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BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR APPROVAL OF SOLICITATION PROCESS OF WIND RESOURCES	Docket No. 17-035-23

INITIAL COMMENTS OF THE UTAH ASSOCIATION OF ENERGY USERS ON ROCKY MOUNTAIN POWER'S PROPOSED SOLICITATION PROCESS

The Utah Association of Energy Users ("**UAE**") hereby files its initial comments on the Solicitation Process proposed by PacifiCorp in this docket. UAE appreciates the opportunity to submit comments on the proposed RFP. UAE's counsel and consultants have reviewed the testimony and exhibits filed by PacifiCorp, attended the technical conference in this docket, and reviewed PacifiCorp's proposed request for proposals ("**RFP**"). The available time has not permitted a comprehensive review of the proposed RFP or its lengthy attachments. Moreover, many of the details of PacifiCorp's plans were not revealed until PacifiCorp filed its "Energy Vision2020 Update" two days ago as an "Informational Filing" in the IRP docket, 17-035-16, which UAE has not yet had an opportunity to review in detail. Nevertheless, UAE has identified several significant concerns. As proposed, the RFP will not attract a broad array of bids sufficient to permit comparison and selection of the most cost-effective options as contemplated by Utah's Energy Resource Procurement Act[1] (the "**Act**"). Rather, the proposed RFP will result in very few complying bids and essentially ensure that PacifiCorp's benchmark resources will be the only available options.

UAE respectfully submits that the proposed RFP is not consistent with the Act and the RFP cannot properly be approved unless changes are made to maximize the likelihood that bids from a wide array of available resources will be received. Only then can PacifiCorp, the independent evaluator, ratepayers or the Commission identify and select resources that are likely to produce the lowest costs and risk for ratepayers as contemplated by the Act.

Background on the Utah Energy Resource Procurement Act

The Act, and the Commission regulations implementing the same[2] ("**Rules**"), impose numerous requirements on the solicitation and procurement of significant energy resources by public utilities in this State. UAE, along with others, actively participated in negotiating and supporting adoption of the Act in 2005. UAE's goal, then and now, is to make electric utility resource solicitations and procurements fair and competitive so that the most cost-effective resources can be identified and procured for the benefit of Utah ratepayers. UAE perceived a strong need for the Act because historically PacifiCorp has routinely selected itself to build or own virtually all new major generating resources.

Part 2 of the Act includes requirements for a solicitation process. The intent of Part 2, and the Rules implementing it, is to ensure a robust array of bids from all available resource

[1] Utah Code §§ 54-17-101, et seq.
[2] Utah Administrative Code §§ R746-420, et seq.

types and from varying owners/developers.[3] Only if a robust set of bids for market resources is received can any proposed utility self-build options be fairly compared and evaluated. The ultimate goal of the Act and the Rules is to ensure that the resources with the lowest reasonable cost to customers can be identified and procured, regardless of the nature or ownership of the resources.

Before a utility's proposed solicitation process can be approved by the Commission, the Act requires the Commission to first determine that the proposed solicitation process "will ***most likely*** result in the acquisition, production and delivery of electricity ***at the lowest reasonable cost*** to [the utility's] retail customers."[4] This same finding must also be made before the Commission can pre-approve procurement of any given resource.[5] These critical statutory requirements are designed to ensure that Utah ratepayers will not be burdened with anything other than the lowest-cost resources available.

The Proposed Solicitation is Inconsistent with the Act

The proposed solicitation process in this docket is facially defective; it is not even intended to produce a robust set of diverse resource options from which PacifiCorp, the independent evaluator, ratepayers or the Commission could compare benchmark bids and PPA bids to determine which resources are "most likely [to] result in … the lowest reasonable cost" to customers. As proposed, the solicitation will only accept bids of a single resource type (wind) located in a small geographical area of one state in PacifiCorp's six state utility footprint

[3] *See* Rule R746-420-3(8)(i) (RFPs must be "designed to solicit a robust set of bids").
[4] Utah Code § 54-17-201(2)(c)(ii)(A) (emphasis added). Other relevant factors, such as risk and reliability, are also to be considered, *id.*, but ensuring the lowest reasonable cost for customers is central to the Commission's public interest determination under the Act.
[5] Utah Code § 54-17-302(3)(c)(i) (emphasis added).

(Wyoming). As such, it cannot possibly satisfy the intent or requirements of the Act for pre-approval.

The RFP imposes severe limitations on the type, location and potential owners of resources that can submit qualifying bids, and will severely restrict the universe of possible resource options in a manner inconsistent with the pre-approval requirements of Parts 2 and 3 of the Act—which focus on solicitation and acquisition of the lowest-cost resources among a wide array of options in response to capacity and energy needs identified through a utility's long-range (IRP) planning process.[6] The proposed solicitation in this docket is not designed to meet resource needs identified through a planning process.[7] Rather, PacifiCorp is pursuing what it claims to be a time-limited opportunity to secure wind resources that qualify for federal production tax credits, both by repowering 12 of PacifiCorp's 13 existing wind resources (that originally cost PacifiCorp ratepayers over $2 billion, and with over 2/3 of their service lives remaining on average) ("**Repowering**"),[8] and by procuring significant new wind resources and several new local areas transmission segments in Wyoming ("**New Wind/Transmission**") (all such resources collectively, the "**Proposed New Resources**").[9] PacifiCorp projects that the Proposed New Resources will result in long-term costs to customers that may be modestly lower than the projected cost of resource acquisition alternatives identified in its resource planning

[6] *See, e.g.*, Utah Code § 54-17-301.
[7] As explained in more detail in section 3, below, PacifiCorp's Proposed New Resources are not, under any stretch of the imagination, based on resource needs identified through the IRP planning process.
[8] *See* Energy Vision 2020 Update, Docket 17-035-16, dated August 2, 2017; and PacifiCorp's 2016 FERC Form 1, page 410.
[9] *See* Energy Vision 2020 Update, Docket 17-035-16, dated August 2, 2017; and PacifiCorp's 2016 FERC Form 1, page 410.

processes (the "**Prevailing Resources"**)—which rely primarily on demand side management and market transactions for many years.

The Act contemplated the possibility of time-limited opportunities of this sort that are not responsive to needs identified in the long-range planning process. Part 5 of the Act gives PacifiCorp the option to seek Commission waivers of the solicitation and/or resource approval processes and requirements if a utility has identified "a time-limited commercial or technical opportunity that provides value to the customers."[10] A utility that successfully obtains a waiver of the Parts 2 and 3 solicitation and procurement processes may proceed to acquire the identified resources, but will not receive pre-approval or any presumption of prudence as to the acquisition.[11] Had PacifiCorp requested such waivers, the Commission could have solicited input on and made determinations as to whether the alleged time-limited opportunities are sufficiently compelling to warrant the requested waivers. PacifiCorp could then have determined whether to pursue those opportunities, subject to later prudence review.

PacifiCorp's proposal in this docket is inconsistent with the intended course for a time-limited opportunity. PacifiCorp is attempting to cram a square peg into a round hold in a rushed effort to secure pre-approval of resources without evaluation of other competitive options. The proposed solicitation process is inconsistent with the intent and requirements of Parts 2 and 3 of the Act and should not be approved.

Because the RFP as proposed by PacifiCorp permits bids from only a small segment of available resource options, it cannot possibly give the Commission the information it would need to determine whether the selected resources will "most likely" result in the identification of the

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[10] Utah Code § 54-17-501(1)(b).
[11] *Id.*, § 54-17-501(10).

"lowest reasonable cost" resources available. At best, the RFP ***might*** lead to determinations (in Dockets 17-035-39 and 17-035-40) that the cost to customers for the Proposed New Resources as projected by PacifiCorp is slightly lower over time than the cost as projected by PacifiCorp for the Prevailing Resources. That is a far cry from the requirements of Parts 2 and 3 of the Act for a determination that the selected resources will "most likely" result in the "lowest reasonable cost" resources in comparison to all other available resource options. The Commission will be in a position to determine whether any given resource is most likely the most cost-effective resource ***only*** if the scope of the solicitation is increased to include all resource types—renewable and non-renewable; west side and east side; all owners/developers; and with and without new transmission upgrades in various locations. The findings required in Parts 2 and 3 of the Act simply cannot be made with PacifiCorp's proposed limitations of the RFP to specific Wyoming wind resources only.

Summary of Major RFP Concerns

In addition to the facially defective nature of the proposed RFP, UAE has identified several significant concerns with the proposed RFP. UAE respectfully submits that additional time and evaluation is necessary to develop an RFP properly designed to solicit a robust set of bids and permit a proper determination as to the most cost-effective options. Nevertheless, based on the brief time that UAE and its consultants have had to review the RFP to date, a number of significant concerns have been identified, which are discussed briefly below.

1. The RFP Should Allow Bids from all Resource Types, Owners and Locations.

As noted above, a proper determination that the RFP will most likely lead to identification of the lowest-cost resources is possible only if the RFP is opened up to all resources, all locations, all developers, and other transmission upgrades. It would be fundamentally unfair to Utah ratepayers if PacifiCorp were allowed to acquire new resources of this significance and cost without first rigorously testing the market, unrestricted by geography or resource type, and especially troubling given PacifiCorp's admission that is has no need for incremental resources in the near term. PacifiCorp notes that significant benefits will accrue to the State of Wyoming as a result of the Proposed New Resources. While UAE has no objection to such benefits to Wyoming, it opposes acquisition of such a significant amount of new resources without first testing the market to determine whether the Proposed New Resources are less expensive than other available resources, considering both short term and long term impacts as contemplated by the Act.[12] Without such a demonstration, nobody can possibly know whether lower cost resources might be available elsewhere—such as in southern Utah. If market bids demonstrate that the lowest cost resources are located in Utah, for example, Utah ratepayers would benefit not only from lower rates, but Utah would also receive significant economic and other benefits, including the possibility of transmission investments to relieve congestion that currently limits access to Utah's extensive solar resources. PacifiCorp's proposed RFP must be expanded to include all available resources, including those freed up by transmission investments elsewhere, to avoid unfair impacts on Utah citizens and ratepayers.

2. PacifiCorp's Actions Have Not Been Not Consistent with the Act.

UAE has concerns with the way in which PacifiCorp has aggressively pursued efforts to construct and own significant new wind and transmission resources that have not been shown to be needed and cannot be shown to be the lowest-cost options. It appears that, while regulators,

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[12] Utah Code §§ 54-17-201(2)(c)(2)(B), 54-17-302(3)(c)(ii).

ratepayers and potential competitors were not notified of PacifiCorp's plans until well into 2017, PacifiCorp was quietly developing its plans well before the end of 2016 to invest billions of dollars in new transmission and wind rate base assets. Indeed, PacifiCorp apparently spent over $111 million in 2016 to acquire wind assets and options on wind assets designed to meet an assumed "safe harbor" for federal production tax credits[13], acquired strategic wind sites, and submitted interconnection requests to its transmission function (relying on six previously unannounced transmission infrastructure projects in Central Wyoming that PacifiCorp merchant alone apparently knew might be expanded. It appears that PacifiCorp alone had reason to believe the congestion would be relieved with new transmission assets. Had PacifiCorp timely notified regulators, developers and other stakeholders of its plans in 2016 when PacifiCorp made over $111 million in wind turbine purchases, there might be a chance today for a fair and competitive solicitation process that could lead to identification of the most cost-effective resources available under the timeline proposed by PacifiCorp. Unfortunately, everyone but PacifiCorp (including its merchant function) appears to have been deprived of a fair opportunity to compete in this RFP for these new resources, in contravention of the intent and purposes of the Act and the Rules, and contrary to the best interest of Utah ratepayers.

Under the Act, an affected electrical utility must secure approval of any significant energy resource decision "***before*** [it] may construct or enter into a binding agreement to acquire the significant energy resource.[14] Here, PacifiCorp entered into purchase agreements at a cost of millions of dollars for wind turbine equipment long before it notified the Commission of its

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[13] *See* PacifiCorp's 2016 FERC Form 1, page 216. PacifiCorp reported total investment in "Wind Repowering/New Development/Safe Harbor Equipment Purchases" of $111,124,301 as of December 31, 2016.
[14] Utah Code § 54-17-302(1)(b) (emphasis added).

intent or sought approval. This type of pre-purchase cannot qualify for pre-approval under Section 3 of the Act, nor form the proper basis for approval of an RFP under Part 2.

3. The Proposed New Resources Are Not Consistent with the IRP.

Evaluation of PacifiCorp's 2017 IRP will occur in another docket, 17-035-16. For purposes of this docket, however, it is important to note that PacifiCorp's Proposed New Resources cannot in any manner be considered resources evaluated or selected through a proper, public IRP process. Evaluation and selection of the Proposed New Resources were done solely by PacifiCorp, in secret and in a vacuum. This concern was aptly described by the Oregon Public Utility Commission staff in comments submitted to the Oregon Commission regarding PacifiCorp's 2017 IRP:[15]

> The Commission expects the IRP process to be transparent and to allow for stakeholder input to the Company's preferred portfolio choice, as well as all the analysis the Company performs to reach this choice. In this IRP cycle, the Company essentially completed the public input process of seven public meetings, beginning in June 2016 and going through the end of the year. The Company then produced a draft Action Plan reflecting no new resource acquisition, as the Company's analysis projected no need for Additional resources in order to serve load reliably.
>
> It was only at the end of this process that the Company drastically altered its Action Plan to include both the repowering of 905 MW of existing Company-owned wind resources (Wind Repowering) and the purchase of 1,100 MW of new wind with the associated new transmission line (New Wind) that would enable transport of the New Wind power. These proposed capital investments are projected to cost approximately $3.5 billion. Despite the significance of these costs and unfamiliarity with the projects themselves in the context of the IRP, stakeholders had little to no time to review because it was brought to the table at the very end of the process.
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> Staff is uncertain as to why the Company waited so long to introduce such major resource acquisitions, but in any case, Staff is concerned that the lack of stakeholder review violates a core IRP principle that fosters an open and participatory process and thus may pose a risk to ratepayers. The late inclusion of such a significant set of investments has deprived Staff and other stakeholders of the opportunity to preview that capital addition

[15] Executive Summary, page 1. A copy of the Oregon Commission Staff's comments is attached hereto.

> proposal and ask the Company questions prior to the filing of the IRP. Staff is further concerned with the late addition of these two Action Items (New Wind and Wind Repower) because the Company has no need to justify these resource acquisitions and makes no claim to have a need – it presents this $3.5 billion acquisition purely as a long-term economic benefit to customers over the course of twenty years.

Given that PacifiCorp allowed no substantive public evaluation of or input into its Proposed New Resources as part of the 2017 IRP process, no credibility can be given to any notion that the Proposed New Resources were selected as least cost/least risk resources pursuant to an IRP planning process.

4. The Proposed New Resources Entail Significant Ratepayer Risk.

Acquisition of PacifiCorp's Proposed New0 Resources would create significant risks for ratepayers. PacifiCorp's own evaluation shows only modest projected benefits (in comparison to its own cost projections for the Prevailing Resources). Moreover, in claiming long-term economic benefits of its planned investments, PacifiCorp did not limit its focus to the 20-year IRP planning horizon. Rather, PacifiCorp's evaluation of its "preferred portfolio" in the 2017 IRP relies, in part, on speculative benefits associated with some of the proposed new investment stretching at least 14 years beyond the 20-year IRP planning period.[16]

PacifiCorp itself acknowledges that the New Wind/Transmission resources will not be economical if natural gas prices remain low—which is certainly possible, and predicted by many. In addition, PacifiCorp's proposal for long-term fixed-price renewable resources is wholly inconsistent with the "fixed-price risk" arguments that it advanced aggressively, and that the Commission accepted, at least in part, in Docket 15-035-53. It appears that PacifiCorp may

[16] *See e.g.*, 2017 IRP at p. 210. ("The results for the OP-REP and OP-GW4 cases include benefits for the wind repower project through 2050, accounting for the significant incremental energy benefits beyond the IRP planning period when the life of repowered wind resources is extended.")

worry about fixed cost price risk for ratepayers only when someone other than PacifiCorp will own the resources.

It is also not clear that the touted production tax credits for repowered projects will necessarily be realized. PacifiCorp is relying upon an IRS "notice" (#2016-31) that does not carry the weight of a statute or regulation, and that could be changed or challenged in court. Furthermore, qualification for production tax credits relies on an independent appraisal of the value of retained assets after repowering is completed. As such, the repowering of over $2 billion of existing wind assets that have only been serving RMP's ratepayers for less than 10 years based solely upon the uncertain reward of tax credits appears to pose unreasonable risks on ratepayers. And, while PacifiCorp requires bidders to demonstrate that they will qualify for 100% of the federal production tax credits—and will require bidders to carry the risk of non-qualification—ratepayers will presumably be expected to bear that risk for any resources owned by PacifiCorp.

The prefiled testimony of Rick Link in this docket indicates that PacifiCorp's benchmark options will not be firm bids, but rather cost estimates,[17] including 30-year, pro-forma estimates for operation, maintenance and capital expenditures. This will allow PacifiCorp to bid estimates—while presumably expecting ratepayers to bear the risk of the actual, unknown costs. As discussed in more detail below, other bidders are required to bid firm prices for the entire life of the PPA. It will be difficult to fairly evaluate benchmark bids that reflect general estimates in comparison to firm bids from other parties.

[17] *See* Exhibit RMP__(RTL-1) Page 10 of 13 ("Benchmarks will utilize safe harbor PTC qualified equipment. Company will have a separate RFP process to secure firm fixed pricing to engineer-procure-construct the balance of plant. Benchmarks will include 30-year pro-forma estimates for operations, maintenance and on-going capital expenditures.")

5. The Proposed RFP Will Not Allow Evaluation of Bids and Benchmarks on a Fair and Comparable Basis.

UAE has no inherent bias in favor of utility-built resources (benchmarks) or bids from others (bids). UAE focus is on cost. It is both a statutory requirement and a critical component of fairness to PacifiCorp ratepayers that benchmarks and bids be evaluated on a fair and comparable basis. The proposed RFP does not satisfy this requirement. If PacifiCorp succeeds in treating its benchmark bids preferentially to other bids, the result will be bias in favor of the benchmark bids.

Critical to satisfaction of the public interest standard is comparability to the greatest extent practicable in the evaluation of benchmarks and bids. This standard is emphasized in Commission Rules: "All bids must be considered and evaluated against the Benchmark Option on a ***fair and comparable basis***."[18]. Moreover, "[a]ll aspects of a Solicitation and Solicitation Process must be fair, reasonable and in the public interest."[19]

There are many inherent differences in benefits and risks faced by ratepayers with a benchmark resource as opposed to a bid. PacifiCorp plans to submit benchmark resources as to which virtually all significant risks will be borne by ratepayers. This is in stark contrast to the requirements imposed on PPA bidders; bidders must assume all project development and operational risks. Examples of risks imposed on PPA bidders but that PacifiCorp does not intend to assume for its self-build benchmark options include the following:

a) PPA bidders are subject to delay damages for each day the project is late past the "Scheduled Commercial Operation Date" (PPA at 17).

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[18] Commission Rule R746-420-3(8)(i) (emphasis added)
[19] *Id*., R746-420-3(1)(b)(ii).

b) PPA bidders are subject to cancellation of the entire PPA if the facility does not achieve commercial operation by the "Guaranteed Commercial Operation Date". (PPA at 17).

c) If any turbines have not been fully completed when the Facility achieves final completion, there is no option for the PPA seller to cure the shortfall and the turbines cannot later be completed as part of the project, nor can the turbines be completed and the output sold to third parties. (PPA at 17).

d) Under a PPA, PacifiCorp will not pay for any energy curtailed by the transmission operator, whether curtailed for reliability purposes or by the market operator or Transmission Service Provider for general curtailment, reduction, or redispatch of generation in the area, or even if an event of Force Majeure prevents either Party from delivering or receiving Net Output (PPA at 24). In contrast, PacifiCorp will undoubtedly expect to recover the costs of its benchmark resources without regard to production levels, curtailments, or events of Force Majeure. This requirement is particularly onerous on bidders given that PacifiCorp wants to add up to 1,270 MW of new wind resources behind an already constrained flowgate (Bridger West), which may well lead to significant increases in curtailments for reliability reasons. PacifiCorp expects PPA bidders to lose compensation when their resources are curtailed through no fault of their own, while being paid for its benchmark resources under comparable conditions

e) PPA rates "shall not be subject to change for any reason" for the life of the PPA (PPA at 29), while PacifiCorp can ask for rate changes to reflect changes in benchmark resource costs at any time.

f) PPA bidders are subject to liquidated damages for failure to achieve Guaranteed Availability, without regard to actual output of the plant, on top of both foregone energy payments under the PPA plus the cost of replacement energy. These liquidated damages are assessed to the PPA bidder even if the actual energy output of the plant exceeds the expected energy output in that year. PacifiCorp does not intend to pay liquidated damages for its benchmark resources, no matter how poorly the resources perform.

g) PPA bidders face expensive security requirements, project milestones, multiple types of liquidated damages, and other requirements, which PacifiCorp's benchmarks will not face.

h) PacifiCorp reserves the right to reject a bidder if any requirements outlined in the RFP "are not met to the satisfaction of PacifiCorp, as determined in its sole discretion." This provision will chill biding and is inappropriate in light of PacifiCorp's inherent bias in favor of investing in benchmark resources, and given the statutory requirements for Commission and independent evaluator involvement.

UAE recognizes that many of the issues addressed above are inherent anytime a resource procurement process involves utility benchmark options and market bids. However, to properly compare all resource options, appropriate steps must be taken to identify, quantify and evaluate the way in which different risks may impact ratepayers. UAE encourages the Commission to solicit advice from the independent evaluator and other parties and professionals in order to minimize, to the greatest extent possible, biases in favor of utility-owned resources, and to properly recognize the risk-mitigating elements of PPA resources in the solicitation and evaluation process.

6. The RFP as Proposed Will Unnecessarily Chill Bidding.

Several of the 31 reasons listed by PacifiCorp on pages 8-9 of the RFP for rejecting bids are unfair, chilling and inappropriate and should be eliminated or revised, including the following:

a) #3: "A new resource that will not qualify for the full PTC." This requirement is unnecessary and unreasonable, as the PTC accrues to the PPA bidder and failure to qualify for the full PTC will not affect firm PPA bids.[20]

b) Reason # 9: "The bidder, or an affiliate of bidder, is in current litigation with PacifiCorp or has, in writing, threatened litigation against PacifiCorp, respecting an amount in dispute in excess of one hundred thousand dollars." This requirement is particularly unreasonable. In the normal course of business, business must sometimes resort to litigation to enforce rights—particularly against a monopoly. Some major renewable energy developers in the region are currently in litigation with PacifiCorp seeking enforcement or clarification of rights and obligations. PacifiCorp should not be permitted to disqualify what may be a significant subset of regional renewable energy developers simply because they (or their affiliates) have resorted to, or ever "threatened," litigation of any type against PacifiCorp. There is no reasonable justification for this requirement and it is directly inconsistent with the interests of PacifiCorp's ratepayers.

[20] This provision also appears contradicted by information provided at the Pre-Issuance Bidders' Conference on May 31, 2017 (Exhibit PacifiCorp__(RTL-1), Rick Link, page 8), that "Projects do not necessarily have to qualify for production tax credits (PTC's); however, benchmark resources are expected to be PTC-eligible…"

c) Reason #11: "Project not in Wyoming." As noted above, an RFP that limits projects to Wyoming will not provide the information necessary to support approval of any resource under Part 3 of the Act and will not protect the interests of ratepayers.

d) Reason # 12: "Failure to provide completed interconnection system impact study (SIS) in bid proposal." This requirement is particularly onerous and unreasonable. Potential bidders (other than PacifiCorp Merchant) had no way of knowing that PacifiCorp would announce a new 500 kV transmission line and multiple new 230 kV transmission lines that would open new opportunities for project interconnections that did not previously exist. When PacifiCorp announced its intention to potential bidders on May 31, there were only approximately 135 days left until the October 13 deadline when PacifiCorp proposes that bids must be submitted. This effectively precludes anyone from bidding that had not already requested a system impact study for interconnection to a constrained transmission line (that nobody but PacifiCorp and its affiliates knew would be upgraded). The timeline for obtaining a completed SIS under PacifiCorp's OATT is well in excess of 135 days.[21] PacifiCorp, with advance knowledge of the proposals for new wind and transmission resources, may be the only potential bidder, or one of a very small universe, who can satisfy this requirement. There is ample time before the 2020 completion date for projects to secure the necessary interconnection studies. This

[21] PacifiCorp's OATT (Large Generator Interconnection Procedures) contemplate a timeline for completing an Interconnection SIS of a minimum of about 200 days. In reality, the process is often much longer.

requirement will preclude receipt of an array of competitive bids, is unreasonable, and should be eliminated.

e) Reason #14: Proposal presents unacceptable level of development risk (at PacifiCorp's sole discretion). Again, PacifiCorp should not be permitted to chill participation by threatening to reject bids at its sole discretion based on unquantifiable and discretionary reasons.

f) Reason #26: Any matter impairing the bidder, the specified resource or the generation of power or environmental attributes of the renewable resource. (at PacifiCorp's sole discretion). For the same reason as above, this "sole discretion" right of PacifiCorp should be deleted.

g) Reason #30: "Failure to submit an operations and maintenance agreement materially compliant with Appendix K for proposals involving PacifiCorp ownership or operational control upon commercial operation or substantial completion date". This requirement would force bidders to offer an O&M contract for a plant they will not own. This will unnecessarily increase the cost of bidding to cover operational risks, a requirement not imposed on benchmark resources.

h) Reason # 31: "Any matter impairing bidder, specified resources or the generation of power or non-power attributes therefrom" (at PacifiCorp's sole discretion). This "sole discretion" provision should also be rejected.

Elsewhere in the RFP, PacifiCorp "[r]eserves the right, without limitation or qualification and in its sole discretion, to reject any or all bids" (RFP at 10). As with other similar requirements, statements as to PacifiCorp's "sole discretion" should be removed. In addition, references to the role of the Commission and the independent evaluators should be emphasized, and any provisions purporting to allow PacifiCorp to reject bidders for virtually any (or no) reason should be removed. At most, these types of issues should be listed as matters to be considered in awarding bids, as opposed to PacifiCorp's alleged right to reject any bid for any reason.

7. The Projected Economic Benefits of the Proposed New Resources Do Not Justify a Hurried or Incomplete RFP Process.

The speed with which PacifiCorp proposes to issue its RFP and procure wind and transmission resources is a significant concern. PacifiCorp may argue that the RFP changes proposed by UAE (and others) are not feasible and would jeopardize the claimed time-limited opportunities. It is not in the interest of captive ratepayers for PacifiCorp's timing and actions to preclude a thorough evaluation of the Proposed New Resources, along with all other potential resource options. The risk of losing the opportunity to acquire the Proposed New Resources—particularly given that they are not needed and have only minor projected benefits—should be of far less concern to ratepayers than the consequences of allowing a flawed solicitation and procurement process to proceed. Simply stated, the minor economic benefits projected by PacifiCorp are nowhere near sufficiently compelling to warrant making ratepayers take a $4 billion risk on Proposed New Resources without first confirming that those resources are the most economical resources in comparison to ***all*** other potential resource options. Such confirmation is unavailable absent a robust set of market bids for all potential resources.

UAE understands that the economic justification for PacifiCorp's Proposed New Resources are intended to be addressed in Dockets 17-035-39 and 40. However, given the minor, and risky, economic benefits projected by PacifiCorp in comparison to its projected costs for the Prevailing Resources, UAE submits that there is no justification for a rushed RFP process that will preclude a supportable determination of the least-cost options for ratepayers.

PacifiCorp's economic projections are projections for one discrete set of possible resources as opposed to another discrete set. They do not in any way reflect analysis of all available resources. Moreover, there are sound reasons to carefully evaluate PacifiCorp's projections and proposals. PacifiCorp would clearly prefer to invest $3 - $4 billion in new rate base assets rather than relying on the Prevailing Resources, where most future needs will be met for year through energy efficiency, market purchases and other means that will not provide PacifiCorp with significant new investment opportunities. A utility's inherent bias in favor of investing capital over purchasing power provides a sufficient basis for skepticism of its proposed resource portfolio--especially one not designed to meet demonstrated needs and with only minor projected economic benefits that may or may not be realized over a long period of time.

There are other reasons to be skeptical of PacifiCorp's proposal. Approval of the proposed new transmission resources would finally, after decades of trying, allow PacifiCorp to get its proverbial nose under the tent with construction of over $700 million of the Gateway West transmission project, which PacifiCorp has never been able to justify economically. Moreover, if one sub-segment is built, making an economic case for other Gateway West sub-segments will likely become easier. Furthermore, because most of the vast amounts of wind energy to be injected into the new sub-segment will be stranded east of Bridger, which will require significant curtailment of the Bridger unit,[22] the economic case for Gateway South will likely also be

[22] The proposed Gateway West D2 project will relax a local area nomogram for WECC Path TOT 4A and TOT 4B, and will theoretically increase the capacity across TOT 4A and TOT 4B by 750 MW, but much or all of this expanded local area transfer capability will largely be of limited use because constraints west

stronger. There is a real possibility that the nearly $4 billion in projected costs for the Proposed New Resources will be just the beginning of massive additional unnecessary capital investments, which would put ratepayers at significant risk of higher rates.

8. The Proposed New Transmission Segment Has Not Been Properly Vetted through the Required OATT Process.

PacifiCorp's proposed new transmission "sub-segment" will not reduce congestion in moving power out of Wyoming to meet PacifiCorp's loads. At best, it will move additional wind energy from one part of rural southern Wyoming to another. In comments filed by PacifiCorp in the Oregon IRP docket, PacifiCorp admitted that the proposed new transmission will not increase transfer capability west of Jim Bridger, a chronically congested path and the only path by which the new Wyoming resources could reach Utah loads.[23]

In proposing this new 500 kV sub-segment and multiple 230 kv transmission lines, PacifiCorp has not followed the transmission planning requirements outlined in Attachment K of its open-access transmission tariff ("**OATT**"). PacifiCorp has never publicly defined as a proposed transmission project the "sub-segment" that it now proposes. PacifiCorp calls its proposed project "sub segment D2" of the proposed Gateway West project. However, no such "sub-segment" of Gateway West has been defined or studied as required by Attachment K to PacifiCorp's OATT. Segment D of Gateway West has always been defined as a single segment, and the new proposed sub-segment has never been publicly proposed or studied in the past.

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of Bridger/Anticline will trap the new wind generation in remote Wyoming, far from load. The only way for the new wind to get to load in most hours will be for PacifiCorp to curtail coal generation at Jim Bridger, one of the lowest cost resources in PacifiCorp's generation portfolio.

[23] PacifiCorp Reply Comments, Oregon Docket LC-67, July 28, 2017, at 35.

Attachment K further requires that projects designed to address local needs only—like the proposed Gateway West sub-segment D2—must follow a "Local Transmission System Plan" developed through a two-year planning process, with extensive public review and input. PacifiCorp has not presented a remote 500 kV Wyoming line in its Attachment K Local Area transmission planning process.[24] Also, while PacifiCorp claims economic benefits associated with relieving local area congestion, it has not performed any economic congestion studies as required by Attachment K. Moreover, since the party requesting this new transmission segment is PacifiCorp's merchant function, a question arises as to whether PacifiCorp transmission is in compliance with not only the OATT Attachment K requirements, but also the OATT Standards of Conduct.[25] The Federal Energy Regulatory Commission, which regulates the bulk electric grid, focuses on ensuring non-discriminatory open access and establishment of clear regulatory requirements and processes designed to limit the ability of incumbent transmission monopolies to discriminate in favor of their merchant affiliates and against non-affiliated owners/developers of power generation facilities. The appearance of such discrimination here is troubling and has a clear potential to lead to costly litigation before the Federal Energy Regulatory Commission.

[24] Attachment K indicates that such local transmission plans should inform the next IRP. In contrast, here PacifiCorp is trying to use the IRP process to justify a $750 million "local" transmission project outside of the Attachment K planning process.

[25] One could easily assume that PacifiCorp's transmission and merchant functions must have cooperated to plan and announce the building of multiple transmission lines and segments that would primarily benefit PacifiCorp, while bypassing transmission planning obligations in Attachment K and proposing RFP terms to severely limit competition in favor PacifiCorp-owned resources, suggesting a failure to maintain separation of functions as required by FERC.

9. PacifiCorp' Proposed Treatment of Transmission Costs Unduly Discriminates in Favor of Benchmark Bids.

PacifiCorp acknowledges that, when evaluated on a stand-alone basis, neither the proposed new Wyoming wind resources nor the proposed new transmission resources are economic on their own.[26] Yet, PacifiCorp claims that the combination of these two uneconomic projects somehow will produce (minor) benefits to ratepayers. This dubious claim can best be tested by opening the RFP to all resources, wherever located.

PacifiCorp recently made what it calls an "informational filing" in the 2017 IRP docket, 17-035-16. UAE has not yet had an opportunity to review this filing in any detail. However, the filing includes the following description of the six elements of its proposed new transmission investment:

> The new transmission investment includes six major elements: (1) the 140-mile, Aeolus-to Anticline 500 kV line…; (2) the five-mile Anticline to Jim Bridger 345 kV line…; (3) installation of a voltage control device at the Latham substation; *(4) a new 16-mile 230 kV transmission line parallel to an existing 230 kV line from the Shirley Basin substation to the proposed Aeolus substation, including modifications to the existing Shirley Basin substation; (5) the reconstruction of four miles of an existing 230 kV line between the proposed Aeolus substation and the Freezeout substation including modification as required at the Freezeout substation; and (6) the reconstruction of 14 miles of an existing 230 kV transmission line between the Freezeout substation and the Standpipe substation, including modifications as required at the Freezeout and Standpipe substations*.

Page 4 (emphasis added). The italicized transmission components described in subsections (4)-(6) above do not appear to have anything to do with Gateway West, and appear rather to be proposed extensions of PacifiCorp's 230 kV transmission system designed specifically to support PacifiCorp's planned benchmark resource bids. This is significant because PacifiCorp

[26] "The new wind resources are not economic without the Transmission Project, which is needed to relieve existing congestion and to interconnect and integrate new PTC-eligible wind resources in high-wind areas of Wyoming. The Transmission Project is not economic without incremental, cost-effective wind resources. This interdependence requires developing these projects together." RMP Application for Approval of Solicitation Process at 5.

proposes to evaluate all bids before considering any costs of the so-called “Gateway sub-segment 4b”. This would mean that PacifiCorp’s benchmark cost estimates would not include the full cost of interconnection of the benchmark resources, whereas PPA bidders will need to include all projected interconnection costs in making their firm bids. The result would be inappropriate discrimination in favor of benchmark resources.

10. PacifiCorp’s Repowering Proposals Should be Bid into the RFP.

Although the economics of PacifiCorp’s Repowering proposal will be evaluated in Docket 17-035-39, UAE believes a few aspects of the Repowering Proposal should be considered in this docket. PacifiCorp’s projected benefits of Repowering, while better than those for the New Wind/Transmission, are still relatively minor and subject to significant risks. Fairly minor changes in PacifiCorp’s assumptions could make the Repowering uneconomic. Moreover, as with the New Wind/Transmission, the economics of Repowering has not been effectively compared to other available resources.

In the context of the 2016 Portland General Electric (“PGE”) integrated resource plan, PGE reached a very different conclusion about the economics of repowering its Bigelow wind project. In comments filed with the Public Utility Commission of Oregon, PGE explained:

> Repowering would require a significant rate base investment relative to the magnitude of its contributions to meeting the capacity and REC needs identified in PGE’s 2016 IRP. Additionally, compared to RPS Early Action, an investment in repowering brings little additional energy and a correspondingly smaller reduction to carbon emissions.
>
> In considering a Biglow repowering scenario, it is important to note that PGE would remove existing equipment that has roughly ten years of service, and likely little, if any, salvage value. The Company would need to recover the remaining undepreciated cost. At the end of 2016, the total remaining undepreciated cost for Biglow Canyon was approximately $450M.

> PGE does not recommend that RPS actions be decided purely on the basis of maximizing PTCs in isolation of other considerations. PGE does not find repowering to be a compelling alternative to Early Action.[27]

UAE shares some of the concerns expressed by PGE. In any event, in order to properly assess the economics of Repowering, it should be evaluated as one of many available resource options in comparison to all other available options. PacifiCorp should thus be directed to bid each proposed Repowering project into the expanded RFP to be evaluated along with all other options on a fair and comparable basis.

[27] Portland General Electric Company's Final Reply Comments, Public Utility Commission of Oregon, Docket LC-66, at 22. Three of the wind projects that PacifiCorp originally proposed for repowering are in Washington (Marengo 1 and 2) and Oregon (Leaning Juniper). Leaning Juniper is roughly 20 miles from PGE's Biglow Canyon wind plant that is the subject of the above comments. PacifiCorp's recent supplemental information filing indicates that Goodnoe Hills has also been added to the proposed repowering portfolio. The Goodnoe Hills project is only seven miles from PGE's Biglow Canyon plant.

11. The Proposed New Resources Will Significantly Complicate MSP Efforts.

RMP's IRP suggests that both the PacifiCorp East region (PACE) and the PacifiCorp West region (PACW) are roughly equal in capacity load resource balance in summer peak conditions. However, given that PacifiCorp considers its full 1,600 MW share of the Wyoming Jim Bridger resource as a PACW (i.e., Oregon) resource in the IRP, it is clear that there is actually an approximate 2,000 MW resource deficit in PACW and an approximate 2,000 MW resource surplus in PACE. Yet, the proposed new resources are all located on the east side[28.] Not only is the prudence of such an approach questionable, it will also significantly complicate ongoing multi-state cost allocation (MSP) negotiations, in which cost allocation approaches under consideration include assignment of fixed portions of existing resources to each region or state, and voluntary subscription to future resources.

12. Other RFP Suggestions and Considerations.

UAE is dubious about PacifiCorp's apparent position that broader social and economic consequences or detriments of using tax benefits to justify the premature scrapping of resources with two thirds of their economic lives remaining to produce marginal efficiency gains should be ignored.

Given significant differences in benefits and risks of bids and benchmarks as discussed above, they cannot be evaluated against each other on a "fair and comparable basis" as required by Utah law unless the significance of these differences is recognized or addressed through assignment of values to the different risks or by taking appropriate steps to reduce these differences. For example, PacifiCorp could be required to submit a "not-to-exceed" benchmark

[28] *See* 2017 Integrated Resource Plan, Volume 1, April 4, 2017 at pages 91-92.

cost estimate that it will be required to live with, like bidders. The independent evaluator and other parties may have other reasonable suggestions for evaluating bids and benchmark resources on a comparable and fair basis. Similarly, PacifiCorp could be required to sell or allow use of PacifiCorp's sites, interconnection rights and safe-harbor equipment by other bidders.

The 20-year term for the proposed PPAs—compared to a much longer life of comparable PacifiCorp-owned resources—is also a concern. Models used to compare resources of comparable lengths are imperfect in facilitating apples-to-apples comparisons under such circumstances. Steps should be taken to avoid such incomparability. For example, bidders could be encouraged to offer a fair market value purchase option at the end of the term, which might facilitate a fair comparison. UAE encourages the Commission to solicit input on this (and other) issues from the independent evaluator, parties, and professionals to ensure a fair and reasonable process.

Conclusion

UAE appreciates the opportunity to submit these initial comments and looks forward to continued involvement in this process. The Act contemplates approval of a solicitation and a resource only if they are consistent with the Act and otherwise in the public interest. UAE respectfully submits that the RFP as proposed is inconsistent with intent and requirements of the Act and not in the public interest, given that it is not designed to permit a comprehensive evaluation of available resource options.

The Commission has several available options under the Act, including extending the timeline for review and approval of the solicitation process, holding a hearing to receive evidence to help it make an informed determination, rejecting PacifiCorp's proposed RFP altogether, or recommending modifications for a properly designed RFP that can properly lead to approval of a resource under the Act.[29] UAE respectfully asks the Commission to hold a public hearing in this matter, and otherwise to avail itself of the available options in order to ensure development of a proper RFP that will facilitate the public interest considerations promoted by the Act and ensure that Utah customers will be forced to bear the costs of only those resources that have properly been shown to be the most economical.

DATED this 4th day of August 2017.

HATCH, JAMES & DODGE

/s/ ________________________
Gary A. Dodge
Attorneys for UAE

[29] U.C.A. §§ 54-17-201 (2)(a), (e), (f)

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

Docket No. LC 67

In the Matter of PACIFICORP, dba PACIFIC POWER, 2017 Integrated Resource Plan	Staff’s Initial Comments

EXECUTIVE SUMMARY

Staff of the Public Utility Commission of Oregon files these Initial Comments on Pacific Power's (or Company) 2017 Integrated Resource Plan (IRP or Plan), filed on April 4, 2017. Staff will continue to evaluate the Company's plan, conduct discovery and review stakeholders' comments prior to submitting its Final Comments, currently scheduled to be filed on September 1, 2017.

The series of public input meetings which initiated the IRP process began in June of 2016. This process included five state meetings and seven general meetings[1] between June of 2016 and March of 2017. A full list of these meetings as well as a list of the meeting participants can be found in Chapter 2 (pages 21 – 24) and in Appendix C (pages 57 – 62 of Volume II) of the Company's 2017 IRP.

Staff utilizes this first round of Comments as an opportunity to both commend Pacific Power for its comprehensive and detailed IRP, and to raise initial areas of interest that will need additional analysis and potentially additional clarification from the Company.

Staff first offers comments on the major Action Plan items proposed by Pacific Power. Near term actions in Pacific Power's 2017 Action Plan (found in Chapter 9 on pages 265–269 of the Plan) are of paramount importance and continue to be analyzed by Staff. Following the comments on the Action Plan are discussions on various subjects that Staff believes need further clarification from the Company, or that raise concerns with the Company's assumptions or methods used in analyzing this IRP.

Foundational Issues
The Commission expects the IRP process to be transparent and to allow for stakeholder input to the Company's preferred portfolio choice, as well as all the analysis the Company performs to reach this choice. In this IRP cycle, the Company essentially completed the public input process of seven public meetings, beginning in June 2016 and going through the end of the year.The Company then produced a draft Action Plan reflecting no new resource acquisition, as the Company's analysis projected no need for additional resources in order to serve load reliably.

It was only at the end of this process that the Company drastically altered its Action Plan to include both the repowering of 905 MW of existing Company-owned wind resources (Wind Repowering) and the purchase of 1,100 MW of new wind with the associated new transmission line (New Wind) that would enable transport of the New Wind power. These proposed capital investments are projected to cost approximately $3.5 billion. Despite the significance of these costs and unfamiliarity with the projects themselves in the context of the IRP, stakeholders had little to no time to review because it was brought to the table at the very end of the process.

Staff is uncertain as to why the Company waited so long to introduce such major resource acquisitions, but in any case, Staff is concerned that the lack of stakeholder review violates a core IRP principle that fosters an open and participatory process and thus may pose a risk to ratepayers. The late inclusion of such a significant set of investments has deprived Staff and other stakeholders of the opportunity to preview that capital addition proposal and ask the Company questions prior to the filing of the IRP. Staff is further concerned with the late addition of these two Action Items (New Wind and Wind Repower) because the Company has no need to justify these resource acquisitions and makes no claim to have a need – it presents this $3.5 billion acquisition purely as a long-term economic benefit to customers over the course of twenty years.

The fact that the Company has identified no need for the new resources, but instead presents their acquisition as a purely economic decision, means that the normal standards of IRP review may not be relevant because system "need" is an essential element of that review standard. The originating order

[1] "State meeting" topics were concentrated on the impacts of the IRP to individual states; "General meeting" topics concerned the issues of the system as a whole.

that established least cost planning for Oregon regulated utilities, Order No. 89-507, clearly defines the purpose of the planning process – to choose the least-cost approach to meeting the utility's load through thorough consideration of all potential resources. When the utility presents an IRP that establishes the fact that the Company can reliably meet projected load with available resources, it also makes clear that there is no need for further resource analysis or acquisition to fulfill the least-cost planning goals.

This raises another general concern with the inclusion of a major resource in the Action Plan without any apparent physical or compliance need for approximately a decade.. This IRP assumes the investment of more than $2 billion in traditional utility-scale generation 10 years prior to the physical need for that resource at a time when the industry is going through significant structural change. Evolutionary and revolutionary shifts in technology, environmental policies, and customer expectations are changing how investments are made on the electricity system. A commitment of such significant capital carries with it inherent risk of cost overrun and other potential bad outcomes, and the Commission must ask whether the potential benefits to ratepayers are worth exposing them to great risk when there is no reliability need motivating the transaction.

To complicate matters, the Company has begun engaging its state regulators in a conversation to rethink the development of future generating resources and the allocation of costs in the Multi-State Process (MSP) forum. Early concepts indicate the possibility of a very different paradigm for how customers in each Pacific Power state will be served and how new generating resources will be selected and included in rates. These concepts assume this major change in how system resources are developed within the next decade. All of these concerns factor significantly into Staff's review of this filing.

ISSUE DISCUSSION

ACTION PLAN

ENERGY GATEWAY SUB-SEGMENT D2 AND NEW WIND PROJECT

The Company has presented a "package" proposal that includes 140 miles of new transmission, as well as the construction of 1,100 MW of new wind in Wyoming. The Company expects the $2.5 billion project to yield minor economic benefits for customers (in the $20 million range), but only under a limited range of economic conditions. Specifically, the Company acknowledges that the project would likely not be economic if natural gas prices stay low through 2036.

The purpose of the IRP process is to facilitate "least-cost, least-risk" planning with a primary purpose of assuring the Company has adequate resources to provide reliable service to meet anticipated load. Because of the uncertainties inherent in physical, engineered, and economic systems, the least-cost, least-risk planning process requires considerable modeling of factors introducing these uncertainties. It is critical for model assumptions and scope to be non-arbitrary and justified by available data, as well as be considered with a well-reasoned perspective on externalities which can influence past and future trends in these areas. It is not always the case that the least-cost approach to planning will also yield a least-risk solution. Often, there is a necessary tradeoff between cost and risk, and the challenge is to find a portfolio which balances these two criteria. In this IRP, Staff finds the analysis challenging for three reasons.

First, without a clearly defined need for this resource, it is difficult to consider the Action Plan to be least risk. The proposed Action Plan is claimed by the Company to be the least-cost planning approach for resource acquisition based on its stochastic present value revenue requirement (PVRR) portfolio analysis. At the same time, however, the Company claims that it has no deficiency in meeting the projected future load with current resources through the IRP planning window. In addition, the Company does not appear to need the proposed wind resource or transmission resource to meet either federal or state regulatory requirements.

The proposed wind and transmission projects carry the same extensive risks (cost overruns, schedule delays, etc.) as any other capital-intensive projects, despite not being needed to serve load or fulfill a regulatory requirement within the Action Plan timeframe. It would therefore be implausible to consider these projects as less risky than the option of acquiring no resources. It appears instead that the Company considers these projects feasible only because they represent a marginal economic benefit to customers under the analysis.

Second, Staff is interested in knowing the extent to which the economics of this project rely on the existence of the Clean Power Plan or similar, as it appears increasingly likely that there will be no such federal regulation for the next four or perhaps even eight years. Staff expands on this point within the Environmental Regulation Compliance section below.

Third, as mentioned previously in these comments, Staff is concerned that stakeholders have had little to no time to review this proposed capital investment of around $2.5 billion because it was brought to the table at the very end of the process.

Staff continues to investigate the assumptions and methodology the Company has used to draw its conclusion that the acquisition of this wind project and associated transmission will be a net benefit to customers. Staff notes that the Company's analysis shows only a relatively small net benefit – on the order of $20 million savings on a PVRR of nearly $23 billion over 20 years[2] – while incurring risk of potential costs that reasonably could be an order of magnitude greater than the small projected benefit.

WIND REPOWERING

Staff is encouraged to learn that Pacific Power undertook an analysis to determine whether repowering its wind generation fleet could be economic for its customers. The Company's analysis indicates that, despite replacing equipment that has a decade or more of book life remaining, the project is expected to reduce revenue requirement by $35 million over the period 2017-2036, and by $350 million over the period 2017-2049.

Although the Company's analysis indicates a small to material economic benefit to customers over all of the several sensitivity scenarios considered, Staff is still concerned that minor changes in assumptions could result in significantly different results. Staff additionally retains the same concerns with this acquisition as it does with the New Wind/Transmission project discussed previously in these comments. The Company does not support this acquisition with a claim of any need – the resource is not strictly needed for reliability or serving load, nor is the repower needed for RPS compliance within the Action Plan time frame.

The Company has justified this acquisition solely on its economic merits. In light of this, Staff anticipates focusing its discovery on the various assumptions and analysis that provide the support for this proposed economic transaction.

RENEWABLE PORTFOLIO STANDARD (RPS) COMPLIANCE

As outlined in the IRP, Pacific Power's supply-side plan will allow the Company to comply with Oregon's RPS through 2034, with a limited number of unbundled purchases starting in 2018.[3] As Staff currently understands the supply-side plan, the Company is justifying the Wind Repower and the 1,100 MW of New Wind and transmission on a strictly economic basis, and are neither required nor justified by an

[2] Pacific Power 2017 IRP Volume I, Figure 8.52, p. 224.

[3] Pacific Power 2017 Integrated Resource Plan, Volume 1 P.8.

immediate RPS compliance need. Staff plans to confirm that Pacific Power has also assigned no value to the RECs produced by the proposed new projects in terms of valuing the portfolios.[4]

In Order No. 17-010 the Commission approved Pacific Power's revised 2017-2021 Renewable Portfolio Standard Implementation Plan (RPIP). Pacific Power observed as part of that plan that "competitively priced near-term procurement opportunities that can defer the need for future renewable resources until the 2028-2030 timeframe are most likely to yield customer benefits."[5] In that filing, Pacific Power also noted that unbundled RECs can have a significant, low cost role in complying with the RPS in a given year. In the IRP, Pacific Power's supply-side resources meet Oregon RPS compliance needs through 2034. Pacific Power notes in the IRP that it will utilize unbundled RECs for compliance, apply RECs to jurisdictions where they can used when produced in jurisdictions where they are not needed, and sell RECs when REC banks reach certain thresholds.

In recommending approval of Pacific Power's 2016 RPIP, Staff noted mismatches in timing between the RPIP development and approval process and the acquisition of electric Company renewable energy assets.[6] The approved RPIP proposed meeting the five-year needs through existing resources, coupled with unbundled REC purchases.

Staff does not expect the Company to deviate from its approved 2016 RPIP for the five year period of the 2017-2021 RPIP. In order to capture PTC values at the 100 percent level, Pacific Power plans to complete the installation of the new supply-side resources identified in the Action Plan by December 31st, 2020. Accordingly, this resource, which was not included as part of the 2016 RPIP analysis, may be producing additional RECs during the five years of the 2017-2021 RPIP--principally in 2021. However, because Pacific Power utilizes a first-in-first-out REC retirement structure, RECs from the renewable supply-side facilities proposed in this IRP will likely not be used for compliance with the RPS during the term of the 2016 RPIP.

Staff notes however that the 2016 RPIP, which was filed on July 15, 2016 and approved on January 13, 2017, was developed and adopted in a period just prior to the April 4, 2017, filing of the IRP. This timing mismatch highlights the challenges noted by Staff in the recommendation to approve the 2016 RPIP of RPS compliance planning and resource acquisition.

Although the Company is not planning on counting the RECs of the new proposed wind projects toward its near term RPS compliance, Staff anticipates that in the future the benefits of the RECs and the capital cost of the projects will both affect the RPS incremental cost calculation. Staff anticipates further discovery to understand the impact of the proposed supply-side actions on future incremental cost calculations made for the purposes of RPS compliance.

FRONT OFFICE TRANSACTIONS (FOTS) AND MARKET DEPTH

The Company continues to plan to meet energy shortfalls by relying on access to the liquid energy markets (Four Corners, Mid-Columbia, etc.). Staff agrees with the Company that there is likely not a significant capacity deficit looming in 2021, and load can be reliably met with a combination of existing fleet resources and FOTs. Staff believes this is not only the less-costly strategy, but, given the increasing uncertainty about how energy markets will evolve in the future, is also the less risky strategy. Therefore this component of Pacific Power's Plan seems to represent one "least-cost, least-risk" component of its

[4] Pacific Power April 18, 2017 presentation to Staff on IRP components.
[5] Pacific Power's Revised 2017 – 2021 RIPP, Confidential Appendix A, at page 20, Docket No. UM 1790, July 15, 2016.
[6] Order No. 17-010, Appendix A, p.16.

planning at this time. Staff expects the Company to notify the Commission in the event that the Company anticipates or experiences market changes which would alter its Action Plan.

Staff is exploring the differences in expected market depth reported by various regional sources, including the Northwest Power & Conservation Council and the Oregon regulated utilities. Staff will continue to evaluate the reasonableness of Pacific Power's assumptions and conclusions regarding the available level of front office transactions.

ENERGY EFFICIENCY (EE, ORCLASS 2DEMAND SIDE MANAGEMENT (DSM))

Pacific Power proposes to acquire at least 120 MW of EE annually throughout the Action Plan timeframe.

Staff finds Pacific Power's overall position on Class 2 demand-side management (energy efficiency) in the 2017 IRP acceptable, but has several questions that it would like to have addressed prior to final acknowledgement. Staff notes that while incremental forecasted energy efficiency (EE) covers an increasing percentage of forecasted load growth, the total amount of energy savings expected to be achieved has actually dropped relative to the 2015 IRP preferred portfolio. This is due to several factors.[7] Staff is unclear as to what amount of this reduction is forecast for Oregon specifically. Staff plans to work with Pacific Power on this and to determine the extent to which and exact reasons why previously cost-effective energy efficiency may not be pursued in Oregon as part of this IRP. Additionally, Staff would like to better understand the avoided cost methodology used to determine the value and selection of energy efficiency in the Oregon portfolio and how it relates to the new avoided costs values proposed to Energy Trust by Pacific Power for use in 2018.

In addition, Staff is unclear as to what the Oregon-specific EE winter and summer peak reduction is. While Pacific Power did a good job of attempting to comply with Order 14-252,[8] Staff would like to better understand the Oregon contribution to meeting its winter and summer peaks and how Pacific Power made these determinations.

Staff is also concerned about the energy efficiency forecasts for Oregon. In the past, Energy Trust has over-achieved its Pacific Power energy efficiency IRP targets. Staff is unclear how past over-achievements are reflected in current load forecasts and how, if at all, Energy Trust's latest energy efficiency forecasts are adjusted by Pacific Power to reflect Energy Trust's past performance.

THE COMPANY TRANSMISSION PLANNING

Staff does not have any initial concerns with the Company's transmission planning activities, other than the Aeolis-Bridger line proposal as articulated above.

COAL RESOURCE ACTIONS

Staff appreciates the Company's efforts in limiting the cost and risk to customers through its challenges to the Regional Haze plans it is affected by. Analysis presented by the Company in both previous IRPs[9] and

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[7] "Decreased selection of energy efficiency resources relative to the 2015 IRP is driven by reduced loads and reduced costs for wholesale market power purchases and renewable resource alternatives." the Company 2017 IRP (LC 67), April 4, 2017, p.4

[8] As modified by Order 14-288. Order 14-242 states, in relevant part: "In future IRPs, PacifiCorp will provide yearly Class 1 and Class 2 DSM acquisition targets in both GWh and MW for each year in the planning period, by state." See *In the Matter of PacifiCorp*, *dba Pacific Power*, OPUC Docket No. LC 57, Order No. 14-242 (July 08, 2014).

[9] *See* PacifiCorp 2015 IRP, chapter 9.

the current IRP consistently indicates that avoidance of selective catalytic reduction (SCR) is a least-cost, least-risk approach to managing the coal fleet.

The Action Plan lists eight coal plants and their associated federal or state Regional Haze implementation program schedules. The schedules for Hunter 1 & 2, Huntington 1 & 2 and Jim Bridger 1 &2 require the installation of SCRs by 2022. The Company states that its intention is to avoid an SCR installation at the Dave Johnston, Naughton, Wyodak, Cholla and Craig plants through litigation, gas conversion (Naughton and perhaps Craig), or plant closure.

Although the Company discusses the EPA schedules for SCR installation, it does not commit to the installation of the SCRs in the Action Plan. Instead, the coal related Action Items promise both ongoing litigation aimed at eliminating the SCR requirements and updated economic analysis in a future IRP or IRP update.

The Company asserts that avoiding installation of this equipment will save customers hundreds of millions of dollars and retain compliance-planning flexibility for the Clean Power Plan or other potential state and environmental policies. By the end of the planning horizon, Pacific Power assumes 3,650 MW of existing coal generation will be retired. Staff supports the Company's efforts to avoid the SCR installations, the installation of which has been shown by the Company to not be the least-cost planning alternative.

NATURAL GAS RESOURCES

Natural gas-fired resources do not appear in the preferred portfolio until 2029 (one year later than in the 2015 IRP). By the end of the planning horizon, natural gas-fired capacity totals 1,313 MW, a reduction of 1,540 MW relative to the 2015 IRP preferred portfolio. Although recognizing the current strengths of natural gas-fired generation in its resource planning, Pacific Power also recognizes the risks inherent in long term planning around natural gas. Both commodity price and policy volatility have proven high in the past for natural gas, and the Company has consequently constrained natural gas in its portfolio to manage those risks. Staff appreciates that the Company will continue to evaluate potential long-term supply alternatives, including that of energy storage. Staff will continue to work with the Company to evaluate the ongoing need and efficacy of natural gas resources, especially in light of the coming availability of storage and new potential technologies across the planning horizon.

GENERAL ISSUES

ENVIRONMENTAL REGULATION COMPLIANCE

Staff applauds Pacific Power's extensive efforts to model Clean Power Plan (CPP) compliance in conjunction with other environmental regulatory requirements. Pacific Power also imputed shadow carbon prices within its market modeling. These steps demonstrate a level of environmental modeling not seen before, and an effort that Staff believes is commendable. Pacific Power undertook modeling several different Clean Power Plan compliance scenarios which informed nearly all structural aspects of its IRP portfolios runs, scenario modeling and ultimately portfolio selection.

While Staff recognizes the effort undertaken by Pacific Power to model CPP compliance, Staff does have initial concerns related to the handling of the CPP in this IRP, and will need additional information and time to understand how the modeling of the CPP may have informed modeling runs, portfolio selection and preferred resource acquisition.

Pacific Power's CPP compliance model CPP(b) was used as a structural pillar in its preferred portfolio modeling framework. The CPP(b) model makes several assumptions about compliance that ultimately affect resource acquisition strategy. For example, Pacific Power seems to assume a WECC-wide compliance agreement which includes EPA's New Source Complement option. These two assumptions contemplate a level of coordination between WECC states that at present is not indicated by discussions between the states or in regional forums which had taken place during the high-point of CPP discussions. Pacific Power should be aware of this, as it was present at many of these WECC and sub-regional meetings.

Additionally, Pacific Power assumes the WECC states would opt for a New Source Complement. The New Source Complement, with its increased emissions allowance allocations, will likely affect how Pacific Power's aging coal fleet is treated in modeling runs, particularly regarding operating hours and retirement dates. Additionally, in the outer years the New Source Complement may affect resource acquisition decisions, as any new fossil generation would need to fit within the emissions allowance cap. This may shift the model's preference to non-fossil resources, such as wind resources. Additionally, Staff is concerned that other assumptions and modeling choices regarding CPP compliance may have unduly influenced which portfolio ultimately became the preferred portfolio -- such as the inclusion of a shadow carbon price, the assumption that Pacific Power jurisdictional states would opt for early wind treatment under the CPP and participation in Clean Energy Incentive Program (CEIP) under the Clean Power Plan compliance rules.

Additionally, Staff is concerned that Pacific Power modeled CPP compliance in every portfolio and scenario modeling run, save two. Neither of the two non-CPP modeling runs chose the level of early renewable generation acquisition present in the preferred portfolio, suggesting that modeling based on an assumption that the CPP is altered or eliminated could yield a significantly different preferred portfolio than that chosen in this IRP.

Lastly, although at the time Pacific Power developed their IRP modeling framework the Clean Power Plan was still an applicable rule, it is presently in serious jeopardy of being either invalidated or rescinded. Pacific Power, as party to the present action in the D.C. Court of Appeals against the Clean Power Plan, is well aware of this threat to the Clean Power Plan. Having this knowledge, it does not seem unreasonable for Pacific Power to have either adjusted its modeling or conducted additional modeling that does not have the CPP as a weighty factor.

Staff intends to conduct analysis to determine the extent to which Clean Power Plan compliance informs or drives Pacific Power's resource procurement choices in its preferred portfolio.

LOAD FORECASTING & BALANCE

In completing a review of recent Pacific Power IRPs, Staff identified at least three past issues related to the Company's approach to load forecasting and assumptions to meet that projected load, and questions whether these issues have been resolved in this IRP.

The first question for Staff is whether Pacific Power can reliably meet its winter peak in its West Balancing Authority (BA) given the limited transmission between the two balancing areas (PACE and PACW). The second area of concern for Staff is whether the forecasts reflect decreased loads due to customer-owned solar. A related third concern is whether the forecasts reflect decreased loads due to customers opting for direct access. Each of these issues is discussed below.

Can Pacific Power meet its winter peak in its west Balancing Authority Area (BAA)?

The question was raised by Staff in prior IRPs without a definitive answer being agreed upon between Staff and the Company. Although Pacific Power appears to have ample capacity in its fleet to meet the load requirements of the winter peak, there was a question of whether transmission and perhaps other operational constraints might impair the ability of the Company to move the energy. Much of Company's reserve capacity lies in the East BAA while most of the Oregon load lies in the west BAA. The Company has limited transfer capability between the two BAA's and in the past Staff has questioned whether the transfer capability would be adequate to serve the load on the west side during the winter peak.

On page 75 of the IRP, Pacific Power states, "in response to stakeholder feedback in the previous IRP cycle, this 2017 IRP includes the modeling of the winter coincident peak as an improvement over previous IRPs." Table 5.15 on page 92 confirms the Company's ability to meet its west winter peak obligation plus 13 percent reserves (3,670 MW in 2026) using existing west resources and available front office transactions (4,590 MW in 2026). The transmission constraint does not appear to have impeded the Company's ability to meet the winter peak in the West BAA.

Do the forecasts reflect decreased loads due to customer-owned solar?

As customer-side solar generation increases, the utility experiences a reduction in net load when considered on a monthly or annual basis. It was not clear to Staff from examining prior IRPs exactly how this expanding solar base was incorporated into the Company's load forecast.

Page 85 of the current IRP states, "as in the 2015 IRP, the Navigant [Consulting Inc.] study identifies expected levels of customer-sited private generation, which is applied as a reduction to Pacific Power's forecasted load for IRP modeling purposes." Generally, Staff recommends against these types of ad-hoc adjustments to the load forecast outside of the regression model, but in this case, the Company's approach can be viewed as a conservative approach to prevent over-forecasting load. Staff is currently investigating how the Company incorporates customer-sited private generation into its peak load forecasts.

Do the forecasts reflect decreased loads due to customers opting for direct access?

The final order in LC 57(Pacific Power's 2013 IRP docket) states, "Staff and ICNU contend that Pacific Power's assumption of zero long-term direct access loads is not reasonable."[10] Staff maintains that position and believes that the Company's assumption that no additional customers will opt for long-term direct access in the next 10 years is unlikely to match reality. The Company is aware that large industrial customers maximize their economic position; for example, by stating on page 15 of Appendix A, "the Company has seen several large industrial customers cancel expected load when [commodity] prices have fallen." Given that customers will cancel new projects when expected revenues get too low, it is reasonable to assume that customers will switch to direct access if they can save money by doing so.

Staff encourages the Company to develop a forecast of expected load that will opt out of cost of service tariffs and reduce the cost-of-service load appropriately.

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[10] Order No. 14-252, p21.

General Comments on the Load Forecast Methodology

The Company finds a positive relationship between employment and the quantity of retail electricity sales. Accordingly the Company uses employment as a forecast driver in its regression-based forecast of Oregon commercial use-per-day and industrial use-per-day. On page 4 of Appendix A, related to employment, the Company identifies that "the relationship between the economic variable and sales has "flattened", meaning electric usage has become less responsive to the economic variable." This is problematic because the regression equations used by the Company identify a single coefficient relationship between employment and electricity usage. Thus because the coefficient was developed using data related to a relationship that is now more flat, the forecasts may be inaccurate. Staff raised this concern in detail in Staff's comments related to PGE's 2016 IRP and is continuing to investigate whether it impacts Pacific Power's forecasts.

Staff continues discovery into issues related to load forecasting. Staff will investigate the Company's energy and peak forecasts in greater detail and will have further discussion on this subject in the Final Comments.

LOAD AND RESOURCE BALANCE

Overall, Staff finds the Company's Load and Resource Balance analysis to be comprehensive and thorough. Using an annual load growth rate of 0.85 percent, as well as assumptions about generation additions and retirements, energy efficiency savings, hydro contract renewals, and the availability of front-office transactions (FOTs), the Company concludes it will not have any energy shortfall during off-peak hours until 2026, and only very small projected short-duration on-peak energy shortfall in 2022.

On pages 10-11 in the current IRP the Company presents a ten year capacity position which shows effective reserve margins of over 17 percent in the summer and 36 percent in the winter, indicating that the Company has ample capacity to meet projected load in the IRP timeframe and requires no new major resources to do so.

RISK METRICS

Staff has concerns about the use of the upper tail statistics for measuring risk, as well as with the "risk adjusted PVRR" metric, as both analyses may suffer from an element of arbitrariness and lead to inconsistent results for "least-cost, least-risk" planning.

The Company states in its IRP draft that the upper-tail mean PVRR is a measure of high-end stochastic risk. It is calculated by first identifying the Monte Carlo iterations with the three highest production costs on a net present value basis. The portfolio's real-levelized fixed costs (taken from System Optimizer) are added to the production costs, and the mean of the resulting PVRRs is computed. However without removing the expected cost from the upper-tail cost, the metric indicates higher-cost portfolios are generally also more "risky." This is not the case.

The risk-adjusted PVRR is intended to capture risk by incorporating the expected value cost of low-probability, high cost outcomes. It is calculated by the Company as the PVRR of stochastic mean system variables plus 5 percent of system variable costs from the 95th percentile. It is based on 50 Monte Carlo simulations for each resource portfolio. The PVRR of the fixed costs are added to this system variable cost metric. The risk-adjusted PVRR is supposed to represent a consolidated stochastic cost indicator for portfolio rankings. Staff is concerned about potential shortcomings in this screening metric: The Company provides no rationale for the 5 percent risk weighting. It is unclear if this value is chosen based on some statistical or natural clustering measure, or if it is based on economic principles. It is also unclear to Staff how this measurement – if not arbitrary – is a better estimation of risk than the other PVRR metrics employed by the Company.

The variability of portfolio cost around the expected value is certainly a reasonable measure for the severity or intensity of risk. However, variability metrics in themselves do not measure the probability of an event occurring. Staff believes both pieces of information are crucial to more fully understand the amount of risk represented by a portfolio.

RECENT RESOURCE PROCUREMENT ACTIVITIES

Pacific Power notes that it has conducted the following four requests for proposals (RFPs) since November 2015:

- 2017 Transfer Frequency Response RFP
- 2016 Natural Gas Asset Management and Supply RFP
- 2016 Renewable RFP
- 2015 Market Resource RFP[11]

Staff did not have any specific issues or obvious reason for concern regarding these RFPs. However given the amount of money potentially involved and the impact current procurement activity could have on future planning, Staff requested an opportunity to review all materials related to these RFPs. The Company was agreeable and facilitated a review of these materials. Staff was able to confirm that in all cases, the modeling and analysis was appropriate and at the right level of sophistication for the task at hand. Staff does not anticipate any further need for review of these RFPs in this IRP process.

MODELING AND STOCHASTIC PARAMETERS

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. Pacific Power uses the System Optimizer (SO) capacity expansion module to produce unique resource portfolios across a range of different planning assumptions. Informed by the public input process, Pacific Power ultimately produced and evaluated 43 different SO portfolios for its 2017 IRP. Pacific Power uses Planning and Risk (PaR) modeling 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 carbon dioxide (CO2) 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, Pacific Power 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.

In order to perform its modeling analysis, the Company made several assumptions related to date conventions, inflation rates, and discount factors.

Staff questions certain specific assumptions. in particular, Staff questions the in-service date assumed. Specifically, in-service dates of January 1 are used, with the exception of coal generation. June 1 is the in-service date used for coal generation. The Company states that the reason for the use of variable in

[11] Pacific Power 2017 Integrated Resource Plan, Volume 1 P.53.

service dates by resource type is due to need for alternatives to be available during the summer peak period. Staff is unclear as to why the Company treats coal-to-natural gas conversions separately for this purpose. Availability of coal versus other resource types noted do not vary seasonally. It is possible that the availability, storage and delivery of natural gas resources to meet peak summer demand are embedded in the Company's assumption, but this is not clearly articulated. Staff continues to explore this issue.

The Company performed complex modeling and portfolio analysis as part of the IRP process. The model and portfolio evaluation appears to be robust and of a level of complexity well suited to the IRP process. Staff is interested in the Monte Carlo analysis Pacific Power applied for the portfolio evaluation. Staff has questions regarding the modeling rules. For instance, it is unclear to Staff why the draws for hydroelectric generation are applied on a weekly basis, whereas others are applied daily. In addition, Staff questions why the expected values of the simulation are the average of all 50 iterations. Depending on whether or not the simulation was a Markov Chain Monte Carlo, the averaging may simply result in a portfolio selection that is identical to the model inputs. Staff continues discovery regarding the detailed Monte Carlo methodology used by the Company to answer these questions.

With regard to the Company's treatment of loss of load probability and cumulative CO2 emissions in the IRP, Staff is interested in how assumptions related to future changes in transmission topology as well as potential shifts in CO2 emissions regulation might be integrated into the model. In general however, the Company appears to be appropriately considering a wide range of variables in its studies. Staff would appreciate the Company providing greater clarity regarding the aforementioned assumptions which will help Staff to evaluate the selection of cases for analysis, and least-risk portfolios.

The Company updated and re-estimated its 2015 stochastic parameters for use in the current Planning and Risk (PaR) model runs. The purpose of the PaR model is to stochastically shock the electricity price forecast (and other key drivers) which will in turn alter the model outputs. By comparing the variability in the output to the variability in the input, the Company could draw conclusions about PVRR sensitivity to the input variables. As an example, if a five percent increase in gas cost assumption results in a 10 percent increase in system cost (i.e., PVRR) one could conclude that the output is relatively sensitive to input price assumptions. If on the other hand the five percent increase in gas cost results in insignificant change in PVRR, one could assume the modeling is relatively insensitive to gas prices.

The Company uses a two-factor mean reverting model.

The general process used by the Company 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.

Short-run stochastic parameters were used in the IRP, and the Company set long run parameters to zero. The basis for the decision to set long run parameters to zero given by the Company is that it 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--loads and fuels. 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. Staff has concerns that incorrect selection of input-level variables can propagate uncertainty across the forecast horizon. Staff is also concerned about the variability in the fits of the regression analysis of the uncertainty parameters. Specifically, there does not appear to be consistency in the correlations across the tested parameters, and Staff questions whether there is justification for using both the regression analysis as well as input variables.

Staff will work with the Company to evaluate the data sources used in the stochastic parameter analysis, and to better understand the regional scale modeling. Staff is particularly interested in understanding why missing price data were “blanked” for natural gas prices, but interpolated for electricity. Staff is also interested learning about the significance of the model “fits” for the different scenarios. However, the use of a mean-reverting model, and the use of lognormal distributions and regression analysis appear to be reasonable and generally accepted distributions and analysis tools for stochastic parameter estimation in an IRP process.

PLANNING RESERVE MARGIN STUDY

The planning reserve margin (PRM) is a percentage of coincident system peak load that is needed to ensure that there are adequate resources to meet the forecasted load over time. PRM will provide the Company a “cushion” to account for forecasting errors when matching resources to load. The level of PRM that is considered adequate for reliability is determined by the Company through a PRM study. Setting the PRM too high will result in wasteful cost since capacity is being acquired that will likely never be needed. On the other hand, setting the PRM too low may present a reliability issue at peak times, especially if there is an unexpected loss of a generating resource when it is needed. The PRM study is designed to find the best balance between cost and reliability margin.

In the Company’s 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 then performed using the Planning and Risk production cost model to calculate reliability metrics for each PRM level.

There are five basic modeling steps described by the Company:

1. The Company’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 the Company’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 percent to 20 percent, additional resources are added to the portfolio. The resources the Company adds are demand side management (DSM),; gas fired combined cycle combustion turbines (CCCT), gas fired coal combustion turbines (SCCT), renewable resources, and front office transactions (FOTs). Staff has initiated requests regarding the rationale for resource selection combinatorics at different PRM levels. It is not immediately clear how System Optimizer resolves the resource selection in varying cases.

Staff also will work with the Company to understand better how the Monte Carlo random sampling was performed; particularly whether any rules were applied to the random sampling – such as whether selected stochastic variables were removed from the sample pool upon selection. Staff is also interested in understanding why a ten year test period is used for the marginal cost outcomes across different PRM levels. Finally, Staff notes that the incremental cost of reliability (as calculated) rises dramatically as PRM levels increase from 16 percent to 20 percent and would like to better understand this steep increase.

At this initial stage, Staff is generally 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 about the methodology and assumptions.

FLEXIBLE RESERVE STUDY

The 2017 Flexible Reserve Study (FRS) estimates the regulation reserve required to maintain the Company's system reliability and comply with North American Electric Reliability Corporation (NERC) reliability standards, as well as the incremental cost of this regulation reserve. The Company's overall operating reserve requirements (regulation and contingency) are also compared to its flexible resource supply across the IRP study period. The Company must maintain sufficient regulation reserve to remain within NERC's Balancing Area Authority (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 from variable energy resources (VERs) as well as non-VERs. The Company's study concludes that the regulation reserve burden associated with wind deviations from scheduled amounts are twice the amount associated with solar, three times the amount associated with load, and four times the amount associated with non-VERs. As a result, the Company 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 the Company to attribute different levels of regulation reserve to these variables.

Because the methodology in the 2017 FRS differs from prior years, Staff has initiated discovery to better understand the data sources and calculations utilized by the Company. In these comments, Staff will primarily address changes from prior years. The first major change from prior years is that the regulation reserve requirements are now tied directly to compliance with the new BAL-001-2 standard. Second, the FRS uses a portfolio-wide approach to determine the overall regulation reserve requirement, including the aggregated diversity benefits for all customer classes. Third, all customer classes that contribute to the overall requirement are now allocated to a share of the diversity benefits resulting from aggregating their requirement with that of the whole system. Finally, the FRS reflects updated data based on actual operational experience, including data and benefits from the Company's participation in the EIM.

Staff has initiated discovery regarding the data sources and calculations used in the FRS. Specifically, Staff is interested in understanding the Company's data correction procedures, and the proportion of data that were excluded from analysis. Staff is also interested in understanding the Company's assertion that BAL-001-2 events are rare. Because the standard is new for these types of events, Staff would like to learn how this conclusion was drawn.

Staff expects that the discovery process will clarify details of the Company's analysis. However, it is expected that the Company is justified in attributing different levels of regulation reserve to load, wind, solar, and non-VERs, based on the data sources, methods, and calculations employed.

DEMAND RESPONSE

Staff has questions about how Pacific Power models and expects to acquire demand response over the next several years. Additionally, Staff is concerned that Pacific Power seems to plan long lead times for demand response development—particularly in Oregon—even though the Company has solid experience in implementing demand response in other areas of its system. Staff found Pacific Power's demand response potential study to be complicated and disjointed. This makes analysis extremely time consuming. At present Staff finds the study to be non-transparent. Additionally, Staff is concerned that Pacific Power may not be undertaking full efforts to pilot and acquire cost effective demand response as identified in the demand response potential study and as required by SB 1547. Staff will take steps to work with the material provided but may want revisions to the narrative and to the study's structure in future IRPs

SMART GRID

The most significant smart grid update in the IRP involved Pacific Power's description of its intention to install Advanced Metering Infrastructure (AMI) technology. As part of the AMI rollout, the Company intends to replace 590,000 existing customer meters with smart meters. Pacific Power plans on initiating installations of the new smart meters this year and finishing the installations by 2019. The Company's decision to go through with the meters is attributed to reduced operations and maintenance costs, a platform for future smart grid applications, increased worker safety, reduced emissions, and increased data for efficient management of the network.

While additional details about the AMI rollout are found in Pacific Power's 2016 Smart Grid Report in docket UM 1667, in the 2017 IRP, the Company does not indicate how the rollout intertwines with the IRP. Pacific Power does not present the costs or savings of this project in its IRP, nor does the Company indicate how or whether the new technology will enable or further support growth of demand response, distributed energy resources, or energy efficiency applications. Instead, the Company states that the "net present value of implementing a comprehensive smart grid system throughout Pacific Power is negative," and does not elaborate on what "comprehensive" entails.

Given that the AMI rollout is a significant addition to the Company's smart grid anatomy, Staff is surprised that few additions to planning and resource applications are included in the current IRP. Staff requests that some commentary about any interrelation (or lack thereof) between AMI and planning and resource applications be included in the Company's Reply Comments, specifically as it pertains to AMI data, demand response, distributed energy resources, and energy efficiency applications.

DISTRIBUTION SYSTEM PLANNING

The Company included distributed energy resources (DERs) including energy efficiency, demand response and privately owned distributed generation within the IRP yet, as noted in the Smart Grid section above, lacked discussion or analysis regarding how the Company's grid modernization investment decisions will impact further growth of DERs and vice versa. It is widely recognized that increased adoption of DERs has the potential to greatly change the power sector such that within the planning horizon of the IRP, the distribution system itself will become a significant resource. Planning for the cost effective, prudent transition to two-way managed power flow has led other state regulators to adopt some form of Distribution System Planning (DSP). Although Oregon and the Company's system have unique characteristics that may lead to the conclusion that DERs are small and of little impact today, beginning to adapt our regulatory planning needs now to enable transparent review of grid modernization investments could be helpful to the Commission and the Company.

As Staff found in reviewing this IRP and PGE's 2016 IRP, there are three main drivers behind Staff's mention of DSP at this time.

1) A comprehensive, transparent look at how the Company is planning for grid modernization that pulls together elements of Smart Grid reports, existing distribution planning and IRP planning is missing. Staff suggests that integrating our planning processes and requirements would better provide the Commission with tools necessary for review of the prudency of grid investment plans.

2) Current planning processes may be underrepresenting the potential impact of DERs. For example, in Appendix O, Navigant estimates growth of distributed generation in Oregon ranging between 200 MW and 550 MW in 20 years based on assumptions for technology costs, system performance and electricity rates. If in five years the Company were able to identify locations within the distribution system where installation of DERs would provide higher value and was able to compensate customers or third parties for the increased value, would installations grow beyond what is forecasted in this IRP?

3) There may be a cost of not adopting a comprehensive process DSP that sufficiently considers market advancements and opportunities for improving the efficiency of grid operations.

Staff plans to continue to explore these issues and provide process recommendations in the Final Comments on the IRP for next steps for investigating, defining, and potentially implementing DSP over the next several years. Staff is interested in hearing the Company's response to the following questions in its reply comments.

- How does the Company envision improving the connection between planning for and investing in a distribution system that is needed to efficiently, reliably and safely manage higher levels of DERs?
- Does the Company see benefit in reassessing and possibly reworking the current regulatory processes connecting locational value dockets (e.g., Resource Value of Solar (UM 1716) and Energy Storage (UM 1751)), distribution infrastructure planning, the Smart Grid Report and the IRP?
- Would greater, more comprehensive regulatory guidance related to distribution system planning enable more efficient prioritization of Company action and resources toward grid modernization goals?
- Could greater transparency of location specific aspects of distribution system resources and load lead to greater adoption of cost effective DERs than currently reflected in IRP planning assumptions and potentially lessen cost of system operations?

PROGRESS ON PREVIOUS ACTION PLAN ITEMS

The Company's progress on past IRP orders is outlined at the end of Chapter 9 – Action Plan and Resource Procurement (pp. 270-275). These items are discussed below.

1) Renewable Portfolio Standard Compliance tasks

The Company is projected to meet the Oregon RPS through 2027 with existing resources, including the REC bank. Therefore, it plans no additional RPS compliance acquisitions, either bundled or unbundled, through the Action Plan timeframe. However, the Company does actively manage its REC bank, which involves the sale of vintage RECs not needed for compliance purposes.

Staff has no issues at present with the Company's REC management.

The Company also notes that it is no longer actively seeking compliance with the Oregon Solar Capacity Standard since this was eliminated with the passage of SB 1547.

2) Front Office Transactions

The Company continues to acquire short-term firm market purchases explicitly for delivery during on-peak periods. For 2017, it had secured approximately 450 MW to 700 MW of purchases for the 2017 peak.

Staff has no issues at present with the Company's purchase of short-term firm products. However, Staff continues to analyze the market depth and potential constraints posed by any illiquidity in the market. No particular issues have been identified to date.

3) Demand Side Management

a) Class 1 DSM (Load Control)

Pacific Power has implemented an Irrigation Load Control pilot program that was approved on May 4, 2016. Staff is encouraged that the Company has implemented a load control pilot and expects to be able to analyze results from the program in the coming months.

b) Class 2 DSM (EE)

The Company continues to meet or exceed Class 2 DSM targets. Staff has no issues at this time with the Company's EE procurement activities.

4) Coal Resource Actions

a) Naughton Conversion

The Company continues to analyze the economic benefit of converting this unit to natural gas, as opposed to shutting the unit down at the end of 2018. Pacific Power is keeping both options open until the next IRP update.

b) Dave Johnston

The Company is currently in litigation, the result of which will determine whether this plant is closed at the end of 2027 without additional emissions control. If it loses on appeal, the 2017 IRP Update will contain additional analysis to determine the best course of action for the plant.

c) Wyodak

The Company is awaiting results of its appeal and will provide further information in the 2017 IRP Update.

d) Cholla

The Arizona implementation plan was accepted by the EPA, which will include closure of this plant in 2025 without SCR installation.

Staff continues to monitor the legal activities surrounding the Company's coal resources, but has no particular issues at this time.

5) Transmission Items

a) Energy Gateway Permitting

Pacific Power continues the permitting activities related to this project.

b) Wallula to McNary line

Pacific Power continues the permitting and right-of-way activities related to this project.

Staff has no issues with these transmission activities at this time.

This concludes Staff's comments.

Dated at Salem, Oregon, this 23rd day of June, 2017.

Geoff Ihle

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