PACIFIC POWER
A DIVISION OF PACIFICORP

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September 24, 2015

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Public Utility Commission of Oregon
201 High Street SE, Suite 100
Salem, OR 97301-1166

Attn: Filing Center

Re: LC 62 PacifiCorp's Reply Comments

PacifiCorp d/b/a Pacific Power (PacifiCorp or Company) submits for filing its Reply Comments on PacifiCorp's 2015 Integrated Resource Plan. Confidential Attachment 1 is provided per Protective Order No. 14-416.

Informal questions may be directed to Erin Apperson, Manager, Regulatory Affairs, at (503) 813-6642.

Sincerely,

R Bryce Dalley / EEA

R. Bryce Dalley
Vice President, Regulation
Enclosures

CERTIFICATE OF SERVICE

I certify that I electronically filed a true and correct copy of PacifiCorp's Application with the Public Utility Commission of Oregon Filing Center, who will serve the parties listed below via electronic mail in compliance with OAR 860-001-0180. PacifiCorp will provide a Confidential CD to the following parties that can receive confidential information via Overnight Delivery.

LC 62

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Dated this 24th of September , 2015.

Carrie Meyer
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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 62

In the Matter of PACIFICORP, dba PACIFIC POWER 2015 Integrated Resource Plan	REPLY COMMENTS

1. INTRODUCTION

PacifiCorp d/b/a Pacific Power (PacifiCorp or Company) filed its 2015 Integrated Resource Plan (IRP) with the Public Utility Commission of Oregon (Commission) on March 31, 2015. The Company's IRP was prepared in accordance with the terms of Order No. 14-252, in which the Commission acknowledged the Company's 2013 IRP, with exceptions and revisions to the Action Plan, as well as Order No. 14-296 covering the specific fleet analyses to be performed in the 2015 IRP, and Order Nos. 07-002 and 07-047, in which the Commission adopted the Oregon IRP Guidelines. As part of its review, the Commission considers the extent to which the plan satisfies the procedural and substantive requirements of Oregon's IRP Guidelines and whether the plan is reasonable at the time of acknowledgement.

As part of the IRP acknowledgment schedule adopted by the administrative law judge for this proceeding, parties filed written comments and recommendations on August 27, 2015. Eight parties submitted written comments: Commission staff (Staff), Citizens' Utility Board of Oregon (CUB), Northwest Energy Coalition (NWEC), Oregon Department of Energy (ODOE), Industrial Customers of Northwest Utilities (ICNU), Renewable Energy

Coalition (RC), Renewable Northwest (RN), and Sierra Club (SC). In response to these comments, PacifiCorp submits these reply comments for consideration. Following the recommendation section, the Company replies to the parties' written comments, organized by responding party.

In addition to providing comments to the Commission since the filing of the Company's 2015 IRP, the parties to this docket also participated in an extensive pre-filing process that included multiple public input meetings and technical workshops where the Company discussed a comprehensive set of planning topics, including the analysis of EPA's draft Clean Power Plan (CPP) rule. The pre-filing process provided a forum for stakeholder to provide feedback to the Company as the 2015 IRP was being developed. The 2015 IRP was prepared with the following process and modeling improvements:

- Expanded coal unit investment analysis, reflecting potential inter-temporal and fleet tradeoff compliance outcomes for both known and prospective Regional Haze (RH) compliance requirements;
- Expanded public input process with advent of a "feedback form" wherein stakeholders were encouraged to submit additional input, recommendations, comments, and pose questions;
- Addition of a new modeling tool, the 111(d) Scenario Maker, needed to study the EPA's proposed Clean Power Plan;
- Addition of distributed generation (DG) resource assessment examining solar photovoltaic, small scale wind, small scale hydro, combined heat and power reciprocating engines, and combined heat and power micro-turbines specific to PacifiCorp's service territory;

- Addition of anaerobic digester resource assessment reporting on the amount of potential electric power generation from dairy waste in PacifiCorp's Washington service territory;
- Updated conservation potential assessment which drives the demand side management (DSM) resource potential assumptions;
- Updated energy storage screening study which catalogs characteristics and costs of commercially available utility scale and distributed scale storage technologies;
- Updated analysis of regional resource adequacy to support assumptions for Front Office Transmission (FOT) limits;
- Updated planning reserve margin study which supports the 13 percent planning reserve margin assumption used in the 2015 IRP;
- Updated wind and solar capacity contribution study, developed using the capacity factor approximation method accounting for loss of load probability among all hours in the year;
- Updated wind integration study incorporating new data, as well as recommendations from an independent technical review committee;
- Updated stochastic parameter study for stochastic variables including natural gas and wholesale electricity prices, load and hydro generation; and
- Updated flexible resource needs assessment which shows that PacifiCorp's system has sufficient resources to meet its flexible resource needs.

2. RECOMMENDATION

PacifiCorp's reply comments respond to written comments filed by Staff and parties on August 27, 2015. In these reply comments, PacifiCorp provides additional information, clarification of its positions, and specific recommendations for the Commission's consideration in its review of the Company's 2015 IRP.

PacifiCorp has met the Oregon IRP Guidelines and requests that the Commission acknowledge the 2015 IRP. In particular, PacifiCorp requests that the Commission acknowledge its 2015 IRP Action Plan, with a clarification that Action Item 5b, pertaining to the Wallula to McNary 230 kilovolt transmission line, is required by PacifiCorp's FERC-approved Open Access Transmission Tariff (OATT).

3. COMMISSION STAFF OPENING COMMENTS

Staff provides general comments on the IRP process and analysis, along with evaluation of supporting studies and tools used for portfolio selection as provided in PacifiCorp's 2015 IRP. Some specific areas of concern are also addressed.

Staff states: "Overall, the Company provides a thorough and robust process for developing the IRP." Staff notes that there was "ample opportunity" for stakeholder input. Finally Staff finds PacifiCorp's 2015 IRP "Action Plan represents a reasonable combination of least-cost and least-risk solutions to meeting the Company's future load/resource balance." Specific areas of concern raised by Staff are addressed below.

Review of Supporting Studies and Forecasts

Staff requests a "narrative evaluation of each study." It is unclear specifically what additional information Staff would like included in the IRP. The Executive Summary of the main 2015 IRP report contains a high-level discussion of the IRP supporting studies. The full studies are included in their respective appendices in Volume II of the 2015 IRP. Each of these appendices contains an introduction providing the rationale for each study and additional narrative that presents the methods and findings from each study.

Staff determined the majority of the supporting studies and forecasts to be either "reasonable for planning purposes" or "not unreasonable." These include price forecasts for both power and natural gas. Staff likewise found transmission assumptions to be reasonable; however, Staff notes that the Company should reflect results of docket UP 315 as approved in Order No. 15-184 in future IRPs. Staff also requests more information going forward on market availability of FOTs.

In regards to setting FOT limits, the Company discusses how it arrived at its FOT limits in the main body of its 2015 IRP report (Chapter 6), Appendix J to the IRP report, as well as in responses to Staff's data requests and meetings with the Staff. Appendix J has an overview of studies done at the regional level by the Western Electricity Coordinating Council (WECC) and the Northwest Power and Conservation Council (NWPCC, or the Council). WECC's forecast shows that the planning reserve margin in the sub-region in which PacifiCorp operates, the NWPP sub-region, is not expected to drop below the targeted planning reserve margin in the near future. The Council's study indicates that the loss of load probability in the region may increase due to retirement of generation resources in the region. However, the Council states that "an LOLP assessment greater than 5 percent for 2019 and 2021 does not mean that the region has failed to maintain an adequate supply." In responding to Staff's data requests, the Company provided historical data on short term firm market purchase transactions that the Company executed since January 2010. Those transactions show that the Company has access to market at multiple delivery points and that the Company has been able to purchase different types of firm products at various times. These historical transaction data showed firm market purchases that frequently exceed FOT limits that the Company modeled in its IRP. As described in Chapter 6 of the Company's IRP report:

> Solicitations for FOTs can be made years, quarters or months in advance, however, most transactions made to balance PacifiCorp's system are made on a balance of month, day-ahead, hour-ahead, or intra-hour basis. Annual transactions can be available three or more years in advance. Seasonal transactions are typically delivered during quarters and can be available from one to three years or more in advance. The terms, points of delivery, and products will all vary by individual market point.

Additionally, the fact that the Company purchased little from the market at times does not necessarily suggest that market depth was limited. Rather, it merely indicates that the Company did not need additional resources to balance its system at the time. The above discussion clearly demonstrates that the Company has provided both qualitative and quantitative analyses to support its FOT limit assumptions in the 2015 IRP.

Coal Analysis

Staff is satisfied that the Company completed all coal-unit analysis as called for in Order No. 14-252. This includes both inter-temporal and fleet-trade off analysis. As Staff notes, there is still uncertainty regarding EPA's final CPP rules. Staff determined the approach for Wyodak to avoid an SCR as a "reasonable and low risk" approach. This is also Staff's determination regarding the current approach to close Dave Johnson Unit 3 at the end of its depreciable life, 2027. For Cholla Unit 4, Staff believes that the approach to avoid an SCR is reasonable with either a 2025 shutdown or conversion to natural gas as the end result.

For Naughton Unit 3 Staff notes there is a small cost difference between converting to natural gas and shutdown, and suggests quarterly re-evaluation prior to the project implementation scheduled to begin in the first quarter of 2017. While implementation begins in 2017, there is preparation work, such as procurement of gas transportation and selection of an engineering, procurement, and construction (EPC) contractor and negotiation of the associated contracts that will take place prior to the project implementation. The Company believes an update may be necessary dependent on the cost of gas transportation and EPC through the respective requests for proposals. However, the Company believes that quarterly updates are neither practical nor needed.

Smart Grid

In its comments, Staff contends there are issues with the Company's implementation of Smart Grid, and the fact that time-of-use (TOU) tariffs show only "diminutive participation levels" is troubling. Other issues raised include grid optimization and renewable generation management. Some of these issues, such as TOU tariffs, are best addressed through rate design and not through the IRP. Customer-sited distributed energy resources (DERs) are covered in the DG report in Appendix O. Resource needs to integrate intermittent resources are covered both in Appendix F – Flexible Resource Needs Assessment and Appendix H – Wind Integration Study. Overall, PacifiCorp has chosen a least cost-least risk approach to planning in the IRP. As discussed in Appendix E – Smart Grid:

> Through a comprehensive review and analysis of smart grid report published each year, PacifiCorp is able to ascertain the value proposition of emerging technologies and, at the appropriate time, recommend them for demonstration or integration.

The Company included the most current reports on the data disks that accompanied the 2015 IRP. Going forward the Company will continue this approach to mitigate both costs and risks associated with such projects.

Flexible Resource Needs Assessment/Wind Integration Study

Staff raises some potential issues with the flexible needs assessment, wanting more subhourly detail, but does assert that, "[t]echnically, the Company did meet the OPUC guideline...” Staff also notes the Wind Integration Study (WIS) covers the methodology needed in the flexibility study. Staff’s suggestion is to combine the two studies above with the Planning Reserve Margin (PRM) Study, Western Resource Adequacy Evaluation, Wind and Solar Capacity Contribution Study, and the Energy Storage Screening Study into a single comprehensive study. The goal of the combined study, as suggested by Staff, is “to ensure that the system is reliable yet optimized for least cost and risk.”

In essence that is the goal of the IRP, which incorporates the results of all the supplemental studies as appropriate and selects the preferred resource portfolio to meet projected resource needs reliably and in the least cost, least risk manner. Combining all studies into one study may obscure some of the detail contained in the individual studies. The wind integration study identifies additional operating reserve *requirements* besides contingency reserves in order to manage the variability of the wind generation resources on the Company’s system. The additional operating reserve requirements will be met by the resources that are capable of providing operating reserves. The Company’s “Flexible Resource Needs Assessment” compares the *capability* of the Company’s generation resources that are sufficiently flexible to cover the requirements of contingency reserves and additional reserves to integrate variable wind generation resources. The Company is willing to work with Staff and other stakeholders in the 2017 IRP process to clarify the goal of an all-encompassing study and to organize the materials in an efficient and comprehensive manner.

Planning Reserve Margin Study

In its discussion regarding the Company’s planning reserve margin (PRM) study, Staff seems to agree that the Company provided comprehensive analysis with a wealth of data and analysis. At the same time, Staff suggests that the "Company falls short in quantitatively using the data to choose an appropriate PRM." Appendix I to the Company's 2015 IRP report not only lists the studies that were performed around the reliability measures and the cost impact of different levels of assumed PRM, it also discusses results that support the study conclusion and selection of the PRM for the 2015 IRP. The Company is unsure what Staff believes is missing from the study in its current form but is willing to work with Staff in the 2017 IRP process to address any perceived shortcomings.

Western Resources Adequacy Evaluation

Staff is satisfied with the findings of the study that there are adequate supplies during the Action Plan time horizon. Staff does mention potential areas of supply concern going forward, including plant closures and environmental regulations. With these concerns in mind, Staff recommends updating the study in future IRPs. PacifiCorp believes this is a reasonable recommendation.

Net Metering/Distributed Generation Study

Staff states the portfolio cost differences between low, base and high DG cases, while modest, are more than the cost differences between top ranked portfolios. Staff suggests that the Company could potentially offer incentives to remove barriers to DG installations. Currently, customers have access to existing federal tax credits and net metering programs. In addition, Washington customers enjoy a sales tax exemption on solar PV installations less than 10 kilowatts as well as state funded production incentives. Staff believes that additional incentives offered by the Company might lead to more installation of DG; it would also certainly involve equity issues among all customers. Regulatory proceedings are underway nationally and in several of the Company's jurisdictions to resolve outstanding net metering cost allocation issues. Once resolved these will result in better alignment of the value of DG for the Company and its customers, who may or may not install DG facilities.

Staff raises some questions on the Navigant DG study, regarding the amount of DG reported for 2013 and 2014, and with respect to perceived conservative forecasts for solar PV in Oregon. Staff's interpretation of the result is incorrect, as the study results presented in the report show the incremental amounts of forecasted DG beginning in 2013 as opposed to the total amount of DG on the Company's system. Existing net-metered generation is already reflected in PacifiCorp's load forecast.

As for potential disparate state level forecasts, the study examined PacifiCorp's service territory only, which at times diverges significantly from whole-state averages. The study itself used a Fisher-Pry payback analysis to determine market penetration for the Company's service territories with customer rates based on the Company's tariffs. For example, page 6-10 of Volume II, Appendix O documents reasons driving higher amounts of DG in California, which notes that California DG penetration levels are because "...grid parity is closer than in other PacifiCorp states and payback periods are lower." The Company will update the study for the 2017 IRP and will continue to look at improving these estimates with the best information available for our service territory.

Clean Power Plan Modeling

Staff is unsure that PacifiCorp's treatment of Renewable Energy Certificates (RECs) was appropriate for modeling the CPP Rule 111(d). They point to the definition of a REC as defined in Revised Code Washington Title 19, Chapter 285 (Energy Independence Act), Section 30 (Definitions), (20) and Oregon Administrative Rule 330-160-0015(15)[1] and suggest that the Company's assumption allowing for the separation of the 111(d) attribute

[1] Staff's comments reference OAR 330-160-0015(9), but provide the text of OAR 3330-160-0015(15).

from REC resources was too flexible under these definitions. Staff suggests the Company should have "created a model where REC resources could not be used for different compliance obligations in different States."

Given the level of uncertainty around the proposed rule and how the proposed rule will ultimately interact with state law, the Company's assumptions regarding RECs were reasonable. In the proposed rule, the EPA requested comments on what would consist of duplicative counting of attributes. One pointed to a duplicative standard as:

> An example of a duplicative emission standard would occur where recognition of avoided CO_2 emissions from, for example, a wind farm, could be applied in more than one state's CAA section 111(d) plan.

PacifiCorp's 111(d) modeling did not allow the same CO_2 emission reductions to be counted in multiple states. With respect to non-duplicative standards regarding renewable energy generation, the proposed rule indicated that renewable generation may meet more than one requirement:

> This does not mean that measures in an emission standard cannot also be used for other purposes. For example, if a state wished to take credit for CO_2 emissions avoided due to electric generation from a new wind farm, those avoided emissions could be considered non-duplicative and included for purposes of CAA section 111(d), even if electric generation from that wind farm was also being used to generate renewable energy certificates (RECs) to comply with the state's RPS requirements.

EPA's proposed rule made clear that a single megawatt-hour of renewable generation can be used for both 111(d) and RPS compliance. Both the proposed rule and current state law are silent as to whether renewable generation could be used for both 111(d) compliance and RPS compliance in separate states. Both the proposed rule and state law are similarly silent as to whether a REC must be retired when the underlying renewable generation is "used" for 111(d) compliance. A strict reading of the state definitions of REC cited by Staff, which include all of the environmental attributes associated with renewable generation, would most reasonably be interpreted to preclude the use of a single megawatt-hour of renewable generation for both 111(d) and RPS compliance, even if used in the same state. Given the proposed rule's intent to leverage state RPS programs and allow renewable generation to be used for both purposes, it would not have been reasonable to assume that current state law would preclude this outcome.

The Company acknowledges that there is lack of clarity regarding the interaction of 111(d) and state RPS requirements. In light of this lack of clarity, the Company's assumptions were reasonable at the time they were made (i.e., before EPA's final rule was published). In any event, PacifiCorp will update modeling consistent with assumptions based on the recently released final CPP rule. The 2015 IRP Update and future IRPs will look at the ongoing evolution of requirements under the CPP as well as incorporate information as states begin to develop their CPP implementation plans. Separately, the Company has also committed to working with state agencies while they are developing state plans to implement the CPP to work through many of these complexities.

Discussion of PVRR Metrics

Staff takes issue with the Company's choice of metrics for portfolio selection stating it could lead to incorrect or inconsistent results. Throughout the discussion Staff offers "hypothetical situation, for illustration only." Detailed information for all portfolios was provided on the data disks accompanying the Company's 2015 IRP filing. It is unclear why Staff did not avail themselves of this information as opposed to providing hypothetical situations. Further, the Company received no criticism when it presented its methodology and selection of the Preferred Portfolio during pre-filing public input meetings attended by Staff and other stakeholders.

The Company is unsure where Staff's "A Note About Risk" on page 18 of its comment originates because no citation was given. The Company's IRP is agnostic to ratepayer/shareholder risks; this is not a consideration in selecting a preferred portfolio. To suggest otherwise is misleading.

First, Staff takes issue with the exclusion of fixed costs from the Upper Tail Mean that is used to measure the risk of the portfolios, and states that the measure "may produce portfolio decisions that are neither truly least-cost nor least risk to ratepayers." PacifiCorp agrees that portfolios can have different cost and risk profiles, which is precisely why both cost and risk metrics are used to screen resource portfolios. This is achieved by evaluating the cost and risk metrics for each portfolio in "scatter plots," with the risk metric for each portfolio plotted on the y-axis, and the cost metric for each portfolio plotted on the x-axis. Staff's discussion on hypothetical situation implies that portfolios could be compared and conclusions could be drawn with just one measure, the Upper Tail Mean. Upper Tail Mean is a measure of how high the production cost of a portfolio could be through the stochastic process. Upper Tail Mean less fixed cost measures the variability in variable production costs or risk of the portfolio, given that the fixed cost of a portfolio does not vary in the stochastic process.

The Stochastic Mean measures the expected total costs of the portfolio. If the fixed costs are not excluded from the Upper Tail Mean, the "scatter plots" would show a nearly diagonal line because the amount of portfolios' fixed costs would mask the value of the risk measures. As a result, both the x- and y-axes would show cost information of the portfolios, as opposed to the tradeoff of risk and cost. In the case of the hypothetical evaluation Matrix #1, the Company agrees with Staff in that "(i)f the choice of portfolio is based solely on these criteria, the choice apparently would be the nuclear portfolio." The Company's decision is not made solely on one criterion. During the initial screening process, superior portfolios are identified as those that are either within two percent of the least cost portfolio or within two percent of the least risk portfolio. Consequently, the least cost, least risk portfolios move on to the next phase of the preferred portfolio selection process, which includes comparative portfolio analysis on risk-adjusted PVRR, reliability, emissions, and fuel diversity measures to inform selection of the preferred portfolio. Staff's hypothetical evaluation Matrix #2 seems to suggest the same issue, only with a different measure of 95th percentile stochastic PVRR. The Company did not use the measure, excluding fixed costs, in its portfolio selection process.

Second, Staff takes issue with how the Company ranks the portfolios in the final screening for the preferred portfolio. In the final screen process, the Company utilized the Risk Adjusted PVRR measure, which incorporates the mean stochastic PVRR of the portfolios and the risk premium of the portfolios. The risk premium of a portfolio is defined as five percent of the portfolio's 95th Percentile Stochastic PVRR. The Company believes that the choice of five percent of the portfolio's 95th Percentile Stochastic PVRR is sufficient to capture risk impact of the portfolio. In addition, if Staff had reviewed the study results that the Company provided rather than the hypothetical examples, it could see that the change in the percentage value would not materially impact the ranking of the portfolios because the underlining calculation of the ranking is on the mean stochastic PVRR of the portfolios. Assuming:

M1 = Stochastic Mean PVRR of Portfolio 1,

M2 = Stochastic Mean PVRR of Portfolio 2,

P1 = 95^{th} Percentile PVRR of Portfolio 1,

P2 = 95^{th} Percentile PVRR of Portfolio 2,

Then the ranking is based on:

Rank = (M1 – M2) + 5% * (P1 – P2)

Unless the difference between P1 and P2 is significant enough, the ranking of the portfolios is not expected to change materially. In addition, as mentioned above and discussed in the Company's 2015 IRP report, other factors are also used in the selection of the preferred portfolio, such as energy not served, emission and resource mix.

Demand Response/Demand Side Management

Staff questions the usefulness of showing the "nameplate capacity" of DSM in PacifiCorp's portfolio capacity tables calling it a "somewhat useless value." The Company respectfully disagrees with Staff's assessment. To demonstrate changes in a portfolio of resources, such as retirement or conversion of existing resources, and location and size of new resources, all resources are shown on a nameplate capacity value, including intermittent resources. This provides insight on what resources are added at what time, and the magnitude of the resource changes on a comparable basis among all resource alternatives. Staff does not, however, suggest this approach to be in error. The multiple reports produced in an IRP convey information about study results from different perspectives. Resource capacities at the time of the system coincident peak are reported in load and resource balance (L&R) reports. The IRP is used by a diverse group of stakeholders, and the Company believes the information provided provides value for stakeholder and Commission review.

Staff “encourages the Company to follow Energy Trust’s drive to acquire all cost effective resource and invest in new approaches and emerging technology development throughout its territories to accelerate cost effective achievable energy efficiency.” The Company plans to pursue all cost-effective Class 2 DSM over the Action Plan window, as defined by the amounts selected by the 2015 IRP and supported by the value of Class 2 DSM provided in the 2015 Class 2 DSM Decrement Study.

Staff’s Table 2 in its comments shows the accelerated Class 2 DSM scenarios tested in the 2015 IRP led to both higher costs and lower 20-year Class 2 DSM selections than the Preferred Portfolio; see line 1 “Base (preferred portfolio)” compared to line 3, “Accelerated (C11-1, C11-2).” However, Staff’s assumed adjustment for the years 2016-2034 as included in Table 2 for the Accelerated Case, line 4, “Adj. Accelerated (removes $1.5m/yr)” is incorrect. The Company is not sure where the assumed adjustment came from; it may be the value for Class 2 DSM that begins in 2015. If so, Staff misinterprets the $1.52 million as a “cost penalty,” which it is not. The $1.52 million is a levelized cost of the DSM resources selected in 2015 and recurs on an annual basis beginning in 2015. Costs are counted every year because supply curve costs are generated on a levelized basis. Re-applying the levelized cost in every year of the study period ensures that the full cost is counted in PVRR analysis. This is the same method used for Base DSM modeling and supply-side resources.

Staff requests that the Company run the Preferred Portfolio with the accelerated DSM case for the 2015 IRP Update to help Staff and the Company better understand how accelerated DSM performs under a range of future conditions and system risks relative to base case DSM. The Company believes the base and accelerated DSM cases to be similar enough that there will not be much additional information gleaned from such a run.

The Company will work with Staff and other stakeholders in the 2017 IRP process to address other items raised in Staff's comments around modeling DSM. These include presenting Oregon Class 2 DSM existing and potential resource in a more integrated fashion within the plan for the other five states in the Company's service territory to make interpretation of the analysis for efficiency more effective. Another recommendation is an alternative method for creating Class 2 DSM levelized cost bundles, where cost credits would be applied at a measure level before bundling measures with similar adjusted costs.

Staff suggests that the Company should more directly incorporate new technology projections from the Northwest Energy Efficiency Alliance (NEEA) into DSM modeling in future IRPs. The Company's DSM potential studies rely on a variety of sources, including NEEA, to identify emerging technologies with reliable savings, cost, applicability, and availability projections. As noted in Staff's comments, the 2015 DSM potential study included measures that overlap with NEEA's 2015 initiatives. The Company notes that the IRP determines cost-effective levels of Class 2 DSM, but does not prescribe the best way to acquire these savings, such as through market transformation, utility programs, codes and standards or other methods.

<u>Class 1 and Class 3 DSM</u>

Staff is concerned that PacifiCorp's 2015 IRP shows little potential for Class I DSM on the western part of its system and references potential issues with residential metering and data-gathering infrastructure that is not modern enough to implement such opportunities. The Company clarifies that metering infrastructure was not a factor in determining the potential for, or cost of, Class 1 DSM resources in the 2015 DSM potential study, which identified nearly 110 megawatt (MW) of potential on the west side of the system.

Opportunities for Class 1 DSM targeting summer peak loads are lower on the west side of the system due to lower saturations of whole house residential and small commercial air conditioning, commercial and industrial curtailment opportunities, and differences in irrigation characteristics as compared to the east side of the system.[2]

That said, the Company acknowledges the value of demand response resources and intends to pursue their acquisition as the need and cost justifies. For example, the Company has over 450 MW of load control and curtailment demand response resources under management to date, such as Utah residential and small commercial air conditioning load control program resources, Utah and Idaho irrigation load control resources and Utah and Idaho special contract curtailment resources. The Company also estimates it realizes 100 MW of summer peak reduction from existing Class 3 time-based pricing resources and saves annually between 55-149 GWh from the Company's residential inverted rate pricing programs. The lack of incremental demand response in the IRP Action Plan is the result of lower cost resource options available within the planning window, not lack of company interest. The IRP model optimizes resources selected based on their reliability, risk and cost and did not select any economic demand response resources in the Preferred Portfolio until the west-side irrigation load control resource selection in 2022.

Staff also raises issues with the lack of demand response pilot programs on the west side. As previously stated, the Company's 2015 DSM potential study identified nearly 110 MW of Class 1 DSM potential on the west side of the Company's system by 2034. However, due to system requirements and least cost planning options, the 2015 IRP did not select west side demand response, Oregon Irrigation Load Control resources, until 2022. As such, the

[2] 2015 Applied Energy Group Demand-Side Resource Potential Assessment for 2015-2034 identified 570 MW of Class 1 resource opportunities in PacifiCorp's east service areas (Utah, Idaho and Wyoming) compared to 108 MW in its west service areas (Oregon, Washington and California).

2015 IRP Action Plan includes an action item (3a) to pursue a west side Irrigation Load Control pilot in 2016 to test the feasibility of the Company's contracted program design. The 2015 IRP also selected 32 MW of Commercial Curtailment on the west side beginning with 2023. However, as commercial operations are less diverse than irrigation environments a pilot program here is not necessary at the current time.

<u>Wallula to McNary Transmission Line</u>

In initial comments, Staff states that it cannot support acknowledgement of PacifiCorp's Action Item 5b, construction of the Wallula to McNary 230 kV transmission line. Staff argues that the IRP does not provide an adequate economic justification for this Action Item. Staff comments, however, misapprehend the need for the Wallula to McNary transmission line.

As described in the IRP, Chapter 4, PacifiCorp has a non-discretionary obligation to construct the Wallula to McNary transmission line in order to satisfy the federal regulatory obligations to transmission customers under its OATT. PacifiCorp has a point-to-point transmission service agreement to provide 25 MW of transmission service by December 31, 2017, over the new transmission line pursuant to requirements in its OATT.[3]

As described in more detail in response to Staff DR 55, PacifiCorp is required under sections 15.4 and 28.2 of its OATT to satisfy the customer's need for transmission service. Specifically, under section 15.4 of the OATT, PacifiCorp is obligated to the following:

> If the Transmission Provider determines that it cannot accommodate a Completed Application for Firm Point-To Point Transmission Service because of insufficient capability on its Transmission System, the Transmission Provider will use due diligence to expand or modify its Transmission System

[3] PacifiCorp previously had two transmission service agreements for capacity over the Wallula to McNary line. Although one of the agreements was terminated, the Company's mandatory obligation to provide transmission service to its other customer has not changed.

> to provide the requested Firm Transmission Service consistent with its planning obligations in Attachment K...

Additionally, under section 28.2, PacifiCorp is obligated to:

> [P]lan, construct, operate and maintain its Transmission System in accordance with Good Utility Practice and its planning obligations in Attachment K in order to provide the Network Customer with Network Integration Transmission Service over the Transmission Provider's Transmission System.

These sections of the OATT require PacifiCorp, as a transmission provider, to perform transmission system upgrades as necessary to satisfy a customer's need for transmission service. The needs are driven either from network or point-to-point transmission service requests.

- Network needs arise when the yearly network load and resource planning study shows projected load growth and system changes are required to meet this growth.
- Point-to-point needs arise from specific point to point transmission requests when system upgrades are necessary to satisfy the requested service.

With regards to network transmission service, the existing Wallula to McNary transmission line is fully subscribed for network service to PacifiCorp's Energy Supply Management. PacifiCorp is obligated however, per its transmission service agreement, to provide long-term firm point-to-point transmission service to its transmission customer once the Wallula to McNary transmission line is complete.

In identifying the least cost option for meeting its obligation to its transmission customer, PacifiCorp analyzed two construction alternatives and three other service alternatives described in detail in the Investment Appraisal Document submitted in response to Staff DR 58 and provided as Confidential Attachment 1 to these reply comments. The construction alternatives considered included a re-build of the existing Wallula to McNary transmission line to a double circuit line, or re-conductoring the existing Wallula to McNary transmission line with high temperature conductor in order to increase the capacity of the transmission line. At minimum, both options were more than nearly twice the cost of constructing the new transmission line and one option more than double the cost.

Constructing a new Wallula to McNary transmission line was the least cost option while still meeting PacifiCorp's obligations as a transmission provider under its OATT. As described in the Investment Appraisal Document and responses to Staff's data requests, the existing transmission line is contractually fully subscribed, and provides no capacity for satisfying PacifiCorp's obligation to serve new transmission service requests or interconnection of new resources to serve customer load.

In addition to meeting regulatory obligations, the Wallula to McNary transmission project also provides a number of benefits. For example, the new line will alleviate the existing constrained transmission path by creating new line capacity that can be utilized to serve the existing transmission service agreement obligations and new transmission service requests and resources that can be used to serve customer load growth. The project also improves reliability in the region and Pacific Power customers served in the Wallula area by having a second transmission line from Wallula to McNary. The transmission service allows the transmission customer to continue purchase of a renewable resource with delivery to its customers in order to meet Oregon renewable portfolio standard requirements.

The proposed Wallula to McNary transmission line is the least cost, least risk alternative for PacifiCorp to satisfy its mandatory obligations to the transmission customer under the OATT. Ignoring its transmission service obligations would subject the Company to customer complaint proceedings at the Federal Energy Regulatory Commission, which would expose the Company and its customers to potential penalties and litigation costs.

Furthermore, the Commission has already recognized the need for the Wallula to McNary project. In Order No. 11-366, the Commission approved PacifiCorp's requests for a Certificate of Convenience and Public Necessity for the project, finding that it "is necessary, safe, practicable, and justified in the public interest, and consistent with land use regulations."[4] The Commission recognized that the Wallula to McNary line "will allow Pacific Power to help meet its OATT obligations and provide additional transmission in an area that currently operates at full capacity."[5] The Commission also recognized that "failing to build the line will negatively affect EWEB and its customers; customer rates could increase by as much as $2 million annually."[6]

Constructing the Wallula to McNary transmission line is the least cost option and provides a number of reliability and other benefits to PacifiCorp's transmission system and customers. PacifiCorp strongly encourages the Commission to acknowledge Action Item 5b in this IRP. As described in Chapter 4 of the IRP, Chapter Highlights, PacifiCorp is requesting acknowledgement of its plan to construct the Wallula to McNary portion of the line "based on customer need and associated regulatory requirements." As such, PacifiCorp would not object to the Commission acknowledging Action Item 5b with highlighted clarifying language to reflect such requirements: "Complete Wallula to McNary project construction per plan with 2017 expected in-service date, as required by PacifiCorp's OATT as approved by FERC. Continue to support the permitting process for Walla Walla to McNary."

Winter Peak Constraint

Staff is concerned that by targeting the system peak (which occurs in the summer) for

[4] Docket No. UM 1495, Order No. 11-366 at 10 (Sept. 22, 2011).
[5] *Id.* at 6.
[6] *Id*.

modeling purposes the Company could face resource deficiencies during the winter peak in its west control area. It is correct that the Company assumed that the FOTs are available to meet the summer system peak needs, except for FOTs from the Mid-Columbia market that are available, for modeling purposes, in all months. This assumption does not suggest in any way that these FOTs are not available during winter seasons, which is evident from the data that the Company provided Staff on historical short term firm purchase transactions. In response to Staff's request to study the impact of meeting the targeted planning reserve margin for the winter system coincident peaks (after meeting the targeted planning reserve margin for the summer system coincident peaks)[7], it is also clear that the Company has sufficient resources to meet its winter peak requirement. In that study, a peaking resource was selected in 2019. However, this is an artifact that the study enforced a planning reserve margin for the winter peaks, when the planning reserve margin is to target the resource needs for summer peaks and at the same time to achieve reliability of the system for an *entire* 12-month period. Enforcing a planning reserve margin for both summer and winter system peak would lead to unnecessary costs for customers. The Company is willing to discuss the issue with Staff and other interested stakeholders in the context of planning reserve margin target in general.

4. CUB OPENING COMMENTS

CUB is generally supportive of PacifiCorp's 2015 IRP. Highlights cited in CUB's comments include "more transparency, more cooperation with stakeholders, and more cost-effective planning..."[8]

[7] OPUC Data Request 4.
[8] CUB Opening Comments at page 7.

Improvements in the Plan

CUB cites several areas that were improved in the 2015 IRP as compared to the 2013 IRP. The first is in the modeling for Regional Haze investments. The incorporation of inter-temporal and fleet tradeoff analysis in these decisions is viewed favorably. CUB also commended the Company for the approach to requesting, and incorporating stakeholder input via the online Feedback Form.

Demand-Side Management

CUB is pleased to see the level of DSM has substantially increased in the 2015 IRP. They note that the DSM values in the 2015 IRP are in line with their expectations based on the accelerated DSM case from the 2013 IRP. The Company would like to clarify that the increase in DSM potential is driven by additional potential becoming available due to rapid advances in the solid state lighting market since the time the 2013 DSM potential study was conducted. However, the increase in potential does not imply the hypothetical accelerated DSM case modeled in the 2013 IRP (where the timing of acceleration and the resource costs were based on company estimates) should have been selected in the 2013 IRP preferred portfolio as CUB suggests.

Clean Power Plan

While the CPP was only finalized as of August 3, 2015, CUB appreciated the work that the Company did in examining the draft rule. They also lauded the incorporation of stakeholder feedback in developing the modeling scenarios. In its comments CUB discusses changes between the draft and final rules, and is anticipating the Company will incorporate new analysis going forward. They do not, however, expect to see changes in the current preferred portfolio.

5. NWEC OPENING COMMENTS

NWEC noted areas of progress in developing the 2015 IRP as compared to past IRPs. They cite considerable improvement in the public process, including willingness to incorporate stakeholder suggestions which led to a stronger IRP. Other areas of note include the increase in DSM and extensive modeling of the CPP. There are concerns with reliance on unbundled RECs to meet state RPS requirements and inclusion of solar costs that might be too high. Reliance on gas resources and lack of new renewables are also issues raised.

Demand-Side Management

The Company appreciates NWEC's praise of its progress toward achieving the level of DSM from the 2013 IRP and for its 2015 DSM potential study. However, the increase in DSM potential in the 2015 DSM Conservation Potential Assessment and related IRP selections compared to the DSM potential in the 2013 Conservation Potential Study and IRP are not a result of "improvements to the conservation potential study methodology" as NWEC suggests. Both 2013 and 2015 studies used the same industry-standard methodology for estimating DSM potential and relied on the best information available at the time of the study to inform projections of available potential. The primary drivers of increased Class 2 DSM potential and selections in the 2015 IRP were updated projections from the US Department of Energy of solid state lighting cost and efficacy. Differences in and reasons for changes in potential between the 2013 and 2015 DSM potential studies are detailed in Chapter 5 of Volume 2 of the 2015 DSM Potential Study, which is summarized in Appendix D to the Company's 2015 IRP report.

Coal Resource Analysis

NWEC notes that the 2015 IRP process for analyzing coal plant investments has improved since the 2011 and 2013 IRPs. This analysis is specific to EPA's regional haze requirements. NWEC specifically commends the Company for engaging "in meaningful dialog with stakeholders in the 2015 IRP development process..."

Carbon Regulation and Pricing

When noting the responsiveness to stakeholder input, NWEC states the Company should "be commended for their extensive analysis of the EPA's CPP [111(d)] draft regulations." However, NWEC raises concerns similar to those raised by Staff related to use of RECs for RPS requirements but also allowing use of a 111(d) attribute in another state. The Company addressed this issue above in response to Staff's comments. NWEC also believes the CO_2 reductions seen in the 2015 IRP need to be larger to address potential climate concerns.

PacifiCorp agrees the development of compliance plans in the states that it operates in will need to be fully vetted in the 2017 IRP, and likely other more distant IRPs. The Company will incorporate known and expected regulations going forward as it has historically done.

Renewable Resources

NWEC raises issues with the lack of new renewable resources in the Preferred Portfolio. However, what is important to note is the Preferred Portfolio relies on DSM and FOTs in the front years of the planning horizon. In fact there are no major generation assets selected until 2028 when a CCCT is added after an existing plant retires. Simply stated, the 2015 IRP shows that incremental renewable resources, beyond the 816 MW of QF renewable resources expected to come online by the end of 2016, are not needed in the near-term. Nonetheless, the Company recognizes that there are numerous potential state and federal policy developments that might introduce and accelerate the need for incremental renewable resources. PacifiCorp will continue to evaluate the need for renewable resources with changes in the planning environment.

NWEC is unconvinced that PacifiCorp's plan to use unbundled RECs to meet Washington RPS compliance is appropriate, mentioning potential impacts of the final CPP. While concerns with Washington requirements would be best addressed by the Washington Utility and Transportation Commission, the Company addresses the use of unbundled RECs in general. The 2015 IRP examines a strategy to use unbundled RECs (see page 182 of the Company's 2015 IRP report). This analysis found an unbundled REC price of $18/REC yields break-even economics. As long as the price of RECs is less than that it is more cost-effective to use unbundled RECs. Additionally, Table 9.3 in the report covers near- and long-term resource acquisition paths. If there are strict state requirements associated with implementation of 111(d) the Company would likely initiate new renewable resource procurement activities. In other words, the Company is aware of the risk and will make adjustments as necessary.

Solar costs are also at issue for NWEC, with expectations that they should be lower. The Company did prepare sensitivities to examine solar cost assumptions provided by stakeholders in sensitivity case S-12. This sensitivity showed an increased amount of renewable generation installed as compared to the benchmark case (C05-1). This is not surprising, as the assumptions led to decreases in the cost of renewable generation. Penetration of distributed solar is also assumed to be high as driven by customer-economics as discussed in Appendix O. NWEC also suggests increasing gas forecasts to achieve a desired outcome in projected solar. However, this is not appropriate, because the inputs should determine the outcome, not the reverse. As discussed above, if the Company does see major disruptive events occurring, it will re-evaluate its resource plans in subsequent IRPs and IRP Updates.

Gas Forecasts

NWEC notes "(t)he natural gas price forecast is a key driver for IRP modeling because it basically sets the reference level for selection of other resources into the preferred portfolio or a given sensitivity case." NWEC "urge(s) the Company to review and improve its methodology for including natural gas price uncertainty and risk in IRP modeling in the next IRP."

The Company agrees with NWEC in that there are uncertainties around gas forecasts, both long term and short term. Such uncertainties are addressed in the studies of the Company's 2015 IRP via short term stochastic parameters and long term low, medium and high gas forecasts, each subjected to short-term volatility. NWEC points to Figure 7.15 in the Company's 2015 IRP report and states that a mid-period high gas forecast of about $6.50/MMBtu in 2024 is too optimistic and it should be closer to $8.00 or more. However, Figure 7.15 shows the stochastic range of gas price volatility on the west side of the Company around a "base" forecast. In addition to considering a base gas price forecast, the Company studied a range of underling natural gas price scenarios. The range in gas prices among these underlying long term gas price scenarios can be observed in Figure 7.24. In its stochastic analysis, the Company applies short term volatility parameters to these different underlying scenarios to create a distribution of price outcomes driven by short term volatility. For instance, in the high gas price scenario, the underlying west side natural gas price is

$7.84/MMBtu in 2024. Applying short term volatility leads to a 99th percentile price of $8.21/MMBtu in 2024.

<u>Transmission</u>

NWEC suggests with changes in both load forecasts and technologies (renewables, storage, and DG among others) that the 2017 IRP should reassess the Energy Gateway strategy. The Company will assess Energy Gateway alternatives in its resource plan to support any prospective transmission build out scenario that is part of the Company's least cost least risk plan. PacifiCorp will work with stakeholders to assess the appropriate analytical tools and methods for any such analysis in the 2017 IRP.

6. ODOE OPENING COMMENTS

ODOE begins its comments by expressing appreciation for the "thorough stakeholder process" and "level of effort the Company put into this IRP." They also recommend Commission acknowledgement, along with requirements for additional demand response pilots. PacifiCorp appreciates ODOE's recognition of the effort that went into the 2015 IRP. In addition to the complimentary comments, ODOE raises several concerns including: RPS compliance, DSM (modeling and additional pilot programs), 111(d) modeling, regional haze assumptions, and energy storage.

<u>Action Plan Items</u>

ODOE raises concerns about the Company's modeling approach to EPA's CPP, and interaction with current RPS regulations in its discussion of PacifiCorp's RPS compliance. The Company will continue to meet all requirements for RPS as well as those developed for state-based CPP-implementation plans. ODOE explains that Oregon administrative rules require "whole" RECs for compliance with state RPS and indicates that the zero-carbon attribute of RECs cannot be "split off" and retired separately from its original REC. ODOE further notes that the RPS has thus become a central element of Oregon's strategy for reducing greenhouse gas emissions.

As an initial matter, the Company notes that it did not have the benefit of ODOE's interpretation of state law when developing assumptions regarding the interaction of 111(d) and RPS compliance. However, a potentially more reasonable interpretation of the definition of a REC and ODOE's position is that because Oregon administrative rules require a "whole" REC for compliance with state RPS, that REC cannot also be used for 111(d) compliance – even in the same state. As explained above, the Company did not think it would be reasonable to assume a single megawatt-hour of renewable generation could not be used for both 111(d) and RPS compliance.

In addition, because there are differences between the proposed rule's renewable generation requirements and state RPS compliance requirements, as well as differences in banking provisions, ODOE's interpretation would effectively limit the application of renewable generation to the more stringent program. Because they are separate programs with distinct requirements, it was reasonable for the Company to treat them as such. Regardless, all of this suggests that the interaction between state RPS requirements and 111(d) is not as clear as ODOE seems to indicate. Accordingly, as discussed earlier, PacifiCorp will update modeling consistent with assumptions based on the recently released final CPP rule. The 2015 IRP Update and future IRPs will look at the current evolution of requirements under the CPP as well as incorporate information as states begin to develop their CPP implementation plans.

On Page 9 of its comment, ODOE incorrectly states that, "the Company assumes there will be no compliance obligation for the coal-fired power plants that the Company owns in Montana, Colorado and Arizona." See page 139 of the Company's 2015 IRP report for discussion on the development of the 111(d) Scenario Maker spreadsheet tool. Footnote 63 specifically lists all states with generation that are included in the model, the list includes, "**Arizona, Colorado, Montana**, Oregon, Utah, Washington, and Wyoming" (emphasis added). The Company examined several different compliance approaches as discussed on page 143 of the 2015 IRP report. One such approach examined, "Emission Rate Target (All States)," and includes "those states in which PacifiCorp does not serve retail customers."

ODOE also raises concerns with allocation of Class 2 DSM from Idaho and California to other states to meet 111(d) compliance obligations. Without state-specific compliance plans available as of the time of the IRP modeling, assumptions had to be made. Without an assumption of fungible Class 2 DSM from California and Idaho it is likely that all portfolios would have exhibited approximately the same increase in costs. The Company will follow all requirements for each of the state-based plans once they are developed.

New Pilot Programs

ODOE recommends the Commission add action items requiring additional pilot programs for accelerated Class 2 DSM in other states, and Class 1 DSM in Oregon. They do not, however, provide any specific suggested pilot programs. There are few demand response options that can provide impacts in all seasons. The most common option is the Commercial Curtailment product assessed in the Company's 2015 DSM potential study, which the 2015 IRP Preferred Portfolio did not identify as a cost-effective resource until 2023. The cost and feasibility of this product does not vary as much by jurisdiction as irrigation load control. As such, the Company does not believe a pilot is warranted at this time.

ODOE also believes the Action Plan should include an item to pursue energy efficiency (EE) pilots in other states, while again providing no specific recommendations for sectors, customer segments, end uses, or technologies that these pilots should target. The Company plans to pursue the cost-effective acquisition of Class 2 DSM resources identified in Company's 2015 DSM potential study, selected by the 2015 IRP and noted in the IRP Action Plan and will continue to adaptively manage its DSM programs to capture emerging opportunities and best serve its customers. If through this process cost-effective opportunities for pilot programs are identified, then the Company will consider implementing them to determine if they are appropriate for broad-scale implementation to meet Action Plan goals.

Modeling Issues

ODOE is dissatisfied with the results of the stochastic modeling in the 2015 IRP as they were not constrained in such a manner to force compliance with 111(d). It is correct that the model used by the Company for stochastic studies was unable to ensure compliance with potential state-based 111(d) compliance plans. The Company is exploring options to capture the impact on stochastic basis. The 2017 IRP will incorporate the best known information for the state-based compliance plans, using the best available tools for analysis.

ODOE expressed a need for "(i)nclusion of a reasonable approximation of the effects of the final 111d rule on western wholesale prices." ODOE further expands on this concern on page six of its comment, lines 8-11: "As noted above, PacifiCorp assumed that the draft 111d carbon regulations over the next 20 years would *reduce* wholesale prices in the base case as compared to the no carbon regulation case. The Department finds this outcome implausible." ODOE believes imposition of 111(d) constraints should increase market prices, not see them decline.

PacifiCorp recognizes that the concept of adding 111(d) constraints to modeling of wholesale prices could appear to increase wholesale prices as addition of environmental constraints tends to increase total cost. However, this is a specious argument when it comes to the effect of 111(d) constraints on wholesale energy prices. The draft 111(d) rule relied on four building blocks to achieve its goals: increased coal unit efficiency, increased reliance on natural gas, increased use of zero and low-emitting power sources, and expansion of EE programs. The combined effect of these measures, in conjunction with low natural gas forwards, is to slightly increase capital (fixed) costs while reducing variable operating costs. It is variable costs that determine wholesale energy prices.

When added in mass, the build-out of renewables as required by 111(d) reduces the average cost of dispatch since renewables such as wind and solar have no fuel cost component. Moreover, the proposed 111(d) rules assumed expansion of EE acts to lower the dispatch stack by reducing load. Coal unit heat rate improvements also reduce the average cost of dispatch; even the replacement of coal units with efficient CCCTs can be cost competitive given the low-cost outlook for natural gas. It is for these reasons that the base case, which incorporates 111(d) constraints, is slightly lower than the no-carbon policy case. Thus, what is perceived as a "modeling anomaly" is the theory of economic dispatch in action.

One reason why the no-carbon policy does not have even higher market prices is due to a significant amount of renewable builds. While not including 111(d) constraints, it does contain existing RPS requirements, as does the base case. These requirements are the key driver of renewable builds – more so than 111(d). Of course, slightly lower wholesale electricity prices do not necessarily translate to lower rates as the increase in fixed costs needs to be recouped.

Conversely, the addition of an explicit carbon tax would undoubtedly increase wholesale energy costs as it is a variable cost adder. This was seen in the cases that included 111(d) constraints with incremental CO_2 pricing. To address the wide range of alternative futures, PacifiCorp developed and applied a range of scenarios. These were developed in conjuncture with stakeholders with CO_2 prices recommended by the Clean Energy Scenario Stakeholders and as supported by ODOE.

As discussed above there is not a downward bias in gas forecasts as ODOE states. As such, any fear of underpayment to QF's is unwarranted here.

Additionally, while ODOE is correct that the portfolios with extreme CO_2 costs were not chosen for the Action Plan, the results were instrumental in PacifiCorp's resource strategy. See for instance Table 9.3 – Near-Term and Long-Term Resource Acquisition Paths. This table is informative as to what strategies the Company would follow should certain events come into play. If incremental CO_2 policy was applied on top of 111(d) requirements the Company would potentially increase gas-fired resources to offset coal plants, increase Class 2 DSM, and start adding renewables resources.

ODOE is off-base when it asserts PacifiCorp has not met Guideline 8a which calls for a base case in the IRP consistent with the utility's assumptions for future CO_2 regulations. In Appendix B for the discussion on how the Company meets this guideline, the Company stated

> PacifiCorp's base scenario assumes implementation of EPA's proposed 111(d) rule as an emission rate standard allowing flexible allocation of

existing renewable resources among states to achieve compliance. Additional 111(d) policy scenarios and compliance strategies are also studied. Further, PacifiCorp studies CO_2 policy scenarios with CO_2 prices incremental to compliance requirements assumed in EPA's draft 111(d) rule.

The Company also implemented the CPP plus CO_2 adders as requested by stakeholders to explore the upper limits of assumed costs associated with CO_2 regulation as required. The Commission requirement is to "reflect what it considers to be the most likely regulatory compliance future" as opposed to a CO_2 price. It is also completely inaccurate and inappropriate to assert, as ODOE does, that the Company has incorporated negative CO_2 prices in the base case based on its incorrect understanding on why market prices are lower when enforcing 111(d) compliance.

ODOE does not approve of the portfolio comparisons included in the 2015 IRP and suggests that the portfolios can only be compared if they share the same Regional Haze assumption. The Company does not agree. Regional Haze assumptions are one of many assumptions that the Company utilized in its 2015 IRP. To select a portfolio that would guide the Company's action plan, it is necessary to compare multiple portfolios created with different assumptions. If the Company could "only make comparisons where the basic assumptions are comparable," the Company would have to compare portfolios with same assumptions on level of potential demand side management programs, 111(d) strategies, CO_2 prices, or availability of FOTs, for example.

ODOE requests that the Commission "instruct the Company to perform a full risk analysis on a more aggressive energy efficiency portfolio." In the discussion on the subject, it is unclear to the Company which case (C11 or C13) ODOE alleges "was not properly analyzed." Given ODOE's reference to comparisons between case C11-1 versus case C05-1 and case C11-2 versus case C05-2, the Company assumes that ODOE is concerned that the accelerated EE modeled for case C11 was not evaluated in the context of case C13, which assumes mass-based 111(d) compliance. As stated by the Company in the response to ODOE data request, case C13 was developed to understand how a mass cap approach might influence long term resource needs amidst the uncertainty around state implementation plans, while assuming the rate-based compliance requirement was a more appropriate assumption. Comparison between case C11 and case C05 has already provided the potential impact of accelerated EE programs under the core assumptions with rate-based 111(d) compliance.

Additionally, like any other resource alternative, the benefit of accelerated DSM (EE programs) should not be assumed to be positive just because more resources are available sooner. The benefit of a resource also depends on the timing of the system need for resources and the cost effectiveness of the resource as compared to other resource alternatives. As the needs assessment suggests, the Company does not need resources early in the 20-year study period. When the DSM resources are accelerated to the earlier years but not selected immediately because of the availability of other more cost-effective resources, they would no longer be available later when the system does exhibit a need for resources. In addition, when the DSM resources are accelerated, the costs of the resources also increase. As such, the benefit of accelerated DSM may be limited.

<u>Storage</u>

ODOE would like to see expanded analysis of storage options in PacifiCorp's IRP. They do not believe evaluation as a resource option is robust, or captures the full potential value of storage. As a result of a "narrow analysis" storage was not found to be "an economic alternative."

In response, the Company is following trends in storage, including the development of models to quantify a broadening range of benefits from specific applications of storage systems. The Company is working to identify sites where battery storage may offer value, especially those where multiple value streams can be stacked as suggested by ODOE. Currently, PacifiCorp does not believe it is economically competitive to implement a battery-storage solution. The Company will continue to improve upon its modeling approach for energy storage systems and will be evaluating procurement alternatives to acquire an energy storage system of at least five MWh by January 1, 2020, as required by Oregon House Bill 2193.

7. ICNU OPENING COMMENTS

ICNU raises two issues in its comments. The first focuses on the concerns of the Western Control Area (WCA) and whether there are sufficient resources to meet the winter obligation in a cost-effective manner. The other issue ICNU comments on is PacifiCorp's wind integration study incorporation of NERC BAL-001-2 standards. Both are addressed below.

Winter Peaking Needs

ICNU is under the impression that the Company's transmission rights between east and west side of its system limit its capability to transfer power to the west side and does not prudently plan to meet the winter peak on the west side of the Company's system. The Company disagrees with ICNU's characterization of its planning process. It is correct that the Company's resource portfolios are developed to meet the system coincident peak that occurs in the summer. This does not, however, put one side of the system at risk for winter capacity needs. This is the same issue raised by the Staff, which the Company responded in section "Winter Peak Constraint."

ICNU singles out the expiration of two contracts that the Company is party to as the Company's failure to plan for its west side needs. One is an option to continue to purchase half of the generation from the Hermiston plant. The other is an exchange contract with Bonneville Power Administration (BPA), whereby the Company serves BPA's load on the east side of the Company's system and receives the return energy on the west side of the Company's system plus losses. ICNU claims that "the Company made the decisions to terminate these two capacity contracts without consideration of whether they may defer or replace the need for future winter capacity in the Northwest." It is unclear on what basis that ICNU made such a claim. The decision to acquire and/or retain particular resources should not be made solely based on the perceived needs for resources at one location of the system without considering other factors.

The Hermiston Power Project is a gas-fired generating plant. In 1993, the Company entered into a power purchase agreement (PPA) to purchase the entire output of the plant. The next year, the Company exercised its option to purchase a 50 percent interest in the plant. Therefore, the Company now owns 50 percent of the plant and has a PPA for the other 50 percent of the plant's output. On July 1, 2016, the PPA terminates. The PPA included an option to extend the contract, which, if exercised, would have allowed the Company to continue to purchase the output from the 50 percent share not owned by the Company at the prices set in 1994. Per terms of the PPA, the Company had to decide whether to extend the PPA by July 1, 2014. Based on an economic analysis performed shortly before that date the Company decided not to extend the PPA because there would be other resources available at lower than the offered prices.[9] In response to ICNU's claim on the same subject in docket UE-296, the Company provided the analysis supporting its decision not to extend the contract.

In 1989, the Company entered into an agreement with BPA. Following the terms of the agreement, the Company serves BPA's load of an isolated area in Idaho and, in exchange, the Company receives an equal amount of energy in each hour plus losses on the west side. The peak obligation of the BPA load is approximately 300 MW at the time of the Company's coincident peak.[10] The contract terminates in June 2016. The Company has decided not to continue this arrangement with BPA because the Company's load obligation in the area has grown, which in turn has put pressure on the generation capability on the east side of the Company's system and the transmission path leading into the area. In short, it will not be in the customers' interest to continue to provide such service to BPA.

Reduction in PacifiCorp resources on the west side of the Company's system does not directly translate into resource shortage on the west side, nor does it indicate that the Company has lost the opportunity for lower-cost resources. Without these two contracts, the Company's resources located on the west side decrease; however, there are other less expensive resources to serve customers. Even ICNU recognizes that there is "large amount of market capacity currently available in the Northwest."

In addition, the resource portfolios in the IRP are selected using a 13 percent planning reserve margin based on a series of stochastic loss of load probability studies. These studies estimate the unserved load on the Company's total system for each hour of the study period,

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[9] A component of the offered price was subsequently revised. However, it did not materially alter the result of the economic analysis.

[10] Tables A.1 and A.2 on page 3 of Volume II to the Company's 2015 IRP report shows the load and peak load at the time of the Company's coincident peak for the remaining term of the agreement.

not just for the summer peak. The selection of a 13 percent planning reserve margin meets a one-day-in-ten-year lost-of-load event target, a commonly used measure for resource planning in the industry, at the lowest reasonable cost.[11]

In regard to future recovery of any potential resource on the west side of the Company's system, ICNU states that "to the extent that the Company later determines that it must build a winter resource to fill this lost winter capacity, customers should not be responsible for costs that could have been avoided had the Company properly analyzed the winter peak when evaluating the capacity resources noted above." The comment is without merit. ICNU is, in effect, asking for the Commission to preemptively find the Company at fault for a resource it has not even contemplated. The determination of whether resources are needed in any location on the Company's system can only be based on the then-current information, including resource needs, resource availability, and market conditions. The determination that the 2015 IRP Preferred Portfolio does not include a resource on the west side of the system is fully supported by the inputs, assumptions and modeling that the Company employed in the 2015 IRP and shared with stakeholders.

NERC BAL Standards

ICNU states that "the Company's 2015 IRP fails to incorporate the benefits of the new North American Electric Reliability Corporation (NERC) reliability stands into wind integration costs calculations," and suggests that the Commission should require the Company to incorporate such. It is unclear to the Company how ICNU arrived at this conclusion. The introduction in Appendix H to the Company's 2015 IRP report begins with,

> "This wind integration study (WIS) estimates the operating reserves required to both maintain PacifiCorp's system reliability and comply with North American Electric Reliability Corporation (NERC) reliability standards. The

[11] The studies are discussed in Volume II, Appendix I to the Company's 2015 IRP report.

Company must provide sufficient operating reserves to meet NERC's balancing authority area control error limit (BAL-001-2) at all times, incremental to contingency reserves, which the Company maintains to comply with NERC standard BAL-002-WECC-2."

Since March 1, 2010, and the advent of the Reliability Based Control (RBC) field trial, the Company has always operated its system to comply with the BAL-001-2 standard and to comply with the new RBC. The difference of the recent FERC approval is to incorporate RBC into BAL-001-2 replacing CPS2. As discussed also in Appendix H, the Company discussed how it implemented the requirement of BAL-001-02, which is to control frequency of the grid:

> NERC standard BAL-001-2, called the Balancing Authority Area Control Error Limit (BAAL), allows a greater ACE during periods when the ACE is helping frequency. However, the Company cannot plan on knowing when the ACE will help or exacerbate frequency so the L_{10} is used for the bandwidth in both directions of the ACE. Thus the Company determines, based on the unique level of wind and load variation in its system, and the prevailing operating conditions, the unique level of incremental operating reserve it must carry. This reserve, or regulating margin, must respond to follow load and wind changes throughout the delivery hour.

Nowhere in the study does the Company rely on CPS2. ICNU incorrectly suggests that the reliability measures the Company adopted for its 2014 wind integration study is somehow tied to CPS2. It is correct that the Company continued to use the 99.7 percent reliability in the determination of reserve requirements. However, it is not derived from the CPS2 standard, and the Company did not simply make a passing reference to the technical review committee (TRC) concern. The following statement in Appendix H, clarifies the TRC's concern and how the Company addressed the issue:

> In discussing this recommendation with the TRC, it was clarified that the intent was a request to better explain how the exceedance level ties to operations. PacifiCorp has included discussion in this 2014 WIS on its selection of a 99.7% exceedance level when calculating regulation reserve

needs, and further clarifies that the WIS results informs the amount of regulation reserves planned for operations.

The more detailed discussion is in section "Application of Regulating Margin Reserves in Operations" of Appendix H.

Planning Reserve Margin Reevaluation

ICNU recommends that the Commission should require the Company to re-evaluate its planning reserve margin to incorporate the results of "the Company's participation in the Energy Imbalance Market (EIM), the Northwest Power Pool reserve sharing group, the BAL-001-2 reliability standard, and other factors, …" For its 2015 IRP, the Company updated the study on planning reserve margin and provided the study report as Appendix I. Based on the updated study, the Company concluded that the 13 percent planning reserve margin continue to be supported and sufficient to strike a balance between reliability and cost.

To support the Company's 2015 IRP, multiple supplemental studies were performed concurrently and the planning reserve margin study was completed without the updated results from the 2014 wind integration study that addressed the impact of the Company's participation in EIM. However, as stated in Appendix H (report on the wind integration study), the updated amount of total regulating margin from the 2014 wind integration study is higher than what was from the prior study, and the updated amount included 65 MW of reduction attributed to the impact of EIM. Also, as stated in the introduction of Appendix I,

> PacifiCorp's loss of load study results reflect its participation in the Northwest Power Pool (NWPP) reserve sharing agreement. This agreement allows a participant to receive energy from other participants within the first hour of a contingency event, defined as an event when there is an unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch, or other electrical element. PacifiCorp's participation in the NWPP reserve sharing agreement improves reliability at a given PRM level.

That is, the Company's planning reserve margin has considered the impact of being a participant of the NWPP reserve sharing agreement. The Company plans to update its study on planning reserve margin when new information is available, including the impact of EIM.

ICNU also presented concern on applying the planning reserve margin for the peak load hour only while the energy-not-served was captured for every hour of the year and seems to believe that "(t)he Company's failure to separately consider WCA or Oregon needs has resulted in an excessive 13% planning reserve margin." As stated in the introduction of Appendix I on the study result of the planning reserve margin,

> The planning reserve margin (PRM), measured as a percentage of coincident system peak load, is a parameter used in resource planning to ensure there are adequate resources to meet forecasted load over time. PacifiCorp selects a PRM for use in its resource planning by studying the relationship between cost and reliability among ten different PRM levels, accounting for variability and uncertainty in load and generation resources.

The determination of a resource portfolio is based on the load obligation at the time of the system peak, and the study of loss of load events in all hours is to determine whether such a resource portfolio would be sufficient to maintain reliability of the system *during a period of time* at a reasonable cost. Existence of loss of load events does not imply that there will be lost load, but rather indicates the probability of losing load is not zero. The tradeoff between reliability and costs is the goal of the PRM study. As concluded in Appendix I,

> A PRM below 13 percent would not sufficiently cover the need to carry short-term operating reserve needs (contingency and regulating margin) and longer-term uncertainties such as extended outages and changes in customer load. A PRM above 15 percent improves reliability above a one event in ten year planning level, though with a 125 percent to 370 percent increase in the incremental cost per megawatt-hour of reduced EUE when compared to a 13 percent PRM.

If ICNU is to suggest that a planning reserve margin should be enforced such that there would not be any loss of load event in any hour during the year, customers would bear unnecessarily high cost burden.

8. RC OPENING COMMENTS

RC's opening comments are filed to address the relationship between avoided costs and the IRP, and in support of recommendations in docket UM 1610 (Investigation into Qualifying Facility Contracting and Pricing). In its comments, RC supports ODOE's proposal in docket UM 1610 for an Avoided Cost docket to run parallel to this IRP filing. PacifiCorp addressed the unnecessary nature of duplicative processes in that docket, and will not repeat the rationale here. Requests regarding process are properly addressed in the UM 1610 docket, not in this proceeding. RC also raised concern about the depth of wholesale market the Company modeled, and non-acknowledgement of 2028 as the thermal resource deficiency demarcation.

Market Analysis

RC's discussion on market depth is the same as the issue raised by the Staff. The Company has addressed the issue in the response to Staff's comments under the section titled "Review of Supporting Studies and Forecasts."

PacifiCorp contends its market analysis is robust and reasonable, given the facts presented in Chapter 6 of the 2015 IRP report, Appendix J to the report, confidential data responses, and further corroborating analysis by industry groups.

Deficiency Demarcation

RC questions PacifiCorp's year of deficiency in the 2015 IRP being 2028. RC believes that market dependence should play a role in determining deficiency instead of the current practice of relying on acquisition of a major new resource."[12] PacifiCorp's approach is consistent with PURPA regulations and historical Commission practices. Utilities may rely on wholesale market transactions to meet their resource needs because the wholesale market provides the most economic resources. If relying on the wholesale market were to be considered as "resource deficient," the avoided costs would be the prices of market transactions, which is consistent with the currently-approved structure of Oregon avoided costs. RC also argues environmental upgrades are equivalent to a new plant. As addressed thoroughly in docket UM 1610 testimony, environmental upgrades are not avoidable, and RC's argument should not be considered here.[13] Regardless, any change in Commission policy to address issues impacting all utilities should occur in a general docket such as UM 1610, not in a utility-specific IRP docket.

RC offers other arguments requiring a change in the deficiency period including environmental uncertainties related to 111(d) and the amount of DSM in the Preferred Portfolio. RC raises these arguments without offering any real support. As RC does not offer any real proposal, the Commission should ignore their request.

9. RN OPENING COMMENTS

Comments submitted by RN are focused mainly on modeling of EPA's 111(d) rules (Sections I-IV). An additional section notes PacifiCorp's Wind Integration Study reflects increased efficiency. RN also takes note of the Distributed Generation study performed by Navigant that supports the Company's 2015 IRP. RN concludes its comments with appreciation for the process, as well as a willingness to work together with the Company and other stakeholders on implementation of the CPP going forward. The Company values the

[12] The Commission determined "Major Resources are resources with durations greater than five years and quantities greater than 100 MW." Order No. 06-446 Appendix A page 1.
[13] See Response Testimony of Brian Dickman, Pac/1100, Dickman/12-15, Docket UM 1610 (July 24, 015).

stakeholder involvement in the IRP process. The RN modeling comments are addressed more fully below.

Modeling Issues

RN has similar concerns as those mentioned by ODOE and Staff in the severability of RECs and an associated 111(d) attribute. As discussed above the EPA's proposed rule did not foreclose on that option. In fact, RN cites from the EPA's Final Rule where it explicitly states an Emission Rate Credit (ERC) is separable from a REC. On page five of their comments, RN states:

> An ERC is issued separately from any other instrument that may be issued for a MWh of energy generation or energy savings from a qualifying measure. Such other instruments may be issued for use in meeting other regulatory requirements (e.g., such as state RPS and EERS requirements) or for use in voluntary markets.

It is still unclear to the Company what form Oregon's final 111(d) compliance plan will take. RN's suggested approach assumes the 111(d) compliance will be in addition to current state RPS requirements:

> Given that - in theory—a state plan could be structured where a REC can be retired for both RPS and 111(d) compliance, at this stage Renewable Northwest has interpreted existing law to mean that if a REC is retired in a state, for whatever purpose, then that state's policies must capture all environmental benefits, whether that be for RPS compliance purposes or 111(d).

Here RN also admits that there will need to be work before a final compliance plan is actually in place. Given all of the associated uncertainty described above, PacifiCorp's approach was not "risky" as RN states; rather it was a sensible modeling approach that made assumptions around complex issues and recognized a currently evolving regulatory landscape.

The Company is likewise unconvinced by RN that using separable ERCs and RECs would cap compliance at the EPA level. Similarly, extensive modeling of more ambitious state environmental policies is unnecessary. As seen in the 2015 IRP increased costs of compliance will lead to increased portfolio costs, the analysis is straightforward. This is also true with relying on coal plant retirements to meet 111(d) requirements. PacifiCorp developed a range of different resource portfolios to meet these 111(d) targets under different compliance strategies and considering alternative coal unit retirement assumptions. Based on the robust analysis performed in the 2015 IRP, compliance strategies that have incremental coal unit retirements above those already assumed in the preferred portfolio were higher cost.

10. SC OPENING COMMENTS

Sierra Club offers comments on a wide range of issues, along with inclusion of a Synapse report that ostensibly develops alternative portfolios for the Company's system. SC also states they consider PacifiCorp's 111(d) modeling flawed, and overly complex. They find the coal plant retirement options included in the modeling to be deficient. SC also claims that Class 2 DSM resources are underestimated. The Company responds to these issues below.

<u>Class 2 DSM</u>

SC is the only intervenor to claim projection of annual incremental energy efficiency savings in PacifiCorp's 2015 IRP is overly conservative. They believe that Class 2 DSM is understated for three reasons which are addressed below.

Issue one, potential studies inherently rely on current commercially available technologies and lack information on savings from future efficiency measures. The Company's DSM potential studies are performed by independent, third-party contractors and utilize industry best practice methodology. Supply curve development for IRP requires quantification of savings potential and associated cost. As such, supply curves can only include measures with reliable estimates of cost and potential. DSM potential studies do not attempt to predict what technologies might emerge over the study period and their associated costs, beyond identifying emerging technologies with reasonably reliable projections available. Where available and reliable, the Company's studies do account for projected changes in costs and savings. Most notably, the Company's 2015 DSM potential study assumes increasing efficacy and declining costs for LED lighting based on work published by the US Department of Energy. A list of all included emerging technologies, as well as those excluded and the accompanying rationale can be found in Appendix D in Volume 4 of the 2015 DSM potential study.

Issue two, the projection of annual incremental energy savings in PacifiCorp's 2015 IRP is lower than what leading states and utilities have achieved in the past or are planning to achieve in the near future. The Company appreciates the SC's efforts to compare the identified potential to historical achievements of other states and utilities and is also aware of these metrics. However, there are several reasons to use caution when using these metrics to assess the validity of a utility's DSM potential study or IRP:

- A utility's IRP process focuses on identifying cost-effective demand-side resources and assessing their economic value to inform appropriate levels of program delivery. Resource need and value will vary between different utility/program administrator service territories.
- EE program and market successes coupled with differences in building codes and equipment efficiency standards can have large impacts on forecasted potential relative to historical activity.
- Accurately comparing historical achievements or forecasted potential for different utilities is even more difficult due to factors such as:
    - Differences in housing stock, industry mix, and climate
    - Differences in cost-effectiveness metrics and avoided cost
    - Differences in electricity use per customer and/retail rates

- Prior program activity and current efficient measure saturations
- How and when savings are updated to reflect improved codes and standards
- Presence of high savings niche end use opportunities, such as pool pumps
- Possible fuel-switching initiatives for dual-fuel utilities

While the lure of such comparisons across jurisdictions and time periods is understandable, given the possible multitude of differences, such comparisons are at best a starting place for further discussions not basis for making conclusive statements regarding a utility's performance or planning analysis.

Issue three, "...the projected annual savings significantly decrease year by year." As illustrated in SC's Figure 1, system-level DSM selections increase annually from 2015 through 2019. Selections decrease in 2020 as the lighting backstop provision of the Energy Independence and Security Act of 2007 takes effect, but then increase year-on-year through 2024. Annual selections begin to decline in 2025 as many discretionary opportunities are assumed to be fully captured in the first 10 years of the planning horizon.

SC states that PacifiCorp should seek to accelerate EE programs in the near term to capture cost-effective savings illustrated in the potential study. The Company's 2015 DSM Potential Study included an assessment of the feasibility and cost of accelerating Class 2 DSM acquisition (Chapter 6 of Volume 3 of the 2015 DSM potential study). The findings of this analysis were used to develop a set of accelerated supply curves, which were modeled in two of the core cases for the 2015 IRP, C11-1 and C11-2. As neither of these core cases showed lower cost/risk than the preferred portfolio, the Company has no information to suggest that the value of accelerating acquisition outweighs the additional cost.

<u>Energy Storage</u>

There is a thorough discussion of storage provided by SC in its comments. PacifiCorp is very interested in identifying economic applications for energy storage within the Company's network. There has been significant progress within the past year related to energy storage including reduction of battery costs, estimating and forecasting battery system costs and the development of models for quantifying the economic benefits of battery storage. PacifiCorp is closely following this progress, investigating the impacts of new information and seeking ways to apply it for our customers' benefit.

Several locations on the PacifiCorp grid have been identified as potential sites where battery storage may be beneficial. The Company continues to look for sites where multiple value streams can be stacked, including value streams in the EIM. Development of a company-wide standardized process for evaluation is underway. To this end, PacifiCorp is working to develop battery storage evaluation tools. Once the process is refined, it may be used to evaluate battery storage as an option for applicable capital investment projects.

PacifiCorp has noticed the recent decline in battery prices as indicated by the graph in the 2015 study cited in SC's comments (page 24). It should be noted that this graph shows forecasts for electric vehicle battery prices only. These forecasts do not include additional costs associated with utility scale battery systems: power conversion system costs, battery management system costs, control algorithm software costs or owner's costs. The lowest battery cost estimates on the graph in 2025 and 2030 are just touching the region below $150/kWh indicated as the goal for commercialization. Even with the decline in battery prices, the cost of battery storage is and will remain far above the costs for other utility-scale storage, such as pumped hydro.

Currently, of the possible sites that have been identified, none of them has been determined as economically competitive to implement a battery storage solution. As penetration of variable generation grows, energy storage will become more attractive as an option to provide high quality, reliable service. In the near future, PacifiCorp will consider both the Oregon Request for Grant Applications for utility-scale, electrical energy storage demonstration projects and Washington's Clean Energy Fund grant for an energy storage and/or renewable project. The Company will also explore options to procure an energy storage system of at least 5 MWh by January 1, 2020, as required by Oregon House Bill 2193.

Synapse Analysis

The analysis provided by Synapse is critical of PacifiCorp's approach to 2015 modeling. Synapse is concerned with PacifiCorp's use of a rate-based approach to meeting EPA's draft section 111(d) rules. The Company believes that the rate-based approach sets a maximum emission rate target (expressed as pounds of CO_2 per MWh) consistent with EPA's draft proposal. While Synapse may believe a mass-based approach is a preferable modeling approach to studying EPA's draft 111(d) rule, there was very little guidance in the draft rule indicating how states would develop and adopt mass-based targets, let alone information to suggest that such an approach would be adopted by all states. However, the Company in fact looked at both rate-based and mass-based approaches in the 2015 IRP.

Synapse further raises concerns that portfolio modeling does not allow for endogenous determination of early retirement dates for coal plants. The Company did not model endogenous retirements because this modeling option would be problematic as there are many details to consider when assessing the cost for early retirement. As Synapse points out, "(i)n the years leading up to a unit's phase-out, it would (be) unreasonable to incur major capital expenditures." For this, Synapse made the assumption to reduce major capital expenditures because "in the two years prior to a unit going offline, retirement is known and major capital expenditures can be avoided."

Aside from issues related to the assumptions about the length of the time period, the amount of the adjustments and when the two-year period begins since the retirement dates are unknown in an endogenous modeling approach, there are other costs that should be considered. For example, coal contracts and fixed costs shared by multiple units of a plant, or even multiple plants, would need to be captured correctly when one of the units retires early. Resource expansion and dispatch models are not able to dynamically reflect changes to these cost variables when endogenously calculating early retirement alternatives. PacifiCorp's current approach, which analyzes coal units' specific alternative retirement scenarios with specific costs for the scenarios, is more robust because the impact of early retirements on other units and system fixed costs is explicitly captured. Synapse's approach on the other hand ignores these impacts.

Synapse believes that "(a)llowing the model to choose to retire units optimally results in a lower cost plan than when retirements are guessed by planners."[14] However, its own analysis shows PacifiCorp's preferred portfolio to be less costly than those generated by Synapse. Below is Table 3 in Synapse's report that summarizes the costs of PacifiCorp Preferred Portfolio and the costs of Synapse's cases:

Costs (M$ NPV)	PAC Preferred	Synapse Case A	Synapse Case B	Synapse Case C
PVRR (2015-2034)	$28,095	$36,233	$36,363	$36,323
PVRR (CO_2 cost excluded)	$28,095	$28,137	$28,678	$28,720
Difference from PAC Pref.		$42	$541	$583

Additionally, Synapse states that it uses the reference case regional haze scenario and assumes that PacifiCorp does not prevail in its Wyoming litigation to roll back the

[14] Synapse report, page 6.

requirements. It is not clear if Synapse incorporated environmental investment costs as required in the reference regional haze case or potentially, both capital and environmental costs for units that continue to operate beyond what is assumed in the Preferred Portfolio. Such costs would drive the presented PVRRs higher than what Synapse shows in Table 3. It is unclear why Synapse models a CO_2 price as opposed to using the mass-cap approach when it states that "(t)he mass-based approach is far simpler" and the System Optimizer (SO) model can be "readily configured to determine a least-cost plan for mass-based compliance."

In Section 2.4 of its report, Synapse questions the capital costs of new wind and solar resources in the 2015 IRP. They compare PacifiCorp's wind and solar capital costs to those recommended by Utah Clean Energy (UCE). The source document for UCE's recommended wind capital costs is the United States Department of Energy's (USDOE) publicly available Wind Vision Report. The portions of the Wind Vision Report referenced by Synapse do not have any costs that directly align with the UCE's recommended costs. Comments and costs provided by UCE provide no basis for determining exactly how their cost estimates were created. PacifiCorp's wind capital costs are based upon wind turbines that are matched to specific wind regimes within PacifiCorp's service territory, price estimates from the wind turbine manufactures for purchase two to three years in the future, and development, construction and owner's costs of actual projects within PacifiCorp's service territory.

The Wind Vision Report indicates the capital costs for installed wind projects in the United States have been volatile during the past 35 years, falling from $5,000/kW in the early 1980s to $1,300/kW in 2004 and then moving up to approximately $2,230/kW in 2009. Between 2012 and 2014, the report indicates average wind capital costs ranged from approximately $1,930/kW in 2012, to $1,630 in 2013, and to $1,750 in 2014. Changes in technology, market conditions and legislation can significantly increase or decrease wind project capital costs. The Wind Vision Report also illustrates how costs can vary by project, as costs within the report for projects built in calendar year 2013 varied between approximately $1,400/kW to $4,500/kW. The difference between the Company's capital cost estimate range of $2,135/kW to $2,188/kW and UCE's recommended cost range of $1,747/kW to $1,800/kW could be due to wind turbine costs differences based upon what year the sales contract is signed and site specific variations in costs for wind turbines and construction.

Wind turbines need to be matched to the exact wind regime of a site and wind regimes vary tremendously across the country. PacifiCorp's wind capital costs are based upon modern wind turbines that manufacturers determined are suited to the wind regimes at sites within specific states. The costs of these turbines are within the range of $1,000 to $1,300/kW that is cited in the Wind Vision Report. PacifiCorp's capital costs include balance of plant costs based upon actual project construction costs and include costs for development, land, sales taxes (where applicable), transmission interconnection, overheads and allowance for funds used during construction (AFUDC). It is not clear to what extent, if any, UCE's recommended cost figures include these additional costs. PacifiCorp's wind capital cost estimates are well within the costs shown in the Wind Vision Report and differences in turbine and project costs for specific sites can vary greatly due to market conditions.

Synapse cite the 2014 US Solar PV Capital Costs and Prices report by the consulting firm IHS as the basis for the UCE's recommended solar costs. PacifiCorp only has access to two charts of the IHS report and does not know exactly what costs are included in the UCE cost estimate. The two charts in the IHS report show capital costs of just under $2/W_{DC}$

which roughly matches UCE's recommended solar capital costs of $1,717/kW to $2,000/kW. UCE's recommended capital costs are likely lower than PacifiCorp's costs for two reasons:

- They are reported on a Direct Current (DC) basis instead of an Alternating Current (AC) basis (i.e. available capacity that can be delivered to the grid), and
- The costs in the IHS report only reflect the lowest cost quartile of project costs.

PacifiCorp's IRP solar capital costs for 50.4 MW_{AC} projects are based upon project designs prepared by Black & Veatch for Milford, UT and Lakeside, OR. These resources have relatively high inverter loading ratios (ILRs) or DC to AC design ratios because they were designed to provide the lowest cost of energy by maximizing panel capacity to inverter capacity that results in the lowest cost of energy. The inverter loading ratios used in PacifiCorp's IRP are consistent with recommended values/assumptions used in E3's "Capital Cost Review of Power Generation Technologies – Recommendations for WECC 10 and 20 Year Studies (March, 2014)."

The E3 study was based on ILRs of 1.3 and 1.4 for utility scale single axis and fixed tilt systems, respectively. PacifiCorp's ILRs were between 1.33 and 1.38 for 50.4 MW_{AC} sized projects for single axis and fixed tilt systems, respectively. UCE's recommended capital costs are adjusted to an AC basis and compared to the Company's IRP costs in the table below. UCE's adjusted capital costs are lower since the IHS data on which they are based only reports costs for projects in the lowest quartile. (A note on each IHS chart that is available to PacifiCorp indicates the "commercial capital costs reflect the average of the least-cost quartile of project costs," which means 75 percent of all PV projects have higher costs and were eliminated from consideration in IHS's cost report). It is likely PacifiCorp's capital costs would be well within IHS's cost range if IHS reported all resource costs, not just those in the lowest quartile. It is also unknown to what extent the costs reported in the IHS study include owner's costs, land, transmission interconnection, allowance for funds used during construction, etc.

50.4 MW PV Resource	UCE Proposed Cost, $\$/kW_{DC}$	Inverter Loading Ratio (DC to AC) factor	UCE Cost, $\$/kW_{AC}$	PacifiCorp IRP Capital cost, $\$/kW_{AC}$	E3 Report (Table 23), $\$/kW_{AC}$
Fixed 26.5% CF,UT	$1,717	1.373	$2,358	$2,546	$3,080
SAT 31.6% CF, UT	$1,873	1.339	$2,508	$2,702	$3,380
Fixed 25.4% CF,OR	$1,830	1.344	$2,459	$2,659	$3,080
SAT 29.2% CF, OR	$2,000	1.339	$2,679	$2,829	$3,380

Given the discussion above, claims that the renewable costs incorporated in the Company's 2015 IRP are, "not indicative of commonly held costs" should be viewed with a healthy dose of skepticism. This statement is not supportable by the information provided by Synapse.

After reducing the costs of renewable resources, the outcome from Synapse's model did not lead to addition of more renewable resources. Instead of studying the Company's needs for renewable resources, contribution to peaks and cost-effectiveness of the alternative resources, Synapse seems to take issue with the constraints used in the Company's setup in the SO model. As Synapse correctly states, "System Optimizer is a highly complex modeling structure that allows extensive flexibility, yet also allows layers of constraints to dictate outcomes." For its 2015 IRP, the Company performed studies for 34 core cases and 15 sensitivity cases, each of which has a distinctive set of inputs. The inputs are prepared utilizing the flexibility that the SO model offers.

Synapse is also correct in that it points out the complexity in modeling of the Company's system. The "nearly 20 scenarios" that Synapse references for the setups of the Company's studies are to select appropriate inputs for the specific cases, such as load forecast, level of Class 2 DSM potentials, market prices and assumptions for Energy Gateway transmission. The "technology groups" are to maintain the relationship of different aspects of the Company's system. For example, the amount of new resources that could be built at the Dave Johnston site in a year is dependent upon when the Dave Johnston plant would retire. Also, the maximum amount of renewables by location (pages 114-115 of the Company's 2015 IRP report) is not for any specific resource, but for a group of potential resources. That is, it is not appropriate to simply point to the complexity of a model as the culprit when the outcomes of the model are unexpected.

PacifiCorp's Preferred Portfolio is least-cost in comparison to all of the Synapse cases. This cost differential is likely understated as the Synapse cases with endogenous coal unit retirements disregard any incremental costs not captured in the SO model, as discussed above.

PacifiCorp also appreciates that Synapse has concluded the preferred portfolio meets the required 111(d) mass-based targets. In comparing the final CPP to the draft Synapse states:

> PacifiCorp's Preferred Portfolio appears to comply with the final mass-based goals, based on PacifiCorp's pro-rata share of emissions in Arizona, Colorado, Montana, Oregon, Utah, Washington, and Wyoming, (shown in 1.3 Why Mass-Based Compliance and Economic Coal Retirement Matters), it does not show that the plan represents a least-cost pathway towards compliance.

In short, Synapse has demonstrated the PacifiCorp 2015 IRP Preferred Portfolio is the least cost approach to meeting Synapse's interpretation of the revised EPA 111(d) rules. While there are other issues with the Synapse report they are only discussed briefly given the report's results.

11. CONCLUSION

PacifiCorp's 2015 IRP complies with the Commission's standards and guidelines. The 2015 IRP also reflects a balanced consideration of customer interests and is well supported by portfolio modeling and prudent planning assumptions leading to selection of a least cost preferred portfolio that is consistent with the long-run public interest. PacifiCorp appreciates the comments received from an active and engaged stakeholder group, and continues to urge stakeholder participation throughout the IRP development process to foster constructive dialogue.

PacifiCorp has met the Oregon IRP Guidelines and requests that the Commission acknowledge the 2015 IRP, and the 2015 IRP Action Plan, with a clarification that Action Item 5b, pertaining to the Wallula to McNary 230 kilovolt transmission line, is required by PacifiCorp's FERC-approved OATT.

DATED: September 24, 2015

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