BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 67

In the Matter of PACIFICORP, dba PACIFIC POWER, 2017 Integrated Resource Plan	Staff Final Comments

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1. Preface

The following are Staff's Final Comments concerning PacifiCorp's (PAC or Company) 2017 Integrated Resource Plan (IRP or Plan). Staff appreciates the hard work and collaborative IRP process with PAC and the other stakeholders. Stakeholders' and PAC's input in comments and in workshops have all been substantive and helpful in understanding the planning issues and the wide variety of perspectives surrounding these issues.

At the heart of this IRP is the Company's proposed Energy Vision 2020 plan, which includes up to 1,270 MW of new wind resources capable of interconnection with PacifiCorp's transmission system, the repowering of 999 MW of its existing wind fleet, and associated new transmission if the new wind is located mostly in Wyoming. Although PAC's Reply Comments address a number of Staff's specific questions, Staff remains unconvinced of the justification to pursue the Energy Vision 2020 plan within the two to four year Action Plan horizon. Consequently Staff does not recommend acknowledgement of the projects within the Energy Vision 2020 plan. Should the Commission wish to consider these projects for acknowledgment, however, Staff offers a set of conditions the Commission may wish to consider to attempt to mitigate risk to customers in the context of economic opportunity-driven resource acquisition.

We cannot conclude anything other than that PAC has failed to demonstrate there is a need for these large capital investments, which is a prerequisite to compelling customers to take on the risk associated with utility investment. Staff's analysis demonstrates that risk associated with the proposed projects is significant, and that even if the resources were needed on a capacity, energy, or reliability basis, it is not clear from the IRP that they represent the lowest cost, lowest risk option. Finally, to the extent that the Company argues these actions are valuable on the basis of economic opportunity or to decarbonize the system, justification under these circumstances requires different analyses outside of our standard planning and rate-setting practice.

A position that the IRP should accommodate an economic opportunity case or a decarbonization case is reasonable. However, in either case, there would have to be much greater exploration of additional policy direction and analysis such as the appropriate sharing of risk between shareholders and customers, level of compensation for use of utility capital employed for reasons other than need, the economic value of existing rate-based resources, and the Commission's statutory authority. For the most part, these issues were not raised or examined by the Company in its filing. We address all of these issues, and the other aspects of the Action Plan, below.

Some, who are unfamiliar with IRPs, may be tempted to interpret Staff's position as a referendum on renewable energy. Such an interpretation would be incorrect and misunderstands the IRP as a tool. In fact, Staff generally assumes that most utility resource acquisition in Oregon going forward will be some form of renewable energy. The IRP is a tool to help identify and determine the amount and timing of any new resource acquisition that best serves the needs of utility customers. The least cost/least risk standard that we use recognizes that customers' energy needs must be met, but also recognizes that these customers may have no choice but to pay for any new resources for decades to come.

2. PAC Action Plan Overview

Per PAC's 2017 IRP, the Company plans to pursue the Action Plan items identified in its Plan to implement its preferred portfolio.[1] Staff's recommendations on PAC's proposed IRP Action Items to the Commission potentially lead to large customer investment in the near-term. Therefore Staff's analysis focuses heavily on the Action Plan. The table below summarizes the Action Plan as filed with the Commission on April 4, 2017:

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.

[1] LC 67 – PacifiCorp 2017 Integrated Resource Plan (IRP), pages 266-269.

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. [Note PacifiCorp has subsequently opened its 2017R RFP to all wind that can connect anywhere on its system (See Docket No. UM 1845). This RFP was released to market September 27, 017 and is available for review online at PacifiCorp.com – 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. – 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.

1c	**Renewable Portfolio Standard Compliance** • 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.
Action Item	2. Transmission Actions
2a	**Aeolus to Bridger/Anticline** • 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.
2b	Energy Gateway Permitting

	• 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 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.
2c	Wallula to McNary 230 kV Transmission Line • 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.
2d	**<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 Actions
4a	**<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 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	**<u>Hunter Units 1 and 2</u>** • 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	**<u>Huntington Units 1 and 2</u>** • 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	**<u>Dave Johnston Unit 3</u>** • 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.

3. Staff Comments on Action Plan Items

This section is specifically focused on the Action Plan items that Staff intends to recommend that the Commission either not acknowledge or acknowledge with requirements. For items not specifically addressed in this section, Staff recommends that the Commission acknowledge those Action Plan Items. Each subsection contains the logic of and evidence for Staff's positions.

3. A. PacifiCorp's Proposed Resource Acquisitions

As discussed in the Preface, PacifiCorp proposes the addition of three major system resources in the near term as part of its 2017 IRP process. PacifiCorp proposes Action Items 1a (wind repowering), 1b (new wind), and 2a (new transmission from Aeolus to Bridger/Anticline). As learned in Docket No. UM 1845, PacifiCorp intends to issue a wind resource request for proposals that includes all wind that can interconnect to its transmission system in any of the states in its service territory.

PacifiCorp has repeatedly stated that these resources are not being added to the system to meet a regulatory requirement such as the RPS, but acknowledges they may be used to contribute towards meeting future RPS compliance needs. [2] PacifiCorp notes that these resources are anticipated to produce enough RECs to meet Oregon compliance needs through 2035.[3]

3. A. 1. The IRP process and system needs.

Integrated resource planning in Oregon exists to "engage in an open and robust resource planning process to help ensure an adequate and reliable *supply of energy or capacity* at the least cost and least risk to the utility and its customers."[4] As indicated by the Commission in Order No. 89-507, the IRP analysis contains several planning elements, but the foundation is identifying system need:

> ….2. Development of high, medium, and low load forecasts for the utility's system and assignment of some probabilities to each. 3. Determination of the levels of peaking capacity and energy capability expected for each

[2] PacifiCorp Response to OPUC Information Request (IR) 52; *see also* UM 1802 – PAC/200, Lockey/8.
[3] PacifiCorp 2017 IRP at 266.
[4] Order No. 14-415 at 1 (emphasis added).

> year of the plan. 4. *Identification of resources needed to bridge the gap between expected loads and resources*…[5]

The identification of need is fundamental because the IRP defines actions to address how the system should change to fill the gap between expected loads and resources (i.e. to meet the need). As discussed more fully below, PacifiCorp's Energy Vision 2020 is not consistent with need-based IRP planning and contrary to the Company's claims otherwise, represents a purely economic opportunity.

PacifiCorp's characterization of need in the IRP process is not supported by Commission practice.

PacifiCorp argues that Staff's position regarding the IRP process that need is a threshold factor for determining the reasonableness of new major resource acquisitions means that PacifiCorp can satisfy its least-cost, least-risk planning obligations by doing nothing.[6] In support of its position, PacifiCorp cites Order No. 89-507, noting that the order discusses an examination of "all known resources."[7] However, this order strongly supports Staff's position that need is fundamental to major resource acknowledgement. As discussed previously, Order No. 89-507 discusses "all known resources" in a context of need, recommending that the IRP process identify "resources needed to bridge the gap between expected loads and resources."[8]

PacifiCorp also argues that Staff's emphasis on need is inconsistent with Staff's previous request that long-term RPS procurement be discussed in the IRP process.[9] But need-based resource acknowledgement and long-term planning are not mutually exclusive. Staff reiterates the same position in these comments as it held in Docket No. UM 1771, which is that the IRP process is the essential forum for analyzing long-term RPS compliance and the economic case for various options. Staff expects this analysis to be part of an IRP.[10] Acknowledging action to acquire RPS compliant resources or energy or capacity resources requires a regulatory, energy, or capacity need. The two concepts work together; the long-term plan is developed, tested, and consistently updated to the point that near-term action is necessary to meet need.

Arguing that the Commission can allow for recovery of non-need based resources, PacifiCorp cites a 1987 decision in which the Commission found investment in a plant prudent despite the output not being needed for six to eight years.[11] Importantly, the Colstrip 4 facility referenced in the docket was not acknowledged in an IRP to serve as an economic opportunity. It was acknowledged to serve a need. In a prudence review,

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[5] Order No. 89-507 at 8 (emphasis added).
[6] LC 67 - PacifiCorp Reply Comments at 15.
[7] Order No. 89-507 at 2.
[8] Order No. 89-507 at 8.
[9] LC 67 - PacifiCorp's Reply Comments at 16. Note: The Commission Acknowledged an IRP action item in Order No. 16-071 to issue this IRP; and did so in part due to an anticipated, near-term 111(d) compliance obligation; not an exclusive RPS obligation, as asserted by PacifiCorp in Reply Comments. *See* Order No. 16-071 at 4.
[10] Order No. 16-188, Appendix A at 6.
[11] LC 67 - PacifiCorp's Reply Comments at 17.

the Commission chose not to penalize the PGE for “not precisely matching the timing of its construction…to the need of its customers.”[12] PacifiCorp’s IRP does not present a need mismatch; there is no need for the proposed resources *at all*.

Previous Commission decision regarding Customer Benefits, Costs, and Risks

In Docket No. UE 308, Order No. 17-088, Commissioners rejected Portland General Electric’s request to include long-term natural gas hedging costs into the Company’s 2017 Annual Update Tariff. Commissioners’ findings included, but were not limited to, identifying that risks were not equitably allocated between shareholders and customers, and indicated an unwillingness to rely on what was described as essentially speculation to approve an investment that has very real risk of costing customers. Staff finds customer exposure to risk in a situation in which the resource is not actually needed would be similar with PAC’s proposed resource acquisitions.[13]

3. A. 2. PacifiCorp’s Action Items 1a, 1b, and 2a are inconsistent with need-based IRP planning.

PacifiCorp’s requested acknowledgement of Action Items 1a, 1b, and 2a is not consistent with the IRP process as developed by the Commission, because these Action Items are not needed to bridge a gap between expected loads and resources. Rather, these Action Items were added to the Company’s likely preferred portfolio just prior to filing, when the Company went beyond a need-based process and created “Final Screening Portfolios.” PacifiCorp describes the creation of the final preferred portfolio, FS-GW4, as follows:

> At the end of screening stage two, the preferred-portfolio eligible Gateway studies indicated potential for a time limited opportunity to align development of Energy Gateway segment D2 with wind projects that can qualify for the full value of the PTCs.[14]

PacifiCorp’s existing resources are able to meet its resource needs. By adding approximately $3.2 billion in wind repower, in new wind resources and transmission to the portfolios that already meet need, existing resources are adjusted accordingly: System market sales would increase, front office transactions would be delayed, demand response program implementation would be delayed, and a 2036 CCCT would be deferred beyond the 20 year horizon. PacifiCorp’s analysis shows a benefit of roughly $124 million over 20 years for the $3.2 billion investment. These resources, which could remain in rate-base for decades, would largely displace resources, such as front office transactions, for which PacifiCorp receives no rate of return. Finally, these additional resources would not lead to replacement or early retirement of any of PacifiCorp’s 24 existing coal fired units and would not serve to “decarbonize” PacifiCorp’s system.

[12] Order No. 87-1017.
[13] PAC’s Action Items 1a, 1b, and 2a, in its 2017 Action Plan (Chapter 9, pages 265-269 of the 2017 IRP).
[14] IRP, page 219.

PacifiCorp argues that its new major resource acquisitions are "conceptually identical to the IRP's treatment of demand-side resources."[15] However, unlike DSM, Action Items 1a, 1b, and 2a have an economic case that rests primarily on assumptions decades into an uncertain future and are subject to extensive risks. As the Commission has observed, "…probabilities that different outcomes will occur can be reasonably assigned for a risk, but not for an uncertainty."[16] In contrast, DSM resources are approved using a variety of tests that rely most heavily on near-term conditions to determine cost-effectiveness, and are inherently low-risk. These DSM resources are subject to annual review, and past and current programs are constantly evaluated and changed.

Spending on individual measures and even individual programs is significantly smaller than on new major resources, so that if an individual program or measure is determined to be performing poorly it can be changed or abandoned and the overall portfolio of measures can continue to be cost-effective. DSM is subject to quick course correction, and is truly "no regrets." In contrast, new major resources are long-term commitments that customers will likely pay for despite what happens in the future. DSM program lives rarely extend beyond a decade, and even when they do, the analysis necessary to determine cost-effectiveness focuses on the near-term, the period inherently subject to risk assessment. DSM is a resource that electric companies are statutorily required to prioritize because of the many recognized customer benefits.

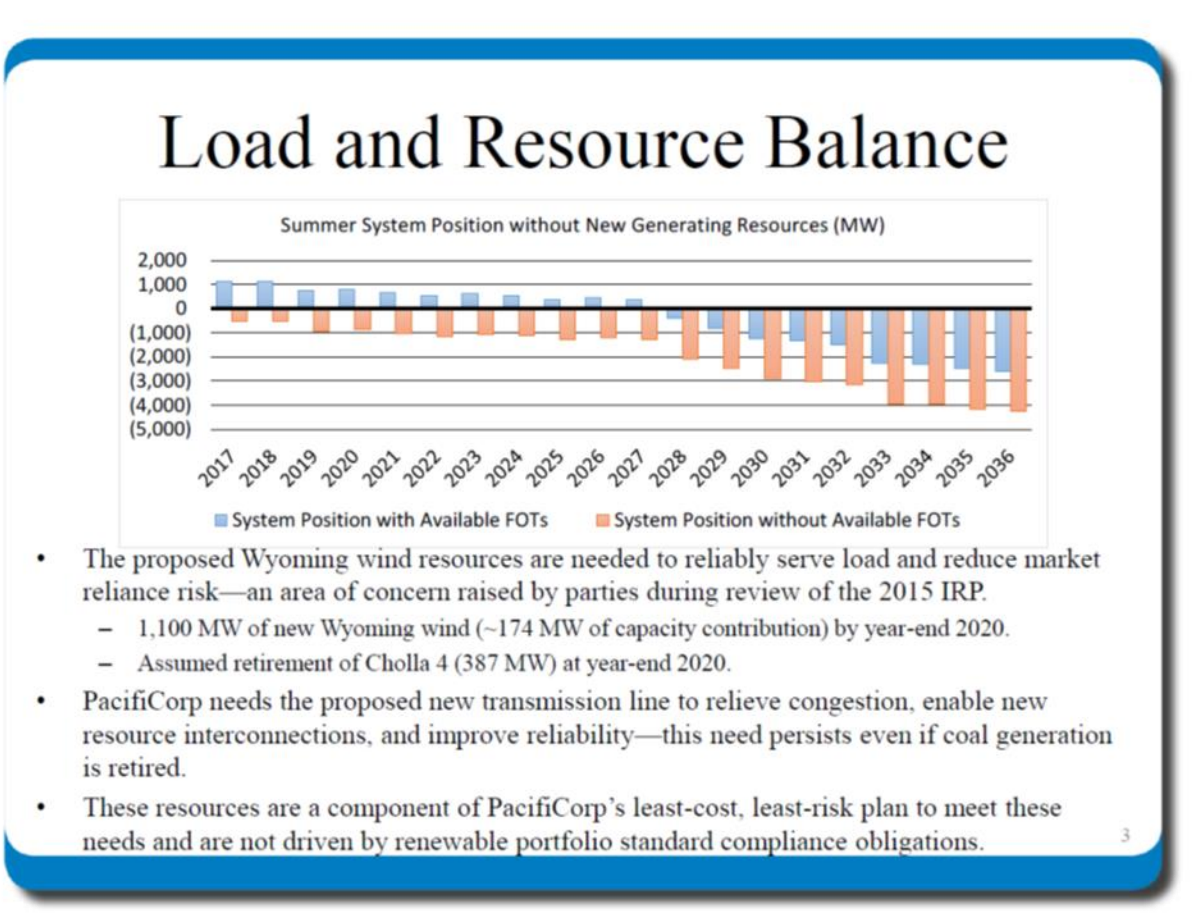
3. A. 3 Action Items 1a, 1b, and 2a represent Economic Opportunities

At the September 14, 2017, Special Public Meeting, PacifiCorp began reframing its justification for the new resources to include need. At the meeting, PacifiCorp represented that the new Wyoming wind and transmission are needed to displace front office transactions (FOTs). No such claim has been made for the wind repowering project—there appears to be consensus that this project represents an economic opportunity. Despite PacifiCorp's claims otherwise, Staff continues to find that the Company's new wind and transmission projects represent an economic opportunity, and do not serve to address a resource need.

1. PacifiCorp's justification has not been consistent

PacifiCorp shared the following slide with the Commission and stakeholders:

[15] LC 67 - PacifiCorp Reply Comments at 18.
[16] Order No. 07-002 at 5.



This slide introduces the following claims:

- Wyoming wind resources are needed to displace system available FOTs, which is equivalent to approximately 174 MW of capacity contribution.
- New transmission is needed to enable the new wind, and to "improve reliability—this need persists even if coal generation is retired."

These claims, however, are not supported by the Company's filings, workshop statements, or statements in other jurisdictions. Even without new major resource acquisitions, PacifiCorp's system remains in a state of resource adequacy. Accordingly, the new major resources are by their nature an unnecessary potential economic opportunity that do not need to be acquired to provide reliable service to customers in a least-cost, least-risk manner. PacifiCorp currently has a clear, least-cost, least-risk path to serving customers without the new major resources.

PacifiCorp's claim that these resources are needed is new, and not something PacifiCorp inadvertently overlooked in developing its RFP. PacifiCorp argued in Commission filings as recently as July 21, 2017, that absent a Wyoming wind acquisition, the Company has no need for capacity until 2028. Specifically, PacifiCorp stated in its avoided cost filings that absent the new wind: "PacifiCorp has surplus capacity through 2027, and a capacity shortfall starting in 2028."[17] Avoided cost filings clearly indicate system needs, because these filings require the utility to identify when a new capacity resource is needed and can be deferred by qualifying facilities. That date is called the "deficiency date," and is the date at which a qualifying facility would be paid higher rates for needed capacity. In avoided cost filings, PacifiCorp has been consistent—without the proposed wind, the Company has no need for capacity until 2028.[18] If the proposed wind were truly needed, as now argued by PacifiCorp, the capacity need would not be 2028 but instead 2021 or earlier—the time by which new resources would be developed and operating on PacifiCorp's system or the time at which PacifiCorp is over-reliant upon FOTs to fulfill load-resource-balance requirements.[19]

PacifiCorp's filings in Docket No. UM 1802 reveal the Wyoming wind proposal for what it truly is, a claimed, potential economic opportunity and not a necessary resource acquisition to meet load requirements. In that filing, parties have argued that PacifiCorp's proposed wind project should be deferrable by qualifying facilities.[20] PacifiCorp has countered that the resource cannot be deferred because it is a PTC-based economic opportunity—not based on a capacity need.

Where capacity is needed, PTCs are irrelevant to the question of whether or not a new resource will be acquired. PTCs may help the Company decide *which* resource to target in an RFP, but for the purposes of a capacity deferral deficiency date, PTCs are meaningless, insomuch as any resource that can deliver capacity to the company at avoided costs up to the capacity need should be acquired. In contrast, PacifiCorp has no stated plans to procure capacity or build new transmission without the PTCs. The Company states this explicitly in direct testimony:

> The loss of the PTC would eliminate much of the benefits associated with the 2021 Wyoming wind resources. And without those benefits, the Wyoming wind would not be a part of PacifiCorp's least-cost, least-risk plan to reliably meet system load.[21]

If the claimed potential Wyoming wind opportunity were lost because of the loss of PTCs, and PacifiCorp had a capacity need, PacifiCorp should nonetheless seek to acquire capacity to fulfill that need. However, without PTCs PacifiCorp indicates it will take no resource acquisition action. The Company has no stated alternative capacity acquisition path to its Plan.

[17] UM 1802 - PAC/300, MacNeil/21.
[18] Ibid.
[19] September 14th Workshop Presentation at 3. According to PacifiCorp's presented information, the Company has a capacity need starting as early as 2017.
[20] UM 1802 - REC-CREA/300, Higgins/2.
[21] UM 1802 - PAC/300, MacNeil/26.

2. PacifiCorp has not clearly identified its capacity need.

Despite claiming that the new wind and associated transmission are necessary to address capacity needs, *PacifiCorp has not identified what its capacity need is*. PacifiCorp merely presents a passing mention of need of 174 MW in a single workshop slide, offered after the submission of the IRP and the IRP Energy Vision 2020 supplement filed with the Company's reply comments, referenced above. This issue is further explored in Section 3.A.3, below.

Staff still does not know if this is the actual capacity need, or if the capacity need asserted by PacifiCorp is greater than 174 MW. Recent developments in Utah create questions as to what the asserted capacity need actually is. In Utah, the Independent Evaluator (IE) requested and the Utah Commission ordered that PacifiCorp expand its Wyoming Wind RFP to include wind resources anywhere on the system.[22] PacifiCorp concurred with this recommendation, and at the September 14, 2017, public meeting update on its RFP in UM 1845 stated that *additional projects, beyond the 1,100 MW of new Wyoming wind*, may be acquired under the expanded RFP, and that the Company is considering an additional solar RFP.[23]

Accordingly, PacifiCorp's capacity need may not be 174 MW. If a claimed capacity need is the impetus for these resource acquisitions, then PacifiCorp's IRP is grossly deficient. Further, the conversation at the September 14 public meeting is indicative of the problem with economic opportunity-based planning and acquisition. The notion that procuring *all* economic resources—regardless of need—is completely inconsistent with Oregon's standing interpretation of the regulatory compact. Such a notion could justify the layering of resource upon resource in customer rates, even when there is no clear reason to do so.

The Commission does not acknowledge actions to meet a need that has not been clearly identified or defined. For example, parties and the Commission engaged in extensive analysis to identify and properly characterize PGE's recently acknowledged capacity need. [24] PacifiCorp's to-date undefined capacity need must be subject to the same rigorous analysis. This analysis must start by PacifiCorp communicating to the Commission and parties the explicit size and timing of the need. Until this crucial step is completed, Staff cannot recommend acknowledgement of an action to meet a need that has not been identified or quantified.

Staff suspects that PacifiCorp has not identified a clear capacity need because the resource acquisition is based on a pure economic opportunity, as originally indicated by the Company. This is borne out in PacifiCorp's discussion and analysis of the Aeolus to Bridger/Anticline transmission segment. Like the 1,100 MW of wind development, PacifiCorp has introduced an assertion that the transmission is needed.

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[22] Utah Docket No. 17-035-23 Order Approving RFP with Suggested Modification at 7.
[23] Statements of PacifiCorp representatives at the September 14, 2917 LC 67 Special Public Meeting.
[24] See docket LC 66.

The above referenced slide states that the wind is needed to "improve reliability—this need persists even if coal generation is retired." PacifiCorp has echoed this point in other recent filings: "PacifiCorp needs and has needed the new transmission line for quite some time."[25] Contrary to these statements, it is clear that the construction of the segment represents an economic opportunity, not a need.

3. PacifiCorp concedes that its proposed transmission line is not needed to address short-term reliability concerns on a stand-alone basis

In the absence of the new wind acquisition, PacifiCorp would not construct or acquire the new transmission line. Representatives of PacifiCorp have repeatedly acknowledged this fact:

> Staff: "Without the 1,100 MW of wind, would PacifiCorp build this transmission?
>
> PacifiCorp: "No, in essence that's what we're trying to demonstrate this transmission line paid for by the benefits of the wind."
>
> Staff: "So there is no reliability need to put this transmission in place absent the wind, is that correct?"
>
> PacifiCorp: "Right. We are currently compliant with NERC reliability standards and expect to be going forward." [26]

PacifiCorp's acquisition of new transmission associated with the 1,100 MW wind development proposal is therefore an economic opportunity, and not a needed system asset. If the resource were needed, it would be needed independent of any wind development. Staff is firmly convinced that PacifiCorp has not demonstrated a system need for capacity or transmission. Accordingly, Action Items 1a (as the above arguments apply equally to the 999 MW wind repowering project), 1b, and 2a should be reviewed and analyzed as economic opportunities, not actions to fulfill a need.

3. A. 4. There are significant Customer Risks Associated with Energy Vision 2020.

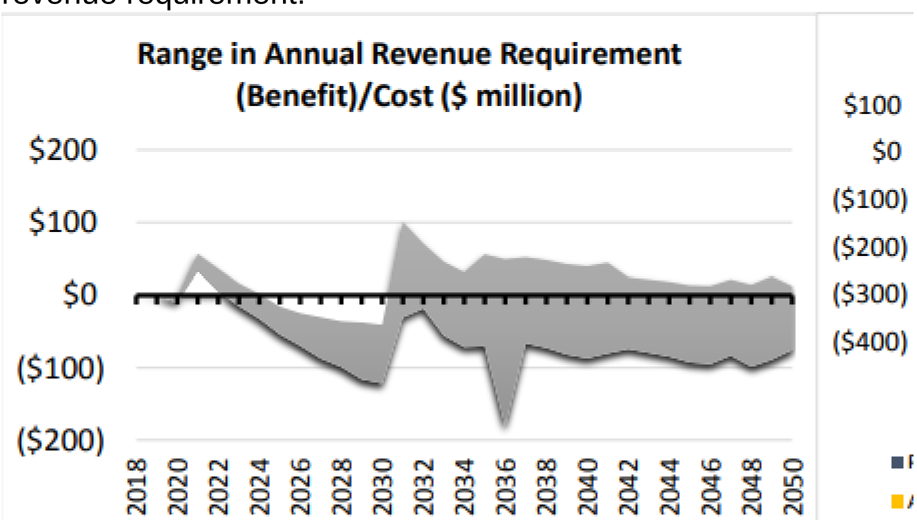
Given that the projects proposed by PacifiCorp do not address a capacity or energy shortfall, the focus on the risks they pose to PacifiCorp's customers becomes more acute. As previously noted, Staff is aware that, when investor-owned utilities invest in large capital projects for their systems, they are necessarily exposing their customers to financial risks the customers would not have otherwise been subject to. Barring a later finding of utility imprudence, it is the customer who absorbs variances in future outcomes, so that the investors of the utilities have the opportunity to realize their Commission-authorized returns with minimal risk. These risks, such as construction cost overruns and revenue shortfalls, can be significant. In this section, Staff highlights

[25] UM 1845 - PacifiCorp's Response Comments to Staff's Recommendation, p.2.
[26] Approximately 2:20 to 2:30 of the September 14, 2017 LC 67 Special Public Meeting.

several of the risks that customers would be exposed to under a generic $2.5 billion, 1,270 MW project consisting of new wind and transmission construction. Where possible, we also provide dollar values of magnitudes of cost to customers should the future not materialize as expected, keeping in mind the Company estimates that in the specific Wyoming wind project considered in its IRP, total project expected benefits to customers to be $137 million over 30 years. Note that this generic project is not PacifiCorp's Wyoming benchmark, and its sensitivities are intended only to be illustrative. For example, if only 1,000 MW of new facilities bid successfully, then the production tax credit risk would be reduced by roughly one-fifth. This same analysis would also apply to a $1 billion wind repowering project, and would lead to similar conclusions.

Major Risks to Customers

At the September 14, 2017 OPUC special public meeting, PacifiCorp presented materials indicating that both the wind repowering and new wind and transmission projects are likely to benefit customers through the eventual potential lowering of the revenue requirement. The Company indicated "near-term net benefits are not speculative."[27] Regarding the new wind and transmission project, PacifiCorp provided the following net revenue requirement risk chart, showing certain near-term upward pressure on the revenue requirement, followed by less-certain future reductions to revenue requirement:



While this funnel of potential outcomes does in fact look speculative to Staff, we note that the risk funnel is produced by changing assumptions on only two variables: gas price and carbon dioxide cost. There are a number of other risks that should be considered, and Staff highlights several of the most significant below.

[27] September 14th Workshop Presentation at 4.

Production Tax Credits are not Realized as Expected

PTCs are a major component of the overall economics of the project. In an August stakeholder meeting, the Company indicated that the value of the PTCs cover over 40 percent of the entire project cost. Therefore it is clear that any PTC shortfall will have significant consequences on the customers paying for the project. There are two primary concerns: first, that there are not *as many* PTCs as expected, and second, that *each individual* PTC is worth less than expected.

1. Not as many PTCs are generated as expected

Each PTC is created with each actual megawatt-hour of qualifying energy generated. To have the best estimate of the value of a given project's PTC stream (and project value overall), companies often hire independent third-party experts to estimate expected capacity factor. However, it is understood by all that the realized production in the first 10 years of a project's life—the years when PTCs are being created by the project—will be different than expected. This difference will also impact the value of the energy generated. Using generic assumptions, a one percent drop in realized wind capacity factor (i.e. recognized realized capacity factor of 40.5 percent instead of an expected 41.5 percent) results in roughly $70 million of loss of economic value of the project to customers.

In this same way, there may also be a PTC (and energy) shortfall due to higher scheduled and forced outages than expected, which reduces the project's realized capacity factor. Staff also notes that both these outcomes could occur simultaneously.

2. Individual PTCs not as valuable as expected

The PTC is set at a value of $0.024 per kilowatt-hour as of 2017. This value is published annually by the Internal Revenue Service (IRS), and is inflation adjusted. However, in a changing regulatory environment, the future value of the PTCs is not necessarily certain. If the IRS were to stop inflation-adjusting the value of the PTC, for example, the value of the PTCs for these projects would fall by almost $100 million. This is an example of the regulatory risk surrounding the future of PTCs. Were the PTC program ended in its entirety, the cost to customers would be roughly $850 million.

Similarly, in order to be guaranteed to qualify for the full, 100 percent value of the PTC, the project's commercial operation date (COD) must be no later than December 31, 2020. If the COD is after this date but before January 1, 2021, the project's entire ten-year stream of PTCs could be reduced by roughly $170 million. This risk is difficult to mitigate, as it would likely only become clear there is an issue as the COD approaches, and the majority of capital has already been spent.

Both these items could occur simultaneously as well, and could also coincide with factors leading to fewer PTCs overall.

The Project Experiences Construction Cost Overruns

Generation projects may experience construction cost overruns for a variety of reasons, from change-order improvements that benefit customers, to added costs to address previously unidentified issues.

The Company has experience building and procuring wind generation, and can partly mitigate some of these risks. For example, contract provisions can shift some amount of risk back to the contractor, to the extent that the contractor is able to support the financial exposure. However, if cost overruns were paired with construction delays, it is unclear how contractors would necessarily be able to bear the substantial costs of the lost PTCs.

Staff also notes that the Company appears to have less experience building 500 kV transmission lines than building lower voltage transmission lines, so the potential for cost overruns would seem even more likely here. In any case, we note that each one percent in cost overrun equates to roughly $50 million in lost value to customers.

Energy Prices are Lower than Anticipated

One of the largest risks to customers is that electricity market prices are lower than expected. IRP models use a forward price curve to determine the net cost of the utility's operations, from generating to meet load to economically buying and selling energy from the market. Energy prices will almost surely turn out to be higher or lower than the model expects. In the present sensitivity model, the energy price forward curve is assumed to start at $30 per megawatt-hour and to grow at inflation. If it were to start one dollar lower, at $29 per megawatt-hour, that would equate to roughly a $70 million dollar impact to customers.

The following table summarizes the sensitivities examined by Staff:

Sensitivity	**Amount of Sensitivity (Change)**	**Impact (Customer Harm)**
Capacity Factor Shortfall	One percent (41.5% -> 40.5%)	$70 million
PTC Value Decrease	PTC value does not grow at inflation	$100 million
COD Date Missed	Less than one year delay	$170 million
Construction Cost Overrun	One percent	$50 million
Energy Price Shortfall	One dollar	$70 million

The above sensitivities demonstrate that a hypothetical $2.5 billion capital project presents an array of risks to customers, in some cases even when the realized outcome is close to the modeled assumption.

The Customer and the Utility as an Investment Partnership

Staff has two significant concerns with PacifiCorp's request for acknowledgement of major resource actions driven not by need but by "economic opportunity," or an apparent customer-utility investment partnership.

1. Major resource investment adds unwarranted risk for customers

All major capital investments present risks, but requiring that ratepayers bear the risk for an investment makes sense in the context of a needed resource. The Commission provides guaranteed rates of return for prudently incurred necessary investments that maintain grid reliability (i.e. "keep the lights on"), limiting ratepayer exposure to cost increases.

Energy Vision 2020 is a request from the utility to the Commission for the utility to invest capital in projects with the understanding that, barring an unusual later finding of imprudence, customers will pay back 100 percent of the capital along with a rate of return. In exchange for this repayment of capital with a rate of return, customers would receive whatever value or costs are associated with the revenue stream from the project which are dependent upon project performance. If the Commission allows this project into rate base, the Company is shielded from project performance risk. Return of and on investment is virtually guaranteed to shareholders. However, the expected net present value revenue requirement (NPVRR) benefits shown in PacifiCorp's analysis are not guaranteed benefits to customers. The benefits are dependent upon several variables, which include the uncertainty of wind patterns and seasonality, the uncertainty of the forward energy market for the next 30+ years, the uncertainty of wind conversion efficiency, uncertainty of future disruptive technologies and many more risks.

In summary, guaranteed rates of return – and customer acceptance of possible cost overruns, performance risks, or investment obsolescence are reasonable where an investment is needed. Customer acceptance of these risks is inappropriate where the investment is unneeded.

2. Risk of setting precedent

If these resource actions were acknowledged, utilities would see reward in finding new resource investments in future IRPs that add capital to the rate base but really aren't needed to provide service. The monopolistic utility model under the regulatory compact encourages this.[28] For example, it is conceivable that the future will bring a time-limited opportunity to purchase a natural gas-fired plant that adds significant capacity and energy to a system, as well as expense to the rate base. If not designed to replace

[28] This is known as the Averch-Johnson Effect. *See* "Behavior of the Firm under Regulatory Constraint," Averch, Harry and Johnson, Leland. (1962), accessed at http://pascal.iseg.utl.pt/~carlosfr/ses/averch_johnson.pdf.

existing coal units or to meet load growth, such supply would simply not be needed. However, if demonstrated "economic," it could justifiably be acknowledged in an IRP proceeding under an economic opportunity framework. Each new additional rate-based resource would have the potential to impose new costs on customers, and utilities would see ever-increasing, virtually risk-free returns. This runs counter to Oregon's basic cost of service construct.

In part, this dynamic is playing out in real-time during the present proceeding. Unbounded by need, the potential for new, rate-based resources is already growing in PacifiCorp's 2017 IRP process. As noted above, the wind acquisition RFP has been expanded at the urging of the Utah IE on the economic opportunity grounds that if the Wyoming wind projects are economic, other wind projects may be economic and should be considered.[29] PacifiCorp agrees, and notes that other resource acquisitions including additional wind and solar may be economic and where they create "net benefits" for customers would be acquired along with and in addition to Wyoming wind.[30]

Now it seems the scope of the originally identified $3.2 billion dollar investments is expanding. As the logic goes, if one economic opportunity makes sense to acquire, others that offer the same or better modelled net benefits to ratepayers should as well. Unbounded by need, any economic opportunity could be the subject of acquisition. Ultimately, ratepayers will be responsible for facing the burden of the risk and cost associated with economic opportunities, unless the Commission recognizes that economic opportunity must not subject ratepayers to these risks and costs in the same manner as truly needed resources.

PacifiCorp's proposal necessitates that the Commission make the IRP into something else altogether. It would need to become a reexamination of all existing resources and an examination of all alternatives to these existing resources.

Traditionally, it is assumed that assets and strategies will continue in the utility's portfolio until the end of their useful economic or strategic lives. Opening the IRP to economic opportunities would require a wholesale review of all existing system elements and their alternatives. Such a broad review would certainly be incomplete without the type of analysis proposed in this case by Sierra Club and the Renewable Energy Coalition.[31] Sierra Club argues that PacifiCorp should examine each existing coal resource individually for economic viability.[32]

This would produce probative information in the context of considering new resources that are not needed. For example: If in the context of individual facility analysis it were determined that the cost and risk associated with an existing resource was greater than the cost and risk associated with a new major resource, replacement of the existing resource by the new resource might make clear, unspeculative economic sense. "Need" would be obviated by the direct analysis associated with comparing known costs and

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[29] Ibid.
[30] Statements of PacifiCorp representatives at the September 14, 2017 LC 67 Special Public Meeting.
[31] LC 67 - Sierra Club Comments at 3.
[32] Ibid. at 8-9.

performance characteristics. This type of analysis, and more besides, would be part of any wholesale system review where existing resources are examined next to new, but not needed alternative major resources. PacifiCorp has not completed such an analysis, and has not proposed to do so. More importantly, the Commission has not designed the IRP process as a comprehensive existing resource review with an eye towards replacement.

3. A. 5. Wind is Not a Desirable Resource Type to Hedge Load or to Replace Front Office Transactions.

Replacing the capacity contribution FOTs provide with variable energy resources, and wind in particular, eliminates the forward hedging benefits FOTs provide. Despite the risks that all large capital projects have—some of which are provided above—they can generally be viewed as a *hedge* of another risk. The risk being hedged is the ability of the utility to safely and reliably serve customers. Each gas turbine added to a utility's fleet, for example, increases the utility's ability to meet expected loads, as well as to adjust to track load when it is not as expected (due to unexpected fluctuations in wind and solar generation, unexpected loss of load, generator trips, etc.).

Every type of generation a utility may add to its fleet is a hedge, in that it incrementally improves the utility's ability to meet load without reliance on spot market transactions. Similarly, FOTs that are for terms of longer duration (month-ahead, quarterly, annual, etc.) are hedges. These FOT hedges, though, are not as effective as the aforementioned natural gas plant because they are generally blocky, fixed megawatt packages of power. So while they are very useful in meeting expected load—as FOTs are often *at least* as reliable as a physical power plant,[33] they often do not provide the ability to follow load. An additional benefit of FOTs, however, is that they also hedge the *price* at which their portion of load will be met. The natural gas plant is subject to the price of natural gas, and the cost of the energy it delivers will fluctuate accordingly, unless the utility separately hedges its natural gas supply.

Clearly, dispatchable generators have attributes that make them both attractive and unattractive for hedging purposes. The same cannot be said for intermittent variable energy resources (VERs) such as wind. In determining its load and resource balance and net surplus or need, a utility will add up its expected available generation for a particular hour[34] using each resource's capacity contribution. Each resource's capacity contribution will be less than its nameplate capacity because, among other things, it may not be able to generate when called upon in a given hour. For example, the resource may not be on-line. In the case of wind, the wind may not be blowing. A natural gas plant may have a capacity contribution over 90 percent of nameplate.

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[33] Many FOTs in the northwest are executed under Western Systems Power Pool Service Schedule C, which provides for firm uninterruptable capacity/energy sale service except under limited situations such as Uncontrollable Force or if parties mutually agree otherwise. This makes them *by definition* more reliable than so-called "unit contingent" energy. *See* http://www.wspp.org/filestorage/current_effective_agreement_062017.doc.

[34] PacifiCorp's 2017 IRP examines its capacity position at both summer and winter expected peak loads. See IRP, pages 10-11.

Because, as previously discussed, many FOTs are firm energy products, their capacity contributions are also very high. In contrast, PacifiCorp's Wind and Solar Capacity Contribution study determined its wind fleet's capacity contribution was 15.8 percent on the east side of its system, and 11.8 percent on the west.[35]

To replace the forward hedging benefits that FOTs provide, many multiples of the FOT contract quantities would need to be built of nameplate wind. PacifiCorp's 10-year summer capacity position forecast includes 1,670 MW of capacity contribution from available FOTs.[36] Assuming PacifiCorp desired to replace *all* of this FOT capacity contribution with east wind, it would need to procure nearly 11,000 MW of wind.[37] For perspective, the total capacity contribution of all existing units in PacifiCorp's fleet is roughly 10,500 MW.[38] Because the wind may not blow any particular hour, reliance on wind to this extent for reliability purposes would need to be closely scrutinized.

It is clear that using VERs generally and wind especially is not a favorable way to replace the capacity or energy contribution FOTs provide. Similar to FOTs, wind also provides little benefit in following load.[39] Therefore Staff concludes that wind is not necessarily a desirable resource type to hedge load or to replace FOTs.

3. A. 6. Utility Planning for Decarbonization Should be Comprehensive

In an August 17 workshop hosted by the Commission, and again at the August 29 hearing for UM 1845 to examine PacifiCorp's proposed RFP, the Company discussed the concept of system decarbonization in conjunction with the new proposed renewable energy resources. PacifiCorp's IRP recognizes decarbonization as a value that these investments will help support.[40] PacifiCorp identifies CO2 emission reduction as a long-term priority that the IRP advances.[41]

Staff considers the concept of decarbonization to be a significant addition to the IRP objective of identifying the least-cost and least-risk portfolio. Staff considers it important to examine how decarbonization could be approached in a manner consistent with the Commission's statutory authority and mission.

A decarbonization strategy is more extensive than a price on carbon for planning purposes

[35] IRP, page 88.
[36] IRP, page 11.
[37] Ignoring diversification effects, for this simple example.
[38] IRP, page 11.
[39] Wind units can be curtailed to track load as it falls, providing so-called "regulation-down" service. The more valuable service, however, is "regulation-up," in which units ramp up with load. As units with no fuel cost and potentially generating valuable production tax credits, it would not be economic for wind units to voluntarily back off generation to be able to provide regulation-up service.
[40] IRP, page 62.
[41] IRP, page 179.

Imputing a future cost to carbon emissions is not equivalent to the development and vetting of a broader decarbonization strategy. Staff envisions a decarbonization strategy as a calculated approach that has as its end-goal a system that is as free of emissions as possible, whereas planning efforts that incorporate a price for carbon do not necessarily dictate a carbon-free resource outcome. Decarbonization planning is significantly more comprehensive and focused than planning efforts that assign costs to carbon but do not prioritize on effecting system transition.

Decarbonization represents a major shift for utility planning, and would introduce new analytical filters into Commission review of utility plans and actions

Service at least cost and least risk are the current values which the Commission employs to review utility planning and action to protect consumers and ensure an affordable, safe, and reliable system. Decarbonization has the potential to affect nearly every aspect of utility investment. In other words, a decarbonization strategy cannot simply be a proposal to add carbon-free investment on top of a rate base that is currently fossil fuel-centric. Accordingly, such a momentous change in our values for examination of utility action must be reflected in changes to utility planning.

Values for Decarbonization planning and action

The Commission can take numerous factors into account in determining whether or not a strategy is least-cost, least-risk, including a review of long-term trends, state policy priorities, and external environmental impacts which may become internalized with future policy changes.

For decarbonization, an analysis would have to be:

- *Legally authorized*. Statutory authorization to consider carbon *per se* in resource acquisition and retirement would have to be clear.
- *Comprehensive and planned.* Decarbonization should be introduced into the system through comprehensive analysis. Decarbonization would be planned, and would inform plans, such as the IRP. Alternatives would be reviewed, and analysis would be provided to support a specific decarbonization plan as least-cost, least-risk.
- *Vetted and supported by a broad group of stakeholders.* Commission rules and decisions place a high value on transparent development of plans with wide stakeholder input.
- *Consistent with other Commission goals.* Commission Staff would expect that decarbonization planning and actions would be harmonized with its Senate Bill 978 and DSP responsibilities, and as well as other regulatory review efforts.
- *Reviews retirement as well as resource acquisition*. New renewable energy resource acquisitions proposed by utilities have been justified in part as decarbonization efforts. Commission Staff would expect that appropriate decarbonization planning would also examine resource retirement in great detail, in conjunction with any new resource acquisition. The plan should lead to actual carbon reduction and not be based on jurisdictional allocation of resources.

The decarbonization plan would form a new, central component of IRP process and other processes. It would have to be updated and reviewed with stakeholder input, acknowledged as part of IRP process, and would inform resource decision making. Although PAC verbally highlighted the decarbonization benefits of the new resources, it appeared to be an afterthought, not an intentional driver for the investment.

1. Recommendation regarding PacifiCorp's Resource Acquisitions

Staff recommends that the Commission not acknowledge PacifiCorp Action Items 1a, 1b, and 2a; the plan to repower existing wind resources, the acquisition of at least 1,100 MW of new Wyoming wind resources to capture PTC benefits, and a 140-mile transmission line (and associated lines) associated with the new wind infrastructure.

2. Potential Framework for Consideration of non-need based Action Items as part of the IRP Process, Should the Commission Reject Staff's Recommendation to not Acknowledge Action Items 1a, 1b, and 2a.

For the reasons expressed above, Staff does not recommend a deviation from a need-based IRP standard, and therefore recommends against acknowledging Action Items 1a, 1b and 2a. Economic opportunities are more appropriately analyzed in a ratemaking proceeding. Traditionally, acknowledgment of a resource in an IRP has been interpreted to be a step towards a demonstration of prudence for cost recovery in a ratemaking proceeding. Staff emphasizes that an IRP is not a ratemaking proceeding, and therefore, there it is not possible to impose specific ratemaking treatment as a condition of acknowledgment in order to balance ratepayer interests. However, the Commission can provide guidance about how it intends to evaluate PacifiCorp's resource acquisition decisions justified by economic opportunity in either acknowledging or not acknowledging them in the IRP process. Should the Commission consider acknowledgment of non-need based resources within the context of this IRP, Staff urges the Commission to provide detailed guidance on how it anticipates it will evaluate these economic opportunities when PacifiCorp seeks rate recovery. More generally, if the Commission is inclined to expand the IRP to include acknowledgment of economic opportunities, Staff recommends that the Commission provide guidance as to how it will evaluate the projects within the context of the IRP.

Ratepayer Protections during and after the Resource Acquisition Process for Action Items 1a, 1b and 2a.

Because resources that are acquired by virtue of an economic opportunity are inherently not needed, the risk and cost that the ratepayer traditionally absorbs in acquisition of a needed resource should not be borne by the ratepayer in such a circumstance. Accordingly, Staff would recommend that the Commission make clear that any economic opportunity acknowledged as part of the IRP process would be subject to strong protections that hold ratepayers harmless for the unnecessary risk and potential cost of the economic opportunity in a subsequent ratemaking proceeding.

These protections are not intended to prevent resource development; instead, they are intended to mitigate customer responsibility for rates of return for resources and strategies that are not needed to provide safe, reliable and affordable service to customers.

The protections we contemplate can be thought of as falling into two time periods: pre-COD and post-COD. We propose the Commission indicate in its order that it intends to consider the following ratepayer protections when a prudence determination and rate recovery are sought:

1. <u>Pre-COD</u>
In the pre-COD phase-the construction phase-the ratepayer protection is simply to set a construction-cost cap. Given that the Company will be provided or will be able to produce detailed construction cost or purchase cost figures associated with some level of all-in economic benefit to its customers, the Commission could convey to the Company that any costs in excess of those the Company indicates customers could economically incur would likely not be recoverable.

2. <u>Post-COD</u>
The second protection, for the post-COD period, would ensure that from customers' perspective, project revenue is at least as favorable as modeled. For the modeled revenue to be realized over 30+ years for each project, several assumptions must hold. Realized spot prices must be as high as modeled forward prices. Both the modeled capacity factor and the units' availability rates must be met. Instead of attempting to create protections for each of these individual assumptions, Staff proposes the Commission discuss creating a protection related to revenue directly.

Specifically, Staff proposes that if actual revenues do not materialize as favorably as the model expected, the Commission indicate that it intends to use the *modeled* revenues in the Company's net power cost calculation over the 30+ year revenue stream modeled by the Company. This will ensure that the anticipated revenue stream benefits the customers were described actually are realized.

General Framework for Review of All Potential Economic Opportunities and Economic Retirements

If economic opportunities are under consideration in the IRP process, then the Commission should make clear that all potential economic opportunities should be explored. A comprehensive review of all opportunities, including those that may not be advantageous to the electric company's shareholders, such as a greater reliance on distributed generation or third parties as resource providers, should be completed.
In order to complete this review and make a recommendation to the Commission, Staff and stakeholders must have greater access to relevant data, models, and alternatives. Additionally, this review must examine resource retirements. If retirements are potentially economic, then they must be considered alongside the preferred economic opportunity. Failing to review these retirements could result in unnecessarily higher costs for customers.

Staff further recommends that time be taken to gather stakeholder input on additional requirements for IRP filings that would support a balanced examination of economic opportunities.

3. B. Coal Resource Actions

Staff believes early coal retirement or changes to coal plant operations are valid resource choices that should be considered as part of the least-cost, least-risk plan to meet system needs. Additional analysis of coal unit economics in PacifiCorp's IRP would provide transparency for stakeholders and could help further optimize PacifiCorp's system costs. As mentioned in Sierra Club's comments, PacifiCorp's 2017 IRP allows economic coal unit retirements in only one out of seven Regional Haze compliance scenarios, and then only for a limited number of coal units. PacifiCorp should assess the economics of its coal units to demonstrate whether keeping them online is truly part of an optimal least cost, least risk portfolio.

The basic economic analysis should consist of four steps.

1. Begin with a 'base case' in System Optimizer (SO) with the following assumptions:
    a. 2017 IRP medium gas
    b. CO_2 Mass Cap B
    c. 'Reference Case' Regional Haze assumptions, but remove all costs for impending SCR requirements at Bridger, Hunter, and Huntington
2. Run the SO model 24 times, using the 'base case' assumptions, but selecting a different unit for early retirement each time. Use December 2022 retirement for consistency.
3. Compare the present value revenue requirement (PVRR) from each of the 24 SO results with the PVRR from the identically structured 'base case' run in which no coal units are retired in December 2022.
4. Provide the resulting SO model outputs in the same standard workbook format provided in the 2017 IRP.

The requested analysis could identify further investigation into which unit or units might reduce system costs through economic retirement. For example, PacifiCorp's power flow modeling could help determine which units could economically retire to help minimize PacifiCorp's system costs while maintaining safe and reliable power.
As a supplement to this analysis, Staff is requesting a list of all the coal units that utilize transmission along the path from PacifiCorp's proposed Wyoming wind project to PacifiCorp's service territory.

Staff believes that PacifiCorp can complete the requested analysis by March 30, 2018.

3. Recommendation regarding Coal Resource Action

In summary, Staff recommends that PacifiCorp should

1. Perform 25 SO runs – one for each coal unit and a 'base case.'
2. Provide the results of the SO runs to parties in LC 67 by March 30, 2018.
    a. Also provide an itemized list of coal unit retirement cost assumptions used in each SO run by the same date.
3. Provide a list of coal units that would free up transmission along the path from the proposed Wyoming wind project if retired, also by March 30, 2018.
4. Summarize the results in PacifiCorp's final comments, providing a table of the difference in PVRR resulting from the early retirement of each unit.

Staff has submitted a data request to PacifiCorp inquiring when the Company could complete the analysis described above. If the Company is unable to perform the requested analysis and report the results in its final comments, it should provide an explanation of why it is unable to do so and whether it can meet the March 30, 2018 date in its final comments.

3. C. Energy Efficiency/Class 2 DSM

Staff's analysis leads it to conclude that PAC's Action Plan Item 4a for energy efficiency (EE or Class 2 DSM) should be acknowledged subject to modifications because PacifiCorp needs to address two issues. First, there appears an ongoing tendency to underrepresent EE as a resource. Staff believes this is due to operational issues around forecasting methodologies, avoided cost development, or resource selection within PacifiCorp's System Optimizer models. This underrepresentation has potential implications throughout the IRP.

Second, PacifiCorp's reduction of total system EE between the 2015 IRP and the 2017 IRP could be perceived as unfair to Oregon customers, as Oregon increased its total savings by 13 percent, yet Utah's savings dropped nearly 30 percent. Given that PacifiCorp's load in Utah is nearly double that in Oregon, the large drop in savings is troubling. Staff also finds the Company's explanation of the disparity between levels of annual EE savings across states somewhat insufficient. We think the Company and its customers could benefit from a more thorough exploration of the elements driving the differences in its level of EE achievement before the next IRP.

Underrepresentation of Class 2 DSM in Forecasts

Staff finds a history of EE savings in PacifiCorp's service territory consistently in excess of its forecasted savings. Staff offers two examples. The first is from Energy Trust's annual reports. Based on this data Energy Trust has consistently overachieved that year's most recent, annual IRP targets by an average of 19 percent since 2010.[42]

[42] Data Sources: Energy Trust Annual Reports, 2010-2016 at https://www.energytrust.org/about/reports-financials/documents/?type=reports and Energy Trust's 2017-2018 Approved Budget and Action Plan at https://www.energytrust.org/documents/approved-2017-annual-budget-2017-2018-action-plan/

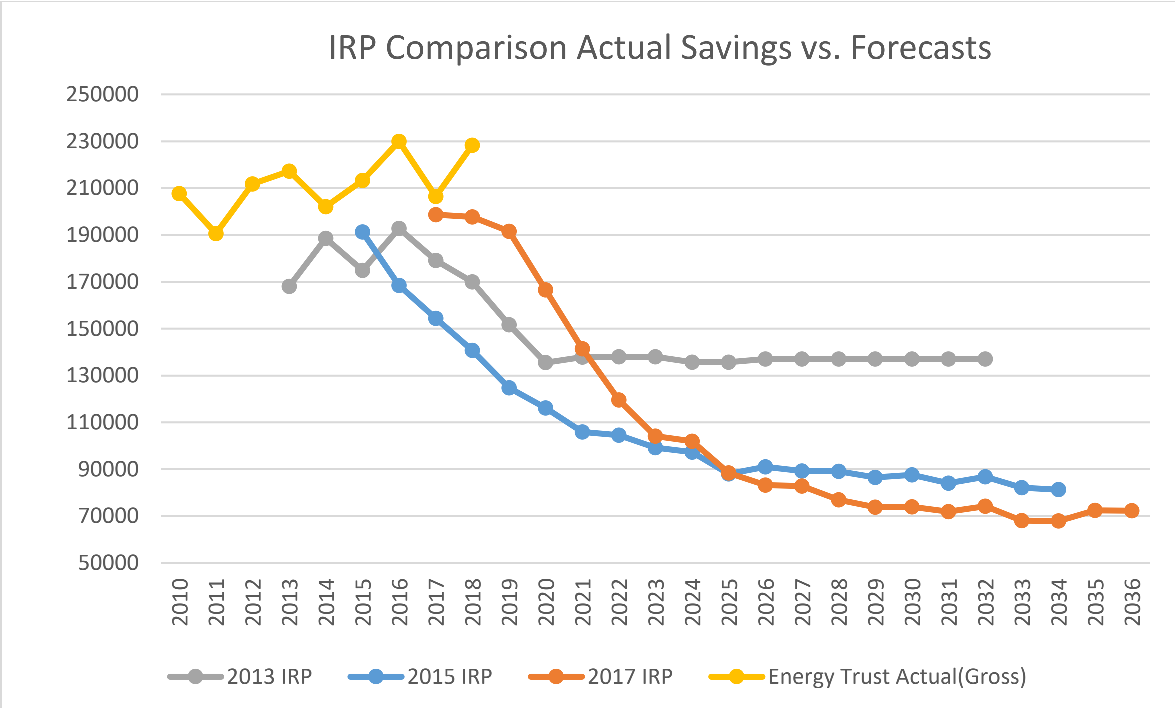
Year	IRP Target (MWa)	Savings per Annual Report	% Difference
2010	17.00	20.10	15.4%
2011	15.29	18.71	18.3%
2012	15.33	20.63	25.7%
2013	16.70	22.19	24.7%
2014	18.98	21.32	11.0%
2015	19.10	22.30	14.3%
2016	16.80	23.60	28.8%

The data shared by PacifiCorp reflects an even greater differential. This difference emerges because the Company "locks-in" the IRP targets from Energy Trust earlier in its IRP process. The table below captures the Energy Trust's actual savings, the IRP target for a given year, and the source year of the IRP target used by PacifiCorp. Energy Trust's over-achievement based on this data averages over 32 percent annually.

Oregon - Class 2 DSM							
	2010	2011	2012	2013	2014	2015	2016
IRP Preferred Portfolio	2008 IRP	2011 IRP	2011 IRP	2013 IRP	2013 IRP	2015 IRP	2015 IRP
Energy Efficiency Selections (MWh)	148,674	133,902	134,361	168,040	188,540	191,240	168,400
Electric Energy (MWh)* Gross Energy Efficiency Savings	207,612	190,618	211,729	217,248	202,093	213,218	229,950
Delta (Actual vs. Target)	58,939	56,717	77,368	49,208	13,553	21,978	61,550
Delta %	40%	42%	58%	29%	7%	11%	37%

* Average megawatts (aMW) provided by the Energy Trust of Oregon (ETO) converted to megawatt-hours (MWh) for comparison with IRP selections

Comparing Energy Trust's actual, annual EE savings to PacifiCorp's past three IRP forecasts for EE paints a vivid picture of the consistent under-forecasting taking place.



** - 2017 and 2018 are forecasts from Energy Trust's Approved 2017 Budget, December 5, 2016*

As PacifiCorp points out, Order No. 07-002 calls for periodically conducting EE potential studies.[43] And while EE potential studies are regularly used to determine available resources, the evidence supports Sierra Club's assertion that PacifiCorp's, "…reduced energy efficiency potential are not supported by historical evidence."[44] The modelling methodology used by Energy Trust and by PacifiCorp in its capacity expansion model needs to be improved before the next IRP.

Staff also finds evidence that avoided costs used to determine EE potential may be undervaluing it as a resource. One notable manifestation of such an undervaluation is in the resource potential for EE. PacifiCorp notes that the total cost-effective potential for EE only dropped by two percent between the 2015 IRP and 2017 IRP. However, PacifiCorp's 20 year technical, achievable potential increased by 16 percent over that same time span.

IRP Comparison (20-year time horizon)			
	2015 IRP	**2017 IRP**	**% Change Between IRP's**
EE Technical, Achievable (MWh)	2,886,391	3,361,587	16.5%
EE Cost-Effective (Selected) (MWh)	2,168,100	2,127,550	-1.9%
% EE Obtained as Resource	*75%*	*63%*	

Source: PacifiCorp, information request. Response to Staff No. 55, July 5, 2017

[43] LC 67 - PacifiCorp Reply Comments at 45.
[44] LC 67 - Sierra Club Comments at 38.

Revisions to avoided costs drive this type of change. Staff looks forward to working with PacifiCorp before the next IRP to identify and implement EE avoided cost improvements that may improve the ratio of EE acquired relative to its potential.

Finally, PacifiCorp makes a few statements regarding the avoided cost of EE relative to other resources. Most notably:

> Reduced loads and reduced costs for wholesale market power purchases and renewable resource alternatives impact the level of energy efficiency that can be procured cost-effectively as these resources complete with other resources, including demand-side resources, on a least-cost/least-risk basis for resource selection.[45]

This would seem to imply that the selection of EE by System Optimizer in PacifiCorp's preferred portfolio is relative to the costs of other resources, rather than being based on all cost-effective EE. Oregon has a rich policy landscape that gives primacy to EE in a utility's resource selection. Most recently in SB 1547:

> (3) For the purpose of ensuring prudent investments by an electric company in energy efficiency and demand response before the electric company acquires new generating resources, and in order to produce cost-effective energy savings, reduce customer demand for energy, reduce overall electrical system costs, increase the public health and safety and improve environmental benefits, each electric company serving customers in this state shall:
>
> (a) Plan for and pursue all available energy efficiency resources that are cost effective, reliable and feasible…[46]

Staff seeks clarification from PacifiCorp that its models do select all cost-effective EE, independent of the cost of other generation resources.

In summary, the confluence of things that lead to PacifiCorp underrepresenting its EE potential can have broad, negative impacts for customers. For example, the ongoing difference between the IRP targets for EE and actual EE savings since 2010 has led to an additional 339,000 MWh of energy savings. That cumulative total is approximately 2 percent of PacifiCorp's 2016 Oregon sales, which is *in addition to* the actual 2016 savings themselves.

Savings relative to other states

Staff does not entirely agree with NWEC's assertion that PacifiCorp has not met IRP Guideline 6.b, which states:

[45] LC 67 - PacifiCorp Reply Comments at 43.
[46] SB 1547, Section 19.

> To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.

It would appear most of the states will contribute levels of EE savings close to their percent of total sales in the 2017 IRP.

State	% PAC's Total EE (2017 – 2027)	% PAC's Total Sales (2017 – 2027)
CA	1.43%	1.03%
OR	24.14%	26.05%
WA	7.35%	6.69%
UT	44.18%	49.29%
ID	6.28%	3.79%
WY	16.62%	13.15%

For the 2017 IRP, Oregon is able to increase its levels of EE over the next ten years, despite a decreasing load forecast. This is not the case in other states.

State	Class 2 DSM	Load Forecast[2]
Oregon	+24%	-2.6%
Idaho	+8%	+3%
Wyoming	-11%	+1.2%
Washington	-16%	-1.3%
Utah	-27%	-6.7%
California	-30%	+6.5%
Total	-13%	-5.3%

Source: LC 67 NWEC Comments, 6/23/17, p. 4

The nearly 30 percent reduction in savings in Utah is extreme given that the state represents roughly 40 percent of PacifiCorp's load and the EE programs in Utah are large and mature. However, Staff currently lacks the evidence to suggest PacifiCorp's reduction in EE savings across other states in this IRP constitutes evidence of not including all best cost/risk portfolio conservation resources, per our IRP guidelines. However, given the potential burden on Oregon customers from unequal levels of EE acquisition, we recommend PacifiCorp hire an independent consultant, in coordination with Staff, to identify and compare potential technical and achievable EE savings across PAC's multi-state territory.

Possible Confusion regarding EE Resource Type

In PacifiCorp's Reply Comments, it seeks to equate investments in its Energy Vision 2020 with Oregon's long-standing policy that requires the acquisition of all cost-effective energy efficiency. Specifically, the Company states the following:

> PacifiCorp's selection of the least-cost mix of supply-side resources [under Energy Vision 2020] 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. 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, even if they are not strictly required to meet an immediate need…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.[47]

Staff feels it is necessary to point out the false equivalency inherent in this comparison, as the only thing these two very distinct activities may have in common are their respective levelized costs.

The need for the projects found in PacifiCorp's Energy Vision 2020 are purely economic and, "…are not intended to meet an immediate need for additional generation."[48] The need for EE is immediate as both an energy resource and as an instrument for regulatory compliance. In terms of an energy and capacity resource, EE displaces the need for front-office transactions in both the near- and long- term. In terms of regulatory compliance, the annual acquisition of all cost-effective EE satisfies regulatory conditions set forth in numerous laws, statutes, rules, and Commission orders passed over the past 25 years. [49]

In terms of risk, the math behind the levelized cost calculations of the Energy Vision 2020 projects highlights the risk tradeoffs with EE. Energy Vision 2020 projects require large, upfront investments and require customer payments for 30 to 62 years during a time of a rapidly changing energy marketplace. The annual investments in EE are incremental and very responsive to immediate market changes. Additionally, once purchased, customers generally do not have to continue to pay for EE savings over its measure life. The risk for EE is much smaller.

4. Recommendations regarding Energy Efficiency/Class 2 DSM

Staff recommends acknowledgment, subject to the following modifications to PAC's EE Action Item:

- Hire an independent consultant, in coordination with Staff and Energy Trust, to conduct an analysis by the next IRP that identifies and compares the ongoing differences between Energy Trust and PacifiCorp's near- to long-term EE forecasts with Energy Trust actual achieved savings. The report should make

[47] LC 67 - PacifiCorp Reply Comments at 18.
[48] Ibid at 14.
[49] *Examples:* Section 19.3(a) of SB 1547.

recommendations to both organizations for forecasting improvements to adopt by the next IRP.

- Hire an independent consultant, in coordination with Staff, to identify and compare potential, technical and achievable EE savings across PAC's multi-state territory.

4. GENERAL IRP COMMENTS

4. A. Load Forecasting and Load and Resource Balance

PAC's Reply Comments addressed four issues raised by Staff and other parties. First, in response to the "forecasted low load growth and correlation to private generation assumptions" issue raised by the Oregon Department of Energy (ODOE), PAC indicated that it "will continue to assess trends in private generation and will … establish sensitivities for future IRP cycles."[50] Staff welcomes PAC's commitment to continued analysis in future IRPs.

In its Reply Comments, PacifiCorp did not respond to Staff's concern that PAC's forecasts might be inaccurate because the relationship between load and economic variables has not been constant over time.[51] In response to Staff IR 61, PAC describes that it believes that its forecasting models are not problematic because variables in the model co-integrate to produce stationary forecast error terms.[52] However, when Staff reran PAC's residential number of customers model with only exogenous variables (i.e. without lagged values of the dependent variable), Staff found that the forecast error terms were not stationary (via the common interpretation of an Augmented Dickey Fuller test). Thus, apparently, PAC is correcting for nonstationarity by adding autoregressive terms. That is not the preferred correction method as recommended by a leading textbook: Stock and Watson (2011) states, "the most reliable way to handle a trend in a series is to transform the series so that it does not have a trend."[53] Differencing the data is a common approach to transform it so that it does not have a trend. In its DR 61 response, PAC describes that it believes that it cannot difference its data due to technical limits of its forecasting software.[54] Staff recommends that the Company investigate if it can transform its data prior to inputting it into its statistical software.

After Staff's Initial Comments, Staff investigated an additional issue in PAC's forecasts. In response to Staff DR 58, PAC described that it has not considered using additional forecast drivers in its street lighting load forecast.[55] Staff believes that additional

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[50] Ibid.
[51] LC 67 - Staff's Initial Comments at 10.
[52] See PAC's response to Staff IR 61.
[53] See Stock, James H. and Mark W. Watson, (2011), "Introduction to Econometrics," Pearson Higher Education, Third Edition, page 555.
[54] See PAC's response to Staff IR 61.
[55] See PAC's response to Staff IR 58.

forecast drivers could help the Company more accurately model energy savings due to customers switching to LEDs. Staff recommends that the Company search for an additional forecast driver related to the switch to LEDs.

5. Recommendation regarding Load Forecasting and Load and Resource Balance

Staff recommends that PAC investigate two additional load forecasting issues. The first issue, the changing relationship between economic variables and load, has an indeterminate impact on the load forecast. Staff believes that the second issue, modeling the impact of LED lighting adoption more accurately, would reduce forecasted load.

4. B. Modeling and Portfolio Approach and Results

The 2017 IRP modeling and evaluation approach consists of three screening stages used to select a preferred portfolio, including Regional Haze screening, eligible portfolio screening, and final screening. PacifiCorp uses the SO model to produce unique resource portfolios across a range of different planning assumptions. Informed by the public input process, PacifiCorp ultimately produced and evaluated 43 different SO portfolios for its 2017 IRP. PacifiCorp uses Planning and Risk (PaR) to perform stochastic risk analysis of the portfolios produced by SO. For each SO portfolio, PaR studies are developed for three natural gas price scenarios (low, base, and high) and two CO_2 emissions limit assumptions, which together form six price-emissions scenarios. The resulting cost and risk metrics are then used to compare portfolio alternatives and inform selection of the preferred portfolio. Taking into consideration stakeholder comments received during the public input process, PacifiCorp also developed 24 sensitivity cases designed to highlight the impact of specific planning assumptions on future resource selections along with the associated impact on system costs and stochastic risks. Six of the sensitivities developed over the course of the 2017 IRP were considered for the preferred portfolio.

Based on the model and risk evaluation in Chapter 7, the Company evaluated a range of resource portfolios, and selected a preferred portfolio reflecting a cost-conscious plan to transition towards a portfolio with a heavier focus on renewables. This requires the Company to make several near term investments for both transmission infrastructure and energy efficiency programs. Wind resources are a primary focus of the Company’s renewables plan, and require the Company to connect a new 140 mile transmission line from Wyoming to the Jim Bridger Plant, as well as to construct associated transmission lines. In addition, the Company relies heavily on energy efficiency as a key factor in the resource mix.

Staff Analysis

The model and portfolio evaluation appears to be robust and of a level of complexity well suited for the IRP process. Nevertheless, Staff has lingering concerns regarding PAC's use of Monte Carlo analysis in the study. Specifically, the Company uses the stochastic mean of 50 iterations in its analysis. In response to OPUC data request 7, PAC states that the stochastic mean is the appropriate measure of central tendency, and is intended to capture the influence of all iterations. With regard to the Company's treatment of loss of load probability and cumulative CO_2 emissions in the IRP, Staff is satisfied that the model framework is sufficient to capture future shifts in CO_2 emission rules, although additional modeling of scenarios is recommended. Staff is satisfied with the model robustness.

In terms of modeling and model results, stakeholder comments did not generally address the mathematics of PAC's model, but instead focused on the variety of core cases, breadth, and results of the model. The Oregon Department of Energy's (ODOE) initial comments expressed a positive outlook on the wider variety of core cases evaluated by the Company as compared to prior years, which they believe will more efficiently produce alternative resource combinations. Renewable Northwest also expressed a generally positive view on the portfolio analysis, focusing on the economic and environmental benefits of the modeled results. In contrast Sierra Club expressed concerns regarding the opacity of the model, as well as the results as related to the retirement of coal plants. Sierra Club, in preliminary comments, expressed concern that PAC's model is "irretrievably flawed" with respect to whether customers are well-served through the continued reliance on coal generation.

6. Recommendation regarding Modeling and Portfolio Approach and Results

Staff recommends that the Company investigate a more diverse renewable portfolio in future IRPs and IRP updates. Staff also recommends that PAC re-run its model under the assumption that EPA regional haze litigation against the Company is successful.

Stochastic Parameters

The Company updated and re-estimated its 2015 stochastic parameters for use in the current PaR model runs. The purpose of the PaR model is to stochastically shock the electricity price forecast (and other key drivers) to develop scenarios for uncertainty forecasting. PAC uses a two-factor mean reverting model.

The general process used by PAC in the development of its stochastic parameters is as follows: Short term uncertainty process parameters are assessed, statistical distributions and time steps for uncertainty quantification are chosen, data sets are selected for the chosen time step, a decision of how to treat missing variables (i.e. disregard versus interpolate) is made, uncertainty is estimated by looking at the daily price deviation for the variables, price expectations are calculated, and uncertainty parameters are computed for each variable by regression analysis.

The results of the PaR are then interpreted by evaluating the slope (which relates the autocorrelation and mean reversion rate to give information on how much price shock from the previous time period propagates into the next time period), intercept (which implies the long-run mean of the price index), and volatility of the price movements.

Short run stochastic parameters were used in the IRP, and the Company set long run parameters to zero because PAC cannot re-optimize its capacity expansion plan. Consequently, only the expected yearly price and load growths are simulated for the forecast horizon.

The Company states that the key drivers that affect price determination fall into two categories: load and fuel. The Company states that targeting only key variables simplifies the analysis while effectively capturing sensitivities of the larger subset of individual variables which fall under the penumbra of the key drivers.

7. Recommendation regarding Stochastic Parameters

Staff appreciates the Company's detailed explanation of how distributions were chosen, and how seasonal and regional correlations were developed. Staff encourages the Company in IRP updates to clearly explain the reasons for the (sometimes) low correlations in the short term forecast.

Planning Reserve Margin Study

The planning reserve margin (PRM) is a percentage of coincident system peak load, and is used to ensure there are adequate resources to meet the forecasted load over time. In a PRM study, the relationship between cost and reliability among ten different PRM levels is evaluated to account for variability and uncertainty in load and generation resources. A stochastic loss-of-load (LoL) study is performed using the Planning and Risk production cost model to calculate reliability metrics for each PRM level. Staff is generally initially satisfied with the procedures the Company used in the PRM study, as well as the selected 13 percent target PRM (pending further clarification of certain modelling assumptions and steps), however Staff will work with the Company to clarify some details, as described in these preliminary comments.

There are five basic modeling steps described by the Company:

1. PAC's System Optimizer (SO) model is used to produce resource portfolios among different PRM levels;
2. The Planning and Risk model is used to produce reliability metrics for each resource portfolio;
    a. Each reliability metric is adjusted to account for PAC's participation in the Northwest Power Program (NWWP) reserve sharing agreement.
3. The Planning and Risk model is used to produce stochastic variable production costs for each resource portfolio;
    a. Monte Carlo random sampling of stochastic variables is used to produce a distribution of system operation.

4. Marginal costs of reliability using the outcomes of different PRM levels are calculated;
    a. A 10 year test period is used for the marginal cost outcomes across different PRM levels.
5. PRM level is selected based on model results.

As the PRM level is increased from 10 to 20 percent, additional resources are added to the portfolio. The resources the Company adds are DSM, gas fired combined cycle combustion turbines (CCCT), gas fired coal combustion turbines (SCCT), renewable resources, and front office transactions (FOTs).

Staff Analysis of the Planning Reserve Margin Study

Staff is generally satisfied with the procedures PAC used in its PRM study, as well as the selected 13 percent target PRM, with some caveats. CUB, in its preliminary comments, suggest that energy efficiency could be an alternative to FOTs. Staff appreciates the inclusion of DSM in the present IRP, but other combinations of resources should be considered in IRP updates. Renewable Northwest, in its preliminary comments, also notes that if the 76 MW Dave Johnston coal plant is retired by 2020 as modeled by the Company, the Company would have limited time to procure potential replacement resource alternatives.

Flexible Reserve Study

The 2017 Flexible Reserve Study (FRS) estimates the regulation reserve required to maintain PAC's system reliability and comply with North American Electric Reliability Corporation (NERC) reliability standards, as well as the incremental cost of this regulation reserve. PAC's overall operating reserve requirements (regulation and contingency) are also compared to its flexible resource supply across the IRP study period. PAC must maintain sufficient regulation reserve to remain within NERC's Balancing Authority Area (BAA) control error limit in compliance with a new standard that became effective on July 1, 2016 (BAL-000-01-2). This standard requires a utility to compensate for changes in load demand and generation output by estimating the amount of regulation reserve required to manage variations in load. PAC's study concludes that the regulation reserve burden associated with wind deviations from scheduled amounts are twice the amount associated with solar, three time the amount associated with load, and four times the amount associated with non-VERs. As a result, PAC attributes different levels of regulation reserve to load, wind, solar and non-VERs. Based on the information available to Staff in the IRP, there appears to be justification for PAC to attribute different levels of regulation reserve to these variables.

Staff Analysis of the Flexible Reserve Study

The FRS utilizes a capacity factor method to forecast capacity factors for wind a solar. The Company also evaluates the impacts of the Energy Imbalance Market (EIM) and Smart Grid and Energy Storage contributions. The Company concludes that after taking into account EIM benefits, the need for regulation reserves to integrate its proposed wind and solar resources is less than 653 MW. The Company relies heavily on its coal plants to meet flexible reserve requirements (as noted in preliminary comments by NGUSA). NGUSA suggests, based on PAC's own analysis, that it consider a pumped storage facility and new natural gas plants to meet future flexible resource needs. Staff agrees with this comment. Pumped storage facilities can provide the fast response needed to balance intermittent solar and wind generation, and at minimal environmental cost.

Staff appreciates the Company's responsiveness to inquiries surrounding the FRS. While Staff has some concerns about the robustness of the resource set analyzed in the FRS, the modeling strategy used by the Company appears to be reasonable. Staff had initial concerns regarding the extent of exclusion of real data from the FRS analysis, particularly load data. PAC, in response to Staff data requests, provided data showing the extent of the exclusion and explained that statistical testing to determine the cause of data anomalies leading to exclusion was unnecessary due to the readily identifiable nature of error types (e.g. instrument errors). Staff is satisfied that the Company has adequately utilized available data and that the omission of clearly erroneous data is not harmful to the FRS analysis. Staff is also satisfied that the scaling factor used by the Company is appropriate. The scaling factor as explained by PAC in response to Staff inquiries is a percentage change from the from the less than 55 minutes from the hour in question (T-55) data point to the hourly average load for the upcoming hour. The actual scaling factor from one week prior is applied to the load value at T-55 to estimate the hourly load base schedule for the upcoming hour.

8. Recommendation regarding Flexible Reserve Study

Staff recommends that the Company model natural gas and storage for meeting FRS needs in the next IRP update. Staff also notes that the FRS results indicate that the need for wind resources to meet FRS needs are considerably lower than what is being proposed elsewhere in the IRP.

4. C. Distribution System Planning

In Staff's Opening Comments, Staff raised the potential need for creating a more comprehensive, transparent look at how the Company is planning for grid modernization that would link elements of the Smart Grid reports, existing distribution planning, IRP planning and the various dockets focused on locational value of DERs.

PAC responded that its long-term planning process appropriately reflects distribution investments, energy efficiency, and private generation and that planning for a reliable and safe distribution system should remain separate from long-term planning. PAC also stated its satisfaction with discrete locational value dockets and noted that the Smart Grid report is a component of the IRP process. PAC's Reply Comments also noted that its existing distribution planning process efficiently prioritizes investments in the distribution system and addresses future trends and customer behaviors.

Essentially, PAC did not seem to share Staff's concerns regarding lack of transparency and comprehensiveness in how the Company is planning for grid modernization and communicating its plan to stakeholders. Staff does not mean to imply that PAC is not currently planning for distribution system investments in a way that will prudently transition its system towards a more modern grid that is capable of meeting changing expectations for energy services, but from the information provided, it is difficult to assess. Historically, distribution system investments have been operational and needed for reliability and safety with decisions made over a very short time frame without regulator involvement. However, as we are increasingly asking the grid to provide different services than originally designed to do, the way in which the utility adapts its system to accommodate new energy services is likely to be a large investment to be passed on to customers.

Staff continues to believe that recognition of this transition warrants new tools and approaches to communicating planning for the benefit of customers, beyond the current Smart Grid Report format, and plans to further explore how some form of integrated planning between IRP and DSP would be useful for the Commission, other stakeholders, and PAC.

4. D. Smart Grid Report

In Staff's Opening Comments, Staff requested that, in its Reply Comments, the Company provide commentary about any interrelation (or lack thereof) between AMI and planning and resource applications. The Company briefly responded to this in its Reply Comments, stating that "any variations in customer usage from behavioral changes resulting from programs such as AMI installation will therefore be captured and reflected in the load forecast in future IRP cycles."[56]

This does not answer Staff's question. Staff notes that in response to the *2016 Smart Grid Report*, Staff filed comments in UM 1667 pertaining to this very circumstance—namely asking what the Company is planning on doing with AMI load data as it relates to the IRP. In the *2016 Smart Grid Report*, and in the more recently filed *2017 Smart Grid Report*, the Company has yet to identify whether it ever intends to use AMI data in its integrated resource planning.

Installing AMI capability is a big step forward in modernizing PacifiCorp's grid, and it seems to Staff to be a notable missed opportunity not to incorporate, or at least confirm, whether this higher-tech and likely more accurate load data will *ever* be used in its resource planning.

5. RECOMMENDATIONS

To summarize, Staff's largest concern in this IRP relates to the proposed wind repowering and new wind and transmission build/buy, all of which are not in response to

[56] LC 67 – PacifiCorp Reply Comments at 52.

an identified reliability need. For the reasons discussed above, Staff does not believe such projects are appropriate for acknowledgement in the IRP framework. Regardless of whether the Commission acknowledges the Company's Energy Vision 2020 projects, Staff reiterates that the Commission should provide guidance on the anticipated sharing of risks and benefits between the Company and its customers that may be considered in a future ratemaking proceeding.

In these Final Comments, Staff recommends the following actions and additional requirements:

- **Actions: Recommend for Non-Acknowledgment**
    a. Wind Repowering:
       Staff recommends that the Commission not acknowledge PacifiCorp Action Item 1a in its 2017 Action Plan.
    b. Wind RFP/Aeolus to Bridger/Anticline:
       Staff recommends that the Commission not acknowledge PacifiCorp Action Items 1b and 2a in its 2017 Action Plan.
    c. Demand Response:
       Staff recommends that the Commission not acknowledge PAC's Action Plan item to acquire only 77 MW of DR by 2021. Instead, Staff recommends that PAC seek to obtain more than 77 MW in 2021 by working with Staff to create a DR Review Committee and by launching a DR Testbed no later than July 2019.

- **Actions: Recommend for Potential Acknowledgement of PacifiCorp's Resource Acquisitions**
  Should the Commission choose to consider conditional acknowledgement based on a finding that PacifiCorp's major resource acquisition represents a low-cost opportunity, Staff proposes that the Commission adopt a framework to protect customers. These protections are not intended to prevent resource development; instead, they are intended to limit guaranteed rates of return to resources and strategies that are needed to provide safe, reliable and affordable service to customers and ensure that the risks associated with resources that are not needed, but may nonetheless represent an economic opportunity, are appropriately borne by project developers.

  The protections we contemplate can be thought of as falling into two time periods: pre-COD and post-COD. In the pre-COD phase, the construction phase- the ratepayer protection is simply to set a construction-cost cap. Given that the Company will be provided or will be able to produce detailed construction cost or purchase cost figures associated with some level of all-in economic benefit to its customers, the Commission could convey to the Company that any costs in excess of those the Company indicates customers could economically incur will not be recoverable.

  The second protection, for the post-COD period, ensures that from customers' perspective, project revenue is at least as favorable as modeled. For the modeled revenue to be realized over 30+ years for each project, several assumptions must hold. Realized spot prices must be as high as modeled forward prices. Both the modeled capacity factor and the units' availability rates must be met. Instead of attempting to create protections for each of these individual assumptions, Staff proposes creating a protection related to revenue directly.

In its models, the Company will determine what 30+ year revenue stream leads to all-in economic benefits to its customers. Staff proposes that if actual revenues do not materialize as favorably as the model expected, it is the *modeled* revenues that are used in the Company's net power cost calculation. This will ensure that the anticipated revenue stream benefits the customers were described are actually realized.

- **Actions: Recommend for Acknowledgement that PacifiCorp Complete Additional Analysis**

  Staff recommends that PacifiCorp should
  1. Perform 25 SO runs – one for each coal unit and a 'base case.'
  2. Provide the results of the SO runs to parties in LC 67 by March 30, 2018.
     a. Also provide an itemized list of coal unit retirement cost assumptions used in each SO run by the same date.
  3. Provide a list of coal units that would free up transmission along the path from the proposed Wyoming wind project if retired, also by March 30, 2018.
  4. Summarize the results in PacifiCorp's final comments, providing a table of the difference in PVRR resulting from the early retirement of each unit.

  Staff has submitted a Data Request to PacifiCorp inquiring when the Company could complete the analysis described above. If the Company is unable to perform the requested analysis and report the results in its final comments, it should provide an explanation of why it is unable to do so in its final comments.

- **Actions: Recommend for Acknowledgement that PacifiCorp Modify EE Action Item**

  Staff recommends acknowledgment, subject to the following modifications to PAC's EE Action Item:
  - Hire an independent consultant, in coordination with Staff and Energy Trust, to conduct an analysis by the next IRP that identifies and compares the ongoing differences between Energy Trust and PacifiCorp's near- to long-term EE forecasts with Energy Trust actual achieved savings. The report should make recommendations to both organizations for forecasting improvements to adopt by the next IRP.
  - Hire an independent consultant, in coordination with Staff, to identify and compare potential, technical and achievable EE savings across PAC's multi-state territory.

- **Actions: Recommend for Acknowledgement that PacifiCorp Complete Additional Analysis**

Staff recommends that PAC investigate two additional load forecasting issues. The first issue, the changing relationship between economic variables and load, has an indeterminate impact on the load forecast. Staff believes that the second issue, modeling the impact of LED lighting adoption more accurately, would reduce forecasted load.

- **Actions: Recommend for Acknowledgement that PacifiCorp Complete Additional Analysis**
  Staff recommends that the Company investigate a more diverse renewable portfolio in future IRPs and IRP updates. Staff also recommends that PAC re-run its model under the assumption that EPA regional haze litigation against the Company is successful.

- **Actions: Recommend for Acknowledgement that PacifiCorp Complete Additional Analysis**
  Staff appreciates the Company's detailed explanation of how distributions were chosen, and how seasonal and regional correlations were developed. Staff encourages the Company in IRP updates to clearly explain the reasons for the (sometimes) low correlations in the short term forecast.

- **Actions: Recommend for Acknowledgement that PacifiCorp Complete Additional Analysis**
  Staff recommends that the Company model natural gas and storage for meeting FRS needs in the next IRP update. Staff also notes that the FRS results indicate that the need for wind resources to meet FRS needs are considerably lower than what is being proposed elsewhere in the IRP.

This concludes Staff's Final Comments.

Dated at Salem, Oregon, this 6th of October, 2017.

Geoffrey Ihle
Senior Economist
Energy Resources & Planning

Lisa Gorsuch
Senior Utility Analyst
Energy Resources & Planning

Nolan Moser
Senior Utility Analyst
Energy Resources & Planning