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GENERAL COUNSEL DIVISION

October 15, 2015

VIA ELECTRONIC MAIL ONLY

Attention: Filing Center
Public Utility Commission of Oregon
2930 Fairview Industrial Drive SE
PO Box 1088
Salem, OR 97308-1088

Re: *In the Matter of PACIFICORP, dba PACIFIC POWER's 2015 Integrated Resource Plan*
OPUC Docket No.: LC 62
DOJ File No.: 330030-GN0339-14

Filing Center:

On behalf of the Oregon Department of Energy, enclosed for electronic filing today with the Commission in the above-captioned matter are FINAL COMMENTS OF THE OREGON DEPARTMENT OF ENERGY.

Sincerely,

Renee M. France
Senior Assistant Attorney General
Natural Resources Section

RMF:jrs/#6847576
c: Jess Kincaid, ODOE

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 62

In the Matter of	)	
	)	
PACIFICORP, dba PACIFIC POWER	)	FINAL COMMENTS OF THE OREGON
	)	DEPARTMENT OF ENERGY
2015 Integrated Resource Plan	)	
	)	
	)	

In our Final Comments on PacifiCorp's (Company) 2015 Integrated Resource Plan (IRP) the Oregon Department of Energy (Department) provides additional support for some of our Opening Comments and clarifies our recommendations for future IRP modeling. As noted in our Opening Comments, the Department recommends that the Commission acknowledge this IRP with addition of a Class 1 DSM (demand response) pilot, pilot Class 2 DSM (energy efficiency) programs outside Oregon, and modifications to how the Company models certain portions of its IRP in the future such as the comprehensive value of energy storage and demand response. In addition, in our Final Comments we recommend that the Company work with stakeholders in Oregon to consider options for increasing utilization of voluntary time of use rates by residential customers in Oregon.

A. The Department Continues to Request an Additional Class 1 DSM Pilot

In its Reply Comments, the Company declines to implement an additional Class 1 DSM (demand response) pilot on either the west side of Oregon or the Klamath Basin that is available in all seasons and is viable for both peak reduction and regulation because it finds the "cost and feasibility of this product does not vary as much by jurisdiction as"[1] other Class 1 DSM resources. In addition, the Company notes that the most common option that provides impacts in all seasons, Commercial Curtailment, is not cost-effective until 2023. While the Department

[1] LC62 Reply Comments of PacifiCorp at 31.

recognizes that demand response may not be a cost-effective resource for the Company at this time and that it may have regional similarity in pricing, we think this is the right time for the Company to *pilot* a program of this type in Oregon in order to familiarize its customers with the technology, ensure that the Oregon market is prepared to implement the product at scale when it demonstrates cost-effectiveness, and accurately determine the total resource value for future planning.

We continue to request this pilot because, while the pilot would not substantially change the quantity of front office transactions in this plan, it may provide information that could substantially alter future IRP action plans. However, we are reluctant to specify an exact pilot program (beyond the location and capabilities noted above) for the Company to implement as requested by the Company in its Reply Comments. We would instead prefer to work with the Company and other stakeholders to develop a program that is effective in meeting stated goals. In addition, we restate our Opening Comment that we "would also like the Company and the Commission to ensure that in all emerging technology pilots, such as those for demand response and storage, priority is given to determining not just the peak shaving value of the resource, but also the full range of potential system benefits."[2]

B. The Department Requests that the Company Investigate Utilization of Voluntary Time of Use Tariffs

In response to Staff's Opening Comments regarding Smart Grid implementation and Time of Use Tariff's (TOU), the Company states that it believes TOU is best addressed through rate design and not the IRP. We agree with the Company that TOU rates are a rate design issue, however advertising and utilization of TOU may not be.

Only 0.3% of residential PacifiCorp customers in Oregon currently participate in the Company's TOU rate option.[3] Yet, the Company assumes a participation potential as high as

[2] LC 62 Opening Comments of Oregon Department of Energy at 3.
[3] PacifiCorp Demand-Side Resource Potential Assessment for 2015 – 2034, Table 3-1.

26.2% for residential opt-in TOU.[4] Building a market of voluntary residential TOU participants in Oregon is important to the Department because, as the Company notes in its potential study, residential TOU customers could provide the Company with 6.1 MW of potential by 2034 at a levelized cost of $17.2 per kW-year.[5]

The Department requests that the Commission ask the Company to engage Oregon stakeholders in an informal process to address increased voluntary participation in TOU and present the outcome of this informal process to the Portfolio Options Committee.

C. The Department asks the Company to Address Carbon Regulation Beyond 111b and 111d in its Modeling

As outlined in our Opening Comments, the Department is concerned that the IRP appears to primarily rely on a wholesale price forecast that is less than the forecast expected in an unconstrained carbon world. We acknowledge that if carbon regulations over the next twenty years for all eleven western states rely entirely on the rate-based method that EPA proposed in its Clean Power Plan under Section 111d of the Clean Air Act (hereinafter 111d), then it is plausible that wholesale rates could be lower than what the Company modeled in the no-carbon case. However, even under EPA's Draft 111d Rule (which is what the Company had available at the time it conducted its IRP modeling), the Department views that scenario as highly unlikely.

The Department is concerned that the Company did not adequately address the risk of carbon regulation in its IRP because there is a reasonable possibility that many more coal plants in the West will be shut down by the end of this planning period (2035) than are shown in the base case Aurora and System Optimizer runs. It may be necessary to plan for additional CO_2 emission reduction strategies over the next 20 years. This IRP provides no clear evidence that the Company is prepared for the loss of many or most of the coal-fired plants in the West within 20 years.

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[4] PacifiCorp Demand-Side Resource Potential Assessment for 2015 – 2034, Table 2-12. The highest residential participation assumption in the PacifiCorp study is for the year 2020. Note, for planning purposes the Company estimates a decline in TOU participation to an average of 10% during the years 2024 through 2034.
[5] PacifiCorp Demand-Side Resource Potential Assessment for 2015 – 2034, Table 4.11.

Discussion about possible actions to address planning risks is largely absent from this IRP. Over the 20 year planning horizon the high price CO_2 scenario (S-11) acquires 6,576 MW of nameplate new capacity for power plants that emit no CO_2 such as wind, solar, and nuclear. Similarly, the medium CO_2 price scenario (C14a-1) with endogenous coal retirements has 4,458 MW of new plants that emit no CO_2. The appropriate mix in such scenarios might include more of these resources and all classes of DSM than the System Optimizer model picked due to technologic and institutional changes that are likely in the next 20 years and increased integration with other utilities in the West.

The Department requests that the Company's next IRP include a focus on actions with small costs that can reduce risks from our highly uncertain planning environment in contrast to the current analysis, which appears to focus on one highly optimistic scenario with less comprehensive analysis of risk.

D. The Department Questions Whether this IRP Complies with Guideline 8a

The Department still asserts that this IRP most likely does not meet Guideline 8a. It agrees with the Company's Reply Comment that guideline 8a allows the Company to assume a base case carbon regulation scenario it feels is "the most likely regulatory compliance future." However, this does not mean that Guideline 8a merely requires the company to produce the carbon scenarios without analyzing their risk implications. The Company should assess more strategies to address risk and uncertainty.

Our concerns over addressing carbon go deeper than one or even a handful of relatively optimistic assumptions that this IRP makes about the base case scenario.[6] While the Company modeled several scenarios other than the base case (C05a-3), the Department cannot discern how these alternative scenarios and portfolios influenced the Company's choice of proposed actions – an understanding that is important to the Department because these alternative scenarios

[6] The Department notes that these assumptions have a low overall risk for the Company and reduce the need to invest in new resources compared to other likely scenarios.

influence many of our proposed actions around pilots for energy efficiency, demand response, and storage.

The Department is unaware of any manner in which the IRP Action Plan is affected by the System Optimizer and Planning and Risk (PaR) analyses of Portfolios C11, C13, C14a, C14b, and S11 and their associated inputs. The point of Guideline 8a is not just to produce the scenarios, but to use them for planning.[7] However, we recognize that the Company may have conducted only limited PaR runs because the PaR could not be constrained to comply with the Draft 111d Rule.

E. The Department asks the Company to use a Historic Costs for Estimating the Range of Future Natural Gas Costs

In addition to concerns over how carbon emissions are addressed, the Department is concerned that none of the scenarios or PaR model runs appear to include a peak natural gas price as high as was seen in 2008.[8] Increasing LNG exports may reconnect the United States with Canadian and other natural gas markets resulting in increased prices. The Department doubts any model can accurately forecast U.S. natural gas prices over the next 20 years; therefore we support using a range of natural gas price forecasts in future IRPs that encompasses recent history.

F. The Department Makes Several Recommendations for Modifications to the Company's Future Modeling Approach

The Department repeats its recommendations to the Commission in our Opening Comments:

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[7] For example, there were no PaR runs using the medium case carbon prices scenario (C14). There was only a limited assessment of the PaR scatter gram of risk and expected PVRR using S11 carbon prices.

[8] U.S. Energy Information Administration, U.S. Natural Gas Electric Power Price *available at* http://www.eia.gov/dnav/ng/hist/n3045us3a.htm. The highest annual price in this historical series for natural gas cost to U.S. power plants is $9.26 per thousand cu. ft. in 2008. This value is substantially higher in real terms than the $8.21 per MMBtu (nominal $) in 2024 noted in the Company's reply to NWEC on page 29 of its LC 62 Reply Comments.

For all future integrated resource plans, the Department requests that the Commission:

1. *Direct the Company to use a method to constrain each stochastic modeling run to roughly comply with the 111d Final Rule*
2. *Direct the Company to run the System Optimizer with a reasonable approximation for the effects of the 111d Final Rule on western wholesale power prices*
3. *Instruct the Company that comparisons of various portfolios should use comparable assumptions on implementation of regional haze rules and other basic assumptions*
4. *Instruct the Company to perform a full risk analysis on a more aggressive energy efficiency portfolio*
5. *Require comprehensive analysis of the system benefits of storage.*[9]

Regarding recommendation one *(Direct the Company to use a method to constrain each stochastic modeling run to roughly comply with the 111d Final Rule)***:** The Company acknowledges that it, "was unable to ensure compliance with the proposed 111d rule" and states it "is exploring options to capture the impact on a stochastic basis."[10] The Department appreciates the Company's agreement to explore options, and requests that the Commission direct the Company to develop and utilize a workable approach in the next IRP. While the Department supported modeling the rate-based path for this IRP, the Department suggests that the Company consider simulating 111d in *future* IRPs by modeling the mass-based path for all 11 Western States with trading of emission allowances. While the Company is unlikely to have certainty on which approach Western States will use at the time that it begins its next IRP, modeling the mass-based approach is likely to be more workable than other options as discussed below.

The Department suggests this approach for three reasons: First, modeling the mass path for all states in the West would provide a reasonable assessment of the overall impact of 111d on the West and the Company. Second, it is impractical for the Company to try to forecast which states in the West will choose the rate path or the mass path because there are too many combinations, and the modeling of any single combination would be very complex. Third, the only plausible modeling alternatives are either to assume all states choose the rate path or choose

[9] LC 62 Opening Comments of Oregon Department of Energy at 3.
[10] LC 62 Reply Comments of PacifiCorp at 32.

the mass path, and the analytics of the all mass path are substantially more straightforward and transparent than the all rate path.

In addition, modeling the rate path in the 111d Final Rule is likely more problematic than modeling the draft rate path. With the final rate path it is possible to trade Emission Rate Credits (ERCs), but the path to trade-readiness is more challenging than for the mass path. Trying to model an all rate path raises the question of whether and how to model trading, particularly if some states may choose to not trade.

In contrast, modeling the mass path is similar to modeling a cap and trade policy. It is easy for states to be trading-ready under the Final Rule's mass path. The Company's existing models (Aurora, the System Optimizer and the Planning and Risk Model) can model a mass-based plan with emission trading.

While the Department suggests simulating 111d in the next IRP using the mass-based method, the Department would have no objection if the Company also wants to model the all rate path assumption, along with the all mass path assumption. In addition, the Company should ensure that the next IRP base model complies with existing state policy regarding environmental attributes of renewable energy certificates used under the Oregon Renewable Portfolio Standard.[11]

Regarding recommendation two *(Direct the Company to run the System Optimizer with a reasonable approximation for the effects of the 111d Final Rule on western wholesale power prices):* If the Company models the 111d Final Rule with the all mass path assumption, it seems unlikely that wholesale prices will be lower than a case with no carbon constraints. If the Company utilizes rate-base path in its next IRP the modeling should include an assumption about the cost to Electric Generating Units (EGUs) covered under 111d of buying ERCs to comply with the Final Rule. Even if a state does not participate in interstate trading of ERCs, the EGUs will still have to acquire ERCs for compliance. There will be at least intrastate opportunities to

[11] Oregon Renewable Portfolio Standard, Or. Rev. Stat. § 469A; Or. Admin. R. 330-160.

trade ERCs, which will have economic value that will influence plant dispatch and wholesale prices.

Regarding recommendation three *(Instruct the Company that comparisons of various portfolios should use comparable assumptions on implementation of regional haze rules and other basic assumptions)****:*** In its Reply Comments, the Company does not clarify why it is appropriate to compare the Present Value Rate of Return (PVRR) costs of two portfolios with different regulatory requirements. The Company does not dispute that regional haze compliance costs under RH3 are less than costs under RH1 or RH2. These costs are part of the PVRR of these scenarios. At minimum, this cost difference should be used to adjust the PVRRs when portfolios subjected to RH1 or RH2 are compared to the C05a-3 portfolio, which had RH3 costs in order to create a control group for modeling purposes. Several of the PVRR differences discussed in the IRP reflect this unfair comparison.

Regarding recommendation four *(Instruct the Company to perform a full risk analysis on a more aggressive energy efficiency portfolio)****:*** The Department recommends that the next IRP examine the effects of short-term increases in energy efficiency costs that expand the amount of cost-effective energy efficiency to determine whether accelerated energy efficiency measures contribute to a least-cost scenario. Pilot energy efficiency programs that are different and only incrementally more expensive than current programs can provide important information to enable incremental improvements.[12] The Department requests that the Company conduct rigorous and broad examinations of strategies to increase capabilities for DSM Classes 1, 2, and 3, and that the Commission adds an Action Plan item that enhances the Company's ability to accelerate Class 2 DSM through pilot projects.

Regarding recommendation five *(Require comprehensive analysis of the system benefits of storage)****:*** The Department appreciates the Company's willingness to look for opportunities to understand and pilot energy storage systems that help determine the comprehensive value of the

[12] For example, the Company could run programs like the Northwest Energy Efficiency Alliance Market Transformation Initiatives in the three PacifiCorp states outside the Northwest.

resource and utilize that value in future IRPs.[13] We look forward to working with the Company on future energy storage initiatives.

G. Conclusion

In summary, in response to the Company's 2015 IRP the Department asks the Company to implement an additional Class 1 DSM pilot in Oregon, pilot accelerated Class 2 DSM programs outside Oregon, model the comprehensive value of energy storage and Class 1 DSM in Oregon, and work with stakeholders in Oregon to consider potential strategies to increase participation in voluntary TOU programs. While we have concerns about the Company's approach to modeling in this IRP, we recommend the Commission acknowledge this IRP and make recommendations for the Company's future approach.

DATED this 15th day of October, 2015.

Respectfully submitted,

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of Energy

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[13] The Department provides a detailed request for future modeling of energy storage in its Opening Comments at 10-12. This request includes incorporating value stacking of all system benefits of energy storage in its modeling, utilizing lessons learned from other energy storage research and pilot programs, and incorporation of a variety of use cases for energy storage that meet the Company's system needs.