Community Solar Project Interconnection

Community Solar Project System Impact Study Report

Completed for

(“Applicant”)
OCS025

Proposed Point of Interconnection

Circuit 5L12 out of Westside substation at 12.0 kV
(At approximately 42°12'27.58"N, 121°48'52.48"W)

July 21, 2020

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1.0 Description of the Community Solar Project

("Applicant") proposed interconnecting 2.8 MW of new generation to PacifiCorp's ("Public Utility") circuit 5L12 out of Westside substation near 42°12'27.58"N, 121°48'52.48"W located in Klamath County, Oregon. The project ("Project") will consist of twenty four (24) Delta M125HV inverters factory limited to a total requested nameplate output of 2.8 MW. The requested commercial operation date is December 31, 2020.

The Public Utility has assigned the Project "OCS025."

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 5L12 out of Westside substation via a new primary meter. The Point of Interconnection ("POI") will be located near 42°12'27.58"N, 121°48'52.48"W in Klamath County, Oregon. Figures 1 and 2 below are one line diagrams that that illustrate the interconnection of the proposed generating facility to the Public Utility's system.

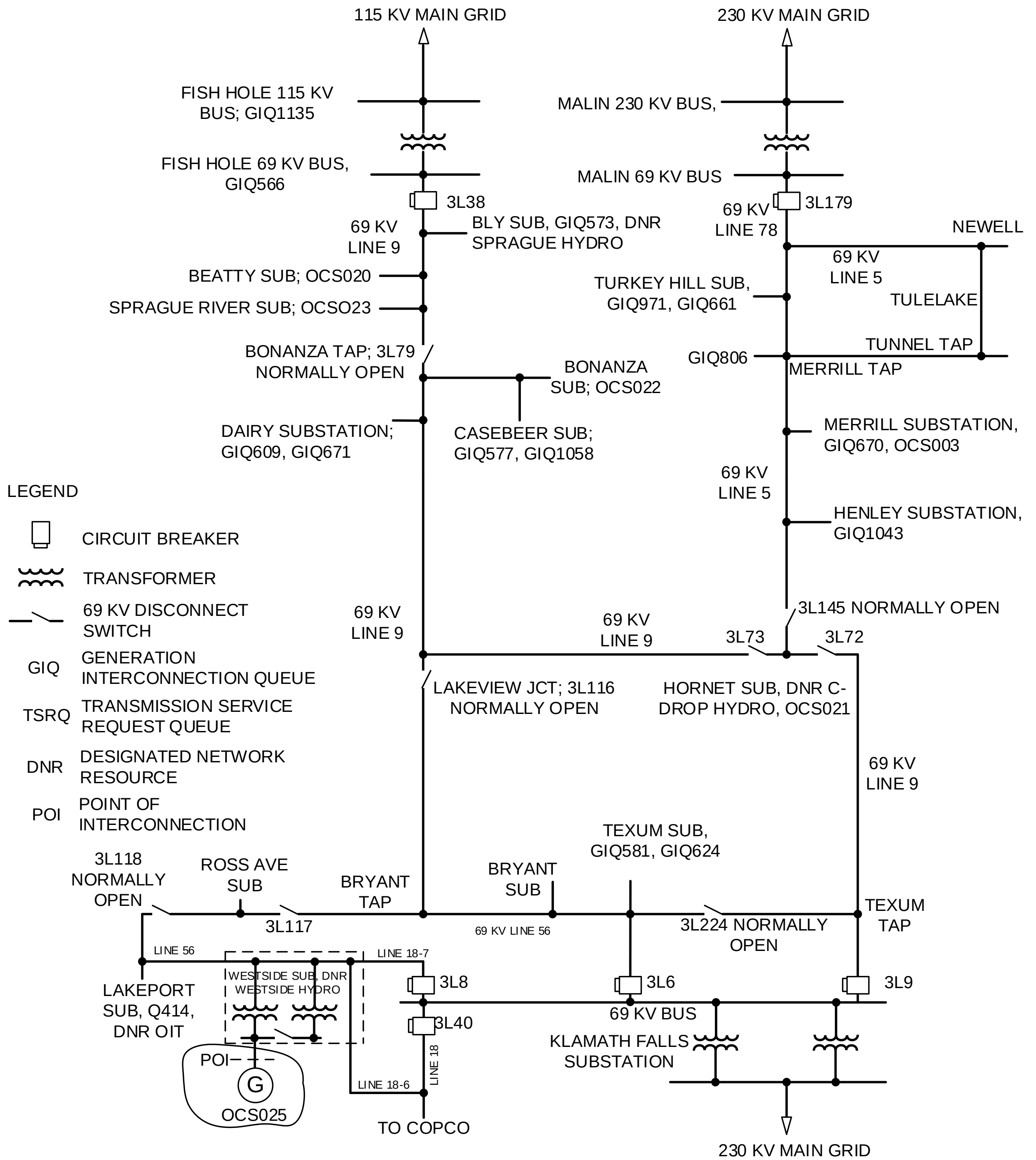

Figure 1: Transmission System One Line Diagram

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 ("POI").
- 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 PacifiCorp distribution facility point closest to the POI is 01439008.0-019460.
- Distribution load flows were performed at peak and light load and full and no generation with summer and winter loading conditions. The circuit 5L12 light load of 1343 kW was measured the weekend of 5/30/2020.
- Contingency transmission configuration for the Public Utility's system is defined as any configuration other than the normal transmission configuration.
- Two case studies were assembled and studied in power flow simulation at the transmission level. Each case was studied under peak loading and light loading conditions:
    1. Normal transmission configuration case no. 1: The distribution system supplied from Westside Substation in Klamath Falls, Oregon supplies OCS025; Westside Substation is supplied by 69 kV Line 18-7 from Klamath Falls Substation; 69 kV Line 56 is open between Lakeport and Ross Avenue substations; Klamath Falls 230 -69 kV transformers are supplied from the energized 230 kV transmission grid.
    2. Contingency transmission configuration case no. 2: Same as normal transmission configuration except that Line 18-7 is open between Klamath Falls and Westside substations; Line 18-6 is closed between Westside Tap and Westside Substation; supply is from Klamath Falls substation breaker 3L40. In power flow simulation, the transmission system was tested for its response to the interruption of the requested OCS025 power flow.
- Summer peak load is defined as the highest load demand that occurs on the Public Utility's power system during the summer season.
- Winter peak load is defined as the highest load demand that occurs on the Public Utility's power system during the winter season.
- Light load is defined as the minimum daytime load demand that occurs on the Public Utility's power system at any time during the year.
- Steady state voltage is defined as the voltage after all voltage regulating devices, both electronic and mechanical, have reached a quiescent state for the power flow and voltage conditions at a specific time.

- Post transient voltage is defined as the voltage measured after high speed switching transients and the effects of generator exciter controls have settled out and before any mechanically operated load tap changing and voltage regulating devices have started to adjust to new system conditions.
- Post transient voltage step is defined as the difference between the voltage before an event and the post transient voltage after the event. The WECC limits the post transient voltage step to a maximum of 8.0 percent for infrequent switching events such as the separation of a generation facility from the transmission system. Any post transient voltage step occurring on the transmission system is imposed directly on customers in the region.
- This report is based on information available at the time of the study. It is the Applicant's responsibility to check the Public Utility's web site regularly for transmission system updates (https://www.oasis.oati.com/ppw).

6.0 REQUIREMENTS

6.1 COMMUNITY SOLAR PROJECT REQUIREMENTS

The Community Solar Project and Interconnection Equipment owned by the Applicant are required to operate under automatic power factor control with the power factor sensed electrically at the Point of Interconnection. The required power factor is 1.0 per unit at the point of interconnection.

In general, the Community Solar Project and Interconnection Equipment should be operated so as to maintain the voltage at the Point of Interconnection between 1.01 pu to 1.04 pu. At the Public Utility's discretion, these values might be adjusted depending on the operating conditions.

The minimum power quality requirements are in PacifiCorp's Engineering Handbook section 1C and are available at https://www.pacificpower.net/about/power-quality-standards.html. Requirements in the System Impact Study that exceed requirements in the Engineering Handbook 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 Point of interconnection. Under normal conditions, the Public Utility's system should not supply reactive power to the Community Solar Project.

6.2 TRANSMISSION SYSTEM MODIFICATIONS

No transmission system modifications are required to accommodate the proposed Interconnection Customer facility.

6.3 DISTRIBUTION/TRANSMISSION LINE MODIFICATIONS

- Extend #4/0 AAC phase and neutral from Highway 140 to the change of ownership. The line extension includes a pole for primary metering and a pole with a 600 amp group operated switch.
- Replace recloser SW# 0011 at facility point 01439009.0077501 with a recloser that has internal voltage sensing for dead-line check and communications for transfer trip.

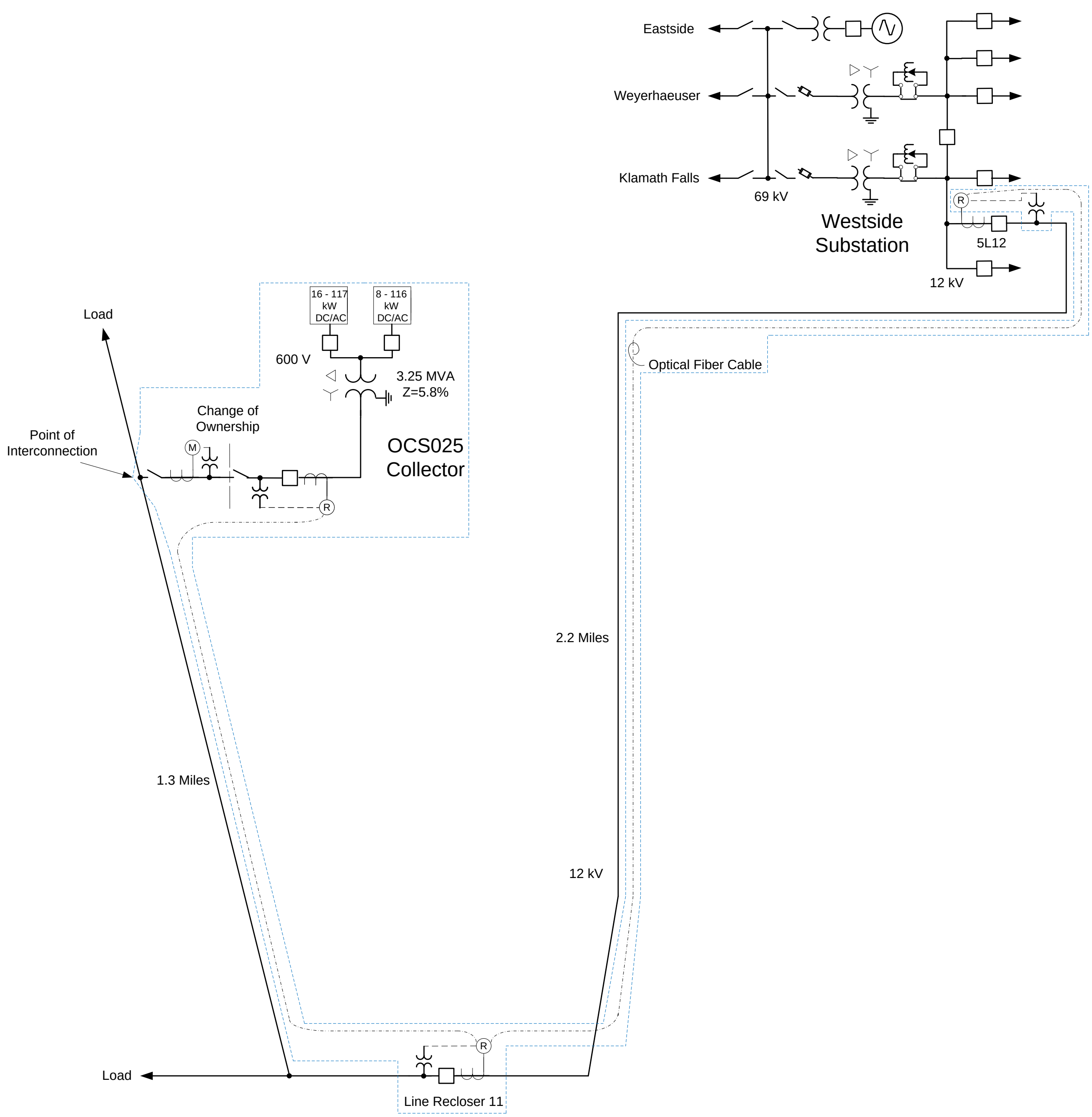

Figure 2: System One Line Diagram

6.4 EXISTING BREAKER MODIFICATIONS – SHORT-CIRCUIT

The increase in the fault duty on the system as the result of the addition of the generation facility with photovoltaic arrays fed through 16 – 117 kW inverters and 8 – 116 kW inverters connected to a 3.25 MVA 12 kV – 600 V transformer with 5.8% impedance will not push the fault duty above the interrupting rating of any of the existing fault interrupting equipment.

6.5 PROTECTION REQUIREMENTS

Between Westside substation and the planned OCS025 project there is a line recloser. The minimum daytime load on circuit 5L12 out of Westside Substation and beyond the line recloser are both below the maximum potential power output of the proposed OCS025 generating facility. For this reason the imbalance condition of the load and generation that the generation facility could be isolated with following the opening of either of these fault interrupting devices cannot be relied upon to cause the high speed disconnection of the generating facility for faults on the distribution system. A transfer trip circuit will need to be installed between the line recloser, Westside substation and the OCS025 generating facility. Since most faults on overhead lines are temporary and the circuit can be restored as soon as all the sources of power to the fault have been disconnected the breaker 5L12 and the line recloser are both equipped with automatic reclosing. When either of the two fault interrupters open a transfer trip signal will be sent to the circuit recloser at the generating facility.

To ensure that the automatic reclosing of breaker 5L12 or the line recloser does not take place before the generating facility disconnects, a dead line checking control circuit will be installed at both locations. The dead line 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 these type of controls will require the addition of a voltage instrument transformer ("VT") on the line side of breaker 5L12. The line recloser with be replaced with a recloser that can handle the dead line checking and the transfer trip.

The typical configuration for the overcurrent devices on the feeder is to have the overcurrent functions non-directional. However, with the addition of the OCS025 generating facility, for ground faults on the other feeders out of Westside substation, the current flowing from the generating facility will be greater than the pickup value for the ground overcurrent elements. Having 5L12 trip for faults on the other feeders will not be acceptable. The feeder relay for 5L12 will need to be directional to prevent this type of operation. The ground relay elements for the line recloser will also need this capability to operate correctly.

The 12 kV circuit recloser planned to be installed at the collector for the OCS025 project will need to be equipped with a Schweitzer Engineering Laboratories ("SEL") 651R relay/controller and voltage instrument transformers mounted on the utility side of the circuit recloser. The 651R will perform the following protection functions:

1. Detect faults on the 12 kV equipment at the generating facility
2. Detect faults on the 12 kV line to Westside substation
3. Monitor the voltage and react to under or over frequency, and /or magnitude of the voltage
4. Receive transfer trip from Westside substation and line recloser

6.6 Data Requirements (RTU)

Due to the power size of the generating 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

The Public Utility will install approximately 3.5 miles of 48-fiber, single-mode, ADSS cable on the distribution line from Westside substation to line recloser 11, and on to the generating facility. The fiber will be terminated in patch panels in enclosures at the generation facility and the recloser, and inside the substation control house at Westside substation. Fiber optic jumpers will be installed from the patch panels to the relays' FO transceivers.

6.8 Substation Requirements

<u>Westside Substation</u>
At Westside substation, a 12 kV VT will be installed to facilitate protection and control requirements. An existing relay will be replaced. Fiber optic cable will be terminated in the substation control building.

6.9 Metering Requirements

<u>Interchange Metering</u>
The metering will be located on the high side of the Interconnection Customer generator step up transformer at the POI. 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.

<u>Station Service/Construction Power</u>
The Interconnection Customer 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.

OCS025 Collector Station *Line extension, relay setting development*	$164,000
Line Recloser *Replace recloser, install communications.*	$113,000
Communications Fiber *Install ~3.5 miles of fiber.*	$152,000
Westside Substation *Replace relay, install VT and communications.*	$97,000
Total	**$526,000**

*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 December 31, 2020.

9.0 Participation by Affected Systems

Public Utility has identified the following Affected Systems: None

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

10.0 APPENDICES

Appendix 1: Higher Priority Requests
Appendix 2: Informational Network Resource Interconnection Service Assessment
Appendix 3: Property Requirements
Appendix 4: Distribution Study Results
Appendix 5: Transmission Study Results

10.1 Appendix 1: Higher Priority Requests

All active higher priority transmission service and/or generator interconnection and Community Solar Project requests will be considered in this study and are identified below. If any of these requests are withdrawn, the Public Utility reserves the right to restudy this request, as the results and conclusions contained within this study could significantly change.

Transmission/Generation Interconnection/Community Solar Queue Requests considered:

Queue #	Size (MW)
660	10
721	55
741	40
849	100
905	50
971	2.7
1029	400
1031	80
1032	80
1033	80
1034	60
1055	4.2
1062	240
1087	50
1104	3
1120	3
1126	8
1133	80
1134	120
1135	80
1147	2.999
1158	1.8
1160	70
1192	238.5
OCS003	0.8
OCS004	0.8
OCS019	0.882
OCS020	0.594
OCS023	0.6

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.

10.4 Appendix 4: Distribution Study Results

- The modeled power flow on Westside Breaker 5L12 is 1447 kW reverse power during light load and full generation.
- Westside substation transformer banks #2 and #3 are operated in parallel and the substation load divides evenly between the two transformers. The modeled power flow on transformer banks #2 and #3 is 890 kW forward power flow each during light load and full generation.
- The modeled power flow on recloser SW# 0011, facility point 01439009.0077501 is 1692 kW reverse power flow during light load and full generation.
- No overloaded equipment or voltage issues were identified on the distribution system.

10.5 Appendix 5: Transmission Study Results

10.5.1 Summary of Power Flow Simulation

A power flow simulation of addition of OCS025 power flow (operating at 2.8 MW maximum) to the Public Utility's system predicted the following:

- Westside Substation transformer and 69 kV Line 18-7 have adequate thermal capacity to carry power flow from OCS025 in normal transmission configuration no. 1.
- Westside Substation transformer and 69 kV Line 18-6 have adequate thermal capacity to carry power flow from OCS025 in contingency transmission configuration no. 2.
- After the addition of OCS025, voltages are predicted to be acceptable in normal transmission configuration no. 1 and contingency transmission configuration no. 2.
- Power could be accepted in normal transmission configuration no. 1 and in contingency transmission configuration no. 2.

10.5.2 NORMAL TRANSMISSION CONFIGURATION NO. 1

In normal transmission configuration no. 1, fully defined in Study Assumptions, Klamath Falls substation supplies 69 kV Line 18-7 to Westside distribution substation and the OCS025 Point of Interconnection. In power flow simulation, OCS025 flow was then interrupted.

Transmission Line Loading

Table 10.5.2.a. Power flow in normal transmission configuration no. 1 (Line 18-7 supplying Westside and OCS025 Point of Interconnection).

Season	OCS025 POI, MW	OCS025 POI, MVAR	Power flow on Westside Sub Transformer, MVA	Limiting Rating on Westside Sub Transformer, MVA	Power flow on 69 kV Line 18-7 at Klamath Falls Sub, MVA	Limiting Rating on 69 kV Line 18-7 at Klamath Falls Sub, MVA
Summer Peak Load	0	0	8.5	10.5	36.1	60
Summer Peak Load	2.8	0	5.8	10.5	33.3	60
Winter Peak Load	0	0	9.4	13.1	37.5	90
Winter Peak Load	2.8	0	6.5	13.1	34.6	90
Light Load	0	0	3.4	10.5	10.4	60
Light Load	2.8	0	1.4	10.5	7.9	60

Table 10.5.2.a shows that the Westside Substation transformer and 69 kV Line 18-7 have adequate thermal capacity to carry power flow from OCS025 in normal transmission configuration no. 1.

Transmission System Voltages

Voltages and post transient voltage steps are projected in power flow simulation to remain within permissible limits during the interruption of the OCS025 power flow in the Public Utility's normal transmission configuration no.1. Table 10.5.2.b shows the most significant predicted post transient voltage steps on the distribution system at Westside Substation caused by the addition of OCS025.

Table 10.5.2.b. Power system voltages when OCS025 power flow interrupted during normal transmission configuration no. 1 (Line 18-7 supplying Westside and OCS025 Point of Interconnection).

Season	**Location**	**OCS025 POI, MW**	**OCS025 POI, MVAR**	**Steady State Voltage, per unit**	**Post Transient Voltage After OCS025 Interruption, per unit**	**Post Transient Voltage Step, percent**
Summer Peak Load	Westside Sub 12 kV bus	2.8	0	1.017	1.012	0.5%
Winter Peak Load	Westside Sub 12 kV bus	2.8	0	1.026	1.021	0.5 %
Light Load	Westside Sub 12 kV bus	2.8	0	1.001	0.999	0.2%

10.5.3 Contingency Transmission Configuration No. 2

In contingency transmission configuration no. 2, fully defined in Study Assumptions, 69 kV Line 18-6 is closed supplying Westside substation and Line 18-7 is open. The power flow simulation test began with OCS025 generating, then generation was interrupted.

Transmission Line Loading

Table 10.5.3.a. Power flow in contingency transmission configuration no. 2 (Line 18-6 supplying Westside and OCS025 Point of Interconnection).

Season	OCS025 POI, MW	OCS025 POI, MVAR	Power flow on Westside Sub Transformer, MVA	Limiting Rating on Westside Sub Transformer, MVA	Power flow on 69 kV Line 18-6 at Westside Tap, MVA	Limiting Rating on 69 kV Line 18-6 at Westside Tap, MVA
Summer Peak Load	0	0	8.6	10.5	36.4	40
Summer Peak Load	2.8	0	5.8	10.5	33.4	40
Light Load	0	0	3.4	10.5	10.5	40
Light Load	2.8	0	1.3	10.5	7.8	40

Table 10.5.3.a shows that the Westside Substation transformer and 69 kV Line 18-6 have adequate thermal capacity to carry power flow from OCS025 in contingency transmission configuration no. 2.

Transmission System Voltages

Voltages and post transient voltage steps are projected in power flow simulation to remain within permissible limits during the interruption of the OCS025 power flow in the Public Utility’s contingency transmission configuration no.2. Table 10.5.3.b shows the most significant predicted post transient voltage steps on the distribution system at Westside Substation caused by the addition of OCS025.

Table 10.5.3.b. Power system voltages when OCS025 power flow interrupted during contingency transmission configuration no. 2 (Line 18-6 supplying Westside and OCS025 Point of Interconnection).

Season	Location	OCS025 POI, MW	OCS025 POI, MVAR	Steady State Voltage, per unit	Post Transient Voltage After OCS025 Interruption, per unit	Post Transient Voltage Step, percent
Summer Peak Load	Westside Sub 12 kV bus	2.8	0	1.019	1.013	0.6%
Light Load	Westside Sub 12 kV bus	2.8	0	1.002	0.998	0.4%