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October 12, 2007

VIA ELECTRONIC FILING
& OVERNIGHT DELIVERY

Oregon Public Utility Commission
550 Capitol Street NE, Suite 215
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Attention: Vikie Bailey-Goggins, Administrator
Regulatory and Technical Support

RE: LC 42- In the Matter of PACIFICORP, dba PACIFIC POWER & LIGHT COMPANY Application for Acknowledgement of its 2007 Integrated Resource Plan., **Response to Oregon Party Comments on PacifiCorp's 2007 IRP**

PacifiCorp (d.b.a. Pacific Power & Light Company) hereby submits for electronic filing an original and one (1) copy of its Response to Oregon Party Comments on PacifiCorp's 2007 IRP for Oregon Public Utility Commission Docket No. LC 42.

Please direct informal questions with respect to this filing to Joelle Steward at 503-813-5542.

Very truly yours,

Andrea L. Kelly / sl

Andrea L. Kelly
Vice President, Regulation

Enclosures
cc: LC 42 Service List (via email and first class mail)

CERTIFICATE OF SERVICE

I certify that I have cause to be served the foregoing **Response to Oregon Party Comments on PacifiCorp's 2007 Integrated Resource Plan** in OPUC Docket No. LC 42 by electronic mail and first class mail to those parties who have not waived paper service on the attached service list.
DATED this 12th day of October, 2007.

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Response to Oregon Party Comments on PacifiCorp's 2007 Integrated Resource Plan

(Docket No. LC 42)

INTRODUCTION

PacifiCorp (or "Company") filed its 2007 Integrated Resource Plan ("IRP") with the Public Utility Commission of Oregon ("Commission") on May 30, 2007, and requested that the Commission acknowledge the IRP. The Commission's criterion for acknowledgment is that the plan seems reasonable based on information available at the time.[1] In determining whether the plan meets this criterion, the Commission considers whether the utility has sufficiently met the guidelines. As part of the IRP acknowledgment schedule, the Commission invited intervenors to submit comments and acknowledgement recommendations by September 19, 2007.

On September 19, 2007, the following four parties submitted comments and recommendations for the Commission to consider regarding the IRP:

- Oregon Department of Energy (ODOE)
- Northwest Energy Coalition (NWEC)
- Citizens Utility Board of Oregon (CUB)
- Renewable Northwest Project (RNP)

The key premise raised by the parties is that PacifiCorp's preferred portfolio does not represent the best cost / risk portfolio due to the Company's underestimation of both the carbon risks of coal plants and the market potential of competing resources such as renewables and energy efficiency measures. On this basis, the Oregon parties recommend that the Commission not acknowledge the 2007 IRP, or at a minimum, reject new coal plants as potential resources for future acquisition.

In addressing the Oregon parties' comments, PacifiCorp first discusses the parties' issues relating to compliance of the plan with specific Commission IRP guidelines. The Company then responds to individual party comments, which, in the context of the Commission's acknowledgment criterion, should pertain to plan reasonableness given information available to the Company at the time the IRP was prepared.

THE INTEGRATED RESOURCE PLANNING AND ACKNOWLEDGEMENT PROCESS

Prior to addressing the specific comments of the Oregon parties, the Company makes the following observations on the value of the integrated resource planning and acknowledgement processes for PacifiCorp.

[1] See *Investigation Into Integrated Resource Planning*, Docket UM 1056, Order No. 07-002 (January 8, 2007), p. 10.

As indicated above, acknowledgement in Oregon generally means that the Company followed the guidelines set out by the Commission and that the plan is reasonable based on the information known at the time the plan was prepared. While this was once a relatively simple and straightforward exercise, it has become increasingly complex and less straightforward given the uncertain and rapidly changing planning environment and the divergent views of the IRP stakeholders across the Company's various state jurisdictions. For example, during the 18 months over which the Company developed the 2007 IRP, there were IRP rule changes in Oregon and Washington, an acknowledgement order of the 2004 IRP in Oregon, renewable portfolio standards enacted into law in Washington, emissions performance standards enacted into law in California and Washington, and a baseload request for proposal that was rejected by Oregon and approved by Utah. On May 30, 2007, the day the 2007 IRP was filed, the Company announced its transmission expansion plan to build more than 1,200 miles of new 500-kilovolt transmission lines originating in Wyoming and connecting into Utah, Idaho, Oregon and the desert southwest, with completion targeted in 2014. Shortly after filing the 2007 IRP, Oregon enacted legislation on renewable portfolio standards and new federal legislation was introduced in Congress addressing carbon regulation. This is compounded by significant and rapidly changing load growth in the Company's Wyoming service territory as oil and gas prices have dramatically run up.

The IRP development and acknowledgement processes are not designed to keep pace with this change. The IRP is by design a snapshot in time, and given the pace of change, the Company finds it increasingly difficult to provide the Commission with an IRP that reflects the current regulatory environment. Some of the above-referenced events to which these parties referred occurred after the plan was filed.

Based on the comments received, it is clear that the carefully designed, collaborative IRP process is not accomplishing its intended purpose. Despite this, the Company intends to continue to plan and run its business in a manner that provides customers with low cost electric power in a manner that accounts for risk and is in the public interest. The Company would be interested in opening up discussions with parties to explore alternatives to the IRP process that are relevant to today's planning environment.

COMPLIANCE WITH THE OREGON PUBLIC UTILITY COMMISSION IRP GUIDELINES

The Commission adopted 13 guidelines for integrated resource planning in 2007 in Docket No. UM 1056. In their comments, the Oregon parties only address two subparts of one of the Commission's IRP guidelines: the least cost/least risk portfolio standard (IRP Guideline 1c), and consistent and comparable treatment of all resources (IRP Guideline 1a). No party filed comments indicating the Company did not comply with the remaining subparts of Guideline 1 or the other 12 guidelines.

Guideline 1c: The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers

Under Guideline 1c, a number of the Oregon parties claim that the IRP fails the least cost/least risk standard by virtue of the inclusion of pulverized coal plants in the preferred portfolio. The crux of their argument is that PacifiCorp significantly underestimated the risks of building coal plants. To support their argument, the Oregon parties cite (1) the significant potential CO_2 costs associated with coal plants, (2) the inconsistency of adding new coal fired plants under a scenario of CO_2 caps or emission performance standards, and (3) cost risks associated with rising construction prices, longer lead times, and more contentious and costly permitting processes.

PacifiCorp conducted a balanced risk analysis that accounts for uncertain CO_2 costs as well as other resource risks. PacifiCorp significantly enhanced a risk assessment methodology that was acknowledged by the Commission for use in the 2004 IRP. The Company spent considerable time with public stakeholders over the course of IRP modeling plan development (January through June of 2006) to explain its proposed CO_2 risk analysis framework and modified it based on recommendations by various parties. From this collaborative effort, and given what was known at the time, PacifiCorp proceeded to implement its modeling plan. The resulting portfolio analysis indicated that inclusion of supercritical pulverized coal plants in portfolios was beneficial for reducing overall costs and mitigating risks introduced by other resources, after accounting for a range of potential CO_2 costs.

The Company finds particular fault with the Oregon parties' strategy of criticizing PacifiCorp's attention to complex issues that could not reasonably be addressed in the IRP given schedule, technical/modeling constraints, and the fact that issues were not identified by the Oregon parties early enough in the IRP development process. PacifiCorp cites a number of these instances in the detailed comments below.

A key misconception of the Oregon parties is the belief that PacifiCorp has committed to building pulverized coal plants by virtue of including proxy coal resources in the preferred portfolio. This misconception stems from confusion regarding the role of a "proxy resource" in portfolio evaluation, and the role of the preferred portfolio itself. As mentioned in Chapter 2 of the IRP report, the purpose of a proxy resource is to represent the indicative characteristics of an asset-type resource that *might* be procured.[2] When included in the preferred portfolio, the proxy resource informs action plan development and selection of benchmark resources for competitive procurements. It does <u>not</u> imply that PacifiCorp has decided to procure this specific resource or even this specific technology.

Importantly, the 2007 IRP action plan does not call for procurement of supercritical pulverized coal resources as claimed by a number of the parties, but rather "base load/intermediate load" resources. As evidenced by the eligible resources in the Company's base load Request for Proposals, such resources can be a conventional coal plant, a CCCT, an IGCC, a power purchase agreement, or even a large biomass or geothermal plant. As part of the bid evaluation process, the Company is refreshing its portfolio analysis framework with bid information, updated costs for the benchmark resources, updated market price and load forecasts, and consideration of regulatory developments.

[2] PacifiCorp, *2007 Integrated Resource Plan*, page 14.

PacifiCorp also refers the Oregon parties to the following statement made on page 13 of the IRP report:

> Because the IRP is a road mapping effort, it is not intended as a referendum on specific resource decisions. The preferred portfolio represents a snapshot view of PacifiCorp's long-term resource planning strategy informed by current information. As emphasized in this IRP and prior ones, specific resource acquisition decisions stem from PacifiCorp's competitive procurement process.

Finally, PacifiCorp does not believe that it is prudent from a risk-adjusted, least-cost perspective to rule out new supercritical pulverized coal plants, even if these plants are ultimately judged by the Company and its regulators to be too risky to acquire in the short-term given the uncertainty of the future. Carbon capture technologies, combined with sequestration, may make pulverized coal plants a cost-effective and environmentally acceptable base load resource option in the future. The Commission should also consider the risks of a strategy that relies solely on natural gas, energy efficiency, and renewables to meet new base load requirements as well as the Company's obligation to provide reliable service to customers.

Guideline 1a: All resources must be evaluated on a consistent and comparable basis

For this guideline, a number of the Oregon parties faulted PacifiCorp for using wind as a proxy for all renewables, and failing to quantify an optimal amount of energy efficiency resources (Class 2 DSM programs).

<u>Use of Wind as a Renewable Resource Proxy</u>

PacifiCorp's decision to continue to use wind as a proxy for all renewables in the 2007 IRP stems from three considerations. First, this resource is widely available throughout PacifiCorp's service territory, and is expected to represent the vast majority of renewable resources anticipated to be added to the Company's portfolio. Wind is a mature, cost-effective, and clean technology—attributes that make it an appropriate standard for representing the risk-reduction benefits of renewables.

Second, the use of wind as the proxy renewable resource is consistent with the modeling approach used in the 2004 IRP and is the approach that has been acknowledged by the Commission. Note that the Commission's new IRP guidelines were issued a year after PacifiCorp held public meetings on renewable technology modeling. The use of wind as a proxy resource was discussed at the January 13, 2006 renewables technical workshop, and participants did not oppose the resource proxy approach at that time.

Third, from a practical modeling standpoint, at the time that PacifiCorp was integrating the Capacity Expansion Module (CEM) into its modeling methodology, and resource options were being formulated for alternative future scenario analysis, the Company was concerned about the implications of approaching the software vendor's recommended upper-limit on the number of resources that can be handled. This technical concern, coupled with the reasons given above, supported the continued use of wind as a proxy for renewable resources in the Company's IRP modeling.

It should be noted that this modeling assumption does not limit the Company's action plan to solely acquiring wind resources. The action plan references cost-effective renewable resources, and there is no limitation on technology type. PacifiCorp intends to investigate for future IRP modeling the addition of more renewable technologies as resource options in the CEM.

Treatment of Class 2 DSM Programs

Regarding the treatment of Class 2 DSM programs, the RNP, NWEC, and ODOE state that by failing to determine the optimal amount of this resource (considering its risk reduction benefits), its potential, particularly in the east control area, has been underestimated.

PacifiCorp has repeatedly stated in public meetings and the IRP report that the Class 2 DSM decrement analysis and planned DSM targets (250 MWa for currently budgeted programs plus an additional 200 MWa of new cost-effective programs) represent an interim resource planning strategy to guide the Company until the results of the multi-state DSM potential study could be incorporated into the IRP modeling process. This interim evaluation strategy was necessary because of the lack of adequate Class 2 DSM cost/supply data for modeling purposes. PacifiCorp determined that a thorough review of available program information, combined with the Company's DSM implementation experience, was preferable to resource optimization modeling with unsound and makeshift cost/supply data. The Class 2 DSM targets represent the best planning estimates that could be developed by the Company during the preparation of the 2007 IRP, and are not intended as a substitute for the comprehensive potential study recently completed by the Company.

Concerning the capture of Class 2 DSM's risk reduction benefits, the use of stochastic simulations captures the stochastic risk reduction resulting from fewer spot market purchases and re-optimized operation of current and IRP resources due to the addition of the Class 2 DSM resource in the preferred portfolio. The benefit of resource deferral associated with Class 2 DSM is reflected in the results of the capacity expansion model, since more resources would have been added had the Class 2 DSM not been included in the retail load forecast. Risk reduction attributable to an \$8/ton CO_2 adder is also accounted for in all of the Company's models.

RESPONSES TO SPECIFIC COMMENTS

Accounting for Capital Cost Risks of Coal Plants

The RNP indicates that PacifiCorp is not accounting for recent coal plant capital cost increases in the resource risk analysis. They cite the IRP's lack of an "alternative future" coal plant cost sensitivity study (referring to the list provided on page 125 of the 2007 IRP report) to substantiate their view that PacifiCorp has inadequately considered the potential for higher-than-expected coal plant capital costs.

Contrary to the RNP's claim, PacifiCorp analyzed portfolio construction cost risk as part of its evaluation of the 17 risk analysis portfolios. This analysis, summarized on page 189 of the 2007 IRP report, focuses on *relative* capital cost risk in recognition that construction costs have significantly increased for all resources, not just coal plants. (The main factors driving up coal plant costs—rising commodity and energy prices, labor shortages, and market demand for power generating equipment in the U.S. and abroad—affect every supply-side resource choice.) To capture relative capital cost risk, the Company developed technology-specific cost adjustments from publicly available Federal Government data and applied them to every resource included in the portfolios. In this way, all resources and portfolios were evaluated on a consistent basis as required in the IRP guidelines.[3]

The Company also notes that IRP public meeting participants were given the opportunity to review and provide recommendations on the proposed sensitivity studies listed on page 125 of the IRP report. The RNP did not identify coal plant capital cost uncertainty to target for sensitivity analysis in any of the public meetings devoted to scenario development.

Finally, PacifiCorp points out that resource-specific capital costs can continue to go up or start to trend downward according to developments in technology markets, state/federal resource policies, and other factors. Capital cost volatility is therefore best addressed by PacifiCorp's resource procurement process, which seeks to obtain fresh cost information for project/bid evaluation and to inform future IRP modeling efforts. This point was made in response to the RNP's same concerns regarding capital cost risk levied in their comments on the draft IRP document (See Appendix F, page 148, of the 2007 IRP report). In addition, the Company has included capital cost risk as one of the factors in its evaluation plan for the current baseload RFP.

<u>Accounting for Price Elasticity of Demand under High Carbon Adder Scenarios</u>

The NWEC characterizes the lack of a modeled linkage between high CO_2 costs and price elasticity of demand effects as a substantive flaw of the IRP. PacifiCorp responds with the following observations:

- Such price elasticity analysis is not currently a requirement in the Commission's IRP guidelines or IRP guidelines for any other state. The NWEC and other parties have only recently raised it as a topic for consideration during the Commission's UM 1302 proceeding on CO_2 risk analysis in utility IRPs.
- The NWEC did not raise this perceived flaw as a concern at any of the IRP public meetings that addressed PacifiCorp's modeling plan and assumptions, including (1) the April 20, 2006 meeting that covered CO_2 analysis, (2) the June 7, 2007 meeting that addressed PacifiCorp's plans for scenario and risk analysis, and (3) the load forecasting technical workshops.
- The NWEC alleges that the Company relies on an overly sophisticated modeling system, yet at the same time is advocating another layer of modeling complexity and analysis with no understanding of the technical, process-related, and work load impacts to PacifiCorp.

[3] PacifiCorp considered implementing stochastic modeling of capital costs for the 2007 IRP; however, developing and using a stochastic capital cost model could not be accommodated for this IRP given work load and schedule constraints.

Incorporating demand response impacts of CO_2 costs would require a new load forecast, by state, for each CO_2 cost stream based on an assessment of rate impacts at the customer class level, as well as potential feedback to PacifiCorp's electricity price forecasting model.

Modeling Coal Plant CO_2 Emissions and Related Costs

The NWEC, CUB, and RNP take issue with PacifiCorp's models regarding the dispatch and wholesale CO_2 emissions accounting of coal plants in PacifiCorp's portfolios. They cite the cap-and-trade modeling framework as problematic from the standpoint that "1) either the model is reducing the electricity generated by existing coal plants in order to sell allowances into the market; or 2) the model is selling the electricity from the coal plants into the market under the presumption that someone else will take the burden of those CO_2 emissions."[4]

An explanation of PacifiCorp's emissions modeling framework is in order, since both interpretations are incorrect and the parties need to understand the limitations of electricity market models for the type of detailed emissions analysis that they expect PacifiCorp to have provided.

For the 2007 IRP, neither the Capacity Expansion Module (CEM) nor Planning and Risk (PaR) module were capable of modeling CO_2 emission externality costs other than as a dispatch cost adder (i.e., a CO_2 tax); allowance trading was not supported.[5] However, it should be noted that the system expansion and dispatch of the system is identical under a cap-and-trade mechanism as it is under a CO_2 tax scenario as long as the CO_2 price is the same in both cases. Further, the cap-and-trade assumption has no effect on the portfolio choice and system dispatch even under different caps. These models will decrease generation from existing plants (and in the case of the CEM, add new coal plants) if that is the optimal solution given the resources and cost assumptions used. This model behavior is consistent with that of other models, such as the AURORAxmp® system used by Portland General Electric and Avista Corporation.[6]

PacifiCorp's IRP models also do not have the capability for tracking the CO_2 emissions associated with nonfirm economy imports or exports.[7] Consequently, no "carbon-laundering scheme" is being perpetrated by the models as suggested by the parties, and the assignment of emissions to specific wholesale parties has no relevancy with respect to the models' capacity addition/dispatch solutions. (The alternative electricity market models investigated by the Company for IRP application do not have this capability either.) Nevertheless, PacifiCorp attempted to enhance CO_2 emissions reporting by including an estimate of the footprint of

[4] "Opening Comments of the Citizens' Utility Board of Oregon," September 19, 2007, page 4.
[5] PacifiCorp acquired a new add-on component of the Capacity Expansion Module in July 2007 that accommodates multiple emission compliance strategies, including emission limits (hard caps) and various cap-and-trade strategies. This component was not available for the 2007 IRP. PacifiCorp is also investigating with the model vendor various customizations to the CEM to handle load-based regulatory schemes as well as the assignment of emission rates to short-term market transactions.
[6] Portland General Electric adopted the AURORAxmp model for their 2007 IRP; Avista has been using this product since 2002.
[7] CO_2 adder costs are, however, factored into the wholesale market prices as described on page 133 of the IRP report.

generation used to serve retail load. This reporting, made as an offline set of calculations, necessarily entailed applying system emission factors to aggregated wholesale purchases and sales. The NWEC has taken this reporting mechanism out of context by implying that the mechanism underlies a model-driven carbon-laundering scheme. Rather than continuing to report such information, PacifiCorp intends to wait until the IRP models are capable of internally accounting for emissions from market purchases and sales to avoid this misinterpretation of results.

Regarding the modeling of a CO_2 cap-and-trade strategy, PacifiCorp reported the cost impact of a trading strategy for the last two IRPs, and is the only utility in the region to have done so. The approach used the PaR emission quantity outputs and a spreadsheet tool that tracked the value of CO_2 allowances acquired or sold based on emissions output relative to a constant year-to-year cap. PacifiCorp notes that this same modeling strategy was accepted by all the state Commissions for the 2004 IRP, and that it has just recently undergone scrutiny by the Oregon parties as debate over implementation details for various CO_2 regulatory proposals has intensified.

For the 2007 IRP, PacifiCorp modeled both tax and CO_2 cap-and-trade strategies—the latter as an adjunct to stochastic production simulations of each portfolio. The Company acknowledges that the modeling of allowance trading uses simplifying assumptions and a cap that is higher than what has been contained in some recent regulatory proposals. However, the tax view is the functional equivalent of no cap at all. Consequently, this analysis is a way to reasonably specify a lower-end cost outcome from CO_2 regulatory design, with a CO_2 tax specified for the upper-end.

In summary, PacifiCorp's CO_2 modeling, while constrained by the capabilities of the models it employs, is reasonable. The NWEC and CUB perceive fatal model flaws throughout the IRP and advocate that PacifiCorp correct these perceived flaws and effectively redo its IRP. This recommendation ignores the fact that the current generation of electricity market and capacity expansion models does not have the functionality to account for the many regulatory nuances being debated, particularly in relation to protocols for CO_2 emission flow accounting. It is a large undertaking to add this functionality, and requires significant structural model changes to accommodate a detailed CO_2 regulatory layer. To expect PacifiCorp or any other utility to have instituted these complicated capabilities as of a year ago without suitable modeling technologies and well-defined regulatory rules is unrealistic. Nevertheless, the Company has applied its state-of-the-art models to represent the effect of a CO_2 tax to the best of its ability, and has taken into account model limitations appropriately when evaluating relative portfolio performance.

Considering Interactive Effects of RPS Policies and CO_2 Regulation with Wholesale Prices

The RNP states that PacifiCorp's IRP does not adequately consider interactive effects of renewable portfolio standards and CO_2 regulation on wholesale electricity prices, and therefore overestimates the wholesale value of electricity generated at pulverized coal plants. The potential of renewables to depress wholesale prices is cited, as well as the impacts of CO_2 regulations such as emissions performance standards and cap-and-trade programs.

In addition to the RNP, a number of participants at PacifiCorp's public meetings voiced concerns over the impact of resource type and emission control regulations on market dynamics, and specifically on the market value of coal-based generation. PacifiCorp pointed out above that current electricity market models do not enable tracking of CO_2 emissions to market transactions. More importantly, tracking the generation and associated CO_2 emissions of a particular coal plant to the market is infeasible, so it is not possible to measure changes in wholesale value related to its CO_2 liability. Even if there were, such analysis would also involve making detailed assumptions on how an undefined market infrastructure would work that allows for the assignment of specific resources to individual wholesale sales, and to properly implement them in a market model that can accommodate them.

Modeling Conventional Coal Plants' Economic Lives For Higher Carbon Adder Scenarios

The NWEC and RNP cite the lack of risk analysis surrounding the possibility of early coal plant retirements. For example, the NWEC makes the following statement in reference to the treatment of coal plants for meeting aggressive carbon reduction targets:

> If higher carbon adders are adopted, it will be in order to meet the longer term carbon-reduction targets adopted by Oregon, California and Washington (and needed to attempt to head off climate catastrophe, according to most scientists.) Under those circumstances, conventional coal plants will either need to be shut down or, if possible, retro-fitted with expensive carbon capture and sequestration technology. This fact was not incorporated into the IRP modeling.[8]

PacifiCorp acknowledges that coal plant retrofits and retirements were not modeled for the 2007 IRP. In the case of plant retrofits, the CEM did not have the capability to model them a year ago; however, the latest version of the software installed in July 2007 has this capability, and the Company intends to investigate this resource option for the next IRP. PacifiCorp notes that retrofits and retirements are longer-term resource options that do not materially impact resource decisions over the next five to seven years, which is the focus of the IRP action plan.

Developing Portfolios from the Initial "CAF" Runs

The NWEC makes a number of arguments for why the CEM alternative future scenario ("CAF") studies are biased toward low-carbon adder futures: (1) the CAF studies were arbitrarily determined with no probabilities, (2) there is no logical consistency among the factors in each CAF scenario, (3) the \$61/ton CO_2 cost adder was not used, and (4) the CEM employs a carbon-laundering scheme.

Given that PacifiCorp relied heavily on feedback from IRP meeting participants to craft the CAF studies, it is puzzling as to why the NWEC did not recommend a different set of alternative future scenarios if there was so much dissatisfaction. To better understand how the CAF studies

[8] "Comments of the NW Energy Coalition," pp. 2-3.

were derived with public input, some background on CAF study development should be helpful for clarification purposes.

After presenting an initial CAF scenario structure to meeting participants, PacifiCorp proposed an alternate version based on IRP participant feedback. This alternate scenario structure allowed more straightforward comparisons among the different variable values, and was symmetrical with respect to high and low values across the scenarios. A number of scenarios where variable values were logically inconsistent were modified appropriately based on participant suggestions. The CO_2 adders selected were also open to deliberation, and a consensus was reached on using the $38 per ton value as the high case (refer to page 121 of the 2007 IRP report).[9]

Regarding the NWEC's comments on probabilities and carbon laundering, PacifiCorp deliberately avoided probability assignment due to the difficulty in developing them and the controversy and criticism that would ensue after assigning them. As noted in Order No. 07-002, the Commission, in its discussion on IRP Guideline 8, "Environmental Costs," agreed with Staff's opinion that probability weightings should not be assigned to various CO_2 adders because there is no good basis for assigning them.[10] By implication, this extends to scenarios defined with various CO_2 adder levels, such as the alternative future scenarios. As described above, the CEM expresses CO_2 costs as a dispatch cost with emissions neither ascribed to wholesale purchases nor sales.

Consideration of an Integrated Gasification Combined Cycle Plant with CO_2 Sequestration Under a High CO_2 Adder scenario

The NWEC comments that PacifiCorp did not include an IGCC plant with carbon sequestration as a resource option under the high ($61/ton) CO_2 adder scenarios.

PacifiCorp chose not to model an IGCC plant with CO_2 sequestration as a standard risk analysis portfolio resource option because this technology combination is unsuitable for inclusion in a preferred portfolio at the present time. IGCC is not a proven technology yet; no large scale, utility-size plant has been built, and performance parameters, particularly regarding lower ranked coals and high altitude applications in the Company's east control area, are still unacceptable. For these reasons, PacifiCorp has not been able to obtain price and performance guarantees from any vendors. Sequestration of large quantities of CO_2 in underground formations, although a promising technology, is in the development stage. Costs and commercial availability are highly speculative, and the extensive supporting physical, legal, and regulatory infrastructures needed to support the technology have yet to be developed. PacifiCorp continues to explore IGCC development projects and is participating in a joint development project with the Wyoming Infrastructure Authority for an IGCC facility in Wyoming.

Assumptions Regarding Renewable Portfolio Standard Compliance

[9] Note that the Commission requires PacifiCorp to evaluate CO_2 externality costs with a $40 per ton adder (in 1990 dollars). This evaluation was done using stochastic simulation with the Planning and Risk module.
[10] Oregon Public Utility Commission, Order No. 07-002, page 17.

The CUB, RNP and NWEC take issue with PacifiCorp's treatment of RPS requirements in the IRP. They state that the Company has not adequately planned for renewables requirements, thereby increasing risks to customers in light of a potential widening of RPS scope to include Utah and/or a federal RPS requirement. The CUB also states that the IRP does not meet the standard of least-cost/least-risk for Oregon customers by virtue of its lack of attention to RPS-related cost allocation issues. (NWEC also cited cost allocation as an issue that should have been addressed in the IRP.)

The Company conducted a preliminary analysis on the renewables capacity necessary to satisfy proposed federal RPS targets by Representative Tom Udall (H.R. 3221, Subtitle G) and Senator Jeff Bingaman, in addition to satisfying more stringent state RPS requirements currently in place. The following table shows the annual cumulative renewable capacity requirements for these two RPS scenarios along with the 2,000 MW of renewables included in the IRP action plan. The IRP renewable resource schedule complies with federal RPS scenarios during much of the phase-in period. This affords PacifiCorp an ample window to continuously assess its renewable resource strategy as RPS formulation at the state and federal levels advance, transmission capacity is added, and integration impacts of large quantities of wind and other renewables become better understood. At the same time, the Company is aggressively pursuing project opportunities in recognition of the high demand for wind sites and turbines, and the uncertainty over the longevity of the renewables production tax credit.

	Rep. Udall RPS Scenario (H.R. 3221, Subtitle G)	**Sen. Bingaman RPS Scenario**	**PacifiCorp's IRP Renewable Resources**
	Cumulative Megawatts		
2006	29	29	400
2007	56	56	700
2008	60	60	1,000
2009	64	64	1,100
2010	**657**	**872**	**1,400**
2011	**797**	**960**	**1,600**
2012	**966**	**979**	**1,700**
2013	**1,314**	**1,790**	**2,000**
2014	**1,498**	**1,822**	**2,000**
2015	**2,097**	**2,263**	**2,000**
2016	**2,333**	**2,333**	**2,000**

Regarding the parties' views on RPS-related cost allocation, the Multi-State Process Standing Committee is the proper forum for sorting out the regulatory implications of multiple, complex sets of RPS rules. Expecting the IRP process to handle this task, or to jointly own it along with the MSP participants, is unrealistic.

Capping Renewables

The NWEC states that artificially capping the amount of renewables that the CEM can pick disregards renewables that could become cost-effective under high carbon cost scenarios.

PacifiCorp developed a profile of available wind sites and installed nameplate capacities per site based on available information, including data from wind developers and the Company's RFPs. While there was some subjectivity in developing this profile, the wind resources were not arbitrarily capped as the NWEC suggests. PacifiCorp described the proxy wind resource base at its May 10, 2006 public meeting, and there were no objections to using it as the basis for wind modeling.

PacifiCorp notes that for the greenhouse gas emission performance standard portfolio study documented on pages 213-9 of the IRP report, PacifiCorp allowed the CEM to select up to 3,700 MW of proxy wind resources along with CO2-sequestered IGCC, but no non-sequestered pulverized coal options. The model chose 3,100 MW of wind. This quantity of wind also happens to be the maximum quantity that the model was allowed to select for the alternative future studies conducted earlier in the IRP. Consequently, 3,100 MW appears to be a reasonable upper-bound based on the totality of CEM studies conducted for this IRP.