KENNETH KAUFMANN, ATTORNEY AT LAW

1785 Willamette Falls Drive • Suite 5 office (503) 230-7715
West Linn, OR 97068 fax (503) 972-2921

Kenneth E. Kaufmann
Ken@Kaufmann.Law
(503) 595-1867

February 22, 2021

Via Electronic Mail

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

Re: OPUC Docket No. UM 2118

Attention Filing Center:

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

Thank you in advance for your assistance.

Sincerely,

Ken Kaufmann
Attorney for Sunthurst Energy, LLC

Attach.

PUBLIC UTILITY COMMISSION
OF
OREGON

SUNTHURST EXHIBIT LIST

Exhibit 300--Daniel Hale Rebuttal Testimony

Exhibit 400--Michael Beanland, P.E., Rebuttal Testimony

Exhibit 401--PacifiCorp Responses to Selected Data Requests

Exhibit 402--PacifiCorp Interconnection Study Reports for NMQ0032 and NMQ0033

Exhibit 403--PacifiCorp System Impact Study Reports for Q0918 and Q0919

Exhibit 404--PacifiCorp System Impact Study Reports for OCS045 and OCS047

Exhibit 405--PacifiCorp Policy 138 Excerpts (12/20/20 rev)

PUBLIC UTILITY COMMISSION
OF
OREGON

SUNTHURST EXHIBIT 300

Rebuttal Testimony of
Daniel Hale
On behalf of
Sunthurst Energy, LLC

February 22, 2020

1. Q. Please state your name and present occupation.

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

2. Please refer to PAC/100, Bremer/11, lines 16-18. Do you agree that Sunthurst chose to pursue this complaint for "marginally small cost reductions" in its interconnection of PRS1 and PRS2?

A. No. I don't. Other public utilities safely complete this scope for 50% less than PacifiCorp's final cost estimate from September 2020. Sunthurst's preferred (union) contractor can install four Class A poles with all equipment for 20% less than PacifiCorp installs 1 pole with tie-in and start-up coordination. Fiber optic communications at Pilot Rock Solar 2 (PRS2) cost twice what PacifiCorp charged Community Solar generators outside Umatilla County. PacifiCorp insists on making Sunthurst pay for branch regulators that will be used to solve their existing voltage problems much further down the 5W406 feeder. PacifiCorp's 8% Capital Surcharge on each cost item is inequitable for Oregon Community Solar (OCS) projects.

PacifiCorp's initial estimate to interconnect PRS1 and PRS2 was over $2 Million. At the time Sunthurst filed this Complaint, PacifiCorp's estimate was $1 Million. As a result of Sunthurst' Opening Testimony, PacifiCorp has proposed $142,000 in additional reductions. Yet Mr. Beanland explains in his Rebuttal

Testimony how reasonable design criteria and equitable allocation of costs can reduce Sunthurst's cost of interconnection by another $345,000.

3. Q: Please refer to PAC/100, Bremer/15, lines 18-20, where Mr. Bremer states "Even Sunthurst's previous consulting engineer stated that <u>many</u> of Sunthurst's proposed alternatives 'highlight how this interconnection could be done with minimal cost, but not necessarily how it should be done.'" (emphasis added). Do you agree?

A. Mr. Bremer is embellishing words from Mr. Gross' detailed letter written July 20, 2020. Mr. Gross' actual words in that letter are "<u>Some</u> of these solutions highlight how this interconnection could be done with minimal cost, but not necessarily how it should be done." (PAC/104, Bremer/8)(emphasis added). His July 20 letter also contains many recommendations to lower interconnection costs by hundreds of thousands of dollars. Mr. Gross is very experienced and shared with Sunthurst that PacifiCorp could safely interconnect Q0666 and Q1045 for $250,000 each- if they wanted to. This is very similar to the cost estimates Mr. Beanland came up with.

4. Did Sunthurst ask Mr. Gross to serve as a witness in this Complaint?

A. Yes. However Mr. Gross declined. He said his company, which has worked for PacifiCorp and hopes to work for PacifiCorp in the future, was uncomfortable with Mr. Gross testifying against PacifiCorp.

5. Please refer to PAC/100, Bremer/18, lines 2-4. Why did you redact the source of e-mails documenting the high cost of PacifiCorp interconnections relative to interconnections to other utilities?

A. The persons providing that information did so under request of confidentiality. As with Mr. Gross, they were worried about offending utilities, including PacifiCorp. Filing their identity under a protective order does not eliminate their concern. I think it's a moot issue now anyway because PacifiCorp has demonstrated my point that its costs were out of line with other utilities. PacifiCorp has eliminated over $1.1 Million in interconnection costs at PRS1 and PRS2, from March 2020 to present. It reduced interconnection costs at PRS1 and PRS roughly $141,728 since Sunthurst filed its complaint.[1]

6. Please refer to PAC/100, Bremer/23, lines 2-3. Did Sunthurst have any way of knowing, when it sited its projects, that it was likely to have higher interconnection costs due to the specific equipment at the Pilot Rock substation?

A. No. In response to this assertion by Mr. Bremer, Sunthurst asked PacifiCorp to describe what mechanisms Sunthurst has, when siting a facility, to determine the age and/or functional capabilities of major components of the substation it seeks to interconnect to. PacifiCorp responded that "[t]here are no official mechanisms available to interconnection customers to obtain this type of information."[2]

[1] See PAC/200, Patzkowski-Taylor-Vaz/42-43.
[2] Sunthurst/401, Beanland/71 (PacifiCorp response to Sunthurst DR9.5(a)).

7. Please refer to PAC/100, Bremer/28, lines 13-14. Do the facts support Mr. Bremer's statement that "[b]ecause the [Direct Transfer Trip] equipment will be installed on PacifiCorp's system, PacifiCorp must install it."

A. No. Sunthurst asked PacifiCorp to cite all laws, orders, or rules Mr. Bremer relied upon for this statement. Mr. Bremer responded, but provided no legal basis for his position. Mr. Bremer's response modified his testimony, above, by stating "[a]ny direct transfer trip related equipment to be installed on new infrastructure at the interconnection customer generating facility can potentially be constructed by the interconnection customer."[3] Sunthurst has the capabilities to perform such installations and will do so if given the opportunity.

8. Please refer to PAC/100, Bremer/29, lines 6-7. Do the facts support Mr. Bremer's statement that Pilot Rock substation was performing well and satisfies all of the applicable reliability and performance standards?

A. In response to discovery, PacifiCorp states that it has spent nearly $0.5 million since 2017 on Pilot Rock Substation repairs. In 2018 it replaced the west fence due to NESC code violation.[4] In 2019 it replaced the battery bank and charger due to degradation.[5] In 2019 it replaced a 3-phase regulator due to catastrophic failure. When it replaced the regulator it upgraded its animal protection devices.[6] In 2019 it replaced a failed regulator control.[7] These facts paint a picture of a 70-year old substation that is at the end of its useful life and in need of significant upgrades.

---

[3] Sunthurst/401, Beanland/70 (PacifiCorp response to Sunthurst DR9.4).
[4] Sunthurst/401, Beanland/30.
[5] *Id.*
[6] *Id.*
[7] *Id.*

Many of those needed upgrades are being bootstrapped to the PRS1 and PRS2 interconnections.

9. Please refer to PAC/100, Bremer/29, lines 19-21. Do the facts support Mr. Bremer's statement that "[t]he only specific item Sunthurst claims has an excessive price is the junction boxes, which, as described in the testimony of Mssrs. Vaz, Taylor, and Patzkowski, is reasonably priced and reflect competitive procurement processes."?

A. In addition to the junction boxes, Sunthurst's opening testimony questioned the excessive pricing of avian protection[8], the PI-111 panel[9], and fiber-optic line[10], specifically. Sunthurst also specifically questioned excessive pricing on metering in discovery[11]. As a result of those challenges PacifiCorp reduced pricing in all of those areas, as set forth in PAC/200, Patzkowski-Taylor-Vaz/42-43 (avian protection reduced $5,610; junction boxes reduced $17,000; fiber reduced $19,556; metering reduced $15,859 for PRS1 and $10,514 for PRS2).

10. Please refer to PAC/100, Bremer/31, lines 6-8. Do you agree with Mr. Bremer's opinion that Sunthurst's remaining costs associated with PacifiCorp's telemetry requirements are "minimal"?

---

[8] Sunthurst/200, Beanland/27, lines 13-18.
[9] Sunthurst/200, Beanland/25, lines 1-8.
[10] Sunthurst/200, Beanland/28, lines 1-8.
[11] Sunthurst/401, Beanland/50 (Metering at PRS1 reduced from "two" to "one"; metering at PRS2 reduced from "four" to "one").

A. In response to this assertion by Mr. Bremer, Sunthurst asked PacfiiCorp to specify the data inputs Sunthurst must provide to support PacifiCorp's telemetry.[12] Sunthurst's consultant, Mr. Beanland, estimates that Sunthurst's cost to provide the data PacifiCorp requires will be approximately $50,000.[13] In addition, Sunthurst must provide permanent AC power, an easement for road access and an enclosed area, and a graded area, fenced with gate.[14] Altogether Sunthurst expects to spend over $75,000 just to support PacifiCorp's telemetry, so I would have to disagree with Mr. Bremer's assertion that Sunthurst's costs are "minimal".

11. Please refer to PAC/100, Bremer/32, lines 4-5. Do you agree with Mr. Bremer's statement that Sunthurst "failed" to make progress payments?

A. Sunthurst has not unilaterally missed any payment. In each instance, PacifiCorp has agreed to extend payment milestones for cause.

12. Please refer to PAC/200, Patzkowski-Taylor-Vaz/22(lines 1-3). Do you agree voltage regulators are required to "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."?

A. No, I believe PacifiCorp is requiring voltage regulators to address an existing deficiency in its system. At a teleconference held June 9, 2020 to discuss the Q1045 interconnection, PacifiCorp stated that under then-existing conditions voltages on Circuit 5W406 were outside of ANSI Range A criteria. If voltage

---

[12] Sunthurst/401, Beanland/96-97.
[13] Sunthurst/400, Beanland/24.
[14] Sunthurst/401, Beanland/41.

regulators are installed, PacifiCorp's system will be better than before; Sunthurst will have paid to correct PacifiCorp's pre-existing condition.

13. Please refer to PAC/200, Patzkowski-Taylor-Vaz/37-39. Do you have any response to PacifiCorp's defense of its Capital Surcharge?

A. I believe PacifiCorp's 8% Capital Surcharge unfairly subsidizes PacifiCorp's construction costs for large, self-owned, resources. I believe the 8% surcharge also unfairly lowers avoided costs rates for Qualifying Facilities. PRS1 and PRS2 are qualifying facilities and may seek a standard Oregon PURPA contract if unsuccessful becoming Community Solar Projects.

14. Please explain.

A. PacifiCorp is charging Sunthurst an 8% Capital Surcharge on the total estimated cost of interconnection. However PacifiCorp charges less than 8% Capital Surcharge on the total estimated cost of its proxy resources in its Integrated Resource Plan. Undercharging the Capital Surcharge on proxy resources ultimately reduces the avoided cost PacifiCorp pays to qualifying facilities. And if PacifiCorp-constructed resources actually pay less than 8% Capital Surcharge when constructed, then non-PacifiCorp resources including PRS1, PRS2, and other Oregon CSPs are subsidizing PacifiCorp.

15. How did PacifiCorp calculate the Capital Surcharge on PRS1 and PRS2?

A. PacifiCorp rolls up its estimated costs into five categories: Internal Labor, Material, Purchased Services, Other and Contingency, and Removal and Salvage. Then it multiplies the sum of those categories by 0.08 to calculate the Capital Surcharge. For PRS1 and PRS2, the Capital Surcharge adds about $75,066 to estimated interconnection costs.[15]

16. How did PacifiCorp calculate the Capital Surcharge in its proxy resources in its 2017 Integrated Resource Plan (IRP)?

A. PacifiCorp provided workpapers showing its calculation of capital costs, including the Capital Surcharge, for four potential resources relied upon in its 2017 IRP.[16] It appears that Capital Surcharge for those projects is capped at $500,000.

17. Why do you say that?

A. For three of four proxy resources in the IRP workpapers, the Capital Surcharge was $500,000, even though the total cost of those resources varied, from $125 Million to $499 Million. For the cheapest resource (Resource (3)), the Capital Surcharge was $482,000. I summarize the data, in Table 1, below:

2017 IRP Resource	(A) Project Cost (before ESC & AFUDC)	Capital Surcharge		
		(B) ($)	(C) ($/kW)	(D) (% of total Project cost)
(1) Utah SCCT	$124,655,000	$500,000	$2.5	0.40%
(2) Willamette Vly CCCT	$498,719,000	$500,000	$1.5	0.10%
(3) Willamette Vly CCCT duct firing	$ 22,595,000	$482,000	$9.4	2.13%
(4) Wyoming Wind	$161,254,000	$500,000	$5.0	0.31%
Source: Sunthurst/410, Beanland/17-20, except Column D calculated as (B)/(A)*100.				

Table 1.

[15] Sunthurst/204, Beanland/1, 7
[16] Sunthurst/401, Beanland/15-18

19. How do PacifiCorp's Capital Surcharge costs compare to Sunthurst's?

A. For my Projects, I pay an 8% Capital Surcharge on all PacifiCorp capital charges. For PacifiCorp's Proxy Resources, the effective Capital Surcharge rate varies from 0.1% to 2.13%.

20. Is it a fair comparison? After all, aren't you comparing only the cost of your interconnection to the total cost of PacifiCorp's proxy resources?

A. PacifiCorp testified "Capital surcharges are applied to every capital project (i.e. not just interconnection requests) on a monthly basis."[17] This indicates that all capital costs of a PacifiCorp-owned proxy resource should be assessed a Capital Surcharge.

21. For comparison's sake, can you estimate the portion of each Proxy Resource's Capital Surcharge attributable to costs of interconnection?

A. PacifiCorp did not break out its interconnection costs from total capital costs. However, based upon the cost figures published by NREL in its 2018 cost study, and included in my Exhibit 211 to Mr. Beanland's Opening Testimony, a reasonable upper bound guesstimate of interconnection costs would be $100,000 per MW of installed capacity.[18] Using that rate, the Capital Surcharge, as a percentage of estimated Proxy Resource interconnection costs is provided in Column D of Table 2, below:

---

[17] PAC/200, Patzkowski-Taylor-Vaz/36, lines 12-13.
[18] Sunthurst/211, Beanland/5.

2017 IRP Resource	(A) Capacity (MW)	(B)* Est Cost of Interconnect ($)	(C) Capital Surcharge ($/kW)	(D)** Surcharge as a % of est. interconnection cost)
(1) Utah SCCT	200	$20,000,000	$500,000	2.50%
(2) Willamette Vly CCCT	436	$43,600,000	$500,000	1.15%
(3) Willamette Vly CCCT duct firing	436	$43,600,000	$482,000	1.11%
(4) Wyoming Wind	N/A			
Source: Sunthurst/410, Beanland/17-20 * $100,000*(A) ** Column D calculated as (C)/(B)*100.				

Table 2.

23. What conclusions do you draw from Table 1 and Table 2?

A. PacifiCorp does not assess its Capital Surcharge uniformly across its interconnection customers.

24. Please refer to PAC/200, Patzkowski-Taylor-Vaz/36, lines 16-18. Do you think it is fair PacifiCorp treats Projects over $10M differently when assessing its Capital Surcharge?

A. No. Table 1 and Table 2 illustrate that the methodology results in PacifiCorp paying a far lower effective rate of Capital Surcharge for its Proxy Resources than the rate it charges small interconnection customers. Any formulae that cap the Capital Surcharge for capital projects costing more than $10 Million (or caps total Capital Surcharge at $500k) is likely to favor PacifiCorp, because it owns the vast majority of capital expenditures over $10 Million that pay a Capital Surcharge. This is an unfair subsidy of PacifiCorp's large capital projects on the back of its smaller competitors. Since the proxy resource costs also become avoided costs under PURPA, this subsidy results in avoided costs being lower than they would be if there were no subsidy.

25. Does this conclude your Rebuttal Testimony?

A. Yes.

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

PUBLIC UTILITY COMMISSION
OF
OREGON

SUNTHURST EXHIBIT 400

Rebuttal Testimony

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

February 22, 2021

Table of Contents

INTRODUCTION AND OVERVIEW OF TESTIMONY

1. Please state your name and business address.

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

2. Please summarize your Rebuttal Testimony:

A. Several areas addressed by PacifiCorp in its testimony merit response. With respect to the need for branch regulators at a cost of $180,000, PacifiCorp did not provide any study results to support such a need. Nor does the evidence in the record support such need. With respect to the need for three revenue meter locations to measure output from two projects, PacifiCorp's desire for three meters, at an additional cost of $49,000, appears driven by preference unsupported by sound engineering principles. The same appears true for its refusal to allow low-side metering, which could reduce costs by up to $20,000. With respect to PacifiCorp's preference for fiber optic communications, spread spectrum radio communications remain the preferred choice, taking into account the $14,000 cost difference between the two options. Finally, the cost of actions PacifiCorp requires Sunthurst to pay for in support of PacifiCorp's telemetry system (which PacifiCorp describes as "minimal") may exceed $75,000. None of the disputed measures, above, are necessary for Pilot Rock Solar 1 (PRS1) and Pilot Rock Solar 2 (PRS2) to safely and reliably interconnect to PacifiCorp.

REBUTTAL REGARDING THE NEED FOR BRANCH REGULATORS

1) Can you please remind us what are branch regulators and LDC, and what they do?

A. An electric distribution circuit is like a tree with multiple branches. Each branch serves customers. Because variations in transmission voltage and load cause voltage to vary on each branch, a branch regulator provides voltage regulation for just the branch it serves.

LDC (line drop compensation) is a way to adjust the voltage set point a set of voltage regulators uses based on the load. It is called "LDC" because the voltage regulator control is programmed with parameters that allow the control to emulate the voltage drop along the line. As load increases, the regulator increases the voltage set point to make sure that voltage is acceptable along the branch. Similarly, as load drops, and the resulting voltage drop along the branch is lower, LDC lowers the voltage set point used by the regulators.

2) Has PacifiCorp reasonably demonstrated a need for branch regulators resulting from interconnecting Pilot Rock Solar 1 and/or Pilot Rock Solar 2?

A. No. PacifiCorp is specifying branch regulators at a cost of over $180,000 without providing any data supporting its decision. Such studies might show that branch regulators *are not* needed because voltage issues are minimal. Such studies might also show that branch regulators *are* needed, but are needed due to preexisting conditions, in which case Sunthurst should not have to pay for PacifiCorp bringing its system up to standards.

3) Please refer to PAC/200, Patzkowski-Taylor-Vaz/3, lines 15-16. Do you agree that branch voltage regulators are required to ensure that interconnection of PRS1 and PRS2 does not degrade service to PacifiCorp's existing customers?

A. No. PacifiCorp has asserted that branch voltage regulators with LDC are needed but has provided no voltage drop study results that demonstrate the lack of preexisting conditions or that the addition of branch voltage regulators using LDC is the best available solution. Further, PacifiCorp has indicated in their response in DR 10.2(b) that "ANSI C84.1 Range A voltages can be maintained without the need for the line voltage regulator banks".[1]

4) Has PacifiCorp performed such studies?

A. PacifiCorp stated that they modeled system voltages in connection with System Impact Study (SIS) Reports for Q0666 and Q1045. However, PacifiCorp did not retain those studies or their results. The only information available is contained in the Q0666 and Q1045 SIS reports. Neither of those studies answer critical questions needed to conclude that branch regulators are reasonably required to interconnect PRS1 or PRS2.

5) Do we know if PRS1 and PRS2 create voltage issues on Circuit 5406?

[1] Sunthurst/401, Beanland/101.

A. PacifiCorp stated, in its System Impact Study Report for Q0666 ("Q0666 SIS")[2] and in its SIS for Q1045 ("Q1045 SIS")[3] that the addition of PRS1 and PRS2 *do not* create transmission level voltage issues. Both reports indicate that distribution system voltage studies were performed but are mute on the results.

6) Why, then, does PacifiCorp maintain that PRS2 requires the addition of branch regulators?

A. PacifiCorp says that its existing voltage regulator controller at Pilot Rock substation won't work "as a result of the addition of PRS2 generation being greater than the feeder peak load."[4]

7) Do you agree with the previous sentence?

A. Yes. I agree that the existing voltage regulator control cannot cope with reverse power flow from the feeder into the substation when generation exceeds load. However, that only indicates that the substation voltage regulator control needs to be replaced by one that can properly deal with the reverse power flow. Failure of the substation voltage regulator control to perform correctly, by itself, does not justify PacifiCorp's position that Sunthurst should pay for branch regulators.

8) Will the addition of the PRS1 project impact the ability of the substation voltage regulator control to perform LDC?

---

[2] Sunthurst/205, Beanland/6 ("Due to the small size of the proposed interconnection relative to the transmission system, no thermal or voltage deficiencies associated with interconnect of Q0666 were observed.")
[3] Sunthurst/207, Beanland/7 ("Due to the small size of the proposed interconnection relative to the transmission system, no thermal or voltage deficiencies associated with interconnect of Q1045 were observed.")
[4] PAC/200, Patzkowski-Taylor-Vaz/20, lines 13-14.

A. Yes. The presence of ANY generation on the distribution circuit will adversely impact the ability of the voltage regulator control LDC to properly regulate voltage. High loads may still exist on the feeder but would not be seen by the LDC control, lessening its ability to properly control voltage. PacifiCorp's insistence on the continued use of LDC at the substation may not be good practice. Non-LDC control may solve this issue.

9) Has PacifiCorp considered the use of non-LDC voltage control methods?

A. PacifiCorp has failed to consider non-LDC voltage regulation approaches; there is no mention of it in any report. In addition to using LDC to adjust the voltage based on load, voltage regulator controls have a simple fixed-voltage mode where the regulator holds the voltage at a constant level that does not vary with load. As long as adequate voltage is provided to customers, this is a fully acceptable voltage regulator control mode.

The use of LDC as a control mode should be compared to fixed voltage regulation in a study. In complex distribution systems with many branches of varying load and length, LDC can prove counter-productive leading to undesirable results. LDC works best where there are long lines with load concentrated at one location and few, if any, branches.

10) If studies show that PacifiCorp's existing system meets ANSI Standard C84.1 at all times, would you agree branch regulators are required?

A. No. If PacifiCorp's existing system meets ANSI Standard C84.1 at all times, I would then want to see study results showing that PRS1 and PRS2 will cause the circuit to not meet ANSI Standard C84.1. PacifiCorp has not provided such study results.

11) Please refer to PAC/200, Patzkowski-Taylor-Vaz/22, lines 1-3. Do you agree that voltage regulators and LDC "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"?

A. Once again PacifiCorp has presented no evidence to support its assertion that the branch regulators improve energy efficiency, nor what that energy savings might be. The addition of branch regulators themselves adds energy losses to the circuit every hour of the year. Therefore, branch regulators do not necessarily improve efficiency unless the total energy savings achieved by using LDC exceeds the total losses from the branch regulators.

12) Do you agree that voltage regulators and LDC "maintain[s] PacifiCorp's ability to meet ANSI Standard C84.1 in temporary switching configurations"?

A. No. PacifiCorp has provided no evidence that voltages would not be acceptable without the addition of the branch voltage regulators, with or without LDC, nor the results of any studies showing that "under temporary switching" arrangements voltage would be unacceptable. Adding voltage regulators to address voltage problems caused by temporary switching arrangements is totally unrelated to the addition of the PRS1 and PRS2 projects, making it a system improvement not a generation addition mitigation.

13) Do the studies typically performed in the course of studying an interconnection request provide the missing evidence you discuss in questions 4, 9, 10, and 11, above?

A. The Q0666 and Q1045 SIS reports state "…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."[5] PacifiCorp has indicated that voltage drop studies have been performed but has not provided the results. The complete results of such studies could provide the missing evidence. Such studies would examine alternate voltage regulator locations and alternate voltage regulator control modes (LDC, fixed).

14) In your experience, do utilities typically install branch regulators to improve efficiency?

A. No. Because of the costs of voltage regulators, the added energy losses, and the increased system maintenance, utilities typically only install branch voltage regulators to solve intractable customer voltage problems.

15) Are there other ways of regulating voltage, should it become an issue in the future?

A. Voltage regulation may also be possible using dynamic volt-ampere reactive sources (dVAR). dVAR is the ability to generate or absorb reactive power in variable amounts to assist in regulating voltage, and is a standard feature of modern

[5] Sunthurst/206, Beanland/3; Sunthurst/207, Beanland/3.

photovoltaic inverters. PRS1 and PRS2 have the ability to provide dVAR from their inverters, however PacifiCorp did not study this capability.[6]

16) Does PacifiCorp ever utilize the dVAR capabilities of distributed generators?

A. Yes. Exhibits 403 (OCS045 and OCS047) and 404 (Q0918 and Q0919) illustrate that PacifiCorp does, in some cases, use the dVAR capabilities of photovoltaic inverters to aid in regulating system voltage.[7] The system impact studies or facilities studies for these four projects require the DER to operate in a voltage control or specific reactive flow mode to assist with voltage regulation.

17) In your experience, is PacifiCorp's requirement for branch regulators typical of other utilities?

A. Line voltage regulators and branch regulators are widely used to provide good voltage service as voltage and load varies on the distribution system. The need for any voltage regulation requires careful study and consideration of all available options including LDC, fixed voltage regulation, reconductoring, the addition of capacitor banks, and reconfiguring of circuits. Because of the high expense involved, the addition of voltage regulators is generally a last resort when all other less costly measures have been exhausted.

18) Do you know if it is typical in PacifiCorp's system?

---

[6] Sunthurst/401, Beanland/64 (For interconnection studies, "[d]istribution connected generators are directed to generate under constant power factor mode with a unity power factor setting.")

[7] *See, also*, Sunthurst/401, Beanland/61 ("Yes. Small generators connected to the distribution system have been required to utilize voltage control capabilities when there is a possibility to not meet ANSI C84.1 Range A voltages to all customers without the small generator's voltage control settings being utilized.")

A. In a review of the published PacifiCorp SIS reports for Oregon Community Solar interconnection studies[8] to see if PRS1 and PRS2 are unique, three instances (in addition to PRS2) of branch regulators were required in 27 studies.[9] From this review, it appears the addition of branch voltage regulators is uncommon. All of the instances were in Umatilla County, except OCS010, which is in adjacent Wallowa County. In one of those cases, OCS024, PacifiCorp indicates branch regulators will be installed but is not requiring the customer to pay for them.[10] That is what I would expect if the voltage issues addressed by the branch regulators existed prior to installation of the new distributed generator.

19) Do you find it interesting that all instances of requiring branch regulators occur in the same geographic region of PacifiCorp's system?

A. Yes. I find it odd that the approach seems localized. This may be due to preferences of the local staff overseeing the design and operation of the distribution system.

20) How realistic is it that PacifiCorp does not apply uniform design criteria when determining whether to require branch regulators?

A. Definitely realistic. PacifiCorp stated in response to discovery that "[t]he specific trigger for the voltage regulators in the field for PRS2 is the inability for the voltage regulator control in the substation to measure load on the feeder to enable the use of Line Drop Compensation (LDC) settings."[11] If PacifiCorp applied this test strictly,

---

[8] http://www.oasis.oati.com/woa/docs/PPW/PPWdocs/pacificorpocsiaq.htm
[9] OCS009; OCS010, OCS024.
[10] July 22, 2020 OCS024 Community Solar Project System Impact Study Report, page 4 ("The POI will need to be along Tutuilla Church Road west of regulators proposed to be installed north of Tutuilla Church Road approximately 150' west of South Market Road on a separate Public Utility project. ")
[11] Sunthurst 401, Beanland/83.

it would require branch regulators using LDC any time output from a proposed distributed energy resource would negatively impact the ability of substation LDC to function. However the PacifiCorp system impact studies for OCS047, OCS045[12], OCS035, OCS008, OCS025, and OCS027, all greater than 2MW in capacity, make no mention of the need for added branch regulators. This demonstrates there is inconsistancy in PacifiCorp's determination regarding the need for branch voltage regulators.

21) In your opinion, are the branch regulators and LDC PacifiCorp is requiring reasonably necessary to provide safe and reliable interconnection to PRS1 and PRS2?

A. No. PacifiCorp's R-816 regulator control for Circuit 5W406 failed in November 6, 2019. PacifiCorp operated circuit 5W406 for an extended period (at least November 6- November 21, 2019) without a functioning regulator.[13] This shows that PacifiCorp did not believe active voltage regulation is required for safe operation. As long as adequate voltage is provided to customers, the presence or absence of voltage regulators has little impact on safety, only on the quality of service.

In my opinion, the branch voltage regulators, with or without LDC, neither enhance nor lessen safe and reliable interconnection at Circuit 5W406.

REBUTTAL REGARDING THE NEED FOR THREE METERS

22) Please recap testimony to date on the necessity of *three* PacifiCorp-owed, revenue grade, metering systems to measure output from PRS1 and PRS2.

---

[12] Sunthurst/403 (System Impact Study Reports for OCS045 and OCS047).
[13] Sunthurst/401, Beanland/52

A. In my opening testimony, I stated that the data from meters at any two of the three locations PacifiCorp requires (PRS1, PRS2, and the Point of Interconnection (POI)) will provide the same data as all three meters.[14] PacifiCorp's response testimony claims that three meters are 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."[15]

23) What is the amount in controversy related to this issue?

A. According to PacifiCorp's most recent estimate, the cost to Sunthurst arising from the meter specified for the Point of Interconnection is $49,000. [16]

24) Do you remain convinced that three meters are unnecessary?

A. Yes.

25) Do you agree three meters are necessary to "negate the ability of one generator serving station or auxiliary load of the other project" [17]?

A. No. With two meters, if one plant is generating power and the other consuming it, the production and consumption would be metered by the producing plant meter and consuming plant meter, respectively; the 3rd POI meter serves no purpose.

---

[14] Sunthurst/200, Beanland/17, lines 14-16.
[15] PAC/200, Patzkowski-Taylor-Vaz/6, lines 1-3.
[16] Sunthurst/401, Beanland/79. PacifiCorp's current estimate, given in response to DR9.11, is greater than the $39,000 estimated cost in PAC/200, Patzkowski-Taylor-Vaz/9, line 1.
[17] PAC/200, Patzkowski-Taylor-Vaz/6, lines 1-2.

26) Do you agree three meters are necessary to "mitigate the potential for one generator to over-generate at the expense of the other generator"[18]?

A. No. Photovoltaic projects are controlled to never generate more than the contractual limit; photovoltaic systems do not over-generate. Even if the solar resource is available, photovoltaic systems are controlled to limit power production to the contractual limit. Since the contractual agreements for operation are generator specific, neither generator can produce more than the limit of its agreement.

27) Do you agree three meters are necessary to "track individual project output and any associated losses for purposes of accurate payments under CSP power purchase agreements" [19]?

A. No. Only two meters are needed to measure the individual project outputs. With meters located on the 12.47kV side of the transformers, or if transformer loss compensation is implemented, the losses in each project are accurately accounted. The losses between the POI meter and the two project meters are much less than the error in the metering systems.

28) Does PacifiCorp dispute your testimony[20] that using only two meters is safe?

A. No. PacifiCorp did not raise any question about the safety of using only two meters in its testimony. Although PacifiCorp repeatedly cited safety as a justification for

[18] PAC/200, Patzkowski-Taylor-Vaz/6, lines 2-3.
[19] PAC/200, Patzkowski-Taylor-Vaz/6, lines 3-4.
[20] Sunthurst/200, Beanland/19, lines 1-7.

three meters during discovery[21], its most recent response concedes that two meters are safe.[22]

29) Is using only two meters a reliable means of measuring output from PRS1 and PRS2?

A. Metering equipment is extremely reliable. Millions of metering systems are in service and operating reliably. There is always the chance that a component of a metering system can fail, nothing is perfect. However, adding a 3rd metering system increases the odds of a failure by 50%.

The addition of a 3rd meter could actually pose a conundrum in that the error of each meter could easily be large enough so that there can never be mathematical agreement such that the POI meter exactly equals the sum of the two project meters; calculated losses could be an impossible negative number.

30) Please refer to PAC/200, Patzkowski-Taylor-Vaz/7, lines 6-16, where PacifiCorp cites Oregon Wind Farms and Cedar Springs Wind Project as examples of PacifiCorp consistently requiring three meters for projects configured like PRS1 and PRS2. Do you agree those are good examples?

A. No, I don't. Oregon Wind Farms (65 MW) and Cedar Springs Wind Project (520MW) interconnect at 115 kV and 230 kV, respectively, whereas PRS1 and PRS2 interconnect at 12.5 kV. PacifiCorp has different interconnection policies for distribution-level voltage interconnections and transmission-level voltage interconnections. Policy 138 ("Distributed Energy Resource Interconnection

---

[21] Sunthurst/401, Beanland/9, 24 (PacifiCorp answers to DR3.2 and DR4.1(f)).
[22] Sunthurst/401, Beanland/107 (PacifiCorp answer to DR10.6(a)).

Policy") sets forth PacifiCorp's interconnection policies for distribution systems 34.5 kV and below. Policy 139 ("Facility Connection Requirements for Transmission Systems") sets forth PacifiCorp's interconnection policies for transmission systems 46 kV and above. Accordingly, PRS1 and PRS2 interconnect are subject to Policy 138, whereas Oregon Wind Farms and Cedar Springs Wind Project interconnections are governed by Policy 139.[23]

31) Does Policy 139 expressly require metering at the Point of Interconnection for transmission-voltage interconnections?

A. Yes. Section 4.1.1 of Policy 139 states "PacifiCorp requires revenue metering at the physical delivery point, typically at a PacifiCorp-owned transmission substation."[24] However I found no such explicit provision in Policy 138 applicable to PRS1 and PRS2.

32) PacifiCorp says that Section 4.1 of Policy 138 requires three meters at Pilot Rock Solar 1 and Pilot Rock Solar 2.[25] Do you agree?

A. No. PacifiCorp pointed to the following language from Policy 138, Section 4.1:

> *Sites with multiple DER [Distributed Energy Resource] resources such as wind collectors, or solar arrays may be considered as separable revenue facilities and, when applicable, require metering at each facility point. Metering requirements with multiple DER facilities will be identified in the interconnection facilities study report. Metering used for any PacifiCorp revenue purpose will be certified and maintained identically to the point of interconnect revenue metering.*

---

[23] Sunthurst/401, Beanland/76
[24] *See* http://www.oasis.oati.com/woa/docs/PPW/PPWdocs/PacifiCorp_Policy_139.pdf.
[25] Sunthurst/401, Beanland/35

Policy 138, (8/13/2018 Revision). I read the paragraph above to require: if PacifiCorp specifies metering at each separate DER resource, then each separate meter shall be of the same accuracy quality PacifiCorp requires at the point of interconnection, in the case of a single project.

33) Do you think Policy 138 requires revenue metering at the point of interconnection in every case?

A. No. When I read the policy, requiring a meter at the POI would contradict Section 2.1, which provides:

> 2.1 Ownership and Operation of Interconnection Facilities and Equipment
> *For new DER facilities,* ***PacifiCorp shall not own, operate, or maintain any of the interconnection equipment that is electrically located downstream of PacifiCorp's meter****. It is assumed that this equipment is owned, operated, and maintained by the Interconnection Customer. This equipment commonly includes the transformer, breaker, relay and other protection devices.*

Policy 138 (8/13/2018 Revision) (emphasis added). If PacifiCorp installs a meter at the POI, then it will have interconnection equipment (the PRS1 and PRS2 meters) located downstream of its meter at the POI. According to its policy, PacifiCorp "shall not" do this. Metering at PRS1 and PRS2, but not the POI, complies with Section 2.1 and Section 4.1.

34) Please refer to PAC/200, Patzkowski-Taylor-Vaz/3, lines 8-11, where PacifiCorp states that it requires three revenue meters for all interconnection customers similarly situated to PRS1 and PRS2. Do you know if this statement is true?

A. PacifiCorp's system is very large. Only PacifiCorp can know the answer, and likely nobody knows without reviewing every single distribution voltage generator interconnection. However, I know of one similarly situated interconnection on PacifiCorp's system because I was the responsible engineer for the interconnection customer. The customer interconnected two adjacent 898 kW net metering installations to PacifiCorp's Dorris substation in Dorris, California, in 2018. PacifiCorp called them NMQ0032 and NMQ0033.[26]

35) Q. Are net metering interconnection customers NMQ0032 and NMQ0033 similarly situated to PRS1 and PRS2?

A. Functionally, from an electrical standpoint they are identical; both are two DER resources connected to a single point on the PacifiCorp distribution system.

36) Did PacifiCorp require a third meter at NMQ0032 and NMQ0033?

A. No. The two photovoltaic systems were connected to a common PacifiCorp power transformer with a separate metering system for each photovoltaic system. There was no 3rd meter requirement. The System Impact Study reports for NMQ0032 and NMQ0033 show only a single meter for both photovoltaic systems; in reality separate PacifiCorp meters were installed, one for each photovoltaic project.

37) What can you conclude from PacifiCorp Net Meter interconnections NMQ0032 and NMQ0033?

A. That PacifiCorp does not require three meters at all interconnections where two separate DER are connected to a single point on the PacifiCorp distribution system;

---

[26] Sunthurst/402 (PacifiCorp's System Impact Study reports for Q0918 and Q0919).

and (b) that using two DER meters instead of three is neither unsafe nor unreasonable.

38) Please refer to PAC/200, Patzkowski-Taylor-Vaz/8, lines 1-6, wherein PacifiCorp's witness states that a third meter at the POI is necessary because, in the event a meter failure occurred at either generator, PacifiCorp would not be able to quantify the amount of generation provided from the facility during the time of a meter outage. Do you agree with this statement?

A. No. In this statement it appears that PacifiCorp is stating that metering systems must be redundant so that the failure of any component or system allows continued metering data collection. This standard does not appear to be articulated in Policy 138, Section 4, Metering Policy for Interconnection Customers; nor is it necessary.

PacifiCorp acknowledged in discovery (DR 9.24) that should one phase of a 3-phase metering system fail, the accepted approach is to assume that all three phases carry equal load and to estimate the missing data by changing the meter multiplier.[27] PacifiCorp acknowledged in testimony that the telemetry it plans to install will provide yet another means of measuring output in the unlikely event of meter malfunction.[28]

39) Is it your opinion that two meters, one at PRS1 and one at PRS2, can safely and reliably measure output without a third meter at the POI?

---

[27] Sunthurst/401, Beanland/98
[28] PAC/200, Patzkowski-Taylor-Vaz/13, lines 9-12.

A. Yes. The purpose of the metering is to obtain sufficiently accurate data on the production of a DER. Requiring redundant metering does not provide additional data or improved accuracy.

With respect to reliability, with one meter on each PRS1 and PRS2, any failure of this metering equipment will affect only PRS1 or PRS2 and would require only PRS1 or PRS2 to be taken out of service for repairs. Placing a 3rd meter at the point where both projects tie to the distribution system would mean that a failure of this meter will affect both PRS1 and PRS2 and that repair of this 3rd meter will require both PRS1 and PRS2 be taken out of service for repairs. Having a 3rd meter also increases the odds by 50% that a meter failure will occur.

REBUTTAL REGARDING LOW SIDE METERING

40) What is "low side" metering?

A. "Low side" refers to the lower voltage on the DER-side of the power transformer that interconnects with the PacifiCorp distribution system. In a DER like PRS1 and PRS2, the PacifiCorp medium-voltage is 12,470V and the low side of the power transformer is 480V. Low side metering is the most common type of metering used for typical electric service metering. Per the 2016 edition of the PacifiCorp Electric Service Requirements manual, low side metering can be used for 480V services up to 4000A, this is about 3300kW/kVA in capacity.

41) How does "low side" metering differ from medium-voltage metering?

A. The difference in voltage makes low side metering generally less expensive. The electric meters used by utilities can generally accept 480V input voltages directly at the meter eliminating the need for the voltage transformers used to step down and isolate the medium voltage from the meter. Further, the current transformers required for low voltage metering are rated for 600V use which makes them simpler and less expensive than medium-voltage current transformers required for 12,470V. In addition, because of the low voltage, the meter and current transformers are typically installed in the 480V switchgear installed at the project. This avoids the need for a power pole to keep the 12,470V safely up in the air away from people.

42) How does low side metering deal with the transformer losses between the low side and medium-voltage side of the transformer?

A. The power transformer between the medium-voltage 12,470V and the low side 480V will incur losses that reduce the energy the DER delivers to the grid. The physical and engineering aspects of copper and iron loss are well understood. Most modern electronic meters have the ability to incorporate loss factors that can add in the iron and copper losses so that energy quantities measured at the low side of the transformer can be accurately known at the medium-voltage side of the transformer. This kind of adjustment for losses is widely used and is not novel. The Bonneville Power Administration uses transformer loss compensation where power delivery is metered at a lower voltage and needs to be reflected to a higher voltage by including losses.

43) Would low side metering lower the cost of interconnection?

A. Yes. Low side metering will lower the cost of interconnection metering by allowing the use of less expensive equipment and by eliminating the need for power poles and other medium-voltage apparatus. There is an increase in the cost of the low side switchgear to provide the required enclosure for the low side metering equipment but this added cost will be less than the savings.

44) Does PacifiCorp allow the use of low side metering for distributed energy resources?

A. As mentioned above, the NMW0032 and NMQ0033 projects near Dorris, CA, were metered at the 480V level. PacifiCorp's recently constructed Q0918 and Q0919 projects in Utah, which PacifiCorp discusses in its testimony, were metered at the 480V level. According to PacifiCorp, Q0918 and Q0919 have "essentially the same configuration as PRS1 and PRS2."[29]

45) Is low side metering as accurate as medium-voltage metering?

A. Low side metering is more accurate. The potential and current transformers used in medium-voltage metering have typical accuracies of 0.3%. The electronic meters typically used have accuracy of about 0.1%. A complete medium-voltage system using potential transformers, current transformers and an electronic meter can be considered to have a total possible error of about (0.3%+0.3%+0.1%)= 0.7%. A low side metering system will have current transformers with an error of 0.3% and an electronic meter with an error of 0.1% for a total metering error system of about

[29] PAC/200, Patzkowski-Taylor-Vaz/7, lines 17-19

(0.3%+0.1%)= 0.4%. Based on this, low side metering would be expected, on average, to be more accurate than medium-voltage metering.

The loss calculations implemented in an electronic meter are not perfect; some error will occur because the copper loss varies slightly with the operating temperature of the transformer. For a seasonal average ambient air temperature variation of 37F (20C) as occurs in Pendleton, OR, the seasonal variation in copper loss is about +/-4%, however, copper losses are typically only about 0.5% of transformer full load. As a result, the seasonal variation of copper loss relative to full load will be 0.02% resulting in a total metering system error of about 0.42%; in comparison to the 0.7% error of medium-voltage metering.

REBUTTAL REGARDING COST OF FIBER OPTIC CABLE VS SPREAD SPECTRUM RADIO

46) Please refer to PAC/200, Patzkowski-Taylor-Vaz/22, lines 20-22. Do you agree that fiber optic "has become a utility best practice"?

A. "Best practice" does not have any standard definition or use in the utility industry. PacifiCorp may be using "best practice" to mean what it would do if money were no object. However, in many cases there is such thing as "good enough", where a better solution may exist but may not justify the extra expense.

47) Is spread-spectrum radio "good enough" for use at PRS1 and PRS2?

A. Yes. Spread-spectrum radio is considered good utility practice in applications such as the Direct Transfer Trip (DTT) communication path from PRS1 and PRS2 to Pilot

Rock substation. PacifiCorp has specified spread-spectrum radio for DTT communication at OCS024 and OCS045[30], to name two current examples.

48) What is the cost difference between spread spectrum radio and fiber?

A. At the time I filed my testimony, PacifiCorp estimated that a fiber link cost $14,000 more than spread-spectrum radio.[31] In its testimony, PacifiCorp reduced the estimated cost of fiber by $19,556[32], but I would disregard that testimony for the reasons I explain below.

49) How did PacifiCorp achieve this $19,556 price reduction?

A. That is unclear. PacifiCorp explained in its testimony that the original cost estimate for fiber was calculated at a rate of $60,000/mile for underbuild on existing distribution lines, and $42,000/mile for installation with new distribution line.[33] Pilot Rock Solar requires 0.6 miles underbuild on existing line and 0.3 miles installation with new distribution line. So, the original estimated cost is $60,000*0.6+$42,000*0.3, or $48,600. To arrive at its new estimate, PacifiCorp assumed all 0.9 miles of fiber would cost $42,000/mile. The new total is $42,000*0.9, or $37,800.[34] The difference between the two estimates is $10,800 ($48,600-$37,800). PacifiCorp does not document how it arrived at estimated savings of $19,556. Their explanation only accounts for a $10,800 reduction.

---

30 Sunthurst/403, Beanland/9 (Section 6.7).
31 PAC/200, Patzkowski-Taylor-Vaz/24, lines 13-14.
32 PAC/200, Patzkowski-Taylor-Vaz/24, lines 5-9.
33 PAC/200, Patzkowski-Taylor-Vaz/23(line 20)-24(lines 1-3).
34 PAC/200, Patzkowski-Taylor-Vaz/24, line 15.

50) Does PacifiCorp's reduction in estimated cost of fiber make fiber a preferred choice?

A. No. PacifiCorp's reduced estimate is not based on sound methodology. According to PacifiCorp, underbuild on existing distribution line "typically involv[es] pole replacements or strengthening and workarounds for existing space restrictions".[35] For that reason, it budgets $60,000/mile versus $42,000 per mile for new buildout. To lower the cost, PacifiCorp assumed, *without evidence* and contrary to its prior estimates, that it will encounter no such complications in the 0.6 mile underbuild portion of fiber for PRS1 and PRS2. PacifiCorp admitted in subsequent discovery that it has not yet designed the fiber link, and that if improvements are required the cost could go higher.[36] So the $19,556 reduction in estimated costs is based upon wishful thinking. I would continue to rely on the original estimate for cost comparisons between fiber and radio. On that basis, spread-spectrum radio is the preferred choice because it is substantially cheaper. It also has less likelihood of cost overruns because the cost of spread spectrum radio is not dependent upon unknown site conditions to the same extent as fiber.

REBUTTAL REGARDING MAGNITUDE OF TELEMETRY RELATED COSTS

51) Please refer to PAC/100, Bremer/31, lines 1-9. Do you agree that the costs to purchase additional equipment to provide the PacifiCorp telemetry equipment with analog signals PacifiCorp requires is "minimal"?

[35] PAC/200, Patzkowski-Taylor-Vaz/24, lines 2-3.
[36] Sunthurst/401, Beanland/86.

A. I don't agree. The meteorological data to be provided by the customer to PacifiCorp for telemetering will require a climate weather station, which will cost about $20,000. The voltages required, because they are not normal metering parameters, will require special transducers at a cost of about $5,000.[37] Further, PacifiCorp's requirement that all data be provided by analog signal means that any digital system used to gather data must have a specialized digital-to-analog converter to generate the required signal. Sunthurst also must supply AC power for the telemetry system. Taken altogether, Sunthurst' cost to provide the analog data for PacifiCorp's telemetry could exceed $50,000.

52) Does this include the cost of the graded telemetry equipment site with chain link fence and vehicle gate?

A. No. It's hard to accurately estimate the cost of these items with no specification, but based on my experience I would expect the grading and fencing to cost another $25,000.

53) Are there other costs paid by Sunthurst that should be borne by PacifiCorp.

A. Yes. PacifiCorp testified that it can provide a credit for engineering and management costs associated with the PI-111 annunciator panel design already paid by PacifiCorp.[38] PacifiCorp has since quantified that credit to be $6,987.27.[39]

54) Does this conclude your testimony?

A. Yes.

---

[37] Sunthurst/207, Beanland/39.
[38] PAC/200, Patzkowski-Taylor-Vaz/42, lines 7-10.
[39] Sunthurst/401, Beanland/95.

PUBLIC UTILITY COMMISSION

OF

OREGON

SUNTHURST EXHIBIT 401

PacifiCorp Responses to Selected Data Requests

FEBRUARY 22, 2021

	Employee Name	Job Title	Job Repsonsibilities	Dates of Involvement	Nature of Involvement	Hours Charged to Request
Q0666	BELESIOTIS ANASTASIA	Business Analyst	Transmission services administration	2015	Administration of interconnectoin queue	2.0
	BEYER SCOTT	Director, Transmission Planning	Transmission planning management	2015	Study performance	3.0
	CHAN TIM	Substation Engineer	Substation Engineer	2015	Study performance	0.0
	ELDER STEVEN	Transmission Engineer	Transmission Engineer	2015	Study performance	3.0
	FISHBACK THOMAS	Project Manager	Project Manager	2015	Administration of interconnectoin queue	37.0
	GUTTROMSON DOUGLAS	Area Engineer	Area Engineer	2015	Study performance	26.0
	MARK JOHN	Meter Engineer	Meter Engineer	2015	Study performance	2.0
	MILLER DEAN	Protection & Control Engineer	Protection & Control Engineer	2015	Study performance	14.0
	MOORE ROBIN	Project Manager	Generation interconnection request project management	2015-2016	Administration of interconnectoin queue	36.0
	RETZLAFF GRAHAM	Contract Specialist	Transmission contracts	2015-2016	Administration of interconnectoin queue	9.0
	RIDD RYAN	Cost Engineer	Cost estimate creation	2015-2016	Study performance	1.0
	ROBINSON MARK	Communications Engineer	Communications Engineer	2015	Study performance	5.0
	STAGLIANO GINO	Civil Engineer	Civil Engineer	2015	Study performance	2.0
	TABOR THERESA	Business Analyst	Transmission services administration	2015	Administration of interconnectoin queue	1.0
	TREMBATH MICHAEL	Cost Engineer	Cost estimate creation	2015-2016	Study performance	5.0
Q1045	BELESIOTIS ANASTASIA	Business Analyst	Transmission services administration	2018-2020	Administration of interconnectoin queue	1.5
	BREMER KRISTOPHER	Director, Generation Interconne	Generation interconnection process management	2020	Administration of interconnectoin queue	14.0
	CULLEN KENDRA	Civil Engineer	Civil Engineer	2018	Study performance	3.0
	DU CHENYI	Substation Engineer	Substation Engineer	2018	Study performance	4.0
	ENGLE TY	Project Manager	Generation interconnection request project management	2020	Administration of interconnectoin queue	33.0
	FUERST ROGER	Substation Engineer	Substation Engineer	2020	Study performance	6.8
	GUTTROMSON DOUGLAS	Area Engineer	Area Engineer	2020	Study performance	29.0
	LINT ADAM	Transmission Planner	Transmission Planner	2018-2020	Study performance	24.0
	LOUCKS ANNE	Meter Engineer	Meter Engineer	2020	Study performance	16.5
	MARK JOHN	Meter Engineer	Meter Engineer	2018-2020	Study performance	7.0
	MOORE ROBIN	Project Manager	Generation interconnection request project management	2018-2019	Administration of interconnectoin queue	10.3
	RETZLAFF GRAHAM	Contract Specialist	Transmission contracts	2018-2020	Administration of interconnectoin queue	10.5
	ROBINSON MARK	Communications Engineer	Communications Engineer	2018-2020	Study performance	11.0
	SMITH CHRISTOPHER	Cost Engineer	Cost estimate creation	2018-2020	Study performance	77.5
	TREMBATH TRAVIS	Cost Engineer	Cost estimate creation	2018-2020	Study performance	5.0

OR - UM 2118
Sunthurst 1.4

Name	Relation to PacifiCorp	Nature of Involvement
SHAFI SHAKEEL	Consultant	Study performance
MILLER DEAN	Consultant	Study performance
ELDER STEVEN	Consultant	Study performance

UM 2118 / PacifiCorp
October 16, 2020
Sunthurst Data Request 1.9

Sunthurst Data Request 1.9

The table below contains data from PacifiCorp's OASIS web page. It lists in-service Oregon solar interconnections under 10 MW, from 2012 to present. For each Q#, below, please provide:

(a) the estimated total cost to construct the interconnection facilities in the executed interconnection agreement (IA),

(b) the amount of "Contingency" included in the executed IA,

(c) the amount of "Surcharge" included in the executed IA; and

(d) the final total cost to construct the interconnection facilities paid by the customer.

Interconnect Request Information				Max MW Output	Location of Facility		In-Service Date (Commercial Operations)	
Q#	Company Name	Service Type	Application Rules	S	ST	Region	Agreed to Commercial Operations Da	Type
389-A	PacifiCorp Energy	ER	OGI	2	OR	PACW	7/1/12	Solar
555	Adams Solar Center, LLC	NR	OGI	10	OR	PACW	4/13/18	Solar
556	Elbe Solar Center, LLC	NR	OGI	10	OR	PACW	5/25/18	Solar
566	Bly Solar Center, LLC	NR	OGI	8.5	OR	PACW	11/20/18	Solar
571	NorWest Energy 2, LLC	NR	OGI	10	OR	PACW	12/31/16	Solar
572	Oregon Solar Land Holdings, LLC	NR	OGI	10	OR	PACW	12/31/16	Solar
573	Old Mill Solar, LLC	ER	SGI	5	OR	PACW	12/18/15	Solar
577	NorWest Energy 4, LLC	NR	OGI	4.8	OR	PACW	12/14/18	Solar
578	NorWest Energy 7, LLC	NR	OGI	10	OR	PACW	12/31/17	Solar
580	Bear Creek Solar Center, LLC	NR	OGI	10	OR	PACW	7/23/18	Solar
581	Klamath Falls Solar 1, LLC	NR	OGI	0.83	OR	PACW	4/5/16	Solar
585	BC Solar, LLC	NR	OGI	8	OR	PACW	12/16/16	Solar
586	NorWest Energy 9, LLC	NR	OGI	6	OR	PACW	7/31/18	Solar
609	Woodline Solar, LLC	NR	OGI	8	OR	PACW	12/20/17	Solar
612	Chiloquin Solar LLC	NR	OGI	9.9	OR	PACW	12/29/17	Solar
613	Tumbleweed Solar LLC	NR	OGI	9.9	OR	PACW	12/22/17	Solar
624	Klamath Falls Solar 2, LLC	NR	OGI	2.9	OR	PACW	9/16/17	Solar
661	OR Solar 3, LLC	NR	OGI	10	OR	PACW	12/31/17	Solar
670	OR Solar 5, LLC	NR	OGI	8	OR	PACW	12/31/17	Solar
671	OR Solar 8, LLC	NR	OGI	10	OR	PACW	12/31/17	Solar
672	OR Solar 6, LLC	NR	OGI	10	OR	PACW	12/15/17	Solar
780	Airport Solar, LLC	ER	LGI	1.25	OR	PACW	5/27/19	Solar

Identify the person from whom the information and documents supplied in response to the Data Request were obtained, the person who prepared each response, the person who reviewed each response, and the person who will bear ultimate responsibility for the truth of each response.

Response to Sunthurst Data Request 1.9

UM 2118 / PacifiCorp
October 16, 2020
Sunthurst Data Request 1.9

Please refer to Attachment Sunthurst 1.9.

Respondent(s): Kris Bremer

Q#	S	ST	Point of Interconnection	oltage (k	Type	Estimated Cost	Contingenc	Surcharge	Actual Costs	Notes
389-A	2	OR	Circuit 5L105 out of Mile Hi substation	12	Solar	$884,415	15.0%	10.0%	$430,098	
555	10	OR	Tap 5D295 out of Cherry Lane substation	12.47	Solar	$1,547,000	0.0%	13.0%	$1,425,833	The estimate in the agreement was revised following the commencement of detailed design therefore no contingency was included.
556	10	OR	Tap 5D52 out of Madras substation	12.47	Solar	$2,769,600	0.0%	13.0%	$2,247,210	The estimate in the agreement was revised following the commencement of detailed design therefore no contingency was included.
566	8.5	OR	Fishhole substation	69	Solar	$2,266,000	0.0%	13.0%	$2,921,805	The estimate in the agreement was revised following the commencement of detailed design therefore no contingency was included.
571	10	OR	Circuit 5D261, Klondike, out of Pilot Butte subst	12.47	Solar	$1,398,800	0.0%	13.0%	$1,464,123	The estimate in the agreement was revised following the commencement of detailed design therefore no contingency was included.
572	10	OR	Circuit 5D263, Drake, out of Pilot Butte substati	12.5	Solar	$679,000	20.0%	10.5%	$1,213,014	
573	5	OR	Circuit 5L14 out of Bly substation	12	Solar	$1,786,500	20.0%	10.5%	$1,934,769	
577	4.8	OR	Circuit 4L16, Langell Valley, out of Casebeer sub	20.8	Solar	$1,713,000	15.0%	13.0%	$2,217,397	
578	10	OR	Circuit 5R110, McLauglin, out of Vilas road subs	12.5	Solar	$2,308,000	15.0%	13.0%	$1,135,698	
580	10	OR	Pilot Butte substation	12.5	Solar	$1,372,000	15.0%	13.0%	$1,578,111	
581	0.8	OR	Circuit 5L112, out of Texum substation	12	Solar	$130,800	20.0%	11.8%	$84,156	
585	8	OR	Circuit 5L105, Town , out of Mile-Hi substation	12	Solar	$1,676,000	15.0%	13.0%	$1,606,188	
586	6	OR	Circuit 5W201, State Hospital, out of Buckaroo s	12.5	Solar	$1,781,698	15.0%	13.0%	$1,791,585	
609	8	OR	Circuit 5L42 out of Dairy substation	12.5	Solar	$1,808,200	20.0%	13.0%	$1,012,665	
612	9.9	OR	Circuit 5L57, Crater Lake, out of Chiloquin subst	12.5	Solar	$1,824,000	15.0%	13.0%	$2,124,457	
613	9.9	OR	Circuit 5D184, Pronghorn, out of Deschutes sub	12.5	Solar	$1,748,000	15.0%	13.0%	$1,592,456	
624	2.9	OR	Circuit 5L116, out of Texum substation	12	Solar	$744,000	15.0%	13.0%	$955,519	
661	10	OR	Circuit 5L23, Rural out of Turkey Hill substation	12.5	Solar	$3,164,800	0.0%	13.0%	$3,534,283	The estimate in the agreement was revised following the commencement of detailed design therefore no contingency was included.
670	8	OR	Circuit 5L27 out of Merrill substation	12	Solar	$1,773,400	0.0%	13.0%	$1,861,942	The estimate in the agreement was revised following the commencement of detailed design therefore no contingency was included.
671	10	OR	Circuit 5L43 out of Dairy substation	12	Solar	$1,879,200	0.0%	13.0%	$2,154,371	The estimate in the agreement was revised following the commencement of detailed design therefore no contingency was included.
672	10	OR	Circuit 5L104 out of Mile Hi substation	12.5	Solar	$1,974,000	20.0%	13.0%	$1,861,942	
780	1.3	OR	Alturas-Mile Hi transmission line	115	Solar	NA	NA	NA	NA	This incremental amount was added to Q0729 therefore no estimated costs for this queue position.

UM 2118 / PacifiCorp
October 23, 2020
Sunthurst Data Request 2.2

Sunthurst Data Request 2.2

Provide a list of PacifiCorp owned renewable generators (location, date metering began, size) metered on low side used anywhere in Pacific Power or Rocky Mountain Power service territory.

Response to Sunthurst Data Request 2.2

PacifiCorp interprets the question as regarding generators that are interconnected to the PacifiCorp transmission system. Based on the foregoing interpretation, the Company responds as follows:

Please refer to Attachment Sunthurst 2.2 which provides a list of PacifiCorp-owned renewable resources, metered on the low side.

Respondent(s): Matt Hastings

PacifiCorp Owned Renewable Resources - metered on the low side

Location	Plant	Type	Generator Name Plate Rating (kilowatts (kW))	Initial Service Date	Note
CA	Fall Creek	Hydro	2,200	1903	
CA	Iron Gate	Hydro	18,000	1962	
ID	Ashton	Hydro	6,700	1917	
ID	Grace	Hydro	33,000	1908	
ID	Oneida	Hydro	30,000	1915	
ID	Soda	Hydro	14,000	1924	
MT	Big Fork Net	Hydro	4,150	1910	
OR	Bend	Hydro	1,110	1913	
OR	Clearwater #1	Hydro	15,000	1953	
OR	Clearwater #2	Hydro	26,000	1953	
OR	Eagle Point	Hydro	2,813	1957	
OR	Eastside	Hydro	3,200	1924	
OR	Fish Creek	Hydro	11,000	1952	
OR	J C Boyle Total	Hydro	97,980	1958	
OR	Lemolo #1 Total	Hydro	31,990	1955	
OR	Lemolo #2 Total	Hydro	38,500	1956	
OR	Slide Creek Total	Hydro	18,000	1951	
OR	Soda Springs	Hydro	11,000	1952	
OR	Toketee Total	Hydro	42,501	1949	
OR	Wallowa Falls	Hydro	1,100	1921	
OR	West Side	Hydro	600	1908	
UT	Cutler	Hydro	30,000	1927	
UT	Granite	Hydro	2,000	1896	
UT	Gunlock	Hydro	750	1917	
UT	Pioneer	Hydro	5,000	1897	
UT	Sand Cove	Hydro	800	1926	
UT	Stairs	Hydro	1,000	1895	
UT	Veyo	Hydro	500	1920	
UT	Weber	Hydro	3,850	1911	
WA	Yale Total	Hydro	134,000	1953	
WY	Viva Naughton	Hydro	740	1986	

UM 2118 / PacifiCorp
October , 2020
Sunthurst Data Request 2.4

Sunthurst Data Request 2.4

What is the approximate age of the existing interconnection facilities a Pilot Rock substation?

Response to Sunthurst Data Request 2.4

The existing facilities at Pilot Rock substation were placed into service in approximately 1961.

Respondent(s): Scott Beyer

UM 2118 / PacifiCorp
November 18, 2020
Sunthurst Data Request 3.2

Sunthurst Data Request 3.2

Please refer to Paragraph 16 in Sunthurst' Complaint describing Sunthurst' first alternative metering proposal (Alternative 1). Describe any reason why Alternative 1 is not a (a) safe; and (b) effective means of metering PRS1 and PRS2.

Response to Sunthurst Data Request 3.2

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

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

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

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

Finally, as both PRS1 and PRS2 are proposing to participate in the Oregon Community Solar (OCS) program, the accuracy of the meter data for these facilities is even more important. The OCS program requires generator owners to sign up subscribers for their solar generators. If there is a meter failure or a data calculation error as described above, under the OCS program not only is there a potential dispute or recalculation necessary for PRS1 and PRS2, but also potentially disputes or recalculations for dozens or even hundreds of subscribers. This scenario could lead to substantial accounting work for

PacifiCorp and creates the possibility of hundreds of disputes with subscribers. Having three meters would substantially limit these potential issues.

Respondent: Kris Bremer

UM 2118 / PacifiCorp
November 18, 2020
Sunthurst Data Request 3.4

Sunthurst Data Request 3.4

Refer to question 10 of PacifiCorp's First Set of Data Requests. Is PacifiCorp aware of instances where PacifiCorp has not required three meters to measure output from two adjacent projects that utilize the same point of interconnection? If yes, please list each instance.

Response to Sunthurst Data Request 3.4

No.

Respondent: Kris Bremer

UM 2118 / PacifiCorp
November 18, 2020
Sunthurst Data Request 3.5

Sunthurst Data Request 3.5

Please identify, by PacifiCorp Interconnection Queue number, all small Oregon interconnection requests, 2012 to present, where the customer requesting interconnection is PacifiCorp or its affiliate.

Response to Sunthurst Data Request 3.5

The customer queue numbers are as follows:

- Q0538
- Q0914
- Q1185

Respondent: Kris Bremer

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

UM 2118 / PacifiCorp
February 12, 2021
Sunthurst Data Request 3.7 – 1st Revised

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.

1st Revised Response to Sunthurst Data Request 3.7

Further to the Company's response to Sunthurst Data Request 3.7 dated November 18, 2020, the Company provides this 1st Revised response to replace one of the attachments previously designated as confidential, now designated non-confidential.

Please refer to Attachment Sunthurst 3.7-2 1st Revised. Note: this attachment was previously provided as confidential due to the inclusion of IHS Global inflation forecast information, a third party proprietary work product. The Company has received permission from IHS Global that the inflation forecast information contained in Attachment Sunthurst 3.7-2 1st Revised can be provided as non-confidential.

Important note: the redesignation of Attachment Sunthurst 3.7-2 from confidential to non-confidential is the only change to the Company's response to Sunthurst Data Request 3.7; all other aspects of the Company's response remains correct, unchanged and valid.

Respondent(s): Counsel

UT N - 200 MW - SCCT Frame "F" x1 - East Side Resource (5,050')
$702/kw

Project Capital Costs with AFUDC

	$Thousands	$/kW
Total Project Cost before AFUDC	$ 124,655	623.5
Capitalized Property Tax	$ 2,080	10.4
Surcharge	$ 500	2.5
AFUDC	$ 13,032	65.2
Total Project Cost Incl. AFUDC	**$ 140,267**	701.6
	Total Cost	
Project Cost before ESC & AFUDC	124,655	

2016 $000

Calendar Y	Investment	Escalation Rate	AFUDC Rate	Nominal Dollar Cost Summary: Construction Cost before Financial Costs	Escalation	Prop. Tax	Surcharge	AFUDC	TOTAL
2017	3,711	1.0000	7.86%	3,711	-	-	15	71	3,798
2018	7,423	1.0000	7.33%	7,423	-	-	30	548	8,001
2019	27,509	1.0000	7.04%	27,509	-	142	110	1,465	29,226
2020	72,526	1.0000	7.72%	72,526	-	492	291	6,162	79,472
2021	13,485	1.0000	7.55%	13,485	-	1,446	54	4,785	19,771
2022	-	1.0000	7.30%	-	-	-	-	-	-
2023	-	1.0000	7.15%	-	-	-	-	-	-
2024	-	1.0000	7.50%	-	-	-	-	-	-
	124,655			124,655	-	2,080	500	13,032	140,267
								1.125	
tated to IRP Reference Year 2016$				124,655	-	2,080	500	13,032	140,267
$/kW 2016$				$624	$0	$10	$3	$65	$702

FINANCIAL ANALYSIS ASSUMPTIONS 2016 (updated 02/19/2016)

YEAR	AFUDC	Escalation	ESC FACTOR	Year No.	(P/F,I,n)
2016	7.80%	1.60%	1.0160	-	1.0000
2017	7.86%	2.40%	1.0404	1	0.9435
2018	7.33%	2.20%	1.0633	2	0.8902
2019	7.04%	2.20%	1.0867	3	0.8399
2020	7.72%	2.30%	1.1117	4	0.7924
2021	7.55%	2.40%	1.1383	5	0.7477
2022	7.30%	2.50%	1.1668	6	0.7054
2023	7.15%	2.40%	1.1948	7	0.6656
2024	7.50%	2.30%	1.2223	8	0.6280
2025	7.65%	2.20%	1.2492	9	0.5925
Average Escalation		2.25%	Weighted Average Escalation		2.23%

Willamette Valley - 436 MW - CCCT Dry "G/H", 1x1 - West Side Resource (1,500')
$1,484/kw

Project Capital Costs with AFUDC

	$Thousands	$/kW
Total Project Cost before AFUDC	$ 498,719	1,294.2
Capitalized Property Tax	$ 7,814	20.3
Surcharge	$ 500	1.3
AFUDC	$ 64,962	168.6
Total Project Cost Incl. AFUDC	**$ 571,995**	1,484.3
	Total Cost	
Project Cost before ESC & AFUDC	498,719	

Calendar Y	Investment (2016 $000)	Escalation Rate	AFUDC Rate	Nominal Dollar Cost Summary: Construction Cost before Financial Costs	Escalation	Prop. Tax	Surcharge	AFUDC	TOTAL
2017	8,161	1.0000	7.86%	8,161	-	-	8	157	8,326
2018	22,669	1.0000	7.33%	22,669	-	100	23	1,323	24,114
2019	109,718	1.0000	7.04%	109,718	-	389	110	4,784	115,001
2020	290,164	1.0000	7.72%	290,164	-	1,769	291	23,315	315,539
2021	68,007	1.0000	7.55%	68,007	-	5,556	68	35,384	109,015
2022	-	1.0000	7.30%	-	-	-	-	-	-
2023	-	1.0000	7.15%	-	-	-	-	-	-
2024	-	1.0000	7.50%	-	-	-	-	-	-
	498,719			498,719	-	7,814	500	64,962	571,995
								1.147	
tated to IRP Reference Year 2016$				498,719	-	7,814	500	64,962	571,995
$/kW 2016$				$1,294	$0	$20	$1	$169	$1,484

FINANCIAL ANALYSIS ASSUMPTIONS 2016 (updated 02/19/2016)

YEAR	AFUDC	Escalation	ESC FACTOR	Year No.	(P/F,I,n)
2016	7.80%	1.60%	1.0160	-	1.0000
2017	7.86%	2.40%	1.0404	1	0.9435
2018	7.33%	2.20%	1.0633	2	0.8902
2019	7.04%	2.20%	1.0867	3	0.8399
2020	7.72%	2.30%	1.1117	4	0.7924
2021	7.55%	2.40%	1.1383	5	0.7477
2022	7.30%	2.50%	1.1668	6	0.7054
2023	7.15%	2.40%	1.1948	7	0.6656
2024	7.50%	2.30%	1.2223	8	0.6280
2025	7.65%	2.20%	1.2492	9	0.5925
Average Escalation		2.25%	Weighted Average Escalation		2.23%

Willamette Valley - 436 MW - CCCT Dry "G/H", 1x1 - West Side Resource (1,500') Duct Firing
$443/kw

Project Capital Costs with AFUDC

	$Thousands	$/kW
Total Project Cost before AFUDC	$ 19,261	377.6
Capitalized Property Tax	$ 289	5.7
Surcharge	$ 482	9.4
AFUDC	$ 2,563	50.2
Total Project Cost Incl. AFUDC	**$ 22,595**	443.0
	Total Cost	
Project Cost before ESC & AFUDC	19,261	

2016 $000

Calendar Y	Investment	Escalation Rate	AFUDC Rate	Nominal Dollar Cost Summary: Construction Cost before Financial Costs	Escalation	Prop. Tax	Surcharge	AFUDC	TOTAL
2017	315	1.0000	7.86%	315	-	-	8	6	329
2018	876	1.0000	7.33%	876	-	-	22	52	949
2019	4,237	1.0000	7.04%	4,237	-	-	106	188	4,531
2020	11,207	1.0000	7.72%	11,207	-	70	280	920	12,477
2021	2,627	1.0000	7.55%	2,627	-	219	66	1,396	4,308
2022	-	1.0000	7.30%	-	-	-	-	-	-
2023	-	1.0000	7.15%	-	-	-	-	-	-
2024	-	1.0000	7.50%	-	-	-	-	-	-
	19,261			19,261	-	289	482	2,563	22,595
								1.173	
tated to IRP Reference Year 2016$				19,261	-	289	482	2,563	22,595
$/kW 2016$				$378	$0	$6	$9	$50	$443

FINANCIAL ANALYSIS ASSUMPTIONS 2016 (updated 02/19/2016)

YEAR	AFUDC	Escalation	ESC FACTOR	Year No.	(P/F,I,n)
2016	7.80%	1.60%	1.0160	-	1.0000
2017	7.86%	2.40%	1.0404	1	0.9435
2018	7.33%	2.20%	1.0633	2	0.8902
2019	7.04%	2.20%	1.0867	3	0.8399
2020	7.72%	2.30%	1.1117	4	0.7924
2021	7.55%	2.40%	1.1383	5	0.7477
2022	7.30%	2.50%	1.1668	6	0.7054
2023	7.15%	2.40%	1.1948	7	0.6656
2024	7.50%	2.30%	1.2223	8	0.6280
2025	7.65%	2.20%	1.2492	9	0.5925
Average Escalation		2.25%	Weighted Average Escalation		2.23%

Sunthurst/401
Beanland/18

Wyoming Wind Resource
$1,637/kw

Project Capital Costs with AFUDC

	$Thousands	$/kW
Total Project Cost before AFUDC	$ 161,254	1,612.5
Capitalized Property Tax	$ 1,678	16.8
Surcharge	$ 500	5.0
AFUDC	$ 10,292	102.9
Total Project Cost Incl. AFUDC	**$ 173,725**	1,737.2
	Total Cost	
Project Cost before ESC & AFUDC	161,254	

	2016 $000			Nominal Dollar Cost Summary					
Calendar Y	Investment	Escalation Rate	AFUDC Rate	Construction Cost before Financial Costs	Escalation	Prop. Tax	Surcharge	AFUDC	TOTAL
2017	645	1.0000	7.86%	645	-	-	2	10	657
2018	1,451	1.0000	7.33%	1,451	-	-	5	92	1,548
2019	1,935	1.0000	7.04%	1,935	-	-	6	223	2,164
2020	17,093	1.0000	7.72%	17,093	-	-	53	621	17,767
2021	90,302	1.0000	7.55%	90,302	-	266	280	4,722	95,570
2022	49,828	1.0000	7.30%	49,828	-	1,412	155	4,624	56,018
2023	-	1.0000	7.15%	-	-	-	-	-	-
2024	-	1.0000	7.50%	-	-	-	-	-	-
	161,254			161,254	-	1,678	500	10,292	173,725
								1.077	
tated to IRP Reference Year 2016$				161,254	-	1,678	500	10,292	173,725
$/kW 2016$				$1,613	$0	$17	$5	$103	$1,737

FINANCIAL ANALYSIS ASSUMPTIONS 2016 (updated 02/19/2016)

YEAR	AFUDC	Escalation	ESC FACTOR	Year No.	(P/F,I,n)
2016	7.80%	1.60%	1.0160	-	1.0000
2017	7.86%	2.40%	1.0404	1	0.9435
2018	7.33%	2.20%	1.0633	2	0.8902
2019	7.04%	2.20%	1.0867	3	0.8399
2020	7.72%	2.30%	1.1117	4	0.7924
2021	7.55%	2.40%	1.1383	5	0.7477
2022	7.30%	2.50%	1.1668	6	0.7054
2023	7.15%	2.40%	1.1948	7	0.6656
2024	7.50%	2.30%	1.2223	8	0.6280
2025	7.65%	2.20%	1.2492	9	0.5925
Average Escalation		2.25%	Weighted Average Escalation		2.23%

UM 2118 / PacifiCorp
November 18, 2020
Sunthurst Data Request 3.8

Sunthurst Data Request 3.8

Refer to PacifiCorp's August 7, 2020 letter from Matt Loftus to Ken Kaufmann, at page 1, where PacifiCorp states: "PacifiCorp is willing to remove the P1-111 annunciator panel. The reduction in costs for this modification is $15,000".

(a) Does the current cost estimate for Q0666 reflect a $15,000 deduct for removing the P1-111 annunciator?

(b) Does PacifiCorp intend to install the P1-111 annunciator panel at PacifiCorp's cost, or is the panel being removed from the installation?

(c) Explain why the P1-111 annunciator panel is necessary (or not necessary).

Response to Sunthurst Data Request 3.8

(a) Yes, the most recent estimate provided to Sunthurst Energy, LLC (Sunthurst Energy) does not contain a cost for an annunciator panel, although Sunthurst Energy has not executed the proposed interconnection agreement amendment provided by PacifiCorp so that estimate is not considered as part of the effective agreement.

(b) Yes, PacifiCorp intends to install, at its cost, an annunciator panel in Pilot Rock substation if the Q0666 project proceeds.

(c) An annunciator is an electronic indicator panel that identifies what specific pieces of equipment are experiencing issues within a substation. Annunciators are a very useful and valuable piece of equipment which makes troubleshooting significantly easier when a substation is experiencing some sort of technical issue. It is similar to the indicators in cars that identify items such as low oil. PacifiCorp is installing the annunciator because of the interconnection of Q0666, i.e., if Q0666 does not ultimately interconnect, PacifiCorp will not install the annunciator. Therefore, the annunciator panel is necessitated by the interconnection request of Q0666 and would not be installed but for the interconnection request.

Respondent: Kris Bremer

UM 2118 / PacifiCorp
November 18, 2020
Sunthurst Data Request 3.11

Sunthurst Data Request 3.11

Please refer to the System Impact Study for Oregon Q0389 dated August 10, 2011. (posted on PacifiCorp's OASIS website).

(a) Was PacifiCorp Energy or its affiliate the "Interconnection Customer" for Q0389?

Response to Sunthurst Data Request 3.11

(a) PacifiCorp was not the interconnection customer that submitted the Q0389 interconnection request. PacifiCorp purchased the generating facility after it achieved commercial operation.

Respondent: Kris Bremer

UM 2118 / PacifiCorp
November 18, 2020
Sunthurst Data Request 3.14

Sunthurst Data Request 3.14

Please refer to the System Impact Study for (abandoned) Q0569 dated October 31, 2014 (posted on PacifiCorp's OASIS website).

(a) Was PacifiCorp Energy or its affiliate the "Interconnection Customer" for Q0569?

Response to Sunthurst Data Request 3.14

The Company advises that the System Impact Study for Q0569 was dated August 8, 2014. The Facilities Study for Q0569 was dated October 31, 2014. Based on the foregoing correction to the stated data request, the Company responds as follows:

(a) Yes.

Respondent(s): Kris Bremer

UM 2118 / PacifiCorp
November 18, 2020
Sunthurst Data Request 3.15

Sunthurst Data Request 3.15

Please refer to page 9 of the Facilities Study report for Q0573 (Old Mill Solar, LLC) dated October 30, 2014.

(a) Please explain how the $1,329,700 in Network Upgrades costs required by that study are billed differently from the $570,800 in Direct Assigned costs. Does PacifiCorp reimburse Q0573 for all Network Upgrades costs paid by the Q0573 customer?

Response to Sunthurst Data Request 3.15

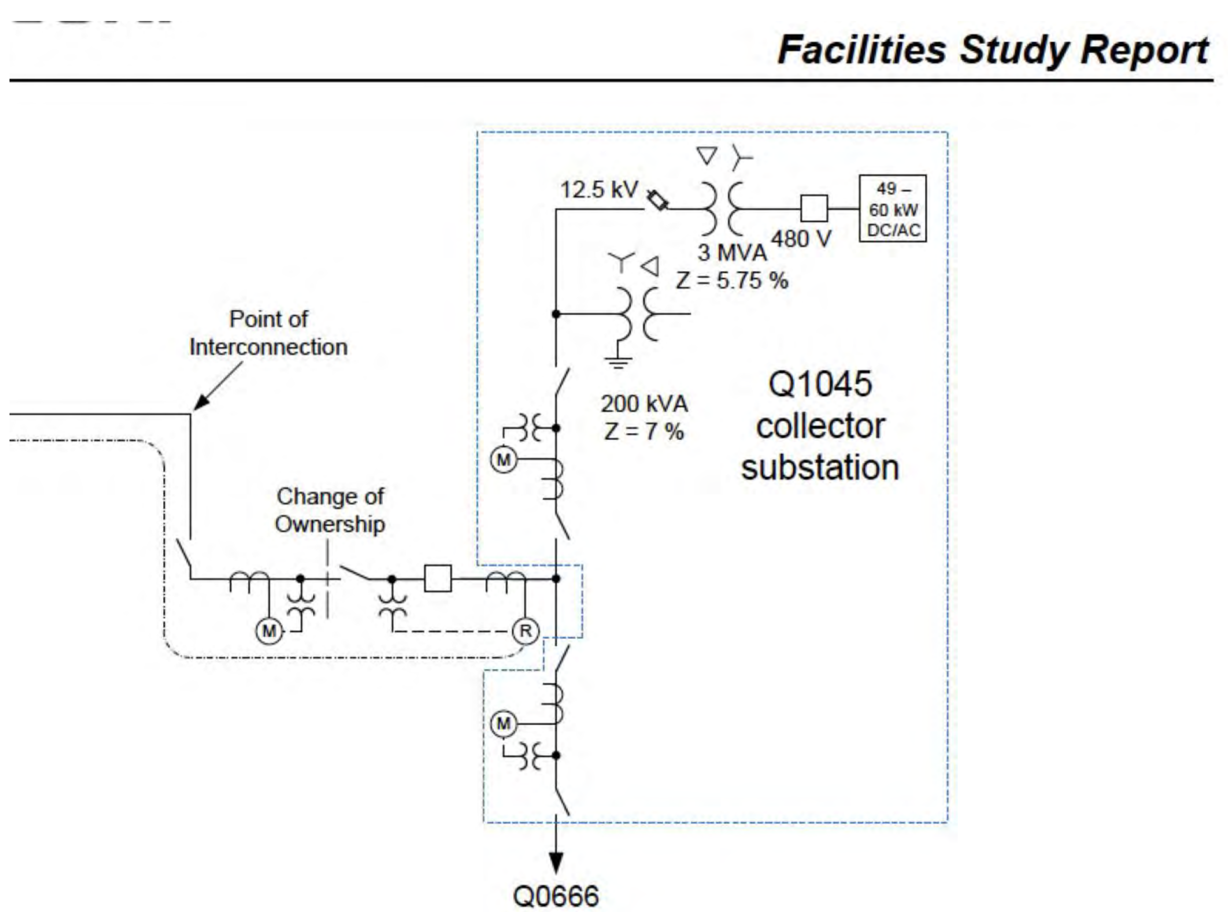
(a) The interconnection of Q0573 is subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC). As a FERC-jurisdictional interconnection, costs were billed in accordance with the cost allocation requirements set forth in PacifiCorp's Open Access Transmission Tariff (OATT), which distinguishes between network upgrade and direct assigned costs. As required by the OATT, the interconnection customer receives reimbursement for network upgrade costs.

Respondent: Kris Bremer

UM 2118 / PacifiCorp
December 9, 2020
Sunthurst Data Request 4.1

Sunthurst Data Request 4.1

For the following questions, please refer to the one-line diagram below, copied from Attachment A to the Complaint, showing PacifiCorp's required metering for Pilot Rock Solar 1 (PRS1)(Q0666) and Pilot Rock Solar 2 (PRS2)(Q1045):



Source: Tier 4 Facilities Study Report for Pilot Rock Solar 2, LLC (Q1045), June 30, 2020, p.2 [from Attachment A to Sunthurst's Complaint UM 2118]

Please refer to PacifiCorp's response to Data Request 3.2, paragraph 1, which states:

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

UM 2118 / PacifiCorp
December 9, 2020
Sunthurst Data Request 4.1

(a). Does Attachment A, above, show the "metering equipment that PacifiCorp is requiring" to interconnect PRS1 and PRS2?
(b). Explain how, if only the meter at the Change of Ownership Point (COP) is removed in Attachment A, above, "generation could flow onto PacifiCorp's system without PacifiCorp having the ability to monitor it".
(c). In Attachment A, approximately how far is the PRS1 meter from the COP meter?
(d). In Attachment A, approximately how far is the PRS2 meter from the COP meter?
(e). What does PacifiCorp estimate are average losses (%), from PRS1 to COP; and from PRS2 to COP? How were these numbers estimated?
(f). Explain how removal of only the meter at the COP "could lead to unsafe operating conditions for PacifiCorp's employees".

Response to Sunthurst Data Request 4.1

(a) Yes.

(b) If either of the meters fail, generation would be flowing onto PacifiCorp's system and PacifiCorp would not have the ability to monitor it, meaning the possibility exists that PacifiCorp personnel would be unaware that facilities are energized while performing maintenance activities.

(c) The distance has not been determined as the interconnection customer has only provided a conceptual one-line diagram.

(d) Please refer to the Company's response to subpart (c) above.

(e) PacifiCorp cannot estimate losses based upon a conceptual design.

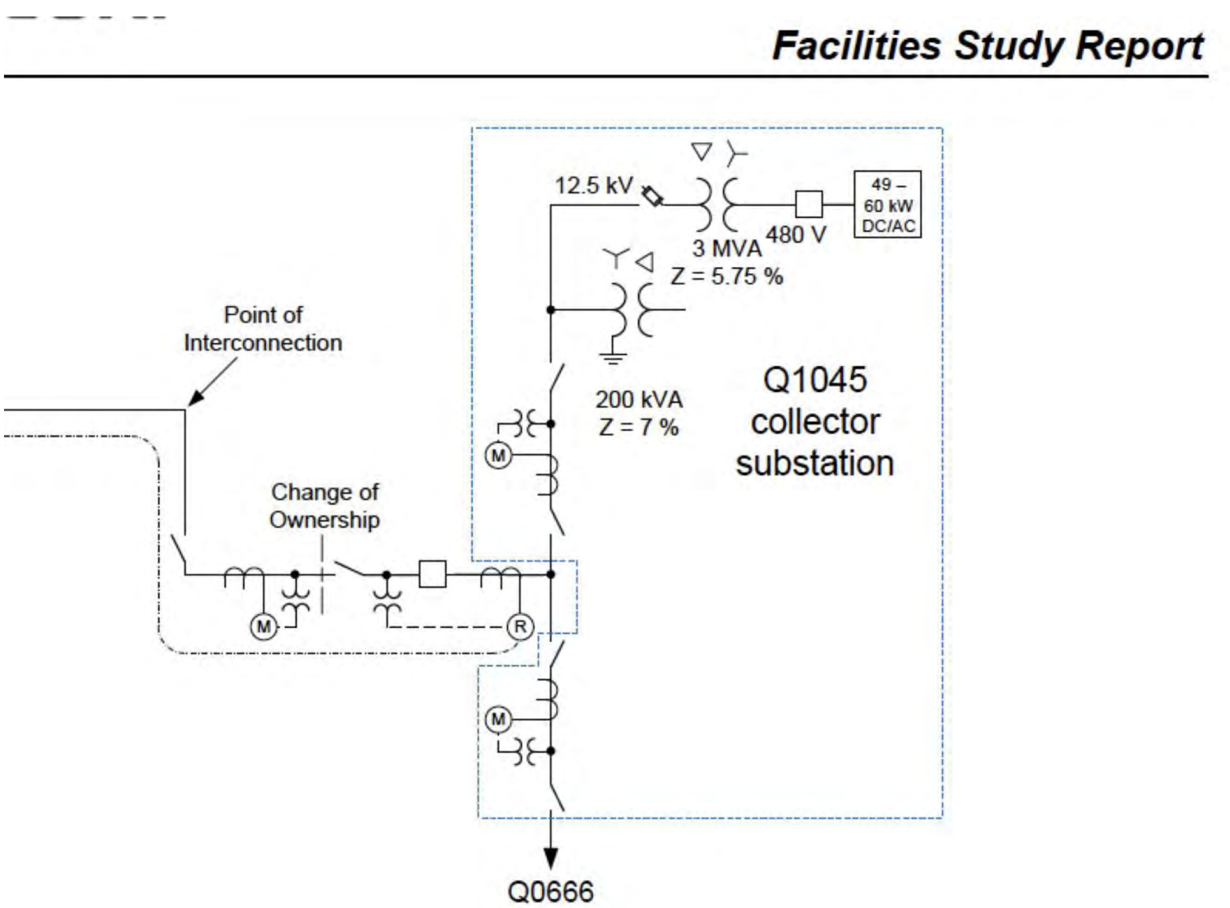
(f) Please refer to the Company's response to subpart (b) above.

Respondent(s): Kris Bremer

UM 2118 / PacifiCorp
December 9, 2020
Sunthurst Data Request 4.2

Sunthurst Data Request 4.2

For the following questions, please refer to the one-line diagram below, copied from Attachment A to the Complaint, showing PacifiCorp's required metering for Pilot Rock Solar 1 (PRS1)(Q0666) and Pilot Rock Solar 2 (PRS2)(Q1045):



Source: Tier 4 Facilities Study Report for Pilot Rock Solar 2, LLC (Q1045), June 30, 2020, p.2 [from Attachment A to Sunthurst's Complaint UM 2118]

Please refer to PacifiCorp's response to Data Request 3.2, paragraph 2, which states:

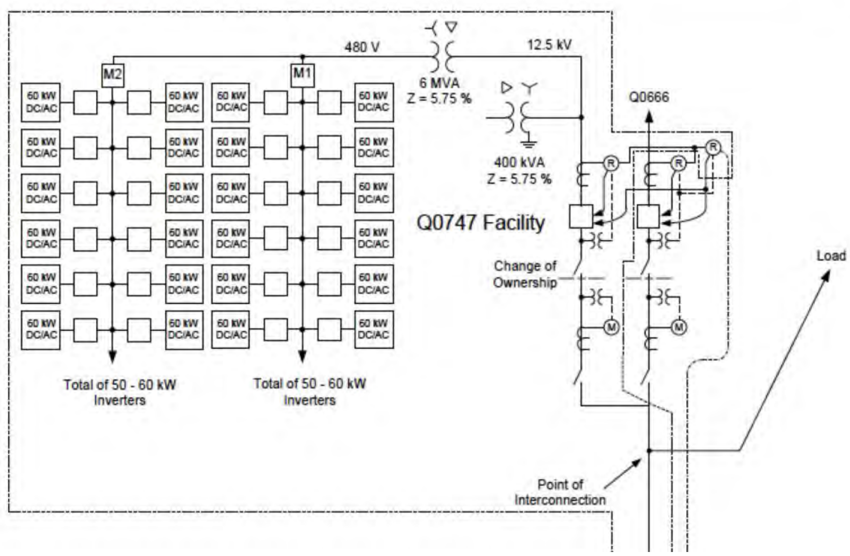
"Additionally, the "Alternative 1" metering proposal from Sunthurst Energy, LLC (Sunthurst Energy) is not effective (or acceptable) because PacifiCorp would not have a meter at the point of interconnection (POI) where the generation from both facilities is injected onto PacifiCorp's system. This is unacceptable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

UM 2118 / PacifiCorp
December 9, 2020
Sunthurst Data Request 4.2

Please refer to Complaint, Attachment B, shown below, when answering (a)-(d).

PACIFICORP TRANSMISSION

Tier 4 System Impact Study Report



Source: Tier 4 System Impact Study Report for Pilot Rock Solar 2, LLC (Q0747), August 26, 2016, p.3 [from Attachment B to Sunthurst Complaint UM 2118]

(a) How does PacifiCorp know how much energy is flowing onto its distribution system at the POI in the case of Q0747, shown in Attachment B, above?
(b) If "PacifiCorp must have a meter at the POI to ensure it knows how much energy is flowing onto its distribution system", why did PacifiCorp not require a meter at the POI in Q0747?
(c) Explain PacifiCorp's basis for stating "A POI meter is standard industry practice."
(d) Does this "standard industry practice" apply to distribution systems? Please cite any authority for this proposition.
(e) Does PacifiCorp have generator interconnections to its distribution system that do not meter at the POI? Is this also consistent with "standard industry practice"?
(f) Does IEEE 1547 or any other applicable code require metering at the POI? Please provide citations to any such requirement.
(g) In Q0747, does PacifiCorp's proposed design (shown in Attachment B, above) merge the tie lines from PRS1(Q0666) and PRS2(Q0747) prior to the Point of Interconnection? How does PacifiCorp account for losses from Q0666 and Q0747 between the point of metering and the Point of Interconnection?

UM 2118 / PacifiCorp
December 9, 2020
Sunthurst Data Request 4.2

Response to Sunthurst Data Request 4.2

(a) As the one-line diagram shows, Q0747 was proposed to be metered at the point of interconnection (PO).

(b) This question incorrectly assumes there is not a meter required at the POI for Q0747. PacifiCorp did propose to have a meter at the POI, as the one-line diagram shows.

(c) Any utility has a responsibility to meter generation flowing onto its system for safety and reliability purposes. PacifiCorp considers meeting these goals to be good utility practice.

(d) Yes. It is PacifiCorp's uniform practice to install meters at the POI for distribution level interconnections. In particular, the same responsibilities and safety and reliability purposes stated in response to part (c) equally apply to distribution-level interconnections. PacifiCorp is unaware of utilities that do not require installation of meters at the POI.

(e) All generators proposing to interconnect to PacifiCorp's distribution system are required to adhere to PacifiCorp Policy 138. The policy has required metering at the POI for many years.

(f) PacifiCorp is unaware of any standard that requires meters to be installed at the POI, but nonetheless asserts it is good (or standard) utility practice based on its experience.

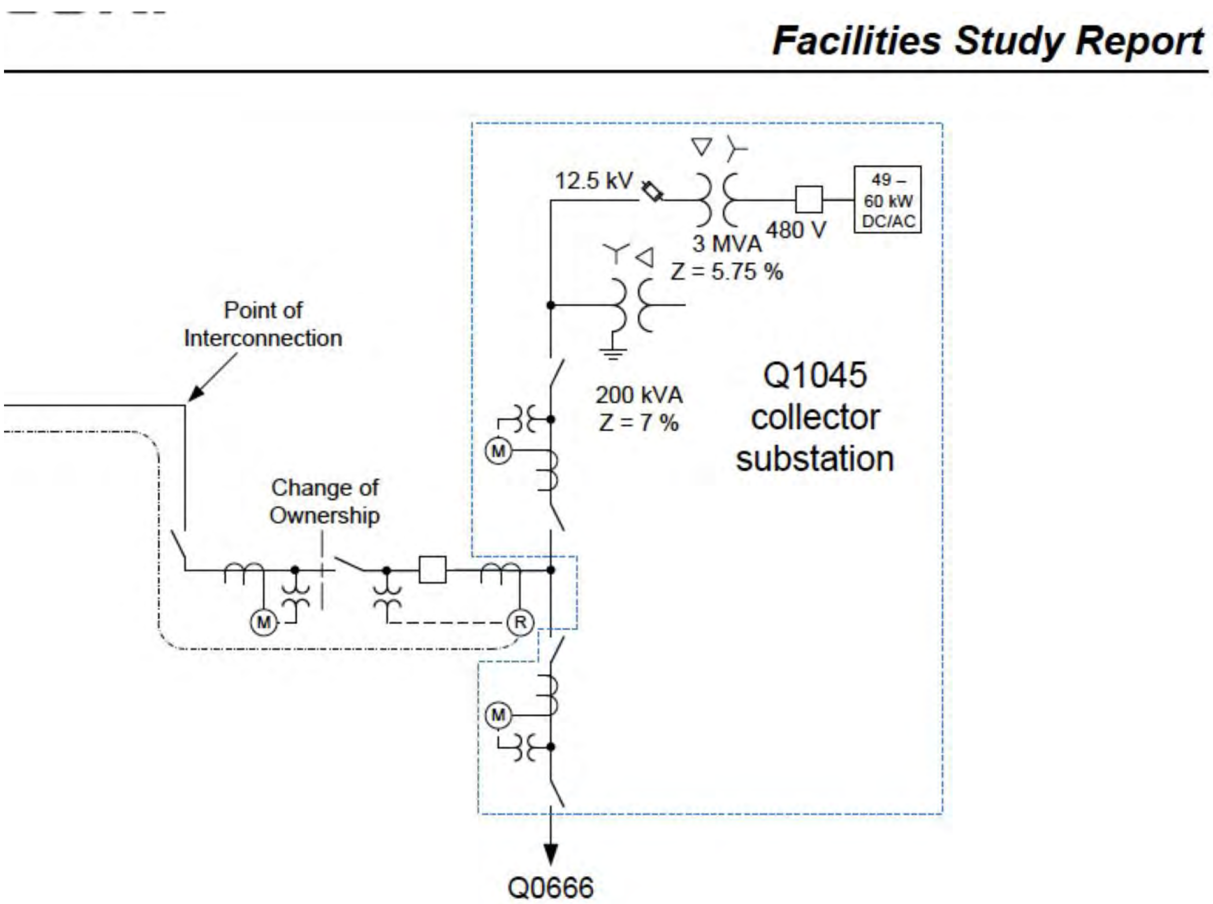
(g) No, the proposed design of the Q0747 and Q0666 metering did not "merge" the tie lines prior to the POI. They are both metered independently at the POI. There are no losses because the projects are metered at the point of interconnection.

Respondent(s): Eric Taylor, Kris Bremer

UM 2118 / PacifiCorp
December 9, 2020
Sunthurst Data Request 4.4

Sunthurst Data Request 4.4

For the following questions, please refer to the one-line diagram below, copied from Attachment A to the Complaint, showing PacifiCorp's required metering for Pilot Rock Solar 1 (PRS1)(Q0666) and Pilot Rock Solar 2 (PRS2)(Q1045):



Source: Tier 4 Facilities Study Report for Pilot Rock Solar 2, LLC (Q1045), June 30, 2020, p.2 [from Attachment A to Sunthurst's Complaint UM 2118]

In its response to Sunthurst DR 2.2, PacifiCorp listed 31 PacifiCorp owned renewable resources that meter on the low side (generator side) of the collector station transformer.
(a) Of those 31 renewable resources, which ones interconnect to a PacifiCorp-owned or controlled distribution system (34.5kV and below).
(b) For each renewable resource listed in response to (a):
    (i) state the approximate distance from the low-side meter to the point of interconnection to the distribution system (POI).
    (ii) state how PacifiCorp determines the amount of energy flowing at the POI to the distribution system.

UM 2118 / PacifiCorp
December 9, 2020
Sunthurst Data Request 4.4

(iii) state the adjustment(s), if any, PacifiCorp makes to its low-voltage revenue meter readings to account for changes between the metering point and the point of interconnection.
(iv) are the adjustments listed in (iii), above, "standard industry practice"? Please explain.

Response to Sunthurst Data Request 4.4

PacifiCorp objects to this request because it seeks information that is not relevant. In particular, with one exception, the generators identified in Attachment Sunthurst 2.2 were interconnected between the 1890's and 1960's. The one exception was interconnected in 1986. These interconnections do not reflect current industry practice. If the generators requested interconnection today, they could not use the low-side metering configuration.

Respondent(s): Matthew Loftus, Kris Bremer

UM 2118 / PacifiCorp
December 14, 2020
Sunthurst Data Request 5.1

Sunthurst Data Request 5.1

Please describe any modifications to the Pilot Rock substation undertaken since August 2015.

Response to Sunthurst Data Request 5.1

- In 2017, the control house wall air conditioning unit was replaced due to failure.
- In 2018, the west fence was replaced allowing for the installation of an additional gate and to correct a National Electrical Safety Code (NESC) clearance violation.
- In 2019, the Pilot Rock battery bank and charger were replaced due to battery degradation.
- In 2019, the three-phase regulator R542 was replaced due to catastrophic failure in September of 2018. As part of this project transformer bank #1 arresters, animal guarding, and current transformer bank #9 were installed or replaced.
- In 2019, the control for regulator R816 was replaced due to failure.

Respondent(s): Doug Guttromson

UM 2118 / PacifiCorp
December 14, 2020
Sunthurst Data Request 5.2

Sunthurst Data Request 5.2

Please describe all items contributing to a $7,650 estimated cost for avian protections set forth in PacifiCorp's September 1, 2020 detailed cost estimate for Q0666. Describe all avian protection measures associated with Q0666 and/or Q1045.

Response to Sunthurst Data Request 5.2

The estimated cost for avian protections for Q666, includes the following:

- Material and installation cost for about 20 feet of animal guard hose, (Midsun #E/INS-025G).

- Material and installation cost for about 100 feet of animal guard hose, (Midsun #E/INS-175G).

- Material and installation cost for three 24 inch diameter, regulator bypass switch barrier, (TYCO/RAYCHEM #BISG-G-24-01).

There are no avian protection requirements for Q1045.

Respondent(s): Alex Vaz

UM 2118 / PacifiCorp
January 4, 2021
Sunthurst Data Request 6.2

Sunthurst Data Request 6.2

In the Q1045 Facilities Study Report (September 4, 2020 version), Section 6.2.1 states that PacifiCorp will:

- 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.

Please provide the detailed voltage drop and fault current analysis showing that these are required only by the presence of Q1045 and are the only viable solution. When were these studies performed?

Response to Sunthurst Data Request 6.2

When the analysis was performed for Q1045, the load flow software used was the ABB/Ventex FeederAll software package. In 2015, the vendor stopped supporting the software and due to company critical security controls to reduce threat of cyber security incidents and to maintain ISO certification for company software, FeederAll was subsequently removed from all company computers. Therefore, detailed voltage drop and fault current analysis from the FeederAll model is not available.

To provide feeder voltage regulation in a standard, effective, and energy efficient manner, the company 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 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 Q0666 and Q1045 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. These 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.

Respondent(s): Doug Guttromson

UM 2118 / PacifiCorp
January 4, 2021
Sunthurst Data Request 6.3

Sunthurst Data Request 6.3

Please identify each line item in the Q1045 September 1, 2020 Detailed Expenditure Report (provided by PacifiCorp to Sunthurst in response to Sunthurst Data Request 1.10) that includes costs or charges related to the regulators mentioned in Section 6.2.1 of the Q1045 Facilities Study Report.

Response to Sunthurst Data Request 6.3

The cost for the distribution regulators is $180,000. The Q1045 September 1, 2020, Expenditure Report provided as Sunthurst Data Request 1.10 incorrectly indicated these costs were for the regulators and recloser; however, these costs are only for the regulators. The description has been updated in the revised estimate dated December 23, 2020, as shown in Attachment Sunthurst 6.3.

Respondent(s): Alex Vaz

OR UM 2118

Attachment Sunthurst 6.3

DESCRIPTION	INTERNAL LABOR	MATERIAL	PURCHASE SERVICE	OTHER & CONTINGENCY	REMOVAL & SALVAGE	SURCHARGE	AFUDC	GROSS CAPITAL COST	CIAC
Pilot Rock Substation	$9,049	$0	$0	$0	$0	$724	$0	$9,772	($9,772)
Q1045 Collector Substation Metering	$46,903	$44,400		$1,500		$7,424	$0	$100,228	($100,228)
Distribution Regulators	$66,667	$100,000				$13,333	$0	$180,000	($180,000)
Grand Total	$122,619	$144,400	$0	$1,500	$0	$21,481	$0	$290,000	($290,000)

UM 2118 / PacifiCorp
January 4, 2021
Sunthurst Data Request 6.5

Sunthurst Data Request 6.5

In response to Sunthurst DR 4.2(e), Eric Taylor and Kris Bremer stated "All generators proposing to interconnect to PacifiCorp's distribution system are required to adhere to PacifiCorp Policy 138. The policy has required metering at the POI for many years." Please quote and cite the language in PacifiCorp Policy 138 that requires metering at the POI. Please specify the revision date of the latest Policy 138 containing this language.

Response to Sunthurst Data Request 6.5

Section 4.1 of PacifiCorp Policy 138 states the following:

> Sites with multiple DER resources such as wind collectors, or solar arrays may be considered as separable revenue facilities and, when applicable, require metering at each facility point. Metering requirements with multiple DER facilities will be identified in the interconnection facilities study report. Metering used for any PacifiCorp revenue purpose will be certified and maintained identically to the point of interconnect revenue metering.

This language has been part of this policy since Revision 3 of the policy published in 2015.

Respondent(s): Kris Bremer / Eric Taylor

UM 2118 / PacifiCorp
January 4, 2021
Sunthurst Data Request 6.6

Sunthurst Data Request 6.6

Refer to Detailed Expenditure Report for Q0666 dated September 2, 2020 (excerpted here:)

Sunthurst/204
Beanland/4

PACIFICORP

DETAILED EXPENDITURE REPORT

Q666 SUNTHURST ENERGY, LLC - PILOT ROCK

SUBORDINATE	DIVISION	DIVISION ACTIVITY	DESCRIPTION	VALUE CATEGORY	YEAR	QUANTITY	UNIT	UNIT COST	DIRECT CAPITAL COST
Pilot Rock Substation	Operations	Substation Operations	Journeyman, Relay Tech, PP	Internal	2021	640	HRS	$153.31	$98,116
	General	General Requirements	Construction Management	External	2021	1	LS	$10,200.00	$10,200
			Mobilization & Demobilization	External	2021	1	LS	$15,300.00	$15,300

(a) What does "LS" in the Units column mean? (E.g. Construction Management line item states 1 LS at a cost of $10,200).

(b) Please describe the scope of "Substation Operations" and provide supporting calculations and explanation for how PacifiCorp estimated the 640 hours cost for Substation Operations.

(c) Please provide supporting calculations and explanation for how PacifiCorp estimated the $10,200 cost for Construction Management.

(d) Please provide supporting calculations and explanation for how PacifiCorp calculated the $15,300 cost for Mobilization and Demobilization.

(e) Please explain how PacifiCorp adjusted the cost of Construction Management and the cost of Mobilization and Demobilization when it removed the cost of the PI-111 annunciator from Sunthurst's estimated costs for Q0666 and Q1045.

Response to Sunthurst Data Request 6.6

Note: PacifiCorp is reviewing the estimates for interconnection costs for Q0666 and Q1045 to ensure costs related to the PI-111 annunciator panel and telemetry have been removed. As a result of its review, PacifiCorp has found some costs related to these items, which will be removed. PacifiCorp will provide updated estimates for interconnection costs for PRS1 and PRS2 as a part of its response testimony.

(a) The unit "LS" stands for "Lump Sum," which is a price amount for the entire description of work where no breakdown or unit price is provided.

(b) Substation Operations includes costs associated with PacifiCorp field crews including, but not limited to, relay technicians, substation wiremen, communications technicians, and distribution estimators and journeymen. At Pilot Rock Substation, the hours for relay and substation technicians was estimated at 160 hours, and 80 hours per new panel, respectively. The estimate reflects hours for four new panels, including the PI-111 Annunciator. In its August 7, 2020, letter to counsel for Sunthurst, PacifiCorp stated it would remove the costs for the PI-111 annunciator panel. This was an attempt to help resolve Sunthurst's concerns. In response to Sunthurst Data Request 3.8(b), PacifiCorp explained that it would be installing the PI-111 annunciator panel at its cost if Q0666 proceeded. In keeping with PacifiCorp's offer to remove the costs of the PI-111 annunciator panel, PacifiCorp will modify the cost estimate to remove costs associated with the PI-111 annunciator panel.

(c) PacifiCorp will bid all construction services. The Construction Management is the estimated amount a contractor will bid for their respective management activities. The cost is estimated at approximately 10 percent of the total construction service cost.

(d) PacifiCorp will bid all construction services. The Mobilization and Demobilization is the estimated amount a contractor will bid to mobilize and demobilize to the site, including any temporary facilities and utilities that may be required. The cost is estimated at approximately 15 percent of the total construction service cost.

(e) The cost for the PI-111 Annunciator Panel is included in the estimate provided. An updated cost estimate will be provided for Q0666 that removes all costs associated with the Annunciator Panel.

NOTE: The estimate dated December 23, 2020, has been updated to remove all costs associated with the annunciator panel.

Respondent(s): Alex Vaz

UM 2118 / PacifiCorp
January 4, 2021
Sunthurst Data Request 6.7

Sunthurst Data Request 6.7

Refer to Detailed Expenditure Report for Q0666 dated September 2, 2020 (excerpted here:)

Panel, PI Type, Indication	Panel, PI-111, Indication, Annunciator	Material	2021	1	EA	$12,246.62	$12,247
		External	2021	1	EA	$5,100.00	$5,100

(a) Please explain what PacifiCorp will purchase with the $12,246.62 reserved for "Material".

(b) Please explain the purpose of the $5,100 cost for "External".

(c) Has PacifiCorp, in fact, removed all charges related to P1-111 panel installation from the Detailed Expenditure Report for Q0666?

Response to Sunthurst Data Request 6.7

(a) The material cost is the estimated cost to purchase a new P1-111 Annunciator panel. As noted in response to Sunthurst Data Request 6.6, an updated estimate will be provided for Q0666 to remove all costs associated with the P1-111 Annunciator panel.

(b) The external cost is the estimated amount for an external contractor to install the PI-111 Annunciator panel.

(c) The cost related to PI-111 Annunciator panel is included in the estimate dated September 2, 2020 and was not removed from the estimate. An updated estimate will be provided.

NOTE: The estimate dated December 23, 2020, has been updated to remove all costs associated with the annunciator panel.

Respondent(s): Alex Vaz

UM 2118 / PacifiCorp
January 4, 2021
Sunthurst Data Request 6.10

Sunthurst Data Request 6.10

Refer to Superior Expenditure Report for Q0666 dated September 2, 2020 and excerpted below:

Sunthurst/204
Beanland/1

PACIFICORP

SUPERIOR EXPENDITURE REPORT

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

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

SUPERIOR EXPENDITURE SUMMARY

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

(a) Has PacifiCorp already incurred the charges for "Internal Labor" and "Purchase Service" shown for years 2016-2020, above? If not, please explain.

(b) Do PacifiCorp's charges for "Internal Labor" and "Purchase Service", above include charges related to design and installation of the P1-111 panel?

(c) Please estimate the included charges (years 2016-2020 above) related to design and installation of the P1-111 panel, if any, and the basis for the estimate.

Response to Sunthurst Data Request 6.10

(a) Yes.

(b) Yes.

(c) PacifiCorp estimates that it has incurred approximately $4,750 in engineering labor associated with the annunciator panel. This is based on the cost estimate for protection and control engineering and engineering consultant work in the Pilot Rock substation. As four panels were included in the design at Pilot Rock substation, PacifiCorp estimates that 25 percent of the protection and control engineering costs were for the one annunciator panel or approximately $1,450. PacifiCorp is estimating that 5 percent of the engineering consultant costs were associated with the P1-111 annunciator panel or approximately $3,300. Therefore, a total of $4,750 related to design and installation of the P1-111 annunciator panel. No material has been ordered so no material or construction labor costs have been incurred. As noted in response to Sunthurst Data Request 6.6, PacifiCorp will provide an updated estimate of costs for Q0666 that removes all costs related to the P1-111 annunciator panel.

Respondent(s): Greg Stratton / Kris Bremer

UM 2118 / PacifiCorp
January 4, 2021
Sunthurst Data Request 6.11

Sunthurst Data Request 6.11

Refer to the September 2, 2020 version of Q1045 Facilities Study Report, page 5, excerpted in part, below:

Sunthurst/207
Beanland/39

PACIFICORP

Facilities Study Report

- 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

a. Regarding the "necessary easement", how large an enclosure does PacifiCorp require for its equipment?
b. Please provide a copy of PacifiCorp's Transmission Provider standards for "fencing, gates, and road access" referred to above.
c. List the components in PacifiCorp's enclosure, above, that require AC power.
d. What amperage AC power circuit does PacifiCorp require?

Response to Sunthurst Data Request 6.11

As Sunthurst has not proceeded with Q1045, this information is not available. Only high-level scoping associated with the Q1045 studies has been completed to date. After the interconnection agreement has been executed, and a design team is assigned to the project, will this level of detail be available.

Respondent(s): Kris Bremer

UM 2118 / PacifiCorp
January 7, 2021
Sunthurst Data Request 7.4

Sunthurst Data Request 7.4

Please provide the authority in PacifiCorp's OASIS or in the OARs for entering into the Q0547 amendments extending the COD for its remaining 8MW.

Response to Sunthurst Data Request 7.4

Section 12.2 of the Standard Small Generator Interconnection Agreement for a Qualifying Facility allows for the parties to amend the agreement by a written instrument duly executed by both parties.

Respondent(s): Counsel

UM 2118 / PacifiCorp
January 7, 2021
Sunthurst Data Request 7.5

Sunthurst Data Request 7.5

The revised Q0666 interconnection agreement tendered by PacifiCorp on September 4, Form 8, pages 28-29, states Pilot Rock Solar 1 shall:

- *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 appropriate 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.*

(a) Please name two other (non-Sunthurst) Oregon small generator interconnections where PacifiCorp has included the requirements, above.

(b) Does PacifiCorp intend to utilize the voltage control capabilities required of Q0666, above?

(c) Why does PacifiCorp require new voltage regulators if it utilizes Q0666's required capabilities, above?

UM 2118 / PacifiCorp
January 7, 2021
Sunthurst Data Request 7.5

Response to Sunthurst Data Request 7.5

(a) Q0825 and Q0971.

(b) No, the Q0666 interconnection agreement language referenced above in this request includes outdated language, the current language references Institute of Electrical and Electronics Engineers (IEEE) Standard 1547-2018, and requires distribution interconnected generation facilities to operate under constant power factor mode with a unity power factor setting unless specifically requested otherwise by the public utility. PacifiCorp will neither require nor allow this interconnect to utilize voltage control capabilities at this time, but reserves the right to implement other control modes as allowed by IEEE Standard 1547-2018 in the future, if the need arises.

(c) Please refer to the Company's response to Sunthurst Data Request 6.2 explaining the need and justification for installation of the two sets of voltage regulators.

Respondent(s): Kris Bremer / Doug Guttromson

UM 2118 / PacifiCorp
January 7, 2021
Sunthurst Data Request 7.6

Sunthurst Data Request 7.6

Please specify the exact location of the voltage regulators being installed during PRS1 and PRS2 interconnection, and who pays for them.

Response to Sunthurst Data Request 7.6

The exact location of the two sets of voltage regulators have not been determined. However, they are planned to be in the vicinity shown in Attachment Sunthurst 7.6, Pilot Rock substation 5W406 feeder and point of interconnection (POI) drawing. The 100-amp set of regulators will be located to the west of the POI and the 219-amp set of regulators will be installed east of the POI and on the east tap of the line coming from the Pilot Rock substation. The costs associated with these two voltage regulator sets will be borne by the interconnection customer.

Respondent(s): Doug Guttromson

UM 2118 / PacifiCorp
January 7, 2021
Sunthurst Data Request 7.7

Sunthurst Data Request 7.7

Please specify the specific equipment being purchased for $50,000 under "Distribution Recloser & Regulators" line item in the Q1045 Detailed Expenditure Report.

Response to Sunthurst Data Request 7.7

The estimate provided in the Detailed Expenditure Report dated September 1, 2020, included $50,000 in material costs under a "Distribution Recloser and Regulators", which is broken down as follows:

Table A

DESCRIPTION	INTERNAL LABOR	MATERIAL	PURCHASE SERVICE	OTHER & CONTINGENCY	REMOVAL & SALVAGE	SURCHARGE	AFUDC	GROSS CAPITAL COST	CIAC
Distribution Recloser & Regulators	$119,626	$50,000				$13,570	$0	$183,196	($183,196)
Material	$0	$50,000	$0	$0	$0	$4,000	$0	$54,000	($54,000)
Operations	$119,626	$0	$0	$0	$0	$9,570	$0	$129,196	($129,196)

The description and estimate has been revised to include $100,000 in material costs under a "Distribution Regulators" description, which is broken down as follows:

Table B

DESCRIPTION	INTERNAL LABOR	MATERIAL	PURCHASE SERVICE	OTHER & CONTINGENCY	REMOVAL & SALVAGE	SURCHARGE	AFUDC	GROSS CAPITAL COST	CIAC
Distribution Regulators	$66,667	$100,000				$13,333	$0	$180,000	($180,000)
Material	$0	$100,000	$0	$0	$0	$8,000	$0	$108,000	($108,000)
Operations	$66,667	$0	$0	$0	$0	$5,333	$0	$72,000	($72,000)

PacifiCorp will provide an updated Detailed Expenditure Report for Q1045 in its response testimony. The material included in the revised estimate in Table B includes material to install a 219-amp and a 100-amp set of voltage regulators as follows:

1. 219-amp voltage regulator set
    a. Quantity three of stock item #7999445 voltage regulators which are 7620 voltage class, 219-amp, 55C rise, with mild steel tanks.
        i. Please refer to Attachment Sunthurst 7.7, standard EP 402 Table 2, for standard regulator details.
    b. Quantity one of a three phase, two-pole rack.
        i. Please refer to Attachment Sunthurst 7.7, standard EP 302, Table 1 along with Figures 1 & 2, for material details.
    c. Two poles, crossarms, and associated pole-line material as shown in standard EP 302 Figures 1 & 2 but not included in the material details of

Table 1 of that standard.

2. 100-amp voltage regulator set
    a. Quantity three of stock item #7999437 voltage regulators which are 7200 voltage class, 100-amp, 55C rise, with mild steel tanks.
        i. Please refer to Attachment Sunthurst 7.7, standard EP 402 Table 2, for standard regulator details.
    b. Quantity one of a three phase, two-pole rack.
        i. Please refer to Attachment Sunthurst 7.7, standard EP 302, Table 1 along with Figures 1 & 2, for material details.
    c. Two poles, crossarms, and associated pole-line material as shown in standard EP 302 Figures 1 & 2 but not included in the material list of Table 1 of that standard.

Respondent(s): Doug Guttromson

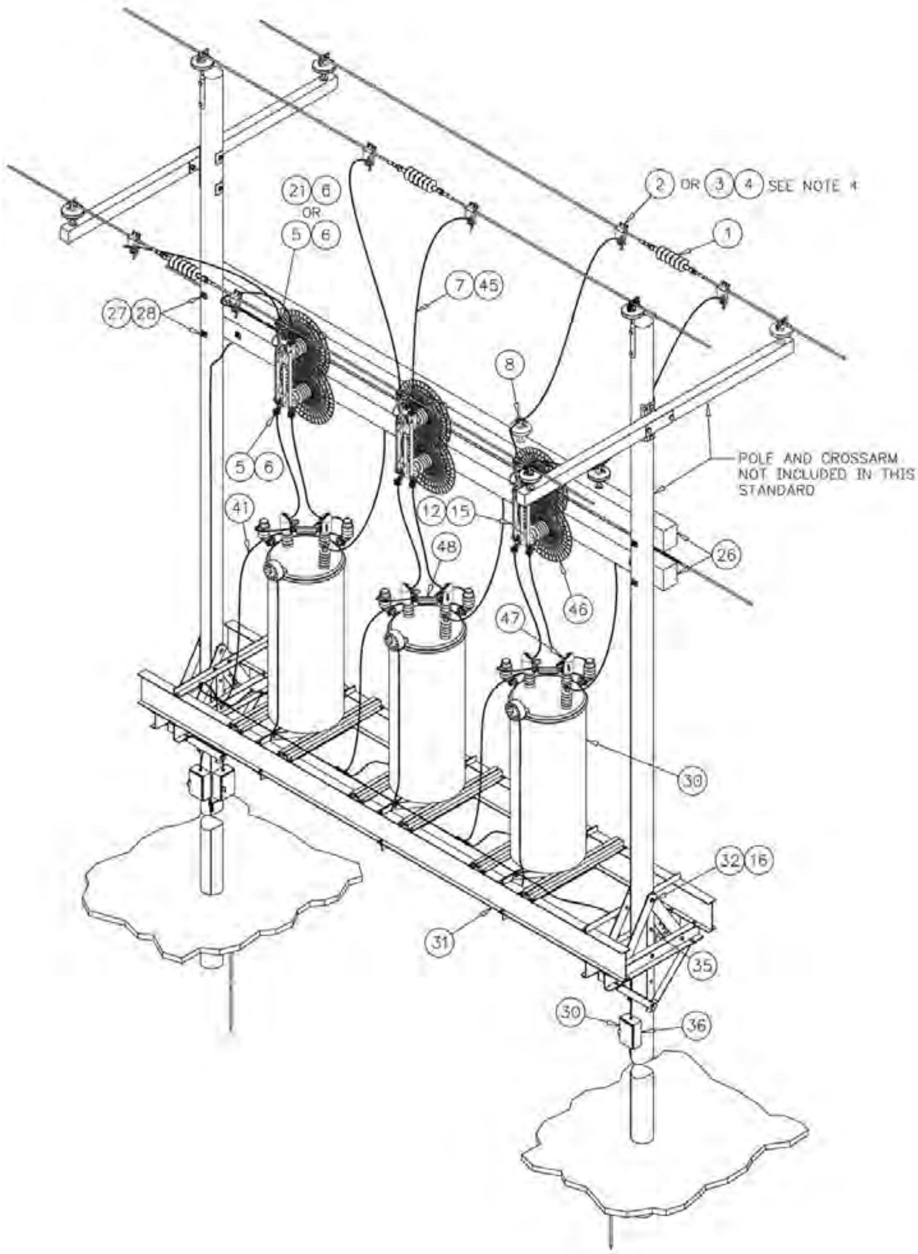


Figure 3—Two-Pole Rack, Three Regulators (Isometric View)

UM 2118 / PacifiCorp
January 7, 2021
Sunthurst Data Request 7.9

Sunthurst Data Request 7.9

Please explain why the Detailed Expenditure Report for Q0666 (Q-0666 Collector, Metering) indicates (in the "Quantity" column) two sets of meters.

Response to Sunthurst Data Request 7.9

This was an oversight as only one meter is being required. A revised Detailed Expenditure Report will be provided in PacifiCorp's response testimony.

Respondent(s): Eric Taylor

UM 2118 / PacifiCorp
January 7, 2021
Sunthurst Data Request 7.10

Sunthurst Data Request 7.10

Please explain why the Detailed Expenditure Report for Q1045 (Q-1045 Collector Substation Metering, metering) indicates (in the "Quantity" column) four sets of meters.

Response to Sunthurst Data Request 7.10

This was an oversight; only one meter is required at the Q1045 generator, and two meters (primary and back-up) are required at the point-of-interconnection metering point. A revised Detailed Expenditure Report will be provided in PacifiCorp's response testimony.

Respondent(s): Eric Taylor

UM 2118 / PacifiCorp
January 29, 2021
Sunthurst Data Request 8.3

Sunthurst Data Request 8.3

What is the estimated total cost to replace the R-816 regulator control? Please itemize all costs, including engineering, supervision and imputed overheads included in the 2015 Q0666 System Impact Study and 2016 Q0666 Facilities Study and attributable to removal and replacement of the R-816 regulator.

Response to Sunthurst Data Request 8.3

Please refer to the Company's response to Sunthurst Data Request 8.2 and Sunthurst Data Request 8.12.

Respondent(s): Alex Vaz

UM 2118 / PacifiCorp
January 29, 2021
Sunthurst Data Request 8.4

Sunthurst Data Request 8.4

When did the R-816 regulator control fail?

Response to Sunthurst Data Request 8.4

The earliest indication PacifiCorp has of the failure is November 6, 2019. As discussed in the Company's response to Sunthurst Data Request 8.5, PacifiCorp needed to replace the regulator control as soon as possible, which occurred on November 21, 2019.

Respondent(s): Douglas Guttromson

UM 2118 / PacifiCorp
January 29, 2021
Sunthurst Data Request 8.5

Sunthurst Data Request 8.5

When was the R-816 replacement regulator control placed in service? Please state the total cost of replacement.

Response to Sunthurst Data Request 8.5

Based on time charged to the replacement order, the new control was put into service November 21, 2019. Please refer to the Company's 1st Supplemental response to Sunthurst Data Request 6.4 for total replacement cost.

Respondent(s): Douglas Guttromson

UM 2118 / PacifiCorp
January 29, 2021
Sunthurst Data Request 8.6

Sunthurst Data Request 8.6

How did PacifiCorp control voltage on circuit 5W406 between the time of failure of the controller and the time of replacement? Please explain whether PacifiCorp's efforts to control voltage within allowable limits during this time period were successful.

Response to Sunthurst Data Request 8.6

The regulator R-816 was locked down with no local active voltage regulation occurring prior to the control replacement. There is no data to show what degree of voltage regulation occurred on the feeder during this timeframe. The one phase voltage, monitored via supervisory control and data acquisition (SCADA) at Pilot Rock substation beyond regulator R-816, remained within ANSI C 84.1 range A voltage limits during this period.

Respondent(s): Douglas Guttromson

UM 2118 / PacifiCorp
January 29, 2021
Sunthurst Data Request 8.7

Sunthurst Data Request 8.7

Were circuit 5W406 voltage measurements within specification during the period of the R-816 controller outage? Please explain.

Response to Sunthurst Data Request 8.7

There is no data regarding the 5W406 circuit voltage measurements during this time frame.

Respondent(s): Douglas Guttromson

UM 2118 / PacifiCorp
January 29, 2021
Sunthurst Data Request 8.11

Sunthurst Data Request 8.11

Does the September 2020 Q0666 revised Interconnection Agreement [Sunthurst/208; Beanland/30] include costs for replacing R-816 regulator? If not, please explain what costs were removed, and when they were removed?

Response to Sunthurst Data Request 8.11

No. As discussed in the Company's response to Sunthurst Data Request 8.8, the Q0666 System Impact Study (SIS) identified the need for the capability to regulate voltage with settings based on direction of power flow. However, the costs were inadvertently not included in the revised interconnection agreement for Q0666. The costs have been included in the Superior Expenditure Report for Q0666, which is provided as Exhibit PAC/201 to the Response Testimony of Patzkowski, Taylor, and Vaz filed January 26, 2021.

Respondent(s): Alex Vaz

UM 2118 / PacifiCorp
January 29, 2021
Sunthurst Data Request 8.12

Sunthurst Data Request 8.12

In light of PacifiCorp replacing the R-816 Beckwith control in 2019, is the scope of work in the September 2020 Q0666 IA [Sunthurst/208; Beanland/30] correct? Are the costs in the September 2020 Q0666 detailed expenditure report correct [Sunthurst/204; Beanland/1]? If not, please explain why they are incorrect and how they will be corrected.

Response to Sunthurst Data Request 8.12

No and No. Please refer to the Company's responses to Sunthurst Data Request 8.2 and Sunthurst Data Request 8.8. The R-816 regulator control was replaced due to failure in 2019; however, the replaced controller does not have reverse power flow capabilities. Therefore, the controller still needs to be replaced to accommodate the Q666 interconnection. The Superior Expenditure Report for Q0666, which is provided as Exhibit PAC/201 to the Response Testimony of Patzkowski, Taylor, and Vaz filed January 26, 2021, in this proceeding, includes the costs for regulator control replacement. In particular, the following costs were added: (1) A total of $2,124 in material costs to purchase a new Beckwith M-2001C with Adapter Panel; and (2) a total of $1,200 for external contract labor to install the Beckwith controller.

Respondent(s): Alex Vas / Douglas Guttromson

UM 2118 / PacifiCorp
January 29, 2021
Sunthurst Data Request 8.13

Sunthurst Data Request 8.13

Refer to PacifiCorp's response to Sunthurst DR 5.1. For each modification to the Pilot Rock substation listed in PacifiCorp's response, please provide (a) the total authorized cost; and (b) the total amount spent to date in the table below; and (c) resulting interruptions to service:

Job (as reported in PAC Response to DR 5.1)	**(a)Total authorized cost**	**(b) Total Amount Spent to Date:**	**(c) service disruptions, if any:**
2017- replace control house wall air conditioner due to failure			
2018 -west fence replace due to code violation			
2019- replace battery bank and charger due to battery degradation			
2019- replace three-phase regulator 542 due to failure in Sep 2018; replace transformer bank 1 arresters, install animal guarding, and replace bank #9 current transformer bank.			
2019- replace regulator R816 controller due to failure.			

Response to Sunthurst Data Request 8.13

(a) Please refer to the Company's 1st Supplemental response to Sunthurst Data Request 6.4.

(b) Please refer to the Company's response to subpart (a) above.

(c) None identified.

Respondent(s): Kris Bremer

UM 2118 / PacifiCorp
February 2, 2021
Sunthurst Data Request 8.20

Sunthurst Data Request 8.20

Please refer to Sunthurst DR 7.5(b), and PacifiCorp's response, both set forth in italics, below:

> *[Sunthurst DR7.5](b) Does PacifiCorp intend to utilize the voltage control capabilities required of Q0666, above?*
> ***Response to Sunthurst Data Request 7.5***
> *(b) No, the Q0666 interconnection agreement language referenced above in this request includes outdated language, the current language references Institute of Electrical and Electronics Engineers (IEEE) Standard 1547-2018, and requires distribution interconnected generation facilities to operate under constant power factor mode with a unity power factor setting unless specifically requested otherwise by the public utility. PacifiCorp will neither require nor allow this interconnect to utilize voltage control capabilities at this time, but reserves the right to implement other control modes as allowed by IEEE Standard 1547-2018 in the future, if the need arises.*

(a) Is the italicized language in DR 7.5 outdated language? If yes, when did it become outdated? Please specify which portions of DR 7.5 language is outdated.

(b) Define "outdated" as used above. Does PacifiCorp still use "outdated" language on occasion? If yes, please explain.

(c) Was the italicized language in DR 7.5 outdated when PacifiCorp added it to the September 4, 2020 Q0666 interconnection agreement (IA) amendment?

(d) Did PacifiCorp know it was outdated when it proposed the September 4, 2020 IA to Sunthurst?

(e) When did PacifiCorp discover that the language in DR 7.5 is outdated?

(f) When did it notify Sunthurst that the language is outdated?

(g) Does PacifiCorp intend to revise the language in the September 4, 2020 IA set forth in Sunthurst DR 7.5? If so, what will the new language say?

(h) Please provide a copy of the latest version of its standard Oregon small generator interconnection agreement, and cite the operative language replacing the language excerpted in DR 7.5.

(i) Who decided that "*PacifiCorp will neither require nor allow this interconnect to utilize voltage control capabilities at this time, but reserves the right to implement*

UM 2118 / PacifiCorp
February 2, 2021
Sunthurst Data Request 8.20

other control modes as allowed by IEEE Standard 1547-2018 in the future, if the need arises."?

(j) Does PacifiCorp ever require small generators to make available their voltage control capabilities? If yes, how does PacifiCorp determine when to impose such a requirement?

(k) Assuming PacifiCorp utilizes a small generator for voltage support. Does the provision of voltage support affect the total generation delivered by the small generator? Please explain. What magnitude of reduction in net MWh output could voltage support reasonably cause?

(l) Under what future circumstances might the need arise for PacifiCorp to utilize Pilot Rock Solar Project voltage control, if it is not needed today?

(m) When was the italicized language in Sunthurst DR 7.5 (excerpted from the September 4, 2020 Q0666 IA amendment) developed? Has it been utilized in PacifiCorp interconnections? If so, please explain where, when, and how long the language has been used.

Response to Sunthurst Data Request 8.20

(a) Yes. PacifiCorp recently made updates to this language and has begun using it in studies for small solar facilities.

(b) The language cited is template language that was developed in the past. PacifiCorp is constantly refining its language as it gains more experience with distributed solar projects and as standards change. There are sometimes lags in updating studies and/or agreements as the language evolves.

(c) Yes.

(d) No. The personnel preparing the amendment did not know it was outdated.

(e) Only recently when technical personnel noticed.

(f) PacifiCorp provided the update in its response to Sunthurst Data Request No. 7.5.

(g) Should Sunthurst choose to move forward with Q0666 then yes, the following updated language will be included:

The Community Solar Project and Interconnection Equipment owned by the Applicant are required to operate under constant power factor mode with a unity power factor setting unless specifically requested otherwise by the Public Utility.

UM 2118 / PacifiCorp
February 2, 2021
Sunthurst Data Request 8.20

The Community Solar Project is expressly forbidden from actively participating in voltage regulation of the Public Utilities system without written request or authorization from the Public Utility. The Community Solar Project shall have sufficient reactive capacity to enable the delivery of 100 percent of the plant output to the POI at unity power factor measured at 1.0 per unit voltage under steady state conditions.

Generators shall be capable of operating under Voltage-reactive power mode, Active power-reactive power mode, and Constant reactive power mode as per IEEE Std. 1547-2018. This project shall be capable of activating each of these modes one at a time. The Public Utility reserves the right to specify any mode and settings within the limits of IEEE Std 1547-2018 needed before or after the Community Solar Project enters service. The Applicant shall be responsible for implementing settings modifications and mode selections as requested by the Public Utility within an acceptable timeframe. The reactive compensation must be designed such that the discreet switching of the reactive device (if required by the Applicant) does not cause step voltage changes greater than +/-3 percent on the Public Utility's system. In all cases the minimum power quality requirements in PacifiCorp's Engineering Handbook section 1C shall be met and are available at https://www.pacificpower.net/about/power-quality-standards.html. Requirements specified in the System Impact Study that exceed requirements in the Engineering Handbook section 1C power quality standards shall apply.

(h) Please refer to Attachment Sunthurst 8.20. The language cited in response to part (g) above would be inserted into Attachment 4.

(i) PacifiCorp engineering staff.

(j) Yes. Small generators connected to the distribution system have been required to utilize voltage control capabilities when there is a possibility to not meet ANSI C84.1 Range A voltages to all customers without the small generator's voltage control settings being utilized.

(k) The requirements of IEEE Standard 1547-2018 need to be met for a Category B generator; the required reactive power capabilities are addressed in section 5.2. Per Table 7 of this section, a Category B generator is required to be capable of injecting or absorbing reactive power up to 44 percent of the generator's nameplate apparent power rating. The magnitude of the effect on the real power output of the generator to meet these IEEE 1547-2018 requirements is not known.

(l) Many circumstances may require a future need for PRS 1 and/or PRS2 to utilize one of the DER control strategies allowed under IEEE Standard 1547-2018 beyond the initially required Constant Power Factor mode. Some examples include equipment failure, load growth, and permanent or temporary feeder reconfiguration.

UM 2118 / PacifiCorp
February 2, 2021
Sunthurst Data Request 8.20

(m) PacifiCorp had been using that language for small generator interconnection requests however an exact date cannot be provided. As stated in response to part 8.20(b) above, PacifiCorp refines this type of language as it gains more experience with distribution generation on its system.

Respondent(s): Kris Bremer, Douglas Guttromson

UM 2118 / PacifiCorp
January 29, 2021
Sunthurst Data Request 8.21

Sunthurst Data Request 8.21

Please refer to Section 5.1 of the Q0666 System Impact Report, which, in part, states:

> *Generators capable of operating under voltage control with a voltage droop are required to do so. Studies will be required to coordinate the voltage droop setting with other facilities in the area. In general, Small Generating Facility and Interconnection Facilities should be operated so as to maintain the voltage at the Point of Interconnection between 1.01 pu to 1.04 pu. <u>At the Public Utility's discretion, these values might be adjusted depending on the operating conditions.</u> Within this voltage range, the generating and interconnecting facilities should operate so as to minimize the reactive interchange between the Small Generating Facility and Interconnection Facilities and the Public Utility's system (delivery of power at the Point of Interconnection at approximately unity power factor). The voltage control settings of the Small Generating Facility and Interconnection Facilities must be coordinated with the Public Utility prior to energization (or interconnection).*

(a) Does PacifiCorp consider this language binding upon Q0666?

Response to Sunthurst Data Request 8.21

No. This language is outdated and is no longer used for small, distributed generator interconnection requests as it is more applicable to transmission level generation interconnections. It is also not included in the most recent amended interconnection agreement for Q0666.

Respondent(s): Kris Bremer

UM 2118 / PacifiCorp
January 29, 2021
Sunthurst Data Request 8.22

Sunthurst Data Request 8.22

Did PacifiCorp study whether, if Pilot Rock Solar 1 and/or Pilot Rock Solar 2 provide voltage support, voltage regulators are needed: (a) on the 5W406 circuit branch west of the interconnection tap, and (b) on the McKay branch? If yes, please provide study results and all documentation of the study.

Response to Sunthurst Data Request 8.22

No. Distribution connected generators are directed to generate under constant power factor mode with a unity power factor setting.

Please refer to the Company's response to Sunthurst Data Request 6.2 for justification for the two referenced voltage regulators.

Respondent(s): Douglas Guttromson

UM 2118 / PacifiCorp
January 29, 2021
Sunthurst Data Request 8.23

Sunthurst Data Request 8.23

When did PacifiCorp perform voltage drop and fault current analysis of (i) Q0666; and (ii) Q1045? Please describe all records PacifiCorp maintains of those studies, and their results. Please provide all such records.

Response to Sunthurst Data Request 8.23

(i) 2015.

(ii) 2018.

Please refer to the PacifiCorp Open Access Same-Time Information System (OASIS) website for the System Impact Studies (SIS) for Q0666 and Q1045 (https://www.oasis.oati.com/ppw). PacifiCorp does not have any other records regarding the analyses.

Respondent(s): Douglas Guttromson

UM 2118 / PacifiCorp
January 29, 2021
Sunthurst Data Request 8.24

Sunthurst Data Request 8.24

Please refer to PacifiCorp's response to Sunthurst DR 6.2. In the first paragraph, PacifiCorp states:

> *When the analysis was performed for Q1045, the load flow software used was the ABB/Ventex FeederAll software package. In 2015, the vendor stopped supporting the software and due to company critical security controls to reduce threat of cyber security incidents and to maintain ISO certification for company software, FeederAll was subsequently removed from all company computers. Therefore, detailed voltage drop and fault current analysis from the FeederAll model is not available.*

(a) If the vendor stopped supporting the software in 2015, what software did PacifiCorp use for its Q1045 System Impact Study (published March 27, 2020) to determine that voltage regulators are needed?

(b) Did PacifiCorp perform a voltage study in connection with (i) the Q1045 System Impact Study, or (ii) at any time thereafter?

Response to Sunthurst Data Request 8.24

(a) FeederAll.

(b) (i) Yes. (ii) No.

Respondent(s): Douglas Guttromson

UM 2118 / PacifiCorp
February 10, 2021
Sunthurst Data Request 9.2

Sunthurst Data Request 9.2

Please refer to PAC /100, Bremer/14, lines 6-10 ("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").

(a) Under what circumstances does PacifiCorp refuse to grant extensions to contract milestones?

(b) Does PacifiCorp ever require a party seeking a milestone exception in an existing interconnection agreement to make any representation or warranty about the cause of the delay and/or the likelihood it will meet the revised timeline?

(c) If PacifiCorp performs no commercial assessment of its interconnection customers, then which of the following bases does it consider when assessing whether to grant an extension?

i. Junior requests impacted by the extension;
ii. identity of the applicant and/or its affiliates;
iii. the expected buyer of the project output;
iv. whether PacifiCorp needs the generation;
v. commercial impossibility (e.g. Seller's PPA terminated);
vi. Other (please explain).

(d) Under what circumstances does PacifiCorp grant an extension of a milestone in an interconnection agreement/interconnection study agreement without a formal request for extension from the counterparty?

Response to Sunthurst Data Request 9.2

(a) It is possible that a request to modify milestones in an interconnection agreement could be determined to be a material modification to a lower priority interconnection request. In that scenario PacifiCorp would be unable to agree to an amendment of the existing milestones.

(b) No.

(c) Please refer to the Company's response to subpart 9(a) above.

(d) PacifiCorp does not grant an extension absent a request from the counterparty.

UM 2118 / PacifiCorp
February 10, 2021
Sunthurst Data Request 9.2

Respondent(s): Kris Bremer

UM 2118 / PacifiCorp
February 10, 2021
Sunthurst Data Request 9.3

Sunthurst Data Request 9.3

Please refer to PAC /100, Bremer/16, lines 10-14 ("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").

(a) Which of the above studies did PacifiCorp perform on Q0666, and when?

(b) Which of the above studies did PacifiCorp perform on Q1045, and when?

(c) Which of the above studies did PacifiCorp provide to Sunthurst, and when?

(d) Please provide the studies, above.

Response to Sunthurst Data Request 9.3

(a) Power flow; voltage drop and flicker; short circuit; and protection analyses were performed for the Q0666 System Impact Study (SIS) dated August 15, 2015. Transient stability and reactive margin analyses was determined to not be required for the SIS based on results of prior stability and reactive margin studies in the local area. No grounding reviews were conducted.

(b) Power flow; voltage drop and flicker; short circuit; and protection analyses were performed for the Q1045 SIS dated March 27, 2020. Transient stability and reactive margin analyses was determined to not be required for the SIS based on results of prior stability and reactive margin studies in the local area. No grounding reviews were conducted.

(c) The results of the analyses were included in the SIS with the dates listed in the Company's responses to subparts (a) and (b) above.

(d) The studies were provided to the customer on the dates listed in the Company's responses to subparts (a) and (b) above. Detailed short circuit results can be provided for any bus on request by the customer. This type of data is normally asked for during the design period.

Respondent(s): Scott Beyer / Douglas Guttromson / Dean Miller

UM 2118 / PacifiCorp
February 10, 2021
Sunthurst Data Request 9.4

Sunthurst Data Request 9.4

Please refer to PAC /100, Bremer/28, lines 13-14 ("Because the [Direct Transfer Trip] equipment will be installed on PacifiCorp's system, PacifiCorp must install it").

(a) Why "must" equipment installed on PacifiCorp's system be installed by PacifiCorp? Please cite all orders, laws, or rules relied upon for this opinion.

Response to Sunthurst Data Request 9.4

The quote referenced in this question is referring to work to be performed on existing, energized equipment. PacifiCorp does not allow interconnection customers to perform construction activities on energized equipment. Any direct transfer trip related equipment to be installed on new infrastructure at the interconnection customer generating facility location can potentially be constructed by the interconnection customer.

Respondent(s): Kris Bremer

UM 2118 / PacifiCorp
February 10, 2021
Sunthurst Data Request 9.5

Sunthurst Data Request 9.5

Please refer to PAC /100, Bremer/28, lines 15-21.

(a) Describe what mechanism(s) Sunthurst has, when siting a facility, to determine the age and/or functional capabilities of major components of the substation it seeks to interconnect to.

(b) Does PacifiCorp respond to requests from prospective interconnection customers for information pertaining to age or functional capabilities of its substation equipment?

Response to Sunthurst Data Request 9.5

(a) There are no official mechanisms available to interconnection customers to obtain this type of information. PacifiCorp offers products such as pre-application reports or informational interconnection requests in which interconnection customers can obtain useful information to assist in siting decisions but details about age and/or functional capabilities would not be provided through those mechanisms.

(b) Yes, within reason, PacifiCorp responds to informal requests such as what is being discussed in this question.

Respondent(s): Kris Bremer

UM 2118 / PacifiCorp
February 10, 2021
Sunthurst Data Request 9.6

Sunthurst Data Request 9.6

Please refer to PAC /200, Patzkowski, Taylor, Vaz/1. For Mr. Patzkowski:

(a) Please list your professional certifications and state licensures.

(b) How long have you served as Manager of Substation Engineering at PacifiCorp?

(c) Please list your other PacifiCorp positions, and time served at each, from 2015-present.

(d) When did you first become involved in (i) Q0666 interconnection, and (ii) Q1045 interconnection?

(e) Please describe your involvement in Q0666 and Q1045 interconnections.

(f) Please describe the materials and information you reviewed in preparation for your testimony.

Response to Sunthurst Data Request 9.6

(a) Registered Professional Electrical Engineer, Vice Chair – Western Electricity Coordinating Council (WECC) Remedial Action Scheme Reliability Subcommittee (RASRS)

(b) Since January 2017.

(c) Manager of Telecom and SCADA Engineering – June 2000 to August 2013.
Manager of Transmission System Operations - August 2013 to December 2015.
Manager of Meter Engineering – January 2016 to December 2016.

(d) 2020.

(e) For all generation interconnection studies, I make assignments of the substation engineer to complete studies and follow up on generation interconnection study information.

(f) Review of the system impact and feasibility studies for Q0666 and Q1045. Review of standards IEEE 1547, IEEE 1547.2, and IEEE 1547.7.

Respondent(s): Milt Patzkowski

UM 2118 / PacifiCorp
February 10, 2021
Sunthurst Data Request 9.7

Sunthurst Data Request 9.7

Please refer to PAC /200, Patzkowski, Taylor, Vaz/1-2. For Mr. Taylor:

(a) Please list your professional certifications and state licensures.

(b) Explain what it means to be responsible for high end metering applications.

(c) When did you first become involved in (i) Q0666 interconnection, and (ii) Q1045 interconnection?

(d) Please describe your involvement in Q0666 and Q1045 interconnections.

(e) Please describe the materials and information you reviewed in preparation for your testimony.

Response to Sunthurst Data Request 9.7

(a) None.

(b) This responsibility involves the following: (1) managing a team of meter engineers who study, specify and design meter applications for borderload, interchange, generation and large industrial loads; (2) providing direction to metering engineers, oversee project schedules and compliance requirements for metering applications including, but not limited to the North American Electric Reliability Corporation (NERC), the California Independent System Operator (CAISO), the Western Electricity Coordinating Council (WECC), and for the Western Renewable Energy Generation Information System (WREGIS); and (3) collaborating with grid operations and dispatch to ensure applicable new metering points are mapped in the energy management system correctly.

(c) (i) Q0666 - I became involved in the project in July 2018.
(ii) Q1045 – I became involved in the project in May 2020.

(d) My involvement involves ensuring milestone deadlines are met for project engineers, coordinating with back-office to make sure paperwork and drawings are in place so the projects can energize on time.

(e) PacifiCorp Policy 138, PacifiCorp Policy 139, PacifiCorp 2016 Electric Service Agreement, CASIO Best Metering Practices and previously designed multiple distributed energy resources (DER) behind point of interconnections (POI).

Respondent(s): Eric Taylor

UM 2118 / PacifiCorp
February 10, 2021
Sunthurst Data Request 9.8

Sunthurst Data Request 9.8

Please refer to PAC /200, Patzkowski, Taylor, Vaz/1. For Mr. Vaz:

(a) Please list your professional certifications and state licensures.

(b) What is your current job title?

(c) When did you first become involved in (i) Q0666 interconnection, and (ii) Q1045 interconnection?

(d) Please describe your involvement in Q0666 and Q1045 interconnections.

(e) Please describe the materials and information you reviewed in preparation for your testimony.

Response to Sunthurst Data Request 9.8

(a) Licensed Professional Engineer in the State of Utah.

(b) Cost Engineering Manager.

(c) August 2020.

(d) Reviewer and editor of cost estimates associated with both Q666 and Q1045.

(e) Reviewer of studies, estimates, engineering scopes, actual costs to date, and design completed for Q666, and associated data requests.

Respondent(s): Alex Vaz

UM 2118 / PacifiCorp
February 10, 2021
Sunthurst Data Request 9.9

Sunthurst Data Request 9.9

Please refer to PAC /200, Patzkowski, Taylor, Vaz/7, lines 2-16

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 * * * 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".

(a) What is the nameplate capacity of each of the nine Oregon Wind Farms projects?

(b) What is the voltage at the Point of Interconnection for the Oregon Wind Farms to PacifiCorp's system?

(c) What is the nameplate capacity of each of the three Cedar Springs Wind sub-projects?

(d) What is the voltage at the Point of Interconnection for the Cedar Springs Wind Project to PacifiCorp's system?

(e) Which PacifiCorp Interconnection Policy (Policy 138 or Policy 139) applies to Oregon Wind Farms interconnection?

(f) Which PacifiCorp Interconnection Policy (Policy 138 or Policy 139) applies to Cedar Springs Wind Project interconnection?

(g) Please specify the name of the person sponsoring this answer.

Response to Sunthurst Data Request 9.9

(a) Please refer to the table provided below:

Q#	Size (megawatts (MW))
102	9.9
103	6.6
104	10

UM 2118 / PacifiCorp
February 10, 2021
Sunthurst Data Request 9.9

Q#	Size (megawatts (MW))
105	9.9
106	10
145-A	8.25
145-B	4.95
146	1.65
147	3.3

(b) 115 kilovolts (kV)

(c) 520 megawatts (MW)

(d) 230 kV

(e) Policy 139

(f) Policy 139

(g) Kris Bremer

Respondent(s): Kris Bremer

UM 2118 / PacifiCorp
February 10, 2021
Sunthurst Data Request 9.10

Sunthurst Data Request 9.10

Please refer to PAC /200, Patzkowski, Taylor, Vaz/7, lines 17-20 ("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").

(a) Did PacifiCorp allow 65MW Q0918 and 1.25 MW Q0919 to meter output at 480V voltage level?

(b) Please explain why PacifiCorp allowed .65MW Q0918 and 1.25 MW Q0919 to meter output at 480V voltage level, but requires Sunthurst to meter output for Q0666 and Q1045 at 12.5 kV level?

(c) Are there other instances where PacifiCorp allows solar projects to meter at the low side? Please explain?

(d) Please specify the name of the person sponsoring this answer.

Response to Sunthurst Data Request 9.10

(a) The Company notes that the request incorrectly refers to "65MW"; the correct amount is 0.65 megawatts (MW). Based on the foregoing correction, the Company responds as follows:

Yes.

(b) Q0918 and Q0919 were studied as being connected to a single step-up power transformer with two secondaries. Each generator, a battery resource and a solar resource, were connected to a separate step up transformer secondary. Metering on the low side was the only feasible solution for measuring each generator independently in this application.

(c) PacifiCorp objects to the extent that this request requires production of new analyses. Notwithstanding the objection, and without waiving its rights to maintain the objection, PacifiCorp responds as follows:

PacifiCorp has not conducted an exhaustive review of all solar projects interconnected to its system. However, referencing the list of solar projects that Sunthurst Energy , LLC, (Sunthurst) provided in Sunthurst Data Request 1.9, none of these projects are metered on the low-side:

UM 2118 / PacifiCorp
February 10, 2021
Sunthurst Data Request 9.10

In addition, PacifiCorp's Community Solar Program (CSP) Interconnection Procedures, approved by the Public Utilities Commission of Oregon in Order No. 20-122, states that any Community Solar Project that is 360 kilowatts (kW) or less will be eligible for low side metering.

(d) Eric Taylor and Kris Bremer.

Respondent(s): Eric Taylor / Kris Bremer

UM 2118 / PacifiCorp
February 10, 2021
Sunthurst Data Request 9.11

Sunthurst Data Request 9.11

Please refer to PAC /200, Patzkowski, Taylor, Vaz/8-9 ("Removing the third meter at the POI would reduce the costs to interconnect PRS1 and PRS2 by approximately $39,000").

(a) Does the $39,000 include engineering costs (including engineering already performed)? If not, what are the costs of engineering?

(b) Does the $39,000 include savings from 8% Surcharge costs? If not, what are the savings in Surcharge costs?

(c) Please specify the name of the person sponsoring this answer.

Response to Sunthurst Data Request 9.11

(a) PAC/202 to the Response Testimony of Patzkowski, Taylor, and Vas includes the costs for the meter at the point of interconnection (POI) as shown in the table below. Costs for engineering are included in the approximate value of $49,000, as shown in the table below. This meter is required as a part of Q1045 (PRS2) and no costs have been spent to date for PRS2

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

(b) Yes. In addition to the costs listed above, the approximately $39,000 also includes the 8 percent surcharge.

(c) Alex Vaz.

Respondent(s): Alex Vaz

UM 2118 / PacifiCorp
February 10, 2021
Sunthurst Data Request 9.12

Sunthurst Data Request 9.12

Please refer to PAC /200, Patzkowski, Taylor, Vaz/17, lines 14-16 ("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.")

(a) Assuming Sunthurst were to accept such an offer, would PacifiCorp require a recloser for DTT for each project, as opposed to the single recloser it requires in the current configuration?

(b) Does PacifiCorp expect that its September 23 offer would lower Sunthurst's combined net cost of interconnecting PRS1 and PRS2? If so, please explain; and give magnitude of expected savings.

(c) Please specify the name of the person sponsoring this answer.

Response to Sunthurst Data Request 9.12

(a) Yes.

(b) PacifiCorp cannot comment on whether the "offer would lower Sunthurst Energy, LLC's (Sunthurst) combined net cost of interconnecting PRS1 and PRS2" because most of the changes in this configuration would change costs to Sunthurst's infrastructure for which PacifiCorp has no information. This configuration would remove the need for a third meter and its associated costs.

(c) Kris Bremer and Dean Miller.

Respondent(s): Kris Bremer / Dean Miller

UM 2118 / PacifiCorp
February 10, 2021
Sunthurst Data Request 9.13

Sunthurst Data Request 9.13

Please refer to PAC /200, Patzkowski, Taylor, Vaz/18, lines 12-15 ("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").

(a) Does PacifiCorp have discretion to allow low-side metering of <3 MW projects under Policy 138?

(b) Is it non-discriminatory for PacifiCorp to allow low side metering at projects Q0918 and Q0919, but to require high side metering for Q0666 and Q1045? Please explain.

(c) Does PacifiCorp or an affiliate own the projects known as Q0918 and Q919?

(d) Please specify the name of the person sponsoring this answer.

Response to Sunthurst Data Request 9.13

(a) No.

(b) Yes. Please refer to the Company's response to Sunthurst Data Request 9.10.

(c) Q0918 and Q0919 are PacifiCorp-owned resources.

(d) Eric Taylor.

Respondent(s): Eric Taylor

UM 2118 / PacifiCorp
February 10, 2021
Sunthurst Data Request 9.14

Sunthurst Data Request 9.14

Please refer to PAC /200, Patzkowski, Taylor, Vaz/19, lines 8-9 ("PacifiCorp requires meters on the high side of the transformer because it removes the inaccuracies of the losses").

(a) How does PacifiCorp remove inaccuracies of losses when transformers are located on the low side, as with Q0918 and Q0919?

(b) Does PacifiCorp consider it good utility practice to meter output from under-3MW solar projects on the low side? If not, why was it done at Q0918 and Q0919?

(c) Please specify the name of the person sponsoring this answer.

Response to Sunthurst Data Request 9.14

(a) The Company's response to subpart (a) assumes that the request intended to ask about losses when the meters are located on the low side of the transformer, otherwise the question is not answerable as written. Based on the foregoing assumption, PacifiCorp responds as follows:

Inaccuracies cannot be resolved 100 percent when metered on the low side of a transformer. Two primary contributing factors are iron losses and copper losses of the step-up transformer. Iron losses are fixed losses; it is the amount of energy required to energize the transformer. Copper losses are variable depending on how much the transformer is loaded at any given time. A reasonable effort is made to determine the copper losses by assuming where the step-up transformer will likely operate. These values (i.e., the iron losses and the copper losses) are programmed into the meter to emulate the meter as if the meter were installed on the high side of the transformer.

(b) No, for the reasons stated in the Company's response to subpart (a) above. Please refer to the Company's response to Sunthurst Data Request 9.10, subpart (b).

(c) Eric Taylor.

Respondent(s): Eric Taylor

UM 2118 / PacifiCorp
February 10, 2021
Sunthurst Data Request 9.15

Sunthurst Data Request 9.15

Please refer to PAC /200, Patzkowski, Taylor, Vaz/19, lines 18 ("only PRS2 triggers the need for voltage regulators.") and PAC /200, Patzkowski, Taylor, Vaz/20, lines 13-15 ("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").

(a) Does PacifiCorp assert that the need for voltage regulation arises when generation is greater than load, on an instantaneous basis? If not, what is the specific trigger for voltage regulation?

(b) Please specify the name of the person sponsoring this answer.

Response to Sunthurst Data Request 9.15

(a) Please refer to the Company's response to Sunthurst Data Request 6.2 for justification for the voltage regulators on the distribution feeder due to PRS2. PacifiCorp makes no assertion that the need for voltage regulation on the feeder arises only when generation is greater than load. The specific trigger for the voltage regulators in the field for PRS2 is the inability for the voltage regulator control in the substation to measure load on the feeder to enable the use of Line Drop Compensation (LDC) settings.

(b) Douglas Guttromson.

Respondent(s): Douglas Guttromson

UM 2118 / PacifiCorp
February 10, 2021
Sunthurst Data Request 9.16

Sunthurst Data Request 9.16

On page PAC /200, Patzkowski, Taylor, Vaz/39, lines 13-14, you stated that "[p]otential power production from PRS1 will be greater than the daytime load on the feeder and on the transformer some days of the year".

(a) Assuming only PRS1 were constructed, how would PacifiCorp measure and control voltage on the PRS1 feeder, during time when power production from PRS1 is greater than load on the feeder and/or transformer?

(b) Why did PacifiCorp not require new voltage regulators for PRS1 in the PRS1 studies and/or interconnection agreement?

(c) What information have you reviewed regarding existing voltage conditions on Circuit 5W406? Please provide.

(d) Please specify the name of the person sponsoring this answer.

Response to Sunthurst Data Request 9.16

(a) If only PRS 1 was constructed, voltage and amperage would be measured and voltage would be controlled at the Pilot Rock substation regulator for any magnitude of load or generation.

(b) No new voltage regulators on the distribution system were required to be installed in the PRS 1 System Impact Study (SIS) because American National Standards Institute (ANSI) C84.1 Range A steady state voltages can be maintained to all customers and Line Drop Compensation (LDC) settings can be implemented with some degree of effectiveness as peak load is over three times connected generation.

(c) The SIS reports for Q0666 and Q1045 have been reviewed. Please refer to Attachment Sunthurst 9.16 for copies of these reports.

(d) Douglas Guttromson.

Respondent(s): Douglas Guttromson

UM 2118 / PacifiCorp
February 10, 2021
Sunthurst Data Request 9.17

Sunthurst Data Request 9.17

Please refer to PAC /200, Patzkowski, Taylor, Vaz/22, lines 17-22 ("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").

(a) Does the above statement mean that fiber optic is now PacifiCorp's "best practice". If so, where is this status of fiber optic documented?

(b) What is the significance of stating that something is a "best practice"?

(c) Does PacifiCorp allow spread spectrum radio on other Oregon CSP interconnections?

(d) Please specify the name of the person sponsoring this answer.

Response to Sunthurst Data Request 9.17

(a) Best practices are generally accepted and understood amongst engineering staff without the need for formal documentation as to preference. They are discussed and reviewed during departmental Engineering Standards calls and refined over years of practice. Often, best practices are the result of balancing complex decision points and weighing relative merit.

PacifiCorp deploys a variety of communication systems and services for a variety of applications including radio and fiber optic. PacifiCorp has deployed thousands of miles of fiber optic cable and systems for many applications including the most critical of transmission line protection and remedial action scheme (RAS) circuits. In the communication systems deployed across the PacifiCorp service territory, fiber optic has proven to be highly reliable and effective.

(b) The significance of a best practice is that when all options are reviewed and considered to be relatively equal, the best practice is the chosen implementation due to positive outcomes of previous deployments.

(c) Yes. PacifiCorp has deployed select spread spectrum radios for systems that meet internal criteria around project size, number of communications channels needed, appropriate geographic conditions, and cost benefit versus other methods of communications.

(d) Milt Patzkowski and Joe Lieneweber.

Respondent(s): Milt Patzkowski / Joe Lieneweber

UM 2118 / PacifiCorp
February 10, 2021
Sunthurst Data Request 9.18

Sunthurst Data Request 9.18

Please refer to PAC /200, Patzkowski, Taylor, Vaz/24, lines 5-6 ("PacifiCorp has adjusted the estimated [fiber] costs for PRS1 to use $42,000/mile. At 0.9 miles for Q0666, the updated estimated cost is approximately $38,000").

(a) How was this error in estimating cost of fiber detected by PacifiCorp? Please provide the documents showing the erroneous price of fiber which PacifiCorp discovered and corrected.

(b) Please specify the name of the person sponsoring this answer.

Response to Sunthurst Data Request 9.18

(a) PacifiCorp does not agree there was an error in the cost for estimating fiber. For high level estimating, PacifiCorp assumes a rate of $60,000 per mile ($/mile) for fiber installation on existing lines and a rate of $42,000/mile for fiber installation on new lines. Once design is completed, these high-level estimates are revised and updated as needed. PacifiCorp originally assumed a rate of $60,000/mile as Q0666 requires installation of fiber to an existing distribution line and assuming some modifications to the existing line may be required to accommodate new fiber installation. After reviewing and considering witness Michael Beanland's opening testimony, PacifiCorp reduced the cost to $42,000/mile. As this has not been designed to date, it is still unknown what improvements to the existing line are required. The revised cost assumes no improvements are required to the existing line. If improvements are required, the cost could be higher. The only documentation showing the differences in cost are the expenditure reports already provided.

(b) Alex Vaz.

Respondent(s): Alex Vaz

UM 2118 / PacifiCorp
February 10, 2021
Sunthurst Data Request 9.19

Sunthurst Data Request 9.19

Please refer to PAC /200, Patzkowski, Taylor, Vaz/25, lines 5-9 ("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").

(a) How many spares, conceivably, will ever be needed to support the PRS1 and PRS2 projects?

(b) How many spare fibers in the 48-count fiber cable does PacifiCorp intend to reserve for PRS1 and PRS2's exclusive future use?

(c) Isn't PacifiCorp's answer, above, an excellent description of a system benefit provided by installing a 48-count fiber when only a 12-count fiber is needed to serve PRS1 and PRS2?

(d) Please specify the name of the person sponsoring this answer.

Response to Sunthurst Data Request 9.19

(a) PacifiCorp objects to this question to this question to the extent it calls for speculation. Notwithstanding its objection, and without waiving its rights to assert such objection, PacifiCorp responds as follows:

If the cable is somehow damaged, then any of the remaining fibers may be required for PRS1 and PRS2. Use of spare fibers in the cable may enable PacifiCorp to return PRS1 and PRS2 to service sooner than replacing a damaged cable.

(b) PacifiCorp objects to this question to the extent that it calls for speculation. Notwithstanding its objection, and without waiving its rights to assert such objection, PacifiCorp responds as follows:

At this time, PacifiCorp has no plans to use any of the other fibers in this cable.

(c) PacifiCorp objects to this question to this question to the extent it calls for speculation. Notwithstanding its objection, and without waiving its rights to assert such objection, PacifiCorp responds as follows:

No. It would only become a benefit if a new interconnection customer were to be situated along the fiber cable route and could be spliced into the cable. Currently there are no indications of a future interconnection along this route.

(d) Milt Patzkowski and Joseph Leineweber.

UM 2118 / PacifiCorp
February 10, 2021
Sunthurst Data Request 9.19

Respondent(s): Milt Patzkowski / Joseph Leineweber

UM 2118 / PacifiCorp
February 10, 2021
Sunthurst Data Request 9.20

Sunthurst Data Request 9.20

Please refer to PAC /200, Patzkowski, Taylor, Vaz/28. Please provide all data regarding the occurrence and frequency of trips on Circuit 5W406.

Response to Sunthurst Data Request 9.20

Please refer to Attachment Sunthurst 9.20.

Respondent(s): Doug Guttromson

Sunthurst/401
Beanland/90

JobNo	Interrupted	Restored	Duration	CI	CMI	mCI	mCMI	SAIDI BU	SAIFI BU	CAIDI	Reportable Flag	RareIncidentFlag	SafetyHold Flag	Lockout Flag	MajorEvent Flag	MomentaryRestorationFlag	Restoration Stages	BU	State	OpArea
CPCC189218	7/26/04 9:44	7/26/04 9:58	13.6	1291	17514.567	0	0	0.02	0.0018	14	Y	N	Y	N	N	N	1	PP	OR	PENDLETON
CPCC461800	12/3/07 9:43	12/3/07 10:40	57	1351	77007	0	0	0.1	0.0018	57	Y	N	N	N	N	N	1	PP	OR	PENDLETON
CPCC501059	5/11/08 18:15	5/11/08 18:15	0.2	0	0	725	120.833	0	0	0	Y	N	N	N	N	Y	1	PP	OR	PENDLETON
CPCC505540	6/10/08 1:28	6/10/08 6:58	329.7	1340	304642.75	0	0	0.4	0.0018	227	Y	N	N	N	N	N	2	PP	OR	PENDLETON
CPCC501036	5/11/08 15:03	5/11/08 18:15	191.5	1340	139351.5	0	0	0.18	0.0018	104	Y	N	N	N	N	N	2	PP	OR	PENDLETON
CPCC453506	11/12/07 9:45	11/12/07 13:09	203.9	1350	275197.5	0	0	0.37	0.0018	204	Y	N	N	N	N	N	1	PP	OR	PENDLETON
CPCC505560	6/10/08 6:21	6/10/08 6:58	36.9	615	22693.5	0	0	0.03	0.0008	37	Y	N	N	N	N	N	1	PP	OR	PENDLETON
CPCC1230241	9/20/18 23:24	9/21/18 0:14	49.2	1395	68587.5	0	0	0.09	0.0018	49	Y	N	N	N	N	N	1	PP	OR	PENDLETON

Sunthurst/401
Beanland/91

JobNo	Substation	Circuit	DirectCauseCat	DirectCause	ContributoryCauseCat	ContributoryCause	Component	EquipmentID	Comments
CPCC189218	PILOT ROCK	5W406	OTHER	UNKNOWN				PRO_CB5W406	PROSPER: crew had hole on breaker at sub, did not get into line. closed in breaker @ sub, no cause yet.
CPCC461800	PILOT ROCK	5W406	TREES	TREE - NON-PREVENTABLE			PRIMARY CONDUCTOR OH	PRO_CB5W406	PROSPER: Crew made repairs to the overhead priamry that was taken down by a tree, customers are back in full service.
CPCC501059	PILOT ROCK	5W406	PLANNED	EMERGENCY DAMAGE REPAIR			NO DISTRIBUTION DAMAGE	PRO_CB5W406	PROSPER: Took a 10 sec outage to be able to close in on solid blades and pick up all custoemrs.
CPCC505540	PILOT ROCK	5W406	TREES	TREE - NON-PREVENTABLE	WEATHER	WIND	PRIMARY CONDUCTOR OH	PRO_CB5W406	PROSPER: Primary down and broken cross arms due to tree falling because of winds.
CPCC501036	PILOT ROCK	5W406	INTERFERENCE	OTHER INTERFERING OBJECT	WEATHER	WIND	PRIMARY CONDUCTOR OH	PRO_CB5W406	PROSPER: Cell tower fell onto primary and tore it down. Cause was to to it being windy. Made repairs and customer is back on.
CPCC453506	PILOT ROCK	5W406	TREES	TREE - NON-PREVENTABLE			NO DISTRIBUTION DAMAGE	PRO_CB5W406	PROSPER:
CPCC505560	PILOT ROCK	5W406	TREES	TREE - NON-PREVENTABLE	WEATHER	WIND	PRIMARY CONDUCTOR OH	PRO_CB5W406	PROSPER:
CPCC1230241	PILOT ROCK	5W406	LOSS OF SUPPLY	LOSS OF SUBSTATION			NO DISTRIBUTION DAMAGE	PRO_CB5W406	SOURCE: Fault on transmission line between BPA Round up & open SW 3W191 at Mckay. Sectionalized at Pilot Rock SW 3W3. Switchman headed for SW 3W191 at Mckay. CAUSE UNKNOWN AT THIS TIME

**Sunthurst/401
Beanland/92**

JobNo	OutageClass	OutageSubclass	EstRepair	OutageStatus	Phase	Dispatch (min)	Dispatch to Arrive (min)	Arrive to Restore (min)
CPCC189218	DISTRIBUTION	DEVICE		COMPLETED	ABC	0.4	0	13.2
CPCC461800	DISTRIBUTION	DEVICE		COMPLETED	ABC	12.2	0	44.8
CPCC501059	DISTRIBUTION	DEVICE		COMPLETED	ABC			
CPCC505540	DISTRIBUTION	DEVICE		COMPLETED	ABC	0.5	31	298.2
CPCC501036	DISTRIBUTION	DEVICE		COMPLETED	ABC	2.8	17.5	171.2
CPCC453506	DISTRIBUTION	DEVICE		COMPLETED	ABC	193.8	0	10.1
CPCC505560	DISTRIBUTION	DEVICE		COMPLETED	ABC			
CPCC1230241	DISTRIBUTION	DEVICE	9/21/18 2:15	COMPLETED	ABC	25.6		0

Sunthurst/401
Beanland/93

PKID	Tripped	TimeClosed	Breaker	TrippedReclos	TrippedOpen	WasOpened	Closed	Operations	ORS	DispatchCenter	Area	SubstationID	SubstationName	FeederName	Cause	UpdatedPST
PDX-12000	7/26/04 9:44	9:55:00	5W406	False	True	False	True	1	No	Portland	North	420	PILOT ROCK	CITY FEEDER	crew had hold on line, didn't get into line, Psuedo CB, closed in and holding, targets AG-I	9/20/19 15:07
PDX-22938	11/12/07 10:45	13:08:03	5W406	False	True	False	True	1	No	Portland	North	420	PILOT ROCK	CITY FEEDER	Wind	9/20/19 15:07
PDX-23237	12/3/07 9:43	10:40:55	5W406	False	True	False	True	2	No	Portland	North	420	PILOT ROCK	CITY FEEDER		9/20/19 15:07
PDX-24493	6/10/08 1:25	3:21:00	5W406	True	True	False	True	3	No	Portland	North	420	PILOT ROCK	CITY FEEDER	Tree through primary	9/20/19 15:07
PDX-24291	5/11/08 15:03	15:33:42	5W406	False	True	False	True	2	No	Portland	North	420	PILOT ROCK	CITY FEEDER	Cell Tower fell and tore down primary	9/20/19 15:07

Attachment Sunthurst 9.20

Field	Value
Breaker	5W406
BU	PP
OpAreaName	PENDLETON
Substation	PILOT ROCK
Source	PRO_T2144
Momentary Interruptions	0
Sustained Interruptions	5
Momentary Events	0
Events	5
Momentary Interruption Ratio	0
Momentary Event Ratio	0
Operations	9
MomOperations	0
Customers	1402

UM 2118 / PacifiCorp
February 10, 2021
Sunthurst Data Request 9.21

Sunthurst Data Request 9.21

Please refer to PAC /200, Patzkowski, Taylor, Vaz/42. Please quantify the credit referred to in lines 9-10.

Response to Sunthurst Data Request 9.21

PacifiCorp can provide the following credit for costs spent through December 31, 2020:

SCADA Consultant for Telemetry Work =	$4,474.70
Power Engineers Design Cost for Annunciator Panel =	$1,374.00
25 percent of the Costs Spent by PacifiCorp P&C Engineer =	$621.00
Applicable Capital Surcharge (8 percent) =	$517.57
Total Credit =	**$6,987.27**

The credit above relates to engineering expenses associated with design of the annunciator panel and telemetry work.

Respondent(s): Alex Vaz

UM 2118 / PacifiCorp
February 10, 2021
Sunthurst Data Request 9.22

Sunthurst Data Request 9.22

Please refer to Bremer/31, lines 2-9, wherein PacifiCorp agrees that some equipment may be needed to provide signals for the PacifiCorp telemetry but asserts that the costs are "minimal." Please specifically identify the nature of the analog signals required by the PacifiCorp RTU for each of the variables listed in the Q1045 Facilities Study Report. This means the magnitude of voltage and/or current, the possible scaling factor, and whether analog signals are alternating or direct voltage or current and whether grounded or floating. For the signals required by PacifiCorp, identify the typical performance criteria for the conversion devices acceptable to PacifiCorp to generate each signal. Please provide examples of the conversion devices by manufacturer and part number.

Response to Sunthurst Data Request 9.22

This section refers to the supervisory control and data acquisition (SCADA) points to be provided by the Interconnection Customer to PacifiCorp's telemetry system, which corresponds to the list below from the Facilities Study.

- 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)

Most of the analog points (megawatts (MW), mega volt-ampere reactive (MVAR), and volts) required for this project would typically be provided to the PacifiCorp Energy Management System (EMS) directly from PacifiCorp owned installed meters. If Company meters are not used for these analogs, they would need to be supplied by equipment from the solar facility via hardwired connections to the PacifiCorp installed remote terminal unit (RTU). Serial connections directly from non-PacifiCorp electronic intelligent devices (IED) are not allowed per Company policy. Devices that will supply these analogs should deliver a 0 to 1 milli ampere (ma) signal, plus or minus where applicable.

The kilowatt-hours (kWh) values shall be delivered to PacifiCorp with a hardwired KYZ energy impulses connection from the customer meters.

The metrological analog points (Global Horizontal Irradiance (GHI), Average Plant Atmospheric Pressure (Bar), and Average Plant Temperature (Celsius)), shall be delivered from an instrument that supplies a hardwired 0 to 1 ma signal. If the instrument only delivers a serial output, an intermediate device will be needed that will convert the serial connection to outputs that can deliver a hardwired 0 to 1 ma signal.

The breaker status point can be hardwired from a 52a circuit breaker contact, or from a relay that has an output contact that follows the 52a circuit breaker contact operation.

Scaling is done in the PacifiCorp EMS database and will be determined during the project design process based on the requirements of the solar facility project and from solar facility equipment output capabilities.

Respondent(s): Anne Loucks / Greg Lyons

UM 2118 / PacifiCorp
February 10, 2021
Sunthurst Data Request 9.24

Sunthurst Data Request 9.24

If Q0666 and Q1045 had been tied to separate POIs with a single separate metering system each, can PacifiCorp describe how it would deal with the loss of a potential or current transformer signal to the meter? Why would this be acceptable to PacifiCorp when should a similar situation occur when the projects share a POI PacifiCorp will require a 3rd complete metering system? Please specify the name of the person sponsoring this answer.

Response to Sunthurst Data Request 9.24

In a three-phase system, each phase has a voltage instrument transformer and a current transformer. If one of the instrument transformers fails, a temporary multiplier is used in the meter data management system to correct for the failed transformer providing a signal to the non-telemetered meter until the failed transformer can be replaced. This solution would be used with independent point of interconnection (POI) for each generator. This solution would also be used for two generators behind the same POI with a third metering point at the POI.

Respondent(s): Eric Taylor

UM 2118 / PacifiCorp
February 17, 2021
Sunthurst Data Request 10.1

Sunthurst Data Request 10.1

Please refer to the italicized language, quoting PacifiCorp's Response to Sunthurst DR8.20(g):

> *Should Sunthurst choose to move forward with Q0666 then yes, the following updated language will be included*:
>
> *The Community Solar Project and Interconnection Equipment owned by the Applicant are required to operate under constant power factor mode with a unity power factor setting unless specifically requested otherwise by the Public Utility.*
>
> *The Community Solar Project is expressly forbidden from actively participating in voltage regulation of the Public Utilities system without written request or authorization from the Public Utility. The Community Solar Project shall have sufficient reactive capacity to enable the delivery of 100 percent of the plant output to the POI at unity power factor measured at 1.0 per unit voltage under steady state conditions.*
>
> *Generators shall be capable of operating under Voltage-reactive power mode, Active power-reactive power mode, and Constant reactive power mode as per IEEE Std. 1547-2018. This project shall be capable of activating each of these modes one at a time. The Public Utility reserves the right to specify any mode and settings within the limits of IEEE Std 1547-2018 needed before or after the Community Solar Project enters service. The Applicant shall be responsible for implementing settings modifications and mode selections as requested by the Public Utility within an acceptable timeframe. The reactive compensation must be designed such that the discreet switching of the reactive device (if required by the Applicant) does not cause step voltage changes greater than +/-3 percent on the Public Utility's system. In all cases the minimum power quality requirements in PacifiCorp's Engineering Handbook section 1C shall be met and are available at https://www.pacificpower.net/about/power-quality-standards.html. Requirements specified in the System Impact Study that exceed requirements in the Engineering Handbook section 1C power quality standards shall apply.*

(a) Does PacifiCorp include similar language in its Oregon small generator interconnection agreements? If yes, please provide an executed Oregon small generator interconnection agreement as an example.

(b) Does PacifiCorp include similar language in its FERC small generator interconnection agreements? If yes, please provide an executed FERC small generator interconnection agreement as an example.

(c) Do Oregon's Administrative Rules authorize PacifiCorp to unilaterally apply IEEE Std 1547-2018 requirements to its interconnection agreements? If yes, please explain.

(d) Did the Oregon PUC ever approve the italicized language, above?

Response to Sunthurst Data Request 10.1

(a) Yes. Please refer to Attachment Sunthurst 10.1.

(b) PacifiCorp has not executed a Federal Energy Regulatory Commission (FERC) jurisdictional interconnection agreement for a small generator requesting interconnection to PacifiCorp's distribution system since the current language was developed. However, if PacifiCorp received a FERC jurisdictional interconnection request for a small generator requesting interconnection to PacifiCorp's distribution system, this language would be included in the interconnection agreement.

(c) The Public Utility Commission of Oregon (Commission) rules (OAR 860-082-0025(7)(e)(A)) allow PacifiCorp and the applicant to negotiate terms of the interconnection agreement. As noted in the response to Sunthurst Data Request 8.20, the language at issue in this question would be included in Attachment 4 of the interconnection agreement, which is not an attachment that has specific terms and conditions approved by the Commission as part of PacifiCorp's pro forma small generator interconnection agreement.

(d) No, as noted in response to Sunthurst Data Request 10.1(c), the Commission's rules allow PacifiCorp and the applicant to negotiate terms of the interconnection agreement. Attachment 4 of the interconnection agreement is not an attachment that has specific terms and conditions approved by the Commission as part of PacifiCorp's pro forma small generator interconnection agreement.

Respondent(s): Kris Bremer

UM 2118 / PacifiCorp
February 17, 2021
Sunthurst Data Request 10.2

Sunthurst Data Request 10.2

Please refer to the italicized language, below, quoting PacifiCorp's Response to Sunthurst DR8.20(j):

> *(j) Yes. Small generators connected to the distribution system have been required to utilize voltage control capabilities when there is a possibility to not meet ANSI C84.1 Range A voltages to all customers without the small generator's voltage control settings being utilized.*

(a) Is Pilot Rock Solar an instance where its voltage control capabilities could be used to meet C84.1 Range A voltages?

(b) Did PacifiCorp study whether the Pilot Rock Solar projects could be used to meet ANSI C84.1 Range A voltages to all customers on circuit 5W406 without the installation of new branch regulators? If yes, please provide the study and results. If no, explain why no study was performed.

(c) How does PacifiCorp determine whether to use voltage control capabilities of a small generator or to install new voltage regulators on its system?

(d) For small (<5MW) PacifiCorp owned PV projects, does PacifiCorp utilize the voltage control capabilities of the project inverters?

Response to Sunthurst Data Request 10.2

(a) PacifiCorp assumes the reference to "Pilot Rock Solar" is intended to mean the Pilot Rock Solar Projects (i.e., Q0666 and Q1045). Based on that assumption, the Company responds as follows:

No. The System Impact Studies (SIS) for Pilot Rock Solar (PRS) 1 and 2 determined that neither additional line voltage regulators nor the generators voltage control functionality are needed to meet American National Standards Institute (ANSI) C84.1 range A voltages. However, the line regulators are required to allow for existing Line Drop Compensation (LDC) settings to be maintained on the system. Additionally, PRS 1 and 2 need to have voltage control functionality as described in PacifiCorp Policy 138, Section 2.2.4 in the event it is needed in the future.

(b) Yes. Voltage analyses were completed for both PRS 1 and PRS 2, and it was determined that ANSI C84.1 Range A voltages can be maintained without the need for the line voltage regulator banks. The SIS for the PRS 1 and PRS 2 projects detail the upgrades required for each. Please refer to the Company's responses to Sunthurst Data Request 6.2, Sunthurst Data Request 7.8, and Sunthurst Data Request 8.25 for the line voltage regulator bank justifications. There are no separate voltage studies for

PRS 1 or PRS 2. The resulting requirements from the voltage studies are in the SIS for PRS 1 and PRS 2, respectively.

(c) As per PacifiCorp Policy 138, Section 2.2.4, the voltage regulating capabilities of Distributed Energy Resources (DER) are to be disabled by default. The SIS determines what utility system upgrades are required to maintain C84.1 Range A voltages with the generator operating in constant power factor mode. Generally, the determination of new voltage regulators in this scenario is dependent on maintaining existing voltage regulation capability or maintaining C84.1 ANSI range A limits.

(d) No.

Respondent(s): Doug Guttromson, Jonathan Connelly

UM 2118 / PacifiCorp
February 17, 2021
Sunthurst Data Request 10.4

Sunthurst Data Request 10.4

Please refer to PacifiCorp's Response to Sunthurst DR6.2.

(a) Does PacifiCorp use Line Drop Compensation (LDC) on all of its feeders? For example: does PacifiCorp agree that if you have a large substation with on-load tap changer (OLTC) (voltage regulator built into the main power transformer), using LDC is problematic because the load on any one feeder can affect the voltage on ALL feeders?

(b) What portion of voltage regulators and OLTC used in the PacifiCorp system use LDC?

(c) What are the advantages and disadvantages of using LDC with Pilot Rock Solar locked at unity power factor versus not using LDC and utilizing PRS for voltage regulation?

(d) How does PacifiCorp determine when it requires LDC? Please specify any PacifiCorp policy or professional standard relied upon for this determination.

(e) Where ANSI C84.1 Range A voltages along a circuit can be achieved without the use of LDC, what is the rationale for the use of LDC?

(f) If the use of LDC is not required to meet ANSI C84.1 Range A voltages, is LDC used in order to save energy? How does PacifiCorp determine the amount of energy savings achieved through the use of LDC? Was the energy savings studied on the Pilot Rock feeder that PRS1 and PRS2 connect into? If so, please provide those studies.

Response to Sunthurst Data Request 10.4

(a) PacifiCorp standard is to use Line Drop Compensation (LDC) settings when controlling voltage on its distribution system. However, LDC settings are not used on all feeders, but they are in use on vast majority of feeders. In the scenario of a single substation transformer serving multiple feeders with different load profiles and load levels, while it is correct all feeder voltage levels are controlled to the same level at the source, LDC settings used in conjunction with first house protection settings can normally be used to control the regulator or Load Tap Changer (LTC) voltage output while still maintaining C84.1 ANSI range A voltage to all customers at all loading levels.

(b) While PacifiCorp does not have a database to obtain the percentage, LDC settings are generally in use on all regulator and LTC voltage controls whenever possible and are used on the vast majority of controls.

(c) The advantage of using LDC settings is based on energy efficiency and maintaining existing voltage regulation capability. The advantage of PRS 1 and PRS 2 generating in constant power factor mode is to maintain the ability to control voltage into upper ranges of American National Standards Institute (ANSI) C84.1 Range B when required by emergent abnormal system events or temporary configurations and not have PRS 1 or PRS 2 trying to lower the voltage at the same time.

(d) PacifiCorp standard is to use LDC settings when controlling voltage on its distribution system. Please refer to Attachment Sunthurst 10.4, which is Section 7.D from the Pacific Power Engineering Handbook 1E.3.1 – Distribution Planning Study Guide. 7.D regards regulator control settings.

(e) Please refer the Company's response to Sunthurst Data Request 6.2, which addresses the rational for using LDC voltage regulation control settings.

(f) Yes. As explained in the Company's response to Sunthurst Data Request 6.2, two distribution line regulator banks for PRS1 and PRS2 are required to maintain the Company's ability to utilize LDC settings. LDC settings are used in the case of PRS 1 and 2 to save energy. While detailed studies to determine energy efficiency savings can be completed using distribution modeling software, none were undertaken for PRS 1 or PRS 2. The System Impact Study (SIS) determined the upgrades required to maintain existing system capabilities and efficiency, which resulted in the required two distribution line regulator banks.

Respondent(s): Doug Guttromson

UM 2118 / PacifiCorp
February 17, 2021
Sunthurst Data Request 10.5

Sunthurst Data Request 10.5

Did PacifiCorp interconnect two <1MW PV solar projects near Dorris, CA, (NMQ0032 & NMQ0033) each with its own 480V meter, with a common POI, a single PacifiCorp-owned power transformer and Direct Transfer Trip to a single protection scheme that provided protection to both projects? Please provide a one-line diagram showing the metering and DTT protection scheme, from each project to the POI. Please provide any completed interconnection studies for NMQ0032 and NMQ0033.

Response to Sunthurst Data Request 10.5

PacifiCorp objects to this data request because the requested information is not relevant to the claims asserted by Sunthurst and as such is not reasonably calculated to lead to the discovery of admissible evidence.

Notwithstanding the foregoing objection, and without waiving its right to maintain the objection, the Company responds as follows:

The two interconnection customers referred to above (NMQ0032 and NMQ0033) are net metering projects that are subject to different interconnection study processes and requirements than Q0666 and Q1045. In addition, NMQ0032 and NMQ0033 are in another state. Therefore, the interconnection requirements for the two out-of-state net metering projects are irrelevant to the interconnection requirements for Sunthurst's Q0666 and Q1045 projects.

Respondent(s): Counsel, Eric Taylor

UM 2118 / PacifiCorp
February 19, 2021
Sunthurst Data Request 10.5 – 1st Supplemental

Sunthurst Data Request 10.5

Did PacifiCorp interconnect two <1MW PV solar projects near Dorris, CA, (NMQ0032 & NMQ0033) each with its own 480V meter, with a common POI, a single PacifiCorp-owned power transformer and Direct Transfer Trip to a single protection scheme that provided protection to both projects? Please provide a one-line diagram showing the metering and DTT protection scheme, from each project to the POI. Please provide any completed interconnection studies for NMQ0032 and NMQ0033.

1st Supplemental Response to Sunthurst Data Request 10.5

In further support of the Company's response to Sunthurst Data Request 10.5, dated February 17, 2021, the Company provides the following additional information:

PacifiCorp continues to object to this data request because the requested information is not relevant to the claims asserted by Sunthurst and as such is not reasonably calculated to lead to the discovery of admissible evidence.

Notwithstanding the foregoing objection, and without waiving its right to maintain the objection, the Company responds as follows:

The two interconnection customers referred to above (NMQ0032 and NMQ0033) are net metering projects, unlike Q0666 and Q1045. Each project has its own meter. However, PacifiCorp owns the step-up transformer that NMQ0032 and NMQ0033 feed into. Therefore, the meters do not have to account for transformer losses and the meters can be on the low-side of the transformer, consistent with the treatment of net metering interconnections where PacifiCorp takes ownership of the electricity on the low side of the meters. The meters are on the utility side of each recloser for each project, like the point of interconnection meter for Q0666 and Q1045. This means that the metering configuration for NMQ0032 and NMQ0033 is comparable to the metering configuration for Q0666/Q0747, not Q0666/Q1045.

Please refer to Attachment Sunthurst 10.5 1st Supplemental, which provides the System Impact Studies (SIS) for NMQ0032 and NMQ0033.

Respondent(s): Counsel, Eric Taylor

UM 2118 / PacifiCorp
February 17, 2021
Sunthurst Data Request 10.6

Sunthurst Data Request 10.6

Please refer to PacifiCorp's Response to Sunthurst DR3.2, below:

> [Sunthurst DR]3.2 Please refer to Paragraph 16 in Sunthurst' Complaint describing Sunthurst' first alternative metering proposal (Alternative 1). Describe any reason why Alternative 1 is not a (a) safe; and (b) effective means of metering PRS1 and PRS2.
>
> *[PacifiCorp's (Mr. Bremer's) response:] Without the metering equipment that PacifiCorp is requiring, the possibility exists that generation could flow onto PacifiCorp's system without PacifiCorp having the ability to monitor it which could lead to unsafe operating conditions for PacifiCorp's employees.*

(a) Is Mr. Bremer saying, above, that Sunthurst's Alternative 1 proposal to use two meters instead of three meters is not reasonably safe?

(b) Is it PacifiCorp's position that Mr. Bremer is qualified to give the opinion in italics, above? If yes, please explain the bases for his expert knowledge regarding the question (DR3.2).

(c) If yes (to question (a)), does Mr. Milt Patzkowski also believe that Sunthurst's Alternative proposal to use two meters instead of three meters is not reasonably safe? Please provide Mr. Patzkowski's response.

(d) If yes (to question (a)), does Mr. Richard Taylor also believe that Sunthurst's Alternative proposal to use two meters instead of three meters is not reasonably safe? Please provide Mr. Taylor's response.

(e) If the proposed, two-meter scheme is not reasonably safe, please explain why PacifiCorp allowed a similar two-meter scheme for two adjacent PV solar projects in Dorris, CA (NMQ0032 & NMQ0033).

Response to Sunthurst Data Request 10.6

(a) No. Safety has not been the primary reason for the three meter configuration required for PRS 1 and PRS 2, accounting (i.e. accurate settlements) is the primary reason.

(b) Yes. The basis for Mr. Bremer's view is based on his experience with management responsibility of customer generator interconnection requests since 2014. However, the technical aspects of the three-meter configuration required for PRS 1 and PRS 2 are primarily supported by PacifiCorp witness Richard Eric Taylor.

UM 2118 / PacifiCorp
February 17, 2021
Sunthurst Data Request 10.6

(c) Not applicable.

(d) Not applicable.

(e) Please refer to the Company's response to Sunthurst Data Request 10.5

Respondent(s): Eric Taylor / Kris Bremer

UM 2118 / PacifiCorp
February 17, 2021
Sunthurst Data Request 10.7

Sunthurst Data Request 10.7

Please refer to PacifiCorp's response to DR9.22. Does PacifiCorp agree that the total cost to Sunthurst to provide signals PacifiCorp requires for its RTU could be between $10,000 and $20,000? If not, please explain.

Response to Sunthurst Data Request 10.7

PacifiCorp only accepts hard-wired signals. Sunthurst will determine how to establish the direct connection to the remote terminal unit (RTU). The costs that Sunthurst would incur to provide signals are within its control. Depending on the types of equipment Sunthurst chooses to use, the costs could be below $20,000.

Respondent(s): Greg Lyons

UM 2118 / PacifiCorp
February 17, 2021
Sunthurst Data Request 10.8

Sunthurst Data Request 10.8

Does PacifiCorp ever rent or lease access to surplus fiber optic lines on its system? Does PacifiCorp claim the right to use, lease, or rent the extra fibers in the fiber optic line on PacifiCorp's system paid for by Sunthurst?

Response to Sunthurst Data Request 10.8

PacifiCorp objects to this question to the extent it assumes Sunthurst has paid for the fiber optic cable required for PRS 1 and PRS 2. As of the date of this response, Sunthurst has not paid for the fiber optic cable. Notwithstanding the objection, and without waiving its rights to maintain the objection, PacifiCorp responds as follows:

PacifiCorp has established a program for leasing out surplus fiber, however, it has found no market interest in fiber assets similar to the fiber required for this interconnection(s). As such, PacifiCorp does not place any commercial value on this short segment of fiber and does not anticipate any potential for lease revenue on it.

PacifiCorp owns all the interconnection facilities installed on the PacifiCorp system. As such, PacifiCorp retains the ability to use, as necessary, the 48-count fiber optic cable that is required for PRS 1 and PRS 2, and will be owned by PacifiCorp.

Respondent(s): Counsel, Mark Robinson, Joseph Leineweber

UM 2118 / PacifiCorp
February 17, 2021
Sunthurst Data Request 10.12

Sunthurst Data Request 10.12

Please refer to PacifiCorp's response to Sunthurst DR 8.23.

(a) Did Shakeel Shafi, Dean Miller, Steven Elder, or any other consultant to PacifiCorp perform interconnection related studies on Q0666 or Q1045?

(b) If yes (to (a)), has PacifiCorp contacted such persons to request all Q0666 and Q1045 studies? If not, please do so and provide copies of any such studies not identified in DR 8.23.

Response to Sunthurst Data Request 10.12

(a) Yes.

(b) Yes.

Respondent(s): Kris Bremer

UM 2118 / PacifiCorp
February 19, 2021
Sunthurst Data Request 10.12 – 1st Supplemental

Sunthurst Data Request 10.12

Please refer to PacifiCorp's response to Sunthurst DR 8.23.

(a) Did Shakeel Shafi, Dean Miller, Steven Elder, or any other consultant to PacifiCorp perform interconnection related studies on Q0666 or Q1045?

(b) If yes (to (a)), has PacifiCorp contacted such persons to request all Q0666 and Q1045 studies? If not, please do so and provide copies of any such studies not identified in DR 8.23.

1st Supplemental Response to Sunthurst Data Request 10.12

In further support of the Company's response to Sunthurst Data Request 10.12, dated February 17, 2021, the Company provides the following additional information to subpart (b):

(b) Yes. There are no additional studies other than what was identified in the Company's response to Sunthurst Data Request 8.23. Please also refer to the Company's response to Sunthurst Data Request 9.3.

Respondent(s): Kris Bremer

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

PUBLIC UTILITY COMMISSION
OF
OREGON

SUNTHURST EXHIBIT 402

PacifiCorp Interconnection Study Reports
for NMQ0032 and NMQ0033

FEBRUARY 22, 2021

PacifiCorp
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Small Generator Interconnection
System Impact Study Report

Completed for
Porterfield Ranch
("Interconnection Customer")
898 kW Solar Project

Proposed Interconnection
On PacifiCorp's Existing
FP 06148001.0 332000

WO# 45043621

Due: 5/12/17

TABLE OF CONTENTS

1.0 DESCRIPTION OF THE GENERATING FACILITY

Porterfield Ranch ("Interconnection Customer") proposed interconnecting .898 MW of new generation to PacifiCorp's ("Transmission Provider") FP 06148001.0 332000 located in Siskiyou County, CA. The Porterfield Ranch project will consist of 26 ABB inverters with a total AC capacity rating of 780 KW and a total output of .898 MW. The requested commercial operation date is approximately Fall 2017

Interconnection Customer will not operate this generator as a Qualified Facility as defined by the Public Utility Regulatory Policies Act of 1978 (PURPA).

The Transmission Provider has assigned the project "NMQ032."

2.0 APPROVAL CRITERIA FOR LEVEL 3 INTERCONNECTION REVIEW

Pursuant to R746-312-10(1), A generating facility which meets the following criteria is eligible for Level 3 interconnection review:

(a) the generating facility has a capacity of greater than two megawatts but no larger than 20 megawatts;
(b) the generating facility is not certified; or
(c) the generating facility does not qualify for or failed to meet Level 1 or Level 2 interconnection review requirements.

3.0 SCOPE OF THE STUDY

Pursuant to R746-312-10(2)(f), 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:

- provide details on the impacts to the electric distribution system which would result if the generating facility were interconnected without modifications to either the generating facility or to the electric distribution system;
- identify any modifications to the public utility's electric distribution system necessary to accommodate the proposed interconnection;
- focus on power flows and utility protective devices, including control requirements; and
- include the following elements, as applicable:
    a. a load flow study;
    b. a short-circuit study;
    c. a circuit protection and coordination study;
    d. the impact on the operation of the electric distribution system;
    e. a stability study, along with the conditions that would justify including this element in the impact study;
    f. a voltage collapse study, along with the conditions that would justify including this element in the impact study; and
    g. additional elements, if justified by the public utility and approved in writing by the public utility and the interconnection customer prior to the impact study.

4.0 PROPOSED POINT OF INTERCONNECTION

The proposed generation facility is to be interconnected, through an existing service at Pacific Power map string 06148001.0; facility point 332000

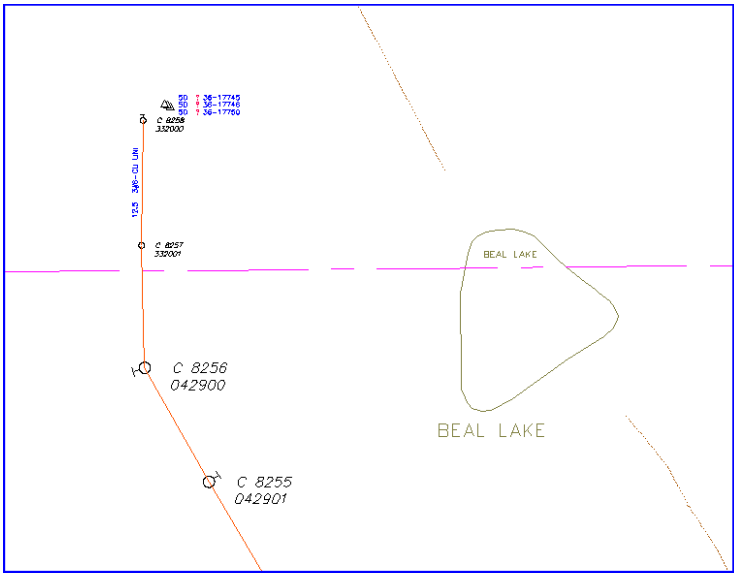


Figure 1: System Map

4.1 STUDY ASSUMPTIONS

- All active higher priority transmission service and/or generator interconnection requests will be considered in this study and are listed in Appendix 1. If any of these requests are withdrawn, the Transmission Provider 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, network upgrades required to provide delivery will only be modeled for projects which have requested network resource integration service only or qualified facility status. 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 Transmission Provider's system at the agreed upon and/or proposed point of interconnection.

- The Interconnection Customer will construct and own the any facilities required between the point of interconnection and the Project.
- Generator tripping may be required for certain outages.
- All facilities will meet or exceed the minimum WECC, NERC, and Transmission Provider performance and design standards.
- The generator is expected to operate 12 hours per day 7 days per week 12 months per year. The primary meter (point of interconnection) power factor range studied was 100% prior to the proposed generation facility being installed.
- This report is based on information available at the time of the study. It is the Interconnection Customer's responsibility to check the Transmission Provider's web site regularly for transmission system updates (http://www.pacificorp.com/tran.html)

Four case studies were assembled and studied:

1. Feeder 5L62 with typical summer peak loading levels. Analysis was performed at full generation and no generation by the Interconnection Customer, as well as with full generation and no generation by all other interconnection customers connected to feeder 5L62.
2. Feeder 5L62 with typical winter peak loading levels. Analysis was performed at full generation and no generation by the Interconnection Customer, as well as with full generation and no generation by all other interconnection customers connected to feeder 5L62.
3. Feeder 5L62 with typical spring/summer minimum daytime loading levels. Analysis was performed at full generation and no generation by the Interconnection Customer, as well as with full generation and no generation by all other interconnection customers connected to feeder 5L62.
4. Feeder 5L62 with typical winter minimum daytime loading levels. Analysis was performed at full generation and no generation by the Interconnection Customer, as well as with full generation and no generation by all other interconnection customers connected to feeder 5L62.

5.0 RESULTS

5.1 GENERATING FACILITY MODIFICATIONS

The Interconnection Customer shall design its generating facility to operate reactive compensation, typically located at the collector station, under voltage control mode with the voltage sensed electrically at the point of interconnection, and to have sufficient reactive capacity to enable the facility to deliver 100 percent of the plant output to the point of interconnection at unity power factor measured at 1.0 per unit voltage.

The voltage control shall be designed to include a voltage control band, nominally set to 1.01 and 1.04 per unit (actual voltage band may be adjusted depending on typical voltage at the interconnection or other area local conditions), such that if the actual voltage is above the upper band setting, capacitor increments will be automatically removed and if the actual voltage is below the lower band setting, capacitor increments will be automatically be added. The control scheme should be designed so as to avoid hunting when switching between modes (i.e., effectively power factor control inside the band, voltage control outside the band). Inside the voltage bandwidth, the facility shall operate as much as possible to a unity power factor. Settings must be coordinated with the Transmission Provider who may, from time to time, request changes in response to operating conditions or actual operating experience. The reactive compensation must be designed such that the capacitor switching does not cause step voltage changes greater than +/-3% on the Transmission Provider's system.

A grounding transformer as specified by the generation customer will be required for this project. The impedance of the transformer, Xo = 1.9 ohms and Ro = 0.161 ohms, would be adequate. The continuous current rating of 60 A would also be adequate. Based on our fault study the 2-second withstand current rating of 1010 A will not be adequate. For a transformer of the specified impedance for this application will need to have a 2-second withstand current rating of 3250 A. A transformer with higher impedance would also be adequate which would lower the needed withstand current rating requirement.

5.2 Property Requirements for Transmission Provider's Point of Interconnection Substation

The following applies to property acquired by an Interconnection Customer on which a point of interconnection substation will be built to accommodate the Interconnection Customer's project. The property will ultimately be assigned to PacifiCorp, the Transmission Provider.

- Property must be environmentally, physically and operationally acceptable to PacifiCorp without any material defects of title (or as deemed acceptable to PacifiCorp) and without unacceptable encumbrances. The property shall be a permitted or permittable use in all zoning districts. Property lines shall be surveyed and show all encumbrances, roads (private or public); easements (prescriptive or express) etc.
- Examples of potentially unacceptable environmental, physical, or operational conditions:
  - Environmentally unacceptable conditions could include but are not limited to known contamination of site; evidence of environmental contamination by any dangerous, hazardous or toxic materials as defined by any governmental agency; property is in violation of building, health, safety, environmental, fire, land use, zoning or other such regulation, ordinances, or statues of any governmental entities having jurisdiction over the property; underground or above ground storage tanks; known remediation sites on property; ongoing mitigation activities or monitoring activities; asbestos; lead-based paint, etc. At a minimum, a phase I environmental study is required for company land being acquired in fee. Evidence will be required prior to execution of the interconnection agreement.
  - Physically unacceptable conditions could include but are not limited to inadequate drainage; in flood zone; erosion issues; wetland overlays; threatened and endangered species; archeological or culturally sensitive areas; inadequate sub-surface elements, etc. Geotechnical studies are required by company.

- Operationally unacceptable conditions could include but are not limited to inadequate access for company equipment; existing structures on land that require removal prior to building of substation; ongoing maintenance for landscaping or extensive landscape requirements; ongoing homeowner's or CC&R's that are not acceptable to company.

- Property should be acquired by fee ownership. If fee acquisition is not possible, then the term shall be perpetual and the use exclusive and provide PacifiCorp with all property rights it deems necessary. In the event that the only option is via a lease, the lease payments shall be one time only – on going lease payments are not acceptable to PacifiCorp. All contracts are subject to PacifiCorp approval prior to execution.
- The Interconnection customer is required to identify any and all land rights to the subject property, which are to be retained by the Interconnection customer prior to conveying property. All retained land rights are subject to PacifiCorp approval.
- If the Interconnection Customer is building facilities to be owned by the Transmission Provider, then the Interconnection Customer must obtain all permits required by all relevant jurisdictions for the use including but not limited to conditional use permits, Certificates of Public Convenience and Necessity, California Environmental Quality Act, etc., as well as all construction permits for the project
- Interconnection Customer will not reimburse through network upgrades for more than the market value of the property.
- Property must be assignable to company and without litigation, suit, liens, condemnation actions, foreclosures actions, etc.

5.3 DISTRIBUTION/TRANSMISSION MODIFICATIONS

5.3.1 LOAD FLOW STUDY

The existing transformer bank supplying this installation has a transformation capacity of 150 kVA. The transformer capacity will be required to be increased to accommodate this generation. The available PacifiCorp standard transformer is a pad mount, three phase, 1000 kVA transformer. A primary underground extension will be required to accommodate this installation.

The addition of this generation will cause the aggregate generation interconnected to feeder 5L62 to be 921 kW. The minimum daytime load during winter loading conditions is 207 kW. The aggregate generation will be greater than 10% of the minimum daytime load and it will be required that the generation be effectively grounded. It will be required that a #2 ACSR neutral conductor be installed from facility point 06148001.0-320061 to 06148001.0-332000. This will be approximately 11,300 feet.

Feeder circuit breaker 5L62 will experience reverse power flow during winter minimum daytime load conditions. It will be required that the Protection and Control department evaluate the impacts of the reverse power flow.

Feeder 5L62 will experience voltage above ANSI Range A during winter loading conditions and summer minimum daytime loading conditions while the 1200 kVAR capacitor bank at FP 06147001.0-112361 is online. 5L62 will also experience voltage conditions below ANSI Range A during summer minimum daytime loading conditions with the 1200 kVAR capacitor bank at FP 06147001.0-112361 offline. It will be required to replace the 1200 kVAR, fixed capacitor bank with a 900 kVAR, switched capacitor bank to accommodate this generation interconnection.

5.3.2 SHORT CIRCUIT STUDY

It is expected that NMQ0032 will be capable of contributing up to 144 A to a short circuit condition. At the point of interconnection, the maximum available fault current is 1111 A. NMQ0032 will be capable of contributing up to 13% of the available fault current. Any concerns due to the available fault current from the generation are addressed by the system upgrades required by the Circuit Protection and Coordination Study.

5.3.3 CIRCUIT PROTECTION AND COORDINATION STUDY

The installation of a 1000 kVA pad mount transformer will require a 100T riser fuse. This fuse will not coordinate with the existing 40T fuse at facility point 06147001.0-043401 or the existing 100T fuse at 06148001.0-320062. To accommodate the installation of the 1000 kVA transformer, the following system changes will be required:

- Replace existing 40T fuses at facility point 06147001.0-043401 with 100T fuses.
- Replace existing 100T fuses at facility point 06148001.0-320062 with 140T fuses.
- Update the DPU-2000 relay at Dorris substation for feeder breaker 5L62 with new phase and ground current pickup values and time dial values to allow for feeder protection coordination.

There will be an accepted mis-coordination between the 100T fuses at facility points 06147001.0-043401 and 06148001.0-332000. This is a tap line off of the main line and is dedicated to the interconnection customer. In the event of a fault downstream of either of these fuses, the interconnection customer will be taken off-line and no other customer will be affected.

5.3.4 STABILITY STUDY

A stability study was performed to determine the effects of the sudden loss of generation due to system or weather conditions. It is PacifiCorp's policy that voltage fluctuations lasting longer than 10 seconds be limited to 3%.

- During summer peak conditions, the voltage fluctuation caused by the sudden disconnection of the generation will cause a 2.5% voltage change at the point of interconnection.

- During summer MDTL conditions, the voltage fluctuation caused by the sudden disconnection of the generation will cause a 2.3% voltage change at the point of interconnection.
- During winter peak conditions, the voltage fluctuation caused by the sudden disconnection of the generation will cause a 2.3% voltage fluctuation at the point of interconnection.
- During winter MDTL conditions, the voltage fluctuation caused by the sudden disconnection of the generation will cause a 2.3% voltage fluctuation at the point of interconnection.

The voltage fluctuation due to the sudden removal of the generation is within PacifiCorp guidelines.

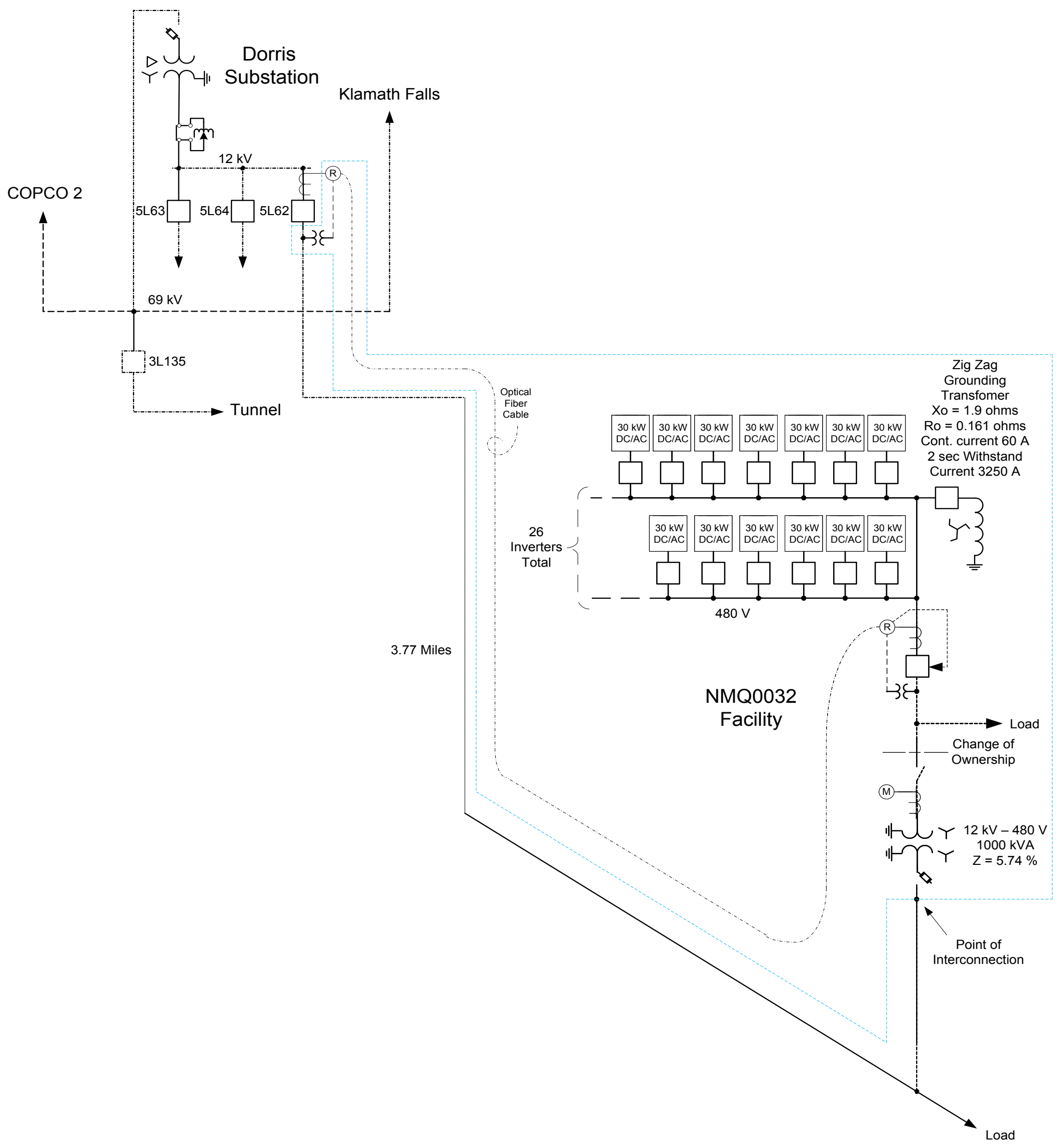


Figure 2: System One Line Diagram

5.4 Existing Breaker Modifications – Short-Circuit

The increase in the fault duty on the system as the result of the addition of the generation facility with photovoltaic arrays fed through 26 – 30 kW inverters connected to a 1000 kVA 12 kV – 480 V transformer with 5.74% impedance will not push the fault duty above the interrupting rating of any of the existing fault interrupting equipment.

5.5 Protection Requirements

The proposed solar electric generation facility will need to disconnect in a high speed manner from the distribution circuit out of Dorris Substation for faults on the 12 kV line. The daytime load on circuit 5L62 out of Dorris Substation can be less than the power output of this facility plus the existing generation on the circuit. As a result, the load to generation unbalance when the generation facility is isolated with the load cannot be relied upon to cause a timely disconnection of the solar facility for faults on the line. 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, the breaker 5L62 has automatic reclosing enabled. The opening of 5L62 will need to trigger the high speed disconnection of the solar facility to permit the successful operation of the automatic reclosing. This will be accomplished by sending a transfer trip signal from Dorris Substation to the solar facility via an optical fiber cable. The installation of the optical fiber cable will be requirement for this project.

The 12 kV circuit's relay for 5L62 will be replaced as part of this project with a relay that can perform the following functions as well are overcurrent functions the existing relay provides:

1) The relay will communicate with the relay at the collector substation to support the transfer trip signal.
2) With the addition of a voltage transformer on the line side of breaker 5L62 the automatic reclose of 5L62 will be delayed until there is indication that the circuit is dead. The delaying of the reclosing operation is so that if for some reason the solar facility is not disconnected in a timely manner due to a delay in receiving or reacting to the transfer trip the customers' equipment on the circuit will not be exposed to potential damage due to the rapid acceleration of the rotating equipment which would result from the reclosing into the energized circuit.

The solar electric generation facility will need to be equipped with a main 480 V breaker that can disconnect all of the inverters and the grounding transformer from the distribution network. The main breaker needs to have stored energy operate capability so that the breaker can be tripped open in a zero AC voltage state. The main breaker needs to be equipped with a SEL relay. A SEL 751 relay would be a good choice. The SEL 751 relay will be configured to perform the following functions:

1. Receive transfer trip from Dorris Substation
2. Detect faults on the 480 V bus at the generation facility
3. Detect faults on the 12 kV line to Dorris Substation

4. Monitor the current through the grounding transformer to protect the transformer from unbalance current conditions on the 12 kV system that are not resolved in a timely matter.
5. Monitor the voltage and react to under or over frequency, and /or magnitude of the voltage

5.6 DATA REQUIREMENTS (RTU)

Due to the small power size of this generation facility no real time data will be required from the generation facility so no RTU will be required there.

5.7 COMMUNICATION REQUIREMENTS

5.7.1 FOR LINE PROTECTION

The Distribution Provider will design, procure, and install an ADSS, 48-fiber, single-mode cable on the 12kV line between Dorris Substation and the collector station. The Distribution Provider will design, procure, and install patch panels to terminate the fiber in the control house at Dorris and the interconnection customer's relay at the collector facility. Jumpers will be installed from the patch panels to the relays' fiber optic modems at both ends. The customer will be responsible for providing DC voltage to the fiber optic modems at the collector site, if necessary.

5.7.2 FOR DATA DELIVERY TO THE CONTROL CENTERS

Since no RTU will be required at the generation facility no communication from the generation facility to the Control Centers will be required.

5.8 SUBSTATION REQUIREMENTS

A 12 kV voltage transformer will be installed on the line side of breaker 5L62.

5.9 METERING REQUIREMENTS

At the point of delivery a bidirectional revenue meter will be programmed and installed on customer supplied service equipment. The customer will need to update the existing 277/480 volt service if it does not meet Electric Service Requirement standards for the load size. The Public Utility will procure, install, test, and own all revenue metering equipment.

The proposed size of the Small Generating Facility will not require additional metering communications or SCADA information.

6.0 COST ESTIMATE

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

Distribution Line Work	$53,000
Fiber Addition	$152,547
Adding VT's & Replacing Relays	$188,880
Install Transfer Trip	$72,935
	$467,362
Total	**$934,724**

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

7.0 SCHEDULE

At this time, it is estimated that the upgrades required to place this project in service could be completed within _________ months of a signed interconnection agreement. Further details regarding the schedule will be available through the Facilities Study when a more detailed estimate has been prepared and lead times for the required equipment have been calculated.
The schedule is driven by the date that the Small Generator Interconnect Agreement is signed. Changes in this date affect the entire schedule.

8.0 PARTICIPATION BY AFFECTED SYSTEMS

No Affected Systems were identified in relation to this Interconnection Request.

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Small Generator Interconnection
System Impact Study Report

Completed for
Porterfield Ranch
("Interconnection Customer")
898 kW Solar Project

Proposed Interconnection
On PacifiCorp's Existing
FP 06148001.0 332000

WO# 45043622

Due: 5/12/17

TABLE OF CONTENTS

1.0 DESCRIPTION OF THE GENERATING FACILITY

Porterfield Ranch ("Interconnection Customer") proposed interconnecting .898 MW of new generation to PacifiCorp's ("Transmission Provider") FP 06148001.0 332000 located in Siskiyou County, CA. The Porterfield Ranch project will consist of 26 ABB inverters with a total AC capacity rating of 780 KW and a total output of .898 MW. The requested commercial operation date is approximately Fall 2017.

Interconnection Customer will not operate this generator as a Qualified Facility as defined by the Public Utility Regulatory Policies Act of 1978 (PURPA).

The Transmission Provider has assigned the project "NMQ033."

2.0 APPROVAL CRITERIA FOR LEVEL 3 INTERCONNECTION REVIEW

Pursuant to R746-312-10(1), A generating facility which meets the following criteria is eligible for Level 3 interconnection review:

(a) the generating facility has a capacity of greater than two megawatts but no larger than 20 megawatts;
(b) the generating facility is not certified; or
(c) the generating facility does not qualify for or failed to meet Level 1 or Level 2 interconnection review requirements.

3.0 SCOPE OF THE STUDY

Pursuant to R746-312-10(2)(f),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:

- provide details on the impacts to the electric distribution system which would result if the generating facility were interconnected without modifications to either the generating facility or to the electric distribution system;
- identify any modifications to the public utility's electric distribution system necessary to accommodate the proposed interconnection;
- focus on power flows and utility protective devices, including control requirements; and
- include the following elements, as applicable:
  a. a load flow study;
  b. a short-circuit study;
  c. a circuit protection and coordination study;
  d. the impact on the operation of the electric distribution system;
  e. a stability study, along with the conditions that would justify including this element in the impact study;
  f. a voltage collapse study, along with the conditions that would justify including this element in the impact study; and
  g. additional elements, if justified by the public utility and approved in writing by the public utility and the interconnection customer prior to the impact study.

4.0 Proposed Point of Interconnection

The proposed generation facility is to be interconnected, through an existing service at Pacific Power map string 06148001.0; facility point 332000.

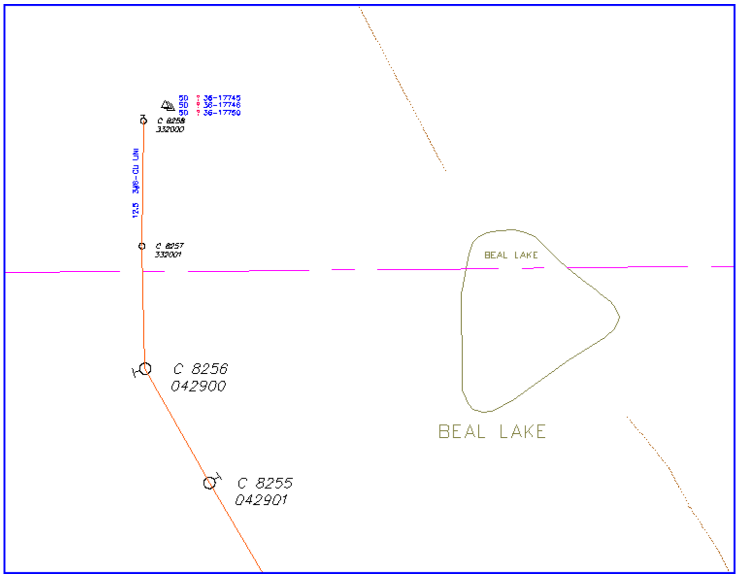


Figure 1: System Map

4.1 Study Assumptions

- All active higher priority transmission service and/or generator interconnection requests will be considered in this study and are listed in Appendix 1. If any of these requests are withdrawn, the Transmission Provider 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, network upgrades required to provide delivery will only be modeled for projects which have requested network resource integration service only or qualified facility status. 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 Transmission Provider's system at the agreed upon and/or proposed point of interconnection.
- The Interconnection Customer will construct and own the any facilities required between the point of interconnection and the Project.
- Generator tripping may be required for certain outages.
- All facilities will meet or exceed the minimum WECC, NERC, and Transmission Provider performance and design standards.
- The generator is expected to operate 12 hours per day 7 days per week 12 months per year. The primary meter (point of interconnection) power factor range studied was 100 % leading prior to the proposed generation facility being installed.
- This interconnection was studied with the assumption that the interconnection request NMQ0032 would be interconnected in conjunction with NMQ0033. The Level 3 System Impact Study for NMQ0032 was done under the assumption that it would be interconnected prior to NMQ0033. For both generation projects to be interconnected, the requirements of this study must be completed.
- This report is based on information available at the time of the study. It is the Interconnection Customer's responsibility to check the Transmission Provider's web site regularly for transmission system updates (http://www.pacificorp.com/tran.html)

Four case studies were assembled and studied:

1. Feeder 5L62 with typical summer peak loading levels. Analysis was performed at full generation, partial generation, and no generation by the Interconnection Customer, as well as with full generation and no generation by all other interconnection customers connected to feeder 5L62.
2. Feeder 5L62 with typical winter peak loading levels. Analysis was performed at full generation, partial generation, and no generation by the Interconnection Customer, as well as with full generation and no generation by all other interconnection customers connected to feeder 5L62.
3. Feeder 5L62 with typical spring/summer minimum daytime loading levels. Analysis was performed at full generation, partial generation, and no generation by the Interconnection Customer, as well as with full generation and no generation by all other interconnection customers connected to feeder 5L62.
4. Feeder 5L62 with typical winter minimum daytime loading levels. Analysis was performed at full generation, partial generation, and no generation by the Interconnection Customer, as well as with full generation and no generation by all other interconnection customers connected to feeder 5L62.

5.0 RESULTS

5.1 GENERATING FACILITY MODIFICATIONS

The Interconnection Customer shall design its generating facility to operate reactive compensation, typically located at the collector station, under voltage control mode with the voltage sensed electrically at the point of interconnection, and to have sufficient reactive capacity to enable the facility to deliver 100 percent of the plant output to the point of interconnection at unity power factor measured at 1.0 per unit voltage.

The voltage control shall be designed to include a voltage control band, nominally set to 1.01 and 1.04 per unit (actual voltage band may be adjusted depending on typical voltage at the interconnection or other area local conditions), such that if the actual voltage is above the upper band setting, capacitor increments will be automatically removed and if the actual voltage is below the lower band setting, capacitor increments will be automatically be added. The control scheme should be designed so as to avoid hunting when switching between modes (i.e., effectively power factor control inside the band, voltage control outside the band). Inside the voltage bandwidth, the facility shall operate as much as possible to a unity power factor. Settings must be coordinated with the Transmission Provider who may, from time to time, request changes in response to operating conditions or actual operating experience. The reactive compensation must be designed such that the capacitor switching does not cause step voltage changes greater than +/-3% on the Transmission Provider's system.

A grounding transformer as specified by the generation customer will be required for this project. The impedance of the transformer, Xo = 1.9 ohms and Ro = 0.161 ohms, would be adequate. The continuous current rating of 60 A would also be adequate. Based on our fault study the 2-second withstand current rating of 1010 A will not be adequate. For a transformer of the specified impedance for this application will need to have a 2-second withstand current rating of 3500 A. A transformer with higher impedance would also be adequate and the higher impedance would lower the needed withstand current rating requirement.

5.2 PROPERTY REQUIREMENTS FOR TRANSMISSION PROVIDER'S POINT OF INTERCONNECTION SUBSTATION

The following applies to property acquired by an Interconnection Customer on which a point of interconnection substation will be built to accommodate the Interconnection Customer's project. The property will ultimately be assigned to PacifiCorp, the Transmission Provider.

- Property must be environmentally, physically and operationally acceptable to PacifiCorp without any material defects of title (or as deemed acceptable to PacifiCorp) and without unacceptable encumbrances. The property shall be a permitted or permittable use in all zoning districts. Property lines shall be surveyed and show all encumbrances, roads (private or public); easements (prescriptive or express) etc.
- Examples of potentially unacceptable environmental, physical, or operational conditions:
  - Environmentally unacceptable conditions could include but are not limited to known contamination of site; evidence of environmental contamination by any dangerous, hazardous or toxic materials as defined by any governmental agency; property is in violation of building, health, safety, environmental, fire, land use, zoning or other such regulation, ordinances, or statues of any governmental entities having jurisdiction over the property; underground or above ground storage tanks;

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

5.3 DISTRIBUTION/TRANSMISSION MODIFICATIONS

5.3.1 LOAD FLOW STUDY

The existing transformer bank supplying this installation has a transformation capacity of 150 kVA. The total transformation required to accommodate NMQ0032 and NMQ0033 will be 1796 kVA. The transformer capacity will be required to be increased to accommodate this generation. The available PacifiCorp standard transformer is a pad mount, three phase, 2500 kVA transformer. A primary underground extension will be required to accommodate this installation.

The addition of this generation will cause the aggregate generation interconnected to feeder 5L62 to be 1819 kW. The minimum daytime load during winter conditions is 207 kW. The aggregate generation will be greater than 10% of the minimum daytime load and it will be required that the generation be effectively grounded. NMQ0032 required that a neutral extension using #2 ACSR of approximately 11,300 feet from facility point 06148001.0-320061 to 06148001.0-332000 be completed prior to interconnection. NMQ0033 will require reconductoring of the line as specified in the Stability Study and #2 ACSR will not be sufficient. The correct neutral size is specified in the Stability Study.

Feeder circuit breaker 5L62 will experience reverse power flow during summer minimum daytime load conditions and all winter loading conditions. It will be required that the Protection and Control department evaluate the impacts of the reverse power flow.

Feeder 5L62 will experience voltage levels above ANSI range A during winter loading conditions and during summer minimum loading conditions between facility point 06147001.0-058660 and 06147001.0-113300. It will be required to re-conductor the existing #6 Cu, uni-ground with #4/0 AAC, #4/0 AAC neutral from facility point 06147001.0-043401 to 06148001.0-332000. This re-conductor will be approximately 3660 feet with limited access.

Feeder 5L62 will experience voltage above ANSI Range A during winter loading conditions and summer minimum daytime loading conditions while the 1200 kVAR capacitor bank at FP 06147001.0-112361 is online. 5L62 will also experience voltage conditions below ANSI Range A during summer minimum daytime loading conditions with the 1200 kVAR capacitor bank at FP 06147001.0-112361 offline. The NMQ0032 System Impact Study required that the existing 1200 kVAR, fixed capacitor bank at facility point 06147001.0-112361 be replaced with a 900 0kVAR, switched capacitor bank. It will be required to replace the capacitor bank to accommodate NMQ0033.

5.3.2 *Short Circuit Study*

It is expected that NMQ0033 will be capable of contributing up to 144 A to a short circuit condition. The results of this study are dependent on the line re-conductor work being complete as specified in the Stability Study. At the point of interconnection, the maximum available fault current is 1245 A. NMQ0033 will be capable of contributing up to 11.5% of the available fault current. Any concerns due to the available fault current from the generation are addressed by the system upgrades required by the Circuit Protection and Coordination Study.

5.3.3 *Circuit Protection and Coordination Study*

The existing 40T fuses at facility point 06147001.0-043401 are rated for a continuous current of 40 A. The expected current during full generation by NMQ0032 and NMQ0033 and no load conditions is 75 A. It will be required to replace the 40T fuses at facility point 06147001.0-043401 with 100T fuses.

The existing 100T fuses at facility point 06148001.0-320062 are upstream of the existing fuses at facility point 06147001.0-043401 and will not coordinate with the 100T fuses that will be installed. It will be required to install 140T fuses at facility point 06148001.0-320062.

The existing relay settings for feeder breaker 5L62 will not allow for downstream coordination with fuses sizes larger than 100T. It will be required to update the DPU-2000 relay at Dorris substation for feeder breaker 5L62 with new phase and ground current pickup values and time dial values for feeder protection coordination.

The installation of a 2500 kVA, pad mount transformer typically requires a 140T fuse to coordinate with the 125HA bayonet fuse in the transformer. It will be acceptable to install 100T fuses feeding the primary between facility point 06148001.0-332000 and the new 250 kVA transformer. There will be an accepted miscoordination between the 100T fuses at facility point 06147001.0-043401 and 06148001.0-332000. This is a tap line off of the main line and is dedicated to the interconnection customer. In the event of a fault downstream of either of these fuses, the interconnection customer will be taken off-line and no other customer will be affected.

5.3.4 Stability Study

A stability study was performed to determine the effects of the sudden loss of generation due to system or weather conditions. It is PacifiCorp's policy that voltage fluctuations lasting longer than 10 seconds be limited to 3%.

- During summer peak conditions, the voltage fluctuation caused by the sudden disconnection of NMQ0032 and NMQ0033 will cause a 3.3% voltage change at the point of interconnection.
- During summer MDTL conditions, the voltage fluctuation caused by the sudden disconnection of NMQ0032 and NMQ003 will cause a 3.1% voltage change at the point of interconnection.
- During winter peak conditions, the voltage fluctuation caused by the sudden disconnection of NMQ0032 and NMQ003 will cause a 3.1% voltage fluctuation at the point of interconnection.
- During winter MDTL conditions, the voltage fluctuation caused by the sudden disconnection of NMQ0032 and NMQ003 will cause a 3.1% voltage fluctuation at the point of interconnection.

Due to these voltage fluctuations, it will be required to re-conductor the existing #4 Cu and #2 ACSR beginning at facility point 06148001.0-320061 to 06147001.0-043401 with #1/0 AAAC, #1/0 neutral. This re-conductor will cross agricultural fields and high grade terrain with limited access.

- Install 2500 kVA pad mount transformer with primary underground extension from facility point 06148001.0-332000. Install 100T fuses to underground riser.
- NMQ0033 will be required to be effectively grounded.
- 5L62 will experience reverse power flow during summer minimum daytime load conditions and all winter loading conditions.

- Re-conductor the existing #6 Cu, uni-ground with #4/0 AAC, #4/0 neutral from facility point 06147001.0-043401 to 06148001.0-332000.
- The existing 1200 kVAR, fixed capacitor bank at facility point 06147001.0-112361 is to be replaced with a 900 kVAR, switched capacitor bank.
- Replace the 40T fuses at facility point 06147001.0-043401 with 100T fuses.
- Replace the 100T fuses at facility point 06148001.0-320062 with 140T fuses.
- Update the DPU relay at Dorris substation for feeder breaker 5L62 with new phase and ground current pickup values and time dial values.
- Re-conductor the existing #4 Cu and #2 ACSR beginning at facility point 06148001.0-320061 to 06147001.0-043401 with #1/0 AAAC, #1/0 neutral.

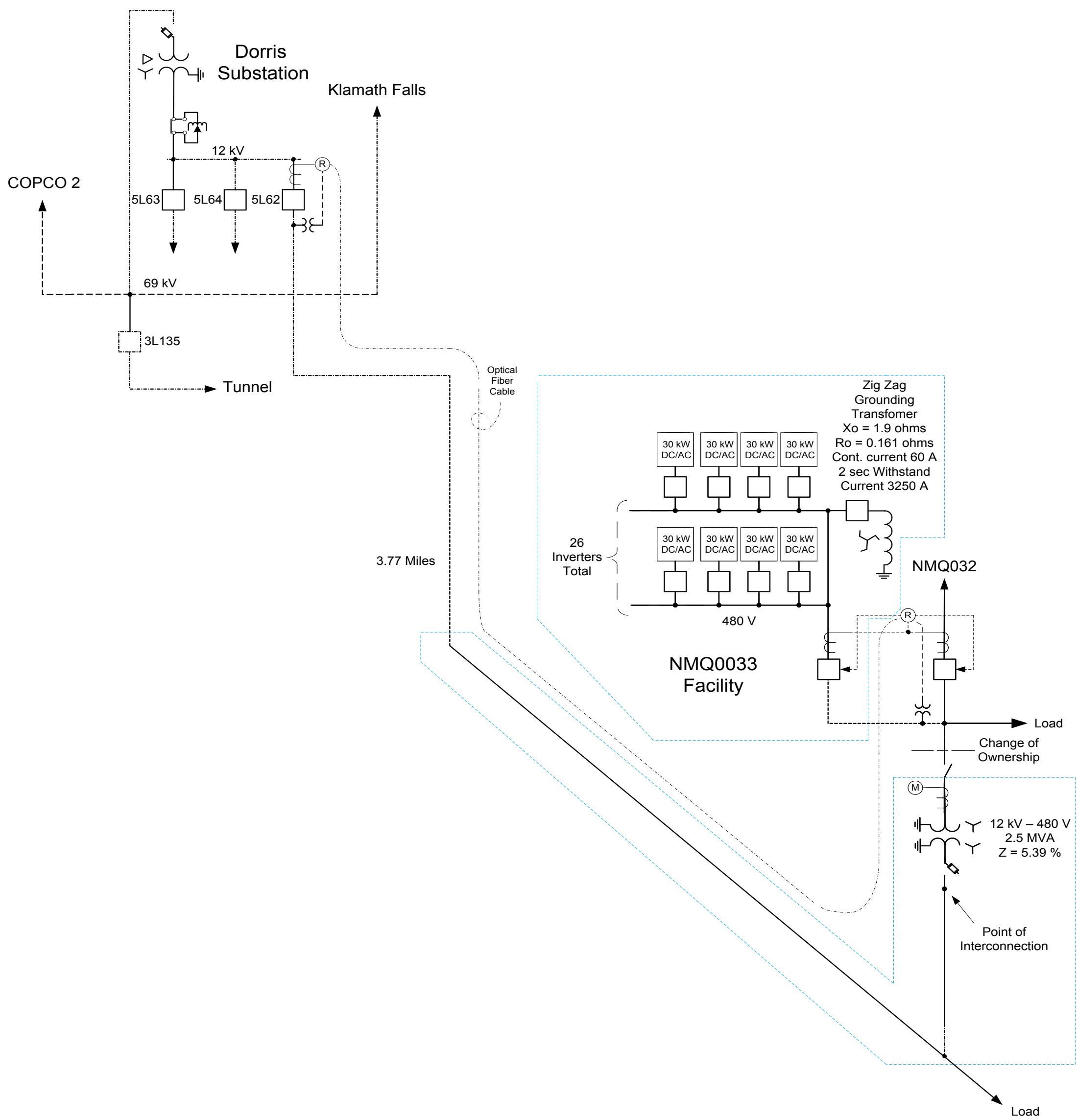


Figure 2: System One Line Diagram

5.4 Existing Breaker Modifications – Short-Circuit

The increase in the fault duty on the system as the result of the addition of the generation facility with photovoltaic arrays fed through 26 – 30 kW inverters connected to a 2.5 MVA 12 kV – 480 V transformer with 5.74% impedance along with the generation facility planned for NMQ032 will not push the fault duty above the interrupting rating of any of the existing fault interrupting equipment.

5.5 Protection Requirements

The proposed solar electric generation facility will need to disconnect in a high speed manner from the distribution circuit out of Dorris Substation for faults on the 12 kV line. The daytime load on circuit 5L62 out of Dorris Substation can be less than the power output of this facility plus the existing generation on the circuit. As a result, the load to generation unbalance when the generation facility is isolated with the load cannot be relied upon to cause a timely disconnection of the solar facility for faults on the line. 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, the breaker 5L62 has automatic reclosing enabled. The opening of 5L62 will need to trigger the high speed disconnection of the solar facility to permit the successful operation of the automatic reclosing. This will be accomplished by sending a transfer trip signal from Dorris Substation to the solar facility via an optical fiber cable. The installation of the optical fiber cable for the transfer trip is assumed to have been installed for the NMQ032 project which is at the same location but prior to this project in the Distribution Provider's Generation Interconnection queue.

The 12 kV circuit's relay for 5L62 will have been replaced as part of the NMQ032 project. The relay and the other work planned for Dorris Substation as part of the NMQ032 project will meet the requirements for this project. The relay will perform the following functions in addition to overcurrent and reclosing functions:

1) The relay will communicate with the relay at the collector substation to support the transfer trip signal.
2) With the addition of a voltage transformer on the line side of breaker 5L62 the automatic reclose of 5L62 will be delayed until there is indication that the circuit is dead. The delaying of the reclosing operation is so that if for some reason the solar facility is not disconnected in a timely manner due to a delay in receiving or reacting to the transfer trip the customers' equipment on the circuit will not be exposed to potential damage due to the rapid acceleration of the rotating equipment which would result from the reclosing into the energized circuit.

The solar electric generation facility will need to be equipped with a main 480 V breaker that can disconnect all of the inverters and the grounding transformer from the distribution network. The main breaker needs to have stored energy operate capability so that the breaker can be tripped open in a zero AC voltage state. The main breaker required for the NMQ032 project, which is earlier in the Distribution Provider's Generation Interconnection queue, will be equipped with a SEL relay. That same SEL 751 relay will need to be connected to the paralleled combination of the output from current transformers (CTs) from both of the main breakers for the two solar electric generation projects. The one relay will trip both main breakers and will perform the following functions:

1. Receive transfer trip from Dorris Substation
2. Detect faults on the 480 V bus at the generation facility
3. Detect faults on the 12 kV line to Dorris Substation
4. Monitor the current through the grounding transformer to protect the transformer from unbalance current conditions on the 12 kV system that are not resolved in a timely manner.
5. Monitor the voltage and react to under or over frequency, and /or magnitude of the voltage

5.6 DATA REQUIREMENTS (RTU)

Due to the small power size of this generation facility no real time data will be required from the generation facility so no RTU will be required there.

5.7 COMMUNICATION REQUIREMENTS

5.7.1 FOR LINE PROTECTION

The Transmission Provider installed an ADSS optical fiber cable between Dorris Substation and the solar electric generation facility for the NMQ032 project. That same optical fiber cable will be used for this project. Fiber jumpers will be installed from the existing patch panels to the relays used for this project.

5.7.2 FOR DATA DELIVERY TO THE CONTROL CENTERS

Since no RTU will be required at the generation facility no communication from the generation facility to the Control Centers will be required.

5.8 SUBSTATION REQUIREMENTS

A 12 kV voltage transformer will be installed on the line side of breaker 5L62.

5.9 METERING REQUIREMENTS

At the point of delivery a bidirectional revenue meter will be programmed and installed on customer supplied service equipment. The customer will need to update the existing 277/480 volt service if it does not meet Electric Service Requirement standards for the load size. The Public Utility will procure, install, test, and own all revenue metering equipment.

The proposed size of the Small Generating Facility will not require additional metering communications or SCADA information.

6.0 COST ESTIMATE

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

Distribution Line Work and Reconductoring	$735,000
Modify Communications	$20,304
Install Transfer Trip	$43,151
Total	**$798,455**

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

7.0 Schedule

At this time, it is estimated that the upgrades required to place this project in service could be completed within _________ months of a signed interconnection agreement. Further details regarding the schedule will be available through the Facilities Study when a more detailed estimate has been prepared and lead times for the required equipment have been calculated.

The schedule is driven by the date that the Small Generator Interconnect Agreement is signed. Changes in this date affect the entire schedule. Please note that this timeframe [does/ does not] support the Interconnection Customer's requested in-service date of _____________, 20__.

8.0 Participation by Affected Systems

No Affected Systems were identified in relation to this Interconnection Request.

PUBLIC UTILITY COMMISSION

OF

OREGON

SUNTHURST EXHIBIT 403

PacifiCorp System Impact Study Reports for OCS045 and OCS047

FEBRUARY 22, 2021

PACIFICORP

Community Solar Project Interconnection
Community Solar Project System Impact Study Report

Completed for

(“Applicant”)
OCS045

Proposed Point of Interconnection
Circuit 5D5 out of Culver substation at 12.5 kV
(Approximately 44.487442°N, 121.249867°W)

January 8, 2021

TABLE OF CONTENTS

1.0 DESCRIPTION OF THE COMMUNITY SOLAR PROJECT

(“Applicant”) proposed interconnecting 2.875 MW of new generation to PacifiCorp’s (“Public Utility”) circuit 5D5 out of Culver substation located in Jefferson County, Oregon. The project (“Project”) will consist of twenty-three Solectria XGI 1500 125 kV inverters for a total requested nameplate output of 2.875 MW. The requested commercial operation date is October of 2021.

The Public Utility has assigned the Project “OCS045.”

2.0 APPROVAL CRITERIA FOR TIER 4 INTERCONNECTION REVIEW

Pursuant to the Section I(1) of the Public Utility’s CSP Interconnection Procedures, a Public Utility must use the Tier 4 review procedures for an application to interconnect a Community Solar Project that meets the following requirements:

(a) The Community Solar Project does not qualify for or failed to meet Tier 2 review requirements; and

(b) The Community Solar Project must have a nameplate capacity of three (3) megawatts or less.

3.0 SCOPE OF THE STUDY

Pursuant to Section I(6)(g) of the CPS Interconnection Procedures, the System Impact Study Report shall consist of: (1) the underlying assumptions of the study; (2) a short circuit analysis; (2) a stability analysis; (3) a power flow analysis; (4) voltage drop and flicker studies; (5) protection and set point coordination studies; (6) grounding reviews; (7) the results of the analyses; and (8) any potential impediments to providing the requested Interconnection Service, including a non-binding informational NRIS portion that addresses the additions, modifications, and upgrades to the Public Utility’s Transmission System that would be required at or beyond the point at which the Interconnection Facilities connect to the Public Utility's Transmission System to accommodate the interconnection of the CSP Project In addition, the System Impact Study shall provide a list of facilities that are required as a result of the Community Solar Project request and non-binding good faith estimates of cost responsibility and time to construct.

4.0 PROPOSED POINT OF INTERCONNECTION

The Applicant’s proposed Community Solar Project is to be interconnected to the Public Utility’s distribution circuit 5D5 out of Culver substation via a 12.47 kV primary meter. The proposed Point of Interconnection (“POI”) will be located at approximately 44.487442°N, 121.249867°W located in Jefferson County, Oregon. Figure 2 below is a one line diagram that illustrates the interconnection of the proposed generating facility to the Public Utility’s system.

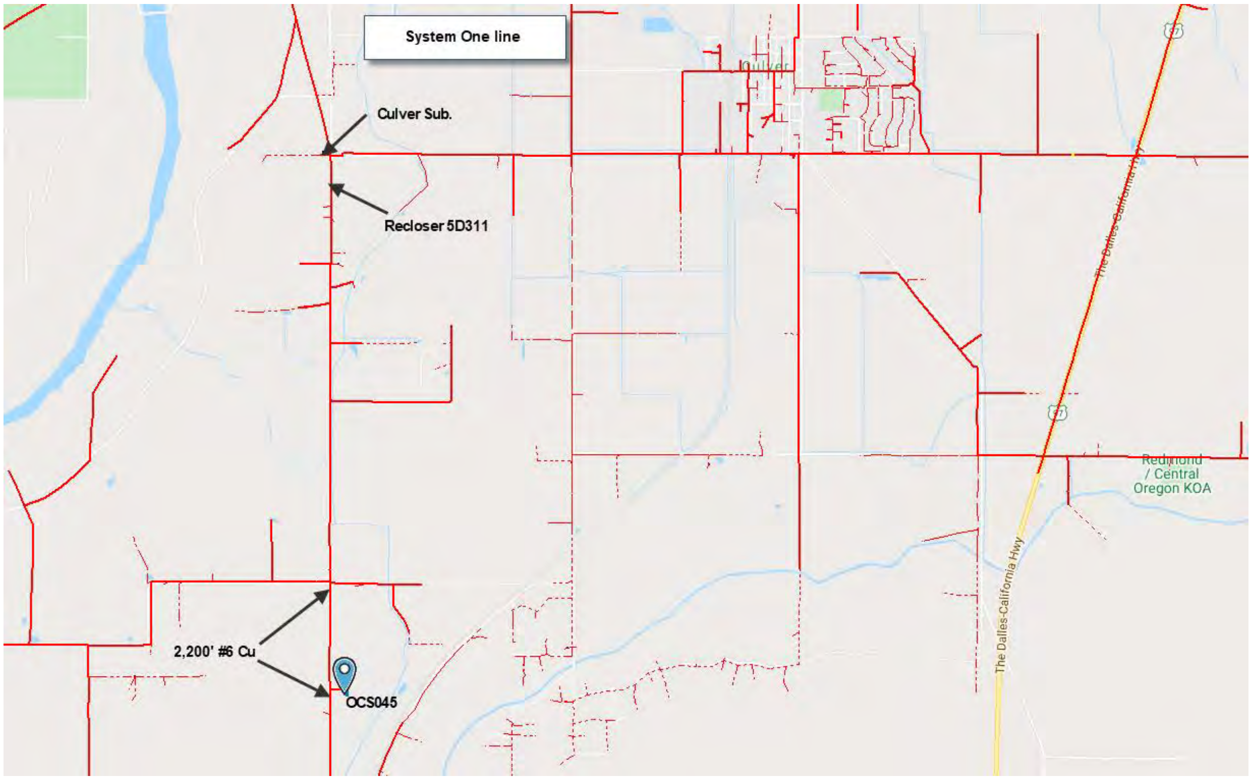


Figure 1: System Map

5.0 STUDY ASSUMPTIONS

- All active higher-priority requests for transmission service and/or generator interconnection service (including requests in the traditional interconnection queue and other requests in the Community Solar queue) in the local area of the requested POI 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.
- The Applicant'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 POI.
- The Applicant 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 Applicant'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.

- This report is based on the Preliminary One-Line (drawing E-1, Revision A) for the “” project, provided by the Customer and dated 09-23-2020
- Existing and queued generation on this line is expected to result in export to the 69 kV and 230 kV buses at Cove substation for much of the 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 the 69 kV transmission sourced from Cove substation.
  - Case 2: Contingency configuration with the 69 kV transmission sourced from Redmond substation (switch 3D85 closed at Crooked River tap; switch 3D27 open at Culver substation)
  - Case 3: Contingency configuration with one 230-69 kV transformer or one 230 kV transmission line out of service at Cove
- This report is based on information available at the time of the study. It is the Applicant’s responsibility to check the Public Utility’s web site regularly for transmission system updates (https://www.oasis.oati.com/ppw)

6.0 REQUIREMENTS

6.1 COMMUNITY SOLAR PROJECT REQUIREMENTS

The Community Solar Project and Interconnection Equipment owned by the Applicant are required to operate under automatic voltage control with the voltage sensed electrically at the POI. The Community Solar Project should have sufficient reactive capacity to enable the delivery of 100 percent of the plant 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 voltage drop are required to do so. Studies will be required to coordinate the voltage droop setting with other facilities in the area. In general, the Community Solar Project 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 Community Solar Project should operate so as to minimize the reactive interchange between the Community Solar Project and the Public Utility’s system (delivery of power at the POI at approximately unity power factor). The voltage control settings of the Community Solar Project 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 Applicant) 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 Community Solar Project.

The Applicant will be required to install a transformer that will hold the phase to neutral voltages within limits when the Community Solar Project is isolated with the Distribution Provider's local system until the generation disconnects. The circuit that the project is connecting to is a four wire multi-grounded circuit with line to neutral connected load. The documentation supplied by the Applicant showed using a 200 kVA wye – delta grounding transformer with an impedance of 5.0%. Base on the Distribution Provider's calculation a transformer of that size and impedance would supply more than 25 times the transformer rating in current for a single line to ground fault on the 12.47 kV system. There is a concern that a transformer of that size and impedance would be damaged for a close in line fault. It is recommended that a 200 kVA transformer with 5.5% impedance be used.

6.2 TRANSMISSION SYSTEM MODIFICATIONS

The wood poles along the length of the Distribution reconductor portion (structures 11/18 – 21/18, excluding 12/18) will be replaced with 50ft Class 1 TF100 structures to accommodate the upgraded distribution conductor and new ADSS.

6.3 DISTRIBUTION/TRANSMISSION LINE MODIFICATIONS

Public Utility will rebuild approximately 2,200 feet of existing three phase #6 copper distribution with 4/0 Al conductor. The line rebuild will start at pole 1412012.0-359961 and end at pole 359560. This makes the assumption that the primary meter tap line will be just to the north of pole 359560, based on the site plan that was provided. Remove 100T line fuses at pole 359961 as part of the line rebuild and install 100T line fuses at pole 359560. Construct a short tap line east to the generation site primary meter. Exact location has not been determined but the Public Utility assumes from the site plan this tap line will be 100 to 600 feet in length.

The 69-12.5 kV regulator at Culver substation will require settings adjustments to ensure that customers on the line remain within ANSI A and B voltage range for all loading conditions.

Under the normal configuration and the contingency configurations identified for this study, there are no identified power flow restrictions with OCS045 generation online.

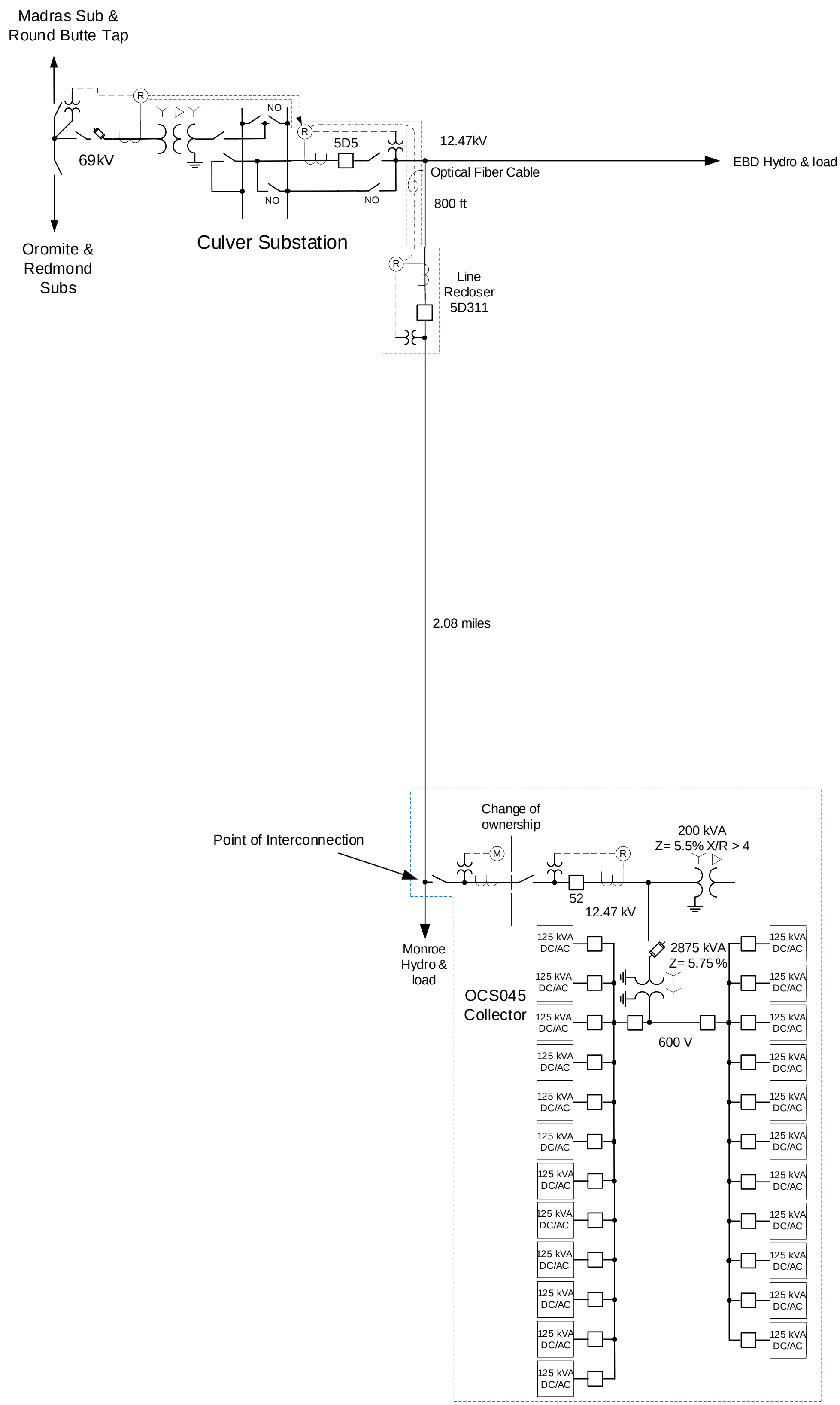


Figure 2: System One Line Diagram

6.4 Existing Breaker Modifications – Short-Circuit

The increase in the fault duty on the system as the result of the addition of the Community Solar Project with photovoltaic arrays fed through 23 – 125 kW inverters connected to 1 – 2.875 MVA 12.47 kV – 600 V transformer with 5.75 % impedance will not push the fault duty above the interrupting rating of any of the existing fault interrupting equipment.

6.5 Protection Requirements

The OCS045 Community Solar Project will need to disconnect from the network in a high-speed manner for faults on the 12.47 kV line on circuit 5D5 out of Culver substation, on the 69 kV transmission network feeding Culver substation or in the 69 – 12.47 kV transformer. There are existing generation plants on the circuit that has required the addition of relays to be installed at Culver substation to detect faults on the 69 kV transmission system or in the 69 – 12.47 kV transformer at Culver substation and send transfer trip to the generation plant. The OCS045 project will also need to receive this transfer trip signal from Culver substation.

The OCS045 Community Solar Project will be beyond a line recloser located 800 feet south of Culver substation. The Community Solar Project will need to disconnect in a high-speed manner for the operation of the line recloser. Frequently during light load and peak generation conditions with the addition of the OCS045 project approximately 2 MW of reverse power flow will occur at the line recloser. Most faults on overhead distribution lines are temporary so that once all sources of fault current have been disconnected the line recloser can automatically close restoring the service to the customers. Since the unbalance between the islanded load and generation cannot be relied upon to cause high speed disconnection of the Community Solar Project, transfer trip circuits will need to be installed between Culver substation, line recloser 5D311 and the POI recloser for the OCS045 Community Solar Project. A communication system will be required to carry the transfer trip circuits.

Modifications will be done to the existing relays at Culver Substation to key the transfer trip to the OCS045 POI recloser for detection of faults on the 69 kV system, in the 69-12.47 kV transformer, on the 12.47 kV circuit or the opening of the line recloser 5D311.

The 12.47 kV circuit recloser planned to be installed at the OCS045 project will need to equipped Schweitzer Engineering Laboratories (SEL) 651R relay/controller and voltage instrument transformers mounted on the utility side of the circuit recloser. The 651R will perform the following protection functions:

1. Detect faults on the 12.47 kV equipment at the solar-electric Community Solar Project
2. Detect faults on the 12.47 kV line to Culver Substation
3. Monitor the unbalance current flowing through the grounding transformer and protect the transformer from damage due to phase unbalances on the 12.47 kV circuit
4. Monitor the voltage and react to under or over frequency, and /or magnitude of the voltage

5. Receive transfer trip from Culver Substation

6.6 DATA REQUIREMENTS (RTU)

Due to the power size of the Community Solar Project no real time monitoring will be required by the Public Utility for the operation of the transmission network so no RTU will be required.

At Culver Substation the alarm from the field recloser as to the health of the radio system will be monitored by the existing RTU.

6.7 COMMUNICATION REQUIREMENTS

A single-mode ADSS optical fiber cable will be installed between line recloser 5D311 and Culver substation. A SEL radio system will be installed between Culver substation and the OCS045 POI recloser. These systems will carry the transfer trip circuits between three locations. The radios, fiber transceivers, and patch panels will be mounted in cabinets at the recloser and the customer's facility.

6.8 SUBSTATION REQUIREMENTS

Install concrete capped conduits to accommodate new fiber within the substation yard.

6.9 METERING REQUIREMENTS

<u>Interchange Metering</u>

The metering will be located on the high side of the customer generator step up transformer at the POI. An overhead metering setup is assumed for this study. The metering transformers will be installed overhead on a pole per distribution DM construction standards. The meter itself will be installed at the base of the pole. The Public Utility will procure, install, test, and own all revenue metering equipment. The metering will be bi-directional to measure KWH and KVARH quantities for both generation received and back feed retail load delivered. There will be no additional station service metering for supplying generation load. The metering generation and billing data will be remotely interrogated via the Public Utility's MV90 data acquisition system.

<u>Station Service/Construction Power</u>

The Applicant must arrange distribution voltage retail meter service for electricity consumed by the project when not generating. Temporary construction power metering shall conform to the Six State Electric Service Requirements manual. Applicant must call the PCCC Solution Center 1-800-640-2212 to arrange this service. Approval for back feed is contingent upon obtaining station service.

7.0 COST ESTIMATE

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

OCS045 Collector Station $111,000

Install metering, communications and develop relay settings

Culver Substation *Install communications and modify line relays*	$64,000
Recloser 5D311 *Install communications*	$42,000
Distribution *Line extension, line reconductor, pole replacements, replace recloser*	$307,000
Communications *Install ~900 feet of fiber*	$13,000
Total	**$537,000**

*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 Applicant may request that the Public Utility perform this field analysis, at the Applicant'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 Applicant 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 Community Solar Project to Public Utility's electrical distribution or transmission system. An estimate, based on finer detail, will be calculated during the Facilities Study. The Applicant will be responsible for all actual costs, regardless of the estimated costs communicated to or approved by the Applicant.

8.0 SCHEDULE

The Public Utility estimates it will require approximately 15-18 months to design, procure and construct the facilities described in this report following the execution of an Interconnection Agreement. The schedule will be further developed and optimized during the Facilities Study.

Please note, the time required to perform the scope of work identified in this report appears to result in a timeframe that does not support the Applicant's requested commercial operation date of October of 2021

9.0 PARTICIPATION BY AFFECTED SYSTEMS

Public Utility has identified the following Affected Systems: Portland General Electric and Bonneville Power Administration

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

10.0 APPENDICES

Appendix 1: Higher Priority Requests
Appendix 2: Informational Network Resource Interconnection Service Assessment
Appendix 3: Property Requirements

10.1 Appendix 1: Higher Priority Requests

All active higher priority transmission service and/or generator interconnection and Community Solar Project 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/Community Solar Queue Requests considered:

Queue #	Size (MW)
TCS-43	40
TCS-44	80
TCS-45	40
TCS-46	80
TCS-51	9
TCS-52	20
TCS-53	20
TCS-54	40
OCS001	1.46
OCS002	0.9

PGE:

- 17-068; 65 MW. Requested ISD 12/31/2019.
- 19-080; 80 MW. Requested ISD 12/31/2023.
- 19-081; 53 MW. Requested ISD 12/31/2022.

10.2 APPENDIX 2: INFORMATIONAL NETWORK RESOURCE INTERCONNECTION SERVICE ASSESSMENT

The study results described above reflect an energy resource interconnection service ("ERIS") evaluation, modified in the CSP program rules to examine only generation and load conditions local to the requested CSP project's interconnection point (sometimes referred to as the "zoomed in view"). The "zoomed in view" functions to: (1) study the project's proposed interconnection without considering certain existing or higher-queued requests outside of the local area; and (2) to inform whether the CSP facility must cap its project to mitigate, although not eliminate, the risk of potential deliverability-related network upgrades to accommodate the proposed CSP generator.

By contrast, the following informational section provides a network resource interconnection service ("NRIS") evaluation performed with traditional assumptions, i.e., not modified to examine only local generation and load conditions, but rather one that assumes that all existing interconnections, higher-queued requests for interconnection service (in both the traditional and CSP queue), and generators with executed contracts beyond the local area are in-service. Depending on the severity of the conditions created when absorbing additional generation (capped or not capped) in that broader, "zoomed out" area, the local area-focused generator size cap developed in the "zoomed in" examination may not be sufficient to mitigate the need for deliverability-related network upgrades. Regardless of this report's informational NRIS results, the deliverability-related network upgrades ultimately necessary to accommodate the proposed CSP generator will depend on conditions present when the future transmission service study is performed, as well as whether network upgrade alternatives are available at that time.

There are currently a significant number of higher-queued requests seeking interconnection in the central Oregon area where the CSP generator proposes to interconnect. These interconnection studies must be completed before the transmission provider can determine what upgrades and associated cost estimates may be required for the aggregate of generation in the local area to be delivered to the aggregate of load on the transmission provider's transmission system (the NRIS study scope).

10.3 Appendix 3: Property Requirements

Requirements for rights of way easements
Rights of way easements will be acquired by the Applicant 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. Applicant 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 Applicant to accommodate the Applicant's project. The real property must be acceptable to Public Utility. Applicant 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 Applicant 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 Applicant 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.

Applicant 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 Applicant 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 Applicant to procure various studies and surveys as determined necessary by Public Utility.

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

10.4 APPENDIX 4: TRANSMISSION/DISTRIBUTION STUDY RESULTS

The following study results were observed for a power flow study of the affected system:

Assumption:

- Culver 3 MW proposed capacitor is in service on the unregulated 12.5 kV bus

Case 1: Normal Configuration

No power flow restrictions were identified.

Minimum daytime loads in the Madras area are less than the sum of all queued and in-service generation year-round. Thus, for much of the year generation at any level is likely to result in export through the 230 kV bus at Cove.

Voltages and post transient voltage steps are projected in power flow simulation to remain within permissible limits during the interruption of the OCS045 generation in the Public Utility's normal transmission configuration for all load levels.

Case 2: Contingency configuration with the 69 kV transmission sourced from Redmond substation (switch 3D85 closed at Crooked River tap; switch 3D27 open at Culver substation)

No power flow restrictions were identified.

Voltages and post transient voltage steps are projected in power flow simulation to remain within permissible limits during the interruption of the OCS045 generation in this contingency configuration for all load levels.

Case 3: Contingency configuration with one 230-69 kV transformer or one 230 kV transmission line out of service at Cove:

No power flow restrictions were identified.

Voltages and post transient voltage steps are projected in power flow simulation to remain within permissible limits during the interruption of the OCS045 generation in this contingency configuration for all load levels.

PACIFICORP

Community Solar Project Interconnection
Community Solar Project System Impact Study Report

Completed for

(“Applicant”)
OCS047

Proposed Point of Interconnection
Circuit 5L54 out of Lakeport substation at 12.0 kV
(At approximately 42°16’49.7”N, 121°48’44.5’W)

January 4, 2020

TABLE OF CONTENTS

1.0 DESCRIPTION OF THE COMMUNITY SOLAR PROJECT

("Applicant") proposed interconnecting 2.25 MW of new generation to PacifiCorp's ("Public Utility") circuit 5L54 out of Lakeport substation located in Klamath County, Oregon. The project ("Project") will consist of eleven (11) Delta M125HV inverters factory de-rated to 118 kW and eight (8) Delta M125HV inverters factory de-rated to 119 kW for a total requested nameplate output of 2.25 MW. The requested commercial operation date is November 30, 2021.

The Public Utility has assigned the Project "OCS047."

2.0 APPROVAL CRITERIA FOR TIER 4 INTERCONNECTION REVIEW

Pursuant to the Section I(1) of the Public Utility's CSP Interconnection Procedures, a Public Utility must use the Tier 4 review procedures for an application to interconnect a Community Solar Project that meets the following requirements:

(a) The Community Solar Project does not qualify for or failed to meet Tier 2 review requirements; and
(b) The Community Solar Project must have a nameplate capacity of three (3) megawatts or less.

3.0 SCOPE OF THE STUDY

Pursuant to Section I(6)(g) of the CPS Interconnection Procedures, the System Impact Study Report shall consist of: (1) the underlying assumptions of the study; (2) a short circuit analysis; (2) a stability analysis; (3) a power flow analysis; (4) voltage drop and flicker studies; (5) protection and set point coordination studies; (6) grounding reviews; (7) the results of the analyses; and (8) any potential impediments to providing the requested Interconnection Service, including a non-binding informational NRIS portion that addresses the additions, modifications, and upgrades to the Public Utility's Transmission System that would be required at or beyond the point at which the Interconnection Facilities connect to the Public Utility's Transmission System to accommodate the interconnection of the CSP Project In addition, the System Impact Study shall provide a list of facilities that are required as a result of the Community Solar Project request and non-binding good faith estimates of cost responsibility and time to construct.

4.0 PROPOSED POINT OF INTERCONNECTION

The Applicant's proposed Community Solar Project is to be interconnected to the Public Utility's distribution circuit 5L54 out of Lakeport substation via a 12.0 kV primary meter. The proposed Point of Interconnection ("POI") will be located at approximately 42°16'49.7"N, 121°48'44.5'W located in Klamath County, Oregon. Figure 1 below is a one line diagram that illustrates the interconnection of the proposed generating facility to the Public Utility's system.

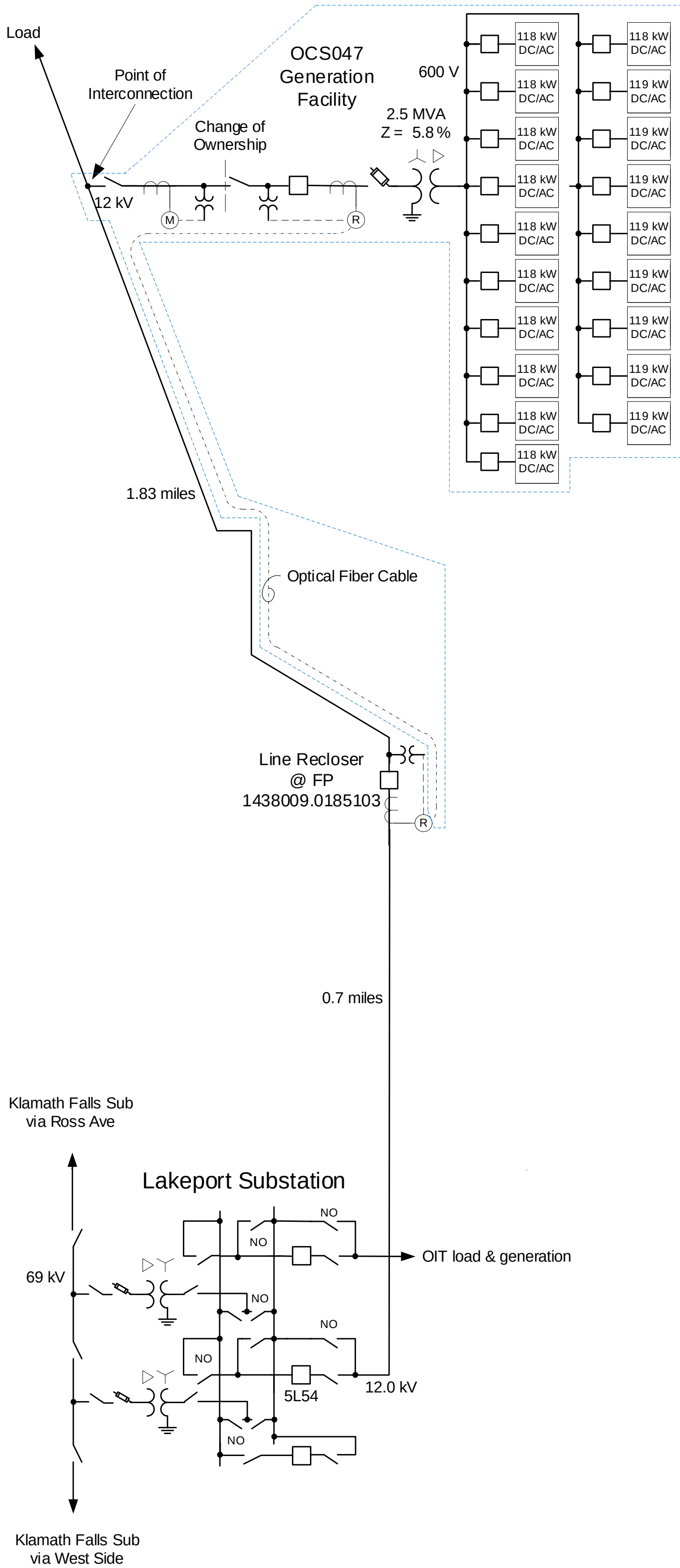


Figure 1: System One Line Diagram

5.0 STUDY ASSUMPTIONS

- All active higher-priority requests for transmission service and/or generator interconnection service (including requests in the traditional interconnection queue and other requests in the Community Solar queue) in the local area of the requested POI 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.
- The Applicant'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 POI.
- The Applicant 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 Applicant'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.
- The PacifiCorp distribution facility point closest to the POI is 01438009.0-071500 on Highway 97 south of Cove Point Road.
- Distribution load flows were performed at peak and light load and full and no generation with summer and winter loading conditions
- This report is based on information available at the time of the study. It is the Applicant's responsibility to check the Public Utility's web site regularly for transmission system updates (https://www.oasis.oati.com/ppw)

6.0 REQUIREMENTS

6.1 COMMUNITY SOLAR PROJECT REQUIREMENTS

The Community Solar Project and Interconnection Equipment owned by the Applicant are required to operate under automatic power factor control with the power factor sensed electrically at the POI. The required power factor is 0.95 per unit leading (absorbing reactive) at the POI.

In general, the Community Solar Project 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.

The minimum power quality requirements are in PacifiCorp's Engineering Handbook and are available at https://www.pacificpower.net/about/power-quality-standards.html. Requirements in the System Impact Study that exceed requirements in the Engineering Handbook power quality standards shall apply.

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 Community Solar Project.

6.2 Transmission System Modifications

No transmission system modifications are required to accommodate the Applicant's proposed Community Solar Project.

6.3 Distribution Modifications

The following are required to the Public Utility's distribution system in order to facilitate the interconnection of the Applicant's Community Solar Project.

- Extend #2 AAAC phase and neutral from Highway 97 at or near facility point 01438009.0-071500 to the POI. The line extension includes a pole for primary metering and a pole with a 600 amp group operated switch.
- Program the SEL-651R recloser control at facility point 01438009.0-185103 with dead-line check and transfer trip to the POI recloser.
- Relocate the 900 kVAR fixed capacitor bank from 01437009.0-301500 to 01438009.0-196902. Remove the 450 kVAR capacitor bank installed at 01438009.0-182602.
- Replace the 65T fuses with solid blades and faulted circuit indicators at 01438009.0-183906. Install 65T fuses at 01438009.0-071200 and 65T fuses at or near 01438009.0-071501 north of the POI tap.

6.4 Existing Breaker Modifications – Short-Circuit

The increase in the fault duty on the system as the result of the addition of the Community Solar Project with photovoltaic arrays fed through 11– 118 kW inverters and 8 – 119 kW inverters connected to 1 – 2.5 MVA 12 kV – 600 V transformer with 5.8 % impedance will not push the fault duty above the interrupting rating of any of the existing fault interrupting equipment.

6.5 Protection Requirements

The OCS047 Community Solar Project will need to disconnect from the network in a high-speed manner for faults on the 12 kV line on circuit 5L54 out of Lakeport substation. The minimum daytime load on circuit 5L54 is 2.5 MW which is above the maximum potential power output of the proposed OCS047 Community Solar Project. For this reason, the imbalance condition of the load and generation can be relied upon to cause the high-speed disconnection of the generating facilityfor faults on the distribution system.

The Community Solar Project is planned to be connected beyond an existing line recloser at facility point 01438009.0185103. During some daytime periods the load beyond the recloser will be less than the potential generation from the proposed Community Solar

Project. Since the unbalance between the generation and load cannot be relied upon to cause the timely disconnection of the Community Solar Project for faults on the 12 kV circuit beyond the recloser a transfer trip circuit will be required between the line recloser and the OCS047 POI recloser at the Community Solar Project. A deadline checking control circuit will be required for the line recloser to delay the automatic reclose if the generation at the Community Solar Project is not disconnected due to a failure of the relay circuitry.

With the addition of the OCS047 Community Solar Project there will be a potential for the Community Solar Project to contribute more fault current for phase to ground faults between line recloser at facility point 01438009.0185103 and Lakeport substation to be above the pickup value for the ground overcurrent element in the recloser. With the current configuration of the recloser this will cause it to trip for these type faults. This will down grade the service to the existing retail customers and will not be acceptable. The recloser has the capabilities needed for the OCS047 project so new settings will be required.

The 12 kV circuit recloser planned to be installed at the OCS047 project will need to equipped Schweitzer Engineering Laboratories (SEL) 651R relay/controller and voltage instrument transformers mounted on the utility side of the circuit recloser. The 651R will perform the following protection functions:

1. Detect faults on the 12 kV equipment at the solar-electric Community Solar Project
2. Detect faults on the 12 kV line to Lakeport Substation
3. Monitor the voltage and react to under or over frequency, and/or magnitude of the voltage
4. Communicate with line recloser at facility point 01438009.0185103 to receive transfer trip from the line recloser

6.6 Data Requirements (RTU)

Due to the power size of the solar-electric Community Solar Project no real time monitoring will be required by the Public Utility for the operation of the transmission network so no RTU will be required.

6.7 Communication Requirements

48-fiber, single-mode, ADSS cable will be installed along the distribution line between the line recloser at facility point 01438009.0185103 and the OCS047 POI recloser for transfer trip. The fiber will be terminated in patch panels mounted in cabinets. Fiber optic jumpers will connect the patch panels to the relays' fiber optic transceivers.

6.8 Substation Requirements

No substation requirements.

6.9 Metering Requirements

Interchange Metering

The metering will be located on the high side of the Applicant generator step up transformer at the POI. The metering transformers will be installed overhead on a pole per distribution

DM construction standards. The meter itself will be installed at the base of the pole. The Public Utility will procure, install, test, and own all revenue metering equipment. The metering will be bi-directional to measure KWH and KVARH quantities for both generation received and back feed retail load delivered. There will be no additional station service metering for supplying generation load. The metering generation and billing data will be remotely interrogated via the Public Utility's MV90 data acquisition system.

Station Service/Construction Power
The Applicant must arrange distribution voltage retail meter service for electricity consumed by the project when not generating. Temporary construction power metering shall conform to the Six State Electric Service Requirements manual. Applicant must call the PCCC Solution Center 1-800-640-2212 to arrange this service. Approval for back feed is contingent upon obtaining station service.

7.0 COST ESTIMATE

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

OCS047 Collector Station *Install metering and communications equipment, develop relay settings.*	$76,000
Line Recloser *Install communications equipment and update relay settings.*	$30,000
Distribution *Line extension, relocate capacitor bank and install fuses.*	$55,000
Communications *Install ~1.8 miles of fiber underbuild.*	$63,000
Total	**$224,000**

*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 Applicant may request that the Public Utility perform this field analysis, at the Applicant'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 Applicant 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 Community Solar Project to Public Utility's electrical distribution or transmission system. An estimate, based on finer detail, will be calculated during the Facilities Study. The Applicant will be responsible for all actual costs, regardless of the estimated costs communicated to or approved by the Applicant.

8.0 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 Applicant's requested commercial operation date of November 30, 2021.

9.0 PARTICIPATION BY AFFECTED SYSTEMS

Public Utility has identified the following Affected Systems: None

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

10.0 APPENDICES

Appendix 1: Higher Priority Requests
Appendix 2: Informational Network Resource Interconnection Service Assessment
Appendix 3: Property Requirements
Appendix 4: Transmission/Distribution Study Results

10.1 APPENDIX 1: HIGHER PRIORITY REQUESTS

All active higher priority transmission service and/or generator interconnection and Community Solar Project 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/Community Solar Queue Requests considered:

Queue #	Size (MW)
721	55
741	40
849	100
905	50
971	2.7
1120	3
1126	8
1147	2.999
1160	70
OCS003	0.8
OCS004	0.8
OCS019	0.882
OCS020	0.594
OCS025	2.8
OCS034	0.978
OCS036	1.125
OCS037	1.5
OCS039	2.25
OCS040	1.64
OCS042	0.13
OCS044	0.447
OCS046	2.25

10.2 Appendix 2: Informational Network Resource Interconnection Service Assessment

The study results described above reflect an energy resource interconnection service ("ERIS") evaluation, modified in the CSP program rules to examine only generation and load conditions local to the requested CSP project's interconnection point (sometimes referred to as the "zoomed in view"). The "zoomed in view" functions to: (1) study the project's proposed interconnection without considering certain existing or higher-queued requests outside of the local area; and (2) to inform whether the CSP facility must cap its project to mitigate, although not eliminate, the risk of potential deliverability-related network upgrades to accommodate the proposed CSP generator.

By contrast, the following informational section provides a network resource interconnection service ("NRIS") evaluation performed with traditional assumptions, i.e., not modified to examine only local generation and load conditions, but rather one that assumes that all existing interconnections, higher-queued requests for interconnection service (in both the traditional and CSP queue), and generators with executed contracts beyond the local area are in-service. Depending on the severity of the conditions created when absorbing additional generation (capped or not capped) in that broader, "zoomed out" area, the local area-focused generator size cap developed in the "zoomed in" examination may not be sufficient to mitigate the need for deliverability-related network upgrades. Regardless of this report's informational NRIS results, the deliverability-related network upgrades ultimately necessary to accommodate the proposed CSP generator will depend on conditions present when the future transmission service study is performed, as well as whether network upgrade alternatives are available at that time.

Considering existing generation and higher-queued requests to interconnect in the Southern Oregon/Northern California area where the CSP generator proposes to interconnect, 2.25 MW of additional generation can be absorbed. As a result, the transmission provider determines that no additional network upgrades would be required for the aggregate of generation in the local area to be delivered to the aggregate of load on the transmission provider's transmission system (the NRIS study scope).

10.3 APPENDIX 3: PROPERTY REQUIREMENTS

Requirements for rights of way easements
Rights of way easements will be acquired by the Applicant 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. Applicant 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 Applicant to accommodate the Applicant's project. The real property must be acceptable to Public Utility. Applicant 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 Applicant 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 Applicant 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.

Applicant 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 Applicant 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 Applicant to procure various studies and surveys as determined necessary by Public Utility.

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

10.4 APPENDIX 4: TRANSMISSION/DISTRIBUTION STUDY RESULTS

Transmission:

Three base cases were developed to represent heavy summer, heavy winter and light spring load conditions. A Power flow analysis was performed on each case for three system configurations.

1. Normal transmission configuration: Lakeport substation fed radial out of Klamath Falls at 69 kV on Line 18-7 with normally open switch 3L118 near Ross Ave. Tap.
2. Contingency transmission configuration: 69kV line section between Lakeport and Westside plant out of service. Lakeport transferred to alternate feed using switch 3L118 near Ross Ave.
3. Contingency transmission configuration: 69kV line section between Klamath Falls and Westside out of service. Switch 3L33 at Westside planet closed feeding Lakeport radially using line 18-6.

Each Power flow analysis was conducted pre and post OCS047. The study focused on the 69 kV system in the Klamath Falls area and distribution voltages at Lakeport substation. Voltage and thermal limitation of surrounding substation buses and lines were monitored.

The results for the transmission study concluded that steady state and post transient voltages are within acceptable limits. No thermal violations were identified. The proposed OCS047 project does not result in additional deficiencies to the Public Utility's transmission system.

There are no contingent facilities identified for this interconnection request.

Distribution:

- The modeled voltage at the POI is 1.061 per unit during light load and full generation and OCS047 generating at 1.0 per unit power factor.
- The modeled current on the 65T fuses at 01438009.0-183906 is 103 amps, 158% of rating, during full generation.
- The modeled load flow on the line recloser at 01438009.0-185103 is 1616 kW reverse power flow during light load and full generation.
- The modeled load flow at breaker 5L54 is 278 kW forward power flow during light load and full generation.

PUBLIC UTILITY COMMISSION
OF
OREGON

SUNTHURST EXHIBIT 404

PacifiCorp System Impact Study Reports
for Q0918 and Q0919

FEBRUARY 22, 2021

PACIFICORP

Small Generator Interconnection
System Impact Study Report

Completed for
PacifiCorp ESM
(“Interconnection Customer”)
Q0918
Panguitch Solar

Proposed Point of Interconnection
Circuit PAN12 out of Panguitch substation at 12.5 kV
(at approximately 37°49'31.5"N, 112°26'49.72"W)

Revised February 9, 2018

1.0 Description of the Generating Facility

PacifiCorp ESM ("Interconnection Customer") proposed interconnecting 0.65 MW of new generation to PacifiCorp's ("Public Utility") circuit PAN12 out of Panguitch substation at 12.5 kV located in Garfield County, Utah. The Panguitch Solar project ("Project") will consist of a 650 kW photovoltaic array connected through a Sunny Central 720CP XT inverter for a total output of .65 MW. The requested commercial operation date is May 31, 2018.

Interconnection Customer will NOT 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 "Q0918."

2.0 Scope of the Study

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 requirements 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.

Stability study is not required due to the small size of Distributed Energy Resource installation.

3.0 Description of Proposed Interconnection

The Interconnection Customer's proposed Small Generating Facility is to be interconnected through the PAN12 distribution circuit. Figure 1 below, is a one-line diagram that illustrates the interconnection of the proposed Small Generating Facility to the Public Utility's system.

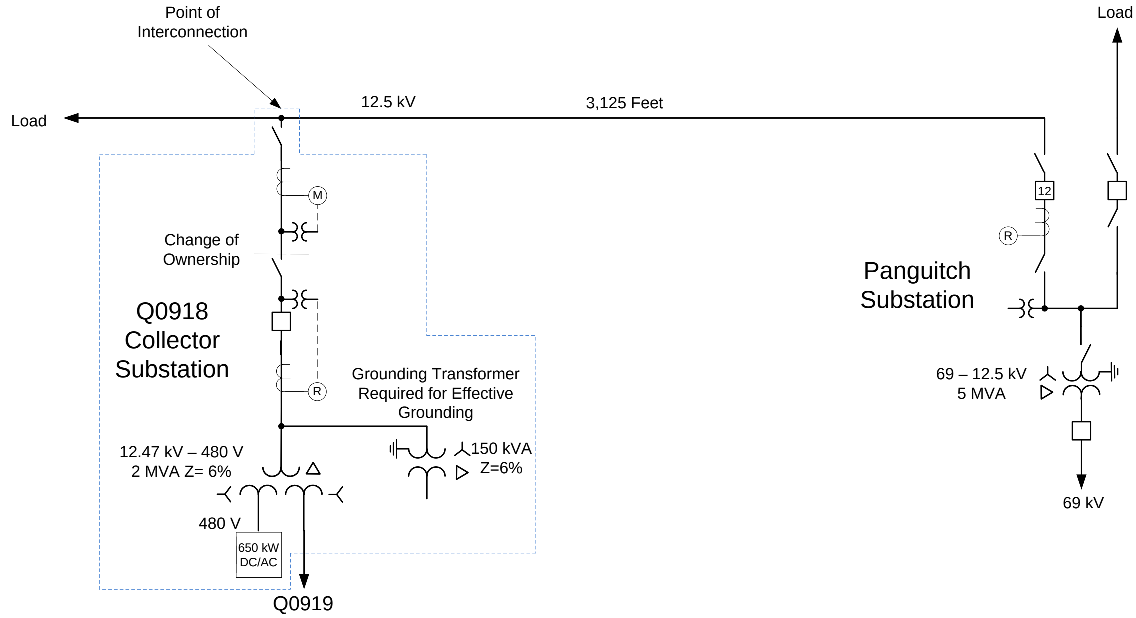


Figure 1: Simplified System One Line Diagram

4.0 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 will be modeled in this study.
  - Generation Interconnection Queue: Interconnection Facilities associated with higher queue interconnection requests will be modeled in this study.
- The Interconnection Customer's request for interconnection service in and of itself does not convey transmission service.
- This study assumes the Project will be integrated into Public Utility's system at the agreed upon and/or proposed Point of Interconnection ("POI").
- The Interconnection Customer will construct and own the 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
- This request will be studied in conjunction with Q0919.

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

5.0 REQUIREMENTS

5.1 GENERATING FACILITY MODIFICATIONS

All interconnecting synchronous and non-synchronous generators are required to design their Generating Facilities with reactive power capabilities necessary to operate within the full power factor range of 0.95 leading to 0.95 lagging. 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. For synchronous generators, the power factor requirement is to be measured at the POI. For non-synchronous generators, the power factor requirement is to be measured at the high-side of the generator substation. The Small Generating Facility must provide dynamic reactive power to the system in support of both voltage scheduling and contingency events that require transient voltage support, and must be able to provide reactive capability over the full range of real power output.

If the Small Generating Facility is not capable of providing positive reactive support (i.e., supplying reactive power to the system) immediately following the removal of a fault or other transient low voltage perturbations, the facility must be required to add 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. Generators shall be equipped with automatic voltage-control equipment and normally operated with the voltage regulation control mode enabled unless written authorization (or directive) from the Public Utility is given to operate in another control mode (e.g. constant power factor control). The control mode of generating units shall be accurately represented in operating studies. The generators shall be capable of operating continuously at their maximum power output at its rated field current within +/- 5% of its rated terminal voltage.

As required by NERC standard VAR-001-1a, the Public Utility will provide a voltage schedule for the POI. In general, Generating Facilities should be operated so as to maintain the voltage at the POI, or other designated point as deemed appropriated by Public Utility. The Public Utility may also specify a voltage and/or reactive power bandwidth as needed to coordinate with upstream voltage control devices such as on-load tap changers. At the Public Utility's discretion, these values might be adjusted depending on operating conditions.

Generating Facilities capable of operating with a voltage droop are required to do so. Voltage droop control enables proportionate reactive power sharing among generation facilities. Studies will be required to coordinate voltage droop settings if there are other facilities in the area. It will be the Interconnection Customer's responsibility to ensure that a voltage coordination study is performed, in coordination with Public Utility, and implemented with appropriate coordination settings prior to unit testing.

All generators must meet the Federal Energy Regulatory Committee ("FERC") and WECC low voltage ride-through requirements as specified in the interconnection agreement.

The Interconnection Customer will provide a dead-end pole with guying to receive the Public Utility's last span of conductor. This pole will meet Public Utility (Rocky Mountain Power) construction standards.

The Interconnection Customer will be required to install a transformer that will hold the phase to neutral voltages within limits when the Small Generating Facility is isolated with the Public Utility's local system until the generation disconnects. The proposed delta – wye step-up transformer 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 Interconnection Customer will be required to install a 12.5 kV circuit recloser equipped with a SEL 351R or 615R relay/controller. A three phase set of 12.5 kV voltage instrument transformers will need to be installed on the utility side of the circuit recloser and the secondaries of these transformers connected to the SEL 351R relay/controller.

5.2 DISTRIBUTION SYSTEM MODIFICATIONS

A line tap will be constructed from the POI and the Small Generating Facility. This will consist of an inter-set take-off pole, three-phase unitized switch, and a primary metering pole with dead-end guying.

5.3 EXISTING BREAKER MODIFICATIONS – SHORT-CIRCUIT

The increase in the fault duty on the system as the result of the addition of the Small Generating Facility with photovoltaic arrays fed through 1 - 650 kW inverter connected to 1– 2 MVA 12.5 kV – 480 V transformer with 6% impedance will not push the fault duty above the interrupting rating of any of the existing fault interrupting equipment.

5.4 PROTECTION REQUIREMENTS

Due to the daytime load on circuit 12 (PAN12) out of Panguitch substation, the potential power output of the Small Generating Facility along with the existing generation on the circuit will not be able to carry the load when isolated with the circuit load due to the opening of CB 12. Because the reclosing time on the Panguitch substation recloser is 1.5 seconds the Q0918 generation should be disconnected before the reclose takes place at the substation. Therefore no modifications of the existing protection system will be required.

At the POI a SEL 351R or 651R protective relay will be installed to perform the following functions:

1. Detect faults on the 12.5 kV at the Small Generating Facility
2. Detect faults on the 12.5 kV line to Panguitch substation
3. Protect the grounding transformer from damage due excessive unbalance currents on the circuit.
4. Monitor the voltage and react to under or over frequency, and / or magnitude of the voltage

All of these relaying functions will be performed by a single relay.

5.5 DATA REQUIREMENTS (RTU)

Due to the size of this proposed Small Generating Facility there are no data provision requirements.

5.6 COMMUNICATION REQUIREMENTS

A leased T1 from the Q0918 collector substation to the Cedar City Service Center is required to provide real time and MV-90 metering data from the “Solar Meter” at the Q0918 collector substation. A telecommunications company leased T1 interface will be in the Interconnection Customer’s side of the Q0918 collector substation building. Public Utility’s electronics will be housed in Public Utility’s side of the Interconnection Customer’s building. The building will be physically separated into two parts, one part for the Interconnection Customer and one part for Public Utility.

5.7 SUBSTATION REQUIREMENTS

Q0918 collector substation

The Interconnection Customer will provide a secure space in their collector substation control house, which is separately accessible to the Public Utility, for any required metering or communications equipment. AC station service and DC power will be supplied by the Interconnection Customer.

5.8 METERING REQUIREMENTS

Interchange Metering

The POI bi-directional metering (back-feed and generation) will be located near the Interconnection Customer tap point on circuit PAN12 out of Panguitch 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 metering construction standards. The proposed size of the Small Generating Facility is below the need for back up metering.

The metering design package will include a high end ION meter, test switch, with DNP real time digital data that will be direct polled. The metering data will include bidirectional KWH KVARH, revenue quantities including instantaneous PF, MW, MVAR, and MVA, including per phase voltage and amps data.

A cell package will be included for generation accounting via the MV-90 translation system.

Station Service/Construction Power

The Project is within the Public Utility’s service territory. The back-feed arrangements will continue with the Commercial Trading back-office.

6.0 COST ESTIMATE

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

<u>Direct Assigned</u>	
Distribution line	$68,000
Tap from POI to collector substation	
Q0918 collector substation	$215,000
Add communications and develop relay settings for customer owned POI relay	
Control centers	$26,000
Total	**$309,000**

*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 Generating Facility to Public Utility's electrical distribution or transmission system. A more detailed estimate will be calculated during the Facilities Study. The Interconnection Customer will be responsible for all actual costs, regardless of the estimated costs communicated to or approved by the Interconnection Customer.

7.0 SCHEDULE

The Public Utility estimates it will require approximately 12-18 months to design, procure and construct the facilities described in this report following the execution of an Interconnection Agreement. The schedule will be further developed and optimized during the Facilities Study.

Please note, the time required to perform the scope of work identified in this report appears to result in a timeframe that does not support the Interconnection Customer's requested commercial operation date of May 31, 2018.

8.0 PARTICIPATION BY AFFECTED SYSTEMS

Public Utility has identified the following affected systems: None

9.0 APPENDICES

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

9.1 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:

None.

9.2 APPENDIX 2: PROPERTY REQUIREMENTS

Property Requirements for Point of Interconnection Substation

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 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 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:

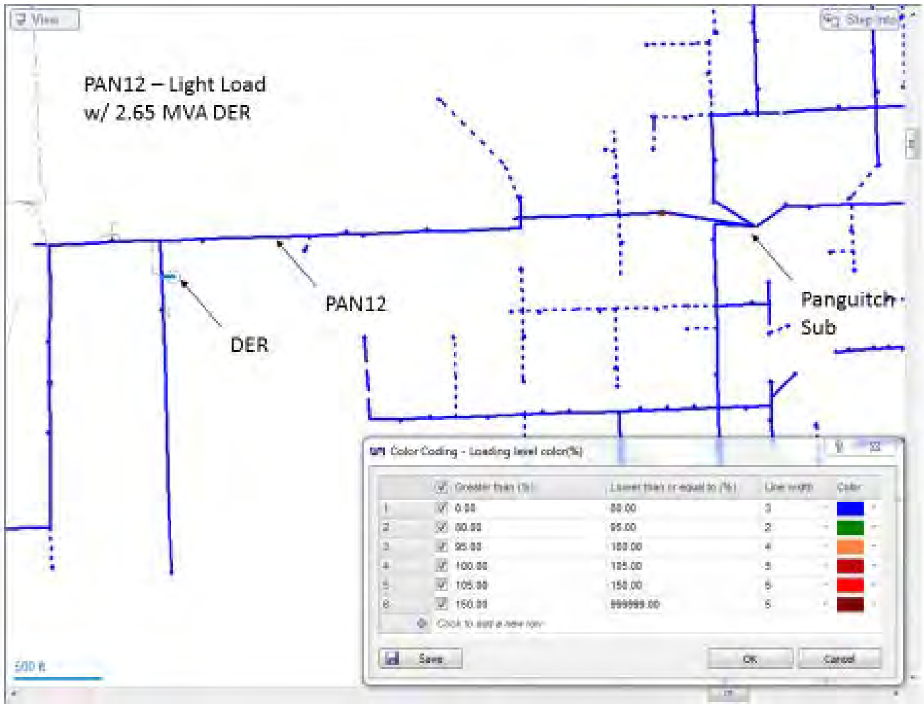
1. Environmental: known contamination of site; evidence of environmental contamination by any dangerous, hazardous or toxic materials as defined by any governmental agency; violation of building, health, safety, environmental, fire, land use, zoning or other such regulation; violation of ordinances or 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

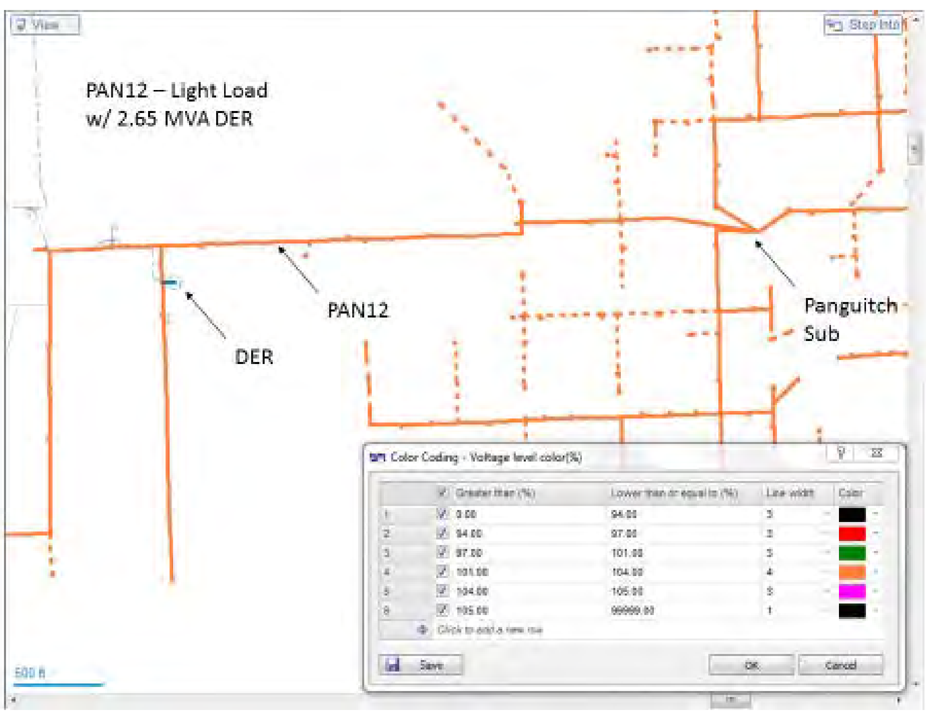
phase I environmental study is required for land being acquired in fee by the Public Utility unless waived by Public Utility.

2. 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.

9.3 APPENDIX 3: STUDY RESULTS





PACIFICORP

Small Generator Interconnection
System Impact Study Report

Completed for
PacifiCorp ESM
(“Interconnection Customer”)
Q0919
Panguitch Storage

Proposed Point of Interconnection
Circuit PAN12 out of Panguitch substation at 12.5 kV
(at approximately 37°49'31.5"N, 112°26'49.72"W)

Revised February 9, 2018

1.0 DESCRIPTION OF THE GENERATING FACILITY

PacifiCorp ESM ("Interconnection Customer") proposed interconnecting 1 MW of new generation to PacifiCorp's ("Public Utility") circuit PAN12 out of Panguitch substation at 12.5 kV located in Garfield County, Utah. The Panguitch Storage project ("Project") will consist of a 1,000 kW battery for a total output of 1 MW. The requested commercial operation date is May 31, 2018.

Interconnection Customer will NOT operate this generator as a Qualified Facility as defined by the Public Utility Regulatory Policies Act of 1978 (PURPA).

The Transmission Provider has assigned the Project "Q0919."

2.0 SCOPE OF THE STUDY

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 requirements 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.

Stability study is not required due to the small size of the Small Generating Facility.

3.0 DESCRIPTION OF PROPOSED INTERCONNECTION

The Interconnection Customer's proposed Small Generating Facility is to be interconnected to the PAN12 distribution circuit utilizing the interconnection facilities to be constructed for the Q0918 project. Figure 1 below, is a one-line diagram that illustrates the interconnection of the proposed Small Generating Facility to the Transmission Provider's system.

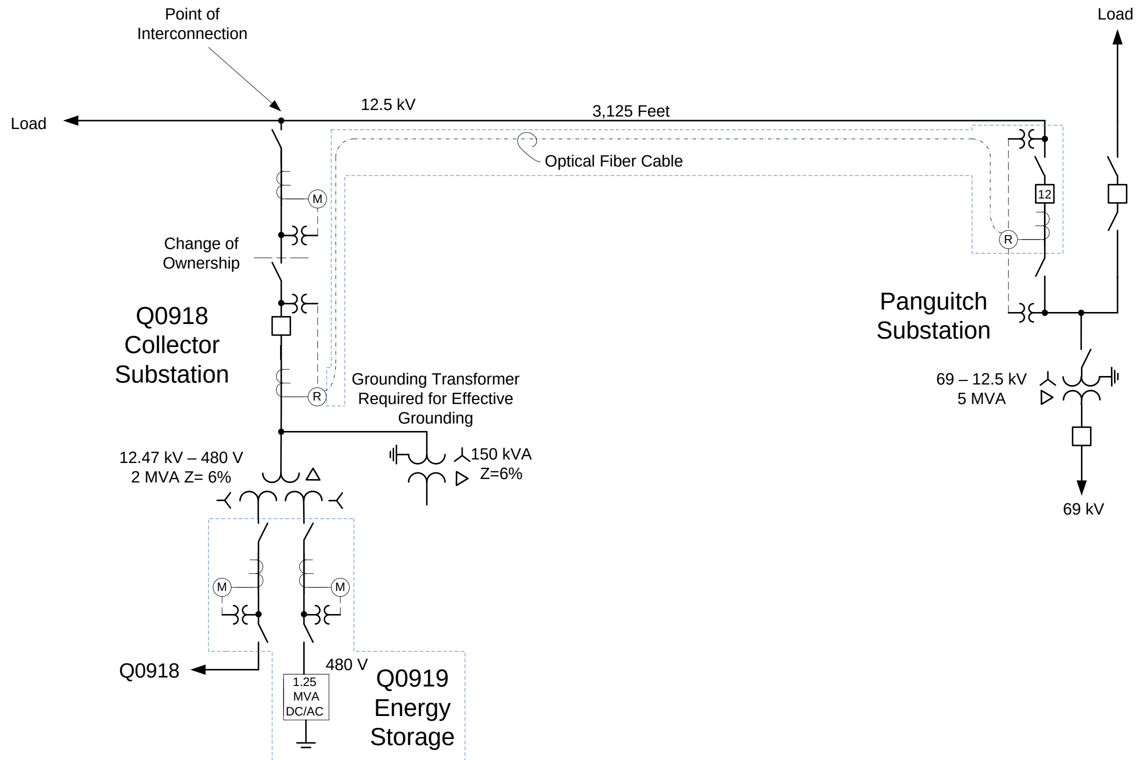


Figure 1: Simplified System One Line Diagram

4.0 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 Transmission Provider 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 will be modeled in this study.
  - Generation Interconnection Queue: Interconnection Facilities associated with higher queue interconnection requests will be modeled in this study.
- The Interconnection Customer's request for interconnection service in and of itself does not convey transmission service.
- This study assumes the Project will be integrated into Transmission Provider's system at the agreed upon and/or proposed Point of Interconnection ("POI").
- The Interconnection Customer will construct and own the any facilities required between the POI and the Project unless specifically identified by the Transmission Provider.
- Line reconductor or fiber underbuild required on existing poles will be assumed to follow the most direct path on the Transmission Provider'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 Transmission Provider performance and design standards
- This request will be studied in conjunction with Q0918.
- All improvements specified in Q0918 must be in service concurrent with or before this Project can be placed in service.
- This report is based on information available at the time of the study. It is the Interconnection Customer's responsibility to check the Transmission Provider's web site regularly for transmission system updates (http://www.pacificorp.com/tran.html)

5.0 REQUIREMENTS

5.1 GENERATING FACILITY MODIFICATIONS

All interconnecting synchronous and non-synchronous generators are required to design their Generating Facilities with reactive power capabilities necessary to operate within the full power factor range of 0.95 leading to 0.95 lagging. This power factor range shall be dynamic and can be met using a combination of the inherent dynamic reactive power capability of the Small Generating Facility or inverter, dynamic reactive power devices and static reactive power devices to make up for losses. For synchronous generators, the power factor requirement is to be measured at the POI. For non-synchronous generators, the power factor requirement is to be measured at the high-side of the generator substation.

The Small Generating Facility must provide dynamic reactive power to the system in support of both voltage scheduling and contingency events that require transient voltage support, and must be able to provide reactive capability over the full range of real power output. If the Small Generating Facility is not capable of providing positive reactive support (i.e., supplying reactive power to the system) immediately following the removal of a fault or other transient low voltage perturbations, the facility must be required to add 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. Generators shall be equipped with automatic voltage-control equipment and normally operated with the voltage regulation control mode enabled unless written authorization (or directive) from the Grid Operator is given to operate in another control mode (e.g. constant power factor control). The control mode of generating units shall be accurately represented in operating studies. The generators shall be capable of operating continuously at their maximum power output at its rated field current within +/- 5% of its rated terminal voltage.

As required by NERC standard VAR-001-1a, the Transmission Provider will provide a voltage schedule for the POI. In general, Generating Facilities should be operated so as to maintain the voltage at the POI, or other designated point as deemed appropriated by Transmission Provider. The Transmission Provider may also specify a voltage and/or reactive power bandwidth as needed to coordinate with upstream voltage control devices such as on-load tap changers. At the Transmission Provider's discretion, these values might be adjusted depending on operating conditions.

Generating Facilities capable of operating with a voltage droop are required to do so. Voltage droop control enables proportionate reactive power sharing among generation facilities. Studies will be required to coordinate voltage droop settings if there are other facilities in the area. It will be the Interconnection Customer's responsibility to ensure that a voltage coordination study is performed, in coordination with Transmission Provider, and implemented with appropriate coordination settings prior to unit testing.

All generators must meet the Federal Energy Regulatory Committee ("FERC") and WECC low voltage ride-through requirements as specified in the interconnection agreement.

The grounding transformer specified in the Q0918 system impact study report is assumed to be installed for that Project.

5.2 TRANSMISSION SYSTEM MODIFICATIONS

None necessary.

5.3 EXISTING BREAKER MODIFICATIONS – SHORT-CIRCUIT

The increase in the fault duty on the system as the result of the addition of the Small Generating Facility with a battery fed through 1 – 1.25 MVA inverter connected to 1– 2 MVA 12.5 kV – 480 V transformer with 6% impedance along with the Q0918 Small Generating Facility will not push the fault duty above the interrupting rating of any of the existing fault interrupting equipment.

5.4 PROTECTION REQUIREMENTS

Due to the minimum load on circuit 12 out of Panguitch substation the potential power output of the battery facility and the Q0918 Small Generating Facility along with the existing generation on the circuit will not be able to carry the load when isolated with the circuit load due to the opening of CB 12. The unbalance between the load and generation cannot be relied upon to cause the high speed disconnection of the Small Generating Facility following the opening of CB 12 at Panguitch substation and before the reclosing of CB 12. A transfer trip signal will need to be sent from Panquitch substation to the Q0918 collector substation to force the opening of the Q0918 collector substation recloser before the reclosing of CB 12. An optical fiber cable will need to be installed between Panguitch substation and the Q0918 collector substation to carry the transfer trip signal.

A voltage transformer will need to be added to the line side of CB 12 and the output of this transformer connected to a new relay. The relay will be configured to delay automatic reclosing of the recloser following a line fault detection until the lack of voltage on the line is an indication that the distributed generation has disconnected. Dead line checking will be required to block the automatic reclosing for cases when a failure of the protective systems leads to delayed tripping of the generation facility for a feeder fault. Reclosing for this type of situation could cause damage to the equipment and needs to be prevented.

The current that the Small Generating Facility will contribute to a line fault on the other feeder circuit out of Panguitch substation will be in excess that the pickup value of the overcurrent relay function applied in CB 12 at Panguitch substation. This will result in the CB 12 opening for a fault on the other circuit. This will not be acceptable and must be prevented. The overcurrent relay function on CB 12 will need to be directional so that it will only operate for faults on the CB 12 circuit.

The CB 12 recloser at Panguitch substation will need to be replaced with a unit that can performer the following functions:

1. Phase and ground overcurrent functions that can be set to be directional to operate for faults only on the CB 12 circuit.
2. Monitor the voltage on the line side of the breaker to delay the reclosing until the line is no longer energized.
3. Send transfer trip to the Q0918 POI recloser.

The relay/controller for the recloser planned to be installed at the Q0918 collector substation for the Q0918 project will be modified to accept the transfer trip signal from Panguitch substation and trip the recloser.

5.5 DATA REQUIREMENTS (RTU)

No requirements.

5.6 COMMUNICATION REQUIREMENTS

5.6.1 *LINE Protection*

A transfer trip circuit is required between the Panguitch substation and the Q0918/919 POI recloser via direct fiber communication.

5.6.2 *Data Delivery to the Control Centers*

A transfer trip circuit is required between the Panguitch substation and the Q0918/919 POI recloser via direct fiber communication.

5.7 SUBSTATION REQUIREMENTS

Q0918 Collector substation

The control house, or space in Interconnection Customer control house, specified in Q0918 will be adequate for additional equipment.

Panguich substation

Replace CB 12 with a 12.5 kV self-contained recloser. Install one 12.5 kV VT on line side of distribution circuit 12.

5.8 METERING REQUIREMENTS

<u>Interchange Metering</u>

Metering at the POI will be installed as part of Q0918 and located near the Interconnection Customer tap point on circuit PAN12 out of Panguitch substation.

Production Solar Metering & Battery:
For the purpose of statistical data requested by the Interconnection Customer including metering for WREGIS energy certificates it will be necessary to separate the metering of the Q0918 and Q0919 projects.

Metering will be installed on the low side three phase 4 wire (480 VAC) at both the Q918 and Q0919 sites. The metering design package will be identical including a high end ION meter, test switch, with DNP real time digital that will be direct polled. The metering data will include bidirectional KWH KVARH, revenue quantities including instantaneous PF, MW, MVAR, MVA, including per phase voltage and amps data. Any other data the Interconnection Customer requests will be programmed into the ION meters

The data will also be remotely interrogated via the Transmission Provider's MV90 data acquisition system. The proposed size of the Small Generating Facility is below the need for back up metering.

The solar generation metering will be installed within the Interconnection Customer supplied 480 VAC service entrance equipment. The Interconnection Customer is responsible for providing all mounting devices for instrument transformers and meter.

Panguitch substation:
The Interconnection Customer has requested additional real time metering data. Replace the existing mechanical meter on the low side of the 69/12.5 kV power transformer with an ION meter. Replace the shallow metering enclosure with a standard sized meter enclosure. Within substation interconnect communication fiber with metering at NEMA enclosure.

The metering design package will include a high end ION meter, DNP real time digital that will be direct polled an RTU is not required. The metering data will include bidirectional KWH KVARH, revenue quantities including instantaneous PF, MW, MVAR, and MVA, including per phase voltage and amps data.

Any other data the Interconnection Customer requests will be programmed into the ION meters.

Station Service/Construction Power
The Project is within the Transmission Provider's service territory. The back-feed station service metering will be measured at the POI delivery point as described in Q0918. The back-feed arrangements will be with the Transmission Provider Commercial Trading back-office group.

6.0 Cost Estimate

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

Q0918 collector substation $133,000
Add metering, transfer trip, and modify relay settings

Panguitch substation $236,000
Add metering, transfer trip, and modify relay settings

Fiber $51,000
Add fiber for relaying between Panguitch substation and Q0918 collector substation

Total $420,000

*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 is as accurate as possibly given the level of detailed study that has been completed to date and approximates the costs incurred by Transmission Provider to interconnect this Small Generating Facility to Transmission Provider'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.

7.0 SCHEDULE

The Transmission Provider estimates it will require approximately 12-18 months to design, procure and construct the facilities described in this report following the execution of an Interconnection Agreement. The schedule will be further developed and optimized during the Facilities Study.

Please note, the time required to perform the scope of work identified in this report appears to result in a timeframe that does not support the Interconnection Customer's requested commercial operation date of May 31, 2018.

8.0 PARTICIPATION BY AFFECTED SYSTEMS

Transmission Provider has identified the following affected systems: None

9.0 APPENDICES

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

9.1 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 Transmission Provider reserves the right to restudy this request, as the results and conclusions contained within this study could significantly change.

Transmission/Generation Interconnection Queue Requests considered:

Q0918 (0.65 MW)

9.2 APPENDIX 2: PROPERTY REQUIREMENTS

Property Requirements for Point of Interconnection Substation

Requirements for rights of way easements

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

Real Property Requirements for Point of Interconnection Substation

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

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

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

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

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

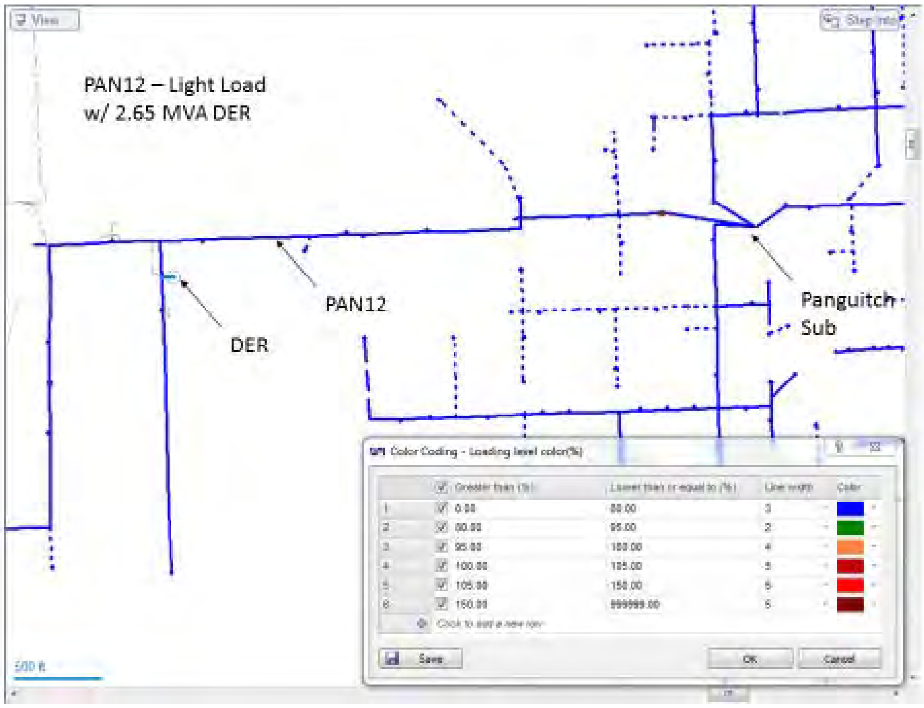
1. Environmental: known contamination of site; evidence of environmental contamination by any dangerous, hazardous or toxic materials as defined by any governmental agency; violation of building, health, safety, environmental, fire, land use, zoning or other such regulation; violation of ordinances or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

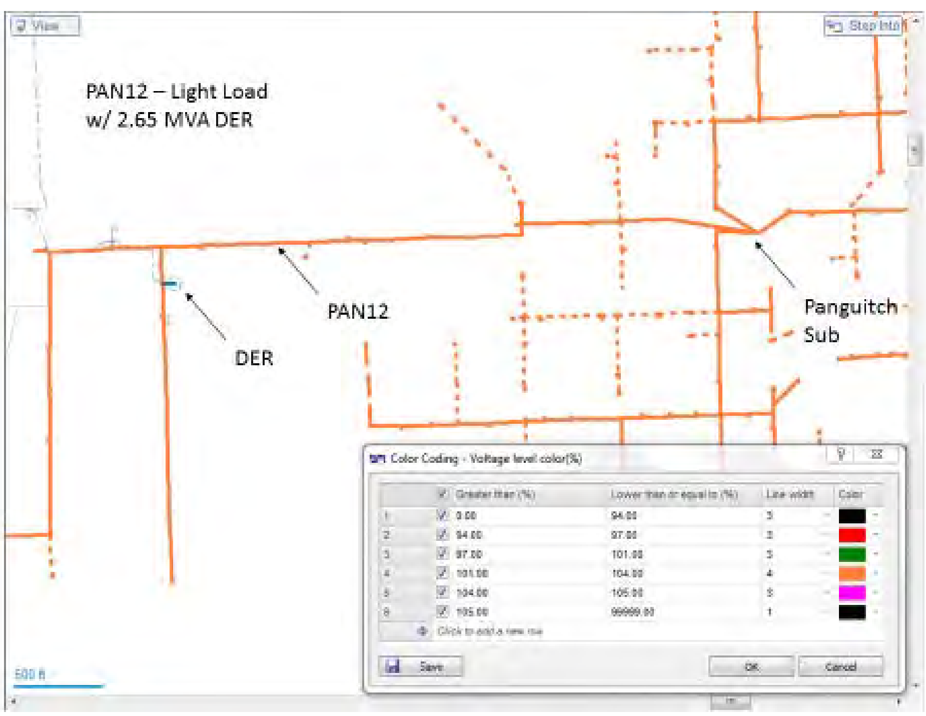
phase I environmental study is required for land being acquired in fee by the Transmission Provider unless waived by Transmission Provider.

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

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

9.3 APPENDIX 3: STUDY RESULTS





PUBLIC UTILITY COMMISSION
OF
OREGON

SUNTHURST EXHIBIT 405

PacifiCorp Policy 138 Excerpts
(12/20/20 rev)*

*Compare to 8/13/2018 version at Sunthurst/209

FEBRUARY 22, 2021

Policy

DISTRIBUTED ENERGY RESOURCE (DER) INTERCONNECTION POLICY

Facility Connection (Interconnection) Requirements for Distribution Systems 34.5 kV and Below

Engineering Services & Asset Management Policy 138

Author:	Lee Solum, Luis Perez, John Mark, David Heffernan, Mark Robinson, Greg Lyons, Nicholas Babcock, Lance McDaniel, Glen Sidney, Bill Carlson, Alan Wayment, Blair Squires, Jonathan Connelly, Kris Bremer, Jake Baker, Dustin Herrick
Approval:	Rohit Nair
Authoring Department:	Engineering Standards & Technical Services
Approved File Location:	J:\Publications\FPP\DIS\POL
File Number-Name:	138-Distributed Energy Resource (DER) Interconnection Policy.docx
Revision Number:	7
Revision Date:	12/28/2020

Document Security Category			
	Confidential	X	External
	Restricted		BES Cyber System Information (BCSI)
X	Internal		

Revision Log		
0	12/11/07	Initial issue.
1	2/5/08	Rev 1
2	11/3/11	Rev 2: changes to section 5.7, paragraph 2 only.
3	7/2/15	Changes have been made throughout this policy.
4	1/11/17	Changes have been made throughout this policy.
5	11/9/17	Maximum parallel time w. EPS for closed-transition method has been updated.
6	7/25/18	Transient overvoltage management has been updated in section 6.4.
7	12/28/20	Changes have been made throughout this policy.

PACIFICORP
A BERKSHIRE HATHAWAY ENERGY COMPANY

Policy

Contents

Single-phase DER interconnection facilities are to be connected phase-to-neutral on PacifiCorp's distribution system.

3.4 Metering

The general requirements for metering a DER facility are similar to that of metering electrical retail service from PacifiCorp. The metering requirements are available in the PacifiCorp's Electric Service Requirements (ESR), chapter 9.

Back-up deliveries to the DER facility to support auxiliary loads (bi-directional metering) must be separately recorded from generation and treated as separate transactions under applicable PacifiCorp tariff.

Sites with multiple fueled resources such as wind collectors, solar arrays and energy storage, may be separately metered at the DER including metering at the Point of Delivery.

When energy storage (batteries) are charged both from the PacifiCorp distribution system and a generation solar or wind fuel source, metering will be required to separate the fuel source from the distribution source. That is, metering will be required at the Generation Facility/ Energy Storage Facility and at the Pacificorp Point of Interconnection.

The station service loads will be metered separately and exclusively for both the Storage Facility and Generation Facility. The station service source can be from the local distribution. This requirement would not apply to net billing customers.

3.4.1 California Independent System Operator (CAISO) Compliance

The metering process, specification and requirements can be found in the CAISO Tariff and Business Practice Manual for Metering located on the CAISO website. The criteria for metering ensure operational accuracy and certification of the PacifiCorp CAISO facilities. All generators above 3 MW output and all tie-lines must have a settlement quality meter data (SQMD) plan in place prior to energization. SQMD plans require specific meter and instrument transformer information that is submitted to CAISO for approval. Any changes to the metering configuration at a particular site will require a new SQMD plan to be submitted to CAISO.

3.4.2 Basic Meter Programs

The standard PacifiCorp meter program will include:

- Bi-directional active (MWh) and reactive energy (MVArh)
- Sliding, peak demand (MW) quantities
- Interval MW, MVAr, volt, and amp data

3.4.3 Multiple Generators

When multiple generators are connected at a single PacifiCorp Point of Delivery that is aggregated at a nameplate rating of 3 MW and above, additional real-time telemetry metering is required at the Point of Delivery to the PacifiCorp system. The DER facility shall have each DER unit metered, and in addition the Point of Delivery will also be metered.

3.4.4 Customer Request for Metering Data

Customers will not be approved to interrogate PacifiCorp meters registers and profile channels using cellular or ethernet communications. Customer requests for third-party meter data shall follow company meter engineering Policy 500.