BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON
LC 52

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

I. Introduction

Sierra Club respectfully submits these comments on PacifiCorp's 2011 Integrated Resource Plan (IRP). The Sierra Club actively participated in the stakeholder input process during the development of the 2011 IRP and submitted preliminary comments on August 25, 2011 in anticipation of PacifiCorp complying with the Commission's August 10, 2011 directive that PacifiCorp provide a thorough plant by plant and unit by unit analysis of its coal resources. In response, PacifiCorp provided some additional details. However, as discussed below, important data gaps remain so that the Commission still lacks the level of information and analysis it needs to make an informed acknowledgement decision in December.

Sierra Club therefore asks that the Commission direct PacifiCorp to immediately hold technical workshops to exchange necessary information so that the Commission, staff and stakeholders can adequately assess the costs and risks associated with maintaining the company's aging coal fleet plant by plant.[1]

These comments address the following: (1) PacifiCorp's Coal Replacement Study; and (2) the energy efficiency resources considered in PacifiCorp's demand side management (DSM) programs.

[1] In order to facilitate the free exchange of information, Sierra Club proposes that workshop participants be signatories to the company's confidentiality agreement.

II. The Coal Replacement Study Did not Provide a Full and Unbiased Analysis of the Coal Fleet

Sierra Club received the Coal Replacement Study on September 21st, 2011. Our experts immediately reviewed the study and found that there was not enough detail to determine whether the company had accurately assessed the costs and risks associated with maintaining its coal fleet. Sierra Club promulgated discovery requests seeking clarification and detail in a number of key areas, and received responses only 48 hours before the filing deadline for these comments, a highly compressed period in which to review technical data. Nevertheless, it is apparent that PacifiCorp did not provide a clear and comprehensive analysis of its coal fleet, and has not reviewed the performance of individual units in its fleet.

According to the company, "the Coal Replacement Study advances the proof-of-concept coal utilization sensitivity analysis in the 2011 IRP with design modifications" [Coal Replacement Study, p2] including greenfield replacement, and the forced retirement of coal units at the end of their depreciable lives. While some of the improvements in the Coal Replacement Study simply brought some areas of concern up to a minimum standard, the company omitted sufficient detail and explanation such that the Commission and stakeholders cannot reasonably interpret whether PacifiCorp made assumptions that inadvertently or purposefully favor a specific outcome. In fact, several choices made by the company, and discussed here, suggest that this study may contain methodological flaws that ensure a specific outcome – namely, the continued retrofit and operation of an aging coal fleet.

The Coal Replacement Study provided some additional useful information, but still left numerous information gaps and did not explain whether the company appropriately evaluated the risks posed by its coal fleet. Information obtained in 2011 PacifiCorp rate cases in both Wyoming and Utah revealed that the company historically has never evaluated the ratepayer risks of continued operation of the coal fleet. This lack of planning is evident in PacifiCorp's 2011 IRP; the company continues to regard environmental compliance risks as *de minimus* and the condition of their coal fleet as outside of the purview of IRP planning.[2] The Coal Replacement Study, filed as an

[2] Sierra Club data request 3.1 in Utah Docket 10-035-124 (General Rate Case) asked: "State whether the company, or any party working on behalf of the company, performed any analysis as part of the 2008 or 201 1 Integrated Resource Plans (IRP) preparation to test for the cost effectiveness of alternatives to the

amendment to the 2011 IRP, further illustrated that, despite nearly a year of stakeholder comment, specific Commission requests, and at least two lengthy rate cases, the company continues to both obscure the economic condition of its coal fleet, and pursue high-cost and high-risk pollution control investments.

There are several key features of the replacement study that show the company is out of step with both good utility practice, as well as other utilities, regarding the feasibility of meeting rigorous environmental compliance obligations through retiring the least efficient, highest cost, and, of course, most polluting elements of its fleet. Utilities throughout the U.S. have begun seriously evaluating the cost effectiveness of shuttering older, inefficient coal plants to meet environmental protection measures. Safeguarding public health and the environment will require changes to the coal fleet; PacifiCorp, too, should consider the wisdom of installing state-of-the-art controls on 50 year-old units at ratepayer expense. The Coal Replacement Study should have represented such an assessment – instead, it failed to address one of the most important questions facing utilities: whether investing in aging, polluting coal plants is the best way to comply with a number of new and emerging environmental regulations.

The Coal Replacement Study partially improved upon the coal utilization sensitivities in the IRP. The improvements included the some changes to underlying assumptions; for example, the company offered a range of CO_2 and natural gas prices; the company acknowledged that coal combustion residual (CCR) and water intake structures (Clean Water Act section 316(b)) rules may impose costs; and the company evaluated the cost of additional selective catalytic reduction (SCR) at its coal units. The study appeared to take stock of costs on the retirement ledger as well, helping to ensure that costs for retirement and "applicable liquidated damages for not meeting minimum take provisions in existing coal supply contracts" [Coal Replacement Study, p2] were assigned to the cost of retirement. Unlike the 2011 IRP, the Coal Replacement Study "allow[s] coal resources to be displaced with greenfield [resources]" including gas, DSM, and "front office transactions" as of 2015 [Coal Replacement Study, p3].

[coal plant] environmental upgrades at issue in this docket. If yes, please list the specific alternatives that were modeled. If no, explain why no alternatives where modeled." To which the company responded: No specific cost-effectiveness analyses of the environmental upgrades at issue in this docket were performed by the company or external parties as part of the 2008 or 2011 IRPs. **Consistent with current state IRP guidelines, the company's IRP process and associated system planning models have focused on the economics and risks of acquiring future resources rather than potential investments connected with existing assets.**"

While these changes were improvements, the omission of important elements of the Coal Replacement Study showed that the company did not view this as an opportunity to review the cost effectiveness of maintaining the current fleet. These flaws call into question the purpose of the study, and indeed, the purpose of the IRP as a rigorous planning document.

A. The company assumed that the most significant environmental costs cannot be avoided.

Much of the company's investments to date and planned investments are designed to meet regional haze and the hazardous air pollution (HAPS/MACT) requirements. The company noted that HAPS MACT in "2015… is currently assumed to be the first substantive environmental compliance deadline." [Coal Replacement Study, p3] Yet, unlike other utilities (in Kansas, Georgia, Kentucky, Ohio, West Virginia, and Texas, to name a few), PacifiCorp assumed that it <u>must</u> invest in environmental controls to meet this deadline as "it is unrealistic to expect that sufficient and reliable cost-effective power could be obtained as a replacement for coal units idled prior to the 2015 HAPS MACT compliance deadline." (Discovery response to Sierra Club #13, Oct 31, 2011) **By putting these substantial investments in the baseline, rather than as avoidable costs, the company ensured that its approach to environmental controls would be incremental and piecemeal, rather than comprehensive.** From an analytical standpoint, putting these costs in the baseline made them unavoidable for purposes of the analysis, and therefore the only purpose of the cost-benefit analysis was to evaluate the longevity of the coal units past 2025.

B. The company did not produce a plant-by-plant continued use and operations study.

The company claimed in multiple forums that their Coal Replacement Study was a state-of-the-art and cutting edge use of the System Optimizer tool. However, the company's failure to produce a basic unit-by-unit study examining the costs and benefits of maintaining potentially non-economic units put it well behind the practices of other utilities. The study is simply a black-box of operational planning, rather than a useful and transparent tool to assess different alternatives. The basic elements of a continued use study should include either

(1) a transparent cash-flow analysis for each unit under consideration (including the equivalent market value of the plant's energy and capacity, and expected annual capital, variable operating costs, and fixed costs), or

(2) a set of build-out scenarios that includes the forced retirement of individual units in a near-term year (allowing environmental expenditures to be completely avoided) and compares the relative value of retrofit versus retirement at each unit.

Under the current structure, it is very difficult to determine how robust any given decision to retrofit and maintain a unit versus retiring it with respect to uncertain capital, fuel, or emissions costs.

C. The company confounded "Sensitivities" by mixing gas price and CO_2 signals.

In the Coal Replacement Study, PacifiCorp ran a base case, as well as "high" and "low" scenarios. However, in the "high" and "low" cases, both the gas and CO_2 prices were pushed in the same direction and thus neither scenario provided useful sensitivities for the purposes of independently evaluating high CO_2 resources, such as coal. A high gas price will generally favor the retirement of coal units (and replacement with natural gas); a high CO_2 price will also generally favor gas resources over coal. The company implicitly assumes that CO_2 prices and gas prices are somehow correlated, despite presenting no evidence of or theoretical foundation for such a correlation. This assumption may bias the analysis in favor of retrofitting coal plants, and ignores important sensitivities.[3]

[3] The Company stated that "higher CO_2 prices would most likely increase natural gas demand resulting in higher natural gas prices. It is less likely that a high CO_2 price future would be paired with a low natural gas price future" (Discovery response to Sierra Club #8, Oct 31, 2011). This Company did not provide any justification for this reasoning. In fact, the results from well-vetted economic models (such as EIA studies conducted for Congressional requests) suggest that there is no such correlation between gas and CO_2 prices. One could similarly postulate that in areas where there is unutilized, low-cost renewable energy availability (such as in PacifiCorp's service territory), high CO_2 costs would drive down gas utilization in favor of yet lower emissions alternatives. There has been little if any vetted literature offered to suggest that higher CO_2 prices will, in fact, result in higher natural gas prices.

D. The company artificially limited the role of renewable energy in providing low-cost power.

PacifiCorp specifically excluded "intermittent renewable resource alternatives" from replacing energy or capacity from the existing coal resources. [Coal Replacement Study, p3] The company reasoned that "system coal resources provide valuable system capacity." [Coal Replacement Study, p3] This reasoning would imply that PacifiCorp is a capacity limited, rather than energy limited, system. The company's modeling system already assigned a wind integration cost (generally meant to account for the cost of backing up intermittent resources) and explicitly modeled hourly variability; therefore, it would appear that uncertainty associated with wind was already integrated into the model. It would seem that from a logical standpoint, if the model is found to favor significant amounts of wind or solar as a replacement resource, the company should evaluate whether those resources are a reasonable and cost-effective alternative, and, if so, model it as such – rather than excluding this potentially low cost resource out of hand.

E. The company disregarded important environmental costs.

The company continued to claim that its environmental control cost estimates "conservatively capture the effect of potentially significant incremental pollution control capital investments" [Coal Replacement Study, p4] while disregarding important, and potentially costly, impending regulations. EPA is expected to issue its draft effluent limitation guidelines in the summer of 2012 and to finalize the guidelines by 2014. In contrast to PacifiCorp, other utilities have accounted for the impact of these potential costs. As noted by Southern Company in a concurrent IRP:

> EPA may decide to phase in requirements as permits are renewed over the five-year NPDES permitting cycle, or it could take a more extreme position and require quicker compliance. The impact of this rulemaking could be very substantial, and could include requirements for stringent FGD wastewater treatment, a prohibition on wet sluicing of fly ash and bottom ash for all coal-fired facilities, and treatment of landfill leachate. The rule is not limited to coal-fired facilities and could potentially address

> wastewater limits at nuclear, gas, and combined-cycle facilities as well."[4]

In a concurrent CPCN case in Kentucky, a utility estimated, for the purposes of a retire/retrofit decision, assessed the potential impact of EPA guidelines: "[The estimate includes] the revenue requirements associated with future capital costs for complying with effluent guidelines scheduled to be proposed in late 2012… The capital costs are estimated based on a range of control costs… [and] further refined using actual costs from a sister company's water treatment installation."[5] In short, various other utilities accounted for costs that PacifiCorp ignored or assumed to be zero. By failing to model these costs, PacifiCorp decided *a priori* in this planning docket that these costs would be zero, and therefore the risk that the EPA guidelines may result in future compliance costs falls completely on ratepayers.

F. The company failed to allow for avoided transmission investments.

PacifiCorp is currently investing heavily in upgraded transmission infrastructure between its eastern resources and eestern load centers. The Company's analysis did not consider how much of this expensive infrastructure project could be avoided if the company were able to retire inefficient eastern coal and build new generation in the west, closer to load centers.

III. The Energy Efficiency Resource Plan Does Not Achieve the Full Energy Efficiency Potential in PacifiCorp's Service Territory

Sierra Club reviewed PacifiCorp's 2011 IRP energy efficiency resource assumptions for Class 2 demand side-management (DSM) programs. DSM offers the opportunity to reduce load and capacity requirements throughout PacifiCorp's service territory through cost-effective programs, relieving, in part, the pressures that might be

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[4] Georgia Power Company, Environmental Compliance Strategy 2011, p27

[5] The Application of Kentucky Utilities Company / Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Approval of Its 2011 Compliance Plan for Recovery by Environmental Surcharge. Cases No. 2011-00161/00162. Response to the Supplemental Requests for Information of Environmental Groups. Question 4. September 1, 2011. Available online at: http://psc.ky.gov/PSCSCF/2011%20cases/2011-00161/20110901_KUs%20Response%20to%20Environmental%20Groups%20Supp%20Requests%20for%20Info%20with%20Motion%20and%20Petition.pdf

incurred from rising load requirements and the retirement of inefficient and non-cost effective generators.

Overall, the 2011 IRP did not provide adequate data for us or other interveners to validate the legitimacy of the analyses conducted for the plan. Specifically, the plan is not adequate in addressing the full, achievable energy efficiency potential in PacifiCorp's service territory. In particular:

1. Annual maximum energy savings were significantly lower than historically achieved in leading jurisdictions.

2. Energy efficiency program ramp ups appeared to be deeply conservative. PacifiCorp should assume a faster ramp-up for its efficiency program and plan to increase EE administrative budgets during early years to support accelerated program ramping.

3. PacifiCorp overestimated the cost of energy efficiency non-Oregon states.

4. The energy efficiency potential estimate used for the 2011 IRP was conservative.

PacifiCorp issued its 2011 IRP in March of 2011. The IRP incorporated three types of demand side management (DSM) resources: Class 1, Class 2, and Class 3. Class 1 and 3 resources are capacity resources including load control resources (e.g., AC recycling and irrigation direct load control), and energy pricing resources (e.g., time of use rate and critical peak pricing). Class 2 resources, representing the largest share of available DSM programs, are energy efficiency resources. PacifiCorp derived the DSM resource estimates used in the IRP from a 2010 DSM potential study by Cadmus, titled "Assessment of Long-Term, System-Wide Potential for Demand-Side and Other Supplemental Resources."(The 2010 DSM Potential Study). The IRP aggregated detailed DSM resource cost and savings data into 10 cost bundles, except in Oregon. These bundles essentially defined cost curves of available EE in the System Optimizer model.

Sierra Club conducted a detailed review of the Class 2 DSM resources (energy efficiency resources). Our review found that the plan did not provide adequate data for peer reviewers to validate the legitimacy of the analyses conducted for the plan.

The type of basic data needed to analyze for each scenario would typically include:

- Annual energy savings projection by state and load region
- Corresponding lifetime energy savings projection for each year by state and load region
- Annual capacity savings projection by state and load region
- Sales and peak load projection through 2030 by state and load region
- Annual energy efficiency cost (program investment and participant cost) by state and load region

A fundamental source of information, energy savings data (given in GWh or average MW [aMW]) were not available in the IRP by state and region. The capacity savings, included in the IRP in terms of megawatts (MW), were insufficient to determine how the chosen EE programs rate in reducing *energy* requirements (rather than just peak savings). In addition, the IRP used different jurisdictional categories for different scenarios (i.e., state jurisdiction for Energy Gateway scenarios and energy load zones for other scenarios), which made it difficult to determine how efficiency savings were spread throughout the utility's states in different scenarios. In contrast, peak load data were only available by state, not by load zone. Energy sales forecast were also only available by state, and only up to 2020. This approach is problematic because the core cases and many others (33 scenarios in total) used energy load jurisdictions instead of state boundaries, while sales and peak data were only available at the state level. These data inadequacy and inconsistency among energy savings, capacity savings, sales data, and peak load data made it difficult for reviewers to draw definitive conclusions on the efficacy of EE in PacifiCorp's plan. However, given the limited data and some publicly available data, we were able to draw a general conclusion about PacifiCorp's energy efficiency resource plans. Our preliminary assessment suggested that the plan was not adequate in addressing the full, achievable energy efficiency potential in its jurisdictions.

A. Annual maximum energy savings were significantly lower than historically achieved in other jurisdictions.

Figure 1 shows MW savings under PacifiCorp's territory by state projected under Energy Gateway Scenario 1. The Utah area has the highest savings, but the level of savings suddenly drops in year 4 by more than half. Washington and Oregon areas are also expected to see declining energy savings over time, and Idaho, California, and Wyoming areas are expected to see a very slow, gradual increase in energy savings.

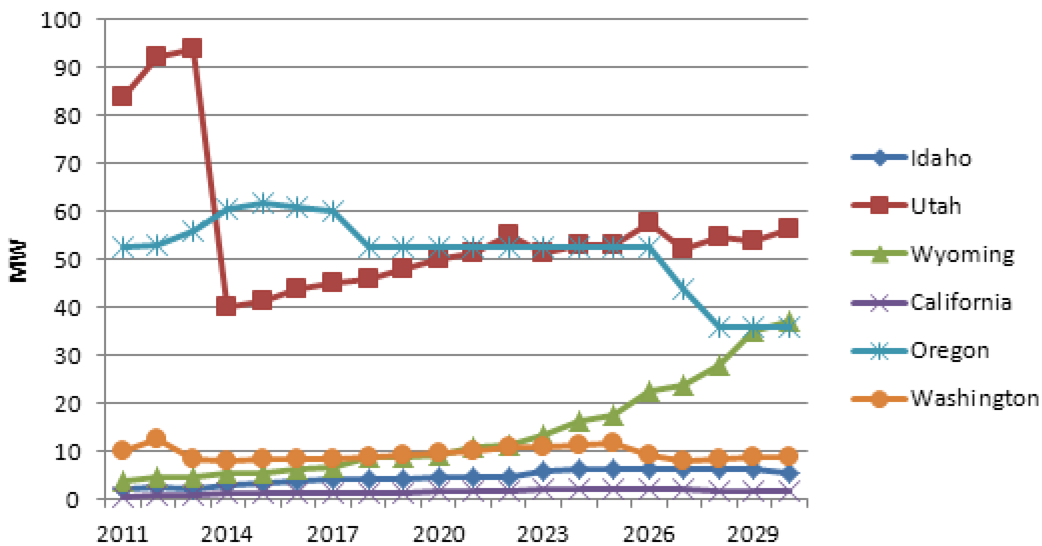

Figure 1: Energy Efficiency Capacity Savings by State in PacifiCorp 2011 IRP – Energy Gateway Scenario 1 (MW)

Sierra Club attempted to estimate energy savings as a percentage of retail sales, a widely used metric. Unfortunately the IRP did not provide energy savings for any of the scenarios. We estimated energy savings (GWh) from capacity savings data (MW) using state specific energy efficiency measure load factors. For all states except Oregon, we used load factors derived from the 2010 DSM potential study by Cadmus. For Oregon, we examined the latest energy savings projection in 2011 prepared by Energy Trust of Oregon (ETO) for PacifiCorp's territory and estimated a load factor that results in the same level of GWh savings.[6] The load factor was then applied to all study years to estimate energy savings for all years.

[6] The ETO projects 14.05 aMW energy savings in 2011 (equal to about 123 GWh). 52.6 MW capacity savings projected by PacifiCorp for Oregon would translate into about 123 GWh at a 27% capacity factor.

	Oregon	Washington	California	Utah	Wyoming	Idaho
EE load factor	27%	54%	63%	37%	78%	61%

Table 1: EE Load Factors for All States in PacifiCorp Service Region. Oregon factor derived from ETO data. Other data from Cadmus.

Sierra Club estimated energy savings as a percentage of retail sales projection. The retail sales from 2011 to 2020 were obtained from Appendix A (Load Forecast Details) in PacifiCorp IRP 2011. Sierra Club projected retail sales after 2020 using the annual average growth rate between 2011 and 2020 for each state since the IRP did not provide the sales forecasts after 2020. Figure 2 below shows the results of this analysis.

It is surprising that no states are expected to achieve 2% savings or even 1.5% (except Wyoming in the last year) in any given year. In contrast, some leading states and utilities already achieved energy efficiency savings of 1.5% to 2% (e.g., Vermont, Hawaii, Minnesota, Massachusetts) and at least 11 states established goals of annual energy savings at or above 2% of retail sales in the near future (see Attachment 1 and 2 for these examples).

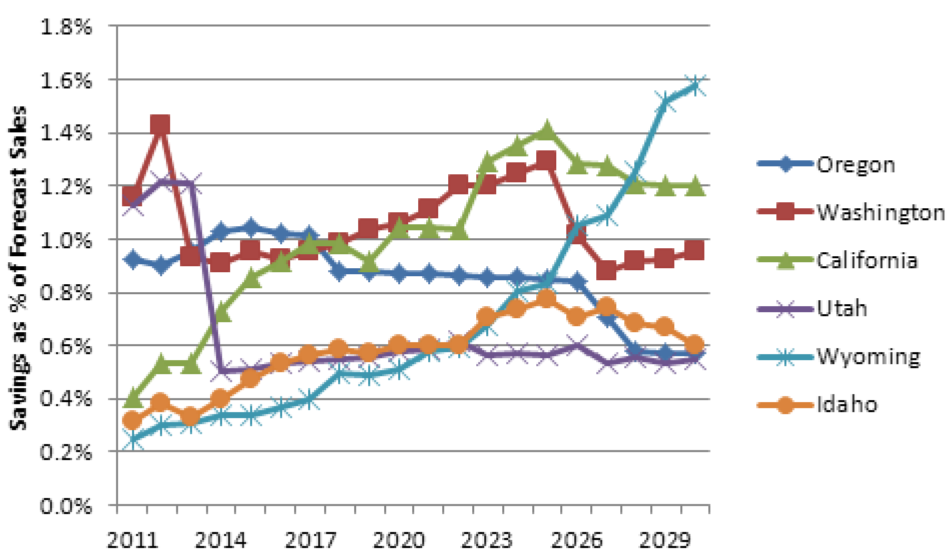

Figure 2: Energy Efficiency Energy Savings as % of Forecast Sales by State in PacifiCorp 2011 IRP – Energy Gateway Scenario 1

The energy savings data was obtained from ETO's "2011-2012 Proposed Final Action Plan and Budget" dated on December 17, 2010, available at http://energytrust.org/About/policy-and-reports/Plans.aspx

Figure 3 compares energy savings (% of sales) and program cost ($ per "first year" kWh savings) for the top 10 largest entities in terms of retail sales in the Northwest region from 2008 to 2010.[7] As shown in the chart, PacifiCorp achieved from 0.5% to 0.8% savings, while many other leading utilities in the same region achieved higher savings (at or above 1% to 1.4%) than PacifiCorp. Such entities include City of Seattle, Energy Trust of Oregon, Idaho Power, Puget Sound Energy, Snohomish Co. PUD, and Clark Co. PUD. It is important to note that Idaho Power achieved 1% to 1.3% savings for the past three years. In contrast, PacifiCorp in Idaho is only expected to achieve at maximum 0.8% savings, which the IRP expects will be attained in nearly 15 years. In addition, the Energy Trust of Oregon (ETO) recently achieved an over 1.3% savings while PacifiCorp projected less than 1% savings for Oregon for the next few years. This deficiency occurred primarily because the other jurisdiction of the ETO, Portland General Electric, provided more funding and achieved more energy savings than PacifiCorp.

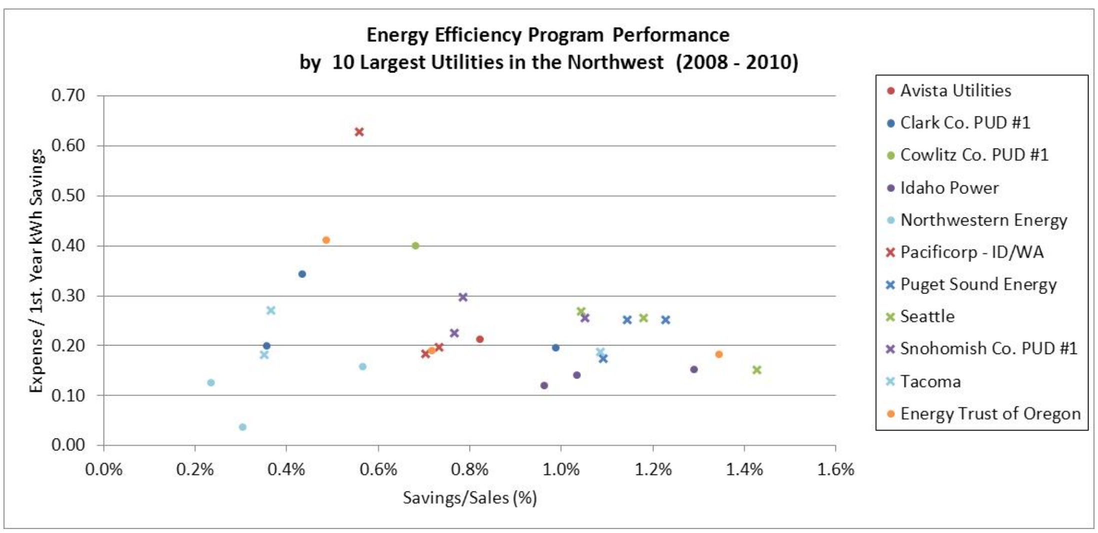

Figure 3: Energy Efficiency Program Performance by 10 Largest Utilities in the Northwest (2008-2010).

[7] Savings data obtained from the Northwest Energy Conservation and Power Council, available at http://www.nwcouncil.org/energy/rtf/consreport/2010/; energy sales data obtained from U.S. EIA 861 form data for 2008 and 2009. Because 2010 utility sales data are not available from EIA, we used 2008 sales data as a proxy for 20010 since 2009 sales are not normal due to the economic recession.

B. Energy efficiency program ramp ups appear significantly conservative

As provided in Figure 1 and Figure 2 above, energy savings ramp rates assumed in the IRP are very slow. For example, the IRP assumed about a 15 year ramp up period to reach 1.5% annual incremental energy savings for Wyoming, and a 15 year ramp up to reach its maximum 0.7% annual savings for Idaho. The IRP further assumed significant drops in savings for Utah (for Rocky Mountain Power) from about 1.25% to 0.5% in 2014, and for Washington from 1.4% to 0.9% in 2013. Although the IRP expected the energy savings for Washington to increase again in later years, the assumed savings for Idaho were almost flat at a low level (0.6%) throughout the study period. In our view, these assumptions were overly conservative. PacifiCorp could reasonably obtain a faster ramp-up, and the company should plan to allocate more resources to EE programs in early years to support the ramp-up.

PacifiCorp provided the following comments regarding the energy efficiency savings ramp rates:

> In the updated DSM Potential Study, the technical achievable potential for each measure by state is assigned a ramp rate that reflects the relative state of technology and state programs. New technologies and states with newer programs were assumed to take more time to ramp up than states and technologies with more extensive track records.[8]
>
> The ramp rates are not limiting overall acquisition, just realistically constraining amounts for the year in which it is available. [9]

PacifiCorp also stated that the application of ramp rates in the potential study (and thus the IRP) was consistent with the 6th Power Plan and referred to the following statement from the Plan:

> The second constraint is annual deployment, which represents the upper limit of annual conservation resource development based on implementation capacity. Such constraints include the relative ease of difficulty of market penetration, regional experience with the measures, likely implementation strategies, and market delivery channels,

[8] page 142 of the 2011 IRP
[9] Page 9 in "LC 52 - PacifiCorp's Response to Comments and Supplemental Coal Replacement Study" submitted on September 21, 2011.

> availability of qualified installers and equipment, the number of units that must be addressed…[10]

While Sierra Club somewhat agrees with these comments in concept, we disagree with the actual ramp rates modeled in the IRP. Experience shows that states with newer programs, including that of Rocky Mountain Power (PacifiCorp subsidiary), proved that EE programs can be ramped and sustained at rates faster than assumed in the PacifiCorp IRP (Figure 4 below). Rocky Mountain Power was a newcomer back in 2001, but it steadily increased its annual energy savings to 1.1% of sales in about eight years. Another new comer, Arizona Public Service, increased energy savings to a 1.25% level in six years and expects to save even more (1.75%) in 2012.

Efficient Vermont was established in 2000, and the program increased annual savings to a 1% savings level in just four years and maintained it for four years. After the budget cap was removed in 2005, Efficiency Vermont was able to increase its budget and accordingly increased energy savings significantly to even above a 2% level.[11] This quick ramp up may in part be attributable to the fact that the State of Vermont had an extensive track record in efficiency programs from before 2000. Nevertheless, it's useful to show that even such a state like Vermont, which has tapped into significant amounts of efficiency potential in the past, can reach higher levels with increased budget.

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[10] Chapter 4 of the 6th Power Plan, pp. 4-15.

[11] DSIRE website, available at http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=VT08R&re=1&ee=1

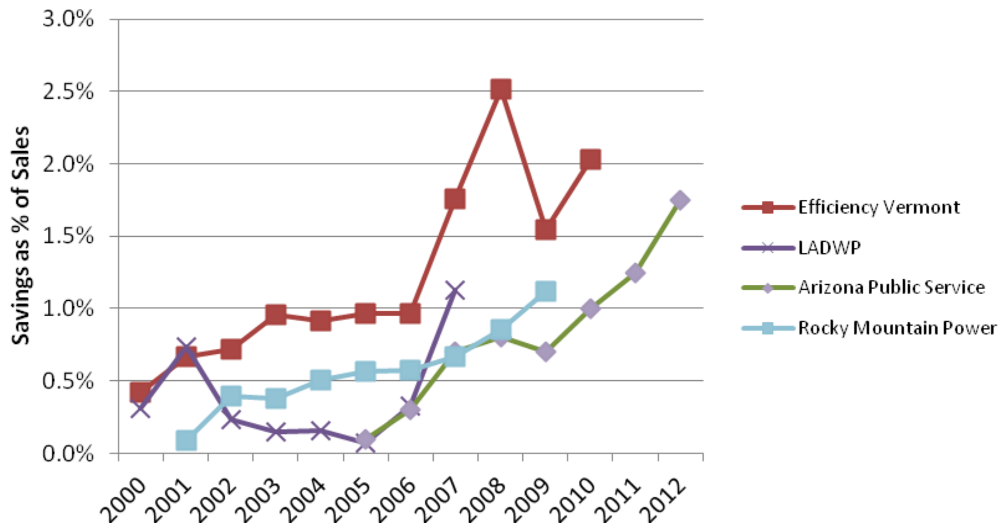

Figure 4: A Comparison of Energy Efficiency Program Ramp Rates (% of Sales)[12]

C. The IRP likely overestimated the cost of energy efficiency

The IRP provided the levelized cost of energy efficiency for a number of cost bundles of different resources to be used in its resource modeling. However, it did not provide total available resources along with those efficiency costs, nor did it provide the levelized cost for selected resources by scenario and state or energy load zone. In addition, while the IRP provided present value revenue requirements (PVRR) by a number of scenarios, it did not provide sufficient data to estimate overall cost of efficiency per kWh savings in each of the load zones or states.

Because Sierra Club cannot calculate the overall cost of energy efficiency for each scenario, we cannot properly assess these scenarios from the perspective of DSM savings. However, cost of energy efficiency used in the IRP and the 2010 DSM potential study appeared questionable. PacifiCorp used cost and resource estimates provided by the 2011 DSM potential study by Cadmus for all states except Oregon. For Oregon, PacifiCorp used energy efficiency potential and cost estimates provided by the Energy

[12] LADWP 2007. "FY07-09 Energy Efficiency Work Program" June 13, 2007, (CEC Presentation on Energy Efficiency Funding Mechanisms); Geller, Bumgarner, and Dent 2010. The Utah Story: Rapid Growth of Utility Demand-Side Management Programs in the Intermountain West; Wontor 2010. "Arizona Public Service DSM Update Presented to SWEEP Workshop" November 8, 2010; Efficiency Vermont annual reports, available at http://www.efficiencyvermont.com/about_us/information_reports/annual_reports.aspx

Trust of Oregon.[13] The efficiency cost bundles for Oregon included only three bundles and ranged from $47 to $59 per MWh, while the cost of the efficiency cost bundles for other regions included ten bundles and ranged from about $15 to over $900 per MWh, with six of the bundles costing over $100 per MWh (see Figure 5 below). It is unclear why the two studies had such a significant discrepancy, but the data suggested that PacifiCorp had not examined all cost-effective energy efficiency resources available in non-Oregon states.

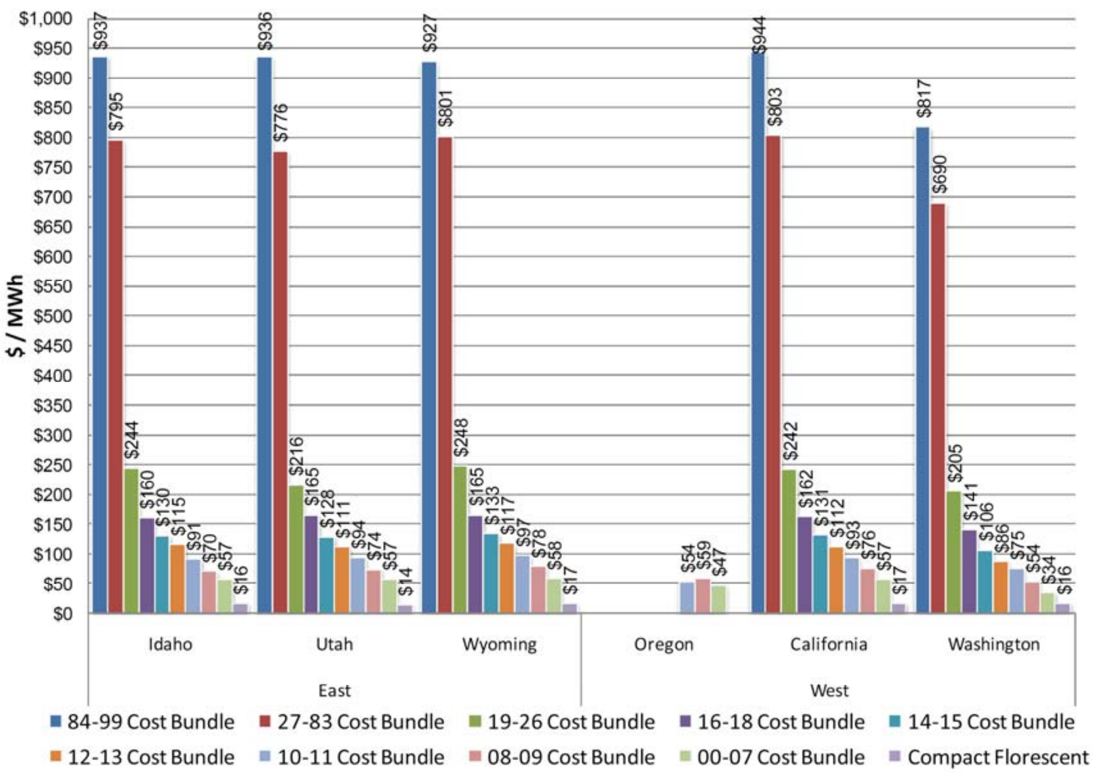

Figure 5: Class 2 DSM Cost Bundles and Bundle Prices in PacifiCorp states

Admittedly, the Cadmus study for the non-Oregon states was both more recent and apparently specific to the PacifiCorp service territory compared to the Energy Trust of Oregon results. Nonetheless, simply having a more targeted story does not suggest that these cost estimates are more realistic assumptions. On the contrary, evidence suggests the opposite: the cost assumptions for Oregon are more likely correct. Generally, the Energy Trust of Oregon has a long history of running its efficiency

[13] Page 148

program. The cost assumptions made by Energy Trust of Oregon were likely based on their experience to date, and the costs were not as expensive as those in other states included in the IRP. Similarly, experience across numerous states indicates that the per unit cost of energy efficiency ($/kWh) to reach a 2% of sales level remains low (less than six cents per kWh [$60/MWh], and often much less).[14]

D. The energy efficiency potential estimate used for the 2011 IPR was conservative

The energy efficiency potential identified by the 2011 potential study was lower than the potential identified by the 2010 Sixth Northwest Conservation and Electric Power Plan (6th Plan). The 6th Plan identified 5,900 average megawatts (approximately 52 GWh) of cost-effective energy efficiency, or about 23% of the projected load by 2030.[15] In contrast, the 2011 DSM potential study found efficiency potential for PacifiCorp equal to 16% of the projected load by 2030.[16]

The comments submitted by PacifiCorp in response to stakeholder comments on September 21, 2011 explained some of the reasons for the lower savings using an example of Washington State.[17] Some explanations were understandable, such as PacifiCorp's specific situations about the industrial customer potential. However, the comments did not provide sufficient data to demonstrate exactly how the overall potential by sector was so different from that identified by the 6th Plan for Washington, nor did the company provide any data for the other states in terms of the difference in costs and efficiency potential.

We examined the original data in the 2011 DSM potential study and compared them with the 6th Plan, existing efficiency programs, and efficiency measures available in the market. For its energy efficiency analysis based on the 2011 DSM potential study, PacifiCorp's IRP used outdated or overly conservative data regarding costs and savings of some efficiency measures.

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[14] For example, see Synapse Energy Economics 2008. Cost and Benefits of Electric Utility Energy Efficiency in Massachusetts, available at http://www.synapse-energy.com/Downloads/SynapseReport.2008-08.0.MA-Electric-Utility-Energy-Efficiency.08-075.pdf.

[15] NWPCC. 2010 Sixth Northwest Conservation and Electric Power Plan (6th plan), chapter 10.

[16] Cadmus Group 2011. Assessment of Long-Term, System-Wide Potential for Demand-Side and Other Supplemental Resources, page ES-6

[17] "LC 52 - PacifiCorp's Response to Comments and Supplemental Coal Replacement Study" submitted on September 21, 2011.

For example, we can examine PacifiCorp's assumptions about the availability and efficacy of ductless heat pumps, a fairly large fraction of savings available to residential and commercial consumers. The performance of ductless heat pump in the 2011 DSM potential was SEER 13 and HSPF 7.7. This level of performance was significantly lower than the actual performance of most of ductless heat pumps available in the market sold as efficient systems, and was in fact the lowest level of the currently available products.[18] The best performance achieved by some of the current products was SEER 26 and HSPF 12. Per unit energy savings assumed in the IRP for this technology were also overly conservative. The 2011 Cadmus DSM potentials study assumed 1442 kWh savings for a single family in Washington for heating and cooling, [19] which was far lower than savings found by other studies (from 3,500 kWh to 4,800 kWh).[20] The implication of this error in the 2011 DSM Potential Study and PacifiCorp's 2011 IRP starts to add up to real numbers quite quickly: of the approximately 6,000 households that were assumed in the DSM Potential Study to install ductless heat pumps by 2030, the missing savings using higher savings level for this entire population would be about 15,500 MWh in Washington.[21]

In addition, the IRP included the potential associated with standard or spiral CFL only for 2011 to 2012, despite the fact that there is still significant potential available from this type of CFL even after the Federal lighting standard under the EISA takes effects. One conference report analyzing the impact of the lighting standard concluded the following:

> [V]arious stakeholders and regulatory bodies have misinterpreted what EISA will actually require. For example, passage of the law does not mean that the lighting market will automatically be "transformed" when the standards begin to go into effect in 2012, since the standards are only fully phased in by 2020. Furthermore, EISA does not ban incandescent bulbs or

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[18] AHIR directory of certified product performance. Mini-split heat pump data are available at http://www.ahridirectory.org/ahridirectory/pages/vsmshp/defaultSearch.aspx

[19] 1417 kWh for heating and 25 kWh for cooling

[20] *See,* goingductless.com website: 3,500 kWh annual savings; NWPCC' 6th plan assumes 3783 kWh to 4865 kWh for a system for a single family http://www.nwcouncil.org/energy/powerplan/6/supplycurves/default.htm; Ecotope, Inc. and Bonneville Power Administration. http://eec.ucdavis.edu/ACEEE/2010/data/papers/1949.pdf

[21] The DSM Potential Study shows an 8,449 MWh potential in 2030 from the mini-split heat pump as a single family retrofit measure. This suggests that a total of (4000 kWh – 1400 kWh) times 6000 households.

require compact florescent bulbs to be used. Rather, between 2012 and 2014, the EISA standard phases in a requirement that bulbs use 20-30% less power. In 2020 the law requires roughly CFL-level efficiency (but not the use of CFLs specifically). Between 2012 and 2020 CFLs (which are 75%-80% more efficient than the main stream incandescent bulbs) will continue to provide low-cost and above-code savings.[22]

Overall, we concluded that PacifiCorp underestimated the savings potentials from EE, estimated a higher cost of EE than other parties, used a slower than expected ramp rate for EE programs, and provided otherwise inadequate information to suggest that the company did not consider this low cost, low emissions resource as a serious option, except when compelled.

IV. Conclusion

For nearly a year, Sierra Club and other stakeholders have asked PacifiCorp to disclose basic information that might explain the costs and risks associated with its assumptions that making expensive pollution control investments on every unit, no matter how old and decrepit, is in the best interest of ratepayers. This Commission recently made similar requests of the company, largely to no avail. We requests that the Commission not acknowledge PacifiCorp's 2011 IRP until these basic informational requirements are fulfilled. In furtherance of that goal, Sierra Club requests that the Commission direct the company to immediately hold technical workshops with staff and stakeholders in order to satisfactorily complete the coal utilization study.

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[22] Ettenson and Long 2010. Market Transformation and Resource Acquisition: Challenges and Opportunities in California's Residential Efficiency Lighting Programs. Proceedings of 2010 ACEEE Summer Study on Energy Efficiency in Buildings

Dated: November 3, 2011

Respectfully submitted,

__/s/___________________________
Gloria D. Smith
Senior Staff Attorney
Sierra Club
85 Second St., 2nd Fl.
San Francisco, CA 94105
(415) 977-5532
gloria.smith@sierraclub.org

Attachment 1: High Energy Efficiency Savings by Leading Utilities and States (outside of Northwest)

Jurisdiction or Entity	Annual Savings (%)	Year(s)	Source
Interstate Power & Light (IPL) (MN)	3.0	2001	Garvey, E. 2007. "Minnesota's Demand Efficiency Program."
Vermont	2.6	2008	ACEEE 2010 State Scorecard
San Diego Gas & Electric (SDG&E) (CA)	2.1	2005	SDG&E 2006. Energy Efficiency Programs Annual Summary
Hawaii utilities	2.0	2008	ACEEE 2010 State Scorecard
Minnesota Power	1.9	2005	Garvey, E. 2007
Sacramento Municipal Utility District (SMUD) (CA)	1.9	1994	Data provided by SMUD
Southern California Edison (SCE)	1.7	2005	SCE 2006. Energy Efficiency Annual Report
Western Mass. Electric Co. (MA)	1.6	1991	MA Dept. of Telecommunications & Energy (DTE) 2003. Electric Utility Energy Efficiency Database
Pacific Gas & Electric (PG&E) (CA)	1.5	2005	PG&E 2006. Energy Efficiency Programs Annual Summary
Massachusetts Electric Co.	1.3	2005	MECo 2006. 2005 Energy Efficiency Annual Report Revisions
Connecticut IOUs	1.3	2006	CT Energy Conservation Management Board (ECMB). 2007
Nevada utilities	1.3	2009	ACEEE 2009 State Scorecard

Attachment 2: Assessment of all available cost effective electric and gas savings

State Energy Efficiency Resource Standards Activity				
State	**Date Established**	**Goal**	**Target End Date**	**Implied Annual % savings (% of total forecast load)**
Texas	2007	20% of load growth	2010	0.50%
Vermont	2008	2.0% per year (contract goals)	2011	2.00%
California	2004	EE is first resource to meet future electric needs	2013	2.0% +
Hawaii	2004	.4% - .6% per year	2020	0.50%
Pennsylvania	2008	3.0% of 2009-2010 load	2013	0.60%
Connecticut	2007	All Achievable Cost Effective	2018	2.0% +
Nevada	2005	0.6% of 2006 annually4	n/a	0.60%
Washington	2006	All Achievable Cost Effective	2025	2.0% +
Colorado	2007	1.0% per year	2020	1.00%
Minnesota (elec & gas)	2007	1.5% per year	2010	1.50%
Virginia	2007	10% of 2006 load	2022	2.20%
Illinois	2007	2.0% per year	2015	2.00%
North Carolina	2007	5% of load	2018	0.40%
New York (electric)	2008	10.5% of 2015 load	2015	1.50%
New York (gas)	2009	15% of 2020 load	2020	1.50%
New Mexico	2009	All achievable cost-effective, minimum 10% of 2005 load	2020	1.0% +
Maryland	2008	15% of 2007 per capita load	2015	3.30%
Ohio	2008	2.0% per year	2019	2.00%
Michigan (electric)	2008	1.0% per year	2012	1.00%
Michigan (gas)	2008	0.75% per year	2012	0.80%
Iowa (electric)	2009	1.5% per year	2010	1.50%
Iowa (gas)	2009	0.85% per year	2013	0.30%
Massachusetts	2008	All Achievable Cost Effective		2.0% +
New Jersey (elec & gas)	2008	20% of 2020 load	2020	≤2.0%
Rhode Island	2008	All Achievable Cost Effective		2.0% +

Source: Massachusetts Energy Efficiency Advisory Council. 2009. Assessment of All Available Cost-Effective Electric and Gas Savings: Energy Efficiency and CHP," July 9, 2009.

CERTIFICATE OF SERVICE

I hereby certify that on this 3rd day of November, 2011, I caused to be served the foregoing SIERRA CLUB REPLY COMMENTS on all party representatives on the official service list for this proceeding via electronic mail.

Oregon Department Of Energy
Vijay A Satyal, Senior Policy Analyst
Rebecca Sherman, Senior Policy Analyst
625 Marion St. NE
Salem, OR 97301
vijay.a.satyal@state.or.us
rebecca.sherman@state.or.us

Citizens' Utility Board Of Oregon
Gordon Feighner, Energy Analyst
Robert Jenks, Executive Director
G. Catriona Mccracken, Legal Counsel/Staff Atty
610 SW Broadway, Ste. 400
Portland, OR 97205
gordon@oregoncub.org
bob@oregoncub.org
catriona@oregoncub.org

Community Action Partnership Of Oregon
Jess Kincaid, Energy Partnership Coordinator
PO Box 7964
Salem, OR 97301
jess@caporegon.org

Davison Van Cleve
Irion A Sanger, Associate Attorney
333 SW Taylor, Ste. 400
Portland, OR 97204
mail@dvclaw.com

Department Of Justice
Janet L Prewitt, Assistant Attorney General
Natural Resources Section
1162 Court St. NE
Salem, OR 97301-4096
janet.prewitt@doj.state.or.us

Esler Stephens & Buckley
John W Stephens
888 SW Fifth Ave., Ste. 700
Portland, OR 97204-2021
stephens@eslerstephens.com
mec@eslerstephens.com

NW Energy Coalition
Wendy Gerlitz, Senior Policy Associate
1205 SE Flavel
Portland, OR 97202
wendy@nwenergy.org

NW Energy Coalition
Fred Heutte, Senior Policy Associate
PO Box 40308
Portland, OR 97240-0308
fred@nwenergy.org

Pacific Power
Mary Wiencke
825 NE Multnomah St., Ste. 1800
Portland, OR 97232-2149
mary.wiencke@pacificorp.com

PacifiCorp Energy
Pete Warnken, Manager, Irp
825 NE Multnomah St., Ste. 600
Portland, OR 97232
irp@pacificorp.com

PacifiCorp, d/b/a Pacific Power
Oregon Dockets
825 NE Multnomah St., Ste. 2000
Portland, OR 97232
oregondockets@pacificorp.com

Portland General Electric
Randy Dahlgren
121 SW Salmon St., 1WTC0702
Portland, OR 97204
pge.opuc.filings@pgn.com

Portland General Electric
Brian Kuehne
121 SW Salmon St., 3WTC BR06
Portland, OR 97204
brian.kuehne@pgn.com

Portland General Electric
V. Denise Saunders
121 SW Salmon St., 1WTC1301
Portland, OR 97204
denise.saunders@pgn.com

Public Utility Commission
Erik Colville
PO Box 2148
Salem, OR 97308-2148
erik.colville@state.or.us

PUC Staff--Department Of Justice
Jason W. Jones
Business Activities Section
1162 Court St. NE
Salem, OR 97301-4096
jason.w.jones@state.or.us

Regulatory & Cogeneration Services Inc.
Donald W. Schoenbeck
900 Washington St., Ste. 780
Vancouver, WA 98660-3455
dws@r-c-s-inc.com

Renewable Northwest Project
Megan Walseth Decker
Jimmy Lindsay
917 SW Oak St., Ste. 303
Portland, OR 97205
megan@rnp.org
jimmy@rnp.org

Dated this 3rd day of November, 2011 at San Francisco, CA.

/s/
Jeff Speir
Program Assistant
Sierra Club
85 Second St., 2nd Fl.
San Francisco, CA 94105
(415) 977-5595
jeff.speir@sierraclub.org