Appendix A – WDT1388

[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) interconnecting to the California ISO Controlled Grid. The Project requested a Point of Interconnection (POI) at Southern California Edison Company's (SCE) Faro 12 kV Circuit served out of Johanna Substation, located in Santa Ana, CA. The IC elected Full Capacity Deliverability Status (FCDS) for the Project. The IC desires an In-Service Date (ISD) of October 10, 2019 and a Commercial Operation Date (COD) of December 31, 2019. 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 Johanna 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. Distribution system impacts caused by the Project.
2. System reinforcements necessary to mitigate the adverse impacts caused by the Project under various system conditions.
3. A list of required facilities and a good faith estimate of the Project's cost responsibility and time to construct[1] these facilities. Such information is provided in Attachment 1 and Attachment 2 as separate documents in the Appendix A Project report package.

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

Consequently, the report also discloses the adequacy of SCE's Distribution System to support the charging aspects of the charging facilities, identifies system limitations that may restrict the charging facility's ability to charge during certain demand conditions, and provides a high-level explanation of potential exposure to charging restrictions on the distribution system in addition to identifying distribution system improvements, which would mitigate such restrictions to charging. The energy storage device will be charged from the grid.

[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.

[2] Charging is defined as when the Project draws energy from the grid to "charge" the Project-associated charging facilities.

All the equipment and facilities comprising the Project's Generating Facility are located in Santa Ana, California, as disclosed by the IC in its IR, as may have been amended during the Interconnection Study process, which consists of (i) [redacted] with an output of [redacted] each for a combined gross rated output of [redacted] as measured at the inverter terminals, (ii) the associated infrastructure, (iii) meters and metering equipment, (iv) appurtenant equipment, and (v) [redacted] of auxiliary loads.[3]

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. Please note the Project shall not exceed the total net output of 10.0 MW at the POI.

[3] Auxiliary loads are served by secondary feed. Secondary feed not depicted in the Figure A.1: Project Plan of Service & IC Facilities One-Line Diagram.

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 Metro Area
POI	Faro 12 kV Circuit out of Johanna Substation
Number and Types of Generators	Five (5) MW Parker Inverters for a combined installed capacity of 10.0 MW at inverter terminal
Interconnection Voltage	12 kV
Requested Maximum Project Output	[redacted]
Limited maximum Net Output at Generating Facility (High-Side of Main Transformer) to achieve requested POI Delivery	10.0 MW
Step-up Transformer(s)	[redacted]
Generator Auxiliary Load	[redacted]
Power Factor Range	Lead 0.95 / Lag 0.95
POI	Distribution Provider's Johanna 12 kV Substation
ISD	October 10, 2019
Initial Synchronization Date/Trial Operation	October 15, 2019
COD	December 31, 2019

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 installed capacity of 10.0 MW interconnecting at the Point of Interconnection through the Faro 12 kV Circuit via Johanna Substation 12 kV Bus.

2. The following facilities will be installed by SCE and **<u>are included</u>** in this Interconnection Study report:
   - Approximately 2,500 feet of 1000 JCN underground cable
   - One (1) 3 Way Gas Switch
   - One (1) new blister on existing cable trench
   - One (1) Intercept Vault
   - One (1) 5 Way Pad Mounted Gas Switch
   - One (1) Remote Controlled Switch Generation (RCSG) for isolation
   - One (1) Pad Mounted Ground Bank
   - 12 kV Primary Metering and associated wiring

- Approximately 100 feet of 2-5" ducts at Johanna Substation
- Dedicated Remote Terminal Unit (RTU)
- Substation Automation System (SAS) programming activities to support SAS point Addition
- SAS Point Addition

NOTE: Distribution Provider will install metering potential transformers (PTs) and current transformers (CTs), to be used for the Distribution Provider-owned retail and wholesale load meters. The PTs and CTs can be used for the Interconnection Customer's ISO metering.

3. The following facilities will be installed by the IC and **<u>are not included</u>** in this Interconnection Study report:
    - Ducts as required
    - Structures as required
    - 12 kV primary switchgear
    - Isolating circuit breaker
    - 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
    - The required metering cabinet
    - The required metering equipment (PTs, CTs, and CAISO meters) and metering cabinet for SCE retail and wholesale load meters.

4. Environmental Activities, Permits, Licensing

    This study assumes that SCE's level of disturbance during construction would not require development and implementation of a Stormwater Pollution Prevention Plan.

    - Internal Substation Work

      CPUC License: This study assumes that SCE's scope of work would not require a California Public Utilities Commission license.

      SCE Responsibility: The 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.

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

    - Small Field Engineering Projects

      CPUC License: This study assumes that SCE's scope of work would not require a California Public Utilities Commission license.

SCE Responsibility: 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 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/CES) 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
- 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

IC Responsibility: 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 cost 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 monitoring 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 and developing mitigation plans
- Developing environmental reports or submittals, if required

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

5. Charging Facility Considerations:
    - The Project encompasses Charging facilities. The details pertaining to the Reliability Study for the charging of the Project's charging facilities are included in this Appendix A report.
    - The load assumptions used for the Distribution Provider's Distribution System consider SCE's 2016-2025 Distribution Load Forecast and the previous two (2) years of historical data.
    - To model the hourly forecast demand performance of the Distribution Provider's Distribution System, historical year 2015-2016 B-Bank and circuit data were obtained and adjusted to reflect the worst case year within SCE's Distribution Load forecast. The use of historical data established a baseline upon which to build a comparable hourly demand performance for the worst case year in SCE's Distribution Load Forecast.
    - The IC should note that due to the dynamic nature of the Distribution Provider's distribution system, the operational limitations yielded by the charging analysis results disclosed in this report are for informational purposes only. Furthermore, the charging analysis used historical system performance information, which can only speak to past system performance. Hence, the charging analysis results cannot establish hard conditions for future real time operational conditions in which the Project's charging are restricted
    - Distribution Provider's Distribution Standards and practices are in the process of being updated to address charging facilities. The proposed POS in this report may require changes to comply with the updated distribution design standards and practices.

- This study assumes that the Generating Facility will include all equipment, software, appropriate controls, and other related equipment necessary to maintain the charging facility demand profile per Distribution Provider requirements.
- Upon execution of the GIA, Distribution Provider will provide the IC with the required ramp rate[4] control parameters and other necessary information to allow the customer to develop its storage control limit.
- 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.
- A Storage Management System (SMS), which at this stage is conceptual, is under development to incorporate the increased amount of energy storage applications to SCE's Distribution System with minimal Distribution Upgrades. It is assumed that a SMS will not be available prior to the In Service Date (ISD) of the generating/charging facility. Further details will be available during the engineering and design phase of the Project. Conceptually, the SMS is a system composed of communication equipment, customer equipment, SCE equipment and logical algorithms which together will actively communicate the allowable charging limits to the customer storage project control system. The levels of allowable charging will be based on the capacity of the distribution system components at the circuit, substation and A-bank levels as to maintain safe and reliable operation of the distribution system.
- The facilities and costs to implement the SMS are included in Attachments 1 and 2. In order to ensure storage charging capabilities limits and restrictions are communicated in a timely and reliable manner, the IC is responsible for providing reliable communications and yet to be identified equipment at an agreed location within the project location. The agreed on location for communication interphase will be based on the requirements outlined within SCE's Interconnection Handbook (Telemetry section). Should the communication channel fail, the Project's operating limits will automatically revert to zero (no charging allowed) or previously determined charging schedule.
- The use of "charging" restrictions (or curtailment of charging facilities), in lieu of physical upgrades, are considered a viable alternative for this charging study provided such restriction is implemented as part of the SMS Any restrictions identified here are purely projections, and the SMS mentioned above will need to be installed as an upgrade to determine the storage demand limits for the charging facility. However, per the aforementioned section, the SMS will need to be further assessed and will only be allowed if it is ultimately determined that actual implementation is feasible for Distribution Provider's real-time system operations.
- The Project encompasses charging facilities. The details pertaining to the Power Flow Reliability Assessment Results for the charging of the Project's charging

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

facilities are included in this Appendix A report and applicable Subtransmission Assessment Report.

- The energy storage component of the Project will need to be metered separately. The IC should be prepared to install multiple sets of metering (i.e. separate sets of potential transformers & current transformers and supporting metering equipment) for the Project.

6. Other Items Considered
    - Other Potential Distribution Upgrades: The Project is dependent upon the installation of the Storage Management System (SMS). The installation of the SMS was triggered by prior queued projects which currently hold the cost responsibility for the upgrade. In the event that: (i) the interconnection requests for one or more of such projects are withdrawn; (ii) any of the interconnection agreements for such projects are terminated prior to the in-service date of such distribution upgrade; or (iii) it is determined by the Distribution Provider that some or all of such distribution upgrade currently assigned to earlier-queued projects are no longer required by such projects but are required for the Project at hand, then the Interconnection Customer may be responsible for the costs of other potential distribution upgrade(s). The Interconnection Customer's cost responsibility for any distribution upgrade costs not already identified in this study report will be reflected in an addendum report or GIA amendment. Therefore, in the event that prior queued projects do not execute a GIA and the SMS is still required, the Project may be allocated up to 100% responsibility related to the initial programming (backbone) of the SMS.

7. 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.

C. RELIABILITY STANDARDS, STUDY CRITERIA AND METHODOLOGY

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

1. Discharging Analysis Planning Criteria

   Refer to above Section B: Study Assumptions for the reliability standards, study criteria and methodology applied in this study.

2. Charging Analysis Planning Criteria

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

- The thermal rating of any conductor, connector, or apparatus shall not exceed 100% of its normal rated capacity 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) conditions.
- 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 conditions.
- 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 energy storage system facility is assumed to be within WDAT Tariff requirements of 0.95 lagging or leading.
- Expected loading on the distribution system as projected by SCE's internal 2016-2025 distribution system forecast is utilized for the purposes of this charging analysis.
- Charging facilities connected to the distribution system are analyzed offline (pre-project) and online (post-project) during peak demand conditions, as well as during absolute minimum demand conditions, as to determine the worst case scenario between these two "book-ends" of demand.

D. POWER FLOW RELIABILITY ASSESSMENT RESULTS

Discharging 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. The details of the analysis are provided in the Metro Area Report.

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

The group study 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. The details of the analysis are provided in the Johanna Subtransmission Assessment Report.

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

1. Thermal Overloads

The study found that the Project contributes to the following facility overloads with all existing facilities and prior queued upgrades. The details of the analysis as well as the recommended mitigations are provided as follows:

I. Base Case
   - No thermal overloads have been identified

II. Single Contingency
   - No thermal overloads have been identified

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.

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 required 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 VAR schedule provided by the Distribution Provider. The Distribution Provider will determine if the VAR schedule is necessary based on future re-arrangements of the Distribution Provider's Distribution System.

4. **Protection**
   - Johanna 12 kV Substation:
     - The addition of the Project did not trigger adjustment of the relay settings of the transformer banks

5. **Relevant Project Notes**
Under emergency N-1 conditions (loss of a B-Bank, or loss of the [redacted] no thermal overloads were triggered by the Project.

6. **Required Mitigations**
Per the WDAT, the Project is required to provide [redacted] power factor regulation capability at the POI, in addition to upgrades mentioned in Section B.2, the following Distribution Upgrade(s) (DUs) to mitigate the power flow impacts of the Project described above under Voltage Performance.

   a. Substation Automation System (SAS) programming activities to support SAS point Addition to monitor MW.

   Refer to Attachment 1 and Attachment 2 for scope description and associated project cost responsibility of these Distribution Upgrade(s).

Charging 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. The details of the analysis are provided in the Metro Area Report.

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

The group study 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. Further details are provided in the Johanna System Subtransmission Assessment Report.

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

1. Thermal Overloads

The study found that the Project contributes to overloads on the following facilities listed below. The details of the analysis as well as the recommended mitigations are provided as follows:

I. Base Case
- No thermal overloads have been identified

II. Single Contingency
- Under emergency (N-1) conditions (loss of circuit or B-bank), SCE may deem it necessary to isolate this project during N-1 conditions until the Distribution System returns to normal conditions.

2. Power Flow Non-Convergence

There were no non-convergence issues identified with the inclusion of the Project at the required power factor range.

3. Voltage Performance

a. Individual Project 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 POCO at a power factor within the range of [redacted] Additionally, the generation system must be designed to accommodate a Voltage and/or VAR schedule provided by the Distribution Provider. The Distribution Provider will determine if a Voltage and/or VAR schedule is necessary based on future re-arrangements of the Distribution Provider's system.

b. Distribution System Power Factor Requirements – 33 kV or below

The [redacted] out of Johanna 66/12 kV Substation is not expected to experience a voltage rise that exceeds Rule 2 requirements with the Project in service.

4. Protection

- Johanna 66/12 kV Substation:
  - No additional protection requirements are triggered by the charging aspect of the Project.

- [redacted]
  - No additional protection requirements are triggered by the charging aspect of the Project.

5. Charging Restrictions

I. System Condition

- Base Case

  Based on the assessment of the system loading projections, there were no charging restrictions identified for the Project. The charging restrictions are a function of system loading conditions and load forecast. Modification or adjustments to the charging restrictions will be evaluated as required by SCE to maintain its distribution system within operating criteria. These modification or adjustments reviews may be completed on yearly basis, at any time when significant load is added to the distribution system or as determined necessary by SCE. These reviews may trigger the storage charging capabilities. Assuming adjusted 2016-2017 historical demand patterns adequately represent worst case year within SCE's Distribution Load forecast performance, the evaluation identified the need to restrict charging during portions of the day, month, and year. The need to restrict charging will increase over time as normal system demand continues to grow. See tables below for projected charging forecast.

- Single Contingency

  - Loss of B bank at Johanna 66/12 kV Substation:

  At this time, the study showed that there is available capacity at the substation with Project charging restrictions.

  Note: Under emergency N-1 conditions (loss of a B-Bank, or loss of the [redacted] no thermal overloads were triggered by the Project. However, due to the dynamic distribution system conditions and configurations, the Distribution Provider may deem it necessary to open the source gas switch to remove the Project from the Distribution Provider's Distribution System, in order to reduce bank loading or line loading to its normal ratings. Once the Distribution Provider's system is restored to normal, the Distribution Provider would then close the gas switch and the generation system can resume normal operation.

II. Additional Factor(s) to Restrictions

It is important to note that the increased risk of restrictions is not only based on load forecast, load growth, and demand performance assumptions but are also based on the feasibility of implementing real-time system information and ability to use the SMS as a means of maximizing the loading limit that can be accommodated. The SMS would limit amount of charging to stay within the limits of the Distribution Provider's equipment ratings.

The subsequent tables provide an estimate of number of hours that the charging facility may be restricted to charge at a given demand value in a given month per the adjusted hourly demand. This is subject to change as loading on the system changes. Note that charging restrictions illustrated in the tables below are for the respective areas within the distribution system (i.e. distribution substation or distribution circuit). The Project's charging restrictions will be based on the most restrictive area and based and real time information from the distribution and transmission system.

Table 2-1: Johanna 66/12 kV Substation
# of Charging Hours Restricted for Energy Storage System

[redacted]

Table 2-2: Johanna 66/12 kV Substation
B-Bank Hourly Demand Performance Bank #6

[redacted]

Table 2-3: Charging Hour Restrictions of Day for Energy Storage System

[redacted]

Table 3-1: Faro 12 kV Circuit
# of Charging Hours Restricted for Energy Storage System

[redacted]

Table 3-2: Faro 12 kV Circuit
Hourly Demand Performance

[redacted]

Table 3-3: Faro 12 kV Circuit
Charging Hour Restrictions of Day for Energy Storage System

[redacted]

6. Required Mitigations

The Project is required to provide [redacted] power factor regulation capability at the POI, in addition to the following Distribution Upgrade(s) to mitigate the power flow impacts of the Project described above under Voltage Performance.

a. Storage Management System (SMS)

The Storage Management System provides monitoring of specified/identified loading conditions to which the charging component of the facilities contribute. From the monitored data the SMS calculates charging capacity limits and those limits are transmitted to the IC's control system. It is expected that the IC's control system maintain the charging level to the level provided. If the IC does not comply with the provided limits the Distribution Provider will mitigate this condition at its discretion including, but not limited to disconnecting the IC from the grid utilizing the dedicated remote automated switched installed exclusively for the storage facility.

Refer to Attachment 1 and Attachment 2 for scope description and associated project cost responsibility of these Distribution Upgrade(s).

Please note that the ability to charge at any time may not be attainable even when customers agree to pay the cost to implement substation and/or distribution system upgrades. This is because the increase in load, system modification or changes in load profiles will cause limitations on other parts of the distribution and transmission system to be exceeded.

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.

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

   <u>Generation Step-Up and Pad-Mount Transformers</u>
   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 responsibility to finance short-circuit related Reliability Network Upgrades identified through a Group Study shall be assigned to all IRs in that Group Study pro-rata on the basis of SCD contribution of each Generating Facility.

   Please refer to the Area Report for the Phase I breaker evaluation, 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.

F. 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]. 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 Transmission System.

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[5] The current CAISO 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 CAISO's compliance filing to FERC Order 827.

G. DELIVERABILITY ASSESSMENT RESULTS

1. **On Peak Deliverability Assessment**
   The Project does not contribute to any deliverability issues.

2. **Off- Peak Deliverability Assessment**
   The Project does not contribute to any off-peak deliverability issues.

3. **Required Mitigations**
   No Delivery Network Upgrades are required.

H. 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.

I. COST AND CONSTRUCTION DURATION ESTIMATES

To determine the cost responsibility of each generation project in Phase I, the CAISO 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.

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, CAISOs Annual Reassessment and the CAISOs Transmission Planning Deliverability (TPD)[6] 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 CAISO 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[7] 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 CAISO 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

[6] Transmission Plan Deliverability: Deliverability supported by the CAISO's Transmission Plan
[7] The TPD Allocation Process is estimated to be completed in April 2018. The actual date may vary

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 October 10, 2019 cannot be met due to the estimated 27-month timeline identified for the Plan of Service (POS) facilities and installation of the Storage Management System (SMS) required to interconnect the Project. 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[8] 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.

J. 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.

K. ENVIRONMENTAL EVALUATION, PERMITS, AND LICENSING

Please see Appendix K of the Area Report.

L. 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.

[8] 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%)

- 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 Attachment B within 5 business days from the Phase I results meeting. Any changes that extend beyond the modifications allowed in Attachment 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 CAISO. 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 CAISO. 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 CAISO 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. **Future Charging Restrictions**
Charging restrictions not identified in this study may occur in the future if the underlying operating assumptions prove to be significantly different than the conditions evaluated in this study.

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

18. 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

None identified in the QC9 PI study for the Project.

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:
Not Used

Attachment 7:
Not Used

Attachment 8:
Subtransmission Assessment Report
Please refer to separate document