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May 17, 2024

VIA E-MAIL TO

Public Utility Commission of Oregon
Filing Center
201 High Street SE, Suite 100
Salem, Oregon 97301-3398

Re: Docket No. 2322 - *Pilot Rock Solar 1, LLC et al. v. PacifiCorp, dba Pacific Power.*

Attached for filing in the above-referenced docket, please find PacifiCorp's Motion to Dismiss, including Attachments A-I.

Please contact this office with any questions.

Sincerely,

Cole Albee

Cole Albee
Paralegal
McDowell Rackner Gibson PC

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UM 2322

PILOT ROCK SOLAR 1, LLC; PILOT ROCK SOLAR 2, LLC; TUTUILLA SOLAR, LLC; BUCKAROO SOLAR 1, LLC; and BUCKAROO SOLAR 2, LLC, Complainants, v. PACIFICORP, d/b/a PACIFIC POWER, Respondent. Pursuant to ORS 756.500.	**PACIFICORP'S MOTION TO DISMISS**

I. INTRODUCTION

In accordance with OAR 860-001-0420(3) and Oregon Rule of Civil Procedure (ORCP) 21, PacifiCorp, d/b/a Pacific Power, submits this Motion to Dismiss (Motion) to the Public Utility Commission of Oregon (Commission). The Commission should dismiss several claims included in the First Amended Complaint (Complaint) filed by Pilot Rock Solar 1, LLC (PRS1), Pilot Rock Solar 2, LLC (PRS2), Tutuilla Solar, LLC (Tutuilla), Buckaroo Solar 1, LLC (Buckaroo 1), and Buckaroo Solar 2, LLC (Buckaroo 2) (collectively, the Complainants or Sunthurst[1]) on April 17, 2024. Specifically, the Commission should dismiss the following for failure to state a claim on which relief can be granted:

[1] Each of the five projects is wholly owned by Sunthurst Energy, LLC. *See Pilot Rock Solar 1, LLC et al. v. PacifiCorp, dba Pacific Power*, Docket No. 2322, First Amended Complaint at n.1 (Apr. 17, 2024) (*hereinafter*, "First Am. Compl.").

- Sunthurst's request that the Commission eliminate the requirement to install direct transfer trip (DTT) equipment at PRS1 and PRS2 (First Claim for Relief, Count 1 and Second Claim for Relief);
- Sunthurst's request to modify the line extension required to interconnect PRS1 and PRS2 with PacifiCorp's system and to require retail customers to pay for the line extension (Third Claim for Relief);
- Sunthurst's request that the Commission require PacifiCorp to upfront fund and finance the interconnection costs for Buckaroo 1, Tutuilla, and PRS2 (First Claim for Relief, Count 3); and
- Sunthurst's request to install a battery energy storage system (BESS) at Buckaroo 1 and amend its interconnection agreement and power purchase agreement (PPA) accordingly (Third Claim for Relief).

First, claim preclusion applies to contested cases before the Commission and acts to prevent parties from relitigating matters the Commission already decided.[2] Here, Sunthurst seeks to improperly relitigate interconnection requirements for PRS1 and PRS2 that were explicitly raised in Sunthurst's prior complaint case, docket UM 2118. Sunthurst specifically challenged the DTT requirement and PacifiCorp filed extensive testimony and briefing explaining why DTT is necessary to safely and reliably interconnect PRS1 and PRS2. In response to PacifiCorp's testimony, Sunthurst "dropped its objections to costly [DTT] relay protection after PacifiCorp provided a reasoned justification."[3] The

[2] *Drews v. EBI Cos*., 310 Or 134, 142, 795 P.2d 531, 536 (1990) ("Both issue preclusion and claim preclusion apply to administrative proceedings, provided that the tribunal's decision-making processes include certain requisite characteristics.").
[3] *Sunthurst v. PacifiCorp*, Docket No. UM 2118, Sunthurst Energy, LLC's Reply Brief at 3 (Apr. 13, 2021) (included as Attachment H).

Commission ultimately dismissed Sunthurst's complaint with prejudice.[4] Sunthurst's Complaint here neither acknowledges its prior litigation nor provides any justification for relitigating the same matters here. The Commission must dismiss the DTT claims for PRS1 and PRS2 because they are precluded by Sunthurst's prior litigation.

Second, Sunthurst's claims related to the line extension required for PRS1 and PRS2 are also barred by claim preclusion. Like DTT, Sunthurst also challenged the line extension for PRS1 and PRS2 in docket UM 2118. In the prior case, Sunthurst argued that retail customers should share the costs of the line extension because it will be used to serve other PacifiCorp customers in the vicinity of PRS1 and PRS2. Sunthurst makes the same argument here. Because the issue was already litigated, claim preclusion bars relitigating here.

In addition, there is no justiciable dispute because Sunthurst's request for relief presumes that at some future point in time additional retail customers will materialize, and when those customers materialize, the line extension should be redesigned and paid for by retail customers. At present, however, there are no other retail customers taking service in the vicinity of PRS1 and PRS2, and PacifiCorp has no plans to construct additional distribution facilities to serve customers that do not presently exist. Because Sunthurst's claim "depend[s] on the occurrence of future events that may or may not happen,"[5] it must be dismissed.

Third, the Commission's rules require Sunthurst to either make progress payments under an agreed upon schedule in its interconnection agreements or pay a deposit equal to

[4] *See Sunthurst v. PacifiCorp*, Docket No. UM 2118, Order No. 21-296 (Sept. 15, 2021) (included as Attachment I).

[5] *Berg v. Hirschy*, 206 Or App 472, 475, 136 P.3d 1182, 1184 (2006).

100 percent of the estimated interconnection costs.[6] Sunthurst asks the Commission to force PacifiCorp to amend its interconnection agreements for Buckaroo 1, Tutuilla, and PRS2 to allow Sunthurst to pay all or most of the interconnection costs after its projects reach commercial operation. This request is contrary to the Commission's rules and would expose PacifiCorp—and by extension retail customers—to unreasonable risk of harm in the event Sunthurst fails to pay the interconnection costs once they are incurred. Given Sunthurst's track record of consistently failing to honor its contractual obligations set forth in its interconnection agreements, the risk of non-payment is particularly acute and Sunthurst's request that PacifiCorp upfront fund and finance its interconnection costs must be dismissed.

Fourth, there is no present dispute between PacifiCorp and Sunthurst related to the installation of BESS at Buckaroo 1 and therefore the issue is not ripe for adjudication by the Commission. Sunthurst has never requested an amended PPA to include BESS and has failed to provide the information necessary to amend its interconnection agreement. If Sunthurst wants to amend its agreements, it must do so in accordance with the Commission-approved PPA and interconnection processes. Unless and until there is an actual dispute, this claim for relief is premature.

[6] OAR 860-082-0035(5). The Commission has granted PacifiCorp a waiver of certain interconnection rules in order to accommodate its transition to cluster studies and as a result PacifiCorp implemented its own small generator interconnection procedures, which were filed as a compliance filing in docket UM 2108. For purposes of this filing, however, the relevant rules in Division 82 and PacifiCorp's small generator interconnection procedures are the same and therefore the references here will be to the rule.

II. BACKGROUND

A. Sunthurst's five solar projects

Complainants are five projects that have been pre-certified to participate in the Oregon Community Solar Program (CSP).[7] For purposes of PacifiCorp interconnection process, PRS1 has been designated Q0666, PRS2 has been designated Q1045, Tutuilla has been designated OCS0245, Buckaroo 1 has been designated OCS062, and Buckaroo 2 has been designated OCS063.[8] The projects are wholly owned by Sunthurst Energy, LLC.[9] Sunthurst and PacifiCorp executed interconnection agreements for all five projects.

1. PRS1

PRS1 is a 1.98 MW solar facility.[10] Sunthurst completed the interconnection study process and entered into a small generator interconnection agreement on March 14, 2016.[11] In the interconnection agreement, Sunthurst agreed to meet critical project development milestones and adhere to a payment schedule that would allow interconnection to occur by May 15, 2017.[12] At Sunthurst's request, PacifiCorp agreed to extend the project development milestones and payment schedule on seven separate occasions.[13] Sunthurst has repeatedly failed to meet its obligations under the interconnection agreements.

2. PRS2

PRS2 was originally a 6 MW solar facility that was studied for interconnection before being withdrawn and resized to 2.99 MW.[14] PRS1 and PRS2 proposed to use the

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[7] First Am. Compl. at 1, n.1.
[8] First Am. Compl. at 1, n.1.
[9] First Am. Compl. at 2.
[10] First Am. Compl., Attachment B at 19 (Interconnection Agreements between Sunthurst Energy, LLC and PacifiCorp).
[11] First Am. Compl., Attachment B at 2.
[12] First Am. Compl., Attachment B at 21.
[13] *See* First Am. Compl., Attachment B at 31–78.
[14] First Am. Compl., Attachment B at 96.

same interconnection facilities and have the same point of interconnection. PRS2 executed a small generator interconnection agreement on March 17, 2022.[15] Sunthurst agreed to meet critical project development milestones and adhere to a payment schedule that would allow interconnection to occur by December 31, 2022.[16] At Sunthurst's request, PacifiCorp agreed to extend the project development milestones and payment schedule on two occasions.[17] Sunthurst has repeatedly failed to meet its obligations under the interconnection agreements.

3. Tutuilla

Tutuilla is a 1.56 MW solar facility.[18] Sunthurst and PacifiCorp entered into a community solar project interconnection agreement on December 28, 2021.[19] In the agreement, Sunthurst agreed to meet critical project development milestones and adhere to a payment schedule that would allow interconnection to occur by December 30, 2022.[20] At Sunthurst's request, PacifiCorp agreed to extend the milestones on two occasions.[21] Sunthurst has repeatedly failed to meet its obligations under the interconnection agreements.

4. Buckaroo 1

Buckaroo 1 is a 2.4 MW solar facility.[22] Buckaroo 1 executed a community solar program interconnection agreement on September 30, 2022.[23] In the agreement, Sunthurst agreed to meet critical project development milestones and adhere to a payment schedule

[15] First Am. Compl., Attachment B at 79.
[16] First Am. Compl., Attachment B at 98.
[17] *See* First Am. Compl., Attachment B at 110–23.
[18] First Am. Compl., Attachment B at 140.
[19] First Am. Compl., Attachment B at 124.
[20] First Am. Compl., Attachment B at 142.
[21] *See* First Am. Compl., Attachment B at 154–64.
[22] First Am. Compl., Attachment B at 181.
[23] First Am. Compl., Attachment B at 165.

that would allow interconnection to occur by July 21, 2023.[24] At Sunthurst's request, PacifiCorp agreed to extend milestones for Buckaroo 1 and issued an amended interconnection agreement, which was entered into on May 22, 2023.[25] Sunthurst failed to meet its obligations under the original interconnection agreement.

5. Buckaroo 2

Buckaroo 2 is a 2.99 MW solar facility.[26] Buckaroo 2 executed a community solar program interconnection agreement on September 30, 2022.[27] In the agreement, Sunthurst agreed to meet critical project development milestones and adhere to a payment schedule that would allow interconnection to occur by July 21, 2023.[28] At Sunthurst's request, PacifiCorp agreed to extend milestones for Buckaroo 2 and issued an amended interconnection agreement, which was entered into on May 22, 2023.[29] Sunthurst failed to meet its obligations under the original interconnection agreement.

B. Sunthurst's prior litigation related to PRS1 and PRS2 (docket UM 2118)

On September 29, 2020, Sunthurst filed a complaint against PacifiCorp related to the interconnection of PRS1 and PRS2. The complaint was docketed as UM 2118. In its complaint, Sunthurst challenged the estimated interconnection costs and requirements for PRS1 and PRS2 and, as relevant here, specifically challenged the DTT requirement and the line extension necessary to interconnect PRS1 and PRS2.[30]

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[24] First Am. Compl., Attachment B at 183.
[25] First Am. Compl., Attachment B at 196–200.
[26] First Am. Compl., Attachment B at 217.
[27] First Am. Compl., Attachment B at 201.
[28] First Am. Compl., Attachment B at 219.
[29] First Am. Compl., Attachment B at 231–35.
[30] *See Sunthurst v. PacifiCorp*, Docket No. UM 2118, Compl. at 11–12 (Sept. 29, 2020) (included as Attachment D); *see, e.g.*, *Sunthurst v. PacifiCorp*, Docket No. UM 2118, Sunthurst Energy, LLC's Opening Testimony of Daniel Hale and Michael Beanland at Sunthurst/100, Hale/5–6 and Sunthurst/200, Beanland/5, 7, 9–11, 29 (Dec. 15, 2020) (included as Attachment E).

On September 15, 2021, the Commission issued Order No. 21-296, which found that the costs for interconnection with respect to PRS1 and PRS2 were reasonable and dismissed Sunthurst's complaint with prejudice.[31]

C. Interconnection agreement project milestones and progress payments

Interconnection agreements contain "milestones" that describe specific actions that both PacifiCorp and the interconnection customer must undertake to enable the interconnection to occur on the timeline contemplated in the interconnection agreement. The milestones include critical project development dates (e.g., requiring an interconnection customer to provide its project design by a date certain) and a progress payment schedule. The progress payment schedule ensures that PacifiCorp has sufficient funds from the interconnection customer to begin (and continue) the design, procurement, and construction work necessary to achieve interconnection.

The progress payment requirements included in PacifiCorp's interconnection agreements implement OAR 860-082-0035(5),[32] which provides two options for an interconnection customer to pay for the costs of its interconnection. First, an interconnection customer can agree "to make progress payments on a schedule established by the applicant and the interconnecting public utility[.]"[33] Second, if an interconnection

[31] Docket No. UM 2118, Order No. 21-296.
[32] OAR 860-082-0035(5) ("A public utility may not begin work on interconnection facilities or system upgrades before an applicant receives the public utility's good-faith, non-binding cost estimate and provides written notice to the public utility that the applicant accepts the estimate and agrees to pay the costs. A public utility may require an applicant to pay a deposit before beginning work on the interconnection facilities or system upgrades.").
[33] OAR 860-082-0035(5)(a) ("If an applicant agrees to make progress payments on a schedule established by the applicant and the interconnecting public utility, then the public utility may require the applicant to pay a deposit of up to 25 percent of the estimated costs or $10,000, whichever is less. The public utility and the applicant must agree on progress billing, final billing, and payment schedules before the public utility begins work.").

customer does not agree on a progress payment schedule, "then the public utility may require the applicant to pay a deposit of up to 100 percent of the estimated costs."[34]

Completion of the interconnection and achieving commercial operation of a project is dependent on the interconnection customer fulfilling its milestone obligations by the dates in the agreement. The milestones are typically sequential in nature and later milestones cannot be undertaken if an earlier milestone obligation is not met. Therefore, if an interconnection customer fails to timely meet its milestone obligations, then often all the remaining milestone dates—including the commercial operation date—must be reassessed and modified. Typically, if earlier milestones are not met, later milestones must be re-scheduled to account for the delay.

III. LEGAL STANDARD

The Commission's administrative rules along with the ORCP govern contested case proceedings before the Commission.[35] ORCP 21 authorizes a defense against a pleading through a motion to dismiss for "failure to state ultimate facts sufficient to constitute a claim."[36] When considering a motion to dismiss for failure to state a claim, "all factual allegations are assumed to be true, and construed in a light most favorable to the nonmoving

[34] OAR 860-082-0035(5)(b) ("If an applicant does not agree to make progress payments, then the public utility may require the applicant to pay a deposit of up to 100 percent of the estimated costs. If the actual costs are lower than the estimated costs, then the public utility must refund the unused portion of the deposit to the applicant within 20 business days after the actual costs are determined.").
[35] OAR 860-001-0000(1).
[36] ORCP 21A(1)(h).

party."[37] Upon granting a motion to dismiss, the Commission "may enter judgment in favor of the moving party."[38]

IV. DISCUSSION

A. Sunthurst cannot relitigate the DTT requirement for PRS1 and PRS2 (First Claim for Relief, Count 1; Second Claim for Relief).

"It is appropriate for an administrative agency to apply res judicata to cases in which it acts in a quasi-judicial capacity."[39] Res judicata, or claim preclusion,[40] applies not only to issues actually litigated in prior cases, but also to claims that could have been raised and that arise out of the same factual transaction.[41] A "claim" for purposes of claim preclusion encompasses "a group of facts which entitled [complainant] to relief."[42] Claim preclusion does not require that the parties actually litigated an issue or fact; instead, "the rule forecloses a party that has litigated a claim against another from further litigation on that same claim or any ground or theory of relief that the party could have litigated in the

[37] *Portland General Electric Co. v. Dayton Solar I LLC, et al*., Docket No. UM 2151, Order No. 21-210 at 3 (June 25, 2021); *Huang v. Claussen,* 147 Or App 330, 332, 936 P.2d 394, 394 (1997) ("In considering the sufficiency of plaintiff's complaint, we accept as true all well-pleaded allegations and all reasonable inferences that may be drawn therefrom, *Stringer v. Car Data Systems, Inc.*, 314 Or 576, 584, 841 P.2d 1183 (1992), *recon den*, 315 Or 308, 844 P.2d 905 (1993), but disregard any allegations that are conclusions of law, *Tydeman v. Flaherty*, 126 Or App 180, 182, 868 P.2d 755 (1994).").

[38] ORCP 21(A)(2)(c).

[39] Or Op Atty Gen OP-6454 (June 8, 1992); *In the Matter of PacifiCorp, dba Pacific Power, Application to Reduce the Qualifying Facility Contract Term and Lower the Qualifying Facility Standard Contract Eligibility Cap*, Docket No. UM 1734, Order No. 15-209 at 3 (July 7, 2015) (When acting in its judicial capacity, "it is appropriate for [the Commission] to prevent parties from relitigating matters[.]").

[40] *Drews*, 310 Or at 139 ("Because decisions use the term '*res judicata'* inconsistently, it is important to clarify the terminology used here. 'Preclusion by former adjudication' is a doctrine of rules and principles governing the binding effect on a subsequent proceeding of a final judgment previously entered in a claim. The term comprises two doctrines: claim preclusion, also known as *res judicata*, and issue preclusion, also known as collateral estoppel. Some authors use the term *res judicata* to refer to both subdivisions of former adjudication doctrine.").

[41] *Rennie v. Freeway Transport,* 294 Or 319, 323, 656 P.2d 919, 921 (1982) ("[A] plaintiff who has prosecuted one action against a defendant through to a final judgment is barred from prosecuting another action against the same defendant where the claim in the second action is one which is based on the same factual transaction that was at issue in the first, seeks a remedy additional or alternative to the one sought earlier, and is of such a nature as could have been joined in the first action.").

[42] *Reynolds v. USF Reddaway, Inc.*, 283 Or App 21, 24–25, 394 P.3d 998, 1000 (2016).

first instance."[43] "To prevent splitting of the dispute or controversy, courts employ a broad definition of what could have been litigated."[44] Here, Sunthurst's prior litigation in docket UM 2118 precludes relitigating the interconnection requirements for PRS1 and PRS2.

1. Sunthurst challenged the interconnection requirements for PRS1 and PRS2 <u>and lost</u>.

Sunthurst's Complaint seeks an order declaring that DTT is unreasonable for all five of Sunthurst's projects, including PRS1 and PRS2.[45] However, Sunthurst already litigated the interconnection requirements for PRS1 and PRS2 in docket UM 2118.[46] In that case, Sunthurst challenged the estimated interconnection costs and requirements and alleged, *inter alia*, that "PacifiCorp's interconnection costs for Oregon small generating facilities [were] unreasonably high."[47] The Commission rejected Sunthurst's argument and dismissed Sunthurst's complaint *with prejudice*.[48] To "protect limited dispute-resolution resources from repeated expenditure upon the same overall dispute," Sunthurst is barred from relitigating the interconnection requirements for PRS1 and PRS2.[49]

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[43] *Hawkins v. 1000 Ltd. Partnership*, 282 Or App 735, 749, 388 P.3d 347, 355 (2016).
[44] *Drews*, 310 Or at 141.
[45] First Am. Compl. at 40.
[46] Docket UM 2118 arose after Sunthurst filed a formal complaint on September 29, 2020. Formal complaints like docket UM 2118 require the use of a "quasi-judicial contested case proceeding." *In the Matter of Pub. Util. Comm'n of Or., Amending Internal Operating Guidelines*, Docket No. UM 2055, Order No. 20-386, App. A at 3 (Oct. 27, 2020); *see also id.* at 15 ("The Commission acts in a quasi-judicial capacity when it determines the rights of individual parties, or where the Commission has determined to use trial-like procedures to investigate a particular matter.").
[47] Docket No. UM 2118, Compl. at 11–12 (included as Attachment D).
[48] Docket No. UM 2118, Order No. 21-296.
[49] *Drews*, 310 Or at 141.

2. Sunthurst conceded DTT was reasonable for PRS1 and PRS2.

Sunthurst not only challenged the overall interconnection costs and requirements in docket UM 2118, Sunthurst specifically challenged the DTT requirement.[50] Sunthurst's direct testimony from Daniel Hale stated:

> When I received the System Impact Study (SIS) for [PRS1], I saw that the costs were dominated by the **direct transfer trip scheme (DTT)**. I hired a cost consultant to determine why costs were so high. He was a long time PacifiCorp systems engineer, now consulting to project developers. He reviewed IEEE 1547 requirements as they apply to smart inverters and determined that most utilities do not require DTT for projects under 2 MW if the inverters comply with IEEE 1547. . . PacifiCorp would not remove the [DTT] requirement.[51]

Sunthurst also filed expert testimony challenging the communication requirements for implementing DTT at PRS1 and PRS2.[52]

PacifiCorp provided detailed response testimony and briefing addressing Sunthurst's objections to DTT.[53] In docket UM 2118, like here, Sunthurst claimed that DTT is unnecessary to prevent unintentional islanding.[54] In docket UM 2118, PacifiCorp explained that DTT was required to ensure timely disconnection of Sunthurst's generation in the event of a system fault, i.e., without DTT unintentional islanding could occur on the circuit and cause adverse system conditions.[55] In docket UM 2118, like here, Sunthurst

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[50] *See, e.g.*, Sunthurst/100, Hale/5–6; Sunthurst/200, Beanland/5, 7, 9–11, 29 (emphasis added) (included as Attachment E).

[51] *Id*. at Sunthurst/100, Hale/5–6.

[52] *Id*. at Sunthurst/200, Beanland/5, 7, 9–11, 29.

[53] *See* PAC/100, Bremer/18, 28 and PAC/200, Patzkowski, Taylor, Vaz/39–42 (Jan. 26, 2021) (included as Attachment F); *Sunthurst v. PacifiCorp*, Docket No. UM 2118, PacifiCorp Opening Brief at 26–27 (Mar. 26, 2021) (included as Attachment G).

[54] First Am. Compl. at 23–24.

[55] *See* PAC/200, Patzkowski, Taylor, Vaz/39 ("Mr. Hale claims that he reviewed the Institute of Electrical and Electronics Engineers (IEEE) 1547 requirements as they apply to smart inverters and determined that most utilities do not require DTT for projects under 2 MW if the inverters comply with IEEE 1547. This is incorrect. PRS1 and PRS2 will interconnect to the 12.5 kilovolt (kV) circuit 5W406 out of the Pilot Rock substation. Circuit 5W406 is the only feeder connected to the 69 – 12.5 kV transformer bank #2 at the substation. Potential power production from PRS1 will be greater than the daytime load on the feeder and on the transformer some days of the year. With the addition of PRS2, the combined potential power from the

claimed that DTT is not required because it will use inverters capable of quickly separating its generation from the system.[56] In docket UM 2118, PacifiCorp explained at length why the inverters were insufficient.[57] PacifiCorp's extensive testimony summarized the need for DTT:

> The protective relay system that is required for PRS1 will meet the requirements to: (1) disconnect the solar generation in a timely manner for faults on the 12.5 kV circuit; (2) maintain the 20-cycle recloser function of 5W406; and (3) minimize the potential damage for a problem in the 69 – 12.5 kV transformer—all without causing the disconnection of the generation facilities for faults on the 230 kV network. The proposed inverter controls cannot meet these requirements. The protective relay system required for PRS1 will be adequate for the addition of PRS2.[58]

In response to PacifiCorp's testimony and briefing, Sunthurst's reply brief stated that Sunthurst "*dropped its objections to costly Direct Transfer Trip relay protection after*

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two generation facilities will be greater than the daytime load on the feeder and the transformer most days of the year. Due to this generation to load ratio under/over voltage and frequency conditions when the generation is isolated with the load cannot be relied on to cause the timely disconnection of the generation from the circuit.") (included as Attachment F).

[56] First Am. Compl. at 24.

[57] *See* PAC/200, Patzkowski, Taylor, Vaz/40–41 ("Sunthurst proposed that the inverters will be equipped with control circuits capable of detecting and disconnecting the inverters for conditions when the generation is isolated with load without relying on under/over voltage and frequency relay elements to meet IEEE 1547 requirements. IEEE 1547 requires that the inverters stop injecting power into the system in less than two seconds from the isolation of the generation with the load. The timing between the tripping of breaker 5W406 at Pilot Rock substation and the reclosing of the breaker is 20 cycles. However, meeting the IEEE 1547 requirements will not be adequate to support successful reclosing on this feeder. In addition to the problem of supporting a successful trip and reclose event, there is the risk of damage to the 69 – 12.5 kV transformer for a problem in the transformer Two seconds is an unacceptable amount of time to attempt to minimize damage to a faulted transformer. At two seconds, there would be no hope of salvaging anything from the transformer and there would be risks of a fire in the substation, which could damage other equipment and present a safety concern for PacifiCorp's employees and the public in general. Additionally, the solar projects are required to remain connected to the transmission network for faults on the network that do not result in the isolation of the generation, low voltage ride through, in compliance with NERC PRC-024-2. Pilot Rock substation is fed from BPA's 230 – 69 kV Roundup substation. There are two 230 kV lines into Roundup substation. For a fault on one of these 230 kV lines, the voltage at PRS1 and PRS2 will be zero for the time it takes to detect and isolate the fault. PRS1 and PRS2 are required to remain connected to the system for such an event so that once the faulted line is disconnected and the system is left with just one 230 kV line, the remaining system does not suffer the additional loss of local generation. The requirement to remain connected under NERC PRC-024-2 is another reason why the inverter controls will not suffice.") (included as Attachment F).

[58] *Id.* at 41–42.

PacifiCorp provided a reasoned justification."[59] Sunthurst's actual litigation of the DTT requirement and its eventual agreement that it is reasonable precludes relitigating the same matter here—particularly when Sunthurst is making identical claims.

3. Claim preclusion applies even though the Commission's order did not directly address DTT.

Because Sunthurst agreed that DTT was reasonable, the Commission's final order in docket UM 2118 did not directly address it, although the Commission specifically rejected Sunthurst's challenge to the communication requirements necessary to implement DTT.[60] Claim preclusion, however, does not "require that the determination of the issue be essential to the final or end result reached in the action, claim or proceeding."[61] Instead, claim preclusion only requires the "opportunity to litigate . . . whether or not it is used" and finality.[62] "Where there is an opportunity to litigate the question along the road to the final determination of the action or proceeding, neither party may later litigate the subject or question."[63] Here, Sunthurst initially attempted to litigate the DTT requirement, then later agreed it was reasonable, and the Commission's order in docket UM 2118 is final. Therefore, Sunthurst is precluded from litigating the same claims here.

4. Sunthurst raises no new factual allegations that could not have been raised in docket UM 2118.

Sunthurst may argue that it has made new factual allegations here that were not made in docket UM 2118. However, every claim Sunthurst makes in its Complaint could

[59] Docket No. UM 2118, Sunthurst Energy, LLC's Reply Brief at 3 (emphasis added) (included as Attachment H).
[60] Docket No. UM 2118, Order No. 21-296 at 7–8.
[61] *Drews*, 310 Or at 140.
[62] *Id*.
[63] *Id*.

have been raised in docket UM 2118 when Sunthurst submitted hundreds of pages of testimony and exhibits disputing the interconnection requirements for PRS1 and PRS2.

Sunthurst points to the recent rulemaking implementing IEEE 1547-2018 to suggest that use of that updated standard is a changed circumstance that warrants removal or modification of the DTT requirement.[64] But that standard was adopted in 2018—years before Sunthurst filed its prior complaint.[65] Had Sunthurst sought to take advantage of the 2018 version of that standard, it was required to so in docket UM 2118.

Sunthurst also claims that PacifiCorp's interconnection studies were "flawed" because PacifiCorp allegedly modeled solar generators based on their direct current (DC) capacity, as opposed to the alternating current (AC) capacity flowing onto the grid.[66] This claim, however, is based on a gross misrepresentation of the record in docket AR 659[67] and is contradicted by the interconnection studies for PRS1 and PRS2.[68] Moreover, even assuming for purposes of this Motion that PacifiCorp's studies had contained the alleged flaws, Sunthurst was obligated to raise the supposed flaw in docket UM 2118.

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[64] First Am. Compl. at 25.
[65] OAR 860-082-0015(15).
[66] First Am. Compl. at 22–23; 25.
[67] In docket AR 659, the Commission revised both the small generator interconnection rules (Division 82) and the net metering interconnection rules (Division 39). The prior net metering rules defined a net metering facility's "generation capacity" based on the DC nameplate rating of the facility. The Commission's new rules for net metering facilities, however, "reflect export capacity value, which is typically measured at the inverter as an alternating current (AC) nameplate rating." The record in docket AR 659 clearly explains that this transition from DC to AC ratings applied to only net metering facilities, not small generators like PRS1 and PRS2 because PacifiCorp has always used small generator's AC output when studying the generator's interconnection (i.e., PacifiCorp studies interconnections based on the customer's requested capacity that will be injected onto the grid). Contrary to Sunthurst's mischaracterization of the record in docket AR 659, PacifiCorp did not have a "historical practice" of studying small generators based on their DC capacity.
[68] *See* PRS1 Interconnection Study (Mar. 27, 2020) (included as Attachment B) and PRS2 Interconnection Study (June 2, 2020) (included as Attachment C).

B. Sunthurst's request to modify the line extension for PRS1 and PRS2 is barred by claim preclusion and is not a justiciable dispute. (Third Claim for Relief, Count 1).

1. Challenging the line extension for PRS1 and PRS2 is barred by claim preclusion.

The interconnection agreements for PRS1 and PRS2 require Sunthurst to construct and pay for a line extension so that its projects can reach PacifiCorp's system.[69] Sunthurst requests that the Commission order PacifiCorp to reconfigure the line extension and require retail customers to pay for the line because Sunthurst claims that the reconfigured line will be used to serve future retail customers.[70] Sunthurst raised this exact same argument in docket UM 2118. In that case, Sunthurst recommended that PacifiCorp share the cost of the line extension to Sunthurst's projects because the line will allow the Company "to serve new loads where it previously did not."[71] Sunthurst argued that "PacifiCorp derives benefit from this addition to its distribution system" because the line extension "lowers the cost of serving new customers in the vicinity."[72] PacifiCorp responded in testimony that, "there is no anticipated load that would be served by the new line, it would not be built but for the Sunthurst projects, and provides no other tangible benefit to PacifiCorp."[73]

Ultimately, Sunthurst dropped its line-extension claim and the Commission dismissed Sunthurst's complaint with prejudice.[74] However, because Sunthurst already litigated this claim in docket UM 2118, it is precluded from relitigating the same claim here.

[69] First Am. Compl. at 32–33.
[70] First Am. Compl. at 9–10.
[71] Sunthurst/200, Beanland/30 (included as Attachment E).
[72] Sunthurst/200, Beanland/33–34; *see also* Sunthurst/200, Beanland/29–30 (included as Attachment E).
[73] *See* PAC/200, Patzkowski, Taylor, Vaz/35 (included as Attachment F).
[74] Docket No. UM 2118, Order No. 21-296 at 1.

2. Sunthurst's line extension claim is based on a hypothetical and therefore not justiciable.

In a complaint case, the Commission will not resolve hypothetical disputes based on ". . . speculation [of] facts that may present themselves in the future."[75] When a claim is "contingent on the happening of some event that cannot be forecast and that may never take place, the dispute is not justiciable."[76]

Here, Sunthurst's claim "depend[s] on the occurrence of future events that may or may not happen."[77] Sunthurst alleges that at some undisclosed point in the future, PacifiCorp may be required to build additional facilities near PRS1 and PRS2 to serve future customers that may materialize in an industrial park located in the city of Pilot Rock.[78] Therefore, according to Sunthurst, the interconnection requirements for PRS1 and PRS2 should be modified now to account for this possibility. Interconnection requirements, however, are based on actual conditions, not hypothetical scenarios that may arise sometime in the future.

Sunthurst does not allege that PacifiCorp is planning to build the additional facilities to serve the industrial park, or that there are actual customers currently taking service in the industrial park, or that there are actual customers that will take service in the industrial park in the future. Rather, Sunthurst speculates that it is possible that at some point in the future their interconnection facilities may prove useful to other future PacifiCorp customers. That hypothetical possibility is no basis to modify the

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[75] *Blue Marmot V LLC et al. v. Portland General Electric Co.*, Docket No. UM 1829, Order No. 20-025 at 4 (Jan. 23, 2020); see also *Berg v. Hirschy*, 206 Or App 472, 475, 136 P.3d 1182, 1184 (2006) ("A justiciable controversy must involve present facts, not future events or hypothetical issues.").

[76] *Berg*, 206 Or App at 475 (citing *Hale v. Fireman's Fund Ins. Co. et al*, 209 Or 99, 103–04, 302 P.2d 1010, 1012 (1956)).

[77] *Id*.

[78] First Am. Compl. at 9–11.

interconnection facilities for PRS1 and PRS2 or force customers to pay for a line extension that serves no purpose but to interconnect PRS1 and PRS2.

C. The Commission's rules require Sunthurst to make progress payments (First Claim for Relief, Count 3).

Sunthurst requests an order directing PacifiCorp to agree to amend the Sunthurst interconnection agreements for Buckaroo 1, Tutuilla, and PRS2 to allow Sunthurst to pay for all or most of the costs of its interconnection *after* the projects have reached commercial operation.[79] This request, however, is contrary to the Commission's rules, which do not require PacifiCorp—and by extension retail customers—to upfront fund and finance the costs of Sunthurst's interconnection.

Before beginning work on interconnection facilities or system upgrades, an applicant must accept and agree to pay the estimated interconnection costs.[80] The Commission's rules provide two options for applicants to pay for their interconnection costs.

First, OAR 860-082-0035(5)(a) states:

> If an applicant agrees to make progress payments on a schedule established by the applicant and the interconnecting public utility, then the public utility may require the applicant to pay a deposit of up to 25 percent of the estimated costs or $10,000, whichever is less. The public utility and the applicant must agree on progress billing, final billing, and payment schedules before the public utility begins work.

[79] *See* First Am. Compl. at 40–41. Although Sunthurst's Complaint is not entirely clear, it appears that this claim applies to only these three projects. To the extent the claim applies more broadly, the same basis for dismissal applies too.

[80] OAR 860-082-0035(5) ("A public utility may not begin work on interconnection facilities or system upgrades before an applicant receives the public utility's good-faith, non-binding cost estimate and provides written notice to the public utility that the applicant accepts the estimate and agrees to pay the costs. A public utility may require an applicant to pay a deposit before beginning work on the interconnection facilities or system upgrades.").

Second, OAR 860-082-0035(5)(b) states:

> If an applicant does not agree to make progress payments, then the public utility may require the applicant to pay a deposit of up to 100 percent of the estimated costs. If the actual costs are lower than the estimated costs, then the public utility must refund the unused portion of the deposit to the applicant within 20 business days after the actual costs are determined.

These payment options are set forth in the interconnection agreements for Buckaroo 1, Tutuilla, and PRS2. Sunthurst therefore had the option to either agree to make progress payments or pay 100 percent of the estimated costs up front. Sunthurst chose to provide progress payments, with the schedule of payments set forth in the milestones. The rules do not allow an applicant to require PacifiCorp to fund the interconnection costs and get repaid once the work is complete. Sunthurst's request for relief is therefore contrary to the Commission's interconnection rules and provides no basis for relief.

Sunthurst relies on OAR 860-029-0060(2) to argue that the Commission's QF rules allow a QF to "reimburse" a utility for interconnection costs, thereby providing a basis for Sunthurst's request here.[81] However, even assuming OAR 860-029-0060(2) could be construed to allow the relief Sunthurst seeks, the Commission's small generator interconnection rules state that "[i]f there is a conflict between the small generator interconnection rules and the rules in OAR chapter 860, division 029, then the small generator interconnection rules control."[82] Given that the Division 82 rules specifically prohibit utility financing of interconnection costs, the ambiguous reimbursement language in OAR 860-029-0060(2) does not provide a basis for relief.

[81] First Am. Compl. at 7.
[82] OAR 860-082-0005(4).

Further, OAR 860-082-0025(7)(f)(A) states that a "public utility is entitled to the terms in the standard form [interconnection] agreement." The Commission-approved interconnection agreements do not provide for utility financing and do not include necessary provisions to protect retail customers from potential harm if an interconnection applicant fails to pay the costs to interconnect after they are financed by a utility. For example, at a minimum, the interconnection agreement would need to include reasonable financial security requirements, which are entirely lacking from the Commission-approved interconnection agreement that PacifiCorp is entitled to use. PacifiCorp is entitled to the benefits of the standard, Commission-approved interconnection agreement and Sunthurst cannot force a different agreement on the Company—particularly an agreement that exposes retail customers to unreasonable risk that Sunthurst will not repay amounts fronted by PacifiCorp to pay for Sunthurst's interconnection. This risk of non-payment exists for all interconnection customers, but particularly for Sunthurst, given its history of failing to make to make the payments.

D. The request to install BESS at Buckaroo 1 is not ripe (Third Claim for Relief, Count 2).

"An issue is ripe for judicial determination when the interests of the plaintiff are in fact subjected to or imminently threatened with substantial injury."[83] Here, there is no present dispute between PacifiCorp and Sunthurst and therefore no risk of imminent injury.

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[83] *In the Matter of Portland General Electric Co. Deferred Accounting Authorization for Certain Expenses/Revenue Refunds Associated with Senate Bill 408 and the Sale of Certain Non-Utility Assets*, Docket No. UM 1271, Order No. 07-421 at 8 (Sept. 26, 2007) (quoting *Oregon Newspaper Publishers Ass'n v. Peterson*, 244 Or 116, 120, 415 P.2d 21, 23 (1966)).

1. PacifiCorp is willing to amend the interconnection agreement if installing BESS is not a material modification.

PacifiCorp has instructed Sunthurst that if it wants to install BESS, PacifiCorp must undertake an assessment to determine the BESS constitutes a material modification.[84] Sunthurst has failed to provide the information necessary for PacifiCorp to perform this assessment. If the addition of BESS is not a material modification, then PacifiCorp can amend the existing interconnection agreement for Buckaroo 1 to include BESS. If the addition of BESS is a material modification, then Sunthurst will need to submit a new interconnection request.[85] At present, however, there is no dispute and no risk of imminent harm to Sunthurst because Sunthurst has failed to provide the requested information to determine if BESS can be added to Buckaroo 1.

2. Sunthurst has never requested a PPA that includes BESS.

Because Sunthurst has never requested an amended PPA to include BESS at Buckaroo 1, there is no present dispute or risk of harm. However, the Commission's approved CSP PPA and CSP avoided cost prices do not contemplate the installation of BESS. Therefore, if Sunthurst wants to install BESS at Buckaroo 1, it will be required to terminate its existing PPA and either execute a standard QF PPA utilizing the recently approved solar-plus-storage avoided cost prices or negotiate a non-standard PPA and non-standard pricing that includes the BESS. In either case, however, Sunthurst must follow the procedures laid out in PacifiCorp's avoided cost schedule.

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[84] Emails Between Sunthurst Energy, LLC, and PacifiCorp (Jan. 12, 2024) (included as Attachment A).
[85] OAR 860-082-0025(1)(c).

V. CONCLUSION

For the foregoing reasons, the Commission should dismiss Sunthurst's First Claim for Relief, Count 1 and Second Claim for Relief applicable to PRS1 and PRS2 and Sunthurst's Third Claim for Relief in its entirety.

Respectfully submitted this 17th day of May 2024.

By: ____________________

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Attachments to PacifiCorp's Motion to Dismiss

Attachment A

Email Between Sunthurst and PacifiCorp

Monica Mahal

From: Bremer, Kristopher (PacifiCorp) <Kristopher.Bremer@pacificorp.com>
Sent: Friday, January 12, 2024 11:14 AM
To: daniel@buckaroosolar.com
Cc: 'Michael Beanland'
Subject: RE: [INTERNET] OCS 062 Study Option Ignored + BESS
Attachments: BP83 - MMA.pdf

Daniel,

First, I won't rehash the communications that occurred back when the request to split the request first took place other than to say, that is not allowed. That would constitute two points of interconnection which is not something PacifiCorp can do under a single interconnection request and/or agreement. The only option to do this would be to reduce the OCS062 to your desired size for the current circuit interconnection and submit a new request for the second phase to interconnect to the other circuit. Also, just something worth noting, it appears the open point you're citing is nearly 1.5 miles away from the OCS062 site.

Second, if you wish to add battery storage to this request that will likely be OK, but can you please fill out the attached form to summarize the proposed change. This is the document PacifiCorp's engineers are familiar with when developers ask to make changes to an interconnection project after the project has already been fully studied. Please also provide a detailed on line diagram that shows how the BESS will be tied in with the solar. Forgive me if you already sent that but I couldn't find it. PacifiCorp will need to perform a brief restudy to add the BESS and an amendment to the interconnection agreement will be required to memorialize that.

Finally, please submit the next progress payment of $61K that was due for this project on January 2, 2024 so the project can be formally kicked off and the proposed changes can get incorporated.

Thank you.

Kris Bremer

From: daniel@buckaroosolar.com <daniel@buckaroosolar.com>
Sent: Sunday, December 31, 2023 12:44 PM
To: Bremer, Kristopher (PacifiCorp) <Kristopher.Bremer@pacificorp.com>
Cc: 'Michael Beanland' <mike@wipoen.com>
Subject: [INTERNET] OCS 062 Study Option Ignored + BESS
Importance: High

PacifiCorp,

During the protracted study exchanged stemming from this site's feeder reconfiguration *after* our accepted application and estimate initially from a *further*, more expensive substation and feeder to Pendleton Sub 5W403; our EE requested a Study Option to split on project to both feeders to avoid costly substation upgrades (requested formally by our Attorney, Ken Kaufmann as “Sunthurst’s Response #1” in his October 27, 2021, email attached. According to our records, that Study Option was never provided.

Since, the Company 2023 Clean Energy Plan, attached, acknowledges (see notations) Buckaroo Solar 1’s CREP CS + BESS Project. City of Pendleton WTP facility is a County critical facility and ODOE, State, and other stakeholders intimate with the CS Program agree this application is ideal and important to realize. We are offering our nearby site as the solar host. Our electrical engineer provided a letter and schematic how the existing open tie can be controlled to keep the feeder segment closed between OCS 062 and City WTP. All energy from the ESS is charged by East portion of the OCS 062 and behind PAC CS meter and will have no impact on the system net energy recording. In fact, if the feeder 5W403 does drop, energy from our ESS will discharge as intended and flow through the Company’s WTP meter at the normal billing rate. Without ESS, the WTP transfer switch will open and all energy consumed will be by their generator and 100% lost energy revenue.

The split option, in light of AR 659’s clear recommendations by IREC and implementation in 2024, is requested to applied when this withheld study is conducted. In short, the IEEE-1547-2018 inverters are CPS 100kW (datasheet attached) give adequate protection that the DTT is not “necessary” and chargeable to our project/s. Attached, CPS inverters also will not require a grounding transformer as meet Section 7.4 requirements approved by Company.

In sum, we appreciate the long overdue study option splitting generation and like Study to account for removing DTT and including the modest ESS for 5W203. We are encouraged Company “verbally said to City’s main project contact” they have interest in ESS projects with City very recently. We appreciate a fair and timely study as we’re required to offer updates to ODOE C-REP and CS PA Team, who are specifically asked for this information in reporting.

Sincerely,

Daniel Hale, Managing Member
MRED, LEED AP, STI Certified
Buckaroo Solar, LLC
P: 323.480.3835 | F: 323.782.0760
W: BuckarooSolar.com

Attachment B

PRS1 Interconnection Study

Small Generator Interconnection

Oregon Tier 4 System Impact Study Report

Completed for

("Interconnection Customer")
Q1045

A Qualifying Facility

Proposed Point of Interconnection

Circuit 5W406 out of Pilot Rock substation at 12.5 kV
(at approximately 45° 30' 32.67", -118° 49' 38.87")

March 27, 2020

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1.0 Description of the Generating Facility

("Interconnection Customer") proposed interconnecting 3 MW of new generation to PacifiCorp's ("Public Utility") Circuit 5W406 out of Pilot Rock substation at 12.5 kV located in Umatilla County, Oregon. The project ("Project") will consist of forty-nine (49) Sungrow SG60KU-M inverters for a total requested output of 3 MW. The requested commercial operation date is December 31, 2019.

Interconnection Customer will operate this generator as a Qualifying Facility as defined by the Public Utility Regulatory Policies Act of 1978 (PURPA).

The Public Utility has assigned the Project "Q1045."

2.0 Approval Criteria for Tier 4 Interconnection Review

Pursuant to 860-082-0060(1), a public utility must use the Tier 4 interconnection review procedures for an application to interconnect a small generator facility that meets the following requirements:

(a) The small generator facility does not qualify for or failed to meet Tier 1, Tier 2, or Tier 3 interconnection review requirements; and
(b) The small generator facility must have a nameplate capacity of ten (10) megawatts or less.

3.0 Scope of the Study

Pursuant to 860-082-0060(7)(g) the System Impact Study Report shall consist of a short circuit analysis, a stability analysis, a power flow analysis, voltage drop and flicker studies, protection and set point coordination studies, and grounding reviews, as necessary. The System Impact Study shall state the assumptions upon which it is based, state the results of the analyses, and provide the requirement or potential impediments to providing the requested interconnection service, including a preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. The System Impact Study shall provide a list of facilities that are required as a result of the Interconnection Request and non-binding good faith estimates of cost responsibility and time to construct.

4.0 Independent Study Evaluation

Pursuant to 860-082-0060(7)(h), the application has not provided an independent system impact study that is to be addressed and evaluated along with the results from the Public Utility's own evaluation of the interconnection of the proposed Small Generator Facility.

5.0 Proposed Point of Interconnection

The Interconnection Customer's proposed Small Generator Facility is to be interconnected to the Public Utility's distribution circuit 5W406 out of Pilot Rock substation, roughly 1,400' north of the existing facility point 01401032.0090961. The Interconnection Customer's Small Generator Facility will utilize the interconnection facilities associated with the Interconnection Request studied under queue position Q0666. Figure 1 below, is a one-line diagram that illustrates the interconnection of the proposed Small Generator Facility to the Public Utility's system.

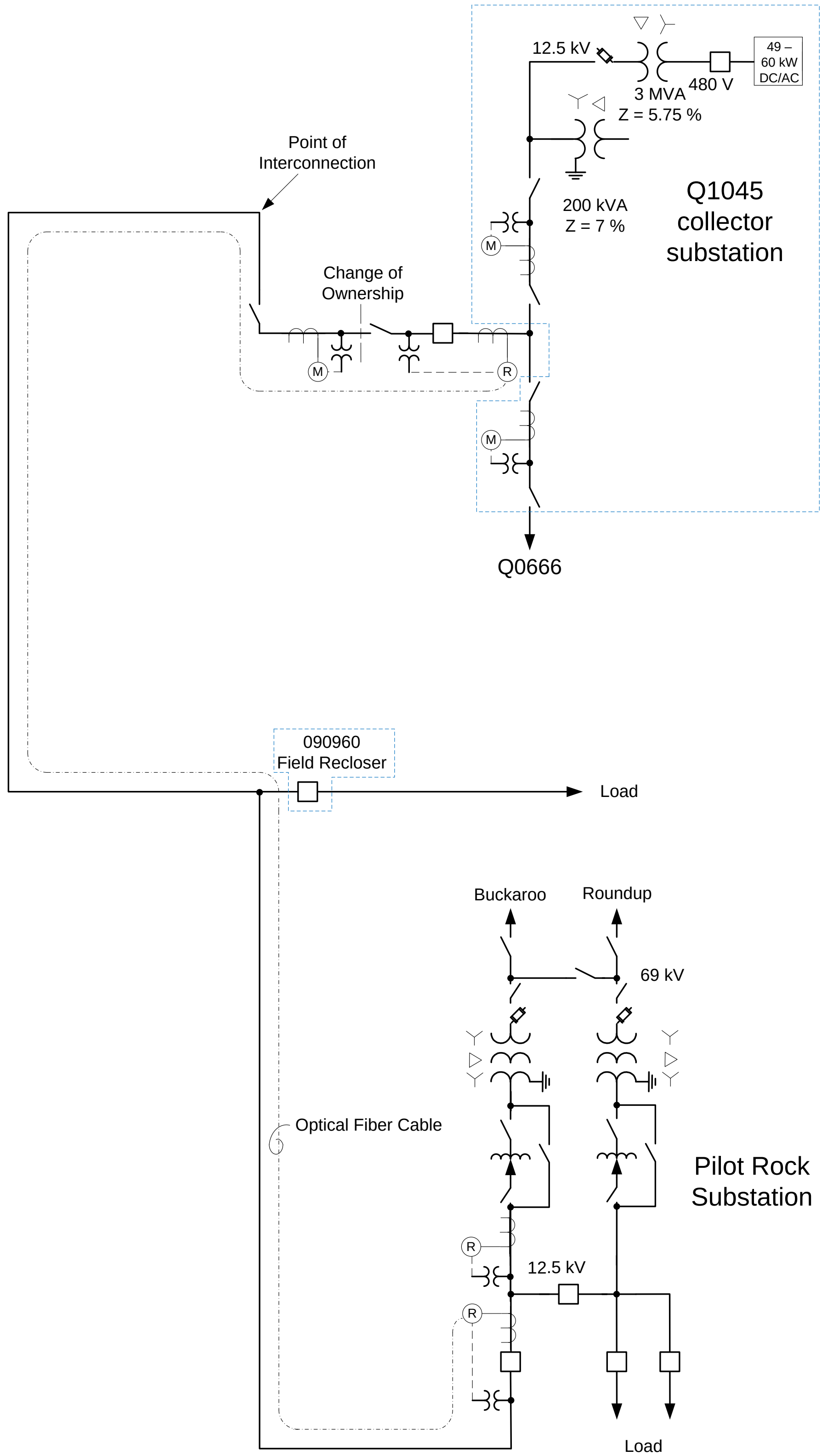

Figure 1: System One Line Diagram

6.0 Study Assumptions

- All active higher priority transmission service and/or generator interconnection requests will be considered in this study and are listed in Appendix 1. If any of these requests are withdrawn, the Public Utility reserves the right to restudy this request, as the results and conclusions contained within this study could significantly change.
- For study purposes there are two separate queues:
  - Transmission Service Queue: to the extent practical, all System Upgrades that are required to accommodate active transmission service requests will be modeled in this study.
  - Generation Interconnection Queue: All relevant higher queue interconnection requests will be modeled in this study.
- The Interconnection Customer's request for interconnection service in and of itself does not convey transmission service.
- This study assumes the Project will be integrated into Public Utility's system at the agreed upon and/or proposed Point of Interconnection ("POI").
- The Interconnection Customer will construct and own any facilities required between the POI and the Project unless specifically identified by the Public Utility.
- Line reconductor or fiber underbuild required on existing poles will be assumed to follow the most direct path on the Public Utility's system. If during detailed design the path must be modified it may result in additional cost and timing delays for the Interconnection Customer's Project.
- Generator tripping may be required for certain outages.
- All facilities will meet or exceed the minimum Western Electricity Coordinating Council ("WECC"), North American Electric Reliability Corporation ("NERC"), and Public Utility performance and design standards.
- Time of use metering does not exist for Pilot Rock substation. The daytime minimum demand for the feeder 5W406 is estimated based on the peak demand on the circuit.
- Peak demand for 5W406 is approximately 6600 kW and 2600 kVAR. There is one 600 kVAR capacitor bank installed on the feeder.
- The minimum daytime load on 5W406 is estimated at 1820 kW and 960 kVAR.
- The solar generation interconnection was studied with a maximum output of 3 MW and a reactive consumption by the Project of 900 kVAR.
- This report is based on the AC Oneline provided by the Interconnection Customer and dated April 28, 2018.
- Inverter specifications were also provided by the Interconnection Customer.
- The power output of the inverters is to 6600 kVA / 6000 kW as stated in the inverter specifications. This appears to comply with reactive requirements for this Project; however, Interconnection Customer is responsible for additional reactive compensation, if needed, to assure total Project output can be delivered at unity power factor.
- The Small Generator Facility is expected to operate during daylight hours every day 7 days per week 12 months per year.
- Contingency transmission configuration for the Public Utility's system is defined as any configuration other than normal transmission configuration.
- Three case studies were assembled and studied in power flow simulation at the transmission level:

- Case 1: Normal Configuration with Pilot Rock fed from BPA breaker L-1122 at Roundup, via the “Birch Creek” 69 kV Line.
- Case 2: Contingency configuration with Pilot Rock fed from Buckaroo and Roundup via the “Coyote Creek” 69 kV line. Switch 3W191 closed, BPA breaker L-1122 open.
- Case 3: Pendleton 69 kV Loop Split (Switch 3W26 open at Buckaroo, breaker L-1123 open at BPA Roundup).

- This report is based on information available at the time of the study. It is the Interconnection Customer’s responsibility to check the Public Utility’s web site regularly for transmission system updates (http://www.pacificorp.com/tran.html)

7.0 REQUIREMENTS

7.1 SMALL GENERATOR FACILITY REQUIREMENTS

The Small Generator Facility and Interconnection Equipment owned by the Interconnection Customer are required to operate under automatic voltage control with the voltage sensed electrically at the POI. The Small Generator Facility should have sufficient reactive capacity to enable the delivery of 100 percent of the Project output to the POI at unity power factor measured at 1.0 per unit voltage under steady state conditions.

Generators capable of operating under voltage control with a voltage droop are required to do so. Studies will be required to coordinate the voltage droop setting with other facilities in the area. In general, the Small Generator Facility and Interconnection Equipment should be operated so as to maintain the voltage at the POI between 1.01 pu to 1.04 pu. At the Public Utility’s discretion, these values might be adjusted depending on the operating conditions. Within this voltage range, the Small Generator Facility should operate so as to minimize the reactive interchange between the Small Generator Facility and the Public Utility’s system (delivery of power at the POI at approximately unity power factor). The voltage control settings of the Small Generator Facility must be coordinated with the Public Utility prior to energization (or interconnection). The reactive compensation must be designed such that the discreet switching of the reactive device (if required by the Interconnection Customer) does not cause step voltage changes greater than +/-3% on the Public Utility’s system.

All generators must meet applicable WECC low voltage ride-through requirements as specified in the interconnection agreement.

As per NERC standard VAR-001-1, the Public Utility is required to specify voltage or reactive power schedule at the POI. Under normal conditions, the Public Utility’s system should not supply reactive power to the Small Generator Facility.

As the Public Utility cannot submit a user written model to WECC for inclusion in base cases, a standard model from the WECC Approved Dynamic Model Library is required 180 days prior to trial operation. The list of approved generator models is continually updated and is available on the http://www.WECC.biz website.

The Interconnection Customer will be required to install a transformer that will hold the phase to neutral voltages within limits when the Small Generator Facility is isolated with the Public Utility's local system until the generation disconnects. The proposed delta – wye step-up transformer with the delta winding on the 12.47 kV side will not accomplish the stabilization of the phase to neutral voltages on the 12.47 kV system. The circuit that the Project is connecting to is a four wire multi-grounded circuit with line to neutral connected load. Figure 1 shows the addition of a wye – delta grounding transformer of adequate power size and impedance that will meet the requirement. The grounding transformer proposed for the Q0666 project alone will not be adequate for both projects. Since the two projects will share a common circuit recloser the projects could also share a common grounding transformer. If that is desired by the Interconnection Customer a grounding transformer can be sized for the combination of the two generation projects.

Under the normal configuration described in Case 1, and the contingency configurations described in Case 2 and 3, there are no identified power flow restrictions with Q1045 generation online. Certain extreme contingency configurations, such as a BPA Roundup 230 kV bus outage, though not explicitly studied, may warrant generation curtailment to 0 MW until the system returns to a normal state.

As the Interconnection Customer's Small Generator Facility will utilize the Interconnection Customer Interconnection Facilities associated with a different Interconnection Request the Interconnection Customer must provide the Public Utility with demonstration of approval from the owner of the Q0666 Interconnection Request for the shared facilities.

7.2 Transmission System Modifications

Transmission level power flow study cases were evaluated for heavy summer, winter, and light loading conditions. For each of the cases, power flows and system voltages were evaluated with and without the proposed Q1045 Small Generator Facility to determine the impact on the transmission system during system normal operation and following various contingency events in the local system. Due to the small size of the proposed interconnection relative to the transmission system, no thermal or voltage deficiencies associated with interconnection of Q1045 were observed.

Historical load records were reviewed to determine the Public Utility's minimum daytime load in the Pendleton area 69 kV system. The minimum daytime load was determined to be less than all in-service and prior queued generation. As a result, reverse power flow at the BPA Roundup 230-69 kV source is anticipated during light load conditions.

7.3 Distribution Modifications

- Install one three phase recloser at a location east of 090960 to insure coordinated fault clearing on the McKay branch of the feeder.
- Install one three phase bank of 219 amp 7.2 kV voltage regulators on the McKay branch to ensure ANSI range A voltages can be maintained at the end of the line.

- Install one three phase bank of 100 amp 7.2 kV voltage regulators on the circuit branch west of the interconnection tap to ensure ANSI range A voltages can be maintained at the end of the line.

7.4 Existing Breaker Modifications – Short-Circuit

The increase in the fault duty on the system as the result of the addition of the Small Generator Facility with photovoltaic arrays fed through 49 – 60 kW inverters connected to a 3 MVA 12.5 kV – 480 V transformer with 5.75% impedance along with the earlier Q0666 project will not push the fault duty above the interrupting rating of any of the existing fault interrupting equipment.

7.5 Protection Requirements

Since the Q1045 Project will share the same circuit recloser as the Q0666 project for the interconnection to the 12.5 kV feeder out of Pilot Rock substation therefore no protection modifications will be required for the Q1045 Project. New relay settings will be developed and installed in the relay associated with the circuit recloser to accommodate the addition of the Q1045 Project.

7.6 Data Requirements (RTU)

Data for the operation of the transmission system will be needed from the collector substation for Q1045. The Public Utility will install a remote terminal unit ("RTU") at the Interconnection Customer collector substation site. The following data will be acquired.

Analogs:

- Net Generation real power MW
- Net Generator reactive power MVAR
- Energy Register KWH
- Q0666 real power MW
- Q0666 reactive power MVAR
- Q0666 Energy Register KWH
- Q1045 real power MW
- Q1045 reactive power MVAR
- Q1045 Energy Register KWH
- A phase 12.5 kV voltage
- B phase 12.5 kV voltage
- C phase 12.5 kV voltage
- Global Horizontal Irradiance (GHI)
- Average Plant Atmospheric Pressure (Bar)
- Average Plant Temperature (Celsius)

Status:

- 12.5 kV circuit recloser

The Interconnection Customer's Small Generator Facility may be required to accept setpoint control signals from the Public Utility's control centers. If required the Small Generator Facility will need to communicate the following points.

- Max Gen MW
- Max Gen MW FB

7.7 Communication Requirements

7.7.1 Line Protection

The optical fiber cable planned to be installed for the Q0666 project between Pilot Rock substation and the collector substation will be used for relaying between the collector site and Pilot Rock substation.

7.7.2 Data Delivery to the Control Centers

The Transmission Provider will install a radio system between Pilot Rock substation and the Public Utility's Cabbage Hill communications site. The tower at Cabbage Hill will have a load analysis done to ensure it can support the new antenna, and will be strengthened if necessary. Radios will be installed at Pilot Rock and Cabbage Hill. At Pilot Rock, a channel bank, 48VDC charger and batteries, router and switch will be installed to carry SCADA, telemetry, voice, and data circuits from the substation to control centers. At Cabbage Hill circuits will be cross-connected to existing comm systems.

7.8 Substation Requirements

<u>Q1045 collector substation</u>

The Public Utility will install a control building at the Interconnection Customer's shared collector substation location for the installation of protective, communications and metering equipment.

The Interconnection Customer will provide a separate graded, grounded and fenced area along the perimeter of the Interconnection Customer's Small Generator Facility for the Public Utility to install the control building. This area will have unencumbered access for the Public Utility. AC station service will be supplied by the Interconnection Customer and DC power for the control house will be supplied by the Public Utility.

<u>Pilot Rock substation</u>

At Pilot Rock substation the settings of regulator R-816 will need to be modified to account for this additional generation. Communications equipment will need to be installed to support the new microwave system.

7.9 Metering Requirements

<u>Interchange Metering</u>

The revenue metering will be located at the Interconnection Customer collector substation. The Public Utility will procure, install, test, and own all revenue metering equipment. The revenue metering instrument transformers will be installed overhead on a pole at the POI. The meter instrument transformer mounting shall conform to the Public Utility's DM construction standards.

There will be two meters installed in the control building with the metering programmed bi-directional to measure KWH and KVARH quantities for both generation received and retail load delivered.

The present output rating of the generation Project requires metering real time bidirectional SCADA, KWH KVARH MW, MVAR including per phase voltage data. The metering data will include a backup meter for alternate path EMS data.

Communication equipment will be required to remotely interrogate the meter for generation and billing data via the Public Utility's MV-90 data acquisition system. If available Ethernet is preferred and if not available a cell phone package is acceptable.

Station Service/Construction Power

The Project is within the Public Utility's service territory. Please note that prior to backfeed, Interconnection Customer must arrange transmission retail meter service for electricity consumed by the Project that will be drawn from the system when the Project is not generating. Interconnection Customer must call the PCCC Solution Center 1-800-625-6078 to arrange this service. Approval for back feed is contingent upon obtaining station service.

8.0 Cost Estimate

The following estimate represents only scopes of work that will be performed by the Public Utility. Costs for any work being performed by the Interconnection Customer are not included.

Q01045 Collector Substation *Install control building, metering and communications equipment*	$600,000
Distribution Circuit 5W406 *Install recloser and regulators*	$265,000
Pilot Rock Substation *Install communications equipment, modify regulator settings*	$250,000
Cabbage Hill Communications Site *Install communications equipment*	$74,000
System Operations Control Centers *Update databases*	$6,000
Total	**$1,195,000**

*Any distribution line modifications identified in this report will require a field visit analysis in order to obtain a more thorough understanding of the specific requirements. The estimate provided above for this work could change substantially based on the results of this analysis. Until this field analysis is performed the Public Utility must develop the Project schedule using conservative assumptions. The Interconnection Customer may request that the Public Utility perform this field

analysis, at the Interconnection Customer's expense, prior to the execution of an Interconnection Agreement in order to obtain more cost and schedule certainty.

Note: Costs for any excavation, duct installation and easements shall be borne by the Interconnection Customer and are not included in this estimate. This estimate is as accurate as possibly given the level of detailed study that has been completed to date and approximates the costs incurred by Public Utility to interconnect this Small Generator Facility to Public Utility's electrical distribution or transmission system. A more detailed estimate will be calculated during the Facilities Study. The Interconnection Customer will be responsible for all actual costs, regardless of the estimated costs communicated to or approved by the Interconnection Customer.

9.0 SCHEDULE

The Public Utility estimates it will require approximately 12-15 months to design, procure and construct the facilities described in this report following the execution of an Interconnection Agreement. The schedule will be further developed and optimized during the Facilities Study.

Please note, the time required to perform the scope of work identified in this report does not support the Interconnection Customer's requested commercial operation date of December 31, 2019.

10.0 PARTICIPATION BY AFFECTED SYSTEMS

Public Utility has identified the following Affected Systems: Bonneville Power Administration and Columbia Power

Copies of this report will be shared with each Affected System.

11.0 APPENDICES

Appendix 1: Higher Priority Requests
Appendix 2: Contingent Facilities
Appendix 3: Property Requirements
Appendix 4: Study Results

11.1 Appendix 1: Higher Priority Requests

All active higher priority transmission service and/or generator interconnection requests will be considered in this study and are identified below. If any of these requests are withdrawn, the Public Utility reserves the right to restudy this request, as the results and conclusions contained within this study could significantly change.

Transmission/Generation Interconnection Queue Requests considered:

Q0547 (18 MW)
Q0666 (1.98 MW)

11.2 APPENDIX 2: CONTINGENT FACILITIES

The following Interconnection Facilities and/or upgrades to the Public Utility's system are Contingent Facilities for the Interconnection Customer's Interconnection Request and must be in service prior to the commencement of generation activities:

All interconnection facilities and system upgrades required for higher priority Interconnection Request Q0666 are Contingent Facilities for the Interconnection Customer's Interconnection Request including the following:

- Extension of approximately 0.3 miles of distribution line.
- Installation of approximately 0.9 miles of fiber optic cable.
- Installation of protective, communications and metering equipment in the Public Utility's Pilot Rock substation.
- Installation of standard Public Utility distribution interconnection package consisting of a metering equipment and switch.
- Installation of a Interconnection Customer owned recloser and relay package.

The estimated completion date of these upgrades is 2021. The estimated cost of the Public Utility's interconnection facilities and upgrades is approximately $805K. For additional details please review the system impact study for the Q0666 Interconnection Request on the Public Utility's OASIS website.

11.3 Appendix 3: Property Requirements

Requirements for rights of way easements

Rights of way easements will be acquired by the Interconnection Customer in the Public Utility's name for the construction, reconstruction, operation, maintenance, repair, replacement and removal of Public Utility's Interconnection Facilities that will be owned and operated by Public Utility. Interconnection Customer will acquire all necessary permits for the Project and will obtain rights of way easements for the Project on Public Utility's easement form.

Real Property Requirements for Point of Interconnection Substation

Real property for a POI substation will be acquired by an Interconnection Customer to accommodate the Interconnection Customer's Project. The real property must be acceptable to Public Utility. Interconnection Customer will acquire fee ownership for interconnection substation unless Public Utility determines that other than fee ownership is acceptable; however, the form and instrument of such rights will be at Public Utility's sole discretion. Any land rights that Interconnection Customer is planning to retain as part of a fee property conveyance will be identified in advance to Public Utility and are subject to the Public Utility's approval.

The Interconnection Customer must obtain all permits required by all relevant jurisdictions for the planned use including but not limited to conditional use permits, Certificates of Public Convenience and Necessity, California Environmental Quality Act, as well as all construction permits for the Project.

Interconnection Customer will not be reimbursed through network upgrades for more than the market value of the property.

As a minimum, real property must be environmentally, physically, and operationally acceptable to Public Utility. The real property shall be a permitted or able to be permitted use in all zoning districts. The Interconnection Customer shall provide Public Utility with a title report and shall transfer property without any material defects of title or other encumbrances that are not acceptable to Public Utility. Property lines shall be surveyed and show all encumbrances, encroachments, and roads.

Examples of potentially unacceptable environmental, physical, or operational conditions could include but are not limited to:

- Environmental: known contamination of site; evidence of environmental contamination by any dangerous, hazardous or toxic materials as defined by any governmental agency; violation of building, health, safety, environmental, fire, land use, zoning or other such regulation; violation of ordinances or statutes of any governmental entities having jurisdiction over the property; underground or above ground storage tanks in area; known remediation sites on property; ongoing mitigation activities or monitoring activities; asbestos; lead-based paint, etc. A phase I environmental study is required for land being acquired in fee by the Public Utility unless waived by Public Utility.

- Physical: inadequate site drainage; proximity to flood zone; erosion issues; wetland overlays; threatened and endangered species; archeological or culturally sensitive areas; inadequate sub-surface elements, etc. Public Utility may require Interconnection Customer to procure various studies and surveys as determined necessary by Public Utility.

- Operational: inadequate access for Public Utility's equipment and vehicles; existing structures on land that require removal prior to building of substation; ongoing maintenance for landscaping or extensive landscape requirements; ongoing homeowner's or other requirements or restrictions (e.g., Covenants, Codes and Restrictions, deed restrictions, etc.) on property which are not acceptable to the Public Utility.

11.4 Appendix 4: Study Results

Distribution Study Results:

The distribution feeder was analyzed under the following conditions of demand loading and generation output.

The feeder peak demand with and without generation was evaluated.

The minimum daytime demand on the feeder with and without generation was evaluated.

The transient case was evaluated for maximum voltage variation caused by the generation changing from zero output to maximum output as well as the generation changing from maximum output to zero output.

Transmission Study Results:

Case 1: Normal Configuration (Pilot Rock fed from BPA Roundup, breaker L-1122):

No power flow restrictions were identified.

Minimum daytime loads in the Pendleton area are less than the sum of all generation year-round. Thus, Q1045 generation at any level is likely to result in export through the 230 kV bus at BPA Roundup.

Area bus voltages remain close to 0.978 pu for all load levels, thus a generator setpoint voltage of 0.978 pu at the POI was used for evaluation of the proposed interconnection with respect to voltage performance and deviation. Voltages and post transient voltage steps are projected in power flow simulation to remain within permissible limits during the interruption of the Q1045 generation in the Public Utility's normal transmission configuration.

A QV analysis was performed for this configuration, and positive reactive margin is maintained.

Previously, a stability study was performed for this configuration and demonstrated satisfactory transient stability in the local area and no stability issues would be expected for the addition of this request.

Case 2: Contingency Configuration (Pilot Rock fed from Buckaroo and BPA Roundup, breaker L-1123, Switch 3W191 closed, breaker L-1122 open):

No restrictions, pending a stability study. A stability study will be required to determine the effects of generating into the Pendleton 69 kV loop with existing wind generation online.

Voltages and post transient voltage steps are projected in power flow simulation to remain within permissible limits during the interruption of the Q1045 generation in this contingency configuration.

A QV analysis was performed for this configuration, and positive reactive margin is maintained.

Case 3: Contingency Configuration (Pendleton 69 kV loop open at Buckaroo and BPA Roundup Breaker L-1123, Pilot Rock fed from Breaker L-1122, 60 MVA transformer at Roundup offline)

During this contingency, the 69 kV loop in the Pendleton area is split, and Buckaroo substation is fed radially via the two 33 MVA transformers at BPA Roundup. Public Utility's 60 MVA transformer at BPA Roundup is offline, thus the 69 kV system is weakened and voltages in the area may drop to 0.92 pu. However, even with lowered voltages, there were no identified power flow restrictions.

Voltages and post transient voltage steps are projected in power flow simulation to remain within permissible limits during the interruption of the Q1045 generation in this contingency configuration.

Previously, a stability study was performed for this configuration and demonstrated satisfactory transient stability in the local area and no stability issues would be expected for the addition of this request.

A QV analysis was performed for this configuration, and positive reactive margin is maintained.

Attachment C

PRS2 Interconnection Study

Small Generator Interconnection
Tier 4 Facilities Study Report

Completed for

(“Interconnection Customer”)
Q1045

A Qualifying Facility

Proposed Interconnection
On PacifiCorp’s
Circuit 5W406 out of Pilot Rock Substation at 12.5 kV
(at approximately 45° 30' 32.67", -118° 49' 38.87")

June 2, 2020

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1.0 Description of the Project

("Interconnection Customer") proposed interconnecting 2.99 MW of new generation to PacifiCorp's ("Public Utility") Circuit 5W406 out of Pilot Rock substation at 12.5 kV located in Umatilla County, Oregon. The project ("Project") will consist of forty-nine (49) Sungrow SG60KU-M inverters for a total requested output of 2.99 MW. The requested commercial operation date is December 31, 2019.

Interconnection Customer will operate this generator as a Qualified Facility as defined by the Public Utility Regulatory Policies Act of 1978 (PURPA).

The Public Utility has assigned the project "Q1045."

2.0 Approval Criteria for Tier 4 Interconnection Review

Pursuant to 860-082-0060(1), a public utility must use the Tier 4 interconnection review procedures for an application to interconnect a small generator facility that meets the following requirements:

(a) The small generator facility does not qualify for or failed to meet Tier 1, Tier 2, or Tier 3 interconnection review requirements; and
(b) The small generator facility must have a nameplate capacity of ten (10) megawatts or less.

3.0 Scope of the Study

Pursuant to 860-082-0060(8) the Facilities Study Report shall consist of:

(a) A detailed scope identifying the interconnection facilities and system upgrades required to safely interconnect the small generator facility including the electrical switching configuration of the equipment, including the transformer, switchgear, meters, and other station equipment as applicable;
(b) A reasonable schedule for completion of the study;
(c) A good-faith, non-binding estimate of the costs for the facilities and upgrades, including equipment, engineering, procurement, and construction costs, and;
(d) A detailed estimate of the time required to procure, construct, and install the required interconnection facilities and system upgrades.

4.0 Proposed Point of Interconnection

. The proposed generation facility is to be interconnected to the Public Utility's distribution circuit 5W406 out of Pilot Rock substation, roughly 1,400' north of the existing facility point 01401032.0090961. The Interconnection Customer's Small Generator Facility will utilize the interconnection facilities associated with the Interconnection Request studied under queue position Q0666. Figure 1 below, is a one-line diagram that illustrates the interconnection of the proposed Small Generator Facility to the Public Utility's system.

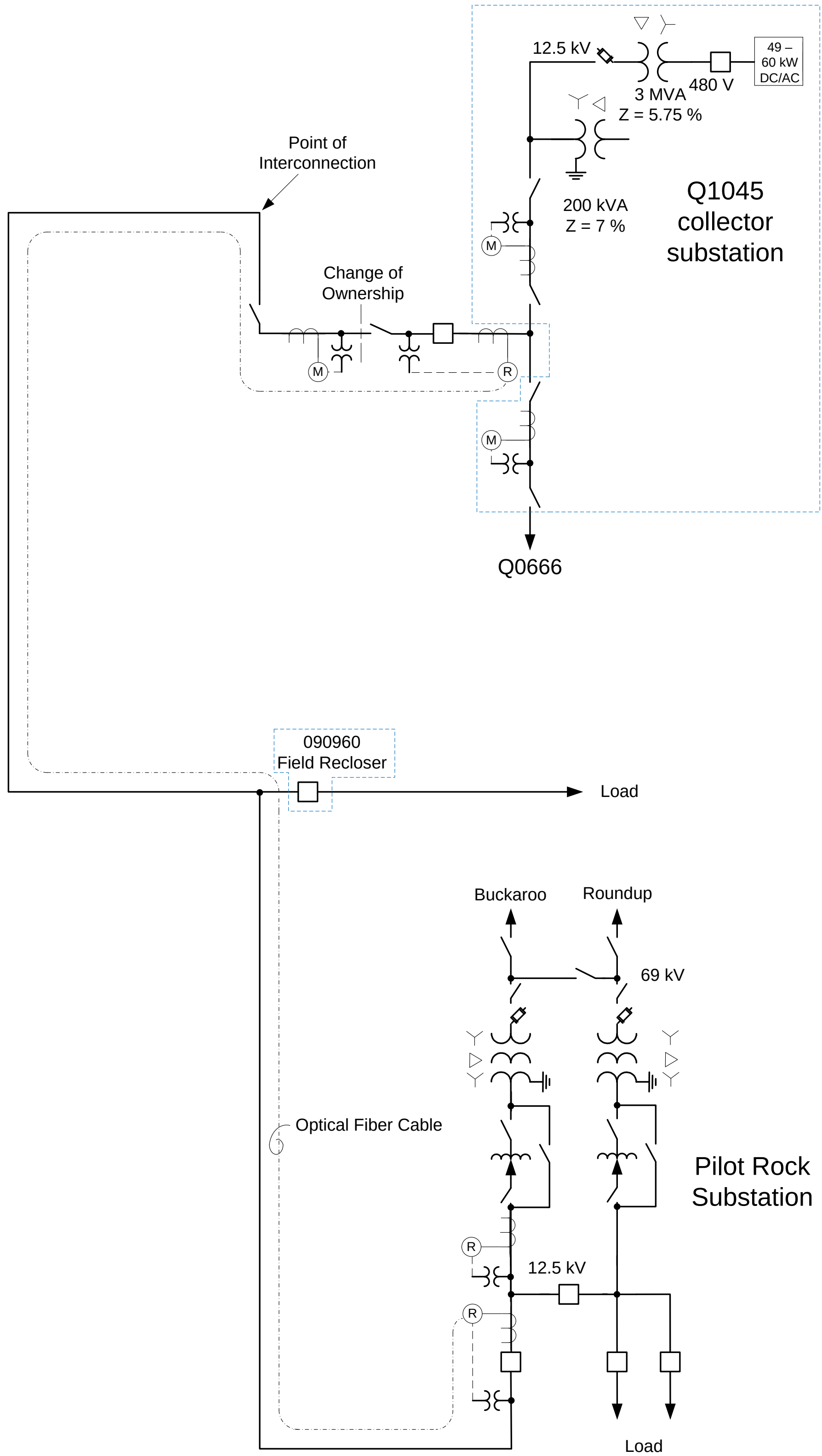

Figure 1: System One Line Diagram

5.0 Study Assumptions

- All active higher priority transmission service and/or generator interconnection requests will be considered in this study and are listed in Appendix 1. If any of these requests are withdrawn, the Public Utility reserves the right to restudy this request, as the results and conclusions contained within this study could significantly change.
- For study purposes there are two separate queues:
  - Transmission Service Queue: to the extent practical, all network upgrades that are required to accommodate active transmission service requests and are expected to be in-service on or after the Interconnection Customer's requested in-service date for the Project will be modeled in this study.
  - Generation Interconnection Queue: when relevant, interconnection facilities associated with higher queue interconnection requests will be modeled in this study. However, no generation will be simulated from any higher queued project unless a commitment has been made to obtain transmission service.
- The Interconnection Customer's request for interconnection service in and of itself does not convey transmission service.
- This study assumes the Project will be integrated into Public Utility's system at the agreed upon and/or proposed point of interconnection.
- The Interconnection Customer will construct and own the facilities required between the point of interconnection and the Project.
- Generator tripping may be required for certain outages.
- All facilities will meet or exceed the minimum WECC, NERC, and Public Utility performance and design standards.
- The Interconnection Customer's Interconnection Request will utilize interconnection facilities of higher priority Interconnection Request studied under queue position Q0666 and will also require additional equipment to be installed at the Q0666 collector substation location. The Public Utility assumes that the Interconnection Customer has the contractual right for the utilization of the Q0666 interconnection facilities and for the Public Utility to implement its requirements to the Q0666 collector substation. If that contractual right is not granted to the Interconnection Customer the requirements in this report will be significantly different which will require a restudy by the Public Utility.
- This report is based on information available at the time of the study. It is the Interconnection Customer's responsibility to check the Public Utility's web site regularly for transmission system updates (http://www.pacificorp.com/tran.html)

6.0 Requirements

6.1 Shared Q0666-Q1045 Small Generator Facility Requirements

The following outlines the design, procurement, construction, installation, and ownership of equipment at the Interconnection Customer's Small Generation Facility.

6.1.1 Interconnection Customer to be Responsible For

- Procure all necessary permits, lands, rights of way and easements required for the construction and continued maintenance of the Q1045 Small Generator Facility and collector substation.
- Design, procure, construct, own and maintain the Interconnection Customer's Small Generator Facility and associated collector substation.
- Execute any necessary agreements (e.g. shared facilities agreement) to allow the Interconnection Customer to utilize the interconnection facilities constructed and owned by the Interconnection Customer with the rights to the Interconnection Request studied under queue position Q0666. Provide this demonstration to the Public Utility prior to the commencement of design activities.
- Design the Small Generator Facility with reactive power capabilities necessary to operate within the full power factor range of 0.95 leading to 0.95 lagging as measured at the high side of the Interconnection Customer's GSU transformer. This power factor range shall be dynamic and can be met using a combination of the inherent dynamic reactive power capability of the generator or inverter, dynamic reactive power devices and static reactive power devices to make up for losses.
- Design the Small Generator Facility such that it can provide positive reactive support (i.e., supply reactive power to the system) immediately following the removal of a fault or other transient low voltage perturbations or install dynamic voltage support equipment. These additional dynamic reactive devices shall have correct protection settings such that the devices will remain on line and active during and immediately following a fault event.
- Equip the Small Generator Facility with automatic voltage-control equipment and operate with the voltage regulation control mode enabled unless explicitly authorized to operate another control mode by the Public Utility.
- Operate the Small Generator Facility so as to maintain the voltage at the Point of Interconnection, or other designated point as deemed appropriated by Public Utility, at a voltage schedule to be provided by the Public Utility following testing.
- Operate the Small Generator Facility with a voltage droop.
- Have any Public Utility required studies, such as a voltage coordination study, performed and provide results to Public Utility. Any additional requirements identified in these studies will be the responsibility of the Interconnection Customer.
- Meet the NERC and WECC low voltage ride-through requirements as specified in the interconnection agreement.
- Provide the Public Utility a standard model from the WECC Approved Dynamic Model Library.

- Install a transformer that will hold the phase to neutral voltages within limits when the Small Generator Facility is isolated with the Public Utility's local system until the generation disconnects such as a wye-delta grounding transformer. Please note that the transformer thus far proposed by the Interconnection Customer is not acceptable to the Public Utility.
- Input the updated settings provided by the Public Utility into the Q0666 recloser relay.
- Provide the Public Utility the necessary easement to allow the Public Utility to install an enclosure for its equipment.
- Provide a separate graded and fenced area along the perimeter of the share Q0666/Q1045 collector substation for the Public Utility to install an enclosure. The enclosure shall have unencumbered access for the Transmission Provider. Fencing, gates and road access shall meet Transmission Provider standards.
- Provide permanent AC power to the Transmission Provider's enclosure.
- Design, procure and install conduit and Public Utility provided control cabling and hard wire all Q0666 and Q1045 source devices to the Public Utility's remote terminal unit ("RTU"). Provide sufficient control cable for the Public Utility to terminate inside the Public Utility enclosure.
- Interconnection Customer shall provide the following data points:
  <u>Analogs:</u>
  - Net Generation real power MW
  - Net Generator reactive power MVAR
  - Energy Register KWH
  - Q0666 real power MW
  - Q0666 reactive power MVAR
  - Q0666 Energy Register KWH
  - Q1045 real power MW
  - Q1045 reactive power MVAR
  - Q1045 Energy Register KWH
  - A phase 12.5 kV voltage
  - B phase 12.5 kV voltage
  - C phase 12.5 kV voltage
  - Global Horizontal Irradiance (GHI)
  - Average Plant Atmospheric Pressure (Bar)
  - Average Plant Temperature (Celsius)

  <u>Status:</u>
  - 12 kV Circuit Recloser
  - Max Gen MW
  - Max Gen MW FB
- Arrange for and provide permanent retail service for power that will flow from the Public Utility's system when the Q0666 and Q1045

Small Generator Facilities are not generating. This arrangement must be in place prior to approval for backfeed.
- Provide any construction or backup retail service necessary for the Project.
- Provide the Public Utility a Professional Engineer ("PE") approved maintenance plan for all Interconnection Customer facilities prior to commencement of generation activities.

6.1.2 Public Utility to be Responsible For

- Develop and provide updated settings for the Q0666 recloser relay to account for the addition of the Q1045 Small Generator Facility. Observe and provide acceptance of the update.
- Procure and install a weather proof enclosure on the site prepared by the Interconnection Customer.
- Procure and install backup a DC battery system for the Public Utility enclosure.
- Install communications equipment in the collector substation enclosure including an RTU, transceivers, batteries and DC charger.
- Procure, install, own and maintain fiber optic cable from the collector substation enclosure to a splice with the fiber to be installed on the Public Utility's distribution line as part of the Q0666 project.
- Provide the Interconnection Customer control cable in sufficient quantity to allow the Interconnection Customer to tie its source devices to the Public Utility's enclosure communications equipment.
- Terminate the control cable running from the Interconnection Customer source devices in the enclosure.
- Design, procure and install within a NEMA enclosure mounted on a pole, two sets of revenue metering equipment to separate the Q0666 and Q1045 Small Generator Facilities including a metering panel, instrument transformers, primary and secondary revenue quality meters, test switches, junction boxes and secondary metering wire.
- Establish an Ethernet connection for retail sales and generation accounting via the MV-90 translation system. If Ethernet is unavailable, install a cell phone package.

6.2 Other

The following outlines the design, procurement, construction, installation, and ownership of equipment beyond the Point of Interconnection.

6.2.1 Public Utility to be Responsible For

- Distribution Circuit
    - Procure and install one three phase recloser at a location east of facility point 090960.

- Procure and install one three phase bank of 219 amp 7.2 kV voltage regulators on the McKay branch.
- Procure and install one three phase bank of 100 amp 7.2 kV voltage regulators on the circuit branch west of the interconnection tap.

- Pilot Rock Substation
  - Modify the settings of the R-816 substation voltage regulator.
  - Construct a new radio system to develop a communications link with the Public Utility's Cabbage Hill communications site including radio, battery set & charger, channel bank, router and switch.

- Cabbage Hill Communications Site
  - Evaluate the existing tower for space and loading for a new antenna. If necessary, modify the tower.
  - Procure and install an antenna and supporting communications equipment to establish a communications link with the system to be installed in Pilot Rock substation.
  - Cross connect communications circuits to existing Public Utility communications systems.

- Bonneville Power Administration ("BPA")
  - Coordinate with BPA on any studies and/or upgrades that may be necessary.

- System Operations Centers
  - Modify databases to include the Interconnection Customer's Small Generator Facility, new interconnection facilities and system upgrades.

7.0 Cost Estimate

The following estimate represents only scopes of work that will be performed by the Public Utility. Costs for any work being performed by the Interconnection Customer are not included.

Q1045 Collector substation $374,000
Install enclosures, metering and communications equipment

Distribution Circuit 5W406 $265,000
Install recloser and regulators

Pilot Rock Substation $250,000
Install communications equipment, modify regulator settings

Cabbage Hill Communications Site *Install communications equipment*	$72,000
System Operations Control Centers *Update databases*	$4,000
Total	**$965,000**

*Any distribution line modifications identified in this report will require a field visit analysis in order to obtain a more thorough understanding of the specific requirements. The estimate provided above for this work could change substantially based on the results of this analysis. Until this field analysis is performed the Transmission Provider must develop the project schedule using conservative assumptions. The Interconnection Customer may request that the Transmission Provider perform this field analysis, at the Interconnection Customer's expense, prior to the execution of an Interconnection Agreement in order to obtain more cost and schedule certainty.

Note: Costs for any excavation, duct installation and easements shall be borne by the Interconnection Customer and are not included in this estimate. This estimate approximates the costs incurred by the Public Utility to interconnect this Small Generator Facility to the Public Utility's electrical distribution or transmission system based upon the level of study completed to-date. The Interconnection Customer will be responsible for all actual costs, regardless of the estimated costs communicated to or approved by the Interconnection Customer.

8.0 SCHEDULE

Execute Interconnection Agreement	July 13, 2020
Interconnection Customer Financial Security Provided	July 13, 2020
Interconnection Customer Shared Facilities Agreement Provided	July 27, 2020
*Interconnection Customer Initial Design Information Provided	August 3, 2020
**Public Utility Engineering & Procurement Commences	August 24, 2020
***Energy Imbalance Market Modeling Data Submittal	September 14, 2020
Interconnection Customer Property/Permits/ROW Procured	November 2, 2020
Public Utility Property/Permits/ROW Procured	December 7, 2020
*Interconnection Customer Final Design Information Provided	December 21, 2020
Public Utility Engineering Design Complete	February 26, 2021
Public Utility Construction Commences	March 22, 2021

Interconnection Customer Maintenance Plan Provided	April 5, 2021
Public Utility and Interconnection Customer Construction Complete	May 7, 2021
Public Utility Commissioning Complete	June 4, 2021
Interconnection Customer's Facilities Receive Backfeed Power	June 8, 2021
Initial Synchronization/Generation Testing	June 14, 2021
Commercial Operation	June 21, 2021

*Interconnection Customer initial design package shall include final generating facility location, inverter/turbine selection, basic protection package, tie line route and collector system locations and data as applicable. Interconnection Customer final design package shall include PE stamped issued for construction ("IFC") drawings for generating facility, collector substation, tie line as well as electromagnetic transient ("EMT") model as applicable.

**As applicable and determined by the Public Utility, within 60 days of the Interconnection Customer's authorization for the Public Utility to begin engineering, the Interconnection Customer shall provide a detailed short circuit model of its generation system. This model must be constructed using the ASPEN OneLine short circuit simulation program and contain all individual electrical components of the Interconnection Customer's generation system.

***Any design modifications to the Interconnection Customer's Small Generating Facility after this date requiring updates to the Public Utility's network model may result in a minimum of 3 months added to all future milestones including Commercial Operation.

Please note, the time required to perform the scope of work identified in this report does not support the Interconnection Customer's requested commercial operation date of December 31, 2019.

9.0 Participation by Affected Systems

Public Utility has identified the following Affected Systems: Bonneville Power Administration

Copies of this report will be shared with each Affected System.

10.0 Appendices

Appendix 1: Higher Priority Requests
Appendix 2: Contingent Facilities
Appendix 3: Property Requirements

10.1 Appendix 1: Higher Priority Requests

All active higher priority transmission service and/or generator interconnection requests will be considered in this study and are identified below. If any of these requests are withdrawn, the Public Utility reserves the right to restudy this request, as the results and conclusions contained within this study could significantly change.

Transmission/Generation Interconnection Queue Requests considered:

Q0547 (18 MW)
Q0666 (1.98 MW)

10.2 Appendix 2: Contingent Facilities

The following Interconnection Facilities and/or upgrades to the Public Utility's system are Contingent Facilities for the Interconnection Customer's Interconnection Request and must be in service prior to the commencement of generation activities:

All interconnection facilities and system upgrades required for higher priority Interconnection Request Q0666 are Contingent Facilities for the Interconnection Customer's Interconnection Request including the following:

- Extension of approximately 0.3 miles of distribution line.
- Installation of approximately 0.9 miles of fiber optic cable.
- Installation of protective, communications and metering equipment in the Public Utility's Pilot Rock substation.
- Installation of standard Public Utility distribution interconnection package consisting of a metering equipment and switch.
- Installation of an Interconnection Customer owned recloser and relay package.

The estimated completion date of these upgrades is 2021. The estimated cost of the Public Utility's interconnection facilities and upgrades is approximately $805K. For additional details please review the system impact study for the Q0666 Interconnection Request on the Public Utility's OASIS website.

10.3 Appendix 3: Property Requirements

Requirements for rights of way easements

Rights of way easements will be acquired by the Interconnection Customer in the Public Utility's name for the construction, reconstruction, operation, maintenance, repair, replacement and removal of Public Utility's Interconnection Facilities that will be owned and operated by PacifiCorp. Interconnection Customer will acquire all necessary permits for the project and will obtain rights of way easements for the project on Public Utility's easement form.

Real Property Requirements for Point of Interconnection Substation

Real property for a point of interconnection substation will be acquired by an Interconnection Customer to accommodate the Interconnection Customer's project. The real property must be acceptable to Public Utility. Interconnection Customer will acquire fee ownership for interconnection substation unless Public Utility determines that other than fee ownership is acceptable; however, the form and instrument of such rights will be at Public Utility's sole discretion. Any land rights that Interconnection Customer is planning to retain as part of a fee property conveyance will be identified in advance to Public Utility and are subject to the Public Utility's approval.

The Interconnection Customer must obtain all permits required by all relevant jurisdictions for the planned use including but not limited to conditional use permits, Certificates of Public Convenience and Necessity, California Environmental Quality Act, as well as all construction permits for the project.

Interconnection Customer will not be reimbursed through network upgrades for more than the market value of the property.

As a minimum, real property must be environmentally, physically, and operationally acceptable to Public Utility. The real property shall be a permitted or permittable use in all zoning districts. The Interconnection Customer shall provide Public Utility with a title report and shall transfer property without any material defects of title or other encumbrances that are not acceptable to Public Utility. Property lines shall be surveyed and show all encumbrances, encroachments, and roads.

Examples of potentially unacceptable environmental, physical, or operational conditions could include but are not limited to:

- Environmental: known contamination of site; evidence of environmental contamination by any dangerous, hazardous or toxic materials as defined by any governmental agency; violation of building, health, safety, environmental, fire, land use, zoning or other such regulation; violation of ordinances or statutes of any governmental entities having jurisdiction over the property; underground or above ground storage tanks in area; known remediation sites on property; ongoing mitigation activities or monitoring activities; asbestos; lead-based paint, etc. A phase I environmental study is required for land being acquired in fee by the Public Utility unless waived by Public Utility.

- Physical: inadequate site drainage; proximity to flood zone; erosion issues; wetland overlays; threatened and endangered species; archeological or culturally sensitive areas; inadequate sub-surface elements, etc. Public Utility may require Interconnection Customer to procure various studies and surveys as determined necessary by Public Utility.

- Operational: inadequate access for Public Utility's equipment and vehicles; existing structures on land that require removal prior to building of substation; ongoing maintenance for landscaping or extensive landscape requirements; ongoing homeowner's or other requirements or restrictions (e.g., Covenants, Codes and Restrictions, deed restrictions, etc.) on property which are not acceptable to the Public Utility.

Attachment D

UM 2118 Complaint

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 2118

Served electronically at Salem, Oregon, 09/29/2020, to:

Respondent's Attorney
Barb Coughlin
PacifiCorp dba Pacific Power
barb.coughlin@pacificorp.com

Complainant's Attorney(s) & Representative(s)
Ken Kaufmann
ken@kaufmann.law

Re: UM 2118, SUNTHURST ENERGY, LLC, Complainant
vs. PACIFICORP dba PACIFIC POWER, Respondent

SUNTHURST ENERGY, LLC has filed a complaint against PACIFICORP dba PACIFIC POWER. A copy of the complaint is attached and served on Respondent, under ORS 756.512(1). The Commission has assigned Docket No. UM 2118 to this complaint. Please use this number whenever you refer to this case.

The Public Utility Commission must receive an Answer from the Respondent or its attorney by October 19, 2020, under OAR 860-001-0400(4)(a). A copy must be served on the complainant.

After the filing of the answer, the PUC will contact the parties to provide information about further proceedings in this matter.

PUBLIC UTILITY COMMISSION OF OREGON

/s/Cheryl Walker
Cheryl Walker
Administrative Specialist 2
Administrative Hearings Division
(971) 388-3806 *(new telephone number)*

C: Kathleen M. Sauer, Pacific Power (w/attachments), at tariffpolicy@pacificorp.com

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Attachments: Complaint; Notice of Contested Case Rights and Procedures

NOTICE OF CONTESTED CASE RIGHTS AND PROCEDURES

Oregon law requires state agencies to provide parties written notice of contested case rights and procedures. Under ORS 183.413, you are entitled to be informed of the following:

Hearing: The time and place of any hearing held in these proceedings will be noticed separately. The Commission will hold the hearing under its general authority set forth in ORS 756.040 and use procedures set forth in ORS 756.518 through 756.610 and OAR Chapter 860, Division 001. Copies of these statutes and rules may be accessed via the Commission's website at www.puc.state.or.us. The Commission will hear issues as identified by the parties.

Right to Attorney: As a party to these proceedings, you may be represented by counsel. Should you desire counsel but cannot afford one, legal aid may be able to assist you; parties are ordinarily represented by counsel. The Commission Staff, if participating as a party in the case, will be represented by the Department of Justice. Generally, once a hearing has begun, you will not be allowed to postpone the hearing to obtain counsel.

Notice to Active Duty Servicemembers: Active Duty Servicemembers have a right to stay these proceedings under the federal Servicemembers Civil Relief Act. For more information contact the Oregon State Bar at 800-452-8260, the Oregon Military Department at 503-584-3571 or the nearest United States Armed Forces Legal Assistance Office through http://legalassistance.law.af.mil. The Oregon Military Department does not have a toll free telephone number.

Administrative Law Judge: The Commission has delegated the authority to preside over hearings to Administrative Law Judges (ALJs). The scope of an ALJ's authority is defined in OAR 860-001-0090. The ALJs make evidentiary and other procedural rulings, analyze the contested issues, and present legal and policy recommendations to the Commission.

Hearing Rights: You have the right to respond to all issues identified and present evidence and witnesses on those issues. *See* OAR 860-001-0450 through OAR 860-001-0490. You may obtain discovery from other parties through depositions, subpoenas, and data requests. *See* ORS 756.538 and 756.543; OAR 860-001-0500 through 860-001-0540.

Evidence: Evidence is generally admissible if it is of a type relied upon by reasonable persons in the conduct of their serious affairs. *See* OAR 860-001-0450. Objections to the admissibility of evidence must be made at the time the evidence is offered. Objections are generally made on grounds that the evidence is unreliable, irrelevant, repetitious, or because its probative value is outweighed by the danger of unfair prejudice, confusion of the issues, or undue delay. The order of presenting evidence is determined by the ALJ. The burden of presenting evidence to support an allegation rests with the person raising the allegation. Generally, once a hearing is completed, the ALJ will not allow the introduction of additional evidence without good cause.

Record: The hearing will be recorded, either by a court reporter or by audio digital recording, to preserve the testimony and other evidence presented. Parties may contact the court reporter about ordering a transcript or request, if available, a copy of the audio recording from the Commission for a fee set forth in OAR 860-001-0060. The hearing record will be made part of the evidentiary record that serves as the basis for the Commission's decision and, if necessary, the record on any judicial appeal.

Final Order and Appeal: After the hearing, the ALJ will prepare a draft order resolving all issues and present it to the Commission. The draft order is not open to party comment. The Commission will make the final decision in the case and may adopt, modify, or reject the ALJ's recommendation. If you disagree with the Commission's decision, you may request reconsideration of the final order within 60 days from the date of service of the order. *See* ORS 756.561 and OAR 860-001-0720. You may also file a petition for review with the Court of Appeals within 60 days from the date of service of the order. *See* ORS 756.610.

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September 29, 2020

Via Electronic Mail

Filing Center
Public Utility Commission of Oregon
P.O. Box 1088
Salem, OR 97308-1088
puc.filingcenter@state.or.us

Re: Sunthurst Energy, LLC, Complainant
PacifiCorp, Defendant

Attention Filing Center:

Attached for filing in the above-captioned docket is an electronic version of *Sunthurst Energy, LLC's Complaint.*

Thank you in advance for your assistance.

Sincerely,

Ken Kaufmann
Attorney for Sunthurst Energy, LLC

Attach.

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. ______________

SUNTHURST ENERGY, LLC, an Oregon limited liability company, Complainant, v. PACIFICORP d/b/a Pacific Power, an Oregon corporation, Defendant	COMPLAINT OAR 860-082-0070(a); OAR 860-029-0060(1). Expedited Review Requested

Sunthurst Energy, LLC ("Sunthurst") is the developer of Pilot Rock Solar 1 and Pilot Rock Solar 2--two pre-certified Oregon Community Solar projects seeking to interconnect to Pacific Power ("PacifiCorp"). Sunthurst hereby petitions the Public Utility Commission of Oregon ("Commission") to resolve disputes that have arisen between Sunthurst and PacifiCorp during interconnection negotiations. Sunthurst diligently participated in Oregon's years-long efforts to make the Community Solar Program ("CSP") successful and is concerned PacifiCorp's interconnection practices will prevent such success. Sunthurst challenges the reasonableness of PacifiCorp's cost estimates, in general, and PacifiCorp's insistence on unnecessarily expensive metering, in particular. PacifiCorp's unreasonable costs and unnecessary metering requirements threaten to make Pilot Rock Solar 1 and Pilot Rock Solar 2 economically infeasible, thereby frustrating the State's Community Solar Program. Without expedited review Sunthurst is unlikely to qualify for the 26% federal Investment Tax Credit, which steps down to 22% after December 31, 2020.

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BASES FOR COMMISSION JURISDICTION AND IDENTITY OF PARTIES:

1.

Oregon Revised Statute 756.500 provides that any person may file a complaint before the Public Utility Commission against any person whose business or activities are regulated by some one or more of the statutes, jurisdiction for the enforcement or regulation of which is conferred upon the commission. The complaint shall state all grounds on which the complainant seeks relief or the violation of any law claimed to have been committed by the defendant, and the prayer of the complaint shall pray for the relief to which the complainant claims the complainant is entitled. *Id* at ¶(3).

2.

PacifiCorp is a public utility subject to the obligations to interconnect small generators set forth in OAR 860, Division 82 and OAR 860-029-0030. PacifiCorp's Oregon headquarters is located at 825 NE Multnomah Street, Suite 2000, Portland, OR 97232.

3.

Sunthurst is an Oregon limited liability company whose address is PO Box 549, Stanfield, Oregon 97875. Sunthurst is sole owner of Pilot Rock Solar 1, LLC, a 1.98 MW solar photovoltaic project, and the adjacent Pilot Rock Solar 2, LLC, a 2.99 MW solar photovoltaic project. Both projects reside in PacifiCorp service territory and intend to sell net output to PacifiCorp as a qualifying facility under Oregon's Community Solar Program. Sunthurst may develop additional Oregon small solar qualifying facilities in the future.

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MATERIAL FACTS

4.

Sunthurst' Pilot Rock Solar 1 ("PRS1") project is designated Q0666 in PacifiCorp's Oregon interconnection queue. Sunthurst' adjacent Pilot Rock Solar 2 ("PRS2") project is designated Q1045. Both projects will interconnect to PacifiCorp's Pilot Rock substation near the city of Pilot Rock via Circuit 5W406. Both PRS1 and PRS2 received pre-certification under Oregon's Community Solar Program.

5.

Sunthurst and PacifiCorp executed the Q0666 Interconnection Agreement on or about March 14, 2016. When the CSP launched in early 2020, both parties sought changes to the Q0666 Interconnection Agreement. While Sunthurst was still engaging PacifiCorp in negotiations, PacifiCorp tendered Sunthurst an amended Q0666 Interconnection Agreement on September 4, 2020. PacifiCorp told Sunthurst to execute it, unconditionally, by September 28, 2020 (later extended to October 1), or else PacifiCorp will deem the interconnection request withdrawn.

6.

PacifiCorp also sent Sunthurst a revised Facilities Study for Q1045 on September 4, 2020. As with Q0666, PacifiCorp (on at least two occasions) told Sunthurst to agree unconditionally (to pay the actual construction costs for the work identified in the Facilities Study) by September 28, 2020 (later extended to October 1), or else PacifiCorp will deem Sunthurst's Q1045 interconnection request withdrawn.

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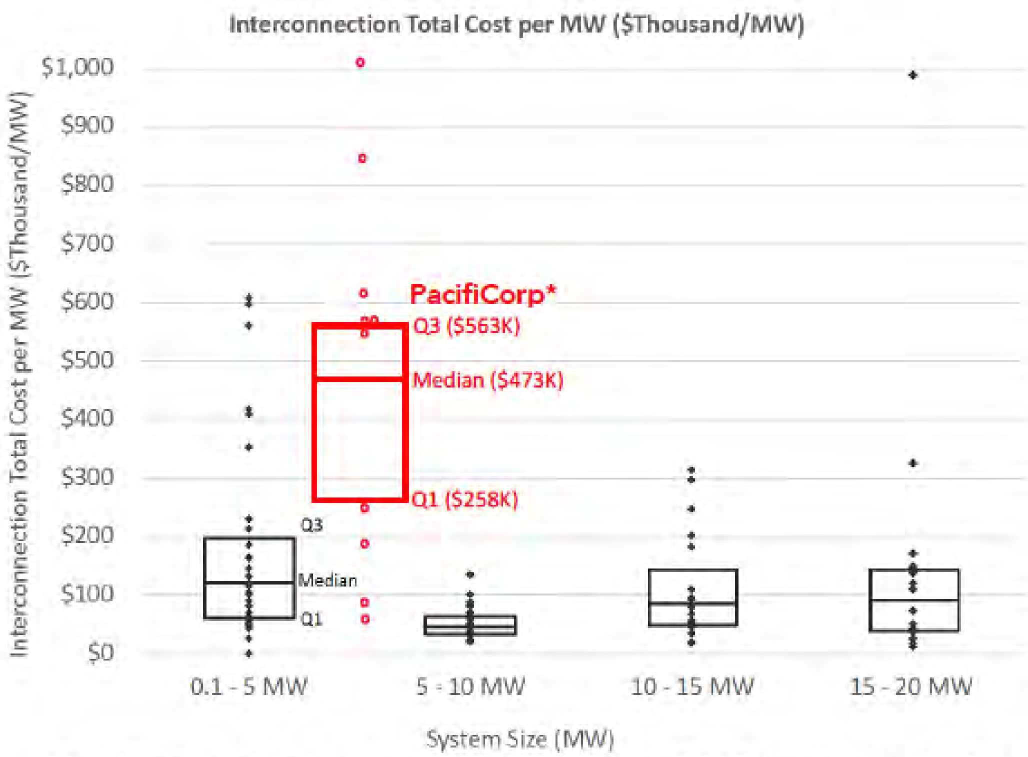
7.

Published data suggest that PacifiCorp's average small generator interconnection costs are exorbitant compared to such costs charged by other utilities in Oregon and the Western United States. A 2018 NREL study[1] showed 25 interconnections throughout the Western United States between 100kW and 5MW had a median cost of about $110k/MW. PacifiCorp's ten completed Oregon CSP facilities studies have a median cost of $473k/MW, or more than 400% of the nationwide average.[2]



*PacifiCorp cost data are from 7/22/20 PacifiCorp OCSP Interconnection Queue

Figure 11. Total mitigation cost ranges in thousands of dollars, by system size (MW)

---

[1] REVIEW OF INTERCONNECTION PRACTICES AND COSTS IN THE WESTERN STATES, Lori Bird, *et al* (Technical Report NREL/TP-6A20-71232, April 2018) ("NREL Interconnection Cost report"), page 18. The report is available free at www.nrel.gov/publications.

[2] *See* PacifiCorp Oregon CSP interconnection queue, as of July 22, 2020, at http://www.oasis.oati.com/woa/docs/PPW/PPWdocs/pacificorpocsiaq.htm

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8.

PacifiCorp initially estimated total cost to interconnect PRS1 and PRS2 at $2 Million, or $402k/MW (even though neither project requires network upgrades or produces excess generation in a load pocket). After months of strenuous negotiations requiring Complainant to engage expert electrical engineering and legal support, PacifiCorp-estimated costs to interconnect PRS1 and PRS2 have come down to $1.002M ($202/MW), which is still nearly twice the regional average cost calculated in the 2018 NREL study. Unless the costs are reduced further, PRS1 and PRS2 likely will be economically non-viable.

9.

Many Community Solar projects have been abandoned by their owners after learning the high costs of interconnection published in a PacifiCorp interconnection study.

10.

On December 31, 2020, the federal Investment Tax Credit for solar projects like PRS1 and PRS2 will step down, from 26% to 22%. (When Oregon first enacted the CSP, the ITC was 30%). Failure to resolve this dispute in time for Sunthurst to qualify for the 2020 ITC will result in irreparable harm to Sunthurst.

11.

PacifiCorp's metering requirements are a significant driver of Sunthurst's interconnection costs. PacifiCorp is requiring <u>three</u> revenue grade meters to measure output from Q0666 and Q1045. One meter is specified at the high side of 480V to 12.5kV

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step-up transformer for each, PRS1 and PRS2. The third meter measures the combined output of PRS1 and PRS2 at the Change of Ownership Point ("COP")—only a few feet away. See **Attachment A**.

12.

PacifiCorp does not always require three meters to measure output from two adjacent projects.

13.

PacifiCorp originally proposed a two-meter configuration for Pilot Rock Solar 1 and Pilot Rock Solar 2. The one-line diagram on page 3 of the Q0747 System Impact Study shows the two projects, side by side with a common COP, metered with only two meters. *See* **Attachment B.**

14.

Sunthurst withdrew its request for a 6 MW Pilot Rock Solar 2 project and submitted a new request for a smaller (2.99 MW) Pilot Rock Solar 2 project (Q0747). Q1045 has the same COP and same Point of Interconnection as Q0747. However, PacifiCorp now requires three meters to interconnect the same two projects.

15.

Sunthurst provided two alternative metering configurations vetted by its consulting electrical engineer that would allow PacifiCorp to accurately meter both projects using only two meters at substantially lower cost than PacifiCorp's 3-meter configuration. Sunthurst

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estimates that either one of its alternative metering configurations would save Sunthurst between $25,000 and $50,000.

16.

Alternative 1. Sunthurst proposed that PacifiCorp eliminate the meter at the COP because it is redundant to the PRS1 and PRS2 meters. PacifiCorp's metering configuration in the Q0747 SIS shows that Alternative 1 is safe, effective, and precedented.

17.

Alternative 2. Alternatively, Sunthurst proposed metering only at the COP and at PRS2, using those meters to automatically calculate and report generation at PRS1 as the difference between the COP meter and the PRS2 meter. This arrangement is shown schematically on **Attachment C**. Other utilities (and on good faith belief PacifiCorp) use similar metering configurations when calculating energy flow on interconnected transmission lines, showing that Alternative 2 is safe, effective, and precedented.

18.

Sunthurst also proposed metering PRS1 and PRS2 on the 480V side of the project step-up transformers--because low voltage meters are less expensive than higher voltage meters. In Docket UM 1930, PacifiCorp joined PGE and Idaho Power in recommending low-side metering as a means of lowering the cost to interconnect Community Solar projects, but arbitrarily limited eligibility to Community Solar projects 360 kW and smaller, and

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non-profit owned Community Solar projects of *any* size.[3]

19.

There is no engineering justification for allowing non-profit owned Community Solar projects larger than 360kW to meter on the low side while requiring for-profit Community Solar projects (such as PRS1 and PRS2) to meter on the high side.

20.

Staff in Docket UM 1930 encouraged utilities to look for one-off interconnection accommodations (such as low-side metering) to help Community Solar projects succeed.[4] However, PacifiCorp declined to make such a one-off exception for Sunthurst.

21.

PacifiCorp has not adequately explained why three meters are necessary. Initially, it argued three meters were required under its Policy 139; however, it later conceded that Policy 139 does not apply to distribution voltage interconnections such as PRS1 and PRS2. Currently, PacifiCorp rejects Alternative 2 because it claims PacifiCorp's merchant function requires metering directly at PRS1 and PRS2; however, no such requirement is set forth in PacifiCorp's standard Community Solar power purchase agreement (PPA) or related tariff. And PacifiCorp rejected Alternative 1, even though it proposed a similar two-meter configuration *at the same site* in 2016.

---

[3] *See* Docket UM 1930, Joint Utilities' CSP Interconnection Proposal, August 6, 2019, p. 4.

[4] *See* Docket UM 1930, Staff Report, October 22, 2019, p. 13.

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SUNTHURST'S FIRST CLAIM FOR RELIEF: PACIFICORP WRONGFULLY REQUIRES SUNTHURST TO PAY FOR THREE REVENUE METERS FOR PILOT ROCK SOLAR 1 AND PILOT ROCK SOLAR 2.

Count 1--Violation of OAR 860-082-0070(a);

22.

Complainant re-alleges paragraphs 1-21, above, and incorporates them by reference herein.

23.

OAR 860-082-0070(a) provides that the interconnection customer is responsible for the "reasonable" costs associated with metering and data acquisition equipment.

24.

Where measurement of output from adjacent projects using two meters is consistent with past precedent, and where a 3-meter configuration would cost substantially more, PacifiCorp's 3-meter configuration is unreasonable and therefore not authorized for reimbursement under OAR 806-082-0070(a). To find otherwise would invite utilities to prescribe ever more expensive interconnections.

Count 2--violation of OAR 860-029-0060(1)

25.

Complainant re-alleges paragraphs 1-21, above, and incorporates them by reference

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herein.

26.

OAR 860-029-0010 defines "costs of interconnection" as "the reasonable costs of connection, switching, dispatching, metering, transmission, distribution, equipment necessary for system protection, safety provisions, and administrative costs incurred by an electric utility directly related to installing and maintaining the physical facilities *necessary* to permit purchases from a qualifying facility." (Emphasis added). OAR 860-029-0060 requires a qualifying facility to reimburse the utility for any reasonable interconnection costs.

27.

Three meters are not necessary to measure output from Sunthurst' PRS1 and PRS2 projects, which can be measured using only two meters at substantially lower cost consistent with past precedent.

28.

PacifiCorp does not have authority under OAR 806-029-0060 to require Sunthurst to pay for 3 meters--because either (a) the 3 meters are not "costs of interconnection" as defined by OAR 860-029-0010, or (b) 3 meters are not reasonably required, where PacifiCorp is aware of substantially less expensive 2-meter alternatives offering comparable performance and safety.

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SUNTHURST'S SECOND CLAIM FOR RELIEF: PACIFICORP'S INTERCONNECTION COSTS FOR OREGON SMALL GENERATING FACILITIES ARE UNREASONABLY HIGH.

29.

Complainant re-alleges paragraphs 1-28, above, and incorporates them by reference herein.

30.

The 400% disparity between PacifiCorp's Oregon Community Solar Program interconnection costs and interconnection costs across the Western United States documented in the 2018 NREL study is *prima facie* proof that PacifiCorp interconnection costs for small generators may be unreasonable. On good faith belief, PacifiCorp's Oregon Small Generation Interconnection costs are also substantially higher than costs charged by Idaho Power Company and PGE for similar interconnections.

31.

The following factors contribute to PacifiCorp's unreasonable costs:

a. On good faith belief, PacifiCorp designs interconnections using pre-engineered equipment panels, which it configures for specific applications. In order to be versatile for many applications, the pre-engineered panels may contain components and/or functionality that are not necessary for a particular interconnection. The versatility of standardized panels unreasonably increases the cost of interconnection components beyond the cost to install only components necessary for interconnection.

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b. PacifiCorp adds a 20% contingency on all materials and labor in its Facilities Study estimates. Such a large contingency has a significant adverse impact on the finance-ability of a small generation project. However, PacifiCorp does not know how, on average, its actual interconnection construction costs compare to its estimated construction costs. Because it does not know what contingency is justified based upon the actual versus estimated costs of its recent interconnections, PacifiCorp's 20% contingency is unreasonable.

c. PacifiCorp charges an 8% "surcharge" on top of the 20% contingency for all materials and labor in its Facility Study estimates. On good faith belief, PacifiCorp has never obtained express approval from the Commission to include this charge. An 8% surcharge has a material adverse impact on a small generator's finance-ability. PacifiCorp's use of the surcharge to recover any costs not expressly authorized by the Commission or Commission rules is unreasonable.

RELIEF REQUESTED

WHEREFORE, Complainant prays for a judgment against Defendant as follows:

1. On Complainant's First Claim for Relief, an order:

    a. finding that PacifiCorp's 3-meter configuration specified for PRS1 and PRS2 is unnecessary;

    b. declaring that PacifiCorp's 3-meter configuration specified for PRS1 and PRS2 is unreasonable;

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c. prohibiting PacifiCorp from charging Sunthurst any cost of a 3-meter configuration that is over and above the cost of a two-meter alternative.

d. requiring PacifiCorp to allow Sunthurst to install meters on the low voltage side of PRS1 and PRS2 ; and

e. granting such other relief the Commission determines appropriate.

2. On Complainant's Second Claim for Relief:

a. a finding that average PacifiCorp interconnection costs for small generator interconnections are substantially higher than average costs of similar interconnections across the Western United States;

b. an order directing PacifiCorp to identify all components and functionality included in interconnections and pay an equitable portion of the cost of pre-engineered panels when those panels contain components or functionality not necessary for customer's interconnection;

c. an order directing PacifiCorp to reduce its standard 20% contingency on its PRS1 and PRS2 to a lower percentage to be based upon historic data showing the average difference between Facilities Studies Interconnection Cost estimates and actual final costs;

d. an order directing PacifiCorp to show cause why the 8% surcharge on Sunthurst' PRS1 and PRS2 interconnections is reasonable;

e. an order directing PacifiCorp to allow Sunthurst to construct the facilities specified in its interconnection agreements in conformance with the requirements of PacifiCorp; and

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f. such other relief the Commission determines appropriate.

Dated this 29th day of September 2020.

By: Ken Kaufmann

Kenneth E. Kaufmann, OSB 982672
Attorney for Sunthurst Energy, LLC

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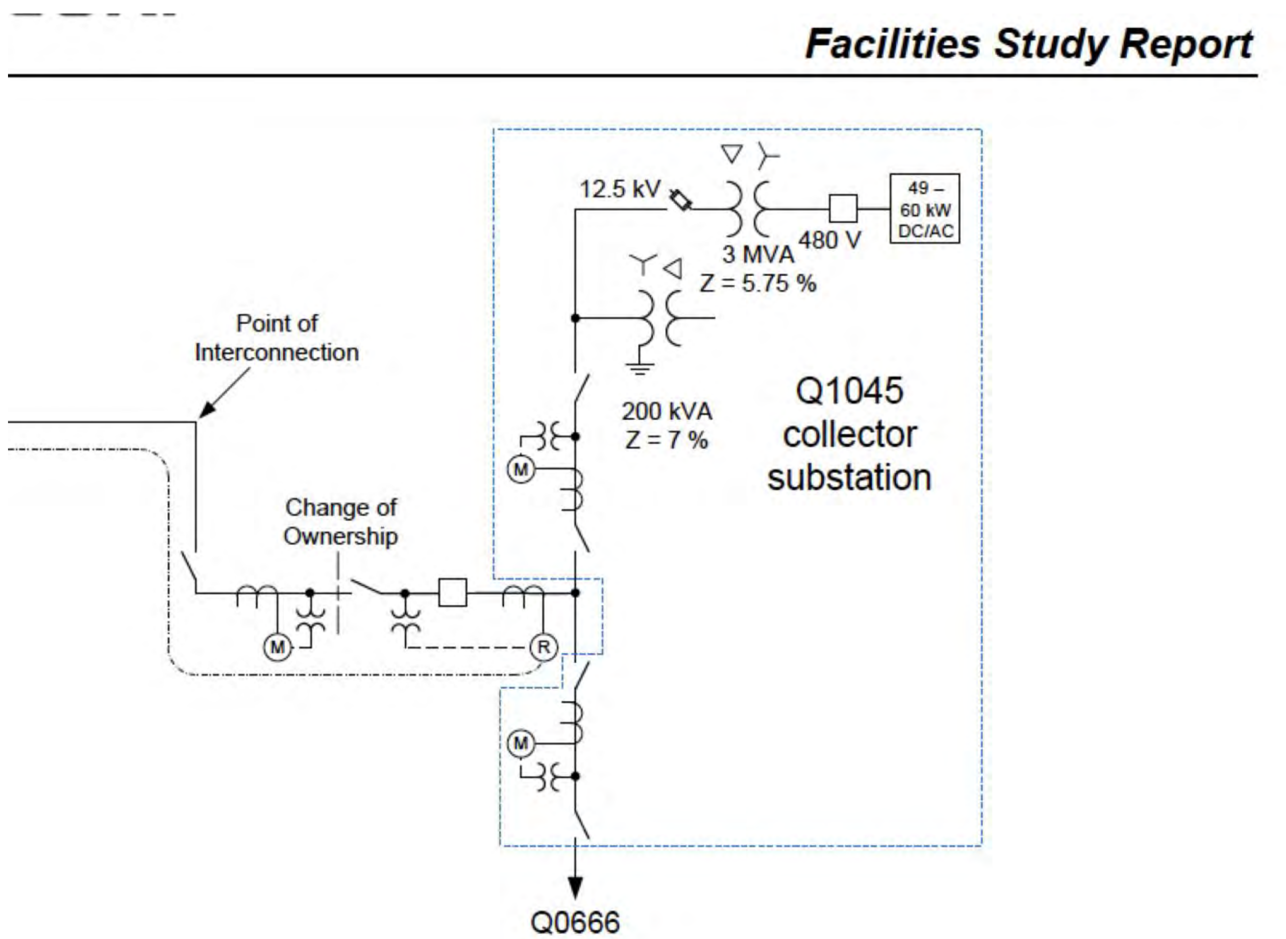
Attachment A
PacifiCorp's Proposed 3-meter Configuration for PRS1 and PRS2



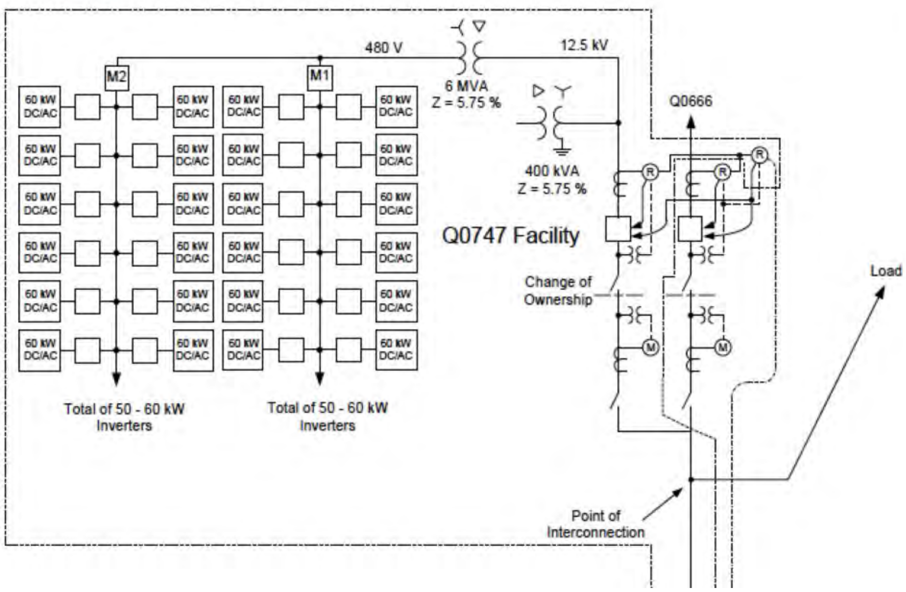
Source: Tier 4 Facilities Study Report for Pilot Rock Solar 2, LLC (Q1045), June 30, 2020, p.2

Attachment B

Page 3 of the PacifiCorp Q0747 SIS showing
two adjacent projects with a common COP, metered with only two meters

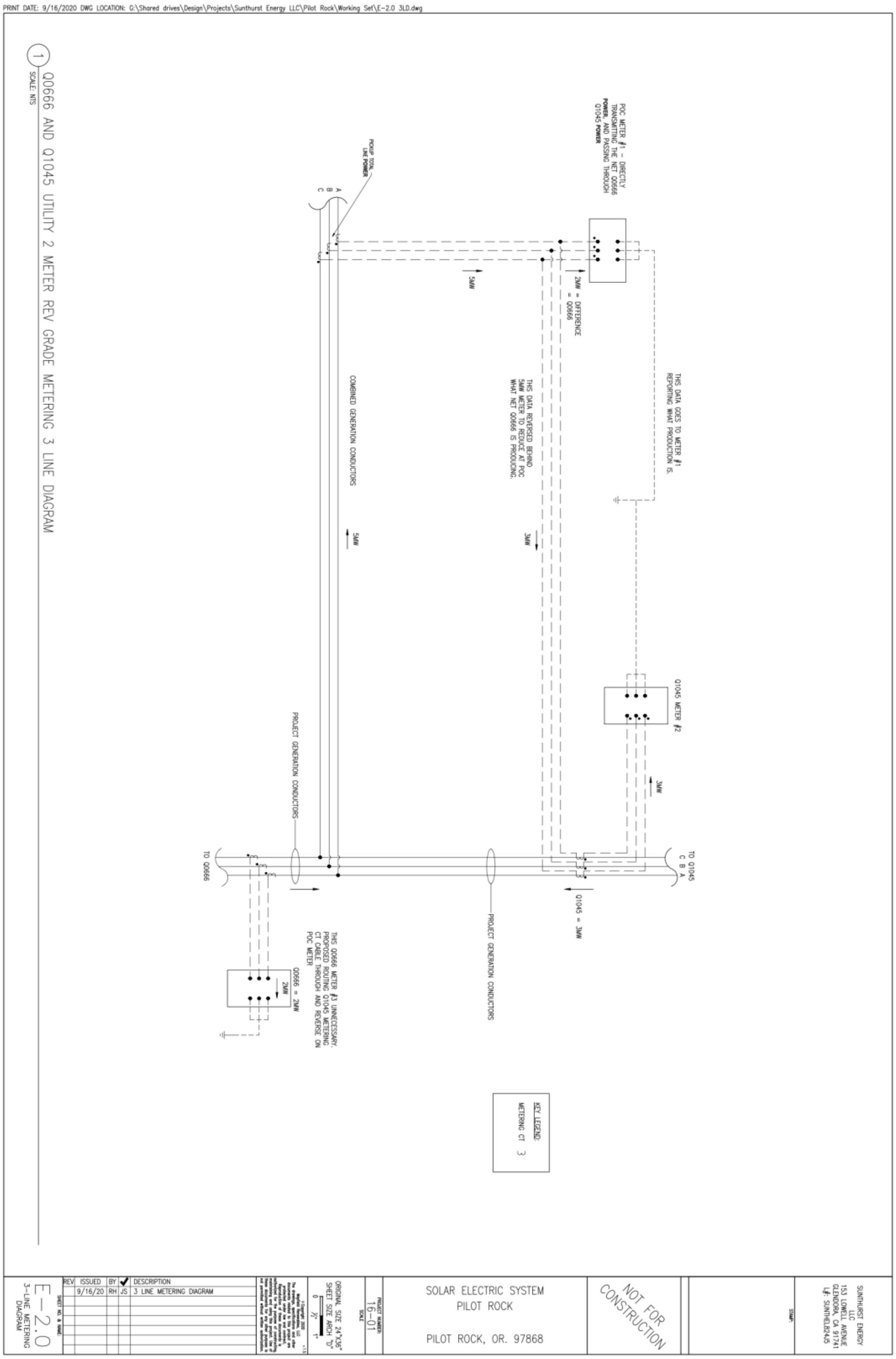
PACIFICORP TRANSMISSION

Tier 4 System Impact Study Report



Source: Tier 4 System Impact Study Report for Pilot Rock Solar 2, LLC (Q0747), August 26, 2016, p.3

Attachment C
Schematic showing Sunthurst <u>Alternative 2</u>
for measuring PRS1 and PRS2 output with only two meters



Attachment C to Sunthurst's Complaint

Attachment E

UM 2118 Sunthurst's Opening Testimony

KENNETH KAUFMANN, ATTORNEY AT LAW

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December 15, 2020

Via Electronic Mail

Filing Center
Public Utility Commission of Oregon
P.O. Box 1088
Salem, OR 97308-1088
puc.filingcenter@state.or.us

Re: OPUC Docket No. UM 2118

Attention Filing Center:

Attached for filing in the above-captioned docket is Sunthurst Energy, LLC's Opening Testimony of Daniel Hale and Michael Beanland.

Thank you in advance for your assistance.

Sincerely,

Ken Kaufmann

Ken Kaufmann
Attorney for Sunthurst Energy, LLC

Attach.

PUBLIC UTILITY COMMISSION
OF
OREGON

SUNTHURST EXHIBIT 100

Daniel Hale
On behalf of
Sunthurst Energy, LLC

DECEMBER 15, 2020

Q. Please state your name and present occupation.

A. Daniel Hale. I am president and owner of Sunthurst Energy, LLC, an Oregon company located at: 43682 SW Brower Lane, Pendleton, OR.

Q. Tell us about yourself.

A. I am from Umatilla County and have lived in Oregon for 35 years. My Grandfather founded Pendleton Electric in 1952 where our entire family worked. My step-father was a lifetime employee with Pacific Power & Light until retirement as Regional Customer Service Manager in Walla Walla.

In 1996, I earned a Bachelor of Science degree in Construction Management from Washington State University. In 2007, I earned a Master of Arts degree in Real Estate. Between 2007 and 2009, I earned a LEED AP, Solar Training Institute, and Southern California Edison Contractor Certificates and completed 3 semesters at Southwestern Law School in Los Angeles before working full-time as a Solar Project Manager and Regional Development Manager.

Q. Tell us about Sunthurst Energy, LLC

A. In 2013, I founded Sunthurst Energy, LLC (Sunthurst). Sunthurst currently is licensed in 5 Western States. Our focus is commercial solar EPC and development. We are members of Community Coalition for Solar Access ("CCSA") and Oregon Solar Energy Industries Association ("OSEIA").

Q. Are you a licensed electrician?

A. Above a BS in Construction Management, I have an OR LRT license under Renewable Energy JATC. Previously, I held a union journeyman carpenter's card from Portland Local #247.

Q. Tell us about your participation in development of Oregon CSP program.

A. As an OSEIA member, Sunthurst joined the Community Solar Group and participated in industry stakeholder calls and input to shape the Community Solar Program (CSP) created by SB 1547. I was the only developer at the PUC's two UM1930 workshops and participated actively in both. My PRS1 Project was the first to apply in PacifiCorp's CSP queue and I have been on the ragged edge of Oregon CSP implementation from the beginning.

Q. How many Oregon CSP Projects is Sunthurst developing?

A. I currently have three solar projects seeking Oregon CSP status: Pilot Rock Solar 1 (PRS1), Pilot Rock Solar 2 (PRS2) and Tutuilla Solar Project (TSP). All three are located in PacifiCorp service territory:

	PRS1	**PRS2**	**TSP**
Nameplate (MW)	1.98	2.99	1.56
Location	Pilot Rock, OR	Pilot Rock, OR	Umatilla, OR
PacifiCorp Substation	Pilot Rock	Pilot Rock	McKay
PAC 12.5 kV Circuit	5W406	5W406	5W857
PAC Queue #	Q0666	Q1046	OCS024
Status	IA executed	IA pending	IA executed
Oregon CSP Status	Pre-certified	Pre-certified	

Q. Which are the subject of this Complaint?

A. Pilot Rock Solar 1 (Q0666) and Pilot Rock Solar 2 (Q1045).

Q. Please provide a brief background on Q0666 and Q1045:

A. In 2015, I learned of Oregon's Renewable Portfolio Standard (RPS), and the up and coming community solar efforts in the legislature. I secured a site and applied to PacifiCorp for interconnection for the Pilot Rock Solar 1 Project (PRS1) in 2015. I believe PRS1 was the first Oregon CSP in PacifiCorp's interconnection queue (Q0666). But PacifiCorp's estimated $805k cost to interconnect a 1.98 MW project remains not economically feasible.

To absorb PacifiCorp's high interconnection cost, I attempted to add capacity on the feeder with Q0747 adjacent to PRS1, with the expectation that the second interconnection at the same location would be cheaper--thereby defraying the high costs from PRS1. I designed PRS2 and submitted a 6 MW interconnection request (Q0747) for a second project adjacent to PRS1. PacifiCorp's estimated cost to interconnect Q0747 was $42,199,000. After confirming that PacifiCorp's estimate was not a joke, I withdrew my request.

In 2018, I submitted a 3 MW application for PRS2 (Q1045). Oregon's CSP looked like it was approaching implementation, and I decided to develop PRS1 and PRS2 as CSPs. I remained hopeful that the smaller PRS2 interconnection costs would be lower because it could utilize some of the same equipment installed to interconnect PRS1. PacifiCorp executed my Q1045 Study Agreement in August 2018, but unilaterally delayed completing any study for 18 months. Meanwhile, the

Oregon CSP launched in February 2019. Because PacifiCorp had not finished an interconnection study, PRS2 was not eligible for Pre-Certification. In February 2020, PacifiCorp told me that it would complete the Q1045 study in “6 to 8 months”. On March 10, 2020, the Commission denied Sunthurst’ petition for a waiver of the completed interconnection study requirement for CSP Pre-Certification. I then sent PacifiCorp a notice of intent to file a complaint, on March 20, 2020. On March 25, PacifiCorp sent me a completed System Impact Study (SIS) for PRS2, with an estimated cost of $1,195,000. Sunthurst’ total cost to interconnect PRS1 and PRS2 was exactly $2,000,000.

Q. Why did you file your Complaint?

A. Given the price paid for output and other Project burdens under the CSP, PRS1 and PRS2 are not financeable with the interconnection costs quoted by PacifiCorp, and I doubt PacifiCorp will be successful filling its CSP capacity procurement goals. From our extensive experience, validation by credible 3rd party studies, and solar development industry contacts, we know it is feasible to interconnect small solar projects like PRS1 and PRS2 for $0.05-0.15 cents per watt-dc, which is approximately 25% of PacifiCorp’s initial estimate. Through protracted negotiations the last six months, PacifiCorp has reduced its cost estimate by about 50%; however, the costs remain unreasonable.

Q. Describe what happened.

A. <u>Q0666 application.</u> When I received the System Impact Study (SIS) for Q0666, I saw that the costs were dominated by the direct transfer trip scheme

(DTT). I hired a cost consultant to determine why costs were so high. He was a long-time PacifiCorp systems engineer, now consulting to project developers. He reviewed IEEE1547 requirements as they apply to smart inverters and determined that most utilities do not require DTT for projects under 2 MW if the inverters comply with IEEE 1547. A 2016 NREL Report he provided me said only Hawaiian utilities were requiring transfer trip (a large cost) on under 5W projects. PacifiCorp would not remove the TT requirement. Nor would they allow me to install the DTT at my cost.

<u>Q0747 application.</u> Two priority generators in this pocket had known issues. Q547 (18MW) was only permitted for 10MW, while Q586, a 6MW, let their FAA Glare Study lapse and was having permitting challenges. Additionally, City of Pilot Rock, a small rural community, was hit hard economically with a mill closed and laid off their only policeman; they encouraged us to use more solar giving them more lease revenue. Therefore, we filed hoping for available transmission capacity if either senior queue position defaulted. However, Q586 did come online, and Q547 received three 12-month extensions and is still tying up 8MW. For my 6 MW project (Q0747), PacifiCorp estimated a cost to interconnect of $40 million dollars, including network upgrades to move generation to Grandview, Washington, some 100 miles north. Ethically, PacifiCorp should have removed Q547's 8MW and granted it to Q747, the next applicant in the queue. Q547 blocked development of remaining capacity in its Pendleton Pocket for 4 years.

<u>Q1045 application.</u> To avoid the cost of network upgrades, Sunthurst downsized PRS2 to 2.99 MW and submitted a new interconnection request (Q1045).

By that time, published avoided cost prices had fallen but the new Community Solar Program looked promising. We signed the SIS Study Agreement in August 2018, but PacifiCorp breached the study agreement timelines. When I e-mailed to PacifiCorp in October seeking explanation, they said there was a "generation to load" issue. They NEVER gave an update for 12 months during which the queue was closed. This halted my ability to develop Q0666 while I waited for Q1045 study results. I asked PacifiCorp to pause engineering on Q0666 pending Q1045 results but PacifiCorp spent my $79,000 Q0666 milestone deposit anyway and halted giving me monthly invoices, which they had done up until that payment was made.

Q. After you received Q1045 SIS, what did you do?

A. I was surprised and disappointed when I found out the SIS interconnection costs were $1.195 Million. I wondered whether the fact that PRS1 and PRS2 interconnection costs totaled $2.000.00 Million was coincidence, or if PacifiCorp rounded to the nearest million.

With the help of a retired former utility electrical engineer, I investigated and found that PacifiCorp's estimated costs were high by any measure. I read a 2018 NREL Technical Report titled *Review of Interconnection Practices and Costs in the Western United States*, which Commission Staff presented in a public meeting hosted by the authors. Figure ES-1 in that report shows a median interconnection cost in western states of about $120K/MW. PacifiCorp's estimated costs for my two projects were $400K/MW.

I consulted a nationwide developer of utility-scale solar. I obtained data from a national solar finance company familiar with many project pro-forma financing models. A nationally-known renewable engineering firm with expertise estimating transmission costs for developers reviewed my costs. I also have personal experience managing solar for a national developer and knowing the actual costs of a comparable interconnection to PGE. Every source pointed to PacifiCorp's costs being out of line.

Q. Why do you think they were so high?

A. I think there are several reasons.

One reason is excessive scope. Two consulting engineers have confirmed to me that my interconnections do not require telemetry or the $600,000 building to shelter it that PacifiCorp initially proposed. Nor do they require annunciator panels, 48-pair fiber optic cable, or other components that would be nice to have but are not necessary. Expert Michael Bean's Opening Testimony filed on Sunthurst's behalf goes into this reason in detail.

Another reason is the age of PacifiCorp equipment. I am paying for upgrades to PacifiCorp's protection scheme and other components because PacifiCorp's substation is still using equipment installed in 1961. US DOE WEAP Replacement recommendations for distribution equipment is 30-50 years. PacifiCorp's retail customers paid for this aged equipment several times over but rather than reserve money to replace obsolete equipment, PacifiCorp charges generators who interconnect to their system to defray its programmatic replacement costs.

PacifiCorp is benefitting from this new equipment but doesn't pay for it. (For examples: feeder transformers, voltage regulators, telemetry, and annunciator.)

A third reason is the high cost of work done by PacifiCorp. Its direct cost of materials in its estimates is high even though it claims to leverage its size to buy at favorable prices. Its manpower is intensive. Approximately 10 PacifiCorp agents attend each interconnection-related teleconference I have attended. And its overhead is high. On top of the direct costs, PacifiCorp surcharges every item with its Capital Surcharge, which is currently about 8%.

All three factors are what one might expect given PacifiCorp's economic incentives: it benefits economically when it generates its own power rather than purchasing it from 3rd parties; it benefits from new interconnection facilities paid for by 3rd parties; and it is entitled to recover its actual costs, even if it overruns its estimate. It's not surprising that a utility that benefits from high interconnection costs that discourage competition, and also benefits from gold-plated interconnection facilities paid for by the competition, charges above-market rates for interconnection.

Q. Did PacifiCorp address your concerns?

A. PacifiCorp has always been courteous and patient. But progress is slow and expensive. I ask for System Impact Study results and I'm told I might get them in "6-8 months"; my lawyer writes a letter and I have the study in 5 days. I complained that a control building was not needed for my project and nothing happened. When my lawyer complained they took it out. Likewise for the annunciator panel and for telemetry, which PacifiCorp initially required but no longer requires. I don't think a regulated utility should ask for more than it is entitled to and force me to get an attorney to claw it back.

I have had a lot of decisions break against me, too. Senior queue position Q547, with 8MW of reserved, unused interconnection rights, blocked my development of additional capacity for years, although I notified PacifiCorp it was clear it would never be used. PacifiCorp's 16-month delay processing Q1045 may have deprived me from other development opportunities for the projects. I have another project, OCS024, that was originally sized at 2.45 MW based on UM2000 data reported on Jan 24, 2020. After I optioned a site for 2 MW, and after PacifiCorp confirmed the feeder number and this allowable generation size, PacifiCorp informed me that it was switching much of my feeder load to another circuit, which reduced the buildable size of my project down to 1.56 MW.

Q. What is the cost of the interconnection today?

A. In the PacifiCorp's Community Solar transmission queue, PUC Staff's report says interconnection costs for the first 24 applicants ranged between $200K/MW and $420K/MW ($0.20-0.42watt-dc). But PacifiCorp's costs for recently studied Community Solar projects OCS027-037 came in around $100K/MW ($0.10watt-dc). It appears to me that PacifiCorp's interconnection costs are dropping in its most recent community solar interconnection studies. One example is that fiber optic installation costs appear to be dropping, on a $/Linear Foot basis (as discussed in

Mr. Beanland's testimony). PacifiCorp has not revisited unit costs of fiber or other systems in my studies, however.

Q. Why aren't you satisfied with PacifiCorp's efforts to reduce costs?

A. Decreasing costs in recently published interconnection studies reinforces my belief that PacifiCorp can and should do more to further reduce the interconnection costs for PRS1 and PRS2. Mr. Beanland's testimony identifies ten specific changes that appear to be either required by, or justifiable under, existing interconnection rules.

In addition, there are changes that PacifiCorp might not be empowered to do without Commission involvement. One example is the 8% Capital Surcharge imposed on top of all project costs. To my knowledge the Commission has never examined how PacifiCorp applies the charge, let alone approved its use. I tried but was unable to verify that the 8% Capital Surcharge is included in the calculations used to calculate PacifiCorp avoided costs. On good faith, I believe they are not.

Another issue is the gross disparity between treatment of interconnection costs under FERC's SGIP rules, compared to Oregon's SGIP rules, which in my opinion unfairly allocate virtually all costs to the developer. My complaint provides a forum for the Commission to become aware of these issues and devise appropriate remedies.

My ultimate hope is to end up with interconnection costs that are financeable and to build PRS1 and PRS2, which have been my preoccupation the last 5 years.

Q. Does this conclude your testimony?

A. Yes.

CASE: UM 2118
WITNESS: MICHAEL BEANLAND, P.E.

PUBLIC UTILITY COMMISSION
OF
OREGON

SUNTHURST EXHIBIT 200

Opening Testimony

Michael Beanland, P.E.
On behalf of
Sunthurst Energy, LLC

DECEMBER 15, 2020

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I. INTRODUCTION AND OVERVIEW OF TESTIMONY

1. Please state your name and business address.

A. Michael David Beanland. 11616 NE 7th Cir, Vancouver, WA 98684.

2. Please describe your background and experience.

A. I received both a Bachelor of Science and a Masters of Engineering from California Polytechnic State University, San Luis Obispo, California, in electrical engineering. I am a registered professional engineer in CA, OR, WA, ID, HW, NV and NM. I have been working as an electrical engineer since 1977. From 1977-2001 I worked for electric utilities in various engineering capacities. In 2001 I moved to the consulting arena. In early 2018 I opened my own business and have been the President of Willamette Power Engineering, Inc. since then.

My work since 2001 has been both for electric utilities and for energy sector developers, including wind, battery storage, and photovoltaic. These projects have varied in size from a few MW to 100s of MW. I am the engineer of record for several small (under 10MW) photovoltaic projects.

In my capacity of performing interconnection studies and reviewing the studies performed by others, I have become familiar with the typical scope of work required for interconnections and the costs associated with that scope. In my role as a utility electrical designer, I am often called upon to develop construction cost estimates, and in that capacity I am familiar with the typical costs for equipment and construction. A summary of my qualifications is provided as **Exhibit Sunthurst/202**.

3. Please describe the information you reviewed in preparation of your testimony:

A. I was provided with large number (over 400) of documents and records addressing the Q0666 (Pilot Rock Solar 1 a/k/a "PRS1") and Q1045 (Pilot Rock Solar 2 a/k/a "PRS2") interconnections to PacifiCorp. These included the system impact studies, facilities studies, design drawings, cost estimates, and communications between Sunthurst and PacifiCorp. Documents I refer to in my testimony are included as exhibits.

4. On whose behalf are you appearing in this docket (UM 2118)?

A. I was approached by Sunthurst and asked to review the documents and offer my experience and expertise as to the reasonableness of the PacifiCorp interconnection requirements and estimated costs for its Pilot Rock Solar 1 (PRS1) and its Pilot Rock Solar 2 (PRS2) projects.

5. Have you previously provided testimony in any state or federal regulatory dockets or court cases?

A. In 2010, I provided testimony on behalf of PacifiCorp as it related to a generator interconnection in the Illinois Valley, Oregon area.

6. Please summarize your testimony:

A. Sunthurst's 1.98 MW Pilot Rock Solar 1 (PRS1) and its 2.99 MW Pilot Rock Solar 2 (PRS2) photovoltaic generating projects are typical of dozens of under-5MW photovoltaic projects interconnecting to distribution systems across PacifiCorp and other utility territories throughout the Pacific Northwest. These projects pose no particular technical challenges for interconnection. PacifiCorp initially estimated the cost to interconnect PRS1 and PRS2 at $805,000 and $1,195,000, for a combined cost of $2,000,000. In my experience projects like PRS1 and PRS2 can be interconnected for far less.

When challenged by Sunthurst, PacifiCorp later agreed several requirements were not essential to interconnect, including a line recloser, substation annunciator panel, a remote terminal unit (RTU, a/k/a "telemetry"), and a building to house the RTU. I agree with PacifiCorp's decision to remove the control building requirement, and to pay for the substation annunciator and telemetry package itself. However, the current $1,000,321 interconnection costs remain unjustifiably high for reasons including the following:

- substantial costs related to the annunciator panel and telemetry remain in PacifiCorp's proposed final scope of work and cost estimate, contrary to PacifiCorp's stated intent;

- PacifiCorp has included, in the relaying upgrade, the installation of line potential transformers to sense the voltage on the line ("dead-line check") as a method of reducing the possibility of restoring (reclosing) power into an energized line. A more favored practice in the region is to extend the delay on reclosing long enough that dead-line checking is not needed;
- PacifiCorp is requiring fiber optic cable from the Pilot Rock Substation to the projects as the communication path for implementing the direct transfer trip. Using spread spectrum radio is likely a substantially cheaper and fully adequate alternative;
- PacifiCorp is requiring installation of two sets of line voltage regulators. There is no supporting justification for the inclusion of the voltage regulators and begs the question of whether this is to resolve an existing problem;
- Because the Q0666 and Q1045 projects are collocated, in addition to the usual point of interconnection (POI) metering for each project, PacifiCorp is requiring a third meter to measure the total power delivered by both projects. Three meters are both excessive and not useful;
- Some of PacifiCorp's itemized costs appear unreasonably high. "Avian protection" is listed in the Q1045 cost estimate as $7,650 for what appears to be three 36-inch sections of insulating tubing installed on conductors. This is one of several line items that appear unreasonable on their face.

In addition to the unreasonable interconnection charges listed above, it may be reasonable for PacifiCorp to share the cost of certain necessary interconnection facilities that provide tangible benefits to the greater distribution system, in particular the 0.3-mile line extension and fiber optic line from PacifiCorp's existing system.

Finally, PacifiCorp requires Sunthurst to pay for project features needed to support PacifiCorp's RTU and telemetry scheme. PacifiCorp should reimburse Sunthurst for all such out-of-pocket charges.

My testimony is organized into four Parts. Part I describes my background and previews the remainder of my testimony. Part II describes the interconnection design and apportionment of installation costs, as set forth in PacifiCorp's PRS1 and PRS2 Interconnection Agreement and Interconnection Studies. In Part III, I discuss unreasonable aspects of PacifiCorp's design, estimated costs, and apportionment of estimated costs. In Part IV, I suggest changes in the design, estimated cost, and assignment of costs intended to minimize overall costs and to reasonably apportion remaining costs between PacifiCorp and Sunthurst.

II. PACIFICORP'S PROPOSED INTERCONNECTION DESIGN and COST APPORTIONMENT

1. Describe the interconnection at Pilot Rock Solar 1 and Pilot Rock Solar 2.

A. The interconnection facilities include all hardware necessary to safely interconnect the PRS1 and PRS2 solar projects to PacifiCorp's existing 12.5 kV Circuit 5W406 out of its Pilot Rock Substation, Transformer T-2144 near Pendleton. A one-line diagram of the proposed interconnection is provided in **Exhibit Sunthurst/203**. On the Project's side of the Change of Ownership Point (COP), each Pilot Rock Solar facility includes photovoltaic (PV) modules, inverters to convert the direct current produced by the solar modules to alternating current, low-voltage (480V) switchgear needed to combine the outputs from multiple inverters, a step-up transformer to raise the low-voltage produced by the inverters to the medium-voltage (12.5 kV) of the PacifiCorp distribution system, and a meter on the 12.5 kV side of the project transformer to measure the power produced by the plant.

In common to both projects is the interconnection interrupter that implements the PacifiCorp-required protection scheme including direct transfer trip. See **Sunthurst/203, Beanland/1.**

On PacifiCorp's side of the COP, the facilities include a third meter to measure combined output of PRS1 and PRS2, the 12.5 kV overhead power line, the fiber optic communication line, and at the substation, the protective relaying and communication. The PacifiCorp substation is a 69kV to 12.5 kV distribution substation with existing fused step-down transformer, voltage regulator, circuit breakers, and supporting equipment, most of which was installed in the 1960s.

Functionally, the interconnection equipment may be grouped into four categories: conductor related, system protection, metering, and telemetry. I briefly describe the facilities, by functional group, below.

CONDUCTOR RELATED DISTRIBUTION SYSTEM UPGRADES

2. What are conductor-related distribution system upgrades?

A. Conductor-related distribution system upgrades can include both the construction of new overhead or underground medium-voltage (12.5 kV to 34.5 kV) power lines or the reconstruction of existing overhead or underground medium-voltage power lines. This includes apparatus needed such as poles, cross arms, insulators, cross-arm braces, down guys, guy anchors, ground rods and wire, group-operated switches, hook-operated disconnects, etc.

3. Describe the conductor related upgrades planned for PRS interconnection.

A. For the PRS projects, the only medium-voltage distribution line work required is the overhead extension of the 12.5 kV line for a distance of about 0.3 miles (roughly five new wooden poles, plus cross arms, guys, conductor, and disconnect switches).

4. Are there any others?

A. The Q1045 system impact and facilities study reports conclude that two sets of line voltage regulators are to be installed. Line voltage regulators are intended to compensate for the normal voltage swings that occur on the electric grid as load increases which tends to drive voltage lower or as load abates which tends to drive voltage higher. The regulators automatically adjust the line voltage to deliver acceptable voltage to all customers on the distribution line after the voltage regulator. The regulators are not shown on the single line diagrams but are listed as being on tap lines from the line between the Pilot Rock Substation and the projects. They appear in the 3/27/2020 Q1045 system impact study report and the 9/4/2020 Q1045 facilities study report. The cost of the regulators appears in the 9/1/20 detailed expenditure report.

INTERCONNECTION PROTECTION REQUIREMENTS

5. What is Protection?

A. Protection equipment and systems are used in the electric power system primarily to detect and isolate electrical faults. Electrical faults are any undesired disturbance to the normal flow of electricity and thus power to the loads served. Most electrical faults in medium-voltage systems are from "shorts" where excessive electrical current flows. Shorts can be caused by vegetation, animals, lightning, or equipment failures. The intent of protective systems is to rapidly sense a fault and to rapidly isolate the faulted system or equipment from the rest of the electric system to minimize the impact of the power outage.

Protection sometimes includes the safe operation of the electric system including maintaining voltage and frequency for the proper operation of customers' electronics and electrical equipment.

6. Describe the protection elements specified for PRS.

A. The existing substation feeder protection includes protective relays to detect and separate from electrical faults, but does not include systems to detect voltage or frequency abnormalities.

The new protection equipment being installed by PacifiCorp in the Pilot Rock Substation includes a modern electronic fault-detecting relay to replace the 60-year old feeder protective relays, a pair of transformer fault-detecting relays, potential transformers to detect abnormal line voltage when the feeder breaker has opened, and communication equipment.

7. What does Transfer Trip do?

A. Transfer trip is a scheme whereby the utility, upon detecting an electrical fault on its system, sends a signal to the distributed generator, tripping it off-line rapidly, to prevent the formation of an island. An "island" is a condition where the isolated generation (e.g. PRS1 and PRS2) and isolated load (e.g. load on PacifiCorp feeder 5W406) are in rough balance, enabling the isolated generation to continue operation.

An island is likely to experience abnormal voltage and frequency, which can damage customer and utility equipment if not eliminated rapidly.

8. What are the main components of the Transfer Trip scheme for the PRS projects?

A. The PRS projects' transfer trip system consists of the protective relay at the utility substation, a communication system from the substation to the project using a fiber link, and a protective device at the project to receive and implement disconnection of the photovoltaic generation.

9. Describe the transfer trip relay at PRS projects (Project TT relay).

A. The direct transfer trip (DTT) system proposed for the PRS projects includes a new substation feeder protective relay panel with an electronic relay capable of communicating with the project protection, a fiber optic communication system from the substation to the project, and a medium-voltage interrupter and protective relay at the project to receive the DTT signal and disconnect the photovoltaic system.

10. Describe the transfer trip relay at the substation (Substation TT relay)

A. The protective relay at the substation is a microprocessor-based device that is fed current and voltage signals from the medium-voltage system. It converts these voltage and current analog signals to digital form, then, using a microprocessor, performs calculations and logic to take corrective actions.

11. Describe the fiber communications link.

A. The fiber optic link is a communication system where light, either from a light-emitting diode or laser, is shined down a small glass fiber and detected by a photo-electric sensor on the receiving end. Because of the speed of light and the speeds at which the

LED can be modulated, fiber optics is well suited for high-speed communication, as are microwave transmitters and radio transmitters.

12. Tell us about the dead line checking.

A. PacifiCorp designed the substation feeder protection to detect faults, open the 5W406 circuit interrupter located at the Projects to clear the fault, then to quickly close (reclose) the circuit interrupter to restore power. The assumption is that many faults are momentary in nature and can be cleared by interrupting the fault current. Quick reclosing allows customers to be restored without requiring human intervention.

Reclosing the utility circuit interrupter at the substation into the PRS Projects can lead to equipment damage from high transient currents and voltages if the PRS Projects are online. Therefore PacifiCorp will install a "dead line" check system to monitor the voltage on the Project side of the feeder circuit interrupter at the substation and delay reclosing the circuit interrupter at the substation until no voltage is detected. The potential transformers required for the dead line check system will require the addition of a steel structure in the outdoor substation yard.

13. Are there any other components of the TT scheme at PRS?

A. Power supplies and batteries are used at both the substation and project to provide reliable power to the protective relays. Various conduits, control houses, and enclosures are needed to provide environmental and physical protection for the DTT equipment. Engineering is needed to program the protective relays and to design the entire relay and communication systems.

METERING REQUIREMENTS

14. What does metering do?

A. Metering provides information regarding the power consumed or produced by a generator. Just like the meter on a home or business that measures the energy consumed so that billing can be performed, the meter on a generator serves the same function. A bi-directional meter, such as the ones specified for PRS Projects, reads flow of power in either direction (generation or consumption).

15. What are the main components of the metering scheme for the PRS projects?

A. Each medium-voltage meter includes the medium-voltage potential and current transformers,[1] the meter socket and electronic meter, supporting structures and wires for the equipment, and the communication media needed to transmit the meter data.

16. Describe the "communication media" mentioned above.

A. Communication media includes any equipment or communication path used to promulgate a signal from one protective device to another or from the meter to the centrally-located meter-reading computer. The typical meter installed at a distributed generation site will use a cellular data modem to send and receive data over the cellular phone network, much the way a modern cell phone sends and receives data. Utilities tie their billing meter systems to the cellular network to gather data from meters.

TELEMETRY REQUIREMENTS

17. What is telemetry?

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[1] The meter is an electronic device designed for connection to low voltages (<600V). Because the medium-voltage distribution line is operating at 12,470V, potential transformers and current transformers are used to provide inputs at safe voltage and amperage to the meter.

A. Telemetry is the quasi-real time communication of situational information to a remote location.

18. What are the main components of the telemetry scheme at the PRS projects?

A. A remote terminal unit (RTU) will gather project data (MW, MVAR, etc.) and communicate it back to a central location via fiber optic communication link from the projects to the Pilot Rock substation, and radio link from the substation to PacifiCorp's existing system at Cabbage Hill substation.

19. Is Telemetry a requirement for interconnection?

A. PacifiCorp (and Bonneville Power Administration) requires telemetry for projects 3MW or larger. Neither PRS1 nor PRS2 is 3MW, but PacifiCorp has opted to require telemetry for both. After initially assigning cost responsibility to the Projects, PacifiCorp has offered to pay for telemetry.

20. Are there any other components of the telemetry scheme?

A. The RTU is housed in a small control house or outdoor enclosure that provides power and environmental protection. The control house or enclosure includes batteries and a battery charger to provide the 48VDC used by the RTU and its communication equipment. PacifiCorp initially specified a $600,000 control house but was challenged and switched to a smaller metal equipment enclosure instead.

21. Have you described all of the PRS interconnection facilities?

A. PacifiCorp additionally is requiring the installation of an annunciator panel in the substation. This panel is a box filled with lights that illuminate to provide the local operator with a quick indication of the state of the power system. It is my understanding that after initially assigning cost responsibility to the Projects, PacifiCorp has agreed to pay for the substation annunciator panel.

PacifiCorp has indicated a concern about fault current flow into the substation power transformer should the transformer suffer a failure. To detect such situation, PacifiCorp has indicated that a transformer relay system will be installed to detect abnormal fault current flow into the transformer and trip the distributed generation. This new microprocessor-based electronic relaying system will provide improved fault detection, lower maintenance costs, and improved situational awareness for PacifiCorp.

ASSIGNMENT OF COSTS

22. Is PacifiCorp requiring Sunthurst pay for all of the interconnection facilities, above?

A. According to the documents I have reviewed, Sunthurst will pay for all work performed with two exceptions: PacifiCorp will pay for the P1-111 annunciator and for the telemetry RTU:

		Cost			**"Necessary"?**
	Item	**Sunthurst**	**PacifiCorp**	**Installer**	
1	Conductor/voltage	100%		PacifiCorp	Yes
2	Protection	100%		PacifiCorp	Yes
3	Metering	100%		PacifiCorp	Yes
4	Telemetry	Fiber, land, power, cabling	RTU	PacifiCorp	No
5	P1-111 panel	Total cost less $15k	$15K	PacifiCorp	No
6	Voltage regulators			PacifiCorp	No

PacifiCorp has included in the costs to be borne by Sunthurst all of the interconnection-necessitated substation, distribution and COP costs and the engineering and project management associated with that work. In addition to interconnection-necessitated additions, PacifiCorp is installing a P1-111 panel, line voltage regulators, and a telemetry package, which are not necessary for the interconnection but will be installed as part of the interconnection facility construction. PacifiCorp offered, in an August 7 letter, to credit Sunthurst $15,000 for the P1-111 panel, which PacifiCorp has designed but not installed. It is not clear what the $15,000 is based upon, and whether it reflects the full cost of the P1-111 panel, including completed engineering, overhead, surcharge, and contingency. PacifiCorp, in its revised Q1045 Facilities Study dated September 4, 2020, removed the RTU from Sunthurst's (PRS1 and PRS2's) assigned costs. However, Sunthurst is still required to install control cabling and conduit from PRS1 and PRS2 source devices to PacifiCorp's RTU. It is still required to provide an easement for PacifiCorp to install an enclosure for its RTU, and to provide AC power to PacifiCorp's RTU enclosure.

23. What is the total estimated cost to Sunthurst?

A. According to the most recent contract documents from PacifiCorp, the estimated cost of interconnecting PRS1 is $700,000 (9/2/20) and the estimated cost of interconnecting PRS2 is $300,321 (9/1/20), for a total estimated cost of $1,000,321.

24. What is the total estimated cost to PacifiCorp?

A. PacifiCorp's costs to install the P1-111 annunciator panel and the RTU are not specified in the interconnection studies. In a letter Dated August 7, 2020, PacifiCorp stated that removal of the RTU from the required facilities saved Sunthurst "approximately $525,000," and removal of the P1-111 panel saved Sunthurst about $15,000. **Sunthurst/211.**

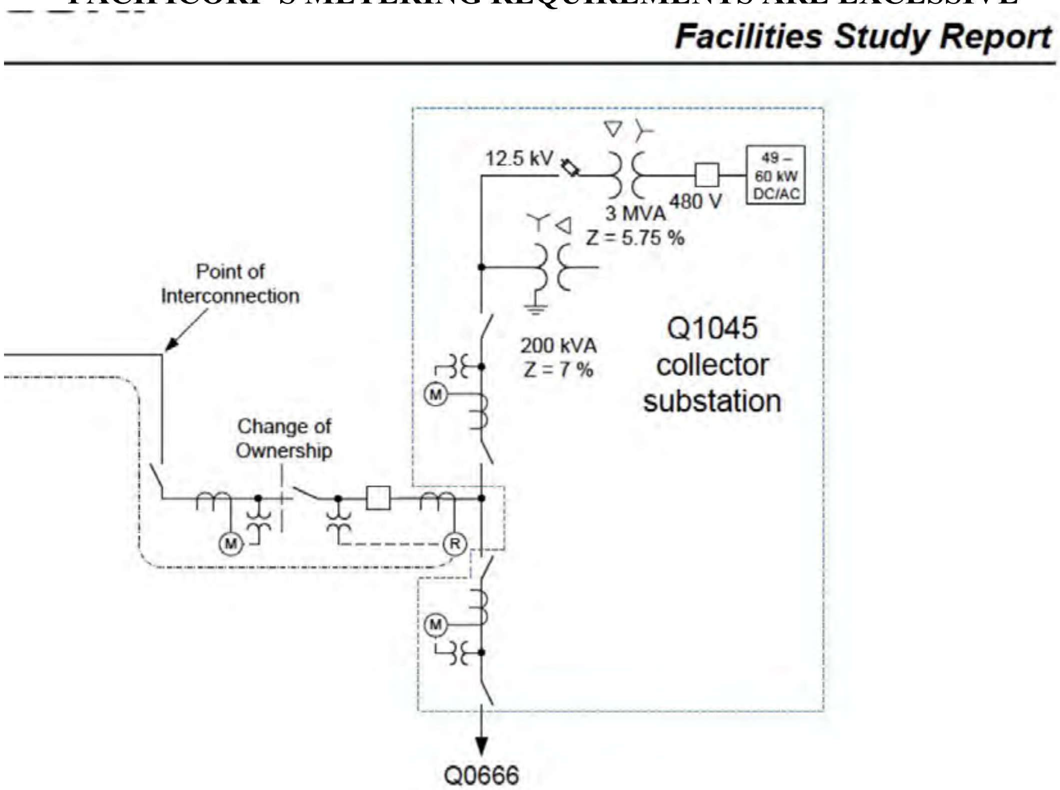
25. Who is responsible for installation?

A. Installation work performed in the Pilot Rock Substation and in the medium-voltage distribution line leading to the projects is being performed by PacifiCorp. Installation of primary metering at the project POI is being performed by PacifiCorp. Sunthurst, in addition to installing the photovoltaic generation system, is responsible for the protection equipment installed at the POI. Sunthurst also is responsible for installing control lines delivering analog data from its projects to PacifiCorp's RTU.

III. REASONABLENESS OF INTERCONNECTION DESIGN, COST, AND COST RESPONSIBILITY

This section discusses interconnection requirements that are unreasonable in scope, unreasonable in cost, and/or not reasonably allocated between Sunthurst and PacifiCorp.

PACIFICORP'S METERING REQUIREMENTS ARE EXCESSIVE



1. The one-line diagram, above, is from PacifiCorp Q1045 Facilities Study Report. Will you please describe the metering scheme PacifiCorp proposes for PRS1 and PRS2, above?

A. PacifiCorp proposes to use three medium-voltage-connected bi-directional electric metering systems. Each metering system, includes a wood power pole to support the equipment, a cluster mount to support the potential and current transformers, three medium-voltage potential transformers, three medium-voltage current transformers, a meter socket, an electronic meter, a cellular modem, and miscellaneous conduits, hardware and wire.

PacifiCorp shows one meter measuring the Pilot Rock Solar 1 power flows, one meter showing the Pilot Rock Solar 2 power flows, and a 3rd meter measuring the combined power flows from both projects.

2. Are three meters necessary to interconnect PRS1 and PRS2?

A. No. The data from any two of the meters will provide the same data as all three meters. This is known as Blondel's Theorem.

3. What is another way to meter PRS1 and PRS2 using two meters:

A. There are two feasible approaches to determine the combined power flows from PRS1 and PRS2 without using a 3rd entire metering system. Both approaches are widely used and are not novel. If we start by assuming that the meters on PRS1 and PRS2 are installed, the data can be summed digitally or electrically.

Using the digital method, the time interval data stored in each meter, when the internal clocks in the meters are roughly synchronized, can be summed to determine the total power flow. For example, if in one 5-minute interval one project is seen to have

1MW of power flow and the other is seen to have 2MW of power flow, we know that the sum of the two projects in that 5-minute interval will be 3MW.

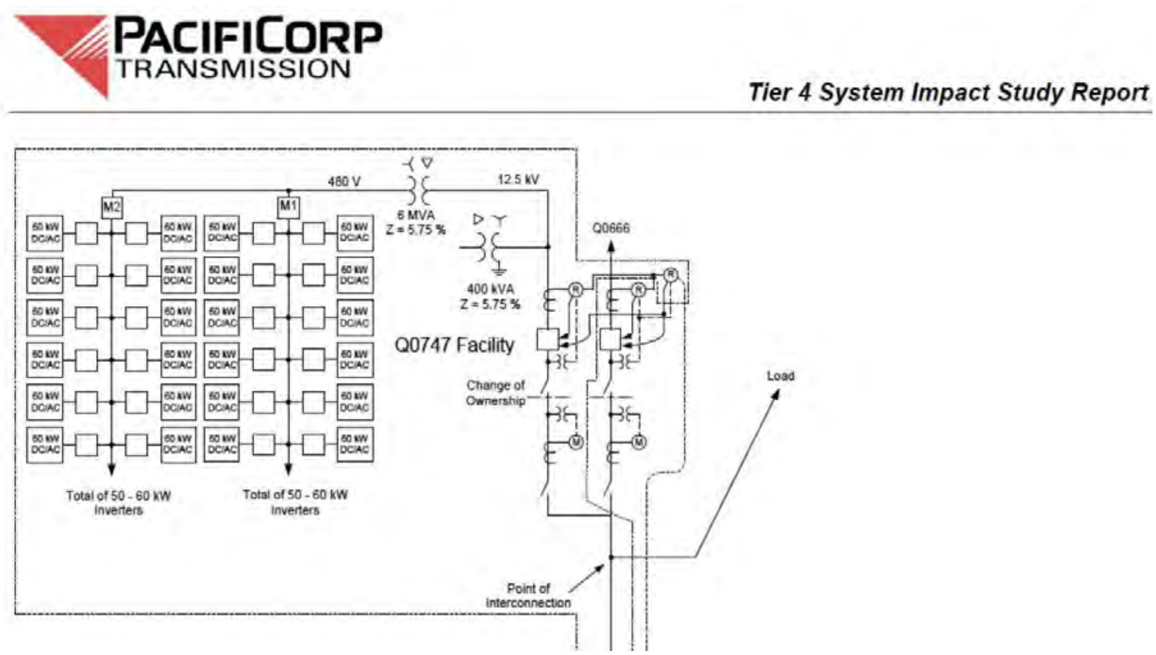
Using the electrical method, the currents flowing through the PRS1 and PRS2 meters can be placed in parallel and used as the measuring current feeding into a 3rd meter. This allows the 3rd meter to accurately measure the total power flow. For example, if 1 Amp is flowing through the PRS1 meter and 2 Amps is flowing through the PRS2 meter, then the sum of these currents can be measured in a 3rd meter to determine the total power flow.

4. Is the COP meter necessary as a backup in case PRS1 or PRS2 meters fail?

A. Electric meters are well made and extremely reliable. The utility does not install redundant metering on electrical loads and meters have a service life of 30-50 years. When a rare meter failure component failure occurs, utilities have many methods available to estimate meter readings. If a single current or potential transformer fails, the resulting power flow will be only 2/3 of the actual. Where the customer has continuous performance monitoring, such as that used at typical larger distributed generators, this data can be correlated with the utility data to provide a tool for estimating data upon meter failure. If the utility has installed an RTU and telemetry to gather data in real time, this data is saved and the historical data can be used to estimate missing data. There are many options available to the utility for estimating missing data when necessary, though it is seldom necessary.

5. Are two meters unsafe?

A. No. Electrical operations crews will never rely solely on the data from an electric meter to determine if a generator is operating. PacifiCorp requires that all distributed generators be equipped with line disconnect switches that allow PacifiCorp to disconnect the DG from the distribution system. This mandatory disconnect switch is shown to the left of the Change of Ownership in the above diagram. The stated purpose for this switch is to provide PacifiCorp with a means of safely and securely disconnecting DG from the grid.



6. The one-line diagram, above, is from PacifiCorp Q0747 System Impact Study Report. Please compare the metering scheme in Q0747 to the metering scheme in Q1045:

A. Both diagrams show PRS1 and PRS2 collector systems tying into PacifiCorp's 12.5 kV distribution system at a common Point of Interconnection. (Q0666 is PRS1; Q0747 was PRS2 when PRS2 was a 6MW design). Both meter PRS1 and PRS2 separately, prior to the POI. However the Q1045 scheme has a third meter at the POI whereas the Q0747 scheme does not.

7. How do you explain this difference?

A. In the above diagram, each project has a meter and each project has a circuit interrupter. The two projects are built and operated as completely independent of each other. PacifiCorp deems two meters adequate in this early version of the project and in the later development of this project, PacifiCorp deems two meters inadequate. If these were two projects, owned and developed by different entities, connecting at the same POI, the use of the two meters is exactly what I would expect to see.

8. What is PacifiCorp Policy 138, "*Facility Connection (Interconnection) Requirements for Distribution Systems 34.5 kV and Below*"?

A. This 65-page document is the written policy established by PacifiCorp to provide for a uniform standard for the connection of distributed generation to PacifiCorp distribution systems operating at voltages of 34,500V and below. The portions discussing metering are attached as Exhibit Sunthurst/209.

9. What does PacifiCorp Policy 138 say about metering?

A. Section 4 of Policy 138 describes in general terms the metering systems PacifiCorp will require be installed for distributed generation. In general, the metering will be similar to that required for commercial retail electric service with the exception that meters must be able to measure power bi-directionally.

10. Does Policy 138 require metering at each facility and at the POI?

A. Policy 138 requires metering for each distributed generator but is mute on requiring aggregate metering for multiple projects. In my experience, PacifiCorp treats each distributed generator as an independent project based on the interconnection application.

11. What is the approximate distance from the facility metering point at PRS1 and PRS2, respectively, to the POI?

A. Based on the design information available, the distance from the PRS1 and PRS2 connections to the PacifiCorp medium-voltage supply are less than 400 feet.

12. Approximately how great are electrical losses on 400' between the COP meter and the PRS meters?

A. Making reasonable assumptions about the resistances of the conductor and load factors for PRS1 and PRS2, typical total losses between project meters and the COP meter are about 3,406W or roughly 0.07% of the plant output. Metering systems typically are accurate to about 1%. Accordingly, the losses between the project meters and the COP meter are far less than the meter's measurement error, meaning that they are undetectable with the metering system PacifiCorp plans to use.

13. Can they be estimated without a meter at the POI?

A. Conductor loss follows well known rules and can be reasonably estimated. The electrical resistance of the overhead conductors does vary slightly with temperature but reasonable assumption can be made as to the average operating temperature of the conductors. The remainder of the loss estimating is simple math based on Ohm's Law.

14. Is the three-meter requirement considered Good Utility Practice?

A. Good Utility Practice implies making a reasonable effort to provide reliable quality service at reasonable costs. Using a 3rd meter to estimate the total delivery of two distributed generator projects at one point provides little benefit to the utility. The third meter also creates an additional maintenance expense and adds another possible point of failure to the medium-voltage system. I do not consider the requirement for the 3rd meter Good Utility Practice.

15. In Data Request 3.2, Sunthurst asked PacifiCorp to describe any reason why eliminating the POI meter from the PRS1 and PRS2 metering scheme was not safe or effective. PacifiCorp replied:

[1] Without the metering equipment that PacifiCorp is requiring, the possibility exists that generation could flow onto PacifiCorp's system without PacifiCorp having the ability to monitor it which could lead to unsafe operating conditions for PacifiCorp's employees.

[2] Additionally, the "Alternative 1" metering proposal from Sunthurst Energy, LLC (Sunthurst Energy) is not effective (or acceptable) because PacifiCorp would not have a meter at the point of interconnection (POI) where the generation from both facilities is injected onto PacifiCorp's system. This is unacceptable as PacifiCorp must have a meter at the POI to ensure it knows how much energy is flowing onto its distribution system. A POI meter is standard industry practice.

[3] In addition, PRS1 and PRS2 are separate and distinct generation interconnection requests with two interconnection customers. Sunthurst Energy's proposal would create a scenario in which disputes are much more likely. First, if either meter were to fail then one or both facilities would be forced to cease operation as PacifiCorp would not have the ability to separate the generation of the two facilities. Allowing one of facilities to continue operation would potentially be discriminatory and put PacifiCorp in the position of having to defend either allowing only one facility to operate or disconnect both facilities.

[4] Second, Sunthurst Energy's metering proposal would force PacifiCorp to rely on the use of a calculation to determine meter values rather than on actual meter data. If PacifiCorp's meter interrogation system were to experience a timing error in which the timing of the reads of the two meters becomes misaligned, then Sunthurst Energy's proposal would not result in accurate data. In this scenario, the generation attributed to each project would be incorrect and lead not only to disputes between PacifiCorp, PRS1 and PRS2, but also potentially substantial accounting work to revise the data.

[5] Finally, as both PRS1 and PRS2 are proposing to participate in the Oregon Community Solar (OCS) program, the accuracy of the meter data for these facilities is even more

important. The OCS program requires generator owners to sign up subscribers for their solar generators. If there is a meter failure or a data calculation error as described above, under the OCS program not only is there a potential dispute or recalculation necessary for PRS1 and PRS2, but also potentially disputes or recalculations for dozens or even hundreds of subscribers. This scenario could lead to substantial accounting work for PacifiCorp and creates the possibility of hundreds of disputes with subscribers. Having three meters would substantially limit these potential issues.

16. What is your response to PacifiCorp's Answer, above?

A. I respond to each above-numbered paragraph with my corresponding numbered paragraph, below:

[1] No unsafe condition is created by the absence of the 3rd meter. If PacifiCorp learns of a meter failure, corrective action will be required. No utility crews will work on the electric systems without using the mandatory disconnect switches to assure that the generation is not operating.

[2] The added meter at the POI can be functionally provided either digitally or electrically without the costs of installing an entire 3rd metering system. The difference that a 3rd meter would possibly show is less than the metering error. In fact, the 3rd meter may "run fast" and overestimate production from the DG.S

[3] Since PRS1 and PRS2 are independent entities, standard interconnection practice requires independent metering. If either meter fails, that project could be taken off-line with no effect to the other project while repairs are being made. There is no mandate that both projects be taken out of service to repair the meter on one. In fact, the requirement for the 3rd meter has now created a worse-case scenario where the failure of the 3rd meter requires both projects to be taken out of service while repairs are made.

[4] The digital summation of data from metering points is common utility practice. Virtual net metering allows customers to digitally combine the load from several meters to be offset by the generation at different meters. Meter timing error can occur but the meters are utility-grade, meeting general commercial retail metering standards, and PacifiCorp will be regularly receiving data from the meters to allow determination of any timing error. If timing error is a problem in meters, the 3rd meter will also suffer from this same problem.

[5] Regardless of the number of virtual net meters that may be included in a community solar program, the problems of combining meters is nothing new. PacifiCorp is implying that meters fail or are inaccurate regularly and so there is a burden on PacifiCorp but there is no data supporting this hypothetical problem that would exist system-wide for every project.

OTHER FACILITIES THAT ARE UNNECESSARY

1. OAR 860-029-0010 defines "costs of interconnection" as the "reasonable costs of connection, switching, dispatching, metering, transmission, distribution, equipment necessary for system protection, safety provisions, and administrative costs incurred by an electric utility directly related to installing and maintaining the physical facilities necessary to permit purchases from a qualifying facility." Do you understand the above definition?

A. I find it to be pretty clear.

2. Do you consider the P1-111 panel a "cost of interconnection"?

A. Some technical requirements fall into the "it would be nice to have" category but not the "necessary for safe operation" category. Many substations, including Pilot Rock are not equipped with such panels. Presumably for this reason, PacifiCorp removed the P1-111 substation annunciator from Sunthurst's costs of interconnection, and I agree. If the annunciator is not a cost of interconnection, it seems to follow that all project costs arising from installing the P1-111 annunciator also are not "costs of interconnection." A detailed cost estimate for Q0666 provided by PacifiCorp on September 4, 2020 shows $17,347 in direct costs for the P1-111 panel ($12,247 in direct material costs plus $5,100 in direct "external" costs). It therefore appears from the September 4 cost breakdown that Sunthurst is paying costs related to the P1-111 panel, despite PacifiCorp's expressed intent to the contrary. If that is the case, I would say assigning these unnecessary interconnection costs to Sunthurst is unreasonable.

3. Based upon OAR 860-029-0010, would you consider telemetry a "cost of interconnection"?

A. Telemetry for projects under 3 MW is another feature that would be nice to have but is not necessary. Neither PacifiCorp, nor BPA, nor any applicable standard require telemetry for projects under 3 MW. If PacifiCorp required telemetry at PRS1 and PRS2 it would be treating them differently from other similarly-sized projects which have been allowed to build without telemetry. Presumably for this reason, PacifiCorp removed telemetry from Sunthurst's costs of interconnection, and I agree.

If telemetry is not a cost of interconnection, it seems to follow that all project costs arising from installing telemetry also are not "costs of interconnection." A detailed cost estimate for Q0666 provided by PacifiCorp on September 4, 2020 shows $3,798 for "SCADA Engineer", which seems to be related to telemetry. Sunthurst/204. Furthermore, the Q1045 Facilities Study requires Sunthurst to provide an easement for location of the RTU facilities, the AC power supply, and all the wires and conduit necessary to supply data to the RTU from the Projects. Sunthurst may need to purchase additional equipment to provide the PacifiCorp RTU with the analog signals PacifiCorp requires. All of these costs arise from PacifiCorp's decision to install unnecessary telemetry with the interconnection facilities. Charging these costs to Sunthurst is unreasonable.

4. Based upon OAR 860-029-0010, would you consider the voltage regulators a "cost of interconnection"?

A. Voltage regulators may be necessary where the addition of new generation causes line voltages to fluctuate outside allowable limits. My own calculations indicate a voltage rise of less than 0.5% when both photovoltaic projects are operating at peak production. I have seen no supporting justification for the inclusion of the voltage regulators, which begs the question of whether they are being prescribed is to resolve an existing problem. Barring such evidence I believe that voltage regulators are not necessary and therefore not reasonably assigned to Sunthurst.

5. Based upon OAR 860-029-0010, would you consider the 0.9 mile fiber optic link to Pilot Rock substation a "cost of interconnection"?

A. PacifiCorp required Sunthurst to install fiber optic link, although a radio link likely would be cheaper. DTT system can reliably function using the slower spread-spectrum radio. Although DTT requires a communication for which fiber is well suited, any cost for fiber above the cost for radio is unnecessary.

6. Based upon OAR 860-029-0010, would you consider the dead line check system a "cost of interconnection"?

A. The dead line check system is one way to avoid reclosing a circuit interrupter into an energized line. It is not the only approach used. Another way is to slow the automatic reclose delay to provide additional time for generators and loads to disconnect. Most utilities are going away from rapid reclosing because of the problems they can cause industrial customers. With new electronic control systems, even a 0.1 second outage will require a complete shutdown and restarting of a process. Changing from a 0.35-second interval, which I understand is PacifiCorp's current setting on circuit 5W406, to a 5-second interval can achieve the same functionality at minimal risk or expense. Most utilities that use a 5-second reclosure interval do not also use the dead-line check.

Where rapid reclosing is used, large motor loads can also backfeed into the utility grid after an outage and reclosing can cause damage to the large motors. For rapid reclosing, the dead-line check is a good idea, with or without generation, to mitigate the risk of damage to large motors.

COSTS THAT APPEAR UNREASONABLY HIGH

7. Do any of the costs seem unreasonable to you?

Avian protection. In reviewing the detailed cost estimates for Q0666 and Q1045, the cost of several items seems unusually high. I mentioned already the $7,650 for "avian protection." The cost to install avian protection is not commensurate with the costs for a few feet of insulating tubing. I note that at OCS24 (a similar-size Sunthurst PV project located near Pilot Rock), PacifiCorp's estimated total cost for avian and animal enhancements is only $438.

Junction boxes. The cost of junction boxes for potential and current transformers also seems extreme. The Q0666 detailed estimate, page 4, lists four junction boxes with unit prices between $2,040 and $4,080. The J-Box normally used for yard connections to VTs and CTs is typically a mild-steel metal box about 12"x12"x6" and costs under $100.

Fiber optic cable. The $60,000 direct cost of 0.9 miles of fiber optic cable for PRS1 and PRS2 equates to nearly $10.23/linear foot (LF). This seems questionably high compared to the following recent data points obtained from Community Solar Facilities Studies (FS) and System Impact Studies (SIS) published on PacifiCorp's OASIS website:

OCS27 FS 1 mile of fiber $38,000. $7.20/ft

OCS38 SIS 1.6 miles fiber for $29k. $3.43/FT

OCS25 FS, 3.5 miles of fiber for $146k. $7.90/ft

OCS35 SIS 0.7 miles fiber for $29k. $7.85/ft

Accrued Engineering and Management costs from Non-"interconnection facilities." Further, because the engineering and project management expenses accrued include items that are no longer the responsibility of the generation projects, the engineering and costs for those items remain embedded in the costs and should be backed out. Where it is not possible to itemize specific costs, a proportional decrease in engineering and project management costs should be implemented.

Engineering hours expended on Q0666. As stated elsewhere, I will reiterate here, that accrued engineering and project management costs, both internal and external, have been incurred that are related to portions of the work that have been removed as requirements. In addition to the materials and installation time for these activities, a reasonable allocation of engineering and project management time should also be assigned to these activities and not charged to the projects.

Remaining engineering budgeted. It is likely that there is some time budgeted in 2021 for engineering and project management that are related to elements of work that are no longer considered the responsibility of the projects. The estimated labor for 2021 needs to be reexamined and re-estimated considering the reduced scope of work.

FACILITIES THAT ARE REQUIRED BUT NOT REASONABLY ASSIGNED SOLELY TO SUNTHURST

8. Does advanced fiber optic communication infrastructure provide system benefits?

A. The fiber optic cable from the substation to the project specified for the direct transfer trip (DTT) system is also being used to link the remote terminal unit installed by PacifiCorp at the project. In fact, the RTU requires the higher data speeds and bandwidth provided by the fiber; the DTT system can reliably function using the slower spread-spectrum radio. With no requirement for a data-intensive RTU at the project, the fiber optic system could be replaced by a spread-spectrum radio system at likely lower cost.

Furthermore, PacifiCorp's requirement of a 48-fiber fiber optic cable is excessive. Since only two fibers are needed to establish a bi-directional communication loop, with the DTT requiring one pair and a PacifiCorp RTU requiring a second pair, 44 of the 48 fibers are spare and unused. Because fibers are made of glass and are fragile, having spares is critical, but a 12-fiber cable is more than adequate. Although it is accepted that the incremental costs to install 48 fibers rather than 12 fibers is small, it is unlikely that 48 fibers will ever be required for any Project-related purpose and it therefore appears PacifiCorp values the extra pairs for its own future use.

9. Does the 0.3 miles of new conductor, from the Point of Interconnection (POI) to the COP, provide system benefits?

A. The 0.3 miles is an enlargement to PacifiCorp's existing distribution system. PacifiCorp will have the ability to serve new loads where it previously did not. PacifiCorp chose the location of the COP for the Projects. It could have required Sunthurst to own the 0.3 miles of line and make the COP at the closest existing PacifiCorp pole. The fact that PacifiCorp selected to put the COP at Project and not the POI shows that PacifiCorp values owning the 0.3 miles of new 12.5 kV line.

10. Are there other real, if imprecise, system benefits from the interconnection?

A. An electric grid is in fact a massively interconnected system; events hundreds of miles away will affect the power at any location. The presence of the photovoltaic generation at the medium-voltage distribution level reduces power flow on the transmission system, lowering losses, and reducing fuel used or water spilled in generating electricity.

Distributed generation may extend service life of substation transformers. When a distributed generator offsets power loads, the effect for the transformer is lower loading. For example, with 5MVA of load being served and 4MVA of generation, the transformer only sees 1MVA of power flow. The lower loading results in less heat dissipation inside the transformer and lower operating temperatures. The lower operating temperatures can add life to the transformer. The effects on life of loading are discussed in detail in ANSI/IEEE C57.92, "Guide for Loading Mineral-oil-insulated Power Transformers." Because of the dynamic nature of loads and distributed generation, there has not been a definitive analysis of the salubrious effects of distributed generation on transformer life.

The modern micro-processor protective relay required by the DTT system has many more functions than the existing analog protective relaying. A typical modern relay may have 100 or more functions of which 10-20 are typically used; the remainder are available. A modern protective relay provides detailed digital records of events that are not otherwise available. The ability to download and analyze detailed event records will provide PacifiCorp with data that can be used to improve the electric system.

The necessary facilities, including metering and protection, provide PacifiCorp with enhanced performance and situational awareness in a 60-year old substation that has not been modernized. There are benefits to PacifiCorp in that these facilities, installed at the expense of the distributed generator, will not need to be installed during any future modernization of the substation, saving PacifiCorp the costs in the future.

IV. PROPOSED MODIFICATIONS TO THE PROPOSED INTERCONNECTION AGREEMENTS.

1. What would you recommend to make the interconnection costs and allocation of costs more reasonable?

A. I have ten recommended modifications:

(1) Eliminate annunciator and telemetry related costs from Sunthurst's interconnection costs. All labor, material, and consulting costs for the P1-111 annunciator panel and telemetry included in the detailed Q1045 and Q0666 cost estimates should be paid by PacifiCorp, because those components are not necessary for PRS1 and PRS2 interconnection.

(2) Credit past and future expenditures on non-interconnection facilities. PacifiCorp should take an honest look at the sunk engineering costs that should not have been included in the final scope of work where the RTU and Annunciator are deleted from the scope.

Some proportional allocation of engineering and project management costs should be assigned to those items and paid by PacifiCorp (including overheads and PacifiCorp's blanket 8% Capital Surcharge). Similarly, PacifiCorp should state whether any of the Project Management, Engineering, and Project support (e.g. as-built drawings, de-/mobilization costs) resources in the interconnection scope of work will support PacifiCorp's work on associated non-interconnection facilities (telemetry, annunciator, etc). If yes, then the cost of any shared resources (including overheads and PacifiCorp's blanket 8% Capital Surcharge) should be equitably apportioned between Sunthurst and PacifiCorp.

(3) Credit Sunthurst its reasonable cost to accommodate PacifiCorp's telemetry. All telemetry-related costs borne by Sunthurst (described in Section III(3), above) should be reimbursed by PacifiCorp.

(4) Eliminate dead line checking. Most utilities are going away from rapid reclosing because of the problems they can cause industrial customers. Changing from a 0.35-second reclosing interval, which I understand is PacifiCorp's current setting on circuit 5W406, to a 5-second interval can achieve the same functionality at minimal risk and render the dead-line check system unnecessary.

(5) Eliminate Voltage Regulators. PacifiCorp needs to provide proof that the line voltage regulators are solving a problem created solely by the PRS1 and PRS2 generation and are not being installed to mitigate an existing condition. PacifiCorp already requires distributed generation to operate in a voltage-control mode where the distributed generator adjusts its reactive power flow to mitigate high or low voltages caused by

fluctuations in the distributed generation. Without demonstrated proof, the costs of the voltage regulators should not be assigned to the PRS1 and PRS2 projects.

(6) Eliminate 3-meters. PacifiCorp provided no rationale for the claim that digitally summing the PRS1 and PRS2 meters was unreliable, necessitating a 3rd metering system at the COP. Also, as an alternative to digitally summing metering data, it is very feasible to wire the PRS1 and PRS2 meters in a current-summing approach to feed a 3rd meter without the need to install a 3rd set of metering PT/CT and the pole and bracket required to support them. PacifiCorp should eliminate the COP meter or otherwise work with the customer to develop a cost effective and functional metering approach. Alternative approaches could include (a) metering PRS1 and PRS2 on the low voltage side, with a 3rd , mid-voltage, meter at the COP; or (b) PacifiCorp paying the costs of the 3rd meter.

(7) Revise excessive costs. At the very least, the estimated costs need to pass a reality check and not appear to be hyper-inflated. Three pieces of "avian" protection tubing that cost $7650 is unreasonable. A 12" x 12" metal box that costs $4000 is unreasonable. Fiber optic cable costs look high (on a $/LF basis) compared to similar small interconnections. PacifiCorp should justify those costs, revise them to be reasonable, or else remove them.

(8) Share cost of 0.3 mile line extension. Sharing the cost recognizes that PacifiCorp derives benefit from this addition to its distribution system. It lowers the cost of serving new customers in the vicinity. At the very least, if PacifiCorp ever in the future uses this line, paid for by the Projects, for other purposes, then PacifiCorp should be required to

compensate the Projects for that use. This type of shared cost and reimbursement for use is widely used in the utility industry.

(9) Share the cost of fiber communication. For communication, PacifiCorp and Sunthurst should split the cost of a 12-fiber cable. One fiber pair will serve the DTT; one fiber pair will serve the PacifiCorp's RTU, and the remaining fibers can be available for spares. PacifiCorp can pay the incremental cost difference if it desires 48-count fiber. If PacifiCorp objects, then Sunthurst could pay for a spread-spectrum radio system that provides the required DTT functionality at lower cost and PacifiCorp can pay fiber optics related costs, including engineering.

(10) Let Sunthurst self-perform construction. Because the regulations allow PacifiCorp to charge actual costs to the interconnecting customer, there is no incentive to PacifiCorp to be frugal or develop a more cost-effective design. PacifiCorp's high rates and overheads, including an 8% surcharge on all job costs, practically ensure that its construction costs will be well above market rates. On other interconnection projects I am familiar with, PacifiCorp allows the Project to supply and install equipment for PacifiCorp use.

2. Does this conclude your testimony?

A. Yes.

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SUNTHURST EXHIBIT 201-- Exhibit List

Exhibit 100 Opening Testimony (Hale)

Exhibit 200 Opening Testimony (Beanland)

Exhibit 201 List of Exhibits

Exhibit 202 Witness Qualifications Statement

Exhibit 203 One-Line Diagrams for Q0666, Q0747, and Q1045

Exhibit 204 Detailed Expenditure Reports for Q0666, Q1045, and OCS024

Exhibit 205 Q0666 Interconnection Studies

Exhibit 206 Q0747 System Impact Study Report

Exhibit 207 Q1045 Interconnection Studies

Exhibit 208 Q0666 Interconnection Agreements

Exhibit 209 PacifiCorp Interconnection Policies

Exhibit 210 [RESERVED]

Exhibit 211 Correspondences between Sunthurst and PacifiCorp

CASE: UM 2118--SUNTHURST V. PACIFICORP
SUNTHURST WITNESS: MICHAEL BEANLAND

PUBLIC UTILITY COMMISSION
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OREGON

SUNTHURST EXHIBIT 202

Witness Qualifications Statement

DECEMBER 16, 2020

WITNESS QUALIFICATION STATEMENT

NAME:	Michael Beanland, P.E.
EMPLOYER:	Willamette Power Engineering
TITLE:	Principal
ADDRESS:	11616 NE 7th Cir, Vancouver, WA 98684
EDUCATION:	Master of Engineering, Electrical Power Engineering, California Polytechnic State University (1976) Bachelor of Science, Electronic Engineering, California Polytechnic State University (1975)
PROFESSIONAL ENGINEER LICENSURES:	California (11947, exp 9/30/2021) Oregon (18947, exp 12/31/2021) Washington (38093, exp 9/2/2022) Idaho (13076, exp 9/30/2021) New Mexico (20259, exp 12/31/2021) Hawaii (15270, exp 4/30/2022) Nevada (23404, exp 12/31/2022)
DISTINGUISHING QUALIFICATIONS:	Over 40 years of experience in electric system design, planning, engineering, and management Specialist in protective relaying, metering, and substation control systems Experienced in utility substations design, high-voltage overhead and underground distribution design, photovoltaic and wind project design Significant experience with the design, construction, and inspection of photovoltaic power plants from kW to multi-MW rating Specialist in system studies and special investigations including FE thermal analysis, transient simulation, protection coordination, magnetic fields, voltage drop, and fault current analysis Experience with commercial building electrical design; electric service design, power distribution and grounding; experienced with arc flash analysis and mitigation Extensive background in long-range planning, contingency studies, and construction work plan development
MODELING EXPERTISE:	Spreadsheet applications; engineering programming languages; expert in ASPEN Distriview system modeling and protective coordination software, QuickField finite element analysis software for electromagnetic and thermal modeling.
ELECTRIC UTILITY POWER	Protective relay coordination designs and settings for SEL, ABB, Basler, Cooper relays, including commissioning support

DISTRIBUTION:	Expert in interconnections between distributed power producers and electric utility systems Power substation control design for large and small substations including full control schematics and wiring diagrams Evaluation of power factor and loading for industrial and generation facilities including design of multi-stage automatic power factor correction control for capacitor installation Designed and evaluated medium-voltage (4-, 12-, 21-kV) distribution systems capacity, protection, and voltage regulation improvements Developed methods for evaluating and optimizing the locations of transpositions in medium-voltage high-power circuits Designed expansion of and control improvements to high-voltage (60-, 69-, 115-, 230-kV) transmission systems Developed specifications and standards for materials and construction practices Provides detailed power quality analyses for distributed generation
PHOTOVOLTAIC AND WIND PROJECTS:	Provide low-voltage and medium-voltage design for the connection of photovoltaic power projects in net metering and independent power production applications Acted as 3rd-party reviewer for large (100MW+) photovoltaic power plant projects providing comprehensive design review Provided on-site construction inspection for large-scale photovoltaic power plant including substation, underground collection and inverters Act as owner's engineer during the interconnection application and study process for photovoltaic power plants connected to medium- and high-voltage grids Provided collection and substation design for wind projects from single-generator to large-scale projects.
PLANNING AND ANALYSIS:	Perform fault studies, load-flow/voltage drop studies, long- and short-range workplans Protective system coordination studies including complex distance and over-current devices and complete system studies Perform finite element analysis of the thermal capacity of underground transmission cables including transient and dynamic loading Familiar with underground transmission line design including cross-bonding. Provide forensic support in areas of underground cable analysis, protective systems, arc flash hazard, and power quality.

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SUNTHURST WITNESS: MICHAEL BEANLAND

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OF
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SUNTHURST EXHIBIT 203

One-Line Diagrams for:
Q0666
Q0747
Q1045

DECEMBER 16, 2020

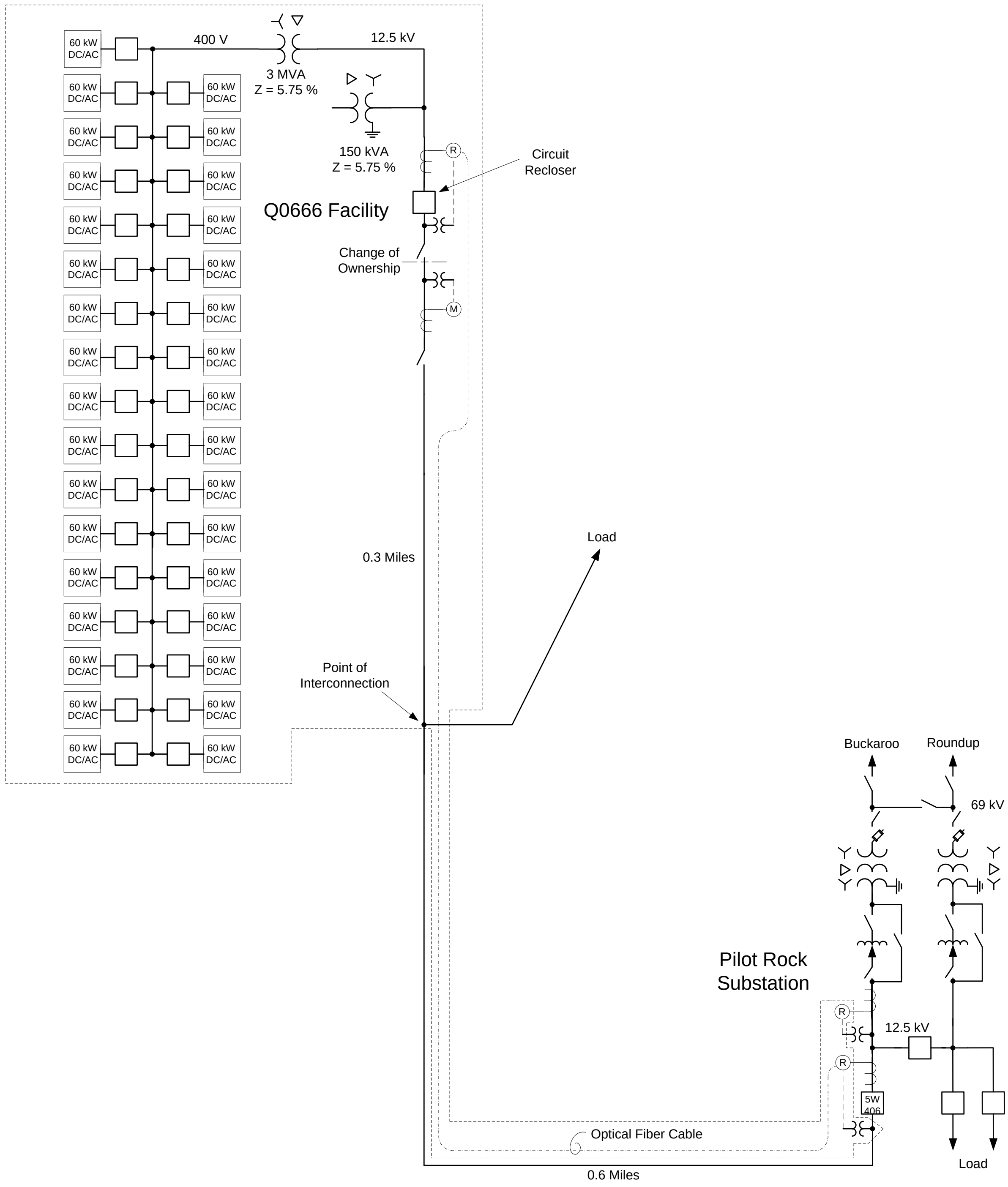

Figure 1: System One Line Diagram

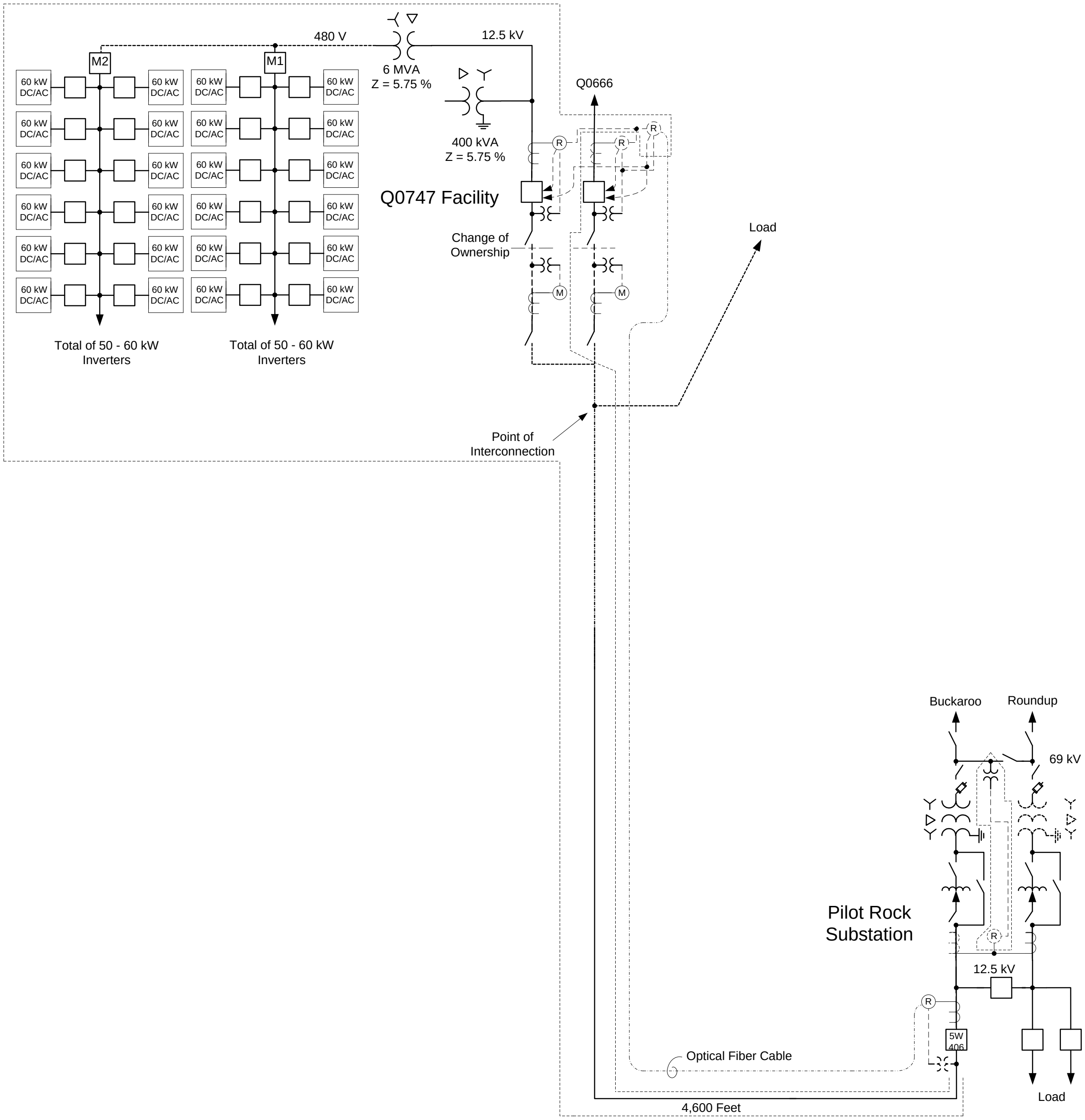

Figure 1: System One Line Diagram

5.1 STUDY ASSUMPTIONS

- All active higher priority transmission service and/or generator interconnection requests will be considered in this study and are listed in Appendix 1. If any of these requests are withdrawn, the Public Utility reserves the right to restudy this request, as the results and conclusions contained within this study could significantly change.
- For study purposes there are two separate queues:
  - Transmission Service Queue: to the extent practical, all System Upgrades that are required to accommodate active transmission service requests will be modeled in this study.

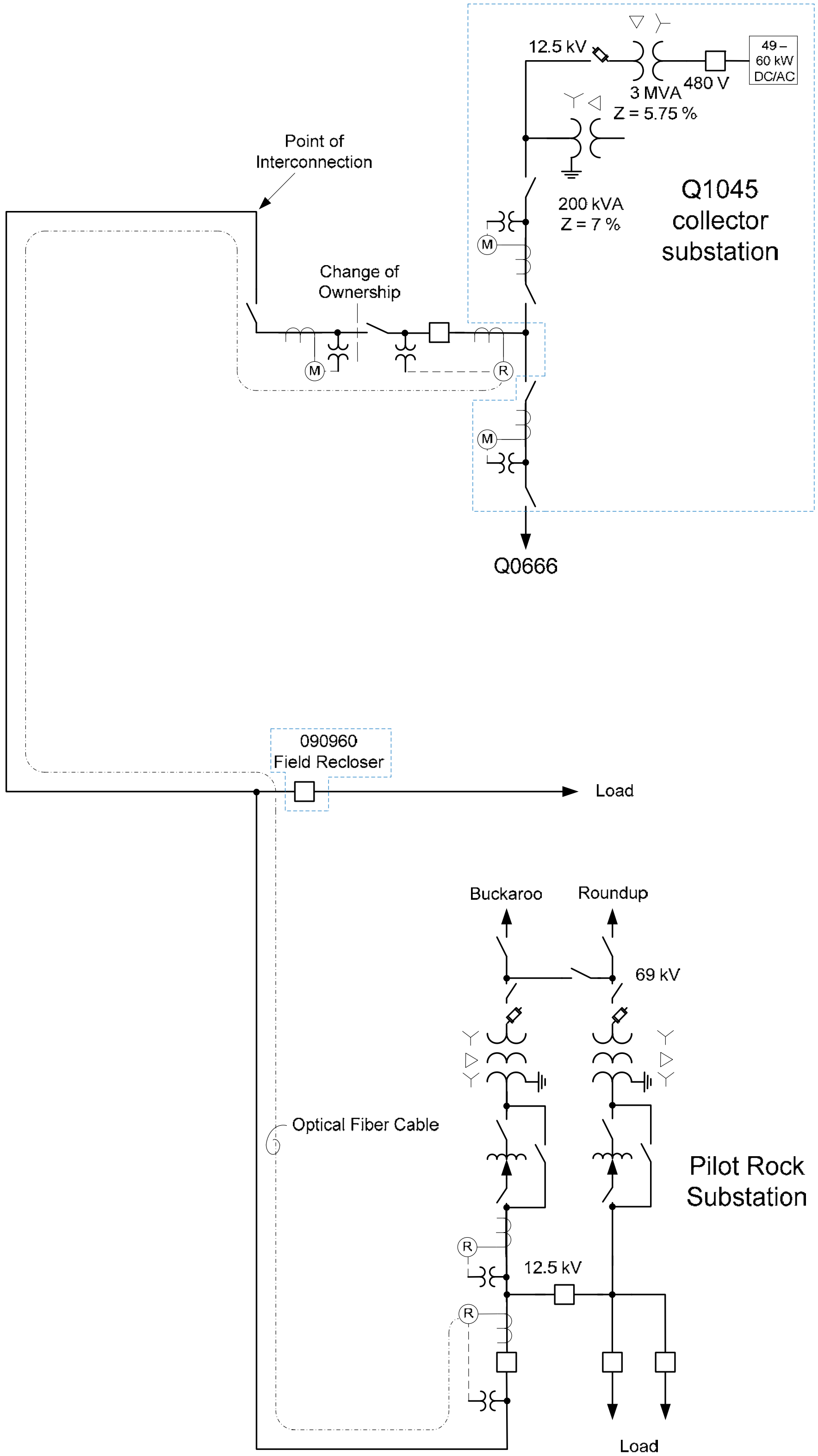

Figure 1: System One Line Diagram

CASE: UM 2118--SUNTHURST V. PACIFICORP
SUNTHURST WITNESS: MICHAEL BEANLAND

PUBLIC UTILITY COMMISSION
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OREGON

SUNTHURST EXHIBIT 204

Detailed Expenditure Reports for:

Q0666

Q1045

OCS024

DECEMBER 16, 2020

PACIFICORP

SUPERIOR EXPENDITURE REPORT

Q666 SUNTHURST ENERGY, LLC - PILOT ROCK		Estimate Date 09/02/20	Estimate Type PSRAT Approved (±20%)
Cost Estimatng Engineer Mike Trembath	Project Manager Greg Straton	Start Date 01/06/16	Requested By Kris Bremmer
Project Definition (WBS) TIOR/2016/C/002/B	Project Type Generation Interconnection	In-Service Date 08/21/21	Investment Reason NO

WORK SUMMARY:

Interconnection of 1.98 MW of solar electric generation to the 12.5 kV circuit 5W406 on of Pilot Rock Substation.

SUPERIOR EXPENDITURE SUMMARY

Calendar Year	Internal Labor	Material	Purchase Service	Other & Contingency	Removal	Salvage	Surcharge & AFUDC	Total Gross Capital	CIAC	O&M Expense	Net Project Cost
2016	$ 2,442	$ -	$ 8,624	$ -	$ -	$ -	$ 1,581	$ 12,647	$ (12,647)	$ -	$ -
2017	$ 3,146	$ -	$ 6,436	$ -	$ -	$ -	$ 1,343	$ 10,925	$ (10,925)	$ -	$ -
2018	$ 2,889	$ -	$ -	$ -	$ -	$ -	$ 317	$ 3,205	$ (3,205)	$ -	$ -
2019	$ 18,424	$ -	$ 49,466	$ 16,600	$ -	$ -	$ 6,994	$ 91,484	$ (91,484)	$ -	$ -
2020	$ 15,793	$ -	$ 18,960	$ (16,600)	$ -	$ -	$ 906	$ 19,060	$ (19,060)	$ -	$ -
2021	$ 263,698	$ 105,768	$ 151,532	$ -	$ -	$ -	$ 41,680	$ 562,678	$ (562,678)	$ -	$ -
TOTAL	**$ 306,393**	**$ 105,768**	**$ 235,018**	$ -	$ -	$ -	**$ 52,820**	**$ 700,000**	**$ (700,000)**	$ -	**$ 0**

ASSUMED RATES:

Capital Surcharge	AFUDC	Escalation	State Adjustment	Contingency	OR Sales Tax
8.00%	7.65%	2.00%	NA	0.00%	0.00%

SUPERIOR EXPENDITURE DETAILS

SAP EASY COST PLANNING

INTERNAL LABOR	Property & Environmental Services	$0
	Engineering	$63,432
	Project Management	$35,124
	Operations	$207,836
MATERIAL	PacifiCorp Furnished Materials	$105,768
PURCHASE SERVICES	Consultants & Technical Services	$83,487
	Construction Services	$151,532
OTHER	Employee Expenses	$0
	Utilities & Services	$0
OVERHEADS	Surcharge	$52,820
	AFUDC	($0)
TOTAL GROSS COSTS (Capital + O&M)		**$700,000**
CUSTOME ADVANCES (CIAC)		$0
NET PROJECT COSTS (Capital+Expense)		**$700,000**

ATTENTION

Estimate is subject to change following scope revisions, design modifications, property and permitting alterations, schedule adjustments, or change to customer requirements. In addition, estimates exceeding one year from the date of issuance should be updated to reflect project changes and to account for current market conditions. Contact the cost engineer for updates.

ESTIMATES SHOULD BE UPDATED PER ENGINEERING POLICY 306

± 30% Estimate	Preliminary Scopes
± 20% Estimate	PSRAT Approved Scopes
± 10% Estimate	Review 3 Drawings

RANGE OF ESTIMATED GROSS COSTS (±20%)

Low-End Range	$560,000
Estimate	**$700,000**
High-End Range	$840,000

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SUBORDINATE EXPENDITURE REPORT

Q666 SUNTHURST ENERGY, LLC - PILOT ROCK
GROSS COSTS BY SUBORDINATE

DESCRIPTION	INTERNAL LABOR	MATERIAL	PURCHASE SERVICE	OTHER & CONTINGENCY	REMOVAL & SALVAGE	SURCHARGE	AFUDC	GROSS CAPITAL COST	CIAC
Pilot Rock Substation	$209,281	$56,619	$181,792	$0	$0	$36,975	($0)	$484,668	($484,668)
Q-0666 Collector	$60,621	$22,914	$9,471	$0	$0	$7,327	($0)	$100,332	($100,332)
Extend 12.5kV Circuit 5W406	$31,291	$19,635	$0	$0	$0	$4,074	$0	$55,000	($55,000)
Fiber	$5,200	$6,600	$43,756	$0	$0	$4,444	$0	$60,000	($60,000)
Grand Total	$306,393	$105,768	$235,018	$0	$0	$52,820	($0)	$700,000	($700,000)

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DETAILED EXPENDITURE REPORT

Q666 SUNTHURST ENERGY, LLC - PILOT ROCK

SUBORDINATE	DIVISION	DIVISION ACTIVITY	DESCRIPTION	VALUE CATEGORY	YEAR	QUANTITY	UNIT	UNIT COST	DIRECT CAPITAL COST
Pilot Rock Substation	Engineering	Engineering Design	Civil Engineering, Engineer	Internal	2016	1	LS	$113.26	$113
					2019	1	LS	$44.35	$44
			Transmission Engineering, Engineer	Internal	2017	1	LS	$186.40	$186
					2019	1	LS	$2,472.30	$2,472
			Project Delivery, Engineer	Internal	2016	1	LS	$1,572.78	$1,573
					2019	1	LS	$5,458.29	$5,458
					2020	1	LS	$179.46	$179
			P&C Engineering, Engineer	Internal	2019	1	LS	$2,227.42	$2,227
					2020	40	HRS	$88.95	$3,558
			Engineering Consultant, Design	External	2016	1	LS	$6,302.00	$6,302
					2017	1	LS	$6,136.05	$6,136
					2019	1	LS	$35,077.60	$35,078
					2020	1	LS	$18,234.32	$18,234
			Engineering Design Expenses	External	2019	1	LS	$243.07	$243
		Engineering Services	Civil Services, As-Built Engineer	Internal	2021	12	HRS	$82.72	$993
			Civil Services, As-Built Drafter	Internal	2021	8	HRS	$59.11	$473
			Cost Engineering, Engineer	Internal	2020	1	LS	$1,441.34	$1,441
					2021	24	HRS	$90.43	$2,170
			Document Control, Business Analyst	Internal	2016	1	LS	$56.54	$57
					2019	1	LS	$126.44	$126
					2021	4	HRS	$62.49	$250
			Resource Planning, Material Analyst	Internal	2019	1	LS	$133.01	$133
					2021	8	HRS	$60.50	$484
		Planning	Area Planning, PP	Internal	2019	1	LS	$575.95	$576
					2020	1	LS	$97.62	$98
	Project Management	Project Management	Project Manager, PP	Internal	2018	1	LS	$1,115.70	$1,116
					2019	1	LS	$3,462.45	$3,462
					2020	1	LS	$227.25	$227
						40	HRS	$106.37	$4,255
					2021	80	HRS	$108.50	$8,680
			Project Control Specialist, PP	Internal	2016	1	LS	$153.88	$154
					2017	1	LS	$687.30	$687
					2020	10	HRS	$75.75	$758
					2021	20	HRS	$77.27	$1,545
		Technical Support	Commissioning Engineer	Internal	2021	4	HRS	$88.74	$355
	Operations	Substation Operations	Journeyman, Substation, PP	Internal	2018	1	LS	$567.04	$567
					2019	1	LS	$394.31	$394
					2021	320	HRS	$153.31	$49,058

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DETAILED EXPENDITURE REPORT

Q666 SUNTHURST ENERGY, LLC - PILOT ROCK

SUBORDINATE	DIVISION	DIVISION ACTIVITY	DESCRIPTION	VALUE CATEGORY	YEAR	QUANTITY	UNIT	UNIT COST	DIRECT CAPITAL COST
Pilot Rock Substation	Operations	Substation Operations	Journeyman, Relay Tech, PP	Internal	2021	640	HRS	$153.31	$98,116
	General	General Requirements	Construction Management	External	2021	1	LS	$10,200.00	$10,200
			Mobilization & Demobilization	External	2021	1	LS	$15,300.00	$15,300
	Substation	Excavation	Excavation, Hydrovac	External	2021	10	HRS	$306.00	$3,060
		Transformer, Instrument, VT	Transformer, Instrument, VT, 12.5kV	Material	2021	3	EA	$688.50	$2,066
				External	2021	3	EA	$1,020.00	$3,060
		Substation Steel Structures, 12.5 kV	Structure, Steel, VT Brackets	External	2021	150	LBS	$15.30	$2,295
		Control Cable	Control Cable, 600V, Shielded, 8 pair, #18	Material	2021	100	LF	$1.25	$125
				External	2021	100	LF	$6.24	$624
			Control Cable, 600V, Shielded, #10-4C	Material	2021	170	LF	$1.31	$222
				External	2021	170	LF	$6.12	$1,040
			Control Cable, 600V, Unshielded, #14-2C	Material	2021	25	LF	$0.38	$10
				External	2021	25	LF	$6.24	$156
			Control Cable, 600V, Unshielded, #14-4C	Material	2021	90	LF	$0.63	$57
				External	2021	90	LF	$6.24	$562
			Control Cable, 600V, Unshielded, #14-12C	Material	2021	60	LF	$1.36	$82
				External	2021	60	LF	$6.24	$375
			Control Cable, 600V, Unshielded, #10-2C	Material	2021	165	LF	$0.49	$81
				External	2021	165	LF	$6.24	$1,030
			Control Cable, 600V, Terminations	External	2021	100	EA	$40.80	$4,080
		Panel, PC Type, Control and Metering	Panel, PC-510, Transformer Metering	Material	2021	2	EA	$6,630.00	$13,260
				External	2021	2	EA	$5,100.00	$10,200
			Panel, PC-611, Distribution Feeder	Material	2021	1	EA	$13,477.26	$13,477
				External	2021	1	EA	$5,100.00	$5,100
		Panel, PI Type, Indication	Panel, PI-111, Indication, Annunciator	Material	2021	1	EA	$12,246.62	$12,247
				External	2021	1	EA	$5,100.00	$5,100
		Outdoor CT, VT, CT/VT, and Misc J-Boxes	Junction Box, DC Load Center	Material	2021	1	EA	$2,040.00	$2,040
				External	2021	1	EA	$2,040.00	$2,040
			Junction Box, Enclosure	Material	2021	1	EA	$4,080.00	$4,080
				External	2021	1	EA	$2,040.00	$2,040
			Junction Box, Voltage Transformer	Material	2021	2	EA	$4,080.00	$8,160
				External	2021	2	EA	$2,040.00	$4,080
		Conduits	Conduit, PVC	External	2021	120	LF	$51.00	$6,120
			Conduit, GRC	External	2021	40	LF	$81.60	$3,264
		Station Grounding	Grounding, Substation, Complete	External	2021	100	LF	$25.50	$2,550
		Avian & Animal Enhancements	Avian & Animal Enhancements	External	2021	1	LS	$7,650.00	$7,650
		Commissioning	Acceptance and Operational Tests	External	2021	1	LS	$7,650.00	$7,650

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DETAILED EXPENDITURE REPORT

Q666 SUNTHURST ENERGY, LLC - PILOT ROCK

SUBORDINATE	DIVISION	DIVISION ACTIVITY	DESCRIPTION	VALUE CATEGORY	YEAR	QUANTITY	UNIT	UNIT COST	DIRECT CAPITAL COST
Pilot Rock Substation	Substation	Miscellaneous Substation	Capital Accruals-No AFUDC-Cntrct Svcs	Other	2019	1	LS	$16,599.83	$16,600
					2020	-1	LS	$16,599.83	-$16,600
	Telecommunications	Telecommunications Engineering	Communications Engineer	Internal	2019	1	LS	$971.79	$972
					2021	32	HRS	$132.60	$4,243
			Communications Drafter	Internal	2021	16	HRS	$51.00	$816
			Communications Consultant	External	2016	1	LS	$1,190.00	$1,190
					2019	1	LS	$11,207.25	$11,207
					2020	1	LS	$726.00	$726
		SCADA Engineering	SCADA Engineer	Internal	2021	40	HRS	$94.96	$3,798
		Substation Operations	Journeyman, Electronic Tech, PP	Internal	2021	40	HRS	$153.31	$6,132
		Miscellaneous (MISC)	Communications, SEL 2829 Transceiver	Material	2021	2	EA	$357.00	$714
			Communications, ADSS Conduit	External	2021	1	LS	$5,100.00	$5,100
	Metering	Engineering Design	Metering Engineering, Engineer	Internal	2019	1	LS	$1,332.24	$1,332
Q-0666 Collector	Engineering	Engineering Design	Substation Engineering, Engineer	Internal	2017	1	LS	$466.00	$466
			Project Delivery, Engineer	Internal	2016	1	LS	$314.57	$315
					2019	1	LS	$384.19	$384
			P&C Engineering, Engineer	Internal	2019	1	LS	$257.01	$257
					2021	80	HRS	$90.73	$7,258
			Engineering Consultant, Design	External	2016	1	LS	$1,132.00	$1,132
					2017	1	LS	$300.00	$300
					2019	1	LS	$2,938.50	$2,939
		Engineering Services	Cost Engineering, Engineer	Internal	2017	1	LS	$1,590.49	$1,590
					2021	8	HRS	$90.43	$723
			Document Control, Business Analyst	Internal	2021	4	HRS	$62.49	$250
			Resource Planning, Material Analyst	Internal	2021	8	HRS	$60.50	$484
	Project Management	Project Management	Project Manager, PP	Internal	2018	1	LS	$639.04	$639
					2019	1	LS	$384.58	$385
					2020	1	LS	$77.37	$77
					2021	80	HRS	$108.50	$8,680
			Project Control Specialist, PP	Internal	2016	1	LS	$230.82	$231
					2017	1	LS	$216.10	$216
					2018	1	LS	$567.04	$567
					2021	40	HRS	$77.27	$3,091
	Operations	Field Operations (Wires)	Journeyman, Estimator, PP	Internal	2019	1	LS	$199.98	$200
					2020	40	HRS	$130.00	$5,200
	Telecommunications	Telecommunications Engineering	Communications Engineer	Internal	2021	32	HRS	$132.60	$4,243
			Communications Drafter	Internal	2021	16	HRS	$51.00	$816
		Substation Operations	Journeyman, Electronic Tech, PP	Internal	2021	40	HRS	$132.60	$5,304

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DETAILED EXPENDITURE REPORT

Q666 SUNTHURST ENERGY, LLC - PILOT ROCK

SUBORDINATE	DIVISION	DIVISION ACTIVITY	DESCRIPTION	VALUE CATEGORY	YEAR	QUANTITY	UNIT	UNIT COST	DIRECT CAPITAL COST
Q-0666 Collector	Telecommunications	Miscellaneous (MISC)	Communications, SEL 2829 Transceiver	Material	2021	2	EA	$357.00	$714
			Communications, ADSS Conduit	External	2021	1	LS	$5,100.00	$5,100
	Metering	Engineering Design	Metering Engineering, Engineer	Internal	2021	80	HRS	$95.88	$7,670
		Substation Operations	Journeyman, Meter Tech, PP	Internal	2021	80	HRS	$144.68	$11,574
		Metering Equipment	Pole & Mounting	Material	2021	2	EA	$4,500.00	$9,000
			Meter and Test Switch	Material	2021	2	EA	$1,500.00	$3,000
			Instrument Transformers, 12.5 KV	Material	2021	2	EA	$4,500.00	$9,000
			Communications Cell Pack	Material	2021	2	EA	$500.00	$1,000
			Miscellaneous	Material	2021	2	EA	$100.00	$200
Fiber	Telecommunications	Telecommunications Engineering	Communications Engineer	Internal	2021	40	HRS	$130.00	$5,200
		Fiber Optics (Fiber)	Fiber Optic, ADSS, Material	Material	2021	5280	LF	$1.25	$6,600
			Fiber Optic, ADSS, Installation	External	2021	5280	LF	$8.29	$43,756
Extend 12.5kV Circuit 5W406	Distribution	Field Operations (Wires)	Journeyman, Lineman, Distribution, PP	Internal	2021	1	LS	$31,290.93	$31,291
		Distribution Work	Distribution Material	Material	2021	1	LS	$19,635.00	$19,635
Grand Total									**$647,180**

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SUPERIOR EXPENDITURE REPORT

Q-1045 PILOT ROCK SOLAR		Estimate Date 09/01/20	Estimate Type System Impact Study (±30%)
Prepared By Chris Smith	Project Manager TBD	Start Date 01/01/21	Requested By Kris Bremer
Project Definition (WBS) TBD	Project Type Generation Interconnection	In-Service Date 12/31/21	Investment Reason NO

WORK SUMMARY:

Pilot Rock Solar 2, LLC proposed interconnecting 3 MW of new generation to PacifiCorp's Circuit 5W406 out of Pilot Rock substation at 12.5 kV located in Umatilla County, Oregon. The Pilot Rock Solar 2 project will consist of forty-nine (49) Sungrow SG60KU-M inverters for a total requested output of 3 MW.

09/01/2020 Revision - The communications and SCADA requirements have been eliminated. Cost assumes primary metering (12.5kV).

See next page for assumptions.

SUPERIOR EXPENDITURE SUMMARY

Calendar Year	Internal Labor	Material	Purchase Service	Other & Contingency	Removal	Salvage	Surcharge & AFUDC	Total Gross Capital	CIAC	O&M Expense	Net Project Cost
2021	$181,855	$94,720	$0	$1,500	$0	$0	$22,246	$300,321	($300,321)	$0	$0
TOTAL	**$181,855**	**$94,720**	$0	**$1,500**	$0	$0	**$22,246**	**$300,321**	**($300,321)**	$0	**$0**

ASSUMED RATES:

Capital Surcharge	AFUDC	Escalation	State Adjustment	Contingency	OR Sales Tax
8.00%	0.00%	2.00%	NA	0.00%	0.00%

SUPERIOR EXPENDITURE DETAILS

SAP EASY COST PLANNING

INTERNAL LABOR	Property & Environmental Services	$0
	Engineering	$20,446
	Project Management	$11,540
	Operations	$149,869
MATERIAL	PacifiCorp Furnished Materials	$94,720
PURCHASE SERVICES	Consultants & Technical Services	$0
	Construction Services	$0
OTHER	Employee Expenses	$1,500
	Utilities & Services	$0
OVERHEADS	Surcharge	$22,246
	AFUDC	$0
TOTAL GROSS COSTS (Capital + O&M)		**$300,321**
CUSTOME ADVANCES (CIAC)		($300,321)
NET PROJECT COSTS (Capital+Expense)		$0

SAP VALUE CATEGORY

1. Internal Labor (All PacifiCorp Labor)	$181,855
2. Material (PacifiCorp Purchased Only)	$94,720
3. Purchase Service (External Contract)	$0
4. Other (Employee Related, Utility, Misc C/E)	$1,500
5. Contingency	$0
6. Removal Costs	$0
7. Salvage	$0
8. TOTAL DIRECT CAPITAL COSTS (1 to 7)	**$278,075**
9. Surcharge	$22,246
10. AFUDC	$0
11. TOTAL GROSS CAPITAL COSTS (8 to 10)	**$300,321**
12. Customer Advance (CIAC)	($300,321)
13. O&M Expenses	$0
NET PROJECT COSTS (Capital+Expense)	**$0**

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SUBORDINATE EXPENDITURE REPORT

Q-1045 PILOT ROCK SOLAR
GROSS COSTS BY SUBORDINATE

DESCRIPTION	INTERNAL LABOR	MATERIAL	PURCHASE SERVICE	OTHER & CONTINGENCY	REMOVAL & SALVAGE	SURCHARGE	AFUDC	GROSS CAPITAL COST	CIAC
Pilot Rock Substation	$14,026	$160	$0	$0	$0	$1,135	$0	$15,321	($15,321)
Distribution Recloser & Regulators	$119,626	$50,000	$0	$0	$0	$13,570	$0	$183,196	($183,196)
Q1045 Collector Substation Metering	$48,203	$44,560	$0	$1,500	$0	$7,541	$0	$101,804	($101,804)
Grand Total	$181,855	$94,720	$0	$1,500	$0	$22,246	$0	$300,321	($300,321)

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DETAILED EXPENDITURE REPORT

Q-1045 PILOT ROCK SOLAR

SUBORDINATE	DIVISION	DIVISION ACTIVITY	DESCRIPTION	VALUE CATEGORY	YEAR	QUANTITY	UNIT	UNIT COST	DIRECT CAPITAL COST
Q1045 Collector Substation Metering	Engineering	Engineering Design	P&C Engineering, Engineer	Internal	2021	55	HRS	$88.95	$4,892
			Engineering Design Expenses	Other	2021	1	LS	$1,500.00	$1,500
	Project Management	Project Management	Project Manager, PP	Internal	2021	80	HRS	$106.37	$8,510
			Project Control Specialist, PP	Internal	2021	40	HRS	$75.75	$3,030
	Telecommunications	Telecommunications Engineering	Communications Engineer	Internal	2021	8	HRS	$102.54	$820
			Communications Drafter	Internal	2021	4	HRS	$62.30	$249
		Substation Operations	Journeyman, Electronic Tech, PP	Internal	2021	16	HRS	$150.30	$2,405
		Miscellaneous (MISC)	Single Mode Jumper, 6 meters with SC connectors	Material	2021	2	EA	$80.00	$160
	Metering	Engineering Design	Metering Engineering, Engineer	Internal	2021	120	HRS	$94.00	$11,280
		Substation Operations	Journeyman, Meter Tech, PP	Internal	2021	120	HRS	$141.81	$17,017
		Metering Equipment	Pole & Mounting	Material	2021	4	EA	$4,500.00	$18,000
			Meter and Test Switch	Material	2021	4	EA	$1,500.00	$6,000
			Instrument Transformers, 12.5 KV	Material	2021	4	EA	$4,500.00	$18,000
			Communications Cell Pack	Material	2021	4	EA	$500.00	$2,000
			Miscellaneous	Material	2021	4	EA	$100.00	$400
Pilot Rock Substation	Engineering	Engineering Design	P&C Engineering, Engineer	Internal	2021	24	HRS	$88.95	$2,135
	Operations	Substation Operations	Journeyman, Substation, PP	Internal	2021	16	HRS	$150.30	$2,405
			Journeyman, Relay Tech, PP	Internal	2021	40	HRS	$150.30	$6,012
	Telecommunications	Telecommunications Engineering	Communications Engineer	Internal	2021	8	HRS	$102.54	$820
			Communications Drafter	Internal	2021	4	HRS	$62.30	$249
		Substation Operations	Journeyman, Electronic Tech, PP	Internal	2021	16	HRS	$150.30	$2,405
		Miscellaneous (MISC)	Single Mode Jumper, 6 meters with SC connectors	Material	2021	2	EA	$80.00	$160
Distribution Recloser & Regulators	Distribution	Field Operations (Wires)	Journeyman, Lineman, PP	Internal	2021	1	LS	$119,625.52	$119,626
		Distribution Work	Distribution Material	Material	2021	1	LS	$50,000.00	$50,000
Grand Total									**$278,075**

DETAILED EXPENDITURE REPORT

OCS-024 TUTUILLA SOLAR

SUBORDINATE	DIVISION	DIVISION ACTIVITY	DESCRIPTION	VALUE CATEGORY	YEAR	QUANTITY	UNIT	UNIT COST	DIRECT CAPITAL COST
McKay Sub	Engineering	Engineering Design	Substation Engineering, Engineer	Internal	2021	16	HRS	$89.05	$1,425
			P&C Engineering, Engineer	Internal	2021	24	HRS	$89.13	$2,139
			Engineering Consultant, CDEGS	External	2021	1	LS	$8,843.40	$8,843
			Engineering Consultant, Design	External	2021	120	HRS	$124.85	$14,982
		Engineering Services	Civil Services, As-Built Engineer	Internal	2021	24	HRS	$85.64	$2,055
			Civil Services, As-Built Drafter	Internal	2021	18	HRS	$60.29	$1,085
			Cost Engineering, Engineer	Internal	2021	40	HRS	$94.17	$3,767
			Document Control, Business Analyst	Internal	2021	4	HRS	$65.77	$263
			Resource Planning, Material Analyst	Internal	2021	32	HRS	$61.71	$1,975
		Field Engineering	Field Engineer, PP	Internal	2021	8	HRS	$89.43	$715
		Planning	Area Planning, PP	Internal	2021	8	HRS	$119.84	$959
	General	General Requirements	Construction Management	External	2021	1	LS	$2,601.00	$2,601
			Mobilization & Demobilization	External	2021	1	LS	$3,121.20	$3,121
	Operations	Substation Operations	Journeyman, Substation, PP	Internal	2021	12	HRS	$144.22	$1,731
			Journeyman, Relay Tech, PP	Internal	2021	24	HRS	$144.22	$3,461
	Project Management	Project Management	Project Manager, PP	Internal	2020	20	HRS	$117.60	$2,352
					2021	120	HRS	$119.95	$14,394
			Project Control Specialist, PP	Internal	2020	10	HRS	$76.32	$763
					2021	60	HRS	$77.84	$4,671
			Project Management Expenses	Other	2021	1	LS	$530.60	$531
		Technical Support	Commissioning Engineer	Internal	2021	12	HRS	$90.51	$1,086
	Substation	Excavation	Excavation, Hydrovac	External	2021	10	HRS	$301.72	$3,017
		Aggregates	Yard Finish Rock	External	2021	10	CY	$104.04	$1,040
		Concrete Foundations	Foundation, Pad, Transformer	External	2021	1	CY	$3,060.00	$3,060
		Transformer, Instrument, VT	Transformer, Instrument, VT, 15kV	External	2021	1	EA	$848.97	$849
				Material	2021	1	EA	$716.32	$716
		Substation Steel Structures	Structure, Steel, Transformer Stand	External	2021	150	LBS	$3.95	$593
		Bare Aluminum Conductor	Conductor, AAC, 1272, NARCISSUS	External	2021	50	LF	$17.69	$884
				Material	2021	50	LF	$2.04	$102
		Control Cable	Control Cable, 600V, Shielded, #10-4C	External	2021	300	LF	$5.46	$1,639
				Material	2021	300	LF	$4.16	$1,248
			Control Cable, 600V, Terminations	External	2021	10	EA	$32.25	$323
		Conduits	Conduit, PVC	External	2021	100	LF	$52.02	$5,202
			Conduit, GRC	External	2021	40	LF	$104.04	$4,162
		Station Grounding	Conductor, Copper, 4/0, Bare, Soft Drawn, 19 Strand	External	2021	50	LF	$14.86	$743
				Material	2021	50	LF	$2.38	$119
		Avian & Animal Enhancements	SV 425 - VT Bushing Cover	External	2021	1	EA	$100.00	$100

PACIFICORP

DETAILED EXPENDITURE REPORT

OCS-024 TUTUILLA SOLAR

SUBORDINATE	DIVISION	DIVISION ACTIVITY	DESCRIPTION	VALUE CATEGORY	YEAR	QUANTITY	UNIT	UNIT COST	DIRECT CAPITAL COST
McKay Sub	Substation	Avian & Animal Enhancements	SV 425 - VT Bushing Cover	Material	2021	1	EA	$3.22	$3
			SV 611 - Jumper, Covered Wire	External	2021	90	LF	$3.00	$270
				Material	2021	90	LF	$0.72	$65
		Commissioning	Acceptance and Operational Tests	External	2021	1	LS	$2,601.00	$2,601
	Telecommunications	Telecommunications Engineering	Communications Engineer	Internal	2021	24	HRS	$98.89	$2,373
			Communications Drafter	Internal	2021	8	HRS	$73.18	$585
		Substation Operations	Journeyman, Electronic Tech, PP	Internal	2021	40	HRS	$144.22	$5,769
		Fiber Optics (Fiber)	SEL-2829, Transmitter/Receiver, Fiber Optic	Material	2021	1	EA	$378.85	$379
		Miscellaneous (MISC)	Communications Materials	Material	2021	1	LS	$1,322.35	$1,322
OCS-024 Collector Site	Distribution	Field Operations (Wires)	Journeyman, Lineman, Distribution, PP	Internal	2021	100	HRS	$130.05	$13,005
	Engineering	Engineering Design	Metering, Drafter	Internal	2021	4	HRS	$52.19	$209
			P&C Engineering, Engineer	Internal	2021	55	HRS	$89.13	$4,902
	Metering	Engineering Design	Metering Engineering, Engineer	Internal	2021	8	HRS	$90.89	$727
		Substation Operations	Journeyman, Meter Tech, PP	Internal	2021	16	HRS	$113.64	$1,818
		Metering Equipment	Meter Equipment	Material	2021	1	EA	$8,323.20	$8,323
	Operations	Substation Operations	Journeyman, Substation, PP	Internal	2021	24	HRS	$144.22	$3,461
			Journeyman, Relay Tech, PP	Internal	2021	32	HRS	$144.22	$4,615
	Telecommunications	Telecommunications Engineering	Communications Engineer	Internal	2021	80	HRS	$98.89	$7,911
			Communications Drafter	Internal	2021	24	HRS	$73.18	$1,756
			Communications Expenses	Other	2021	1	LS	$424.48	$424
		Substation Operations	Journeyman, Electronic Tech, PP	Internal	2021	80	HRS	$144.22	$11,538
		Fiber Optics (Fiber)	SEL-2829, Transmitter/Receiver, Fiber Optic	Material	2021	1	EA	$378.85	$379
		Miscellaneous (MISC)	Communications Materials	Material	2021	1	LS	$15,054.59	$15,055
			Communications Purchased Services	Material	2021	1	LS	$7,140.00	$7,140
Line Recloser UMBD1	Engineering	Engineering Design	P&C Engineering, Engineer	Internal	2021	55	HRS	$89.13	$4,902
	Operations	Substation Operations	Journeyman, Relay Tech, PP	Internal	2021	16	HRS	$144.22	$2,308
	Telecommunications	Telecommunications Engineering	Communications Engineer	Internal	2021	80	HRS	$104.59	$8,367
			Communications Drafter	Internal	2021	24	HRS	$63.55	$1,525
		Substation Operations	Journeyman, Electronic Tech, PP	Internal	2021	80	HRS	$144.22	$11,538
		Fiber Optics (Fiber)	SEL-2829, Transmitter/Receiver, Fiber Optic	Material	2021	1	EA	$378.85	$379
		Miscellaneous (MISC)	Communications Materials	Material	2021	1	LS	$21,338.60	$21,339
			Communications Purchased Services	Material	2021	1	LS	$7,140.00	$7,140
Cabbage Hill Comm Site	Telecommunications	Telecommunications Engineering	Communications Engineer	Internal	2021	40	HRS	$104.59	$4,184
			Communications Drafter	Internal	2021	16	HRS	$63.55	$1,017
		Substation Operations	Journeyman, Electronic Tech, PP	Internal	2021	60	HRS	$144.22	$8,653
		Miscellaneous (MISC)	Communications Materials	Material	2021	1	LS	$4,984.56	$4,985
Buckaroo	Telecommunications	Telecommunications Engineering	Communications Engineer	Internal	2021	16	HRS	$104.59	$1,673

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DETAILED EXPENDITURE REPORT

OCS-024 TUTUILLA SOLAR

SUBORDINATE	DIVISION	DIVISION ACTIVITY	DESCRIPTION	VALUE CATEGORY	YEAR	QUANTITY	UNIT	UNIT COST	DIRECT CAPITAL COST
Buckaroo	Telecommunications	Telecommunications Engineering	Communications Drafter	Internal	2021	8	HRS	$63.55	$508
		Substation Operations	Journeyman, Electronic Tech, PP	Internal	2021	16	HRS	$144.22	$2,308
Distribution	Distribution	Field Operations (Wires)	Journeyman, Lineman, Distribution, PP	Internal	2021	140	HRS	$130.05	$18,207
		Distribution Work	Distribution Material	Material	2021	1	LS	$11,113.55	$11,114
Grand Total									**$301,493**

CASE: UM 2118--SUNTHURST V. PACIFICORP
SUNTHURST WITNESS: MICHAEL BEANLAND

PUBLIC UTILITY COMMISSION
OF
OREGON

SUNTHURST EXHIBIT 205

Q0666 Interconnection Studies:

August 14, 2015 System Impact Study Report

November 23, 2015 Facilities Study Report

DECEMBER 16, 2020

PACIFICORP

Small Generator Interconnection
Tier 4 System Impact Study Report

Completed for
Sunthurst Energy, LLC
(“Interconnection Customer”)
Pilot Rock
Q0666
A Qualifying Facility

Proposed Interconnection
On PacifiCorp’s Existing
Circuit 5W406, City feeder, out of Pilot Rock substation
(at approximately 45°30'32.67"N, 118°49'38.87"W)

August 14, 2015

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1.0 Description of the Small Generating Facility

Sunthurst Energy, LLC ("Interconnection Customer") proposed interconnecting 1.98 MW of new generation to PacifiCorp's ("Public Utility") City feeder 5W406, out of Pilot Rock substation (at approximately 45°30'32.67"N, 118°49'38.87"W) located in Umatilla County, Oregon. The Pilot Rock Solar project ("Project") will consist of thirty-three (33) SMA MLX-60 60kW inverters for a total output of 1.98 MW. The requested commercial operation date is December 31, 2015.

Interconnection Customer will operate this generator as a Qualified Facility as defined by the Public Utility Regulatory Policies Act of 1978 (PURPA).

The Public Utility has assigned the project "Q0666."

2.0 Approval Criteria for Tier 4 Interconnection Review

Pursuant to 860-082-0060(1), a public utility must use the Tier 4 interconnection review procedures for an application to interconnect a small generator facility that meets the following requirements:

(a) The small generator facility does not qualify for or failed to meet Tier 1, Tier 2, or Tier 3 interconnection review requirements; and
(b) The small generator facility must have a nameplate capacity of ten (10) megawatts or less.

3.0 Scope of the Study

Pursuant to 860-082-0060(7)(g) the System Impact Study Report shall consist of a short circuit analysis, a stability analysis, a power flow analysis, voltage drop and flicker studies, protection and set point coordination studies, and grounding reviews, as necessary. The System Impact Study shall state the assumptions upon which it is based, state the results of the analyses, and provide the requirement or potential impediments to providing the requested interconnection service, including a preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. The System Impact Study shall provide a list of facilities that are required as a result of the Interconnection Request and non-binding good faith estimates of cost responsibility and time to construct.

Due to the small size of this project (1.98 MW) and the results of previous transient stability studies in the Pilot Rock area, the Public Utility has determined that no additional transient stability analysis will be needed to evaluate this request. The results of the previous transient stability studies demonstrated satisfactory transient stability in the local area and no stability issues would be expected for the addition of the small Q0666 interconnection request.

A reactive margin analysis was performed for a previous interconnection request of a larger size, 10 MW, proposed for interconnection near the present location of Q0666. In that analysis, positive reactive margin was observed for all of the studied contingencies. Due to the smaller size of Q0666 and similar reactive power capabilities of the inverters, the Public Utility has determined that no steady state voltage stability would be expected from this smaller, 1.98 MW, request and no further reactive margin analysis is required.

4.0 Proposed Point of Interconnection

The proposed Small Generating Facility is to be interconnected, through new 12.47 kV overhead primary metering located North of the town of Pilot Rock roughly 1,400' north of existing map string 01401032.0 facility point #090961.

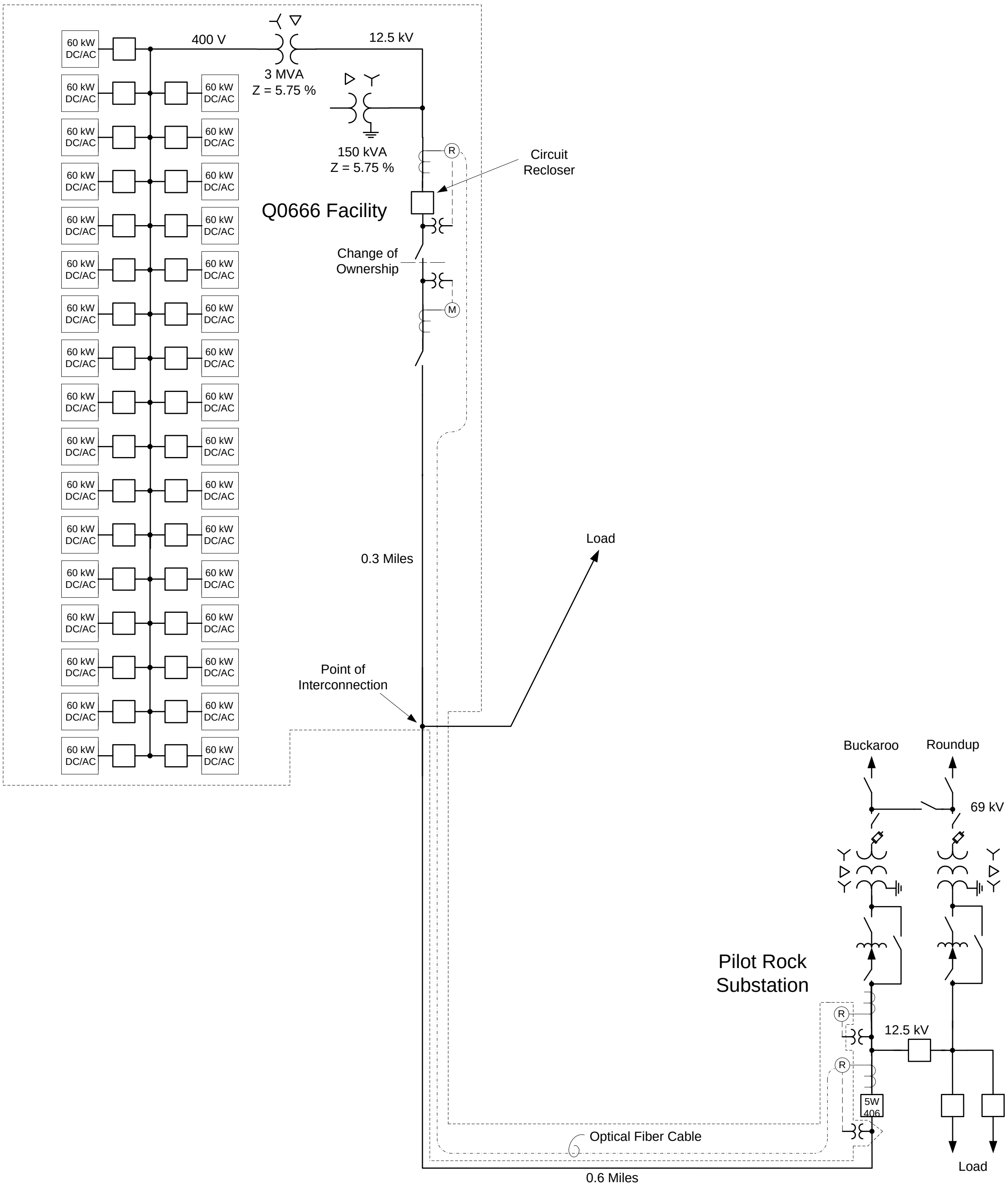

Figure 1: System One Line Diagram

4.1 STUDY ASSUMPTIONS

- All active higher priority transmission service and/or generator interconnection requests will be considered in this study and are listed in Appendix 1. If any of these requests are withdrawn, the Public Utility reserves the right to restudy this request, as the results and conclusions contained within this study could significantly change.
- For study purposes there are two separate queues:
  - Transmission Service Queue: to the extent practical, all network upgrades that are required to accommodate active transmission service requests and are expected to be in-service on or after the Interconnection Customer's requested in-service date for the Project will be modeled in this study.
  - Generation Interconnection Queue: when relevant, interconnection facilities and network upgrades associated with higher queue interconnection requests will be modeled in this study.
- The Interconnection Customer's request for interconnection service in and of itself does not convey transmission service.
- This study assumes the Project will be integrated into Public Utility's system at the agreed upon and/or proposed Point of Interconnection.
- The Interconnection Customer will construct and own any facilities required between the Point of Interconnection and the Project.
- Generator tripping may be required for certain outages.
- All facilities will meet or exceed the minimum WECC, NERC, and Public Utility performance and design standards.
- The generator is expected to operate during daylight hours, 7 days per week, 12 months per year.
- The Interconnection Customer shall provide 125 VDC power to any required Public Utility facilities located on the Interconnection Customer's facilities as required to power all Public Utility protection & control, metering and communication equipment.
- The Interconnection Customer shall provide AC station service to any required Public Utility facilities located on the Interconnection Customer's facilities as required.
- The Public Utility does not provide the Interconnection Customer with back-up station service as part of the interconnection. Station service is covered by separate tariff.
- The Interconnection Customer's Interconnection Facilities are as shown on the Pilot Rock Solar Facility Photovoltaic System drawings, sheet PV4, supplied by the Interconnection Customer on May 21, 2015.
- The project was studied with 33 SMA MLX-60 60kW inverters with a power factor range of +/- 0.8 as specified by the Interconnection Customer on drawing PV5 supplied April 29, 2015.
- Historic time of use metering does not exist for the Pilot Rock substation transformers or feeders. Fifteen minute peak demand kW and KVAR reads documented 8 times per year is the only load data recorded. Daytime minimum load studied for this generator assumed 30% of the documented lowest peak load recorded.

- Pilot Rock City feeder 5W406 peak demand load is 6.6 MVA at a 0.94 pf. The minimum daytime load studied is 1.2 MVA at 0.94 pf.
- This report is based on information available at the time of the study. It is the Interconnection Customer's responsibility to check the Public Utility's web site regularly for transmission system updates (http://www.pacificorp.com/tran.html)

5.0 RESULTS

Transmission level power flow study cases were evaluated for heavy summer and daytime minimum loading conditions. For each of the cases, power flows and system voltages were evaluated with and without the proposed Q0666 Small Generating Facility to determine the impact on the transmission system during system normal operation and following various contingency events in the local system. Due to the small size of the proposed interconnection relative to the transmission system, no thermal or voltage deficiencies associated with interconnection of Q0666 were observed.

Historical load records were reviewed to determine the Public Utility's minimum daytime network load in the Pendleton area 69 kV system. The minimum daytime network load was determined to be 24 MW. Prior to consideration of the proposed Q0666 Small Generating Facility, two higher priority queued generation interconnection requests, sized 18 MW and 6 MW, respectively, may utilize the full network load available as a sink. The 1.98 MW Q0666 request could result in a new generation surplus of up to 1.98 MW.

The Public Utility's Pendleton-Walla Walla area system as a whole is generation surplus. As a Qualifying Facility, the proposed Q0666 project must be used to serve network load. Deliverability to network load is determined through the separate transmission service request process. The following discussion is included for informational purposes only:

In order to sink the generation in network load using Public Utility facilities, a new 230 kV transmission line from the Pendleton area to the Yakima area system may be required. The new line would interconnect Roundup substation with Wine Country substation in the vicinity of Grandview, Washington. The new 230 kV line would be approximately 80 to 90 miles, depending on the line route.

A power flow analysis was performed to evaluate the proposed generation interconnection on the Public Utility's existing distribution system served by the Pilot Rock substation City feeder 5W406. Several case studies were assembled and studied:

1. Distribution power flow studies where performed at minimum daylight feeder loading levels for zero to 1.9 MW of generation output.
2. Distribution power flow studies where performed at maximum daylight feeder loading levels for zero to 1.9 MW of generation output.

Generation steady state operation as well as generation breaker trip and close conditions were analyzed for these cases to reveal the worst scenarios on the Public Utility's 12.5kV system.

After the proposed substation regulator controller replacement is completed it is predicted that during any generation trip or close scenario ANSI range A voltage will be maintained.

The maximum voltage fluctuation for any trip and close events was calculated at 1.7%. As stated in section 6.1, it is the Small Generating Facility's responsibility to ensure voltage fluctuations and frequency remain within standards.

5.1 Small Generating Facility Modifications

The Small Generating Facility and Interconnection Facilities owned by the Interconnection Customer are required to operate under automatic voltage control with the voltage sensed electrically at the Point of Interconnection. The Small Generating Facility and Interconnection Facilities should have sufficient reactive capacity to enable the delivery of 100 percent of the plant output to the Point of Interconnection at unity power factor measured at 1.0 per unit voltage under steady state conditions.

As per NERC standard VAR-001-1, the Public Utility is required to specify voltage or reactive power schedule at the Point of Interconnection. Under normal conditions, the Public Utility's system should not supply reactive power to the Small Generating Facility and Interconnection Facilities. The Q0666 Small Generating Facility will be operated in fixed power factor control mode at unity power factor.

The following information will apply if, in the future, voltage control of the proposed Small Generating Facility is required to maintain satisfactory system operation:

Generators capable of operating under voltage control with a voltage droop are required to do so. Studies will be required to coordinate the voltage droop setting with other facilities in the area. In general, Small Generating Facility and Interconnection Facilities should be operated so as to maintain the voltage at the Point of Interconnection between 1.01 pu to 1.04 pu. At the Public Utility's discretion, these values might be adjusted depending on the operating conditions. Within this voltage range, the generating and interconnecting facilities should operate so as to minimize the reactive interchange between the Small Generating Facility and Interconnection Facilities and the Public Utility's system (delivery of power at the Point of Interconnection at approximately unity power factor). The voltage control settings of the Small Generating Facility and Interconnection Facilities must be coordinated with the Public Utility prior to energization (or interconnection). The reactive compensation must be designed such that the discreet switching of the reactive device (if required by the Interconnection Customer) does not cause step voltage changes greater than +/-3% on the Public Utility's system.

The Interconnection Customer's facilities must be operated in a manner so as not to cause objectionable power quality issues to other Public Utility customers. Voltage fluctuations caused by the Small Generating Facility are required to meet the Public Utility's Engineering Handbook, Voltage Fluctuation and Flicker, Standard 1C.5.1 which is found at https://www.pacificpower.net/con/pqs.html. Table 1 of Standard 1C.5.1 indicates that for this project the medium voltage planning levels for voltage fluctuation under any condition is a Pst < 0.9 and a Plt < 0.7. It is the Interconnection Customer's responsibility to design and construct a system capable of meeting these levels. Specific system information will be provided on request to the Interconnection Customer for design purposes. During operation if measured voltage fluctuation levels exceed the limits specified in Standard 1C.5.1 the Interconnection Customer is required to cease generation until the condition is mitigated. The requirement for the Interconnection Customer's system to meet Standard 1C.5.1 will be incorporated in the interconnection contract. The Public Utility may, at its' discretion, disconnect the Interconnection Customer's facilities until mitigations to meet these standards are made. The Interconnection Customer must also comply with all of the Public Utility's Engineering Handbook standards addressing power quality, including but not limited to Voltage Level, Voltage Balance, Harmonic Distortion, and Voltage Frequency.

If in actual operating practice the Small Generating Facility does cause power quality issues, the Interconnection Customer is required to immediately correct these issues or cease generation until these issues are resolved at the Interconnection Customer's expense. The Interconnection Customer will be responsible for designing and setting the control systems to maintain the acceptable voltage range, if requested to operate on voltage control mode. The voltage control settings of the Small Generating Facility and Interconnection Facilities must be coordinated with the Public Utility prior to interconnection. The Public Utility may, from time to time, require changes to the settings in response to operating conditions or actual operating experience.

The Interconnection Customer will be required to install a transformer that will hold the phase to neutral voltages within limits when the Small Generating Facility is isolated with the Public Utility's local system until the generation disconnects. The proposed delta – wye step-up transformer with the delta winding on the 12.47 kV side will not accomplish the stabilization of the phase to neutral voltages on the 12.47 kV system. The circuit that the project is connecting to is a four wire multi-grounded circuit with line to neutral connected load. Figure 1 shows the addition of a wye – delta grounding transformer of adequate power size and impedance that will meet the requirement.

5.2 Property Requirements for Public Utility's Point of Interconnection Substation

The following applies to property acquired by an Interconnection Customer on which a Point of Interconnection substation will be built to accommodate the Interconnection Customer's project. The property will ultimately be assigned to Public Utility, the Public Utility.

- Property must be environmentally, physically and operationally acceptable to Public Utility without any material defects of title (or as deemed acceptable to Public Utility) and without unacceptable encumbrances. The property shall be a permitted or able to be permitted use in all zoning districts. Property lines shall be surveyed and show all encumbrances, roads (private or public); easements (prescriptive or express) etc.

- Examples of potentially unacceptable environmental, physical, or operational conditions:
  - Environmentally unacceptable conditions could include but are not limited to known contamination of site; evidence of environmental contamination by any dangerous, hazardous or toxic materials as defined by any governmental agency; property is in violation of building, health, safety, environmental, fire, land use, zoning or other such regulation, ordinances, or statutes of any governmental entities having jurisdiction over the property; underground or above ground storage tanks; known remediation sites on property; ongoing mitigation activities or monitoring activities; asbestos; lead-based paint, etc. At a minimum, a phase I environmental study is required for Public Utility land being acquired in fee. Evidence will be required prior to execution of the interconnection agreement.
  - Physically unacceptable conditions could include but are not limited to inadequate drainage; in flood zone; erosion issues; wetland overlays; threatened and endangered species; archeological or culturally sensitive areas; inadequate sub-surface elements, etc. Geotechnical studies are required by Public Utility.
  - Operationally unacceptable conditions could include but are not limited to inadequate access for Public Utility equipment; existing structures on land that require removal prior to building of substation; ongoing maintenance for landscaping or extensive landscape requirements; ongoing homeowner's or CC&R's that are not acceptable to Public Utility.
- Property should be acquired by fee ownership. If fee acquisition is not possible, then the term shall be perpetual and the use exclusive and provide Public Utility with all property rights it deems necessary. In the event that the only option is via a lease, the lease payments shall be one time only – on going lease payments are not acceptable to Public Utility. All contracts are subject to Public Utility approval prior to execution.
- The Interconnection Customer is required to identify any and all land rights to the subject property, which are to be retained by the Interconnection Customer prior to conveying property. All retained land rights are subject to Public Utility approval.
- If the Interconnection Customer is building facilities to be owned by the Public Utility, then the Interconnection Customer must obtain all permits required by all relevant jurisdictions for the use including but not limited to conditional use permits, Certificates of Public Convenience and Necessity, California Environmental Quality Act, etc., as well as all construction permits for the project
- Interconnection Customer will not reimburse through network upgrades for more than the market value of the property.
- Property must be assignable to Public Utility and without litigation, suit, liens, condemnation actions, foreclosures actions, etc.

5.3 Distribution/Transmission Modifications

No existing 12.5 kV overhead conductor sizes will need to be changed in the 0.6 miles from the proposed Point of Interconnection at map string 01401032.0 facility point #090961 back to Pilot Rock substation.

0.3 miles of 4/0 AAC primary conductors and one 4/0AAC neutral conductor will be installed from the Point of Interconnection (proposed fp #090961) to the Point of Change of Ownership. One pole will be for the installation of a gang operated switch and one pole will be to install the primary metering for this Project. The Public Utility will provide one span of overhead primary conductors from the primary metering pole to Interconnection Customer's pole, the termination of this conductor at the Small Generating Facility will serve as the Point of Change of Ownership. Easy year round access to utility owned facilities by the Public Utility is required.

Interconnection Customer will be responsible for obtaining a perpetual easement on the Public Utility's standard easement forms for this extension. The proposed location for the pole line 1' off the edge of the easement will not work as the overhead conductors need to be contained within the easement area.

5.4 Existing Breaker Modifications – Short-Circuit

The increase in the fault duty on the system as the result of the addition of the Small Generating Facility with photovoltaic arrays fed through 33– 60 kW inverters connected to a 3000 kVA 12.47 kV – 400 V transformer with 5.75% impedance will not push the fault duty above the interrupting rating of any of the existing fault interrupting equipment.

5.5 Protection Requirements

The proposed Small Generating Facility will need to disconnect in a high speed manner from the distribution circuit out of Pilot Rock substation for faults on the 12.47 kV line. The day time load on the 5W406 circuit out of Pilot Rock substation can be less than the power output of the Small Generating Facility. As a result, the load to generation unbalance when the Small Generating Facility is isolated with the load cannot be relied upon to cause a timely disconnection of the Small Generating Facility for faults on the line. Protective relays are installed to detect faults on the line at Pilot Rock substation. A transfer trip circuit will need to be installed between Pilot Rock substation and the Small Generating Facility. The transfer trip circuit will be carried over an optical fiber cable.

Currently the 69 – 12.47 kV transformers are protected with 69 kV fuses. The fuses were adequate since presently there are no sources of fault current on the 12.47 kV side. A relay will be installed to detect transformer faults. If a transformer fault is detected in the transformer the transfer trip to the Small Generating Facility will be keyed.

Dead line checking will need to be installed at Pilot Rock substation to block the automatic reclosing of CB 5W406 until the Small Generating Facility has disconnected. Reclosing for this type of situation could cause damage to the equipment and needs to be prevented. The relays presently installed for CB 5W406 will not accommodate the dead line checking or the transfer trip circuit so those relays will be replaced with an unit that has these functions. 12.47 kV instrument voltage transformers will be added to the line side of CB 5W406 and the secondary circuit of those transformers connected to the new relay.

At the Small Generating Facility a protective relay will be installed to perform the following functions:

1. Receive transfer trip from Pilot Rock substation
2. Detect faults on the 12.47 kV at the Small Generating Facility
3. Detect faults on the 12.47 kV line to Pilot Rock substation
4. Monitor the voltage and react to under or over frequency, and / or magnitude of the voltage

All of these relaying functions are all parts of one SEL 351R relay.

All of the protective relaying that has been noted in this report is for the protection and safe, reliable operation of the distribution and transmission facilities. Additional relaying is needed for detecting problems in the Small Generating Facility. The relaying for the plant is the responsibility of the Interconnection Customer.

5.6 Data Requirements (RTU)

Data for the operation of the power system will not be needed due to the small power size of this Small Generating Facility.

5.7 Communication Requirements

5.7.1 For Line Protection

Public Utility will purchase, install, and maintain a 48-fiber, single-mode, ADSS optical cable between Pilot Rock substation and the Q0666 collector substation at Interconnection Customer’s cost. Public Utility will terminate the fiber in patch panels and install fiber-optic jumper cables between the patch panels and the relays’ fiber-optic modems.

5.7.2 For Data Delivery to the Control Centers

None required

5.8 Substation Requirements

The Pilot Rock 12.47 kV feeder 5W406 is served by the 69-12.47 kV, 9.375 MVA transformer T-2144 and 12.47 kV substation voltage regulator R-816. As discussed in the Study Assumptions, section 5.1, there is no historical time of use metering data available for Pilot Rock substation. In the absence of historical data, the study assumes a daytime minimum load of 1.2 MVA at 0.94 pf (0.4 MW). At this assumed load level, during daytime light load and high generation conditions, the proposed Q0666 Small Generating Facility may result in reverse power through regulator R-816 and transformer T-2144. To accommodate this reverse power flow, the tap changing controller on R-816 will need to be replaced with a controller capable of operating with settings for both the forward and reverse directions.

Time of use metering providing KW and KVAR data for both the feeder 5W406 and transformer T-2144 is required to provide system load data for the substation and feeder without generation.

Three 12.5kV VTs to be installed at the 12.5 kV bus at Pilot Rock substation in order to support the protection scheme identified in Section 5.5.

5.9 METERING REQUIREMENTS

Interchange Metering

The Public Utility will procure, install, test, and own all revenue metering equipment. It is expected the revenue metering 12 kV instrument transformers will be installed overhead on a pole at the change of ownership. The meter instrument transformer mounting shall be provided by the Public Utility and conform to the DM construction standards. The meter will be mounted below the instrument transformers on the pole.

The metering will be bi-directional to measure KWH and KVARH quantities for both generation received and retail load delivered. There will be no additional station service metering for supplying generation load. The metering generation and billing data will be remotely interrogated via the Public Utility's MV90 data acquisition system.

The Interconnection Customer may request a digital output from the revenue meters but it must be made before the design phase of the project.

Station Service/Construction Power

Prior to construction, Interconnection Customer must arrange construction power with the electric service provider holding the certificated service territory rights for the area in which the load is physically located. For permanent station service load, additional metering may be required if the Project load is tapped from another Public Utility circuit or other utility provider's source. If within the Public Utility service territory, station service and temporary construction power metering shall conform to the Six State Electric Service Requirements manual.

Please note, prior to back feed Interconnection Customer must arrange distribution voltage retail meter service for electricity consumed by the Project and arrange back up station service for power that will be drawn from the transmission or distribution line when the Project is not generating. Interconnection Customer must call the PCCC Solution Center 1-800-640-2212 to arrange this service. Approval for back feed is contingent upon obtaining station service.

6.0 Cost Estimate

The following estimate represents only scopes of work that will be performed by the Public Utility. Costs for any work being performed by the Interconnection Customer are not included.

Q0666 Small Generating Facility *Add communications and metering equipment and specify protection & control settings.*	$ 151,000
Distribution line work *Extend distribution line and add fiber.*	$ 138,000
Pilot Rock substation *Add VTs and metering equipment, specify protection & control settings .*	$ 432,000
Total	**$ 721,000**

Note: Costs for all excavation, duct installation and easements shall be borne by the Interconnection Customer and are not included in this estimate. This estimate is as accurate as possibly given the level of detailed study that has been completed to date and approximates the costs incurred by Public Utility to interconnecting this generator to Public Utility's electrical distribution system. A more detailed estimate is calculated during the Facilities Study. The Interconnection Customer will be responsible for all actual costs, regardless of the estimated costs communicated to or approved by the Interconnection Customer.

7.0 Schedule

The Public Utility estimates it will require approximately 18-24 months to design and build the facilities described in this report after the completion of the items below.

1. *Obtain the necessary permits and rights of way to construct the facilities necessary to interconnect the Q0666 project (Interconnection Customer's responsibility).*
2. *Execute a Generation Interconnection Agreement.*
3. *Submission of PacifiCorp required Energy Imbalance Market "EIM" generation modeling data.*

Please note, the time required to obtain the necessary permits, execute the interconnection agreement and perform the scope of work appears to result in a timeframe that does not support the Interconnection Customer's requested in-service date of December 31, 2015.

8.0 Participation by Affected Systems

The Bonneville Power Administration has been identified as a potential affected system.

9.0 Appendices

Appendix 1: Higher Priority Requests

APPENDIX 1:
HIGHER PRIORITY REQUESTS

All active higher priority transmission service and/or generator interconnection requests will be considered in this study and are identified below. If any of these requests are withdrawn, the Public Utility reserves the right to restudy this request, as the results and conclusions contained within this study could significantly change.

Transmission/Generation Interconnection Queue Requests considered:

Q0547 (18 MW)
Q0586 (6 MW)

Small Generator Interconnection
Tier 4 Facilities Study Report

Completed for
Sunthurst Energy, LLC
("Interconnection Customer")
Q0666
Pilot Rock

A Qualifying Facility

Proposed Interconnection
On PacifiCorp's
City feeder 5W406, out of Pilot Rock substation
(at approximately 45°30'32.67"N, 118°49'38.87"W)

November 18, 2015

Revised November 23, 2015

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1.0 DESCRIPTION OF THE PROJECT

Sunthurst Energy, LLC ("Interconnection Customer") proposed interconnecting 1.98 MW of new generation to PacifiCorp's ("Distribution Provider") City feeder 5W406, out of Pilot Rock substation (at approximately 45°30'32.67"N, 118°49'38.87"W) located in Umatilla County, Oregon. The Pilot Rock project ("Project") will consist of thirty-three (33) SMA MLX-60 60kW inverters for a total output of 1.98 MW. The requested commercial operation date is December 31, 2015.

Interconnection Customer will operate this generator as a Qualified Facility as defined by the Distribution Provider Regulatory Policies Act of 1978 (PURPA).

The Distribution Provider has assigned the Project "Q0666."

2.0 APPROVAL CRITERIA FOR TIER 4 INTERCONNECTION REVIEW

Pursuant to 860-082-0060(1), a Distribution Provider must use the Tier 4 interconnection review procedures for an application to interconnect a small generator facility that meets the following requirements:

(a) The small generator facility does not qualify for or failed to meet Tier 1, Tier 2, or Tier 3 interconnection review requirements; and
(b) The small generator facility must have a nameplate capacity of ten (10) megawatts or less.

3.0 SCOPE OF THE STUDY

Pursuant to 860-082-0060(8) the Facilities Study Report shall consist of:

(a) A detailed scope identifying the interconnection facilities and system upgrades required to safely interconnect the small generator facility including the electrical switching configuration of the equipment, including the transformer, switchgear, meters, and other station equipment as applicable;
(b) A reasonable schedule for completion of the study;
(c) A good-faith, non-binding estimate of the costs for the facilities and upgrades, including equipment, engineering, procurement, and construction costs, and;
(d) A detailed estimate of the time required to procure, construct, and install the required interconnection facilities and system upgrades.

4.0 PROPOSED POINT OF INTERCONNECTION

The proposed Small Generating Facility is to be interconnected, through a new 12.47 kV overhead primary metering located north of the town of Pilot Rock roughly 1,400' north of existing map string 01401032.0 facility point #090961. This will be on the City feeder 5W406, out of Pilot Rock substation (at approximately 45°30'32.67"N, 118°49'38.87"W) located in Umatilla County, Oregon.

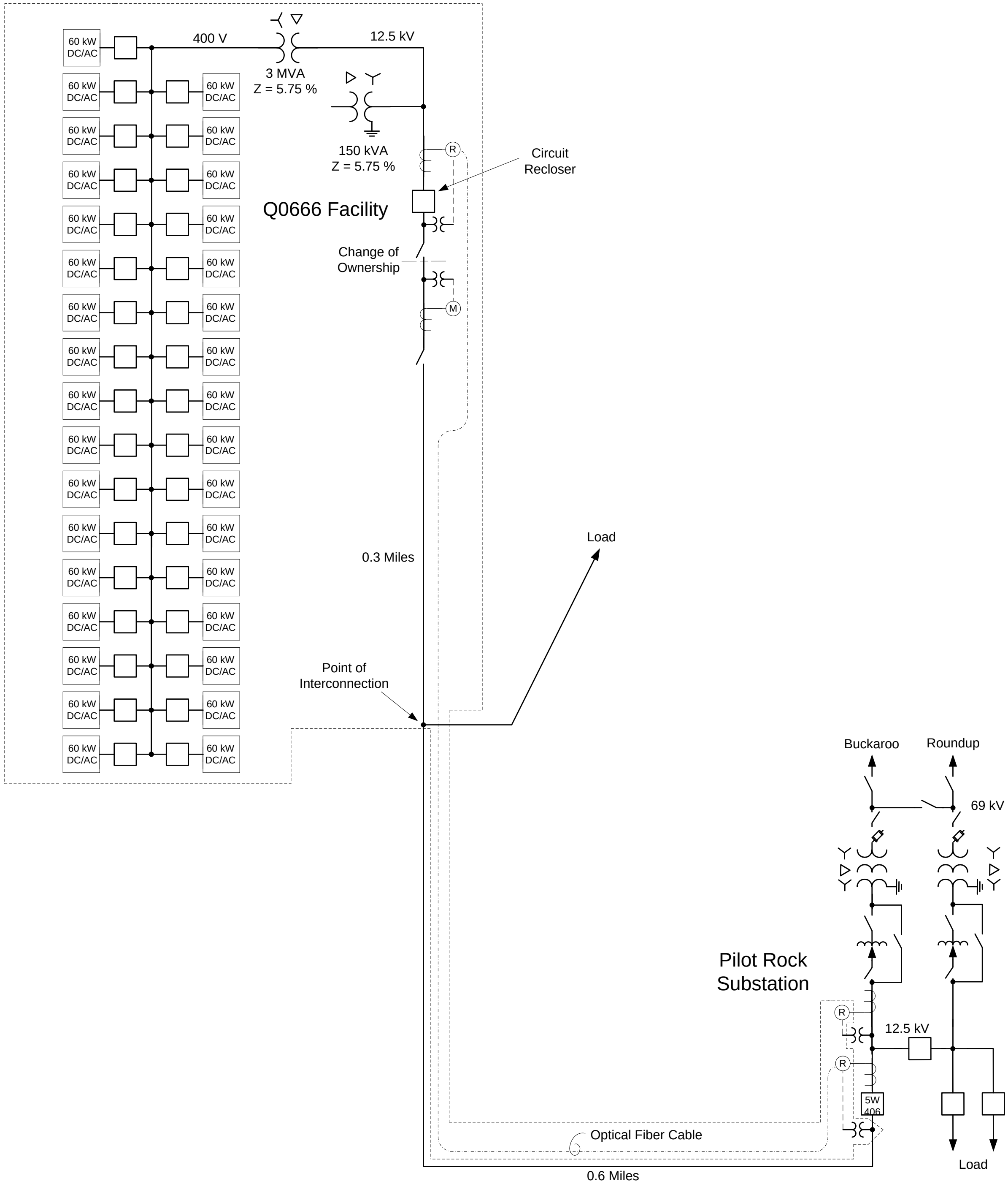

Figure 1: System One Line Diagram

5.0 STUDY ASSUMPTIONS

- The Interconnection Customer's request for interconnection service in and of itself does not convey transmission service.
- This study assumes the Project will be integrated into Distribution Provider's system at the agreed upon and/or proposed Point of Interconnection.
- The Interconnection Customer will construct and own the facilities required between the Point of Interconnection and the Project unless specifically identified by the Distribution Provider.
- Generator tripping may be required for certain outages.
- All facilities will meet or exceed the minimum Western Electricity Coordinating Council ("WECC"), North American Electric Reliability Corporation ("NERC"), and Distribution Provider performance and design standards.

6.0 RESULTS

6.1 GENERATING FACILITY MODIFICATIONS

At the Small Generating Facility a relay will need to be installed that will monitor the voltage magnitude and frequency. If the magnitude or frequency of the voltage is outside of the normal range of operation the relay will need to disconnect the Small Generating Facility. It is our recommendation that a SEL 351 type relay be installed for this purpose. This relay has six pickup levels with different time delays for both the frequency and magnitude of the voltage to make the relay sensitive to small diversions from nominal but with adequate time delay and also fast reacting for extreme diversions.

The Distribution Provider will procure, install, test, and own all revenue metering equipment. It is expected the revenue metering instrument transformers will be installed overhead on a pole at the Point of Interconnection. The meter instrument transformer mounting shall conform to Distribution Provider's construction standards.

The metering will be bidirectional to measure KWH and KVARH quantities for both the generation received and the retail load delivered. The Interconnection Customer may request an output from the Distribution Provider's revenue meters.

Communication equipment will be required to remotely interrogate the meter for generation and billing data via Distribution Provider's MV90 data acquisition system.

6.1.1 EQUIPMENT SPECIFICATIONS

The following outlines the design, procurement, installation, and ownership of equipment for Interconnection Customer's Small Generating Facility.

6.1.1.1 INTERCONNECTION CUSTOMER WILL BE RESPONSIBLE TO

- Design, procure, install, and own an SEL 351 type relay to monitor the voltage and frequency of the Small Generating Facility.

- Provide professional engineer ("PE") signed and stamped drawings for Interconnection Customer's Small Generating Facility to Distribution Provider to allow development of required relay settings.
- Install and own a recloser for the Distribution Provider's SEL 2829 optical transceiver.

6.1.1.2 DISTRIBUTION PROVIDER WILL BE RESPONSIBLE TO

- Design and communicate to the Interconnection Customer the settings to be programmed into the SEL 351 type relay.
- Own the revenue class instrument transformers required for the interconnection of the Small Generating Facility.
- Procure, install, and own two (2) meters are required for retail load Customer Net Gen reverse feed.
- Own the revenue class instrument transformers required for the interconnection of the Small Generating Facility.
- Design, procure, install, and own of Ethernet (preferred) or a cell phone to be designed as part of the meter and utilized to allow for remote interrogation of the Small Generating Facility.
- Design, procure, install, and own one (1) metering panel.
- Design, procure, install, and own of the required meter, test switches and secondary meter wire needed to interconnect the Small Generating Facility.
- Design, procure, install, and own the required meter, test switches and secondary meter wire needed to interconnect the Small Generating Facility.
- Design, procure and install all required communication fiber patch panel, fiber modem, and related communication equipment needed to connect to new 48-fiber, single mode, ADSS cable and to Interconnection Customer's recloser/equipment.

6.2 DISTRIBUTION LINE REQUIREMENTS

The following outlines the design, procurement, installation, and ownership of equipment for the distribution line.

6.2.1 EQUIPMENT SPECIFICATIONS

The following outlines the design, procurement, installation, and ownership of equipment for Distribution Provider's distribution line.

6.2.1.1 INTERCONNECTION CUSTOMER WILL BE RESPONSIBLE TO

- Obtain required right of way for newly required tap line from City Feeder to Small Generating Facility.

6.2.1.2 DISTRIBUTION PROVIDER WILL BE RESPONSIBLE TO

- Design, install, and own 0.3 miles of 4/0 AAC primary conductors and one 4/0AAC neutral conductor from the Point of Interconnection (proposed facility point #090961) to the Point of Change of Ownership.
- Design, install, and own a gang operated switch and primary metering units.
- Procure and install one (1) span of overhead primary conductors from the primary metering pole to Interconnection Customer's pole, the termination of this conductor at the Small Generating Facility will serve as the Point of Change of Ownership.
- Replace the tap changing controller on R-816 with a controller capable of handling reverse power flow.
- Design, procure, install, and own new 48-fiber, single mode, ADSS cable from Small Generating Facility to Pilot Rock substation.

6.3 PILOT ROCK SUBSTATION

The following outlines the design, procurement, installation, and ownership of equipment required for the upgrade of the Distribution Provider's Pilot Rock substation.

6.3.1 EQUIPMENT SPECIFICATIONS

The following outlines the design, procurement, installation, and ownership of required equipment.

6.3.1.1 DISTRIBUTION PROVIDER WILL BE RESPONSIBLE TO

- Procure, install, and own three (3) 12.5 kV VT's.
- Design, procure, and install required steel support structures and associated foundations for all new equipment if required.
- Design, procure, and install a one (1) new PC-611 panel.
- Design, procure, and install a one (1) new PI111 annunciator panel.
- Design, procure, and install two (2) new PC 510 transformer metering panels.
- Design, procure and install all required communication fiber patch panel, fiber modem, and related communication equipment needed to connect to new 48-fiber, single mode, ADSS cable and to Interconnection Customer's recloser/equipment.
- Design, procure and install a fiber-optic channel to send direct transfer trip to the Interconnection Customer's collector site recloser using mirrored bits.

7.0 COST ESTIMATE

See attached Appendix B.

Note: Costs for all easements shall be borne by the Interconnection Customer and are not included in this estimate. This estimate approximates the costs incurred by Distribution Provider in interconnecting this generator to Distribution Provider's electrical distribution system based upon the level of study completed to-date. The Interconnection Customer will be responsible for all actual costs, regardless of the estimated costs communicated to or approved by the Interconnection Customer.

8.0 SCHEDULE

See attached Appendix C.

The Distribution Provider estimates it will require approximately 9 months to design and build the facilities required to interconnect the Small Generating Facility as described in this report.
Please note the time required to obtain the necessary permits, execute the interconnection agreement and perform the scope of work appears to result in a timeframe that does not support the Interconnection Customer's requested in-service date of December 31, 2015.

9.0 APPENDICES

9.1 APPENDIX A: HIGHER PRIORITY REQUESTS

All active higher priority transmission service and/or generator interconnection requests will be considered in this study and are identified below. If any of these requests are withdrawn, the Distribution Provider reserves the right to restudy this request, as the results and conclusions contained within this study could significantly change.

Transmission/Generation Interconnection Queue Requests considered:

Q0547 (18 MW)
Q0586 (6 MW)

9.2 APPENDIX B: COST ESTIMATE (+/- 30%)

Q0666 Generating Facility *Add communications, metering and specify protection & control settings.*	$ 203,000
Distribution Line Work *Extend 0.3 miles of distribution circuit.*	$ 55,000
Fiber *Add fiber on distribution line.*	$ 70,000
Pilot Rock substation *Add VTs and metering, modify communications and protection & control at Pilot Rock substation.*	$ 477,000
Estimated Project Total	**$ 805,000**

9.3 APPENDIX C: SCHEDULE

MILESTONE	DATE
Interconnection Agreement executed and Financial Security provided	January 4, 2016
Interconnection Customer provides all required design information	March 7, 2016
Start Engineering Design	March 28, 2016
Interconnection Customer obtains all required property rights prior to construction	June 6, 2016
Complete Engineering Design	September 5, 2016
Installation and Construction Begins	October 3, 2016
Receive Policy 138 stipulated test plan from Interconnection Customer	November 7, 2016
Construction Complete and backfeed	December 5, 2016
Commercial Operations	December 31, 2016

9.4 APPENDIX D: PROPERTY REQUIREMENTS

Requirements for rights of way easements

Rights of way easements will be acquired by the Interconnection Customer in the Transmission Provider's name for the construction, reconstruction, operation, maintenance, repair, replacement and removal of Transmission Provider's Interconnection Facilities that will be owned and operated by PacifiCorp. Interconnection Customer will acquire all necessary permits for the project and will obtain rights of way easements for the project on Transmission Provider's easement form.

Real Property Requirements for Point of Interconnection Substation

Real property for a point of interconnection substation will be acquired by an Interconnection Customer to accommodate the Interconnection Customer's project. The real property must be acceptable to Transmission Provider. Interconnection Customer will acquire fee ownership for interconnection substation unless Transmission Provider determines that other than fee ownership is acceptable; however, the form and instrument of such rights will be at Transmission Provider's sole discretion. Any land rights that Interconnection Customer is planning to retain as part of a fee property conveyance will be identified in advance to Transmission Provider and are subject to the Transmission Provider's approval.

The Interconnection Customer must obtain all permits required by all relevant jurisdictions for the planned use including but not limited to conditional use permits, Certificates of Public Convenience and Necessity, California Environmental Quality Act, as well as all construction permits for the project.

Interconnection Customer will not be reimbursed through network upgrades for more than the market value of the property.

As a minimum, real property must be environmentally, physically, and operationally acceptable to Transmission Provider. The real property shall be a permitted or permittable use in all zoning districts. The Interconnection Customer shall provide Transmission Provider with a title report and shall transfer property without any material defects of title or other encumbrances that are not acceptable to Transmission Provider. Property lines shall be surveyed and show all encumbrances, encroachments, and roads.

Examples of potentially unacceptable environmental, physical, or operational conditions could include but are not limited to:

- Environmental: known contamination of site; evidence of environmental contamination by any dangerous, hazardous or toxic materials as defined by any governmental agency; violation of building, health, safety, environmental, fire, land use, zoning or other such regulation; violation of ordinances or statutes of any governmental entities having jurisdiction over the property; underground or above ground storage tanks in area;

known remediation sites on property; ongoing mitigation activities or monitoring activities; asbestos; lead-based paint, etc. A phase I environmental study is required for land being acquired in fee by the Transmission Provider unless waived by Transmission Provider.

- Physical: inadequate site drainage; proximity to flood zone; erosion issues; wetland overlays; threatened and endangered species; archeological or culturally sensitive areas; inadequate sub-surface elements, etc. Transmission Provider may require Interconnection Customer to procure various studies and surveys as determined necessary by Transmission Provider.

Operational: inadequate access for Transmission Provider's equipment and vehicles; existing structures on land that require removal prior to building of substation; ongoing maintenance for landscaping or extensive landscape requirements; ongoing homeowner's or other requirements or restrictions (e.g., Covenants, Codes and Restrictions, deed restrictions, etc.) on property which are not acceptable to the Transmission Provider.

CASE: UM 2118--SUNTHURST V. PACIFICORP
SUNTHURST WITNESS: MICHAEL BEANLAND

PUBLIC UTILITY COMMISSION
OF
OREGON

SUNTHURST EXHIBIT 206

Q0747 System Impact Study Report
Dated August 26, 2016

DECEMBER 16, 2020

PACIFICORP TRANSMISSION

Small Generator Interconnection

Oregon Tier 4 System Impact Study Report

Completed for

Sunthurst Energy, LLC
(“Interconnection Customer”)
Q0747
Pilot Rock 2
A Qualifying Facility

Proposed Point of Interconnection

City feeder 5W406, out of Pilot Rock substation
(at approximately 45°30'32.67"N, 118°49'38.87"W)
(same as Q0666)

Original
July 27, 2016

Revised
August 26, 2016

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1.0 Description of the Generating Facility

Sunthurst Energy, LLC ("Interconnection Customer") proposed interconnecting 6 MW of new generation to PacifiCorp's ("Public Utility") City feeder 5W406, out of Pilot Rock substation (at approximately 45°30'32.67"N, 118°49'38.87"W) (same as Q0666) located in Umatilla County, Oregon. The Pilot Rock 2 project ("Project") will consist of one hundred (100) 60 kW Sungrow SG60KU-M inverters for a total output of 6 MW. The requested commercial operation date is December 31, 2017.

Interconnection Customer will operate this generator as a Qualifying Facility as defined by the Public Utility Regulatory Policies Act of 1978 (PURPA).

The Public Utility has assigned the Project "Q0747."

2.0 Approval Criteria for Tier 4 Interconnection Review

Pursuant to 860-082-0060(1), a public utility must use the Tier 4 interconnection review procedures for an application to interconnect a small generator facility that meets the following requirements:

(a) The small generator facility does not qualify for or failed to meet Tier 1, Tier 2, or Tier 3 interconnection review requirements; and
(b) The small generator facility must have a nameplate capacity of ten (10) megawatts or less.

3.0 Scope of the Study

Pursuant to 860-082-0060(7)(g) the System Impact Study Report shall consist of a short circuit analysis, a stability analysis, a power flow analysis, voltage drop and flicker studies, protection and set point coordination studies, and grounding reviews, as necessary. The System Impact Study shall state the assumptions upon which it is based, state the results of the analyses, and provide the requirement or potential impediments to providing the requested interconnection service, including a preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. The System Impact Study shall provide a list of facilities that are required as a result of the Interconnection Request and non-binding good faith estimates of cost responsibility and time to construct.

A transient stability analysis was not performed for this study due to the size of the generator.

4.0 Independent Study Evaluation

Pursuant to 860-082-0060(7)(h), the application has not provided an independent system impact study that is to be addressed and evaluated along with the results from the Public Utility's own evaluation of the interconnection of the proposed Small Generating Facility.

5.0 Proposed Point of Interconnection

The Interconnection Customer's proposed Small Generating Facility is to be interconnected through a primary metering located north of the town of Pilot Rock, Oregon roughly 1,400' north of existing map string 01401032.0 facility point #090961.

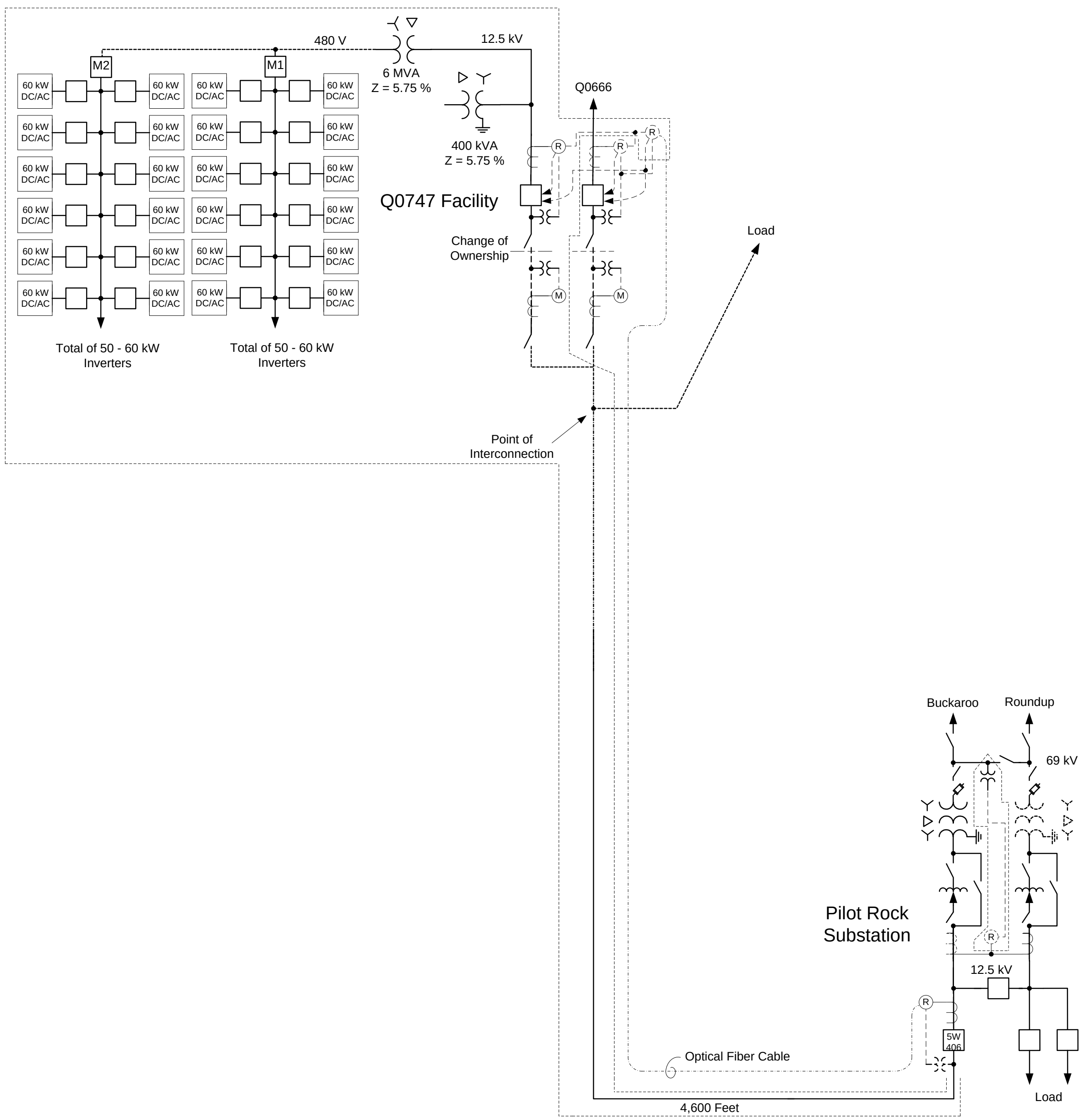

Figure 1: System One Line Diagram

5.1 Study Assumptions

- All active higher priority transmission service and/or generator interconnection requests will be considered in this study and are listed in Appendix 1. If any of these requests are withdrawn, the Public Utility reserves the right to restudy this request, as the results and conclusions contained within this study could significantly change.
- For study purposes there are two separate queues:
  - Transmission Service Queue: to the extent practical, all System Upgrades that are required to accommodate active transmission service requests will be modeled in this study.

  - Generation Interconnection Queue: All relevant higher queue interconnection requests will be modeled in this study.
- The Interconnection Customer's request for interconnection service in and of itself does not convey transmission service.
- This study assumes the Project will be integrated into Public Utility's system at the agreed upon and/or proposed Point of Interconnection.
- The Interconnection Customer will construct and own any facilities required between the Point of Interconnection and the Project unless specifically identified by the Public Utility.
- Generator tripping may be required for certain outages.
- All facilities will meet or exceed the minimum Western Electricity Coordinating Council ("WECC"), North American Electric Reliability Corporation ("NERC"), and Public Utility performance and design standards.
- The generator is expected to operate during daylight hours every day 7 days per week 12 months per year. The primary meter (Point of Interconnection) power factor range studied was unity power factor or 1.0 as identified by the Interconnection Customer in the application prior to the proposed Small Generating Facility being installed.
- The project was studied with One hundred (100) 60 kW Sungrow SG60KU-M inverters with reactive power capabilities as shown in the Customer provided inverter information document, "160510 Inverter Specs.pdf" dated May, 10 2016.
- The Small Generating Facility and collector substation are as shown on the Interconnection Customer supplied One Line Diagram "160518 Q0747 One Line.pdf", dated May 18, 2016.
- The Project was studied with the following active higher priority queue projects on-line: Q0547, Q0586, Q0666 and Q0728 (all Qualifying Facilities).
- Historic time of use metering does not exist for the Pilot Rock substation transformers or feeders. Fifteen minute peak demand kW and kvar reads documented 8 times per year is the only load data recorded. Daytime minimum load studied for this generator assumed 30% of the documented peak load when modeling the distribution 12.5 kV feeder.
- Pilot Rock City feeder 5W406 peak demand load is 6.6 MVA at a 0.94 pf. The minimum daytime load studied is 2.0 MVA at 0.94 pf.
- This report is based on information available at the time of the study. It is the Interconnection Customer's responsibility to check the Public Utility's web site regularly for transmission system updates (http://www.pacificorp.com/tran.html).

6.0 REQUIREMENTS

6.1 SMALL GENERATOR FACILITY MODIFICATIONS

The Small Generating Facility and Interconnection Equipment owned by the Interconnection Customer are required to operate under automatic power factor control with the power factor sensed electrically at the Point of Interconnection. The required power factor is 1.0 per unit initially, but may be reviewed and adjusted as appropriate for coordination.

In general, the Small Generating Facility and Interconnection Equipment should be operated so as to follow the voltage at the Point of Interconnection between 1.01 pu to 1.04 pu. At the Public Utility's discretion, these values might be adjusted depending on the operating conditions.

As per NERC standard VAR-001-1, the Public Utility is required to specify voltage or reactive power schedule at the Point of interconnection. Under normal conditions, the Public Utility's system should not supply reactive power to the Small Generating Facility.

The Interconnection Customer will be required to install a transformer that will hold the phase to neutral voltages within limits when the Small Generating Facility is isolated with the Public Utility's local system until the generation disconnects. The proposed delta – wye step-up transformer with the delta winding on the 12.5 kV side will not accomplish the stabilization of the phase to neutral voltages on the 12.5 kV system. The circuit that the project is connecting to is a four wire multi-grounded circuit with line to neutral connected load. Figure 1 shows the addition of a wye – delta grounding transformer of adequate power size and impedance that will meet the requirement.

6.2 TRANSMISSION SYSTEM MODIFICATIONS

Historical load records were reviewed to determine the Public Utility's minimum daytime network load in the Pendleton area 69 kV system. The minimum daytime network load was determined to be 24 MW. The 6 MW Q0747 request will result in an increased generation surplus of up to 6 MW.

The limiting element for circuit 5W406 is the 12.5 kV regulator R-816 which is rated by the manufacturer for 7.5 MVA. With the previous 2 MVA Q0666 and the new 6 MVA Q0747 the regulator would be overloaded. However, considering the absorption of the Pilot Rock town load and that the Public Utility's standards allow for regulators to operate to 105% of manufacturer's name plate rating, this circuit would not technically be overloaded.

The Public Utility's Pendleton-Walla Walla area system as a whole is generation surplus during light load conditions. As a Qualifying Facility, the proposed Q0747 project must be used to serve network load. In order to sink the generation in network load, a new 230 kV transmission line from the Pendleton area to the Yakima area system will be required. The new line will interconnect Roundup substation with Wine Country substation in the vicinity of Grandview, Washington. The new 230 kV line would be approximately 80 to 90 miles, depending on the line route.

In lieu of the transmission construction described above, the Interconnection Customer may be able negotiate with the power purchaser to obtain third-party transmission rights to deliver any excess generation from the Pendleton-Walla Walla area system to an area with sufficient load to sink the generation. This alternative would require an agreement between the Interconnection Customer and the power purchaser. Without that agreement in place, the transmission construction alternative will be required as part of the Project.

6.3 DISTRIBUTION/TRANSMISSION LINE MODIFICATIONS

Reconductor approximately 4,600 feet of 1/0 CU to 795 AAC w/477 neutral. Circuit 5W406 out of Pilot Rock substation is underbuilt on the 69kV transmission line poles north out of the substation. The requirement to reconductor feeder 5W406 with larger conductor will exceed the loading capacity of those poles. An estimated 10 wood poles will be required to be replaced. The solid blade cutouts at FP:090963 will need to be replaced with a 600 Amp gang operated switch.

6.4 EXISTING BREAKER MODIFICATIONS – SHORT-CIRCUIT

The increase in the fault duty on the system as the result of the addition of the Generating Facility with photovoltaic arrays fed through 100 – 60 kW inverters connected to a 6000 kVA 12.5 kV – 480 V transformer with 5.75% impedance along with the earlier Q0666 project will not push the fault duty above the interrupting rating of any of the existing fault interrupting equipment.

6.5 PROTECTION REQUIREMENTS

Protective relaying systems will need to be installed that will detect faults and cause the disconnection of the Small Generating Facility for 12.5 kV line faults on circuit 5W406 out of Pilot Rock substation, faults in the 69 – 12.5 kV transformers in Pilot Rock substation, and faults on the 69 kV line that Pilot Rock substation is connected to. The minimum day time load on Pilot Rock substation is less than the maximum potential power output of the proposed Q0747 Small Generating Facility in addition to the Q0666 Small Generating Facility. For this reason the unbalance condition of the load and generation cannot be relied upon to cause the high speed disconnection of the Small Generating Facility for faults on the distribution and transmission system. Relaying will be installed for project Q0666 that will detect the fault conditions on the 12.5 kV line and send transfer trip from Pilot Rock substation to the solar facility to cause the disconnection of the generation. An optical fiber cable will be installed between Pilot Rock substation and the Small Generating Facility for Project Q0666. Since the reclosers for project Q0666 and for this Project will be adjacent to each other the same optic fiber cable will be used for both projects. The transfer trip signal will be sent over the optical fiber cable.

For 12.5 kV circuit faults the transfer trip will be keyed by the opening of breaker 5W406 at Pilot Rock substation. The 69 kV line faults cannot be detected by monitoring the voltages on the 12.5 kV system due to the isolation the transformers at Pilot Rock substation provides. Line relays will be installed at Pilot Rock substation that will monitor the 69 kV bus voltage and the 12.5 kV current through the transformers. With these relays the 69 kV line faults will be detected and the transfer trip will be keyed. These relays will need to operate high speed to disconnect the generation before the automatic reclosing that will be taking place at Roundup substation to restore the circuit. Most faults on overhead lines are temporary in nature so that after all the sources of energy to the fault have been disconnected the circuit can be reenergized and the service to the loads restored. It will not be possible to set the line relays to be selective as to limiting the operation for faults only on the line that Pilot Rock substation is connected to and still clear the faults high speed. The relays will occasionally operate for faults on other 69 kV lines out of Roundup substation. This will cause the Small Generating Facility to be disconnected on occasions when the line to the Small Generating Facility does not go dead. The only way to maximize the energy production of the Small Generating Facility would be to install communication facilities to receive transfer trip from Roundup substation to Pilot Rock substation. This option would increase the cost of this Project. It is assumed that the Interconnection Customer wants the less costly option and will tolerate the occasional unnecessary interruptions. For 69 – 12.5 kV transformers faults are presently detected and cleared with 69 kV fuses. These are adequate since there were no sources on the 12.5 kV side. With the addition of these generation facilities the relays that are planned for detecting 69 kV faults will also detect transformer faults and send transfer trip to the Project.

The line relays associated with the CB 5W406 will have been replaced for the Q0666 project. Those facilities will be adequate for the addition of this project.

The voltage regulator R-542's controller in Pilot Rock substation will need to be replaced with a unit that can sense reverse power flow and modify the controller's operating mode.

At the Small Generating Facility there will need to be two circuit reclosers. One will be the recloser installed for the Q0666 project and one for this Project. These reclosers will need to be close together so that the grounds of the two reclosers are tied together and that copper control cables can be used between the two units. Each recloser will have a relay that will detect faults on the individual solar facility's 12.5 kV circuits. The individual relay will just trip the individual recloser. A third relay will need to be installed. This relay will have the combination of the current from the two recloses fed into it. The third relay will communicate with Pilot Rock substation, be set to detect faults on the 12.5 kV circuit back to Pilot Rock substation, and operate for under/over frequency or voltage conditions. The third relay will trip both of the reclosers.

6.6 Data Requirements (RTU)

Data for the operation of the power system will be needed from the collector facility for Q0747. This data can be acquired by installing RTUs at the collector facility. The following data will be acquired from the collector facility:

Analogs:

- Net Generation MW
- Net Generator MVAR
- Energy Register KWH
- Real Power through Main 1
- Reactive Power through Main 1
- Real Power through Main 2
- Reactive Power through Main 2
- A phase 12.5 kV voltage
- B phase 12.5 kV voltage
- C phase 12.5 kV voltage
- Global Horizontal Irradiance (GHI)

- Average Farm Atmospheric Pressure (Bar)
- Average Farm Temperature (Celsius)

Status:
- 480 V Main 1 Breaker
- 480 V Main 2 Breaker
- 12.5 kV Circuit Recloser
- Relay alarm

6.7 COMMUNICATION REQUIREMENTS

6.7.1 LINE PROTECTION

The optical fiber cable that is to be installed for the Q0666 project will be also used for this project. Fiber jumpers will be installed from the Q0666 recloser patch panel to the Q0747 recloser relays, and also from the Pilot Rock patch panel to the relays there. The jumpers will be protected by innerduct.

6.7.2 DATA DELIVERY TO THE CONTROL CENTERS

FO jumpers will also be installed from the recloser patch panel to FO modems for SCADA, telemetry, voice, and data equipment in the customer facility. RLH modems will be used for voice and data circuits from the meters, and SEL-2829 modems will be used for RTU and Alt Meter communication to Public Utility's Energy Management System. The modems will communicate back to Pilot Rock Substation and circuits will be cross-connected there to the existing channel bank and T1 lease, carrying the circuits to the Public Utility's control centers.

6.8 SUBSTATION REQUIREMENTS

Q0747 Collector Substation

The Interconnection Customer will provide a separate graded, grounded and fenced area along the perimeter of the Interconnection Customer's Small Generating Facility for the Public Utility to install a control house for any required metering, protection or communication equipment. This area will share a fence and ground grid with the Small Generating Facility and have separate, unencumbered access for the Public Utility. AC station service and DC power for the control house will be supplied by the Public Utility.

Pilot Rock Substation

Pilot Rock substation will require the addition of 3 CCVTs on the 69 kV bus.

6.9 METERING REQUIREMENTS

Interchange Metering

The interchange metering shall be designed for the total net generation of the project. The Transmission Provider shall specify and order all interconnection revenue metering, including the instrument transformers, metering panels, junction box and secondary metering wire. The primary metering transformers shall be combination CT/VT extended range for high accuracy metering with ratio's to be determined during the design phase of the project

The metering design package shall include two revenue quality meters, test switch, with DNP real time digital data terminated at a metering interposition block. One meter will be designated a primary SCADA meter and a second meter will be used designated as backup with metering DNP data delivered to the alternate control center. The metering data will include bidirectional KWH KVARH, revenue quantities including instantaneous PF, MW, MVAR, MVA, including per phase voltage and amps data.

An Ethernet connection is required for retail sales and generation accounting via the MV-90 translation system.

Station Service/Construction Power

Prior to construction, Interconnection Customer must arrange construction power with the electric service provider holding the certificated service territory rights for the area in which the load is physically located. For permanent station service load, additional metering may be required if the Project load is tapped from another Public Utility circuit or other utility provider's source. If within the Public Utility service territory, station service and temporary construction power metering shall conform to the Six State Electric Service Requirements manual.

Please note, prior to back feed Interconnection Customer must arrange distribution voltage retail meter service for electricity consumed by the Project and arrange back up station service for power that will be drawn from the transmission or distribution line when the Project is not generating. Interconnection Customer must call the PCCC Solution Center 1-800-640-2212 to arrange this service. Approval for back feed is contingent upon obtaining station service.

7.0 Cost Estimate

The following estimate represents only scopes of work that will be performed by the Public Utility. Costs for any work being performed by the Interconnection Customer are not included.

Q0747 Small Generating Facility *Add metering, protection and control, communications and control house*	$ 704,000
Distribution line work *Reconductor 4,600 feet and replace switch*	$ 581,000
Transmission line work *Replace transmission structures*	$ 334,000
Pilot Rock substation *Add 69 kV CCVTs, communications and relays*	$ 510,000
Modify communications *Modify communications at control centers*	$ 70,000
‡Transmission line work *Pendleton 1-Roundup-Wine Country 70 miles of 230kV transmission line*	$40,000,000
Total	**$42,199,000**

*Any distribution line modifications identified in this report will require a field visit analysis in order to obtain a more thorough understanding of the specific requirements. The estimate provided above for this work could change substantially based on the results of this analysis. Until this field analysis is performed the Public Utility must develop the Project schedule using conservative assumptions. The Interconnection Customer may request that the Public Utility perform this field analysis, at the Interconnection Customer's expense, prior to the execution of an Interconnection Agreement in order to obtain more cost and schedule certainty.

‡Transmission line upgrades will only be required if Interconnection Customer and ESM are unable to come to agreement to obtain third party transmission service as specified in Section 6.2 of the Study.

Note: Costs for any excavation, duct installation and easements shall be borne by the Interconnection Customer and are not included in this estimate. This estimate is as accurate as possibly given the level of detailed study that has been completed to date and approximates the costs incurred by Public Utility to interconnect this Small Generating Facility to Public Utility's electrical distribution or transmission system. A more detailed estimate will be calculated during the Facilities Study. The Interconnection Customer will be responsible for all actual costs, regardless of the estimated costs communicated to or approved by the Interconnection Customer.

8.0 SCHEDULE

The Public Utility estimates it will require approximately 18 months to design, procure and construct the facilities described in this report following the execution of an Interconnection Agreement. The schedule will be further developed and optimized during the Facilities Study.

Please note, the time required to perform the scope of work identified in this report appears to result in a timeframe that does not support the Interconnection Customer's requested commercial operation date of December 31, 2016.

9.0 PARTICIPATION BY AFFECTED SYSTEMS

Public Utility has identified the following Affected Systems: Bonneville Power Administration

Copies of this report will be shared with each Affected System.

10.0 APPENDICES

Appendix 1: Higher Priority Requests
Appendix 2: Property Requirements
Appendix 3: Study Results

10.1 APPENDIX 1: HIGHER PRIORITY REQUESTS

All active higher priority transmission service and/or generator interconnection requests will be considered in this study and are identified below. If any of these requests are withdrawn, the Public Utility reserves the right to restudy this request, as the results and conclusions contained within this study could significantly change.

Transmission/Generation Interconnection Queue Requests considered:

Q0547 (18 MW)
Q0586 (6 MW)
Q0666 (2 MW)
Q0728 (3 MW)

10.2 APPENDIX 2: PROPERTY REQUIREMENTS

Requirements for rights of way easements
Rights of way easements will be acquired by the Interconnection Customer in the Public Utility's name for the construction, reconstruction, operation, maintenance, repair, replacement and removal of Public Utility's Interconnection Facilities that will be owned and operated by PacifiCorp. Interconnection Customer will acquire all necessary permits for the project and will obtain rights of way easements for the project on Public Utility's easement form.

Real Property Requirements for Point of Interconnection Substation
Real property for a Point of Interconnection substation will be acquired by an Interconnection Customer to accommodate the Interconnection Customer's Project. The real property must be acceptable to Public Utility. Interconnection Customer will acquire fee ownership for interconnection substation unless Public Utility determines that other than fee ownership is acceptable; however, the form and instrument of such rights will be at Public Utility's sole discretion. Any land rights that Interconnection Customer is planning to retain as part of a fee property conveyance will be identified in advance to Public Utility and are subject to the Public Utility's approval.

The Interconnection Customer must obtain all permits required by all relevant jurisdictions for the planned use including but not limited to conditional use permits, Certificates of Public Convenience and Necessity, California Environmental Quality Act, as well as all construction permits for the project.

Interconnection Customer will not be reimbursed through network upgrades for more than the market value of the property.

As a minimum, real property must be environmentally, physically, and operationally acceptable to Public Utility. The real property shall be a permitted or permittable use in all zoning districts. The Interconnection Customer shall provide Public Utility with a title report and shall transfer property without any material defects of title or other encumbrances that are not acceptable to Public Utility. Property lines shall be surveyed and show all encumbrances, encroachments, and roads.

Examples of potentially unacceptable environmental, physical, or operational conditions could include but are not limited to:

- Environmental: known contamination of site; evidence of environmental contamination by any dangerous, hazardous or toxic materials as defined by any governmental agency; violation of building, health, safety, environmental, fire, land use, zoning or other such regulation; violation of ordinances or statutes of any governmental entities having jurisdiction over the property; underground or above ground storage tanks in area; known remediation sites on property; ongoing mitigation activities or monitoring activities; asbestos; lead-based paint, etc. A phase I environmental study is required for land being acquired in fee by the Public Utility unless waived by Public Utility.

- Physical: inadequate site drainage; proximity to flood zone; erosion issues; wetland overlays; threatened and endangered species; archeological or culturally sensitive areas; inadequate sub-surface elements, etc. Public Utility may require Interconnection Customer to procure various studies and surveys as determined necessary by Public Utility.

- Operational: inadequate access for Public Utility's equipment and vehicles; existing structures on land that require removal prior to building of substation; ongoing maintenance for landscaping or extensive landscape requirements; ongoing homeowner's or other requirements or restrictions (e.g., Covenants, Codes and Restrictions, deed restrictions, etc.) on property which are not acceptable to the Public Utility.

10.3 APPENDIX 3: STUDY RESULTS

Transmission Study
Three cases studies involving the transmission system were assembled and studied:
1. Heavy Summer Load with full generation
2. Heavy Winter Load with full generation
3. Daytime minimum load with full generation

The three cases were analyzed for thermal limits, steady state voltage and voltage deviation. The limits for which are defined in the PacifiCorp Engineering Handbook Section 1.

System Normal (N-0) Results
With all lines in service and the Walla Walla/Pendleton system in its normal configuration, the addition of Q0747 showed no thermal or steady-state voltage deficiencies. There is an expected export of up to 5.8 MVA from Pilot Rock to BPA's Roundup station during light loading conditions.

Single Element Outage (N-1) Results
With the system modeled in its normal configuration outages were simulated for all 69 kV and 230 kV transmission elements in the Pendleton Area. The transmission elements included all branches and transformers. Each outage assumed normal clearing of adjacent circuit breakers. The deviation results are listed below. An outage of either of the BPA-Roundup 230-69 kV transformers bank #1 or bank #2 would cause voltages at Pilot Rock to reach 1.083 pu, but was within the emergency high voltage limit applicable to this type of transformer outage (1.10 pu).

Multiple Transmission Element Outage Results
Pilot Rock is served radially from the Public Utility's 230-69 kV transformer, bank #3 at BPA-Roundup. As such, there were only a few applicable N-1-1 outages for this study. The worst outage contingency is the combined loss of either Roundup transformer banks #1 or #2 along with Roundup Bank #3. This scenario causes the remaining Roundup transformer to be overloaded to 154% of the nameplate rating. This overload is accompanied by critically low voltages across the Pendleton area. This is an existing exposure, prior to addition of Q0747. The addition of Q0747 along with the prior queued GIQs do not increase the deficiency associated with the contingency combination and may provide some benefit to avoid a voltage collapse during summer peak. No additional mitigation due to Q0747 is required. The only Bulk Electric System element in the area that would be subject to NERC TPL standards is the 230 kV bus and circuit switcher supplying the Public Utility's Roundup 230-69 kV transformer. A bus fault (TPL category P2-2) on this section would cause consequential load loss and is not a reliability deficiency.

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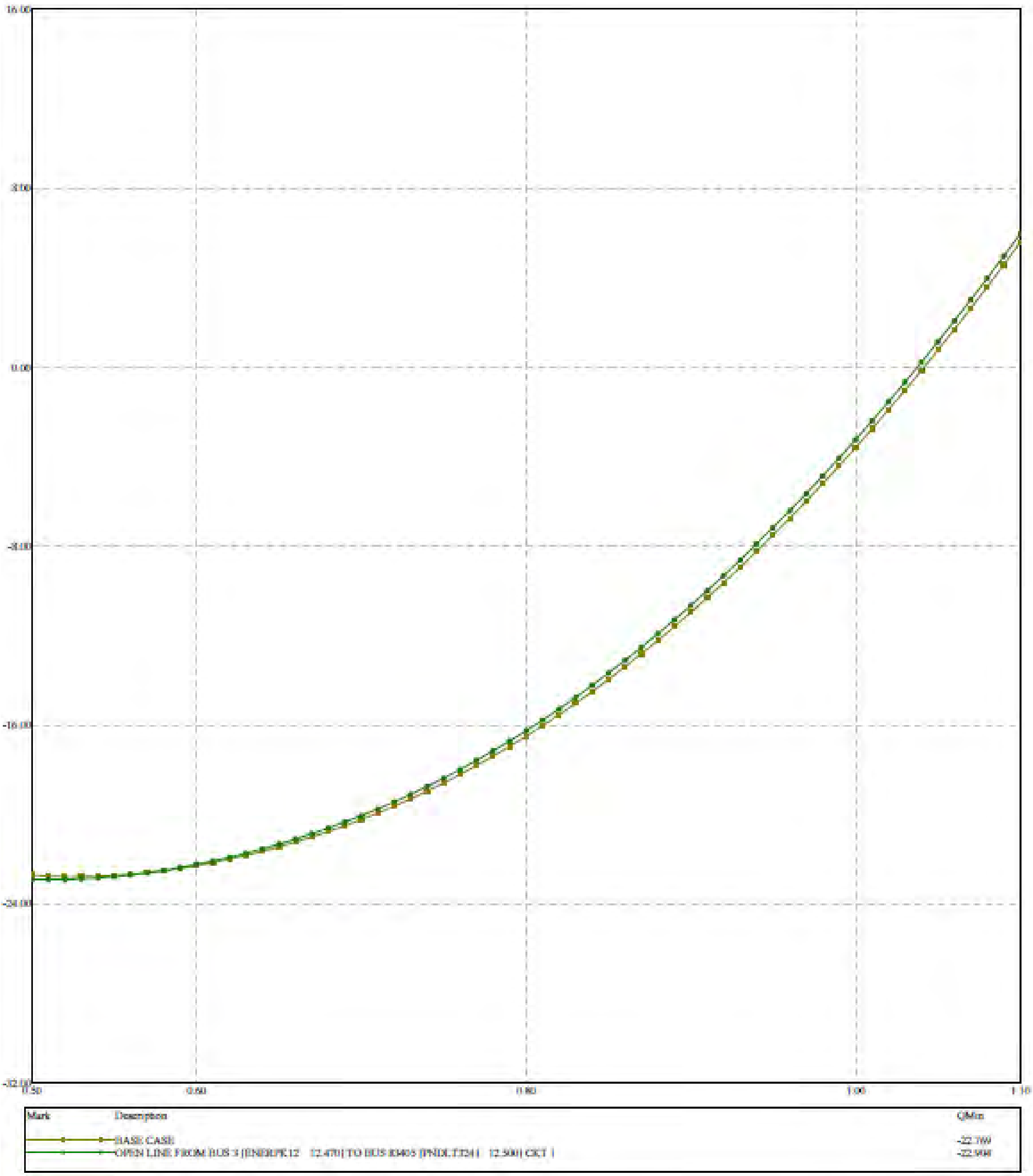

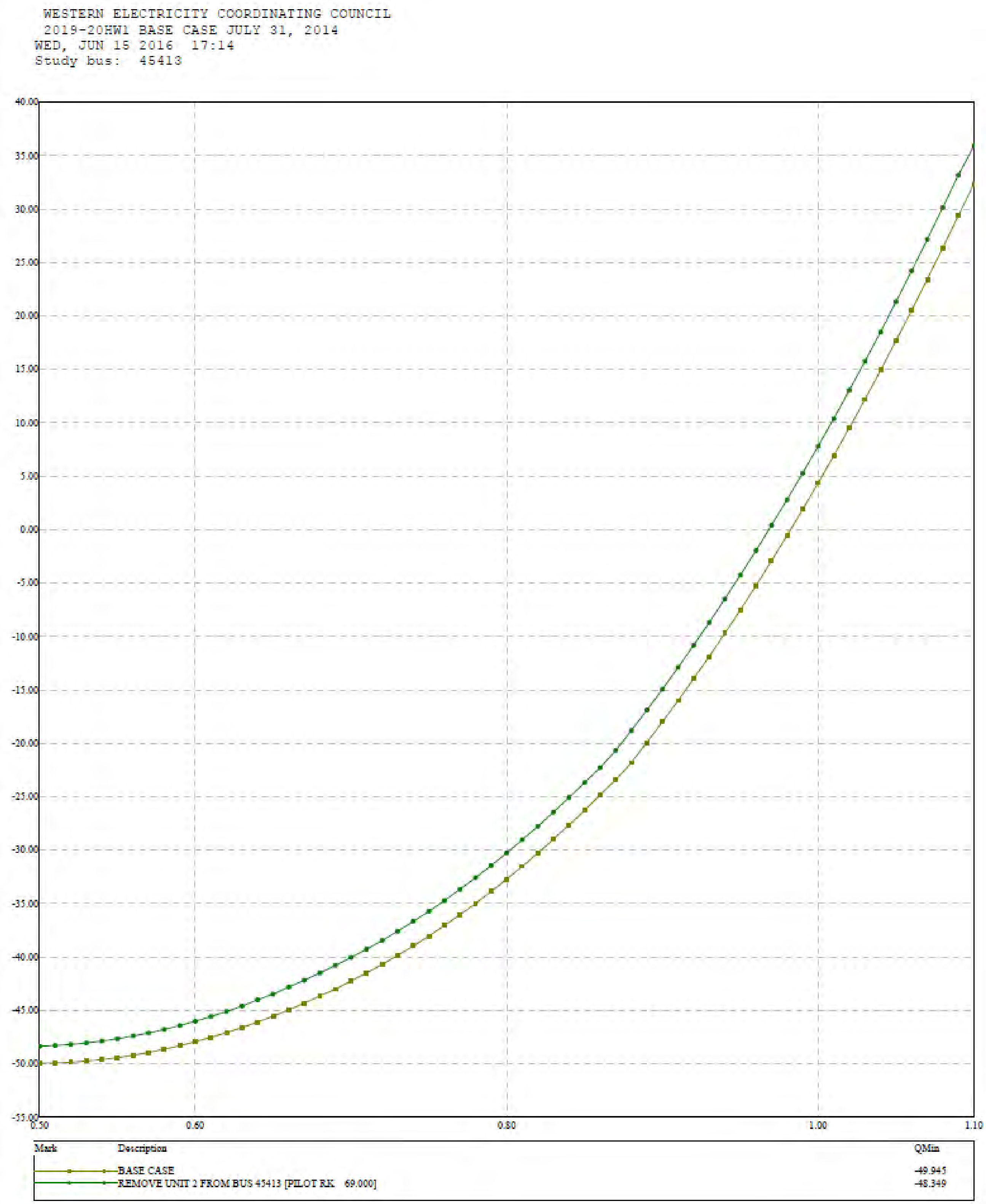
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1.00
1.10
Mark
Description
QMin
BASE CASE
-49.945
REMOVE UNIT 2 FROM BUS 45413 [PILOT RK 69.000]
-48.349

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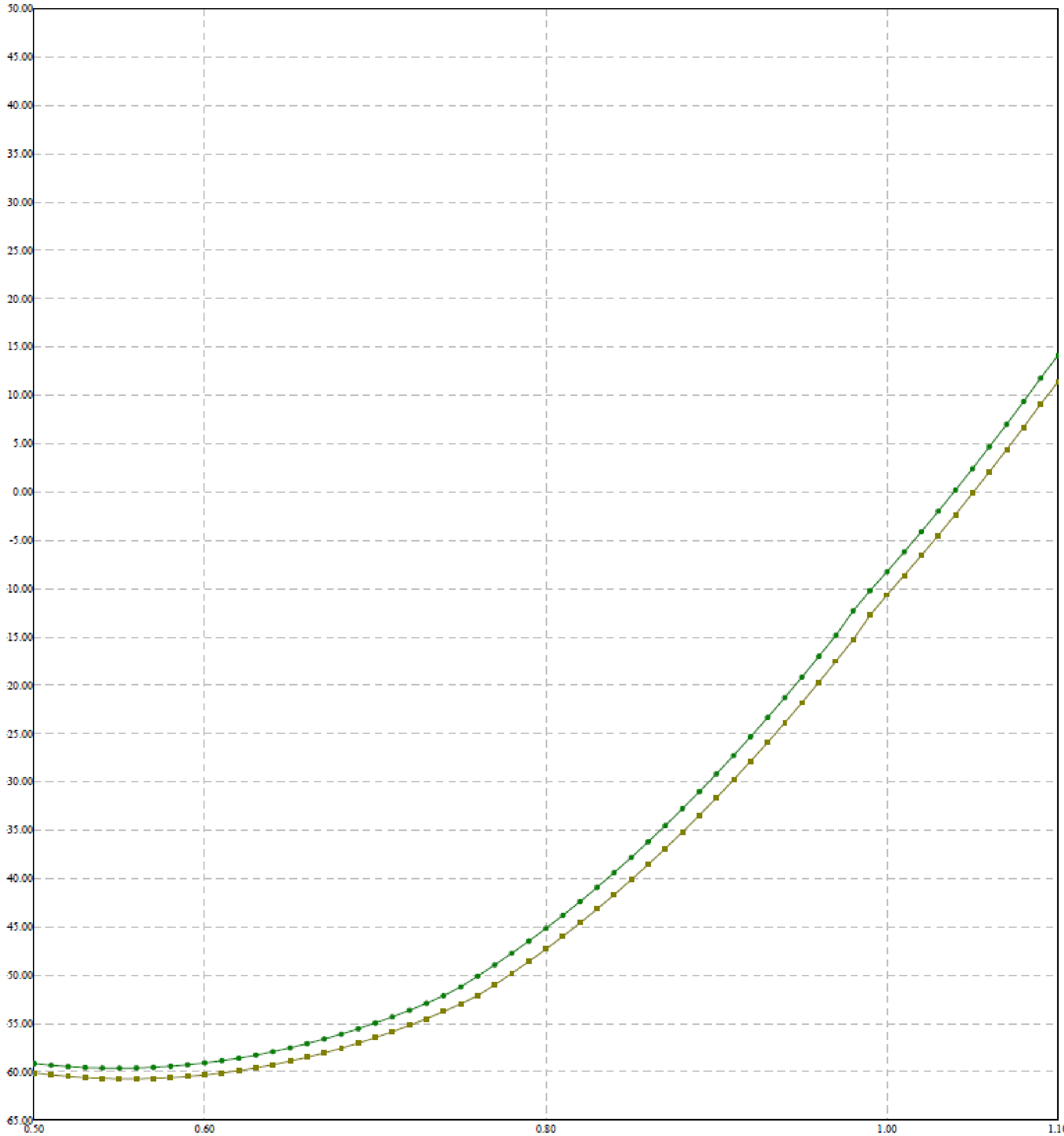

Mark	Description	QMin
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Powerflow Case	Outage	Roundup Voltage	Voltage Deviation Roundup	Pendleton Voltage	Voltage Deviation Pendleton	Pilot Rock Voltage	Voltage Deviation Pilot Rock	Thermal issues
Heavy Summer 2016	System Normal	0.987	n/a	0.978	n/a	0.969	n/a	none
Heavy Summer 2016	Pendleton - Buckaroo	0.979	0.8%	0.967	1.1%	0.961	0.8%	none
Heavy Summer 2016	Pendleton - Roundup	1.013	2.6%	0.956	2.2%	0.995	2.7%	none
Heavy Summer 2016	Pendleton - Athena	0.985	0.2%	0.974	0.4%	0.967	0.2%	none
Heavy Summer 2016	Roundup - Buckaroo	0.982	0.5%	0.969	0.9%	0.964	0.5%	none
Heavy Summer 2016	Roundup transformer #3	0.956	3.1%	0.935	4.4%	0.938	3.2%	none
Heavy Summer 2016	Roundup transformer #1	0.945	4.3%	0.969	0.9%	0.956	1.3%	none
Heavy Summer 2016	Roundup transformer #2	0.974	1.3%	0.969	0.9%	0.956	1.3%	none
Heavy Summer 2016	Q0747 Plant	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Heavy Summer with Q0747	System Normal	0.989	n/a	0.979	n/a	0.983	n/a	none
Heavy Summer with Q0747	Pendleton - Buckaroo	0.98	0.9%	0.968	1.1%	0.974	0.9%	none
Heavy Summer with Q0747	Pendleton - Roundup	1.014	2.5%	0.957	2.2%	1.008	2.5%	none
Heavy Summer with Q0747	Pendleton - Athena	0.988	0.1%	0.976	0.3%	0.981	0.2%	none
Heavy Summer with Q0747	Roundup - Buckaroo	0.983	0.6%	0.97	0.9%	0.977	0.6%	none
Heavy Summer with Q0747	Roundup transformer #3	0.96	2.9%	0.939	4.1%	0.954	3.0%	none
Heavy Summer with Q0747	Roundup transformer #1	0.977	1.2%	0.971	0.8%	0.971	1.2%	none
Heavy Summer with Q0747	Roundup transformer #2	0.977	1.2%	0.971	0.8%	0.971	1.2%	none
Heavy Summer with Q0747	Q0747 Plant	0.987	0.2%	0.978	0.1%	0.969	1.4%	none

Powerflow Case	Outage	Roundup Voltage	Voltage Deviation Roundup	Pendleton Voltage	Voltage Deviation Pendleton	Pilot Rock Voltage	Voltage Deviation Pilot Rock	Thermal issues
Heavy Winter 2016-17	System Normal	0.999	n/a	0.992	n/a	0.969	n/a	none
Heavy Winter 2016-17	Pendleton - Buckaroo	0.99	0.9%	0.98	1.2%	0.96	0.9%	none
Heavy Winter 2016-17	Pendleton - Roundup	1.019	2.0%	0.98	1.2%	0.99	2.2%	none
Heavy Winter 2016-17	Pendleton - Athena	1.003	0.4%	0.996	0.4%	0.973	0.4%	none
Heavy Winter 2016-17	Roundup - Buckaroo	0.993	0.6%	0.982	1.0%	0.962	0.7%	none
Heavy Winter 2016-17	Roundup tranformer #3	0.982	1.7%	0.966	2.6%	0.951	1.9%	none
Heavy Winter 2016-17	Roundup tranformer #1	0.986	1.3%	0.983	0.9%	0.955	1.4%	none
Heavy Winter 2016-17	Roundup tranformer #2	0.986	1.3%	0.983	0.9%	0.955	1.4%	none
Heavy Winter 2016-17	Q0747 Plant	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Heavy Winter with Q0747	System Normal	1.001	n/a	0.993	n/a	0.983	n/a	none
Heavy Winter with Q0747	Pendleton - Buckaroo	0.992	0.9%	0.981	1.2%	0.974	0.9%	none
Heavy Winter with Q0747	Pendleton - Roundup	1.021	2.0%	0.98	1.3%	1.003	2.0%	none
Heavy Winter with Q0747	Pendleton - Athena	1.006	0.5%	0.998	0.5%	0.988	0.5%	none
Heavy Winter with Q0747	Roundup - Buckaroo	0.994	0.7%	0.983	1.0%	0.976	0.7%	none
Heavy Winter with Q0747	Roundup tranformer #3	0.985	1.6%	0.968	2.5%	0.966	1.7%	none
Heavy Winter with Q0747	Roundup tranformer #1	0.989	1.2%	0.985	0.8%	0.971	1.2%	none
Heavy Winter with Q0747	Roundup tranformer #2	0.989	1.2%	0.985	0.8%	0.971	1.2%	none
Heavy Winter with Q0747	Q0747 Plant	0.999	0.2%	0.992	0.1%	0.969	1.4%	none

Powerflow Case	Outage	Roundup Voltage	Voltage Deviation Roundup	Pendleton Voltage	Voltage Deviation Pendleton	Pilot Rock Voltage	Voltage Deviation Pilot Rock	Thermal issues
Light Load	System Normal	1.041	n/a	1.033	n/a	1.04	n/a	none
Light Load	Pendleton - Buckaroo	1.033	0.8%	1.025	0.8%	1.032	0.8%	none
Light Load	Pendleton - Roundup	1.074	3.2%	0.998	3.4%	1.073	3.2%	none
Light Load	Pendleton - Athena	1.061	1.9%	1.055	2.1%	1.059	1.8%	none
Light Load	Roundup - Buckaroo	1.034	0.7%	1.026	0.7%	1.033	0.7%	none
Light Load	Roundup transformer #3	1.03	1.1%	1.02	1.3%	1.028	1.2%	none
Light Load	Roundup transformer #1	1.025	1.5%	1.019	1.4%	1.023	1.6%	none
Light Load	Roundup transformer #2	1.025	1.5%	1.019	1.4%	1.023	1.6%	none
Light Load	Q0747 Plant	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Light Load with Q0747	System Normal	1.042	n/a	1.034	n/a	1.051	n/a	none
Light Load with Q0747	Pendleton - Buckaroo	1.034	0.8%	1.025	0.9%	1.043	0.8%	none
Light Load with Q0747	Pendleton - Roundup	1.074	3.1%	0.998	3.5%	1.073	2.1%	none
Light Load with Q0747	Pendleton - Athena	1.061	1.8%	1.055	2.0%	1.059	0.8%	none
Light Load with Q0747	Roundup - Buckaroo	1.034	0.8%	1.026	0.8%	1.033	1.7%	none
Light Load with Q0747	Roundup transformer #3	1.03	1.2%	1.02	1.4%	1.028	2.2%	none
Light Load with Q0747	Roundup transformer #1	1.025	1.6%	1.019	1.5%	1.023	2.7%	none
Light Load with Q0747	Roundup transformer #2	1.025	1.6%	1.019	1.5%	1.023	2.7%	none
Light Load with Q0747	Q0747 Plant	1.041	0.1%	1.033	0.1%	1.04	1.0%	none

CASE: UM 2118--SUNTHURST V. PACIFICORP
SUNTHURST WITNESS: MICHAEL BEANLAND

PUBLIC UTILITY COMMISSION
OF
OREGON

SUNTHURST EXHIBIT 207

Q1045 Interconnection Studies:

March 27, 2020 System Impact Study Report

June 30, 2020 Facilities Study Report

September 4, 2020 [Revised] Facilities Study Report

DECEMBER 15, 2020

Small Generator Interconnection

Oregon Tier 4 System Impact Study Report

Completed for

("Interconnection Customer")
Q1045

A Qualifying Facility

Proposed Point of Interconnection

Circuit 5W406 out of Pilot Rock substation at 12.5 kV
(at approximately 45° 30' 32.67", -118° 49' 38.87")

March 27, 2020

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1.0 Description of the Generating Facility

("Interconnection Customer") proposed interconnecting 3 MW of new generation to PacifiCorp's ("Public Utility") Circuit 5W406 out of Pilot Rock substation at 12.5 kV located in Umatilla County, Oregon. The project ("Project") will consist of forty-nine (49) Sungrow SG60KU-M inverters for a total requested output of 3 MW. The requested commercial operation date is December 31, 2019.

Interconnection Customer will operate this generator as a Qualifying Facility as defined by the Public Utility Regulatory Policies Act of 1978 (PURPA).

The Public Utility has assigned the Project "Q1045."

2.0 Approval Criteria for Tier 4 Interconnection Review

Pursuant to 860-082-0060(1), a public utility must use the Tier 4 interconnection review procedures for an application to interconnect a small generator facility that meets the following requirements:

(a) The small generator facility does not qualify for or failed to meet Tier 1, Tier 2, or Tier 3 interconnection review requirements; and
(b) The small generator facility must have a nameplate capacity of ten (10) megawatts or less.

3.0 Scope of the Study

Pursuant to 860-082-0060(7)(g) the System Impact Study Report shall consist of a short circuit analysis, a stability analysis, a power flow analysis, voltage drop and flicker studies, protection and set point coordination studies, and grounding reviews, as necessary. The System Impact Study shall state the assumptions upon which it is based, state the results of the analyses, and provide the requirement or potential impediments to providing the requested interconnection service, including a preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. The System Impact Study shall provide a list of facilities that are required as a result of the Interconnection Request and non-binding good faith estimates of cost responsibility and time to construct.

4.0 Independent study evaluation

Pursuant to 860-082-0060(7)(h), the application has not provided an independent system impact study that is to be addressed and evaluated along with the results from the Public Utility's own evaluation of the interconnection of the proposed Small Generator Facility.

5.0 Proposed Point of Interconnection

The Interconnection Customer's proposed Small Generator Facility is to be interconnected to the Public Utility's distribution circuit 5W406 out of Pilot Rock substation, roughly 1,400' north of the existing facility point 01401032.0090961. The Interconnection Customer's Small Generator Facility will utilize the interconnection facilities associated with the Interconnection Request studied under queue position Q0666. Figure 1 below, is a one-line diagram that illustrates the interconnection of the proposed Small Generator Facility to the Public Utility's system.

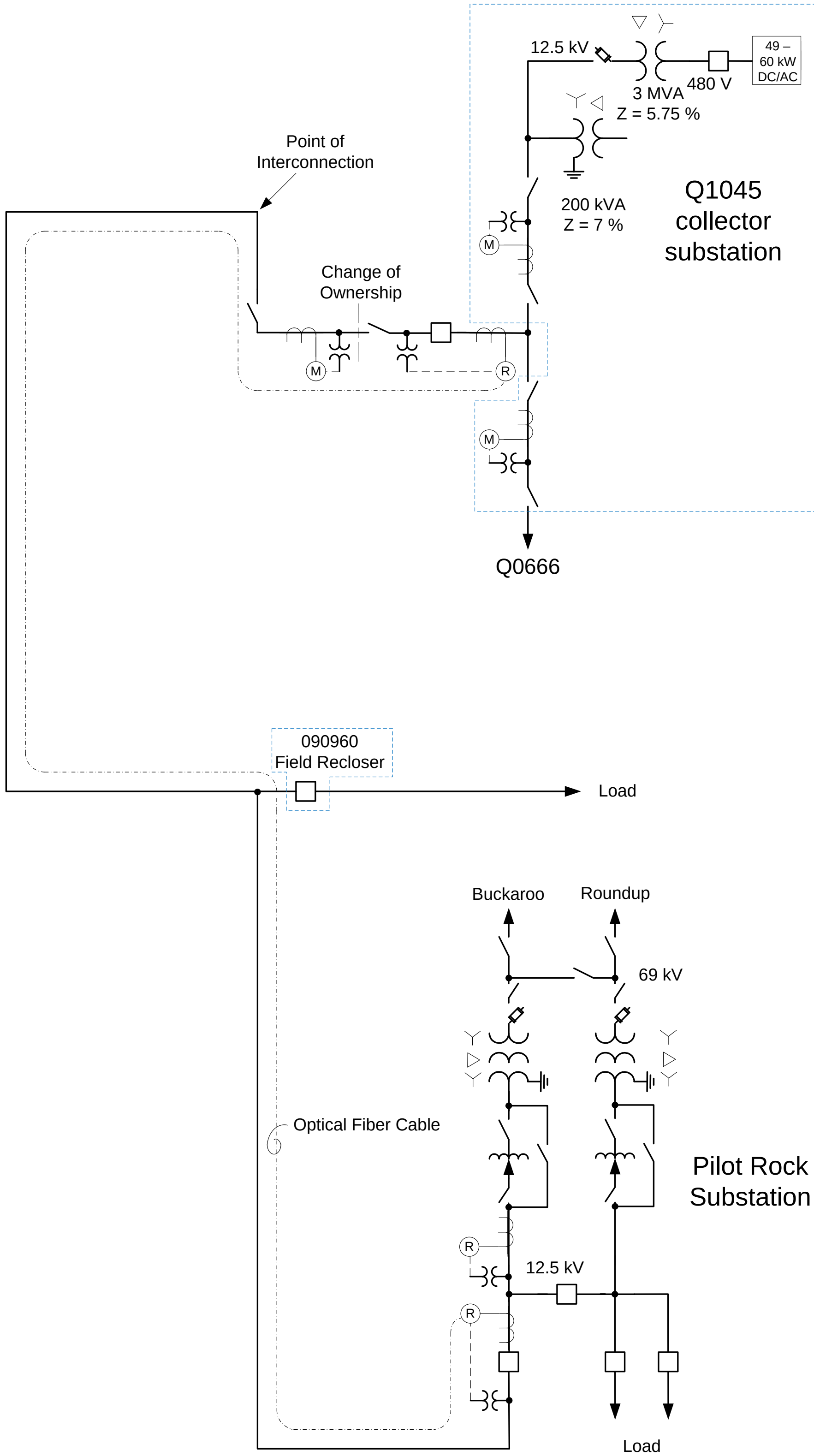

Figure 1: System One Line Diagram

6.0 Study Assumptions

- All active higher priority transmission service and/or generator interconnection requests will be considered in this study and are listed in Appendix 1. If any of these requests are withdrawn, the Public Utility reserves the right to restudy this request, as the results and conclusions contained within this study could significantly change.
- For study purposes there are two separate queues:
  - Transmission Service Queue: to the extent practical, all System Upgrades that are required to accommodate active transmission service requests will be modeled in this study.
  - Generation Interconnection Queue: All relevant higher queue interconnection requests will be modeled in this study.
- The Interconnection Customer's request for interconnection service in and of itself does not convey transmission service.
- This study assumes the Project will be integrated into Public Utility's system at the agreed upon and/or proposed Point of Interconnection ("POI").
- The Interconnection Customer will construct and own any facilities required between the POI and the Project unless specifically identified by the Public Utility.
- Line reconductor or fiber underbuild required on existing poles will be assumed to follow the most direct path on the Public Utility's system. If during detailed design the path must be modified it may result in additional cost and timing delays for the Interconnection Customer's Project.
- Generator tripping may be required for certain outages.
- All facilities will meet or exceed the minimum Western Electricity Coordinating Council ("WECC"), North American Electric Reliability Corporation ("NERC"), and Public Utility performance and design standards.
- Time of use metering does not exist for Pilot Rock substation. The daytime minimum demand for the feeder 5W406 is estimated based on the peak demand on the circuit.
- Peak demand for 5W406 is approximately 6600 kW and 2600 kVAR. There is one 600 kVAR capacitor bank installed on the feeder.
- The minimum daytime load on 5W406 is estimated at 1820 kW and 960 kVAR.
- The solar generation interconnection was studied with a maximum output of 3 MW and a reactive consumption by the Project of 900 kVAR.
- This report is based on the AC Oneline provided by the Interconnection Customer and dated April 28, 2018.
- Inverter specifications were also provided by the Interconnection Customer.
- The power output of the inverters is to 6600 kVA / 6000 kW as stated in the inverter specifications. This appears to comply with reactive requirements for this Project; however, Interconnection Customer is responsible for additional reactive compensation, if needed, to assure total Project output can be delivered at unity power factor.
- The Small Generator Facility is expected to operate during daylight hours every day 7 days per week 12 months per year.
- Contingency transmission configuration for the Public Utility's system is defined as any configuration other than normal transmission configuration.
- Three case studies were assembled and studied in power flow simulation at the transmission level:

  - Case 1: Normal Configuration with Pilot Rock fed from BPA breaker L-1122 at Roundup, via the “Birch Creek” 69 kV Line.
  - Case 2: Contingency configuration with Pilot Rock fed from Buckaroo and Roundup via the “Coyote Creek” 69 kV line. Switch 3W191 closed, BPA breaker L-1122 open.
  - Case 3: Pendleton 69 kV Loop Split (Switch 3W26 open at Buckaroo, breaker L-1123 open at BPA Roundup).
- This report is based on information available at the time of the study. It is the Interconnection Customer’s responsibility to check the Public Utility’s web site regularly for transmission system updates (http://www.pacificorp.com/tran.html)

7.0 Requirements

7.1 Small Generator Facility Requirements

The Small Generator Facility and Interconnection Equipment owned by the Interconnection Customer are required to operate under automatic voltage control with the voltage sensed electrically at the POI. The Small Generator Facility should have sufficient reactive capacity to enable the delivery of 100 percent of the Project output to the POI at unity power factor measured at 1.0 per unit voltage under steady state conditions.

Generators capable of operating under voltage control with a voltage droop are required to do so. Studies will be required to coordinate the voltage droop setting with other facilities in the area. In general, the Small Generator Facility and Interconnection Equipment should be operated so as to maintain the voltage at the POI between 1.01 pu to 1.04 pu. At the Public Utility’s discretion, these values might be adjusted depending on the operating conditions. Within this voltage range, the Small Generator Facility should operate so as to minimize the reactive interchange between the Small Generator Facility and the Public Utility’s system (delivery of power at the POI at approximately unity power factor). The voltage control settings of the Small Generator Facility must be coordinated with the Public Utility prior to energization (or interconnection). The reactive compensation must be designed such that the discreet switching of the reactive device (if required by the Interconnection Customer) does not cause step voltage changes greater than +/-3% on the Public Utility’s system.

All generators must meet applicable WECC low voltage ride-through requirements as specified in the interconnection agreement.

As per NERC standard VAR-001-1, the Public Utility is required to specify voltage or reactive power schedule at the POI. Under normal conditions, the Public Utility’s system should not supply reactive power to the Small Generator Facility.

As the Public Utility cannot submit a user written model to WECC for inclusion in base cases, a standard model from the WECC Approved Dynamic Model Library is required 180 days prior to trial operation. The list of approved generator models is continually updated and is available on the http://www.WECC.biz website.

The Interconnection Customer will be required to install a transformer that will hold the phase to neutral voltages within limits when the Small Generator Facility is isolated with the Public Utility's local system until the generation disconnects. The proposed delta – wye step-up transformer with the delta winding on the 12.47 kV side will not accomplish the stabilization of the phase to neutral voltages on the 12.47 kV system. The circuit that the Project is connecting to is a four wire multi-grounded circuit with line to neutral connected load. Figure 1 shows the addition of a wye – delta grounding transformer of adequate power size and impedance that will meet the requirement. The grounding transformer proposed for the Q0666 project alone will not be adequate for both projects. Since the two projects will share a common circuit recloser the projects could also share a common grounding transformer. If that is desired by the Interconnection Customer a grounding transformer can be sized for the combination of the two generation projects.

Under the normal configuration described in Case 1, and the contingency configurations described in Case 2 and 3, there are no identified power flow restrictions with Q1045 generation online. Certain extreme contingency configurations, such as a BPA Roundup 230 kV bus outage, though not explicitly studied, may warrant generation curtailment to 0 MW until the system returns to a normal state.

As the Interconnection Customer's Small Generator Facility will utilize the Interconnection Customer Interconnection Facilities associated with a different Interconnection Request the Interconnection Customer must provide the Public Utility with demonstration of approval from the owner of the Q0666 Interconnection Request for the shared facilities.

7.2 TRANSMISSION SYSTEM MODIFICATIONS

Transmission level power flow study cases were evaluated for heavy summer, winter, and light loading conditions. For each of the cases, power flows and system voltages were evaluated with and without the proposed Q1045 Small Generator Facility to determine the impact on the transmission system during system normal operation and following various contingency events in the local system. Due to the small size of the proposed interconnection relative to the transmission system, no thermal or voltage deficiencies associated with interconnection of Q1045 were observed.

Historical load records were reviewed to determine the Public Utility's minimum daytime load in the Pendleton area 69 kV system. The minimum daytime load was determined to be less than all in-service and prior queued generation. As a result, reverse power flow at the BPA Roundup 230-69 kV source is anticipated during light load conditions.

7.3 DISTRIBUTION MODIFICATIONS

- Install one three phase recloser at a location east of 090960 to insure coordinated fault clearing on the McKay branch of the feeder.
- Install one three phase bank of 219 amp 7.2 kV voltage regulators on the McKay branch to ensure ANSI range A voltages can be maintained at the end of the line.

- Install one three phase bank of 100 amp 7.2 kV voltage regulators on the circuit branch west of the interconnection tap to ensure ANSI range A voltages can be maintained at the end of the line.

7.4 Existing Breaker Modifications – Short-Circuit

The increase in the fault duty on the system as the result of the addition of the Small Generator Facility with photovoltaic arrays fed through 49 – 60 kW inverters connected to a 3 MVA 12.5 kV – 480 V transformer with 5.75% impedance along with the earlier Q0666 project will not push the fault duty above the interrupting rating of any of the existing fault interrupting equipment.

7.5 Protection Requirements

Since the Q1045 Project will share the same circuit recloser as the Q0666 project for the interconnection to the 12.5 kV feeder out of Pilot Rock substation therefore no protection modifications will be required for the Q1045 Project. New relay settings will be developed and installed in the relay associated with the circuit recloser to accommodate the addition of the Q1045 Project.

7.6 Data Requirements (RTU)

Data for the operation of the transmission system will be needed from the collector substation for Q1045. The Public Utility will install a remote terminal unit ("RTU") at the Interconnection Customer collector substation site. The following data will be acquired.

Analogs:

- Net Generation real power MW
- Net Generator reactive power MVAR
- Energy Register KWH
- Q0666 real power MW
- Q0666 reactive power MVAR
- Q0666 Energy Register KWH
- Q1045 real power MW
- Q1045 reactive power MVAR
- Q1045 Energy Register KWH
- A phase 12.5 kV voltage
- B phase 12.5 kV voltage
- C phase 12.5 kV voltage
- Global Horizontal Irradiance (GHI)
- Average Plant Atmospheric Pressure (Bar)
- Average Plant Temperature (Celsius)

Status:

- 12.5 kV circuit recloser

The Interconnection Customer's Small Generator Facility may be required to accept setpoint control signals from the Public Utility's control centers. If required the Small Generator Facility will need to communicate the following points.

- Max Gen MW
- Max Gen MW FB

7.7 Communication Requirements

7.7.1 Line Protection

The optical fiber cable planned to be installed for the Q0666 project between Pilot Rock substation and the collector substation will be used for relaying between the collector site and Pilot Rock substation.

7.7.2 Data Delivery to the Control Centers

The Transmission Provider will install a radio system between Pilot Rock substation and the Public Utility's Cabbage Hill communications site. The tower at Cabbage Hill will have a load analysis done to ensure it can support the new antenna, and will be strengthened if necessary. Radios will be installed at Pilot Rock and Cabbage Hill. At Pilot Rock, a channel bank, 48VDC charger and batteries, router and switch will be installed to carry SCADA, telemetry, voice, and data circuits from the substation to control centers. At Cabbage Hill circuits will be cross-connected to existing comm systems.

7.8 Substation Requirements

Q1045 collector substation

The Public Utility will install a control building at the Interconnection Customer's shared collector substation location for the installation of protective, communications and metering equipment.

The Interconnection Customer will provide a separate graded, grounded and fenced area along the perimeter of the Interconnection Customer's Small Generator Facility for the Public Utility to install the control building. This area will have unencumbered access for the Public Utility. AC station service will be supplied by the Interconnection Customer and DC power for the control house will be supplied by the Public Utility.

Pilot Rock substation

At Pilot Rock substation the settings of regulator R-816 will need to be modified to account for this additional generation. Communications equipment will need to be installed to support the new microwave system.

7.9 Metering Requirements

Interchange Metering

The revenue metering will be located at the Interconnection Customer collector substation. The Public Utility will procure, install, test, and own all revenue metering equipment. The revenue metering instrument transformers will be installed overhead on a pole at the POI. The meter instrument transformer mounting shall conform to the Public Utility's DM construction standards.

There will be two meters installed in the control building with the metering programmed bi-directional to measure KWH and KVARH quantities for both generation received and retail load delivered.

The present output rating of the generation Project requires metering real time bidirectional SCADA, KWH KVARH MW, MVAR including per phase voltage data. The metering data will include a backup meter for alternate path EMS data.

Communication equipment will be required to remotely interrogate the meter for generation and billing data via the Public Utility's MV-90 data acquisition system. If available Ethernet is preferred and if not available a cell phone package is acceptable.

Station Service/Construction Power
The Project is within the Public Utility's service territory. Please note that prior to backfeed, Interconnection Customer must arrange transmission retail meter service for electricity consumed by the Project that will be drawn from the system when the Project is not generating. Interconnection Customer must call the PCCC Solution Center 1-800-625-6078 to arrange this service. Approval for back feed is contingent upon obtaining station service.

8.0 Cost Estimate

The following estimate represents only scopes of work that will be performed by the Public Utility. Costs for any work being performed by the Interconnection Customer are not included.

Q01045 Collector Substation *Install control building, metering and communications equipment*	$600,000
Distribution Circuit 5W406 *Install recloser and regulators*	$265,000
Pilot Rock Substation *Install communications equipment, modify regulator settings*	$250,000
Cabbage Hill Communications Site *Install communications equipment*	$74,000
System Operations Control Centers *Update databases*	$6,000
Total	**$1,195,000**

*Any distribution line modifications identified in this report will require a field visit analysis in order to obtain a more thorough understanding of the specific requirements. The estimate provided above for this work could change substantially based on the results of this analysis. Until this field analysis is performed the Public Utility must develop the Project schedule using conservative assumptions. The Interconnection Customer may request that the Public Utility perform this field

analysis, at the Interconnection Customer's expense, prior to the execution of an Interconnection Agreement in order to obtain more cost and schedule certainty.

Note: Costs for any excavation, duct installation and easements shall be borne by the Interconnection Customer and are not included in this estimate. This estimate is as accurate as possibly given the level of detailed study that has been completed to date and approximates the costs incurred by Public Utility to interconnect this Small Generator Facility to Public Utility's electrical distribution or transmission system. A more detailed estimate will be calculated during the Facilities Study. The Interconnection Customer will be responsible for all actual costs, regardless of the estimated costs communicated to or approved by the Interconnection Customer.

9.0 Schedule

The Public Utility estimates it will require approximately 12-15 months to design, procure and construct the facilities described in this report following the execution of an Interconnection Agreement. The schedule will be further developed and optimized during the Facilities Study.

Please note, the time required to perform the scope of work identified in this report does not support the Interconnection Customer's requested commercial operation date of December 31, 2019.

10.0 Participation by Affected Systems

Public Utility has identified the following Affected Systems: Bonneville Power Administration and Columbia Power

Copies of this report will be shared with each Affected System.

11.0 Appendices

Appendix 1: Higher Priority Requests
Appendix 2: Contingent Facilities
Appendix 3: Property Requirements
Appendix 4: Study Results

11.1 Appendix 1: Higher Priority Requests

All active higher priority transmission service and/or generator interconnection requests will be considered in this study and are identified below. If any of these requests are withdrawn, the Public Utility reserves the right to restudy this request, as the results and conclusions contained within this study could significantly change.

Transmission/Generation Interconnection Queue Requests considered:

Q0547 (18 MW)
Q0666 (1.98 MW)

11.2 Appendix 2: Contingent Facilities

The following Interconnection Facilities and/or upgrades to the Public Utility's system are Contingent Facilities for the Interconnection Customer's Interconnection Request and must be in service prior to the commencement of generation activities:

All interconnection facilities and system upgrades required for higher priority Interconnection Request Q0666 are Contingent Facilities for the Interconnection Customer's Interconnection Request including the following:

- Extension of approximately 0.3 miles of distribution line.
- Installation of approximately 0.9 miles of fiber optic cable.
- Installation of protective, communications and metering equipment in the Public Utility's Pilot Rock substation.
- Installation of standard Public Utility distribution interconnection package consisting of a metering equipment and switch.
- Installation of a Interconnection Customer owned recloser and relay package.

The estimated completion date of these upgrades is 2021. The estimated cost of the Public Utility's interconnection facilities and upgrades is approximately $805K. For additional details please review the system impact study for the Q0666 Interconnection Request on the Public Utility's OASIS website.

11.3 Appendix 3: Property Requirements

Requirements for rights of way easements

Rights of way easements will be acquired by the Interconnection Customer in the Public Utility's name for the construction, reconstruction, operation, maintenance, repair, replacement and removal of Public Utility's Interconnection Facilities that will be owned and operated by Public Utility. Interconnection Customer will acquire all necessary permits for the Project and will obtain rights of way easements for the Project on Public Utility's easement form.

Real Property Requirements for Point of Interconnection Substation

Real property for a POI substation will be acquired by an Interconnection Customer to accommodate the Interconnection Customer's Project. The real property must be acceptable to Public Utility. Interconnection Customer will acquire fee ownership for interconnection substation unless Public Utility determines that other than fee ownership is acceptable; however, the form and instrument of such rights will be at Public Utility's sole discretion. Any land rights that Interconnection Customer is planning to retain as part of a fee property conveyance will be identified in advance to Public Utility and are subject to the Public Utility's approval.

The Interconnection Customer must obtain all permits required by all relevant jurisdictions for the planned use including but not limited to conditional use permits, Certificates of Public Convenience and Necessity, California Environmental Quality Act, as well as all construction permits for the Project.

Interconnection Customer will not be reimbursed through network upgrades for more than the market value of the property.

As a minimum, real property must be environmentally, physically, and operationally acceptable to Public Utility. The real property shall be a permitted or able to be permitted use in all zoning districts. The Interconnection Customer shall provide Public Utility with a title report and shall transfer property without any material defects of title or other encumbrances that are not acceptable to Public Utility. Property lines shall be surveyed and show all encumbrances, encroachments, and roads.

Examples of potentially unacceptable environmental, physical, or operational conditions could include but are not limited to:

- Environmental: known contamination of site; evidence of environmental contamination by any dangerous, hazardous or toxic materials as defined by any governmental agency; violation of building, health, safety, environmental, fire, land use, zoning or other such regulation; violation of ordinances or statutes of any governmental entities having jurisdiction over the property; underground or above ground storage tanks in area; known remediation sites on property; ongoing mitigation activities or monitoring activities; asbestos; lead-based paint, etc. A phase I environmental study is required for land being acquired in fee by the Public Utility unless waived by Public Utility.

- Physical: inadequate site drainage; proximity to flood zone; erosion issues; wetland overlays; threatened and endangered species; archeological or culturally sensitive areas; inadequate sub-surface elements, etc. Public Utility may require Interconnection Customer to procure various studies and surveys as determined necessary by Public Utility.

- Operational: inadequate access for Public Utility's equipment and vehicles; existing structures on land that require removal prior to building of substation; ongoing maintenance for landscaping or extensive landscape requirements; ongoing homeowner's or other requirements or restrictions (e.g., Covenants, Codes and Restrictions, deed restrictions, etc.) on property which are not acceptable to the Public Utility.

11.4 APPENDIX 4: STUDY RESULTS

Distribution Study Results:

The distribution feeder was analyzed under the following conditions of demand loading and generation output.

The feeder peak demand with and without generation was evaluated.

The minimum daytime demand on the feeder with and without generation was evaluated.

The transient case was evaluated for maximum voltage variation caused by the generation changing from zero output to maximum output as well as the generation changing from maximum output to zero output.

Transmission Study Results:

<u>Case 1: Normal Configuration (Pilot Rock fed from BPA Roundup, breaker L-1122):</u>

No power flow restrictions were identified.

Minimum daytime loads in the Pendleton area are less than the sum of all generation year-round. Thus, Q1045 generation at any level <u>is likely</u> to result in export through the 230 kV bus at BPA Roundup.

Area bus voltages remain close to 0.978 pu for all load levels, thus a generator setpoint voltage of 0.978 pu at the POI was used for evaluation of the proposed interconnection with respect to voltage performance and deviation. Voltages and post transient voltage steps are projected in power flow simulation to remain within permissible limits during the interruption of the Q1045 generation in the Public Utility’s normal transmission configuration.

A QV analysis was performed for this configuration, and positive reactive margin is maintained.

Previously, a stability study was performed for this configuration and demonstrated satisfactory transient stability in the local area and no stability issues would be expected for the addition of this request.

<u>Case 2: Contingency Configuration (Pilot Rock fed from Buckaroo and BPA Roundup, breaker L-1123, Switch 3W191 closed, breaker L-1122 open):</u>

No restrictions, pending a stability study. A stability study will be required to determine the effects of generating into the Pendleton 69 kV loop with existing wind generation online.

Voltages and post transient voltage steps are projected in power flow simulation to remain within permissible limits during the interruption of the Q1045 generation in this contingency configuration.

A QV analysis was performed for this configuration, and positive reactive margin is maintained.

<u>Case 3: Contingency Configuration (Pendleton 69 kV loop open at Buckaroo and BPA Roundup Breaker L-1123, Pilot Rock fed from Breaker L-1122, 60 MVA transformer at Roundup offline)</u>

During this contingency, the 69 kV loop in the Pendleton area is split, and Buckaroo substation is fed radially via the two 33 MVA transformers at BPA Roundup. Public Utility's 60 MVA transformer at BPA Roundup is offline, thus the 69 kV system is weakened and voltages in the area may drop to 0.92 pu. However, even with lowered voltages, there were no identified power flow restrictions.

Voltages and post transient voltage steps are projected in power flow simulation to remain within permissible limits during the interruption of the Q1045 generation in this contingency configuration.

Previously, a stability study was performed for this configuration and demonstrated satisfactory transient stability in the local area and no stability issues would be expected for the addition of this request.

A QV analysis was performed for this configuration, and positive reactive margin is maintained.

PACIFICORP

Small Generator Interconnection
Tier 4 Facilities Study Report

Completed for
Pilot Rock Solar 2, LLC
(“Interconnection Customer”)
Q1045
Pilot Rock Solar 2
A Qualifying Facility

Proposed Interconnection
On PacifiCorp’s
Circuit 5W406 out of Pilot Rock Substation at 12.5 kV
(at approximately 45° 30' 32.67", -118° 49' 38.87")

June 30, 2020

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1.0 Description of the Project

Pilot Rock Solar 2 LLC ("Interconnection Customer") proposed interconnecting 2.99 MW of new generation to PacifiCorp's ("Public Utility") Circuit 5W406 out of Pilot Rock substation at 12.5 kV located in Umatilla County, Oregon. The Pilot Rock Solar 2 project ("Project") will consist of forty-nine (49) Sungrow SG60KU-M inverters for a total requested output of 2.99 MW. The requested commercial operation date is December 31, 2019.

Interconnection Customer will operate this generator as a Qualified Facility as defined by the Public Utility Regulatory Policies Act of 1978 (PURPA).

The Public Utility has assigned the project "Q1045."

2.0 Approval Criteria for Tier 4 Interconnection Review

Pursuant to 860-082-0060(1), a public utility must use the Tier 4 interconnection review procedures for an application to interconnect a small generator facility that meets the following requirements:

(a) The small generator facility does not qualify for or failed to meet Tier 1, Tier 2, or Tier 3 interconnection review requirements; and

(b) The small generator facility must have a nameplate capacity of ten (10) megawatts or less.

3.0 Scope of the Study

Pursuant to 860-082-0060(8) the Facilities Study Report shall consist of:

(a) A detailed scope identifying the interconnection facilities and system upgrades required to safely interconnect the small generator facility including the electrical switching configuration of the equipment, including the transformer, switchgear, meters, and other station equipment as applicable;

(b) A reasonable schedule for completion of the study;

(c) A good-faith, non-binding estimate of the costs for the facilities and upgrades, including equipment, engineering, procurement, and construction costs, and;

(d) A detailed estimate of the time required to procure, construct, and install the required interconnection facilities and system upgrades.

4.0 Proposed Point of Interconnection

. The proposed generation facility is to be interconnected to the Public Utility's distribution circuit 5W406 out of Pilot Rock substation, roughly 1,400' north of the existing facility point 01401032.0090961. The Interconnection Customer's Small Generator Facility will utilize the interconnection facilities associated with the Interconnection Request studied under queue position Q0666. Figure 1 below, is a one-line diagram that illustrates the interconnection of the proposed Small Generator Facility to the Public Utility's system.

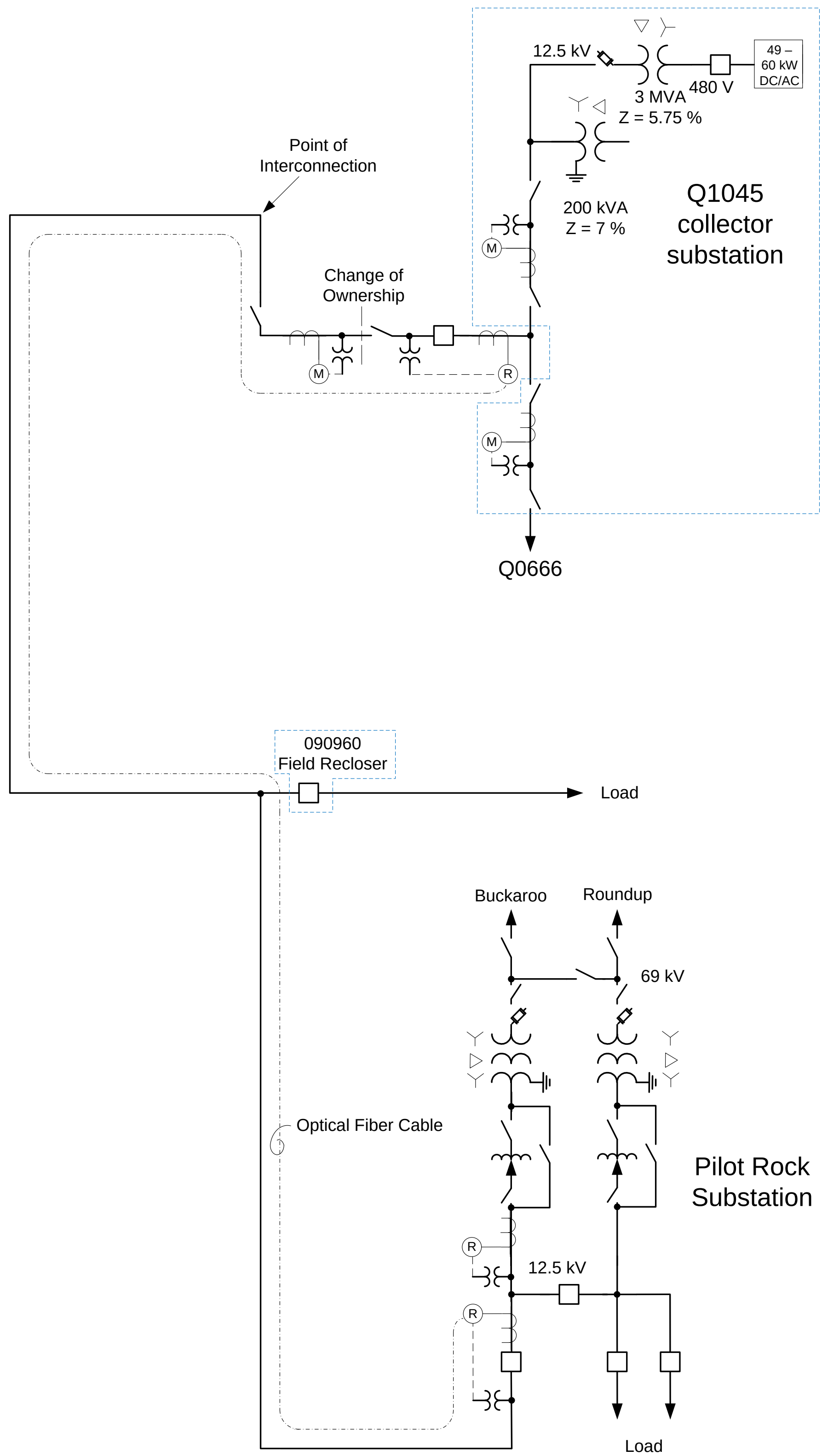

Figure 1: System One Line Diagram

5.0 Study Assumptions

- All active higher priority transmission service and/or generator interconnection requests will be considered in this study and are listed in Appendix 1. If any of these requests are withdrawn, the Public Utility reserves the right to restudy this request, as the results and conclusions contained within this study could significantly change.
- For study purposes there are two separate queues:
  - Transmission Service Queue: to the extent practical, all network upgrades that are required to accommodate active transmission service requests and are expected to be in-service on or after the Interconnection Customer's requested in-service date for the Project will be modeled in this study.
  - Generation Interconnection Queue: when relevant, interconnection facilities associated with higher queue interconnection requests will be modeled in this study. However, no generation will be simulated from any higher queued project unless a commitment has been made to obtain transmission service.
- The Interconnection Customer's request for interconnection service in and of itself does not convey transmission service.
- This study assumes the Project will be integrated into Public Utility's system at the agreed upon and/or proposed point of interconnection.
- The Interconnection Customer will construct and own the facilities required between the point of interconnection and the Project.
- Generator tripping may be required for certain outages.
- All facilities will meet or exceed the minimum WECC, NERC, and Public Utility performance and design standards.
- The Interconnection Customer's Interconnection Request will utilize interconnection facilities of higher priority Interconnection Request studied under queue position Q0666 and will also require additional equipment to be installed at the Q0666 collector substation location. The Public Utility assumes that the Interconnection Customer has the contractual right for the utilization of the Q0666 interconnection facilities and for the Public Utility to implement its requirements to the Q0666 collector substation. If that contractual right is not granted to the Interconnection Customer the requirements in this report will be significantly different which will require a restudy by the Public Utility.
- This report is based on information available at the time of the study. It is the Interconnection Customer's responsibility to check the Public Utility's web site regularly for transmission system updates (http://www.pacificorp.com/tran.html)

6.0 Requirements

6.1 Shared Q0666-Q1045 Small Generator Facility Requirements

The following outlines the design, procurement, construction, installation, and ownership of equipment at the Interconnection Customer's Small Generation Facility.

6.1.1 INTERCONNECTION CUSTOMER TO BE RESPONSIBLE FOR

- Procure all necessary permits, lands, rights of way and easements required for the construction and continued maintenance of the Q1045 Small Generator Facility and collector substation.
- Design, procure, construct, own and maintain the Interconnection Customer's Small Generator Facility and associated collector substation.
- Execute any necessary agreements (e.g. shared facilities agreement) to allow the Interconnection Customer to utilize the interconnection facilities constructed and owned by the Interconnection Customer with the rights to the Interconnection Request studied under queue position Q0666. Provide this demonstration to the Public Utility prior to the commencement of design activities.
- Design the Small Generator Facility with reactive power capabilities necessary to operate within the full power factor range of 0.95 leading to 0.95 lagging as measured at the high side of the Interconnection Customer's GSU transformer. This power factor range shall be dynamic and can be met using a combination of the inherent dynamic reactive power capability of the generator or inverter, dynamic reactive power devices and static reactive power devices to make up for losses.
- Design the Small Generator Facility such that it can provide positive reactive support (i.e., supply reactive power to the system) immediately following the removal of a fault or other transient low voltage perturbations or install dynamic voltage support equipment. These additional dynamic reactive devices shall have correct protection settings such that the devices will remain on line and active during and immediately following a fault event.
- Equip the Small Generator Facility with automatic voltage-control equipment and operate with the voltage regulation control mode enabled unless explicitly authorized to operate another control mode by the Public Utility.
- Operate the Small Generator Facility so as to maintain the voltage at the Point of Interconnection, or other designated point as deemed appropriated by Public Utility, at a voltage schedule to be provided by the Public Utility following testing.
- Operate the Small Generator Facility with a voltage droop.
- Have any Public Utility required studies, such as a voltage coordination study, performed and provide results to Public Utility. Any additional requirements identified in these studies will be the responsibility of the Interconnection Customer.
- Meet the NERC and WECC low voltage ride-through requirements as specified in the interconnection agreement.
- Provide the Public Utility a standard model from the WECC Approved Dynamic Model Library.

- Install a transformer that will hold the phase to neutral voltages within limits when the Small Generator Facility is isolated with the Public Utility's local system until the generation disconnects such as a wye-delta grounding transformer. Please note that the transformer thus far proposed by the Interconnection Customer is not acceptable to the Public Utility.
- Input the updated settings provided by the Public Utility into the Q0666 recloser relay.
- Provide the Public Utility the necessary easement to allow the Public Utility to install an enclosure for its equipment.
- Provide a separate graded and fenced area along the perimeter of the share Q0666/Q1045 collector substation for the Public Utility to install an enclosure. The enclosure shall have unencumbered access for the Transmission Provider. Fencing, gates and road access shall meet Transmission Provider standards.
- Provide permanent AC power to the Transmission Provider's enclosure.
- Design, procure and install conduit and Public Utility provided control cabling and hard wire all Q0666 and Q1045 source devices to the Public Utility's remote terminal unit ("RTU"). Provide sufficient control cable for the Public Utility to terminate inside the Public Utility enclosure.
- Interconnection Customer shall provide the following data points:
  Analogs:
    - Net Generation real power MW
    - Net Generator reactive power MVAR
    - Energy Register KWH
    - Q0666 real power MW
    - Q0666 reactive power MVAR
    - Q0666 Energy Register KWH
    - Q1045 real power MW
    - Q1045 reactive power MVAR
    - Q1045 Energy Register KWH
    - A phase 12.5 kV voltage
    - B phase 12.5 kV voltage
    - C phase 12.5 kV voltage
    - Global Horizontal Irradiance (GHI)
    - Average Plant Atmospheric Pressure (Bar)
    - Average Plant Temperature (Celsius)

  Status:
    - 12 kV Circuit Recloser
    - Max Gen MW
    - Max Gen MW FB
- Arrange for and provide permanent retail service for power that will flow from the Public Utility's system when the Q0666 and Q1045

Small Generator Facilities are not generating. This arrangement must be in place prior to approval for backfeed.

- Provide any construction or backup retail service necessary for the Project.
- Provide the Public Utility a Professional Engineer ("PE") approved maintenance plan for all Interconnection Customer facilities prior to commencement of generation activities.

6.1.2 PUBLIC UTILITY TO BE RESPONSIBLE FOR

- Develop and provide updated settings for the Q0666 recloser relay to account for the addition of the Q1045 Small Generator Facility. Observe and provide acceptance of the update.
- Procure and install a weather proof enclosure on the site prepared by the Interconnection Customer.
- Procure and install backup a DC battery system for the Public Utility enclosure.
- Install communications equipment in the collector substation enclosure including an RTU, transceivers, batteries and DC charger.
- Procure, install, own and maintain fiber optic cable from the collector substation enclosure to a splice with the fiber to be installed on the Public Utility's distribution line as part of the Q0666 project.
- Provide the Interconnection Customer control cable in sufficient quantity to allow the Interconnection Customer to tie its source devices to the Public Utility's enclosure communications equipment.
- Terminate the control cable running from the Interconnection Customer source devices in the enclosure.
- Design, procure and install within a NEMA enclosure mounted on a pole, two sets of revenue metering equipment to separate the Q0666 and Q1045 Small Generator Facilities including a metering panel, instrument transformers, primary and secondary revenue quality meters, test switches, junction boxes and secondary metering wire.
- Establish an Ethernet connection for retail sales and generation accounting via the MV-90 translation system. If Ethernet is unavailable, install a cell phone package.

6.2 OTHER

The following outlines the design, procurement, construction, installation, and ownership of equipment beyond the Point of Interconnection.

6.2.1 PUBLIC UTILITY TO BE RESPONSIBLE FOR

- Distribution Circuit
    - Procure and install one three phase bank of 219 amp 7.2 kV voltage regulators on the McKay branch.

- Procure and install one three phase bank of 100 amp 7.2 kV voltage regulators on the circuit branch west of the interconnection tap.

- Pilot Rock Substation
  - Modify the settings of the R-816 substation voltage regulator.
  - Construct a new radio system to develop a communications link with the Public Utility's Cabbage Hill communications site including radio, battery set & charger, channel bank, router and switch.

- Cabbage Hill Communications Site
  - Evaluate the existing tower for space and loading for a new antenna. If necessary, modify the tower.
  - Procure and install an antenna and supporting communications equipment to establish a communications link with the system to be installed in Pilot Rock substation.
  - Cross connect communications circuits to existing Public Utility communications systems.

- Bonneville Power Administration ("BPA")
  - Coordinate with BPA to execute any necessary agreements with BPA and the Interconnection Customer to allow BPA to modify relay settings at BPA's roundup substation required in order to mitigate system outage condition risks to the Public Utility's system.

- System Operations Centers
  - Modify databases to include the Interconnection Customer's Small Generator Facility, new interconnection facilities and system upgrades.

7.0 Cost Estimate

The following estimate represents only scopes of work that will be performed by the Public Utility. Costs for any work being performed by the Interconnection Customer or Affected Systems are not included.

Q1045 Collector substation *Install enclosures, metering and communications equipment*	$374,000
Distribution Circuit 5W406 *Install regulators*	$180,000
Pilot Rock Substation *Install communications equipment, modify regulator settings*	$250,000

Cabbage Hill Communications Site *Install communications equipment*	$72,000
System Operations Control Centers *Update databases*	$4,000
Total	**$880,000**

*Any distribution line modifications identified in this report will require a field visit analysis in order to obtain a more thorough understanding of the specific requirements. The estimate provided above for this work could change substantially based on the results of this analysis. Until this field analysis is performed the Transmission Provider must develop the project schedule using conservative assumptions. The Interconnection Customer may request that the Transmission Provider perform this field analysis, at the Interconnection Customer's expense, prior to the execution of an Interconnection Agreement in order to obtain more cost and schedule certainty.

Note: Costs for any excavation, duct installation and easements shall be borne by the Interconnection Customer and are not included in this estimate. This estimate approximates the costs incurred by the Public Utility to interconnect this Small Generator Facility to the Public Utility's electrical distribution or transmission system based upon the level of study completed to-date. The Interconnection Customer will be responsible for all actual costs, regardless of the estimated costs communicated to or approved by the Interconnection Customer.

8.0 SCHEDULE

Execute Interconnection Agreement	July 13, 2020
Interconnection Customer Financial Security Provided	July 13, 2020
Interconnection Customer Shared Facilities Agreement Provided	July 27, 2020
*Interconnection Customer Initial Design Information Provided	August 3, 2020
**Public Utility Engineering & Procurement Commences	August 24, 2020
***Energy Imbalance Market Modeling Data Submittal	September 14, 2020
Interconnection Customer Property/Permits/ROW Procured	November 2, 2020
Public Utility Property/Permits/ROW Procured	December 7, 2020
*Interconnection Customer Final Design Information Provided	December 21, 2020
Public Utility Engineering Design Complete	February 26, 2021

Public Utility Construction Commences	March 22, 2021
Interconnection Customer Maintenance Plan Provided	April 5, 2021
Public Utility and Interconnection Customer Construction Complete	May 7, 2021
Public Utility Commissioning Complete	June 4, 2021
Interconnection Customer's Facilities Receive Backfeed Power	June 8, 2021
Initial Synchronization/Generation Testing	June 14, 2021
Commercial Operation	June 21, 2021

*Interconnection Customer initial design package shall include final generating facility location, inverter/turbine selection, basic protection package, tie line route and collector system locations and data as applicable. Interconnection Customer final design package shall include PE stamped issued for construction ("IFC") drawings for generating facility, collector substation, tie line as well as electromagnetic transient ("EMT") model as applicable.

**As applicable and determined by the Public Utility, within 60 days of the Interconnection Customer's authorization for the Public Utility to begin engineering, the Interconnection Customer shall provide a detailed short circuit model of its generation system. This model must be constructed using the ASPEN OneLine short circuit simulation program and contain all individual electrical components of the Interconnection Customer's generation system.

***Any design modifications to the Interconnection Customer's Small Generating Facility after this date requiring updates to the Public Utility's network model may result in a minimum of 3 months added to all future milestones including Commercial Operation.

Please note, the time required to perform the scope of work identified in this report does not support the Interconnection Customer's requested commercial operation date of December 31, 2019.

9.0 PARTICIPATION BY AFFECTED SYSTEMS

Public Utility has identified the following Affected Systems: Bonneville Power Administration

Copies of this report will be shared with each Affected System.

10.0 APPENDICES

Appendix 1: Higher Priority Requests
Appendix 2: Contingent Facilities
Appendix 3: Property Requirements

10.1 APPENDIX 1: HIGHER PRIORITY REQUESTS

All active higher priority transmission service and/or generator interconnection requests will be considered in this study and are identified below. If any of these requests are withdrawn, the Public Utility reserves the right to restudy this request, as the results and conclusions contained within this study could significantly change.

Transmission/Generation Interconnection Queue Requests considered:

Q0547 (18 MW)
Q0666 (1.98 MW)

10.2 APPENDIX 2: CONTINGENT FACILITIES

The following Interconnection Facilities and/or upgrades to the Public Utility's system are Contingent Facilities for the Interconnection Customer's Interconnection Request and must be in service prior to the commencement of generation activities:

All interconnection facilities and system upgrades required for higher priority Interconnection Request Q0666 are Contingent Facilities for the Interconnection Customer's Interconnection Request including the following:

- Extension of approximately 0.3 miles of distribution line.
- Installation of approximately 0.9 miles of fiber optic cable.
- Installation of protective, communications and metering equipment in the Public Utility's Pilot Rock substation.
- Installation of standard Public Utility distribution interconnection package consisting of a metering equipment and switch.
- Installation of an Interconnection Customer owned recloser and relay package.

The estimated completion date of these upgrades is 2021. The estimated cost of the Public Utility's interconnection facilities and upgrades is approximately $805K. For additional details please review the system impact study for the Q0666 Interconnection Request on the Public Utility's OASIS website.

10.3 APPENDIX 3: PROPERTY REQUIREMENTS

Requirements for rights of way easements

Rights of way easements will be acquired by the Interconnection Customer in the Public Utility's name for the construction, reconstruction, operation, maintenance, repair, replacement and removal of Public Utility's Interconnection Facilities that will be owned and operated by PacifiCorp. Interconnection Customer will acquire all necessary permits for the project and will obtain rights of way easements for the project on Public Utility's easement form.

Real Property Requirements for Point of Interconnection Substation

Real property for a point of interconnection substation will be acquired by an Interconnection Customer to accommodate the Interconnection Customer's project. The real property must be acceptable to Public Utility. Interconnection Customer will acquire fee ownership for interconnection substation unless Public Utility determines that other than fee ownership is acceptable; however, the form and instrument of such rights will be at Public Utility's sole discretion. Any land rights that Interconnection Customer is planning to retain as part of a fee property conveyance will be identified in advance to Public Utility and are subject to the Public Utility's approval.

The Interconnection Customer must obtain all permits required by all relevant jurisdictions for the planned use including but not limited to conditional use permits, Certificates of Public Convenience and Necessity, California Environmental Quality Act, as well as all construction permits for the project.

Interconnection Customer will not be reimbursed through network upgrades for more than the market value of the property.

As a minimum, real property must be environmentally, physically, and operationally acceptable to Public Utility. The real property shall be a permitted or permittable use in all zoning districts. The Interconnection Customer shall provide Public Utility with a title report and shall transfer property without any material defects of title or other encumbrances that are not acceptable to Public Utility. Property lines shall be surveyed and show all encumbrances, encroachments, and roads.

Examples of potentially unacceptable environmental, physical, or operational conditions could include but are not limited to:

- Environmental: known contamination of site; evidence of environmental contamination by any dangerous, hazardous or toxic materials as defined by any governmental agency; violation of building, health, safety, environmental, fire, land use, zoning or other such regulation; violation of ordinances or statutes of any governmental entities having jurisdiction over the property; underground or above ground storage tanks in area; known remediation sites on property; ongoing mitigation activities or monitoring activities; asbestos; lead-based paint, etc. A phase I environmental study is required for land being acquired in fee by the Public Utility unless waived by Public Utility.

- Physical: inadequate site drainage; proximity to flood zone; erosion issues; wetland overlays; threatened and endangered species; archeological or culturally sensitive areas; inadequate sub-surface elements, etc. Public Utility may require Interconnection Customer to procure various studies and surveys as determined necessary by Public Utility.

- Operational: inadequate access for Public Utility's equipment and vehicles; existing structures on land that require removal prior to building of substation; ongoing maintenance for landscaping or extensive landscape requirements; ongoing homeowner's or other requirements or restrictions (e.g., Covenants, Codes and Restrictions, deed restrictions, etc.) on property which are not acceptable to the Public Utility.

PACIFICORP

Small Generator Interconnection
Tier 4 Facilities Study Report

Completed for
Pilot Rock Solar 2, LLC
(“Interconnection Customer”)
Q1045
Pilot Rock Solar 2
A Qualifying Facility

Proposed Interconnection
On PacifiCorp’s
Circuit 5W406 out of Pilot Rock Substation at 12.5 kV
(at approximately 45° 30' 32.67", -118° 49' 38.87")

September 4, 2020

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1.0 Description of the Project

Pilot Rock Solar 2 LLC ("Interconnection Customer") proposed interconnecting 2.99 MW of new generation to PacifiCorp's ("Public Utility") Circuit 5W406 out of Pilot Rock substation at 12.5 kV located in Umatilla County, Oregon. The Pilot Rock Solar 2 project ("Project") will consist of forty-nine (49) Sungrow SG60KU-M inverters for a total requested output of 2.99 MW. The requested commercial operation date is December 31, 2019.

Interconnection Customer will operate this generator as a Qualified Facility as defined by the Public Utility Regulatory Policies Act of 1978 (PURPA).

The Public Utility has assigned the project "Q1045."

2.0 Approval Criteria for Tier 4 Interconnection Review

Pursuant to 860-082-0060(1), a public utility must use the Tier 4 interconnection review procedures for an application to interconnect a small generator facility that meets the following requirements:

(a) The small generator facility does not qualify for or failed to meet Tier 1, Tier 2, or Tier 3 interconnection review requirements; and
(b) The small generator facility must have a nameplate capacity of ten (10) megawatts or less.

3.0 Scope of the Study

Pursuant to 860-082-0060(8) the Facilities Study Report shall consist of:

(a) A detailed scope identifying the interconnection facilities and system upgrades required to safely interconnect the small generator facility including the electrical switching configuration of the equipment, including the transformer, switchgear, meters, and other station equipment as applicable;
(b) A reasonable schedule for completion of the study;
(c) A good-faith, non-binding estimate of the costs for the facilities and upgrades, including equipment, engineering, procurement, and construction costs, and;
(d) A detailed estimate of the time required to procure, construct, and install the required interconnection facilities and system upgrades.

4.0 Proposed Point of Interconnection

. The proposed generation facility is to be interconnected to the Public Utility's distribution circuit 5W406 out of Pilot Rock substation, roughly 1,400' north of the existing facility point 01401032.0090961. The Interconnection Customer's Small Generator Facility will utilize the interconnection facilities associated with the Interconnection Request studied under queue position Q0666. Figure 1 below, is a one-line diagram that illustrates the interconnection of the proposed Small Generator Facility to the Public Utility's system.

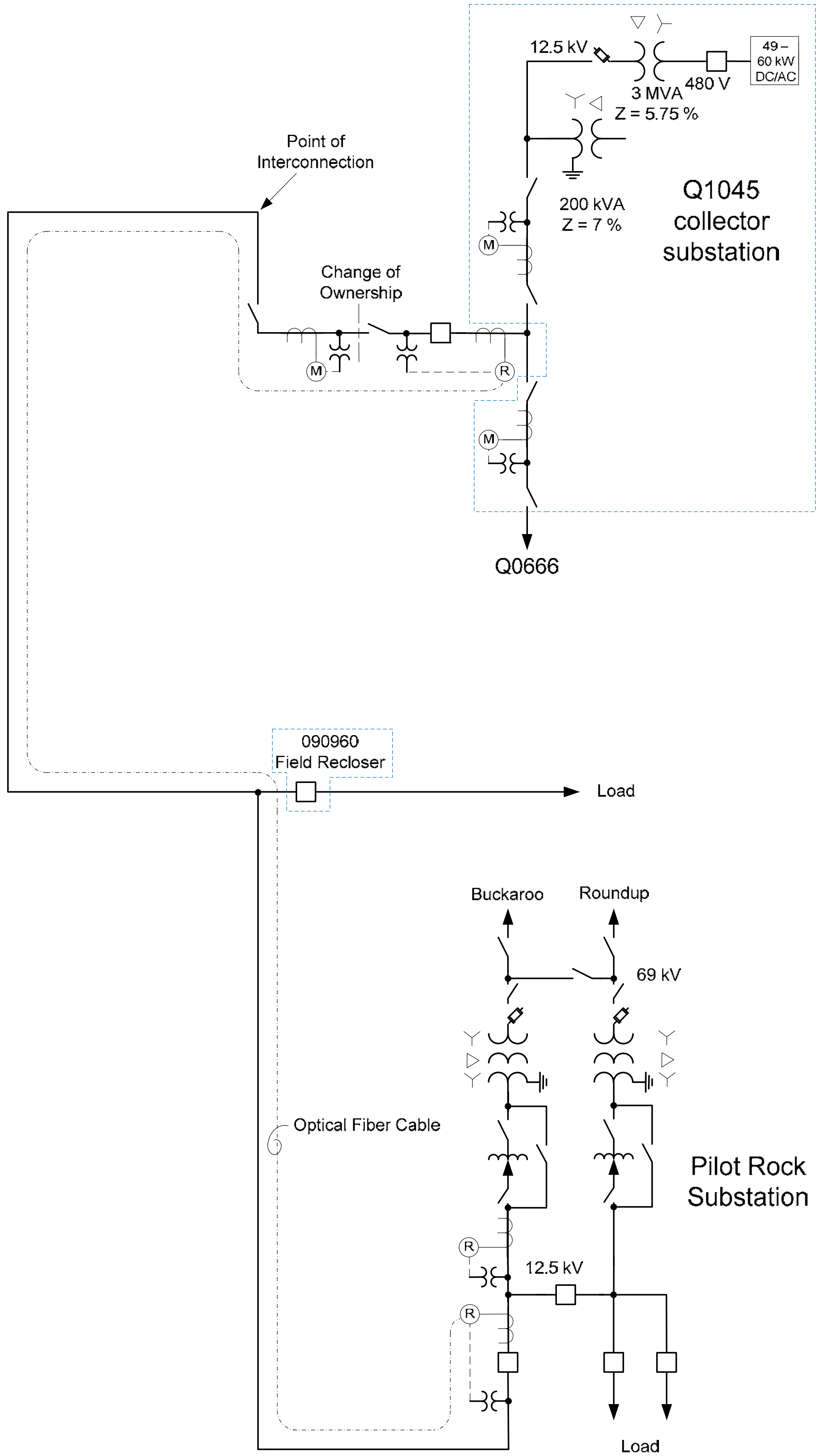

Figure 1: System One Line Diagram

5.0 Study Assumptions

- All active higher priority transmission service and/or generator interconnection requests will be considered in this study and are listed in Appendix 1. If any of these requests are withdrawn, the Public Utility reserves the right to restudy this request, as the results and conclusions contained within this study could significantly change.
- For study purposes there are two separate queues:
  - Transmission Service Queue: to the extent practical, all network upgrades that are required to accommodate active transmission service requests and are expected to be in-service on or after the Interconnection Customer's requested in-service date for the Project will be modeled in this study.
  - Generation Interconnection Queue: when relevant, interconnection facilities associated with higher queue interconnection requests will be modeled in this study. However, no generation will be simulated from any higher queued project unless a commitment has been made to obtain transmission service.
- The Interconnection Customer's request for interconnection service in and of itself does not convey transmission service.
- This study assumes the Project will be integrated into Public Utility's system at the agreed upon and/or proposed point of interconnection.
- The Interconnection Customer will construct and own the facilities required between the point of interconnection and the Project.
- Generator tripping may be required for certain outages.
- All facilities will meet or exceed the minimum WECC, NERC, and Public Utility performance and design standards.
- The Interconnection Customer's Interconnection Request will utilize interconnection facilities of higher priority Interconnection Request studied under queue position Q0666 and will also require additional equipment to be installed at the Q0666 collector substation location. The Public Utility assumes that the Interconnection Customer has the contractual right for the utilization of the Q0666 interconnection facilities and for the Public Utility to implement its requirements to the Q0666 collector substation. If that contractual right is not granted to the Interconnection Customer the requirements in this report will be significantly different which will require a restudy by the Public Utility.
- This report is based on information available at the time of the study. It is the Interconnection Customer's responsibility to check the Public Utility's web site regularly for transmission system updates (http://www.pacificorp.com/tran.html)

6.0 Requirements

6.1 Shared Q0666-Q1045 Small Generator Facility Requirements

The following outlines the design, procurement, construction, installation, and ownership of equipment at the Interconnection Customer's Small Generation Facility.

6.1.1 Interconnection Customer to be Responsible For

- Procure all necessary permits, lands, rights of way and easements required for the construction and continued maintenance of the Q1045 Small Generator Facility and collector substation.
- Design, procure, construct, own and maintain the Interconnection Customer's Small Generator Facility and associated collector substation.
- Execute any necessary agreements (e.g. shared facilities agreement) to allow the Interconnection Customer to utilize the interconnection facilities constructed and owned by the Interconnection Customer with the rights to the Interconnection Request studied under queue position Q0666. Provide this demonstration to the Public Utility prior to the commencement of design activities.
- Design the Small Generator Facility with reactive power capabilities necessary to operate within the full power factor range of 0.95 leading to 0.95 lagging as measured at the high side of the Interconnection Customer's GSU transformer. This power factor range shall be dynamic and can be met using a combination of the inherent dynamic reactive power capability of the generator or inverter, dynamic reactive power devices and static reactive power devices to make up for losses.
- Design the Small Generator Facility such that it can provide positive reactive support (i.e., supply reactive power to the system) immediately following the removal of a fault or other transient low voltage perturbations or install dynamic voltage support equipment. These additional dynamic reactive devices shall have correct protection settings such that the devices will remain on line and active during and immediately following a fault event.
- Equip the Small Generator Facility with automatic voltage-control equipment and operate with the voltage regulation control mode enabled unless explicitly authorized to operate another control mode by the Public Utility.
- Operate the Small Generator Facility so as to maintain the voltage at the Point of Interconnection, or other designated point as deemed appropriated by Public Utility, at a voltage schedule to be provided by the Public Utility following testing.
- Operate the Small Generator Facility with a voltage droop.
- Have any Public Utility required studies, such as a voltage coordination study, performed and provide results to Public Utility. Any additional requirements identified in these studies will be the responsibility of the Interconnection Customer.
- Meet the NERC and WECC low voltage ride-through requirements as specified in the interconnection agreement.
- Provide the Public Utility a standard model from the WECC Approved Dynamic Model Library.

- Install a transformer that will hold the phase to neutral voltages within limits when the Small Generator Facility is isolated with the Public Utility's local system until the generation disconnects such as a wye-delta grounding transformer. Please note that the transformer thus far proposed by the Interconnection Customer is not acceptable to the Public Utility.
- Input the updated settings provided by the Public Utility into the Q0666 recloser relay.
- Provide the Public Utility the necessary easement to allow the Public Utility to install an enclosure for its equipment.
- Provide a separate graded and fenced area along the perimeter of the share Q0666/Q1045 collector substation for the Public Utility to install an enclosure. The enclosure shall have unencumbered access for the Transmission Provider. Fencing, gates and road access shall meet Transmission Provider standards.
- Provide permanent AC power to the Transmission Provider's enclosure.
- Design, procure and install conduit and Public Utility provided control cabling and hard wire all Q0666 and Q1045 source devices to the Public Utility's remote terminal unit ("RTU"). Provide sufficient control cable for the Public Utility to terminate inside the Public Utility enclosure.
- Interconnection Customer shall provide the following data points:
  <u>Analogs:</u>
    - Net Generation real power MW
    - Net Generator reactive power MVAR
    - Energy Register KWH
    - Q0666 real power MW
    - Q0666 reactive power MVAR
    - Q0666 Energy Register KWH
    - Q1045 real power MW
    - Q1045 reactive power MVAR
    - Q1045 Energy Register KWH
    - A phase 12.5 kV voltage
    - B phase 12.5 kV voltage
    - C phase 12.5 kV voltage
    - Global Horizontal Irradiance (GHI)
    - Average Plant Atmospheric Pressure (Bar)
    - Average Plant Temperature (Celsius)

  <u>Status:</u>
    - 12 kV Circuit Recloser
    - Max Gen MW
    - Max Gen MW FB
- Arrange for and provide permanent retail service for power that will flow from the Public Utility's system when the Q0666 and Q1045

Small Generator Facilities are not generating. This arrangement must be in place prior to approval for backfeed.

- Provide any construction or backup retail service necessary for the Project.
- Provide the Public Utility a Professional Engineer ("PE") approved maintenance plan for all Interconnection Customer facilities prior to commencement of generation activities.

6.1.2 PUBLIC UTILITY TO BE RESPONSIBLE FOR

- Develop and provide updated settings for the Q0666 recloser relay to account for the addition of the Q1045 Small Generator Facility. Observe and provide acceptance of the update.
- Procure and install, at the Public Utility's expense, a weather proof enclosure on the site prepared by the Interconnection Customer.
- Provide the Interconnection Customer control cable in sufficient quantity to allow the Interconnection Customer to tie its source devices to the Public Utility's enclosure communications equipment.
- Terminate the control cable running from the Interconnection Customer source devices in the enclosure.
- Design, procure and install within a NEMA enclosure mounted on a pole, two sets of revenue metering equipment to separate the Q0666 and Q1045 Small Generator Facilities including a metering panel, instrument transformers, primary and secondary revenue quality meters, test switches, junction boxes and secondary metering wire.
- Establish an Ethernet connection for retail sales and generation accounting via the MV-90 translation system. If Ethernet is unavailable, install a cell phone package.

6.2 OTHER

The following outlines the design, procurement, construction, installation, and ownership of equipment beyond the Point of Interconnection.

6.2.1 PUBLIC UTILITY TO BE RESPONSIBLE FOR

- Distribution Circuit
  - Procure and install one three phase bank of 219 amp 7.2 kV voltage regulators on the McKay branch.
  - Procure and install one three phase bank of 100 amp 7.2 kV voltage regulators on the circuit branch west of the interconnection tap.

- Pilot Rock Substation
  - Modify the settings of the R-816 substation voltage regulator.

- Bonneville Power Administration ("BPA")

- Coordinate with BPA to execute any necessary agreements with BPA and the Interconnection Customer to allow BPA to modify relay settings at BPA's roundup substation required in order to mitigate system outage condition risks to the Public Utility's system.

7.0 Cost Estimate

The following estimate represents only scopes of work that will be performed by the Public Utility. Costs for any work being performed by the Interconnection Customer or Affected Systems are not included.

Q1045 Collector substation *Metering equipment*	$102,000
Distribution Circuit 5W406 *Install regulators*	$184,000
Pilot Rock Substation *Modify regulator settings*	$16,000
Total	**$302,000**

*Any distribution line modifications identified in this report will require a field visit analysis in order to obtain a more thorough understanding of the specific requirements. The estimate provided above for this work could change substantially based on the results of this analysis. Until this field analysis is performed the Transmission Provider must develop the project schedule using conservative assumptions. The Interconnection Customer may request that the Transmission Provider perform this field analysis, at the Interconnection Customer's expense, prior to the execution of an Interconnection Agreement in order to obtain more cost and schedule certainty.

Note: Costs for any excavation, duct installation and easements shall be borne by the Interconnection Customer and are not included in this estimate. This estimate approximates the costs incurred by the Public Utility to interconnect this Small Generator Facility to the Public Utility's electrical distribution or transmission system based upon the level of study completed to-date. The Interconnection Customer will be responsible for all actual costs, regardless of the estimated costs communicated to or approved by the Interconnection Customer.

8.0 Schedule

Execute Interconnection Agreement	October 9, 2020
Interconnection Customer Financial Security Provided	October 9, 2020
Interconnection Customer Shared Facilities Agreement Provided	October 23, 2020
*Interconnection Customer Initial Design Information Provided	November 2, 2020

**Public Utility Engineering & Procurement Commences	August 24, 2020
Interconnection Customer Property/Permits/ROW Procured	January 8, 2021
Public Utility Property/Permits/ROW Procured	February 12, 2021
*Interconnection Customer Final Design Information Provided	February 26, 2021
Public Utility Engineering Design Complete	April 30, 2021
Public Utility Construction Commences	June 21, 2021
Interconnection Customer Maintenance Plan Provided	July 2, 2021
Public Utility and Interconnection Customer Construction Complete	August 27, 2021
Public Utility Commissioning Complete	September 24, 2021
Interconnection Customer's Facilities Receive Backfeed Power	October 4, 2021
Initial Synchronization/Generation Testing	October 11, 2021
Commercial Operation	October 18, 2021

*Interconnection Customer initial design package shall include final generating facility location, inverter/turbine selection, basic protection package, tie line route and collector system locations and data as applicable. Interconnection Customer final design package shall include PE stamped issued for construction ("IFC") drawings for generating facility, collector substation, tie line as well as electromagnetic transient ("EMT") model as applicable.

**As applicable and determined by the Public Utility, within 60 days of the Interconnection Customer's authorization for the Public Utility to begin engineering, the Interconnection Customer shall provide a detailed short circuit model of its generation system. This model must be constructed using the ASPEN OneLine short circuit simulation program and contain all individual electrical components of the Interconnection Customer's generation system.

Please note, the time required to perform the scope of work identified in this report does not support the Interconnection Customer's requested commercial operation date of December 31, 2019.

9.0 PARTICIPATION BY AFFECTED SYSTEMS

Public Utility has identified the following Affected Systems: Bonneville Power Administration

Copies of this report will be shared with each Affected System.

10.0 APPENDICES

Appendix 1: Higher Priority Requests
Appendix 2: Contingent Facilities
Appendix 3: Property Requirements

10.1 Appendix 1: Higher Priority Requests

All active higher priority transmission service and/or generator interconnection requests will be considered in this study and are identified below. If any of these requests are withdrawn, the Public Utility reserves the right to restudy this request, as the results and conclusions contained within this study could significantly change.

Transmission/Generation Interconnection Queue Requests considered:

Q0547 (18 MW)
Q0666 (1.98 MW)

10.2 Appendix 2: Contingent Facilities

The following Interconnection Facilities and/or upgrades to the Public Utility's system are Contingent Facilities for the Interconnection Customer's Interconnection Request and must be in service prior to the commencement of generation activities:

All interconnection facilities and system upgrades required for higher priority Interconnection Request Q0666 are Contingent Facilities for the Interconnection Customer's Interconnection Request including the following:

- Extension of approximately 0.3 miles of distribution line.
- Installation of approximately 0.9 miles of fiber optic cable.
- Installation of protective, communications and metering equipment in the Public Utility's Pilot Rock substation.
- Installation of standard Public Utility distribution interconnection package consisting of a metering equipment and switch.
- Installation of an Interconnection Customer owned recloser and relay package.

The estimated completion date of these upgrades is 2021. The estimated cost of the Public Utility's interconnection facilities and upgrades is approximately $805K. For additional details please review the system impact study for the Q0666 Interconnection Request on the Public Utility's OASIS website.

10.3 APPENDIX 3: PROPERTY REQUIREMENTS

Requirements for rights of way easements

Rights of way easements will be acquired by the Interconnection Customer in the Public Utility's name for the construction, reconstruction, operation, maintenance, repair, replacement and removal of Public Utility's Interconnection Facilities that will be owned and operated by PacifiCorp. Interconnection Customer will acquire all necessary permits for the project and will obtain rights of way easements for the project on Public Utility's easement form.

Real Property Requirements for Point of Interconnection Substation

Real property for a point of interconnection substation will be acquired by an Interconnection Customer to accommodate the Interconnection Customer's project. The real property must be acceptable to Public Utility. Interconnection Customer will acquire fee ownership for interconnection substation unless Public Utility determines that other than fee ownership is acceptable; however, the form and instrument of such rights will be at Public Utility's sole discretion. Any land rights that Interconnection Customer is planning to retain as part of a fee property conveyance will be identified in advance to Public Utility and are subject to the Public Utility's approval.

The Interconnection Customer must obtain all permits required by all relevant jurisdictions for the planned use including but not limited to conditional use permits, Certificates of Public Convenience and Necessity, California Environmental Quality Act, as well as all construction permits for the project.

Interconnection Customer will not be reimbursed through network upgrades for more than the market value of the property.

As a minimum, real property must be environmentally, physically, and operationally acceptable to Public Utility. The real property shall be a permitted or permittable use in all zoning districts. The Interconnection Customer shall provide Public Utility with a title report and shall transfer property without any material defects of title or other encumbrances that are not acceptable to Public Utility. Property lines shall be surveyed and show all encumbrances, encroachments, and roads.

Examples of potentially unacceptable environmental, physical, or operational conditions could include but are not limited to:

- Environmental: known contamination of site; evidence of environmental contamination by any dangerous, hazardous or toxic materials as defined by any governmental agency; violation of building, health, safety, environmental, fire, land use, zoning or other such regulation; violation of ordinances or statutes of any governmental entities having jurisdiction over the property; underground or above ground storage tanks in area; known remediation sites on property; ongoing mitigation activities or monitoring activities; asbestos; lead-based paint, etc. A phase I environmental study is required for land being acquired in fee by the Public Utility unless waived by Public Utility.

- Physical: inadequate site drainage; proximity to flood zone; erosion issues; wetland overlays; threatened and endangered species; archeological or culturally sensitive areas; inadequate sub-surface elements, etc. Public Utility may require Interconnection Customer to procure various studies and surveys as determined necessary by Public Utility.

- Operational: inadequate access for Public Utility's equipment and vehicles; existing structures on land that require removal prior to building of substation; ongoing maintenance for landscaping or extensive landscape requirements; ongoing homeowner's or other requirements or restrictions (e.g., Covenants, Codes and Restrictions, deed restrictions, etc.) on property which are not acceptable to the Public Utility.

CASE: UM 2118--SUNTHURST V. PACIFICORP
SUNTHURST WITNESS: MICHAEL BEANLAND

PUBLIC UTILITY COMMISSION
OF
OREGON

SUNTHURST EXHIBIT 208

Q0666 Interconnection Agreements:

March 11, 2016 Interconnection Agreement

September 4, 2020 Agreement to Amend Interconnection Agreement for Small Generator Facility

DECEMBER 16, 2020

PACIFICORP

Form 8

Interconnection Agreement for Small Generator Facility
Tier 1, Tier 2, Tier 3 or Tier 4 Interconnection
(Small Generator Facilities with Electric Nameplate Capacities of 10MW or less)

This Interconnection Agreement for Small Generator Facility ("Agreement") is made and entered into this 14th day of MARCH, 2016 by and between Sunthurst Energy, LLC (Pilot Rock, Q0666), a Limited Liability Company organized and existing under the laws of the State of Oregon, ("Interconnection Customer") and PacifiCorp, a Corporation, existing under the laws of the State of Oregon, ("Public Utility"). The Interconnection Customer and Public Utility may be referred to hereinafter singly as a "Party" or collectively as the "Parties."

Recitals:

Whereas, the Interconnection Customer is proposing to develop a Small Generator Facility, or to add generating capacity to an existing Small Generator Facility, consistent with the Application completed on May 7, 2015;

Whereas, the Interconnection Customer desires to interconnect the Small Generator Facility with Public Utility's Transmission System and/or Distribution System ("T&D System") in the State of Oregon; and

Whereas, the interconnection of the Small Generator Facility and the Public Utility's T&D System is subject to the jurisdiction of the Public Utility Commission of Oregon ("Commission") and governed by OPUC Rule OAR 860, Division 082 (the "Rule").

Now, therefore, in consideration of and subject to the mutual covenants contained herein, the Parties agree as follows:

Article 1. Scope and Limitations of Agreement

1.1 Scope
This Agreement establishes the standard terms and conditions under which the Small Generator Facility with a Nameplate Capacity of no more than 10 megawatts ("MW") will interconnect to, and operate in Parallel with, the Public Utility's T&D System. The Commission has approved standard terms and conditions governing this class of interconnection. Any additions, deletions or changes to the standard terms and conditions of interconnection approved by the Commission must be mutually agreed by the Parties or, if required by the Rule, any such changes must be approved by the Commission. Terms with initial capitalization, when used in this Agreement, shall have the meanings given in the Rule. This Agreement shall be construed where possible to be consistent with the Rules; to the extent this Agreement conflicts with the Rule, the Rule shall take precedence.

1.2 No Agreement Regarding Power Purchase, Transmission, or Delivery
This Agreement does not constitute an agreement to purchase, transmit, or deliver any power or capacity from the interconnected Small Generating Facility nor does it constitute

an electric service agreement.

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1.3 Other Agreements
Nothing in this Agreement is intended to affect any other agreement between the Public Utility and the Interconnection Customer or any other interconnected entity. If the provisions of this Agreement conflict with the provisions of any other Public Utility tariff, the Public Utility tariff shall control.

1.4 Responsibilities of the Parties

1.4.1 The Parties shall perform all obligations of this Agreement in accordance with all applicable laws.

1.4.2 The Interconnection Customer will construct, own, operate, and maintain its Small Generator Facility in accordance with this Agreement, IEEE Standard 1547 (2003 ed), IEEE Standard 1547.1 (2005 ed), the National Electrical Code (2005 ed) and applicable standards required by the Commission.

1.4.3 Each Party shall be responsible for the safe installation, maintenance, repair and condition of their respective lines and appurtenances on their respective sides of the Point of Interconnection. Each Party shall provide Interconnection Facilities that adequately protect the other Parties' facilities, personnel, and other persons from damage and injury. The allocation of responsibility for the design, installation, operation, maintenance and ownership of Interconnection Facilities is prescribed in the Rule and this Agreement and the attachments to this Agreement.

1.5 Parallel Operation and Maintenance Obligations
Once the Small Generator Facility has been authorized to commence Parallel Operation by execution of this Agreement and satisfaction of Article 2.1 of this Agreement, the Interconnection Customer will abide by all written provisions for operating and maintenance as required by this Agreement and any attachments to this Agreement as well as by the Rule and as detailed by the Public Utility in Form 7, title "Interconnection Equipment As-Built Specifications, Initial Settings and Operating Requirements".

1.6 Metering & Monitoring
The Interconnection Customer will be responsible for metering and monitoring as required by OAR 860-082-0070 and as may be detailed in any attachments to this Agreement.

1.7 Power Quality
The Interconnection Customer will design its Small Generator Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection that meets the requirements set forth in IEEE 1547. The Public Utility may, in some

PACIFICORP

MAR 1 1

Form 8

Interconnection Agreement for Small Generator Facility
Tier 1, Tier 2, Tier 3 or Tier 4 Interconnection
(Small Generator Facilities with Electric Nameplate Capacities of 10MW or less)

circumstances, also require the Interconnection Customer to follow voltage or VAR schedules used by similarly situated, comparable generators in the control area. Any special operating requirements will be detailed in Form 7 and completed by the Public Utility as required by the Rule. The Public Utility shall not impose additional requirements for voltage or reactive power support outside of what may be required to mitigate impacts caused by interconnection of the Small Generator Facility to the Public Utility's system.

Article 2. **Inspection, Testing, Authorization, and Right of Access**

2.1 Equipment Testing and Inspection

The Interconnection Customer will test and inspect its Small Generator Facility and Interconnection Facilities prior to interconnection in accordance with IEEE 1547 Standards as provided for in the Rule. The Interconnection will not be final and the Small Generator Facility shall not be authorized to operate in parallel with the Public Utility's T&D System until the Witness Test and Certificate of Completion provisions in the Rule have been satisfied. The Interconnection Customer shall pay or reimburse the Public Utility for its costs to participate in the Witness Test. Operation of the Small Generator Facility requires an effective Interconnection Agreement; electricity sales require a Power Purchase Agreement.

To the extent that the Interconnection Customer decides to conduct interim testing of the Small Generator Facility prior to the Witness Test, it may request that the Public Utility observe these tests. If the Public Utility agrees to send qualified personnel to observe any interim testing proposed by the Interconnection Customer, the Interconnection Customer shall pay or reimburse the Public Utility for its cost to participate in the interim testing. If the Interconnection Customer conducts interim testing and such testing is observed by the Public Utility and the results of such interim testing are deemed acceptable by the Public Utility (hereinafter a "Public Utility-approved interim test"), then the Interconnection Customer may request that such Public Utility-approved interim test be deleted from the final Witness Testing. If the Public Utility elects to repeat any Public Utility-approved interim test as part of the final Witness Test, the Public Utility will bare its own expenses associated with participation in the repeated Public Utility-approved interim test.

2.2 Right of Access:

As provided in OAR 860-082-0030(5), the Public Utility will have access to the Interconnection Customer's premises for any reasonable purpose in connection with the Interconnection Application or any Interconnection Agreement that is entered in to pursuant to the Rule or if necessary to meet the legal obligation to provide service to its customers. Access will be requested at reasonable hours and upon reasonable notice, or at any time without notice in the event of an emergency or hazardous condition.

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Form 8

Interconnection Agreement for Small Generator Facility
Tier 1, Tier 2, Tier 3 or Tier 4 Interconnection
(Small Generator Facilities with Electric Nameplate Capacities of 10MW or less)

Article 3. Effective Date, Term, Termination, and Disconnection

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3.1 Effective Date
The Agreement shall become effective upon execution by the Parties.

3.2 Term of Agreement
The Agreement will be effective on the Effective Date and will remain in effect for a period of twenty (20) years or the life of the Power Purchase agreement, whichever is shorter or a period mutually agreed to by the Parties, unless terminated earlier by the default or voluntary termination by the Interconnection Customer or by action of the Commission.

3.3 Termination
No termination will become effective until the Parties have complied with all provisions of OAR 860-082-0080 and this Agreement that apply to such termination.

3.3.1 The Interconnection Customer may terminate this Agreement at any time by giving the Public Utility twenty (20) Business Days written notice.

3.3.2 Either Party may terminate this Agreement after default pursuant to Article 5.6 of this Agreement.

3.3.3 The Commission may order termination of this Agreement.

3.3.4 Upon termination of this Agreement, the Small Generator Facility will be disconnected from the Public Utility's T&D System at the Interconnection Customer's expense. The termination of this Agreement will not relieve either Party of its liabilities and obligations, owed or continuing at the time of the termination.

3.3.4 The provisions of this Article 3.3 shall survive termination or expiration of this Agreement.

3.4 Temporary Disconnection
The Public Utility or Interconnection Customer may temporarily disconnect the Small Generator Facility from the Public Utility's T&D System for so long as reasonably necessary, as provided in OAR 860-082-0075 of the Rule, in the event one or more of the following conditions or events occurs:

3.4.1 Under emergency conditions, the Public Utility or the Interconnection Customer may immediately suspend interconnection service and temporarily disconnect the Small Generator Facility without advance notice to the other Party. The Public Utility shall notify the Interconnection Customer promptly when it becomes aware of an emergency condition that may reasonably be expected to affect the Small Generator Facility operation. The Interconnection Customer will notify the Public Utility promptly when it becomes aware of an emergency condition that may reasonably be expected to affect the Public Utility's T&D System. To the extent information is known, the notification shall describe the emergency condition, the extent of the damage or deficiency, the expected effect on the operation of both Parties' facilities and operations, its anticipated duration, and the necessary corrective action.

3.4.2 For routine Maintenance, Parties will make reasonable efforts to provide five Business Days notice prior to interruption caused by routine maintenance or construction and repair to the Small Generator Facility or Public Utility's T&D system and shall use reasonable efforts to coordinate such interruption.

3.4.3 The Public Utility shall use reasonable efforts to provide the Interconnection Customer with prior notice of forced outages of the T&D System. If prior notice is not given, the Public Utility shall, upon request, provide the Interconnection Customer written documentation after the fact explaining the circumstances of the disconnection.

3.4.4 For disruption or deterioration of service, where the Public Utility determines that operation of the Small Generator Facility will likely cause disruption or deterioration of service to other customers served from the same electric system, or if operating the Small Generator Facility could cause damage to the Public Utility's T&D System, the Public Utility may disconnect the Small Generator Facility. The Public Utility will provide the Interconnection Customer upon request all supporting documentation used to reach the decision to disconnect. The Public Utility may disconnect the Small Generator Facility if, after receipt of the notice, the Interconnection Customer fails to remedy the adverse operating effect within a reasonable time which shall be at least five Business Days from the date the Interconnection Customer receives the Public Utility's written notice supporting the decision to disconnect, unless emergency conditions exist, in which case the provisions of 3.4.1 of the agreement apply.

3.4.5 If the Interconnection Customer makes any change to the Small Generating Facility, the Interconnection Equipment, the Interconnection Facilities, or to any other aspect of the interconnection, other than Minor Equipment Modifications, without prior written authorization of the Public Utility, the Public Utility will have the right to disconnect the Small Generator Facility until such time as the impact of the change has been studied by the Public Utility and any reasonable requirements or additional equipment or facilities required by the Public Utility to address any impacts from the changes have been implemented by the Parties and approved in writing by the Public Utility. The requirement to apply to the Public Utility for study and approve of modifications is governed by OAR 860-082-0005 (b).

3.5 Restoration of interconnection:
The Parties shall cooperate with each other to restore the Small Generator Facility, Interconnection Facilities, and Public Utility's T&D System to their normal operating state as soon as reasonably practicable following any disconnection pursuant to Article 3.4.

<u>Article 4.</u> Cost Responsibility and Billing:
As provided in OAR 860-082-0035, the Interconnection Customer is responsible for the cost of all facilities, equipment, modifications and upgrades needed to facilitate the interconnection of the Small Generator Facility to the Public Utility's T&D System.

4.1 Minor T&D System Modifications:
As provided in the Rule addressing Tier 2 review (OAR 860-082-0050) and in the Rule addressing Tier 3 review (OAR 860-082-0055), it may be necessary for the Parties to construct certain Minor Modifications in order to interconnect under Tier 2 or Tier 3 review. The Public Utility has itemize any required Minor Modifications in the attachments to this Agreement, including a good-faith estimate of the cost of such Minor Modifications and the time required to build and install such Minor Modifications. The Interconnection Customer agrees to pay the costs of such Minor Modifications.

4.2 Interconnection Facilities:
The Public Utility has identified under the review procedures of a Tier 2 review or under a Tier 4 Facilities Study, the Interconnection Facilities necessary to safely interconnect the Small Generator Facility with the Public Utility. The Public Utility has itemized the required Interconnection Facilities in the attachments to this Agreement, including a good-faith estimate of the cost of the facilities and the time required to build and install those facilities. The Interconnection Customer is responsible for the cost of the Interconnection Facilities.

4.3 Interconnection Equipment:
The Interconnection Customer is responsible for all reasonable expenses, including overheads, associated with owning, operating, maintaining, repairing, and replacing its Interconnection Equipment.

4.4 System Upgrades:
The Public Utility will design, procure, construct, install, and own any System Upgrades. The actual cost of the System Upgrades, including overheads, will be directly assigned to the Interconnection Customer. An Interconnection Customer may be entitled to financial compensation from other Public Utility Interconnection Customers who, in the future, benefit from the System Upgrades paid for by the Interconnection Customer. Such compensation will be governed by separate rules promulgated by the Commission or by

terms of a tariff filed and approved by the Commission. Such compensation will only be available to the extent provided for in the separate rules or tariff.

4.5 Adverse System Impact:
The Public Utility is responsible for identifying the possible Affected Systems and coordinating with those identified Affected Systems, to the extent reasonably practicable, to allow the Affected System owner an opportunity to identify Adverse System Impacts on its Affected System, and to identify what mitigation activities or upgrades may be required on the Public Utility's system or on the Affected System to address impacts on Affected Systems and accommodate a Small Generator Facility. Such coordination with Affected System owners shall include inviting Affected System owners to scoping meetings between the Public Utility and the Interconnection Customer and providing the Affected System owner with study results and other information reasonably required and requested by the Affected System owner to allow the Affected System owner to assess impacts to its system and determine required mitigation, if any, for such impacts. The Parties acknowledge that the Public Utility cannot compel the participation of the Affected System owner and that the Public Utility is not itself responsible for identifying impacts or mitigation associated with an Affected System. The actual cost of any actions taken to address the Adverse System Impacts, including overheads, shall be directly assigned to the Interconnection Customer. The Interconnection Customer may be entitled to financial compensation from other Public Utilities or other Interconnection Customers who, in the future, utilize the upgrades paid for by the Interconnection Customer, to the extent allowed or required by the Commission. Such compensation will only be available to the extent provided for in the separate rules, Commission order or tariff. If the Parties have actual knowledge of an Adverse System Impact on an Affected System, the Interconnection Customer shall not interconnect and operate its Small Generator Facility in parallel with the Public Utility's system, and the Public Utility shall not authorize or allow the continued interconnection or parallel operation of the Small Generator Facility, unless and until such Adverse System Impact has been addressed to the reasonable satisfaction of the Affected System owner.

4.6 Deposit and Billings:
The Interconnection Customer agrees to pay to the Public Utility a deposit toward the cost to construct and install any required Interconnection Facilities and/or System Upgrades. The amount of the deposit shall be (select one of the following):

☐ The Parties have not agreed to a schedule of progress payments and the Interconnection Customer shall pay a deposit equal to 100 percent of the estimated cost of the Interconnection Facilities and System Upgrades – the amount of the deposit shall be $805,000; or

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☒ The Parties have agreed to progress payments and final payment under the schedule of payments attached to this Agreement; the Interconnection Customer shall pay a deposit equal to the lesser of (a) 25 percent of the estimated cost of the Interconnection Facilities and System Upgrades, or (b) $10,000 – the amount of the deposit shall be $10,000.

If the actual costs of Interconnection Facilities and/or System Upgrades are different than the deposit amounts and/or progress and final payments provided for above, then the Interconnection Customer shall pay the Public Utility any balance owing or the Public Utility shall refund any excess deposit or progress payment within 20 days of the date actual costs are determined

Article 5. Assignment, Liability, Indemnity, Force Majeure, Consequential Damages, and Default

5.1 Assignment
The Interconnection Agreement may be assigned by either Party upon fifteen (15) Business Days prior written notice. Except as provided in Articles 5.1.1 and 5.1.2, said assignment shall only be valid upon the prior written consent of the non-assigning Party, which consent shall not be unreasonably withheld.

5.1.1 Either Party may assign the Agreement without the consent of the other Party to any affiliate (which shall include a merger of the Party with another entity), of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Agreement;

5.1.2 The Interconnection Customer shall have the right to assign the Agreement, without the consent of the Public Utility, for collateral security purposes to aid in providing financing for the Small Generator Facility. For Small Generator systems that are integrated into a building facility, the sale of the building or property will result in an automatic transfer of this agreement to the new owner who shall be responsible for complying with the terms and conditions of this Agreement.

5.1.3 Any attempted assignment that violates this Article is void and ineffective. Assignment shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. An assignee is responsible for meeting the same obligations as the assigning Interconnection Customer.

5.2 Limitation of Liability and Consequential Damages
A Party is liable for any loss, cost claim, injury, or expense including reasonable attorney's fees related to or arising from any act or omission in its performance of the provisions of

this Agreement entered into pursuant to the Rule except as provided for in ORS 757.300(4)(c). Neither Party will seek redress from the other Party in an amount greater than the amount of direct damage actually incurred.

5.3 Indemnity

5.3.1 Liability under this Article 5.3 is exempt from the general limitations on liability found in Article 5.2.

5.3.2 The Parties shall at all times indemnify, defend, and hold the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's action or failure to meet its obligations under this Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

5.3.3 If an indemnified person is entitled to indemnification under this Article 5.3 as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under this Article 5.3, to assume the defense of such a claim, such indemnified person may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

5.3.4 If an indemnifying party is obligated to indemnify and hold any indemnified person harmless under this Article 5.3, the amount owing to the indemnified person shall be the amount of such indemnified person's actual loss, net of any insurance or other recovery.

5.3.5 Promptly after receipt by an indemnified person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in this Article 5.3 may apply, the indemnified person shall notify the indemnifying party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying party.

5.3.6 The indemnifying Party shall have the right to assume the defense thereof with counsel designated by such indemnifying Party and reasonably satisfactory to the indemnified person. If the defendants in any such action include one or more indemnified persons and the indemnifying Party and if the indemnified person reasonably concludes that there may be legal defenses available to it and/or other indemnified persons which are different from or additional to those available to the indemnifying Party, the indemnified person shall have the right to select separate counsel to assert such legal defenses and to otherwise participate in the defense of such action on its own behalf. In such instances, the indemnifying Party shall only be required to pay the fees and expenses of one additional attorney to represent an indemnified person or indemnified persons having such differing or additional legal defenses.

5.3.7 The indemnified person shall be entitled, at its expense, to participate in any such action, suit or proceeding, the defense of which has been assumed by the indemnifying Party. Notwithstanding the foregoing, the indemnifying Party (i) shall not be entitled to assume and control the defense of any such action, suit or proceedings if and to the extent that, in the opinion of the indemnified person and its counsel, such action, suit or proceeding involves the potential imposition of criminal liability on the indemnified person, or there exists a conflict or adversity of interest between the indemnified person and the indemnifying Party, in such event the indemnifying Party shall pay the reasonable expenses of the indemnified person, and (ii) shall not settle or consent to the entry of any judgment in any action, suit or proceeding without the consent of the indemnified person, which shall not be reasonably withheld, conditioned or delayed.

5.4 Consequential Damages

Neither Party shall be liable to the other Party, under any provision of this Agreement, for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to the other Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

5.5 Force Majeure

5.5.1 As used in this Agreement, a Force Majeure Event shall mean "any act of God, labor disturbance, act of the public enemy, war, acts of terrorism, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment through no direct, indirect, or contributory act of a Party, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure Event does not include an act of negligence or intentional wrongdoing."

5.5.2 If a Force Majeure Event prevents a Party from fulfilling any obligations under this Agreement, the Party affected by the Force Majeure Event (Affected Party) shall promptly notify the other Party of the existence of the Force Majeure Event. The notification must specify in reasonable detail the circumstances of the Force Majeure Event, its expected duration, and the steps that the Affected Party is taking to mitigate the effects of the event on its performance, and if the initial notification was verbal, it should be promptly followed up with a written notification. The Affected Party shall keep the other Party informed on a continuing basis of developments relating to the Force Majeure Event. Until the Force Majeure Event ends the Affected Party will be entitled to suspend or modify its performance of obligations under this Agreement (other than the obligation to make payments) only to the extent that the effect of the Force Majeure Event cannot be reasonably mitigated. The Affected Party will use reasonable efforts to resume its performance as soon as possible. The Parties shall immediately report to the Commission should a Force Majeure Event prevent performance of an action required by the Rule that the Rule does not permit the Parties to mutually waive.

5.6 Default

5.6.1 No default shall exist where such failure to discharge an obligation (other than the payment of money) is the result of a Force Majeure Event as defined in this Agreement, or the result of an act or omission of the other Party. Upon a breach, the non-breaching Party shall give written notice of such breach to the breaching Party. Except as provided in Article 5.6.2, the breaching Party shall have sixty (60) Calendar Days from receipt of the beach notice within which to cure such breach; provided however, if such breach is not capable of cure within 60 Calendar Days, the breaching Party shall commence such cure within twenty (20) Calendar Days after notice and continuously and diligently complete such cure within six months from receipt of the breach notice; and, if cured within such time, the breach specified in such notice shall cease to exist.

5.6.2 If a breach is not cured as provided for in this Article 5.6, or if a breach is not capable of being cured within the period provided for herein, the non-breaching Party shall have the right to declare a default and terminate this Agreement by written notice at any time until cure occurs, and be relieved of any further obligation hereunder and, whether or not that Party terminates this Agreement, to recover from the breaching Party all amounts due hereunder, plus all other damages and remedies to which it is entitled at law or in equity. Alternatively, the non-breaching Party shall have the right to seek dispute resolution with the Commission in lieu of default. The provisions of this Article 5.6 will survive termination of the Agreement.

Article 6. Insurance

Interconnection Agreement for Small Generator Facility
Tier 1, Tier 2, Tier 3 or Tier 4 Interconnection
(Small Generator Facilities with Electric Nameplate Capacities of 10MW or less)

6.1 Pursuant to the Rule adopted by the Commission, the Public Utility may not require the Interconnection Customer to maintain general liability insurance in relation to the interconnection of a Small Generator Facility with an Electric Nameplate Capacity of 200 KW or less. With regard to the interconnection of a Small Generator Facility with an Electric Nameplate Capacity equal to or less than 10 MW but in excess of 200 KW, the Interconnection Customer shall, at its own expense, maintain in force throughout the period of this Agreement general liability insurance sufficient to protect any person (including the Public Utility) who may be affected by the Interconnection Customer's Small Generation Facility and its operation and such insurance shall be sufficient to satisfy the Interconnection Customer's indemnification responsibilities under Article 5.3 of this Agreement.

6.2 Within ten (10) days following execution of this Agreement, and as soon as practicable after the end of each fiscal year or at the renewal of the insurance policy and in any event within ninety (90) days thereafter, the Interconnection Customer shall provide the Public Utility with certification of all insurance required in this Agreement, executed by each insurer or by an authorized representative of each insurer.

6.3 All insurance required by this Article 6 shall name the Public, its parent, associated and Affiliate companies and their respective directors, officers, agents, servants and employees ("Other Party Group") as additional insured. All policies shall contain provisions whereby the insurers waive all rights of subrogation against the Other Party Group and provide thirty (30) Calendar Days advance written notice to the Other Party Group prior to anniversary date of cancellation or any material change in coverage or condition. The Interconnection Customer's insurance shall contain provisions that specify that the policies are primary and shall apply to such extent without consideration for other policies separately carried and shall state that each insured is provided coverage as though a separate policy had been issued to each, except the insurer's liability shall not be increased beyond the amount for which the insurer would have been liable had only one insured been covered. The insurance policies, if written on a Claims First Made Basis, shall be maintained in full force and effect for two (2) years after termination of this Agreement, which coverage may be in the form of tail coverage or extended reporting period coverage if agreed by the Parties.

6.4 The Parties agree to report to each other in writing as soon as practical all accidents or occurrences resulting in injuries to any person, including death, and any property damage arising out of this Agreement.

6.5 The requirements contained herein as to insurance are not intended to and shall not in any manner, limit or qualify the liabilities and obligations assumed by the Parties under this Agreement.

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Interconnection Agreement for Small Generator Facility
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Article 7. Dispute Resolution

Parties will adhere to the dispute resolution provisions in OAR 860-082-0080.

Article 8. Miscellaneous

8.1 Governing Law, Regulatory Authority, and Rules

The validity, interpretation and enforcement of the Agreement and each of its provisions shall be governed by the laws of the State of Oregon, without regard to its conflicts of law principles. The Agreement is subject to all applicable laws. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a governmental authority.

8.2 Amendment

The Parties may mutually agree to amend the Agreement by a written instrument duly executed by both Parties in accordance with provisions of the Rule and applicable Commission Orders and provisions of the laws if the State of Oregon.

8.3 No Third-Party Beneficiaries

The Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and where permitted, their assigns.

8.4 Waiver

8.4.1 The failure of a Party to the Agreement to insist, on any occasion, upon strict performance of any provision of the Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

8.4.2 The Parties may agree to mutually waive a section of this Agreement so long as prior Commission approval of the waiver is not required by the Rule.

8.4.3 Any waiver at any time by either Party of its rights with respect to the Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of the Agreement. Any waiver of the Agreement shall, if requested, be provided in writing.

8.5 Entire Agreement

This Agreement, including any supplementary Form attachments that may be necessary, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of the Agreement. There are no other agreements, representations, warranties, or covenants that constitute any part of the consideration for, or any condition to, either Party's compliance with its obligations under this Agreement.

8.6 Multiple Counterparts
This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

8.7 No Partnership
This Agreement will not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

8.8 Severability
If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other governmental authority; (1) such portion or provision shall be deemed separate and independent; (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling; and (3) the remainder of this Agreement shall remain in full force and effect.

8.9 Subcontractors
Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor, or designating a third party agent as one responsible for a specific obligation or act required in this Agreement (collectively subcontractors), as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party will require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party will remain primarily liable to the other Party for the performance of such subcontractor.

8.9.1 The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Party for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made. Any applicable obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and will be construed as having application to, any subcontractor of such Party.

8.9.2 The obligations under this Article 8.9 will not be limited in any way by any limitation of subcontractor's insurance.

8.10 Reservation of Rights

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Either Party will have the right to make a unilateral filing with the Commission to modify this Agreement. This reservation of rights provision will includes but is not limited to modifications with respect to any rates terms and conditions, charges, classification of service, rule or regulation under tariff rates or any applicable State or Federal law or regulation. Each Party shall have the right to protest any such filing and to participate fully in any proceeding before the Commission in which such modifications may be considered.

Article 9. **Notices and Records**

9.1 General
Unless otherwise provided in this Agreement, any written notice, demand, or request required or authorized in connection with this Agreement shall be deemed properly given if delivered in person, delivered by recognized national courier service, or sent by first class mail, postage prepaid, to the person specified below:

9.2 Records
The Public Utility will maintain a record of all Interconnection Agreements and related Form attachments for as long as the interconnection is in place as required by OAR 860-082-0065. The Public Utility will provide a copy of these records to the Interconnection Customer within 15 Business Days if a request is made in writing.

If to the Interconnection Customer:
Interconnection Customer: Sunthurst Energy, LLC
Attention: Daniel Hale
Address: 153 Lowell Ave
City: Glendora State: California Zip: 91741
Phone: 310-975-4732 Fax: 323-782-0760

If to Public Utility:
Public Utility: PacifiCorp
Attention: Transmission Service
Address: 825 NE Multnomah, Suite 550
City: Portland State: Oregon Zip: 97232
Phone: 503-813-6077 Fax: 503-813-6893

9.3 Billing and Payment
Billings and payments shall be sent to the addresses set out below: (complete if different than article 9.2 above)

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If to the Interconnection Customer
Interconnection Customer: PILOT ROCK SOLAR 1 LLC
Attention: DANIEL HALE
Address: 43682 SW BROWER LANE
City: PENDLETON State: OR Zip: 97801

If to Public Utility
Public Utility: PacifiCorp Transmission
Attention: Central Cashiers Office
Address: P.O. Box 2757
City: Portland State: OR Zip: 97208-2757

9.4 Designated Operating Representative
The Parties will designate operating representatives to conduct the communications which may be necessary or convenient for the administration of the operations provisions of this Agreement. This person will also serve as the point of contact with respect to operations and maintenance of the Party's facilities (complete if different than article 9.2 above)

Interconnection Customer's Operating Representative: SUNTHURST ENERGY, LLC
Attention: DANIEL HALE
Address: 153 LOWELL AVENUE
City: GLENDORA State: CA Zip: 91741
Phone: 310.975.4732 Fax: 323.782.0760 E-Mail daniel@SUNTHURSTENERGY.COM

Public Utility's Operating Representative: PacifiCorp
Attention: Grid Operations
Address: 9915 S.E. Ankeny Street
City: Portland State: OR Zip: 97216
Phone: 503-251-5197 Fax: 503-251-5228

9.5 Changes to the Notice Information
Either Party may change this notice information by giving five Business Days written notice prior to the effective date of the change.

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(Small Generator Facilities with Electric Nameplate Capacities of 10MW or less)

Article 10. Signatures

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their respective duly authorized representatives.

For Public Utility:

Name: [signature]

Title: VP, Transmission

Date: 3/14/16

For the Interconnection Customer:

Name: D Hal

Title: OWNER/PRINCIPAL

Date: 3/9/16

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Attachment 1

**Description of Interconnection Facilities
And Metering Equipment Operated or Maintained by the Public Utility**

Small Generating Facility: A 1.98 MW solar generating facility consisting of thirty-three (33) SMA MLX-60 60 kW inverters, connected to one (1) generation step up transformer (3 MVA, 5.75%), and one (1) 150 kVA grounding bank with an impedance of 5.75%, connected to Public Utility's Distribution System in Umatilla County, Oregon. See Attachment 2.

Interconnection Customer Interconnection Facilities: A short, 12.5 kV tie connecting the step-up transformer to the Interconnection Customer owned recloser and relay. Interconnection Customer will also own a gang-operated disconnect switch that Public Utility can access. See Attachment 2.

Public Utility's Interconnection Facilities: A short run of distribution circuit connected to a 12.5 kV disconnect switch, bi-directional revenue metering facilities and fiber optic cable equipment necessary for transfer-trip between the Small Generating Facility and Pilot Rock substation. See Attachment 2.

Estimated cost of Public Utility's Interconnection Facilities directly assigned to Interconnection Customer: $203,000

Estimated Annual Operation and Maintenance Cost of Public Utility's Interconnection Facilities: $1,500. Interconnection Customer shall be responsible for Public Utility's actual cost for maintenance of the Public Utility's Interconnection Facilities.

Point of Interconnection: The point where the Public Utility's Interconnection Facilities connect to the Public Utility's 12.5 kV distribution circuit 5W406 out of Pilot Rock substation. See Attachment 2.

Point of Change of Ownership: The point where the Interconnection Customer's Interconnection Facilities connect to the Public Utility's Interconnection Facilities. See Attachment 2.

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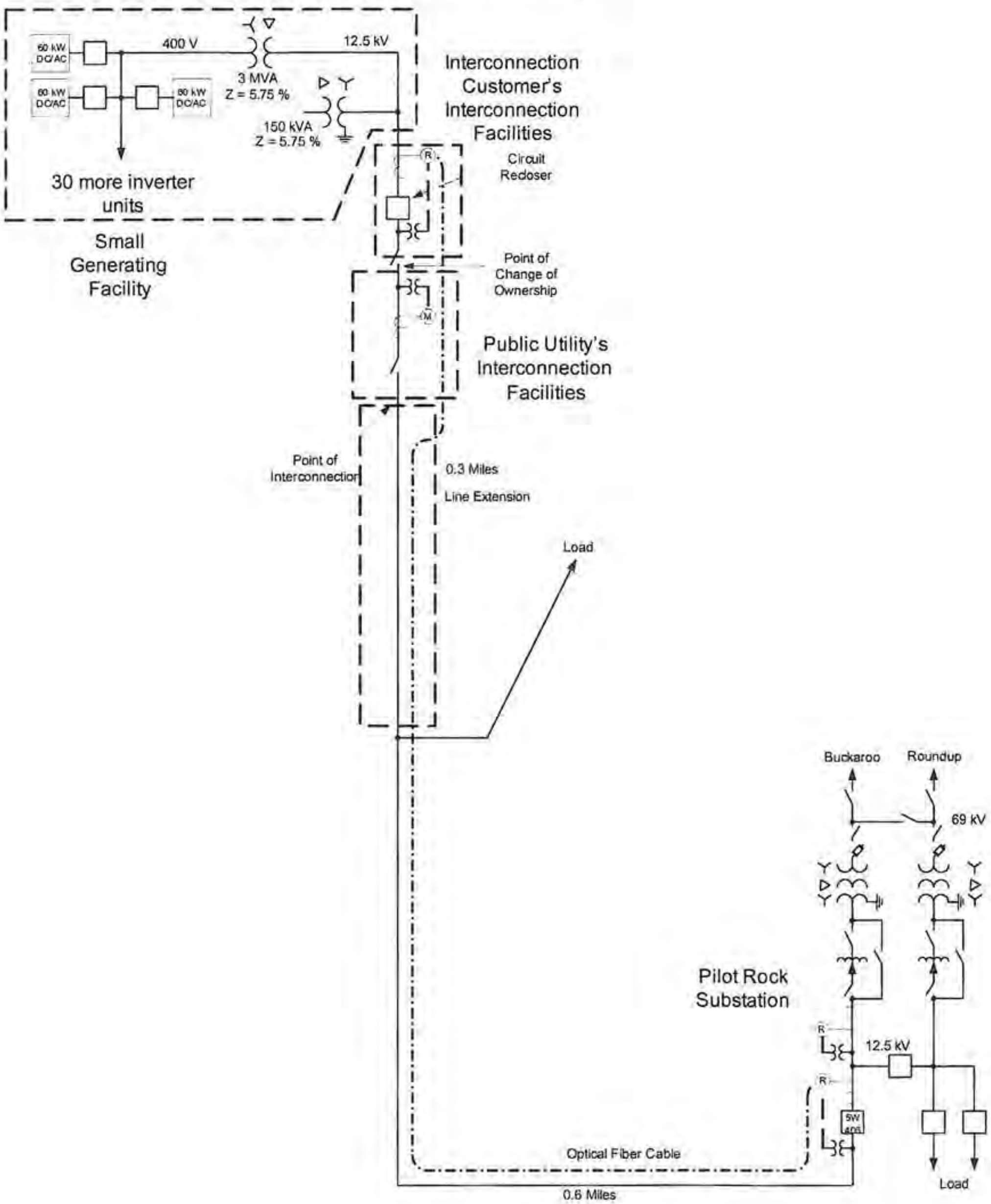
Attachment 2

One-line Diagram Depicting the Generating Facility, Interconnection Facilities, Metering Equipment, and Upgrades



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Attachment 3

Milestones

Estimated In-Service Date: May 15, 2017

Critical milestones and responsibility as agreed to by the Parties:

	Milestone/Date	Responsible Party
(1)	Execute Agreement and Provide Financial Security / March 15, 2016	Interconnection Customer
(2)	Provide All Required Design Information / May 15, 2016	Interconnection Customer
(3)	Begin Engineering Design / July 15, 2016	Public Utility
(4)	Obtain Property Rights / July 15, 2016	Interconnection Customer
(5)	Complete Engineering Design / December 20, 2016	Public Utility
(6)	Begin Construction / February 18, 2017	Public Utility
(7)	Provide Policy 138 required Test Plan / March 1, 2017	Interconnection Customer
(8)	Complete Construction & Backfeed / April 15, 2017	Both
(9)	Complete Testing & First Synch / May 1, 2017	Both
(10)	Commercial Operations / May 15, 2017	Both

Interconnection Customer is to request Backfeed, 1st Sync, and Commercial Operations in writing (email acceptable) prior to the above dates. Public Utility is to approve Interconnection Customer requests without unreasonable delay. The Interconnection Customer will be required to demonstrate the reactive

capability of the Small Generating Facility and the voltage control system prior to Commercial Operations.

* Any design modifications to the Interconnection Customer's Small Generating Facility after this date requiring updates to the Public Utility's network model will result in a minimum of 3 months added to all future milestones including Commercial Operation.

**The Public Utility cannot guarantee the availability of a mobile transformer. As such, any delay in the arrival of the mobile transformer could result in delay of the remaining milestones including Commercial Operation.

Payment Schedule

If Interconnection Customer elects the progress payments option under Article 4.6 of the Interconnection Agreement, there are two potential options for a payment schedule below (please select one). If Interconnection Customer elects progress payment option but an option below is not selected, the Levelized Option will be selected by default. Failure to comply with the selected payment schedule will result in immediate contractual breach, work stoppage, and slip of the milestone schedule above on a day-for-day basis. Interconnection Customer will still be responsible for all costs of the project. Public Utility will conduct initial accounting for the project within thirty (30) days of granting Commercial Operations approval and will determine if a partial refund of project costs is acceptable.

Please select an option:	☐	☐
Funds due no later than	Levelized Option	Stepped Option
March 15, 2016 (or when Interconnection Agreement is executed)	$10,000	$10,000
June 1, 2016	$198,750	$79,500
August 1, 2016	$198,750	$159,000
October 1, 2016	$198,750	$238,500
January 1, 2017	$198,750	$318,000

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Interconnection Agreement for Small Generator Facility
Tier 1, Tier 2, Tier 3 or Tier 4 Interconnection
(Small Generator Facilities with Electric Nameplate Capacities of 10MW or less)

Attachment 4

Additional Operating Requirements for the Public Utility's Transmission System and/or Distribution System and Affected Systems Needed to Support the Interconnection Customer's Needs

The interconnection of the Small Generator Facility is subject to the rules contained within OAR 860 division 82. The interconnection of the Small Generator Facility to the Public Utility's Distribution System shall be subject to, and the Interconnection Customer shall operate the Small Generating Facility in accordance with, the Public Utility's policies governing interconnection of generation facilities to the distribution system entitled "Facility Connection (Interconnection) Requirements for Distribution Systems (34.5 kV and below)" which policy document is available upon request from the Public Utility and is incorporated by this reference as part of the Interconnection Agreement between the Parties. The interconnection of the Small Generator Facility to the Public Utility's Transmission System shall be subject to, and the Interconnection Customer shall operate the Small Generating Facility in accordance with, the Public Utility's policies governing interconnection of generation facilities to the transmission system entitled "Facility Connection (Interconnection) Requirements for Transmission Systems (46 kV and above)" which policy document is available upon request from the Public Utility and is incorporated by this reference as part of the Interconnection Agreement between the Parties. In the event of a conflict between any aspect of this Attachment 4 (including without limitation the Public Utility's policies governing interconnection of generation facilities to the distribution system or the transmission system) and the rules contained in OAR 860, division 82, the rules shall prevail.

<u>Parallel Operation.</u> Interconnection Customer may operate the Generating Facility in parallel with the Public Utility's Transmission System or Distribution System (collectively the "T&D System"), but subject at all times to any operating instructions that the Public Utility's dispatch operators may issue and in accordance with all the provisions of this Interconnection Agreement and Good Utility Practice, and any other conditions imposed by the Public Utility in its sole discretion.

<u>Generating Facility Operation Shall Not Adversely Affect the Public Utility's T&D System.</u> Interconnection Customer shall operate the Generating Facility in such a manner as not to adversely affect the Public Utility's T&D System or any other element of the Public Utility's electrical system. Interconnection Customer's Generating Facility shall deliver not more than the Design Capacity of 1,980 kW. Except as otherwise required by this Interconnection Agreement, Interconnection Customer shall operate the Generating Facility in a manner compatible with the Public Utility's applicable voltage level and fluctuating voltage guidelines, entitled Facility Connection (Interconnection) Requirements for Distribution Systems (34.5 kV and below), as it may be amended or superseded from time to time in the Public Utility's reasonable discretion, at the Point of Interconnection during all times that the Generating Facility is connected and operating in parallel with the Public Utility's T&D System. In its sole discretion, the Public Utility may specify rates of change in Interconnection Customer's deliveries to the Public Utility's T&D System during any start-up of the Generating Facility, during reconnection to the

Public Utility's T&D System, and during normal operations to assure that such rates of change are compatible with the operation of the Public Utility's voltage regulation equipment.

Maximum Authorized Power Flow. The Generating Facility shall not be operated in a manner that results in the flow of electric power onto the Public Utility's T&D System during any fifteen (15) minute interval at levels in excess of 2,080 kVA from the Generating Facility. If this provision is violated, the Public Utility may terminate this Interconnection Agreement or lock the Interconnection Customer Disconnect Switch in the open position until such time as: (a) the Public Utility has studied the impact of additional generation on the T&D System (at Interconnection Customer's cost and pursuant to a new study agreement between the Public Utility and Interconnection Customer) and the interconnection has been upgraded (at Interconnection Customer's cost and pursuant to a new or amended Facilities Construction Agreement and a new or amended Interconnection Agreement if deemed necessary by the Public Utility) in any manner necessary to accommodate the additional generation; or (b) the Interconnection Customer has modified the Generating Facility or Interconnection Customer's Interconnection Facilities in such manner as to insure to the Public Utility's satisfaction that the Generating Facility will no longer cause electric power to flow onto the Public Utility's T&D System at a level in excess of 2,080 kVA.

Harmonic Distortion or Voltage Flicker. Notwithstanding the Study Results, upon notice from the Public Utility that operation of the Generating Facility is producing unacceptable harmonic distortions or voltage flicker on the Public Utility's T&D System, Interconnection Customer shall at its sole cost remedy such harmonic distortions or voltage flicker within a reasonable time.

Reactive Power. Interconnection Customer shall at all times control the flow of reactive power between the Generating Facility and the Public Utility's T&D System within limits established by the Public Utility. The Public Utility shall not be obligated to pay Interconnection Customer for any Kvar or Kvar Hours flowing into the Public Utility's T&D System.

Islanding. If at any time during the term of this Interconnection Agreement the interconnection of the Generating Facility to the Public Utility's T&D System results in a risk of electrical islanding, or actual occurrences of electrical islanding, which the Public Utility reasonably concludes are incompatible with Good Utility Practice, the Parties shall (as necessary) study the issue and implement a solution that will eliminate or mitigate the risk of electrical islanding to a level deemed acceptable by the Public Utility. All costs associated with addressing any electrical islanding problems as required by this paragraph shall be paid by the Interconnection Customer, including without limitation any study costs, engineering costs, design costs, or costs to procure, install, operate and/or maintain required interconnection facilities or protective devices.

Voltage Regulation. The Interconnection Customer agrees to operate at a ± 95% leading or lagging power factor. Prior to installation, Interconnection Customer shall provide the Public Utility with written notice of the device and/or operational constrains selected to satisfy this requirement and shall obtain the Public Utility's written approval of such device and/or operational constraints, which approval shall not be unreasonably withheld. In the event Interconnection Customer fails to operate the Generating Facility within the voltage regulation constraints of this requirement, the Public Utility may disconnect the Generating Facility.

Modification of Nominal Operating Voltage Level. By providing Interconnection Customer with a one hundred and eighty (180) day notice, the Public Utility may at its sole discretion change the Public Utility's nominal operating voltage level at the Point of Interconnection. In the event of such change in voltage level Interconnection Customer shall, at Interconnection Customer's sole expense, modify Interconnection Customer's Interconnection Facilities as necessary to accommodate the modified nominal operating voltage level. Interconnection Customer has been informed that initial use of a dual voltage Interconnection Customer may ameliorate the cost of accommodating a change in nominal operating voltage level.

Equipment Failure. Interconnection Customer acknowledges that it is responsible for repair or replacement of Interconnection Customer's primary transformer and for any and all other components of the Generating Facility and the Interconnection Customer's Interconnection Facilities. Interconnection Customer is aware that it's inability to timely repair or replace its transformer or any other component of the Generating Facility or Interconnection Customer's Interconnection Facility could result in Interconnection Customer's inability to comply with its responsibilities under this Interconnection Agreement and could lead to disconnection of the Generating Facility from the Public Utility's T&D System and/or termination of this Interconnection Agreement pursuant to the terms of this Interconnection Agreement. Interconnection Customer acknowledges that the risk of this result is born solely by Interconnection Customer and may be substantially ameliorated by Interconnection Customer's elective maintenance of adequate reserve or spare components including but not limited to the Interconnection Customer's primary transformer.

Operation and Maintenance of Facilities Not Owned by the Public Utility. Interconnection Customer shall maintain, test, repair, keep accounts current on, or provide for the proper operation of any and all interconnection facilities, including but not limited to telemetry and communication equipment, not owned by the Public Utility.

Metering and Telemetry Communications Equipment. Notwithstanding any language of OAR 860-082-0070, Public Utility shall not require Interconnection Customer to install a redundant or back-up meter or other telemetry communications equipment. However, Public Utility reserves the right to request that the Oregon Public Utility Commission authorize Public Utility to require Interconnection Customer to be responsible for all reasonable costs associated with redundant metering and communications equipment installed at the Small Generating Facility, upon a determination by Public Utility that such equipment is necessary to maintain compliance with the mandatory reliability standards enforced by the North American Electric Reliability Corporation and the Western Electricity Coordinating Council.

Property Language. Interconnection Customer is required to obtain for the benefit of Public Utility at Interconnection Customer's sole cost and expense all real property rights, including but not limited to fee ownership, easements and/or rights of way, as applicable, for Public Utility owned Facilities using Public

Utility's standard forms. Public Utility shall not be obligated to accept any such real property right that does not, at Public Utility's sole discretion, confer sufficient rights to access, operate, construct, modify, maintain, place and remove Public Utility owned Facilities or is otherwise not conveyed using Public Utility's standard forms. Further, all real property on which Public Utility's Facilities are to be located must be environmentally, physically and operationally acceptable to the Public Utility at its sole discretion. Interconnection Customer is responsible for obtaining all permits required by all relevant jurisdictions for the project, including but not limited to, conditional use permits and construction permits; provided however, Public Utility shall obtain, at Interconnection Customer's cost and schedule risk, the permits necessary to construct Public Utility's Facilities that are to be located on real property currently owned or held in fee or right by Public Utility. Except as expressly waived in writing by an authorized officer of Public Utility, all of the foregoing permits and real property rights (conferring rights on real property that is environmentally, physically and operationally acceptable to Public Utility) shall be acquired as provided herein as a condition to Public Utility's contractual obligation to construct or take possession of facilities to be owned by the Public Utility under this Agreement. Public Utility shall have no liability for any project delays or cost overruns caused by delays in acquiring any of the foregoing permits and/or real property rights, whether such delay results from the failure to obtain such permits or rights or the failure of such permits or rights to meet the requirements set forth herein. Further, any completion dates, if any, set forth herein with regard to Public Utility's obligations shall be equitably extended based on the length and impact of any such delays.

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Attachment 5

Public Utility' s Description of its Upgrades and Best Estimate of Upgrade Costs

Distribution Upgrades: Extend Circuit 5W406 by approximately .3 miles. Install approximately .9 miles of fiber optic cable. Add VTs and circuit metering and modify communications and protection scheme at Pilot Rock substation. Estimated cost is $602,000.

Network Upgrades: The following locations will require the Network Upgrades described below:
- No upgrades

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Attachment 6

Scope of Work

GENERATING FACILITY MODIFICATIONS

At the Small Generating Facility, a relay will need to be installed that will monitor the voltage magnitude and frequency. If the magnitude or frequency of the voltage is outside of the normal range of operation, the relay will need to disconnect the Small Generating Facility. It is our recommendation that a SEL 351 type relay be installed for this purpose. This relay has six pickup levels with different time delays for both the frequency and magnitude of the voltage to make the relay sensitive to small diversions from nominal but with adequate time delay and also fast reacting for extreme diversions.

The Public Utility will procure, install, test, and own all revenue metering equipment. It is expected the revenue metering instrument transformers will be installed overhead on a pole at the Point of Interconnection. The meter instrument transformer mounting shall conform to Public Utility's construction standards.

The metering will be bidirectional to measure KWH and KVARH quantities for both the generation received and the retail load delivered. The Interconnection Customer may request output from the Public Utility's revenue meters.

Communication equipment will be required to remotely interrogate the meter for generation and billing data via Public Utility's MV90 data acquisition system.

INTERCONNECTION CUSTOMER WILL BE RESPONSIBLE FOR THE FOLLOWING:

- Design, procure, install, and own an SEL 351 type relay to monitor the voltage and frequency of the Small Generating Facility.
- Provide professional engineer ("PE") signed and stamped drawings for Interconnection Customer's Small Generating Facility to Public Utility to allow development of required relay settings.
- Install and own a recloser for the Public Utility's SEL 2829 optical transceiver.

PUBLIC UTILITY WILL BE RESPONSIBLE FOR THE FOLLOWING:

- Design and communicate to the Interconnection Customer the settings to be programmed into the SEL 351 type relay.
- Own the revenue class instrument transformers required for the interconnection of the Small Generating Facility.
- Procure, install, and own two (2) meters are required for retail load Customer Net Gen reverse feed.
- Own the revenue class instrument transformers required for the interconnection of the Small Generating Facility.
- Design, procure, install, and own of Ethernet (preferred) or a cell phone to be designed as part

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of the meter and utilized to allow for remote interrogation of the Small Generating Facility.

- Design, procure, install, and own one (1) metering panel.
- Design, procure, install, and own of the required meter, test switches and secondary meter wire needed to interconnect the Small Generating Facility.
- Design, procure, install, and own the required meter, test switches and secondary meter wire needed to interconnect the Small Generating Facility.
- Design, procure and install all required communication fiber patch panel, fiber modem, and related communication equipment needed to connect to new 48-fiber, single mode, ADSS cable and to Interconnection Customer's recloser/equipment.

DISTRIBUTION LINE REQUIREMENTS

The following outlines the design, procurement, installation, and ownership of equipment for the distribution line.

INTERCONNECTION CUSTOMER WILL BE RESPONSIBLE FOR THE FOLLOWING:

- Obtain required right of way for newly required tap line from City Feeder to Small Generating Facility.

PUBLIC UTILITY WILL BE RESPONSIBLE FOR THE FOLLOWING:

- Design, install, and own 0.3 miles of 4/0 AAC primary conductors and one 4/0AAC neutral conductor from the Point of Interconnection (proposed facility point #090961) to the Point of Change of Ownership.
- Design, install, and own a gang operated switch and primary metering units.
- Procure and install one (1) span of overhead primary conductors from the primary metering pole to Interconnection Customer's pole. The termination of this conductor at the Small Generating Facility will serve as the Point of Change of Ownership.
- Replace the tap changing controller on R-816 with a controller capable of handling reverse power flow.
- Design, procure, install, and own new 48-fiber, single mode, ADSS cable from Small Generating Facility to Pilot Rock substation.

PILOT ROCK SUBSTATION

The following outlines the design, procurement, installation, testing and ownership of equipment for Public Utility's Distribution Circuit.

PUBLIC UTILITY WILL BE RESPONSIBLE FOR THE FOLLOWING:

- Procure, install, and own three (3) 12.5 kV VT's.
- Design, procure, and install required steel support structures and associated foundations for all new equipment if required.
- Design, procure, and install a one (1) new PC-611 panel.
- Design, procure, and install a one (1) new PI111 annunciator panel.

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- Design, procure, and install two (2) new PC 510 transformer metering panels.
- Design, procure and install all required communication fiber patch panel, fiber modem, and related communication equipment needed to connect to new 48-fiber, single mode, ADSS cable and to Interconnection Customer's recloser/equipment.
- Design, procure and install a fiber-optic channel to send direct transfer trip to the Interconnection Customer's collector site recloser using mirrored bits.

AGREEMENT TO AMEND INTERCONNECTION AGREEMENT FOR SMALL GENERATOR FACILITY

This **Agreement To Amend Interconnection Agreement for Small Generator Facility** (“Agreement”) is made and entered into this _______ day of __________________, 20_____, by and between PacifiCorp, an Oregon corporation (the “Public Utility”) and Sunthurst Energy, LLC (Q0666), an Oregon limited liability company (the “Interconnection Customer”). Transmission Provider and Interconnection Customer may be referred to as a “Party” or collectively as the “Parties.”

RECITALS

WHEREAS, Transmission Provider and Interconnection Customer have entered into a Generator Interconnection Agreement (“Interconnection Agreement”), dated March 14, 2016, and amended as of June 20, 2016, October 11, 2016, November 21, 2017, and November 6, 2018;

WHEREAS, Public Utility and Interconnection Customer have mutually agreed to amend one or more appendices, attachments, and/or exhibits to the Interconnection Agreement; and

WHEREAS, Article 8.2 of the Interconnection Agreement states that the Parties may mutually agree to amend this Interconnection Agreement by a written instrument duly executed by both parties;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein, it is agreed:

1.0 The Parties acknowledge and mutually agree that the following attached attachments will substitute in their entirety the same attachment in the Interconnection Agreement:

- Attachment 1
- Attachment 3
- Attachment 5
- Attachment 6

2.0 Service under the Interconnection Agreement with the amended attachments will commence only upon execution by both Parties.

3.0 The Interconnection Agreement, with the attached substitute attachments shall constitute the entire agreement between the Parties.

4.0 TO THE FULLEST EXTENT PERMITTED BY LAW, EACH OF THE PARTIES HERETO WAIVES ANY RIGHT IT MAY HAVE TO A TRIAL BY JURY IN RESPECT OF LITIGATION DIRECTLY OR INDIRECTLY ARISING OUT OF, UNDER OR IN CONNECTION WITH THIS AGREEMENT. EACH PARTY FURTHER WAIVES ANY RIGHT TO CONSOLIDATE, OR TO REQUEST THE CONSOLIDATION OF, ANY ACTION IN WHICH A JURY TRIAL HAS BEEN

WAIVED WITH ANY OTHER ACTION IN WHICH A JURY TRIAL CANNOT BE OR HAS NOT BEEN WAIVED.

5.0 All other provisions of the Interconnection Agreement will continue to apply.

IN WITNESS WHEREOF, the Parties have executed this Agreement in duplicate originals, each of which shall constitute and be an original effective Agreement between the Parties.

PacifiCorp

By: ______________________

Title: ______________________

Date: ______________________

Sunthurst Energy, LLC (Q0666)

By: ______________________

Title: ______________________

Date: ______________________

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Interconnection Agreement for Small Generator Facility
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(Small Generator Facilities with Electric Nameplate Capacities of 10MW or less)

Attachment 1

**Description of Interconnection Facilities
And Metering Equipment Operated or Maintained by the Public Utility**

Small Generating Facility: A 1.98 MW solar generating facility consisting of thirty-three (33) SMA MLX-60 60 kW inverters, connected to one (1) generation step up transformer (3 MVA, 5.75%), and one (1) 150 kVA grounding bank with an impedance of 5.75%, connected to Public Utility's Distribution System in Umatilla County, Oregon. See Attachment 2.

Interconnection Customer Interconnection Facilities: A short, 12.5 kV tie connecting the step-up transformer to the Interconnection Customer owned recloser and relay. Interconnection Customer will also own a gang-operated disconnect switch that Public Utility can access. See Attachment 2.

Public Utility's Interconnection Facilities: A short run of distribution circuit connected to a 12.5 kV disconnect switch, bi-directional revenue metering facilities and fiber optic cable equipment necessary for transfer-trip between the Small Generating Facility and Pilot Rock substation. See Attachment 2.

Estimated cost of Public Utility’s Interconnection Facilities directly assigned to Interconnection Customer: $155,000

Estimated Annual Operation and Maintenance Cost of Public Utility's Interconnection Facilities: $1,500. Interconnection Customer shall be responsible for Public Utility's actual cost for maintenance of the Public Utility's Interconnection Facilities.

Point of Interconnection: The point where the Public Utility's Interconnection Facilities connect to the Public Utility's 12.5 kV distribution circuit 5W406 out of Pilot Rock substation. See Attachment 2.

Point of Change of Ownership: The point where the Interconnection Customer's Interconnection Facilities connect to the Public Utility's Interconnection Facilities. See Attachment 2.

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Attachment 3

Milestones

Estimated In-Service Date: October 18, 2021

Critical milestones and responsibility as agreed to by the Parties:

	Milestone/Date	Responsible Party
(1)	Execute Agreement and Provide $10,000 deposit March 15, 2016	Interconnection Customer
(2)	Provide All Required Design Information July 12, 2018	Interconnection Customer
(3)	Begin Engineering Design February 1, 2019	Public Utility
(4)	*Initial Design Information Provided November 2, 2020	Interconnection Customer
(5)	Obtain Property Rights January 8, 2021	Interconnection Customer
(6)	*Final Design Information Provided February 26, 2021	Interconnection Customer
(7)	Complete Engineering Design April 30, 2021	Public Utility
(8)	Begin Construction June 21, 2021	Public Utility
(9)	Provide Policy 138 required Test & Maintenance Plans July 2, 2021	Interconnection Customer
(10)	Complete Construction August 27, 2021	Both
(11)	Commissioning Complete September 24, 2021	Public Utility

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(12)	Backfeed October 4, 2021	Both
(13)	Initial Synchronization/Generation Testing October 11, 2021	Both
(14)	Commercial Operations October 18, 2021	Both

Interconnection Customer is to request Backfeed, 1st Sync, and Commercial Operations in writing (email acceptable) prior to the above dates. Public Utility is to approve Interconnection Customer requests without unreasonable delay. The Interconnection Customer will be required to demonstrate the reactive capability of the Small Generating Facility and the voltage control system prior to Commercial Operations.

*Interconnection Customer initial design package shall include final generating facility location, inverter/turbine selection, basic protection package, tie line route and collector system locations and data as applicable. Interconnection Customer final design package shall include PE stamped issued for construction ("IFC") drawings for generating facility, collector substation, tie line as well as an updated PSS/e model and updated WECC approved model, electromagnetic transient ("EMT") model and a detailed short circuit model of its generation system using the ASPEN OneLine short circuit simulation program as applicable. The WECC model parameters must be adjusted to reflect the plant's actual anticipated performance. The plant controller must be included in the model. If there is to be coordination between facilities or a master VAR controller, this must be included in the detailed WECC dynamic model, as well as in the PSS/e user-written model.

Payment Schedule

If Interconnection Customer elects the progress payments option under Article 4.6 of the Interconnection Agreement, there are two potential options for a payment schedule below (please select one). If Interconnection Customer elects progress payment option but an option below is not selected, the Levelized Option will be selected by default. Failure to comply with the selected payment schedule will result in immediate contractual breach, work stoppage, and slip of the milestone schedule above on a day-for-day basis. Interconnection Customer will still be responsible for all costs of the project. Public Utility will conduct initial accounting for the project within thirty (30) days of granting Commercial Operations approval and will determine if a partial refund of project costs is acceptable.

Please select an option:	☐
Funds due no later than	Stepped Option
March 15, 2016 (or when Interconnection Agreement is executed)	$10,000 - Paid

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July 1, 2018	$79,500 - Paid
November 1, 2020	$250,000
May 1, 2021	$360,500

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Attachment 5

Public Utility' s Description of its Upgrades and Best Estimate of Upgrade Costs

Distribution Upgrades: Extend Circuit 5W406 by approximately .3 miles. Install approximately .9 miles of fiber optic cable. Add VTs and circuit metering and modify communications and protection scheme at Pilot Rock substation. Estimated cost is $545,000.

Network Upgrades: The following locations will require the Network Upgrades described below:

- No upgrades

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Attachment 6

Scope of Work

GENERATING FACILITY MODIFICATIONS

At the Small Generating Facility, a relay will need to be installed that will monitor the voltage magnitude and frequency. If the magnitude or frequency of the voltage is outside of the normal range of operation, the relay will need to disconnect the Small Generating Facility. It is our recommendation that a SEL 351 type relay be installed for this purpose. This relay has six pickup levels with different time delays for both the frequency and magnitude of the voltage to make the relay sensitive to small diversions from nominal but with adequate time delay and also fast reacting for extreme diversions.

The Public Utility will procure, install, test, and own all revenue metering equipment. It is expected the revenue metering instrument transformers will be installed overhead on a pole at the Point of Interconnection. The meter instrument transformer mounting shall conform to Public Utility's construction standards.

The metering will be bidirectional to measure KWH and KVARH quantities for both the generation received and the retail load delivered. The Interconnection Customer may request output from the Public Utility's revenue meters.

Communication equipment will be required to remotely interrogate the meter for generation and billing data via Public Utility's MV90 data acquisition system.

INTERCONNECTION CUSTOMER WILL BE RESPONSIBLE FOR THE FOLLOWING:

- Procure all necessary permits, lands, rights of way and easements required for the construction and continued maintenance of the Q0666 Small Generator Facility and collector substation.
- Design, procure, construct, own and maintain the Interconnection Customer's Small Generator Facility and associated collector substation.
- Design the Small Generator Facility with reactive power capabilities necessary to operate within the full power factor range of 0.95 leading to 0.95 lagging as measured at the high side of the Interconnection Customer's GSU transformer. This power factor range shall be dynamic and can be met using a combination of the inherent dynamic reactive power capability of the generator or inverter, dynamic reactive power devices and static reactive power devices to make up for losses.
- Design the Small Generator Facility such that it can provide positive reactive support (i.e., supply reactive power to the system) immediately following the removal of a fault or other transient low voltage perturbations or install dynamic voltage support equipment. These additional dynamic reactive devices shall have correct protection settings such that the devices will remain on line and active during and immediately following a fault event.
- Equip the Small Generator Facility with automatic voltage-control equipment and operate with the voltage regulation control mode enabled unless explicitly authorized to operate another control mode by the Public Utility.

- Operate the Small Generator Facility so as to maintain the voltage at the Point of Interconnection, or other designated point as deemed appropriated by Public Utility, at a voltage schedule to be provided by the Public Utility following testing.
- Operate the Small Generator Facility with a voltage droop.
- Have any Public Utility required studies, such as a voltage coordination study, performed and provide results to Public Utility. Any additional requirements identified in these studies will be the responsibility of the Interconnection Customer.
- Meet the NERC and WECC low voltage ride-through requirements as specified in the interconnection agreement.
- Provide the Public Utility a standard model from the WECC Approved Dynamic Model Library.
- Design, procure, install, and own an SEL 351 type relay to monitor the voltage and frequency of the Small Generating Facility.
- Provide the Public Utility second level password control of the Interconnection Customer's relay to ensure no settings changes can be made to the relay without Public Utility review and approval.
- Provide professional engineer ("PE") signed and stamped drawings for Interconnection Customer's Small Generating Facility to Public Utility to allow development of required relay settings.
- Install and own a recloser for the Public Utility's SEL 2829 optical transceiver.
- Arrange for and provide permanent retail service for power that will flow from the Public Utility's system when the Small Generator Facility is not generating. This arrangement must be in place prior to approval for backfeed.
- Provide any construction or backup retail service necessary for the Project.
- Provide the Public Utility a Professional Engineer ("PE") approved maintenance plan for all Interconnection Customer facilities prior to commencement of generation activities.

PUBLIC UTILITY WILL BE RESPONSIBLE FOR THE FOLLOWING:

- Design and communicate to the Interconnection Customer the settings to be programmed into the SEL 351 type relay.
- Own the revenue class instrument transformers required for the interconnection of the Small Generating Facility.
- Procure, install, and own two (2) meters are required for retail load Customer Net Gen reverse feed.
- Own the revenue class instrument transformers required for the interconnection of the Small Generating Facility.
- Design, procure, install, and own of Ethernet (preferred) or a cell phone to be designed as part of the meter and utilized to allow for remote interrogation of the Small Generating Facility.
- Design, procure, install, and own one (1) metering panel.
- Design, procure, install, and own of the required meter, test switches and secondary meter wire needed to interconnect the Small Generating Facility.
- Design, procure, install, and own the required meter, test switches and secondary meter wire needed to interconnect the Small Generating Facility.

- Design, procure and install all required communication fiber patch panel, fiber modem, and related communication equipment needed to connect to new 48-fiber, single mode, ADSS cable and to Interconnection Customer's recloser/equipment.

DISTRIBUTION LINE REQUIREMENTS

The following outlines the design, procurement, installation, and ownership of equipment for the distribution line.

INTERCONNECTION CUSTOMER WILL BE RESPONSIBLE FOR THE FOLLOWING:

- Obtain required right of way for newly required tap line from City Feeder to Small Generating Facility.

PUBLIC UTILITY WILL BE RESPONSIBLE FOR THE FOLLOWING:

- Design, install, and own 0.3 miles of 4/0 AAC primary conductors and one 4/0AAC neutral conductor from the Point of Interconnection (proposed facility point #090961) to the Point of Change of Ownership.
- Design, install, and own a gang operated switch and primary metering units.
- Procure and install one (1) span of overhead primary conductors from the primary metering pole to Interconnection Customer's pole. The termination of this conductor at the Small Generating Facility will serve as the Point of Change of Ownership.
- Replace the tap changing controller on R-816 with a controller capable of handling reverse power flow.
- Design, procure, install, and own new 48-fiber, single mode, ADSS cable from Small Generating Facility to Pilot Rock substation.

PILOT ROCK SUBSTATION

The following outlines the design, procurement, installation, testing and ownership of equipment for Public Utility's Distribution Circuit.

PUBLIC UTILITY WILL BE RESPONSIBLE FOR THE FOLLOWING:

- Procure, install, and own three (3) 12.5 kV VT's.
- Design, procure, and install required steel support structures and associated foundations for all new equipment if required.
- Design, procure, and install a one (1) new PC-611 panel.
- Design, procure, and install a one (1) new PI111 annunciator panel.
- Design, procure, and install two (2) new PC 510 transformer metering panels.
- Design, procure and install all required communication fiber patch panel, fiber modem, and related communication equipment needed to connect to new 48-fiber, single mode, ADSS cable and to Interconnection Customer's recloser/equipment.

- Design, procure and install a fiber-optic channel to send direct transfer trip to the Interconnection Customer's collector site recloser using mirrored bits.

PUBLIC UTILITY COMMISSION
OF
OREGON

SUNTHURST EXHIBIT 209

PacifiCorp Interconnection Policies:

Excerpts from Policy 138

DECEMBER 15, 2020

Policy

DISTRIBUTED ENERGY RESOURCE (DER) INTERCONNECTION POLICY

Facility Connection (Interconnection) Requirements for Distribution Systems 34.5 kV and Below

Engineering Services & Asset Management Policy 138

Author:	Rohit Nair
Approval:	Douglas Marx
Authoring Department:	Engineering Standards & Technical Services
Approved File Location:	PacifiCorp.us\Dfs\Pdxco\Shr04\ Publications\FPP \DIS\POL
File Number-Name:	138-Distributed Energy Resource (DER) Interconnection Policy.docx
Revision Number:	6
Revision Date:	8/13/2018

Document Security Category			
	Confidential	X	External
	Restricted		BES Cyber System Information (BCSI)
X	Internal		

Revision Log		
0	12/11/07	Initial issue.
1	2/5/08	Rev 1
2	11/3/11	Rev 2: changes to section 5.7, paragraph 2 only.
3	7/2/15	Changes have been made throughout this policy.
4	1/11/17	Changes have been made throughout this policy.
5	11/9/17	Maximum parallel time w. EPS for closed-transition method has been updated.
6	8/13/18	Transient overvoltage management has been updated in section 6.4.

Contents

3.5 Communications Operating Procedures

3.5.1 Normal Operating Conditions

The Interconnection Customer shall provide PacifiCorp the information necessary to communicate with the equipment and/or personnel at the DER facility during routine operating conditions. This information shall be updated as soon as a material change becomes available for use by notifying PacifiCorp's grid operations centers in either Salt Lake City, Utah or Portland, Oregon, depending on the facility's operating area.

3.5.2 Emergency Operating Conditions

The Interconnection Customer shall provide PacifiCorp with the information necessary to communicate with the equipment and/or personnel at the DER facility during the loss of the primary communication medium. This would be considered the emergency operating condition. This information is also to be updated as soon as a material change becomes available for use by notifying PacifiCorp's grid operations centers in either Salt Lake City, Utah or Portland, Oregon, depending on the facility's operating area.

4 Metering Policy for Interconnection Customers

4.1 General

The purpose of this section is to assist the customer in accommodating PacifiCorp's metering of electricity supplied to the EPS. The general requirements are similar to the general requirements for metering the supply of electrical retail service by PacifiCorp.

When a DER is installed with the intent of providing power to the EPS, electric service to the auxiliary load associated with the generator plant is also needed. As such, power may flow into or out of the DER facility at different times. Deliveries to and from the DER facility (bi-directional metering) must be separately recorded and treated as separate transactions under applicable PacifiCorp tariff.

All meters and instrument transformers will be provided, owned, and maintained by PacifiCorp at the customer's expense. At customer-owned facilities, the customer will provide, own, and maintain all mounting structures, conduits, metering transformer cabinets, and switchboard service sections of the size and type approved by PacifiCorp.

Sites with multiple DER resources such as wind collectors, or solar arrays may be considered as separable revenue facilities and, when applicable, require metering at each facility point. Metering requirements with multiple DER facilities will be identified in the interconnection facilities study report. Metering used for any PacifiCorp revenue purpose will be certified and maintained identically to the point of interconnect revenue metering.

4.2 Basic Meter Programs

Bi-directional meters will be programmed to measure the generation output delivered to the EPS and reverse load or back feed delivered to the customer from the EPS. The standard PacifiCorp meter program will include:

- Bi-directional MWh and Mvarh energy
- Sliding demand quantities MW
- Mvar with instantaneous MW, Mvar, volt, and amp data

For smaller DER facilities, the energy and demand quantities may be measured in kilo units instead of mega units.

The meters will be programmed to record interval profile demand including bi-directional MWh and Mvarh and per-phase volt-hours. Additional profile data or time-of-use quantities will be added to the standard program when needed.

Requests from customers for digital or analog metering I/O outputs must be made prior to the final design.

4.3 Customer Requests for Metering Data

The meter will be programmed to measure Mvars (lagging) only when PacifiCorp is delivering to the customer, not when the customer is generating.

When requested, PacifiCorp shall provide digital DNP, Modbus, or analog data outputs from revenue meters. Requests for outputs must be made before final metering design and may be written into contract agreements. The metering data from PacifiCorp meters shall not be used for customer control purposes. The metered data is provided to the customer for indication and energy display purposes only.

Customers will not be approved to interrogate PacifiCorp meters' register and profile channels using ethernet communications. Inside the DER facility, the customer does have the option to provide a data phone line. However, it must be operational and tested prior to the installation of the revenue metering communication equipment.

4.4 PacifiCorp Provided Equipment

The revenue meters, and any specialized communication or other hardware will be specified, ordered, and installed by PacifiCorp at the customer's expense. Instrument transformers shall be provided by PacifiCorp unless other arrangements are written into the interconnection agreement and/or construction agreement.

4.5 Meter Certification and Compliance Testing

PacifiCorp shall perform periodic meter certification per Metering Operations Practices and Procedures (MOPP) and Meter Engineering Standard 10.1.1, *High-End Revenue Metering Test Policy*.

When applicable, certification is required to meet PacifiCorp, NERC BAL005 compliance, American National Standard Institute (ANSI), and Western Renewable Energy Generation Information System (WREGIS) standards.

PacifiCorp will give all interested parties advance notification for the impending test. The tests will be performed and recorded per Meter Engineering Form 129F *Commissioning and Test Record Form*. A copy will available for all parties involved to review.

4.6 Metering Requirements for Point of Interconnect Below 600 Volts

PacifiCorp's *Electric Service Requirements* (ESR) provides the requirements for service termination and metering equipment. Refer to ESR Section 9 for all secondary direct-connect and instrument-rated requirements.

4.7 Primary Metering 2.4 kV through 25 kV Underground Applications

Approved switchgear enclosures for PacifiCorp instrument transformers, meter, and applicable communication equipment are outlined below:

- For medium-voltage applications the customers shall meet minimal requirements of the Electric Utility Service Equipment Requirements Committee, EUSERC

Section 400 for metering switchgear equipment. Additional requirements for the underground or overhead assembly, such as a meter plate for the utility compartment, shall be defined during the facility design.

- A clear work space (per current NEC regulations) is required.
- The metering instrument transformers will be specified by PacifiCorp and shall be installed by the manufacturer of the switchgear.
- Approved metering stations shall be specified by PacifiCorp and shall conform to company material specification ZM 003, *Primary Metering Enclosure, Pad-mounted*. All box pads and vaults shall comply with material specifications ZG 421, *Box Pad—Sectionalizing Cabinets* and ZG 571, *Padvault—Metering Cabinet Lid*.
- The location of the meters, including mounting and enclosure facilities, shall be determined during the facility design.

4.8 Primary Metering Underground 34.5 kV

The metering requirements for 34.5 kV underground applications will be defined during the facility design.

4.9 Primary Metering Overhead Pole-Mounted 2.4 through 34.5 kV

To establish a mutually suitable location for pole-mounted metering, the customer shall consult with PacifiCorp before construction begins. The meter mounting shall conform with PacifiCorp distribution metering overhead construction standards.

The meters may be mounted on the pole in an outside enclosure or inside a control house.

4.10 Station Service Power

Depending upon the DER facility's electrical sources, the station service power for connecting substation facilities may require separate revenue metering or may be required to be negotiated for with a foreign utility.

The metering requirements may also require totalization of the gross and auxiliary loads for measured net generation.

4.11 Meter Communications

An ethernet or phone line connection is required by PacifiCorp to remotely interrogate the meter profile and register data.

The customer is not allowed to remotely interrogate the meter registers or load profile data. PacifiCorp will provide interval or register data to customer as agreed to contractually.

4.12 Indoor Panels

The DER facility may require installation of a standard 12" × 90" meter panel inside a control house. PacifiCorp will provide and own a standard panel per meter engineering standard requirements.

PUBLIC UTILITY COMMISSION
OF
OREGON

SUNTHURST EXHIBIT 210

[Reserved]

DECEMBER 15, 2020

PUBLIC UTILITY COMMISSION
OF
OREGON

SUNTHURST EXHIBIT 211

Correspondences between Sunthurst and PacifiCorp

- **May 15 e-mail from PacifiCorp to Sunthurst**
- **July 23, 2020 letter from Sunthurst to PacifiCorp**
- **August 7, 2020 letter from PacifiCorp to Sunthurst**

DECEMBER 15, 2020

From: **Loftus, Matthew** Matthew.Loftus@PacifiCorp.com
Subject: RE: Pilot Rock Solar (Q1045) --Please confirm receipt
Date: May 15, 2020 at 1:36 PM
To: Ken Kaufmann Ken@kaufmann.law
Cc: Kruse, Karen Karen.Kruse@pacificorp.com

ML

Ken,

Attached is the explanation from the PacifiCorp engineers regarding the protective relay system.

Please let me know if you have any questions.

Sincerely,

Matt

Matthew Loftus
Senior Transmission Counsel
PacifiCorp
W:503-813-6642
825 NE Multnomah St, Suite 1600
Portland, OR 97232

From: Ken Kaufmann [mailto:Ken@kaufmann.law]
Sent: Friday, May 8, 2020 4:15 PM
To: Loftus, Matthew <Matthew.Loftus@PacifiCorp.com>
Cc: Kruse, Karen <Karen.Kruse@pacificorp.com>
Subject: [INTERNET] Re: Pilot Rock Solar (Q1045) --Please confirm receipt

**** REMEMBER SAIL WHEN READING EMAIL ****

Sender	The sender of this email is Ken@kaufmann.law using a friendly name of Ken Kaufmann . Are you expecting the message? Is this different from the message sender displayed above?
Attachments	Does this message contain attachments? No If yes, are you expecting them?
Internet Tag	Messages from the Internet should have **[INTERNET]** added to the subject.
Links	Does this message contain links? No Check links before clicking them or removing BLOCKED in the browser.
Cybersecurity risk assessment: Low	

Thank you, Matt.
Have a nice weekend.

Kenneth Kaufmann
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<u>Q0666 & Q1045 solar electric generation projects</u>

The proposed Q0666 & Q1045 solar projects are planned to be connected to 12.5 kV circuit 5W406 out of the Pilot Rock substation. Circuit 5W406 is the only feeder connected to the 69 – 12.5 kV transformer bank #2 at the substation. Potential power production from the Q0666 generation facility will be greater than the daytime load on the feeder and on the transformer some days of the year. With the addition of Q1045, the combined potential power from the two generation facilities will be greater than the daytime load on the feeder and the transformer most days of the year. Due to this generation to load ratio under/over voltage and frequency conditions when the generation is isolated with the load cannot be relied on to cause the timely disconnection of the generation from the circuit.

The timely disconnection of the generation from the circuit is required for two reasons. First, since most faults on overhead distribution lines are transient in nature once all of the sources of power to the fault are disconnected the circuit can be re-energized and service restored to customers as automatic reclosing is enabled on breaker 5W406 at Pilot Rock substation. Second, the 69 – 12.5 kV transformer is currently protected with 69 kV fuses. Since the 69 kV side is the only current source of power to the transformer, the blowing of the fuses for faults in the transformer are a reliable way of isolating the transformer for internal problems. The addition of the Q0666 & Q1045 solar projects provides a source of power to transformer faults from the 12.5 kV side that must also be disconnected to cease the injection of power into the fault. In many cases if internal transformer issues are isolated quickly the damage to the transformer is minimized and the transformer can be repaired and returned to service. If the transformer is not isolated from power sources in a few cycles the damage to the transformer will be extensive and there will be no usable value left in the transformer.

It has been proposed that the inverters planned for the Q0666 & Q1045 solar projects will be equipped with control circuits capable of detecting and disconnecting the inverters for conditions when the generation is isolated with load without relying on under/over voltage and frequency relay elements to meet IEEE 1547 requirements. The requirements for IEEE 1547 is that the inverters stop injecting power into the system in less than two seconds from the isolation of the generation with the load. The timing between the tripping of breaker 5W406 at Pilot Rock substation and the reclosing of the breaker is 20 cycles. However, meeting the IEEE 1547 requirements will not be adequate to support successful reclosing on this feeder. In addition to the problem of supporting a successful trip and reclose event, there is the risk of damage to the 69 – 12.5 kV transformer for a problem in the transformer. Two seconds is an unacceptable amount of time to attempt to minimize damage to a faulted transformer. At two seconds, there would be no hope of salvaging anything from the transformer and there would be risks of a fire in the substation, which could damage other equipment and present a safety concern for PacifiCorp's employees and the public in general.

Additionally, the solar projects are required to remain connected to the transmission network for faults on the network that do not result in the isolation of the generation, low voltage ride through, in compliance with NERC PRC-024-2. Pilot Rock substation is fed from BPA's 230 – 69 kV Roundup substation. There are two 230 kV lines into Roundup substation. For a fault on one of these 230 kV lines, the voltage at the Q0666 & Q1045 generation facilities will be zero for the time it takes to detect and isolate the fault. The Q0666 & Q1045 generation facilities are required to remain connected to the system for such an event so that once the faulted line is disconnected and the system is left with just one 230 kV line, the remaining system does not suffer the additional loss of local generation. The requirement to remain connected under NERC-PRC-024-2 is another reason why the inverter controls will not suffice.

The protective relay system that is planned for the Q0666 project will meet the requirements to: (1) disconnect the solar generation in a timely manner for faults on the 12.5 kV circuit; (2) maintain the 20 cycle recloser function of 5W406; (3) minimize the potential damage for a problem in the 69 – 12.5 kV transformer – all without causing the disconnection of the generation facilities for faults on the 230 kV network. The proposed inverter controls cannot meet these requirements. The protective relay system planned for the Q0666 project will be adequate for the addition of the Q1045 project.

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West Linn, OR 97068
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fax (503) 972-2921

July 23, 2020

VIA ELECTRONIC MAIL (Matthew.Loftus@PacifiCorp.com)

Mr. Matt Loftus
Senior Transmission Counsel, PacifiCorp
825 NE Multnomah, Suite 1600
Portland, OR 97232

Subject: **Pilot Rock Solar 1, LLC (Q0666) and Pilot Rock Solar 2, LLC (Q1045)**
Questions re cost and scope of Interconnection requirements

Dear Matt:

With the acquiescence of PacifiCorp, Sunthurst Energy, LLC (Sunthurst) provides the following comments on the interconnection design for Q0666 and Q1045, including requests for cost reductions, or for design changes and cost reductions. Additional information is requested where Sunthurst requires it to complete its review.

Sunthurst appreciates PacifiCorp's willingness to engage in discussions on these matters. However since PacifiCorp is obligated to impose only "reasonable" costs of equipment "necessary" to interconnect the customer, PacifiCorp has a duty to do more than just listen; it has the burden to justify the necessity of equipment and the reasonableness of its design, or else correct it. *See* OAR 860-029-0010 ("Costs of Interconnection"). The following list of opportunities to reduce the cost of Q0666 and Q1045 provides ample room for capturing savings that will facilitate a cooperative resolution. Sunthurst, in cooperation with PacifiCorp and the Commission, has invested a great deal of time and treasure to help Oregon implement its CSP program and looks forward to delivering PRS1 and PRS2 as economically and technically sound projects. Sunthurst welcomes PacifiCorp's willingness to consider reasonable cost-saving changes to facilitate success of the Oregon CSP.

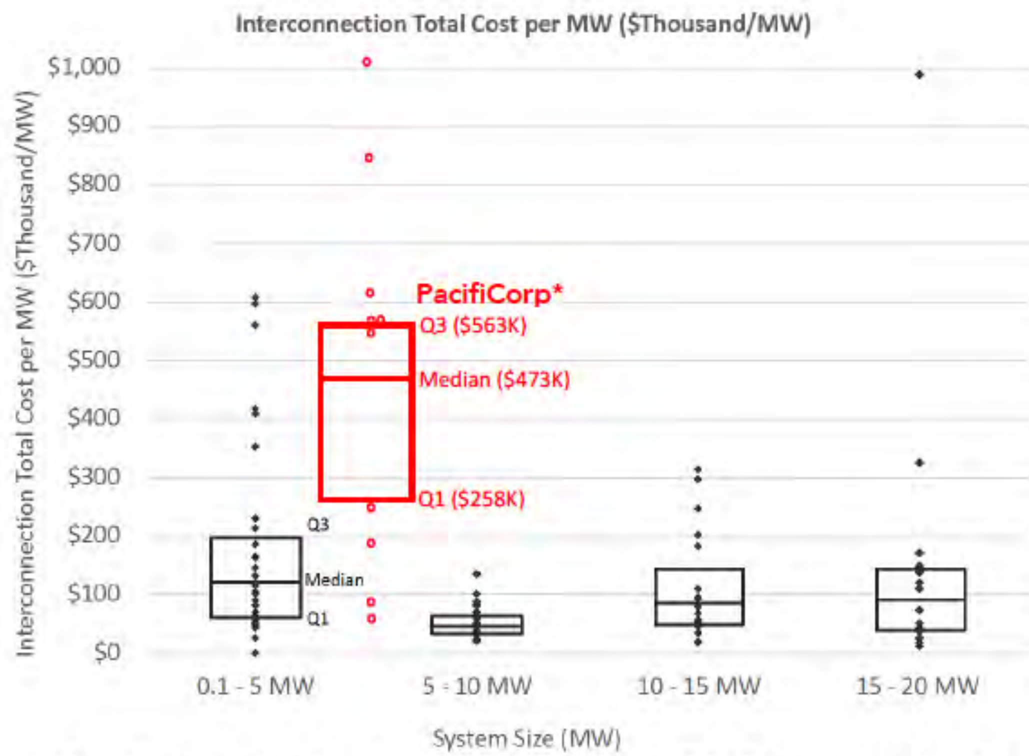
Background

Sunthurst Energy, LLC (Sunthurst) is an Oregon solar PV project developer and installer. It is developing the 1.98 MW Pilot Rock Solar 1, LLC (PRS1) and the 2.99 MW Pilot Rock Solar 2, LLC (PRS2) projects located in PacifiCorp territory near Pendleton. Both projects received pre-certification under Oregon's Community Solar Program (CSP). ***PacifiCorp's estimated cost to interconnect PRS1 and PRS2 is $805,000 and $ 879,000, respectively, even though neither project requires network upgrades or transmission from a load pocket***. These costs make PRS1 and PRS2 un-financeable.

Mr. Matt Loftus
July 23, 2020
Page 2 of 7

Published data suggest that PacifiCorp's small generator interconnection costs are exorbitant compared to such costs charged by other utilities in Oregon and the Western United States. A 2018 NREL study showed 25 interconnections throughout the Western United States between 100kW and 5MW had a median cost of about $110k/MW.[1] **PacifiCorp's ten completed Oregon CSP facilities studies have a median cost of $473k/MW, or more than 400% of the nation-wide average.**[2]

Figure 11 from 2018 NREL Study, Annotated with 2020 PacifiCorp CSP Data.



*PacifiCorp cost data are from 7/22/20 PacifiCorp OCSP Interconnection Queue
Figure 11. Total mitigation cost ranges in thousands of dollars, by system size (MW)

PacifiCorp's interconnection costs also are believed to be much higher than comparable interconnection costs assessed by Oregon's other IOUs, PGE and Idaho

[1] REVIEW OF INTERCONNECTION PRACTICES AND COSTS IN THE WESTERN STATES, Lori Bird, Francisco Flores, Christina Volpi, and Kristen Ardani of the National Renewable Energy Laboratory, and David Manning and Richard McAllister of the Western Interstate Energy Board (Technical Report NREL/TP-6A20-71232, April 2018) ("NREL Interconnection Cost report"), page 18. The report is available free at www.nrel.gov/publications.
[2] *See* PacifiCorp Oregon CSP interconnection queue, as of July 22, 2020, at http://www.oasis.oati.com/woa/docs/PPW/PPWdocs/pacificorpocsiaq.htm

Power.[3] If PacifiCorp's interconnection costs were in line with other utilities, the Sunthurst projects would be financeable.

Sunthurst engaged Larry Gross, P.E., VP – Power System Protection Electrical Consultants, Inc., to review PacifiCorp's design. Mr. Gross is an electrical engineer with considerable expertise in utility scale interconnections and protection and data integration schemes. Mr. Gross reviewed the Interconnection Studies prepared by PacifiCorp and attended two meetings with PacifiCorp's interconnection team to ask questions about PacifiCorp's proposed interconnection requirements. Based on the documents and the meetings, Mr. Gross provided extensive comments on PacifiCorp's proposed design, attached hereto as **Attachment A**. Although not judging the "good design practice" of PacifiCorp's proposed upgrades, Mr. Gross identified several areas where PacifiCorp's proposed interconnection facilities and distribution upgrades were either likely unnecessary, redundant, and/or provided system benefits above what PRS1 and PRS2 reasonably require from a direct technical perspective. He also noted where the documentation provided by PacifiCorp was not of sufficient detail for him to confirm the necessity of all of the requirements.

Specific interconnection design modification and supplemental data requests

1. **Metering requirements are unnecessarily expensive.**[4] The Q0666 interconnection agreement specified one metering point (two meters) at or near the Point of Interconnection (POI). After Q1045 Facilities Study, that requirement changed to require one metering point at the Pilot Rock Solar 1 (PRS1) collector substation, a second metering point at the Pilot Rock Solar 2 (PRS2) collector substation and a third metering point at the Change of Ownership Point (COP).

   Sunthurst requests that the specified meters at the PRS1 (Q0666) collector substation and the specified meters at the PRS2 (Q1045) collector substation be moved to the low side, and the specified meters at the COP be eliminated. Combined net generation from Q0666 and Q1045 facilities at the COP can be calculated using low-side meters at Q0666 and Q1045. In fact, Oregon's CSP rules require utilities to allow low-side metering for CSPs under 360 kW because of evidence that low-side metering saves tens of thousands of dollars. Order 19-392, Appdx A, p. 13. If PacifiCorp is concerned about allocating transformation losses between two projects, Sunthurst will contractually guarantee that

[3] Because PGE does not publish studies from withdrawn projects on its OASIS, Sunthurst does not currently have data to make an exact comparison between PGE and PacifiCorp. The available PGE data show much lower interconnection costs than PacifiCorp. Sunthurst found three interconnection studies for small Oregon solar published by Idaho Power, which had a median cost of $101k/MW.

[4] Sunthurst's comments regarding metering affect aspects of both (Q0666 and Q1045) interconnections.

PacifiCorp will be kept whole from transformation losses. ***Alternatively, Sunthurst requests that metering be accomplished with one metering point at the COP and one meter at the low (480V) side of PRS2.*** Generation from PRS1 can be calculated based upon the difference between COP and PRS2 meter readings.

Sunthurst's consulting electrical engineer concluded that the above metering schemes are technically sound and using the two lower voltage metering points is frequently used at the transmission level.[5] The requested alternatives to the proposed design would slash the combined cost of metering PRS1 and PRS2 without affecting safety, accuracy, or reliability.

2. **PC-611 Panel installation may not be necessary**. Based on information provided by PacifiCorp, Sunthurst's professional consulting engineer identified that the functionality required by PacifiCorp as a result of PRS1 and PRS2 interconnections does not appear to require the added PC-611 panel. Specifically, transfer trip can be performed using an SEL-2505 relay bolted inside the existing panel, and the reclosing could be delayed with other means using the SEL-2505 contacts.[7] ***Sunthurst requests PacifiCorp explain why PC-611 is required. If the justification includes updating old equipment that otherwise is scheduled for programmatic replacement, then Sunthurst asks PacifiCorp to contribute the difference between the cost of the PC-611 panel and the cost of the alternative proposed by Sunthurst's engineer, or else eliminate the PC-611 panel***.

3. **Cost of new Fiber Optic install should be shared.** The $70,000 fiber optic installation specified by PacifiCorp is a more expensive means of communication for the required transfer trip protection than point-to-point radio. PacifiCorp's choice of a 48-fiber cable provides much more fiber than PRS1 and PRS2 need and may show PacifiCorp's anticipation of using spare fibers for non-customer related uses. Sunthurst does not object if PacifiCorp prefers the expandability and excess capacity built into its choice of 48-fiber cable communications, however the excess cost of fiber compared to a functionally adequate radio communication link should be born by PacifiCorp. ***Sunthurst requests that PacifiCorp pay the difference between the cost of the fiber optic system specified by PacifiCorp and the cost of direct radio communication to Pilot Rock substation suitable for PRS1 and PRS2***.

4. **Voltage Measurement at the feeder relay is not necessary**. Sunthurst's consulting engineer reviewed PacifiCorp's design and believes based on the information available to him that the three line side voltage transformers (VTs) specified by PacifiCorp are not required for reclose voltage sensing as that

[5] See July 20 email from Larry Gross, attached, page 2, ¶2.
[7] See July 20 email from Larry Gross, attached, page 4, ¶2.

function may be performed using the transfer trip scheme communication channel.[9] Nor are the specified voltage transformers necessary for directionality determination necessary to protect PacifiCorp's equipment from Pilot Rock generation in the event of a bus, transformer or transmission line fault, because PRS1 and PRS2's inverters' will only contribute fault current of about 107% of nameplate after about 4 ms and islanding protection after the main distribution transformer fuse clears will disconnect the generation. This appears to make PacifiCorp's proposed voltage directionality based protection unnecessary.[10] ***Sunthurst requests that PacifiCorp remove the three high-side VTs after confirming that these optional protection practices and warranted performance of Sunthurst's inverters provide adequate protection.***

5. **P1-111 Annunciator Panel at Pilot Rock substation is not necessary.** Sunthurst's consulting engineer concluded based on the available information that the P1-111 panel specified in the Q0666 interconnection agreement is an unnecessary upgrade of existing functionality at Pilot Rock substation, which does not currently have annunciation. The existing relays have targets to indicate tripping and the SEL-2505 relay proposed by Sunthurst, above, has status lights that would make the annunciator redundant.[11] ***Sunthurst requests that the panel be deleted or reimbursed by PacifiCorp as a network upgrade or a distribution system upgrade not necessitated by PRS1 and PRS2.***

6. **PC-510 Transformer Metering Panels at Pilot Rock substation are unnecessary.** Sunthurst's consulting engineer noted that PacifiCorp's intended uses for the two PC-510 panels add additional benefit to the protection system that go beyond current protection philosophies for fault clearing. The generation equipment (recloser control or inverters) will provide adequate fault clearing when configured properly, rendering the PC-510 panels unnecessary upgrades.[12] ***Sunthurst requests that PacifiCorp remove the PC-510 panels.*** Sunthurst also notes that a single panel using an SEL-787 would provide better protection at lower cost than two PC-510 panels.[13]

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9 See July 20 email from Larry Gross, attached, page3, ¶ 1(a).
10 See July 20 email from Larry Gross, attached, pages 3-4, ¶¶1(b)-(c).
11 See July 20 email from Larry Gross, attached, page 5, ¶3.
12 See July 20 email from Larry Gross, attached, page 5, ¶4.
13 See July 20 email from Larry Gross, attached, page 5, ¶4.

7. **<u>Telemetry is unnecessary</u>.** PacifiCorp is requiring telemetry as part of the Q1045 interconnection, although neither Q0666 nor Q1045 exceeds the 3MW threshold for telemetry enshrined in Oregon's OAR. Sunthurst understands based on the data provided that telemetry adds at least $180,000 to the cost of the Q1045 interconnection. A portion of the telemetry equipment will be installed, if at all, on PacifiCorp's transmission system, meaning those components are network upgrades. ***Sunthurst requests that PacifiCorp eliminate telemetry from the interconnection requirement.***

8. **<u>Justification for regulator controller replacement not provided</u>.** ***Sunthurst requests copies of PacifiCorp's analysis used to determine that a controls upgrade is required in this specific application.***

9. **<u>Itemized cost estimate for installations</u>.** ***To complete its review, Sunthurst requires the work papers or summaries behind its high level cost estimates. Such documentation should, at a minimum, identify all components over $5,000 as well as contingency and overhead costs.***

10. **<u>Drawings requested</u>**. ***To complete its review, Sunthurst requires copies of the Station One line Diagrams (meter and relay), AC Schematics (Three Line Diagrams), DC Schematics, and any removal drawings.***

11. **<u>Historical Final Costs of Interconnection</u>.** Information provided by PacifiCorp show a $169,000 contingency included in the Q1045 cost estimate. ***Sunthurst requests that PacifiCorp provide data characterizing what fraction of budgeted contingency it typically consumes on similar interconnections*.** This data would help Sunthurst and its lenders better anticipate the final cost of interconnecting to PacifiCorp.

Summation

The changes above, taken together, suggest strongly that safe, reliable interconnection of Q1045 and Q0666 comprised of only necessary interconnection facilities and distribution upgrades can be achieved at costs in line with the median costs published in the 2018 NREL study. Given the availability of technically sound alternatives at much lower installation cost, Sunthurst believes PacifiCorp's current interconnection scheme proposed for PRS1 and PRS2, is unreasonable.

Neither IEEE 1547, federal, nor Oregon law appear to proscribe the specific alternative interconnection solutions proposed by Sunthurst, meaning that PacifiCorp has discretion to grant Sunthurst's request for functionally equivalent, less costly, measures. However, if PacifiCorp desired, Sunthurst (and, presumably, Commission staff and the CSP Program Administrator) would cooperate in seeking express approval from the Commission in this instance in order to serve the Commission's goal of delivering CSPs to PacifiCorp customers. A previous PacifiCorp request for waiver of interconnection requirements to facilitate cost-effective customer-owned solar received enthusiastic approval of staff and the Commission.[14]

In Docket No. UM 1930 (the docket that implemented the Oregon CSP), Staff recently expressed concern that "additional opportunities to enable efficient integration of small generators are not being considered collaboratively". **The Commission, in adopting staff's recommendations, instructed staff to *"work with parties to continue to explore avenues for CSP generators and utilities to collaboratively consider additional one-off interconnection enhancements*.**"[15] Sunthurst respectfully requests that PacifiCorp adhere to the Commission's instructions, and collaborate to facilitate interconnection of Q0666 and Q1045.

Thank you for your time and consideration.

Kenneth Kaufmann
Attorney for Sunthurst Energy, LLC

Attachment A-- **July 20 email from Consulting Engineer Larry Gross to Sunthurst**

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[14] *In re SOLWATT, LLC and KENT and LAURA MADISON, Request for Waiver of the Primary Voltage Interconnection Requirements under OAR 860-084-0130 (2) of the Solar Photovoltaic Pilot Program.* 2012 Ore. PUC LEXIS 98, *5-8 (March 27, 2012) Order No. 12-107; UM 1538.
[15] Order No. 19-392, Appdx A at 13-14, 2019 ORE. PUC LEXIS 486, *29-30 (November 8, 2019).

Attachment A, Page 1

July 20 email from Consulting Engineer Larry Gross to Sunthurst

Daniel,

Sunthurst has asked Electrical Consultants, Inc. to review the technical interconnection requirements identified by the utility for the Q0666 project. The following summary of findings is based on the review of the Tier 4 Facilities Study Report dated November 18, 2015 and revised November 23, 2015, and additional project data provided by Sunthurst. In addition, information gathered during a telephone conversation with utility technical representatives, and my experience with renewable generation, protection, metering, SCADA, and communication systems was used as a technical basis. Due to schedule and limited design details at this time, this review is subject to change if further data is provided.

The following is a description of the utility requirements and the likely technical basis of the requirements. There is mention of typical practice, but this review is not intended to identify with any certainty the legal basis of the requirements or what the utility policies state. Utilities base their facility studies on the technical requirements that are expected, and the complete design and detailed analysis may not have been thoroughly completed if the proposed equipment is flexible enough to handle several scenarios. Another item worth noting is the consistency of designs between projects. If there is customization of a scheme it may reduce hardware costs, but increase engineering costs and maintenance costs for the utility. The utility has very specific pre-designed panels that are a “one size fits all” which reduces the time and cost to design and construct but often adds costs to the panel due to additional hardware and panel building.

Some of these solutions highlight how this interconnection could be done with minimal cost, but not necessarily how it should be done. The utility can still proceed with the upgrades based on them being good practice. What you would have to explore is if all those costs should be allocated to the project. For example, if this was a modern distribution station, the only upgrades you may have to do are the fiber and the regulator controls. Everything else would be already in place.

Generating Facility Modifications ($203,000)

1. **An SEL-351 type relay is required.** Sunthurst plans to use an SEL-351R or SEL-651R in conjunction with a recloser (pole mounted fault interrupting device). Either is acceptable with the SEL-651R being a more modern option with added features. This device will detect faults on the 12.47 kV system between the recloser and the step up transformers. The utility will determine the settings with input from the customer if additional protection or coordination requirements are desired. The programming will be provided by the utility. The programming will include voltage and frequency islanding protection. **There are no suggested methods for reducing or reallocating costs unless the engineering cost for the settings development is itemized for review and determined to be higher than expected. The only item provided by the utility is relay programming, no hardware.**
2. **The utility requires and will provide metering (two meters) and measurement devices** at or near the change of ownership. This is required to adequately measure the project production at the change of ownership. Two meters monitor the same data for redundancy. There is a question that was posed by Sunthurst regarding a single

Attachment A, Page 2

metering location instead of three when both Q0666 and Q1045 are connected. The technical solution proposed by Sunthurst to have a single metering location with a split allocation reported by Sunthurst is a technically sound solution and is often done at the transmission level. The utility will provide access for Sunthurst to read the metering data via communication port or pulsed contacts. **There are no suggested methods for reducing or reallocating costs of the single project metering. Only a single meter is required but the second meter is for redundancy in the case of failure the site would not require being shut down or production being under-reported. The Sunthurst proposal for metering the two co-located projects would reduce install costs but will add some additional regular reporting for Sunthurst.**

3. **Communication equipment will be required to remotely interrogate the meter using MV90.** This is a common requirement for interconnections and allows the utility to automatically read the interconnection meter using an industry standard protocol that integrates with the overall utility metering system. Communication paths are usually via telephone (cellular or basic dial up) or Ethernet connectivity on a utility Ethernet network. The utility indicated they were going to use the Utility Ethernet Network via the required fiber (see fiber discussion below). **As a standalone system upgrade, the least expensive would be to use a cellular modem. It is unclear who would pay for any ongoing cellular fees, but the data volume is minimal and is often included in a utility plan for little to no additional charge. Due to other system upgrades, the lower cost adder may be to use the fiber and utility network. See other line items.**
4. **SEL-2829 optical transceiver.** This is required for the transfer trip scheme, and **is the least expensive way to communicate between two SEL relays that are not co-located. If the SEL-2505 alternative is used (see discussions below), then this device is not needed at the utility substation end.**
5. **A metering panel is required.** This will hold the two meters and test switches to allow for online testing. It is unclear if this metering panel is intended and priced to be installed in a building or not. There is no mention in the facility report that any voltage for powering the meters is required like Q1045. It is expected that these will be powered by the equipment installed by the utility. **There may be a cost savings if this was priced as a full indoor panel as opposed to a pole mounted NEMA box that only contains the two meters and test switches. The specific pricing is unclear.**
6. **Communication Fiber associated equipment.** The utility will install fiber hung on the poles under the distribution line for the entire length of the distribution line from Pilot Rock substation to the generating facility. The fiber is a 48-count fiber, single mode, ADSS. A fiber patch panel and other communication equipment will be installed. It is unclear what other communication equipment is required, but with the large fiber count, homeruns could be made to every device not requiring any additional network switches. **There would be savings in installing a smaller count fiber if all of the fiber was not going to be dedicated to these projects. If the 48 ct fiber is specified for future capacity beyond the tap location, then the cost is not directly attributable to the technical requirements of this project. Higher count fibers are often specified because the majority of the cost is the installation so the additional fiber is best installed at the initial install.**

Distribution Line Requirements ($55,000)

Attachment A, Page 3

1. **Line Extension.** The utility will install 0.3 miles of new distribution line to extend a tap connection from the existing distribution line to the change of ownership. **There are no suggested methods for reducing or reallocating costs.**
2. **Gang operated switch and primary metering units.** The gang-operated switch is required for an isolation point operated by the utility. The metering units are what measure the system values for metering. **There are no suggested methods for reducing or reallocating costs.**
3. **Replace the tap-changing controller to address reverse power.** When there is power flow from the distribution system to the transmission system, the calculated voltage drop between the substation and the end-of-the-circuit customer is not accurate. A different controller can adjust its control requirements when power is flowing in the reverse direction. **There is the possibility that a controls upgrade is not required depending on the load flow details, which we do not have. If additional generation is added to the circuits, then the reverse power requirement may become more important. This may include Q1045.**

Fiber ($70,000)

1. **Fiber.** The fiber is required for the transfer trip. It is not required for the metering for Q0666, but it is preferred to use for the metering if the fiber is already required for other reasons. **There is likely a slight reduction in hardware and installation costs if point-to-point radios were used for the transfer trip scheme. This solution is not as reliable but is used by many utilities. The installed cost is likely less than installed fiber. This solution requires line of site visibility and a licensed frequency is recommended. Also, as mentioned above there is some savings in using a fiber with a smaller count of strands.**

Pilot Rock Substation ($477,000)

1. **Three Line Side VTs.** These voltage transformers are required for providing the feeder and transformer relays directional sensing and verification that the generator has disconnected prior to reclosing the breaker after a fault.
    a. For reclosing the line side voltage measurement provides indication that the generator is disconnected before it recloses. This is a typical utility practice. If it is not, the relay delays its reclosing. **The voltage sensing for reclosing is not required since the transfer trip scheme is in place. The scheme can provide positive feedback that the recloser is open via mechanical auxiliary contact as well as that the voltage is reduced to an acceptable level via measurement by the recloser. The processing delay will be about 2-4 ms. If the communication system is out of service, the recloser can either go to lockout or a reasonable time delay (5 seconds) could be used.**
    b. The feeder directional sensing is usually needed to determine the difference between a forward and reverse fault. For forward faults the utility source feeds the fault through the feeder breaker. For bus, transformer, transmission, or adjacent feeder faults, the generator feeds the fault through the feeder breaker. If the difference in current flow between the two directions is not a large enough difference, then the protection pickup value cannot be set high enough. The existing setting pickup value is about 600 Amps instantaneous. This is an unusually low value for an instantaneous setting, but the utility indicated they are using a fuse saving scheme, which typically has a fast initial

trip for the first fault trip before reclosing. This value is believed to be above the fault contribution of the inverters after about 4 ms, which is identified to be 107%. This would need to be confirmed by the inverter manufacturer including during voltage ride through time periods. It should also be noted that it is expected that the generation transformers are larger than the existing customer load transformers currently on the distribution line. This means that inrush currents could exceed the 600 Amp fault level and the utility may want to reconsider the fuse saving scheme. This can also be addressed by using harmonic blocking at the recloser, which in turn could block the relaying at the substation. Although these upgrades are good protection design practice, **based on these expectations, a voltage measurement at the feeder relay is not required for this interconnection.**

c. The other requirement for the VTs is to provide directionality for the transformer relay. For transformer or transmission faults, the generator feeds the fault into or through the transformer. The utility wants to minimize damage to the transformer for any fault. The directional relay would allow a low set overcurrent element to trip for any current flowing from the distribution circuit into or through the transformer. This may not be an effective means to detect faults because the fault current generated by the generation is only slightly above its normal full generation output, so trying to detect fault current versus normal generation flowing into the transformer may not be practical. In addition, the full fault contribution from the generation is believed to be below the withstand capabilities (normal load capacity) of the transformer, so no additional damage could develop other than at the fault location. The damage at the fault location is determined by the time delay of the fault clearing. The amount of current that the generation may produce is expected to be well below the existing fuse protection of the transformer, so any additional requirements to better protect the transformer from fault duration at the point of the fault would not be represented by the existing protection philosophy on the transformer. Due to the difficulty of determining a reverse fault versus a forward fault at the transformer, a neutral CT could be added and directionality could be provided or a differential relay with REF would provide high-speed protection for removing generation, but none of these schemes improve the time delay of the fuse clearing which is the existing protection. Although these upgrades are good protection design practice, **based on these expectations, a voltage measurement is not needed for this interconnection for the reverse transformer protection.**

2. **PC-611 Panel.** This is believed to be the feeder protection panel. The feeder relays are old electromechanical relays. Most utilities in the US have upgraded their distribution feeder relays to an advance microprocessor relay already or have a plan in place to do so without regard to interconnections, however, many require upgrading when an interconnection is on a distribution circuit with an old relay. This often provides flexibility to perform directionality (see above), better monitoring, and flexibility for transfer tripping and special logic schemes that possibly are required. The concern in this case is that the fault currents and existing system does not appear to require the upgrade. There may be specific studies that show advanced relaying is required but it is not clear why. The current levels and voltage requirements were addressed above. The transfer tripping could be performed using the SEL-2505 bolted inside the existing panel,

a lower cost solution, and the reclosing could be delayed with other means when necessary using contacts from the SEL-2505. Although the feeder upgrade is good protection design practice, **based on these expectations, a new, advanced relay does not appear to be technically required for this interconnection.**

3. **PI-111 annunciator panel.** It is not clear why this panel is required for this interconnection since the existing station does not have any annunciation. The existing relays have targets to indicate tripping and an SEL-2505 has lights to indicate input and output contact statuses including data digital alarm points from the Generator up to 8 indications. This device could be upgraded to an SEL-2506, which would then have front panel indication. **Based on these expectations, the annunciator panel does not appear to be technically required.**
4. **PC-510 Transformer Metering Panel (qty 2).** This panel was confirmed by the utility to not be for metering, although the relay can provide metering and is often used for that by the utility. This panel would include the SEL-751 relay for detecting transformer faults and tripping the generator. As Identified above, this relay may be good protection practice, but it adds additional benefit to the protection system that is beyond what are the current protection philosophies for fault clearing times. The recloser or inverters will clear for a fault themselves in a reasonable amount of time given the current flow value for a transformer fault once the fuse clears. Although adding the transformer metering panels is good protection and station upgrade practice, **based on these expectations, an advanced transformer relay is not required for this interconnection.** It should also be noted that a single panel that uses an SEL-787 could monitor both transformer low sides for REF protection. This would not be a typical panel design for the utility, would provide much faster protection, but is still not required for this interconnection.
5. **Fiber channel and associated equipment.** The fiber is required for the transfer trip. This equipment could be limited to a patch panel only if no relays were upgraded or installed as described above. The device that would interface with the existing relays for transfer trip and block reclosing would be the SEL-2505, which has a built-in fiber port. **No other communication equipment appears to be needed. By keeping the relay system design simplified, the fiber design could be as well. The number of fibers as mentioned above is another possible cost reduction item.**

Lawrence C. Gross, Jr.

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August 7, 2020

Mr. Ken Kaufman
1785 Willamette Falls Drive, Suite 5
West Linn, Oregon 97086

RE: Pilot Rock Solar 1, LLC (Q0666) and Pilot Rock Solar 2, LLC (Q1045).

Dear Mr. Kaufman:

The purpose of this letter is to respond to your letter to PacifiCorp dated July 23, 2020, regarding the two above-referenced interconnection requests. For reasons discussed further below, PacifiCorp agrees to two of Sunthurst Energy LLC's ("Sunthurst") proposed design modifications.

First, regarding the Q1045 Pilot Rock Solar 2 interconnection request, PacifiCorp agrees to a modification for telemetry. However, PacifiCorp views the strategy by Sunthurst of siting two projects totaling 4.97 megawatts ("MW") at the same point of interconnection ("POI") as gaming the Oregon Division 82 Small Generator Interconnection Rules. OAR 860-082-0070(2) states that a small generator facility with a nameplate capacity of less than three MW cannot be required to provide or pay for data acquisition or telemetry. However, together the Pilot Rock Solar 1 and 2 projects far exceed the three MW threshold. To be clear, PacifiCorp views a lack of telemetry for generation of Pilot Rock Solar 1 and 2's sizes to be an irresponsible way to run a distribution system and, absent telemetry, will result in degradation of service to other customers in this area. Therefore, PacifiCorp, at its ratepayers' expense, will install the necessary telemetry equipment to monitor the two Pilot Rock solar projects, should they proceed.

The reduction in costs for this modification is estimated to be approximately $525,000. PacifiCorp will be reissuing a new facilities study for Q1045 to Sunthurst with these changes. Upon receipt of the new facilities study, Sunthurst will have 15 business days to consent; otherwise, PacifiCorp will deem the interconnection request withdrawn.

Next, regarding the Q0666 Pilot Rock Solar 1 interconnection request, PacifiCorp is willing to remove the P1-111 annunciator panel. The reduction in costs for this modification is $15,000. PacifiCorp will provide an amendment to the interconnection agreement for Q0666 to remove this requirement. However, in addition to this minor scope and estimate revision, the interconnection agreement will also contain proposed changes to bring the agreement up to current conditions as it is currently long outdated. The changes will include revised milestone dates to demonstrate the project reengaging on a schedule to finish within the next year. It will also contain an updated overall project estimate that reflects the costs that have already been incurred, as well as PacifiCorp's estimated costs to finish the Q0666 project. Upon receipt of the amended interconnection agreement, Sunthurst will have 15 business days to execute the amendment. Otherwise, PacifiCorp will proceed with termination of the interconnection agreement.

Other than the two modifications discussed above, PacifiCorp cannot agree to the other design modifications proposed in Sunthurst's July 23, 2020 letter. The remaining proposed modifications are discussed further in Section II.

I. Background

Sunthurst initially provided notice of an intent to file a complaint regarding Pilot Rock Solar 2, LLC (Q1045) due to the delay associated with the system impact study for that project on March 20, 2020. The system impact study was provided on March 27, 2020. Thereafter, you sent a letter to Karen Kruse dated April 28, 2020, in which Sunthurst cited two concerns not only regarding Q1045, but also regarding Q0666—the latter for which Sunthurst had already executed an interconnection agreement, dated March 14, 2016, agreeing to pay costs associated with interconnection of that project. The two concerns expressed in your April 28, 2020 letter regarded: (1) a protective relay system for Q0666; and (2) a control building at the Pilot Rock Solar 1 and 2 site to house interconnection equipment.

PacifiCorp readily agreed to a conference call to discuss the issues cited by Sunthurst. Sunthurst requested the conference call be delayed and requested written responses to the two topics raised in the April 28, 2020 letter. On May 15, 2020, PacifiCorp provided a written response explaining the need for the protective relay system that is planned for the Q0666 project. In addition, the facilities study for Q1045 was adjusted to require the installation of a weather proof enclosure on the site, as opposed to a control building, which lowered the cost of Q1045 by approximately $200,000.

On June 8, 2020, in advance of the June 9, 2020 conference call to review the facilities study for Q1045, Sunthurst provided additional questions for both Q0666 and Q1045. PacifiCorp responded to the Q1045 questions during the June 9th conference call and offered to follow up with Sunthurst regarding: (1) the removal of a field recloser and the associated costs from the facilities study, and (2) ongoing discussions with Bonneville Power Administration of possible mitigation of islanding risks. PacifiCorp requested two weeks to provide this follow up information. Due to the number of questions posed regarding Q0666, PacifiCorp scheduled a separate conference call with Sunthurst for June 18, 2020, which was subsequently rescheduled to accommodate Sunthurst.

On June 10, 2020, Sunthurst requested additional time to consent to the costs of the facilities study for Q1045. On June 22, 2020, Sunthurst again requested an update on the possible mitigation of islanding risks and the field recloser.

On June 25, 2020, PacifiCorp responded to Sunthurst: (1) advising it could remove the field recloser (upon confirmation from Sunthurst); and (2) providing an update regarding BPA system upgrades needed to avoid islanding and a status update on a higher priority interconnection request Q0547 for 18 MW. On June 25, 20202, Sunthurst contacted PacifiCorp regarding the pending Oregon queue reform filing, to request a more detailed cost breakdown for Q1045, to request a single meter configuration for Q1045 and Q0666, confirm that it wanted the field recloser remove, and to request the scheduling of a conference call to discuss the Q0666 questions. PacifiCorp subsequently set up the conference call for July 17, 2020.

On June 30, 2020, PacifiCorp provided an updated facilities study for Q1045, which reflected the removal of the field recloser and requesting a response by July 22, 2020. On July 1, 2020, Sunthurst acknowledged receipt of the updated facilities study. On July 2, 2020, PacifiCorp provided a response to Sunthurst regarding the need for the three meter configuration identified in the studies and providing a more detailed breakdown of costs for Q1045. On July 2, 2020, PacifiCorp also provided a response regarding the pending Oregon queue reform filing.

On July 17, 2020, a conference call was held at which time Sunthurst's questions regarding Q0666 were addressed by PacifiCorp engineering personnel. In addition to the questions, Sunthurst again raised the question of a single issue metering configuration. Sunthurst also requested an extension to respond to the facilities study.

On July 20, 2020 PacifiCorp responded to Sunthurst explaining: (1) it cannot not agree to an alternative metering arrangement because the proposed metering arrangement is consistent with how PacifiCorp has treated other similar requests and is consistent with its "Metering Policy for Interconnection Customers" # 139; (2) it would not provide an extension to the June 22, 2020 date for Sunthurst to consent to costs for Q1045; (3) that an amended interconnection agreement would be issued that has new dates for milestones for Q0666, which will allow PacifiCorp to recommence construction of that project; (4) if Sunthurst needs additional cost breakdowns for Q1045, it should state specifically what costs is seeks additional breakdowns for given that PacifiCorp already gave a cost breakdown on July 2, 2020; (5) PacifiCorp needs additional detail on the engineering design drawings that Sunthurst seeks for Q0666; and (6) PacifiCorp will start working on updated forecasts of costs to complete Q0666.

Later on July 20, 2020, in response to a request from Sunthurst, PacifiCorp agreed to an additional extension for Sunthurst to respond to the facilities study for Q1045 and requested that Sunthurst provide any outstanding questions to PacifiCorp on or before July 28, 2020. Thereafter, Sunthurst provided its July 23, 2020 letter which proposes multiple design modifications for Q0666 and Q1045, as well as additional requests for information.

As demonstrated above, PacifiCorp has engaged in reasonable discussions with Sunthurst for several months, provided written and oral responses to questions and proposals from Sunthurst, and modified costs based on those discussions. Thus, PacifiCorp has done more than "just listen", it has acted in good faith, adjusted costs where reasonable to do so, and supported the remaining costs for interconnection.

II. Responses to Sunthurst's Proposed Design Modifications

In keeping with its good faith efforts, below PacifiCorp provides responses to the additional design modifications proposed by Sunthurst in its July 23, 2020 letter. With the exception of the two modifications noted earlier, PacifiCorp cannot agree with the other proposed modifications. At a high level, the other design modifications will either result in a degradation of service to other customers, harm other customers' facilities, or otherwise be contrary to good utility practice. I note that Sunthurst's own consultant engineer, Larry Gross, recognizes that Sunthurst's proposed modifications are things that "could be done with minimal cost, but not necessarily how it should be done. The utility can still proceed with the upgrades based on them being good practice."[1] Mr. Gross's summary is directly on point – Sunthurst seeks to make design modifications solely to reduce costs of interconnection, while not acknowledging that the costs identified by PacifiCorp are driven by good utility practice.

1. ***Sunthurst requests that the specified meters at the PRS1 (Q0666) collector substation and the specified meters at the PRS2 (Q1045) collector substation be moved to the low side, and the specified meters at the change of ownership point (COP) be eliminated.***

   Alternatively, Sunthurst requests that metering be accomplished with one metering point at the COP and one meter at the low (480V) side of PRS2.

<u>**PacifiCorp Response:**</u>

As Sunthurst is aware based on PacifiCorp's previous explanations, the metering configuration required for Q1045 and Q0666 is driven by the fact that there are two separate and distinct generator projects being proposed at the same POI with two different customers. Q0666 is with Sunthurst Energy, LLC and Q1045 is with Pilot Rock Solar 2, LLC. PacifiCorp understands that both projects are currently owned by the same parent company, but PacifiCorp has no authority to prevent a sale of one or both the projects to different entities; therefore, they must be metered separately. PacifiCorp's metering design is consistent with all similarly situated interconnection requests, including projects owned by PacifiCorp.

Sunthurst's request to install the project meters on the low side of Sunthurst's step up transformers is also inconsistent with PacifiCorp's policy and all other similarly situated interconnection requests. Sunthurst's assertion that installing low side meters would result in significant costs savings is not accurate. PacifiCorp estimates that this change would result in only approximately $25,000 in cost savings for PacifiCorp's costs. In addition, low side meters would require additional equipment to be installed by Sunthurst to house PacifiCorp's meters, which would result in even less cost savings. Additionally, PacifiCorp's merchant will require the Pilot Rock Solar projects be metered separately for power purchase purposes, i.e., one at the POI to measure the total output onto the system and then two more at the generators to distinguish how much generation is coming from each project.

2. ***PC-611 Panel Installation may not be necessary – Sunthurst request PacifiCorp explain why PC-611 is needed.***

<u>**PacifiCorp Response:**</u>

There are three functions for the feeder relays and controls that are needed for the addition of the solar electric plant that the current equipment cannot perform: (1) communication with the circuit recloser's relay at the POI for the solar electric plant, this communication circuit is for the transfer trip; (2) monitoring the line side voltage on the feeder breaker to delay the reclosing until the line is dead due to the disconnection of the solar electric plant; and (3) configuration of the

1 Attachment A, page 1 to Sunthurst's July 23, 2020 letter.

overcurrent functions to not operate for faults on the other feeders connected to Pilot Rock Substation by enabling directional overcurrent elements.

The installation of the PacifiCorp standard feeder relay and control panel PC-611 will provide all of these functions, as well as provide the functions that the existing relay and control panel provides for the feeder breaker to which Sunthurst desires the solar electric plant to connect. The usage of the SEL 2505 device the Mr. Gross proposes will only provide the communication function.

3. ***The cost of the new fiber optic cable should be shared. Sunthurst requests that PacifiCorp pay the difference between the cost of the fiber optic system specified by PacifiCorp and the cost of direct radio communication to Pilot Rock substation suitable for PRS1 and PRS2.***

PacifiCorp Response:

PacifiCorp has determined that a microwave radio option to provide communications between the Pilot Rock solar site and Pilot Rock substation is not the most cost effective alternative. It would require the construction of possibly three microwave sites to develop a communications link, which would be more expensive than installing fiber optic cable. Therefore, Sunthurst's underlying assumption of cost is not accurate.

Sunthurst also asserts that PacifiCorp could install a smaller fiber optic cable than the standard 48-count fiber. The 48-count fiber is what PacifiCorp installs for all similarly situated projects -- including its own projects. It is also the type of fiber PacifiCorp has in stock, which allows for timely repairs. 48-count fiber also provides greater reliability on the communication path in the event fibers break. Thus, a fiber system is far more dependable and easier to maintain than the spread spectrum radio solution.

Thus, the use of the 48-count fiber reflects good utility practice. Sunthurst's proposal to use 24-count fiber would not only be contrary to PacifiCorp's standards, but it would require PacifiCorp to keep spares 24-count fiber in stock solely for the two Pilot Rock Solar projects, which would be inefficient and require the incurrence of additional costs.

Finally, PacifiCorp notes that there is a small cost difference between 48 and 24-count fiber. This is because other than the count, the fiber is similar (e.g., same patch panels). The cost difference is approximately $0.13 per foot. There is approximately one mile of fiber at issue for the Pilot Rock Solar 1 and 2 projects. Therefore, the potential cost savings, even without including the costs of purchasing and maintaining spare 24-count fiber is less than $700.

Sunthurst's request that PacifiCorp share some of the cost for the fiber optic cable is contrary to the Oregon Division 82 Small Generator Interconnection Rules. Pursuant to OAR 860-082-0035(2), the applicant must pay the reasonable costs of the interconnection facilities identified by the public utility. As noted earlier, the use of 48-count fiber reflects good utility practice. Thus, Sunthurst is required to pay these reasonable costs. The costs for this fiber would also not be incurred but for Sunthurst's interconnection requests.

In regard to the fiber channel and the associated equipment, PacifiCorp notes that Mr. Gross states, "this equipment could be limited to a patch panel only if no relays were upgraded or installed…"[2] Please see the answer from PacifiCorp below to Question 2 above.

4. ***Voltage measurement at the feeder relay is not necessary. Sunthurst requests that PacifiCorp remove the three high-side voltage transformer ("VTs") after confirming that these optional protection practices and warranted performance of Sunthurst's inverters provide adequate protection.***

PacifiCorp Response:

On May 15, 2020, PacifiCorp previously addressed in writing why the inverters at the Pilot Rock Solar projects cannot meet the protective relay system requirements. In addition, PacifiCorp provides the following additional explanation:

a. The three line side VTs are not planned to be used for the transformer relays. The transformer relays will be using the existing VTs in the substation.

   The dead line check, by the feeder relay, prior to reclosing is required to prevent potential damage to other customers' equipment for a case in which, following the opening of the feeder breaker at Pilot Rock Substation; either due to a communication failure or a generation customer recloser operation failure; the solar electric generation is not disconnected prior to the reclose of the breaker at Pilot Rock Substation. This type of event would cause damage to the other customers' equipment, especially pump motors. The dead line check before the reclose will prevent this potential damage.

   The timing of the automation reclose at Pilot Rock Substation for the feeder breaker that the solar electric generation wants connected is configured to provide a dead time between the tripping of the breaker and the closing of the breaker of 0.35 seconds. This timing is to provide the best quality of service to the customers. The modifications to the utility's system to accommodate the solar electric generation is to maintain the same level of service quality to the existing customers as they are currently experiencing. The transfer trip and the dead line check will accomplish this.

b. It has been documented that solar electric plant inverters that are configured with controls that will provide the low voltage ride through, that is require for solar electric plant inverters that connect to the WECC system, will produce current in excess of their current limit for faults on the electrical system that they are connected to in the order of 2.5 – 2 times the inverter's rating for 16-25 milliseconds. In the case of the Pilot Rock Substation, the current from the inverters for close in faults on the other feeders out of Pilot Rock Substation will cause the feeder relay on the circuit that the solar electric plant will be connected to trip for those faults if the overcurrent elements in the relay are not directional. This will not be an acceptable operation and will significantly reduce the quality of service to the existing customers. To prevent this

2 Attachment A, page 5 to Sunthurst's July 23, 2020 letter.

type of operation the new feeder relay using the new VTs on the line will be set so that the overcurrent elements will be directional, only operating for faults on the feeder circuit. This is a relay function available in the new feeder relay that is not available in the relays currently being used at Pilot Rock Substation.

The use of fuse saving scheme on the feeder circuit that the solar electric plant wants to be connected to is an important feature of the relay and controls to maintain the quality of service to the existing customers. Because of that the removal of the fuse saving scheme will not be concerned for the addition of the solar electric plant.

c. (*for response to PC-510 Transformer Metering Panels, as well*) The new VTs will not be used for the directionality for the transformer relays, as noted in (a). Each of the buses that the transformers are connected to are equipped with VTs to provide the voltage for the transformer relays.

Since the majority of the energy that the solar electric plant will be producing will be used to carry the load on the 12.5 kV circuit, normally very little to no current will be flowing into the transformer from the 12.5 kV side. Based on the minimum daytime load on the feeder, which would produce the maximum current into the transformer, the most current that will be flowing into the transformer from the 12.5 kV side will be 35 A. For the first two cycles into a fault in the transformer the solar electric plant will be supplying 250 A. The directional instantaneous overcurrent elements in the SEL 751 relay will be set to detect this increased reversed current flow and key transfer trip to the solar electric plant. With this arrangement, the solar electric plant will be disconnected at about the same time as the fuses are blowing on the 69 kV side of the transformer. The resulting protection for the transformer remains at the same level of performance as the current configuration. Mr. Gross suggested the use of a SEL 787 relay, which would be a good option, but it is a higher cost item than the usage of the SEL 751 relay.

5. As a standalone system upgrade, the least expensive would be to use a cellular modem.

PacifiCorp Response:

As PacifiCorp explained in its May 15, 2020 communication, and reiterates again in this letter, a protective relay system that is needed for the Q0666 project to: (1) disconnect the solar generation in a timely manner for faults on the 12.5 kV circuit; (2) maintain the 20 cycle recloser function of 5W406; (3) minimize the potential damage for a problem in the 69 – 12.5 kV transformer – all without causing the disconnection of the generation facilities for faults on the 230 kV network. Due to the relays, fiber is needed and a cellular modem would not be sufficient. A cellular modem would be sufficient if only data were being communicated. Even if a cellular modem could be used, it would not be substantially less expensive. As noted earlier, there is one mile of fiber at issue for the Pilot Rock Solar projects and the difference in price is approximately $0.13 per foot.

6. ***There may be a cost savings if this [meter panel] was priced as a full indoor panel as opposed to a pole mounted NEMA box that only contains the two meters and test switches.***

PacifiCorp Response:

As noted earlier, one of the original concerns expressed by Sunthurst in its April 28, 2020 letter regarded a control building at the Pilot Rock Solar 1 and 2 site to house interconnection equipment. After further consideration, PacifiCorp modified the control building was removed from the Facilities Study for Q1045, and instead the installation of a weather proof enclosure on the site was used. This lowered the cost of Q1045 by approximately $200,000. The result is the meter panel is now pole mounted, as opposed to being installed within the control building (which is no longer included in the Facilities Study).

7. ***Itemized cost estimate for installations. To complete its review, Sunthurst requires the work papers or summaries behind its high level cost estimates. Such documentation should, at a minimum, identify all components over $5,000 as well as contingency and overhead costs.***

PacifiCorp Response:

PacifiCorp provides more itemized cost estimates for Q1045 as an attachment to this letter, which reflects the agreed upon modifications described in this letter. The breakdown of costs includes contingency and overhead costs. PacifiCorp is also not willing to provide specific pricing for equipment that it purchases as the information is considered confidential.

8. ***Drawings requested. To complete its review, Sunthurst requires copies of the Station One line Diagrams (meter and relay), AC Schematics (Three Line Diagrams), DC Schematics, and any removal drawings.***

PacifiCorp Response:

PacifiCorp is concerned about providing these drawings for security reasons and therefore cannot provide the requested drawings. Furthermore, there is no basis for Sunthurst to have drawings of PacifiCorp facilities.

9. ***Sunthurst requests that PacifiCorp provide data characterizing what fraction of budgeted contingency it typically consumes on similar interconnections.***

PacifiCorp Response:

The more itemized cost estimate for Q1045 includes contingency cost details. However, Sunthurst is responsible for the actual costs. If Sunthurst pays a deposit for the estimated costs and the actual costs are lower, then pursuant to OAR 860-082-0035, the unused portion of the deposit will be returned to Sunthurst. If the actual costs are higher, Sunthurst will be invoiced for the amount over any provided deposits.

Sincerely,

/s/ *Matthew P. Loftus*

Matthew P. Loftus

Attachment F

UM 2118 PacifiCorp's Response Testimony

PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

January 26, 2021

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Attn: Filing Center
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RE: UM 2118—PacifiCorp's Response Testimony and Exhibits

PacifiCorp d/b/a Pacific Power hereby submits for filing the Response Testimony and Exhibits of Mr. Kris Bremer, and the Response Joint Testimony and Exhibits of Mr. Milt Patzkowski, Mr. Alex Vaz, and Mr. Richard Taylor.

Please direct any informal correspondence and questions regarding this filing to Cathie Allen, Regulatory Affairs Manager, at (503) 813-5934.

Sincerely,

Etta Lockey
Vice President, Regulation

Enclosure

Docket No. UM 2118
Exhibit PAC/100
Witness: Kris Bremer

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Response Testimony of Kris Bremer

January 2021

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ATTACHED EXHIBITS

I. INTRODUCTION

Q. Please state your name, business address, and present position.

A. My name is Kris Bremer. My business address is 825 NE Multnomah, Suite 1600, Portland, Oregon 97232. My present position is Director of Generation Interconnection and Transmission Project Management at PacifiCorp. I am responsible for customer generator interconnection requests.

Q. Please describe your educational background and professional experience.

A. I have a Bachelor of Science in Business Administration from Warner Pacific College. I have had management responsibility of customer generator interconnection requests since 2014. I have been employed by PacifiCorp since 2004.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to respond to the assertions made by Mr. Daniel Hale and Mr. Michael Beanland in their Opening Testimony on behalf of Sunthurst Energy, LLC (Sunthurst) regarding the interconnection costs PacifiCorp has estimated for the 1.98 megawatt (MW) Pilot Rock Solar 1, LLC and the 2.99 MW Pilot Rock Solar 2, LLC (the projects are also referred to herein as “PRS1” and “PRS2”, respectively).[1] PacifiCorp has steadfastly worked with Mr. Hale and Sunthurst to ensure safe and reliable interconnections, consistent with industry standards and good utility practice for both Pilot Rock Solar projects. My testimony describes PacifiCorp’s good faith efforts to work with Sunthurst to reduce the interconnection costs for its projects and addresses Mr. Hale’s general allegations related to PacifiCorp’s interconnection study

[1] PRS1 has been designated as interconnection Queue No. 0666 (Q0666) and PRS2 has been designated as Queue No. 1045 (Q1045).

process and cost estimates. My testimony also responds to certain issues raised by Mr. Beanland.

Q. Are there other witnesses providing testimony in this docket?

A. Yes. Messrs. Eric Taylor, Milton Patzkowski, and Alex Vaz generally respond to the testimony provided by Mr. Beanland and address the technical issues and cost estimates related to the interconnection of PRS1 and PRS2. Messrs. Taylor, Patzkowski, and Vaz explain that the Commission should not allow interconnection customers to dictate the implementation and operation of PacifiCorp's distribution or transmission system by approving Sunthurst's recommended design modifications, none of which meet PacifiCorp's existing practices, are contrary to the intent of interconnection studies, and could potentially degrade service and reliability for all retail customers.

Q. Please summarize your testimony.

A. PacifiCorp has expended considerable time and resources working with Sunthurst to answer Sunthurst's questions and concerns regarding the estimated costs to interconnect PRS1 and PRS2. Through this effort, PacifiCorp has reduced the estimated interconnection costs and requirements in an effort to accommodate Sunthurst's projects and advance Oregon's Community Solar Program (CSP). PacifiCorp can only go so far, however, and ultimately Sunthurst is responsible for bearing the reasonable costs to interconnect its projects. It is important that *reasonable cost* does not mean the *absolute lowest cost*, especially when the latter is contrary to good utility practice, PacifiCorp policies, and could result in a degradation of service to other customers.

Sunthurst seeks to shift, as much as possible, the PRS1 and PRS2 interconnection costs to PacifiCorp's retail customers. However, PacifiCorp's retail customers cannot subsidize Sunthurst's development efforts and it is Sunthurst's responsibility to site and plan its projects in a way that makes them economically feasible to construct.

Sunthurst's general and non-specific complaint that PacifiCorp's estimated interconnection costs are too high has no merit. The estimated costs for PRS1 and PRS2 result from interconnection studies undertaken by PacifiCorp. The purpose of the interconnection studies is to determine what interconnection facilities are needed, if any, to accommodate the interconnection request without adversely impacting the system and the quality of service that existing customers are receiving. Each project's estimated interconnection costs and requirements are fact-specific and depend on a multitude of factors, including where the project is sited, what other projects are in the vicinity, local area loads, and the specific configuration of the project or projects. In support of its complaint, Sunthurst relies on a combination of limited generic data from other utilities in other states and unsupported hearsay from anonymous sources. But that data, some of which is entirely unverifiable, does not in any way show that the costs to interconnect the Pilot Rock Solar Projects is too high or unreasonable.

Sunthurst also incorrectly claims that its projects are disadvantaged because they are interconnecting pursuant to the Commission's interconnection policies instead of the Federal Energy Regulatory Commission's (FERC). In addition to the fact that the Commission's interconnection policies are not at issue in this case, Sunthurst is simply wrong. If their project were processed in accordance with

PacifiCorp's Open Access Transmission Tariff (OATT), the results would be the same.

III. BACKGROUND

Q. Please further describe the Pilot Rock Solar Projects.

A. PRS1 and PRS2 are two photovoltaic generation resources that are proposed to be located in Umatilla County, Oregon. Both projects are owned by Sunthurst but are organized as separate legal entities. Both projects are QFs and have requested interconnection with PacifiCorp—PRS1 has been designated interconnection Queue No. 0666 (Q0666), and PRS2 has been designated interconnection Queue No. 1045 (Q1045).

Q. Has either project completed an interconnection study process?

A. Yes. PRS1 completed the interconnection study process and executed a Small Generator Interconnection Agreement (SGIA) on March 14, 2016. The executed SGIA is attached to this testimony as PAC/101. The SGIA included interconnection requirements, an interconnection schedule, and milestone payments intended to allow PRS1 to interconnect by May 15, 2017. The SGIA included estimated costs to interconnect PRS1 of $805,000.

Q. Are the estimated costs included in PRS1's SGIA the amounts that Sunthurst will actually pay to interconnect PRS1?

A. No. The SGIA includes *estimated* costs based on the Company's best estimate made when the SGIA was executed of the costs to construct the facilities required to interconnect PRS1. PRS1, however, will pay the *actual* costs to construct the facilities, which may be lower or may be higher depending on the specific circumstances.

Similarly, interconnection studies, including those at issue here, provide *estimated* costs to interconnect the proposed project to PacifiCorp's system. The interconnection customer, however, pays the *actual* costs, not the estimated costs.

Q. After executing its SGIA, did Sunthurst ask PacifiCorp to extend the milestones included in the agreement to allow Sunthurst to delay interconnecting PRS1?

A. Yes, and PacifiCorp has largely agreed to allow Sunthurst additional time to interconnect PRS1. PacifiCorp agreed to extend the milestones of the SGIA at the request of Sunthurst four times by amending the SGIA on June 20, 2016; October 11, 2016; November 27, 2017; and November 6, 2018.

Most recently, on March 20, 2019, Sunthurst provided PacifiCorp a letter informing the Company that it planned to submit PRS1 as a CSP project.[2] Sunthurst asked for additional time before PacifiCorp continued with its scope of work for the PRS1 interconnection to allow the Commission to more fully develop the CSP. PacifiCorp agreed to delay any further work on PRS1 until the Commission finalized the framework for the CSP.

Q. Has PacifiCorp ever issued a notice of breach to Sunthurst for breaching the SGIA for PRS1 (Q0666)?

A. No. Even when Sunthurst was unable to meet its obligations under the terms of the SGIA, PacifiCorp worked with them rather than seeking to terminate the agreement. Granting repeated extensions to Sunthurst has meant that PacifiCorp personnel have

[2] *See* PAC/102 (Sunthurst's March 20, 2019, letter).

had to start and stop their work related to PRS1, which has increased costs and taken resources away from other interconnection customers.

Q. Did Sunthurst reengage in construction of the PRS1 interconnection facilities after the Commission approved the final elements of the CSP in late 2019[3]?

A. No. Sunthurst did not reengage with PacifiCorp to complete the interconnection of PRS1. Instead, Sunthurst sought to renegotiate the terms of the SGIA and disputed the estimated costs it agreed to pay in the SGIA.

Q. Did PacifiCorp continue to work with Sunthurst in good faith in response to its request to renegotiate the SGIA for PRS1?

A. Yes. The work continued in conjunction the System Impact Study (SIS) for PRS2, which was provided on March 27, 2020.[4]

Q. Why did it take so long to issue the SIS for PRS2?

A. It took PacifiCorp nearly 18 months to complete the SIS for PRS2 because of the backlog in PacifiCorp's serial interconnection queue that existed at that time.[5] As the Commission is aware, the serial queue order interconnection study process was particularly susceptible to delays because studies were performed serially, which meant that before PacifiCorp could complete the study for PRS2 (Q1045), it had to first complete studies for all higher priority interconnection requests.

[3] Although I am not intimately familiar with the non-interconnection aspects of the CSP, I understand that the Commission adopted the final elements of the program in Order No. 19-392, which was issued on November 8, 2019.
[4] PAC/103 includes all the interconnection studies PacifiCorp provided for PRS2 (Q1045).
[5] Sunthurst and PacifiCorp executed an interconnection system impact study form agreement on August 29, 2018.

Moreover, when projects drop out of the interconnection queue PacifiCorp is often required to perform restudies, which also must occur in serial queue order and which cause additional delays.

PacifiCorp worked diligently to complete all the higher priority studies and the SIS for PRS2 as expeditiously as possible given the constraints inherent in the serial queue order process. Unfortunately, however, because of PRS2's relatively low priority queue position, its study could not be completed in the timeframe contemplated by the Commission's small generator interconnection rules.

Q. Did the serial queue order study of PRS2 assume that PRS1 was in-service?

A. Yes. Consistent with the process described above, PacifiCorp studied PRS2 based on the assumption that PRS1, and the interconnection facilities required for PRS1, were in-service. PacifiCorp studied each project independently, however, consistent with the fact that each project is a separate legal entity and separate interconnection customer. PacifiCorp did not, and cannot, assume common ownership by Sunthurst because Sunthurst could sell one or both projects to others.

Q. Is it fair for Mr. Hale to complain about the length of time to finalize the SIS for PRS2[6] notwithstanding the multiple extensions that PacifiCorp granted for PRS1?

A No. As I noted earlier, PacifiCorp agreed to extend the milestones in the PRS1 SGIA at the request of Sunthurst four times by amending the SGIA. The extensions provided approximately two and one-half years of additional time for Sunthurst to interconnect PRS1 and yet Mr. Hale complains about the 18 months to complete the

[6] Sunthurst/100, Hale/4.

SIS for PRS1. Moreover, the delays associated with the completion of the SIS were outside the control of PacifiCorp, whereas the extensions provided to PRS1 were requested by Sunthurst.

Q. Please describe the efforts PacifiCorp undertook to work with Sunthurst to address concerns over the interconnection costs for PRS1 and PRS2.

A. In April 2020, Sunthurst raised questions regarding both the SIS for PRS2 and the SGIA for PRS1. PacifiCorp readily provided written responses to the questions and offered to have a conference call, which was held on June 9, 2020. Before the June 9th conference call, on May 15, 2020, PacifiCorp provided a written response to several questions from Sunthurst. On June 2, 2020, PacifiCorp issued a Facilities Study for PRS2 that lowered the estimated interconnection cost (in comparison to the estimate set forth in the SIS) by approximately $200,000 due to an adjustment to require a weatherproof enclosure on site, as opposed to a control building.

Then, on the day before the scheduled June 9th conference call, Sunthurst provided additional written questions to PacifiCorp. Due to the timing, PacifiCorp was only able to respond to PRS2-related questions during the June 9th conference call.

Q. Did PacifiCorp continue to work with Sunthurst after the June 9th conference call?

A. Yes. PacifiCorp scheduled another conference call for June 18, 2020, to respond to questions related to PRS1. In addition, on June 10, 2020, Sunthurst requested an extension of time to review the Facilities Study for PRS2 and PacifiCorp agreed to an extension.

Q. Did Sunthurst participate in the June 18th conference call?

A. No. Other than Sunthurst's engineer, no other personnel participated, and consequently PacifiCorp canceled the conference call.

Q. What happened next?

A. On June 25, 2020, PacifiCorp provided additional written responses to Sunthurst. Sunthurst continued to express concerns about interconnection costs, primarily about the metering configuration for the combined facilities. In response, PacifiCorp offered another conference call; Sunthurst accepted the offer for a conference call and provided additional questions, including the metering configuration for PRS1 and PRS2.

Then, on June 30, 2020, PacifiCorp issued a revised facilities study for PRS2, in response to Sunthurst's concerns, and requested Sunthurst to consent to the interconnection costs. The revised facilities study for PRS2 further reduced the interconnection costs for PRS2 due to the removal of a field recloser. The next day, Sunthurst submitted additional questions. PacifiCorp promptly responded to the queries and justified the interconnection costs in its revised study on July 2, 2020.

Q. Did PacifiCorp's written responses resolve Sunthurst's concerns?

A. No. Therefore, PacifiCorp scheduled another conference call for July 17, 2020, during which PacifiCorp responded to more written questions from Sunthurst. Sunthurst then asked for additional time to consent to costs in facilities study for PRS2. PacifiCorp then provided additional written responses to Sunthurst's questions on July 20, 2020, and PacifiCorp agreed to an additional extension of time for Sunthurst to consent to the costs for PRS2 on July 21, 2020.

On July 23, 2020, Sunthurst submitted a written letter to PacifiCorp requesting numerous design changes for PRS1 and PRS2, including an alternate metering configuration. PacifiCorp responded on August 7, 2020, and addressed each of Sunthurst's proposed design modifications and agreed to remove an additional $540,000 in interconnection costs for PRS1 and PRS2. The majority of the reduced interconnection costs ($525,000) related to PacifiCorp's decision to remove cost of telemetry equipment. PacifiCorp also offered to remove the costs related to the PI-111 annunciator panel, which at the time was estimated to be approximately $15,000.[7]

Q. Why did PacifiCorp remove the telemetry requirements for Sunthurst's projects?

A. It is my understanding that the Commission's small generator interconnection rules state that telemetry is not required for projects with a nameplate capacity less than 3 MW.[8] But I also understand the rules state:

> If an applicant proposes to interconnect multiple small generator facilities to the public utility's transmission or distribution system at a single point of interconnection, then the public utility must evaluate the applications based on the combined total nameplate capacity for all of the small generator facilities.[9]

In this case, PRS1 and PRS2 appear to have been specifically sized at less than 3 MW to avoid the telemetry requirement, e.g., PRS2 is proposed to be 2.99 MW. However, both projects have a single point of interconnection and essentially represent a single 4.97 MW generation facility for purposes of operating PacifiCorp's distribution

[7] The costs of the PI-111 annunciator panel were inadvertently not removed from the estimated interconnection costs for PRS1, but have been removed from the updated estimated interconnection costs for PRS1, which is provided in PAC/201.
[8] *See* OAR 860-082-0070(2).
[9] *See* OAR 860-082-0025(4).

system. PacifiCorp explained to Sunthurst that it would be inconsistent with PacifiCorp's policy to not require telemetry from PRS1 and PRS2 given their combined size and shared point of interconnection, and that doing so could result in degradation of service to other customers in the area. However, in its good faith efforts to facilitate the Oregon Community Solar program and to effectuate a less expensive interconnection of PRS1 and PRS2, PacifiCorp agreed to remove all costs for telemetry equipment on PacifiCorp's system from the PRS2 request. PacifiCorp will address the legal implications of these rules in briefing.

Q. Did the removal of the telemetry equipment resolve Sunthurst's concerns?

A. No. Even after PacifiCorp removed the cost of the telemetry equipment, Sunthurst continued to insist on additional reductions. In response, PacifiCorp and Sunthurst exchanged several more communications in August and September related to the interconnection requirements for PRS1 and PRS2.[10] After months of continued communications and negotiations over the interconnection costs of both the PRS1 and PRS2 projects, Sunthurst filed its complaint, focusing primarily on the proposed metering configuration. Despite these consistent efforts over six months, Sunthurst chose to pursue this compliant, which focuses on marginally small cost reductions for interconnection of the PRS1 and PRS2 projects.

Q. Was PRS2 originally proposed as a different project?

A. Yes. PRS2 was initially proposed as a 6 MW photovoltaic solar facility under interconnection Queue No. 0747 (Q0747). After PacifiCorp issued an SIS for Q0747, Sunthurst withdrew the project and resized PRS2 to 2.99 MW, in part, in an attempt

[10] PacifiCorp's Answer provides a more detailed description of the communications.

to avoid telemetry costs. PacifiCorp issued an SIS for Q0747 on July 27, 2016. The interconnection costs for Q0747 in PacifiCorp's revised SIS were approximately $42,199,000. These costs reflected the fact that the addition of the 6 MW project to the Pendleton area created surplus generation that had to be exported to load elsewhere on PacifiCorp's system. The interconnection study therefore identified additional transmission system infrastructure necessary to export the surplus generation to load in the Yakima, Washington area.

Q. In contrast to the Q0747 SIS, does PacifiCorp's current SIS for either PRS1 or PRS2 include network upgrade costs?

A. No. The SGIA for PRS1 and the Facilities Study for PRS2 do not identify any upgrades to the transmission system required to interconnect the projects.

Q. Sunthurst claims that PacifiCorp should have removed another QF (Q0547) from the interconnection queue to allow the original configuration of PRS2 (Q0747) to interconnect without triggering network upgrade costs due to surplus generation.[11] Do you agree?

A. No. Q0547 is a higher priority interconnection request for an 18 MW wind facility proposed to interconnect into the Pendleton-Walla Walla area system. Q0547 is slated to be built in two phases—an initial 10 MW phase followed by a second 8 MW phase. PacifiCorp first completed an SIS for this project in May 2014. Like Q0666 and Q1045, Q0547 will be operated as a QF. And because of the nature of PacifiCorp's serial queue order study process, the 18 MW produced by the facility must be considered when assessing the interconnection requirements of both Q0666

[11] Sunthurst/100, Hale/6.

and Q1045. Q0547 executed an interconnection agreement on December 19, 2014. The first 10 MW phase became operational on September 30, 2016. Thereafter, the QF developer requested that PacifiCorp extend the development milestones for the second 8 MW phase, not unlike Sunthurst's repeated requests that PacifiCorp extend the SGIA milestones for PRS1. Consistent with its approach to Sunthurst, PacifiCorp negotiated in good faith with Q0547 to allow several extensions for the second phase of the project, which is now planned for commercial operation on August 6, 2021.

Q. Could PacifiCorp have unilaterally terminated in the Q0547 interconnection agreement, as Sunthurst claims?

A. No. PacifiCorp could have issued a breach of contract notice to Q0547 instead of working with the project to extend the SGIA milestones, just like PacifiCorp could have issued a breach of contract notice to Sunthurst. But the Company's general practice is to work with customers in good faith and consistent with the terms of the executed agreement with that project.

Q. Can PacifiCorp assume away Q0547 when assessing the impact of Sunthurst's interconnection requests?

A. No. PacifiCorp must consider the impact of Q0547 when assessing the interconnection costs for PRS1 and PRS2, which is a function of PacifiCorp's prior serial queue order study process. PacifiCorp could not assume away Q0547 when studying Sunthurst's projects and was required by the terms of its legally binding interconnection agreement to allow Q0547 to interconnect according to the terms of that agreement even if doing so created challenges for lower priority interconnection customers like Sunthurst.

Q. Sunthurst claims that PacifiCorp should have terminated Q0547's interconnection agreement because Mr. Hale "notified PacifiCorp it was clear" that Q0547 would never use the 8 MW of interconnection capacity in its second phase of development.[12] Is Mr. Hale's claim a sufficient basis for PacifiCorp to terminate an interconnection agreement?

A. No. PacifiCorp does not speculatively terminate legally binding interconnection agreements based on another customer's claim that a higher priority project is uneconomic. Indeed, PacifiCorp does not engage in any independent commercial assessment of its interconnection customers before deciding whether to execute, or terminate, an interconnection agreement. Mr. Hale's testimony on this point is also inconsistent with his own testimony that PRS1 was uneconomic when he executed its SGIA.[13] Had PacifiCorp performed the type of assessment Mr. Hale claims should have occurred for Q0547, then PacifiCorp may well have determined that PRS1's interconnection agreement should have been terminated based on Mr. Hale's testimony here.

Q. Are the delays that have occurred with respect to Q0547 common?

A. Yes. PacifiCorp has granted similar extensions to Sunthurst in the development of its PSR1 and PSR2 facilities. To ensure that PacifiCorp negotiates in good faith throughout the development and interconnection process, it frequently grants extensions to interconnection developers to provide balanced and non-discriminatory treatment for all QFs.

[12] Sunthurst/100, Hale/10.
[13] Sunthurst/100, Hale/4.

IV. PACIFICORP'S INTERCONNECTION COST ESTIMATES

Q. Please summarize the estimated interconnection costs PacifiCorp has identified for PRS1 and PRS2.

A. In response to Sunthurst's testimony in this case, PacifiCorp has updated the estimated costs to interconnect PRS1 (Q0666) and PRS2 (Q1045). Detailed cost estimates are set forth in PAC/201 and PAC/202. These costs reflect the reasonable estimated costs to interconnect PRS1 and PRS2 to PacifiCorp's system without adversely affecting system performance, compromising the safety and reliability of the system, or degrading service to other customers. The Commission's small generator interconnection rules require Sunthurst to pay for the reasonable cost of interconnecting its projects, which does not necessarily equate to the lowest cost. PacifiCorp cannot cut corners simply to reduce Sunthurst's costs.

Q. Overall, do you believe that PacifiCorp's interconnection costs for Q0666 and Q1045 are reasonable?

A. Yes. Mr. Hale and Mr. Beanland outline several specific costs that they believe are unreasonably high. The updated estimated costs set forth in PAC/201 and PAC/202 are reasonable and necessary for safe and reliable service after the interconnection of PRS1 and PRS2 takes place. Even Sunthurst's previous consulting engineer stated that many of Sunthurst's proposed alternatives "highlight how this interconnection could be done with minimal cost, *but not necessarily how it should be done*."[14] Sunthurst's previous consulting engineer specifically stated that PacifiCorp's interconnection requirements were consistent with "good practice."[15] PacifiCorp

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[14] PAC/104 at 8. (Sunthurst Letter of July 23, 2020) (emphasis added)
[15] PAC/104 at 8.

strives to ensure its interconnection study requirements are consistent with good utility practice by ensuring the project's interconnection will not adversely impact system safety and reliability. Its current costs for both Q0666 and Q1045 reflect utility best practices and cannot be reduced further without compromising the interconnection's safety and reliability.

Q. Mr. Hale makes general allegations that PacifiCorp's interconnection costs are high when compared to interconnection costs for other utilities.[16] What are some reasons that interconnection costs for a particular project may be higher or lower than another project?

A. Interconnection costs are distinctly fact dependent on a specific project. PacifiCorp has a well-defined process for developing estimated interconnection costs of every request in its interconnection queue. This process can include a short circuit analysis; a stability analysis; a power flow analysis; voltage drop and flicker studies; protection and set point coordination studies; and grounding reviews. Many of these technical studies that make up a SIS can vary dramatically depending on the proposed configuration of the project; other projects seeking interconnection or already interconnected in the relevant area; the particular geography of the project site; PacifiCorp's load; and the already existing distribution and transmission resources surrounding the project. PacifiCorp's system configuration in Oregon, which consists of load pockets that are connected via third-party transmission resources, creates a unique set of challenges for interconnecting projects in Oregon that does not necessarily apply to other utilities that may have more contiguous systems.

[16] *See, e.g.*, Sunthurst/100, Hale/7.

Because of the highly variable nature of interconnection costs, generalized statements and comparisons of interconnection costs between different projects in different areas throughout Oregon cannot inform what reasonable interconnection costs should be for any particular project.

These comparisons become even less salient when comparing interconnection costs from other states to interconnection costs in Oregon. Regional studies can be helpful to policymakers to determine areas of improvement and policy successes in other states. Still, even these studies acknowledge that interconnection rules and practices vary substantially across states and utility service territories.[17] Drawing blanket comparisons of interconnection costs for specific projects in Oregon to average interconnection costs in other states is not a meaningful comparison and certainly no basis to make any adjustments to the interconnection costs for PRS1 and PRS2.

Q. Mr. Hale claims that small solar projects can be interconnected for $50,000/MW to $150,000/MW in Oregon.[18] Do you agree with those cost estimates?

A. No. First, as stated above, interconnection costs vary substantially from utility to utility and from project to project. Accordingly, generalizations do not help determine what costs are reasonable estimates specifically for the PRS1 and PRS2 projects.

Second, Mr. Hale's claims are based on unsupported statements from other persons or studies. Mr. Hale testifies that his interconnection cost estimate was

[17] Lori Bird et al., *Review of Interconnection Practices and Costs in the Western States* 21 (2018) [Hereinafter 2018 NREL Report].
[18] Sunthurst/100, Hale/5.

"validat[ed] by credible 3rd party studies, and solar development industry contacts."[19] But when asked in discovery to provide the "credible 3rd party studies" he relied on, Mr. Hale provided two emails, neither of which appears to be a study.[20] Mr. Hale also deleted the source of the emails. So even if the emails contained the "studies" Mr. Hale referenced (which they do not), there is no way to know if the source is credible because Mr. Hale has concealed the sources.

Moreover, one email says that "[interconnection] costs are all over the board" so it would be hard to determine interconnection costs for 2 to 5 MW projects. But even that unnamed and unverified source said that costs could range up to $500,000 per project, which would place the estimated interconnection costs for PRS1 and PRS2 within the range provided by this unnamed industry contact.

The second email, which was also redacted and from an unverified and unnamed source, provided a "quick and random scrape of interconnection fees," which is not the credible third-party study Mr. Hale claims it to be. Sunthurst's reliance on "quick and random" emails from anonymous sources should be given no weight.

The current cost estimates are reasonable for both Q0666 and Q1045. Messrs. Vaz, Taylor, and Patzkowski's testimony will further support the cost estimates pertaining to individual line items in the SGIA for Q0666 and the SIS for Q1045.

[19] Sunthurst/100 Hale/5.
[20] PAC/105 (Sunthurst Response to PacifiCorp Data Request 2.3, with attachments).

Q. Mr. Hale also claims that he "consulted a nationwide developer of utility-scale solar" to support his claim that PacifiCorp's interconnection costs are "out of line."[21] How do you respond to this claim?

A. Mr. Hale again relies on hearsay and his claim cannot be verified and should receive no weight. In response to a discovery request, Mr. Hale indicated that he was told over the telephone that the costs to interconnect PRS1 and PRS2 were higher than the costs to interconnect a single project to PGE's system.[22] Comparing PRS1 and PRS2 to a single project demonstrates nothing because interconnection costs are project specific, as discussed above. Moreover, the fact that PacifiCorp's costs to interconnect are different from PGE's does not indicate that PacifiCorp's costs are unreasonable because the costs to interconnect are driven by the specific utility system. Because PacifiCorp and PGE have very different systems, it would not be surprising if the interconnection costs differed.

Q. Mr. Hale also relies on a 2018 NREL study that reports a median interconnection cost for solar projects under 5 MW of $120,000/MW.[23] Is that figure relevant to the interconnection costs for PRS1 and PRS2?

A. No. The NREL study was based on a limited data set of interconnections in California, Arizona, New Mexico, and Colorado and provides limited insight into Oregon interconnection costs generally and no insight whatsoever into Sunthurst's interconnection costs.[24] The report itself states that the "data provide perspective on

[21] Sunthurst/100, Hale/8.
[22] PAC/105 (Sunthurst Response to PacifiCorp Data Request 2.7).
[23] Sunthurst/100, Hale/7.
[24] 2018 NREL Report at 12.

costs and mitigation measures recommended for the systems examined *but is not necessarily representative of systems in the West*."[25]

When Staff previously cited this same NREL study, they expressly noted that the study is "purely illustrative and limited by the wildly variable nature of interconnection upgrades[.]"[26] Staff further explained that the "cost and type of upgrades (distribution or transmission) estimated for a generator are specific to the generator's location, project design, the makeup of other generators in the area or in queue, and additional characteristics of the generator and utility system."[27]

Q. Do you believe that the interconnection costs reported in the 2018 NREL study demonstrate that PacifiCorp's interconnection costs for Q0666 and Q1045 are unreasonable?

A. No. The NREL study does not show that PacifiCorp's interconnection costs are unreasonable. First, the study only analyzed 34 different solar projects under 5 MW over four states, primarily in the southwest.[28] Many of these projects could have been sited in locations that allowed for efficient and low-cost interconnections. Without a more rigorous analysis of these projects' entire history and siting, it is unreasonable to use the NREL study to conclude that PacifiCorp's interconnection costs are unreasonable for PRS1 and PRS2.

Second, the NREL report does not break down the size of the projects included under 5 MW. Many of these projects could be less than 1 MW or even less

[25] 2018 NREL Report at 12.
[26] *In the Matter of Public Utility Commission of Oregon, Community Solar Program Implementation*, Docket No. UM 1930, Order No. 19-392, App'x A, at 43 (Nov. 8, 2019).
[27] *Id.*
[28] *Id.* at 13.

than 360 kilowatts (kW). Without more information on the exact size of these 34 projects included in the study, the report is not an accurate comparison to the costs for the larger-scale CSP projects that Sunthurst has proposed in Q0666 and Q1045.

Finally, the interconnection costs of the projects included in the NREL study have a wide deviation, ranging from $0/MW to over $600,000/MW. Five of the 34 projects have costs above $400,000/MW, and eight had costs above $200,000/MW. This data supports PacifiCorp's (and Staff's) belief that each interconnection study is highly fact dependent on the particular circumstances of the project. Therefore, general studies, like the NREL study, cannot be reliably used to draw conclusions about the reasonableness of interconnection costs at any one facility.

In contrast, the interconnection costs for PRS1 and PRS2 are based on their siting location within the Pendleton-Walla Walla service area, their distance from the Pilot Rock Substation, and the enhancements to the Pilot Rock Substation that are required to safely and reliably interconnect the projects.

Q. How does the most recent interconnection costs for Q0666 and Q1045 compare to the median costs for similar-sized projects in the 2018 NREL study?

A. After the nine months of good faith efforts with Sunthurst, PacifiCorp significantly lowered its projected costs for both PRS1 and PRS2. As the testimony of Messrs. Vaz, Taylor, and Patzkowski addresses, the costs have been lowered further and updated. The current estimate for PRS1 is $571,306 and the current estimate for PRS2 is $287,287. The revised costs average roughly $173,000/MW for both projects.

Even acknowledging the limited relevance of the 2018 NREL study, these interconnection costs are within the 75th percentile for solar projects under 5 MW analyzed by the study. In his testimony, Mr. Hale mentions that interconnection costs for the first 24 applicants in PacifiCorp's CSP queue ranged between $420,000/MW and $200,000/MW.[29] Under this range of studies, Sunthurst's interconnection costs are on the low end for interconnection costs of CSP projects in Oregon in PacifiCorp's service territory.

Q. Mr. Hale argues that many CSP interconnection costs are dropping in more recent interconnection studies.[30] Should this fact lower interconnection costs for Q0666 and Q1045?

A. Not necessarily. Moreover, PacifiCorp has already identified specific items that have resulted in lower estimated interconnection costs for both projects since it initially published its SIS for PRS2. Additionally, PAC/201 and PAC/202 reflect further cost reductions. However, PacifiCorp cannot substantially reduce interconnection costs for either project without affecting the safety and reliability of the area network.

As discussed above, a general trend in lower interconnection costs does not mean that any individual project's costs should be substantially lower. Each project's unique factors determine the interconnection costs, not any general trends towards lower costs at other projects in other areas. This trend towards lower interconnection costs could be caused by the targeted siting of projects to reduce interconnection costs.

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[29] Sunthurst/100, Hale/10.
[30] Sunthurst/100, Hale/10.

Notwithstanding that it was Sunthurst's decision to not locate PRS1 and PRS2 in an area that was reasonably likely to have lower interconnection costs, Sunthurst seeks to improperly have PacifiCorp's customers subsidize its interconnection costs.

Q. Has PacifiCorp worked with Sunthurst on any other CSP projects?

A. Yes. PacifiCorp has worked with Sunthurst on the Tutuilla Solar Project (TSP). TSP is another 1.56 MW CSP project located in Umatilla County, Oregon. The estimated costs to interconnect TSP are roughly $325,000. At roughly $216,000/MW the cost to interconnect TSP is higher than the per-MW costs for PRS1 and PRS2. Yet, Sunthurst provided written correspondence to PacifiCorp agreeing to the requirements outlined in the TSP studies and testifies that they are prepared to sign an interconnection agreement for TSP.[31]

Q. Do you believe that PacifiCorp will reach its CSP capacity procurement goals?

A. Yes. As stated in Staff's last report on the CSP interconnection queue, 14 out of the 27 CSP generators that requested interconnection in PacifiCorp's CSP queue received studies in the first and second quarter of 2020.[32] Since that time, PacifiCorp has completed studies for another 25 CSP requests. PacifiCorp has executed 12 interconnection agreements for nearly 15 MW and has another 34 requests comprised of nearly 52 MW actively being studied. While many challenges remain to reach CSP capacity procurement goals, PacifiCorp is committed to achieving these

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[31] Sunthurst/100, Hale/3. Sunthurst states that it executed an interconnection agreement for TSP. PacifiCorp, however, has not because Sunthurst made unilateral and unacceptable modifications to the Commission-approved interconnection agreement for CSP projects.

[32] *See In the Matter of Public Utility Commission of Oregon*, *Community Solar Program Implementation*, Docket No. UM 1930, Comm'n Staff Report, Community Solar Program Interconnection Solutions, Six Month Update at 6 (July 20, 2020).

goals and continues to work with CSP generators, third-party reviewers of the interconnection process, and Commission Staff to meet these targets.

Q. Has PacifiCorp successfully interconnected other similar generators to PRS1 and PRS2 to its Oregon system?

A. Yes. Since 2016 PacifiCorp has interconnected 20 small solar generators to its system in Oregon totaling more than 160 MW.

Q. Mr. Hale claims that PacifiCorp has an incentive to increase interconnection costs to reduce competition for the Company's generation projects and that PacifiCorp benefits if interconnection customers pay for new interconnection facilities.[33] Do you agree?

A. No. PacifiCorp's interconnection cost estimates are created in accordance with a non-discriminatory process and PacifiCorp applies the same estimating methodologies to all customers, whether the interconnection customer is PacifiCorp's merchant function, a QF, or non-QF generator. PacifiCorp then uses the same approach for constructing interconnection facilities across all generators without regard for ownership structure.

Sunthurst's testimony is also inconsistent. On the one hand, they claim that PacifiCorp has a disincentive to execute QF PPAs because the Company does not earn a return on a PPA.[34] Sunthurst then argues that PacifiCorp is incented to force QFs to pay for interconnection facilities even though PacifiCorp does not earn a return on those facilities.[35] If PacifiCorp is truly incented by earning returns, as

[33] Sunthurst/100, Hale/9.
[34] Sunthurst/100, Hale/9.
[35] Sunthurst/100, Hale/9.

Mr. Hale claims, then it would seek to construct interconnection facilities thereby earning a return on the investment.

Q. Mr. Hale makes generalized claims that the Commission's small generator interconnection rules unfairly requires QFs to bear costs that FERC-jurisdictional generators do not.[36] How do you respond?

A. PacifiCorp disagrees that Oregon's cost allocation framework for QFs is unfair simply because it requires interconnecting QFs to bear costs that they would not necessarily pay if they were not a QF (and interconnecting under PacifiCorp's OATT). But such claims are entirely irrelevant in this case.

If Sunthurst had interconnected as a FERC-jurisdictional generator subject to PacifiCorp's OATT, Sunthurst would have been assigned the same costs that it has been assigned as a state-jurisdictional interconnection customer. FERC policy requires generators to pay for all interconnection facilities. The only costs not ultimately paid by developers under FERC rules are network upgrade costs, although FERC requires interconnection customers to upfront fund network upgrade costs. Because neither PRS1 nor PRS2 requires network upgrades, the allocation of interconnection costs would be the same for both projects under FERC policy.

Moreover, if Sunthurst were requesting FERC-jurisdictional interconnection, and seeking to avail itself of FERC's interconnection policies for non-QFs, then PacifiCorp would have no obligation to purchase the output of PRS1 and PRS2.

[36] Sunthurst/100, Hale/11.

V. ECONOMIC FEASIBILITY OF PRS1 AND PRS2

Q. Mr. Hale testifies that his "ultimate hope is to end up with interconnection costs that are financeable and to build PRS1 and PRS2[.]"[37] Does Sunthurst know what level of interconnection costs would make the projects economically feasible?

A. No. When asked what level of interconnection costs could make PRS1 and PRS2 economically feasible, Sunthurst could not identify with any specificity what those costs would be.[38] Moreover, it is unclear the extent to which the interconnection cost estimates are the barrier to development of these projects. In response to a discovery request, Sunthurst indicated that, "Sunthurst expected that PRS1 would be financeable when it signed the $805k interconnection agreement."[39] But according to Sunthurst, the project is not financeable because of "delays in rolling out Oregon's Community Solar Program (CSP); low net prices paid in the CSP; costs of PRS2 interconnection; federal import tariffs affecting solar project components; and reductions in the federal ITC and other government tax incentives and/or subsidies." It appears that there are many factors beyond interconnection that have made Sunthurst's projects uneconomic.

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[37] Sunthurst/100, Hale/11.
[38] PAC/105 (Response to DR 2.2).
[39] PAC/105 (Response to DR 2.2).

VI. VAGUELY DEFINED SYSTEM BENEFITS

Q. Mr. Beanland generally argues that there are "real, if imprecise, system benefits from the interconnection" of PRS1 and PRS2 that support shifting interconnection costs from Sunthurst to PacifiCorp's retail customers.[40] Do you agree?

A. No. Mr. Beanland makes several broad statements regarding his view of the general benefits associated with distributed generation. None of those purported benefits, however, has any bearing on the allocation of costs required to interconnect PRS1 and PRS2. PacifiCorp's legal briefing will address this issue in more detail, but my understanding is that the Commission does not require retail customers to pay for interconnection costs for distributed generation based on the notion that distributed generation generally provides "real, if imprecise" benefits.

Q. Mr. Beanland specifically claims that PRS1 and PRS2 will reduce power flow on the transmission system, lower losses, reduce fuel use, and extend transformer life.[41] Are any of these purported benefits a basis to relieve Sunthurst of the costs to interconnect PRS1 and PRS2?

A. No. PRS1 and PRS2 are QFs—they are compensated for the costs that PacifiCorp avoids and nothing more. The Commission has to date declined to include avoided transmission and distribution expenses in avoided cost prices, and to the extent that PRS1 and PRS2 allow PacifiCorp to reduce fuel use, the projects are already compensated for those avoided costs.

[40] Sunthurst/200, Beanland/30.
[41] Sunthurst/200, Beanland/30.

VII. MISCELLANEOUS

Q. Mr. Beanland claims that the Direct Transfer Trip (DTT) system that will be installed can have 100 or more functions that can be used after Sunthurst interconnects and therefore recommends that PacifiCorp share in the costs of the DTT equipment.[42] How do you respond?

A. As explained in the testimony of Messrs. Vaz, Taylor, and Patzkowski, PacifiCorp is required to install DTT equipment to safely and reliably interconnect Sunthurst's projects. But for their interconnections, PacifiCorp would not install DTT and therefore retail customers should not be required to pay for equipment that is caused by Sunthurst's projects and not necessary to provide retail service.

Q. Sunthurst also questioned why PacifiCorp would not allow Sunthurst to install DTT at its own cost?

A. Because the DTT equipment will be installed on PacifiCorp's system, PacifiCorp must install it.

Q. Sunthurst also generally complains that its interconnection requirements are costly because it has chosen to interconnect to the Pilot Rock substation, which was built in 1961.[43] Is this a basis to reduce the interconnection costs?

A. No. Sunthurst chose to interconnect to the Pilot Rock substation. Had Sunthurst chosen a different site and interconnected to a more recently built substation, its interconnection costs may well have been lower. But PacifiCorp did not dictate Sunthurst's siting choice.

[42] Sunthurst/200, Beanland/31.
[43] Sunthurst/100, Hale/8.

Moreover, PacifiCorp disagrees with the implication that Sunthurst is being required to fund upgrades to the Pilot Rock substation that PacifiCorp should have been making in the normal course of business. None of the interconnection facilities that Sunthurst is required to fund would have been built but for Sunthurst's desire to interconnect its facilities. Although the Pilot Rock substation was constructed in 1961, it was performing well and satisfies all of the applicable reliability and performance standards.

Q. Mr. Beanland claims that the metering and protection equipment installed at the Pilot Rock substation will modernize the facilities and allow PacifiCorp to avoid future investments.[44] Is this a basis for Sunthurst to be relieved of its obligations to pay its interconnection costs?

A. No. As discussed above, PacifiCorp would not have made any of the investments that have been assigned to Sunthurst but for the interconnection. To the extent Mr. Beanland is recommending that avoided cost prices should reflected avoided transmission and distribution system expenses, as discussed above, it is my understanding that current avoided cost prices do not include those amounts.

Q. Sunthurst also complains generally that PacifiCorp's estimated equipment prices are excessive.[45] Is this a fair criticism?

A. No. The only specific item Sunthurst claims has an excessive price is the junction boxes, which, as described in the testimony of Messrs. Vaz, Taylor, and Patzkowski, is reasonably priced and reflect competitive procurement processes.

[44] Sunthurst/200, Beanland/31.
[45] Sunthurst/100, Hale/9.

Q. Sunthurst also complains that PacifiCorp overstaffs its interconnection study process.[46] Do you agree?

A. No. Performing interconnection studies requires input from a variety of specialized disciplines. The fact that PacifiCorp relies on subject matter experts in every applicable field reflects good utility practice not unreasonable overstaffing.

Q. Sunthurst also requests the opportunity to "self-perform" construction to remove the alleged incentive for PacifiCorp to inflate costs.[47] Is this a reasonable request?

A. No. Because much of the interconnection facilities will be owned by PacifiCorp and installed on PacifiCorp's system, PacifiCorp must construct the facilities.

Q. Mr. Beanland recommends that PacifiCorp remove $3,798 in estimated costs for PRS1 that are related to a "SCADA Engineer" because he believes those costs are related to telemetry.[48] Does PacifiCorp agree to remove those costs from the estimated costs to interconnect PRS1?

A. Yes. Again, while it is unclear that the combining of PRS1 and PRS2 at the same POI qualify them for avoiding telemetry costs, PacifiCorp removed the $3,798 identified by Mr. Beanland.

Q. Mr. Beanland also claims that additional costs related to telemetry remain in the cost estimates for PRS1 and PRS2.[49] Do you agree there are additional costs that should be removed?

A. No. Mr. Beanland claims that Sunthurst is required to provide an easement for

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[46] Sunthurst/100, Hale/9.
[47] Sunthurst/200, Beanland/34.
[48] Sunthurst/200, Beanland/15.
[49] Sunthurst/200, Beanland/15, 25.

location of the telemetry facilities, the AC power supply, and all the wires and conduit necessary to supply data to the telemetry facilities from PRS1 and PRS2. He also speculates that Sunthurst may need to purchase additional equipment to provide the PacifiCorp telemetry equipment with the analog signals PacifiCorp requires. While it is true that these costs would not be incurred but for the need to install telemetry, as discussed above, PacifiCorp removed those costs to accommodate Sunthurst. It is reasonable for Sunthurst to pay these minimal costs associated with telemetry requirements, particularly in light of the fact that PacifiCorp could have charged the full costs of telemetry given the combined nameplate capacity of PRS1 and PRS2.

Q. Mr. Hale also claims that PacifiCorp spent $79,000 that was provided as a deposit for the interconnection of PRS1 and stopped providing monthly invoices.[50] Has Mr. Hale made all of the requisite deposits under the PRS1 interconnection agreement?

A. No. The interconnection agreement for PRS1 required Sunthurst to make a series of progress payments as deposits for the estimated interconnection costs. Sunthurst made its first payment of $10,000 on March 14, 2016, when it originally executed the PRS1 interconnection agreement. A second progress payment of $79,500 was made on August 30, 2018. A third progress payment of $53,500 was due to be made on April 1, 2019, in compliance with the currently effective interconnection agreement. Three additional payments totaling $715,500 were required June 1, August 1 and October 15, 2019.

[50] Sunthurst/100, Hale/7.

Q. Other than the first payment of $10,000 and the second payment of $79,500, has Sunthurst made any of the other progress payments it was required to make for PRS1?

A. No. As noted above, Sunthurst has failed to make several progress payments, the last of which was due approximately 11 months before Sunthurst filed its complaint.

Q. When does PacifiCorp issue invoices for interconnection requests?

A. PacifiCorp's typical process is to issue invoices if actual costs exceed the progress payments made by interconnection customer. However, in the case of PRS1, Sunthurst asked to delay the project, and therefore PacifiCorp personnel were instructed to withhold invoices until PRS1 is either restarted or terminated.

Q. Does this conclude your response testimony?

A. Yes.

Docket No. UM 2118
Exhibit PAC/101
Witness: Kris Bremer

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Response Testimony of Kris Bremer

Q0666 SGIA, as amended

January 2021

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Interconnection Agreement for Small Generator Facility
Tier 1, Tier 2, Tier 3 or Tier 4 Interconnection
(Small Generator Facilities with Electric Nameplate Capacities of 10MW or less)

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This Interconnection Agreement for Small Generator Facility ("Agreement") is made and entered into this 14th day of MARCH, 2016 by and between Sunthurst Energy, LLC (Pilot Rock, Q0666), a Limited Liability Company organized and existing under the laws of the State of Oregon, (''Interconnection Customer") and PacifiCorp, a Corporation, existing under the laws of the State of Oregon, (''Public Utility''). The Interconnection Customer and Public Utility may be referred to hereinafter singly as a ''Party'' or collectively as the ''Parties.''

Recitals:

Whereas, the Interconnection Customer is proposing to develop a Small Generator Facility, or to add generating capacity to an existing Small Generator Facility, consistent with the Application completed on May 7, 2015;

Whereas, the Interconnection Customer desires to interconnect the Small Generator Facility with Public Utility's Transmission System and/or Distribution System ("T&D System") in the State of Oregon; and

Whereas, the interconnection of the Small Generator Facility and the Public Utility's T&D System is subject to the jurisdiction of the Public Utility Commission of Oregon ("Commission") and governed by OPUC Rule OAR 860, Division 082 (the "Rule").

Now, therefore, in consideration of and subject to the mutual covenants contained herein, the Parties agree as follows:

Article 1. Scope and Limitations of Agreement

1.1 Scope
This Agreement establishes the standard terms and conditions under which the Small Generator Facility with a Nameplate Capacity of no more than 10 megawatts ("MW") will interconnect to, and operate in Parallel with, the Public Utility's T&D System. The Commission has approved standard terms and conditions governing this class of interconnection. Any additions, deletions or changes to the standard terms and conditions of interconnection approved by the Commission must be mutually agreed by the Parties or, if required by the Rule, any such changes must be approved by the Commission. Terms with initial capitalization, when used in this Agreement, shall have the meanings given in the Rule. This Agreement shall be construed where possible to be consistent with the Rules; to the extent this Agreement conflicts with the Rule, the Rule shall take precedence.

1.2 No Agreement Regarding Power Purchase, Transmission, or Delivery
This Agreement does not constitute an agreement to purchase, transmit, or deliver any power or capacity from the interconnected Small Generating Facility nor does it constitute

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an electric service agreement.

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1.3 Other Agreements
Nothing in this Agreement is intended to affect any other agreement between the Public Utility and the Interconnection Customer or any other interconnected entity. If the provisions of this Agreement conflict with the provisions of any other Public Utility tariff, the Public Utility tariff shall control.

1.4 Responsibilities of the Parties

1.4.1 The Parties shall perform all obligations of this Agreement in accordance with all applicable laws.

1.4.2 The Interconnection Customer will construct, own, operate, and maintain its Small Generator Facility in accordance with this Agreement, IEEE Standard 1547 (2003 ed), IEEE Standard 1547.1 (2005 ed), the National Electrical Code (2005 ed) and applicable standards required by the Commission.

1.4.3 Each Party shall be responsible for the safe installation, maintenance, repair and condition of their respective lines and appurtenances on their respective sides of the Point of Interconnection. Each Party shall provide Interconnection Facilities that adequately protect the other Parties' facilities, personnel, and other persons from damage and injury. The allocation of responsibility for the design, installation, operation, maintenance and ownership of Interconnection Facilities is prescribed in the Rule and this Agreement and the attachments to this Agreement.

1.5 Parallel Operation and Maintenance Obligations
Once the Small Generator Facility has been authorized to commence Parallel Operation by execution of this Agreement and satisfaction of Article 2.1 of this Agreement, the Interconnection Customer will abide by all written provisions for operating and maintenance as required by this Agreement and any attachments to this Agreement as well as by the Rule and as detailed by the Public Utility in Form 7, title "Interconnection Equipment As-Built Specifications, Initial Settings and Operating Requirements".

1.6 Metering & Monitoring
The Interconnection Customer will be responsible for metering and monitoring as required by OAR 860-082-0070 and as may be detailed in any attachments to this Agreement.

1.7 Power Quality
The Interconnection Customer will design its Small Generator Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection that meets the requirements set forth in IEEE 1547. The Public Utility may, in some

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circumstances, also require the Interconnection Customer to follow voltage or VAR schedules used by similarly situated, comparable generators in the control area. Any special operating requirements will be detailed in Form 7 and completed by the Public Utility as required by the Rule. The Public Utility shall not impose additional requirements for voltage or reactive power support outside of what may be required to mitigate impacts caused by interconnection of the Small Generator Facility to the Public Utility's system.

Article 2. Inspection, Testing, Authorization, and Right of Access

2.1 Equipment Testing and Inspection

The Interconnection Customer will test and inspect its Small Generator Facility and Interconnection Facilities prior to interconnection in accordance with IEEE 1547 Standards as provided for in the Rule. The Interconnection will not be final and the Small Generator Facility shall not be authorized to operate in parallel with the Public Utility's T&D System until the Witness Test and Certificate of Completion provisions in the Rule have been satisfied. The Interconnection Customer shall pay or reimburse the Public Utility for its costs to participate in the Witness Test. Operation of the Small Generator Facility requires an effective Interconnection Agreement; electricity sales require a Power Purchase Agreement.

To the extent that the Interconnection Customer decides to conduct interim testing of the Small Generator Facility prior to the Witness Test, it may request that the Public Utility observe these tests. If the Public Utility agrees to send qualified personnel to observe any interim testing proposed by the Interconnection Customer, the Interconnection Customer shall pay or reimburse the Public Utility for its cost to participate in the interim testing. If the Interconnection Customer conducts interim testing and such testing is observed by the Public Utility and the results of such interim testing are deemed acceptable by the Public Utility (hereinafter a "Public Utility-approved interim test"), then the Interconnection Customer may request that such Public Utility-approved interim test be deleted from the final Witness Testing. If the Public Utility elects to repeat any Public Utility-approved interim test as part of the final Witness Test, the Public Utility will bare its own expenses associated with participation in the repeated Public Utility-approved interim test.

2.2 Right of Access:

As provided in OAR 860-082-0030(5), the Public Utility will have access to the Interconnection Customer's premises for any reasonable purpose in connection with the Interconnection Application or any Interconnection Agreement that is entered in to pursuant to the Rule or if necessary to meet the legal obligation to provide service to its customers. Access will be requested at reasonable hours and upon reasonable notice, or at any time without notice in the event of an emergency or hazardous condition.

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Article 3. Effective Date, Term, Termination, and Disconnection

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3.1 Effective Date
The Agreement shall become effective upon execution by the Parties.

3.2 Term of Agreement
The Agreement will be effective on the Effective Date and will remain in effect for a period of twenty (20) years or the life of the Power Purchase agreement, whichever is shorter or a period mutually agreed to by the Parties, unless terminated earlier by the default or voluntary termination by the Interconnection Customer or by action of the Commission.

3.3 Termination
No termination will become effective until the Parties have complied with all provisions of OAR 860-082-0080 and this Agreement that apply to such termination.

3.3.1 The Interconnection Customer may terminate this Agreement at any time by giving the Public Utility twenty (20) Business Days written notice.

3.3.2 Either Party may terminate this Agreement after default pursuant to Article 5.6 of this Agreement.

3.3.3 The Commission may order termination of this Agreement.

3.3.4 Upon termination of this Agreement, the Small Generator Facility will be disconnected from the Public Utility's T&D System at the Interconnection Customer's expense. The termination of this Agreement will not relieve either Party of its liabilities and obligations, owed or continuing at the time of the termination.

3.3.4 The provisions of this Article 3.3 shall survive termination or expiration of this Agreement.

3.4 Temporary Disconnection
The Public Utility or Interconnection Customer may temporarily disconnect the Small Generator Facility from the Public Utility's T&D System for so long as reasonably necessary, as provided in OAR 860-082-0075 of the Rule, in the event one or more of the following conditions or events occurs:

3.4.1 Under emergency conditions, the Public Utility or the Interconnection Customer may immediately suspend interconnection service and temporarily disconnect the Small Generator Facility without advance notice to the other Party. The Public Utility shall notify the Interconnection Customer promptly when it becomes aware of an emergency condition that may reasonably be expected to affect the Small Generator Facility operation. The Interconnection Customer will notify the Public Utility promptly when it becomes aware of an emergency condition that may reasonably be expected to affect the Public Utility's T&D System. To the extent information is known, the notification shall describe the emergency condition, the extent of the damage or deficiency, the expected effect on the operation of both Parties' facilities and operations, its anticipated duration, and the necessary corrective action.

3.4.2 For routine Maintenance, Parties will make reasonable efforts to provide five Business Days notice prior to interruption caused by routine maintenance or construction and repair to the Small Generator Facility or Public Utility's T&D system and shall use reasonable efforts to coordinate such interruption.

3.4.3 The Public Utility shall use reasonable efforts to provide the Interconnection Customer with prior notice of forced outages of the T&D System. If prior notice is not given, the Public Utility shall, upon request, provide the Interconnection Customer written documentation after the fact explaining the circumstances of the disconnection.

3.4.4 For disruption or deterioration of service, where the Public Utility determines that operation of the Small Generator Facility will likely cause disruption or deterioration of service to other customers served from the same electric system, or if operating the Small Generator Facility could cause damage to the Public Utility's T&D System, the Public Utility may disconnect the Small Generator Facility. The Public Utility will provide the Interconnection Customer upon request all supporting documentation used to reach the decision to disconnect. The Public Utility may disconnect the Small Generator Facility if, after receipt of the notice, the Interconnection Customer fails to remedy the adverse operating effect within a reasonable time which shall be at least five Business Days from the date the Interconnection Customer receives the Public Utility's written notice supporting the decision to disconnect, unless emergency conditions exist, in which case the provisions of 3.4.1 of the agreement apply.

3.4.5 If the Interconnection Customer makes any change to the Small Generating Facility, the Interconnection Equipment, the Interconnection Facilities, or to any other aspect of the interconnection, other than Minor Equipment Modifications, without prior written authorization of the Public Utility, the Public Utility will have the right to disconnect the Small Generator Facility until such time as the impact of the change has been studied by the Public Utility and any reasonable requirements or additional equipment or facilities required by the Public Utility to address any impacts from the changes have been implemented by the Parties and approved in writing by the Public Utility. The requirement to apply to the Public Utility for study and approve of modifications is governed by OAR 860-082-0005 (b).

3.5 Restoration of interconnection:
The Parties shall cooperate with each other to restore the Small Generator Facility, Interconnection Facilities, and Public Utility's T&D System to their normal operating state as soon as reasonably practicable following any disconnection pursuant to Article 3.4.

Article 4. Cost Responsibility and Billing:
As provided in OAR 860-082-0035, the Interconnection Customer is responsible for the cost of all facilities, equipment, modifications and upgrades needed to facilitate the interconnection of the Small Generator Facility to the Public Utility's T&D System.

4.1 Minor T&D System Modifications:
As provided in the Rule addressing Tier 2 review (OAR 860-082-0050) and in the Rule addressing Tier 3 review (OAR 860-082-0055), it may be necessary for the Parties to construct certain Minor Modifications in order to interconnect under Tier 2 or Tier 3 review. The Public Utility has itemize any required Minor Modifications in the attachments to this Agreement, including a good-faith estimate of the cost of such Minor Modifications and the time required to build and install such Minor Modifications. The Interconnection Customer agrees to pay the costs of such Minor Modifications.

4.2 Interconnection Facilities:
The Public Utility has identified under the review procedures of a Tier 2 review or under a Tier 4 Facilities Study, the Interconnection Facilities necessary to safely interconnect the Small Generator Facility with the Public Utility. The Public Utility has itemized the required Interconnection Facilities in the attachments to this Agreement, including a good-faith estimate of the cost of the facilities and the time required to build and install those facilities. The Interconnection Customer is responsible for the cost of the Interconnection Facilities.

4.3 Interconnection Equipment:
The Interconnection Customer is responsible for all reasonable expenses, including overheads, associated with owning, operating, maintaining, repairing, and replacing its Interconnection Equipment.

4.4 System Upgrades:
The Public Utility will design, procure, construct, install, and own any System Upgrades. The actual cost of the System Upgrades, including overheads, will be directly assigned to the Interconnection Customer. An Interconnection Customer may be entitled to financial compensation from other Public Utility Interconnection Customers who, in the future, benefit from the System Upgrades paid for by the Interconnection Customer. Such compensation will be governed by separate rules promulgated by the Commission or by

terms of a tariff filed and approved by the Commission. Such compensation will only be available to the extent provided for in the separate rules or tariff.

4.5 Adverse System Impact:
The Public Utility is responsible for identifying the possible Affected Systems and coordinating with those identified Affected Systems, to the extent reasonably practicable, to allow the Affected System owner an opportunity to identify Adverse System Impacts on its Affected System, and to identify what mitigation activities or upgrades may be required on the Public Utility's system or on the Affected System to address impacts on Affected Systems and accommodate a Small Generator Facility. Such coordination with Affected System owners shall include inviting Affected System owners to scoping meetings between the Public Utility and the Interconnection Customer and providing the Affected System owner with study results and other information reasonably required and requested by the Affected System owner to allow the Affected System owner to assess impacts to its system and determine required mitigation, if any, for such impacts. The Parties acknowledge that the Public Utility cannot compel the participation of the Affected System owner and that the Public Utility is not itself responsible for identifying impacts or mitigation associated with an Affected System. The actual cost of any actions taken to address the Adverse System Impacts, including overheads, shall be directly assigned to the Interconnection Customer. The Interconnection Customer may be entitled to financial compensation from other Public Utilities or other Interconnection Customers who, in the future, utilize the upgrades paid for by the Interconnection Customer, to the extent allowed or required by the Commission. Such compensation will only be available to the extent provided for in the separate rules, Commission order or tariff. If the Parties have actual knowledge of an Adverse System Impact on an Affected System, the Interconnection Customer shall not interconnect and operate its Small Generator Facility in parallel with the Public Utility's system, and the Public Utility shall not authorize or allow the continued interconnection or parallel operation of the Small Generator Facility, unless and until such Adverse System Impact has been addressed to the reasonable satisfaction of the Affected System owner.

4.6 Deposit and Billings:
The Interconnection Customer agrees to pay to the Public Utility a deposit toward the cost to construct and install any required Interconnection Facilities and/or System Upgrades. The amount of the deposit shall be (select one of the following):

☐ The Parties have not agreed to a schedule of progress payments and the Interconnection Customer shall pay a deposit equal to 100 percent of the estimated cost of the Interconnection Facilities and System Upgrades – the amount of the deposit shall be $805,000; or

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☒ The Parties have agreed to progress payments and final payment under the schedule of payments attached to this Agreement; the Interconnection Customer shall pay a deposit equal to the lesser of (a) 25 percent of the estimated cost of the Interconnection Facilities and System Upgrades, or (b) $10,000 – the amount of the deposit shall be $10,000.

If the actual costs of Interconnection Facilities and/or System Upgrades are different than the deposit amounts and/or progress and final payments provided for above, then the Interconnection Customer shall pay the Public Utility any balance owing or the Public Utility shall refund any excess deposit or progress payment within 20 days of the date actual costs are determined

Article 5. Assignment, Liability, Indemnity, Force Majeure, Consequential Damages, and Default

5.1 Assignment
The Interconnection Agreement may be assigned by either Party upon fifteen (15) Business Days prior written notice. Except as provided in Articles 5.1.1 and 5.1.2, said assignment shall only be valid upon the prior written consent of the non-assigning Party, which consent shall not be unreasonably withheld.

5.1.1 Either Party may assign the Agreement without the consent of the other Party to any affiliate (which shall include a merger of the Party with another entity), of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Agreement;

5.1.2 The Interconnection Customer shall have the right to assign the Agreement, without the consent of the Public Utility, for collateral security purposes to aid in providing financing for the Small Generator Facility. For Small Generator systems that are integrated into a building facility, the sale of the building or property will result in an automatic transfer of this agreement to the new owner who shall be responsible for complying with the terms and conditions of this Agreement.

5.1.3 Any attempted assignment that violates this Article is void and ineffective. Assignment shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. An assignee is responsible for meeting the same obligations as the assigning Interconnection Customer.

5.2 Limitation of Liability and Consequential Damages
A Party is liable for any loss, cost claim, injury, or expense including reasonable attorney's fees related to or arising from any act or omission in its performance of the provisions of

this Agreement entered into pursuant to the Rule except as provided for in ORS 757.300(4)(c). Neither Party will seek redress from the other Party in an amount greater than the amount of direct damage actually incurred.

5.3 Indemnity

5.3.1 Liability under this Article 5.3 is exempt from the general limitations on liability found in Article 5.2.

5.3.2 The Parties shall at all times indemnify, defend, and hold the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's action or failure to meet its obligations under this Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

5.3.3 If an indemnified person is entitled to indemnification under this Article 5.3 as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under this Article 5.3, to assume the defense of such a claim, such indemnified person may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

5.3.4 If an indemnifying party is obligated to indemnify and hold any indemnified person harmless under this Article 5.3, the amount owing to the indemnified person shall be the amount of such indemnified person's actual loss, net of any insurance or other recovery.

5.3.5 Promptly after receipt by an indemnified person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in this Article 5.3 may apply, the indemnified person shall notify the indemnifying party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying party.

5.3.6 The indemnifying Party shall have the right to assume the defense thereof with counsel designated by such indemnifying Party and reasonably satisfactory to the indemnified person. If the defendants in any such action include one or more indemnified persons and the indemnifying Party and if the indemnified person reasonably concludes that there may be legal defenses available to it and/or other indemnified persons which are different from or additional to those available to the indemnifying Party, the indemnified person shall have the right to select separate counsel to assert such legal defenses and to otherwise participate in the defense of such action on its own behalf. In such instances, the indemnifying Party shall only be required to pay the fees and expenses of one additional attorney to represent an indemnified person or indemnified persons having such differing or additional legal defenses.

5.3.7 The indemnified person shall be entitled, at its expense, to participate in any such action, suit or proceeding, the defense of which has been assumed by the indemnifying Party. Notwithstanding the foregoing, the indemnifying Party (i) shall not be entitled to assume and control the defense of any such action, suit or proceedings if and to the extent that, in the opinion of the indemnified person and its counsel, such action, suit or proceeding involves the potential imposition of criminal liability on the indemnified person, or there exists a conflict or adversity of interest between the indemnified person and the indemnifying Party, in such event the indemnifying Party shall pay the reasonable expenses of the indemnified person, and (ii) shall not settle or consent to the entry of any judgment in any action, suit or proceeding without the consent of the indemnified person, which shall not be reasonably withheld, conditioned or delayed.

5.4 Consequential Damages

Neither Party shall be liable to the other Party, under any provision of this Agreement, for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to the other Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

5.5 Force Majeure

5.5.1 As used in this Agreement, a Force Majeure Event shall mean "any act of God, labor disturbance, act of the public enemy, war, acts of terrorism, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment through no direct, indirect, or contributory act of a Party, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure Event does not include an act of negligence or intentional wrongdoing."

5.5.2 If a Force Majeure Event prevents a Party from fulfilling any obligations under this Agreement, the Party affected by the Force Majeure Event (Affected Party) shall promptly notify the other Party of the existence of the Force Majeure Event. The notification must specify in reasonable detail the circumstances of the Force Majeure Event, its expected duration, and the steps that the Affected Party is taking to mitigate the effects of the event on its performance, and if the initial notification was verbal, it should be promptly followed up with a written notification. The Affected Party shall keep the other Party informed on a continuing basis of developments relating to the Force Majeure Event. Until the Force Majeure Event ends the Affected Party will be entitled to suspend or modify its performance of obligations under this Agreement (other than the obligation to make payments) only to the extent that the effect of the Force Majeure Event cannot be reasonably mitigated. The Affected Party will use reasonable efforts to resume its performance as soon as possible. The Parties shall immediately report to the Commission should a Force Majeure Event prevent performance of an action required by the Rule that the Rule does not permit the Parties to mutually waive.

5.6 Default

5.6.1 No default shall exist where such failure to discharge an obligation (other than the payment of money) is the result of a Force Majeure Event as defined in this Agreement, or the result of an act or omission of the other Party. Upon a breach, the non-breaching Party shall give written notice of such breach to the breaching Party. Except as provided in Article 5.6.2, the breaching Party shall have sixty (60) Calendar Days from receipt of the beach notice within which to cure such breach; provided however, if such breach is not capable of cure within 60 Calendar Days, the breaching Party shall commence such cure within twenty (20) Calendar Days after notice and continuously and diligently complete such cure within six months from receipt of the breach notice; and, if cured within such time, the breach specified in such notice shall cease to exist.

5.6.2 If a breach is not cured as provided for in this Article 5.6, or if a breach is not capable of being cured within the period provided for herein, the non-breaching Party shall have the right to declare a default and terminate this Agreement by written notice at any time until cure occurs, and be relieved of any further obligation hereunder and, whether or not that Party terminates this Agreement, to recover from the breaching Party all amounts due hereunder, plus all other damages and remedies to which it is entitled at law or in equity. Alternatively, the non-breaching Party shall have the right to seek dispute resolution with the Commission in lieu of default. The provisions of this Article 5.6 will survive termination of the Agreement.

<u>Article 6.</u> Insurance

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6.1 Pursuant to the Rule adopted by the Commission, the Public Utility may not require the Interconnection Customer to maintain general liability insurance in relation to the interconnection of a Small Generator Facility with an Electric Nameplate Capacity of 200 KW or less. With regard to the interconnection of a Small Generator Facility with an Electric Nameplate Capacity equal to or less than 10 MW but in excess of 200 KW, the Interconnection Customer shall, at its own expense, maintain in force throughout the period of this Agreement general liability insurance sufficient to protect any person (including the Public Utility) who may be affected by the Interconnection Customer's Small Generation Facility and its operation and such insurance shall be sufficient to satisfy the Interconnection Customer's indemnification responsibilities under Article 5.3 of this Agreement.

6.2 Within ten (10) days following execution of this Agreement, and as soon as practicable after the end of each fiscal year or at the renewal of the insurance policy and in any event within ninety (90) days thereafter, the Interconnection Customer shall provide the Public Utility with certification of all insurance required in this Agreement, executed by each insurer or by an authorized representative of each insurer.

6.3 All insurance required by this Article 6 shall name the Public, its parent, associated and Affiliate companies and their respective directors, officers, agents, servants and employees ("Other Party Group") as additional insured. All policies shall contain provisions whereby the insurers waive all rights of subrogation against the Other Party Group and provide thirty (30) Calendar Days advance written notice to the Other Party Group prior to anniversary date of cancellation or any material change in coverage or condition. The Interconnection Customer's insurance shall contain provisions that specify that the policies are primary and shall apply to such extent without consideration for other policies separately carried and shall state that each insured is provided coverage as though a separate policy had been issued to each, except the insurer's liability shall not be increased beyond the amount for which the insurer would have been liable had only one insured been covered. The insurance policies, if written on a Claims First Made Basis, shall be maintained in full force and effect for two (2) years after termination of this Agreement, which coverage may be in the form of tail coverage or extended reporting period coverage if agreed by the Parties.

6.4 The Parties agree to report to each other in writing as soon as practical all accidents or occurrences resulting in injuries to any person, including death, and any property damage arising out of this Agreement.

6.5 The requirements contained herein as to insurance are not intended to and shall not in any manner, limit or qualify the liabilities and obligations assumed by the Parties under this Agreement.

Article 7. Dispute Resolution
Parties will adhere to the dispute resolution provisions in OAR 860-082-0080.

Article 8. Miscellaneous

8.1 Governing Law, Regulatory Authority, and Rules
The validity, interpretation and enforcement of the Agreement and each of its provisions shall be governed by the laws of the State of Oregon, without regard to its conflicts of law principles. The Agreement is subject to all applicable laws. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a governmental authority.

8.2 Amendment
The Parties may mutually agree to amend the Agreement by a written instrument duly executed by both Parties in accordance with provisions of the Rule and applicable Commission Orders and provisions of the laws if the State of Oregon.

8.3 No Third-Party Beneficiaries
The Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and where permitted, their assigns.

8.4 Waiver

8.4.1 The failure of a Party to the Agreement to insist, on any occasion, upon strict performance of any provision of the Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

8.4.2 The Parties may agree to mutually waive a section of this Agreement so long as prior Commission approval of the waiver is not required by the Rule.

8.4.3 Any waiver at any time by either Party of its rights with respect to the Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of the Agreement. Any waiver of the Agreement shall, if requested, be provided in writing.

8.5 Entire Agreement
This Agreement, including any supplementary Form attachments that may be necessary, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of the Agreement. There are no other agreements, representations, warranties, or covenants that constitute any part

of the consideration for, or any condition to, either Party's compliance with its obligations under this Agreement.

8.6 Multiple Counterparts
This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

8.7 No Partnership
This Agreement will not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

8.8 Severability
If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other governmental authority; (1) such portion or provision shall be deemed separate and independent; (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling; and (3) the remainder of this Agreement shall remain in full force and effect.

8.9 Subcontractors
Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor, or designating a third party agent as one responsible for a specific obligation or act required in this Agreement (collectively subcontractors), as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party will require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party will remain primarily liable to the other Party for the performance of such subcontractor.

8.9.1 The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Party for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made. Any applicable obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and will be construed as having application to, any subcontractor of such Party.

8.9.2 The obligations under this Article 8.9 will not be limited in any way by any limitation of subcontractor's insurance.

8.10 Reservation of Rights

Either Party will have the right to make a unilateral filing with the Commission to modify this Agreement. This reservation of rights provision will includes but is not limited to modifications with respect to any rates terms and conditions, charges, classification of service, rule or regulation under tariff rates or any applicable State or Federal law or regulation. Each Party shall have the right to protest any such filing and to participate fully in any proceeding before the Commission in which such modifications may be considered.

Article 9. Notices and Records

9.1 General

Unless otherwise provided in this Agreement, any written notice, demand, or request required or authorized in connection with this Agreement shall be deemed properly given if delivered in person, delivered by recognized national courier service, or sent by first class mail, postage prepaid, to the person specified below:

9.2 Records

The Public Utility will maintain a record of all Interconnection Agreements and related Form attachments for as long as the interconnection is in place as required by OAR 860-082-0065. The Public Utility will provide a copy of these records to the Interconnection Customer within 15 Business Days if a request is made in writing.

If to the Interconnection Customer:
Interconnection Customer: Sunthurst Energy, LLC
Attention: Daniel Hale
Address: 153 Lowell Ave
City: Glendora State: California Zip: 91741
Phone: 310-975-4732 Fax: 323-782-0760

If to Public Utility:
Public Utility: PacifiCorp
Attention: Transmission Service
Address: 825 NE Multnomah, Suite 550
City: Portland State: Oregon Zip: 97232
Phone: 503-813-6077 Fax: 503-813-6893

9.3 Billing and Payment

Billings and payments shall be sent to the addresses set out below: (complete if different than article 9.2 above)

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If to the Interconnection Customer
Interconnection Customer: PILOT ROCK SOLAR 1 LLC
Attention: DANIEL HALE
Address: 43682 SW BROWER LANE
City: PENDLETON State: OR Zip: 97801

If to Public Utility
Public Utility: PacifiCorp Transmission
Attention: Central Cashiers Office
Address: P.O. Box 2757
City: Portland State: OR Zip: 97208-2757

9.4 Designated Operating Representative
The Parties will designate operating representatives to conduct the communications which may be necessary or convenient for the administration of the operations provisions of this Agreement. This person will also serve as the point of contact with respect to operations and maintenance of the Party's facilities (complete if different than article 9.2 above)

Interconnection Customer's Operating Representative: SUNTHURST ENERGY, LLC
Attention: DANIEL HALE
Address: 153 LOWELL AVENUE
City: GLENDORA State: CA Zip: 91741
Phone: 310.975.4732 Fax: 323.782.0760 E-Mail: daniel@sunthurstenergy.com

Public Utility's Operating Representative: PacifiCorp
Attention: Grid Operations
Address: 9915 S.E. Ankeny Street
City: Portland State: OR Zip: 97216
Phone: 503-251-5197 Fax: 503-251-5228

9.5 Changes to the Notice Information
Either Party may change this notice information by giving five Business Days written notice prior to the effective date of the change.

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Article 10. Signatures

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their respective duly authorized representatives.

For Public Utility:

Name: [signature]

Title: VP, Transmission

Date: 3/14/16

For the Interconnection Customer:

Name: D Hale

Title: OWNER/PRINCIPAL

Date: 3/9/16

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Attachment 1

Description of Interconnection Facilities
And Metering Equipment Operated or Maintained by the Public Utility

Small Generating Facility: A 1.98 MW solar generating facility consisting of thirty-three (33) SMA MLX-60 60 kW inverters, connected to one (1) generation step up transformer (3 MVA, 5.75%), and one (1) 150 kVA grounding bank with an impedance of 5.75%, connected to Public Utility's Distribution System in Umatilla County, Oregon. See Attachment 2.

Interconnection Customer Interconnection Facilities: A short, 12.5 kV tie connecting the step-up transformer to the Interconnection Customer owned recloser and relay. Interconnection Customer will also own a gang-operated disconnect switch that Public Utility can access. See Attachment 2.

Public Utility's Interconnection Facilities: A short run of distribution circuit connected to a 12.5 kV disconnect switch, bi-directional revenue metering facilities and fiber optic cable equipment necessary for transfer-trip between the Small Generating Facility and Pilot Rock substation. See Attachment 2.

Estimated cost of Public Utility's Interconnection Facilities directly assigned to Interconnection Customer: $203,000

Estimated Annual Operation and Maintenance Cost of Public Utility's Interconnection Facilities: $1,500. Interconnection Customer shall be responsible for Public Utility's actual cost for maintenance of the Public Utility's Interconnection Facilities.

Point of Interconnection: The point where the Public Utility's Interconnection Facilities connect to the Public Utility's 12.5 kV distribution circuit 5W406 out of Pilot Rock substation. See Attachment 2.

Point of Change of Ownership: The point where the Interconnection Customer's Interconnection Facilities connect to the Public Utility's Interconnection Facilities. See Attachment 2.

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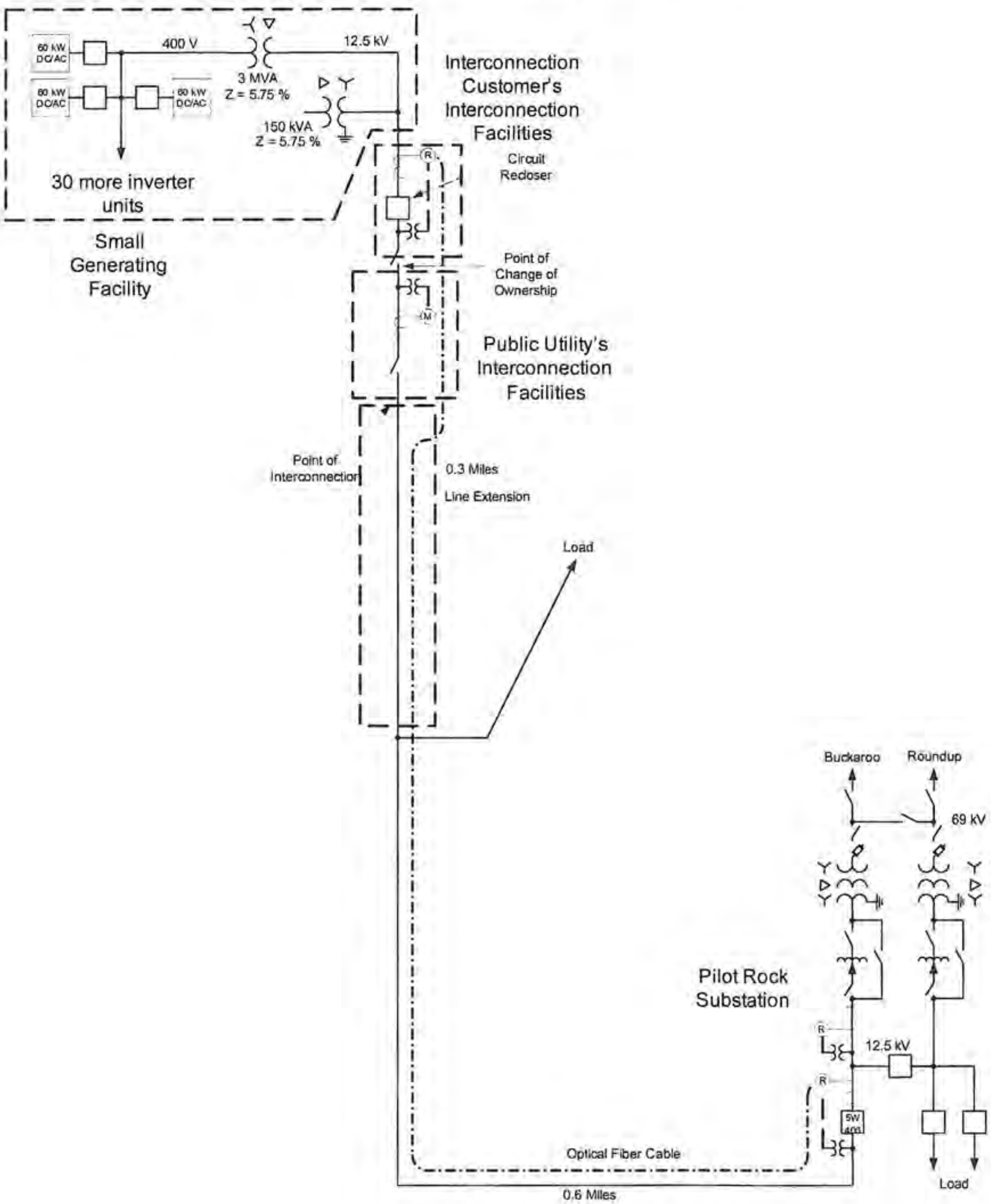
Attachment 2

One-line Diagram Depicting the Generating Facility, Interconnection Facilities, Metering Equipment, and Upgrades



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Attachment 3

Milestones

Estimated In-Service Date: May 15, 2017

Critical milestones and responsibility as agreed to by the Parties:

	Milestone/Date	Responsible Party
(1)	Execute Agreement and Provide Financial Security / March 15, 2016	Interconnection Customer
(2)	Provide All Required Design Information / May 15, 2016	Interconnection Customer
(3)	Begin Engineering Design / July 15, 2016	Public Utility
(4)	Obtain Property Rights / July 15, 2016	Interconnection Customer
(5)	Complete Engineering Design / December 20, 2016	Public Utility
(6)	Begin Construction / February 18, 2017	Public Utility
(7)	Provide Policy 138 required Test Plan / March 1, 2017	Interconnection Customer
(8)	Complete Construction & Backfeed / April 15, 2017	Both
(9)	Complete Testing & First Synch / May 1, 2017	Both
(10)	Commercial Operations / May 15, 2017	Both

Interconnection Customer is to request Backfeed, 1st Sync, and Commercial Operations in writing (email acceptable) prior to the above dates. Public Utility is to approve Interconnection Customer requests without unreasonable delay. The Interconnection Customer will be required to demonstrate the reactive

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capability of the Small Generating Facility and the voltage control system prior to Commercial Operations.

* Any design modifications to the Interconnection Customer's Small Generating Facility after this date requiring updates to the Public Utility's network model will result in a minimum of 3 months added to all future milestones including Commercial Operation.

**The Public Utility cannot guarantee the availability of a mobile transformer. As such, any delay in the arrival of the mobile transformer could result in delay of the remaining milestones including Commercial Operation.

Payment Schedule

If Interconnection Customer elects the progress payments option under Article 4.6 of the Interconnection Agreement, there are two potential options for a payment schedule below (please select one). If Interconnection Customer elects progress payment option but an option below is not selected, the Levelized Option will be selected by default. Failure to comply with the selected payment schedule will result in immediate contractual breach, work stoppage, and slip of the milestone schedule above on a day-for-day basis. Interconnection Customer will still be responsible for all costs of the project. Public Utility will conduct initial accounting for the project within thirty (30) days of granting Commercial Operations approval and will determine if a partial refund of project costs is acceptable.

Please select an option:	☐	☐
Funds due no later than	Levelized Option	Stepped Option
March 15, 2016 (or when Interconnection Agreement is executed)	$10,000	$10,000
June 1, 2016	$198,750	$79,500
August 1, 2016	$198,750	$159,000
October 1, 2016	$198,750	$238,500
January 1, 2017	$198,750	$318,000

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Attachment 4

Additional Operating Requirements for the Public Utility's Transmission System and/or Distribution System and Affected Systems Needed to Support the Interconnection Customer's Needs

The interconnection of the Small Generator Facility is subject to the rules contained within OAR 860 division 82. The interconnection of the Small Generator Facility to the Public Utility's Distribution System shall be subject to, and the Interconnection Customer shall operate the Small Generating Facility in accordance with, the Public Utility's policies governing interconnection of generation facilities to the distribution system entitled "Facility Connection (Interconnection) Requirements for Distribution Systems (34.5 kV and below)" which policy document is available upon request from the Public Utility and is incorporated by this reference as part of the Interconnection Agreement between the Parties. The interconnection of the Small Generator Facility to the Public Utility's Transmission System shall be subject to, and the Interconnection Customer shall operate the Small Generating Facility in accordance with, the Public Utility's policies governing interconnection of generation facilities to the transmission system entitled "Facility Connection (Interconnection) Requirements for Transmission Systems (46 kV and above)" which policy document is available upon request from the Public Utility and is incorporated by this reference as part of the Interconnection Agreement between the Parties. In the event of a conflict between any aspect of this Attachment 4 (including without limitation the Public Utility's policies governing interconnection of generation facilities to the distribution system or the transmission system) and the rules contained in OAR 860, division 82, the rules shall prevail.

Parallel Operation. Interconnection Customer may operate the Generating Facility in parallel with the Public Utility's Transmission System or Distribution System (collectively the "T&D System"), but subject at all times to any operating instructions that the Public Utility's dispatch operators may issue and in accordance with all the provisions of this Interconnection Agreement and Good Utility Practice, and any other conditions imposed by the Public Utility in its sole discretion.

Generating Facility Operation Shall Not Adversely Affect the Public Utility's T&D System. Interconnection Customer shall operate the Generating Facility in such a manner as not to adversely affect the Public Utility's T&D System or any other element of the Public Utility's electrical system. Interconnection Customer's Generating Facility shall deliver not more than the Design Capacity of 1,980 kW. Except as otherwise required by this Interconnection Agreement, Interconnection Customer shall operate the Generating Facility in a manner compatible with the Public Utility's applicable voltage level and fluctuating voltage guidelines, entitled Facility Connection (Interconnection) Requirements for Distribution Systems (34.5 kV and below), as it may be amended or superseded from time to time in the Public Utility's reasonable discretion, at the Point of Interconnection during all times that the Generating Facility is connected and operating in parallel with the Public Utility's T&D System. In its sole discretion, the Public Utility may specify rates of change in Interconnection Customer's deliveries to the Public Utility's T&D System during any start-up of the Generating Facility, during reconnection to the

Public Utility's T&D System, and during normal operations to assure that such rates of change are compatible with the operation of the Public Utility's voltage regulation equipment.

Maximum Authorized Power Flow. The Generating Facility shall not be operated in a manner that results in the flow of electric power onto the Public Utility's T&D System during any fifteen (15) minute interval at levels in excess of 2,080 kVA from the Generating Facility. If this provision is violated, the Public Utility may terminate this Interconnection Agreement or lock the Interconnection Customer Disconnect Switch in the open position until such time as: (a) the Public Utility has studied the impact of additional generation on the T&D System (at Interconnection Customer's cost and pursuant to a new study agreement between the Public Utility and Interconnection Customer) and the interconnection has been upgraded (at Interconnection Customer's cost and pursuant to a new or amended Facilities Construction Agreement and a new or amended Interconnection Agreement if deemed necessary by the Public Utility) in any manner necessary to accommodate the additional generation; or (b) the Interconnection Customer has modified the Generating Facility or Interconnection Customer's Interconnection Facilities in such manner as to insure to the Public Utility's satisfaction that the Generating Facility will no longer cause electric power to flow onto the Public Utility's T&D System at a level in excess of 2,080 kVA.

Harmonic Distortion or Voltage Flicker. Notwithstanding the Study Results, upon notice from the Public Utility that operation of the Generating Facility is producing unacceptable harmonic distortions or voltage flicker on the Public Utility's T&D System, Interconnection Customer shall at its sole cost remedy such harmonic distortions or voltage flicker within a reasonable time.

Reactive Power. Interconnection Customer shall at all times control the flow of reactive power between the Generating Facility and the Public Utility's T&D System within limits established by the Public Utility. The Public Utility shall not be obligated to pay Interconnection Customer for any Kvar or Kvar Hours flowing into the Public Utility's T&D System.

Islanding. If at any time during the term of this Interconnection Agreement the interconnection of the Generating Facility to the Public Utility's T&D System results in a risk of electrical islanding, or actual occurrences of electrical islanding, which the Public Utility reasonably concludes are incompatible with Good Utility Practice, the Parties shall (as necessary) study the issue and implement a solution that will eliminate or mitigate the risk of electrical islanding to a level deemed acceptable by the Public Utility. All costs associated with addressing any electrical islanding problems as required by this paragraph shall be paid by the Interconnection Customer, including without limitation any study costs, engineering costs, design costs, or costs to procure, install, operate and/or maintain required interconnection facilities or protective devices.

Voltage Regulation. The Interconnection Customer agrees to operate at a ± 95% leading or lagging power factor. Prior to installation, Interconnection Customer shall provide the Public Utility with written notice of the device and/or operational constrains selected to satisfy this requirement and shall obtain the Public Utility's written approval of such device and/or operational constraints, which approval shall not be unreasonably withheld. In the event Interconnection Customer fails to operate the Generating Facility within the voltage regulation constraints of this requirement, the Public Utility may disconnect the Generating Facility.

Modification of Nominal Operating Voltage Level. By providing Interconnection Customer with a one hundred and eighty (180) day notice, the Public Utility may at its sole discretion change the Public Utility's nominal operating voltage level at the Point of Interconnection. In the event of such change in voltage level Interconnection Customer shall, at Interconnection Customer's sole expense, modify Interconnection Customer's Interconnection Facilities as necessary to accommodate the modified nominal operating voltage level. Interconnection Customer has been informed that initial use of a dual voltage Interconnection Customer may ameliorate the cost of accommodating a change in nominal operating voltage level.

Equipment Failure. Interconnection Customer acknowledges that it is responsible for repair or replacement of Interconnection Customer's primary transformer and for any and all other components of the Generating Facility and the Interconnection Customer's Interconnection Facilities. Interconnection Customer is aware that it's inability to timely repair or replace its transformer or any other component of the Generating Facility or Interconnection Customer's Interconnection Facility could result in Interconnection Customer's inability to comply with its responsibilities under this Interconnection Agreement and could lead to disconnection of the Generating Facility from the Public Utility's T&D System and/or termination of this Interconnection Agreement pursuant to the terms of this Interconnection Agreement. Interconnection Customer acknowledges that the risk of this result is born solely by Interconnection Customer and may be substantially ameliorated by Interconnection Customer's elective maintenance of adequate reserve or spare components including but not limited to the Interconnection Customer's primary transformer.

Operation and Maintenance of Facilities Not Owned by the Public Utility. Interconnection Customer shall maintain, test, repair, keep accounts current on, or provide for the proper operation of any and all interconnection facilities, including but not limited to telemetry and communication equipment, not owned by the Public Utility.

Metering and Telemetry Communications Equipment. Notwithstanding any language of OAR 860-082-0070, Public Utility shall not require Interconnection Customer to install a redundant or back-up meter or other telemetry communications equipment. However, Public Utility reserves the right to request that the Oregon Public Utility Commission authorize Public Utility to require Interconnection Customer to be responsible for all reasonable costs associated with redundant metering and communications equipment installed at the Small Generating Facility, upon a determination by Public Utility that such equipment is necessary to maintain compliance with the mandatory reliability standards enforced by the North American Electric Reliability Corporation and the Western Electricity Coordinating Council.

Property Language. Interconnection Customer is required to obtain for the benefit of Public Utility at Interconnection Customer's sole cost and expense all real property rights, including but not limited to fee ownership, easements and/or rights of way, as applicable, for Public Utility owned Facilities using Public

Utility's standard forms. Public Utility shall not be obligated to accept any such real property right that does not, at Public Utility's sole discretion, confer sufficient rights to access, operate, construct, modify, maintain, place and remove Public Utility owned Facilities or is otherwise not conveyed using Public Utility's standard forms. Further, all real property on which Public Utility's Facilities are to be located must be environmentally, physically and operationally acceptable to the Public Utility at its sole discretion. Interconnection Customer is responsible for obtaining all permits required by all relevant jurisdictions for the project, including but not limited to, conditional use permits and construction permits; provided however, Public Utility shall obtain, at Interconnection Customer's cost and schedule risk, the permits necessary to construct Public Utility's Facilities that are to be located on real property currently owned or held in fee or right by Public Utility. Except as expressly waived in writing by an authorized officer of Public Utility, all of the foregoing permits and real property rights (conferring rights on real property that is environmentally, physically and operationally acceptable to Public Utility) shall be acquired as provided herein as a condition to Public Utility's contractual obligation to construct or take possession of facilities to be owned by the Public Utility under this Agreement. Public Utility shall have no liability for any project delays or cost overruns caused by delays in acquiring any of the foregoing permits and/or real property rights, whether such delay results from the failure to obtain such permits or rights or the failure of such permits or rights to meet the requirements set forth herein. Further, any completion dates, if any, set forth herein with regard to Public Utility's obligations shall be equitably extended based on the length and impact of any such delays.

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Form 8

Interconnection Agreement for Small Generator Facility
Tier 1, Tier 2, Tier 3 or Tier 4 Interconnection
(Small Generator Facilities with Electric Nameplate Capacities of 10MW or less)

Attachment 5

Public Utility' s Description of its Upgrades and Best Estimate of Upgrade Costs

Distribution Upgrades: Extend Circuit 5W406 by approximately .3 miles. Install approximately .9 miles of fiber optic cable. Add VTs and circuit metering and modify communications and protection scheme at Pilot Rock substation. Estimated cost is $602,000.

Network Upgrades: The following locations will require the Network Upgrades described below:

- No upgrades

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Interconnection Agreement for Small Generator Facility
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Attachment 6

Scope of Work

GENERATING FACILITY MODIFICATIONS

At the Small Generating Facility, a relay will need to be installed that will monitor the voltage magnitude and frequency. If the magnitude or frequency of the voltage is outside of the normal range of operation, the relay will need to disconnect the Small Generating Facility. It is our recommendation that a SEL 351 type relay be installed for this purpose. This relay has six pickup levels with different time delays for both the frequency and magnitude of the voltage to make the relay sensitive to small diversions from nominal but with adequate time delay and also fast reacting for extreme diversions.

The Public Utility will procure, install, test, and own all revenue metering equipment. It is expected the revenue metering instrument transformers will be installed overhead on a pole at the Point of Interconnection. The meter instrument transformer mounting shall conform to Public Utility's construction standards.

The metering will be bidirectional to measure KWH and KVARH quantities for both the generation received and the retail load delivered. The Interconnection Customer may request output from the Public Utility's revenue meters.

Communication equipment will be required to remotely interrogate the meter for generation and billing data via Public Utility's MV90 data acquisition system.

INTERCONNECTION CUSTOMER WILL BE RESPONSIBLE FOR THE FOLLOWING:

- Design, procure, install, and own an SEL 351 type relay to monitor the voltage and frequency of the Small Generating Facility.
- Provide professional engineer ("PE") signed and stamped drawings for Interconnection Customer's Small Generating Facility to Public Utility to allow development of required relay settings.
- Install and own a recloser for the Public Utility's SEL 2829 optical transceiver.

PUBLIC UTILITY WILL BE RESPONSIBLE FOR THE FOLLOWING:

- Design and communicate to the Interconnection Customer the settings to be programmed into the SEL 351 type relay.
- Own the revenue class instrument transformers required for the interconnection of the Small Generating Facility.
- Procure, install, and own two (2) meters are required for retail load Customer Net Gen reverse feed.
- Own the revenue class instrument transformers required for the interconnection of the Small Generating Facility.
- Design, procure, install, and own of Ethernet (preferred) or a cell phone to be designed as part

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of the meter and utilized to allow for remote interrogation of the Small Generating Facility.

- Design, procure, install, and own one (1) metering panel.
- Design, procure, install, and own of the required meter, test switches and secondary meter wire needed to interconnect the Small Generating Facility.
- Design, procure, install, and own the required meter, test switches and secondary meter wire needed to interconnect the Small Generating Facility.
- Design, procure and install all required communication fiber patch panel, fiber modem, and related communication equipment needed to connect to new 48-fiber, single mode, ADSS cable and to Interconnection Customer's recloser/equipment.

DISTRIBUTION LINE REQUIREMENTS

The following outlines the design, procurement, installation, and ownership of equipment for the distribution line.

INTERCONNECTION CUSTOMER WILL BE RESPONSIBLE FOR THE FOLLOWING:

- Obtain required right of way for newly required tap line from City Feeder to Small Generating Facility.

PUBLIC UTILITY WILL BE RESPONSIBLE FOR THE FOLLOWING:

- Design, install, and own 0.3 miles of 4/0 AAC primary conductors and one 4/0AAC neutral conductor from the Point of Interconnection (proposed facility point #090961) to the Point of Change of Ownership.
- Design, install, and own a gang operated switch and primary metering units.
- Procure and install one (1) span of overhead primary conductors from the primary metering pole to Interconnection Customer's pole. The termination of this conductor at the Small Generating Facility will serve as the Point of Change of Ownership.
- Replace the tap changing controller on R-816 with a controller capable of handling reverse power flow.
- Design, procure, install, and own new 48-fiber, single mode, ADSS cable from Small Generating Facility to Pilot Rock substation.

PILOT ROCK SUBSTATION

The following outlines the design, procurement, installation, testing and ownership of equipment for Public Utility's Distribution Circuit.

PUBLIC UTILITY WILL BE RESPONSIBLE FOR THE FOLLOWING:

- Procure, install, and own three (3) 12.5 kV VT's.
- Design, procure, and install required steel support structures and associated foundations for all new equipment if required.
- Design, procure, and install a one (1) new PC-611 panel.
- Design, procure, and install a one (1) new PI111 annunciator panel.

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(Small Generator Facilities with Electric Nameplate Capacities of 10MW or less)

- Design, procure, and install two (2) new PC 510 transformer metering panels.
- Design, procure and install all required communication fiber patch panel, fiber modem, and related communication equipment needed to connect to new 48-fiber, single mode, ADSS cable and to Interconnection Customer's recloser/equipment.
- Design, procure and install a fiber-optic channel to send direct transfer trip to the Interconnection Customer's collector site recloser using mirrored bits.

AGREEMENT TO AMEND INTERCONNECTION AGREEMENT FOR SMALL GENERATOR FACILITY

This **Agreement To Amend Interconnection Agreement for Small Generator Facility** ("Agreement") is made and entered into this 20th day of June, 2016, by and between PacifiCorp, an Oregon corporation (the "Public Utility") and Sunthurst Energy, LLC (Q666), an Oregon Limited Liability Company (the "Interconnection Customer"). Transmission Provider and Interconnection Customer may be referred to as a "Party" or collectively as the "Parties."

RECITALS

WHEREAS, Transmission Provider and Interconnection Customer have entered into a Generator Interconnection Agreement ("Interconnection Agreement"), dated March 14, 2016;

WHEREAS, Public Utility and Interconnection Customer have mutually agreed to amend one or more appendices, attachments, and/or exhibits to the Interconnection Agreement; and

WHEREAS, Article 8.2 of the Interconnection Agreement states that the Parties may mutually agree to amend this Interconnection Agreement by a written instrument duly executed by both parties;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein, it is agreed:

1.0 The Parties acknowledge and mutually agree that the following attachment will substitute in its entirety for the same attachment in the Interconnection Agreement:

- Attachment 3

2.0 Service under the Interconnection Agreement with the amended attachment will commence only upon execution by both Parties.

3.0 The Interconnection Agreement, with the substitute attachment shall constitute the entire agreement between the Parties.

4.0 TO THE FULLEST EXTENT PERMITTED BY LAW, EACH OF THE PARTIES HERETO WAIVES ANY RIGHT IT MAY HAVE TO A TRIAL BY JURY IN RESPECT OF LITIGATION DIRECTLY OR INDIRECTLY ARISING OUT OF, UNDER OR IN CONNECTION WITH THIS AGREEMENT. EACH PARTY FURTHER WAIVES ANY RIGHT TO CONSOLIDATE, OR TO REQUEST THE CONSOLIDATION OF, ANY ACTION IN WHICH A JURY TRIAL HAS BEEN WAIVED WITH ANY OTHER ACTION IN WHICH A JURY TRIAL CANNOT BE OR HAS NOT BEEN WAIVED.

5.0 All other provisions of the Interconnection Agreement will continue to apply.

IN WITNESS WHEREOF, the Parties have executed this Agreement in duplicate originals, each of which shall constitute and be an original effective Agreement between the Parties.

PacifiCorp

By: [signature]

Title: VP, Transmission

Date: 6/20/16

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Sunthurst Energy, LLC (Q666)

By: D Hale

Title: Principal

Date: 6.15.16

PACIFICORP

Form 8

Interconnection Agreement for Small Generator Facility
Tier 1, Tier 2, Tier 3 or Tier 4 Interconnection
(Small Generator Facilities with Electric Nameplate Capacities of 10MW or less)

Attachment 3

Milestones

Estimated In-Service Date: September 15, 2017

JUN 20 REC'D

Critical milestones and responsibility as agreed to by the Parties:

	Milestone/Date	**Responsible Party**
(1)	Execute Agreement and Provide $10,000 deposit March 15, 2016	Interconnection Customer
(2)	Provide All Required Design Information October 15, 2016	Interconnection Customer
(3)	Begin Engineering Design November 15, 2016	Public Utility
(4)	Obtain Property Rights November 15, 2016	Interconnection Customer
(5)	Complete Engineering Design April 20, 2017	Public Utility
(6)	Begin Construction June 18, 2017	Public Utility
(7)	Provide Policy 138 required Test Plan July 1, 2017	Interconnection Customer
(8)	Complete Construction & Backfeed August 15, 2017	Both
(9)	Complete Testing & First Sync September 1, 2017	Both
(10)	Commercial Operations September 15, 2017	Both

Interconnection Customer is to request Backfeed, 1st Sync, and Commercial Operations in writing (email acceptable) prior to the above dates. Public Utility is to approve Interconnection Customer requests without unreasonable delay. The Interconnection Customer will be required to demonstrate the reactive

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Form 8

JUN 20 2016

Interconnection Agreement for Small Generator Facility
Tier 1, Tier 2, Tier 3 or Tier 4 Interconnection
(Small Generator Facilities with Electric Nameplate Capacities of 10MW or less)

capability of the Small Generating Facility and the voltage control system prior to Commercial Operations.

* Any design modifications to the Interconnection Customer's Small Generating Facility after this date requiring updates to the Public Utility's network model will result in a minimum of 3 months added to all future milestones including Commercial Operation.

**The Public Utility cannot guarantee the availability of a mobile transformer. As such, any delay in the arrival of the mobile transformer could result in delay of the remaining milestones including Commercial Operation.

Payment Schedule

If Interconnection Customer elects the progress payments option under Article 4.6 of the Interconnection Agreement, there are two potential options for a payment schedule below (please select one). If Interconnection Customer elects progress payment option but an option below is not selected, the Levelized Option will be selected by default. Failure to comply with the selected payment schedule will result in immediate contractual breach, work stoppage, and slip of the milestone schedule above on a day-for-day basis. Interconnection Customer will still be responsible for all costs of the project. Public Utility will conduct initial accounting for the project within thirty (30) days of granting Commercial Operations approval and will determine if a partial refund of project costs is acceptable.

Please select an option:	☐	☐
<u>Funds due no later than</u>	<u>Levelized Option</u>	<u>Stepped Option</u>
March 15, 2016 (or when Interconnection Agreement is executed)	$10,000	$10,000 - Paid
October 1, 2016	$198,750	$79,500
December 1, 2016	$198,750	$159,000
February 1, 2017	$198,750	$238,500
May 1, 2017	$198,750	$318,000

AGREEMENT TO AMEND INTERCONNECTION AGREEMENT FOR SMALL GENERATOR FACILITY

This **Agreement To Amend Interconnection Agreement for Small Generator Facility** ("Agreement") is made and entered into this 11th day of October, 2016, by and between PacifiCorp, an Oregon corporation (the "Public Utility") and Sunthurst Energy, LLC (Q666), an Oregon Limited Liability Company (the "Interconnection Customer"). Transmission Provider and Interconnection Customer may be referred to as a "Party" or collectively as the "Parties."

RECITALS

WHEREAS, Transmission Provider and Interconnection Customer have entered into a Generator Interconnection Agreement ("Interconnection Agreement"), dated March 14, 2016;

WHEREAS, Public Utility and Interconnection Customer have mutually agreed to amend one or more appendices, attachments, and/or exhibits to the Interconnection Agreement; and

WHEREAS, Article 8.2 of the Interconnection Agreement states that the Parties may mutually agree to amend this Interconnection Agreement by a written instrument duly executed by both parties;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein, it is agreed:

1.0 The Parties acknowledge and mutually agree that the following attachment will substitute in its entirety for the same attachment in the Interconnection Agreement:
   - Attachment 3.

2.0 Service under the Interconnection Agreement with the amended attachment will commence only upon execution by both Parties.

3.0 The Interconnection Agreement, with the substitute attachment shall constitute the entire agreement between the Parties.

4.0 TO THE FULLEST EXTENT PERMITTED BY LAW, EACH OF THE PARTIES HERETO WAIVES ANY RIGHT IT MAY HAVE TO A TRIAL BY JURY IN RESPECT OF LITIGATION DIRECTLY OR INDIRECTLY ARISING OUT OF, UNDER OR IN CONNECTION WITH THIS AGREEMENT. EACH PARTY FURTHER WAIVES ANY RIGHT TO CONSOLIDATE, OR TO REQUEST THE CONSOLIDATION OF, ANY ACTION IN WHICH A JURY TRIAL HAS BEEN WAIVED WITH ANY OTHER ACTION IN WHICH A JURY TRIAL CANNOT BE OR HAS NOT BEEN WAIVED.

5.0 All other provisions of the Interconnection Agreement will continue to apply.

IN WITNESS WHEREOF, the Parties have executed this Agreement in duplicate originals, each of which shall constitute and be an original effective Agreement between the Parties.

PacifiCorp

By: ______________

Title: VP, Transmission

Date: 10/11/16

Sunthurst Energy, LLC (Q666)

By: D Hale

Title: OWNER

Date: 10.4.16

PACIFICORP

Form 8

Interconnection Agreement for Small Generator Facility
Tier 1, Tier 2, Tier 3 or Tier 4 Interconnection
(Small Generator Facilities with Electric Nameplate Capacities of 10MW or less)

Attachment 3

Milestones

Estimated In-Service Date: September 30, 2018

Critical milestones and responsibility as agreed to by the Parties:

	Milestone/Date	Responsible Party
(1)	Execute Agreement and Provide $10,000 deposit March 15, 2016	Interconnection Customer
(2)	Provide All Required Design Information October 15, 2016	Interconnection Customer
(3)	Begin Engineering Design November 15, 2017	Public Utility
(4)	Obtain Property Rights November 15, 2017	Interconnection Customer
(5)	Complete Engineering Design April 20, 2018	Public Utility
(6)	Begin Construction June 18, 2018	Public Utility
(7)	Provide Policy 138 required Test Plan July 1, 2018	Interconnection Customer
(8)	Complete Construction & Backfeed September 1, 2018	Both
(9)	Complete Testing & First Sync September 15, 2018	Both
(10)	Commercial Operations September 30, 2018	Both

Interconnection Customer is to request Backfeed, 1st Sync, and Commercial Operations in writing (email acceptable) prior to the above dates. Public Utility is to approve Interconnection Customer requests without unreasonable delay. The Interconnection Customer will be required to demonstrate the reactive

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Form 8

Interconnection Agreement for Small Generator Facility
Tier 1, Tier 2, Tier 3 or Tier 4 Interconnection
(Small Generator Facilities with Electric Nameplate Capacities of 10MW or less)

capability of the Small Generating Facility and the voltage control system prior to Commercial Operations.

* Any design modifications to the Interconnection Customer's Small Generating Facility after this date requiring updates to the Public Utility's network model will result in a minimum of 3 months added to all future milestones including Commercial Operation.

**The Public Utility cannot guarantee the availability of a mobile transformer. As such, any delay in the arrival of the mobile transformer could result in delay of the remaining milestones including Commercial Operation.

Payment Schedule

If Interconnection Customer elects the progress payments option under Article 4.6 of the Interconnection Agreement, there are two potential options for a payment schedule below (please select one). If Interconnection Customer elects progress payment option but an option below is not selected, the Levelized Option will be selected by default. Failure to comply with the selected payment schedule will result in immediate contractual breach, work stoppage, and slip of the milestone schedule above on a day-for-day basis. Interconnection Customer will still be responsible for all costs of the project. Public Utility will conduct initial accounting for the project within thirty (30) days of granting Commercial Operations approval and will determine if a partial refund of project costs is acceptable.

Please select an option:	☐	☒
Funds due no later than	Levelized Option	Stepped Option
March 15, 2016 (or when Interconnection Agreement is executed)	$10,000	$10,000 - Paid
October 1, 2017	$198,750	$79,500
December 1, 2017	$198,750	$159,000
February 1, 2018	$198,750	$238,500
May 1, 2018	$198,750	$318,000

AGREEMENT TO AMEND INTERCONNECTION AGREEMENT FOR SMALL GENERATOR FACILITY

This **Agreement To Amend Interconnection Agreement for Small Generator Facility** ("Agreement") is made and entered into this 27th day of November, 2017, by and between PacifiCorp, an Oregon corporation (the "Public Utility") and Sunthurst Energy, LLC (Q666), an Oregon limited liability company (the "Interconnection Customer"). Transmission Provider and Interconnection Customer may be referred to as a "Party" or collectively as the "Parties."

RECITALS

WHEREAS, Transmission Provider and Interconnection Customer have entered into a Generator Interconnection Agreement ("Interconnection Agreement"), dated March 14, 2016, and amended as of June 20, 2016, and October 11, 2016;

WHEREAS, Public Utility and Interconnection Customer have mutually agreed to amend one or more appendices, attachments, and/or exhibits to the Interconnection Agreement; and

WHEREAS, Article 8.2 of the Interconnection Agreement states that the Parties may mutually agree to amend this Interconnection Agreement by a written instrument duly executed by both parties;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein, it is agreed:

1.0 The Parties acknowledge and mutually agree that the following attachment will substitute in its entirety the same attachment in the Interconnection Agreement:
- Attachment 3.

2.0 Service under the Interconnection Agreement with the amended attachment will commence only upon execution by both Parties.

3.0 The Interconnection Agreement, with the attached substitute attachments shall constitute the entire agreement between the Parties.

4.0 TO THE FULLEST EXTENT PERMITTED BY LAW, EACH OF THE PARTIES HERETO WAIVES ANY RIGHT IT MAY HAVE TO A TRIAL BY JURY IN RESPECT OF LITIGATION DIRECTLY OR INDIRECTLY ARISING OUT OF, UNDER OR IN CONNECTION WITH THIS AGREEMENT. EACH PARTY FURTHER WAIVES ANY RIGHT TO CONSOLIDATE, OR TO REQUEST THE CONSOLIDATION OF, ANY ACTION IN WHICH A JURY TRIAL HAS BEEN WAIVED WITH ANY OTHER ACTION IN WHICH A JURY TRIAL CANNOT BE OR HAS NOT BEEN WAIVED.

5.0 All other provisions of the Interconnection Agreement will continue to apply.

IN WITNESS WHEREOF, the Parties have executed this Agreement in duplicate originals, each of which shall constitute and be an original effective Agreement between the Parties.

PacifiCorp

By: Rick Vail

Title: VP, Transmission

Date: 11/27/17

Sunthurst Energy, LLC (Q666)

By: DH

Title: Owner

Date: 11/21/17

PACIFICORP

Form 8

Interconnection Agreement for Small Generator Facility
Tier 1, Tier 2, Tier 3 or Tier 4 Interconnection
(Small Generator Facilities with Electric Nameplate Capacities of 10MW or less)

Attachment 3

Milestones

Estimated In-Service Date: June 30, 2019

Critical milestones and responsibility as agreed to by the Parties:

	Milestone/Date	Responsible Party
(1)	Execute Agreement and Provide $10,000 deposit March 15, 2016	Interconnection Customer
(2)	Provide All Required Design Information July 12, 2018	Interconnection Customer
(3)	Begin Engineering Design July 12, 2018	Public Utility
(4)	Obtain Property Rights September 1, 2018	Interconnection Customer
(5)	Complete Engineering Design December 13, 2018	Public Utility
(6)	Begin Construction April 1, 2019	Public Utility
(7)	Provide Policy 138 required Test Plan May 1, 2019	Interconnection Customer
(8)	Complete Construction & Backfeed June 1, 2019	Both
(9)	Complete Testing & First Sync June 25, 2019	Both
(10)	Commercial Operations June 30, 2019	Both

Interconnection Customer is to request Backfeed, 1st Sync, and Commercial Operations in writing (email acceptable) prior to the above dates. Public Utility is to approve Interconnection Customer requests without unreasonable delay. The Interconnection Customer will be required to demonstrate the reactive

capability of the Small Generating Facility and the voltage control system prior to Commercial Operations.

* Any design modifications to the Interconnection Customer's Small Generating Facility after this date requiring updates to the Public Utility's network model will result in a minimum of 3 months added to all future milestones including Commercial Operation.

**The Public Utility cannot guarantee the availability of a mobile transformer. As such, any delay in the arrival of the mobile transformer could result in delay of the remaining milestones including Commercial Operation.

Payment Schedule

If Interconnection Customer elects the progress payments option under Article 4.6 of the Interconnection Agreement, there are two potential options for a payment schedule below (please select one). If Interconnection Customer elects progress payment option but an option below is not selected, the Levelized Option will be selected by default. Failure to comply with the selected payment schedule will result in immediate contractual breach, work stoppage, and slip of the milestone schedule above on a day-for-day basis. Interconnection Customer will still be responsible for all costs of the project. Public Utility will conduct initial accounting for the project within thirty (30) days of granting Commercial Operations approval and will determine if a partial refund of project costs is acceptable.

Please select an option:	☐	☒
Funds due no later than	Levelized Option	Stepped Option
March 15, 2016 (or when Interconnection Agreement is executed)	$10,000	$10,000 - Paid
July 1, 2018	$198,750	$79,500
August 1, 2018	$198,750	$159,000
October 1, 2018	$198,750	$238,500
December 1, 2018	$198,750	$318,000

AGREEMENT TO AMEND INTERCONNECTION AGREEMENT FOR SMALL GENERATOR FACILITY

This **Agreement To Amend Interconnection Agreement for Small Generator Facility** ("Agreement") is made and entered into this 6th day of November, 20 18, by and between PacifiCorp, an Oregon corporation (the "Public Utility") and Sunthurst Energy, LLC (Q666), an Oregon limited liability company (the "Interconnection Customer"). Transmission Provider and Interconnection Customer may be referred to as a "Party" or collectively as the "Parties."

RECITALS

WHEREAS, Transmission Provider and Interconnection Customer have entered into a Generator Interconnection Agreement ("Interconnection Agreement"), dated March 14, 2016, and amended as of June 20, 2016, October 11, 2016, and November 21, 2017;

WHEREAS, Public Utility and Interconnection Customer have mutually agreed to amend one or more appendices, attachments, and/or exhibits to the Interconnection Agreement; and

WHEREAS, Article 8.2 of the Interconnection Agreement states that the Parties may mutually agree to amend this Interconnection Agreement by a written instrument duly executed by both parties;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein, it is agreed:

1.0 The Parties acknowledge and mutually agree that the following attached attachment will substitute in its entirety the same attachment in the Interconnection Agreement:
- Attachment 3

2.0 Service under the Interconnection Agreement with the amended attachment will commence only upon execution by both Parties.

3.0 The Interconnection Agreement, with the attached substitute attachments shall constitute the entire agreement between the Parties.

4.0 TO THE FULLEST EXTENT PERMITTED BY LAW, EACH OF THE PARTIES HERETO WAIVES ANY RIGHT IT MAY HAVE TO A TRIAL BY JURY IN RESPECT OF LITIGATION DIRECTLY OR INDIRECTLY ARISING OUT OF, UNDER OR IN CONNECTION WITH THIS AGREEMENT. EACH PARTY FURTHER WAIVES ANY RIGHT TO CONSOLIDATE, OR TO REQUEST THE CONSOLIDATION OF, ANY ACTION IN WHICH A JURY TRIAL HAS BEEN WAIVED WITH ANY OTHER ACTION IN WHICH A JURY TRIAL CANNOT BE OR HAS NOT BEEN WAIVED.

5.0 All other provisions of the Interconnection Agreement will continue to apply.

IN WITNESS WHEREOF, the Parties have executed this Agreement in duplicate originals, each of which shall constitute and be an original effective Agreement between the Parties.

PacifiCorp

By: ____________________
Rick Vail

Title: VP, Transmission

Date: 11/6/18

Sunthurst Energy, LLC (Q666)

By: ____________________

Title: Owner

Date: 11/6/18

PACIFICORP

Form 8

Interconnection Agreement for Small Generator Facility
Tier 1, Tier 2, Tier 3 or Tier 4 Interconnection
(Small Generator Facilities with Electric Nameplate Capacities of 10MW or less)

Attachment 3

Milestones

Estimated In-Service Date: December 31, 2019

Critical milestones and responsibility as agreed to by the Parties:

	Milestone/Date	**Responsible Party**
(1)	Execute Agreement and Provide $10,000 deposit March 15, 2016	Interconnection Customer
(2)	Provide All Required Design Information July 12, 2018	Interconnection Customer
(3)	Begin Engineering Design February 1, 2019	Public Utility
(4)	Obtain Property Rights April 1, 2019	Interconnection Customer
(5)	Complete Engineering Design July 15, 2019	Public Utility
(6)	Begin Construction September 1, 2019	Public Utility
(7)	Provide Policy 138 required Test Plan November 1, 2019	Interconnection Customer
(8)	Complete Construction & Backfeed December 1, 2019	Both
(9)	Complete Testing & First Sync December 25, 2019	Both
(10)	Commercial Operations December 31, 2019	Both

Interconnection Customer is to request Backfeed, 1st Sync, and Commercial Operations in writing (email acceptable) prior to the above dates. Public Utility is to approve Interconnection Customer requests without unreasonable delay. The Interconnection Customer will be required to demonstrate the reactive

capability of the Small Generating Facility and the voltage control system prior to Commercial Operations.

* Any design modifications to the Interconnection Customer's Small Generating Facility after this date requiring updates to the Public Utility's network model will result in a minimum of 3 months added to all future milestones including Commercial Operation.

**The Public Utility cannot guarantee the availability of a mobile transformer. As such, any delay in the arrival of the mobile transformer could result in delay of the remaining milestones including Commercial Operation.

Payment Schedule

If Interconnection Customer elects the progress payments option under Article 4.6 of the Interconnection Agreement, there are two potential options for a payment schedule below (please select one). If Interconnection Customer elects progress payment option but an option below is not selected, the Levelized Option will be selected by default. Failure to comply with the selected payment schedule will result in immediate contractual breach, work stoppage, and slip of the milestone schedule above on a day-for-day basis. Interconnection Customer will still be responsible for all costs of the project. Public Utility will conduct initial accounting for the project within thirty (30) days of granting Commercial Operations approval and will determine if a partial refund of project costs is acceptable.

Please select an option:	☐	☐
Funds due no later than	Levelized Option	Stepped Option
March 15, 2016 (or when Interconnection Agreement is executed)	$10,000	$10,000 - Paid
July 1, 2018	$143,100	$79,500 - Paid
April 1, 2019	$143,100	$53,500
June 1, 2019	$143,100	$159,000
August 1, 2019	$143,100	$238,500
October 15, 2019	$143,100	$318,000

AGREEMENT TO AMEND INTERCONNECTION AGREEMENT FOR SMALL GENERATOR FACILITY

This **Agreement To Amend Interconnection Agreement for Small Generator Facility** ("Agreement") is made and entered into this _______ day of __________________, 20_____, by and between PacifiCorp, an Oregon corporation (the "Public Utility") and Sunthurst Energy, LLC (Q0666), an Oregon limited liability company (the "Interconnection Customer"). Transmission Provider and Interconnection Customer may be referred to as a "Party" or collectively as the "Parties."

RECITALS

WHEREAS, Transmission Provider and Interconnection Customer have entered into a Generator Interconnection Agreement ("Interconnection Agreement"), dated March 14, 2016, and amended as of June 20, 2016, October 11, 2016, November 21, 2017, and November 6, 2018;

WHEREAS, Public Utility and Interconnection Customer have mutually agreed to amend one or more appendices, attachments, and/or exhibits to the Interconnection Agreement; and

WHEREAS, Article 8.2 of the Interconnection Agreement states that the Parties may mutually agree to amend this Interconnection Agreement by a written instrument duly executed by both parties;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein, it is agreed:

1.0 The Parties acknowledge and mutually agree that the following attached attachments will substitute in their entirety the same attachment in the Interconnection Agreement:
- Attachment 1
- Attachment 3
- Attachment 5
- Attachment 6

2.0 Service under the Interconnection Agreement with the amended attachments will commence only upon execution by both Parties.

3.0 The Interconnection Agreement, with the attached substitute attachments shall constitute the entire agreement between the Parties.

4.0 TO THE FULLEST EXTENT PERMITTED BY LAW, EACH OF THE PARTIES HERETO WAIVES ANY RIGHT IT MAY HAVE TO A TRIAL BY JURY IN RESPECT OF LITIGATION DIRECTLY OR INDIRECTLY ARISING OUT OF, UNDER OR IN CONNECTION WITH THIS AGREEMENT. EACH PARTY FURTHER WAIVES ANY RIGHT TO CONSOLIDATE, OR TO REQUEST THE CONSOLIDATION OF, ANY ACTION IN WHICH A JURY TRIAL HAS BEEN

WAIVED WITH ANY OTHER ACTION IN WHICH A JURY TRIAL CANNOT BE OR HAS NOT BEEN WAIVED.

5.0 All other provisions of the Interconnection Agreement will continue to apply.

IN WITNESS WHEREOF, the Parties have executed this Agreement in duplicate originals, each of which shall constitute and be an original effective Agreement between the Parties.

PacifiCorp

By: _____________________

Title: _____________________

Date: _____________________

Sunthurst Energy, LLC (Q0666)

By: _____________________

Title: _____________________

Date: _____________________

Docket No. UM 2118
Exhibit PAC/102
Witness: Kris Bremer

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Response Testimony of Kris Bremer

Sunthurst Letter

January 2021

Sunthurst Energy, LLC

March 20, 2019

PacifiCorp
Robin Moore
825 NE Multnomah
Portland, OR 97232

RE: Q0666 Extension Letter- PUC Delay CS Program Launch

Dear Robin,

Thank you for your past cooperation in this difficult matter. Last month, in good faith, we evidenced progress by providing project design and recorded Property Rights (Items 3 and 4) of Agreement Attachment 3; however, I write you again to ask PacifiCorp to waive upcoming payment milestones for Sunthurst Energy, LLC's Pilot Rock Solar project (Q-0666) in its March 14, 2016 Interconnection Agreement with PacifiCorp.

As you know, Sunthurst Energy, LLC (Sunthurst) developed the 1.98 MW Pilot Rock solar project (Facility) in reliance upon the Community Solar program ordered by the legislature and currently being implemented by the Oregon PUC AR603. However that implementation has experienced delays beyond anyone's contemplation. The Commission targeted implementation for 2018. However in February 2019, OPUC staff predicted that it would take 6 more months before the program would be ready to accept applications for pre-certification.

Construction of Pilot Rock's $800k interconnection facilities before it is pre-certified for Tier 1 of the Commission's Community Solar Program would not be prudent. Due to its size, the Pilot Rock solar project is unlike other, larger, projects that have other viable means of development. Unless the project is pre-certified it will not be built. But-for administrative delays beyond either party's control, Sunthurst would already have had a decision on pre-certification well in advance of the major payment milestones in the Interconnection Agreement.

The Community Solar program is mandated by state law and supported with funding from the Oregon Department of Energy ($250,000 in the case of Pilot Rock solar project). In Order No. 18-088, page 2, the Commission found that the legislature intended the Community Solar program to be implemented in a timely manner and that the Commission could take interim steps to ensure that the intent of the legislature was not thwarted by implementation delays. So as not to thwart the State's Community Solar program it would be reasonable to postpone Pilot Rock's remaining payment milestones (and to preserve Pilot Rock's queue position per OAR 860-082-0010(2)(c)) until 10 days after it receives a pre-certification ruling from the Commission's program manager (expected in late 2019 or early 2020).

The above circumstances are a prime example of why the Commission adopted OAR 860-082-0010, permitting PacifiCorp to agree to reasonable extensions to the required timelines without requesting waiver from the

Sunthurst Energy, LLC

Commission. However, if PacifiCorp and Sunthurst cannot agree to an extension by March 20, Sunthurst expects that the Commission will grant its request, and possibly additional relief.

Sunthurst and its attorney are available to meet with PacifiCorp at any time to discuss Sunthurst's request. Thank you for your time and consideration.

Sincerely,

President, Sunthurst Energy, LLC

Docket No. UM 2118
Exhibit PAC/103
Witness: Kris Bremer

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Response Testimony of Kris Bremer

Q1045 Interconnection Studies

January 2021

Small Generator Interconnection

Oregon Tier 4 System Impact Study Report

Completed for

Pilot Rock Solar 1, LLC
("Interconnection Customer")
Q1045
Pilot Rock Solar 2
A Qualifying Facility

Proposed Point of Interconnection

Circuit 5W406 out of Pilot Rock substation at 12.5 kV
(at approximately 45° 30' 32.67", -118° 49' 38.87")

March 27, 2020

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1.0 Description of the Generating Facility

Pilot Rock Solar 1, LLC ("Interconnection Customer") proposed interconnecting 3 MW of new generation to PacifiCorp's ("Public Utility") Circuit 5W406 out of Pilot Rock substation at 12.5 kV located in Umatilla County, Oregon. The Pilot Rock Solar 2 project ("Project") will consist of forty-nine (49) Sungrow SG60KU-M inverters for a total requested output of 3 MW. The requested commercial operation date is December 31, 2019.

Interconnection Customer will operate this generator as a Qualifying Facility as defined by the Public Utility Regulatory Policies Act of 1978 (PURPA).

The Public Utility has assigned the Project "Q1045."

2.0 Approval Criteria for Tier 4 Interconnection Review

Pursuant to 860-082-0060(1), a public utility must use the Tier 4 interconnection review procedures for an application to interconnect a small generator facility that meets the following requirements:

(a) The small generator facility does not qualify for or failed to meet Tier 1, Tier 2, or Tier 3 interconnection review requirements; and
(b) The small generator facility must have a nameplate capacity of ten (10) megawatts or less.

3.0 Scope of the Study

Pursuant to 860-082-0060(7)(g) the System Impact Study Report shall consist of a short circuit analysis, a stability analysis, a power flow analysis, voltage drop and flicker studies, protection and set point coordination studies, and grounding reviews, as necessary. The System Impact Study shall state the assumptions upon which it is based, state the results of the analyses, and provide the requirement or potential impediments to providing the requested interconnection service, including a preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. The System Impact Study shall provide a list of facilities that are required as a result of the Interconnection Request and non-binding good faith estimates of cost responsibility and time to construct.

4.0 Independent Study Evaluation

Pursuant to 860-082-0060(7)(h), the application has not provided an independent system impact study that is to be addressed and evaluated along with the results from the Public Utility's own evaluation of the interconnection of the proposed Small Generator Facility.

5.0 Proposed Point of Interconnection

The Interconnection Customer's proposed Small Generator Facility is to be interconnected to the Public Utility's distribution circuit 5W406 out of Pilot Rock substation, roughly 1,400' north of the existing facility point 01401032.0090961. The Interconnection Customer's Small Generator Facility will utilize the interconnection facilities associated with the Interconnection Request studied under queue position Q0666. Figure 1 below, is a one-line diagram that illustrates the interconnection of the proposed Small Generator Facility to the Public Utility's system.

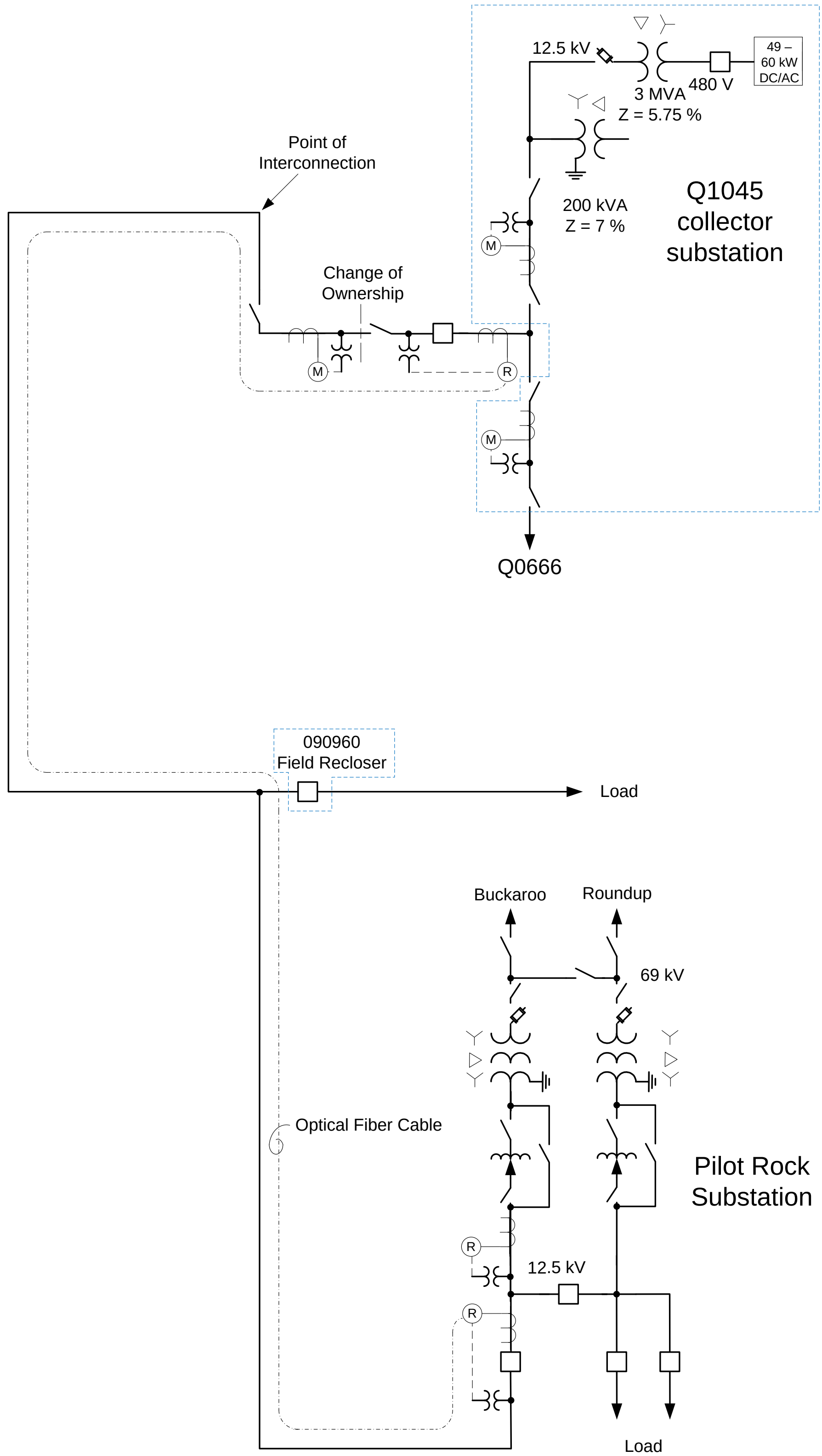

Figure 1: System One Line Diagram

6.0 Study Assumptions

- All active higher priority transmission service and/or generator interconnection requests will be considered in this study and are listed in Appendix 1. If any of these requests are withdrawn, the Public Utility reserves the right to restudy this request, as the results and conclusions contained within this study could significantly change.
- For study purposes there are two separate queues:
  - Transmission Service Queue: to the extent practical, all System Upgrades that are required to accommodate active transmission service requests will be modeled in this study.
  - Generation Interconnection Queue: All relevant higher queue interconnection requests will be modeled in this study.
- The Interconnection Customer's request for interconnection service in and of itself does not convey transmission service.
- This study assumes the Project will be integrated into Public Utility's system at the agreed upon and/or proposed Point of Interconnection ("POI").
- The Interconnection Customer will construct and own any facilities required between the POI and the Project unless specifically identified by the Public Utility.
- Line reconductor or fiber underbuild required on existing poles will be assumed to follow the most direct path on the Public Utility's system. If during detailed design the path must be modified it may result in additional cost and timing delays for the Interconnection Customer's Project.
- Generator tripping may be required for certain outages.
- All facilities will meet or exceed the minimum Western Electricity Coordinating Council ("WECC"), North American Electric Reliability Corporation ("NERC"), and Public Utility performance and design standards.
- Time of use metering does not exist for Pilot Rock substation. The daytime minimum demand for the feeder 5W406 is estimated based on the peak demand on the circuit.
- Peak demand for 5W406 is approximately 6600 kW and 2600 kVAR. There is one 600 kVAR capacitor bank installed on the feeder.
- The minimum daytime load on 5W406 is estimated at 1820 kW and 960 kVAR.
- The solar generation interconnection was studied with a maximum output of 3 MW and a reactive consumption by the Project of 900 kVAR.
- This report is based on the AC Oneline provided by the Interconnection Customer and dated April 28, 2018.
- Inverter specifications were also provided by the Interconnection Customer.
- The power output of the inverters is to 6600 kVA / 6000 kW as stated in the inverter specifications. This appears to comply with reactive requirements for this Project; however, Interconnection Customer is responsible for additional reactive compensation, if needed, to assure total Project output can be delivered at unity power factor.
- The Small Generator Facility is expected to operate during daylight hours every day 7 days per week 12 months per year.
- Contingency transmission configuration for the Public Utility's system is defined as any configuration other than normal transmission configuration.
- Three case studies were assembled and studied in power flow simulation at the transmission level:

- o Case 1: Normal Configuration with Pilot Rock fed from BPA breaker L-1122 at Roundup, via the "Birch Creek" 69 kV Line.
- o Case 2: Contingency configuration with Pilot Rock fed from Buckaroo and Roundup via the "Coyote Creek" 69 kV line. Switch 3W191 closed, BPA breaker L-1122 open.
- o Case 3: Pendleton 69 kV Loop Split (Switch 3W26 open at Buckaroo, breaker L-1123 open at BPA Roundup).

- This report is based on information available at the time of the study. It is the Interconnection Customer's responsibility to check the Public Utility's web site regularly for transmission system updates (http://www.pacificorp.com/tran.html)

7.0 REQUIREMENTS

7.1 SMALL GENERATOR FACILITY REQUIREMENTS

The Small Generator Facility and Interconnection Equipment owned by the Interconnection Customer are required to operate under automatic voltage control with the voltage sensed electrically at the POI. The Small Generator Facility should have sufficient reactive capacity to enable the delivery of 100 percent of the Project output to the POI at unity power factor measured at 1.0 per unit voltage under steady state conditions.

Generators capable of operating under voltage control with a voltage droop are required to do so. Studies will be required to coordinate the voltage droop setting with other facilities in the area. In general, the Small Generator Facility and Interconnection Equipment should be operated so as to maintain the voltage at the POI between 1.01 pu to 1.04 pu. At the Public Utility's discretion, these values might be adjusted depending on the operating conditions. Within this voltage range, the Small Generator Facility should operate so as to minimize the reactive interchange between the Small Generator Facility and the Public Utility's system (delivery of power at the POI at approximately unity power factor). The voltage control settings of the Small Generator Facility must be coordinated with the Public Utility prior to energization (or interconnection). The reactive compensation must be designed such that the discreet switching of the reactive device (if required by the Interconnection Customer) does not cause step voltage changes greater than +/-3% on the Public Utility's system.

All generators must meet applicable WECC low voltage ride-through requirements as specified in the interconnection agreement.

As per NERC standard VAR-001-1, the Public Utility is required to specify voltage or reactive power schedule at the POI. Under normal conditions, the Public Utility's system should not supply reactive power to the Small Generator Facility.

As the Public Utility cannot submit a user written model to WECC for inclusion in base cases, a standard model from the WECC Approved Dynamic Model Library is required 180 days prior to trial operation. The list of approved generator models is continually updated and is available on the http://www.WECC.biz website.

The Interconnection Customer will be required to install a transformer that will hold the phase to neutral voltages within limits when the Small Generator Facility is isolated with the Public Utility's local system until the generation disconnects. The proposed delta – wye step-up transformer with the delta winding on the 12.47 kV side will not accomplish the stabilization of the phase to neutral voltages on the 12.47 kV system. The circuit that the Project is connecting to is a four wire multi-grounded circuit with line to neutral connected load. Figure 1 shows the addition of a wye – delta grounding transformer of adequate power size and impedance that will meet the requirement. The grounding transformer proposed for the Q0666 project alone will not be adequate for both projects. Since the two projects will share a common circuit recloser the projects could also share a common grounding transformer. If that is desired by the Interconnection Customer a grounding transformer can be sized for the combination of the two generation projects.

Under the normal configuration described in Case 1, and the contingency configurations described in Case 2 and 3, there are no identified power flow restrictions with Q1045 generation online. Certain extreme contingency configurations, such as a BPA Roundup 230 kV bus outage, though not explicitly studied, may warrant generation curtailment to 0 MW until the system returns to a normal state.

As the Interconnection Customer's Small Generator Facility will utilize the Interconnection Customer Interconnection Facilities associated with a different Interconnection Request the Interconnection Customer must provide the Public Utility with demonstration of approval from the owner of the Q0666 Interconnection Request for the shared facilities.

7.2 Transmission System Modifications

Transmission level power flow study cases were evaluated for heavy summer, winter, and light loading conditions. For each of the cases, power flows and system voltages were evaluated with and without the proposed Q1045 Small Generator Facility to determine the impact on the transmission system during system normal operation and following various contingency events in the local system. Due to the small size of the proposed interconnection relative to the transmission system, no thermal or voltage deficiencies associated with interconnection of Q1045 were observed.

Historical load records were reviewed to determine the Public Utility's minimum daytime load in the Pendleton area 69 kV system. The minimum daytime load was determined to be less than all in-service and prior queued generation. As a result, reverse power flow at the BPA Roundup 230-69 kV source is anticipated during light load conditions.

7.3 Distribution Modifications

- Install one three phase recloser at a location east of 090960 to insure coordinated fault clearing on the McKay branch of the feeder.
- Install one three phase bank of 219 amp 7.2 kV voltage regulators on the McKay branch to ensure ANSI range A voltages can be maintained at the end of the line.

- Install one three phase bank of 100 amp 7.2 kV voltage regulators on the circuit branch west of the interconnection tap to ensure ANSI range A voltages can be maintained at the end of the line.

7.4 EXISTING BREAKER MODIFICATIONS – SHORT-CIRCUIT

The increase in the fault duty on the system as the result of the addition of the Small Generator Facility with photovoltaic arrays fed through 49 – 60 kW inverters connected to a 3 MVA 12.5 kV – 480 V transformer with 5.75% impedance along with the earlier Q0666 project will not push the fault duty above the interrupting rating of any of the existing fault interrupting equipment.

7.5 PROTECTION REQUIREMENTS

Since the Q1045 Project will share the same circuit recloser as the Q0666 project for the interconnection to the 12.5 kV feeder out of Pilot Rock substation therefore no protection modifications will be required for the Q1045 Project. New relay settings will be developed and installed in the relay associated with the circuit recloser to accommodate the addition of the Q1045 Project.

7.6 DATA REQUIREMENTS (RTU)

Data for the operation of the transmission system will be needed from the collector substation for Q1045. The Public Utility will install a remote terminal unit ("RTU") at the Interconnection Customer collector substation site. The following data will be acquired.

Analogs:

- Net Generation real power MW
- Net Generator reactive power MVAR
- Energy Register KWH
- Q0666 real power MW
- Q0666 reactive power MVAR
- Q0666 Energy Register KWH
- Q1045 real power MW
- Q1045 reactive power MVAR
- Q1045 Energy Register KWH
- A phase 12.5 kV voltage
- B phase 12.5 kV voltage
- C phase 12.5 kV voltage
- Global Horizontal Irradiance (GHI)
- Average Plant Atmospheric Pressure (Bar)
- Average Plant Temperature (Celsius)

Status:

- 12.5 kV circuit recloser

The Interconnection Customer's Small Generator Facility may be required to accept setpoint control signals from the Public Utility's control centers. If required the Small Generator Facility will need to communicate the following points.

- Max Gen MW
- Max Gen MW FB

7.7 Communication Requirements

7.7.1 Line Protection

The optical fiber cable planned to be installed for the Q0666 project between Pilot Rock substation and the collector substation will be used for relaying between the collector site and Pilot Rock substation.

7.7.2 Data Delivery to the Control Centers

The Transmission Provider will install a radio system between Pilot Rock substation and the Public Utility's Cabbage Hill communications site. The tower at Cabbage Hill will have a load analysis done to ensure it can support the new antenna, and will be strengthened if necessary. Radios will be installed at Pilot Rock and Cabbage Hill. At Pilot Rock, a channel bank, 48VDC charger and batteries, router and switch will be installed to carry SCADA, telemetry, voice, and data circuits from the substation to control centers. At Cabbage Hill circuits will be cross-connected to existing comm systems.

7.8 Substation Requirements

<u>Q1045 collector substation</u>

The Public Utility will install a control building at the Interconnection Customer's shared collector substation location for the installation of protective, communications and metering equipment.

The Interconnection Customer will provide a separate graded, grounded and fenced area along the perimeter of the Interconnection Customer's Small Generator Facility for the Public Utility to install the control building. This area will have unencumbered access for the Public Utility. AC station service will be supplied by the Interconnection Customer and DC power for the control house will be supplied by the Public Utility.

<u>Pilot Rock substation</u>

At Pilot Rock substation the settings of regulator R-816 will need to be modified to account for this additional generation. Communications equipment will need to be installed to support the new microwave system.

7.9 Metering Requirements

<u>Interchange Metering</u>

The revenue metering will be located at the Interconnection Customer collector substation. The Public Utility will procure, install, test, and own all revenue metering equipment. The revenue metering instrument transformers will be installed overhead on a pole at the POI. The meter instrument transformer mounting shall conform to the Public Utility's DM construction standards.

There will be two meters installed in the control building with the metering programmed bi-directional to measure KWH and KVARH quantities for both generation received and retail load delivered.

The present output rating of the generation Project requires metering real time bidirectional SCADA, KWH KVARH MW, MVAR including per phase voltage data. The metering data will include a backup meter for alternate path EMS data.

Communication equipment will be required to remotely interrogate the meter for generation and billing data via the Public Utility's MV-90 data acquisition system. If available Ethernet is preferred and if not available a cell phone package is acceptable.

Station Service/Construction Power
The Project is within the Public Utility's service territory. Please note that prior to backfeed, Interconnection Customer must arrange transmission retail meter service for electricity consumed by the Project that will be drawn from the system when the Project is not generating. Interconnection Customer must call the PCCC Solution Center 1-800-625-6078 to arrange this service. Approval for back feed is contingent upon obtaining station service.

8.0 Cost Estimate

The following estimate represents only scopes of work that will be performed by the Public Utility. Costs for any work being performed by the Interconnection Customer are not included.

Q01045 Collector Substation *Install control building, metering and communications equipment*	$600,000
Distribution Circuit 5W406 *Install recloser and regulators*	$265,000
Pilot Rock Substation *Install communications equipment, modify regulator settings*	$250,000
Cabbage Hill Communications Site *Install communications equipment*	$74,000
System Operations Control Centers *Update databases*	$6,000
Total	**$1,195,000**

*Any distribution line modifications identified in this report will require a field visit analysis in order to obtain a more thorough understanding of the specific requirements. The estimate provided above for this work could change substantially based on the results of this analysis. Until this field analysis is performed the Public Utility must develop the Project schedule using conservative assumptions. The Interconnection Customer may request that the Public Utility perform this field

analysis, at the Interconnection Customer's expense, prior to the execution of an Interconnection Agreement in order to obtain more cost and schedule certainty.

Note: Costs for any excavation, duct installation and easements shall be borne by the Interconnection Customer and are not included in this estimate. This estimate is as accurate as possibly given the level of detailed study that has been completed to date and approximates the costs incurred by Public Utility to interconnect this Small Generator Facility to Public Utility's electrical distribution or transmission system. A more detailed estimate will be calculated during the Facilities Study. The Interconnection Customer will be responsible for all actual costs, regardless of the estimated costs communicated to or approved by the Interconnection Customer.

9.0 SCHEDULE

The Public Utility estimates it will require approximately 12-15 months to design, procure and construct the facilities described in this report following the execution of an Interconnection Agreement. The schedule will be further developed and optimized during the Facilities Study.

Please note, the time required to perform the scope of work identified in this report does not support the Interconnection Customer's requested commercial operation date of December 31, 2019.

10.0 PARTICIPATION BY AFFECTED SYSTEMS

Public Utility has identified the following Affected Systems: Bonneville Power Administration and Columbia Power

Copies of this report will be shared with each Affected System.

11.0 APPENDICES

Appendix 1: Higher Priority Requests
Appendix 2: Contingent Facilities
Appendix 3: Property Requirements
Appendix 4: Study Results

11.1 Appendix 1: Higher Priority Requests

All active higher priority transmission service and/or generator interconnection requests will be considered in this study and are identified below. If any of these requests are withdrawn, the Public Utility reserves the right to restudy this request, as the results and conclusions contained within this study could significantly change.

Transmission/Generation Interconnection Queue Requests considered:

Q0547 (18 MW)
Q0666 (1.98 MW)

11.2 APPENDIX 2: CONTINGENT FACILITIES

The following Interconnection Facilities and/or upgrades to the Public Utility's system are Contingent Facilities for the Interconnection Customer's Interconnection Request and must be in service prior to the commencement of generation activities:

All interconnection facilities and system upgrades required for higher priority Interconnection Request Q0666 are Contingent Facilities for the Interconnection Customer's Interconnection Request including the following:

- Extension of approximately 0.3 miles of distribution line.
- Installation of approximately 0.9 miles of fiber optic cable.
- Installation of protective, communications and metering equipment in the Public Utility's Pilot Rock substation.
- Installation of standard Public Utility distribution interconnection package consisting of a metering equipment and switch.
- Installation of a Interconnection Customer owned recloser and relay package.

The estimated completion date of these upgrades is 2021. The estimated cost of the Public Utility's interconnection facilities and upgrades is approximately $805K. For additional details please review the system impact study for the Q0666 Interconnection Request on the Public Utility's OASIS website.

11.3 APPENDIX 3: PROPERTY REQUIREMENTS

Requirements for rights of way easements

Rights of way easements will be acquired by the Interconnection Customer in the Public Utility's name for the construction, reconstruction, operation, maintenance, repair, replacement and removal of Public Utility's Interconnection Facilities that will be owned and operated by Public Utility. Interconnection Customer will acquire all necessary permits for the Project and will obtain rights of way easements for the Project on Public Utility's easement form.

Real Property Requirements for Point of Interconnection Substation

Real property for a POI substation will be acquired by an Interconnection Customer to accommodate the Interconnection Customer's Project. The real property must be acceptable to Public Utility. Interconnection Customer will acquire fee ownership for interconnection substation unless Public Utility determines that other than fee ownership is acceptable; however, the form and instrument of such rights will be at Public Utility's sole discretion. Any land rights that Interconnection Customer is planning to retain as part of a fee property conveyance will be identified in advance to Public Utility and are subject to the Public Utility's approval.

The Interconnection Customer must obtain all permits required by all relevant jurisdictions for the planned use including but not limited to conditional use permits, Certificates of Public Convenience and Necessity, California Environmental Quality Act, as well as all construction permits for the Project.

Interconnection Customer will not be reimbursed through network upgrades for more than the market value of the property.

As a minimum, real property must be environmentally, physically, and operationally acceptable to Public Utility. The real property shall be a permitted or able to be permitted use in all zoning districts. The Interconnection Customer shall provide Public Utility with a title report and shall transfer property without any material defects of title or other encumbrances that are not acceptable to Public Utility. Property lines shall be surveyed and show all encumbrances, encroachments, and roads.

Examples of potentially unacceptable environmental, physical, or operational conditions could include but are not limited to:

- Environmental: known contamination of site; evidence of environmental contamination by any dangerous, hazardous or toxic materials as defined by any governmental agency; violation of building, health, safety, environmental, fire, land use, zoning or other such regulation; violation of ordinances or statutes of any governmental entities having jurisdiction over the property; underground or above ground storage tanks in area; known remediation sites on property; ongoing mitigation activities or monitoring activities; asbestos; lead-based paint, etc. A phase I environmental study is required for land being acquired in fee by the Public Utility unless waived by Public Utility.

- Physical: inadequate site drainage; proximity to flood zone; erosion issues; wetland overlays; threatened and endangered species; archeological or culturally sensitive areas; inadequate sub-surface elements, etc. Public Utility may require Interconnection Customer to procure various studies and surveys as determined necessary by Public Utility.

- Operational: inadequate access for Public Utility's equipment and vehicles; existing structures on land that require removal prior to building of substation; ongoing maintenance for landscaping or extensive landscape requirements; ongoing homeowner's or other requirements or restrictions (e.g., Covenants, Codes and Restrictions, deed restrictions, etc.) on property which are not acceptable to the Public Utility.

11.4 Appendix 4: Study Results

Distribution Study Results:

The distribution feeder was analyzed under the following conditions of demand loading and generation output.

The feeder peak demand with and without generation was evaluated.

The minimum daytime demand on the feeder with and without generation was evaluated.

The transient case was evaluated for maximum voltage variation caused by the generation changing from zero output to maximum output as well as the generation changing from maximum output to zero output.

Transmission Study Results:

Case 1: Normal Configuration (Pilot Rock fed from BPA Roundup, breaker L-1122):

No power flow restrictions were identified.

Minimum daytime loads in the Pendleton area are less than the sum of all generation year-round. Thus, Q1045 generation at any level is likely to result in export through the 230 kV bus at BPA Roundup.

Area bus voltages remain close to 0.978 pu for all load levels, thus a generator setpoint voltage of 0.978 pu at the POI was used for evaluation of the proposed interconnection with respect to voltage performance and deviation. Voltages and post transient voltage steps are projected in power flow simulation to remain within permissible limits during the interruption of the Q1045 generation in the Public Utility's normal transmission configuration.

A QV analysis was performed for this configuration, and positive reactive margin is maintained.

Previously, a stability study was performed for this configuration and demonstrated satisfactory transient stability in the local area and no stability issues would be expected for the addition of this request.

Case 2: Contingency Configuration (Pilot Rock fed from Buckaroo and BPA Roundup, breaker L-1123, Switch 3W191 closed, breaker L-1122 open):

No restrictions, pending a stability study. A stability study will be required to determine the effects of generating into the Pendleton 69 kV loop with existing wind generation online.

Voltages and post transient voltage steps are projected in power flow simulation to remain within permissible limits during the interruption of the Q1045 generation in this contingency configuration.

A QV analysis was performed for this configuration, and positive reactive margin is maintained.

Case 3: Contingency Configuration (Pendleton 69 kV loop open at Buckaroo and BPA Roundup Breaker L-1123, Pilot Rock fed from Breaker L-1122, 60 MVA transformer at Roundup offline)

During this contingency, the 69 kV loop in the Pendleton area is split, and Buckaroo substation is fed radially via the two 33 MVA transformers at BPA Roundup. Public Utility’s 60 MVA transformer at BPA Roundup is offline, thus the 69 kV system is weakened and voltages in the area may drop to 0.92 pu. However, even with lowered voltages, there were no identified power flow restrictions.

Voltages and post transient voltage steps are projected in power flow simulation to remain within permissible limits during the interruption of the Q1045 generation in this contingency configuration.

Previously, a stability study was performed for this configuration and demonstrated satisfactory transient stability in the local area and no stability issues would be expected for the addition of this request.

A QV analysis was performed for this configuration, and positive reactive margin is maintained.

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Small Generator Interconnection
Tier 4 Facilities Study Report

Completed for
Pilot Rock Solar 2, LLC
(“Interconnection Customer”)
Q1045
Pilot Rock Solar 2
A Qualifying Facility

Proposed Interconnection
On PacifiCorp’s
Circuit 5W406 out of Pilot Rock Substation at 12.5 kV
(at approximately 45° 30' 32.67", -118° 49' 38.87")

June 2, 2020

TABLE OF CONTENTS

1.0 Description of the Project

Pilot Rock Solar 2 LLC ("Interconnection Customer") proposed interconnecting 2.99 MW of new generation to PacifiCorp's ("Public Utility") Circuit 5W406 out of Pilot Rock substation at 12.5 kV located in Umatilla County, Oregon. The Pilot Rock Solar 2 project ("Project") will consist of forty-nine (49) Sungrow SG60KU-M inverters for a total requested output of 2.99 MW. The requested commercial operation date is December 31, 2019.

Interconnection Customer will operate this generator as a Qualified Facility as defined by the Public Utility Regulatory Policies Act of 1978 (PURPA).

The Public Utility has assigned the project "Q1045."

2.0 Approval Criteria for Tier 4 Interconnection Review

Pursuant to 860-082-0060(1), a public utility must use the Tier 4 interconnection review procedures for an application to interconnect a small generator facility that meets the following requirements:

(a) The small generator facility does not qualify for or failed to meet Tier 1, Tier 2, or Tier 3 interconnection review requirements; and
(b) The small generator facility must have a nameplate capacity of ten (10) megawatts or less.

3.0 Scope of the Study

Pursuant to 860-082-0060(8) the Facilities Study Report shall consist of:

(a) A detailed scope identifying the interconnection facilities and system upgrades required to safely interconnect the small generator facility including the electrical switching configuration of the equipment, including the transformer, switchgear, meters, and other station equipment as applicable;
(b) A reasonable schedule for completion of the study;
(c) A good-faith, non-binding estimate of the costs for the facilities and upgrades, including equipment, engineering, procurement, and construction costs, and;
(d) A detailed estimate of the time required to procure, construct, and install the required interconnection facilities and system upgrades.

4.0 Proposed Point of Interconnection

. The proposed generation facility is to be interconnected to the Public Utility's distribution circuit 5W406 out of Pilot Rock substation, roughly 1,400' north of the existing facility point 01401032.0090961. The Interconnection Customer's Small Generator Facility will utilize the interconnection facilities associated with the Interconnection Request studied under queue position Q0666. Figure 1 below, is a one-line diagram that illustrates the interconnection of the proposed Small Generator Facility to the Public Utility's system.

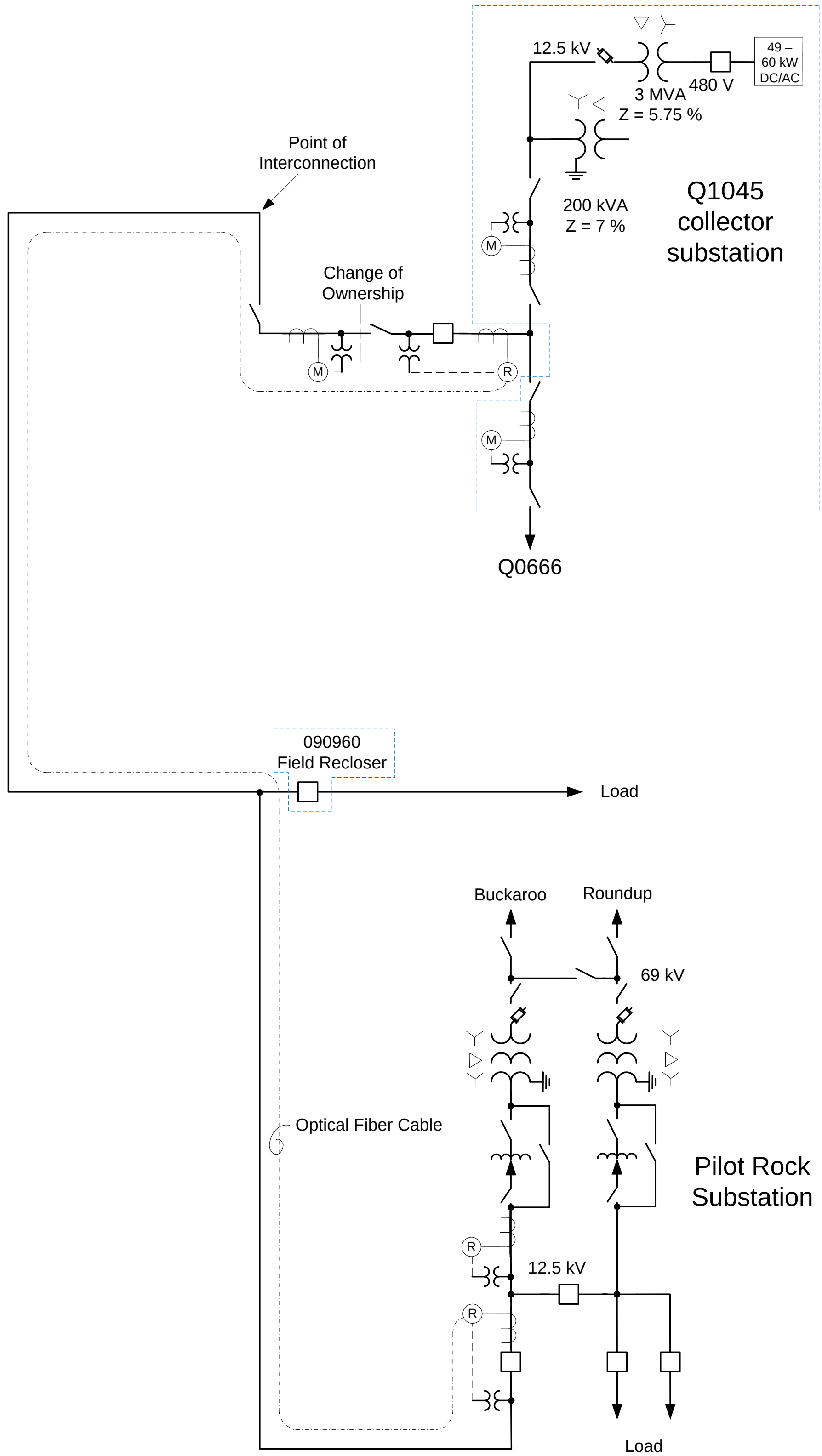

Figure 1: System One Line Diagram

5.0 Study Assumptions

- All active higher priority transmission service and/or generator interconnection requests will be considered in this study and are listed in Appendix 1. If any of these requests are withdrawn, the Public Utility reserves the right to restudy this request, as the results and conclusions contained within this study could significantly change.
- For study purposes there are two separate queues:
  - Transmission Service Queue: to the extent practical, all network upgrades that are required to accommodate active transmission service requests and are expected to be in-service on or after the Interconnection Customer's requested in-service date for the Project will be modeled in this study.
  - Generation Interconnection Queue: when relevant, interconnection facilities associated with higher queue interconnection requests will be modeled in this study. However, no generation will be simulated from any higher queued project unless a commitment has been made to obtain transmission service.
- The Interconnection Customer's request for interconnection service in and of itself does not convey transmission service.
- This study assumes the Project will be integrated into Public Utility's system at the agreed upon and/or proposed point of interconnection.
- The Interconnection Customer will construct and own the facilities required between the point of interconnection and the Project.
- Generator tripping may be required for certain outages.
- All facilities will meet or exceed the minimum WECC, NERC, and Public Utility performance and design standards.
- The Interconnection Customer's Interconnection Request will utilize interconnection facilities of higher priority Interconnection Request studied under queue position Q0666 and will also require additional equipment to be installed at the Q0666 collector substation location. The Public Utility assumes that the Interconnection Customer has the contractual right for the utilization of the Q0666 interconnection facilities and for the Public Utility to implement its requirements to the Q0666 collector substation. If that contractual right is not granted to the Interconnection Customer the requirements in this report will be significantly different which will require a restudy by the Public Utility.
- This report is based on information available at the time of the study. It is the Interconnection Customer's responsibility to check the Public Utility's web site regularly for transmission system updates (http://www.pacificorp.com/tran.html)

6.0 Requirements

6.1 Shared Q0666-Q1045 Small Generator Facility Requirements

The following outlines the design, procurement, construction, installation, and ownership of equipment at the Interconnection Customer's Small Generation Facility.

6.1.1 INTERCONNECTION CUSTOMER TO BE RESPONSIBLE FOR

- Procure all necessary permits, lands, rights of way and easements required for the construction and continued maintenance of the Q1045 Small Generator Facility and collector substation.
- Design, procure, construct, own and maintain the Interconnection Customer's Small Generator Facility and associated collector substation.
- Execute any necessary agreements (e.g. shared facilities agreement) to allow the Interconnection Customer to utilize the interconnection facilities constructed and owned by the Interconnection Customer with the rights to the Interconnection Request studied under queue position Q0666. Provide this demonstration to the Public Utility prior to the commencement of design activities.
- Design the Small Generator Facility with reactive power capabilities necessary to operate within the full power factor range of 0.95 leading to 0.95 lagging as measured at the high side of the Interconnection Customer's GSU transformer. This power factor range shall be dynamic and can be met using a combination of the inherent dynamic reactive power capability of the generator or inverter, dynamic reactive power devices and static reactive power devices to make up for losses.
- Design the Small Generator Facility such that it can provide positive reactive support (i.e., supply reactive power to the system) immediately following the removal of a fault or other transient low voltage perturbations or install dynamic voltage support equipment. These additional dynamic reactive devices shall have correct protection settings such that the devices will remain on line and active during and immediately following a fault event.
- Equip the Small Generator Facility with automatic voltage-control equipment and operate with the voltage regulation control mode enabled unless explicitly authorized to operate another control mode by the Public Utility.
- Operate the Small Generator Facility so as to maintain the voltage at the Point of Interconnection, or other designated point as deemed appropriated by Public Utility, at a voltage schedule to be provided by the Public Utility following testing.
- Operate the Small Generator Facility with a voltage droop.
- Have any Public Utility required studies, such as a voltage coordination study, performed and provide results to Public Utility. Any additional requirements identified in these studies will be the responsibility of the Interconnection Customer.
- Meet the NERC and WECC low voltage ride-through requirements as specified in the interconnection agreement.
- Provide the Public Utility a standard model from the WECC Approved Dynamic Model Library.

- Install a transformer that will hold the phase to neutral voltages within limits when the Small Generator Facility is isolated with the Public Utility's local system until the generation disconnects such as a wye-delta grounding transformer. Please note that the transformer thus far proposed by the Interconnection Customer is not acceptable to the Public Utility.
- Input the updated settings provided by the Public Utility into the Q0666 recloser relay.
- Provide the Public Utility the necessary easement to allow the Public Utility to install an enclosure for its equipment.
- Provide a separate graded and fenced area along the perimeter of the share Q0666/Q1045 collector substation for the Public Utility to install an enclosure. The enclosure shall have unencumbered access for the Transmission Provider. Fencing, gates and road access shall meet Transmission Provider standards.
- Provide permanent AC power to the Transmission Provider's enclosure.
- Design, procure and install conduit and Public Utility provided control cabling and hard wire all Q0666 and Q1045 source devices to the Public Utility's remote terminal unit ("RTU"). Provide sufficient control cable for the Public Utility to terminate inside the Public Utility enclosure.
- Interconnection Customer shall provide the following data points:
  <u>Analogs:</u>
    - Net Generation real power MW
    - Net Generator reactive power MVAR
    - Energy Register KWH
    - Q0666 real power MW
    - Q0666 reactive power MVAR
    - Q0666 Energy Register KWH
    - Q1045 real power MW
    - Q1045 reactive power MVAR
    - Q1045 Energy Register KWH
    - A phase 12.5 kV voltage
    - B phase 12.5 kV voltage
    - C phase 12.5 kV voltage
    - Global Horizontal Irradiance (GHI)
    - Average Plant Atmospheric Pressure (Bar)
    - Average Plant Temperature (Celsius)

  <u>Status:</u>
    - 12 kV Circuit Recloser
    - Max Gen MW
    - Max Gen MW FB
- Arrange for and provide permanent retail service for power that will flow from the Public Utility's system when the Q0666 and Q1045

Small Generator Facilities are not generating. This arrangement must be in place prior to approval for backfeed.

- Provide any construction or backup retail service necessary for the Project.
- Provide the Public Utility a Professional Engineer ("PE") approved maintenance plan for all Interconnection Customer facilities prior to commencement of generation activities.

6.1.2 PUBLIC UTILITY TO BE RESPONSIBLE FOR

- Develop and provide updated settings for the Q0666 recloser relay to account for the addition of the Q1045 Small Generator Facility. Observe and provide acceptance of the update.
- Procure and install a weather proof enclosure on the site prepared by the Interconnection Customer.
- Procure and install backup a DC battery system for the Public Utility enclosure.
- Install communications equipment in the collector substation enclosure including an RTU, transceivers, batteries and DC charger.
- Procure, install, own and maintain fiber optic cable from the collector substation enclosure to a splice with the fiber to be installed on the Public Utility's distribution line as part of the Q0666 project.
- Provide the Interconnection Customer control cable in sufficient quantity to allow the Interconnection Customer to tie its source devices to the Public Utility's enclosure communications equipment.
- Terminate the control cable running from the Interconnection Customer source devices in the enclosure.
- Design, procure and install within a NEMA enclosure mounted on a pole, two sets of revenue metering equipment to separate the Q0666 and Q1045 Small Generator Facilities including a metering panel, instrument transformers, primary and secondary revenue quality meters, test switches, junction boxes and secondary metering wire.
- Establish an Ethernet connection for retail sales and generation accounting via the MV-90 translation system. If Ethernet is unavailable, install a cell phone package.

6.2 OTHER

The following outlines the design, procurement, construction, installation, and ownership of equipment beyond the Point of Interconnection.

6.2.1 PUBLIC UTILITY TO BE RESPONSIBLE FOR

- Distribution Circuit
  - Procure and install one three phase recloser at a location east of facility point 090960.

  - o Procure and install one three phase bank of 219 amp 7.2 kV voltage regulators on the McKay branch.
  - o Procure and install one three phase bank of 100 amp 7.2 kV voltage regulators on the circuit branch west of the interconnection tap.

- Pilot Rock Substation
  - o Modify the settings of the R-816 substation voltage regulator.
  - o Construct a new radio system to develop a communications link with the Public Utility's Cabbage Hill communications site including radio, battery set & charger, channel bank, router and switch.

- Cabbage Hill Communications Site
  - o Evaluate the existing tower for space and loading for a new antenna. If necessary, modify the tower.
  - o Procure and install an antenna and supporting communications equipment to establish a communications link with the system to be installed in Pilot Rock substation.
  - o Cross connect communications circuits to existing Public Utility communications systems.

- Bonneville Power Administration ("BPA")
  - o Coordinate with BPA on any studies and/or upgrades that may be necessary.

- System Operations Centers
  - o Modify databases to include the Interconnection Customer's Small Generator Facility, new interconnection facilities and system upgrades.

7.0 COST ESTIMATE

The following estimate represents only scopes of work that will be performed by the Public Utility. Costs for any work being performed by the Interconnection Customer are not included.

Q1045 Collector substation $374,000
Install enclosures, metering and communications equipment

Distribution Circuit 5W406 $265,000
Install recloser and regulators

Pilot Rock Substation $250,000
Install communications equipment, modify regulator settings

Cabbage Hill Communications Site $72,000
Install communications equipment

System Operations Control Centers $4,000
Update databases

Total **$965,000**

*Any distribution line modifications identified in this report will require a field visit analysis in order to obtain a more thorough understanding of the specific requirements. The estimate provided above for this work could change substantially based on the results of this analysis. Until this field analysis is performed the Transmission Provider must develop the project schedule using conservative assumptions. The Interconnection Customer may request that the Transmission Provider perform this field analysis, at the Interconnection Customer's expense, prior to the execution of an Interconnection Agreement in order to obtain more cost and schedule certainty.

Note: Costs for any excavation, duct installation and easements shall be borne by the Interconnection Customer and are not included in this estimate. This estimate approximates the costs incurred by the Public Utility to interconnect this Small Generator Facility to the Public Utility's electrical distribution or transmission system based upon the level of study completed to-date. The Interconnection Customer will be responsible for all actual costs, regardless of the estimated costs communicated to or approved by the Interconnection Customer.

8.0 SCHEDULE

Execute Interconnection Agreement	July 13, 2020
Interconnection Customer Financial Security Provided	July 13, 2020
Interconnection Customer Shared Facilities Agreement Provided	July 27, 2020
*Interconnection Customer Initial Design Information Provided	August 3, 2020
**Public Utility Engineering & Procurement Commences	August 24, 2020
***Energy Imbalance Market Modeling Data Submittal	September 14, 2020
Interconnection Customer Property/Permits/ROW Procured	November 2, 2020
Public Utility Property/Permits/ROW Procured	December 7, 2020
*Interconnection Customer Final Design Information Provided	December 21, 2020
Public Utility Engineering Design Complete	February 26, 2021
Public Utility Construction Commences	March 22, 2021

Interconnection Customer Maintenance Plan Provided	April 5, 2021
Public Utility and Interconnection Customer Construction Complete	May 7, 2021
Public Utility Commissioning Complete	June 4, 2021
Interconnection Customer's Facilities Receive Backfeed Power	June 8, 2021
Initial Synchronization/Generation Testing	June 14, 2021
Commercial Operation	June 21, 2021

*Interconnection Customer initial design package shall include final generating facility location, inverter/turbine selection, basic protection package, tie line route and collector system locations and data as applicable. Interconnection Customer final design package shall include PE stamped issued for construction ("IFC") drawings for generating facility, collector substation, tie line as well as electromagnetic transient ("EMT") model as applicable.

**As applicable and determined by the Public Utility, within 60 days of the Interconnection Customer's authorization for the Public Utility to begin engineering, the Interconnection Customer shall provide a detailed short circuit model of its generation system. This model must be constructed using the ASPEN OneLine short circuit simulation program and contain all individual electrical components of the Interconnection Customer's generation system.

***Any design modifications to the Interconnection Customer's Small Generating Facility after this date requiring updates to the Public Utility's network model may result in a minimum of 3 months added to all future milestones including Commercial Operation.

Please note, the time required to perform the scope of work identified in this report does not support the Interconnection Customer's requested commercial operation date of December 31, 2019.

9.0 Participation by Affected Systems

Public Utility has identified the following Affected Systems: Bonneville Power Administration

Copies of this report will be shared with each Affected System.

10.0 Appendices

Appendix 1: Higher Priority Requests
Appendix 2: Contingent Facilities
Appendix 3: Property Requirements

10.1 APPENDIX 1: HIGHER PRIORITY REQUESTS

All active higher priority transmission service and/or generator interconnection requests will be considered in this study and are identified below. If any of these requests are withdrawn, the Public Utility reserves the right to restudy this request, as the results and conclusions contained within this study could significantly change.

Transmission/Generation Interconnection Queue Requests considered:

Q0547 (18 MW)
Q0666 (1.98 MW)

10.2 APPENDIX 2: CONTINGENT FACILITIES

The following Interconnection Facilities and/or upgrades to the Public Utility's system are Contingent Facilities for the Interconnection Customer's Interconnection Request and must be in service prior to the commencement of generation activities:

All interconnection facilities and system upgrades required for higher priority Interconnection Request Q0666 are Contingent Facilities for the Interconnection Customer's Interconnection Request including the following:

- Extension of approximately 0.3 miles of distribution line.
- Installation of approximately 0.9 miles of fiber optic cable.
- Installation of protective, communications and metering equipment in the Public Utility's Pilot Rock substation.
- Installation of standard Public Utility distribution interconnection package consisting of a metering equipment and switch.
- Installation of an Interconnection Customer owned recloser and relay package.

The estimated completion date of these upgrades is 2021. The estimated cost of the Public Utility's interconnection facilities and upgrades is approximately $805K. For additional details please review the system impact study for the Q0666 Interconnection Request on the Public Utility's OASIS website.

10.3 Appendix 3: Property Requirements

Requirements for rights of way easements

Rights of way easements will be acquired by the Interconnection Customer in the Public Utility's name for the construction, reconstruction, operation, maintenance, repair, replacement and removal of Public Utility's Interconnection Facilities that will be owned and operated by PacifiCorp. Interconnection Customer will acquire all necessary permits for the project and will obtain rights of way easements for the project on Public Utility's easement form.

Real Property Requirements for Point of Interconnection Substation

Real property for a point of interconnection substation will be acquired by an Interconnection Customer to accommodate the Interconnection Customer's project. The real property must be acceptable to Public Utility. Interconnection Customer will acquire fee ownership for interconnection substation unless Public Utility determines that other than fee ownership is acceptable; however, the form and instrument of such rights will be at Public Utility's sole discretion. Any land rights that Interconnection Customer is planning to retain as part of a fee property conveyance will be identified in advance to Public Utility and are subject to the Public Utility's approval.

The Interconnection Customer must obtain all permits required by all relevant jurisdictions for the planned use including but not limited to conditional use permits, Certificates of Public Convenience and Necessity, California Environmental Quality Act, as well as all construction permits for the project.

Interconnection Customer will not be reimbursed through network upgrades for more than the market value of the property.

As a minimum, real property must be environmentally, physically, and operationally acceptable to Public Utility. The real property shall be a permitted or permittable use in all zoning districts. The Interconnection Customer shall provide Public Utility with a title report and shall transfer property without any material defects of title or other encumbrances that are not acceptable to Public Utility. Property lines shall be surveyed and show all encumbrances, encroachments, and roads.

Examples of potentially unacceptable environmental, physical, or operational conditions could include but are not limited to:

- Environmental: known contamination of site; evidence of environmental contamination by any dangerous, hazardous or toxic materials as defined by any governmental agency; violation of building, health, safety, environmental, fire, land use, zoning or other such regulation; violation of ordinances or statutes of any governmental entities having jurisdiction over the property; underground or above ground storage tanks in area; known remediation sites on property; ongoing mitigation activities or monitoring activities; asbestos; lead-based paint, etc. A phase I environmental study is required for land being acquired in fee by the Public Utility unless waived by Public Utility.

- Physical: inadequate site drainage; proximity to flood zone; erosion issues; wetland overlays; threatened and endangered species; archeological or culturally sensitive areas; inadequate sub-surface elements, etc. Public Utility may require Interconnection Customer to procure various studies and surveys as determined necessary by Public Utility.

- Operational: inadequate access for Public Utility's equipment and vehicles; existing structures on land that require removal prior to building of substation; ongoing maintenance for landscaping or extensive landscape requirements; ongoing homeowner's or other requirements or restrictions (e.g., Covenants, Codes and Restrictions, deed restrictions, etc.) on property which are not acceptable to the Public Utility.

Small Generator Interconnection
Tier 4 Facilities Study Report

Completed for
Pilot Rock Solar 2, LLC
(“Interconnection Customer”)
Q1045
Pilot Rock Solar 2
A Qualifying Facility

Proposed Interconnection
On PacifiCorp’s
Circuit 5W406 out of Pilot Rock Substation at 12.5 kV
(at approximately 45° 30' 32.67", -118° 49' 38.87")

June 30, 2020

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1.0 Description of the Project

Pilot Rock Solar 2 LLC (“Interconnection Customer”) proposed interconnecting 2.99 MW of new generation to PacifiCorp’s (“Public Utility”) Circuit 5W406 out of Pilot Rock substation at 12.5 kV located in Umatilla County, Oregon. The Pilot Rock Solar 2 project (“Project”) will consist of forty-nine (49) Sungrow SG60KU-M inverters for a total requested output of 2.99 MW. The requested commercial operation date is December 31, 2019.

Interconnection Customer will operate this generator as a Qualified Facility as defined by the Public Utility Regulatory Policies Act of 1978 (PURPA).

The Public Utility has assigned the project “Q1045.”

2.0 Approval Criteria for Tier 4 Interconnection Review

Pursuant to 860-082-0060(1), a public utility must use the Tier 4 interconnection review procedures for an application to interconnect a small generator facility that meets the following requirements:

(a) The small generator facility does not qualify for or failed to meet Tier 1, Tier 2, or Tier 3 interconnection review requirements; and
(b) The small generator facility must have a nameplate capacity of ten (10) megawatts or less.

3.0 Scope of the Study

Pursuant to 860-082-0060(8) the Facilities Study Report shall consist of:

(a) A detailed scope identifying the interconnection facilities and system upgrades required to safely interconnect the small generator facility including the electrical switching configuration of the equipment, including the transformer, switchgear, meters, and other station equipment as applicable;
(b) A reasonable schedule for completion of the study;
(c) A good-faith, non-binding estimate of the costs for the facilities and upgrades, including equipment, engineering, procurement, and construction costs, and;
(d) A detailed estimate of the time required to procure, construct, and install the required interconnection facilities and system upgrades.

4.0 Proposed Point of Interconnection

. The proposed generation facility is to be interconnected to the Public Utility’s distribution circuit 5W406 out of Pilot Rock substation, roughly 1,400’ north of the existing facility point 01401032.0090961. The Interconnection Customer’s Small Generator Facility will utilize the interconnection facilities associated with the Interconnection Request studied under queue position Q0666. Figure 1 below, is a one-line diagram that illustrates the interconnection of the proposed Small Generator Facility to the Public Utility’s system.

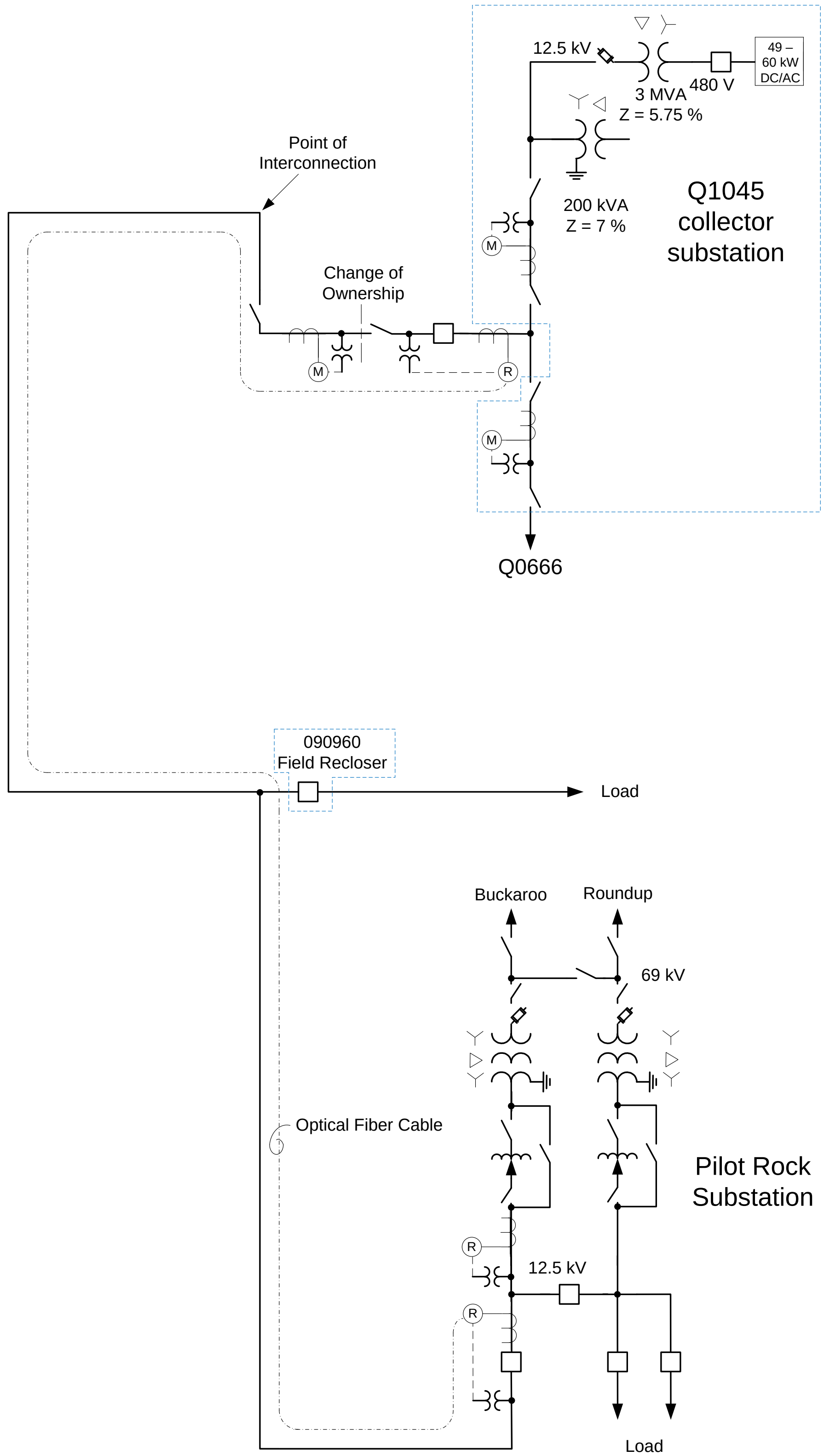

Figure 1: System One Line Diagram

5.0 Study Assumptions

- All active higher priority transmission service and/or generator interconnection requests will be considered in this study and are listed in Appendix 1. If any of these requests are withdrawn, the Public Utility reserves the right to restudy this request, as the results and conclusions contained within this study could significantly change.
- For study purposes there are two separate queues:
  - Transmission Service Queue: to the extent practical, all network upgrades that are required to accommodate active transmission service requests and are expected to be in-service on or after the Interconnection Customer's requested in-service date for the Project will be modeled in this study.
  - Generation Interconnection Queue: when relevant, interconnection facilities associated with higher queue interconnection requests will be modeled in this study. However, no generation will be simulated from any higher queued project unless a commitment has been made to obtain transmission service.
- The Interconnection Customer's request for interconnection service in and of itself does not convey transmission service.
- This study assumes the Project will be integrated into Public Utility's system at the agreed upon and/or proposed point of interconnection.
- The Interconnection Customer will construct and own the facilities required between the point of interconnection and the Project.
- Generator tripping may be required for certain outages.
- All facilities will meet or exceed the minimum WECC, NERC, and Public Utility performance and design standards.
- The Interconnection Customer's Interconnection Request will utilize interconnection facilities of higher priority Interconnection Request studied under queue position Q0666 and will also require additional equipment to be installed at the Q0666 collector substation location. The Public Utility assumes that the Interconnection Customer has the contractual right for the utilization of the Q0666 interconnection facilities and for the Public Utility to implement its requirements to the Q0666 collector substation. If that contractual right is not granted to the Interconnection Customer the requirements in this report will be significantly different which will require a restudy by the Public Utility.
- This report is based on information available at the time of the study. It is the Interconnection Customer's responsibility to check the Public Utility's web site regularly for transmission system updates (http://www.pacificorp.com/tran.html)

6.0 Requirements

6.1 Shared Q0666-Q1045 Small Generator Facility Requirements

The following outlines the design, procurement, construction, installation, and ownership of equipment at the Interconnection Customer's Small Generation Facility.

6.1.1 INTERCONNECTION CUSTOMER TO BE RESPONSIBLE FOR

- Procure all necessary permits, lands, rights of way and easements required for the construction and continued maintenance of the Q1045 Small Generator Facility and collector substation.
- Design, procure, construct, own and maintain the Interconnection Customer's Small Generator Facility and associated collector substation.
- Execute any necessary agreements (e.g. shared facilities agreement) to allow the Interconnection Customer to utilize the interconnection facilities constructed and owned by the Interconnection Customer with the rights to the Interconnection Request studied under queue position Q0666. Provide this demonstration to the Public Utility prior to the commencement of design activities.
- Design the Small Generator Facility with reactive power capabilities necessary to operate within the full power factor range of 0.95 leading to 0.95 lagging as measured at the high side of the Interconnection Customer's GSU transformer. This power factor range shall be dynamic and can be met using a combination of the inherent dynamic reactive power capability of the generator or inverter, dynamic reactive power devices and static reactive power devices to make up for losses.
- Design the Small Generator Facility such that it can provide positive reactive support (i.e., supply reactive power to the system) immediately following the removal of a fault or other transient low voltage perturbations or install dynamic voltage support equipment. These additional dynamic reactive devices shall have correct protection settings such that the devices will remain on line and active during and immediately following a fault event.
- Equip the Small Generator Facility with automatic voltage-control equipment and operate with the voltage regulation control mode enabled unless explicitly authorized to operate another control mode by the Public Utility.
- Operate the Small Generator Facility so as to maintain the voltage at the Point of Interconnection, or other designated point as deemed appropriated by Public Utility, at a voltage schedule to be provided by the Public Utility following testing.
- Operate the Small Generator Facility with a voltage droop.
- Have any Public Utility required studies, such as a voltage coordination study, performed and provide results to Public Utility. Any additional requirements identified in these studies will be the responsibility of the Interconnection Customer.
- Meet the NERC and WECC low voltage ride-through requirements as specified in the interconnection agreement.
- Provide the Public Utility a standard model from the WECC Approved Dynamic Model Library.

- Install a transformer that will hold the phase to neutral voltages within limits when the Small Generator Facility is isolated with the Public Utility's local system until the generation disconnects such as a wye-delta grounding transformer. Please note that the transformer thus far proposed by the Interconnection Customer is not acceptable to the Public Utility.
- Input the updated settings provided by the Public Utility into the Q0666 recloser relay.
- Provide the Public Utility the necessary easement to allow the Public Utility to install an enclosure for its equipment.
- Provide a separate graded and fenced area along the perimeter of the share Q0666/Q1045 collector substation for the Public Utility to install an enclosure. The enclosure shall have unencumbered access for the Transmission Provider. Fencing, gates and road access shall meet Transmission Provider standards.
- Provide permanent AC power to the Transmission Provider's enclosure.
- Design, procure and install conduit and Public Utility provided control cabling and hard wire all Q0666 and Q1045 source devices to the Public Utility's remote terminal unit ("RTU"). Provide sufficient control cable for the Public Utility to terminate inside the Public Utility enclosure.
- Interconnection Customer shall provide the following data points:
  <u>Analogs:</u>
    - Net Generation real power MW
    - Net Generator reactive power MVAR
    - Energy Register KWH
    - Q0666 real power MW
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    - Q0666 Energy Register KWH
    - Q1045 real power MW
    - Q1045 reactive power MVAR
    - Q1045 Energy Register KWH
    - A phase 12.5 kV voltage
    - B phase 12.5 kV voltage
    - C phase 12.5 kV voltage
    - Global Horizontal Irradiance (GHI)
    - Average Plant Atmospheric Pressure (Bar)
    - Average Plant Temperature (Celsius)

  <u>Status:</u>
    - 12 kV Circuit Recloser
    - Max Gen MW
    - Max Gen MW FB
- Arrange for and provide permanent retail service for power that will flow from the Public Utility's system when the Q0666 and Q1045

Small Generator Facilities are not generating. This arrangement must be in place prior to approval for backfeed.

- Provide any construction or backup retail service necessary for the Project.
- Provide the Public Utility a Professional Engineer ("PE") approved maintenance plan for all Interconnection Customer facilities prior to commencement of generation activities.

6.1.2 Public Utility to be Responsible For

- Develop and provide updated settings for the Q0666 recloser relay to account for the addition of the Q1045 Small Generator Facility. Observe and provide acceptance of the update.
- Procure and install a weather proof enclosure on the site prepared by the Interconnection Customer.
- Procure and install backup a DC battery system for the Public Utility enclosure.
- Install communications equipment in the collector substation enclosure including an RTU, transceivers, batteries and DC charger.
- Procure, install, own and maintain fiber optic cable from the collector substation enclosure to a splice with the fiber to be installed on the Public Utility's distribution line as part of the Q0666 project.
- Provide the Interconnection Customer control cable in sufficient quantity to allow the Interconnection Customer to tie its source devices to the Public Utility's enclosure communications equipment.
- Terminate the control cable running from the Interconnection Customer source devices in the enclosure.
- Design, procure and install within a NEMA enclosure mounted on a pole, two sets of revenue metering equipment to separate the Q0666 and Q1045 Small Generator Facilities including a metering panel, instrument transformers, primary and secondary revenue quality meters, test switches, junction boxes and secondary metering wire.
- Establish an Ethernet connection for retail sales and generation accounting via the MV-90 translation system. If Ethernet is unavailable, install a cell phone package.

6.2 Other

The following outlines the design, procurement, construction, installation, and ownership of equipment beyond the Point of Interconnection.

6.2.1 Public Utility to be Responsible For

- Distribution Circuit
  - Procure and install one three phase bank of 219 amp 7.2 kV voltage regulators on the McKay branch.

- Procure and install one three phase bank of 100 amp 7.2 kV voltage regulators on the circuit branch west of the interconnection tap.

- Pilot Rock Substation
  - Modify the settings of the R-816 substation voltage regulator.
  - Construct a new radio system to develop a communications link with the Public Utility's Cabbage Hill communications site including radio, battery set & charger, channel bank, router and switch.

- Cabbage Hill Communications Site
  - Evaluate the existing tower for space and loading for a new antenna. If necessary, modify the tower.
  - Procure and install an antenna and supporting communications equipment to establish a communications link with the system to be installed in Pilot Rock substation.
  - Cross connect communications circuits to existing Public Utility communications systems.

- Bonneville Power Administration ("BPA")
  - Coordinate with BPA to execute any necessary agreements with BPA and the Interconnection Customer to allow BPA to modify relay settings at BPA's roundup substation required in order to mitigate system outage condition risks to the Public Utility's system.

- System Operations Centers
  - Modify databases to include the Interconnection Customer's Small Generator Facility, new interconnection facilities and system upgrades.

7.0 Cost Estimate

The following estimate represents only scopes of work that will be performed by the Public Utility. Costs for any work being performed by the Interconnection Customer or Affected Systems are not included.

Q1045 Collector substation $374,000
Install enclosures, metering and communications equipment

Distribution Circuit 5W406 $180,000
Install regulators

Pilot Rock Substation $250,000
Install communications equipment, modify regulator settings

Cabbage Hill Communications Site $72,000
Install communications equipment

System Operations Control Centers $4,000
Update databases

Total **$880,000**

*Any distribution line modifications identified in this report will require a field visit analysis in order to obtain a more thorough understanding of the specific requirements. The estimate provided above for this work could change substantially based on the results of this analysis. Until this field analysis is performed the Transmission Provider must develop the project schedule using conservative assumptions. The Interconnection Customer may request that the Transmission Provider perform this field analysis, at the Interconnection Customer's expense, prior to the execution of an Interconnection Agreement in order to obtain more cost and schedule certainty.

Note: Costs for any excavation, duct installation and easements shall be borne by the Interconnection Customer and are not included in this estimate. This estimate approximates the costs incurred by the Public Utility to interconnect this Small Generator Facility to the Public Utility's electrical distribution or transmission system based upon the level of study completed to-date. The Interconnection Customer will be responsible for all actual costs, regardless of the estimated costs communicated to or approved by the Interconnection Customer.

8.0 SCHEDULE

Execute Interconnection Agreement	July 13, 2020
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Public Utility Engineering Design Complete	February 26, 2021

Public Utility Construction Commences	March 22, 2021
Interconnection Customer Maintenance Plan Provided	April 5, 2021
Public Utility and Interconnection Customer Construction Complete	May 7, 2021
Public Utility Commissioning Complete	June 4, 2021
Interconnection Customer's Facilities Receive Backfeed Power	June 8, 2021
Initial Synchronization/Generation Testing	June 14, 2021
Commercial Operation	June 21, 2021

*Interconnection Customer initial design package shall include final generating facility location, inverter/turbine selection, basic protection package, tie line route and collector system locations and data as applicable. Interconnection Customer final design package shall include PE stamped issued for construction ("IFC") drawings for generating facility, collector substation, tie line as well as electromagnetic transient ("EMT") model as applicable.

**As applicable and determined by the Public Utility, within 60 days of the Interconnection Customer's authorization for the Public Utility to begin engineering, the Interconnection Customer shall provide a detailed short circuit model of its generation system. This model must be constructed using the ASPEN OneLine short circuit simulation program and contain all individual electrical components of the Interconnection Customer's generation system.

***Any design modifications to the Interconnection Customer's Small Generating Facility after this date requiring updates to the Public Utility's network model may result in a minimum of 3 months added to all future milestones including Commercial Operation.

Please note, the time required to perform the scope of work identified in this report does not support the Interconnection Customer's requested commercial operation date of December 31, 2019.

9.0 Participation by Affected Systems

Public Utility has identified the following Affected Systems: Bonneville Power Administration

Copies of this report will be shared with each Affected System.

10.0 Appendices

Appendix 1: Higher Priority Requests
Appendix 2: Contingent Facilities
Appendix 3: Property Requirements

10.1 APPENDIX 1: HIGHER PRIORITY REQUESTS

All active higher priority transmission service and/or generator interconnection requests will be considered in this study and are identified below. If any of these requests are withdrawn, the Public Utility reserves the right to restudy this request, as the results and conclusions contained within this study could significantly change.

Transmission/Generation Interconnection Queue Requests considered:

Q0547 (18 MW)
Q0666 (1.98 MW)

10.2 APPENDIX 2: CONTINGENT FACILITIES

The following Interconnection Facilities and/or upgrades to the Public Utility's system are Contingent Facilities for the Interconnection Customer's Interconnection Request and must be in service prior to the commencement of generation activities:

All interconnection facilities and system upgrades required for higher priority Interconnection Request Q0666 are Contingent Facilities for the Interconnection Customer's Interconnection Request including the following:

- Extension of approximately 0.3 miles of distribution line.
- Installation of approximately 0.9 miles of fiber optic cable.
- Installation of protective, communications and metering equipment in the Public Utility's Pilot Rock substation.
- Installation of standard Public Utility distribution interconnection package consisting of a metering equipment and switch.
- Installation of an Interconnection Customer owned recloser and relay package.

The estimated completion date of these upgrades is 2021. The estimated cost of the Public Utility's interconnection facilities and upgrades is approximately $805K. For additional details please review the system impact study for the Q0666 Interconnection Request on the Public Utility's OASIS website.

10.3 APPENDIX 3: PROPERTY REQUIREMENTS

Requirements for rights of way easements

Rights of way easements will be acquired by the Interconnection Customer in the Public Utility's name for the construction, reconstruction, operation, maintenance, repair, replacement and removal of Public Utility's Interconnection Facilities that will be owned and operated by PacifiCorp. Interconnection Customer will acquire all necessary permits for the project and will obtain rights of way easements for the project on Public Utility's easement form.

Real Property Requirements for Point of Interconnection Substation

Real property for a point of interconnection substation will be acquired by an Interconnection Customer to accommodate the Interconnection Customer's project. The real property must be acceptable to Public Utility. Interconnection Customer will acquire fee ownership for interconnection substation unless Public Utility determines that other than fee ownership is acceptable; however, the form and instrument of such rights will be at Public Utility's sole discretion. Any land rights that Interconnection Customer is planning to retain as part of a fee property conveyance will be identified in advance to Public Utility and are subject to the Public Utility's approval.

The Interconnection Customer must obtain all permits required by all relevant jurisdictions for the planned use including but not limited to conditional use permits, Certificates of Public Convenience and Necessity, California Environmental Quality Act, as well as all construction permits for the project.

Interconnection Customer will not be reimbursed through network upgrades for more than the market value of the property.

As a minimum, real property must be environmentally, physically, and operationally acceptable to Public Utility. The real property shall be a permitted or permittable use in all zoning districts. The Interconnection Customer shall provide Public Utility with a title report and shall transfer property without any material defects of title or other encumbrances that are not acceptable to Public Utility. Property lines shall be surveyed and show all encumbrances, encroachments, and roads.

Examples of potentially unacceptable environmental, physical, or operational conditions could include but are not limited to:

- Environmental: known contamination of site; evidence of environmental contamination by any dangerous, hazardous or toxic materials as defined by any governmental agency; violation of building, health, safety, environmental, fire, land use, zoning or other such regulation; violation of ordinances or statutes of any governmental entities having jurisdiction over the property; underground or above ground storage tanks in area; known remediation sites on property; ongoing mitigation activities or monitoring activities; asbestos; lead-based paint, etc. A phase I environmental study is required for land being acquired in fee by the Public Utility unless waived by Public Utility.

- o Physical: inadequate site drainage; proximity to flood zone; erosion issues; wetland overlays; threatened and endangered species; archeological or culturally sensitive areas; inadequate sub-surface elements, etc. Public Utility may require Interconnection Customer to procure various studies and surveys as determined necessary by Public Utility.

- o Operational: inadequate access for Public Utility's equipment and vehicles; existing structures on land that require removal prior to building of substation; ongoing maintenance for landscaping or extensive landscape requirements; ongoing homeowner's or other requirements or restrictions (e.g., Covenants, Codes and Restrictions, deed restrictions, etc.) on property which are not acceptable to the Public Utility.

PACIFICORP

Small Generator Interconnection
Tier 4 Facilities Study Report

Completed for
Pilot Rock Solar 2, LLC
(“Interconnection Customer”)
Q1045
Pilot Rock Solar 2
A Qualifying Facility

Proposed Interconnection
On PacifiCorp’s
Circuit 5W406 out of Pilot Rock Substation at 12.5 kV
(at approximately 45° 30' 32.67", -118° 49' 38.87")

September 4, 2020

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1.0 Description of the Project

Pilot Rock Solar 2 LLC ("Interconnection Customer") proposed interconnecting 2.99 MW of new generation to PacifiCorp's ("Public Utility") Circuit 5W406 out of Pilot Rock substation at 12.5 kV located in Umatilla County, Oregon. The Pilot Rock Solar 2 project ("Project") will consist of forty-nine (49) Sungrow SG60KU-M inverters for a total requested output of 2.99 MW. The requested commercial operation date is December 31, 2019.

Interconnection Customer will operate this generator as a Qualified Facility as defined by the Public Utility Regulatory Policies Act of 1978 (PURPA).

The Public Utility has assigned the project "Q1045."

2.0 Approval Criteria for Tier 4 Interconnection Review

Pursuant to 860-082-0060(1), a public utility must use the Tier 4 interconnection review procedures for an application to interconnect a small generator facility that meets the following requirements:

(a) The small generator facility does not qualify for or failed to meet Tier 1, Tier 2, or Tier 3 interconnection review requirements; and
(b) The small generator facility must have a nameplate capacity of ten (10) megawatts or less.

3.0 Scope of the Study

Pursuant to 860-082-0060(8) the Facilities Study Report shall consist of:

(a) A detailed scope identifying the interconnection facilities and system upgrades required to safely interconnect the small generator facility including the electrical switching configuration of the equipment, including the transformer, switchgear, meters, and other station equipment as applicable;
(b) A reasonable schedule for completion of the study;
(c) A good-faith, non-binding estimate of the costs for the facilities and upgrades, including equipment, engineering, procurement, and construction costs, and;
(d) A detailed estimate of the time required to procure, construct, and install the required interconnection facilities and system upgrades.

4.0 Proposed Point of Interconnection

. The proposed generation facility is to be interconnected to the Public Utility's distribution circuit 5W406 out of Pilot Rock substation, roughly 1,400' north of the existing facility point 01401032.0090961. The Interconnection Customer's Small Generator Facility will utilize the interconnection facilities associated with the Interconnection Request studied under queue position Q0666. Figure 1 below, is a one-line diagram that illustrates the interconnection of the proposed Small Generator Facility to the Public Utility's system.

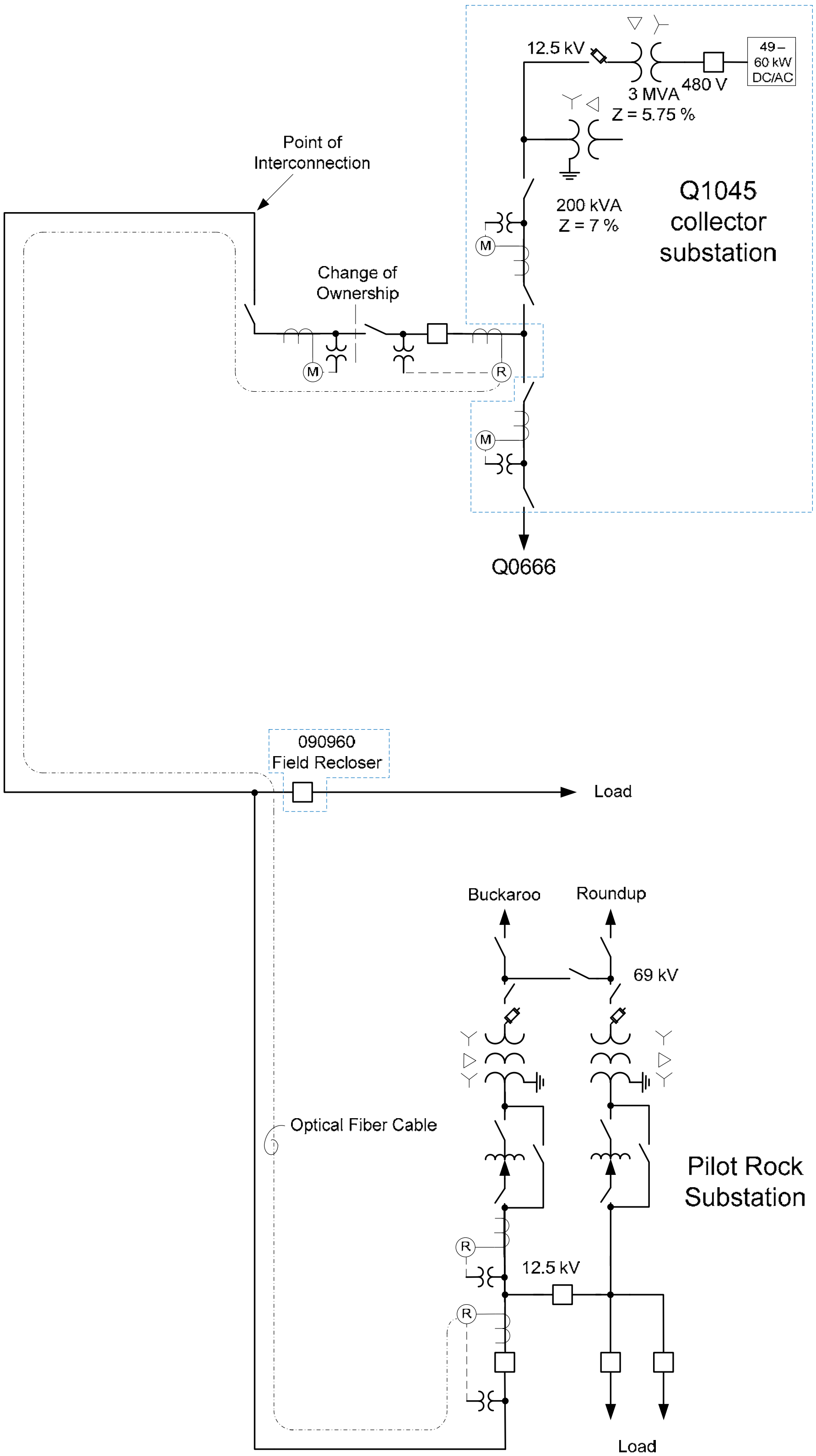


Figure 1: System One Line Diagram

5.0 Study Assumptions

- All active higher priority transmission service and/or generator interconnection requests will be considered in this study and are listed in Appendix 1. If any of these requests are withdrawn, the Public Utility reserves the right to restudy this request, as the results and conclusions contained within this study could significantly change.
- For study purposes there are two separate queues:
  - Transmission Service Queue: to the extent practical, all network upgrades that are required to accommodate active transmission service requests and are expected to be in-service on or after the Interconnection Customer's requested in-service date for the Project will be modeled in this study.
  - Generation Interconnection Queue: when relevant, interconnection facilities associated with higher queue interconnection requests will be modeled in this study. However, no generation will be simulated from any higher queued project unless a commitment has been made to obtain transmission service.
- The Interconnection Customer's request for interconnection service in and of itself does not convey transmission service.
- This study assumes the Project will be integrated into Public Utility's system at the agreed upon and/or proposed point of interconnection.
- The Interconnection Customer will construct and own the facilities required between the point of interconnection and the Project.
- Generator tripping may be required for certain outages.
- All facilities will meet or exceed the minimum WECC, NERC, and Public Utility performance and design standards.
- The Interconnection Customer's Interconnection Request will utilize interconnection facilities of higher priority Interconnection Request studied under queue position Q0666 and will also require additional equipment to be installed at the Q0666 collector substation location. The Public Utility assumes that the Interconnection Customer has the contractual right for the utilization of the Q0666 interconnection facilities and for the Public Utility to implement its requirements to the Q0666 collector substation. If that contractual right is not granted to the Interconnection Customer the requirements in this report will be significantly different which will require a restudy by the Public Utility.
- This report is based on information available at the time of the study. It is the Interconnection Customer's responsibility to check the Public Utility's web site regularly for transmission system updates (http://www.pacificorp.com/tran.html)

6.0 Requirements

6.1 Shared Q0666-Q1045 Small Generator Facility Requirements

The following outlines the design, procurement, construction, installation, and ownership of equipment at the Interconnection Customer's Small Generation Facility.

6.1.1 Interconnection Customer to be Responsible For

- Procure all necessary permits, lands, rights of way and easements required for the construction and continued maintenance of the Q1045 Small Generator Facility and collector substation.
- Design, procure, construct, own and maintain the Interconnection Customer's Small Generator Facility and associated collector substation.
- Execute any necessary agreements (e.g. shared facilities agreement) to allow the Interconnection Customer to utilize the interconnection facilities constructed and owned by the Interconnection Customer with the rights to the Interconnection Request studied under queue position Q0666. Provide this demonstration to the Public Utility prior to the commencement of design activities.
- Design the Small Generator Facility with reactive power capabilities necessary to operate within the full power factor range of 0.95 leading to 0.95 lagging as measured at the high side of the Interconnection Customer's GSU transformer. This power factor range shall be dynamic and can be met using a combination of the inherent dynamic reactive power capability of the generator or inverter, dynamic reactive power devices and static reactive power devices to make up for losses.
- Design the Small Generator Facility such that it can provide positive reactive support (i.e., supply reactive power to the system) immediately following the removal of a fault or other transient low voltage perturbations or install dynamic voltage support equipment. These additional dynamic reactive devices shall have correct protection settings such that the devices will remain on line and active during and immediately following a fault event.
- Equip the Small Generator Facility with automatic voltage-control equipment and operate with the voltage regulation control mode enabled unless explicitly authorized to operate another control mode by the Public Utility.
- Operate the Small Generator Facility so as to maintain the voltage at the Point of Interconnection, or other designated point as deemed appropriated by Public Utility, at a voltage schedule to be provided by the Public Utility following testing.
- Operate the Small Generator Facility with a voltage droop.
- Have any Public Utility required studies, such as a voltage coordination study, performed and provide results to Public Utility. Any additional requirements identified in these studies will be the responsibility of the Interconnection Customer.
- Meet the NERC and WECC low voltage ride-through requirements as specified in the interconnection agreement.
- Provide the Public Utility a standard model from the WECC Approved Dynamic Model Library.

- Install a transformer that will hold the phase to neutral voltages within limits when the Small Generator Facility is isolated with the Public Utility's local system until the generation disconnects such as a wye-delta grounding transformer. Please note that the transformer thus far proposed by the Interconnection Customer is not acceptable to the Public Utility.
- Input the updated settings provided by the Public Utility into the Q0666 recloser relay.
- Provide the Public Utility the necessary easement to allow the Public Utility to install an enclosure for its equipment.
- Provide a separate graded and fenced area along the perimeter of the share Q0666/Q1045 collector substation for the Public Utility to install an enclosure. The enclosure shall have unencumbered access for the Transmission Provider. Fencing, gates and road access shall meet Transmission Provider standards.
- Provide permanent AC power to the Transmission Provider's enclosure.
- Design, procure and install conduit and Public Utility provided control cabling and hard wire all Q0666 and Q1045 source devices to the Public Utility's remote terminal unit ("RTU"). Provide sufficient control cable for the Public Utility to terminate inside the Public Utility enclosure.
- Interconnection Customer shall provide the following data points:
  <u>Analogs:</u>
    - Net Generation real power MW
    - Net Generator reactive power MVAR
    - Energy Register KWH
    - Q0666 real power MW
    - Q0666 reactive power MVAR
    - Q0666 Energy Register KWH
    - Q1045 real power MW
    - Q1045 reactive power MVAR
    - Q1045 Energy Register KWH
    - A phase 12.5 kV voltage
    - B phase 12.5 kV voltage
    - C phase 12.5 kV voltage
    - Global Horizontal Irradiance (GHI)
    - Average Plant Atmospheric Pressure (Bar)
    - Average Plant Temperature (Celsius)

  <u>Status:</u>
    - 12 kV Circuit Recloser
    - Max Gen MW
    - Max Gen MW FB
- Arrange for and provide permanent retail service for power that will flow from the Public Utility's system when the Q0666 and Q1045

Small Generator Facilities are not generating. This arrangement must be in place prior to approval for backfeed.
- Provide any construction or backup retail service necessary for the Project.
- Provide the Public Utility a Professional Engineer ("PE") approved maintenance plan for all Interconnection Customer facilities prior to commencement of generation activities.

6.1.2 PUBLIC UTILITY TO BE RESPONSIBLE FOR

- Develop and provide updated settings for the Q0666 recloser relay to account for the addition of the Q1045 Small Generator Facility. Observe and provide acceptance of the update.
- Procure and install, at the Public Utility's expense, a weather proof enclosure on the site prepared by the Interconnection Customer.
- Provide the Interconnection Customer control cable in sufficient quantity to allow the Interconnection Customer to tie its source devices to the Public Utility's enclosure communications equipment.
- Terminate the control cable running from the Interconnection Customer source devices in the enclosure.
- Design, procure and install within a NEMA enclosure mounted on a pole, two sets of revenue metering equipment to separate the Q0666 and Q1045 Small Generator Facilities including a metering panel, instrument transformers, primary and secondary revenue quality meters, test switches, junction boxes and secondary metering wire.
- Establish an Ethernet connection for retail sales and generation accounting via the MV-90 translation system. If Ethernet is unavailable, install a cell phone package.

6.2 OTHER

The following outlines the design, procurement, construction, installation, and ownership of equipment beyond the Point of Interconnection.

6.2.1 PUBLIC UTILITY TO BE RESPONSIBLE FOR

- Distribution Circuit
  - Procure and install one three phase bank of 219 amp 7.2 kV voltage regulators on the McKay branch.
  - Procure and install one three phase bank of 100 amp 7.2 kV voltage regulators on the circuit branch west of the interconnection tap.

- Pilot Rock Substation
  - Modify the settings of the R-816 substation voltage regulator.

- Bonneville Power Administration ("BPA")

- Coordinate with BPA to execute any necessary agreements with BPA and the Interconnection Customer to allow BPA to modify relay settings at BPA's roundup substation required in order to mitigate system outage condition risks to the Public Utility's system.

7.0 COST ESTIMATE

The following estimate represents only scopes of work that will be performed by the Public Utility. Costs for any work being performed by the Interconnection Customer or Affected Systems are not included.

Q1045 Collector substation *Metering equipment*	$102,000
Distribution Circuit 5W406 *Install regulators*	$184,000
Pilot Rock Substation *Modify regulator settings*	$16,000
Total	**$302,000**

*Any distribution line modifications identified in this report will require a field visit analysis in order to obtain a more thorough understanding of the specific requirements. The estimate provided above for this work could change substantially based on the results of this analysis. Until this field analysis is performed the Transmission Provider must develop the project schedule using conservative assumptions. The Interconnection Customer may request that the Transmission Provider perform this field analysis, at the Interconnection Customer's expense, prior to the execution of an Interconnection Agreement in order to obtain more cost and schedule certainty.

Note: Costs for any excavation, duct installation and easements shall be borne by the Interconnection Customer and are not included in this estimate. This estimate approximates the costs incurred by the Public Utility to interconnect this Small Generator Facility to the Public Utility's electrical distribution or transmission system based upon the level of study completed to-date. The Interconnection Customer will be responsible for all actual costs, regardless of the estimated costs communicated to or approved by the Interconnection Customer.

8.0 SCHEDULE

Execute Interconnection Agreement	October 9, 2020
Interconnection Customer Financial Security Provided	October 9, 2020
Interconnection Customer Shared Facilities Agreement Provided	October 23, 2020
*Interconnection Customer Initial Design Information Provided	November 2, 2020

**Public Utility Engineering & Procurement Commences	August 24, 2020
Interconnection Customer Property/Permits/ROW Procured	January 8, 2021
Public Utility Property/Permits/ROW Procured	February 12, 2021
*Interconnection Customer Final Design Information Provided	February 26, 2021
Public Utility Engineering Design Complete	April 30, 2021
Public Utility Construction Commences	June 21, 2021
Interconnection Customer Maintenance Plan Provided	July 2, 2021
Public Utility and Interconnection Customer Construction Complete	August 27, 2021
Public Utility Commissioning Complete	September 24, 2021
Interconnection Customer's Facilities Receive Backfeed Power	October 4, 2021
Initial Synchronization/Generation Testing	October 11, 2021
Commercial Operation	October 18, 2021

*Interconnection Customer initial design package shall include final generating facility location, inverter/turbine selection, basic protection package, tie line route and collector system locations and data as applicable. Interconnection Customer final design package shall include PE stamped issued for construction ("IFC") drawings for generating facility, collector substation, tie line as well as electromagnetic transient ("EMT") model as applicable.

**As applicable and determined by the Public Utility, within 60 days of the Interconnection Customer's authorization for the Public Utility to begin engineering, the Interconnection Customer shall provide a detailed short circuit model of its generation system. This model must be constructed using the ASPEN OneLine short circuit simulation program and contain all individual electrical components of the Interconnection Customer's generation system.

Please note, the time required to perform the scope of work identified in this report does not support the Interconnection Customer's requested commercial operation date of December 31, 2019.

9.0 Participation by Affected Systems

Public Utility has identified the following Affected Systems: Bonneville Power Administration

Copies of this report will be shared with each Affected System.

10.0 APPENDICES

Appendix 1: Higher Priority Requests
Appendix 2: Contingent Facilities
Appendix 3: Property Requirements

10.1 APPENDIX 1: HIGHER PRIORITY REQUESTS

All active higher priority transmission service and/or generator interconnection requests will be considered in this study and are identified below. If any of these requests are withdrawn, the Public Utility reserves the right to restudy this request, as the results and conclusions contained within this study could significantly change.

Transmission/Generation Interconnection Queue Requests considered:

Q0547 (18 MW)
Q0666 (1.98 MW)

10.2 Appendix 2: Contingent Facilities

The following Interconnection Facilities and/or upgrades to the Public Utility's system are Contingent Facilities for the Interconnection Customer's Interconnection Request and must be in service prior to the commencement of generation activities:

All interconnection facilities and system upgrades required for higher priority Interconnection Request Q0666 are Contingent Facilities for the Interconnection Customer's Interconnection Request including the following:

- Extension of approximately 0.3 miles of distribution line.
- Installation of approximately 0.9 miles of fiber optic cable.
- Installation of protective, communications and metering equipment in the Public Utility's Pilot Rock substation.
- Installation of standard Public Utility distribution interconnection package consisting of a metering equipment and switch.
- Installation of an Interconnection Customer owned recloser and relay package.

The estimated completion date of these upgrades is 2021. The estimated cost of the Public Utility's interconnection facilities and upgrades is approximately $805K. For additional details please review the system impact study for the Q0666 Interconnection Request on the Public Utility's OASIS website.

10.3 APPENDIX 3: PROPERTY REQUIREMENTS

Requirements for rights of way easements

Rights of way easements will be acquired by the Interconnection Customer in the Public Utility's name for the construction, reconstruction, operation, maintenance, repair, replacement and removal of Public Utility's Interconnection Facilities that will be owned and operated by PacifiCorp. Interconnection Customer will acquire all necessary permits for the project and will obtain rights of way easements for the project on Public Utility's easement form.

Real Property Requirements for Point of Interconnection Substation

Real property for a point of interconnection substation will be acquired by an Interconnection Customer to accommodate the Interconnection Customer's project. The real property must be acceptable to Public Utility. Interconnection Customer will acquire fee ownership for interconnection substation unless Public Utility determines that other than fee ownership is acceptable; however, the form and instrument of such rights will be at Public Utility's sole discretion. Any land rights that Interconnection Customer is planning to retain as part of a fee property conveyance will be identified in advance to Public Utility and are subject to the Public Utility's approval.

The Interconnection Customer must obtain all permits required by all relevant jurisdictions for the planned use including but not limited to conditional use permits, Certificates of Public Convenience and Necessity, California Environmental Quality Act, as well as all construction permits for the project.

Interconnection Customer will not be reimbursed through network upgrades for more than the market value of the property.

As a minimum, real property must be environmentally, physically, and operationally acceptable to Public Utility. The real property shall be a permitted or permittable use in all zoning districts. The Interconnection Customer shall provide Public Utility with a title report and shall transfer property without any material defects of title or other encumbrances that are not acceptable to Public Utility. Property lines shall be surveyed and show all encumbrances, encroachments, and roads.

Examples of potentially unacceptable environmental, physical, or operational conditions could include but are not limited to:

- Environmental: known contamination of site; evidence of environmental contamination by any dangerous, hazardous or toxic materials as defined by any governmental agency; violation of building, health, safety, environmental, fire, land use, zoning or other such regulation; violation of ordinances or statutes of any governmental entities having jurisdiction over the property; underground or above ground storage tanks in area; known remediation sites on property; ongoing mitigation activities or monitoring activities; asbestos; lead-based paint, etc. A phase I environmental study is required for land being acquired in fee by the Public Utility unless waived by Public Utility.

- Physical: inadequate site drainage; proximity to flood zone; erosion issues; wetland overlays; threatened and endangered species; archeological or culturally sensitive areas; inadequate sub-surface elements, etc. Public Utility may require Interconnection Customer to procure various studies and surveys as determined necessary by Public Utility.

- Operational: inadequate access for Public Utility's equipment and vehicles; existing structures on land that require removal prior to building of substation; ongoing maintenance for landscaping or extensive landscape requirements; ongoing homeowner's or other requirements or restrictions (e.g., Covenants, Codes and Restrictions, deed restrictions, etc.) on property which are not acceptable to the Public Utility.

Docket No. UM 2118
Exhibit PAC/104
Witness: Kris Bremer

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Response Testimony of Kris Bremer

Sunthurst Letter

January 2021

KENNETH KAUFMANN ATTORNEY AT LAW
1785 Willamette Falls Drive • Suite 5 office (503) 230-7715
West Linn, OR 97068 fax (503) 972-2921

July 23, 2020

VIA ELECTRONIC MAIL (Matthew.Loftus@PacifiCorp.com)

Mr. Matt Loftus
Senior Transmission Counsel, PacifiCorp
825 NE Multnomah, Suite 1600
Portland, OR 97232

Subject: **Pilot Rock Solar 1, LLC (Q0666) and Pilot Rock Solar 2, LLC (Q1045)**
Questions re cost and scope of Interconnection requirements

Dear Matt:

With the acquiescence of PacifiCorp, Sunthurst Energy, LLC (Sunthurst) provides the following comments on the interconnection design for Q0666 and Q1045, including requests for cost reductions, or for design changes and cost reductions. Additional information is requested where Sunthurst requires it to complete its review.

Sunthurst appreciates PacifiCorp's willingness to engage in discussions on these matters. However since PacifiCorp is obligated to impose only "reasonable" costs of equipment "necessary" to interconnect the customer, PacifiCorp has a duty to do more than just listen; it has the burden to justify the necessity of equipment and the reasonableness of its design, or else correct it. *See* OAR 860-029-0010 ("Costs of Interconnection"). The following list of opportunities to reduce the cost of Q0666 and Q1045 provides ample room for capturing savings that will facilitate a cooperative resolution. Sunthurst, in cooperation with PacifiCorp and the Commission, has invested a great deal of time and treasure to help Oregon implement its CSP program and looks forward to delivering PRS1 and PRS2 as economically and technically sound projects. Sunthurst welcomes PacifiCorp's willingness to consider reasonable cost-saving changes to facilitate success of the Oregon CSP.

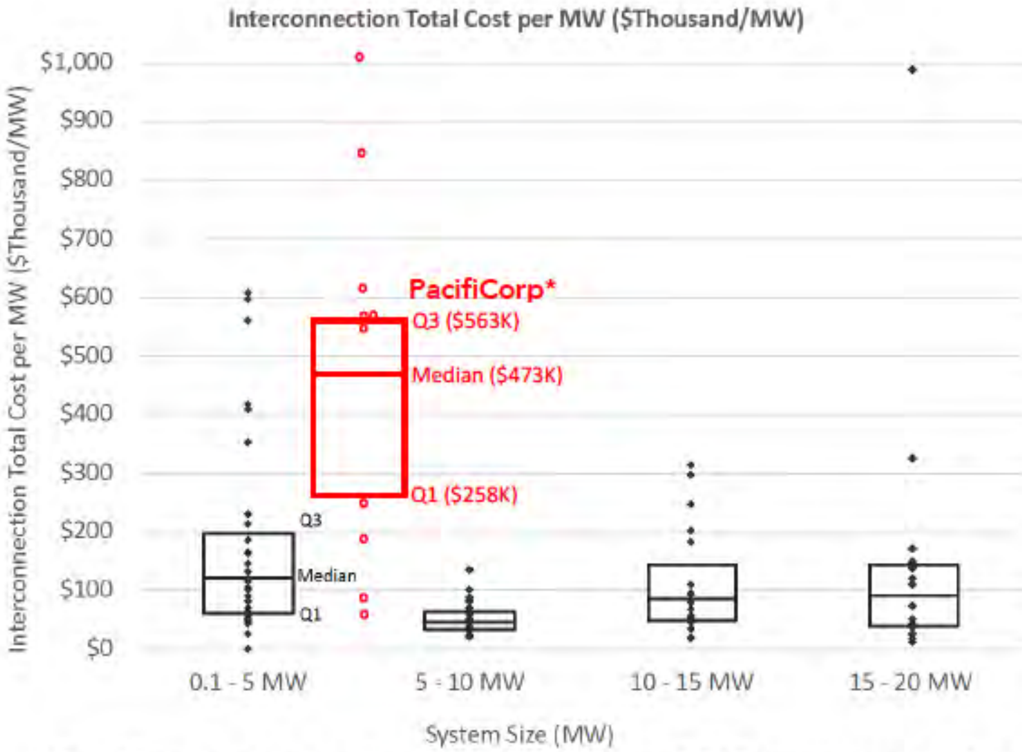
Background

Sunthurst Energy, LLC (Sunthurst) is an Oregon solar PV project developer and installer. It is developing the 1.98 MW Pilot Rock Solar 1, LLC (PRS1) and the 2.99 MW Pilot Rock Solar 2, LLC (PRS2) projects located in PacifiCorp territory near Pendleton. Both projects received pre-certification under Oregon's Community Solar Program (CSP). ***PacifiCorp's estimated cost to interconnect PRS1 and PRS2 is $805,000 and $ 879,000, respectively, even though neither project requires network upgrades or transmission from a load pocket***. These costs make PRS1 and PRS2 un-financeable.

Mr. Matt Loftus
July 23, 2020
Page 2 of 7

Published data suggest that PacifiCorp's small generator interconnection costs are exorbitant compared to such costs charged by other utilities in Oregon and the Western United States. A 2018 NREL study showed 25 interconnections throughout the Western United States between 100kW and 5MW had a median cost of about \$110k/MW.[1] **PacifiCorp's ten completed Oregon CSP facilities studies have a median cost of \$473k/MW, or more than 400% of the nation-wide average.**[2]

Figure 11 from 2018 NREL Study, Annotated with 2020 PacifiCorp CSP Data.



*PacifiCorp cost data are from 7/22/20 PacifiCorp OCSP Interconnection Queue
Figure 11. Total mitigation cost ranges in thousands of dollars, by system size (MW)

PacifiCorp's interconnection costs also are believed to be much higher than comparable interconnection costs assessed by Oregon's other IOUs, PGE and Idaho

1 REVIEW OF INTERCONNECTION PRACTICES AND COSTS IN THE WESTERN STATES, Lori Bird, Francisco Flores, Christina Volpi, and Kristen Ardani of the National Renewable Energy Laboratory, and David Manning and Richard McAllister of the Western Interstate Energy Board (Technical Report NREL/TP-6A20-71232, April 2018) ("NREL Interconnection Cost report"), page 18. The report is available free at www.nrel.gov/publications.
2 *See* PacifiCorp Oregon CSP interconnection queue, as of July 22, 2020, at http://www.oasis.oati.com/woa/docs/PPW/PPWdocs/pacificorpocsiaq.htm

Power.[3] If PacifiCorp's interconnection costs were in line with other utilities, the Sunthurst projects would be financeable.

Sunthurst engaged Larry Gross, P.E., VP – Power System Protection Electrical Consultants, Inc., to review PacifiCorp's design. Mr. Gross is an electrical engineer with considerable expertise in utility scale interconnections and protection and data integration schemes. Mr. Gross reviewed the Interconnection Studies prepared by PacifiCorp and attended two meetings with PacifiCorp's interconnection team to ask questions about PacifiCorp's proposed interconnection requirements. Based on the documents and the meetings, Mr. Gross provided extensive comments on PacifiCorp's proposed design, attached hereto as **Attachment A**. Although not judging the "good design practice" of PacifiCorp's proposed upgrades, Mr. Gross identified several areas where PacifiCorp's proposed interconnection facilities and distribution upgrades were either likely unnecessary, redundant, and/or provided system benefits above what PRS1 and PRS2 reasonably require from a direct technical perspective. He also noted where the documentation provided by PacifiCorp was not of sufficient detail for him to confirm the necessity of all of the requirements.

Specific interconnection design modification and supplemental data requests

1. **Metering requirements are unnecessarily expensive.**[4] The Q0666 interconnection agreement specified one metering point (two meters) at or near the Point of Interconnection (POI). After Q1045 Facilities Study, that requirement changed to require one metering point at the Pilot Rock Solar 1 (PRS1) collector substation, a second metering point at the Pilot Rock Solar 2 (PRS2) collector substation and a third metering point at the Change of Ownership Point (COP).

   Sunthurst requests that the specified meters at the PRS1 (Q0666) collector substation and the specified meters at the PRS2 (Q1045) collector substation be moved to the low side, and the specified meters at the COP be eliminated. Combined net generation from Q0666 and Q1045 facilities at the COP can be calculated using low-side meters at Q0666 and Q1045. In fact, Oregon's CSP rules require utilities to allow low-side metering for CSPs under 360 kW because of evidence that low-side metering saves tens of thousands of dollars. Order 19-392, Appdx A, p. 13. If PacifiCorp is concerned about allocating transformation losses between two projects, Sunthurst will contractually guarantee that

[3] Because PGE does not publish studies from withdrawn projects on its OASIS, Sunthurst does not currently have data to make an exact comparison between PGE and PacifiCorp. The available PGE data show much lower interconnection costs than PacifiCorp. Sunthurst found three interconnection studies for small Oregon solar published by Idaho Power, which had a median cost of $101k/MW.
[4] Sunthurst's comments regarding metering affect aspects of both (Q0666 and Q1045) interconnections.

PacifiCorp will be kept whole from transformation losses. ***Alternatively, Sunthurst requests that metering be accomplished with one metering point at the COP and one meter at the low (480V) side of PRS2.*** Generation from PRS1 can be calculated based upon the difference between COP and PRS2 meter readings.

Sunthurst's consulting electrical engineer concluded that the above metering schemes are technically sound and using the two lower voltage metering points is frequently used at the transmission level.[5] The requested alternatives to the proposed design would slash the combined cost of metering PRS1 and PRS2 without affecting safety, accuracy, or reliability.

2. **PC-611 Panel installation may not be necessary**. Based on information provided by PacifiCorp, Sunthurst's professional consulting engineer identified that the functionality required by PacifiCorp as a result of PRS1 and PRS2 interconnections does not appear to require the added PC-611 panel. Specifically, transfer trip can be performed using an SEL-2505 relay bolted inside the existing panel, and the reclosing could be delayed with other means using the SEL-2505 contacts.[7] ***Sunthurst requests PacifiCorp explain why PC-611 is required. If the justification includes updating old equipment that otherwise is scheduled for programmatic replacement, then Sunthurst asks PacifiCorp to contribute the difference between the cost of the PC-611 panel and the cost of the alternative proposed by Sunthurst's engineer, or else eliminate the PC-611 panel***.

3. **Cost of new Fiber Optic install should be shared.** The $70,000 fiber optic installation specified by PacifiCorp is a more expensive means of communication for the required transfer trip protection than point-to-point radio. PacifiCorp's choice of a 48-fiber cable provides much more fiber than PRS1 and PRS2 need and may show PacifiCorp's anticipation of using spare fibers for non-customer related uses. Sunthurst does not object if PacifiCorp prefers the expandability and excess capacity built into its choice of 48-fiber cable communications, however the excess cost of fiber compared to a functionally adequate radio communication link should be born by PacifiCorp. ***Sunthurst requests that PacifiCorp pay the difference between the cost of the fiber optic system specified by PacifiCorp and the cost of direct radio communication to Pilot Rock substation suitable for PRS1 and PRS2***.

4. **Voltage Measurement at the feeder relay is not necessary**. Sunthurst's consulting engineer reviewed PacifiCorp's design and believes based on the information available to him that the three line side voltage transformers (VTs) specified by PacifiCorp are not required for reclose voltage sensing as that

[5] See July 20 email from Larry Gross, attached, page 2, ¶2.
[7] See July 20 email from Larry Gross, attached, page 4, ¶2.

function may be performed using the transfer trip scheme communication channel.[9] Nor are the specified voltage transformers necessary for directionality determination necessary to protect PacifiCorp's equipment from Pilot Rock generation in the event of a bus, transformer or transmission line fault, because PRS1 and PRS2's inverters' will only contribute fault current of about 107% of nameplate after about 4 ms and islanding protection after the main distribution transformer fuse clears will disconnect the generation. This appears to make PacifiCorp's proposed voltage directionality based protection unnecessary.[10] ***Sunthurst requests that PacifiCorp remove the three high-side VTs after confirming that these optional protection practices and warranted performance of Sunthurst's inverters provide adequate protection.***

5. **P1-111 Annunciator Panel at Pilot Rock substation is not necessary.** Sunthurst's consulting engineer concluded based on the available information that the P1-111 panel specified in the Q0666 interconnection agreement is an unnecessary upgrade of existing functionality at Pilot Rock substation, which does not currently have annunciation. The existing relays have targets to indicate tripping and the SEL-2505 relay proposed by Sunthurst, above, has status lights that would make the annunciator redundant.[11] ***Sunthurst requests that the panel be deleted or reimbursed by PacifiCorp as a network upgrade or a distribution system upgrade not necessitated by PRS1 and PRS2.***

6. **PC-510 Transformer Metering Panels at Pilot Rock substation are unnecessary.** Sunthurst's consulting engineer noted that PacifiCorp's intended uses for the two PC-510 panels add additional benefit to the protection system that go beyond current protection philosophies for fault clearing. The generation equipment (recloser control or inverters) will provide adequate fault clearing when configured properly, rendering the PC-510 panels unnecessary upgrades.[12] ***Sunthurst requests that PacifiCorp remove the PC-510 panels.*** Sunthurst also notes that a single panel using an SEL-787 would provide better protection at lower cost than two PC-510 panels.[13]

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[9] See July 20 email from Larry Gross, attached, page3, ¶ 1(a).
[10] See July 20 email from Larry Gross, attached, pages 3-4, ¶¶1(b)-(c).
[11] See July 20 email from Larry Gross, attached, page 5, ¶3.
[12] See July 20 email from Larry Gross, attached, page 5, ¶4.
[13] See July 20 email from Larry Gross, attached, page 5, ¶4.

7. **<u>Telemetry is unnecessary</u>.** PacifiCorp is requiring telemetry as part of the Q1045 interconnection, although neither Q0666 nor Q1045 exceeds the 3MW threshold for telemetry enshrined in Oregon's OAR. Sunthurst understands based on the data provided that telemetry adds at least $180,000 to the cost of the Q1045 interconnection. A portion of the telemetry equipment will be installed, if at all, on PacifiCorp's transmission system, meaning those components are network upgrades. ***Sunthurst requests that PacifiCorp eliminate telemetry from the interconnection requirement.***

8. **<u>Justification for regulator controller replacement not provided</u>.** ***Sunthurst requests copies of PacifiCorp's analysis used to determine that a controls upgrade is required in this specific application.***

9. **<u>Itemized cost estimate for installations</u>.** ***To complete its review, Sunthurst requires the work papers or summaries behind its high level cost estimates. Such documentation should, at a minimum, identify all components over $5,000 as well as contingency and overhead costs.***

10. **<u>Drawings requested</u>**. ***To complete its review, Sunthurst requires copies of the Station One line Diagrams (meter and relay), AC Schematics (Three Line Diagrams), DC Schematics, and any removal drawings.***

11. **<u>Historical Final Costs of Interconnection</u>.** Information provided by PacifiCorp show a $169,000 contingency included in the Q1045 cost estimate. ***Sunthurst requests that PacifiCorp provide data characterizing what fraction of budgeted contingency it typically consumes on similar interconnections*.** This data would help Sunthurst and its lenders better anticipate the final cost of interconnecting to PacifiCorp.

Summation

The changes above, taken together, suggest strongly that safe, reliable interconnection of Q1045 and Q0666 comprised of only necessary interconnection facilities and distribution upgrades can be achieved at costs in line with the median costs published in the 2018 NREL study. Given the availability of technically sound alternatives at much lower installation cost, Sunthurst believes PacifiCorp's current interconnection scheme proposed for PRS1 and PRS2, is unreasonable.

Neither IEEE 1547, federal, nor Oregon law appear to proscribe the specific alternative interconnection solutions proposed by Sunthurst, meaning that PacifiCorp has discretion to grant Sunthurst's request for functionally equivalent, less costly, measures. However, if PacifiCorp desired, Sunthurst (and, presumably, Commission staff and the CSP Program Administrator) would cooperate in seeking express approval from the Commission in this instance in order to serve the Commission's goal of delivering CSPs to PacifiCorp customers. A previous PacifiCorp request for waiver of interconnection requirements to facilitate cost-effective customer-owned solar received enthusiastic approval of staff and the Commission.[14]

In Docket No. UM 1930 (the docket that implemented the Oregon CSP), Staff recently expressed concern that "additional opportunities to enable efficient integration of small generators are not being considered collaboratively". **The Commission, in adopting staff's recommendations, instructed staff to *"work with parties to continue to explore avenues for CSP generators and utilities to collaboratively consider additional one-off interconnection enhancements*.**"[15] Sunthurst respectfully requests that PacifiCorp adhere to the Commission's instructions, and collaborate to facilitate interconnection of Q0666 and Q1045.

Thank you for your time and consideration.

Kenneth Kaufmann
Attorney for Sunthurst Energy, LLC

Attachment A-- **July 20 email from Consulting Engineer Larry Gross to Sunthurst**

[14] *In re SOLWATT, LLC and KENT and LAURA MADISON, Request for Waiver of the Primary Voltage Interconnection Requirements under OAR 860-084-0130 (2) of the Solar Photovoltaic Pilot Program.* 2012 Ore. PUC LEXIS 98, *5-8 (March 27, 2012) Order No. 12-107; UM 1538.
[15] Order No. 19-392, Appdx A at 13-14, 2019 ORE. PUC LEXIS 486, *29-30 (November 8, 2019).

Attachment A, Page 1

July 20 email from Consulting Engineer Larry Gross to Sunthurst

Daniel,

Sunthurst has asked Electrical Consultants, Inc. to review the technical interconnection requirements identified by the utility for the Q0666 project. The following summary of findings is based on the review of the Tier 4 Facilities Study Report dated November 18, 2015 and revised November 23, 2015, and additional project data provided by Sunthurst. In addition, information gathered during a telephone conversation with utility technical representatives, and my experience with renewable generation, protection, metering, SCADA, and communication systems was used as a technical basis. Due to schedule and limited design details at this time, this review is subject to change if further data is provided.

The following is a description of the utility requirements and the likely technical basis of the requirements. There is mention of typical practice, but this review is not intended to identify with any certainty the legal basis of the requirements or what the utility policies state. Utilities base their facility studies on the technical requirements that are expected, and the complete design and detailed analysis may not have been thoroughly completed if the proposed equipment is flexible enough to handle several scenarios. Another item worth noting is the consistency of designs between projects. If there is customization of a scheme it may reduce hardware costs, but increase engineering costs and maintenance costs for the utility. The utility has very specific pre-designed panels that are a “one size fits all” which reduces the time and cost to design and construct but often adds costs to the panel due to additional hardware and panel building.

Some of these solutions highlight how this interconnection could be done with minimal cost, but not necessarily how it should be done. The utility can still proceed with the upgrades based on them being good practice. What you would have to explore is if all those costs should be allocated to the project. For example, if this was a modern distribution station, the only upgrades you may have to do are the fiber and the regulator controls. Everything else would be already in place.

Generating Facility Modifications ($203,000)

1. **An SEL-351 type relay is required.** Sunthurst plans to use an SEL-351R or SEL-651R in conjunction with a recloser (pole mounted fault interrupting device). Either is acceptable with the SEL-651R being a more modern option with added features. This device will detect faults on the 12.47 kV system between the recloser and the step up transformers. The utility will determine the settings with input from the customer if additional protection or coordination requirements are desired. The programming will be provided by the utility. The programming will include voltage and frequency islanding protection. **There are no suggested methods for reducing or reallocating costs unless the engineering cost for the settings development is itemized for review and determined to be higher than expected. The only item provided by the utility is relay programming, no hardware.**
2. **The utility requires and will provide metering (two meters) and measurement devices** at or near the change of ownership. This is required to adequately measure the project production at the change of ownership. Two meters monitor the same data for redundancy. There is a question that was posed by Sunthurst regarding a single

Attachment A, Page 2

metering location instead of three when both Q0666 and Q1045 are connected. The technical solution proposed by Sunthurst to have a single metering location with a split allocation reported by Sunthurst is a technically sound solution and is often done at the transmission level. The utility will provide access for Sunthurst to read the metering data via communication port or pulsed contacts. **There are no suggested methods for reducing or reallocating costs of the single project metering. Only a single meter is required but the second meter is for redundancy in the case of failure the site would not require being shut down or production being under-reported. The Sunthurst proposal for metering the two co-located projects would reduce install costs but will add some additional regular reporting for Sunthurst.**

3. **Communication equipment will be required to remotely interrogate the meter using MV90.** This is a common requirement for interconnections and allows the utility to automatically read the interconnection meter using an industry standard protocol that integrates with the overall utility metering system. Communication paths are usually via telephone (cellular or basic dial up) or Ethernet connectivity on a utility Ethernet network. The utility indicated they were going to use the Utility Ethernet Network via the required fiber (see fiber discussion below). **As a standalone system upgrade, the least expensive would be to use a cellular modem. It is unclear who would pay for any ongoing cellular fees, but the data volume is minimal and is often included in a utility plan for little to no additional charge. Due to other system upgrades, the lower cost adder may be to use the fiber and utility network. See other line items.**
4. **SEL-2829 optical transceiver.** This is required for the transfer trip scheme, and **is the least expensive way to communicate between two SEL relays that are not co-located. If the SEL-2505 alternative is used (see discussions below), then this device is not needed at the utility substation end.**
5. **A metering panel is required.** This will hold the two meters and test switches to allow for online testing. It is unclear if this metering panel is intended and priced to be installed in a building or not. There is no mention in the facility report that any voltage for powering the meters is required like Q1045. It is expected that these will be powered by the equipment installed by the utility. **There may be a cost savings if this was priced as a full indoor panel as opposed to a pole mounted NEMA box that only contains the two meters and test switches. The specific pricing is unclear.**
6. **Communication Fiber associated equipment.** The utility will install fiber hung on the poles under the distribution line for the entire length of the distribution line from Pilot Rock substation to the generating facility. The fiber is a 48-count fiber, single mode, ADSS. A fiber patch panel and other communication equipment will be installed. It is unclear what other communication equipment is required, but with the large fiber count, homeruns could be made to every device not requiring any additional network switches. **There would be savings in installing a smaller count fiber if all of the fiber was not going to be dedicated to these projects. If the 48 ct fiber is specified for future capacity beyond the tap location, then the cost is not directly attributable to the technical requirements of this project. Higher count fibers are often specified because the majority of the cost is the installation so the additional fiber is best installed at the initial install.**

Distribution Line Requirements ($55,000)

Attachment A, Page 3

1. **Line Extension.** The utility will install 0.3 miles of new distribution line to extend a tap connection from the existing distribution line to the change of ownership. **There are no suggested methods for reducing or reallocating costs.**
2. **Gang operated switch and primary metering units.** The gang-operated switch is required for an isolation point operated by the utility. The metering units are what measure the system values for metering. **There are no suggested methods for reducing or reallocating costs.**
3. **Replace the tap-changing controller to address reverse power.** When there is power flow from the distribution system to the transmission system, the calculated voltage drop between the substation and the end-of-the-circuit customer is not accurate. A different controller can adjust its control requirements when power is flowing in the reverse direction. **There is the possibility that a controls upgrade is not required depending on the load flow details, which we do not have. If additional generation is added to the circuits, then the reverse power requirement may become more important. This may include Q1045.**

Fiber ($70,000)

1. **Fiber.** The fiber is required for the transfer trip. It is not required for the metering for Q0666, but it is preferred to use for the metering if the fiber is already required for other reasons. **There is likely a slight reduction in hardware and installation costs if point-to-point radios were used for the transfer trip scheme. This solution is not as reliable but is used by many utilities. The installed cost is likely less than installed fiber. This solution requires line of site visibility and a licensed frequency is recommended. Also, as mentioned above there is some savings in using a fiber with a smaller count of strands.**

Pilot Rock Substation ($477,000)

1. **Three Line Side VTs.** These voltage transformers are required for providing the feeder and transformer relays directional sensing and verification that the generator has disconnected prior to reclosing the breaker after a fault.
   a. For reclosing the line side voltage measurement provides indication that the generator is disconnected before it recloses. This is a typical utility practice. If it is not, the relay delays its reclosing. **The voltage sensing for reclosing is not required since the transfer trip scheme is in place. The scheme can provide positive feedback that the recloser is open via mechanical auxiliary contact as well as that the voltage is reduced to an acceptable level via measurement by the recloser. The processing delay will be about 2-4 ms. If the communication system is out of service, the recloser can either go to lockout or a reasonable time delay (5 seconds) could be used.**
   b. The feeder directional sensing is usually needed to determine the difference between a forward and reverse fault. For forward faults the utility source feeds the fault through the feeder breaker. For bus, transformer, transmission, or adjacent feeder faults, the generator feeds the fault through the feeder breaker. If the difference in current flow between the two directions is not a large enough difference, then the protection pickup value cannot be set high enough. The existing setting pickup value is about 600 Amps instantaneous. This is an unusually low value for an instantaneous setting, but the utility indicated they are using a fuse saving scheme, which typically has a fast initial

Attachment A, Page 4

trip for the first fault trip before reclosing. This value is believed to be above the fault contribution of the inverters after about 4 ms, which is identified to be 107%. This would need to be confirmed by the inverter manufacturer including during voltage ride through time periods. It should also be noted that it is expected that the generation transformers are larger than the existing customer load transformers currently on the distribution line. This means that inrush currents could exceed the 600 Amp fault level and the utility may want to reconsider the fuse saving scheme. This can also be addressed by using harmonic blocking at the recloser, which in turn could block the relaying at the substation. Although these upgrades are good protection design practice, **based on these expectations, a voltage measurement at the feeder relay is not required for this interconnection.**

c. The other requirement for the VTs is to provide directionality for the transformer relay. For transformer or transmission faults, the generator feeds the fault into or through the transformer. The utility wants to minimize damage to the transformer for any fault. The directional relay would allow a low set overcurrent element to trip for any current flowing from the distribution circuit into or through the transformer. This may not be an effective means to detect faults because the fault current generated by the generation is only slightly above its normal full generation output, so trying to detect fault current versus normal generation flowing into the transformer may not be practical. In addition, the full fault contribution from the generation is believed to be below the withstand capabilities (normal load capacity) of the transformer, so no additional damage could develop other than at the fault location. The damage at the fault location is determined by the time delay of the fault clearing. The amount of current that the generation may produce is expected to be well below the existing fuse protection of the transformer, so any additional requirements to better protect the transformer from fault duration at the point of the fault would not be represented by the existing protection philosophy on the transformer. Due to the difficulty of determining a reverse fault versus a forward fault at the transformer, a neutral CT could be added and directionality could be provided or a differential relay with REF would provide high-speed protection for removing generation, but none of these schemes improve the time delay of the fuse clearing which is the existing protection. Although these upgrades are good protection design practice, **based on these expectations, a voltage measurement is not needed for this interconnection for the reverse transformer protection.**

2. **PC-611 Panel.** This is believed to be the feeder protection panel. The feeder relays are old electromechanical relays. Most utilities in the US have upgraded their distribution feeder relays to an advance microprocessor relay already or have a plan in place to do so without regard to interconnections, however, many require upgrading when an interconnection is on a distribution circuit with an old relay. This often provides flexibility to perform directionality (see above), better monitoring, and flexibility for transfer tripping and special logic schemes that possibly are required. The concern in this case is that the fault currents and existing system does not appear to require the upgrade. There may be specific studies that show advanced relaying is required but it is not clear why. The current levels and voltage requirements were addressed above. The transfer tripping could be performed using the SEL-2505 bolted inside the existing panel,

Attachment A, Page 5

a lower cost solution, and the reclosing could be delayed with other means when necessary using contacts from the SEL-2505. Although the feeder upgrade is good protection design practice, **based on these expectations, a new, advanced relay does not appear to be technically required for this interconnection.**

3. **PI-111 annunciator panel.** It is not clear why this panel is required for this interconnection since the existing station does not have any annunciation. The existing relays have targets to indicate tripping and an SEL-2505 has lights to indicate input and output contact statuses including data digital alarm points from the Generator up to 8 indications. This device could be upgraded to an SEL-2506, which would then have front panel indication. **Based on these expectations, the annunciator panel does not appear to be technically required.**
4. **PC-510 Transformer Metering Panel (qty 2).** This panel was confirmed by the utility to not be for metering, although the relay can provide metering and is often used for that by the utility. This panel would include the SEL-751 relay for detecting transformer faults and tripping the generator. As Identified above, this relay may be good protection practice, but it adds additional benefit to the protection system that is beyond what are the current protection philosophies for fault clearing times. The recloser or inverters will clear for a fault themselves in a reasonable amount of time given the current flow value for a transformer fault once the fuse clears. Although adding the transformer metering panels is good protection and station upgrade practice, **based on these expectations, an advanced transformer relay is not required for this interconnection.** It should also be noted that a single panel that uses an SEL-787 could monitor both transformer low sides for REF protection. This would not be a typical panel design for the utility, would provide much faster protection, but is still not required for this interconnection.
5. **Fiber channel and associated equipment.** The fiber is required for the transfer trip. This equipment could be limited to a patch panel only if no relays were upgraded or installed as described above. The device that would interface with the existing relays for transfer trip and block reclosing would be the SEL-2505, which has a built-in fiber port. **No other communication equipment appears to be needed. By keeping the relay system design simplified, the fiber design could be as well. The number of fibers as mentioned above is another possible cost reduction item.**

Lawrence C. Gross, Jr.

VP – Power System Protection
Electrical Consultants, Inc.
"Engineering with Distinction"

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Docket No. UM 2118
Exhibit PAC/105
Witness: Kris Bremer

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Response Testimony of Kris Bremer

Sunthurst DR Responses

January 2021

2.2 Refer to Sunthurst/100, Hale/4, lines 8-9, where Mr. Hale testifies that, "PacifiCorp's estimated $805k cost to interconnect a 1.98 MW [PRS 1] project remains not economically feasible."

a. Please confirm that Sunthurst executed a small generator interconnection agreement with PacifiCorp that included interconnection costs of $858,500 to interconnect PRS1. If Sunthurst cannot confirm, please explain the basis for Sunthurst's denial.

A. Incorrect. Sunthurst executed a small generator interconnection agreement to interconnect PRS1 at a cost of $805k, on March 9, 2016.

b. Please explain why Sunthurst executed a legally binding small generator interconnection agreement that required Sunthurst to pay $858,500 to interconnect PRS1 if the project was not economically feasible.

A. Although Sunthurst strenuously objected to the costs of PRS1 interconnection, including objections raised in a letter dated August 30, 2015, Sunthurst expected that PRS1 would be financeable when it signed the $805k interconnection agreement. However it currently is not. Factors negatively affecting finance-ability include: delays in rolling out Oregon's Community Solar Program (CSP); low net prices paid in the CSP; costs of PRS2 interconnection; federal import tariffs affecting solar project components; and reductions in the federal ITC and other government tax incentives and/or subsidies. While most of the above factors are beyond Sunthurst's reasonable control, excessive interconnection costs are not. Sunthurst has continuously worked to reduce interconnection costs at PRS1 and PRS2 that it believes are unreasonable.

c. What level of interconnection costs would make PRS1 and PRS2 economically feasible? Please provide all analysis supporting this response.

A. Sunthurst objects to the question to the extent it calls for speculation and/or production of new analyses. Notwithstanding the objection, Sunthurst answers that over 10 finance companies looked at Pilot Rock Solar 1 and said they couldn't make it work with PacifiCorp's interconnection costs and the net CSP rates. Sunthurst believes that with reasonable interconnection costs, both PRS1 and PRS2 can be financed.

2.3. Refer to Sunthurst/100, Hale/5, lines 14-17. Please provide all "validation by 3rd party studies, and solar development industry contacts" that Mr. Hale relied on in support of his statement that it is feasible to interconnect small solar projects like PRS1 and PRS2 for $0.05 to $0.15 per watt-dc.

A. While employed at Lanco as Regional Development manager from 2013-2014, Mr. Hale read more than 30 utility interconnection agreements in Mohave Elect Co-Op, PNM, PGE-CA, SCE, and HECO during employment. At Enerparc, where he was a project manager from 2016-2017, he read interconnection agreements at National Grid, PSEG, PG&E-CA, PGE-OR Project manager from 2016-2017.

In addition to the above contracts, Mr. Hale received an e-mail from a solar project financier stating that normal interconnection costs of deals they review was about $0.10/W-dc. See SUN-0118.

In addition, Mr. Hale received a detailed e-mail from a confidential source which provided average interconnection costs of 44 projects in 9 states. SUN-0119.

In addition, an Avista engineer suggested Sunthurst budget of $0.04/w-dc to interconnect a proposed 20MW solar project to Avista in Lind, WA, in response to Avista's 2017 Solar RFP.

2.7. Refer to Sunthurst/100, Hale/8, lines 1-4.
a. Please provide a detailed explanation of the consultation that occurred between Mr. Hale and the “nationwide developer of utility-scale solar,” including but not limited to the identity of the “nationwide developer,” the date that the consultation occurred and whether the consultation was in person or telephonic. Please also provide all communications between Sunthurst and the “nationwide developer” and all documents sent to and received from the “nationwide developer.”

A. Mr. Hale’s testimony refers to a telephone conversation with Enerparc AG on around August, 14, 2015. Enerparc’s VP of Construction told Mr. Hale Portland General Electric’s (PGE’s) cost to interconnect the 5mW Steel Bridge project in Willamina. The cost was far less than PacifiCorp’s charges to interconnect PRS1 and PRS2.

b. Please identify the “national solar finance company familiar with many project pro-forma financing models” that Mr. Hale references. Please also provide the data Mr. Hale received from the “national solar finance company familiar with many project pro-forma financing models” and provide all communications between Sunthurst and the “national solar finance company” and all documents sent to or received from the “national solar finance company.”

A. Mr. Hale’s testimony refers to an e-mail conversation in July 2020. See SUN-0118.

c. Please identify the “nationally-known renewable engineering firm with expertise estimating transmission costs for developers” that reviewed Sunthurst’s interconnection costs. Please also provide all communications between Sunthurst and the “nationally-known renewable engineering firm” and provide all documents sent to or received from the “nationally known renewable engineering firm with expertise estimating transmission costs for developers” that reviewed Sunthurst’s interconnection costs.

A. Mr. Hale’s testimony refers to a telephone conversation on around April 29, 2020, which resulted in cost data for 44 interconnections. See SUN-0119.

d. Please provide all evidence relied on by Mr. Hale to support his comparison to a comparable PGE interconnection.

A. See response to 7a above.

Sunthurst Energy

From:
Sent: Tuesday, July 14, 2020 11:09 AM
To: Sunthurst Energy
Subject: RE: CSP Pilot Rock Solar 1 and 2 Update

Dan,

Thanks for the update. IX costs are all over the board so it'd be hard for me to say. I recently sized up a portfolio of 20 projects (all within 1-5 MW) and IX was anywhere from 50k to 500k.

Best,

Joe

From: Sunthurst Energy <daniel@sunthurstenergy.com>
Sent: Monday, July 13, 2020 10:45 PM
To:
Subject: RE: CSP Pilot Rock Solar 1 and 2 Update

Hi Joe,

What are you seeing IX cost for 2-5mW at lately in other utilities?

Sincerely,

Daniel Hale, Principal
MRED, LEED AP, STI Certified
Sunthurst Energy, LLC
P: 310.975.4732 | F: 323.782.0760
W: SunthurstEnergy.com
Energy Trust of Oregon Trade Ally
Licensed in CA, ID, OR, UT, WA

IDENTITY OF SOURCE REDACTED

Sunthurst Energy

From:
Sent: Friday, May 01, 2020 7:08 PM
To: Charlie Coggeshall; Sunthurst Energy
Cc:
Subject: Interconnection Service Fee Review

Hi Charlie and Daniel,

I had a couple minutes to do a quick and random scrape of interconnection fees, based on some of the commercial scale projects that we've done IE Work on. Here's the anonymous aggregated results.

says that developer costs (comprised of interconnection, due diligence, and other developer overhead costs) is ~$0.13/Wdc for the next 4 yrs for a 1MW ground mount. This is generally in line with my scrape.

Hope this helps with the RFP and one-off reviews of Interconnection fees. Talk soon.
PLEASE KEEP THIS CONFIDENITAL

Total count	44			
Total ave $	$ 283,859			
Total ave MW	2.58			
Total ave $/Wac	$ 0.11			
MWac	ave price	Data pts		
.3 to .5	$ 20,684	6		
.6-1.9	$ 90,854	4		
2 to 3	$ 389,300	21		
3.1 to 5	$ 294,383	13		
State	count	ave MW	Ave cost	
CA	2	0.5	$ 3,943	SCE
IL	6	2.0	$ 872,133	ComEd and Ameren
MA	5	1.2	$ 165,603	NSTAR & Nat Grid; range from 0.3 to 3.3MW
MD	3	0.5	$ 29,213	Baltim. G&E
MN	4	5.0	$ 473,525	Xcel
NC	9	4.32	$ 171,851	Duke; range from 2 to 5MW
NJ	1	5.00	$ 10,130	Jersey Central P&L
NY	5	1.85	$ 229,794	NY State E&G
OR	9	2.20	$ 192,622	PGE

Docket No. UM 2118
Exhibit PAC/200
Witnesses: Milt Patzkowski,
Alex Vaz, Richard Taylor

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Response Testimony of Milt Patzkowski, Alex Vaz, Richard Taylor

January 2021

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ATTACHED EXHIBITS

Exhibit 201 – Detailed Cost Estimate Report for PRS1

Exhibit 202 – Detailed Cost Estimate Report for PRS2

Exhibit 203 – Sunthurst Response to Data Requests 1.10, 1.12, 2.22, and 2.29

Exhibit 204 – PacifiCorp Response to Data Request 3.7

I. INTRODUCTION

Q. Please state your names, business addresses, and present positions.

A. My name is Milt Patzkowski. My business address is 825 NE Multnomah, Suite 1600, Portland, Oregon 97232. My present position is Manager of Substation Engineering at PacifiCorp.

My name is Alex Vaz. My business address is 1407 W North Temple, Salt Lake City, Utah 84116. My present position is Cost Engineering Manager at PacifiCorp.

My name is Richard Taylor. My business address is 825 NE Multnomah, Suite 1600, Portland, Oregon 97232. My present position is Manager of Metering Engineering at PacifiCorp.

Q. Mr. Patzkowski, please describe your educational background and professional experience.

A. I received a Bachelor of Science in Electrical Engineering from Colorado State University and a Master of Science in Electrical Engineering from University of Southern California. I joined PacifiCorp in 1995 and I have held various engineering and management positions with responsibility across PacifiCorp's service territory. As manager of Substation Engineering, I have management responsibility to provide project scopes and project designs for substation layouts and equipment installation and for providing support to the field operations.

Q. Mr. Taylor, please describe your educational background and professional experience.

A. I have a Bachelor of Science in Physics from Southern Oregon University. I worked for Alstom Inc, a manufacturer of power and instrument transformers, in quality control, engineering and supervisory capacity from 1990 to 1999. I have been employed by PacifiCorp since 2014. I have had management responsibility of metering engineering since 2017. In my capacity as Manager of Metering Engineering at PacifiCorp, I am responsible for high end metering applications.

Q. Mr. Vaz, please describe your educational background and professional experience.

A. I have a bachelor's degree in Civil Engineering from Brigham Young University and master's degrees in Civil Engineering and Business Administration from Western Governor's University. I have been a licensed professional engineer since 2013 and I have worked at PacifiCorp's cost engineering group since 2016. The cost engineering group is responsible for preparing cost estimates for all of PacifiCorp's major projects, including all estimates for generation interconnection requests.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to the Opening Testimony of Sunthurst Energy, LLC's witnesses Messrs. Daniel Hale and Michael Beanland. In particular, I respond to the 10 modifications that Mr. Beanland recommends to the proposed interconnections for the 1.98 megawatt (MW) Pilot Rock Solar 1, LLC (PRS1) and the 2.99 MW Pilot Rock Solar 2, LLC (PRS2).[1] I also address technical issues raised by Mr. Hale.

[1] PRS1 has been designated as interconnection Queue No. 0666 (Q0666) and PRS2 has been designated as Queue No. 1045 (Q1045).

Q. Please summarize your testimony.

A. PacifiCorp's estimated costs to interconnect PRS1 and PRS2 are reasonable, non-discriminatory, and consistent with good utility practice and PacifiCorp's standard interconnection policies. The proposed cost reductions recommended by Sunthurst would unreasonably shift costs to interconnect its projects onto retail customers and potentially degrade service to existing customers.

Because Sunthurst has proposed two separate projects that interconnect at a single point of interconnection (POI) using common facilities, PacifiCorp requires three meters—one at each generating facility and one at the POI. PacifiCorp requires this metering configuration for all similarly situated interconnection customers, including PacifiCorp-owned resources. The three-meter configuration is critical for Sunthurst because PRS1 and PRS2 will participate in Oregon's Community Solar Program (CSP) and, therefore, accurate metering is particularly important because of the complexities associated with the CSP metering and billing framework.

To ensure that the interconnection of PRS1 and PRS2 does not degrade service to PacifiCorp's existing customers, the Company also requires voltage regulators and dead-line checking.

PacifiCorp's estimated costs to interconnection PRS1 and PRS2 also include reasonable charges for construction overhead costs that will be incurred by the Company. These costs are reflected in the capital surcharge, which is applied to PRS1 and PRS2 just as it is applied to all PacifiCorp capital projects.

In response to Mr. Beanland's testimony, PacifiCorp reevaluated the costs for interconnecting PRS1 and PRS2, including: (1) ensuring that costs related to telemetry and the PI-111 Annunciator panel have been removed, and (2) considering whether the estimated costs related to avian protection, fiber optic cable, and junction boxes could be refined. As a result of this review, as well as other updates in cost estimates, PacifiCorp has implemented estimated cost reductions of $141,728 (or $128,694 for PRS1 and $13,034 for PRS2); those estimated reductions are outlined in my testimony and updated detailed cost estimate expenditure reports for PRS1 and PRS2 are provided as PAC/201 and PAC/202, respectively.

While the above reflects PacifiCorp's continued good faith consideration of the questions and issues raised by Sunthurst regarding PRS1 and PRS2 (going back to March of 2020), the remaining design modifications Mr. Beanland recommends for the PRS1 and PRS2 must be rejected as they are contrary to good utility practice and seek to cut corners solely to reduce costs while potentially degrading the quality of service to other PacifiCorp retail customers and negatively impacting the reliability of the PacifiCorp system.

Q. Before you begin your testimony, explain why you are referencing *estimated* costs for PRS1 and PRS2?

A. The interconnection studies that are developed through the interconnection process result in estimated interconnection costs. As the interconnection customer progresses through the interconnection study process, the estimate of costs becomes more refined. Once an interconnection agreement is executed, detailed design work and bidding for certain work occurs, so that the costs are further finalized. Actual costs are what are ultimately invoiced to the interconnection customer.

Mr. Beanland's testimony addresses prior estimates of costs that PacifiCorp provided in good faith. Certain errors were included, such as inadvertently not removing all costs related to telemetry and the PI-111 annunciator panel. However, other cost categories that Mr. Beanland addresses were estimates that have been updated as a part of this testimony.

III. METERING

Q. Please describe the metering requirements that PacifiCorp proposed for PRS1 and PRS2.

A. Because PRS1 and PRS2 are separate projects that share interconnection facilities and have a common POI, PacifiCorp must meter each project individually and then also meter the combined output at the POI. Using three meters, PacifiCorp can reasonably determine the output of each individual project, which is critical for determining subscription and compensation under the CSP, and determine the electricity that is flowing onto the distribution system.

Q. Does the three-meter configuration you address in your testimony assume PRS1 and PRS2 complete their interconnection requests?

A. Yes. PacifiCorp witness Mr. Kris Bremer explains that PacifiCorp studied PRS2 based on the assumption that PRS1, and the interconnection facilities required for PRS1, were in-service. However, if PRS2 does not interconnect, the three-meter configuration is no longer required. The remainder of my testimony regarding the three-meter configuration assumes both PRS1 and PRS2 complete the interconnection process and become interconnected.

Q. Why is metering the output from each individual project important?

A. Metering the output from each individual project, as well as the POI, is necessary to:

(1) negate the ability of one generator serving station or auxiliary load of the other project; (2) mitigate the potential for one generator to over-generate at the expense of the other generator; and (3) track individual project output and any associated losses for purposes of accurate payments under CSP power purchase agreements. This last point is particularly critical because under the framework of the CSP, hundreds of individual customers could potentially subscribe to the output of PRS1 or PRS2. To accurately credit each subscriber's account, PacifiCorp must know with certainty what PRS1 and PRS2 generate. Customers must have confidence that they are receiving the benefit of the bargain they strike when they subscribe to the CSP and ambiguity over how much generation the customer has subscribed to undermines confidence in the program.

Q. Is PacifiCorp's proposed metering requirements consistent with the Company's interconnection policies?

A. Yes. Consistent with good utility practice and PacifiCorp's non-discriminatory interconnection Policy 138 (Distributed Energy Resource (DER) Interconnection Policy), each individual generating facility must be metered individually. Furthermore, because Sunthurst has proposed a single tie-line and a single POI for both PRS1 and PRS2, PacifiCorp must also install a meter at the POI to ensure that it receives accurate data regarding the electricity actually flowing onto the system.

Importantly, the three-meter configuration is required because of Sunthurst's chosen project design and its decision to construct two separate facilities that use common interconnection facilities. Had Sunthurst developed a single 4.97 MW project, there would be only one meter required, but as Mr. Bremer explains, the single project would have clearly been subject to telemetry costs.

Q. Does PacifiCorp consistently require three meters for projects configured like PRS1 and PRS2?

A. Yes. PacifiCorp applies this same policy for distribution or transmission system interconnections and applies the same policy to its own resources when one or more share a single POI. For example, Oregon Wind Farms is a collection of nine renewable qualifying facility projects located in Oregon that share a common generation tie-line and utilize the same POI to interconnect to PacifiCorp's system; each of the nine projects has a meter to measure actual generation and station service at the project, as well as a meter at the POI to allocate losses on the gen tie-lie to the appropriate project. The nine Oregon Wind Farms projects have multiple owners, but a single operations manager and vary in size from 1 to 10 MW.

Similarly, on a much larger scale, the Cedar Springs Wind Project has three separate renewable projects located in Wyoming that share a common generation tie-line and utilize the same POI to interconnect to PacifiCorp's system; each project has a meter, as well as a meter at the POI.

Finally, PacifiCorp's merchant function submitted and ultimately constructed two small generating facilities (Q0918 and Q0919) in Utah with essentially the same configuration as PRS1 and PRS2. PacifiCorp required the exact same meter configuration that it is calling for with PRS1 and PS2.

Q. Why is the use of three meters good utility practice?

A. Recall that PacifiCorp is requiring three meters under Sunthurst's chosen project design as follows: (1) one at the POI, and (2) one at each generating facility. Assuming both

Q0666 and Q1045 are interconnected as proposed, the purpose of the meter at the POI is to allow the output of each generator to be accurately metered in the event of a meter failure at either of the generators. Without the meter at the POI, if a meter failure occurs at either facility, PacifiCorp will not be able to quantify the amount of generation provided from the facility during the time of the meter outage. The meter at the POI addresses this potential problem.

It is also important for each generator site to have its generation and usage measured separately for billing and payment purposes. If this were two separate private residences, for example, there would be no question that each residence would have its own meter. The same is true here—each project, like each residence, should be measured separately.

In summary, using the three-meter configuration, if either of the individual generator meters failed, there is a pathway to provide uninterrupted accurate billing until the meters are replaced. There is almost a zero percent chance that both the primary and back-up meters at the POI would fail at the same time. Thus, PacifiCorp would have the ability to settle generation correctly, even if one of the generator meters failed. Data from the meters at the POI would be established in PacifiCorp's energy management system.

Q. If PacifiCorp allowed Sunthurst to use only two meters for PRS1 and PRS2, as Sunthurst proposes, how would that approach impact the projects' interconnection costs?

A. Removing the third meter at the POI would reduce the costs to interconnect PRS1 and

PRS2 by approximately $39,000.[2]

Q. Mr. Beanland recommends meters be installed at PRS1 and PRS2 and the combined power flows be summed digitally or electrically.[3] Is there a downside to the digital summation approach?

A. Yes. First, if PacifiCorp's meter interrogation system were to experience a timing error in which the timing of the reads of either meter becomes misaligned, then Mr. Beanland's proposal would not result in accurate data. In this scenario, the generation attributed to each project would be incorrect and potentially lead not only to disputes between PacifiCorp, PRS1, and PRS2, but also potentially substantial accounting work to revise the data.

Additionally, as both PRS1 and PRS2 are proposing to participate in the CSP, the accuracy of the meter data for these facilities is even more important. The CSP requires generator owners to sign up subscribers for their solar generators. If there is a meter failure or a data calculation error as described above, under the CSP not only is there a potential dispute or recalculation necessary for PRS1 and PRS2, but also potentially disputes or recalculations for dozens or even hundreds of subscribers. This scenario could lead to substantial accounting work for PacifiCorp and creates the possibility of hundreds of disputes with subscribers. In contrast to the summing approach Mr. Beanland recommends, having three meters would substantially limit these potential issues as the potential for meter failure or a data calculation error is

[2] In Paragraph 13 of PacifiCorp's answer to Sunthurst's complaint, PacifiCorp noted that the cost of the third meter would be approximately $25,000. This was responding to the "Alternative 2", as outlined in paragraph 17 of the complaint, under which the meter at PRS1 would be removed. Meters at the generators are approximately $25,000. The meter at the POI is referenced above and is approximately $39,000.
[3] Sunthurst/200, Beanland/17.

mitigated, while PacifiCorp's ability to more quickly respond to meter failure or data calculation error is enhanced.

Q. Mr. Beanland claims that "digital summation from metering points is common utility practice," and cites to virtual net metering as an example.[4] Do you agree?

A. No. It is not common practice for PacifiCorp to digitally sum meters for multiple generation projects like PRS1 and PRS2 in lieu of installing a meter at the POI. And the virtual net metering example is entirely inapposite because each customer has their own meter so all that is required is summing the usage measured by different meters at different places. Here, PRS1 and PRS2 are co-mingling their output, which is not analogous to virtual net metering.

Q. Although Mr. Beanland claims that digital summation is common, did Sunthurst identify examples where PacifiCorp or other utilities utilized a metering arrangement comparable to Sunthurst's recommendation in this case?

A. No. As discussed above, PacifiCorp's metering requirement in this case is consistent with its standard interconnection policies and is applied non-discriminatorily to PacifiCorp and non-PacifiCorp interconnection requests.

Moreover, in discovery, PacifiCorp asked Sunthurst to identify "all instances where PacifiCorp has not required three meters to measure output from two adjacent projects that utilize the same point of interconnection." In response, Sunthurst stated that it is "familiar with one instance: the Q0747 interconnection," which was an earlier configuration of PRS2 and, as discussed below, is distinguishable.[5]

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[4] Sunthurst/200, Beanland/24.
[5] PAC/203 (Sunthurst Response to PacifiCorp Data Request 1.10).

PacifiCorp also asked Sunthurst to "identify all instances where PacifiCorp or any other utility has used similar metering configuration" that would only require one meter at the POI and one meter at one of the two generators.[6] Sunthurst indicated that it was "awaiting confirmation of its assertion . . . and will supplement its response when it receives confirmation." Sunthurst never supplemented that discovery response, which indicates that they could not identify any other instances where a utility utilized only two meters for two separate projects interconnecting at the same POI, like PRS1 and PRS2. Indeed, it appears that Sunthurst is no longer supporting this recommended metering configuration based on Mr. Beanland's recommendations.

Q. Mr. Beanland agrees with PacifiCorp that there can be timing errors, but asserts a third meter will suffer from the same concern.[7] Is this a legitimate reason to not include a third meter at the POI?

A. No. While a third meter would be subject to the same problems, the probability that PacifiCorp would have timing issues on all three meters at once is much lower than the probability that PacifiCorp would have a timing issue with one of three meters. Therefore, if there is a timing error on the third meter, PacifiCorp can correct data on a third meter by using two good meters. If there were only two meters and one of those has a timing error, there is no way to correct that error.

[6] PAC/203 (Sunthurst Response to PacifiCorp Data Request 1.12).
[7] Sunthurst/200, Beanland/24.

Q. Does Mr. Beanland respond to PacifiCorp's concern that having only two meters creates the potential for disputes or recalculations for dozens or even hundreds of CSP subscribers?

A. Yes. But his response misses the mark. Mr. Beanland testifies:

> Regardless of the number of virtual net meters that may be included in a community solar program, the problems of combining meters is nothing new. PacifiCorp is implying that meters fail or are inaccurate regularly and so there is a burden on PacifiCorp, but there is no data supporting this hypothetical problem that would exist system-wide for every project.[8]

Q. Is PacifiCorp implying that meters fail regularly, as Mr. Beanland believes?

A. No. While it is true that meter failure does not occur on every single project, given the number of meters PacifiCorp has, the Company regularly deals with meter failures. Moreover, over the useful life of a meter, a meter failure is possible.

Q. How does the CSP further complicate matters if there is a meter failure?

A. Under the CSP, output can be subscribed by customers and PacifiCorp will be required to purchase any unsubscribed output. PacifiCorp will provide actual meter data for each project to the CSP program manager, who will divide up the generation among all subscribers and then inform PacifiCorp of the amount of unsubscribed generation that PacifiCorp must purchase. If calculation errors occur, PacifiCorp's three-metering configuration will readily allow corrections.

Q. Will it be an administrative burden if meter failure or a data calculation error occur in connection with the CSP?

A. Yes. Mr. Beanland misses the point when he states the problems of combining meters

[8] Sunthurst/200, Beanland/24.

is nothing new.[9] To the contrary, the CSP is new, as well as having several subscribers per project and potentially hundreds of CSP subscribers in total. The level of administrative burden of dealing with disputes or recalculations due to meter failure or calculation error is compounded when dealing with a new program with potentially hundreds of CSP subscribers.

Q. Mr. Beanland also argues that if there is a meter failure, PacifiCorp can rely on telemetry to gather data in real time to estimate that missing data resulting from the meter failure.[10] How do you respond?

A. I agree that there are ways that PacifiCorp can estimate missing data resulting from a meter failure, but it is disingenuous for Sunthurst to argue on the one hand that it should not be required to pay for the installation of telemetry while also arguing that telemetry is required to mitigate the risk associated with its chosen metering configuration.

Q. Is Mr. Beanland's proposal to electrically sum the meter readings from just two meters reasonable?[11]

A. No. Mr. Beanland's proposal to electrically sum the meters would place the meters at PRS1 and PRS2 in parallel and then used a third meter to measure the combined current.

Q. How is this proposal different from PacifiCorp's proposal to use three meters?

A. That is unclear. Mr. Beanland testifies that PacifiCorp proposed using a "3rd entire metering system," whereas his proposal would use a "3rd, mid-voltage, meter" at the

[9] Sunthurst/200, Beanland/24.
[10] Sunthurst/200, Beanland/18.
[11] Sunthurst/200, Beanland/17.

POI.[12] When asked in discovery what he meant by a "3rd entire metering system," Mr. Beanland responded:

> A "3rd entire metering system" (what PacifiCorp is requiring) would consist of and be a repetition of the medium-voltage metering systems used on the individual projects. A system would be expected to consist of a wood power pole, cross arms with braces, insulators, a cluster mount for the potential and current transformers, the three current and three potential transformers, conduit and wiring to bring the transformer secondary currents and voltages to the meter located in a metal enclosure mounted at the base of the pole, the electronic meter installed in the enclosure, and the cellular data modem used to communicate with the utility metering system.[13]

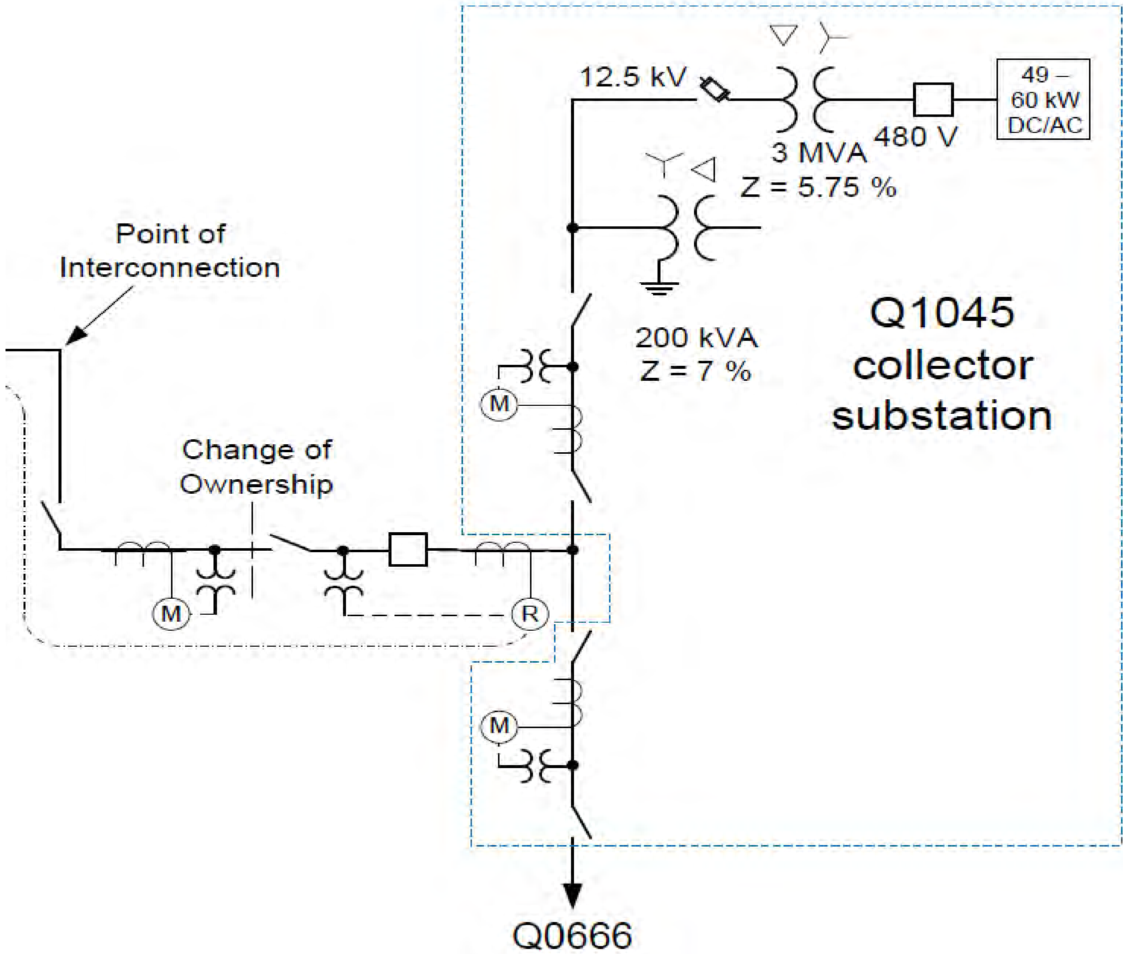
In the same discovery response, Mr. Beanland indicated that:

> With current summation (described Sunthurst/200, Beanland/18, lines 3-8), the pole, crossarm, cluster mount, and transformers are no longer needed. The equipment involves a meter and enclosure and conduit and wiring needed to connect to the other two project meters.[14]

Q. Why is Mr. Beanland's proposal for a third meter unacceptable?

A. For PRS1 and PRS2, as well as other similarly situated interconnection requests, PacifiCorp would typically build the site with three entirely separate metering points, as illustrated below:

[12] Sunthurst/200, Beanland/17, 33.
[13] PAC/203 (Sunthurst Response to PacifiCorp Data Request 2.22).
[14] PAC/203 (Sunthurst Response to PacifiCorp Data Request 2.22).



My understanding is that under Mr. Beanland's electrical summation approach, he would use transformer secondary signals from two of the meters to provide input to the third meter. There are several downsides to this approach. In particular, under Mr. Beanland's recommended approach:

- The current transformers (CTs) must be the same ratio. This can compromise accuracy because if the CT signals are combine and something happens to one, it could negatively impact the signal from the other CT it is connected to.
- Voltages are no longer measured at the actual combined point. Therefore, the activity of switches, reclosers, or other equipment can contribute to metering errors.

- Current signal wiring is made more complex, which increases the possibility of error.
- Conduit must be run to combine the current secondary signals and transmit voltage secondary signals, which adds costs.
- It becomes easier to provide overcurrent to the meter taking a combined current, which increases the possibility of damage to the meter.

Q. Mr. Beanland compares the metering requirements for Q0747 to Q1045 (PRS2), concluding that "PaciCorp deems two meters adequate in this earlier version of the project and in the later development of this project, PacifiCorp deems two meters inadequate."[15] Is this a fair comparison?

A. No. Mr. Beanland's comparison of Q0747 and Q1045 is not relevant due to different configurations. By way of background, Sunthurst originally proposed PRS2 as a 6 MW project that was assigned interconnection queue position Q0747. The earlier configuration of PRS1 and PRS2 (when PRS2 was studied as interconnection queue position Q0747) would have allowed PacifiCorp to install two meters on the utility side of the Sunthurst's equipment, which would have effectively created two POIs. In particular, the Q0666/Q0747 configuration proposed separate and individual tie line interconnection facilities, with two reclosers for Q0747 and Q0666, which then would have interconnected at the same POI. This configuration would have allowed PacifiCorp to meter the facilities separately at the POI since there would have been two separate lines at the POI.

[15] Sunthurst/200, Beanland/19-20.

In contrast, Sunthurst's current configuration for PRS1 (Q0666) and PRS2 (reflected in the Q1045 request) proposes that Q0666 and Q1045 share a single tie line and recloser tying in at the same POI. This configuration does not allow PacifiCorp to meter the facilities at the POI because there is a shared line connecting both projects to the POI. In other words, the Q0666/Q1045 configuration comingles the generation from PRS1 and PRS2 *before* the combined output is interconnected to the Pilot Rock substation, whereas the Q0666/Q0747 configuration did not comingle the combined output. Therefore, PRS1 and PRS2, under Sunthurst's proposed configuration, must be metered before the point where they share interconnection facilities, in addition to the single meter needed at the POI to meter the combined output onto PacifiCorp's system.

Q. Would PacifiCorp be opposed to Sunthurst returning to the Q0666/Q0747 configuration, which would allow the use of only two meters?

A. No. In an email dated September 23, 2020, PacifiCorp offered Sunthurst to return to the Q0666/Q0747 configuration, which would require only two meters. Sunthurst did not accept this offer. Nonetheless, Sunthurst could still revert back to the Q0666/Q0747 configuration, which would necessitate only two meters.

Q. Mr. Beanland also claims that if PRS1 and PRS2 were "two projects, owned and developed by different entities, connecting at the same POI, the use of the two meters [in the Q0747 configuration] is exactly what I would expect to see."[16] Do you agree?

A. Yes. But that is not what Sunthurst has proposed here. The current configuration of

[16] Sunthurst/200, Beanland/20.

PRS1 and PRS2 share common facilities and co-mingle both project's generation before the POI. If they connected at the POI using separate tie-lines, like in the Q0666/Q0747 configuration, which is generally consistent with how two separate projects would interconnect, PacifiCorp would not require the third meter.

Q. Mr. Beanland states that PacifiCorp's Policy 138 is "mute" on requiring aggregate metering for multiple projects.[17] **Do you agree?**

A. No. Mr. Beanland is incorrect. Section 4.14 of that policy provides:

> *For installations less than three (3) megawatts, as applicable, it shall be at PacifiCorp's discretion to require gathering data on circuit breaker status, MW and Mvar.* Each DER facility shall have each DER unit metered. (emphasis added).

Thus, the policy is not mute. PacifiCorp has the discretion to require the three-meter configuration, as it has done for PRS1 and PRS2. PacifiCorp implements Policy 138 in a non-discriminatory manner and required the use of three meters in similar situations as proposed by PRS1 and PRS2, as illustrated above.

Q. Based on Policy 138, Mr. Beanland testifies that in his experience "PacifiCorp treats each distributed generator as an independent project based on the interconnection application."[18] Do you agree?

A. Yes. It is Sunthurst that is requesting an expressly *dependent* metering arrangement based on the use of a shared tie-line to the POI. If each project had its own facilities, like in the Q0666/Q0747 configuration, PacifiCorp would not require three meters. It is only because PRS1 and PRS2 are dependent on the same shared facilities that PacifiCorp requires an additional meter.

[17] Sunthurst/200, Beanland/19-20.
[18] Sunthurst/200, Beanland/21.

Q. Mr. Beanland also recommends that PacifiCorp could meter PRS1 and PRS2 on the low-voltage side of the transformer.[19] Is that a reasonable recommendation?

A. No. Mr. Beanland provides no justification for this recommendation. The Oregon Public Utility Commission (Commission) has approved the use of low-side metering for CSP projects that are less than 360 kilowatts. PRS1 and PRS2 are significantly larger than that threshold and are therefore ineligible for the CSP low-side metering arrangement. The location of the metering is relevant for accounting for losses. PacifiCorp requires meters on the high side of the transformer because it removes the inaccuracies of the losses.

IV. VOLTAGE REGULATORS

Q. Mr. Beanland questions the justification for the voltage regulators required for PRS1 and PRS2.[20] What are voltage regulators?

A. Power distribution voltage regulators maintain power distribution system voltages within a defined range. Regulated voltages ensure that electrical products and equipment will operate optimally and allow for the energy efficient operation of the electrical distribution system.

Q. Are the voltage regulators necessary for PRS1 and PRS2?

A. No—only PRS2 triggers the need for voltage regulators. With the addition of the generation from PRS2, the generation will far exceed any load in that area of the system. As a result, there is a need to maintain power distribution system voltages within a defined range in an energy efficient manner. The cost of the voltage regulators

[19] Sunthurst/200, Beanland/33.
[20] Sunthurst/200, Beanland/26.

is approximately $180,000.

Q. Explain further.

A. To provide feeder voltage regulation in a standard, effective, and energy efficient manner, PacifiCorp uses Line Drop Compensation (LDC) settings on voltage regulator controls. These settings regulate the voltage at a simulated distance from the device and allows for lower voltages and energy use (e.g., Conservation Voltage Reduction or CVR) during non-peak load conditions. As load and the subsequent voltage drop along the feeder increases or decreases, the LDC settings increases or decreases voltage to maintain American National Standards Institute (ANSI) standard C84.1 range A "favorable zone" service voltages to all customers. This allows for energy efficient voltage regulation during all loading conditions.

The proposed voltage regulators are required to maintain the Company's ability to utilize LDC settings. As a result of the addition of PRS2 generation being greater than the feeder peak load, the voltage regulator control at the substation will have no measurement indicating the actual loading on the feeder, making LDC settings not possible and negatively impact PacifiCorp's ability to meet ANSI standard C84.1 in temporary switching configurations.

Q. How do the sets of voltage regulators positively impact PacifiCorp's ability to maintain voltage regulation?

A. The two sets of voltage regulators—being beyond these projects—will enable efficient feeder voltage regulation as exists today, i.e., prior to these projects being interconnected. As noted above, absent the voltage regulators, PacifiCorp's ability to meet ANSI standard C84.1 in temporary switching configurations would be negatively impacted.

Q. Mr. Beanland speculates that the voltage regulators are being required to address an existing problem.[21] What is your response?

A. I disagree. The voltage regulators are needed due to the interconnection request of PRS2. As I stated above, the voltage regulators will enable efficient feeder voltage regulation as exists today, i.e., prior to these projects being interconnected.

Q. Is Mr. Beanland's recommendation to remove the voltage regulators consistent with the purpose of an interconnection study?

A. No. The purpose of an interconnection study is to determine what interconnection facilities are needed, if any, to accommodate the interconnection request without adversely impacting the system and the quality of service other customers are receiving. Mr. Beanland's recommendation would be to remove interconnection facilities that are needed to maintain the reliability of the system that exists today and, instead, would result in a lack of an ability to maintain efficient voltage regulation, which exists today.

Q. Mr. Beanland testifies that voltage regulation is not required because he calculated a voltage rise of less than 0.5 percent when both PRS1 and PRS2 are operating at peak production.[22] Does that have any bearing on the justification for the voltage regulators?

A. No. Mr. Beanland states that, "Voltage regulators may be necessary where the addition of new generation causes line voltages to fluctuate outside allowable limits."[23] However, as I noted earlier, voltage regulators are required here to maintain the

[21] Sunthurst/200, Beanland/17.
[22] Sunthurst/200, Beanland/26.
[23] Sunthurst/200, Beanland/26.

Company's ability to utilize LDC settings. Thus, they allow the continuation of energy efficient operation of the electrical system that exists today and maintain PacifiCorp's ability to meet ANSI standard C84.1 in temporary switching configurations.

V. FIBER OPTICS

Q. Mr. Beanland notes that PacifiCorp is requiring the installation of a fiber optic link, but speculates that a radio link would "likely be cheaper."[24] What function is served by the fiber optic link?

A. Electric utilities transmit and distribute electrical power over a large geographic area. The systems include power generating stations, alternative energy sources (solar, wind, etc.), and substations for distribution and microgrids. These networks must be monitored and managed to ensure reliable power for the utility's customers. For monitoring and managing networks, electric utilities use a variety of means of communications, including running fiber optic cables along the transmission and distribution towers, radio links and contracting landline and cellular communications services from telecom carriers for various applications.

Q. Is a fiber optic link more reliable than a radio link?

A. Yes. For the proposed application of using an unlicensed spread spectrum radio for a relaying transfer trip signal, the spread spectrum radio can be interfered with by other spread-spectrum users. The potential for spread spectrum radio interference and potential reliability impact requires communication channel monitoring. Because of the enhanced reliability afforded by fiber optic link, its utilization has become a utility best practice.

[24] Sunthurst/200, Beanland/26.

Q. Does PacifiCorp require other similarly situated interconnection requests to install fiber optic links for communicate on purposes?

A. Yes. PacifiCorp implements its policy regarding fiber optic links in a non-discriminatory manner. Thus, interconnection requests similar to PRS1 and PRS2, including many CSP interconnection requests, would similarly be required to use a fiber optic link.

Q. Does Sunthurst challenge PacifiCorp's estimated cost to install the fiber link?

A. Yes. Mr. Beanland claims that the estimated costs per foot for fiber optic cable is higher for PRS1 and PRS2 when compared to other CSP projects and the costs reflected in other system impact studies. Specifically, Mr. Beanland notes, "The $60,000 direct cost of 0.9 miles of fiber optic cable for PRS1 2 and PRS2 equates to nearly $10.23/linear foot (LF)."[25]

Q. How did PacifiCorp estimate the costs to install fiber for Sunthurst's projects?

A. For PRS1 and PRS2, and other similarly-situated interconnection requests, PacifiCorp installs the fiber optic cable via "All-Dielectric Self Supporting" or "ADSS", which means the fiber doesn't need a messenger cable[26] when hung. PacifiCorp uses this method when it is installing fiber under a transmission or distribution line. When installing fiber above the conductors, the Company uses Optical Ground Wire, which is fiber as well as static wire.

When estimating the costs for ADSS, PacifiCorp typically estimates $42,000

[25] Sunthurst/200, Beanland/28.
[26] A messenger cable is a cable used to support a power cable or other conductor of electricity; a suspension cable or wire.

per mile for new distribution lines and $60,000 per mile for existing distribution lines. The latter requires more work to install fiber on an existing line, typically involving pole replacements or strengthening and workarounds for existing space restrictions.

Q. Has PacifiCorp adjusted the estimated costs for fiber optic cable for PRS1?

A. Yes. PacifiCorp has adjusted the estimated costs for PRS1 to use $42,000/mile. At 0.9 miles for Q0666, the updated estimated cost is approximately $38,000. This adjustment: (1) brings the estimate for Q0666 in line with the facilities studies for OCS27 and OCS25, which Mr. Beanland identifies on page 28 of his testimony, and is a reduction in the estimated costs for PRS1 of $19,556.

Q. With the updated estimated costs for fiber optic cable, are the costs for the spread spectrum radio "likely a substantially cheaper" alternative as Mr. Beanland speculates?[27]

A. No. At the pre-existing $60,000 per mile estimate, the fiber optic cable option was approximately $14,000 more than the radio. At the updated $42,000 per mile estimate (or approximately $38,000 for the 0.9 miles at issue for PRS1), the fiber optic cable option is comparable in cost to the radio link option, which as I noted above is a less reliable option.

Q. Mr. Beanland also recommends that PacifiCorp share in the cost of fiber installation because he claims it will provide a system benefit.[28] Do you agree?

A. No. The fiber that will be installed extends from the Pilot Rock substation to PRS1 and PRS2. PacifiCorp would not install that fiber link if PRS1 and PRS2 were not

[27] Sunthurst/200, Beanland/5, 26.
[28] Sunthurst/200, Beanland/29.

interconnecting. Therefore, the fiber is not a cost that would have been incurred but for Sunthurst's interconnection.

Q. Mr. Beanland also claims that installing a 48-fiber fiber optic cable is excessive and therefore PacifiCorp should share in the installation costs.[29] Do you agree?

A. No. PacifiCorp uses 48-fiber fiber optic cables across its system, which reduces overall costs and provides reliability. Using standard equipment allows PacifiCorp to more efficiently design, procure and construct upgrades to its system and is a common practice. If PacifiCorp used different equipment across its system, attempting to retrofit a system as large as PacifiCorp's every time there is a need for new equipment would lead to inconsistencies that make operation and maintenance more challenging and more expensive.

Moreover, Mr. Beanland agrees that it is "critical" to have spare fibers,[30] which means that Sunthurst would also have to pay for the spares of the 12-count fiber optic cable because its interconnection would be causing these special costs to be incurred and there is nowhere else on PacifiCorp's system that uses 12-count fiber optic cable. Thus, in addition to the costs to purchase the 12-count fiber cable, costs for maintaining sufficient spares would also need to be borne by Sunthurst, which further increases the costs in comparison to 48-count fiber optic cable.

[29] Sunthurst/200, Beanland/29.
[30] Sunthurst/200, Beanland/29.

VI. DEAD-LINE CHECKING

Q. Mr. Beanland recommends that PacifiCorp eliminate dead-line checking based on his belief that "most utilities are going away from rapid reclosing because of the problems they can cause industrial customers."[31] What is rapid reclosing?

A. Rapid reclosing, which is normally called high-speed reclosing, is an automatic control function applied to circuit breakers to which overhead lines are connected. Since most faults on overhead lines are temporary and the circuit can be restored as soon as all the sources of power to the fault have been disconnected, high speed automatic reclosing is applied to minimize the interruption of service to the customers due to a temporary fault. Rapid reclosing works well if the substation is the only major source of power to the circuit.

Q. How does rapid reclosing and the dead-line checking relate to PRS1 and PRS2?

A. PacifiCorp is mandated to ensure that its existing customers continue to receive the same level of service that existed prior to the interconnection of distributed energy resources such as PRS1 and PRS2. To maintain the high-speed reclosing on circuits that have certain levels of distributed generation, transfer trip is installed to force the disconnection of the distributed generation when the circuit breaker opens. With the transfer trip, high-speed reclosing can be maintained.

However, transfer trip is done over communication circuits and there is a possibility that the transfer trip will not function in the typical short time period. If that happens, the rapid reclose will still take place, but it will not be successful in that the

[31] Sunthurst/200, Beanland/26-27.

arc at the location of the fault would not have gone out. Consequently, the circuit breaker will trip again, but if there are any motors being serviced on the circuit, the distributed generation will keep the motor energized and turning, but at a slower speed. When the circuit breaker reclosing takes place, the motor will be sped up instantly, which will cause damage to the motors. This is a severe outcome to customers' service that must be avoided.

The deadline check is used to delay the automatic reclose until there is an indication that the distributed generation has disconnected and, thus, allows the motors to be disconnected. Transfer trip operation will result in a high-speed trip of the generation to avoid delaying the reclosing of the circuit breaker.

Q. Do you agree that PacifiCorp should eliminate dead-line checking for PRS1 and PRS2?

A. No. Mr. Beanland's speculation of what other utilities are doing is not relevant to PacifiCorp.

Q. Mr. Beanland recommends that PacifiCorp change from a 0.35-second reclosing interval to a 5-second interval as an alternative to dead-line checking.[32] What is a reclosing interval?

A. The reclosing interval relates to the amount of time customers on the circuit experience an outage. At 0.35-seconds, a customer will experience only a 0.35-second outage for temporary faults on the circuits. The 5-second interval that Mr. Beanland recommends would mean the customer experiences a 5-second outage for temporary faults on the circuits.

[32] Sunthurst/200, Beanland/27.

Q. Do you agree with the change that Mr. Beanland recommends?

A. No. PacifiCorp has been using a 0.35-second reclosing interval for circuit 5W406 out of Pilot Rock substation for many years. As noted above, this control function for the circuit breaker at Pilot Rock substation makes it possible for the customers on the circuit to experience only a 0.35 second outage for temporary faults on the circuits. Ninety percent of faults on overhead lines are temporary, so that after all sources of fault current have been disconnected the circuit can be restored. The dead-line check automatically minimizes the extent of most outages.

Q. Is Mr. Beanland's recommendation to eliminate the dead-line check consistent with the purpose of an interconnection study?

A. No. Similar to the voltage regulators, implementing Mr. Beanland's recommendation would degrade the quality of service that PacifiCorp's retail customer receive today. As a public utility, PacifiCorp strives to provide the most reliable service to its retail customers; with the interconnection of distributed generation, dead-line checking is necessary to enable PacifiCorp to maintain reliable service. In particular, the proposed design modifications to the protection and control circuits at Pilot Rock substation for the interconnection make it possible to maintain the same level of service to PacifiCorp's existing retail customers and still accommodate the interconnection of the generation facility.

VII. PI-111 ANNUNCIATOR PANEL

Q. What is the PI-111 annunciator panel?

A. A PI-III Indication - Annunciator panel is a piece of equipment that PacifiCorp uses to provide alarm points for substation equipment. Operations personnel use the annunciator to diagnose problems and issues with the substation and power system. The annunciator is also used as an aggregation point for substation alarms to bring a subset of the station alarms into the 24/7 dispatch monitoring center.

Q. Does the PI-111 annunciator panel impact both PRS1 and PRS2?

A No, it only impacts PRS1 (Q0666). The PRS1 Small Generator Interconnection Agreement (SGIA) called for the PI-111 annunciator panel because the addition of PRS1 increases the complexity of the protection and control at Pilot Rock substation that calls for the need of an annunciator to assist the operation personnel to diagnose problems.

Q. Would PacifiCorp install the annunciator panel if Sunthurst's project were not interconnecting to the Pilot Rock substation?

A. No.

Q. Did PacifiCorp offer to remove the costs of the annunciator panel from PRS1?

A. Yes. As an accommodation to Sunthurst, in its August 7, 2020, letter to Sunthurst, PacifiCorp offered to remove the costs of the PI-111 annunciator panel from the SGIA for PRS1. At that time, the estimated cost of the panel was $15,000. As noted below, this figure has been updated and superseded by a new value.

Q. Is the PI-111 annunciator panel still needed, notwithstanding that PacifiCorp offered to remove its costs?

A. Yes.

Q. If the PI-111 annunciator panel is still needed, why did PacifiCorp offer to remove the costs from PRS1?

A. PacifiCorp worked extensively and in good faith with Sunthurst to address its concerns over the estimated interconnection costs for its projects and sought where possible to accommodate Sunthurst's need for lower costs. PacifiCorp assumed the costs of the annunciator panel in an attempt to help address and resolve Sunthurst's concerns. Although PacifiCorp believes that the annunciator panel could reasonably be charged to Sunthurst, PacifiCorp agreed to bear its cost should Sunthurst decide to proceed with its interconnection request.

Q. Mr. Beanland questions whether the $15,000 cost estimate is comprehensive and includes all of the costs associated with removing the annunciate panel from the interconnection costs assigned to Sunthurst.[33] Has PacifiCorp provided a more comprehensive cost estimate?

A. Yes. PacifiCorp reviewed the cost estimates for PRS1. Based on this more detailed review, PacifiCorp's updated estimate for the annunciator panel reduces the interconnection costs by PRS1 by $17,347. The $17,347 updates and supersedes the estimate of $15,000 that PacifiCorp provided in its August 7, 2020 letter.

In addition, testing and commissioning expenses relating to PRS1 were reduced as follows to account for the PI-111 Annunciator Panel: (1) substation journeyman hours were reduced from 320 to 240 hours, and (2) relay tech journeyman hours were reduced from 640 to 480 hours. Each hour has a cost of $153.31, so the total reduction for engineering and project management expenses was $36,794.

[33] Sunthurst/200, Beanland/15.

VIII. AVIAN PROTECTION COSTS

Q. Mr. Beanland questions the estimated costs for avian protection.[34] **What is your response?**

A. In response to Mr. Beanland's testimony, PacifiCorp reviewed the estimate provided for avian protection and agreed that the costs were high. A prior estimate provided in August of 2020 for Q0666 was more in line with other CSP projects. PacifiCorp has revised the avian protection costs for Q0666 (avian protection is not required for Q1045).

As the figure above indicates, PacifiCorp has revised the cost estimate for avian protection to reflect 120 feet of grey hose and three VT bushing covers only. The purpose of these materials is to protect birds and various other animals from electrocution and associated outages resulting from contact with electrical equipment. The new total estimated cost is $2,040, which represents a reduction in costs of $5,610 from the September 2020 detailed expenditure report for PRS1.

IX. JUNCTION BOXES

Q. Mr. Beanland asserts the estimated costs for junction boxes for PRS1 are high.[35] **What costs are at issue for the junction boxes?**

A. The two primary categories of costs that apply to junction boxes are the costs for materials and costs for installing the junction boxes.

Q. How does PacifiCorp determine the costs for junction boxes?

[34] Sunthurst/200, Beanland/27.
[35] Sunthurst/200, Beanland/27.

A. For the cost of the junction box(es), preferred suppliers are determined based on what entities are available to provide conforming materials and at the best cost available. PacifiCorp purchases junction boxes and other materials from REXEL USA, which was selected through a competitive tender event.

Regarding the costs for installation, the external contractor selected to perform construction services is procured through a competitive bidding process. The lowest bidder is awarded the construction contract. At this time, because Sunthurst has delayed the interconnection, PacifiCorp has not completed the bidding process and, accordingly the costs provided for junction boxes in the detailed expenditure report are estimated amounts.

Q. Has PacifiCorp updated the estimate for junction boxes?

A. Yes. The final drawings for engineering are ready for PRS1 (Q0666) to move forward with this project. This has allowed PacifiCorp to provide the following update for junction boxes, as reflected in PAC/201 for PRS1. The change in costs from the September 2020 detailed expenditure report for PRS1 is a reduction of approximately $17,000.

Q. Mr. Beanland claims the costs for junction boxes should be around $100.[36] **Are the types of junction boxes he cites the ones that PacifiCorp is using for PRS1?**

A. No. The boxes Mr. Beanland researched are for 12”x12” boxes. However, PacifiCorp will be using 24”x24” boxes. In fairness to Mr. Beanland, the 12”x12” junction boxes were referenced in error for PRS1 (Q0666). Although PacifiCorp is using the 24”x24” junction boxes, the costs reductions for PRS1 reflect the cost of the 12”x12” junction

[36] Sunthurst/200, Beanland/27.

boxes, at $2,000 each.

Q. What costs are included in the $2,000 price for each 12"x12" junction box?

A. The $2,000 in the current estimate covers the cost of the junction boxes, plus all equipment that goes inside these boxes, including fuse block, fuses, ground bar, terminal block, and the cost of labor for installation.

Q. Setting aside that 12"x12" junction boxes will not be used for interconnecting PRS1, were there other problems with Mr. Beanland's investigation into the pricing for junction boxes?

A. Yes. In discovery, PacifiCorp asked Sunthurst to identify "all evidence relied on by Mr. Beanland for his estimated junction box cost, including any cost studies performed by Mr. Beanland or examples he is aware of where a comparable junction box cost 'under $100'". In response, Sunthurst stated that retail prices were investigated on the internet and that prices ranged from $81 to $181.[37] The four examples provided in SUN-0143-SUN-0151 reflected ratings of "NEMA 12" or "NEMA 3R", which do not meet PacifiCorp Standards.[38] PacifiCorp uses NEMA 4X for all substation VT and CT junction boxes because NEMA 4X adds additional protection against corrosion.

Q. **To your knowledge, do other electric utilities simply purchase junction boxes from the internet as Mr. Beanland appears to believe PacifiCorp should do?**

A. Not to my knowledge. Moreover, the competitive procurement processes I described above are designed to obtain the lowest, reasonable cost for materials such as junction boxes, as well as the associated contract labor.

[37] PAC/203 (Sunthurst Response to PacifiCorp Data Request 2.29).
[38] NEMA is the National Electrical Manufacturer's Association, which develops ratings for electronic enclosures.

X. 0.3 MILES OF LINE EXTENSION

Q. Mr. Beanland asserts that PacifiCorp should have to pay for 0.3 miles of conductor needed to interconnect PRS1 and PRS2.[39] What is the 0.3 miles of conductor he references?

A. To interconnect PRS1 and PRS2, PacifiCorp is required to install an approximate 0.3-mile distribution line extension because it needs to install a switch and a meter prior to the point of change of ownership, as those facilities do not exist currently. The line extension will be installed on new poles and will be owned and maintained by PacifiCorp.

Q. What is the approximate cost of the 0.3-mile line extension?

A PacifiCorp estimates that the cost of this line extension to be approximately $50,000.

Q. Would PacifiCorp construct this 0.3-mile line extension if PRS1 and PRS2 were not interconnecting?

A. No. The new distribution line serves no purpose except to interconnect Sunthurst's projects. If there were no projects, PacifiCorp would not construct a 0.3-mile distribution line to the middle of nowhere.

Q. Does Sunthurst believe it should have to pay for the costs of the new 0.3-mile line?

A. No. Mr. Beanland claims that this new line "is an enlargement of PacifiCorp's existing distribution system" that will allow PacifiCorp "to serve new loads where it previously did not."[40] Therefore, Sunthurst claims that PacifiCorp should pay for a portion of the

[39] Sunthurst/200, Beanland/30.
[40] Sunthurst/200, Beanland/30.

costs of this line because it will provide system-wide benefits.

Q. How do you respond to Mr. Beanland's claim that the 0.3-mile distribution line provides system-wide benefits?

A. PacifiCorp disagrees. There is no anticipated load that would be served by the new line, it would not be built but for the Sunthurst projects, and provides no other tangible benefit to PacifiCorp. To the contrary, the 0.3-mile line is a detriment to PacifiCorp's system as it adds exposure to faults, which if one occurred would be cleared by the substation breaker resulting in an outage to all customers on the feeder. The line also creates additional maintenance costs for PacifiCorp. Finally, the fact that PacifiCorp will own the line does not indicate in any way that PacifiCorp "values" the line or that the line will provide system-wide benefits.

Q. Why did PacifiCorp propose to construct and own the 0.3 miles of line instead of letting Sunthurst construct and own the line?

A. In the case of PRS1 and PRS2, PacifiCorp is installing the 0.3-mile line extension because PacifiCorp needs to install a disconnect switch and a meter prior to the point of change of ownership as those facilities do not exist. The disconnect switch and meter are facilities that PacifiCorp will own and maintain, which necessitates installing new poles on which these items will be installed. Because these are to be Company-owned equipment, PacifiCorp would not install those pieces of equipment on customer owned poles (i.e., 0.3 miles of line) as it would create issues with maintenance and access.

XI. CAPITAL SURCHARGE

Q. Sunthurst questions the inclusion of a capital surcharge in the estimated interconnection costs.[41] Please describe the capital surcharge that PacifiCorp uses to estimate interconnection costs.

A. The purpose of a capital surcharge (also referred to as a construction overhead) is to include an appropriate portion of administrative and general costs, which cannot be charged directly to a capital project, in accordance with Federal Energy Regulatory Commission (FERC) and United States Generally Accepted Accounting Principles (GAAP). Capital Surcharges are applied to every capital project on a monthly basis.

Q. Does PacifiCorp apply the capital surcharge to all capital projects, including the Company's own?

A. Yes. Capital surcharges are applied to every capital project (i.e., not just interconnection requests) on a monthly basis.

Q. What capital surcharge was used to estimate the interconnection costs for PRS1 and PRS2?

A. The Company used an 8 percent surcharge. For projects of $10 million or less, the capital surcharge rates vary slightly from month-to-month, and it is currently estimated at 8 percent of the total direct costs.

Q. How does PacifiCorp calculate the capital surcharge?

A. Each year, PacifiCorp's controllers review and approve the capital surcharge rate to be used for estimating purposes. The capital surcharge rate represents the construction support for various cost centers throughout the Company that cannot charge directly to

[41] Sunthurst/100, Hale/11.

the capital projects. The rate is derived by taking the construction support costs and dividing it by the direct capital spending for the year. For example, if total construction support is $70 million and the direct capital spending is $875 million, an 8 percent capital surcharge rate is applied to account for those costs.

Each Company cost center is reviewed annually to verify and update the construction support amount that should be part of the capital surcharge assessment. The review includes comparison to prior year, organization changes and changes to specific individual roles.

Each year the Company drafts a capital budget plan. This is comprised of existing capital projects under construction, planned capital projects for the year and capital investment programs. Some examples of capital investment programs are new connects, replacing assets, equipment failures, storm and casualty, capital projects to address additional load requirements, regulatory mandated projects and customer-initiated requests. The actual capital surcharge rate may vary during the year depending on the actual / forecast construction support costs and capital spending. The capital surcharge rate is reviewed and approved by the Company controllers based on actual and forecast construction support costs and capital spending, ensuring accuracy and consistency with FERC and GAAP.

Q. Sunthurst claims that the Commission has never approved the use of a capital surcharge.[42] How do you respond?

A. The Commission has, in Oregon Administrative Rules 860-027-0045, adopted FERC's

[42] Sunthurst/100, Hale/11.

Uniform System of Accounts (USOA) for electric companies.[43] The FERC USOA in Code of Federal Regulations 18, Part 101, Electric Plant Instructions 4 (A-C) addresses the allowance for a Construction Overhead (PacifiCorp uses the term Capital Surcharge):

> 4. *Overhead Construction Costs.*
>
> A. All overhead construction costs, such as engineering, supervision, general office salaries and expenses, construction engineering and supervision by others than the accounting utility, law expenses, insurance, injuries and damages, relief and pensions, taxes and interest, shall be charged to particular jobs or units on the basis of the amounts of such overheads reasonably applicable thereto, to the end that each job or unit shall bear its equitable proportion of such costs and that the entire cost of the unit, both direct and overhead, shall be deducted from the plant accounts at the time the property is retired.
>
> B. As far as practicable, the determination of pay roll charges includible in construction overheads shall be based on time card distributions thereof. Where this procedure is impractical, special studies shall be made periodically of the time of supervisory employees devoted to construction activities to the end that only such overhead costs as have a definite relation to construction shall be capitalized. The addition to direct construction costs of arbitrary percentages or amounts to cover assumed overhead costs is not permitted.
>
> C. For Major utilities, the records supporting the entries for overhead construction costs shall be so kept as to show the total amount of each overhead for each year, the nature and amount of each overhead expenditure charged to each construction work order and to each electric plant account, and the bases of distribution of such costs.

PacifiCorp's capital surcharge is consistent with these requirements.

Q. Sunthurst also claims that PacifiCorp's avoided costs do not include a capital surcharge amount.[44] How do you respond?

A. PacifiCorp disagrees. The costs of the proxy resources used to determine avoided cost

[43] OAR 860-027-0045.
[44] Sunthurst/100, Hale/11.

prices are taken directly from PacifiCorp's acknowledged Integrated Resource Plans (IRPs). The resource costs used in the IRPs include capital surcharges.[45]

XII. DIRECT TRANSFER TRIP

Q. Sunthurst also questions the need for Direct Transfer Trip (DTT).[46] How do you respond?

A. Mr. Hale claims that he reviewed the Institute of Electrical and Electronics Engineers (IEEE) 1547 requirements as they apply to smart inverters and determined that most utilities do not require DTT for projects under 2 MW if the inverters comply with IEEE 1547. This is incorrect.

PRS1 and PRS2 will interconnect to the 12.5 kilovolt (kV) circuit 5W406 out of the Pilot Rock substation. Circuit 5W406 is the only feeder connected to the 69 – 12.5 kV transformer bank #2 at the substation. Potential power production from PRS1 will be greater than the daytime load on the feeder and on the transformer some days of the year. With the addition of PRS2, the combined potential power from the two generation facilities will be greater than the daytime load on the feeder and the transformer most days of the year. Due to this generation to load ratio under/over voltage and frequency conditions when the generation is isolated with the load cannot be relied on to cause the timely disconnection of the generation from the circuit.

Q. Why is it critical that generation be timely disconnected from the circuit?

A. The timely disconnection of the generation from the circuit is required for two reasons. First, since most faults on overhead distribution lines are transient in nature, once all

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[45] PAC/204 (PacifiCorp's Response to Sunthurst Data Request 3.7).
[46] Sunthurst/100, Hale/6.

of the sources of power to the fault are disconnected the circuit can be re-energized and service restored to customers as automatic reclosing is enabled on breaker 5W406 at Pilot Rock substation. Second, the 69 – 12.5 kV transformer is currently protected with 69 kV fuses. Since the 69 kV side is the only current source of power to the transformer, the blowing of the fuses for faults in the transformer are a reliable way of isolating the transformer for internal problems. The addition of the Sunthurst solar projects provides a source of power to transformer faults from the 12.5 kV side that must also be disconnected to cease the injection of power into the fault. In many cases if internal transformer issues are isolated quickly the damage to the transformer is minimized and the transformer can be repaired and returned to service. If the transformer is not isolated from power sources in a few cycles the damage to the transformer will be extensive and there will be no usable value left in the transformer.

Q. Why are the inverters at PRS1 and PRS2 insufficient?

A. Sunthurst proposed that the inverters will be equipped with control circuits capable of detecting and disconnecting the inverters for conditions when the generation is isolated with load without relying on under/over voltage and frequency relay elements to meet IEEE 1547 requirements. IEEE 1547 requires that the inverters stop injecting power into the system in less than two seconds from the isolation of the generation with the load. The timing between the tripping of breaker 5W406 at Pilot Rock substation and the reclosing of the breaker is 20 cycles. However, meeting the IEEE 1547 requirements will not be adequate to support successful reclosing on this feeder. In addition to the problem of supporting a successful trip and reclose event, there is the risk of damage to the 69 – 12.5 kV transformer for a problem in the transformer.

Two seconds is an unacceptable amount of time to attempt to minimize damage to a faulted transformer. At two seconds, there would be no hope of salvaging anything from the transformer and there would be risks of a fire in the substation, which could damage other equipment and present a safety concern for PacifiCorp's employees and the public in general.

Additionally, the solar projects are required to remain connected to the transmission network for faults on the network that do not result in the isolation of the generation, low voltage ride through, in compliance with NERC PRC-024-2. Pilot Rock substation is fed from BPA's 230 – 69 kV Roundup substation. There are two 230 kV lines into Roundup substation. For a fault on one of these 230 kV lines, the voltage at PRS1 and PRS2 will be zero for the time it takes to detect and isolate the fault. PRS1 and PRS2 are required to remain connected to the system for such an event so that once the faulted line is disconnected and the system is left with just one 230 kV line, the remaining system does not suffer the additional loss of local generation. The requirement to remain connected under NERC PRC-024-2 is another reason why the inverter controls will not suffice.

Q. In light of the foregoing, why is DTT required?

A. The protective relay system that is required for PRS1 will meet the requirements to: (1) disconnect the solar generation in a timely manner for faults on the 12.5 kV circuit; (2) maintain the 20-cycle recloser function of 5W406; and (3) minimize the potential damage for a problem in the 69 – 12.5 kV transformer—all without causing the disconnection of the generation facilities for faults on the 230 kV network. The proposed inverter controls cannot meet these requirements. The protective relay system required for PRS1 will be adequate for the addition of PRS2.

XIII. MISCELLANEOUS ISSUES

Q. Mr. Beanland recommends that PacifiCorp remove all engineering and management costs associated with items that PacifiCorp has agreed to pay for.[47] Has PacifiCorp done so?

A. Yes. As discussed above, PacifiCorp reviewed its estimates and removed an additional $3,798 related to telemetry.[48] However, engineering and management costs associated with the PI-111 annunciator panel design had already been paid by Sunthurst at the time this complaint was filed. PacifiCorp can provide a credit to Sunthurst for these costs if PRS1 continues with its interconnection.

Q. Earlier in your testimony you addressed cost reductions for PRS1 related to avian protection, fiber optic cable, junction boxes, the PI-111 annunciator panel, and telemetry. Are there other adjustments to the estimated interconnection costs for PRS1 and PSR2?

A. Yes. As reflected in PAC/201 and PAC/202, the total cost adjustments for PRS1 and PRS2, respectively, are shown below.

- For PSR1, there is an overall reduction of $128,694 as follows:
  1. Removal of PI-111 annunciator panel - $17,347 (Material and external contract work);
  2. Removal of PI-111 annunciator panel - $36,974 (Field operations time for testing/commissioning);

[47] Sunthurst/200, Beanland/28.
[48] PacifiCorp notes that it had already removed approximately $525,000 for telemetry costs at the time Sunthurst filed its complaint.

3. Reduction in cost for avian protection - $5,610;
4. Reduction in quantity, size, and prices for junction boxes - $17,000;
5. Removal of time for SCADA engineer (telemetry) - $3,798;
6. Reduction in cost for fiber installation - $19,556;
7. Reduction in metering costs - $15,859;
8. Reduction to capital surcharge - $9,098; and
9. Other minor reductions - $3,452.

- For PSR2, there is an overall reduction of $13,034 as follows:

1. Reduction in metering costs - $10,514;
2. Reduction to regulator cost - $2,959;
3. Reduction to capital surcharge - $965; and
4. Other minor increases - $1,404.

Q. Does this conclude your response testimony?

A. Yes.

Docket No. UM 2118
Exhibit PAC/201
Witnesses: Milt Patzkowski,
Alex Vaz, Richard Taylor

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Response Testimony of Milt Patzkowski, Alex Vaz, Richard Taylor
Detailed Cost Estimate Report for PRS1

January 2021

PACIFICORP

SUPERIOR EXPENDITURE REPORT

Q666 SUNTHURST ENERGY, LLC - PILOT ROCK		Estimate Date: 01/21/21	Estimate Type: PSRAT Approved (±20%)
Cost Estimatng Engineer: Alex Vaz	Project Manager: Greg Straton	Start Date: 01/06/16	Requested By: Kris Bremmer
Project Definition (WBS): TIOR/2016/C/002/B	Project Type: Generation Interconnection	In-Service Date: 08/21/21	Investment Reason: NO

WORK SUMMARY:

Interconnection of 1.98 MW of solar electric generation to the 12.5 kV circuit 5W406 on of Pilot Rock Substation.

Revision: Removed Annunciator panel; Updated metering and communications costs; Updated actual expenses through 2020; Updated costs based on IFC package for Pilot Rock.

SUPERIOR EXPENDITURE SUMMARY

Calendar Year	Internal Labor	Material	Purchase Service	Other & Contingency	Removal	Salvage	Surcharge & AFUDC	Total Gross Capital	CIAC	O&M Expense	Net Project Cost
2016	$ 2,442	$ -	$ 8,624	$ -	$ -	$ -	$ 1,581	$ 12,647	$ (12,647)	$ -	$ -
2017	$ 3,146	$ -	$ 6,436	$ -	$ -	$ -	$ 1,343	$ 10,925	$ (10,925)	$ -	$ -
2018	$ 2,889	$ -	$ -	$ -	$ -	$ -	$ 317	$ 3,205	$ (3,205)	$ -	$ -
2019	$ 18,424	$ -	$ 49,466	$ 16,600	$ -	$ -	$ 6,994	$ 91,484	$ (91,484)	$ -	$ -
2020	$ 4,506	$ -	$ 22,012	$ (16,600)	$ -	$ -	$ 717	$ 10,634	$ (10,634)	$ -	$ -
2021	$ 202,256	$ 91,862	$ 115,520	$ -	$ -	$ -	$ 32,771	$ 442,410	$ (442,410)	$ -	$ -
TOTAL	**$ 233,663**	**$ 91,862**	**$ 202,058**	$ -	$ -	$ -	**$ 43,722**	**$ 571,306**	**$ (571,306)**	$ -	$ -

ASSUMED RATES:

Capital Surcharge	AFUDC	Escalation	State Adjustment	Contingency	OR Sales Tax
8.00%	7.65%	2.00%	NA	0.00%	0.00%

SUPERIOR EXPENDITURE DETAILS

SAP EASY COST PLANNING

INTERNAL LABOR	Property & Environmental Services	$0
	Engineering	$44,477
	Project Management	$25,904
	Operations	$163,281
MATERIAL	PacifiCorp Furnished Materials	$91,862
PURCHASE SERVICES	Consultants & Technical Services	$91,538
	Construction Services	$110,520
OTHER	Employee Expenses	$0
	Utilities & Services	$0
OVERHEADS	Surcharge	$43,722
	AFUDC	$0
TOTAL GROSS COSTS (Capital + O&M)		**$571,306**
CUSTOME ADVANCES (CIAC)		$0
NET PROJECT COSTS (Capital+Expense)		**$571,306**

ATTENTION

Estimate is subject to change following scope revisions, design modifications, property and permitting alterations, schedule adjustments, or change to customer requirements. In addition, estimates exceeding one year from the date of issuance should be updated to reflect project changes and to account for current market conditions. Contact the cost engineer for updates.

ESTIMATES SHOULD BE UPDATED PER ENGINEERING POLICY 306

± 30% Estimate	Preliminary Scopes
± 20% Estimate	PSRAT Approved Scopes
± 10% Estimate	Review 3 Drawings

RANGE OF ESTIMATED GROSS COSTS (±20%)

Low-End Range	$457,044
Estimate	**$571,306**
High-End Range	$685,567

PACIFICORP

SUBORDINATE EXPENDITURE REPORT

Q666 SUNTHURST ENERGY, LLC - PILOT ROCK
GROSS COSTS BY YEAR

YEAR / DESCRIPTION	INTERNAL LABOR	MATERIAL	PURCHASE SERVICE	OTHER & CONTINGENCY	REMOVAL & SALVAGE	SURCHARGE	AFUDC	GROSS CAPITAL COST	CIAC
2016	**$2,442**	$0	**$8,624**	$0	$0	**$1,581**	**$0**	**$12,647**	**($12,647)**
2017	**$3,146**	$0	**$6,436**	$0	$0	**$1,343**	**$0**	**$10,925**	**($10,925)**
2018	**$2,889**	$0	$0	$0	$0	**$317**	**$0**	**$3,205**	**($3,205)**
2019	**$18,424**	$0	**$49,466**	**$16,600**	$0	**$6,994**	**$0**	**$91,484**	**($91,484)**
2020	**$4,506**	$0	**$22,012**	**-$16,600**	$0	**$717**	**$0**	**$10,634**	**($10,634)**
2021	**$202,256**	**$91,862**	**$115,520**	$0	$0	**$32,771**	**$0**	**$442,410**	**($442,410)**
Pilot Rock Substation	**$135,913**	**$39,096**	**$80,320**	$0	$0	**$20,426**	**$0**	**$275,755**	**($275,755)**
Project Management	$11,540	$0	$0	$0	$0	$923	$0	$12,463	($12,463)
Engineering	$10,145	$0	$0	$0	$0	$812	$0	$10,957	($10,957)
Operations	$114,228	$0	$0	$0	$0	$9,138	$0	$123,366	($123,366)
Material	$0	$39,096	$0	$0	$0	$3,128	$0	$42,223	($42,223)
Construction Services	$0	$0	$80,320	$0	$0	$6,426	$0	$86,746	($86,746)
Collector Metering	**$37,843**	**$19,541**	**$10,000**	$0	$0	**$5,391**	**$0**	**$72,775**	**($72,775)**
Project Management	$5,770	$0	$0	$0	$0	$462	$0	$6,231	($6,231)
Engineering	$12,681	$0	$0	$0	$0	$1,014	$0	$13,696	($13,696)
Operations	$19,392	$0	$0	$0	$0	$1,551	$0	$20,943	($20,943)
Material	$0	$19,541	$0	$0	$0	$1,563	$0	$21,104	($21,104)
Consulting & Technical Services	$0	$0	$5,000	$0	$0	$400	$0	$5,400	($5,400)
Construction Services	$0	$0	$5,000	$0	$0	$400	$0	$5,400	($5,400)
Fiber	$0	**$10,800**	**$25,200**	$0	$0	**$2,880**	**$0**	**$38,880**	**($38,880)**
Material	$0	$10,800	$0	$0	$0	$864	$0	$11,664	($11,664)
Construction Services	$0	$0	$25,200	$0	$0	$2,016	$0	$27,216	($27,216)
Extend 12.5kV Circuit 5W406	**$28,500**	**$22,426**	$0	$0	$0	**$4,074**	**$0**	**$55,000**	**($55,000)**
Operations	$28,500	$0	$0	$0	$0	$2,280	$0	$30,780	($30,780)
Material	$0	$22,426	$0	$0	$0	$1,794	$0	$24,220	($24,220)
Grand Total	**$233,663**	**$91,862**	**$202,058**	$0	$0	**$43,722**	**$0**	**$571,306**	**($571,306)**

PACIFICORP

DETAILED EXPENDITURE REPORT

Q666 SUNTHURST ENERGY, LLC - PILOT ROCK

This report shows remaining costs only (Year 2021)

SUBORDINATE	DIVISION	DIVISION ACTIVITY	DESCRIPTION	VALUE CATEGORY	YEAR	QUANTITY	UNIT	UNIT COST	DIRECT CAPITAL COST
Pilot Rock Substation	Project Management	Project Management	Project Manager, PP	Internal	2021	80	HRS	$106.37	$8,510
			Project Control Specialist, PP	Internal	2021	40	HRS	$75.75	$3,030
	Engineering	Engineering Design	P&C Engineering, Engineer	Internal	2021	40	HRS	$88.95	$3,558
		Engineering Services	Civil Services, As-Built Engineer	Internal	2021	8	HRS	$81.10	$649
			Civil Services, As-Built Drafter	Internal	2021	4	HRS	$57.95	$232
			Cost Engineering, Engineer	Internal	2021	8	HRS	$88.66	$709
			Document Control, Business Analyst	Internal	2021	4	HRS	$61.26	$245
			Resource Planning, Material Analyst	Internal	2021	8	HRS	$59.31	$474
	Operations	Substation Operations	Journeyman, Substation, PP	Internal	2021	240	HRS	$150.30	$36,072
			Journeyman, Relay Tech, PP	Internal	2021	480	HRS	$150.30	$72,144
	General	General Requirements	Construction Management	External	2021	1	LS	$7,500.00	$7,500
			Mobilization & Demobilization	External	2021	1	LS	$12,500.00	$12,500
	Substation	Excavation	Excavation, Hydrovac	External	2021	10	HRS	$300.00	$3,000
		Transformer, Instrument, VT	Transformer, Instrument, VT, 12.5kV	Material	2021	3	EA	$675.00	$2,025
				External	2021	3	EA	$2,000.00	$6,000
		Substation Steel Structures, 12.5 kV	Structure, Steel, VT Mounting Assembly	External	2021	1	EA	$3,500.00	$3,500
		Bare Copper Conductor and EHS Steel	Conductor, Bare, 4/0 CU, 19 Strand	Material	2021	70	LF	$2.25	$158
				External	2021	70	LF	$20.00	$1,400
		Control Cable	Control Cable, 600V	Material	2021	610	LF	$1.20	$732
				External	2021	610	LF	$8.00	$4,880
			Control Cable, 600V, Terminations	External	2021	100	EA	$40.00	$4,000
		Panel, PC Type, Control and Metering	Panel, PC-510, Metering Transformer	Material	2021	2	EA	$6,500.00	$13,000
			Panel, PC-611, Distribution Feeder	Material	2021	1	EA	$13,213.00	$13,213
		Panel Components	Regulator Controller, Beckwith M-2001C w/ Adapter Panel	Material	2021	1	EA	$2,124.00	$2,124
				External	2021	1	EA	$1,200.00	$1,200
		Outdoor CT, VT, CT/VT, and Misc J-Boxes	Junction Box, Load Center	Material	2021	1	EA	$2,700.00	$2,700
				External	2021	1	EA	$1,500.00	$1,500
			Junction Box, VT	External	2021	2	EA	$2,000.00	$4,000
		Conduits	Conduit, PVC	External	2021	120	LF	$50.00	$6,000
			Conduit, GRC	External	2021	60	LF	$80.00	$4,800
		Station Grounding	Grounding, Substation, Complete	External	2021	100	LF	$30.00	$3,000
		Avian & Animal Enhancements	Guard, Animal, Hose	External	2021	120	LF	$12.00	$1,440
			Guard, Animal, VT Bushing Cover	External	2021	3	EA	$200.00	$600
		Commissioning	Acceptance and Operational Tests	External	2021	1	LS	$10,000.00	$10,000
	Telecommunications	Telecommunications Engineering	Communications Engineer	Internal	2021	32	HRS	$102.54	$3,281
			Communications Drafter	Internal	2021	16	HRS	$62.30	$997

PACIFICORP

DETAILED EXPENDITURE REPORT

Q666 SUNTHURST ENERGY, LLC - PILOT ROCK

This report shows remaining costs only (Year 2021)

SUBORDINATE	DIVISION	DIVISION ACTIVITY	DESCRIPTION	VALUE CATEGORY	YEAR	QUANTITY	UNIT	UNIT COST	DIRECT CAPITAL COST
Pilot Rock Substation	Telecommunications	Substation Operations	Journeyman, Electronic Tech, PP	Internal	2021	40	HRS	$150.30	$6,012
		Miscellaneous (MISC)	Communications, Misc Materials	Material	2021	1	EA	$5,144.00	$5,144
			Communications, ADSS Conduit	External	2021	1	LS	$5,000.00	$5,000
Collector Metering	Project Management	Project Management	Project Manager, PP	Internal	2021	40	HRS	$106.37	$4,255
			Project Control Specialist, PP	Internal	2021	20	HRS	$75.75	$1,515
	Engineering	Engineering Design	P&C Engineering, Engineer	Internal	2021	55	HRS	$88.95	$4,892
			Engineering Consultant, Design	External	2021	1	LS	$5,000.00	$5,000
	Operations	Substation Operations	Journeyman, Relay Tech, PP	Internal	2021	16	HRS	$150.30	$2,405
	Metering	Engineering Design	Metering Engineering, Engineer	Internal	2021	40	HRS	$87.77	$3,511
		Substation Operations	Journeyman, Meter Tech, PP	Internal	2021	80	HRS	$137.19	$10,975
		Metering Equipment	Pole & Mounting	Material	2021	1	EA	$4,500.00	$4,500
			Meter and Test Switch	Material	2021	1	EA	$1,500.00	$1,500
			Instrument Transformers, 12.5 KV	Material	2021	3	EA	$1,500.00	$4,500
			Communications Cell Pack	Material	2021	1	EA	$500.00	$500
			Miscellaneous	Material	2021	1	EA	$100.00	$100
	Telecommunications	Telecommunications Engineering	Communications Engineer	Internal	2021	32	HRS	$102.54	$3,281
			Communications Drafter	Internal	2021	16	HRS	$62.30	$997
		Substation Operations	Journeyman, Electronic Tech, PP	Internal	2021	40	HRS	$150.30	$6,012
		Fiber Optics (Fiber)	Communications, Misc Materials	Material	2021	1	LS	$8,441.00	$8,441
			Communications, ADSS Conduit	External	2021	1	LS	$5,000.00	$5,000
Fiber	Telecommunications	Fiber Optics (Fiber)	Fiber Optic, ADSS, Material	Material	2021	0.9	MI	$12,000.00	$10,800
			Fiber Optic, ADSS, Installation	External	2021	0.9	MI	$28,000.00	$25,200
Extend 12.5kV Circuit 5W406	Distribution	Field Operations (Wires)	Journeyman, Lineman, PP	Internal	2021	1	LS	$28,500.00	$28,500
		Distribution Work	Distribution Material	Material	2021	1	LS	$22,425.93	$22,426
Grand Total									**$409,638**

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CURRENT & PREVIOUS ESTIMATE VARIANCE

Q666 SUNTHURST ENERGY, LLC - PILOT ROCK

DESCRIPTION	PREVIOUS GROSS CAPITAL COST	CURRENT GROSS CAPITAL COST	VARIANCE	NOTES
Estimate Date:	09/02/20	01/21/21		
Estimate Type:	±20%	±20%		
Pilot Rock Substation	$484,668	$393,958	-$90,709	*Removed PI-111 Annunciator Panel; Adjusted J-Box and Avian Costs*
Collector Metering	$100,332	$83,467	-$16,865	*Updated Metering Costs*
Fiber	$60,000	$38,880	-$21,120	*Changed Length from 1 mile to 0.9 mile; Updated Installation Cost Rate*
Extend 12.5kV Circuit 5W406	$55,000	$55,000	$0	
Grand Total	$700,000	$571,306	-$128,694	

Docket No. UM 2118
Exhibit PAC/202
Witnesses: Milt Patzkowski,
Alex Vaz, Richard Taylor

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Response Testimony of Milt Patzkowski, Alex Vaz, Richard Taylor
Detailed Cost Estimate Report for PRS2

January 2021

PACIFICORP

SUPERIOR EXPENDITURE REPORT

Q-1045 PILOT ROCK SOLAR		Estimate Date 12/30/20	Estimate Type System Impact Study (±30%)
Prepared By Chris Smith	Project Manager TBD	Start Date 01/01/21	Requested By Kris Bremer
Project Definition (WBS) TBD	Project Type Generation Interconnection	In-Service Date 12/31/21	Investment Reason NO

WORK SUMMARY:

Pilot Rock Solar 2, LLC proposed interconnecting 3 MW of new generation to PacifiCorp's Circuit 5W406 out of Pilot Rock substation at 12.5 kV located in Umatilla County, Oregon. The Pilot Rock Solar 2 project will consist of forty-nine (49) Sungrow SG60KU-M inverters for a total requested output of 3 MW.

12/30/2020 Revision - Metering costs have been updated. Cost assumes two sets of primary metering (12.5kV).

See next page for assumptions.

SUPERIOR EXPENDITURE SUMMARY

Calendar Year	Internal Labor	Material	Purchase Service	Other & Contingency	Removal	Salvage	Surcharge & AFUDC	Total Gross Capital	CIAC	O&M Expense	Net Project Cost
2021	$135,487	$130,020	$0	$500	$0	$0	$21,281	$287,287	($287,287)	$0	$0
TOTAL	**$135,487**	**$130,020**	**$0**	**$500**	**$0**	**$0**	**$21,281**	**$287,287**	**($287,287)**	**$0**	**($0)**

ASSUMED RATES:

Capital Surcharge	AFUDC	Escalation	State Adjustment	Contingency	OR Sales Tax
8.00%	0.00%	2.00%	NA	0.00%	0.00%

SUPERIOR EXPENDITURE DETAILS

SAP EASY COST PLANNING

INTERNAL LABOR	Property & Environmental Services	$0
	Engineering	$19,698
	Project Management	$11,540
	Operations	$104,249
MATERIAL	PacifiCorp Furnished Materials	$130,020
PURCHASE SERVICES	Consultants & Technical Services	$0
	Construction Services	$0
OTHER	Employee Expenses	$500
	Utilities & Services	$0
OVERHEADS	Surcharge	$21,281
	AFUDC	$0
TOTAL GROSS COSTS (Capital + O&M)		**$287,287**
CUSTOME ADVANCES (CIAC)		($287,287)
NET PROJECT COSTS (Capital+Expense)		$0

SAP VALUE CATEGORY

1. Internal Labor (All PacifiCorp Labor)	$135,487
2. Material (PacifiCorp Purchased Only)	$130,020
3. Purchase Service (External Contract)	$0
4. Other (Employee Related, Utility, Misc C/E)	$500
5. Contingency	$0
6. Removal Costs	$0
7. Salvage	$0
8. TOTAL DIRECT CAPITAL COSTS (1 to 7)	**$266,007**
9. Surcharge	$21,281
10. AFUDC	$0
11. TOTAL GROSS CAPITAL COSTS (8 to 10)	**$287,287**
12. Customer Advance (CIAC)	($287,287)
13. O&M Expenses	$0
NET PROJECT COSTS (Capital+Expense)	**($0)**

PACIFICORP

SUBORDINATE EXPENDITURE REPORT

Q-1045 PILOT ROCK SOLAR
GROSS COSTS BY SUBORDINATE

DESCRIPTION	INTERNAL LABOR	MATERIAL	PURCHASE SERVICE	OTHER & CONTINGENCY	REMOVAL & SALVAGE	SURCHARGE	AFUDC	GROSS CAPITAL COST	CIAC
Pilot Rock Substation	$14,026	$160	$0	$0	$0	$1,135	$0	$15,321	($15,321)
Collector Substation Metering	$54,794	$29,860	$0	$500	$0	$6,812	$0	$91,966	($91,966)
Distribution Regulators	$66,667	$100,000	$0	$0	$0	$13,333	$0	$180,000	($180,000)
Grand Total	$135,487	$130,020	$0	$500	$0	$21,281	$0	$287,287	($287,287)

PACIFICORP

DETAILED EXPENDITURE REPORT

Q-1045 PILOT ROCK SOLAR

SUBORDINATE	DIVISION	DIVISION ACTIVITY	DESCRIPTION	VALUE CATEGORY	YEAR	QUANTITY	UNIT	UNIT COST	DIRECT CAPITAL COST
Collector Substation Metering	Project Management	Project Management	Project Manager, PP	Internal	2021	80	HRS	$106.37	$8,510
			Project Control Specialist, PP	Internal	2021	40	HRS	$75.75	$3,030
	Engineering	Engineering Design	P&C Engineering, Engineer	Internal	2021	55	HRS	$88.95	$4,892
			Engineering Design Expenses	Other	2021	1	LS	$500.00	$500
	Operations	Substation Operations	Journeyman, Relay Tech, PP	Internal	2021	16	HRS	$150.30	$2,405
	Telecommunications	Telecommunications Engineering	Communications Engineer	Internal	2021	8	HRS	$102.54	$820
			Communications Drafter	Internal	2021	4	HRS	$62.30	$249
		Substation Operations	Journeyman, Electronic Tech, PP	Internal	2021	16	HRS	$150.30	$2,405
		Communications Misc	Single Mode Jumper, 6 meters with SC connectors	Material	2021	2	EA	$80.00	$160
	Metering (Q1045)	Engineering Design	Metering Engineering, Engineer	Internal	2021	40	HRS	$87.77	$3,511
		Substation Operations	Journeyman, Meter Tech, PP	Internal	2021	80	HRS	$137.19	$10,975
		Metering Equipment	Pole & Mounting	Material	2021	1	EA	$4,500.00	$4,500
			Meter and Test Switch	Material	2021	1	EA	$1,500.00	$1,500
			Instrument Transformers, 12.5 KV	Material	2021	3	EA	$1,500.00	$4,500
			Communications Cell Pack	Material	2021	1	EA	$500.00	$500
			Miscellaneous	Material	2021	1	EA	$100.00	$100
	Metering (POI)	Engineering Design	Metering Engineering, Engineer	Internal	2021	80	HRS	$87.77	$7,022
		Substation Operations	Journeyman, Meter Tech, PP	Internal	2021	80	HRS	$137.19	$10,975
		Metering Equipment	Pole & Mounting	Material	2021	1	EA	$4,500.00	$4,500
			High End Meter and Test Switch (Primary and Backup)	Material	2021	2	EA	$4,500.00	$9,000
			Instrument Transformers, 12.5 KV	Material	2021	3	EA	$1,500.00	$4,500
			Communications Cell Pack	Material	2021	1	EA	$500.00	$500
			Miscellaneous	Material	2021	1	EA	$100.00	$100
Pilot Rock Substation	Engineering	Engineering Design	P&C Engineering, Engineer	Internal	2021	24	HRS	$88.95	$2,135
	Operations	Substation Operations	Journeyman, Substation, PP	Internal	2021	16	HRS	$150.30	$2,405
			Journeyman, Relay Tech, PP	Internal	2021	40	HRS	$150.30	$6,012
	Telecommunications	Telecommunications Engineering	Communications Engineer	Internal	2021	8	HRS	$102.54	$820
			Communications Drafter	Internal	2021	4	HRS	$62.30	$249
		Substation Operations	Journeyman, Electronic Tech, PP	Internal	2021	16	HRS	$150.30	$2,405
		Communications Misc	Single Mode Jumper, 6 meters with SC connectors	Material	2021	2	EA	$80.00	$160
Distribution Regulators	Distribution	Field Operations (Wires)	Journeyman, Lineman, PP	Internal	2021	1	LS	$66,667.00	$66,667
		Distribution Work	Distribution Material	Material	2021	1	LS	$100,000.00	$100,000
Grand Total									**$266,007**

PACIFICORP

CURRENT & PREVIOUS ESTIMATE VARIANCE

Q-1045 PILOT ROCK SOLAR

Estimate Date:	09/01/20	12/30/20		
Estimate Type:	±30%	±30%		
DESCRIPTION	**PREVIOUS GROSS CAPITAL COST**	**CURRENT GROSS CAPITAL COST**	**VARIANCE**	**NOTES (NOTES APPLY AT DIVISION LEVEL)**
Collector Substation Metering	$101,804	$91,966	-$9,838	*Updated metering costs*
Pilot Rock Substation	$15,321	$15,321	$0	
Distribution Regulators	$183,196	$180,000	-$3,195	*Updated material and labor costs for regulator*
Grand Total	$300,321	$287,287	-$13,034	

Docket No. UM 2118
Exhibit PAC/203
Witnesses: Milt Patzkowski,
Alex Vaz, Richard Taylor

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Response Testimony of Milt Patzkowski, Alex Vaz, Richard Taylor
Sunthurst Response to Data Requests 1.10, 1.12, 2.22, and 2.29

January 2021

1.10. Refer to Paragraph 12 of the Complaint. Please identify all instances where PacifiCorp has not required three meters to measure output from two adjacent projects that utilize the same point of interconnection.

Response: Sunthurst is familiar with one instance: the Q0747 interconnection described in its Complaint.

1.12. Refer to Paragraph 17 of the Complaint. Please identify all instances where PacifiCorp or any other utility has used similar metering configuration as the one described as Alternative 2 in Paragraph 17 of the Complaint and Attachment C. Provide all supporting documentation.

Response: Sunthurst is awaiting confirmation of its assertion in Paragraph 17 and will supplement its response when it receives confirmation.

2.22. Refer to Sunthurst/200, Beanland/17, line 19 and page 18, lines 3-8. Please explain the difference between using a “3rd entire metering system” and the approach described on page 18, lines 3-8, including any difference in cost associated with each approach.

A. Mr. Beanland’s response: A “3rd entire metering system” (what PacifiCorp is requiring) would consist of and be a repetition of the medium-voltage metering systems used on the individual projects. A system would be expected to consist of a wood power pole, cross arms with braces, insulators, a cluster mount for the potential and current transformers, the three current and three potential transformers, conduit and wiring to bring the transformer secondary currents and voltages to the meter located in a metal enclosure mounted at the base of the pole, the electronic meter installed in the enclosure, and the cellular data modem used to communicate with the utility metering system.

With digital totalizing (described in Sunthurst/200, Beanland/17, lines 22-24, and page 18, lines 1-2) none of this equipment would be required to be installed because the data is processed in the electric utility metering system.

With current summation (described Sunthurst/200, Beanland/18, lines 3-8), the pole, crossarm, cluster mount, and transformers are no longer needed. The equipment involves a meter and enclosure and conduit and wiring needed to connect to the other two project meters.

Either approach will result in a reduction in the required equipment and will result in lower costs. With typical pole-mounted metering systems estimated to cost about $25,000 complete, the savings would be comparable, plus the resulting savings in engineering, indirects, overheads, and 8% capital surcharge.

2.29. Refer to Sunthurst/200, Beanland/27, lines 21-23. Please provide all evidence relied on by Mr. Beanland for his estimated junction box cost, including any cost studies performed by Mr. Beanland or examples he is aware of where a comparable junction box cost “under $100.”

A. Mr. Beanland’s response: Retail prices for enclosures were investigated on the Internet. Prices ranged from $81 to $181 depending on the features selected. Four examples are provided. SUN-0143-SUN-0151.

Docket No. UM 2118
Exhibit PAC/204
Witnesses: Milt Patzkowski,
Alex Vaz, Richard Taylor

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Response Testimony of Milt Patzkowski, Alex Vaz, Richard Taylor
PacifiCorp Response to Data Request 3.7

January 2021

UM 2118 / PacifiCorp
November 18, 2020
Sunthurst Data Request 3.7

Sunthurst Data Request 3.7

Explain how PacifiCorp included the Capital Surcharge in the Base Capital costs of its proxy Resource(s) in the 2017 IRP. Provide documentation showing Capital Surcharge costs in PacifiCorp's calculation of its Avoided Cost Rate.

Response to Sunthurst Data Request 3.7

PacifiCorp assumes that "Avoided Cost Rate" refers to prices available to qualifying facilities (QF) selling their output in Oregon, in accordance with associated Public Utility Commission of Oregon (Commission) rules and orders. A schedule with standard avoided cost rates for Oregon QFs is approved by the Commission.

The avoided cost rates approved by the Commission in July 2018 used proxy resource costs and characteristics from PacifiCorp's 2017 Integrated Resource Plan (IRP). Please refer to Attachment Sunthurst 3.7-1 which provides a copy of the calculation, specifically tabs "Table 9" and "Table 12."

The capital costs of proxy resources identified in the 2017 IRP, specifically Table 6.2, are the sum of direct capital costs, capital surcharge, and allowance for funds used during construction. For the purpose of calculating avoided cost rates, these capital costs are converted to a real-levelized payment stream over the life of the resource using a "Payment Factor." The "Payment Factor" translates PacifiCorp's cost of capital, resource's life, and tax life into a percentage of the capital cost that is incurred in the first year of operation. This value then escalates at inflation through the resource's life. The resulting payment stream has a net present value that is equal to PacifiCorp's expected costs, including the cost of capital. PacifiCorp's 2017 IRP, page 50, identified the assumed cost of capital as 6.57 percent. The "Payment Factor" for proxy resources in the 2017 IRP are identified in Table 6.2. For additional details on the inclusion of the capital surcharge in the capital costs identified in the 2017 IRP, please refer to Confidential Attachment Sunthurst 3.7-2.

PacifiCorp's 2017 IRP is publicly available and can be accessed at the following website link:

https://www.pacificorp.com/energy/integrated-resource-plan.html

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

Respondent(s): Dan Swan / Dan MacNeil / Ian Hoag

Attachment G

UM 2118 PacifiCorp's Opening Brief

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JENNIFER MILLER
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March 26, 2021

VIA ELECTRONIC FILING

Attention: Filing Center
Public Utility Commission of Oregon
P.O. Box 1088
Salem, Oregon 97308-108

Re: UM 2118 –SUNTHURST ENERGY, LLC vs. PACIFICORP dba PACIFIC POWER

Attention Filing Center:

Attached for filing in the above-captioned docket is PacifiCorp's Opening Brief.

Please contact this office with any questions.

Thank you,

Jennifer Miller
Legal Assistant

Attachment

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 2118

In the Matter of: SUNTHURST ENERGY, LLC, Complainant vs. PACIFICORP dba PACIFIC POWER, Respondent.	**PACIFICORP'S OPENING BRIEF**

Table of Contents

I. INTRODUCTION AND SUMMARY OF ARGUMENT

The Public Utility Commission of Oregon's ("Commission") implementation of the Public Utility Regulatory Policies Act of 1978 ("PURPA") rests on one bedrock principle—transactions with qualifying facilities ("QFs") must not harm utility customers. The Commission has made clear its intent to faithfully adhere to this standard to maintain "customer indifference" to QFs transactions and protect Oregonians from harm.[1] To maintain customer indifference, both the Commission's interconnection rules and PURPA require interconnecting QFs to pay the costs incurred by a utility to interconnect the project, thereby leaving retail customers indifferent to the QF interconnection.[2] Sunthurst Energy, LLC ("Sunthurst") seeks to violate the customer-indifference standard, and thereby harm PacifiCorp's (or the Company) customers by: (1) shifting interconnection costs of two projects to PacifiCorp customers; and (2) insisting that PacifiCorp design, maintain, and operate its system in a manner that would degrade the quality of service that PacifiCorp customers currently enjoy.

Sunthurst has proposed two QFs to interconnect to PacifiCorp's distribution system and participate in Oregon's Community Solar Program ("CSP"). Through the interconnection study process—and extensive negotiations and refinements—PacifiCorp has provided comprehensive estimates of the costs required to safely and reliably interconnect both projects. PacifiCorp's interconnection requirements ensure that the interconnection of Sunthurst's projects do not degrade service to existing customers—which is critical to maintaining customer indifference. PacifiCorp has worked in good faith with Sunthurst to explain its interconnection requirements

[1] *In re Pub. Util. Comm'n of Or., Investigation into Qualifying Facility Contracting and Pricing*, Docket No. UM 1610, Order No. 14-058, at 12 (Feb. 24, 2014).
[2] Order No. 14-058, at 12; *S. Cal. Edison Co., San Diego Gas & Elec. Co.*, 71 FERC ¶ 61,269, at ¶ 62,080 (1995).

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and reduce costs where possible. The resulting costs for interconnecting the projects are reasonable, consistent with good utility practice, and consistent with the interconnection requirements for similarly situated interconnection requests, including PacifiCorp's own resources.

As noted earlier, Sunthurst asks the Commission to either require retail customers to foot the bill for its interconnection facilities or implement recommendations that would degrade the quality of service that PacifiCorp customers currently enjoy. In particular, Sunthurst demands that:

- Customers pay for voltage regulators that are required so those customers can maintain their current level of service. PacifiCorp currently implements Conservation Voltage Reduction ("CVR") to efficiently regulate voltage on the feeder that will interconnect Sunthurst's projects. Using CVR means that all else being equal, customers consume less energy and therefore pay less for service. After Sunthurst interconnects its second project (the 2.99-MW Pilot Rock Solar 2, LLC project), PacifiCorp cannot implement CVR without installing additional voltage regulators. Requiring customers to pay more for the same service is a clear-cut and indefensible violation of PURPA's strict customer indifference requirement. Therefore, Sunthurst must pay for the voltage regulators.

- Customers pay the construction overhead costs to interconnect Sunthurst's projects. Consistent with standard accounting practices, PacifiCorp allocates overhead costs using a capital surcharge, which is applied consistently to all capital projects, including PacifiCorp's own projects. Sunthurst provides no evidence that PacifiCorp does not incur these costs, provides no evidence that PacifiCorp's surcharge methodology is flawed, and provides no evidence that PacifiCorp's surcharge is contrary to standard accounting practices. Customers are not indifferent if they are required to pay the overhead costs incurred to interconnect Sunthurst's projects.

- PacifiCorp install less reliable spread spectrum radio communications because they are "good enough," although such facilities are subject to radio interference and, therefore, could cost Sunthurst more.

- Customers pay for fiber optic cables and a distribution line extension that serve no purpose except to allow Sunthurst's projects to interconnect. Customers are not indifferent if they must pay for equipment that would not be installed but for Sunthurst's interconnection requests.

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- PacifiCorp allow longer outages from temporary faults instead of installing a dead-line check system. If customers experience more prolonged outages because of Sunthurst's interconnection, then those customers are not indifferent. Therefore, Sunthurst must pay for dead-line checking.

- Customers pay for Direct Transfer Trip ("DTT") equipment, which is necessary to protect PacifiCorp's system in the event of a fault. Customers are not indifferent if they must pay to mitigate a risk created by Sunthurst's interconnection requests.

- Customers pay for limited telemetry equipment that will be installed on Sunthurst's facilities to enable safe and reliable system operations. PacifiCorp has already assumed the cost of the vast majority of the telemetry equipment as an accommodation to Sunthurst. Sunthurst can bear the reasonable costs of telemetry equipment on its own facilities.

- PacifiCorp depart from standard utility practice and meter its projects on the low side of the step-up transformer even though doing so requires PacifiCorp to estimate losses.

Implementing Sunthurst's recommendations would be contrary to Commission policy as customers would be required to pay costs that would not have been incurred but for Sunthurst's interconnection requests, while also resulting in a less efficient, less reliable system.

Ultimately, Sunthurst must bear the reasonable costs to interconnect its projects. Reasonable interconnection costs do not mean the absolute lowest costs, especially when the latter is contrary to good utility practice, Commission and Company policies, and could result in a degradation of service to PacifiCorp customers. PacifiCorp's retail customers cannot subsidize Sunthurst's development efforts, and Sunthurst must plan its projects in a way that makes them economically feasible to construct.

Finally, under ORS 756.500, "the moving party, the complainant, has the burden of persuasion." Thus, Sunthurst has the burden of proof in this complaint proceeding to demonstrate that PacifiCorp customers must: (1) pay costs related to Sunthurst's interconnection requests, and (2) accept a compromised system that would degrade the quality of service that PacifiCorp customers currently enjoy. Sunthurst has failed to meet its burden of proof.

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II. FACTUAL BACKGROUND

Sunthurst's complaint involves two photovoltaic QF generation resources—the 1.98-megawatt ("MW") Pilot Rock Solar 1, LLC and the 2.99-MW Pilot Rock 2, LLC ("PRS1" and "PRS2", respectively). Each project is owned by a separate legal entity that Sunthurst wholly owns.[3] Both projects have requested interconnection to PacifiCorp's city feeder circuit 5W406, out of its Pilot Rock Substation.[4] PRS1 has been designated interconnection Queue No. 0666 ("Q0666").[5] PRS2 is a 2.99-MW CSP facility, designated as interconnection Queue No. 1045 ("Q1045").[6]

A. PacifiCorp's interconnection study process.

PacifiCorp's interconnection study process applicable to PRS1 and PRS2 is governed by the Commission's small generator interconnection rules, which are contained in OAR Chapter 860, Division 82.

The purpose of an interconnection study is to identify the requirements, including the necessary equipment and modifications to the utility's system, that are necessary to allow a generator to interconnect to the utility's system safely and reliably and without degrading service to existing customers.[7] In other words, the interconnection study determines what interconnection facilities are needed, if any, to accommodate interconnection requests *without adversely impacting*

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[3] PAC/100, Bremer/4.
[4] PAC/103, Bremer/3.
[5] PAC/101, Bremer/1.
[6] PAC/103, Bremer/3.
[7] *See* PAC/200, Patzkowski, Taylor, Vaz/26 ("PacifiCorp is mandated to ensure that its existing customers continue to receive the same level of service that existed prior to the interconnection of distributed energy resources such as PRS1 and PRS2.").

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the existing system.[8] The purpose is to fundamentally place the utility system in the same position it was in before the interconnection in terms of safety, reliability, and quality of service.

Additionally, the interconnection study process identifies the *estimated* costs to implement the interconnection requirements.[9] As the interconnection customer progresses through the interconnection study process, the estimate of costs becomes more refined. Once the parties execute an interconnection agreement, detailed design work and bidding for individual facilities occur to finalize the costs further. Utilities ultimately invoice the actual expenses of interconnection to the interconnection customer.[10]

B. Execution of the Small Generator Interconnection Agreement for PRS1.

On May 7, 2015, Sunthurst submitted its interconnection application for PRS1 to PacifiCorp.[11] By March 14, 2016, Sunthurst and PacifiCorp had entered into a Small Generator Interconnection Agreement ("SGIA") for PRS1.[12] The SGIA included interconnection requirements, an interconnection schedule, and milestone payments intended to allow PRS1 to interconnect by May 15, 2017.[13] The SGIA estimated interconnection costs for the facility at $805,000.[14] These costs reflected the Company's best estimate of interconnection requirements and cost at the time.[15]

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[8] *See* OAR 860-082-0035(2) ("[A] public utility must identify the interconnection facilities necessary to safely interconnect the small generator facility with the public utility's transmission or distribution system. The [interconnection customer] must pay the reasonable costs of the interconnection facilities. The public utility constructs, owns, operates, and maintains the interconnection facilities.").
[9] PAC/200, Patzkowski, Taylor, Vaz/3.
[10] PAC/200, Patzkowski, Taylor, Vaz/4-5.
[11] PAC/101, Bremer/1.
[12] PAC/101, Bremer/1.
[13] PAC/100, Bremer/4.
[14] PAC/100, Bremer/4.
[15] PAC/100, Bremer/4.

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Since signing the SGIA in 2016, Sunthurst has continued to request extensions of the interconnection schedule and milestone payments required by the SGIA. PacifiCorp agreed to extend the milestones for interconnection four times at the request of Sunthurst by amending the SGIA on June 20, 2016; October 11, 2016; November 27, 2017; and November 6, 2018.[16] Even when Sunthurst has been unable to meet its obligations and deadlines under the SGIA, including the provision of agreed upon progress payments to pay for work performed by PacifiCorp, PacifiCorp worked in good faith with Sunthurst to amend the agreement without seeking termination.[17] Regardless, the uncertainty surrounding PRS1 and its interconnection delays have increased costs for PacifiCorp and taken away resources from other interconnection customers.[18]

C. Interconnection process and studies for PRS2.

Concurrently with the ongoing negotiations and amendments to the PRS1 SGIA, Sunthurst submitted an interconnection request for PRS2, which was initially a 6-MW photovoltaic facility that would interconnect to the same feeder as PRS1.[19] PacifiCorp designated this original proposal for PRS2 as interconnection Queue No. 0747 ("Q0747").[20] As part of the configuration of Q0666 and Q0747, Sunthurst's design included separate tie line interconnection facilities, with separate reclosers for PRS1 and PRS2.[21] This configuration for Q0666/Q0747 allowed PacifiCorp to propose a two-meter configuration for interconnection because power from the two projects would not comingle before the power interconnected into PacifiCorp's system.[22]

[16] PAC/100, Bremer/5.
[17] PAC/100, Bremer/5–6.
[18] PAC/100, Bremer/5–6.
[19] Sunthurst/206, Beanland/3.
[20] Sunthurst/206, Beanland/3.
[21] *See* Sunthurst/206, Beanland/4 (system one line diagram for the proposed Q0666/Q0747 project).
[22] Sunthurst/206, Beanland/9–10.

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Given its 6 MW size, Q0747 created surplus generation on the local Pendleton area system that required extensive network upgrades to resolve.[23] Therefore, Sunthurst withdrew Q0747.

Sunthurst then decided to resize PRS2 to avoid the network upgrade costs associated with the 6-MW facility and submitted a new interconnection request for 2.99 MW, which was designated Q1045.[24] In addition, Sunthurst clearly attempted to use a perceived loophole by sizing the project exactly one kilowatt below the 3 MW threshold for which the Commission's rules allow PacifiCorp to assess telemetry upgrades to an interconnection request even while siting PRS2 at the same Point of Interconnection ("POI") as its earlier Q0666 request, which in aggregate clearly exceeds 3 MW.[25] In addition to reducing the size of PRS2, Sunthurst also modified the configuration of PRS1 and PRS2 compared to the Q0666/Q0747 design. Specifically, under the current project design, PRS1 and PRS2 have a common interconnection tie line such that the output of both facilities is combined before reaching the common POI.[26] PacifiCorp completed its initial SIS for PRS2 on March 27, 2020.[27]

[23] Sunthurst/206, Beanland/6. Sunthurst has claimed that Q0747 would not have created surplus generation in the Pendleton area but for the proposed 8-MW second phase of another project designated as interconnection Queue No. 0547 (Q0547). Sunthurst/100, Hale/6. However, PacifiCorp's serial queue study process does not allow the Company to jump the serial queue order when conducting system impact studies. PAC/100, Bremer/12–13. Q0547 executed an interconnection agreement on December 19, 2014, almost two years before PacifiCorp completed its interconnection study for Q0747. PAC/100, Bremer/13. Consistent with its approach on Sunthurst's projects, PacifiCorp has negotiated in good faith with Q0547 to allow several extensions to its 8-MW second phase, which is now planned for commercial operation on August 6, 2021. PAC/100, Bremer/13. PacifiCorp cannot simply disregard the impact of Q0547 when studying the impact of lesser queue priority projects such as Q0747 according to the terms of the Company's legally binding interconnection agreement with Q0547. PAC/100, Bremer/12–13.
[24] PAC/100, Bremer/11–12.
[25] PAC/100, Bremer/10–12.
[26] *See* PAC/103, Bremer/4 (system one line diagram for the proposed Q0666/Q1045 project).
[27] PAC/100, Bremer/6.

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D. PacifiCorp's extensive efforts to refine its cost estimates and lower the costs to interconnect PRS1 and PRS2.

Following receipt of the PRS2 SIS, PacifiCorp and Sunthurst engaged in six months of negotiations addressing the interconnection requirements for both PRS1 and PRS2. During this process, PacifiCorp worked in good faith with Sunthurst to refine its cost estimates and accommodate, where possible, Sunthurst's need for reduced interconnection requirements and costs. PacifiCorp's efforts reduced the interconnection costs for PRS1 and PRS2 by over $1 million. Over half of the reduced expenses ($525,000) resulted from PacifiCorp's agreement to bear the expense of telemetry equipment despite the apparent attempt by Sunthurst to avoid these costs by sizing PRS2 exactly 1 kilowatt below the threshold.[28] The Company initially assigned telemetry costs to Sunthurst because the combined size of PRS1 and PRS2 require telemetry equipment at the common POI.[29] Other major reductions in costs of approximately $250,000 reflected: (1) design modifications PacifiCorp was willing to undertake that would not negatively impact the quality of service to other customers; or (2) offers by PacifiCorp to pay for costs in an effort to resolve Sunthurst's concerns.[30]

III. LEGAL STANDARDS

A. The Commission's rules require interconnection customers to pay for the reasonable costs to interconnect their projects.

The Commission's small generator interconnection rules, specifically, OAR 860-082-0035, sets forth the interconnection customer's cost responsibility for interconnecting its project

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[28] PAC/100, Bremer/10.

[29] PAC/100, Bremer/10–11. See section IV.A.7 for a more detailed discussion of telemetry costs for PRS1 and PRS2.

[30] *See* PAC/100, Bremer/8 (removal of $200,000 due to an adjustment to require a weatherproof enclosure on site, as opposed to a control building); *see also* PAC/100, Bremer/10; PAC/200, Patzkowski, Taylor, Vaz/30. PacifiCorp also offered to remove the costs related to the PI-111 annunciator panel at a total of approximately $54,000.

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to a utility's system.[31] Subsection (2) of that rule addresses *interconnection facilities*, which are defined as the "facilities and equipment required by a public utility to accommodate the interconnection of a small generator facility to the public utility's transmission or distribution system and used exclusively for that interconnection."[32] OAR 860-082-0035(2) states that, "a public utility must identify the interconnection facilities necessary to safely interconnect the small generator facility with the public utility's transmission or distribution system."[33] The interconnection customer "must pay the reasonable costs of the interconnection facilities," even though the "public utility constructs, owns, operates, and maintains the interconnection facilities."[34]

Subsection (3) addresses *interconnection equipment*, which "means a group of components or an integrated system provided by an interconnection customer or applicant to connect a small generator facility to a public utility's transmission or distribution system."[35] OAR 860-082-0035(3) states that the interconnection customer "must pay all expenses associated with constructing, owning, operating, maintaining, repairing, and replacing its interconnection equipment."[36]

Subsection (4) addresses *system upgrades*, which are "addition[s] or modification[s] to a public utility's transmission or distribution system or to an affected system that is required to accommodate the interconnection of a small generator facility."[37] OAR 860-082-0035(4) states that a "public utility must design, procure, construct, install, and own any system upgrades to the

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[31] OAR 860-082-0035.
[32] OAR 860-082-0015(16).
[33] OAR 860-035-0035(2).
[34] OAR 860-035-0035(2).
[35] OAR 860-082-0015(15).
[36] OAR 860-035-0035(3).
[37] OAR 860-082-0015(34).

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public utility's transmission or distribution system necessitated by the interconnection of a small generator facility."[38] As part of the study process, a "public utility must identify any adverse system impacts on an affected system caused by the interconnection of a small generator facility to the public utility's transmission or distribution system" and "must determine what actions or upgrades are required to mitigate these impacts."[39] The interconnection customer "must pay the reasonable costs of any system upgrades."[40]

Collectively, these provisions set forth a comprehensive cost allocation policy that requires the interconnection customer to pay for interconnection facilities installed on the utility's system, interconnection equipment installed on the interconnection customer's system, and system upgrades.

B. PURPA mandates customer indifference to QF interconnections.

The Commission's Division 82 interconnection rules do not apply exclusively to QF interconnections. But the cost allocation policies promulgated in those rules are consistent with the requirements of PURPA. PURPA not only requires utilities to purchase power generated by QFs, but also mandates that the rates utilities pay for such power must be "just and reasonable" to the consumers of the electric utility and "in the public interest."[41] Federal law requires that customers remain indifferent to QF generation.[42] This customer-indifference standard is firmly

[38] OAR 860-082-0035(4).
[39] OAR 860-082-0035(4).
[40] OAR 860-082-0035(4).
[41] 18 C.F.R. § 292.304(a)(1).
[42] *See* 16 U.S.C. § 824a-3(d) (stipulating that the rate for QF purchases may not exceed "the cost to the electric utility of the electric energy which, ***but for*** the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source" (emphasis added)); s*ee also S. Cal. Edison Co., San Diego Gas & Elec. Co.*, 71 FERC ¶ 61,269, at ¶ 62,080 (1995) ("The intention [of Congress] was to make ratepayers indifferent as to whether the utility used more traditional sources of power or the newly-encouraged alternatives.").

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established in Oregon, and the Commission has repeatedly emphasized that its implementation of PURPA must not cause customer harm.[43] The Commission has emphasized that it "has broad authority to prevent customer harm."[44]

Under the Federal Energy Regulatory Commission's ("FERC") PURPA regulations, QFs must pay interconnection costs,[45] which is consistent with the Commission's interconnection rules promulgated in Division 82.[46] FERC's regulations define "interconnection costs" broadly:

> [T]he reasonable costs of connection, switching, metering, transmission, distribution, safety provisions and administrative costs incurred by the electric utility directly related to the installation and maintenance of the physical facilities ***necessary to permit interconnected operations with a qualifying facility***, to the extent such costs are in excess of the corresponding costs which the electric utility would have incurred if it had not engaged in interconnected operations, but instead generated an equivalent amount of electric energy itself or purchased an equivalent amount of electric energy or capacity from other sources. Interconnection costs do not include any costs included in the calculation of avoided costs.[47]

This definition includes a wide range of costs—of varying types—that would not be incurred but for the QF interconnection.

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[43] *See, e.g.*, Order No. 14-058, at 12 ("We first return to the goal of this docket: to ensure that our PURPA policies continue to promote QF development while ensuring that utilities pay no more than avoided costs."); *In re Investigation into Elec. Util. Tariffs for Cogeneration and Small Power Prod. Facilities*, Docket No. R-58, Order No. 81-319, at 3 (May 6, 1981) (stating goal of PURPA is "to provide maximum economic incentives for development of qualifying facilities while insuring that the costs of such development do not adversely impact utility ratepayers who ultimately pay these costs").

[44] *In re PacifiCorp, dba Pac. Power, Updates Standard Avoided Cost Purchases from Eligible Qualifying Facilities*, Docket No. UM 1729, Order No. 18-289, at 4 (Aug. 9, 2018).

[45] 18 C.F.R. § 292.306(a) ("Each qualifying facility shall be obligated to pay any interconnections costs which the State regulatory authority . . . may assess against the qualifying facility on a nondiscriminatory basis with respect to other customers with similar load characteristics."); s*ee also Pioneer Wind Park I, LLC*, 145 FERC ¶ 61,215, at ¶ 62,168 n.73 (2013) (stating that PURPA requires a utility to make transmission arrangements for the QF power, but that "[t]his is not to suggest that the QF is exempt from paying interconnection costs, which may include transmission or distribution costs directly related to installation and maintenance of the physical facilities necessary to permit interconnected operations." (internal citations omitted)).

[46] *See generally* OAR 860-082-0035.

[47] 18 C.F.R. § 292.101(b)(7) (emphasis added).

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Oregon's PURPA rules echo FERC's regulations, providing that:

> Interconnection costs are the responsibility of the owner or operator of the qualifying facility. Interconnection costs that may reasonably be incurred by the public utility will be assessed against a qualifying facility on a nondiscriminatory basis with respect to other customers with similar load or other cost-related characteristics.[48]

The Commission's PURPA rules reinforce the cost allocation framework outlined in Division 82.

C. Sunthurst carries the burden of proof.

Sunthurst filed its complaint under ORS 756.500.[49] Under ORS 756.500, "the moving party, the complainant, has the burden of persuasion."[50] Sunthurst also bears the burden of proof to establish that they are entitled to relief.[51]

IV. ARGUMENT

A. PacifiCorp's most recent cost estimates accurately reflect the reasonable interconnection costs of PRS1 and PRS2.

PacifiCorp's estimated costs to interconnect PRS1 and PRS2 are reasonable, nondiscriminatory, and consistent with good utility practice. Throughout this case, and consistent with the general process of refining cost estimates as the interconnection process proceeds, PacifiCorp has submitted updated detailed cost estimates for both projects.[52] PacifiCorp's most up-to-date analysis estimates the interconnection costs are $571,306 for PRS1 and $287,287 for

[48] OAR 860-029-0060(1).
[49] Complaint ¶ 1; ORS 756.500(1) ("Any person may file a complaint before the Public Utility Commission, or the commission may, on the commission's own initiative, file such complaint. The complaint shall be against any person whose business or activities are regulated by some one or more of the statutes, jurisdiction for the enforcement or regulation of which is conferred upon the commission.").
[50] *In re Application of Portland Gen. Elec. Co. for an Accounting Order and Order Approving Tariff Sheets Implementing a Rate Reduction*, Docket No. UM 989, Order No. 01-152, at 2 (Feb. 2, 2001).
[51] *See, e.g.*, *Richter v. Nw. Nat. Gas Co.*, Docket No. UC 526, Order No. 00-649, at 2 (noting that the "[c]omplainant bears the burden of proof" in actions under ORS 756.500); *M.J. v. PacifiCorp*, Docket No. UCR 125, Order No. 10-293, at 2 (denying complaint for failure to meet the requisite burden of proof).
[52] PAC/201, Patzkowski, Taylor, Vaz/1–5 (PRS1 detailed cost estimate report); PAC/202, Patzkowski, Taylor, Vaz/1–2 (PRS2 detailed cost estimate report).

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PRS2.[53] These estimated costs represent the minimum requirements for PRS1 and PRS2 to safely interconnect and reliably operate on PacifiCorp's system. Specifically, PacifiCorp has ensured that any expenses associated with telemetry on its system and the PI-111 Annunciator panel have been removed from the latest detailed cost estimates.[54] The Company's latest estimates have also refined the estimated costs for avian protection, fiber optic cable installation, and junction boxes.[55]

Any further cost reductions proposed by Sunthurst would unreasonably shift interconnection costs onto retail customers and potentially degrade service to existing customers. Even Sunthurst's previous consulting engineer stated that some of Sunthurst's alternatives "highlight how this interconnection could be done with minimal cost, but not necessarily how it should be done."[56]

Similarly, Sunthurst's current consulting engineer, Mr. Michael Beanland, urges PacifiCorp to set aside best practices in lieu of design modifications that are simply "good enough."[57] However, the Commission and FERC hold PacifiCorp accountable for the reliable design, operation, and maintenance of its system, as well as the quality of service for its customers. Consequently, PacifiCorp cannot cut corners merely to reduce Sunthurst's costs. Sunthurst's goal is to have its costs for interconnection reflect the absolute lowest possible cost (notwithstanding the potential detrimental impact on customer service), which is not the same as the "reasonable" costs of interconnection required under OAR 860-035-0035(3). Sunthurst's goal is inconsistent with the Commission's small generator interconnection rules requirement for Sunthurst to pay for the reasonable costs to interconnect its projects.[58]

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[53] PAC/201, Patzkowski, Taylor, Vaz/5; PAC/202, Patzkowski, Taylor, Vaz/2.
[54] PAC/200, Patzkowski, Taylor, Vaz/3–4.
[55] PAC/200, Patzkowski, Taylor, Vaz/4.
[56] PAC/104, Bremer/8.
[57] Sunthurst/400, Beanland/21.
[58] *See* OAR 860-082-0035(2).

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1. Voltage regulators are required to maintain energy-efficient operations.

PacifiCorp uses Line Drop Compensation ("LDC") to provide effective, efficient voltage regulation on its feeder networks.[59] LDC allows PacifiCorp to regulate voltage remotely and allows for lower voltages during light load and higher voltages during higher load. This process is referred to as CVR.[60] The ability to lower system voltage while still maintaining American National Standards Institute ("ANSI") Range A lowers energy use and system losses, which impacts both customers (who pay less) and PacifiCorp (who generates less).[61] Thus, using LDC settings to regulate voltage is an energy efficient way for PacifiCorp to operate its system. The Commission has repeatedly emphasized the need for utilities to expand CVR capabilities on their systems as part of their resource planning process and deployment of smart grid technologies.[62]

The addition of the PRS2 generation to the feeder line increases the peak load beyond the level PacifiCorp can control with its current LDC settings.[63] Without voltage regulators, PacifiCorp would no longer be able to utilize LDC settings to deploy this basic CVR capability on the feeder. This means that voltage regulators are required to *maintain the same level of service*

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[59] PAC/200, Patzkowski, Taylor, Vaz/20.
[60] PAC/200, Patzkowski, Taylor, Vaz/20.
[61] *See Implementing CVR through voltage regulator LDC settings*, Jeffrey M. Triplett, P.E., Sean A. Kufel, P.E. (Inst. of Electrical and Electronic Engineers May 7, 2012) (abstract available here: https://ieeexplore.ieee.org/abstract/document/6194566/footnotes#footnotes) ("Line Drop Compensation (LDC) is a standard feature that is available on virtually all voltage regulator controls that can be used to implement CVR. Rather than simply lowering the voltage output of the regulator, LDC uses a load-side CT and voltage-compensation settings representing the resistance and reactance of the feeder to monitor load current and maintain a desired voltage level at some point down the lines. The current-monitoring capability of the LDC system allows it to keep the feeder voltage as low as possible during both peak and light loading periods in a dynamic response to real-time system needs.").
[62] *See, e.g.*, *In re Portland Gen. Elec. Co., 2016 Integrated Resource Plan*, Docket No. LC 66, Order No. 17-386, at 9–10 (Oct. 9, 2017) (approving PGE's proposal to deploy 1 MWa of conservation voltage reduction in its IRP); *In re Idaho Power Co. 2014, Annual Smart Grid Report*, Docket No. UM 1675, Order No. 15-053, App'x A at 6–7 (Feb. 23, 2015) (discussing and approving of Idaho Power's implementation of CVR technology through its deployment of smart grid technologies).
[63] PAC/200, Patzkowski, Taylor, Vaz/20.

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that currently exists.[64] The customer indifference requirement mandated by PURPA and reinforced by the Commission's interconnection rules, therefore, requires Sunthurst to pay for voltage regulators. Indeed, if PacifiCorp can no longer use its LDC settings after PRS2 interconnects, customers served by the feeder will pay more (all else being equal) because of higher voltages. Eliminating the Company's CVR capability as a result of interconnecting Sunthurst's projects will therefore not only harm customers, but would be a step backward by disabling energy efficient voltage regulation, which is contrary to Commission guidance.

Sunthurst questioned PacifiCorp's inclusion of voltage regulators as part of the reasonable interconnection costs for PRS1 and PRS2.[65] Sunthurst argues that PacifiCorp has included these costs to redress an existing problem in the Pilot Rock substation.[66] This claim is untrue, and Sunthurst has failed to provide a reasonable basis to support its conjecture.

But for the increased generation from PRS2, PacifiCorp would not need to install voltage regulators.[67] Without PRS2, PacifiCorp can efficiently control the voltage using LDC settings. With PRS2, PacifiCorp cannot. Thus, the installation of line voltage regulators is a necessary and reasonable cost of interconnection for PRS2 to ensure the interconnection of PRS2 does not adversely impact customers.

Sunthurst further claims that PacifiCorp has not provided a study to demonstrate that the voltage regulators are necessary.[68] Sunthurst's argument, however, misunderstands the need for the voltage regulators. PacifiCorp does not need a study to know that it currently uses LDC settings to *efficiently* regulate voltage on the feeder. However, PacifiCorp *has* determined that after PRS2

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[64] PAC/200, Patzkowski, Taylor, Vaz/20–21.
[65] Sunthurst/200, Beanland/26.
[66] Sunthurst/300, Hale/6–7.
[67] PAC/200, Patzkowski, Taylor, Vaz/20.
[68] *See*, *e,g.*, Sunthurst/400, Beanland/2.

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interconnects, PacifiCorp will be unable to use LDC settings to *efficiently* regulate voltage on the feeder. PacifiCorp does not need a study to know that without using the LDC settings, the system will be less efficient and its CVR capabilities will be impaired—both to the detriment of customers.

Sunthurst's testimony acts as if PacifiCorp were deciding whether to use LDC settings in the first instance. However, whether PacifiCorp should use LDC settings is not at issue in this case because PacifiCorp is already using LDC settings. Customers are currently receiving a particular quality of service because PacifiCorp uses LDC settings to control voltage, and customers will lose those benefits if PRS2 interconnects without the voltage regulators. These facts demonstrate in clear and simple terms why customer indifference requires Sunthurst to pay for voltage regulators.

Sunthurst suggests that the interconnection of PRS1 and PRS2 will only result in a voltage rise of 0.5 percent when operating at peak production.[69] Sunthurst also argues that PacifiCorp can maintain appropriate voltages without additional voltage regulators.[70] These arguments, again, miss the mark because the installation of voltage regulators is needed to maintain the Company's *existing* ability to *efficiently* maintain system voltage using CVR capabilities.[71] Mr. Beanland acknowledged not knowing whether the use of LDC settings is a more energy efficient manner of regulating voltage versus his recommended method of fixed voltage regulation.

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[69] Sunthurst/200, Beanland/26.
[70] Sunthurst/400, Beanland/3.
[71] PAC/200, Patzkowski, Taylor, Vaz/21–22.

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Put simply, PacifiCorp can currently use LDC settings to regulate voltage and implement CVR. After PRS2 interconnects, PacifiCorp cannot implement CVR *without additional voltage regulators*. Therefore, to maintain current system performance and leave customers indifferent to PRS2's interconnection, Sunthurst must pay for voltage regulators.

Sunthurst also argues that requiring voltage regulation is uncommon based on its review of other CSP interconnection studies.[72] Each interconnection request is studied based on its unique circumstances.[73] Just because some interconnections require voltage regulators to maintain system capabilities does not necessarily mean that others will too.[74] As PacifiCorp explained, the interconnecting generator's size relative to load on the feeder drove the need for voltage regulators in this case.[75] It is not surprising that different generators interconnecting to different feeders with different loads may produce different results.

Sunthurst also points out that for one CSP project, PacifiCorp agreed to fund the voltage regulators.[76] But that is because PacifiCorp planned to install the regulators before the interconnection customer's request. Thus, the interconnection request did not trigger the need for voltage regulators. That is not the case here where PacifiCorp had no plans to install additional voltage regulators because the relationship of feeder load to generation currently allows PacifiCorp to use LDC settings to implement CVR.[77] The voltage regulators here are required only because of Sunthurst's interconnection.

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[72] Sunthurst/400, Beanland/9.
[73] PSC/100, Bremer/16.
[74] *See* PAC/100, Bremer/16-17.
[75] PAC/200, Patzkowski, Taylor, Vaz/19–22.
[76] Sunthurst/400, Beanland/9.
[77] PAC/200, Patzkowski, Taylor, Vaz/20.

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2. Sunthurst must pay construction overhead costs incurred to interconnect its projects.

PacifiCorp incurs construction overhead costs to interconnect QFs like PRS1 and PRS2. To ensure that the QFs, not retail customers, pay the overhead costs to interconnect the QF, PacifiCorp includes a capital surcharge as a reasonable component of its interconnection cost estimates.[78] The capital surcharge reflects a reasonable portion of the administrative and general costs that cannot be charged directly to a capital project, in accordance with FERC and United States Generally Accepted Accounting Principles ("GAAP").[79] FERC authorized capital surcharges in its Uniform System of Accounts ("USOA") for electric companies.[80] The Commission has adopted FERC's USOA for electric companies.[81] Requiring interconnection customers to pay a reasonable portion of the overhead costs incurred to construct interconnection facilities is consistent with the Commission's rules.[82] PacifiCorp applies this capital surcharge to all projects—including its own projects—and it has long been a reasonable component of interconnection costs.[83]

PacifiCorp ensures that its capital surcharge represents the construction costs that the Company cannot charge directly to capital projects. The Company derives the rate by taking the construction support costs and dividing it by the direct capital spending for the year.[84] Each year,

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[78] PAC/200, Patzkowski, Taylor, Vaz/36.
[79] PAC/200, Patzkowski, Taylor, Vaz/36. Type of activities covered by overhead costs include capital project estimates, annual capital budget, engineering, scope and design, financial reviews, approval reviews, long lead material planning, resource scheduling, project priority and scheduling, forecasting, governance review, asset management, accounting, procurement, human resource supp.
[80] PAC/200, Patzkowski, Taylor, Vaz/37.
[81] PAC/200, Patzkowski, Taylor, Vaz/37–38; *see also* OAR 860-027-0045(1).
[82] *See* OAR 860-082-0035 (requiring interconnection customer to pay interconnection costs); OAR 860-029-0060 (requiring QFs to pay interconnection costs); *see also* OAR 860-029-0010(9) (defining interconnection costs to include administrative costs).
[83] *See* Sunthurst/401, Beanland/5 (showing capital surcharge included for Oregon interconnection requests).
[84] PAC/200, Patzkowski, Taylor, Vaz/37.

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PacifiCorp reviews each one of its cost centers to verify and update the construction support amount that should be part of the capital surcharge assessment. PacifiCorp then adjusts its annual capital surcharge based on planned capital projects for the year and capital investment programs.[85]

PacifiCorp applies the same capital surcharge to its own capital projects interconnecting Company-owned generation. PacifiCorp also uses the same capital surcharge framework for resource cost assumptions used in its Integrated Resource Plans ("IRP").[86] And because PacifiCorp's avoided cost prices are derived from the resource cost assumptions in its IRP, the capital surcharge is also included in PacifiCorp's avoided cost prices.[87]

Sunthurst complains about PacifiCorp's inclusion of an 8 percent capital surcharge to the interconnection costs for PRS1 and PRS2 because Sunthurst originally argued that PacifiCorp's avoided cost prices do not include the capital surcharge.[88] This is incorrect.[89]

Sunthurst then claimed that the resource costs included in PacifiCorp's 2017 IRP included a smaller capital surcharge as a percentage of overall costs than the 8 percent applied to interconnection customers.[90] However, this comparison is inapt because, as Sunthurst acknowledges, the capital surcharge for large capital projects (like proxy resources in an IRP) is calculated differently than the capital surcharge for projects costing less than $10 million.[91] Moreover, it is not surprising that large capital projects, like a new natural gas-fired generating

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[85] PAC/200, Patzkowski, Taylor, Vaz/37. Some examples of capital investment programs are new connects, replacing assets, equipment failures, storm and casualty, capital projects to address additional load requirements, regulatory mandated projects, and customer-initiated requests. The actual capital surcharge rate may vary during the year depending on the actual costs of capital spending, if different from the forecasted costs.
[86] PAC/200, Patzkowski, Taylor, Vaz/38–39.
[87] PAC/200, Patzkowski, Taylor, Vaz/38–39.
[88] Sunthurst/200, Hale/11.
[89] PAC/200, Patzkowski, Taylor, Vaz/38–39.
[90] Sunthurst/300, Hale/8–10.
[91] Sunthurst/300, Hale/10–11.

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plant, would have a lower capital surcharge percentage because much of the capital spending associated with projects of that scale is performed by outside contractors, who include their own overhead costs in the amounts charged to PacifiCorp.[92] In contrast, for smaller capital projects of less than $10 million, PacifiCorp personnel perform the overhead tasks (such as engineering and procurement), which necessitates a higher capital surcharge percentage.[93]

Sunthurst also claims that PacifiCorp is not assessing capital surcharges uniformly across its interconnection customers.[94] However, the evidence for this baseless assertion is a comparison of projects *above* $10 million to PRS1 and PRS2, which are *below* $10 million.[95] This comparison willfully ignores that PacifiCorp treats all capital projects of less than $10 million similarly. Simply put, PacifiCorp assessed the capital surcharge for PRS1 and PRS2 in the same manner as other similarly situated interconnection requests.

Sunthurst carries the burden of demonstrating that the capital surcharge does not accurately reflect a reasonable cost of interconnection.[96] Yet, Sunthurst has not: (1) disputed that PacifiCorp incurs construction overhead costs; (2) disputed PacifiCorp's methodology used to calculate the capital surcharge; (3) disputed the inputs PacifiCorp uses to calculate the capital surcharge; or (4) provided an alternative methodology for charging interconnection customers for construction overhead costs. Sunthurst has, therefore, failed to meet its burden of proof.

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[92] Sunthurst/500, Beanland/4.
[93] Sunthurst/500, Beanland/4.
[94] Sunthurst/300, Hale/10.
[95] Sunthurst/300, Hale/10–11.
[96] ORS 756.500(1).

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3. Sunthurst must bear the cost of fiber optic cables connecting PRS1 and PRS2 to the Pilot Rock Substation.

Fiber optic cables allow utilities to monitor and manage electrical networks to ensure reliable power for customers.[97] Unlike a fiber optic cable, a spread spectrum radio can experience interference from other spread-spectrum users in the area.[98] The enhanced reliability of fiber optic cable links has made them part of a utility's best practices for ensuring reliable and fast communication networks.[99] For this reason, PacifiCorp has a nondiscriminatory policy requiring interconnection requests—including many CSP interconnection requests—to use fiber optic links.[100]

Sunthurst has argued that PacifiCorp's requirement of a fiber optic cable for monitoring and managing the system between PRS1, PRS2, and the Pilot Rock substation is unnecessary when a radio link "likely would be cheaper"[101] and is "good enough."[102] While a radio link would accomplish many of the same tasks a fiber optic cable, it is unrefuted that radio links are less reliable. Moreover, using a radio link does not reflect current utility best practices.[103]

Further, the cost of a fiber optic link for PRS1 and PRS2 is comparable to the cost for a less reliable spread-spectrum radio link. In its most recent interconnection estimate for PRS1, PacifiCorp estimates that a fiber optic will cost approximately $38,000,[104] which is comparable to the $46,000 estimated cost for a radio link.[105] Sunthurst's prior consulting engineer agreed that using radio instead of fiber would produce a "slight" reduction in costs while acknowledging that

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[97] PAC/200, Patzkowski, Taylor, Vaz/22.
[98] PAC/200, Patzkowski, Taylor, Vaz/22.
[99] PAC/200, Patzkowski, Taylor, Vaz/22.
[100] PAC/200, Patzkowski, Taylor, Vaz/23.
[101] Sunthurst/200, Beanland/26.
[102] Sunthurst/400, Beanland/21.
[103] PAC/200, Patzkowski, Taylor, Vaz/22.
[104] PAC/201, Patzkowski, Taylor, Vaz/5; PAC/200, Patzkowski, Taylor, Vaz/24.
[105] PAC/200, Patzkowski, Taylor, Vaz/24.

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the radio link would be "not as reliable."[106] Considering the comparable costs of radio and fiber, the fiber optic link represents reasonable communication costs between PRS1, PRS2, and the Pilot Rock substation. Sunthurst insists on the absolute lowest cost, which—as noted earlier—is not required by OAR 860-035-0035(2) and would result in less system reliability.

Sunthurst also argues that installing a 48-fiber cable is excessive, and therefore PacifiCorp should share the cost of installation or install a 12-fiber cable instead.[107] However, the 48-fiber cable PacifiCorp proposed for PRS1 is the standard fiber optic cable the Company uses across its system.[108] Using standard equipment allows PacifiCorp to more efficiently design, procure, and construct upgrades to its system. Besides, even Sunthurst acknowledges the need for spare fibers in a fiber optic link.[109] Thus, Sunthurst would have to pay for any spare 12-count fiber optic cables PacifiCorp would purchase for maintaining a unique, 12-count fiber line for the PRS1 project. This special procurement of 12-fiber count cable would also increase installation costs because of lost efficiencies with PacifiCorp's standard 48-fiber count purchasing agreements. Given that Sunthurst estimates savings of roughly $2,376 from using 12-count fiber, its costs would likely be higher after accounting for spares.[110]

Finally, Sunthurst argues that PacifiCorp will benefit independently from installing a fiber optic cable to PRS1 and PRS2 and should therefore pay for the cable's installation.[111] Once again, Sunthurst misunderstands what qualifies as the reasonable costs of interconnection under the Commission's rules.[112] Because PacifiCorp would not install this particular fiber optic link but

[106] Sunthurst/211, Beanland/13.
[107] Sunthurst/200, Beanland/29.
[108] PAC/200, Patzkowski, Taylor, Vaz/25.
[109] Sunthurst/200, Beanland/29.
[110] PAC/300 at 3 (12-count fiber about 50 cents/foot less than 48-count fiber).
[111] Sunthurst/200, Beanland/29.
[112] *See* OAR 860-082-0035(2).

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for Sunthurst's interconnection requests, its installation is a reasonable interconnection cost.[113] PacifiCorp customers cannot, as Sunthurst desires, pay for expenses that would not be incurred but for PRS1 and PRS2's interconnection requests.

4. Dead-line checking is required to maintain PacifiCorp's current level of service.

PacifiCorp utilizes a system called "high-speed reclosing" to quickly restore power after a temporary fault in an overhead line as part of its effort to minimize service interruption to its customers.[114] High-speed reclosing is an automatic control function applied to circuit breakers connected to transmission and distribution lines.[115] To ensure that PacifiCorp's existing customers continue to receive the same level of service that existed before the interconnection of PRS1 and PRS2, the Company has included the cost of a dead-line checking system to maintain high-speed reclosing as part of its proposed interconnection costs.[116] The dead-line checking system monitors the voltage at the Pilot Rock substation and delays automatic reclosing until there is an indication that the distributed generator has disconnected.[117]

Sunthurst concedes that the use of dead-line checking here is consistent with PacifiCorp's interconnection policies for distributed generation.[118] However, Sunthurst speculates that "most utilities are going away from rapid reclosing" and suggests that a five-second reclosing interval for circuit 5W406 "can achieve the same functionality [as dead-line checking] at minimal risk or expense."[119] Sunthurst's unsubstantiated conjecture about other utilities' reclosing practices is not relevant to its interconnection request with PacifiCorp. PacifiCorp has been using a 0.35-second

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[113] PAC/200, Patzkowski, Taylor, Vaz/24–25.
[114] PAC/200, Patzkowski, Taylor, Vaz/26.
[115] PAC/200, Patzkowski, Taylor, Vaz/26.
[116] PAC/200, Patzkowski, Taylor, Vaz/26.
[117] PAC/200, Patzkowski, Taylor, Vaz/27.
[118] PAC/300 at 13.
[119] Sunthurst/200, Beanland/26–27.

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reclosing interval for feeder circuit 5W406 for many years.[120] This high-speed reclosing interval allows customers to experience only a 0.35-second outage for temporary faults on the 5W406 circuit.[121] Because ninety percent of all faults are temporary, this interval minimizes the extent of most power outages.[122] In contrast, Sunthurst's suggestion of a five-second reclosing interval would mean that PacifiCorp's customers would experience a five-second outage for all temporary faults on the circuit.[123]

Under the Commission's rules, Sunthurst is required to pay for all interconnection costs to maintain the same level of service other PacifiCorp customers have enjoyed before its interconnection requests.[124] Sunthurst's proposal to change PacifiCorp's reclosing policy and significantly increase the length of power outages for other Company customers is inapposite to its duty to pay reasonable interconnection costs. The dead-line checking system makes it possible to maintain the same level of service for PacifiCorp's customers and still accommodate the interconnection of PRS1 and PRS2.[125] As such, these modifications are reasonable costs of interconnection that Sunthurst must pay.

5. Sunthurst must pay for the 0.3-mile line extension to PRS1 and PRS2 because the line would not be constructed but for Sunthurst's interconnection requests.

To interconnect PRS1 and PRS2, PacifiCorp must install a 0.3-mile distribution line extension to place a switch and meter at the POI between Sunthurst's projects and the Company's 5W406 circuit. The line extension will be installed on new poles and will be owned and maintained

[120] PAC/200, Patzkowski, Taylor, Vaz/28.
[121] PAC/200, Patzkowski, Taylor, Vaz/28.
[122] PAC/200, Patzkowski, Taylor, Vaz/28.
[123] PAC/200, Patzkowski, Taylor, Vaz/27.
[124] *See* OAR 860-082-0035(2).
[125] PAC/200, Patzkowski, Taylor, Vaz/28.

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by PacifiCorp.[126] Even though this new distribution line serves no purpose except to interconnect PRS1 and PRS2, Sunthurst baselessly contends that PacifiCorp should pay for the cost of installing the new line because it will allow the Company "to serve new loads where it previously did not."[127] But no new customers exist on the 0.3-mile extension line required to interconnect Sunthurst's projects. In fact, the 0.3-mile line is a detriment to PacifiCorp's system because it adds more exposure to faults, which increases stress on the local substation breaker.[128] Sunthurst's prior consulting engineer agreed that "[t]here are no suggested methods for reducing or reallocating costs" of the line extension.[129]

Sunthurst tries to argue that the line has value to PacifiCorp because they will own the poles and lines.[130] This assertion ignores the requirement under the Commission's small generator interconnection rules that the interconnection customer "must pay the reasonable costs of the interconnection facilities," even though the "public utility constructs, owns, operates, and maintains the interconnection facilities."[131] Moreover, PacifiCorp does not place any particular value on this distribution line. PacifiCorp would not install the Company-owned metering and switch equipment required at the POI on customer-owned poles because it would create disputes for maintenance and access of PacifiCorp's metering property.[132] If Sunthurst had not requested interconnection for PRS1 and PRS2, PacifiCorp would not construct this distribution line.[133] It is thus a reasonable cost of interconnection, and Sunthurst must pay for its construction.

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[126] *See* OAR 860-082-0035(2) ("The public utility constructs, owns, operates, and maintains the interconnection facilities.").
[127] Sunthurst/200, Beanland/30.
[128] PAC/200, Patzkowski, Taylor, Vaz/35.
[129] Sunthurst/211, Beanland/13.
[130] Sunthurst/200, Beanland/30.
[131] OAR 860-035-0035(2).
[132] PAC/200, Patzkowski, Taylor, Vaz/35.
[133] PAC/200, Patzkowski, Taylor, Vaz/34.

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6. Direct transfer trip is required to interconnect PRS1 and PRS2 safely.

PacifiCorp has included a Direct Transfer Trip ("DTT") system to ensure the Company can disconnect the projects from the circuit in the event of a fault.[134] PacifiCorp must include DTT as part of the interconnection costs of PRS1 because DTT is essential for restoring power after an electrical fault and protecting transformers during these faults.[135] In particular, PacifiCorp requires a DTT system for PRS1 because the system will: (1) disconnect PRS1 quickly for any faults that occur on the Company's 12.5 kV feeder line; (2) maintain a rapid reclosing cycle for the 5W406 circuit; and (3) minimize the potential for damage to the Company's Pilot Rock transformer.[136]

Sunthurst has questioned the inclusion of DTT for the project by claiming that "most utilities do not require DTT for projects under 2 MW" if the smart inverters comply with the Institute of Electrical and Electronics Engineers ("IEEE") 1547 requirements.[137] Sunthurst's assertions are incorrect. Inverters meeting the IEEE 1547 standards will not adequately protect the 5W406 circuit.[138] To that end, IEEE 1547 lists DTT as an appropriate system to ensure automatic reclosing in the case of any faults on the circuit. Notably, the only support Sunthurst musters for its claim is hearsay from an unnamed "consultant" hired by Sunthurst; Sunthurst's claim, therefore, has no evidentiary support in the record.[139] Because Sunthurst's inverters cannot provide the required level of protection, DTT is a reasonable interconnection cost for PRS1.[140]

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[134] PAC/100, Bremer/28.
[135] PAC/200, Patzkowski, Taylor, Vaz/39–40.
[136] PAC/200, Patzkowski, Taylor, Vaz/41.
[137] Sunthurst/100, Hale/6.
[138] PAC/200, Patzkowski, Taylor, Vaz/40.
[139] Sunthurst/100, Hale/6.
[140] The addition of a DTT system for PRS1 will also serve the same benefits for PRS2. PAC/200, Patzkowski, Taylor, Vaz/41–42. Therefore, only PRS1's interconnection costs include a DTT system.

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Sunthurst also requests the ability to install DTT itself and claims that PacifiCorp's discovery responses did not identify any legal basis to preclude Sunthurst from installing the equipment itself.[141] PacifiCorp indicated that because the DTT equipment will be installed on PacifiCorp facilities, standard practice requires PacifiCorp to install the equipment.[142] This approach is consistent with OAR 860-082-0060, which allows utilities to contract with a third-party consultant to construct interconnection facilities *at the discretion of the utility* and subject to the utility's "oversight and approval."[143] PacifiCorp policy requires Company installation of DTT equipment under the Commission's rules.[144]

7. Sunthurst's costs to install telemetry equipment are reasonable.

The Commission's small generator interconnection rules do not allow a utility to require telemetry for projects with less than 3 MW of nameplate capacity.[145] But if "an applicant proposes to interconnect multiple small generator facilities to [a] public utility's transmission or distribution system *at a single point of interconnection*," the public utility must evaluate the interconnection request "based on the combined total nameplate capacity."[146] These rules are consistent with PacifiCorp's interconnection Policy 138, which also requires telemetry if multiple generators using a single POI exceed 3 MW.[147]

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[141] Sunthurst/300, Hale/4.
[142] PAC/100, Bremer/28.
[143] OAR 860-082-0060(8)(f); *see also Sandy River Solar, LLC v. Portland Gen. Elec. Co.*, Docket No. UM 1967, Order No. 19-218, at 20 (June 24, 2019) (determining that OAR 860-082-0060(8)(f) "does not require a utility to consent to a small generator's request to hire a third-party consultant to complete interconnection facilities and system upgrades, and does not authorize [the Commission] to require a utility to do so").
[144] *See* OAR 860-082-0060(8)(f).
[145] OAR 860-082-0070(I)(2).
[146] OAR 860-082-0025(4) (emphasis added).
[147] Sunthurst/405, Beanland/4 ("When multiple generators are connected at a single PacifiCorp Point of Delivery that is aggregated at a nameplate rating of 3 MW and above, additional real-time telemetry metering is required at the point of delivery to the PacifiCorp system.").

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Here, Sunthurst purposefully sized its projects to avoid having to pay for necessary telemetry equipment. Yet, because PRS1 and PRS2 have the same POI, their interconnection should be evaluated as a single 4.97 MW facility under the Commission's rules and Policy 138.[148] PacifiCorp has significant concerns regarding Sunthurst's obvious gaming of the interconnection rules to try to avoid costs for telemetry despite Sunthurst proposing to interconnect 4.97 MW of generation at a single POI because PRS1 and PRS2 will impact the Company's ability to provide the same level of reliable service to its retail customers on the circuit.

Despite the combined 4.97 MW size and common POI of PRS1 and PRS2, as well as the Company's concerns with Sunthurst's gaming of the Commission's rules, PacifiCorp agreed—in order to accommodate the interconnection of PRS1 and PRS2—to remove the costs of installing telemetry equipment on PacifiCorp's system.[149] What remains is the estimated costs to install certain equipment on Sunthurst's facilities to enable the installation of telemetry equipment if PacifiCorp chooses to install such equipment.[150]

8. Sunthurst's request for low-side metering is contrary to standard practice.

PacifiCorp's standard metering practice for generators like PRS1 and PRS2 is to install meters on the high-side of the transformer, which coincides with the point where PacifiCorp takes ownership of electricity. Metering on the low side of the transformer requires the Company to estimate losses occurring across the transformer, which leads to inherently inaccurate metering.[151] For this reason, low-side metering is contrary to standard utility practice. Indeed, the Commission recognized this fact when it approved low-side metering in limited circumstances for small CSP

[148] *See* OAR 860-082-0025(4); Sunthurst/405, Beanland/4.
[149] PAC/100, Bremer/10–11. As noted earlier, the removal of these costs was significant at $525,000.
[150] PAC/100, Bremer/30-31.
[151] Sunthurst/401, Beanland/82.

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generators that are less than 360 kW, where the losses are less material.[152] Similarly, in Order No. 20-122, the Commission approved "CSP Interconnection Procedures" for PacifiCorp, which state that any CSP that is 360 kW or less will be eligible for low side metering.[153]

Sunthurst requests the Commission set aside its approval of low-side metering for small CSP generators and allow PRS1 and PRS2 to utilize low-side metering.[154] Sunthurst has failed to meet its burden to show low-side metering is reasonable for PRS1 and PRS2. Sunthurst's direct testimony provided no justification for the use of low-side metering and mentioned it once and only in passing.[155] Then, in its rebuttal testimony, Sunthurst presented evidence *for the first time* supporting its request for low-side metering. By withholding its affirmative case until rebuttal testimony and thereby depriving PacifiCorp of an opportunity to respond, Sunthurst's evidence should be given no weight; Sunthurst has therefore failed to meet its burden of proof.[156]

Moreover, Sunthurst cannot dispute that low-side metering is contrary to standard practice, as memorialized in Order Nos. 19-392 and 20-122. In testimony, Sunthurst claimed that low-side metering is the "most common type of metering used for electric service metering."[157] But Mr. Beanland admitted in discovery that his testimony was not referring to metering associated

[152] *Cf.* Order No. 19-392, App'x A at 13.
[153] PacifiCorp CSP Interconnection Procedures at Section J(2).
[154] Sunthurst/400, Beanland/18-21.
[155] Sunthurst/200, Beanland/33.
[156] *See, e.g., In re Portland Gen. Elec. Co. Application for Deferral of Incremental Administrative Costs Associated with the Trojan Refund*, Docket No. UM 1402, Order No. 11-315, at 2 (Aug. 17, 2011) ("We will not consider arguments that are raised for the first time in a reply brief when those arguments are not directly in response to arguments made in another party's response. We therefore will not consider those arguments that URP attempts to incorporate by reference."); *Two Two v. Fujitec Am., Inc.*, 355 Or 319, 325-26, 325 P3d 707 (2014) (parties may not raise new arguments in a reply memorandum at summary judgment); *Fox v. Gov't of Dist. of Columbia*, 794 F3d 25, 30 (D.C. Cir. 2015) ("[W]here a litigant has forfeited an argument by not raising it in the opening brief, we need not reach it.").
[157] Sunthurst/400, Beanland/18.

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with distributed energy resources like PRS1 and PRS2.[158] Indeed, Sunthurst was able to identify only two instances where PacifiCorp approved low-side metering for distributed generation resources, but each case is easily distinguished.

First, Sunthurst relies on two *net metering* projects that used low-side metering.[159] Sunthurst failed to explain, however, that low-side metering is standard for net metering projects because those projects tie into PacifiCorp-owned transformers, and PacifiCorp takes ownership of the generation on the low side of the transformer.[160] Accordingly, PacifiCorp placed the meter where the Company accepts delivery of the generator's output. Here, PacifiCorp accepts delivery of the output of PRS1 and PRS2 on the high-side of the transformer. Therefore, metering at the high side is reasonable and comparable to the *net metering* example cited by Sunthurst.

Second, Sunthurst relies on two non-net metering projects—interconnection Queue Nos. 0918 and 0919 ("Q0918" and "Q0919", respectively)—and claims that they are essentially the same as PRS1 and PRS2.[161] PacifiCorp explained in discovery, however, that Q0918 and Q0919 are not the same as PRS1 and PRS2 for purposes of low-side metering.[162] Each of those projects interconnect to a single step-up transformer with two secondaries, and each generator interconnects to a separate step-up transformer secondary.[163] Therefore, low-side metering was the only feasible solution to meter each project independently.

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[158] PAC/300 at 8.
[159] Sunthurst/400, Beanland/20.
[160] Sunthurst/401, Beanland/106.
[161] Sunthurst/400, Beanland/20.
[162] Sunthurst/401, Beanland/77.
[163] Sunthurst/401, Beanland/77.

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Sunthurst also claims that low-side metering is more accurate, even though it requires the utility to estimate the losses across the transformer.[164] Sunthurst's testimony, however, is unpersuasive and does not provide a reasonable basis to depart from standard utility practice. Mr. Beanland's testimony included calculations purporting to show that there is a larger error when using high-side metering.[165] But when asked in discovery to support and verify his calculations, Mr. Beanland changed his calculations without explanation.[166] Mr. Beanland also could not verify the accuracy of the error he assigned to the estimated losses that PacifiCorp must impute when using low-side metering.[167]

Finally, departing from standard utility practice and implementing low-side metering will result in relatively small savings—Sunthurst estimates cost savings of only $6,000 (excluding labor costs).[168] Based on the above, Sunthurst has failed to meet its burden to show low-side metering is reasonable for PRS1 and PRS2.

9. PacifiCorp has removed any costs associated with the necessary PI-111 Annunciator Panel from its most recent cost estimates for Q0666.

During its negotiations with Sunthurst over the summer of 2020, PacifiCorp agreed to pay for a PI-111 annunciator panel that the Company will install as part of PRS1's interconnection.[169] PacifiCorp's operations personnel use this annunciator panel to diagnose problems and as an aggregation point for substation alarms to bring any subset of station alarms into the Company's 24/7 dispatch monitoring center.[170] While the panel is needed to interconnect PRS1 into PacifiCorp's system, PacifiCorp has worked extensively and in good faith to address Sunthurst's

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[164] Sunthurst/400, Beanland/20-21.
[165] Sunthurst/400, Beanland/20-21.
[166] PAC/300 at 10-11.
[167] PAC/300 at 10-11.
[168] PAC/300 at 9.
[169] PAC/100, Bremer/10.
[170] PAC/200, Patzkowski, Taylor, Vaz/28–29.

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interconnection costs concerns. PacifiCorp has assumed the PI-111 annunciator panel costs as part of this effort even though it believes that the Company could reasonably charge the panel to Sunthurst as part of its interconnection costs. PacifiCorp initially removed the $15,000 cost estimate for the PI-111 annunciator panel.[171] As explained in its response testimony, the cost estimates for the PI-111 annunciator panel were updated to remove $54,321.[172]

10. PacifiCorp has refined and reduced avian protection costs in its most recent estimates for Q0666.

PacifiCorp has also refined its cost estimate for avian protection.[173] Sunthurst challenged the estimated costs for avian protection included in the August 2020 estimate for PRS1.[174] While this prior estimate was in line with other similarly situated CSP projects, the most recent estimated costs for avian protection reflect the cost of 120 feet of grey hose and three VT bushing covers only.[175] This refinement represents a further cost reduction of $5,610 from the latest detailed expenditure report for PRS1.[176]

11. PacifiCorp's junction box costs are reasonable.

In PacifiCorp's September 2020 expenditure report for PRS1, the Company included the cost of several junction boxes as part of the project's interconnection costs.[177] Sunthurst challenged this estimate and argued that the price PacifiCorp quoted for junction boxes is unreasonably high.[178] Based on prices for junction boxes from the internet, Sunthurst asserted that the price for junction boxes should be around $100.[179] But the prices Sunthurst found for junction

[171] Sunthurst/200, Beanland/15.
[172] PAC/201 Patzkowski, Taylor, Vaz/5; PAC/200, Patzkowski, Taylor, Vaz/42.
[173] PAC/200, Patzkowski, Taylor, Vaz/31.
[174] Sunthurst/200, Beanland/27.
[175] PAC/200, Patzkowski, Taylor, Vaz/31.
[176] PAC/201 Patzkowski, Taylor, Vaz/5; PAC/200, Patzkowski, Taylor, Vaz/31.
[177] PAC/200, Patzkowski, Taylor, Vaz/32–33.
[178] Sunthurst/200, Beanland/27.
[179] PAC/203, Patzkowski, Taylor, Vaz/4.

boxes online only include the box without the assembled and installed terminal blocks, fuse blocks, fuses, and ground bar.[180] Furthermore, the boxes quoted by Sunthurst do not meet PacifiCorp's standards for electronic enclosures.[181] The more robust junction boxes PacifiCorp uses are also more resistant to corrosion, increasing their lifespan and ensuring a safe and secure electronic enclosure.[182]

Even though Sunthurst's cost estimates did not accurately reflect the costs of junction boxes that meet PacifiCorp standards, the Company has now completed its final engineering drawings for PRS1's interconnection.[183] These drawings have allowed PacifiCorp to update and revise the junction boxes' cost in its latest expenditure report, reducing the final costs by an additional $17,000.[184] Because Sunthurst has delayed interconnection, these costs continue to be estimated until PacifiCorp can complete the competitive bidding process.[185] Regardless, this further cost reduction continues to demonstrate: (1) PacifiCorp's commitment to reducing interconnection costs where possible without requiring its customers to subsidize Sunthurst's interconnections or degrade the quality of service; and (2) that as the interconnection customer progresses through the interconnection study process, the estimate of costs becomes more refined.

[180] PAC/200, Patzkowski, Taylor, Vaz/33.
[181] PAC/200, Patzkowski, Taylor, Vaz/33.
[182] PAC/200, Patzkowski, Taylor, Vaz/33.
[183] PAC/200, Patzkowski, Taylor, Vaz/32.
[184] PAC/201, Patzkowski, Taylor, Vaz/5; PAC/200, Patzkowski, Taylor, Vaz/32.
[185] PAC/200, Patzkowski, Taylor, Vaz/32.

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12. PacifiCorp has removed cost responsibility for the POI meter.

As a further accommodation to Sunthurst and to narrow the disputed issues in this case, PacifiCorp has agreed that Sunthurst will no longer be obligated to pay for the meter at the POI. Sunthurst must still pay for the meters located at each generating facility, but PacifiCorp will bear the cost of the POI meter.

B. Sunthurst's interconnection costs would be the same if the Commission applied FERC's non-QF cost allocation policies.

Sunthurst argues that if PRS1 and PRS2 were interconnected subject to FERC's cost allocation policies for non-QFs, their interconnection costs would have been lower. Sunthurst is wrong. FERC requires interconnection customers like PRS1 and PRS2 to pay for all interconnection facilities and distribution upgrades.[186] FERC's non-QF cost allocation policy differs only for network upgrades. But neither PRS1 nor PRS2 require network upgrades to interconnect.[187] Therefore, Sunthurst's interconnection costs would be the same even if the Commission applied FERC's cost allocation policy for non-QFs to Sunthurst's projects.[188]

C. Sunthurst's reliance on general interconnection study costs from other projects is misplaced.

Sunthurst makes general assertions that the interconnection costs of PRS1 and PRS2 are unreasonably high compared to the interconnection costs of similarly situated projects connecting to other utilities. Sunthurst's claims miss the mark, and the bases for its assertions are feeble.

First, Sunthurst relies on a 2018 NREL study to claim the interconnection costs for PRS1 and PRS2 are too high.[189] That study, however, provides no insight into the specific interconnection costs for PRS1 and PRS2. When Commission Staff previously cited this same

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[186] *See Pro Forma* Small Generator Interconnection Agreement, Articles 4.2 and 5.2.
[187] PAC/100, Bremer/25.
[188] PAC/100, Bremer/25.
[189] Sunthurst/100, Hale/7.

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NREL study, they expressly recognized that the "cost and type of upgrades (distribution or transmission) estimated for a generator are specific to the generator's location, project design, the makeup of other generators in the area or in queue, and additional characteristics of the generator and utility system."[190] Staff further noted that the study was "purely illustrative and limited by the wildly variable nature of interconnection upgrades."[191]

Second, Sunthurst relies on improper hearsay from unnamed and unverifiable sources that claim other projects interconnecting in other locations to other utilities have had lower interconnection costs than the estimates for PRS1 and PRS2.[192] Not only is the hearsay from anonymous sources unreliable, but even taking the statements at face value, they say nothing about the interconnection costs for PRS1 and PRS2. One unnamed source compared Sunthurst's projects to a single project interconnecting to PGE, and the other described the information in his email as "quick and random."[193]

Drawing blanket comparisons from any individual study, unnamed sources, or inapposite interconnection costs from other utilities does not meet Sunthurst's burden to demonstrate that PacifiCorp's interconnection costs for PRS1 and PRS2 are unreasonable. Sunthurst's assertions that PacifiCorp's cost estimates are unreasonable based on its comparisons to other small solar projects are unhelpful to determine reasonable interconnection costs for PRS1 and PRS2.

[190] *In re Pub. Util. Comm'n of Or., Community Solar Program Implementation*, Docket No. UM 1930, Order No. 19-392, App'x A at 43 (Nov. 8, 2019); *see also* PAC/100, Bremer/16–17, 19–20.
[191] Order No. 19-392, App'x A at 43.
[192] PAC/100, Bremer/17–19.
[193] PAC/100, Bremer/18–19.

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D. Sunthurst must bear the costs resulting from its siting decision.

Sunthurst argues that PacifiCorp is "bootstrapping" upgrades that would have to be made anyway into Sunthurst's interconnection studies.[194] This claim is untrue. Indeed, Sunthurst does not specifically identify any upgrade that purportedly falls into this category, except perhaps the voltage regulators addressed above. With regard to the latter, Sunthurst claims that its interconnection costs are excessive because the Pilot Rock substation "is at the end of its useful life and in need of significant repairs."[195] This outlandish claim has no support in the record. Indeed, the only evidence Sunthurst can muster to support this claim is the fact that PacifiCorp recently rebuilt a fence and replaced several components because of degradation or failure.[196] None of this work demonstrates that the Pilot Rock substation is at the end of its useful life or in need of "significant repairs." PacifiCorp testified that the substation was performing well and met all the applicable reliability and performance standards.[197] Sunthurst provided no evidence to dispute these facts.

Sunthurst also complains that there was no way for it to know that its interconnection costs would be higher because of the Pilot Rock substation's age.[198] However, Sunthurst submitted the interconnection request for PRS2 (Q1045) after it had received numerous interconnection studies related to Q0666 and Q0747. Sunthurst cannot claim ignorance of the costs required to interconnect its projects to the Pilot Rock substation.

[194] Sunthurst/300, Hale/4-5.
[195] Sunthurst/300, Hale/4.
[196] Sunthurst/300, Hale/4; PAC/300 at 7.
[197] PAC/100, Bremer/29.
[198] Sunthurst/300, Hale/3.

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Sunthurst also misleadingly quotes a PacifiCorp discovery response to imply there was no way to learn about the equipment in the Pilot Rock substation before requesting interconnection. Specifically, Mr. Hale testified that PacifiCorp indicated in a discovery response that there are no "official mechanisms" available to interconnection customers to determine the age and/or functional capabilities of major substation components.[199] However, Mr. Hale omits from his testimony the complete discovery response, which paints a very different picture. PacifiCorp noted that there was no "official mechanism" but explained that it "offers products like pre-application reports or informational interconnection requests in which interconnection customers can obtain useful information to assist in siting decisions."[200] The discovery response also stated that PacifiCorp responds to requests from prospective interconnection customers seeking information pertaining to the age or functional capabilities of its substation equipment.[201] Had Sunthurst availed itself of the available resources identified by PacifiCorp, it may have better understood the potential costs associated with its chosen interconnection site.

V. CONCLUSION

The Commission's rules require Sunthurst to pay the reasonable costs to interconnect its projects and require PacifiCorp's customers to remain indifferent both from a financial and service quality standpoint as a result of its interconnection requests. This means that Sunthurst should bear the costs required to ensure that after its projects interconnect, PacifiCorp's system performance is not adversely impacted, and customers continue to receive the same safe and reliable service they received before interconnection. PacifiCorp's most recent detailed cost estimates for PRS1 and PRS2 reflect the lowest estimated interconnection costs the Company can

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[199] Sunthurst/300, Hale/3.
[200] Sunthurst/401, Hale/71.
[201] Sunthurst/401, Hale/71.

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provide without degrading service to its existing customers. Accordingly, all costs included in these estimates are reasonable interconnection costs that Sunthurst must pay to interconnect its projects.

Dated: March 26, 2021.

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Attachment H

UM 2118 Sunthurst's Reply Brief

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April 13, 2021

Via Electronic Mail

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Re: OPUC Docket No. UM 2118

Attention Filing Center:

Attached for filing in the above-captioned docket is *Sunthurst Energy, LLC's Reply Brief*.

Thank you in advance for your assistance.

Sincerely,

Ken Kaufmann
Attorney for Sunthurst Energy, LLC

Attach.

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BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UM 2118

Sunthurst Energy, LLC Complainant, **vs.** **PacifiCorp dba Pacific Power** Respondent.	**Sunthurst Energy, LLC's Reply Brief**

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I. OVERVIEW OF SUNTHURST'S REBUTTAL

PacifiCorp's Opening Brief marks at least the fifth time PacifiCorp claims it has arrived at the "minimum requirements"[1] for interconnecting Sunthurst's 1.98 MW Pilot Rock Solar 1 (PRS1) and 2.99 MW Pilot Rock Solar 2 (PRS2) projects, and cannot lower costs any more. Each time, after additional evaluation by PacifiCorp and Sunthurst, PacifiCorp has further reduced the scope and cost of interconnection. Through its (protracted, tedious, and expensive) efforts, Sunthurst has caused PacifiCorp to reduce its estimated costs to interconnect PRS1 and PRS2, from $2,000,000, in early 2020, to approximately $860,000 today.[2] In pressing PacifiCorp to defend its requirements, Sunthurst has performed a service to the state, by testing the (sometimes) arbitrary policies, assumptions and requirements of Oregon small generator interconnections and demonstrating that great reduction to costs of small generator interconnection are possible.

Negotiations have not been a one-way affair. While PacifiCorp has come a long way towards Sunthurst's position on many issues, Sunthurst has made many concessions to PacifiCorp as well. Sunthurst dropped its objections to costly Direct Transfer Trip relay protection after PacifiCorp provided a reasoned justification. Sunthurst also dropped its objection to PacifiCorp's requirements of dead-line checking. And Sunthurst has dropped its request that PacifiCorp allow it to self-build the interconnection facilities. A detailed list of resolved issues was provided on pages 4-6 of Sunthurst's Opening Brief.

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[1] PacifiCorp's Opening Brief, at 13, line 1.

[2] PacifiCorp's Opening Brief, at 12, line 19. (The cost, above, does not include approximately $75,000 in costs addressed in telemetry related costs to be incurred by Sunthurst, and discussed in Section III(C) of this Reply).

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What remains are the issues the Parties have failed to compromise. PacifiCorp, in some instances, has eschewed discernment in favor of dogma. In other cases, it seeks to continue to enjoy what it has always enjoyed, where its decisions have escaped review for too long. In this Reply Brief, Sunthurst rebuts PacifiCorp's arguments why the scope and cost to Sunthurst to interconnect PRS1 and PRS2 should not be reduced further, and renews its prayer for relief from its Opening Brief.

II. PACIFICORP HAS THE BURDEN OF SHOWING ITS TERMS ARE REASONABLE.

PacifiCorp asserts Sunthurst bears the burden of proving that a term or condition of interconnection that is not specified in the rules or PacifiCorp's compliance filing is unjust and unreasonable.[3] To Sunthurst's knowledge, this is a matter of first impression before this Commission; however the substance of PacifiCorp's assertion was rejected by FERC, in similar disputes regarding the reasonableness of negotiated terms in Large Generator Interconnection Agreements (LGIAs) subject to FERC jurisdiction.

In *Southern Company Services, Inc.,* interconnection customer Longleaf Energy Associates, LLC (Longleaf), and Southern Company Services (Southern) were unable to reach agreement on the terms and conditions in the appendices of their LGIA.[4] Longleaf asserted that the public utility had the burden of proof under Section 205 of the Federal Power Act to show rates and charges in the Appendices to the LGIA (but not in the

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[3] PacifiCorp's Opening Brief, at 12.

[4] *Southern Company Services, Inc.* 116 F.E.R.C. P61,231, 61939-61940, 2006 FERC LEXIS 2055, *16 (F.E.R.C. September 8, 2006).

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Commission approved *pro forma* LGIA) are just and reasonable.[5] FERC agreed with Longleaf that the utility bore the burden of proof:

> 26. As a preliminary matter, we agree that a particular appendix that parties have negotiated in accordance with section 11.2 of the *pro forma* LGIP is not presumed to be just and reasonable. Unlike the provisions of an interconnection agreement that conform to the *pro forma* LGIA, *such appendices must be shown to be just and reasonable under section 205 of the FPA*.

116 F.E.R.C. P61,231, 61940 (emphasis added).

In *Midwest Independent Transmission System Operator, Inc.* [6], which also concerned, among other issues, the reasonableness of negotiated terms not specified in the utility's LGIA, FERC reiterated the rule of *Southern Company Services, Inc.*:

> 12. In contrast [to a transmission provider seeking a deviation from its *pro forma* interconnection agreement], *provisions that are to be negotiated between the parties must be shown to be just and reasonable under section 205 of the FPA*. The *pro forma* Interconnection Agreement does not dictate the terms and conditions of every provision, allowing certain provisions to be negotiated by the parties. The just and reasonable standard applies unless the *pro forma* Interconnection Agreement sets forth a more specific standard.

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[5] *Id.* at ¶25. ("Longleaf also requests a number of substantive changes to the appendices to the LGIA. Longleaf asserts that, because these provisions are not in Southern's *pro forma* LGIA, they do not enjoy the same deference afforded to other provisions of the LGIA. Longleaf states that section 11.2 of the *pro forma* LGIP generally leaves matters relating to the appendices to negotiations between [*61940] the transmission provider and the interconnection customer. In addition, Longleaf states that in proposing the rates, terms and conditions contained in the appendices, the public utility has the burden of proof under section 205 of the FPA to show that the increased rate or charge is just and reasonable.").

[6] 116 F.E.R.C. P61,252, 62005, 2006 FERC LEXIS 2098, *9 (F.E.R.C. September 18, 2006).

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116 F.E.R.C. P61,252, 62005, 2006 FERC LEXIS 2098, *9 (F.E.R.C. September 18, 2006) (emphasis added).

Southern Company Services, Inc., and *Midwest Independent Transmission System Operator, Inc.*, which are settled law, make clear that, for FERC-jurisdictional interconnections, the utility bears the burden to show that rates and charges *not in* the *pro forma* interconnection agreement are reasonable unless the *pro forma* Interconnection Agreement sets forth a more specific standard. The question then becomes whether the same standard should apply to state-jurisdictional interconnections regulated by this Commission. For the reasons below, the answer is "yes."

The Commission regulates interconnections where a qualifying facility seeks to interconnect to sell all of its net output to the interconnecting utility. Sunthurst is such a qualifying facility (or "QF"). PURPA[7] requires the QF to pay interconnection costs determined in accordance with the state's rules (as long as those rules are non-discriminatory).[8]

The Commission promulgated rules (codified at OAR 860, Division 82 and Division 29) governing interconnection of small generating facilities, and qualifying facilities, respectively.[9] Those rules require that interconnection requirements be: reasonable in scope; reasonable in cost; and nondiscriminatory:

[7] Public Utility Regulatory Policies Act of 1978 (P.L. 95-617).

[8] 18 CFR 292.306.

[9] ORS 758.505 to 758.555 provide Oregon's statutory scheme for rate regulation of PURPA purchases and interconnections. (See Order No. 10-132, at 6, in Docket No. UM 1401). ORS 758.535(2)(a) states that "The

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- OAR 860-082-0035(1), Study Costs, provides in part "Whenever a study is required under the small generator interconnection rules, the applicant must pay the public utility for the *reasonable* costs incurred in performing the study." (Emphasis added).
- OAR 860-082-0035(2), Interconnection facilities, provides in part "The applicant must pay the *reasonable* costs of the interconnection facilities." (Emphasis added).
- OAR 860-082-0035(3), Interconnection equipment, provides in part that "An applicant or interconnection customer must pay all expenses associated with constructing, owning, operating, maintaining, repairing, and replacing its interconnection equipment. Interconnection equipment is constructed, owned, operated, and maintained by the applicant or interconnection customer.
- OAR 860-082-0035(4), System upgrades, provides in part "The applicant must pay the *reasonable* costs of any system upgrades". (Emphasis added).
- OAR 860-082-0005(4) provides that "A small generator facility that qualifies as a 'small power production facility' under OAR 860-029-0010(25) must also comply with the rules in OAR chapter 860, division 029. If there is a conflict between the small generator interconnection rules and the rules in OAR chapter 860, division 029, then the small generator interconnection rules control."
- OAR 860-029-0060(1) provides in part that "interconnection costs that may *be reasonably incurred* by the public utility will be assessed against a qualifying facility on a *non-discriminatory basis* with respect to other customers with similar load or other cost-related characteristics." (Emphasis added).

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terms and conditions for the purchase of energy or energy and capacity from a qualifying facility shall: (a) be established by rule by the commission if the purchase is by a public utility."

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- OAR 860-029-0060(2) provides in part that "the public utility will be reimbursed by the qualifying facility for any *reasonable* interconnection costs." (Emphasis added).
- OAR 860-029-000(10)(9) provides that "Costs of interconnection" means the *reasonable* costs of connection, switching, dispatching, metering, transmission, distribution, equipment necessary for system protection, safety provisions and administrative costs incurred by an electric utility directly related to installing and maintaining the physical facilities necessary to permit purchases from a qualifying facility. (Emphasis added).

The reasonableness requirement permeates the Division 082 and Division 029 rules. Every aspect of the interconnection costs incurred by the utility and recovered from the applicant (study, scope, construction, and operation) must be reasonable.

Upon adopting the Division 082 small generator interconnection rules, in Docket No. AR-521, the Commission ordered the utilities to file draft forms and agreements, and to secure Commission Staff's agreement that the final versions of those forms and agreements conform to the Division 082 rules.[10] The Commission approved PacifiCorp's *pro forma* forms and agreements, on September 8, 2009.[11] However none of the terms Sunthurst is disputing in its Complaint were set forth in PacifiCorp's *pro forma* agreements.

Under FERC's framework, terms of a FERC-approved *pro forma* agreement are presumed to be just and reasonable. Therefore, an interconnection applicant seeking to challenge them bears the burden of proof when claiming they are unreasonable. However,

[10] Order No. 09-196, at 6 (June 8, 2009).
[11] Order No. 09-350 at 2.

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if the term being challenged is not part of the approved *pro forma* agreement, then the utility bears the burden to show that the term is reasonable, because FERC has not previously reviewed and approved the term. This is the framework described in FERC's holdings in *Southern Company Services, Inc.*, and *Midwest Independent Transmission System Operator, Inc*. discussed above. Under the FERC framework, the burden of proof clearly lies with PacifiCorp (were this complaint before FERC).

Although Sunthurst found no Commission decision stating which party bears the burden of proof in a challenge to the reasonableness of terms of interconnection *not* specified in a *pro forma* agreement, there is no apparent reason why the Commission would deviate from FERC's standard, after having mirrored FERC's interconnection framework so closely in other respects. FERC's framework is consistent with a fundamental premise of regulated utility rates--that a utility bears the initial burden to prove its terms of service are just and reasonable.[12] At its essence, PacifiCorp's design, construction, and operation of Sunthurst's interconnection is a retail service provided by a regulated monopoly, and deserves regulation as such. Furthermore, as a practical matter, asking an applicant (who usually has limited resources and always has limited access to knowledge and information a utility possesses about its rates) to prove a rate is unreasonable puts a heavy burden on the party that is less well-positioned to make such a case.

[12] ORS 756.040 expressly delegates to the Commission the duty to protect all customers of regulated utilities "from unjust and unreasonable exactions and practices and to obtain for them adequate service at fair and reasonable rates." ORS 757.210(1) provides that the Commission may conduct a hearing on any rate request to determine whether the rate or schedule is "fair, just and reasonable." The statute further provides that the utility bears the burden at the hearing of showing that the proposed rate "is fair, just and reasonable," and that the Commission "may not authorize a rate or schedule of rates that is not fair, just and reasonable." Finally, ORS 757.020 states that any charges for electric utility service "shall be reasonable and just, and every unjust or unreasonable charge for such service is prohibited." *Wah Chang v. PacifiCorp,* 2009 Ore. PUC LEXIS 291, *94 (Or. P.U.C. September 2, 2009)(Comm. Savage, dissent).

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For all the reasons above, in disputes over the reasonableness of a term or condition of interconnection *not* part of a *pro forma* agreement, the utility should bear the burden of proof, in Oregon-, as well as FERC-, jurisdictional interconnections.

III. REMAINING ISSUES IN THIS COMPLAINT

A. Cost Liability for Branch Regulators

1. Sunthurst's Rebuttal Argument

a. PacifiCorp bears the burden of proving branch regulators are reasonable.

Sunthurst is required to pay PacifiCorp the reasonable cost of installation of branch regulators, [13] *provided that* branch regulators are a reasonable requirement[14] and required on a non-discriminatory basis with respect to other customers with similar load or other cost-related characteristics[15]. Because PacifiCorp's requirement for branch regulators is not part of its *pro forma* interconnection agreements filed with the Commission, PacifiCorp bears the burden of proving that they are a reasonable requirement of Sunthurst.

b. PacifiCorp's assertion that branch regulators do not redress an existing problem[16] is undermined by its unreasonable failure to preserve probative evidence.

Without prompting, PacifiCorp stated on a call with Sunthurst held June 9, 2020, that then-existing voltages on circuit 5W406 were outside of ANSI Range A criteria.[17]

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[13] OAR 860-082-0015(34)("System upgrade" means an addition or modification to a public utility's transmission or distribution system or to an affected system that is required to accommodate the interconnection of a small generator facility."); OAR 860-082-0035(4) ("The applicant must pay the *reasonable* costs of any system upgrades")..

[14] OAR 860-029-0060(1).

[15] OAR 860-029-0060(1)

[16] PacifiCorp's Opening Brief, at 15, line 10.

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PacifiCorp's assertion in its Opening Brief that voltage regulators are not required to "redress an existing problem in the Pilot Rock *substation*"[18] does not expressly deny Mr. Hale's testimony that PacifiCorp admitted existing voltage issues on circuit 5W406. And PacifiCorp cites no evidence to support its claim. Sunthurst explained in its Opening Brief, pp 12-14, how PacifiCorp unreasonably failed to preserve any records from the June 9 call, which could have provided important information relevant to the need for branch regulators, although Sunthurst provided its corroborating notes from the call to PacifiCorp.

PacifiCorp also improperly disposed of the studies it conducted while preparing the System Impact Study Report for PRS2. Sunthurst had a right to see not just the study conclusions but also the supporting documentation--all of which Sunthurst has paid for.[19] PacifiCorp's loss of the detailed studies, which it had a duty to share with Sunthurst, deprived Sunthurst of information that may well have undermined PacifiCorp's stated rationale for branch regulators. If PacifiCorp's assertion that "Sunthurst has failed to provide a reasonable basis to support its conjecture"[20] turns out to be correct, it was not for lack of effort on the part of Sunthurst.

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[17] Sunthurst/300, Hale/6, lines 18-20.

[18] PacifiCorp's Opening Brief, at 15, lines 9-11.

[19] *See Small Generator Interconnection Agreements* , 145 F.E.R.C. P61,159, 61920, 2013 FERC LEXIS 1966, *171, 2013 WL 6360657 (F.E.R.C. November 22, 2013) ("FERC Order 792")(" 204. The Commission agrees with SEIA that the Interconnection Customer is entitled to view the facilities study supporting documentation because it is funding the study.")

[20] PacifiCorp's Opening Brief, at 15, line 11.

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c. PacifiCorp's assertion that it does not need to study voltage regulators invites unreasonable conditions and discriminatory treatment.

PacifiCorp's Opening Brief asserts that "After PRS2 interconnects, PacifiCorp cannot implement CVR without additional [branch] voltage regulators."[21] This is a problematic assertion because, as explained on page 11 of Sunthurst's Opening Brief, PacifiCorp uses subjective criteria to determine how much distributed generation a circuit using CVR can tolerate. But even if PacifiCorp's assertion is assumed to be correct, it does not follow that no study is needed to determine whether branch regulators are required.

PacifiCorp's assertion that no study is required ignores the fact that alternatives to branch voltage regulation exist, which may be so much better as to make voltage regulators an unreasonable choice. Sunthurst described five widely applied alternatives to voltage regulators in its Opening Brief, and noted that branch regulators are typically a last resort due to their high cost.[22]

PacifiCorp's assertion that no study is required runs contrary to its own Engineering Handbook (Handbook). Sunthurst learned about the Handbook during discovery, when. PacifiCorp stated that it uses the standards in its Pacific Power Engineering Handbook.[23] An

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[21] PacifiCorp's Opening Brief, at 17, lines 2-3.

[22] Sunthurst's Opening Brief, at 8-10 (The five alternatives cited are: fixed voltage regulation, re-conductoring, the addition of capacitor banks, and reconfiguring of circuits, with branch regulators being a last resort due to their expense). *Id.*

[23] Sunthurst/401, Beanland/103-104 (PacifiCorp's response to Sunthurst Data Request 10.4(d)).

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excerpt from Section 7.8 of PacifiCorp's Handbook[24], stating the standard for assessing voltage conditions and redress, is provided below:

7.8. Voltage Analysis

All distribution system studies require voltage analysis, which consider the following:

1. high and low voltage
2. tap zones or voltage spread
3. voltage balance
4. available voltage regulation
5. installed capacitors

Typically the voltage analysis will be done by a computer program such as FeederAll. When the analysis is done, voltage problems are identified per company standards, and solutions are compared on an economic basis.

In order to meet company standards during normal operation, the FeederAll model should typically have the node low voltage limit set at .97 p.u. and the node high voltage limit set at 1.04 p.u. In areas where tapped transformers are used, the node low voltage limit can be set to .95 p.u.

The voltage is modeled on the primary system, and is the annual high and low for all of the locations in the area. The area should be modeled under at least three loading conditions:

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Section 7.8 says that "all" distribution system studies require voltage analysis so that "voltage problems are identified *per company standards*, and solutions are *compared on an economic basis*." PacifiCorp ignored Section 7.8. Because it performed no study, it did not determine whether voltage problems exist per any defined standard, did not identify alternatives, and made no comparison of alternatives on an economic basis. Any one of these three omissions is sufficient basis to find PacifiCorp has not carried its burden.

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[24] Sunthurst/500, Beanland/27.

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d. PacifiCorp's assertion that "Commission guidance" supports its use of Conservation Voltage Reduction (CVR) is flawed.

PacifiCorp's Opening Brief cites two Commission orders in support of its assertion that the Commission wants utilities to expand CVR capabilities.[25] Neither order, however, endorses use of CVR *without economic study*. One of the orders PacifiCorp cites, Order 15-053, approves a CVR policy program for the express purposes of "validating savings associated with CVR", "quantifying costs and benefits associated with CVR", and "determining methods for ongoing measurement and validation of CVR effectiveness".[26] The orders PacifiCorp cites actually support Sunthurst's argument that CVR, being an efficiency upgrade, should be utilized in a verifiable, cost-effective manner. PacifiCorp made no attempt to show that branch regulators, at a cost of about $180,000, (a) have benefits commensurate to costs; or (b) are cheaper than other alternatives.

e. PacifiCorp's assertion that Customer Indifference requires installation of branch regulators is *ipse dixit*.[27]

PacifiCorp's utterance of "customer indifference" 10 times in its brief does not justify its positions. PacifiCorp must show its decisions are reasonable. In this case, instead of attempting to show that branch regulators, at a cost of $180,000, are reasonable, in isolation and compared to other alternatives, PacifiCorp utters "customer indifference" as though it is a talisman absolving it of responsibility to exercise reasonable judgment.

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[25] PacifiCorp's Opening Brief, at 14, lines 10-11.

[26] Order No.. 15-053, App'x A at 6.

[27] *Ipse dixit* is an assertion without proof, or a dogmatic expression of opinion. The fallacy of defending a proposition by baldly asserting that it is "just how it is" distorts the argument by opting out of it entirely: the claimant declares an issue to be intrinsic, and not changeable. Wikipedia.

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Customer Indifference does not mean zero impact is allowed. Every change to PacifiCorp's system, by definition, *changes it.* As an example, PacifiCorp's Engineering Handbook, describes how shifting load from one circuit to another may impact reliability:

> A change in the system configuration also changes the reliability to the customers affected by the load transfer. An example is increasing the number of momentary operations by transferring a rural area with high tree exposure to a suburban residential area.

Sunthurst/500, Beanland/21. PacifiCorp's Engineering Handbook recognizes that transfer of load between circuits may make one circuit less reliable than before. But it does not require that the effect be eliminated; rather the Handbook requires an engineering analysis, and may allow such a change provided the effects are reasonable.[28]

In the case of branch regulators, PacifiCorp would spend $180,000 (of Sunthurst money) solely to eliminate claimed but unquantified efficiency losses on a single feeder. Not only does PacifiCorp make no attempt to quantify those losses, it also would disregard all offsetting reductions in losses due to PRS1 and PRS2. Those reductions include reduced transformer losses and reduced transmission losses resulting from local generation displacing distant generation to serve local load. So while PacifiCorp may be correct that PRS1 and PRS2 impact system losses, we don't know if the net impact is positive or negative, and uttering "customer indifference" does not excuse the lack of any analysis.

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[28] See Engineering Handbook, Section 7.8, *supra*.

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f. PacifiCorp's requirement that Sunthurst pay for branch regulators is unreasonable.

(Except for whether PacifiCorp despoiled material evidence of a pre-existing condition requiring branch voltage regulators) the material facts are not in dispute. PacifiCorp admits that: (a) PacifiCorp did not provide Sunthurst supporting documentation or detailed study results for the PRS2 System Interconnection Study Report[29]; (b) PacifiCorp does not have a specific defined standard for determining when branch regulators are required[30]; (c) PacifiCorp did not quantify the net or gross efficiency benefits of branch voltage regulators;[31] and (d) PacifiCorp did not consider any other alternative to branch voltage regulators. [32]

Given PacifiCorp's refusal to apply objective technical or economic standards for the use of branch regulators, its not surprising that PacifiCorp's requirement of branch regulators in Oregon Community Solar Interconnections is irregular--confined to one small corner of PacifiCorp's Oregon service territory.[33] PacifiCorp's lack of studies and lack of objective standards make it impossible to determine how much losses branch regulators will avoid, whether those losses may be avoided using a more economic alternative, and whether they are required consistently under similar conditions. In short, the reasonableness of its requirement cannot be determined. Therefore, PacifiCorp cannot

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[29] See Sunthurst's Opening Brief, page 13, note 30.

[30] PacifiCorp's Opening Brief, at 17, lines 5-11.

[31] PacifiCorp's Opening Brief, at 15, lines 19-20. ("Sunthurst further claims that PacifiCorp has not provided a study to demonstrate that the voltage regulators are necessary. Sunthurst's argument, however, misunderstands the need for the voltage regulators. PacifiCorp does not need a study to know that it currently uses LDC settings to efficiently regulate voltage on the feeder").

[32] *Id*.

[33] *See* Sunthurst's Opening Brief, at 12.

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carry its burden to show that its requirement of branch regulators for the sole alleged purpose of maintaining optimal voltage, at a cost of $180,000, is reasonable.

2. Requested Remedy

Sunthurst reaffirms its request, on page 14 of its Opening Brief, for an Order declaring that Sunthurst is not required to pay for branch regulators as a condition to interconnecting PRS1 or PRS2.

B. <u>Cost Liability for Fiber Optic Communications Link</u>

1. Sunthurst's Rebuttal Argument

a. PacifiCorp has the burden to show its required fiber optic communications link is reasonable.

Sunthurst is required to pay PacifiCorp the reasonable cost of installation of fiber optic link to enable its relay protection scheme, [34] *provided that* fiber optic is a reasonable requirement[35] and required on a non-discriminatory basis with respect to other customers with similar load or other cost-related characteristics[36]. Because PacifiCorp's requirement for fiber optic link is not part of its *pro forma* interconnection agreements filed with the Commission, PacifiCorp bears the burden of proving that they are a reasonable requirement of Sunthurst.

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[34] OAR 860-082-0015(34)("System upgrade" means an addition or modification to a public utility's transmission or distribution system or to an affected system that is required to accommodate the interconnection of a small generator facility."); OAR 860-082-0035(4) ("The applicant must pay the *reasonable* costs of any system upgrades")..

[35] OAR 860-029-0060(1).

[36] OAR 860-029-0060(1)

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b. PacifiCorp's insistence on fiber optic cable is not reasonable.

Sunthurst's Opening Brief explains how PacifiCorp's analysis depends on the faulty premise that the cost of fiber is comparable to the cost of spread spectrum radio.[37] Sunthurst's two consulting engineers stated that spread spectrum radio costs less than fiber optic.[38] PacifiCorp's own calculations show that radio is likely to cost $14,000 less than fiber optic.[39] PacifiCorp argues that fiber is a reasonable choice over radio where the costs to install the two are comparable. However the costs are not comparable; therefore, PacifiCorp's primary rationale fails. PacifiCorp's alternative rationale--that fiber optic is more reliable--is speculative, and is controverted by the fact that PacifiCorp routinely specifies spread spectrum radio in interconnections similar to Pilot Rock Solar 1 and 2.[40]

c. PacifiCorp's claim that a fiber optic cable meets the "but-for" test is wrong.

Under PacifiCorp's version of the "but for" test, the interconnection customer bears the costs of network upgrades that "would not be needed but for the interconnection of its generating facility." Fiber link fails the "but for" test, because it is not needed for the interconnection so long as a cheaper alternative--spread spectrum radio link--is installed.

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[37] Sunthurst's Opening Brief, at 16-17 (explaining that PacifiCorp's estimators juggled their numbers during the pendency of the Complaint to arrive at revised cost figures supporting its legal argument).

[38] Sunthurst/211, Beanland/13 (Larry Gross); Sunthurst/200, Beanland/29, lines 12-13 (Michael Beanland).

[39] PAC/200, Patzkowski-Taylor-Vaz/24, lines 13-14 ("At the pre-existing $60,000 per mile estimate, the fiber optic cable option was approximately $14,000 more than the radio.).

[40] *See*, Sunthurst's Opening Brief, at 15, note 32 (citing examples of spread spectrum radio specified by PacifiCorp in Oregon CSP interconnections).

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PacifiCorp's (real) primary reason for requiring fiber is to provide a communication link for its Pilot Rock solar telemetry system.[41] Although PacifiCorp is precluded by OAR 860-082-0070 from charging Sunthurst for telemetry (as explained in Sunthurst's Opening Brief, pp. 25-28), PacifiCorp intends to install telemetry at PRS1 and PRS2 at its own cost. That telemetry system cannot function using spread spectrum radio, but can function using fiber optic, which can accommodate the more intensive data transmission associated with telemetry. PacifiCorp intends to make Sunthurst use fiber link instead of radio for its transfer trip communications link so that PacifiCorp can use excess capacity of the fiber link for its telemetry communications. In other words, fiber optic is not needed *but for* PacifiCorp's installation of telemetry, because otherwise radio is the less expensive and reasonable option. Because OAR 860-082-0070 precludes telemetry as part of the PRS1/PRS2 "interconnection facilities", PacifiCorp's assertion that fiber optic is required for the interconnection of PRS1 and PRS2 is wrong.

d. PacifiCorp's fiber optic requirement violates the intent of the Division 82 rules.

In Docket No. AR 521, the Commission adopted rules for small generator interconnections, codified at OAR 860, Division 82. The Commission rejected generators' request for express rules permitting cost sharing between applicants or between an applicant and the utility, because reimbursing applicants through bill credits was deemed

[41] Sun/200, Beanland/29, lines 7-13 ("The fiber optic cable from the substation to the project specified for the direct transfer trip (DTT) system is also being used to link the remote terminal unit installed by PacifiCorp at the project. In fact, the RTU requires the higher data speeds and bandwidth provided by the fiber; the DTT system can reliably function using the slower spread-spectrum radio. With no requirement for a data-intensive RTU at the project, the fiber optic system could be replaced by a spread-spectrum radio system at likely lower cost.").

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infeasible *and because the rules were intended to prevent a public utility from requiring a small generator to pay for system upgrades that primarily benefit the utility*.[42] In other words, if a system upgrade primarily benefits the utility, then it should not be charged to the interconnection applicant.

Applying the above rule to the facts of this Complaint, it is clear that PacifiCorp should pay for fiber because spread spectrum radio can adequately provide the communication link required for PRS1/PRS2 relay protection, and radio costs substantially less than fiber. If PacifiCorp requires fiber for the relay protection, and then uses the same fiber equipment to serve its telemetry system, it is requiring Sunthurst to pay for system upgrades that primarily benefit the utility--in contravention of the Division 82 rules.

2. Requested Remedy

For all the reasons set forth in its Opening Brief, Sunthurst reaffirms its prayer for relief on page 21 of its Opening Brief. It asks the Commission to order PacifiCorp to cap Sunthurst's costs for relay-protection communications at the cost of a radio link or, alternatively, order PacifiCorp to pay half of the cost of fiber optic link, or, alternatively, order PacifiCorp to pay all the cost of fiber optic link, and lease excess capacity in the fiber optic link to Sunthurst for its relay-protection communications link.

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[42] *The proposed rules, however, include language that is meant to strictly limit a public utility's ability to require one small generator facility to pay for the cost of system upgrades that primarily benefit the utility* or other small generator facilities, or that the public utility planned to make regardless of the small generator interconnection. Under the proposed rules, a public utility may only require a small generator facility to pay for system upgrades that are "necessitated by the interconnection of a small generator facility" and "required to mitigate" any adverse system impacts "caused" by the interconnection.

Order 09-196, at 5 (emphasis added).

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C. Cost Liability for Telemetry-Related Costs

1. Summary of Sunthurst's and PacifiCorp's Contentions.

Sunthurst asserted in its Opening Brief that, because neither PRS1 nor PRS2 has a nameplate capacity greater than the 3 MW, OAR 860-082-0070 prohibits PacifiCorp from imposing telemetry related charges on PRS1 and PRS2. Sunthurst cited the Commission's order adopting the rule, which stated that the bright line rule captures the appropriate delineation of telemetry costs.

PacifiCorp *admits that rule OAR 860-082-0070(I)(2) does not allow a utility to require telemetry for projects with less than 3 MW of nameplate capacity*.[43] However PacifiCorp claims that PRS1 and PRS2 "should be evaluated as a single 4.97 MW facility under [OAR 860-82-0025(4)] and Policy 138."[44]

2. Sunthurst's Rebuttal Argument

a. Policy 138 does not govern allocation of telemetry costs.

In an apparent reaction to Sunthurst's Complaint, PacifiCorp revised its interconnection Policy 138, on December 20, 2020, and now cites it in support of its position. Changes to Policy 138 effective December 20, 2020 specify that generators connected to a common point of delivery require telemetry when their nameplate ratings aggregate to 3 MW or more. Prior to December 20, 2020, the Policy 138 contained no such

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[43] PacifiCorp's Opening Brief, at 27, lines 10-11 ("The Commission's small generator interconnection rules do not allow a utility to require telemetry for projects with less than 3 MW of nameplate capacity.").

[44] PacifiCorp's Opening Brief, at 28, lines 3-4.

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requirement. PacifiCorp never, prior to its Opening Brief, informed Sunthurst of the rule change, nor asserted it applied to PRS1/PRS2.

Regardless the unfairness of PacifiCorp's attempt to bootstrap its position with a secret new policy, PacifiCorp's interconnection policies cannot contravene any requirement in the Oregon Administrative Code, including OAR 860-082-0070*(I)(2), which PacifiCorp has admitted does not allow a utility to require telemetry for projects with less than 3 MW of nameplate capacity*.

b. OAR 860-82-0025(4) does not govern allocation of telemetry costs.

PacifiCorp seeks to circumvent the direct prohibition in OAR 860-082-0070(I)(2), for the first time in its Opening Brief, by proposing a very strained interpretation of OAR 860-082-0025(4).

OAR 860-082-0025(4) states:

> If an applicant proposes to interconnect multiple small generator facilities to a public utility's transmission or distribution system at a single point of interconnection, then the public utility must evaluate the applications based on the combined total nameplate capacity for all of the small generator facilities. If the combined total nameplate capacity exceeds 10 megawatts, then the small generator interconnection rules do not apply.

The rule 0025(4) does not specify the meaning of "evaluate", however it is clear from the last sentence of the rule, above, that the applications are "evaluated" together to determine

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whether they aggregate in excess of 10 MW, which PRS1 and PRS2 do not. Nothing in the paragraph suggests it applies generally to the other Division 82 rules.

Further, the rule does not reasonably apply to applications separated in time by more than three years. Initially, Sunthurst intended to develop only PRS1. It applied for interconnection in 2015. PacifiCorp assigned that application queue number Q0666 and issued a System Impact Study (SIS) report on August 14, 2015.[45] In 2016, Sunthurst submitted an application for PRS2 with 6 MW nameplate capacity. PacifiCorp assigned that application Q0747, and issued a SIS report on July 27, 2016.[46] Sunthurst withdrew Q0747 after PacifiCorp estimated the cost to interconnect would be $ 42,199,000.00. In August 2018, Sunthurst submitted a revised application for PRS2 with 2.99 MW nameplate capacity. PacifiCorp assigned that application Q1045, and issued a SIS report on March 27, 2020.[47]

Whatever OAR 860-82-0025(4) does mean, the suggestion that it required PacifiCorp to require telemetry for Q1045 in 2020 because of the Q0666 application in 2015, is both a contorted reading of the language and unfair to Sunthurst, who has relied on the rules when endeavoring to build its projects.

c. PacifiCorp's allegation that Sunthurst engaged in "obvious gaming" is patently untrue.

[45] Sunthurst/205, Beanland/1.
[46] Sunthurst/206, Beanland/1.
[47] Sunthurst/207, Beanland/1.

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PacifiCorp allegation of “Sunthurst’s obvious gaming of the interconnection rules to try to avoid costs for telemetry” is untrue.[48] According to the Oxford English Dictionary, the verb “gaming” means to “manipulate (a situation), typically in a way that is unfair or unscrupulous.” Sunthurst applied for a 2 MW interconnection in 2015, a 6 MW project in 2016, and a 2.99 MW project in 2018. Each was an independent act, not part of any scheme to manipulate the rules. PacifiCorp presents no evidence to the contrary. Sunthurst’s only goal was, and remains, to interconnect to PacifiCorp at reasonable cost. PacifiCorp either doesn’t know what “gaming” means, or ascribes a different definition than that of the Oxford English Dictionary.

3. Remedy Requested.

Because PacifiCorp has admitted OAR 860-082-0070 does not permit it to collect *any* costs associated with telemetry from Sunthurst, and because PacifiCorp’s collateral attacks on that express prohibition lack merit, Sunthurst reaffirms its request for relief, on page 29 of its Opening Brief, which has an estimated benefit to Sunthurst of $75,000.

D. Cost Liability for High-side Project Meters

1. Sunthurst’s Rebuttal Argument

a. PacifiCorp has the burden to prove high-side metering, at an added cost of $25,000, is reasonable.

[48] PacifiCorp’s Opening Brief, at 28, lines 4-5.

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Sunthurst is required to pay PacifiCorp the reasonable cost of installation of metering on the high side of each project transformer,[49] *provided that* high side metering is a reasonable requirement[50] and required on a non-discriminatory basis with respect to other customers with similar load or other cost-related characteristics[51]. Because PacifiCorp's requirement for high side metering is not part of its *pro forma* interconnection agreements filed with the Commission, *PacifiCorp* bears the burden of proving it is a reasonable requirement of Sunthurst.

b. PacifiCorp did not disclose its use of low-side metering until its direct testimony.

Sunthurst first questioned the need for high-side metering in a July 23, 2020 letter to PacifiCorp.[52] In its August 7, 2020 response, PacifiCorp stated "Sunthurst's request to install the project meters on the low side of Sunthurst's step up transformers is also inconsistent with PacifiCorp's policy and *all other similarly situated interconnection requests.*"[53] Sunthurst raised the issue again in its Complaint.[54] During discovery, however, PacifiCorp asserted to Sunthurst, on December 9, 2020, that "no generator interconnecting today would be allowed to use a low-side metering configuration."[55] In reliance on

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49 OAR 860-082-0015(34)("System upgrade" means an addition or modification to a public utility's transmission or distribution system or to an affected system that is required to accommodate the interconnection of a small generator facility."); OAR 860-082-0035(4) ("The applicant must pay the *reasonable* costs of any system upgrades")..

50 OAR 860-029-0060(1).

51 OAR 860-029-0060(1)

52 Sunthurst/211, Beanland, pp. 6-7.

53 Sunthurst/211, Beanland, p. 19 (emphasis added).

54 PacifiCorp Complaint, ¶18.

55 Sunthurst/401, Beanland/29 ("PacifiCorp objects to this request because it seeks information that is not relevant. In particular, with one exception, the [low-side metered] generators identified in Attachment

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PacifiCorp's statement, Sunthurst dropped the matter in its December 16 Opening Testimony.

Then, in its Opening Testimony filed January 26, 2021, PacifiCorp testified "PacifiCorp's merchant function submitted and ultimately constructed two small generating facilities (Q0918 and Q0919) in Utah with essentially the same configuration as PRS1 and PRS2."[56] Sunthurst investigated and determined that in February 2018 (in Q0918 and Q0919) PacifiCorp allowed adjacent, small solar projects owned by PacifiCorp to meter each project on the *low side*.[57]

Sunthurst notes, without spin, that on at least the two previous occasions described above, PacifiCorp told Sunthurst that low side metering was inconsistent with all other similarly situated interconnection requests, when in fact it is not. Sunthurst did not address low-side metering until its rebuttal testimony because it relied on those erroneous statements from PacifiCorp, which it did not know to be erroneous until PacifiCorp contradicted itself in its Opening Testimony. Given the above context, PacifiCorp's contention in its Opening Brief, that addressing low-side metering in its rebuttal testimony was untimely,[58] is without merit.

Sunthurst 2.2 were interconnected between the 1890's and 1960's. The one exception was interconnected in 1986. These interconnections do not reflect current industry practice. *If the generators requested interconnection today, they could not use the low-side metering configuration*.")(emphasis added)

[56] PAC/200, Patzkowski-Taylor-Vaz/7, line 17-18.

[57] *See* one-line diagram of Q0918/Q0919 showing low side metering at Sunthurst/404, Beanland/16. PacifiCorp's attempt to rationalize its disparate treatment of Q0918/Q0919 (owned by PacifiCorp Merchant) from PRS1/PRS2 based upon Q0918/Q0919's use of a single step-up transformer is a distinction without a difference. If PacifiCorp truly believed it was necessary to meter transformer losses on the high side of the transformer, and using a single transformer prevents it from doing so, then it would not have permitted Q0918/Q0919 to use a single transformer.

[58] PacifiCorp's Opening Brief,, at 29, lines 8-11.

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c. The Commission requested utilities try to accommodate non-standard metering of community solar projects, in Docket No. UM 1930.

In Order No. 19-392, the Commission approved low-side metering for generators 360 kW or less, and asked generators and utilities to "continue to explore additional one-off interconnection enhancements."[59] Low-side metering is one of the easiest ways to improve the economics of Oregon community solar projects without sacrificing safety or reliability.

d. Low-side metering of adjacent small generators is reasonable where combined generation on the high side is also metered.

PacifiCorp's stated reasons for requiring high-side metering are: (a) its PacifiCorp's policy; and (b) high-side meters enable direct measurement of transformer losses.[60] Allowing low-side metering in cases where combined generation on the high side is also metered would not undermine either of PacifiCorp's justifications. Adjacent projects where combined generation is metered on the high side is a special case, where three high side meters would be excessive, because the high side meter at the Point of Interconnection can measure transformation losses. PacifiCorp already created this special category in 2018, when it approved Q0918 and Q0919.

e. PacifiCorp failed to to show high side metering is reasonable.

The record demonstrates that low-side metering of adjacent projects where a third meter is located at the point of interconnection is well-suited for PacifiCorp-owned projects

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[59] Order 19-392, Appendix A at pp. 13-14.
[60] PacifiCorp's Opening Brief, p. 28, lines 16-19.

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Q0919 and Q0918. The record also shows that PacifiCorp estimated low-side meters would reduce metering costs by $25,000.[61] After stating in its opening testimony that its projects Q0918 and Q0919 are "essentially the same configuration as PRS1 and PRS2,"[62] PacifiCorp has failed to demonstrate that requiring Sunthurst to meter at the high side, at an added cost of $25,000, is reasonable.

2. Remedy Requested

Because PacifiCorp failed to articulate a reasonable basis for requiring high side metering at PRS1/PRS2 while allowing low-side metering at Q0918/Q0919, Sunthurst reiterates its request, on page 35 of its Opening Brief, that the Commission order PacifiCorp to permit low-side metering, or else credit Sunthurst the difference in cost between low- and high-side metering.

E. Reasonableness of the 8% Capital Surcharge

1. Sunthurst's Rebuttal Argument

a. PacifiCorp's statement that Sunthurst carries the burden of proof is incorrect.

Sunthurst is required to pay PacifiCorp a reasonable fraction of PacifiCorp's construction overhead costs, [63] *provided that* such costs are assessed on a non-

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[61] Sunthurst/211, Beanland/19, PacifiCorp's August 7, 2020 letter to Sunthurst ("PacifiCorp estimates that this change would result in only approximately $25,000 in cost savings for PacifiCorp's costs.").

[62] PAC/200, Patzkowski-Taylor-Vaz/7, lines 17-19.

[63] OAR 860-082-0015(34)("System upgrade" means an addition or modification to a public utility's transmission or distribution system or to an affected system that is required to accommodate the interconnection of a small generator facility."); OAR 860-082-0035(4) ("The applicant must pay the *reasonable* costs of any system upgrades").

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discriminatory basis with respect to other customers with similar load or other cost-related characteristics[64]. PacifiCorp has never filed its methodology for allocating construction overheads with the Commission, let alone obtained the Commission's approval. Because PacifiCorp's construction overhead allocation methodology is not part of its *pro forma* interconnection agreements filed with the Commission, *PacifiCorp* bears the burden of proving that they are a reasonable requirement of Sunthurst.

b. PacifiCorp's claim that Sunthurst has not disputed PacifiCorp's methodology for apportioning construction overhead costs[65] is false.

Sunthurst's Opening Brief, pp 35-38, describes multiple instances where PacifiCorp's methodology unreasonably favors PacifiCorp and is unduly discriminatory against small QFs: (a) In 2019, PacifiCorp counted multiple PacifiCorp projects against a single cost cap. (b) In 2019, one of the repowerings PacifiCorp treated as a turn-key project was not a turn-key project. (c) In 2019, only projects paid for by PacifiCorp benefitted from PacifiCorp's Capital Surcharge rate and cost caps. As a result of PacifiCorp's biased methodology, in 2019, the average Capital Surcharge rate on PacifiCorp generation projects was only 0.109%, whereas the rate charged to Sunthurst is 8%. The fact that Sunthurst pays for PacifiCorp's construction overheads at a rate 73 times higher than PacifiCorp's 2019 windmill repowering projects paid for construction overheads is *prima facie* proof PacifiCorp's allocation methodology is unreasonable.

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64 OAR 860-029-0060(1).

65 PacifiCorp's Opening Brief, p. 20, lines 14-15.

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2. Remedies sought for unreasonable Capital Surcharge

Because PacifiCorp's Capital Surcharge methodology is standardized, it should have been filed for approval along with PacifiCorp's standard Oregon small generator interconnection agreement. Had it done so, the Commission likely would have ordered changes to the methodology long ago. In recognition of PacifiCorp's burden to justify its methodology, Sunthurst maintains its request, as set forth in its Opening Brief, pp 43-45, that:

- PacifiCorp should show cause why PacifiCorp's Exceptions to proportional allocation of overhead costs should be retained.
- PacifiCorp's rules for allocating overhead charges to QFs should be filed with, and approved by, the Commission.
- PacifiCorp should not charge PRS1 and PRS2 any Capital Surcharge payment until the Commission approves a new methodology.
- Changes to the Capital Surcharge methodology should be applied to PacifiCorp's proxy resource costs in its IRP and in its avoided costs.

IV. CONCLUSION

Sunthurst respectfully requests the Commission order the parties to comply with the actions each has pledged to take in furtherance of resolving this matter, as described in Section II of Sunthurst's Opening Brief, and grant Sunthurst the relief requested in Section III of its Opening Brief.

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Dated this 13th day of April 2021.

Respectfully submitted,

By: ____________________
Kenneth E. Kaufmann, OSB 982672
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Attachment I

UM 2118 Order No. 21-296

ORDER NO. 21-296

ENTERED Sep 15 2021

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 2118

SUNTHURST ENERGY, LLC, Complainant, vs. PACIFICORP, dba PACIFIC POWER, Respondent.	ORDER

DISPOSITION: COMPLAINT DISMISSED WITH PREJUDICE

I. SUMMARY

In this order, we address five remaining issues identified in Sunthurst's complaint. We deny the relief requested by Sunthurst for each of these five issues. Sunthurst's complaint is dismissed with prejudice.

II. FACTUAL, LEGAL, AND PROCEDURAL BACKGROUND

On September 29, 2020, Sunthurst Energy, LLC (Sunthurst), filed a complaint under ORS 756.500 against PacifiCorp, dba Pacific Power. Sunthurst's complaint regards the "reasonableness of the scope and cost of facilities" required to interconnect two photovoltaic generation sources to PacifiCorp's electrical distribution system in order to sell their net output under the Oregon Community Solar Program (CSP): Pilot Rock Solar 1, LLC (PRS1), a 1.98 megawatt (MW) project; and Pilot Rock Solar 2, LLC (PRS2), a 2.99 MW project. Sunthurst's PRS1 and PRS2 projects are qualifying facilities (QFs) under the Public Utility Regulatory Policies Act of 1978 (PURPA).[1]

Both projects requested interconnection to PacifiCorp's city feeder circuit (5W406) from the Pilot Rock Substation and were designated queue numbers: PRS1 was designated Queue No. 0666 (Q0666); and PRS2 was designated Queue No. 1045 (Q1045). Interconnection for QFs to PacifiCorp's system is subject to regulation by the Commission under PURPA, as well as Oregon's implementing statutes in ORS 758.505 to 758.555. The interconnection study process for PacifiCorp is governed by the Commission's small generator interconnection rules in OAR Chapter 860, Division 82.

[1] Public Utility Regulatory Policies Act of 1978 (PURPA) 16 USC § 824a-*et seq*., Pub L 95-617, 92 Stat 3117.

The purpose of an interconnection study for a small generator is to identify the requirements, including modifications and additions to the utility's system, which will be needed to interconnect a small generator to the utility's system in a safe and reliable manner. The requirements are individualized for the specific small generator's characteristics, the utility's system, and the interconnection situation, and must be reasonable not only with regard to cost, but also with regard to scope and technical standards, as well as nondiscriminatory in application. Sunthurst challenges certain requirements identified in the interconnection studies for PRS1 and PRS2 on these various bases. The relief that Sunthurst primarily seeks regarding the five remaining issues raised in its complaint is to have PacifiCorp remove requirements specified in the interconnection studies, or alternatively, to eliminate or mitigate costs for the requirements.

Sunthurst filed opening testimony and exhibits on December 15, 2020. On February 22, 2021, PacifiCorp filed response testimony and exhibits. The parties agreed to not cross-examine any witnesses and no hearing was held. On March 26, 2021, the parties filed simultaneous opening briefs. On April 13, 2021, the parties filed simultaneous reply briefs.

III. DISCUSSION

A. Overview

Sunthurst acknowledges and accepts that PacifiCorp made several corrections or adjustments to interconnection cost estimates during the course of these proceedings. These corrections and adjustments result in a net reduction of $128,694 to the PRS1 interconnection estimate, and a net reduction of $13,034 to the PRS2 interconnection estimate.[2] Total estimated costs for the interconnection of PRS1 and PRS2 have been reduced from $2,000,000 in early 2020 to approximately $860,000 (excluding approximately $75,000 for telemetry costs still at issue) as of the close of the record for these proceedings.[3] Although most of the changes were identified in PacifiCorp's opening testimony, PacifiCorp later agreed to remove approximately $39,000 for meter costs at the point of interconnection (POI) for PRS1 and PRS2. Sunthurst disputes only one change: PacifiCorp's $19,556 reduction in PRS1 costs for fiber installation, as further discussed in this order. Sunthurst also acknowledges and accepts credits by PacifiCorp for future interconnection engineering and management costs for Sunthurst's PI-111 annunciator panel design (quantified at $6,097.27). Sunthurst indicates that it also made several concessions during negotiations and dropped several issues.

As a result of all the concessions and adjustments, only five of the original issues identified in Sunthurst's complaint are still in dispute, and addressed in this docket. We resolve the five issues on their merits based on the evidence and arguments presented, as further discussed below.

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[2] Sunthurst's Opening Brief at 4, fn 1 citing PAC/200, Patzkowski-Taylor-Vaz/42-43.
[3] Sunthurst's Reply Brief at 3, fn 2 citing PacifiCorp's Opening Brief at 12, line 19.

B. Cost Liability for Branch Regulators

1. Overview

PacifiCorp's interconnection studies specify branch regulators as a condition for the interconnection of PRS2. The branch regulators would be installed on two circuit branches at a cost of approximately $180,000.[4] Sunthurst challenges the requirement.

2. Sunthurst's Position

Sunthurst questions whether PacifiCorp demonstrates that "branch regulators are reasonable and necessary to interconnect PRS2,"[5] on the basis that they are not needed for safety or voltage maintenance. PacifiCorp does not assert that system safety requires branch regulators, Sunthurst states; indeed, there is evidence that Circuit 5W406 safely functions without voltage regulation (*e.g.*, Circuit 5W406 operated for at least thirteen days in 2019 without voltage regulation when the regulator control failed).[6] PacifiCorp also does not assert that branch regulators are needed to maintain voltage levels within acceptable ranges for service, Sunthurst states; PacifiCorp testified that: "[v]oltage analyses were completed for both PRS1 and PRS2 and it was determined that ANSI C84.1 Range A voltages can be maintained without the need for the line voltage regulator banks."[7] Sunthurst contends that branch regulators may be needed to redress an existing problem on PacifiCorp's system, noting that during a call on June 9, 2020, PacifiCorp indicated that existing voltages on Circuit 5W406 were then outside of ANSI Range A criteria.[8]

Sunthurst understands that PacifiCorp's primary reason for requiring branch regulators to interconnect PRS2 is to support Conservation Voltage Reduction (CVR). To determine the reasonableness of requiring branch regulators for efficiency reasons, however, the estimated costs and the expected benefits associated with the branch regulators requirement must be compared, Sunthurst observes, yet PacifiCorp did not attempt to quantify such, and provided no evidence that branch regulators would reduce losses.[9] Sunthurst acknowledges the orders cited by PacifiCorp that encourage CVR, but notes that they did not refute the need for economic study of the option, but instead encouraged its measurement and validation.[10] Sunthurst challenges PacifiCorp's repeated claim that PURPA's customer indifference standard means that there can be no system changes. When asked about the specific conditions triggering the need for voltage requirement, PacifiCorp stated that it was needed because of "the inability for the voltage regulator control in the substation to measure load on the feeder to enable the use of Line Drop

[4] *Id*. at 17.
[5] *Id*. at 14.
[6] Sunthurst's Opening Brief at 6, fn 8 citing Sunthurst/400, Beanland/10, lines 11-18.
[7] *Id*.at 7, fn 9 citing Sunthurst/401, Beanland/101 (Response to Sunthurst DR10.2(b)).
[8] Sunthurst's Reply Brief at 11, fn 17 citing Sunthurst/300, Hale/6, lines 18-20.
[9] *Id*. at 9.
[10] *Id*. at 14.

Compensation (LDC) settings."[11] Sunthurst responds, "[t]his standard is not really a standard because we don't know how much load on the circuit is too much for the voltage regulator control."[12] Sunthurst argues that *PacifiCorp's Engineering Handbook 1E.3.1-Distribution Planning Study Guide* (2015) supports Sunthurst's argument that voltage regulators are reasonably required only if economically justified.[13] This document also called for analysis of alternatives which PacifiCorp did not do, Sunthurst protests. Sunthurst further complains about PacifiCorp's documentation of the requirement because PacifiCorp disposed of studies that were conducted when preparing the System Impact Study (SIS) report for PRS2. PacifiCorp indicated that "detailed voltage drop and fault current analysis" for Q0666 and Q1045 is not available because the software used to perform the analysis was removed from Company computers.[14] Sunthurst also cannot determine any consistency regarding when branch regulators are required, noting confinement of the requirement to a small corner of PacifiCorp's Oregon service territory.[15] Although PacifiCorp uses LDC regulation on most feeders across its systems, Sunthurst only found three instances other than PRS2 in 27 Oregon Community Solar (CSP) SIS reports where PacifiCorp specified branch regulators, and two were in Umatilla County and one in the adjacent Wallowa County.[16]

3. PacifiCorp's Position

PacifiCorp states that it currently uses LDC settings on the company's voltage regulator controls to remotely regulate voltage to maintain a defined range (American National Standards Institute (ANSI) standard C84.1 range A), resulting in reduced energy use and system losses, thereby creating a more energy efficient system that lowers costs for customers.[17] As Sunthurst acknowledges, PacifiCorp observes, this process is called CVR, and we encourage its use.[18] Sunthurst does not deny that PacifiCorp uses LDC regulation across its system, PacifiCorp indicates.[19] Moreover, PacifiCorp indicates that LDC is currently used on the feeder that will interconnect PRS1 and PRS2 to implement CVR, and Sunthurst does not contest such. As the determination was already made to use LDC settings to implement CVR on Circuit 5W406 or whether LDC should be used, there is not currently an issue; instead, the issue is identification of requirements to interconnect PRS1 and PRS2 while maintaining current customer service.

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[11] Sunthurst's Opening Brief at 11, fn 21 citing Sunthurst/401, Beanland/83 (response to Sunthurst Data Request 9.15(a)).
[12] *Id*.
[13] *Id*. at 9-10.
[14] *Id.* at 13, fn 30 citing Sunthurst/401, Beanland/7, lines 32.
[15] Sunthurst's Reply Brief at 16, fn 33.
[16] Sunthurst's Opening Brief at 12, fn 26 citing Sunthurst/400, Beanland/9, lines 1-7.
[17] PacifiCorp's Opening Brief at 14, fn 60 citing PAC/200, Patzkowski, Taylor, Vaz/20.
[18] *Id*. fn 62 (*See*, *e.g.*, *In re Portland Gen. Elec. Co*., *2016 Integrated Resource Plan*, Docket No. LC 66, Order No. 17-386 at 9-10 (Oct 9, 2017); *In re Idaho Power Co. 2014, Annual Smart Grid Report*, Docked No. UM 1675, Order No. 15-053, Apex A at 6-7 (Feb 23, 2015).
[19] PacifiCorp's Reply Brief at 7, fn 18 citing Sunthurst's Opening Brief at 12.

The addition of the PRS2 project at the intended feeder would increase peak load past the level that can be controlled with current LDC settings, PacifiCorp indicates, making CVR capability unavailable, and causing higher prices for customers.[20] For this reason, PacifiCorp argues, the voltage regulators are a necessary and reasonable interconnection cost for PRS2. PacifiCorp performed the voltage studies for PRS2 in 2018, but no longer has them because the vendor stopped supporting the underlying software and PacifiCorp had to remove it from company computers for cybersecurity reasons and to maintain certification with the California Independent System Operator.[21] However, the voltage studies are not needed, PacifiCorp asserts, because voltage regulators are required to continue using LDC settings at all (rather than to just maintain ANSI Range A voltages).

Whether other CSP interconnections require voltage requirements is irrelevant, PacifiCorp explains, because each interconnect request is unique. Countering Sunthurst's assertion that the voltage regulators are necessary to address an existing problem, PacifiCorp explains that the company previously paid for voltage regulators when the company already planned to install them, despite an interconnection request that would have also required regulators; PacifiCorp did so as the company recognized that the request did not trigger the need for voltage requirements, as opposed to the situation here where a request for interconnection triggers the need for branch regulators.

4. Resolution

PacifiCorp's preexisting use of LDC settings to implement CVR on the Circuit 5W406 is not contested here. As PacifiCorp observes, the decision to implement CVR on the Circuit 5W406 was a decision previously made and implemented by the company and is not at issue now. Rather, the issue we address here is whether it is reasonable for PacifiCorp to require branch regulators as a condition for the interconnection of PRS2 in order to maintain the LDC settings needed to maintain CVR and its benefits. We find that it is.

As PacifiCorp also points out, we encourage the utilities to implement CVR due to the system efficiencies and cost savings that it produces. When an interconnection request triggers the need for voltage regulators to maintain the LDC settings needed to implement CVR, we find that it is reasonable for PacifiCorp to require the interconnecting generator to pay for those voltage regulators. It is reasonable to require an interconnecting generator to pay for interconnection costs to ensure that system efficiencies remain in place and customer savings already in effect can continue. As a system-based cost/benefit analysis regarding operating CVR was previously made, we find it unnecessary to redo the analysis. We acknowledge that the trigger for a voltage regulator requirement may be a basic determination that an interconnection will increase peak load past the level that can be controlled with existing LDC settings, thereby making CVR capability unavailable, where CVR was previously implemented.

[20] PacifiCorp Opening Brief at 14.
[21] PacifiCorp Reply Brief at 11, fn 45 citing Sunthurst/401, Beanland/32.

C. Cost Liability for Fiber Optic Link

1. Overview

PacifiCorp requires a high-speed communication link between a recloser relay at PRS1/PRS2 and the company's Pilot Rock substation. Although the need for the high-speed communication is not in dispute, Sunthurst and PacifiCorp disagree about the type of high-speed communication link that should be used.

2. Sunthurst's Position

Sunthurst indicates that there are two high-speed communication link options currently used on PacifiCorp's system: 1) fiber optic cable strung on PacifiCorp poles from PRS1/PRS2 to the substation; or 2) dedicated spread spectrum, high-speed radio link that uses radio signals for communication.[22] Sunthurst points to two examples of community solar projects using radio links,[23] and objects to PacifiCorp's characterization of fiber optic as the "best practice."[24] Asserting that costs are lower with spread spectrum radio, and arguing that claims about the greater reliability of fiber optic cable are speculative, Sunthurst asks that PacifiCorp be directed to use spread spectrum radio, or alternatively, to cover any cost differential for fiber optic cable. While the high-speed communication link at issue would not be installed in the absence of the interconnection of Sunthurst's projects, that interconnection need not be a fiber optic cable, Sunthurst argues.

Sunthurst challenges PacifiCorp's contention that costs for fiber optic cable and spread spectrum radio are comparable. PacifiCorp initially estimated that fiber optic cable costs would be approximately $14,000 (based on an estimate of $60,000 per mile) more than a spread spectrum radio link.[25] With regard to PacifiCorp's revised estimate of $42,000 per mile, Sunthurst asserts that the "estimate is not based on sound methodology, but rather wishful thinking," and contends that PacifiCorp tries to justify a preference for fiber optic cable with an estimate not supported by evidence.[26]

Sunthurst further asserts that PacifiCorp favors fiber optic because it provides system benefits that spread spectrum radio does not—*e.g.*, allowing replacement of existing poles, and facilitating the use of telemetry. As PacifiCorp insists on using a 48-pair fiber-optic cable even though interconnection of Sunthurst's projects likely requires two fibers, PacifiCorp will own the additional fibers and may be able to lease them. Sunthurst argues that the underlying intent of the small generator interconnection rules (OAR 860, Division 82) is to prevent a utility from requiring a small generator to pay for a system upgrade that primarily benefits the utility.

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[22] Sunthurst's Opening Brief at 15.
[23] *Id*. fn 32 (OCS045 (Sunthurst/403, Beanland/9) and OCS024 (posted online on PacifiCorp's OASIS website)).
[24] *Id*., fn 33 PAC/200, Patzkowski-Taylor-Vax/22, line 21-22.
[25] *Id*. at 16, citing PAC/200 Patzkowki-Taylor-Vaz/24, lines 13-17.
[26] *Id*. at 18, fn 42 Sunthurst/400, Beanland/3, lines 3-16.

3. *PacifiCorp's Position*

PacifiCorp argues that fiber optic cable links are more reliable than spread spectrum radio which can experience interference from other spread-spectrum users in a particular area. As the purpose of a high-speed communication link between the recloser relay at PRS1/PRS2 and the company's Pilot Rock substation is to facilitate monitoring and managing the company's electrical networks to ensure reliable power, the enhanced reliability of cable links makes using them a utility's best practice, PacifiCorp states, and the company has a nondiscriminatory policy that requires *all* interconnection requests to use fiber optic links. Regardless of whether the fiber optic link installed between the company's Pilot Rock substation and PRS1/PRS2 will provide any benefits to the company's system, that link would not be installed *but for* Sunthurst's interconnection requests, PacifiCorp asserts; for this reason, the interconnection costs for PRS1 and PRS2 are reasonable costs for Sunthurst, not other customers, to pay.

PacifiCorp disputes the claim that the cost of a fiber optic link for PRS1 and PRS2 is more expensive than a radio link. PacifiCorp initially estimated the cost to be approximately $60,000, or $14,000[27] more than the estimated cost of $46,000 for a radio link[28] The company typically estimates $42,000 per mile for a new distribution line, and $60,000 per mile for an existing distribution line; PacifiCorp ultimately amended the estimated cost for Sunthurst by using the $42,000 per mile cost multiplied by 0.9 miles for a total cost of $38,000. OAR 860-082-0035(2) does not require lowest cost, and both estimates are in a comparable range with a radio link, PacifiCorp indicates.

The 48-fiber cable that Sunthurst calls excessive is the company's standard cable used across its system, PacifiCorp indicates. The company uses standard equipment to facilitate more efficient design, procurement, and construction, PacifiCorp states. As PacifiCorp estimates that the special procurement of a 12-fiber count cable would increase installation, Sunthurst's projected savings of approximately $2,376 from using the 12-fiber count cable could be erased. PacifiCorp also refutes Sunthurst's contention that the company may monetize any excess capacity, stating that the company does not anticipate any opportunity for lease revenue.[29]

4. *Resolution*

Although a utility's best practices and company standards are not insurmountable justifications for interconnection requirements, they merit significant consideration when there is a request to set them aside. Based on the enhanced reliability measures of the technology, PacifiCorp asserts that fiber optic links are a utility's best practice and a company standard that is applied in a nondiscriminatory manner to all interconnection requests.

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[27] PacifiCorp's Reply Brief at 18.
[28] *Id.*
[29] *Id.* at 21.

Contending that a spread spectrum, high-speed radio link can be used and may be less expensive than a fiber optic link, Sunthurst asks us to direct PacifiCorp to allow the use of spread spectrum radio as the communication link between the recloser relay at PRS1/PRS2 and the company's Pilot Rock substation. We find, however, that reducing Sunthurst's interconnection costs by an uncertain amount of money is insufficient justification for setting aside a standard that appears reasonable and justified to facilitate reliable power for all customers. We also note that Sunthurst fails to undermine PacifiCorp's credible claims that a fiber optic link is technologically more reliable than spread spectrum radio.

D. Liability for Telemetry-Related Costs

1. Overview

PacifiCorp uses telemetry to monitor, in real time, the status of componentry on its electrical system. A remote terminal unit (RTU) gathers and communicates project data (MW, MVAR, etc.) when telemetry is installed at a distributed energy resource (DER). PacifiCorp specified telemetry for PRS2, but not PRS1.

In the initial Facilities Report for PRS2, telemetry was a principal cost. Sunthurst asked PacifiCorp to eliminate the telemetry requirement for PRS2 and PacifiCorp agreed to remove over $525,000 in estimated costs for PacifiCorp-owned telemetry equipment, but did not remove potential costs to install telemetry equipment on Sunthurst's facilities. Sunthurst objects to these remaining costs.

2. Sunthurst's Position

Sunthurst argues that OAR 860-082-0070(2) controls on this issue, meaning that PacifiCorp is prohibited from imposing any charges related to telemetry on Sunthurst for either PRS1 or PRS2, as each facility is under 3 MW.[30] This rule is inapplicable only if the exception in OAR 860-082-0070(3)(b) is effective,[31] which it is not for PRS1 and PRS2, Sunthurst explains. Sunthurst asks us to direct PacifiCorp to either not charge or reimburse for any and all telemetry charges.

PacifiCorp's attempt to apply OAR 860-082-0025(4) is strained, Sunthurst contends. Sunthurst analyzes the provision in context of its last sentence of the rule's text, which PacifiCorp does not address, and argues that the rule provides that the small generator interconnection rules do not apply when multiple small generator facilities having a total nameplate capacity exceeding 10 MW are connected at a single point of

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[30] Sunthurst's Opening Brief at 25, citing OAR 860-08-0070(2) ("Except as provided in subsection 3(b), a public utility may not require an applicant or interconnection customer with a small generator facility with a nameplate capacity of less than three megawatts to provide or pay for the data acquisition or telemetry equipment necessary to allow the public utility to remotely monitor the small generator facility's electric output.").

[31] *Id.*

interconnection.[32] As the combined nameplate capacity of PRS1 and PRS2 is well under 10 MW, the provision does not apply. In any case, Sunthurst argues, combining PRS1 and PRS2 is not reasonable when their interconnection applications were made more than three years apart.

Sunthurst also challenges the appropriateness of PacifiCorp relying on Policy 138, as revised on December 20, 2020. It is unfair that PacifiCorp did not advise Sunthurst of Policy 138's application prior to its brief, Sunthurst notes.

3. PacifiCorp's Position

PacifiCorp agrees that OAR 860-082-0070 generally prohibits a utility from requiring telemetry for projects that have a nameplate capacity of less than 3 MW, but notes that this rule must be read in context of all Commission-approved interconnection rules and policies. Because the applicant proposes to interconnect multiple generator facilities at a single point of interconnection, OAR 860-082-005(4) applies, and directs that the interconnection request be evaluated based on total nameplate capacity.[33] The company's Interconnection Policy 138 is consistent with these rules, PacifiCorp indicates, by requiring telemetry if multiple generating facilities exceed 3 MW and use a single POI.

While PRS1 and PRS2 are each under 3 MW, they have the same POI and a combined nameplate capacity of 4.97 MW, PacifiCorp states. For this reason, PacifiCorp argues, they should be jointly evaluated as a single 4.97 MW facility under the Commission's rules and Policy 138. Nevertheless, PacifiCorp agreed not to require Sunthurst to pay the costs associated with installing telemetry equipment on PacifiCorp's system, and removed over $525,000 from the cost estimates for the interconnection of PRS1 and PRS2.[34] However, should PacifiCorp install the telemetry equipment, PacifiCorp asserts that Sunthurst should pay any costs to install equipment on Sunthurst's facilities that would enable the installation of the telemetry equipment.

4. Resolution

OAR 860-082-0025(4) addresses the interconnection of multiple generator facilities at a single POI. The first and second sentences of the provision stand on their own, we find; to read the second sentence as Sunthurst suggests, it would be necessary to assume language not there—*i.e.*, an initial phrase such as "for purposes of determining whether the small generator interconnection rules apply, the public utility must evaluate applications based on the combined total nameplate capacity * * *."

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[32] Sunthurst's Reply Brief at 22-23 citing OAR 860-08-0025(4) ("If the combined total nameplate capacity exceeds 10 megawatt, then the small generator interconnection rules do not apply.").
[33] *Id.*, citing OAR 860-082-0025(4) (when "an applicant proposes to interconnect multiple small generator facilities to [a] public utility's transmission or distribution system at a single point of interconnection," the public utility "must evaluate based on the combined total nameplate capacity.").
[34] PacifiCorp's Reply Brief at 21, fn 105 citing PAC/100, Bremer/10-11.

The first sentence directs a utility to jointly evaluate interconnection applications at the same POI. As PRS1 and PRS2 will have the same POI, the provision applies, and we find that PacifiCorp is correct to jointly evaluate their interconnection applications with regard to the system impact of the total energy, a nameplate capacity of 4.97 MW, that will flow through the POI. We note that the provision does not address the timing of the interconnection applications. We conclude that despite the three-year interval between applications, it is appropriate to jointly evaluate interconnection applications at the same POI when the opportunity presents itself; for this reason, we disagree with Sunthurst that OAR 860-082-0070(2) controls.

E. Cost Liability for High-Side Project Meters

1. Overview

The parties disagree about where the project meters should be sited. Sunthurst seeks permission to site meters on the "low side" of the transformer. PacifiCorp contends that metering must be done on the "high side" of the transformer, with the only exception being for Community Solar Projects less than 360 kilowatts.

2. Sunthurst's Position

The "low side" refers to the lower voltage on the DER side of the power transformer that interconnects with the PacifiCorp distribution system, Sunthurst states.[35] Arguing that low-side metering is less expensive, Sunthurst requests that we order PacifiCorp to: 1) allow low-side metering for the PRS1 and PRS2 projects; or 2) pay the incremental cost difference between metering on the high and low sides.

Sunthurst cites the 2016 edition of the *PacifiCorp Electric Service Requirements* manual as evidence that low-side metering can be used for 480V services up to 4,000 amps, about 3,300kW/kVA in capacity, and therefore for PRS1 (1,980kW) and PRS2 (2,900kW).[36] Sunthurst also identifies two instances during 2018 where PacifiCorp permitted solar generators similar in size to PRS1 and PRS2 to use low-side metering. In one instance, two adjacent 898 kW net metering installations (NMQ0032 and NMQ0033) were interconnected to PacifiCorp's Dorris substation in Dorris, California.[37]

In the other instance, two small, adjacent, generating facilities owned by PacifiCorp (Panguitch Solar and Panguitch Storage) are interconnected with the company's system in Utah by low-side metering. Sunthurst further explains that the 0.65 MW Panguitch Solar Project (Q0918) and the 1.00 MW Panguitch Storage Project (Q0919) are similar to PRS1 and PRS2, as PacifiCorp admits, being adjacent, interconnecting to a 12.5 kV distribution line at a common point, and having a meter on the high side (in addition to

[35] Sunthurst's Opening Brief at 29.
[36] *Id*. at 30-31, fn 71 citing Sunthurst/400, Beanland/18, line 16-19.
[37] *Id*. at 31, fn 74 citing Sunthurst/400, Beanland/16, lines 3-7.

the meter on the low side for each) that measures combined output at the change of ownership point (as is also specified for PRS1/PRS2).[38] Sunthurst argues that the Panguitch Solar/Storage projects demonstrate the reasonableness of specifying low-side meters for each of two adjacent DERs that interconnect at a common point along with a third meter on the high side that measures combined output at the change of ownership point. This third meter eliminates concerns about inaccuracies, Sunthurst indicates. The only significant difference between the PRS1/PRS2 projects and the Panguitch Solar/Storage projects is ownership, Sunthurst asserts, which is not a proper basis for dissimilar treatment.

For DERs like PRS1 and PRS2, Sunthurst asserts that low-side metering is generally less expensive.[39] The low-side of the power transformer is 480V; since utility meters can generally accept 480V input voltages directly at the meter, the need for a transformer to step down voltage is eliminated, Sunthurst explains. Moreover, the transformers required for low voltage metering are rated for 600V usage, making them simpler and less expensive to implement than transformers needed on the high side, particularly since they typically can be installed on the ground and do not require a pole. Sunthurst testifies that using low-side metering for PRS1 and PRS2 could result in savings of up to $20,000.[40] Arguing that low-side metering is an easy way to improve the economics for community solar projects in Oregon, Sunthurst notes that when approving low-side metering for generators that are 360 kW or less, we asked utilities to further explore accommodation of non-standard metering for community solar projects.[41]

Sunthurst rebuts PacifiCorp's contention that Sunthurst did not timely raise concerns about high-side metering. Although Sunthurst initially raised concerns about high-side metering in a letter to PacifiCorp, dated July 23, 2020, and in the complaint,[42] Sunthurst indicates the issue was dropped in opening testimony in reliance on PacifiCorp's statement "that 'no generator interconnecting today would be allowed to use a low-side metering configuration.'"[43] PacifiCorp's opening testimony regarding the Panguitch projects, however, led Sunthurst to investigate the issue more, and to address it in reply testimony, Sunthurst explains.

3. *PacifiCorp's Position*

PacifiCorp indicates that the company's standard metering practice for distributed generators such as PRS1 and PRS2 is to install meters on the high-side of the transformer

[38] *Id*. at 32-33, fn 81 citing PAC/200, Patzkowski-Taylor-Vaz/7, lines 17-19 ("PacifiCorp's merchant function submitted and ultimately constructed two small generating facilities (Q0918 and Q0919) in Utah with essentially the same configuration as PRS1 and PRS2.").
[39] *Id*. at 30.
[40] *Id*.
[41] Sunthurst Reply Brief at 27, fn 59 citing Order 19-392, Appendix A at 13-14 ("continue to explore additional one-off interconnection enhancements").
[42] *Id*. at 25.
[43] *Id*. fn 55 citing Sunthurst/401, Beanland/29.

where the company takes ownership of the electricity. High-side metering is consistent with current standard utility practice, a fact that Sunthurst does not dispute, PacifiCorp asserts. Low-side metering requires estimation of transformer losses, PacifiCorp indicates, causing inaccurate metering. PacifiCorp indicates that this is the reason that low-side metering is contrary to standard utility practice. We acknowledged such, PacifiCorp states, when we approved using low-side metering only in limited circumstances—*i.e.*, for small CSP generators that are less than 360 kW because losses are less material.[44]

PacifiCorp complains that Sunthurst denied PacifiCorp a full opportunity to address Sunthurst's claims, as Sunthurst's opening testimony on the issue was minimal, with comments about the issue made only in passing.[45] Reply testimony offered selective citations to the company's discovery responses in order to suggest that low-side metering is common across the company's system, PacifiCorp observes.[46] Sunthurst ignored the company's discovery response that provided a comprehensive census of low-side metered generators on its systems showing that except for one project, all PacifiCorp-owned renewable generators with low-side metering were installed between 1895 and 1962.[47]

PacifiCorp challenges the pertinence of Sunthurst's two examples where low-side metering was approved for distributed generation resources, distinguishing each from PRS1 and PRS2. PacifiCorp argues that Sunthurst's discussion of the NMQ0032 and NMQ0033 projects is inapposite as they are net metering projects and PacifiCorp placed the meter on the low side because the company takes ownership of the generation there.[48] Although Q0918 and Q0919 are not net metering projects, they are not the same as PRS1 and PRS2 for the purposes of low-side metering as low-side metering was the only viable option for them, PacifiCorp explains.[49]

Finally, PacifiCorp challenges Sunthurst's estimate that low-side metering would reduce costs by approximately $20,000. PacifiCorp asserts that Sunthurst could not substantiate that number, and revised the estimate to about $6,000, excluding labor costs.[50]

4. Resolution

Sunthurst does not dispute that high-side metering is a current standard for PacifiCorp and the utility industry. Rather, Sunthurst argues that low-side metering can, and should be done, for PRS1 and PRS2 to improve the projects' economics. Indeed, Sunthurst observes that allowing more low-side metering for community solar projects could

[44] PacifiCorp's Opening Brief at 28-29, citing Order No. 20-122 and fn 152 citing Order No. 19-392, App'x A at 13.
[45] *Id*. at 29, fn 155 citing Sunthurst/200, Beanland/33.
[46] PacifiCorp's Reply Brief at 23.
[47] *Id*.
[48] PacifiCorp's Opening Brief at 30.
[49] *Id*.
[50] PacifiCorp's Reply Brief at 24, fn 119 citing PAC/300 at 9.

generally improve the economics of these projects, and noted encouragement of exploration of enhanced interconnection options for CSP generators in Order No. 19-392.

While the Staff Report that was attached to Order No. 19-392 (entered in docket UM 1930) mentioned Staff working "with parties to continue to explore avenues for CSP generators and utilities to collaboratively consider additional one-off interconnection enhancements," the Staff Report envisioned ongoing collaborative work in conjunction with a request for information for third-party expert interconnection study review services and docket UM 2032 proceedings. Sunthurst asking on its own initiative that we make an exception and allow low-side metering for PRS1 and PRS2, two specific CSP generators that are sized well above the 360 kW limit we set in Order No. 19-392 for low-side metering for CSP generators, does not fall under the study and collaborative work anticipated by Staff in docket UM 1930

As we discussed above, a default standard for the utility industry and an individual utility should not be set aside easily. In this case, that bar is particularly high because we recently determined that the high-side metering standard should only be set aside for CSP generators less than 360 kW. Although PacifiCorp does not challenge the feasibility of low-side metering for PRS1 or PRS2, the company effectively explains why high-side metering is the company and industry standard, and undercuts the relevance of the two examples offered by Sunthurst as evidence that PacifiCorp has already allowed low-side metering for distributed generation resources similar to PRS1 and PRS2. Sunthurst also failed to clearly establish the amount of cost savings that would be associated with low-side metering for PRS1 and PRS2, with savings potentially being as low as $6,000 (plus some labor costs). As we held above, we find that uncertain cost savings for individual projects do not warrant setting aside a utility and industry standard.

F. Reasonableness of the Eight Percent Capital Surcharge

1. Overview

OAR 860-029-0010(9) allow utilities to charge interconnection customers for construction overhead expenses that are associated with the interconnection of a generation resource but cannot be directly charged.[51] PacifiCorp applies a capital surcharge, on a monthly basis, to all capital projects to apportion an appropriate amount of administrative and general costs that cannot be directly charged under FERC rules and the United States Generally Accepted Accounting Principles (GAAP). The capital surcharge percentage for projects with total costs of $10 million or less is 8 percent. Application of this 8 percent capital surcharge adds approximately $65,000 to estimated interconnection costs for PRS1 and PRS2.[52] Sunthurst challenges the reasonableness of the 8 percent capital surcharge.

[51] *See* OAR 860-029-0010(9).
[52] Sunthurst's Opening Brief at 35.

2. *Sunthurst's Position*

Sunthurst's opening testimony raises concerns that we never approved the 8 percent capital surcharge or its underlying methodology, and that Sunthurst's expert witness could not verify the surcharge's inclusion in the calculation of avoided costs.[53] Conducting additional discovery on the matter and receiving responses from PacifiCorp after the close of testimony, Sunthurst separately filed Exhibits 500 and 501, and addressed them in briefs. Based on these exhibits, Sunthurst contends that the capital charge is not equally applied due to exceptions that only benefit PacifiCorp's projects. Arguing that the capital surcharge should be a standardized rate, Sunthurst contends that the methodology should have been filed with PacifiCorp's standard Oregon small generator interconnection agreement for vetting and approval; Sunthurst asks that the capital surcharge not be applied until this is done.

Sunthurst indicates that PacifiCorp applies exceptions to the capital surcharge as follows: 1) turn-key transmission projects are charged one-fourth the surcharge rate, with projects over $10 million capped at 2.5 percent of the total cost; and 2) turn-key generation facilities are charged one-fourth the surcharge rate, capped at $500,000. Sunthurst's discovery indicates that PacifiCorp completed 16 projects over $10 million in 2019, spending a total cost of $873.6 million, with nine of those projects being windmill repowering projects having a total cost of $707.2 million (81 percent of the total amount spent on the 16 projects). The nine wind power projects were aggregated to apply the $500,000 cap despite not all not being located adjacent to one another. PacifiCorp spent $707 million to repower nine of its own generation projects in 2019. The total capital surcharge was $773,945. Dividing the total surcharge amount by the total cost indicates that the capital surcharge rate was only 0.109 percent.

Sunthurst contends that PacifiCorp's capital surcharge does not conform to FERC's Uniform System of Accounts (USOA) due to the identified exceptions which make the surcharge arbitrary.[54] Sunthurst also argues that the arbitrary nature of the exceptions are inequitable and discriminatory, in violation of FERC Rule 292.306(a) and OAR 860-029-0060, as PacifiCorp alone benefits from the exceptions, while all other projects pay a set 8 percent charge.

3. *PacifiCorp's Position*

The current capital surcharge applied to all capital projects, with a total cost of less than $10 million, across the company's six-state service territory, including to its own such projects, is 8 percent, PacifiCorp states.[55] PacifiCorp annually calculates this surcharge by dividing total construction support costs by the direct capital spending for the year.[56] PacifiCorp attests that this methodology is consistent with GAAP and the USOA, and

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[53] Sunthurst/100, Hale/11.
[54] Sunthurst's Opening Brief at 40, citing Code of Federal Regulations 18, Part 101, Electric Plant Instructions 4 (A-C).
[55] PacifiCorp's Reply Brief at 12, fn 55, citing PAC/200, Patzkowski, Taylor, Vaz/37.
[56] *Id.*, fn 56, citing PAC/200, Patzkowski, Taylor, Vaz/37.

argues that Sunthurst fails to provide any contravening evidence. Prior to performing this calculation, the company reviewed each cost center to verify and update amounts included in the capital surcharge assessment, with comparisons to the prior year and analysis of any organizational or role changes. PacifiCorp asserts that this rigorous process is not arbitrary. PacifiCorp further explains that capital surcharges are included in ratemaking, and resource cost assumptions used in the company's Integrated Resource Plan (IRP). Moreover, Commission-approved avoided cost prices include the same capital surcharge such that QFs are compensated for avoided construction overhead costs. Sunthurst's initial claims to the contrary are wrong, PacifiCorp asserts. Granting Sunthurst's requested relief would result in significant, unwarranted changes to PacifiCorp's established accounting practices across its six-state service area, PacifiCorp argues.

PacifiCorp rebuts Sunthurst's contention that the 8 percent capital surcharge is discriminatorily applied to favor the company's projects, pointing out that Sunthurst wrongly tries to compare the capital surcharge for large capital projects over $10 million to the capital surcharge for projects that are less than $10 million, such as PRS1 and PRS2.[57] PacifiCorp also notes that the two surcharges (for projects above and below $10 million) are calculated differently and explains that it should not be surprising that the surcharge percentage for a large capital project, such as a new natural gas-fired generating plant, is lower due to the significant involvement of outside contractors (that charge their own capital surcharges) rather than company personnel, PacifiCorp notes. Although the company did not have a proper opportunity to address Sunthurst's complaints that PacifiCorp discriminatorily treated repowering as a single project, PacifiCorp notes that there is nothing prohibiting PacifiCorp from doing so for surcharge purposes.

4. Resolution

We find that the 8 percent seems to be calculated on a reasonable basis, and decline to prohibit PacifiCorp from issuing this charge. It is not contested that: 1) our rules permit a utility to charge for overhead expenses incurred to interconnect a generation facility; 2) PacifiCorp will incur overhead expenses to interconnect PRS1 and PRS2; and 3) PacifiCorp generally uses the same capital surcharge methodology across its six-state service area. Although Sunthurst initially questioned whether inclusion of the 8 percent capital surcharge is in avoided costs, the concern was addressed by PacifiCorp's explanation that it is.

There is confusion regarding application of the 8 percent capital surcharge. PacifiCorp effectively rebuts Sunthurst's contention that the 8 percent capital surcharge is discriminatorily applied to favor the company's projects by explaining that the 8 percent capital surcharge only applies to projects that are less than $10 million, which includes PRS1 and PRS2, and not to projects that are more than $10 million, such as PacifiCorp's

[57] PacifiCorp's Opening Brief at 20, fn 95 citing Sunthurst/300, Hale, 10-11.

repowering projects. We do not find a basis here to determine that this division or treatment is unreasonable.

Sunthurst's remaining concern is that we have specifically not approved the 8 percent capital surcharge or its underlying methodology. We agree with PacifiCorp, however, that capital surcharges are included in numerous ratemaking, resource evaluation, and avoided cost rate proceedings. The fact that the 8 percent capital surcharge and its underlying methodology have never been specifically identified as needing individualized review does not mean that it is invalid. We decline to direct that it not be applied until further reviewed.

IV. ORDER

IT IS ORDERED that the complaint brought by Sunthurst Energy, LLC, against PacifiCorp, dba Pacific Power, is dismissed with prejudice.

Made, entered, and effective Sep 15 2021.

Megan W. Decker
Chair

Letha Tawney
Commissioner

Mark R. Thompson
Commissioner

A party may request rehearing or reconsideration of this order under ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-001-0720. A copy of the request must also be served on each party to the proceedings as provided in OAR 860-001-0180(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480 through 183.484.