BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1208

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

Pursuant to Judge Grant's memorandum of August 18, 2006, staff submits its opening comments on PacifiCorp's Draft 2012 Request for Proposals (RFP) for Base Load Resources (Draft 2012 RFP).

Staff's comments today are preliminary and focus on alignment of the RFP with the company's acknowledged Integrated Resource Plan (IRP) and, to a lesser extent, compliance with the Commission's competitive bidding guidelines. The Commission only recently issued its order updating these guidelines. *See* Order No. 06-446. Staff has spent considerable time addressing issues for this proceeding related to the Independent Evaluator (IE) under Guidelines 5, 6, 10, 11 and 13. *See* September 11, 2006, Staff Report for the September 19, 2006, public meeting.

Staff also notes that under the Commission's original order on competitive bidding, the public comment period preceded staff's comments. *See* Order No. 91-1383 at 10. Staff intends to submit additional comments on the designated date for reply comments on RFP conditional approval. Further, the Commission decided at its public meeting on September 19, 2006, that it will select an IE at its public meeting on November 7, 2006. The Commission further determined that the IE will provide an assessment of the design of the 2012 RFP six weeks after the IE executes a contract with PacifiCorp. Staff expects to have additional comments based on the IE's assessment, including discussion of criteria 3 for RFP approval, below.

Order No. 06-446 established a Commission policy to acquire all Major Resources[1] through competitive bidding. Therefore, PacifiCorp should issue an RFP to fill its projected resource needs. However, the company should rebut to the Commission's satisfaction the concerns staff raises below, or modify its draft RFP to address these concerns prior to issuance. Alternatively, the Commission should impose additional conditions and exceptions for RFP approval.[2]

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[1] Resources with a term of more than five years and quantity over 100 MW.
[2] In addition to the conditional approval related to the Oregon IE assessment.

RFP Summary

PacifiCorp's 2012 RFP seeks to acquire 1,775 megawatts (MW) of base load resources during the period 2012-2014 for delivery to the east side of its system. To be eligible, the resource "must provide 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 14, 2014." *See* Draft 2012 RFP at 3.

Except for resources eligible under the Load Curtailment and Qualifying Facility (QF) categories,[3] the minimum bid the company will accept is for 100 MW of "dependable capacity" and a minimum term of 10 years. These criteria match the definition of significant energy resources that fall under a prescriptive competitive bidding process under Utah law and mandatory pre-approval of resources.[4]

In addition to proposals for load curtailment and QFs, bidders can submit proposals for eight transaction types:

1. Power purchase agreement (PPA) at a PacifiCorp site or bidder's site;
2. Tolling service agreement;
3. Asset purchase and sales agreement for a new facility at PacifiCorp's Currant Creek or Lake Side sites;
4. Asset purchase and sales agreement for a new facility at bidder's site;
5. Engineering, Procurement and Construction (EPC) contract at the Currant Creek site;
6. Purchase of an existing facility;
7. Purchase of a portion of a facility jointly owned and operated by PacifiCorp; and
8. Restructuring of an existing PPA or Exchange Agreement, resulting in incremental capacity and energy.

See Draft 2012 RFP at 4-6.

Market bids will compete against each other, as well as PacifiCorp's Benchmark Resources:[5]

- A 600 MW supercritical (pulverized) coal plant at the Hunter site in Utah in 2012.
- A 340 MW share in a supercritical coal plant in Utah known as the Intermountain Power Project (IPP) Unit 3 in 2012.
- A 750 MW supercritical coal plant at Jim Bridger Unit 5 in Wyoming in 2013.[6]

[3] Minimum size for load curtailment is 3 MW; minimum size for QFs is 10 MW.

[4] See Utah State Law 54-17-101.

[5] The Commission defines a Benchmark Resource as a "site-specific, self-build option." *See* Order No. 06-446 at 5.

[6] If PacifiCorp acquires resources in an amount equal to both the Hunter and IPP plants in 2012, it projects resource needs in 2013 would be 335 MW. If instead the company acquires resources in 2012 in an amount equal only to the IPP project, the projected 2013 requirement would be 935 MW. *See* Draft 2012 RFP at 2.

- A 250 MW to 600 MW Integrated Gasification Combined Cycle (IGCC) coal plant in 2014, location to be determined before the Utah IE locks down the 2014 Benchmark Resource.

A summary of the company's proposed evaluation process follows:

- The company will use the market bids (and Benchmark Resources) as submitted to determine both the initial short-list and the final short-list of bids; PacifiCorp will not ask for, or accept, updated pricing during these evaluation phases.
- To develop the initial short-list of bids, pricing will be weighted 70% and non-price factors will be weighted 30%. The company will use a spreadsheet model ("RFP Base Model") to evaluate pricing. The comparison metric will be projected net present value of revenue requirements (PVRR) per kilowatt per month. Non-price factors include (1) development, construction and operational experience; (2) conformance with the pro forma contracts included in the RFP; and (3) site control and permitting. The maximum score in each of these three areas is 10%.
- Once PacifiCorp determines the initial short-list of bids for each transaction type (PPA, EPC, etc.), the company will use two production cost models to determine the final short list. The company will use its Capacity Expansion Model to optimize portfolios for lowest cost. The portfolios generated by this model will then be run in the Planning and Risk Model two ways: (1) "deterministic" mode, to derive expected costs using base case assumptions and scenarios (e.g., different CO_2 adders) and (2) "stochastic" mode, to assess outcomes under a range of future market prices, loads, etc.
- PacifiCorp will negotiate both price and non-price factors for proposals that make it to the final short-list.

The current schedule assumes issuance of the RFP in November 2006, bids due in 75 days, and PacifiCorp's resource selection in September 2007. At that point, a Utah-mandated 180-day pre-approval process would begin, which would not result in a Utah decision until March 2008.

Criteria for RFP Approval

Order No. 06-446 (at 9) states that the Commission will focus its consideration of RFP approval on three criteria:

(1) The alignment of the utility's RFP with its acknowledged IRP;
(2) Whether the RFP satisfies the Commission's competitive bidding guidelines; and
(3) The overall fairness of the utility's proposed bidding process.
See Guideline 7.

Staff presents its initial comments below under each of these criteria.

Alignment of RFP with PacifiCorp's Acknowledged IRP

2004 IRP Action Plan

PacifiCorp filed its 2004 IRP on January 20, 2005, in compliance with Order No. 89-507. *See* Docket No. LC 39. The company requested acknowledgment of the Action Plan for its "Preferred Portfolio" — Portfolio E with Demand-Side Management (DSM).

The Action Plan included activities for any decision the company intended to make in the next two to four years. The company's Preferred Portfolio included procurement of a 550 MW "flexible" resource (modeled as a natural gas-fired plant) by the summer of 2009 and a 600 MW "high capacity factor" resource (modeled as a pulverized coal plant) by the summer of 2011, both for delivery to Utah. All portfolios evaluated for the 2004 IRP included the following "Planned Resources":

- Up to 1,200 MW of Front Office Transactions, including 700 MW of heavy-load hour products on the east side of the company's system in the summer months — 500 MW at the Four Corners market hub and 200 MW at the Mona hub.
- 1,400 MW of renewable resources system-wide.
- Up to 450 average MW of conservation system-wide.
- 100 MW of known Qualifying Facilities on the East side.

The company defined these Planned Resources as "resources that PacifiCorp is *firmly committed* to acquire, and either is in the process of procuring the resource(s) or *there is a solidly established historical pattern associated with the resource acquisition.* Planned Resources are included in the Load and Resource (L&R) balance because they reflect decisions and/or acquisition processes that can be predicted with some degree of confidence." *See* PacifiCorp 2004 IRP, Technical Appendix, p. 242, emphasis added.

Demand response and distributed generation resources also were part of the company's Action Plan. In addition, the company agreed to a number of Action Plan modifications, including an evaluation of the following items for the *next* IRP or Action Plan:

- IGCC technology in a location potentially suitable for carbon dioxide (CO_2) sequestration, including cost, commercialization status, technology risk, and comparative performance under future uncertainties, including market prices and CO_2 regulation.
- The costs and risks of portfolios with various combinations of additional transmission to reach resources that are shorter term or lower cost, along with new generating resources and their associated transmission.

2004 IRP Action Plan Update

On November 3, 2005, the company filed a 2004 IRP Update with a revised Action Plan based on updated inputs and assumptions. The company concluded in the Update that it no longer needed to pursue the 2009 flexible resource and could delay the high capacity factor resource from summer 2011 to summer 2012. The other large resources in the Action Plan — the 1,200 MW of Front Office Transactions and the 1,400 MW of renewable resources — remained unchanged in the updated Action Plan.

Commission Acknowledgment Order

On January 23, 2006, the Commission acknowledged PacifiCorp's 2004 IRP with agreed-upon modifications, requirements for the next planning cycle, and the following two exceptions:

> Action Item 7, Procure a 550 MW flexible resource in or delivered to Utah by the summer of 2009, is not acknowledged.
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> Action Item 8, Procure a 600 MW high capacity factor resource in or delivered to Utah by the summer of 2011, is not acknowledged.
> *See* Order No. 06-029 at 60.

The Commission said it could not dismiss the need for one such plant on the east side of the company's system in the near future. However, due to deficiencies in the IRP analysis, the Commission could not tell when a plant might be needed, how large it should be, or what resource type(s) should be pursued. The Commission stated:

> [W]e 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[7], 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.
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> 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

[7] Beyond the 700 MW of Front Office Transactions already included in the company's Preferred Portfolio.

the RFP process by providing flexibility for bidders regarding online date, contract length, resource type and technology. *Id* at 51.

The Commission noted that the company filed its IRP Update for informational purposes and requested no Commission action. Parties in Docket No. LC 39 did not have the opportunity to submit comments. Therefore, the Commission did not consider the IRP Update in its decision on acknowledgment of the 2004 IRP. *Id* at 6.

Use of 2006 IRP Inputs, Analysis and Modeling in the 2012 RFP

Staff notes that the Commission's first review criteria for RFP approval is alignment of the utility's RFP with its *acknowledged* IRP.

PacifiCorp states that for the 2012 RFP it is using the 2006 IRP analysis and modeling process. The portfolio modeling and decision criteria used to select the final short-list of bids will be consistent with the modeling and decision criteria used to develop the 2006 IRP Action Plan. Further, the sources of input data used in the models to evaluate the bids and the company's Benchmark Resources will be updated to reflect current conditions, consistent with those to be used in the 2006 IRP. *See* PacifiCorp's letter accompanying its amended UM 1208 filing, August 30, 2006.

The company expects to file its 2006 IRP in January 2007. Staff and parties have not yet reviewed thoroughly the inputs or analysis and modeling processes. And, of course, the Commission has not yet had the opportunity to consider acknowledgment of the IRP.

Load/Resource Balance

PacifiCorp states in its amended RFP filing on August 30, 2006, that the company projected in its 2004 IRP a need for 1,775 MW of new large thermal resources on the east side of the company's system by 2014, in addition to 700 MW of short-term market purchases. Staff notes that the Commission did not acknowledge in the 2004 IRP cycle the magnitude of PacifiCorp's resource needs *even through 2011*. The Commission cited deficiencies in IRP analysis, such as the company's assumption that 261 MW of interruptible contracts on the east side would not continue,[8] inadequate modeling of demand-side and renewable resources, and deficiencies in the company's determination that the planning reserve margin should be set at 15% and be based on the single peak hour of the year.

The company developed a new long-term load forecast and updated its load/resource balance in spring 2006 for its current (2006) planning cycle. The Commission has not yet had the opportunity to review these forecasts and projections, nor have staff and the public formally weighed in on the matter.

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[8] The company changed this assumption in its 2004 IRP Update, effectively reducing its projected resource need on the east side of its system by 261 MW.

More recently, the company updated its load/resource balance to reflect recent acquisitions in response to staff data requests.

The company's most recent forecast of the capacity position on the east side of its system shows a resource deficit of 98 MW in 2012, which increases with load growth to 421 MW in 2014. This is the raw capacity position before consideration of a planning reserve margin or resource additions, such as base load resources or Front Office Transactions.

Adding the company's 15 percent planning margin to these peak resource deficits results in the following proposed resource needs:

- 1,268 MW in 2012
- 1,451 in 2013
- 1,639 MW in 2014

See PacifiCorp Response to Staff Data Request No. 11b.

The addition of a 750 MW super-critical pulverized coal plant in 2013 would reduce the east side capacity deficit to 701 MW in 2013 and 890 MW in 2014. This resource addition, however, also results in a forecast *energy surplus* on the east side of PacifiCorp's system of 1,036 annual average megawatts (MWa) in 2013 and 917 MWa in 2014. *See* PacifiCorp Response to Staff Data Request No. 29.

The above load/resource analysis raises the following concerns. First, the Commission did not acknowledge a 15 percent planning reserve margin for PacifiCorp's 2004 IRP. The Commission stated in part:

> PacifiCorp's IRP analysis does not convince us that its proposed 15% planning margin is appropriate. The 12% planning margin stress-case portfolio is less costly on a deterministic basis, and its expected stochastic cost and upper tail cost are similar to Portfolio E, which includes a 15% planning margin. The assumed costs to customers of unserved energy, and the cost for reducing it, are disputable. Further, under PacifiCorp's proposed implementation, the actual planning margin for its preferred portfolio with DSM will be higher than 15% during several years of the planning cycle. Moreover, the Company did not analyze the cost-risk tradeoff of various planning margins within stochastic modeling of actual portfolios. PacifiCorp's proposed planning reserve margin of 15% is not acknowledged. *See* Order No. 06-029 at 21-22.

Second, given existing market depth and liquidity constraints on the east side of PacifiCorp's system, staff has concerns about the ability of PacifiCorp to sell surplus energy in wholesale markets. Comparatively, a strategy that included targeted Front Office Transactions in the company's resource mix could be a more cost-beneficial way to meet the company's east-side capacity deficit. Staff believes that Front Office Transactions need to be able to compete with base load resources on a comparable basis for inclusion in PacifiCorp's resource portfolio.

In short, the company has not demonstrated the need for 1,775 MW of resources with a term not less than 10 years on the east side of its system during the period 2012-2014.

Resources in the 2004 IRP Action Plan vs. the 2012 RFP

As stated above, the company's 2004 IRP included a high capacity factor resource delivered to Utah in summer 2011. After modifying certain assumptions and inputs for its 2004 IRP Update, the company determined that this resource should be deferred until summer 2012.

Regarding the company's projected resource need in 2013, the company's 2004 IRP did not contemplate the need for a large thermal resource to come on-line in that year. Rather, the company's projected resource need of 335 MW to 935 MW in summer 2013[9] appears to have arisen quite recently as a result of removal of 700 MW of Front Office Transactions on the east side of the company's system.

In its 2004 planning cycle, the company did not ask for Commission acknowledgment of a large thermal resource to come on-line in summer 2014.[10] However, the company's Preferred Portfolio included a pulverized coal plant in Wyoming in summer 2014 as part of its 20-year modeling of load requirements and resource needs.

The Commission's acknowledgment order on PacifiCorp's 2004 IRP includes an agreed-upon modification to the Action Plan for the company to evaluate IGCC technology and carbon capture-ready provisions for the next IRP or Action Plan. The company believes that such technology may be ready for commercial application for a large power plant in 2014. Consistent with the Commission's order on the company's 2004 IRP, staff encourages the company to continue to explore IGCC technology to come on-line at a time the company finds it to be commercially feasible.

Front Office Transactions

In its amended filing on August 30, 2006, the company stated: "...PacifiCorp is now evaluating whether short-term market purchases are an appropriate resource to meet ... projected resource needs. This evaluation is necessary because PacifiCorp is moving toward hedging its system through stable, cost-based resources instead of being subject to increasing market prices and uncertainty associated with reliance on short-term markets to meet long-term needs. This has resulted in the Company removing the planned Front Office transactions in the IRP, which the Company assumed in the preferred portfolio in the 2004 IRP Action Plan.... [I]t is assumed that an additional coal plant will replace the assumptions of Front Office transactions."

This is a dramatic departure from the company's 2004 IRP, the 2004 IRP Update filed just 10 months ago, and the acknowledgment order issued by the Commission in

[9] See Draft 2012 RFP at 2.
[10] The resource was not included in the 2004 IRP Action Plan.

January of this year. Further, as staff explains below, the company has provided no analytical basis for the departure.

In its 2004 IRP, the company stated that Front Office Transactions "represent procurement activity expected to be made on an annual, rolling, forward basis to help cover PacifiCorp's short position, and are applied for all years of the planning horizon. The Company has reviewed historical operational data and, based upon this information, existing transmission constraints and institutional experience, arrived at the 1,200 MW level. For planning purposes, Front Office Transactions were priced at the forward market price curve used in the IRP." *Id at 57.*

The plan addressed both the benefits and risks of these transactions: "The IRP process, when planning to the 15% [planning reserve] margin, is attempting to add flexibility to the portfolio by including Front Office Transactions. The risk analysis for this flexibility has been captured by the stochastic portfolio analyses performed on the dispatchable Front Office Transactions. Given a stochastic distribution of market conditions, Front Office Transactions were dispatched within a portfolio and the resulting PVRRs were included in a risk analysis....

"These transactions comport with the forward market view and environment of the current IRP. The IRP is a dynamic process influenced by numerous changing market variables. The addition of *the Front Office Transactions offers flexibility and diversity to the portfolio, allowing the Company a degree of nimbleness in the short-term and medium-term markets*." *Id.* (emphasis added).

Specifically, the company stated: "These shorter-term, historically-based resources are *intended to bridge the gap between reliance on spot market activity and long-term build-or-buy commitments* in order to balance the system." *See* PacifiCorp's 2004 IRP at 52, emphasis added.

Such 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." *Id.* at 52-53.

At the request of Utah parties, PacifiCorp conducted a "stress test" on its Preferred Portfolio in the 2004 IRP to determine the effect on expected revenue requirements if it were to replace the 1,200 MW of Front Office Transactions on the east and west sides of the company's system with natural gas-fired, combined-cycle combustion turbines in FY 2009 and FY 2013. PacifiCorp's conclusions were as follows:

> Compared to the preferred supply side portfolio, E, the following cost impacts are evident:
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> - The PVRR [present value of revenue requirements over the 20-year test period] is $639 million higher than the PVRR for Portfolio E.

- Spot market purchase costs and sales revenues are lower by $142.8 million and $106.2 million, respectively, reflecting the large relative increase in generation resources available.
- Front Office Transactions that more closely fit load shape are significantly more cost-effective than building or buying long-term assets.

See PacifiCorp's 2004 IRP at 172-173.

The company's filings for the 2012 RFP do not provide a reasonable analytical basis for the sudden change from the company's historical operational level of Front Office Transactions, or the change from the company's "firm" decision in its 2004 IRP and 2004 IRP Update to continue to acquire this level of short-term purchases to maintain flexibility and diversity in its resource portfolio.

Staff submitted several data requests to the company in Docket UM 1208 seeking an analytical basis for the company's plans to abandon its long-standing practice of one- to three-year rolling market purchases, and replacing them with resources with a term not less than 10 years. For example, staff asked the company to provide "documents and analysis that comprise PacifiCorp's evaluation of the appropriateness of short-term market purchases for meeting its projected east-side resource needs." *See* Staff Data Request No. 26. In response to staff's requests, the company states the following:

- "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.[11] 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...." *See* PacifiCorp's response to Staff Data Request No. 1.
- "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." *See* PacifiCorp's response to Staff Data Request No. 3.
- "...[T]he 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." *See* PacifiCorp's response to Staff Data Request No. 8.
- "...Comprehensive stochastic risk analyses comparing these purchases to cost-based resources alternatives was not conducted [for the 2004 IRP] nor were other levels of short-term market purchases evaluated.... The choice of using cost-based

[11] Staff notes that natural gas prices have since fallen. The Commission will be addressing this issue shortly for the annual gas price adjustments for the gas distribution companies.

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…." *See* PacifiCorp's response to Staff Data Request No. 26.

To date, PacifiCorp has not presented any compelling analytical basis for the removal of the 700 MW of Front Office Transactions on the east side of the company's system from its acknowledged 2004 Action Plan, or the company's updated Action Plan filed just 10 months ago. For example, the increase in natural gas and market prices, and increased price volatility, PacifiCorp cites in response to Data Request No. 1 was evident at the time the company filed the 2004 IRP Update in November 2005.

Magnitude of Base Load Resources and Duration of the Highest Peak Loads

Staff has concerns about the magnitude of base load resources the company proposes to acquire, particularly coal resources that operate 24/7 instead of ramping up and down to meet peak demands. Staff has requested load duration curves in 2012, 2013 and 2014 to better understand the duration (number of hours per year) of projected "needle peak" loads in summer on the east side. *See* Staff Data Request No. 42. Additional demand response resources, conservation directed at air-conditioning needs, Front Office Transactions, and natural gas resources may be better able to meet needle-peak demand than coal plants.

Staff also has concerns about PacifiCorp's ability to sell surplus power from proposed base load resources given market depth and liquidity constraints on the east side of its system.

Staff has additional concerns about the company's ability to sell surplus power from new coal plants related to greenhouse gas emissions standards under development. For example, staff of the California Public Utilities Commission (CPUC) is proposing rules that would apply to the state's investor-owned utilities to cap CO_2 emissions at 1,000 pounds per megawatt-hour. The standard would apply to power supplies with a term of five years or more. Coal plants that do not sequester CO_2, or that do not have plans to do so, would not be able to meet the standard as proposed by CPUC staff. Assembly Bill 32, recently enacted by California, limits the state's global warming emissions to 1990 levels by 2020 and institutes an emissions reporting system to monitor compliance. Under the law, California's consumer-owned utilities (as well as other industries) also will be required to meet a CO_2 cap.

Capacity Expansion Model

The Capacity Expansion Model is new to the 2006 IRP and this RFP; the company did not use this economic optimization model for its acknowledged 2004 IRP. The company acquired the model at the behest of Utah parties. Oregon staff has not yet thoroughly reviewed the model. Staff has seen only preliminary runs for the 2006 IRP. This model should be explored further by Oregon's IE to ensure a fair evaluation process.

Resource Diversity

Guideline 9 requires resource diversity with respect to fuel type and resource duration for the initial short list. The draft 2012 RFP does not address diversity for the initial short-list with regard to fuel type. With regard to resource duration, the company asserts that it meets the diversity requirement with flexibility in transaction type (e.g., PPA vs. EPC vs. asset purchase and sales agreement), flexibility for bidders to propose terms greater than 10 years, and flexibility for bidders to propose on-line dates. Staff finds the draft RFP, with a minimum term of 10 years, does not meet the full intent of Guideline 9 with respect to resource duration.

Renewable Resources

The company will accept bids for renewable resources that can meet its definition of base load resources, such as biomass and geothermal plants. Intermittent renewable resources such as wind, however, are not eligible to bid.

The company plans to include in its bid evaluation modeling the commitment by Mid-American Holding Company (MEHC) to 400 MW renewable resources by year-end 2007. However, PacifiCorp has made no provision in the Draft 2012 RFP to account for the appropriate levels of wind resources to acquire after 2007, through the 2012-2014 period covered by the RFP.

The company has not proposed to evaluate wind resources contemporaneously with the coal, natural gas and other resources eligible for the 2012 RFP. There are two ways in which the company could accomplish this: (1) issuing an RFP for wind resources for the same time period or (2) incorporating wind resource and cost data along with modeling of market bids and Benchmark Resources. Staff finds option 2 far more preferable. It would be difficult for developers to bid wind resources with such a long lead-time until 2012, given uncertainty regarding tax credits, technology improvements and cost.

Unless this deficiency is corrected, the company will not be able to use the 2012 RFP to improve upon the IRP in determining the optimal portfolio for customers — the appropriate quantities of each type of resource to acquire through 2014.

Further, because wind resources require other resources (particularly hydro and natural gas) for shaping to loads — and certain types of coal resources may have better ramp rates than others — consideration of wind resources must be taken into account during the evaluation of market bids and Benchmark Resources for the 2012 RFP.

Demand-Side Resources

PacifiCorp issued its 2005 Demand-Side Management RFP covering both energy efficiency and demand response resources on the east and west sides of the company's system nearly a year ago. The RFP stemmed from the company's acknowledged 2004 IRP. The company has not yet selected any demand response project that bid into the RFP. *See* PacifiCorp's response to Staff Data Request No. 23 in UM 1188, July 27, 2006.

Demand response resources targeting peak hours in the summer months, as well as energy efficiency measures that can reduce air-conditioning needs, may be more suitable for meeting the company's needle peaks than base load resources.

Satisfaction of Commission's Competitive Bidding Guidelines

PacifiCorp made a compliance filing on August 30, 2006, endeavoring to conform its originally filed draft RFP to the Commission's competitive bidding guidelines issued after the company's initial filing. Among the changes from the original filing are the following:

- Allowing firm QFs over 10 MW to participate, consistent with Guideline 6.[12]
- Modifying the evaluation criteria so that indirect debt is evaluated only for the final short-list of bids, not in evaluating bids for the initial short-list, consistent with Guideline 9(c).
- Including express language allowing bidders to negotiate mutually agreeable final contract terms different from those in the pro forma contracts included with the RFP, so long as those contract terms either benefit or are neutral to PacifiCorp and its customers, in compliance with Guideline 6.
- Stating that the IE will independently evaluate the Benchmark Resources and at least a sample of the bids to determine whether the company's selections for the initial and final short-lists are reasonable, and the IE will evaluate the unique risks and advantages of the Benchmark Resources, consistent with Guideline 10(d).
- Stating that evaluation results by the company and IE will be compared, consistent with Guideline 10(e).
- Addition of an internal code of conduct (Attachment 20) laying out divisions of responsibility among PacifiCorp staff members.
- Addition of the final short-list acknowledgment process set out in Guideline 13.

Staff has not completed its review of the draft RFP's compliance with the Commission's new competitive bidding guidelines. However, staff offers the following comments at this time.

Staff finds deficient PacifiCorp's plan to ensure resource diversity with respect to fuel type and resource duration pursuant to Guideline 9. In addition to staff's comments above regarding Front Office Transactions and wind resources, staff recommends the Oregon IE review the issue more broadly with respect to the Commission's guidelines and make recommendations to the Commission on the matter.

Staff has concerns about 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," given that the company does not plan to include in its evaluation models any incremental wind resources beyond the MEHC commitment of 400 MW by

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[12] Only high capacity factor QFs are eligible to participate; wind QFs are not eligible.

2007. Staff also has concerns about how PacifiCorp plans to evaluate in the 2012 RFP process whether there should be "a preference to acquire some types of resources over others" (e.g., wind vs. coal or natural gas), given that the company is neither planning to issue an all-source RFP to meet its projected loads in the 2012 to 2014 period, nor running simultaneous resource-specific solicitations for that period. *See* Guideline 9, Order No. 06-446. Staff is awaiting responses to Data Requests Nos. 33-35 on this issue.

Staff has concerns about the ability of bidders to bid an IGCC plant into the RFP, given practical considerations such as the state of technology, the market and financing for IGCC projects. Staff is awaiting responses to Data Requests Nos. 36 and 37 on this issue.

Staff has not yet reviewed credit requirements, including the credit matrix provided by the company at the August 16, 2006, UM 1208 workshop. Staff plans to listen in at the Utah credit workshop on September 21, 2006, and submit comments on credit-related issues on the date set aside for UM 1208 reply comments on RFP conditional approval.

Staff has an outstanding data request to the company regarding how "Lease Accounting Inputs" for the RFP Base Model, which is used to evaluate the price factor for the initial short-list of bids, complies with Guideline 9(c) which states, "Consideration of ratings agency debt imputation should be reserved for the selection of the final bids…." *See* Order No. 06-446 at 11; Staff Data Request No. 41.

In its amended filing, the company requested the Commission not apply the provision from Guideline 6 requiring the utility to consult with the IE in preparing the RFP, and requiring the IE to submit its assessment of the final draft RFP to the Commission when the utility files for RFP approval. Staff believes the Commission resolved this issue in its decision at the September 19, 2006, public meeting.

The company further requested that the Commission not apply the provision in Guideline 5 regarding cost recovery for the IE. Utah law provides for bidders to pay a bid fee. The Draft 2012 RFP requires a $10,000 bid fee for each resource proposal as well as two alternatives for that resource.[13] Any bid fees collected in excess of IE payments will be refunded to non-winning bidders on a pro-rata basis.

Staff agrees with PacifiCorp that the differing state policies regarding IE cost recovery may take time to resolve. Staff further notes that the Oregon UM 1208 proceeding will have its own IE, and PacifiCorp will be able to recoup these IE expenses through the Oregon Commission's proposed process. Therefore, at this time, staff supports PacifiCorp's request that the Commission not apply Guideline 5 as it relates to bidders' fees for the 2012 RFP.

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[13] The bid fee for Qualifying Facility proposals is $1,000.

Summary of Staff's Initial Comments

1. The company has not proved the need for 1,775 MW of resources for the period 2012-2014, or the amount of resources needed in each of these years.

2. The company has not made the case for 10-year minimum resource commitments for 1,775 MW of resources for the period 2012-2014, raising questions related to compliance with Guideline 9 requiring diversity in resource duration for the initial short-list.

3. The company has not made the case that base load resources should be acquired for 1,775 MW of projected resource need for the period 2012-2014.

4. The company has not made the case for its departure from its acknowledged 2004 IRP Action Plan to continue to acquire 700 MW of Front Office Transactions on the east side of its system.

5. If the Commission is inclined to approve the RFP, in whole or in part, staff recommends at this time the following minimum conditions: [14]
   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.[15]
   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 10-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).

6. The Commission should encourage the company to assess the feasibility of IGCC technology at a specific site, including plant design, cost, performance and performance guarantees, carbon-capture ready provisions, and potential for CO_2 sequestration (including transport options) in the future.

7. In general, the type of analysis and modeling the company is proposing, if conducted correctly, can indicate the optimal mix of resources to fill the company's needs. However, staff finds deficiencies in the proposed modeling, given that wind resources are not eligible to bid into the RFP and the company has not proposed to

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[14] In addition to the conditional approval related to the Independent Evaluator. *See* Commission decision on the Staff Report for the September 19, 2006, public meeting.

[15] This provision is similar to one adopted by the Commission in Order No. 04-091 (Docket No. UM 1118) for PacifiCorp's renewable resources RFP.

evaluate them contemporaneously — either through a simultaneous RFP for the same period, or, better, incorporating wind resource and cost data in the RFP modeling. Unless corrected, the company will not be able to determine the optimal portfolio for customers — the right quantities of each to acquire through 2014. Ultimately, the tradeoff of cost vs. risk is a matter of judgment.

8. Among the issues staff recommends the Oregon IE explore regarding RFP design are the following items:[16]
   a. Issues raised by the IE hired by the Public Service Commission of Utah;
   b. The company's proposed modeling, including but not limited to the new Capacity Expansion Model, to ensure a fair comparison of resource types (natural gas vs. pulverized coal vs. IGCC vs. wind, etc.) and build vs. buy options;
   c. The pro forma contracts to ensure no build vs. buy bias, or bias toward or against a particular transaction type or fuel type;
   d. The magnitude of the proposed base load additions, including the 24/7 coal resources serving as Benchmark Resources, versus more flexible resource options that could serve at least a portion of the projected resource need, considering load/resource balances and load duration curves for the planning period;
   e. Resource diversity on the short-lists with respect to fuel type and resource duration;
   f. Credit requirements;
   g. Issues related to removal of the Front Office Transactions, including potential ways to model such transactions during evaluation of bids and Benchmark Resources;
   h. Issues related to considering in the RFP process the appropriate levels of renewable resources to acquire after 2007; and
   i. Whether IGCC proposals can realistically bid into the RFP as designed.

[16] This is not an exhaustive list. Staff is still reviewing the draft RFP as amended, conducting discovery, and reviewing issues raised in the Utah proceeding. Staff also has not yet had the opportunity to review comments from Oregon parties.

CERTIFICATE OF SERVICE

I certify that on September 19, 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.

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