Appendix A – WDT1289

[redacted]

Queue Cluster 8 Phase II Report

November 23, 2016

This study has been completed in coordination with the California Independent System Operator Corporation (ISO) per Southern California Edison Company's Wholesale Distribution Access Tariff (WDAT), Attachment I Generator Interconnection Procedures (GIP)

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A. Introduction

[redacted] the Interconnection Customer (IC), has submitted a completed Interconnection Request (IR) to Southern California Edison Company (SCE) for their proposed [redacted] (Project), an expansion to the existing [redacted] The Project requested a Point of Interconnection (POI) to SCE's Wellgen 66 kV Substation. The IC has elected Energy Only Deliverability Status (EODS) for their Project. The IC desires an In-Service Date (ISD) of December 1, 2016 and a Commercial Operation Date (COD) of January 1, 2017. Such dates are specified in the Project's Attachment B to the Generator Interconnection Study Process Agreement. Actual ISD and COD will depend on licensing, engineering, detailed design, and construction requirements to interconnect the Project to SCE's Distribution System; after the Generator Interconnection Agreement (GIA) has been executed and filed at the Federal Energy Regulatory Commission (FERC) for acceptance.

In accordance with FERC approved SCE's WDAT Attachment I Generator Interconnection Procedures (GIP), the Project was grouped with other Queue Cluster 8 (QC8) Phase II projects to determine the impacts of the group as well as impacts of the Project on the ISO Grid.

An Area Report and Subtransmission Assessment Report have been prepared separately identifying the combined impacts of all projects in the group on the ISO Grid and to distribution facilities served out of the Vestal 66 kV Subtransmission System, respectively. This Appendix A report focuses only on the impacts or impact contributions specific to the Project and is not intended to supersede any contractual terms or conditions that may be specified in a GIA.

The report provides the following:

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

Additionally, the Project encompasses energy storage equipment that required additional analysis be performed to evaluate the impacts of the charging facility within SCE's Distribution System. These analyses focused on the charging[2] aspects of the charging facilities and consider varying levels of system demand with minimal generation dispatch within the local distribution system.

Consequently, the report also discloses the adequacy of SCE's Distribution System to support the charging aspects of the charging facilities, identifies system limitations that may restrict the charging facility's ability to charge during certain demand conditions, and provides a high-level explanation of

[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 from the IC to proceed with the work which will be specified in the GIA.

[2] Charging is defined as the operating condition when the Project draws energy from the grid to "charge", or store energy, for later discharge into the electric system.

potential exposure to charging restrictions on the distribution system in addition to identifying distribution system improvements, which would mitigate such restrictions to charging.

All the equipment and facilities comprising the Generating Facility (GF) are located in Delano, CA, as disclosed by the IC in its IR. The GF, as may have been amended during the Interconnection Study process, is an energy storage GF which consists of (i) [redacted] with a rated output of [redacted] each for a combined gross rated output of [redacted] as measured at the inverter terminals, (ii) the associated infrastructure and step-up transformers, (iii) meters and metering equipment, (iv) appurtenant equipment, and (v) auxiliary loads.

Based on the technical data provided for the pad-mount and main transformer banks, the total internal Project losses were identified to be 0.04 MW. The net output, as measured at the high-side of the main transformer bank, is identified to be 8.71 MW when subtracting only the total internal Project losses since the IC identified zero auxilary loads. Losses on the gen-tie were identified to be minimal thereby resulting in a POI delivery of 8.71 MW, which is less than the 8.75 MW POI delivery requested amount.

The Project shall consist of the GF and the IC's Interconnection Facilities as illustrated below in Figure A.1 and summarized in Table A.1. A map illustrating the location of the Project is provided below in Figure A.2.

Figure A.1: Project Plan of Service & IC Facilities One-Line Diagram

[redacted]

Figure A.2: Project Location Map

[redacted]

Table A.1 Project General Information per IR

Project Location	[redacted]
Distribution Provider's Planning Area	Distribution Provider's SCE Northern Area
Interconnection Voltage	66 kV
POI	Distribution Provider's Wellgen 66 kV Substation
Requested Maximum Project Output as Measured at POI	8.75 MW
Number and Types of Generators	[redacted]
Power Factor Range	[redacted]
Step-Up Transformer(s)	[redacted]
Gen-Tie	Utilizing existing one-span gen-tie constructed for WDT190[redacted]
Generator Auxiliary Load	[redacted]
Internal Generating Facility Losses	0.04 MW
Maximum Net Output as Metered on High-Side of Main Transformer (Gross output less auxiliary load less internal losses)	8.71 MW
Estimated Losses on Gen-Tie Facilities	Negligible
Maximum POI Delivery (Net output less gen-tie losses)	8.71 MW
ISD	December 1, 2016
Initial Synchronization Date/Trial Operation	December 15, 2016
COD	January 1, 2017

Note 1: The MW output at the POI varies under different operating conditions.

Note 2: The IC is reminded that this value is tied to the generation tie-line losses. The estimated Maximum Net Output at POI and Generation Tie-Line Losses values illustrated above are contingent upon the accuracy of the technical data provided by the IC in the Appendix B, and are subject to change should the IC change its generation tie line parameters during the final engineering and design phase of the Project.

B. Study Assumptions

For detailed assumptions regarding the group cluster analysis at the transmission and subtransmission levels, please refer to the applicable Area Report and Subtransmission Assessment Report. Below are the assumptions specific to the Project.

1. The Plan of Service (POS) is defined as the facilities needed to interconnect the Project to SCE's Distribution System. The following is the POS assumed for the Project:

   The Project was modeled as interconnecting to the Wellgen 66 kV Substation bus utilizing existing facilities constructed for WDT190[redacted]

2. The following facilities will be installed by SCE and **are included** in this Interconnection Study report:

   - [redacted]
   - The required retail and wholesale load meters.
   - [redacted]
   - Lightwave, channel bank, CRIARs, CRIAC, and associated equipment at [redacted] and GF.

   NOTE: SCE installation does not include metering potential transformer (PTs) and current transformers (CTs), and metering cabinet. The SCE meters will be connected to the generator-owned PTs and CTs to be installed for their ISO metering.

3. The following facilities will be installed by the IC and **are not included** in this Interconnection Study report:

   - The required meter for generation and Negative Generation.
   - The required ISO metering equipment (PTs and CTs and ISO meters) and metering cabinet for SCE retail and wholesale load meters.

     NOTE: The metering PTs and CTs installed for the ISO metering will also be used for the SCE owned retail and wholesale load meters.

   - The following line protection relays to be installed at the GF end of the [redacted] 66 kV gen-tie line:
     - Two (2) line current differential relays via diversely routed dedicated digital communications channel to Wellgen Substation. The make and type of the line current differential relays will be specified by the Distribution Provider during final engineering of the Distribution Provider's Interconnection Facilities.

4. Environmental Activities, Permits, and Licensing.

   Internal Substation Scope:

   - SCE will perform all environmental studies and monitoring of al SCE internal substation construction activities.
   - SCE's scope of work will not require a California Public Utilities Commission 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 Environmental Services (ES) 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 (SCE/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.
- 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 and 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 and 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 estimate must be updated to reflect the changes to the assumptions.

5. Charging Facility Considerations

   - SCE's Distribution Standards and practices are in the process of being updated to address charging facilities. The proposed POS in this report may require changes to comply with the updated distribution design standards and practices.

- This study assumes that the GF will include all equipment, software, appropriate controls, and other related equipment necessary to maintain the charging facility demand profile per SCE requirements.

- A Storage Management System (SMS), which at this stage is conceptual, is under development to incorporate the increased amount of energy storage applications to SCE's Distribution System with minimal Distribution Upgrades. It is assumed that an SMS or similar system will be available prior to the ISD of the charging facility and further details will be available during the detailed engineering and design phase of the Project. The SMS will actively communicate allowable storage demand limits under charging mode to maintain safe and reliable operation of the distribution system.

- Any project identified to be required to participate in the SMS will have those facilities and costs included in Attachments 1 and 2. In order to ensure storage demand limits are communicated in a timely and reliable manner, the IC is responsible for providing reliable communications between the Project and the POI to transmit the required telemetry data. Should the communication channel fails, the Project's operating limits will automatically revert to zero (no charging allowed).

- The use of "charging" restrictions (or curtailment of charging facilities), in lieu of physical upgrades, are considered a viable alternative for this charging study[3] provided such restriction is implemented as part of the SMS. Any restrictions identified here are purely projections, and the SMS mentioned above will need to be installed as an upgrade to determine the storage demand limits for the charging facility. However, per the aforementioned section, the SMS will need to be further assessed and will only be allowed if it is ultimately determined that actual implementation is feasible for SCE's real-time system operations.

- The Project encompasses charging facilities. The details pertaining to the Power Flow Reliability Assessment Results for the charging of the Project's charging facilities are included in this Appendix A report and applicable Subtransmission Assessment Report.

- The energy storage component of the Project will need to be metered separately. The IC should be prepared to install multiple sets of metering (i.e. separate sets of PTs and CTs and supporting metering equipment) for the Project. Additionally, the Project may also need to connect the energy storage component to a dedicated transformer.

C. Reliability Standards, Study Criteria and Methodology

The generator interconnection studies were conducted to ensure the ISO Grid complies 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.

[3] The advent of distribution-connected energy storage brings with it challenges for utility planners, system operators, and regulatory/jurisdictional issues. More specifics of how the management systems of the future grid are to function will develop as progress is made in all of the aforementioned areas.

D. Power Flow Reliability Assessment Results

Discharge Analysis of the Project

I. Steady State Power Flow Analysis Results – 220 kV and above

1. Power Flow Thermal Overloads

   The study identified base case power flow issues on the Bulk Electric System that are addressed via the use of ISO Congestion Management (South of Magunden Nomogram). Congestion management mitigation is required to ensure system operation is maintained within nomogram limits. Refer to enclosed Area Report in the report package for the Phase II power flow analysis results.

2. Power Flow Non-Convergence

   There were no non-convergence issues identified with the inclusion of the Project operating at the required power factor range. Refer to enclosed Area Report in the report package for the Phase II power flow analysis results.

3. Voltage Performance

   The Project is required to provide power factor regulation capability [redacted] to alleviate power flow non-convergence and maintain the transmission transfer capability.

4. Required Mitigations

   No mitigation, beyond power factor regulation capability, is required by the Project on the transmission system.

II. Steady State Power Flow Analysis Results – 66 kV

1. Thermal Overloads

   a. Base Case Conditions

      The Vestal 66 kV Subtransmission Assessment indicated that the Project contributes to overloads problems on the Vestal 66 kV Subtransmission System. Specifically, the addition of the project was identified to exacerbate an existing base case overload on the [redacted] of the [redacted] SCE is currently undertaking a project with an estimated operational date of June 2018 which would address this overload. As a result, operation of the Project may be restricted the mitigation is completed.

2. Power Flow Non-Convergence

   There were no non-convergence issues identified with the inclusion of the Project operating at the required power factor range. Refer to enclosed Subtransmission Assessment Report in the report package for the Phase II power flow analysis results.

3. Voltage Performance

   The Project is required to provide power factor regulation capability [redacted] to alleviate power flow non-convergence and maintain the transmission transfer capability.

4. Required Mitigations

   With the exception of potential operating restrictions on the Project, no additional mitigations on the Vestal 66 kV Subtransmission System were identified to be required by the Project.

Charging Analysis of Project

I. Steady State Power Flow Analysis Results – 220 kV and above

   1. Thermal Overloads

      The inclusion of the Projects operating in charge mode did not contribute to any overload on the Bulk Electric System.

   2. Power Flow Non-Convergence

      There were no 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

      The Project is required to provide power factor regulation capability [redacted] to alleviate power flow non-convergence and maintain the transmission transfer capability.

II. Steady State Power Flow Analysis Results – 66 kV

   1. Thermal Overloads

      The Vestal 66 kV Subtransmission Assessment indicated that the Project contributes to thermal overloads problems on the Vestal 66 kV Subtransmission System. Specifically, the addition of the Project was identified to exacerbate a queued-ahead base case and contingency overloads as summarized below:

   a. Base Case Conditions

      i. Vestal A-Bank: The addition of the Project was identified to exacerbate a queued-ahead base case overload on the single Vestal A bank currently in operation. [redacted]

      ii. [redacted] of the [redacted] The addition of the Project was identified to exacerbate a previously identified base case overload on the [redacted] of the [redacted] SCE is currently undertaking a project that would address this identified overload. The estimated operational date for this mitigation is June 2018. Consequently, the Project will have charging restrictions imposed from 8:00 am to Midnight until the mitigation is completed.

iii. [redacted] The addition of the Project was identified to exacerbate a previously identified base case overload on the [redacted] of the [redacted] SCE is currently undertaking a project that would address this identified overload. The estimated operational date for this mitigation is June 2018. Consequently, the Project will have charging restrictions imposed from 8:00 am to Midnight until the mitigation is completed.

iv. [redacted] The addition of the Project was identified to exacerbate a previously identified base case overload on the [redacted] SCE is currently undertaking a project that would address this identified overload. The estimated operational date for this mitigation is June 2018. Consequently, the Project will have charging restrictions imposed from 8:00 am to Midnight until the mitigation is completed.

b. Outage Condition

An outage related overload on the [redacted] of the [redacted] was found to be exacerbated with the inclusion of the Project. Specifically, the overload would occur under a bus outage condition anytime the opposite 66 kV bus side circuit breaker at the [redacted] is taken out of service for maintenance. To address the incremental contribution, the Project will not be allowed to charge anytime a [redacted] is taken out of service.

2. Power Flow Non-Convergence

There were no non-convergence issues identified with the inclusion of the Project operating at the required power factor range, refer to the Subtransmission Assessment Report for additional details.

3. Voltage Performance

The Project is required to provide power factor regulation capability [redacted] for asynchronous generation and [redacted] at terminal voltage for synchronous generation) to alleviate power flow non-convergence and maintain the transfer capability.

4. Required Mitigations

Identified required mitigation involves charging restrictions under base case and outage conditions implemented through the use of a storage management system to address the incremental project contribution to these overload conditions.

i. No charging allowed from 8:00 am to Midnight

Based on study results, the interconnection of the Project in advance of the reconductoring projects and prior to the installation of a storage management system requires limitations to charging operation between the hours of 8:00 AM and midnight. In other words the project can **<u>only</u>** charge between midnight and 8:00 am.

ii. Install Storage Management System

Until such time that the current proposed reconductor mitigation is completed, the installation of an SMS is recommended to increase the window available for charging. The use of an SMS will monitor flows on the impacted 66 kV lines and issue charging restriction signals based on the flow values. In the event that these proposed mitigations are completed prior to interconnection of this Project, the SMS may not be required. Additionally, the IC can request a change to the Project's ISD to align with the completion of these reconductoring projects in order to eliminate the need for the SMS. Currently this date is estimated to be December 2018.

E. Short-Circuit Duty Results

Short-circuit studies were performed to determine the fault duty impact of adding the Phase II projects to the transmission system and to ensure system coordination. The fault duties were calculated with and without the projects to identify any equipment overstressed 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.

2. Short-Circuit Duty Study Input Data

The IC provided technical data for the identified inverter (specified in Section 2). SCE compared the technical data provided against manufacturer data, if the manufacturer Short-Circuit Duty (SCD) information for the specific inverter was available. If the technical data provided by the IC differed from the inverter manufacturer data, then SCE utilized the manufacturer data in the SCD analysis. Based on the comparison, SCE utilized the manufacturer data for the SCD analysis.

Battery Energy Storage System (BESS)

Max Fault Contribution for Each Generation Unit: [redacted]

Main Generation Step Up Transformer

Technical details are provided above in Table A.1.

2. Short-Circuit Duty Study Results

All bus locations where the Phase II projects increase the SCD 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 equipment is overstressed as a result of the inclusion of Phase II interconnections and corresponding Network Upgrades and Distribution Upgrades, if any.

The responsibility to finance short-circuit related Reliability Network Upgrades (RNU) and Distribution Upgrades (DU) identified through this SCD study shall be assigned to all Interconnection Requests in this QC8 PII study pro rata on the basis of SCD contribution of each GF.

Please refer to in the Area Report for the Phase II breaker evaluation discussion, which identified overstressed circuit breakers at the SCE buses, and Attachment 2 for the pro-rata allocation with corresponding estimated costs (if any) for the Project, based on SCD contribution at each location.

3. Potential Affected Systems – SCD Results

   The SCD incremental increase to neighboring utilities due to the addition of all QC8 Phase II projects are provided in the Area Report (Section J.2). The studies determined this project does not provide any incremental duty to neighboring utilities.

4. SCE Substations with Ground Grid Duty Concerns

   The short-circuit studies flagged SCE-owned substations beyond the Project's POI with ground grid duty concerns that necessitate a ground grid study. However, this Project was not identified to provide meaningful single-line-to-ground fault contribution at any location where the single line to ground short-circuit duty contribution increase was in excess of 0.25 kA where known ground grid ratings were less than the study results. Consequently, the project is not allocated scope or cost related to Ground Grid duty concerns.

F. Preliminary Protection Requirements

Protection requirements are designed and intended to protect the Distribution Provider's electrical system only. The preliminary protection requirements were based upon the interconnection plan as shown in the one-line diagram depicted in line item #7 in Attachment 1.

The IC is responsible for the protection of its own GF and must meet the requirements in the SCE Interconnection Handbook provided in Attachment 4.

G. Transient Stability Evaluation

With the Project providing [redacted] correction as measured at the POI, transient stability performance was found to be acceptable. Refer to Sections C.3 and D.2 of the Area Report, for additional details pertaining to the transient stability evaluation criteria and assessment results, respectively.

H. Power Factor Requirements

Based on the results of the Study, the Project will need to be designed to maintain a composite power delivery at continuous rated power at the POI at a power factor within the range of [redacted] at POI for asynchronous generation and [redacted] at generator terminals for synchronous generators. Additionally, the generation system must be designed to accommodate a voltage or VAR schedule provided by SCE. SCE will determine if a Voltage and/or VAR schedule is necessary based on future re-arrangements of SCE's Transmission System.

I. Deliverability Assessment Results

The Project requested Energy Only Deliverability Status.

J. In-Service Date and Commercial Operation Date Assessment

The latest information provided by the IC confirms a requested ISD of December 1, 2016 and a COD of January 1, 2017. To determine if these dates are feasible, an ISD and COD assessment was performed, which considered both the Phase II process timelines as well as the following facilities needed to provide for reliable energy-only interconnection of the Project. Timing of the upgrades required to provide for the requested EODS are discussed in the section below.

The ISD and COD assessment identified that the following facilities are required in order to provide for reliable interconnection for the Project:

1. QC8 Interconnection Process Timelines

   To enable physical interconnection, an executed GIA is required. As part of the Phase II interconnection process, a GIA is not scheduled to be tendered until after completion of the ISO's Reassessment and Transmission Planning Deliverability (TPD) Allocation Study Process which does not commence until late January or early February 2017. The TPD Allocation is scheduled to be completed by April 2017. If the ISO and SCE can make a determination that the TPD Allocation Study Process outcomes do not change the scope requirements, a letter will be provided at the end of April 2017[4] informing the IC that there are no changes to Network Upgrades requirements and initiating the GIA negotiation process. Otherwise, further re-assessment will be performed for the Project. Any updates to scope, cost, and schedule are developed and updated reports will be issued by the end of July 2017. The GIA negotiations commence after either the issuance of the letter of no change to Network Upgrades requirements at the end of April 2017 or upon issuance of the updated Reassessment reports at the end of July 2017. Provided the Project does not elect to park for one (1) year, the letter issued by the ISO and/or the updated Phase II Interconnection Study reports will be used as the basis to proceed with the GIA negotiations. Assuming a three (3) month timeframe for GIA negotiations after the draft GIA has been issued to the IC, an executable GIA is not expected until either late August 2017 or early November 2017 depending on TPD Allocation Study Process results, which required a decision from the IC to park or proceed to the GIA negotiations or wait until the completion of the ISO's Reassessment Study to commence GIA negotiations.

2. System Upgrade Timelines for Interconnection

   The Operational Studies identified that the following facilities are required in order to provide interconnection of the Project:

   a. Distribution Provider's Interconnection Facilities

      Refer to Section 1.b of Attachment 1 for details.

   b. Reliability Network Upgrades

      SCD operational mitigation was identified taking into account new generation projects which have executed GIAs, approved Transmission System upgrades fully permitted and under construction, and new generation projects including the 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 and project contribution, no additional short-circuit duty mitigation is required to enable interconnection of the Project.

[4] The TPD Allocation Study Process is to be completed in April 2017. The actual date may vary.

c. Voltage Support Mitigation

No voltage support upgrades were identified to be required to enable this Project to interconnect.

d. Distribution Upgrades:

No Distribution Upgrades were identified to be required to enable this Project to interconnect.

3. Conclusion

Following the standard process which would result in a GIA tendered no earlier than August 2017 and the estimated 27-month time to construct the Interconnection Facilities, the requested IC's ISD of December 1, 2016 cannot be met. The best case ISD is December 2019. It should be noted that the ability to meet a best case ISD is tied directly to the IC's timely execution of the GIA, submittal of construction payments, posting Interconnection Financial Security, and written notice to proceed.

K. Timing of Full Capacity Deliverability Status, Interim Deliverability, Area Constraints, and Operational Information

The IC elected Energy Only Deliverability Status for their Project. There are no Delivery Network Upgrades required. However all generators, FC or EO, are behind the same area constraints and subject to congestion. See Section D.1.1-(ii) for more details regarding South of Vincent and Big Creek Corridor Constraints.

As stated in Attachment 7, studies indicate that as high amounts of resources in the East of Lugo area develop and are dispatched, the amount of available Transmission capacity for the Northern Area resources is diminished. Such conclusions point to a potential need for congestion management, and generation resource curtailments. For additional information on potential congestion under expected amounts of renewable generation development in 2021, please see Chapter 5 of the ISO 2015-2016 Transmission Plan report. http://www.ISO.com/Documents/Board-Approved2015-2016TransmissionPlan.pdf

L. Distribution Provider's Interconnection Facilities, Network Upgrades, and Distribution Upgrades

Please see Attachment 1 for the Distribution Provider's Interconnection Facilities (IFs), RNUs, DNUs, and DUs allocated to the Project. Please note that SCE will not "reserve" the identified IF's for the proposed POI. 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.

M. Cost and Construction Duration Estimates

To determine the cost responsibility of each generation project in Phase II, the ISO developed cost allocation factors (Attachment 3) for RNUs, Local Delivery Network Upgrades (LDNUs), and Area Delivery

Network Upgrades (ADNUs). Attachment 2[5] provides the 'constant' 2016 dollars and their escalation to the estimated COD year for IFs, RNUs, DNUs, and DUs, which the Project was allocated cost.

The IC should note that any RNUs above the $60k/MW repayment cap allocated to the Project may be assessed 35% Income Tax Component of Contribution (ITCC), in addition to the 35% ITCC assessed to the Distribution Provider's IFs and DUs assigned to the Project. For your information, Attachment 2 contains a potential ITCC estimate[6] based on the final Phase II cost in this study. It does not represent the "maximum ITCC exposure" to the Project. Attachment 2 provides an estimated non-reimbursable RNU cost that would be subject to ITCC, taking into account the maximum cost responsibility for Network Upgrades. The maximum ITCC assessed to the Project will be addressed, calculated, and included during the GIA development phase after the IC submits the TP Deliverability Allocation Study Process options form confirming to accept, decline, or park the allocation of deliverability awarded to the Project.

N. SCE Technical Requirements

The IC is responsible for the protection of its own system and equipment and must meet the requirements in the SCE Interconnection Handbook provided in Attachment 4. In addition, the IC is responsible for complying with IEEE Std 519-2014 Recommended Practice and Requirements for Harmonic Control in Electric Power Systems on SCE's Distribution/Subtransmission/Transmission System.

O. Environmental Evaluation, Permitting, and Licensing

Please see Appendix K of the Area Report.

P. Affected Systems Coordination

Please see Section H of the Area Report.

Q. Items not covered in this study

1. Conceptual Plan of Service

   The results provided in this study are based on conceptual engineering and a preliminary POS and are not sufficient for permitting of facilities. The POS is subject to change as part of detailed engineering and design.

2. 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 Western Electricity Coordinating Council (WECC) path ratings, SCD outside of the ISO Grid, and SSR. Refer to Affected Systems Coordination Section of the Area Report for additional information.

3. Use of and/or Crossing Distribution Provider's Property

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[5] For Energy Storage Projects the Attachment 2 includes upgrade(s) identified from the "Charging" analysis.

[6] The maximum ITCC exposure applies ITCC (35%) to the assigned DUs and Distribution Provider's IF. For Network Upgrades, costs that are not subject to transmission credits and/or exceed the $60k/MW cap will be subject to ITCC (35%). For an Option (A) or Option (B) Generating Facility: the maximum ITCC exposure is calculated by applying the following formula: (IF*35%) + ((RNU Costs – (Project MW*($60k/MW)))*35%) + (DU*35%).

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 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 Distribution Provider's property. The crossing of Distribution Provider property rights shall only be permitted upon written agreement between the Distribution Provider and the IC at the Distribution Provider's sole determination. Any proposed crossing of the Distribution Provider's property rights will require a separate study and/or evaluation, at the IC's expense, to determine whether such use may be accommodated.

4. SCE Interconnection Handbook

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

5. 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.

6. 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.

7. Standby Power and Temporary Construction Power

   The Phase II 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. Should the Project require standby power or temporary construction power from the Distribution Provider prior to the ISD of the Interconnection Facilities, the IC is responsible to make appropriate arrangements with the Distribution Provider to receive and pay for such retail service.

8. Licensing Cost and Estimated Time to Construct Estimate (Duration)

   The estimated licensing cost and durations applied to this Project are based on the Project's scope details presented in this Phase II study. These estimates are subject to change as 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.

9. Ground Grid Analysis

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

10. Applicability

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

11. Process for synchronization/trial operations and commercial operations 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 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:
    http://www.ISO.com/participate/Pages/NewResourceImplementation/Default.aspx

    NRI Checklist:
    http://www.ISO.com/Documents/NewResourceImplementationChecklist.xls

    NRI Guide:
    http://www.ISO.com/Documents/NewResourceImplementationGuide.doc

12. Potential Changes in Cost Responsibility

    The IC is advised that interconnection of its proposed Generating Facility may be dependent upon the construction of certain Network Upgrades, which are currently the obligation of projects ahead of its proposed Generating Facility in the interconnection application queue. These other potential network upgrades are referenced in Section B.5 of the Area Report and outlined in Attachment 2 to the ICs final Phase I or Phase II Study Report (Appendix A).

    Whether the IC becomes responsible for all or a portion of these other potential network upgrades depends upon several factors, some of which are unknown at the time of this study. However, in an effort to alert the IC to its maximum cost responsibility for Network Upgrades, were these other potential network upgrades to become the obligation of the IC, SCE has included the IC's proportionate cost responsibility for these upgrades under the other potential network upgrades section in Attachment 2 to this report. The IC is not required to post Interconnection Financial Security for these other potential network upgrades, but the prospective obligation to finance and construct these other potential network upgrades is included in the IC's maximum cost responsibility.

    The obligation to finance and construct these other potential network upgrades is governed by Sections 4.6.8 and 10.3.2 of the GIP and 14.2.2 of the GIDAP. Both the GIP and GIDAP contain similar language, which is summarized as follows:

1) If the earlier-queued generating facilities that have cost responsibility for the other potential network upgrades withdraw prior to executing a GIA (or the filing of an unexecuted GIA at FERC), the following will occur:

    a. The ISO and SCE will evaluate whether the other potential network upgrades are still needed to support the interconnection for later-queued generating facilities. The ISO and SCE will reapportion the cost of the other potential network upgrades to the later-queued generating facilities that require the upgrades.

    b. Steps (a and b) will occur as a result of the ISO's Annual Reassessment as set forth in Section 7.4 of GIDAP and Section 6.2.9.2 of the ISO's GIDAP business practice manual.

    c. The reapportioned cost of the other potential network upgrades will be reflected in the reassessment report as outlined in the ISO's Annual Reassessment process, which will be reflected in the GIAs of the responsible parties.

2) Please refer to Section 10.3.2 of the GIP and Section 14.2.2 of the GIDAP for additional requirements regarding treatment of other potential network upgrades for ICs that select an Option (B) Generating Facility.

13. Additional limitations may be driven by the ISO market and distribution system operations.

14. Please note that SCE has made its best efforts to convey as much information as possible based on information provided by the IC about its proposed project. The information contained herein may indicate to ICs that a project of its magnitude may be better suited to interconnect at higher voltage levels, or downsize as to not incur significant amount of restrictions. Any determination to change POIs or downsize is purely at the IC's discretion and would be subject to a Distribution Provider's material modification review pursuant to the tariff.

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
Not Used

Attachment 4

SCE Interconnection Handbook

Preliminary Protection Requirements for Interconnection Facilities are outlined in the SCE Interconnection Handbook (separate document)

Attachment 5

Short-Circuit Duty Calculation Study Results

Please refer to the Appendix H of the Bulk Area Report

Attachment 6

Interconnection Customer Provided Project Dynamic Data

The following data were submitted by the IC for Dynamic simulation:

[redacted]

Attachment 7
SCE Northern Hemisphere Import Nomogram
Please refer to separate document

Attachment 8

Subtransmission Assessment Report

Please refer to separate document