PACIFIC POWER
A DIVISION OF PACIFICORP

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January 26, 2021

VIA ELECTRONIC FILING

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

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

Exhibit PAC/101—Q0666 SGIA, as amended

Exhibit PAC/102—Sunthurst Letter

Exhibit PAC/103—Q1045 Interconnection Studies

Exhibit PAC/104—Sunthurst Letter

Exhibit PAC/105—Sunthurst DR Responses

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.

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[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

[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

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[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.

[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

[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.

[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.

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[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

[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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TRANSMISSION SERVICES
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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

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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

☒ 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.

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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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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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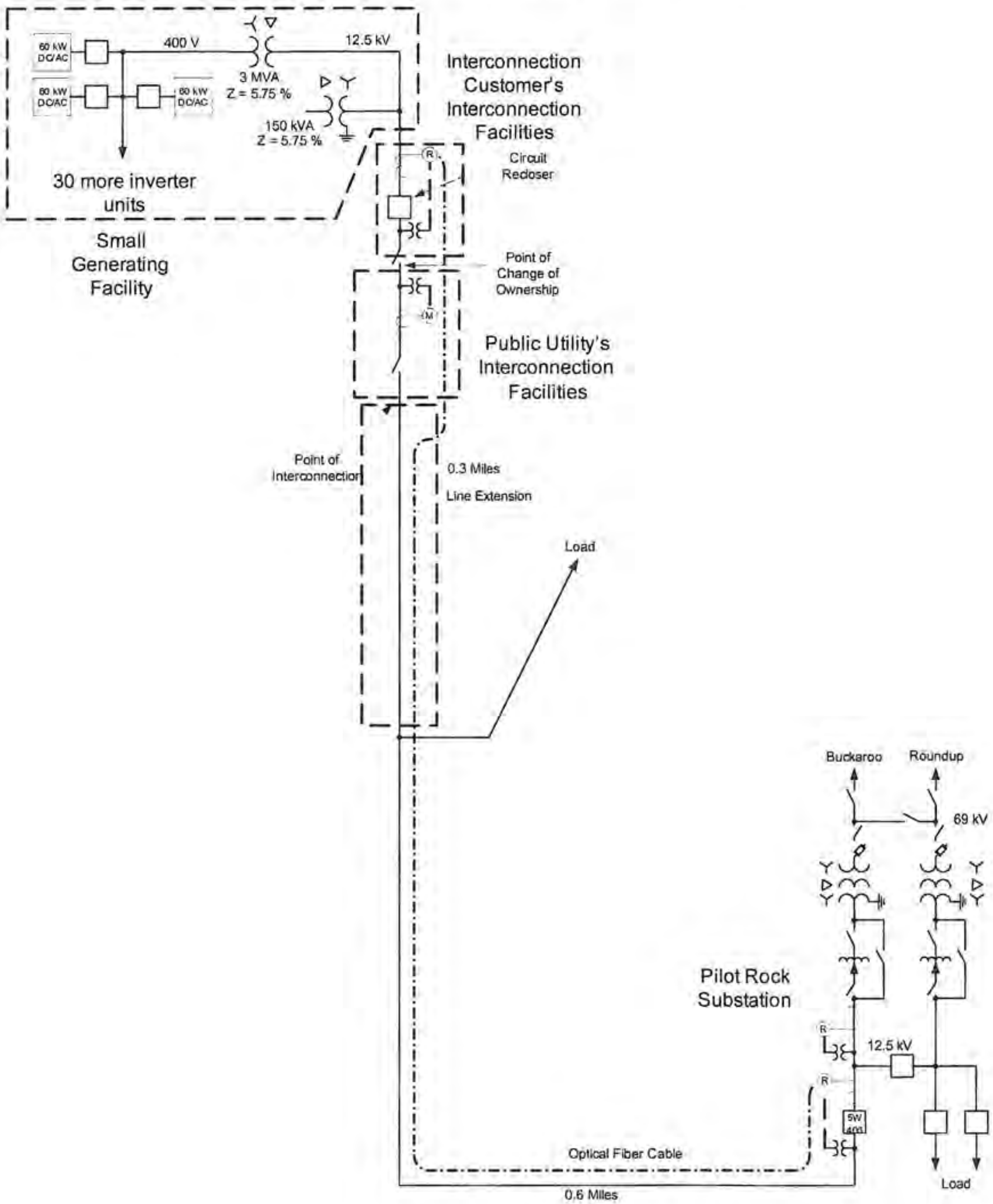
Attachment 2

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.

<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

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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

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(Small Generator Facilities with Electric Nameplate Capacities of 10MW or less)

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

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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)

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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Tier 1, Tier 2, Tier 3 or Tier 4 Interconnection
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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 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: ____________________

Title: VP, Transmission

Date: 6/20/16

Sunthurst Energy, LLC (Q666)

By: D Hale

Title: Principal

Date: 6.15.16

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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 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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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, 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

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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 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:

Title: Owner

Date: 11/21/17

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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 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

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Form 8

Interconnection Agreement for Small Generator Facility
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capability of the Small Generating Facility and the voltage control system prior to Commercial Operations.

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**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

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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 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

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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

PACIFICORP

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.

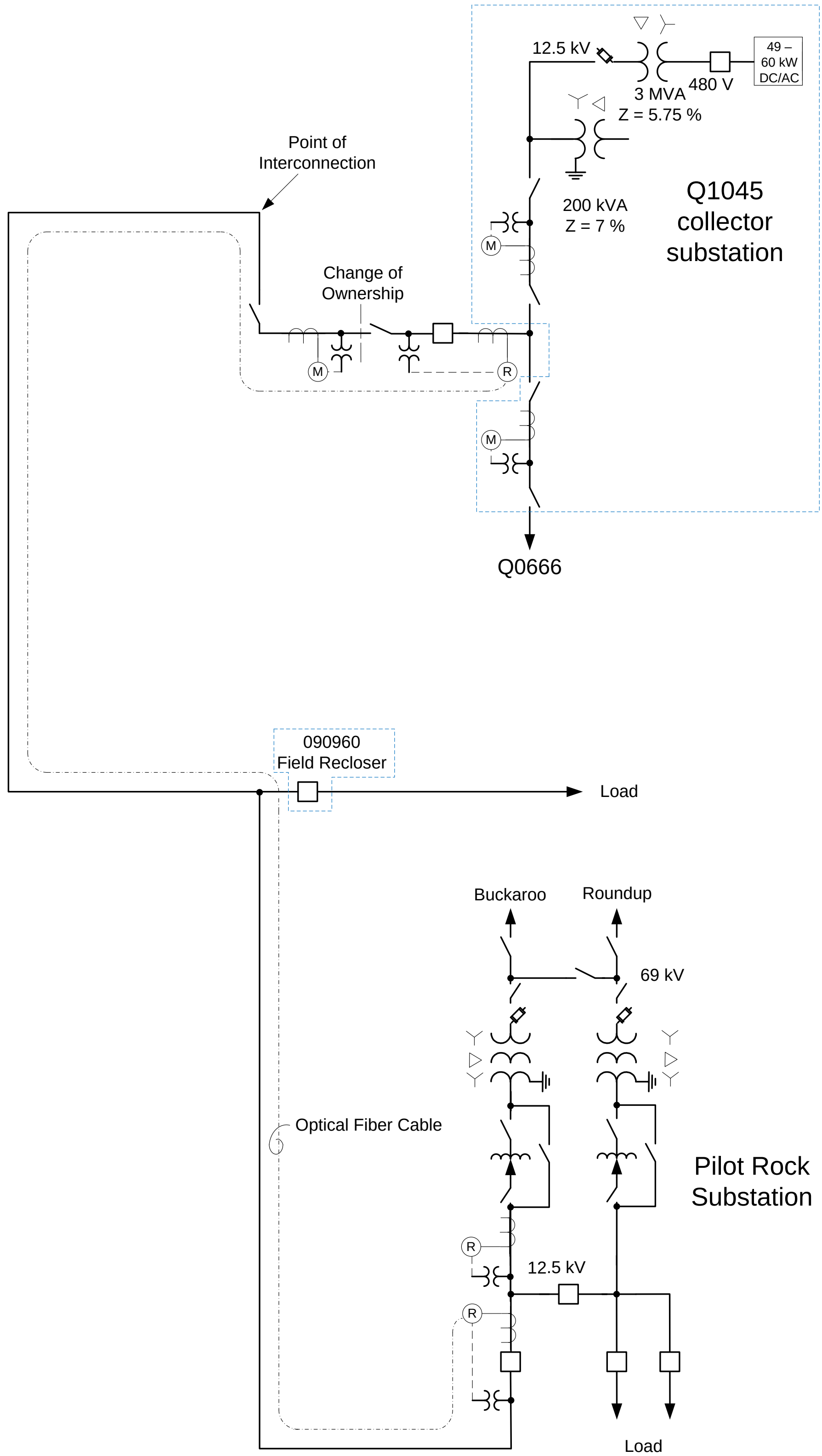

Figure 1: System One Line Diagram

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:

- 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.

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.

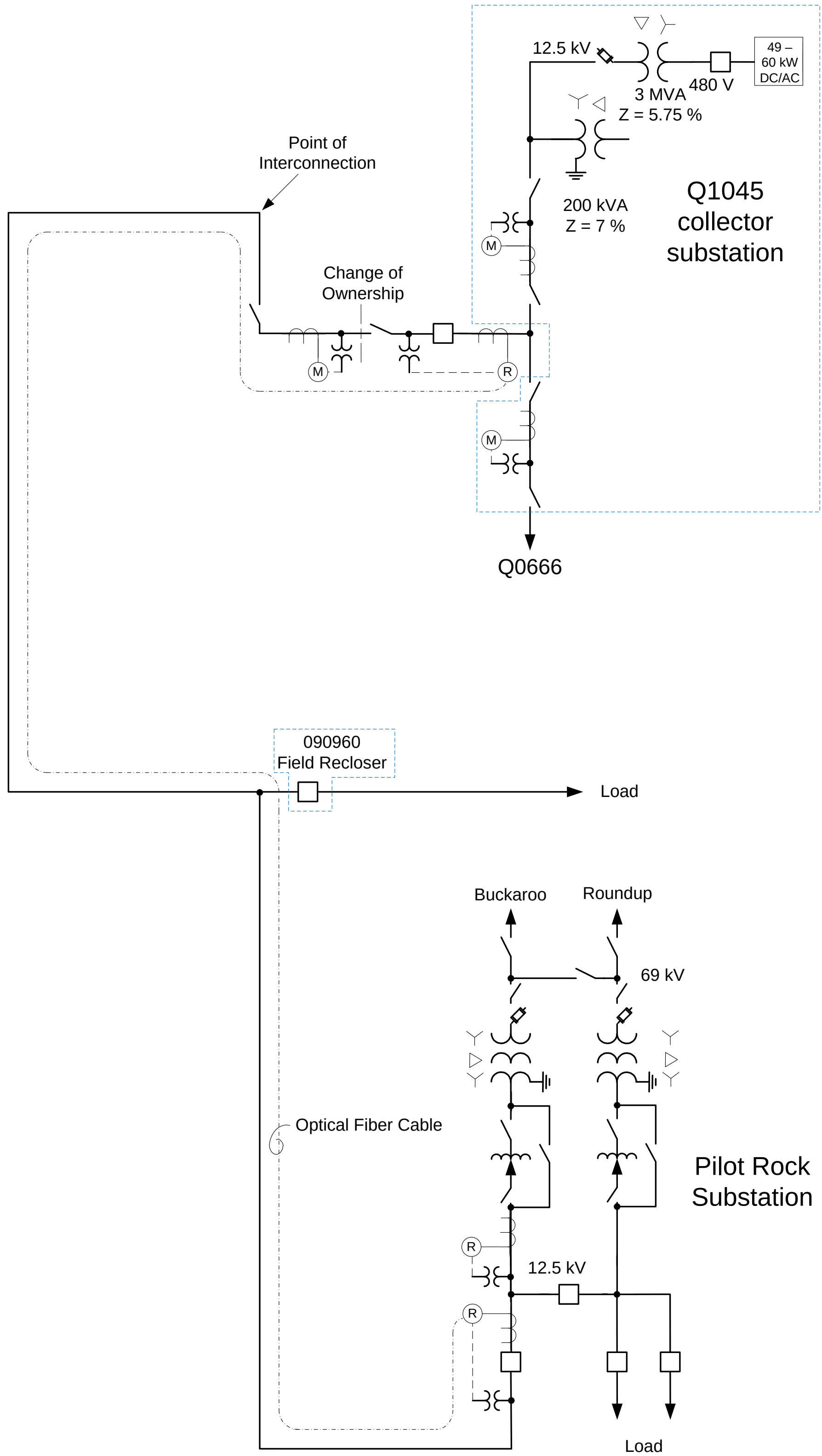

Figure 1: System One Line Diagram

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.

  - 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.

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.

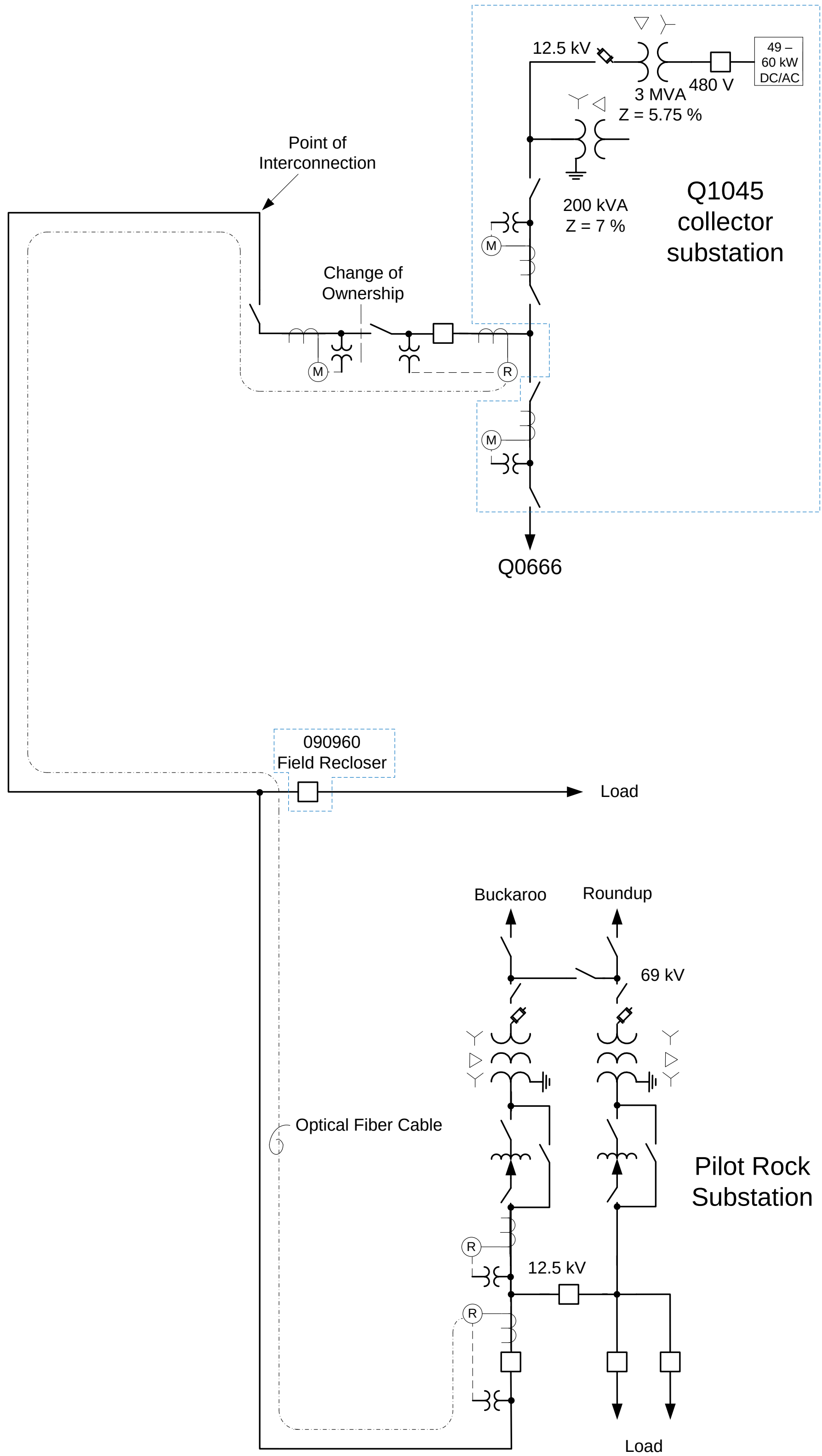

Figure 1: System One Line Diagram

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.

- 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 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
  - 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 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 *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.

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.

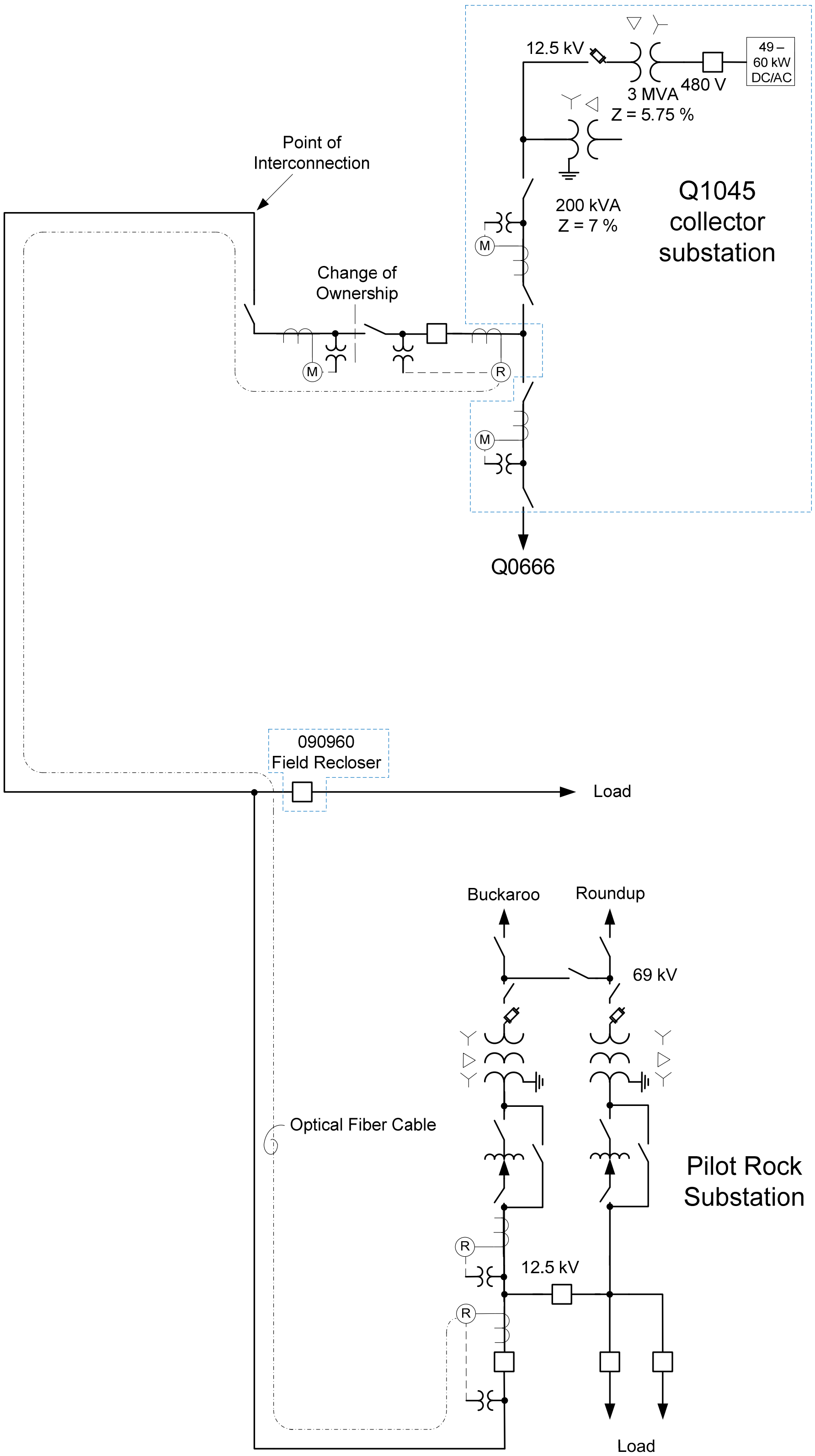

Figure 1: System One Line Diagram

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:
  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, 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
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Public Utility and Interconnection Customer Construction Complete	August 27, 2021
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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.

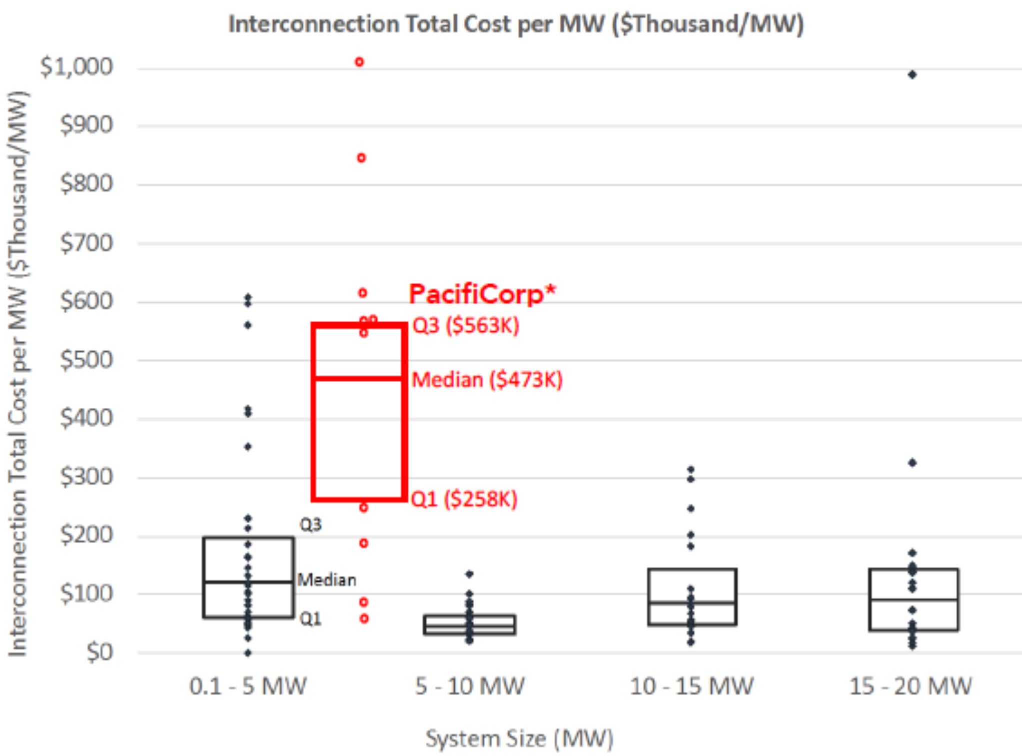
Background

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

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. **<u>PC-611 Panel installation may not be necessary</u>**. 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. **<u>Cost of new Fiber Optic install should be shared</u>.** 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. **<u>Voltage Measurement at the feeder relay is not necessary</u>**. 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

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[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. **Telemetry is unnecessary.** 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. **Justification for regulator controller replacement not provided**. ***Sunthurst requests copies of PacifiCorp's analysis used to determine that a controls upgrade is required in this specific application.***

9. **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.***

10. **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.***

11. **Historical Final Costs of Interconnection.** 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

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[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]

[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]

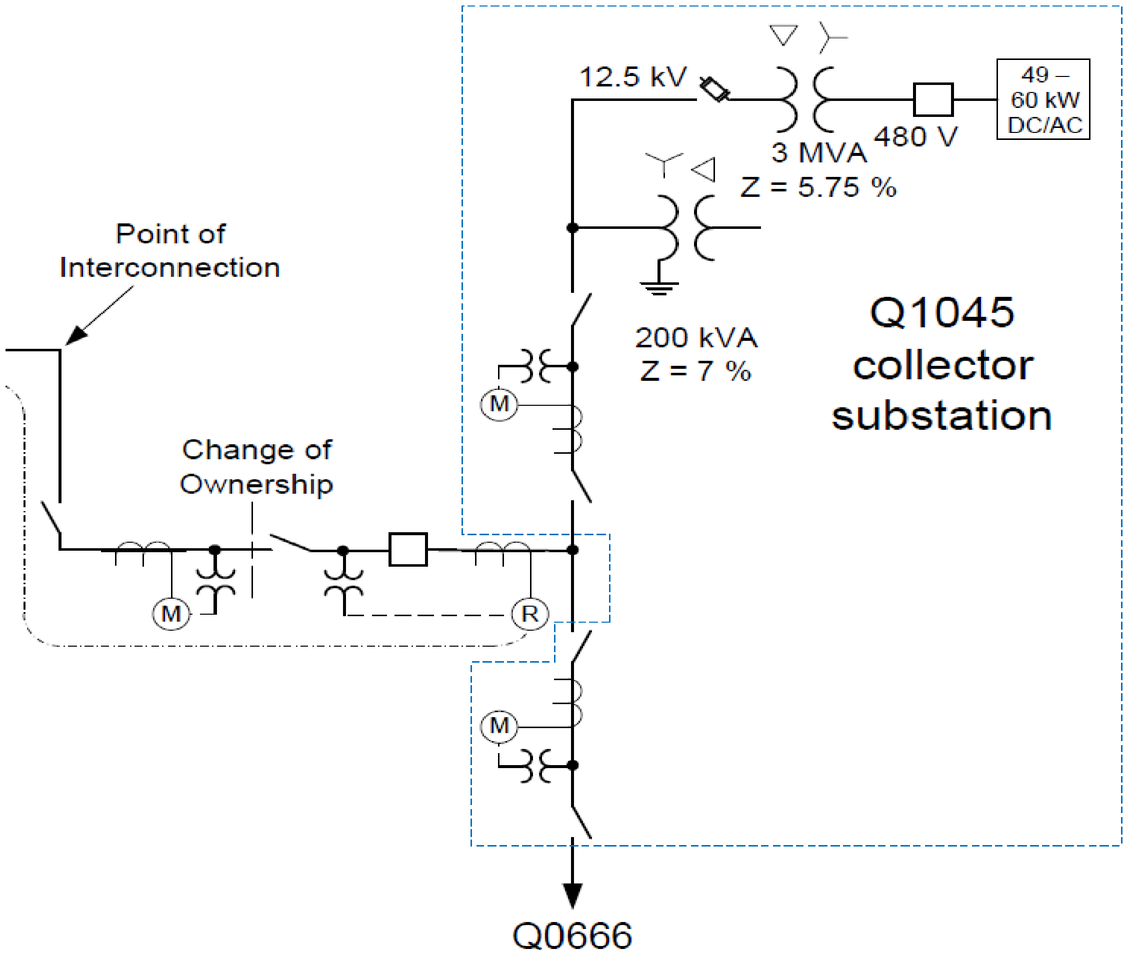
In the same discovery response, Mr. Beanland indicated that:

> 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.

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[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

[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

Estimate Date:	**09/02/20**	**01/21/21**		
Estimate Type:	**±20%**	**±20%**		
DESCRIPTION	**PREVIOUS GROSS CAPITAL COST**	**CURRENT GROSS CAPITAL COST**	**VARIANCE**	**NOTES**
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

DESCRIPTION	PREVIOUS GROSS CAPITAL COST	CURRENT GROSS CAPITAL COST	VARIANCE	NOTES (NOTES APPLY AT DIVISION LEVEL)
Estimate Date:	09/01/20	12/30/20		
Estimate Type:	±30%	±30%		
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