Appendix A – WDAT621

[redacted]

QUEUE CLUSTER 3 & 4 PHASE II REPORT

November 9, 2012

This study has been completed in coordination with Southern California Edison per CAISO Tariff Appendix Y Generator Interconnection Procedures (GIP) for Interconnection Requests in a Queue Cluster Window.

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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 photovoltaic modules with an output of 2 MW to the requested Point of Interconnection (POI) on SCE's Forage 12 kV line out of Piute Substation. The generated power would be delivered to the California independent System Operator ("CAISO") grid at the 66 kV bus of SCE's Forage Substation. The IC requested Commercial Operation Date for the Project is [redacted]

Pursuant to the Generator Interconnection Procedures (GIP) for Interconnection Requests in a Queue Cluster Window (CAISO Appendix Y), including Appendix 8 of the GIP (Transition of Existing SGIP Interconnection Requests to the GIP) under the terms of SCE's WDAT, the Project was grouped with the Queue Cluster 3&4 (QC 3&4) Phase II Study (Phase II) projects to determine the impacts of the group as well as impacts of the Project on the CAISO Controlled Grid and SCE's distribution system.

The group report has been prepared separately identifying the combined impacts of all QC3&4 Phase II projects on the CAISO Controlled Grid. This report focuses only on the impacts of the Project. This report focuses only on the impacts or impact contributions of this Project, and it is not intended to supersede any contractual terms or conditions specified in an interconnection agreement.

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 non-binding, good faith estimate of the Project's cost responsibility and time to construct these facilities.

The QC3&4 Phase II Study was performed to determine problems for which mitigation plans may be proposed for the Project. Mitigation plans for the Project are detailed in Section C of this report.

The QC3&4 Phase II 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 non-binding SCE cost estimates to interconnect the Project are:

Interconnection Facilities	$ **184,000**
ITCC for Interconnection Facilities	$ **65,000**
Distribution Upgrades	$ **11,167,000**
ITCC for Distribution Upgrades	$ **3,909,000**
Reliability Network Upgrades	$ **11,000**

The non-binding cost estimate of Interconnection Facilities[1] and Distribution Upgrades[2] to interconnect the Project is approximately $249,000 and $15,076,000 respectively, including ITCC[3]. The non-binding cost estimate for the allocated Reliability Network Upgrades[4] (RNUs) necessary to interconnect the project is $11,000.

There were no Delivery Network Upgrades[5] (DNUs) allocated to the project due to the requested Full Capacity Deliverability Status in the QC3&4 Phase II Study.

The non-binding schedule to license, engineer, and construct the Interconnection Facilities, Distribution Upgrades, and any allocated Reliability Network Upgrades (i.e. "Energy Only" interconnection) is approximately 88 months from the signing of the Generator Interconnection Agreement and the receipt of all required information & funding, and from SCE specified milestones associated with applicant responsibilities.

B. Project Information and Interconnection Details

All equipment and facilities comprising the [redacted] generating facility located in Lancaster, California, as disclosed by the Interconnection Customer in its Interconnection Request, as may have been amended during the Interconnection Study process, which consists of (i) [redacted] inverters, (ii) [redacted]ransformers (iii) photovoltaic panels.

Table B.1 provides a summary of the project information and Figure B.1 provides a map of the project location and transmission facilities in the vicinity.

Table B.1: Project General Information

Project Location	Lancaster, California
Distribution Provider's Planning Area	Northern
Number and Type of Generators	[redacted]nverter type generating units, using PV technology (each rated for 500 kW)
Interconnection Voltage	12 kV
Maximum Generator Output	2 MW
Generator Auxiliary Load	0 MW
Maximum Net Output to Grid	2 MW
Power Factor Range	0.95 Lagging to 0.95 Leading
Step-up Transformer(s)	[redacted]ansformer rated for 0.2 kV/ 12 kV 500 MVA with 5.75% impedance on a 500 MVA base.
Point of Interconnection	Forage 12 kV circuit out of [redacted]
Interconnection Customer Requested Commercial Operation Date	[redacted]

[1] The electrical facilities installed and maintained by SCE necessary to physically and electrically interconnect the Project to the SCE Distribution system from the point of change in ownership to the point of interconnection, and are not reimbursable.
[2] These upgrades are not part of the CAISO Controlled Grid, and are not reimbursable.
[3] Income Tax Component of Contribution. The ITCC included in this cost estimate was computed using a 35% rate.
[4] 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.
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 support Full Capacity Deliverability Status, if requested

Figure B.1: Map of the Proiect

C. Interconnection Facilities, Network Upgrades, and Distribution Upgrades

The Distribution Provider's Interconnection Facilities, Network Upgrades and Distribution Upgrades described in this section are based on the Distribution Provider's preliminary engineering and design. Such descriptions are subject to modification to reflect the actual facilities constructed and installed following the Distribution Provider's final engineering and design, identification of field conditions, and compliance with applicable environmental and permitting requirements.

1. Interconnection Facilities.

(a) **Interconnection Customer's Interconnection Facilities**: The study assumes that the Interconnection Customer will perform the following:

(i) Install a12 kV switchgear ("Last Structure") within the Interconnection Customer's property line, designed and engineered in accordance with the Distribution Provider's specification, to terminate the Distribution Provider's cable.

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

(iii) Install a breaker within the Interconnection Customer's property line in accordance with the Electrical Service Requirements to comply with the Distribution Provider's protection requirements. Additional protection requirements may be required.

(iv) Install, in coordination with, and as specified by, the Distribution Provider, a dedicated T1 circuit from the local telephone company to support the RTU communication to the Distribution Provider's energy management system in accordance with the Interconnection Handbook if an RTU is installed locally at the Generating Facility if an RTU is installed locally at the Generating Facility.

(v) Allow the Distribution Provider to review the Interconnection Customer's telecommunication equipment design and perform inspections to ensure compatibility with the Distribution Provider's terminal equipment and protection engineering requirements; 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 if telecommunication is installed locally at the Generating Facility.

(vi) 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 an RTU installed locally at the Generating Facility.

(vii) 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, and provide required data signals in accordance with the Interconnection Handbook if an RTU is installed locally at the Generating Facility.

(viii) 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 telecommunications terminal equipment in accordance with the Interconnection Handbook if telecommunication is installed locally at the Generating Facility.

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

(x) Allow the Distribution Provider to install revenue meters and appurtenant equipment required to meter the retail load at the Generating Facility.

(xi) Provide switchgear drawings which shall comply with Distribution Provider's Electrical Service Requirements of which can be obtained at: http:www.sce.com/AboutSCE/Regulatory/distributionmanuals/esr.htm

(b)**Distribution Provider Interconnection Facilities**: The Distribution Provider's Interconnection Facilities are comprised of the Interconnection Customer-Constructed Interconnection Facilities and the Distribution Provider-Constructed Interconnection Facilities.

(i) **Interconnection Customer-Constructed:** The Interconnection Customer shall:

1. Perform underground civil work per Distribution Provider's design, specifications, requirements and acceptance (including but not limited to all necessary trenching, backfilling, and other digging as required, and furnishing and installing of all necessary substructures, conduits and protective structures), for new 12 kV underground line (refer to Section C.1.(b)(ii)2 below) from the distribution pole towards the Interconnection Customer's 12 kV switchgear's pull section.

2. Obtain all necessary permits and easements associated with installation of Interconnection Customer-Constructed Interconnection Facilities.

3. Provide all engineering and design drawings and bills of material associated with the Interconnection Customer-Constructed Interconnection Facilities.

4. Permit Distribution Provider to inspect the construction being done pursuant to this Section C.1.(b)(i)1. In the event the work is not being completed pursuant to Distribution Provider's requirements, Distribution Provider will be permitted to assume work, with costs to be charged to Interconnection Customer. Prior to any such assumption of work, Interconnection Customer shall be provided with thirty (30) days written notice of Distribution Provider's intention to assume work and to cure any defects in, or concerns relating to, that construction to Distribution Provider's satisfaction.

5. Immediately transfer ownership of, and transfer title to each and every component part thereof, to Distribution Provider free and clear of all liens and encumbrances, upon Interconnection Customer's completed construction, and subject to Distribution Provider's approval of those facilities.

6. If applicable, provide the following:

   a. Completed Interconnection Customer information sheet

   b. Street improvement plans

   c. Unique address for point of interconnect

   d. Public right-of-way (street) base maps as required by the interconnection

   e. Site plot plan on a 30:1 scale digital file as follows:

      1. Easements/lease agreement

      2. Grading plans

      3. Sewer and storm plot plans

      4. Landscape, sprinkler, pedestal locations

      5. Underground civil construction is released by the Distribution Provider's inspectors

(ii) **Distribution Provider-Constructed:** The Distribution Provider shall:

1. Install a 3-Way Pad-Mounted Gas Switch with Automation, and Riser.

2. Install approximately 250 feet of 350 JCN 12 kV primary underground line extension to the Interconnection Customer's 12 kV panel's pull section.

3. Telecommunications.

   Install all required equipment (including terminal equipment) supporting the RTU including the communications 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.

4. 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, as necessary, for the installation of the Distribution Provider's Interconnection Facilities.

5. Metering.

   Install revenue meters, potential and current transformers, 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 will own, operate and maintain such facilities as part of the Distribution Provider's Interconnection Facilities.

6. Power System Controls.

   Install [redacted] the Generating Facility to monitor typical generation elements [redacted], 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 if an RTU is installed locally at the Generating Facility. Notwithstanding that the RTU will be located on the Interconnection Customer's side of the Point of Change of Ownership, the Distribution Provider will own, operate and maintain the RTU as part of the Distribution Provider's Interconnection Facilities if an RTU is installed locally at the Generating Facility.

2. Network Upgrades.

(a)**Stand Alone Network Upgrades** - None.

(b)**Other Network Upgrades.**

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

1. Short-Circuit Duty (SCD) Mitigation

   Upgrade transmission network circuit breakers (pro-rata share of upgrade based on project contribution to SCD at each location).

   Vincent 500 kV Substation
   Install [redacted] sets of TRV capacitors to mitigate the increased duty on four circuit breakers, and perform ground grid analysis for substation.

   Colorado River 220 kV Substation
   Install [redacted] sets of TRV capacitors to mitigate the increased duty on six circuit breakers.

   Antelope 220 kV Substation
   Replace [redacted] 220 kV circuit breaker, and perform ground grid analysis for

substation.

Note: The timing of these short circuit duty upgrades are tied to actual development of generation projects throughout SCE's service territory. Additional review of these upgrades will be performed as projects execute interconnection agreements to identify need and schedule installation of these upgrades.

2. 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, as necessary, for the installation of the Distribution Provider's Reliability Network Upgrades and associated telecommunication equipment.

(ii) **Distribution Provider's Delivery Network Upgrades** – None.

3. Distribution Upgrades - The Distribution Provider shall:

(a) Replace [redacted] single phase 3 MVA transformers at Piute 66/12 kV Substation with [redacted] 3 phase 14 MVA transformers with LTC- Shared with WDT620.

(b) Install [redacted] Remote Automatic Reclosers (RAR) with load Encroachment on the Forage 12 kV circuit to accommodate the addition of the proposed WDT621 project-Shared with WDT620.

(c) Replace the existing relay schemes at Piute Substation with [redacted] new SEL-351 relays and install [redacted] 12 kV line potential transformers-Shared with WDT620.

(d) Install [redacted] Voltage Regulator on Forage 12 kV circuit - Shared with WDT 620.

(e) Equip a new 12 kV breaker at Piute 66/12 kV Substation - Shared with WDT 620.

(f) Rebuild the Redman portion of the Lancaster-Purify-Redman 66 kV line.

   (i) Transmission.

   Rebuild approximately 4 miles of 66 kV line with 954 SAC. Install approximately 130 light weight steel poles and four engineered tubular steel poles.

(g) 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, as necessary, for the installation of Distribution Upgrades.

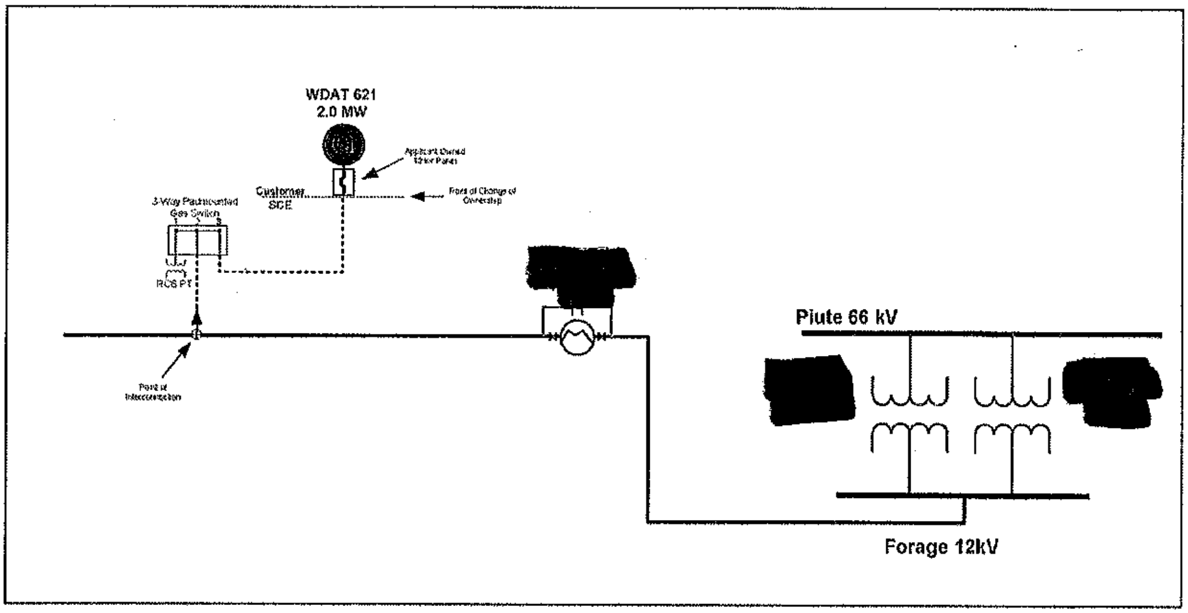
4. **Point of Change of Ownership.**

   The Point of Change of Ownership shall be where the Distribution Provider's conductor connects to the Interconnection Customer-owned 12 kV Switchgear's pull section.

5. **Point of Interconnection.**

   The Distribution Provider's Forage 12 kV line.

6. **One-Line Diagram of Interconnection to Forage 12 kV Distribution Line**



D. Cost and Construction Duration Estimates

To determine the cost responsibility of each generation project in QC3&4 Phase II, the ISO developed cost allocation factors based on the individual contribution of each project (Attachment 1). Table D.1 below provides the cost responsibility of the Project in '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 QC3&4 Phase II Study, the estimated O.D. is derived by assuming the duration of the work element will begin in [redacted] the scheduled completion date of the QC4 Phase II Study plus 90 days for the GIA signing period.

Table D.1: Summary of Estimated Costs and Estimated Time to Construct for Interconnection Facilities, Reliability Network Upgrades, Delivery Network Upgrades, and Distribution Upgrades

Element	Interconnection Facilities Cost x 1,000 Constant Dollar (2012)	Reliability Network Upgrades Cost x 1,000 Constant Dollar (2012)	Delivery Network Upgrades Cost x 1,000 Constant Dollar (2012)	Distribution Upgrades Cost x 1,000 Constant Dollar 2012)	ITCC* x 1,000 Constant Dollar (2012)	One Time Cost x 1,000 Constant Dollar (2012)	Total Estimated Cost x 1,000 w/o ITCC Constant Dollar (2012)	Total Estimated Cost x 1,000 Constant Dollar (2012)	Total Estimated Cost x 1,000 Escalated Constant Dollar (OD Year)	Estimated Time to Construct (Note 3)
DP's Interconnection Facilities (Note 1)										
Install approximately 250ft of 12 kV line (350 JCN), new 3-way Padmounted Gas Switch, automation, 12 kV metering	$127				$45					
Telemetry	$15				$5					
Corporate Environmental Services	$42				$15					
Subtotal	$184				$65		$184	$249	$270	24
PTO's Reliability Network Upgrades										
Short Circuit Duty		$11								
Subtotal		$11					$11	$11	$12	24
Distribution Upgrades (Note 2)										
Shared upgrade with WDT620 - Install a 12 kV Voltage Regulator				$96	$34					
Shared upgrade with WDT620 - Install 2-RAR with load encroachment on the Forage 12 kV circuit to accommodate the addition of the proposed WDT621 project				$113	$39					
Shared Upgrade with WDT620 - Replace (3) single phase 3 MVA 66/12 kV transformers with (2) 3 phase 14 MVA 66/12 kV transformers with LTC				$4,197	$1,469					
Shared Upgrade with WDT620 - Equip a new 12 kV breaker at Piute 66/12 kV Substation				$205	$72					
Shared Upgrade with WDT 620 - Replace existing relay schemes with 2-SEL 351 Relays and Install 3-12 kV Potential Transformers				$94	$33					
CES activities to support for shared Distribution Upgrade with WDT620				$56	$20					
Rebuild portion of the Lancaster-Purify-Redman 66 kV line				$6,406	$2,242					
Subtotal				$11,167	$3,909		$11,167	$15,076	$18,554	88
Other										
Ground Grid Analysis for flagged SCE substations						$21				

Element	Interconnection Facilities Cost x 1,000 Constant Dollar (2012)	Reliability Network Upgrades Cost x 1,000 Constant Dollar (2012)	Delivery Network Upgrades Cost x 1,000 Constant Dollar (2012)	Distribution Upgrades Cost x 1,000 Constant Dollar 2012)	ITCC* x 1,000 Constant Dollar (2012)	One Time Cost x 1,000 Constant Dollar (2012)	Total Estimated Cost x 1,000 w/o ITCC Constant Dollar (2012)	Total Estimated Cost x 1,000 Constant Dollar (2012)	Total Estimated Cost x 1,000 Escalated Constant Dollar (OD Year)	Estimated Time to Construct (Note 3)
Subtotal						$21	$21	$21	$26	88
Total	$184	$11		$11,167	$3,974	$21	$11,383	$15,357	$18,862	88

Note 1: The Interconnection Customer is obligated to fund these upgrades and will not be reimbursed.
Note 2 The Interconnection Customer is obligated to fund these upgrades and will not be reimbursed. Allocated costs may change if all projects responsible for these upgrades do not execute GIAs.
Note 3: 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.
Note 4: SCE's QC3&4 Phase II cost estimating is done in 'constant' dollars 2012 and then escalated to the estimated O.D. year. For the QC3&4 Phase II Study, the estimated O.D. is derived by assuming the duration of the work element will begin in March 2013, which is the CAISO tariff scheduled completion date of the QC3&4 Phase II Study plus 90 days for the Interconnection Agreement negotiations/execution. For instance, if a work element is estimated to take a total of 24 months (permitting, design, procurement, and construction), then the estimated O.D. would be March 2015. If an IC's requested O.D. (In-Service Date) is beyond the estimated O.D. of a work element, the IC's requested O.D. is used. However, should the Generator Interconnection Agreement not be executed, or the necessary information, funding, and written authorization to proceed is not be provided by the IC, in time for the Distribution Provider to perform the work within these time frames, the information provided in Table D.1 may be subject to change.
Note 5: These facilities are not expected to be subject to O&M charges.

E. Study Assumptions

For detailed assumptions, please refer to the QC3&4 Phase II area 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 II 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 CPUC's Rule 2 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 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.

2. **The following Facilities were estimated and included in the Phase II Study:**
   - Approximately 250 feet of primary conductor (350 JCN)
   - Replace existing [redacted] single phase 3 MVA 66/12 kV transformers at Piute Substation with [redacted] 66/12 kV transformers with LTC
   - 3-Way Padmounted Gas Switch
   - Switch Automation
   - 2- Remote Automatic Reclosers
   - [redacted]elays & 3-12 kV Potential Transformers at Piute Substation
   - [redacted]Voltage Regulator
   - Equip a new 12 kV breaker at Piute 66/12 kV Substation
   - 12 kV meter, CTs, PTs, and VTs
   - Remote Terminal Unit

- Telecommunication System for RTU

3. **The following facilities are to be installed by the Interconnection Customer and are not included in this Phase II Study:**
   - Ducts as required
   - Structures as required
   - Point of interconnection breaker
   - CAISO metering as required
   - Protection Systems required to comply SCE Interconnection requirements
   - Transformation as required
   - Metering Equipment compliant with SCE Electrical Service Requirements (http://www.sce.com/AboutSCE/Regulatory/distributionmanuals/esr.htm)

F. Power Flow Analysis

1. **Transmission Level Assessment – 220 kV or above**

   Please see Section G of the QC3&4 Phase II Northern area group report for the transmission level power flow analysis discussion and results.

2. **SubTransmission System – 66 kV**

   The subtransmission system is not sufficient to accommodate all the new QC3&4 Phase II generation projects in the area. The subtransmission system reliability assessment identified the Project contributes to overloads in the Northern area subtransmission system and subsequently the project was allocated the following required mitigation:

   - Rebuild portion of the Lancaster-Purify-Redman 66 kV line.

   For details on the Northern area subtransmission reliability assesment refer to Section G of the QC3&4 Phase II Northern area group report.

3. **Distribution System – 34.5 kV or below**

   The QC3&4 Phase II distribution study indicated that the Project contributes to the following distribution facility overloads:

   (a) **Overloaded Distribution Facilities**

   (i) Under normal base case conditions, daytime minimum load and maximum generation, the addition of this project resulted in a reverse power flow back into the 12 kV bus at Piute Substation, which trigger an overload at Piute 66/12 kV Substation. With the proposed 12 kV QC4 PHII projects at Piute Substation in service during base case conditions, the [redacted] single phase 3 MVA 66/12 kV transformers at Piute 66/12 kV Substation become overloaded to 120% of the transformer normal rating.

   (ii) Under emergency (N-1) conditions, daytime minimum load and maximum generation, the addition of this project did not trigger an overload on any distribution facilities. However, due to the dynamic distribution system configurations, SCE may deem it necessary to isolate this project until the distribution system returns to normal conditions.

(b) **Recommended Distribution Mitigations**

Replace [redacted] single phase 3 MVA 66/12 kV transformers with [redacted] 3 phase 14 MVA 66/12 kV transformers with LTC.

G. Short Circuit Analysis

Short circuit studies were performed to determine the fault duty impact of adding the QC3&4 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 QC3&4 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 Y.

1. Short Circuit Study Input Data

The following input data provided by the Interconnection Customer and 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 [redacted]

Each transformer is a three-phase, [redacted] 12/0.200 kV (D- YG), for 500 kVA with an H-X Impedance Value of 5.75 % @ 500 kVA base.

2. Short Circuit Duty Study Results

All bus locations where the QC3&4 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 group report Appendix H. These values have been used to determine if any equipment is overstressed as a result of the inclusion of QC3&4 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.

As discussed in the group report, the QC3&4 Phase II breaker evaluation identified overstressed circuit breakers at the following buses. The pro-rata cost allocation for this project, based on SCD contribution at each location, is also provided:

SCD Mitigation – Table of Network Upgrades

Project	Vincent 500 kV		Colorado River 220 kV		Antelope 220 kV	
	%	Allocated Cost	%	Allocated Cost	%	Allocated Cost
WDT621	[redacted]					

SCD Mitigation – Table of Distribution Upgrades

NA

(a) SCE Substations with Ground Grids Duty Concerns

The short circuit studies identified substations where the QC3&4 Phase II Projects increased the substation ground grid duty by 0.5 kA or more. The SCE substations flagged to have ground grid duty concerns are disclosed in Section H of the QC3&4 Phase II area group report.

3. 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 #6 of Section C of this report.

The applicant is responsible for the protection of its own system and equipment and must meet the requirements in the Distribution Provider's Interconnection Handbook provided in Attachment 3.

H. Transient Stability Evaluation

Please see Sections I and J of the QC3&4 Phase II Northern area group report for the transient stability evaluation discussion and results.

I. Reactive Power Deficiency Analysis

1. Transmission Level Assessment – 66 kV or above

Please see Section G of the QC3&4 Phase II Northern area group report for the transmission level reactive power deficiency analysis discussion and results.

2. 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 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.

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

A portion of the Forage 12 kV circuit is expected to experience a voltage rise of 6.71%, which exceeds allowable Rule 2 requirements by 2.22 % with the addition of the project under the generating facility's condition of maximum generation during minimum load. The proposed mitigation is to install a new voltage regulator to limit the voltage rise.

J. Deliverability Assessment

1. On Peak Deliverability Assessment

CAISO performed an On-Peak Deliverability Assessment. No overload was identified under the study assumptions.

2. Off- Peak Deliverability Assessment

CAISO performed an informational Off-Peak Deliverability Assessment. The Project does not contribute to any overload.

3. Required Mitigations

There is no Delivery Network Upgrade identified for the Project. The deliverability assessment was performed with all the transmission upgrades approved by the CAISO and the network upgrades required for the earlier queued generation interconnection projects. All these upgrades are required for the Project to achieve its Full Capacity Deliverability Status. For details of the deliverability assessment, refer to Section F of the group report.

K. Operational Studies

1. IC Proposed Project Timelines

The latest information provided by the IC has indicated that the requested generator In-Service Date is [redacted]

2. System Upgrade Timelines for Energy Only Interconnection

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

(a) **DP's Interconnection Facilities**

See Section C.1.b

(b) **Reliability Network Upgrades**

(i) Short-Circuit Duty (SCD) Mitigation

1. Pre-QC3&4 Phase II Projects
   The circuit breaker upgrades that were triggered by queued-ahead projects are identified in Section H.1 of the QC3&4 Phase II group report.

2. Including the QC3&4 Phase II Projects

   The Operational Study undertaken with the inclusion of the QC3&4 Phase II projects identified the required timing for circuit breaker upgrades and/or SCD mitigation(s) under seven different scenarios. These scenarios were selected as the most appropriate operational study conditions and are discussed in Section H.2 of the QC3&4 Phase II area group report.

   The Operational study results, which discuss the timing for breaker upgrades and/or required SCD mitigation(s) at each of the substations identified, are addressed in Section H.3. of the QC3&4 Phase II area group 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 operating date of this project. Additional review for the identified breaker upgrades and/or SCE mitigation(s) discussed in Section H.3 of the QC3&4 Phase II area group report will be performed to evaluate timing of these breaker replacements and SCD mitigation(s) as projects execute Generation Interconnection Agreements

(ii) Subtransmission Upgrades

Based on application queue order, QC3&4 triggered the need for the new Antelope-Del Sur No. 2 66 kV line and a bus reconductor at Del Sur. In addition, higher queued projects have triggered the need to reconductor approximately 0.5 miles of the Antelope leg of the Antelope-Del Sur-Rosamond 66 kV line between the Antelope substation and a future Q649B substation. The need for these upgrades to be in place prior to the interconnection of the Project is dependent on how many projects actually materialize in advance of the Project.

It is estimated that these upgrades will require 88 months to complete. In order to expedite the interconnection of the Project, the licensing and permitting process for both the new Antelope-Del Sur No. 2 66 kV line and 0.5 miles of reconductor on the Antelope leg must begin upon execution of the Project Agreement.

The Project can interconnect in advance of these upgrades provided the IC advances payment of the 0.5 mile line upgrade, and funds the allocated portion of the new Antelope-Del Sur No. 2 66 kV line upgrade. Under this scenario, the Project could interconnect once the Participating TO completes the licensing and permitting process for the two upgrades above and obtains a Permit to construct them from the California Public Utilities Commission.

(c) **Distribution Upgrades**

The Distribution Upgrades allocated to this project are mentioned in Sections C.1.b.i, C.1.b.ii, C.3., and K.2.b.iii. Timing of such upgrades is tied to the available construction resources to perform the work.

(d) **Other Energy Only Operational Issues**

[redacted]Dependency

The study included the modeling of the [redacted] Area ([redacted]) 66 kV reconfiguration project. This project was proposed by SCE in the CAISO 2010 Transmission Plan as a reliability project to address numerous reliability criteria violations in the existing Antelope-Bailey 66 kV network. This project was presented and recommended for approval by CAISO at the [redacted] CAISO transmission plan stakeholder meeting. The [redacted] project was approved by CAISO on [redacted]

In today's operational system, existing generation projects are being curtailed due to insufficient 66 kV system capabilities. Because of this reality, all higher queued projects seeking interconnection in the Antelope-Bailey 66 kV system area that aggravate the constraints have been informed that they must wait for [redacted] prior to interconnection.

Based on this Project's physical location, connecting this Project ahead of [redacted] would aggravate the existing constraints.

The QC3&4 Phase II Operational Study has reaffirmed the conclusion that the addition of this Project is not possible prior to the completion of the [redacted] Project. See Section H of the QC3&4 Phase II area group report.

3. System Upgrades Required for Full Capacity Deliverability Status

In order to provide for Full Capacity Deliverability Status, the following facilities are required:

(a) Tehachapi Renewable Transmission Project (TRTP) - the estimated completion date of the entire TRTP is 2015; however this date is subject to change pending on-going licensing activities at the California Public Utilities Commission (CPUC).

(b) Reliability Network Upgrades that must be in service before the Project could interconnect as identified in Section K.2 above.

4. Interim Operational Deliverability Assessment for Information Only

The operational deliverability assessment was performed for study years 2013 and 2014 by modeling the transmission and generation in service in the corresponding study year. For details of the transmission and generation assumption, refer to Section F of the group report. There is no deliverability constraint identified and the Project could have 100% interim deliverability under the year by year transmission and generation assumptions. However, if some or all the transmission upgrades are delayed or more generation is actually in commercial operation than assumed, the interim deliverability of the Project will be impacted.

5. South of Vincent-Lugo Area Nomogram

As part of the QC3&4 Phase II studies there were no Delivery Network Upgrades allocated to the Project for its requested Full Capacity Deliverability Status. It is important to note that while no Delivery Network Upgrades were allocated to the Project, this outcome does not mean that the Project will be able to generate at its maximum Generating Facility output. Congestion could happen whenever the amount of generating resources exceeds the available transmission capability. The generating resources' output may be curtailed, regardless of their deliverability status, as the result of congestion under the CAISO market operation.

As stated in Attachment 7, studies indicate that as high amounts of resources in the East of Lugo area develop and are dispatched, the amount of available transmission capacity for the Northern Area resources is diminished. Such conclusions point to a potential need for congestion management, and generation resource curtailments. For additional information on expected amounts of renewable generation development in 2022, please see renewable portfolio assumptions for the ISO 2012-2013 Transmission Plan http://www.caiso.com/Documents/2012-2013-FinalRenewableGenerationPortfoliosRecommended_CPUC-CEC.pdf.

6. Conclusion

The requested generator In-Service Date of November 2013 cannot be met due to the anticipated duration of 88 months for the facilities needed to enable Energy Only Interconnection. The requested Full Delivery will not be available until the appropriate Deliverability Network Upgrades are placed into service.

L. Environmental Evaluation/Permitting

Please see Section L of the QC3&4 Phase II area group report.

M. Items not covered in this study

1. **Conceptual Method 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. **Customer's Technical Data**

   The study accuracy and results for the QC3&4 Phase II 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**

   This generation project interconnection may require additional studies, facility additions, and/or operating procedures to address impacts to neighboring utilities. 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. **Relocations and Other Use of SCE Facilities**

   The Interconnection Customer is responsible for all costs associated with necessary relocation of any SCE facilities as a result of this project and acquiring all property rights necessary for the Interconnection Customer's Interconnection Facilities, including those required to cross SCE facilities and property. The relocation of SCE facilities or use of SCE property rights shall only be permitted upon written agreement between SCE and the Interconnection Customer. Any proposed relocation of SCE facilities or use of SCE property rights may require a separate study and/or evaluation to determine whether such use may be accommodated, and any associated cost would be non-refundable.

5. **SCE Interconnection Handbook**

   The Interconnection Customer shall be required to adhere to all applicable requirements in the SCE 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 SCE-owned protection and Interconnection Customer-owned protection. If adequate protection coordination cannot be achieved, then modifications to the Interconnection Customer-owned facilities may be required to allow for ample protection coordination.

8. **Standby Power and Temporary Construction Power**

The QC3&4 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 SCE prior to the In-Service Date of the interconnection facilities, the IC is responsible to make appropriate arrangements with SCE to receive and pay for such retail service.

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. Ground Grid Analysis

The results provided for the ground grid review are preliminary and may be subject to change. A more detailed ground grid analysis will need to be part of the final engineering for the project.

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 in accordance to the Point of Interconnection that was evaluated in the QC3&4 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 and the Interconnection Customer.

Attachment 1

Allocation of Network Upgrades for Cost Estimates

NA

Attachment 2

Not Used

Attachment 3

Distribution Provider Interconnection Handbook

Preliminary Protection Requirements for Interconnection Facilities are outlined in the Distribution Provider 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

Not Used

Attachment 7

SCE Northern Hemisphere Import Nomogram

Please refer to the separate document.