
Appendix A – WDT1277




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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1. Interconnection Facilities, Network Upgrades, and Distribution Upgrades
2. Escalated Cost and Time to Construct for Interconnection Facilities, Reliability Network Upgrades, Delivery Network Upgrades, and Distribution Upgrades
3. Not Used
4. SCE Interconnection Handbook
5. Short Circuit Duty Calculation Study Results (see Appendix H of the Area Report)
6. Not Used
7. SCE Northern Hemisphere Import Nomogram
8. Subtransmission Assessment Report – Antelope 66 kV System

A. Introduction

██████████ the Interconnection Customer (IC), has submitted a completed Interconnection Request (IR) to Southern California Edison Company (SCE) for their proposed ██████████ (Project). The Project requested a Point of Interconnection (POI) at Distribution Provider's Hovey 12 kV Circuit out of Redman 66/12 kV Substation, located in Lancaster, CA. The IC elected to be an Option A Generating Facility (GF) with Energy Only Deliverability Status for their Project¹. The IC desires an In-Service Date (ISD) of November 15, 2017 and a Commercial Operation Date (COD) of December 31, 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 Distribution Provider'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 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 and served out of the Antelope 66kV 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 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 unit cost estimate of the Project's cost responsibility and time to construct² 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 Project are located in Lancaster, CA, as disclosed by the IC in their Interconnection Request (IR). The Project's GF, as may have been amended during the Interconnection Study process, consists of (i) ██████████ with an output of ██████████ each for a combined gross/rated output of ██████████ with an auxiliary load of ██████████ for a total net output of 3.0 MW, (ii) the associated infrastructure, (iii) meters and metering equipment, and (iv) appurtenant equipment. The Project shall consist of the Generating Facility and the IC's Interconnection Facilities as illustrated below in Figure A.1, as well as, Figure A.2 is a map that illustrates the location of

¹ The IC participated in the 2016 Distributed Generation Deliverability allocation and was awarded Full Capacity Deliverability Status in accordance with ISO Tariff section 40.4.6.3.

² 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.

the Project. Moreover, the Project information is summarized in Table A.1 below. The Project shall not exceed the total net output of 3.0 MW at the Point of Change of Ownership (POCO).

Figure A.1: Project Plan of Service (POS)

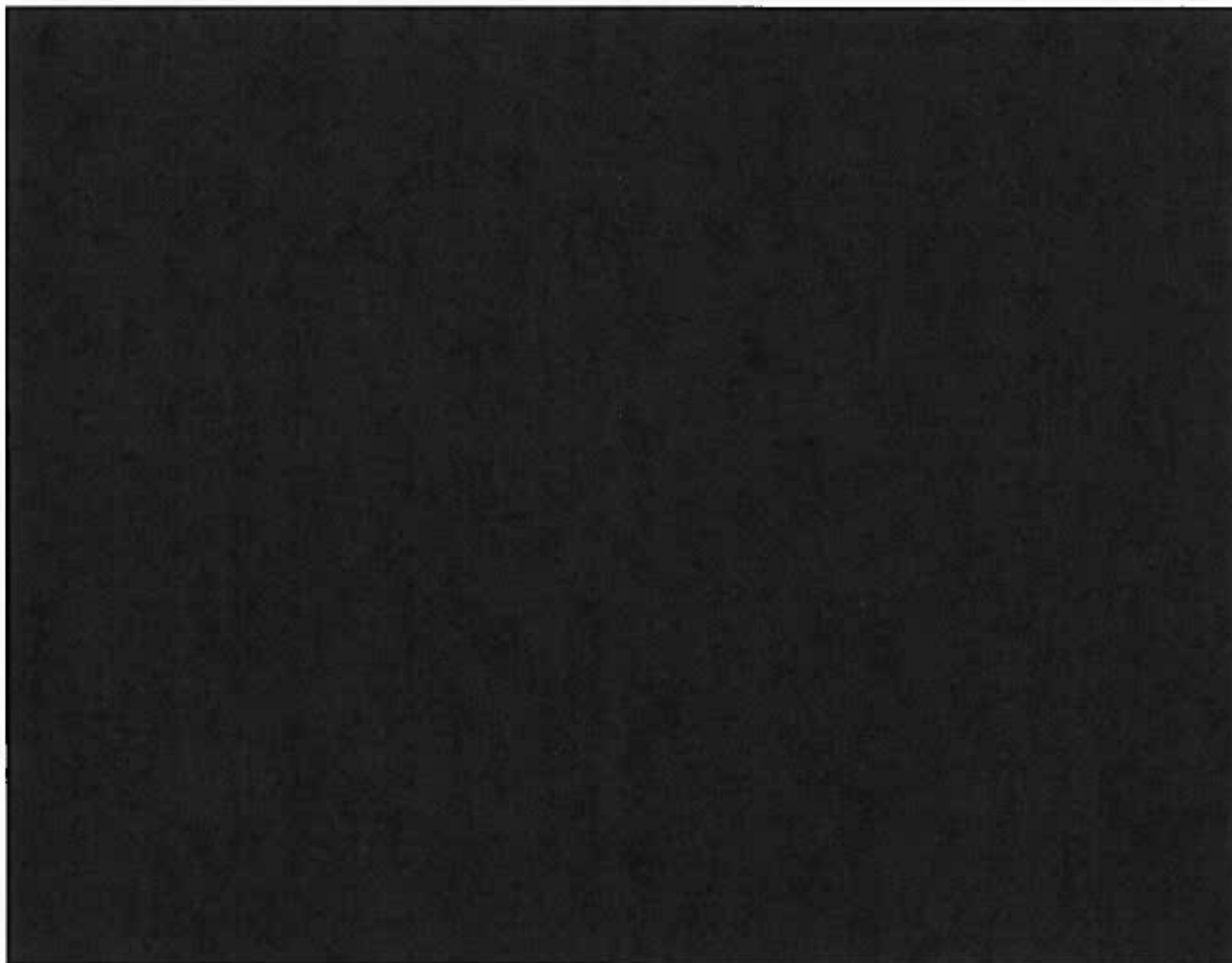


Figure A.2: Project Location Map

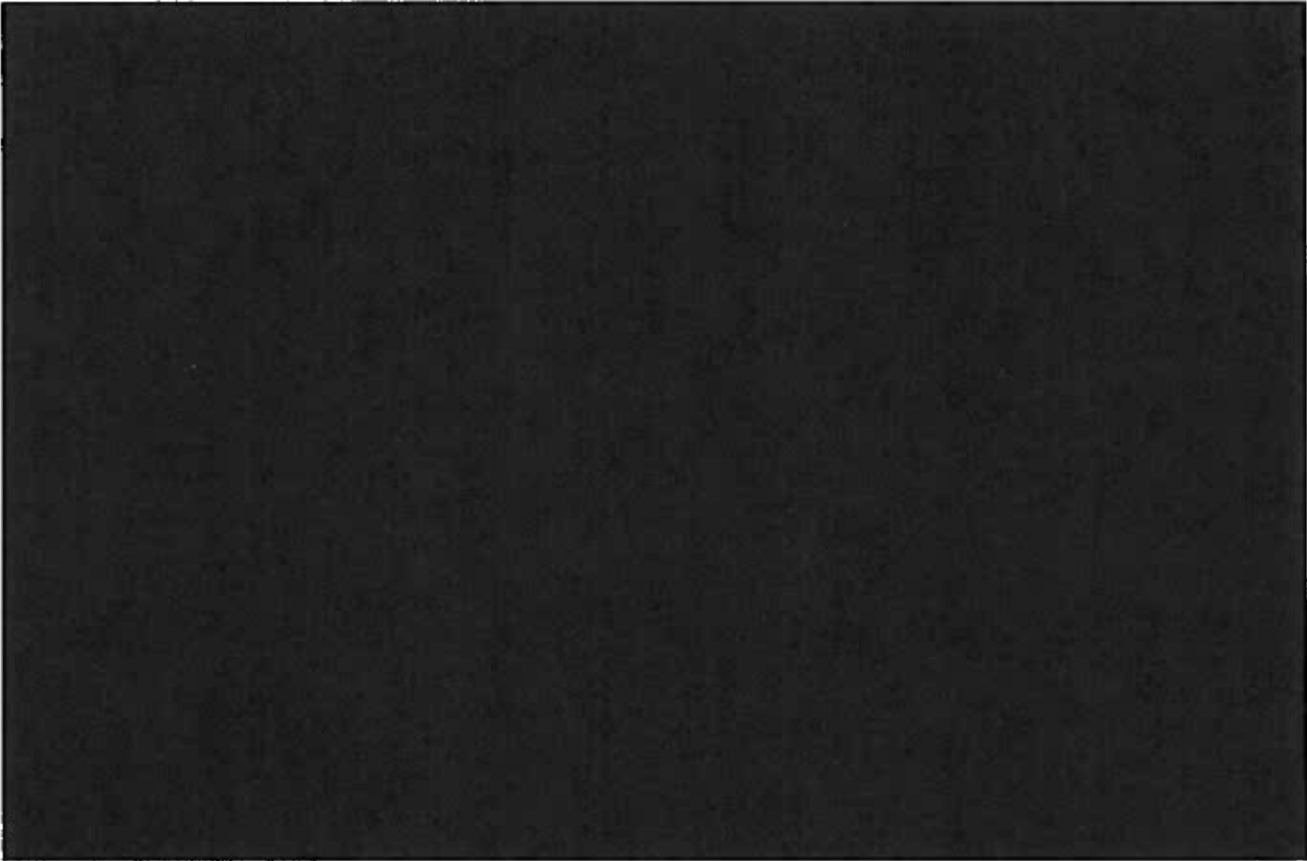


Table A.1 Project General Information per IR

Project Location	[REDACTED]
Distribution Provider's Planning Area	Distribution Provider's Northern Area
Number and Types of Generators	[REDACTED]
Interconnection Voltage	12 kV
Maximum Generator Output	[REDACTED]
Generator Auxiliary Load	[REDACTED]
Maximum Net Output at Generating Facility	3.0 MW
Power Factor Range	[REDACTED] per IR application
Step-Up Transformer(s)	[REDACTED]
POI	Distribution Provider's Hovey 12 kV Circuit out of Redman 66/12 kV Substation
ISD	November 15, 2017
Initial Synchronization Date/Trial Operation	December 15, 2017
COD	December 31, 2017

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 POS is defined as the facilities needed to interconnect the Project to Distribution Provider's Distribution System. The following is the POS assumed for the Project:

The Project was modeled as net output of 3.0 MW at the Generating Facility with its POI to the Distribution Provider's Distribution System at the Hovey 12 kV Circuit out of Redman 66/12 kV Substation via a line extension to the applicant owned 12 kV Primary Switchgear at the Point of Change of Ownership (POCO).

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

- Install one (1) distribution riser pole
 - [REDACTED]
 - [REDACTED]
 - [REDACTED]
- 12 kV Primary Metering, Current Transformers (CTs), Potential Transformers (PTs), and Associated Wiring
- Telemetry – Centralized Remote Terminal Unit (RTU)
 - [REDACTED]
 - [REDACTED]

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

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

- Ducts as required
- Structures as required
- 12 kV Primary Switchgear
- Protection System requirements to comply with the Distribution Provider's Interconnection Handbook
- Transformation as required
- Metering equipment compliant with Distribution Provider's Electrical Service Requirements
- Wholesale load meter
- The required metering cabinet

NOTE: The Distribution Provider will install metering, PTs and CTs to be used for the Distribution Provider owned retail meters. The PTs and CTs can be used for the ISO metering.

4. Environmental Activities, Permits, and Licensing

- This estimate assumes that SCE would file for an "expedited" Permit to Construct by attaching the IC's final CEQA document with SCE's scope of work incorporated in lieu of a Proponent's Environmental Assessment.
- This estimate assumes Environmental Services (ES) will act as the environmental liaison between SCE's team and IC's team, and the lead for regulatory agency communication. This estimate includes, but is not limited to, the following ES activities, as applicable:
 - 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 (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 IC's environmental team, discuss/ approved 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
- Preconstruction coordination field visit
- Construction and post-construction site assessments

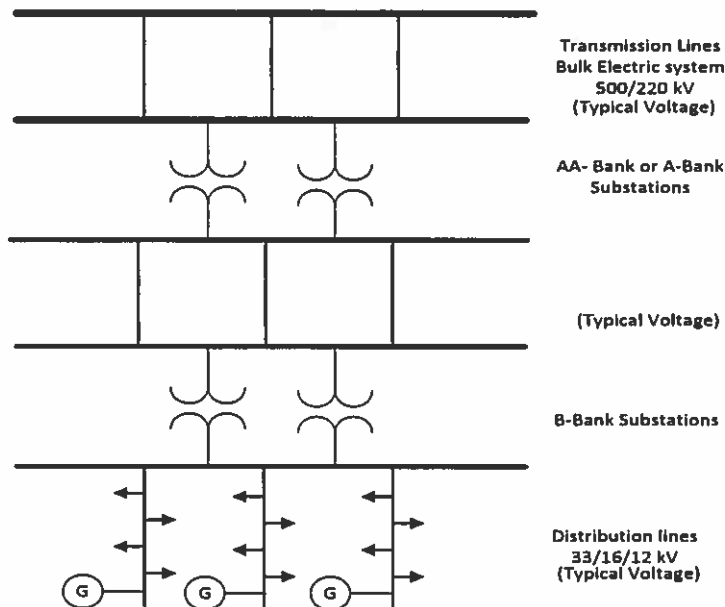
This estimate assumes the IC performs all environmental studies and prepares draft environmental permit applications related to the installation of SCE's Interconnection Facilities and Upgrades. The IC's responsibilities include, but are not limited to notifications to the Native American Heritage Commission (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. SCE's System Topology

The topological structure of SCE's transmission lines, substations, and subtransmission lines is depicted below to provide an overview of SCE's Transmission and Distribution Systems pursuant to this study.

Figure 2-1: Topology of SCE's Electric System



6. The following SCE Distribution System Planning Criteria and Conditions were included in the Study:

- Distributed generation resources connected to the distribution system are analyzed offline and online during peak load conditions as well as during daytime minimum load conditions as to determine the worst case scenario.
- The short circuit duty contribution from the inverter systems was determined using inverter manufacturer documents.
- The Study assumes the upgrades triggered by queued-ahead projects, including Rule 21 projects under California Public Utilities Commission (CPUC) jurisdiction as In-Service, are included in the base case. If any queued-ahead projects were to withdraw, then the projects may be subject to the cost identified for those queued-ahead projects.
- Distribution Provider's Distribution Standards and practices are in the process of being updated to address interconnection facilities. The proposed POS in this report may require changes to comply with the updated distribution design standards and practices.

7. Additional Study and/or Assumption Notes:

- Upon execution of the GIA, Distribution Provider will provide the IC with the required ramp rate³ control parameters. The ramp rate controls will be a function of the demand on the distribution system, as well as Distribution Provider's Distribution System configuration (additional parameters may be considered, as necessary).
- Ongoing changes to the ramp rate control scheme may be required as determined by changes in the distribution system topology or other changes in the distribution system. However, typical ramp rates for facilities connected to Distribution Provider's Distribution System are 10% of nameplate rating, per minute.

C. Reliability Standards, Study Criteria and Methodology

This study was conducted by applying SCE's Distribution Planning Criteria. More specifically, the key criteria applicable to this Phase II Study are as follows:

- The thermal rating of any conductor, connector, or apparatus shall not exceed 100% of its normal rated capacity⁴ with all facilities in service (N-0 or base case).
- The thermal rating of any conductor, connector, or apparatus shall not exceed 100% of its emergency rated capacity under loss of one element (N-1) condition(s).
- The thermal rating of any B-Bank shall not exceed 100% of its nameplate rated capacity with all facilities in service (N-0 or base case).
- The thermal rating of any B-Bank shall not exceed 100% of its nameplate rating capacity under loss of one element (N-1) or emergency condition(s).
- Operational flexibility, safety, and reliability of the distribution system shall be maintained at all times.
- Circuit voltage profiles shall be maintained to comply with SCE's CPUC Jurisdictional Rule 2 tariff requirements. The IC will be responsible for maintaining designated voltage levels under all conditions, including but not limited to the conditions identified above.
- The power factor for the GF is assumed to be within WDAT requirements of [REDACTED]
- Expected loading on the distribution system as projected by SCE's internal 2016-2025 distribution system forecast is utilized for the purposes of this Study.

D. Power Flow Reliability Assessment Results

Analysis of the Project

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

The group study indicated that the Project does not contribute to any overloads/non-convergence problems on the transmission system of the area. Consequently, the Project did not get allocated costs for any Network Upgrades. Refer to enclosed Area Report in the Phase II report package, for the Phase II power flow analysis results.

³ It is assumed that ramp rates for each GF will be dependent upon their inherent technology types. While very quick response ramp rates 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.

⁴ Normal rated capacity or Planned Loading Limit (PLL) capacity is determined by the lesser of the limiting component on the distribution system or 75% of minimum trip of the upstream protection device.

II. Steady State Power Flow Analysis Results – 66 kV and 115 kV

The subtransmission assessment indicated that the Project does not contribute to any overloads/non-convergence problems on the subtransmission system of the area. Consequently, the Project did not get allocated costs for any upgrades at the subtransmission level. Refer to enclosed Subtransmission Assessment Report in the Phase II report package, for the Phase II power flow analysis results.

III. Steady State Power Flow Analysis Results – 33 kV and below

1. Thermal Overloads

The distribution level study indicated that the Project did not contribute to the facility overloads or non-convergence problems.

- Base Case (All facilities in service, N-0)
 - [REDACTED]
 - No thermal overloads has been identified.
 - [REDACTED]
 - The addition of the Project did not cause a thermal overload.
- Single Contingency (loss of a single element, N-1)
 - [REDACTED]
 - No thermal overloads has been identified.
 - [REDACTED]
 - The addition of the Project did not cause a thermal overload.

Due to the dynamic distribution system conditions and configurations, under emergency N-1 conditions (loss of a B-Bank, or loss of the [REDACTED]) the Distribution Provider may deem it necessary to open the source to remove the Project from Distribution Provider’s distribution system. Once the Distribution Provider system is restored to normal, the Distribution Provider would then close in the source and the generation system can resume normal operation.

2. Power Flow Non-Convergence

There were no non-convergence issues identified with the inclusion of the Project.

3. Voltage Performance

The [REDACTED] is not expected to experience a voltage rise that exceeds allowable Rule 2 requirements with the Project in-service. The Project is expected to operate at unity power factor with the capacity to provide power factor regulation capability [REDACTED] to alleviate power flow non-convergence and maintain the transmission transfer capability. Additionally, the generation system must be designed to accommodate a Voltage/VAR schedule provided by the Distribution Provider. The Distribution Provider will

determine if the Voltage/VAR schedule is necessary based on future re-arrangements of Distribution Provider's distribution system.

4. Protection

There were no additional protection requirements.

5. Required Mitigations

Per the WDAT tariff, the Project is required to provide 0 [REDACTED] capability at the POI.

Refer to Attachment 1 and Attachment 2 for scope description and associated project cost responsibility.

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.

1. Short Circuit Duty Study Input Data

The IC provided technical data for the identified generator type as specified in Table A.1. The technical data provided by the IC were compared against the manufacturer data obtained by SCE. Upon SCE's comparison, it was determined that the technical data provided by the IC matched the generator manufacturer data obtained by SCE. Please note that for this study, SCE used the generator manufacturer data obtained by SCE.

Inverter Based Generation Data for Each Generation Unit

Maximum Fault Contribution: [REDACTED]

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.

However, the Project does not contribute to the duty concerns at hand, and did not get allocated costs for ground grid studies at the flagged Distribution Provider-owned substations.

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 Generating Facility and must meet the requirements in the SCE Interconnection Handbook provided in Attachment 4.

G. Transient Stability Evaluation

1. Area Study Transient Stability Results – 220 kV and above

Refer to enclosed Area Report in the Phase II report package, for the Phase II transient stability evaluation criteria, and assessment results, respectively, at the 220 kV and above voltage level.

2. Area Transient Stability Results – 66 kV or 115 kV

Refer to enclosed Subtransmission Assessment Report in the Phase II report package for the Phase II transient stability evaluation, criteria, and assessment results at the applicable subtransmission voltage level (66 kV or 115 kV).

3. Area Transient Stability Results – 33 kV or below

At the 33 kV and below voltage level this type of study is not performed.

H. Deliverability Assessment Results

The IC participated in the 2016 Distributed Generation Deliverability (DGD) allocation and was awarded Full Capacity Deliverability Status in accordance with ISO Tariff section 40.4.6.3. There are no deliverability constraints for this generator under the (DGD) study assumption.

I. In-Service Date and Commercial Operation Date Assessment

The latest information provided by the IC in Attachment B confirms a requested ISD of November 15, 2017 and a COD of December 31, 2017. To determine if these dates could be met, an ISD and COD assessment was performed, which considered both the Phase II Interconnection Study process timelines as well as the facilities needed to enable an energy-only interconnection of the Project. Details pertaining to Deliverability are provided in the section below.

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.

Assuming a three (3) month timeframe for GIA negotiations, after the GIA draft is tendered in accordance with GIP Section 4.9, the earliest that an executable GIA can be provided to the IC is May 2017.

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. Distribution Provider’s Interconnection Facilities – 18 months

Please refer to Section 1.b of Attachment 1 for details related to the Distribution Provider’s Interconnection Facilities.

b. Reliability Network Upgrades

i. Plan of Service Reliability Network Upgrades – None

ii. Special Protection System (SPS) – None

iii. Short-Circuit Duty (SCD) Mitigation

Short-circuit duty operation mitigation took into account new generation projects which have executed GIAs, approved transmission system upgrades fully permitted and under construction, and new generation projects including 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 (GSI) Short Circuit Duty evaluation (Appendix G). Based on the study results, upgrades/mitigation are not required to be in place in order to enable energy only interconnection of this Project.

iv. 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:

To interconnect this Project, the following Distribution Upgrades are required:

o

[REDACTED]

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 November 15, 2017 and COD of December 21, 2017 are not achievable. Following the standard process, this would result in a best case in-service date of November 1, 2018. Such conclusion is consistent with the conclusions provided in the Project's Phase II Interconnection Study report. This assumes that May 2017 is the earliest that an executable GIA can be provided to the IC.

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

The IC elected EO⁵ for their Project, but awarded FCDS in the 2016 Distribution Generator Deliverability assignment. Timing of obtaining the assigned DGD is dependent on the completion of Delivery Network Upgrades assumed in the DGD study. Until such time that the Delivery Network Upgrades are completed and placed into service, the Project may be granted interim deliverability based on annual system availability. The sections below provide a discussion of the timing of EO, interim deliverability, area constraints, and operational information.

1. 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 in Section J.2 of this report:

- a. Triggered Delivery Network Upgrades - None
- b. Delivery Network Upgrades Triggered by Earlier Queued Projects - None
- c. Approved Transmission Upgrades
- d. The entire Tehachapi Renewable Transmission Project (TRTP) is required to support the FCDS of the Project. The expected in-service date of TRTP is late 2016.
- e. Transmission Upgrades outside the ISO Controlled Grid - None

2. 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 Area Report. No deliverability issues were identified. Once TRTP is in service, the Project will have Full Capacity Deliverability Status if it meets the criteria to retain DGD assignment.

⁵ The IC participated in the 2016 Distributed Generation Deliverability allocation and was awarded Full Capacity Deliverability Status in accordance with ISO Tariff section 40.4.6.3

K. Distribution Provider’s Interconnection Facilities, Network Upgrades, and Distribution Upgrades

Please see Attachment 1 for the Distribution Provider’s IFs, RNUs, DNUs, and DUs allocated to the Project. Please note that the Distribution Provider 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 the Distribution Provider has completed the detailed design and engineering of the facilities according to tariff timelines.

L. 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 estimate⁷ 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.

M. 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.

The IC is responsible for complying with IEEE 519 harmonic impact limits to Distribution Provider’s Distribution System (related retail service rules, such as Rule 2).

N. Environmental Evaluation, Permitting, and Licensing

Please see Appendix K of the Area Report.

O. Affected Systems Coordination

Please see Section H of the Area Report.

⁷ 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: $(IF*35\%) + ((RNU\ Costs - (Project\ MW*\{ \$60k/MW\}))*35\%) + (DU*35\%)$.

P. 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:

- **System morning start up for solar systems.** That is when each morning the generating facility 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 generating facility 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. SCE Distribution System Operational Flexibility

It should be noted that the study results disclosed in this report are dependent upon the system conditions known at the point in time the study is conducted. Given that the system conditions could very well change because of the dynamic nature of the Distribution System after issuance of this report; a new operational/technical study may be needed.

4. IC's Technical Data

The study accuracy and results for the Phase II Interconnection Study are contingent upon the accuracy of the technical data provided by the IC. Any changes from the data provided could void the Phase II Interconnection Study results.

5. 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.

6. 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.

7. 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.

8. 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.

9. 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.

10. 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 IFs, the IC is responsible to make appropriate arrangements with the Distribution Provider to receive and pay for such retail service.

11. 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 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.

12. Ground Grid Analysis

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

13. Applicability

This document has been prepared to identify the impact(s) contributions of the Project on the Distribution Provider'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.

14. 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:

<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>

15. 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:

- 2) 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
- 3) 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.

16. Additional limitations may be driven by the ISO market and distribution system operations.
17. Please note that the 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 6
Not Used

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

Attachment 8
Subtransmission Assessment Report
Please refer to separate document