BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1208

In the Matter of PacifiCorp Draft 2012 Request for Proposals.	STAFF'S REPLY COMMENTS

Pursuant to Judge Grant's memorandum of September 27, 2006, staff submits its reply comments on PacifiCorp's Draft 2012 Request for Proposals for Base Load Resources (Draft 2012 RFP).

Staff stated in opening comments that "the company should rebut to the Commission's satisfaction the concerns staff raises … or modify its draft RFP to address these concerns prior to issuance. Alternatively, the Commission should impose additional conditions and exceptions for RFP approval."[1] Staff also recommended a number of sweeping "minimum" conditions "[i]f the Commission is inclined to approve the RFP, in whole or in part." *See* Staff's opening comments at 1 and 15.

PacifiCorp filed a modified draft 2012 RFP on October 4, 2006, that addresses only some of the concerns staff raised in its opening comments. The company's reply comments filed on the same date either do not address, or do not sufficiently rebut, the remaining concerns raised by staff.

The magnitude of the unresolved issues related to the draft 2012 RFP lead staff to recommend the Commission not approve the draft RFP as filed. Staff addresses these unresolved issues below and the reasons for its recommendation.

First, however, staff addresses (1) procedural issues and (2) modifications in PacifiCorp's October 4, 2006, filing that improve the RFP. Staff also addresses other issues related to the RFP as recently amended. Appendix A consists of PacifiCorp's responses to data requests cited in staff's opening comments; Appendix B consists of PacifiCorp's responses to data requests cited in staff's reply comments.

[1] In addition to the conditional approval related to the Oregon Independent Evaluator's assessment of RFP design.

Procedural Issues

Staff addresses below three assertions in PacifiCorp's reply comments that involve procedural issues: (1) whether the RFP may proceed without the conditional approval of the Oregon Commission; (2) the purpose of the conditional approval process; and (3) issues related to the Revised Protocol. Staff also addresses a fourth procedural issue, the role of the Oregon Independent Evaluator (IE) if the Commission does not approve the company's draft 2012 RFP.

1. PacifiCorp can issue the 2012 RFP without the Commission's approval.

PacifiCorp implies in its reply comments (at 4) that it cannot issue the 2012 RFP without the approval of the Oregon Commission.[2] The Commission's order on competitive bidding (Order No. 06-446) contains no such requirement. Further, unlike Utah, Oregon does not have a resource procurement law requiring Commission approval of the RFP, or the resources themselves, prior to acquisition.

2. The process the Commission adopted for considering conditional approval relates strictly to the involvement of an Oregon IE.

PacifiCorp incorrectly characterizes the purpose of the conditional approval framework staff recommended, and the Commission adopted, as follows: "Staff proposed a conditional approval framework to provide assurances to parties that approval of this RFP does not constitute pre-approval of the resources to be acquired in the RFP." *See* PacifiCorp's reply comments at 10.

Staff explained that the purpose of the conditional approval process is to "allow the Commission to *reconsider* any initial approval of the 2012 RFP following an assessment by an IE … selected by the Oregon Commission." (Emphasis in original.) *See* Staff Report for the September 19, 2006, public meeting at 9.

Further, the conditional approval process adopted by the Commission explicitly reserved all of its options for considering RFP approval at its UM 1208 public meeting on October 26, 2006.[3] Staff explained its recommendation further at the meeting on September 19, 2006:

[2] For example, the company refers to "Oregon delaying or blocking this RFP."

[3] On September 27, 2006, Judge Grant issued a ruling stating that "… the Commission does not expect to render a decision at the October 26th Public Meeting. Rather, the Commission intends to take this case under advisement and render its decision in the form of a written order. The Commission will make every effort to issue an order by the target date of November 2, 2006."

> [S]taff's proposed Commission motion would approve a conditional approval process for PacifiCorp's RFP in order to avoid delay in issuing the RFP due to hiring an Oregon IE and having that evaluator review the RFP design….
>
> [Y]ou would be preserving your full range [of options], on October 26th, of approval. In other words, for example, you could approve the RFP straight up with this one condition that we've laid out today, pending the Oregon evaluator's assessment. You could reject it entirely based on your three RFP approval criteria. You could approve the RFP in part and with any kinds of conditions and exceptions….
>
> You would today if you adopted staff's … proposed motion ... be adopting a process for conditional approval, not considering whether or not you want to approve or would approve the RFP, but the process for that. *Audio at:* http://apps.puc.state.or.us/agenda/audio/2006/091906/091906item6.mp3.

3. The Commission has not deviated from the Multi-State Protocol standards related to resource planning and acquisition.

Contrary to PacifiCorp's reply comments (at 3-4), the Commission is in no way obligated to conditionally approve the 2012 RFP and initiate a concurrent process with the Multi-State Protocol (MSP) Standing Committee. The Commission's acknowledgment order in the 2004 Integrated Resource Planning (IRP) cycle (Order No. 06-029), as well as staff's recommendation in the current proceeding, are entirely consistent with a least-cost, least-risk standard as well as system-wide planning and resource acquisition. Two states that have approved the MSP can easily hold different views on what constitutes the best combination of resources to meet a least-cost, least-risk standard on a system-wide basis.

Unless PacifiCorp finds a better deal from the market through this RFP – or a change in conditions leads PacifiCorp to change its plans, the company will build its Benchmark Resources. In Docket LC 39, staff and other parties raised concerns about the future regulatory costs of carbon dioxide (CO_2) associated with conventional coal plants. Staff raises additional concerns in this proceeding related to sales of excess energy from 24/7 conventional coal resources.

Staff's concerns in this resource acquisition proceeding, however, go beyond fuel (e.g., coal vs. natural gas) and technology type (e.g., traditional vs. advanced coal technology). Staff has fundamental concerns regarding the overall magnitude of resources PacifiCorp is seeking through the 2012 RFP, considering the company's projected load-resource balance on a capacity *and* energy basis as well as planning reserve margin — in particular, the magnitude of *base load* resources. Staff also has raised significant concerns regarding the departure from the company's acknowledged level of short-term market purchases that provide diversity in resource term and flexibility in the company's portfolio, without any evidence that this deviation is appropriate.

4. The Oregon Independent Evaluator's role remains relevant if the Commission does not approve the draft 2012 RFP.

Staff finds the Oregon IE's role remains relevant if the Commission does not approve PacifiCorp's 2012 RFP and the company nevertheless proceeds with the RFP process. If in six to eight years from now PacifiCorp seeks to put into rates the resources it selected through the process, the Commission will be faced with determining whether those resources were prudently acquired. In doing so, the Commission will consider the concerns that led to its rejection of the RFP. The Oregon IE's activities, including assessment of RFP design and a Closing Report, will help inform the Commission's decision.

Further, the Commission's competitive bidding order directs that the IE be involved in any proceeding to consider acknowledgment of a utility's final short-list of resources, prior to negotiations. The order is silent on whether the Commission will grant a utility's request for an acknowledgment proceeding if the Commission declines to approve the RFP. As PacifiCorp notes in its reply comments (at 11), the acknowledgment process addresses consistency with the utility's acknowledged IRP Action Plan. *See* Order No. 06-446 at 14-15.

Improvements to the Initial 2012 RFP Filing

The following RFP amendments reflected in the company's filing on October 4, 2006, will improve the bidding process:

Minimum Term

PacifiCorp amended the RFP to reduce the minimum resource term from 10 years to five years. This change responds in small part to staff's concern that the draft RFP did not sufficiently provide for resource diversity with respect to resource duration. *See* Guideline 9, Order No. 06-446; Staff's opening comments at 12.

However, the change from a 10-year to a five-year minimum term does not address in any way the company's departure from its historic, and Commission-acknowledged, level of short-term market purchases, including such purchases for the East side of the system targeting summertime on-peak hours. Front Office Transactions are for far shorter duration and are not contracted six to eight years in advance. Also, staff is uncertain whether power producers[4] will bid six to eight years out for medium-term power purchase agreements (PPAs).

Modeling of Wind Resources

PacifiCorp amended the RFP in response to comments from staff and the Oregon Department of Energy that the initial filing did not account for the 1,400 MW of wind resources in the company's acknowledged IRP. PacifiCorp now proposes to reserve 1,400 MW for renewable resources in the 2012 RFP evaluation modeling, as staff recommended. Staff notes, however, that the company so far has incorporated in its updated load-resource balances only 1,114 MW of renewable resources in 2015 toward its 1,400 MW commitment. *See* PacifiCorp's response to Staff Data Request No. 48.[5] This should be corrected and reflected in the load-resource balance used for the 2012 RFP.

Previously, the company was planning to include only 400 MW of wind resources in the RFP modeling – the amount the company committed to acquire by 2007 as part of the Mid-American Energy Holdings Company acquisition. At the company's assumed capacity contribution of wind resources during the peak hour — 20 percent[6], PacifiCorp's amendment to include 1,400 MW of wind resources in the bid evaluation modeling effectively reduces the company's peak-hour capacity needs by 200 MW in 2015.[7]

[4] And customers, for the load curtailment exception category.

[5] Dividing the "Renewable" capacity amounts in the load-resource tables by the capacity contribution of 20 percent.

[6] See PacifiCorp's 2004 IRP Technical Appendix, p. 39.

[7] (1,400 MW – 400 MW) * 0.2 capacity contribution during peak hour = 200 MW.

Staff agrees with PacifiCorp that the revised modeling assumption is a step toward the Commission's goal of promoting resource diversity through the competitive bidding process. Further, it is a step toward the company evaluating wind resources on a comparable basis with thermal options without the challenges of conducting a renewable resource RFP for the 2012-2014 timeframe. However, PacifiCorp's 2006 IRP, and additional wind RFPs, may find that levels of wind resources beyond 1,400 MW are appropriate.

Credit and Security

PacifiCorp added a credit matrix to its amended RFP which improves transparency for bidders. As noted in our opening comments (at 15), staff recommends that the Oregon IE explore credit and related issues further with respect to the Commission's third criteria for RFP approval, the overall fairness of the utility's proposed bidding process. Staff includes under "Other Issues" a list of items related to credit and security that the Oregon IE should explore.

Reasons for Rejecting PacifiCorp's Draft 2012 RFP

In our opening comments, we expressed concerns in particular regarding the following:

- Lack of alignment with the company's acknowledged IRP, including the company's unjustified departure from short-term market purchases on the East and West sides of its system
- Magnitude of the identified need, including magnitude of base load resources sought through the RFP
- Inability of bidders to bid an Integrated Gasification Combined-Cycle (IGCC) coal plant into the RFP

Since our initial comments, staff has obtained additional information through discovery and reviewed PacifiCorp's reply comments and its amended draft 2012 RFP, both filed on October 4, 2006. We provide additional comments in these areas below.

PacifiCorp's amended draft 2012 RFP does not meet the Commission's standard for alignment with the acknowledged IRP.

Staff disagrees with PacifiCorp that "The RFP/IRP alignment standard … focuses on whether the *major objectives* of the two processes are in sync, not whether all of the implementation detail matches." Simply being generally "Aligned in Seeking Least Cost, Least Risk Resources for PacifiCorp's Customers" does not meet the Commission's first criteria for RFP approval – alignment of the utility's RFP with its acknowledged IRP. *See* PacifiCorp's Reply Comments at 1 (emphasis added).

While the Commission's order is clear that a utility should not simply march in lock-step with its acknowledged IRP in conducting subsequent RFPs, and staff supported this position in Docket UM 1182, the implementation details matter.

First, a utility must justify any substantive deviation from the IRP – for example, deviating from the 1,200 MW of short-term market purchases in the company's IRP Action Plan acknowledged by the Commission. Second, a utility must justify any continuing assumptions or actions that the Commission has explicitly declined to acknowledge – for example, PacifiCorp's continued use of a 15 percent planning margin based on the single peak hour of the year.

The utility can seek to justify substantive deviations from the acknowledged IRP, or to justify non-acknowledged assumptions and actions, through (1) a new IRP or IRP Action Plan filed for the Commission's acknowledgment or (2) the RFP approval process. If the utility fails to make its case through either forum, the Commission should not approve the RFP.

Elimination of Short-Term Market Purchases

Despite opportunities through additional data requests, PacifiCorp has not provided evidence reasonably supporting the departure from its historic levels of short-term market purchases. In addition to the citations staff provided in opening comments, PacifiCorp confirmed in response to a recent data request that it will not be analyzing in its bid evaluation modeling for the 2012 RFP the trade-offs between short-term and long-term resources.

The company states: "The company will address the trade-offs between Benchmark Resources and *10-year* minimum market bids in its bid evaluation in the 2012 RFP. Market bids that are less than 10 years in duration are not permitted in the 2012 RFP and, therefore, will not be evaluated in the 2012 RFP evaluation process…. The 2006 Integrated Resource Planning analysis will address the trade-offs between long-term resources and short-term market purchases."[8] *See* PacifiCorp's response to Staff Data Request No. 43 (emphasis added).

In fact, for its 2006 IRP modeling, the company recently decided to impose a constraint on its Capacity Expansion Model to limit short-term market purchases to historic levels (700 MW on the East side during summertime on-peak hours and 500 MW on the West side) because the company was concerned that its economic optimization model was selecting very high levels of such transactions when running unconstrained.

The company states in its letter to the Commission accompanying its August 30, 2006, RFP modifications (at 2): "The removal of these planned Front Office transactions on the west and the east has resulted in a system-wide deficit in the [2006] IRP. The 2012 RFP will solicit resources to fill this deficit. The benchmark resources will be a coal plant that can make deliveries into the system by the summer of 2012, and an IGCC benchmark for 2014, and it is assumed that an additional coal plant will replace the assumptions of Front Office transactions." The additional coal plant is the 750 MW 2013 Benchmark Resource at Bridger.

Unless the company hard-wires short-term market purchases in bid evaluation modeling when selecting the initial short-list of bids, staff does not understand how PacifiCorp will otherwise "provide resource diversity (e.g., with respect to … resource duration)." Similarly, staff does not understand how PacifiCorp will select the final short-list of bids "based, in part, on the results of modeling the effect of candidate resources on overall system costs and risks." Staff also does not understand how the company will determine whether there should be "a preference to acquire some types of resources over others" – for example, short-term market purchases targeting the near-term seasonal on-peak need versus base load resource acquisitions providing excess capacity for long-term load growth – "in case the market yields different costs than assumed in the IRP." *See*

[8] The company has since changed the minimum resource term to five years.

Guideline No. 9, Order No. 06-446; PacifiCorp's response to Staff Data Request No. 32.

If, instead, the company planned to continue its historic level of short-term market purchases, a modeling fix similar to the change the company made for wind resources could address staff's concern in this regard. That is, the RFP evaluation modeling could reserve 1,200 MW for short-term market purchases – 500 MW on the West side during all hours, and 700 MW on the East side during third-quarter heavy-load hours. These purchases would reduce the 2012 capacity shortfall, for example, from 1,268 MW to 568 MW.

The company's recent amendment to reduce the minimum term from 10 years to five years does not address in any way the company's departure from its historic, and Commission-acknowledged, level of short-term market purchases. As PacifiCorp explains, short-term market purchases are for far shorter duration, and are not contracted six to eight years in advance:

"Solicitations for Front Office Transactions can be made years, quarters or months in advance. Annual transactions can be available up to as much as three or more years in advance. Seasonal transactions are typically delivered during quarters and can be available from one to three years or more in advance." The company further states that these transactions are "expected to be made on an annual, rolling, forward basis." *See* PacifiCorp's 2004 IRP at 52-53; Technical Appendix at 57.[9]

Staff notes that the historic 700 MW of short-term market purchases on the east side of the company's system are seasonal transactions — specifically, heavy-load hours in the summer months (third quarter). The company's proposal to replace short-term market purchases with base load resources is ill-suited to meet that demand.

Planning Reserve Margin

In opening comments, staff noted that the Commission did not acknowledge the company's planning reserve margin of 15 percent on the single peak hour of the year.[10] *See* staff's opening comments at 6-11. The company has not provided any analysis in this proceeding that acquiring resources on this basis is appropriate. *See* PacifiCorp's response to ICNU Data Request No. 3.4. The 2006 IRP may provide additional analysis that will be useful in this regard, but the company will not file the 2006 IRP until December, and staff and parties have not yet seen the analysis.

[9] Note that citations in staff's opening comments (at 9) to p. 57 of PacifiCorp's 2004 IRP refer to the Technical Appendix. (References to pp. 52-53 refer to the main IRP document.)

[10] The Commission stated, "PacifiCorp's proposed planning reserve margin of 15% is not acknowledged," and "We … find flawed, the analysis the Company used in support of its 15% planning margin." *See* Order No. 06-229 at 22 and 50.

PacifiCorp has not demonstrated that a range of 1,600 MW to 2,900 MW is the appropriate level of resources to acquire.

Perhaps the most basic issue in the Commission's review of an RFP is whether the utility has appropriately defined its resource need, consistent with its acknowledged IRP. That includes the characteristics of the resources the company is seeking – flexible versus base load resources, for example.

PacifiCorp's most recent RFP filing clarifies that the company is seeking a range of base load resources from a minimum of 1,600 MW up to 2,290 MW. PacifiCorp picked the top end of this range by totaling the following Benchmark Resources:

- 600 MW at Hunter (2012)
- 340 MW share of proposed Intermountain Power Plant (IPP) 3 (2012)
- 750 MW at Bridger (2013) to replace historic short-term market purchases
- 600 MW IGCC plant in 2014 (high end of 250 MW to 600 MW range)

= *2,290 MW*

In the prior 2012 RFP filings (July 19 and August 30, 2006), the company identified a range of 335 MW to 935 MW for 2013 for the "Total Resources identified … as a combination of Supply Side resources and Front Office purchases in the 2004 IRP Update." The company qualified this need in Footnote 1 as follows: "If resource quantities in the amount of Hunter and IPP benchmark are acquired in 2012, then the 2013 resources quantities are 335 MW. If resource quantities only in the amount of IPP benchmark are acquired in 2012, then the 2013 resource requirement is 935 MW." *See* 2012 RFP, July 19, 2006, at 2. The company deleted this footnote in its most recent filing. The top end of PacifiCorp's range, 2,290 MW, appears to significantly overshoot the company's previously stated resource need.

Moreover, staff's analysis below shows that the company at most needs capacity resources by 2014 at the lowest end of the range – 1,600 MW.

Capacity Position[11]

PacifiCorp plans to meet the highest forecasted hourly load during each year of its planning horizon. The peak hourly load on the east side of the system is forecast to be 7,549 MW in 2012. Adding the wholesale sales obligation of 595 MW and a 15 percent planning reserve margin, totaling 1,170 MW, results in forecasted east side requirements of 9,314 MW in 2012.

[11] Staff relied on PacifiCorp's responses to Staff Data Request Nos. 42 and 48 in describing the company's capacity and energy positions.

PacifiCorp estimates that its existing resources will be able to provide 8,046 MW in 2012. The overall result is a capacity shortfall of 1,268 MW in 2012. The East side shortfall is 1,451 MW in 2013 and 1,639 MW in 2014.

The accuracy of the forecasted maximum hourly load is an important consideration when planning to meet the highest hourly peak load. One way to gauge the significance of this planning assumption is to consider the number of hours during the year that hourly peak load is forecasted to exceed the load that would result in a balanced position (after the addition of wholesale obligations and the planning reserve margin).

For 2012 through 2014, the company's existing resources would be capable of meeting a *15 percent* planning reserve margin at a maximum hourly load of 6,446 MW. For 2012, PacifiCorp's forecasted hourly peak load exceeds this threshold during 587 hours (6.7 percent) of the year. All of these hours occur during June, July and August.

For 2012 through 2014, the company's existing resources would be capable of meeting a *12 percent* planning reserve margin at a maximum hourly load of 6,613 MW. For 2012, PacifiCorp's forecasted hourly peak load exceeds this threshold during only 442 hours (5.0 percent) of the year. Under this alternative planning assumption, forecasted peak hourly load for 2012 exceeds the company's existing resource capability by 936 MW. PacifiCorp's east-side capacity shortfall is robust under this alternative planning assumption.

Staff finding: PacifiCorp's summertime capacity gap on the east side of its system under the company's assumed planning margin is 1,268 MW in 2012 and grows to 1,639 MW in 2014. Because these gaps are based on a 15 percent planning reserve margin and the single peak hour of the year, staff considers these numbers to be an upper bound on total capacity acquisition targets. As described above, the Commission did not acknowledge the company's 15 percent planning reserve margin. PacifiCorp's 2006 IRP analysis may show that a lower planning margin, such as 12 percent, is appropriate.

PacifiCorp states that a 12 percent planning margin, which is the planning margin level Portland General Electric (PGE) used for its acknowledged IRP,[12] reduces the "identified 2006 IRP total east-side resource needs to 1,048 MW in 2012, 1,410 MW in 2014 and 1,808 MW in 2016, still well within the range covered by the 2012 RFP." *See* PacifiCorp's reply comments at 8.

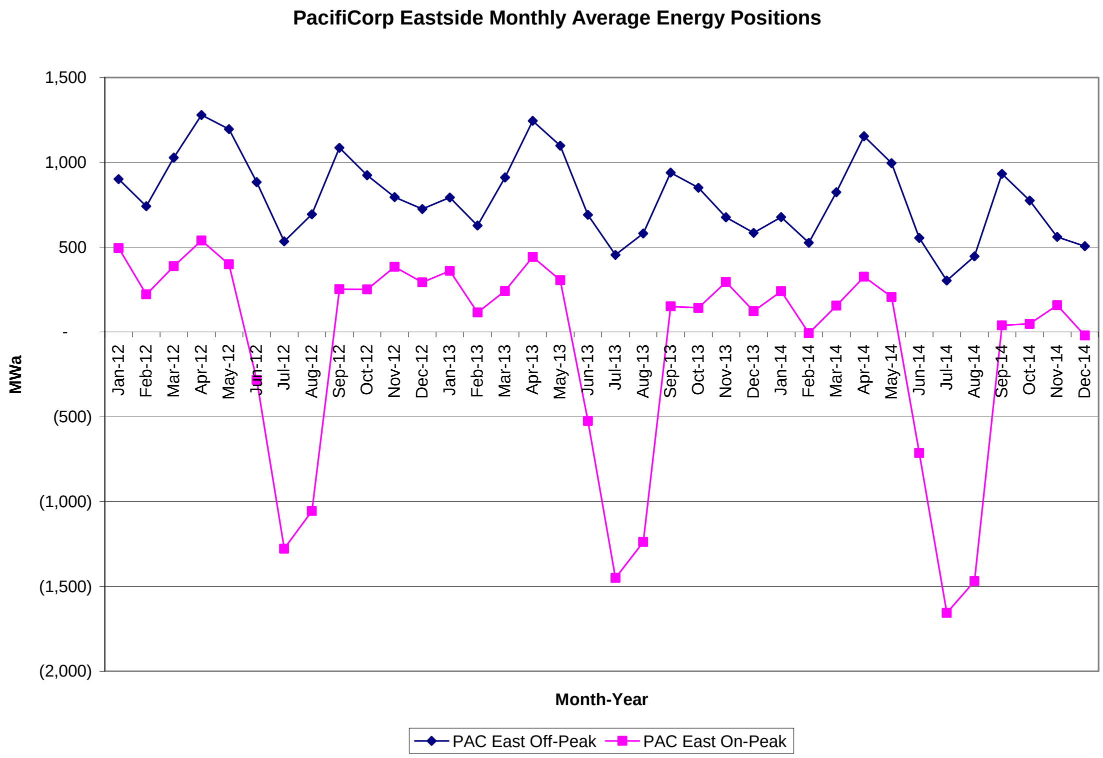
Staff notes that the RFP is seeking resources to come on-line during the 2012-2014 period, not in 2016, 10 years from now. Moreover, the identified 2014

[12] *See* PGE's 2002 IRP Final Action Plan, March 2004, at 16, 34-35, and Order No. 04-375. PGE's 12 percent planning reserve margin consists of 6 percent operating reserves as required by the Western Electricity Coordinating Council and an additional 6 percent planning reserve, all under average hydro conditions.

capacity need under a 12 percent planning margin is *less than the lowest level* of the range of resources the company is seeking to acquire through the 2012 RFP.

Energy Position

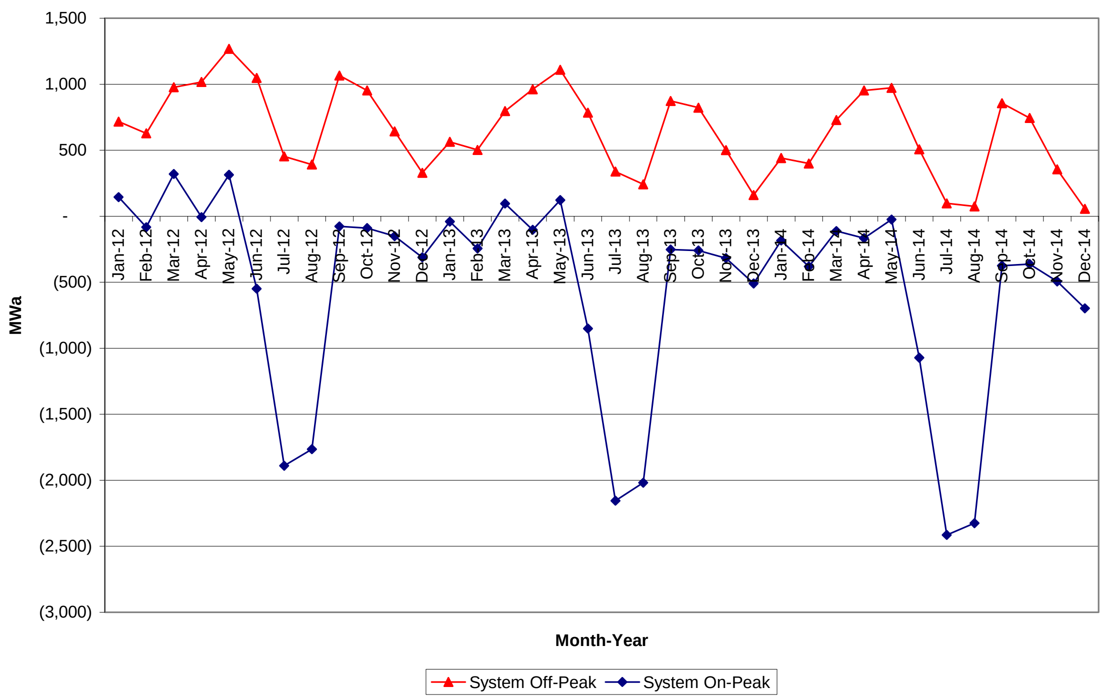
The following chart shows PacifiCorp's *east side* monthly energy position for 2012-2014.



PacifiCorp's energy forecast for the east side of its system shows a long position during all months and delivery periods except during the on-peak hours of June, July and August of 2012-2014.

The following chart shows PacifiCorp's *total system* monthly energy position for 2012-2014.

PacifiCorp System Monthly Average Energy Positions



On a total system basis, PacifiCorp forecasts large energy deficits during the on-peak hours of June, July and August of 2012-2014. Small on-peak deficits during non-summer months begin to appear in 2013. The shape of the system energy position is dominated by the summertime energy gap on the east side of the system.

Staff finding: PacifiCorp's east side energy gap is limited to summertime on-peak hours during 2012-2014. There is no identified energy need for other seasons or delivery periods.

PacifiCorp has not shown that it should meet its resource needs by acquiring base load resources on the east side of its system.

The Draft 2012 RFP defines base load supply-side resources as "any resource with any type of fuel source that provides unit contingent or firm capacity and associated energy that are incremental to the Company's existing capacity and energy resources and are available for dispatch or scheduling by June 1, 2012, June 1, 2013, and/or June 1, 2014." *See* Draft 2012 RFP at 1, as amended on October 4, 2006.

Meeting the company's resource needs through base load resources[13] is inappropriate when considering the seasonal nature of its capacity and energy needs on the east side of its system. Short-term market purchases targeting summertime on-peak hours, natural gas-fired peaking resources, and demand response resources are better than 24/7 base load resources at targeting the summertime on-peak shortfall. It appears to staff that PacifiCorp's definition of base load resources prohibits proposals targeting summertime on-peak hours. Considering the company's load-resource balances and load duration curves, staff does not understand why such proposals would not be encouraged.

In opening comments, staff pointed out serious concerns that seeking base load resources through the 2012 RFP would lead to a large energy surplus. As an example, staff demonstrated that adding just *one* of the three coal plants that comprise the Benchmark Resources for 2012 and 2013 — the 750 MW coal plant in 2013 — would make the company surplus on its east side by more than a thousand average megawatts that year. *See* staff's opening comments at 7.

The company did not address this issue in reply comments or rebut staff's concerns in response to data requests.

Referring to the calculation PacifiCorp uses to determine whether it is resource-deficient for the purpose of determining avoided costs for Qualifying Facilities,[14] the company stated the following:

> The calculation determines at what point the Company needs to add the next base load resource, the proxy plant. This point is defined as when the Company becomes *both energy and capacity deficit* since the proxy plant is intended to represent a baseload resource." *See* PPL/105, Widmer/2, Docket UM 1129 – Phase I Compliance Investigation (emphasis added).

The company emphasizes that the 2012 RFP is for meeting east-side needs. *See* PacifiCorp's reply comments at 4, 6 and 8.[15] The east side of the company's system is energy-deficit only during the summer months. The west side of the company's system is energy-deficit almost year-round. PacifiCorp appears to be arguing that base load resources to serve east-side loads are the appropriate way to meet the west-side energy deficit. If the company is trying to meet west-side energy needs, why is it restricting eligible resources to those that can deliver power to its eastern control area?

[13] Beyond 1,400 MW of wind.

[14] Avoided cost rates are higher when the company is in a resource-deficit position and lower when the company is resource-sufficient.

[15] For example, PacifiCorp states at 4, "Deference to the concerns of other states is especially appropriate with the 2012 RFP because it addresses a resource need for PacifiCorp's east-side states…," and at 8: "The 2012 RFP seeks a range of resources for PacifiCorp's east-side system, between 1,600 MW and 2,290 MW by 2014."

In PacifiCorp's 2004 IRP, the company used a supply-side strategy combining short-term market purchases, flexible natural gas-fired plants with peaking capability, wind resources, and base load resources to meet its projected resource needs. PacifiCorp has inexplicably abandoned this strategy. Because PacifiCorp has failed to justify its change in strategy, and does not intend to revisit this issue as part of its 2012 RFP analysis, staff recommends that the Commission not approve the 2012 RFP.

Over-Building Risk

The company states, "Because PacifiCorp ultimately bears the recovery risks associated with under building or over building resources, its economic interests are fully aligned with customers in assuring the accuracy of its resource need projections." *See* PacifiCorp's reply comments at 9.

Staff agrees with the company that it bears that risk. If in the future the Commission considers whether to disallow costs because the company has more resources than it needs, the Commission will look back to what was known at the time PacifiCorp made its resource decisions, including comments from staff and others in this proceeding. The Commission's competitive bidding guidelines set up the RFP process as one of the points where the Commission weighs in on the company's resource acquisition strategy. Based on staff's analysis, the Commission should find that the company's new strategy will lead to overbuilding.

Lack of Market to Sell Surplus

PacifiCorp has expressed concerns about market liquidity when considering short-term market *purchases*. Staff is puzzled that the company does not have similar concerns about market *sales* if it overbuilds, especially during off-peak hours.

In opening comments, staff stated its concern that PacifiCorp might not be able to sell the excess energy from coal plants in *wholesale* markets to California (or other states if they, or the federal government, follow California's lead in constraining greenhouse gas emissions). *See* staff's opening comments at 11.

PacifiCorp states that because it serves fewer than 75,000 retail customers in California, the company qualifies for an exception under SB 1368 that allows it to file an alternative compliance plan. However, to qualify for this alternative, the law requires that the company's emissions of greenhouse gases to generate electricity for retail customers must first be subject to review by at least one of its other state utility commissions. PacifiCorp also states that the law applies only to power supplies to serve its customers in California, comprising only 1.7 percent of the company's 2005 retail sales. The company's comments are irrelevant to the issue staff raised related to market sales.

Further, the company states that "because this law covers only long-term power resources (i.e. 5 years or more), it does not impact the ability of PacifiCorp to sell coal-backed products into the short- and medium-term markets." See PacifiCorp’s reply comments at 5.

Staff notes that this apparent loophole for short-term purchases may well be closed in the future, including through implementation of California AB 32. This mandatory cap on greenhouse gas emissions requires compliance regardless of whether a utility meets its load with short-, medium- or long-term resources.

PacifiCorp states that "Such a cap would not necessarily preclude new pulverized coal plants as long as they are sufficiently offset by other resources in the portfolio to allow overall compliance with the cap. PacifiCorp's significant new wind resource additions (which rely on PacifiCorp's thermal base load units for firming), will play a balancing role to new conventional coal in any future cap and trade regime." See PacifiCorp’s reply comments at 5-6.

Staff notes that California utilities may be hard-pressed to add enough wind or other renewable resources to their portfolios in order to offset greenhouse gas emissions from pulverized coal plant purchases and meet AB 32.

SB 1368 requires that the greenhouse gas emissions for any base load generation commitment of five years or more not exceed the rate of greenhouse gas emissions for combined-cycle, natural gas base load generation. Further, the California Public Utilities Commission rulemaking already underway addressing the same issue will be the forum for developing rules to meet the new law. Under the statute, it appears that utilities will be allowed to make purchases of five years or longer from coal plants only if the CO_2 is injected in geological formations in order to prevent releases into the atmosphere.[16]

Staff also points out that several states in the West have adopted mandatory Renewable Portfolio Standards (RPS) and several others, including Washington and Oregon, are considering an RPS. Such standards beg the question of whether a go-long strategy that relies on excess energy sales of non-renewable resources is prudent, especially as RPS requirements ramp up through time.

Bidders cannot bid an IGCC plant into the 2012 RFP.

In opening comments, staff expressed concern that proposers could not bid an IGCC plant into the 2012 RFP as drafted, given practical considerations such as the state of technology, the market and financing for IGCC projects. Given such considerations, we sought clarification from the company regarding which “Eligible Resource” category (i.e., transaction type) would facilitate a bidder to propose an IGCC plant. The company stated that a bidder could bid an IGCC

[16] See Section 8341(d)(5).

plant only as a Power Purchase Agreement or Tolling Service Agreement. *See* PacifiCorp's response to Staff Data Request No. 36. Staff does not see how anyone could bid an IGCC plant into one of these categories.

Staff further inquired why the company is not considering acquiring an IGCC plant through the 2012 RFP based on an Engineering, Procurement and Construction (EPC) contract at a PacifiCorp site[17], or an Asset Purchase and Sale Agreement (APSA) on a PacifiCorp site or the bidder's site. The company replied as follows:

> In order to build an IGCC resource on an existing PacifiCorp site, a FEED [Front-End Engineering and Design] study would be necessary. The study would identify the detailed scope, commercial terms, and lump sum turn key price for the project. Prior to initiating a FEED study, a feasibility study would be the basis for selecting the technology supplier who would perform the FEED study. Currently, no technology-supplied feasibility or FEED studies have been completed for any of PacifiCorp's sites. The counterparty that completes the FEED study would most likely be the entity the company would contract with to supply and construct the IGCC project. *See* PacifiCorp's response to Staff Data Request No. 37.

PacifiCorp further explains that it would undertake a FEED study only if the company's (2014) IGCC Benchmark Resource was selected in the RFP process. *See* PacifiCorp's response to Staff Data Request No. 46.

PacifiCorp should amend its RFP to allow proposers a meaningful opportunity to bid an IGCC plant for the following reasons: 1) to test cost estimates of PacifiCorp's 2014 Benchmark Resource, 2) to provide a potential IGCC option in the event PacifiCorp decides not to proceed with a self-build IGCC plant, and 3) to elicit creative options from the market.

Staff notes that the company has the option to request acknowledgment of an alternative acquisition method for an IGCC plant in its 2006 IRP under Guideline 2(b) or request a waiver pursuant to Guideline 2(c). *See* Order No. 06-446 at 4-5.

[17] The company is allowing bidders to propose an EPC contract only for the Currant Creek site, which is host to a natural gas-fired plant.

Other Issues

Non-Price Factors

PacifiCorp's recently amended filing removes as a non-pricing factor compliance with the pro-forma contracts attached to the RFP.[18] The company did so in response to comments in Utah that scoring criteria might discourage bidders from offering flexible and innovative proposals, particularly proposals relying on power purchase agreements. *See* PacifiCorp's reply comments at 7. Therefore, PacifiCorp proposes to determine its initial short list of bids based 80 percent on price, and 20 percent on non-price factors (10 percent for site control and permitting and 10 percent for development, construction and operational experience).

Staff does not object to this change. The Commission's competitive bidding order allows flexibility in weighting price vs. non-price factors. Staff notes that the company does not score itself on these non-price factors. *See* PacifiCorp's response to ICNU Data Request Nos. 2.42, 2.43 and 4.3. Therefore, removing this non-price factor will not undermine the Commission's objective of fairly evaluating market bids versus Benchmark Resources.

Further, the Commission's competitive bidding order requires the company to negotiate price and non-price terms with bidders on the final short-list, and any approval the Commission might consider for the 2012 RFP should contain a condition that the Commission is not approving the pro-forma contracts in whole or in part.

Amount of Resources in Initial Short List

The draft 2012 RFP states, "The initial short list will include the top bids in each Resource Alternative, up to the approximate megawatt needs for each year during the term." *See* 2012 RFP at 38. Staff is concerned that limiting the amount of resources on the initial short-list, from which the final short-list is derived, to the megawatt needs for each year would cut the company's options short. What if a resource on the initial short-list does not hold up in subsequent risk analysis in developing the final short-list? What if during negotiations the bidder sells its project to another party? It is prudent to have more resources on the initial and final short-lists than needed.

Staff notes that PGE used such a process for its 2003 RFP for supply-side resources. The result was a wide variety of resources in terms of fuel type, transaction type and term.

---

[18] Staff notes that the reference to "compliance with the Proforma contracts" at the top of page 35 of the draft 2012 RFP should therefore be removed.

Timing of Final Short-List Acknowledgment

PacifiCorp's draft 2012 RFP states that the Commission would consider acknowledgment of the company's final short-list of resources 275 days after RFP issuance. *See* 2012 RFP at 16.

Staff's proposal in UM 1182 for RFP acknowledgment clearly indicated that the process occurs before negotiations begin. For example, staff stated:

> The utility would gain assurance that at the time of RFP acknowledgment, the Commission found the utility's plans to pursue negotiations with the final short-list bidders to be reasonable…. Commission RFP acknowledgment should not impair the negotiation position of the utility. By acknowledging a final short-list that contains several options for putting together the preferred incremental portfolio … the Commission can avoid inadvertently weakening the negotiating position of the utility. " *See* staff's opening comments, Docket UM 1182, at 10.
>
> Staff agrees with ICNU that the Commission should not acknowledge the final negotiated bids. *See* staff's reply comments, Docket UM 1182, at 10.

Super-Critical, Pulverized Coal Benchmark Resources

PacifiCorp states that "…data in the 2004 IRP … demonstrated that conventional coal was an important component of all of the least cost, least risk portfolios examined." *See* PacifiCorp's reply comments at 2. The Commission's acknowledgment order does not support PacifiCorp's statement:

> [T]he Commission does not acknowledge the choice of one fuel type, gas or coal, over the other. Both resource types present significant risks – fuel price uncertainty and volatility for the gas-fired CCCT and possible CO_2 regulatory costs for the pulverized coal plant….
>
> While it is impossible to predict CO_2 regulatory costs over the expected life of a new coal plant, all parties commenting in this proceeding, including PacifiCorp, recognize the associated uncertainties and risks for ratepayers. That makes an IGCC plant, with the ability to later add CO_2 sequestration, an attractive option. At the same time, PacifiCorp cites uncertainties about performance of IGCC technology.
>
> Our decision does not mean that it would be imprudent to choose a gas-fired CCCT or a pulverized coal plant. It simply means that we

> cannot conclude, based on the information before us, that it is reasonable to commit to either one of these resources without additional analysis.
>
> Coupled with reasonable measures that could be taken to avoid outages (e.g., additional short-term purchases, demand response programs and distributed resources), analysis of the coal plant delay scenarios indicates that it may be reasonable to wait a couple of years until IGCC technology is further developed before the Company commits to its next large thermal resource. *See* Order No. 06-029 at 50-51.

Distributed Generation

In its amended filing, PacifiCorp has removed “Distributed Generation” as an Eligible Resource. The company provided no explanation for eliminating this category.

Distributed generation was originally included in the exception category, allowing a minimum resource size of 3 MW rather than 100 MW. *See* Draft 2012 RFP at 15 (page 18 in redline version shows deletion).

PacifiCorp stated that its definition of Distributed Generation conformed with the definition in the company’s 2004 IRP — “a source of distributed generation that can be dispatched on a standby or emergency basis.” The company further stated that proposers bidding in this category would have to explain if there are permit restrictions, limitations or constraints that would impact the economics of the projects or limit operating hours. *See* PacifiCorp’s response to Staff’s Informal Data Request No. 1.

Dispatchable standby generation was part of the company’s acknowledged 2004 IRP Action Plan — specifically, “Include a provision for Standby Generators in supply-side RFPs. Investigate, with Air Quality Officials, the viability of this resource option.” The resource size evaluated for the 2004 IRP was 75 MW in Utah, spread between summer of 2009 and summer of 2011. *See* PacifiCorp’s 2004 IRP at 181.

The company should allow dispatchable standby generation under its Eligible Resource exceptions providing the bidder can demonstrate that permitting issues related to air quality concerns have been addressed. PGE’s dispatchable standby generation program provides reliable capacity resources it can call on when needed.

Qualifying Facilities that can adhere to the same terms and conditions as other supply-side resources, such as cogeneration facilities, hydro, biomass and geothermal facilities, are eligible to bid under the exception category. The exception is that the minimum size for Qualifying Facilities is 10 MW pursuant to Order No. 06-446, instead of 100 MW. [19]

Coordination of Oregon IE and Utah IE

The Oregon IE will work with Commission Staff and PacifiCorp to coordinate activities for administrative efficiency. For example, staff finds it unnecessary that both the Utah and Oregon IEs "review all submissions, to ensure that only bid numbers are in the proposals and electronic submissions, prior to forwarding them to the RFP 2012 Evaluation Team." *See* Draft 2012 RFP at 17. Staff will work with PacifiCorp and the Commission-selected Oregon IE to avoid unnecessary redundancy while ensuring consistency with the detailed scope of work in Oregon's IE solicitation.

Credit and Security

In its amended filing, PacifiCorp removed "Lease Accounting Inputs" in its list of RFP Base Model inputs for evaluating the price factor for its initial short-list of bids. *See* draft 2012 RFP at 36 (page 47 in redline version shows deletion). This resolves the related issue staff raised in opening comments (at 14).

PacifiCorp intends its process to require evidence from counterparties of their ability to provide required credit support, i.e., a Comfort or Commitment letter from financial institutions or a Comfort or Commitment letter from a proposed guarantor (not an actual Letter of Credit). PacifiCorp does not require an actual "up-front" guarantee, because that would create an actual cost during the initial screening process.

Staff recommends the Oregon IE further explore the following credit and security issues. During the process, the IE should determine if there are any credit or security issues that have not been addressed or resolved.

- Does PacifiCorp propose a reasonable negotiated process that works for both the company and potential counterparties regarding how "credit" should be utilized in the screening process, considering that the RFP process takes considerable time?

- How will potential Affiliated Interest counterparties be treated in order to put them on an equal footing with other market bids regarding credit requirements?

[19] Staff recommends the company clarify in its table of Eligible Resources, under "Exceptions," that the minimum size for Qualifying Facilities is 10 MW (see page 7). While the company makes this clear on page 15, the blanket statement in the table that "Bidder must adhere to the same terms and conditions as other supply side resources in the RFP 2012" may create confusion.

- Is the process reasonable for pre-screening the credit profile of prospective bidders? The intent is to determine that the counterparties have the financial feasibility and credit qualifications or appropriate parent/third-party support for the viability of the project they are proposing. These RFQ screening elements should be considered in light of the company's need to assure that the winning bidders have the means to fulfill the terms of their proposals. However, the screening elements should not be so burdensome as to preclude potential candidates that would otherwise be qualified bidders.

- Should a "pre-commitment" form letter be developed to facilitate the Request for Qualification screening tool? What types of "carve outs" will be accepted?

- What other potential forms of credit assurance can be offered?

- Are the Monte Carlo simulation parameters for non-asset-backed bids reasonable?

- Are the required replacement power costs reasonable, or would they impose an undue burden? The intent of the credit matrix is to determine the level of 1.5 standard deviations (84 percent confidence interval) used for the company's analysis of credit risks. Is this level appropriate in comparison to the level applied by other companies? PacifiCorp indicated that three standard deviations would provide them a "perfect hedge" and that the company usually uses a 95 percent confidence interval, or (about) two standard deviations. Is the level which PacifiCorp intends to reduce its exposure reasonably sufficient, with regard to the level typically imposed in the industry?

- Is the credit scoring model developed in conjunction with Standard & Poor's transparent and reasonable? The IE should review the model for overall reasonableness. Given a known credit rating, does the model provide a reasonably comparable analysis?

- If the bid is "project specific" and asset-backed, should the bidder be treated differently than if a bid is based on general system output (which might be expected to come from a larger company that may have better credit)? Are the tenor and level of potential exposure reasonable and objectively calculated (e.g., 12 months of replacement power)?

- What is the threshold for the concentration issues regarding existing counterparties? How does PacifiCorp determine the tolerance, and is it reasonable?

- How will the company determine how to adjust credit requirements if the bidder's credit changes during the course of the RFP process? What triggers would be identified? If the rating is based on an internal analysis, how often would there be a review? Would there be reasonable expectations regarding new postings or refundings? Could the on-going analysis or potential volatility cause problems with independent financing of potential projects?

- After power supply contracts are in-force, how will changing credit requirements be determined, if any, including refunding or new postings?

- Is the language for "Step-in Rights" meaningful or reasonable upon default?

- Would bidders offer "Step-in Rights," or would PacifiCorp impose such requirements? What is the timeframe that would meaningfully allow the company to obtain control and operation of a project?

- What types of "rights to cure" might be provided? Would any potential subordination of lien rights preclude reasonable financing by third parties? Would PacifiCorp propose limitations of financing terms, such as amount of equity required?

Other Issues for the Oregon IE to Explore

- Is the evaluation weighting between price and non-price components reasonable and appropriate?

- What criteria will PacifiCorp use to determine the level of "technical expertise" in the Request for Qualifications screening process?

- Is the proposed treatment of bids with respect to transmission requirements reasonable?

- How does PacifiCorp intend to determine the potential impact related to the company's "debt imputation," and is it balanced and reasonable?

- How would the impact of accounting for Variable Interest Entities be treated by PacifiCorp, if such might be offered? Are there other accounting issues that require review?

Summary of Staff Recommendation

Staff recommends the Commission not approve PacifiCorp's draft 2012 RFP for Base Load Resources for the following reasons described in detail above:

1. Lack of alignment with the company's acknowledged IRP, including the company's unjustified departure from short-term market purchases on the East and West sides of its system
2. Magnitude of the identified need, including magnitude of base load resources sought through the RFP
3. Inability of bidders to bid an IGCC plant into the RFP

If, however, the Commission is inclined to conditionally approve the RFP in whole or in part, pursuant to the process adopted at the public meeting on September 19, 2006, staff recommends the Commission include the minimum conditions outlined in staff's opening comments (at 15), amending item c. to reflect the reduced minimum resource term of five years.[20]

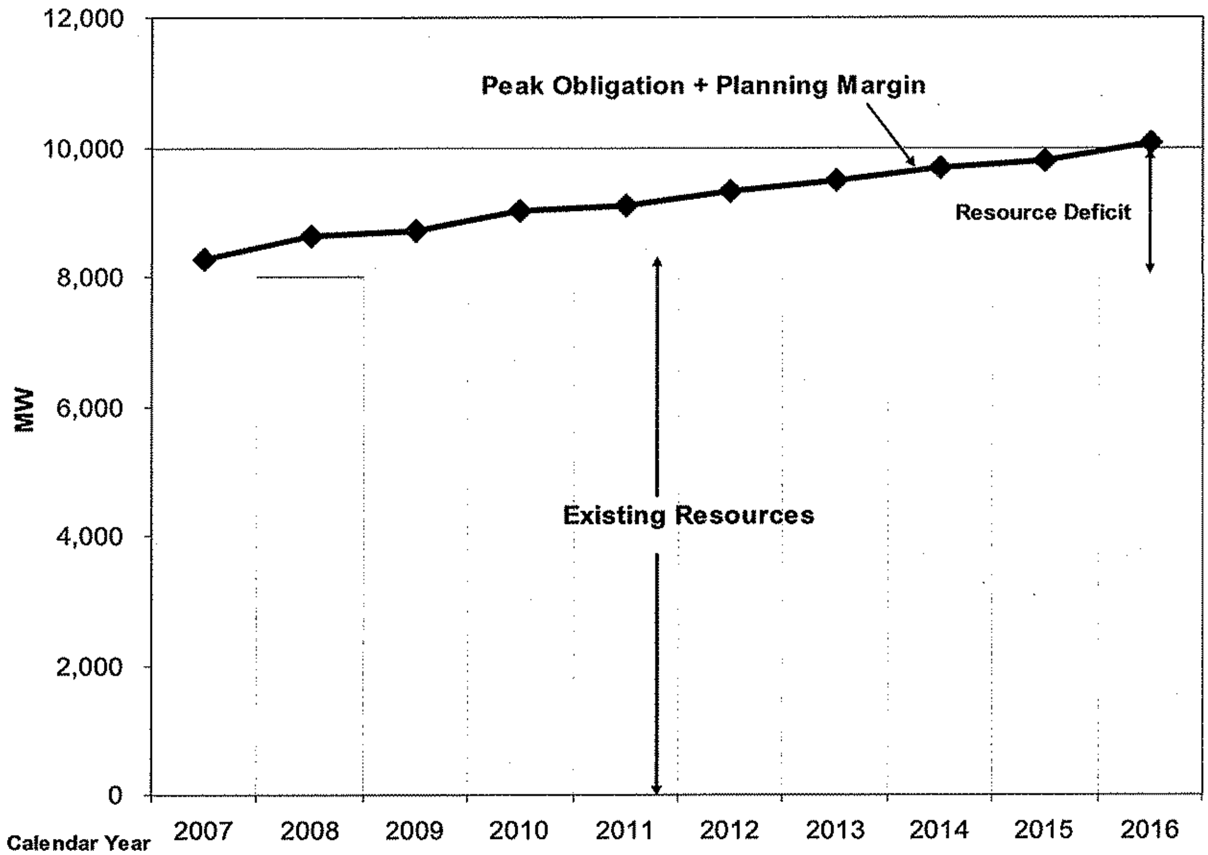
[20] As amended to reflect a minimum five-year resource term:

a. RFP approval does not imply endorsement of any of the company's Benchmark Resources.
b. The Commission is neither approving the pro forma agreements included in the 2012 RFP in their entirety, nor endorsing any specific term therein.
c. RFP approval does not imply acknowledgment of the magnitude of the proposed level of resource acquisitions, the level of resources for which the company is seeking five-year minimum commitments, or the level of base load resources that should be acquired to meet its resource needs during the period 2012-2014.
d. The Commission does not acknowledge the departure from the company's 2004 IRP Action Plan related to removing 700 MW of Front Office Transactions on the east side of the company's system (and 500 MW of these transactions on the West side).

Response OPUC Staff 11 (b)

The requested load and resource balance information is provided as Figure 11b and Table 11b below.

Figure 11b – East-Side Coincident Peak Capacity Chart



Resources	8,278	7,975	8,149	8,251	8,246	8,046	8,046	8,046	8,042	8,021
Obligation+15%	8,283	8,637	8,708	9,025	9,099	9,314	9,497	9,686	9,805	10,069

Table 11b – East-Side Load and Resource Balance

Calendar Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
East										
Thermal	6,134	5,941	5,941	5,941	5,941	5,941	5,941	5,941	5,941	5,941
Hydro	135	135	135	135	135	135	135	135	135	135
DSM	153	163	163	163	163	163	163	163	163	163
Renewable	65	109	109	141	141	141	141	141	137	137
Purchase	904	679	778	548	543	343	343	343	343	322
QF	200	200	200	200	200	200	200	200	200	200
Interruptible	233	233	308	308	308	308	308	308	308	308
Transfers	454	515	515	815	815	815	815	815	815	815
East Existing Resources	8,278	7,975	8,149	8,251	8,246	8,046	8,046	8,046	8,042	8,021
RFP Wind	0	0	0	0	0	0	0	0	0	0
Front Office Transactions	0	0	0	0	0	0	0	0	0	0
East Planned Resources	0	0	0	0	0	0	0	0	0	0
East Resources	8,278	7,975	8,149	8,251	8,246	8,046	8,046	8,046	8,042	8,021
Load	6,460	6,778	6,972	7,253	7,352	7,549	7,708	7,872	7,976	8,203
Sale	849	811	702	666	631	595	595	595	595	595
Non-owned reserves	71	71	71	71	71	71	71	71	71	71
East Obligation	7,309	7,589	7,674	7,919	7,983	8,144	8,303	8,467	8,571	8,798
PM	973	1,048	1,034	1,106	1,116	1,170	1,194	1,218	1,234	1,271
East Obligation + PM	8,283	8,637	8,708	9,025	9,099	9,314	9,497	9,686	9,805	10,069
East Position	(5)	(662)	(559)	(774)	(853)	(1,268)	(1,451)	(1,640)	(1,763)	(2,048)

UM-1208/Pacific Power
September 14, 2006
OPUC Data Request 29

OPUC Data Request 29

Please provide two sets of annual eastside MW and MWa load-resource balance tables for 2007-2016; first with the level of Front Office Transactions assumed in the 2004 IRP, but without the additional coal plant that will replace the Front Office Transactions, and second without the Front Office Transactions, but including the additional coal plant. Describe all new resources added.

Response to OPUC Data Request 29

Below are PacifiCorp's capacity (MW) and energy (MWa) tables using the most recent load-resource balance (2006 IRP) for the east side of the system.

Table 1 includes 700 MW of Front Office Transactions (FOT) and excludes the additional coal plant. Note that the FOT assumption before 2012 differs from the 2004 IRP by the amounts of newly executed FOT contracts, which are included in Existing Resources. The total of newly executed FOTs and the planned FOTs shown in Table 1 below is equivalent to FOTs in the 2004 IRP.

Table 2 shows the East energy position with FOT. By the way, resource detail is not available for the annual energy positions (MWa) shown in Table 2.

Table 3 includes a coal plant resource beginning in 2013 and excludes Front Office Transactions for all years in the table. PacifiCorp does not assume that any particular coal resource addition replaces Front Office Transactions but for purposes of this request will include a 750 MW Super-critical Pulverized Coal plant as a comparable resource.

Table 4 shows the East energy position with a coal plant resource. Again resource details are not available for the annual energy positions.

East Side

Table 1 – Capacity (MW) L&R Balance with 2004 Front Office Transactions

2006 IRP L&R Balance (Draft)

Planning Reserve Margin Target = 15%

Calendar Year	2007	20082	009	2010	2011	2012	2013	20142015		2016
East										
Thermal	6,134	5,941	5,941	5,941	5,941	5,941	5,941	5,941	5,941	5,941
Hydro	135	135	135	135	135	135	135	135	135	135
DSM	153	163	163	163	163	163	163	163	163	163
Renewable	65	109	109	141	141	141	141	141	137	137
Purchase	904	679	778	548	543	343	343	343	343	322
QF	200	200	200	200	200	200	200	200	200	200
Interruptible	233	233	308	308	308	308	308	308	308	308
Transfers	454	515	515	815	815	815	815	815	815	815
East Existing Resources	8,278	7,975	8,149	8,251	8,246	8,046	8,046	8,046	8,042	8,021
Resource 1	0	0	0	0	0	0	0	0	0	0
Front Office Transactions	0	175	325	500	500	700	700	700	700	700
East Planned Resources	0	175	325	500	500	700	700	700	700	700
East Resources	8,278	8,150	8,474	8,751	8,746	8,746	8,746	8,746	8,742	8,721
Load	6,460	6,778	6,972	7,253	7,352	7,549	7,708	7,872	7,976	8,203
Sale	849	811	702	666	631	595	595	595	595	595
Non-owned reserves	71	71	71	71	71	71	71	71	71	71
East Obligation	7,309	7,589	7,674	7,919	7,983	8,144	8,303	8,467	8,571	8,798
PM	973	1,021	986	1,031	1,041	1,065	1,089	1,113	1,129	1,166
East Obligation + PM	8,283	8,611	8,660	8,950	9,024	9,209	9,392	9,581	9,700	9,964
East Position	(5)	(461)	(186)	(199)	(278)	(463)	(646)	(835)	(958)	(1,243)

East Side

Table 2 – Energy (MWa) L&R Balance with 2004 Front Office Transactions

Annual MWa	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
L&R + FOT	1,033	963	793	738	650	574	452	333	244	122

East Side
Table 3 – Capacity (MW) L&R Balance with Coal Plant Resources

2006 IRP L&R Balance (Draft)

Planning Reserve Margin Target = 15%

Calendar Year	2007	20082	009	2010	2011	2012	2013	20142015		2016
East										
Thermal	6,134	5,941	5,941	5,941	5,941	5,941	5,941	5,941	5,941	5,941
Hydro	135	135	135	135	135	135	135	135	135	135
DSM	153	163	163	163	163	163	163	163	163	163
Renewable	65	109	109	141	141	141	141	141	137	137
Purchase	904	679	778	548	543	343	343	343	343	322
QF	200	200	200	200	200	200	200	200	200	200
Interruptible	233	233	308	308	308	308	308	308	308	308
Transfers	454	515	515	815	815	815	815	815	815	815
East Existing Resources	8,278	7,975	8,149	8,251	8,246	8,046	8,046	8,046	8,042	8,021
Coal Resource (SCPC-Bridge	0	0	0	0	0	0	750	750	750	750
Front Office Transactions	0	0	0	0	0	0	0	0	0	0
East Planned Resources	0	0	0	0	0	0	750	750	750	750
East Resources	8,278	7,975	8,149	8,251	8,246	8,046	8,796	8,796	8,792	8,771
Load	6,460	6,778	6,972	7,253	7,352	7,549	7,708	7,872	7,976	8,203
Sale	849	811	702	666	631	595	595	595	595	595
Non-owned reserves	71	71	71	71	71	71	71	71	71	71
East Obligation	7,309	7,589	7,674	7,919	7,983	8,144	8,303	8,467	8,571	8,798
PM	973	1,048	1,034	1,106	1,116	1,170	1,194	1,218	1,234	1,271
East Obligation + PM	8,283	8,637	8,708	9,025	9,099	9,314	9,497	9,686	9,805	10,069
East Position	(5)	(662)	(559)	(774)	(853)	(1,268)	(701)	(890)	(1,013)	(1,298)

East Side
Table 4 – Energy (MWa) L&R Balance with Coal Plant Resources

Annual MWa	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
L&R + coal plant	1,033	937	746	666	578	475	1,036	917	828	706

UM-1208/Pacific Power
September 12, 2006
OPUC Data Request 26

OPUC Data Request 26

PacifiCorp has indicated that it is: (a) evaluating whether short-term market purchases are an appropriate resource for meeting projected resource needs on the east-side of its system, (b) moving towards hedging its system through cost-based resources, and as a result, (c) adding 700 MW of east-side resource need to the 2012 RFP. PacifiCorp indicated that an additional coal plant is assumed to replace the 700 MW of Front Office Transactions included in its 2004 IRP. *See* PacifiCorp Compliance Filing, Docket No. UM 1208, August 30, 2006, at page 2.

a. Please provide the documents and analysis that comprise PacifiCorp's evaluation of the appropriateness of short-term market purchases for meeting its projected east-side resource need.
b. Please provide the documents and analysis that were the basis for PacifiCorp's decision to move towards cost-based resources to hedge its system.
c. What changes have occurred since Commission Order No. 06-029 that justify modifying the preferred portfolio used as the basis for PacifiCorp's 2004 IRP Action Plan by substituting an additional coal plant for the 700 MW of Front Office Transactions?

Response to OPUC Data Request 26

a. PacifiCorp included 700 megawatts of short-term market purchases for meeting a portion of its projected east-side resource need in its 2004 Integrated Resource Plan based on historical operational data and PacifiCorp's forward market view. Comprehensive stochastic risk analyses comparing these purchases to cost-based resources alternatives was not conducted nor were other levels of short-term market purchases evaluated. This represented a departure from the 2003 Integrated Resource Plan and prior plans which relied on cost-based resources to hedge its system.

b. The choice of using cost-based resources or short term market purchases to hedge its system is being addressed in the 2006 Integrated Resource Planning process which is not yet complete.

c. Since PacifiCorp's last Integrated Resource Plan was filed with the Commission, natural gas and market prices have increased sharply and there is no indication that they will stabilize soon. These market realities have increased the risk associated with reliance on short-term market purchases and have caused the company to move to replace these purchases on the east side of its system with long-term resources.

OPUC Data Request 1

Order No. 06-029 states (at 51):

> [W]e cannot conclude, based on the information before us, that it is reasonable to commit to either one of these resources [a gas-fired CCCT or a pulverized coal plant] without additional analysis.
>
> Coupled with reasonable measures that could be taken to avoid outages (e.g., additional short-term purchases, demand response programs and distributed resources), analysis of the coal plant delay scenarios indicates that it may be reasonable to wait a couple of years until IGCC technology is further developed before the Company commits to its next large thermal resource.
>
> In considering approval of an RFP for such a resource, the Commission would first need to determine whether the Company has demonstrated the need for it. We also expect the Company to fully explore whether delaying a commitment to coal until IGCC technology is further commercialized is a reasonable course of action. We believe it may be possible to do so within the RFP process by providing flexibility for bidders regarding online date, contract length, resource type and technology.

Please explain how PacifiCorp's filed *2012 Request for Proposals – Base Load Resources* meets the following Commission requirements in Order No. 06-029:

a. Demonstration of resource need

b. Demonstration that delaying the commitment to coal (through measures such as additional short-term purchases, demand response programs and distributed resources) until Integrated Gasification Combined Cycle (IGCC) technology is further commercialized is not a reasonable course of action.

Response to OPUC Data Request 1

In a recent order in this docket, the Commission indicated that it would soon issue an order in UM 1182, the Commission's investigation on resource procurement, and apply the order retroactively to PacifiCorp's draft 2012 RFP. The retroactive application of still-to-be-announced new standards to this draft RFP raises various issues and concerns, especially given the importance of expedited review of this RFP. One of these issues is the difficulty that it creates for PacifiCorp in responding to discovery before the UM 1182 Order is issued. PacifiCorp submits this and all other discovery responses provisionally, subject to revision or modification after the UM 1182 Order is issued.

The quote from Order 06-029 in this Data Request addressed action items 7 and 8 from PacifiCorp's 2004 Integrated Resource Plan. These items proposed procurement of a 550 MW resource in 2009 (proxy gas resource) and a 600 MW resource in 2011 (proxy coal resource). The Commission's Order made clear that its concerns were primarily focused on the timing of the new resource additions, rather than on the underlying need. See Order 06-029 at 50 (citing Staff's statement that it was unlikely that the company's planning was so amiss as to obviate the need for the new resources). Based upon the data that demonstrated that it might be reasonable for the Company "to wait a couple of years" before it committed to a new large thermal resource, the Commission refused to acknowledge action items 7 and 8. Id. at 51. The point of the delay, according to the Commission, was to permit IGCC technology to further develop. Id.

Consistent with Order 06-029, PacifiCorp's draft 2012 RFP effectively delays the addition of the first new large thermal resource by three years from the proposals contained in the 2004 IRP, from 2009 to 2012. Also consistent with the Order, this delay has permitted PacifiCorp to include an IGCC benchmark in the draft 2012 RFP.

Additionally, as suggested by Order No. 06-029 at 51, the draft 2012 RFP allows PacifiCorp to further analyze the trade-offs among different resource options by providing flexibility for bidders regarding the online date, contract length, resource type and technology in case new, more appropriate technologies are developed. For example, page 2 of the draft request for proposal says: "To the extent Bidders want to propose in service date deferral options and or contract buyout options as a component of their bids, they should be sure to identify them clearly with specific triggers (i.e., triggers associated with specific milestones) within the Bidder's proposal."

The company has solicited the market to provide proposals from eight eligible resources and two exceptions. These proposals include flexibility of resource type, technology and the ability to build resources to specified criteria on the company's sites. The solicitation offers contract length flexibility with a minimum of ten years and a maximum of the life for the asset as determined in the Integrated Resource plan.

With respect to resource need, an IRP is intended to provide guidance and rationale for PacifiCorp's resource procurement over the next few years. It provides a snapshot of the company's future needs and resource options at a given point in time. The 2004 Integrated Resource Plan was provided to the Oregon Commission in January 2005, over 18 months ago, and was based on data that is now two years old. Even so, at that time the company anticipated that over 2,000 megawatts of new large thermal resources, both coal-fired and natural gas-fired, would be required on the east-side of the company's system by 2014. This was in addition to 700 megawatts of short-term market purchases.

When determining the benchmark resources for the draft 2012 RFP, the company conducted additional load-resource balance analysis. Resource needs on the east side of the system are now about 1,250 MW in 2012, rising to over 2,000 MW by 2016 as shown in the response to OPUC Request 11b. At the same time, the west-side of the system is 1,000 to 1,200 MW short. With the addition of all or some of the benchmark resources, the company remains short on the east-side of the system in most years as shown in the response to OPUC Requests 15 and 16. Even after the addition of the benchmark resources, the company remains 1,000 to 1,200 MW short on the west-side of the system.

To meet its large resource needs, the company has been vigorously pursuing renewable resource additions and recently announced the acquisition of the 100 MW Leaning Juniper 1 wind power facility. The company is actively reviewing Requests for Proposal for both Class 1 and Class 2 demand side management programs. With regard to the availability of distributed resources, PacifiCorp had a conference call with Utah Department of Air Quality staff subsequent to the filing of the draft RFP to determine if customer-owned standby generators represented a viable resource option for the east control area. The purpose of the call was to address Action Item No. 4 in the 2004 IRP Update--"Investigate, with Air Quality Officials, the viability of this resource option". The takeaway from the call was that re-permitting of standby generators for non-emergency use would be difficult in most areas of the state, and that diesel generators in particular could not be re-permitted at all in the Salt Lake City area. Based on the Utah Department of Air Quality's assessment, PacifiCorp has decided to exclude standby generators as an eligible resource in the 2012 RFP.

Notwithstanding successes in these various procurement efforts, it is clear that the size resource needed for the term cannot be filled by renewables, demand response and distributed resources alone. Nor can PacifiCorp simply wait and hope for early and effective commercialization of new technologies such as Integrated Gasification Combined Cycle technology. In order to fill this large remaining gap, the practical question becomes one of evaluating the trade-offs among coal, natural gas and short-term market purchases.

Since PacifiCorp's last IRP, natural gas and market prices have increased sharply and there is no indication that they will stabilize or come down soon. On July 20, 2006, the Commission was alerted by the local distribution companies to expect 4-12 percent higher natural gas prices this upcoming heating season. These market realities have increased the risk associated with reliance on short-term market purchases and have caused the company to move to replace these purchases on the east side of its system with long-term resources, as reflected in the draft 2012 RFP. The company will continue to address the resource trade-offs in its bid evaluation in the 2012 RFP and will also be addressing these trade-offs in its 2006 Integrated Resource Planning analysis which is currently underway.

OPUC Data Request 3

Please provide the analysis the company used to determine that the planned 700 megawatts (MW) of Front Office Transactions on the east side of its system should be replaced by long-term thermal resources.

Response to OPUC Data Request 3

This determination was based on expected volatility of market costs and liquidity further into the future. This tradeoff will receive further analysis in the bid evaluation process and in the 2006 IRP. Please also see Responses to OPUC Data Requests 1 and 8.

OPUC Data Request 8

Did the company consider requesting bids for firm power purchases of terms two years, three years, four years and five years? Please explain how the 10-year bid requirement better meets the delay scenarios as discussed in Order No. 06-029 than these short-term purchases.

Response to OPUC Data Request 8

Yes, the company has issued mid term request for proposals out to 2012 and has received proposals from only one counterparty for a standard product in 2012. The company has no knowledge of market liquidity for standard products delivered to the eastern control area beyond 2012. The company is subject to market prices and the fear of future unknowns with no alternatives as a hedge for resources beyond 2012 delivered into or in the eastern control area.

The ten year bid requirement allows bidders to provide a proposal that has an asset backed resource as the source of their power purchase proposal (ie: an anchor tenant) if there is a minimum of ten years. The minimum of ten years facilitates financing of new resources and provides an asset to support the physical requirement of serving load. Thus, the 10-year bid requirement is meant to facilitate financing and does not affect the timing of the resource.

OPUC Staff Data Request 23

Please provide a detailed description of the methodology used by the company to determine whether any Class 1 (fully dispatchable or firm schedulable) Demand-Side Management (DSM) bid received in response to the company's 2005 DSM Request for Proposals (RFP) is cost-effective. Provide any white paper describing the methodology.

Response to OPUC Staff Data Request 23

To date, the company has relied on the 2004 IRP Class 1 program cost assumptions (Table 8.26 – DSM Proxy Program Options for the Capacity Expansion Model, page 166 of PacifiCorp's 2004 Integrated Resource Plan) as an initial, but not final, cost-effectiveness screen for the Class 1 DSM proposals received. At this time, the company has not rejected the Class 1 DSM proposals received through the RFP, and will continue its bid evaluation to determine which proposals may prove to be cost-effective. PacifiCorp plans to use the results of the Quantec proxy supply curve and program valuation study currently underway to assist in this process.

HARDY MYERS
Attorney General

PETER D. SHEPHERD
Deputy Attorney General

DEPARTMENT OF JUSTICE
GENERAL COUNSEL DIVISION

October 13, 2006

Filing Center
Public Utility Commission of Oregon
550 Capitol Street NE - Suite 215
Salem Oregon 97301-2551

Re: UM 1208 - Staff Reply Comments
DOJ File No. 860115-GP0065-06

Dear Filing Center:

Enclosed for filing are Staff's Reply Comments and Appendix A. Staff intends to file Appendix B on October 16, 2006. Appendix B consists of PacifiCorp's responses to data requests cited in staff's reply comments.

Sincerely,

Neoma Lane

Neoma Lane
Legal Secretary
Regulated Utility & Business Section

NAL:nal/GENR6268
Enclosures
cc: Service list w/enclosures

1162 Court Street NE, Salem, OR 97301-4096 Telephone: (503) 378-6322 Fax: (503) 378-5300 TTY: (503) 378-5938

CERTIFICATE OF SERVICE

I certify that on October 13, 2006, I served the foregoing upon all parties of record in this proceeding by delivering a copy by electronic mail and by mailing a copy by postage prepaid first class mail or by hand delivery/shuttle mail to the parties accepting paper service.

SUSAN K ACKERMAN
ATTORNEY
PO BOX 10207
PORTLAND OR 97296-0207
susan.k.ackerman@comcast.net

W / CITIZENS' UTILITY BOARD OF OREGON
OPUC DOCKETS
610 SW BROADWAY STE 308
PORTLAND OR 97205
dockets@oregoncub.org

W / CITIZENS' UTILITY BOARD OF OREGON
JASON EISDORFER - **CONFIDENTIAL**
ENERGY PROGRAM DIRECTOR
610 SW BROADWAY STE 308
PORTLAND OR 97205
jason@oregoncub.org

DAVISON VAN CLEVE PC
MELINDA J DAVISON - **CONFIDENTIAL**
333 SW TAYLOR - STE 400
PORTLAND OR 97204
mail@dvclaw.com

W / DEPARTMENT OF JUSTICE
JANET L PREWITT
ASST AG
1162 COURT ST NE
SALEM OR 97301-4096
janet.prewitt@doj.state.or.us

ESLER, STEPHENS & BUCKLEY
JOHN W STEPHENS
888 SW FIFTH, SUITE 700
PORTLAND OR 97204-2021
stephens@eslerstephens.com

W / NORTHWEST ENERGY COALITION
STEVEN WEISS
SR POLICY ASSOCIATE
4422 OREGON TRAIL CT NE
SALEM OR 97305
steve@nwenergy.org

NW INDEPENDENT POWER PRODUCERS
ROBERT D KAHN
EXECUTIVE DIRECTOR
7900 SE 28TH ST STE 200
MERCER ISLAND WA 98040
rkahn@nippc.org

W / OREGON DEPARTMENT OF ENERGY
PHILIP H CARVER
SENIOR POLICY ANALYST
625 MARION ST NE STE 1
SALEM OR 97301-3742
philip.h.carver@state.or.us

W / OREGON INTERFAITH GLOBAL WARMING CAMPAIGN
JAMES EDELSON
415 NE MIRIMAR PL
PORTLAND OR 97232
edelson8@comcast.net

OREGON PUBLIC UTILITY COMMISSION
LISA C SCHWARTZ - **CONFIDENTIAL**
SENIOR ANALYST
PO BOX 2148
SALEM OR 97308-2148
lisa.c.schwartz@state.or.us

W /OREGON STATE PUBLIC INTEREST RESEARCH GROUP
JEREMIAH BAUMANN
CLEAN ENERGY ADVOCATE
1536 SE 11TH AVE
PORTLAND OR 97214
jeremiah@ospirg.org

PACIFICORP
LAURA BEANE
MANAGER - REGULATORY
825 MULTNOMAH STE 2000
PORTLAND OR 97232
laura.beane@pacificorp.com

PACIFICORP
NATALIE HOCKEN
ASSISTANT GENERAL COUNSEL
825 NE MULTNOMAH #1800
PORTLAND OR 97232
natalie.hocken@pacificorp.com

RENEWABLE NORTHWEST PROJECT
ANN ENGLISH GRAVATT - **CONFIDENTIAL**
917 SW OAK STE 303
PORTLAND OR 97205
ann@rnp.org

RFI CONSULTING INC
RANDALL J FALKENBERG
PMB 362
8351 ROSWELL RD
SANDY SPRINGS GA 30350
consultrfi@aol.com

Neoma Lane

Neoma Lane
Legal Secretary/Department of Justice
Regulated Utility & Business Section