Appendix A – WDT1395

[redacted]

Queue Cluster 9 Phase I Report

January 18, 2017

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)

Interconnection Study Document History

No.	Date	Document Title	Description of Document
1	1/18/2017	Queue Cluster 9 Phase I Appendix A Report	Final Phase I Interconnection Study Report

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ATTACHMENTS

A. INTRODUCTION

[redacted] the Interconnection Customer (IC), has submitted a completed Interconnection Request (IR) to Southern California Edison (SCE) for their proposed [redacted] (Project). The Project requested a Point of Interconnection (POI) at Southern California Edison Company's (SCE) Wilsona 66 kV Substation, located in Palmdale, CA with delivery to the California Independent System Operator (ISO) at the Antelope 66 kV Switchrack. The IC elected Full Capacity Deliverability Status (FCDS) for the Project. The IC desires an In-Service Date (ISD) of November 1, 2019 and a Commercial Operation Date (COD) of September 1, 2020. Such dates are specified in the Project's IR. Actual ISD and COD will depend on licensing, engineering, detailed design, and construction requirements to interconnect the Project 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 9 (QC9) Phase I 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 on the ISO Grid and to distribution facilities served out of the Antelope 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 is not intended to supersede any contractual terms or conditions specified in the 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 Project's Generating Facility are located in Palmdale, California, as disclosed by the IC in its IR, as may have been amended during the Interconnection Study process, which consists of (i) [redacted] each for an installed capacity of [redacted] as measured at the inverter terminals, (ii) the associated infrastructure, (iii) meters and metering equipment, (iv) appurtenant equipment, and (v) 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 0.61 MW. The IC identified that the auxilary will of offset by onsite power. Losses on the gen-tie were identified to be 0.2 MW.

[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.

Subtracting losses and estimated aux load from the gross 40.33 MW would result in a POI delivery of 39.52 MW.

The Project shall consist of the Generating Facility and the IC's Interconnection Facilities as illustrated below in Figure A.1. Below also is Figure A.2, a map that illustrates the location of the Project. Moreover, the Project information is summarized in Table A.1 below.

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

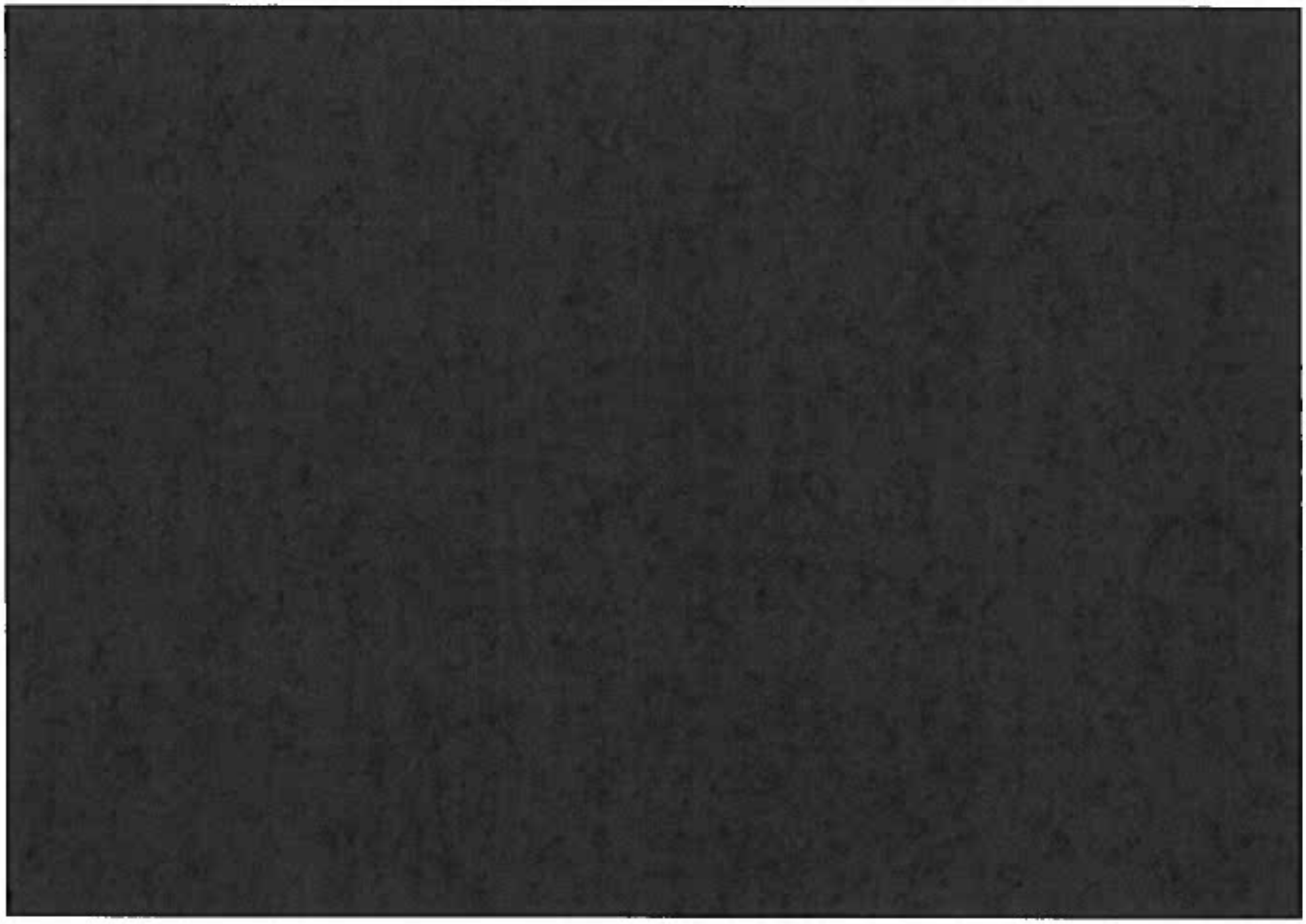

Figure A.2: Project Location Map

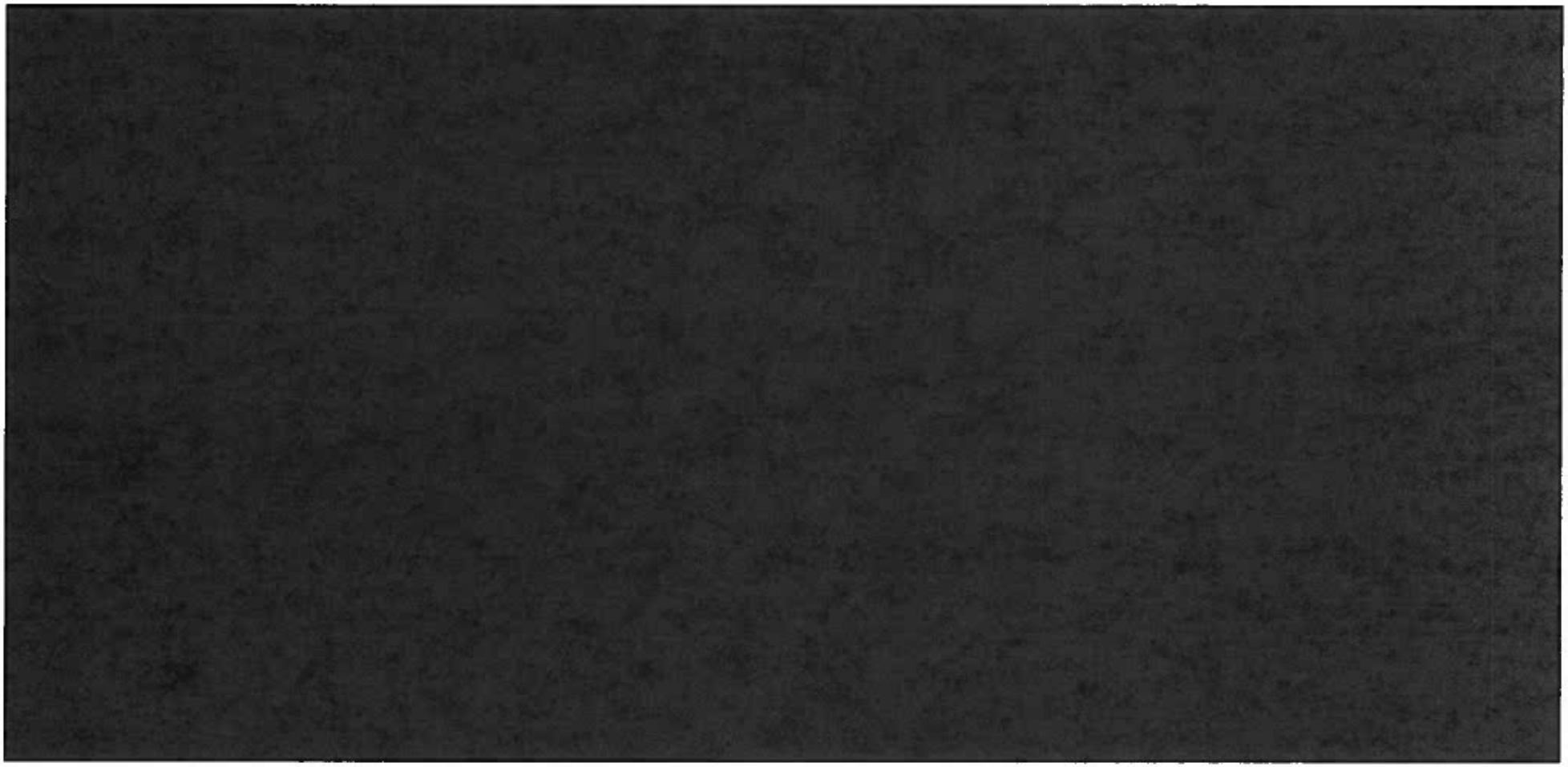

Table A.1 Project General Information per IR

Project Location	[redacted]
Distribution Provider's Planning Area	Distribution Provider's Northern Area
Interconnection Voltage	66 kV
POI	Distribution Provider's Wilsona 66 kV Substation
Requested Maximum Project Output as Measured at POI (Note 1)	[redacted]
Number and Types of Inverters	[redacted]
Power Factor Range for Inverters	Lead 0.91 / Lag 0.91
Step-up Transformer(s)	[redacted]
Generator Auxiliary Load	[redacted]
Internal Generating Facility Losses	0.62 MW
Gen-Tie	3 miles, 556.5 kcmil ACSR
Estimated total losses on Generation Tie Line	0.2 MW
Maximum Net Output at Generating Facility (High-Side of Main Transformer) (Note 2)	39.71 MW
ISD	November 1, 2019
Initial Synchronization Date/Trial Operation	November 15, 2019
COD	September 1, 2020

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 (gen-tie) losses. The estimated Maximum Net Output value at POI and gen-tie Losses illustrated above are contingent upon the accuracy of the technical data provided by the IC, and are subject to change should the IC change its gen-tie parameters during the final engineering and design phase of the Project.

B. STUDY ASSUMPTIONS

For detailed assumptions regarding the group cluster analysis, please refer to the QC9 Phase I Area 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 with a total gross output capacity of 40.33 MW of PV generation delivering 39.52 MW of generation at the POI.

2. The following facilities will be installed by SCE and **are included** in this Interconnection Study report:
    - The new 66 kV line position at Wilsona Substation for terminating the customer gen-tie.
    - The new 66 kV bus tie position at Wilsona Substation.
    - The segment of 66 kV gen-tie line inside the Wilsona Substation property line.
    - The segments of each one of the two telecommunications paths inside the Wilsona Substation property line.
    - The fiber optic cable requirements on the Little Rock-Wilsona and Sparkle-Wilsona 66 kV Lines.
    - Dedicated Remote Terminal Unit (RTU)
    - The required retail load meter.
    - Protection System requirements to comply with the SCE Interconnection Handbook.
    - Lightwave, channel banks, and associated equipment at Wilsona 66 kV Substation and at the Generating Facility.

    NOTE: SCE installation does not include metering potential transformers (PTs), 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 66 kV gen-tie line from the Generating Facility to the Last Structure outside the Wilsona Substation property line.
    - The 66 kV gen-tie line main and diverse fiber optic line to provide two diversely routed telecommunication paths required for the Remote Terminal Unit (RTU), and line protection relays.
    - The required metering equipment (PTs, CTs, and ISO meters) and metering cabinet for SCE retail load meter.

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

    - The following line protection relays to be installed at the Generating Facility end of the Wilsona-WDT1395 66 kV line:
        - Two (2) line current differential relays with dual dedicated digital communication channels to Wilsona Substation.

4. Preliminary Protection Requirements
    - Protection Requirements are designed and intended to protect the Distribution Provider's 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 system and equipment and must meet the requirements in the Distribution Provider's Interconnection Handbook provided in Attachment 4.

5. Environmental Activities, Permits, and Licensing

   i. Internal Substation
   - This study assumes Environmental Services (ES) will perform all environmental studies and perform monitoring of all SCE internal substation construction activities. This study assumes no nesting bird issues during construction.
   - ES recommends that the IC include SCE's scope of work in their environmental document.

   ii. Line Extension
   - This study 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 Proponent's Environmental Assessment.

   This study assumes ES will act as the environmental liaison between SCE's team and IC's team, and the lead for regulatory agency communication. This study 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 or license 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, or similar document
   - 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 study assumes the IC performs all environmental studies and prepares draft environmental permit applications related to the 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.

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 resources during construction, 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 draft environmental permit applications
- Performing pre-construction biological resource surveys
- Performing biological resource monitoring during construction
- Mitigation costs including, but not limited to, offsite/compensatory mitigation and onsite restoration
- Developing other mitigation plans
- Developing environmental reports or submittals, if needed

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

C. RELIABILITY STANDARDS, STUDY CRITERIA AND METHODOLOGY

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

D. POWER FLOW RELIABILITY ASSESSMENT RESULTS

I. Steady State Power Flow Analysis Results – Bulk Electric System

1. Thermal Overloads

The group study indicated that the Project contributes to overloads on the following facilities listed below under Single Contingency and Common Corridor. The details of the analysis and overload levels as well as the details of the recommended mitigation to address these Single Contingency and Common Corridor overloads are provided in the Northern Area Report.

I. Base Case

- None identified

II. Single Contingency

- None identified

III. Common Corridor

- [redacted]
- [redacted]

2. Voltage Performance

The Project is required to provide power factor regulation capability [redacted] at POI. With the Project providing power factor regulation, no voltage performance issues were identified.

3. Required Mitigations

A combination of congestion management and the Project providing [redacted] power factor regulation capability at the POI are required to mitigate the power flow impacts of the Project described above.

II. Steady State Power Flow Analysis Results – Subtransmission System

1. Thermal Overloads

The Antelope 66 kV Subtransmission Assessment indicated the Project does contribute to facility overloads under Single Contingency scenarios with all existing and prior queued transmission upgrades on the Antelope 66 kV Subtransmission System. Consequently, the Project is allocated cost for Distribution Upgrades identified to address power flow issues. The details of the power flow analysis are provided in Antelope 66 kV Subtransmission Assessment. The results identified in this section assume QC9 Phase I Projects dispatched at their requested maximum output.

I. Base Case

- None identified

II. Single Contingency

- [redacted]
- [redacted]

2. **Voltage Performance**
   The Project is required to provide power factor regulation capability [redacted] at POI. With the Project providing power factor regulation, no voltage performance issues were identified.

3. **Required Mitigations**
   The following is required to mitigate the subtransmission power flow impacts of the Project described above:

   - [redacted]
   - [redacted]

E. SHORT-CIRCUIT DUTY RESULTS

Short-circuit studies were performed to determine the fault duty impact of adding the Phase I projects to the distribution system and to ensure system coordination. The fault duties were calculated with and without the projects to identify any equipment overstress conditions. Once overstressed circuit breakers are identified, the fault current contribution from each individual project in Phase I 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 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. In this case, SCE utilized the manufacturer data.

   Inverter/Converter Based Generation Data for Each Generation Unit
   Maximum Fault Contribution: [redacted]

   Generation Tie-Line:
   This generation tie-line impedance was based on a typical tower configuration and the line conductor characteristics provided by the IC.

Length:	[redacted]
Conductor:	[redacted]
Z1(p.u.) conductor impedance information:	[redacted]
Z0(p.u.) conductor impedance information:	[redacted]

   Collector System:
   Technical data provided by the IC indicates the following parameters as representative for the collector system served out of the main transformer bank.

Amperes	[redacted]

Z1(p.u.) conductor impedance information:	[redacted]

Generation Step-Up and Pad-Mount Transformers

Technical details are provided above in Table A.1.

2. **Short-Circuit Duty Study Results**

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

   The Project contributes to overstressing Antelope 66kV circuit breakers. The short circuit duty can be reduced under the breaker rating by:

   [redacted]

   Relay coordination analysis is required to achieve the above mitigation measures. [redacted]. The ultimate determination of facility classification is outside the scope of the QC9 Phase I Study. For purpose of this study, the cost estimate of relay coordination analysis is provided assuming Distribution Upgrades classification.

3. **Potential Affected Systems – SCD Results**

   The SCD incremental increase to neighboring utilities due to the addition of all QC9 Phase I projects are provided in the Area Report (Section H.2). The individual SCD contribution from the Project will be evaluated as part of QC9 Phase II.

4. **SCE Substations with Ground Grid Duty Concerns**

   The short-circuit studies flagged for further review two existing substations in the Antelope Subtransmission System where the Phase I projects increased the substation ground grid duty by at least 0.25 kA. Additional review will be performed as part of Phase II to determine if any of these locations will require a detailed ground grid analysis performed as part of project execution once GIAs are in place and projects proceed forward towards interconnection.

F. TRANSIENT STABILITY EVALUATION

With the Project providing [redacted] as measured at the POI and including the required mitigation identified above, 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 PI transient stability evaluation criteria and assessment results, respectively.

G. 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 0.95 leading and 0.95 lagging.[2] Additionally, the generation system must be designed to accommodate a Voltage and/or VAR schedule provided by SCE. SCE will determine if the Voltage and/or VAR schedule is necessary based on future re-arrangements of SCE's Distribution System.

H. DELIVERABILITY ASSESSMENT RESULTS

1. **On Peak Deliverability Assessment**

   The Project contributes to the following deliverability constraints

   - [redacted]
   - [redacted]
   - [redacted]
   - [redacted]

   Refer to Section E.1 of the area report for details

1. **Off- Peak Deliverability Assessment**

   Under off-peak conditions, [redacted] are overloaded under various contingency conditions. For details, see Section E.2 of the Area Report.

2. **Required Mitigations**

   To increase area deliverability, the [redacted] is proposed as an Area Delivery Network Upgrade. Or the Project could choose Option (A) for deliverability that requires Transmission Plan Deliverability being allocated to the Project.

I. INTERCONNECTION FACILITIES, NETWORK UPGRADES, AND DISTRIBUTION UPGRADES

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

J. COST AND CONSTRUCTION DURATION ESTIMATES

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

[2] The current ISO Tariff requires that projects be able to meet power factor requirements of 0.95 lagging and 0.95 leading at the POI, if studies identify the need based on meeting reliability and safety requirements. The requirement will change pending FERC approval of ISO's compliance filing to FERC Order 827.

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.

For the QC9 Phase I Study, the estimated COD is derived by taking into account time requirements to complete the QC9 Interconnection Process and tender a draft Generator Interconnection Agreement (GIA). A GIA is not scheduled to be tendered until after the completion of the QC9 Phase II Studies, ISOs Annual Reassessment and the ISOs Transmission Planning Deliverability (TPD)[3] Allocation Study Process. The QC9 Phase II Study is scheduled to start on May 2017 and be completed by November 2017. Subsequently, the Annual Reassessment effort and TPD Allocation Study does not commence until late January or early February 2018. The TPD Allocation Study is scheduled to be completed by April 2018. If the ISO and SCE can make a determination that the TPD Allocation Study Process outcomes do not change the scope requirements for the project, a letter will be provided at the end of April 2018[4] informing the IC that there will be no changes to their Network Upgrades requirements and GIA negotiations can begin. Otherwise, further re-assessment will be performed for the project. If updates to scope, cost and schedule are developed, an updated Interconnection Study report will be issued to the IC by the end of July 2018. The GIA negotiations commence after either the issuance of the letter of no change to the project's Network Upgrades requirements at the end of April 2018 or upon issuance of the updated Interconnection Study report 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 Interconnection Study reports will be used as the basis to negotiate the GIA. 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 early August 2018 or early November 2018 depending on TPD Allocation Study Process results, which requires a decision from the IC to Park or proceed and will determine if the Project needs to complete the Reassessment Study. QC9 Phase I assumed the duration of the work element begins in December 2018, which accounts for the negotiation and execution of a GIA and submittal of required funds by the IC.

Based on the above, the requested IC In-Service Date (ISD) of November 1, 2019 cannot be met due to the estimated 68-month timeline identified for the Plan of Service (POS) facilities and Distribution Upgrades. Following the standard interconnection process, the ISD should be modified accordingly. The IC should note that a 35% Income Tax Component of Contribution (ITCC) will be assessed for IFs, DUs, and RNUs above the $60K/MW repayment cap allocated to the Project. Attachment 2 to your Interconnection Study report contains a potential ITCC estimate[5] based on the Phase I cost in this study. It does not represent the "maximum ITCC exposure" of the Project. Attachment 3 provides an estimated non-reimbursable RNU cost that would be subject to ITCC, taking into account the Network Upgrades maximum cost responsibility. The maximum ITCC warranted by the Project will be addressed, calculated, and included during the GIA development phase once the IC submits the TP Deliverability Allocation Study Process options form used to confirm the acceptance, waiver (parking), or denial of the awarded deliverability assigned to the Project.

[3] Transmission Plan Deliverability: Deliverability supported by the ISO's Transmission Plan

[4] The TPD Allocation Process is estimated to be completed in April 2018. The actual date may vary

[5] The maximum ITCC exposure applies ITCC (35%) to assigned IF and DU facilities. 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 Option A facilities: The maximum ITCC exposure is calculated by applying the following formula: (IF*35%) + ((RNU Costs – (Project MW*($60k/MW)))*35%) + (DU*35%). For Option B facilities: The maximum ITCC exposure is calculated by applying the following formula: (IF*35%) + ((RNU Costs – (Project MW*($60k/MW)))*35%) + (DU*35%)

K. SCE TECHNICAL REQUIREMENTS

The IC is responsible for the protection of its own system and equipment and must meet the requirements in the Distribution Provider's Interconnection Handbook provided in Attachment 4.

The IC is responsible for complying with IEEE Standard 519-2014 Recommended Practice and Requirements for Harmonic Control in Electric Power Systems on SCE's Transmission System.

L. SUBSYNCHRONOUS INTERACTION EVALUATIONS

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

For projects interconnecting at the 220 kV voltage level and above in close electrical proximity of series capacitor banks on the transmission system a study will need to be performed to evaluate the SSI between Generating Facilities and the transmission system. Given the project location it will not be necessary to perform these evaluations.

M. ENVIRONMENTAL EVALUATION, PERMITS, AND LICENSING

Please see Appendix K of the Area Report.

N. AFFECTED SYSTEMS COORDINATION

Please see Section H of the Area Report.

O. 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. **The study does not include analysis related to the power output rate of change that may occur due to the following or other conditions:**

   - System morning start up for solar systems. That is when each morning the generating facility commences to generate and export electrical energy to the electric system.
   - Cloud Cover. Solar generating facilities have significant generation output variation (Variability) which can have an impact on electric system voltage profiles.
   - 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 electric system as well as SCE's electric 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 generation, changes in the electric system topology, or other changes in the electric system.

3. **IC's Technical Data**

   The study accuracy and results for the QC9 Phase I Study are contingent upon the accuracy of the technical data provided by the each IC for their respective IR(s). Any changes from the data provided as allowed by the tariff would need to be submitted in Appendix B within 5 business days from the Phase I results meeting. Any changes that extend beyond the modifications allowed in Appendix B submission will need to be evaluated following the Material Modification Assessment to determine if such change results in a material impact to queued-behind generation requests. These change(s) would only be allowed if it is determined that there is no material impact to queued-behind requests.

4. **Study Impacts on Neighboring Utilities**

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

5. **Use of Distribution Provider Facilities**

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

6. **Distribution Provider's Interconnection Handbook**

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

7. **Western Electricity Coordinating Council (WECC) Policies**

   The IC shall be required to adhere to all applicable WECC policies including, but not limited to, the WECC Generating Unit Model Validation Policy.

8. **System Protection Coordination**

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

9. **Standby Power and Temporary Construction Power**

   The Phase I 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 Distribution Provider to receive and pay for such retail service.

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

    The estimated licensing cost and durations applied to this Project are based on the Project scope details presented in this Phase I study. These estimates are subject to change as the Project's environmental and real estate elements are further defined. Upon execution of the GIA, additional evaluation including but not limited to preliminary engineering, environmental surveys, and property right checks may enable licensing cost and/or duration updates to be provided.

11. **Network/Non-Network Classification of Telecommunication Facilities**

    The cost for telecommunication facilities that were identified as part of the IC's Interconnection Facilities was based on an assumption that these facilities would be sited, licensed, and constructed by the IC. The IC will own, operate, maintain, and construct diverse telecommunication paths associated with the IC's generation tie line, excluding terminal equipment at both ends. In addition, the telecommunication requirements for the RAS were assumed based on tripping of the generator's breaker in lieu of tripping the circuit breakers at the Distribution Provider's substation. Due to uncertainties related to telecommunication upgrades for the numerous projects in queue ahead of Phase I, telecommunication upgrades for higher queued projects were not considered in this study. Depending on the outcome of interconnection studies for higher queued projects, the telecommunication upgrades identified for Phase I may be reduced. Any changes in these assumptions may affect the cost and schedule for the identified telecommunication facilities.

12. **Ground Grid Analysis**

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

13. **Applicability**

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

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.caiso.com/participate/Pages/NewResourceImplementation/Default.aspx

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

NRI Guide:
http://www.caiso.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:

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.

16. ISO Market Dispatch

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

17. 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:
Allocation of Network Upgrades for Cost Estimates and Maximum Network Upgrade Cost Responsibility

Queue	WDT1395

Row Labels	NU Total Constant (2016 $k)	Incremental MW	Cost Rate (2016 $k/MW)	Project MW	Allocated Cost (2016 $k)	Allocated Cost (Escalated $k)
Build 2nd Vincent – Mesa 500kV line	$520,327	4549	$114	40	$4,575	$5,852
Grand Total					**$4,575**	**$5,852**

Attachment 4:

Distribution Provider's Interconnection Handbook

Preliminary Protection Requirements for Interconnection Facilities are outlined in the Distribution Provider's Interconnection Handbook (separate document)

Attachment 5:
Short-Circuit Duty Calculation Study Results
Please refer to the Appendix H of the Area Report

Attachment 6:
Interconnection Customer Provided Project Dynamic Data

[redacted]

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

Attachment 8:
Subtransmission Assessment Report
Please refer to separate document