Appendix A-WDT1300

[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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Attachments:

1. Interconnection Facilities, Network Upgrades, and Distribution Upgrades
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4. SCE Interconnection Handbook
5. Short-Circuit Duty Calculation Study Results (see Appendix H of the Bulk Area Report)
6. Interconnection Customer Provided Dynamic Data
7. South of Magunden Nomogram
8. Subtransmission Assessment Report-Vestal 66 kV Subtransmission System

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). The Project requested a Point of Interconnection (POI) at SCE's Vestal-Growers-Kern River 3 66 kV subtransmission line via the Growers 66 kV Substation, located in Delano, CA. The IC elected Option A Generating Facility (GF) with Full Capacity Deliverability Status (FCDS) for their Project. The IC desires an In-Service Date (ISD) of March 1, 2019 and a Commercial Operation Date (COD) of March 20, 2019. 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 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 Northern Area served out of the Vestal 66 kV Subtransmission System, respectively. This Appendix A report focuses only on the impacts or impact contributions of the Project at the local Distribution System, and it is not intended to supersede any contractual terms or conditions 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.

All the equipment and facilities comprising the 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, consists of (i) a [redacted] each with a rated output of [redacted] for a combined rated output of [redacted] at the generator and inverter terminals, (ii) the associated infrastructure and step-up transformers, (iii) meters and metering equipment, (iv) appurtenant equipment, and (v) [redacted] of auxiliary loads.

Based on the technical data provided for the collector system equivalent, pad-mount and main transformer banks, the total internal Project losses were identified to be 0.1 MW. The net output, as

[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 from the IC as will be specified in the GIA to commence the work.

measured at the high-side of the main transformer bank, is identified to be 9.7 MW when subtracting the 0.2 MW of aux load. Losses on the gen-tie were identified to be minimal thereby resulting in a POI delivery of 9.7 MW, which is less than the 10 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 Northern Area
Interconnection Voltage	66 kV
POI	Distribution Provider's Vestal-Growers-Kern River 3 66 kV subtransmission line
Requested Maximum Project Output as measured at POI	10 MW
Number and Types of Generators	[redacted]
Power Factor Range	[redacted]
Step-up Transformer(s)	[redacted]
Generator Auxiliary Load	[redacted]
Internal Generating Facility Losses	0.1 MW
Maximum Net Output as metered on High-Side of Main Transformer (Gross output less auxiliary load less internal losses)	9.7 MW
Maximum POI Delivery (Net output less gen-tie losses)	9.7 MW
ISD	March 1, 2019
Initial Synchronization Date/Trial Operation	March 15, 2019
COD	March 20, 2019

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 level, 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 in the Phase II Study: The Project was modeled as interconnecting 10 MW of generation through the Growers 66 kV Substation.
2. The following facilities will be installed by SCE and <u>are included</u> in this Interconnection Study report:

- The required retail load meter.

- Cross connects and associated equipment at Growers and Vestal Substations.

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 ISO metering equipment (PTs and CTs and ISO meters) and metering cabinet for SCE retail load meters.

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

4. Environmental Activities, Permitting, and Licensing

   This estimate assumes that SCE's scope of work would not require a California Public Utilities Commission license.

   This Estimate assumes SCE will perform all environmental studies, prepare draft environmental permit applications, and perform monitoring of all SCE construction activities related to the installation of SCE's Interconnection Facilities and Upgrades. SCE's Environmental Services Department (ESD) will act as the environmental liaison between SCE's team and IC's environmental team.

   This estimate includes, but is not limited to, the following ESD activities as appropriate:

   - Prepare California Environmental Quality Act (CEQA) and National Environmental Policy Act (NEPA) documents, studies, surveys and other environmental documentation necessary for licensing the project (ESD recommends that the IC includes SCE's scope of work in their environmental document)
   - 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 IC's environmental team
   - Prepare Environmental Requirements for Construction Clearance
   - General Order 131-D Consistency Determination and Environmental Evaluation
   - Environmental Awareness/ Worker Environmental Awareness Program (WEAP) training
   - Preconstruction coordination field visit
   - Preconstruction biological surveys
   - Protocol biological surveys, if required
   - Construction monitoring
   - Construction and post-construction site assessments
   - 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 construction monitoring, when/if required
- 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 and acquiring environmental permits
- Performing pre-construction biological resource surveys
- Performing biological resource monitoring during construction
- Consulting with regulatory agencies

Mitigation costs including, but not limited to, offsite compensatory and onsite restoration activities (under ESD's direction), are not included in this estimate.

This estimate is based upon the scope listed in Attachment 1. If the scope is altered, this estimate is no longer valid and the cost estimate must be reviewed and updated.

IC Responsibility:

ES recommends that the IC includes SCE's scope of work in their environmental document.

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.

D. Power Flow Reliability Assessment Results

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 California Independent System Operator (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. Contingency Conditions

      The Vestal 66 kV Subtransmission Assessment indicated that the Project contributes to overloads problems on the Vestal 66 kV Subtranmission System. Specifically, the addition of the project was identified to exacerbate a contingency overload on the [redacted] out for maintenance followed by a bus outage. To address the incremental loading generation restrictions (curtailment) will be required anytime the [redacted] is out. This restriction is needed until such time that the transfer trip scheme which disconnects generation, as identified for a queued-ahead generation project, is put in place.

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

   The [redacted] is triggered by prior queued project WDT938. Such reconductoring work is also required to support the interconnection of this Project.

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.

5. 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, the technical data provided by the IC are consistent with the manufacture data.

<u>Inverter Based Generation</u>
Max fault contribution for each unit: [redacted]

<u>Collector System:</u>

[redacted]	[redacted]
[redacted]	[redacted]

<u>Main Generation and Step-Up Transformers Information:</u>
Technical details are provided 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.

   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 PII 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 and/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

1. On Peak Deliverability Assessment
   The Project does not contribute to any deliverability constraint.
2. Off- Peak Deliverability Assessment
   The Project does not contribute to any deliverability constraint.
3. Required Mitigations
   No Delivery Network Upgrades are required.

J. In-Service Date and Commercial Operation Date Assessment

The information provided by the IC in Appendix B indicates that the requested ISD and COD is March 1, 2019 and March 30, 2019, respectively. To determine if these dates could be met, an ISD and COD assessment was performed which considered both the QC8 Phase II Interconnection Study process timelines as well as the facilities needed to enable an energy only interconnection of the Project. Details pertaining to FCDS and Interim Deliverability are provided below in Section K.

1. Interconnection Process Timelines

   To enable physical interconnection, a Generation Interconnection Agreement (GIA) is required. As part of the interconnection Study cycle, a GIA is tendered following completion of the final Phase II Interconnection Study with the timing for tendering such GIA impacted by the ISO's Transmission Planning Deliverability (TPD) Allocation Study and the ISO's Annual Reassessment, if applicable.

The TPD Allocation Study process is scheduled to be completed by April 2017 and if no changes to scope requirements are identified, a letter is provided by the ISO at the end of April 2017 outlining the TPD Allocation Study results. However, if changes to scope requirements are identified as part of the ISO's Annual Reassessment Study process, updates to scope, cost, and schedule are developed and provided in a Reassessment Study Report issued by the end of July. For Projects seeking a GIA with Partial Capacity Deliverability Status (PCDS) or FCDS pursuant to the TPD Allocation Study process, GIA negotiations may commence after the issuance of the letter at the end of April 2017, which outlines the TPD Allocation Study results, or upon issuance of the Reassessment Study Report at the end of July 2017, which updates scope, cost, and schedule. Assuming a three (3) month timeframe for GIA negotiations, after the GIA is tendered, the earliest that an executable GIA can be provided to the IC is August 2017, which is contingent on the IC's acceptance of the TPD Allocation Study results. If the Reassessment Study process affects the Project, an executable GIA is not expected until November 2017. The timeline for executing a GIA could be further delayed if the IC elects to "park" its IR until the following year's allocation of TP Deliverability.

2. Upgrade timelines needed for energy only Interconnection

   The ISD and COD assessment identified that the following facilities are required in order to interconnect the Project. The month durations shown represent the estimated amount of time needed to design and construct the facilities with the start date of the duration based on the effective date of the GIA, IC granting authorization to proceed (ATP), and IC posting financial security

   a. PTO's Interconnection Facilities – 27 months

      These facilities involve non-network facilities located within SCE's Growers 66 kV Substation and at the IC's Project that are necessary to complete physical interconnection of the Project and ensure adequate line protection. Please refer to Section 1.b of Attachment 1 for details related to these facilities.

   b. Reliability Network Upgrades – 27 months

      SCD operational mitigation was identified taking into account new generation projects that have executed GIAs, approved Distribution Provider's 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.

c. Voltage Support Mitigation

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

d. Distribution Upgrades - 27 months

The [redacted] is triggered by prior queued project WDT938. This upgrade has not yet been installed, is estimated to require 27 months to complete, and is also required to support interconnection of this Project.

3. Conclusion

Based on the GIA execution timelines and milestone timelines to design and construct the facilities noted above, the IC's requested ISD of March 1, 2019 and COD of March 20, 2019 are not achievable. Such conclusion is consistent with the conclusions provided in the Project's Phase I Interconnection Study report. Assuming the earliest that an executable GIA can be provided to the IC is August 2017, which is contingent on the IC's acceptance of the 2017 TPD Allocation Study results, the ISD should be modified to reflect December 1, 2019 and the COD should be modified to reflect a date after the ISD. To modify such dates, the IC will need to submit a request for material evaluation following section 4.5.7.2 of the SCE's WDAT Attachment I Generator Interconnection Procedures (GIP).

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

The Project would be granted its requested FCDS only if the Project receives TDP allocation in the forthcoming TPD Allocation Study. Furthermore, timing of obtaining the requested FCDS is dependent on the completion of Delivery Network Upgrades identified below in this report, which may be updated in any subsequent annual reassessment. Until such time that the these Delivery Network Upgrades are completed and placed into 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, Area Constraints, and Operational Information.

4. System Upgrades Required for Full Capacity Deliverability Status

   In order to provide for Full Capacity Deliverability Status, the following facilities are required in addition to the Reliability Network Upgrades, if any, described in Section J.2 of this report:

   a. Triggered Delivery Network Upgrades

      None - The IC elected Option A with FCDS for the Project.

   b. Delivery Network Upgrades Triggered by Earlier Queued Projects – None.

   c. Approved Transmission Upgrades

      - The entire Tehachapi Renewable Transmission Project (TRTP), expected to be complete and placed in service in the last quarter of 2016

- The Eldorado Line Swap Project, expected to be complete and placed in service in 2018
- The Eldorado-Lugo Series Capacitor Project, expected to be complete and placed in service in 2019
- The Lugo-Mohave Series Capacitor Project, expected to be complete and placed in service in 2019

d. Transmission Upgrades outside the ISO Controlled Grid – None.

5. Interim Operational Deliverability Assessment for Information Only

The operational deliverability assessment was performed for study years 2017 ~ 2020 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 Bulk Area Report. The Project contributes to Lugo – Victorville overloads. It may receive interim deliverability in 2019 until all required upgrades listed above are in service.

6. Area Constraints

With all approved transmission upgrades modeled, no area deliverability constraints were identified for the Project. However, interconnection of new generation in advance of completing the approved transmission upgrades and upgrades triggered by queued-ahead generation projects may result in increased congestion on the system. Furthermore, there are known transfer capability limitations, such as Path 26 and South of Vincent flows. See Section D.1.1-(ii) for more details.

7. SCE Northern Hemisphere Import Nomogram

Refer to Attachment 2 and section G for details of the deliverability and upgrades results, respectively. It is important to note that if no Delivery Network Upgrades were allocated to the Project, this outcome does not mean that the Project will be able to generate at its maximum net GF output. Congestion management could happen whenever the amount of generating resources exceeds the available Transmission capability. The generating resources' output may be curtailed, regardless of their deliverability status, as the result of congestion management under the ISO market operation.

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 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[2] based on the final Phase II cost in this study. It does not represent the "maximum ITCC exposure" to the Project. Attachment 3 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. This study does not include analysis related to the power output rate of change that may occur due to the following or other conditions:

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[2] 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%).

- System morning start up for solar systems. That is when each morning the GF commences to generate and export electrical energy to the distribution system.
- Cloud Cover. Solar generating facilities have significant generation output variation (Variability) which can have an impact on distribution system voltage profiles.
- The customer's GF will have equipment, software, and the appropriate controls as in place to be able to control the generation output rates of change, as specified by SCE, in order to maintain appropriate voltage levels under all conditions including, but not limited to, the conditions identified above. Upon execution of the appropriate Interconnection Agreement, SCE will provide the Interconnection Customer the required ramp rate control parameters. The ramp rate controls will be a function of the generation penetration on the distribution system as well as SCE's distribution system configuration but other parameters may be considered. Therefore, changes to the ramp rate control scheme may be required from time to time as required by increased in generation, changes in the distribution system topology, or other changes in the Distribution System.

3. 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.

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

   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.

5. 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.

6. 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.

7. 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.

8. 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.

9. 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.

10. 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.

11. 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.

12. 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

13. Changes in Cost Responsibility for Other Potential Network Upgrades

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
    b. The ISO and SCE will reapportion the cost of the other potential network upgrades to the later-queued generating facilities that require the upgrades
    c. 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
    d. 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.

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

15. Please note that Distribution Provider 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
South of Magunden Nomogram
Please refer to separate document

Attachment 8
Subtransmission Assessment Report
Please refer to separate document