Appendix A – WDAT946

[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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A. Executive Summary

[redacted] an 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 is a Full Capacity Deliverability Status, Parabolic Solar Co-Generation Plant with a total net output of 175 MW, a 67 MW expansion to the existing 108 MW of on-site co-generation; to the proposed Point of Interconnection (POI) at Southern California Edison Company's (SCE) McGen 115 kV Bus in Searles Valley, County, California. The customer has requested a proposed In-Service Date of March 16, 2015 and a proposed Commercial Operation Date of [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 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 construct and 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[1] the facilities required for the Project are summarized below.

The good faith cost estimates of Interconnection Facilities[2] (IF) and Distribution Upgrades[3] to interconnect the Project are:

Interconnection Facilities	$177,000
ITCC for Interconnection Facilities	$62,000
Distribution Upgrades	$177,575,000
ITCC for Distribution Upgrades	$62,127,000

The non-binding cost estimate of Interconnection Facilities (IF) and Distribution Upgrades to interconnect the Project is approximately $240,000 and $239,702,000 respectively, including ITCC[4].

[1] 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.
[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.
[4] Income Tax Component of Contribution. The ITCC included in this cost estimate was computed using a 35% rate.

The good faith cost estimate for the allocated Reliability Network Upgrades[5] (RNUs) necessary to interconnect the project is $2,777,000.

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 $51,543,000. The good faith estimated cost for Distribution Upgrades needed to support the ADNUs is $506,000.

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

Facility Type	**Duration (Months)**
Interconnection Facilities	24
Distribution Upgrades to support interconnection	88
Reliability Network Upgrades	24
Local Delivery Network Upgrades	NA
Area Delivery Network Upgrades	115
Distribution Upgrades to support ADNU	109

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. Note, interconnection of this project in advance of the upgrades identified will necessitate telecommunication whose scope is currently being defined for licensing. As such, this project will have to wait until the telecommunications is placed into service.

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.

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.

Table B.1: Project General Information

Project Location	[redacted] San Bernardino County
Participating TO's Planning Area	SCE North of Lugo System
Number and Type of Generators	[redacted]
Interconnection Voltage	115 kV
Maximum Generator Rated Output	180 MW
Generator Auxiliary Load	5 MW
Maximum Net Output to Grid	175 MW (67MW Incremental to the existing 108 MW of Co-Generation)
Power Factor Range	0.85 PF
Step-up Transformer(s)	**Interconnection consists of a total of 3 generating units:** **One (80MW) STG & Two (50MW) CTGs** **<u>Main Steam Turbine (Steam Turbine)</u>** **<u>Transformer Data (X1):</u>** Rated Voltage: 115/13.8 kV Rated MVA: 88 MVA Impedance: Z = 15% @ 82 MVA H Winding: Wye X Winding: Delta **<u>Individual Unit (Gas Turbine)</u>** **<u>Transformer Data (X2):</u>** Rated Voltage: 115/13.8 kV Rated MVA: 63 MVA Impedance: Z=15% @ 63 MVA H Winding: Wye X Winding: Delta Load Tap Changer: +/-8 x 1.25%
Point of Interconnection	McGen 115 kV Bus, located in Trona, California
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 PROVIDERS'S INTERCONNECTION FACILITIES

1. **Telecommunications**

   Install cross connections and associated equipment supporting diverse protection and SCADA.

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

2. **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).

3. **Power System Controls**

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

4. **Real Properties, Transmission Project Licensing, and Corporate Environmental Services**

   Obtain access easement for RTU at the generating facility.

RELIABILITY NETWORK UPGRADES (RNU)

- **Inyokern Substation Reactive Support**

  Insta[redacted] 46.8 MVAR 115 kV shunt capacitor bank at Inyokern 115 kV Bus to address low voltage performance and stability issues triggered by the addition of QC5 generation projects.

- ***Modify Mojave Desert (Water Valley) SPS***

- ***Modify proposed Jasper SPS***

- ***Modify High Desert Power Plant SPS***

See group report Section K for details.

- **Short Circuit Duty (SCD) Mitigation - RNU**

  Upgrade transmission network circuit breakers (pro-rata share of upgrade based on project contribution to SCD at each location – refer to Section H of this report).

  See group report for Section H and K additional details.

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. **Kramer 500 kV expansion, Llano 500 kV Switching Station, Kramer-Llano 500 kV T/L, Looping Lugo-Vincent No.2 500 kV T/L into Llano.**
2. **Distribution Upgrades to support the Kramer 500 kV Substation expansion**
3. **East of Pisgah Area Delivery Network Upgrade(s) allocated to Project**

   - **Expand SCE Pisgah 220 kV Substation to 500 kV and Loop Eldorado-Lugo 500 kV T/L into Pisgah 500 kV Substation.**
   - **New Eldorado – Pisgah (Presently Eldorado – Lugo) 500 kV T/L series capacitor**

See group report Section K for details.

DISTRIBUTION PLAN OF SERVICE UPGRADES

1. **Substation**

   McGen Substation

   Install relays and satellite clock required as a part of a special protection scheme.

2. **Power System Controls**

   Install one RTU at McGen 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.

DISTRIBUTION UPGRADES

1. **New Inyokern – McGen No.3 115 kV line**

See group report section K for details.

NOTE: The Distribution Upgrades to support the Kramer 500 kV Substation expansion 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 facilities will be installed by SCE and are included in this Phase I Study:**
   - The required Retail Meters to meter the generating facility retail load.

     NOTE: SCE installation does not 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.
2. **The following facilities are to be installed by the Interconnection Customer and are not included in this Phase I Study:**
   - 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.

F. Deliverability Assessment

The deliverability assessment indicated that the Project contributes to the following deliverability constraints:

Category "A" Overloads

- Lugo No.1 500/230 kV Transformer
- Lugo No.2 500/230 kV Transformer
- Kramer-Lugo No.1 230 kV Line
- Kramer-Lugo No.2 230 kV Line

Category "B" Overloads

- Inyokern-Kramer-Randsburg 115 kV Line
- Inyokern 230/115 kV Transformer
- Jasper-Pisgah 230 kV Line
- Kramer-Lugo No.1 230 kV Line
- Kramer-Lugo No.2 230 kV Line
- Lugo No.1 500/230 kV Transformer
- Lugo No.2 500/230 kV Transformer

Category "C" Overloads

- Roadway-Victor 115 kV Line
- Kramer-Roadway 115 kV Line
- Kramer-Victor 115 kV Line

To mitigate the overloads identified, network upgrades are required. For details of the study methodology, refer to the Group Report Section F.

Reliability Network Upgrade

- The Project is required to participate in the Inyokern SPS, Mojave Desert (Water Valley) SPS, Jasper SPS and High Desert Power Plant SPS.
- In addition, a new 46.8 MVAR shunt capacitor bank at Inyokern 115 kV is needed to address low voltage performance and stability issues.

Local Delivery Network Upgrade

- There were no Local Delivery Network Upgrades (LDNUs) identified or allocated in this Phase I study in order to provide the Full Capacity Deliverability Status requested in the Interconnection Request.

Area Delivery Network Upgrade

- Kramer 500 kV expansion, Llano 500 kV Switching Station, Kramer-Llano 500 kV T/L, Looping Lugo-Vincent No.2 500 kV T/L into Llano.

- Expand SCE Pisgah 220 kV Substation to 500 kV and Loop Eldorado-Lugo 500 kV T/L into Pisgah 500 kV Substation. New Eldorado – Pisgah (Presently Eldorado – Lugo) 500 kV T/L series capacitor.

See group report Section K for details.

G. Power Flow Analysis

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

(a) **Overloaded Transmission Facilities**

Category "A"

- Inyokern-McGen-Searles 115 kV T/L
- Downs-Inyokern-McGen-Searles 115 kV T/L
- Kramer-Lugo No.1 220 kV transmission line
- Kramer-Lugo No.2 220 kV transmission line
- Lugo No.1AA 500/220 kV transformer bank
- Lugo No.2AA 500/220 kV transformer bank

Category "B"

- Kramer 115/220 kV No. 1 A-Bank
- Kramer 230/500 kV No. 1 AA-Bank
- Jasper-Pisgah 220 kV T/L
- Lugo-Pisgah 220 kV T/L
- Kramer-Lugo No.1 220 kV transmission line
- Kramer-Lugo No.2 220 kV transmission line
- Lugo No.1AA 500/220 kV transformer bank
- Lugo No.2AA 500/220 kV transformer bank

Category "C"

- Kramer No.1 AA 500/220 kV transformer bank

(b) **System Limitation**

With the inclusion of the QC5 projects there are a total of 1,866.62 MW of generation interconnection requests within the North of Lugo Bulk System as shown in the table below. SCE's SOK Project will only provide approximately 1,000 MW of additional export capacity to Lugo Substation. Therefore, without an additional upgrade to increase generation export from Kramer to Lugo Substation, significant generation curtailments would be required due to this system capacity limitation.

Study Type	NOL Queued Project MWs	Cumulative Total MWs
Rule 21	124.3	124.3
Serial	532.0	656.3
Transition Cluster	40.7	697.0
SGIPs	164.1	861.1
Queue Cluster 1	0.0	861.1
Queue Cluster 2	120.0	981.1
Queue Cluster 3	0.0	981.1
Queue Cluster 4	68.0	1049.1
Queue Cluster 5	817.5	1866.6
Total		**1866.62**

(c) Power Flow Non-Convergence

There were no non-convergence issues identified by the addition of this project.

(d) Voltage Performance

Under base case conditions, this project contributed to low voltage performance in the Inyokern area.

(e) Required Mitigations

To eliminate the power flow impact contributions of the project, it is required to install a combination of a limited set of Delivery Network Upgrades together with congestion management to address base case overloads; an SPS to trip the Project under identified contingency outage conditions. See the group report for additional details.

The scope for the Network Upgrades assigned to the Project is as follows:

- **Inyoker[redacted]ubstation Reactive Support**
  Install [redacted] 46.8 MVAR 115 kV shunt capacitor bank at Inyokern 115kV Bus to address low voltage performance and stability issues triggered by the addition of QC5 generation projects.

- **Mojave Desert (Water Valley) SPS Modification**
  The QC5 study identified the need to expand the proposed Mojave Desert SPS to add the Project as a participant eligible for arming and tripping under loss of both the Kramer-Lugo No.1 & No.2 220 kV T/Ls.

- **Jasper SPS Modification**
  The QC5 study identified the need to expand the proposed Jasper SPS to add the Project as a participant eligible for arming and tripping under loss of the Jasper-Lugo 220 kV T/L or the Coolwater-Jasper 220 kV T/L.

- **High Desert Power Plant SPS Modification (also referred to as Victor SPS)**
  The QC5 study identified the need to expand the proposed Victor SPS to add the Project as a participant eligible for arming and tripping under loss of the Lugo No.1AA, No.2AA 500/220 kV, or loss of both Lugo No.1AA, No.2AA 500/220 kV transformer banks.

  Note: For loss of both the Lugo No.1AA and No.2AA 500/220 kV transformer banks, the Mojave Desert SPS and the Victor SPS will both operate as a safety net; tripping all generation that is associated with each SPS.

- **Kramer Substation 500 kV Expansion**
  The QC5 study identified the need to expand the existing Kramer 220/115 kV Substation with 500 kV facilities with one 500/220 kV transformer bank to appropriately deliver the new generation capacity and mitigate base case over loads.

- **Kramer-Llano 500 kV Transmission Line Upgrades**
  The QC5 study identified the need to install a new Kramer-Llano 500 kV T/L to appropriately deliver the new generation capacity and mitigate base case over loads.

- **Pisgah Substation Expansion and 500 kV Transmission Lines Reconfiguration**
  The QC5 study identified the need to expand the existing Pisgah 220 kV Substation with 500 kV facilities with one 500/220 kV transformer bank to appropriately deliver the new generation capacity and mitigate base case over loads.

- **Allocated SCD Mitigation(s) – Refer to Section H below.**

See the group report for additional details.

The scope and cost for the Distribution Upgrades assigned to the Project is as follows:

- **New Inyokern – Mcgen No.3 115kv line**
- **Modify proposed Inyokern SPS**

H. Short Circuit Analysis

Short circuit studies were performed to determine the fault duty impact of adding the QC5 projects to the Participating TO 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 (specified in Section B). If the technical data obtained from the manufacturer by SCE illustrates differences in the Short Circuit Duty (SCD) parameters, then SCE utilized the manufacturer data of the 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 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 matched the technical data obtained from the manufacturer.

The following additional input data was used in this study:

Step-up Transformer for the Steam Turbine Generator (total of 1)
Each transformer is a three-phase, 115/13.8 kV (Wye-Delta), 88 MVA with the following impedance information:

- Z: 15% @ 82 MVA

Step-up Transformer for the Combustion Turbine Generator (total of 1)
Each transformer is a three-phase, 115/13.8 kV (Wye-Delta), 63 MVA with the following impedance information:

- Z: 15% @ 63 MVA

Generation Tie Line

The generation tie line was assumed to be 0.015 miles of 795 AAC 115kV with a line rating: 997A Normal / 1184A Emergency.

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 and LDNUs 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)

Project	Vista 220 kV	
	%	Allocated Cost
WDAT946	0.70%	$16,406

(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. Subtransmission System Reactive Power Deficiency Analysis - 115 kV

Limited reactive power deficiency analysis was performed. In the base case study, serious voltage and VAR issues were identified based on system VAR requirements for power flow convergence. Specifically, with addition of QC5 projects, the following VAR support is proposed:

Inyokern Substation Reactive Support

Install [redacted] 46.8 MVAR 115 kV shunt capacitor bank at Inyokern 115kV Bus to address low voltage performance and stability issues triggered by the addition of QC5 generation projects.

With the proposed system upgrades listed above and in Section F, the power flow studies for Category "B" and Category "C" contingencies 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. This project, therefore, did not cause any adverse voltage impacts on the CAISO Controlled Grid with the proposed upgrades in place.

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

2. 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. This will be fully evaluated as part of the Phase II Study.

J. Transient Stability Evaluation

Limited transient stability studies were conducted using full loop base cases to ensure that the Participating TO system remains in operating equilibrium, as well as operating in a coordinated fashion; through abnormal operating conditions after the QC5 projects begin operation. The generator dynamic data used in the study for the Project is shown in (Attachment 6).

1. **Transmission System – 220 kV and 500 kV and Subtransmission System – 115 kV**

   (a) **Transient Stability Study Scenarios**

   Disturbance simulations were performed for a study period of 10 seconds to determine whether the QC5 projects will create any system instability during a variety of line and generator outages. The most critical single contingency and double contingency outage conditions in the North of Lugo Bulk System were evaluated.

   For the list of specific line and generator outages evaluated, see the group report.

   (b) **Transient Stability Study Results**

   Limited stability analysis was performed for the North of Lugo Bulk system to identify "relative" as opposed to "absolute" conclusions regarding the stability impacts of the QC5 queued generation projects. In the limited stability analysis performed in the 500 kV, 220 kV and 115 kV systems with the upgrades in place to mitigate base case and outage related overload problems, the transient voltage was acceptable.

   (c) **Mitigation**

   N/A

Stability plots are shown in Appendix F of the group report.

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 RNU cost

Upgrade	Type	Needed For	Total Cost ($1000) (2012)	Cost Share	Allocated Cost ($1000) (2012)
Vista 220 kV CB upgrades	RNU	SCD mitigation	2,344	0.70%	16
Add a new 46.8 MVAR capacitor at Inyokern 115 kV Bus	RNU	Low voltage in the Inyokern Area under normal condition	1,564	100%	1,564
Inyokern SPS Expansion	RNU	Contingency overload on Inyokern-Kramer-Randsburg 115 kV Line under loss of Inyokern 230/115 kV Transformer or Inyokern-Kramer 230 kV Line. Contingency overload on Inyokern 230/115 kV Transformer under loss of Inyokern-Kramer-Randsburg 115 kV Line.	806	100%	806
Expand Mojave Desert SPS	RNU	Contingency overloads on Kramer-Victor 115 kV Line, Kramer-Roadway 115 kV Line and Roadway-Victor 115 kV Line under loss of Kramer-Lugo No.1 & No.2 230 kV Lines	153	100%	153
Modify the Jasper SPS	RNU	Contingency overloads on Lugo-Pisgah 230 kV Line, Jasper-Pisgah 230 kV Line, Kramer-Lugo No.1 230 kV Line and Kramer-Lugo No.2 230 kV Line under loss of (1) Cool Water-Jasper 230 kV Line or (2) Jasper-Lugo 230 kV Line	105	100%	105
Modify High Desert Power Plant SPS	RNU	Contingency overload on the remaining Lugo 500/230 kV Transformer under loss of the other Lugo 500/230 kV Transformer.	133	100%	133

Attachment 1 continued

Allocation of Network Upgrades for Cost Estimates

Table 2: Allocation of ADNU cost

Upgrades	Type	Needed For	MW	Cost Rate ($1000/MW) (2012)	Allocated Cost ($1000) (2012)
Kramer 500 kV expansion, Llano 500 kV Switching Station, Kramer-Llano 500 kV T/L, Looping Lugo-Vincent No.1 500 kV T/L into Llano	ADNU	Lugo No.1 and No.2 500/230 kV Transformers Capacity, Kramer-Lugo No.1 and No.2 230 kV Lines, and Pisgah-Lugo 230 kV Line Constrains	67	513	34,357
Upgrade the Pisgah Substation to 500 kV with one 500/230 kV transformer Loop the Eldorado – Lugo 500 kV Line into the Pisgah 500 kV Substation	ADNU		67	206	13,783
New Eldorado–Pisgah 500 kV T/L Series Capacitor	ADNU		67	51	3,403

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

Not Used

Attachment 6

Customer Provided Project Dynamic Data

The following data was submitted by the Interconnection Customer for Dynamic simulation:

```
# ACE Co-generation 180 MW combined cycle repowering project - Phoenix 1
# dynamic data
# gas unit data
# generators
 gensal    100 "GAS UNIT 1  "  13.80 "1 " : #0 mva=55  tpdo=9.41  tppdo=0.04
tppqo=0.12  h=5.89  d=0.0   ld=1.69  lq=0.76 lpd=0.23  lppd=0.14  ll=0.1  s1=0.05
s12=0.30  ra=0.0  rcomp=0.0  xcomp=0.0
 gensal    200 "GAS UNIT 2  "  13.80 "1 " :  #0 mva=55  tpdo=9.41  tppdo=0.04
tppqo=0.12  h=5.89  d=0.0   ld=1.69  lq=0.76 lpd=0.23  lppd=0.14  ll=0.1  s1=0.05
s12=0.30  ra=0.0  rcomp=0.0  xcomp=0.0
# Power system stabilizer
 pss2b     100 "GAS UNIT 1  "  13.80 "1 " : J1=2 K1=0 J2=3 K2=0 Vsi1max=999.0
Vsi1min=-999.0 Tw1=5.0 Tw2=5.0 Vsi2max=999.0 Vsi2min=-999.0 /
  Tw3=5.0 Tw4=0.0 T6=0.0 T7=5.0 Ks2=0.6 Ks3=1.0 T8=0.0 T9=0.1 n=1 m=5 Ks1=15.0
T1=0.1 T2=0.02 T3=0.18 T4=0.02 T10=0.26 T11=0.02 Vstmax=0.1 Vstmin=-0.1 /
  a=1 Ta=0.0 Tb=0.0 Ks4=1
 pss2b     200 "GAS UNIT 2  "  13.80 "1 " : J1=2 K1=0 J2=3 K2=0 Vsi1max=999.0
Vsi1min=-999.0 Tw1=5.0 Tw2=5.0 Vsi2max=999.0 Vsi2min=-999.0 /
  Tw3=5.0 Tw4=0.0 T6=0.0 T7=5.0 Ks2=0.6 Ks3=1.0 T8=0.0 T9=0.1 n=1 m=5 Ks1=15.0
T1=0.1 T2=0.02 T3=0.18 T4=0.02 T10=0.26 T11=0.02 Vstmax=0.1 Vstmin=-0.1 /
  a=1 Ta=0.0 Tb=0.0 Ks4=1
# turbine-governor model
 ggov1     100 "GAS UNIT 1  "   13.8 "1 " : #5 mwcap=55     r=0.04   rselect=1.0
tpelec=1.0  maxerr=0.2  minerr=-0.2  kpgov=7.7 kigov=1.1 kdgov=0.0 tdgov=1.0
vmax=0.665  vmin=0.05  tact=0.2  kturb=2.083  wfnl=0.175 tb=0.1 tc=0.0  flag=0.0
teng=0.0  tfload=0.0 kpload=10.0  kiload=0.0  ldref=2.0  dm=0  ropen=3.3 rclose=-3.3
kimw=0.0 /
  pmwset=50.0 aset=1.0  ka=10.0 ta= 0.0 db=0.0 Tsa=0.0 Tsb=0.0 rup=1.0 rdown=-1.0
 ggov1     200 "GAS UNIT 2  "   13.8 "1 " : #5 mwcap=55     r=0.04   rselect=1.0
tpelec=1.0  maxerr=0.2  minerr=-0.2  kpgov=7.7 kigov=1.1 kdgov=0.0 tdgov=1.0
vmax=0.665  vmin=0.05  tact=0.2  kturb=2.083  wfnl=0.175 tb=0.1 tc=0.0  flag=0.0
teng=0.0  tfload=0.0 kpload=10.0  kiload=0.0  ldref=2.0  dm=0  ropen=3.3 rclose=-3.3
kimw=0.0 /
  pmwset=50.0 aset=1.0  ka=10.0 ta= 0.0 db=0.0 Tsa=0.0 Tsb=0.0 rup=1.0 rdown=-1.0
# excitation system
 esac8b    100 "GAS UNIT 1  " 13.8  "1 " : #9 Tr=0.06 Kpr=24.33 Kir=7.0 Kdr=5.88
Tdr=.29 Vrmax=7.763 Vrmin=-0.1553 Ka=1.577 Ta=0. Te=.59 Vfemax=99999. Vemin=0.
Ke=1. Kc=1. Kd=0.0 E1=9.15 SE1=.01 E2=12.2 SE2=.01 vtmult=0. spdmlt=0.
 esac8b    200 "GAS UNIT 2  " 13.8  "1 " : #9 Tr=0.06 Kpr=24.33 Kir=7.0 Kdr=5.88
Tdr=.29 Vrmax=7.763 Vrmin=-0.1553 Ka=1.577 Ta=0. Te=.59 Vfemax=99999. Vemin=0.
Ke=1. Kc=1. Kd=0.0 E1=9.15 SE1=.01 E2=12.2 SE2=.01 vtmult=0. spdmlt=0.
#
#steam unit data
# generators
 genrou    300 "STEAM UNIT 1"  13.80 "1 " : #0 mva=86 Tpdo=6.708 Tppdo=0.042
Tppqo=0.05 H=6.36 D=0 Ld=2.24 Lq=2.13 Lpd=0.259 Lpq=0.458 Lppd=.182 Ll=.146
S1=0.101 S12=0.585 Ra=0.0 Rcomp=0.0 Xcomp=0.0
# power system stabilizer
```

pss2a 300 "STEAM UNIT 1" 13.80 "1 " : J1=3 K1=0 J2=5 K2=0 Vsi1max=500.0 Vsi1min=-0.05 Tw1=5000.0 Tw2=5000.0 Vsi2max=500.0 Vsi2min=-0.05 /
Tw3=5000.0 Tw4=0.0 T6=0.0 T7=5000.0 Ks2=0.462 Ks3=1.0 T8=500.0 T9=150.0 n=1 m=5 Ks1=4 T1=300.0 T2=30.0 T3=100.0 T4=10.0 Ks4=1
# turbine-governor model
ieeeg1 300 "STEAM UNIT 1" 13.80 "1 " : K=20.0 T1=9.9 T2=3.3 T3=0.3 Uo=0.49 Uc=-0.44 Pmax=1.02 Pmin=0 T4=0.2 K1=1.0 K2=0.0 T5=0.0 K3=0.0 K4=0.0 /
T6=0.0 K5=0.0 K6=0.0 T7=0.0 K7=0.0 K8=0.0 db1=0.0 eps=0.0 db2=0.0 GV1=0.0 Pgv1=0.0 GV2=0.0 Pgv2=0.0 GV3=0.0 Pgv3=0.0 GV4=0.0 Pgv4=0.0 GV5=0.0 Pgv5=0.0 GV6=0.0 Pgv6=0.0
# excitation system model
esac7b 300 "STEAM UNIT 1" 13.80 "1 " : Tr=0 Kpr=15.81 Kir=31.62 Kdr=0.0 Tdr=9999.0 Vrmax=8.48 Vrmin=0.0 Kpa=8.34 Kia=41.72 Vamax=21.11 Vamin=-21.11 Kp=0.0 /
Kl=10.0 Te=0.66 Vfemax=8.48 Vemin=0.0 Ke=1.0 Kc=0.36 Kd=0.6 Kf1=0.0 Kf2=1.0 Kf3=0.0 Tf=9999.0 E1=7.42 S(E1)=0.14 E2=6.6 S(E2)=0.06 spdmlt=0

Attachment 7

SCE Northern Hemisphere Import Nomogram

Please refer to separate document.