BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 57

In the Matter of PACIFICORP, dba PACIFIC POWER, 2013 Integrated Resource Plan	STAFF'S FINAL COMMENTS

Introduction

The goal of an Integrated Resource Plan (IRP) is the selection of a portfolio of resources with the best combination of expected cost and associated risks and uncertainties for the utility and its customers.[1] These comments address near-term issues and action items, as well as recommendations for future IRPs and related processes.

In this IRP, the Company is not proposing to add capacity resource additions. In its long-term planning, the first capacity additions appear in 2024. Until then, only demand side management (DSM) and front office transactions (FOTs) are being acquired as new resources. However, multiple large coal plant investments to meet environmental compliance obligations are or will be required in the next two to ten years. These investments are the primary focus on this IRP.

Coal Analysis

In PacifiCorp's 2012 rate case Docket UE 246, Commission Order No. 12-493 the Commission disallowed costs related to coal plant investments because the Commission determined that PacifiCorp: a) failed to explore alternative courses of action, both in terms of the mix of compliance actions and, particularly, in the timing of those actions, that would have allowed Pacific Power to meet its air quality requirements at a lower cost and risk to Oregon ratepayers, and b) failed to perform appropriate analyses to determine the cost-effectiveness of its [coal plant] investments.[2]

The Commission's actions in UE 246 provide a basis for Staff's analysis and recommendations related to PacifiCorp's coal plant actions items in this case.

[1] Order 07-047 from the Adopted Integrated Resource Plan (IRP) guideline 1.c.
[2] *See* Docket UE 246, In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision, Order 12-493 at. 27-31 (Dec 20, 2012).

At the public meeting on October 28, 2013, Staff asserted that the Company needed to provide analysis for many more plants than it did in this IRP and that the analysis provided was inadequate.[3] Consistent with Order No. UE 246, Staff made clear that in addition to providing a basic analysis of all plants with expected pending actions, the Company needed to perform alternative compliance analysis, including early retirements and tradeoffs between coal units and that the Company needed to factor in the impact of coal plant scenarios on the need for or sizing of new transmission lines.

On page 21 of PacifiCorp's reply comments, the Company indicates that it supports a new planning and review process in Oregon for coal unit investment analysis. This process would supplement, not replace the IRP process. Staff supports the use of a separate coal analysis docket for those cases where timing does not line up with the standard IRP schedule. The new docket is not intended to diminish the rigor of the current IRP process or operate as pre-approval of investment decisions. The robustness of the IRP process would be maintained as the IRP would continue to be the primary focal point for detailed resource planning. The new outboard coal analysis process would not be divorced from the IRP process.

This outboard process would be limited to PacifiCorp's coal fleet because unlike typical utility resource decisions, Clean Air Act compliance actions may be beholden to specific dates outside the control of the utility.

PacifiCorp should continue to do a full examination of alternatives in its IRPs and include anything with the potential for action within five years, whether or not the Company believes it is sufficiently "ripe". If necessary, the same compliance decision can be brought back to the Commission through the separate coal analysis docket once alternatives have been evaluated and the Company is proposing to take action.

Staff has developed specific types of coal analyses we need to see going forward in order to make recommendations to the Commission on whether actions on specific investments should be acknowledged. They are:

a) Conduct <u>fleet analysis</u> by evaluating tradeoffs between plants that achieve the desired result at the lowest cost and risk

b) Evaluate <u>multiple compliance alternatives and dates</u>

c) Factor in <u>the impacts on the need for or sizing of new transmission lines</u>.

More details on these analyses are provided in Appendix B.

Timing is of critical importance both in the IRP, and in the proposed separate coal analysis docket. Robust analysis needs to be provided with sufficient time for parties to see and evaluate the results prior to key investments being made that might limit viable

[3] Staff's handout from the October 28, 2013 meeting is included as Appendix A

options going forward. In this IRP Hunter is an example of proposed actions that were brought to the Commission for acknowledgement too late.

The Company provided a Confidential Volume III to this IRP that contained analyses used to support the following action items relating to coal plant:

8a. Naughton Unit 3

- *Continue permitting and development efforts in support of the Naughton Unit 3 natural gas conversion project. The permit application requesting operation on coal through year-end 2017 is currently under review by the Wyoming Department of Environmental Quality, Air Quality Division.*
- *Issue a request for proposal to procure gas transportation for the Naughton plant as required to support compliance with the conversion date that will be established during the permitting process.*
- *Issue an RFP for engineering, procurement, and construction of the Naughton Unit 3 natural gas retrofit as required to support compliance with the conversion date that will be established during the permitting process.*

8b. Hunter Unit 1 - *Complete installation of the baghouse conversion and low NOx burner compliance projects at Hunter Unit 1 as required by the end of 2014.*

8c. Jim Bridger Units 3 and 4 - *Complete installation of selective catalytic reduction (SCR) compliance projects at Jim Bridger Unit 3 and Jim Bridger Unit 4 as required by the end of 2015 and 2016, respectively.*

8d. Cholla Unit 4 - *Continue to evaluate alternative compliance strategies that will meet Regional Haze compliance obligations, related to the U.S. Environmental Protection Agency's Federal Implementation Plan requirements to install SCR equipment at Cholla Unit 4. Provide an update of the Cholla Unit 4 analysis regarding compliance alternatives in the 2013 IRP Update.*

Bridger Units 3 and 4

Based on the existing Wyoming State Implementation Plan (SIP) and the U.S. Environmental Protection Agencies (EPA's) proposed Federal Implementation Plan (FIP), PacifiCorp is required to install selective catalytic reduction (SCR) equipment on Bridger Unit 3 by the end of 2015 and Bridger Unit 4 by the end of 2016.[4]

In the Company's 2013 IRP in Confidential Volume III the Company provides an analysis of the following alternatives relative to Bridger:

[4] The EPA is scheduled to issue a final FIP for the State of Wyoming on January 10, 2014. In the draft FIP, the EPA asked for comments on the option to not require SCRs on Bridger 3 and 4 in 2015 and 2016 but rather allow PacifiCorp the flexibility to determine the best date to install SCRs on all Bridger units within five years of the date the Wyoming FIP is finalized.

Base Case Alternative A - Install SCR equipment in 2015 and 2016 at Bridger units 3 and 4, respectively and continue to operate as coal through 2037[5]

Alternative B - Convert Bridger units 3 and 4 to gas in 2016 and 2017, respectively

Alternative C - Retire Bridger units 3 and 4 at the end of 2020 and 2021, respectively without adding SCR equipment

Staff asked the Company to evaluate the following fourth alternative:

Alternative D - Retire Bridger 3 and 4 at the end of 2022 and 2023, respectively without adding SCR equipment

Alternatives C and D would require PacifiCorp to negotiate early retirement instead of installing SCR measures, similar to what was done in the case of PGE's Boardman plant.

System Optimizer Deterministic Results

Table 1. summarizes the present value of revenue requirement (PVRR) for the four alternatives from the Company's System Optimizer model, under medium gas and carbon assumptions.

[5] 2037 is the end of Bridger's current depreciable life in all PacifiCorp states other than Oregon, where it is 2025

[redacted]

Based on System Optimizer, using medium gas and CO2 prices the PVRR of adding SCR equipment to Bridger 3 and 4 in 2015 and 2016 [redacted] respectively over the 20 years of the IRP planning period.

Planning and Risk Model (PaR) Stochastic Results

Table 2 shows the PaR results for Alternative C and D compared to the PaR results for base case Alternative A.[6] The PVRRs shown in Table 2 are the average of 100 different model runs for each case. This average is the standard metric PacifiCorp uses to establish the estimated cost of a portfolio in order to compare the cost against other portfolios and select the preferred portfolio.

[6] PaR analysis for Alternative B was not specifically requested by staff and was not conducted by the Company

[redacted]

Positive numbers are where the alternatives are cheaper than the base case and negative numbers are where base case is cheaper than the alternatives.

The stochastic results [redacted]

The results [redacted]

[redacted]

Deficiencies in analysis

Admittedly, Staff believes there are deficiencies or gaps in the Company's coal unit analyses. PacifiCorp did not consider a sufficient number of alternatives to ascertain the best alternative. There are three fundamental gaps or deficiencies in PacifiCorp's analysis. The first deficiency is in the number of dates considered for either adding SCRs, retiring early or converting to gas. In the case of Naughton 3, PacifiCorp is applying to Wyoming DEQ to delay gas conversion from the original compliance date listed in the Wyoming SIP of 2015, to 2018. In the case of Bridger 3 and 4, no such alternatives have been presented. PacifiCorp only evaluated one set of SCR install

[7] Staff's lower gas price distribution, although slightly lower than the base gas price distribution used as the base case in the 2013 IRP, is slightly higher than PacifiCorp's most recent gas forecast from September 2013

dates, one set of potential early retirement dates and only one set of firm gas conversion dates. At Staff's request, the Company evaluated a second set of early retirement dates as described above and represented in Alternative D. For Staff's proposed alternative set of retirement dates, [redacted] PacifiCorp should be analyzing more than one alternative date for each compliance option.

Second, PacifiCorp didn't look at potential tradeoffs between units at Bridger or between coal plants to identify the most cost effective compliance options from a state or fleet wide perspective. Admittedly this type of cross-plant analysis is an emerging practice as utilities work with states to develop creative ways to meet Clean Air Act regulations. PacifiCorp should develop scenarios where it negotiates shutdown or gas conversion at one plant in exchange for eliminated or reduced pollution control requirements at another.

Third, PacifiCorp didn't evaluate proposing alternate types of treatment and levels of pollutant removal in exchange for changing plant retirement dates or cross-unit tradeoffs.

Without these three types of analyses, there are gaps in the arguments in support of PacifiCorp's proposed Bridger action item. In future efforts, PacifiCorp should develop feasible alternatives to meet Clean Air Act regulations and explore those alternatives with environmental regulators.

Ongoing risks from continued coal-fired operations

PacifiCorp is a coal heavy utility. Staff recognizes that the following factors represent risks to Oregon rate-payers from a heavy coal-based resource portfolio:

- the risks of aggressive national and/or state carbon policies,
- increasing uptake of renewables and the need for more flexible resources,
- the potential for the price of coal and coal futures to continue to grow, and
- the potential for direct or indirect carbon penalty for selling into California.

If PacifiCorp were to increase the diversity of its resource mix, it could mitigate these risks. Converting coal plants to natural gas is one way to diversify. Based on Staff's analysis summarized below, there are other plants in PacfiCorp's fleet that it would make more sense to shut down or convert to natural gas, than Bridger.

Bridger is an important resource

[redacted] Jim Bridger is an important resource for PacifiCorp. The Jim Bridger plant consists of four coal fueled units maintained and operated by PacifiCorp and co-owned by PacifiCorp and Idaho Power Company (Idaho Power). The total nameplate capacity of the Jim Bridger plant is approximately 2,100 MW with PacifiCorp's and Idaho Power's ownership of approximately 1,400 MW and 700 MW respectively. PacifiCorp currently has an installed capacity of approximately 10,425 MW and a baseload capacity of approximately 7,900 MW.[8]

The plant is dispatched on a system-wide basis and is integral for PacifiCorp to provide electrical service to its customers in its multistate service territories. The Jim Bridger substation is contiguous to the plant and connects six transmission lines[9] electrically connecting its east and west electric systems. The plant is adjacent to PacifiCorp's and Idaho Power's co-owned Jim Bridger mine, which supplies approximately two thirds of its coal needs. The rest of the Jim Bridger plant is supplied by other mines in southwestern Wyoming via rail or truck.

Jim Bridger represents approximately 14 percent of PacifiCorp's fleet capacity; however, from a baseload perspective the plant represents approximately 20 percent of online capacity on average. The Jim Bridger plant provides ancillary services such as voltage regulation, frequency regulation and response, energy imbalance correction and operating reserves to PacifiCorp's balancing authorities.[10]

Additional fleet analysis may not change the results for Bridger

Even if fleet analysis had been performed to determine the plants eligible for potential early retirement, Bridger is not likely to have been selected. Staff's own analysis using FERC Form 1 data shows that from a fuel, heat rate and operating costs perspective, Jim Bridger is a middle of the road plant compared to others in PacifiCorp's fleet. If a plant were to be chosen for early retirement based on its economic value, the poorer performing plants would be chosen over Bridger.

If one or more of PacifiCorp's coal plants were at risk of having to shut down, it would be better for the ratepayer to see an expensive and inefficient plant shut down or converted as opposed to a median performing plant like Bridger. When relatively uneconomic coal plants shut down, Oregon ratepayers benefit from reduced risk at lower cost.

Another reason it is unlikely that a Bridger unit would be selected for early retirement in a tradeoff analysis, is the value of the multiple ancillary services Bridger provides such as voltage regulation, frequency regulation and response, energy imbalance correction and operating reserves to PacifiCorp's balancing authorities.

Staff recommends acknowledgement of Bridger 3 and 4 SCR investments

[redacted] However, based upon the evidence currently available, Staff

[8] PacifiCorp 2012 FERC Form 1
[9] Populus #1 at 345 kilovolts ("kV"), Populus #2 at 345 kV, Threemile Knoll at 345 kV, Rock Springs at 230 kV, Point of Rocks at 230 kV and Mustang at 230 kV.
[10] PacifiCorp 2012 FERC Form 1

believes it is unlikely a fleet analysis would have led to an alternative outcome for Bridger because there are other coal plants in the fleet that would likely be better candidates for alternative compliance opportunities. Because acknowledgment of an action item is based upon information known at the time and does not indicate that the Company's actions will be found prudent in a rate proceeding, Staff recommends the Commission acknowledge Action Item 8c based upon the information known at this time.

However, given that the EPA is scheduled to issue a final FIP for the State of Wyoming today (on January 10, 2014), Staff makes this recommendation contingent on the EPA's ruling that the SCRs are required on Jim Bridger Unit 3 and 4 by 2015 and 2016 respectively. In the alternative, Staff reserves the right to modify its recommendation for the Commission to acknowledge Action Item 8c related to Jim Bridger 3 and 4.

More analysis is needed in the future

Staff's analysis of Bridger demonstrates the need for a) thorough analysis of alternatives available to the Company, and b) the need to look at coal investments from both a portfolio perspective (System Optimizer and PaR) and a plant by plant look (as in the screening tool developed by the company in the 2011 IRP update). Staff's recommendation here is largely based on a plant by plant look rather than the whole portfolio perspective. Both are needed to paint a complete picture.

Therefore, going forward, Staff needs to see more alternatives considered as part of coal analyses before recommending acknowledgement of related action items.

Hunter Unit 1

Hunter Unit 1 is facing pollution control requirements based on the EPA's Regional Haze Rule and Mercury and Air Toxics Standards (MATS) Rule; specifically, the installation of a baghouse filter and a low NOx burner (LNB). PacifiCorp requests acknowledgement of these investments in Action Item 8b.

PacifiCorp's compliance options are driven by Utah's State Implementation Plan (SIP). Parts of the Utah SIP were disapproved by the U.S. EPA. The process is now under litigation. Sierra Club contends that a state SIP is not enforceable if under EPA disapproval.[11] PacifiCorp's response to OPUC Data Request (DR) 286 rebuts the claim that a disapproved SIP is not binding.

Staff has determined that, *based on current rules*, PacifiCorp has two compliance options related to Hunter 1 control investments:

[11] See Sierra Club Post-Hearing Brief Addressing EPA Ruling filed with Utah Public Service Commission under Docket No. 12-035-92 on April 5, 2013. This document argues that Wyoming's disapproved SIP is not legally binding. However, a similar argument could be applied to Utah's SIP.

1) Implement planned controls on the current time frame, or

2) Cease coal operations by April of 2014.

These are the only two alternatives PacifiCorp evaluated in this IRP. Staff requested PacifiCorp model the following two fleet tradeoff compliance alternatives for the Hunter investments:

3) Hunter 1 is allowed to operate without baghouse or coal investments until 2018. Hypothetical Hunter 3 SCR requirement is reduced to Selective Non-catalytic Reduction (SNCR).

4) Hunter 1 is allowed to operate without baghouse or coal investments until 2016. Hypothetical Huntington 2 SCR requirement is reduced to SNCR.

The modeling results indicate that [redacted]

PacifiCorp's treatment of Hunter 1 in the current IRP raises the following key concerns:

- PacifiCorp does not appear to be proactively identifying or evaluating alternatives to coal investments.

- PacifiCorp is requesting acknowledgement of a historic investment and not a future plan.

PacifiCorp maintains that Staff's proposed alternatives are hypothetical and speculative. Staff agrees with this assessment. However, it is not Staff's responsibility to develop alternatives to be considered that might be better for Oregon ratepayers. The company should be developing and testing multiple alternatives in a timely manner, as directed by the Commission in UE 246, Order 12-493.

Staff believes that the proposed alternatives (and additional alternatives) were viable at the time PacifiCorp was making its investment decision. [redacted]

[redacted], Staff does not believe that the action item is appropriate for the current IRP. According to PacifiCorp's response to OPUC DR 280, as of December 12, 2013 the baghouse project is approximately 50 percent complete and the LNB project is approximately 20 percent complete. This means that a significant portion of the investment costs have already been committed. Because the investment is required by April 2014 and because the investments are largely already committed, this is an example of a coal analysis that is being brought before the Commission for acknowledgment too late.

PacifiCorp did not reference any pollution controls at Hunter 1 in the 2011 IRP. Staff feels that the 2011 IRP would have been an appropriate avenue to raise awareness about the Hunter 1 pollution control requirements. The function of the IRP is to evaluate planned investment decisions, not historic investment decisions. Historic investment decisions should be evaluated in a general rate case.

The current situation with Hunter 1 highlights the need for special planning treatment of upcoming PacifiCorp pollution control investments. Pollution control regulations require that the company make significant investment decisions at dates that do not align with the IRP planning cycle. However, these investment decisions have permanent fleet wide planning impacts. When the proposed outboard coal analysis docket is implemented, parties will have the opportunity to provide PacifiCorp with feedback on the issues in both the traditional IRP setting prior to reaching decision points and outside the IRP setting when the investment decision is being made.

The Commission's acknowledgement or non acknowledgement of the Hunter 1 action item will not influence the investment at Hunter 1 because it is not a current planning issue; rather the installation of the investment is already substantially completed. [redacted]. However, Staff and other parties did not have the opportunity to fully test alternatives before the investment installation had begun. Therefore, Staff recommends the Commission not acknowledge Action Item 8b.

Naughton Unit 3

The Wyoming SIP and the draft EPA FIP both call for SCR equipment and a baghouse at Naughton Unit 3, with a deadline for the baghouse at the end of 2014.[12] In this IRP PacifiCorp provided analysis results for the following Naughton Unit 3 alternatives:

1) Install SCR and the baghouse in 2015

2) Retire Unit 3 early in 2015

3) Convert Unit 3 to natural gas in 2015

Strangely, the option included in action item 8a is *not* one of the options PacifiCorp analyzed in this IRP. The IRP looked only at a 2015 convert or retire option for Naughton 3, whereas the Company is asking for acknowledgement of permitting and RFPs that would support conversion of Naughton 3 to gas in 2018. The Company is not asking for acknowledgment of the actual conversion. Staff is recommending acknowledgement of the permitting and RFP action item for Naughton 3, but at this time would not support actual conversion of Naughton 3 because of the Company's current resource position and because insufficient analysis has been provided.

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[12] The final EPA FIP is scheduled to be released January 10, 2014

The analysis the Company did provide in the 2013 IRP indicates [redacted] As mentioned above, Action item 8a asks the Commission to acknowledge the Company's application for a permit (which is an application for an exception to the current Wyoming regional haze requirements) to continue operation of Naughton Unit 3 as a coal unit without a baghouse *through the end of 2017* before converting the plant to natural gas in 2018. Although this option was not analyzed in the IRP, it is an example of a timing or Boardman type alternative compliance option.

Even though this Boardman-like option is not considered in the Company's analysis, [redacted]

Staff does not believe PacifiCorp's analysis is comprehensive enough to represent the options available to the Company. PacifiCorp did not present alternative timing options (even though the date for Naughton 3 conversion was modified between when the analysis was performed and when the action items were developed), nor did it perform fleet-type tradeoff analyses for Naughton Unit 3.

In summary, Staff recommends the Commission acknowledge action item 8a, regarding continuing permitting and RFPs for a Naughton gas conversion in 2018. Staff is not recommending the Commission acknowledge the actual gas conversion in 2018. The Company should bring the potential investment back to the Commission in the 2015 IRP with additional analysis. See the proposed revised action item 8a below:

Proposed Revised Action Item 8a. Naughton Unit 3:

- *Continue permitting and development efforts in support of the Naughton Unit 3 natural gas conversion project. The permit application requesting operation on coal through year-end 2017 is currently under review by the Wyoming Department of Environmental Quality, Air Quality Division.*

- *Issue a request for proposal to procure gas transportation for the Naughton plant as required to support compliance with the conversion date that will be established during the permitting process.*

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[13] Delaying the conversion (and consequently an investment of equal size) from 2015 to 2018 is highly likely to manifest itself as a reduction in PVRR due to the time value of money

- *Issue an RFP for engineering, procurement, and construction of the Naughton Unit 3 natural gas retrofit as required to support compliance with the conversion date that will be established during the permitting process.*

- *Bring this investment decision back to the Commission in the 2015 IRP with further analysis.*

Cholla

Staff notes that Cholla is one of the most expensive of PacifiCorp's coal plants and that in four of the core cases modeled in this IRP and in one sensitivity case, PacifiCorp's models demonstrate that it is economical for Cholla to shut down in 2017.

In initial comments, Staff expressed concerns about the timing of the Cholla investment and requested flowcharts showing key milestones and timelines for both installing an SCR at Cholla by the compliance deadline of the end of 2017 and for retiring Cholla early and replacing the energy and capacity as needed with the next best alternative. The Company has provided those timelines in response to Staff Data Request 246. Data Request 246 indicates that at the earliest, construction to install SCR would start in Q2 of 2015. If Cholla were to be converted to natural gas, the Construction Permit Application would need to start in Q4 in 2014 with construction starting at the earliest in Q3 2016. Staff has made it clear that given these timeframes, the Company cannot wait long before bringing the analysis before the Commission while there are still viable alternatives for Cholla that the Commission can consider. The Commission needs to see analyses in timely manner, not when all parties are boxed in due to looming compliance deadlines.

Staff understands the Company is currently working with Arizona Public Service and the EPA to develop options for Cholla. Staff reiterates our concern about the economics of Cholla Unit 4 and looks forward to the Company bringing a recommendation and analysis on Cholla before the Commission as soon as possible, perhaps through the new separate coal analysis docket.

Staff recommends the following changes to Action Item 8d.

Proposed revised Action Item 8d. Cholla Unit 4 - *Continue to evaluate alternative compliance strategies that will meet Regional Haze compliance obligations, related to the U.S. Environmental Protection Agency's Federal Implementation Plan requirements to install SCR equipment at Cholla Unit 4. Provide an update of the Cholla Unit 4 analysis regarding compliance alternatives ~~in the 2013 IRP Update~~ to the Commission in a timely manner as part of a separate coal analysis docket.*

Joint Ownership Plants

In this IRP the Company provided no numerical analysis related to the SCR additions at Craig 1 and 2 and Hayden 1 and 2, where PacifiCorp is a minority owner. In its reply comments, the Company indicates that environmental controls at Craig 1 and 2 and Hayden 1 and 2 are required by law, specifically in the promulgated and EPA approved Regional Haze SIP for Colorado. The Company explains that the adopted Colorado Clean Air Clean Jobs Act requires installation of emission controls at Hayden 1 and Hayden 2 and the Colorado Public Service Commission (CPSC) found installation of SCR equipment at Hayden 1 and 2 to be reasonable and prudent in a Certificate of Public Convenience and Necessity (CPCN) application. The Clean Air Clean Jobs Act does not apply to Craig 1 and 2 and the operator of the Craig plant is not regulated by the CPSC.

PacifiCorp indicated that if they were to contest installation of SCR at Craig and Hayden, the Company would have been forced to take the other owner's decision to install that investment to arbitration where PacifiCorp would have to show that the other owners were acting inconsistent with the participation agreement or inconsistent with generally accepted practices in the electric utility industry. PacifiCorp believed it had minimal likelihood of success in arbitration.

However, the Commission has ruled that even when a company has minority ownership in a plant, the Company needs to analyze the possible costs and consequences of environmental regulations associated with the Company's partial ownership in coal plants.[14] In Docket UE 233, Order 13-132, the Commission stated:

A minority owner who seeks to pass through to its ratepayers the costs of environmental upgrades may not sign away its independent duty to review and carefully consider a majority owner's decision-making.

The Commission imposed a management disallowance of $40,000 on Idaho Power due to lack of adequate oversight of investment decisions where they were minority owner.[15]

In this docket, Staff asked PacifiCorp for a copy of the PVRR(d) analysis for the Craig and Hayden investments.[16] The Company indicates that "a present value revenue requirement differential (PVRR(d)) analysis has not been used to evaluate the environmental investments required at the Craig and Hayden Units."[17]

In its response to Staff Data Request 204 the Company indicates that it voted against the Craig Unit 1 and 2 pollution control equipment installations because the results of PacifiCorp's own analysis of the proposed pollution control equipment installations was unfavorable. When Staff asked for a copy of the analysis, the Company stated that the

[14] Idaho Power Company Docket LC 53, Order 12-177
[15] UE 233, Order 13-132 at 7
[16] Data Request 86 in this Docket LC 57
[17] PacifiCorp response to Staff Data Request (DR) 86

analysis was conducted under attorney-client privilege at the request of counsel and was not subject to disclosure. It is important to highlight here that the Company is not seeking acknowledgment of any investments related to Craig and Hayden.

Consistent with Commission direction, Staff recommends the Company bring all material coal investment decisions to the Commission through the new proposed coal analysis proceedings, even where PacifiCorp is a joint owner or contracts plant operation to a third-party. Accordingly, Staff recommends the Company provide analysis on Craig 1 and 2 and Hayden 1 and 2 through the new process and recommends the following new Action Item:

<u>Proposed New Action Item 8e</u>: *PacifiCorp will submit to the Commission for acknowledgement specific analysis on the resource decisions associated with Craig 1 and 2 and Hayden 1 and 2 within six months of the Commission's determination on this IRP.*

Transmission

Staff comments focus on the following transmission-related action items acknowledged in the PacifiCorp 2011 IRP and the transmission-related action items proposed by the Company in the PacifiCorp 2013 IRP:

Table 3: Action Items Discussed by Staff

Docket #	IRP	Action Item #	Action Item Category	Action Item
LC52	2011 IRP	10	Transmission	*In the scenario definition phase of the IRP process, the Company will address with stakeholder the inclusion of any transmission projects on a case-by-case basis.* *Develop an evaluation process and criteria for evaluating transmission additions.* *Review with stakeholders which transmission projects should be included and why.* *Based on the outcome of these steps, PacifiCorp will provide appropriate transmission segment analysis for which the Company requests acknowledgment (including Wallula to McNary and Sigurd to Red Butte).*
LC57	2013 IRP	9a	Transmission System Operational and Reliability Benefits Tool (SBT)	*60 days after filing the 2013 IRP, establish a stakeholder group and schedule workshops to further review the System Benefit Tool (SBT).* *For the 2013 IRP Update, complete additional analysis of the Energy Gateway West Segment D that evaluates staging implementation of Segment D by sub-segment.* *In preparation for the 2015 IRP, continue to refine the SBT for Energy Gateway West Segment D and develop SBT analyses for additional Energy Gateway segments.*

		9b	Transmission Energy Gateway Permitting	*Continue permitting for the Energy Gateway transmission plan, with near term targets as follows:* *Segment D, E, and F, continue funding of the required federal agency permitting environmental consultant as actions to achieve final federal permits.* *Segment D, E, and F, continue to support the federal permitting process by providing information and participating in public outreach projected through the next 2 to 4 years.* *Segment H Cascade Crossing, complete benefits analysis in 2013.* *Segment H Boardman to Hemingway, continue to support the project under the conditions of the Boardman to Hemingway Transmission Project Joint Permit Funding Agreement, projected through 2015.*
		9c	Transmission Sigurd to Red Butte (S2RB) 345 kilovolt Transmission Line	*Complete project construction per plan.*

LC52 2011 IRP Action Item 10 (Transmission) and LC57 2013 IRP Action Item 9a (Transmission SBT)

Regarding Action Item 10 of PacifiCorp 2011 IRP, which was acknowledged in Order No. 12-082,[18] PacifiCorp engaged in extensive efforts to address the scenario definition of its 2013 IRP with stakeholders through a public process.[19] Specifically, the Company made an effort to provide appropriate transmission segment analysis, for which the Company requests acknowledgment related action items in its 2013 IRP [i.e., Sigurd to Red Butte (S2RB) transmission project[20] and Populus to Windstar (P2W) transmission project[21]], by developing, in consultation with stakeholders, the System Operational and Reliability Tool (SBT). The tool is designed for "identifying and quantifying benefits"[22] and the costs of transmission projects such as: power costs savings, avoided transmission system capital cost, system reliability benefits, improved generation dispatch, energy and capacity segment loss savings, customer and regulatory benefits, and wheeling revenue opportunities.

Additionally, the Company appropriately included in its 2013 IRP the P2W and S2RB transmission projects because they comply substantially with Guideline 5 of the IRP Guidelines adopted in Order No. 07-002,[23] which states that "utilities should consider

[18] See Appendix A, page 8 of 8 (page 18 of the PDF file) of the referenced order at http://apps.puc.state.or.us/orders/2012ords/12-082.pdf.
[19] As part of its public process, PacifiCorp conducted 26 public meetings/conference calls; three of those meetings covered transmission-related issues (i.e., July 13, 2012; November 5, 2012; and February 27, 2013).
[20] The Company also refers to this segment as Energy Gateway Segment G.
[21] The Company also refers to this segment as Energy Gateway Segment D.
[22] See last paragraph of page 57 in Volume I of PacifiCorp 2013 IRP.
[23] Guideline 5 reads as follows: "Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities

electric transmission facilities as resource options taking into account [among other things] their value for improving reliability." In the case of the P2W transmission project, the project allows the Company to access 650 MW of new generation in Wyoming included as part of PacifiCorp's 2013 IRP preferred portfolio.[24, 25] In the case of the S2RB transmission project, this project is not only a resource option for the Company's network customers, such as PacifiCorp Energy,[26] Utah Associated Municipal Power Association (UAMPS), and Deseret Generation & Transmission Cooperative, Inc. (DG&T),[27] to serve their respective retail load, but also, most importantly, allows the Company to comply with mandatory FERC,[28] NERC,[29] and WECC[30] reliability obligations.

Regarding Action Item 9a of PacifiCorp 2013 IRP, the Company represented that "[t]he metrics that comprise the SBT will continue to improve and evolve over time, with stakeholder input and thorough utility industry experience."[31] Staff and parties concur with this notion.[32]

Staff Recommendation

Staff recommends that the Commission conclude that the Company has thoroughly implemented Action Item 10 of PacifiCorp 2011 IRP. Regarding Action Item 9a of PacifiCorp 2013 IRP, Staff appreciates that the SBT will continue to evolve with the input of stakeholders, however, the proposed action item is not a specific resource action and therefore does not require acknowledgement by the Commission.

<u>LC57 2013 IRP Action Item 9b (Energy Gateway Permitting)</u>

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should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving reliability." See http://apps.puc.state.or.us/orders/2007ords/07-002.pdf.

[24] See PacifiCorp 2013 IRP, Volume I, page 132.

[25] Also see PacifiCorp's response to Staff Data Request 39.

[26] PacifiCorp Energy serves PacifiCorp's retail customers and comprises the bulk of the Company's transmission network customer needs. See PacifiCorp 2013 IRP, Volume I, page 56.

[27] See PacifiCorp 2013 IRP, Volume I, page 63.

[28] FERC stands for the Federal Energy Regulatory Commission.

[29] NERC stands for the North American Electric Reliability Corporation.

[30] WECC stands for the Western Electricity Coordinating Council.

[31] See PacifiCorp's 2013 IRP, Volume I, page 59.

[32] See:

- Renewable Northwest Project (RNP) Opening Comments, pages 10 and 11, "PacifiCorp's IRP Made Great Headway in Modeling Transmission Resources,": "RNP agrees with the Company that the tool is preliminary and there remains considerable flexibility as to how these should be measured";
- Northwest Energy Coalition, page 15: "We also agree that the development of [the SBT] is in the preliminary stage and needs more refinement before the results can be relied upon";
- CUB Opening Comments, page 23, lines 18-20; and
- ICNU Opening Comments, page 5, "2. SBT Warrants Further Review".

The Company's Action Item 9b is related to permitting actions for the following segments of Energy Gateway: [33, 34] P2W (Segment D),[35] Populus to Hemingway (Segment E),[36] Aeolus to Mona (Segment F),[37] and West of Hemingway (Segment H).[38]

Regarding Segment D, the Company has performed a preliminary SBT analysis to quantify the benefits of Segment D, which is included in the Company's preferred portfolio.[39, 40] The preliminary analysis shows that the benefits of this project[41] outweigh the costs.[42] However, in their initial comments, several parties commented that it is not appropriate to include the Customer and Regulatory Benefits in the SBT analysis of Segment D.[43]

In its reply comments, the Company represented that in consideration of the feedback received in the SBT workgroup workshop process, PacifiCorp committed to separate the Customer and Regulatory Benefits figure from its cost-to-benefit ratio calculation of the SBT going forward.[44] Therefore, even excluding the Company-proposed $249 million of Customer and Regulatory Benefits, Staff finds that the benefit-cost ratio of the project is approximately one,[45] justifying the Company's continued permitting efforts.

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[33] PacifiCorp describes Energy Gateway as "an ambitious, multi-year, multi-billion dollar investment plan that will add approximately 2,000 miles of new transmission lines across the West." See www.pacificorp.com/energygateway.

[34] Also see PacifiCorp's 2013 IRP, Volume I, pages 70-74.

[35] The Windstar to Populus segment is part of the Gateway West project. This segment will stretch more than 400 miles starting near Glenrock, Wyoming, proceeding south to Medicine Bow and then spanning across southern Wyoming to the Populus substation near Downey, Idaho (see www.pacificorp.com/tran/tp/eg/gw/sdwtp.html). The anticipated in-service date for this project is between 2019 and 2021 (see PacifiCorp's 2013 IRP, Volume I, page 74).

[36] The Populus to Hemingway segment is part of the Gateway West project. This segment will originate near Downey, Idaho, and run approximately 600 miles across Idaho to the Hemingway substation near Melba, Idaho southwest of Boise, Idaho (see www.pacificorp.com/tran/tp/eg/gw/septh.html). The anticipated in-service date for this segment is between 2020 and 2023 (see PacifiCorp's 2013 IRP, Volume I, page 74).

[37] The Aelous to Mona segment extends approximately 400 miles from the planned Aeolus substation in southeastern Wyoming into the new Clover substation near Mona, Utah (see www.pacificorp.com/tran/tp/eg/gs.html). The anticipated in-service date of this segment is between 2020 and 2022 (see PacifiCorp's 2013 IRP, Volume I, page 74).

[38] This segment is a 500 kV single circuit transmission line that starts at the Hemingway substation in Idaho. The anticipated in-service date is sponsor-driven (see PacifiCorp's 2013 IRP, Volume I, page 74).

[39] See Table 8.7 of PacifiCorp 2013 IRP, Volume I, page 227, "Preferred Portfolio (EG2 Case 07a)". EG2 stands for Energy Gateway scenario 2.

[40] Energy Gateway scenario 2 includes Segment C (Mona to Oquirrh), Segment D (Windstar-Populus), and Segment G (Sigurd to Red Butte). See Table 7.5 in PacifiCorp 2013 IRP, Volume I, page 172.

[41] The approximately $1.17 billion in benefits comprises power costs savings, avoided transmission system capital cost, system reliability benefits, improved generation dispatch, energy and capacity segment loss savings, customer and regulatory benefits, and wheeling revenue opportunity.

[42] The cost of the project is approximately $930 million.

[43] See NW Energy Coalition Opening Comments, page 16, second paragraph. See Sierra Club Preliminary Comments, page 18, first paragraph. See ICNU Opening Comments, page 5, "2. SBT Warrants Further Review," first paragraph. See CUB Opening Comments, page 21, lines 7-19.

[44] See Reply Comments of PacifiCorp, page 60, lines 15-19.

[45] Excluding the entire amount of Customer and Regulatory Benefits results in a benefit-cost ratio of 0.98.

Staff supports the Company's approach of continuing the permitting actions on this project.

Regarding Segments E, F, and H,[46] Staff recognizes that there is uncertainty in developing these segments until their anticipated in-service dates,[47] however such uncertainty which should not hinder the Company's efforts to continue exploring the projects in light of the preliminary benefits of these segments.[48] In its future IRP, the Company should perform the SBT analyses for these segments for Staff recommending acknowledgment of further permitting action items. The Company recognizes this fact and has proposed in Action Item 9a that "[i]n preparation for the 2015 IRP, [the Company will] continue to refine the SBT for Energy Gateway West Segment D and develop SBT analyses for additional Energy Gateway segments."[49]

Staff Recommendation

Staff recommends acknowledging the Company's Action Item 9b with the modifications shown below:

Proposed modified Action Item 9b. *Continue permitting Segments D, E, F, and H until PacifiCorp files its 2015 IRP, when SBT analyses for these segments will be performed.*

~~Continue permitting for the Energy Gateway transmission plan, with near term targets as follows:~~

~~– Segment D, E, and F, continue funding of the required federal agency permitting environmental consultant as actions to achieve final federal permits.~~
~~– Segment D, E, and F, continue to support the federal permitting process by providing information and participating in public outreach projected through the next 2 to 4 years.~~
~~– Segment H Cascade Crossing, complete benefits analysis in 2013.~~
~~– Segment H Boardman to Hemingway, continue to support the project under the conditions of the Boardman to Hemingway Transmission. Project Joint Permit Funding Agreement, projected through 2015.~~

LC57 2013 IRP Action Item 9c (S2RB Transmission Project)

PacifiCorp Remarks

The S2RB transmission project is a 170-mile 345 kV transmission line that runs between the Sigurd substation near the City of Richfield, Utah, and an expanded Red

[46] In the context of this round of comments, Staff recognizes Segment H as the Boardman to Hemingway segment.
[47] Between 2020 to 2022 for Segments E and F.
[48] See PacifiCorp response to Staff Data Request 258.
[49] See PacifiCorp's 2013 IRP, Volume I, page 19, second bullet of Action Item 9a.

Butte substation near the City of Central, Utah.[50] The project is under construction and expected to come into service in June 2015.[51]

As the Company represented, the key drivers supporting PacifiCorp's request for acknowledgment of the Sigurd to Red Butte transmission project include: 1) complying with mandatory FERC, NERC, and WECC reliability standards (FERC, NERC, and WECC Reliability Obligations), 2) meeting its regulatory obligations to its network transmission customers consistent with its Open Access Transmission Tariff (Open Access Transmission Tariff Obligations), and 3) the positive cost-benefit analysis of this project compared to other alternatives (Cost-Benefit Analysis).[52]

FERC, NERC, and WECC Reliability Obligations

PacifiCorp represents that "the [S2RB transmission project] will provide needed redundancy to the existing infrastructure and substantially improve the Company's ability to provide reliable electric service to its customers in compliance with mandatory FERC, NERC, and WECC reliability standards, which require that transmission providers evaluate all expected customer demand levels and operating conditions, and plan for adequate redundancy in their systems in order to maintain required system reliability and performance levels."[53]

Open Access Transmission Tariff (OATT) Obligations

Under PacifiCorp's Open Access Transmission Tariff, approved by FERC, the Company has the obligation to provide transmission services into and out of southwest Utah. OATT obligates the Company to provide adequate and nondiscriminatory network transmission service for delivery of network generation to loads.[54] OATT Section 28.2 requires PacifiCorp to plan, construct, operate, and maintain the transmission system; OATT Section 31.6 requires PacifiCorp to determine future load and resource requirements for all transmission network customers; and OATT Section 28.3 requires PacifiCorp to provide firm service over the system so that designated resources can be delivered to designated loads.[55]

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[50] See page 3 of the Application of Rocky Mountain Power (RMP) for a Certificate of Public Convenience and Necessity (CPCN) Authorizing Construction of the Sigurd to Red Butte 345 kV Transmission Line (S2RB transmission project) filed with the Utah Public Service Commission (UPSC) in Docket No. 12-035-97.
[51] See PacifiCorp's 2013 IRP, Volume I, Chapter 1, "Executive Summary," page 3, first paragraph.
[52] See 2013 IRP, Volume I, Chapter 4, "Factors Supporting Acknowledgment," page 63.
[53] See 2013 IRP, Volume I, Chapter 4, "Improved System Reliability," page 64.
[54] See 2013 IRP, Volume I, Chapter 4, "Enhanced Transfer Capability to Promote Energy Transfers," page 63.
[55] See pages 8-9 of the Direct Testimony of Darrell T. Gerrard – Errata in the Application of RMP for a CPCN Authorizing Construction of the S2RB transmission project filed with the UPSC in Docket No. 12-035-97.

As represented by the Company,[56] PacifiCorp plans, designs, and operates its transmission system to meet or exceed NERC standards for bulk electric systems and WECC regional standards and criteria. The NERC standards are federal law stated in 18 Code of Federal Regulations, Part 40 (Mandatory Reliability Standards for Bulk-Power Systems). The WECC standards and criteria are deemed necessary for the WECC region to meet or exceed NERC standards. PacifiCorp must comply with approximately 100 approved standards, several of which require the project.[57]

PacifiCorp concludes by citing that one of the standards and criteria that drove the timing of the project is NERC Transmission Planning Standard TPL 002 [System Performance Criteria Following Loss of a Single Bulk Electric System (BES) Element; or "N-1 criteria"], whose purpose is to have transmission providers "*ensure that reliably systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.*" Standard TPL 002 also requires that each transmission provider shall "*demonstrate through valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm Transmission Services at all demand levels over the range of forecast system demands under [the event resulting in the loss of a single element.*]"[58]

Cost-Benefit Analysis

PacifiCorp performed an SBT analysis of the S2RB transmission project in its 2013 IRP,[59] which includes benefits and costs. The present-value-expressed benefits are approximately $645 million and comprise operational cost savings, segment loss savings, and system reliability benefits. The costs of approximately $392 million represent capital costs.[60] The cost-benefit analysis results in a benefit-to-cost ratio of 1.64. Approximately 90 percent of the benefits of the project are attributed to operational costs savings, which were calculated by the Company "estimat[ing] that an

[56] See pages 9-10 of the Direct Testimony of Darrell T. Gerrard – Errata in the Application of RMP for a CPCN Authorizing Construction of the S2RB Transmission Project filed with the UPSC in Docket No. 12-035-97.
[57] The standards to which PacifiCorp refers are: NERC TPL-001 (System Performance under Normal Conditions), NERC TPL-002 (System Performance Following Loss of a Single Bulk Electric System (BES) Element), NERC TPL-003 (System Performance Following Loss of Two or More BES Elements), NERC TPL-004 (System Performance Following Extreme BES Events), TPL 001-WECC-1-CR (System Performance Criteria Normal Conditions), TPL 002-WECC-1-CR (System Performance Criteria Following Loss of a Single BES Element), TPL 004-WECC-1-CR (System Performance Criteria Following Loss of Two or More BES Elements), NERC TOP-002 (Normal Operations Planning), NERC TOP-004 (Transmission Operations), and NERC TOP-007 (Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations).
[58] See page 11 of the Direct Testimony of Darrell T. Gerrard – Errata in the Application of RMP for a CPCN Authorizing Construction of the S2RB Transmission Project filed with the UPSC in Docket No. 12-035-97.
[59] See PacifiCorp's 2013 IRP, Volume I, Chapter 4, "Sigurd to Red Butte Cost-Benefit Analysis," pages 64-65.
[60] The capital costs include a return on and return of capital, income taxes, and property taxes. See PacifiCorp's response to Staff Data Request 37.

option to secure firm energy at Palo Verde Hub over a 20-year period would cost 25 [percent] of the total present value of purchasing firm energy for the 20-year period (2015-2034)."[61]

Guideline 5 of the IRP Guidelines adopted in Order No. 07-002 states that *"[p]ortfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving reliability.*"[62]

From Staff's point of view, the S2RB transmission project is a resource option for the Company's network customers such as PacifiCorp Energy (which serves PacifiCorp's retail customers and comprises the bulk of the Company's transmission network customer needs),[63] UAMPS, and DG&T.[64] The only question is whether the Company has addressed Guideline 5 regarding "*taking into account their value for making additional purchases and sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving reliability.*"

The project will allow PacifiCorp "*mak[ing] additional purchases and sales*" because "[f]ollowing the completion of the Sigurd to Red Butte project, the transfer capacity of the existing system between Utah and Nevada will increase by an additional 200MW. This additional transmission capacity may be used by the Company for off-system sales during periods when surplus energy exists."[65] From Staff's point of view, "*accessing less costly resources in remote locations*" is captured by the fact that the S2RB transmission project allows "*making additional purchases"* whenever such purchases are less costly. Regarding the improved "*reliability"* aspect, the Company represented the S2RB transmission project will allow the Company to comply with mandatory FERC, NERC, and WECC reliability obligations.

Staff Conclusion

The Company justified the S2RB transmission project principally by noting that, first, it complies with mandatory FERC, NERC, and WECC reliability obligations and, second, it meets its obligations to network transmission customers consistent with its OATT. Staff

[61] See MS Excel workbook "PacTrans_SigurdToRedButte-SBT_4-30-13," worksheet "SIG-RB #2 Dashboard," provided by the Company at www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2013IRP/PacTra
ns_SigurdToRedButte-SBT_4-30-13.xlsx
[62] See at http://apps.puc.state.or.us/orders/2007ords/07-002.pdf.
[63] See 2013 IRP, Volume I, page 56.
[64] See 2013 IRP, Volume I, page 63.
[65] See PacifiCorp's 2013 IRP, Volume I, Chapter 4, "Enhanced Transfer Capability to Promote Energy Transfers," page 63.

finds that the two justifications as represented by the Company are valid and support the Company in complying with its regulatory obligations.

Staff recommends acknowledging Action Item 9c (S2RB Transmission Project) without modifications. However, because the primary beneficiaries are the Company's network transmission customers (i.e., PacifiCorp Energy, UAMPS, and DG&T), and specifically their loads in southwest Utah, the allocation of costs should be commensurate with the benefits received by each network transmission customer or state. This may be addressed in the appropriate venue, such as multistate allocation processes and general rate proceedings.

Demand Side Management (DSM)

In Action Item 7a. the Company proposes to acquire 1,425 - 1,876 gigawatt hours (GWh) of cost effective Class 2 energy efficiency resources by the end of 2015 and 2,034 to 3,180 GWh by the end of 2017. The Company then lists twelve categories of activities that it will perform to achieve those DSM targets.

Because DSM is situs allocated and generation and market purchases system allocated, at the October 28, 2013, public meeting, Staff raised concern that Oregon ratepayers are being burdened by a lack of sufficient DSM in other states. Staff also expressed frustration that the Company has repeatedly delayed or cancelled action items related to DSM activities in other states, without explanation. For example, a 120 MW commercial curtailment product negotiated contract was cancelled in Q3 2013[66] and a direct install and commercial conservation DSM RFP was put on hold following the Company's revised load forecast that came in lower than expected.[67] However, Staff notes that even with the lower load forecast that was used in this IRP, the accelerated DSM portfolio C-15 performed better than any other portfolio. Accelerated DSM Core Case C-15 shows that getting more conservation sooner is better than cancelling programs, even when loads are lower.

Staff also recommended that the Company reinstate the cancelled commercial curtailment project and move forward with the direct install and commercial conservation RFP. Staff also recommended that some sort of annual accountability process be established and the Commission consider disallowing costs in a rate proceeding if the Company does not meet energy efficiency levels established in other states.

Staff met with the Company following the October 28, 2013 public meeting to discuss DSM issues. Relative to the target ranges expressed in Action Item 7a, PacifiCorp explained the lower end of the range represents the amount of DSM in the preferred portfolio and the upper end of the target range is the amount of DSM that was selected

[66] See PacifiCorp's response to Staff DR 222
[67] In PacifiCorp's reply comments, it is indicated that the direct install and commercial conservation DSM projects are being restarted.

by System Optimizer in the accelerated DSM case C-15. The Company also pointed out how the specific subtasks identified as part of Action Item 7a are accelerated from what the Company would otherwise have done. Staff would like to see the Company follow through on the more aggressive DSM targets and report back to the Commission on its progress.

In the meetings between Staff and the Company and in the Company's reply comments, PacifiCorp expresses a willingness to provide the Commission and Oregon parties, during Commission public meetings, an update on its DSM resource activities outside of Oregon on a periodic basis, similar to routine updates provided by the Energy Trust of Oregon. Staff is optimistic this will help improve understanding of the Company's current efforts outside Oregon. Staff recommends that PacifiCorp start by providing two updates per year for two years. After that, Staff and parties can recommend whether or not the updates need to continue. Staff recommends that the updates include very specific data about how PacifiCorp is doing relative to meeting the IRP target range and not just contain qualitative reporting.

The Company notes in its LC 57 reply comments on page 61 and 62, as they respond to Northwest Energy Coalition's (NWEC's) assertion that they did not follow through on the 2011 action item related to Special Contract customers, that they decided to work directly with Special Contract customers rather than seeking Commission approval for a plan to address this customer group. In regular updates going forward, Staff would like to receive updates on progress with individual meetings with these customers as described on page 62, lines 8-11.

In Staff's initial comments, Staff raised a concern that it appeared the amount of DSM was going down in this IRP from what was agreed to in the last IRP, even though the accelerated DSM case C-15 showed that accelerating DSM is lowest cost and lowest risk to ratepayers. It is now clear that Staff misunderstood the DSM targets as expressed in the 2011 and 2013 IRPs because of differences in how they were expressed in each document. In conversations with the representatives from PacifiCorp, it was indicated that going forward, yearly DSM acquisition targets will be provided in a consistent basis (in GWh and MW) for each year of the planning period. Staff is supportive of this and would like to see this information expressed in a table and broken down by state.

Staff supports the part of Action Item 7a. which states: "*Include in the 2014 conservation potential study an analysis testing assumptions in support of accelerating acquisition of cost-effective Class 2 DSM resources, and apply findings from this analysis into the development of candidate portfolios in the 2015 IRP*."

Staff would like to see the RFP that is developed for this study and be involved with the development of the scope of the study.

In addition, Staff recommends that an Implementation Study be conducted that is specific to PacifiCorp's service area. Based on conversations with the Company, the analysis that PacifiCorp is requesting is assumed to be more general and theoretical in nature in terms industry-wide standard costs for accelerating DSM acquisition. Staff asserts that the information proposed will be of limited value from a practical perspective. Specific information about how much DSM can be accelerated specific to PacifiCorp's programs and service territory will be much more meaningful and relevant. Because case C-15 was the best performing portfolio from a cost and risk perspective, it is important to ratepayers that PacifiCorp accelerate DSM to the extent possible and the service territory specific information obtained through an Implementation Study will tell the real story about how much DSM is available and how quickly it might be acquired.

Staff supports the other details proposed in PacifiCorp's Action Item 7a.

Staff recommends that the following two bullets be added to PacifiCorp's <u>proposed Action Item 7a:</u>

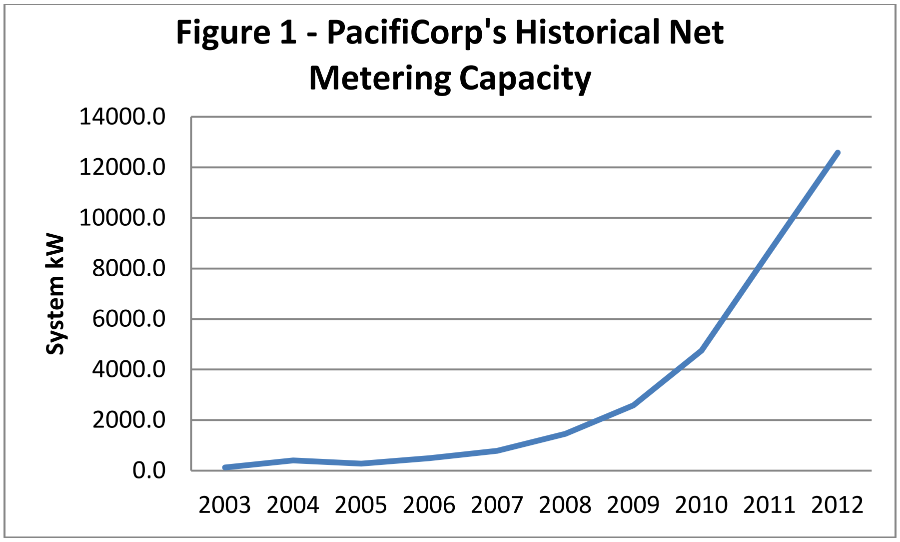
- <u>*Provide twice yearly updates on the status of DSM IRP acquisition goals to the Oregon Commission in 2014 and 2015 at regular public meetings.*</u>

- <u>*Include in the 2014 conservation potential study an Implementation Plan specific to PacifiCorp service territory for all states other than Oregon which quantifies the how much Class 2 DSM programs can be accelerated and how much it will cost to accelerate acquisition*</u>

Load Forecast

Staff is concerned that the Company's modeling is not adequately accounting for potential future load reductions due to net metering. Numerous industry articles have identified net metering as a threat to the viability of traditional utility structures. PacifiCorp's own data indicate that net metering capacity has followed a rapid exponential growth curve over the last several years. PacifiCorp claims that their forecast methodology accurately anticipates net metering growth, and that because of this the Company does not need to account for net metering growth in the IRP. Staff looked at this in detail and disagrees with both of these positions.

Figure 1 below plots PacifiCorp's historic growth in net metering. Currently, at 12 megawatts, net metering represents a relatively small portion of PacifiCorp's demand. However net metering is growing at approximately 40 percent annually. As the market matures, prices will continue to decrease. However, a federal tax credit that is currently supporting this growth is set to expire in 2016. If the growth in net metering is maintained at 40 percent for 10 years, PacifiCorp's net metering capacity would be 350 MW by 2023.



Direct Access

Another risk factor that impacts PacifiCorp's planned load obligation is the potential loss of retail loads in Oregon to direct access. Order No. 12-500 in Docket No. 1587 directs Pacific Power to, "file a tariff for a five-year opt out program that allows a qualified customer to go to direct access and pay fixed transition charges for the next five years, and then to be no longer subject to transition adjustment." PacifiCorp's compliance filing, which proposed to capture 20 years of transition payments over a five year period, was subsequently suspended due to concerns expressed by Staff and other parties, and Docket No. UE 267 was opened. According to the current schedule in that docket, the Company will make a new compliance filing at the conclusion of this case in late 2014, to take effect January 2015.

As of this time, all of the UE 267 parties[68] other than PacifiCorp have stipulated to a settlement that covers the period 2015 to 2018, sets a cap of 175 average megawatt (aMW) of direct access eligible load, and requires a four-year notice prior to a load returning to cost-of-service rates. The 175 aMW cap is approximately half of the eligible load under the proposed design, and represents an amount that is roughly equivalent to PGE's direct access offering. This amount is also similar to the system cumulative load the IRP anticipates adding through 2017.[69]

The IRP states that: "PacifiCorp continues to plan for load for direct access customers."[70] Because the Company does not currently offer a direct access program

[68] Staff; Industrial Customers of Northwest Utilities; Nobles Americas Energy Solutions LLC; Wal-Mart Stores, Inc.; Shell Energy North America (UW), LP; Constellation NewEnergy, Inc.; Fred Meyer Stores, Inc./Kroger Co.; Northwest and Intermountain Power Producers Coalition; Safeway, Inc.; and Vitesse, LLC.
[69] Staff testimony, Compton, UE 267, "PacifiCorp's response to OPUC Data Request 2 the Company said, "The 2013 IRP [Integrated Resource Plan] load forecast shows that on a system basis PacifiCorp will add cumulative load of approximately 175 aMW (1,533 GWh) in 2017 or approximately four years."
[70] 2013 IRP, APPENDIX B – IRP REGULATORY COMPLIANCE, p. 44.

that has finite transition payments, relatively few customers have participated. However, given the Commission's direction in UM 1587 and the parameters of the long-term direct access program that has been offered for several years by PGE,[71] Staff asserts that the Company's assumption of zero long-term direct access load is not reasonable.

Risk Metric

In its recently filed Reply Comments,[72] PacifiCorp re-"confirmed" its claim that the upper-tail mean PVRR less the stochastic mean PVRR—rather than the upper-tail mean PVRR by itself—was the appropriate risk metric for the initial screening of candidate portfolios. The argument given was that "PacifiCorp nets the stochastic mean PVRR against the upper tail mean PVRR to remove the effect of fixed costs…from the risk metric, [since the fixed costs] are identical among all 100 Monte Carlo iterations and therefore not a risk variable."

PacifiCorp's argument would be acceptable ***if**, when comparing different portfolios, **the fixed costs were identical among all the portfolios***, not just for the 100 Monte Carlo iterations performed for each portfolio. That's not the case: different portfolios are distinguished by having different fixed-resource components, which means they have different, not identical, fixed costs. Where risk is viewed as indicating either the probability of a given bad PVRR outcome, or, in this case, how bad might be the PVRR outcome given a certain probability of its occurrence, then those "indicators" clearly lose all meaning if a *variable* mean PVRR is being subtracted from the bad, or upper-tail, PVRR.

The problem with the PacifiCorp approach is that a really bad mean PVRR can be subtracted from a merely bad upper-tail mean PVRR to yield a relatively small difference, i.e., a relative *good*/low risk score. A simple numerical example shown in Table 4 below should clarify how subtracting the stochastic mean PVRR from the upper-tail mean PVRR can yield a low "risk score" even though its risk, as more accurately defined in the previous paragraph, is clearly greater than the risk associated with an alternative portfolio.

[71] Staff testimony, Compton, UE 267, "PGE (Portland General Electric) has also offered a five-year-minimum plan, at least since 2008. A significant share of PGE's distribution load is accounted for under its five-year direct access option. PGE, Staff and other interested parties recently stipulated to refinements to that program as part of PGE's general rate case Docket UE 262. I was the author of Staff's direct access testimony in that docket. Many of the same issues dealt with in the UE 262 docket are also addressed here. Staff's methods of analysis and approach in this docket are the same as were used in UE 262, which should dispel any concerns about inconsistent regulatory treatment."
[72] *See* page 32.

Table 4. Example of risk metric calculation

Portfolio	Mean PVRR	Upper-tail Mean PVRR	Upper-tail Mean PVRR Minus Mean PVRR
A	50	60	10
B	58	63	5

According to PacifiCorp, the risk, or risk score, for Portfolio A is twice that of Portfolio B. Such would render the conclusion that risk-wise, Portfolio B is superior to Portfolio A. But that would be nonsensical. All else the same, why would a decision maker prefer, or judge superior in some sense of risk, a portfolio with a worse bad outcome than that of another portfolio (i.e., holding constant the probability of achieving those bad outcomes)? Such a mistake would be avoided by focusing on the upper-tail means by themselves as the correct risk metric.

That focus is reflected on page 23 of the Oregon Commission's LC 42 Order 08-232 where it says, "We direct the Company to rank portfolios according to these metrics (95^{th} percentile and Upper-Tail [mean] PVRR) in the next IRP…."

RPS and RECs

<u>Action Item 1b. Renewable Portfolio Standard Compliance</u>
With renewable portfolio standard (RPS) compliance achieved with unbundled renewable energy credit (REC) purchases, the preferred portfolio does not include incremental renewable resources prior to 2024. Given that the REC market lacks liquidity and depth beyond one year forward, the Company will pursue unbundled REC requests for proposal (RFP) to meet its state RPS compliance requirements.

> *– Issue at least annually, RFPs seeking then current-year or forward-year vintage unbundled RECs that will qualify in meeting Washington renewable portfolio standard obligations.*
> *– Issue at least annually, RFPs seeking historical, then current-year, or forward-year vintage unbundled RECs that will qualify for Oregon renewable portfolio standard obligations. As part of the solicitation and bid evaluation process, evaluate the tradeoffs between acquiring bankable RECs early as a means to mitigate potentially higher cost long-term compliance alternatives.*
> *– Issue at least annually, RFPs seeking then current-year or forward-year vintage unbundled RECs that will qualify for California renewable portfolio standard obligations.*

Staff recognizes the Company's efforts to meet RPS requirements in the lowest cost manner via RECs, where possible. However, as noted in Staff's initial comments, the lack of projected costs associated with those RECs and the lack of a forward REC price forecast present gaps in the analysis. Forecasts of REC markets have undergone

substantive changes in recent years, sometimes dramatically increasing and other times decreasing, depending upon known and anticipated shifts in state and federal policies. Staff recommends acknowledgment of Action Plan item 1b with two conditions:
1) expected REC costs be explicitly incorporated into the portfolio analysis; and,
2) a forecasted range of REC prices be included in the IRP update and the 2015 IRP.

<u>Action Item 1c. Renewable Energy Credit Optimization</u>
On a quarterly basis, issue reverse RFPs to sell RECs not required to meet state RPS compliance obligations.

It our initial comments Staff indicated that PacifiCorp should revise its modeling to include an alternative that allows for all of PacifiCorp renewable resources to meet Oregon's RPS requirements and that for Washington RPS the Company can continue to assume purchasing RECs on the market. Staff suggested that PacifiCorp's renewable resources available to Oregon should not be limited to those resources allocated to Oregon and that Oregon can compensate other states for the market value of the RECs and this could be a lower-cost alternative as evidenced by analysis conducted to date by PacifiCorp.

Staff reaffirms its position that the Company's renewable resources should be made available to Oregon, with the associated compensation based on the market value of the RECs. Oregon Staff is currently working through the Multi-State Process (MSP) to acquire bundled RECs from other PacifiCorp jurisdictions. Because the action item conflicts with this objective, Staff does not recommend acknowledgment of this Action Plan item.

Renewables

Below are Staff's recommendations on the renewable energy focused action items.

<u>Action Item 1d. Solar</u>
- *Issue an RFP in the second quarter of 2013 soliciting Oregon solar photovoltaic resources to meet the Oregon small solar compliance obligation (Oregon House Bill 3039). Coordinate the selection process with the Energy Trust of Oregon to seek 2014 project funding. Complete evaluation of proposals and select potential winning bids in the fourth quarter of 2013.*

- *Issue a request for information 180 days after filing the 2013 IRP to solicit updated market information on utility scale solar costs and capacity factors.*

Staff is satisfied that the Company's approach to fulfilling its solar compliance obligation through the RFP process is reasonable and is also the best choice for establishing compliance. A bid process establishes fairness among bidders and helps assure that a resulting contract will be "least cost" and minimize risk. Staff recommends acknowledging this action item.

Action Item 1e. Capacity Contribution
Track and report the statistics used to calculate capacity contribution from wind resources and available solar information as a means of testing the validity of the peak load carrying capability (PLCC) method.

The Company reports that it plans to track and report statistics used to test the validity of the “peak load carrying capability” (PLCC) of solar and wind generators. Staff believes that this a useful exercise and one which has potential to lead to more efficient utilization of renewable resources. The data collected will allow the Company to compare the capacity contribution calculated through PLCC analysis with similar “effective load carrying capability” (ELCC) methods in order to fully assess solar and wind capacity contributions to the system reliability. However, because this Action Item contains no resource acquisition goals, this is not an action item requiring Commission acknowledgement.

Action Item 2a. Distributed Solar
Manage the expanded Utah Solar Incentive Program to encourage the installation of the entire approved capacity. Beginning in June 2014, as stipulated in the Order in Docket No. 11-035-104, the Company will file an Annual Report with program results, system costs, and production data. These reports will also provide an opportunity to evaluate and improve the program as the Company will use this opportunity to recommend changes. Interested parties will have an opportunity to comment on the report and any associated recommendations.

The Company expects to manage the expanded Utah Solar Incentive Program in order to “encourage the installation of the entire approved capacity.” Staff appreciates the Company’s willingness to encourage the development of solar capacity. However, because this Action Item recognizes a Utah Commission mandated offering and does not state explicit resource acquisition goals, Staff does not feel this Action Item requires Commission acknowledgement.

Action Item 2b. Combined Heat & Power (CHP)
Pursue opportunities for acquiring CHP resources, primarily through the Public Utilities Regulatory Policies Act PURPA Qualifying Facility contracting process. For the 2013 IRP Update, complete a market analysis of CHP opportunities that will: (1) assess the existing, proposed, and potential generation sites on PacifiCorp’s system; (2) assess availability of fuel based on market information; (3) review renewable resource site information (i.e. permits, water availability, and incentives) using available public information; and (4) analyze indicative project economics based on avoided cost pricing to assist in ranking probability of development.

The Company is committed to completing a market analysis of potential CHP opportunities and to pursue acquisition opportunities through PURPA. Staff is supportive of the Company’s efforts in obtaining reasonably priced CHP resources.

However, because this Action Item contains no state resource acquisition goals, Staff does not deem this item as warranting Commission acknowledgement.

Modeling and Process

Staff commends PacifiCorp for developing 19 core future scenarios, 11 sensitivity future scenarios, and a number of others for the coal unit environmental retrofit analysis. Staff also commends the Company for conducting numerous public input meetings.

Relative to PacifiCorp's IRP modeling, Staff has some has noted the following areas that could use improvement:

1) The diversity of portfolios created through System Optimizer (See Appendix C for specific details)

2) The natural gas prices input to the Company's PaR model seem to be biasing the analysis in favor of coal by underestimating cost risk of natural gas resources (See Appendix D for details)

3) The PaR model is not varying coal prices, CO2 prices, or other environmental compliance requirements/costs stochastically as it is other key variables. This mutes potential coal risks and biases the model toward coal heavy portfolios. Staff suggests that coal prices, CO2 prices, and other environmental compliance requirements and costs vary stochastically in future IRPs, so the Company's risk metric can more accurately account for these risks.

4) Stochastic treatment of system loads are favoring overbuilt scenarios (See Appendix E for details)

At the October 28, 2013 public meeting Staff expressed that System Optimizer may be too complex, non-transparent and not the right tool for the job when multiple alternatives need to be evaluated. Staff also expressed a desire to see an updated version of the screening tool that was developed and distributed as part of the 2011 IRP Update. Staff continues to want to see the screening tool updated and used as part of the coal analyses going forward, perhaps in conjunction with System Optimizer. Staff is concerned with the transparency of System Optimizer inputs and outputs.

In these times of lower load growth and increasing environmental regulation, the usefulness and relevance of the IRP has shifted from simply evaluating capacity additions to analyzing expenditures at existing plants and transmission. The IRP should highlight and analyze investments and alternatives at existing plants, in addition to focusing on capacity additions. To that end, the following two recommendations are made:

1) Tables similar to PacifiCorp's 2013 IRP Volume I, Table 8.7 should be provided for each portfolio, detailing major planned expenditures with estimated cost in each year for each plant under different scenarios. This information should not have to be data requested by Staff as it is a key factor in the Company's overall IRP.

2) IRPs need to include more detailed information about the projected timing of compliance alternatives, including key milestones, procurement times and decision points. Recognizing there is and will continue to be large amounts of uncertainty about specific requirements; timing information needs to be provided for various potential futures.

Action Items Summary

Many of PacifiCorp's action items can be considered business as usual activities. Staff does not typically acknowledge these types of activities. Rather they are items any reasonable utility would do in the regular course of business. The table below includes a summary of each action item proposed and Staff's recommendation.

Action Item #	**Resource**	**Summary**	**Staff recommendation**
1a.	Wind Integration	Update wind integrations study	Action Item doesn't require Commission acknowledgement
1b.	RPS Compliance	Unbundled REC RFP to meet RPS	Recommend acknowledgment with conditions: *1) <u>expected REC costs be explicitly incorporated into the portfolio analysis</u>;* and, *2) <u>a forecasted range of REC prices be included in the IRP update and the 2015 IRP</u>.*
1c.	RECs	Quarterly issue RFPs to sell RECs not required to meet state RPS compliance	Recommend not acknowledge because conflicts with ongoing MSP discussions about Oregon obtaining PAC system RECs
1d.	Solar	Issue RFP in Q2 2013 for Oregon solar PV resources to meet solar compliance obligation	Recommend acknowledgement
1e.	Capacity Contribution	Track and report statistics on capacity contributions of wind and solar	Action Item doesn't require Commission acknowledgement
2a.	Distributed Solar	Manage Utah Solar Incentive	Action Item doesn't require

		Program	Commission acknowledgement
2b.	Combined Heat & Power	Pursue opportunities to acquire CHP resources and complete a market analysis	Action Item doesn't require Commission acknowledgement
3a.	Front Office Transactions	Acquire economic FOTs or PPAs as needed through summer 2017	Business as usual - Doesn't require Commission acknowledgement
4a.	Energy Imbalance Market	Continue to pursue EIM activities with Cal-ISO and NWPP	Action Item doesn't require Commission acknowledgement
5a.	Natural Gas RFP	Convene workshop to discuss potential changes to evaluating bids	Action Item doesn't require Commission acknowledgement
6a.	Plant Efficiency Improvements	Continue moving forward on production efficiency efforts relative to Washington I-937	Action Item doesn't require Commission acknowledgement
7a.	Class 2 DSM	Acquire 1,425-1,876 GWH by end of 2015 and 2,034-3,180 GWh by end of 2017, plus details of specific efforts	Recommend acknowledgement with additions of: *1)* *Provide twice yearly updates on the status of DSM IRP acquisition goals to the Oregon Commission in 2014 and 2015 at regular public meetings.* 2) *Include in the 2014 conservation potential study an Implementation Plan specific to PacifiCorp service territory for all states other than Oregon* which quantifies the how much Class 2 DSM programs can be accelerated and how much it will cost to accelerate acquisition
7b.	Class 3 DSM	Develop pilot in Oregon for Class 3 irrigation TOU program	Action Item doesn't require Commission acknowledgement
8a.	Naughton Unit 3	1) Continue permitting in support of natural gas conversion 2) Issue an RFP to procure gas transportation to plant 3) Issue RFP for engineering,	Recommend acknowledgement with the following addition: • *Bring this investment decision back to the Commission in the 2015 IRP with further analysis*

		procurement and construction	
8b.	Hunter Unit 1	Complete installation of baghouse and low NOx burner by end of 2014	Recommend not acknowledge
8c.	Jim Bridger Units 3 and 4	Complete installation of SCR at Bridger 3 and 4 by end of 2015 and 2016, respectively	Recommend acknowledgement
8d.	Cholla Unit 4	Continue to evaluate compliance strategies and provide update in the 2013 update	Recommend modify action item as follows: *Continue to evaluate alternative compliance strategies that will meet Regional Haze compliance obligations, related to the U.S. Environmental Protection Agency's Federal Implementation Plan requirements to install SCR equipment at Cholla Unit 4. Provide an update of the Cholla Unit 4 analysis regarding compliance alternatives ~~in the 2013 IRP Update~~ to the Commission in a timely manner as part of a separate coal analysis docket.*
Proposed New Action Item 8e.	**Craig Units 1 and 2, and Hayden Units 1 and 2**	***PacifiCorp will submit to the Commission for acknowledgement specific analysis on the resource decisions associated with Craig 1 and 2 and Hayden 1 and 2 within six months of the Commission's determination on this IRP.***	
9a.	Transmission System Operational and Reliability Benefits Tool (SBT)	Establish stakeholder group and have workshops to further review SBT	Action Item doesn't require Commission acknowledgement
9b.	Energy Gateway Permitting	Continue permitting for Energy Gateway transmission plan. Near term targets are identified.	Recommend modify and acknowledge. Staff's proposed modified action item is: *Continue permitting Segments D, E, F, and H until PacifiCorp files its 2015 IRP, when SBT analyses for these*

			segments will be performed.
9c.	Sigurd to Red Butte 345 kilovolt Transmission Line	Complete project construction per plan	Recommend acknowledge
10a.	Planning Reserve Margin	Continue to evaluate in 2015 IRP a range of planning reserve margins	Action Item doesn't require Commission acknowledgement
11a.	Modeling and Process	Schedule IRP workshop with stakeholders to discuss process improvements	Action Item doesn't require Commission acknowledgement
11b.	Cost/Benefit of DSM Resource Alternatives	Complete a cost/benefit analysis on level of detail used to evaluate DSM resources in IRP	Action Item doesn't require Commission acknowledgement

This concludes Staff's Final Comments.

Dated at Salem, Oregon, this 10th day of January, 2014.

Juliet Johnson
Sr. Utility Analyst
Energy Resources & Planning

Appendix A - Staff's Handout from October 28, 2013 Public Meeting

<u>3 core principles we are using to look at this:</u>

A. All coal plants with potential action by 2019 need to be considered now. These are:
   a) Cholla 4
   b) Hayden 1
   c) Hayden 2
   d) Craig 1
   e) Craig 2
   f) Dave Johnson 3
   g) Jim Bridger 1
   h) Jim Bridger 2
   i) Naughton 1
   j) Naughton 2
   k) Hunter 1
   l) Hunter 2
   m) Huntington 1
   n) Huntington 2

B. Addressing coal plants in IRP updates is not sufficient

C. Thorough analysis needed of every plant with potential retrofit through 2019 using the most recent up to date information, including adequate stress testing

<u>5 areas of concern:</u>

1. The number of coal plants analyzed is insufficient. With few exceptions, PacifiCorp either conducted no analysis or inadequate analysis of the coal retrofits in question.

The Company did not provide any analysis of Cholla. The IRP is functionally incomplete without it because:

- An SCR is required on Cholla in late 2017 / early 2018
- In four of the core cases modeled and one sensitivity case, it is economical for Cholla to shut down in 2017
- Waiting until the IRP update or the next IRP would be too late.
    - The Company bidding for engineering, procurement and construction contractor for Cholla SCR starts in the second quarter of 2014
    - Time is of the essence in terms of negotiating potential alternative compliance alternatives with State and EPA
- Providing analysis in the IRP Update is inadequate because the IRP Update is an informational filing (per OAR 860-027-0400(8)) without the same analytical rigor

In addition, no analysis was provided by the Company for near term retrofits at Craig 1 and 2 and Hayden 1 and 2. These are joint-ownership plants. Because Oregon ratepayers will be paying for these upgrades, analysis should be provided for each.

Four months prior to PacifiCorp filing this IRP, EPA had disapproved parts of the Utah state implementation plan (SIP) related to regional haze pollution control requirements. The Company's preferred portfolio was developed using base case pollution control requirements that included items that were part of the disapproved Utah SIP. *Therefore, even at the time the IRP was filed, the Company's preferred portfolio did not represent the most current conditions.*

Similarly, two months after PAC filed this IRP, the EPA came out with a Federal Implementation Plan (FIP) for Wyoming that was more stringent than the previously proposed Wyoming SIP. The preferred portfolio and base case assumptions also do not reflect this change. Although it was reasonable for the Company to use the base case assumptions for Wyoming they did at the time, the more recent EPA actions in WY and UT have serious potential implications to future investments that need to be assessed in this IRP due to timing of potential compliance actions in 2019. Waiting for the 2015 IRP would be too late for plants that potentially require major investments in 2019. The Commission should not acknowledge an IRP that does not reflect current circumstances, related to such major investments.

The following coal plants are currently potentially in play for major investments by 2019 and were not addressed as part of this IRP[73]:

a. Cholla 4
b. Hayden 1
c. Hayden 2
d. Craig 1
e. Craig 2
f. Dave Johnson 3
g. Jim Bridger 1
h. Jim Bridger 2
i. Naughton 1
j. Naughton 2
k. Hunter 1
l. Hunter 2
m. Huntington 1
n. Huntington 2

<u>Request</u>: In this IRP, perform analysis of all plants with potential for investment by 2019 under most recent conditions

2. Alternative compliance options analysis is needed now for all plants in play.

[73] Hayden 1 and Hayden 2 and Craig 1 and Craig 2 are joint-ownership plants that also require near-term investments and analysis was not provided by the Company

In addition to providing a basic analysis of all plants in play, the Company needs to perform alternative compliance analysis, including early retirements and tradeoffs between coal units. Where there was uncertainty about the extent of and timing of pollution control investments and where there was a pending lawsuit, the Company did not perform an analysis of potential compliance alternatives.

Scenarios and alternatives were not sufficiently stress tested against future conditions, including carbon regulations, which could be coal specific and may not be adequately approximated by an across-the-board price on carbon.

Staff requested specific model runs related to alternative compliance scenarios for Dave Johnston 3 and Hunter 1. Staff requested the Company analyze shutting down Dave Johnston 3 in 2022 instead of installing an SCR in 2019, as required in the proposed Wyoming FIP. Staff has confidential results of this analysis that can be shared with parties who have signed the protective order in this case. Under the proposed Wyoming FIP, four other coal units (Naughton 1 and 2, and Jim Bridger 1 and 2) are potentially in the same boat as Dave Johnston 3 in terms of needing an SCR in 2019.

Staff had the Company analyze shutting down Hunter 1 early, in 2018 instead of installing an SCR in 2018. In exchange, it was assumed that Hunter 2 could be retrofit with an SNCR rather than an SCR. Results from this analysis can be shared with those who have signed a protective order. Depending on what EPA rules relative to other Utah coal plants, compliance actions could additionally be required at Huntington 1 and 2 in the 2019 timeframe and an analysis similar to the one Staff requested for Hunter 1, could be useful for those plants as well.

<u>Request:</u> Work with parties and with an updated version of the Company's screening tool (described in item 3 below) to develop alternative compliance scenarios for Cholla 4, Dave Johnson 3, Naughton 1 and 2, Jim Bridger 1 and 2, Hunter 1 and 2, and Huntington 1 and 2 and analyze those alternatives. Include transmission implications of each alternative.

3. Stress testing of alternatives and modeling transparency needed.

Coal plant analysis needs to include rigorous stress testing of key variables including carbon and potential negotiated alternative compliance scenarios such as shut as early retirement and unit by unit tradeoffs. Particularly when the level of uncertainty is high, trigger points need to be established, (i.e., at what carbon price or carbon policy does a retrofit become uneconomic, what gas prices make conversion economic or what negotiated shutdown date would be most cost effective).

When Commission Staff requested two scenarios be analyzed by the Company, the Company indicated it would take seven weeks for results. This leads staff to believe that **System Optimizer is too complex and not the right tool for the job when multiple variables need to be tweaked and trigger points established.**

Additionally Staff has no way to verify the results of System Optimizer. As part of 2011 IRP Update, a simple "screening tool" spreadsheet model was provided that allows parties to perform plant by plant analysis under different dates, carbon futures, compliance requirements, etc. Staff was able to use the screening tool to ascertain potentially economically beneficial pollution control scenarios. The screening tool may be an effective way to test sensitivity of multiple variables on the economics of individual plants. The screening tool could be used in conjunction with System Optimizer, PaR or some other model.

Request: Provide updated screening tool as part of this IRP

Longer-term: Work with parties to develop more streamlined and transparent way of evaluating coal plants and retrofit options, potentially using a phased approach that starts with the screening tool and may or may not include System Optimizer

4. Need for and size of new transmission not factored into shutdown analyses.

The Company has not factored into its coal analyses the impact of coal plant scenarios on the need for or sizing of new transmission lines. Alternatives should consider and optimize transmission options. Replacement gas plants could be located closer to load and thereby change the need for new transmission.

Request: When alternative compliance scenarios are developed, transmission implications should also be explored and parties agree on how to model impacts.

5. The Company has ignored or delayed action plan items related to DSM in other states.

The Company cancelled or delayed acknowledged DSM action items when load projections came in lower than expected.[74] Because DSM is situs and generation and market purchases system allocated, Oregon ratepayers are being burdened by lack of DSM in other states.

Even with lower load projections, in this IRP accelerated DSM portfolio performed better than any other portfolio. Accelerated DSM Core Case C-15 shows that getting more conservation sooner is better than cancelling programs. Current proposed action items are not sufficient to capture benefits of accelerated DSM demonstrated by top performing portfolio. DSM acquisition should be tied to long-term benefit not short-term need

Proposed action item: Reinstate canceled commercial curtailment project and move forward with delayed direct install and commercial RFP.

[74] 120 MW commercial curtailment product negotiated contract cancelled in Q3 2013. A direct install and commercial DSM RFP was put on hold following revised load forecast

<u>Longer-term:</u> Develop annual accountability process (reporting and analysis) and establish a means for disallowing costs in a rate proceeding for lack of performance on meeting EE goals in other states. Potentially develop DSM targets for other states and have PacifiCorp report yearly on DSM acquisition in other states with disallowance in rate cases for underperforming.

Appendix B - Proposed Separate Coal Analysis Docket

In the Company's reply comments in this docket, on page 19 the Company indicates it supports providing financial analysis of its environmental investment decisions for specific assets so that parties can have an opportunity to review and comment on those decisions before a prudence review in a future general rate case. On page 21, the Company expresses support for a suggestion Citizens' Utility Board (CUB) made at the October 28, 2013 public meeting to develop a new planning and review process in Oregon that would allow the Company and parties to develop parameters for coal unit investment analysis and for the Company to seek advance Commission review of unit-specific environmental investments. Staff supports this approach. An initial meeting was held with parties on January 6, 2014 to discuss what this type of new planning and review process would entail.

It is important to note that this new process would not lead to pre-approval and it should not take away from the strength and rigor of the current IRP process. Rather its purpose is more to deal with timeliness issues. This outboard process would be limited to PacifiCorp's coal fleet. The separate coal analysis docket would not relieve PacfiCorp of the need to rigorously explore options in an IRP. The Company needs to allow plenty of time for potential negotiations with environmental regulators if viable and economic alternatives are identified through the IRP process. ***PacifiCorp should continue to include in IRPs anything with the potential for action within five years, whether or not the Company believes it is sufficiently "ripe". The same action can be brought back to the Commission through the separate coal analysis docket once the alternatives have been evaluated and the Company is proposing to take action.***

Staff appreciates efforts made by PacifiCorp in the last two IRPs to improve and enhance their coal analysis. Staff has put a lot of thought into what analysis is needed to see in order to make clear recommendations to the Commission in future regulatory proceedings.

Below is a list of the types of analysis Staff needs to see in order to make recommendations to the Commission on whether actions on specific investments should be acknowledged in an IRP:

1. Fleet analysis (looking at potential tradeoffs and optimizations across PacifiCorp's coal fleet)

2. What Staff is calling inter-temporal analysis (similar to what occurred for Boardman)

3. Transmission impact analysis

Additionally, Staff needs to see stochastic results of coal analysis portfolios and needs to see an analysis of possible costs and consequences of environmental regulations associated with the Company's partial ownership in coal plants.

Below are more details on the three types of analysis Staff needs to see for environmental compliance investments. Staff will continue to work with parties on appropriate timelines for these analyses.

1. Analyze investment in context of a fleet analysis within Class 1 areas and by state
    a. For each Class 1 area impacted by plant in question, analyze fleet tradeoffs by calculating the Present Value Revenue Requirement (PVRR) for all reasonable combinations of shutdown and reduced emission controls between plant in question and other plants that impact the same Class 1 area.
    b. Identify all other PacifiCorp coal units in the same *state* as the coal unit/plant in question. Identify the Class 1 areas impacted by emissions from the analysis coal unit being analyzed. Use PacifiCorp's air quality model to determine all possible combinations of in-state unit shutdowns/natural gas conversions that satisfy the two prong test for the greater reasonable progress test.[75]
    c. Develop an optimized portfolio for each reasonable compliance combination.
    d. Analyze fleet tradeoffs by completing stochastic analysis of the different portfolios that meet the prerequisite pollution level reductions.
    e. Identify lowest cost, least risk compliance option.

2. Perform inter-temporal single unit analysis (aka Boardman type analysis)
    a. This analysis explores the compliance options achievable by altering the timing and strength of controls at a single unit based on different potential plant closure dates.
    b. Provide the analysis on both a single plant basis and from a whole system look (PVRR).

3. Assess Transmission Implications of Coal Plan Retirements
    a. Identify which Energy Gateway transmission paths are impacted by coal unit in question.
    b. Estimate present value of capital expenditures of future transmission upgrades or new transmission lines assuming the coal unit in question operates until its useful life.

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[75] Alternative compliance plans resulting in a different distribution of emissions than Best Available Retrofit Technology (BART) must satisfy "A test with the following two criteria (the ''two-pronged visibility test'') would demonstrate ''greater reasonable progress'' under the alternative program if both prongs of the test are met: visibility does not decline in any Class I area,6 and there is an overall improvement in visibility, determined by comparing the average differences between BART and the alternative over all affected Class I areas." FR 13693

c. Estimate the present value of capital expenditures of downsized/avoided transmission reinforcements or downsized/avoided new transmission lines in the next 20 years assuming the analysis coal unit is retired.
d. Calculate the difference between the two and incorporate that into the Company's analysis.

Staff is cognizant of the amount of work this is. Staff will work with the Company to help focus the analysis on meaningful and consequential alternatives.

Appendix C - Diversity of Portfolios created with System Optimizer

When one evaluates the 19 future scenarios the Company fed into SO to get the 19 portfolios it subsequently analyzed to select the preferred portfolio, it becomes clear that (1) many of the future scenarios are too similar to each other and (2) too many of the future scenarios represent extreme environments/bookend scenarios.

The end result is that many of the 19 portfolios the Company analyzes are nearly identical. The table below rearranges the 18 future scenarios PacifiCorp developed and analyzed[76] by their natural gas price future[77] to show how similar many of the futures actually are:

Case	Gas Price	CO2 Price	Coal Price	RPS	Class 2 DSM	Regional Haze	Other
C04	Low	High	High	None	Base	Base	n/a
C05	Low	High	High	State & Federal	Base	Base	n/a
C08	Low	High	High	None	Base	Stringent	n/a
C09	Low	High	High	State & Federal	Base	Stringent	n/a
C14	Medium	Hard Cap(Med Gas)	Medium	State & Federal	Accelerated	Base	n/a
C18	Medium	Hard Cap(High Gas)	Medium	None	Accelerated	Base	Clean Energy
C01	Medium	Medium	Medium	None	Base	Base	n/a
C02	Medium	Medium	Medium	State	Base	Base	n/a
C03	Medium	Medium	Medium	State & Federal	Base	Base	n/a
C15	Medium	Medium	Medium	State & Federal	Accelerated	Base	No CCCt
C16	Medium	Medium	Medium	State & Federal	Base	Base	Geothermal/RPS
C10	Medium	Medium	Medium	None	Base	Stringent	n/a
C11	Medium	Medium	Medium	State & Federal	Base	Stringent	n/a
C06	High	Zero	Low	None	Base	Base	n/a
C07	High	Zero	Low	None	Base	Base	n/a
C12	High	Zero	Low	None	Base	Stringent	n/a
C13	High	Zero	Low	State & Federal	Base	Stringent	n/a
C17	High	Medium	Medium	State & Federal	Base	Base	Market Spike

It can be seen that low gas prices were never paired with anything other than high CO_2 prices and high coal prices, an environment that is predictably favorable to natural gas resources. It can also be seen that high gas prices were almost exclusively paired with zero CO_2 prices and low coal prices, an environment that heavily favors coal resources. As expected, the low gas price grouping of futures (C04, C05, C08, and C09) produced portfolios where *almost every* PacifiCorp coal unit is retired *early* and replaced primarily with natural gas resources. Also, unsurprisingly, the high gas price grouping produced portfolios (C06, C07, and C12) where the only early retirement of coal resources are those that have already been planned by the Company (and were therefore imposed on the model from the start).

[76] Excluding the 19th future scenario with a different transmission regime the Company excluded from its portfolio evaluation

[77] A careful analysis of the results of the 2013 IRP shows that the strongest driver of changes in optimal generation resources is the expected price of natural gas.

Staff contends it would be enlightening to see what portfolio is optimal in a number of other future scenarios (such as a low gas price, medium carbon price, medium coal price world, or a high gas price, medium carbon price, medium coal price world) that are more likely to produce portfolios that are not entirely dependent upon one thermal source or another for base load capacity.

Staff suggests that it may be better to “hand-make” portfolios while keeping energy diversification as a goal rather than generating them with SO from an incomplete set of future scenarios. At the very least PacifiCorp should adjust the portfolio construction process so the portfolios that come out of SO are more diverse than those in the 2013 IRP.

Appendix D - Natural Gas prices in PaR

Staff believes that Natural gas prices have proven to be the most important driver of portfolio choice in this IRP for the following reasons:

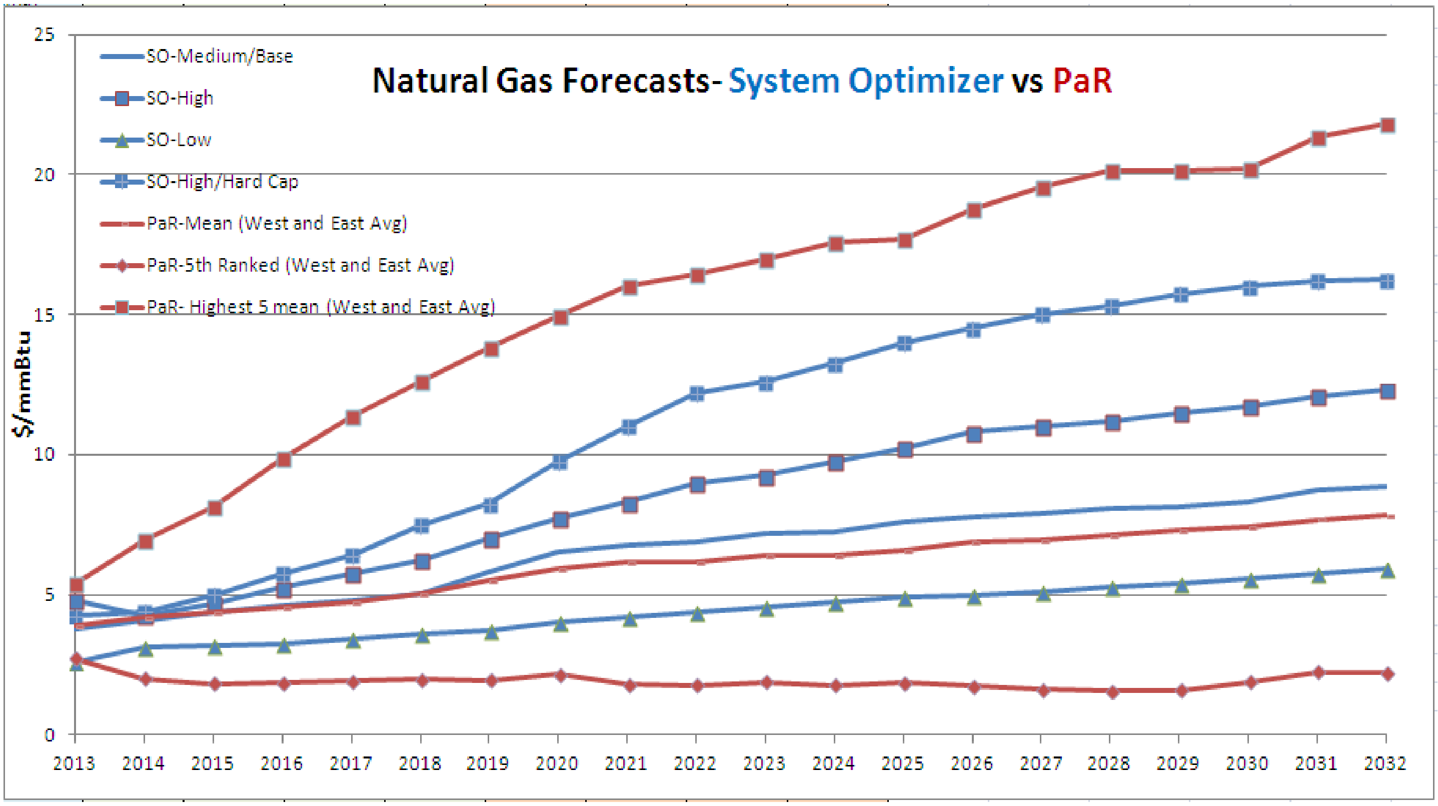
1) In PacifiCorp's modeling natural gas prices are dependent upon and highly correlated with CO_2 prices
2) Natural gas prices determine wholesale electricity prices in PacifiCorp's modeling, and gas and power prices are highly correlated so electricity prices track gas prices closely
3) Because coal prices are relatively stable (and in PaR do not vary at all) the coal versus gas decision is driven mostly by variation in natural gas prices

As such, the natural gas price projections the Company uses are of particular interest to Staff's recommendations.

As Staff pointed out in its opening comments in this docket as well as in the portfolio construction section above, it sees the natural gas price futures PacifiCorp used to generate portfolios using SO as reasonable for the time the gas prices were set for analysis in the 2013 IRP (which was September 2012) as they are consistent with the level and spread of many other reputable sources. However, as Staff also pointed out in its opening comments, these futures are less important than those that are used in the stochastic analysis (those of concern here). While the futures included in the IRP document (the ones input into SO to obtain the portfolios, not the ones used for the stochastic PaR analysis) are useful for the reader to see, Staff maintains that displaying the stochastic PaR inputs is integral to understanding the results and selection of the preferred portfolio (which dictates the Action Plan the Company filed with the OPUC for acknowledgement).

In its reply comments to Staff, the Company objects to including the PaR futures in the IRP document. However, the Company's responses to Staff suggest PacifiCorp realizes that the PaR futures are ultimately more important in determining the preferred portfolio than are the SO futures. In its response to Staff DR 104 the Company addresses Staff's concerns about the preferred portfolio (C07) having been produced by SO with a high gas price future scenario by noting "the high natural gas price assumption that defines case C07 was *only* used to produce a resource portfolio. The resulting portfolio developed using the System Optimizer model (SO Model), was then evaluated on a comparable basis to other resource portfolios using Planning and Risk (PaR)." (emphasis added) Staff agrees with this assertion and this is the main reason the PaR futures need to be included in the IRP document. After all, the gas price futures used in the PaR simulations are the ones that determine the stochastic mean and upper tail mean metrics that are used for choosing the preferred portfolio. Staff maintains that it is necessary for the Company to display these futures in the IRP (in comparison to distribution characteristics at snapshots in time) and does not believe that it is overly burdensome to do so.

To illustrate this point and to demonstrate how enlightening the results may be, Staff used the Company's DR responses to calculate the 100 natural gas futures associated with a base/medium CO_2 future so that they could be compared with the futures the Company constructed to produce portfolios with SO. The following graph shows the difference between the natural gas futures input into SO (the blue lines) and those randomly drawn from a probability distribution and used in the PaR analysis (the red lines):



This graph clearly demonstrates that while the mean of the 100 gas price futures is fairly comparable with the medium/base gas price used as an input in SO, the *spread* of gas prices is *much* larger in the stochastic analysis than in the portfolio selection analysis. In fact, the average of the highest five natural gas futures (ranked by levelized price) in the stochastic analysis is roughly twice the price of the "high" gas price the Company defined as a bookend for its portfolio selection analysis, and is even much higher than the most extreme future the Company could muster for its portfolio planning - the high gas price in conjunction with a hard carbon cap scenario. The average of the highest five gas prices from PaR reaches a preposterous \$14.92/mmBtu by 2020 and \$21.78/mmBtu by 2032.[78] While it is not guaranteed that the five highest natural gas futures align perfectly with the five highest cost runs that make up the upper tail mean risk metric for each portfolio, since gas prices are not the only stochastic input, it is likely there is a very strong correlation. Therefore, it is evident that the cost risk of relatively

[78] Note that these are not temporary shocks that could be associated with a supply disruption but points along a path that exhibits a clear trend.

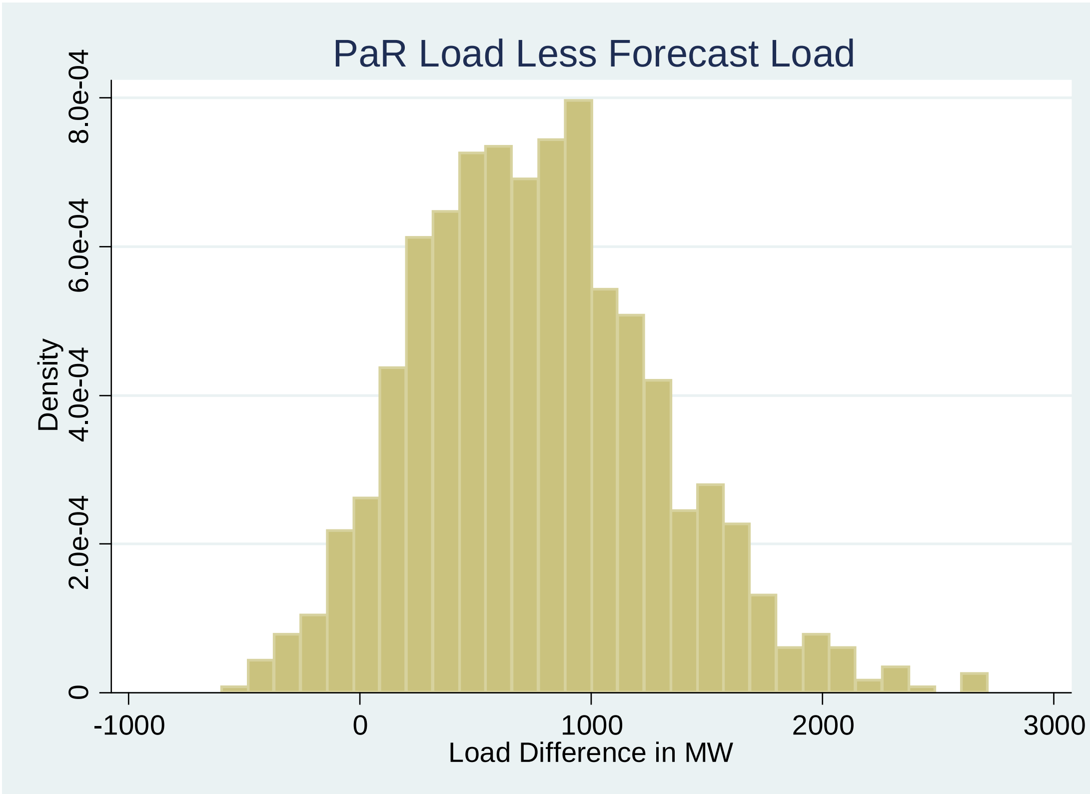
natural gas heavy portfolios (which, as shown above, are portfolios with very high proportions of natural gas capacity) is being severely overestimated with the current definition of the natural gas price distribution used to generate these 100 natural gas futures.[79]

[79] Also, the benefit from natural gas prices being lower than the expected mean is not accounted for in the current analysis.

Appendix E - *Stochastic treatment of system load*

A very important factor in the evaluation of the proposed portfolios is the reliability of the system. Energy not served is modeled as increased system costs. The company also separately examines the amount of energy not served in Tables 8.3 and 8.4 and Figure 8.24 of Volume 1. These numbers are grossly overestimated due to the manner in which the Planning and Risk model perturbate loads. The PaR model simulates 100 futures, each with different loads. The response to OPUC DR 73 provides the stochastic load parameters used for each future. Each future is independent. This means that the load parameter in any period from one future is uncorrelated with the load parameters for the same period in all the other futures. The loads are calculated individually for each jurisdiction. Staff aggregated the individual jurisdiction loads into a sign load parameter by weighting each jurisdictional load factor by the jurisdiction's contribution to system peak.

Staff generated the perturbated system loads for each future by multiplying the hourly load forecast from the confidential response to OPUC DR 278 with the associated load parameter. This changed the day on which the system peak occurred because some futures had a low load parameter on the day of the forecasted peak, but a high load factor on a day with near peak loads. Because of this, nearly all futures had peak loads significantly higher than forecasted load. The Figure below provides a histogram of the difference between the PaR peak loads and the forecast peak loads between 2013 and 2022. The distribution should be centered around zero. In fact, on average PaR annual peak loads are 770 MW higher than the forecasted peaks. This effectively reduces the Planning and Reserve Margin from 13 percent to 7 percent when portfolios are evaluated in the PaR model. Approximately 14 percent of all years evaluated in PaR have peak loads that exceed the planning and reserve margin. The result of this is inflated costs for all portfolios, and an over estimation of energy not served for all portfolios. The company provides energy not served results only from the PaR modeling. An important consequence of this is that, in PaR results, overbuilt portfolios appear to be resource stressed.


PaR Load Less Forecast Load
Density
0
2.0e-04
4.0e-04
6.0e-04
8.0e-04
-1000
0
1000
2000
3000
Load Difference in MW

CERTIFICATE OF SERVICE

LC 57

I certify that I have, this day, served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-001-0180, to the following parties or attorneys of parties.

Dated this 10th day of January, 2014 at Salem, Oregon

Kay Barnes

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Public Utility Commission
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