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December 9, 2019

Via Electronic Filing

Chair David Danner
Commissioner Ann Rendahl
Commissioner Jay Balasbas
Washington Utilities and Transportation Commission
621 Woodland Square Loop SE
Lacey, WA 98503

Re: Utility PURPA Compliance Filings –
Comments on PacifiCorp PURPA Compliance Filing

Docket Nos. UE-190663 – Avista
UE-190665 – Puget Sound Energy
UE-190666 – PacifiCorp

Dear Commissioners:

The Northwest and Intermountain Power Producers Coalition ("NIPPC") and the Renewable Energy Coalition ("REC") submit these Comments on PacifiCorp's Public Utility Regulatory Policies Act ("PURPA") Compliance Filing submitted in Docket No. UE-190666. NIPPC and REC have also filed separate comments exclusively on the Avista and Puget Sound Energy's ("PSE's") compliance filings. These comments specifically respond to PacifiCorp's Compliance Filing but contain topics and themes that are relevant for consideration in PURPA implementation generally and so are being filed in all three dockets.

I. EXECUTIVE SUMMARY

PacifiCorp's filing has significant issues with both price and non-price components. Specifically:

1) PacifiCorp's approach to valuing capacity is overly complex and attempts to accomplish through implementation a proposal PacifiCorp made in and that was rejected by the Washington Utility and Transportation Commission ("WUTC" or "Commission") in the Commission's PURPA rulemaking docket. Notably:

   a) PacifiCorp attempts to avoid using the proxy method in years where it has planned market purchases by only including the capacity value of the proxy unit in two rather than twelve months;

b) PacifiCorp justifies this proposal by asserting that the benefits of the proxy unit should be netted against its costs, an approach that the Commission rejected in rulemaking;

c) PacifiCorp also proposes to subtract energy benefits from its planned resource capacity value; thus mixing energy and capacity values inconsistent with the Commission's rules;

d) PacifiCorp's approach overly complicates the calculation and just encourages manipulation of the numbers; and

e) PacifiCorp should use the energy profile of the 2017 IRP Oregon tracking solar, which reflects the additional energy value of tracking solar facilities.

2) PacifiCorp also proposes interconnection requirements that are inconsistent with PURPA and would effectively prevent QFs from executing power purchase agreements ("PPAs") in an environment where everyone, including PacifiCorp, acknowledges that its interconnection queue is significantly stalled or delayed. NIPPC and REC's specific recommendation is that the QF not be required to finalize or complete any specific interconnection steps prior to obtaining a PPA, as is the case in Oregon. Notably:

a) The Federal Energy Regulatory Commission ("FERC") has expressly found that it is inconsistent with PURPA for a utility to condition the execution of a PPA or formation of a legally enforceable obligation ("LEO") on the execution of an interconnection agreement or other process within the exclusive control of the utility, as PacifiCorp proposes in its tariff;

b) PacifiCorp's proposed process will make it impossible or impractical for a QF to functionally comply with both the interconnection processes and the PPA process because few QFs will be able to invest significant time and resources in the interconnection process years in advance of executing a PPA as PacifiCorp proposes; and

c) PacifiCorp's recent efforts to reform its interconnection queue may create an impossible Catch 22 where a QF will be required to have a PPA to enter the interconnection queue, while at the same time be required to have an interconnection agreement in order to execute a PPA.

3) The following changes should be made to PacifiCorp's filing:

a) PacifiCorp's rate schedule should not refer to the standard contract as a "template" because the Commission's rules require PacifiCorp to file a complete standard contract;

b) PacifiCorp's proposed contracting process includes an unnecessary interim step of a "proposed final version" of the PPA prior to obtaining an executable PPA;

c) A QF should have 45 business days rather than 15 business days to sign the executable PPA;

d) A QF should not be required to provide PacifiCorp with notice 90 days (effectively three months) before filing a complaint with the Commission; and

e) PacifiCorp only includes part of the Commission's LEO rule in the tariff, and all the relevant provisions should be included.

NIPPC and REC regret the length and number of disputed issues; however, PacifiCorp's tariff and contracting process raise insurmountable hurdles for QF development in Washington. PacifiCorp needs to make numerous and significant changes to its Schedule QF or else the status quo, in which there are only three operating QFs selling power to the utility in Washington, will simply continue. In the event that PacifiCorp does not make the recommended changes herein, the Commission should suspend PacifiCorp's filing.

II. Avoided Cost Prices

PacifiCorp prices capacity in two periods[1] both of which have issues as discussed below. First, because PacifiCorp's most recent integrated resource plan ("IRP") selects capacity in the form of market purchases in the early years, PacifiCorp's avoided capacity cost includes an initial period where the capacity value is based on the cost of a simple cycle combustion turbine ("SCCT").[2] Then, in the later years, PacifiCorp's avoided cost of capacity is based on its next planned resource addition.[3]

A. PacifiCorp Fails to Appropriately Price Capacity in the Early Years Where It Uses the Costs of a SCCT as a Proxy for Market Purchases

NIPPC and REC object to both of PacifiCorp's proposed methodologies to pay QFs the costs of a capacity resource as a proxy for market resource. First, the Commission should reject PacifiCorp's proposal to use a SCCT as a proxy for market purchases in only two months rather than all twelve months.[4] Second NIPPC and REC recommend that the Commission reject PacifiCorp's "alternative" proposal to adjust costs, i.e., "subtract the capitalized energy costs representing the energy dispatch and operating reserve benefits the SCCT proxy would provide,"

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1 *See* WUTC Docket No. UE-190666, PacifiCorp's draft Schedule QF and QF.15 (Table C) (Aug. 9, 2019).

2 *See Id.* at Table C rows 2019 and 2020.

3 *See Id.* at Table C rows 2021 through 2039.

4 *See* WUTC Docket No. U-161024, PacifiCorp Comments at 3 (April 1, 2019) ("Net Capacity Costs, Not Fixed, Meets Customer Indifference.").

i.e., to "net" the costs.[5] The Commission should reject both of PacifiCorp's proposals because they are inaccurate, overly complex, and were rejected by the Commission in the rulemaking to adopt the current rules.

1. The Full Fixed Cost of a SCCT Must Be Paid Even if it Only Operates Part of the Time

PacifiCorp's proposal to base its capacity price in the early years on only the cost of a SCCT unit in two months (July and December) directly violates of the Commission's rule requiring that a SCCT be used as a proxy resource when the IRP selects market purchases. Specifically, if the most recently acknowledged IRP identified the need for capacity in the form of market purchases not yet executed, "then the utility shall use the projected fixed costs of a [SCCT] unit as identified in the [IRP]."[6] This methodology is referred to as the "[p]roxy for planned market purchases."[7]

Practically speaking, even if PacifiCorp only has a capacity need in two months of the year, then PacifiCorp would need to pay the full fixed cost of a SCCT to meet that need. Given that the Commission has directed PacifiCorp to use the fixed costs of a SCCT as a proxy for market purchases, PacifiCorp cannot rewrite the rules and only include part of the fixed costs of a SCCT. The proxy method should assume that, instead of acquiring its capacity with market purchases, PacifiCorp is acquiring its capacity with the proxy resource.

Assuming that a SCCT was actually acquired instead of market purchases, it should be noted that it is not sitting idle and providing zero benefit to PacifiCorp in the months when it is not being used to fill a capacity need. PacifiCorp itself notes that while the proxy SCCT provides the most benefits in the west-wide peak months of July and August, where "the implied market heat rate is well above an SCCT," it "can provide benefits even in months where the HLH implied heat rate… is less than its heat rate."[8] Therefore, the higher fixed cost of an SCCT over a market purchases is justified.

2. Accounting for Net Costs Rather than Fixed Costs Overly Complicates the Capacity Calculation and PacifiCorp's Analysis is Implausible

PacifiCorp's proposal to use only two months' worth of the SCCT value also directly violates of the Commission's decision not to base the capacity price on "net" costs, but on "fixed" costs. PacifiCorp notes that "[i]ncluding twelve months of SCCT fixed costs as a proxy

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5 WUTC Docket No. UE-190666, PacifiCorp's Initial Filing Cover Letter at 4 (Aug. 9, 2019).
6 WAC 480-106.040(1)(b)(ii).
7 *Id.*
8 WUTC Docket No. UE-190666, PacifiCorp's Supplemental Filing Cover Letter at 6 (Nov. 18, 2019).

for the market price… would result in a one-sided reflection of SCCT costs without a corresponding reflection of SCCT benefits."[9] However, the Commission already decided that this is the outcome it wanted.

In the Commission's PURPA rulemaking docket, PacifiCorp requested that the Commission alter the draft WAC 480-106-040(1)(b) and 480-106-040(1)(b)(ii) to require that the utilities base their avoided costs on "net" capacity costs rather than the "fixed" costs.[10] Commission Staff responded to this asserting that the public interest and goals of PURPA weigh in favor of a rule that is relatively simple to calculate, and that PacifiCorp's proposal "unnecessarily complicates the issue, while not demonstrating that its outcome would produce a more accurate avoided cost."[11] The Commission expressly agreed with Staff and adopted Staff's recommendation to not make any change to the rules based on PacifiCorp's comment.[12] The final version of the rule states that the schedule must include "[a]n estimated avoided cost of capacity expressed in dollars per megawatt based on the projected *fixed cost* of the next planned capacity addition."[13] Similarly, when the most recently acknowledged integrated resource plan ("IRP") identifies the need for capacity in the form of market purchases, the rules require that the "utility shall use the projected *fixed costs* of a [SCCT] as identified in the [IRP]."[14]

Staff's initial justification not to use "net" costs in the PURPA rulemaking, is confirmed by a closer look at PacifiCorp's calculations: it is overly complicated. PacifiCorp asserts that numerous "benefits" that an SCCT provides should be netted against the costs. PacifiCorp adjusts the cost of its proxy SCCT to account for the "benefits that an SCCT would provide if it was under the company's control."[15] PacifiCorp asserts that an SCCT under its control will provide energy benefits, operating reserves, and intra-hour benefits not accounted for in simply calculating the fixed costs of such a unit.[16] To appropriately review each of these adjustments, all of the underlying assumptions and data would need to be provided and carefully reviewed. Additionally, in order to capture the full "net" costs of a SCCT, PacifiCorp would need to complicate the equation further and account for other costs (not only benefits) not captured in the fixed costs, such as additional administrative costs, environmental compliance costs, engineering, maintenance, logistics, security, management, payroll, accounting, etc.[17] PacifiCorp further asserts that the benefits it suggests in this filing "are not a comprehensive

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9 WUTC Docket No. UE-190666, PacifiCorp's Initial Filing Cover Letter at 3.
10 WUTC Docket No. U-161024, PacifiCorp Comments at 3 (April 1, 2019).
11 WUTC Docket No. U-161024, General Order R-597, Appendix A at 23 (June 12, 2019).
12 WUTC Docket No. U-161024, General Order R-597 at ¶ 13 ("We agree with Staff and adopt these recommendations.").
13 WAC 480-106-040(1)(b) (emphasis added).
14 WAC 480-106-040(1)(b)(ii) (emphasis added).
15 WUTC Docket No. UE-190666, PacifiCorp's Supplemental Filing Cover Letter at 3.
16 *See id* at 3-4.
17 This also continues the anti-competitive theme in PacifiCorp's approach to RFPs, which favor self-ownership of resources because these ancillary costs are not allocated to the individual project.

representation of all of the benefits associated with an SCCT,"[18] so if the Commission approves PacifiCorp's deviation from the Commission's rules now, the Commission it is likely that PacifiCorp will enter new elements and further complicate the filing in the future. Therefore, this overly complicates PacifiCorp's filing just as Staff predicted.

3. PacifiCorp's Estimate of the Operating Reserve "Benefit" of a SCCT is Overstated

NIPPC and REC offer some additional substantive comments in response to PacifiCorp's calculations demonstrating the complexity (and inaccuracy) of PacifiCorp's method. PacifiCorp's Table 1, in the cover letter to its November 18, 2019 supplemental filing, provides a startling conclusion.[19] If the analysis is to be believed, the result states that PacifiCorp could lower its total generation costs by adding combustion turbines to its fleet of generation. Notice that in any year where the capitalized energy cost is greater than the total capacity cost, PacifiCorp can pay for the full annual fixed cost of the plant through these energy cost savings. Also, if the Net Capacity Cost column is summed, PacifiCorp estimates that the benefit of adding an additional SCCT, over the 2020 to 2039 time period, is over $400,000 per MW above and beyond paying for the full capacity cost. If this is true, then not only PacifiCorp, but other utilities in the western US with ancillary reserves requirements should be adding SCCT to their generation fleets and by making those capital additions total costs will be reduced.

PacifiCorp's analysis regarding the operating reserve benefits provided by an SCCT is based on the assumption that with a SCCT, PacifiCorp would use that resource for select ancillary services such as spinning reserves, and free up a lower variable cost resource to generate power rather than being held in reserve.[20] NIPPC and REC agree that this is a benefit that a with SCCT will provide; however, there are other sources of such ancillary reserves. In the PacifiCorp Northwest, with an energy constrained hydroelectric system, a source of spinning reserves is hydroelectric generators.

As discussed in PacifiCorp's 2019 IRP:

> Hydro resources are generally deployed first to meet the spinning reserve requirements because of their flexibility and their ability to respond quickly. The amount of reserve that these resources can provide depends upon the difference between their expected capacities and their generation level at the time. The hydro resources that PacifiCorp may use to cover reserve requirements in the PacifiCorp West balancing authority area include its facilities on the Lewis River and the Klamath River as well as contracted generation from the Mid-Columbia projects. In the PacifiCorp East balancing authority area, PacifiCorp may use facilities on the Bear River to provide spinning reserve.

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[18] WUTC Docket No. UE-190666, PacifiCorp's Supplemental Filing Cover Letter at 4.

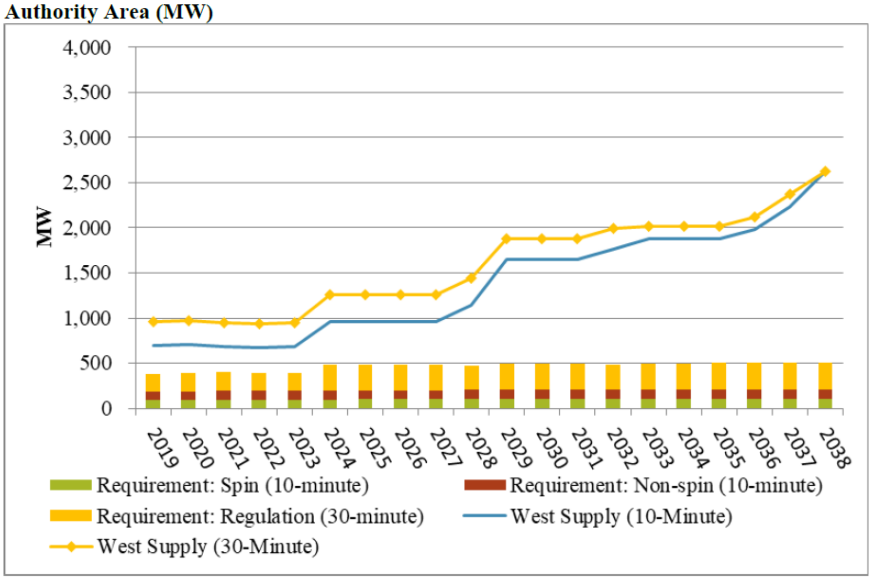
[19] *Id.*

[20] *Id.* at 3.

Thermal resources are also used to meet the spinning reserve requirements when they are online. The amount of reserve provided by these resources is determined by their ability to ramp up within a 10-minute interval. For natural gas-fired thermal resources, the amount of reserve can be close to the differences between their nameplate capacities and their minimum generation levels. In the current IRP, PacifiCorp's reserve are served not only from existing coal- and gas-fired resources, but also from new gas-fired resources selected in the preferred portfolio.[21]

Additionally, PacifiCorp has adequate reserve requirements:

Figure F.17 - Comparison of Reserve Requirements and Resources, West Balancing Authority Area (MW)



[22]

Therefore, with excess reserves, PacifiCorp's estimate of "capitalized energy costs" is grossly overstated and without foundation.

Another way to check the reasonableness of the PacifiCorp analysis is to look at prices charged for spinning reserves in the Western US. The CAISO publishes information to this regard. The CAISO publishes Market Performance Reports each month. The following table displays the results for the January through August time period for which CAISO reports have been published.

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21 PacifiCorp 2019 IRP, Appendix F at 112-113.

22 *Id*. at 113.

	Average Procured		Average Price $/mW	
2019	Spinning	Non Spinning	Spinning	Non Spinning
January	831	839	5.19	0.11
February	699	753	11.82	0.11
March	751	753	7.12	0.35
April	803	806	8.87	0.16
May	835	843	10.37	0.11
June	883	884	6.72	0.41
July	907	908	5.75	1.01
August	937	931	5.27	1.05

Should PacifiCorp have access to the CAISO market, then these reserves could be purchased.

In sum, there are a variety of factors that complicate PacifiCorp's proposal. The Commission's rules are clear on this point and the Commission expressly did not adopt PacifiCorp's proposal to use "net" costs in the interests of clarity, accuracy and simplicity. By overly complicating the matter, PacifiCorp will hamstring the Commission Staff and other stakeholders who may not have the resources to adequately evaluate such a complicated proposal. And even if there are the resources to do so, it would likely result in prolonged litigation each time PacifiCorp files an update in order to appropriately vet each of the adjustments. It is therefore in the public interest to implement the rule consistent with the rule's express language and not misrepresent the application of the proxy resource and as a result, overly complicate the matter.

B. NIPPC and REC Recommend that the Date of Change from When Capacity Payments Are Based on the Market Proxy Capacity Value to When they Are Paid Based on the Next Planned Resource Should Be 2028 Rather Than PacifiCorp's Proposal of 2020

PacifiCorp limits the avoided capacity cost transition from the market proxy value based on a SCCT to the planned resource value to 2020. PacifiCorp selected this year because it is the year of the proposed planned resource from its 2017S RFP.[23] However, PacifiCorp's most recently acknowledged IRP called for a western control area ("WCA") resource in 2028 in the form of an 11 MW Yakima Solar project.[24] Therefore, the market proxy value (SCCT) should be used for capacity costs up to 2028, which is the date of PacifiCorp's next planned resource acquisition in its acknowledged IRP.

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23 WUTC Docket No. UE-190666, PacifiCorp's Initial Filing Cover Letter at 4.
24 *Id.*

The Commission's rules require that the estimated avoided capacity costs be "based on the projected fixed cost of the next planned capacity addition identified in the succeeding twenty years in the utility's most recently acknowledged [IRP]."[25] The *costs* of that planned capacity addition, however, may be based on either the estimates in the most recently acknowledged IRP or the most recent project proposals received pursuant to an RFP.[26] That does not necessarily mean, however, that the *date* upon which that resource is acquired may be based on the RFP. Where the timing of the IRP's next planned resource acquisition and the timing of the RFP project are so far apart, eight years, as in this instance, the Commission should require that PacifiCorp demonstrate that the RFP resource is actually deferrable. Here, however, PacifiCorp has not provided any justification, nor does the Company state that the 2020 resource is deferrable. In other filings PacifiCorp does not present this resource as deferrable, and as a result, capacity payments should be based upon the next planned resource in 2028.[27]

C. PacifiCorp Fails to Appropriately Price Capacity for its Planned Resource

1. The Capacity Costs for the Planned Resource Should Be Consistent with the Timing of the Planned Resource

The avoided capacity costs for the planned resource should be realistic and consistent with the timing of the planned resource. PacifiCorp uses 2020 prices for the capacity costs of a 2028 planned resource, which results in a mishmash with an end result of lowering capacity payments to QFs. There are three major flaws with this approach:

1. The 2020 price likely incorporates the impact of the federal investment solar tax credit which will expire prior to the 2028 resource;
2. Inflation will push the 2020 construction costs up over time; and
3. Technological progress will push the 2020 solar costs down over time; however, it is unclear how much lower solar costs can go.

The first item alone can account for a 30 percent increase in the capital cost of solar generation. The avoided capacity cost can be based on either the fixed cost estimates in its most recently acknowledged IRP or RFP; however, the timing difference makes the use of the 2020 RFP costs incomparable to the 2028 avoided resource. PacifiCorp should use the avoided costs indicated in the IRP for the 2028 resource for an apples-to-apples valuation. PacifiCorp can update these costs when the next IRP is acknowledged.[28]

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[25] WAC 480-106-040(1)(b).
[26] WAC 480-106-040(1)(b(i).
[27] Docket No. 20000-545-ET-18, Page 14 – Direct Testimony of Daniel J. MacNeil.
[28] Or other date as determined to be, appropriate in light of the Commission's recent decision to defer the IRPs pending implementation of recently passed legislation.

2. Accounting for Net Costs Rather than Fixed Costs Overly Complicates the Planned Resource Capacity Calculation

As with the market proxy resource discussed above, here too with the planned capacity resource, PacifiCorp proposes to base avoided capacity costs on “net” rather than “fixed” costs by netting out the “energy benefits” in what it calls a “capitalized energy cost adjustment.”[29] PacifiCorp proposes to “subtract capitalized energy costs” from the planned resource cost, in an effort to still account for “both energy and capacity benefits” provided by such capacity additions.[30] As discussed above, PacifiCorp’s proposal to price capacity base on “net” costs rather than “fixed” costs is overly complicated, inconsistent with the rules, and PacifiCorp again attempts to do through implementation that which the Commission rejected in its rulemaking.

D. The Capacity Factor of Solar Should be Based on Tracking Solar Facilities

PacifiCorp’s workpapers use the energy profile of the 2017 IRP Oregon fixed tilt solar for tracking solar resources. This is a mistake; PacifiCorp should use the energy profile of 2017 IRP Oregon tracking solar, which reflects the additional energy value of tracking solar facilities.

E. PacifiCorp’s Use of Confidential Calculations Decreases Stakeholder Transparency into the Avoided Cost Calculations

PacifiCorp’s workpapers have a number of redacted values due to the use of the 2017 RFP results and the use of PacifiCorp’s Mid-C price forecast. These confidential values prevent any meaningful review of PacifiCorp’s calculations.

PacifiCorp’s methodology and calculations warrant review because the methodology results in an illogical and incorrect conclusion. PacifiCorp’s confidential calculations arrive at a levelized cost of capacity of negative $6,083 per MW-yr. According to PacifiCorp’s logic, the addition of planned resources lowers system revenue requirement relative to making market purchases. However, according to PacifiCorp’s IRPs, the addition of planned resources raises revenue requirement (relative to using market purchases).[31] PacifiCorp’s IRP has been subjected to multiparty input and review and has more logical and reasonable findings, and as a result, is more reliable.

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29 WUTC Docket No. UE-190666, PacifiCorp’s Initial Filing Cover Letter at 5.

30 WUTC Docket No. UE-190666, PacifiCorp’s Initial Filing Cover Letter at 5.

31 *See* PacifiCorp 2017 IRP, 244. This statement is inferred from the observation that in 2028 PacifiCorp selects the maximum amount of market resources (FOTs) in 2028 and meets the remaining capacity deficiency with non-market resources. The fact that PacifiCorp’s model maximizes FOTs shows that FOTs are modeled as lower cost resources than solar resources.

III. Non-Pricing Issues

A. PacifiCorp's Interconnection Requirements Violate PURPA or Otherwise Impose Conditions that Are Impossible or Impractical to Meet

1. PacifiCorp Cannot Require a QF to Execute Interconnection and Transmission Studies or Agreements Prior to Obtaining or Executing a PPA

PacifiCorp inappropriately and in violation of PURPA proposes to require that QFs have completed interconnection studies, agreements, and transmission arrangements prior to executing a power purchase agreement ("PPA") with PacifiCorp. First, PacifiCorp requires that a QF "must secure an interconnection agreement," and PacifiCorp explicitly conditions its purchase of QF output "upon the [QF] completing *all* necessary interconnection arrangements."[32] Second, PacifiCorp requires that a QF provide "evidence that any necessary interconnection studies and. . . transmission arrangements, have been completed" prior to proceeding with the contracting process.[33] In other words, a QF will need to be physically interconnected and/or have appropriate transmission arrangements prior to actually delivering power to PacifiCorp; this is inconsistent with PURPA to require the completion of these studies or arrangements *prior* to contract execution. As the Commission rules allow, there may be a period of up to three years between contract execution and actual power deliveries where the QF may be in the process of completing its interconnection and other development efforts such as permitting. Accordingly, PacifiCorp should remove the requirement to require interconnection studies, agreements, or transmission arrangements prior to finalizing a PPA.

NIPPC and REC's recommendation is that the PacifiCorp use the language in PacifiCorp's Oregon small QF tariff, which states that in order to obtain a draft PPA a QF must provide "status of interconnection or transmission arrangements."[34] There is no requirement to provide any specific study or execute any interconnection agreements. If PacifiCorp does not do this, then the Commission should suspend its filing.

FERC has ordered that a state cannot require a facilities study or an executed interconnection agreement in order to achieve a LEO, under which the utility is required to

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32 PacifiCorp draft Schedule QF at QF.8 (Aug. 9, 2019) (emphasis added).

33 PacifiCorp draft Schedule QF at QF.4 (section I.B.4(f)) for standard QFs) (Aug. 9, 2019) and PacifiCorp draft Schedule QF at QF.6 ((section I.B.4(f)) for non-standard QFs) (Nov. 18, 2019).

34 PacifiCorp Oregon Standard Avoided Cost Rates at 10 (effective for service Apr. 24, 2019) available at https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/rates-regulation/oregon/tariffs/purpa/Standard_Avoided_Cost_Rates_Avoided_Cost_Purchases_From_Eligible_Qualifying_Facilities.pdf.

purchase a QF's net output.[35] In that case, the Montana Public Service Commission required a QF to tender an executed interconnection agreement to establish a LEO.[36] A LEO is broader than simply a contract and "is intended to prevent a utility from circumventing the requirement that provides capacity credit for an eligible [QF] merely by refusing to enter into a contract with the [QF]."[37] FERC reasoned then that the requirement to tender an executed interconnection agreement was inconsistent with PURPA's mandate that public utilities purchase a QF's net output, because it "allows the utility to control whether and when a [LEO] exists—e.g., by delaying the facilities study or by delaying the tendering by the utility to the QF of an executable interconnection agreement."[38] FERC explained that "the utility can delay the facilities study or delay tendering an executable interconnection agreement."[39] Thus, FERC has found that a QF's ability to sell power to a utility cannot be conditioned upon a process that the utility controls because otherwise the utility could circumvent PURPA's must-purchase obligation.

Here, PacifiCorp specifically requires the completion of interconnection studies, agreements, or transmission arrangements before providing an executable PPA, which explicitly violates *FLS Energy, Inc.* because it conditions the QF's ability to sell power on something within PacifiCorp's sole control. PacifiCorp could circumvent its must-purchase obligation under PURPA by simply refusing to complete interconnection studies, agreements, and transmission arrangements, and these obligations are solely within PacifiCorp's control. While it is true that PacifiCorp's interconnection process is subject to its own applicable deadlines in its open access transmission tariff ("OATT") or applicable state interconnection rules, recently many of those deadlines have not been respected.[40] Thus, since PacifiCorp has control over the interconnection and transmission processes, it would be a violation of PURPA for PacifiCorp to condition an executable PPA on the QF completing those agreements or meeting a certain milestone within that process.

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35 *FLS Energy*, 157 FERC ¶ 61,211 at P. 20 (Dec. 15, 2016) ("finding that a requirement for a facilities study or an interconnection agreement, given that the utility can delay the facilities study or delay tendering an executable interconnection agreement, as a predicate for a legally enforceable obligation is inconsistent with PURPA and the Commission's regulation under PURPA.").

36 *Id.* at P. 22.

37 *Id.* at P. 24

38 *Id.* at P. 23.

39 *Id.* at P. 20.

40 *See generally* PacifiCorp's 2019 Interconnection Queue Reform Effort, available at http://www.oasis.oati.com/ppw/index.html folder "Interconnection Queue Reform 2019"; *See also* NIPPC's Comments on PacifiCorp Interconnection Queue Reform (Dec. 9, 2019) available at http://www.oasis.oati.com/woa/docs/PPW/PPWdocs/NIPPC_PAC_GIQ_Reform_DEC2019_final.pdf.

2. PacifiCorp's Interconnection Requirements Are Impossible or Impractical to Meet

PacifiCorp's proposed tariff also allows PacifiCorp to prevent or delay providing executable PPAs by imposing timelines for the PPA process and the interconnection process that make it impossible or impractical to meet both.

PacifiCorp recommends that a QF initiate its interconnection process 24 to 48 months prior to its anticipated PPA execution date to "help ensure that necessary interconnection arrangements proceed in a timely manner and that the QF can deliver its power consistent with the anticipated in-service date."[41] The Commission's rules contemplate that the QF can choose to complete the interconnection process after PPA execution, which is one reason why the Commission allows the contract to be executed up to three years prior to the date of commercial operation. PacifiCorp propose that the QF move through two to four years of interconnection study process to obtain an interconnection agreement before a PPA[42] and then an additional three years after PPA execution to actually complete the construction, for a total of five to seven years. This is unreasonable.

First, many QFs will not be able to justify spending time and money in the interconnection process years in advance of executing a PPA. This is because many QFs (especially small QFs) cannot obtain financing for interconnections until they know their PPA prices. Therefore, it would be impractical for some QFs to enter the interconnection queue 24 to 48 months prior to executing a PPA.

Second, five to seven years is way too long. PacifiCorp's Oregon PURPA tariff recommends that a QF initiate its interconnection request 18 months ahead of the anticipated commercial operation date (rather than the 2-4 years *before* PPA execution).[43] It is PacifiCorp's responsibility to appropriately mange its interconnection queue so that it can complete interconnections in a timely manner. If it cannot do so, it should not push the burden onto its QF

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41 PacifiCorp draft Schedule QF at QF.8 (Aug. 9, 2019).

42 The interconnection process typically involves three studies, each completed successively after the last study was completed and after the interconnection customer and the utility execute an agreement to perform the study. The studies include the Feasibility Study, System Impact. Study, and Facilities Study, but sometimes the Feasibility Study is skipped. Each study agreement typically requires a deposit and the interconnection customer to pay the full cost to perform each study. Once those are complete and the interconnection customer agrees to pay the costs of the interconnection, the utility will provide an interconnection agreement.

43 PacifiCorp Oregon Standard Avoided Cost Rates at 9 (effective for service Apr. 24, 2019) available at https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/rates-regulation/oregon/tariffs/purpa/Standard_Avoided_Cost_Rates_Avoided_Cost_Purchases_From_Eligible_Qualifying_Facilities.pdf.

interconnection customers to initiate interconnections years before they have any idea what their pricing will be. To the extent that PacifiCorp does not complete an interconnection within the three years between the PPA's execution and the QF's expected commercial operation date, there should be room to extend the commercial operation date or otherwise provide a remedy. Otherwise, a QF will be forced to miss its commercial operation date, and PacifiCorp will terminate the PPA, which is not the appropriate outcome.

Finally, a look at PacifiCorp's FERC-jurisdictional interconnection queue reform effort illustrates an example of an impossible scenario that could arise. There, PacifiCorp proposes that an interconnection customer not even be permitted to enter its interconnection queue, unless it can demonstrate "commercial readiness," including an executed term sheet or PPA.[44] When read in light of its tariff proposed in this docket, recommending that a QF apply for and execute an interconnection agreement prior to signing a PPA, an impossible dilemma arises. You cannot get a PPA without an interconnection agreement, and you cannot get into the interconnection queue without a PPA.

NIPPC and REC recognize that the Commission cannot take direct action in PacifiCorp's interconnection queue reform proposal and that that proposal applies only to FERC-jurisdictional interconnections. However, it is possible that the proposals PacifiCorp makes in its FERC-jurisdictional processes could also be imposed on QFs in Washington State if there is no functional alternative.[45] It is important for the WUTC to know, that PacifiCorp's interconnection process has had a severely negative impact on market access for QFs. Most specifically, interconnection customers are experiencing unprecedented delays, and an inability for interconnection requests to advance through the normal interconnection study process in a

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44 PacifiCorp Second Revised Straw Proposal, Section 5.0 available at http://www.oasis.oati.com/woa/docs/PPW/PPWdocs/PacifiCorp_Queue_Reform_-_Second_Revised_Straw_Proposal.pdf.

45 The Commission, not FERC, has jurisdiction over PURPA interconnections. However, it is not clear what interconnection standards apply to QFs in Washington as the Commission's interconnection rules located in WAC 480-108 note specifically that "[t]his chapter does not govern interconnection of, or electrical company services to, PURPA qualifying facilities pursuant to chapter 480-107 WAC." WAC 480-108-001(4). Under WAC 480-107, there are only very limited provisions on interconnections. NIPPC and REC noted concerns about the interconnection process in the PURPA rulemaking docket before this Commission. *See* WUTC Docket No. U-161024, General Order R-597 at ¶ 18 ("The third issue is the proposal made by several commenters that the Commission revisit its interconnection rules and provide more guidance in light of the Proposed revisions to these rules and recent legislation governing renewable energy issues. These Commenters are concerned that utilities have a financial incentive to delay the commercial operation of QF projects through the interconnection process and thus effectively shorten the contract term.").

manner consistent with PacifiCorp's Open Access Transmission Tariff ("OATT") or applicable state jurisdictional timelines.[46]

In light of all of the above, the Commission should ensure that PacifiCorp's proposed Schedule QF tariff in Washington does not prevent QFs from executing PPAs because they do not have an executed interconnection agreement, completed study or completed transmission arrangements. Specifically, PacifiCorp should remove any requirement to complete any interconnection studies to obtain a PPA. Should PacifiCorp fail to do so, the Commission should suspend PacifiCorp's filing.

B. QFs From Other States Should Be Eligible

On sheet QF.1, PacifiCorp notes that the schedule "applies to any person or entity who owns a [QF] and proposes to make sales of electricity from a QF in the State of Washington to the Company."[47] This language is ambiguous. It is not clear whether "in the State of Washington" is intended to mean the location where the sale of electricity takes place or where the QF is located. A QF from another state is entitled to sell its electricity across state lines and therefore, this section should be reworded to clarify that the sale of the electricity must be in Washington, i.e., that the QF must deliver its net output to PacifiCorp's system in Washington.[48]

C. The Standard PPA Should Not Be A "Template"

On sheet QF.2, PacifiCorp notes that the standard PPA is a "template" and "the starting point for the Company to prepare a draft agreement that conforms to the QF's specific pricing elections and project configuration."[49] While, NIPPC and REC intend to address the terms and conditions of PacifiCorp's PPA separately in early 2020, it is important to note here that the PPA should not be referred to in the tariff as a "template" that is subject to revision depending on whether the QF is on- or off-system, variable, new or existing[50] but should be an off-the-rack contract where only blanks need to be filled in to complete the contract.

D. A "Proposed Final Version" of the PPA is Not Necessary for Standard QFs

On sheet QF.4 (section I.B.4.), PacifiCorp proposes an interim step of a "proposed final version" of the PPA once the QF agrees to the draft version, but before PacifiCorp provides an

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46 *See* NIPPC's Comments on PacifiCorp Interconnection Queue Reform (Nov. 11, 2019) available at http://www.oasis.oati.com/woa/docs/PPW/PPWdocs/NIPPC_PAC_GIQ_Reform_NOV11final.pdf

47 PacifiCorp draft Schedule QF at QF.1 (Aug. 9, 2019).

48 *Kootenai Elec. Coop., Inc.*, 143 FERC ¶ 61,232 at P. 33 (2013).

49 PacifiCorp draft Schedule QF at QF.2 (Nov. 19, 2019).

50 *See* WUTC Docket No. UE-190666, PacifiCorp's Initial Filing Cover Letter at 8.

executable version.[51] This interim step is not necessary since all PacifiCorp is doing at this point is filling in the blanks of a form agreement and should already have all of the QF's necessary information to complete the form and exhibits. If the QF reviews the draft and wants to proceed, it should be able to proceed directly to the executable PPA.

In addition to this step being completely unnecessary, PacifiCorp provides itself with no deadline within which to provide said "proposed final version." At a minimum, there should be a deadline of 15 business days.

This step should be changed to reflect that interim draft PPAs will be provided at 15-business-day intervals, if a QF requests a change to the draft PPA. This is similar to language that is included in PSE's tariff that "[t]he Company will make mutually-agreeable changes, if needed, to the PPA within 15 business days."[52] Often there will be an error or other issue in the PPA and the QF will request a change; the utility should have a deadline within which to respond to such changes so the utility does not have the opportunity to delay and so the QF knows when to expect its next draft.

The information requested in this section for standard QFs is not necessary.[53] Standard QFs are small and not complex. They provide enough information in their initial information disclosure to sufficiently prepare a draft and executable contract and little time has passed between when the initial information was provided and when this supplemental information is requested. As such, the informational requirements should be removed.

E. 15 Business Days is Not Sufficient Time for Some QFs to Secure Signatures on an Executable PPA

On sheet QF.4 (section I.B.6) for standard QFs and sheet QF.7 (section I.B.7) for non-standard QFS, PacifiCorp requires that the QF execute and return the partially executed PPA to PacifiCorp within 15 business days of the QF's receipt of the executable version.[54] Fifteen business days is not sufficient time to secure internal approval of the contract form for many QFs. For example, for some companies, it is mid-level employee who negotiates the contract, and then they need to get approval of the company executives, which can sometimes take time. Similarly, governmental units like cities, counties and irrigation districts often have internal review and decision-making processes that occur on a monthly basis. These reviews often sometimes cannot start in earnest until after the have obtained an executable contract. PSE's tariff proposed 45 business days,[55] which should provide more than enough time for the QF to

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51 PacifiCorp draft Schedule QF at QF.4 (Aug. 9, 2019).
52 UE-190666 PSE draft Schedule 91 at Section 8.C (Nov. 22, 2019).
53 And also, as discussed above, the interconnection requirements are inconsistent with PURPA.
54 PacifiCorp draft Schedule QF at QF.4, QF.7 (Aug. 9, 2019).
55 UE-190666 PSE draft Schedule 91 at Section 8.E (Nov. 22, 2019).

review and sign off. As such, PacifiCorp's tariff should be revised to allow 45 business days for the QF to sign the executable PPA.

F. 90 Days' Notice Prior to Filing a Complaint is Unreasonable

On sheet QF.9, PacifiCorp requires a QF to provide it with notice 90 days or almost three months before filing a complaint with the Commission. This is completely unreasonable. While it is generally desirable to resolve disputes outside of formal proceedings, there are many reasons for not providing notice to PacifiCorp before it files a complaint.

G. PacifiCorp Should Include the Commission's Entire LEO Rule in the Tariff

On sheet QF.9 (section I.D), PacifiCorp includes some but not all of the language from the Commission's rule regarding the formation of LEOs. Specifically, PacifiCorp states that should an irreconcilable disagreement arise, the QF may petition the Commission to determine "whether the Seller is entitled to a legally enforceable obligation and the date such obligation occurred based on the facts and circumstances of such case."[56] PacifiCorp notably leaves out the part of the rule that "[i]n making its determination, the commission will recognize that the formation of a [LEO] is based on a [QF] committing itself to sell all or part of its electric output to an electric utility."[57] NIPPC and REC believe that including only part of the rule creates an ambiguity and possibly a confusing and/or conflicting legal standard. As such, PacifiCorp should be required to include all of the rule language or omit the LEO language from the tariff.

H. Timing Should be Flexible

As with Avista and PSE, NIPPC and REC wish to clarify that timing is flexible. If a draft contract is done in less than 15 business days (or other applicable deadline), there is no reason to wait until the 15th day just "to run out the clock" when there is an impending rate decrease as some utilities have done. If there is an impending rate decrease, then the utility should endeavor to provide the draft contracts back as quickly as possible.

I. Additional Requests for Information Should be Made in Good Faith

Again, similar to comments made regarding Avista and PSE, NIPPC and REC understand that statements giving PacifiCorp the authority or permission to request additional, open-ended information are limited to information that is reasonably necessary and that PacifiCorp will only request in good faith and not out of any drive to delay the contracting process. For example, PacifiCorp "[m]ay request any additional information from the Seller necessary to finalize the terms of the PPA and satisfy the Company's due diligence with respect to the QF and proposed PPA."[58] This is the type of language that a utility may lean on to delay the negotiation process

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[56] PacifiCorp draft Schedule QF at QF.4, QF.9 (Aug. 9, 2019).

[57] WAC 480-106-030(2)(b).

[58] PacifiCorp draft Schedule QF at QF.7 (Aug. 9, 2019).

until a lower avoided cost price becomes effective and for that reason is suspect. NIPPC and REC understand, however, that there may instances where such information is reasonably necessary. As such, NIPPC and REC have no specific changes, but are merely taking this opportunity to clarify that requests for such information must be made in good faith and must be reasonable.

IV. Other Issues

It is NIPPC and REC's understanding that the remaining issues related to PacifiCorp's compliance filing will be resolved on the following schedule:

- The methodology for negotiating non-standard prices will be filed by PacifiCorp in a separate filing before December 31, 2019.
- The PPA contract terms and conditions will be addressed in 2020.

V. Conclusion

NIPPC and REC appreciate the opportunity to submit comments, and hope that PacifiCorp uses the time prior to the Commission's decision on these issues to work with NIPPC and REC to resolve some of these disputed issues.

Sincerely,

Irion A. Sanger

cc: John Lowe, Executive Director REC
Carol Opatrny, Interim Executive Director NIPPC