PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF FINAL COMMENTS

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BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON
LC 47

In the Matter of PacifiCorp 2008 Integrated Resource Plan.	STAFF'S FINAL COMMENTS AND RECOMMENDATIONS

Following are Staff's final comments and recommendations on PacifiCorp's 2008 Integrated Resource Plan (IRP), organized according to guidelines the Commission adopted in Order No. 07-002.[1] Attachment A and Confidential Attachment B consist of PacifiCorp's responses to selected data requests and supplemental information.

In these Final Comments Staff addresses concerns raised by the Renewable Northwest Project (RNP), the Citizens Utility Board (CUB), and the Northwest Energy Coalition (NWEC), however, we recognize that these comments do not cover all of the concerns raised in this docket. In its proposed draft order Staff will provide a comprehensive discussion on the concerns raised by parties in both opening and final comments.[2][3]

I. General Issues

Staff's recommendation to the Commission is to acknowledge PacifiCorp's 2008 IRP, subject to several conditions. For example, Staff recommends that PacifiCorp be required to review its wind integration study and work with parties on developing a new study. All Staff's recommendations are contained within Staff's Review of the Plan Based on the Commissions IRP Guidelines.

In its initial comments, filed on October 8, 2009, Staff cited several concerns associated with PacifiCorp's 2008 IRP. Specifically, Staff believed that Action Items associated with the acquisition of a Combined Cycle Combustion Turbine (CCCT) in 2014, a Single Cycle Combustion Turbine (SCCT) in 2016, and proposed transmission segments in its 2008 IRP were not well supported given the "significant changes in customer load" and a lack of analysis provided by the Company. Additionally, Staff and intervening parties expressed concerns with the Company's wind integration analysis, the level of conservation resources in the preferred portfolio, and the level of demand side management resources (DSM) reflected in Oregon as opposed to the rest of PacifiCorp's territory.[4]

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[1] As corrected by Order No. 07-047.
[2] Staff will make available its proposed draft order on January 21, 2010.
[3] Final comments by parties and the Company are scheduled to be filed January 7, 2010.
[4] *See* Staff Draft Comments and Recommendations.

The Company has responded to Staff's concerns with regard to the CCCT and SCCT in 2014 and 2016 by claiming that Action Item 3 designates a span of time, 2012 through 2016, during which the Company intends to acquire firm capacity, and it is this "flexible acquisition strategy" rather than a specific resource on a specific date that the Company is requesting acknowledgement of.[5] The Company goes on to state that it will update its portfolio analysis as part of the 2008 IRP update cycle, and in the context of its 2008 all-source RFP, it will provide the justification for resource acquisition given the most current evaluation of loads, market prices, and regulatory activity.

Staff agrees with the Company, that the resources identified in the plan act as a guide for resource procurement, and should not be held to a rigid interpretation. However, the language in Action Item 3 should be changed to more clearly explain the flexible timing of the base-load resource (2014-2016), as well as the Company's intent to further justify any resource acquisition decisions prior to the 2008 IRP update or next IRP cycle.

In its Draft Comments Staff was concerned that the Company did not provide quantitative analysis of its proposed transmission Action Items 10-12. Specifically, Staff was concerned that the Company did not provide adequate analysis which supported the conclusion that this resource was the best investment decision as compared to a CCCT, SCCT or other proxy resource.

On November 19, 2009 the Company provided additional analysis with regard to the proposed transmission acknowledgement items 10-12; obtaining the Certificate of Public Convenience and Necessity for segments of Gateway Central and Gateway West; constructing Path C Upgrades including the Populus-Terminal segment; and, constructing the Mona-Oquirrh segment. Staff believes that the information provided by the Company on November 19th satisfies the requirements of guideline 5.[6]

Staff and parties have commented that PacifiCorp has not adequately demonstrated maximum achievable energy savings from DSM related activities, and has failed to study or incorporate distribution efficiency improvements (i.e. voltage reduction) in its IRP.

Staff has significant concerns with regard to PacifiCorp's wind integration study. The Company responded to these concerns in its Response to Oregon Party Comments by acknowledging the limitations in its study and requests that the Commission not precondition the IRP acknowledgement on any additional analysis or studies that it may require. Staff agrees with the Company, and

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[5] *See* PacifiCorp 2008 IRP Response to Oregon Party Comments, at 2.
[6] *See* Confidential Attachment B, PacifiCorp's response to Staff Data Request No. 32.

recommends that the Commission require the Company to conduct a stakeholder process in developing a new wind integration study prior to the 2008 IRP update.[7]

RNP, CUB, and NWEC also filed Opening comments on PacifiCorp's 2008 IRP on October 8, 2009. RNP, CUB and NWEC agreed with Staff that the Company's wind integration analysis contains significant flaws, and that PacifiCorp should complete a new study that is part of a public stakeholder process.

RNP and CUB would like to see the Company more effectively model greenhouse gas emission reductions within its portfolios, model the closure of coal facilities, and look at developing a two phased approach to portfolio development. NWEC also cites concerns with regard to the Company's modeling approach, and suggests that PacifiCorp use a *dynamic* methodology similar to that of the Power Planning council, or within the last 10 years of the planning cycle, use only one resource.

II. Review of the Plan Based on the Commission's IRP Guidelines

Below staff provides its assessment of whether PacifiCorp's 2008 IRP meets each of the Commission's guidelines for resource planning. In so doing, staff recommends whether the company's action plan should be modified,[8] including direction for the next planning cycle pursuant to guideline 3e.

Guideline 1: Substantive Requirements

a. All resources must be evaluated on a consistent and comparable basis.

Staff addresses this requirement by major resource category, further below. First, however, staff addresses the specific guidance provided under guideline 1a.

- *All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of power … and demand-side options which focus on conservation and demand response.*

In its 2007 IRP Staff cited concerns that the Company did not go far enough in its modeling of different types of renewable resources and new technologies such as carbon capture and sequestration (CCS) and integrated gasification combined-cycle coal plants (IGCC). PacifiCorp has expanded its supply-side resource options to include those resources cited by Staff and

[7] Prior to the conclusion of this analysis, Staff does not believe that the existing wind integration study is reasonable for use in other ratemaking proceedings.
[8] See the final section of this document for staff's recommendations related to major thermal resources in the action plan.

RNP in their comments. Staff finds that the Company met this requirement. See IRP Chapter 6, tables 6.2-6.10.

- *Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling.*

  Staff finds that the company met this requirement.

- *Consistent assumptions and methods should be used for evaluation of all resources.*

  Staff agrees with the company's assessment that it met this requirement. *See* IRP Technical Appendices at 237.

- *The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs.*

  The company applied its after-tax WACC of 7.4 percent to discount all cost streams. *See* IRP Technical Appendices at 237.

Following are staff's assessments by resource category:

Demand-Side Management. In its Draft Comments Staff cites several concerns with the Company's evaluation of conservation and demand response resources.[9] Specifically, PacifiCorp has not conducted a system-wide study to determine the potential, cost-effectiveness, and customer impacts of a distribution system efficiency (conservation voltage reduction) program, and has therefore not included it as a resource in its current DSM acquisition goal. Additionally, the Company shows acquisition of DSM resources in Oregon to be significantly less than what is modeled in the rest of its territory. Staff addresses these issues in more detail under guidelines 6 and 7.

Renewable Resources. The Company modeled wind, geothermal, biomass and solar. All parties, Staff, RNP, CUB and NWEC, take issue with PacifiCorp's wind integration study presented in this 2008 IRP.

Specifically, RNP and CUB believe that PacifiCorp has overstated its reserve requirement on wind by assuming that existing and new wind resources are 100 percent correlated, and that the Company erroneously assumed that all day-ahead energy imbalances are settled through market transactions. PacifiCorp agrees that the wind integration study requires more research, but is concerned that this represents a major undertaking for the Company due to not only the cited concerns of parties, but also taking into consideration other questions associated with transmission constraints and wind ramping events on integration costs.

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[9] *See* Staff Draft Comments and Recommendations.

Integration costs are a growing concern for Oregon, as the region continues to use wind as a least cost means of meeting the requirements of the state's renewable portfolio standard (RPS). Although Staff finds that Action item 1 of the IRP adequately incorporates sufficient acquisition targets of wind resources,[10] with the existing wind integration study the Company risks over or under estimating the most cost-effective amount of wind to incorporate in its portfolio of renewable resources.

<u>Staff recommends the following addition to PacifiCorp's 2008 IRP Action Plan to address this issue: In the 2008 IRP update, provide a wind integration study that has been vetted by key regional stakeholders through a public participation process.</u>

Market Purchases. In the current resource plan the Company has included in Action Item 2 up to 1,400 MW of front office transactions through 2013, taking advantage of favorable market conditions. As originally discussed in Staff Draft Comments, PacifiCorp's inputs into its IRP are out of date compared to what has actually occurred with regard to load, wholesale power prices and natural gas prices. PacifiCorp's stated intent is not to treat the IRP as a rigid schedule, but to allow flexibility in its procurement of not only market purchases, but more importantly, in timing resource acquisitions.

The Company recognizes that the IRP is based on a snapshot view of the future; however, the intent of the risk analysis is to determine which portfolio strategy might work best under alternate futures. The IRP risk analysis for high load, low load, high gas, low gas, etc… did not go far enough to capture the actual events that occurred at the time this IRP was filed. For example, the low gas scenario utilized in the IRP has a price of $5.83/MMBtu,[11] whereas currently the Henry Hub trading price is less than $5.00/MMBtu[12] with no expectations of significant increases in the future. Similarly, wholesale power prices have also seen significant declines since the Company's forecasts in June 2008. The Company has stated that it recognizes these significant price drops and their potential to "lower power supply costs through market purchases before the Company needs to commit to a large new thermal power plant."[13]

PacifiCorp recently requested to resume its 2008 All-source RFP,[14] which the Commission approved at its November 23, 2009 public meeting. Staff's adopted recommendation to the Commission was that the Company provides justification and analysis for the timing, type and location of the resource need based on its most current evaluation of loads, market prices and regulatory activity. Staff

[10] PacifiCorp states that it will acquire an incremental 1,400 MW of renewable by 2018, for a projected renewable resource inventory of 2,540 MW.
[11] *See* 2008 IRP table 7.6, page 150.
[12] Bloomberg spot price on December 3, 2009 was $4.53/MMBtu, which was approximately 28% lower than the previous year.
[13] *See* IRP page 3.
[14] *See* Docket UM 1360, PacifiCorp's request to resume the 2008 RFP, filed November 2, 2009.

believes that this condition should show whether or not market purchases are a more cost-effective means of supplying intermediate load, as opposed to the acquisition of a new resource whose timing may need to better coincide with a protracted recovery from the current recession.

<u>Staff recommends the following addition to PacifiCorp's 2008 IRP Action Plan to address this issue: In the 2008 IRP update, evaluate the intermediate-term market purchases, taking into consideration the most current evaluation of loads, market prices and regulatory activity, in order to determine the best resource option.</u>

Distributed Generation. The company included dispatchable standby generation, combined heat and power (CHP) plants, and on-site solar as resources for the Capacity Expansion Model to select. Action Item 8 of the IRP states that the Company will "pursue 100 MW of distributed generation resources by 2018."[15]

Fossil-Fuel Resources. Due to the uncertainty of future carbon regulation, and the costs for large coal-fired boilers rising approximately 50% - 60% since the 2007 IRP, the Company is postponing the selection of coal as a resource before 2020.[16]

PacifiCorp did include CCS and IGCC technologies for selection in the model at an existing coal plant. However, the Company does not believe that CCS is a viable option before 2025 "due to risk issues associated with technological maturity and underground sequestration liability."[17] With regard to the IGCC technology, gasification plants have been built and demonstrated around the world. However, for the purposes of power generation, these facilities have been demonstration projects and cost significantly more than conventional coal plants. PacifiCorp is a member of the Gasification User's Association, and over the last two years has held a series of IGCC working group public meetings to "help provide a broader level of understanding for this technology."[18]

In its 2008 IRP PacifiCorp has included 170 MW of emission free, coal plant capacity gains. The Company is taking advantage of upgraded technology called the "dense pack" coal plant turbine upgrade initiative. This upgrade does not increase fuel consumption, heat input, or emission, and the capacity expansion modeling indicated that this upgrade initiative was cost-effective.

Both SCCT and CCCT gas plants were considered for capacity additions and both resources were chosen by the model and included in the preferred portfolio. The SCCT is shown as being added in 2016, but with recent changes in load it is unlikely that this resource will be needed in this time-frame.[19] The CCCT gas

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[15] *See* IRP page 257.
[16] *See* IRP page 113.
[17] *Id.*
[18] *See* IRP page 114.
[19] When the Company evaluated the February 2009 load forecast on its preferred portfolio the capacity expansion model determined that a SCCT resource in 2016 was no longer needed. PacifiCorp maintained the SCCT in the preferred portfolio because of the uncertainty with the

plant, a recent topic in docket UM 1360, is in the preferred portfolio as coming on-line in the summer of 2014. However, the Company has stated that it will continue to "seek cost-effective resource deferral and acquisition opportunities in-line with near-term updates to load/price forecast, market conditions, transmission plans, and regulatory developments."[20]

Staff recommends the following additions to PacifiCorp's 2008 IRP Action Item 3 to address this issue:

<u>In the 2008 all-source RFP the Company will demonstrate the need and timing for the resource, taking into consideration current load/price forecasts, market conditions, transmission plans, and regulatory developments. The Company will demonstrate that additional deferral of a base load resource using cost-effective intermediate market purchases, or other alternatives is not in the best interest of customers.</u>

<u>In the 2008 IRP update, evaluate the continued need for the SCCT resource in 2016 given current load/price forecast, market conditions, transmission plans, and regulatory developments.</u>

Transmission. PacifiCorp has stated it is moving forward with an expansion plan that will eventually construct transmission lines and substations required to provide 1,500 MW on the proposed Gateway West and 1,500 MW on the proposed Gateway South lines. The transmission system model topology map on page 138 of the IRP shows all segments that were included in the System Optimizer model used to derive optimal resource expansion plans for all portfolios.

In its Draft Comments, Staff cited significant concerns with PacifiCorp's lack of provided analysis with regard to transmission. Staff addresses this issue in more detail under guideline 5.

b. *Risk and uncertainty must be considered.*

- *At a minimum, electric utilities should address the following sources of risk and uncertainty: load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices, and costs to comply with any regulation of greenhouse gas emissions.*

  The company's stochastic modeling addresses all of the sources of risk and uncertainty that the plan must consider: load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices and emission prices. To address the cost to comply with future regulation of greenhouse gas

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timing and pace of an economic recovery, and that the resource was not scheduled to be included until 2016.

[20] *See* IRP page 256.

emissions, the Company conducted the Commission-required scenario analyses (0, $45, $70, and $100 in 2008$), modeled both cap-and-trade and tax strategies, and analyzed a portfolio that would comply with a regional emissions performance standard. The Company also performed sensitivity studies with various combinations of low, medium and high levels of the following factors: load growth, natural gas and electricity prices, CO_2 compliance costs, renewable portfolio standards, renewable energy tax credit expiration, high plant construction costs, capacity planning reserve margin, and achievable market potential for demand response programs.

- *Utilities should identify in their plans any additional sources of risk and uncertainty.*

Additional sources of risk and uncertainty identified in the plan are capital costs, the level of achievable DSM potential, expiration of federal tax credits for renewable energy resources, capacity planning reserve margins and renewable portfolio standards.

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

The company describes its selection and justification of the preferred portfolio on pp. 241-251 of the IRP. The Company considered both expected costs and associated risks and uncertainties. Additionally, the Company took into consideration the impact of the 2012 gas resource deferral decision and performed additional portfolio studies reflecting the removal of Lake Side II as a planned resource in 2012.

- *The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.*

The company uses a 20-year study period for portfolio modeling and a real levelized revenue requirement methodology for treatment of end effects consistent with past IRP practice.

In opening comments parties raised concerns about PacifiCorp's modeling of the last 10 years of the 20 year cycle. Specifically, NWEC believes that the Company's approach in the last 10 years is not illustrative of real-world decision making, which would react to the constantly changing market conditions. NWEC believes that flexibility and optionality should be tested and valued in the Company's portfolio modeling approach. They have proposed that the Company should either adopt the Power Planning Council dynamic modeling approach or “fix” a resource in all portfolios for the latter half of the planning period.

RNP and CUB also raise concerns about the Company’s approach to the last 10 years of the planning period. They feel that it is “appropriate to allow the system optimizer model to select the near term part of the portfolio and then fix those decisions, but allow for different choices in later years as necessary.”[21] They are concerned that PacifiCorp is effectively freezing its decision making at the present time, and not allowing for the fact that it is likely that the future will be different. RNP and CUB raise this issue as a concern that these later resource decisions may unduly weight the portfolio selection process by unduly weighting its performance.

RNP and CUB recommend that PacifiCorp conduct capacity expansion optimizations in two passes: simulations to determine near-term resources to link to the IRP action plan, followed by simulations with the near-term resources fixed and allowing System Optimizer to optimize resources in the out years. The Company responds to this suggestion by stating that the approach has an “intuitive appeal,” but feels that it would dramatically increases its run times to an “unrealistic level.”

<u>Staff agrees with RNP, CUB, and NWEC, and recommends to the Commission that for the next IRP planning cycle PacifiCorp will work with parties on developing an approach that addresses all parties concerns and can sufficiently show that portfolio performance is not unduly influenced by decisions that are not relevant to the IRP Action plan.</u>

- *Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all long lived resources such as power plants, gas storage facilities, and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases.*

  The IRP complies with this standard.

- *To address risk, the plan should include, at a minimum:*

  1. *Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes.*

     The plan complies with this requirement. The Company uses standard deviation of stochastic production costs as the measure of cost variability. For the severity of bad outcomes, the company calculates several measures, including stochastic upper-tail PVRR (mean of

[21] *See* Opening Comments of RNP and CUB, at 8.

highest five Monte Carlo iterations) and the 95th percentile stochastic PVRR.

2. *Discussion of the proposed use and impact on costs and risks of physical and financial hedging.*

   The IRP includes a discussion of hedging on p. 274.

- *The utility should explain in its plan how its resource choices appropriately balance cost and risk.*

The Company summarizes its cost/risk tradeoff analysis in Chapter 8 of the IRP, and ultimately explains its rationale for the preferred portfolio on p. 241.

d. *The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.*

The increasing mix of renewable and clean resources reflected in the 2008 IRP preferred portfolio reduces the carbon intensity of PacifiCorp's generation fleet and positions the Company well for meeting future climate change and renewable resource requirements. As it is proposed, the preferred portfolio exceeds current jurisdictional RPS requirements and would potentially meet a 15 percent federal RPS requirement currently proposed in "The American Clean Energy and Security Act of 2009" by Waxman/Markey recently passed through the House of Representatives.

Guideline 2: Procedural Requirements

PacifiCorp met all procedural requirements.

a. *Public involvement in the preparation of the IRP*

The Company provided extensive opportunities for public input. *See* IRP at page 22.

b. *The plan should include non-confidential information that is relevant to the company's resource evaluation and action plan.*

The Company provided non-confidential information in the main IRP document and Technical Appendices, meeting handouts, via e-mail and in response to data requests.

c. *Draft IRP for public review and comment*

The company provided its draft IRP for public review and comment on April 8, 2009.

Guideline 3: Plan Filing, Review, and Updates

a. Timeliness of IRP filing

The company filed its 2008 IRP timely, approximately 1-1/2 years after acknowledgment of the last plan.

b. Timely presentation of the results of the filed plan at a Commission public meeting

The company presented the results of its plan to the Commission at a public meeting on September 8, 2009.

c.-g. N/A

Guideline 4: Plan Components

At a minimum, the plan must include the following elements:

a. An explanation of how the utility met each of the substantive and procedural requirements

Appendix C of the IRP provides this explanation.

b. Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions

The Company included low, medium and high load growth forecasts for scenario analysis using the System Optimizer model for portfolio development. Stochastic variability of loads was also captured in the risk analysis. The company included loads among its stochastic risk parameters in testing all its Risk Analysis portfolios.

PacifiCorp made six major changes with regard to its sales and load forecasting method. First, PacifiCorp used load research data to model the impact of weather on monthly retail sales and peaks by state by class. Second, the time period used to define normal weather was updated from the previous period of 1971-2000 to a 20-year time period of 1988-2007. This time period change better captured the trend of increasing temperatures observed in both summer and winter. Third, the historical data period used to develop the monthly retail sales forecasts was updated to cover 1997-2007. Fourth, monthly peaks were forecasted for each state using a peak model with historical data from 1990-2007. This model allows the Company to better predict monthly and seasonal peaks. Fifth, system lines losses were updated to reflect actual losses for the 5-years ending December 31, 2007, as opposed to the previous IRP which was based on calendar-year 2001 data. Finally, analysis was performed and adjustments made to reflect current economic conditions, the Company mirrored the load changes experienced in the previous recession (2001-2002).

c. *For electric utilities, a determination of the levels of peaking capacity and energy capability expected for each year of the plan, given existing resources; identification of capacity and energy needed to bridge the gap between expected loads and resources; modeling of all existing transmission rights, as well as future transmission additions associated with the resource portfolios tested*

PacifiCorp estimates a summer peak resource deficit for the system beginning in 2010 to 2011. The Company projects it will become capacity deficit in 2011, based on a 12 percent planning reserve margin. The company estimates that deficit will grow from 498 MW in 2011 to 1,936 MW in 2012, and to nearly 3,528 MW by 2018. *See* IRP at 96.

PacifiCorp relied on a November 2008 load forecast for the development of the load and resource balance and portfolio evaluations. The Company also performed sensitivity analysis on the preferred portfolio using a February 2009 load forecast, which better took into consideration the current economic climate. Staff continues to have concerns associated with the use of the November 2008 load forecast in the development of the preferred portfolio. On an actual basis, loads have declined by 5 percent year over year,[22] with industry experts not expecting a rebound recovery from this recession, but instead, it is thought that a more prolonged protracted recovery may occur in which the economy may never achieve previous levels of production.

The Company claims that it was not able to calculate a complete refresh of its 2008 IRP using the February 2009 forecast due to the additional scope in this IRP model, which would have made it impossible for the Company to meet its IRP filing deadlines with the state commissions. Staff agrees that re-doing the IRP portfolio analysis, taking into consideration large load and market price changes, would have been a major undertaking. The Company has provided a more comprehensive sensitivity analysis of the load change on the preferred portfolio, inclusive of break-even points with regard to acquisition of the CCCT and the level of peak load change that would be required to defer the acquisition of the resource to later years.[23]

Energy Needs. PacifiCorp projects energy consumption to grow system-wide at an average annual rate of 2.1 percent from 2009 through 2018. This rate is lower than the 10-year average rate of 2.4 percent in the company's 2007 IRP. For the second half of the study period, the company projects a 1.2 percent

[22] *See* PacifiCorp's response to Staff Data Request No. 23, Attachment A.
[23] *See* PacifiCorp's supplemental information, Attachment A.

system-wide growth rate, and for the 20 year period an overall 1.6 percent growth rate.

Energy consumption in the east continues to growth faster than in the west — 2.34 percent versus 1.02 percent per year, respectively. The company expects Wyoming to grow at a faster rate than any other state — 3.4 percent per year on average.

The Company's February 2009 forecast also shows a 2.1 percent growth rate for the period of 2009-2018, with the second half of the study period at 1.1 percent and an overall 20 year period growth rate of 1.6 percent.

Capacity Needs. In the November 2008 forecast PacifiCorp forecasts coincident peak loads to grow by 2.4 percent system-wide from 2009-2018.[24] For comparison, the 2007 IRP forecasted coincident peak load to grow by 2.6 percent for the period of 2007-2016. By control area, the company expects peak loads to grow by 2.7 percent in the east and 1.6 percent in the west. Total peak load growth is forecast to be 238 MW annually, with Oregon expected to contribute only 37 MW. The February 2009 forecast shows coincident peak loads to grow by 2.2 percent system-wide from 2009-2018 with load growth of 217 MW annually.

Staff's Analysis of Load Forecasts. As compared to previous IRP's the Company projects both energy and capacity to grow, but at a lower rate than the historical average. Current economic conditions have had a significant effect on PacifiCorp's loads. As previously discussed, the Company has realized a five percent decline in energy and an even greater decrease in peak demand. However, when comparing the November 2008 load forecast to the February 2009 load forecast it shows that peak loads for the east side of the system actually increased relative to the November 2008 forecast. Staff is skeptical that the Company's November 2008 or February 2009 forecast is able to capture the current economic climate. It is this skepticism that prompted the condition to require the Company to perform additional analysis and justification in the recently resumed 2008 all-source RFP. In addition, the Company has stated in the 2008 IRP that it will do a more thorough analysis of the implications of a declining load and market price forecast, and the impact this may have on any resource acquisitions, in its 2008 IRP update.

Transmission. The company modeled existing transmission rights and future transmission additions associated with the portfolios tested. In addition, the Company included three transmission resource options in System Optimizer, however, none of these options was selected. *See* IRP at 279-289 and 186.

d. N/A

[24] Coincident peak load occurs in summer driven by air conditioning.

e. *Identification and estimated costs of all supply-side and demand-side resource options, taking into account anticipated advances in technology*

See Tables 6.2 through 6.10 for supply-side resource and Tables 6.15 through 6.20 for demand-side resources, IRP at 93-96, as well as resource descriptions in Chapter 6.

f. *Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs*

The IRP meets this requirement.

g. *Identification of key assumptions about the future (e.g., fuel prices and environmental compliance costs) and alternative scenarios considered*

The IRP meets this requirement by describing the base case assumptions (Chapter 7) and testing a range of alternative scenarios addressing key variables such as load growth, natural gas and electricity prices, and regulatory compliance costs for CO_2 emissions.

h. *Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations – system-wide or delivered to a specific portion of the system*

The IRP meets this requirement.

i. *Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties*

The IRP meets this requirement. Chapter 8 presents the results of deterministic and stochastic analyses.

j. *Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results*

The IRP meets this requirement. *See* Chapter 8.

k. *Analysis of the uncertainties associated with each portfolio evaluated*

The IRP meets this requirement. *See* Chapter 8.

l. *Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers*

PacifiCorp estimates future revenue requirements over a 20-year study period to compare the costs and risks of candidate portfolios. The company considers both stochastic and scenario risks. Stochastic risk applies when probability distribution functions can be estimated. Such is the case with fuel and electricity market prices, hydro conditions, loads and thermal availability. Scenario risks represent abrupt changes in risk factors, such as sudden changes in natural gas prices, regulatory compliance costs and capital costs.

PacifiCorp conducts stochastic analyses to arrive at both its cost and risk determinations. One hundred stochastic runs over the 20-year study period are conducted for each of four modeled levels of CO_2 adders, ranging from zero to $100 per ton (levelized, in 2009 dollars) and has an assumed 2013 implementation date. The company calculates present value of revenue requirement (PVRR) assuming a direct tax adder and a cap-and-trade compliance strategy whose trading values are equivalent to the tax adders. Stochastic Mean PVRR, the average of 100 modeled PVRR outcomes, is the company's primary cost metric.

Risk-adjusted Mean PVRR – The risk-adjusted PVRR is calculated as the stochastic mean PVRR plus the expected value of the 95th percentile PVRR. This metric expresses a low-probability portfolio cost outcome as a risk premium applied to the expected PVRR based on the 100 Monte Carlo simulations conducted for each production cost run. Other risk measures displayed in the IRP are the Upper-Tail PVRR, the 95th Percentile and 5th percentile PVRR, and the Production Cost Standard Deviation. *See* IRP Table 7.8 at 175 and page 173 for a full description of these measures.

PacifiCorp also presents scatter-plot graphs of the stochastic mean PVRR versus upper-tail mean PVRR for portfolios as a means to visualize the tradeoff between expected and high-cost outcomes. *See* IRP Figures 8.16 through 8.19 at 209-211.

m. *Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation*

The Company included sensitivity case 40 to meet the Commission's requirement from the 2007 IRP, which stated that it should "develop a plan to meet the CO_2 emissions reduction goals in Oregon HB 3543."[25]Staff and intervening parties are not satisfied with the Company's inclusion of one sensitivity case and believe that the Company should go further in modeling a declining number of carbon credits and hard-cap emission standards.

<u>Staff recommends the following: for the 2008 IRP update and next planning cycle, develop a more comprehensive inclusion of a hard-cap emissions</u>

[25] *See* Docket LC 42, Order No. 08-232 at 36.

standard and emission reduction plans, which includes the evaluation of the effect of the closure of coal facilities.

n. *An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing*

Table 9.2 (IRP at 255-259) provides the company's action plan.

Guideline 5: Transmission

PacifiCorp is requesting Commission acknowledgement of key short term transmission issues; obtaining the Certificate of Public Convenience and Necessity for segments of Gateway Central and Gateway West and constructing Path C Upgrades including the Populus-Terminal and the Mona-Oquirrh segments. In its IRP the Company has described its expansion plans with regard to transmission[26] and the individual segments that make-up the Gateway transmission project. However, what the Company did not provide was a cost/benefit analysis, or comparative analysis to other resource types, which showed that these proposals, and specifically those currently being sought for acknowledgement, were in the best interest of PacifiCorp's customers. Staff commented in its Draft Comments that it believed that PacifiCorp failed to meet the requirements of guideline 5. Since that time, PacifiCorp has provided a more thorough write up of the on-going Energy Gateway financial analysis and supporting work papers.[27]

PacifiCorp notes that the Energy Gateway development is a *transmission strategy*, which was developed to be flexible and scalable as conditions change over time. The overall strategy is financially assessed each year and each segment is also reviewed and justified individually. The Company considers multiple inputs in the decision making process including: compliance and reliability, net power cost analysis, and least-cost analysis of alternatives.

With regard to the Path C Upgrades including Populus-Terminal and Mona Oquirrh the Company performed portfolio evaluation with and without the 300 MW Path C upgrade using the IRP stochastic production cost model. Portfolios with the Path C upgrade out-performed portfolios without the upgrade on the basis of stochastic cost, risk, and supply reliability measures. Therefore, after reviewing the analysis,[28] Staff finds that the proposed transmission segments provide increased reliability, additional transfer capability, and at the same time

[26] *See* IRP Chapters 4 and 10.
[27] *See* Confidential Attachment B for PacifiCorp's response to Staff Data Request No. 32, Summary of Energy Gateway Financial Analysis, November 19, 2009.
[28] *Id.*

support integration with larger segments, for an overall benefit to Oregon customers that outweighs the proposed capital investment.

Based on the financial analysis modeling results, eight transmission projects were part of all risk analysis portfolios, including the preferred portfolio. *See* IRP at 208-281.

With regard to guideline 5 and the requirement that the company treat the transmission facility as a resource option, Staff finds that the Company has met this guideline. In its response to Staff Data Request No. 32 the Company discussed its analysis of the Gateway transmission project with and without Wyoming resources. Using the preferred portfolio as the base case assumption the analysis showed that the preferred portfolio was more cost effective with the inclusion of the transmission projects as opposed to incremental Wyoming resources.

Staff recommends for the 2008 IRP update and future IRP planning cycle the inclusion of its on-going financial analysis with regard to transmission, which includes: a comparison of alternative supply side resources, deferred timing decision criteria, the unique capital cost risk associated with transmission projects and the scenario analysis used to determine the implications of this risk on customers, and all summaries of stochastic annual production cost with and without the proposed transmission segments, and base case assumptions.

Guideline 6: Conservation

a. Periodic conservation potential study for the entire service territory

Under the Commission's updated planning guidelines, the utility should analyze potential conservation resources regardless of any limits on funding. The IRP included data provided from a system wide DSM potential study completed in June 2007, which were then converted for the first time into the prescribed supply-curve methodology. This study provided a broad estimate of the size, type, location and cost of demand-side resources.

Staff and intervening parties questioned whether the IRP understates the cost-effective potential outside of PacifiCorp's Oregon service territory based on a comparison with the Northwest Power and Conservation Council's conservation potential study for the Northwest.

Staff recommends that PacifiCorp assess its service area-wide study against the Council study in the 2008 IRP update and commission a new system-wide potential study for its next planning cycle.

b. To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan *all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.*

c. To the extent that an outside party administers conservation programs in a utility's service territory at a level of funding that is beyond the utility's control, the utility should:

- *Determine the amount of conservation resources in the best cost/risk portfolio without regard to any limits on funding of conservation programs; and*
- *Identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition.*

For PacifiCorp's Oregon service area, the Company relied on an augmented study prepared by the Energy Trust of Oregon in May 2008. PacifiCorp did not incorporate into its plan the findings from the Energy Trust's February 2009 Conservation Potential Study. Working with Staff and Energy Trust of Oregon, PacifiCorp should incorporate this study in its 2008 IRP update.

The 2008 IRP does not identify any savings from distribution efficiency measures (conservation voltage reduction measures). These conservation measures were highlighted in both the May 2006 and February 2009 conservation potential studies. Further, they have been identified as a major cost-effective resource in the Northwest Power and Conservation Council's 6th Annual Plan.

<u>Staff recommends conditioning the action plan to require PacifiCorp to participate in Commission workshops on distribution efficiency measures, assess the costs and savings of implementing those measures, and set forth an action plan for implementation in next year's IRP update.</u>

As discussed above, PacifiCorp incorporated into its 2008 IRP the Energy Trust's May 2008 energy efficiency resource acquisition plan, but did not incorporate its most recent resource potential study completed in February 2009. However, Staff and PacifiCorp have reached an agreement on SB 838 funding intended to increase PacifiCorp's energy efficiency funding by 1.7 percent, and Staff anticipates that the Company will meet its aggregated 2010 and 2011 IRP targets by the end of 2011.

Guideline 7: Demand Response

PacifiCorp categorizes demand response into two types: Class 1 DSM includes dispatchable load control, scheduled irrigation and thermal energy storage; Class 3 DSM includes curtailable rates, critical peak pricing and demand buyback.

In the 2004 IRP, the company took its first step toward comparable treatment of demand response and supply-side resources by allowing the CEM to choose Class

1 DSM and displace supply-side resources in the preferred portfolio. In its 2007 IRP the Company was required to include Class 1 and Class 3 DSM supply curves, modeling them as portfolio options that compete with supply-side options, and analyzing cost and risk reduction benefits. The Company complied with this requirement; however, the selection of Class 3 DSM as a supply-side option was not selected by the model into any of its portfolios. The model did select a small amount of Class 1 DSM capacity (2 to 7 MW) and a sizable amount of Class 2 DSM (1,537 MW to 2,183 MW).

With regard to Class 3 DSM the Company explains that "it requires more information on the extent to which these products could be sufficiently reliable to be classified as firm capacity resources, and has incorporated such research as part of IRP action item number 7." *See* PacifiCorp 2008 IRP Response to Oregon Party Comments, at 6.

To the extent that guideline 7 requires the Company to evaluate demand response resources on par with supply-side and demand-side resources, it has met this guideline. However, the Company needs to go farther in evaluating the cost and amount of resources from curtailable rates, demand buybacks, and critical peak pricing programs.

Guideline 8: Environmental Costs

The Company met the Commission's current guidelines for analyzing portfolios.

Given that no single CO_2 reduction compliance approach has emerged as a consistent front-runner for adoption, the Company considered a wide range of carbon cost outcomes. The Company modeled CO_2 tax for all core cases with an implementation date of 2013. However, RNP suggests that the Company did not go far enough in modeling reductions in emissions or the effect of the closure of coal facilities. Staff agrees with RNP and believes that the Company should further evaluate emission reductions, showing total emissions for each portfolio, and should further evaluate the effect of the closure of coal facilities in its next IRP planning cycle.

The Company's trigger analysis looks at the production cost impact of up to \$70/ton CO_2 tax. The resulting changes in the preferred portfolio resulted in greater acquisition of demand-side management programs and high-efficiency distrusted generation to help minimize the carbon footprint. The greatest change however would be the additional acquisition of 2,500 MW of wind and at least 70 MW of geothermal capacity or other base-load renewable resources with the timing and annual amounts tied to the start of the CO_2 regulations and a trajectory of the cost.

Guideline 9: Direct Access Loads

PacifiCorp complies with this guideline. The Company does not offer a permanent opt-out program. Therefore, it plans for all Oregon loads, including those customers who have selected direct access or standard offer service.

Guideline 10: Multi-state Utilities

The company planned on a system-wide basis, as specified under this guideline.

Guideline 11: Reliability

Under Guideline 11, electric utilities should:

a. Analyze reliability within the risk modeling of the actual portfolios being considered
b. Determine loss of load probability (LOLP), expected planning reserve margin, and expected and worst-case unserved energy by year
c. Demonstrate that the selected portfolio achieves the utility's stated reliability, risk and cost objectives

PacifiCorp analyzed reliability within the risk modeling of the actual portfolios being considered by evaluating a subset of portfolios at both a 12 percent and a 15 percent planning reserve margin and then evaluating loss of load probability and average and worst-case energy not served (ENS). Ultimately, the company selected a portfolio with a 12 percent planning reserve margin and concluded that "it is not cost-effective to invest in incremental generating capacity for reserves given that the cost premium for such investment is above the assumed ENS cost." *See* IRP at 221.[29]

Table 8.15 in the IRP displays the average LOLP for each of the candidate portfolios during the summer peak at various ENS event thresholds. Staff finds that the selected portfolio achieves the Company's reliability, risk and cost objectives.

Guideline 12: Distributed Generation

PacifiCorp evaluated combined heat and power (CHP, or cogeneration) and dispatchable customer standby (diesel) generation resources. The Company's Action Item 8 includes 50 MW of CHP and 50 MW of cost-effective customer standby generation. Additionally, the Company states that if the economic recession and market conditions continue to support elimination of simple-cycle gas units or other peaking resources, as indicated by the IRP portfolio modeling for the 2010 business plan, the Company will seek to acquire an additional 40 MW of customer standby generation.

[29] The identified cost premium of ENS reduction at a 15 percent planning reserve margin was $659/MWh. *See* IRP at 219.

The Company also looked at rooftop photovoltaic systems, but a sensitivity test showed that due to the higher fixed costs and lower availability relative to small competing resources such as CHP and DSM, the model did not choose any micro-solar resources.

Guideline 13: Resource Acquisition

a. An electric utility should, in its IRP:

- *Identify its proposed acquisition strategy for each resource in its action plan.*
- *Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party.*
- *Identify any Benchmark Resources it plans to consider in competitive bidding.*

The company complied with these requirements. The company provided its acquisition strategy for its action plan and a brief assessment of the advantages and disadvantages of owning vs. purchasing resources. *See* IRP at 264-268. At the time of filing the Company had suspended its 2008 RFP, under the now resumed 2008 all-source RFP, the Company has included a single benchmark resource which will be a CCCT at the Lake Side site.

b. N/A

This concludes staff's Final comments.

Dated at Salem, Oregon, this 8th day of December, 2009

Kelcey Brown
Senior Economist
Electric Rates & Planning

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF FINAL COMMENTS

ATTACHMENT A

December 8, 2009

OPUC Data Request 23

Please provide a weather normalized change in load from January through July 2008 versus January through July 2009. Please provide your response in the following format; showing actual loads for each month, weather normalized loads for each month and the calculated change by month in excel format with formulas intact.

Response to OPUC Data Request 23

Please refer to Attachment OPUC 23.

Please refer to non-confidential Attachment OPUC 23 on the enclosed CD.

Month over Month change in weather adjusted sales

Actual Load 2008	Actual Load 2009
31,369,447	29,928,977
Difference	-4.80%

	Forecasted 2009	Actual 2009
Peak Load	9,987	9,420
Difference	-5.68%	

Sum of MWh								
State	Revenue Class	January	February	March	April	May	June	July
STATE OF CALIFORNIA - PPL	RESIDENTIAL SALES	(9,316)	(3,483)	2,015	(2,172)	(494)	(3,035)	3,455
	COMMERCIAL SALES	(3,698)	1,235	(454)	2,713	1,740	2,122	(187)
	INDUSTRIAL SALES	(1,401)	(3,592)	(3,156)	(2,368)	(3,338)	(3,000)	(2,386)
	IRRIGATION SALES	(1,788)	(607)	(473)	(2,038)	(19,316)	(19,184)	(28,899)
	PUBLIC STREET&HIGHWAY LIGHTING	32	7	(10)	(0)	(4)	(9)	4
STATE OF IDAHO - UPL	RESIDENTIAL SALES	(9,649)	(9,898)	6,758	(235)	1,659	(3,491)	2,200
	COMMERCIAL SALES	19,355	(7,622)	2,871	(1,906)	(3,095)	12,648	(3,267)
	INDUSTRIAL SALES	6,521	(29,757)	4,346	(52,896)	(62,110)	(90,568)	(78,628)
	IRRIGATION SALES	(1,529)	129	845	716	24,059	(27,254)	(25,731)
	PUBLIC STREET&HIGHWAY LIGHTING	(11)	(107)	(16)	45	7	(159)	128
STATE OF OREGON - PPL	RESIDENTIAL SALES	(111,866)	(69,365)	28,851	(24,314)	(15,447)	(5,279)	(20,027)
	COMMERCIAL SALES	(8,489)	(30,405)	(26,756)	2,929	189	(22,011)	14,632
	INDUSTRIAL SALES	(15,278)	(57,510)	(60,308)	(22,987)	(35,775)	(71,007)	(46,860)
	IRRIGATION SALES	248	(175)	443	(3,148)	(9,066)	12,411	(9,340)
	PUBLIC STREET&HIGHWAY LIGHTING	1,206	(218)	(818)	273	(178)	129	862
STATE OF UTAH - UPL	RESIDENTIAL SALES	(22,587)	24,269	(879)	1,843	(3,913)	27,263	(22,395)
	COMMERCIAL SALES	1,940	(33,253)	90,860	(13,070)	2,825	(1,899)	2,490
	INDUSTRIAL SALES	(40,873)	(55,628)	(85,963)	(67,471)	(96,639)	(119,413)	22,820
	IRRIGATION SALES	526	396	(53)	(193)	(6,816)	422	(6,616)
	OTHER SALES TO PUBLIC AUTH	1,665	(1,780)	(2,798)	(10,491)	7,930	1,448	(360)
	PUBLIC STREET&HIGHWAY LIGHTING	410	126	(662)	934	184	(1,268)	1,674
STATE OF WASHINGTON - PPL	RESIDENTIAL SALES	25,381	(21,881)	13,202	6,150	(16,888)	17,994	(23,533)
	COMMERCIAL SALES	14,563	(8,859)	(6,270)	(3,203)	(3,110)	27,230	10,869
	INDUSTRIAL SALES	(10,433)	(23)	(8,196)	19,424	(19,634)	(7,966)	(4,625)
	IRRIGATION SALES	243	(254)	461	(7,681)	4,946	38	393
	PUBLIC STREET&HIGHWAY LIGHTING	306	6	(260)	(393)	592	1,039	(39)
STATE OF WYOMING - PPL	RESIDENTIAL SALES	(2,965)	(11,331)	55	3,040	1,568	(5,479)	3,793
	COMMERCIAL SALES	(12,120)	(15,688)	11,615	21,877	(4,112)	(11,349)	8,775
	INDUSTRIAL SALES	(58,979)	(4,487)	(49,540)	(27,656)	(16,947)	(6,518)	(89,424)
	IRRIGATION SALES	133	(54)	(20)	111	666	776	(925)
	PUBLIC STREET&HIGHWAY LIGHTING	32	(12)	53	101	(111)	(71)	139
STATE OF WYOMING - UPL	RESIDENTIAL SALES	(1,148)	2,100	(966)	(1,893)	781	(1,706)	(244)
	COMMERCIAL SALES	3,230	25	(610)	(4,354)	2,331	2,166	2,936
	INDUSTRIAL SALES	72,043	45,075	29,900	59,784	38,973	5,077	7,839
	IRRIGATION SALES		-		-	184	469	2,353
	PUBLIC STREET&HIGHWAY LIGHTING	(20)	44	218	66	132	120	118
STATE OF WYOMING	RESIDENTIAL SALES	(4,113)	(9,230)	(911)	1,147	2,349	(7,185)	3,549
	COMMERCIAL SALES	(8,890)	(15,663)	11,006	17,523	(1,782)	(9,182)	11,711
	INDUSTRIAL SALES	13,064	40,589	(19,640)	32,127	22,026	(1,442)	(81,585)
	IRRIGATION SALES	133	(54)	(20)	111	850	1,244	1,428
	PUBLIC STREET&HIGHWAY LIGHTING	13	31	271	167	20	49	257
Total	RESIDENTIAL SALES	(132,150)	(89,588)	49,035	(17,580)	(32,735)	26,267	(56,751)
	COMMERCIAL SALES	14,781	(94,565)	71,256	4,986	(3,233)	8,907	36,247
	INDUSTRIAL SALES	(48,400)	(105,921)	(172,917)	(94,170)	(195,470)	(293,397)	(191,264)
	IRRIGATION SALES	(2,168)	(566)	1,204	(12,234)	(5,342)	(32,323)	(68,765)
	OTHER SALES TO PUBLIC AUTH	1,665	(1,780)	(2,798)	(10,491)	7,930	1,448	(360)
	PUBLIC STREET&HIGHWAY LIGHTING	1,956	(154)	(1,495)	1,026	621	(219)	2,888
		(164,316)	(292,574)	(55,714)	(128,464)	(228,230)	(289,317)	(278,005)
						Total		(1,436,620)

OR LC-47
OPUC 23

Attachment OPUC 23

Sales, Not Weather Adjusted

Sum of MWh		Calendar Year / Calendar Month 2008							2009						
State	Revenue Class	January	February	March	April	May	June	July	January	February	March	April	May	June	July
STATE OF CALIFORNIA - PPL	RESIDENTIAL SALES	50,717	40,074	38,750	34,024	30,383	27,719	27,908	43,646	37,790	40,300	30,529	29,385	24,458	31,362
	COMMERCIAL SALES	29,269	24,689	26,783	23,782	24,539	24,136	26,444	26,257	26,257	26,257	26,257	26,257	26,257	26,257
	INDUSTRIAL SALES	3,468	5,659	5,223	4,435	5,405	5,067	4,453	2,067	2,067	2,067	2,067	2,067	2,067	2,067
	IRRIGATION SALES	1,809	615	412	1,703	18,586	19,104	27,443	11	11	11	11	11	11	11
	PUBLIC STREET&HIGHWAY LIGHTING	183	208	225	215	219	224	211	215	215	215	215	215	215	215
STATE OF IDAHO - UPL	RESIDENTIAL SALES	95,341	76,992	61,866	59,269	46,559	44,515	50,393	83,400	70,743	67,315	56,835	46,554	38,957	50,224
	COMMERCIAL SALES	44,585	33,459	30,852	32,327	31,065	28,600	34,600	63,528	26,532	33,475	29,973	28,021	39,929	30,480
	INDUSTRIAL SALES	118,795	155,620	131,887	159,709	145,723	168,817	132,645	125,316	125,863	136,234	106,813	83,613	78,249	54,017
	IRRIGATION SALES	1,978	19	24	205	50,064	120,105	196,312	453	123	494	86	85,543	70,392	157,275
	PUBLIC STREET&HIGHWAY LIGHTING	292	280	183	217	115	310	152	282	173	167	262	123	151	280
STATE OF OREGON - PPL	RESIDENTIAL SALES	692,921	556,468	521,947	473,626	407,805	352,379	430,122	584,592	532,304	544,849	422,576	382,883	331,660	448,842
	COMMERCIAL SALES	444,509	383,447	441,328	368,897	405,437	421,238	452,284	438,142	365,857	413,123	368,765	408,209	400,584	495,261
	INDUSTRIAL SALES	218,632	260,329	272,651	234,911	223,288	275,578	252,672	203,355	202,819	212,343	211,924	187,513	204,570	205,812
	IRRIGATION SALES	549	657	659	8,764	35,591	32,749	71,861	797	482	1,102	5,616	26,525	45,160	62,522
	PUBLIC STREET&HIGHWAY LIGHTING	2,276	3,395	4,159	2,988	2,624	3,190	2,995	3,482	3,177	3,341	3,261	2,445	3,319	3,857
STATE OF UTAH - UPL	RESIDENTIAL SALES	643,415	442,293	492,384	467,990	420,796	542,740	854,202	606,062	467,584	488,919	457,808	429,457	454,226	814,521
	COMMERCIAL SALES	617,719	575,381	518,869	593,397	594,144	635,844	771,536	610,606	542,565	612,015	575,312	617,268	589,732	768,879
	INDUSTRIAL SALES	732,462	692,852	713,973	577,059	642,384	685,726	599,736	691,586	637,220	628,558	509,149	550,176	556,280	621,145
	IRRIGATION SALES	364	103	830	1,219	62,929	34,235	54,754	890	499	777	1,026	56,113	34,657	48,137
	OTHER SALES TO PUBLIC AUTH	37,596	37,711	36,306	42,777	31,239	40,873	35,062	38,971	35,951	33,580	31,769	40,414	39,673	34,314
	PUBLIC STREET&HIGHWAY LIGHTING	6,210	6,027	7,270	5,896	6,990	7,025	5,572	6,620	6,153	6,607	6,830	7,174	5,758	7,247
STATE OF WASHINGTON - PPL	RESIDENTIAL SALES	213,858	153,777	136,963	120,955	106,944	87,951	136,463	232,029	157,125	157,006	116,174	91,611	109,013	130,259
	COMMERCIAL SALES	121,025	116,433	114,664	91,705	119,827	97,466	121,784	133,619	114,696	110,279	87,838	117,081	128,358	139,882
	INDUSTRIAL SALES	77,028	71,792	80,001	47,637	89,517	71,550	62,011	66,634	71,767	71,728	67,584	69,466	65,777	60,114
	IRRIGATION SALES	272	756	(1)	24,455	18,942	33,561	36,166	533	502	424	17,013	23,698	34,603	37,807
	PUBLIC STREET&HIGHWAY LIGHTING	890	992	975	642	1,102	810	757	1,195	998	715	249	1,694	1,849	718
STATE OF WYOMING - PPL	RESIDENTIAL SALES	106,737	95,995	83,015	72,639	59,975	59,726	76,698	101,407	84,439	82,039	75,658	59,496	52,604	73,743
	COMMERCIAL SALES	116,100	116,029	116,696	91,729	105,795	113,036	96,221	103,317	100,276	128,087	113,565	101,815	101,315	102,690
	INDUSTRIAL SALES	452,354	435,698	454,218	429,925	459,338	447,101	483,254	393,375	431,212	404,678	402,268	442,391	440,583	393,829
	IRRIGATION SALES	(5)	49	12	84	559	3,039	5,155	128	(6)	33	172	1,564	3,679	3,690
	PUBLIC STREET&HIGHWAY LIGHTING	828	865	838	854	925	771	895	860	853	891	956	813	700	1,034
STATE OF WYOMING - UPL	RESIDENTIAL SALES	19,081	11,827	14,000	13,532	8,682	9,410	8,772	17,615	13,894	12,902	11,662	9,058	7,705	8,350
	COMMERCIAL SALES	8,749	15,088	14,161	14,083	9,277	11,773	5,663	11,803	15,092	13,500	9,742	11,528	13,900	8,283
	INDUSTRIAL SALES	60,085	75,631	77,553	91,463	101,941	121,827	115,549	132,128	120,706	107,453	151,246	140,914	126,904	123,388
	IRRIGATION SALES		-		-	184	469	2,353	-	53	-	60	143	864	1,456
	PUBLIC STREET&HIGHWAY LIGHTING	(20)	44	218	66	132	120	118	166	122	248	94	130	205	(27)
STATE OF WYOMING	RESIDENTIAL SALES	125,818	107,822	97,015	86,170	68,657	69,136	85,471	119,022	98,333	94,942	87,320	68,554	60,309	82,093
	COMMERCIAL SALES	124,849	131,117	130,857	105,812	115,072	124,809	101,884	115,120	115,367	141,587	123,308	113,343	115,215	110,972
	INDUSTRIAL SALES	512,439	511,330	531,771	521,388	561,280	568,928	598,802	525,503	551,918	512,131	553,515	583,305	567,487	517,217
	IRRIGATION SALES	(5)	49	12	84	743	3,508	7,508	128	47	33	231	1,708	4,543	5,147
	PUBLIC STREET&HIGHWAY LIGHTING	808	909	1,056	920	1,056	890	1,013	1,026	975	1,139	1,050	943	905	1,006
Total	RESIDENTIAL SALES	1,822,069	1,377,426	1,348,925	1,242,034	1,081,144	1,124,441	1,584,559	1,668,751	1,363,878	1,393,331	1,171,241	1,048,443	1,018,624	1,557,300
	COMMERCIAL SALES	1,381,955	1,264,527	1,263,353	1,215,920	1,290,083	1,332,093	1,508,532	1,387,273	1,191,273	1,336,736	1,211,453	1,310,179	1,300,075	1,571,732
	INDUSTRIAL SALES	1,662,824	1,697,582	1,735,507	1,545,139	1,667,596	1,775,666	1,650,319	1,614,460	1,591,654	1,563,060	1,451,052	1,476,140	1,474,430	1,460,373
	IRRIGATION SALES	4,968	2,199	1,934	36,432	186,855	243,263	394,043	2,812	1,663	2,841	23,983	193,597	189,366	310,899
	OTHER SALES TO PUBLIC AUTH	37,596	37,711	36,306	42,777	31,239	40,873	35,062	38,971	35,951	33,580	31,769	40,414	39,673	34,314
	PUBLIC STREET&HIGHWAY LIGHTING	10,659	11,811	13,867	10,879	12,107	12,450	10,699	12,820	11,692	12,185	11,867	12,595	12,197	13,324

Attachment A
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Weather Adjustment

Sum of MWh		Calendar Year / Calendar Month													
		2008							2009						
State	Revenue Class	January	February	March	April	May	June	July	January	February	March	April	May	June	July
STATE OF CALIFORNIA - PPL	RESIDENTIAL SALES	(2,718)	(921)	(2,701)	(2,086)	81	(86)	1	(4,964)	(2,120)	(2,236)	(762)	586	140	3
	COMMERCIAL SALES	(802)	(137)	(446)	(263)	18	0	-	(1,488)	(470)	(374)	(26)	39	1	-
	INDUSTRIAL SALES	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	IRRIGATION SALES	39	142	470	712	(321)	138	(274)	49	139	399	367	(1,062)	47	(1,741)
	PUBLIC STREET&HIGHWAY LIGHTING	-	-	-	-	-	-	-	-	-	-	-	-	-	-
STATE OF IDAHO - UPL	RESIDENTIAL SALES	(4,387)	(2,031)	(4,742)	(4,093)	(1,226)	(1,371)	(1,403)	(2,095)	(5,680)	(3,433)	(1,894)	438	695	966
	COMMERCIAL SALES	(806)	(378)	(883)	(705)	(56)	(301)	(665)	(395)	(1,072)	(635)	(257)	(107)	1,018	188
	INDUSTRIAL SALES	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	IRRIGATION SALES	12	-	777	2,958	6,340	1,215	(11,612)	8	24	1,151	3,794	(5,080)	23,674	1,693
	PUBLIC STREET&HIGHWAY LIGHTING	-	-	-	-	-	-	-	-	-	-	-	-	-	-
STATE OF OREGON - PPL	RESIDENTIAL SALES	(51,687)	(5,514)	(43,904)	(41,790)	(9,488)	(6,952)	2,898	(55,223)	(50,714)	(37,956)	(15,055)	(13)	8,488	(35,849)
	COMMERCIAL SALES	(14,364)	426	(6,752)	(2,602)	(3,274)	3,760	2,594	(16,486)	(12,388)	(5,303)	459	(5,858)	2,402	(25,751)
	INDUSTRIAL SALES	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	IRRIGATION SALES	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	PUBLIC STREET&HIGHWAY LIGHTING	-	-	-	-	-	-	-	-	-	-	-	-	-	-
STATE OF UTAH - UPL	RESIDENTIAL SALES	(26,423)	(5,063)	(14,431)	(13,436)	13,081	(26,910)	(45,562)	(11,656)	(6,086)	(11,844)	(1,411)	507	88,867	(28,276)
	COMMERCIAL SALES	(15,314)	(2,065)	(3,602)	(986)	14,613	(3,556)	(15,948)	(6,261)	(2,501)	(5,888)	4,029	(5,687)	40,657	(10,802)
	INDUSTRIAL SALES	4	27	504	707	3,155	(1,220)	(3,871)	7	31	(43)	1,145	(1,276)	8,812	(2,461)
	IRRIGATION SALES	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	OTHER SALES TO PUBLIC AUTH	(523)	(119)	(264)	(202)	887	(176)	(1,079)	(234)	(138)	(335)	314	(358)	2,471	(691)
	PUBLIC STREET&HIGHWAY LIGHTING	-	-	-	-	-	-	-	-	-	-	-	-	-	-
STATE OF WASHINGTON - PPL	RESIDENTIAL SALES	(19,368)	8,950	(7,895)	(12,448)	(2,349)	(1,596)	(1,252)	(12,158)	(16,278)	(14,737)	(1,516)	(3,904)	(4,663)	(18,581)
	COMMERCIAL SALES	(5,909)	2,764	(384)	(773)	(2,518)	(552)	(1,203)	(3,940)	(4,357)	(2,269)	(109)	(2,882)	(4,215)	(8,431)
	INDUSTRIAL SALES	-	17	198	1,001	(1,661)	(40)	(519)	(40)	19	275	479	(1,244)	(2,233)	(3,246)
	IRRIGATION SALES	-	8	90	458	(760)	(19)	(237)	(18)	9	126	219	(569)	(1,022)	(1,486)
	PUBLIC STREET&HIGHWAY LIGHTING	-	-	-	-	-	-	-	-	-	-	-	-	-	-
STATE OF WYOMING - PPL	RESIDENTIAL SALES	(4,443)	296	(3,465)	(3,087)	(1,237)	2,740	(841)	(2,078)	522	(2,434)	(3,066)	810	4,382	5,907
	COMMERCIAL SALES	(1,244)	84	(894)	(685)	277	1,540	(400)	(581)	149	(670)	(644)	145	1,912	1,906
	INDUSTRIAL SALES	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	IRRIGATION SALES	0	1	43	79	312	448	(96)	0	2	2	102	(27)	584	443
	PUBLIC STREET&HIGHWAY LIGHTING	-	-	-	-	-	-	-	-	-	-	-	-	-	-
STATE OF WYOMING - UPL	RESIDENTIAL SALES	(616)	41	(480)	(435)	(297)	11	(20)	(299)	75	(349)	(459)	108	11	158
	COMMERCIAL SALES	(356)	24	(260)	(213)	(29)	207	(54)	(180)	46	(209)	(227)	50	246	263
	INDUSTRIAL SALES	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	IRRIGATION SALES	(0)	(0)	(17)	(31)	(120)	(172)	37	(0)	(1)	(1)	(38)	10	(216)	(164)
	PUBLIC STREET&HIGHWAY LIGHTING	-	-	-	-	-	-	-	-	-	-	-	-	-	-
STATE OF WYOMING	RESIDENTIAL SALES	(5,059)	337	(3,946)	(3,522)	(1,534)	2,751	(861)	(2,377)	596	(2,783)	(3,525)	918	4,393	6,065
	COMMERCIAL SALES	(1,600)	108	(1,154)	(898)	249	1,747	(454)	(761)	195	(879)	(871)	195	2,158	2,169
	INDUSTRIAL SALES	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	IRRIGATION SALES	0	0	26	49	192	276	(59)	0	1	1	64	(17)	368	280
	PUBLIC STREET&HIGHWAY LIGHTING	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	RESIDENTIAL SALES	(109,641)	(4,241)	(77,618)	(77,375)	(1,436)	(34,164)	(46,179)	(88,473)	(80,282)	(72,989)	(24,162)	(1,470)	97,920	(75,672)
	COMMERCIAL SALES	(38,795)	718	(13,221)	(6,228)	9,030	1,098	(15,676)	(29,332)	(20,593)	(15,348)	3,225	(14,299)	42,023	(42,628)
	INDUSTRIAL SALES	4	44	702	1,708	1,494	(1,261)	(4,390)	(33)	51	232	1,624	(2,520)	6,579	(5,707)
	IRRIGATION SALES	52	150	1,364	4,178	5,451	1,611	(12,183)	39	173	1,677	4,444	(6,727)	23,067	(1,254)
	OTHER SALES TO PUBLIC AUTH	(523)	(119)	(264)	(202)	887	(176)	(1,079)	(234)	(138)	(335)	314	(358)	2,471	(691)
	PUBLIC STREET&HIGHWAY LIGHTING	-	-	-	-	-	-	-	-	-	-	-	-	-	-

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Sales, Weather Adjusted

Sum of MWh		Calendar Year Calendar Month													
		2008							2009						
State	Revenue Class	January	February	March	April	May	June	July	January	February	March	April	May	June	July
STATE OF CALIFORNIA - PPL	RESIDENTIAL SALES	47,999	39,152	36,049	31,938	30,464	27,634	27,910	38,682	35,670	38,064	29,766	29,970	24,598	31,365
	COMMERCIAL SALES	28,467	24,552	26,337	23,519	24,557	24,136	26,444	24,769	25,787	25,883	26,232	26,297	26,259	26,257
	INDUSTRIAL SALES	3,468	5,659	5,223	4,435	5,405	5,067	4,453	2,067	2,067	2,067	2,067	2,067	2,067	2,067
	IRRIGATION SALES	1,848	757	882	2,415	18,265	19,242	27,169	60	149	409	377	(1,051)	57	(1,730)
	PUBLIC STREET&HIGHWAY LIGHTING	183	208	225	215	219	224	211	215	215	215	215	215	215	215
STATE OF IDAHO - UPL	RESIDENTIAL SALES	90,954	74,960	57,125	55,176	45,333	43,144	48,989	81,306	65,063	63,883	54,942	46,991	39,652	51,189
	COMMERCIAL SALES	43,778	33,081	29,969	31,622	31,009	28,299	33,935	63,133	25,459	32,840	29,716	27,914	40,947	30,668
	INDUSTRIAL SALES	118,795	155,620	131,887	159,709	145,723	168,817	132,645	125,316	125,863	136,234	106,813	83,613	78,249	54,017
	IRRIGATION SALES	1,990	19	801	3,164	56,404	121,320	184,699	461	147	1,645	3,880	80,464	94,066	158,968
	PUBLIC STREET&HIGHWAY LIGHTING	292	280	183	217	115	310	152	282	173	167	262	123	151	280
STATE OF OREGON - PPL	RESIDENTIAL SALES	641,234	550,955	478,042	431,835	398,317	345,427	433,020	529,368	481,590	506,893	407,521	382,869	340,148	412,993
	COMMERCIAL SALES	430,145	383,873	434,576	366,295	402,162	424,998	454,878	421,657	353,468	407,820	369,224	402,351	402,987	469,510
	INDUSTRIAL SALES	218,632	260,329	272,651	234,911	223,288	275,578	252,672	203,355	202,819	212,343	211,924	187,513	204,570	205,812
	IRRIGATION SALES	549	657	659	8,764	35,591	32,749	71,861	797	482	1,102	5,616	26,525	45,160	62,522
	PUBLIC STREET&HIGHWAY LIGHTING	2,276	3,395	4,159	2,988	2,624	3,190	2,995	3,482	3,177	3,341	3,261	2,445	3,319	3,857
STATE OF UTAH - UPL	RESIDENTIAL SALES	616,992	437,230	477,953	454,554	433,877	515,830	808,640	594,405	461,499	477,075	456,397	429,964	543,093	786,245
	COMMERCIAL SALES	602,404	573,316	515,267	592,411	608,756	632,288	755,587	604,345	540,064	606,127	579,341	611,581	630,389	758,077
	INDUSTRIAL SALES	732,466	692,879	714,478	577,765	645,539	684,505	595,865	691,593	637,251	628,515	510,295	548,900	565,092	618,684
	IRRIGATION SALES	364	103	830	1,219	62,929	34,235	54,754	890	499	777	1,026	56,113	34,657	48,137
	OTHER SALES TO PUBLIC AUTH	37,073	37,593	36,042	42,575	32,126	40,697	33,983	38,737	35,813	33,245	32,084	40,056	42,145	33,623
	PUBLIC STREET&HIGHWAY LIGHTING	6,210	6,027	7,270	5,896	6,990	7,025	5,572	6,620	6,153	6,607	6,830	7,174	5,758	7,247
STATE OF WASHINGTON - PPL	RESIDENTIAL SALES	194,490	162,727	129,068	108,507	104,595	86,356	135,211	219,871	140,847	142,269	114,657	87,707	104,350	111,678
	COMMERCIAL SALES	115,116	119,198	114,280	90,932	117,309	96,914	120,581	129,679	110,339	108,010	87,729	114,199	124,144	131,451
	INDUSTRIAL SALES	77,028	71,810	80,199	48,639	87,856	71,510	61,493	66,595	71,787	72,003	68,063	68,222	63,544	56,868
	IRRIGATION SALES	272	764	89	24,914	18,182	33,543	35,928	515	511	550	17,232	23,128	33,581	36,321
	PUBLIC STREET&HIGHWAY LIGHTING	890	992	975	642	1,102	810	757	1,195	998	715	249	1,694	1,849	718
STATE OF WYOMING - PPL	RESIDENTIAL SALES	102,294	96,291	79,550	69,552	58,738	62,466	75,857	99,330	84,961	79,605	72,592	60,306	56,987	79,650
	COMMERCIAL SALES	114,856	116,113	115,802	91,044	106,072	114,576	95,821	102,736	100,425	127,417	112,921	101,960	103,227	104,596
	INDUSTRIAL SALES	452,354	435,698	454,218	429,925	459,338	447,101	483,254	393,375	431,212	404,678	402,268	442,391	440,583	393,829
	IRRIGATION SALES	(5)	50	55	164	871	3,487	5,059	128	(4)	35	274	1,538	4,263	4,134
	PUBLIC STREET&HIGHWAY LIGHTING	828	865	838	854	925	771	895	860	853	891	956	813	700	1,034
STATE OF WYOMING - UPL	RESIDENTIAL SALES	18,464	11,868	13,520	13,096	8,385	9,421	8,752	17,316	13,969	12,553	11,203	9,166	7,715	8,508
	COMMERCIAL SALES	8,393	15,112	13,901	13,869	9,248	11,980	5,609	11,623	15,138	13,291	9,516	11,579	14,146	8,546
	INDUSTRIAL SALES	60,085	75,631	77,553	91,463	101,941	121,827	115,549	132,128	120,706	107,453	151,246	140,914	126,904	123,388
	IRRIGATION SALES		-		-	184	469	2,353	-	53	-	60	143	864	1,456
	PUBLIC STREET&HIGHWAY LIGHTING	(20)	44	218	66	132	120	118	166	122	248	94	130	205	(27)
STATE OF WYOMING	RESIDENTIAL SALES	120,758	108,160	93,070	82,648	67,123	71,887	84,609	116,645	98,929	92,158	83,795	69,472	64,702	88,158
	COMMERCIAL SALES	123,249	131,225	129,703	104,914	115,320	126,556	101,430	114,359	115,562	140,708	122,437	113,539	117,374	113,141
	INDUSTRIAL SALES	512,439	511,330	531,771	521,388	561,280	568,928	598,802	525,503	551,918	512,131	553,515	583,305	567,487	517,217
	IRRIGATION SALES	(5)	50	55	164	1,055	3,956	7,412	128	49	35	334	1,681	5,127	5,590
	PUBLIC STREET&HIGHWAY LIGHTING	808	909	1,056	920	1,056	890	1,013	1,026	975	1,139	1,050	943	905	1,006
Total	RESIDENTIAL SALES	1,712,427	1,373,184	1,271,307	1,164,659	1,079,708	1,090,277	1,538,379	1,580,278	1,283,596	1,320,342	1,147,079	1,046,973	1,116,544	1,481,629
	COMMERCIAL SALES	1,343,160	1,265,245	1,250,132	1,209,692	1,299,113	1,333,191	1,492,856	1,357,941	1,170,680	1,321,388	1,214,678	1,295,880	1,342,098	1,529,103
	INDUSTRIAL SALES	1,662,828	1,697,626	1,736,209	1,546,847	1,669,090	1,774,405	1,645,929	1,614,428	1,591,705	1,563,292	1,452,677	1,473,620	1,481,009	1,454,666
	IRRIGATION SALES	5,019	2,350	3,315	40,640	192,426	245,045	381,823	2,851	1,837	4,519	28,466	186,860	212,649	309,809
	OTHER SALES TO PUBLIC AUTH	37,073	37,593	36,042	42,575	32,126	40,697	33,983	38,737	35,813	33,245	32,084	40,056	42,145	33,623
	PUBLIC STREET&HIGHWAY LIGHTING	10,659	11,811	13,867	10,879	12,107	12,450	10,699	12,820	11,692	12,185	11,867	12,595	12,197	13,324

OPUC Data Request 27

In its sensitivity analysis on the preferred portfolio, using the February 2009 forecast, please discuss why the Company held the CCCT constant in the capacity expansion model. Why did the Company not allow this resource to be determined by the capacity expansion model in the same way that it did the SCCT? See page 10 of the IRP.

1st Supplemental Response to OPUC Data Request 27

In response to Commission staff's request for additional data, please refer to Attachment OPUC 27 -1 1st Supplemental and Attachment OPUC 27 -2 1st Supplemental.

Please refer to non-confidential Attachment OPUC 27 -1 1st Supplemental and Attachment OPUC 27 -2 1st Supplemental on the enclosed CD.

Load Forecast Impact on the Timing of the CCCT
November 4, 2009

In response to a data request from Public Utility Commission of Oregon staff regarding the fixing of a combined-cycle combustion turbine (CCCT) plant in 2014[1], PacifiCorp indicated that the small change in peak load from the November 2008 to February 2009 load forecast did not require that the capacity expansion optimization model be allowed to optimize the timing of the 570 MW CCCT resource. To reduce model run-time, the Company chose to fix the CCCT in 2014.

To dispel any doubt regarding the impact of the February 2009 load forecast on the timing of the CCCT, the Company recently conducted a capacity expansion run with the February 2009 load forecast, but allowed the model to optimize the timing of the CCCT. For this run, the Company used the preferred portfolio development input assumptions (October 2008 forward price curves and a \$45/ton CO_2 tax). Because stochastic production cost modeling has consistently found that CCCT capacity is more cost-effective on a risk-adjusted basis than simple-cycle combustion turbine (SCCT) capacity, SCCT resources were excluded as resource options for the capacity expansion run.[2]

The result of this run is that the capacity expansion model not only selected the CCCT in 2014, but that the resource has a high capacity factor in that year (88%). This high utilization indicates that the resource is deep in the money as well as needed to meet capacity requirements. The run thus confirms that the small peak load differences between November 2009 and February 2009 forecasts are insufficient to justify deferring the CCCT resource.

PacifiCorp also conducted a capacity expansion sensitivity analysis to determine the CCCT timing impact of decreasing the November 2008 load forecast by 100 MW increments. For these sensitivities, the Company again used the 2008 IRP preferred portfolio development assumptions, but decreased loads in the Utah North load area. (Specifically, the "load shape" was reduced such that the peak hour load was 100 MW lower; on an average MW basis, the load decrease was about 12 MW for each 100-MW increment.) As indicated in the table below, a peak load reduction in the 200-300 MW range is needed to defer the CCCT to 2015.

	November 2008 Load Forecast				
	MW Load Reduction Sensitivities, Utah North				
	100	200	300	400	500
Year Selected for the CCCT	2014	2014	2015	2015	2015
Annual Capacity Factor, 2014	83.7%	83.7%	--	--	--
Annual Capacity Factor, 2015	83.7%	83.7%	83.7%	83.7%	83.7%

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[1] Data Request 27, Docket No. LC 47: "In its sensitivity analysis on the preferred portfolio, using the February 2009 forecast, please discuss why the Company held the CCCT constant in the capacity expansion model. Why did the Company not allow this resource to be determined by the capacity expansion model in the same way that it did the SCCT? See page 10 of the IRP."

[2] On page 235 of the 2008 IRP and in the Company's response to Oregon party comments (page 7), PacifiCorp notes that the System Optimizer model does not account for optionality and reserve holding value that is captured by the stochastic production cost model.

1. Please provide the PVRR for the portfolio runs that you did for all sensitivities analysis that you showed in the table provided on the existing sheet, including the portfolio without the resource before 2014.

Response:

The table below reports the PVRR values for the preferred portfolio and each of the associated sensitivity portfolios developed with the 100 MW load reduction increments. The PVRR decreases for the 100 MW and 200 MW load reduction portfolios are due to smaller quantities of front office transactions needed, while the relatively larger PVRR decreases for the 300-500 MW load reduction portfolios also reflects the deferral of the combined-cycle combustion turbine (CCCT) resource from 2014 to 2015.

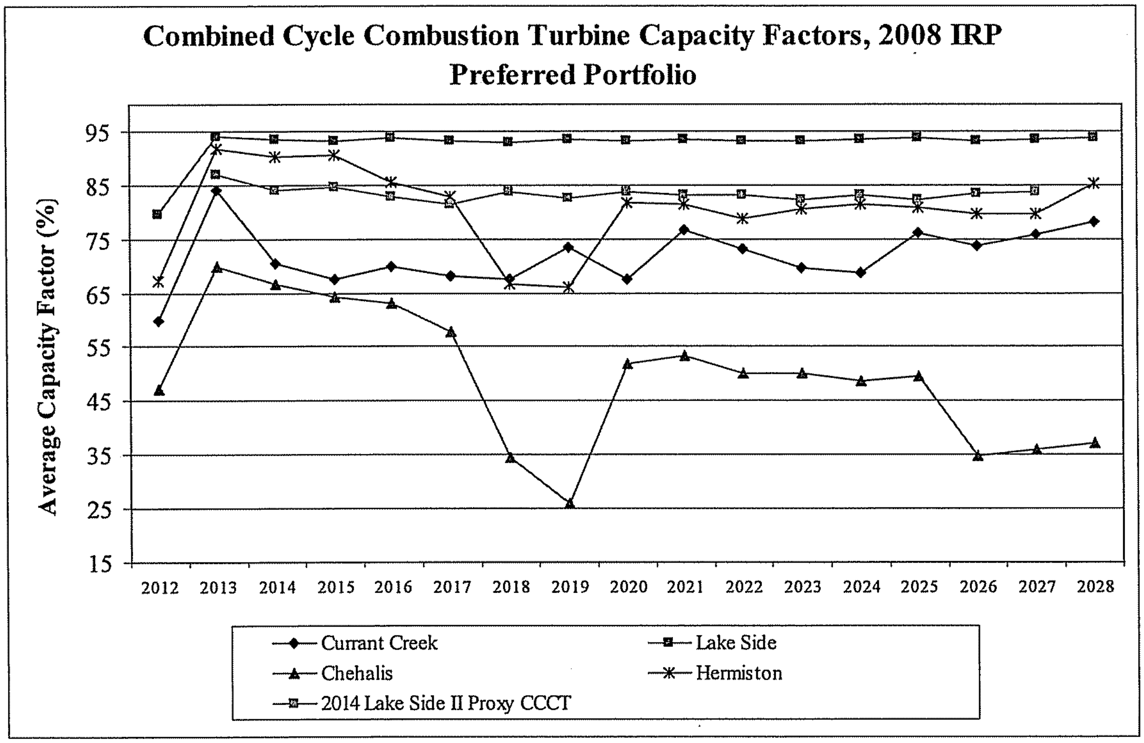
Deterministic PVRR, 2009-2028	Preferred Portfolio	100 MW Load Reductions				
		100	200	300	400	500
PVRR, Million $	41,566	41,558	41,551	41,518	41,501	41,494
PVRR difference, preferred portfolio less sensitivity portfolio	0	(7)	(15)	(48)	(64)	(72)

2. Please provide a report which shows the capacity factor of all portfolio resources before adding the CCCT and after adding the CCCT. What staff would like to understand is the impact of adding this additional CCCT on PacifiCorp's existing resources. For example, does Current Creek go from a 48% capacity factor to 10%? Please provide enough information so that we can understand this.

Response:

See the attached capacity factor report for the 2008 IRP preferred portfolio. This workbook reports the average annual capacity factors by portfolio resource for 2012 (the start of the system capacity deficit) through 2028 assuming a $45/ton CO_2 cost is implemented in 2013 and escalated annually at the corporate inflation rate (2.9%). The CCCT capacity factors are highlighted.

The graph below shows the capacity factors for the existing and new CCCT resources in the preferred portfolio. Note that the dip in Chehalis capacity factors beginning in 2017 is due to increased imports from PacifiCorp East made possible by the Energy Gateway transmission added in that year, and a switch from reliance on third-quarter heavy load hour market purchases to flat annual market purchases. The strong capacity factor recovery in 2020 is mainly due to assumed hydro and coal plant retirements (Klamath River hydro and Carbon units 1 and 2).


Combined Cycle Combustion Turbine Capacity Factors, 2008 IRP Preferred Portfolio
Average Capacity Factor (%)
95
85
75
65
55
45
35
25
15
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
Currant Creek
Lake Side
Chehalis
Hermiston
2014 Lake Side II Proxy CCCT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF FINAL COMMENTS

ATTACHMENT B
REDACTED

December 8, 2009

CERTAIN INFORMATION CONTAINED IN ATTACHMENT B

IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE

ORDER NO. 09-392. YOU MUST HAVE SIGNED

APPENDIX B OF THE PROTECTIVE ORDER IN

DOCKET LC 47 TO RECEIVE THE

CONFIDENTIAL VERSION

OF THIS EXHIBIT.

OPUC Data Request 32

Please provide the analysis which shows the $3.5 to $4.0 billion net present value power cost benefit for Energy Gateway referenced in your Response to Oregon Party Comments on page 4. Please provide this analysis with all formulas intact in an Excel workbook.

Response to OPUC Data Request 32

In response to OPUC Data Request 32, please refer to the document supplied herein as Confidential Attachment OPUC 32. Within the attachment, the specific information requested in Question OPUC 32 can be found starting on page 7 in the section titled, "2008 Analyses". This information is confidential and is provided subject to the terms and conditions of the protective order in this proceeding.

Request for Commission Acknowledgment

Also, please note that in reviewing the attachment, PacifiCorp is requesting Commission acknowledgement of key short term transmission issues (specifically action items through the year 2012) referenced in the IRP. These items include obtaining the Certificate of Public Convenience and Necessity for segments of Gateway Central and Gateway West. They also include constructing Path C Upgrades including the Populus-Terminal and the Mona-Oquirrh segments, both of which are necessary as the Gateway transmission strategy unfolds.

Attachment B
Page 2 through Page 19

These pages are confidential.

You must have signed the protective order in this docket in order to view this page.

LC 47
Service List (Parties)

***DEPARTMENT OF JUSTICE**	
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CERTIFICATE OF SERVICE

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I certify that I have this day served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-13-0070, to the following parties or attorneys of parties.

Dated at Salem, Oregon, this 8th day of December, 2009.

Kay Barnes

Kay Barnes
Public Utility Commission
Regulatory Operations
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