# Appendix A – WDT1033

[redacted]

## Queue Cluster 6 Phase II Report

**November 20, 2014**

This study has been completed in coordination with the California Independent System Operator Corporation (CAISO) per CAISO Tariff Appendix DD Generator Interconnection and Deliverability Allocation Procedures (GIDAP)

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4. Distribution Provider Interconnection Handbook
5. Short Circuit Calculation Study Results (see Appendix H of the area 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] (Project). The Project plans to have a total net output of 9 MW at its Point of Interconnection (POI) which is Southern California Edison Company's (SCE) Lauda 33 kV Circuit of out the Nelson 115/33 kV Substation, with a CAISO delivery point at the Valley 500 kV bus. The IC elected that the Project be Option B with Full Capacity Deliverability Status, and desires an In-Service Date (ISD) and Commercial Operation Date (COD) of October 1, 2016 and November 15, 2016 respectively. Such dates are specified in the Project Attachment B. Actual ISD and COD will depend on design and construction requirements to interconnect for the Project.

In accordance with Federal Energy Regulatory Commission (FERC) approved CAISO Tariff Appendix DD Generator Interconnection and Deliverability Allocation Procedures (GIDAP) of Attachment I of SCE's Wholesale Distribution Access Tariff (WDAT), the Project was grouped with Queue Cluster 6 (QC6) Phase II projects to determine the impacts of the group as well as impacts of the Project on the CAISO Controlled Grid.

The area report has been prepared separately identifying the combined impacts of all projects in the group on the CAISO Controlled Grid. This report focuses only on the impacts or impact contributions of the Project, and it is not intended to supersede any contractual terms or conditions specified in an Interconnection Agreement.

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.

All the equipment and facilities comprising the Project are located in San Jacinto, California, as disclosed by the IC in its Interconnection Request (IR), as may have been amended during the Interconnection Study process, which consists of [redacted]

The Project shall consist of the Generating Facility and the IC's Interconnection Facilities as illustrated below in Figure A. Similarly, the Project information is summarized in Table A.1 below, as well as, Figure

[1] It should be noted that construction is only part of the duration of months specified in the study, includes final engineering, licensing, etc, and other activities required to bring such facilities into service. These durations are from the execution of the Interconnection Agreement, receipt of: all required information, funding, and written authorization to proceed from the IC as will be specified in the Interconnection Agreement to commence the work

A.2 is a map that illustrates the location of the Project. The Project shall not exceed the total NET output.

Figure A.1: Project IC Facilities One-Line Diagram

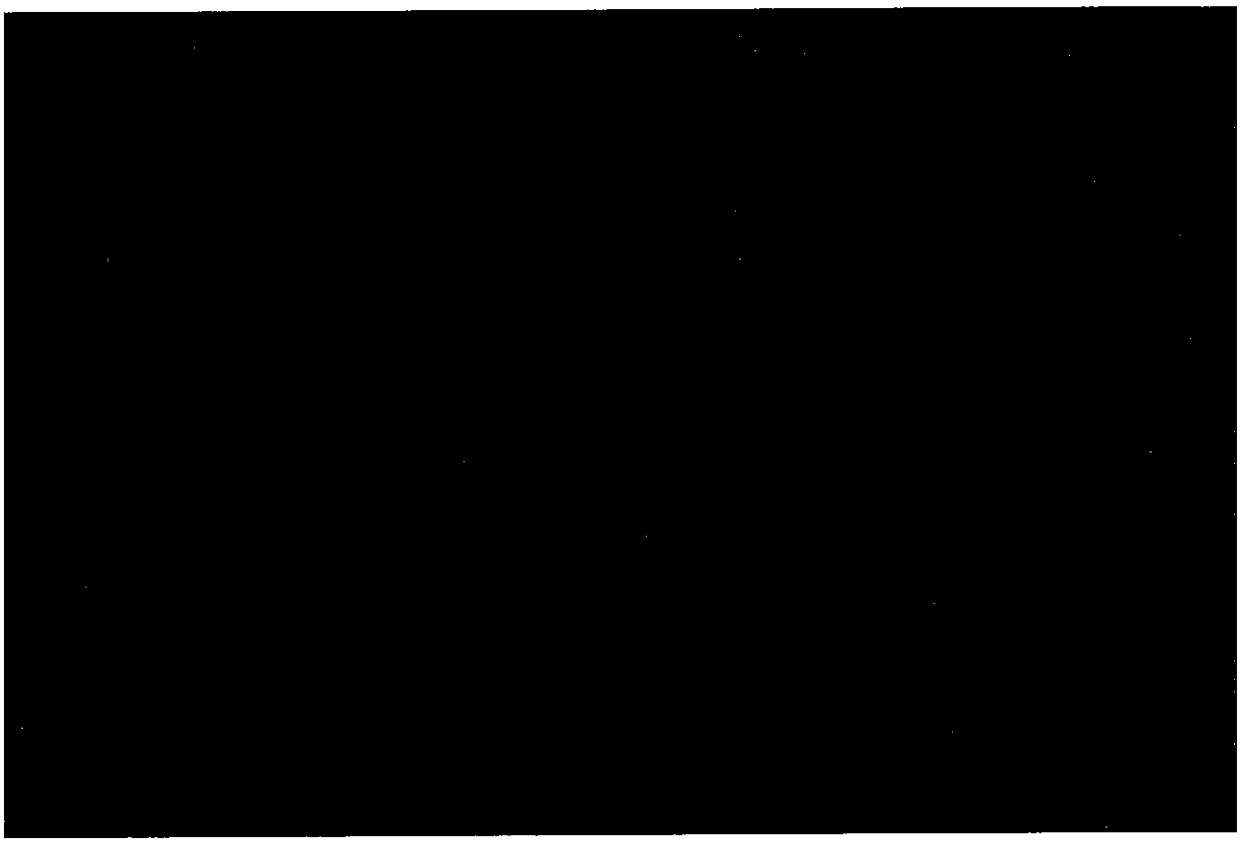
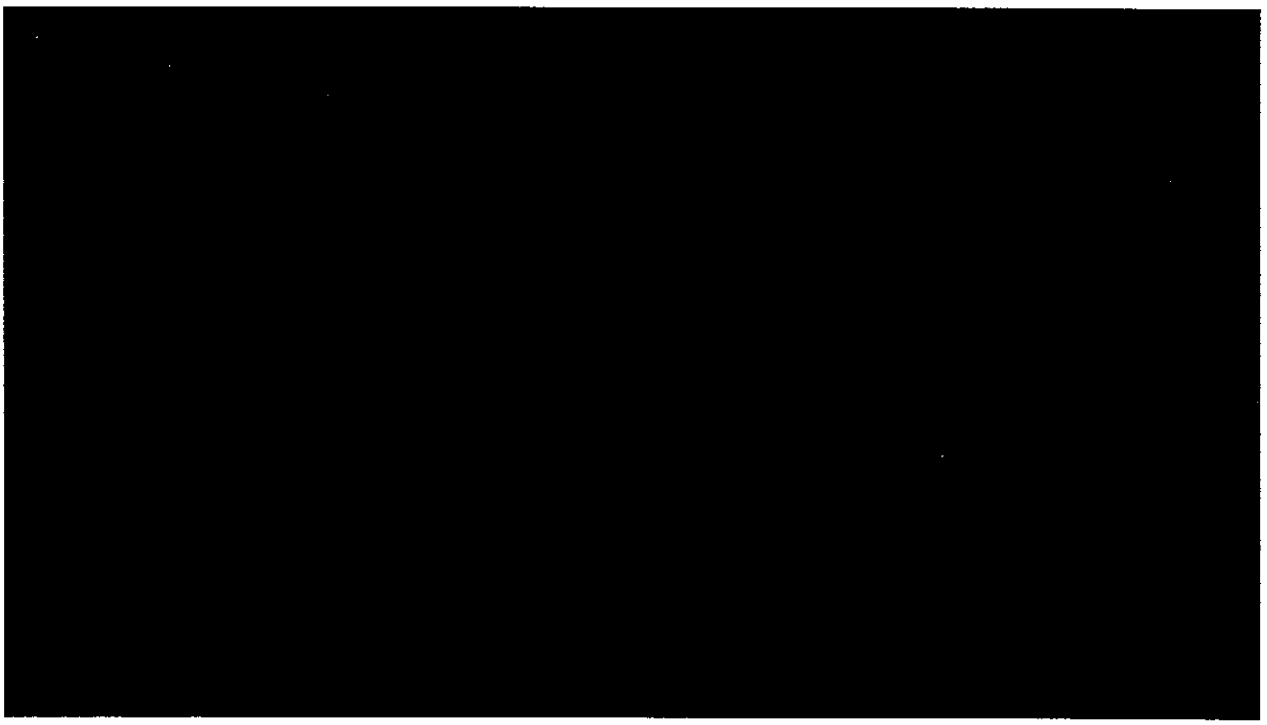


Table A.1 Project General Information

| | |
|---|---|
| Project Location | [redacted] |
| Distribution Provider's Planning Area | SCE Eastern Bulk System |
| Number and Types of Generators | [redacted] |
| Interconnection Voltage | 33 kV |
| Maximum Generator Output | 9 MW |
| Generator Auxiliary Load | 0.034 MW |
| Maximum Net Output to Grid | 8.96 MW |
| Power Factor Range | Lead 0.90 / Lag 0.90 |
| Step-up Transformer(s) | [redacted] |
| POI | Distribution Provider's proposed Lauda 33 kV Circuit out of Nelson 115/33 kV Substation |
| IC Requested COD | November 15, 2016 |

Figure A.2: Project Map



## B. Study Assumptions

For detailed assumptions regarding the group cluster analysis, please refer to the QC6 Phase II area report. Below are the assumptions specific to the Project in respect to the SCE Distribution System.

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

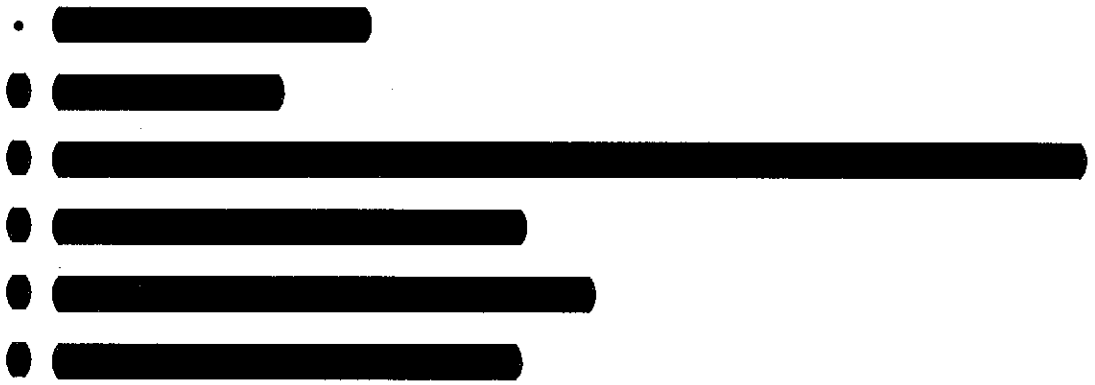
   The project was modeled as interconnecting 8.96 MW of net generation to the SCE Distribution System at the proposed [redacted] via an line extension to the applicant owned 33 kV gang operated disconnect at the point of change of ownership.

2. The following SCE Distribution System Planning Criteria and Conditions were included in the Phase II 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 2014 - 2023 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 II 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 II projects. If any previously queued projects were to withdraw, then the Phase II 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 final 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 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.

3. The following Facilities will be installed by SCE and are included in this Phase II Study:



4. The following Facilities will be installed by IC and are not included in this Phase II Study:
   - Ducts as required
   - Structures as required
   - Isolating circuit breaker
   - Protection System requirements to comply with the SCE Interconnection Handbook
   - Transformation as required
   - One (1) gang operated, overhead switch
   - Metering Equipment compliant with SCE Electrical Service Requirements
   - CAISO metering as required

5. The following additional items were considered in the Phase II Study:

   **Other Potential Distribution Upgrades:** The Project is dependent upon the completion of certain Distribution Upgrades that were triggered by prior queued projects which currently hold the cost responsibility for those Distribution Upgrades. 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 Upgrades; or (iii) it is determined by the Distribution Provider that some or all of such Distribution Upgrades 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 Distribution Upgrades. The Interconnection Customer's cost responsibility for any Distribution Upgrades not already identified in this study report will be reflected in an addendum report or GIA amendment.

## C. Reliability Standards, Study Criteria and Methodology

Refer to Section B.1 SCE Distribution study assumptions above for the Reliability Standards, Study Criteria and Methodology applied in this study.

## D. Reliability Assessment Results

### 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 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 Network Upgrades.

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

1. Thermal Overloads

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

- Substation
    i. Base Case – None
    ii. N-1 – None
- Distribution Lines
    i. Base Case – None
    ii. N-1 – None

Note: Under emergency N-1 conditions, No thermal overloads were triggered by the Project. However, due to the dynamic distribution system conditions and

configurations, SCE may deem it necessary to disconnect this project under N-1 conditions until the distribution system returns to normal conditions.

2. 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 POI 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.

   b. Distribution System Power Factor Requirements – 34.5 kV or below

      The Lauda 33 kV Circuit is not expected to experience a voltage rise that exceeds Rule 2 requirements with the Project in service. Information regarding VAR schedule is described above in Section D.2.a.

3. Required Mitigations

   The Project providing 0.95 leading/0.95 lagging power factor regulation capability at the POI is required to mitigate the power flow impacts of the Project described above. There was no distribution system upgrades assigned to the Project beyond those required for the interconnection of the project.

## E. Short Circuit Duty Results

Short circuit studies were performed to determine the fault duty impact of adding the QC6 Phase II projects to the transmission system and to ensure system coordination. The fault duties were calculated with and without the projects to identify any equipment overstress conditions. Once overstressed circuit breakers are identified, the fault current contribution from each individual project in QC6 Phase II is determined. Each project in the cluster will be responsible for its share of the upgrade cost based on the rules set forth in CAISO Tariff Appendix DD.

1. Short Circuit Duty Study Input Data

   The customer provided technical data for the identified inverter (specified in Section 2). If the technical data obtained from the inverter manufacturer by SCE illustrates 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 utilized the parameters provided by the IC. The data provided by the IC for this project did not match the technical data obtained from the inverter manufacturer.

   "Inverter Based Generation" Data for Each generation unit:

[redacted]

[redacted]

[redacted]

2. Short Circuit Duty Study Results

   All bus locations where the QC6 Phase II 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 QC6 Phase II 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 short circuit duty contribution of each Generating Facility.

   Please refer to the QC6 Phase II area report for the QC6 Phase II 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 Grids Duty Concerns

   The short circuit studies flagged SCE-owned substations beyond the Project POI with ground grid duty concerns that necessitate a ground grid study. However, the Project does not contribute to the duty concerns at hand, and did not get allocated costs for ground grid studies at the flagged SCE-owned substations.

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 Interconnection Handbook provided in Attachment 4.

## F. Reactive Power Deficiency Analysis

Reactive Power Deficiency Analysis was conducted using full loop base cases to ensure that there is enough reactive support such that the system (66 kV and above) remains in operating equilibrium, as well as operating in a coordinated fashion; through abnormal operating conditions after the QC6 Phase II projects begin operation.

5. Area Study Reactive Power Deficiency Results – 220 kV and above

   The study concluded that the reactive power requirements for the Eastern Bulk system is acceptable with the combination of all network upgrades identified with all generating facilities in QC6 Phase II in the Eastern Bulk required to be designed to provide 0.95 leading/lagging power factor at their POI.

6. 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 POI 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 Transmission system.

## G. Deliverability Assessment Results

Please see Section E in the area report.

## H. In-Service Date and Commercial Operation Date Assessment

The In-Service Date and Commercial Operation Date Assessment identified that the following facilities are required in order to provide for reliable interconnection for the Project:

1. IC Proposed Project Timelines

   The latest information provided by the IC has indicated that the requested generator ISD is October 1, 2016 and a proposed COD of November 15, 2016.

2. System Upgrade Timelines for Reliable Interconnection

The Operational Studies identified that the following facilities are required in order to provide for reliable interconnection:

a. Distribution Provider's Interconnection Facilities

See Section 1.b of Attachment 1

b. Reliability Network Upgrades

i. Plan of Service Reliability Network Upgrades – None.

ii. Special Protection System (SPS) – None.

iii. Short-Circuit Duty (SCD) Mitigation

- Pre-QC6 Phase II Projects

  The circuit breaker upgrades that were triggered by queued-ahead projects are identified in Section B.5 of the QC6 Phase II area report.

- Including the QC6 Phase II Projects

  The In-Service Date and Commercial Operation Date Assessment undertaken with the inclusion of the QC6 Phase II projects identified the required timing for circuit breaker upgrades and/or SCD mitigation(s) under six different scenarios. These scenarios were selected as the most appropriate operational study conditions and are discussed in Appendix G of the QC6 Phase II area report.

  Additionally, the In-Service Date and Commercial Operation Date Assessment results, which discuss the timing for breaker upgrades and/or required SCD mitigation(s) at each of the substations identified, are addressed in Appendix G of the QC6 Phase II area report.

  It should be noted that the timing of the need for the breaker upgrades and SCD mitigation(s) is dependent on actual timing of generation projects and corresponding upgrades materializing. The identified breaker upgrades and/or SCE mitigation(s) will not adversely impact the COD of this Project. Additional review for the identified breaker upgrades and/or SCE mitigation(s) discussed in Appendix G of the QC6 Phase II area report will be performed to evaluate timing of these breaker replacements and SCD mitigation(s) as projects execute Interconnection Agreements.

iv. Reactive Support Upgrades – None

c. Distribution Upgrades

See Section 1.b and 3 of Attachment 1

3. System Upgrades Required for Full Capacity Deliverability Status

   In order to provide for Full Capacity Deliverability Status, the following facilities are required in addition to the Reliability Network Upgrades in Section 2.(b):

   a. Triggered Delivery Network Upgrades - None

   b. Delivery Network Upgrades Triggered by Earlier Queued Projects –

      West-of-Devers 220 kV Upgrades (WOD) Project

      Along the west side of SCE's Devers Substation, the existing 5-220 kV T/Ls have been identified as the capacity delivery bottle-neck with limited transfer capability due to overloading problems. The WOD Project was proposed to upgrade the existing 5 – 220 kV T/Ls to 2B-1590 ACSR conductor and mitigate identified overloads. The completion date for this upgrade is December 31, 2020.

      Unless the WOD Project is in-service, new generation interconnections in the east of Devers area would need to be as Energy Only status. The CAISO conducts the deliverability assessment to determine the minimum deliverable capacity each year until the WOD Project is in-service.

   c. Approved Transmission Upgrades - None

   d. Transmission Upgrades outside the CAISO Controlled Grid - None

4. Interim Operational Deliverability Assessment for Information Only

   The operational deliverability assessment was performed for study years 2015 and 2018 by modeling the transmission and generation in service in the corresponding study year. For details of the transmission and generation assumption, refer to Section E of the area report.

5. Conclusion

   The requested IC In-Service Date of October 1, 2016 cannot be met due to the anticipated duration of 12 months for the facilities needed to enable Energy Only Interconnection for the Project. It should be noted that the specified duration of 12 months is from the day an Interconnection Agreement is executed, payments are made, and notice to proceed with interconnection is provided. Consequently, the ability to meet the requested In-Service Date is directly tied to the Project's timely execution of the Interconnection Agreement, funding of facilities needed for Energy Only interconnection, and issuance of notice to proceed. Therefore, in order to have a reasonable chance of meeting the requested In-Service Date, execution of the Interconnection Agreement, submittal of payments, and notice to proceed with Energy Only Interconnection needs to be completed within the time frames prescribed in the applicable Tariff.

   Lastly, please note that the requested Full Capacity Deliverability Status will not be achievable until the required system upgrades mentioned in Section G.3 above are placed into service.

## I. Interconnection Facilities, Network Upgrades, and Distribution Upgrades

Please see **Attachment 1** for the Interconnection Facilities, Reliability Network Upgrades, Delivery Network Upgrades and Distribution Upgrades allocated to the Project. Please note that SCE will not "reserve" the identified IF's for the proposed POI. The identified scope/facilities will be allocated to the project upon the successful execution of the Generation Interconnection Agreement and SCE has completed the final design and engineering of the facilities according to tariff timelines.

## J. Cost and Construction Duration Estimates

To determine the cost responsibility of each generation project in QC6 Phase II, the CAISO developed cost allocation factors (Attachment 3) for Reliability Network Upgrades, Local Delivery Network Upgrades and Area Delivery Network Upgrades. Attachment 2 provides the 'constant' 2014 dollars and their escalation to the estimated COD year for Interconnection Facilities, Reliability Network Upgrades, Delivery Network Upgrades, and Distribution Upgrades which the Project was allocated cost.

For the QC6 Phase II Study, the estimated COD is derived by assuming the duration of the work element will begin in December 2015, which accounts for the CAISO tariff scheduled completion date of the QC6 Phase II study plus: the TP Deliverability (TPD)[2] allocation, Annual Reassessment effort, and the interconnection agreement signing period and submittal of required funds by the IC.

The IC should note that any Local Delivery Network Upgrades and Area Delivery Network Upgrades allocated to the Project may be assessed 35% ITCC pending the results of the TPD allocation Process several months after the QC Phase II Study Reports are released, in addition to the 35% ITCC assessed for the IFs, DUs, and RNUs above the $60K/MW repayment cap allocated to the Project. For your information, Attachment 2 contains a potential ITCC estimate[3] based on the Phase II 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 Upgrade maximum cost responsibility. The maximum ITCC warranted by the Project will be addressed, calculated, and included during the Interconnection Agreement development phase once the IC submits the TPD Affidavit confirming the acceptance, waiver (parking), or denial of awarded deliverability assigned to the Project.

## K. SCE Technical Requirements

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

## L. Environmental Evaluation, Permitting, and Licensing

Please see Appendix K of the QC6 Phase II area report.

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[2] Transmission Plan Deliverability: Deliverability supported by the CAISO's Transmission Plan

[3] The maximum ITCC exposure applies ITCC (35%) to assigned IF and DU facilities, Network Upgrades that are not subject to transmission credits incremental to a repayment $/MW cap or an award of 0 MW TPD Allocation, and that SCE will own the facilities in question. The maximum ITCC exposure was calculated by applying the following formula: (IF*35%)+ ((RNU Costs – (Project MW * ($60k/MW)))*35%)+(LDNU*35%)+(ADNU*35%)+(DU*35%)

## M. Affected Systems Coordination

Please see Section H of the QC6 Phase II area report.

## N. 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 Plan of Service and are not sufficient for permitting of facilities. The Plan of Service is subject to change as part of final engineering and design.

2. IC's Technical Data

   The study accuracy and results for the QC6 Phase II 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 QC6 Phase II 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 QC6 Phase II 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 retail service.

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

   The estimated licensing cost and durations applied to this Project are based on the Project 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 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 QC6 Phase II, 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 QC6 Phase II 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 final 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 QC6 Phase II Study for the Project. Nothing in this report is intended to supersede or establish terms/conditions specified in interconnection agreements 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 II study, nor are the potential impacts to the IC's maximum cost responsibility outlined.

15. System Variability

This study does not include analysis related to the following system variability conditions:

- Generator ramp rate: Solar Photovoltaic generator's increasing output profile during sunrise, (i.e. system start-up)
- Generator output variability: Solar photovoltaic generator's output variability correlated with weather conditions, (i.e. cloud cover)
- Generator return-to-service: Solar photovoltaic generator's output profile following a system outage, (i.e. faulted condition)

**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

### Allocation of RNU and LDNU for Cost Estimates

| Queue # | WDT1033 | | | |
|---|---|---|---|---|
| | Upgrade Cost 2014 ($1000) | Project Allocation (%) | Project Cost 2014 ($1000) | Project Cost Escalated ($1000) |
| ⊟RNU | $1,327 | 0.000% | $0 | $0 |
| Del Amo 220kV CB upgrade | $1,327 | 0.00% | $0 | $0 |
| Grand Total | $1,327 | | $0 | $0 |

### Summary of Cost Estimates

| SAN JACINTO SOLAR 2 | QWDT1033 | |
|---|---|---|
| Total Phase I RNU & LDNU (Escalated $1000) | $ | - |
| Total Phase II RNU (Escalated $1000) | $ | - |
| Total Phase II LDNU (Escalated $1000) | $ | - |
| Total Phase II RNU & LDNU (Escalated $1000) | $ | - |
| Max RNU & LDNU Cost Responsibility (Escalated $1000) | $ | - |
| Total RNU & LDNU Cost (Escalated $1000) | $ | - |
| Deliverability Option | | B |
| Phase II ADNU (Escalated $1000) | $ | - |
| Max Net Output (MW) | | 9 |
| RNU Cost Reimbursement Limit ($1000) | $ | 540 |
| RNU Cost (Escalated $1000) | $ | - |
| RNU Non-Reimbursable Cost (Escalated $1000) | $ | - |

## Attachment 4
## Distribution Provider Interconnection Handbook

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

**Attachment 5**
**Short Circuit Calculation Study Results**
Please refer to the Appendix H of the area report

**Queue Cluster 6 Phase II - Attachment 1**
**WDAT 1033 –** [redacted]
**Interconnection Facilities, Network Upgrades, and Distribution Upgrades**

Interconnection Facilities, Network Upgrades and Distribution Upgrades

To determine the cost responsibility of each generation project in QC6, the California Independent System Operator Corporation (CAISO) developed cost allocation factors (Attachment 3) for Reliability Network Upgrades and Local Delivery Network Upgrades. The CAISO developed the $/MW cost rate for incremental Area Delivery Network Upgrades. The cost rate multiplied by the requested deliverable MW capacity provides the cost estimate for the Area Delivery Network Upgrades. The Interconnection Facilities are the sole cost responsibility of the Project. The Interconnection Facilities, Network Upgrades, and Distribution Upgrades allocated to the project are listed below[1].

**1. Distribution Provider's Interconnection Facilities.**

(a) **Interconnection Customer's Interconnection Facilities.** The Interconnection Customer shall:

(i) [redacted]

(ii) Procure and construct underground duct banks and related structures required for Distribution Provider's Interconnection Facilities and Distribution Upgrades ("Civil Construction[2]") in accordance with specifications and designs provided by the Distribution Provider.

(iii) Obtain all necessary permits and easements associated with the installation of Civil Construction.

(iv) If applicable, provide the following:

1. Completed Interconnection Customer information sheet
2. Street improvement plan(s)
3. Unique address for Point of Interconnection
4. Public right-of-way (street) base map(s) as required by the interconnection
5. Site plot plan on a 30:1 scale digital file as follows:
   a. Easements/lease agreement(s)
   b. Grading plan(s)
   c. Sewer and storm plot plan(s)
   d. Landscape, sprinkler, pedestal location(s)
   e. Complete construction of underground systems for the Distribution Provider's Interconnection Facilities and Distribution Provider's Distribution Upgrades

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[1] Such descriptions are subject to modification to reflect the actual facilities that are constructed and installed following the Distribution Provider's final engineering and design, identification of field conditions, and compliance with applicable environmental and permitting requirements.

[2] The Interconnection Customer understands and acknowledges that the Civil Construction in support of the interconnection for the Project may be classified as the Interconnection Customer-constructed Distribution Provider interconnection facilities and/or Distribution Upgrades and may require transfer of ownership pursuant to Section 3 (1) under Appendix C of the GIA. The Interconnection Customer understands and acknowledges that it shall be responsible for the ITCC and ongoing monthly Interconnection Facilities Charge and/or Distribution Upgrades charge of the portion of Civil Construction and prior to the in-service date of the Civil Construction, Interconnection Customer shall provide to Distribution Provider the final invoiced costs of the portion of Civil Construction transferred to Distribution Provider and shall be an acceptable form to Distribution Provider.

(v) Acquire an agreement from the property owner at [redacted] for the Distribution Provider to have the following:

1. The right to enter property owner's premises for any purpose connected with the Distribution Provider's Interconnection Facilities or interconnection service.
2. The right for the use of a Distribution Provider approved locking device if Interconnection Customer wants to prevent unauthorized access to Distribution Provider's Interconnection Facilities.
3. The right for safe and ready The right for safe and ready access for Distribution Provider's personnel free from unrestrained animals.
4. The right for unobstructed ready access for Distribution Provider's vehicles and equipment to install, remove, repair, and maintain its Interconnection Facilities.
5. The right to remove Distribution Provider's Interconnection Facilities after termination of interconnection service.

(vi) Telemetry.

In accordance with specifications provided by the Distribution Provider, provide the following in compliance with the telemetry requirements of the Interconnection Handbook:

a. Allow the Distribution Provider to review and approve the Interconnection Customer's telemetry equipment design and perform inspections to ensure compatibility with the Distribution Provider's telemetry equipment; allow the Distribution Provider to perform acceptance testing of the telemetry equipment and the right to require the correction of installation deficiencies.
b. Provide broadband internet service to support communication of the telemetering data to the Distribution Provider's grid control center.
c. Provide and install a Distribution Provider approved serial device server ("SDS") in an approved enclosure located in an area with a suitable environment.
d. Provide a convenience power source to the SDS enclosure for SDS power.
e. Provide and install data communication cabling for the required telemetering data from the Interconnection Customer's data acquisition system to the SDS enclosure.
f. Allow the Distribution Provider to terminate the data communication cables inside the Interconnection Customer's SDS enclosure and program the SDS.

(vii) Install, in coordination with, and as specified by, the Distribution Provider, a dedicated T1 circuit from the local telephone company to support the Remote Terminal Unit ("RTU") communication to the Distribution Provider's energy management system in accordance with the

Interconnection Handbook if a RTU is installed locally at the Generating Facility[3].

(viii) Designate, to the T1 circuit provider, the Distribution Provider as a representative authorized to report trouble to, and to initiate repairs with, the communication circuit provider on the Interconnection Customer's behalf in the event of an interruption of service on the communication circuit if a T1 circuit is required for the support of a RTU installed locally at the Generating Facility.

(ix) Allow the Distribution Provider to review the Interconnection Customer's telecommunication equipment design and perform inspections to ensure compatibility with the Distribution Provider's RTU, or equipment related to an alternative approved by the Distribution Provider, and related terminal equipment; allow the Distribution Provider to perform acceptance testing of the telecommunication equipment and the right to request and/or to perform correction of installation deficiencies.

(x) Provide required data signals, make available adequate space, facilities. and associated dedicated electrical circuits within a secure building having suitable environmental controls for the installation of the Distribution Provider's RTU, or equipment related to an alternative approved by the Distribution Provider, in accordance with the Interconnection Handbook.

(xi) Make available adequate space, facilities, and associated electrical circuits within a secure building having suitable environmental controls for the installation of the Distribution Provider's telecommunications terminal equipment in accordance with the Interconnection Handbook if a RTU is installed locally at the Generating Facility.

(xii) Install all required ISO-approved compliant metering equipment at the Generating Facility, in accordance with Section 10 of the ISO Tariff.

(xiii) Allow the Distribution Provider to install, in the switchgear provided by the Interconnection Customer, revenue meters, potential transformers ("PTs"), and current transformers ("CTs"), to meter retail load at the Generating Facility in accordance with the Distribution Provider's Electrical Service Requirements ("ESR") as described in the Interconnection Handbook.

(xiv) Install all equipment necessary to comply with the power factor requirements of Article 9.6 of the GIA, including the ability to regulate power factor to a schedule (VAR schedule) in accordance with the Interconnection Handbook.

(xv) Provide switchboard drawings which shall comply with Distribution Provider's ESR which can be obtained at: http://www.sce.com/AboutSCE/Regulatory/distributionmanuals/esr.htm

[3] The cost and scope of telemetry may significantly increase to include a dedicated RTU, as required by SCE's Interconnection Handbook, in the event that the centralized RTU method is not feasible for this project.

(xvi) Install disconnect facilities in accordance with the Distribution Provider's Interconnection Handbook to comply with the Distribution Provider's switching and tagging procedures.

(xvii) Install a breaker within the Interconnection Customer's property line in accordance with the ESR to comply with the Distribution Provider's protection requirements.

(xviii) Install all equipment and controls necessary to maintain the Generating Facility's output ramp rate within the parameters set forth, and provided to the Interconnection Customer, by the Distribution Provider.

(b) **Distribution Providers's Interconnection Facilities.** The Distribution Provider shall:

(i) [redacted]

(ii) **Telecommunications.**
Install all required equipment (including terminal equipment) supporting the RTU including the conmmunications interface with the Distribution Provider's energy management system. In accordance with the Interconnection Handbook, the Distribution Provider shall provide the required interface equipment at the Generating Facility necessary to connect the RTU to the Interconnecting Customer's T1 circuit if an RTU is installed locally at the Generating Facility. Notwithstanding that certain telecommunication equipment, including the telecommunications terminal equipment, will be located on the Interconnection Customer's side of the Point of Change of Ownership, the Distribution provider shall own, operate and maintain such telecommunication equipment as part of the Distribution Provider's Interconnection Facilities if an RTU is installed locally at the Generating Facility.

(iii) **Real Properties, Transmission Project Licensing, and Corporate Environmental Health and Safety.**
Obtain easements and/or acquire land, obtain licensing and permits, and perform all required environmental activities for the installation of the Distribution Provider's Interconnection Facilities, including any associated telecommunication equipment.

(iv) **Metering.**
Install revenue meters and appurtenant equipment required to meter the retail load at the Generating Facility. Notwithstanding that the meters and appurtenant equipment will be located on the Interconnection Customer's side of the Point of Change of Ownership, the Distribution Provider shall own, operate and maintain such facilities as part of the Distribution Provider's Interconnection Facilities.

(v) **Power System Control.**

Telemetry.

a. Terminate the Interconnection Customer provided communication cables inside the Interconnection Customer's SDS enclosure.
b. Program and test the SDS.
c. Perform setup and programming on the Distribution Provider's telemetry equipment as required to support communication of the telemetered data to the Distribution Provider's grid control center.
d. Perform a functional test of the telemetry equipment to verify compliance with the requirements of the Interconnection Handbook.

Or if required, Install one (1) RTU at the Generating Facility to monitor typical generation elements such as MW, MVAR, terminal voltage and circuit breaker status for the Generating Facility and plant auxiliary load, and transmit the information received thereby to the Distribution Provider's grid control center. Notwithstanding that the RTU will be located on the Interconnection Customer's side of the Point of Change of Ownership, the Distribution Provider shall own, operate and maintain the RTU as part of the Distribution Provider's Interconnection Facilities.

**2. Network Upgrades.**

(a) **Stand Alone Network Upgrades.**
None identified as part of the Phase II study.

(b) **Other Network Upgrades.**

(i) **Distribution Provider's Reliability Network Upgrades.**

None identified as part of the Phase II study.

(ii) **Distribution Provider's Delivery Network Upgrades.**

1. **Area Delivery Network Upgrades.**

None identified as part of the Phase II study.

2. **Local Delivery Network Upgrades.**

None identified as part of the Phase II study.

**3. Distribution Upgrades.**
None identified as part of the Phase II study.

**4. Point of Change of Ownership.**

(a) The Point of Change of Ownership shall be the point where the conductors of the Distribution Provider's Interconnection Facilities 33 kV line are attached to

the Interconnection Customer's 33 kV Circuit at the last structure (location of the gang operated disconnect). The Interconnection Customer shall own and maintain the Last Structure, the conductors, insulators and jumper loops from such Last Structure to the Interconnection Customer's Generating Facility. The Distirbution Provider will own the insulators that are used to attach the conductors to the last structure.

5. **Point of Interconnection.** A Tap on the Distribution Provider's Lauda 33 kV Circuit out of Nelson 115/33 kV Substation.

6. **One-Line Diagram of Interconnection to Lauda 33 kV Circuit out of Nelson 115/33 kV Substation.**