# Appendix A – WDAT923

[redacted]

## Queue Cluster 5 Phase I Report

**January 30, 2013**

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

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Attachments:
1. Allocation of Network Upgrades for Cost Estimates
2. Escalated Cost and Time to Construct for Interconnection Facilities, Reliability Network Upgrades, Delivery Network Upgrades, and Distribution Upgrades
3. Interconnection Handbook
4. Short Circuit Calculation Study Results (see Appendix H of the group report)
5. Area Deliverability Constraints Associated with Colorado River to Valley 500 kV Upgrade.
6. Not Used
7. SCE Northern Hemisphere Import Nomogram

## A. Executive Summary

[redacted] the Interconnection Customer (IC), has submitted a completed Interconnection Request (IR) to the Southern California Edison Company (SCE) for their proposed [redacted] (Project) under the terms of SCE's Wholesale Distribution Access Tariff (WDAT). The Project has requested Full Capacity Deliverability Status and is comprised of inverter based photovoltaic modules with an output of 20 MW to the requested Point of Interconnection (POI) on SCE's Borel-Isabella-Kern River 3-Lakegen-Weldon 66 kV Line. The generated power would be delivered to the California Independent System Operator ("CAISO") grid at the 220 kV[1] bus of SCE's Vestal Substation. The IC requested Commercial Operation Date for the Project is [redacted]

In accordance with Federal Energy Regulatory Commission (FERC) approved Generator Interconnection and Deliverability Allocation Procedures (GIDAP) (CAISO Tariff Appendix DD), the Project was grouped with Queue Cluster 5 Phase I (QC5) study projects to determine the impacts of the group as well as impacts of the Project on the CAISO Controlled Grid.

The group 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 of this Project.

The report provides the following:

1. Transmission and 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 required to bring these facilities into service.

The QC5 study has determined that the Project contributes to various reliability and/or deliverability problems for which mitigation plans have been proposed. These mitigation plans are detailed in Section C of this report. The cost responsibility and estimated time to construct the facilities required for the Project are summarized below.

The non-binding cost estimates of Interconnection Facilities[2] (IF) and Distribution Upgrades[3] (DU) to interconnect the Project are:

| | |
|---|---|
| Interconnection Facilities | $2,043,000 |
| ITCC for Interconnection Facilities | $715,000 |
| Distribution Upgrades to support interconnection | $53,067,000 |
| ITCC for Distribution Upgrades to support interconnection | $18,407,000 |

The non-binding cost estimate of IF and DU to interconnect the Project is approximately $2,758,000 and $71,474,000 respectively, including ITCC[4].

[1] Identification of facility voltages (220 kV) in this Phase I Study are shown consistent with SCE System Operating Bulletin 123. However, all studies were predicated on the base voltages reflected in the Western Electricity Coordinating Council (WECC) base cases. For the SCE bulk power system, the WECC base cases reflect 230 kV and 500 kV base voltages; consequently, all per-unit calculations presented were based on 230 kV and 500 kV voltages.

[2] The transmission facilities identified between the generation facility and the point of interconnection necessary to physically and electrically interconnect the Project to the CAISO-Controlled Grid.

[3] These upgrades are not part of the CAISO Controlled Grid, and are not reimbursable.

The good faith cost estimate for the allocated Reliability Network Upgrades[5] (RNUs) necessary to interconnect the project is $0.

There were no Local Delivery Network Upgrades[6] (LDNUs) identified or allocated in this Phase I study in order to provide the Full Capacity Deliverability Status requested in the interconnection request.

The good faith estimated cost for Area Delivery Network Upgrades[7,8] (ADNUs) is $17,410,000. The good faith estimated cost for Distribution Upgrades needed to support the ADNUs is $2,384,000.

The non-binding estimated time to interconnect the project and construct[9] the facilities corresponding with the mitigation plans associated to the Project is as follows:

| Facility Type | Duration (Months) |
|---|---|
| Interconnection Facilities | 80 |
| Distribution Upgrades to support interconnection | 24 |
| Reliability Network Upgrades | NA |
| Local Delivery Network Upgrades | NA |
| Area Delivery Network Upgrades | 115 |
| Distribution Upgrades to support ADNU | 115 |

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.

The QC5 study determined that this Project is dependent on queued ahead upgrades being in place prior to interconnection of the Project. The estimated time to construct QC5 Phase I upgrades specified above do not take into account the time to construct queued ahead upgrades.

## B. Project and Interconnection Information

The Project's general information, as stated in the IR provided by the IC, and Interconnection Facilities are illustrated below in Table B.1, Figure B.1 provides the map for the Project and the transmission facilities in the vicinity, and Figure B.2 shows the conceptual single line diagram of the Project as modeled in the study.

4 Income Tax Component of Contribution. The ITCC included in this cost estimate was computed using a 35% rate.

5 The SCE transmission facilities, other than Interconnection Facilities, at or beyond the point of interconnection necessary to physically and electrically interconnect the Project, needed to maintain system integrity and reliability.

6 The SCE transmission facilities, other than Interconnection Facilities, at or beyond the point of interconnection necessary to physically and electrically interconnect the Project, and are network upgrades built to address local deliverability constraints for projects that request Full or Partial Capacity Deliverability Status.

7 The SCE transmission facilities, other than Interconnection Facilities, at or beyond the point of interconnection necessary to physically and electrically interconnect the Project, and are network upgrades built to address area deliverability constraints for projects that request Full or Partial Capacity Deliverability Status.

8 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.

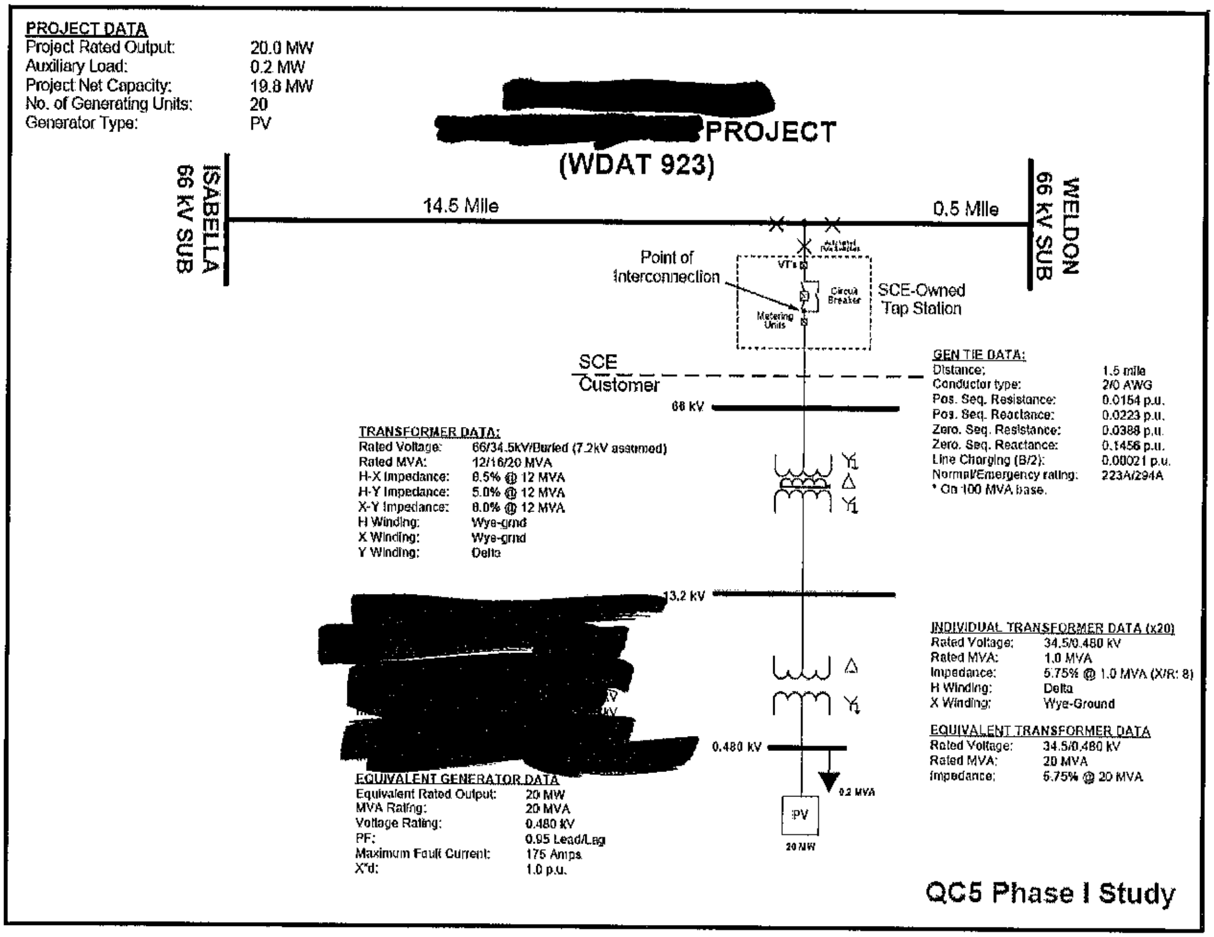
9 Construction is only part of the duration of months scheduled in the study, includes final engineering, licensing, etc. and other activities required to bring such facilities into service

**Table B.1: Project General Information**

| | |
|---|---|
| Project Location | [redacted]<br>Kern County |
| Participating TO's Planning Area | SCE Northern System |
| Number and Type of Generators | [redacted] |
| Interconnection Voltage | 66 kV |
| Maximum Generator Output | 20.0 MW |
| Generator Auxiliary Load | 0.2 MW |
| Maximum Net Output to Grid | 19.8 MW |
| Power Factor Range | Lead 0.95 / Lag 0.95 |
| Step-up Transformer(s) | **Main Transformer (1):**<br>66/34.5/Buried kV (YG-YG-D), 12/16/20 MVA<br>H-X Impedance Value: 8.5 % @ 12 MVA<br>H-Y Impedance Value: 5.0 % @ 12 MVA<br>X-Y Impedance Value: 8.0 % @ 12 MVA<br>X/R = 30<br><br>**Padmount Transformer (20):**<br>34.5/0.480 (D-YG), 1.0 MVA<br>H-X Impedance Value: 5.75 % @ 1.0 MVA<br>X/R = 8 |
| Point of Interconnection | SCE's Borel-Isabella-Kern River 3-Lakegen-Weldon 66 kV line |
| Interconnection Customer Requested Commercial Operation Date | [redacted] |

**Figure B.1: Map of the Project**

**Figure B.2: Proposed Single Line Diagram**




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

To determine the cost responsibility of each generation project in QC5, the CAISO developed cost allocation factors (Attachment 1) 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 and Network Upgrades are listed below:

### DISTRIBUTION PROVIDER'S INTERCONNECTION FACILITIES

1. **Subtransmission**
   **WDAT923 66 kV Generation Tie Line**
   Install one (1) structure and two spans of overhead conductor from the dead-end structure at the new tapped substation to the customer owned generation tie line.

2. **Substations**
   **WDAT923 Tapped Substation**
   Install a 66 kV single circuit breaker tap substation to terminate the new WDAT923 66 kV generation tie line.

   The interconnection facilities will be installed as follows:
   - [redacted] dead-end structure
   - [redacted] oltage transformers
   - Line protection relays

3. **Telecommunications**
   Extend customer's fiber optic (FO) cables and install lightwave, channel, and associated equipment at WDAT923 tapped substation and customer's facilities.

   Also install all required lightwave, channel and related terminal equipment at each end of both FO paths in interface with the required Line Protection Relays and RTU.

4. **Metering Services Organization**
   Install SCE revenue meters required to meter the retail load at the generating facility. The SCE meter will be installed in tandem with the ISO meter circuit.

   The customer will provide the required metering equipment (voltage and current transformers and meter enclosure).

5. **Power System Controls**
   Insta[redacted] RTU at the generating facility to monitor typical elements such as MW, MVAR, terminal voltage, and circuit breaker status at each generating unit and the plant auxiliary load and to transmit this information to the SCE grid control center.

6. **Real Properties, Transmission Project Licensing, and Corporate Environmental Services**
   Obtain licensing, permits, easements and perform all required environmental activities for the installation of the following project elements if applicable:
   - Tapped substation property
   - Segments 66 kV generation tie line within the new substation property

## PLAN OF SERVICE RELIABILITY NETWORK UPGRADES

No Plan of Service Distribution Upgrades were allocated to the Project as part of this QC5 Phase I study for Project.

## RELIABILITY NETWORK UPGRADES (RNU)

No Reliability Network Upgrades were identified as part of this QC5 Phase I study for Project.

## LOCAL DELIVERY NETWORK UPGRADES (LDNU)

No Local Delivery Network Upgrades were identified as part of this QC5 Phase I study for Project.

## AREA DELIVERY NETWORK UPGRADES (ADNU) AND ASSOCIATED DISTRIBUTION UPGRADES USED TO DERIVE DOLLAR-PER-MW VALUE

1. **Mesa 500 kV System Upgrades**
2. **Distribution Upgrades to Support the Mesa 500 kV System Upgrade**
3. **Eastern Area Delivery Network Upgrade(s) allocated to Project**
   - **Colorado River – Red Bluff No. 3 500 kV T/L**
   - **Red Bluff – Valley 500 kV T/L**

See group report Section K for details.

## DISTRIBUTION PLAN OF SERVICE UPGRADES

1. **Subtransmission**
   **WDT923 Tap Line**
   Install [redacted] engineered, bolted footing steel poles, three light weight steel poles, three automated pole switches, and approximately 500 circuit feet of conductor.

   **Borel – Isabella – Kern River 3 – Lakegen – Weldon 66 kV Line**
   Modify line at upgraded Isabella Substation.

2. **Substations**
   **WDAT923 Tapped Substation**
   Install a 66 kV single circuit breaker tap substation to terminate the new WDT903 66 kV generation tie line.

   The distribution upgrade facilities are as follows:
   - [redacted] dead-end structures
   - [redacted] 66 kV circuit breaker
   - [redacted] sets of disconnect switches
   - MEER

   **Isabella Substation**
   Re-build substation using an Operating/Transfer Bus configuration
   - Equip three positions to terminate existing lines
     - [redacted] ead-end structure
     - [redacted] sets of disconnect switches
     - [redacted] otential transformer
     - [redacted] rcuit breaker
     - [redacted] air of protection relays
   - Equip [redacted] us tie position
     - [redacted] rcuit breaker
     - [redacted] ets of disconnect switches
     - [redacted] otential transformers
     - [redacted] otection relay
   - Equip one bank position
     - [redacted] ead-end structure
     - [redacted] rcuit breaker
     - [redacted] ets of disconnect switches
     - [redacted] air of protection relays
   - MEER

3. **Power System Controls**
   WDAT923 Tapped Substation
   Install [redacted] RTU at the new tapped substation to monitor typical elements such as MW, MVAR, terminal voltage, and circuit breaker status at each generating unit and the plant auxiliary load and to transmit this information to the SCE grid control center.

   **Isabella Substation**
   Add points at the existing substation RTU to monitor relay status.

4. **Telecommunications**
   Install 81,100 ft.of 48/SMF FO cable between Isabella and WDAT923 Substations and 72,500 ft. of 48/SMF FO cable between Isabella Substation and Kernville Service Center.

   Install 26,200 ft. of FO cable to Borel and all the required lightwave, channel, and associated equipment.

   Also, install all the required lightwave, channel, and associated equipment at Isabella and WDAT923 Substations and Kern River 3 Power House which support 66 kV line protection and SCADA.

5. **Real Properties, Transmission Project Licensing, and Corporate Environmental Services**
   Obtain easements and / or acquire land, obtain licensing and permits and perform all required environmental activities for the installation of the following project elements if applicable:
   - WDAT923 Tap Substation Property
   - Tap and Generation Tie Line
   - Isabella Substation Upgrades
   - Loop in lines to Isabella Substation
   - Re-conductor Vestal – Kern River 3 66 kV Line
   - Telecommunications requirements

**DISTRIBUTION UPGRADES**

1. **Vestal – Kern River 3 66 kV T/L Re-conductor**

**NOTE:** The Distribution Upgrades to support the Mesa 500 kV System Upgrade are addressed in the ADNU scope and cost tables.

## D. Cost and Construction Duration Estimates

To determine the cost responsibility of each generation project in QC5, the CAISO developed cost allocation factors (Attachment 1) 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. Attachment 2 provides the 'constant' 2012 dollars and their escalation to the estimated operating date year for Interconnection Facilities, Reliability Network Upgrades, Delivery Network Upgrades, and Distribution Upgrades which the Project was allocated cost. For the QC5 study, the estimated O.D. is derived by assuming the duration of the work element will begin in March 2014, which is the CAISO tariff scheduled completion date of the QC5 Phase II study plus 90 days for the interconnection agreement signing period.

## E. Study Assumptions

For detailed assumptions, please refer to the group report. The following assumptions are only specific to the Project:

1. **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 should not exceed 100% of its normal rated capacity with all facilities in service (base case).
   - The thermal rating of any conductor, connector, or apparatus should not exceed 100% of its emergency rating under N-1 conditions.
   - Operational flexibility and reliability of the distribution system shall be maintained at all times.
   - Circuit voltage profiles should be maintained to comply within SCE's voltage criteria requirements.
   - The power factor for the new generation facility was assumed to be within WDAT requirements of 0.95 lagging or leading.
   - Expected loading on the distribution system as projected by the SCE 2012 - 2021 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 final design to comply with the updated distribution design standards.

2. **The following facilities will be installed by SCE and <u>are included</u> in this Phase I Study:**
   - The required Retail Meters to meter the generating facility retail load.

     **NOTE:** SCE installation <u>does not</u> include metering voltage and current transformers. The SCE meters will be connected to the generator – owned voltage and current transformers to be installed for their CAISO metering.
   - The required Remote Terminal Unit (RTU) to be installed at the generating facility which will be installed by SCE.

3. **The following facilities are to be installed by the Interconnection Customer and <u>are not included</u> in this Phase I Study:**
   - The 66 kV customer line with FO cable from the generating facility to the last structure outside the new tapped substation.
   - The 66 kV customer line will not be constructed in or across Franchise or any SCE Right-of-Way.
   - The diverse telecommunications path from the new substation to the generator site.

- The required CAISO metering equipment (voltage and current transformers and CAISO meters).

  **NOTE:** The metering voltage and current transformers installed for the CAISO metering will also be used for the SCE owned retail meters.
- Line protection relays to be installed at the generating facility end of the WDT923 66 kV generation tie line.

## F. Deliverability Assessment

The deliverability assessment indicated that the Project contributes to the South of Vincent flow deliverability constraints. The South of Vincent flow limit has been identified in the previous studies as driven by the voltage stability following Lugo – Vincent 500kV No. 1 & 2 outage. It is an area deliverability constraint that impacts deliverability of generators north of Vincent. To increase the South of Vincent transfer capability, network upgrades south of Vincent are needed. For details of the area deliverability constraint, refer to the group report Section F.

The Project also contributes to the overload of Lugo – Victorville 500kV line under the outage of Lugo – Eldorado 500kV line, which is one of the area deliverability constraints associated with the Colorado River to Valley 500kV upgrade. For details of the area deliverability constraints, refer to Attachment 5.

**Area Delivery Network Upgrade**

- Mesa 500kV upgrades
- Colorado River – Red Bluff – Valley 500kV line

## G. Power Flow Analysis

1. **Transmission System – 220 kV and 500 kV**
   Please see Section G of the group report for the transmission level power flow analysis discussion and results.

2. **Subtransmission System – 66 kV (Non CAISO Controlled)**

   The QC5 study indicated that the Project contributes to the following subtransmission system overloads or non-convergence problems. The details of the subtransmission analysis and overload levels are provided in the group report.

   **(a) Overloaded Subtransmission Facilities**

   **Category "A"**

   - Vestal-WDT433 leg of the Vestal-Kern River 3 66 kV Line is overloaded to 167% of it's normal rating of 63 MVA.

   **Category "B"**

   - None

   **(b) System Limitation**

   With the inclusion of QC5 Phase I projects there are total of 448 MW of generation interconnection requests at the Vestal System. The QC5 Phase I Study results indicated that without both SCE replacement sponsored 220/66 kV A-bank upgrades at Vestal Substation to provide the capacity needed to accommodate QC5 interconnection requests, the maximum Vestal 66 kV system capability is limited to 200 MW. The SCE replacement program is scheduled to upgrade one A-Bank in 2014 and the other in 2016.

Due to the requested COD of the Project, it would require the Project to advance the funds required to complete the SCE sponsored 220/66 kV A-bank projects. Additional evaluations will be completed as part of Phase II to determine the duration and other factors required to complete the SCE sponsored projects. This will also determine the earliest possible COD for the Project.

**(c) Power Flow Non-Convergence**

There were non-convergence issues under certain contingencies identified by the addition of this project due to the limited system capacity.

**(d) Voltage Performance**

Under base case conditions, there were no identified substations to have voltage performance below allowable limits.

**(e) Required Mitigations**

In order to mitigate the overloads on the Vestal-Kern River 3 66 kV Line, a re-conductor is anticipated to be needed.

The scope and pro rata share of the cost for the Distribution Upgrades assigned to the Project is as follows:

- **Vestal-Kern River 3 66 kV Line Re-conductor**

  Re-conductor approximately 12,250 feet of 4/0 Cu and 1,456 feet of 653 ACSR of the Vestal-Kern River 3 66 kV line section between Vestal Substation and WDAT433 to 954 SAC.

  As a result of the re-conductor, a transfer of the Caratan 12 kV circuit out of Vestal Substation across Famoso Highway through Highway is required.

- **Allocated SCD Mitigation– Refer to Section G below.**

## H. Short Circuit Analysis

Short circuit studies were performed to determine the fault duty impact of adding the QC5 projects to the Distribution Provider's 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 QC5 is determined. Each project in QC5 will be responsible for its share of the upgrade cost based on the rules set forth in CAISO Tariff Appendix DD.

### 1. Short Circuit Study Input Data

The customer provided technical data for the identified inverter (specified in Section B). 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. Otherwise, SCE utilized the parameters provided by the IC. The IC should verify with the manufacturer the appropriate SCD contributions of the inverter prior to commencement of the Phase II study and should update the application to reflect the appropriate data. The data provided by the IC for this project did not match the technical data obtained from the inverter manufacturer.

The following additional input data was used in this study:

PV Inverter Data for each generation unit (on 0.5 MVA Base):

| | |
|---|---|
| X"1 - positive sequence subtransient reactance: | 1.0 PU |
| X"2 - negative sequence subtransient reactance: | 1.0 PU |
| X"0 - zero sequence subtransient reactance: | 1.0 PU |

Generation Step-up Transformers (total of 1)
The transformer is a three-phase, 66/34.5/7.2 kV[10] (YG- YG-D), 12/16/20 MVA with the following impedance information:

- H-X: 8.5% @ 12 MVA
- H-Y: 5.0% @ 12 MVA
- X-Y: 8.0% @ 12 MVA
- X/R = 30

Padmount Transformers (total of 20)

Each transformer is a three-phase, 34.5/0.480 (D-YG), 1.0 MVA with the following impedance information:

- H-X: 5.75% @ 1.0 MVA
- X/R = 8

Customer 66 kV Line

The customer's 66 kV line is 1.5 miles of 2/0 ACSR conductor.

## 2. Short Circuit Duty Study Results

All bus locations where the QC5 projects increase the short-circuit duty by 0.1 kA or more and where duty is in excess of 60% of the minimum breaker nameplate rating are listed in the group report Appendix H. These values have been used to determine if any equipment is overstressed as a result of the QC5 interconnections and corresponding network upgrades, if any.

The responsibility to finance short circuit related 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. In addition, the SCD impact of the associated proposed Network Upgrades was allocated to each Generating Facility using the same percentage assigned for the triggered Network Upgrade.

### (a) Application Queue with RNUs and LDNUs Analysis Results

Fault duties were calculated with the inclusion of the QC5 projects and the identified RNUs to identify the incremental impacts associated with these Facilities. As discussed in Section H of the group report, under this scenario the QC5 study breaker evaluation identified overstressed circuit breakers. The following is the pro-rata cost allocation for this project, based on SCD contribution at each location.

SCD Mitigation - Table of Network Breaker Replacements (RNU)

NA

[10] Assumed third winding voltage to be 7.2 kV for study purposes.

### (b) Application Queue with RNUs, LDNUs, & ADNUs Analysis Results

Fault duties were re-calculated to include the QC5 projects and the identified RNUs, LDNUs, and ADNUs from the power flow and stability analysis to identify the incremental impacts associated with these Facilities. As discussed in Section H of the group report, under this scenario the QC5 study breaker evaluation identified overstressed circuit breakers at Mira Loma and Valley. As part of this Phase I cost estimates for mitigation of short circuit duty impacts under this scenario are not included. As part of Phase II if this mitigation is identified to still be required, cost estimates and corresponding pro-rata cost allocation will be determined.

### (c) Application Queue Distribution Analysis Results

Fault duties were calculated for the QC5 projects on the distribution system. Under this scenario the QC5 study breaker evaluation identified overstressed circuit breakers at the following distribution substations. The following is the pro-rata cost allocation for this project, based on SCD contribution at each location.

SCD Mitigation -Table of Distribution Breaker Replacements

NA

### 3. Preliminary Protection Requirements

Protection requirements are designed and intended to protect SCE's system only. The preliminary protection requirements were based upon the interconnection plan as shown in Figure B.2.

The applicant is responsible for the protection of its own system and equipment and must meet the requirements in the SCE Interconnection Handbook which is provided in Attachment 3.

## I. Reactive Power Deficiency Analysis

### 1. Transmission System Reactive Power Deficiency Analysis - 220 kV and 500 kV

Please see Section G of the group report for the transmission level reactive power deficiency analysis discussion and results.

### 2. Subtransmission System Reactive Power Deficiency Analysis - 66 kV (Non CAISO Controlled)

Limited reactive power deficiency analysis was performed. In the base case study, there were no serious voltage and VAR issues that were identified based on system VAR requirements for power flow convergence.

With all proposed system upgrades listed above and in Section F, the power flow studies for Category "B" contingency indicated that this QC5 project did not cause voltage drops of 5% or more from the pre-project levels, or cause the SCE system to fail to meet applicable voltage criteria.

A more detailed reactive power deficiency analysis will need to be performed as part of the Phase II Study.

3. **Individual Project Power Factor Requirements**

   Based on the findings obtained from QC5 study analysis, it is expected that the Project will need to be designed to maintain a composite power delivery at continuous rated power at the Point of Interconnection at a power factor within the range of 0.95 leading to 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 distribution system. This will be fully evaluated as part of the Phase II Study.

## J. Transient Stability Evaluation

Please see Sections I and J of the group report for the transient stability evaluation discussion and results.

## K. Environmental Evaluation/Permitting

Please see Section L of the QC5 group report.

## L. Items not covered in this study

1. **Conceptual Plan of Service**

   The results provided in this study are based on conceptual engineering and a preliminary plan of service and are not sufficient for permitting of facilities. The Plan of Service is subject to change as part of the Phase II Interconnection Study.

2. **Customer's Technical Data**

   Additional technical data related to the Interconnection Customer's project may be required as part of the Phase II study. The study accuracy and results for the QC5 Phase I Study are contingent upon the accuracy of the technical data provided by the Interconnection Customer. Any changes from the data provided could void the Study results.

3. **Study Impacts on Neighboring Utilities**

   Results or consequences of this QC5 Phase I Study and/or to-be-performed Phase II Interconnection Study may require additional studies,, facility additions, and/or operating procedures to address impacts to neighboring utilities and/or regional forums. For example, impacts may include but are not limited to WECC Path Ratings, short circuit duties outside of the CAISO Controlled Grid, and sub-synchronous resonance (SSR).

4. **Use of Participating TO Facilities**

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

5. **Participating TO Interconnection Handbook**

   The Interconnection Customer shall be required to adhere to all applicable requirements in the Participating TO 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 Interconnection Customer 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 Participating TO-owned protection and Interconnection Customer-owned protection. If adequate protection coordination cannot be achieved, then modifications to the Interconnection Customer-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 QC5 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 Participating TO prior to the In-Service Date of the Interconnection Facilities, the IC is responsible to make appropriate arrangements with Participating TO to receive and pay for such retail.

9. **Licensing Cost and Duration Estimate (Estimated Construction Schedule)**

   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 gen tie, 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 Participating TO substation. Due to uncertainties related to telecommunication upgrades for the numerous projects in queue ahead of QC5 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 QC5 Phase I may be reduced. Any changes in these assumptions may affect the cost and schedule for the identified telecommunication facilities.

11. **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 Point of Interconnection that was evaluated in the QC5 Phase I 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 Interconnection Customer.

# Attachment 1

## Allocation of Network Upgrades for Cost Estimates

Table 1: Allocation of ADNU cost and Associated Distribution Upgrade Cost

| Upgrades | Type | Needed For | MW | Cost Rate ($1000/MW) | Allocated Cost ($1000) |
|---|---|---|---|---|---|
| Mesa 500kV upgrades | ADNU | South of Vincent flow limit due to voltage instability | 20 | $ 515.80 | $ 10,315.96 |
| Distribution relocation | Distribution | South of Vincent flow limit due to voltage instability | 20 | $ 119.20 | $ 2,384.00 |
| Red Bluff – Valley 500kV No. 1 | ADNU | Various normal and contingency overloads in Desert area | 20 | $ 295.28 | $ 5,905.60 |
| Colorado River – Red Bluff 500kV No. 3 | ADNU | Various normal and contingency overloads in Desert area | 20 | $ 59.42 | $ 1,188.43 |

# 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

## Participating TO Interconnection Handbook

Preliminary Protection Requirements for Interconnection Facilities are outlined in the Participating TO Interconnection Handbook.

# Attachment 4

## Short Circuit Calculation Study Results

Please refer to the Appendix H of the group report.

# Attachment 5

**Area Deliverability Constraints Associated with Colorado River to Valley 500 kV Upgrade**

Please refer to separate document.

# Attachment 6

## Not Used

# Attachment 7

## SCE Northern Hemisphere Import Nomogram

Please refer to separate document.