BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 39

In the Matter of	)
PACIFICORP,	)
2004 Integrated Resource Plan.	)

OPENING COMMENTS

OF THE

CITIZENS' UTILITY BOARD OF OREGON

May 23, 2005

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I. Introduction

The Citizens' Utility Board is unable to say that the action items and the preferred portfolio presented in PacifiCorp's 2004 Integrated Resource Plan represent a prudent resource development strategy. The primary problem is that, despite PacifiCorp's extensive modeling, the process failed to adequately address the enormous risks and costs associated with climate change and greenhouse gas emissions. This is primarily demonstrated by the following:

1. The Company's plan to add two additional coal plants to its already coal-intensive system flies in the face of the mounting scientific evidence demonstrating the occurrence and effects of climate change. The plan also flies in the face of the current, as well as future, response of Oregon, the United States, and the international community to the crisis that evidence suggests is impending.

2. The difference in the present value of revenue requirement (PVRR) between PacifiCorp's preferred scenario and a scenario that replaces the coal plants with natural gas turbines is negligible, yet PacifiCorp did not make a compelling case that the risk of gas price volatility is greater than the risk of CO_2 regulation, much less the potential cost of climate change.

3. Coal-fired generating resources serve as economic development for several states on the East Side of PacifiCorp's service territory, and PacifiCorp is comfortable with and knowledgeable about coal resources. These two factors pull the Company towards coal resources, and thus, we believe the IRP is qualitatively skewed toward coal.

4. The IRP fails to reexamine the quantity of wind resource that was identified in the Company's 2003 IRP to determine if that amount is still adequate or appropriate. This omission may skewed the modeling toward base-load coal, rather than the more flexible, more easily dispatched gas-fired CCCT.

5. The urgency to make an investment in coal, and the reason Oregon is faced with a Hobson's choice[1] between a pulverized coal plant or an Integrated Gasification Combined Cycle (IGCC) plant, is the growth in Utah's load. The choice between the risk of way too much CO_2 or the risks of associated with the immature technologies of IGCC and carbon capture and sequestration is not a pretty one, and the IRP has not satisfied us that all possible measures have been or will be taken to aggressively address the real problem by reducing Utah's load, especially its peak load.

6. Given the likelihood of future carbon regulation, the addition of a more-efficient coal plant – be it pulverized or IGCC – may simply result in the retirement of a

[1] After Thomas Hobson (1544?-1630), English keeper of a livery stable, from his requirement that customers take either the horse nearest the stable door or none.

less-efficient coal plant, leaving us faced with yet another costly resource acquisition to close the load-resource gap. This would significantly increase the cost of the preferred portfolio as it is currently modeled.

II. Discussion

A. Climate Change

We believe that global climate change may well become the dominant policy and cost driver in the energy industry in the decades to come. A coal-heavy utility like PacifiCorp may reasonably be targeted by governmental and societal responses to atmospheric carbon loading. Such a situation would prove exceedingly costly to both PacifiCorp shareholders and customers. Failing to look ahead and plan for such an eventuality is imprudent in the extreme. While we would like to see PacifiCorp avoid carbon-intensive coal generation for the sake of the planet, we also want to avoid exacerbating PacifiCorp's already significant carbon exposure for the sake of our pocketbooks.

i. The Intergovernmental Panel on Climate Change

The scientific community is approaching unanimity in the opinion that most of the warming observed over the last 50 years is attributable to human activities. Consider the following statements from the Intergovernmental Panel on Climate Change's 2001 report.

- Globally, it is very likely that 1998 is the warmest year on record and the 1990s the warmest decade.
- The atmospheric concentration of carbon dioxide (CO_2) has increased 31% since 1750. The present CO_2 concentration has not been exceeded during the past 420,000 years and likely not during the past 20 million years.
- The atmospheric concentration of methane (CH_4) has increased 151% since 1750 and has not been exceeded during the past 420,000 years.

- There is very likely to have been a 10% decrease in snow cover since the 1960s.
- Emissions of CO_2 due to fossil fuel burning are virtually certain to be the dominant influence on the trends in atmospheric CO_2 during the 21st century.
- The average global surface temperature is projected to increase by 1.4 to 5.8 degrees centigrade in the next 100 years.

Intergovernmental Panel on Climate Change.
Climate Change 2001: Synthesis Report: Summary for Policy Makers.

Though there will always be naysayers, the world's scientific community, as represented by the IPCC, is acknowledging the connection between anthropogenic greenhouse gas emissions and changes in the world's climate.

ii. Science Magazine

There is little doubt that scientists, governments, and, ultimately, citizens will call for proposals and strategies to curb atmospheric carbon loading in order to slow, if not reverse, the process of climate change. One fairly modest, but well-known proposal published in *Science* last year calls for stabilizing current CO_2 emissions at the current level of 7 billion tons of carbon per year for the next 50 years[2]. The current atmospheric concentration of CO_2 is 375 parts per million (ppm), compared to the pre-industrial concentration of 280 ppm. The proposal presented in *Science* would stabilize the atmospheric CO_2 concentration at 500 ppm. While this is fairly modest compared to other proposals (see below), accomplishing such a task would be a significant victory, because in the next 50 years the annual emission of CO_2 is expected to double. Of the 15 technology options offered by the authors in *Science*, a number of them relate to the generation of electricity, including substituting natural gas for coal (Option 5), storage of carbon captured in power plants (Option 6), and wind electricity (Option 10).

[2] Pascala, S. and Socolow, R. "Stabilization Wedges: Solving the Climate Problem for the Next 50 Years with Current Technologies." *Science* 305, 968. 13 August 2004.

iii. The Governor's Advisory Group on Global Warming

Recently the Governor's Advisory Group on Global Warming issued its Strategy for Greenhouse Gas Reductions in Oregon. This group recommends the following emission reduction goals:

- By 2010, arrest the growth of greenhouse gas emissions and begin to reduce them,
- By 2020, achieve a 10% reduction below 1990 greenhouse gas emission levels, and
- By 2050, achieve a climate stabilization emission level of at least 75% below 1990 levels.

These kinds of greenhouse gas reductions will require serious adjustments to business-as-usual. The energy sector is a prime candidate for greenhouse gas emission reductions. As noted above, fossil fuel burning is the major anthropogenic source of CO_2 emissions. In fact, the electricity industry alone represents 40% of CO_2 emissions in the United States. In turn, US CO_2 emissions account for 25% of global CO_2 emissions. Therefore, the electricity industry in the US accounts for 10% of global CO_2 emissions!

This pertains to Oregonians because, as noted in the Oregon Department of Energy's Comments in this docket, PacifiCorp emits about 22% of Oregon's CO_2 emissions, and PacifiCorp's preferred portfolio would represent a 20% growth of CO_2 emissions from its current generation portfolio between 2005 and 2018. It is difficult to see how the carbon risk inherent in PacifiCorp's plan could be considered an acceptable level of risk for customers, much less how it could come close to meeting the CO_2 reductions called for in the Strategy for Greenhouse Gas Reductions in Oregon.

CUB requested, and PacifiCorp willingly provided, a discussion in the IRP of the current state of climate change science and regulatory response. IRP/19-21. Despite the scientific data available and the national and international activity addressing climate change, modeling a likely regulatory response is difficult at best. While the carbon adder PacifiCorp used in its IRP ($8 per ton of CO_2) is a helpful tool, it cannot seriously be considered a realistic internalization of the potential regulatory response to carbon. In fact, it could be argued that $8 per ton is now obsolete and too low given attempts in other jurisdictions to determine an appropriate adder. See NWEC's Comments. This public policy question cannot be solely answered using analytical tools available today. Yet, climate change is very much an issue of portfolio diversity and risk reduction.

Oregon's Strategy for Greenhouse Gas Reduction recommends to the Governor that he appoint a special interim task force to examine the feasibility of, and develop a design for, a load-based greenhouse gas allowance standard. Oregon Strategy, page iv. We understand that the Governor's Office is currently examining how to implement this recommendation. PacifiCorp has made clear that the Company thinks states with carbon regulations ought to bear the cost of their regulations. This seems to militate against committing to additional coal plants in PacifiCorp's carbon-intensive generation portfolio until Oregon can establish its policy direction. Committing Oregon ratepayers to coal resources before Oregon's CO_2 regulation and its accompanying costs are known seems irresponsible at best. Conversely, the knowledge that Oregon has burdened itself with additional coal-fired generation may well have a dampening effect on the creativity and drive of the interim task force. Given that Oregon seems to be moving to a CO_2 net reduction objective, and that we will not know what Oregon's near-term regulatory response will be for another year, it seems imprudent to commit, on behalf of Oregon customers, to one more, much less two more, coal plants in PacifiCorp's system.

iv. Climate Change Is Central To Least Cost Planning

We think climate change is an essential consideration in any least-cost planning process, yet it is a risk that is difficult to adequately model. Order 89-507, issued at the end of the Oregon Public Utility Commission's investigation into least-cost planning, states the following:

> The result of the process is the selection of that mix of options which yields, for society over the long run, the best combination of expected costs and variance of costs. . . The goal of utility planning is to assure an adequate and reliable supply of energy at the least cost to the utility and its customers consistent with the long-run public interest. Long-run public interest is included as part of the goal because not all costs of a supply- or demand-side resource are necessarily borne by the utility and the ratepayers. Nor are all costs quantifiable. However it is the Commission's intent that all costs should be considered in the planning process and that their effect on the public interest should be a factor in determining a plan's resource mix.

Order 89-507, April 20, 1989, page 2.

While there may be controversy or confusion over some of these points for ratemaking purposes, for planning purposes it is the Commission's stated intent to consider the ramifications of all decisions on the public interest. In its order, the Commission recognized that not all costs are quantifiable, and that a responsibility of the least-cost planning process is to consider whether the utility's interests and the ratepayers' interests are compatible with the public interest in general. Therefore, it is not only consistent with, but very much a part of, the Commission's intent to examine the costs of climate change not only on PacifiCorp's shareholders and ratepayers but also on society as a whole, especially as PacifiCorp's current resource mix contributes significantly to Oregon's and the West's CO_2 emissions.

B. The Path Paved With Coal Is Not Necessarily Cheaper

The difference in PVRR between PacifiCorp's preferred portfolio and an all-gas portfolio is minute, and the fact that computer modeling cannot yet begin to adequately address the risks and costs of climate change renders such a small PVRR difference meaningless. We are not convinced that the Company's choice stands a chance of being the least-cost option over the long run, in light of the scientific data and political movement surrounding climate change that we cited earlier. We are becoming increasingly apprehensive that additional coal-fired generation is not only very risky, but also potentially very expensive.

i. Negligible Cost Difference Between Coal Portfolio & Gas Portfolio

The PVRR difference between PacifiCorp's preferred scenario with coal, Portfolio E with DSM, and a scenario that replaces the coal plants with gas-fired turbines, Portfolio M, is less than 1%. IRP/Technical Appendix E/75-77. Presumably, for PacifiCorp, the non-quantifiable risk of future gas price volatility is more meaningful than the non-quantifiable risk of both climate change and the future regulatory response to CO_2 emissions. Yet PacifiCorp did not make a compelling case that the scenario risk of gas price volatility is greater than the scenario risk of CO_2 regulation – much less the potential cost of climate change. When one factors in PacifiCorp's current portfolio and the carbon regulation risk inherent in the Company's heavy coal reliance, we come to the opposite conclusion. PacifiCorp would be taking on additional, unacceptable risk on behalf of its customers by building more coal resources.

The Oregon Department of Energy asked PacifiCorp to compare portfolio E, the coal portfolio, with portfolio M, the gas portfolio, using three different plant life assumptions, both high and base gas price assumptions, and CO_2 costs ranging from $8/ton to $37.50/ton. PacifiCorp's response shows that the gas portfolio has a lower PVRR than the coal portfolio in the base gas cost case when CO_2 costs are $14.9/ton or $37/ton. Even in the high gas cost case, depending on the life of the plant, when carbon costs are $14.9/ton CO_2, the gas portfolio is only 2% to 4% more expensive. The difference between these portfolios is mere background noise, especially given the mounting threat of climate change. PacifiCorp response to ODOE Data Request 1.2, attached as CUB Exhibit 1.

ii. Make Time & Use It

As we will discuss later, before the Company turns to coal, there are other resources, such as demand-side resources and wind, which could serve a significant amount of PacifiCorp's load without contributing any carbon risk. When, and only when, these resources have been fully utilized, should the Company consider adding coal to its already coal-heavy portfolio. In its IRP, PacifiCorp addresses the possibility of IGCC technology to reduce the cost of potential CO_2 regulation while pursuing the coal path. IRP/90-91.

While IGCC would reduce the risk of CO_2 emissions regulation it would increase the technology risk exposure for customers, as well as the risk of stranded assets – addressed in section F. Both IGCC and carbon sequestration technologies are not yet mature, and therefore create potential future cost exposure as the bugs are worked out and the performance of these technologies is tested and improved. With time, however, these technologies should mature, and these risks will diminish.

If more coal were ever to be considered for PacifiCorp's already coal-heavy portfolio, it should be the most efficient, cleanest coal resource that is in commercial use, and it should be ready for carbon capture and sequestration. These circumstances preclude rushing to invest in a coal resource in the near-term, much less a traditional coal resource. Instead, we recommend a more cautious, more creative approach whereby the utility takes measures to meet load in a reasonable manner, while aggressively managing Utah's growing load, and waiting, first to see if coal is really necessary, and, if so, for the appropriate technology to mature.

iii. A Rush To Judgment

Our frustration in this IRP is that, for reasons mostly relating to growth of load and peak load in Utah, we are being rushed to judgment. This Commission and customers in Oregon should not be pushed to embrace either a resource that may unreasonably increase cost exposure to an increasingly likely but currently unquantifiable environmental regulatory cost, or a resource whose technology and cost profile are not yet mature. PacifiCorp is offering us Ford's black Model T choice: you can have any resource you want, as long as it's coal. By offering pulverized coal or gasified coal, period, PacifiCorp is forcing us to pick our poison. We reject this optionless option.

iv. A Better Solution

The OPUC Staff asked PacifiCorp what the model result would be if a coal plant were postponed three years. The answer is that the present value of revenue requirement actually decreases, and is less than the PVRR of PacifiCorp's preferred portfolio. The problem that emerges in this scenario, is that the Company's planning margin dips down to 10% in 2013, the only year it would be below 12%, before rising again. The "bathtub chart" in Figure N.16, page 221 of Technical Appendix N, shows an increasing cost of expected unserved energy as the Company's planning margin drops. The Company has settled on a planning margin of 15%, which represents about 2 days of outages over 10 years. However, a 12.5% planning margin represents only 5.6 days of outages over 10 years (about ½ day per year)[3]. Weighing the risks of climate change and carbon cost, against such a small magnitude of expected outage, makes PacifiCorp's choice to invest in more coal extremely difficult to justify.

We cannot help but wonder, given a lead time of seven or eight years, given the savings in PVRR, given an aggressive peak-load shaving program and a motivated East Side, and given the option to site a single-cycle gas turbine close to the peak load, what would be lost by waiting a few years before making a 50-year, billion-dollar investment in a increased CO_2 future? Certainly, the reason to wait is clear. Use the time to manage the load, find a resource other than coal if load-management doesn't suffice, and, as a last resort, wait for further maturation of IGCC technology. We would like to see an aggressive peak-load shaving portfolio rather than a heavy-ratebase, coal scenario. Ultimately, we believe the former to be less expensive to customers and society.

C. Different Worlds … Same Planet

It is no secret that coal-fired generating resources are seen as economic development in several states on the East Side of PacifiCorp's service territory. We like to think that a component of Oregon's economic future is clean energy technology. Regardless, utility planning and procurement is not the place for economic development,

[3] From the chart on page 221 of Appendix N, a 15% planning margin represents about 2 outage days over 10 years and the Expected Unserved Energy is about 1,786 MWh. A 12.5% planning margin represents about 5,000 MWh of EUE, or 5.6 outage days in 10 years.

and, coal, even as economic development, does not comport well with the future health of the planet that we all share.

While the political decision of whether to invest in coal to satisfy some constituencies on the system is not a stated part of the IRP, we are aware of such pressures within PacifiCorp. This makes us wary about the qualitative aspects of the public process and the process results. Add to this dynamic, PacifiCorp's familiarity with coal-fired generation, and it is not unfathomable that non-quantitative pressures could shape the quantitative results to favor the acquisition of coal.

D. Wind Has Been Left Behind

PacifiCorp's IRP fails to reexamine the amount of wind resource that was identified in the 2003 IRP to determine what is now cost-effective or appropriate. PacifiCorp "retains the IRP 2003 conclusion that the 1400 MW of renewables, modeled as wind resources, will continue to be cost effective." IRP/Technical Appendix J/144. To its credit, PacifiCorp appears to have updated some of its assumptions, including wind's capacity contribution, but it is unclear whether wind resources were given a de novo analysis along with all other resources. It is not clear to us why PacifiCorp did not include a portfolio including more than 1400 MW of wind generation.

Part of the problem may be PacifiCorp's assertion that more wind will be difficult to integrate into its system. This is both a transmission and a generation problem, as the wind generation, due to its intermittent nature, is optimally used in conjunction with a flexible resource that can ramp up and down to take full advantage of whatever wind generation is available. However, choosing to add a significant amount of base-load coal, which is not particularly flexible, to its system exacerbates PacifiCorp's integration problem. More-flexible, gas-fired resources not only are less carbon-intensive, but better complement wind generation. We think the IRP not only fails to fully examine wind's potential, but, in so doing, specifically selects a portfolio that hinders the integration of wind into PacifiCorp's system. The Company's preferred portfolio further marginalizes wind at a time when we need wind generation more than ever.

On top of the failure to run a de novo wind analysis with an eye to solving the Company's claimed integration problems, is the fact that PacifiCorp is progressing quite slowly in acquiring the wind resources it identified in its 2003 IRP. We applaud PacifiCorp's recent wind acquisition in Idaho, and we understand the frustrations caused by the on-again, off-again production tax credit, but we do not yet get the sense that PacifiCorp is committed to wind either in its IRP or its generation portfolio.

E. Utah Load Growth Is The Driver

The primary driver behind the presented urgency to make a coal investment decision, and the reason Oregon has been presented with a non-choice between pulverized coal or IGCC, is growth in load in Utah. It is not lost on us that the pressure to choose between the risk of way too much CO_2 or the risk of immature IGCC and sequestration technologies, comes from the growth in load in Utah. The IRP has not satisfied us that all possible measures have been, or will be, taken to aggressively address the real problem by reducing the Company's East-Side peak load.

i. Utah's Load Growth Is Not A Surprise

For a decade now, PacifiCorp has known that Utah's load growth and its peak load growth have been cost drivers. Even as the average annual growth of Oregon's contribution to PacifiCorp's system coincident peak has been negative over the past 13 years, Utah's contribution to the system coincident peak has grown an average of 6.2% every year. IRP/Technical Appendix I/Table I.4. Over the next 10 years, PacifiCorp forecasts that, while the average annual growth of Oregon's contribution to PacifiCorp's system coincident peak will be 1.3%, Utah's contribution will grow by an average of 4.6% annually. IRP/Technical Appendix I/Table I.5.

On an energy basis, Utah's load growth has outpaced Oregon's by nearly 10 times over the last 13 years. IRP/Technical Appendix I/Table I.2. In the next 10 years, PacifiCorp expects the rate of Utah's load to outstrip Oregon's by a factor of 3. IRP/Technical Appendix I/Table I.3.

It irritates us then, that we suddenly find ourselves in a bind with regard to resources, when PacifiCorp has seen this coming for years. During the Energy Crisis, PacifiCorp felt the sting of having less resource available to serve load, in part because of the remarkably aggressive rate of Utah load growth. We wonder if this rush to add base-load coal is both a too-late reaction to serving Utah's inexorable load growth, and an overreaction to it through massive base-load additions. That coal contributes heavily to the Company's ratebase should also not be forgotten.

ii. Relying On DSM In The IRP Pushes The Company To Develop DSM

We acknowledge that PacifiCorp is now beginning to address the East Side peaking problem, but we wonder if PacifiCorp is doing enough, and if the IRP analysis pushed the Company enough. PacifiCorp's response to CUB Data Request 4, attached as CUB Exhibit 2, identifies nine East-Side peak-load reduction activities, but notes that four of them are not included in the IRP analysis, and that one included program is set to expire.

The expiration of the major interruptible tariffs, or negotiated curtailment agreements, represent the end of a 261 MW peak load reduction. PacifiCorp should assume that this significant program continues, and then makes sure that it does. The load lightener program builds to 27 MW, but was not included in the analysis, apparently because of timing issues. We have no basis to criticize the level of certain peak shaving programs, but we do wonder if PacifiCorp is aggressive enough in its pursuit of air conditioning peak load reduction, summer irrigation load reduction, industrial buy-back programs, etc. Utah may see these as social programs, but, for the PacifiCorp system, they provide cost control when it is most needed.

We realize that the Company is being conservative, and does not want to include resources in its IRP that it isn't fully comfortable with, but, unfortunately, this creates a negative feedback loop. If PacifiCorp does not rely on its DSM programs in its IRP, then the IRP will include enough resources such that the Company won't need those DSM programs. If the Company doesn't need the programs, its incentive to pursue and develop them, especially when it needs to pay for the resources it just built, evaporates. Though unintentional, it is a self-defeating – or DSM-defeating – approach.

iii. Transmission

We also notice that transmission becomes a forcing factor in addressing the Utah load growth problem. Transmission constraints on the East Side of PacifiCorp's system force long lead-times in resource development to account for transmission siting and construction. Planning to meet growth on the East Side with coal generation for the next decade means committing to building that resource now.

It was not clear to us from the IRP whether transmission was valuable only when associated with a particular resource, like a coal plant, or whether transmission investment could delay a commitment to a coal plant by relieving constraints and opening up pathways to market centers. We asked PacifiCorp to address the tradeoffs between building transmission to market centers and building transmission to a dedicated resource. The Company said, "PacifiCorp is open to evaluating purchases from remote new or existing resources via new transmission expansions as they could prove to be more cost-effective than investing in new generation with associated transmission." PacifiCorp response to CUB Data Request 3, attached as CUB Exhibit 3. Given this response, we are not sure if Utah's load problem is causing us to build a coal plant, as the preferred portfolio assumes, or is causing us to fix a transmission problem in the absence of a coal plant.

F. New Coal Is An Expensive Way To Tread Water

With carbon regulation looming on the horizon, and with PacifiCorp's system as carbon-intensive as it is, the addition of a more-efficient coal plant may simply result in the retirement of a less-efficient coal plant. This would net out to a very small resource gain, and would require yet another costly resource acquisition to replace the load met by the retired plant. This would significantly increase the cost of the Company's preferred portfolio. PacifiCorp agrees that, if the new plant displaced a less efficient plant, we would not have advanced the ball very far. "Shutting down the Company's least efficient power plant would create an additional need for new supply and/or demand resources. This additional resource requirement would need to be filled in the same way as any other resource gap. . ." PacifiCorp response to CUB Data Request 6, attached as CUB Exhibit 4.

While we don't know if the investment in a more-efficient plant necessarily means shutting down a less-efficient plant, the possibility certainly exists, and is moving, none too slowly, into the reasonable range of foreseeable futures. Needless to say, it is an outcome that would be enormously costly for ratepayers and shareholders alike. A non-coal resource investment is a far more logical way to avoid the potential problem, by avoiding coal's significant addition to PacifiCorp's overall exposure to carbon-risk.

III. Conclusion

We are not asking the Commission to do something it cannot do, or that is outside the scope of its authority. We are not asking the Commission to incorporate costs that are phantom, even if plausible. We are asking the Commission to consider carbon-intensive resources in light of the long-run public interest standard established in the Least Cost Planning order. We are asking the Commission to reject a new coal plant at this time, and ask the Company how it would proceed on a path that included aggressive peak-load shaving programs and no new coal-fired generation. This course would better serve customers, society, and ultimately the Company.

Respectfully Submitted,
May 23, 2005,

Jason Eisdorfer
Legal Counsel

ODOE Data Request 1.2 Supplemental

Original Request
Please provide deterministic Present Values of Revenue Requirements (PVRR) for Portfolio E (“preferred”) and Portfolio M (“all gas”) for base case and high gas prices (four cases of portfolio/gas price assumption) for the following 9 cases:

Three lifetime assumptions (for all cases use base case of 25 years for Aero-CTs):
Pulverized Coal 40 yrs, CCCT 35 years (base case)
Pulverized Coal 30 yrs, CCCT 30 years
Pulverized Coal 20 yrs, CCCT 20 years

Combined with:

Three C02 cost scenarios (2010 $/ton of C02)
$8.38 (base case)
$14.90
$37.25

This will yield a total 36 scenario (4 x 3 x 3). Twenty-six of these will be new and eight are already in the IRP (the IRP has portfolios E and M with: a base case, 2 C02 scenarios, and a high gas case).

Revised Request

Based on an April 20, 2005 conference call[1], agreement was reached on how PacifiCorp will respond to the outstanding items related to request 1.2. The agreement was to provide:

1. The results of the $14.90 CO_2 allowance cost scenario with the high gas price case for the different plant life assumptions for both the Preferred Portfolio and Portfolio M (six additional scenarios). The total number of scenarios to be provided for the revised response is 30.
2. Graphs showing Base and High Case gas prices for each of the CO_2 scenarios.

Supplemental Response to ODOE Data Request 1.2

PacifiCorp has provided deterministic Present Values of Revenue Requirements (PVRR) results for an additional 6 scenarios. The data for the 30 scenarios is provided in Table 1.2-1, “PVRRs by Scenario”. (The gray-shaded table rows indicate the additional six scenarios provided.) Figures 1.2-1 and 1.2-2 show West

[1] Participants included Phil Carver (ODOE), Janet Prewitt (ODOJ), Katherine MacDowell (Attorney at Stoel Rives), and Melissa Seymour (PacifiCorp).

and East gas prices, respectively, for the Base and High cases, by the three CO_2 allowance cost scenarios.

Table 1.2-1, PVRRs by Scenario

Portfolio Name	Gas Case	Lifetime Assumptions -Yrs PC	CCCT	CO2 $/ton	PVRR $000s
E	Base	40	35	8.38	13,284,523
E	Base	30	30	8.38	13,448,009
E	Base	20	20	8.38	13,883,017
E	Base	40	35	14.9	13,338,723
E	Base	30	30	14.9	13,502,208
E	Base	20	20	14.9	13,937,217
E	Base	40	35	37.25	13,656,615
E	Base	30	30	37.25	13,820,100
E	Base	20	20	37.25	14,255,109
E	High Gas	40	35	8.38	14,369,775
E	High Gas	30	30	8.38	14,533,261
E	High Gas	20	20	8.38	14,968,269
E	High Gas	40	35	14.9	14,379,595
E	High Gas	30	30	14.9	14,543,080
E	High Gas	20	20	14.9	14,978,088
M	Base	40	35	8.38	13,255,607
M	Base	30	30	8.38	13,373,710
M	Base	20	20	8.38	13,660,990
M	Base	40	35	14.9	13,206,576
M	Base	30	30	14.9	13,324,679
M	Base	20	20	14.9	13,611,959
M	Base	40	35	37.25	13,283,241
M	Base	30	30	37.25	13,401,344
M	Base	20	20	37.25	13,688,624
M	High Gas	40	35	8.38	14,933,521
M	High Gas	30	30	8.38	15,051,624
M	High Gas	20	20	8.38	15,338,904
M	High Gas	40	35	14.9	14,955,208
M	High Gas	30	30	14.9	15,073,311
M	High Gas	20	20	14.9	15,360,591

Note: Portfolio E is the supply side preferred portfolio before the addition of Class 1 DSM.

Figure 1.2-1. West-Side Gas Prices: Base and High Cases by CO2 Scenarios

CUB Exhibit 1

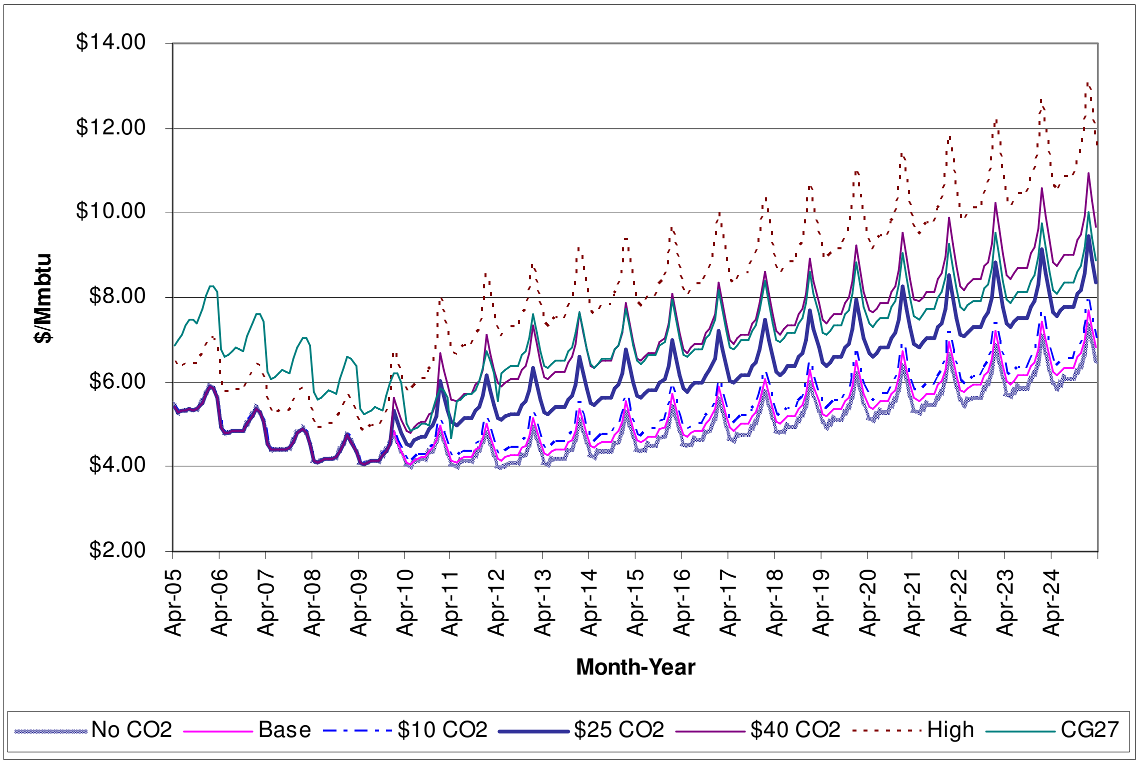
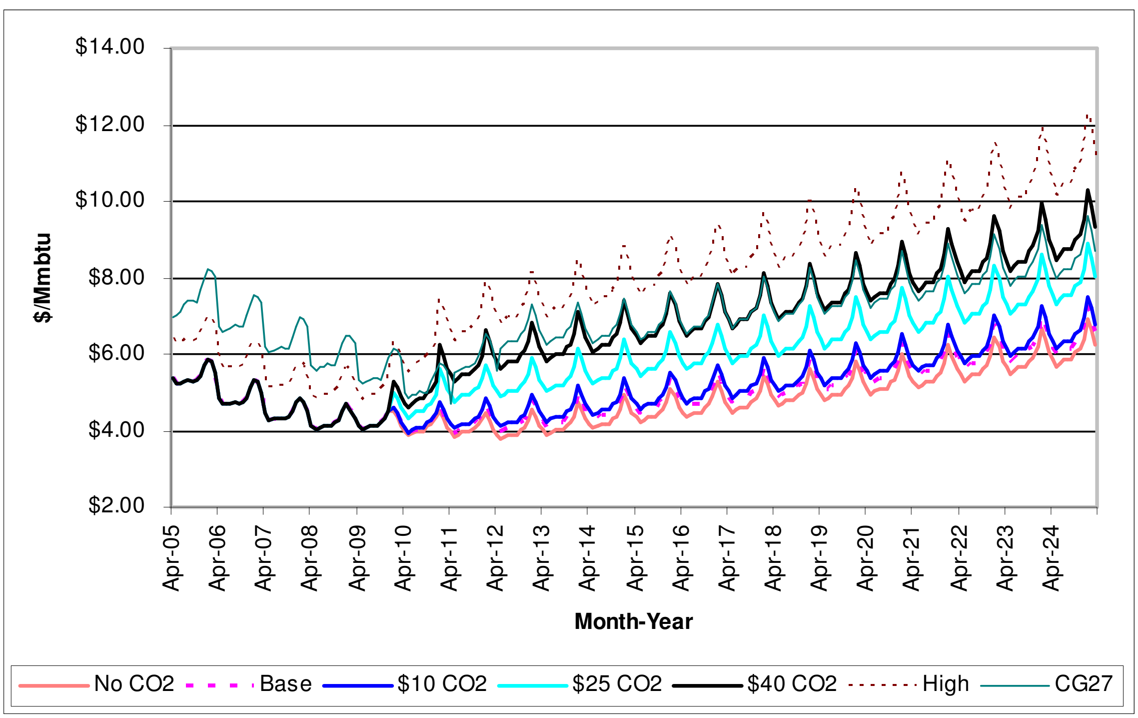


Figure 1.2-2. East-Side Gas Prices: Base and High Cases by CO2 Scenarios



CUB Data Request 4

Please list all activities targeting peak load reduction on the East Side. For each activity, list the NPV cost, assumed reduction in peak load and whether the activity is assumed in the IRP. Are there additional peak load actions not included in the IRP and, if so, why not?

Response to CUB Data Request 4

The following table summarizes the East-side peak load reduction activities, associated NPV information (if applicable), and whether the activity is assumed in the IRP.

Program	Description	NPV Cost	Peak Load Reduction	Load reduction assumed in IRP
Cool Keeper	Residential and small commercial central electric air conditioner control in Utah.	Costs not included in IRP as this is an existing resource assumed in all portfolios.	Builds to 90 MW	Yes
Idaho Irrigation Load Control	Control of irrigation pumps. Pre-scheduled June through mid-Sept.	Prices offered customers change each year based on forward market prices. Summer 2005 prices contained in Idaho Schedule 72. Costs not included in IRP as this is an existing resource assumed in all portfolios.	35 MW	Yes
Load Lightener	Commercial and Industrial lighting load control.	N/A	Builds to 27 MW	No, contract not completed in time to include as IRP resource.
Class 2 DSM	Variety of programs contained in Appendix C of volume 2 of 2004 IRP.	Nominal annual costs shown in Appendix C of 2004 IRP Volume 2: by program and by State. Costs not included in IRP as this is a base case resource assumed in all portfolios.	323 MW systemwide. East system figure not calculated (see Appendix L, page 167 of 2004 IRP Volume 2)	Yes, explicitly included as reduction to load forecast.

Energy Exchange	Day ahead hourly price offers during high wholesale market price periods. Eligible customers over 1 MW of load.	Prices offered customers are less than day ahead hourly prices.	0-93 MW enrolled 6.4 MW maximum curtailed during summer, 2004.	No, results not consistent or predictable
UT TOU tariff and inverted block rate	Price incentives for customers to reduce energy use.	N/A	N/A	No, price elasticity not evident in price range offered in Utah pricing tariffs.
Major customer interruptible tariffs	Negotiated curtailment agreements.	N/A	261 MW	Yes, until expiration
Power Forward	“Stop light” public appeal system used on critical load days.	N/A	0-69 MW (load reduction estimated for historical “yellow” alert days)	No, load reduction not consistent or predictable
New DSM RFP	Action plan illustrates plans to acquire more DSM resources.	Not yet determined.	177 MW Class 1 Additional Class 2 as found cost effective.	Yes.

CUB Data Request 3

Please address the tradeoffs the company sees between investing in substantial new transmission assets to access market opportunities (primarily but not exclusively on the East Side) and investing in new generation assets with associated transmission.

Response to CUB Data Request 3

PacifiCorp uses the IRP process to determine the least-cost, risk-weighted combination of proxy supply side and demand side resources to meet its obligation to serve. Based on discussion with CUB, PacifiCorp interprets the question to mean "will the company evaluate building transmission to viable remote shorter-term purchasing opportunities in addition to longer-term resources as supply side options in its IRP process". PacifiCorp is open to evaluating purchases from remote new or existing resources via new transmission expansions as they could prove to be more cost effective than investing in new generation with associated transmission. A variety of issues have the potential to impact a decision to invest in any supply side option involving building transmission to access markets. Among these are economic viability of the project via the RFP process, timing (ability to build in time to meet the need), and regional planning efforts.

PacifiCorp will determine the most viable supply side options via the RFP process including supply side options to markets that involve transmission investment. The actual resources selected will typically be determined via the procurement process.

CUB Data Request 6

The Governor's Advisory Group on Global Warming report of December 2004 listed the following goals: by 2010, stop the growth of Oregon's greenhouse gas emissions, by 2020, achieve a 10% reduction of 1990 greenhouse gas levels, and by 2050, achieve emissions levels at least 75% below 1990 levels. If that standard were applied to PacifiCorp, please describe how the company would meet those goals. Could PacifiCorp meet those goals by adding a new coal plant to its portfolio of resources? How would the company propose to fill the load-resource gap created by shutting down its least efficient coal plants?

Response to CUB Data Request 6

The emissions reductions goals included in the report of the Governor's Advisory Group on Global Warming were aspirational, particularly since they rely on partners elsewhere at the national level and include figures such as the 2010 target that are accepted in the report to be virtually unattainable. At the Advisory Group meetings, PacifiCorp representatives stressed our concern about the goals given the deep underlying economic and technical challenges. Other Advisory Group members stressed that such ambitious goals were important in expressing the Group's concern about climate change, rather than offering a clear blueprint for state-wide reductions.

PacifiCorp does not have a specific plan described for meeting the aspirational targets set out by the Governor's Advisory Group. Ultimately, both Oregon as well as individual entities such as PacifiCorp requires cost curves for CO2 reductions to understand reduction strategies and their cost implications. It appears that offset investments will offer some of the lowest-cost reductions, at least in the near term. "On-system" investments such as renewable energy and energy efficiency can offer substantial co-benefits alongside a low emissions profile, as demonstrated in our integrated resource plan. Other measures, such as early retirement of coal-fired generation, may entail high costs.

It is impossible to know exactly what would be required of the Company in meeting the Advisory Group's goals after adding a new coal plant. Specific requirements after adding a new coal-fired plant would depend on two primary factors: (1) the nature of the regulations (e.g., are emissions grandfathered?) and (2) the availability of low-cost reductions elsewhere, whether on-system or off-system.

Shutting down the Company's least efficient power plant would create an additional need for new supply and/or demand resources. This additional resource requirement would need to be filled in the same way any other resource gap must be met, through a review of all alternatives in the Integrated Resource Planning process.

CERTIFICATE OF SERVICE

I hereby certify that on this 23rd day of May, 2005, I served the foregoing Comments of the Citizens' Utility Board of Oregon in docket LC 39 upon each party listed below, by email and U.S. mail, postage prepaid, and upon the Commission by email and by sending 6 copies by U.S. mail, postage prepaid, to the Commission's Salem offices.

Respectfully submitted,

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