

Community Solar Project Interconnection
Community Solar Project System Impact Study Report

Completed for

(“Applicant”)
OCS035

Proposed Point of Interconnection
Circuit 4M201 out of Dallas substation at 20.8 kV
(At approximately 44°56'43.2"N, 123°18'38.5"W)

October 7, 2020

TABLE OF CONTENTS

1.0 DESCRIPTION OF THE COMMUNITY SOLAR PROJECT	2
2.0 APPROVAL CRITERIA FOR TIER 4 INTERCONNECTION REVIEW	2
3.0 SCOPE OF THE STUDY	2
4.0 PROPOSED POINT OF INTERCONNECTION	2
5.0 STUDY ASSUMPTIONS.....	4
6.0 REQUIREMENTS	4
6.1 COMMUNITY SOLAR PROJECT REQUIREMENTS	4
6.2 TRANSMISSION SYSTEM MODIFICATIONS.....	5
6.3 DISTRIBUTION/TRANSMISSION LINE MODIFICATIONS	5
6.4 EXISTING BREAKER MODIFICATIONS – SHORT-CIRCUIT	7
6.5 PROTECTION REQUIREMENTS	7
6.6 DATA REQUIREMENTS (RTU)	8
6.7 COMMUNICATION REQUIREMENTS	8
6.8 SUBSTATION REQUIREMENTS	8
6.9 METERING REQUIREMENTS	8
7.0 COST ESTIMATE	8
8.0 SCHEDULE	9
9.0 PARTICIPATION BY AFFECTED SYSTEMS	9
10.0 APPENDICES.....	9
10.1 APPENDIX 1: HIGHER PRIORITY REQUESTS	10
10.2 APPENDIX 2: INFORMATIONAL NETWORK RESOURCE INTERCONNECTION SERVICE ASSESSMENT	11
10.3 APPENDIX 3: PROPERTY REQUIREMENTS.....	12
10.4 APPENDIX 4: TRANSMISSION/DISTRIBUTION STUDY RESULTS	14

1.0 DESCRIPTION OF THE COMMUNITY SOLAR PROJECT

(“Applicant”) proposed interconnecting 2.25 MW of new generation to PacifiCorp’s (“Public Utility”) circuit 4M201 out of Dallas substation located in Polk County, Oregon. The project (“Project”) will consist of eighteen (18) Delta M125HV 125 kW inverters for a total requested output of 2.25 MW. The requested commercial operation date is May 31, 2021.

The Public Utility has assigned the Project “OCS035.”

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 4M201 out of Dallas substation via a 20.8 kV primary meter. The proposed Point of Interconnection (“POI”) will be located at approximately 44°56'43.2"N, 123°18'38.5"W located in Polk County, Oregon. Figure 1 below is a one line diagram that illustrates the interconnection of the proposed generating facility to the Public Utility’s system.

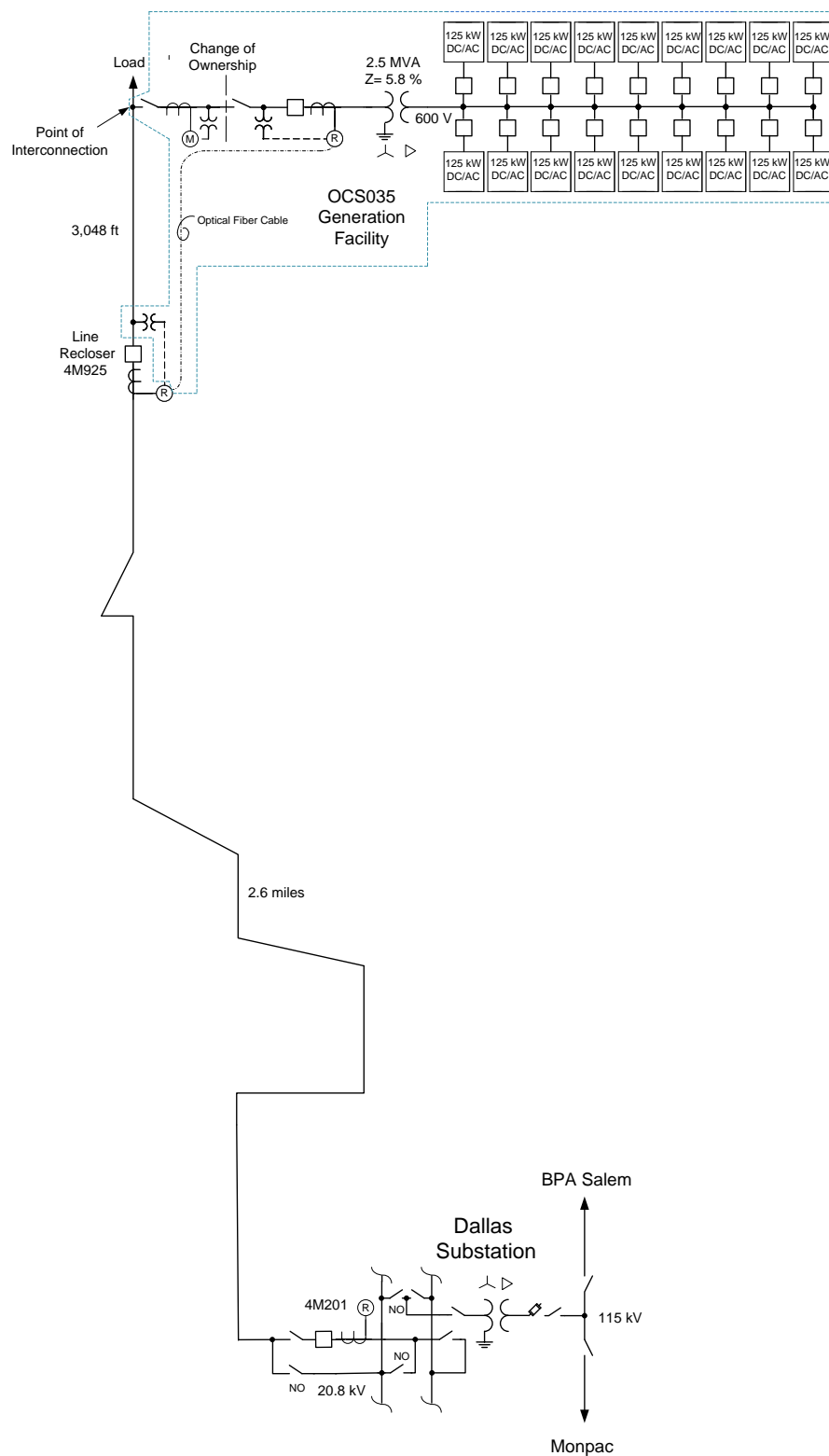


Figure 1: System One Line Diagram

5.0 STUDY ASSUMPTIONS

- All active higher-priority requests for transmission service and/or generator interconnection service (including requests in the traditional interconnection queue and other requests in the Community Solar queue) in the local area of the requested POI will be considered in this study and are listed in Appendix 1. If any of these requests are withdrawn, the Public Utility reserves the right to restudy this request, as the results and conclusions contained within this study could significantly change.
- The Applicant's request for interconnection service in and of itself does not convey transmission service.
- This study assumes the Project will be integrated into Public Utility's system at the agreed upon and/or proposed POI.
- The Applicant will construct and own any facilities required between the POI and the Project unless specifically identified by the Public Utility.
- Line reconductor or fiber underbuild required on existing poles will be assumed to follow the most direct path on the Public Utility's system. If during detailed design the path must be modified it may result in additional cost and timing delays for the Applicant's project.
- Generator tripping may be required for certain outages.
- All facilities will meet or exceed the minimum Western Electricity Coordinating Council ("WECC"), North American Electric Reliability Corporation ("NERC"), and Public Utility performance and design standards.
- This report is based on information available at the time of the study. It is the Applicant's responsibility to check the Public Utility's web site regularly for transmission system updates (<https://www.oasis.oati.com/ppw>)

6.0 REQUIREMENTS

6.1 COMMUNITY SOLAR PROJECT REQUIREMENTS

The Community Solar Project and Interconnection Equipment owned by the Applicant are required to operate under automatic power factor control with the power factor sensed electrically at the POI. The Community Solar Project should have sufficient reactive capacity to enable the delivery of 100 percent of the plant output to the POI at unity power factor measured at 1.0 per unit voltage under steady state conditions.

In general, the Community Solar Project and Interconnection Equipment should be operated so as to maintain the voltage at the POI between 1.01 pu to 1.04 pu. At the Public Utility's discretion, these values might be adjusted depending on the operating conditions. Within this voltage range, the Community Solar Project should operate so as to minimize the reactive interchange between the Community Solar Project and the Public Utility's system (delivery of power at the POI at approximately unity power factor). The voltage control settings of the Community Solar Project must be coordinated with the Public Utility prior to energization (or interconnection). The reactive compensation must be designed such that the discreet switching of the reactive device (if required by the Applicant) does not cause step voltage changes greater than +/-3% on the Public Utility's system. No

additional reactive compensation requirements are identified as a result of this system impact study.

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

As per NERC standard VAR-001-1, the Public Utility is required to specify voltage or reactive power schedule at the POI. Under normal conditions, the Public Utility's system should not supply reactive power to the Community Solar Project.

6.2 TRANSMISSION SYSTEM MODIFICATIONS

No transmission system modifications are required to accommodate the proposed Applicant's facility.

6.3 DISTRIBUTION/TRANSMISSION LINE MODIFICATIONS

Distribution construction items and study findings for the Applicant's interconnection request are listed below. Construction is based on the Applicant's requested POI specific locations for pole placement may need to be revised for actual construction. It is important to note there is an upstream recloser 4M925 that will require new settings located 3,048' upstream of the POI.

- New 3 phase tap pole will need to be installed just north of FP 01307005.0212301.
- Install new pole and 3 phase gang operated switch on the east side of Perrydale road adjacent from the new 3 phase tap pole.
- Install new pole for primary metering adjacent to new switch pole.
- Extend 3 phase #2AAAC approximately 100' east of new tap pole to new 3 phase gang operated load break switch.
- Extend new 3 phase #2AAAC approximately 100' east from new switch location to new primary metering location.

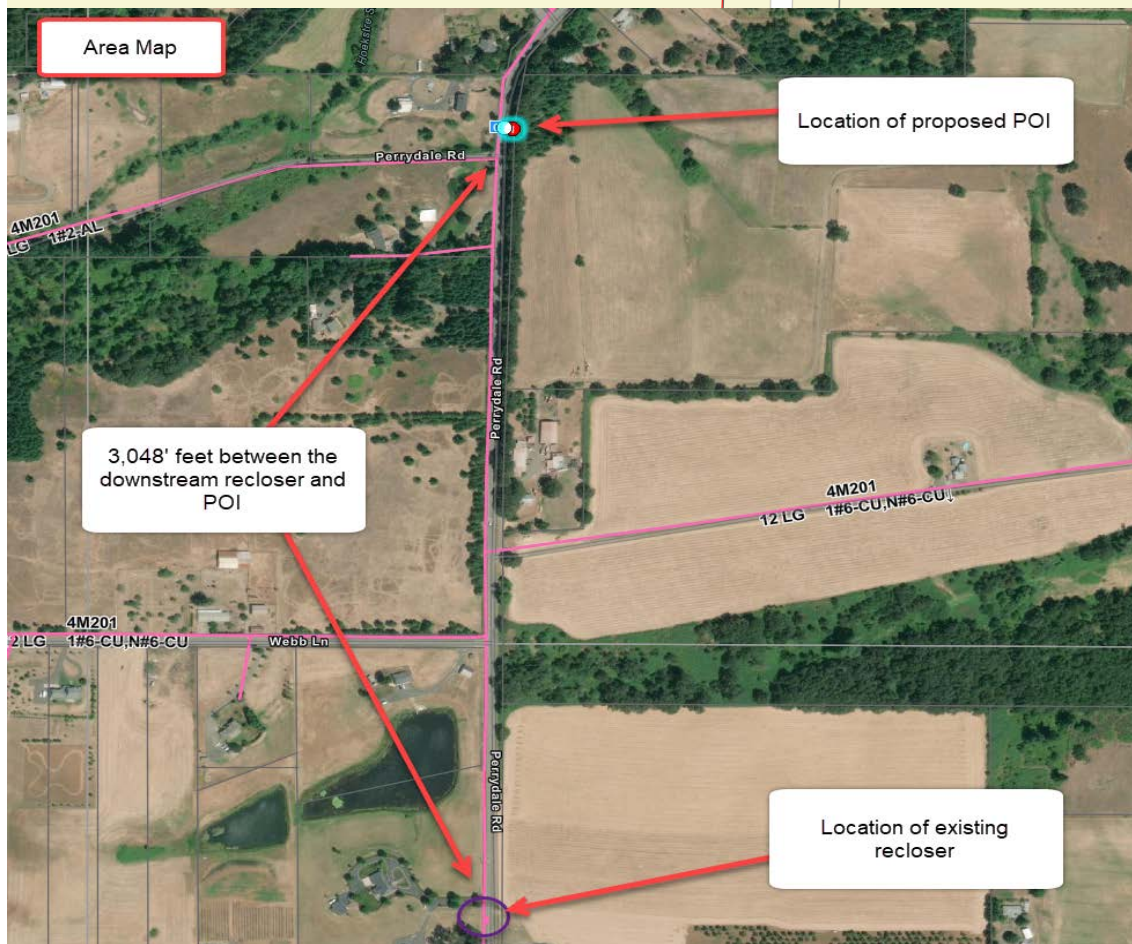
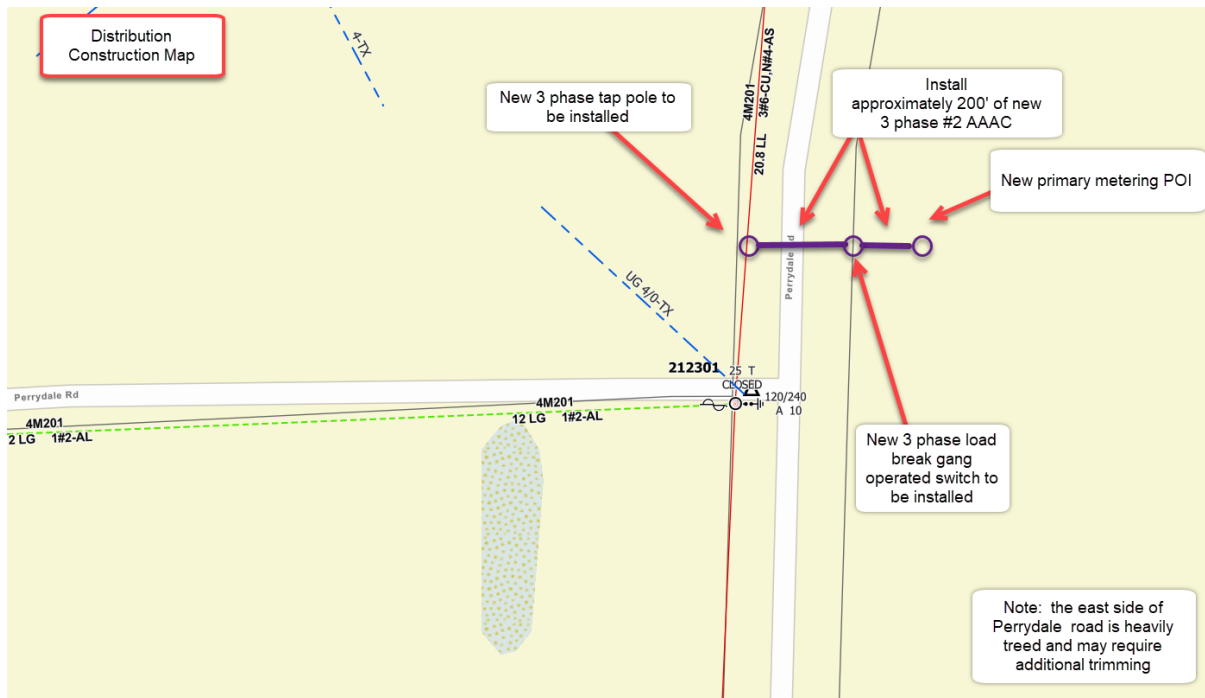


Figure 2: Distribution Maps

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 18 – 125 kW inverters connected to the 2.5 MVA 20.8 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 OCS035 generating facility will need to disconnect from the network in a high speed manner for faults on the 20.8 kV line on circuit 4M201 out of Dallas substation. The minimum daytime load on circuit 4M201 is 2,850 kW which is above the maximum potential power output of the proposed OCS035 generating facility. For this reason the imbalance condition of the load and generation can be relied upon to cause the high speed disconnection of the generating facility for faults on the distribution system.

The generating facility is planned to be interconnected beyond an existing line recloser 4M925 at facility point 01307005.0282802. During some daytime periods the load beyond the recloser will be less than the potential generation from the proposed generating facility. Because the unbalance between the generation and load cannot be relied upon to cause the timely disconnection of the generating facility for faults on the 20.8 kV circuit beyond the recloser a transfer trip circuit will be required between the line recloser and the OCS035 POI recloser at the generating facility. A dead line checking control circuit will need to be added to the line recloser to delay the automatic reclose if the generating facility is not disconnected due to a failure of the relay circuitry.

The typical configuration for the overcurrent devices on line reclosers is to have the overcurrent functions non-directional. However, with the addition of the OCS035 generating facility, for ground faults on the line between Dallas substation and the line recloser, the current flowing from the generating facility will be greater than the pickup value for the ground overcurrent elements. Having the line recloser 4M925 trip for these faults will not be acceptable. The overcurrent elements for line recloser 4M925 will need to be directional to prevent this type of operation. The line recloser equipped with the instrument voltage transformers for the dead line checking control circuit will have the capability to have the overcurrent functions to be set directional.

The 20.8 kV circuit recloser planned to be installed at the OCS035 project will need to be 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 20.8 kV equipment at the generating facility
2. Detect faults on the 20.8 kV line to Dallas substation
3. Monitor the voltage and react to under or over frequency, and /or magnitude of the voltage
4. Receive transfer trip from the line recloser 4M925

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 48-fiber, single-mode, ADSS cable along the distribution line between the line recloser 4M925 and the OCS035 POI recloser for transfer trip. The fiber will be terminated in patch panels inside cabinets at both locations. Fiber optic jumper cables will be installed from the patch panels to the relays' fiber optic transceivers.

6.8 SUBSTATION REQUIREMENTS

No substation modifications are required.

6.9 METERING REQUIREMENTSInterchange Metering

The metering will be located on the high side of the 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.

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.

OCS035 Collector Substation	\$84,000
------------------------------------	-----------------

Install metering, communications equipment, and develop relay settings.

Line Extension	\$40,000
-----------------------	-----------------

Install poles, switch and conductor

Line Recloser 4M925	\$73,000
----------------------------	-----------------

Install instrument transformers, communications equipment

Communications	\$29,000
-----------------------	-----------------

Install approximately .7 miles of fiber

Total**\$226,000**

*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

Appendix 4: 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:

Q#	Size (MW)
1098	3
1149	0.108
1150	0.504
1151	0.285
OCS008	2.16
OCS026	1.5
OCS027	2.875

10.2 APPENDIX 2: INFORMATIONAL NETWORK RESOURCE INTERCONNECTION SERVICE ASSESSMENT

The study results described above reflect an energy resource interconnection service (“ERIS”) evaluation, modified in the CSP program rules to examine only generation and load conditions local to the requested CSP project’s interconnection point (sometimes referred to as the “zoomed in view”). The “zoomed in view” functions to: (1) study the project’s proposed interconnection without considering certain existing or higher-queued requests outside of the local area; and (2) to inform whether the CSP facility must cap its project to mitigate, although not eliminate, the risk of potential deliverability-related network upgrades to accommodate the proposed CSP generator.

By contrast, the following informational section provides a network resource interconnection service (“NRIS”) evaluation performed with traditional assumptions, i.e., not modified to examine only local generation and load conditions, but rather one that assumes that all existing interconnections, higher-queued requests for interconnection service (in both the traditional and CSP queue), and generators with executed contracts beyond the local area are in-service. Depending on the severity of the conditions created when absorbing additional generation (capped or not capped) in that broader, “zoomed out” area, the local area-focused generator size cap developed in the “zoomed in” examination may not be sufficient to mitigate the need for deliverability-related network upgrades. Regardless of this report’s informational NRIS results, the deliverability-related network upgrades ultimately necessary to accommodate the proposed CSP generator will depend on conditions present when the future transmission service study is performed, as well as whether network upgrade alternatives are available at that time.

Considering existing generation and higher-queued requests to interconnect in the Willamette Valley area where the CSP generator proposes to interconnect, 2.25 MW of additional generation can be absorbed. As a result, the transmission provider determines that no additional network upgrades would be required for the aggregate of generation in the local area to be delivered to the aggregate of load on the transmission provider’s transmission system (the NRIS study scope).

10.3 APPENDIX 3: PROPERTY REQUIREMENTS**Requirements for rights of way easements**

Rights of way easements will be acquired by the Applicant in the Public Utility's name for the construction, reconstruction, operation, maintenance, repair, replacement and removal of Public Utility's Interconnection Facilities that will be owned and operated by PacifiCorp. Applicant will acquire all necessary permits for the project and will obtain rights of way easements for the project on Public Utility's easement form.

Real Property Requirements for Point of Interconnection Substation

Real property for a POI substation will be acquired by an Applicant to accommodate the Applicant's project. The real property must be acceptable to Public Utility. Applicant will acquire fee ownership for interconnection substation unless Public Utility determines that other than fee ownership is acceptable; however, the form and instrument of such rights will be at Public Utility's sole discretion. Any land rights that Applicant is planning to retain as part of a fee property conveyance will be identified in advance to Public Utility and are subject to the Public Utility's approval.

The Applicant must obtain all permits required by all relevant jurisdictions for the planned use including but not limited to conditional use permits, Certificates of Public Convenience and Necessity, California Environmental Quality Act, as well as all construction permits for the project.

Applicant will not be reimbursed through network upgrades for more than the market value of the property.

As a minimum, real property must be environmentally, physically, and operationally acceptable to Public Utility. The real property shall be a permitted or able to be permitted use in all zoning districts. The Applicant shall provide Public Utility with a title report and shall transfer property without any material defects of title or other encumbrances that are not acceptable to Public Utility. Property lines shall be surveyed and show all encumbrances, encroachments, and roads.

Examples of potentially unacceptable environmental, physical, or operational conditions could include but are not limited to:

- Environmental: known contamination of site; evidence of environmental contamination by any dangerous, hazardous or toxic materials as defined by any governmental agency; violation of building, health, safety, environmental, fire, land use, zoning or other such regulation; violation of ordinances or statutes of any governmental entities having jurisdiction over the property; underground or above ground storage tanks in area; known remediation sites on property; ongoing mitigation activities or monitoring activities; asbestos; lead-based paint, etc. A phase I environmental study is required for land being acquired in fee by the Public Utility unless waived by Public Utility.

- Physical: inadequate site drainage; proximity to flood zone; erosion issues; wetland overlays; threatened and endangered species; archeological or culturally sensitive areas; inadequate sub-surface elements, etc. Public Utility may require Applicant to procure various studies and surveys as determined necessary by Public Utility.
- Operational: inadequate access for Public Utility's equipment and vehicles; existing structures on land that require removal prior to building of substation; ongoing maintenance for landscaping or extensive landscape requirements; ongoing homeowner's or other requirements or restrictions (e.g., Covenants, Codes and Restrictions, deed restrictions, etc.) on property which are not acceptable to the Public Utility.

10.4 APPENDIX 4: TRANSMISSION/DISTRIBUTION STUDY RESULTS**Transmission:**

Three base cases were developed to represent heavy summer, heavy winter and light spring load conditions. A Power flow analysis was performed on each case for two system configurations described below.

1. Normal transmission configuration: Dallas substation in a radial 115 kV system configuration fed from BPA's Salem substation.
2. Contingency transmission configuration: 115 kV transmission line from Dallas to BPA Salem substation is open. Close switch 2M88 at Monpac to BPA Monmouth to feed Dallas out of BPA Salem substation.

Each Power flow analysis was conducted pre and post OCS035. The study focused on the 115 kV system in Dallas and Monmouth area and distribution voltages at Dallas substation. Voltage and thermal limitation of surrounding substation buses and lines were monitored.

The results for the transmission study concluded that steady state and post transient voltages are within acceptable limits. No thermal violations were identified. The proposed OCS035 project does not result in additional deficiencies to the Public Utility's transmission system.

There are no contingent facilities identified for this interconnection request.