ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

1407 W North Temple, Suite 310
Salt Lake City, Utah 84114

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VIA ELECTRONIC FILING

Utah Public Service Commission
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City, UT 84114

Attention: Gary Widerburg
Commission Secretary

RE: **Docket No. 17-035-16 PacifiCorp's 2017 Integrated Resource Plan Reply Comments**

Pursuant to the Reply Comment Deadline, issued April 25, 2017, in the above referenced matter PacifiCorp (dba Rocky Mountain Power) submits for electronic filing its reply comments.

Rocky Mountain Power respectfully requests that all formal correspondence and requests for additional information regarding this filing be addressed to the following:

By E-mail (preferred): datarequest@pacificorp.com
irp@pacificorp.com
Jana.saba@pacificorp.com
yvonne.hogle@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, OR 97232

Informal inquiries may be directed to Jana Saba at (801) 220-2823.

Sincerely,

Joelle Steward

Joelle R. Steward
Vice President, Regulation

Enclosures

cc: Matt Pacenza, HEAL Utah
Sarah Propst, Interwest Energy Alliance
Kelly Francone, Utah Association of Energy Users
Mitalee Gupta, Utah Clean Energy
John Neilsen, Western Resource Advocates

Response to the Utah Party Comments on PacifiCorp's 2017 Integrated Resource Plan

Docket No. 17-035-16

1. INTRODUCTION

PacifiCorp (or the Company) filed its 2017 Integrated Resource Plan (IRP) with the Public Service Commission of Utah (Commission) on April 4, 2017. The Company's IRP was prepared in accordance with the Commission's IRP Standards and Guidelines in Docket No. 90-2035-01 and 2015 IRP acknowledgment requirements from the Report and Order in Docket No. 15-035-04. To be acknowledged, the plan must be deemed reasonable at the time it is presented. As part of its review, the Commission determines whether the IRP adequately adheres to the IRP Standards and Guidelines established under Docket No. 90-2035-01, and takes into consideration the "merit and applicability" of public comments.[1]

Consistent with the IRP acknowledgment schedule adopted by the Commission in this proceeding, the Division of Public Utilities (DPU)[2], Interwest Energy Alliance (IEA)[3], Office of Consumer Services (OCS)[4], Renewable Energy Coalition (REC)[5], Sierra Club (SC)[6], Utah Clean Energy (UCE)[7], Utah Association of Energy Users (UAE), and jointly, UCE and Southwest Energy Efficiency Project (SWEEP)[8], filed comments and recommendations by October 24, 2017.

In these reply comments, PacifiCorp:

- Summarizes the Commission's Standards and Guidelines for IRP acknowledgement, and explains how the 2017 IRP and the associated action plan meets these Standards and Guidelines.
- Recognizes the importance and need for parties' and Commission's on-going review of the Energy Vision 2020 projects, and provides an overview of these projects and explains its efforts to complete the necessary analysis and share it with IRP stakeholders in real-time during the public input process.
- Explains the Energy Vision 2020 projects are part of the Company's least-cost, least-risk plan to meet system load, and consistent with long-standing treatment of other resource alternatives.

[1] Public Service Commission of Utah, *Report and Order on Standards and Guidelines* (Docket No. 90-2035-01), p. 33.
[2] Division of Public Utilities, Corrected Comments on PacifiCorp's 2017 IRP, dated October 24, 2017 (Initial Comments of DPU).
[3] Initial Comments of Interwest Energy Alliance, dated October 24, 2017 (Initial Comments of IEA).
[4] Office of Consumer Services, Initial Comments, dated October 24, 2017 (Initial Comments of OCS).
[5] Comments of Renewable Energy Coalition, dated October 24, 2017 (Initial Comments of REC).
[6] Sierra Club Comments (Confidential), dated October 24, 2017 (Initial Comments of Sierra Club).
[7] Initial Comments of Utah Clean Energy, dated October 24, 2017 (Initial Comments of UCE).
[8] Initial Comments of Utah Clean Energy and Southwest Energy Efficiency Project, dated October 24, 2017 (Joint Comments of UCE and SWEEP).

- Responds to claims that an early coal-plant retirement might provide a lower cost alternative to building new transmission by explaining that it is not physically possible to interconnect 1,100 megawatts of new wind resources in the area of the proposed new Aeolus substation (Medicine Bow, Wyoming) by retiring the Dave Johnston plant, which provides critical voltage support to the existing 230 kilovolt transmission system from the plant's location near the existing Windstar substation (Glenrock, Wyoming). PacifiCorp also outlines the significant benefits associated with the new transmission line that are not factored into parties' comments. Specifically, the new transmission line will: (1) relieve congestion and increase transmission capacity across Wyoming, allowing interconnection of new generation resources and greater flexibility in managing existing resources; (2) provide crucial voltage support to the transmission system; (3) improve system reliability; and (4) reduce energy and capacity losses.
- Addresses parties' comments on coal resource analysis, demand-side management (DSM), battery and energy storage, distributed generation (private generation), and other modeling considerations.

2. OVERVIEW OF THE 2017 IRP

A. The 2017 IRP Satisfies the Commission's Standards and Guidelines for Acknowledgement

The Commission's standard for acknowledgement of an IRP under the Standards and Guidelines means it "substantially complies with the regulatory requirements of the planning process, but conveys no sense of regulatory approval of any specific PacifiCorp acquisition decision or strategy for meeting obligations; PacifiCorp management retains responsibility for its resource acquisition decisions."[9] "The IRP is an open, public process through which all relevant supply-side and demand-side resources are investigated in the search for the optimal set of resources to meet current and future electric service needs at the lowest total cost to the utility and its customers, in a manner consistent with the long-term public interest, given the expected combination of costs, risks and uncertainty."[10]

The Commission's IRP Standards and Guidelines require the IRP include:

- A range of estimates or forecasts of load growth, including both capacity (kW) and energy (kWh) requirements;
- An evaluation of all resources on a consistent and comparable basis;
- An analysis of the role of competitive bidding for demand-side and supply-side resource applications;
- A 20-year planning horizon;
- An action plan outlining the specific resource decisions intended to implement the IRP in a manner consistent with the strategic business plan, and span a four-year horizon describing specific actions to be taken in the first two years and outlining anticipated actions in the last two years;

[9] *In the Matter of Rocky Mountain Power's 2015 Integrated Resource Plan,* Docket No. 15-035-04, Report and order, at 6 (January 8, 2016).
[10] *Id.* (quoting the Standards and Guidelines, ¶ 1, p. 39).

- A plan of different resource acquisition paths for different economic circumstances with a decision mechanism to select among and modify paths as the future unfolds;
- An evaluation of the cost-effectiveness of the resource options from the utility's perspective and different customer classes;
- An evaluation of the financial, competitive, reliability, and operational risks associated with various resource options and how the action plan addresses these risks in the context of both the business plan and the 20-year IRP;
- Considerations permitting flexibility in the planning process so the Company can take advantage of opportunities and can prevent the premature foreclosure of options;
- An analysis of tradeoffs; for example, between such conditions of service as reliability and dispatchability and the acquisition of lowest cost resources.
- A range, rather than attempts at precise quantification of estimated external costs that may be intangible to show how explicit consideration of them might affect selection of resource options; and
- A narrative describing how current rate design is consistent with the Company's IRP goals and how changes in rate design might facilitate IRP objectives[11]

PacifiCorp's 2017 IRP and action plan complies with the Commission's Standards and Guidelines for resource planning and ensures PacifiCorp will provide adequate and reliable electricity supply at a reasonable cost. The economic benefits of the near-term, time-limited Energy Vision 2020 projects included in the 2017 IRP preferred portfolio are bolstered by the extension of federal wind production tax credits (PTCs). These heavily discounted resources will be used to partially meet both near-term and long-term resource needs, are lower cost than near-term and long-term resource alternatives, and will provide significant savings to customers. As supported by extensive cost and risk analysis, Energy Vision 2020 projects are a critical element of PacifiCorp's least-cost, least-risk plan and are in the long-run public interest.

The selection of the preferred portfolio was supported by more than 200 Planning and Risk (PaR) studies. Each PaR study includes 50 iterations of system performance, which equates to over 10,000 simulations of potential 20-year system dispatch outcomes.[12] The preferred portfolio was selected after evaluating 39 different cases.[13] The portfolios were developed from 88 different supply-side resource options, including thermal generation resources, a broad spectrum of renewables, including wind, solar, and geothermal resources; and several different types of storage resources. PacifiCorp also analyzed its ability to meet system load with firm market transactions, and included robust transmission analysis when producing and evaluating resource portfolios that can reliably and cost-effectively meet customer demand with manageable risk.

PacifiCorp retained a reputable third-party to assess demand-side resource potential over the 2017 to 2036 time frame, which served as the basis for updated DSM resource cost-and-performance inputs. DSM resources continue to play a key role in PacifiCorp's resource mix. Over the first 10

[11] Public Service Commission of Utah, *Report and Order on Standards and Guidelines* (Docket No. 90-2035-01), pp. 39-42.

[12] 2017 IRP, Vol. I, p. 179 (April 4, 2017).
[13] *Id.*, at 203.

years of the planning horizon, accumulated acquisition of new energy efficiency resources meets 88 percent of forecasted load growth from 2017 through 2026 (up from 86 percent in the 2015 IRP).

Although the 2017 IRP uses a 20-year planning horizon, the action plan identifies the specific resource actions PacifiCorp intends to undertake in the next two years and its anticipated actions in the last two years of the four-year action plan horizon.[14] The key resource actions in the 2017 IRP action plan include the following items that are the cornerstones of the Company's proposed Energy Vision 2020 projects:

- **Action Item 1a**: PacifiCorp's plan to upgrade, or "repower," existing wind resources because it provides net benefits to customers by increasing energy production, reducing operating costs, and requalifying PacifiCorp's existing wind resources for PTCs, which expire 10 years after a facility's original commercial operation date. To achieve the full PTC benefits, PacifiCorp must complete the wind repowering project by the end of 2020.

- **Action Items 1c and 2a**: The acquisition of at least 1,100 MW of new Wyoming wind resources that will capture a time-limited resource opportunity arising from the expiration of PTCs. The proposed wind resources will be acquired in conjunction with a new 140-mile, 500 kV transmission line and associated infrastructure running from the new Aeolus substation near Medicine Bow, Wyoming, to a new annex substation, Bridger/Anticline, which will be located near the existing Jim Bridger substation (Aeolus-to-Bridger/Anticline line). The transmission resource is necessary to relieve existing congestion and will enable interconnection of the proposed wind resources into PacifiCorp's transmission system. The proposed wind resources net of PTC benefits, when combined with the transmission resource, are expected to meet near- and long-term resource needs and provide economic benefits for PacifiCorp's customers, if both resources are operational by the end of 2020.

Upon being placed in service, these resources will be used to meet system load requirements and will continue to meet system load requirements through their respective lives. Completion of these projects by the end of 2020 will ensure the repowered and new wind resources will qualify for the full value of PTCs and will displace higher-cost market transactions in the near-term and defer the need for other, higher-cost resource alternatives in the long-term. PacifiCorp's modeling indicates these resources represent the least-cost, least-risk approach to serving customers as part of the 2017 IRP preferred portfolio.

[14] Standards and Guidelines, 4.e., p. 41.

A. The Energy Vision 2020 Projects in the Preferred Portfolio Provide Substantial Customer Benefits and Mitigate Future Regulatory Risk

1. Overview of wind repowering.

Recent advancements in wind generation technology, including innovations in wind turbine design and control systems, allow modern wind turbines to generate greater energy from available wind resources. To take advantage of these recent technologies, the 2017 IRP action plan includes repowering most of PacifiCorp's Wyoming wind fleet (Glenrock I, Glenrock III, Rolling Hills, Seven Mile Hill I, Seven Mile Hill II, High Plains, McFadden Ridge, and Dunlap); the Marengo I and Marengo II facilities in Washington; and the Leaning Juniper facility in Oregon. These facilities currently represent a total of 905 MW. Consistent with its 2017 IRP action plan, PacifiCorp has since updated its economic analysis and expanded the scope of the wind repowering project to include the 94 MW Goodnoe Hills facility located in Washington.[15] Also consistent with the action plan, PacifiCorp will continue to evaluate repowering the Foote Creek project.

Wind repowering involves the installation of new rotors with longer blades and new nacelles with higher-capacity generators. Longer blades increase the wind-swept area of the wind turbine and allow it to produce more energy at lower wind speeds. The nacelle is the housing that sits atop the tower and contains the gear box, low- and high-speed shafts, generator, controller, and brake. The new nacelles will include sophisticated control systems and more robust mechanical and generator components necessary to handle the greater loads that come with longer blades. Together, the new rotors and nacelles are estimated to increase wind project generation from 13 to 35 percent depending on the project, assuming the projects continue operating within the limits of their current large-generator interconnection agreements.

The innovative technologies available with the new wind turbines provide for greater control of power quality and voltage, allowing PacifiCorp to more easily integrate the energy from the wind facilities into the transmission system and support the reliability of the grid. The new equipment also reduces future operating costs and extends the useful life of each wind plant by approximately 10 years. With Goodnoe Hills included in the wind repowering scope, over the current life of the repowered facilities, incremental annual energy production exceeds 700 gigawatt hours (GWh) in each of the first 20 years and exceeds 3,600 GWh in each of the last 10 years.[16] Importantly, because the wind repowering project involves efficiency improvements to existing facilities, these benefits can be achieved without the costs and complexity of permitting and constructing entirely new facilities.

PacifiCorp's economic analysis in the 2017 IRP demonstrates that repowering provides substantial customer benefits. The 2017 IRP analysis also demonstrates that the new wind and transmission projects result in base-case present-value customer savings of $35 million before accounting for the significant increase in incremental energy expected from the repowered wind facilities beyond the end of the 20-year IRP-planning time frame. When accounting for these additional benefits,

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[15] *See* 2017 IRP, Volume I, Chapter 9, Action Plan and Resource Procurement, Table 9.1 – 2017 IRP Action Plan, Item 1a "by September 2017, complete technical and economic analysis of other repowering opportunities at PacifiCorp wind plants not studied in the 2017 IRP (i.e. Foote Creek 1 and Goodnoe Hills)."

[16] These updated results were provided to the Commission in Docket No. 17-035-39 in PacifiCorp testimony filed on October 19, 2017.

the base-case present-value customer savings rises to over $350 million. In the updated analysis filed in Docket No. 17-035-39, customer savings based on costs and projected benefits extended out through 2050 are $359 million, assuming medium natural gas and medium carbon dioxide (CO_2) prices. Conservatively, none of these benefit estimates assign any value to the incremental renewable-energy credits (RECs) that will be produced by the repowered wind facilities. Over the remaining life of these assets, present-value benefits improve by an additional $11 million for every dollar assigned to the incremental RECs that will be generated after repowering. In further updated analysis as part of PacifiCorp's rebuttal filing in the same docket, projected benefits extended out through 2050 are $471 million, and the present-value benefits improved by an additional $13 million for every dollar assigned to the incremental RECs that will be generated after repowering.

PacifiCorp analyzed the wind repowering project under many different scenarios, each with varying natural gas and CO_2 policy assumptions. Importantly, *in every scenario analyzed*, wind repowering provides customer benefits relative to scenarios that exclude the wind repowering project.

The economic benefits of repowering are bolstered by the fact that the repowered facilities are able to requalify for federal PTCs. To ensure the repowered facilities are eligible for 100 percent of available PTC benefits, in December 2016, PacifiCorp purchased new wind turbine generator equipment sufficient to satisfy Internal Revenue Service (IRS) "safe harbor" provisions requiring at least five percent of the expected cost of repowering to be incurred in 2016. These 2016 "safe-harbor equipment" purchases allow the repowered wind facilities to qualify for 100 percent of the value of available PTCs, assuming commercial operation by the end of 2020.

2. Overview of new wind and transmission resources.

The action plan in the 2017 IRP advances PacifiCorp's commitment to low-cost clean energy with the proposed addition of at least 1,100 MW of new wind resources by the end of 2020. These new wind resources will rely on a new 140-mile, 500 kV transmission line segment and associated infrastructure running from the Aeolus substation near Medicine Bow, Wyoming, to a new annex substation, Bridger/Anticline, which will be located near the existing Jim Bridger substation. The transmission project and the new wind resources are mutually dependent. The wind resources will rely on the transmission line for interconnection to PacifiCorp's transmission system. In turn, the transmission line is supported by the key economic attributes of the wind resources—zero-fuel-cost generation that lowers net power costs and provides 10 years of PTCs.

The transmission project also provides significant benefits to customers independent of the wind resources. The Aeolus-to-Bridger/Anticline line is a sub-segment of the Company's Energy Gateway West transmission project, and is an integral component of the long-term transmission plan for the region. PacifiCorp, with stakeholder involvement, has pursued permitting of the Energy Gateway West transmission project, which includes the Aeolus-to-Bridger/Anticline line, since 2008. This transmission investment will relieve existing congestion on the current transmission system in eastern Wyoming, provide critical voltage support to the Wyoming transmission network, improve overall reliability of the transmission system, enhance PacifiCorp's ability to comply with mandated reliability and performance standards, reduce line losses, and create the potential for further increases to the transfer capability across the Aeolus-to-

Bridger/Anticline line with the construction of additional segments of the Energy Gateway project in the future.

The 2017 IRP analysis, which assumes repowering of existing wind resources, demonstrates that the new wind resources will provide the cost savings necessary to support construction of this key transmission project and provide economic benefits for customers. The 2017 IRP analysis demonstrates that the new wind and transmission projects result in base-case present-value customer savings of $21 million. In the updated analysis filed in the Company's direct filing, PacifiCorp analyzed the new wind and transmission as standalone investments (*i.e.*, in isolation from the wind repowering project) with costs and projected benefits extended out through 2050 to align with the assumed life of the new wind assets. This economic analysis shows customer savings of $137 million under medium natural gas and medium CO_2 price assumptions. As is the case with wind repowering economic analysis, these benefits conservatively do not assign any value to the incremental RECs that will be produced by the new wind. Over the remaining life of these assets, present-value benefits would improve by an additional $26 million for every dollar assigned to the incremental RECs that will be generated by the new wind resources.

In addition to being least-cost, the resources described in the preferred portfolio, including the 1,100 MW of new wind by 2020, are also least-risk. Portfolio modeling performed for the 2017 IRP shows the resource acquisition path in the preferred portfolio is robust among a wide range of policy and market conditions, particularly in the near-term.

PacifiCorp has included the 1,100 MW of additional wind resources in its preferred portfolio as cost-effective system resources that will be used to serve system load. These resources, however, will also contribute to PacifiCorp's ability to meet state renewable energy targets in Oregon, Washington, California and Utah, as well as meet the growing desire for renewable energy resources in local jurisdictions PacifiCorp serves.[17]

3. RESPONSE TO PARTIES' COMMENTS

A. Energy Vision 2020

1. The preferred portfolio, including the Energy Vision 2020 projects, is the least-cost, least-risk portfolio to meet the resource needs identified in the 2017 IRP.

As indicated in the Initial Comments of IEA supporting acknowledgement of the 2017 IRP, the IRP's preferred portfolio includes the Energy Vision 2020 projects as the least-cost, least-risk approach to serving customers. This approach obviates the need for more expensive resource alternatives and facilitates construction of a key transmission segment. DPU's and UAE's recommendations that the Commission not acknowledge the action items associated with the Energy Vision 2020 projects rest largely on their claim that PacifiCorp has not demonstrated a resource "need."

[17] Salt Lake City, Utah Park City, Utah, Moab, Utah, Summit County, Utah, Portland, Oregon, Multnomah County, Oregon; and Hood River, Oregon have local ordinances, resolutions, or climate plans calling for increases in the delivery of electricity from renewable energy resources.

The fundamental issue presented by DPU is whether resources that displace Front Office Transactions (FOTs) in the near-term and satisfy an energy and capacity need in the long-term are "needed" as that term is used in the traditional IRP framework. DPU claims that PacifiCorp's load and resource balance shows no projected need for additional resources to reliably serve system load and that a capacity need is not shown until 2029. In defining capacity need, DPU assumes that uncommitted FOTs will be procured, and by extension, that lower-cost resources cannot displace these uncommitted FOTs—treating these resource alternatives differently than all other resource types analyzed in the IRP—a direct contradiction to the Standards and Guidelines that the IRP must evaluate "all known resources on consistent and comparable basis." Here, the preferred portfolio was selected over competing portfolios that did not acquire new PTC-eligible resources during the limited window when those resources are available. It would be inconsistent with least-cost planning principles for PacifiCorp to select a higher-cost, higher-risk portfolio simply because it did not include, or even consider, opportunities to procure PTC-eligible new resources within the context of its IRP.

Moreover, DPU continues to rely on an overly narrow interpretation of need that focuses exclusively on near-term need, even though the IRP is required to analyze resource need, and the least-cost and least-risk combination of resource to meet that need, over a 20-year planning horizon. When viewed through its proper scope, the Energy Vision 2020 projects meet an identified resource need and fit within the traditional framework for least-cost, least-risk resource planning.

PacifiCorp's thorough portfolio analysis demonstrates that the preferred portfolio is the least-cost, least-risk combination of resources because the acquisition of PTC-eligible renewable generation provides all-in economic benefits for customers by displacing higher cost market purchases in the near-term and deferring the need for higher cost resources over the long term. If taking such action is the least-cost, least-risk option, then doing so is consistent with the Commission's principles for least-cost planning which evaluates resources in order to meet "current and future customer needs."[18]

PacifiCorp's selection of the least-cost mix of supply-side resources is conceptually identical to the IRP's treatment of demand-side resources. The Commission requires least-cost planning to evaluate all resources on a consistent and comparable basis, including both supply- and demand-side resources.[19] When evaluating DSM resources, PacifiCorp's analysis is not limited by a need for additional DSM. Rather, PacifiCorp plans to acquire all cost-effective DSM resources, because DSM resources will displace higher cost FOTs in the near-term, and over time, reduce the need to procure higher cost resources in the long-term—just like the Energy Vision 2020 projects.

When assessed on comparable footing, PacifiCorp's investment in DSM is similar to the level of proposed investment associated with the Energy Vision 2020 project. Over the last 10 years, PacifiCorp's nominal spend on total system Class 2 DSM (energy efficiency) is approximately $979 million. Accounting for inflation so that this can be compared to the initial capital proposed with the Energy Vision 2020 projects, this equates to over $1.1 billion (2020 dollars). PacifiCorp's most recent estimate of in-service capital for the Energy Vision 2020 project is approximately $3.2

[18] Docket No. 90-2035-01, Report and Order, June 18, 1992, p.18.
[19] *Id.*, at 40.

billion (total system). However, these projects are expected to have a 30-year life (both repowered and new wind) or a 62-year life (new transmission). The 10-year levelized revenue requirement for these assets, which is more comparable to the last 10-years of spend on Class 2 DSM, totals $1.1 billion—equal to the cost of acquiring cost-effective Class 2 DSM resources over the most recent 10-year period.

Further, other regulatory commissions have recognized the customer benefits resulting from similar proposals for the early acquisition of least-cost, least-risk renewable resources. In January 2017, the Minnesota Public Utilities Commission (MPUC) approved Xcel Energy's IRP, which included the acquisition of 1,000 MW of new wind resources by 2019. In this proceeding, the MPUC noted that 1,000 MW of wind was "least-cost even through Xcel does not show a planning capacity deficit until the mid-2020s because it will provide incrementally lower-cost energy, thereby reducing system costs."[20]

UAE notes risks associated with potential changes in gas prices, construction costs, facility performance, and tax codes may impact the economic benefits of the Energy Vision 2020 projects and submits that pending a meaningful and thorough evaluation of ratepayer risks and potential benefits in other dockets, the Commission should not acknowledge the 2017 IRP.[21] Similarly, DPU notes risks the PTCs may not be realized as expected, the individual PTCs may not be as valuable as expected, there may not be as many PTCs generated as expected, the projects may experience cost overruns or project delays, and energy prices may be lower than expected, among other risks.[22] The DPU characterizes the Energy Vision 2020 projects as opportunities that "might be modestly beneficial to ratepayers if a host of risks do not come to pass."[23]

The Company acknowledges these risks; however, notes that all of its economic analysis will be updated before moving forward with any of the Energy Vision 2020 projects. This updated analysis will account for any changes in the tax code, market, or project cost estimates based on the most up-to-date information available. These updated analyses will be addressed in the specific resource decision dockets examining in more detail the Energy Vision 2020 projects.

In addition, there are considerable customer risks associated with doing nothing. Specifically, if the Company forgoes the Energy Vision 2020 projects, it will be forgoing the opportunity for customers to acquire heavily-discounted resources in the near term in exchange for greater reliance on near-term market transactions and waiting until after the expiration of PTCs to acquire zero-fuel-cost resources to meet growing energy and capacity needs. Contrary to the implication that there are no customer risks associated with forgoing the opportunity to procure PTC-eligible resources, there are risks associated with greater reliance on higher-cost market resources over the near term and greater reliance on higher-cost resources over the long term—and those risks will be borne by customers.

[20] *In the Matter of Xcel Energy's 2016-2030 Integrated Resource Plan*, Docket No. E-002/RP-15-21, at 7 (Jan. 11, 2017).
[21] Initial Comments of UAE, at 4.
[22] *Id.*, at 9.
[23] *Id.*, at 10.

The Company's robust portfolio modeling in the 2017 IRP compared the Energy Vision 2020 resources to portfolios with a larger volume of FOTs and delayed resource procurement, and the model consistently selected the Energy Vision 2020 resources as the least-cost resources in the vast majority of scenarios. Although the Energy Vision 2020 projects have risks, that fact alone does not demonstrate that the projects are higher risk than the next best alternative. In fact, the 2017 IRP clearly demonstrates that the Energy Vision 2020 projects are least-cost, least-risk compared to all other alternatives, including alternative portfolios with heavier reliance on FOTs.

Moreover, the utility industry is currently in a time of transition, with both rapidly evolving technologies and changing regulatory environments. It is not, however, consistent with long-term resource planning or in customers' interests for PacifiCorp to halt resource development in light of a changing policy and regulatory landscape, particularly when halting resource development would forgo the opportunity to pursue cost-effective renewable resources and further decarbonize PacifiCorp's resource portfolio. PacifiCorp cannot pass on opportunities like the current time-sensitive opportunity presented in this IRP, which include heavily discounted renewable resources in the hope there may be a better opportunity in the future or simply because the future is uncertain. PacifiCorp must plan for the future based on the best information available today, taking into consideration the inherent uncertainties that are present in today's planning environment. This time-sensitive opportunity is consistent with the Commission's Standards and Guidelines, ¶ 4.i. which permits "flexibility in the planning process so that the Company can take advantage of opportunities …"

2. PacifiCorp's reply to parties' comments on repowering.

Sierra Club, the REC, DPU, UAE and the OCS recommend the Commission decline to acknowledge repowering. Sierra Club argues that rather than spending significant funds to tear down existing resources with effectively no incremental customer benefit, PacifiCorp should invest in new cost-effective renewable energy projects.[24] Sierra Club's conclusion that repowering provides only a marginal customer benefit relies on the exclusion of the PTC benefits, which drive the investment decision. When PTCs are accounted for, repowering provides substantial benefits and, as Sierra Club concedes, accounting for PTCs is "a legitimate, if not entirely standard, business practice."[25] The recommendations made by the REC, DPU, UAE and OCS to not acknowledge repowering stem largely from their claim of a lack of transparency in the process. The Company will respond to that specific claim later in these reply comments.

3. PacifiCorp's reply to parties' comments on the new wind and transmission resources.

UAE claims that the proposed wind and transmission resources were not contemplated in prior IRPs and are not necessary.[26] UAE provides no analysis demonstrating that foregoing PTC-eligible resources is less beneficial than moving forward with the PTC-eligible new wind resources. In other words, UAE ignores any opportunity costs to customers of inaction. Notably, the 2017 IRP contains numerous portfolios that did not include the new wind and transmission investments and the preferred portfolio outperformed those competing portfolios. Without any analysis, UAE

[24] Initial Comments of Sierra Club, at 24-25.
[25] *Id.*
[26] Initial Comments of UAE, at 2.

cannot reasonably claim that not acquiring these resources is the least-cost, least-risk option, particularly given the time-limited opportunity presented by the PTCs.

UAE notes that the proposed new resources would also create significant customer risks and that not acknowledging gas price risk, construction cost risk, facility performance risk, tax rate risk, among others, will presumably fall to customers. UAE further states that failing to properly acknowledge or evaluate these potential risks, the 2017 IRP violates Standards and Guidelines 1 and 4h. PacifiCorp notes the only scenario in the 2017 IRP where the new wind and transmission resources are non-economic is the low gas scenario. In every other scenario, PacifiCorp's analysis shows that the new resources provide customer benefits and the upside associated with higher natural gas prices far exceeds any potential downside if natural gas prices remain low through the life of the assets. Moreover, PacifiCorp's analysis conservatively assigns no incremental value to the RECs generated by the new wind facilities and does not consider incremental benefits associated with the new transmission line, which will relieve congestion for existing resources, provide critical voltage support, enhance PacifiCorp's ability to comply with mandated reliability and performance standards, and provide an opportunity for further increases to the future transfer capability out of wind-rich regions of Wyoming with construction of additional segments of Energy Gateway. Since Staff filed its initial comments, PacifiCorp completed an updated economic analysis that was recently filed in this docket. This updated analysis, which isolates the benefits of the new wind and transmission investments from wind repowering, shows that with medium natural gas and medium CO_2 price assumptions, the present-value customer benefits total $137 million when calculated from the change in system costs over the life of the new wind resources.

Sierra Club also recommends the Commission not acknowledge the new wind and transmission resources. Sierra Club argues that PacifiCorp's analysis show only a marginal benefit of these resources.[27] To clarify, the portfolio that included the new wind and transmission resources (GW-4) was presented at the March public input meeting and showed benefits above the draft preferred portfolio (OP-NT3), even without wind repowering (OP-REP). When combined in the final screening stage, the portfolio that included both wind repowering and the new wind and transmission resources (FS-GW4) showed greater benefits than the portfolio that included wind repowering on its own (FS-REP). As discussed above, PacifiCorp's updated analysis isolates the benefits of the new wind and transmission from the wind repowering project and shows present-value customer benefits totaling $137 million.

Second, Sierra Club claims its analysis demonstrates retiring the Dave Johnston coal plant to free-up transmission, instead of building the new line would be a lower cost option.[28] While the 750 MW of incremental transfer capability across the Aeolus-to-Bridger/Anticline transmission line is of similar magnitude to the 762 MW capacity of the Dave Johnston plant, this argument fails to recognize limitations on interconnecting new generators due to voltage instability on the 230-kV transmission system. Regardless of the economics, it is simply not physically possible to interconnect 1,100 MW of new wind resources by retiring the Dave Johnston plant. The 762 MW Dave Johnston plant provides critical voltage support to the 230-kV transmission system and

[27] Initial Comments of Sierra Club, at 25 and 27.
[28] *Id.* at 3.

without that support, the company could not integrate the level of economic wind resources selected in the preferred portfolio.

Moreover, the Dave Johnston plant is one of the lowest variable-cost assets on PacifiCorp's system and operationally, provides flexibility that facilitates PacifiCorp's ability to import low-cost renewable energy from California through the energy imbalance market (EIM). The plant also provides significant system capacity needed to satisfy PacifiCorp's 13 percent target planning reserve margin (PRM) and provides fault current support to maintain "stiffness" of the grid which is necessary to support system voltages. If Dave Johnston retired at the end of 2020 (approximately three years out), there would be limited time to procure potential replacement resource alternatives capable of delivering energy and capacity benefits comparable to those provided by the Dave Johnston plant and could necessarily increase PacifiCorp's reliance on market purchases. Retiring Dave Johnston by the end of 2020 would also create substantial upward pressure on customer rates due to the accelerated depreciation resulting from early retirement. The Aeolus-to-Bridger/Anticline line will also provide additional benefits that would not be realized simply by retiring the Dave Johnston plant.

Further, PacifiCorp modeled and evaluated a number of Regional Haze cases that assumed a range of coal unit retirement assumptions and incorporated stakeholder feedback. In the first stage of the 2017 IRP portfolio development process, PacifiCorp identified least-cost, least-risk Regional Haze case adopted for further portfolio analysis. The 1,100 MW of new Wyoming wind and Aeolus-to-Bridger/Anticline line included in the 2017 IRP preferred portfolio was selected as part of the least-cost, least-risk preferred portfolio reflecting the least-cost, least-risk Regional Haze compliance alternatives and associated early coal unit retirement assumptions.

UAE also notes the new transmission segments and other proposed transmission projects will not reduce congestion in moving power out of Wyoming to meet PacifiCorp's loads.[29] To the contrary, the new transmission line will: (1) relieve congestion and increase transmission capacity across Wyoming, allowing interconnection of new generation resources and greater flexibility in managing existing resources; (2) provide critical voltage support to the transmission system; (3) improve system reliability; and (4) reduce energy and capacity losses.

Currently, PacifiCorp's transmission system in southeastern Wyoming is operating at capacity, which limits transfer of existing resources from eastern Wyoming. Also, due to limited fault current in the southeastern portion of the transmission system, which indicates a weak grid, interconnection of additional resources in this prime wind region is precluded to maintain grid stability. The transmission project will not only increase the transfer capability from east to west by 750 MW, but will also improve the fault current providing "stiffness" to the grid. This will allow interconnection of additional wind facilities in and around the proposed Aeolus substation, which is not possible today.

In addition, under certain operating conditions, voltage control issues have limited the ability to add additional resources, particularly wind facilities, in southeastern Wyoming. The proposed transmission project will solve the voltage control issues and allow up to approximately 1,270 MW of additional wind generation to be interconnected into the transmission system.

[29]Initial Comments of UAE, at 4.

The transmission project will also increase system reliability. The transmission grid can be affected in its entirety by what happens on an individual transmission line or path. For example, the transmission system between eastern and central Wyoming is composed of several individual transmission lines or line segments. A single outage on any of the individual lines or line segments due to storm, fire, or other interference can and does cause significant reductions in transmission capacity and can negatively impact PacifiCorp's ability to serve customers. Line outages require PacifiCorp to significantly curtail generation resources to stabilize system voltages and require less efficient re-dispatch of system resources to meet network load requirements. If there is a line outage, the redundancy provided by the proposed transmission line will allow PacifiCorp to continue to meet native load-service obligations and continue to meet other contractual obligations to third parties. Strengthening this path and increasing system redundancy with the new transmission line will benefit all customers by reducing the risk of outages and inefficient dispatch resulting from those outages.

Also, the transmission resource will improve PacifiCorp's ability to perform required maintenance without significant operational impacts to the system, and will reduce impacts to customers during planned and forced system outages. Transmission line and substation maintenance windows are currently limited because the system is operating at capacity. By relieving congestion and providing additional transmission paths, the transmission resource will allow greater flexibility.

The transmission resource will reduce energy and capacity losses on the transmission system, and has the potential to provide significant cost savings over time. Generally, the addition of a new transmission path in parallel with existing lines, like the proposed Aeolus-to-Bridger/Anticline line, will reduce the energy and capacity losses by reducing the impedance of the transmission system. Reduced line losses mean more efficient delivery of energy and capacity at reduced costs.

B. The 2017 IRP Public Input Process was Robust and Satisfies the Commission's IRP Standards and Guidelines.

1. The 2017 IRP Public Input Process Provided Ample Opportunity for Public Input and Information Exchange During the Development of the Plan.

Integrated resource planning requires extensive public involvement in the development and review of the plan. To that end, beginning in June 2016, PacifiCorp organized five state meetings and held seven public meetings[30] to facilitate information sharing and collaboration, and to set expectations for the 2017 IRP. The public process covered all facets of the IRP process, ranging from specific input assumptions to the portfolio modeling and risk analysis strategies employed. Based on public feedback provided through this process and in the 2015 IRP process, the 2017 IRP included process and modeling improvements. Efficiencies gained through improvements to the resource development process better positioned PacifiCorp to develop additional studies requested by stakeholders during the public input process. PacifiCorp and stakeholders identified and requested alternative modeling scenarios that were informed by the initial and intermediate analysis that was

[30] DPU incorrectly states only five public input meetings were held. The DPU did not account for the November 17, 2017 public input meeting held via conference call and the January 26-27, 2017 meeting held in-person in its count of five public input meetings.

reviewed during the public input process. This improved process in the 2017 IRP enabled PacifiCorp to develop additional Regional Haze compliance cases and alternative environmental policy cases in response to stakeholder requests. Results from some of these studies led PacifiCorp to consider additional scenarios, which directly influenced the resource mix in the preferred portfolio.

2. The 2017 IRP Public Input Process Did Not Include Discussion of the Energy Vision 2020 Project Until the End Because the Resource Opportunities Emerged Late in the Public Process.

The OCS recommends the Commission not acknowledge the 2017 IRP based on perceived modeling deficiencies it asserts may have biased the selection of the final preferred portfolio to include PacifiCorp's "pre-selected" resources.[31] The OCS states the 2017 IRP did not meet the Standards and Guidelines because the Company did not provide "ample opportunity for public input and information exchange during the development of the IRP."[32] UAE also notes the Energy Vision 2020 Project and repowering were not evaluated or selected through a "meaningful" public process in violation of the Standards and Guidelines. Likewise, the DPU recommends the Commission not acknowledge the 2017 IRP, and notes Energy Vision 2020 was developed late in the IRP process and away from other participants in the process.[33] The DPU proceeds to make specific recommendations and requests the Commission make specific findings on process and transparency to be used in future IRP stakeholder processes. Sierra Club states the 2017 IRP process was neither transparent nor open.[34] REC generally indicates PacifiCorp introduced the new wind and transmission late in the process.[35]

In December 2016, PacifiCorp concluded that repowering wind units could generate cost savings if implemented on at least a subset of wind facilities in the fleet. To preserve the repowering option for application at additional facilities and to preserve the option to qualify new wind facilities for the full value of PTCs, subject to further review and analysis, PacifiCorp made safe harbor wind equipment purchases at that time.

PacifiCorp completed its additional review and expanded economic analysis of wind repowering in early 2017, toward the end of the IRP's pre-filing process. In February 2017, PacifiCorp finalized its IRP analysis of wind repowering. PacifiCorp incorporated repowering into the IRP process as the portfolio option referred to as OP-REP. PacifiCorp rescheduled the February 2017 public input meeting to the first of March to enable the company to complete and share its wind repowering analysis. PacifiCorp expedited its analysis of wind repowering to ensure its consideration in the 2017 IRP, even though this resource opportunity emerged just a few months before the IRP's filing date; simultaneously, PacifiCorp was also completing its analysis of 24 sensitivity cases and eight core cases initially presented in the January 2017 public input meeting.

[31] Initial Comments of OCS, at 1.
[32] *Id.*
[33] Initial Comments of DPU, at 3.
[34] Initial Comments of Sierra Club, at 2.
[35] Initial Comments of REC, at 8.

Also in late 2016 and early 2017, PacifiCorp continued to study and refine its resource portfolios, *all of which contained new Wyoming wind resources*. In reviewing these resource portfolios, it became clear that the amount of Wyoming wind included in these resource portfolios were limited by transmission constraints. The presence of the Wyoming wind resources in these initial portfolios led PacifiCorp to assess whether additional wind resources enabled by sub-segments of Energy Gateway West would further lower system costs. Consequently, after the January public input meeting, PacifiCorp incorporated the Aeolus-to-Bridger/Anticline line as a specific sensitivity case in its broader Energy Gateway sensitivity analysis. In late February, PacifiCorp's modeling of four Energy Gateway transmission sensitivities indicated there were potential benefits to including the Aeolus-to-Bridger/Anticline line in the portfolio. At the March 2017 public input meeting, PacifiCorp presented this analysis to stakeholders, along with next steps that communicated PacifiCorp's intention to further refine key assumptions for this sensitivity case.

While the pre-filing stakeholder review process of Energy Vision 2020 projects was necessarily limited by the timing of PacifiCorp's analysis, it was in customers' interest to consider these resources in the 2017 IRP. Recognizing the need to be open and transparent, PacifiCorp explicitly chose to share the results of its analysis with stakeholders as they were being produced. Given the time-sensitivity of these resource opportunities, delaying the IRP to allow additional pre-filing review was not a viable option. Instead, PacifiCorp expeditiously completed the necessary analysis and shared it with IRP stakeholders in real-time. PacifiCorp has not executed any agreements committing PacifiCorp to move forward with development of the Energy Vision 2020 projects other than the December 2016 purchases of wind turbine safe harbor equipment to preserve the option of qualifying wind resources for the full value of federal PTCs.

3. The Public Input Process Modifications Requested by DPU are Restrictive Overly Burdensome.

The DPU recommends the Company schedule a general meeting in December of the year prior to starting the next IRP public input process in order to draft an agenda for the next year's IRP public input process. The DPU claims this approach would ensure there are no more "surprise" IRP results.[36] The DPU is fundamentally misunderstanding the nature of the IRP in which detailed modeling and results are not available until closer to the filing date of the IRP. As studies are completed and information is updated over the year-long preparation process, PacifiCorp reasonably addresses items as needed in its analysis to ensure the most up-to-date information is analyzed. In addition, the DPU requires two-day meetings held monthly for a minimum six to eight hour period of time. PacifiCorp plans for and strives to hold two-day meetings on a monthly basis during its public input process but must also be permitted flexibility to ensure the meetings are meaningful. The DPU also recommends that the executive overseeing the IRP process be required to attend at least every other (or half) of the public input meetings in Utah. This recommendation is overly burdensome, recognizing that executive leadership is directly involved in establishing the agenda, messaging, and presentation materials throughout the public input process. Participation in the public input meetings is also facilitated via video conference from the Portland, Oregon, Salt Lake City, Utah and in the 2017 IRP PacifiCorp also included Cheyenne, Wyoming and Denver, Colorado. Lastly, the DPU recommends requirements to file meeting materials a minimum of one week in advance of the public input meetings and with all charts and figures in native format.

[36] Initial Comments of DPU, at 19.

PacifiCorp strives to provide materials in advance however, due to the short duration between monthly public input meetings and the volume of analysis and or material that is prepared it is not possible to always provide one week in advance. PacifiCorp has made charts and figures from public input meeting presentations in native format as requested and is willing to continue to do so as part of the public input meeting process on an as needed basis.

C. Coal Resource Analysis

1. PacifiCorp's coal fleet modeling is robust, reflects significant stakeholder input during the public input process and is consistent with the Commission's 2015 IRP Report and Order.[37]

PacifiCorp's modeling of its coal fleet has evolved over the last several IRP proceedings in response to Commission and stakeholder input, and PacifiCorp views the IRP proceeding as the appropriate forum to analyze these issues. In PacifiCorp's 2013 IRP, PacifiCorp presented analysis addressing the potential investments that would be required at coal-fired generating plants.[38] In that case, parties criticized PacifiCorp's analysis and recommended that PacifiCorp analyze more flexible compliance alternatives.[39]

In its order acknowledging the 2013 IRP, the Commission "encouraged PacifiCorp to continue to monitor and prudently respond to the constantly changing landscape" in the 2015 IRP.[40] To further refine the coal fleet analysis, PacifiCorp also conducted workshops to determine the parameters of coal analyses in future IRPs.[41] Subsequently, in the 2015 IRP, PacifiCorp implemented the modeling refinements that grew out of the 2013 IRP and the Commission accepted PacifiCorp's analysis as "a reasonable analytical approach."[42]

PacifiCorp's 2017 IRP includes the same analysis and modeling approach that was used in the 2015 IRP, and approved by the Commission, with a significant focus during the public input process to incorporating stakeholder feedback and increasing the number of scenarios studied. PacifiCorp studied seven regional haze compliance cases in the 2017 IRP. Based on the robust analysis conducted, the 2017 IRP preferred portfolio does not include any incremental selective catalytic reduction (SCR) equipment. Avoiding installation of SCR equipment will save customers hundreds of millions of dollars and retain compliance-planning flexibility associated with potential state and federal environmental policies. The 2017 IRP studied a range of Regional Haze compliance scenarios, reflecting potential bookend alternatives that consider early retirement

[37] *See,* Docket No. 15-035-04, Report and Order, at p. 16, (stating, "[w]e urge Pac to give priority to the public process of its 2017 IRP to discuss and weigh alternative approaches for determining the least cost path, adjusting for risk and uncertainty, for addressing federal environmental compliance obligations."

[38] 2013 Integrated Resource Plan, Volume I, p. 3.

[39] *See e.g.,* Docket No. 13-2035-01, Report and Order, issued January 2, 2014, pp. 14 and 15 (quoting UCE's recommendation to "evaluate all future potential environmental compliance obligations for coal plants simultaneously; quoting IEA's recommendation to require PacifiCorp to "update its modeling prior to the update required in the Spring of 2014, where there will be additional information of the revised EPA rules applicable to coal plants providing electricity to ratepayers in Utah.")

[40] *Id.*, at 14.

[41] *See e.g.,* Utah Commission Technical Workshop, dated August 27, 2013 and IRP Process Improvement Workshop, dated September 23, 2013.

[42] Docket No. 15-035-04, Report and Order, p. 16.

outcomes as a means to avoid installation of expensive SCR equipment. By the end of the planning horizon, PacifiCorp assumes 3,650 MW of existing coal capacity will be retired.

The 2017 action plan has one item related to coal resources, Action Item 5, and that item includes only further study and monitoring of developments that impact the economics of PacifiCorp's coal units for inclusion in future IRPs.

2. PacifiCorp's reply.

UAE claims the process used to determine the preferred portfolio as least-cost and least-risk was incomplete and flawed because "the sequence of coal plant retirement modeling done early in the process did not allow coal plant retirements to be considered as an alternative to new transmission."[43] IEA states "PacifiCorp continues to side-step least-cost optimization of its coal units which accurately assumes all costs and risks of existing regulations."[44]

Sierra Club challenges PacifiCorp's coal resource modeling and recommends the Commission decline to acknowledge Action Item 5. Sierra Club argues that the 2017 IRP is not least-cost, least-risk because it does not include the retirement of non-economic coal resources. Sierra Club claims that approximately 40 percent of PacifiCorp's coal units are uneconomic on a prospective basis, even without meeting required environmental compliance obligations.[45] Sierra Club's analysis is flawed. Sierra Club performs a unit-by-unit analysis to determine whether each individual unit is economic without examining how the retirement of individual unit(s) impacts the system as a whole. In other words, each analysis implicitly assumes that the coal unit being studied is the only one that would be retired. Proper analysis, however, would need to assess the economic impact of each unit that is retired on the next unit analyzed. In addition, Sierra Club's analysis fails to consider the operational impacts of retiring so many coal units. From an operational perspective, it is untenable to simply retire 40 percent of the coal units, as Sierra Club recommends.

Relatedly, Sierra Club argues that PacifiCorp's analysis only considers the continued viability of coal units in the face of considerable capital investments, like SCRs, instead of engaging in a continual process to evaluate whether coal units remain economic compared to available alternatives.[46] Sierra Club argues that the Commission must direct PacifiCorp to analyze as part of its fundamental planning process the viability of each individual coal unit and demonstrate that continued operation is in the customers' interest. Sierra Club's proposal should not be considered without additional justification, analysis, and support.

Sierra Club also claims that PacifiCorp failed to include a Regional Haze case that allows endogenous coal unit retirements, despite agreeing to include such a case as part of a settlement reached with Sierra Club in 2016.[47] On the contrary, PacifiCorp conducted seven Regional Haze cases, including an endogenous case (RH-6) that evaluated early retirement versus installation of SCR equipment on the coal plants facing Regional Haze compliance obligations. This Regional

[43] Initial Comments of UAE, at 5.
[44] Initial Comments of IEA, at 7.
[45] Initial Comments of Sierra Club, at 6.
[46] *Id.* at 6.
[47] *Id.* at 14.

Haze case was analyzed among the same market price and greenhouse gas policy assumptions applied to PacifiCorp's analysis of other Regional Haze cases.

Sierra Club claims that despite repeated requests from stakeholders going back years, PacifiCorp continues to withhold tools and data that are necessary to assess the viability of its coal resources.[48] Sierra Club argues that PacifiCorp has a strategy of hindering the valuation of its coal fleet. This claim is at odds with the record in prior IRP cases, where the Commission has found PacifiCorp's work in the 2015 IRP to be a reasonable analytical approach.[49] Moreover, PacifiCorp has worked with Sierra Club and other stakeholders to allow them access and training to the same tools and modeling used by PacifiCorp. The reality of modeling, operating, and delivering electricity supply across a multi-state vertically integrated energy system is that complex tools are required to ensure that PacifiCorp meets its obligations to provide risk-adjusted, least-cost planning, operation, and delivery of electricity for customers. PacifiCorp remains committed to continually improving the analytical support it provides to stakeholders with limited resources. To the extent stakeholders request models used by PacifiCorp that are only licensed to PacifiCorp, consent is needed before the third party models can be accessed.[50]

Sierra Club claims that PacifiCorp's modeling in the 2017 IRP cannot meet enforceable Clean Air requirements.[51] Sierra Club also claims that PacifiCorp's long-term planning assumes that it will prevail in litigation against EPA and will therefore have a lower compliance obligation that is currently required by EPA.[52] This is inaccurate. PacifiCorp developed a range of compliance scenarios working with stakeholders and selected the least-cost, least-risk compliance portfolio as its benchmark for the core case and sensitivity analysis that followed in development of the preferred portfolio. PacifiCorp will continue to update its assumptions and scenarios in future IRP cycles and working with stakeholders, taking into account the then-current policy, rulemaking and litigation outcomes as appropriate.

Sierra Club argues that PacifiCorp is unwilling to demonstrate the basis of its Regional Haze alternatives.[53] This is also not the case. PacifiCorp began discussing its Regional Haze compliance obligations and the wide range of cases it planned to assess in the 2017 IRP as early as the second public input meeting in July and continued to discuss and incorporate stakeholder feedback on Regional Haze alternatives that would be studied at subsequent public input meetings, including an endogenous retirement scenario (RH-6) at the request of Sierra Club.

UCE claims PacifiCorp did not provide transparent analysis of the Company's existing coal units compared to alternative options.[54] While PacifiCorp disagrees in light of the extensive coal discussed above, PacifiCorp is willing to conduct additional unit-by-unit analysis that will inform the 2019 IRP. Such studies will require significant work to produce and may not give a complete, portfolio-level view of the economics of PacifiCorp's coal portfolio nor capture system cost impacts that would result with early retirements at more than one facility. These are issues not

[48] *Id.* at 6.
[49] Docket No. 15-035-04, Report and Order, at p.16.
[50] Initial Comments of REC, at 15.
[51] Initial Comments of Sierra Club, at 30.
[52] *Id.* at 34.
[53] *Id.* at 22.
[54] Initial Comments of UCE, at 3.

present in the 2017 IRP Regional Haze analysis and therefore results from these additional studies will provide limited insight into a least-cost, least-risk resource portfolio. PacifiCorp however, will commit to conduct 25 System Optimizer runs with retirement dates assumed at the end of 2022 by June 30, 2018, which aligns with the beginning of the stakeholder process for the 2019 IRP. This will allow the new analysis to inform subsequent analysis in the 2019 IRP by providing coal-unit screening studies early in the public-input process. With hypothetical retirement dates assumed to occur at the end of 2022, portfolio impacts from these simulations are unlikely to influence the 2017 IRP action plan, which identifies specific resource actions required over the next two-to-four years.

D. Demand-Side Management

1. Parties' comments.

UCE and SWEEP (in joint comments) and Sierra Club provide similar comments with regard to Class 2 DSM (energy efficiency) resources in the 2017 IRP. Parties commend Rocky Mountain Power's track record of electricity savings through its DSM program, but express concerns regarding the decrease in projected energy efficiency resources as compared to the 2015 IRP.

UCE and SWEEP recommend PacifiCorp's action plan item 4a be updated to state that PacifiCorp must acquire "all" cost-effective Class 2 DSM and "at least equal" to the preferred portfolio amount.[55]

2. PacifiCorp's reply.

PacifiCorp's IRP continues to identify all energy efficiency resources that are cost-effective compared to resource alternatives. Indeed, energy efficiency remains the primary resource used to meet incremental load growth over the next 10 years.

While the 2017 IRP demonstrates PacifiCorp's continuing commitment to energy efficiency as a resource, PacifiCorp understands stakeholders' interest in better understanding the decrease in Utah energy efficiency resource selections relative to the 2015 IRP. PacifiCorp updates its energy efficiency supply curves for each IRP to reflect updated information on the cost and availability of energy efficiency resources since the previous assessment. As the past several IRP cycles have shown, the available technical energy efficiency potential is not static, but fluctuates based on changes in the market, the emergence of new technologies, improvements to building codes and equipment efficiency standards, and updated load forecasts.

Sierra Club's suggestion that energy efficiency resources in PacifiCorp's IRP should be held flat at historical acquisition levels rather than based on a potential study has several flaws. First, it fails to account for the market dynamics that can affect available energy efficiency potential and the importance of updating these projections regularly. Second, it fails to recognize the many factors that affect the cost-effectiveness of energy efficiency resources as compared to supply-side resource alternatives—acquiring energy efficiency resources at levels significantly higher than what the IRP deemed cost-effective could drive additional costs to PacifiCorp customers. Third,

[55] Joint Comments of UCE and Sweep, at 3.

the suggestion seems to be in direct conflict with allowing DSM and supply side resources to compete, based on lowest cost, to meet forecasted load growth.

As discussed above, the IRP selects all cost-effective energy efficiency resources, as identified in the preferred portfolio. As such, UCE and SWEEP's suggested modifications to action item 4a could result in additional costs to customers, which is in direct conflict with least-cost planning principals. Due to the nature of energy efficiency programs, including variable customer participation, PacifiCorp does not have the ability to deliver exact MWh savings. Requiring the Company to achieve "at least" the IRP preferred portfolio targets in any given year would effectively require the Company to plan for energy efficiency savings above and beyond those selected in the IRP, otherwise the Company would be at risk of not being in compliance.

E. Battery and Energy Storage

1. Parties' comments.

The 2017 IRP expanded efforts to study battery and energy storage supply-side resource options. PacifiCorp worked with external consultants to update two energy storage studies including a battery energy storage study that focused on battery technologies and a bulk energy storage study that focused on pumped hydro and compressed air energy storage. In addition, PacifiCorp developed a separate battery energy storage supply-side resource table to provide additional information and inputs for five different size scenarios not included in the bulk energy storage systems included in the supply-side resource table, Table 6.1, of the 2017 IRP. PacifiCorp also studied two energy storage sensitivities specifically evaluating the impact of battery storage and CAES resource selection.

Despite these improvements in the 2017 IRP, both IEA and UCE comment that energy storage requires further analysis in future IRPs. IEA expresses appreciation for PacifiCorp's work in the 2017 IRP to develop methodologies for valuation of energy storage resources and acknowledges its work with independent consultants on these issues since 2015, but believes there is further work that needs to be done to identify benefits of energy storage in PacifiCorp's modeling methodologies. To that end, IEA recommends that energy storage assumptions be vetted through a technical advisory committee prior to using the studies in the next IRP. Similarly, UAE requests PacifiCorp (or the Commission) convene technical workgroups to discuss challenges and needs related to the modeling of battery storage so that PacifiCorp may refine its modeling of battery storage in the 2019 IRP. In addition, UAE makes two additional recommendations for the 2019 IRP that PacifiCorp track and update battery cost trends to align modeling assumptions with the most accurate and current market information and that PacifiCorp model customer-sited battery storage programs and incentives.

2. PacifiCorp's reply.

UCE recommends PacifiCorp update the costs inputs for battery storage based on reputable third-party market reports as often as possible. PacifiCorp meets this requirement and will continue to update and expand upon its battery storage studies conducted by reputable third-parties in the 2019 IRP.

Regarding UCE's recommendation that PacifiCorp model customer-sited battery storage programs and incentives, PacifiCorp is willing to consider how this might be done for the 2019 IRP and discuss with stakeholders in a workshop specific to energy storage as requested by IEA and UCE. PacifiCorp will schedule this workshop as part of the 2019 IRP public input process and prior to finalizing the supply-side resource table inputs for battery and energy storage.

F. Distributed Generation (Private Generation)

1. Parties' comments.

The Division and UCE recommend that PacifiCorp modify how it models private generation in the 2019 IRP, stating that it should be modeled as a supply-side resource rather than as a reduction to load.[56]

2. PacifiCorp's reply.

Parties also made this recommendation in response to the 2015 IRP. In acknowledging the 2015 IRP, the Commission recognized that the decision to build customer-owned private generation originates with the customer and found that it is therefore reasonable to model private generation as a load reduction.[57]

PacifiCorp believes that its methodology for modeling private generation, and the Commission's direction from the 2015 IRP are still appropriate. The Division and UCE have not provided any new substantial arguments as to why it would be more reasonable to model private generation as a supply-side resource and PacifiCorp is concerned that such modeling would overstate the load forecast and result in unnecessary resource selections by the model. PacifiCorp continues to utilize a third-party study to update the assessment of private generation based on new market and incentive developments.[58]

G. Modeling Considerations

A. Capacity Value for Expiring Qualifying Facility (QF) Contracts

REC claims that PacifiCorp should study, review and calculate the capacity benefits provided by QFs renewing their contracts and that avoided costs should account for the capacity value provided by exiting QFs.[59]

PacifiCorp's 2017 IRP modeling assumes that no QF contracts are renewed.[60] As a result, the deficiency period in the 2017 IRP is based on the assumption that existing QFs will not renew their contracts. When an existing QF renews its contract, it will receive the same capacity payment that

[56] *See* Initial Comments of UCE, at 8 (citing comments made by DPU during 2015 IRP process).
[57] Docket No. 15-035-04 Report and Order, January 8, 2016, at 19.
[58] In the 2017 IRP, PacifiCorp contracted with Navigant Consulting, Inc. that studied and delivered: 1) technical potential, 2) market potential, and 3) levelized cost of energy for each private generation resource in each of the six states served by PacifiCorp. Specific technologies included solar photovoltaic, small-scale wine, small-scale hydro, and combined heat and power for both reciprocating engines and micro-turbines.
[59] Initial Comments of REC, at 3.
[60] To be clear, in prior IRPs, PacifiCorp assumed that large QFs would not renew their contracts. Thus, in the 2017 IRP, both large and small QF contracts are treated the same.

would be received by a new QF. The Commission approved a methodology that that fully compensates QFs for their capacity contributions that does not assume existing QFs will renew their contracts;[61] therefore, PacifiCorp's 2017 IRP complies and PacifiCorp should not be required to conduct further analysis in the IRP process.

B. Use of an Independent Third Party for Gas Price Forecast

REC incorrectly states that PacifiCorp's 2017 IRP natural gas price forecast "comes from the Company's own expert instead of a widely recognized and accepted gas price forecast like the Energy Information Administration (EIA)."[62] REC further states that while there may be arguments for a "Company-paid expert," the use of such an expert raises questions.

To clarify, PacifiCorp does not pay an expert third-party forecaster to produce any customized natural gas price forecasts. Instead, PacifiCorp subscribes to two widely recognized expert third-party forecasting services to receive multi-client "off-the-shelf" base and scenario forecasts, with supporting data, on a regular basis. The EIA's gas price forecasts were reviewed but not used because the EIA's reference and scenario outlooks were outliers vis-à-vis either of the expert third-party forecasts.

PacifiCorp has not deviated from past principles in developing its gas price outlook. The 2017 IRP document's lower natural gas price forecasts reflect changing price dynamics brought about by structural shifts in natural gas markets. The Company's adopted expert third-party forecast, or combination of forecasts, still represents a moderate long-term view as evidenced by either being straddled by peer forecasts or comporting with another credible forecast. As such, PacifiCorp's outlook reflects more of a mainstream consensus view.

C. Avoided Cost Deficiency Period

REC recommends the Commission find PacifiCorp's first year of renewable resource deficiency is 2021. It then calls into question PacifiCorp's 2029 date of acquisition of its next thermal resource and recommends avoided cost pricing with capacity payments starting in 2021.[63] This is not the appropriate proceeding to recommend avoided cost pricing methodology. This may even be moot at this juncture given the Commission held hearings about Schedules 37 and 38 pricing last week.

4. CONCLUSION

PacifiCorp believes its 2017 IRP adheres to the Commission's Standards and Guidelines, and should therefore, be acknowledged. The 2017 IRP includes robust portfolio modeling and prudent planning assumptions that lead to selection of a least-cost, least-risk preferred portfolio. The 2017 IRP also includes an action plan that is consistent with the long-term public interest. PacifiCorp appreciates the comments received from an active and engaged stakeholder group and continues to support stakeholder participation throughout the IRP development process to foster constructive dialogue.

[61] Docket No. 12-035-100, Order on Phase II Issues (August 16, 2013).
[62] Initial Comments of REC, at 15.
[63] Initial Comments of REC, at 2.

PacifiCorp respectfully requests that the Commission acknowledge the 2017 IRP and the 2017 IRP action plan.

CERTIFICATE OF SERVICE

Docket No. 17-035-16

I hereby certify that on December 15, 2017, a true and correct copy of the foregoing was served by electronic mail to the following:

Utah Office of Consumer Services	
Cheryl Murray **(C)** Utah Office of Consumer Services 160 East 300 South, 2nd Floor Salt Lake City, UT 84111 cmurray@utah.gov	Bela Vastag **(C)** Utah Office of Consumer Services 160 East 300 South, 2nd Floor Salt Lake City, UT 84111 bvastag@utah.gov
Michele Beck **(C)** Utah Office of Consumer Services 160 East 300 South, 2nd Floor Salt Lake City, UT 84111 mbeck@utah.gov	
Division of Public Utilities	
Chris Parker **(C)** Division of Public Utilities 160 East 300 South, 4th Floor Salt Lake City, UT 84111 chrisparker@utah.gov	William Powell **(C)** Division of Public Utilities 160 East 300 South, 4th Floor Salt Lake City, UT 84111 wpowell@utah.gov
Erika Tedder **(C)** Division of Public Utilities 160 East 300 South, 4th Floor Salt Lake City, UT 84111 etedder@utah.gov	
Assistant Utah Attorneys General	
Patricia Schmid **(C)** Assistant Attorney General 500 Heber M. Wells Building 160 East 300 South Salt Lake City, Utah 84111 pschmid@agutah.gov	Justin Jetter **(C)** Assistant Attorney General 500 Heber M. Wells Building 160 East 300 South Salt Lake City, Utah 84111 jjetter@agutah.gov
Robert Moore **(C)** Assistant Attorney General 500 Heber M. Wells Building 160 East 300 South Salt Lake City, Utah 84111 rmoore@agutah.gov	Steven Snarr **(C)** Assistant Attorney General 500 Heber M. Wells Building 160 East 300 South Salt Lake City, Utah 84111 stevensnarr@agutah.gov

Utah Association of Energy Users	
Gary A. Dodge **(C)** HATCH, JAMES & DODGE 10 West Broadway, Suite 400 Salt Lake City, Utah 84101 gdodge@hjdlaw.com	Kevin Higgins **(C)** ENERGY STRATEGIES 215 S. State Street, #200 Salt Lake City, UT 84111 khiggins@energystrat.com
Neal Townsend **(C)** ENERGY STRATEGIES 215 S. State Street, #200 Salt Lake City, UT 84111 ntownsend@energystrat.com	
HEAL Utah	
Michael Shea Senior Policy Associate HEAL Utah 824 South 400 West Suite Bl 11 Salt Lake City, UT 84101 michael@healutah.org	
Utah Clean Energy	
Sophie Hayes **(C)** Utah Clean Energy 1014 2nd Avenue Salt Lake City, UT 84111 801-363-4046 sophie@utahcleanenergy.org	Sarah Wright **(C)** Utah Clean Energy 1014 2nd Avenue Salt Lake City, UT 84111 801-363-4046 sarah@utahcleanenergy.org
Western Resource Advocates	
Jennifer E. Gardner **(C)** Western Resource Advocates 150 South 600 East, Suite 2A Salt Lake City UT 84102 jennifer.gardner@westernresources.org	Nancy Kelly **(C)** Western Resource Advocates 9463 N. Swallow Rd. Pocatello, ID 83201 nkelly@westernresources.org
Steven S. Michel **(C)** Western Resource Advocates 409 E. Palace Avenue, Unit 2 Santa Fe NM 87501 smichel@westernresources.org	Penny Anderson penny.anderson@westernresources.org

Renewable Energy Coalition	
Adam S. Long **(C)** Smith Hartvigsen, PLLC 257 East 200 South, Suite 500 Salt Lake City, Utah 84111 along@shutah.law	Renewable Energy Coalition c/o John Lowe PO Box 25576 Portland, OR 97298 jravenesanmarcos@yahoo.com
Interwest Energy Alliance	
Mitch M. Longson **(C)** MANNING CURTIS BRADSHAW & BEDNAR PLLC 136 East South Temple, Suite 1300 Salt Lake City, Utah 84111 mlongson@mc2b.com	Lisa Tormoen Hickey **(C)** Tormoen Hickey LLC 14 N. Sierra Madre Colorado Springs, CO 80903 lisahickey@newlawgroup.com
Sierra Club	
Gloria D. Smith**(C)** Managing Attorney Sierra Club Environmental Law Program 2101 Webster Street, Suite 1300 Oakland, CA 94612 gloria.smith@sierraclub.org	Alexa Zimbalist Research Analyst Sierra Club Environmental Law Program 2101 Webster St., Suite 1300 Oakland, CA 94612 alexa.zimbalist@sierraclub.org
National Parks Conservation Association	
Stephanie Kodish National Parks Conservation Association 706 Walnut Street, Suite 200 Knoxville, TN 37902 (856) 329-2424 ext. 28 skodish@npca.org	Shannon Fisk Earthjustice 1617 JFK Blvd., Suite 1130 Philadelphia, PA 19103 (215) 717-4522 sfisk@earthjustice.org
Rocky Mountain Power	
Jana Saba Utah Regulatory Affairs Manager Rocky Mountain Power 1407 West North Temple, Suite 330 Salt Lake City, UT 84116 jana.saba@pacificorp.com	Yvonne R. Hogle Assistant General Counsel Rocky Mountain Power 1407 North Temple, Suite 320 Salt Lake City, Utah 84116 yvonne.hogle@pacificorp.com
Data Request Response Center PacifiCorp 825 NE Multnomah Street, Suite 2000 Portland, Oregon, 97232 datarequest@pacificorp.com	irp@pacificorp.com

Katie Savarin

Katie Savarin
Coordinator, Regulatory Operations