Appendix A – WDT1383

Queue Cluster 9 Phase II Report

November 22, 2017

This study has been completed in coordination with Southern California Edison per ISO Tariff Appendix DD Generator Interconnection and Deliverability Allocation Procedures (GIDAP)
## Interconnection Study Document History

<table>
<thead>
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<th>No.</th>
<th>Date</th>
<th>Document Title</th>
<th>Description of Document</th>
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<tr>
<td>4</td>
<td>11/22/2017</td>
<td>Queue Cluster 9 Phase II Appendix A Report</td>
<td>Final Phase II Interconnection Study Report</td>
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<tr>
<td>3</td>
<td>02/28/2017</td>
<td>Addendum #1 to Queue Cluster 9 Phase I Appendix A Final Report</td>
<td>The purpose of this report is to publish the written comments provided by the IC to SCE in accordance with the timelines stated per Section 4.5.7 in GIP</td>
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<td>2</td>
<td>02/21/2017</td>
<td>Revision #1 to the Final Phase I Interconnection Study Report</td>
<td>Revision of Final Phase I Interconnection Study Report to clarify the scope and cost of the Project associated with the Mojave Desert RAS</td>
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A. INTRODUCTION

The Interconnection Customer (IC), has submitted a completed Interconnection Request (IR) to the California Independent System Operator Corporation (ISO) for its proposed Project interconnecting to the ISO Controlled Grid. The Project consists of the Generating Facility and the IC’s Interconnection Facilities as illustrated below in Figure A.1. A map that illustrates the location of the Project is provided below in Figure A.2. Moreover, the Project information is summarized in Table A.1.

In accordance with FERC approved SCE’s WDAT Attachment I Generator Interconnection Procedures (GIP), the Project was grouped with Queue Cluster 9 (QC9) Phase II projects to determine the impacts of the group as well as impacts of the Project on the ISO Grid.

An Area Report has been prepared separately identifying the combined impacts of all projects on the ISO Grid. This Appendix A report focuses only on the impacts or impact contributions of the Project at the local distribution system, and is not intended to supersede any contractual terms or conditions specified in the GIA.

The report provides the following:

1. Distribution system impacts caused by the Project.
2. System reinforcements necessary to mitigate the adverse impacts caused by the Project under various system conditions.
3. A list of required facilities and a good faith estimate of the Project’s cost responsibility and time to construct these facilities. Such information is provided in Attachment 1 and Attachment 2 as separate documents in the Appendix A Project report package.

The Project encompasses energy storage equipment that triggered the need to analyze its charging impacts the Distribution Provider’s (SCE) electric system. The analyses focused on the charging demand aspects of the Project and considered varying levels of system demand with minimal generation dispatch within the local distribution system.

Consequently, the report also discloses the adequacy of SCE’s Electric System to support the Project when operating in charging mode, identifies system limitations that may restrict the Project when operating in charging mode during certain demand conditions, and provides a high-level explanation of potential exposure to the Project of charging restrictions on the electric system. The Generating Facility will follow ISO market dispatch instructions when in charging demand mode and in discharging mode.

All equipment and facilities comprising the Interconnection Customer’s 41.49 MW / 43.68 MVA gross capacity Inverter based Solar Photovoltaic and Battery Storage Generating Facility in Desert Lake California, as disclosed by the Interconnection Customer in its Interconnection Request, as may have been amended during the Interconnection Study process, which consists of (i) [redacted] each with a nominal power output of [redacted] but which will operated to not exceed 1.976 MW for a total gross output of 41.496 MW, and [redacted].

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1 It should be noted that construction is only part of the duration of months specified in the study, which includes detailed engineering, licensing, and other activities required to bring such facilities into service. These durations are from the execution of the GIA, receipt of all required information, funding, and written authorization to proceed with design and engineering, procurement, and construction from the IC as will be specified in the GIA to commence the work.

2 Charging is defined in the Project as drawing energy from the grid to “charge” the Project- associated charging facilities.
each with a nominal power output of 1.0 MVA, but which will operate at unity power factor for a total gross output of 40.0 MW, (ii) the associated infrastructure and step-up transformers, (iii) meters and metering equipment, and (iv) appurtenant equipment. The Project shall consist of the Generating Facility and the Interconnection Customer’s Interconnection Facilities.

Based on the technical data provided for the individual generator unit(s), the collector system equivalent, pad-mount and main transformer banks, the internal project losses are shown in Table 1. In addition, losses incurred on the generation tie line are shown in Table 2 below. The project losses identified represent those assuming the Project limiting its output at the high side of the main transformer bank to achieve the desired MW delivery at the POI.

Table 1

*This represents the MW value needed at the inverter terminal to achieve the desired Net Output MW to meet POI MW.

**MW (net) represents the MW value as measured on the high side of the main transformer bank to achieve the desired MW delivery at the POI

Table 2

*MW (net) represents the MW value as measured on the high side of the main transformer bank to achieve the desired MW delivery at the POI

Since the Generating Facility has the capability of charging more MW at the Point of Interconnection than the requested amount of 40 MW, the Interconnection Customer will need to install or demonstrate that a control system will be put in place which will manage the Generating Facility for Energy Storage under charging operation output to not exceed 40.0 MW as measured at the high side of the main transformer banks.

The Project shall consist of the Large Generating Facility and the Interconnection Customer’s Interconnection Facilities, and is shown in the diagram below.
Figure A.1: Project One-Line Diagram
Figure A.2: Project Location Map
<table>
<thead>
<tr>
<th>Table A.1 Project General Information per Attachment B</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Project Location</strong></td>
</tr>
<tr>
<td><strong>Distribution Provider’s Planning Area</strong></td>
</tr>
<tr>
<td><strong>Distribution Provider’s North of Lugo Area</strong></td>
</tr>
<tr>
<td><strong>Interconnection Voltage</strong></td>
</tr>
<tr>
<td><strong>Point of Interconnection</strong></td>
</tr>
<tr>
<td><strong>Number and Types of Generators</strong></td>
</tr>
<tr>
<td><strong>Requested Maximum Project Delivery at Point of Interconnection</strong></td>
</tr>
<tr>
<td><strong>Generation Tie Line</strong></td>
</tr>
<tr>
<td>0.12 miles, 336.4 ACSR Merlin</td>
</tr>
<tr>
<td>Line Rating: 385A / 519A</td>
</tr>
<tr>
<td>Z_1 (p.u.): 0.000250 + j0.000700, B = 0.00004</td>
</tr>
<tr>
<td>Z_0 (p.u.): 0.000534 + j0.002475, B = 0.00004</td>
</tr>
<tr>
<td><strong>Main Step-Up Transformer(s)</strong></td>
</tr>
<tr>
<td><strong>Collector Equivalent</strong></td>
</tr>
<tr>
<td>Equivalent Rating: 100 MVA</td>
</tr>
<tr>
<td>Nominal Voltage: 34.5 kV</td>
</tr>
<tr>
<td>Z_1 (p.u.): 0.00203 + j0.00661, B = 0.00</td>
</tr>
<tr>
<td>Z_0 (p.u.): 0.00523 + j0.03080, B = 0.00</td>
</tr>
<tr>
<td><strong>Pad-Mount Transformer(s)</strong></td>
</tr>
</tbody>
</table>

*The MW output at the Point of Interconnection varies under different operating conditions. The IC is reminded that this value is tied to the generation tie-line (gen-tie) losses. The estimated Maximum Net Output value at Point of Interconnection and gen-tie losses illustrated above are contingent upon the accuracy of the technical data provided by the IC, and are subject to change should the IC change its gen-tie parameters during the detailed engineering and design phase of the Project. Please note that the Project shall not exceed the total net output of 40 MW at the Point of Interconnection.*
<table>
<thead>
<tr>
<th><strong>Generator Data</strong></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Generator Auxiliary Load and/or Station Light and Power</strong></td>
<td>1.03 MW</td>
</tr>
<tr>
<td><strong>Voltage Regulation Devices</strong></td>
<td>Not applicable</td>
</tr>
</tbody>
</table>
| **Dynamic Models Used** | PV: regc_a, reec_b, repc_a, lhvr, and lhfrt  
BESS: regc_a, reec_b, repc_a, lhvr, and lhfrt |
<p>| <strong>DeliverabilityRequested</strong> | Full Capacity             |
| <strong>Option (A/B) Requested</strong> | Option A                  |</p>
<table>
<thead>
<tr>
<th>Proposed Dates(^4)</th>
<th></th>
</tr>
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<tbody>
<tr>
<td>In-Service Date (ISD)</td>
<td>10/31/2020</td>
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<tr>
<td>Initial Synchronization Date/Trial Operation</td>
<td>11/15/2020</td>
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<tr>
<td>Commercial Operation Date (COD)</td>
<td>12/31/2020</td>
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</table>

<table>
<thead>
<tr>
<th>Model Results</th>
<th></th>
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</thead>
<tbody>
<tr>
<td>Internal Generating Facility Losses</td>
<td>0.4 MW</td>
</tr>
<tr>
<td>Estimated total losses on Generation Tie Line</td>
<td>0.0 MW</td>
</tr>
<tr>
<td>Limited maximum Net Output at Generating Facility (High-Side of Main Transformer) to achieve requested Point of Interconnection Delivery</td>
<td>40.0 MW</td>
</tr>
</tbody>
</table>

B. STUDY ASSUMPTIONS

For detailed assumptions regarding the group cluster analysis, please refer to the QC9 Phase II Area Report. Below are the assumptions specific to the Project:

1. The Project was modeled as described in Table A.1.

2. The facilities that will be installed by SCE and the IC are detailed in Attachment 1.

3. Roles and Responsibilities for Environmental Activities, Permits, and Licensing.

   The assumptions for the Environmental Activities, Permits, and Licensing are as follows:
   
   i. Internal Substation Scope:
      - SCE will perform all environmental studies and monitoring of all SCE internal substation construction activities.
   
   ii. 115 kV Generation Tie Line, Telecomm Scope:
      - SCE’s scope of work will not require a California Public Utilities Commission (CPUC) license.
      - SCE will act as the environmental liaison between the SCE team and IC team, and the lead for regulatory agency communication.
         - Collaborate with the IC during the environmental study phase on proposed study methodologies and findings, as studies are being planned and performed for SCE’s scope of work.
         - Review IC’s California Environmental Quality Act (CEQA) and National Environmental Policy Act (NEPA) documents, technical studies, surveys, and other environmental documentation addressing SCE’s scope of work (IC to include SCE’s scope of work in their environmental document).
         - Review of internal Environmental Services (ES) existing technical documents when available
            - Regulatory agency communication, consultation, and reporting
            - Permit acquisition
            - Support SCE team in developing the project description, including scope changes during permitting/pre-construction or construction.

\(^4\) Such dates are specified in the Project’s Attachment 8. Actual ISD and COD will depend on licensing, engineering, detailed design, and construction requirements to interconnect the Project.
Communicate scope changes to the IC's environmental team, discuss/approve subsequent actions including new surveys as necessary

- Prepare environmental requirements for construction clearance
- Develop communication plan
- Construction monitoring oversight
- General Order 131-D Consistency Determination and Environmental Evaluation
- Environmental Awareness/Worker Environmental Awareness Program (WEAP) training
- Pre-construction coordination field visit
- Construction and post-construction site assessments

- IC performs all environmental studies and prepares draft environmental permit applications related to the installation of SCE's Interconnection Facilities, Distribution Upgrades, and Network Upgrades. The IC's responsibilities include, but are not limited to notifications to the Native American Heritage Commission (NAHC) and follow-up notifications to the tribes and individuals in the NAHC contact list, performing cultural and paleontological resources records searches, performing cultural resources inventories (survey and recording), performing testing and evaluation and/or data recovery of archaeological sites as applicable, and providing the appropriate documentation in the form of inventory reports, research design and/or data recovery reports as applicable, cultural and paleontological monitoring when/if required, and arranging curation agreements for artifacts and fossil specimens collected, performing a California Natural Diversity Database search, performing a habitat assessment, performing protocol or focused surveys for species with the potential of occurring in identified suitable habitat, conducting jurisdictional delineations for wetlands or other regulated waters, preparing draft environmental permit applications, performing pre-construction biological resource surveys, performing biological resource monitoring during construction, performing cultural and paleontological monitoring during construction, mitigation costs including, but not limited to, offsite/compensatory mitigation and onsite restoration, and developing mitigation plans or other environmental reports or submittals, if required, to support installation of SCE's Interconnection Facilities, Distribution Upgrades, and Network Upgrades.

- Prior to commencing work and during execution of work, the IC must collaborate and obtain ES concurrence on all work outlined above. Should the IC-performed environmental studies, surveys, or monitoring not meet the Federal or State industry standards in accordance with Applicable Laws and Regulations, and as determined by ES, the IC shall be obligated to remedy deficiencies under SCE/ES's direction, or ES shall undertake additional environmental studies, surveys, or monitoring at the sole expense of the IC. If these scenarios occur, the cost estimate must be updated to reflect the changes to the assumptions.

4. Charging Facility Considerations:

- The Project encompasses energy storage facilities. The details pertaining to the Reliability Study for the Generating Facility when operating in charging mode are included in this Appendix A report.

- SCE's distribution standards and practices are in the process of being updated to address energy storage facilities. The proposed Plan of Service in this report may require changes to comply with the updated distribution design standards and practices.
• This study assumes that the IC’s facility will include all equipment, software, appropriate controls, and other related equipment necessary to maintain the energy storage facility demand profile per SCE requirements.
• Upon execution of the GIA, SCE will provide the IC with the required ramp rate\(^4\) control parameters. The ramp rate controls will be a function of the demand on the distribution system, as well as SCE’s Electric System configuration (additional parameters may be considered, as necessary).
• In order to ensure limits are communicated in a timely and reliable manner, the IC is responsible for providing reliable communications between the Project and SCE System to transmit the required telemetry data as outlined in the Distribution Provider’s Interconnection Handbook. Should the communication channel fail, the Project’s operating limits will automatically revert to zero (no charging allowed).
• If the Project does not follow the given charging limitations, the Project will be disconnected.
• Depending on the study results, the Project may need to participate in the Distributed Energy Resource Management System (DERMS).
• The energy storage component of the Project will need to be metered separately from the revenue load components. The IC should be prepared to install multiple sets of metering (i.e. separate sets of potential transformers & current transformers and supporting metering equipment) for the Project. Additionally, the Project may also need to connect the energy storage component to a dedicated transformer.

5. Other Items to Consider:
• Relay coordination study will be required for this Project. Results of the relay coordination study may add protection related scope which will be the cost responsibility of this Project.
• Final metering requirements will be identified as part of Project execution and could result in modifications to the Project.
• Short Circuit Duty Considerations: SCD operational mitigation was identified taking into account new generation projects that have executed GIAs, approved Transmission Network Upgrades fully permitted and under construction, and new generation projects including the QC8 Phase II projects, which do not yet have an executed GIA. The study results for these operational studies are provided in Section II of the Generation Sequencing Implementation Short Circuit Duty evaluation (Appendix G). Based on the study results, replacement of four (4) Vincent 500 kV circuit breakers (triggered by QC3&4) are required to be in place in order to enable interconnection of the Project. Replacement of the four (4) Vincent 500 kV circuit breakers has not been initiated, because this upgrade is required only when sufficient generation projects (with executed GIAs in good standing) achieve ISD. The identification of the need for the Vincent 500 kV circuit breaker upgrades is based on the assumption that all queued generation projects actually materialize and are interconnected, but the true need occurs only when sufficient queued generation achieves ISD. This SCD mitigation will be continuously evaluated as part of ongoing GIA negotiations with queued generation projects to properly define the actual trigger of SCD mitigation based on the actual execution of GIAs and development of generation facilities toward commercial operation.

\(^4\) It is assumed that ramp rates for each energy storage facility will be dependent upon their inherent technology types. While very quick response ramp rates (i.e. going from full charge to full discharge instantaneously or vice-versa) may be beneficial for other grid services, the Distribution Provider may, at its discretion, require establishing limits to maintain safety and reliability of its distribution system.
C. TECHNICAL REQUIREMENTS\(^6\)

1. Preliminary Protection Requirements
   Protection requirements are designed and intended to protect SCE’s Electric System only. The preliminary protection requirements were based upon the interconnection plan as shown in the one-line diagram depicted in line item #4 in Attachment 1.

   The IC is responsible for the protection of its own system and equipment and must meet the requirements in the Distribution Provider’s Interconnection Handbook.

2. Power Factor Requirements
   The Generating Facility will be required to maintain a composite power delivery at continuous rated power output at the high-side of the generator substation at a power factor within the range of 0.95 leading to 0.95 lagging. This power factor range standard shall be dynamic.

3. Operating Voltage Requirements
   Under real-time operations, the project will be required to operate under the control of automatic voltage regulator with settings as shown in the figure below. The actual values of the Vmin and Vmax will be provided once the project executes a Generation Interconnection Agreement and detailed engineering and design is complete. The Vmin and Vmax values are to be used as the basis for setting up the automatic voltage control mode (with its automatic voltage regulator in service and controlling voltage) of the Generating Facility in order to maintain scheduled voltage at a reference point.

   ![Project Power Factor Control Diagram]

   *Note: Actual values for V\(_{\text{min}}\) and V\(_{\text{max}}\) will be provided by the Participating TO following final engineering and design.*

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\(^6\)The IC is advised that there may be technical requirements in addition to those that outlined above in Section C of this report that are included in the Interconnection Handbook or that will be addressed in the Project’s GIA.
4. **Harmonic Requirements**
   The harmonic impact of the subject inverter-based generation was not part of this study. Impacts on voltage distortion levels may be significant due to the penetration level of the generation facility with respect to the local distribution grid strength. As with all equipment connected to the SCE electric system, the generation project will be subject to the provisions of CPUC Rule 2.E, allowing SCE to require the IC to mitigate interference with service to other SCE customers, including harmonic impacts, if the harmonic interference is caused by the IC.

5. **Subsynchronous Interaction**
   Certain generators or inverter based generators when interconnected within electrical proximity of series capacitor banks on the transmission system are susceptible to Sub-Synchronous Interaction (SSI) conditions, which must be evaluated. Subsynchronous Interaction evaluations include Subsynchronous Resonance (SSR) and Subsynchronous Torsional Interactions (SSTI) for conventional generation units, and Subsynchronous Control Instability (SSCI) for inverter based generators using power electronic devices (e.g. Solar PV and Wind Turbines).

   For projects interconnecting at the 220 kV voltage level and above and in close electrical proximity of series capacitor banks on the transmission system, a detailed study may need to be performed to evaluate the SSI between the Generating Facilities and SCE’s Transmission System. The IC will be 100% responsible for any studies related to the SSR or SSTI. To ensure that the Project does not damage SCE’s control systems, SCE will perform the SSCI study, if required (at the IC’s expense).

   A detailed SSCI study will require that the IC provide detailed Power System Computer Aided Design (PSCAD) models of its Generating Facility and associated control systems, along with the manufacturer representative’s contact information. The study will identify any mitigation(s) that will be required as part of project execution and need to be completed prior to initial synchronization of the Generating Facility. Any identified mitigation shall be at the expense of the IC.

6. **Low/High Voltage Ride-Through (LHVRT) and Low/High Frequency Ride-Through (LHFRT) Capability**
   Actual fault events have demonstrated that certain asynchronous generators (i.e., inverters) from specific manufacturers may be susceptible to false tripping or temporary shutdown during fault conditions. The most severe disturbance to date resulted in the temporary loss of 1,178 MW at photovoltaic plants when inverter control systems throughout Southern California responded to a 500 kV fault by temporarily stopping the production of electric power. Based on the results of an investigation performed into this issue, several causes and contributing factors have been identified which include:
   
   a. Apparent miscalculated frequency at many inverters when fault-induced phase shifts occurred in the reference voltage
   b. Inverter protection settings set to meet IEEE 1547 standards
   c. Momentary overvoltage
   d. Momentary under-voltage

   The NERC PRC-024-2 standard currently allows generators to trip if the system conditions are outside of a defined set of bounds. Because different inverter manufacturers use different methods to calculate frequency (zero crossing, DFT, PLL, etc.), the methods used by some
manufacturers have resulted in calculations of the instantaneous frequency during power system disturbances that do not accurately reflect actual frequency. Inaccurate frequency calculations may result in the reduction of electric power from inverter-based resources which is an unacceptable response. In addition, voltage transients caused by capacitive switching (among other potential causes) can cause inverters to trip due to a momentary overvoltage condition which too is an unacceptable response unless the Project has reached the power factor lead (buck) limits and the voltage is still in excess of the maximum allowable voltage limit for a duration longer than the no trip timer defined in PRC-024-2.

When under-voltage occurs during the fault, some inverters may cease operation temporarily. Such performance may not be allowed in the future reliability standards/interconnection standards.

The IC should work with the inverter manufacturer to ensure these three issues are properly addressed. Dynamic simulation study results illustrating the frequency and voltage performance of the Project based on the technical parameters supplied for the Project are provided as part of the study results. The results will evaluate performance to ensure that the Project remains online during voltage disturbances up to the time periods and corresponding maximum allowable voltage levels set forth in NERC PRC-024-2 and producing power immediately following fault disturbance clearing at the levels prior to the disturbance.

7. Environmental Activities, Permits, and Licensing
   Please see Appendix K of the Area Report.

D. RELIABILITY STANDARDS, STUDY CRITERIA AND METHODOLOGY

The generator interconnection studies were conducted to ensure the ISO Controlled Grid is in compliance with the North American Electric Reliability Corporation (NERC) reliability standards, WECC regional criteria, and the ISO planning standards. Refer to Section C of the Area Report for details of the applicable reliability standards, study criteria, and methodology.

E. POWER FLOW RELIABILITY ASSESSMENT RESULTS

Discharging Analysis of the Project

Steady State Power Flow Analysis Results

1. Thermal Overloads
   The group and/or subtransmission study indicated that the Project contributes to overloads on the following facilities listed below under normal, single contingency, and multiple contingency conditions. The details of the analysis and overload levels as well as the details of the recommended mitigation to address these overloads are provided in the corresponding North of Lugo Area Report.

   I. Normal Conditions
      • Lugo 500/220 kV No.1 and No.2 Transformer Banks
      • Kramer-Victor No.1 and No.2 220 kV Lines
      • Lugo-Victor No.1, No.2, No.3 and No.4 220 kV Lines
      • Calcite-Lugo 220 kV Line
      • Kramer-Victor, Kramer-Roadway and Roadway-Victor 115 kV Lines
II. Single Contingency
   - Lugo 500/220 kV No. 1 Transformer Bank under the loss of the Lugo 500/220 kV No. 2 Transformer Bank.
   - Lugo 500/220 kV No. 2 Transformer Bank under the loss of the Lugo 500/220 kV No. 1 Transformer Bank.
   - Calcite-Pisgah No. 1 220 kV Line under the loss of the Calcite-Lugo No. 1 220 kV Line.
   - Kramer-Sandlot No. 1 220 kV Line under the loss of the Coolwater-Kramer No. 1 220 kV Line.
   - Coolwater-Kramer No. 1 115 kV Line under the loss of the Kramer-Tortilla No. 1 115 kV Line.
   - Coolwater-SEGS2-Tortilla No. 1 115 kV Line under the loss of the Coolwater-Kramer No. 1 115 kV Line.
   - Control-Inyo No. 1 115 kV Line under the loss of the Control-Coso-Haiwee-Inyokern or Control-Coso-Inyokern 115 kV Lines.
   - Kramer-Tortilla No. 1 115 kV Line under the loss of the Coolwater-Kramer No. 1 115 kV Line.
   - Coolwater-Kramer No. 1 115 kV Line under the loss of the Coolwater-SEGS2-Tortilla No. 1 115 kV Line.
   - Kramer 220/115 kV No. 1 or No. 2 Transformer Bank under the loss of the Kramer-Victor and Roadway-Victor 115 kV Lines.

III. Multiple Contingency
   - Calcite-Pisgah No. 1 220 kV Line under the loss of the Calcite-Lugo No. 1 220 kV Line and Lugo-Pisgah No. 1 220 kV Line.
   - Kramer 220/115 kV No. 1 or No. 2 Transformer Bank under the loss of the Kramer-Victor and Roadway-Victor 115 kV Lines.

2. Power Flow Non-Convergence
   There were non-convergence issues identified with the inclusion of the Project operating at the required power factor range, refer to Area Report for additional details.

3. Voltage Performance
   There were no voltage performance issues identified with the inclusion of the Project, refer to Area Report for additional details.

4. Power Factor Evaluation
   FERC Order 827 provides the reactive power requirements for newly interconnecting nonsynchronous generators which requires these resources to design the facility to be capable of providing reactive power to meet power factor 0.95 as measured on the high-side of the main transformer bank.

   Base case power flow was evaluated to determine reactive power losses internal to the Project in order to ascertain if the reactive capability of the Project are adequate to supply these losses and meet the power factor requirements. A summary of the power factor evaluation is provided in the table below.
<table>
<thead>
<tr>
<th>Reactive Power Requirements</th>
<th>PV</th>
<th>BESS</th>
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</thead>
<tbody>
<tr>
<td>Pad-mount transformer losses</td>
<td>2.08 MVARs</td>
<td>1.60 MVARs</td>
</tr>
<tr>
<td>Collector equivalent losses</td>
<td>0.09 MVARs</td>
<td>0.10 MVARs</td>
</tr>
<tr>
<td>Main transformer losses</td>
<td>3.26 MVARs</td>
<td>3.04 MVARs</td>
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<tr>
<td>PF requirements at High Side of Transformer</td>
<td>13.15 MVARs</td>
<td>12.77 MVARs</td>
</tr>
<tr>
<td>Total VAR Requirements</td>
<td>18.58 MVARs</td>
<td>17.51 MVARs</td>
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<tr>
<th>Reactive Power Requirements</th>
<th>PV</th>
<th>BESS</th>
</tr>
</thead>
<tbody>
<tr>
<td>SMA PV Platform</td>
<td>13.64 MVARs</td>
<td>12.49 MVARs</td>
</tr>
<tr>
<td>Collector Line Charging</td>
<td>0.00 MVARs</td>
<td>0.00 MVARs</td>
</tr>
<tr>
<td>Total VAR Supply</td>
<td>13.64 MVARs</td>
<td>12.49 MVARs</td>
</tr>
</tbody>
</table>

| Reactive Power (Shortage) / Surplus               |         |         |
| Total Requirements less Total Supply             | (4.94) MVARs | (5.02) MVARs |

Based on the technical details provided, the Project, as proposed, does not meet the 0.95 power factor requirement as measured at the high-side of the main transformer bank. The customer needs to install a 5.0 MVAR shunt VAR device on the low side of the main transformer.

5. **Required Mitigations**

A combination of congestion management and RAS to trip the Project under identified contingency outage conditions are required to mitigate the power flow impacts of the Project described above. The Reliability Network Upgrades discussed in the Area Report and assigned to the Project involve adding:

The Project as a participant to the proposed North of Lugo RAS to trip under the following outages:

i. Loss of the Lugo No.1 AA Transformer bank and Lugo-Victor No. 1 220 kV Transmission Line (T/L)

ii. Loss of the Lugo No.2 AA Transformer bank and Lugo-Victor No. 4 220 kV Transmission Line (T/L)

The Project as a participant to the existing Mohave Desert RAS to trip under the following outages:

i. Loss of the Kramer-Victor No.1 or Kramer-Victor No.2 220 kV Transmission Line T/Ls

ii. Loss of the Coolwater-Kramer or Kramer-Sandlot 220 kV Transmission Line T/Ls

iii. Loss of the Kramer-Victor No.1 and Kramer-Victor No.2 220 kV Transmission Line T/Ls

iv. Loss of the Kramer-Roadway and Kramer-Victor 115 kV Transmission Line T/Ls

v. Loss of the Kramer-Victor and Victor-Roadway 115 kV Transmission Line T/Ls

vi. Loss of the Lugo No.1 AA or No.2 AA Transformer Banks

vii. Loss of the Lugo No.1 AA and No.2 AA Transformer Banks
• Any modifications to this RAS will need to be presented to the WECC RASRS for approval. The WECC RASRS currently meets up to three (3) times a calendar year to review new and modifications to RAS systems. It should also be taken into account that engineering and design for any modification to this RAS on both the Distribution Provider and generator facilities must be finalized prior to presenting to the WECC RASRS for approval.

• Participation in the RAS will depend on when the GIA is executed and the availability of arming points. SCE does not reserve any arming points for queue projects. The assignment of arming points is on a first-come-first-serve basis.

Charging Analysis of the Project

Steady State Power Flow Analysis Results

The study indicated that the Project does not contribute to any overloads on the electric system of the area.

F. TRANSIENT STABILITY EVALUATION

1. Project Performance
   Dynamic simulation study results illustrating the frequency and voltage performance of the Project based on the technical parameters supplied for the Project are provided below.
Voltage and Frequency Plots for Generating Facility at high side of main transformer banks with fault at Point of Interconnection.
The results indicate acceptable project performance and reflects the expected performance when Project ultimately interconnects.

2. **System Performance**
   System transient stability performance was found to be acceptable. Refer to the Area Report, for additional details pertaining to the Phase II transient stability evaluation criteria and assessment results, respectively.

**G. SHORT-CIRCUIT DUTY RESULTS**
Short-circuit studies were performed to determine the fault duty impact of adding the Phase II projects to SCE’s Electric System and to ensure system coordination. The fault duties were calculated with and
without the projects to identify any equipment over-stress conditions. Once overstressed circuit breakers are identified, the fault current contribution from each individual project in Phase II is determined. Each project in the cluster will be responsible for its share of the upgrade cost based on the rules set forth in Section 4 of the GIP.

1. Distribution Provider

   All bus locations where the Phase II projects increase the short-circuit duty by 0.1 kA or more and where duty was found to be in excess of 60% of the minimum breaker nameplate rating are listed in the Area Report (Appendix H). These values have been used to determine if any equipment is overstressed as a result of the inclusion of Phase II interconnections and corresponding Network Upgrades, if any.

   The responsibility to finance short circuit related Reliability Network Upgrades identified through a Group Study shall be assigned to all projects in that Group Study pro-rata on the basis of SCD contribution of each Generating Facility.

   The QC9 Phase II breaker evaluation did not identify any additional overstressed circuit breakers triggered with the inclusion of the projects in QC9 Phase II. Please refer to the QC9 Phase II Area Report for additional details.

2. Affected Systems

   The SCD incremental increase to neighboring utilities due to the addition of all QC9 Phase II projects are provided in the Area Report (Section H.2). The specific SCD contribution from WDT1383 is provided in the table below.

![Short-Circuit Duty Evaluation of Adjacent Facilities Impacted by WDT1383](image)

3. Distribution Provider’s Ground Grid Duty Concerns

   The short-circuit studies did not flag any substations that increased the substation ground grid duty by at least 0.25 kA and required a detailed ground grid analysis performed as part of project execution once GIAs are in place and projects proceed towards commercial operation. Refer to the Area Report for further information.

H. DELIVERABILITY ASSESSMENT RESULTS

1. On Peak Deliverability Assessment

   The Project contributes to two area constraints in the North of Lugo area:

   - Lugo 500/200 kV Transformer Capacity Constraint

   The deliverability assessment has identified that the Lugo #1 & #2 500/220 kV transformers are overloaded under normal condition with all queued generation modeled and dispatched according to the methodology.
• South of Kramer Transfer Constraint (consists of Kramer to Victor and Victor to Lugo segment constraints)

The deliverability assessment has identified that the Victor-Kramer No 1 and 2 220 kV Lines, and Lugo - Victor No. 1, 2, 3, and 4 220 kV Lines are overloaded under normal condition with all queued generation modeled and dispatched according to the methodology.

The following base case overloads in this Cluster Study summarize the area constraints identified above:

<table>
<thead>
<tr>
<th>Area 1</th>
<th>Area 2</th>
<th>Area 3</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
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</tr>
</tbody>
</table>

2. **Off-Peak Deliverability Assessment**

Please refer to Section D.1 (Study State Reliability Assessment) in the North of Lugo Area report for information on Off-peak assessment.

3. **Required Mitigations**

For any contingency related overloads, the project has to be added to the following RASs:

• New North of Lugo RAS

• Expanded Mojave Desert RAS

Following the conclusion of the Queue Cluster 9 Phase I Interconnection Study, no generation project within the NOL Area selected Option (B). Therefore, none of the ADNUs identified as part of the QC9 Phase I Interconnection Study were included as part of the QC9 Phase II Interconnection Study.

No LDNUs have been identified for North of Lugo area.

I. **INTERCONNECTION FACILITIES, NETWORK UPGRADES, AND DISTRIBUTION UPGRADES**

Please see Attachment 1 for the Distribution Provider’s Interconnection Facilities (IF’s), Reliability Network Upgrades (RNU’s), Delivery Network Upgrades’ (DNU’s), and Distribution Upgrades (DU’s) allocated to the Project. Please note that SCE will not “reserve” the identified IFs for the proposed Point of Interconnection. The identified scope/facilities will be allocated to the Project upon the successful execution of the GIA and SCE has completed the detailed design and engineering of the facilities according to tariff timelines.

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7 At the IC’s discretion, the IC or parties other than the applicable Distribution Provider pursuant to Section 10.2 of the GIP Attachment I may construct an Option (B) Generating Facility Area Delivery Network Upgrades (ADNUs) not allocated IF Deliverability. If the applicable Distribution Provider does not construct the ADNUs, the IC is not required to make the third Interconnection Financial Security posting to the Applicable Distribution Provider pursuant to Section 4.8.4.2.1 of the GIP Attachment I.
J. COST AND CONSTRUCTION DURATION ESTIMATE

1. Cost Estimate
The Project’s estimated interconnection costs, adjusted for inflation and provided in ‘constant’ 2017 dollars, are provided in Attachment 2 and the Project’s allocated cost for shared network upgrades are provided in Attachment 3. The costs will be utilized in developing the GIA. However, should there be a delay in executing the GIA beyond 2018, a new adjustment for inflation will be required and inserted into the GIA.

2. Construction Duration Estimate
The construction duration for the identified facilities is as follows:

   a. Distribution Provider’s Interconnection Facilities – 27 months
      These facilities involve non-network facilities located within SCE’s Holgate 115 kV Substation and at the IC’s Project that are necessary to complete physical interconnection of the Project and ensure adequate line protection and RAS implementation. Please refer to Attachment 1 for details related to these facilities.

   b. Reliability Network Upgrades
      i. Plan of Service Reliability Network Upgrades – 27 months
         These facilities involve network facilities located within Holgate 115 kV Substation that are necessary to complete physical interconnection of the Project. Please refer to Attachment 1 for details.
      ii. Remedial Action Scheme (RAS) – 24 months
         These facilities involve network facilities necessary to add the Project to the proposed NOL RAS, and Mojave Desert RAS. Please refer Attachment 1 for the detailed description of scope corresponding to this RAS.

   c. Voltage Support Mitigation
      No required voltage support mitigations were identified in this Phase II Interconnection Study.

   d. Distribution Upgrades – 27 months
      These involve facilities located within SCE’s Holgate 115 kV Substation that are necessary to complete physical interconnection of the Project. Please refer to Attachment 1 for details.

K. IN-SERVICE DATE AND COMMERCIAL OPERATION DATE ASSESSMENT

An ISD and COD assessment was performed for this project to establish the Distribution Provider’s estimate of the earliest achievable ISD based on the QC9 Phase II Interconnection Study process timelines and the time required for the Distribution Provider to complete the facilities needed to enable physical interconnection as an Interim Deliverability or Energy Only Deliverability interconnection (as applicable) for the Project. This date may be different from the Interconnection Customer’s requested ISD and will be the basis for establishing the associated milestones in the draft GIA.

Details pertaining to Full Capacity Deliverability Status and Partial Deliverability Status are provided below in Section L.
1. **ISD Estimation Details**

For the QC9 Phase II Interconnection Study, the estimated earliest achievable ISD is derived by the time requirements to complete the QC9 Interconnection Study Process, tender a draft GIA, negotiate and execute the GIA, and construct the necessary facilities as described below in Table A.2.

**Table A.2 ISD and COD Assessment**

<table>
<thead>
<tr>
<th>Reference starting point</th>
<th>Days/Months</th>
<th>Issuance of Phase II Interconnection Study Report</th>
<th>Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Add:</td>
<td>30 CD</td>
<td>Phase II Results Meetings</td>
<td>12/22/2017</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Starting Point: TPD Results issued and IC response provided</td>
<td>04/02/2018</td>
</tr>
<tr>
<td>Add:</td>
<td>30 CD</td>
<td>Earliest Reasonable Tender of draft GIA</td>
<td>05/02/18</td>
</tr>
<tr>
<td>Add:</td>
<td>90 CD</td>
<td>GIA negotiation time, execution, and related activities</td>
<td>07/31/18</td>
</tr>
<tr>
<td>Add: Construction Duration</td>
<td>27 months</td>
<td>Construction duration outlined in the Phase II Study Report. Construction completion no earlier than date which reflects earliest ISD</td>
<td>10/31/20</td>
</tr>
<tr>
<td>Reference:</td>
<td></td>
<td>IC-requested ISD via Attachment B</td>
<td>10/31/2020</td>
</tr>
<tr>
<td>Reference:</td>
<td></td>
<td>IC-requested COD via Attachment B</td>
<td>12/31/2020</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Difference between IC ISD and COD</td>
<td>2 month(s)</td>
</tr>
<tr>
<td><strong>Equals:</strong></td>
<td></td>
<td>Earliest achievable ISD per estimated construction duration</td>
<td>10/31/20</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Earliest achievable COD per estimated construction duration (Using difference between ISD and COD requested by IC)</td>
<td>12/31/20</td>
</tr>
</tbody>
</table>

Notes on the Achievable ISD and COD calculation:

1. Assumess duration required to construct those facilities required for an Interim Deliverability Interconnection or Energy Only interconnection (as applicable) for the Project until the applicable DNUs are completed.
2. The construction durations shown represent the estimated amount of time needed to design, procure, and construct the facilities with the start date of the duration based on the effective date of the GIA; and necessarily include timely receipt of all required information and written authorizations to proceed (ATP), and timely receipt of construction payments and financial security postings and other milestones.

2. ISD Conclusion

Based on these timelines, the IC’s requested ISD of 10/31/2020 and COD of 12/31/2020 appears to be achievable.

The Distribution Provider can reasonably tender a draft GIA by May 2018. The draft GIA should be executed no later than August 2018 and will target the IC’s requested ISD and COD.

The ISO will perform its Annual Reassessment (January - July 2018) and Transmission Plan Deliverability (TPD) Allocation\(^8\) (due April 2018). Any changes to the deliverability allocation resulting in changes in scope, cost, or schedule requirements that come out of ISO’s Annual Reassessment and TPD Allocation will be reflected in a 2018 Reassessment Report which will be used to revise the draft GIA (if under negotiation) or amend the GIA (if already executed).

If ISO and SCE determine that the TPD Allocation Study Process outcomes do not change the scope requirements for the Project, a letter will be provided at the end of April 2018 informing the IC that there will be no changes to the allocated Network Upgrades requirements.

L. TIMING OF FULL CAPACITY DELIVERABILITY STATUS, INTERIM DELIVERABILITY STATUS, AREA CONSTRAINTS, AND OPERATIONAL INFORMATION

The Project would be granted its requested FCDS only if the Project receives TPD allocation in the forthcoming TPD Allocation Study Process. Furthermore, timing of obtaining the requested FCDS is dependent on the completion of DNUs identified below in this report, which may be updated in any subsequent annual reassessment. Until such time that these DNUs are completed and placed in-service, the Project may be granted Interim Deliverability Status based on annual system availability. The sections below provide a discussion of the timing of FCDS, Interim Deliverability Status, Area Constraints, and Operational Information.

1. System Upgrades Required for Full Capacity Deliverability Status (FCDS)

In order to provide for FCDS, the following facilities are required in addition to the Reliability Network Upgrades described in Section 2.(b) of Attachment 1:

a. Triggered Delivery Network Upgrades – None
b. Delivery Network Upgrades Triggered by Earlier Queued Projects – None
b. Approved Transmission Upgrades - None
c. Transmission Upgrades outside the ISO Controlled Grid - None

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\(^8\)The TPD Allocation Process is estimated to be completed in April 2018. The actual date may vary.
2. Interim Operational Deliverability Assessment for Information Only
   The operational deliverability assessment was performed for study years 2018 ~ 2022 by
   modeling the Transmission and generation in service in the corresponding study year. For details
   of the Transmission and generation assumption, refer to Section E.3 of the Area Report. Based
   on the study assumptions, the Project will have the deliverability status as granted by the TPD
   Allocation Study Process upon commercial operation.

3. Area Constraints
   The Project contributes to two area constraints in the North of Lugo area:
   - Lugo 500/200 kV Transformer Capacity Constraint
   - South of Kramer Transfer Constraint (consists of Kramer to Victor and Victor to Lugo
     segment constraints)
   The Project would be granted its requested FCDS only if the Project receives TPD allocation in
   the forthcoming TPD Allocation Study Process.

M. AFFECTED SYSTEMS COORDINATION
   Please see Section H of the Area Report.

N. ADDITIONAL STUDY ANNOTATIONS
   1. Conceptual Plan of Service
      The results provided in this study are based on conceptual engineering and a preliminary Plan of
      Service (POS) and are not sufficient for permitting of facilities. The POS is subject to change as
      part of detailed engineering and design.

   2. The study does not include analysis related to the power output rate of change that may occur
      due to the following or other conditions:
      - System morning start up for solar generating facilities: That is when each morning the
        Generating Facility commences to generate and export electrical energy to the electric
        system.
      - Cloud Cover: Solar generating facilities have significant generation output variation
        (Variability) which can have an impact on electric system voltage profiles.

   3. IC’s Technical Data
      The study accuracy and results for the QC9 Phase II Interconnection Study was contingent upon
      the accuracy of the IR technical data provided by each IC during the Interconnection Study Cycle.
      Any changes from the data provided as allowed by the ISO Tariff would have been submitted in
      Appendix B within ten (10) Business Days following the Phase I Interconnection Study Results
      Meeting. Any changes in the Appendix B submission that extended beyond the modifications
      allowed in accordance with Section 6.7.2.2 of the ISO GIDAP would have been evaluated under a
      Material Modification Assessment (MMA). The MMA process would have determined if such
      change resulted in a material impact to queued-behind generation. These change(s) would have
been permitted if it was determined that there were no material impacts to queued-behind generation.

4. **Study Impacts on Neighboring Utilities**
   Results or consequences of this Phase II Interconnection Study may require additional studies, facility additions, and/or operating procedures to address impacts to neighboring utilities and/or regional forums. For example, impacts may include but are not limited to WECC Path Ratings, short-circuit duties outside of the ISO Controlled Grid, and sub-synchronous resonance (SSR). Refer to Affected Systems Coordination Section of the Area Report for additional information.

5. **Use of Distribution Provider Facilities**
   The IC is responsible for acquiring all property rights necessary for the IC’s Interconnection Facilities, including those required to cross the Distribution Provider’s facilities and property. This Phase II Interconnection Study does not include the method or estimated cost to the IC of Distribution Provider mitigation measures that may be required to accommodate any proposed crossing of the Distribution Provider’s facilities. The crossing of Distribution Provider property rights shall only be permitted upon written agreement between Distribution Provider and the IC at the Distribution Provider’s sole determination. Any proposed crossing of Distribution Provider property rights will require a separate study and/or evaluation, at the IC’s expense, to determine whether such use may be accommodated.

6. **Distribution Provider’s Interconnection Handbook**
   The IC shall be required to adhere to all applicable requirements in the Distribution Provider’s Interconnection Handbook. These include, but are not limited to, all applicable protection, voltage regulation, VAR correction, harmonics, switching and tagging, and metering requirements.

7. **Western Electricity Coordinating Council (WECC) Policies**
   The IC shall be required to adhere to all applicable WECC policies including, but not limited to, the WECC Generating Unit Model Validation Policy.

8. **System Protection Coordination**
   Adequate Protection coordination will be required between Distribution Provider-owned protection and IC-owned protection. If adequate protection coordination cannot be achieved, then modifications to the IC-owned facilities (i.e., Generation-tie or Substation modifications) may be required to allow for ample protection coordination.

9. **Standby Power and Temporary Construction Power**
   The Phase II Interconnection Study does not address any requirements for standby power or temporary construction power that the Project may require prior to the ISD of the Interconnection Facilities (IF’s). Should the Project require standby power or temporary construction power from the Distribution Provider prior to the ISD of the IF’s, the IC is responsible to make appropriate arrangements with Distribution Provider to receive and pay for such retail service.

10. **Licensing Cost and Estimated Time to Construct Estimate (Duration)**
    The estimated licensing cost and durations applied to this Project are based on the Project scope details presented in this Phase II Interconnection Study. These estimates are subject to change as the Project’s environmental and real estate elements are further defined. Upon execution of
the GIA, additional evaluation including but not limited to preliminary engineering, environmental surveys, and property right checks may enable licensing cost and/or duration updates to be provided.

11. Network/Non-Network Classification of Telecommunication Facilities

a. Non-Network (Interconnection Facilities) Telecommunications Facilities: The cost for telecommunication facilities that were identified as part of the IC’s Interconnection Facilities was based on an assumption that these facilities would be sited, licensed, and constructed by the IC. The IC will own, operate, maintain, and construct main and diverse telecommunication paths associated with the IC’s generation tie line, excluding terminal equipment at both ends. In addition, the telecommunication requirements for the RAS were assumed based on tripping of the generator’s breaker in lieu of tripping the circuit breakers and opening the IC’s gen-tie at the Distribution Provider’s substation.

b. Network (Network Upgrades) Telecommunications Upgrades: Due to uncertainties related to telecommunication upgrades for the numerous projects in queues ahead of this Project, telecommunication upgrades for earlier queued projects without a signed GIA which upgrades have not been constructed were not considered in this study. Depending on the scope of these earlier queued projects, the cost of telecommunication upgrades identified for Phase II may be reduced. Any changes in these assumptions may affect the cost and schedule for the identified telecommunication upgrades.

12. Ground Grid Analysis
   A detailed ground grid analysis will be required as part of the detailed engineering for the Project at the SCE substations whose ground grids were flagged with duty concerns.

13. SCE Technical Requirements
   The IC is advised that there may be technical requirements in addition to those that outlined above in Section C of this report that are included in the Interconnection Handbook or that will be addressed in the Project’s GIA.

14. Applicability
   This document has been prepared to identify the impact(s) of the Project on the SCE’s electric system; as well as establish the technical requirements to interconnect the Project to the Point of Interconnection that was evaluated in the final Phase II Interconnection Study for the Project. Nothing in this report is intended to supersede or establish terms/conditions specified in GIAs agreed to by the Distribution Provider, ISO, and the IC.

15. Process for Initial Synchronization Date/Trial Operation Date and COD of the Project
   The IC is reminded that the ISO has implemented a New Resource Implementation (NRI) process that ensures that a generation resource meets all requirements before Initial Synchronization Date/Trial Operation Date and COD. The NRI uses a bucket system for deliverables from the IC that are required to be approved by the ISO. The first step of this process is to submit an “ISO Initial Contact Information Request form” at least seven (7) months in advance of the planned Initial Synchronization Date. Subsequently an NRI project number will be assigned to the Project for all future communications with the ISO. The Distribution Providers have no involvement in
this NRI process except to inform the IC of this process requirement. Further information on the NRI process can be obtained from the ISO Website using the following links:
New Resource Implementation webpage:

NRI Checklist:

NRI Guide:

16. ISO Market Dispatch
This study did not evaluate any potential limitations that may be driven by the ISO market under real-time operating conditions.

17. Future Charging Restrictions
Charging restrictions not identified in this study may occur in the future if the underlying operating assumptions prove to be different from the conditions evaluated in this study.
Attachment 1:
Interconnection Facilities, Network Upgrades, and Distribution Upgrades
Please refer to separate document
Attachment 2:
Escalated Cost and Time to Construct for Interconnection Facilities, Reliability Network Upgrades, Delivery Network Upgrades, and Distribution Upgrades
Please refer to separate document
Attachment 3:
Allocation of Network Upgrades for Cost Estimates and Maximum Network Upgrade Cost Responsibility

### Phase II Network Upgrade Cost Allocation

<table>
<thead>
<tr>
<th></th>
<th>NU Total Cost (2017 $k)</th>
<th>Project Allocation</th>
<th>Allocated Cost (2017 $k)</th>
<th>Allocated Cost (Escalated $k)</th>
</tr>
</thead>
<tbody>
<tr>
<td>RNU</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>New North of Lugo RAS - Backbone Portion</td>
<td>$4,298</td>
<td>6.12%</td>
<td>$263</td>
<td>$282</td>
</tr>
<tr>
<td>New North of Lugo RAS - generator addition</td>
<td>$263</td>
<td>100.00%</td>
<td>$263</td>
<td>$282</td>
</tr>
<tr>
<td>Mojave Desert RAS - generator addition</td>
<td>$1,082</td>
<td>100.00%</td>
<td>$1,082</td>
<td>$1,158</td>
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<tr>
<td>RNU Total</td>
<td></td>
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<td>$1,608</td>
<td>$1,721</td>
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### Network Upgrade Cost Responsibility

<table>
<thead>
<tr>
<th>A. Deliverability Option</th>
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<tbody>
<tr>
<td>B.1. RNU Cost ($)</td>
<td>$1,721</td>
<td>$1,721</td>
</tr>
<tr>
<td>B.2. LDNU Cost ($)</td>
<td>$ -</td>
<td>$ -</td>
</tr>
<tr>
<td>B. Phase II RNU and LDNU Cost ($) (B.1 + B.2)</td>
<td>$1,721</td>
<td>$1,721</td>
</tr>
<tr>
<td>C. Phase II Potential RNU and LDNU Cost ($)</td>
<td>$ -</td>
<td>$ -</td>
</tr>
<tr>
<td>D. Phase I RNU and LDNU Maximum Cost Responsibility ($)</td>
<td>$228</td>
<td>$228</td>
</tr>
<tr>
<td>E. Maximum RNU and LDNU Cost Responsibility ($) (min[B+C], D)</td>
<td>$228</td>
<td>$228</td>
</tr>
<tr>
<td>F. Project RNU and LDNU Cost Responsibility ($) (min[B, E])</td>
<td>$228</td>
<td>$228</td>
</tr>
<tr>
<td>G. Project ADNU Cost Responsibility ($)</td>
<td>$ -</td>
<td>$ -</td>
</tr>
</tbody>
</table>

**Notes:**

"Project RNU and LDNU Cost Responsibility" is the RNU and LDNU cost currently assigned to the Project. It doesn’t include the cost share of the Potential Network Upgrades. This is the RNU and LDNU cost that the Interconnection Customer is required to post the Interconnection Financial Security for.

"Maximum RNU and LDNU Cost Responsibility" is the maximum RNU and LDNU cost that could be assigned to the Project. The total cost re-allocation for RNU and LDNU in the subsequent reassessments shall not exceed this amount.
Attachment 4:
Distribution Provider’s Interconnection Handbook
Preliminary Protection Requirements for Interconnection Facilities are outlined in the Distribution Provider’s Interconnection Handbook at the following link:

Attachment 5:
Short-Circuit Duty Calculation Study Results
Please refer to the Appendix H of the Area Report
Attachment 7:
Not Used