Appendix A – WDT727

[redacted]

Queue Cluster 4 Phase I Report

December 31, 2011

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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Attachments:

1. 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, Solar Photovoltaic (PV) Plant with a total rated output of 20 MW to the proposed Point of Interconnection (POI) at SCE's Little Rock - Wilsona 66 kV Line in Los Angeles County, California. The customer has requested a proposed in-service date of [redacted] and a proposed Commercial Operation Date of [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 4 (QC4) Phase I study (Phase I) 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 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 non-binding, good faith estimate of the Project's cost responsibility and time to construct these facilities.

The QC4 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 10 of this report.

The non-binding cost estimate for the Reliability Network Upgrades allocated to the project is $27,000. The cost estimate for Delivery Network Upgrades[1] based on the CAISO methodology used as part of the QC4 Phase 1 studies due to the Project Full Capacity Deliverability Status is $14,836,200 (20MW X $741.81 thousand/MW)[2]. The estimate of the Project Interconnection Facilities[3] to interconnect the Project is

[1] The SCE transmission facilities, other than Interconnection Facilities, beyond the point of interconnection necessary to physically and electrically interconnect the Project safely and reliably to the CAISO Controlled Grid

[2] The CAISO developed the dollar/MW value based on nominal dollars.

[3] The transmission facilities necessary to physically and electrically interconnect the Project to the CAISO Controlled Grid at the point of interconnection.

approximately $3,786,000 including ITCC, and the cost of the Distribution Upgrades is $63,282,000 including ITCC[4] .

The non-binding schedule to license, engineer, and construct the Interconnection Facilities, Distribution Upgrades, and Reliability Network Upgrades is approximately 88 months from the signing of the Generator Interconnection Agreement and from SCE specified milestones associated with applicant responsibilities. The schedule to license, engineer, and construct the Delivery Network Upgrades will be addressed in the Phase II study. Based on the Queue Cluster 3 (QC3) Phase I group report, the schedule to license, engineer, and construct the Delivery Network Upgrades that were the basis of the Delivery Network Upgrade cost estimate provided above is approximately 84 months upon authorization to proceed.

2. Project and Interconnection Information

Table 2-1 provides general information about the Project as shown in the customer's IR.

Table 2-1 [redacted] General Information

Project Location	Lancaster, CA GPS Coordinates: [redacted]
SCE Planning Area	Northern Bulk
Number and Type of Generators	[redacted]nverters with a rated output of 500 kW each
Interconnection Voltage	66 kV
Maximum Generator Output	20 MW
Generator Auxiliary Load	0 MW
Maximum Net Output to Grid	20 MW
Power Factor Range	+"/- 0.90"
Step-up Transformer(s)	Main Transformer Information (x1): 66/12.47/7.2 kV (YG-D-YG), 18/24/30 MVA H-X: 8% @ 18 MVA H-Y: 8% @ 18 MVA X-Y: 16% @ 18 MVA Pad Mount Transformer Information (x40): H-X: 6% @ 0.500 MVA
Requested Point of Interconnection	Little Rock - Wilsona 66 kV Line
Commercial Operation Date	[redacted]

[4] Income Tax Component of Contribution. The ITCC included in this cost estimate was computed using a 35% rate. Due to the enactment of H.R. 4853, the Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010, and upon formal acceptance by the CPUC of SCE's advice letter (filed on December 27, 2010), this rate may change for electric CIAC recorded or received after September 8, 2010 through December 31, 2011.

Figure 2-1 provides the map for the Project and the transmission facilities in the vicinity.

Figure 2-2 shows the conceptual single line diagram of the Project as modeled in the study.

Figure 2-1 : Map of the Project

Figure 2-2: Proposed Single Line Diagram

3. Study Assumptions

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

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 <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.

The following facilities are to be installed by the Interconnection Customer and are not included in this Phase I Study:

- The 66 kV generation tie line with fiber optic cable from the generating facility to the last structure outside the new looped substation.
- The diverse telecommunications line 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 WDT727 66 kV generation tie line.

4. Deliverability Assessment

The deliverability assessment for this project was performed utilizing the alternative methodology discussed and adopted by the CAISO and the stakeholders. The details of the deliverability assessment analysis are provided in the group report.

Based on the alternative methodology, the QC3 Delivery Network Upgrades and costs were carried forward to the QC4. The Delivery Network Upgrades for the SCE Northern Bulk System include the upgrades required for peak and off-peak deliverability. The per-MW costs are $44,470/MW for peak Delivery Network Upgrades and $697,340/MW for off-peak Delivery Network Upgrades. The Project is assigned both peak and off-peak delivery upgrade costs. The total Delivery Network Upgrade cost assigned to the Project is $14,836,200.

5. Power Flow Analysis

5.1 Transmission System – 220 kV and 500 kV

The transmission system is not sufficient to accommodate all the generation in the area. This conclusion was reached in the QC3 study. With the addition of more generation projects in QC4, system loadings will only increase thereby requiring system upgrades to address the incremental system overloads. However, the use of the Alternative Methodology limits the total output from the generators in the area to what has been studied in the QC3 Phase I study. Therefore, the same conceptual network upgrades are proposed in this study as in the QC3 Phase I study. For reference, a summary of the network upgrades is provided below. The details of the analysis and overload levels are provided in the group study. It should be noted that no cost for the facility upgrades that were assumed in this study under the Alternative Delivery Methodology is assigned to this Project given that the Project requested Energy Only interconnection.

5.1.1 QC3 Recommended Mitigations Used to Derive Dollar-per-MW Value

- North and South of Magunden 230 kV T/L upgrades
- Kramer-Windhub 500 kV T/L
- Mesa 500 kV Upgrades
- PG&E Upgrades Allocated to Northern Bulk System Projects

See the Group Report section 11 for details.

5.2 SubTransmission System – 66 kV

The Subtransmission system is not sufficient to accommodate all the new QC4 generation projects in the area. The reliability assessment has identified the following overloads contributed by the Project.

5.2.1 Overloaded Transmission Facilities

Category "A"

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

Category "B"

- None Identified

In order to mitigate the overloads on the [redacted] purposes of this Phase I study, some [redacted] queued, and QC4 [redacted]s were assumed to be cut over to this new collector substation. This will be further investigated as part of the Phase II study.

See the Group report for additional details.

6. Short Circuit Analysis

Short circuit studies were performed to determine the fault duty impact of adding the QC4 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 QC4 is determined. Each project in QC4 will be responsible for its share of the upgrade cost based on the rules set forth in CAISO Tariff Appendix Y.

6.1 Short Circuit Study (SCD) Input Data

The customer provided technical data for the identified inverter (specified in Section 2). If the technical data obtained from the inverter manufacturer by SCE illustrates differences in the 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 matched the technical data obtained from the inverter manufacturer.

The following additional input data was used in this study:

Generation Step-up Transformers (total of[redacted]

Each transformer is a three-phase, 66/12.47/7.2 kV (YG-D-YG), 18/24/30 MVA with the following impedance information:

- H-X: 8% @ 18 MVA
- H-Y: 8% @ 18 MVA
- X-Y: 16% @ 18 MVA

Padmount Transformers (total of[redacted]

Each transformer is a three-phase, 12.47/0.270 kV (D-YG), 500 kVA with the following impedance information:

- H-X: 6% @ 0.500 MVA
- H-Y: N/A
- X-Y: N/A

Generation Tie Line

The generation tie line was assumed to be of negligible length and impedance.

6.2 Results

Following the alternative methodology, the SCD conclusions were based on QC3 Phase I upgrades. More detailed analysis will be performed as part of the Phase II study.

All bus locations where the QC4 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 QC4 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 Large Generating Facility. In addition, the SCD impact of the associated proposed Network Upgrades was allocated to each Large Generating Facility using the same percentage assigned for the triggered Network Upgrade.

As discussed in the Group Report, the QC4 breaker evaluation identified overstressed circuit breakers at the following buses. The cost allocation for this project, based on SCD contribution at each location, is also provided:

SCD Mitigation -Table of Network Breaker Replacements

Project	Valley 500kV		Antelope 220kV		Colorado River 220kV	
	%	Cost (x1000)	%	Cost (x1000)	%	Cost (x1000)
WDT727	.03	$ 1	.4	$ 3	.01	$ 0

Project	Kramer 220kV		Redondo 220kV		Vista 220kV	
	%	Cost (x1000)	%	Cost (x1000)	%	Cost (x1000)
WDT727	.12	$ 6	.19	$ 14	.09	$ 4

SCD Mitigation -Table of Distribution Breaker Replacements

Project	Garnet 115kV		Inyokern 115kV		Lancaster 12kV	
	%	Cost (x1000)	%	Cost (x1000)	%	Cost (x1000)
WDT727	.02	$ 0	.05	$ 1	5.39	$ 82

Project	Piute 12kV		Victorville 4kV		Vista 66kV	
	%	Cost (x1000)	%	Cost (x1000)	%	Cost (x1000)
WDT727	7.27	$ 3	.0	$ 0	.0	$ 0

6.3 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 2-2.

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 as an appendix to the group report.

7. Reactive Power Deficiency Analysis

7.1 Transmission Reactive Power Deficiency Analysis

Following the alternative methodology, the reactive power deficiency conclusions were based on the analysis performed for the QC3 Phase I Projects.

The QC3 Phase I study demonstrated that the QC3 Phase I Projects collectively contribute to severe reactive power deficiencies in the transmission system under base case and contingency conditions, and voltage criteria violations under contingency conditions. The study concluded that construction of a combination of additional area export transmission facilities and reactive support devices will be required.

It is expected that the addition of the QC4 projects will further exacerbate the problematic system conditions identified in the QC3 Phase I study. These issues will be fully evaluated in a more detailed reactive power deficiency analysis to be performed as part of the Phase II study.

7.2 Subtransmission Reactive Power Deficiency Analysis

Higher queued studies have previously identified the need for power factor correction at the POI of higher queued projects to mitigate the voltage rise problems. It is anticipated that power factor correction will also be required for QC4 projects. This will be evaluated as part of the Phase II study.

7.3 Individual Project Power Factor Requirements

Based on the findings obtained from QC3 Phase I 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.

8. Transient Stability Evaluation

8.1 Transmission System Transient Stability

Following the alternative methodology, the transient stability conclusions were based on analysis at the QC3 Phase I generation level. The QC3 Phase I study concluded that additional area export transmission facilities would have a significant positive impact on system stability margins. These area export transmission facilities could potentially provide sufficient margin capability for the addition of the QC4 projects. A more detailed stability analysis will be performed as part of the Phase II study.

For additional details, see the group report Section 9.

8.2 Subtransmission System Transient Stability

Previous transient stability studies have concluded that the addition of projects interconnecting to the Antelope 66 kV Subtransmission System can result in a transient stability problem which would trip off the generation projects due to system overvoltage conditions under specific outages. For those studies, it was recommended that those projects provide dynamic reactive capability to mitigate these problems. It is anticipated that a similar conclusion will be found for QC4 projects connecting to the Antelope 66 kV Subtransmission System. Detailed transient stability studies will be performed as part of the Phase II study.

9. Environmental Evaluation/Permitting

Please see Section 12 of group report.

10. Upgrades, Cost Estimates and Construction schedule estimates

To determine the cost responsibility of each generation project in QC4, the CAISO developed cost allocation factors based on the individual contribution of each project. The Interconnection Facilities are the sole cost responsible of the Project. The Interconnection Facilities and Network Upgrades required for the Project are listed below:

PTO'S INTERCONNECTION FACILITIES

1. **Sub-Transmission:**
   WDT727 66 kV Generation Tie Line
   Install one tubular steel pole, 200' of 954 ACSR conductor, and one automated pole switch.

2. **Substation:**
   Looped Substation
   Install a 66 kV a three circuit breaker ring bus substation to terminate the new WDT727 66 kV generation tie line.

   The interconnection facilities will be installed as follows:

   - [redacted]ead-end structure
   - [redacted]voltage transformers
   - Line protection relays

3. **Telecommunications:**
   Install circuit cross connections to support SCADA.

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 Control**
   Install one 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 Projects Licensing, and Corporate Environmental Health & Safety Organization**
   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:
   - Segment of 66 kV generation tie line within the new substation property

DISTRIBUTION UPGRADES

7. **Sub-Transmission:**
   WDT727 Loop In Lines
   Install a double circuit engineered steel pole perpendicular to the new substation, double circuit tubular steel pole outside of the new substation, and approximately circuit feet of 954 ACSR conductor.

8. **Substation:**
   Looped Substation
   Install a 66 kV a three circuit breaker ring bus substation to terminate the new WDT727 66 kV generation tie line.

   The distribution upgrade facilities are as follows:
   - [redacted] 66 kV box rack steel structure
   - [redacted] 66 kV circuit breakers
   - [redacted] sets of disconnect switches
   - [redacted] potential transformers
   - Relays
   - MEER to house relays

   Little Rock Substation
   - Install a pair of relays

   Wilsona Substation
   - Install a par of relays

9. **Power System Control**
   Install one RTU at the new looped substation.

10. **Telecommunications:**
    Construct approximately 20 miles of overhead fiber optic cable the new substation and adjacent/affected substations.

    Also, install lightwave and channel equipment the new substation and adjacent/affected substations.

11. **Real Properties, Projects Licensing, andCorporate Environmental Health & Safety Organization**

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:

- New substation property
- Loop in lines
- Telecommunication requirements

RELIABILITY NETWORK UPGRADES

Transmission Network Circuit Breaker Upgrades (SCD)

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

- Install [redacted] sets of 500 kV TRV capacitors at Valley Substation
- Install [redacted] sets of 220 kV TRV capacitors at Antelope Substation
- Install [redacted] sets of 220 kV TRV capacitors at Colorado River Substation
- Replace [redacted] 220 kV CB's at Kramer Substation
- Replace [redacted] 220 kV CB's at Redondo Substation
- Install [redacted] sets of 220 kV TRV capacitors at Vista Substation

See the Group Report for additional details

QC3 RECOMMENDED DELIVERY NETWORK UPGRADES USED TO DERIVE DOLLAR-PER-MW VALUE

- North and South of Magunden 230 kV T/L upgrades
- Kramer-Windhub 500 kV T/L
- Mesa 500 kV Upgrades
- PG&E Upgrades Allocated to Northern Bulk System Projects

It should be noted that no cost for the facility upgrades that were assumed in this study under the Alternative Delivery Methodology is assigned to this Project given that the Project requested Energy Only interconnection.

See the Group Report section 11 for details.

DISTRIBUTION UPGRADES

Distribution Circuit Breaker Upgrades (SCD)

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

- Replace [redacted] 115 kV CB's at Garnet Substation
- Replace [redacted] 115 kV CB's at Inyokern Substation
- Replace [redacted] 66 kV circuit breakers at Vista Substation

- Replace [redacted] 12 kV circuit breakers at Lancaster Substation
- Replace [redacted] 12 kV circuit breakers at Piute Substation
- Replace [redacted] 4 kV circuit breakers at Victorville Substation

See the Group Report for additional details

Antelope East Area Upgrade
Sub-transmission
Rebuild the following subtransmission lines to 954 SAC

Lancaster-Purify Redman 66 kV Line from Collector Substation 2 to Q850

Antelope Area Upgrade

New 500/220/66 kV Substation and subtransmission system reconfiguration
Del Sur substation expansion and subtransmission system reconfiguration

See the Group Report section 11 for details.

Table 10.1: Upgrades, Estimated Costs, and Estimated Time to Construct Summary

Type of Upgrade	Upgrade (May include the following)	Description	Estimated Cost x 1,000 Constant Dollar (2011) *(Note 4)*	Estimated Cost x 1,000 Constant Dollar (OD Year) *(Note 4)*	Estimated Time to Construct (Months) *(Note 3)*
PTO's Interconnection Facilities *(Note 1)*	See Section 10 - PTO'S Interconnection Facilities	Non-network facilities needed to enable interconnection	$3,786	$4,271	27
Plan of Service Reliability Network Upgrades	See Section 10 – Plan of Service Reliability Network Upgrades	Direct Assigned Network Upgrades needed to enable interconnection.	$ 0	$ 0	
Reliability Network Upgrades	See Section 11.2 - Reliability Network Upgrades in the Group Report	Allocated Network Upgrades needed to maintain system Reliability	$ 0	$ 0	0
Reliability Network Upgrades	See Section 11.2 – Reliability Network Upgrades for SCD Mitigation in the Group Report	Allocated Network Upgrades needed to maintain system Reliability	$ 27	$ 30	24
Delivery Network Upgrades	See Section 11.3 - Delivery Network Upgrades in the Group Report	Network Upgrades needed to support Full Capacity Deliverability Status		$14,836	84
Distribution Upgrades *(Note 2)*	See Section 10 – Distribution Upgrades	Non-CAISO SCE Distribution Facilities	$63,195	$79,346	88
Distribution Upgrades *(Note 2)*	See Section 10 – Distribution Upgrades for Short-Circuit Duty Mitigation	Non-CAISO SCE Distribution Facilities	$ 87	$ 98	24
Total SCE Allocated Cost				**$98,581**	**88 Months**

Note 1: The Interconnection Customer is obligated to fund these upgrades and will not be reimbursed.

Note 2: These upgrades are not part of CAISO Controlled Grid, and are not reimbursable. Allocated costs may change if all projects responsible for these upgrades do not execute GIAs.

Note 3: The estimated time to construct (ETC) is for a typical project; schedules duration may change due to number of projects approved and release dates. Stacked projects impact resources, system outage availability, and environmental windows of construction. Assumption is SCE will need to obtain CPUC licensing and regulatory approvals prior to design, procurement and construction of the proposed facilities required to serve the interconnection customer and prerequisite facilities are in service.

Note 4 SCE's Phase I cost estimating is done in 'constant' dollars 2011 and then escalated to the estimated O.D.year. For the QC4 Phase I study, the estimated O.D. is derived by assuming the duration of the work element will begin in January 2013, which is the CAISO tariff scheduled completion date of the QC4 Phase II study plus 90 days for the GIA signing period. 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 January 2015. If an IC's requested O.D.(in- service) is beyond the estimated O.D. of a work element, the IC's requested O.D. is used

[redacted]

Cost Estimate Summary (2011 Dollars)

Scope: Interconnect 20 MW on the Little Rock - Wilsona 66 kV line via new looped substation

No.	ELEMENT	INTERCONNECTION FACILITIES (Subject to ITCC)	ITCC ** (35%)	TOTAL	TOTAL CONSTANT $ (ESTIMATED YEAR O.D.)****
					2015
	Sub - Transmission				
1	Loop in lines	$ -	$ -	$ -	
2	Gen-tie	$ 282,000	$ 99,000	$ 381,000	
	Substations				
1	New loop substation - IF Portion	$ 403,000	$ 141,000	$ 544,000	
2	New loop substation - Distribution Portion	$ -	$ -	$ -	
3	Install relays at Little Rock Substation	$ -	$ -	$ -	
4	Install relays at Wilsona Substation	$ -	$ -	$ -	
	Telecomm				
1	Install RTU circuit cross connections supporting SCADA	$ 12,000	$ 4,000	$ 16,000	
2	Install FO cable, lightwave, channel, & associated equipment supporting diverse Protection & SCADA	$ -	$ -	$ -	
	Environmental Health and Safety				
1	CEH & S - Primary Telecom: Provide control cables 'passed through the fence' to WDT727 Substation - N/A	$ -	$ -	$ -	
2	CEH & S - Install loop-in lines to support looping the 66-kV line and the SCE portion of the 66-kV gen-tie line - N/A	$ -	$ -	$ -	
3	CEH & S - Install loop-in lines to support looping the 66-kV line and the SCE portion of the 66-kV gen-tie line.	$ -	$ -	$ -	
4	CEH & S - Install a new segment of 66 kV gen-tie line between the generator-owned structure and the WDT727 Substation.	$ 563,000	$ 197,000	$ 760,000	
5	CEH & S - Construct a new 66 kV looped interconnection substation, referred to as the WDT726 Substation.	$ -	$ -	$ -	
6	CEH & S - Secondary (Diverse) Telecom: Install diverse fiber optic cable (10 mi.) from WDT727 Substation to Little Rock Substation on existing poles.	$ -	$ -	$ -	
7	CEH & S - Secondary (Diverse) Telecom: Install diverse fiber optic cable (10 mi.) from WDT727 Substation to Little Rock Substation (7 mi. on existing poles and 3 miles of new	$ -	$ -	$ -	
	Real Properties				
1	RP - activities to support project, telecom, gen tie, loop in acquisition, access easement	$ 1,422,000	$ 498,000	$ 1,920,000	
2	RP - activities to support project, substation, diverse telecom acquisition, access easement	$ -	$ -	$ -	
	Transmission Project Licensing				
1	TPL - activities to support project	$ -	$ -	$ -	
	Metering				
1	Retail Meter at the Generation Facility	$ 29,000	$ 10,000	$ 39,000	
	Power System Control				
1	RTU at the generation facility	$ 93,000	$ 33,000	$ 126,000	
2	RTU at the new loop substation	$ -	$ -	$ -	
3	RTU Pts. Names relabeling at Little Rock S/S and Wilsona S/S	$ -	$ -	$ -	
	Totals	$ 2,804,000	$ 982,000	$ 3,786,000	$ 4,271,000

* Pursuant to FERC Order 2003A, ITCC is not collected on Reliability Upgrades and One Time Costs.

** ITCC cost may be satisfied with a letter of credit in accordance with the tax provisions of the LGIA.

*** The ITCC included in this cost estimate was computed using a 35% rate. Because of recent enactment of H.R. 4853, the Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010, and upon formal acceptance by the CPUC of SCE's advice letter (filed on December 27, 2010), this rate may change for electric CIAC recorded or received after September 8, 2010 through December 31, 2011.

Cost estimate is only an estimate based on 2011 constant dollars and actual cost is subject to change depending on project construction date, and inflation

**** SCE's Phase I cost estimating is done in 'constant' dollars 2011 and then escalated to the estimated O.D year. For the QC4 Phase I study, the estimated O.D. is derived by assuming the duration of the work element will begin in January 2013, which is the CAISO tariff scheduled completion date of the QC4 Phase II study plus 90 days for the GIA signing period. 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 January 2015. If an IC's requested O.D. is beyond the estimated O.D. of a work element, the IC's requested O.D. is used.

11. Items not covered in this study

11.1 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.

11.2 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 QC4 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.

11.3 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).

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

11.5 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.

11.6 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.

11.7 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 (i.e., Generation-tie or Substation modifications) may be required to allow for ample protection coordination

11.8 Standby Power and Temporary Construction Power

The QC4 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.

11.9 Construction Schedule

The estimated time to construct (ETC) is for a typical project; schedules and duration may change due to number of projects approved and release dates. Stacked projects impact resources, system outage availability, and environmental windows of construction. The assumption is that SCE will need to obtain CPUC licensing and regulatory approvals prior to design, procurement and construction of the proposed facilities required to serve the interconnection customer and prerequisite facilities are in service.

11.10 Network/Non-Network Classification of Telecommunication Facilities

Telecommunication facilities between the SCE system and the IC generating facility were classified as non-network interconnection facilities. At the beginning of the Phase I study, each IC was asked whether they desired SCE to site, license, and construct diverse telecommunication facilities if such facilities were found to be required in the course of the study. If so, then those facilities were included in the interconnection facilities described in this report. If the customer did not wish SCE to site, license, and construct such facilities, then those facilities were not included in this Phase I report. Going forward, It will be the responsibility of the IC to site, license, and construct such facilities.

Attachment 1

Not Used

Attachment 2

Not Used

Attachment 3

Not Used

Attachment 4

Short Circuit Calculation Study Results

Please refer to the Appendix H of the Group report.

Attachment 5

Deliverability Assessment Results

Please refer to the Appendix I of the Group report.