Community Solar Project Interconnection

Community Solar Project System Impact Study Report

Completed for

("Applicant")
OCS043

Circuit 5W105 out of Umapine substation at 12.47
(At approximately 45°57'26.5"N, 118°25'59.1"W)

Proposed Point of Interconnection

December 23, 2020

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1.0 Description of the Community Solar Project

("Applicant") proposed interconnecting 0.36 MW of new generation to PacifiCorp's ("Public Utility") circuit 5W105 out of Umapine substation located in Umatilla County, Oregon. The project ("Project") will consist of three Delta M125HV (factory derated to 120 kW) inverters for a total requested nameplate output of 0.36 MW. The requested commercial operation date is May 31, 2021.

The Public Utility has assigned the Project "OCS043."

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 5W105 out of Umapine substation via a 12.47 kV primary meter. The proposed Point of Interconnection ("POI") will be located at approximately 45°57'26.5"N, 118°25'59.1"W, is estimated to be along Prunedale road near map string 1106035.0340701 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.

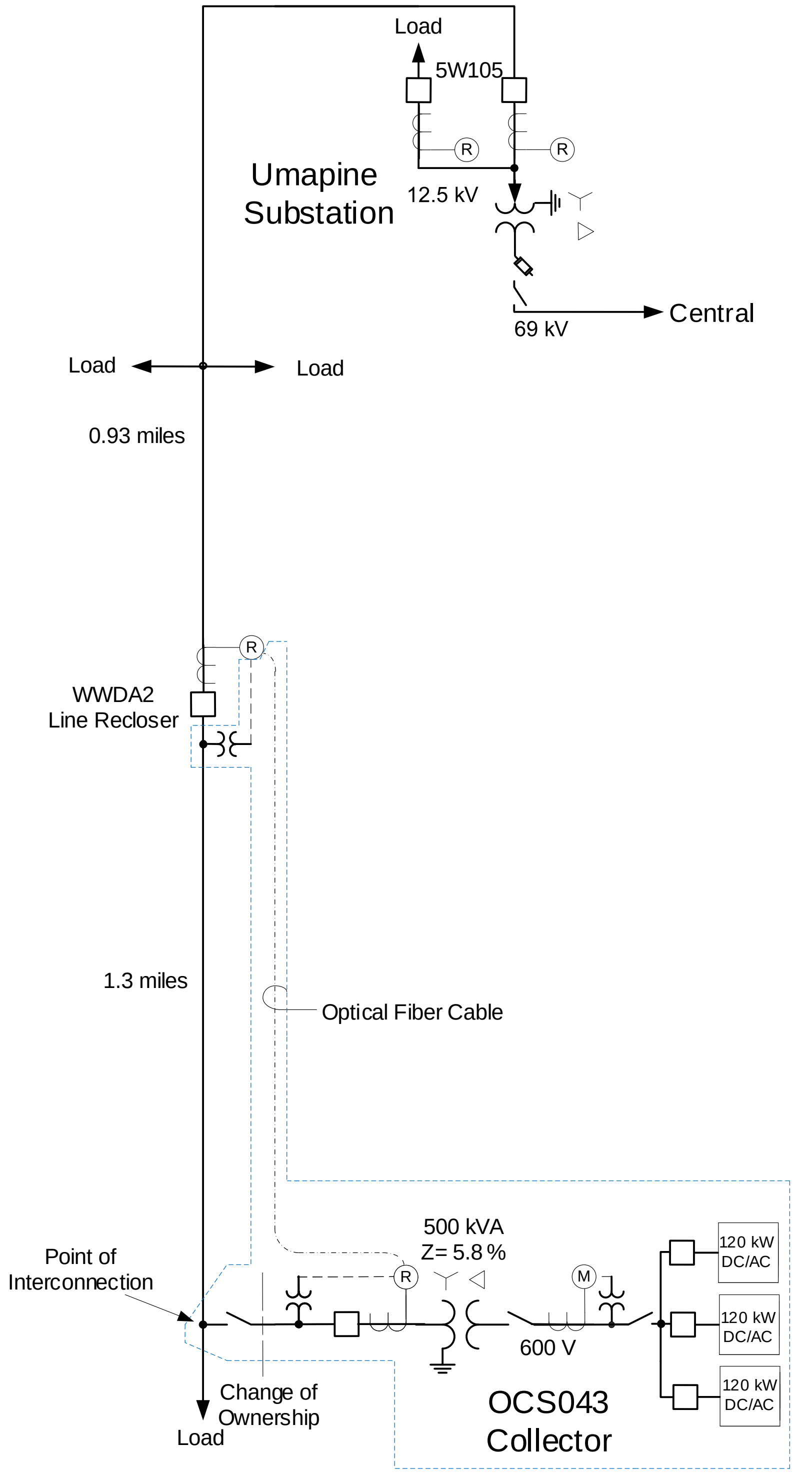

Figure 1: System One Line Diagram

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.
- Umapine substation has no time of use or SCADA metering data, the existing minimum daytime load on the 5W105 feeder is calculated as (35% of minimum monthly peak from manual reads) – (Existing DER) – (Proposed DER). The existing minimum daytime load through field recloser WWDA2 was estimated using a CYME system model computed with the calculated minimum daytime load on the 5W105 feeder.
    - The 5W105 feeder is estimated to have a 48% OCS043 proposed generation to existing minimum daytime load ratio.
        - This is calculated by:
          743 kW existing minimum daytime load (2,464 kW * 35% - 119 kW)
          360 kW proposed generation from OCS043
          48% OCS043 to minimum daytime load ratio (360 ÷ 743)
    - The WWDA2 field recloser is estimated to have a 407% OCS043 proposed generation to existing minimum daytime load ratio.
        - This is calculated by:
          88 kW existing minimum daytime load (93 kW CYME model – 5 kW)
          360 kW total generation from OCS043
          407% generation to minimum daytime load ratio (88 ÷ 360)
- 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.
- Contingency transmission configuration for the Public Utility's system is defined as any configuration other than normal transmission configuration.

- Two case studies were assembled and studied in power flow simulation at the transmission level:
  - Case 1: Normal Configuration, with Umapine substation fed radially via the 69 kV line from Central substation.
  - Case 2: Contingency Configuration with Umapine substation fed radially via the 69 kV line from Pendleton substation
- 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 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.

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.

Certain contingency configurations may warrant generation curtailment until the system returns to a normal state. This includes an outage of the 69 kV line from Central, resulting in loss of service and, under certain circumstances, restoration from the alternate 69 kV line sourced from Pendleton substation.

6.2 Transmission System Modifications

None.

6.3 Distribution/Transmission Line Modifications

From the POI along Prunedale Road south of Burris Lane the Public Utility will design, procure, and install a #2 AAAC primary and neutral conductor line extension onto private property to the Point of Ownership Change (POC). The last pole will hold the Public Utility owned and operated gang switch, conductor from this 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 POC. These Public Utility facilities will require Right of Ways obtained by the Applicant as required in Appendix 3.

6.4 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 3– 120 kW inverters connected to 1 – 500 kVA 12.47 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 OCS043 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 5W105 out of Umapine substation. The minimum daytime load on circuit 5W105 is 734 kW which is above the maximum potential power output of the proposed OCS043 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 facilities for faults on the distribution system.

The Community Solar Project is planned to be connected beyond an existing line recloser WWDA2 at facility point 01106035.0270902. During some daytime periods the load beyond the recloser will be less than the potential generation from the proposed Community Solar Project . Because 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 12.47 kV circuit beyond the recloser a transfer trip circuit will be required between the line recloser and the OCS043 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. An optical fiber cable will be installed between the WWDA2 line recloser and the OCS043 POI recloser to carry the transfer trip signal.

With the addition of the OCS043 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 WWDA2 and Umapine substation to be above the pickup value for the ground overcurrent element in the recloser. With the current recloser this will cause it to trip for these type faults. This will down grade the service to the existing customers and will not be acceptable. The ground overcurrent element in the relay for the line recloser will need to be set to be directional looking toward the OCS043 Community Solar Project.

The line recloser WWDA2 will need to be modified to accommodate the requirements for this project. A three-phase set of voltage instrument transformers will be added to the load side of the recloser. With the three-phase line voltages the ground overcurrent elements can be set to function directional. The voltages from the voltage instrument transformers will also be used to delay the reclosing until there is indication that the line is dead. An optical transceiver will be added to the relay's serial port to communicate over the optical fiber cable with the OCS043 POI recloser to set transfer trip for the opening of the WWDA2 recloser.

The 12.47 kV circuit recloser planned to be installed at the OCS043 Community Solar 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 Community Solar Project
2. Detect faults on the 12.47 kV line to Umapine Substation
3. Monitor the voltage and react to under or over frequency, and/or magnitude of the voltage
4. Communicate with line recloser WWDA2 to receive transfer trip from the line recloser

6.6 DATA REQUIREMENTS (RTU)

Due to the power size of the solar-electric generation facility 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

An optical fiber cable will need to be installed along the distribution line between the line recloser WWDA2 and the OCS043 POI recloser for transfer trip. 48-fiber, single-mode, ADSS cable will be installed on the distribution line and terminated at patch panels at both locations. The patch panels will be mounted in cabinets. SEL-2829 fiber optic transceivers will also be installed in the cabinets at both ends, and jumpers installed between them and the patch panels. The serial ports of the SEL-2829s will be connected to the relays' comm ports at both ends.

6.8 SUBSTATION REQUIREMENTS

No substation modifications are required.

6.9 METERING REQUIREMENTS

Interchange Metering

Due to the size of project at 360 kW the revenue metering equipment will be located on the low side of generator step up transformer. The metering will be bi-directional to measure kWH and KVARH quantities. The metering programming is for both generation received to the Public Utility and delivered retail load to the Applicant per tariff when not generating. The metering generation and billing data will be remotely interrogated via the Public Utility's MV90 data acquisition system.

The present output rating does not require metering DNP real time data

The Public Utility will provide the metering instrument transformers, meter, test switch and communication cellular package. Create meter program/design, test and complete an in-service accuracy verification of the metering package. The Applicant has indicated 600 volt at low side of the Generator Step up Transformer. If this is the final design additional metering transformers JVA-0C will be required to step doing 600 volts to metering voltages. The Applicant will install the secondary service entrance equipment. The meter mounting will conform to the Public Utility's Six State Electric Service Requirements manual. The Applicant will supply the transformer electrical test data as the meter will be transformer loss compensated.

Station Service/Construction Power

Prior to construction, Applicant must arrange temporary construction power metering and retail load power that is 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.

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.

OCS043 Collector Station *Install metering and transfer trip*	$85,000
Distribution *Line extension with gang switch*	$48,000
Line Recloser WWDA2 *Install communications and protection and controls upgrades*	$35,000
Communications *Install ~1.3 miles of fiber*	$62,000
Total	**$230,000**

*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 May 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

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:

Q#	Size (MW)
650	10.000
651	10.000
652	10.000
653	10.000
OCS005	0.36
OCS011	1.00
OCS018	0.567
OCS024	1.56

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.

The proposed POI is part of the Walla Walla transmission bubble, which currently has insufficient network load (at peak) to absorb any additional generation. Therefore, to deliver the aggregate of generation in the local system to the aggregate of load (the NRIS study scope), construction of a new 230 kV transmission line from the Walla Walla area system to the Yakima area system (where the generation could be absorbed) may be required, at a minimum. The new 230 kV line would interconnect Walla Walla substation with Wine Country substation in the vicinity of Grandview, Washington. The new 230 kV line would be approximately 90-100 miles, depending on the line route. Upgrades at both Walla Walla and Wine Country substations would be required to tie in the new line. The Public Utility's high level estimate for this transmission line is $75,000,000.

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

- Two case studies were assembled and studied in power flow simulation at the transmission level:
  - Case 1: Normal Configuration, with Umapine substation fed radially via the 69 kV line from Central substation.
  - Case 2: Contingency Configuration with Umapine substation fed radially via the 69 kV line from Pendleton substation

- Under normal configuration, there are no identified power flow restrictions on the transmission system with the proposed generation online.