BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 2059

In the Matter of PacifiCorp, dba Pacific Power Application for Approval of 2020 All-Source Request for Proposal.	COMMENTS OF NORTHWEST AND INTERMOUNTAIN POWER PRODUCERS COALITION ON DRAFT REQUEST FOR PROPOSAL

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I. INTRODUCTION

The Northwest and Intermountain Power Producers Coalition ("NIPPC") hereby respectfully submits these comments on PacifiCorp's draft 2020 all-source request for proposal ("RFP"). NIPPC is pleased that PacifiCorp has proposed and is proceeding with a significant RFP that will meet the utility's significant energy, capacity and renewable resource needs. NIPPC recommends that the Commission approve the RFP, subject to the revisions identified in these comments, which fall into two main categories: 1) there are unnecessary restrictions that will reduce the robustness of this RFP by excluding low-cost and low-risk resources; and 2) the RFP is biased in favor PacifiCorp-owned resources.

A. PacifiCorp's RFP Is Unreasonably Restrictive and Will Limit Many Low-Cost and Low-Risk Bids

First, the RFP includes provisions which unnecessarily limit the number of potential least-cost and least-risk bids. These provisions are particularly problematic in this case in which PacifiCorp is seeking, and appropriately so, an unprecedented amount of energy and capacity. Some of these provisions include restrictions upon whether the project is already operating, the date upon which it has made its interconnection request, the failure to include basic contract provisions for pumped storage hydro and gas-fired generation, discrimination against smaller developers, limitations on the use of PacifiCorp's transmission resources, and other provisions. This is an issue the Commission should be particularly sensitive to. PacifiCorp's last RFP resulted in low-cost resources, but the full potential of the RFP may not have been realized due to unreasonable limitations. The Commission declined to acknowledge that RFP's results due to the unreasonable limitations that excluded all but a handful of eligible projects from participating.[1] PGE's last RFP was particularly limited due to unnecessarily restrictive transmission requirements and the Commission's decision not to require PGE to use its own transmission rights to benefit ratepayers.[2] Similarly, PGE's RFP that resulted in the Carty generation resource was significantly limited such that PGE's resource was the "winning" bid.[3] NIPPC is concerned that PacifiCorp's RFP includes significant limitations that will result in PacifiCorp's preferred projects, rather than the lowest cost and least risky projects, winning the RFP.

B. The RFP Is Designed to Provide an Advantage to Utility-Owned Generation

Second, the RFP and draft power purchase agreement ("PPA") have elements that bias the results in favor of build transfer agreement ("BTA") bids in which PacifiCorp will own all or part of the facility. As explained in more detail below, this RFP is designed such that higher cost and more risky resources are more likely to "win" due to the advantages to BTA bids. As a consequence, the main hope that bidders seeking to contract through PPAs rather than BTA may have is that PacifiCorp is seeking a

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1 *In re PacifiCorp, dba Pacific Power 2017R Request for Proposals,* Docket No. UM 1845, Order No. 18-178 at 1 (May 23, 2018).

2 *In re Portland Gen. Elec. Co. 2018 Request for Proposals for Renewable Resources,* Docket No. UM 1934, Order No. 18-483 at 3 (Dec. 19, 2018).

3 *See, e.g.,* Ted Sickinger, *Fairness of PGE bids to acquire more electricity questioned*, (Oct. 17, 2012), http://www.oregonlive.com/business/index.ssf/2012/10/fairness_of_pge_bids_to_acquir.html; Ted Sickinger, *Despite acrimony and accusations, Portland General Electric's bid process doesn't need investigating, regulators decide*, (Sept. 20, 2013), http://www.oregonlive.com/business/index.ssf/2013/09/explanation_of_portland_genera.html.

sufficiently high amount of energy and capacity that the company will be willing to allow some non-utility owned resources to be selected. Some of these key elements include:

The BTA bids must only incorporate the post-construction costs of complying with a minimal Operations and Maintenance Agreement ("O&M Agreement") that imposes far less protections for ratepayers than any PPA, and especially this RFP's current draft pro forma PPA. The revenue requirement for BTA bids may be arbitrarily lower than that for the PPA bids due to this differential in requirements, unless conservative post-construction contingent adders are included in the revenue requirement for BTA bids.

Additionally, the pro forma PPA contains many commercially unreasonable provisions. Only the PPA bidders will be potentially subjected to non-price score penalties, and potentially unable to consummate a final contract at the shortlist stage, for attempting to make the pro forma PPA more reasonable through a redline of the document with their bid – a problem that does not exist for BTA bids subjected only to the minimal O&M Agreement.

Next, the draft RFP's apparent use of "generic fill" in its term normalization analysis could substantially advantage the longer term BTA bids over shorter duration PPA bids in the RFP. The RFP's term normalization method should be clarified and brought into compliance with the Commission's administrative rules.

Likewise, the draft RFP fails to establish that it correctly applies Commission policy on treatment of terminal value by providing PPA bidders the opportunity to overcome any terminal value that will be assigned to BTA bids, which could result in an unfair advantage to BTA bids.

The draft RFP's non-price scoring criteria also contain subjective and vague requirements that violate the Commission's administrative rules and will likely bias the solicitation against PPA bids.

The draft RFP's excessively high credit assurance requirements (e.g., letter or credit or parental guarantee) will uniquely impose extra costs on PPA bids because only PPA bids must satisfy these excessive security postings after construction of the facility and build the cost of the same into their bids. The Commission should also require correction of that aspect of the draft RFP.

II. COMMENTS

A. PPA Provisions and Performance Guarantees That Would Not Apply to the Build Transfer Bids May Bias the RFP Toward Ownership Options

The Commission should note that, even though there is no benchmark resource or affiliate bids in this RFP, the same inherent risk still exists for utility bias in favor of a utility ownership structure because PacifiCorp is accepting BTA bids. The risk of bias is no less in this RFP than in an RFP with a self-build benchmark because a winning BTA bid would be placed in PacifiCorp's rate base and reward PacifiCorp's shareholders with return on the undepreciated capital in rate base for the depreciable life of the resource, likely the next 30 years.

NIPPC is not opposed to the inclusion of BTA bids in this RFP, but recommends that the Commission make a number of changes to limit the opportunity for PacifiCorp to bias the results in favor of utility-owned bids. Other sections of the comments identify specific revisions to the RFP and PPA terms, but in this section NIPPC recommends two basic changes to address the bias in favor of BTAs.

- First, the PPA bidders should not be penalized in non-price scoring for reasonable mark-ups of the pro forma PPA, especially mark-ups that relieve some of the risk that BTA bids will always inherently avoid. The only circumstance in which it would be reasonable for PacifiCorp to assess scoring penalties to PPA bidders is if the RFP will also include scoring penalties or conservative contingency adders to BTA bids, which inherently provide few, if any, of the ongoing performance protections of a PPA.

- Second, the BTA bids should include conservative contingency cost adders after commissioning to fairly compare them to PPA bids, which must incorporate such contingencies into their PPA offer price.

In a BTA, PacifiCorp's ratepayers are potentially exposed to any costs to maintain, upgrade, and operate the facility throughout its life. As the Commission is aware, the revenue requirement charged to ratepayers for a utility-owned resource, such as the BTA bids, will be calculated based on the cost of service from the plant over its life, and not necessarily the revenue requirement used for purposes of comparing the BTA bid to other bids in this RFP. Because the actual revenue requirement of the BTA plant can materially increase beyond what was reasonably expected in the RFP analysis, these BTA bids are, in effect, cost-plus bids. In contrast, the revenue requirement charged to bidders for a winning PPA bid would be the fixed price included in the PPA emerging from this RFP – on a fixed dollars-per-megawatt-hour basis for energy and green tags actually delivered, and fixed dollars-per-megawatt basis of capacity actually available. The PPA bidders must include within their PPA price offer all of the potential cost overrun and underperformance risk of the facility, whereas the BTA bidders do not need to include these potential post-commissioning risks in their bid prices, making these BTA bids cost-plus bids.

In this type of RFP, the independent evaluator ("IE") is placed in the difficult position of comparing cost-plus BTA bids against fixed-price PPA bids. Among other issues discussed elsewhere in these comments, this type of RFP requires that the IE and Commission ensure that conservative risk contingencies and conservative performance assumptions be included in the inputs used to develop a revenue requirement for the price scores for all BTA bids in the RFP if the solicitation is to provide a reasonable opportunity for PPA bids to compete. The IE and Commission should also ensure that PPA bidders are not penalized in the scoring process for negotiating reasonable terms into the PPA, which generally speaking will always provide protection of a fixed-price payment only for delivered energy, capacity, and green tags.

The RFP document may leave one with the impression that the BTA bids will make up for the ongoing risks after commissioning by requiring all BTA bids be supported by an O&M Agreement consistent with the RFP's pro forma O&M Agreement, but such an assumption would be wrong.[4] As the IE notes in its April 20, 2020 report, "[r]atepayers are . . . exposed to operating cost risk" in a BTA.[5] Those costs could include occurrences such as a lower-than-forecasted capacity factor, major equipment failures that prevent operation of the plant, or circumstances beyond anyone's

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4 *E.g., PacifiCorp 2020 All-Source Request for Proposals Resource (2020AS RFP)* at 19 (Draft Apr. 22, 2020) [hereinafter PacifiCorp's April 22, 2020 Draft RF*P*] ("Any BTA proposal that does not include an O&M proposal that contains pricing, scope and other key terms will be rejected as a nonconforming proposal.").

5 *PA Consulting's Independent Evaluator Comments on PacifiCorp's draft 2020 All-Source RFP*, at 3, § 6.1 (April 20, 2020) [hereinafter Independent Evaluator's Report].

reasonable control. The IE recommended a handful of changes to the O&M Agreement to mitigate this exposure in the BTA arrangement, and NIPPC does not object to the IE's recommended changes to the O&M Agreement. However, NIPPC stresses that these protections alone are not enough to protect ratepayers against the risks of utility ownership and the potential bias against PPA bids in the RFP.

It is important to recognize the protections of a PPA bid as opposed to a BTA with an O&M Agreement. In the PPA structure, the bidder is only paid for delivered energy, capacity, and green tags. A facility can underperform for a wide variety of reasons, including but not limited to a lower-than-bid capacity factor, unexpected outages due to equipment failure, unexpected curtailments of power by the transmission provider or PacifiCorp's transmission function, or even an unexpected force majeure event (such as an earthquake or pandemic, etc.). PacifiCorp and its ratepayers have no obligation to pay the facility under a PPA during the outages because PacifiCorp only pays for delivered energy, capacity, and green tags. Indeed, in cases of unexcused non-delivery, the PPA will even require the Seller to pay PacifiCorp liquidated damages penalties for the failure to deliver.[6] In contrast, in the case of underperformance of a BTA facility after commissioning, the ratepayers will still pay for the same capital costs and return, plus actual O&M costs through their rates. And, except in the rare event where O&M Agreement assigns liability for the lost generation to the contractor,

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[6] Normally, such penalties for non-performance would include either a mechanical availability guarantee or an output guarantee. In the pro forma PPA, the major performance guarantee is located in Exhibit F, and it includes a proposal for an output guarantee, which is discussed further below.

PacifiCorp and the ratepayers still receive no energy, capacity, and green tags or damage payments to make up for the lost operation.

A review of key aspects of the pro forma PPA and the pro forma O&M Agreement demonstrates the advantages to ratepayers of the PPA structure. First of all, the PPA will be for a term of 15 to 25 years, and its protections will remain in place during that time. In contrast, the pro forma O&M Agreement in PacifiCorp's RFP has a term of three to five years.[7] Perhaps PacifiCorp can secure another O&M Agreement with similar terms and costs after the initial three to five years, but there appears to be no assurance of that. Furthermore, even while the O&M Agreement is in place and even if its term could be extended further, it merely requires the contractor to perform the maintenance on the facility; it does not relieve the ratepayers of the obligation to pay PacifiCorp for the capital costs and return on the facility in the event of an unexpected outage or circumstance of underperformance.

Moreover, the major performance assurance that does exist in the O&M Agreement is *optional*. Specifically, the performance assurance for the O&M Agreement (which appears to be tailored solely to wind facilities) is an *optional* availability guarantee, which would require the contractor to pay an unspecified level of liquidated damages if the facility is not operational and available 95% or 97.5% of each year.[8] Because the O&M Agreement contains only an availability guarantee as opposed to an

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[7] O&M Agreement, Article 3 (including an "Initial Term" of three years, and right for PacifiCorp to extend the term for two additional one-year "Extension Terms").

[8] O&M Agreement at Exhibit G; *see also id.* at Article 13 (noting the availability guarantee is optional).

output guarantee, it is clear that the BTA structure will provide no protection to ratepayers against a lower-than-expected capacity factor at a wind or solar facility. Furthermore, the availability guarantee excuses from the 95% to 97.5% guarantee the following events: weather conditions that preclude access to the site or wind turbines, grid connection problems, curtailment to zero output, and major component failures.[9] If any of those events is the cause of lower-than expected availability, such as 85% annual availability and corresponding drop in output due to any major equipment failure, PacifiCorp and the ratepayers have no right to liquidated damages from the contractor and receive no replacement energy, capacity, or green tags. Yet the ratepayers still must pay the capital, return, and O&M costs on the idle facility. Furthermore, there is no indication in the draft RFP what level of liquidated damages will be required for inclusion in the O&M Agreement during unexcused failures.

In contrast to the optional *availability* guarantee in the five-year O&M Agreement, the draft pro forma PPA contains a performance guarantee that requires an *output* guarantee, which is not optional.[10] There are notable differences between the O&M Agreement's availability guarantee and the pro forma PPA's output guarantee. First, the pro forma PPA's output guarantee does not merely require that the plant be *mechanically available* to produce net output; it affirmatively requires delivery of a minimum amount of net output.[11] It therefore subjects the Seller in the PPA to annual

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9 O&M Agreement at Exhibit G (definition of "Excluded Time").

10 Pro Forma PPA, at Exhibit F. The performance guarantee was filed by PacifiCorp as a supplemental filing on May 19, 2020.

11 *See id.* at § B.1 ("Seller agrees to deliver to PacifiCorp no less than the Guaranteed Amount of Net Output during each Contract Year"); § B.2 (assigning

variations in available wind, solar, or other motive force that the O&M Agreement relieves the BTA bid of needing to consider. The pro forma PPA sets the annual output guarantee at 90% of the estimated annual energy amount, which is an unreasonably high level of guaranteed output, at least for a wind farm where wind availability can vary significantly from year-to-year. In addition to being an output guarantee as opposed to an availability guarantee, the draft pro forma PPA's output guarantee has much narrower excuses than those contained in the O&M Agreement's availability agreement described above. Unlike the O&M Agreement, the pro forma PPA's output guarantee does not excuse output shortfalls that occur for all major component failures; instead, the pro forma PPA only includes the typical excuses for performance normally found in PPAs.[12] The O&M Agreement contains much broader excuses to the contractor through the exclusion of all major component failures. In any event, however, the most notable difference is that ratepayers make no payments to the Seller in the PPA under any circumstance of undelivered energy, capacity, or green tags for whatever reason, whereas the ratepayers still pay for capital, return and O&M during an output shortfall under a BTA/O&M Agreement.

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liquidated damages at PacifiCorp's "Cost to Cover" for an unexcused output shortfall); § A ("Guaranteed Amount" means, for any Contract Year, (i) [ninety percent (90%)] of the Expected Energy of the Facility for such Contract Year").

12 The excused events are limited "extreme weather events" that prevent the generating facility itself from operating, force majeure, curtailments by PacifiCorp, an unspecified but limited number of maintenance outages, and defaults by PacifiCorp. *See* Pro Forma PPA, at Exhibit F, § A (definitions of "Guaranteed Amount", "Uncontrollable Circumstances", and "Weather Event").

A review of a few other common PPA provisions contained in the pro forma PPA further demonstrates this point. The PPA excuses the performance of Seller in an event of Force Majeure (such as an earthquake, volcanic eruption, pandemic, etc.). But as proposed in the pro forma PPA, PacifiCorp may terminate the PPA if a Force Majeure event causes non-performance by the Seller for over 180 days. As drafted in the pro forma PPA, it appears PacifiCorp might even exercise this right to opportunistically acquire lower priced resources in the circumstance of advances in technology. While NIPPC believes 180 days is too short of a period to include in the pro forma PPA for termination during force majeure, the fact that the PPA would contain *any* right for PacifiCorp to terminate due to an extended force majeure event is a major distinction from a BTA/O&M Agreement arrangement. Under a BTA, in contrast, PacifiCorp cannot terminate its acquisition of a rate-based plant after commissioning due to a force majeure event; instead, the ratepayers would be required to continue paying for the capital investment and PacifiCorp's shareholder returns on the plant no matter how long a force majeure event may last.

Another example is the curtailment provisions of the pro forma PPA. These provisions allow PacifiCorp to curtail the facility without payment to the Seller ("Non-Compensable Curtailment") if PacifiCorp's transmission arm curtails the facility for any reason, among other specified reasons.[13] The PPA also includes "Compensable Curtailment" under which PacifiCorp may curtail for any reason it chooses, including economic reasons, if it pays the Seller the specified curtailment price that is potentially

[13] Pro Forma PPA, at § 4.5.1.

distinct from the contract price for delivered energy, capacity, and green tags. NIPPC does not necessarily object to this general concept in the PPA, which is typical in a PPA, even though it needs some clarification in the pro forma PPA as discussed further below. But there is no corresponding mechanism where PacifiCorp's shareholders, as opposed to its ratepayers, lose revenue and return from the utility-owned plant during Non-Compensated Curtailment events and potentially pay less than normal revenue requirement on the plant during all other curtailment events.

The treatment of taxes is yet another area where the pro forma PPA provides protections well beyond what exists in a BTA/O&M Agreement. The pro forma PPA requires the Seller to pay all existing *or new* sales, use, excise, severance, ad valorem, and any similar taxes to the extent they are assessed on the product up to the point of delivery.[14] Again, NIPPC does not necessarily take issue with this treatment in the pro forma PPA as a general matter, but it demonstrates another risk to ratepayers that exists only in the BTA/O&M Agreement, under which PacifiCorp's ratepayers will be responsible for not just existing and known taxes on the facility at the time of this RFP, but also any future taxes or increases beyond estimates used in the RFP to generate the bid's revenue requirement. This is not a purely hypothetical circumstance because at least one state in PacifiCorp's service territory has previously enacted excise tax on wind production and recently considered increasing it.[15] Yet under the RFP structure proposed

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14 Pro Forma PPA at § 5.4.

15 *See* S&P Global, *How Wyoming went from leader to laggard in wind energy* (April 10, 2019), https://www.spglobal.com/marketintelligence/en/news-insights/trending/WDrrAH2joStLEQyVTq5BaA2 (discussing Wyoming's imposition of a $1/MWh tax on wind production and efforts to increase it to $5/MWh).

by PacifiCorp, a PPA bidder that seeks to relieve itself of this risk by editing the PPA will risk a non-price scoring deduction that would never occur for a BTA/O&M Agreement bid.

In sum, the O&M Agreement provides nowhere near the protections for ratepayers as the pro forma PPA, or likely any PPA. While the BTA structure may provide protections against initial cost overruns as opposed to a pure utility self-build structure, the BTA arrangement in this RFP does *not* provide the same type of contractual protections from ongoing cost overruns, unexpected outages, capital upgrades, underperformance, or numerous other unexpected occurrences for which the risk is allocated to the independent power producer ("IPP") under a long-term PPA.

However, the draft RFP's proposed scoring provisions appear to unreasonably assume that an edit to the pro forma PPA is equivalent to an edit to the BTA/O&M Agreement. PacifiCorp's RFP states: "substantive comments to the pro-forma agreement will be considered as part of the non-price scoring in evaluating a project for inclusion in the initial short list. . . ."[16] The draft RFP assigns 10% of the overall score to "Conformance to pro-forma power purchase agreement or BTA agreement."[17] As noted above, however, any long-term PPA is going to contain far more ongoing assurances and protections for ratepayers after commissioning than any BTA/O&M Agreement structure, especially the O&M Agreement proposed in this RFP. Furthermore, the draft RFP does not even contain a pro forma BTA, instead containing only a very high-level term sheet.

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16 *PacifiCorp's April 22, 2020 Draft RFP* at 18.
17 *Id.* at 28.

Thus, it is not credible to pretend as though a PPA bidder's revisions to the pro forma PPA should be comparable to a BTA bidder's revisions to the BTA/O&M Agreement from a scoring perspective.

For these reasons, NIPPC recommends deletion of the scoring penalties for revisions to the pro forma PPA in the initial stage of the RFP. Rather, bidders should be free to make reasonable edits to the pro forma PPA without risk of scoring penalties based on a subjective judgment of how significant the revision might be compared to other bidder's revisions to the pro forma PPA and the BTA's O&M Agreement.

In closing on this topic, NIPPC is not suggesting that BTA bids be barred from the RFP. Instead, our point with this discussion is two-fold: 1) the PPA bidders should not be penalized in non-price scoring for reasonable mark-ups of the pro forma PPA, especially mark-ups that relieve some of the risk that BTA bids will always inherently avoid by their nature; and 2) the BTA bids must include conservative contingency cost adders after commissioning to fairly compare them to PPA bids which must incorporate such contingencies into their PPA offer price.

B. Proposed Revisions to the Pro Forma PPA

NIPPC recommends a number of clarifications and changes to the pro forma PPA supplied with the RFP to provide PPA bidders a more reasonable opportunity to compete. The pro forma PPA is important in any RFP, but it is especially important in this RFP because, as noted above, PacifiCorp proposes to use a bidder's modifications to the pro forma PPA as a basis to assign non-price scores to the bidder. The draft RFP would therefore use the pro forma PPA to put PPA bidders at a distinct disadvantage compared to BTA bidders.

Regardless of whether there are scoring penalties for bid modifications to the pro forma PPA, all commercially unreasonable provisions should be removed and the PPA should be clarified so that PPA bidders are not potentially exposed to arbitrary scoring penalties or later disqualified or face difficulty in final negotiations of the PPA later in the RFP. Along those lines, NIPPC offers the following recommendations for changes to the pro forma PPA supplied with the RFP. In referring to the pro forma PPA, these comments refer to the "Resource Only PPA" unless otherwise noted. NIPPC also intends to review any comments by interested parties and stakeholders and generally reserves the right to raise additional issues with the pro forma PPA.

As an initial point, the draft RFP appears to be incomplete because it does not include all of the potential PPA forms that would appear to be necessary in this RFP. The Commission's administrative rules require the draft RFP to include "standard form contracts to be used in the acquisition[,]" and therefore incomplete or missing forms constitute noncompliance with the rules.[18] The RFP is an "All Source" RFP, but it fails to include a tolling agreement form that would be expected as the off-take agreement for a gas-fired IPP plant and may be the preferred structure for a pumped storage facility. It is clear that PacifiCorp is accepting storage bids, and therefore a tolling agreement form should be included for this purpose, as one was included in PacifiCorp's last RFP that allowed storage bids.[19] Additionally, while NIPPC recognizes the expectation that a renewable resource may prevail and the timing of the RFP was intended to accommodate

[18] OAR 860-089-0250(3)(b).
[19] Attachment A (2019C RFP at Appendix A-2).

tax credits available to renewable resources, the pro forma PPA itself suggests that PacifiCorp will accept gas-fired bids. However, the PPA merely states in a footnote that PacifiCorp will use the pro forma PPA with deletion of renewable-specific provisions for gas-fired resources.[20]

This is not sufficient because the pro forma PPA is designed as a contract for payment of delivered energy and capacity, and it is the wrong form altogether for bids for a tolling arrangement. Normally, one would expect that a gas-fired IPP selling to a utility would sell under a tolling agreement, where the IPP is paid to operate and maintain the facility which it owns, and PacifiCorp pays for the fuel and instructs the IPP when and how to dispatch the plant. In addition, tolling agreements are not new or novel concepts that would require PacifiCorp to spend considerable resources to include in the RFP. Accordingly, the RFP should also include a pro forma tolling agreement suitable for storage facilities and a tolling agreement suitable for gas-fired facilities.

With respect to the pro forma PPA, NIPPC recommends that the Commission and the IE direct PacifiCorp to revise the following provisions:

- <u>Performance Assurance</u>. As discussed in more detail below regarding the draft RFP's credit requirements, the required liquid performance assurance of \$200/kW of plant capacity before commercial operation and \$100/kW thereafter is very high and should be reduced.[21] Additionally, the pro forma PPA's

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20 Pro Forma PPA, at Recitals n. 1.

21 *PacifiCorp's April 22, 2020 Draft RFP* at Appendix D. Note that the amount is left blank in the pro forma PPA, but it is supplied through Appendix D in the Draft RFP.

definition of Qualifying Institutions eligible to provide performance assurance should not be limited to U.S. Banks.[22] Instead, the pro forma PPA should allow international banks with a U.S. presence to be Qualifying Institutions, which is consistent with industry practice and would allow bidders to obtain capital from a larger pool of lenders, reduce costs, and allow more projects to be bid.

- Performance Guarantee. As noted above, the PPA's requirement for an annual *output* guarantee of 90% of the expected/average net output is not a reasonable requirement or standard in a PPA for a resource with high variability from year-to-year, such as wind and potentially solar resources. Bidder should be provided the option of committing to a reasonable mechanical availability guarantee as an alternative. At a minimum, the 90% amount should be further reduced for wind facilities where year-to-year output variability can be significant solely due to weather conditions – a fact that PacifiCorp has itself acknowledged in RFP dockets.[23] Additionally, the failure to meet any output guarantee should result only in liquidated damages, not termination of the PPA as proposed by PacifiCorp for two consecutive years of shortfall in Section 11.1.2(h).
- Venue for Disputes. The PPA's provisions regarding disputes need revision. The draft pro forma PPA should not contain provisions suggesting that a

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22 Pro Form PPA, p. 11 (definition of "Qualifying Institution").

23 *See Re. OPUC Investigation Regarding Competitive Bidding.* Docket No. UM 1182, PacifiCorp's Reply Testimony, at PAC/200, Kusters/30-37 (Jan. 14, 2013) (arguing that long-term wind output data is necessary to evaluate a wind plant's performance and asking the Commission disregard evidence of under-performance of PacifiCorp-owned wind plants in two years due to below average wind conditions in those two years).

state utility commission will have jurisdiction over the agreement or disputes thereunder, as it does both page 3, footnote 3, and Article 19.[24] Instead, the PPA should unambiguously establish that disputes should be resolved in mediation or court, as Article 24 states. Additionally, the jury trial waiver in Article 24.4 should be deleted. In addition, in Section 7 of the confidentiality agreement, PacifiCorp proposes to require that the parties waive their rights to a jury trial and any right to punitive or consequential damages.[25] There is a constitutional right to a jury trial in the United States, and bidders should not have to waive that right to sell power to PacifiCorp. As described further below,[26] a Utah jury has previously found PacifiCorp violated the rights of an IPP by stealing its trade secrets, a right to a jury trial provides necessary protections for counter parties to PacifiCorp in an RFP for cutting edge renewable and storage technologies. The Utah example makes clear that the right to a jury trial and all damages remedies available under the law are essential to protect the rights of the IPP and to hold PacifiCorp accountable for its potential actions. The pro forma PPA should not limit the rights of PacifiCorp's counter parties to obtain appropriate relief.

- Curtailment. The pro forma PPA contains insufficient details as to PacifiCorp's expectations and how it might score proposals for compensated

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24 *See* Pro Form PPA, Section 19 ("This Agreement is subject to the jurisdiction of those Governmental Authorities having jurisdiction over either Party, the Facility or this Agreement."); *See also*, *Portland Gen. Elec. Co. v. Pacific Northwest Solar*, Docket No. UM 1894, Order No. 18-025 at 5 (Jan. 25, 2018) (interpreting section 19 as conferring jurisdiction in the Commission over PPA disputes.).

25 *PacifiCorp's April 22, 2020 Draft RFP* at Appendix G-1 at 2, Section 7.

26 *See infra* p. 37.

curtailment.[27] As discussed above, the concept in the PPA is that PacifiCorp may curtail without compensation to the Seller during certain limited events defined as "Non-Compensated Curtailment," such as a reliability curtailment by the transmission function. PacifiCorp may also pay for additional curtailment events for any reason as "Compensated Curtailment." However, bidders will be unable to meaningfully propose a price for Compensated Curtailment without knowing how many hours per year PacifiCorp proposes to have this right. PacifiCorp should provide more clarity on its expectations and how bids will be scored on this point.

- Lack of Cure for Delayed COD. The pro forma PPA provides no cure period for delay in achieving the scheduled commercial operation date ("COD").[28] That is unreasonable and not commercially typical. The PPA should contain normal cure periods for delay in achieving commercial operation, such as a 180-day cure period after notice of default from PacifiCorp. The delay provisions should also contain standard carve-outs to excuse delays due to force majeure, PacifiCorp-caused delays, and other commercially reasonable excuses for occurrences beyond the control of the Seller. The PPA contains liquidated damages owed to PacifiCorp during the delay as well as performance assurance from which those damages could be drawn, which adequately protects PacifiCorp and its ratepayers from a delay.

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27 Pro Forma PPA at § 4.5.
28 *Id.* at § 2.3.1. § 11.1.2(b).

- Force Majeure. The Force Majeure clause unreasonably allows PacifiCorp to terminate the PPA if the Force Majeure causes non-performance for 180 days.[29] This is an unacceptably short period and bidders should not be penalized for revising this unreasonable provision that gives PacifiCorp rights beyond what it would have in a BTA. The time limit should be extended and/or deleted. Additionally, the list of examples of Force Majeure events should include pandemics,[30] as recent events have demonstrated that pandemics can occur and can impact a party's ability to perform with no fault of their own.
- Storage Pricing. The pro forma PPA for resource plus battery storage is expressed in \$/MW,[31] but in the RFP materials it is expressed in \$/MW-month.[32] This inconsistency should be reconciled to avoid confusion and inaccurate evaluation of bids.
- Incomplete Provisions. The following provisions are incomplete and need to be completed by PacifiCorp in the pro forma PPA before NIPPC, the IE, or any other parties could meaningfully comment or bidders could submit a mark-up of the document with their bid:
    - The "Required Percentage" of Expected Net Output in order to obtain Commercial Operation is not supplied.[33] This is an important provision of the PPA that should be included for review and comment.

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29 *Id.* at § 14.5.
30 *Id.* at § 14.1.
31 Pro Forma PPA for Resource plus BESS at p. 14.
32 *PacifiCorp's April 22, 2020 Draft RFP* at Appendix C-2, Tab 4, Column G.
33 Pro Forma PPA at p. 12 & n. 7.

- Article 4.2.2 fails to identify the level of network upgrade costs at which PacifiCorp may terminate the PPA. NIPPC recommends that this provision be removed; however, at a minimum a specific level of network upgrade costs should be made available and the basis for it explained and demonstrated to be equivalent to the treatment for a BTA bid.
- Article 6.5 fails to identify the months during which the pro forma PPA will require the Seller to conduct Planned Outages and Maintenance Outages. This is important information and must be supplied to bidders and subject to evaluation by parties and the IE.
- Exhibit P of the resource plus battery storage pro forma PPA has an incomplete Storage Availability Guarantee. The annual guarantee is stated to be 98%, when a lower level is more appropriate in a PPA, such as 95%. However, the provision lacks all of the necessary definitions and carve outs to fully evaluate the guarantee. This provision must be made available for review and comment before the RFP is released.
- Exhibit I states that it does not include the final and complete insurance requirements of the PPA.[34] These need to be made available for the IE and parties to confirm that the PPA's insurance requirements do not exceed the levels of insurance for a utility-owned bid after commissioning, and that such costs are properly included in the BTA scores.

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[34] *Id.* at Exhibit I n. 15.

C. The RFP Should be Revised to Provide Reasonable Term Normalization Scoring

The treatment of bids of different term duration, through "term-normalization" analysis, is a critical issue in any RFP, yet PacifiCorp's RFP provides insufficient clarity on this subject. The Commission has confirmed that NIPPC's concern with proper treatment of term-normalization analysis is valid by including the topic as a part of its administrative rules.[35] Therefore, the Commission should require PacifiCorp to make its term-normalization analysis transparent in this RFP and should direct the IE to require PacifiCorp to conduct an analysis that focuses on the annuity-based analysis while not unreasonably penalizing shorter-term PPA bids through use of generic fill costs from the integrated resource plan ("IRP").

1. The Term-Normalization Problem

The term-normalization issue is a problem inherent in a solicitation that attempts to equitably compare a longer-term obligation placed in rate base (typically 30-plus years) and the shorter-term PPA or other IPP structure (only 15 to 25 years in PacifiCorp's draft RFP). With all other factors being equal, the IPP option will be far less expensive to the ratepayer in the early years, and the utility-owned resource will be far more expensive in the early years due to front loading of rate-based costs and returns in normal rate-of-return ratemaking. Additionally, the longer-lived utility-owned resource requires the RFP evaluation to include present value and levelization analysis to

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35 *See* OAR 860-089-0400(5); *Re Rulemaking Regarding Allowances for Diverse Ownership of Renewable Energy Resources,* Docket No. AR 600, Order No. 18-324 at 12 (Aug. 30, 2018).

compare the ratepayer costs of these resources in the RFP. NIPPC believes that assumptions favoring longer-lived utility-owned generation may have been a major contributing factor in the Oregon utilities' ability to "win" nearly all past RFPs with utility-owned bids.

Oregon utilities have in past RFPs use a "generic fill" for the costs of the shorter lived resource after its term expires in the process of selecting the final short list from the initial short list. In other words, the IPP's actual bid price is substituted for a hypothetical assumed cost (the "generic fill") in the latter years simply because the bid has a shorter term than the longer lived utility-owned bids. There is obviously a significant risk of intentional or unintentional errors in of the use of generic fill costs. The risk of error is particularly acute given the fact that in the AR 600 rulemaking where this issue was studied, the utilities stated they traditionally used current costs from their current IRPs as the basis for the assumed replacement costs of the IPP resource in future years. Use of today's costs in the IRP as the likely replacement costs 20 years from now is unreasonable because the costs of renewable energy and storage have been precipitously falling over the past decade and are likely to continue doing so.

In short, NIPPC is very concerned that the Oregon RFPs have been conducted to assume that the 30-year to 45-year bid for utility-owned projects is the norm, and errors have been introduced (through generic fill) to accommodate that type of bid. Furthermore, according to the utilities' presentation at the AR 600 workshop, the "portfolio analysis" that often occurs with IRP Models in the final shortlist stage often must add generic fill from day one to round out the portfolio containing many bids to the full capacity of the overall portfolio sought. This only exacerbates the problem of making up hypothetical costs to assign in the RFP.

For further background on this subject and a reasonable solution, Boston Pacific has prepared an excellent analysis of the issue that recommends use of an "annuity" analysis instead of the use of generic fill.[36] As Boston Pacific persuasively explained:

> Our research indicates that, out of these five methods, the Equivalent Annual Annuity Method (the Annuity Method) should be among the methods required in an evaluation, if not the preferred method. The central appeal of the Annuity Method is that it essentially allows the bid to speak for itself, thereby minimizing the discretion of the bid evaluator. The other methods add needless complexity and uncertainty to the bid evaluation process, and all give too much discretion to the bid evaluator.[37]

NIPPC agrees. An annuity is the equal annual payment over the life of the alternative that has the same present value as the actual, unequal annual costs that are expected to be incurred, and the annuity analysis thus allows the bids to speak for themselves without any manipulation. It provides no advantage to any bid solely by virtue of its longer duration, as the use of generic fill is likely to do. In contrast, Oregon utilities have in the past used the "Filler Method" described in the Boston Pacific white paper[38] to develop the final shortlist. According to Boston Pacific, under this filler method "the evaluator can significantly bias the" shorter term bids by assigning it filler costs after the end of its bid term.[39]

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36 Attachment B (Boston Pacific Company, Inc., Bid Evaluation Methods in Competitive Solicitations: A White Paper on Techniques Used to Evaluate Power Supply Proposals with Unequal Lives).

37 *Id.* at 1.

38 *Id.* at 5.

39 *Id.* at 7.

These problems are compounded in the Oregon RFPs because, based on the utilities' own account in the AR 600 workshop, the utility (which is an inherently interested party) conducts the bulk of this analysis without meaningful oversight from the IE, and certainly without any meaningful participation from stakeholders or Commission Staff.

Thus, the Commission's recently adopted administrative rules require complete transparency on this subject. The Commission explained:

> In the context of an RFP, it is important to understand when utility assumptions embedded in generic fill, or other IRP values, become the determinative or dominant factor in a resource decision. For example, when a resource is lowest cost and lowest risk in the near term, but because of a short term length it is not selected due to the assumptions associated with 'generic fill,' that decision should be subject to greater scrutiny.[40]

The Commission's administrative rule on the subject endorses the use of real levelized or annuity methods in developing the price score to develop the initial short list, and does not authorize use of generic fill at this stage.[41] Additionally, at the final shortlist stage, generic fill may only be used to the extent that its impact is completely transparent and scrutinized by all parties. The rules specifically require a sensitivity analysis demonstrating the impact of "[c]hanges in assumptions used to compare bids or portfolios

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40 Order No. 18-324 at 12.

41 OAR 860-089-0400(2)(a) ("Price scores must be based on the prices submitted by bidders and calculated using units that are appropriate for the product sought and technologies anticipated to be employed in responsive bids using real-levelized or annuity methods. The IE may authorize adjustments to price scores on review of information submitted by bidders.").

of bids, such as assumptions used to extend shorter bids for comparison with longer bids, or assumptions used to compare smaller bids or portfolios with larger ones."[42]

2. NIPPC's Proposed Solution for PacifiCorp's RFP

In this RFP, the Commission should ensure transparency on this issue by requiring complete disclosure as to the methods of conducting term-normalization analysis. This RFP presents the term-normalization issue because PPA bids will have a 15-year to 25-year term, but if a utility-owned generation bid prevails it will be placed in rates for its depreciable life, likely 30 years for a renewable plant.[43]

However, in this RFP, it is not entirely clear how PacifiCorp will conduct term normalization. It appears that PacifiCorp may use the filler method to develop the initial shortlist,[44] but that should certainly not be allowed. The draft RFP states PacifiCorp will use IRP modeling to identify an "optimized portfolio" of resources, presumably including use of generic fill, in development of the initial shortlist of bids.[45] But doing so would violate the administrative rules, which contemplate development of the initial short list solely based on the price and non-price scoring and require use of IRP modeling to narrow the initial short list to a final short list, subject to the sensitivity analysis for impact of use of generic fill.[46]

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42 OAR 860-089-0400(5)(b)(B).

43 In Order No. 13-347, the Commission approved a stipulation adopting PacifiCorp's proposal to use of a 30-year depreciable life for wind facilities. *See Re PacifiCorp Application for Authority to Implement Revised Depreciation Rates,* Docket No. UM 1647, PacifiCorp's Direct Testimony and Exhibits, at PAC/300, Andrews/11-13, PAC/301, Andrews/1-2.

44 *PacifiCorp's April 22, 2020 Draft RFP* at 27.

45 *PacifiCorp's April 22, 2020 Draft RFP* at 28-29.

46 OAR 860-089-400(2) & (5).

Another serious concern is that PacifiCorp proposes to "force rank" the price scores of the bids to develop the initial shortlist.[47] Force ranking will only further move the bid rankings away from a pure comparison of the bids' pricing proposals.

It also appears to be certain that PacifiCorp plans to use the filler method in its portfolio analysis to develop the final shortlist, but the RFP contains no explanation of whether PacifiCorp will also conduct the sensitivity analysis required by the Commission's rules to allow for complete scrutiny of the impact of the filler.[48] The ambiguity and lack of description of the proposed sensitivity analysis violates the Commission's administrative rules, which require the draft RFP to completely describe the scoring criteria so that parties and the Commission may confirm the proposed criteria comply with the requirements for such scoring in the rules.[49] Additionally, the draft RFP further ignores the administrative rules by proposing that "PacifiCorp will not make any of the IRP evaluation models available to the IE, bidders, or stakeholders" and instead will only "summarize how the IRP evaluation models function for the IE" and allow the IE to view the model inputs and outputs.[50] The administrative rules specifically require that PacifiCorp "must provide the IE and Commission with full access to its production cost and risk models and sensitivity analyses."[51]

NIPPC proposes that the Commission provide the following clarification for how PacifiCorp should implement a term-normalization analysis in this RFP:

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47 *PacifiCorp's April 22, 2020 Draft RFP* at 27.
48 *Id.* at 32.
49 OAR 860-089-0250(3)(c); OAR 860-089-0400(1).
50 *PacifiCorp's April 22, 2020 Draft RFP* at 29.
51 OAR 860-089-0400(6).

- No generic fill of PPA bid prices or utility-owned generation costs may be used to evaluate bids of unequal term lengths to develop the initial shortlist.
- The price score should be calculated with the annuity method consistent with the Boston Pacific white paper and without force ranking the bids.
- PacifiCorp must commit to produce complete sensitivity analysis results for the impact of any generic fill or other term normalization techniques used in the final IRP modeling analysis to develop the final short list, with adequate transparency and time for stakeholders, the IE and the Commission Staff to fully evaluate and comment on the results.

D. The RFP Should Not Assign Any Terminal Value to Utility-Owned Resources

The Commission should ensure that the RFP does not bias utility-ownership structures by assigning a speculative terminal value to utility-ownership bids.

This is a subject that has been a frequent point of contention in Oregon RFPs, where Oregon utilities have historically boosted the scores of utility-owned bids by assigning them a scoring benefit for assumed terminal value and the ability to re-develop a site after the useful life of the initially installed facility. The Commission's orders require that if a utility wishes to use a terminal value in an RFP, it must also provide PPA bidders with the option of bidding a renewal right into their PPA to overcome the potential scoring bias on this point.[52]

PacifiCorp's draft RFP is silent on this subject. It is not clear if PacifiCorp plans to assign terminal value to the BTA bids. However, the RFP should either state PacifiCorp will not assign terminal value to BTA bids or the RFP must allow PPA bids to elect to achieve an equal score improvement with a reasonable PPA renewal provision.

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[52] *Re OPUC Investigation Regarding Competitive Bidding,* Docket No. UM 1182, Order No. 14-149 at 5-6 (Apr. 30, 2014).

E. The Draft RFP's Non-Price Scoring Criteria Include Impermissibly Subjective and Vague Items That Should be Deleted

The draft RFP does not comply with the Commission's rules for non-price scoring criteria. Non-price scoring criteria must be carefully scrutinized in an RFP because, unlike a price score, the non-price scoring criteria can be highly susceptible to subjective and biased evaluation. The Commission's administrative rules include important requirements related to the draft RFP's treatment of bids' non-price characteristics. *First*, the non-price characteristics should be converted to minimum bidding requirements as opposed to potentially subjective non-price scoring criteria whenever practical.[53] *Second*, where non-price characteristics cannot be converted to minimum bidding criteria, they may only be used as non-price scoring criteria if they are subject to objective evaluation and self-scoring by bidders.[54] *Third*, such non-price scores must, when practicable, primarily relate to resource characteristics identified in the acknowledged IRP.[55] As explained below, several of the proposed non-price scoring criteria in PacifiCorp's draft RFP fail to meet these requirements.

First, while PacifiCorp included a lengthy list of minimum eligibility requirements for bids and it provided a detailed non-price scoring matrix,[56] at least one

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53 OAR 860-089-0400(2) ("Non-price factors must be converted to price factors where practicable."); *see also* Order No. 18-324 at 12 (noting that the language of the rules "allows utilities two options when reviewing non-price attributes: convert the attribute into a characteristic that can be objectively scored, or make the attribute a minimum threshold.").

54 OAR 860-089-0400(2)(b).

55 *Id.*

56 *PacifiCorp's April 22, 2020 Draft RFP* at pp. 14-16 (proposed minimum bidding criteria); *Id.* at Appendix L (proposed non-price score matrix).

item appears in both the minimum bidding criteria and the non-price score matrix. Specifically, although submitting a complete RFP response with all attachments completed is a minimum bidding requirement,[57] the non-price score matrix assigns 5% of the overall score to the following criteria: "Bids provided all required RFP information pursuant to RFP instructions for PPA and BTA" is allocated 5% of non-price score out of 100% of the total score.[58] Because there is no reason this issue cannot be resolved as a minimum bidding requirement and is already included as one, it should be deleted from the non-price score matrix and the points reallocated to the score price category to reduce the overall points allocated to non-price factors.

Second, consistent with our comments above, NIPPC recommends changes to the use of the pro forma PPA as a basis for non-price scoring. As it stands, the non-price score matrix proposes to allocate 10% of the overall score to compliance with the RFP's requirements to submit a redline to the applicable pro forma PPA, pro forma battery storage document, or the BTA term sheet (depending on bid structure). There are several problems with this proposal. First of all, it is not entirely clear if PacifiCorp is planning to deduct scoring points for bids based on the *content* of the redlines submitted, or whether PacifiCorp will only deduct points if no redlines or incomplete redlines are submitted. The draft RFP document suggests the former,[59] but the non-price scoring

57 *Id.* at p. 14-16, items 2, 12, 15, 20, 24, 25, 26, 28-30.
58 *Id.* at Appendix L.
59 *Id.* at p. 28 (stating it assigns 10% of the overall score to "Conformance to pro-forma power purchase agreement or BTA agreement").

matrix suggests the latter.[60] The matter should be unambiguously clarified so there are no misunderstandings.

To be clear, however, NIPPC objects to any penalty in the scoring to develop the initial shortlist based on a mark-up of the pro forma PPA. As noted above, the RFP's pro forma documents are not complete; the RFP lacks a full pro forma BTA, lacks any form of tolling agreement, and contains a woefully incomplete pro forma PPA. It will be impossible to objectively evaluate whether any given submission is itself incomplete due to incompleteness of the RFP documents or due to the bidder's failure to completely mark-up and supplement such documents. Furthermore, the PPA bidders are very clearly disadvantaged by the draft RFP's allocation of points on this subject. The BTA form is merely a cursory term sheet, which is much easier to completely comment upon than the lengthy but incomplete pro forma PPA. Additionally, to the extent PacifiCorp plans to deduct non-price points for the *content* of a bidder's edits to these documents, such a scoring process would certainly require the type of subjective judgments that the Commission's administrative rules proscribe. No bidder could easily self-score its own mark-up of the pro forma PPA based on the information provided by PacifiCorp in the RFP. Based on the status of documents at this point, NIPPC recommends that this item be deleted as a basis for non-price scoring penalties and the points be reallocated to the score price.

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60 *Id.* at Appendix L.

F. The Draft RFP's Credit Requirements Will Preclude Otherwise Qualified Bidders From Participating

As noted above, the draft pro forma PPAs' requirement for bidders to potentially post performance assurance in the amount of $200/kw of project capacity upon PPA execution and maintain $100/kw throughout the term of the PPA is excessive and should be reduced.[61] To illustrate the excessiveness, a prevailing 400 MW bidder would need to provide a guarantee or letter of credit in the amount of $80 million upon execution of a final contract. It is not commercially reasonable for a developer to post a letter of credit in this amount, which limits bidding to very large companies or to developers with very large partners who can post a qualified guaranty. NIPPC recommends that the Commission require that a maximum performance assurance should be $100/kw before commercial operation, and $50/kw afterwards. Those amounts would be more consistent with market practice and fairer to PPA bidders.

Notably, while the draft RFP imposes the same $200/kw amount on BTA bids between contract execution and commercial operation, the draft RFP relieves the BTA bids of the need to maintain security of $100/kw over the facility's operating life. Because it costs money to maintain the excessive financial assurance after operation, the PPA bidders will need to build that extra cost into their bids – making this yet another example of how the RFP favors BTA bids.

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61 *Id.* at Appendix D at p. 3 (containing required security amounts for each bid type). The draft RFP notes that these amounts may be reduced on individual cases through achievement of project milestones and other considerations, but no firm guidelines are provided on that point. *Id.*

The problem of excessive credit assurances is particularly acute for smaller companies, which may have excellent projects under advanced development but have inherently less access to credit markets. Smaller companies will not be able to qualify for a letter of credit from a financial institution at the $200/kw level, and will need to use a guaranty instead, which will require partnering with larger firms. In turn, the smaller firm will need to increase its bid prices to facilitate this transaction and post the excessive financial assurance proposed by PacifiCorp. If the maximum performance assurance is not reduced, ratepayers may be deprived of valuable assets under development by smaller firms.

Furthermore, in addition to this onerous level of the proposed performance assurance, the draft RFP appears to also include onerous security requirements to even participate in the RFP, which should also be revised. As part of the section on "credit information" to be included with the bidders' initial application, the draft RFP appears to require that bidders include a commitment letter from a qualified guarantor or lender that it will provide financial assurance for the bidder. Specifically, for bidders relying on a third party for credit support, the draft RFP's credit requirements section explains:

> Describe relationship to bidder and describe type of credit assurances to be provided (e.g., parental guaranty, cash deposit, or a letter of credit from an acceptable financial institution). *Bidder must provide to Company a letter of commitment acceptable to Company from the entity(ies) providing the credit assurances on behalf of the bidder executed by an authorized signatory and indicating the amount and form of credit assurances it will provide*. It should be noted that more than one commitment letter, or more than one form of commitment letter, may be necessary.[62]

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62 *Id.* at Appendix D at p. 1 (emphasis added).

Yet, confusingly, the draft RFP later suggests the commitment letter will be required upon reaching the shortlist, as follows:

> If necessary, the bidder will be required to demonstrate the ability to post any required credit assurances in the form of a commitment letter from a proposed guarantor or from a financial institution that would be issuing a Letter of Credit. PacifiCorp will require each bidder to provide an acceptable commitment letter(s), if applicable, twenty (20) business days after the bidder is notified that the bidder has been selected for the Shortlist.[63]

These commitment letters are not free to all bidders, and, for the same reasons noted above, requiring such commitments during the RFP will inhibit smaller companies and those submitting PPA bids more than larger companies and those submitting BTA bids. While it may be reasonable to require bidders to post a reasonable commitment letter upon selection to the short list, there is no basis to require such a commitment letter at any time prior to selection for the shortlist. Indeed, it is not clear what amount would be required before PacifiCorp completes its evaluation of the bid's unique credit circumstances. Therefore, the draft RFP should be corrected and/or clarified on this point to ensure the RFP unambiguously relieves bidders of the requirement to provide commitment letters prior to selection to the shortlist.

G. PacifiCorp Should Clarify or Modify Certain Minimum Eligibility Requirements

PacifiCorp should clarify or change certain minimum eligibility requirements.

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63 *Id.* at Appendix D at p. 2.

1. Minimum Eligibility Requirement No. 8. – Current or Threatened Litigation Should Not Be Precluded

Potential bidders should not be barred from bidding if they are in, or have threatened, material litigation against PacifiCorp. PacifiCorp proposes a minimum eligibility requirement that bidders not be currently in, or have threatened, any litigation involving a dispute over $5 million, excluding a bidder complaint before a state public utility commission.[64] NIPPC appreciates the state commission exception and that PacifiCorp will consult with the IE before rejecting any bidder, but this minimum requirement is still too onerous. PacifiCorp is an efficient and aggressive business entity, which often results in positive ratepayer savings; however, this attempt to lock out potential bidders who seek to enforce their rights against PacifiCorp could have the opposite effect of harming ratepayers. This is so because these potential bidders may have lower cost and lower risk resources that will be outright rejected and never see the light of day. This restriction also disproportionally affects and discriminates against QFs that are potential bidders because PacifiCorp is more aggressive in resisting entering into contractual arrangements with QFs, who are therefore more likely to have threatened litigation.

The Commission's RFP rules are "intended to provide an opportunity to minimize long-term energy costs and risks, . . . and establish a fair, objective, and transparent competitive bidding process."[65] By permitting PacifiCorp to disqualify potential bidders that are in or have threatened litigation, the Commission will do the opposite. It will

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64 *Id.* at p. 14.

65 OAR 860-089-0010(1).

reduce the opportunities to minimize long-term energy costs and risks, and it will create an unfair process that would allow PacifiCorp to assert its rights or threaten litigation against any potential bidder but unnecessarily hamstring a potential bidder's ability to exercise its legal rights or risk being locked out of a key market. The risk of litigation is a normal business risk. If PacifiCorp wants to reduce its exposure to potential litigation, it should do so by acting reasonably with potential bidders rather than by including an anti-competitive "no litigation" requirement in its RFPs. The focus of the RFP should not be on protecting PacifiCorp's shareholders from the risk of litigation, but to obtain the best deal for ratepayers. And the best deal for ratepayers depends on the number and diversity of bids that are received, which will be reduced if this minimum bid requirement remains.

If the Commission is inclined to approve this onerous provision, then it should be modified to allow more bidders.

- First, PacifiCorp should be required to reveal which bidders will be barred (so that its actual impacts can be ascertained).
- Second, the $5 million limitation should be increased to $125 million, the scope of the current or threatened litigation should be limited to only litigation regarding the project that is bid into this RFP, and there should be a time limitation on any threatened litigation. The $125-million threshold is appropriate because that is slightly more than the amount that a jury awarded against PacifiCorp to

compensate a developer for PacifiCorp's theft of trade secrets associated with the Currant Creek gas plant.[66]

- Third, PacifiCorp should clarify that bidders will only be disqualified under this section if the current or threatened litigation is regarding the project that is bid into the RFP. Many potential bidders may be engaged in a number of different projects that have no or little relevance to the project that is bid into the RFP. The RFP should be focused on whether the particular project bid in, is the best option for ratepayers, and unrelated litigation has no relevance to that question.
- Fourth, the meaning of any material threatened litigation, should be limited to only whether the bidder has sent a demand letter within the last 90 days prior to the bid submission date. PacifiCorp includes no limitation to how far into the past the threat to litigate must have been made, and 90 days provides an appropriate time limitation.
- Finally, if this requirement is kept, the term "material litigation" should be refined to exclude any matter before the Federal Energy Regulatory clarification regarding PacifiCorp's tariffs.

2. Minimum Eligibility Requirement No. 11. – What Constitutes "Satisfactory Evidence" that Third-Party Transmission is Readily Obtainable?

PacifiCorp should clarify what constitutes "satisfactory evidence" that third-party transmission rights are already secured or "readily obtainable" for off-system bidders.

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66 *USA Power, LLC v. PacifiCorp*, 2016 UT 20 (Utah May 16, 2016).

PacifiCorp proposes a minimum bid requirement that any off-system bid be required to provide:

> satisfactory evidence that the interconnection to the third-party transmission provider or firm transmission rights are already secured in bidder or project owner's name or readily obtainable by bidder to deliver the full output of the resource to PacifiCorp on or before December 31, 2024, detailing all actual or estimated transmission costs.[67]

This minimum bid requirement clearly contemplates that something short of submitting fully executed interconnection and transmission agreements would be adequate to pass, but there is substantial uncertainty regarding what level of detail is required. For example, PacifiCorp should clarify whether it will be sufficient for a bidder to simply submit a static query of OASIS reservations or a forward-looking inquiry into potential retirements and transmission build-out. Once PacifiCorp identifies what it believes are "satisfactory", then NIPPC will review and potentially comment on those criteria.

3. Minimum Eligibility Requirement No. 23 – "Site Control" Should be Defined as in PacifiCorp's OATT

It is unclear what PacifiCorp requires for site control. NIPPC recommends that the appropriate documentation of site control be evaluated based on the definition of the term "site control" contained in PacifiCorp's Open Access Transmission Tariff ("OATT") approved by FERC. To the extent PacifiCorp proposes to use a different definition of "site control," it should define that term.

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67 *PacifiCorp's April 22, 2020 Draft RFP* at 15

4. Minimum Eligibility Requirement No. 30 – The Interconnection Request Should Not be Limited to Only Applications Submitted Before January 31, 2020

The RFP should treat all interconnection requests in PacifiCorp's April 2021 cluster on equal footing with those in the first "transition" cluster study in its new interconnection process. Specifically, the Commission should reject PacifiCorp's arbitrary cutoff date January 31, 2020 as the cutoff date for projects to participate in PacifiCorp's transition cluster study and be eligible for the RFP.

On May 12, 2020, FERC approved, with conditions, PacifiCorp's revised OATT, which moves from a traditional queue-based interconnection process to a "first ready" cluster study process.[68] In transitioning to this process, PacifiCorp proposed to conduct an initial cluster study of all interconnection requests received and pending by January 31, 2020, and FERC approved that proposal.[69] Then, prospectively, PacifiCorp will conduct annual studies based on all interconnection requests received during a cluster request window which is open for 45 days beginning on April 1st each year.[70] Therefore, PacifiCorp proposed that any requests received after January 31, 2020 until the effective date of the revised interconnection process would simply be deemed to have entered the first prospective cluster study, i.e., for the study process beginning April 1, 2021.[71]

The Solar Energy Industries Association ("SEIA") filed an expedited request for partial rehearing of the FERC's order allowing January 31, 2020 as the cutoff date for

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68 *PacifiCorp,* 171 FERC ¶ 61,112 (May 12, 2020).
69 *Id.* at PP. 115, 148.
70 *Id.* at P. 12.
71 *Id.* at P. 115.

PacifiCorp's transition cluster study.[72] SEIA asserts that PacifiCorp neither provided adequate notice of the January 31, 2020 cutoff date nor informed parties that failure to submit an interconnection request by that date would negatively impact their ability to participate in the upcoming RFP, and SEIA requested that FERC set May 19, 2020 as the cutoff date instead.[73] Should FERC adopt SEIA's proposal, this issue will be significantly mitigated; however, in the event FERC does not, there will be significant risk that viable and cost-effective resources will be summarily excluded from the RFP.

The minimum bidder criteria requiring that interconnection requests be submitted prior to January 31, 2020 will create undue risk and may result in higher costs for ratepayers. Projects submitted after January 31, 2020 may be more tailored to the unique need articulated in this RFP because they are more likely to have been developed during or after the time at which there was public knowledge of this RFP. Therefore, the post-January 31, 2020 projects may be lower risk and lower cost than other projects that have been stuck in PacifiCorp's interconnection queue for some time. While many of the earlier-submitted projects are still viable and may be great options for the RFP, many of the projects may withdraw[74] or otherwise may no longer be viable due to the extended interconnection processing time.[75] While these risks are inherent in choosing any

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72 Attachment C (*PacifiCorp*, Docket Nos. ER20-924, Expedited Request for Partial Rehearing by the Solar Energy Industries Association (May 15, 2020)).

73 *Id.*

74 In justifying its interconnection queue reform proposal, PacifiCorp noted that as of October 28, 2019, it had 161 FERC jurisdictional large generator interconnection procedural ("LGIP") requests in its queue for a total of 37,393 MW, and that 75% of all interconnection requests ultimately withdraw. *PacifiCorp,* 171 FERC ¶61,112 at PP. 2-3

75 PacifiCorp still has projects in its queue that applied in 2015.

particular cutoff date, PacifiCorp's goal should be to expand the pool of eligible projects rather than summarily excluding these later-submitted projects. This is especially true given the long backlog of projects in PacifiCorp's queue and the unprecedented size of this RFP.[76] Therefore, PacifiCorp creates an undue risk that it will not acquire the least-cost option for ratepayers, and to mitigate this risk, the RFP minimum bid requirements should accept all projects with interconnection requests submitted and pending on or before the April 2021 cluster study.

PacifiCorp may use this requirement to ensure that one or more of its "favored" projects win the RFP. PacifiCorp could do this by simply selecting a cutoff date that would ensure its preferred projects were eligible and to completely eliminate the competition from projects that applied later. Notably, PacifiCorp specifically made public statements indicating that it would align its RFP with the transition cluster study process, yet PacifiCorp did not provide potential bidders with sufficient advance notice that January 31, 2020 would be used as the cutoff date to be included in the transition cluster study.[77] Therefore, several promising projects are likely to not be included. There were 29 solar projects with co-located battery storage in PacifiCorp's queue as of January 31, 2020 for a total of 4,475 MW, and in the only three months since that date the number has doubled with an additional 29 solar+battery projects for a total of 4,095

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[76] 1,823 MW of solar co-located with 595 MW of battery storage, and 1,929 MW of wind resources. PacifiCorp Final Draft 2020 AS RFP Cover Letter at 2 (Apr. 22, 2020).

[77] Attachment C (*PacifiCorp*, Docket Nos. ER20-924, Expedited Request for Partial Rehearing by the Solar Energy Industries Association (May 15, 2020) (citing Comments of the Or. Pub. Util. Comm'n Staff at 1, Docket No. ER20-924 (Feb. 21, 2020)).

MW.[78] There is no question that the vast majority of these projects entered the interconnection queue primarily in response to this RFP specifically soliciting solar+storage resources.

In PacifiCorp's last RFP, the Commission declined to acknowledge PacifiCorp's short list of bidders noting that "the bid selection process ended up being limited to selection of only those projects with favorable queue positions . . . ."[79] The same issue is present here.

Projects entering the 2021 cluster study can likely still achieve commercial operation by December 31, 2024. PacifiCorp's revised study process will take approximately one year to complete which would still leave projects with over two and a half years to have the projects and the interconnections constructed. Therefore, to mitigate the risk that cost competitive resources are excluded simply because of an arbitrary cutoff date, the Commission should direct PacifiCorp to treat all interconnection requests in PacifiCorp's April 2021 cluster on equal footing with those in the first "transition" cluster study in its new interconnection process.

5. Minimum Eligibility Requirement No. 31 – PacifiCorp Should Allow Changes to the Interconnection Description That Do Not Constitute "Material Modifications" Under PacifiCorp's OATT

The RFP should allow for differences between the bid interconnection description and capacity and the interconnection request with PacifiCorp Transmission to the extent that such differences do not constitute a "material modification" as defined under

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78 Attachment D (PacifiCorp's Interconnection Queue as of 5/11/2020)

79 *In re PacifiCorp, dba Pacific Power 2017R Request for Proposals*, Docket No. UM 1845, Order No 18-178 at 11 (May 23, 2018).

PacifiCorp's OATT. As drafted, the RFP would disqualify bidders for "[f]ailure of the bid interconnection description and capacity to be consistent with the interconnection request with PacifiCorp Transmission."[80] This requirement should be modified to state that bidders will not be disqualified if they provide confirmation from PacifiCorp Transmission that the difference in capacity or project description in the bid and in the interconnection request do not constitute a "material modification." This is important because many projects have been in PacifiCorp's queue for a significant amount of time and may need to make minor adjustments to account for normal changes that come along with such delay, or to adjust projects slightly to better meet the RFP, such as by adding a BESS as contemplated by the RFP.[81] PacifiCorp contemplates that bidders may have submitted interconnection requests for the renewable project only, and that the BESS may have been added to the project at a later date. Of these circumstances, the RFP states that "[b]idders should provide confirmation from PacifiCorp Transmission that the facility's interconnection request or LGIA, if already executed for the proposed renewable resource, will not require a material modification to add a BESS."[82] The minimum eligibility requirements should therefore be modified to reflect that PacifiCorp will not disqualify bidders for changes to a project if the bid is accompanied by such an assurance from PacifiCorp Transmission.

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80 *PacifiCorp's April 22, 2020 Draft RFP* at 15.
81 *See id.* at 17.
82 *Id.*

H. PacifiCorp Needs to Make Changes to Accommodate Pumped Storage Hydro Resources

PacifiCorp will accept bids from PSH projects requiring a longer lead time and completion beyond the December 31, 2024 COD.[83] NIPPC believes that this accommodation is appropriate and does not believe it is necessary to specify a particular online date for PSH projects given that the lead times for PSH project can be anywhere from 5 to 10 years.[84] Given that PacifiCorp's first goal is to acquire resources that can come online by year-end 2024, PSH projects are aware that a shorter development period is generally ideal; however, a PSH project should not be excluded from consideration simply because it will require a slightly longer lead time.

PacifiCorp noted that any PSH project will be transacted through an individually negotiated tolling agreement.[85] As discussed above, PacifiCorp should provide a draft tolling agreement or, at a minimum, a term sheet for a tolling agreement as part of the RFP.[86] Additionally, PSH projects should not be limited to a maximum contract term of 25 years. PacifiCorp notes that bids with PPA with terms from a minimum of 15 years up to 25 years will be accepted.[87] While it is not clear whether this requirement will apply to PSH projects because PacifiCorp proposes an individually negotiated tolling

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83 *Id.* at 1.

84 San Diego County Water Authority, Pumped Energy Storage: Vital to California's Renewable Energy Future at 3 (May 21, 2019) [hereinafter San Diego County Water Authority, Pumped Energy Storage], https://www.sdcwa.org/sites/default/files/White%20Paper%20-%20Pumped%20Energy%20Storage%20V.16.pdf.

85 *PacifiCorp's April 22, 2020 Draft RFP* at 7.

86 *See id*. at 15-16.

87 *Id.* at 2.

agreement rather than a PPA, PacifiCorp should clarify that PSH projects are not limited to a 25-year contract term. The typical financial and engineering time horizons for PSH are a minimum of 40 to 50 years and even longer time horizons (even up to 100 years), which could result in lower costs for ratepayers.[88] Unlike other storage resources, PSH requires a more capital-intensive investment and can also be more durable. Notably, 50 years is also the longest operating license for pumped hydro offered by FERC and a project can be upgraded at a modest cost in year 50 and relicensed for another 50 years.[89] Therefore, given the unique characteristics of PSH, longer contract terms should be eligible for the RFP. NIPPC does not propose a specific term length at this time and looks forward to reviewing the comments of other parties and the IE on this topic.

I. PacifiCorp Should Clarify the Change from a 2023 to a 2024 COD

Since filing its IRP, PacifiCorp changed the date of expected commercial operation for this RFP from 2023 to 2024. PacifiCorp notes this is because at the time of filing the IRP PacifiCorp assumed projects would need to achieve commercial operation in 2023 to be eligible for the 40% PTC for wind or the 30% ITC for solar with BESS.[90] However, PacifiCorp notes that federal legislation was passed that would allow wind projects that secure safe-harbor equipment such as wind-turbine generators or begin construction in 2020 to receive a 60% PTC if placed into service by year-end 2024.[91] PacifiCorp also recognizes that this change in legislation only impacts the PTC but not

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88 San Diego County Water Authority, Pumped Energy Storage, at 18-19.
89 *Id.*
90 *PacifiCorp's April 22, 2020 Draft RFP* at 1.
91 *Id.*

the ITC, and suggests that solar co-located with BESS bidders account for this in preparing their bids.[92] PacifiCorp should clarify whether its RFP still needs to move forward at its current pace and whether there should be other modifications to the RFP in light of this rule change. Specifically, the move to a 2024 online date makes it more feasible for projects that are going to be studied in PacifiCorp's 2021 cluster study to participate in the RFP.

In addition, the U.S. Department of Treasury has recently indicated that it will likely modify its rules to expand the four-year safe harbor provisions to five years, at least for projects that would come online in 2020.[93] Should this rule change also impact projects on a going forward basis, there may be even more of a reason to make changes to the RFP.

J. PacifiCorp Should Allow Bids from Existing Resources

PacifiCorp proposes to accept bids only from bidders who currently own or have legally binding rights to develop new green-field resources.[94] However, there is no good reason not to accept bids from existing resources or projects that are adjacent to or expansions of existing projects. These projects may be the most cost-effective resources

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92 *Id.*

93 *See* Letter from Frederick Vaughan, Prin. Dep. Assist. Sec'y, Office of Legis. Affairs, to Senator Grassley, Chairman, Committee on Finance (May 7 2020), https://www.finance.senate.gov/imo/media/doc/2020-05-07%20UST%20Response%20to%20Grassley%20et%20al%2004-23%20letter.pdf; *See also* Letter from Chuck Grassley, Senator, to Steven Mnuchin, Secretary of Treasury, U.S. Department of Treasury (Apr. 23, 2020) https://www.grassley.senate.gov/news/news-releases/senators-urge-regulatory-relief-energy-tax-credits-light-pandemic-setbacks.

94 *PacifiCorp's April 22, 2020 Draft RFP* at 2.

that are available, as they are already operating or are more likely to come to fruition due to fewer permitting challenges. These projects may also be able to provide more accurate forecast production based on past production or given their proximity to an operating resource with actual data. Further, PacifiCorp noted in its 2019 IRP that over the planning horizon there are "major capacity reductions in wind purchases."[95] Should any of these contracts expire at or near in time to PacifiCorp's resource need, then there is no reason not to allow them to bid into the RFP and continue providing their power to PacifiCorp. Indeed, PacifiCorp's models used for bid evaluation assume that existing projects stop producing energy at the end of their original useful lives end or when their contract terms expire.[96] Thus, there is no reason why those projects should not be eligible to bid into this RFP. Not allowing those projects or expansions of those projects to bid deprives ratepayers of potentially lower-cost and lower-risk resources with no countervailing justification.

K. PacifiCorp Should Be Required to Use or Explain Why It Is Not Planning on Using Its Own Transmission Assets to Benefit Ratepayers

The Commission's new competitive bidding rules require that the utility "must provide analysis explaining that decision when seeking RFP acknowledgement …"[97] This provision specifically applies to benchmark resources, but the same principle should apply to BTA because they both result in the utility owning the resource and supporting

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95 2019 Integrated Resource Plan, PacifiCorp, Vol. 1 (Oct. 18, 2019) at 108, https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019_IRP_Volume_I.pdf.

96 Attachment E (PacifiCorp Response to NIPPC Data Request 1.3).

97 OAR 860-089-0300(3).

that resource with its own transmission assets. Transmission and interconnection matters have been the main limiting factor in both PacifiCorp's and PGE's last RFPs, and the Commission should learn from these past examples to improve this RFP.

As noted elsewhere, NIPPC recommends that PacifiCorp accept BTA bids for off-system projects using third-party transmission to deliver power to PacifiCorp's system. In that type of arrangement, one would expect that PacifiCorp would use its entire portfolio of transmission assets to economically deliver the output of the plant PacifiCorp would own to PacifiCorp's system. The same treatment should also apply for PPA bids, where PacifiCorp could agree to take title to the energy at the point of interconnection to the third-party utility's system, and use PacifiCorp's existing transmission assets to economically deliver that energy to PacifiCorp's system. Instead, the RFP refuses to accommodate off-system BTA bids and fails to use PacifiCorp existing and future transmission assets to accommodate off-system PPA bids. This is a significant and unnecessary restriction on potentially least-cost projects in the region. Currently, many areas in the Northwest where a bidder cannot obtain transmission to deliver energy to PacifiCorp, and a review of capacity reservations shows that PacifiCorp holds substantial transmission rights on the affected path.

The circumstance of retiring PacifiCorp plants further highlights the problem. PacifiCorp already owns significant transmission resources and contracted rights which can serve loads, and the resources acquired through the RFP will be replacing existing generators and could be serving loads using the same transmission from the same general location as the retiring plants. For example, in the case of PacifiCorp plants that will soon be retiring, there is transmission available to serve the loads, but there may be limited opportunities for an IPP to secure that transmission ahead of PacifiCorp's existing resources coming offline. The Commission should ensure that the RFP does not exclude bids due to a perceived lack of transmission from locations where transmission will soon be freed up to retirement of PacifiCorp plants.

Consistent with the intent of the administrative rules, the Commission should at least require PacifiCorp to explain why it cannot use its existing transmission for any new generation bid into this RFP. If such explanation is inadequate, the Commission should require PacifiCorp to make reasonable accommodation to use PacifiCorp's existing transmission for both PPA bids and BTA bids.

L. The RFP Should Allow Different Contracting Structures as an Alternative Rather Than as an Additional Base Bid

PacifiCorp proposes that there be bid fee(s) of $10,000 required for each base proposal and one alternative, and that bidders may offer up to three additional alternatives at a fee of $3,000 each.[98] NIPPC recommends that different contracting structures like BTAs and PPAs be allowed as alternatives rather than an additional base bid. This will allow a more direct comparison of different contracting structures and greater assurance of least-cost least-risk procurement and less ability to bias toward utility ownership. Moreover, given the increased likelihood that storage resources will participate in this RFP, including storage resources co-located with renewable generators, requiring alternative contract structures to be bid as additional base bids will result in several permutations and potentially several base bids that represent the same physical project.

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98 PacifiCorp Final Draft 2020 AS RFP Cover Letter at 3.

To reduce the costs imposed on bidders, and thus allow the greatest pool of resources to participate, different contracting structures associated with the same physical project should be allowed to be bid as alternatives rather than additional base bids.

M. The RFP Should Be Amended to Reflect PacifiCorp's Revised View of On-Site Data Requirements for Wind and Solar

PacifiCorp should revise the RFP to incorporate its response to an electronically submitted question about the RFP's proposed equivalent on-site data[99] to be used for wind and solar, subject to an amendment described below:

> For required bid information, PacifiCorp will accept two years of solar irradiance satellite data provided from Solargis or SolarAnyway in lieu of on-site solar panel met data for all solar PPA and BTA bids. However, should a solar BTA bidder be selected to the initial shortlist, to remain on the initial shortlist, bidder must commit to install at least one solar monitoring station on the proposed solar site by November 15, 2020 with the ability to capture solar irradiance data for at least eight months and prior to being considered for the final shortlist. If a solar BTA bidder is selected to the final shortlist, bidder will commit to maintaining at least one on-site solar monitoring station through the entire construction period and provide the solar monitoring station and all collected solar irradiance data to PacifiCorp at BTA closing.[100]

A single month (the time between selection of an initial shortlist and proposed installation of a solar monitoring station) may be too short to contract, mobilize, and install a station, particularly if multiple projects are shortlisted in the same locale. PacifiCorp should therefore either extend its November 15 deadline or commit to accept

99 *PacifiCorp's April 22, 2020 Draft RFP* at Appendix C-3.

100 PacifiCorp's April 22, 2020 Draft RFP – Questions and Answers from RFP Mailbox as of May 12, 2020, Q&A ID# 114 https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/suppliers/rfps/2020-all-source-request-for-proposals/documents/2020_All-Source_RFP_Questions_through_05-06-2020.pdf.

reasonable adjustments to the deadline in the event of contracting and related contingencies.

N. The RFP Should Provide Additional Information on How Projects Will be Ranked for Initial Shortlist According to Their Capacity Contribution

The initial shortlist has a dollars-per-kilowatt ranking. PacifiCorp should provide additional details regarding how projects will be ranked according to their capacity contribution. A ranking on a dollars-per-kilowatt of nameplate capacity is appropriate, but can differ significantly based on resource type, especially for co-located renewables and storage. A capacity contribution based on nameplate does not adequately capture the higher capacity credit associated with better performing resources.

O. The RFP Should Not Limit Build-Transfer Opportunities to Projects Interconnecting on the PacifiCorp System

PacifiCorp limits BTA bids to only projects that interconnect on its system.[101] NIPPC is not aware of PacifiCorp's justification for this limitation. PacifiCorp should acquire the least cost and least risk bid regardless of whether it is located on its system or not. A project developer that has long-term transmission rights or that demonstrates a strong likelihood that it can obtain those rights and transfer them to PacifiCorp, should be able to sell its project to PacifiCorp without restriction.

III. CONCLUSION

The Commission should direct PacifiCorp to make the revisions articulated herein.

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101 *PacifiCorp's April 22, 2020 Draft RFP* at 18.

Dated this 22nd day of May 2020.

Respectfully submitted,

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Intermountain Power Producers Coalition

Attachment A

2019C RFP Appendix A-2

Tolling Agreement Term Sheet

APPENDIX A-2 –TOLLING AGREEMENT TERM SHEET

TOLLING AGREEMENT
TERM SHEET

Physical Tolling Transaction ***Term Sheet***	
Seller	[ENTER COUNTERPARTY NAME]
Contact Name	
Phone Number	
Email	
Buyer	PacifiCorp
Description	Seller shall sell and Buyer shall purchase the Product, as delivered to the Point of Interconnection, for the Term
Facility	Describe facility, size, technology, and location ("Facility")
Start Date	Hour Ending ("HE") 0100 Pacific Prevailing Time ("PPT") on [ENTER DATE: Starting no earlier than November 1, 2019]
End Date	HE 2400 PPT on [ENTER DATE: Ending no later than December 31, 2025]
Term Length	Term must be less than five years (60 months)
Delivery Term(s)	January through December
Availability Term	Please specify: All Hours, Standard On Peak (6X16), Standard Off Peak (6X8, Sundays/Holidays), Super-Peak, or other
Planned Maintenance	Planned maintenance for the Facility during the term by mutual agreement
Pre-scheduling	Pre-scheduling will be pursuant to the WECC ISAS daily pre-scheduling calendar and the WECC Business Practices
Plant Capacity	[ENTER #] MW
Contract Quantity	[ENTER #] MW – [ENTER PERCENTAGE] of the Plant and 100% of the Facility
Product	A physical toll of the Facility. Buyer may at any time and from time to time, as provided herein, dispatch the Facility at its discretion in accordance with the Operating Limitations outlined below. Buyer will be responsible for all procurement and costs associated with fuel, fuel transportation and VOM during the Term of this transaction
Dispatch Notice	Buyer shall have the right to dispatch any or all of the Facility's [Turbines], [SPECIFY TIME PERIOD, INCLUDING NUMBER OF DAYS AND NUMBER OF DAYS PER WEEK], by providing a Dispatch Notice on a preschedule basis and subsequent Dispatch Notices in real time via electronic mail and confirmed via telephone. Dispatch notices shall be effective unless and until Buyer modifies such Dispatch Notice by providing Seller with an updated Dispatched Notice. Updated Dispatch Notices may be provided telephonically if necessary and shall be promptly documented by the Buyer via electronic mail utilizing the Dispatch Notice form
Availability Notice	Not later than 5:00 AM PPT on each Preschedule Day Seller shall, using an Availability Notice, provide Buyer with an hourly schedule of the expected availability of the [Turbines] for each hour of the schedule day. Availability Notices shall be provided by electronic mail and shall be effective unless and until Seller modifies such Availability Notice by providing Buyer with an updated Availability Notice. Updated Availability Notices may be provided via electronic mail or telephonically
Guaranteed Availability	[__%] of [___] MW (Plant Capacity)

Physical Tolling Transaction ***Term Sheet***	
Capacity Charge	[ENTER ONE OR MORE TIMEFRAME AND PRICES] From [DATE] through [DATE]: $[X.XX] / kW-mo
Variable O&M Cost	$[XX.XX] per [Dispatched] [Hour] per [Turbine]
Run Hour Charge	[$_____] per [Turbine] Run Hour, for the Authorized Run Hour Starts
Fixed Start Charge	[$_____] charge per Unit start authorized by Buyer
[DISPATCHED] Hour	Number of minutes each [Turbine] is dispatched to generate electricity divided by 60. For example, one [Turbine] dispatched for 75 minutes is 1.25 Fired Hours
Misc. Energy Charges	Emission charges, taxes, etc. are the responsibility of the Seller
Imbalance Penalties	The Buyer and the Seller shall use commercially reasonable efforts to avoid the imposition of any generation, electric transmission, or fuel supply imbalance charges. If Buyer or Seller receives an invoice that includes imbalance charges, the Parties shall determine the validity as well as the cause of such imbalance charges. The Party that caused the imbalance charges shall pay or reimburse the other Party for such imbalance charges
Monthly Capacity Payment	Monthly Capacity Payment equals Capacity Charge multiplied by Contract Capacity, multiplied by 1,000. Buyer will pay the Monthly Capacity Charge to Seller on a monthly basis
Monthly Payment	The Monthly Payment shall equal the sum of (i) the Monthly Capacity Payment, (ii) the monthly VOM Payment, (iii) if applicable, the Station Service Payment. The first Monthly Payment of each calendar year shall also include the Availability Refund, if applicable, from the previous calendar year
Point of Interconnection	The [ENTER POINT OF INTERCONNECTION DESCRIPTION, "high side of busbar at specific substation" for example] (currently the OASIS point-of-receipt called [ENTER OASIS POINT-OF-RECEIPT])
Transmission	Buyer shall make application for Transmission Service from the Facility's [busbar] on the appropriate Transmission System as a Designated Resource with the appropriate transmission provider for the Contract Quantity, in accordance with that transmission provider's requirement
Operating Limitations	Fuel: [DESIGNATE BUYER OR SELLER] will deliver all of the fuel required to meet its Dispatch Notices, including fuel used for start-up Start-Up Notification: Minimum: [ENTER #] minutes Maximum: [ENTER #] minutes Fast Start per Contract Year: Parties will agree on a day ahead basis and use best efforts to provide ([ENTER #] minutes to full load from notification) per contract year Minimum Run Tim: [ENTER #] hour Maximum Starts per Day per [Turbine]: [ENTER #] Minimum Load per [Turbine]: [ENTER #] MW
Heat Rate	Define at various temperatures, capacity. Bidder to provide incremental heat rate curve per APPENDIX A-2, EXHIBIT II and in Appendix C-1 excel spreadsheet

Product Alternatives

Please number and summarize Product alternatives consistent with Section 2.1 of 2019C RFP and provide additional details in Appendix C.

Product Alternative #	Point of Inter-connection	Start Date	End Date	Avail-ability	Quantity (MW)	Capacity Price ($/kW-mo)	Fixed O&M ($/kW-mo)	Variable O&M (VOM) ($/MWh)

Attachment B

Boston Pacific Company
Bid Evaluation Methods in Competitive Solicitations

Bid Evaluation Methods in Competitive Solicitations:
A White Paper on Techniques Used to Evaluate Power Supply Proposals with Unequal Lives

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TABLE OF CONTENTS

I. INTRODUCTION AND SUMMARY

For at least twenty years, utilities across the country have been issuing competitive solicitations to invite power sales proposals from affiliates and non-affiliates.[1] As the number of non-affiliated suppliers has increased, state and federal regulators have encouraged utilities to use such solicitations for an increasing portion of their capacity, energy and ancillary services needs. First and foremost, the goal of competitive solicitations is to evaluate a full range of resources in the wholesale marketplace to obtain the best possible deal for electric utility customers in terms of price, risk, reliability, and environmental performance.

In 2004, Boston Pacific prepared "Getting the Best Deal for Electric Utility Customers: *A Concise Guidebook for the Design, Implementation and Monitoring of Competitive Power Supply Solicitations*."[2] The Guidebook discussed (a) the importance of and role for competitive solicitations, (b) ways to ensure a credible process, (c) choosing solicitation formats and product types, and (d) how to conduct a fair and accurate bid evaluation. The purpose of this White Paper is to expand the discussion of one narrow, but important aspect of the bid evaluation process. Specifically, how should evaluators compare proposals of unequal lives? For example, how should evaluators accurately compare a proposal that has a 5-year term to another proposal that has a 10-year term?

This White Paper describes and quantifies five evaluation techniques for comparing proposals of unequal lives: (a) the Equivalent Annual Annuity Method, (b) Real Levelized Revenue Requirement Method, (c) Filler Method, (d) Deferred Replacement Cost Method, and (e) Option Method.[3] Our research indicates that, out of these five methods, the Equivalent Annual Annuity Method (the Annuity Method) should be among the methods required in an evaluation, if not the preferred method. The central appeal of the Annuity Method is that it essentially allows the bid to speak for itself, thereby minimizing the discretion of the bid evaluator. The other methods add needless complexity and uncertainty to the bid evaluation process, and all give too much discretion to the bid evaluator.

II. EQUIVALENT ANNUAL COST METHOD (ANNUITY METHOD)

According to standard financial theory, the Equivalent Annual Cost Method, or simply the Annuity Method, should be used to compare alternatives that have unequal lives.[4] If a business must choose between Alternative A, which lasts 10 years, and

[1] One of the first such solicitations was used by Central Maine Power in 1984. More recent examples include competitive solicitations issued by utilities in Arizona, Colorado, Maryland, New Jersey, and Florida.
[2] Available at www.bostonpacific.com
[3] All assumptions and exhibits used in this White Paper are purely hypothetical and are only used to clarify the evaluation techniques.
[4] *See* Ross, Stephen A., Westerfield, Randolph W., and Jaffe, Jeffrey. Corporate Finance Fourth Edition Irwin. (1996) p. 185.

Alternative B, which lasts 20 years, the business should compare the annuity costs of the two alternatives. An annuity is the equal annual payment over the life of the alternative that has the same present value as the actual, unequal annual costs that are expected to be incurred. The annuity of Alternative A would be calculated over ten years and that of Alternative B would be calculated over twenty years. The alternative with the lower annuity is the better choice.

Central to all methods of comparing alternatives of unequal lives is the assumption about what happens when the shorter-term choice expires. In the above example, what happens when Alternative A, the 10-year offer ends its initial term? With the Annuity Method, it is implicitly presumed that the initial offer is repeated. This means that the gap between the 10 and 20-year choices, in effect, would be filled in by assuming that the 10-year alternative would be offered again at the same price and non-price terms. The primary benefit of this technique is that it allows bids to speak for themselves and takes discretion out of the evaluator's hands.

There are three main steps involved in applying the Annuity Method to bid evaluation. First, for each bid, the evaluator takes the present value of the total cost of the proposal. Second, an annuity is calculated based on that present value. Again, an annuity is the equal annual payment that yields the same present value as calculated in step one. Third, if the proposals are of different megawatt sizes then the evaluator should adjust the annuity by dividing the annuity by the contract capacity (Annuity/MW). The evaluator can then compare a 10-year annuity to a 20-year annuity and choose the alternative with the lower annuity cost. Exhibit One provides a hypothetical quantitative example of the Annuity Method.

In Exhibit One, Proposal A, a 10-year offer, is compared to Proposal B, a 20-year offer, with the following contract assumptions for a combined cycle natural gas-fired generating facility:

TABLE ONE:
CONTRACT ASSUMPTIONS FOR EXHIBIT ONE

	Proposal A	**Proposal B**
Term Length	10 years	20 years
Heat Rate	6,500 Btu/kWh	7,200 Btu/kWh
Inflation	2.5%	2.5%
Capacity	500 MW	450 MW
After-Tax Cost of Capital	9.50%	9.50%
Fixed Price Fuel Contract	$3.50/MMBtu	$3.50/MMBtu
Capacity Factor	70%	70%
Variable O&M	$1.50/MWh	$1.75/MWh
Capacity Payment	$95/kW-yr	$75/kW-yr

The results of our analysis are shown in Table Two below and illustrate the need for a method to compare the proposals on an apples-to-apples basis. Simply comparing the present value for two proposals could convey misleading results. For example, only comparing the present values would lead one to choose Proposal A ($794.9 million) over Proposal B ($1 billion). Generally, the shorter-term contract would offer a lower present value because there are fewer years of costs; therefore the appropriate next step is to compare the annuities of the proposals. In this example, Proposal A's annuity is $126.6 million and Proposal B's annuity is $114.5 million. This would lead the evaluator to choose Proposal B, as it has the lower cost annuity. Unfortunately, this comparison is still inaccurate.

Comparing the annuities is insufficient because Proposal A is offering 50 more megawatts than Proposal B. The proper method to compare proposals with unequal lives and different capacity sizes is to compare them on an annuity per MW basis. In this illustration, Proposal A wins over Proposal B because its annuity per MW is cheaper ($253,200/MW compared to $254,400/MW).

TABLE TWO:
RESULTS OF EXHIBIT ONE

Results	**PV ($000)**	**Annuity ($000)**	**Annuity/MW ($000/MW)**
Proposal A	$794,899	$126,601	$253.20/MW
Proposal B	$1,008,845	$114,480	$254.40/MW

It should be noted that this example only tested one capacity factor. We recommend that the evaluator test a range of capacity factors and generate a screening curve to analyze how the contracts perform at different levels.[5]

As with any method, the Annuity Method has its possible faults. As previously mentioned, under the Annuity Method, it is presumed that beyond its initial term an offer is extended under the same terms and conditions as its initial term. If a solicitation takes place under severely depressed market conditions, but with the expectation that these conditions will improve in the long term, then the evaluation should request proposals of sufficient length to bridge the gap between the depressed and improved market conditions. Moreover, what if in Exhibit One, Proposal B (450 MW) was actually the lower-cost proposal? The Annuity Method does not have an easy answer regarding how the utility should solicit the remaining 50 MW. Presumably, the practical response is for the soliciting utility to conduct negotiations with Proposal A on those 50 MW.

[5] Using various capacity factors to generate a screening curve is vital to determining which proposal is the best alternative. However, in determining which supplier is the cheaper alternative, the evaluator must use the same capacity factor for each proposal.

III. REAL LEVELIZED REVENUE REQUIREMENTS METHOD

The Real Levelized Revenue Requirements Method is another method of comparing proposals of unequal lives. It is derived from quantitative methods used to evaluate the revenue needed to support the capital costs of building a new generation facility. That is, the cost of constructing and financing spread over the life of a new generation facility, which generally includes the return *of* investment (book depreciation), the return on investment (both equity and debt), and taxes.

There are five main steps involved in applying this approach. First, for each bid, the evaluator calculates the present value of the annual total cost using a nominal discount rate. Second, a real annuity is calculated based on the present value calculated in step one. That is, using a "real" discount rate (i.e., discount rate without inflation), the evaluator calculates the annuity payment (equal annual payment) that yields the same present value as calculated in step one. Third, inflation is factored back in by escalating the real annuity each year by the compounded rate of inflation. The present value of this "inflation-adjusted annuity" *using the nominal discount rate* will equal the present value of the proposal as calculated in step one. Fourth, the evaluator levelizes the MW in the same manner as the bid prices. Fifth, levelized annuity cost is divided by the levelized MW. Thus, to compare proposals of different contract lives and resource sizes, the evaluator would compare the levelized annuity per MW ($/MW) of one proposal to another.

Exhibit Two provides a hypothetical, quantitative example of the Real Levelized Revenue Requirement method. It compares Proposal A, a 10-year 750 MW offer to Proposal B, a 5-year 650 MW offer. The example assumes that the evaluator calculates the annual nominal cost of the capacity and energy prices, etc., listed in each bid ("Total Bid Price Costs" column). For Proposal A, it is assumed the bid prices result in a nominal cost of $95 million in year 1 and decrease by $6 million per year thereafter. For Proposal B, it is assumed the bid prices result in a nominal cost of $85.2 million in year 1 and decrease by $8 million per year thereafter. Table Three, below, describes some of the other assumptions used in the exhibit.[6]

TABLE THREE:
ASSUMPTIONS FOR EXHIBIT TWO

	Proposal A	**Proposal B**
Term Length	10 years	5 years
Discount Rate	10.0%	10.0%
Inflation Rate	2.0%	2.0%
Capacity	750 MW	650 MW
Real Discount Rate	7.84%	7.84%
Year 1 Nominal Costs	$95,000,000	$85,200,000

[6] The real discount rate is calculated by the following formula: real discount rate = [(1+discount rate)/(1+inflation rate)]-1. *See* Brealey, Richard A. and Myers, Stewart C. Principles of Corporate Finance Fourth Edition McGraw-Hill, Inc. (1991) p. 559.

Similar to the Annuity Method, a simple comparison of the present value of the annual nominal costs would produce misleading results. As shown in Exhibit Two, Proposal A has a present value of $446.4 million, while Proposal B results in a present value of $268 million. However, Proposal A has added value that is unaccounted for in this comparison (e.g., providing service in years 6 through 10 and 100 MW more of capacity). To account for these differences, the evaluator levelizes the costs and megawatts associated with each proposal. In year 1, using the real discount rate of 7.84%, the evaluator calculates the real annuity and the levelized megawatts ($66.1 million and 682 MW for Proposal A versus $66.9 million and 615 MW for Proposal B). Next, the evaluator adjusts the real annuity for inflation ("Inflation Adjusted Real Annuity" column). To ensure an apples-to-apples comparison, the same adjustment must be made to the megawatts ("Inflation Adj. Real Annuity MW"). Finally and most importantly, the evaluator divides the Inflation Adjusted Real Annuity by the Inflation Adjusted Real Annuity MW to get a $/MW comparison. Note that this $/MW is the same value in each year. The Table entitled "Proposal A Truncated at 5 Years" demonstrates that even if the evaluator truncates the 10 year bid at 5 years to compare it to Proposal B, the $/MW will remain the same at $96,860/MW.[7]

The concern with the Real Levelized Revenue Requirement Method is that (a) adds unnecessary complexity to the evaluation, which increases the possibility of error and (b) does not properly take into account inflation risk. One way that the evaluators might err is by failing to levelize the megawatts. Failing to adjust the megawatts across all years of the proposal will lead to inaccurate results.[8] In addition, similar to the Annuity Method, this method does not offer an easy solution to fulfilling the remaining megawatts if the lower capacity proposal is the winner. Again, the soliciting utility may choose to negotiate with other suppliers for the remaining balance of the megawatts.

IV. FILLER METHOD

A third technique used is called the Filler Method. In this method, the evaluator will "fill in" behind the shorter term contract with its estimate of future capacity and energy prices until the life of the shorter-term proposal matches the length of the longer-term proposal. To compare Proposal A, a 10-year Purchase Power Agreement (PPA), to Proposal B, a 5-year PPA, the evaluator would assert what capacity and energy prices the supplier in Proposal B would offer in years 6 through 10.

There are three main steps in applying the Filler Method. First, the evaluator determines which bid has the longest term. Second, for each of the shorter-term proposals, the evaluator must estimate the costs that might be incurred when "filling in"

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[7] If performed correctly, the Real Levelized Revenue Requirement Method should produce results similar to the Annuity Method.

[8] It should be noted that if proposals offer staggering capacities throughout its term, (e.g., an increase in year 6 from 750 MW to 800 MW) then this method should accurately account for that increase.

with power purchases each year between the shorter-term and longer-term proposal. As already noted, typically this estimate is made as if the supplier was asked to bid a second time for extra years. Third, the evaluator must compare the present values of bids, which now include the filled-in costs.

This method gives the evaluating entity a significant amount of discretion, which can and often does raise concerns of affiliate abuse or inaccurate comparisons. In short, as compared to the Annuity Method, this Filler Method does not allow the bids to speak for themselves.

Moreover, when assessing future power supply offers, the evaluator must consider (a) improvements to fuel efficiency, (b) development of new technology, and (c) changes in capital costs. For example, ten years ago, a heat rate efficiency of a natural gas-fired generator was in the 8,500-12,000 Btu/kWh range while today new gas-fired generators have heat rates in the 6,000-7,000 Btu/kWh range. Yet, when evaluators utilize the Filler Method, rarely are these technological improvements taken into account, due in part to the difficulty of quantifying and predicting such improvements.

One common assumption made by evaluators during the "filler" years, is the escalation of the capacity price. For example, if the bidder in Proposal B offered a fixed capacity price of $96/kW-yr for each year of the 5-year bid, then the evaluator often assumes the bidder would want to compensate for inflation by increasing its capacity price; that is, the capacity price in year 6 would increase to $108.62/kW-yr ($96/kW-yr times the rate of inflation (2%) compounded over 5 years) and escalate each year by the rate of inflation until year 10. The evaluator is assuming that the bidder (a) did not already factor the rate of inflation into its bid, and (b) would not lower its capacity payment in future years. There are a number of reasons why a lower or equal capacity price could be offered, such as the ability of the supplier to refinance its debt or an excess of supply driving down the return of and on capital. Exhibit Three provides a hypothetical quantitative example of the Filler Method.

Exhibit Three demonstrates how an evaluator would generally extend the term of a shorter-term offer (Proposal A) to match a proposal that has a longer term. In this instance Proposal A has the following contract assumptions:

TABLE FOUR:
ASSUMPTIONS TO EXHIBIT THREE

	Proposal A
Term Length	5 years
Heat Rate	6,500 Btu/kWh
Inflation	2.5%
Capacity	500 MW
After-Tax Cost of Capital	9.50%
Fixed Price Fuel Contract	$5.00/MMBtu
Capacity Factor	70%
Fixed O&M	$4.50/kW-yr
Variable O&M	$1.50/MWh
Capacity Payment	$96/kW-yr

For the first five years of the contract the evaluator takes the bid as is. However after the first five years, the evaluator assumes that the capacity payment increases by 13% in year 6, from $96/kW-yr to $108.62/kW-yr. This is because the evaluator assumes that, in year 6, the effects of inflation (2.5%) compounded over five years have increased the capacity payment from $96/kW-yr to $108.62/kW-yr. Similarly, the evaluator also assumes that fixed operations and maintenance (O&M) costs increase from $4.50/kW-yr in year 5 to $5.09 kW-yr in year 6, but remains fixed for years 7 through 10. Further, with regard to variable costs, the evaluator assumed that the heat rate, variable O&M, and the fixed-price fuel contract remain constant for years 1 through 10.

The primary concern here is that by filling in costs for years 6 through 10 to match the term of a 10-year proposal, the evaluator can significantly bias the 5-year proposal. The filler method gives the evaluator too much discretion, creates uncertainty in the bid process, and thus could undermine the competitive market.

V. DEFERRED REPLACEMENT COST METHOD

A fourth method utilized is the Deferred Replacement Cost Method. This method has often been used to determine if it would be cheaper to self-build generation or to enter into a long-term contract. The presumption is that, for example, if a utility determines that it needs additional capacity and energy, it can either build a combined cycle power plant today with a useful life of 30 years or enter into a 10-year PPA today and build a new facility in year 11.

There are four steps involved in applying the Deferred Replacement Cost Method. First, the evaluator would calculate the present value of the revenue requirement needed to build and finance a new power plant today with an assumed useful life of 30 years. Second, for each bid, the evaluator would calculate the present value of the bid prices (capacity, energy, etc.) for each 10-year offer. Third, a revenue requirement model would calculate the revenue needed to cover the costs of building and financing a new plant in year 11 with a useful life of 30 years ("Year 11 New Plant"). Fourth, the evaluator must estimate the terminal value of the Year 11 New Plant, or the price of selling the Year 11 New Plant after having operated it for twenty years. Fifth, for each bid, the evaluator must compare (a) the present value of the 10-year proposal plus the present value of the revenue requirement of the Year 11 New Plant minus the present value of the terminal value to (b) the present value of building a new plant today.

This method is essentially a variation on the Filler Method and again, it gives the evaluator too much discretion in comparing proposals. The evaluator can err in estimating (a) the decrease or increase in cost of building a new facility in year 11, (b) the increase in fuel efficiency, and (c) the termination payment.

VI. OPTION METHOD

The Option Method is a market-based solution to the unequal lives concern, rather than an analytical method.

A call option is a contract giving the owner the right, but not the obligation to buy an asset at a fixed price on or before a given date. A properly structured RFP could embed a call option into the PPA, which would require the bidder to list the payment (option payment) needed to (a) extend the PPA to a specified date under the same terms and conditions, (b) extend the PPA to a specified date under different terms and conditions, or (c) acquire the generation facility.

For example, assume the RFP is soliciting capacity and energy products for a 10-year term, but wants to compare those 10-year offers to a 20-year offer. In this case, suppliers who are submitting proposals for 10 years should be asked to offer an option payment to extend the contract for another 10 years at the same capacity and energy prices. When evaluating the 10 and 20-year offers, all bids would then have the same term length (i.e., 20 years).

Embedding option payments into the RFP minimizes the evaluator's discretion, but is not without drawbacks. For example, not all suppliers might be willing to enter into the option agreement, especially if they own older facilities that have a useful life of less than 20 years.

VII. CONCLUSIONS

Getting the best deal for utility consumers in terms of price, risk, reliability, and environmental performance should always be the goal of competitive solicitations. To that end, a fair and accurate evaluation of proposals is essential.

Based upon our investigation into the five evaluation techniques (Equivalent Annual Annuity Method, Real Levelized Revenue Requirement Method, Filler Method, Deferred Replacement Cost Method, and Option Method), the Filler Method and the Deferred Replacement Cost Method give too much discretion to the evaluator while the Real Levelized Revenue Requirement Method requires unnecessary complexity. The Option Method is a potential solution to the problem, but raises additional concerns. Thus, it is recommended that at a minimum, the Annuity Method should be required as one way to compare proposals of unequal lives. Most importantly, this method allows the bids to speak for themselves because it minimizes the evaluators' discretion in making assumptions about costs once the initial term expires.

EXHIBIT ONE
COMPARISON OF A 10-YEAR PROPOSAL (PROPOSAL A) TO A
20-YEAR PROPOSAL (PROPOSAL B) USING THE EQUIVALENT ANNUAL COST METHOD (ANNUITY METHOD)

PROPOSAL A

Assumptions

Heat Rate	6,500 Btu/kWh	After-tax CC	9.50%	Term Length	10 yrs
Inflation	2.5%	Fuel Costs	$ 3.50 /MMBtu	Variable O&M	$ 1.50 /MWh
Capacity	500 MW	Capacity Factor	70%	Capacity Payment	$ 95 /kW-yr

Annuity/MW ($000/MW): 253.20

Year	Equip Life	Capacity Payment ($/ kw-yr)	Capacity Costs ($000)	Energy Costs ($000)	Var O&M Costs ($000)	Total Costs ($000)	PV of Total Cost ($000)	Cumulative NPV ($000)	Annuity ($000)
2003		-	$ -	$ -	$ -	$ -	$ -	$ -	
2004	1	95.00	$ 47,500	$ 69,752	$ 4,599	$ 121,851	$ 111,279	$ 111,279	$ 126,601
2005	2	97.38	$ 48,688	$ 69,752	$ 4,599	$ 123,038	$ 102,615	$ 213,894	$ 126,601
2006	3	99.81	$ 49,905	$ 69,752	$ 4,599	$ 124,255	$ 94,639	$ 308,533	$ 126,601
2007	4	102.30	$ 51,152	$ 69,752	$ 4,599	$ 125,503	$ 87,297	$ 395,830	$ 126,601
2008	5	104.86	$ 52,431	$ 69,752	$ 4,599	$ 126,782	$ 80,535	$ 476,365	$ 126,601
2009	6	107.48	$ 53,742	$ 69,752	$ 4,599	$ 128,092	$ 74,309	$ 550,674	$ 126,601
2010	7	110.17	$ 55,085	$ 69,752	$ 4,599	$ 129,436	$ 68,573	$ 619,247	$ 126,601
2011	8	112.93	$ 56,463	$ 69,752	$ 4,599	$ 130,813	$ 63,290	$ 682,538	$ 126,601
2012	9	115.75	$ 57,874	$ 69,752	$ 4,599	$ 132,225	$ 58,423	$ 740,961	$ 126,601
2013	10	118.64	$ 59,321	$ 69,752	$ 4,599	$ 133,671	$ 53,938	$ 794,899	$ 126,601
2014	11	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2015	12	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2016	13	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2017	14	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2018	15	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2019	16	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2020	17	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2021	18	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2022	19	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2023	20	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2024	21	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total			**$ 532,161**	**$ 697,515**	**$ 45,990**	**$ 1,275,666**	**$ 794,899**		

PROPOSAL B

Assumptions

Heat Rate	7,200 Btu/kWh	After-tax CC	9.50%	Term Length	20 yrs
Inflation	2.5%	Fuel Costs	$ 3.50 /MMBtu	Variable O&M	$ 1.75 /MWh
Capacity	450 MW	Capacity Factor	70%	Capacity Payment	$ 75 /kW-yr

Annuity/MW ($000/MW): 254.40

Year	Equip Life	Capacity Payment ($/ kw-yr)	Capacity Costs ($000)	Energy Costs ($000)	Var O&M Costs ($000)	Total Costs ($000)	PV of Total Cost ($000)	Cumulative NPV ($000)	Annuity ($000)
2003		-	$ -	$ -	$ -	$ -	$ -	$ -	
2004	1	75.00	$ 33,750	$ 69,537	$ 4,829	$ 108,116	$ 98,736	$ 98,736	$ 114,480
2005	2	76.88	$ 34,594	$ 69,537	$ 4,829	$ 108,960	$ 90,873	$ 189,609	$ 114,480
2006	3	78.80	$ 35,459	$ 69,537	$ 4,829	$ 109,824	$ 83,648	$ 273,258	$ 114,480
2007	4	80.77	$ 36,345	$ 69,537	$ 4,829	$ 110,711	$ 77,008	$ 350,265	$ 114,480
2008	5	82.79	$ 37,254	$ 69,537	$ 4,829	$ 111,620	$ 70,904	$ 421,169	$ 114,480
2009	6	84.86	$ 38,185	$ 69,537	$ 4,829	$ 112,551	$ 65,293	$ 486,462	$ 114,480
2010	7	86.98	$ 39,140	$ 69,537	$ 4,829	$ 113,505	$ 60,134	$ 546,595	$ 114,480
2011	8	89.15	$ 40,118	$ 69,537	$ 4,829	$ 114,484	$ 55,390	$ 601,985	$ 114,480
2012	9	91.38	$ 41,121	$ 69,537	$ 4,829	$ 115,487	$ 51,028	$ 653,013	$ 114,480
2013	10	93.66	$ 42,149	$ 69,537	$ 4,829	$ 116,515	$ 47,015	$ 700,029	$ 114,480
2014	11	96.01	$ 43,203	$ 69,537	$ 4,829	$ 117,569	$ 43,325	$ 743,353	$ 114,480
2015	12	98.41	$ 44,283	$ 69,537	$ 4,829	$ 118,649	$ 39,929	$ 783,283	$ 114,480
2016	13	100.87	$ 45,390	$ 69,537	$ 4,829	$ 119,756	$ 36,806	$ 820,088	$ 114,480
2017	14	103.39	$ 46,525	$ 69,537	$ 4,829	$ 120,891	$ 33,931	$ 854,019	$ 114,480
2018	15	105.97	$ 47,688	$ 69,537	$ 4,829	$ 122,054	$ 31,285	$ 885,304	$ 114,480
2019	16	108.62	$ 48,880	$ 69,537	$ 4,829	$ 123,246	$ 28,850	$ 914,154	$ 114,480
2020	17	111.34	$ 50,102	$ 69,537	$ 4,829	$ 124,468	$ 26,608	$ 940,763	$ 114,480
2021	18	114.12	$ 51,355	$ 69,537	$ 4,829	$ 125,720	$ 24,544	$ 965,307	$ 114,480
2022	19	116.97	$ 52,638	$ 69,537	$ 4,829	$ 127,004	$ 22,644	$ 987,951	$ 114,480
2023	20	119.90	$ 53,954	$ 69,537	$ 4,829	$ 128,320	$ 20,894	$ 1,008,845	$ 114,480
2024	21	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total			**$ 862,132**	**$ 1,390,738**	**$ 96,579**	**$ 2,349,449**	**$ 1,008,845**		

Results	PV ($000)	Annuity ($000)	Annuity/MW ($000/MW)	
Proposal A	$ 794,899	$ 126,601	$ 253.20 /MW	(Winner)
Proposal B	$ 1,008,845	$ 114,480	$ 254.40 /MW	

EXHIBIT TWO
COMPARISON OF A 10-YEAR PROPOSAL (PROPOSAL A) TO A
5-YEAR PROPOSAL (PROPOSAL B)
USING THE REAL LEVELIZED REVENUE REQUIREMENT APPROACH

Assumptions

Discount Rate	10.00%	Inflation	2.00%	Proposal A	750 MW
Real Rate	7.84%			Proposal B	650 MW

PROPOSAL A

Year	Total Bid Price Costs ($000) (At 10%)	Real Annuity ($000) (At 7.84%)	Inflation Escalation	Inflation Adjusted Real Annuity ($000) (At 10%)	Capacity (MW)	Real Annuity MW (At 7.84%)	Inflation Adj. Real Annuity MW (At 10%)	Infl. Adj.Real Annuity /Infl. Adj. Real MW ($000/MW)
1	$ 95,000	$ 66,055	102%	$ 67,376	750	682	696	96.86
2	$ 89,000	$ 66,055	104%	$ 68,723	750	682	709	96.86
3	$ 83,000	$ 66,055	106%	$ 70,098	750	682	724	96.86
4	$ 77,000	$ 66,055	108%	$ 71,500	750	682	738	96.86
5	$ 71,000	$ 66,055	110%	$ 72,930	750	682	753	96.86
6	$ 65,000	$ 66,055	113%	$ 74,388	750	682	768	96.86
7	$ 59,000	$ 66,055	115%	$ 75,876	750	682	783	96.86
8	$ 53,000	$ 66,055	117%	$ 77,394	750	682	799	96.86
9	$ 47,000	$ 66,055	120%	$ 78,942	750	682	815	96.86
10	$ 41,000	$ 66,055	122%	$ 80,520	750	682	831	96.86
PV	$ 446,386	$ 446,386		$ 446,386	4,608	4,608	4,608	96.86

PROPOSAL A - TRUNCATED AT 5 YEARS

Year	Total Bid Price Costs ($000) (At 10%)	Real Annuity (At 7.84%)	Inflation Escalation	Inflation Adjusted Real Annuity ($000) (At 10%)	Capacity (MW)	Real Annuity MW (At 7.84%)	Inflation Adj, Real Annuity MW (At 10%)	Infl. Adj.Real Annuity /Infl. Adj. Real MW ($000/MW)
1	$ 95,000	$ 66,055	102%	$ 67,376	750	682	696	96.86
2	$ 89,000	$ 66,055	104%	$ 68,723	750	682	709	96.86
3	$ 83,000	$ 66,055	106%	$ 70,098	750	682	724	96.86
4	$ 77,000	$ 66,055	108%	$ 71,500	750	682	738	96.86
5	$ 71,000	$ 66,055	110%	$ 72,930	750	682	753	96.86
6	$ 65,000	$ 66,055	113%					
7	$ 59,000	$ 66,055	115%					
8	$ 53,000	$ 66,055	117%					
9	$ 47,000	$ 66,055	120%					
10	$ 41,000	$ 66,055	122%					
PV	$ 446,386	$ 446,386		$ 264,831			2,734	96.86

EXHIBIT TWO
COMPARISON OF A 10-YEAR PROPOSAL (PROPOSAL A) TO A
5-YEAR PROPOSAL (PROPOSAL B)
USING THE REAL LEVELIZED REVENUE REQUIREMENT APPROACH

PROPOSAL B

Year	Total Bid Price Costs ($000) (At 10%)	Real Annuity ($000) (At 7.84%)	Inflation Escalation	Inflation Adjusted Real Annuity ($000) (At 10%)	Capacity (MW)	Real Annuity MW (At 7.84%)	Inflation Adj. Real Annuity MW (At 10%)	Infl. Adj.Real Annuity /Infl. Adj. Real MW
1	$ 85,200	$ 66,865	102%	$ 68,202	650	615	627	108.80
2	$ 77,200	$ 66,865	104%	$ 69,567	650	615	639	108.80
3	$ 69,200	$ 66,865	106%	$ 70,958	650	615	652	108.80
4	$ 61,200	$ 66,865	108%	$ 72,377	650	615	665	108.80
5	$ 53,200	$ 66,865	110%	$ 73,825	650	615	679	108.80
6								
7								
8								
9								
10								
PV	$ 268,081	$ 268,081		$ 268,081	2,464	2,464	2,464	108.80

Results ($000/MW):

Proposal A	$ 96.86 /MW	(Winner)
Proposal B	$ 108.80 /MW	

EXHIBIT THREE
HOW A 5-YEAR PROPOSAL IS EXTENDED TO A
10-YEAR PROPOSAL USING THE FILLER METHOD

5-YEAR PROPOSAL

Assumptions

Capacity	500 MW	After-tax CC	9.5%	Fixed O&M	$ 4.50 /kW-yr
Capacity Factor	70%	Inflation	2.5%	Variable O&M	$ 1.50 /MWh
Term Length	5 yrs	Capacity Payment	$ 96.00 /kW-yr	Fuel Costs	$ 5.00 /MMBtu
Heat Rate	6,500 Btu/kWh				

Year	Proposal Year	Capacity Payment ($/ kW-yr)	Capacity Costs ($000)	Energy Costs ($000)	Fixed O&M Costs ($000)	Var O&M Costs ($000)	Total Costs ($000)	PV of Total Cost ($000)
2003		-	-	-	-	-	-	-
2004	1	96.00	$ 48,000	$ 99,645	$ 2,250	$ 4,599	$ 154,494	$ 141,090
2005	2	96.00	$ 48,000	$ 99,645	$ 2,250	$ 4,599	$ 154,494	$ 128,850
2006	3	96.00	$ 48,000	$ 99,645	$ 2,250	$ 4,599	$ 154,494	$ 117,671
2007	4	96.00	$ 48,000	$ 99,645	$ 2,250	$ 4,599	$ 154,494	$ 107,462
2008	5	96.00	$ 48,000	$ 99,645	$ 2,250	$ 4,599	$ 154,494	$ 98,139
2009	6	-	$ -	$ -	$ -	$ -	$ -	$ -
2010	7	-	$ -	$ -	$ -	$ -	$ -	$ -
2011	8	-	$ -	$ -	$ -	$ -	$ -	$ -
2012	9	-	$ -	$ -	$ -	$ -	$ -	$ -
2013	10	-	$ -	$ -	$ -	$ -	$ -	$ -
2014	11	-	$ -	$ -	$ -	$ -	$ -	$ -
2015	12	-	$ -	$ -	$ -	$ -	$ -	$ -
			$ 240,000	**$ 498,225**	**$ 11,250**	**$ 22,995**	**$ 772,470**	**$ 593,212**

5-YEAR PROPOSAL FILLED IN TO BE A 10-YEAR PROPOSAL

Assumptions

Capacity	500 MW	After-tax CC	9.5%	Fixed O&M	$ 4.50 /kW-yr
Capacity Factor	70%	Inflation	2.5%	Variable O&M	$ 1.50 /MWh
Term Length	10 yrs	Capacity Payment	$ 96.00 /kW-yr	Fuel Costs	$ 5.00 /MMBtu
Heat Rate	6,500 Btu/kWh				

Year	Proposal Year	Capacity Payment ($/ kW-yr)	Capacity Costs ($000)	Energy Costs ($000)	Fixed O&M Costs ($000)	Var O&M Costs ($000)	Total Costs ($000)	PV of Total Cost ($000)
2003		-	-	-	-	-	-	-
2004	1	96.00	$ 48,000	$ 99,645	$ 2,250	$ 4,599	$ 154,494	$ 141,090
2005	2	96.00	$ 48,000	$ 99,645	$ 2,250	$ 4,599	$ 154,494	$ 128,850
2006	3	96.00	$ 48,000	$ 99,645	$ 2,250	$ 4,599	$ 154,494	$ 117,671
2007	4	96.00	$ 48,000	$ 99,645	$ 2,250	$ 4,599	$ 154,494	$ 107,462
2008	5	96.00	$ 48,000	$ 99,645	$ 2,250	$ 4,599	$ 154,494	$ 98,139
2009	6	108.62	$ 54,308	$ 99,645	$ 2,546	$ 4,599	$ 161,097	$ 93,455
2010	7	111.33	$ 55,665	$ 99,645	$ 2,546	$ 4,599	$ 162,455	$ 86,066
2011	8	114.11	$ 57,057	$ 99,645	$ 2,546	$ 4,599	$ 163,847	$ 79,273
2012	9	116.97	$ 58,483	$ 99,645	$ 2,546	$ 4,599	$ 165,273	$ 73,026
2013	10	119.89	$ 59,945	$ 99,645	$ 2,546	$ 4,599	$ 166,735	$ 67,280
2014	11	-	$ -	$ -	$ -	$ -	$ -	$ -
2015	12	-	$ -	$ -	$ -	$ -	$ -	$ -
2016	13	-	$ -	$ -	$ -	$ -	$ -	$ -
2017	14	-	$ -	$ -	$ -	$ -	$ -	$ -
2018	15	-	$ -	$ -	$ -	$ -	$ -	$ -
			$ 525,459	**$ 996,450**	**$ 23,978**	**$ 45,990**	**$ 1,591,877**	**$ 992,312**

Results:	Present Value
5-Year Proposal	$ 593,212 /MW
Filled In 10-Year Proposal	$ 992,312 /MW

Attachment C

Docket No. ER20-924

Expedited Request for Partial Rehearing

By the Solar Energy Industries Association

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PacifiCorp	**Docket Nos. ER20-924**

EXPEDITED REQUEST FOR PARTIAL REHEARING
BY THE SOLAR ENERGY INDUSTRIES ASSOCIATION

Pursuant to Section 313 of the Federal Power Act ("FPA"), 16 U.S.C. § 825*l*, and Rule 713 of the Federal Energy Regulatory Commission's ("FERC") or ("Commission") Rules of Practice and Procedure, 18 C.F.R. §§ 385. 713 (2019), the Solar Energy Industries Association ("SEIA")[1] respectfully submits this Expedited Request for Partial Rehearing of the Commission's May 12, 2020 Order on Tariff Revisions (the "May 12 Order").[2] SEIA respectfully request that the Commission act on this Request expeditiously. As explained below, PacifiCorp did not provide notice of the January 31, 2020 cutoff date, nor were parties informed that failure to submit a request by January 31, 2020 would negatively impact their ability to participate in the upcoming solicitation where PacifiCorp is expected to procure close to 5 GW of capacity and satisfy its resource needs through 2024. Accordingly, SEIA submits this expedited request for partial rehearing requesting that the Commission reconsider paragraph 148 of the May 12 Order and set the Transition Cluster cutoff date at or after May 19, 2020 (five business days after issuance of the May 12 Order).

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[1] The comments contained in this filing represent the position of SEIA as a trade organization on behalf of the solar industry, but do not necessarily reflect the views of any particular member with respect to any issue. Entities that participated in PacifiCorp's stakeholder process, including the leading independent power producers, are SEIA members and contributed to this submission.

[2] *PacifiCorp*, 171 FERC ¶ 61,112 (2020) ("May 12 Order"). This filing is limited to the one issue SEIA requests the Commission to review on an emergency basis SEIA reserves its other challenges to the May 12 Order.

I. Statement of the Issue

SEIA seeks expedited rehearing of Paragraph 148 of the May 12 Order, where the Commission erroneously concluded that the January 31, 2020 cutoff date proposed by PacifiCorp was reasonable. As explained further herein, and as parties explained in their Protests and Comments, PacifiCorp did not provide notice that the Transition Cluster would have a cutoff date; much less that the cutoff date would be the date of PacifiCorp's submission (January 31, 2020). Further, stakeholders were not informed that failure to be included in the Transition Cluster would negatively impact their evaluation in the upcoming solicitation. Rather, as SEIA previously-explained, stakeholders were led to believe that PacifiCorp would accept interconnection requests after the reforms were filed, but before the RFP was initiated, and many stakeholders were reserving their new project interconnection requests until such time as PacifiCorp submitted its reform proposal.[3] Because stakeholders were not provided notice, and the lack of notice will cause irreparable injury, the Commission should establish a cutoff date for the Transition Cluster on or after May 19, 2020 (five business days following issuance of the Commission's order).[4]

II. Specification of Error

Pursuant to Rule 713(c)(1), SEIA submits the following specification of error:

[3] *See* Supplemental Protest of the Solar Energy Industries Association at 28-29, Docket No. ER20-924 (Apr. 10, 2020) ("SEIA Supplemental Protest").

[4] SEIA does not support PacifiCorp's proposal to establish the cutoff date at April 1, 2020 because that too suffers from the same failure – parties were not provided notice. PacifiCorp offered this concession in a submission made *after* April 1; thus, the only parties that could benefit from this concession are those that ignored the directives and submitted requests even after PacifiCorp notified its customers that the window had closed. Parties should now be on notice that if they wish to be included in the Transition Cluster their requests must be submitted on or before May 19, 2020

The May 12 Order erred in approving the proposed January 31, 2020 cutoff date for the Transition Cluster because stakeholders were not provided notice and will suffer irreparable injury; establishing a cutoff date of May 19, 2020 is just and reasonable and will further the public interest.

III. Background

As explained in the Application,[5] PacifiCorp's timeframe for the proposed revisions to its interconnection process and procedures are driven by PacifiCorp's procurement plans. PacifiCorp intends to open a solicitation for approximately 5 GW of new generation that will fulfill its resource capacity needs through 2024.[6] This is anticipated to be the largest RFP ever conducted by PacifiCorp and presents a significant and substantial opportunity for consumers and competitors in the West.[7] Inclusion in the Transition Cluster is material to the participation in the solicitation.

As the staff of the Oregon Public Utility Commission ("OPUC") explained in its opening comments, PacifiCorp's existing interconnection practice was presenting "significant challenges to PacifiCorp's acquisition of least-cost, least-risk resources to serve its retail customers."[8] The OPUC, as well as a number of other parties, premised their support for PacifiCorp's proposed revisions "on PacifiCorp's intention to have interconnection queue reform align with PacifiCorp's planned 2020

[5] *See* PacifiCorp submits tariff filing per 35.13(a)(2)(iii): OATT Queue Reform to be effective 4/1/2020, Docket No. ER20-924 (Jan. 31, 2020) ("Application").

[6] *See* PacifiCorp's 2020 All-Source Request for Proposals, https://www.pacificorp.com/suppliers/rfps/all-source-rfp.html; *see also, PacifiCorp Readies Huge Solicitation of Renewables, Energy Storage*, GREENTECH MEDIA (May 11, 2020), *available at*: https://www.greentechmedia.com/articles/read/pacificorp-prepares-gigawatt-scale-solar-plus-storage-wind-power-solicitation.

[7] *Id.*

[8] Comments of the Oregon Public Utility Commission Staff at 1, Docket No. ER20-924 (Feb. 21, 2020).

Request for Proposals (RFP) for new resources."[9] As these parties explained, failure to align the interconnection queue reforms "could affect the ability of generators to participate in the Transition Process and therefore the reasonableness of PacifiCorp's ultimate resource selection in its 2020 RFP."[10]

As parties explained to the Commission, at no time did PacifiCorp give stakeholders any notice that its application, filed January 31, 2020, would close the queue from that date forward and that the queue would remain closed until April 2021.[11] PacifiCorp did not indicate that the filing date would be used as an eligibility cutoff date for participation in the Transition Cluster Study; PacifiCorp did not notify stakeholders of when it would file its proposed revisions with FERC, nor did PacifiCorp give stakeholders a draft of proposed tariff revisions to review prior to filing, which would have given parties notice of the potential cutoff date.[12] Since no cluster studies are underway

[9] *Id.* at 2.

[10] *Id.* at 2-3. *See also* Comments of Renewable Northwest at 2, Docket No. ER20-924 (Feb. 21, 2020) ("It is especially important that PacifiCorp shift to a cluster study approach soon in order to facilitate participation in PacifiCorp's All-Source Request For Proposals process, which is expected to begin later in 2020, as well as any other procurement processes that may be held in the near future in the region. "); Protest of Northwest and Intermountain Power Producers Coalition to March 13, 2020 PacifiCorp Tariff Filing, Docket No. ER20-924 (Apr. 10, 2020) ("Extending the eligibility date will allow more robust participation in both the Transition Cluster and the PacifiCorp procurement RFP targeted for the fall of 2020"); Interwest Comments, Docket No. ER20-924 (Apr. 10, 2020) ("explaining that the January 31, 2020 cutoff date "will likely cause many potentially cost-effective potential bidders to be disqualified from the Transitional Cluster without any prior notice or any opportunity to comply with tariff requirements, which PacifiCorp has now postured as a fundamental requirement to be qualified as an eligible bidder in the 2020 RFP).

[11] *See, e.g.,* Renewable Northwest Comments at 4.

[12] *Id.*

right now, adding new requests, whether those requests were submitted in January or in June, will not add any delays to this Transition Cluster Study which has not started yet.

IV. Request for Expedited Rehearing

SEIA respectfully requests rehearing of the conclusion Paragraph 148 of the May 12 Order where the Commission "agree[d] with PacifiCorp that its January 31, 2020 cutoff date is reasonable."[13] In the Protests and Comments, parties explained that forcing interconnection customers who did not have notice to wait until April of 2021 to enter the Prospective Process is unjust and unreasonable and exposes parties to irreparable injury. In its Supplemental Protest, SEIA requested that the Commission allow a notice period of 15-30 days after publication of the order, a request that was made by other commenters including Renewable Northwest, Northwest Intermountain Power Producer Coalition, and Interwest Energy Alliance, among others.[14] SEIA respectfully requests that the Commission rehear this issue and, at a minimum, establish a cutoff date of May 19, 2020 (five business days after issuance of the Commission's order).

As SEIA's members understand; inclusion in the Transition Cluster is a prerequisite to evaluation in the upcoming solicitation. SEIA's members understand that while PacifiCorp will select bids initially with a blind eye towards interconnection costs, further evaluation will require that a project either holds an LGIA or is being studied through the Transition Cluster process. Thus, projects not eligible for inclusion in the Transition Cluster process will face a disadvantage because interconnection costs are not known or knowable until the Prospective Process initiates. If PacifiCorp intends to evaluate on equal footing through the process both projects in the Transition

[13] May 12 Order at P 148.

[14] SEIA Supplemental Protest at 28-29.

Process and projects in the April 2021 Prospective Process such that there is no disadvantage to being included in the April 2021 cluster, then SEIA welcomes the clarification and will withdraw this expedited request for partial rehearing.

As highlighted above, at no time during the stakeholder process did PacifiCorp inform its customers that it was considering establishing a cutoff date for the Transition Cluster that coincided with the date of PacifiCorp's submission to FERC. Rather, as SEIA explained in its Supplemental Protest, stakeholders were led to believe that there would be no harm submitting an interconnection request after PacifiCorp filed its application with FERC.[15] PacifiCorp never corrected stakeholder's assumptions on this point. PacifiCorp did not inform parties that it would submit its filing on January 31 and, while parties were on notice that PacifiCorp intended to submit its filing to FERC in early 2020, parties had no awareness of the specific date at which PacifiCorp intended to file.

Projects that did not have notice of the January 31, 2020 date, but otherwise intended to participate in the upcoming solicitation, now face irreparable injury if they are not able to enter the Transition Cluster. The purpose of the Section 205 requirement mandating that public utilities to file rates and charges for jurisdictional service at least 60 days in advance of service is to ensure that customers are provided notice of such changes and that unjust injuries are avoided. PacifiCorp has not initiated the Transition Cluster study and has not provided any explanation as to the harm in allowing additional parties to enter the Transition Cluster.[16] By failing to provide any notice, or indication, that a January 31, 2020 cutoff date would be included in the proposal, developers that

[15] SEIA Supplemental Protest 28-29.

[16] *Compare* Comments of Renewable Northwest on March 13, 2020 PacifiCorp Tariff Filing at 3-5, Docket No. ER20-924 (Apr. 10, 2020).

were on track to submit interconnection applications in early February 2020 found themselves unexpectedly disadvantaged. SEIA's members that were preparing interconnection request applications during this timeframe would have, in many cases, completed the requests by January 31, 2020 had they been provided notice of the potential of a cutoff date.

In their stakeholder comments, Resource Acquisition expressed that "its desired outcome from queue reform is *more* robust third-party competition in the 2020 all-source RFP, not less."[17] There appears to be no harm in establishing the Transition Cluster cutoff date after the issuance of the May 12 Order. There is, however, substantial harm and irreparable injury in retaining the January 31, 2020 cutoff date. Retaining a January 31, 2020 cutoff date (of which customers had no notice) and failing to extend the cutoff date will result in fewer bids for PacifiCorp to evaluate and fewer choices for the ratepayers within the territory. It is not clear that PacifiCorp intends to conduct further solicitations within the next 5-7 years. Given the size and scope of the upcoming RFP, it is essential that all parties with viable projects be eligible to submit offers into the solicitation for the utility's consideration. Accordingly, SEIA respectfully requests that the Commission act expeditiously and reconsider the holding in paragraph 148. SEIA requests the Commission establish the cutoff date at least five business days after issuance of the May 12 Order, allow all projects that submitted an interconnection request on or before May 19, 2020 to be eligible for the Transition Cluster. A January 31, 2020 cutoff date does not serve the public interest.

[17] Resource Acquisition Comments at 1. All stakeholder comments are available on PacifiCorp's OASIS site under the following folder structure: "Interconnection Queue Reform 2019" – "Straw Proposal" – "Stakeholder Comments Received."

V. CONCLUSION

For the foregoing reasons, SEIA respectfully requests that the Commission act expeditiously to reconsider and rehear the question of a just and reasonable cutoff date for the Transition Cluster. Establishing a cutoff date of May 19, 2020 (five business days after issuance of the Commission's order) will prevent irreparable injury and will serve the public interest by ensuring maximum participation in the upcoming solicitation.

Respectfully submitted,

/s/ Todd Glass
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Counsel to the Solar Energy Industries Association

May 15, 2020

CERTIFICATE OF SERVICE

The undersigned certifies that a copy of this pleading has been served this day upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated this 15th day of May, 2020 in Seattle, WA.

/s/ Heather Curlee

Attachment D

PacifiCorp Generation Interconnection Queue

As of: 5/11/2020 Active: PacifiCorp Generation Interconnection Queue

	Interconnect Request Information					Max MW Output		Location of Generating Facility			Location of Interconnection			Reports					
Q#	Request Date	Request Status	Company Name	Service Type	Application Rules	S	W	County	ST	Region	Point of Interconnection	Customer Re(	Type	Feasibility Study / Fast Track	System Impact Study	Facilities udy	St	Optional Study	Schedule Deviation
718	11/6/2015	In Progress	0	ER	LGI	400	400	Lake	OR	PACW	Burns-Summer Lake transmission line	12/1/2019	Wind	Available	Available	Available			More info
723	12/10/2015	In Progress	0	NR/ER	LGI	750	750	Custer	MT	PACE	Colstrip substation	9/1/2018	Wind	Available					
739	4/29/2016	In Progress	0	ER	LGI	59	59	Crook	OR	PACW	Baldwin Road substation	8/1/2018	Solar	Available	Available	Available			More info
789	8/8/2016	In Progress	0	ER	LGI	75	75	Fremont	WY	PACE	Riverton-Thermopolis transmission line	9/30/2019	Solar		Available	Available			More info
837	12/5/2016	In Progress	0	ER	LGI	450	450	Meagher	MT	PACE	Colstrip transmission line	12/30/2020	Pump Storage						
838	12/8/2016	In Progress	0	NR	LGI	525	525	Tooele	UT	PACE	Clover-Oquirrh transmission line	12/1/2018	Solar		Available				More info
839	12/8/2016	In Progress	0	NR	LGI	525	525	Utah	UT	PACE	Clover-Oquirrh transmission line	12/1/2018	Solar						More info
848	2/2/2017	In Progress	0	NR/ER	LGI	300	300	Yellowstone	MT	PACE	Broadview substation (Colstrip transmission line)	12/1/2020	Solar						
854	3/14/2017	In Progress	0	NR/ER	LGI	190	190	Kane	UT	PACE	Sigurd-Glen Canyon transmission line	12/31/2020	Solar						More info
855	3/17/2017	In Progress	0	NR	LGI	80	80	Converse	WY	PACE	Amasa substation	12/31/2019	Wind	Available	Available	Available			More info
858	4/5/2017	In Progress	PacifiCorp Energy Supply Management	ER	LGI	26	26	Carbon	WY	PACE	Shirley Basin	12/1/2020	Wind		Available	Available			More info
859	4/5/2017	In Progress	PacifiCorp Energy Supply Management	ER	LGI	43	43	Converse	WY	PACE	Windstar substation	7/1/2019	Wind		Available	Available			More info
860	4/5/2017	In Progress	PacifiCorp Energy Supply Management	NR/ER	LGI	30	30	Carbon	WY	PACE	Foote Creek substation	11/1/2019	Wind						More info
861	4/5/2017	In Progress	PacifiCorp Energy Supply Management	NR/ER	LGI	28	28	Carbon	WY	PACE	Freezeout substation	5/1/2019	Wind						More info
863	4/10/2017	In Progress	PacifiCorp Energy Supply Management	NR	LGI	110	110	Carbon	WY	PACE	Foote Creek substation	11/1/2020	Wind		Available				More info
864	4/12/2017	In Progress	0	NR	LGI	78	78	Iron	UT	PACE	Three Peaks substation	6/1/2020	Solar						More info
865	4/12/2017	In Progress	0	NR	LGI	78	78	Iron	UT	PACE	West Cedar substation	6/1/2020	Solar						More info
871	5/5/2017	In Progress	0	NR/ER	LGI	100	100	Juab	UT	PACE	Mona substation	12/1/2020	Solar						More info
872	5/5/2017	In Progress	0	NR/ER	LGI	500	500	Carbon	WY	PACE	Aeolus substation	12/31/2020	Wind						More info
875	5/11/2017	In Progress	0	ER	SGI	20	20	Fremont	WY	PACE	Circuit WCM342 out of WAPA Copper Mountain substation	12/1/2018	Solar						More info
876	5/12/2017	In Progress	PacifiCorp Energy Supply Management	NR/ER	LGI	22	22	Carbon	WY	PACE	Foote Creek substation	9/1/2019	Wind						More info
882	5/22/2017	In Progress	0	NR	SGI	15	15	Carbon	WY	PACE	Freezeout substation OR Aeolus substation	11/1/2020	Wind						More info
898	6/23/2017	In Progress	0	NR/ER	LGI	202	202	Juab	UT	PACE	Clover substation	12/1/2020	Solar & Battery Storage						More info
905	7/12/2017	In Progress	0	NR	LGI	50	50	Klamath	OR	PACW	Copco 2 - Westside Tap to Klamath Falls line (Line 18)	12/1/2019	Solar	Available	Available				More info
915	7/28/2017	In Progress	0	ER	LGI	80	80	Klamath	OR	PACW	Captain Jack - Meridian transmission line	12/1/2019	Solar	Available	Available				More info
916	7/28/2017	In Progress	0	ER	LGI	80	80	Klamath	OR	PACW	Captain Jack - Meridian transmission line	12/1/2019	Solar	Available	Available				More info
917	7/28/2017	In Progress	0	ER	LGI	80	80	Klamath	OR	PACW	Captain Jack - Meridian transmission line	12/1/2019	Solar	Available	Available				More info
920	8/1/2017	In Progress	0	NR/ER	LGI	630	630	Albany	WY	PACE	Aeolus substation	6/15/2020	Wind						More info
925	8/9/2017	In Progress	0	NR/ER	LGI	300	300	Platte	WY	PACE	Aeolus substation	12/31/2020	WInd						More info
926	8/9/2017	In Progress	0	NR/ER	LGI	300	300	Platte	WY	PACE	Aeolus substation	12/31/2020	WInd						More info
927	8/9/2017	In Progress	0	NR/ER	LGI	600	600	Platte	WY	PACE	Aeolus substation	12/31/2020	WInd						More info
928	8/9/2017	In Progress	0	NR/ER	LGI	300	300	Platte	WY	PACE	Foote Creek substation	12/31/2020	WInd						More info
929	8/9/2017	In Progress	0	NR/ER	LGI	300	300	Platte	WY	PACE	Foote Creek substation	12/31/2020	WInd						More info
933	8/9/2017	In Progress	0	NR/ER	LGI	300	300	Albany	WY	PACE	Windstar substation	12/31/2020	WInd						More info
934	8/9/2017	In Progress	0	NR/ER	LGI	300	300	Albany	WY	PACE	Windstar substation	12/31/2020	WInd						More info
935	8/9/2017	In Progress	0	NR/ER	LGI	300	300	Albany	WY	PACE	Shirley Basin substation	12/31/2020	WInd						More info
936	8/9/2017	In Progress	0	NR/ER	LGI	300	300	Albany	WY	PACE	Shirley Basin substation	12/31/2020	WInd						More info
937	8/9/2017	In Progress	0	NR/ER	LGI	250	250	Big Horn	MT	PACE	Yellowtail substation	12/31/2020	WInd						More info
938	8/21/2017	In Progress	0	NR	LGI	40	40	Beaver	UT	PACE	Sulpherdale-Tushar transmission line	9/30/2018	Solar						More info
940	8/24/2017	In Progress	0	NR/ER	LGI	576	576	Carbon	WY	PACE	Shirley Basin substation	1/12/2020	Wind						More info
947	9/19/2017	In Progress	0	NR/ER	LGI	248	248	Carbon	WY	PACE	Shirley Basin substation	1/12/2020	Wind						More info
948	9/19/2017	In Progress	0	NR/ER	LGI	248	248	Carbon	WY	PACE	Shirley Basin substation OR Aeolus substation	1/12/2020	Wind						More info
949	9/19/2017	In Progress	0	NR/ER	LGI	248	248	Carbon	WY	PACE	Shirley Basin substation OR Heward substation	1/12/2020	Wind						More info
950	9/20/2017	In Progress	0	ER	LGI	50	50	Natrona	WY	PACE	Sheridan-Yellowtail-Casper transmission line	12/1/2019	Solar						More info
951	9/20/2017	In Progress	0	ER	LGI	80	80	Fremont	WY	PACE	Mustang - Spence transmission line	12/1/2019	Solar						More info
953	9/27/2017	In Progress	0	NR	LGI	100	100	Yakima	WA	PACW	Union Gap - Midway transmission line	1/1/2020	Solar	Available	Available				More info
966	10/20/2017	In Progress	0	NR	UGI	20	20	Juab	UT	PACE	Nebo-Vickers-Scipio line	7/31/2018	Solar						More info
971	11/7/2017	In Progress	0	NR	OGI	3	3	Klamath	OR	PACW	Turkey Hill substation	12/15/2019	Solar	Available	Available	Available			
974	11/15/2017	In Progress	0	NR	LGI	80	80	Lincoln	WY	PACE	Naughton-Treasureton transmisison line	12/31/2019	Solar		Available	Available			More info
975	11/16/2017	In Progress	0	NR/ER	LGI	101	101	Juab	UT	PACE	Clover substation	12/1/2020	Solar & Battery Storage						More info
976	11/20/2017	In Progress	0	NR/ER	LGI	525	525	Utah	UT	PACE	Camp Williams - Mona #4 OR Camp Williams - Mona #2	12/1/2020	Solar						More info
978	11/20/2017	In Progress	0	NR/ER	LGI	525	525	Box Elder	UT	PACE	Ben Lomond-Populus #2 line	12/1/2020	Solar						More info
979	11/21/2017	In Progress	0	NR/ER	LGI	160	160	Utah	UT	PACE	Camp Williams-Mona #4 line OR Mona substation	12/1/2021	Solar						More info
980	11/27/2017	In Progress	0	NR/ER	LGI	200	200	Box Elder	UT	PACE	Populus-Ben Lomond #1 line OR Populus-Ben Lomond #2 line	9/30/2020	Solar						More info
981	11/27/2017	In Progress	0	NR/ER	LGI	100	100	Box Elder	UT	PACE	Populus-Ben Lomond #1 line OR Populus-Ben Lomond #2 line	9/30/2020	Solar						More info
982	11/29/2017	In Progress	0	NR/ER	LGI	300	300	Utah	UT	PACE	Camp Williams-Mona #4 line OR Camp Williams-Mona #3 line	11/30/2020	Solar						More info
985	11/30/2017	In Progress	0	NR/ER	LGI	300	300	Utah	UT	PACE	Camp Williams-Mona #4 line	12/1/2020	Solar						More info
986	12/8/2017	In Progress	0	NR/ER	LGI	600	600	Beaver	UT	PACE	Red Butte-Sigurd #2 line	12/31/2020	Solar						More info
993	12/18/2017	In Progress	0	NR/ER	LGI	75	75	Weber	UT	PACE	Ben Lomond-Western Zirconium line	10/31/2020	Solar						More info
994	12/21/2017	In Progress	0	NR	LGI	40	40	Converse	WY	PACE	Latigo substation	12/31/2019	Solar						More info
995	12/21/2017	In Progress	0	NR	LGI	40	40	Converse	WY	PACE	Latigo substation	12/31/2019	Solar						More info

997	12/27/2017	In Progress	0	NR/ER	LGI	300	300	Iron	UT	PACE	Sigurd-Red Butte #1 OR Sigurd-Red Butte #2 line	12/30/2020	Solar			More info
999	1/8/2018	In Progress	0	NR	LGI	50	50	Tooele	UT	PACE	Tooele-Horseshoe line	12/31/2019	Solar	Available	Available	More info
1000	1/15/2018	In Progress	0	NR/ER	LGI	120	120	Weber	UT	PACE	Ben Lomond-Western Zirconium line	10/31/2020	Solar			More info
1004	2/12/2018	In Progress	0	ER	SGI	25	25	Box Elder	UT	PACE	Thiokol-Plant 78 line	12/31/2019	Solar			More info
1005	2/15/2018	In Progress	0	NR/ER	LGI	50	50	Summit	UT	PACE	Evanston-Anschutz line	10/31/2020	Wind			More info
1006	3/6/2018	In Progress	0	NR/ER	LGI	60	60	Carbon	UT	PACE	Mathington substation	12/1/2019	Solar			More info
1008	3/8/2018	In Progress	0	NR/ER	LGI	100	100	Yakima	WA	PACW	Union Gap - Midway line	12/1/2020	Solar		Available	
1009	3/16/2018	In Progress	0	NR/ER	LGI	32	32	Tooele	UT	PACE	Tooele-Mercur line	12/31/2019	Solar	Available	Available	
1010	3/16/2018	In Progress	0	NR	LGI	33	33	Box Elder	UT	PACE	Thiokol-Honeyville line	8/1/2019	Solar			More info
1013	3/27/2018	In Progress	0	NR	LGI	80	80	Converse	WY	PACE	Latigo substation	6/30/2020	Solar			More info
1014	3/29/2018	In Progress	0	NR/ER	LGI	100	100	Carbon	WY	PACE	Shirley Basin substation	12/1/2020	Wind			More info
1015	3/29/2018	In Progress	0	NR/ER	LGI	501	501	Carbon	WY	PACE	Aeolus substation	12/1/2020	Wind			More info
1016	3/29/2018	In Progress	0	NR/ER	LGI	501	501	Carbon	WY	PACE	Aeolus substation	12/1/2020	Wind			More info
1019	4/26/2018	In Progress	0	NR	OLGI	80	80	Linn	OR	PACW	Fry substation	12/1/2021	Solar	Available	Available	
1023	5/10/2018	In Progress	0	NR/ER	LGI	50	50	Tooele	UT	PACE	Tooele Depot substation	12/31/2020	Solar			More info
1024	5/10/2018	In Progress	0	NR/ER	LGI	100	100	Cache	UT	PACE	Bridgerland-Green Canyon transmission line	12/31/2020	Solar			More info
1027	5/17/2018	In Progress	0	NR/ER	LGI	251	251	Tooele	UT	PACE	Clover-Oquirrh transmission line	12/1/2022	Solar & Battery Storage			More info
1028	5/17/2018	In Progress	0	NR/ER	LGI	251	251	Tooele	UT	PACE	Clover-Oquirrh transmission line	12/1/2022	Solar & Battery Storage			More info
1029	5/29/2018	In Progress	0	NR/ER	LGI	400	400	Lake	OR	PACW	Hemmingway-Summer Lake transmission line	12/1/2021	Solar	Available	Available	
1031	5/30/2018	In Progress	0	NR/ER	LGI	80	80	Harney	OR	PACW	Hemmingway-Summer Lake transmission line	12/1/2020	Solar			
1032	5/30/2018	In Progress	0	NR/ER	LGI	80	80	Harney	OR	PACW	Hemmingway-Summer Lake transmission line	12/1/2020	Solar			
1033	5/30/2018	In Progress	0	NR/ER	LGI	80	80	Harney	OR	PACW	Hemmingway-Summer Lake transmission line	12/1/2020	Solar			
1034	6/5/2018	In Progress	0	NR/ER	LGI	60	60	Lake	OR	PACW	Alturas-Mile Hi transmission line	11/30/2020	Solar			
1035	6/8/2018	In Progress	0	NR/ER	LGI	100	100	Utah	UT	PACE	Camp Williams - Mona transmission line	12/1/2021	Solar			More info
1036	6/8/2018	In Progress	0	NR/ER	LGI	100	100	Utah	UT	PACE	Camp Williams - Mona transmission line	12/15/2021	Solar			More info
1037	6/8/2018	In Progress	PacifiCorp Energy Supply Management	NR/ER	LGI	35	35	Iron	UT	PACE	West Cedar substation	11/23/2021	Solar			More info
1038	6/11/2018	In Progress	0	NR/ER	LGI	200	200	Utah	UT	PACE	Camp Williams - Mona transmission line	12/15/2021	Battery			More info
1039	6/11/2018	In Progress	0	NR/ER	LGI	30	30	Cache	UT	PACE	Bridgerland-Green Canyon transmission line	12/31/2020	Solar			More info
1043	6/26/2018	In Progress	0	ER	OGI	3	3	Klamath	OR	PACW	Circuit 5L58 out of Henley substation	7/1/2020	Solar		Available	
1045	7/5/2018	In Progress	0	NR	OGI	3	3	Umatilla	OR	PACW	Circuit 5W406 out of Pilot Rock substation	12/31/2019	Solar		Available	
1047	7/16/2018	In Progress	0	NR/ER	LGI	50	50	Utah	UT	PACE	Santaquin-Nebo #2 Burgin Tap transmission line	6/1/2020	Solar			More info
1048	7/16/2018	In Progress	0	NR/ER	LGI	50	50	Utah	UT	PACE	Santaquin-Nebo #2 Burgin Tap transmission line	6/1/2020	Solar			More info
1049	7/16/2018	In Progress	0	NR/ER	LGI	300	300	Utah	UT	PACE	Camp Williams-Four Corners transmission line	12/1/2020	Solar			More info
1050	7/16/2018	In Progress	0	NR/ER	LGI	300	300	Utah	UT	PACE	Camp Williams-Mona #1 OR #2 transmission line	12/1/2020	Solar			More info
1051	7/24/2018	In Progress	0	NR/ER	LGI	100	100	Utah	UT	PACE	Camp Williams - Mona transmission line	12/15/2021	Solar			More info
1052	7/24/2018	In Progress	0	NR/ER	LGI	100	100	Utah	UT	PACE	Camp Williams - Mona transmission line	12/15/2021	Solar			More info
1053	7/26/2018	In Progress	0	NR/ER	LGI	50	50	Millard	UT	PACE	Pavant-Delta transmission line OR McCornick substation	11/30/2020	Solar			More info
1054	7/26/2018	In Progress	0	NR/ER	LGI	30	30	Millard	UT	PACE	Delta – McCornick transmission line OR McCornick substation	11/30/2020	Solar			More info
1055	7/27/2018	In Progress	0	NR	SGI	4	4	Shasta	CA	PACW	Castella substation	12/31/2018	Hydro			
1056	8/8/2018	In Progress	0	NR/ER	LGI	100	100	Juab	UT	PACE	Ashgrove-Clover transmission line	12/31/2021	Solar			More info
1058	8/14/2018	In Progress	0	ER	OGI	3	3	Klamath	OR	PACW	Circuit 4L16 out of Casebeer	9/1/2019	Solar			More info
1059	8/14/2018	In Progress	0	ER	OGI	3	3	Klamath	OR	PACW	Circuit 5L14 out of the Bly substation	9/1/2019	Solar			More info
1062	8/15/2018	In Progress	0	NR/ER	LGI	240	240	Klamath	OR	PACW	Klamath Falls-Malin transmission line	12/31/2022	Solar			More info
1063	8/16/2018	In Progress	0	ER	SGI	5	5	Siskiyou	CA	PACW	McCloud substation	9/30/2019	Solar			More info
1065	9/13/2018	In Progress	0	NR	LGI	600	600	Butte	ID	PACE	Antelope substation	9/1/2026	Nuclear			More info
1066	9/17/2018	In Progress	0	ER	LGI	750	750	Prairie	MT	PACE	Colstrip substation	9/1/2021	Wind			
1067	9/17/2018	In Progress	0	ER	LGI	750	750	Prairie	MT	PACE	Colstrip substation	9/1/2021	Wind			
1068	9/17/2018	In Progress	0	ER	WGI	3	3	Yakima	WA	PACW	White Swan substation OR Circuit 5Y690 out of White Swan substation	12/30/2019	Solar			More info
1069	9/17/2018	In Progress	0	NR	SGI	5	5	Yakima	WA	PACW	White Swan substation OR Circuit 5Y690 out of White Swan substation	12/30/2019	Solar			More info
1070	9/21/2018	In Progress	0	NR/ER	LGI	400	400	Utah	UT	PACE	Camp Willams – Mona #1 transmission line OR Camp Williams-Mona #4 transmission line	12/31/2021	Solar			More info
1071	10/5/2018	In Progress	0	NR	SGI	3	3	Yakima	WA	PACW	Circuit 5Y312 out of Sunnyside substation	12/31/2020	Solar			More info
1072	10/5/2018	In Progress	0	NR	SGI	2	2	Yakima	WA	PACW	Circuit 5Y312 out of Sunnyside substation	12/31/2020	Solar			More info
1073	10/8/2018	In Progress	0	NR/ER	LGI	160	160	Juab	UT	PACE	Mona substation	12/1/2021	Solar			More info
1074	10/8/2018	In Progress	0	NR/ER	LGI	160	160	Utah	UT	PACE	Camp Williams-Mona #4 transmission line	12/1/2021	Solar			More info
1076	10/15/2018	In Progress	0	NR/ER	LGI	58	58	Lincoln	WY	PACE	Naughton-Treasurton transmission line	12/1/2020	Solar			More info
1078	10/23/2018	In Progress	0	NR	LGI	80	80	Lincoln	WY	PACE	Naughton – Treasureton transmission line	12/31/2021	Solar			More info
1080	10/29/2018	In Progress	0	NR/ER	LGI	75	75	Lincoln	WY	PACE	Chappel Creek substation	12/1/2022	Solar			More info
1081	10/29/2018	In Progress	0	NR/ER	LGI	75	75	Lincoln	WY	PACE	Chappel Creek substation	12/1/2022	Solar			More info
1083	11/5/2018	In Progress	0	NR	LGI	80	80	Rich	UT	PACE	Birch Creek-Railroad transmission	12/31/2021	Solar			More info
1084	11/5/2018	In Progress	0	NR	SGI	3	3	Yakima	WA	PACW	Circuit 5Y441 out of Hopland substation	12/31/2020	Solar			More info
1085	11/13/2018	In Progress	0	NR/ER	LGI	80	80	Sublette	WY	PACE	Chimney Butte substation	11/30/2020	Solar			More info
1087	11/26/2018	In Progress	0	NR/ER	LGI	50	50	Lake	OR	PACW	Alturas-Mile Hi transmission line	12/31/2020	Solar			More info
1092	12/6/2018	In Progress	0	NR/ER	LGI	200	200	Millard	UT	PACE	Pavant substation	12/31/2020	Solar			More info
1093	12/6/2018	In Progress	0	NR/ER	LGI	600	600	Crook	OR	PACW	Corral substation OR Corral-Ochoco transmission line	5/30/2021	Solar & Battery Storage			More info
1094	12/13/2018	In Progress	0	NR	LGI	80	80	Rich	UT	PACE	Birch Creek-Railroad transmission line	12/31/2022	Solar & Battery Storage			More info
1095	12/13/2018	In Progress	0	NR	LGI	50	50	Sweetwater	WY	PACE	Raven substation	12/31/2022	Solar & Battery Storage			More info
1096	12/28/2018	In Progress	0	ER	SGI	4	4	Box Elder	UT	PACE	Cutler-El Monte Vulcraft Tap transmission line	2/1/2019	Solar			More info
1097	1/9/2019	In Progress	0	NR	OGI	3	3	Polk	OR	PACW	Circuit 4M22 out of Independence substation	4/15/2020	Solar			More info

1098	1/9/2019	In Progress	0	NR	OGI	3	3	Polk	OR	PACW	Circuit 4M22 out of Independence substation	4/15/2020	Solar		More info
1099	1/9/2019	In Progress	0	ER	OGI	3	3	Jackson	OR	PACW	Circuit 5R239 out of Talent substation	4/15/2020	Solar		More info
1100	1/15/2019	In Progress	0	NR/ER	LGI	250	250	Emery	UT	PACE	Camp Williams-Four Corners transmission line	12/31/2021	Solar & Battery Storage		More info
1101	1/15/2019	In Progress	0	NR/ER	LGI	75	75	Millard	UT	PACE	Black Rock substation	12/31/2021	Solar & Battery Storage		More info
1102	1/15/2019	In Progress	0	NR/ER	LGI	75	75	San Juan	UT	PACE	Abajo substation	12/31/2021	Solar & Battery Storage		More info
1103	1/16/2019	In Progress	0	NR	LGI	30	30	Iron	UT	PACE	West Cedar-Red Butte transmission line	7/31/2022	Solar		More info
1104	1/16/2019	In Progress	0	NR	OGI	3	3	Josephine	OR	PACW	Circuit 5R52 out of Cave Junction substation	4/15/2020	Solar		More info
1105	1/31/2019	In Progress	0	ER	OGI	3	3	Klamath	OR	PACW	Circuit 5L116 out of Texum substation	11/1/2020	Solar		More info
1106	1/31/2019	In Progress	0	NR/ER	LGI	320	320	Sweetwater	WY	PACE	Jim Bridger substation	11/1/2023	Solar		More info
1108	1/31/2019	In Progress	0	NR/ER	LGI	320	320	Sweetwater	WY	PACE	Rock Springs substation	11/1/2023	Solar		More info
1109	1/31/2019	In Progress	0	NR/ER	LGI	320	320	Sweetwater	WY	PACE	West Vaco substation	11/1/2023	Solar		More info
1110	1/31/2019	In Progress	0	NR/ER	LGI	320	320	Sweetwater	WY	PACE	Jim Bridger substation	11/1/2028	Solar		More info
1111	2/6/2019	In Progress	0	NR/ER	LGI	60	60	Emery	UT	PACE	Emery substation or Blackhawk-Ferron 69 kV line	12/31/2021	Solar & Battery Storage		More info
1112	2/6/2019	In Progress	0	NR/ER	LGI	60	60	Emery	UT	PACE	Emery substation or Blackhawk-Ferron 138 kV line	12/31/2021	Solar & Battery Storage		More info
1115	2/21/2019	In Progress	0	NR/ER	LGI	600	600	Wheatland	MT	PACE	Proposed Gordon Butte substation	12/31/2021	Wind		
1116	2/25/2019	In Progress	0	NR	LGI	50	50	Uinta	WY	PACE	Croydon – Railroad transmission line	12/31/2022	Solar & Battery Storage		More info
1117	2/26/2019	In Progress	0	NR	LGI	90	90	Salt Lake	UT	PACE	Terminal-Prison transmission line	12/31/2021	Solar & Battery Storage		More info
1118	3/1/2019	In Progress	0	NR	LGI	350	350	Moffat	CO	PACE	Aeolus-Clover transmission line	3/12/2023	Solar & Battery Storage		More info
1120	3/11/2019	In Progress	0	NR	OGI	3	3	Jackson	OR	PACW	Circuit 5R110 out of the Vilas Road substation	7/15/2020	Solar		More info
1122	3/27/2019	In Progress	0	NR/ER	LGI	300	300	Meagher	MT	PACW	Costrip transmission line	10/31/2022	Wind		
1123	3/29/2019	In Progress	0	NR	UGI	3	3	Box Elder	UT	PACE	Circuit SNO12 out of Snowville substation	12/31/2021	Solar		More info
1124	4/8/2019	In Progress	0	NR	OGI	0	0	Deschutes	OR	PACW	Circuit 5D128 out of Hunters Circle substation	12/31/2019	Solar		More info
1125	4/8/2019	In Progress	0	NR	OGI	0	0	Deschutes	OR	PACW	Circuit 5D128 out of Hunters Circle substation	12/31/2019	Solar		More info
1126	4/8/2019	In Progress	0	NR	OGI	8	8	Klamath	OR	PACW	Klamath Falls-Fishhole transmission line	6/1/2020	Geothermal		More info
1127	4/8/2019	In Progress	0	NR	LGI	30	30	Uinta	WY	PACE	Croydon – Railroad transmission line	12/31/2022	Solar & Battery Storage		More info
1129	4/11/2019	In Progress	0	NR	LGI	78	78	Millard	UT	PACE	Pavant - Sigurd transmission line	9/30/2022	Solar		More info
1130	4/19/2019	In Progress	0	NR/ER	LGI	120	120	Iron	UT	PACE	West Cedar substation	9/1/2022	Solar		More info
1131	4/26/2019	In Progress	0	NR/ER	LGI	200	200	Carbon	WY	PACE	Aeolus substation	12/1/2022	Solar		More info
1132	4/30/2019	In Progress	0	NR	UGI	3	3	Box Elder	UT	PACE	Circuit BSH11 out of Bush substation	12/31/2021	Solar		More info
1133	5/7/2019	In Progress	0	NR/ER	LGI	80	80	Klamath	OR	PACW	Klamath Falls-Yamsay transmission line	12/1/2022	Solar & Battery Storage		More info
1134	5/7/2019	In Progress	0	NR/ER	LGI	120	120	Klamath	OR	PACW	Klamath Falls-Yamsay transmission line	12/1/2022	Solar & Battery Storage		More info
1135	5/7/2019	In Progress	0	NR/ER	LGI	80	80	Klamath	OR	PACW	Chiloquin-Mile Hi transmission line	12/1/2022	Solar & Battery Storage		More info
1141	6/14/2019	In Progress	0	NR/ER	LGI	600	600	Carter	MT	PACE	Colstrip substation	12/1/2022	Wind		
1142	6/14/2019	In Progress	0	NR/ER	LGI	400	400	Carter	MT	PACE	Colstrip substation	12/1/2022	Wind		
1143	6/14/2019	In Progress	0	NR	LGI	45	45	Bonneville	ID	PACE	Goshen-Rigby transmission line or Goshen substation	10/21/2021	Solar		More info
1144	6/14/2019	In Progress	0	NR	LGI	50	50	Bonneville	ID	PACE	Goshen-Rigby transmission line or Goshen substation	10/1/2020	WInd		More info
1145	6/15/2019	In Progress	0	NR	UGI	1	1	Box Elder	UT	PACE	Blue Creek substation	12/31/2021	Solar		More info
1146	6/15/2019	In Progress	0	NR	UGI	3	3	Box Elder	UT	PACE	Gold Rush substation	12/31/2021	Solar		More info
1147	6/25/2019	In Progress	0	NR	OGI	3	3	Jackson	OR	PACW	Circuit 5R55 out of Oak Knoll substation	12/31/2020	Solar		More info
1149	7/11/2019	In Progress	0	ER	OGI	0	0	Benton	OR	PACW	Circuit 4M182 out of Hillview substation	1/0/1900	Solar		More info
1150	7/11/2019	In Progress	0	ER	OGI	1	1	Benton	OR	PACW	Circuit 4M182 out of Hillview substation	1/0/1900	Solar		More info
1151	7/11/2019	In Progress	0	ER	OGI	0	0	Benton	OR	PACW	Circuit 4M182 out of Hillview substation	1/0/1900	Solar		More info
1152	7/17/2019	In Progress	0	ER	UGI	1	1	Utah	UT	PACE	Circuit PKD02 out of Parkside substation	1/0/1900	Solar		
1153	8/23/2019	In Progress	0	NR/ER	LGI	665	665	Carbon	WY	PACE	Aeolus-Anticline transmission line	12/1/2023	Wind		More info
1154	8/23/2019	In Progress	0	NR/ER	LGI	590	590	Carbon	WY	PACE	Aeolus-Anticline transmission line	12/1/2023	Wind		More info
1155	8/23/2019	In Progress	0	NR/ER	LGI	470	470	Carbon	WY	PACE	Aeolus-Anticline transmission line	12/1/2023	Wind		More info
1156	8/23/2019	In Progress	0	NR/ER	LGI	380	380	Carbon	WY	PACE	Aeolus-Anticline transmission line	12/1/2023	Wind		More info
1157	8/30/2019	In Progress	0	NR	UGI	3	3	Tremonton	UT	PACE	Circuit BTH11 out of Bothwell substation	12/31/2021	Solar		More info
1158	9/3/2019	In Progress	0	NR	OGI	2	2	Douglas	OR	PACW	Circuit 5R133 out of Glendale substation	1/1/2022	Hydro	Available	
1159	9/9/2019	In Progress	0	NR	QFLGI	31	31	Beaver	UT	PACE	South Milford substation	12/31/2020	Geothermal		More info
1160	9/17/2019	In Progress	0	NR/ER	LGI	70	70	Modoc	CA	PACW	Alturas-Hornet transmission line	12/30/2022	Solar & Battery Storage		More info
1161	9/19/2019	In Progress	0	NR/ER	LGI	40	40	Crook	OR	PACW	Ponderosa substation or Houston Lake-Ponderosa transmission line	5/30/2022	Solar & Battery Storage		More info
1162	9/19/2019	In Progress	0	NR/ER	LGI	80	80	Crook	OR	PACW	Ponderosa substation or Houston Lake-Ponderosa transmission line	5/30/2022	Solar & Battery Storage		More info
1163	9/19/2019	In Progress	0	NR/ER	LGI	40	40	Crook	OR	PACW	Baldiwn Road-Ponderosa transmission line	5/30/2022	Solar & Battery Storage		More info
1164	9/19/2019	In Progress	0	NR/ER	LGI	80	80	Crook	OR	PACW	Baldiwn Road-Ponderosa transmission line	5/30/2022	Solar & Battery Storage		More info
1165	9/19/2019	In Progress	0	NR/ER	LGI	600	600	Crook	OR	PACW	Corral-Ochoco #2 transmission line or Ochoco substation	1/1/2024	Solar & Battery Storage		More info
1166	9/20/2019	In Progress	0	NR/ER	LGI	400	400	Box Elder	UT	PACE	Ben Lomond substation	11/30/2021	Battery		More info
1167	9/20/2019	In Progress	0	NR/ER	LGI	400	400	Box Elder	UT	PACE	Ben Lomond substation	11/30/2021	Battery		More info
1168	9/20/2019	In Progress	0	NR/ER	LGI	650	650	Bannock	ID	PACE	Populus substation	11/30/2021	Battery		More info
1169	9/20/2019	In Progress	0	ER	SGI	20	20	Yakima	WA	PACW	Sunnyside substation	11/30/2021	Battery		More info
1170	10/4/2019	In Progress	0	NR	LGI	35	35	San Juan	UT	PACE	Pinto- Abajo Havasu Tap transmission line	4/1/2023	Solar		More info
1171	10/8/2019	In Progress	0	NR/ER	LGI	300	300	Converse	WY	PACE	Dave Johnston substation	6/1/2021	Solar & Battery Storage		More info
1172	10/10/2019	In Progress	0	NR/ER	LGI	900	900	Bingham	ID	PACE	Kettle substation	9/30/2022	Wind		More info
1173	10/10/2019	In Progress	0	ER	LGI	625	625	Carbon	WY	PACE	Aeolus substation	8/30/2023	Wind		More info
1174	10/10/2019	In Progress	0	NR/ER	LGI	750	750	Carbon	WY	PACE	Aeolus substation	12/31/2026	Pump Storage		More info
1175	10/11/2019	In Progress	0	NR/ER	LGI	200	200	Salt Lake	UT	PACE	Terminal substation	12/31/2023	Battery		More info
1176	10/11/2019	In Progress	0	NR/ER	LGI	200	200	Salt Lake	UT	PACE	Terminal substation	12/31/2023	Battery		More info
1177	10/11/2019	In Progress	0	NR/ER	LGI	200	200	Utah	UT	PACE	Camp Williams - Mona transmission line	12/31/2023	Battery		More info

1178	10/11/2019	In Progress	0	NR/ER	LGI	200	200	Salt Lake	UT	PACE	Oquirrh substation	12/31/2023	Battery		More info
1179	10/11/2019	In Progress	0	NR/ER	LGI	200	200	Salt Lake	UT	PACE	Oquirrh substation	12/31/2023	Battery		More info
1180	10/11/2019	In Progress	0	NR/ER	LGI	200	200	Juab	UT	PACE	Clover substation	12/31/2023	Battery		More info
1181	10/11/2019	In Progress	0	NR/ER	LGI	200	200	Juab	UT	PACE	Clover substation	12/31/2023	Battery		More info
1182	10/11/2019	In Progress	0	NR	SGI	2	2	Fremont	ID	PACE	Circuit ASH11 out of Ashton substation	TBD	Hydro		More info
1183	10/15/2019	In Progress	0	NR/ER	LGI	400	400	Carbon	WY	PACE	Heward substation	6/1/2024	Wind		More info
1184	10/23/2019	In Progress	0	NR/ER	LGI	500	500	Rosebud	MT	PACE	Colstrip substation	9/1/2024	Wind & Battery Storage		
1188	11/1/2019	In Progress	0	NR/ER	LGI	80	80	Crook	OR	PACW	Stearns Butte substation	12/31/2022	Solar & Battery Storage		More info
1189	11/8/2019	In Progress	0	NR/ER	LGI	130	130	Converse	WY	PACE	Wagonhound-Jackalope transmission line	9/9/2022	Solar & Battery Storage		More info
1190	11/19/2019	In Progress	0	NR/ER	LGI	200	200	Walla Walla	WA	PACW	Walla Walla substation	9/1/2021	Solar & Battery Storage		More info
1191	12/2/2019	In Progress	0	NR	SGI	7	7	Teton	ID	PACE	Circuit CYN21 out of Canyon Creek substation	11/21/2019	Hydro	Available	
1192	2/11/2020	In Progress	0	NR/ER	LGI	239	239	Klamath	OR	PACW	Malin substation	12/31/2025	Wind		
1193	2/17/2020	In Progress	0	NR/ER	LGI	150	150	Yakima	WA	PACW	Union Gap-Midway transmission line	10/1/2023	Solar & Battery Storage		More info
1194	2/17/2020	In Progress	0	NR/ER	LGI	150	150	Yakima	WA	PACW	Union Gap-Midway transmission line	10/1/2023	Solar & Battery Storage		More info
1195	2/24/2020	In Progress	0	NR	SGI	20	20	Big Horn	WY	PACE	Frannie substation	TBD	Solar & Battery Storage		More info
1196	2/24/2020	In Progress	0	NR	SGI	20	20	Big Horn	WY	PACE	Frannie substation	TBD	Solar & Battery Storage		More info
1197	2/24/2020	In Progress	0	NR/ER	LGI	200	200	Yakima	WA	PACW	Midway-Union Gap transmission line	11/30/2023	Solar		
1198	2/28/2020	In Progress	0	NR/ER	LGI	125	125	Yakima	WA	PACW	Grandview substation	12/31/2023	Solar & Battery Storage		
1199	3/21/2020	In Progress	0	NR/ER	LGI	300	300	Power	ID	PACE	Borah substation	11/30/2023	Solar & Battery Storage		
1200	3/30/2020	In Progress	0	NR/ER	LGI	150	150	Yakima	WA	PACW	Outlook substation	1/1/2023	Solar & Battery Storage		
1201	3/30/2020	In Progress	0	NR/ER	LGI	200	200	Clark	ID	PACE	Amps substation	1/1/2023	Solar & Battery Storage		
1202	3/31/2020	In Progress	0	NR/ER	LGI	300	300	San Juan	UT	PACE	Pinto substation	9/1/2022	Solar		
1203	3/31/2020	In Progress	0	NR/ER	LGI	120	120	Iron	UT	PACE	Parowan Valley substation	9/1/2022	Solar		
1204	4/6/2020	In Progress	0	NR	SGI	20	20	Crook	OR	PACW	Ponderosa substation or Baldwin Road-Ponderosa transmission line	5/1/2023	Solar		
1205	4/6/2020	In Progress	0	NR	SGI	20	20	Crook	OR	PACW	Ponderosa substation or Houston Lake-Ponderosa transmission line	5/1/2023	Solar		
1206	4/6/2020	In Progress	0	NR	SGI	20	20	Crook	OR	PACW	Ponderosa substation or Houston Lake-Ponderosa transmission line	5/1/2023	Solar		
1207	4/8/2020	In Progress	0	NR/ER	LGI	150	150	Carbon	UT	PACE	Helper-Moab transmission line	12/31/2023	Solar & Battery Storage		
1208	4/8/2020	In Progress	0	NR/ER	LGI	150	150	Crook	OR	PACW	Ponderosa substation	12/31/2023	Solar & Battery Storage		
1209	4/8/2020	In Progress	0	NR/ER	LGI	200	200	Sweetwater	WY	PACE	Blue Rim-South Trona transmission line	12/31/2023	Solar & Battery Storage		
1210	4/8/2020	In Progress	0	NR/ER	LGI	190	190	Klamath	OR	PACW	Klamath Falls-Yamsay transmission line	12/31/2023	Solar & Battery Storage		
1211	4/8/2020	In Progress	0	NR/ER	LGI	200	200	Yakima	WA	PACW	Union Gap-Midway transmission line	12/31/2023	Solar & Battery Storage		
1212	4/10/2020	In Progress	0	NR/ER	LGI	350	350	Bear Lake	ID	PACE	Naughton-Treasureton transmisison line	9/1/2023	Solar & Battery Storage		
1213	4/13/2020	In Progress	0	NR/ER	LGI	200	200	Crook	OR	PACW	Ponderosa substation or Baldwin Road-Ponderosa transmission line	5/30/2024	Solar & Battery Storage		
1214	4/13/2020	In Progress	0	NR/ER	LGI	40	40	Crook	OR	PACW	Ponderosa substation or Houston Lake-Ponderosa transmission line	5/30/2024	Solar & Battery Storage		
1215	4/13/2020	In Progress	0	NR/ER	LGI	200	200	Crook	OR	PACW	Ponderosa substation or Houston Lake-Ponderosa transmission line	5/30/2024	Solar & Battery Storage		
1216	4/14/2020	In Progress	0	ER	SGI	4	4	Salt Lake	UT	PACE	Circuit RKW17 out of Porter Rockwell substation	TBD	Wind & Battery Storage		
1217	4/15/2020	In Progress	0	NR/ER	LGI	350	350	Uinta	WY	PACE	Evanston-Anschutz transmission line	6/30/2024	Energy Storage		
1218	4/16/2020	In Progress	0	NR/ER	LGI	100	100	Beaver	UT	PACW	Milford substation	7/1/2023	Solar & Battery Storage		
1219	4/20/2020	In Progress	0	NR	OLGI	80	80	Umatilla	OR	PACW	Dalreed substation	6/1/2023	Solar & Battery Storage		
1220	4/24/2020	In Progress	0	NR/ER	LGI	500	500	Klamath	OR	PACW	Malin substation	12/31/2022	Solar		
1221	4/27/2020	In Progress	0	NR/ER	LGI	200	200	Klamath	OR	PACW	Captain Jack - Meridian transmission line	12/1/2023	Solar & Battery Storage		
1222	4/27/2020	In Progress	0	NR/ER	LGI	200	200	Klamath	OR	PACW	Klamath Falls-Lone Pine transmission line	12/1/2023	Solar & Battery Storage		
1223	4/28/2020	In Progress	0	NR	LGI	79	79	Carbon	WY	PACE	Standpipe substation	9/15/2021	Wind		
1224	4/30/2020	In Progress	0	NR/ER	LGI	250	250	San Juan	UT	PACE	Pinto substation	6/1/2023	Solar & Battery Storage		
1225	4/30/2020	In Progress	0	NR/ER	LGI	350	350	Juab	UT	PACE	Mona substation	6/1/2023	Solar & Battery Storage		
1226	5/1/2020	In Progress	0	ER	SGI	20	20	Sweetwater	WY	PACE	Arrowhead substation	12/31/2023	Solar & Battery Storage		
1227	5/1/2020	In Progress	0	ER	SGI	20	20	Sweetwater	WY	PACE	Arrowhead substation	12/31/2023	Solar & Battery Storage		
1228	5/1/2020	In Progress	0	ER	SGI	20	20	Sweetwater	WY	PACE	Arrowhead substation	12/31/2023	Solar & Battery Storage		
1229	5/1/2020	In Progress	0	ER	SGI	20	20	Sweetwater	WY	PACE	Arrowhead substation	12/31/2023	Solar & Battery Storage		
1230	5/1/2020	In Progress	0	ER	SGI	20	20	Sweetwater	WY	PACE	Arrowhead substation	12/31/2023	Solar & Battery Storage		
1231	5/1/2020	In Progress	0	ER	SGI	20	20	Sweetwater	WY	PACE	Arrowhead substation	12/31/2023	Solar & Battery Storage		

Company Name: Only displayed after Interconnection Agreement has been signed or is an affiliate of PacifiCorp.

Affiliate Initial Scoping Meeting Notification: It is PacifiCorp's intention to hold initial scoping meetings for all projects listed that are associated with an affiliate per the relevant timing requirements.

Service Type: Not applicable to Large Generator Interconnection requests made prior to 01/20/2004, Small Generator Interconnection requests, or Qualifying Facility Interconnection requests.

ER: Energy Resource Interconnection Service

NR: Network Resource Interconnection Service

NR with ER: Network Resource Interconnection Service requested, but also studied as Energy Resource. Customer will choose Service Type (ER or NR) prior to Facilities Study.

Study Reports: Available in separate folder on OASIS

Study Schedule Deviation: If displayed, click "More Info" link to view PDF files.

Attachment E

PacifiCorp Response to NIPPC Data Request 1.3

NIPPC Data Request 1.3

Please see PacifiCorp's Oregon IE RFP at page 4. Please explain the assumptions does PacifiCorp make regarding its existing operating facilities operating beyond their contract terms or useful lives in PacifiCorp's bid evaluation methodology?

Response to NIPPC Data Request 1.3

Consistent with the 2019 Integrated Resource Plan (IRP), PacifiCorp will assume that contracted existing facilities will cease delivering capacity and energy to the company at the conclusion of their current contract term. Similarly, for owned existing facilities, PacifiCorp will assume these assets stop operating at the end of their assumed operable life or at the accelerated retirement dates used in the 2019 IRP preferred portfolio.