Generator Interconnection
Final Facility Study Report

for the

[redacted] Project #556

for

[redacted]

in

Grant County, OR

6-4-21

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FINAL FACILITY STUDY REPORT (FSR)

[redacted]

Project #556

6-4-21

1. General Facility Description

[redacted] ("Interconnection Customer") has stated that the proposed project will consist of 30MW of photovoltaic and battery energy storage in Grant County, Oregon and connect to the 138 kV system on Idaho Power Company (IPC)'s [redacted] section of the [redacted] 138 kV line. The total project output as studied is 30 MW.

Contact Information for Interconnection Customer is as follows:

[redacted]

A Standard Large Generator Interconnection Agreement (the "LGIA") under IPC's Open Access Transmission Tariff (OATT) or the Oregon QF-LGIA between Interconnection Customer and IPC (Transmission Provider) for the [redacted] Project, specifically Generator Interconnection Project # 556 ("Project"), will be prepared for this project. The LGIA or QF-LGIA (either referred to below as "LGIA") will be a definitive agreement that contains terms and conditions that supersedes this FSR.

This FSR describes the facilities that would be required to provide the requested interconnection to IPC's system and discusses potential impacts related to Affected Systems.

Project Queue and Affected Systems:
If an earlier-queued project, that is responsible for providing additional sub-transmission capacity, should drop out of the queue, a later queue project that may have been relying on at least a portion of any "surplus" capacity may then be faced with additional project costs for sub-transmission capacity additions of their own. The proposed project has impacts on Transmission Provider's system as well as on an Affected System, the Bonneville Power Administration's transmission system. As of the date of this report, Bonneville Power Administration (BPA) has proposed generation projects in its queue prior to the Project which have requested to be interconnected to lines in the same area and for which the proposed plan(s) of service may impact the requirements for the [redacted] Project. The resolution of BPA's generation requests in this area has not been finalized and any forthcoming material changes may result in the System Impact Study and this FSR to be re-evaluated and re-studied. Once BPA has completed its own Affected System Study and finalized the plan of service results, IPC will review that study and its impact on the IPC's System Impact Study and this FSR for any necessary changes. The recommended upgrades for the proposed generation projects in BPA's queue were assumed to be completed prior to the interconnection of the Project. For this and other reasons, the cost estimates included in this FSR are estimates only, are based on currently known or assumed facts that may not be accurate or materialize, and are subject to change. Until the results from BPA's Affected System Study have been finalized, this Facility Study Report may be subject to change.

1.1 Interconnection Point

The Interconnection Facilities are located in IPC's Western region at approximately [redacted]. The Point of Interconnection ("POI") for the Project will be where the new 400 ft. transmission line tap connects to the Transmission Provider's existing transmission line. A drawing identifying the POI is attached as Exhibit 1.

1.2 Point of Change of Ownership

The Point of Change of Ownership for the Project will be on the dead-end structure of IPC's Interconnection Facilities on the Interconnection Customer's side of air break switch [redacted], as shown in Exhibit 1.

1.3 Interconnection Customer's Interconnection Facilities

The Interconnection Customer's Interconnection Facilities are located adjacent to IPC's Interconnection Facilities. The Interconnection Customer will install generators, disconnect switches, distribution collector system, BESS transformers, appropriate grounding measures, and associated auxiliary equipment. Interconnection Customer will build 138 kV transmission facilities to the Point of Change of Ownership. The project's proposed 138/34.5 kV GSU transformer does **not** meet Idaho Power's transmission interconnection grounding requirements for system protection which requires a ground source on the high-side of the transformer. Idaho Power's requirements for the ground source are specified in Section 1.4.2.

The Interconnection Customer's photovoltaic system will be constructed as follows:

1. The inverter system will comprise of [redacted] Inverters, with each inverter having an apparent power rating of 3,150 KVA.
2. Eleven inverter stations will each comprise of one Utility Inverters and a 3.150 MVA step-up transformer with a 630 V to 34.5 kV rating.
3. A plant controller will be used to control the inverter system and to implement smart inverter functionality for operating the project within a voltage range and power factor specified by IPC at the point of interconnection.

   The above referenced inverters, or equivalent inverters that have the same specifications and functionality as stated above must be utilized. If a different inverter is utilized that has different specifications and functionality than that which was studied, then additional study and/or equipment may be necessary.

1.4 Other Facilities Provided by Interconnection Customer

1.4.1 Telecommunications

In addition to communication circuits that may be needed by the Interconnection Customer, the Interconnection Customer shall provide the following communication circuits for IPC's use. **It is the Interconnection Customer's responsibility to provide the following communication circuits for IPC's use. These circuits can be long-lead items and typically require coordination with third party telecommunications providers. The project's in-service date cannot be granted prior to complete circuit acceptance and testing as referenced below.**

1.

a. One POTS (Plain Old Telephone Service meeting the technical requirements of TR-NWT-000335:1993; NCI code 02LS2-2wire, loop start, 600 ohm) dial-up circuit for voice communication at the generation interconnect site. If the circuit becomes unreliable, Interconnection Customer will be responsible for the circuit repair. For Projects under 3MW, the POTS line must also be capable of supporting reliable sustained data communications at a minimum of 4800 bps with a modem using V32.bis modulation.

b. One DS1 (High Capacity Digital Service meeting the technical requirements of GR-54-CORE:1995 and TR-NWT-000341:1993; NCI code 04DU9.1SN) high capacity serial circuit (ESF, B8ZS, Conventional Interface) between the generation interconnection site demarcation and [redacted] Transmission Station ([redacted]), for multiplexed use by SCADA, data for up to three Revenue Meters, SCADA RTU Management, Protective Relay Management, and Phasor Measurement Unit (PMU) as required. If the minimum data rate is or becomes unattainable or unreliable, Interconnection Customer will be responsible for the circuit repair or replacement.

The Interconnection Customer shall provide all the required communications circuits between the Interconnection site and IPC's operations points (i.e. IPC FEP location, etc.) as specified by IPC.

RELIABILITY AND DATA SECURITY: The communication circuits shall be DC powered at the terminus locations and within any telecommunications provider's network, such that they will continue operation during a power outage for a minimum of 4 hours, and meet the specified reliability and bandwidth requirements. At transmission connected generation interconnect sites, IPC can extend its station battery to a circuit marshalling location in a shared access portion of the station yard if needed for Interconnection Customer telecommunications equipment used only to deliver IPC required circuits, but the Interconnection Customer is responsible for any required AC local service required by their equipment at their station or in the shared access portion of the station yard. The Interconnection Customer may choose to coordinate with a third-party communications provider to provide the communications circuits and pay the provider's associated one-time setup and periodic charges, deliver the circuits using their own infrastructure, or a combination thereof. Regardless of circuit transport implementation, in all cases the SCADA circuit must be transported using solely Layer 2 protocols (e.g. serial point-to-point data communication, no routable Layer 3 transport, such as Internet Protocol).

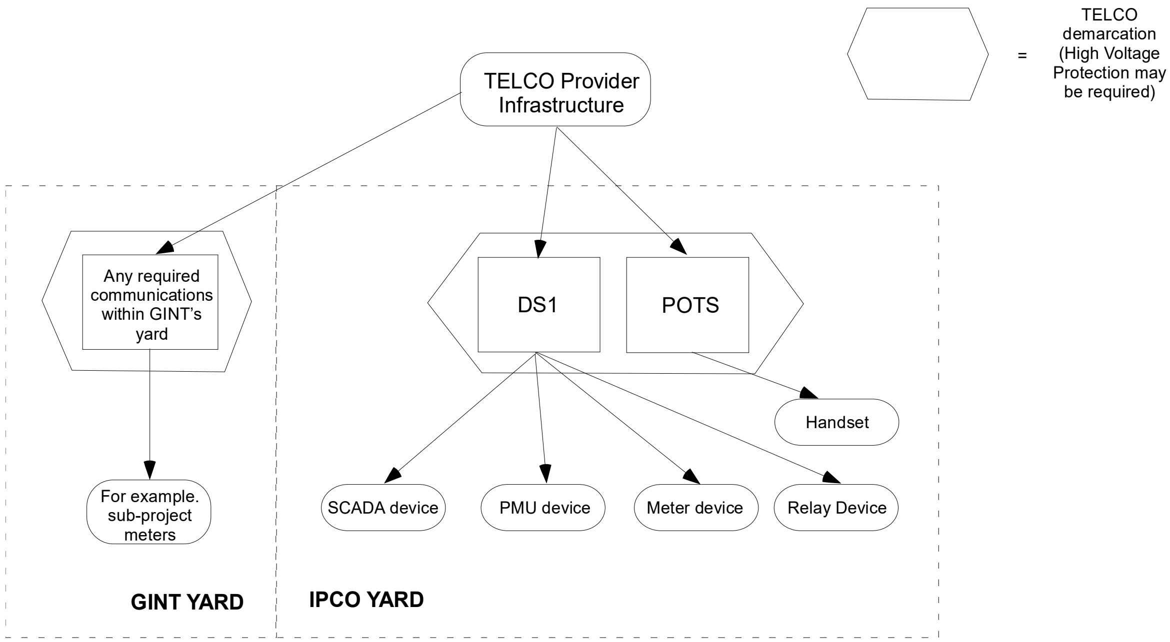
CIRCUIT ACCEPTANCE AND TESTING: The communication circuits shall be terminated in an approved demarcation box with the cable pairs punched down on a telecom block and labeled accordingly at a location approved by IPC. The communication circuits will need to be installed and tested by the Interconnection Customer prior to IPC acceptance testing, and operational prior to the Interconnection Customer being allowed to generate power into IPC's system. A Quasi Random Signal Source (QRSS) test pattern will be used for testing between the DS1 circuit demarcations points, and require 15 consecutive minutes with zero errored seconds and zero severely-errored seconds to pass; a subsequent 15 consecutive minutes (30 minutes total) with three or less total errored seconds and zero severely-errored seconds to pass if previous test failed; a subsequent 15 consecutive minutes (45 minutes total) with nine or less total errored seconds and two or less severely-errored seconds to pass if previous test failed. In addition an "all 1s" stress test with zero errored seconds over a five minute interval to pass, an "all 0s" stress test with zero errored seconds over a thirty second interval to pass, and a "1 in 8" stress test with zero errored seconds over a five minute interval to pass will also be performed. (Reference ANSI T1.510:1999) In either case, circuits with demonstrated reliability issues during commissioning will be required to demonstrate 24 hours of reliable service by the Interconnection Customer prior to final acceptance testing by IPC. Note that installation by a third-party communications provider may take several months and these services should be ordered well in advance to avoid delaying the project.

The Interconnection Customer or their third-party communications provider may need to install communications equipment (i.e. batteries, multiplexers, etc.) near each terminus of the required communications circuits. If this equipment is required, the Interconnection Customer shall be responsible to install this equipment in locations that are not owned or operated by IPC. If high voltage protection is required by the communications provider for the incoming copper cable, the high voltage protection assembly shall be engineered, supplied, and maintained by the Interconnection Customer.

OPERATIONAL RESPONSE:
Interconnection Customer's failure to maintain and/or restore and repair intermittent or non-operational telecommunications circuits may result in disconnection of Interconnection Customer's generation facility/facilities until the circuits successfully complete Idaho Power's end-to-end testing.

The Interconnection Customer is responsible for repairing any circuits and contacting any third-party telecom provider as needed. [Note: IPC cannot contact third party telecom providers on behalf of the Interconnection Customer for circuit outages.] A third-party telecom provider is expected to have the ability to perform some level of remote circuit testing. If the Interconnection Customer's third-party telecom provider needs access to IPC facilities, they will contact IPC per contacts in LGIA.

The leased services required by IPC are to be kept separate from any communication services required by the Interconnection Customer. This includes the location where services are handed off from the telecom provider to IPC, also known as the TELCO demarcation. Under no circumstances will any service delivered to IPC's TELCO demarcation be extended beyond the IPC yard ground grid. If the Interconnection Customer requires their own leased services, they must be provided through a separate TELCO demarcation, as noted below.



1.4.2 Ground Fault Equipment

The Interconnection Customer will install transformer configurations that will provide a ground source to the transmission system.

1.4.3 Generator Output Limit Control

The Interconnection Customer will install equipment to receive signals from IPC Grid Operations for Generation Output Limit Control ("GOLC") - see Section 3 Operating Requirements and Appendix A. IPC's recommended method of communication for GOLC is via fiber between the Interconnection Station and the Project.

1.4.4 Local Service

The Interconnection Customer is responsible to arrange for local service to their site, as necessary.

1.4.5 Property

The Interconnection Customer will acquire and then transfer to IPC, the property for IPC's interconnection station yard, including a year-round access. The interconnection station will be owned and maintained by IPC. The Interconnection Customer, at its sole cost and expense, will provide to IPC documents and services as identified below relating to IPC's land rights required for its interconnection facilities:

1.4.5.1 Land Transaction Documents

Land transaction documents ("Land Transaction Documents") in a form approved by IPC that may include, but are not limited to, the following:

- Right of Entry Agreement;
- Interconnection Facility Easement OR fee ownership parcel ("Fee Ownership Parcel") conveyance pursuant to a Warranty Deed. IPC shall determine whether an Interconnection Facility Easement or a Fee Ownership Parcel is required for the Project and shall advise Interconnection Customer, accordingly;
- For Fee Ownership Parcels, a Purchase and Sale Agreement;

- Access Easement;
- Easements for distribution service lines, major distribution power lines, and transmission power lines and related ancillary facilities as determined necessary by IPC at IPC's sole discretion, to support the interconnection facility and Interconnection Customer's development;
- Completed Applications with respective fees for Release of Easements and/or Crossing Agreements that may be required for the Project;
- Crossing Agreements; and
- Any other Project specific documents deemed necessary by IPC.

1.4.5.2 Project Map/Site Plan

A 90% complete informational map or site plan of the Project Property with locations of all easements to be released, new easements proposed for both Interconnection Customer and IPC, existing IPC lines to be crossed by Interconnection Customer's facilities, Interconnection Customer's lease and easement areas (if any), access roads, and any other features or elements requested to be included by IPC to facilitate review and processing of the project documents.

1.4.5.3 Surveyed Legal Descriptions and Maps

Written legal description and map for each Land Transaction Document, stamped and signed by a licensed surveyor. Each legal description and map is to be submitted to and approved by IPC's surveyor. See IPC survey requirements in Appendix B, attached hereto and made a part hereof.

1.4.5.4 Title Insurance

Title report and American Land Title Association (A.L.T.A.) extended owners' pro forma policy of title insurance for the amount of the value of the Interconnection Facility Easement or Fee Ownership Parcel and access easement areas. Interconnection Customer shall provide proof and information to establish the value of the easement or property to be insured. IPC will review the title policy pro forma and will advise of any necessary title mitigation measures to ensure clear and unencumbered title to the Interconnection Facility Easement or Fee Ownership Parcel and access easement areas. Title mitigation measures shall be performed by Interconnection Customer at Interconnection Customer's sole cost and expense. Title policy to include endorsements as required by IPC at Interconnection Customer's sole cost and expense. Interconnection Customer to provide an electronic copy of all exceptions to title insurance for IPC review. Interconnection Customer to provide Idaho Power with a final A.L.T.A. extended owners' policy of title insurance.

1.4.5.5 A.L.T.A. Survey

An A.L.T.A. survey of the Project property with all existing IPC easement rights and facilities identified. The A.L.T.A. survey shall include and identify all proposed land transaction areas. If IPC requires a Fee Ownership Parcel for the Interconnection Facility, Interconnection Customer shall provide an A.L.T.A. survey of the Fee Ownership Parcel to be conveyed to IPC and all Land Transactions. If IPC requires an Easement for the Interconnection Facility, Interconnection Customer may provide IPC with a copy of Interconnection Customer's A.L.T.A. survey or with an A.L.T.A. survey in IPC's name but the A.L.T.A. survey shall include the Interconnection Facility Easement Area, as well as all Land Transactions.

1.4.5.6 Phase I Environmental Analysis

A Phase I environmental analysis ("Phase I EA") of Interconnection Customer's Project property (whether fee-owned, leased, or on an easement premises) for IPC review. The Phase I EA shall provide a map indicating the location of the IPC Interconnection Facilities in relation to any identified areas of concern. If IPC requires a Fee Ownership Parcel for the Interconnection Facility, Interconnection Customer shall provide a Phase 1 EA in IPC's name with warranties for IPC. If IPC requires an Easement for the Interconnection Facility, Interconnection Customer shall provide IPC with a copy of Interconnection Customer's Phase 1 EA but which shall include and reference the Interconnection Facility Easement Area.

1.4.5.7 Land Use Authorizations/Permits

The Interconnection Customer shall secure all necessary local jurisdiction, state, and/or federal land use authorizations and permits for the IPC Interconnection Facilities, access road, new transmission and distribution lines, buildings, and all facilities in support of Interconnection Customer's Project, as required by local, state or federal entities. A copy of each authorization pertaining to IPC facilities shall be provided to IPC.

1.4.5.8 Land Division

Should a division of land be necessary to create a new Fee Ownership Parcel, Interconnection Customer shall submit application to the proper local jurisdiction and complete all requirements to finalize the creation of a new Fee Ownership Parcel in IPC's name. Interconnection Customer shall provide final approval documentation to IPC.

Interconnection Customer is advised that IPC review and approval of the Land Transaction Documents may require six (6) to nine (9) months. Interconnection Customer is advised to provide all required Land Transaction Documents at earliest possible time. Refer to Appendix C for a quick reference guide to Idaho Power Corporate Real Estate Fee Acquisition and/or Easement Parcel requirements. Upon IPC approval of all Land Transaction Documents, IPC will supply to the Interconnection Customer final form documents for signature by the land owner of record. The Interconnection Customer shall return original signed and recorded Land Transaction Documents to IPC. All recording and mailing fees shall be paid by Interconnection Customer. IPC shall provide to Interconnection Customer electronic copies of all fully executed and recorded Land Transaction documents.

1.4.6 Site Work

The Interconnection Customer will provide; property, property access and site plan. IPC will perform land clearing and grading for IPC's interconnection station.

1.4.7 Monitoring Information

If the Interconnection Customer requires the ability to monitor information related to the IPC breaker/relay (i.e. Mirrored Bits) in the interconnection station, they are required to supply their own communications circuit to the interface area of the interconnection yard. The fiber communication circuit used for GOLC is acceptable.

A separately fenced and lockable corner of the interconnection station yard can be made available, at the Interconnection Customer's request, for interface equipment and facilities.

1.4.8 Meteorological Data

In order to integrate the solar energy into the IPC system and operate IPC's solar forecasting tool, the Interconnection Customer must provide solar irradiation and weather data from the Facility's physical location to IPC via real time telemetry in a form acceptable to IPC. The associated cost for obtaining this data is the Interconnection Customer's responsibility.

The data must be provided at 10 second intervals and consist of:

1. Global Horizontal Irradiance
2. Plane of Array Irradiance
3. Ambient Temperature
4. Wind Speed and Wind Direction
5. Relative Humidity

The installed instruments must equal or exceed the specifications of the following instruments:
Temperature and Relative Humidity: R.M Young Relative Humidity and Temperature Probe Sensors Model 41382
Wind: R.M Young Wind Monitor Model 05103
Pryanometer: Apogee Instruments Model SP-230

1.4.9 Generator Technical Information & Drawings

Interconnection Customer shall provide draft design prints during FSR development containing technical information, like impedances, and equipment brand and models. After construction, the Interconnection Customer shall submit to IPC all the as-built information, including prints with the latest approved technical information and commissioning test results.

1.5 IPC's Interconnection Facilities

IPC's Interconnection Facilities will include:

Substation:

IPC will install a new IPC interconnection substation (200' x 170') including: gates, fencing (180'x150'), prefabricated control building, surface trench, two 138kV dead-end structures, one 138 kV circuit breaker, two 138kV air-break switches, three CT's, five PT's, required foundations, structures, bus, grounding, conduit and conductor for such equipment, a revenue meter and associated relaying/control/SCADA/comm equipment. IPC's Interconnection Facilities will be located in IPC's interconnection station yard up to the Point of Change of Ownership. Revenue metering will be accomplished through metering CTs and PTs on the 138kV bus.

Transmission:

IPC will install a short 138 kV transmission tap between the existing 138 kV transmission line and the interconnection station. The tap is assumed to be approximately 400 feet long or less.

- (1) 3pole, Steel, 1-way dead-end structure for Tap, Flying Tap to Existing Conductor, 300' span of 397 ACSR to Station DE (extra 100' for Tap, Jumpers, etc.)
  - Provisions for access roads, laydown yards and landings, rock

Distribution/Local Service:

A 3-phase distribution circuit will be extended from the nearby OTEC-owned feeder for IPC's interconnection station local service.

Phasor Measurement Unit (PMU) data:

To meet North American Electric Reliability Corporation's (NERC's) MOD-11 and 13-WECC-CRT-1, R1.2 requirements, IPC will install equipment to collect and transmit Phasor Measurement Unit (PMU) data to IPC. The communication circuits required for this data transmission are described above (section 1.4.1). The data can be made available to the Interconnection Customer on request.

<u>The minimum acceptable PMU message rate is 30 samples per second. The minimum set of PMU measurement channels recorded at the POI is shown below. Additional or substitute channels may be required[1] on a per case basis depending on the interconnection configuration and facility design details.</u>

- <u>Frequency</u>
- <u>Frequency Delta (dF/dt)</u>
- <u>Positive Sequence Voltage Magnitude</u>
- <u>Positive Sequence Voltage Angle</u>
- <u>Positive Sequence Current Magnitude</u>
- <u>Positive Sequence Current Angle</u>

1.6 Upgrades

Upgrades to the Distribution System

N/A

Network Upgrades to Substations

- [redacted] **Substation:**
  - Work at [redacted] for connecting new SCADA/EMS comm circuit to EMS FEP DIGI
- [redacted] **Substation:**
  - 60' x 75' site addition, gates, fencing, prefabricated control building, surface trench and conduiting, (2) 138kV dead-end structures

[1] Consult with System Planning to determine acceptability.

- (2) 421/411L line protection panels, 130VDC battery system, AC and DC L.C.s, one 138kV power PT, 200A ATS
- (2) 138kV air-breaks, one 138kV breaker, (4) 138kV PTs
- Single GARD and Test Switch, SAR Hc, 1200A WT, tuner, single yard coax run, CCVT w/carrier acc. (included above), SATCCOM
- Single SCADA panel including (1) SEL-3355 with HMI, (1) ACS SD, (1) ACS KR with (1) GE KI, (1) SEL-3530, (1) SEL-2730M, (1) SEL-2407, (1) SEL-3620, (1) PULS Power Supply
- Communication circuit required for SCADA/EMS (assumed satellite)

- [redacted] **Substation:**
  - Single GARD 8000 and test switch, wave trap, 1200A tuner, dual yard coax run, (re-use existing CCVT)
- [redacted] **Substation**
  - Settings and reconfigurations of existing equipment

Network Upgrades to the Transmission System

- Modifications to existing IPC 138kV line:
  - (2) 2pole, Steel, H-frame Type Switch Structures w/ (2) load break switches
    - Provisions for access roads, laydown yards and landings, rock

2. Estimated Milestones

These milestones will begin, and the construction schedule referenced below will only be valid, upon receipt of funding from Interconnection Customer or its authorized third party no later than the date set forth below for such payment. IPC will not commit any resources toward project construction that have not been funded by Interconnection Customer. Additionally, failure by Interconnection Customer to make the required payments as set forth in this Study by the date(s) specified below may result in the loss of milestone dates and construction schedules set forth below. In the event that the Interconnection Customer is unable to meet dates as outlined below, Interconnection Customer may request an extension of the Operation Date of up to three (3) years. Interconnection Customer's request will be evaluated by IPC to ensure Interconnection Customer's request does not negatively impact other projects in IPC's Generator Interconnection Queue. Such extension will be allowed only if IPC determines, in its sole discretion, that the extension will not negatively impact other projects in IPC's Generator Interconnection Queue. Estimated milestones, which will be updated and revised for inclusion in the LGIA in light of subsequent developments and conditions, are as follows:

Estimated Date	Responsible Party	Estimated Milestones
[DATE]	*Interconnection Customer*	*IPC receives Notice to Proceed and construction funding or arrangements acceptable to IPC are made with IPC's Credit Department*
6 months after construction funds received	*IPC*	*IPC Engineering and Design Complete*
12 months after construction funds received	*IPC*	*IPC Long Lead Material Procured/Received*

12 months after construction funds received	*Interconnection Customer*	*Deed/Easements and permits executed/procured for IPC site, construction will not begin until deed/easements and permits are in place.* *Detailed in Appendix C attached.*
8 months prior to IPC Commissioning	*IPC*	*New generation must be modeled and submitted to the Western Energy Imbalance Market a minimum of 6 months prior to coming online, failure to submit by given lead time will results in project delay.*
16-22 months after construction funds received	*IPC*	*IPC Construction Complete. Construction complete is pending outages, all work complete at other sites (including other parties work).*
16-22 months after construction funds received	*Interconnection Customer*	*Telecommunication circuits identified in Section 1.4.1 are operational and provided to the IPC site*
23 months after construction funds received	*IPC*	*IPC Commissioning Complete, commissioning will not take place until Telecommunication circuits are operational*
5 days after switching request made to IPC Dispatch	*Interconnection Customer*	*Switch at the Point of Interconnection can be closed*
TBD	*IPC*	*Notification from IPC's Energy Contracting Coordinator confirming First Energy of Non-Firm Output*
TBD	*Interconnection Customer*	*Interconnection Customer testing begins*
TBD	*IPC*	*Notification from IPC's Energy Contracting Coordinator confirming Operation Date (pending all requirements are met) of Firm Network Resource Output*

IPC does not warrant or guarantee the foregoing estimated milestone dates, which are estimates only. These milestone dates assume, among other things, that materials can be timely procured, labor resources are available, and that outages to the existing transmission system are available to be scheduled. Additionally, there are several matters, such as permitting issues and the performance of subcontractors that are outside the control of IPC that could delay the estimated Operation Date. For purposes of example only, federal, state, or local permitting, land division approval, identification of Interconnection Facilities location, access to proposed Interconnection Facilities location for survey and geotechnical investigation, coordination of design and construction with the Interconnection Customer, failure of IPC's vendors to timely perform services or deliver goods, and delays in payment from Interconnection Customer, may result in delays of any estimated milestone and the Operation Date of the project. To the extent any of the foregoing are outside of the reasonable control of IPC, they shall be deemed Force Majeure events.

3. Operating Requirements

The Project is required to comply with the applicable Voltage and Current Distortion Limits found in IEEE Standard 519-2014 *IEEE Recommended Practices and requirements for harmonic Control in Electrical Power Systems* or any subsequent standards as they may be updated from time to time.

The Project will be subject to reductions directed by IPC Grid Operations during transmission system contingencies and other reliability events. When these conditions occur, the Project will be subject to Generator Output Limit Control ("GOLC") and will have equipment capable of receiving an analog setpoint via DNP 3.0 from IPC for GOLC. Generator Output Limit Control will be accomplished with a setpoint and discrete output control from IPC to the Project indicating maximum output allowed. For more detail see Appendix A.

Low Voltage Ride Through: The Project must be capable of riding through faults on adjacent sections of the power system without tripping due to low voltage. The interconnection projects must meet or exceed the Low Voltage Ride-Through requirements as set forth in NERC Standard PRC-024.

Frequency Response Requirements: Generation resources must be capable of providing Fast Frequency Response for both positive and negative frequency deviations from 60Hz with a dead-band not to exceed ± 0.036 Hz for Bulk Electric System frequency excursion events. The required frequency response must have an adjustable droop characteristic with a default droop value not to exceed 5%. The required frequency response shall be 0% to 3% of generation capacity, with a maximum required response of 3% of generator's full capacity for as long as the generator is able to provide frequency support. Where applicable, enabling and disabling of the frequency response function shall be made available via a SCADA control point.

Momentary Cessation Requirements: Momentary cessation should not be used within the voltage and frequency ride-through curves specified in PRC-024. Use of momentary cessation is not considered "ride through" within the "No Trip" zone curves of PRC-024. The use of momentary cessation should be eliminated to the extent possible consistent with NERC's *Reliability Guideline for BPS-Connected Inverter-Based Resource Performance*

In digital equipment, frequency should be calculated over a period-of-time (e.g. three to six cycles) and filtered to take control action on the fundamental frequency component of the calculated signal. Calculated frequency must not be susceptible to spikes caused by phase jumps on the Bulk Electric System.

Applicable generation resources should follow NERC's *Reliability Guideline for BPS-Connected Inverter-Based Resource Performance* with respect to Reaction Time, Rise Time, Settling Time, Overshoot, and Settling Band.

4. Reactive Power

The Project must be capable of +/- 0.95 power factor operation, as measured at the Interconnection Point, for all MW production levels. The Project must have equipment capable of receiving an analog setpoint, via DNP 3.0 from IPC for Voltage Control. The setpoint will be the desired voltage level as measured at the interconnect bus. The range of setpoint will be 131.1 kV to 147.7 kV or set such that the voltage setpoint range does not restrict +/- 0.95 power factor operation at the Interconnection Point. . For more detail see Appendix A.

IPC will determine the reactive power required to be supplied by IPC to the Interconnection Customer, based upon information provided by the Interconnection Customer. IPC will specify the equipment required on IPC's system to meet the Facility's reactive power requirements. These specifications will include but not be limited to equipment specifications, equipment location, IPC-provided equipment, Interconnection Customer provided equipment, and all costs associated with the equipment, design and installation of IPC-provided equipment. The equipment specifications and requirements will become an integral part of the LGIA. IPC-owned equipment will be maintained by IPC, with total cost of purchase, installation, operation, and maintenance, including administrative cost to be reimbursed to IPC by the Interconnection Customer. Payment of these costs will be in accordance with the Oregon QF-LGIA and the total reactive power cost will be included in the calculation of monthly Operation and Maintenance charges.

5. Estimated Costs

The following good faith estimates are provided in 2021 dollars and are based on a number of assumptions and conditions. IPC does not warrant or guarantee the estimated costs in the table below, which are estimates only and are subject to change. Interconnection Customer will be responsible for all actual costs incurred in connection with the work to be performed by IPC and its agents, under the terms and subject to the conditions included in any QF-LGIA executed by IPC and Interconnection Customer.

The estimated cost below is required to be paid in full by the Interconnection Customer, or other arrangements acceptable to IPC are made with IPC's Credit Department, prior to IPC commencing construction on the project.

Estimated Cost:

Description	Ownership	Cost Estimate
IPC Interconnection Facilities:		
New 138 kV interconnect station ([redacted])	IPC	$1,943,846
Distribution: Extend OTEC feeder to interconnect station		30,000
Transmission tap to station	IPC	121,335
Sub total		**2,095,181**
Contingency 10%		$209,518
Sub total		**2,304,699**
Overheads 7.25%		167,090
TOTAL		**2,471,7899**
Network Upgrades to Substation:		
[redacted] substation	IPC	1,504,500
[redacted] Substation	IPC	169,000
[redacted] substation	IPC	24,500
[redacted] substation DS1 telecommunications connectivity	IPC	45,654
Sub total		**1,743,654**

Contingency 10%		174,365
Sub total		**1,918,019**
Overheads 7.25%		139,056
TOTAL		**$2,057,075**
Network Upgrades to Transmission:		
138 kV transmission upgrades	IPC	$308,226
Contingency 10%		30,822
Sub total		**339,048**
Overheads 7.25%		24,580
TOTAL		**363,628**
GRAND TOTAL	**$4,892,492**	

Note Regarding Transmission Service:

This FSR is a study of a request for Network Resource Interconnection Service. This FSR identifies the facilities necessary to provide such service. Network Resource Interconnection Service in and of itself does not convey any right to transmission service or to deliver electricity to any specific customer or Point of Delivery.

Note Regarding GIA:

This FSR is a study and preliminary evaluation only and does not constitute, or form the basis of, a definitive agreement related to the matters described in this FSR. Unless and until a QF-LGIA is executed by IPC and Interconnection Customer, no party will have any legal rights or obligations, express or implied, related to the subject matter of this FSR.

Appendix A

Generation Interconnection Control Requirements

A.1 Generator Output Limit Control (GOLC)

A.1.1 IPC requires Interconnected Power Producers to accept GOLC signals from IPC's energy management system ("EMS").

A.1.2 The GOLC signals will consist of four points shared between the IPC EMS (via the IPC RTU) and the Interconnection Customer's Generator Controller ("SGC"). The IPC RTU will be the master and the SGC will be the slave.

A.1.2.1 GOLC Setpoint: An analog output that contains the MW value the Interconnection Customer should curtail to, should a GOLC request be made via the GOLC On/Off discrete output Control point.

A.1.2.1.1 An Analog Input feedback point must be updated (to reflect the GOLC setpoint value) by the SGC upon the SGC's receipt of the GOLC setpoint change, with no intentional delay.

A.1.2.2 GOLC On/Off: A discrete output (DO) control point with pulsing Trip/Close controls. Following a "GOLC On" control (DNP Control Code "Close/Pulse On"), the SGC will run power output back to the MW value specified in the GOLC Setpoint. Following a "GOLC Off" control (DNP Control Code "Trip/Pulse On"), the Interconnection Customer is free to run to maximum possible output.

A.1.2.2.1 A Discrete Input (DI) feedback point must be updated (to reflect the last GOLC DO Control Code received) by the SGC upon the SGC's receipt of the GOLC DO control, with no intentional delay. The feedback DI should latch to an OFF state following the receipt of a "GOLC OFF" control and it should latch to an ON state following the receipt of an "GOLC ON" control.

A.1.3 If a GOLC control is issued, it is expected to see MW reductions start within 1 minute and plant output to be below the GOLC Setpoint value within 10 minutes.

A.2 Voltage Control

A.2.1 IPC requires Transmission-Interconnected Power Producers to accept voltage control signals from IPC's EMS when they are connected to IPC's transmission system.

A.2.2 The voltage control will consist of one setpoint and one feedback point shared between the IPC EMS and the SGC.

A.2.3 The setpoint will contain the desired target voltage for plant operation. This setpoint will have a valid control range between 0.95 and 1.05 per unit ("p.u.") of nominal system voltage.

A.2.4 The control will always be active, there is no digital supervisory point like the Curtail On/Off control above.

A.2.4.1 When a setpoint change is issued an Analog Input feedback point must be updated (to reflect the voltage control setpoint value) by the SGC upon the SGC's receipt of the voltage control setpoint change, with no intentional delay.

A.2.4.2 When a setpoint change is received by the SGC, the voltage control system should react with no intentional delay.

A.2.4.3 The voltage control system should operate at the voltage indicated by the setpoint with an accuracy of +/- 0.5% of the nominal system voltage.

A.2.5 The Interconnection Customer should supervise this control by setting up "reasonability limits", i.e. configure a reasonable range of values for this control to be valid. As an example, they will accept anything in the valid control range (between 0.95 and 1.05 p.u.) but reject values outside this range. If they were fed an erroneous value outside the valid range, their control system would default to the last known, good value.

A.3 Generation Interconnection Data Points Requirements

Digital Inputs to IPC (DNP Obj. 01, Var. 2)			
Index	Description	State (0/1)	Comments:
0	GOLC Off/On (Control Feedback)	Off/On	Feedback provided by Interconnection Customer
1	FREQUENCY RESPONSE OFF/ON (Control Feedback)	Off/On	Feedback provided by Interconnection Customer
2	52A Interconnection Customer Main Breaker (if present)	Open/Closed	Sourced at substation
3	52A Interconnection Customer Capacitor Breaker (if present)	Open/Closed	Sourced at substation

Digital Outputs to Interconnection Customer(DNP Obj. 12, Var. 1)		
Index	Description	Comments:
0	GOLC Off/On	Control issued by IPC
1	Frequency Response Off/On	Control issued by IPC

Analog Inputs to IPC (DNP Obj. 30, Var. 2)							
Index	Description	Raw High	Raw Low	EU High	EU Low	EU Units	Comments:
0	GOLC Setpoint Value Received (Feedback)	32767	-32768	TBD	TBD	MW	Provided by Interconnection Customer
1	Voltage Control Setpoint Value Rec'd (Feedback)	32767	-32768	TBD	TBD	kV	Provided by Interconnection Customer
2	Maximum Park Generating Capacity	32767	-32768	TBD	TBD	MW	Provided by Interconnection Customer
3	Ambient Temperature	32767	-32768	327.67	-327.68	DEG C	Provided by Interconnection Customer
4	Wind Direction	32767	-32768	327.67	-327.68	Deg from North	Provided by Interconnection Customer
5	Wind Speed	32767	-32768	327.67	-327.68	M/S	Provided by Interconnection Customer
6	Relative Humidity	32767	-32768	TBD	TBD	%	Provided by Interconnection Customer

7	Global Horizontal Irradiance	32767	-32768	TBD	TBD	W/M^2	Provided by Interconnection Customer
8	Plane of Array Irradiance	32767	-32768	TBD	TBD	W/M^2	Provided by Interconnection Customer
9	SPARE						
10	SPARE						
11	SPARE						
12	SPARE						
13	SPARE						
14	SPARE						
15	SPARE						
16	SPARE						
17	SPARE						

Analog Outputs to Interconnection Customer **(DNP Obj. 41, Var. 2)**							
Index	Description	Raw High	Raw Low	EU High	EU Low	EU Units	Comments:
0	GOLC Setpoint	32767	-32768	TBD	TBD	MW	Control issued by IPC
1	Voltage Control Setpoint	32767	-32768	TBD	TBD	kV	Control issued by IPC
2	SPARE						
3	SPARE						
4	SPARE						
5	SPARE						
6	SPARE						
7	SPARE						
8	SPARE						
9	SPARE						

Appendix B

IPC Survey Requirements

- ❑ Is the Grantor's Deed Instrument No. noted in the Exhibit 'A' Legal Description or Exhibit 'B' Survey Map?
- ❑ Are the Section, Township, Range, and County information clearly stated on the Exhibits?
- ❑ Is the Basis of Bearings between found monuments called out and noted on the Exhibits?
- ❑ Are the Point of Commencement, Point of Beginning and or Point of Terminus shown on the Exhibits?
- ❑ Do all lines have a bearing and distance associated with them on the Exhibits?
- ❑ All lines need bounding calls to Grantor's ownership lines, Rights-of-Way, etc. in Exhibit A.
- ❑ Are the Subdivision names, lot & block, and streets labeled on the Exhibit B?
- ❑ Are any existing Utility Easements adjoining this Easement called out and shown on the Exhibits?
- ❑ Is the map scale noted and is there a North arrow shown on the Exhibit B?
- ❑ On a strip easement is the width given and does it call to form a closed figure in the Exhibit A?
- ❑ Does the Parcel description close?
- ❑ Are the reference surveys of record or CP&Fs used to prepare the easement called out and shown on the Exhibits?
- ❑ A Professional Land Surveyor or Engineer in responsible charge must stamp, sign and date the exhibits for submission.
- ❑ A copy of the current Deed of Record for the Grantor is needed for submission.

Appendix C

Allow a minimum of six months time frame for land transaction portion of the project – may be longer depending on project specifics.

1. **Project Map/Site Plan**
   A 90% complete informational map or site plan of the Project Property with locations of all easements to be released, new easements proposed for both Interconnection Customer and IPC, existing IPC lines to be crossed by Interconnection Customer's facilities, Interconnection Customer's lease and easement areas (if any), access roads, and any other features or elements requested to be included by IPC to facilitate review and processing of the project documents.

2. **Surveyed Legal Descriptions and Maps**
   Written legal description and map for each Land Transaction Document, stamped and signed by a licensed surveyor. Each legal description and map is to be submitted to and approved by IPC's surveyor. See IPC survey requirements in Appendix B, attached hereto and made a part hereof.

3. **Right of Entry Agreement**. A Right-of-Entry Agreement is attached and will allow Idaho Power to conduct necessary studies and review of the property and substation lands to determine feasibility for development. This document is required to be signed by the underlying property owner as soon as possible and will allow the preliminary stages of project development to commence pending completion of the transfer of substation lands to Idaho Power.

4. **Purchase and Sale Agreement – Warranty Deed – Access Easement – Power Line Easements**. Idaho Power requires the substation land be provided in a form of fee ownership acceptable to Idaho Power. A Purchase and Sale Agreement is attached and provides the terms for the fee ownership transaction. The Purchase and Sale Agreement includes a Warranty Deed for the transfer of the substation land to Idaho Power, a form of Access Easement for access to the substation land, and forms of transmission and distribution easements. Individual forms are attached, as well.

5. **Land Division (if needed)**. Should a division of land be necessary to separate the substation parcel from an underlying, larger property ("Property"), Developer will be required to submit application to the County for the land division and to ensure the satisfaction of all conditions to complete the land division.

6. **Title Commitment**. Idaho Power requires that Developer ensure the substation lands and access easement over the Property are free from any encumbrances to title. To meet this requirement, a Title Commitment with A.L.T.A. extended coverage owner's policy in Idaho Power's name is required. All exceptions to title insurance need to be provided with the Title Commitment for Idaho Power review. Upon receipt, Idaho Power will review all exceptions and will advise of any necessary follow-up actions. Importantly, Idaho Power requires a form of ownership that is free and clear from all encumbrances and will require the developer to complete title curative measures as Idaho Power deems necessary.

7. **Survey**. An A.L.T.A survey for the substation parcel, and which includes the access easement is required. The A.L.T.A. survey will be reviewed by Idaho Power's surveyor who will advise of any necessary revisions.

8. **Legal Descriptions**. Written legal descriptions, stamped and signed by a surveyor licensed in the state of Idaho, are required for the substation parcel, access easement area, and all distribution/transmission line easement parcels. The written legal descriptions will be reviewed by Idaho Power's surveyor who will advise of any necessary revisions.

9. **Phase I Study**. Developer shall provide Idaho Power with a Phase I study prepared by an independent environmental site assessment company, in Idaho Power's name, which recognizes Idaho Power as the purchaser of the substation parcel and User of the Phase I report, and which provides warranties to Idaho Power for the substation parcel and access easement areas. The Phase I study will be reviewed by Idaho Power and Idaho Power will advise if a Phase II or other necessary actions or required based on the results of the Phase I study.

10. **Public Lands Permits or Authorizations (if needed)**. Should any agency lands, rights-of-way, etc. be affected by the granting of land and easement rights to Idaho Power, Developer shall be responsible to any secure necessary agency authorizations or permits in Idaho Power's name, at Developer's sole cost and expense. Developer shall be responsible to ensure all conditions of approval are satisfied, fees are paid, etc.

11. **Land Use Permits or Authorizations**. Developer shall be responsible to secure any necessary land use entitlements or authorizations from the local jurisdiction, local agencies, state of Idaho, or Federal or other agencies to allow the development of the substation parcel, access road and ancillary transmission or distribution lines and facilities (example: Conditional Use Permit from city or county). Any such authorizations shall be secured in Idaho Power's name and for the benefit of Idaho Power. Idaho Power will require the Developer to satisfy all conditions of approval and requirements for any such entitlement or authorization.

12. **Costs**. Any costs pertaining to the above items shall be at the Developer's sole cost and expense.

13. **Miscellaneous Documents.** Other miscellaneous documents as necessary for the project – such as Memorandums of Agreement/Understanding, etc.