Community Solar Project Interconnection

Community Solar Project System Impact Study Report

Completed for

(“Applicant”)
OCS082

Proposed Point of Interconnection

Circuit 5R245 out of Ashland substation

November 2, 2023

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1.0 DESCRIPTION OF THE COMMUNITY SOLAR PROJECT

(“Applicant”) proposed interconnecting 1.0 MW of new generation to PacifiCorp’s (“Public Utility”) circuit 5R245 out of Ashland substation located in Jackson County, Oregon. The Solar project (“Project”) will consist of ten (10) SOLIS 100K 5G US inverters for a total requested output of 1.0 MW. The requested commercial operation date is March 31, 2023.

The Public Utility has assigned the Project “OCS082.”

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 5R245 out of Ashland substation via a 12.47 kV primary meter. The proposed Point of Interconnection is located in Jackson 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.

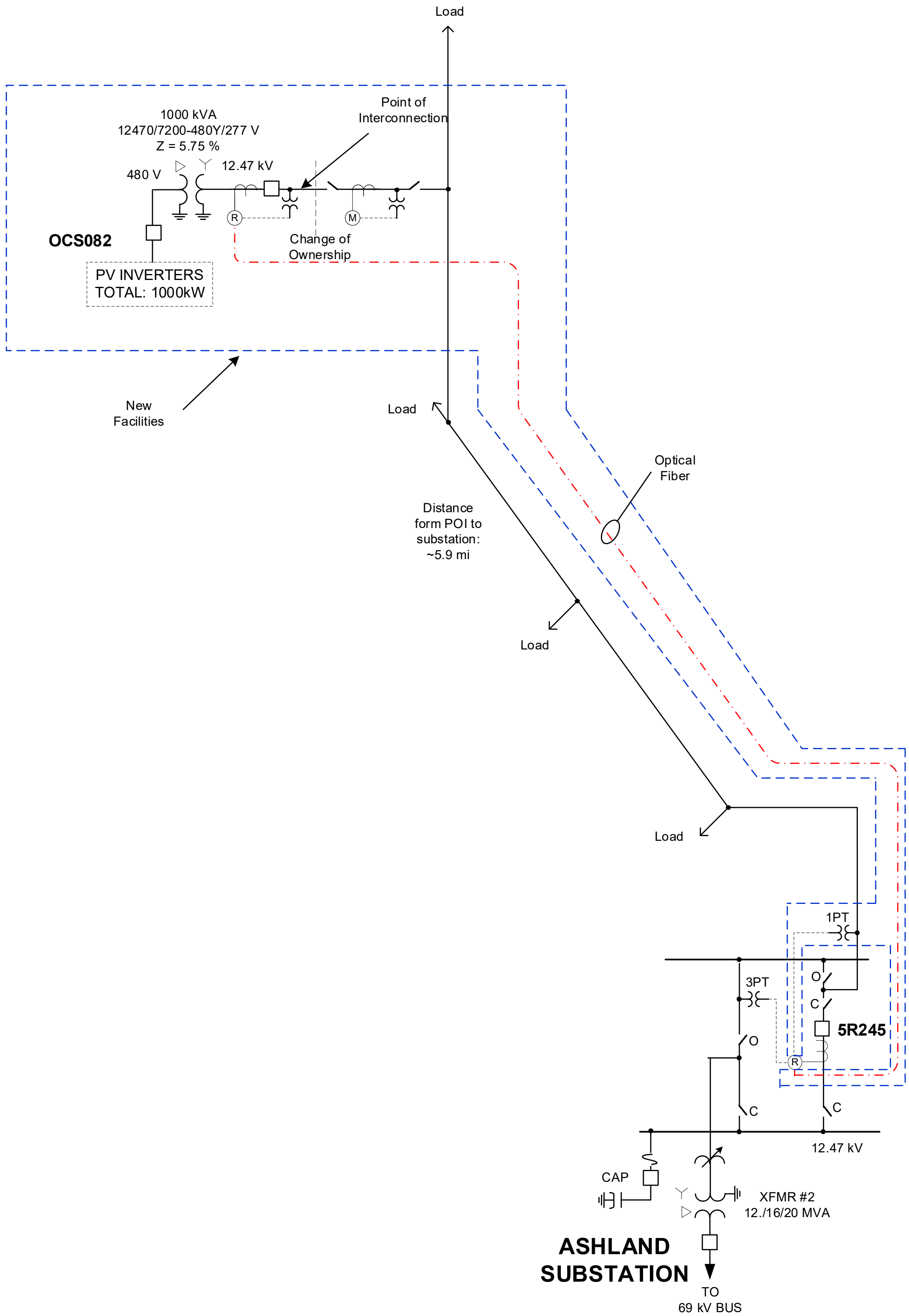

Figure 1: System One Line Diagram

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 Point of Interconnection.
- The Applicant will construct and own any facilities required between the Point of Interconnection 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 line extension is assumed to originate at facility point 1438001.0171300.
- The generators were assumed to operate during daylight hours, 7 days per week, 12 months per year. The generation contribution at the POI was assumed to be 1000 kW at unity power factor.
- The study assumes that the Applicant will provide constant power factor control at unity power factor (100% PF).
- An Ashland T-3499 substation transformer daytime minimum load of 4820 kW at unity power factor was measured in June 2023.
- Ashland 5R245 circuit daytime minimum load of 868 kilowatts was measured in June 2023. The new generation is expected to result in reverse flow on the circuit.
- For Ashland T-3499, a summer peak loading of 19,529 kVA at 98% power factor and a winter peak loading of 17,918 kVA at 100% power factor were assumed.
- For 5R245, a summer peak loading of 4404 kVA at 94% power factor and a winter peak loading of 5450 kVA at 99% power factor were assumed.
- The 480 delta - 12470 grounded-wye connection for the step-up transformer is appropriate and no grounding transformer is needed.
- 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 website 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 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% 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.

6.2 Transmission System Modifications

- The interconnection of the Project is not expected to cause reverse power flow on the 115-12.47 kV transformer T-3499 at Ashland substation.
- No transmission system modifications are required to accommodate the proposed Applicant's generation facility.

6.3 Distribution/Transmission Line Modifications

The load flow model was modified from its present state to its future state by including the following construction items:

- Extend 11,500 feet of three-phase, 4/0 AAC overhead conductor from existing poles 1438001.0308405 to pole 1438001.0171300
- Install three 65T line fuses at pole 1438001.0308406
- Remove the single-phase line regular at pole 1438001.0308500
- Remove the single-phase 25T fuse at pole 1438001.0198500

- Remove the single-phase 15T fuse at pole 1438001.0170300
- Installing a single-phase 15T fuse at pole 1438001.0171400
- Swap the single-phase tap from B-phase to A-phase at pole 1438001.0198001
- Swap the single-phase tap from B-phase to C-phase at pole 1438001.0198202
- Swap the single-phase tap from B-phase to C-phase at pole 1438001.0170300
- Swap the single-phase tap from B-phase to C-phase at pole 1438001.0170303
- Leave all transformers and other taps along the three-phase extension connected to B-phase

Extend 12.47 kV facilities from the existing facility point 1438001.0171300 to the POI. This line extension will required at a minimum of two new utility poles. A three-phase, gang-operated, load break disconnect switch is required on the first pole. A primary metering assembly is required on the second pole. Additional poles may be required if other utility departments specify a control house and/or utility protective device. The Applicant will be responsible for obtaining all necessary permissions and easements.

The load tap changer settings for Ashland T-3499 will be modified to a base voltage of 123 volts with no resistive or reactive compensation.

The calculated voltage fluctuation from full generation to no generation in the daytime minimum load case was 2.5%.

6.4 Existing Breaker Modifications – Short-Circuit

The increase in the fault duty on the system as the result of the addition of the 1000kW Community Solar Project with photovoltaic arrays connected to a 1.0 MVA 12.47 kV – 480 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

OCS082 will need to disconnect in a high-speed manner for any faults on the 12.47 kV circuit 5R245 out of Ashland substation. This creates the need for a recloser at the POI, which will serve a manual an automatic disconnection device for OCS082. This recloser will also open in case the voltage and frequency deviates from the tolerance limits of the Public Utility; therefore, the recloser relay will be programmed to perform that function.

The minimum daytime load on circuit 5R245 is less than the potential power output of the proposed OCS082 Community Solar Project. For this reason, the imbalance condition of the load is such that it cannot be isolated with just the opening of 5R245; therefore, a transfer trip circuit will be needed between Ashland substation and the OCS082 recloser at the POI to deal with this. When breaker 5R245 opens, a transfer trip signal will be sent to the POI recloser to disconnect the Community Solar Project. 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 5R245 will be equipped with automatic reclosing. The reclosing must be delayed until the OCS082 disconnects; this will be achieved by monitoring the line voltage with at least one new potential transformer. The overcurrent protective relay elements associated with the 5R245 circuit breaker need to be directional to avoid operation for faults in the neighbor circuits due to the feeding from the OCS082 plant. The three-phase voltage can be taken form the three bus potential transformers.

6.6 Data Requirements (RTU)

This sites output is less than the 3MW threshold for SCADA addition. No SCADA scope.

6.7 Communication Requirements

A 915 MHz spread spectrum radio system will be installed to carry protective relaying circuits between the POI and Ashland substation. A 30’ AGL wood pole will be installed at the POI along with yagi antenna, coaxial cable, and an SEL-3031 radio. The radio will be installed in a cabinet with DC charger and battery. SEL-2812 transceivers will be installed to interface the radio with the relay. This radio will communicate with another SEL-3031 radio that will be installed at the Public Utility’s Mt Baldy communication site.

The yagi antenna communicating with the POI at Mt Baldy will be mounted at about the 50’ elevation on the existing tower. Another SEL-3031 system will be installed between Mt Baldy and Ashland Substation. The yagi antennas in this system will need to be mounted near the tops of both existing towers: at the 100’ elevation at Mt Baldy and at the 48’ elevation at Ashland substation. A serial port of each of the radios at Mt Baldy will be connected to one on the other radio.

At Ashland, a serial port from the radio will be connected to the relay’s comm port.

6.8 Substation Requirements

The Applicant will provide a separate graded, grounded and fenced area along the perimeter of the Applicant’s OCS082 for the Public Utility to install a control house for any required metering, protection or communication equipment. This area will share a fence and ground grid with OCS082 and have separate, unencumbered access for the Public Utility. AC station service and DC power for the control house will be supplied by the Public Utility.

6.9 Metering Requirements

Interchange Metering

The metering will be located on the high side of the customer generator step up transformer at the Point of Interconnection. The metering will be installed overhead on a pole per distribution DM construction standards. 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

Prior to construction, Applicant must arrange construction power with the Public Utility as holding the certificated service territory rights for the area in which the load is physically located. Station service and temporary construction power metering shall conform to the Six State Electric Service Requirements manual.

Please note, prior to back feed, Applicant must arrange distribution voltage retail meter service for electricity consumed by the Project and arrange back up station service for power that will be drawn from the distribution line when the Project is not generating. 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*	$17,000
Protection and Control *Relay settings development, review and implementation*	$15,000
Distribution Upgrades *Line extension, fuses*	$950,000
Metering *Metering equipment*	$26,000
Communications *Communications equipment at recloser, POI, Mt Baldy communication site*	$77,000
Other Costs *Capital surcharge and contingency*	$232,000
Total	**$1,317,000**

*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 OCS082 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 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 March 31, 2023.

9.0 PARTICIPATION BY AFFECTED SYSTEMS

Public Utility has identified the following Affected Systems: None

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:

GI Queue	Size (MW)
721	55
741	40
849	100
OCS003	0.8
OCS004	0.8
OCS019	0.88
OCS020	0.17
OCS025	2.80
OCS034	0.98
OCS036	1.13
OCS039	2.25
OCS044	0.36
OCS046	2.25
OCSO47	2.25
OCS048	1.50
OCS049	2.99
OCS050	1.00
OCS051	1.50
OCS055	1.35
OCS058	1.25
OCS067	1.00
OCS070	2.00
C1-15	2.30
C2-180	80
C2-181	80
C2-203	400
C2-210	80

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 southern 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 point of interconnection 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.