BRANDON KARPEN
DEPUTY ATTORNEY GENERAL
IDAHO PUBLIC UTILITIES COMMISSION
PO BOX 83720
BOISE, IDAHO 83720-0074
(208) 334-0357
IDAHO BAR NO. 7956

Street Address for Express Mail:
472 W. WASHINGTON
BOISE, IDAHO 83702-5918

Attorney for the Commission Staff

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF PACIFICORP DBA ROCKY MOUNTAIN POWER'S 2017 INTEGRATED RESOURCE PLAN.	)	**CASE NO. PAC-E-17-03**
	)	**COMMENTS OF THE COMMISSION STAFF**

The Staff of the Idaho Public Utilities Commission, submits the following comments regarding the above referenced case.

BACKGROUND

On April 4, 2017, PacifiCorp dba Rocky Mountain Power filed its 2017 Integrated Resource Plan ("IRP") with the Commission pursuant to the Commission's rules and in compliance with the biennial IRP filing requirements mandated in Order No. 22299. PacifiCorp's Application in this case requested acknowledgement of the 2017 IRP. Acknowledgement or acceptance of the 2017 IRP should not be interpreted as an endorsement of any particular element of the plan, nor should it constitute approval of any resource acquisition contained in the plan. *See* Order No. 33396.

The Company's IRP filing consists of the following items: 1) 2017 Integrated Resource Plan – Volume I; 2) 2017 Integrated Resource Plan – Volume II; 3) Supplemental Data Discs; 4)

Supplemental Volume II Corrections; 5) 2017 Integrated Resource Plan – Energy Vision 2020 Update. Volumes I and II of the 2017 Integrated Resource Plan provides details on the IRP process, the information used during the process, and the action plan produced from the process. The Energy Vision 2020 Update is an informational filing which provides additional economic analysis of the Repower and New Wind/Transmission projects identified in Volume I of the 2017 IRP. This informational filing was provided four months after the initial filing date.

The Company stated that the primary objective of the IRP is to identify the best mix of resources to serve customers in the future (PacifiCorp 2107 IRP, Volume 1, pg. 1). The final resources identified for the 20-year planning timeframe of the IRP included 1,959 megawatts (MW) of new wind resources, 905 MW of repowered wind resources, 1,040 MW of new solar resources, 2,077 MW of incremental energy efficiency resources, and 365 MW of new direct load control capacity (PacifiCorp 2017 IRP, Volume 1, pg. 2).

Two major projects, labeled as Energy Vision 2020, are action items identified in the 2017 IRP action plan. Energy Vision 2020 includes repowering 905 MW of Company owned wind resources,[1] 1,100 MW of new Wyoming wind resources, and a new 140 mile 500 kV transmission line in Wyoming to connect the new wind resources. Both of these projects rely on federal production tax credits (PTCs) to provide economic benefits. The Company's complete action plan is provided in Attachment A to these comments.

STAFF REVIEW

Staff completed a comprehensive review of PacifiCorp's 2017 IRP including a review of the load forecast, natural gas forecasts, existing resource assumptions, and new expansion resource assumptions, as well as a review of the Company's preferred portfolio and action plans. Staff comments are organized into several sections around topical areas that Staff believes are important: 1) IRP Process Requirements; 2) Modeling of Coal Plants; 3) Energy Vision 2020; 4) Demand Side Management; and 5) Natural Gas Forecast.

[1] The capacity for the repowering project was increased to 999.1 MW in the Company's IRP update to match the capacity figures reported in the Repowering case, Case No. PAC-E-17-06.

Through its review of this year's IRP, Staff highlights the following findings:

1. The Company met the IRP minimum requirements as set forth in Commission Order No. 22299.
2. The 2017 IRP preferred portfolio showed a continued transition to renewable energy resources and a reduction in coal resources.
3. The Company should identify least-cost coal plant retirement dates using the endogenous retirement functionality within System Optimizer.
4. Inclusion of benefits outside the planning timeframe can distort comparisons between portfolios.
5. There was limited public input on the preferred portfolio due to the late introduction of Energy Vision 2020 projects into the IRP process.
6. The Company is effectively using demand side management in its resource planning.
7. There is high probability that the Company is underestimating natural gas prices over the 20-year planning period.

IRP Process Requirements

In January 1989, the Commission identified the Integrated Resource Plan as a "Resource Management Report" and required it to be completed on a biennial basis [Order No. 22299]. The Commission further specified the following planning requirements for assessing future resource needs:

1. Examination of load forecast uncertainties;
2. Effects of known or potential changes to existing resources;
3. Consideration of demand and supply side resource options;
4. Contingencies for upgrading, optioning and acquiring resources at optimum times (considering cost, availability, lead time, reliability, risk, etc.) as future events unfold.

Staff believes the *PacifiCorp 2017 Integrated Resource Plan* submitted as part of this filing meets the requirements specified by the Commission.

The Company developed its IRP through a series of planned steps. First, the Company prepared a load-resource balance study that compared forecasted loads to existing resource capacity over a 20-year time horizon. The load-resource balance study highlights deficiencies in capacity that occur over the planning horizon. The Company considered a wide range of factors including natural gas and wholesale power prices, along with regulatory, environmental, and public policy issues. These factors are bundled into a set of assumptions of unique planning cases using input from involved stakeholders. For each of these cases, the Company uses System Optimizer (SO) a capacity expansion optimizer that produces a least cost resource portfolio model based on the assumptions of each case. Each portfolio is characterized by the type, timing, and location for new resources. For each of the portfolios, the Company uses Planning and Risk model (PaR) to perform a stochastic risk sensitivity analysis given a range of forecasted carbon dioxide (CO2) and natural gas prices. The Company then looks to validate the need, timing and benefit for adding new generating resources over the 20-year timeframe of the IRP. Results of these analyses support the Company in determining a least-cost least-risk portfolio, defined as the "preferred portfolio." From the preferred portfolio, the Company established an action plan that is used as a guideline for meeting forecasted load requirements.

The planning steps of the IRP process discussed above satisfy all four requirements established in Order No. 22299. The requirement for examination of load forecast uncertainties was satisfied through PaR modeling that captures the risk of varying loads in the future. The requirement for effects of known or potential changes to existing resources was satisfied during Regional Haze screening, a process that created several different potential alternatives for existing coal plant resources. The requirement for consideration of demand and supply-side resource options was satisfied by the Company allowing both demand and supply side resources to be available for selection during the modeling process. The requirement for contingencies in upgrading, optioning, and acquiring resources at optimal times was satisfied through the use of SO and PaR modeling using multiple cases and portfolios.

IRP Preferred Portfolio

The 2017 IRP preferred portfolio relies more heavily on new renewable resources, short-term firm market purchases identified as front-office transactions (FOTs), and DSM load control resources as compared to the 2015 IRP preferred portfolio. The preferred portfolio includes 2,077 MW of incremental energy efficiency resources, 1,959 MW of new wind resources, 1,313 MW of new natural gas resources, 1,040 MW of new solar resources, 905 MW of repowered wind resources, and 365 MW of new direct load control capacity. During the 20-year planning timeframe, 3,650 MW of existing coal capacity is removed from the preferred portfolio along with 358 MW of existing natural gas capacity (PacifiCorp 2107 IRP Volume 1, pg. 2).

The 2017 IRP preferred portfolio shows a reduction in coal resources and a transition to renewable resources through the Company's Energy Vision 2020 program. Pursuant to the program, 1,100 MW of new Wyoming wind resources and 905 MW of repowered wind resources are projected to be installed before 2021, and are made possible through PTCs. The rest of the renewable resources in the preferred portfolio were selected based on economics without receiving PTCs. A reduction in existing coal resources was a result of the Regional Haze screening step of the IRP process which looked at different potential Regional Haze compliance alternatives. One of the major reasons for reduction in coal resources is a projected early retirement of coal plants to avoid installation of expensive SCR equipment. Overall, the 2017 IRP preferred portfolio provides a mix of resources with more renewables and less coal.

Modeling of Coal Plants

The Company's approach to the IRP limits the Company's capacity expansion model (through System Optimizer) from fully weighing the economics of existing generation resources. For existing resources, the Company fixes the resource operating life prior to starting model analysis. In the case of existing coal plants, the operating life is limited by the length of time the Company assumes it can operate the plants without installing costly environmental controls related to regional haze emissions standards. In some cases, this is assumed to be the remaining operating life of the plant.

This approach assumes, by default, that producing energy from existing coal plants without environmental controls is less costly than potential alternatives. In Staff's view, this assumption cannot be justified given: 1) low capacity factors at some of the Company's coal generating units; 2) the relatively low cost of natural gas; 3) the integration of renewable power into the energy system (including any corresponding incentives); and 4) reductions in energy market prices.

Staff believes that the Company should let the functionality of the optimizer model fully assess economically and "endogenously" when a coal plant should be retired. This approach would provide resource portfolios and coal-plant closure scenarios that are least-cost based on cost and operating inputs assumed in the model. Then if the Company believes that the modeled portfolio should not be recommended, it would need to provide justification for deviating from the model's coal plant closure dates based on criteria other than cost, or other short-comings in the model.

The Company tested endogenous coal plant closure modeling based on stakeholder requests during IRP feedback. Specifically within the analysis of "Regional Haze Case 6," the Company utilized endogenous plant closure modeling functionality in SO. The modeling considered specific alternative outcomes tied to coal units: Hunter 1, Hunter 2, Huntington 1, Huntington 2, Jim Bridger 1, and Jim Bridger 2. Nonetheless, Staff is concerned that the amount of analysis was still too limited and should have been broadened across a larger set of cases and across all coal generation units. In fact, allowing the model to make comparisons and choose between new and all existing resources could help the Company identify other existing non-economic resources.

Staff recognizes the dispatchability benefit of coal plants for maintaining system reliability and the need for resource diversity. However, Staff also recognizes that high fixed operations and maintenance costs tied to large aging coal plants that are underutilized can be costly. Further, by arbitrarily prescribing that certain plants remain operational until a defined date, the Company could limit introduction of new resources that may be more economically competitive in the long run. The wind repowering and the new wind/transmission projects discussed below are two such cases. Both projects have favorable economics because significant PTC benefits offset most of the up-front capital cost penalties when compared to existing resources.

<u>Energy Vision 2020 (EV2020)</u>

EV2020 includes two major wind projects: the repowering of 905 MW of Company owned wind resources, and 1100 MW of new wind resources that require and include a new 140 mile 500 kV transmission line and other transmission-related infrastructure. The EV2020 projects are time-limited economic-based projects that became viable when Congress extended PTC benefits for both new wind projects and repowered wind facilities. However, due to the introduction of these projects as expansion resources late in the IRP process, Staff is concerned: 1) there is a mismatch in planning evaluation timeframes; and 2) there was limited public input.

The wind repowering project takes advantage of PTC benefits to install new longer rotors, new nacelles, and higher capacity generators on 11 Company owned wind sites.[2] The new components will result in a longer life and a 19 percent overall average increase in generation.

The new wind and transmission project includes at least 1,100 MW of new wind turbines that will lower net power costs and provide ten years of PTC benefits. The new transmission aspect of the project is required to interconnect the new wind resources to the rest of the system. The Company states that the transmission lines will help relieve current congestion in the eastern Wyoming area. All of the EV2020 projects must be completed by December 31, 2020, to receive 100 percent of PTC benefits.

Because of the late addition of the EV2020 projects, the IRP process was modified to introduce the projects into the IRP analysis. The Company could have performed its economic analysis of the two projects by redoing all of their model runs and include the projects as potential resources to be selected by SO, thereby following the Company's standard IRP process. Instead, the Company chose to evaluate the projects by comparing the net benefits of resource portfolios with and without the projects. Staff believes the Company's modifications to the IRP process saved the Company time and were appropriate for the circumstances. However, because of the approach used and due to the late changes, it caused some unfortunate consequences to arise as discussed below.

Planning Timeframe Mismatch

Staff believes that when evaluating all resource options in the IRP, only the costs and benefits across a common timeframe should be included. However, the Company included benefits beyond the 20-year IRP timeframe for the repower project. This made the portfolios with repower resources more cost-effective than portfolios without repower resources. The Company states the benefits were included to "account for the significant incremental energy benefits beyond the IRP planning period when the life of repowered wind resources is extended."

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[2] The IRP originally included 11 sites for repowering. There are now 12 sites that are proposed to be repowered based on the Energy Vision 2020 Update and Case No. PAC-E-17-06.

(PacifiCorp 2107 IRP, Volume 1, pg. 1). This biased the portfolios that included repowered resources by increasing net present value benefits by approximately $346 million (Public Meeting 8 slide deck, slide 37, Mar. 2-3, 2017).

Allowing estimated benefits outside of the 20-year planning timeframe creates an unfair comparison between cases because all cases have potential benefits and costs beyond the 20-year planning timeframe which could be included but were not. Staff agrees the repower project does have benefits beyond the planning timeframe, but believes these benefits should be handled differently in a separate analysis, such as the EV2020 update, or by extending the planning timeframe and modeling all portfolios on a common timeframe. The Company used such an approach when it submitted its proposals for both of the EV2020 projects for recovery to the Commission in Case Nos. PAC-E-17-06 and PAC-E-17-07.

Limited Public Input

The time-limited opportunity of PTCs caused the Company to deviate from the standard process. The EV2020 projects were not introduced until the last public meeting in March 2017, approximately one month before the expected filing date. This limited the amount of public participation and introduced uncertainty as to the validity of the results. While Staff is aware that the Company did not have total control of when the projects were introduced into the IRP process due to the time-limited opportunity of the PTC benefits, Staff believes the Company could have done a better job with introducing the projects earlier.

The Company made purchases in December 2016 for new wind-turbine generator equipment for the repower project, but did not introduce the repower project until the March 2017 public meeting. Staff assumes the Company did an analysis of the repower before making the December 2016 purchase of the equipment to evaluate the project. Likewise, Staff sees no reason why the analysis was not introduced into the IRP process before March 2017. Not introducing the project until March reduced transparency and limited public input.

Staff recommends projects similar to Energy Vision 2020 be introduced into the IRP process as soon as possible in future IRPs. This will lead to more transparency and provide more time for public input and feedback.

Demand Side Management (DSM)

PacifiCorp indicates that DSM will continue to play a key role in its resource mix, with new energy efficiency (Class 2) resources meeting 88 percent of the forecasted load growth from 2017 through 2026. In the 2015 IRP, PacifiCorp projected that new energy efficiency resources would meet 86 percent of forecasted load growth. While the percent of load growth covered by DSM has increased slightly in the 2017 IRP, total energy efficiency resources decrease for the preferred portfolio relative to the 2015 IRP. In 2015, the Company estimated that it would acquire 1,160 aMW over the 20-year planning period. This declines 20 percent to 930 aMW in the 2017 IRP. The reduction in planned DSM resources is attributed to reduced loads and reduced costs for wholesale power purchases and renewable resource alternatives.

Direct load control (Class 1) becomes a much more significant component of the preferred portfolio in the 2017 IRP. Additional direct load control is assumed to be implemented in the year 2028, and by the years 2034 to 2036 it accounts for approximately 350 MW of load reduction – an increase of over 600 percent from the less than 50 MW of load reduction in the 2015 IRP. PacifiCorp states that the direct load control implementation is coincident with assumed coal unit retirements, which aligns with the resource need when those units retire.

As it has in past IRPs, PacifiCorp created supply curves for groups of similarly priced DSM resources. These cost-based DSM supply curves were then included in the Company's SO model which simultaneously competed against supply-side resources to meet the Company's projected capacity and energy deficits. Staff continues to believe that this methodology provides robust and equal treatment between demand-side and supply-side resources in the modeling process.

Natural Gas Forecast

Variations in price forecasts for natural gas can significantly affect the cost and risk of the Company's resource portfolio and the selection of a preferred portfolio. Staff believes PacifiCorp's baseline IRP assumptions likely understate future natural gas prices. An IRP analysis based on understated gas costs overvalues gas resources and undervalues non-gas resources, including wind, solar, and coal. Consequently, reliance on these future gas cost assumptions could result in overinvestment of gas resources, underinvestment in non-gas resources, and a non-optimal schedule for resource retirements and additions.

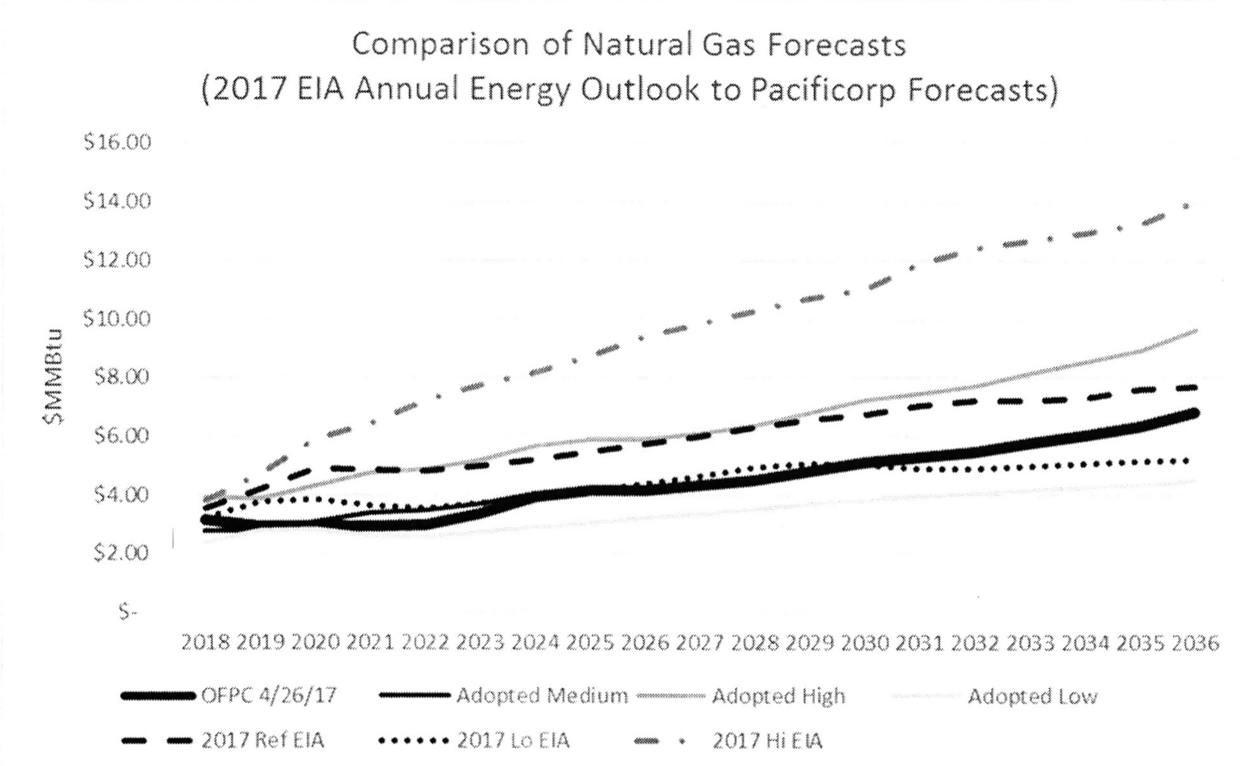
PacifiCorp indicates that forecasted natural gas prices used in the 2017 IRP are significantly lower than the gas prices used in the 2015 IRP. The Company's 2017 IRP contains two natural gas price forecasts. The first, a set of three forecasts, was presented in the Company's original IRP filing and is referred to as the Adopted High, Medium, and Low cases. The second, a single forecast, was presented in the Energy Vision 2020 Update and is referred to as April 2017 Official Forward Price Curve (OFPC).

The Adopted Medium and OFPC forecasts are identical after the first six years. The OFPC uses forward market prices for the first six years of the forecast, followed by a 12-month transition to a forecast from a third-party consultant. The Adopted Low, Medium, and High forecasts are based on a range of third-party forecasts. Staff had concerns about relying exclusively on market forwards for the first six years of the OFPC forecast because the volume of forward purchases declines dramatically over that period. However, the Company confirmed that this does not have a material impact on the Company's preferred portfolio because resource acquisitions occur after the OFPC forecast has transitioned to align with the Company's Adopted Medium case.

According to PacifiCorp, its Adopted Low forecast is based on "surging growth in price-inelastic associated gas, technology improvements, stagnant liquefied-natural-gas exports, and an ever-expanding resource base." (Energy Vision 2020 Update, pg. 8) PacifiCorp states that its Adopted Medium case results when "medium-natural-gas prices are paired with medium or low CO2 price assumptions [and] is based on a base-case forecast from another independent third party that is reasonably aligned with other base-case forecasts." (Energy Vision 2020 Update, pg. 8) PacifiCorp states that the Adopted High is based on a high-price scenario from the same forecaster. The high-price scenario occurs in an environment where natural gas developers are risk averse and become reluctant to commit capital for drilling investments before demand for the commodity materializes. The Company states that this leads to a scenario where demand exceeds supply and creates an exaggerated boom-bust cycle. The Company smoothed the boom-bust cycle in the third party's high-price scenario because the specific timing of these cycles are extremely difficult to project with reasonable accuracy.

Staff compared the Company's gas price forecasts to recent EIA forecasts. The EIA prepares a low, high, and a reference case natural gas forecast for the twenty-year forecast period.

The low-priced forecast, referred to as the "High Oil and Gas Resource Technology" case, aligns closely with current market forward prices extended over 20 years.



Staff is concerned that the Company's OFPC gas price forecast remains excessively low through the entire planning period. The OFPC is less than EIA's low-price forecast for a total of 11 years out of the 19-year planning period. The OFPC is less than EIA's reference forecast for every year of the 19-year period. Staff believes that a forecast based on forward market prices is unreasonably low, and PacifiCorp's forecast is lower than that in over half of the years in the 20-year planning period.

Staff is also concerned about PacifiCorp's comparatively low natural gas price assumption. Staff believes planning to an excessively low gas price forecast is inappropriate because of the disproportionate upside price risk. The Company's 2015 IRP filing cautioned that long-term natural gas price volatility may pose a long-term risk. Nonetheless, the Company did not address that concern in this IRP. Staff encourages the Company to carefully consider risk mitigation in future resource planning and operating action plans because a substantial portion of its future generating resources depends on natural gas.

STAFF RECOMMENDATIONS

The Company's 2017 IRP satisfies all the requirements in Order No. 22299. As previously noted, acknowledgement of the 2017 IRP should not be interpreted as an endorsement of any particular element of the plan, nor does it constitute approval of any resource acquisition contained in the plan.

Staff recommends the Commission acknowledge PacifiCorp's 2017 IRP filing. In addition, Staff recommends the following:

- The Commission should direct the Company to identify least-cost coal plant retirement dates using endogenous System Optimizer functionality.
- The Commission should recommend the Company only include cost and benefits from the same planning timeframe when comparing portfolios in future IRP planning to reduce distortion between portfolios.
- The Commission should recommend the Company provide additional justification for the use of historically low gas costs in its baseline or "medium" forecast in its 2019 IRP.

Respectfully submitted this 12th day of January 2018.

Brandon Karpen
Deputy Attorney General

Technical Staff: Michael Eldred
Bentley Erdwurm
Richard Keller
Mike Louis

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The 2017 IRP Action Plan

The 2017 IRP Action Plan identifies specific actions the Company will take over the next two to four years. Action items are based on the type and timing of resources in the preferred portfolio, findings from analysis completed over the course of portfolio modeling, and feedback received by stakeholders in the 2017 IRP process. Table 9.1 details specific 2017 IRP action items by category.

Table 9.1 – 2017 IRP Action Plan

Action Item	1. Renewable Resource Actions
1a	**Wind Repowering** • PacifiCorp will implement the wind repowering project, taking advantage of safe-harbor wind-turbine-generator equipment purchase agreements executed in December 2016. – Continue to refine and update the economic analysis of plant-specific wind repowering opportunities that maximize customer benefits before issuing the notice to proceed. – By September 2017, complete technical and economic analysis of other potential repowering opportunities at PacifiCorp wind plants not studied in the 2017 IRP (i.e., Foote Creek I and Goodnoe Hills). – Pursue regulatory review and approval as necessary. – By May 2018, issue the engineering, procurement, and construction (EPC) notice to proceed to begin implementing the wind repowering for specific projects consistent with updated financial analysis. – By December 31, 2020, complete installation of wind repowering equipment on all identified projects.
1b	**Wind Request for Proposals** • PacifiCorp will issue a wind resource request for proposals (RFP) for at least 1,100 MW of Wyoming wind resources that will qualify for federal wind production tax credits and achieve commercial operation by December 31, 2020. – April 2017, notify the Utah Public Service Commission of intent to issue the Wyoming wind resource RFP. – May-June, 2017, file a draft Wyoming wind RFP with the Utah Public Service Commission and the Washington Utilities and Transportation Commission. – May-June, 2017, file to open a Wyoming wind RFP docket with the Public Utility Commission of Oregon and initiate the Independent Evaluator RFP. – June-July, 2017, file a draft Wyoming wind RFP with the Public Utility Commission of Oregon and file a Public Convenience and Necessity (CPCN) application with the Public Service Commission of Wyoming. – By August 2017, obtain approval of the Wyoming wind resource RFP from the Public Utility Commission of Oregon, the Utah Public Service Commission, and the Washington Utilities and Transportation Commission. – By August 2017, issue the Wyoming wind RFP to the market. – By October 2017, Wyoming wind RFP bids are due.

Attachment A
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Staff Comments
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<table>
<tr><td></td><td>– November-December, 2017, complete initial shortlist bid evaluation.
– By January 2018, complete final shortlist bid evaluation, seek acknowledgement of the final shortlist from the Public Utility Commission of Oregon, and seek approval of winning bids from the Utah Public Service Commission.
– By March 2018, receive CPCN approval from the Wyoming Public Service Commission.
– Complete construction of new wind projects by December 31, 2020.</td></tr>
<tr><td>1c</td><td><u>Renewable Portfolio Standard Compliance</u>
• PacifiCorp will issue unbundled REC request for proposals (RFP) to meet its state RPS compliance requirements.
– As needed, issue RFPs seeking then-current-year or forward-year vintage unbundled RECs that will qualify in meeting California renewable portfolio standard targets through 2020.
– As needed, issue RFPs seeking low-cost then-current-year, forward-year, or older vintage unbundled RECs that will qualify in meeting Oregon renewable portfolio standard targets, deferring the currently projected 2035 initial shortfall after accounting for preferred portfolio renewable resources.</td></tr>
<tr><td>1d</td><td><u>Renewable Energy Credit Optimization</u>
• Before filing the 2017 IRP Update, evaluate potential opportunities to re-allocate RECs from Utah, Wyoming, and Idaho to Oregon, Washington, or California.
• Maximize the sale of RECs that are not required to meet state RPS compliance obligations.</td></tr>
<tr><td>Action Item</td><td>2. Transmission Actions</td></tr>
<tr><td>2a</td><td><u>Aeolus to Bridger/Anticline</u>
• By December 31, 2020, PacifiCorp will build the 140-mile, 500 kV transmission line running from the Aeolus substation near Medicine Bow, Wyoming, to the Jim Bridger power plant (a sub-segment of the Energy Gateway West transmission project). This includes pursuing regulatory review and approval as necessary.
– June-July 2017, file a CPCN application with the Public Service Commission of Wyoming.
– By March 2018, receive conditional CPCN approval from the Wyoming Public Service Commission pending acquisition of rights of way.
– By December 2018, obtain Wyoming Industrial Siting permit and issue EPC limited notice to proceed.
– By April 2019, issue EPC final notice to proceed.
– Complete construction of the transmission line by December 31, 2020.</td></tr>
<tr><td>2b</td><td><u>Energy Gateway Permitting</u>
• Continue permitting for the Energy Gateway transmission plan, with the following near-term targets:
– For Segments D1, D3, E, and F, continue funding of the required federal agency permitting environmental</td></tr>
</table>

	consultant actions required as part of the federal permits. – For Segments D, E, and F, continue to support the projects by providing information and participating in public outreach. – For Segment H (Boardman to Hemingway), continue to support the project under the conditions of the Boardman to Hemingway Transmission Project Joint Permit Funding Agreement.
3c	**<u>Wallula to McNary 230 kV Transmission Line</u>** • Complete Wallula to McNary project construction per plan with a 2018 expected in-service date. Continue to support the permitting and construction process for Walla Walla to McNary.
4d	**<u>Planning Studies</u>** • Complete planning studies that include proposed coal unit retirement assumptions from the 2017 IRP preferred portfolio and two other scenarios. • Summarize studies in the 2017 IRP Update.
Action Item	**3. Firm Market Purchase Actions**
3a	**<u>Front Office Transactions</u>** • Acquire economic short-term firm market purchases for on-peak summer deliveries from 2017 through 2019 consistent with the Risk Management Policy and Commercial and Trading Front Office Procedures and Practices. These short-term firm market purchases will be acquired through multiple means: – Balance of month and day-ahead brokered transactions in which the broker provides the service of providing a competitive price. – Balance of month, day-ahead, and hour-ahead transactions executed through an exchange, such as Intercontinental Exchange (ICE), in which the exchange provides the service of providing a competitive price. – Prompt month-forward, balance-of-month, day-ahead, and hour-ahead non-brokered transactions.

Action Item	4. Demand Side Management (DSM) Actions
4a	**Class 2 DSM** • Acquire cost-effective Class 2 DSM (energy efficiency) resources targeting annual system energy and capacity selections from the preferred portfolio as summarized in the following table. PacifiCorp's state-specific processes for planning for DSM acquisitions is provided in Appendix D in Volume II of the 2017 IRP.

Year	Annual Incremental Energy (GWh)	Annual Incremental Capacity* (MW)
2017	646	154
2018	559	128
2019	571	131
2020	527	122

*Class 2 DSM capacity figures reflect projected maximum annual hourly energy savings, which is similar to a nameplate rating for a supply-side resource.

Action Item	5. Coal Resource Actions
5a	**Hunter Units 1 and 2** • The EPA's final Regional Haze Federal Implementation Plan (FIP) for Utah requires the installation of selective catalytic reduction (SCR) on Hunter Units 1 and 2 in 2021 and is currently under appeal by the state of Utah and other parties in the U.S. Tenth Circuit Court of Appeals. • As influenced by the litigation schedule and outcomes, PacifiCorp will update its economic analysis of alternative Regional Haze compliance strategies for the units, as applicable, and will provide the associated analysis in a future IRP or IRP Update.
5b	**Huntington Units 1 and 2** • The EPA's final Regional Haze FIP for Utah requires the installation of SCR on Huntington Units 1 and 2 in 2021 and is currently under appeal by the state of Utah and other parties in the U.S. Tenth Circuit Court of Appeals. • As influenced by the litigation schedule and outcomes, PacifiCorp will update its economic analysis of alternative Regional Haze compliance strategies for the units, as applicable, and will provide the associated analysis in a future IRP or IRP Update.
5c	**Dave Johnston Unit 3** • The EPA's final Regional Haze FIP requires the installation of SCR at Dave Johnston Unit 3 in 2019 or a commitment to shut down Dave Johnston Unit 3 by the end of 2027. PacifiCorp's commitment to the latter must be included in a permit before the 2019 compliance deadline. • PacifiCorp will update its analysis of the commitment to shut down Dave Johnston Unit 3 by the end of 2027 as part

	of its 2017 IRP Update.
5d	**<u>Jim Bridger Units 1 and 2</u>** • The Wyoming Regional Haze State Implementation Plan (SIP) and EPA's final Regional Haze FIP for Wyoming require the installation of SCR on Jim Bridger Units 1 and 2 in 2021 and 2022. • PacifiCorp will update its economic analysis of alternative Regional Haze compliance strategies for the units and will provide the associated analysis in its 2017 IRP Update.
5e	**<u>Naughton Unit 3</u>** • PacifiCorp will update its economic analysis of natural gas conversion in its 2017 IRP Update.
5f	**<u>Wyodak</u>** • Continue to pursue PacifiCorp's appeal of the portion of EPA's final Regional Haze FIP that requires the installation of SCR at Wyodak, recognizing that the compliance deadline for SCR under the FIP is currently stayed by the court. • If following appeal, EPA's final FIP as it pertains to installation of SCR at Wyodak is upheld (with a modified schedule that reflects the final stay duration), PacifiCorp will update its evaluation of alternative compliance strategies that will meet Regional Haze compliance obligations and provide the associated analysis in a future IRP or IRP Update.
5g	**<u>Cholla Unit 4</u>** • EPA has approved the Arizona SIP incorporating an alternative Regional Haze compliance approach that avoids installation of SCR with a commitment to cease operating Cholla Unit 4 as a coal-fueled resource by the end of April 2025, with the option of natural gas conversion thereafter. • PacifiCorp will update its evaluation of Cholla Unit 4 alternatives that meet its Regional Haze compliance obligations and provide the associated analysis in a future IRP or IRP Update.
5h	**<u>Craig Unit 1</u>** • EPA is yet to approve the Colorado SIP incorporating an alternative Regional Haze compliance approach that avoids installation of SCR with a commitment to cease operating Craig Unit 1 as a coal-fueled resource by the end of 2025, with an option for natural gas conversion. • PacifiCorp will update its evaluation of Craig Unit 1 alternatives that meet its Regional Haze compliance obligations and provide the associated analysis in a future IRP or IRP Update, as required.

Progress on Previous Action Plan Items

This section describes progress that has been made on previous active action plan items documented in the 2015 Integrated Resource Plan and 2015 Integrated Resource Plan Update reports filed with the state commissions on March 31, 2015 and March 31, 2016, respectively. Many of these action items have been superseded in some form by items identified in the current IRP action plan. The status for all action items is summarized in Table 9.2.

Table 9.2 – 2015 IRP Action Plan Status Update

Action Item	Activity	Status
1a	**Renewable Portfolio Standard Compliance** • The Company will pursue unbundled REC request for proposals (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 targets through 2017. – Issue at least annually, RFPs seeking then current-year or forward-year vintage unbundled RECs that will qualify in meeting California renewable portfolio standard targets through 2017. – With a projected bank balance extending out through 2027, defer issuance of RFPs seeking unbundled RECs that will qualify in meeting Oregon renewable portfolio standard targets until states begin to develop implementation plans under EPA's draft 111(d) rule, providing clarity on whether an unbundled REC strategy is the least cost compliance alternative for Oregon customers.	Consistent with the action plan in its 2015 IRP Update, which revised Action 1a, PacifiCorp issued a renewable resource and REC RFP in 2016. As a result of this RFP process, PacifiCorp executed REC purchase agreements in 2016 to acquire RECs eligible for the Washington, Oregon, and California RPS programs. For the California renewable portfolio standard requirements, the Company issued a REC RFP on March 13, 2017 with bids due April 3, 2017. Any offers that meet the Company's needs and specific pricing criteria will be selected and then submitted to the California Public Utilities Commission for review.
1b	**Renewable Energy Credit Optimization** • On a quarterly basis, and through calendar year 2016, issue reverse RFPs to sell 2016 vintage or older RECs that are not required to meet state RPS compliance obligations.	The Company issued a reverse RFP in December 2016 to sell RECs. The Company will continue to issue reverse RFPs in 2017 to seek REC sale opportunities for RECs allocated to states that do not have a state RPS

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Action Item	Activity	Status
		compliance need.
1c	**Oregon Solar Capacity Standard** • Conclude negotiations with shortlisted bids from the 2013 Request for Proposals (RFP), seeking up to 7 MW of competitively priced capacity from qualifying solar systems that will be used to satisfy PacifiCorp's obligation under Oregon's 2020 solar capacity standard.	The Oregon Solar Capacity Standard was eliminated with the passage of Oregon Senate Bill 1547-B. This action item was deleted from the updated action plan presented in the Executive Summary of the 2015 IRP Update.
2a	**Front Office Transactions** • Acquire economic short-term firm market purchases for on-peak summer deliveries from 2015 through 2017 consistent with the Risk Management Policy and Commercial and Trading Front Office Procedures and Practices. These short-term firm market purchases will be acquired through multiple means: – Balance of month and day-ahead brokered transactions in which the broker provides the service of providing a competitive price. – Balance of month, day-ahead, and hour-ahead transactions executed through an exchange, such as Intercontinental Exchange (ICE), in which the exchange provides the service of providing a competitive price. – Prompt month forward, balance of month, day-ahead, and hour-ahead non-brokered transactions.	For 2016, PacifiCorp acquired approximately 1,025 MW to 3,360 MW of short-term firm market purchases explicitly for delivery during the on-peak summer period. For 2017, as of mid-March 2017, the Company has acquired approximately 450 MW to 700 MW of short-term firm market purchases explicitly for delivery during the on-peak summer period. For 2018, as of mid-March 2017, the Company has not procured any short-term firm market purchases explicitly for delivery during the on-peak summer period.
3a	**Class 1 DSM** • Pursue a west-side irrigation load control pilot beginning 2016 to test the feasibility of program design. Additional information on the proposed pilot is provided in the implementation plan section of Appendix D in Volume II of the 2015 IRP.	On March 4, 2016, PacifiCorp filed with the Oregon Public Utilities Commission to implement an Irrigation Load Control pilot program. The pilot program was approved on May 4, 2016, and called its first event on August 19, 2016.

<table>
<tr><th>Action Item</th><th>Activity</th><th>Status</th></tr>
<tr><td>3b</td><td><u>Class 2 DSM</u>
• Acquire cost effective Class 2 DSM (energy efficiency) resources targeting annual system energy and capacity selections from the preferred portfolio as summarized in the following table. PacifiCorp's implementation plan to acquire cost effective energy efficiency resources is provided in Appendix D in Volume II of the 2015 IRP.
<table><tr><th>Year</th><th>Annual Incremental Energy (GWh)</th><th>Annual Incremental Capacity* (MW)</th></tr><tr><td>2015</td><td>551</td><td>133</td></tr><tr><td>2016</td><td>584</td><td>139</td></tr><tr><td>2017</td><td>616</td><td>146</td></tr><tr><td>2018</td><td>634</td><td>146</td></tr></table>*Class 2 DSM capacity figures reflect projected maximum annual hourly energy savings, which is similar to a nameplate rating for a supply side resource.</td><td>Initial review indicates that in 2015, PacifiCorp acquired 589 GWh of Class 2 DSM, 7 percent above the Action Plan target. Preliminary results for 2016 indicate PacifiCorp acquired 615 GWh of Class 2 DSM, 5 percent above the 2015 IRP target.</td></tr>
<tr><td>4a</td><td><u>Naughton Unit 3</u>
• Issue an RFP to procure gas transportation and resume engineering, procurement, and construction (EPC) contract procurement activities for the Naughton Unit 3 natural gas conversion in the first quarter of 2016.
• PacifiCorp may update its economic analysis of natural gas conversion in conjunction with the RFP processes to align gas transportation and EPC cost assumptions with market bids.</td><td>PacifiCorp updated its economic analysis for the 2017 IRP that reflects higher economic benefits to customers for PacifiCorp to continue to operate Naughton Unit 3 through year-end 2018 as a coal-fueled resource with a subsequent unit retirement. The Company will continue to analyze the economics surrounding Naughton Unit 3 retirement and/or natural gas conversion to achieve the most economic outcome for customers while complying with permits and compliance plans, as described in the 2017 IRP Action Items above.</td></tr>
<tr><td>4b</td><td><u>Dave Johnston Unit 3</u>
• The portion of EPA's final Regional Haze Federal Implementation Plan (FIP) requiring the installation of selective catalytic reduction (SCR) at Dave Johnston Unit 3, or a</td><td>The Company's commitment to shutting down Dave Johnson by the end of 2027 must be promulgated via permit prior to the 2019 compliance deadline. PacifiCorp will update its economic analysis of the commitment as</td></tr>
</table>

Action Item	Activity	Status
	commitment to shut down Dave Johnston Unit 3 by the end of 2027, is currently under appeal by the State of Wyoming in the U.S. Tenth Circuit Court of Appeals. • If following appeal, EPA's final FIP as it pertains to Dave Johnston Unit 3 is upheld, PacifiCorp will commit to shutting down Dave Johnston Unit 3 by the end of 2027. • If following appeal, EPA's final FIP as it pertains to Dave Johnston Unit 3 is or will be modified, PacifiCorp will evaluate alternative compliance strategies that will meet any new requirements, as applicable, and provide the associated analysis in a future IRP or IRP Update.	part of its 2017 IRP Update.
4c	**<u>Wyodak</u>** • Continue to pursue the Company's appeal of the portion of EPA's final Regional Haze FIP that requires the installation of SCR at Wyodak, recognizing that the compliance deadline for SCR under the FIP is currently stayed by the court. • If following appeal, EPA's final FIP as it pertains to installation of SCR at Wyodak is upheld (with a modified schedule that reflects the final stay duration), PacifiCorp will update its evaluation of alternative compliance strategies that will meet Regional Haze compliance obligations and provide the associated analysis in a future IRP or IRP Update.	PacifiCorp is still awaiting results of appeal of EPA's final regional haze FIP.
4d	**<u>Cholla Unit 4</u>** • Continue permitting efforts in support of an alternative Regional Haze compliance approach that avoids installation of SCR with a commitment to cease operating Cholla Unit 4 as a coal-fueled resource by the end of April 2025.	On March 16, 2017, Arizona Regional Haze State Implementation Plan was approved incorporating the alternative compliance approach described in this action item. The EPA's approval will be published in the Federal Register in the coming weeks and become effective thirty days after publication.
5a	**<u>Energy Gateway Permitting</u>** • Continue permitting for the Energy Gateway transmission plan, with near term targets as follows:	PacifiCorp continues to fund the required federal agency permitting environmental consultant as actions to achieve final federal permits. – A final Environmental Impact Statement (EIS) for the

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Action Item	Activity	Status
	– For Segments D, E, and F, continue funding of the required federal agency permitting environmental consultant as actions to achieve final federal permits. – For Segments D, E, and F, continue to support the federal permitting process by providing information and participating in public outreach. – For Segment H (Boardman to Hemingway), continue to support the project under the conditions of the Boardman to Hemingway Transmission Project Joint Permit Funding Agreement.	Gateway South project, Segment F, was published May 2016 and the final Record of Decision was issued in December 2016. – A draft supplemental EIS for the deferred portions of Segment E for the Gateway West project was released in March 2016 and the final supplemental EIS was published in October 2016. A final Record of Decision was signed in January 2017. – The Record of Decisions and right-of-way grants contain many conditions and stipulations that must be met and accepted before the project can move to construction. PacifiCorp will continue the work necessary to meet these requirements and will continue to meet regularly with the Bureau of Land Management to review progress. – PacifiCorp continues to support the Boardman to Hemingway project consistent with the project Joint Permit Funding Agreement. As a participant in the project PacifiCorp continues to collaborate with Idaho Power, the lead organization in the permitting process, by providing guidance of activities and plans associated with the permitting phase of the project.
5b	**Wallula to McNary 230 kilovolt Transmission Line** • Complete Wallula to McNary project construction per plan with 2017 expected in-service date. Continue to support the permitting process for Walla Walla to McNary.	Updates on the construction are as follows: – Received the Umatilla County Conditional Use Permit December 2015. – Received right-of-way agreement and grant from Bureau of Indian Affairs and Confederated Tribes of the Umatilla Indian Reservation in February 2017. – Continue permitting efforts with the Bureau of Land Management and the U.S. Fish and Wildlife agencies. – Bonneville Power Administration continues work on the studies and the development of the plan of service

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Action Item	Activity	Status
		required to interconnect at the McNary substation. – Right-of-way appraisal work is scheduled for first quarter 2016. – Note that all permitting documentation as required by each agency has been submitted and that various agencies are working through their required processes.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 12TH DAY OF JANUARY 2018, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. PAC-E-17-03, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

TED WESTON
ROCKY MOUNTAIN POWER
1407 WEST NORTH TEMPLE STE 330
SALT LAKE CITY UT 84116
E-MAIL: ted.weston@pacificorp.com

YVONNE R HOGLE
ASSITANT GENERAL COUNSEL
ROCKY MOUNTAIN POWER
1407 WN TEMPLE STE 320
SALT LAKE CITY UT 84116
E-MAIL: yovonne.hogle@pacificorp.com

DATA REQUEST RESPONSE CENTER
E-MAIL ONLY:
datarequest@pacificorp.com

Jo Nelson
SECRETARY