Appendix A – WDT1274

[redacted]

Queue Cluster 8 Phase I Report

Revision #1

April 11, 2016

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

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Attachments:

1. Interconnection Facilities, Network Upgrades, and Distribution Upgrades
2. Escalated Cost and Time to Construct for Interconnection Facilities, Reliability Network Upgrades, Delivery Network Upgrades, and Distribution Upgrades
3. Allocation of Network Upgrades for Cost Estimates and Maximum Network Upgrade Cost Responsibility
4. Distribution Provider's Interconnection Handbook
5. Short Circuit Duty Calculation Study Results (see Appendix H of the Area Report)
6. Not Used
7. SCE Northern Hemisphere Import Nomogram

Interconnection Study Document History

Project No.	Project Name	No	Date	Document Title	Description of Document
WDT1274	[redacted]	2	4/11/2016	Queue Cluster 8 Phase I Report Revision #1	Updated Attachment 1, Attachment 2 and Attachment 3.
WDT1274	[redacted]	1	1/15/2016	Queue Cluster 8 Phase II Appendix A Final Report	Final Phase I interconnection study report

A. Introduction

[redacted] the Interconnection Customer (IC), has submitted a completed Interconnection Request (IR) to Southern California Edison Company (SCE) for their proposed [redacted] The project requested a Point of Interconnection (POI) at Distribution Provider's [redacted] located in [redacted] The IC elected that the Project be Full Capacity Deliverability Status (FCDS), and desires an In-Service Date (ISD) of November 01, 2017 and a Commercial Operation Date (COD) of January 1, 2018. Such dates are specified in the Project's IR submittal. Actual ISD and COD will depend on detailed design, engineering, and construction requirements to interconnect for the Project to the Distribution Provider's Distribution System; after the Generator Interconnection Agreement (GIA) has been executed and filed at the Federal Energy Regulatory Commission (FERC) for acceptance.

In accordance with FERC approved CAISO Tariff Appendix DD Generator Interconnection and Deliverability Allocation Procedures (GIDAP), the Project was grouped with Queue Cluster 8 (QC8) Phase I projects to determine the impacts of the group as well as impacts of the Project on the CAISO Controlled Grid.

An Area Report has been prepared separately identifying the combined impacts of all projects in the area on the CAISO Controlled Grid. This report focuses only on the impacts or impact contributions of the Project at the local Distribution system, and it is not intended to supersede any contractual terms or conditions specified in a GIA.

The report provides the following:

1. 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 [redacted] that required additional analysis be performed to evaluate the impacts of [redacted] These analyses focused on the charging[2] aspects of the [redacted] and consider varying levels of system demand with minimal generation dispatch within the local Distribution System.

Consequently, the report also discloses the adequacy of SCE's Distribution System to support the charging aspects of the [redacted] identifies system limitations that may restrict the

[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 Generator Interconnection Agreement, receipt of: all required information, funding, and written authorization to proceed from the IC as will be specified in the Generator Interconnection Agreement to commence the work.

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

[redacted] ability to charge during certain demand conditions, and provides a high-level explanation of potential exposure to charging restrictions on the distribution system.

All the equipment and facilities comprising the Project's Generating Facility are located in [redacted] as disclosed by the IC in its IR, as may have been amended during the Interconnection Study process, which consists of [redacted] (i) the associated infrastructure, (ii) meters and metering equipment, and (iii) appurtenant equipment.

The Project shall consist of the Generating Facility and the IC's Interconnection Facilities as illustrated below in Figure A.1, as well as, Figure A.2 is a map that illustrates the location of the Project. Similarly, the Project information is summarized in Table A.1 below. The Project shall not exceed the total net output of [redacted] at the Point of Change of Ownership (POCO).

Figure A.1: One-Line Diagram

[redacted]

Figure A.2: Project Location Map

[redacted]

Table A.1 Project General Information

Project Location	[redacted]
Distribution Provider's Planning Area	SCE NOL Area
Number and Types of Generators	[redacted]
Interconnection Voltage	[redacted]
Maximum Generator Output	[redacted] (gross)
Generator Auxiliary Load	0.0 MW
Maximum Net Output at Generation Facility	[redacted]
Power Factor Range	Lead 0.95 / Lag 0.95 at POI per interconnection application
Step-up Transformer(s)	[redacted]
POI	[redacted]
IC Requested COD	January 01, 2018

B. Study Assumptions

For detailed assumptions regarding the group cluster analysis at the transmission level, please refer to the applicable QC8 Phase I Area Report. Below are the assumptions specific to the Project.

1. The following is the Plan of Service (POS) assumed for the Project in the Phase I Study:

   The Project was modeled as with a net output of [redacted] at the Generation Facility with its POI to the SCE Distribution System at the [redacted] via a line extension to the applicant owned [redacted] at the POCO.

2. The following Facilities will be installed by SCE with the assumption that WDT 315 has completed the interconnection and **<u>are included</u>** in this Phase I Study:

- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted] Primary Metering, current transformers, potential transformers, and Associated Wiring
- [redacted]

- Substation Automation System Point Addition
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- Adjust relay settings on existing Transformer Bank relays
- Adjust relays settings on existing [redacted]
- The required revenue metering cabinet and retail and wholesale load meters

NOTE: SCE will install metering voltage and current transformers to be used for the Distribution Provider owned retail load meters. The voltage and current transformers can be used for the customer CAISO metering.

3. The following Facilities will be installed by SCE and paid for by the Interconnection Customer under WDAT 1274 in the event that WDAT 315 withdrawals or does not executed a GIA prior to WDAT 1274 comes online:

- Install [redacted]
- [redacted]
- [redacted] Primary Metering, CTs, PTs, and Associated Wiring
- [redacted]
- Substation Automation System Point Addition
- [redacted]
- [redacted]
- Adjust relay settings on existing Transformer Bank relays

- Adjust relays settings on existing [redacted]

  1) For further details on the scope of work for WDAT 315, please refer to the Technical Assessment dated October 15, 2015

- The required revenue metering cabinet and retail and wholesale load meters

NOTE: SCE will install metering voltage and current transformers to be used for the Distribution Provider owned retail load meters. The voltage and current transformers can be used for the customer CAISO metering.

4. The following Facilities will be installed by the IC and **<u>are not included</u>** in this Phase I Study:

- Ducts as required
- Structures as required
- Isolating circuit breaker
- Protection System requirements to comply with the Distribution Provider's Interconnection Handbook
- Transformation as required
- Metering Equipment compliant with SCE Electrical Service Requirements
- CAISO metering as required

NOTE: SCE will install metering voltage and current transformers to be used for the SCE owned retail and wholesale load meters. The voltage and current transformers can be used for the customer CAISO metering.

5. The following SCE Distribution system Planning Criteria and Conditions were included in the Phase I Study:

- The thermal rating of any conductor, connector, or apparatus shall not exceed 100% of its normal rated capacity with all facilities in service (base case).
- The thermal rating of any conductor, connector, or apparatus shall not exceed 100% of its emergency rating under loss of one element (N-1) conditions.
- Operational flexibility and reliability of the Distribution system shall be maintained at all times.
- Circuit voltage profiles shall be maintained to comply within CPUC's Rule 2 requirements.
- The power factor for the new generation facility was assumed to be within WDAT Tariff requirements of 0.95 lagging or leading.

- Expected loading on the Distribution System as projected by the SCE 2015 – 2024 Distribution system plan was used.
- Distributed Generation resources connected to the Distribution System are analyzed offline and online during peak load conditions as well as during minimum daytime load conditions as to determine worst case scenario.
- The short circuit contribution from the inverter systems was determined using inverter manufacturer documents.
- The Phase I Study assumes the upgrades triggered by previously queued projects, including Rule 21 projects under CPUC jurisdiction as In-Service, are included in the base case for the Phase I projects. If any previously queued projects were to withdraw, then the Phase I projects may be subjected to the cost identified for those previously queued projects.
- Current Distribution standards are being updated to address generation interconnection systems. The proposed method of service in this report may change according on detailed design to comply with the updated Distribution design standards.
- This study assumes that the IC generating facility will include all equipment, software, and appropriate controls necessary to maintain the generator output profile per SCE requirements. The IC will be responsible for maintaining designated voltage levels under all conditions, including but not limited to the conditions identified above. Upon execution of the Generator Interconnection Agreement, SCE will provide the IC with the required ramp rate control parameters. The ramp rate controls will be a function of the generation penetration on the Distribution system, as well as SCE's Distribution System configuration (additional parameters maybe considered, as need). Changes to the ramp rate control scheme may be required as determined by increased generation, changes in the Distribution System topology, or other changes in the Distribution System.

6. CASE B Potential Upgrades to the Project:

   The Project is dependent upon the completion of WDT315. In the event that: (i) WDT315 is withdrawn; (ii) the interconnection agreements for WDT315 is terminated prior to the in-service date of the CASE B upgrades listed below; or (iii) it is determined by the Distribution Provider that some or all of the CASE B upgrades listed below; currently assigned are no longer required by WDT315 but are required for the Project at hand, then the IC may be responsible for the costs of the CASE B upgrades listed below.

   The CASE B upgrades designated to WDT1274, whom WDT315 currently holds the cost responsibility for are the following:

1) WDT315 D395 SCOPE (Distribution Upgrade - $4,715,000[3] in 2015 dollars) :

Information Technologies:
Install lightwave, channel, and associated equipment at [redacted] for the [redacted] single fiber optic cable from SCE/D395 vault into communications room at [redacted] and DWDM equipment.

Substations:
Install [redacted]

Power System Controls:
Point additions for [redacted] at [redacted] for new relays associated with the [redacted] SPS programming and testing will be performed.

Corporate Environmental Health and Safety:
Provide review, survey, licensing, and other activities related to the installation of the single fiber optic cable from SCE/D395 vault to [redacted]

Real Properties:
Acquire land rights for the fiber optic cable taps into [redacted]

2) Inyo Substation scope – Phase Shifter (Reliability Network Upgrade (RNU) - $ 20,490,000 in 2015 dollars):

[redacted]

Replace [redacted] Install [redacted] Relocate [redacted]

Corporate Environmental Health and Safety:
Provide review and activities related to the replacement of the Inyo Substation phase shifting transformer.

In the event WDT315 does not execute a GIA and the CASE B upgrades listed above are required, WDT1274 may be allocated up to 100% costs responsibility for to the CASE B upgrades listed above. Specifically, the cost responsibility for these CASE B upgrades will be transferred to WDT1274, this results in an approximate total cost estimate for Distribution

[3] This dollar value includes 35% ITCC

Upgrades in the amount of $21,062,000[3] (2015 dollars) and in an approximate total costs for RNUs in the amount of $20,490,000 (2015 dollars) for WDT1274. At that point, such costs responsibility will be reflected in an addendum report and/or GIA amendment for WDT1274.

7. Charging Termination Assumptions

Dispatch of SCE's Distribution System with connected [redacted] (existing and queued) was done in a manner that would provide for relief on the system if indeed. (Emergencies, N-1 Base case overloads, etc.) This effectively results in termination of sources such that they would not increase demand on the local distribution system.

8. [redacted] Charging Considerations

- The Project encompasses [redacted] The details pertaining to the Reliability Study for the charging of the Project's [redacted] are provided in Attachment 9 and 10, which are separate documents included in this QC8 Phase I report package.

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

- SCE's distribution standards and practices are in the process of being updated to address energy storage facilities. The proposed method of service in this report may require changes to comply with the updated distribution design standards and practices.

- This study assumes that the IC Generating Facility will include all equipment, software, appropriate controls, and other related equipment necessary to maintain the [redacted] demand profile per SCE requirements.

- Upon execution of the GIA, SCE will provide the IC with the required ramp rate[4] control parameters. The ramp rate controls will be a function of the demand on the distribution system, as well as SCE's Distribution System configuration (additional parameters maybe considered, as necessary).

- Ongoing changes to the ramp rate control scheme may be required as determined by changes in the distribution system topology or other changes in the distribution system. However, typical ramp rates for facilities connected to SCE's Distribution System are 10% of nameplate rating, per minute.

- In order to ensure limits are communicated in a timely and reliable manner, the IC is responsible for providing reliable communications between the Project and the Point of Interconnection to transmit the required telemetry data as outlined in the Interconnection Handbook. Should the communication channel fail, the Project's operating limits will automatically revert to zero (no charging allowed).

[4] It is assumed that ramp rates for each [redacted] 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.

- Depending on the study results, the Project may need to participate in the [redacted]

- A [redacted] which at this stage is a technical concept, is under development to incorporate the increased amount of [redacted] applications to SCE's Distribution System with minimal distribution upgrades. It is assumed that a [redacted] or similar system will be available prior to the In-Service Date of the [redacted] and further details will be available during the detailed engineering and design phase of the Project. The [redacted] will actively communicate allowable Project limits under charging mode to maintain safe and reliable operation of the distribution system.

- The use of "charging" restrictions (or curtailment of [redacted] in lieu of physical upgrades, are considered a viable alternative for this charging study [5] provided such restriction is implemented as part of the [redacted] Any restrictions identified here are purely projections, and the [redacted] mentioned above will need to be installed as an upgrade to determine the RDL's for the [redacted] However, per the aforementioned section, the [redacted] will need to be further assessed and will only be allowed if it is ultimately determined that actual implementation is feasible for SCE's real-time system operations.

- The [redacted] of the Project will need to be metered separately from the retail load components. The IC should be prepared to install multiple sets of metering (i.e. separate sets of voltage and current transformers and supporting metering equipment) for the Project. Additionally, the Project may also need to connect the [redacted] to a dedicated transformer.

Figure 2-1 6: Topology of SCE's Electric System

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

[6] For illustrative purposes only.

[redacted]

9. Charging Analysis Load Assumptions

The load assumptions used for SCE's Distribution System considers SCE's 2015 – 2024 Distribution Load Forecast and the previous two (2) years of historical data.

To model the hourly forecast demand performance of SCE's Distribution System, historical year 2014-2015 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. Shown below is the adjusted SCE [redacted] hourly demand performance.

Figure 2-2: [redacted] Hourly Demand Performance

[redacted]

Figure 2-3: [redacted] Hourly Demand Performance

[redacted]

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.

1. Discharge Analysis Planning Criteria

   Refer to Section B.1 SCE Distribution study assumptions above 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 II Study are as follows:

- The thermal rating of any conductor, connector, or apparatus shall not exceed 100% of its normal rated capacity[7] 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 Interconnection Customer (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 [redacted] 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 2015 - 2024 distribution system forecast is utilized for the purposes of this charging analysis.

- [redacted] 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.

- The short circuit contribution analysis is not required for the charging study of energy storage facilities, as it was performed in the generation study described in Appendix A.

- The charging study associated with the Phase I Report assumes the upgrades triggered by previously queued projects, including Rule 21 projects under CPUC jurisdiction as In-Service, are included in the base case for the Phase I projects. If any previously queued projects were to withdraw, then the Phase I projects may be subjected to the cost identified for those previously queued projects.

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

D. Power Flow Reliability Assessment Results

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

The reliability group study indicated that the Project does not contribute to any overloads/non-convergence problems on the Transmission System of the area.

However, the deliverability group study indicated that the Project contributes to overload problems on the Transmission system of the area. Consequently, the Project got allocated costs for the following Area Delivery Network Upgrade(s):

- [redacted]
- [redacted]

Refer to the: Deliverability Assessment Results Section G below, Area Report, Attachment 1, and Attachment 2 for additional information, scope, and associated project cost responsibility.

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

The group study indicated that the Project contributes to overloads/ or non-convergence problems on the Subtransmission system of the area. Consequently, the Project got allocated costs for the following Subtransmission Upgrade(s):

- Add Project to [redacted]

Refer to the Area Report, Attachment 1, and Attachment 2 for additional information, scope, and associated project cost responsibility.

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

1. Thermal Overloads

The details of the analysis and overload levels are provided in the area study.

- Category "P0" (All facilities in service, N-0)
    - [redacted]
        - The addition of the Project will cause a thermal overload on the substation banks of approximately 109 % of the Bank's normal rating.
    - [redacted]
        - None
- Category "P1" (loss of a single element, N-1)
    - [redacted]

- None

- [redacted]
  - None

2. Power Flow Non-Convergence

   There were non-convergence issues identified with the inclusion of the Project due to the limited system capacity.

3. Voltage Performance

   The Project is required to provide power factor regulation capability (0.95 lead/lag at POI) to alleviate power flow non-convergence and maintain the Transmission transfer capability.

4. Protection

   - [redacted]
     - The addition of the Project triggered adjustment of the relay settings of the Transformer Banks
   - [redacted]
     - The addition of the Project triggered adjustment of the relay settings on the [redacted]

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. However, due to the dynamic distribution system conditions and configurations, SCE may deem it necessary to open the source to remove the Project from SCE's distribution system. Once the SCE system is restored to normal, SCE would then close in the source and the generation system can resume normal operation.

6. Required Mitigations

The Project is required to provide 0.95 leading/0.95 lagging power factor regulation capability at the POCO, in addition to the following Distribution Upgrade(s) to mitigate the power flow impacts of the Project described above under Voltage Performance.

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

3) Charging Analysis of 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.

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

The group study indicated that the Project contributes to overloads/non-convergence problems on the (66 kV and 115 kV) Subtransmission System of the area. Consequently, the Project has been allocated a [redacted] to help mitigate the power flow impacts on the Subtransmission System. Further details are provided in section III below.

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

1. Thermal Overloads

The group study indicated that the Project contributes to the following facility overloads or non-convergence problems. The details of the analysis and overload levels are provided in the area study.

- Category "P0" (All facilities in service, N-0)
    - [redacted]
        - None
    - [redacted]
        - None
- Category "P1"" (loss of a single element, N-1)
    - [redacted]
        - None
    - [redacted]
        - None

- 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, SCE may deem it necessary to open the source Operational Control Switch to remove the Project from SCE's Distribution system, in order to reduce bank loading or line loading to its normal ratings. Once the SCE system is restored to normal, SCE would then close the OCS and the generation system can resume normal operation.

7. Power Flow Non-Convergence

There were no non-convergence issues identified with the inclusion of the Project due to the limited system capacity.

8. Voltage Performance

- 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 0.95 leading and 0.95 lagging. Additionally, the generation system must be designed to accommodate a VAR schedule provided by SCE. SCE will determine if the VAR schedule is necessary based on future re-arrangements of SCE's system.

- Distribution System Power Factor Requirements – 34.5 kV or below

The [redacted] out of [redacted] s not expected to experience a voltage rise that exceeds Rule 2 requirements with the Project in service.

9. Protection

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

10. Charging Restrictions

- System Condition

    i. Base Case

    Based on the assessment results, there were charging restrictions identified for the Project. However, charging restrictions may become necessary for the Project in the future. Assuming adjusted 2014-2015 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

    ii. Emergency

    1. B-Bank

    At this moment in time, there is enough B-Bank capacity to allow the Project to charge.

    2. Distribution

There were no emergency overloads identified on the [redacted] because under emergency conditions, this distribution circuit will be de-energized resulting in disconnection of the Project(s). Additionally, due to the dynamic distribution system conditions and configurations, SCE may deem it necessary to disconnect the Project under N-1 conditions on other distribution circuits until the distribution system returns to normal conditions.

- 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 automatic control and ability to use the [redacted] as means of increasing the loading limit that can be accommodated. The [redacted] would need to result in the automatic shutdown of [redacted] operation upon loss of one B-Bank and with possibility of utilizing the [redacted] to limit amount of charging to stay within the limits of SCE's equipment ratings.

The assessment includes an hourly evaluation. Utilizing the adjusted hourly demand performance shown above in Figure 2-2, the number of hours the [redacted] is restricted to charge at a given demand value in a given month are shown below. 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). However, it should not be misinterpreted that the Project is not restricted for a specific time or for a certain number of hours only based on these tables alone. The Project's charging restrictions will be based on the most restrictive conditions from the distribution circuit to the transmission system.

Table 2-1: [redacted]
# of Charging Hours Restricted for [redacted]

[redacted]

Table 2-2: [redacted]
Charging Hour Restrictions of Day for [redacted]

[redacted]

Table 3-1 [redacted]
# of Charging Hours Restricted for [redacted]

[redacted]

Table 3-2: [redacted]

Charging Hour Restrictions of Day for [redacted]

[redacted]

11. Relevant Project Notes

In the event of an N-1 condition (loss of a B-Bank), SCE would send a signal through the [redacted] that will require the [redacted] to be de-energized to stop charging. Once the distribution system is restored to normal, SCE would then send a signal to the IC so that they can resume normal operation.

12. Required Mitigations

The Project is required to provide 0.95 leading/0.95 lagging 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.

a. [redacted]

The [redacted] is needed for loss of a B-bank transformer or the [redacted] The [redacted] provides continuous monitoring of specified/identified contingencies in which the charging/negative generation component of [redacted] contribute to. From the monitored data of both SCE facilities & IC facilities calculated charging capacity limits are generated and transmitted to the IC to stay within. If the IC does not comply with the provided limits SCE will mitigate for the identified contingencies at its discretion.

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

Please note that operational flexibility to charge at any time may not be attainable even with substation and distribution system upgrades due to limitations that may exist further upstream on SCE's Transmission systems. Furthermore, the results included utilize historical data to make a projection of possible charging profiles. As is typically the case with utilizing historical data to make projections, past performance is not guaranteed to be an indicator of future performance. For example, this can be the case due to changes in system topology on the distribution system, which can occur more frequently than on the transmission system

E. Short Circuit Duty Results

Short circuit studies were performed to determine the fault duty impact of adding the QC8 Phase I projects to the transmission 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 QC8 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 CAISO Tariff Appendix DD.

1. Short Circuit Duty Study Input Data

The IC provided technical data for the identified inverter (specified in Section 2). If the technical data obtained from the inverter manufacturer by SCE illustrate differences in the Short Circuit Duty (SCD) parameters, then SCE utilized the manufacturer data of the inverter model specified by the IC in the application in the SCD study. SCE did utilize the parameters provided by the IC.

"Inverter Based Generation" Data for Each generation unit

Maximum Fault contribution: [redacted]

Generation Step up and Pad-Mount Transformers
Technical details are provided in Table A.1.

2. Short Circuit Duty Study Results

All bus locations where the QC8 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 QC8 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 Interconnection Requests in that Group Study pro rata on the basis of SCD of each Generating Facility.

Please refer to the QC8 Phase I Area Report for the QC8 Phase I breaker evaluation identified overstressed circuit breakers at the SCE buses, and Attachment 2 for the pro-rata allocation with corresponding estimated costs (if any) for the Project, based on SCD contribution at each location.

3. SCE Substations with Ground Grid Duty Concerns

The short circuit studies flagged for further review a total of twenty-seven (27) existing substations where the QC8 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.

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.

F. Transient Stability Evaluation

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

Refer to enclosed Area Report in the QC8 PI report package, for the QC8 PI transient stability evaluation criteria, and assessment results, respectively, at the 220 kV and above voltage level.

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

Refer to enclosed Subtransmission Assessment Report in the QC8 PI report package for the QC8 PI transient stability evaluation, criteria, and assessment results at the applicable Subtransmission voltage level (66 kV or 115 kV).

3. Area Transient Stability Results – 33 kV or below

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

G. Deliverability Assessment Results

1. On Peak Deliverability Assessment

The Project contributes to the [redacted] area constraints as shown in the NOL Area Report Section E.1 Table E.1.2.

The project also contributes to the overloads listed in the NOL Area Report Section E.1 Table E.1.1 for the following contingencies:

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

2. Off- Peak Deliverability Assessment

For off-peak condition studies, see Section D.1.1 Table D-2 and Table D-4 in the NOL Area Report.

3. Required Mitigations

For area constraints, conceptual ADNU's are proposed to increase the generation deliverability for additional details, see the NOL Area Report Section E.1.3.

For contingency concerns, the Project is required to participate in the existing [redacted]

H. Interconnection Facilities, Network Upgrades, and Distribution Upgrades

Please see **Attachment 1** for the Distribution Provider Interconnection Facilities, 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 IF 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 final 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 QC8 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' 2015 dollars and their escalation to the estimated COD year for IFs, RNUs, DNUs, and DUs which the Project was allocated cost.

For the QC8 Phase I Study, the estimated COD is derived by taking into account time requirements to complete the QC8 Interconnection Process to tender a GIA. A GIA is not scheduled to be tendered until after completion of the QC8 Phase II Studies, Reassessment and Transmission Planning Deliverability (TPD)[8] Allocation Study Process. The QC8 Phase II Study is scheduled to start on May 2016 and be completed by November 2016. Subsequently, the CAISO's Annual Reassessment effort and TPD Allocation Study does not commence until late January or early February 2017. The TPD Allocation Study is scheduled to be completed by April 2017. If the CAISO and SCE can make a determination that the TPD Allocation Study Process outcomes do not change the scope requirements, a letter will be provided at the end of April 2017[9] informing the IC that there are no changes to Network Upgrade requirements and initiating the GIA negotiation process. Otherwise, further re-assessment will be performed for the Project. Any updates to scope, cost and schedule are developed and updated Interconnection Study reports will be issued by the end of July 2017. The GIA negotiations commence after either the issuance of the letter of no change to Network Upgrade requirements at the end of April 2017 or upon issuance of the updated reports 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 proceed with the GIA negotiations. Assuming a three (3) month timeframe for GIA negotiations after the draft GIA has been issued to the IC, an executable GIA is not expected until either early August 2017 or early November 2017 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 CAISO's Reassessment Study. QC8 Phase I assumed the duration of the work element begins in December 2017, which accounts for the GIA and submittal of required funds by the IC.

Based on the above, the requested IC ISD of November 1, 2017 cannot be met due to the estimated 27 month timeline identified for the POS facilities and SPS required to interconnect the Project. Following the standard interconnection process, the ISD should be modified accordingly.

The IC should note that any LDNUs and ADNUs allocated to the Project may be assessed 35% Income Tax Component of Contribution (ITCC) pending the results of the TPD Allocation Study Process several months after the QC 8 Phase II Study Reports are released, in addition to the 35% ITCC assessed for the IF, DUs, and RNUs above the $60K/MW repayment cap allocated to the Project. For your information, Attachment 2 contains a potential ITCC estimate[10] 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-

[8] Transmission Plan Deliverability: Deliverability supported by the CAISO's Transmission Plan
[9] The TPD Allocation Process is estimated to complete in April 2017. The actual date may vary
[10] 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%) + (LDNU*35%) + (ADNU*35%) + (DU*35%)

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 Interconnection Handbook provided in Attachment 4.

K. Environmental Evaluation, Permitting, and Licensing

Please see Appendix K of the QC8 Phase I Area Report.

L. Affected Systems Coordination

Please see Section H of the QC8 Phase I Area Report.

M. 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. IC's Technical Data

The study accuracy and results for the QC8 Phase I Study are contingent upon the accuracy of the technical data provided by the IC. Any changes from the data provided could void the study results.

3. Study Impacts on Neighboring Utilities

Results or consequences of this QC8 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 CAISO Controlled Grid, and sub-synchronous resonance (SSR). Refer to Affected Systems Coordination Section of the Area Report for additional information.

4. 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 Distribution Provider facilities and property. This Interconnection Study does not include the method or estimated cost to the IC of Distribution Provider mitigation measures that may be required to accommodate any proposed crossing of Distribution Provider facilities. The crossing of Distribution Provider property rights shall only be permitted upon written agreement between Distribution Provider and the IC at 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.

5. Distribution Provider's Interconnection Handbook

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

6. Western Electricity Coordinating Council (WECC) Policies

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

7. System Protection Coordination

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

8. Standby Power and Temporary Construction Power

The QC8 Phase I Study does not address any requirements for standby power or temporary construction power that the Project may require prior to the In-Service Date of the Interconnection Facilities. Should the Project require standby power or temporary construction power from Distribution Provider prior to the In-Service Date of the Interconnection Facilities, the IC is responsible to make appropriate arrangements with Distribution Provider to receive and pay for such revenue service.

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

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

10. 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 SPS were assumed based on tripping of the generator breaker as opposed to tripping the circuit breakers at the Distribution Provider substation. Due to uncertainties related to telecommunication upgrades for the numerous projects in queue ahead of QC8 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 QC8 Phase I may be reduced. Any changes in these assumptions may affect the cost and schedule for the identified telecommunication facilities.

11. 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.

12. 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 QC8 Phase I Study for the Project. Nothing in this report is intended to supersede or establish terms/conditions specified in GIA agreed to by SCE, CAISO and the IC.

13. Process for synchronization/trial operations and commercial operations of the Project

The IC is reminded that the CAISO has implemented a New Resource Implementation (NRI) process that ensures that a generation resource meets all requirements before synchronization/trial operations and commercial operations. 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 7 months in advance of the planned initial synchronization. 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

14. Potential Changes in Cost Responsibility

The IC is hereby placed on notice that interconnection of its proposed generating facility may be dependent upon certain Network Upgrades which are currently the cost responsibility of projects ahead of the proposed generating facility in the interconnection application queue. Section 14.2.2 of the GIDAP provides that should Network Upgrades required for queued-ahead projects be included in an executed GIA (or unexecuted GIA filed at FERC) at the time of withdrawal of the earlier queued Generating Facility, and the upgrades are determined to still be needed by later queued generating facilities, the financial responsibility for such upgrades falls to the Distribution Provider. However, if the Network Upgrades required by earlier queued generating facilities are not subject to an executed GIA (or unexecuted GIA filed at FERC) the financial responsibility for such upgrades may fall to the IC. Section 14.2.2 also discusses how

Network Upgrades required by interconnection customers selecting Option (B) might be required to be reapportioned among interconnection customers selecting Option (B) in the case of withdrawals of earlier queued generating facilities. Changes in costs allocated to the IC could also arise as the result of the CAISO's reassessment process described in Section 7.4 of the GIDAP. SCE encourages the IC to review Sections 7.4 and 14.2.2 of the GIDAP for the rules and processes under which the financial responsibility might be reapportioned to the IC. Potential changes in the IC's cost responsibility resulting from application of the provisions of these Sections of GIDAP are not included in this Phase I study, nor are the potential impacts to the IC's maximum cost responsibility outlined.

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

16. Please note that SCE has made its best efforts to convey as much information 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 SCE 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 #	WDT1278					
	Total NU Cost (2015 $k)	Incremental MW	Cost Rate (2015 $k/MW)	Project MW	Allocated Cost (2015 $k)	Allocated Cost (Escalated $k)
ADNU						
Coolwater - Lugo 220kV T/LModify SPS for:N-1 of Jaspe	$365,957	462	$792	30.00	$23,763	$31,059
Lugo 500/230kV transformer bank No. 3	$126,625	969	$131	30.00	$3,920	$4,563
Grand Total					$27,684	$35,621

Attachment 4
Distribution Provider's Interconnection Handbook

Preliminary Protection Requirements for Interconnection Facilities are outlined in the Distribution Provider 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
SCE Northern Hemisphere Import Nomogram
Please refer to separate document