PACIFICORP
A BERKSHIRE HATHAWAY ENERGY COMPANY

Pacific Power |
Rocky Mountain Power
825 NE Multnomah
Portland, OR 97232

July 20, 2021

Mr. Ken Kaufman
1785 Willamette Falls Drive, Suite 5
West Linn, Oregon 97086

RE: July 1, 2021, letter regarding Notice of Intent to File Complaint for Enforcement regarding OCS 024, 062, and 063. *PacifiCorp second response.*

Dear Mr. Kaufman:

On July 6, 2021, PacifiCorp provided a response to your July 1, 2021, letter to PacifiCorp. In its July 6, 2021, letter, PacifiCorp: (1) agreed to remove the references to IEEE-1547-2018 for study purposes of OCS 062 and 063; (2) stated it was open to removing contingency costs from the cost estimates for OCS 062 and 063; (3) agreed to extensions until July 30, 2021, for Sunthurst Energy LLC's ("Sunthurst") to execute the facility study agreements for OCS 062 and 063; (4) disagreed to study alternate feeder configurations in the vicinity of OCS 062 and 063; and (5) in a separate email dated July 6, 2021, and pursuant to the non-disclosure agreement between Sunthurst and PacifiCorp, provided an additional distribution map of the Pendleton Distribution System that reflects the McKay substation. Below please find responses to other questions from Sunthurst's July 1, 2021, letter.

(1) <u>Will PacifiCorp please provide (a) records documenting the current 69kV protection equipment in the vicinity of Buckaroo, Pendleton, and McKay substations; and (b) descriptions of planned improvements for the same substations</u>?

<u>Answer</u>: PacifiCorp has provided additional information in revised System Impact Study ("SIS") Reports, describing what is currently at McKay (OCS062) and Buckaroo (OCS063) to provide context as to the upgrades that are necessary. The updates are to the one-line diagrams and to Section 6.5 of the SIS Reports. The revised SIS Reports are provided as attachments to this response letter. There are no planned improvements that that would impact the OCS 062 and 063 requests. PacifiCorp also provides the following information regarding OCS 062 and 063 to provide context as to the upgrades that are necessary:

(a) <u>OCS062 at McKay</u>

With combined generation of OCS024 and OCS062, during minimum load, there will be back feed of fault current on the feeder breaker, substation transformer and from substation to the transmission. Feeder breaker 5W856 currently has SEL-751 relay. To install deadline checking control circuit, VTs need to be installed on the line side of breaker 5W856. The existing 751 relay will be connected to these VTs and a transfer trip will be installed between the substation breaker and POI recloser. When breaker 5W856 opens a transfer trip signal will be sent to the POI recloser to disconnect the Community Solar Project. For faults in the transformer, the transformer differential relay will send transfer trip through the existing 751 relaying. To detect faults on the 69kV line, new relays and VTs need to be installed on the high side of transformer. A transfer trip signal will be sent to OCS062 POI recloser for the operation of the line, transformer, or 12.47 kV feeder relays. Transfer trip circuits will also be needed between line reclosers and OCS062 recloser at the POI since MDL on the circuit beyond either of the reclosers is well below the potential power out from the proposed OCS project.

(b) <u>OCS063 at Buckaroo</u>

With combined generation of existing solar and OCS063, during minimum load, there will be back feed of fault current on the feeder breaker, substation transformer and from substation to the transmission. Feeder breaker 5W202 currently has SEL-751 relay. To install deadline checking control circuit, VTs need to be installed on the line side of breaker 5W202. The existing 751 relay will be connected to these VTs and a transfer trip will be installed between the substation breaker and POI recloser. When breaker 5W202 opens a transfer trip signal will be sent to the POI recloser to disconnect the Community Solar Project. For faults in the transformers, the 11T (SEL-751)) relay will send transfer trip through the existing 751 relaying. To detect faults on the 69kV line, new relays and VTs need to be installed on the high side of transformer. A transfer trip signal will be sent to OCS063 POI recloser for the operation of the line, transformers, or 12.47 kV feeder relays.

(2) <u>Removal of reference to IEEE 1547-2018</u>.

<u>Answer</u>: The revised SIS reports remove the references to IEEE 1547-2018. The requirements to interconnect OCS 062 or 063 will not include the reactive power capabilities or voltage /power control as required in IEEE 1547-2018

(3) <u>Sunthurst objects to Policy 138, Section 2.2.5's inclusion because it requires Sunthurst to enlarge its inverter for the sole purpose of providing VAR support beyond what is necessary to mitigate impacts caused by interconnection of OCS 063</u>.

<u>Answer</u>: The inverter will not be required for OCS 063. The project and the interconnection equipment will be required to operate under constant power factor mode as specified in IEEE 1547-2003.

(4) <u>Please provide the detailed analysis supporting its conclusion, in the OCS 062 SIS Report, that OCS 062 will require re-conductoring of 0.7 miles of distribution circuit. Specifically, the Report does not say whether the conclusion is based upon the Volt-VAR performance or whether this is a drop of generation due to fault. It also does not say whether Volt-VAR capabilities of the OCS 063 inverters can provide voltage regulation adequate to avoid re-conductoring.</u>

<u>Answer</u>: The requested analysis was provided as a part of PacifiCorp's responses to Sunthurst's technical questions regarding OCS 062, which were provided by Mr. Ty Engle to Mr. Daniel Hale in an email dated July 2, 2021. PacifiCorp notes that the Volt-VAR

capabilities of OCS 063 does not impact the need for the reconductoring as it is due to a drop in generation.

(5) IEEE 1547-2018 considers the number of occurrences per day as a criterion, not just the magnitude of the change. Requiring re-conductoring because there is one voltage change a month that exceeds the 3% recommendation (for example) is a misuse of the IEEE standard (which says that for events that happen less than 4 times per day, a 5-6% change in voltage is allowable). PacifiCorp documentation in its SIS Report does not establish that re-conductoring is warranted under the IEEE 1547-2018 standard.

Answer: As noted in response to Question 4 above, PacifiCorp provided an analysis to Sunthurst (via an email dated July 2, 2021 to Mr. Hale) substantiating the need for the reconductoring. Moreover, as explained in response to Question 2 above, PacifiCorp has removed the reference to IEEE 1547-2018.

Notwithstanding the above, PacifiCorp notes that Sunthurst's understanding of the IEEE standard is incorrect. The 3% voltage fluctuation limit is based on abrupt output variations that can be caused by Distributed Energy Resource ("DER") mis-operation. IEEE 1547 specifically states this in section 7.2.2. This limit has been used for other OCS projects and has been agreed upon by other developers.

The IEEE standard 1453 referenced for the 5-6% voltage fluctuation limit is not applicable to DER projects since it specifies requirements for recommended practice for the analysis of fluctuating installations on power systems not specific to DER installations. It is also not referenced or acknowledged in OAR rules for DER interconnection.

(6) Removal of contingency.

Answer: The revised SIS Reports remove the contingency costs. However, as PacifiCorp noted in its July 6, 2021, response -- Sunthurst will be responsible for all reasonable costs incurred by PacifiCorp to interconnect OCS 062 and 063.

If Sunthurst would like to have a conference call to discuss the answers to questions relating to OCS 062 or 063, please let me know as soon as possible. The July 30, 2021, extension remains effective for Sunthurst to either execute the facilities study agreements for OCS 062 and OCS 063 or have those requests deemed withdrawn, in accordance with PacifiCorp's Community Solar Program Interconnection Procedures.

Sincerely,

Matthew Loftus

Community Solar Project Interconnection

Community Solar Project System Impact Study Report

Completed for

Sunthurst Energy, LLC

(“Applicant”)

OCS062

Nye Solar

Proposed Point of Interconnection

Circuit 5W856 out of McKay substation at 12.47 kV

(At approximately 45°39'36.3"N, 118°46'15.8"W)

May 3, 2021

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1.0 Description of the Community Solar Project

Sunthurst Solar LLC ("Applicant") proposed interconnecting 2.4 MW of new generation to PacifiCorp's ("Public Utility") circuit 5W856 out of McKay substation located in Umatilla County, Oregon. The Nye Solar project ("Project") will consist of forty (40) CHINT SCA60KTL 60 kW inverters for a total requested output of 2.4 MW. The requested commercial operation date is December 31, 2021.

The Public Utility has assigned the Project "OCS062."

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 proposed Public Utility's distribution circuit 5W856 out of McKay substation with an in-service date presently scheduled for summer of 2021via a 12.47 primary meter. The proposed Point of Interconnection ("POI") is on the Public Utility's pole at map string 01102032.0 facility point #117000 and is located at approximately 45°39'36.3"N, 118°46'15.8"W located in Umatilla County, Oregon. Figure 1 below is a one line diagram that illustrates the interconnection of the proposed Community Solar Project to the Public Utility's system.

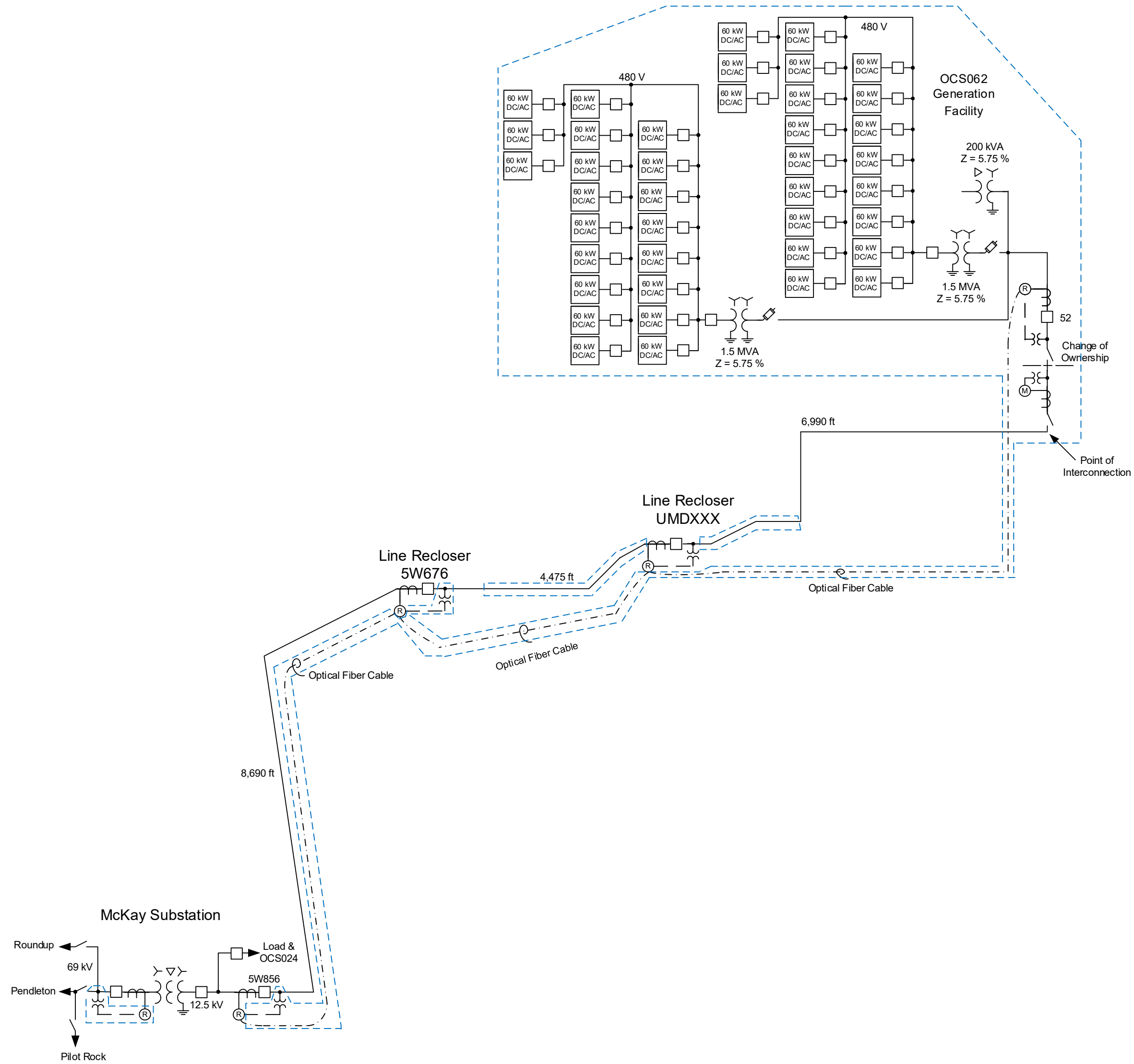

Figure 1: System One Line Diagram

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 Community Solar Project is expected to operate during daylight hours every day 7 days per week 12 months per year.
- The Community Solar Project is expected to operate in constant power factor mode with a unity power factor setting unless otherwise requested by the Public Utility. The study was conducted assuming the generation stayed within the 0.95 +/- power factor range.
- 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 constant power factor 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. 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.
. Any 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. 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.

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

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 Public Utility'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. Figure 1 shows the addition of a 12.47 kV 200 kVA wye – delta grounding transformer with an impedance of 5.75 %. This transformer will meet this requirement.

6.2 TRANSMISSION SYSTEM MODIFICATIONS

No transmission system modifications are anticipated in order to serve this project under normal system conditions.

6.3 DISTRIBUTION/TRANSMISSION LINE MODIFICATIONS

Following are the distribution system upgrades required for the OCS062 project to be connected. Figure 2 below shows the general location of the required projects.

- The Public Utility's Policy 138 requires all protective devices upstream of distribution system interconnected generators over 1.0 MW to be equipped with three pole tripping. There is a set of three 320 ampere, two shot sectionalizers that exist at facility point 01102032.0156603 located along Tutuilla Road south of Nye Avenue and are upstream of the proposed POI. Replacement of these sectionalizers with a Field Recloser ("FR") is required. In this study this recloser is labeled FR UMDXXX. Protection is required to be maintained at this location as a protective device here protects the Pendleton Middle School along with many homes and businesses from outages caused by faults occurring beyond this device. Communication assisted tripping is needed between FR UMDXXX and FR 5W676 as there is not adequate time interval available for timed overcurrent tripping coordination.
- To meet IEEE 1547 voltage fluctuation requirements an instantaneous generator output change from 100% to 0% must not produce more than a 3% change in voltage in any operating scenario. Studies show during peak load a generation output change from 100% to 0% results in a voltage change of up to 5.2 %. To correct this approximately 0.7 miles of three 1/0 ACSR primary and one #2 ACSR neutral conductors needs to be reconductored to three 477 AAC primary and neutral conductors from facility point 01102032.0150505 on SW 23rd St. north of SW Perkins Ave. east to facility point 01102032.0140702 located near latitude 45.656378°N, longitude 118.786757°W. After this reconductor it is projected the voltage change during peak loadings with a generation change from 100% to 0% output will result in a maximum 3.0% voltage change.
- At the POI construction is required; one pole will hold the Public Utility owned and operated gang switch and on one pole primary metering units will be installed. Conductor consisting of three 4/0 AAC primary and one 4/0 AAC neutral conductors will be installed from the POI to past this primary metering pole and will continue one span to land on the first Applicant owned pole, the termination of this conductor at the Applicant's pole will be the POC. These Public Utility facilities will require Right of Ways obtained by the applicant as required in Appendix 3.

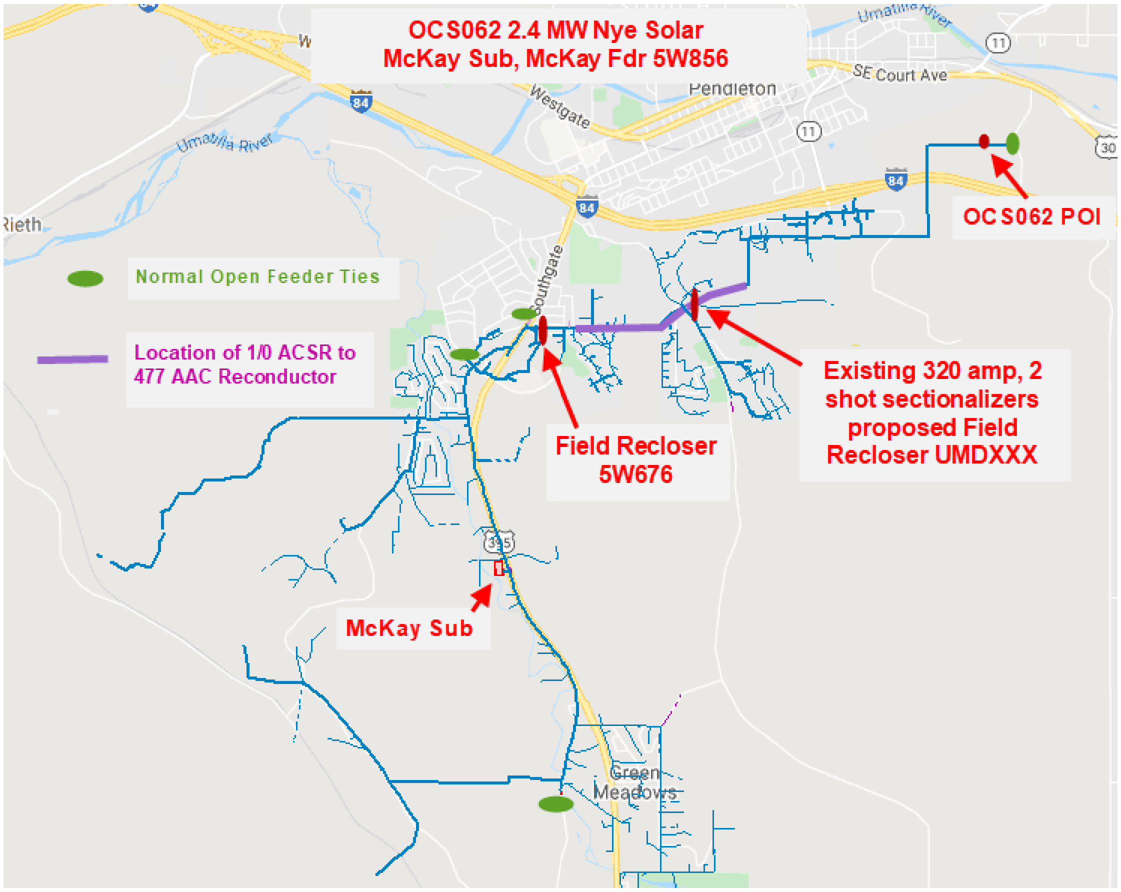

Figure 2: Map of Proposed 12.5 kV Construction

Transmission Line Modifications:

There are no identified power flow restrictions on the transmission system with the proposed generation online.

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 40 – 60 kW inverters connected to 2 – 1.5 MVA 12.47 kV – 480 V transformers 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 OCS062 Community Solar Project will need to disconnect in a high-speed manner for any faults on the 12.47 kV circuit 5W856 out of McKay substation, for faults in the 69 – 12.47 kV transformer, or on the 69 kV lines that McKay substation is connected. The minimum daytime load on circuit 5W856 is 2.06 MW which is less than the potential power output of the proposed OCS062 Community Solar Project. For this reason, the imbalance condition of the load and generation that the Community Solar Project could be isolated with following the opening of 5W856 cannot be relied upon to cause the high-speed disconnection of the Community Solar Project for faults on the distribution system. The combination of the OCS062 project and the OCS024 Community Solar Project which is planned to be connected to a feeder circuit connected to McKay substation will be well in excess of the minimum daytime load connected to McKay substation. A transfer trip circuit will be needed between McKay substation and the OCS062 recloser at the POI to deal with this. Since most faults on overhead lines are temporary and the lines can be restored as soon as all the sources of power to the fault have been disconnected the breaker 5W856 is equipped with automatic reclosing. When breaker 5W856 opens a transfer trip signal will be sent to the POI recloser to disconnect the Community Solar Project.

McKay substation is equipped with a transformer differential relay that can detect the fault current flowing in from both the 69 and 12.47 kV sides of the transformer for a fault in the transformer. For faults in the transformer, the transformer differential relay will send transfer trip through the existing 751 relaying. For the addition of the OCS062 project in combination with the OCS024 project line relays will need to be installed to detect faults on the 69 kV line to which McKay substation is connected. Due to the isolation that the power transformer provides to the 12.47 kV system for 69 kV faults, 69 kV voltage instrument transformers ("VT") will need to be installed to provide volts to the line relays. A transfer trip signal will be sent to the OCS062 POI recloser for the operation of the line, transformer, or 12.47 kV feeder relays.

To ensure that the automatic reclosing of breaker 5W856 does not take place before the Community Solar Project disconnects, a deadline checking control circuit will be installed. The deadline checking control circuit will delay the reclosing until the line is no longer energized to ensure that no damage is done to any of the existing customers' equipment. The enabling of this type of control will require the addition of VTs on the line side of breaker 5W856. The existing SEL 751 relay will be connected to these VTs.

There will be two line field reclosers between McKay substation and the OCS062 POI recloser. Line recloser 5W676 is close to Perkins Avenue which is approximately 8,690 circuit feet from McKay substation and the other is a planned line recloser, UMDXXX, which will be near Tutuilla Road approximately 6,990 feet from the POI. The Community Solar Project will need to disconnect in a high-speed manner for the operation of either of these reclosers so that the circuits can be automatically re-energized, restoring service to the customers on the circuit. The minimum daytime load on the circuit beyond either of these line reclosers will be well below the potential power output from the proposed Community Solar Project. For this reason, the imbalance condition of the load and generation that the Community Solar Project could be isolated with following the opening of either of the line reclosers cannot be relied upon to cause the high-speed disconnection of the Community Solar Project for faults on the distribution system. Transfer trip circuits will be needed between line reclosers and the OCS062 recloser at the POI to deal with this.

To ensure that the automatic reclosing of either line recloser does not take place before the Community Solar Project disconnects, a deadline checking control circuits will be installed. The deadline checking control circuit will delay the reclosing until the line is no longer energized to ensure that no damage is done to any of the existing customers' equipment. The relay/controller for 5W676 has this capability with the addition of VTs on the load side of the line recloser. The line recloser for the UMDXXX location will be purchased with this capability.

A 12.47 kV circuit recloser will need to be installed at the POI for the OCS062 project. This circuit recloser 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 Community Solar Project
2. Detect faults on the 12.47 kV line to McKay 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 McKay substation, line recloser 5W676, or line recloser UMDXXX.

6.6 Data Requirements (RTU)

Due to the power size of 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

A radio / optical fiber system will need to be installed between McKay Substation, line recloser 5W676, line recloser UMDXXX, the OCS062 POI recloser, and Cabbage Hill communication site for transfer trip circuits.

SEL-3031 spread-spectrum radios will be used to communicate with the POI recloser and recloser UMDXXX. Links will be established between those sites and the Public Utility's Cabbage Hill Comm Site. At the UMDXXX recloser, a 90' wood pole will be installed and equipment cabinet. At the POI recloser, 50' wood pole will be installed. At Cabbage Hill, the antennas will be mounted on the existing tower. 48-fiber, single-mode, ADSS cable will be installed on the distribution line from McKay Substation to recloser 5W676. The Public Utility will connect circuits between the four terminal sites from McKay and Cabbage Hill over existing communication systems.

6.8 Substation Requirements

OCS062 POI Substation

No substation requirements have been identified.

McKay Substation

A relay panel will be installed in the existing switchgear. The following equipment has been identified as being required and may change during detailed design.

3 – 69 kV, VT
1 – 12400-120 V, three phase, pad mounted transformer

6.9 METERING REQUIREMENTS

Interchange Metering

The metering will be located on the high side of the customer 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 on the pole near the ground. 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.

Project Administration *Project management and administrative support*	$21,000
Relay Setting Development *P&C Engineer and Relay Technician*	$30,000
Distribution *Line extension, reconductor ~0.7 miles, install recloser*	$402,000
Metering *Metering equipment*	$26,000
Communications *Install fiber, communications at reclosers, POI,* *Cabbage Hill Communications Site and McKay Substation*	$221,000
McKay Substation *Install relay panel, VTs and pad mounted transformer*	$240,000
Other Costs *Capital surcharge*	$75,000
Total	**$1,015,000**

*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 does not support the Applicant's requested commercial operation date of December 31, 2021.

9.0 Participation by Affected Systems

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

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

10.0 Appendices

Appendix 1: Higher Priority Requests
Appendix 2: 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:

Q0547 (18 MW)
Q0586 (6 MW)
Q0666 (1.98 MW)
Q1045 (3 MW)
OCS024 (1.56 MW)

10.2 Appendix 2: Informational Network Resource Interconnection Service Assessment

The following is the Public Utility's assessment of the requirements that would be assigned to this interconnection request were it to be for network resource interconnection service. This assessment is for informational purposes only as part of the Oregon Community Solar program and is not required for the Applicant's interconnection request.

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 Pendleton area where the CSP generator proposes to interconnect, 2.4 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

- The McKay Sub 5W586 McKay Feeder will consist of parts of three different feeders Buckaroo Sub 5W202 Reith and 5W203 Montee Feeders as well as a small part of Pilot Rock's 5W406 City Feeder. SCADA metering exists at Buckaroo Sub with only peak reads available at Pilot Rock. A CYME system study was performed and which projects the following Minimum Daytime Load (MDL) at times during the year on 5W856 and McKay Sub.
  - McKay Sub Bank #1 = 2.87 MW
  - 5W856 – McKay Feeder MDL = 2.06 MW
  - Field Recloser 5W676 MDL = 0.96MW
  - Proposed Field Recloser UMDXXX = 0.38 MW.

- This 2.4 MW OCS062 project will result in this generation being
  - McKay Sub Bank #1 – 138% of the transformers projected MDL (includes higher queued projects)
  - CB 5W856 – 117% of the feeders projected MDL.
  - Field Recloser 5W676 -251% of the recloser projected MDL.
  - Proposed Field Recloser UMDXXX – 628% of the reclosers projected MDL.

- The total minimum daytime load on McKay substation is estimated to be 2.87 MW with all area generation offline / 1.31 MW with previously queued generation online. This project is likely to back-feed the 69 kV transmission system.

- The total minimum daytime load on the 69 kV transmission system, as measured at BPA Roundup substation is 22.9 MW with all area generation offline. This project is likely to back-feed the 230 kV transmission system at BPA Roundup.

Community Solar Project Interconnection

Community Solar Project System Impact Study Report

Completed for

Sunthurst Energy, LLC

(“Applicant”)

OCS063

Reith Solar

Proposed Point of Interconnection

Circuit 5W202 out of Buckaroo substation at 12.47 kV

(at approximately 45°39'51.8"N, 118°50'04.5"W)

May 3, 2021

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1.0 DESCRIPTION OF THE COMMUNITY SOLAR PROJECT

Sunthurst Energy, LLC ("Applicant") proposed interconnecting 2.99 MW of new generation to PacifiCorp's ("Public Utility") circuit 5W202 out of Buckaroo substation located in Umatilla County, Oregon. The Reith Solar project ("Project") will consist of forty-nine (49) CHINT SCA60KTL 60 kW inverters and one (1) CHINT SCA50KTL 50 kW inverter for a total requested nameplate output of 2.99 MW. The requested commercial operation date is December 31, 2021.

The Public Utility has assigned the Project "OCS063."

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 5W202 out of Buckaroo substation via a 12.47 kV primary meter. The proposed Point of Interconnection ("POI") will be located at approximately 45°39'51.8"N, 118°50'04.5"W located in Umatilla County, Oregon. This proposed POI is on the 12.47 kV distribution from Buckaroo Substation underbuild on the Public Utility's Coyote Creek 69 kV Transmission line between the Buckaroo and McKay substations on pole numbered 8/007. Distribution facilities will need to be installed as underbuild along a portion of the 69 kV transmission line. Figure 1 below is a one line diagram that illustrates the interconnection of the proposed Community Solar Project to the Public Utility's system.

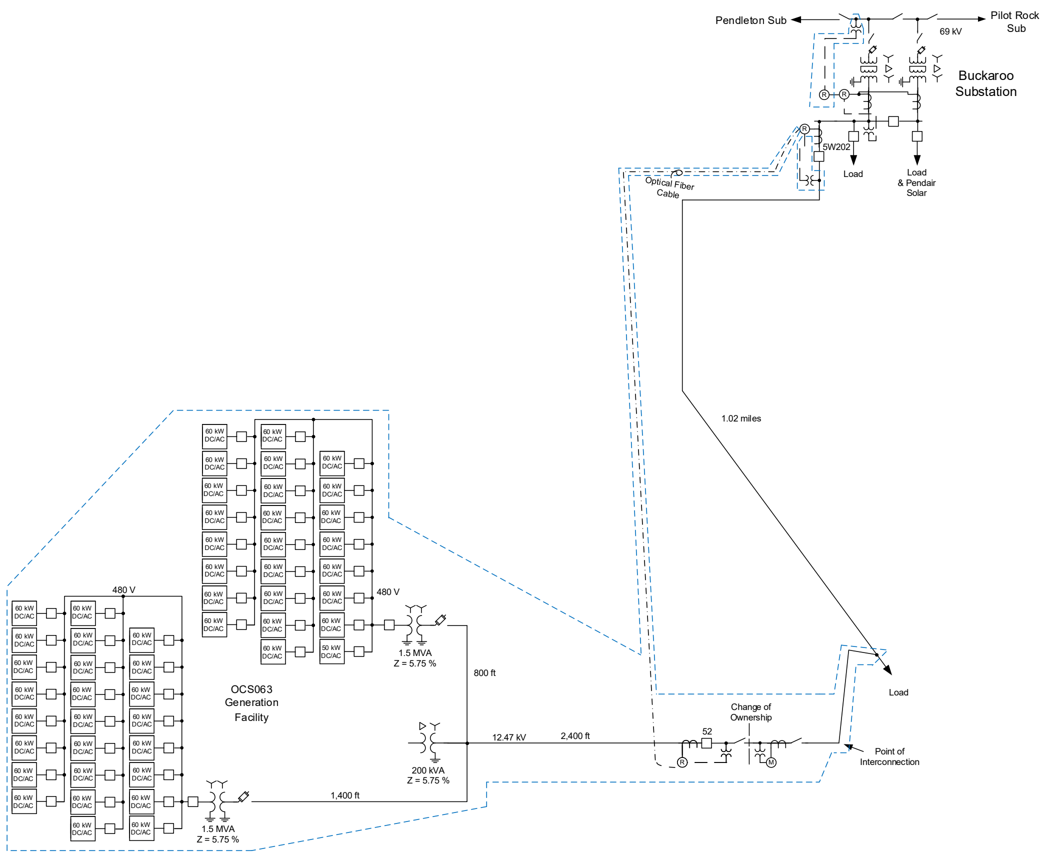

Figure 1: System One Line Diagram

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 Generator Facility is expected to operate during daylight hours every day 7 days per week 12 months per year.
- The Generator Facility is expected to operate in constant power factor mode with a unity power factor setting unless otherwise requested by the Public Utility. The study was conducted assuming the generation stayed within the 0.95 +/- power factor range.
- 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 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. 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.

Any 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. 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.

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

The Generation 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. Figure 1 shows the addition of a 12.47 kV 200 kVA wye – delta grounding transformer with an impedance of 5.75 %. This transformer will meet this requirement.

The submitted site plan shows a 170' span from the Public Utility's primary meter pole to the first Applicant owned switch pole with an additional 50' to the Applicant owned recloser pole. This distance is greater than the allowed distance stated in the Public Utility's Electric Service Requirements (ESR) manual section 9.6 which requires customer owned means of disconnecting and overcurrent protection to be within sight of and not more than 100' from the primary metering location. ESR requirements need to be met, the pole locations holding the Applicant's switch and overcurrent protection will be determined by an onsite meeting with agreement by the Applicant and the Public Utility's local design estimator.

6.2 TRANSMISSION SYSTEM MODIFICATIONS

No Transmission System Modifications are anticipated in order to serve this project under normal system conditions.

6.3 DISTRIBUTION/TRANSMISSION LINE MODIFICATIONS

No 12.5 kV facilities presently exist at the Applicant's proposed POI. As shown in Figure 2 below the following construction will be required for adequate 12.5 kV facilities to exist.

- The Public Utility's Policy 138 requires all protective devices upstream of distribution interconnected generators over 1.0 MW to be equipped with three pole tripping. There are two fusing locations upstream of the proposed POI. In lieu of replacing these fuses with field reclosers the Public Utility proposes to remove these fuses and install fusing on the two existing taps off the proposed route to the POI. This will add additional exposure to faults seen by CB 5W202 at Buckaroo substation.
- Approximately 2,100' of 12.5 kV three phase 4/0 AAC primary and neutral will be installed to include:
  - Replacement of 550' of three existing #6 CU primary and neutral conductors from facility point number ("fp#")087500 to fp#086601. This #6 CU needs to be replaced because it will not be adequately protected by the CB 5W202 at Buckaroo substation after the fusing is removed.
  - Replace 600' of single and two phase existing #6 CU primary and neutral conductors from fp#086603 to fp#087400 as underbuild of the existing 69 kV transmission line.
  - Install 950' of new conductor from fp#087400 south to the POI as underbuild of the existing 69 kV transmission line.
  - Detail design of this job will be required prior to knowing if any pole replacements will be required.

At the POI one pole will hold the Public Utility owned and operated gang switch and on one pole primary metering units will be installed. Conductor from this primary metering pole will be installed one span to land on the first Applicant owned pole, the termination of this conductor at the Applicant's pole will be the change of ownership/point of common coupling. These Public Utility facilities will require Right of Ways obtained by the applicant as required in Appendix 3.All poles which will hold material and equipment belonging to the Public Utility must be accessible year-round by the Public Utility's line trucks.

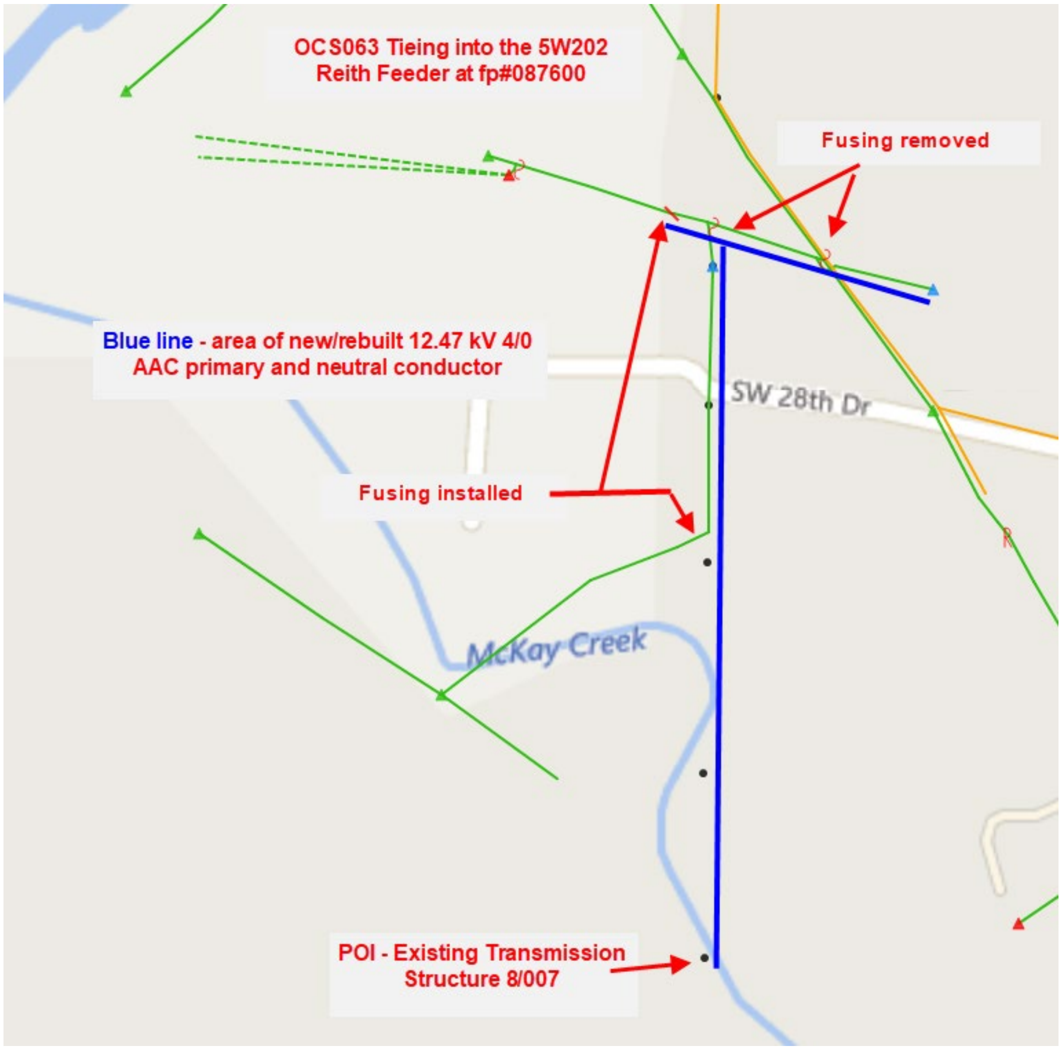

Figure 2: Proposed 12.5 kV Construction

Transmission Line Modifications:

- There are no identified power flow restrictions on the transmission system with the proposed generation online; however, since the POI is along the Public Utility's Coyote Creek 69 kV transmission line, distribution facilities will need to be installed as new underbuild between structures 8/7 and 10/7. Existing underbuild will need to be modified between structures 10/7 and 12/7.
- Transmission structures 9/7, 10/7, and 12/7 require replacement to accommodate the new distribution underbuild.

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 49 – 60 kW inverters and 1 – 50 kW inverter connected to 2 – 1.5 MVA 12.47 kV – 480 V transformers 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 OCS063 Community Solar Project will need to disconnect in a high-speed manner for any faults on the 12.47 kV circuit 5W202 out of Buckaroo substation, for faults in the 69 – 12.47 kV transformers, or on the 69 kV lines to which Buckaroo substation is connected. The minimum daytime load on circuit 5W202 is 1.62 MW which is less than the potential power output of the proposed OCS063 Community Solar Project. For this reason, the imbalance condition of the load and generation that the Community Solar Project could be isolated with following the opening of 5W202 cannot be relied upon to cause the high-speed disconnection of the Community Solar Project for faults on the distribution system. The combination of the OCS063 project and the existing solar-electric generation project which is connected to a feeder circuit connected to Buckaroo substation will be well in excess of the minimum daytime load connected to Buckaroo substation. A transfer trip circuit will be needed between Buckaroo substation and the OCS063 recloser at the POI to deal with this. Since most faults on overhead lines are temporary and the lines can be restored as soon as all the sources of power to the fault have been disconnected the breaker 5W202 is equipped with automatic reclosing. When breaker 5W202 opens a transfer trip signal will be sent to the POI recloser to disconnect the Community Solar Project.

When the existing solar-electric generation project was installed modifications were made to the relays in Buckaroo substation. As part of those modifications, relays were installed to detect faults in the 69 – 12.47 kV transformers. For faults in the transformers, the 11T (SEL-751)) relay will send transfer trip through the existing 751 relaying. For the addition of the OCS063 project line relays will need to be installed to detect faults on the 69 kV line that Buckaroo substation is connected. Due to the isolation that the power transformers provide to the 12.47 kV system for 69 kV faults, 69 kV voltage instrument transformers (VT) will need to be installed to provide volts to the line relays. A transfer trip signal will be sent to the OCS063 POI recloser the operation of the line, transformer, or 12.47 kV feeder relays. To ensure that the automatic reclosing of breaker 5W202 does not take place before the solar-electric plant disconnects, a deadline checking control circuit will be installed. The deadline checking control circuit will delay the reclosing until the line is no longer energized to ensure that no damage is done to any of the existing customers' equipment. The enabling of this type of controls will require the addition of a VT on the line side of breaker 5W202. The existing 751 relay will be connected to these VTs.

A 12.47 kV circuit recloser will need to be installed at the POI for the OCS063 project. This circuit recloser 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 line and equipment at the Community Solar Generation Project
2. Detect faults on the 12.47 kV line to Buckaroo 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 Buckaroo 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.

6.7 Communication Requirements

A radio system will need to be installed between Buckaroo substation and the OCS063 POI recloser for transfer trip. Since no RTU is required at the Community Solar Project no communication circuit will be required for this function.

A 30' wood pole will be installed at the POI recloser. SEL-3031 spread-spectrum radios, yagi antennas and coax cable will be installed at both ends. At Buckaroo substation, the antenna will be mounted on the existing microwave tower. At the POI recloser, the antenna will be mounted on the wood pole, and a comm cabinet will be installed with the radio, an SEL-2812 transceiver, and DC system. The same equipment will be installed at Buckaroo substation, but will be mounted in a comm rack in the control house. Another SEL-2812 transceiver will interface with the relays' RS232 port. Fiber jumpers will be installed between the transceivers at both locations.

6.8 Substation Requirements

OCS063 POI

No substation requirements have been identified.

Buckaroo Substation

The substation fence will be expanded to support the installation of a 12.47 kV VT. The ground grid will be expanded, and a CDEGS grounding analysis will be performed. A relay panel will be installed in the control house. The following equipment has been identified as being required and may change during detailed design.

3 – 69 kV, VT
1 – 12.47 kV, VT

6.9 Metering Requirements

<u>Interchange Metering</u>

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.

Project Administration *Project management, administrative support*	$21,000
Relay Setting Development *P&C Engineer and Relay Technician*	$15,000
Distribution *Line extension, reconductor and install fuses*	$64,000
Metering *Metering equipment*	$26,000
Communications *Install communications at POI and Buckaroo substation*	$54,000
Buckaroo Substation *Expand substation, install relay panel and VTs*	$300,000
Coyote Creek 69 kV Transmission Line *Replace three transmission structures*	$67,000
Other Costs *Capital surcharge*	$44,000
Total	**$591,000**

*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 a does not support the Applicant's requested commercial operation date of December 31, 2021.

9.0 PARTICIPATION BY AFFECTED SYSTEMS

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

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

10.0 APPENDICES

Appendix 1: Higher Priority Requests
Appendix 2: 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:

Q0547 (18 MW)
Q0586 (6 MW)
Q0666 (1.98 MW)
Q1045 (3 MW)
OCS024 (1.56 MW)
OCS062 (2.4 MW)

10.2 Appendix 2: Informational Network Resource Interconnection Service Assessment

The following is the Public Utility's assessment of the requirements that would be assigned to this interconnection request were it to be for network resource interconnection service. This assessment is for informational purposes only as part of the Oregon Community Solar program and is not required for the Applicant's interconnection request.

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 Pendleton area where the CSP generator proposes to interconnect, 2.4 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

- The Buckaroo Sub 5W202 Reith Feeder has SCADA metering and shows 2.7 MW Minimum Daytime Load (MDL) at times during the year. A portion of this 5W202 feeder will be transferred to a new McKay feeder 5W856 presently scheduled to go into service in the summer of 2021. Using our CYME distribution model, it is estimated that the MDL on the remaining 5W202 feeder will be 1.65 MW.

- This 2.99 MW OCS063 project will result in this generation being 182% of the feeders projected existing MDL.

- The total minimum daytime load on Buckaroo substation (both transformers) is estimated to be 5.5 MW with all area generation offline. This project is likely to back-feed the 69 kV transmission system.

- The total minimum daytime load on the 69 kV transmission system, as measured at BPA Roundup substation is 22.9 MW with all area generation offline. This project is likely to back-feed the 230 kV transmission system at BPA Roundup.