - U	2008	2008	Completed	

The following charts represent the reductions in emissions that will occur at units owned by PacifiCorp in Utah, Wyoming and Arizona[1]. It is significant to note that permitting has been completed for all but the SCR projects; permitting for the SCR projects will be completed as needed in advance of project construction. The emission estimates shown in these charts have been calculated using projected unit generation and heat rate data in conjunction with each unit's permitted emission rate. In those cases were the units do not have emissions controls the estimates have been based on projections of the future coal quality. All projections used are from PacifiCorp's ten-year business plan. Actual future emissions will be less than those estimated in these charts since the units will operate below their permitted rates.

[1] PacifiCorp is also a joint owner of coal-fueled facilities in Colorado and Montana that are subject to regional haze planning requirements and for which PacifiCorp will incur associated costs of emissions controls.


2005 - 2009 Actual and 2010 - 2023 Projected SO2 Emissions
PacifiCorp's Arizona, Utah & Wyoming Coal-Fired Units
Annual Tons
Actual Emissions
Projected Emissions
(2010 emissions have been estimated by rationg year-to-date emissions through 10/12/2010 to represent a full year of emissions)
Year
Tons of SO2 Emitted


2004 - 2009 Actual and 2010 - 2023 Projected NOx Emissions
PacifiCorp's Arizona, Utah & Wyoming Coal-Fired Units
Annual Tons
Actual Emissions
Projected Emissions
(2010 emssions have been calculated using actual year-to-date emission rates)
Year
Tons of NOx Emitted

Project Installation Schedule

Emission reduction projects of the number and size described above take many years to engineer, plan and build. When considering a fleet the size of PacifiCorp's, there is a practical limitation on available construction resources and labor. There is also a limit on the number of units that may be taken out of service at any given time as well as the level of construction activities that can be supported by the local infrastructures at and around these facilities. Such limitations directly impact both the overall timing of these projects as well as their timing in relation to each other. Additional cost and construction timing limitations include the loss of large generating resources during some parts of construction and the associated impact on the reliability of PacifiCorp's electrical system during these extended outages. In other words, it is not practical, and it is unduly expensive, to expect to build these emission reduction projects all at once or even in a compressed time period. The pressure on emission reduction equipment and skilled labor is likely to be exacerbated by the significant emission reduction requirements necessitated by the Environmental Protection Agency's Clean Air Transport Rule which requires emission reductions in 31 Eastern states and the District of Columbia beginning in 2012 and 2014. The Environmental Protection Agency has indicated that a second Transport Rule is likely to be issued in 2011, requiring additional reductions in the Eastern U.S. beyond those effective in 2014. The balancing of these concerns is reflected in the timing of PacifiCorp's emission reduction commitments.

Priority of Emission Reductions

PacifiCorp's initial focus has been on installing controls to reduce SO_2 emissions which are the most significant contributors to regional haze in the western US. In addition, PacifiCorp continues to rely on the rapid installation of low NO_x burners to significantly reduce NOx emissions. Also, the installation of five SCRs (or similar NOx-reducing technologies) will be completed by 2023 and reduce NOx emissions even further. PacifiCorp's commitment also includes the installation of several baghouses to control particulate matter emissions. For those units which utilize dry scrubbers, baghouses have the added benefit of improving SO2 removal. Baghouses also significantly reduce mercury emissions.

In addition to reducing emissions at existing facilities, PacifiCorp has avoided increasing emissions by adding more than 1,400 megawatts of renewable generation between 2006 and 2010. In order to meet growing demand for electricity, PacifiCorp added non-emitting wind generation to its portfolio at a cost of over $2 billion and has dismissed further consideration of a new coal-fueled unit.

Emission Reductions and BART Deadlines

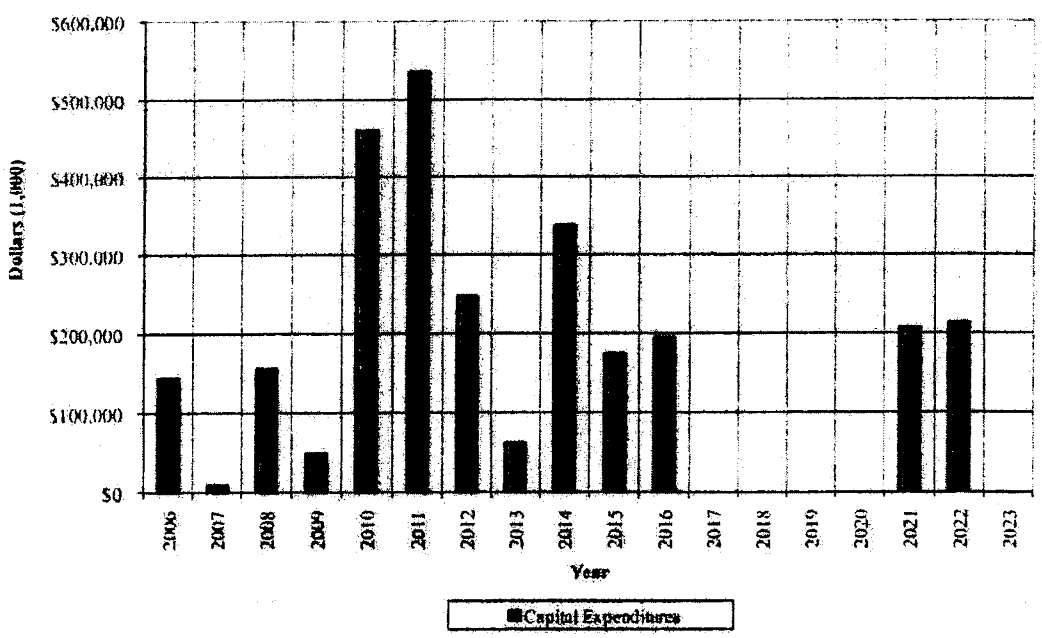
As depicted in the table and charts above, PacifiCorp began implementing its emission reduction commitments in 2005. This was well ahead of the emission reduction timelines under the regional haze rules which require BART to be installed no later than five years following approval of the applicable Regional Haze SIP. This also provides a graphic demonstration of the construction schedule and other limitations described above, as PacifiCorp was required to begin installing emission control projects at some units earlier in order to complete projects at other units within the five years after SIP approval. The table above demonstrates that most of the projects to be built between 2010 and 2014, likewise, will be installed in advance of the required completion date under BART requirements.

Customer Impacts

The following charts identify the timing and magnitude of the capital and O&M expenses that will be incurred due to the projects identified in Table 1. The charts identify:

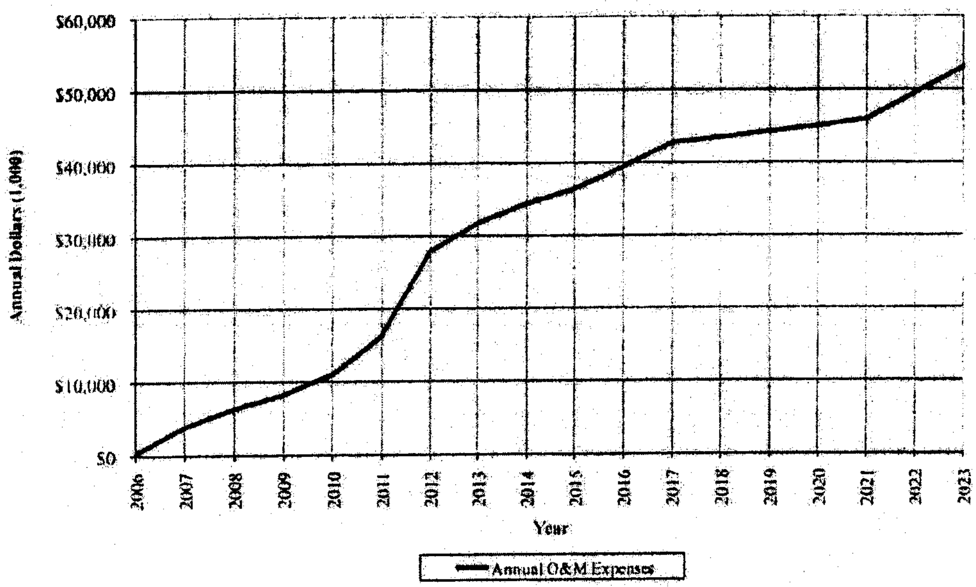
1. The timing and magnitude of the capital costs.
2. The O&M expenses that will be incurred due to these projects.
3. The expected annual costs[2] through 2023 that customers will be incur as a result of these specific pollution control projects.

Capital Expenditures to Add Pollution Control Equipment onPacifiCorp's Arizona, Utah & Wyoming Coal-Fired Units

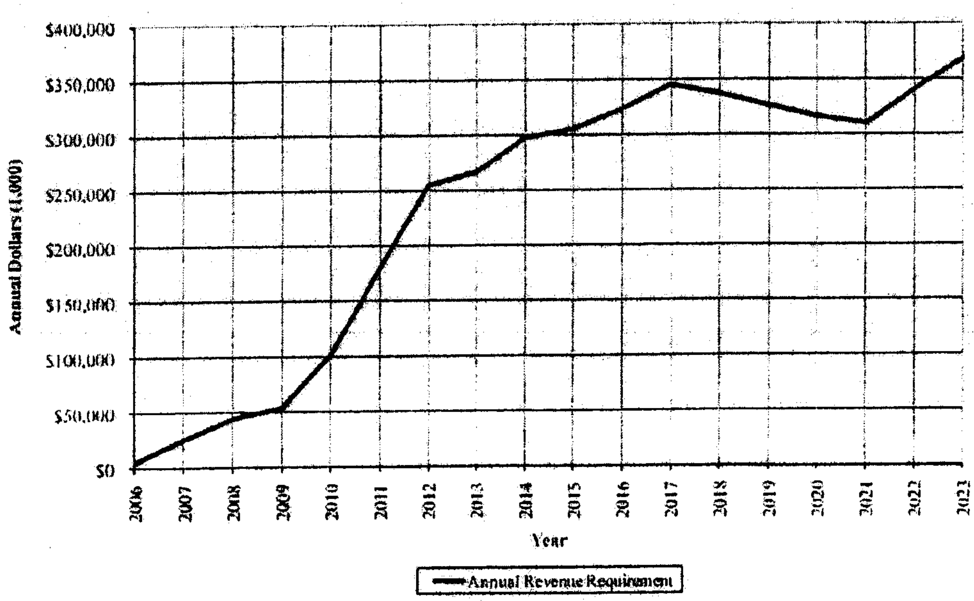


[2] PacifiCorp has made every attempt to provide an accurate estimate of the anticipated increase in annual revenue requirements that will ultimately be translated to increases in customers' electricity rates. However, there are several variables such as interest rates, inflation rates, discount rates, depreciation lives, and final construction costs and operating and maintenance expenses that will be considered at the time these projects actually go into rate base and will influence the actual revenue requirements associated with these capital projects.

Increases In O&M Expenses Due to Additional Pollution Control Equipment on Arizona, Utah & Wyoming Coal-Fired Units



Annual Increase to Customers Due to Additional Pollution Control Equipment on Arizona, Utah & Wyoming Coal-Fired Units



As can be seen from the previous charts, the rate increases for PacifiCorp customers associated with PacifiCorp's emission reduction strategy alone will be significant. In the event that PacifiCorp is required to accelerate or add to the planned emission reduction projects, the cost impacts to our customers can be expected to increase incrementally, particularly as plant outage schedules are extended and the need for skilled labor and material increases in the near term.

Of particular note, the projected costs reflect only the installation of the noted emission reduction equipment. These cost increases do not include other costs expected to be incurred in the future to meet further emission reduction measures or address other environmental initiatives, including but not limited to (see Attachment 1):

1. Implementation of Utah's Long Term Strategy for meeting regional haze requirements during the 2018-2023 time period.

2. The addition of mercury control equipment under the requirements of the upcoming mercury MACT provisions. PacifiCorp estimates that $68 million in capital will be incurred by 2015 and annual operating expenses will increase by $21million per year to comply with mercury reduction requirements. In addition, anticipated regulation to address non-mercury hazardous air pollutant (HAPs) emissions may require significant additional reductions of SO_2, as a precursor to sulfuric acid mist, from non-BART units that currently do not have specific controls to reduce SO_2 emissions.

3. Mitigating and controlling CO_2 emissions. While Congress has not yet passed comprehensive climate change legislation, in December 2009, the Administrator of the Environmental Protection Agency made a finding that greenhouse gases in the atmosphere threaten the public health and welfare of current and future generations. Having made the so-called "endangerment finding," EPA issued the final greenhouse gas tailoring rule, effective January 2, 2011, which will require greenhouse gas emissions to be addressed under PSD and Title V permits[3]. Likewise, mandatory reporting of greenhouse gas emissions to the Environmental Protection Agency commenced beginning in January 2010.

4. In addition, there are a number of regional regulatory initiatives, including the Western Climate Initiative that may ultimately impact PacifiCorp's coal-fueled facilities. PacifiCorp's generating units are utilized to serve customers in six states – Wyoming, Idaho, Utah, Washington, Oregon and California. California, Washington and Oregon are participants in the Western Climate Initiative, a comprehensive regional effort to reduce greenhouse gas emissions by 15% below 2005 levels by 2020 through a cap-and-trade program that includes the electricity sector; each state has implemented state-level emissions reduction goals. California, Washington and Oregon have also adopted greenhouse gas emissions performance standards for base load electrical generating resources under which emissions must not exceed 1,100 pounds of CO_2 per megawatt

[3] The Environmental Protection Agency has not yet published its proposed guidance on what constitutes Best Available Control Technology for greenhouses gases.

hour. The emissions performance standards generally prohibit electric utilities from entering into long-term financial commitments (e.g., new ownership investments, upgrades, or new or renewed contracts with a term of 5 or more years) unless the base load generation supplied under long-term financial commitments comply with the greenhouse gas emissions performance standards. While these requirements have not been implemented in Wyoming, due to the treatment of PacifiCorp's generation on a system-wide basis (i.e., electricity generated in Wyoming may be deemed to be consumed in California based on a multi-state protocol), PacifiCorp's facilities may be subject to out-of-state requirements.

5. Regulations associated with coal combustion byproducts. In June 2010, the Environmental Protection Agency published a proposal to regulate the disposal of coal combustion byproducts under the Resource Conservation and Recovery Act's Subtitle C or D. Under either regulatory scenario, regulated entities, including PacifiCorp, would be required, at a minimum; to retrofit/upgrade or discontinue utilization of existing surface impoundments within five years after the Environmental Protection Agency issues a final rule and state adoption of the appropriate controlling regulations. It is anticipated that the requirements under the final rule will impose significant costs on PacifiCorp's coal-fueled facilities within the next eight to ten years.

6. The installation of significant amounts of new generation, including gas-fueled generation and renewable resources.

7. The addition of major transmission lines to support the renewable resources and other added generation.

8. Increasing escalation rates on fuel costs and other commodities

BART and Regional Haze Compliance

PacifiCorp firmly believes that the commitments described above meet the letter and intent of the regional haze rules, including the guidance provided by the EPA known as "Appendix Y." The regional haze program is a long-term effort with long-term goals ending in 2064. It must be approached from that perspective. It was never intended to require SCR on BART-eligible units within the first five years of the program. Rather, it calls for a transition to lower emissions exactly as PacifiCorp has implemented to date and as it has proposed going forward through 2023.

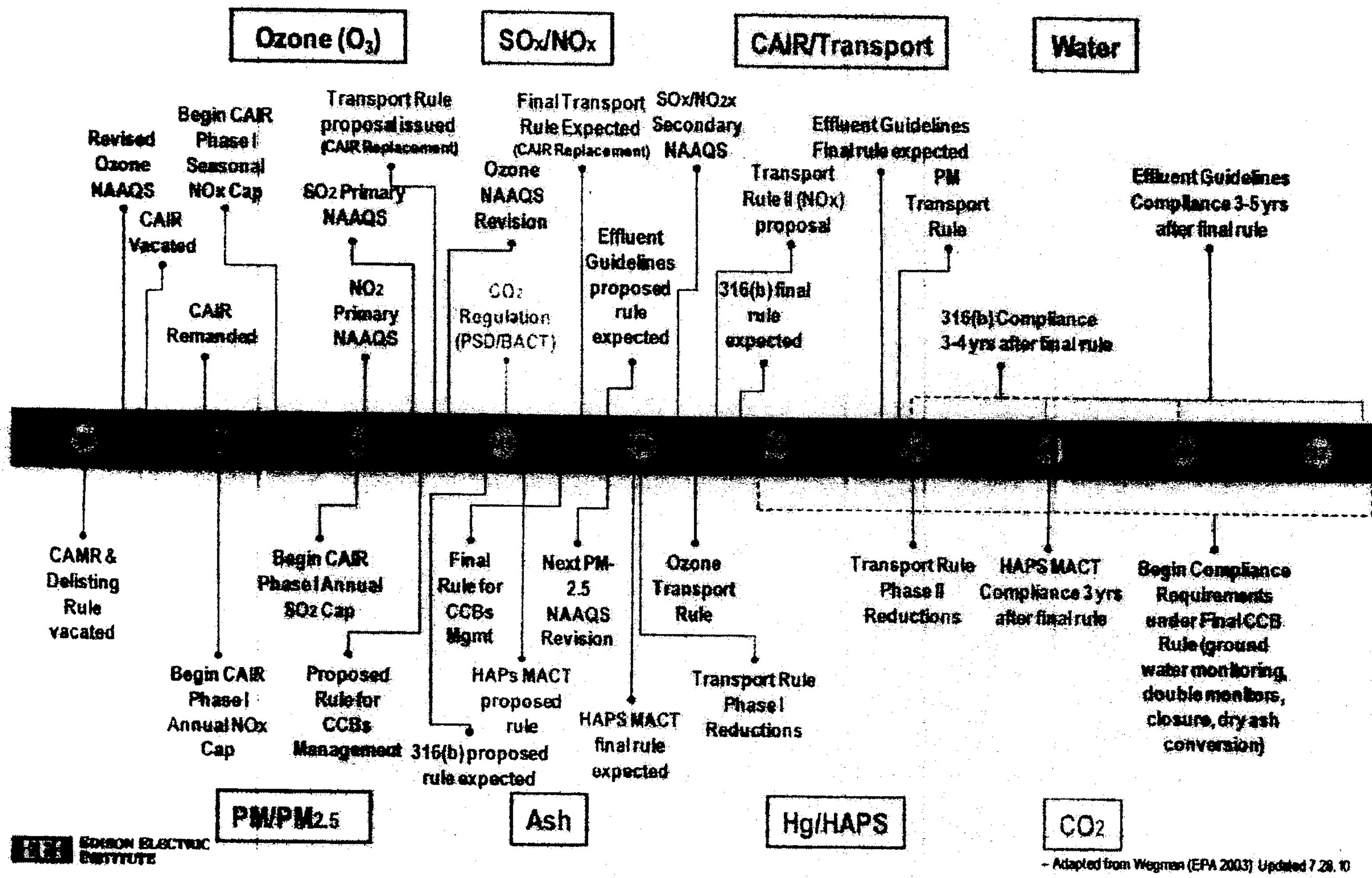
In its evaluation of emission reductions for regional haze purposes, the state should also consider several other variables which will significantly affect emissions and costs over the next ten years. These include such things as the development of new emission control technology, anticipated new emission reduction legislation and rules, the new ozone standard, the one hour SO_2 and NO_2 standards, the $PM_{2.5}$ standard, potential CO_2 regulation and costs, an aging fleet, and changing economic conditions. All of these variables matter and will affect the long-term viability of each PacifiCorp coal unit and will contribute to the reduction of regional haze in the course of the implementation of these programs. This, in turn, will affect the controls, costs and future operational expectations associated with these generating resources.

Conclusion

PacifiCorp has made a significant, long-term commitment to reducing emissions from its coal-fueled facilities and requests that the AQD consider this commitment as a reasonable approach to achieving emission reductions in Wyoming.

November 2, 2010

Attachment 1 Possible Timeline for Environmental Regulatory Requirements for the Utility Industry



Sierra Club/Exhibit 2

Exhibit 3

Testimony of Cathy S. Woollums
Senior Vice President and Chief Environmental Counsel
MidAmerican Energy Holdings Company
Committee on Environment and Public Works
United States Senate
June 15, 2011

Thank you for the opportunity to testify today to provide you with one electric utility's perspective on the costs to comply with new Environmental Protection Agency ("EPA") regulations. My name is Cathy Woollums, and I am the senior vice president and chief environmental counsel of MidAmerican Energy Holdings Company. My comments today are not meant to represent the industry as a whole, although I believe our experiences are largely consistent with those of other U.S. electric utilities, almost all of which have spent – and continue to spend – considerable dollars and resources in planning to comply with these EPA regulations. Every utility, of course, is implementing its own unique compliance strategy based on myriad factors, including its resource base, system impacts, reliability, capital costs, operating and maintenance costs, age of its existing generation units, cost of replacement generation, and projected load growth. What I hope to do this morning is to give you a sense of how these factors translate into our utility operations' overall compliance costs.

Background on MidAmerican

MidAmerican Energy Holdings Company ("MidAmerican") is a global energy services provider serving almost 6.9 million customers worldwide. MidAmerican's five U.S. energy business platforms consist of two electric utilities, two natural gas pipelines and an independent power producer. The two regulated utilities are MidAmerican Energy Company, an Iowa-based utility providing regulated electric and natural gas service to customers in Iowa, Illinois, South Dakota, and Nebraska; and PacifiCorp, which operates as Pacific Power in Northern California, Oregon, and Washington, and as Rocky Mountain Power in Idaho, Utah, and Wyoming. The two interstate pipelines are Kern River Gas Transmission Company, providing natural gas transportation from Wyoming to Southern California; and Northern Natural Gas, which operates from Texas to the Upper Midwest. The fifth platform is CalEnergy, an independent power producer with geothermal facilities in California and cogeneration plants in New York, Arizona, Texas, and Illinois.

At the end of 2010, MidAmerican Energy Company had 7,048 megawatts of owned and contracted generating capacity. Approximately 52 percent was fueled by coal; 21 percent by natural gas and oil; 20 percent by wind, hydroelectric and biomass; and 7 percent by nuclear. PacifiCorp's generating plants have a net owned capacity of 10,623 megawatts. The company operates 78 generating facilities across the West. Approximately 58 percent was fueled by coal; 21 percent by natural gas; and 21 percent by wind, hydroelectric, geothermal, or other.

MidAmerican Energy Company and PacifiCorp are number one and number two, respectively, in the U.S. in ownership of wind-powered generation among rate-regulated utilities. As of December 31, 2010, nearly 20 percent of MidAmerican Energy Company's total owned and contracted generation capacity and nearly 12 percent of PacifiCorp's total owned and contracted generation capacity was powered by wind. When MidAmerican Energy Company's 593 megawatts of wind capacity expansion in Iowa is complete by year-end 2011, approximately 26 percent of its total owned and contracted generation capacity will come from wind.

CalEnergy operates 10 geothermal plants with a cumulative generation capacity of 327 megawatts in California's Imperial Valley. Expansion plans call for six new plants with a total of 470 megawatts of additional geothermal capacity.

SECTION I

I. MidAmerican's Environmental Control Investments

MidAmerican has undertaken significant efforts with our permitting and regulatory agencies to ensure that our environmental control investments are timely in order to ensure compliance with existing environmental requirements, that they proceed in a reasoned fashion, and that they are coordinated with existing outage schedules to avoid additional outage time associated with equipment tie-in. These coordinated efforts reduce costs associated with replacement power and maintain system reliability.

MidAmerican has made substantial investments in pollution control equipment over the past 10 years and has budgeted for additional pollution control projects in the next 10-12 years. We began planning emission control projects targeting sulfur dioxide ("SO_2"), nitrogen oxide ("NOx"), and mercury emissions prior to 2005, when the EPA was developing its Clean Air Interstate Rule ("CAIR") and Clean Air Mercury Rule ("CAMR"). Both rules were ultimately vacated by the D.C. Circuit Court of Appeals, which directed the Agency to rework the regulatory framework underpinning both rules. Ultimately the CAIR was replaced by the Clean Air Transport Rule ("CATR") and the CAMR by the Utility Hazardous Air Pollutants ("HAPS") Maximum Achievable Control Technology ("MACT") rule. While the EPA was reworking these rules, MidAmerican continued planning various emissions control projects. Section II of this document contains a rule-by-rule overview and brief explanation of MidAmerican's compliance strategy.

Through 2010, our Midwest utility, MidAmerican Energy Company, has spent more than $370 million in capital expenditures for required pollution control equipment under these EPA rules. We estimate that the total costs for all pollution control projects (defined as capital, operations and maintenance and other costs) will exceed $1.1 billion by the end of 2020. These total costs are expected to increase annual costs to customers by $130 million per year by 2020.

Our other utility, PacifiCorp, has spent more than $1.2 billion in capital expenditures from 2005 through 2010 to comply with these EPA rules, and we estimate that total capital expenditures will exceed $2.7 billion by the end of 2022. Total costs that will have been incurred by our customers to pay for these pollution control projects during the period 2005 through 2023 are expected to exceed $4.2 billion, and by 2023 the annual costs to customers for these projects will have reached $360 million per year.

It is very difficult at this point to translate these projected costs to comply with the new EPA rules into specific percentage rate increases to our customers in all ten states in which we are subject to state public utility commission regulation, but let me give you one metric to demonstrate the magnitude of these costs. PacifiCorp's fossil steam generation units currently have a cumulative net value (after depreciation) of approximately $3.38 billion. Just compare that current value – $3.38 billion – to the estimated $1.3 billion in additional environmental control project capital costs PacifiCorp will spend between now and 2022, and that gives you a relative sense of the cost of these emissions control devices to our customers.

Due to the large number of our generating units that will be potentially affected by these new EPA regulations, deferring the installation of compliance projects places MidAmerican and our customers at risk of not having access to necessary capital, material, and labor in a compressed time frame concurrent with other utilities. For example, in the eastern United States, utilities are required to install controls under the CATR during the same 2012-2014 time frame within which they are required to comply with the HAPS MACT rule. We have already seen a dramatic rise in these pollution control costs in anticipation of the increased demand for labor and equipment. For example, MidAmerican Energy Company has just negotiated a contract for the installation of scrubbers and baghouses at two of our facilities in 2013 and 2014, and the costs are approximately 20% higher than anticipated. We have no choice, however, but to move forward, in order to ensure that we are in compliance and not subject to penalties for noncompliance or third party lawsuits.

The Department of Energy[1] estimates that between 35-70 gigawatts will shut down nationwide as a result of EPA's new rules. Similarly, a recent study by National Economic Research Associates ("NERA") estimates that 47.8 gigawatts of coal-fueled electricity capacity will likely become uneconomic and retire by 2015. Some of those facilities are also located in key transmission grid areas that provide voltage support that cannot be addressed by the fall of 2014 in order to comply with the anticipated January 1, 2015 implementation date. According to four other independent studies conducted last fall, with which I am sure the Committee is familiar (North American Electricity Reliability Council, Brattle, Credit Suisse, and Sanford Bernstein), this aggressive schedule for implementation of these and other EPA rules will likely result in closures of up to 60 gigawatts of existing U.S. coal capacity by January 2015.

MidAmerican, like many utilities, is concerned about the costs and timetables for the implementation of these EPA rules. These compliance costs will increase rates to our customers at the same time as they see increased rates for other major capital expenditures for new generation to meet increasing demands for electric service and to further diversify our generation portfolios, as well as construct billions of dollars of transmission to be able to deliver energy where it is needed. These rate increases are already occurring at PacifiCorp, with customers seeing annual rate increases, some in double-digit percentages.

Especially in this economic climate, it is critical to minimize the cost impact of these rules, which ultimately will be borne by our customers. If the timetable of the rules remains unchanged, compliance costs will be shouldered by our customers in the form of higher rates in a

[1] "EPA regulations for coal-fired power plants could force shut downs", *Bristol Herald Courier* (May 27, 2011); quoting James Wood, deputy assistant secretary for the U.S. Department of Energy.

very narrow window from 2013-2015. These increases will dramatically increase production costs for industrial plants and could result in job losses. Also, units prematurely retired in response to these EPA rules will have remaining book value issues to address.

Moreover, forcing all U.S. coal plants to comply with these EPA rules during such a short time frame will cause the costs of labor and materials for both retrofits and new generation to rise dramatically as demand for skilled labor and parts will greatly outstrip supply. A boom and bust cycle of craft labor employment created by these proposed EPA deadlines will make it challenging for firms to find, train, and retain skilled domestic craft labor.

II. MidAmerican's Environmental Compliance Planning Process

First and foremost in the decision to invest in environmental controls is our compliance obligation. If a permit or regulation requires one of our plants to reduce emissions or achieve emission limits that cannot be met with existing equipment, we examine compliance options to ascertain what equipment can be installed to achieve the emission requirements. MidAmerican also monitors state and federal rulemaking activities and legislative proposals that would have an impact on the facilities' operations. Monitoring these future requirements gives us a longer term view of the potential investments that may be required to lawfully continue operation of the facilities.

To assess the potential impacts of new environmental regulatory initiatives, the environmental groups in our business units review proposed and final regulatory requirements and actively engage in the regulatory processes at both the state and at the federal levels. We seek feedback from our environmental regulators to assess their concerns, read and analyze legislation and regulations proposed at the state and federal levels, provide feedback on legislation, and review and comment on proposed regulations. We submit written comments in regulatory proceedings and participate in public hearings on the proposals, ensuring that our concerns or support, as appropriate, are considered in these public forums. We are both well informed and engaged on these issues.

III. Compliance and Project Timing Considerations

We, like virtually all other electric utilities, examine a multitude of factors to determine the appropriate mitigation measures. For example, if a regulation prescribes a specific emissions limit, our teams review what types of controls may be available to achieve the requisite emissions limit, given the specific characteristics of each unit. We consider system impacts, reliability, capital costs, operating and maintenance costs, the life of the controls, the life of the unit itself, cost of replacement generation, and many other factors. If an emissions trading mechanism is available to achieve compliance, we compare the costs of obtaining the emissions allowances to the costs of installing and operating new equipment, considering the factors noted above.

We also examine the actual and potential compliance time frames and how those time frames may be coordinated with planned plant outage schedules. Coordinating major environmental control projects with existing outage schedules allows MidAmerican to avoid additional outage time, thus reducing the need for replacement power, minimizing costs, and maintaining system reliability.

Pollution control projects are extremely complex and require a significant amount of evaluation and planning to bring to fruition. Moreover, state environmental agency permitting processes are required to define the technical requirements needed in order to seek competitive bidding and pricing for the work and ultimately executing the projects. The timeline for securing contracts for this type of work through project completion often has a multi-year duration.

IV. Managing Project Execution and Compliance Risk

The full and final scope of environmental regulations is not easily determined, particularly when rulemakings are often lengthy in their own right and just as often followed by extensive and lengthy litigation before the rule is finalized. Perfect foresight is not possible; the EPA has recently begun to acknowledge that its approach to regulation makes it difficult for companies with compliance obligations to make long-term decisions on compliance. In EPA Administrator Lisa Jackson's remarks prepared on the release of the HAPS MACT standards on March 16, 2011, she stated:

> The proposal and implementation of these standards will also have benefits for American utilities. For the first time in twenty years, they will have certainty about the standards they must meet. And setting national standards for mercury and air toxics will level the competitive playing field and close loopholes for big polluters. Utilities that have already put pollution control technology in place will no longer have to compete with those who have delayed those investments – a group that includes almost half of the nation's coal-fired plants, which lack advanced pollution control equipment. In fact, facilities that have already taken responsible steps to reduce the release of toxins into our air will be at a competitive advantage over their heavy-polluting counterparts. And to ensure cost-effectiveness, we have proposed flexibility in meeting the standards. The technologies being required already exist in abundance, and under the proposal, power providers have four years to comply.[2]

MidAmerican believes it would be imprudent to wait until all the regulations are considered, finalized, and quantified to install controls. Doing so would put the facilities at substantial risk of noncompliance and does not reflect the reality of the multistate operations and planning process for large utilities. Moreover, it would be imprudent to assume a large utility can install all required controls under a "just-in-time" plan. This approach to compliance poses a significant risk to MidAmerican and our stakeholders; as a practical matter, it cannot be economically achieved on a system the size of MidAmerican's utility platforms. Emission reduction projects are complex, multi-year projects. Trying to install multiple controls within the same short time frames poses a significant risk of noncompliance, with penalties that can be substantial. Even if a regulatory agency did not impose penalties for failing to achieve emission reduction deadlines,

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[2] Remarks available at:
http://yosemite.epa.gov/opa/admpress.nsf/12a744ff56dbff8585257590004750b6/b7e570d651cadc03852578550057011c!OpenDocument

third parties have not hesitated to bring lawsuits against the operators of those facilities that miss deadlines or are otherwise not in compliance with permit and emission limits. Indeed, the federal Clean Air Act specifically allows for private citizen enforcement of air quality requirements.

V. Other Factors to Consider

Finally, environmental regulations and the cost of implementation are only one factor that influences whether or not to make investments in environmental projects; MidAmerican also must consider the cost of alternative generation, such as small modular nuclear reactors. Future natural gas prices, construction costs for renewable generation, and associated transmission availability and costs are also among the factors we evaluate in determining whether it is economic to install controls at coal-fueled plants.

VI. The Role of State Regulators and Stakeholder Feedback

Our state regulators are the consumers' watchdogs, and they apply standards to ensure that only those costs that are prudently incurred and useful in providing service are recovered in rates. This structure does not encourage utilities to become early movers or emission control technology developers. Those responsibilities lie with the vendor community, where the market provides greater potential rewards for successful innovation. Shareholders of these unregulated companies, not utility customers, earn the rewards of success or bear the costs of failure.

Neither utilities nor regulators have perfect foresight regarding the development of future technologies, future market conditions, or changes in environmental laws, but we make the best projections possible in our resource development decisions. We also appreciate that the American public is concerned with environmental issues, including global climate change. The significant concern for electric utilities is carbon dioxide, the byproduct of the combustion of fossil fuels. Although the primary focus has been on coal-based generation, since it produces more carbon dioxide per unit of electric energy than other fossil fuels, natural gas-fired generation also produces carbon dioxide emissions and is at risk as a continuing source of fuel due to uncertainties around climate change and carbon dioxide regulations.

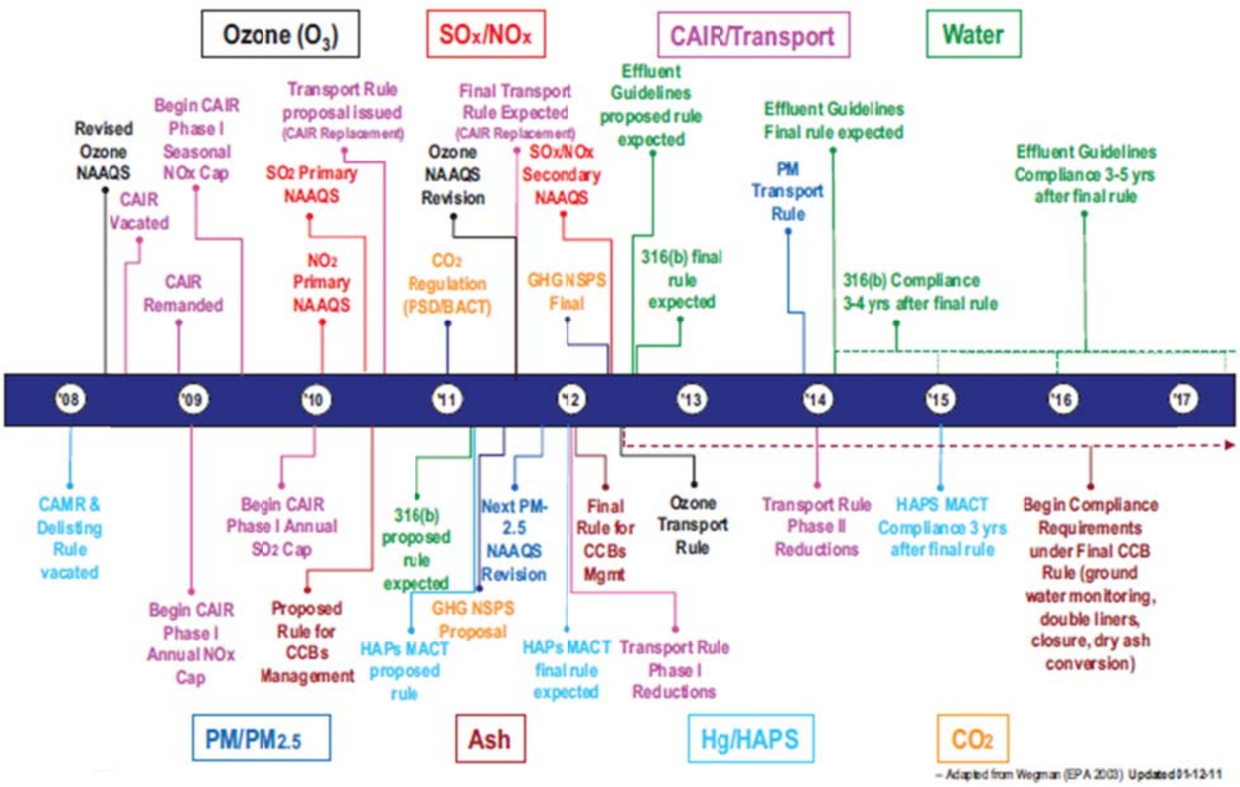
There are many different viewpoints regarding whether MidAmerican should make investments in our existing coal-fueled facilities. Our challenge is to work with these stakeholders and our regulators to come up with solutions that balance state and federal policies, ensure system reliability, maintain 100% compliance with all laws, keep the lights on, meet increasing customer loads, ensure the safety of our employees and customers, and satisfy the obligation to serve, all while maintaining reasonable rates.

SECTION II

The So-Called "EPA Regulatory Train Wreck"

Both MidAmerican Energy Company and PacifiCorp continue to pursue proactive environmental control strategies that are protective of the environment while minimizing cost impacts to our customers. There are a multitude of environmental requirements the electric industry faces over the next several years driving these investments. Figure 1 provides a timeline, referenced colloquially as the so-called "EPA regulatory train wreck" slide. It identifies some of the requirements that are currently underway or in development. There is a great deal of uncertainty associated with future environmental requirements; however, MidAmerican must comply with the requirements that exist today and prepare for the regulations that will be adopted in the future.

Figure 1 - EPA's "Regulatory Train Wreck"



The areas of regulation listed below reflect the color-coded "categories" of regulations identified within Figure 1.

1. **PM/PM2.5**
2. **Ozone (O_3)**
3. **SOx/NOx**
4. **CAIR/Transport Rule**

These first four categories are grouped together because under the Clean Air Act each of these categories is linked to one or more National Ambient Air Quality Standards ("NAAQS"). These "criteria pollutants" – particulate matter ("PM"), sulfur dioxide ("SO_2"), ozone ("O_3"), nitrogen oxides ("NOx"), carbon monoxide ("CO"), and hydrocarbons – while undesirable, are not toxic in typical concentrations in the ambient air. Under the Clean Air Act, they are regulated differently from other types of emissions, such as hazardous air pollutants and greenhouse gases.

A NAAQS by itself does not require emissions reductions from specific sources, such as power plants. Rather, the EPA and/or a state will identify various control measures that once implemented, are meant to achieve the NAAQS. A particular control measure may require emissions reductions from certain types of sources. An example of such a control measure would be the EPA's proposed Clean Air Transport Rule, discussed further below.

The Clean Air Act, which was last amended in 1990, requires the EPA to set NAAQS (40 CFR part 50) for pollutants considered harmful to public health and the environment. The Clean Air Act established two types of national air quality standards. ***Primary standards*** set limits to protect public health, including the health of "sensitive" populations such as asthmatics, children, and the elderly. ***Secondary standards*** set limits to protect public welfare, including protection against decreased visibility, damage to animals, crops, vegetation, and buildings. The Clean Air Act requires the EPA to review the latest scientific information and standards every five years. Before new standards are established, policy decisions undergo rigorous review by the scientific community, industry, public interest groups, the general public and the Clean Air Scientific Advisory Committee (CASAC).

Particulate Matter (PM) and Fine Particulates ($PM_{2.5}$): The Clean Air Act established NAAQS for particle pollution (i.e., particulate matter or "PM"). The EPA last revised the air quality standards for particle pollution in 2006. The next review is expected in 2011.

Ozone (O_3): Ozone is a gas composed of three oxygen atoms. It is not usually emitted directly into the air, but at ground-level is created by a chemical reaction between NOx and volatile organic compounds ("VOC") in the presence of sunlight. EPA last revised the NAAQS for ozone pollution in 2008 (at 75 micrograms per cubic meter), putting some counties into non-attainment and requiring states to take steps to reduce emissions to improve the ambient air concentrations. However, EPA is now reconsidering its 2008 decision and may lower the limit (to between 60 and 70 micrograms). EPA expects to make its decision by the end of July 2011.

Sulfur Dioxide (SO_2) and Nitrogen Oxide (NOx): In 2010, the EPA promulgated new "primary" one-hour NAAQS for SO_2 and nitrogen dioxide ("NO_2") concentrations, which add a temporal nature to emissions reductions necessary to improve the ambient air concentrations. New "secondary" SO_2 and NOx NAAQS are expected in 2012.

Clean Air Transport Rule ("CATR"): EPA's proposed CATR would require new reductions in SO_2 and NOx emissions from large stationary sources, including power plants, located in 31 states and the District of Columbia beginning in 2012. It is meant to help states attain NAAQS set in 1997 for ozone and fine particulate matter. This rule would replace the Bush administration's CAIR, which was vacated in July 2008 and rescinded by a federal court because it failed to effectively address pollution from upwind states that is hampering efforts by downwind states to comply with ozone and PM NAAQS.

The EPA has been discussing the possibility of additional emissions reductions via a "PM Transport" rule (2013) or a "Transport II" rule (2014). Justification for such a rule or set of rules would be triggered by the setting of more stringent ozone or PM NAAQS. For example, a more stringent ozone NAAQS may result in an expansion of NOx emissions reduction requirements to stationary sources operating in the non-CATR states.

MidAmerican's Compliance Strategy: The Clean Air Transport Rule only impacts MidAmerican Energy Company's coal units in Iowa and CalEnergy's natural gas facilities in Texas, Illinois and New York. MidAmerican Energy Company has already completed a low NOx burner and overfire air program across its entire coal-fueled fleet. As a result, NOx emissions have dropped from approximately 40,000 tons per year to slightly over 20,000 tons per year – or nearly 50%. In addition, dry scrubbers have been installed at its Louisa and Walter Scott Energy Center unit 4 in 2007, and Walter Scott Energy Center unit 3 in 2009. Additional scrubber projects are being planned for Neal South in 2013, and Neal North units 2-3 and the Ottumwa Generating Station in 2014. Once these projects are complete, MidAmerican Energy Company's SO_2 emissions will be reduced from a baseline of over 60,000 tons per year to slightly less than 25,000 tons per year – or nearly 60%.

The EPA intends for this Rule to evolve as additional changes are made to the National Ambient Air Quality Standards for SO_2 and NOx. This could lead to significant stranded investments and cause the affected states to also expand to the western coast; if modeling shows those states ultimately contributing to a downwind attainment problem.

Regional Haze Rule: While not depicted within the EPA regulatory train wreck slide, an EPA rule meant to address visibility concerns will drive additional NOx reductions particularly from facilities operating in the Western United States. On June 15, 2005, EPA issued final amendments to its July 1999 regional haze rule. These amendments apply to the provisions of the regional haze rule that require emission controls known as Best Available Retrofit Technology ("BART"), for industrial facilities emitting air pollutants that reduce visibility. These pollutants include $PM_{2.5}$, and compounds which contribute to $PM_{2.5}$ formation, such as NOx, SO_2, certain volatile organic compounds, and ammonia. The 2005 amendments included final guidelines, known as BART guidelines, for states to use in determining which facilities must install controls and the type of controls the facilities must use. States had until December 2007 to develop their implementation plans. States were responsible for identifying the facilities that would have to reduce emissions under BART and then set BART emissions limits for those facilities. Those facilities are expected to install additional emissions controls usually within five years after the EPA approves a state's regional haze plan (2014-2017).

MidAmerican's Compliance Strategy: PacifiCorp operates 19 coal-fueled generating units; 14 of these units are BART or BART-eligible units. Between 1999 and 2014, PacifiCorp will have installed low-NOx burners at 15 units, reducing NOx emissions by 36,800 tons per year. The capital cost of these projects is $125 million; annual operating and maintenance expenses associated with the equipment are $1.6 million. Beginning in 2014, PacifiCorp will install selective catalytic reduction ("SCR") to achieve additional NOx emission reductions. Between 2014 and 2022, five units will have SCR installed, reducing NOx emissions by 21,000 tons at a cost of $951 million; operating and maintenance costs will increase by $25.8 million annually.

Unfortunately, recent discussions with the Utah and Wyoming Departments of Environmental Quality suggest that EPA Region 8 believes it may be necessary, for purposes of Regional Haze BART requirements, to install another five SCR in Wyoming and four SCR in Utah, combined with the five planned installations, within a five-year time period—potentially requiring 14 SCR by 2017 and an additional $1.7 billion to $2 billion in costs. PacifiCorp maintains its outage schedule on a four-year cycle; major projects such as the addition of emission control require a significant outage. Installing controls during times outside of the normal outage schedule creates significant electric reliability and availability concerns and imposes significant additional costs for replacement power. The costs of controls, replacement power, and other project-related costs are reflected in increased costs to customers.

The Regional Haze program does not require that emission reductions occur on a date certain; to the contrary, the Regional Haze program is a long-term program designed to improve visibility in Class I areas with the national goal of achieving natural visibility conditions by 2064. States are required to establish reasonable progress goals to achieve the required visibility improvements. States are required, under Section 169A(b) of the Clean Air Act to consider the following when making their BART determinations:

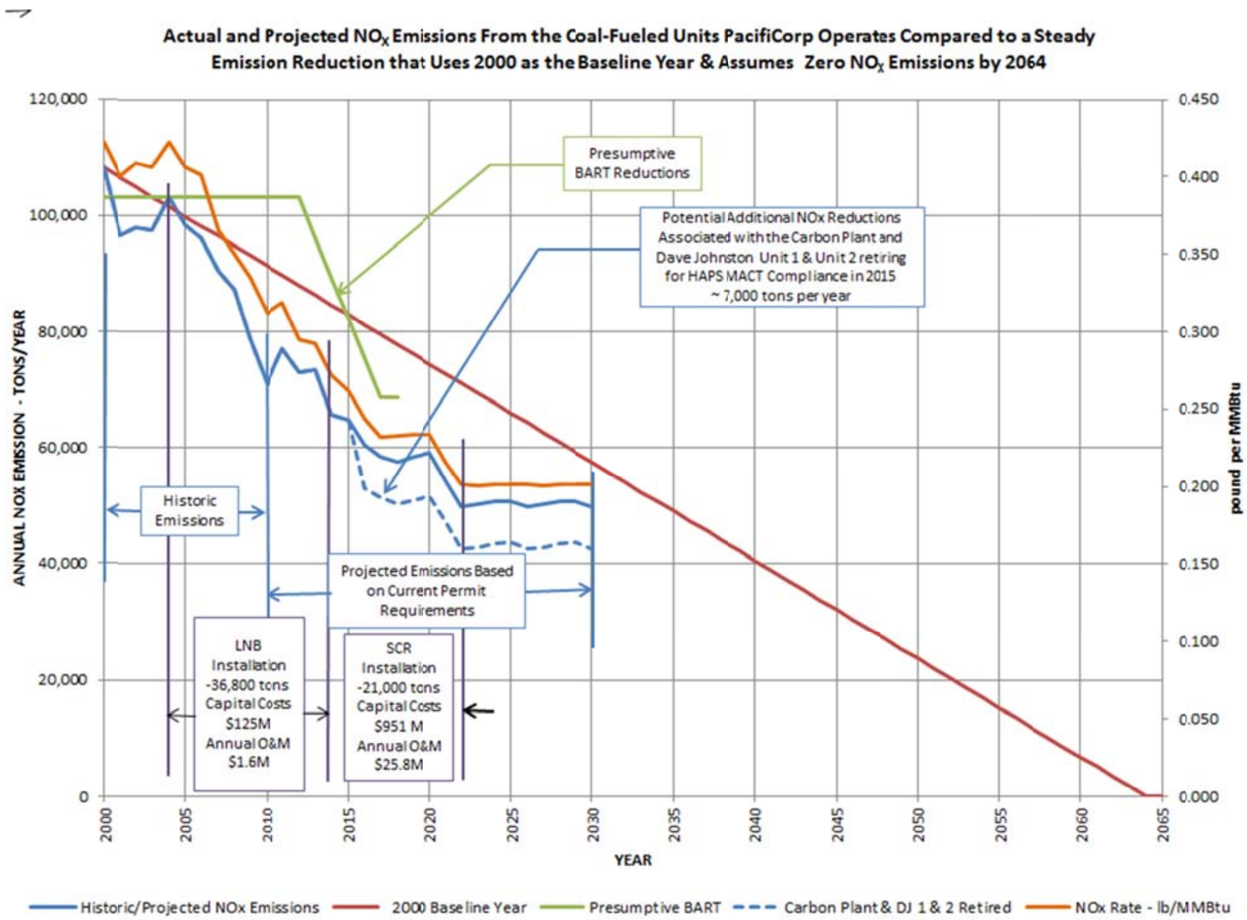
- The costs of compliance;
- The energy and non-air quality environmental impacts of compliance;
- Any existing pollution control technology in use at the source;
- The remaining useful life of the source; and
- The degree of visibility improvement which may reasonably be anticipated from the use of BART.

In considering whether the states' implementation plans are sufficient for approval, EPA appears to be focused, at best, on two criteria – the costs of compliance and the degree of visibility improvement. Effectively, EPA has indicated that any emission reductions that can be accomplished for $5,000 or less per ton at facilities that have more than a 0.50 deciview impact on a Class I area should be controlled. EPA's analysis fails to take into consideration the more robust criteria considered by the states in making their determinations, opting for more reductions sooner.

As a result of EPA's failure to take into consideration factors such as existing pollution control technology in use at the source, its cost per ton of emissions reduced is inaccurate. For example, at PacifiCorp's Jim Bridger Unit 1, low-NOx burners were installed in 2010. Rather than calculating the incremental costs associated with installation of SCR from the reduced baseline that reflects the emission reductions from low-NOx burners, EPA spreads the cost of both low-NOx burners and SCR to achieve a cost per ton removed more than $2,000 per ton lower than the incremental difference between low-NOx burners and SCR.

EPA's suggestions that it will require more emission controls in a shorter period of time is akin to jumping off a cliff, rather than achieving emission reductions in a reasonable period of time through 2064. (See Figure 2.)

Figure 2 – PacifiCorp's Regional Haze/BART Compliance Strategy



5. Hg/HAPS

In March 2005, EPA issued the Clean Air Mercury Rule ("CAMR") to permanently limit and reduce mercury emissions from coal-fired power plants under a market-based cap-and-trade program; this rule would effectively remove coal-fired power plants from the Clean Air Act list of sources of hazardous air pollutants. However, CAMR was vacated in February 2008, with the circuit court finding EPA's removal of coal-fired power plants from the list of generating sources regulated under Clean Air Act Section 112 out of statutory compliance.

On March 16, 2011, the EPA signed the proposed Utility Hazardous Air Pollutants ("HAPS") Maximum Achievable Control Technology ("MACT") rule, which sets standards for 10 non-mercury HAPS metals, mercury and acid gases. It also establishes work practices to ensure the minimization of organic HAPS such as furans and dioxins emitted by coal and oil-fueled electric generating units. The rule is standard-drive, not technology-driven and, as such, there are multiple pathways to comply with the rule; however, it appears the EPA is encouraging utilities to: install baghouses with particulate matter continuous emission monitors for non-mercury metallic HAPS control, install sulfur dioxide scrubbers to control acid gases, and install activated carbon/reagent injection to remove mercury.

MidAmerican's Compliance Strategy: In order to meet emissions projections, MidAmerican Energy Company must complete scrubber projects planned for Neal 4 in 2013, and Neal units 2 and 3 and Ottumwa Generating Station in 2014 and add sorbent injection to Neal 1, Walter Scott Energy Center unit 1, Walter Scott Energy Center unit 2, and Riverside Generating Station. Walter Scott Energy Center unit 4 already employs an activated carbon injection system to control mercury and the remaining units with existing or planned baghouses are expected to install activated carbon injection by fall 2014. The cost of most of these projects is approximately $485 million (MidAmerican Energy Company's share). Additional activated carbon injection and sorbent injection projects at the four small coal-fueled units would require an estimated $30 million (MidAmerican Energy Company's share).

MidAmerican Energy Company's smaller coal-fueled units (Walter Scott Energy Center 1, Walter Scott Energy Center 2, Neal 1, and Riverside) may not be able to comply with the proposed HAPS MACT rule without making significant investments in control technology (unless the units are converted exclusively to fire natural gas).

For PacifiCorp, in order to meet the emission reductions anticipated by the new regulations, PacifiCorp must complete scrubber, baghouse, and mercury emissions controls projects no later than fall of 2014 in order to comply with the anticipated January 1, 2015 implementation date at a cost of approximately $1.26 billion (PacifiCorp's share). This capital cost includes installation of mercury control at all PacifiCorp units, including Carbon Unit 1 and 2 and Dave Johnston Unit 1 and Unit 2 at an estimated $12 million (PacifiCorp's share).

The units most at risk from the new HAPS MACT regulations are unscrubbed units that do not have baghouses. These units (Carbon Units 1 and 2 and Dave Johnston Units 1 and 2) may need to be idled or converted to natural gas (assuming it is available onsite) if the non-mercury metallic HAPS and acid gas HAPS limits cannot be met through dry sorbent injection, or other emergent low-cost technology solutions.

Due to the non-emission-trading nature of the proposed rule, units not meeting the unit-based HAPS MACT emission standards would be required to cease operation on or about January 1, 2015, should that date become the compliance deadline. Some of those facilities are also located in key transmission grid areas that provide voltage support that cannot be addressed by the fall of 2014 in order to comply with the anticipated January 1, 2015 implementation date. As such, we urge EPA to carefully consider potential options to develop a mechanism that avoids significant impacts to the availability, reliability and cost of electricity while balancing the need to reduce emissions.

6. Water

Cooling Water Intake Structure Rule: EPA recently released it proposed cooling water intake structure ("CWIS") rule pursuant to Clean Water Act (CWA) section 316(b) for existing steam-electric power plants. In November 2010, EPA entered into a settlement agreement with the environmental community that sets a binding timetable for a proposed rule by March 2011 and a final rule by July 2012.

MidAmerican's Compliance Strategy: All of MidAmerican Energy's coal-fueled generating facilities, except Louisa, Ottumwa and Walter Scott Unit 4, which have water cooling towers, are regulated facilities under 316(b) of the Clean Water Act and may be impacted by the outcome of the expected rulemaking. Neal 1-4, Walter Scott Energy Center 1-3, and Riverside Generating Station have once through cooling on the Missouri and Mississippi Rivers. At PacifiCorp, only the Dave Johnston plant withdraws enough cooling water to be covered by the 316(b) rule. Every other PacifiCorp facility that is potentially affected by this rule has a recirculating cooling system in place thereby meeting the likely technology requirements of the rule.

Steam Electric Effluent Guidelines: EPA announced in September 2009 that it intends to revise the existing steam electric guidelines, last updated in 1982, that set the technology-based effluent limitations for the steam electric industry. The new effluent guidelines rulemaking is likely to set strict performance standards that will force technological and operational changes at existing coal-fueled, nuclear, gas-fueled, and combined cycle facilities. The most significant impact, however, will likely be to coal-fueled facilities. The proposed rule is due in July 2012 with a final rule expected in January 2014.

MidAmerican's Compliance Strategy: MidAmerican Energy Company does not have any wet scrubbers installed in its coal-fueled fleet, and none are planned. The dry scrubbing process does not produce a significant waste water stream, as the approximate 600 gallons per minute of lime slurry water is evaporated in the process and emitted out the stack as vapor. MidAmerican, however, may face a greater challenge concerning the discharge of process water from its coal ash surface impoundments.

PacifiCorp has a number of wet scrubbers in its coal-fueled fleet which produce waste water streams. In most cases, water from these waste streams is collected and evaporated in waste water ponds. The wet scrubbers are currently installed at Hunter 1-3, Huntington 1-2, Naughton 3, Bridger 1-4, Cholla 4, Craig 1-2, and Colstrip 3-4. New wet scrubbers are planned to be placed in service at Naughton 1-2 in 2012 and 2011, respectively. In addition, the PacifiCorp coal-fueled facilities have a number of coal ash surface impoundments.

Unfortunately, there is no definitive method to ascertain the potential financial impacts of new effluent guidelines on the MidAmerican and PacifiCorp coal-fueled fleets until the actual rule requirements are proposed in mid-2012; and there are no projects budgeted to specifically address these issues. However, as the effluent discharge requirements become more and more stringent, the facilities which have discharges to waterways will likely be required to either add wastewater treatment facilities or redesign their process if possible to be a zero discharge facility. The costs to comply with such a rule are expected to be high. Wastewater treatment systems generally range from tens of millions of dollars for a small facility, to a hundred million or more for a large facility.

7. Ash

In June 2010, EPA proposed two primary regulatory options for coal combustion residuals ("CCR") disposed of in landfills and/or surface impoundments: (1) regulation of the materials as hazardous wastes under Subtitle C of the Resource Conservation and Recovery Act ("RCRA"); or (2) regulation of the materials as non-hazardous wastes under Subtitle D of RCRA. Under both options, the proposed regulatory requirements likely would lead to the accelerated closure of all existing unlined landfills and unlined wet surface impoundments, although the agency's "D Prime" option would allow for the continued use of existing landfills and surface impoundments through their useful life as long as certain environmental and safety standards were met. Under each option, CCRs that are beneficially used would be excluded from regulation; however, the stigma associated with a hazardous waste determination would have a devastating impact on continued beneficial uses. Under the two primary options under consideration by EPA, CCR disposal practices will be impacted significantly and result in significant compliance costs, may lead to the closure of existing disposal facilities, and may threaten continued CCR beneficial use.

MidAmerican's Compliance Strategy: The regulation of CCR under either of the EPA's primary options would have a significant impact on the methods that MidAmerican Energy Company typically employs to manage its ash. With the exception of Walter Scott Unit 4 and Neal Unit 4 which handle all the coal ash dry, all of MidAmerican Energy Company's coal-fueled units sluice the boiler bottom ash to on-site surface impoundments. In addition, if CCR is ultimately designated as a hazardous waste, the beneficial use market could evaporate and eliminate the over $3 million MidAmerican Energy Company receives each year for this commodity. The loss of the beneficial use market would also increase disposal costs and dramatically increase the rate at which the monofills are filled.

Similar to MidAmerican Energy Company, the regulation of CCR under either of the EPA's primary options would have a significant impact on the methods that PacifiCorp typically employs to manage its ash. Currently, Carbon, Hunter, and Huntington do not have any wet surface impoundments at the facilities. The remaining coal-fueled units, however, sluice ash and scrubber waste to on-site surface impoundments. In addition, if CCR is ultimately designated as a hazardous waste, the beneficial use market could evaporate and eliminate the over $3.5 million PacifiCorp receives each year on average from this commodity. The loss of the beneficial use market would also increase disposal costs and dramatically increase the rate at which monofills are filled.

8. CO_2

Best Available Control Technology ("BACT") Guidelines: On November 10, 2010, the EPA published a set of guidance documents to assist state permitting authorities and industry permitting applicants with the Clean Air Act PSD and title V permitting for sources of greenhouse gases ("GHGs"). The guidance consists of a number of different documents. EPA provided a general guidance document entitled "PSD and Title V Permitting Guidance For

Greenhouse Gases," which includes a set of appendices with illustrative examples of BACT determinations for different types of facilities. There also remains ongoing concern about the application of New Source Review ("NSR") rules to GHGs. It is unclear whether owners of fossil power plants should proactively undertake efficiency improvements, lest those efficiency improvements be treated as a modification that triggers the application of NSR rules.

MidAmerican's Compliance Strategy: With respect to the GHG BACT permitting, PacifiCorp recently completed permitting for its Utah Lake Side 2 natural gas combined-cycle power plant, where the additional resources and costs required to complete the permitting effort were estimated to be between $25,000 and $50,000 for GHG-related modeling costs, consultant costs, and internal labor.

MidAmerican Energy Company recently completed its GHG BACT permitting for its George Neal South emission control project located in Iowa, but the additional work was completed internally. However, to comply with the newly proposed GHG limit, MidAmerican Energy Company demonstrated that replacing the existing turbine with a more efficient design is technically feasible and would cost approximately $20 million. We also have to test several boiler injection chemicals to determine if they improve plant efficiency. If it is determined that the chemicals are technically and economically feasible, the unit will be required to utilize them going forward.

It should also be noted, that despite claims to the contrary, there are no post-combustion technologies commercially available to control greenhouse gas emissions. Carbon capture and sequestration is likely at least 5-10 years away from becoming commercially available, and only if certain technical, legal, and liability challenges can be overcome. Additionally, the use of biomass is generally limited to certain boiler types for potential retrofit, and only a small percentage can replace the primary boiler fuel. As a result, facilities undergoing GHG BACT permitting are only left with potential efficiency upgrades / heat rate improvement projects to pursue. Since these types of projects typically result in relatively small improvements in efficiency (i.e. less than 1%-3%), an aggressive GHG BACT permit limit may not be achievable on existing units.

New Source Performance Standards: On December 23, 2010, in a settlement reached with several states and environmental groups in *New York v. EPA*, the EPA agreed to promulgate emissions standards covering GHGs from both new and existing electric generating units under Section 111 of the Clean Air Act by July 26, 2011 and issue final regulations by May 26, 2012.[3] New source performance standards are established under the Clean Air Act for certain industrial sources of emissions determined to endanger public health and welfare and must be reviewed every eight years. New source performance standards apply to new and modified sources and effectively establish the floor for determining what constitutes BACT.

In addition, emission guidelines will apply to existing sources. The emissions guidelines, issued by EPA, are used by states to develop plans for reducing emissions and include targets based on demonstrated controls, emission reductions, costs and expected time frames for installation and

[3] EPA also entered into a similar settlement the same day to address greenhouse gas emissions from refineries with proposed regulations by December 15, 2011 and final regulations by November 15, 2012.

compliance and may be less stringent than the requirements imposed on new sources. States must submit their plans to EPA within nine months after the guidelines' publication unless EPA sets a different schedule. States have the ability to apply less stringent standards or longer compliance schedules if they demonstrate that following the federal guidelines is unreasonably cost-prohibitive, physically impossible, or that there are other factors that reasonably preclude meeting the guidelines. States may also impose more stringent standards or shorter compliance schedules. Lastly, under Section 111, EPA may establish standards that rely upon market mechanisms rather than technology-specific emissions rates.

MidAmerican's Compliance Strategy: It is unclear what approach EPA will take when establishing new source performance standards covering GHGs from both new and existing electric generating units or what the guidelines will be for existing sources. The proposed settlement agreement indicates that EPA's initial evaluation of available GHG control strategies indicates that there are cost-effective control strategies for reducing GHGs from electric generating units and that it would be appropriate for EPA to concurrently propose performance standards from new and modified electric generating units, and emissions guidelines for GHG emissions from existing affected electric generating units. As noted above (p. 15), MidAmerican disagrees that there are cost-effective post-combustion control strategies for reducing greenhouse gas emissions, and only limited efficiency improvements are commercially available at this time. EPA indicated that the GHG standards are likely to apply to existing facilities starting in 2015 or 2016.

Figure 3 - Overview of MidAmerican’s Environmental Control Projects

				NOx Emission Controls					SO_2 Emission Controls		Particulate Controls			Mercury (Hg) Control	CCB Compliance		
Unit	Year Installed	Regulatory Depreciation Life (non-OR)	Accredited Net MW Rating (100% Share)	Neural Network System	Low NOx Burners	Overfire Air	Selective Non-Catalytic Reduction	Selective Catalytic Reduction	Dry Scrubber	Wet Scrubber	Electrostatic Precipitator	Wet Scrubber	Baghouse	Activated Carbon Injection	(Dates shown are initial compliance projects in-service) Pond closure, wet-to-dry conversion, new facilities	Potential to Operate on Full Load Natural Gas	MEC/PAC Ownership
Neal 1	1964		135	Y	N/A	Y	Not Planned	Not Planned	Not Planned	Not Planned	Y - Hot	N/A	Not Planned	2014	2015	Y	100.00%
Neal 2	1972		295	Y	Y	Y	2014	Not Planned	2014	Not Planned	Y - Cold	N/A	2014	2014	2015	N/A	100.00%
Neal 3	1975		515	Y	Y	Y	2014	Not Planned	2014	N/A	Y - Cold	N/A	2014	2014	2015	N/A	72.00%
Neal 4	1979		644	Y	Y	Y	2013	Not Planned	2013	N/A	Y - Cold	N/A	2013	2014	Not Planned	N/A	40.57%
WSEC 1	1954		45	Not Planned	Y	Not Planned	Not Planned	Not Planned	Not Planned	Not Planned	Y - Hot	N/A	Not Planned	2014	2015	N/A	100.00%
WSEC 2	1958		88	Not Planned	Y	Y	Not Planned	Not Planned	Not Planned	Not Planned	Y - Hot	N/A	Not Planned	2014	2015	Y	100.00%
WSEC 3	1978		690	Y	Y	Y	Not Planned	Not Planned	Y	N/A	Y - Cold	N/A	Y	2014	2015	N/A	79.10%
WSEC 4	2007		800	Y	Y	Y	Not Planned	Y	Y	N/A	N/A	N/A	Y	Y	Not Planned	N/A	59.66%
Louisa	1983		745	Y	Y	Y	Not Planned	Not Planned	Y	N/A	Y - Hot	N/A	Y	2014	2014	N/A	88.00%
Riverside	1925/1961		130	Y	Y	Y	Not Planned	Not Planned	Not Planned	Not Planned	Y - Cold	N/A	Not Planned	2014	2015	Y	100.00%
Ottumwa	1981		710	Y	Y	Y	Not Planned	Not Planned	2014	N/A	Y - Hot	N/A	2014	2014	Not Planned	N/A	52.00%
Carbon 1	1954	2020	67	Not Planned	Not Planned	Not Planned	Not Planned	Not Planned	Not Planned	Not Planned	Y - Cold Side	-	Not Planned	Sorb Inj + Oxidizer	2015	Under Review	100.00%
Carbon 2	1957	2020	105	Not Planned	Not Planned	Not Planned	Not Planned	Not Planned	Not Planned	Not Planned	Y - Cold Side	-	Not Planned	Sorb Inj + Oxidizer	2015	Under Review	100.00%
Cholla 4	1981	2042	395	Not Planned	Y	Y	Not Planned	Not Planned	N/A	Y	N/A	-	Y	Coal Oxidizer	2015	Not Planned	100.00%
Colstrip 3	1984	2046	740	Not Planned	Y	Y	Not Planned	Not Planned	N/A	Y	N/A	Y	N/A	Y - Installed	2015	Not Planned	100.00%
Colstrip 4	1986	2046	740	Not Planned	Y	Y	Not Planned	Not Planned	N/A	Y	N/A	Y	N/A	Y - Installed	2015	Not Planned	100.00%
Craig 1	1980	2034	428	Not Planned	Y	Y	2014	Not Planned	N/A	Y	N/A	-	Y	Coal Oxidizer	2015	Not Planned	19.28%
Craig 2	1979	2034	428	Not Planned	Y	Y	2013	Not Planned	N/A	Y	N/A	-	Y	Coal Oxidizer	2015	Not Planned	19.28%
Dave Johnston 1	1958	2027	106	Not Planned	N	N	Not Planned	Not Planned	Not Planned	Not Planned	Y - Cold Side	-	Not Planned	Sorbent Injection	2015	Under Review	100.00%
Dave Johnston 2	1960	2027	106	Not Planned	N	N	Not Planned	Not Planned	Not Planned	Not Planned	Y - Cold Side	-	Not Planned	Sorbent Injection	2015	Under Review	100.00%
Dave Johnston 3	1964	2027	220	Not Planned	Y	Y	Not Planned	Not Planned	Y	N/A	Y - Cold Side	-	Y	Sorbent Injection	2015	Not Planned	100.00%
Dave Johnston 4	1972	2027	330	Not Planned	Y	Y	Not Planned	Not Planned	2012	N/A	Y - Cold Side	-	2012	Sorbent Injection	2015	Not Planned	100.00%
Hayden 1	1965	2030	184	Not Planned	Y	Y	Not Planned	2015	Y	N/A	N/A	-	Y	Sorbent Injection	2015	Not Planned	24.46%
Hayden 2	1976	2030	262	Not Planned	Y	Y	Not Planned	2016	Y	N/A	N/A	-	Y	Sorbent Injection	2015	Not Planned	12.60%
Hunter 1	1978	2042	430	Not Planned	2014	2014	Not Planned	Not Planned	N/A	Y	Y - Cold Side	-	2014	Coal Oxidizer	2015	Not Planned	93.75%
Hunter 2	1980	2042	430	Not Planned	2011	2011	Not Planned	2023	N/A	Y	Y - Cold Side	-	2011	Coal Oxidizer	2015	Not Planned	60.31%
Hunter 3	1983	2042	460	Not Planned	Y	Y	Not Planned	2024	N/A	Y	N/A	-	Y	Coal Oxidizer	2015	Not Planned	100.00%
Huntington 1	1977	2036	445	Not Planned	Y	Y	Not Planned	2023	N/A	Y	Y - Cold Side	-	Y	Coal Oxidizer	2015	Not Planned	100.00%
Huntington 2	1974	2036	450	Not Planned	Y	Y	Not Planned	Not Planned	N/A	Y	N/A	-	Y	Coal Oxidizer	2015	Not Planned	100.00%
Jim Bridger 1	1974	2037	530	Not Planned	Y	Y	Not Planned	2022	N/A	Y	Y - Cold Side	-	Not Planned	Sorb Inj + Oxidizer	2015	Not Planned	66.67%
Jim Bridger 2	1975	2037	527	Not Planned	Y	Y	Not Planned	2021	N/A	Y	Y - Cold Side	-	Not Planned	Sorb Inj + Oxidizer	2015	Not Planned	66.67%
Jim Bridger 3	1976	2037	530	Not Planned	Y	Y	Not Planned	2015	N/A	Y	Y - Cold Side	-	Not Planned	Sorb Inj + Oxidizer	2015	Not Planned	66.67%
Jim Bridger 4	1979	2037	530	Not Planned	Y	Y	Not Planned	2016	N/A	Y	Y - Cold Side	-	Not Planned	Sorb Inj + Oxidizer	2015	Not Planned	66.67%
Naughton 1	1963	2029	160	Not Planned	2012	2012	Not Planned	Not Planned	N/A	2012	Y - Cold Side	-	Not Planned	Sorb Inj + Oxidizer	2015	Not Planned	100.00%
Naughton 2	1968	2029	210	Not Planned	2011	2011	Not Planned	Not Planned	N/A	2011	Y - Cold Side	-	Not Planned	Sorb Inj + Oxidizer	2015	Not Planned	100.00%
Naughton 3	1971	2029	330	Not Planned	Y	Y	Not Planned	2014	N/A	Y	Y - Cold Side	-	2014	Sorb Inj + Oxidizer	2015	Not Planned	100.00%
Wyodak	1978	2039	335	Not Planned	2011	2011	Not Planned	Not Planned	Y	N/A	Y - Cold Side	-	2011	Sorbent Injection	2015	Not Planned	80.00%

Exhibit 4

CAI Capital Projects Study

PacifiCorp's 10-year plan includes multiple comprehensive air initiative (CAI) projects for the coal generation fleet. This analysis addresses, on a macro basis, whether continued unit operations of the company's coal plants through the regulatory depreciation life, produces enough net value to pay for the proposed CAI capital. The present value evaluation takes a merchant plant analysis approach in that each unit's revenue requirement cost is netted against the value of the unit's generation as measured by the forward price curve at projected CO2 price levels. The results of the analyses indicate that at the $8 per ton CO2 price level assumption basis for PacifiCorp's 2009 10-year business plan, all the coal units will be above breakeven in terms of present value revenue requirement differential (PVRR(d)).

The PVRR(d) comparison of continued unit operations with CAI capital versus market value of generation is shown in the attached charts.

Study Approach

The study represents a macro effort to analyze the economics of PacifiCorp's coal fleet with respect to PacifiCorp's plan for CAI capital projects.

The analysis calculates the cumulative incremental PVRR(d) benefit or (detriment) of operating each unit from 1/1/2009 through each successive year through its regulated depreciation life. The PVRR is derived by subtracting the operating and capital revenue requirements from the market value of generation, assuming that the unit end of life is extended in one year increments. The $8 CO2 scenario utilizes the 2009 10-year plan capacity factors.

The PVRR(d) is calculated by subtracting fuel, O&M, environmental emissions cost, and on-going and CAI capital revenue requirement cost from revenue similar to a merchant plant valuation. The revenue is derived using forward price curves from Structure and Pricing's model runs at the $8 CO2 price scenario.

Key Assumptions

Pricing

1. Forward flat price curves for the \$8/ton CO_2 price scenario, as of 12/31/2008, were provided through the end of the study period.
2. Fuel pricing was provided through 2018 from the 2009 10-year plan; prices were escalated at the corporate escalation rate thereafter.
3. Forward price curves do not include the market effects of plant closure(s).

Revenues

1. The analysis period for calculating capital payback is assumed to begin in 2009.
2. Dispatch is based on annual capacity factors derived from the approved 2009 10-year plan capacity factors.
3. Potential extrinsic optionality value in dispatch is not included.

Capital / O&M

1. CAI capital dollars are taken from the approved 2009 10-year plan.
2. The 10-year plan contains multiple CAI projects that go into service in different years.
3. Existing capital is considered a "sunk cost" and is not included.
4. On-going capital and O&M costs from the 10-year plan have been included. Capital and O&M beyond the 10-year plan are based on the company's Strategic Asset Plan.
5. Plant/Unit decommissioning costs of \$40 per installed kW (corporate assumption, 2009 dollars) are included in the year of closure, adjusted at corporate escalation rates.

Other

1. The capacity factors for the \$8 CO_2 scenario are from the 10-year plan GRID run.
2. Discount rate is 7.1%.
3. Analysis life is assumed to be from 2009 through the Utah Commission stipulated book depreciation lives.
4. Full regulatory recovery of all existing and future costs is assumed.
5. SO_2 allowance costs are included based upon corporate emission forward price forecasts.

CAT-3R

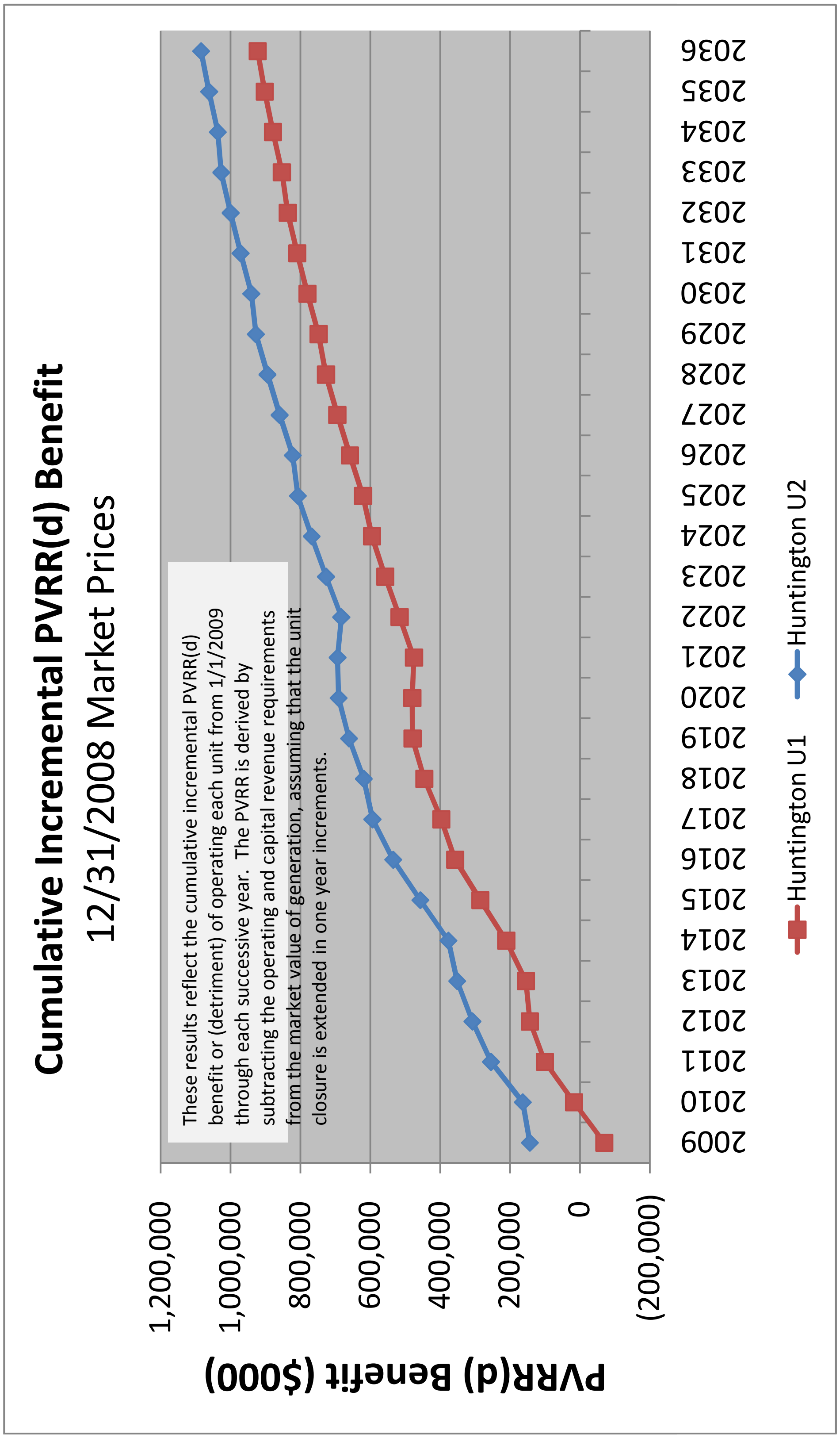
Significant CAI Capital Included

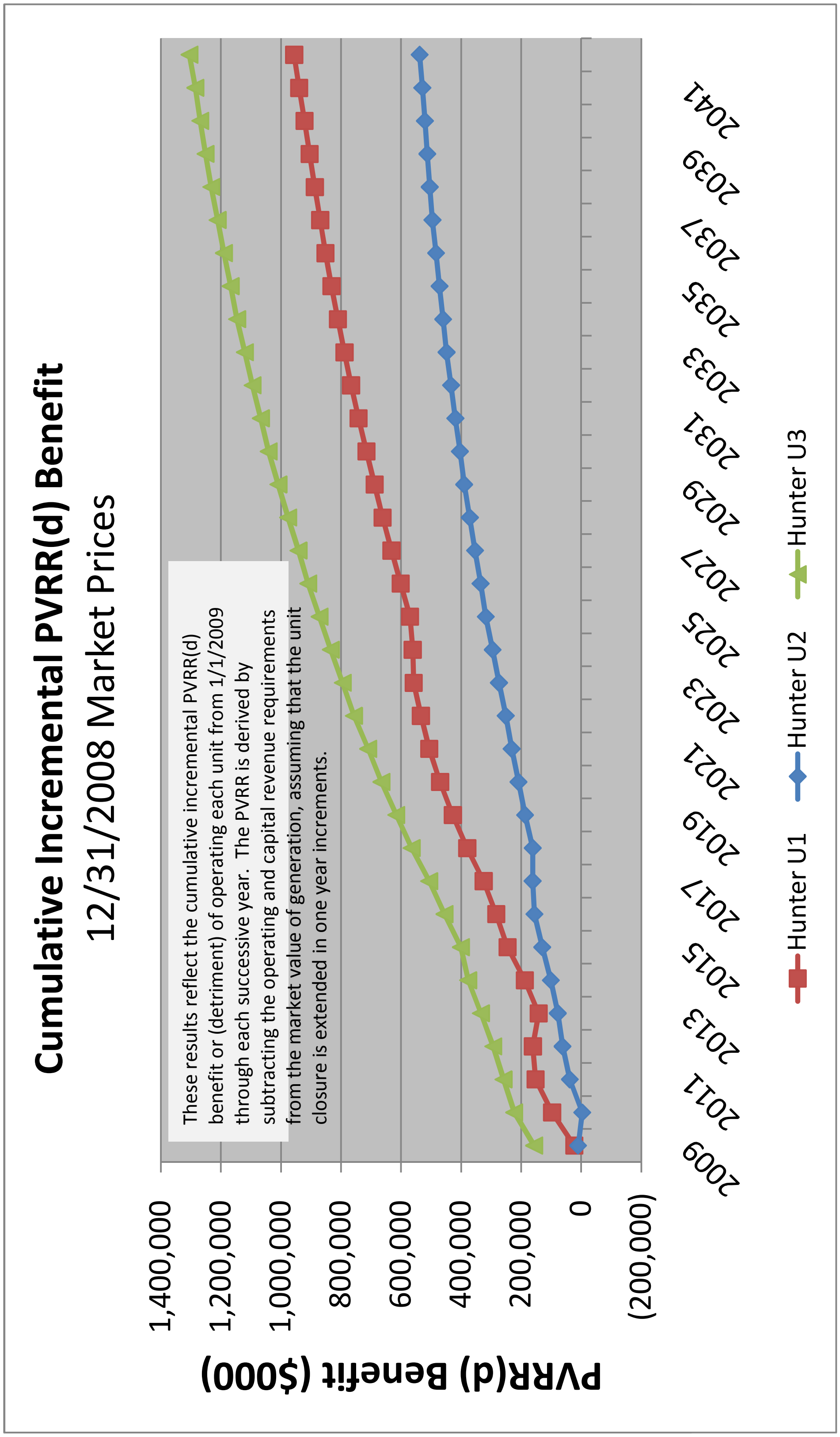
Table 1: Major pollution control equipment costs by year for PacifiCorp owned coal-fueled units included in economic analyses.

Pollutant/Equipment	SOx		PM	NOx	
Unit	Phase 1[1]	Phase 2[2]	Baghouse[3]	LNB	SCR[4]
Hunter 1	2010		2010	2010	2022
Hunter 2	2011		2011	2011	2023
Hunter 3					2016
Huntington 1	2010		2010	2010	2022
Jim Bridger 1	2010	2030		2010	2022
Jim Bridger 2	2009	2029			2021
Jim Bridger 3	2011	2027			2015
Jim Bridger 4	2008	2028		2012	2016
Naughton 1	2012			2012	2027
Naughton 2	2011			2011	2026
Naughton 3	2014		2014		2024
Wyodak	2011		2011	2011	2026

Notes

1 Phase 1 implies baseline scrubber upgrades across the fleet.
2 Phase 2 implies new technology and/or equipment installation to achieve 95% sulfur dioxide removal rate on the Jim Bridger units.
3 Baghouse and scrubber installations also reduce mercury emissions and support anticipated HAPs MACT compliance as a co-benefit.
4 The company has included these SCRs in the economic analyses to add conservatism to the PVRR(d) results presented. The SCRs at Jim Bridger and Naughton are required; however, no company commitments or agency actions have been taken that require installation of the other SCRs listed.


Cumulative Incremental PVRR(d) Benefit
12/31/2008 Market Prices
These results reflect the cumulative incremental PVRR(d) benefit or (detriment) of operating each unit from 1/1/2009 through each successive year. The PVRR is derived by subtracting the operating and capital revenue requirements from the market value of generation, assuming that the unit closure is extended in one year increments.
PVRR(d) Benefit ($000)
1,200,000
1,000,000
800,000
600,000
400,000
200,000
0
(200,000)
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
Huntington U1
Huntington U2


Cumulative Incremental PVRR(d) Benefit
12/31/2008 Market Prices
PVRR(d) Benefit ($000)
1,400,000
1,200,000
1,000,000
800,000
600,000
400,000
200,000
0
(200,000)
2009
2011
2013
2015
2017
2019
2021
2023
2025
2027
2029
2031
2033
2035
2037
2039
2041
These results reflect the cumulative incremental PVRR(d) benefit or (detriment) of operating each unit from 1/1/2009 through each successive year. The PVRR is derived by subtracting the operating and capital revenue requirements from the market value of generation, assuming that the unit closure is extended in one year increments.
Hunter U1
Hunter U2
Hunter U3

Sierra Club/Exhibit 4

Rocky Mountain Power
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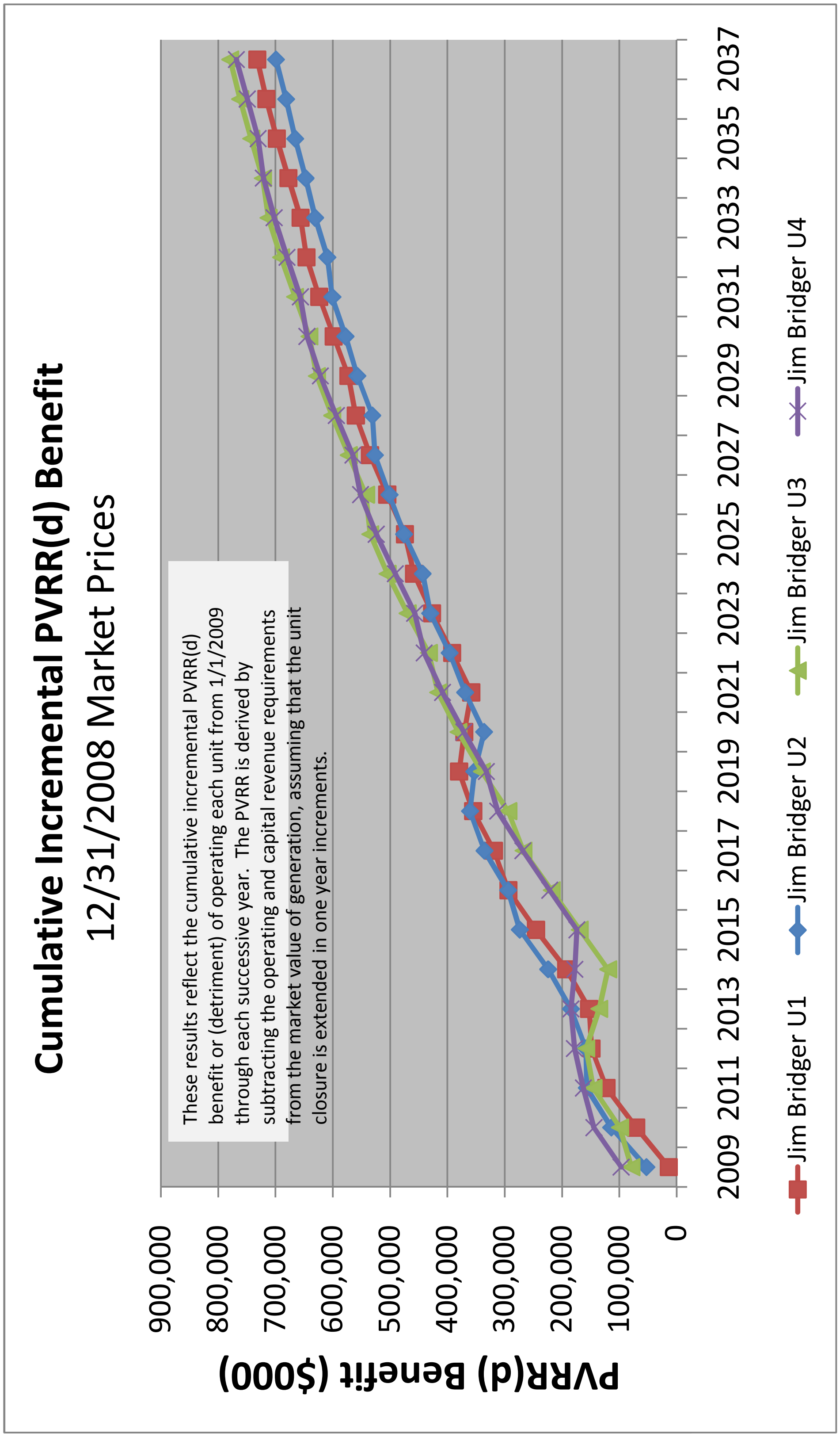
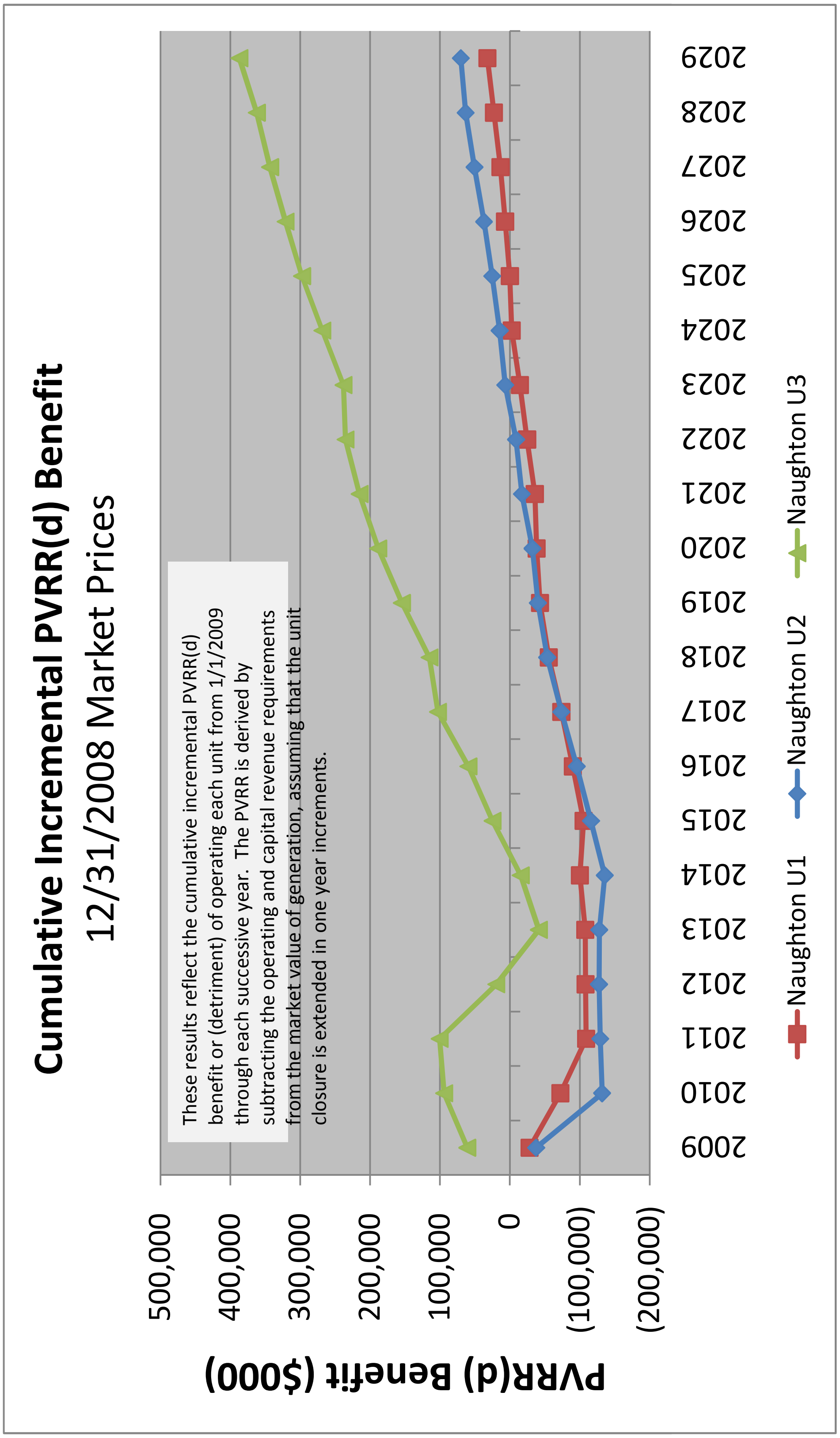
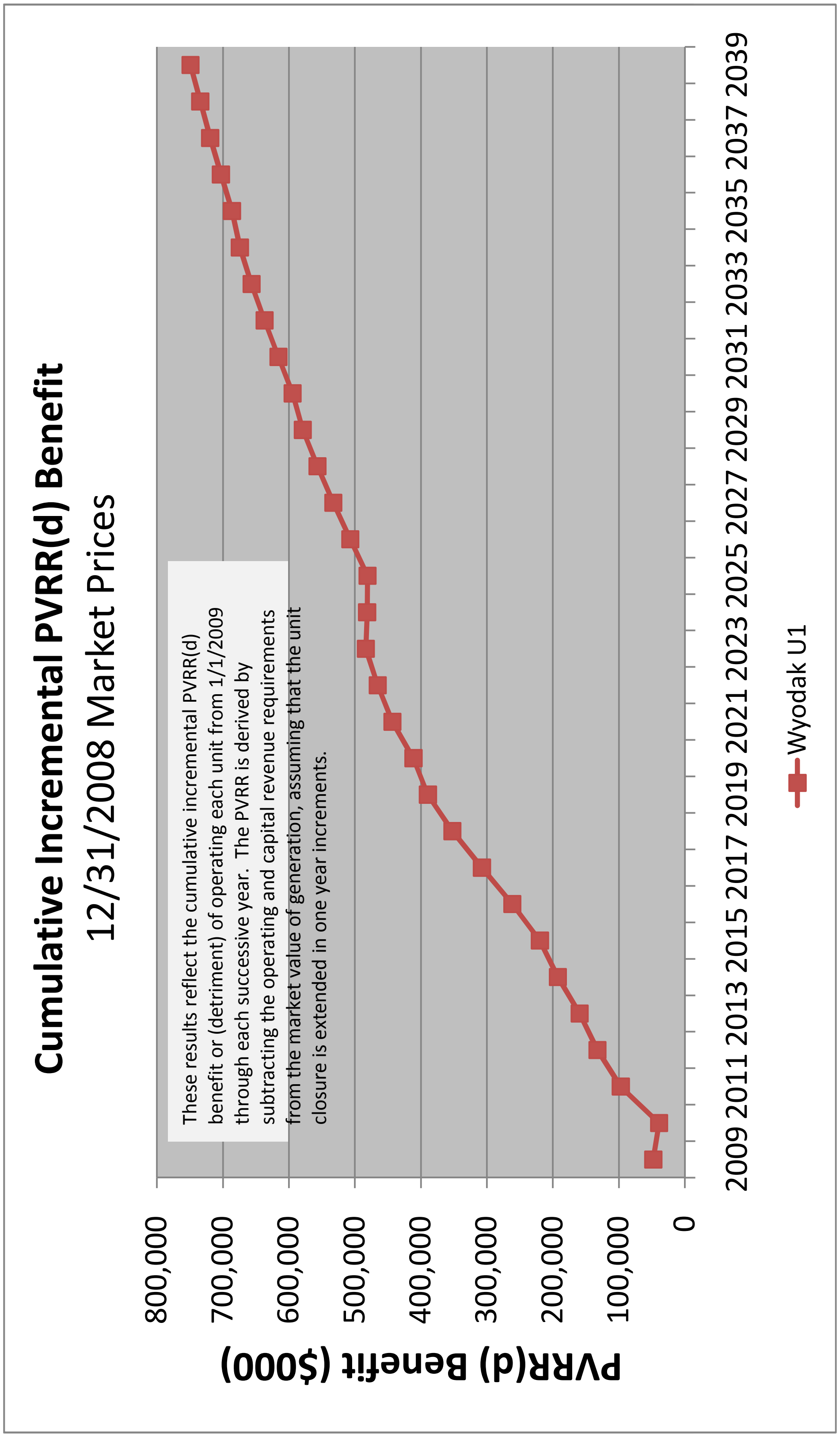
Docket No. 20000-384-ER-10
Witness: Chad A. Teply




Cumulative Incremental PVRR(d) Benefit
12/31/2008 Market Prices
These results reflect the cumulative incremental PVRR(d) benefit or (detriment) of operating each unit from 1/1/2009 through each successive year. The PVRR is derived by subtracting the operating and capital revenue requirements from the market value of generation, assuming that the unit closure is extended in one year increments.
PVRR(d) Benefit ($000)
500,000
400,000
300,000
200,000
100,000
0
(100,000)
(200,000)
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
Naughton U1
Naughton U2
Naughton U3

Sierra Club/Exhibit 4



CERTIFICATE OF SERVICE

I hereby certify that on this 25th day of August, 2011, I caused to be served the foregoing SIERRA CLUB COMMENTS on all party representatives on the official service list for this proceeding via electronic mail.

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Dated this 25th day of August, 2011 at San Francisco, CA.

/s/

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