BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 246

In the Matter of

PACIFICORP, dba PACIFIC POWER's
Request for a General Rate Revision.

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RESPONSE TESTIMONY
OF THE
CITIZENS' UTILITY BOARD OF OREGON

June 20, 2012

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I. Introduction

CUB submits its Response Testimony in this docket with the knowledge that all issues presented by PacifiCorp (or, hereafter, "the Company") in its initial filing are on the table. The first round of settlement negotiations on May 30 ended without the parties reaching even a partial settlement of the issues.

CUB's testimony in this docket will focus two major topics. Section II addresses the Company's proposal to establish a Power Cost Adjustment Mechanism (PCAM) in Oregon. Section III outlines CUB's rationale in calling for further review and greater scrutiny regarding PacifiCorp's capital investments in its fleet of coal-fired generation plants. Section IV discusses the prudence of PacifiCorp's recent investments in clean air compliance technology at its coal plants. Section V contains CUB's detailed recommendations for PacifiCorp's coal investments at each individual plant. Section VI concludes the testimony and includes a summary of CUB's adjustments.

II. PacifiCorp's Request for a PCAM

PacifiCorp cites ORS 469A.120(1) as the enabling legislation that allows utilities to collect all prudently incurred costs associated with compliance with the RPS in rates, including "costs associated with using physical or financial assets to integrate, firm or shape renewable energy sources on a firm annual basis to meet retail electricity needs and other costs associated with transmission and delivery of qualifying electricity to retail electricity consumers." The Company states that it intended to recover all such costs through the TAM and RAC proceedings, but that the GRID model has systematically underestimated net power costs in its forecasts.

A. PacifiCorp's Justification for the Creation of a PCAM

While CUB has reservations regarding PacifiCorp's proposal for a PCAM in addition to its annual TAM and RAC filings, we recognize that it is possible to create one that is not as objectionable as the Company's proposal. Both PGE and Idaho Power have utilized a PCAM in Oregon for the past few years, and in both cases the mechanism has served its purpose of bringing rates back into line with power costs when there are significant cost fluctuations. CUB has a number of concerns with PacifiCorp's proposed mechanism, as it differs from those used by PGE and Idaho Power in numerous ways.

i. Wind Variability vs. Hydro Variability

PacifiCorp bases the bulk of its argument in support of a PCAM on the fact that the costs of integrating, firming, and shaping its wind generation portfolio are inherently variable and difficult to forecast. CUB certainly acknowledges that wind generation comes with a degree of unpredictability that affects PacifiCorp's generation portfolio on an hourly basis. The same can be said, however, of the variability of hydro generation.

Excursions from anticipated levels of wind generation may cause differences in net power costs for periods of hours or days due to balancing issues; hydro-dependent utilities must rely on higher-cost generation and market purchases to make up for reduced hydro generation. The Commission acknowledged as much in its Order establishing PGE's PCAM:

> We conclude that a PCAM should be adopted to capture power cost variations that exceed those considered part of normal business risk. In this case, normal business risk for PGE includes all of the circumstances to which it is exposed, such as hydro variability.[1]

PacifiCorp expresses its belief that Oregon's Renewable Portfolio Standard (RPS) is the primary reason for its increased reliance on wind generation, and therefore its increased costs associated with integrating, firming, and shaping.[2] The Company expresses additional concern that the increase in the level of the RPS to 25 percent in 2025 will cause a further increase in net power costs as a result of the associated unpredictability of wind generation.[3] CUB recognizes that the challenge of balancing renewable generation has led to increased costs for PacifiCorp, and that the Company has a right to include these costs in net power costs. The level of variability in PacifiCorp's portfolio, however, has not been demonstrated to be significantly greater than that in PGE's portfolio, which is also subject to the RPS. CUB therefore does not view costs associated with renewable generation as a singular compelling reason for a PCAM that shields PacifiCorp from being liable for net power cost excursions.

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[1] OPUC Order No. 07-015, page 26.
[2] UE 246 / PacifiCorp / 900 / Duvall / 16.
[3] UE 246 / PacifiCorp / 900 / Duvall / 28, lines 19-21.

ii. Right to Recover Costs vs. Opportunity to Recover Costs

PacifiCorp proposes a PCAM that would allow for a "dollar-for-dollar recovery of prudent NPC and would not use sharing bands, deadbands, or an earnings review."[4] In other words, the Company wants to eliminate the risk that it is ever liable for net power costs that exceed the base estimate established in rates. Oregon principles of ratemaking dictate that the Commission sets rates that will allow utilities to cover their reasonably-incurred costs based on a forecast of generation and distribution costs and customer load projections. It is then up to the utility to manage its costs to within the revenue generated by these rates, as it is not guaranteed such cost recovery. Oregon has traditionally recognized that shareholders absorb some of the normal variation (both positive and negative) that happens between rate cases before shifting that risk to customers. True-ups such as the PCAM are rarely used as a means to ensure cost recovery, and when they are, it is never on a dollar-for-dollar basis, as is being proposed here.

This proposal indicates that PacifiCorp believes it does not need to control its net power costs. Without deadbands or a sharing mechanism, the Company would have very little incentive to work to minimize its net power costs, as these would simply become a pass-through expense to customers. PacifiCorp's proposed PCAM design would result in a risk reduction that would in turn warrant a substantial decrease in the Company's authorized Return on Equity, as shareholders would see their risk of investment significantly reduced.

iii. PacifiCorp's Wind Generation Is Included in Ratebase

The net power costs that PacifiCorp is seeking to recover by establishing a PCAM derive from generation facilities that are in the Company's rate base. PacifiCorp,

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[4] UE 246 / PacifiCorp / 900 / Duvall / 29, lines 6-7.

therefore, is receiving cost recovery on all of its owned generation resources, including its wind generation, which has a marginal generation cost of near zero outside of integration, shaping, and firming. This cost recovery provides a low-risk return on investment for the Company's shareholders. The risk of net power costs exceeding their forecast level is, to CUB, an acceptable tradeoff for the return PacifiCorp is receiving on its rate-based generation resources.

The 2010 Oregon Utility Statbook shows that PacifiCorp's owned generation accounts for over 83% of its total available power, while PGE's owned generation is only 47% of its total.[5] PGE has a much lower level of ratebase compared to PacifiCorp, yet it manages to make do with a PCAM that includes deadbands and a sharing mechanism. Idaho Power, which is in a similar position to PacifiCorp with owned generation making up an 86% of its portfolio, also has a PCAM with deadbands and a sharing mechanism. CUB sees no reason why PacifiCorp's PCAM should shield the Company from the risk of actual net power costs exceeding the forecast values when Oregon's other investor-owned utilities do not enjoy a dollar-for-dollar true-up of costs.

iv. PacifiCorp Has Adjustments in Other States

PacifiCorp claims that it has under-recovered net power costs by over $500 million in the past five years. Table 8 in PacifiCorp/900 shows that these figures are based on the Company's Oregon TAM proceedings, using systemwide numbers for estimated and actual net power costs. CUB does not dispute the differential between the Company's estimated and actual costs; however, the total differential will not be solved simply by implementing a dollar-for-dollar PCAM in Oregon. Oregon represents roughly one quarter of PacifiCorp's system load; as such, an adjustment here, even if it is dollar-

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[5] http://www.oregon.gov/puc/docs/statbook2010.pdf, page 18.

for-dollar, will enable the Company to recover no more than one quarter of any overruns in systemwide net power costs.

The Company has PCAM or other power cost true-ups in place in other jurisdictions. CUB finds it curious that PacifiCorp provides a list of PCAMs and similar adjustments for utilities around the country,[6] yet makes no mention anywhere in its testimony of the mechanisms that are in place in the Company's own service territory. Until recently PacifiCorp's Wyoming territory, the Company's PCAM included deadbands of $40 million and a graduated schedule for sharing costs overruns and/or savings with customers.[7] The Wyoming PSC adopted a new true-up for PacifiCorp called the Energy Cost Adjustment Mechanism (ECAM) on April 1, 2012.[8] This adjustment does not have any deadbands, but does have a sharing mechanism. Customers are responsible for 70% of net power cost overages and are refunded 70% of net power cost savings by the Company through the ECAM billing adjustment. Identical ECAMs are in place in PacifiCorp's service territory in Washington and Utah, and the Company's Idaho service territory has an ECAM with a 90% sharing split.[9]

B. CUB's Proposed PCAM Design

Additional net power costs that are captured in the PCAM should only add to PacifiCorp's rates in extreme circumstances. The mechanism should not be triggered except in rare circumstances where power costs are well beyond the normal range. The

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[6] PacifiCorp Exhibit 901.

[7] Rocky Mountain Power Power Cost Adjustment Mechanism – Schedule 94. Wyoming PSC. https://www.efis.psc.mo.gov/mpsc/commoncomponents/viewdocument.asp?DocId=515454530, pages 17-25.

[8] Rocky Mountain Power Energy Cost Adjustment Mechanism – Schedule 95. Wyoming PSC. http://www.rockymountainpower.net/content/dam/rocky_mountain_power/doc/About_Us/Rates_and_Regulation/Wyoming/Approved_Tariffs/Rate_Schedules/Energy_Cost_Adjustment_Mechanism.pdf.

[9] PacifiCorp 2011 Year-End 10-K Filing. http://www.midamerican.com/include/pdf/sec/20111231_89_pc_annual.pdf.

design of the mechanism therefore requires that minor excursions in power costs do not result in changes to rates, and that the Company's earnings should not exceed the allowed rate of return as a result of a PCAM adjustment. To ensure that the PCAM will work for this purpose, it must include deadbands and an earnings test, as well as a sharing component that provides an incentive for the Company to work to reduce its net power costs.

i. Deadbands

The deadbands and sharing mechanisms in PacifiCorp's PCAM do not have to be symmetrical. Utility regulation is not symmetrical, as a utility always has a greater ability to raise rates when costs go up than customers have the opportunity to lower rates when costs go down. Take, for example, natural gas prices, which are currently in the range of $2/MMBtu. While gas prices may decrease further over the course of the next year, prices will not drop below zero. On the other hand, there is no ceiling on how high prices may increase in the future. The risk to the Company of power costs being lower than forecast is therefore limited, whereas the risk to customers of power costs being higher than forecast is unlimited. Asymmetrical deadbands and sharing percentages compensate for the asymmetrical nature of the risk of power cost excursions.

The Commission should adopt an asymmetrical deadband and sharing percentage in order to protect customers from higher rates except where extreme cost increases make it necessary, while also ensuring that customers receive rate relief when net power costs fall. CUB proposes that the Commission adopt the same deadband structure for PacifiCorp's PCAM as is in place in PGE's PCAM created by Commission Order No. 07-015. This deadband should cover the range in net power cost variation from 75 basis points of the Company's ROE below the base level of NVPC included in rates up to 150 basis points of ROE above the base level. The sharing of expenses should follow the design of PGE's PCAM as well, with 90 percent of expenses or savings assigned to customers and 10 percent to the Company. This design will provide an incentive to PacifiCorp to encourage the effective management of its net power costs.

ii. Earnings Test

CUB recommends that the Commission adopt an earnings test that will be applied to PacifiCorp's PCAM to ensure that the mechanism does not cause the utility to substantially over- or under-earn. The Commission established an earnings test for PGE in Order No. 07-015 of +/- 100 basis points of the utility's ROE; CUB views this as a reasonable earnings test for PacifiCorp as well. If the Company's earnings are within 100 basis points of its authorized ROE, the PCAM will not trigger an adjustment in net power costs. If earnings are more than 100 basis points below PacifiCorp's authorized ROE, 90 percent of excess net power costs outside of the deadband shall be recovered by the Company from customers. Conversely, if earnings are more than 100 basis points below PacifiCorp's authorized ROE, 90 percent of the savings in net power costs outside of the deadband shall be refunded to customers.

iii. Potential Outcomes

CUB Table 1 depicts the potential scenarios that can occur under the PCAM. Out of nine potential outcomes between the deadbands and the earnings test, the PCAM is only triggered twice—once for a customer refund and once for a customer surcharge. While CUB recognizes that the likelihood of these events is not evenly distributed, the table does point out that the Company is rather unlikely to be in a position where it would required to refund money to customers. Even when this scenario is triggered, the sharing mechanism ensures that PacifiCorp's risk exposure is minimized. In all other scenarios the adjustment is either relatively small compared to the Company's overall costs (within the deadband) or will not drastically affect the Company's earnings (within the earnings test).

Table 1. *Potential PCAM Adjustment Scenarios*

Deadband	***Earnings Test***	***Result***
Within	Within	No adjustment
Within	100 bps Above	No adjustment
Within	100 bps Below	No adjustment
150 bps Above	Within	No adjustment
150 bps Above	100 bps Above	Refund to Customers
150 bps Above	100 bps Below	No adjustment
75 bps Below	Within	No adjustment
75 bps Below	100 bps Above	No adjustment
75 bps Below	100 bps Below	Surcharge to Customers

As stated above, CUB maintains that the deadbands and earnings test are intended to ensure that the PCAM only results in adjustments to customers' rates when changes in net power costs have a significant impact on the Company's finances. Fluctuations in net power costs within the deadbands are an acceptable business risk that is accounted for in the calculation of PacifiCorp's ROE. CUB sees no compelling reason why the Commission should grant PacifiCorp a dollar-for-dollar PCAM that eliminates any risk of changes in net power costs to the Company.

III. Why Coal Investments Deserve Greater Examination

This section outlines CUB's reasoning of why PacifiCorp's investments in coal plants need further analysis and scrutiny.

A. Coal Investments Should Be Scrutinized

Coal investments have become risky due to the potential for increased regulation on carbon emissions due to mounting evidence of their contribution to climate change. Many scientists argue that coal plants will have to be closed in the coming years in order to stabilize atmospheric carbon levels.[10] While it is, and has been, possible for utilities to model expected carbon regulatory costs, it is difficult for utilities to model the actual regulatory risk associated with the political response to climate change in the coming decades. This is because the risk of coal investment does not actually reflect a linear path that can be depicted in a graph, and is therefore not accurately accounted for in resource planning models.

PacifiCorp is a part-owner of coal plants in Colorado, a state where voters passed the nation's first Renewable Portfolio Standard (RPS) in 2004.[11] The ultimate risk to these plants is that the Colorado RPS will require them to close earlier than their prior useful life assessment would indicate. Numerous other states have similar RPS requirements, and carbon regulations and other mandates at the federal level further threaten the early closure of many of the country's coal plants.

At the same time, it must be recognized that the Oregon PUC has no authority to regulate carbon emissions. The PUC is an economic regulator that establishes the rates that a utility can charge its customers and is not charged with crafting environmental regulations. Because of the risks associated with future carbon regulation, the Commission should scrutinize investments in coal plants and only make such investments

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[10] Davis, Steven J., Ken Caldeira, and H. Damon Matthews. "Future CO_2 Emissions and Climate Change from Existing Energy Infrastructure." *Science* 10 September 2010. http://www.sciencemag.org/content/329/5997/1330.short

[11] US EPA. http://epa.gov/statelocalclimate/documents/pdf/co_rps_shafer.pdf.

when they are cost effective. Each time a utility is required to make a significant investment in a coal plant, that utility should take the opportunity to reexamine all of its investment plans in that coal plant to ensure that the necessary investment, when combined with future expected investments and regulatory costs, is prudent and reasonable. The Commission must then review the utility's decision on whether its investment was prudent and reasonable.

Put another way, when it is cheaper to close a plant or convert it to a lower-carbon resource, utilities and the Commission should take the opportunity to reduce carbon emissions and to reduce costs to consumers. This will reduce exposure to the future risk of carbon regulation and coal moratoriums. In today's era, this approach should be a no-brainer.

Unfortunately, PacifiCorp has invested a great deal of customer-backed money in coal plants over the past decade without a close examination of whether there are cheaper alternatives for generation. If a utility does not examine its alternatives, it will never find opportunities to reduce costs and carbon emissions by moving away from coal.

CUB has been clear in the IRP process that significant clean air investments, like any major investment in utility generation, should be subject to least-cost/least-risk analysis. PacifiCorp, to its credit, has finally accepted this idea. The Company's first attempt at such an IRP analysis (the Fall IRP Supplement filed September 21, 2011) was fatally flawed because it assumed that all costs made before 2015 to comply with 2015 deadline for environmental investments were sunk costs and could therefore not be avoided. It then tested whether it was least-cost to close the plant in 2015.[12] The March 2012 IRP update provided a much more detailed analysis on a limited scope of coal units.

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[12] LC 52 - CUB Reply Comments filed November 3, 2011 at page 5.

Though an improvement, this analysis failed to consider alternative closure dates. It is unfortunate, however, that the Company has finally provided some good analysis but has already invested hundreds of millions of dollars in these coal plants, including the investments at issue in this docket.

B. PacifiCorp Seeks Opportunities to Make Capital Investments

Since MEHC acquired PacifiCorp, rates for Oregon customers have gone through the roof. MEHC claimed that it could purchase PacifiCorp, invest a great deal in its generation and distribution systems, and prevent rates from increasing more than 4% per year. MEHC has so far failed to meet that claim. Instead, rates have increased by 60%, more than double the pace of increase in Portland General Electric's rates.[13] The primary driver of higher rates has been capital investments, especially the Company's strategy of investing in multiple projects simultaneously: wind, coal, gas, and transmission. Figure 1 is a chart from a presentation MEHC made to an investor's conference touting how much capital investment the Company would be making over the next few years.[14]

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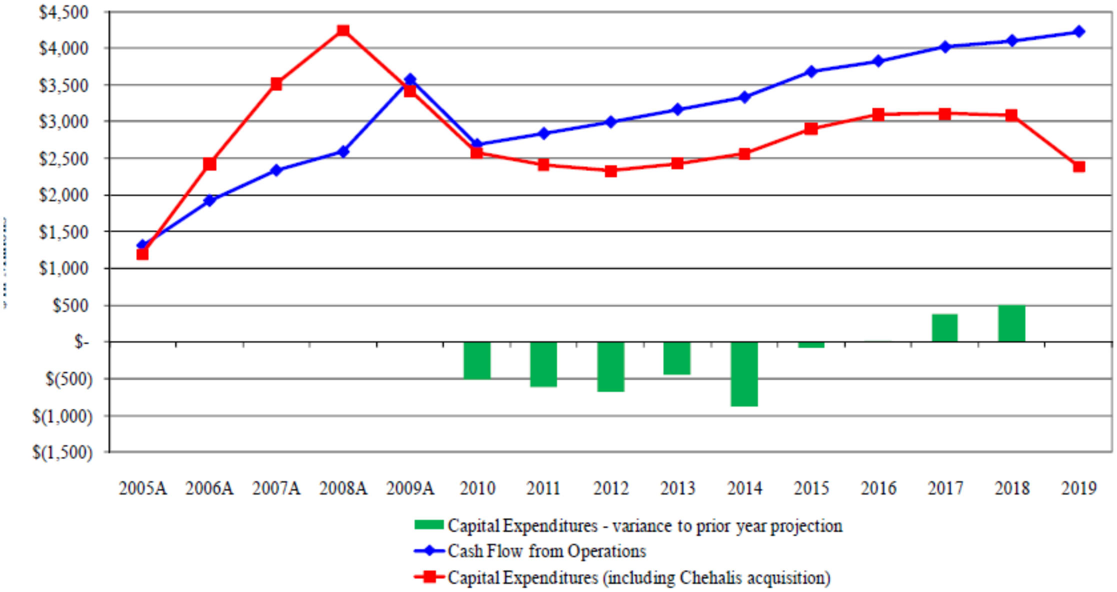
[13] UE 227 / CUB / 100/ Jenks - Feighner / 12-14.

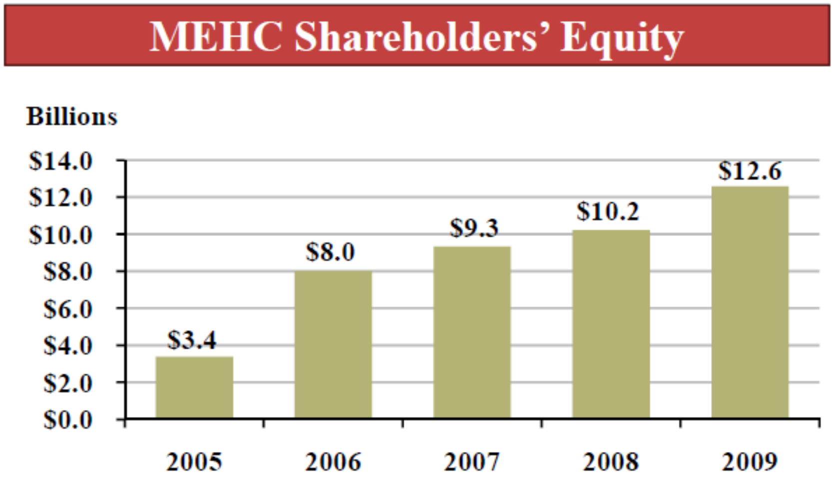
[14] CUB Exhibit 102 - page 13

Figure 1: *PacifiCorp's Annual Capital Investment, 2005-2019 (in $millions)*



Capital investment is important to the Company because it allows MEHC to increase shareholder equity, and therefore the return on that equity. Figure 2 illustrates the growth in shareholder equity since MEHC acquired PacifiCorp:[15]

Figure 2: *MidAmerican Shareholders' Equity (in $billions)*



The driver for capital investment at MEHC is PacifiCorp. If MEHC is going to come close to its goals for capital investment, the vast majority of the costs of these investments will fall on PacifiCorp ratepayers, as shown in Figure 3:[16]

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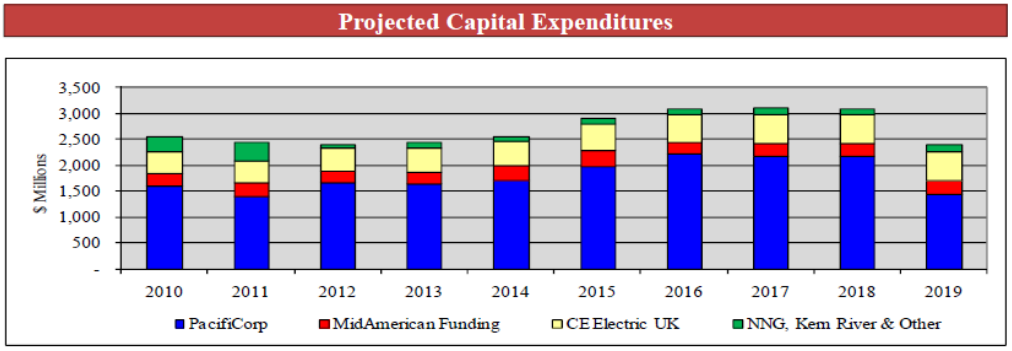
[15] *Ibid*, page 9.

Figure 3: MEHC Projected Annual Capital Expenditures, 2010-2019 (in $millions)



CUB is concerned that PacifiCorp has not adequately analyzed the investments at issue in this case. The analysis that was done before making these clean air investments seemed to be designed to support the investment in case of a prudence review, rather than identify the least-cost approach to meeting the needs of its customers. Customers need assurance that PacifiCorp is meeting its responsibility to conduct least-cost analysis before it makes any capital investments. It would be helpful if the Company saw capital investments as costs that can be avoided, rather than opportunities to increase its shareholder equity.

C. Consequences of Prudence and Imprudence

Whether a utility is prudent or not is usually judged on what the utility knew or should have known when it made a decision. Since it seems like a variety of parties intend to address this extensively in briefs, CUB will not spend much time discussing it here.

But prudent and imprudent actions can have a variety of consequences. In retrospect an action can be good, bad, or indeterminate. The results of a prudent decision

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[16] *Ibid.*, page 14.

by a utility can be good, bad or indeterminate. The Commissions does not judge prudency by its results, but instead recognize that the results of all kinds of actions can vary.

When a utility makes a prudent investment decision, the utility is generally able to recover its prudently incurred investment costs even if its decision turns out to be harmful in hindsight—assuming that the investment is used and useful. But what are the consequences of an imprudent decision, if upon review it is found that the decision was actually beneficial to customers? Do customers pay for the imprudence?

Table 2: *Potential Outcomes of Prudence Decisions*

Type of Decision	**Review Findings**	**Regulatory Consequences**
Prudent	Beneficial	Rate recovery
Prudent	Harmful	Rate recovery
Prudent	Indeterminate	Rate recovery
Imprudent	Harmful	No Rate Recovery
Imprudent	Beneficial	?
Imprudent	Indeterminate	?

In theory, the regulatory consequences of prudent and imprudent decisions by a utility should be parallel. If a prudent decision allows rate recovery for an investment regardless of whether the investment is beneficial, or harmful, then an imprudent decision should lead to no rate recovery regardless of whether the consequences are beneficial or harmful.

While CUB believes that such a parallel construction of prudence and imprudence makes sense and seems fair, we recognize that a large prudence disallowance, when there is no financial harm to customers, may be a stretch for many regulators. At the same time, CUB feels strongly that imprudent actions by utilities should lead to some consequences. If a utility is generally allowed to recover its prudently incurred costs regardless of whether its actions are beneficial, then the utility should face consequences for imprudent acts regardless of whether those acts are harmful.

In this case, CUB is not arguing that PacifiCorp was imprudent with regards to actions that have created benefits. CUB is arguing that PacifiCorp was imprudent with regards to actions that have harmed customers. The exact level of harm is, however, difficult to quantify. It is easy to identify errors in the Company's analysis. It is easy to show that promising alternatives to these coal investments were not considered. But it is difficult to model and demonstrate what would have happened if the Company had considered different options, modeled its analysis differently, approached state regulators differently, modified its investment timeline, and generally followed a more prudent course.

It may be surprising to consider, but the most difficult part of this case is not determining whether PacifiCorp's actions were prudent—they were not. The most difficult part of this case is determining what to do about PacifiCorp's imprudence. CUB thinks there are some options:

Option 1: The Commission could simply disallow investments that are not prudent.

Option 1 seems to CUB to be that the Commission could simply disallow investments that are not prudent. Logically, this makes a lot of sense. If a utility was imprudent in its analysis of an investment and goes forward and makes that investment, disallowing that imprudent cost seems to be straightforward and reasonable.

The consequences of disallowing an imprudent capital investment related to an existing plant that has itself been considered to be prudent, however, are uncertain. If CUB proposes to disallow an imprudent cost that is intended to meet a 2015 environmental deadline related to an otherwise prudent plant, the Company will likely argue that for regulatory purposes the OPUC should no longer base rates on that plant and consider it closed for ratemaking purposes in 2015. This is a problem because the underlying asset is still used and useful in 2015, and customers have a right to the benefits of the investment they have financed through their rates. Complicating this issue is CUB's concern that one of the reasons that some of these investments are not prudent is that the Company did not consider possible alternative closure dates. So the Commission finding that an investment is imprudent because the Company failed to consider alternative closure dates does not necessarily imply that CUB agrees that the least-cost alternative is simply closing the plant in 2015. Finally, we note that removing an asset for ratemaking purposes, but not closing it in real life, could potentially lead to the need to keep two alternative sets of books for the next two decades.

Option 2: The Commission can require that the economic cost to consumers of the imprudence be modeled.

A potentially a better alternative would be to determine the harm caused by the imprudence and impute this value back to customers. This is a method that is designed to hold customers harmless for the imprudence. But should the model be based on the level of harm that would have been forecast when the Company made its imprudent decision, or should it be based on the actual harm that is caused by the imprudence? If the level of harm is indeterminate, what level of damages does the Commission impute?

Option 3: The Commission can assess a financial penalty on the Company.

Option 3 would allow the Commission to assess a financial penalty on PacifiCorp. This would allow the Commission to hold the Company accountable for its imprudence, and imprudence is an important principle to uphold, even if the financial impact of the imprudence cannot be precisely measured. Of course, this raises questions about the level of penalty and its relationship to harm.

In this case, CUB is offering as one option that the Commission disallow 25% of investments that were imprudently made. CUB believes that 25% is enough to get the Company's attention, which is critical. It is also a figure that is reasonable in relationship to the potential cost to customers. With Boardman, the original proposed clean air investment was approximately $500 million. PGE was able to reduce its costs by $200 million by considering and pursuing an alternative closure date.[17] This decision resulted in customers saving approximately 40% of capital investment. Based on the case of Boardman, disallowing 25% of the capital investment here does not seem overly harsh.

D. Used and Useful and Stranded Costs

It is important to realize that in addition to the prudency issue, the piecemeal approach to investment by PacifiCorp also leads to an issue of whether the investments are used and useful. The scrubber upgrade at Bridger 3 that is at issue in this case is a good example. PacifiCorp made the investment in order to comply with Regional Haze Rules. Those rules have not yet been finalized and require the Company to invest in additional pollution controls, including adding a SCR.

The first part of the used and useful question is whether the scrubber upgrade that has been added to the plant is used and useful. It clearly has been added to the plant and the plant is operating with it, meaning it is used. But is it useful? By itself, the scrubber does not allow the plant to meet the requirements of the Regional Haze Rules. By itself, it is not very useful. Without an SCR, it is not useful in meeting regulatory requirements.

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[17] LC 52, CUB Opening Comments, pages 3-4.

As we will demonstrate later in our discussion of the specifics of Bridger 3 and Hunter 1, CUB believes that there is a very good chance that when the Company updates its analysis of these units, it will conclude that it should convert them to natural gas. At that point, while the scrubber upgrade may still be attached to the plant, it will no longer be needed, it will no longer be used and useful, and it will therefore be a stranded cost.

As a stranded cost, the scrubber upgrade is not eligible for recovery unless the Commission finds its retirement is in the public interest. At this point the Company would no longer be allowed to earn a return on its scrubber upgrade investment.

Much of this problem stems from PacifiCorp’s piecemeal approach to making and reviewing clean air investments. Elements of the investment were made years before the requirements were finalized and come into rate cases as they occur in test years, but the Regional Haze Rule investments never come before the Commission as a total project. This is a problem because the investments are only are used and useful when combined as a project. An analogy would be if a utility brought aspects of the original plant to the Commission in a piecemeal approach—one year the Commission got to look at the building, another year the turbine, another year the smokestack, but never the whole coal plant. Of course, that approach is not allowed, as a utility cannot bring construction work in progress to the Commission to place into rates. Until a power plant is used and useful—until it is complete and operating—it cannot be included in rates. CUB believes that it is time to consider a similar view towards review of all Regional Haze Investments. CUB cites to the Commission experience with Naughton 3, Bridger 3 and Hunter 1 to show the potential problems caused by this piecemeal approach.

Under this new scheme of analysis Regional Haze Rule investments would be held as Construction Work in Progress until a coal unit is compliant with the rules requiring the investments, since only at that point is the project used and useful. For example, if the compliance deadline is 2015, then the elements required to meet that deadline would be considered a single project—none is used and useful without the rest of the project. If that deadline is the first of several under that particular rule (for example, an environmental rule that has a compliance deadline for 2015 and another for 2017), then the utility would have to show how the compliance with the 2015 deadline fits with the utilities plan to meet the 2017 deadline. Alternatively, if the utility could show that the 2015 compliance investment will be cost effective in less than 2 years, then it can show that it is prudent no matter what the utility does in 2017. But the utility cannot ask for recovery for investments that by themselves do not meet compliance requirements.

In suggesting this, CUB recognizes that complying with environmental rules is different than meeting RPS targets. A wind facility that is designed to meet a 2015 RPS target does not become stranded if the other units contracted for do not get built. But a clean air investment will become stranded if all other investments needed to meet that deadline do not get built because the consequences are that the plant has to shut down.

E. EPA Rejection of Utah and Wyoming SIP

The EPA recently found that parts of the Wyoming and Utah State Implementation Plans (SIP) for meeting the Regional Haze Requirements were inadequate and sent those plans back to the states. There are a couple of important issues that must be addressed as a result of the required revision of these plans.

First, the most recent evaluations of the coal investments have all assumed that the investments outlined in the draft state SIPs would be adequate to meet the Regional Haze Requirement rules. The PacifiCorp March IRP update, for example, assumed that all of the costs included in this UE 246 docket were sunk costs—costs that could not be avoided—and instead looked forward only to the remaining costs to be incurred under the not-yet-approved SIP. However, now that the SIP has been rejected, the Company must be required to revisit its analysis of the costs necessary to comply with the Regional Haze Rules, as those costs may increase.

Second, the rejection will allow PacifiCorp to revisit the closure date. In the past, PacifiCorp has explicitly ruled out considering any early retirement as part of its SIP applications. Plants will run indefinitely until pollution control costs force them to close. But, as PGE showed with Boardman, an early retirement can reduce the costs of pollution control and can save customers lots of money. CUB thinks the same could be true for several PacifiCorp plants. With the current SIP being rejected, CUB believes that the Company has the opportunity to revisit the alternative closure dates for these plants.

IV. How a Prudent Utility Should Analyze Coal Investments

What is the expectation for a utility that is considering a significant investment in a coal unit? Let us describe how CUB views the expectation of a utility to prudently consider its investment. As part of this review we will also discuss what CUB thinks is the importance of the precedent of PGE’s treatment of Boardman.

A. Examine All Reasonable Options for the Plant

Where should discussion of the reasonable options for the plant, for pollution control on the plant, and for alternative investment paths begin? CUB believes that the review process should begin with the IRP, where the Company considers its investment alternatives. It should analyze, for example, the cost of continuing to operate each coal unit now requiring significant investments versus other alternative scenarios, including closing the plant, switching the plant to natural gas or other fuels, and phasing out the plant in a manner that reduces clean air investment costs. In addition, the Company should conduct sensitivity analysis to consider how these options would fare under different futures related to fuel prices, carbon regulation, clean air requirements, and closure plans.

Once PacifiCorp has an acknowledged plan to invest in significant clean air controls on its plants, or invest in an alternative, the Company then becomes responsible for monitoring market conditions, environmental regulations, and other events that could affect that analysis. Before making an investment, the Company should confirm that that investment continues to be a reasonable one.

B. The Precedent of Boardman

In its IRP Supplement from last September, PacifiCorp discussed why it does not like its plants to be compared to Boardman:

> Comparisons with the Boardman Plant
>
> Several of the comments question how PacifiCorp's investments in emissions control equipment compare to PGE's decision to retire and decommission its Boardman facility 20 years earlier than its previously planned service life of 2040. In response to the questions posed, it is important to note that PacifiCorp's comments with respect to the Boardman decision are limited to its understanding of publicly available information pertaining to the decision; PacifiCorp does not have first-hand knowledge of the underlying factors affecting the facility including pending litigation and settlement discussions, Boardman's environmental compliance history, PGE's long-term capacity needs, PGE's transmission system, a plant-specific analysis of other environmental drivers and impacts, or PGE's business plans and priorities. Notably, electricity

> generated by the coal-fired Boardman plant only supplies approximately 15% of PGE's electricity, as compared to PacifiCorp's larger coal fleet that supplies more than 50% of its electricity. The approved Oregon Regional Haze State Implementation Plan does not avoid all compliance costs associated with emission reductions, nor does it insulate the Boardman plant from incurring additional costs in the event that new environmental regulations are adopted between now and 2020. Likewise, any facility contemplating shutdown in a specified year is not immune from incurring additional compliance costs, regardless of the planned shutdown date, due to changes in environmental regulations. PacifiCorp is uncertain as to the potential impact of such other emerging environmental regulations, including the proposed Utility HAPs MACT, on PGE's Boardman plan.[18]

In addition, in response to a data request in this docket, the Company stated:

> The Company did not artificially inflate the cost of controls by accelerating retirement of the plant or shortening control life, nor did it consider the impacts to customers of using an accelerated retirement date. The Company used a consistent depreciation life for the plant for the purpose of the BART analyses.[19]

CUB agrees that PacifiCorp’s circumstances are different. We largely agree that each coal unit is different and that different states will interpret state authority over the Clean Air Act differently. However, all states are administering the same federal law, and that law requires each state to take a look at the useful life of a plant. If an operator changes the useful life, then that new life has to be taken into consideration. With a shorter life, some pollution control will likely no longer be cost-effective under the Regional Haze Rules because the pollution control will have less time to reduce emissions and therefore will incur a higher cost per ton of emissions removed.

While the states’ approaches to administering the Clean Air Act differ, the Act itself does not. The State of Wyoming recognizes that the life of the plant is one of the fundamental building blocks of BART determination:

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[18] LC 52 - PacifiCorp 2011 IRP, Response to Oregon Party Comments, page 5.

[19] CUB Exhibit 103 – IPCO Response to CUB DR 11

> A BART determination is an emission limit based on the application of a continuous emission reduction technology for each visibility impairing pollutant emitted by a source. It is "…established, on a case-by-case basis, taking into consideration (1) the costs of compliance, (2) the energy and non-air quality environmental impacts of compliance, (3) any pollution equipment in use or in existence at the source, ***(4) the remaining useful life of the source,*** and (5) the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology." A BART analysis is a comprehensive evaluation of potential retrofit technologies with respect to the five criteria above. At the conclusion of the BART analysis, a technology and corresponding emission limit is chosen for each pollutant for each unit subject to BART.[20] (emphasis added)

As PacifiCorp claims, it is important to recognize that in the case of Naughton 3, shortening the useful life in the BART analysis could have actually extended the actual life of that unit as a coal plant. The SCR that is causing PacifiCorp to convert Naughton 3 away from coal probably wouldn't have been required had the Company proposed a 2018 or 2020 date as the end of the useful life. Running Naughton 3 for a few more years without the SCR would have reduced the total cost to customers. It should be recognized that when CUB first asked PGE to model a 2020 closure, PGE refused, because it was unclear whether such a plan would be acceptable to Oregon's DEQ. While a utility may be unable to know at the outset what pollution control costs would be required with an early closure, this is not a reason to avoid considering it. A prudent utility would consider it as an option, model it, and if it that option seems promising, engage the state in discussions about how closure would affect state regulation.

In other words, the importance of Boardman is not that it is a template for other units—we agree that individual coal plants are different. CUB also agrees that each state

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[20] Wyoming DEQ, PacifiCorp Jim Bridger Power Plant AP-6040 BART Application Analysis Page 5. http://deq.state.wy.us/aqd/308%20SIP/BART%20Applications%20and%20AQD%20Analyses/AQD%20Analyses/6040ana_BART.pdf.

that administers the Clean Air Act does so differently. When evaluating the options under the Regional Haze Rules, a prudent utility will consider four primary variables: clean air investment, expected carbon regulatory costs, natural gas costs as an alternative fuel, and the life of the coal plant.

However, it is difficult to determine what the outcome would have been if the utility had engaged state regulators in a discussion of the requirements under different closure date scenarios. Without knowing the outcome, if the Company had engaged in discussions of the requirements under different closure date scenarios, it would still be impossible to predict the cost of not engaging in those considerations.

V. Coal Investments

It became clear during the IRP process that CUB and PacifiCorp have had major differences concerning the evaluation of coal investments. CUB critiqued PacifiCorp first for not considering clean air investments in the IRP. We were then critical of the September IRP analysis that considered the cost of meeting environmental deadlines as sunk and unavoidable. The March Update Coal Study, however, was a reasonable attempt to evaluate coal investments, with the exception of the Company's unwillingness to consider alternative closure dates.

Unfortunately, none of the costs at issue in this docket were evaluated in that March IRP Update. Only two of the units at issue here (Hunter 1 and Bridger 3) were considered in that update, but the update looked only at future costs and made no attempt to evaluate the investments that are at issue in this docket.

Instead, the primary evidence here is the collection of individual studies that PacifiCorp made of each of these investments, mostly in 2008 and 2009. Below we discuss each study and will show some common flaws in the Company's approach. Typically, these studies make a number of mistakes:

First, the studies consider RHR costs before the rules have been determined, without any sensitivities to the fact that the State's BART determination might require additional investments. A sensitivity analysis that considered what would happen if the clean air costs were greater or lower should have been conducted. Alternatively, the Company should have considered waiting until it knew the rules before doing the evaluation.

Second, most studies used immediate closure as the alternative to investments that were not used and useful for 2 or 3 years, and were to meet environmental deadlines that were several years away. The alternative to meeting the clean air requirements should not have been closing coal plants in 2008 or 2009, but instead running them until the compliance deadline (2015) and closing them at that point. If these studies were attempts to determine the least-cost option, they would have been designed to compare the least-cost approach to complying with clean air requirements versus the least-cost approach to closing a coal plant, which, if the plant is currently being dispatched by GRID, would mean continuing to operate it until is required to close.

In addition, in the IRP Supplement coal study from last fall, the Company argues that it would be irresponsible to consider closing the plants before the 2015 compliance deadline because it is a "potentially catastrophic proposal to pursue retirement of facilities before compliance deadlines, if customer loads are expected to be reliably served."[21]

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[21] LC 52 -PacifiCorp 2011 IRP Supplement, Redacted Coal Replacement Study, page 5 (September 21, 2011).

Third, PacifiCorp did not revisit the studies even after it was clear that the forward price curve used in the studies had changed significantly and the cost of retired pollution controls had increased significantly. The Company did not need to rush forward with these investments; it had time to be diligent and update its analysis with the most recent information. The deadline for compliance was 2015, not 2008 or 2009. The Company had time to seek better information and to wait and update its costs. In addition, as the forward price curve fell towards the end of 2008 and 2009, the Company should have realized that it needed to revisit its analysis, which was largely dependent on forward electric prices.

Fourth, PacifiCorp did not consider alternative closure dates that were past the compliance deadline. Not only did the Company not assume that the plant would operate until the deadline, it did not consider any closure date after the deadline, when this would have resulted in reduced pollution controls. As discussed above, the lesson of Boardman is that the closure date is a variable.

Fifth, PacifiCorp only considered one option for replacement—purchasing electricity on the market for the remaining life of the plant. This prevented the Company from considering alternatives such as the switch to natural gas that is now planned for Naughton 3. In addition, this decision made the studies very dependent on the forward price curve. The timing of these studies' forward price curves could have an impact of nearly $1 billion on the study. If the Company is going to be so reliant on a single variable, it should have done better sensitivity analysis concerning how the outcome changes with changes to this variable.

These flaws in PacifiCorp's analysis leave CUB unable to find that the Company has properly evaluated any of the coal investments before pursuing them.

A. Bridger 3

PacifiCorp has conducted two analyses of the Bridger investment. The first is the 2008 study, which was conducted well before the Company made the investment in the scrubber upgrades. The second was conducted more recently; it is focused on next year's SCR and assumes the investment in this case is sunk.

The issue here is the scrubber upgrade. Construction on the scrubber upgrade began in July 2010, with installation completed in 2011.[22] The actual timing of the investment was midway between the two studies.

i. March IRP Update Study

This update analyzed six scenarios for Bridger 3 and concluded that in three of those scenarios—low gas, high CO_2, or both—it would be cost effective to convert the plant to natural gas:[23]

> In the case of Jim Bridger 3, the updated Coal Replacement Study shows that there future scenarios (a low gas price future, a high CO_2 price future, and a future with both low gas and high CO_2 prices) in which gas conversion is a lower cost alternative to the future investments required to operate the unit as a coal-fueled facility. Similarly, there are future scenarios, including the base case, where future investments required to operate the unit as a coal-fueled facility are favorable to gas conversion. The Company has considered each of these scenarios as part of its evaluation of whether future coal investment is the least-cost, accounting for risk, alternative for customers.[24]

In the March 2012, IRP Update, PacifiCorp committed to updating this analysis before making the investment:

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[22] PAC / 500 / Teply / 80.

[23] CUB Exhibit 104—IPCO Response to CUB DRs 4 & 7

[24] *Ibid*.

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[redacted].[25]

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There are several important items contained in this analysis. First, if the gas costs are updated, the Company may find that the plant should be repowered with natural gas, since updated gas forecasts are moving towards the low gas scenario. According to the update, the gas forward price curve is dated from August 2011:

> The 2012 business plan portfolio modeling was based on the August 31, 2011 price curves, downloaded from the Company's forward price system. The price curves reflect June 30, 2011 MIDAS power and gas curves blended with market forwards as of August 31, 2011.[26]

But gas prices have continued on a downward trend since the last forward price curve was completed. A recent check with the Energy Information Agency shows gas prices have fallen by $2.375/MMBtu since last year.[27] The 2012 EIA Annual Energy Outlook has lower forward prices than the 2011 EIA Annual Energy Outlook.[28] The gas price forecast that was contained in the Oregon Gas Update Report provided by Staff to the PUC are below the Low Gas Price forecast in the IRP Update used by PacifiCorp.[29] When PacifiCorp updates its forward price curve contained in the March 2012 study, there is a good chance that Bridger 3 will be converted to gas.

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[25] Confidential CUB Exhibit 105—IPCO Response to CUB DR 7, Attachment 1: LC 52 - 2011 IRP Update, page 89 (March 30, 2012).

[26] LC 52 - PacifiCorp 2011 IRP Supplement, Redacted Coal Replacement Study, page 37 (September 21, 2011).

[27] http://www.eia.gov/dnav/ng/hist/rngc1d.htm. Accessed 11 June 2012.

[28] http://www.eia.gov/forecasts/aeo/er/.

[29] See CUB Exhibit 106—Oregon Gas Update

Second, the scrubber upgrade costs that are in the current UE 246 case were considered sunk—they could not be avoided. This was the first credible study that robustly considered more options that just market purchases, did not use immediate shutdown as the alternative, and did not consider the full cost of compliance as a sunk cost. This was also the first study to consider more than just one future scenario for gas prices and CO_2 prices. But this study comes midway in the process to make the plant compliant with Regional Haze Rules and no longer considers some of the costs as avoidable. If all costs associated with meeting the Regional Haze Requirements were still avoidable, the additional costs would make continuing to burn coal at Bridger less appealing. But, the Company never conducted a robust study that included all of the RHR costs.

Third, PacifiCorp is looking at the pollution control decisions and closure from a binary perspective. Either the SCR investment is made next year or the plant is converted to gas. But, as we have said, there is another variable. If the plant was scheduled to close in 2018 or 2020, for example, it is doubtful that a SCR would have been considered cost effective pollution control. Running a coal plant without as much pollution control for an additional 3 to 5 years would have reduced the costs, since it would produce power more cheaply than either a coal plant that is repowered with gas or a coal plant with significant higher capital investment.

Fourth, with EPA rejecting the Wyoming SIP application, the costs of pollution control may be greater than previously modeled.

ii. 2008 Study

PacifiCorp signed a contract for work on the scrubber upgrade in 2008,[30] but construction did not begin until July 6, 2010, and installation was completed during a plant outage between April 30, 2011 and June 30, 2011.[31] The Company argues that the scrubber upgrade was prudent based on its 2008 study of Clean Air Investments.[32] In that study, the Company compared the costs of the plants, including the "then-expected" clean air investments, to closing the plant and relying on market purchases and concluded that the advantage to customers from making clean air investments and retaining the plant is a net present value of BEGIN CONFIDENTIAL $[redacted].[33] END CONFIDENTIAL

a. Closure Date

This study assumed the alternative to the scrubber upgrade investment was closure in 2008 and replacement with market purchases.[34] That assumption makes no sense. The requirement for a future investment in the scrubber upgrade was not adopted by Wyoming until March 2009.[35] So the alternative closure date had no relationship to the completion date of the project, the deadline for pollution control, or even the date that the state required an upgrade in the future. As of the date of CUB's testimony, Wyoming does not have a SIP that has been approved by the EPA.

CUB's understanding from participating in the Oregon DEQ's BART process is that the deadline for these investments is 2015. PacifiCorp's IRP Supplement last fall

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[30] PAC / 500 / Teply / 84.
[31] CUB Exhibit 104—IPCO Response to CUB DR 4
[32] PAC / 500 / Teply / 84-8.
[33] PAC /500 / Teply / 85. Confidential
[34] PAC / 500 / Teply / 85.
[35] PAC / 500 / Teply / 81.

stated that 2015 was the appropriate closure date for non-compliance.[36] This means that PacifiCorp's model closed the plant seven years early. A significant amount of the savings comes from these years.[37]

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Table 3: *NPV Benefits for Bridger Unit 3*

Year	**Benefit**	**NPV Benefit**
2008	[redacted]	[redacted]
2009	[redacted]	[redacted]
2010	[redacted]	[redacted]
2011	[redacted]	[redacted]
2012	[redacted]	[redacted]
2013	[redacted]	[redacted]
2014	[redacted]	[redacted]
2015	[redacted]	[redacted]

[redacted].

b. Future Electric Prices

The following confidential chart, drawn from data found in Staff DR 220-3, shows the forward electric prices used by PacifiCorp:

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[36] LC 52 - PacifiCorp 2011 IRP Supplement, Redacted Coal Replacement Study, page 5 (September 21, 2011).

[37] CUB Confidential Exhibit 107—IPCO Response to OPUC DR 220, Attachment 220-3, [redacted]

[redacted]

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PacifiCorp's forecast of power prices was significantly higher than the actual behavior of the market. PacifiCorp forecast 2008 electricity prices to be $[redacted]/MWh, 2010 prices to be $[redacted]/MWh, and 2015 prices to be $[redacted]/MWh.

By the end of the 2008, PacifiCorp had a new forward price curve, which it used in its Naughton 1 and 2 CAI studies. In that forward price curve, the Company forecast 2010 prices at $[redacted]/MWh and 2015 prices at $[redacted]/MWh .[38] But the Company did not go back and revisit the Bridger forecast, even though its 2015 prices had fallen by $[redacted]/MWh and its 2015 prices had fallen by more than $[redacted]/MWh.

CUB Exhibit 108 depicts the Northwest Power and Planning Council's (NPPC) graph of historic and future electric prices. This graph shows the price of wholesale electricity decreased significantly from 2008 to 2010, when PacifiCorp began work on the project. The Council's forward price curve from the 6th Power Plan shows it growing slowly from that lower amount. In 2010, the Council's Base Case was forecasting Mid-C

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[38] CUB Confidential Exhibit 109—IPCO Response to OPUC DR 22, Attachment 220-4, [redacted]

electric prices at an average of $30/MWh. This is a $[redacted] difference from what PacifiCorp was projecting in its 2008 study. This means that by the time PacifiCorp actually began work on the project in 2010, it must have been aware that it was overestimating the cost of replacement power by approximately $[redacted] for a single year. Because the model assumed a 30 year life of the plant, this change alone should have been enough to get PacifiCorp to reexamine its analysis, as the net present value of annual costs of $[redacted] is approximately $[redacted]. That large of a change in a forecast should ensure a reexamination of that forecast.

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c. Additional Pollution Controls

In addition, because the scrubber upgrade was not sufficient to meet the BART requirements—a SCR and other investments were required—PacifiCorp should have been updating its analysis on a regular basis to ensure that the overall project to comply with RHR was still cost effective. The 2008 study was done before Wyoming had finished its determination of BART long before a Wyoming SIP was approved by the EPA (that still hasn’t happened). Because of the uncertainty concerning the needed level of clean air investment, the Company should have conducted a sensitivity analysis to demonstrate whether the plant would still be economic to continue to operate if the clean air investment costs increased significantly. Nevertheless, the Company did not do this analysis. In addition, the Company could have updated the study, since construction did not begin until 2010. By not updating the study before making the scrubber upgrade investment, PacifiCorp was taking a risk that future costs related to meeting the Regional Haze Rules would force the plant to stop burning coal and the cost of the scrubber update would be stranded.

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It is also important to note that this 2008 study included a single number for the expected clean air investments: $[redacted].[39] The update from this March shows more than $[redacted] in investment costs.[40] This means that capital investments associated with PacifiCorp's clean air investments nearly [redacted] during this time, but PacifiCorp continued to rely on its earlier study.

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According to PacifiCorp, the 2008 study included all the "then-current cost forecasts for environmental compliance projects required under the Wyoming SIP."[41] Obviously as the SIP continued to be developed, additional costs were added without revisiting the forecast and the analysis.

d. Alternative Investments

In the 2008 study, PacifiCorp limited itself to market purchases to replace the plant, making the study very dependent on its forward price curve. But in this year's IRP update, the Company has now found that converting a plant to gas is the best alternative in 3 of the 6 scenarios considered.[42] This Bridger investment was never compared to the costs of switching the plant to gas or any other replacement power option other than PacifiCorp's forward price curve.

e. Alternative Shutdown dates

In the 2008 study, PacifiCorp never considers any alternatives for Bridger 3 other than run the plant indefinitely or shut it down in 2008. For a plant like Bridger that is now on the edge of economic operation—three scenarios recommend that it stop burning coal

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[39] CUB Confidential Exhibit 107—IPCO Response to OPUC DR 220, Attachment 220-3, [redacted]
[40] CUB Confidential Exhibit 110—IPCO to CUB DR 8, Attachment 1, [redacted]
[41] CUB Exhibit 111—IPCO Response to CUB DR 20
[42] CUB Exhibit 104—IPCO Response to CUB DR 7.

and three scenarios recommend continuing to burn coal[43]—reconsidering the plant's useful life would likely lead to a better alternative. Operating the plant as a coal plant for a few years rather than converting it to a gas plant next year would reduce the cost of operation during those years and lead to a lower overall cost. The lack of interest the Company has shown in even considering alternative shut down dates is troubling, because it suggests that PacifiCorp is not being diligent in looking for the least-cost options. The EPA's rejection of the Wyoming SIP should give the Company a chance to rethink this.

iii. Recommendation

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PacifiCorp claims that its analysis showed that the clean air investments were cost effective and had a positive net present value of $[redacted] to customers over 30 years. However, this analysis assumed that the plant was closed in 2008, seven years before the 2015 deadline for pollution control. In addition, by the time PacifiCorp began construction on the project, the power market had changed dramatically, causing the original analysis to overstate the cost of replacement power by as much as $[redacted] per year. In addition, the cost of pollution control nearly[redacted], to almost $[redacted] since the 2008 study.

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CUB believes the Company acted imprudently by assuming the alternative to its investment was an immediate shutdown of the plant. PacifiCorp was also imprudent for not updating its study before making the scrubber upgrade. Such a study would have captured declining electricity prices and increasing clean air requirements.

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[43] CUB Exhibit 104—IPCO Response to CUB DR 7.

Further, PacifiCorp was imprudent in not analyzing and considering whether a change to the expected life of the plant would produce an outcome with lower costs. Today, it is apparent that such an outcome would be lower than the two current options. The fact that in hindsight this is the lowest cost option does not make the Company imprudent. The fact that the Company has never considered the option and still won't consider this option is what is imprudent. While it is uncertain that Wyoming would have agreed that such a plan met the RHR requirements, or will agree now that the SIP has been rejected, it is clear that Wyoming cannot consider the least-cost option if they are not asked. Finally, CUB recognizes that the investment in the scrubber upgrade may become a stranded cost when the Company updates its Bridger analysis and repowers the unit with natural gas.

CUB asks the Commission to make one of the following finding with regards to the Bridger scrubber upgrade:

1. That the Bridger 3 scrubber upgrade is part of a larger project, which includes an SCR, to meet the expected Wyoming RHR requirements. Without the SCR, the scrubber upgrade is not used and useful. With the SCR in doubt, the Scrubber upgrade may never be used and useful. The Commission finds that the Regional Haze investment is not yet used and useful and that the Company should wait until it is in compliance with the 2015 federal requirements before the plant additions can be considered used and useful and added to ratebase.

Or:

2. That the Company acted imprudently by relying on an inadequate study from 2008 to make the investments in the scrubber upgrade. That study closed the plant

> years ahead of the clean air deadlines and was not updated as new information was developed both about the pollution controls and the cost of alternative resources. The Commission finds that the Company acted imprudently by not considering potential least-cost options when studying what to do with the plant, such as running it until 2018 or 2020.

Because it is not possible to determine the benefits to customers from moving the closure date to 2018, 2020, or some other year, the harm to customers from PacifiCorp's imprudence cannot be determined. CUB recommends that the Commission disallow 25% of the ratebase associated with this project.

B. Naughton 1 and 2

PacifiCorp made significant clean air investments in its Naughton 1 and 2 units, which are being reviewed for prudence in this case. Unit 1 is the oldest of the three Naughton units, having opened in 1963, with Units 2 and 3 having opened in 1971.[44] Earlier this year PacifiCorp announced that Naughton 3 would be converted to natural gas, which is a cheaper course of action than investing in clean air control technology.

Naughton 1 and 2 were never subjected to the same analysis as Naughton 3. PacifiCorp has not, therefore, considered converting these units to natural gas. These plants were not included in the more recent IRP update analysis because they do not have immediate costs that can be avoided. For PacifiCorp's modeling purposes the costs are now sunk.

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[44] http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/EnergyGeneration_FactSheets/RMP_GFS_Naughton.pdf

PacifiCorp did conduct a study much like the 2008 Bridger 3 study that considered closing Naughton 1 and 2 and replacing them with purchased power.[45] The Naughton 1 and 2 studies were conducted in 2009, so the downturn in natural gas and electricity prices is partially captured in this study. Unfortunately, the analysis generally suffers from the same defects as the 2008 Bridger 3 Study.

PacifiCorp also cites to last year's IRP Supplement, "which did not identify an accelerated retirement date" for Naughton 1 and 2.[46] While this statement is true, it is seriously misleading. The IRP Coal Supplement was the September IRP Coal Study, which allowed each plant to be closed in 2015, but assumed that all costs incurred before 2015 were sunk. In other words, it was a study that assumed that the Company made the investments necessary to comply with 2015 BART and MATS requirements, including the costs that are being discussed in this case. The Company then turned around and closed the plant.

The study also highlights that PacifiCorp has not updated its 2009 study for Naughton 1 and 2, even though the forecasts of environmental costs, electric and gas prices, and assumptions regarding replacement power have all changed.

i. 2009 Naughton 1 and 2 Studies

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The studies for the Naughton 1 and 2 projects reflect many of the same flaws as the Bridger 3 study, but start with a much lower expectation of cost effectiveness. For

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[45] PAC / 500 / Teply / 37.

[46] PAC / 500 / Teply/ 39 and 46.

Naughton 1, the 2009 study showed a cost effectiveness of $[redacted] over the life of the facility.[47] For Naughton 2, the cost effectiveness is $[redacted].[48]

a. Closure Date

Like the Bridger 3 study, the Naughton 1 & 2 studies assume that the alternative to clean air investment is immediate plant shutdown. This study indicated a shutdown date of 2009, even though the compliance deadline was 2015.

Table 4: *NPV Benefits for Naughton Unit 1*

Year	Benefit	NPV Benefit
2009	[redacted]	[redacted]
2010	[redacted]	[redacted]
2011	[redacted]	[redacted]
2012	[redacted]	[redacted]
2013	[redacted]	[redacted]
2014	[redacted]	[redacted]
2015	[redacted]	[redacted]

Table 5: *NPV Benefits for Naughton Unit 2*

Year	Benefit	NPV Benefit
2009	[redacted]	[redacted]
2010	[redacted]	[redacted]
2011	[redacted]	[redacted]
2012	[redacted]	[redacted]
2013	[redacted]	[redacted]
2014	[redacted]	[redacted]
2015	[redacted]	[redacted]

b. Forward Electric Prices

Much of the decrease in the value of the clean air investments comes from the company updating its Forward Price Curve at the end of 2008. By the end of 2008, PacifiCorp had a new forward price curve, which it used in its Naughton 1 and 2 studies. In that forward price curve, the Company forecast 2010 prices at $[redacted]/MWh and 2015

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[47] PAC / 500 / Teply / 37 Confidential
[48] PAC / 500 / Teply / 45 Confidential

prices at $[redacted]/MWh.[49] These are considerably lower prices than were used in the earlier Jim Bridger 3 study.

But these estimates are still higher than those in later studies. As we pointed out above, the NPCC, which published its 6th Power Plan in 2010, but conducted the analysis for it in 2009, forecasted 2010 prices at $30/MWh, with the price slowly rising to about $50 in 2015. [50]

For 2013, the Company projects power prices of $[redacted]/MWh. The Council's forecast is about $45/MWh. While PacifiCorp's and the Council's projections tend to come together in 2015 at around $[redacted]/MWh, they begin to diverge again, and by 2018 PacifiCorp is forecasting $[redacted]/MWh and the Council is forecasting $60/MWh. A $10 difference in prices for one year would reduce the cost of replacement power by a little more than $[redacted] at Naughton 1 and approximately $[redacted] at Naughton 2.

If the Company had updated its December 2008 forward price curve before executing the contract for the project in May 2009, there is a good chance that Naughton 1 would not be cost effective and Naughton 2 would have been much closer to the cost effectiveness threshold.

c. Environmental Controls

In the 2009 study the Company forecasted the cost of clean air investments in Naughton 1 at $[redacted] and Naughton 2 at $[redacted].[51] In this case the Company is placing into service $130 million of new rate base associated with Naughton 1[52] and

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[49] CUB Exhibit 109—IPCO Response to OPUC DR 220, Attachment 220-4, [redacted]
[50] CUB Exhibit 108—NPPC 6th Power Plan
[51] CUB Confidential Exhibit 109—IPCO Response to OPUC DR 220, Attachment 220-4 [redacted]
[52] PAC / 500 / Teply / 29; PAC / 500 / Teply / 31.

$164 million for Naughton 2.[53] But these are just the piecemeal amounts of what is going into rates in this rate case.

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Like at Bridger 3, the Company went ahead and made these clean air investments without waiting to find out the full requirements or modeling sensitivities for the range of possible costs. It is also true that the federal rejection of the Wyoming SIP makes it unclear whether there will be additional controls required at Naughton 1 and 2, such as the SCR that caused Naughton 3 to be repowered with gas.

d. Replacement Resources

Like the Bridger study, the 2009 study looked only at replacing Naughton 1 and 2 with market purchases. The Company should have considered other options, such as repowering the unit with natural gas, which has shown to be the least-cost option for Naughton 3.

e. Alternative Closure Date

Because these plants started with a narrow cost-effectiveness of pollution control that was well within the margin of error related to the forward price curve of electricity, the Company should have made more of an effort to examine alternatives, including whether an alternative closure date would have reduced the costs. The capital investment proposed for recovery in this case Naughton Unit 1 is $130 million.[54] The capital investment proposed for recovery in this case for Naughton Unit 2 is $164 million.[55] Avoiding that cost (plus its return on the capital investment) for a couple of years would

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[53] PAC / 500 / Teply / 40; PAC / 500 / Teply / 41.
[54] PAC / 500 / Teply / 29; PAC / 500 / Teply / 31.
[55] PAC / 500 / Teply / 40; PAC / 500 / Teply / 41.

have changed the analysis and led to the early closure of Naughton 1 being cost-effective. Avoiding that cost for 5 years would have made closing Naughton 2 early cost-effective.

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With a net present value of just $[redacted] over the life of the plant for Naughton 1[56] and $[redacted] for Naughton 2,[57] PacifiCorp was imprudent by not conducting additional analysis beyond the 2009 study. This value is extremely low for a coal unit that is expected to last another 20 years and is easily within the margin of error of a forward gas curve. In addition, much of the value of clean air investment comes because the study shut the plant down 6 years ahead of pollution control deadlines when the plant was economic to operate.

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ii. Recommendations

a. Naughton 1 and 2

CUB asks the Commission to make one of the following finding with regards to Naughton Units 1 and 2:

1. That the investment in the test year is not adequate to meet the RHR BART requirements for 2015 and as such is not considered used and useful for meeting those requirements. PacifiCorp must wait until it has used and useful controls that meet BART in order to qualify for rate base treatment.

Or:

2. That PacifiCorp should have responded to this study with follow-up investigation that tried to identify additional clean air requirements, alternative closure dates,

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[56] PAC / 500 / Teply / 37 Confidential
[57] PAC / 500 / Teply / 45 Confidential

> and alternative sources of replacement power, such as repowering with natural gas. Because this plant was so close to the economic edge, PacifiCorp should have waited as long as possible before investing in the plant, so it could have had the most up-to-date forecast of future electric prices. Waiting even a few months would have led to lower forward prices and potentially a different result. The Commission finds that the Company acted imprudently by not considering potential least-cost options when studying its options for these units.

If the Commission chooses the second option, CUB again recommends that 25% of the rate base be removed.

C. Dave Johnston 4

Like Naughton 1 and 2, Dave Johnston 4 is a coal unit that was not included in the recent March IRP update. Therefore, the only available evaluation of the cost effectiveness of pollution control is from 2008, which found that closing the plant in 2008 and using market purchases would cost customers BEGIN CONFIDENTIAL $[redacted].[58] END CONFIDENTIAL

i. Dave Johnston 4 Study

The Dave Johnston 4 study from this period has the same flaws as the other studies: closing the plant several years before such closure is necessary; using a forward price curve from 2007 to evaluate an investment that is not used and useful until 2012; not studying alternative resources to market purchases; and not allowing any alternative closure date except 2008.

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[58] PAC / 500 / Teply / 55 Confidential

a. Closure Date

The study assumes that the plant would be closed in 2008, even though the investment is not used and useful until 2012 and the pollution control deadline is 2015. Much of the benefit of investing in pollution controls comes from the 7 years the plant is closed in the study even though there is no requirement to close the plant.

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Table 6: *NPV Benefits for Dave Johnston Unit 4*

Year	Benefit	NPV Benefit
2008	[redacted]	[redacted]
2009	[redacted]	[redacted]
2010	[redacted]	[redacted]
2011	[redacted]	[redacted]
2012	[redacted]	[redacted]
2013	[redacted]	[redacted]
2014	[redacted]	[redacted]
2015	[redacted]	[redacted]

b. Forward Electric Prices

The forward price curve used for Dave Johnston Unit 4 came from December 2007.[59] The forecasted price for 2008 was $[redacted]/MWh; for 2010, it was $[redacted]/MWh; and for 2015, it was $[redacted]/MWh.[60] By the end of 2008, PacifiCorp had a new forward price curve, which it used in its Naughton 1 and 2 studies. In that forward price curve, the Company forecast 2010 prices at $[redacted]/MWh and 2015 prices at $[redacted]/MWh.[61] With annual generation of [redacted] MWh,[62] a $10 change in forward price was worth $[redacted] per year, while a $15 change in price reflects an annual savings of $[redacted].

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[59] PAC / 500 Teply / 55.
[60] CUB Confidential Exhibit 112—IPCO Response to OPUC DR 220, Attachment 220-1 [redacted]
[61] CUB Confidential Exhibit 109—IPCO Response to OPUC DR 220, Attachment 220-4, [redacted]
[62] CUB Confidential Exhibit 112—IPCO Response to OPUC DR 220, Attachment 220-1 [redacted]

The Net Present Value of an annual savings of $[redacted] over 20 years is nearly greater than $[redacted].

The Company signed a contract to begin work in 2008, even though the installation would not actually begin until 2012.[63] If the Company had delayed moving forward with the contract, it could have taken advantage of lower electricity prices. If the Company could have delayed committing to the project until the following year, prices would have been in line with the 6th Power Plan, with 2010 prices at $30/MWh, [redacted] of what the Company projected, with an annual value of $[redacted] (the net present value of 20 years of annual savings amounting to $[redacted] is $[redacted], more than the benefits of continuing operation).

c. Environmental Controls

The Company committed to this project early in the Regional Haze/BART process, long before Wyoming finished its initial SIP process and before PacifiCorp had much certainty regarding the costs. The 2008 study should have included a sensitivity analysis so the Company could have been aware of how additional pollution control regulations would affect the cost effectiveness of the investment. The March Update indicates that PacifiCorp is now projecting additional capital investment of $[redacted].[64] In addition, because the EPA rejected the Wyoming SIP, there continues to be uncertainty regarding the level of pollution control that is expected.

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[63] PAC / 500 / Teply / 49.

[64] CUB Confidential Exhibit 110—IPCO to CUB DR 8, Attachment 1, [redacted]

d. Replacement Resources

The 2008 study did not look at repowering the unit with natural gas or any other option other than replacement with power purchases based on the Company's then forward price curve. The Company should have looked at alternatives, such as repowering the plant with natural gas.

e. Alternative Closure Date

The Company did not consider any closure date beyond shutting the plant down in 2008. Because there was no approved SIP that would have required the plant to shut down in 2008 without the investment, the Company should have analyzed alternative closure dates and what pollution control would have been required. Since the pollution control was not installed and used and useful until 2012, the Company should not have focused on a 2008 closure date. For example, running the plant until 2012—the date the equipment is used, useful and reducing pollution—would have provided an additional four years of operation and lowered the cost of closure. The Company's analysis did not consider what environmental controls would have been necessary to run the plant until 2012, 2015, 2017, or 2020.

ii. Recommendation

CUB recommends that the Commission endorse one of the following options for this investment:

1. That the investment in the test year is not adequate to meet the RHR BART requirements for 2015 and as such is not considered used and useful for meeting those requirements. PacifiCorp must wait until it has used and useful controls that meet BART in order to qualify for rate base treatment.

Or:

2. The Commission should find that PacifiCorp was imprudent by not conducting a better evaluation of Dave Johnston Unit 4 environmental controls versus other options before investing in the plant. The Company was imprudent by only considering a 2008 closure even though the pollution control was not required until several years later. The Company should have waited for better information regarding the cost of pollution controls and the cost of alternative resources, or, as an alternative, the Company should have conducted a sensitivity analysis that looked at a range of costs for these items. The Company was imprudent by not considering other options besides market purchases to replace the plant. Finally, the Company was imprudent by not considering alternative closure dates as allowed under the Regional Haze Rules.

If the Commission adopts the second option, CUB recommends that 25% of the rate base associated with this investment be disallowed.

D. Hunter 1 and 2

i. 2012 IRP Update Study

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Hunter 1, like Bridger 3, was part of the March IRP Update, which looked at the value of converting the plant to natural gas instead of making additional environmental investments. Like Bridger 3, [redacted].[65] [redacted]

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[65] CUB Confidential Exhibit 105—IPCO Response to CUB DR 7, Attachment: LC 52 - 2011 IRP Update, page 78. (March 30, 2012).

[redacted].

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There are several important items contained in this analysis.

First, if the gas cost estimates are updated, The Company may find that the plant should be repowered with gas, as updated natural gas forecasts will likely be consistent with the low gas scenario. According to the update, the gas forward price curve is dated from August 2011:

> The 2012 business plan portfolio modeling was based on the August 31, 2011 price curves, downloaded from the Company's forward price system. The price curves reflect June 30, 2011 MIDAS[12] power and gas curves blended with market forwards as of August 31, 2011.[66]

But gas prices have continued to fall. A recent check with the Energy Information Agency shows gas prices have fallen by $2.375/MMBtu since last year.[67] The 2012 EIA Annual Energy Outlook has lower forward prices than the 2011 EIA Annual Energy Outlook.[68] The gas price forecast that was contained in the Oregon Gas Update Report provided by Staff to the PUC are below the Low Gas Price forecast in the IRP Update used by PacifiCorp.[69] When PacifiCorp updates its analysis with a new forward price curve for gas, Hunter 1 may be converted to gas.

Second, the scrubber upgrade costs that are in the current UE 246 case were considered sunk—they could not be avoided. This was the first credible study that robustly considered more options than just market purchases, did not use immediate

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[66] LC 52 - PacifiCorp 2011 IRP Supplement, Redacted Coal Replacement Study, page 37 (September 21, 2011).

[67] http://www.eia.gov/dnav/ng/hist/rngc1d.htm. Accessed 11 June 2012.

[68] http://www.eia.gov/forecasts/aeo/er/.

[69] See CUB Exhibit 106—Oregon Gas Update Report

shutdown as the alternative, and did not consider the full cost of compliance as a sunk cost. This was the first study to consider more than just one future scenario for gas prices and CO_2 prices. But this study comes midway in the process to make the plant compliant with Regional Haze Rules and no longer considers some of the costs as avoidable. If all costs associated with meeting the Regional Haze Requirements were still avoidable, the additional costs would make continuing to burn coal at Bridger less appealing. But, the Company never conducted a robust study which included all of the RHR costs.

Third, the Company is looking at the pollution control decisions and closure from a binary perspective. Either PacifiCorp makes the clean air investment next year or converts the plant to gas. But as we have said, there is another variable. If the plant were scheduled to close in 2018 or 2020, for example, it is doubtful that a scrubber would have been considered cost-effective pollution control. Running a coal plant without as much pollution control for an additional 3 to 5 years would have reduced the costs, since it would produce power more cheaply than either a coal plant repowered for gas or a coal plant with significant higher capital investment.

Fourth, with EPA rejecting the Utah SIP application, the costs of pollution control may be greater than modeled including the possibility that an SCR will be required.

ii. 2009 Study

The study that considered the costs that are in this docket was done in 2009. First, it should be noted that this study is improved over earlier studies. Rather than considering an immediate shut down, this study recognized that the plant could operate until the end of 2012 with no added pollution control, so it looked at a 2012 shutdown date.[70] This is the first study that does not assume an immediate closure as the alternative to clean air

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[70] PAC / 500 Teply / 66.

investment. As of this date, PacifiCorp must have realized that its earlier studies were flawed on this point, but there is no evidence that the Company considered reviewing the previous studies. This study found the benefits of continued operation at Hunter 1 to be BEGIN CONFIDENTIAL $[redacted] and $[redacted] at Hunter 2.[71]

a. Early Shutdown

While this study was improved by assuming the plant would not shut down until 2012, it is still unclear why the Company did not use 2015 as the shutdown date. The three extra years of shut down do have significant impact on the study.

Table 7: *NPV Benefits for Hunter Unit 1*

Year	Benefit	NPV Benefit
2012	[redacted]	[redacted]
2013	[redacted]	[redacted]
2014	[redacted]	[redacted]
2015	[redacted]	[redacted]

Table 8: *NPV Benefits for Hunter Unit 2*

Year	Benefit	NPV Benefit
2012	[redacted]	[redacted]
2013	[redacted]	[redacted]
2014	[redacted]	[redacted]
2015	[redacted]	[redacted]

b. Forward Electric Prices

This study used the Company's Forward Price Curve from September 2009.[72] [redacted]. The study projects power prices in the first year of closure in 2013 of $[redacted]/MWh.[73] In 2015, it projected prices of

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[71] PAC / 500 / Teply / 67 Confidential

[72] PAC / 500 / Teply / 67

[73] CUB Exhibit 108—NPPC 6th Power Plan.

$[redacted]/MWh. The NPPC's 2014 forecast is $40/MWh and remains below $50/MWh in 2015. This analysis was based on a 30 year additional life associated with the plant. In 2030, the Council forecasts $75/MWh, and PacifiCorp is forecasting $[redacted]/MWh. The analysis forecasts [redacted] MWh per year.[74] At an average difference of $10/MWh, the difference between the Council's forecast and PacifiCorp's forecast is about $[redacted] per year with a NPV of $[redacted].

c. Environmental Controls

The March 2012 IRP Update presents a view of what PacifiCorp's current expectations are for environmental controls versus what the 2009 study assumed. The 2009 study is not clear, however, as to the environmental compliance costs. PacifiCorp's testimony states that Hunter 2's costs were inflated by about $100 million based on an assumption that a SCR would be needed.[75] This investment was not part of the Hunter 1 analysis, where it was believed that a SCR would not be needed.[76] In reality, that 2009 study underestimated clean air costs by more than $[redacted].

The following table lists the confidential clean air costs from that 2009 study:

Table 9: *Annual Clean Air Compliance Costs*

Year	Hunter Unit 1	Hunter Unit 2
2009	[redacted]	[redacted]
2010	[redacted]	[redacted]
2011	[redacted]	[redacted]
2012	[redacted]	[redacted]
2013	[redacted]	[redacted]
2014	[redacted]	[redacted]
2015	[redacted]	[redacted]
2016	[redacted]	[redacted]
2017	[redacted]	[redacted]
2018	[redacted]	[redacted]
2019	[redacted]	[redacted]

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[74] CUB Confidential Exhibit 113—IPCO Response to OPUC DR 220, Attachment 202-2, [redacted]

[75] PAC / 500 / Teply / 67.

[76] PAC / 500 / Teply / 67.

In PacifiCorp's March 2012 study, the amount of additional capital investment required after 2015 at these plants is $[redacted].[77] In the 2009 study, the total capital investment after 2015 is approximately $[redacted].[78]

This raises the question of when the Company knew that its 2009 analysis was wrong and what investments could have been potentially avoided had the Company updated its analysis or held off on its investments until further information was available regarding which environmental controls were necessary.

d. Replacement Resources

As with the other studies that were done before the 2012 study, the Company only considered replacing the plants with power purchases. Today, it looks like Hunter 1 [redacted].[79] The Company never allowed this option before the March 2012 study, and that study treats all investment before 2015, including the costs included in this docket, as sunk costs that could not be avoided.

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e. Alternative Closure Date

Hunter 1, as a facility like Bridger Unit 3 that is right on the edge between being cost-effective for clean air investments and being cost-effective to convert to gas, is a good candidate for an alternative closure date. By avoiding some of the clean air

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[77] CUB Confidential Exhibit 110—IPCO Response to CUB DR 8, Attachment 1; Tab: [redacted]

[78] CUB Confidential Exhibit 113—IPCO Response to OPUC DR 220, Attachment 220-2; Tab: [redacted]

[79] CUB Confidential Exhibit 105—IPCO Response to CUB DR 7, Attachment: LC 52 - 2011 IRP Update, page 75 (March 30, 2012).

investments for a few years, the plant should cost less to operate then it would if converted to gas, yet the Company has not even considered this option.

iii. Recommendations

CUB recommends that the Commission choose one of two options with regards to Hunter 1 and Hunter 2:

1. The investment in the test year is not adequate to meet the RHR BART requirements for 2015 and as such is not considered used and useful for meeting those requirements. PacifiCorp must wait until it has used and useful controls that meet BART in order to qualify for rate base treatment. Because there is doubt, based on the March Update, as to whether Hunter 1 will be converted to natural gas, some of the investments may never be used and useful.

Or

2. The Commission should find that PacifiCorp was imprudent by not conducting a better evaluation of Hunter 1 and 2 environmental controls versus other options before investing in the plant. The Company was imprudent by only considering a 2012 closure, even though the pollution control was not required until 2015. The Company should have waited for better information as to the cost of pollution controls and the cost of alternative resources, or, as an alternative, the Company should have conducted a sensitivity analysis that looked at a range of costs for these items. The Company was imprudent by not considering other options besides market purchases to replace the plant. Finally, the Company was imprudent by not considering alternative closure dates as allowed under the Regional Haze Rules.

If the Commission adopts the second option, CUB recommends that 25% of the rate base be disallowed.

E. Wyodak

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PacifiCorp did not include the Wyodak plant in the March Update, so the starting point is the Company's analysis from 2009, which estimated the benefit of continued investment in the plant to be $[redacted].[80]

i. Wyodak Study

a. Early Closure

The 2009 study assumed a closure date of 2009,[81] six years before the compliance deadline. The impact of this early closure and loss of several years of economic operation of the plant is:

Table 10: *NPV Benefits for Wyodak*

Year	Benefit	NPV Benefit
2009	[redacted]	[redacted]
2010	[redacted]	[redacted]
2011	[redacted]	[redacted]
2012	[redacted]	[redacted]
2013	[redacted]	[redacted]
2014	[redacted]	[redacted]
2015	[redacted]	[redacted]

b. Forward Electric Prices

This study would allow the plant to close in 2009 and used a March 31, 2009 Forward Price curve. It began with electric prices of $[redacted]/MWh in 2010, $[redacted]/MWh

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[80] PAC / 500 / Teply / 77.
[81] PAC / 500 / Teply / 76.

in 2015, and $[redacted]/MWh in 2020.[82] This compares with the NPPC study's estimates of $30/MWh in 2010, $55/MWh in 2015, and $63/MWh in 2020. In this case the Company is [redacted] to the Council's forecast than in any of the other coal studies, particularly in the earlier years, but the forecasts [redacted] over time.

c. Environmental Controls

The costs at issue in this case relate to a baghouse that was installed in 2011 at a cost of $103 million, and $11 million for the LNB project.[83] The March 2012 study shows an additional $[redacted] of capital expenditures after 2015.[84] By rushing ahead with this investment before the Company knew the full costs of BART, the Company failed to model the environmental costs accurately. As an alternative the Company could have conducted a sensitivity analysis to see the impact of additional controls but it did not do so.

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d. Replacement Resources

The 2009 study only considered replacement with market purchases and did not include alternative replacement resources, such as repowering the plant with natural gas.

e. Alternative Closure Date

The 2009 study assumed the plant would close that year. But since the baghouse was not installed until 2011, the Company should have modeled a later closure date. In addition, the Company should have considered alternative closure dates into the future such as 2018 or 2020, which could have eliminated the need for the additional pollution controls.

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[82] CUB Confidential Exhibit 114—IPCO Response to OPUC DR 220, Attachment 220-5; Tab: [redacted]
[83] PAC / 500 / Teply / 71.
[84] CUB Confidential Exhibit 110—IPCO Response to CUB DR 8, Attachment 1; tab: [redacted]

ii. Recommendation

CUB recommends that the Commission choose one of two options with regards to Wyodak:

1. That the investment in the test year is not adequate to meet the RHR BART requirements for 2015, and as such is not considered used and useful for meeting those requirements. PacifiCorp must wait until it has used and useful pollution controls that meet BART in order to qualify for rate base treatment.

Or:

2. The Commission should find that PacifiCorp was imprudent by not conducting a better evaluation of Wyodak's environmental controls versus other options before investing in the plant. The Company was imprudent by only considering a 2009 closure even though the pollution control was not required until several years later. The Company should have waited for better information as to the cost of pollution controls and the cost of alternative resources, or, as an alternative, the Company should have conducted a sensitivity analysis that looked at a range of costs for these items. The Company was imprudent by not considering other options besides market purchases to replace the plant. Finally, the Company was imprudent by not considering alternative closure dates as allowed under the Regional Haze Rules.

If the Commission adopts the second option, CUB recommends that 25% of the rate base be disallowed.

VI. Conclusion

CUB makes two basic recommendations in this testimony.

A. PacifiCorp's Request for a PCAM

One is simple—that PacifiCorp's request for a PCAM should not be granted as it is presented in the Company's testimony. We recommend that the Commission adopt a PCAM that is modeled after PGE's existing PCAM, which includes deadbands, sharing, and an earnings test, rather than the Company's proposed dollar-for-dollar structure. CUB's proposal would include asymmetric deadbands that cover the range in net power cost variation from 75 basis points of the Company's ROE below the base level of NVPC included in rates up to 150 basis points of ROE above the base level; a sharing agreement, by which 90 percent of expenses or savings assigned to customers and 10 percent to the Company; and an earnings test of +/- 100 basis points of the utility's ROE. These safeguards ensure that PacifiCorp retains some of its risk of fluctuations in net power costs, as well as an incentive to reduce its net power costs where possible.

B. PacifiCorp's Coal Investments

Our testimony argues that a number of clean air compliance investments at PacifiCorp's coal plants have been imprudent, or are not used and useful. We provide two recommended options for the Commission for each of these investments. If the Commission decides that an investment is not adequate to meet the regulatory obligations for which it is intended, then the Commission should rule that the investment is not used and useful, and therefore is not eligible to be placed into the Company's rate base. Alternatively, if the Commission decides that an investment is imprudent due to a lack of due diligence on the part of the Company, then CUB recommends that the Commission disallow 25% of the rate base component of that investment. The following table lists the amount of a 25% disallowance for the investments at each coal plant, on both a system and Oregon basis using an Oregon allocation factor of 25.78%.

Table 11: *CUB's Proposed Prudence Disallowance*

Plant	**PAC Request (Total)**	**25% Disallowance**	**Disallowed Oregon Share**
Bridger Unit 3	$17 million[85]	$4.25 million	$1.10 million
Naughton Unit 1	$130 million[86]	$32.5 million	$8.38 million
Naughton Unit 2	$164 million[87]	$41 million	$10.56 million
Dave Johnston Unit 4	$104 million[88]	$26 million	$6.70 million
Hunter Unit 1	$52 million[89]	$13 million	$3.35 million
Hunter Unit 2	$80 million[90]	$20 million	$5.16 million
Wyodak	$114 million[91]	$28.5 million	$7.35 million
Total	$661 million	$165.25 million	$42.6 million

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[85] PAC/500 Teply/80.
[86] PAC/500 Teply/29; PAC/500/Teply/31.
[87] PAC/500 Teply/40; PAC/500/Teply/41.
[88] PAC 500/Teply /8.
[89] PAC/500/Teply/60.
[90] PAC/500/Teply/61; PAC/500 Teply/62; PAC/500/Teply/62-63.
[91] PAC/500/Teply/71; PAC/500/Teply/72.

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EXPERIENCE: Provided testimony or comments in a variety of OPUC dockets, including UE 88, UE 92, UM 903, UM 918, UE 102, UP 168, UT 125, UT 141, UE 115, UE 116, UE 137, UE 139, UE 161, UE 165, UE 167, UE 170, UE 172, UE 173, UE 207, UE 208, UE 210, UG 152, UM 995, UM 1050, UM 1071, UM 1147, UM 1121, UM 1206, UM 1209, and UM 1355. Participated in the development of a variety of Least Cost Plans and PUC Settlement Conferences. Provided testimony to Oregon Legislative Committees on consumer issues relating to energy and telecommunications. Lobbied the Oregon Congressional delegation on behalf of CUB and the National Association of State Utility Consumer Advocates.

Between 1982 and 1991, worked for the Oregon State Public Interest Research Group, the Massachusetts Public Interest Research Group, and the Fund for Public Interest Research on a variety of public policy issues.

MEMBERSHIP: National Association of State Utility Consumer Advocates
Board of Directors, OSPIRG Citizen Lobby
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Between 2004 and 2008, I worked for the US Environmental Protection Agency and the City of Portland Bureau of Environmental Services, conducting economic and environmental analyses on a number of projects. In November 2008 I joined the Citizens' Utility Board of Oregon as a Utility Analyst and began conducting research and analysis on behalf of CUB.

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Forward-Looking Statements

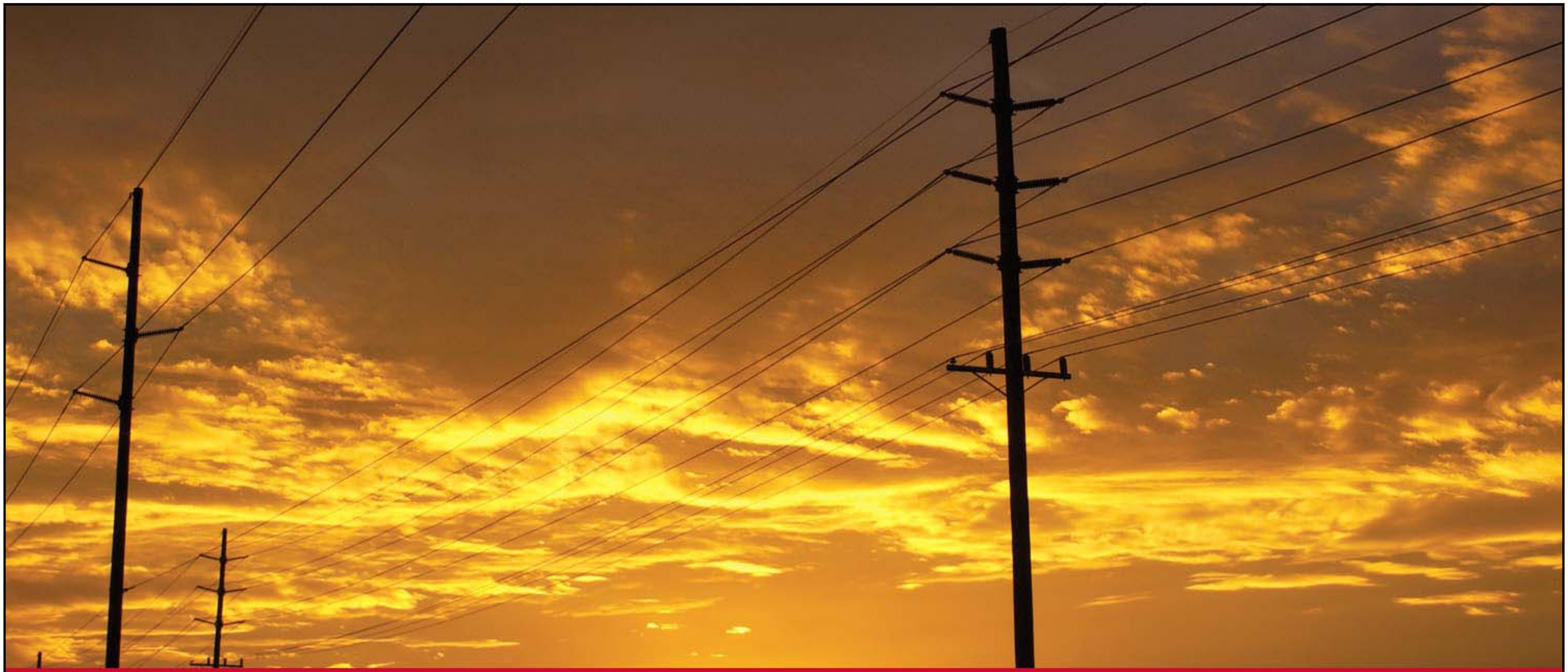
This report contains statements that do not directly or exclusively relate to historical facts. These statements are "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements can typically be identified by the use of forward-looking words, such as "may," "could," "project," "believe," "anticipate," "expect," "estimate," "continue," "intend," "potential," "plan," "forecast" and similar terms. These statements are based upon MidAmerican Energy Holdings Company's ("MEHC") and its subsidiaries' (collectively, the "Company") current intentions, assumptions, expectations and beliefs and are subject to risks, uncertainties and other important factors. Many of these factors are outside the Company's control and could cause actual results to differ materially from those expressed or implied by the Company's forward-looking statements. These factors include, among others:

- general economic, political and business conditions in the jurisdictions in which the Company's facilities operate;
- changes in federal, state and local governmental, legislative or regulatory requirements, including those pertaining to income taxes, affecting the Company or the electric or gas utility, pipeline or power generation industries;
- changes in, and compliance with, environmental laws, regulations, decisions and policies that could, among other items, increase operating and capital costs, reduce plant output or delay plant construction;
- the outcome of general rate cases and other proceedings conducted by regulatory commissions or other governmental and legal bodies;
- changes in economic, industry or weather conditions, as well as demographic trends, that could affect customer growth and usage or supply of electricity and gas or the Company's ability to obtain long-term contracts with customers and suppliers;
- a high degree of variance between actual and forecasted load and prices that could impact the hedging strategy and costs to balance electricity and load supply;
- changes in prices, availability and demand for both purchases and sales of wholesale electricity, coal, natural gas, other fuel sources and fuel transportation that could have a significant impact on generation capacity and energy costs;
- the financial condition and creditworthiness of the Company's significant customers and suppliers;
- changes in business strategy or development plans;
- availability, terms and deployment of capital, including reductions in demand for investment-grade commercial paper, debt securities and other sources of debt financing and volatility in the London Interbank Offered Rate, the base interest rate for MEHC's and its subsidiaries' credit facilities;

Forward-Looking Statements

- changes in MEHC’s and its subsidiaries’ credit ratings;
- performance of the Company’s generating facilities, including unscheduled outages or repairs;
- risks relating to nuclear generation;
- the impact of derivative contracts used to mitigate or manage volume, price and interest rate risk, including increased collateral requirements, and changes in the commodity prices, interest rates and other conditions that affect the fair value of derivative contracts;
- increases in employee healthcare costs and the potential impact of federal healthcare reform legislation;
- the impact of investment performance and changes in interest rates, legislation, healthcare cost trends, mortality and morbidity on pension and other postretirement benefits expense and funding requirements;
- changes in the residential real estate brokerage and mortgage industries that could affect brokerage transaction levels;
- unanticipated construction delays, changes in costs, receipt of required permits and authorizations, ability to fund capital projects and other factors that could affect future generating facilities and infrastructure additions;
- the impact of new accounting pronouncements or changes in current accounting estimates and assumptions on consolidated financial results;
- the Company’s ability to successfully integrate future acquired operations into its business;
- other risks or unforeseen events, including litigation, wars, the effects of terrorism, embargoes and other catastrophic events; and
- other business or investment considerations that may be disclosed from time to time in MEHC’s filings with the United States Securities and Exchange Commission (“SEC”) or in other publicly disseminated written documents.

Further details of the potential risks and uncertainties affecting the Company are described in MEHC’s filings with the SEC, including Item 1A and other discussions contained in Form 10-K. The Company undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The foregoing review of factors should not be construed as exclusive.



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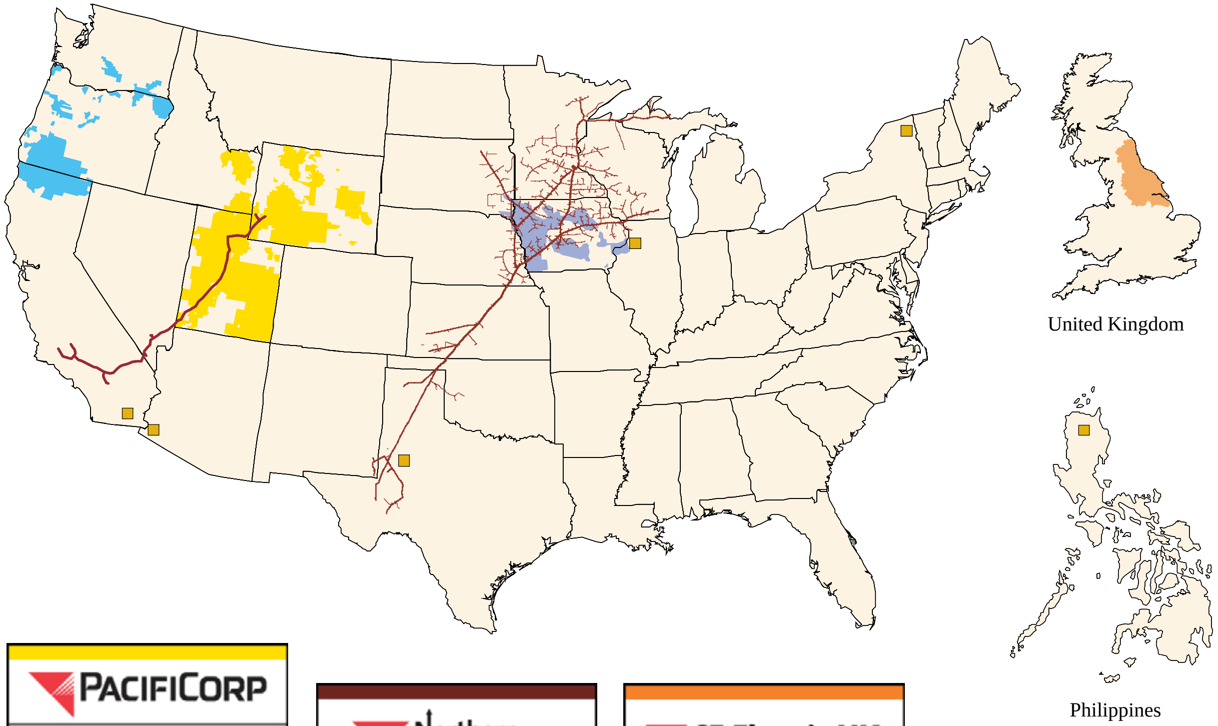
Patrick J. Goodman

Senior Vice President and Chief Financial Officer
MidAmerican Energy Holdings Company

MidAmerican Energy Holdings Company Energy Assets



PACIFICORP

PACIFIC POWER

🟦 Pacific Power Service Territory

Number of Customers: 729,000

ROCKY MOUNTAIN POWER

🟨 Rocky Mountain Power Service Territory

Number of Customers: 997,000

PACIFICORP ENERGY

Northern Natural Gas

／ Northern Natural Gas Pipeline

Number of Customers: 274

Kern River GAS TRANSMISSION COMPANY

／ Kern River Gas Transmission Pipeline

Number of Customers: 32

CE Electric UK

🟧 CE Electric UK Service Territory

Number of Customers: 3,831,000

CALENERGY

🟨 Generation Operations

Number of Customers: 11

MidAmerican ENERGY

🟪 MidAmerican Energy Company Service Territory

Number of Customers: 1,432,000

REVENUES	$11.2 billion
ASSETS	$45 billion
CUSTOMERS	
Electric:	6.2 million
Natural Gas:	0.7 million
EMPLOYEES	16,300

NATURAL GAS TRANSMISSION PIPELINE DESIGN CAPACITY
More than 7.0 billion cubic feet per day

GENERATION CAPACITY
18,092 megawatts(1)

NONCARBON GENERATION
More than 4,200 megawatts(1)
23% of total generation capacity

(1) *Net MW owned in operation and under construction as of December 31, 2009*

Berkshire Hathaway Ownership Benefits

MIDAMERICAN ENERGY HOLDINGS COMPANY

- Berkshire Hathaway ownership allows focus to be on managing medium- to long-term risks, which promotes long-term sustainability
  - Bondholder friendly
- No dividend requirement
  - Cash flow is retained in the business and used to help fund growth and improve credit metrics
- Access to capital from Berkshire Hathaway allows MEHC to take advantage of market opportunities
- Berkshire Hathaway is a long-term holder of assets, and its never-sell philosophy promotes stability and helps make MEHC the buyer of choice

Berkshire Hathaway Equity Commitment

MIDAMERICAN ENERGY HOLDINGS COMPANY

- Equity commitment from AA+ rated parent
  - The $3.5 billion commitment has been amended such that the maturity date has been extended for three years to February 28, 2014, and on March 1, 2011, the commitment will be changed to $2.0 billion
    - The $2.0 billion level reflects lower debt maturities at MEHC and a reduced need for equity contributions into our regulated subsidiaries
  - Access to capital even in times of utility sector and general market stress

    No other utility has this quality of explicit financial support
  - Commitment can only be drawn for two purposes:
    - Paying MEHC parent debt when due
    - Funding the general corporate purposes and capital requirements of MEHC's regulated subsidiaries
  - Agreement requires funding within 180 days of request
  - Future mergers and acquisitions funded separate from this agreement

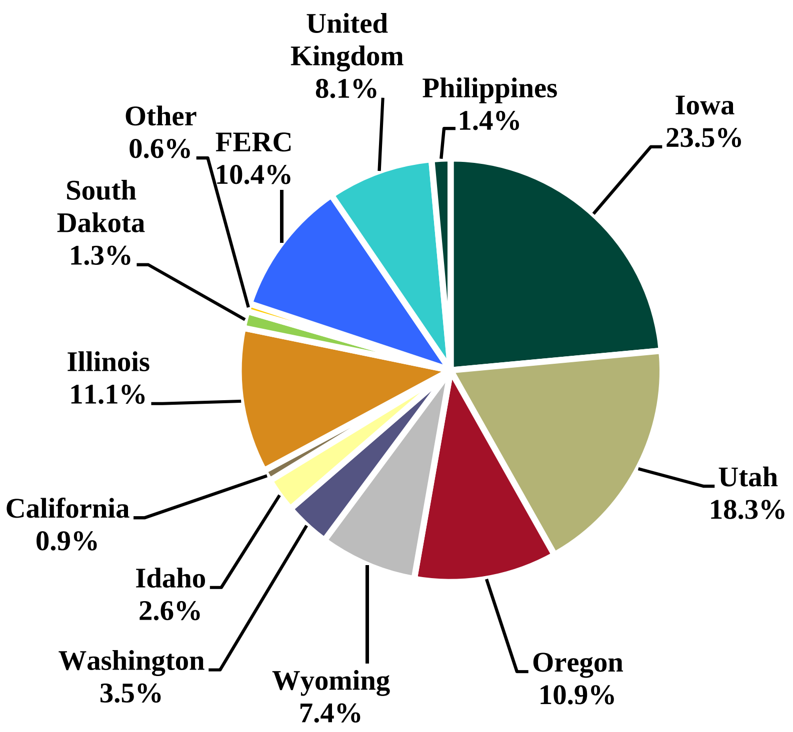
Revenue and EBITDA Diversification

MIDAMERICAN
ENERGY HOLDINGS COMPANY

- Diversification of revenue sources reduces regulatory concentrations
- In 2009, 95% of EBITDA came from investment grade subsidiaries

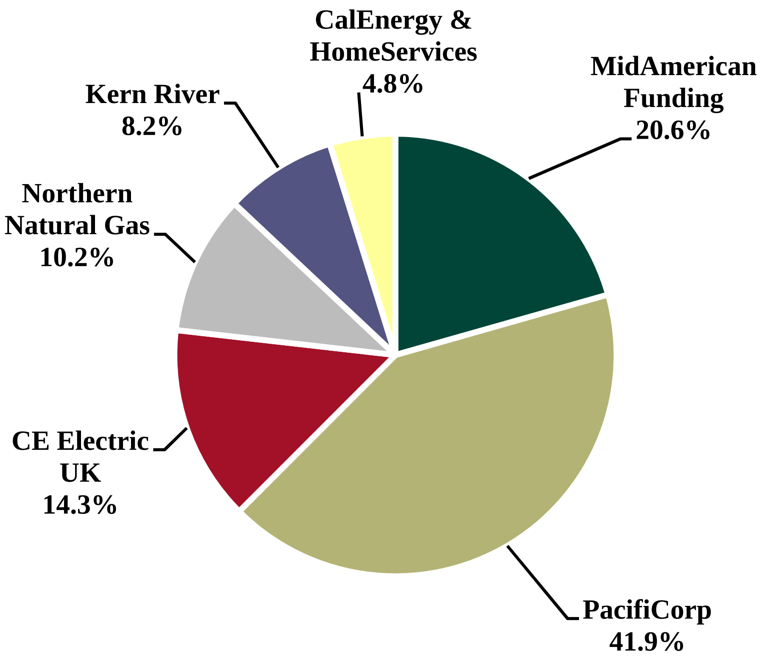
MEHC 2009

Energy Revenue(1): $10.2 Billion



MEHC 2009

Consolidated EBITDA(2): $3.7 Billion



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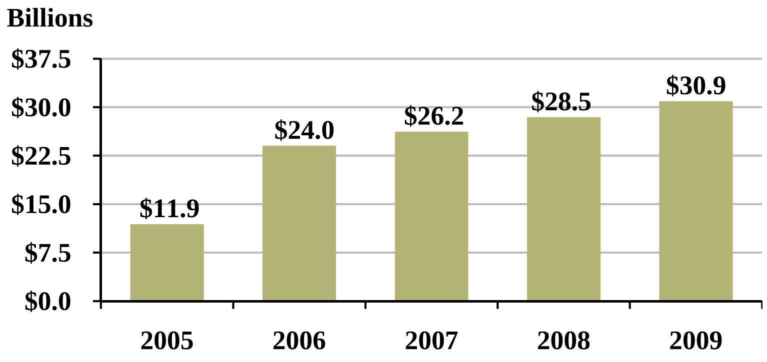
[1] *Excludes HomeServices, which has operations in 20 states and adds further diversification, and equity income from CalEnergy*

[2] *EBITDA represents operating income plus depreciation and amortization; percentages based on $3.9 billion of EBITDA which excludes Corporate/other of $(190) million*

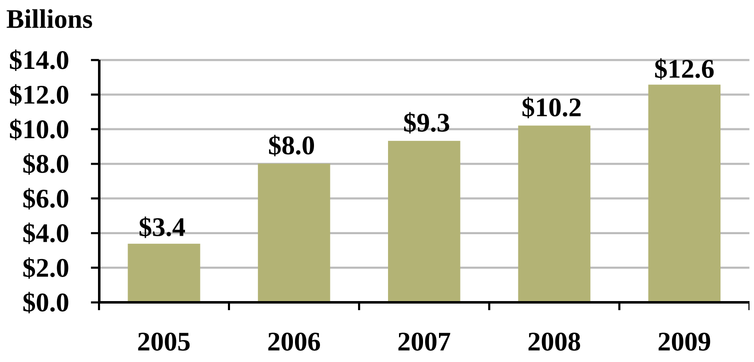
MEHC Financial Summary

MIDAMERICAN
ENERGY HOLDINGS COMPANY

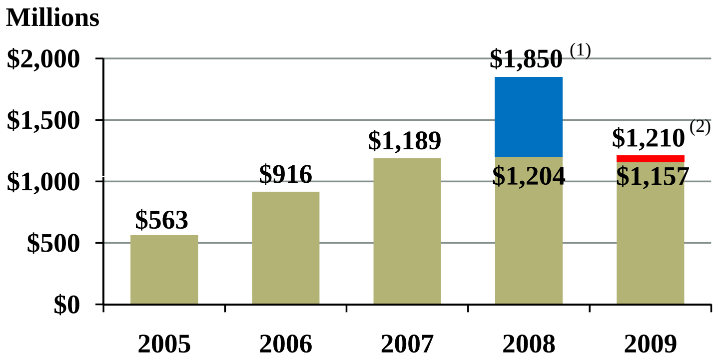
Property, Plant and Equipment (Net)



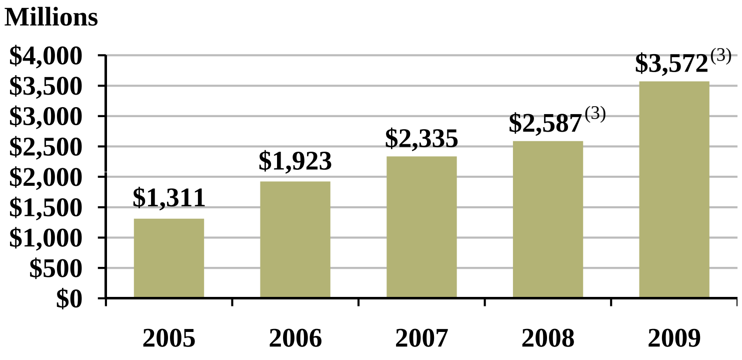
MEHC Shareholders' Equity



Net Income Attributable to MEHC



Cash Flows from Operations



(1) $1,850m net income includes $646m of after-tax gains related to the termination fee and profit from the investment in Constellation Energy

(2) $1,210m net income excludes a $75m after-tax charge for stock-based compensation and $22m of after-tax income from the sale of Constellation Energy shares

(3) $2,587m and $3,572m cash flows from operations include $175m and $128m for 2008 and 2009, respectively, related to the termination fee and profit from the investment in Constellation Energy

Segment Information

MIDAMERICAN
ENERGY HOLDINGS COMPANY

Operating income ($ millions)	**Years Ended December 31,** 2009			2008		2007
PacifiCorp	$	1,079	$	952	$	917
MidAmerican Funding		469		590		514
Northern Natural Gas		337		457		308
Kern River		221		305		277
CE Electric UK		394		514		555
CalEnergy Generation - Foreign		113		103		142
CalEnergy Generation - Domestic		15		15		12
HomeServices		11		(58)		33
Corporate/other		(174)		(50)		(70)
Total operating income		2,465		2,828		2,688
Interest expense		(1,195)		(1,198)		(1,184)
Interest expense on MEHC subordinated debt - Berkshire		(58)		(111)		(108)
Interest expense on MEHC subordinated debt - other		(22)		(24)		(28)
Capitalized interest		41		54		54
Interest and dividend income		38		75		105
Other, net		146		1,188		112
Income before income tax expense and other		1,415		2,812		1,639
Income tax expense		(282)		(982)		(456)
Other		24		20		6
Net income attributable to MEHC	$	1,157	$	1,850	$	1,189

Segment Information

Consolidated Balance Sheet Data ($ millions)	**As of December 31,**		
	2009	**2008**	**2007**
Total assets	$ 44,684	$ 41,441	$ 39,216
Short-term debt	179	836	130
Long-term debt, including current maturities:			
MEHC senior debt	5,371	5,121	5,471
MEHC subordinated debt	590	1,321	1,125
Subsidiary debt	13,791	12,954	13,097
Total MEHC shareholders' equity	12,576	10,207	9,326
Noncontrolling interests	267	270	256
Total Equity	12,843	10,477	9,582

Capital Expenditures ($ millions)	**Years Ended December 31,**		
	2009	**2008**	**2007**
PacifiCorp(1)	$ 2,328	$ 2,097	$ 1,518
MidAmerican Funding	439	1,473	1,300
Northern Natural Gas	177	196	225
Kern River	73	24	15
CE Electric UK	387	440	422
Other	9	15	32
Total Capital Expenditures	$ 3,413	$ 4,245	$ 3,512

(1) *PacifiCorp includes the acquisition of Chehalis in 2008*

Credit Metrics and Ratings

MIDAMERICAN
ENERGY HOLDINGS COMPANY

- **MidAmerican Energy Holdings Company Key Ratios**
  - Zero dividends paid to Berkshire Hathaway allows an accelerated improvement in credit ratios

	2009	**2008**	**2007**	**2006**	**2005**
FFO/Interest(1)	3.9x	3.3x	3.0x	3.2x	2.8x
FFO/Debt(2)	17.7%	14.8%	12.7%	12.8%	12.9%
Debt/Capital(3)	59.0%	61.6%	63.6%	63.4%	66.3%

- **Ratings**

(Issuer or senior unsecured ratings unless noted)

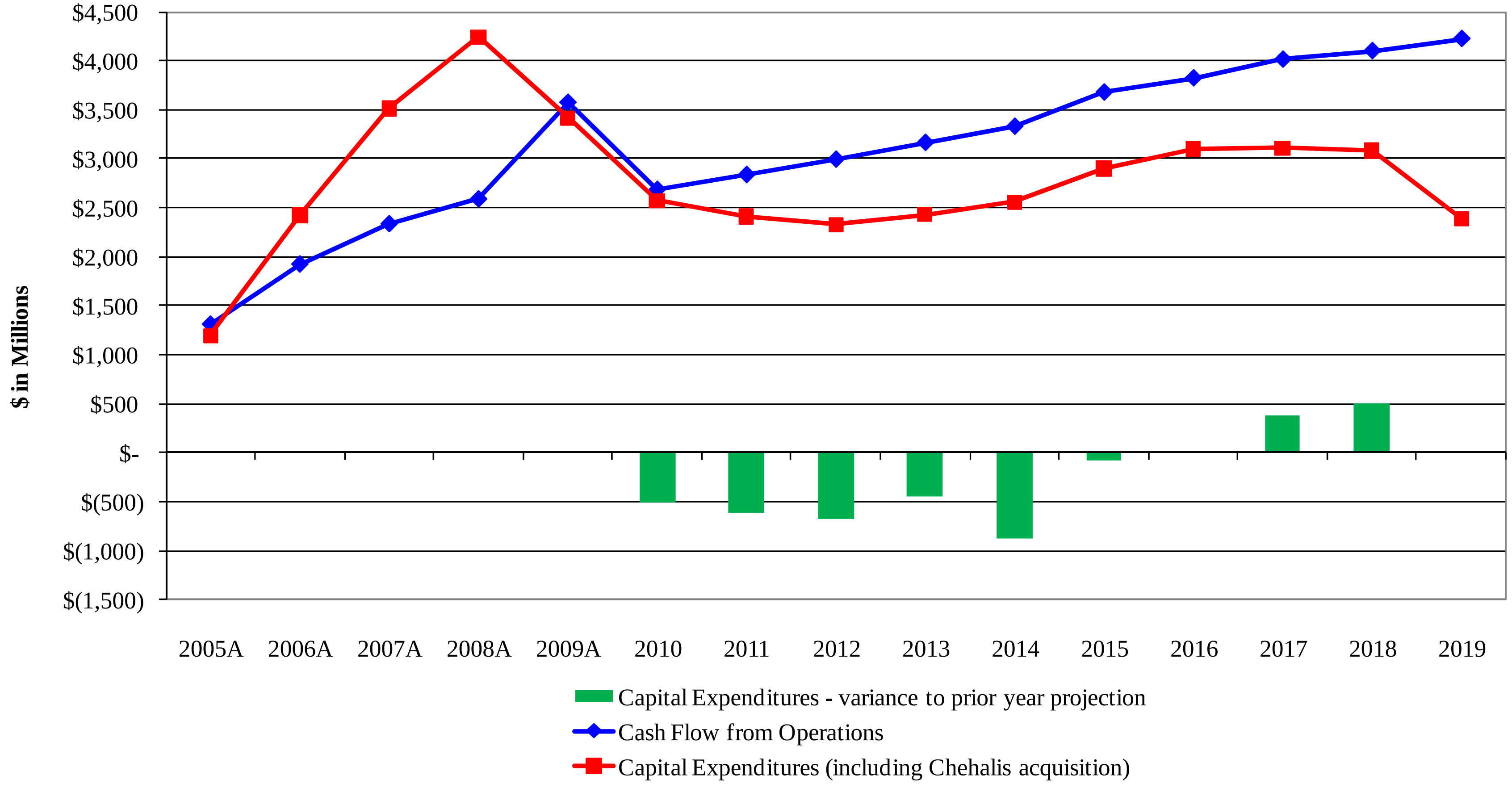
	Moody's	**S&P**	**Fitch**
MidAmerican Energy Holdings Company	Baa1	BBB+	BBB+
MidAmerican Energy Company	A2	A-	A
PacifiCorp(4)	A2	A	A-
Northern Natural Gas Company	A2	A	A
Kern River Funding Corp.(4)	A3	A-	A-
Northern Electric Distribution Ltd	A3	A-	A
Yorkshire Electricity Distribution plc	A3	A-	A

(1) *Interest excludes interest on MEHC subordinated debt*
(2) *Debt excludes MEHC subordinated debt*
(3) *MEHC subordinated debt excluded from Debt but included in Capital*
(4) *Ratings for PacifiCorp and Kern River are senior secured rating*

Projected Capital Expenditures and Cash Flows

MIDAMERICAN
ENERGY HOLDINGS COMPANY

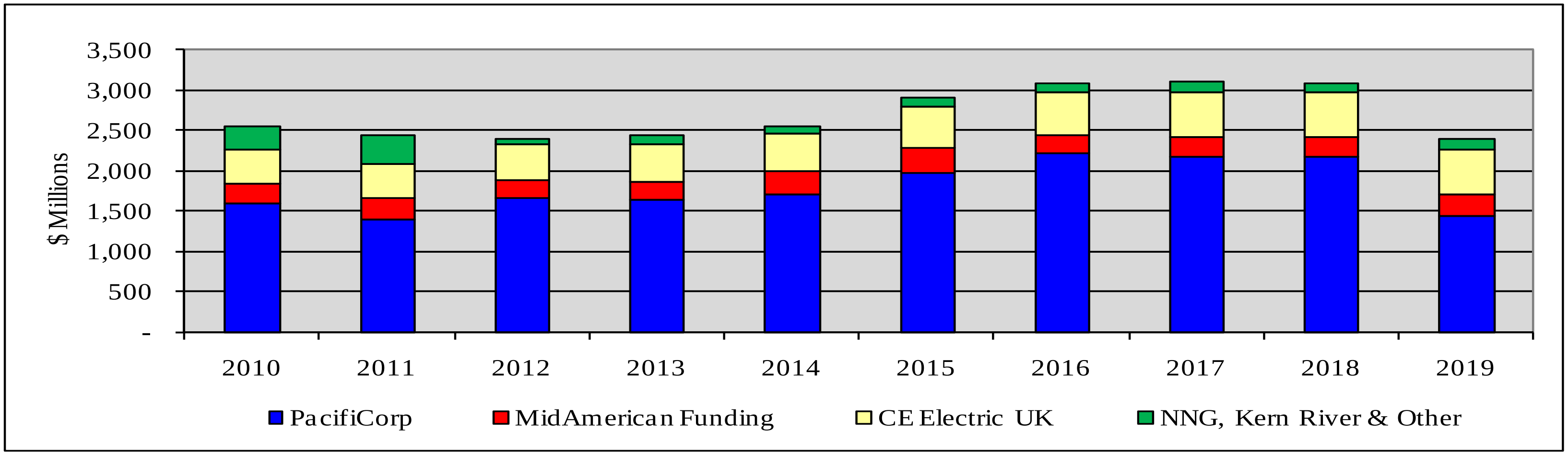
- MEHC and its subsidiaries will spend approximately $12.3 billion over the next five years for development and maintenance capital expenditures. This is a decrease of $3.1 billion from last year's projection for 2010-2014.



Projected Capital Expenditures and Debt Maturities

MIDAMERICAN
ENERGY HOLDINGS COMPANY

Projected Capital Expenditures



Long-Term Debt Maturities[1]

($ millions)

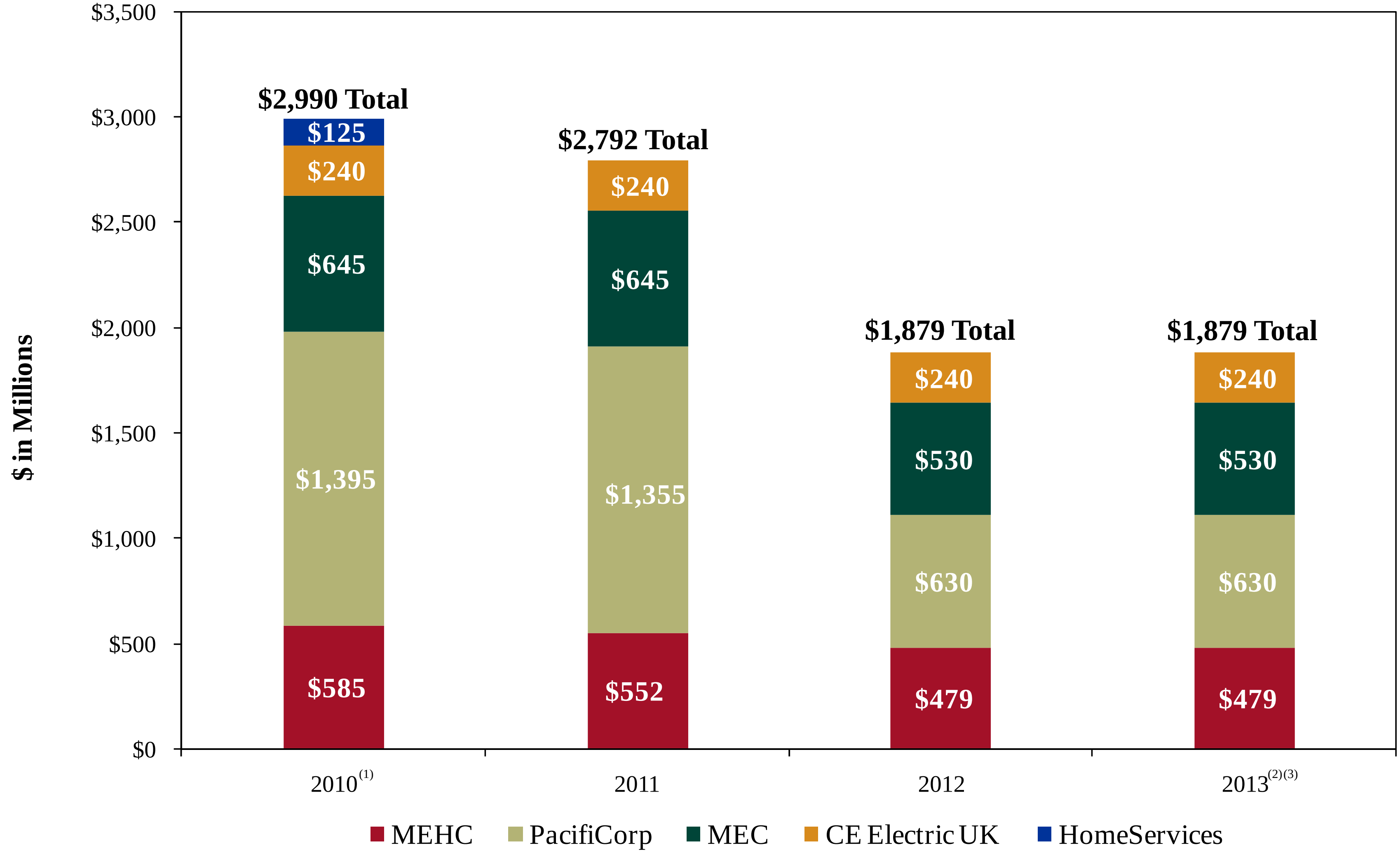
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
MEHC Parent	$ -	$ -	$ (750)	$ -	$ (250)	$ -	$ -	$ -	$ (650)	$ -
PacifiCorp	(15)	(587)	(17)	(261)	(253)	(122)	(57)	(52)	(586)	(350)
MidAmerican Funding	-	(200)	-	-	-	-	-	-	-	-
MidAmerican Energy	-	-	(400)	(275)	(350)	-	-	(250)	(350)	-
Northern Natural Gas	-	(250)	(300)	-	-	(100)	-	-	(200)	-
Kern River	(79)	(81)	(81)	(80)	(81)	(85)	(190)	(62)	(130)	-
CE Electric UK[2]	-	-	-	-	-	-	-	-	-	-
	$ (94)	$ (1,118)	$ (1,548)	$ (616)	$ (934)	$ (307)	$ (247)	$ (364)	$ (1,916)	$ (350)

[1] *Excludes subordinated debt, capital leases and nonregulated project debt*

[2] *Debt maturities at CE Electric UK exclude maturities at CE UK Gas*

Current Credit Facilities

MIDAMERICAN ENERGY HOLDINGS COMPANY



[1] *Credit facility at HomeServices expires on December 31, 2010*

[2] *Credit facility at CE Electric UK expires March 2013; assumes 1.60 $/£ exchange rate*

[3] *Credit facilities at MEHC, PacifiCorp and MidAmerican Energy Company expire on July 6, 2013*

Financing Plan 2010-2011

MIDAMERICAN
ENERGY HOLDINGS COMPANY

- PacifiCorp anticipates a 2011 debt issuance to, in part, refinance its $500 million November 2011 maturity
- Northern Natural Gas anticipates a 2011 debt issuance to, in part, refinance its $250 million June 2011 maturity
- MidAmerican Energy Company will issue if additional wind generation capital expenditures are economic
- Yorkshire Electricity and Northern Electric plan debt issuances in 2010 and 2011 to support distribution business growth
- Kern River 2010 and Apex expansions
- Geothermal plants in Imperial Valley, California, for potential 150 MW expansion
- Electric Transmission Texas, LLC issued $225 million in early 2010 with additional issuances likely later in 2010 and 2011

UE-246/PacifiCorp
June 5, 2012
CUB Data Request 11

CUB Data Request 11

PacifiCorp recently announced that it will convert Naughton Unit 3 to natural gas rather than install the SCR that is required under the Wyoming SIP.

(a) Please provide the analysis that supports this decision.
(b) Under BART/RHR, would an SCR have been required as part of the SIP if the useful life of the plant ended in 2017, or 2020?
(c) As part of the Wyoming BART, did PacifiCorp consider proposing a different retirement date for the plant (other than the retirement date that was used before the decision to convert it to gas)?

Response to CUB Data Request 11

PacifiCorp objects to the characterization in CUB Data Request 11 that it "announced that it will convert Naughton Unit 3 to natural gas rather than install the SCR that is required under the Wyoming SIP" as inaccurate. Without waiving the foregoing objection, PacifiCorp provides the following clarification. PacifiCorp requested that the Company be allowed to withdraw its request for a Certificate of Public Convenience and Necessity for the installation of an SCR and baghouse at Naughton Unit 3 based on updated analyses suggesting that installation of the SCR and baghouse were not the most cost-effective option for compliance with the regional haze requirements. The Wyoming SIP and the EPA's proposed action signed May 15, 2012, both require the Company to install an SCR and baghouse by December 31, 2014. The Company's alternative compliance approach is yet to be approved by the respective state and federal authorities.

(a) Please refer to Attachment CUB 11-1 and Confidential Attachment CUB 11-2 for the analysis supporting the basis for PacifiCorp's withdrawal of the Certificate of Public Convenience and Necessity.

(b) PacifiCorp objects to this request because it calls for speculation. The Company is not required to and cannot speculate about the Wyoming Division of Air Quality's positions under the scenarios presented.

(c) As directed by the Wyoming Division of Air Quality, the cost evaluation for various control technologies used a 20-year control life in the five-factor BART analysis. The Company did not artificially inflate the cost of controls by accelerating retirement of the plant or shortening control life, nor did it consider the impacts to customers of using an accelerated retirement date. The Company used a consistent depreciation life for the plant for the purpose of the BART analyses.

The confidential attachment is designated as confidential under the protective order in these proceedings and may only be disclosed to qualified persons as defined in that order.

UE-246/PacifiCorp
June 1, 2012
CUB Data Request 4

CUB Data Request 4

According to Mr. Teply's testimony (PAC/500/Teply/80/8-13), the Bridger 3 Scrubber Upgrade construction project began in 2010, was placed in service in June 2011, and "was tied into the existing unit during a scheduled plant maintenance outage.
(a) What was the beginning date of the outage and what was the final date of the outage?
(b) What was the specific date that construction on the project began?

Response to CUB Data Request 4

(a) The Jim Bridger Unit 3 outage began April 30^{t}, 2011, and ended June 30, 2011.

(b) Construction of the Jim Bridger Unit 3 scrubber upgrade project began on July 6, 2010.

UE-246/PacifiCorp
June 1, 2012
CUB Data Request 7

CUB Data Request 7

Please provide a copy of the updated Coal Replacement Study referenced on page 100 of Mr. Teply's testimony.

(a) Please identify where this study concludes that it "did not identify an accelerated retirement date for Jim Bridger Unit 3?"
(b) How many scenarios were analyzed in this study?
(c) How many scenarios concluded that it was economic to convert Jim Bridger 3 to natural gas?
(d) Assuming some scenarios found conversion to natural gas to be economic, is PacifiCorp concerned that future conditions will reflect those scenarios?
(e) What are PacifiCorp's plans to ensure that future investment in Bridger 3 reflect conditions that ensure that the investment is economic?
(f) Did this study assume the costs associated with the turbine upgrade were avoidable if the plant was converted to natural gas, or did the plan identify the costs of the turbine upgrade as sunk?
(g) If the answer to the above question "f" is no, would including the cost of the turbine upgrade as an avoidable cost change the analysis?

Response to CUB Data Request 7

Please refer to Confidential Attachment CUB 7 for a copy of the updated Coal Replacement Study referenced on page 100 of Mr. Teply's testimony.

(a) The reference to this study in Mr. Teply's testimony was forward looking (the study had not been completed), and there is no assertion in the referenced section of testimony that the study "did not identify an accelerated retirement date for Jim Bridger 3." Nonetheless, the study provided as Confidential Attachment CUB 7 did not identify an accelerated retirement date for Jim Bridger 3. Please refer to the first paragraph on page 85 under the section titled "Replacement Study Results," specifically the sentence that reads:

> [I]n the event that incremental capital investments are not justified, natural gas conversion served as the most beneficial replacement resource alternative for Naughton unit 3, Jim Bridger units 3 & 4, and Hunter unit 1 among all replacement scenarios studied."

(b) Six.

(c) Three.

(d) As noted in the Conclusions section of the updated Coal Replacement Study, the Company must make near-term investment decisions in the face of tremendous uncertainty around the price of natural gas and coal costs 10 to 20 years into the future. In the case of Jim Bridger 3, the updated Coal Replacement Study shows that there are three future scenarios (a low gas price future, a high CO_2 price future, and a future with both low gas and high CO_2 prices) in which gas conversion is a lower cost alternative to the future investments required to operate the unit as a coal-fueled facility. Similarly, there are future scenarios, including the base case, where future investments required to operate the unit as a coal-fueled facility are favorable to gas conversion. The Company has considered each of these scenarios as part of its evaluation of whether future coal investment is the least cost, accounting for risk, alternative for customers.

(e) The Company will continue to assess information and conditions available at the time investment decisions are made to ensure that investments are economic.

(f) The study did not assume any turbine upgrades for Jim Bridger 3, and therefore there would were no turbine upgrade costs that could have been avoided.

(g) Please refer to the Company's response to subpart (f) above.

The confidential attachment is designated as confidential under the protective order in these proceedings and may only be disclosed to qualified persons as defined in that order.

UE 246 / CUB / 105
Jenks - Feighner / 1

CUB EXHIBIT 105 IS CONFIDENTIAL
SUBJECT TO PROTECTIVE ORDER NO. 12-060

Natural Gas Update

Ken Zimmerman, Ph.D.
Senior Analyst
Oregon Public Utility Commission
Electric & Natural Gas Division
Resource & Market Analysis

Summer 2012

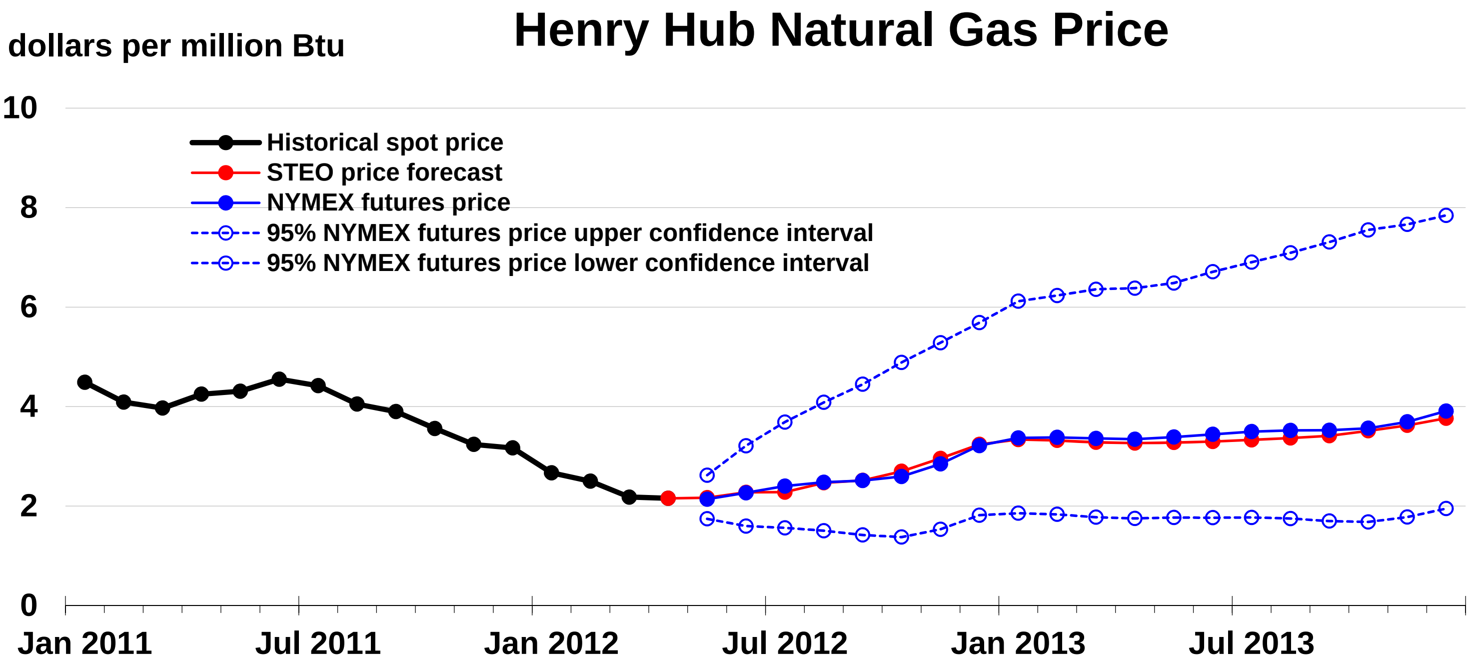
The views expressed in the Update do not necessarily represent those of the OPUC, any Commissioner, or the Staff of the OPUC on the issues considered.

Summer 2012 Natural Gas Price Projections

In its April 2012, Short-term Energy Outlook ("STEO") the EIA indicates that it expects natural gas prices will average $2.51 per MMBtu in 2012. That same STEO also projects natural gas at the Henry Hub to average about $2.39/MMBtu for the summer of 2012.

Almost all business and government forecasters agree with the EIA's projections, some projecting even lower prices. Since early April prices have hovered around the $2.00 mark. On April 14th price at the Henry Hub dropped below $2.00. These are the lowest gas prices since 1997. Many market participants expect the near-term downtrend in prices to continue, with some traders expecting prices to fall to $1.85 in the short-term and eventually testing the all-time low of $1.02 hit in 1992 in the long-term. The April 2012 STEO projection for summer 2012 is in the Figure below.

Figure 1

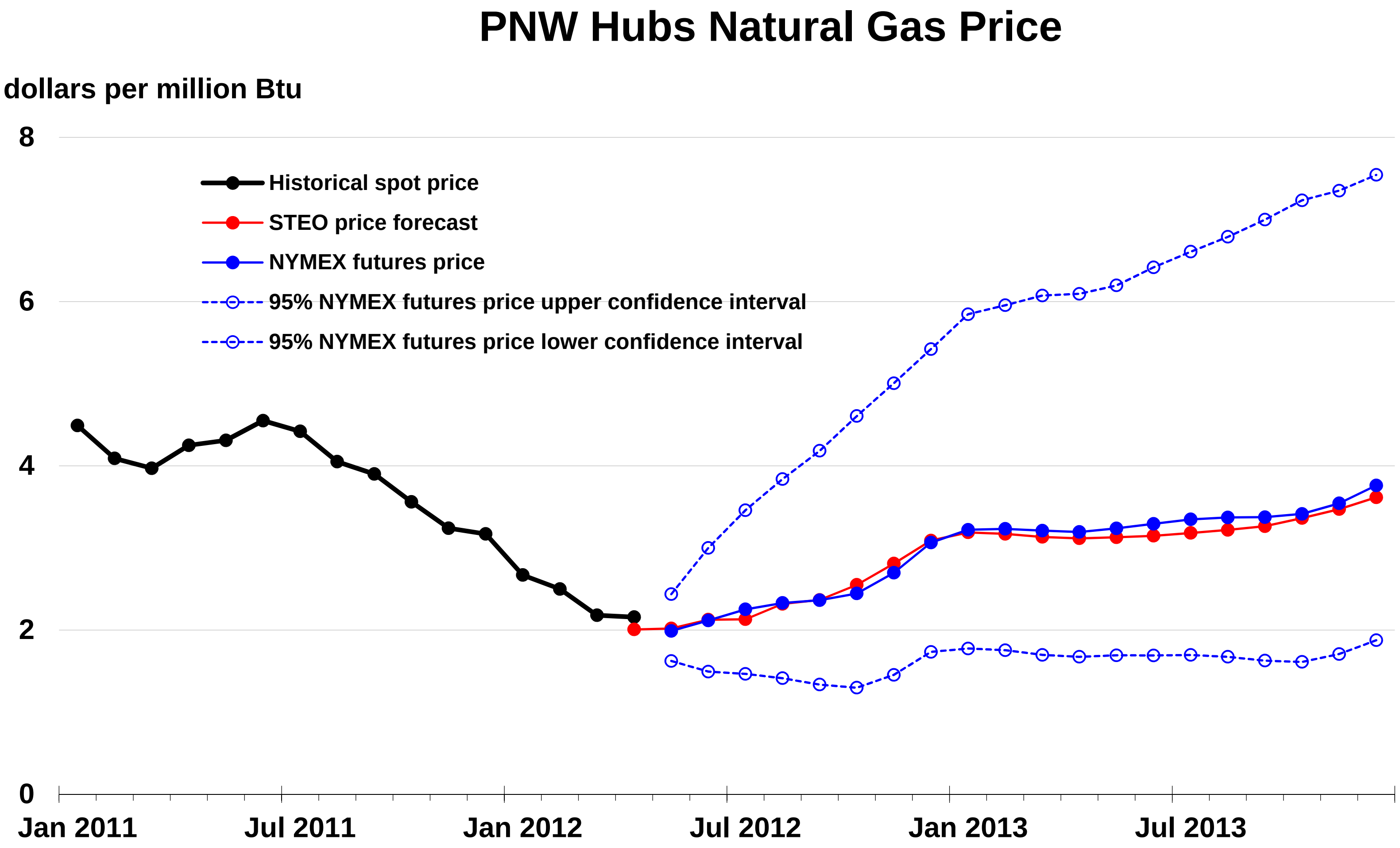


Note: Confidence interval derived from options market information for the 5 trading days ending April 5, 2012
Intervals not calculated for months with sparse trading in "near-the-money" options

Source: Short-Term Energy Outlook, April 2012

Unless the basis difference between the Henry Hub and the PNW Hubs grows over the next few months prices here in Oregon and the rest of the PWN should closely mirror prices in most of the remainder of the nation.

Figure 2



PNW Hubs Natural Gas Price

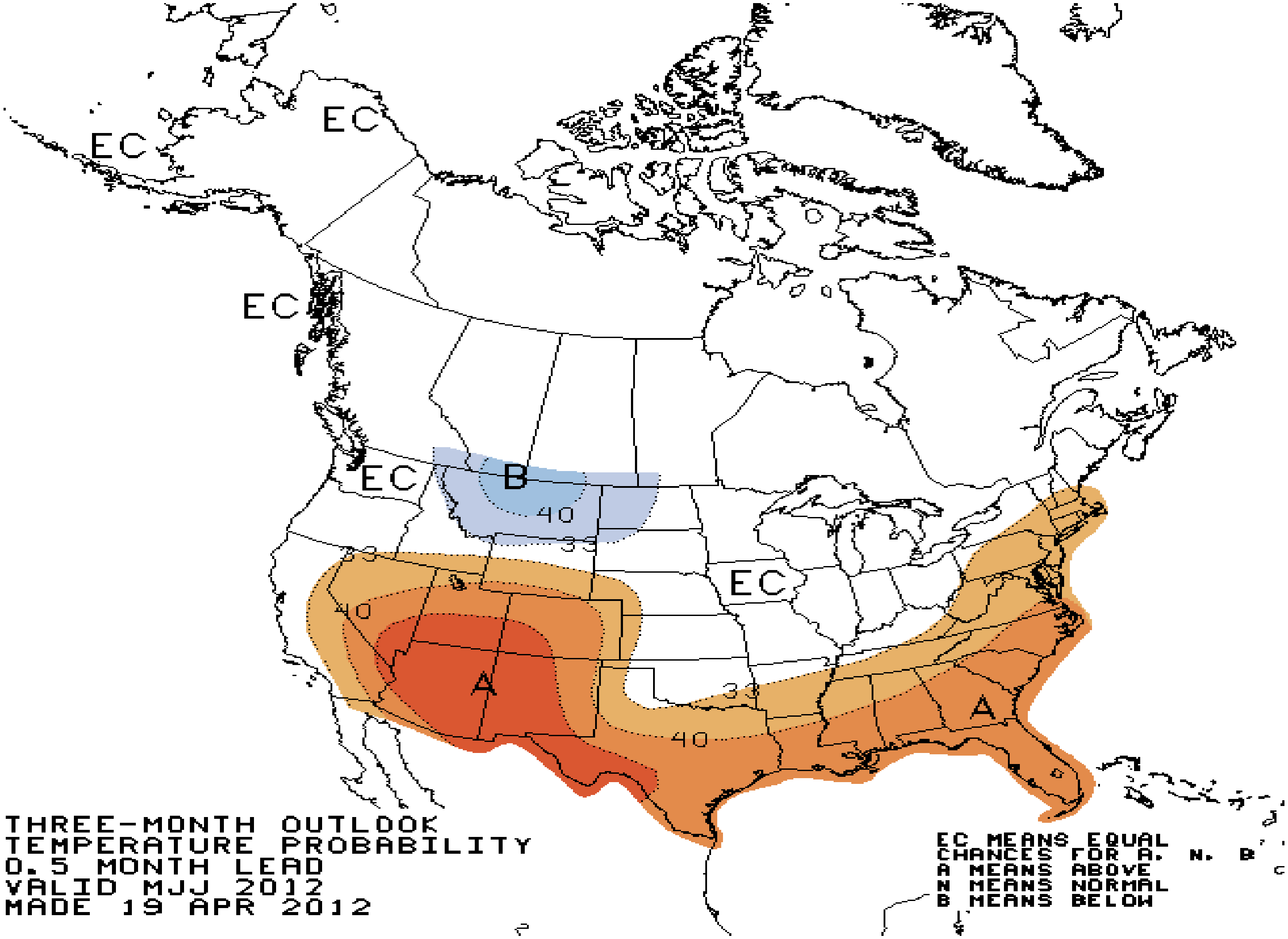
Note: Confidence interval derived from options market information for the 5 trading days ending April 5, 2012
Intervals not calculated for months with sparse trading in "near-the-money" options contracts

Source: Short-Term Energy Outlook, April 2012 As edited by Ken Zimmerman

eia

Map 1 and Map 2 below are the latest projections from the Climate Prediction Center for temperature and rainfall for the country. Note that the PNW's temperature is not expected to be outside the historical normal, while the PNW rainfall is projected to be below the normal.

Map 1



UE 246 CUB/106
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Map 2

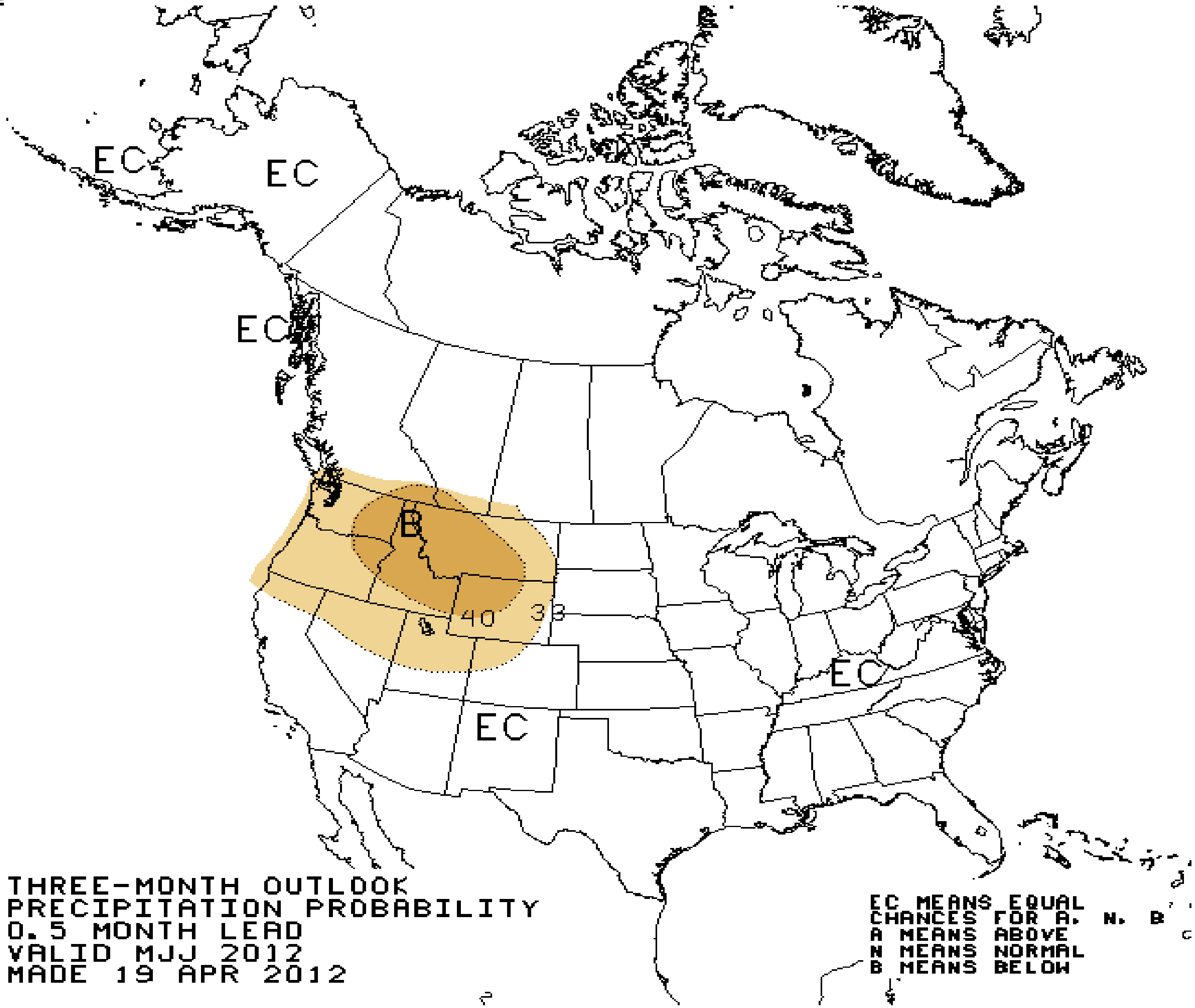
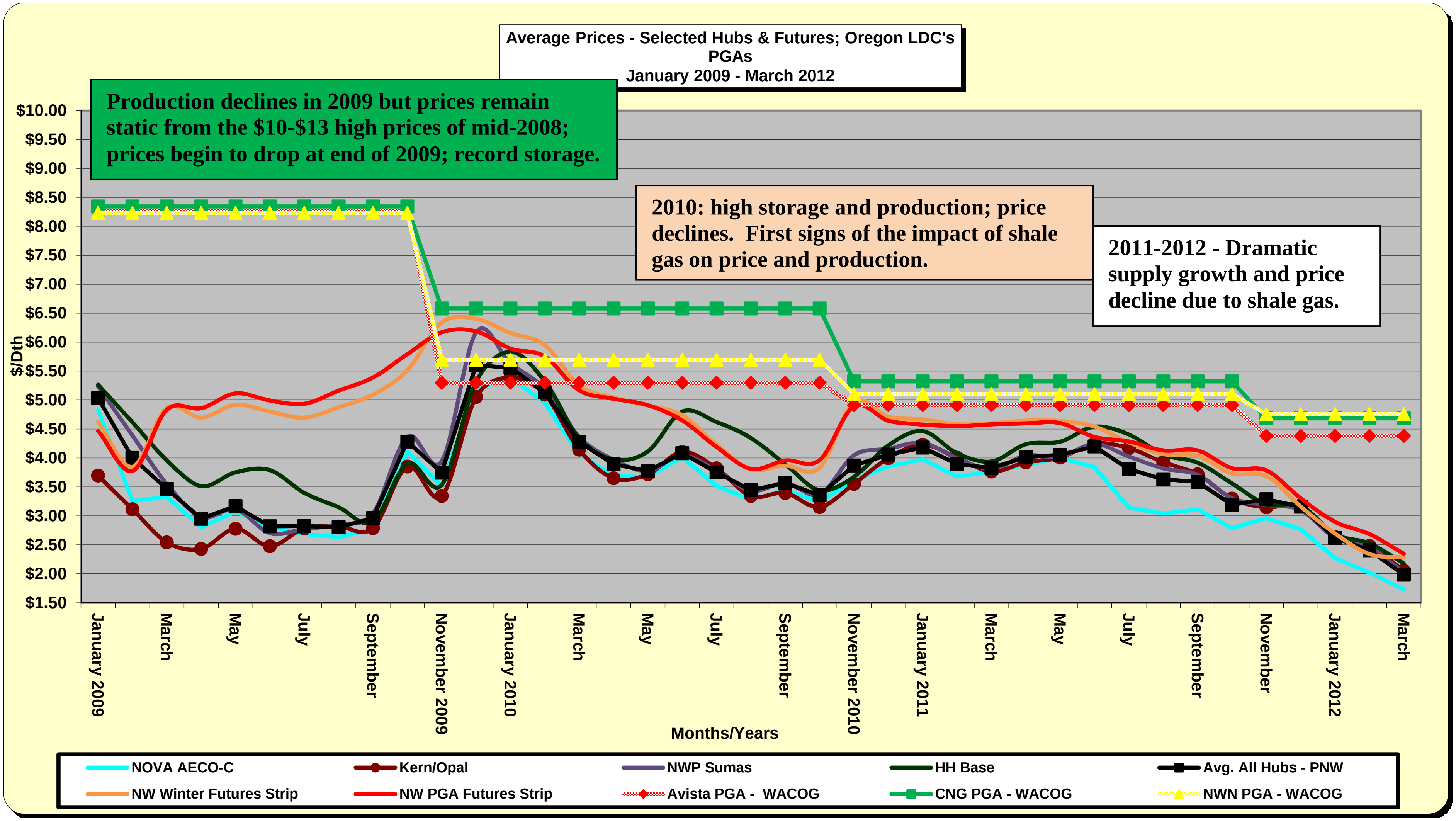


Figure 3: Recent History of US Natural Gas Prices[1]

Since the end of 2009 prices have been falling consistently, due primarily to the expansion in the production of shale gas and the decline in consumption due to the economic recession and mild winters. By historical standards prices overall remain low (see Figure 4).



Production declines in 2009 but prices remain static from the $10-$13 high prices of mid-2008; prices begin to drop at end of 2009; record storage.

2010: high storage and production; price declines. First signs of the impact of shale gas on price and production.

2011-2012 - Dramatic supply growth and price decline due to shale gas.

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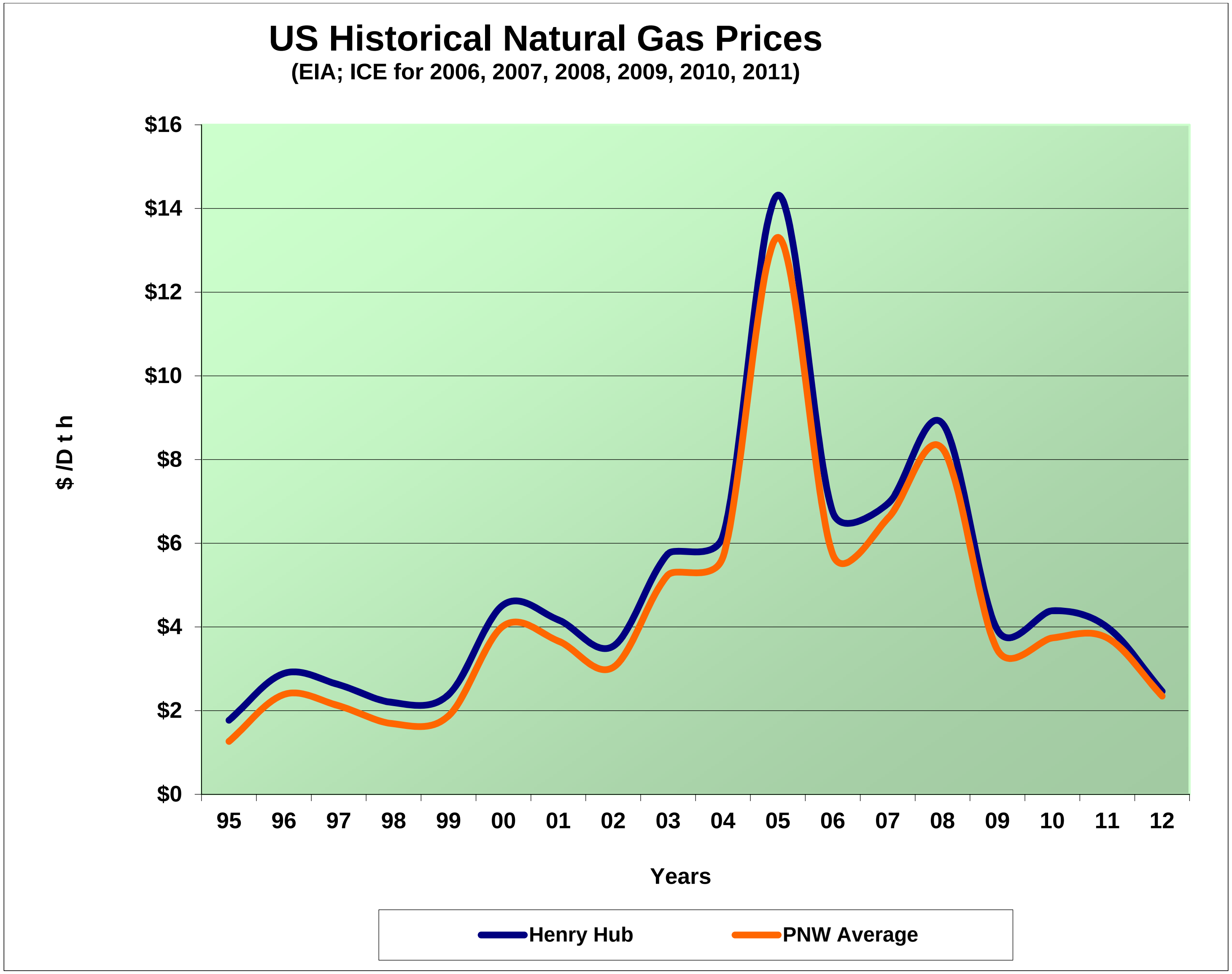
[1] Sources: Ken Zimmerman, with data from published index prices, EIA, and Wikipedia encyclopedia.

Figure 4: Historical US Natural Gas Prices[2]



January – March for 2012

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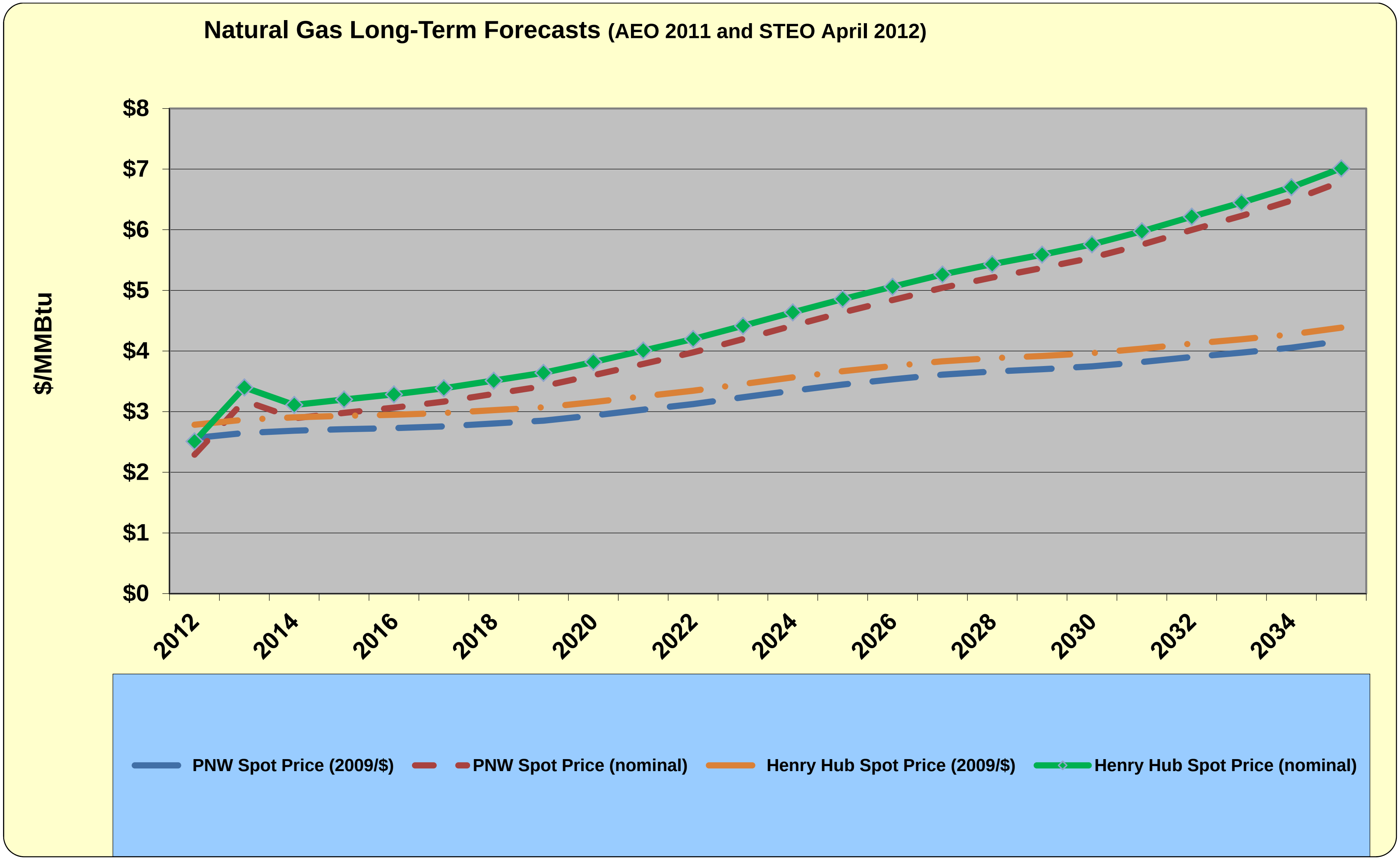
[2] Quite a ride for prices. And now they're back to where they were in 1999-2000. Through end of March 2012. This pattern represents an annual average growth rate in gas prices since 1998 of about 2% for the Pacific Northwest prices.

Figure 5: Forecasted US Natural Gas Prices, based on EIA AEO 2011 ($/MMBtu). [3]



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[3] I've adjusted EIA's natural gas forecasts by -40%/year for real price and nominal price.

Headlines for the Period

➢ Pacific Northwest

- Wind farms generated a record-breaking amount of power during March. The Bonneville Power Administration is hoping to avoid over-generation problems that happened last spring.
- Backers of Jordon Cove LNG terminal proposed for the Oregon Coast are not deterred by the withdrawal of federal approvals for the project. The Federal Energy Regulatory Commission (FERC) ruled April 16th that Jordan Cove could not rely on prior approvals of the terminal and pipeline as an LNG export terminal for making the construction of an export terminal instead. Jordan Cove project manager, Bob Braddock, says his group is already working on getting its export application ready. US DOE has already given its tentative go-ahead to the export terminal.
- Coos County has begun studying routes for a 16-mile section of pipeline that would funnel natural gas from Coos Bay to Bandon. The county awarded NW Natural a contract to find three routes and present them to the commissioners by August. The engineering firm will then design the pipeline. Construction would begin in 2014. The 4-inch pipeline is part of a project to bring natural gas from Roseburg to Coos County. The initial pipeline was built in the early 2000s, but the Bandon lateral was stalled during a contractual dispute between the construction company and the county.
- Pacific Gas & Electric has agreed to pay $70 million in restitution to San Bruno, Calif., for a 2010 pipeline explosion that killed eight people in the San Francisco suburb.

➢ USA

- Natural Gas Price
  - ✓ “We expect the record storage overhang will lead to a turbulent summer as unprecedented coal-to-gas switching will be required to avoid breaching storage capacity before next winter,” wrote David Greely of Goldman Sachs. He sees prices hovering around $2.10 an MMBtu through the second and third quarters. Overall, the firm lowered its 2012 average price forecast to $2.40, from $3.10. But Greely sees some light at the end of the tunnel. He expects prices will shoot higher in 2013 amid slowing production and a return to more normal winter weather conditions next year. Prices could move back to $4 next year.
  - ✓ From the *Tulsa World*, April 11th, “The price of natural gas has fallen to its lowest level in more than a decade, a remarkable decline for a commodity that not long ago was believed to be in short supply. The country's supply of natural gas is growing so fast that analysts worry the country's underground storage facilities could reach their limits by fall. On Wednesday, the futures price of natural gas declined to $1.987 per 1,000 cubic feet, its lowest level since January 28, 2002, when the price hit $1.91. If the price falls to $1.75, it would be the lowest since March 23, 1999. Natural gas production has boomed across the

country as energy companies employ a new drilling technique to tap previously untouched reserves. The process has raised concerns about water safety, and has been temporarily banned in New York and New Jersey. But where it has been allowed, it has led to increases in drilling, job growth and production. The falling price of natural gas has been a boon to homes and businesses that use the fuel for heat and appliances, and for manufacturers that use it to power their factories and make chemicals, plastics and other materials. From October to March, households spent $868 on average on natural gas, a decline of 17 percent from last winter. Those savings have helped to relieve the burden of rising gasoline prices. Households spent $1,940 on gasoline from October to March, a 7 percent increase from the same period a year ago. There is so much natural gas being produced — and still in the ground — that drillers, policymakers, economists and natural gas customers are trying to figure out what to do with it."

- Supply and Demand
  - ✓ According to the *Wall Street Journal* of April 12th,

    > Plummeting natural-gas prices are pushing U.S. industries into virgin terrain, even beginning to dislodge cheap Western coal from its once-untouchable perch as the nation's favorite fuel for power production. The natural-gas surplus has implications for a variety of industries. Energy companies that produce gas are seeing revenue shrink and are searching for more lucrative oil. Cheap gas is stealing power-generation markets from coal, spreading gloom across a mining industry that is being spurned by its most important customer. Railroads, whose single largest source of revenue is typically hauling coal, are hurting. The economics of building a nuclear plant, wind farm or solar-power installation look shakier than ever. The biggest winners from all this: electricity consumers. In February, Boston-based utility NSTAR told its business customers that it will cut their retail electricity rates 34% this spring, to 5.5 cents a kilowatt hour from 8.5 cents. In May, it expects to announce rate cuts for residential customers, too. In many parts of the U.S., cheap gas is pushing wholesale power prices down to two cents to four cents a kilowatt hour. In New England, for example, wholesale power prices were often in the three- or four-cent range in February, compared with six to eight cents on average that month from 2006 to 2011, according to the Energy Information Administration. Oklahoma Gas & Electric, a unit of OGE Energy Corp., OGE +0.84% has traditionally produced most of its power at two plants fired by coal from the Powder River Basin of Wyoming and Montana. But recently that has started to change, said John Wendling, manager of generation planning. The company's two most-efficient gas plants "are pushing coal out of the way and the customer is benefiting," Mr. Wendling said, adding that the utility expects to lower its electricity rates this summer for its customers in Arkansas and Oklahoma. Energy-industry analysts at Sanford C. Bernstein & Co. said utilities could boost power production from gas plants by 450 million megawatt hours this year, increasing natural-gas consumption by 3.3 trillion cubic feet a year. This equals 13.5% of total U.S. natural-gas consumption last year. To be sure, coal isn't going to be completely displaced; some coal-fired plants sit at crucial locations and are needed to keep

the electricity grid stable. Some utilities are contractually bound to take coal deliveries or face hefty penalties. Another wild card is the weather, which is the biggest single factor that determines utilities' consumption of coal and natural gas. High temperatures—and humming air conditioners—would drive utilities to run more power plants, burning more gas and more coal. That could prevent natural-gas storage from filling up by the late summer, some experts said. But others argue that storage is simply too full and too much gas is still being produced. In the face of a gas glut, it would make economic sense for production to decline—but that hasn't happened yet. Most new gas is coming from shale rocks, where companies are using a new combination of techniques to unlock vast amounts of gas and oil. In the past year, companies have scaled back their hunt for gas, but are still harvesting significant amounts as a byproduct of drilling for oil. Indeed, the U.S. has produced more gas, so far in 2012, than during the same period last year, according to industry consultant Bentek Energy. Some experts say electric utilities' growing appetite for inexpensive gas will prevent storage from filling up. "The power market will save the day," predicted Rusty Braziel, an industry consultant with RBN Energy and a former Texaco marketing executive in the mid-1990s, when gas prices last fell below $1.50 per million British thermal units. Southern Co., SO +0.11% for many years one of the largest burners of coal in the U.S., has taken the bait being dangled by low natural-gas prices. "We are in the transition in a big way" from coal to natural gas, says Tom Fanning, chief executive of Atlanta-based Southern. The company is building three gas-fired plants in Georgia as replacements for coal-fired units—and plans to do more coal-to-gas conversions. This summer, it expects to burn more gas than ever to take advantage of low prices. In 2008, when gas prices still were high, Southern got almost 70% of its electricity from coal. Today, it is getting less than half as much power from its coal fleet. Gas-fired plants now are responsible for 46% of its electricity, up from about 16% four years ago. Fuel switching is sending shudders through the coal industry because the power industry consumes more than 90% of all domestic coal. Eastern markets felt the effects of lower gas prices first, because eastern utilities mostly burn Appalachian coal, which is more costly, per ton, than coal from Wyoming's giant Powder River Basin, source of about half the nation's coal. But now, "the coal that was least likely to be displaced is being displaced," said Anthony Yuen, energy analyst for Citigroup Global Markets Inc. He thinks the trend will pick up if prices continue to fall.

- Policy Debates
  - ✓ The Obama administration said April 14th it is creating a high-level working group to coordinate federal oversight of natural gas production, amid industry complaints that excessive regulation could stymie a natural gas boom that has pushed prices to 10-year lows. In an executive order signed April 13th, President Barack Obama said the group was needed to make sure a host of federal agencies that oversee drilling work together. Obama said it is vital that the nation take full advantage of its natural gas

resources, while ensuring that public health and safety - including air and water quality - are not compromised.

- ✓ With Congressional inaction on a national energy policy, the balance of power has tipped to federal regulatory agencies, said Nick Akins, president and CEO of American Electric Power. It's complicating the future for consumers, states and electricity generating companies. Congress can't get anything done, so it's left to the administrative agencies to promulgate rules, and in some cases those rules are not realistic," said Akins, who spoke at a panel on energy transitions at Oklahoma City University's Meinders School of Business. It's going to take some time to move toward a different portfolio mix in the future. AEP is moving from predominantly a coal-fired generator to one that's more balanced. But Akins said timelines by the Environmental Protection Agency to deal with coal-plant emissions are much too aggressive. Installing scrubbers or decommissioning coal plants too fast will mean higher rates for utility customers and could jeopardize electricity reliability, he said.
- ✓ Several environmental groups are voicing their opinions about natural gas drilling on the heels of a West Virginia conference on the topic. The groups are gathering as an industry conference on the topic begins April 1st at the Greenbrier Resort. West Virginia Gov. Earl Ray Tomblin, U.S. Sen. Joe Manchin and others are attending the three-day "Marcellus and Utica Shale Conference and Expo." According to the Greenbrier website, the conference's main themes include the future of natural gas and leveraging its value, as well as navigating legislative rules. Environmental groups are designating April 1st as "Fossil Fool's Day." They say the development of natural gas pose dangers to the environment and people.

➢ World

- o Total world proved natural gas reserves, as of the end of 2010, were 187 trillion cubic meters (TCM; or 6609 trillion cubic feet - Tcf). That would last, at current production rates, 59 years. Reserves have grown about 2%/year. With production also growing, the reserve-to-production ratio has stayed within the range of 58 to 68 years since 1985. The four nations with the largest reserves are Russia (45 TCM), Iran (30 TCM), Qatar (25 TCM) and Turkmenistan (8 TCM). The US is not too far behind at 7.7 TCM. Over the last 20 years or so there has been a revolution in unconventional gas, with the US leading the way. Estimates of technically recoverable resources in the US range as high as roughly eight times reserves. There is little doubt that world reserves will rise substantially. Most of the discussion has been around two new sources. The first is the arctic, which the USGS estimates may contain about 1700 Tcf of technically recoverable, conventional, undiscovered reserves, with the largest share probably on Russian territory. The second is unconventional – most importantly shale – gas. There is little data to go on so far, but experts are guessing that unconventional sources could raise world reserves by 50-100%. The International Energy Agency has rather an outlier estimate that total recoverable gas is approximately 850 TCM.

- Not since the allies leveled Germany in World War II has Europe's biggest economy undertaken a reconstruction of its energy market on this scale. Chancellor Angela Merkel is planning to build offshore wind farms that will cover an area six times the size of New York City and erect power lines that could stretch from London to Baghdad. The program will cost 200 billion euros ($263 billion), about 8 percent of the country's gross domestic product in 2011, according to the DIW economic institute in Berlin. Germany aims to replace 17 nuclear reactors that supplied about a fifth of its electricity with renewables such as solar and wind. Merkel to succeed must experiment with untested systems and policies and overcome technical hurdles threatening the project, said Stephan Reimelt, chief executive officer of General Electric Co. (GE)'s energy unit in the country. "Germany is like a big energy laboratory," Reimelt said in an interview. "The country has a political and societal consensus to drop nuclear power but lacks a clear technological solution."

- Pampered by abundant subsidies Germany´s solar industry saw a massive growth during the past 10 years. However, recently two crucial factors came into play which led to a substantial shift. On the one hand, there was a discussion in Germany as to how much money should be pumped into renewable energies. Economic analyses revealed that more than EUR 100 billion have been directed towards renewables so far. With ever growing installed capacities this amount is bound to grow over the coming years, thus putting a substantial burden on electricity consumers who, in the end, are paying the bill. As a consequence and in order to keep subsidies under control feed-in tariffs have been cut drastically recently. On the other hand, German producers of solar modules are increasingly suffering from competitors, especially in China. This led to a slump in prices for PV modules (more than 70 % since 2009) which, in turn, increased the pressure on German companies. What is going to happen? Once the market forces have done their work, PV will continue its upward trend, though at a more moderate pace. But most importantly, the vast majority of PV modules will come from China, thus leaving not much room for production in Europe. What is bad news for the solar industry is, in turn, good news for the consumers and for investors who will see lower investment expenses as the prices for modules have fallen dramatically. PV as such is not to be blamed for the current problems. On the contrary, PV fills a useful niche in the power grid, but not more than that. However, what is to be blamed is a legal framework which created the illusion of a quasi risk-free economy where feed-in tariffs were guaranteed for 20 years and even paid for non-produced electricity in case of network problems caused by the renewables themselves. The price for this illusion was first to be paid by the consumers and now by the people losing their jobs in the companies going bankrupt. Photovoltaics has certainly a future in Germany as in other parts of Europe. However, its growth needs to be based on a sound economic environment. This process is now under way. It goes without saying that PV will always be a minor player in the field. Nevertheless, it has a role to play and maybe, on a smaller scale and by using smart storage technologies, it may develop into a key power source for local communities.

Historical Natural Gas Prices [4]

Table 1

Historical Prices

Spot Prices ($/MMBtu)	Thu, 5-Apr	Fri, 6-Apr	Mon, 9-Apr	Tue, 10-Apr	Wed, 11-Apr	Thu, 19-Apr	Fri, 20-Apr	Mon, 23-Apr	Tue, 24-Apr	Wed, 25-Apr
Henry Hub	$1.98	Holiday	$1.99	$1.99	$1.91	$1.85	$1.82	$1.89	$1.97	$1.99
New York	$2.19	Holiday	$2.18	$2.17	$2.09	$2.00	$1.96	$2.07	$2.17	$2.18
Chicago	$2.17	Holiday	$2.15	$2.06	$2.02	$2.00	$1.98	$2.01	$2.09	$2.11
AECO	$1.65	Holiday	$1.63	$1.61	$1.53	$1.48	$1.49	$1.51	$1.52	$1.52
Sumas	$2.03		$1.87	$1.81	$1.82	$1.78	$1.77	$1.75	$1.64	$1.74
Rockies	$1.92	Holiday	$1.79	$1.77	$1.73	$1.69	$1.72	$1.75	$1.78	$1.73
Cal. Comp. Avg,*	$2.26	Holiday	$2.24	$2.26	$2.23	$2.14	$2.06	$2.13	$2.22	$2.17
Futures ($/MMBtu)										
May Contract	$2.09	Holiday	$2.11	$2.03	$1.98	$1.91	$1.93	$2.01	$1.98	$2.07
June Contract	$2.20	Holiday	$2.22	$2.15	$2.11	$2.00	$2.02	$2.10	$2.06	$2.17

*Avg. of NGI's reported prices for: Malin, PG&E citygate, and Southern California Border Avg.

Source: NGI's Daily Gas Price Index

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[4] Most current data available at the time this report was prepared.

Forecasted Gas Prices – USA[5]

Table 2

Forecasted						
($/MMBtu)	Three Month	One Year	Three Year	Avista 2012 WACOG	Cascade 2012 WACOG	NWN 2012 WACOG
AECO	$1.86	$2.44	$2.63	$4.38	$4.68	$4.76
Sumas	$2.11	$2.69	$2.88	$4.38	$4.68	$4.76
Rockies	$2.07	$2.65	$2.84	$4.38	$4.68	$4.76
CA Average	$2.50	$3.08	$3.27	$4.38	$4.68	$4.76
Henry Hub	$2.24	$2.82	$3.01	$4.38	$4.68	$4.76

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[5] Forecasts by Ken Zimmerman based on EIA and NGI data.

- Regulatory Reform
    - For decades, Administrations and Congresses have periodically raised the issue of regulatory reform. For the most part, however, reform efforts have been piecemeal and incomplete. Practically every President since Eisenhower has issued Executive Orders designed to make regulations more efficient, cost-effective, and based on a sound factual foundation. And in 1996, Congress even passed the Congressional Review Act—giving it the power to review and reject regulations that were found wanting. Just five years later, lawmakers also passed the Data Quality Act, which was intended to make sure that sound data and objective analyses are the basis of regulation. Neither the orders nor the acts have accomplished there intended purpose. In spite of past efforts, we remain an overregulated society because regulatory reform is only as good as its implementation. Rhetoric is no substitute for oversight and checks and balances that work. Over the past 30 years, the Code of Federal Regulations has increased 50%, growing to over 150,000 pages today. It seems obvious that it would be hard to make the case that we have 50% more regulatory problems than we had in 1980 or that no regulations have out lived their usefulness and should be rescinded. More attention is being paid to regulations today because the Obama Administration, especially its EPA, has acted as a regulatory machine on steroids. In 3 years, it has issued 194 major regulations—those with a cost of $100 million or more—compared with 141 in the first 3 years of the Bush Administration. The regulatory bureaucracy is non-partisan. It just keeps grinding on independent of whether a Republican or Democrat is in the White House. Some Presidents have tried to slow its assault with tough Executive Orders and a strong hand in OMB's Office of Information and Regulatory Review (OIRA). But even then the impact has not been significant. Special interests and their supporters in Congress can make life tough on the Executive Branch. Each regulation has a rent seeking supporter, and regulatory reform just hasn't been a sufficient priority to produce comprehensive reform of the Administrative Procedures Act. In January of last year, President Obama issued Executive Order 13563, aimed at streamlining the regulatory process and making it more effective. But from the response of EPA, you might conclude that his actions were taken with a wink and a nod. In spite of a very weak economy that could benefit from a lighter regulatory burden, EPA aggressively pursued an early rewrite of the ozone NAAQS which would have put most of the nation in non-attainment and brought major construction to a halt, has issued very stringent regulations on mercury, boilers, CAFE standards, and refineries. The refinery MACT comes at a time when U.S. refineries are shutting down because they can't make a reasonable profit. And although, the major sources of air pollution are now stationery sources, EPA is planning a Tier III gasoline rule that will force gasoline sulfur levels close to zero on the basis of very shaky health and environmental benefits. This will further increase the price at the pump. Some might say that EPA is being criticized for simply doing its job. That line of argument might get some sympathy if Administrator Jackson had shown any understanding of the impact of an aggressive regulatory assault when the economy is in such poor shape. In some instances, regulations might be the result of statutory deadlines or court dictated deadlines. But there is a

range of options for compliance and it today's economic circumstances, a light regulatory hand instead of a hammer would be more appropriate. Instead of employing balance and judgment in issuing regulations, EPA has regulated with myopic zeal. One example of regulatory overreach came to light in an appeals court decision last week that over turned EPA's rejection of Texas' program to meet national air quality standards. According to The Wall Street Journal, the court found that EPA "failed to identify a single provision of the Act that Texas had violated, let alone explain its reasons for reaching its conclusion." The court went on to find that the "authorities" cited by the agency were internal memoranda and guidance documents. It is very troubling when an agency creates its own laws instead of implementing those passed by Congress. It is actions such as these that give credibility to claims of Constitutional erosion. Nothing useful is going to happen in an election year. It never does. But if the next Congress and President are serious about restoring robust economic growth and enabling the private sector to successfully compete in the global economy, regulatory reform should be part of a larger reform agenda. Regulatory overhaul can follow common sense principles and need not be radical in nature. First, agencies should be required to review over a five year period existing regulations, starting with the oldest, to determine if they are still necessary and meeting criteria of efficiency and effectiveness. The results should be posted on line to provide transparency. Major regulations that have been in existence for 10 years or more should candidates for being sunset or reissued if a review determines that the implementation cost was greater than 110% of the estimated cost at the time of implementation. New major regulations should be subjected to an independent review of their justification, cost-effectiveness, and compliance with the Data Control Act. And Congress should be provided a statement signed by the agency head certifying how the regulation will achieve Congressional intent and meet criteria of necessity, efficiency, and economic impact. Congress has an important role to play in being clearer about the objectives that are to be achieved and constraints that are to limit implementing regulations. Finally, regulatory reform legislation should contain look-back and sunset provisions for the implementing regulations. The objection that these kinds of requirements would be too burdensome is not convincing. Major regulations should not be easy to implement because their cumulative impact on society and business is significant, exceeding $1 trillion annually. We can do better and should.

~ William O'Keefe, Chief Executive Officer of the Marshall Institute, is President of Solutions Consulting, Inc. He has also served as Senior Vice President of Jellinek, Schwartz and Conolly, Inc., Executive Vice President and Chief Operating Officer of the American Petroleum Institute and Chief Administrative Officer of the Center for Naval Analyses. Mr. O'Keefe has held positions on the Board of Directors of the Kennedy Institute, the U.S. Energy Association and the Competitive Enterprise Institute and is Chairman Emeritus of the Global Climate Coalition.

- A polluted drainage ditch that once flowed with industrial waste from Lake Charles, La., petrochemical plants teems with overgrown, wild plants today. A light-rail line zips past the spot where a now-defunct Portland, Ore., gasoline station advertised in 1972 that it had run out of gas. A smoking Jersey City, N.J., dump piled with twisted, rusty metal has disappeared, along with the twin towers of the World Trade Center in lower Manhattan that were its backdrop. Forty years after the Environmental Protection Agency sent an army of nearly 100 photographers across the country to capture images at the dawn of environmental regulation. The Associated Press went back for Earth Day this year to see how things have changed. It is something the agency never got to do because the “Documerica” program, as it was called, died in 1978, the victim of budget cuts. AP photographers returned to more than a dozen of those locations in recent weeks, from Portland to Cleveland and Corpus Christi, Texas. Of the 20,000 photos in the archive, the AP selected those that focused on environmental issues, rather than the more general shots of everyday life in the 1970s. Gone are the many obvious signs of pollution — clouds of smoke billowing from industrial chimneys, raw sewage flowing into rivers, garbage strewn over beaches and roadsides — that heightened environmental awareness in the 1970s, and led to the first Earth Day and the EPA's creation in 1970. Such environmental consciousness caused Congress to pass almost unanimously some of the country's bedrock environmental laws in the years that followed. Today's pollution problems aren't as easy to see or to photograph. Some in industry and politics question whether environmental regulation has gone too far and whether the risks are worth addressing, given their costs. Republican presidential contender Mitt Romney has called for the firing of EPA chief Lisa Jackson, while GOP rival Newt Gingrich has said the EPA should be replaced altogether. Jackson has faced tough questioning on Capitol Hill so often the in past two years that a top Republican quipped that she needs her own parking spot. "To a certain extent, we are a victim of our own success," said William Ruckelshaus, who headed the EPA when it came into existence under Republican President Richard Nixon and was in charge during the “Documerica” project. "Right now, EPA is under sharp criticism partially because it is not as obvious to people that pollution problems exist and that we need to deal with them." Environmental laws that passed Congress so easily in Ruckelshaus' day are now at the center of a partisan dispute between Republicans and Democrats. Dozens of bills have been introduced to limit environmental protections that critics say will lead to job losses and economic harm, and there are those who question what the vast majority of scientists accept — that the burning of fossil fuels is causing global warming. In the 1970s, the first environmental regulations were just starting to take effect, with widespread support. Now, according to some officials in the oil and gas and electric utility industries, which are responsible for the bulk of emissions and would bear the greatest costs, the EPA has gone overboard with rules. For instance, “Documerica” photographers captured a wave of coal-fired power plants under construction. Republicans and the industry now say environmental regulations are partly to blame for shuttering some of the oldest and dirtiest coal plants. Jim DiPeso of ConservAmerica, a group that recently changed its name from Republicans for Environmental Protection, says the EPA is caught in the center of a perfect storm. "This time of greater cynicism about government, more economic anxiety and the fact that the problems are not immediately apparent, has created this political problem for EPA," he said. In an interview, Jackson said she believes that people in the United States still want to protect the environment. "There's a large gulf between the rhetoric inside the Beltway to do everything from cut back on EPA to get rid of the whole place, and what the American people would actually stand for," she said. "It's very easy to make rash statements without thinking about what that means to the health of everyday Americans." A 2010 Pew Research Center survey showed that 57 percent of those questioned held a favorable view of the EPA, compared with a 1997 poll that showed 69 percent with a positive view of the agency. A CNN/Opinion Research Corp. poll taken last year found that 71 percent of people surveyed said that the government should continue provide money to the EPA to enforce regulations to address global warming and other environmental issues. "We are not done. We still have challenges we have to face," Jackson said. The agency last year began a volunteer photography project called State of the Environment. More than 620 people have participated and submitted 1,800 photographs, but only a few are at the same sites at the 1970s project. Images always have spurred environmental consciousness. A 1980s satellite picture of the ozone hole helped lead to a ban on the chemicals in aerosol cans and refrigerants that were responsible. Underwater video of oil spewing into the Gulf of Mexico in 2010 opened the public's eyes to the gravity of the largest offshore oil spill in U.S. history. But a second “Documerica” project, with professional photographers, would be impossible today, given budget cuts facing the agency and the wariness of industry barring access by photographers. Lyntha Scott Eiler, 65, shot photographs for “Documerica” around her then-home in northern Arizona, as well as one of the early emissions testing sites for automobile exhaust in Hamilton County, Ohio. At the Navajo Generating Station in Arizona, Eiler got right down in a strip mine "where the shovels were." "They weren't afraid of the EPA, so it was, 'What else you do you want to get a photograph of,?" Eiler said. "You probably would have a hard time doing that today."

~ *ChemInsider Newsletter*, April 24, 2012

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Chapter 2: Key Assumptions

SUMMARY OF KEY FINDINGS

Pacific Northwest population and energy costs are expected to increase over the next 20 years. Regional population is likely to increase from 12.7 million in 2007 to 16.7 million by 2030. This 4.0 million increase compares to a 3.8 million increase between 1985 and 2007. The population growth will be focused on older-age categories as the baby-boom generation reaches retirement age. While the total regional population is projected to increase by over 28 percent, the population over age 65 is expected to nearly double. Such a large shift in the age distribution of the population will change consumption patterns and electricity use. Some possible effects could include increased health care, more retirement and elder-care facilities, more leisure activities and travel, and smaller-sized homes.

The cost of energy (natural gas, oil, and electricity) is expected to be significantly higher than during the 1990s. Although prices have decreased significantly since the summer of 2008, current levels, especially for natural gas, are depressed by the effects of the recession. Nonconventional natural gas production has increased in the last few years, encouraged by higher prices. The technology to retrieve these supplies cost-effectively has been a recent development that continues to improve, making expectations for adequate future supplies more certain. Nevertheless, the cost of finding and producing these new supplies is higher than for conventional supplies, which increases the estimated future price trend for natural gas.

Carbon-emission taxes or cap-and-trade policies are likely to raise energy costs further. Wholesale electricity prices are expected to increase from about $30 per megawatt-hour in 2010 to $74 per megawatt-hour by 2030 (2006$). These electricity prices reflect carbon costs that start at zero and increase to $47 per ton of CO_2 emissions by 2030. Higher electricity prices reduce demand, advance new sources of supply and efficiency, and make cost-effective more efficiency measures.

INTRODUCTION

The Northwest Power Act requires the Council's power plan to include a forecast of electricity demand for the next 20 years. Demand, to a large extent, is driven by economic growth, but it is also influenced by the price of electricity and other fuel.

The power plan treats energy efficiency as a resource for meeting future demand. In order to understand and properly assess its potential, demand forecasts must be developed in great detail considering specific uses of electricity in various sectors. Such assessments require significant detail in their underlying economic assumptions; the number and types of buildings, their electrical equipment, and their current efficiency levels are all critical to accurately assessing potential efficiency improvements.

Most of the assumptions and forecasts for the demand forecast are also important for other parts of the power plan. For example, fuel prices affect not only electricity demand, but also the cost of electricity generation from natural gas, oil, and coal-fired power plants. Because of this, fuel price forecasts help determine the wholesale electricity price and the avoided cost of alternative resources when considering the cost-effectiveness of improved efficiency. In addition, sector-specific economic forecasts of building and appliance stocks, their expected growth over time, and their pattern of energy use over different seasons and times of the day are factors in determining efficiency potential and cost-effectiveness. Basic financial assumptions such as rates of inflation, the cost of capital for investments by various entities, equity-to-debt ratios, and discount rates are used throughout the planning analysis.

For many of these assumptions, there is significant uncertainty about the future. That uncertainty creates risk that is addressed in the Council's power plan. These risks and uncertainty include long-term trends, commodity and business cycles, seasonal variations, and short-term volatility.

ECONOMIC GROWTH

Demand for energy is driven by demand for services needed in homes and places of work. In the long-term, the region's economic growth is a key driver of demand. One general measure of the size of the regional economy is its population. As the regional population increases, the number of households increases, the number of jobs increases, and goods and services produced in the economy increase, all driving the need for energy. This is not to say there is a one-to-one relationship between growth in the economy and growth in demand. Other factors, such as energy prices, technology changes, and increased efficiency can all change the relationship between economic growth and energy use.

The residential demand forecast is driven by the number of homes and the amount and types of appliances they contain. Commercial sector demand is determined by square feet of buildings of various types, and industrial demand depends on projections of industrial output in several manufacturing sectors. The expected electricity use in aluminum smelters is forecast independently. A brief overview of the forecast assumptions for each of the key economic drivers of demand follows:

Population. Population in the Northwest states grew from about 8.9 million in 1985 to about 13 million in 2007, increasing at about 1.6 percent per year. The growth in population is projected to slow to about 1.2 percent annually, resulting in a total regional population of 16.7 million by 2030.

Homes. The number of homes is a key driver of demand in the residential sector. Residential units (single family, multifamily, and manufactured homes) are forecast to grow at 1.4 percent annually from 2010-2030. The current (2008) stock of 5.7 million homes is expected to grow to 7.6 million by 2030, or approximately 83,000 new homes per year.

Appliances. In the residential sector, lifestyle choices affect demand. As more homes are linked to the Internet, and as the saturation rate for air conditioning and electronics increases, residential sector demand increases. Over 80 percent of all new homes in the region now have central air conditioning, and the growth rate in home electronics has been phenomenal--over 6 percent per year since 2000, and it is expected to continue growing at about 5 percent per year.

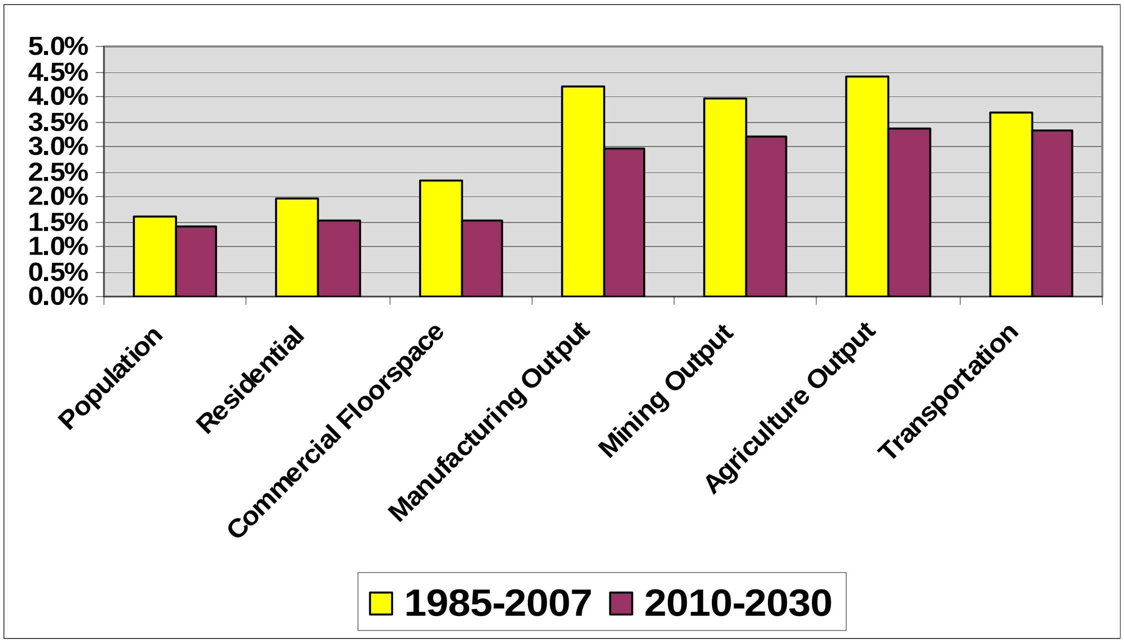
Commercial Square Footage. Demand for electricity in the commercial sector is driven by demand for commercial floor space that requires lighting, air conditioning, and services to make occupants comfortable and productive. The square footage of commercial buildings is forecast to grow at 1.2 percent annually from 2010-2030. The current 2007 commercial building stock of 2.9 billion square feet is expected to grow to 3.9 billion square feet by 2030, or at a rate of about 40 million square feet per year. A growing portion of this commercial floor space is for elder-care facilities.

Industrial Output. The key driver of demand for the industrial and agricultural sectors is dollars of value added (a measure of output) in each industry. Industrial output is projected to grow at 3 percent per year, growing from $83 billion (2006 constant dollars) in 2007 to $149 billion by 2030. Agricultural output, which drives irrigation electricity use, is projected to grow at 3.2 percent per year, from $13 billion (2006 constant dollars) in 2007 to $25 billion by 2030.

Direct Service Industries. Demand for Bonneville's direct service industries (mainly aluminum smelting operations) is projected to be nearly constant, rising from 764 average megawatts in 2007 to 770 average megawatts in 2012, and then remaining constant from 2012 through 2030.

The main source of data for the economic drivers is HIS Global Insight's quarterly forecast of the national and regional economy and Global Insight's U.S. business demographic forecast. Third quarter 2009 data was used in developing the Council's Sixth Power Plan. The Council's financial assumptions, such as the inflation rate, are also drawn from the same economic forecast. Figure 2-1 shows both the historic and medium case growth rate assumed for the development of the Sixth Power Plan. In general, the medium forecast reflects a slowdown in key economic drivers compared to the last 20 years. The impact of the current recession was incorporated into the plan using Global Insight's long-term October 2009 forecast.

Figure 2-1: Comparison of Key Economic Drivers



Alternative Economic Scenarios

Three alternative scenarios are considered in the demand forecast. In the medium-case scenario, the key economic drivers project a long-term, healthy regional economy (albeit with a slower growth rate than in the recent past). In addition to the medium case, two alternative scenarios are considered: one representing a low-economic-growth scenario and the other a high-growth projection of the future. The low-case scenario reflects a future with slow economic growth, weak demand for fossil fuel, declining fuel prices, a slowdown in labor productivity growth, and a high inflation rate. On the other hand, the high-case scenario assumes faster economic growth, stronger demand for energy, higher fossil fuel prices, sustained growth in labor productivity, and a lower inflation rate.

It is assumed in the medium, low, and high scenarios that climate change concerns and demand for cleaner fuel lead to a carbon tax, which pushes fuel prices to a higher trajectory. Table 2-1 summarizes the average growth rate for key inputs in each of the alternative scenarios.

Table 2-1: Historic, Medium-Case, and Alternative Scenarios for Growth Rates

Key Economic Drivers	1985-2007 (Actual)	2010-2030 (Low)	2010-2030 (Medium)	2010-2030 (High)
Population	1.60%	0.49%	1.20%	1.5%
Residential Units	1.90%	0.49%	1.40%	1.5%
Commercial Floor Space	2.30%	0.67%	1.20%	1.43%
Manufacturing Output $	4.10%	0.00%	1.70%	2.11%
Agriculture Output $	4.40%	3.0%	3.60%	4.2%
Light Vehicle Sales	-	2.52%	2.40%	3.05%
Inflation Rate	2.20%	2.70%	1.70%	1.50%
Average Annual Growth Rate in Price (2010-2030)*				
Oil Prices	1.70%	-1.00%	1.04%	2.30%
Natural Gas Prices	1.80%	0.90%	2.80%	3.50%
Coal Prices	-4.80%	-0.50%	0.50%	1.20%

* Fuel price assumptions are consistent with the Council's fuel price and electricity price forecast.

FUEL PRICES

The future prices of natural gas, coal, and oil have an important effect on the Council's power plan. As the Pacific Northwest's electricity system has diversified beyond hydropower, it has become more connected to national and global energy markets. Fuel price assumptions affect demand, choice of fuel, and the cost of electricity generation. The effect on demand is primarily through retail natural gas prices to consumers, but natural gas prices may also affect electricity consumption because of its effect on cost. Oil and coal are not used extensively by end users in the Pacific Northwest. Coal is, however, an important fuel for electricity generation; it affects the wholesale market price of electricity in some hours and the overall cost of electricity for utilities that rely on coal-fired generation.

The connection between fuel costs and electricity planning has been strengthened by changes in energy regulation and the development of active trading markets for energy commodities. Less regulation and mature commodity markets have also made the price of energy more volatile. The volatility of natural gas prices, in particular, is an important factor when considering the use of natural gas for electricity generation. Price volatility creates risks that the Council evaluates in developing a resource plan.

Because natural gas is the primary energy source affecting both the demand and supply of electricity, forecasts of natural gas prices receive far more detailed attention than oil or coal prices. Fuel price forecasts start with global, national, or regional energy commodity prices, depending on the fuel. Oil is a global commodity, natural gas is still primarily a North American commodity (although this could change as liquefied natural gas imports grow), and coal prices tend to be regional in nature. All of these commodities have experienced periods of high and volatile prices since the Fifth Power Plan was issued in 2004. Natural gas prices have collapsed since the summer of 2008. This reduction in price is partly due to natural supply-and-demand responses to a period of high prices, but also to a great extent is a result of the current recession and financial crisis.[1] The Council's forecast of natural gas prices assumes prices will rebound from recent recession-induced lows.

Long-term fuel price trends are uncertain, as reflected in a wide range of assumptions. The Council's power plan reflects three distinct types of uncertainty in natural gas prices: 1) uncertainty about long-term trends; 2) price excursions due to supply-and-demand imbalances that may occur for a number of years; and 3) short-term and seasonal volatility due to such factors as temperatures, storms, or storage levels. This section discusses only the first uncertainty. Shorter-term variations are addressed in the Council's portfolio model analysis as discussed in Chapter 9.

The high and low forecasts are intended to be extreme views of possible future prices from today's context. The high case wellhead natural gas price increases to $9 by 2025 and increases to $10 by 2030. The Council's forecasts assume that rapid world economic growth will lead to higher energy prices, even though the short-term effects of a rapid price increase can adversely affect the economy. For the long-term trend analysis, the need to expand energy supplies, and its effect on prices, is considered the dominant factor. The high natural gas scenario assumes rapid world economic growth. This scenario might be consistent with very high oil prices, high environmental concerns that limit use of coal, limited development of world liquefied natural gas (LNG) capacity, and slower improvements in drilling and exploration technology, combined with the high cost of other commodities and labor necessary for natural gas development. It is a world where both alternative sources of energy and opportunities for reduced demand are limited.

The low case assumes slow world economic growth that reduces the pressure on energy supplies. Wellhead natural gas prices in the low case fall to levels between $4 and $5 per million Btu; still double the prices during the 1990s. It is a future where world supplies of natural gas are made available through the aggressive development of LNG capacity, favorable nonconventional supplies and the technologies to develop them, and low world oil prices that provide an alternative to natural gas use. The low case would also be consistent with a scenario of rapid progress in renewable generating technologies, reducing demand for natural gas. In this case, the normal increases in natural gas use in response to lower prices would be limited by aggressive carbon-control policies. It is a world with substantial progress in efficiency and renewable technologies, combined with more stable conditions in the Middle East and other oil- and natural gas-producing areas.

Many of the assumptions that lead to high or low fuel prices are independent of one another or have offsetting effects. Those conditions lead to the medium-fuel-price cases being considered more likely. Figures 2-2 through 2-4 illustrate the forecast ranges for natural gas, oil, and Powder River Basin (Wyoming) coal prices compared to historical prices. Tables 2-2 through 2-4 show the forecast values for selected years. Appendix A provides a detailed description of the fuel price forecasts.

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[1] The fuel price forecast used for the plan does not completely reflect the current recession and the recent collapse in commodity prices. Therefore, the near-term prices through 2012 are likely higher than the most likely range. These short-term differences are not expected to affect the Council's resource portfolio or planning results significantly, but will be modified for the final power plan.

Most of the cases show fuel prices increasing from their recent depressed levels in the early years of the forecast. Following this near-term recovery, longer-term trends in most of the cases show real fuel prices increasing gradually. All prices, even in the lowest cases, remain well above prices experienced during the 1990s.

The fuel-price-forecast ranges are both higher and broader than the Council's Fifth Power Plan, reflecting greater uncertainty about long-term trends. The smooth lines for the price forecasts should not be taken as an indication that future fuel prices will be stable. Price cycles and volatility will continue. These variations, and the risks they impose, are introduced into the Council's planning by the Resource Portfolio Model analysis.

Figure 2-2: U.S. Wellhead Natural Gas Prices: History and Forecast Range

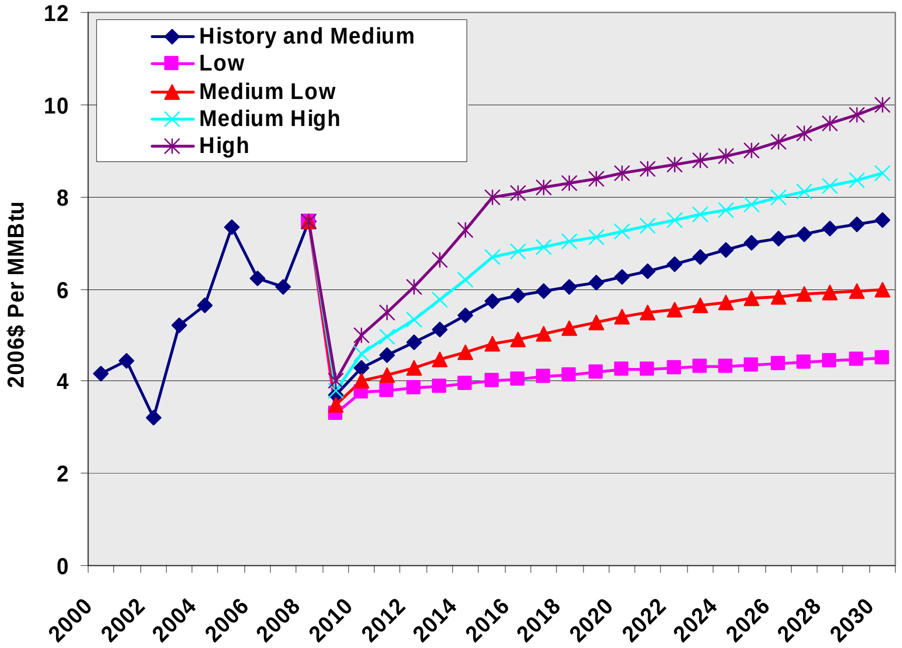

Table 2-2: U.S. Wellhead Natural Gas Price Forecast Range (2006$ per MMBtu)

	Low	Medium Low	Medium	Medium High	High
2008			7.47		
2010	3.75	4.00	4.30	4.60	5.00
2015	4.00	4.80	5.75	6.70	8.00
2020	4.25	5.40	6.25	7.25	8.50
2025	4.35	5.80	7.00	7.85	9.00
2030	4.50	6.00	7.50	8.50	10.00
Growth Rates					
2007 - 15	-7.51%	-5.38%	-3.22%	-1.35%	0.86%
2007 - 30	-2.18%	-0.95%	0.02%	0.56%	1.22%

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Figure 2-3: World Oil Prices: History and Forecast Range

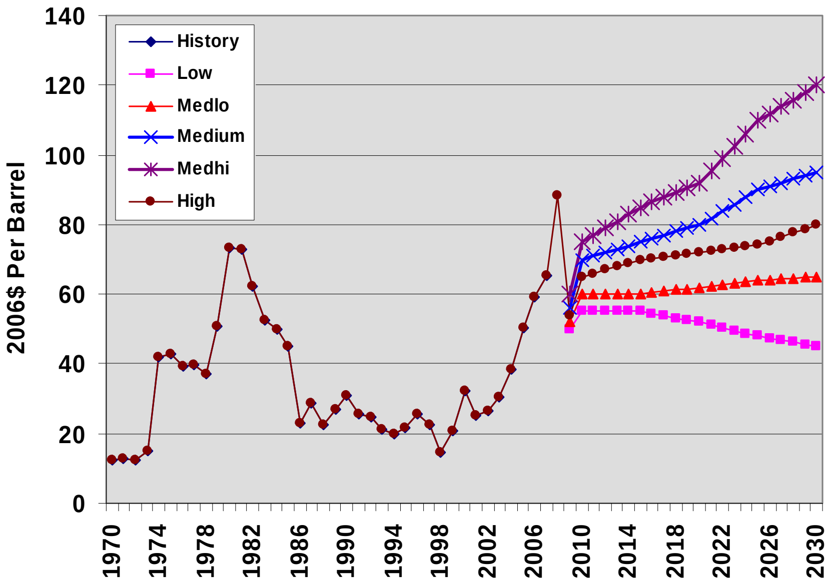


Table 2-3: World Oil Price Forecast Range (2006$ per Barrel)

	Low	Medium Low	Medium	Medium High	High
2007			65.29		
2008			88.42		
2010	55.00	60.00	65.00	70.00	75.00
2015	55.00	60.00	70.00	75.00	85.00
2020	52.00	62.00	72.00	80.00	92.00
2025	48.00	64.00	74.00	90.00	110.00
2030	45.00	65.00	80.00	95.00	120.00
Growth Rates					
2007 - 15	-2.12%	-1.05%	0.88%	1.75%	3.35%
2007 - 30	-1.60%	-0.02%	0.89%	1.64%	2.68%

Figure 2-4: Powder River Basin Minemouth Coal Prices: History and Forecast

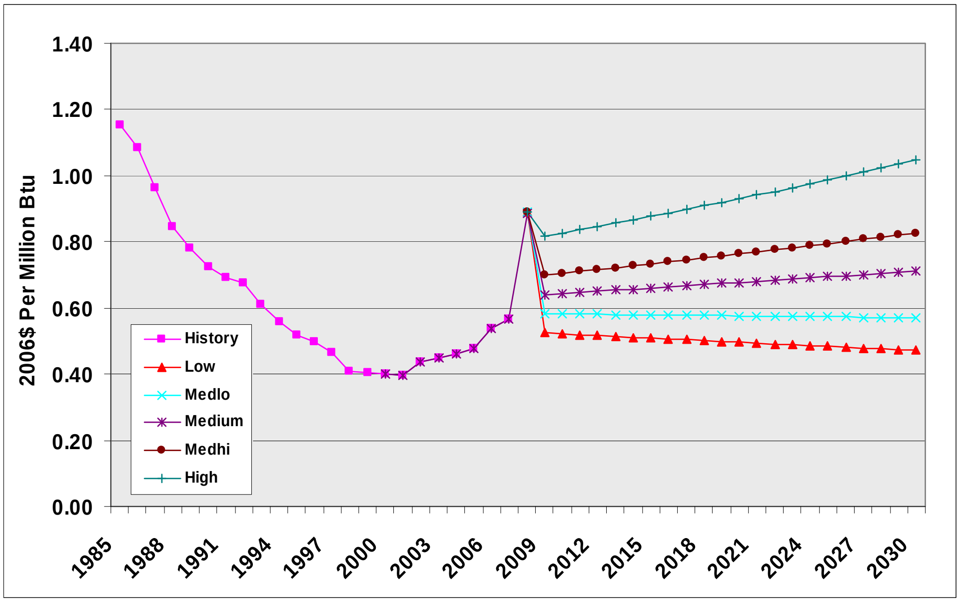


Table 2-4: Powder River Basin Minemouth Coal Price Forecasts (2006$ per MMBtu)

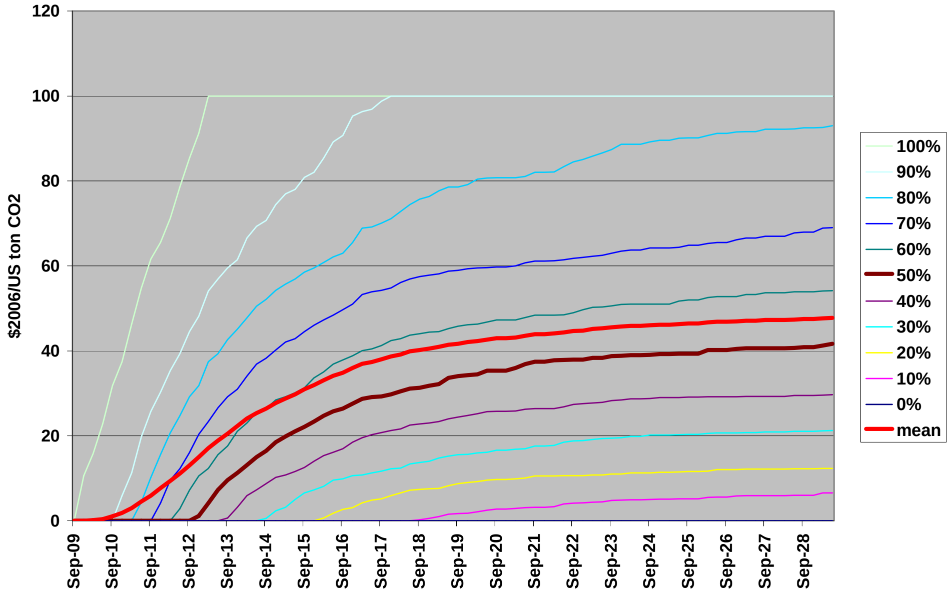
	Low	Medium Low	Medium	Medium High	High
2007	-	-	0.56	-	-
2010	0.52	0.58	0.64	0.70	0.83
2015	0.51	0.58	0.66	0.73	0.88
2020	0.50	0.58	0.68	0.76	0.93
2025	0.48	0.57	0.69	0.79	0.99
2030	0.47	0.57	0.71	0.83	1.05
Growth Rates					
2007-2015	-1.29%	0.32%	1.98%	3.33%	5.65%
2007-2030	-0.78%	0.05%	1.01%	1.67%	2.73%

CARBON DIOXIDE PRICES

The risk of carbon-pricing policies is one of the key uncertainties addressed in the Council's Sixth Power Plan. Such policies have been proposed by the Western Climate Initiative and in proposed federal legislation. Whether, when, and at what level such policies might be implemented are all unknown at this time. Therefore, the plan treats these policies as a risk that should be considered in making electric resource choices made for the region.

The carbon risk scenario captures the carbon pricing risk by modeling both the adoption of a policy and the amount of the carbon price, or penalty, as random variables. The carbon price can be thought of as a carbon tax or the cost of a carbon-emission allowance under a cap-and-trade system. Once a carbon-pricing policy is implemented, the price is assumed to fall between $0 and $100 per ton of carbon emissions. The modeling approach is described in Chapter 9. Figure 2-5 shows a decile chart of the range of resulting carbon prices. The average of the carbon prices begins at zero and increases to above $40 by midway through the forecast period ending at $47 per ton in 2030.

Figure 2-5: Decile Chart of Carbon Prices Used in the Carbon Risk Analysis



Source: workbook "New CO2 Distribution 090425.xls", chart "Carbon Distribution"

The choice of the range of carbon prices to be considered was informed by research and review of the results of studies done by various organizations on the likely cost of carbon allowances that would result under various cap-and-trade policies. The Council commissioned a study by EcoSecurities Consulting Limited to review the literature on carbon-pricing studies and develop a range of likely prices under different policy scenarios. The range of estimates is very wide. Results depend on the study methodology, the carbon-reduction targets assumed, and the assumed scope and role of carbon-credit trading. However, the bulk of the estimates fell between $10 and $100 per ton of CO_2. Understanding that there is some chance that no carbon pricing policy will be agreed on, the Council used a range from $0 to $100 for its carbon-risk analysis.

In addition to this range of prices, a number of fixed-price levels and other price ranges were explored in the draft and final plan. The Council is not taking a position on carbon policy for the region by exploring various levels of carbon prices. The analysis is intended to provide information on what would be required to meet existing goals in some states, and to provide information to the region on possible actions to mitigate the risks of unknown future carbon-pricing policies. Chapters 10 and 11 discuss climate change analysis and issues further.

RENEWABLE PORTFOLIO STANDARD RESOURCE DEVELOPMENT

Renewable resource portfolio standards (RPS) mandating the development of certain types and amounts of resources have been adopted by eight states within the Western Electricity Coordinating Council region: Arizona, California, Colorado, Montana, New Mexico, Nevada, Oregon, and Washington[2]. In addition, British Columbia has adopted an energy plan with

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[2] Utah's *Energy Resource and Carbon Emission Reduction Initiative* adopted in 2008 has characteristics of a renewable portfolio standard, but mandates acquisition of qualifying resources only if cost-effective. Because

conservation and renewable-energy goals similar to an RPS. RPS laws are complex with great variation between states regarding target amounts, qualifying resources, resource "set-asides," existing resource qualification, in-state credits, price caps, and other provisions. State-by-state assumptions used for this forecast are described in Appendix D.

Mandatory development of low-variable-cost renewable resources can significantly affect wholesale power prices and the need for discretionary resources. A forecast of the types of renewable resources that may be developed and the success in achieving the targets is needed for the wholesale-power price forecast and the resource-portfolio analysis. The resulting estimate of need for new renewable energy to meet state RPS obligations is provided in Table 2-5.

Table 2-5: Estimated Committed and Forecast Incremental RPS Generating Resource Requirements (MWa)

	AZ	BC	CA (33%)	CO	MT	NM	NV	OR	WA
Committed	87	366	3954	454	65	111	273	465	520
Cumulative new (100% achievement of standards)									
2010	32	0	425	0	0	0	21	0	0
2011	77	0	1,068	0	0	0	63	0	0
2012	115	0	1,774	0	19	0	137	0	0
2013	157	0	2,416	0	24	112	277	0	0
2014	196	17	2,863	280	31	147	339	0	218
2015	240	85	3,329	368	37	184	452	0	367
2016	313	136	3,401	450	37	214	463	0	511
2017	390	185	3,477	537	37	243	496	0	662
2018	471	239	3,551	626	37	273	508	0	812
2019	555	296	3,602	718	37	304	524	0	958
2020	642	351	3,674	813	37	335	537	0	953
2021	733	406	3,745	836	37	341	551	0	941
2022	826	462	3,816	860	37	346	566	478	939
2023	925	520	3,885	885	37	353	580	538	939
2024	1,027	579	3,954	910	37	359	595	599	941
2025	1,134	638	4,026	935	38	366	610	662	944
2026	1,163	698	4,099	961	38	372	626	670	950
2027	1,192	758	4,171	987	39	379	641	677	956
2028	1,223	819	4,244	1,014	39	385	657	685	965
2029	1,254	882	4,318	1,041	40	392	672	697	977
Total	**1,341**	**1248**	**8,272**	**1,495**	**105**	**503**	**945**	**1,162**	**1,497**

Table 2-5 shows the estimated qualifying energy needed to fully achieve current renewable portfolio standards. Because of price caps and other limiting factors, the forecast used for this plan assumes 95 percent achievement of standards. All energy from potentially qualifying existing capacity is assumed to be credited. Energy-efficiency measures, in states where credited, are assumed to be employed to the extent allowed. The remaining generating resource obligations (i.e., 95 percent of the new energy of Table 2-6) will be met by a mix of new resources, determined by state-specific resource eligibility criteria, new resource availability, resource cost, RPS policies governing use of out-of-state resources, state-specific resource set-asides and special credit and other factors. The resource mix in the near-term was assumed to resemble the mix of recent qualifying resource development. Over the planning period,

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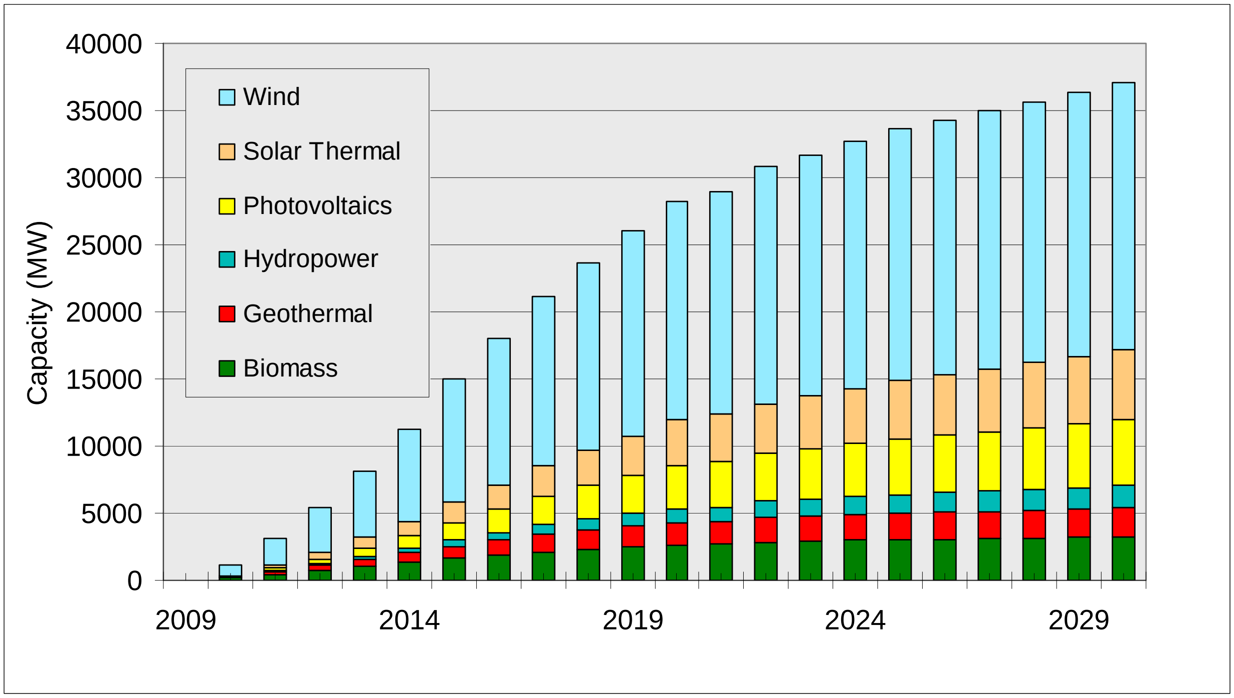
resource acquisitions based on cost-effectiveness are simulated by the capacity expansion logic of the AURORA$^{\text{xmp®}}$ Electricity Market Model used for the wholesale power price forecast, it was not necessary to separately forecast renewable resource development for Utah.

development is assumed to shift toward locally abundant, but relatively undeveloped resources such as solar thermal. Figure 2-6 illustrates the assumed incremental capacity additions needed to provide 95 percent of the cumulative energy requirements of Table 2-5.

To simplify the forecast, the Council assumed that all new resource requirements would be met in-state, although it is clear that states such as California, with substantial need for qualifying RPS resources, will secure much of its RPS needs from out-of-state sources.

Figure 2-6: Forecast RPS capacity by resource type



WHOLESALE ELECTRICITY PRICES

The Council prepares and periodically updates a 20-year forecast of wholesale electric power prices, representing the future price of electricity traded on the wholesale, short-term (spot) market at the Mid-Columbia trading hub. The forecast establishes benchmark capacity and energy costs for conservation and generating resource assessments and serves as the equilibrium wholesale power prices for the Resource Portfolio Model. In addition, the forecast is used for the ProCost model to assess the cost-effectiveness of conservation measures. The Council's electricity price forecast is also used by other organizations for assessing resource cost-effectiveness, developing resource plans, and for other purposes.

An overview of the development of the wholesale electricity price forecast and a summary of the results are provided in this section. A complete description is provided in Appendix D.

The Council uses the AURORA$^{xmp®}$ Electricity Market Model[3] to forecast wholesale power prices. Electricity prices are based on the variable cost of the most expensive generating plant or

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[3] Supplied by EPIS, Inc. (www.epis.com)

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increment of load curtailment needed to meet load for each hour of the forecast period. AURORA$^{\text{xmp®}}$, as configured by the Council, simulates plant dispatch in each of 16 load-resource zones making up the Western Electricity Coordinating Council (WECC) electric reliability area. The Northwest is defined as four of these zones: Western Oregon and Washington; Eastern Oregon and Washington, Northern Idaho and Western Montana; Southern Idaho; and Eastern Montana. The 16 zones are defined by transmission constraints and are each characterized by a forecast load (net of conservation), existing generating units, scheduled project additions and retirements, fuel price forecasts, load curtailment alternatives, and a portfolio of new-resource options. Transmission interconnections between the zones are characterized by transfer capacity, losses, and wheeling costs. The demand within a load-resource zone may be served by native generation, imports from other zones, or (rarely) load curtailment.

Three factors are expected to significantly influence the future wholesale power market: the future price of natural gas; the future cost of carbon dioxide (CO_2) production; and renewable resource development associated with state renewable portfolio standards (RPS). These factors will affect the variable cost of the hourly marginal resource and hence the wholesale power price.

Because natural gas is a relatively expensive fuel, natural gas-fired plants are often the marginal generating unit, and therefore determine the wholesale price of electricity during most hours of the year. CO_2 allowance prices or taxes will raise the variable cost of coal-fired units more than that of gas-fired units because of the greater carbon content of coal. Lower CO_2 costs will raise the variable cost of both gas and coal units, but not enough to push coal above gas to the margin. High CO_2 costs will move coal to the margin, above gas. In either case, the variable cost of the marginal unit will increase. As described earlier in this chapter, state renewable portfolio standards are expected to force the development of large amounts of wind, solar, and other resources with low-variable costs, in excess of the growth in demand. This will force fossil-fueled generators with lower variable costs to the margin, tending to reduce market prices.

A base case forecast, four sensitivity studies, and two bounding-scenario cases were run. The base forecast assumes medium-case fuel prices and mean CO_2 prices. All forecast cases assume 95-percent achievement of state renewable portfolio standards, average hydropower conditions, medium load growth and achievement of all cost-effective conservation. The changing case assumptions are shown in Table 2-6.

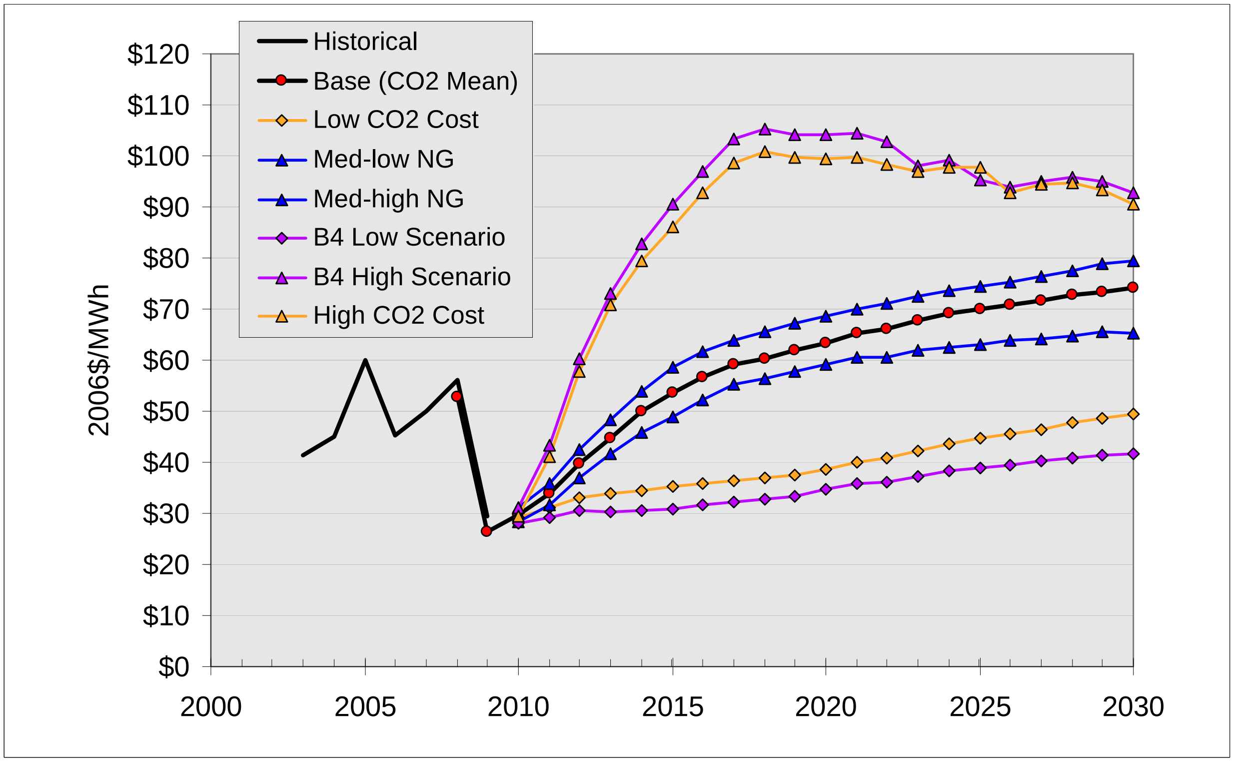
Table 2-6: Price Forecast Case Changing Assumptions

Case	Fuel Prices	CO_2 Cost
Base (mean CO_2)	Medium Case	Mean
Low CO_2 Cost	Medium Case	90% prob. of exceedance decile
High CO_2 Cost	Medium Case	10% prob. of exceedance decile
Medium-Low Natural Gas	Medium-low NG	Mean of RPM cases
Medium-High Natural Gas	Medium-high NG	Mean of RPM cases
Low Scenario	Medium-low NG	90% prob. of exceedance decile
High Scenario	Medium-high NG	10% prob. of exceedance decile

For the base forecast, wholesale power prices at the Mid-Columbia trading hub are projected to increase from $30 per megawatt-hour in 2010 to $74 per megawatt-hour in 2030 (in real 2006 dollar values). For comparison, Mid-Columbia wholesale power prices averaged $56 per megawatt-hour in 2008 (in real 2006 dollars), dropping abruptly to $29 in 2009 with the collapse of natural gas prices and reduction of demand due to the economic downturn. The levelized present value of the 2010-29 base case forecast is $56 per megawatt-hour.

Figure 2-7 illustrates recent and forecast wholesale power prices for the various cases. Comparing the shape of the power price forecasts with the mean CO_2 price forecast of Figure 2-5 clearly demonstrates the significant effect of CO_2 costs on prices. This is particularly evident in the high CO_2 and high-scenario cases. In these cases, prices rise rapidly early in the planning period as CO_2 prices increase, then stabilize and decline as CO_2 prices reach a steady-state of $100/ton of CO_2 and additional low-carbon resources are deployed.

Figure 2-7: Historical and Forecast Annual Average Mid-Columbia Wholesale Power Prices



Northwest electricity prices tend to exhibit a seasonal pattern associated with spring runoff in the Columbia River Basin and lower loads as the weather moderates. The forecasts exhibit this pattern when viewed on a monthly average basis. Figure 2-8 shows the monthly average heavy-load hours, all-hours, and light-load-hours prices for the base forecast. A flattening of prices during high-runoff, lower-load seasons, becoming evident in the mid-term of the planning period, is likely attributable to the increasing proportion of must-run resources with low variable costs.

The levelized 2010-29 forecast values and values for selected years are shown in Table 2-7. The full monthly price series are provided in Appendix D.

Figure 2-8: Monthly Average Base Case (Mean CO_2) Forecast of Mid-Columbia Wholesale Power Prices

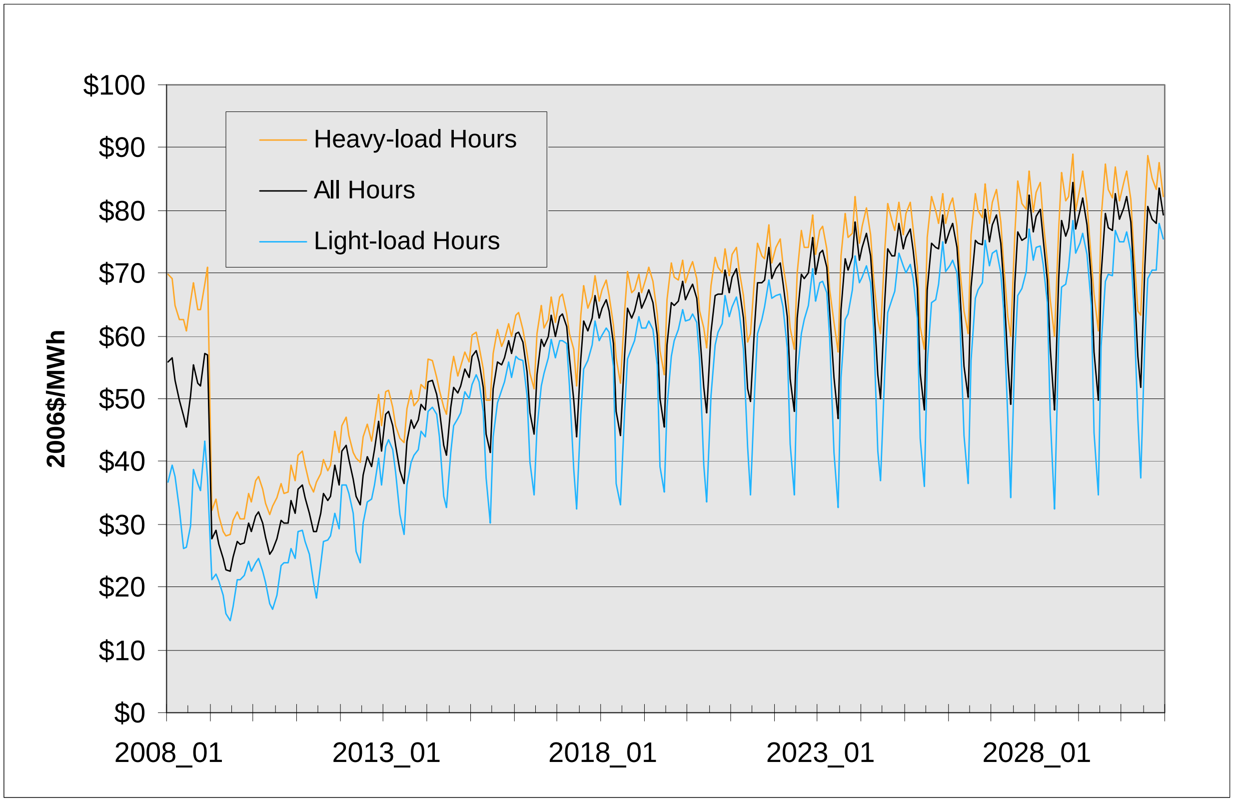


Table 2-7: Forecast of Mid-Columbia Wholesale Power Prices (2006$/MWh)

	Base	Low-CO_2	High CO_2	Med-Low NG	Med-High NG	Low Scenario	High Scenario
2010	$30	$29	$29	$28	$31	$28	$31
2015	$54	$35	$86	$49	$59	$31	$90
2020	$63	$39	$99	$59	$69	$35	$104
2025	$70	$45	$98	$63	$74	$39	$95
2030	$74	$49	$91	$65	$79	$42	$93
Levelized (2010-29)	**$56**	**$38**	**$82**	**$51**	**$60**	**$34**	**$85**
Growth Rates							
2010-2029	4.4%	4.6%	2.6%	5.9%	4.3%	4.7%	2.0%

Forecast wholesale power prices have often been used to determine the avoided cost of new resources. Wholesale energy price forecasts, in general, must be used with caution in setting avoided costs because of capacity and risk considerations. However, this price forecast in particular is not a suitable stand-alone measure of avoided resource costs.[4] This is because the Northwest, with the exception of Southern Idaho, enters the planning period with an energy

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[4] Market price adders representing the risk mitigation and capacity value of specific resource types can be calculated. The resulting sum of energy market prices, capacity credit and risk mitigation credit represents the avoided cost of the resource in question. This is the approach taken in this plan to establish the value of energy efficiency measures.

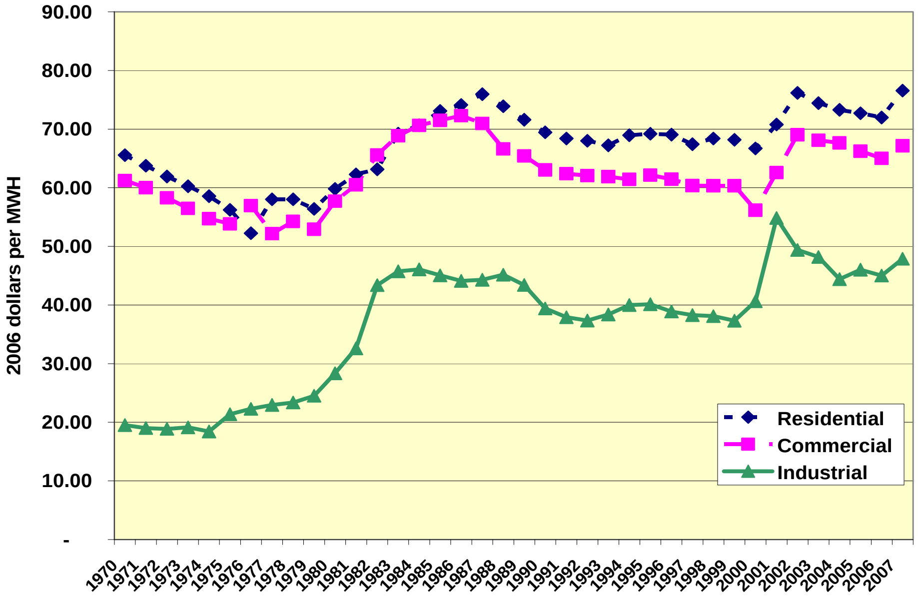
surplus, and remains so throughout the planning period because of the addition of resources to meet renewable-resource-portfolio requirements. Because of this continuing surplus, no discretionary (non-RPS) resources are added by the model and therefore the resulting energy prices do not reflect the avoided cost of any new resource. The actual avoided-resource costs for the three Northwest states with renewable portfolio standards are the costs of the renewable resources added to meet RPS requirements and any capacity additions needed to supply balancing reserves (balancing-reserve requirements are not tracked in the model). Southern Idaho is the exception. Here, about 570 megawatts of simple-cycle gas turbines are added during the planning period to maintain capacity reserves. Because this capacity only contributes incidental energy, even the energy price forecast for Southern Idaho does not represent the avoided cost of needed resources.

RETAIL ELECTRICITY PRICES

History

In the first half of the 1970s, consumers in the Northwest experienced declining electricity prices. However, by mid-1970 and into the 1980s, the region experienced dramatic increases in the price of electricity, followed by an economic recession that hit the region particularly hard. In the latter half of the 1980s, electricity prices began a decade-long decline, in real (inflation-adjusted) terms. But in late 2000, the region again experienced large increases in the price of energy, accompanied by a moderate recession. Since the sharp increase in 2000, electricity prices have stabilized, and even declined in inflation-adjusted prices. However, since 2006, another round of more moderate price increases has begun to be reflected in increases in fuel prices and other commodities. Figure 2-9 illustrates this price history.[5]

Figure 2-9: Average Retail Electricity Price by Sector (2006$/MWh)



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[5] Prices in Figure 2-7 are expressed in constant year 2006 dollars, as are many other tables and graphs throughout the plan.

Forecast of Retail Electricity Prices

Typically, the price of electricity for investor-owned utilities is determined through a regulatory-approval process, with utilities bringing a rate case to their regulatory authority and seeking approval of future rates. Future rates depend on the cost of serving electricity to customers and the level of sales. The approved rates should cover the variable *and* fixed-cost components of serving customers, plus a rate of return on invested capital. For customer-owned utilities, rates are set by elected boards to recover the costs of serving the electricity needs of their customers.

The methodology used for forecasting future electricity prices in the Sixth Power Plan is a simplified approach, where fixed and variable costs of the power system are estimated for each period and then divided by the volume of sales of electricity. The annual growth rate in average revenue requirement derived from the least-risk plan was applied to sector-level electricity prices.

Sector Retail Prices

The estimated price of electricity by sector and state is presented in Tables 2-8 through 2-10. The annual real growth rate of electricity prices is expected to be about 1 percent per year for the 2010-2030 period. It should be noted that these forecasts are at the state level, and within each state, individual electric utility rates may be higher or lower than the figures presented here. Also, individual utilities may have significantly higher or lower rate increases than these average statewide figures would indicate.

Table 2-8: Price of Electricity for Residential Customers (2006$/MWh)

	Oregon	Washington	Idaho	Montana
1985	74	60	68	74
2005	75	68	65	84
2010	89	79	74	96
2015	101	90	83	109
2020	109	97	90	117
2030	108	96	89	116
Annual Growth				
1985-2000	-0.3%	0.0%	-0.3%	0.1%
2000-2007	2.9%	3.9%	0.3%	2.7%
2010-2030	1.0%	1.0%	1.0%	1.0%

Table 2-9: Price of Electricity for Commercial Customers (2006$/MWh)

	Oregon	Washington	Idaho	Montana
1985	81	57	65	67
2005	67	65	56	77
2010	79	71	60	89
2015	89	80	67	101
2020	97	86	73	109
2030	93	83	70	104
Annual Growth				
1985-2000	-1.3%	-0.2%	-1.2%	-0.4%
2000-2007	3.2%	3.6%	-0.3%	3.5%
2010-2030	1.0%	1.0%	1.0%	1.0%

Table 2-10: Price of Electricity for Industrial Customers (2006$/MWh)

	Oregon	Washington	Idaho	Montana
1985	56	34	42	40
2005	50	44	40	50
2010	51	55	45	60
2015	58	62	51	67
2020	63	67	55	73
2030	60	64	53	70
Annual Growth				
1985-2000	-1.3%	0.6%	-0.6%	0.7%
2000-2007	4.8%	3.2%	-0.1%	8.1%
2010-2030	1.0%	1.0%	1.0%	1.0%

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CUB Data Request 20

CUB Data Request 20

Please provide the evaluation of Jim Bridger Unit 3 that is referenced in PAC/500/Teply/85.

(a) Did this evaluation include all costs that are required under the Wyoming SIP?
(b) Did this evaluation include an SCR would be required?
(c) Did this evaluation assume any costs associated with the SIP requirements of Wyoming as sunk costs?

Response to CUB Data Request 20

Please refer to Confidential Attachment OPUC 220 -3 for the requested evaluation.

(a) Yes, the evaluation included all then-current cost forecasts for environmental compliance projects required under the Wyoming SIP.

(b) Yes.

(c) No.

CUB EXHIBIT 112 IS CONFIDENTIAL
SUBJECT TO PROTECTIVE ORDER NO. 12-060

UE 246 / CUB / 113
Jenks - Feighner / 1

CUB EXHIBIT 113 IS CONFIDENTIAL
SUBJECT TO PROTECTIVE ORDER NO. 12-060

UE 246 / CUB / 114
Jenks - Feighner / 1

CUB EXHIBIT 114 IS CONFIDENTIAL
SUBJECT TO PROTECTIVE ORDER NO. 12-060

UE 246 – CERTIFICATE OF SERVICE

I hereby certify that, on this 20th day of June, 2012, I served the foregoing **RESPONSE TESTIMONY OF THE CITIZENS' UTILITY BOARD OF OREGON** in docket UE 246 upon each party listed in the UE 246 PUC Service List by email and, where paper service is not waived, by U.S. mail, postage prepaid, and upon the Commission by email and by sending one original and five copies by U.S. mail, postage prepaid, to the Commission's Salem offices.

(W denotes waiver of paper service)

(C denotes service of Confidential material authorized)

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