BrightSource

December 7, 2012

Pierre Martinez
Project Manager
Systems Assessment & Facility Siting Division
California Energy Commission
1516 Ninth Street, MS-15
Sacramento, CA 95814

SUBJECT: QC3 and QC4 Phase II Interconnection Study Report for Rio Mesa Solar Electric Generating Facility (11-AFC-4)

Dear Mr. Martinez:

Attached please find the Phase 2 Queue Cluster report for QC3 and QC4 for the Eastern Riverside Bulk System. This report is subject to changes per rules set forth by the California Independent System Operator (CAISO) due to the ongoing "results meetings" being held with the various applicants.

I would like to call your attention to Section J of the report, page 57, and ask that your staff person reviewing the Alternatives chapter review this information as it is directly pertinent to the argument that a PV project is preferable to a solar thermal project. This statement from the CAISO should be viewed in companion to the environmental arguments we submitted in comments to the PSA.

In summary, the CAISO states that the system capacity would need to be reduced by 700-900 MW if only PV projects were dispatched in lieu of solar thermal projects due unacceptable system post transient stability performance.

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If you have any questions, please do not hesitate to contact me.

Sincerely,

Todd Stewart
Senior Director of Project Development

QC3 and QC4 Phase II Interconnection Study Report

Group Report in SCE's Eastern Bulk System

Final Report

November 5, 2012

This study has been completed in coordination with Southern California Edison per CAISO Tariff Appendix Y, for Interconnection Requests in a Queue Cluster Window

Table of Contents

Appendices:

Definitions

CAISO	California Independent System Operator Corporation
COD	Commercial Operation Date
Deliverability Assessment	CAISO's Deliverability Assessment
EKWRA	East Kern Wind Resource Area
EO	Energy Only Deliverability Status
FC	Full Capacity Deliverability Status
FERC	Federal Energy Regulatory Commission
IC	Interconnection Customer
IID	Imperial Irrigation District
LADWP	Los Angeles Department of Water and Power
LFBs	Local Furnishing Bonds
LGIA	Large Generator Interconnection Agreement
LGIP	Large Generator Interconnection Procedures
PMax	Maximum generation output
NERC	North American Electric Reliability Corporation
NQC	Net Qualifying Capacity as modeled in the Deliverability Assessment
PG&E	Pacific Gas and Electric Company
Phase I Study	Cluster Phase I Study
Phase II Study	Cluster Phase II Study
PTO	Participating Transmission Owner
RAS	Remedial Action Scheme (also known as SPS)
POI	Point of Interconnection
POS	Plan of Service
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric Company
SPS	Special Protection System (also known as RAS)
SVC	Static VAR Compensator
TPP	CAISO's Transmission Planning Process
TWRA	Tehachapi Wind Resource Area
TRTP	Tehachapi Renewable Transmission Project
WECC	Western Electricity Coordinating Council

A. Executive Summary

In accordance with Federal Energy Regulatory Commission (FERC) approved Generator Interconnection Procedures (GIP) for Interconnection Requests in a Queue Cluster Window (CAISO Appendix Y), this Phase II study was performed to determine the combined impact of all the projects in Queue Cluster 3 and Queue Cluster 4 (QC3&4) on the CAISO Controlled Grid.

There are sixty-two (62) QC3&4generation projects in SCE's service territory considered in the Phase II study. Of these 62 generation projects, 17 are previously queued Energy Only projects requesting Full Capacity Deliverability status (pursuant to CAISO Tariff Appendix Y Section 8.1, the one-time Full Capacity Deliverability status option), and the remaining 45 are new interconnection requests submitted during the open window period associated with QC3&4. Five general study areas[1] are formed based on the electrical impact among the generation projects: Northern Bulk System, Eastern Bulk System, East of Pisgah Bulk System (EOP), North of Lugo Bulk System (NOL), and Metro System.

This study report provides the following:

1. Transmission system impacts caused by the addition of sixteen (16) QC3&4 Phase II projects requesting interconnection in the Eastern Bulk System.

2. System reinforcements necessary to mitigate the adverse impacts of the 16 Phase II projects requesting interconnection in the Eastern Bulk System under various system conditions.

3. The responsibility for financing the cost of necessary system reinforcements and interconnection facilities, and a good faith estimate of the time required to permit, engineer, design, procure, construct, and place into operation these necessary system reinforcements and interconnection facilities.

To determine the system impacts caused by QC3&4 Phase II projects, the following studies were performed:

- Steady State Power Flow Analyses
- Short-Circuit Duty Analyses
- Transient Stability Analyses
- Reactive Power Deficiency Analyses
- Deliverability Assessment
- Operational Studies

[1] Precise electrical groupings were created during the deliverability study for Delivery Network cost allocation purposes.

The results of above studies indicated that QC3&4 Phase II projects are responsible for the overloading of several transmission facilities and overstressing of several circuit breakers at a number of substations in SCE's service territory. Network Upgrades[2] and Distribution Upgrades to mitigate identified problems corresponding to the sixteen QC3&4 Phase II projects requesting interconnection in the Eastern Bulk System have been proposed in this report. The following tables show a summary of the proposed Network Upgrades along with an estimated cost.

Table A – Plan of Service Reliability Network Upgrades[3,4]

1	Various (see individual Appendix A reports)	
	TOTAL	**$15,880,000**

Table B – Reliability Network Upgrades[3,4]

1	Expansion of the proposed Colorado River Corridor SPS	**$1,044,000**
2	New Red Bluff Substation SPS (N-1)	**$1,205,000**
3	Expansion of the proposed Colorado River Substation SPS	**$1,172,000**
4	SCD Mitigation	**$1,713,000**
	TOTAL	**$5,134,000**

Table C – Delivery Network Upgrades[5,4]

1	Colorado River AA-Bank No.3 500/220 kV	**$60,626,000**
2	Devers – Red Bluff No.1 500 kV T/L (Rating Increase)	**$86,827,000**
3	Red Bluff 500/220 kV Substation Capacity Increase	**$60,626,000**
	TOTAL COST FOR EASTERN BULK SYSTEM UPGRADES	**$208,079,000**
	East of Pisgah System Upgrades Allocated to Eastern Bulk Projects	
1	Upgrade Lugo-Eldorado 500 kV T/L series caps to 3800 amps	**$96,756,000**
2	Upgrade Lugo-Eldorado 500 kV T/L Substation terminal equipment to 4000 amps at each end	**$24,063,000**
3	Upgrade Lugo - Mohave 500 kV T/L series cap at Mohave to 3800 amps	**$48,378,000**
4	Equip Lugo line position at Mohave with 4000 Amps rated equipment	**$12,065,000**
	TOTAL COST EAST OF PIGAH SYSTEM UPGRADES ALLOCATED TO EASTERN BULK PROJECTS	**$181,262,000**

2 The additions, modifications, and upgrades to the CAISO Controlled Grid required at or beyond the Point of Interconnection to accommodate the interconnection of the Generating Facility to the CAISO Controlled Grid. Network Upgrades shall consist of Delivery Network Upgrades and Reliability Network Upgrades. Network Upgrades do not include Distribution Upgrades.

3 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.

4 Note: In some instances, the total cost per upgrade provided in this table may include one-time cost. Those one-time costs are non-refundable and if pertinent to your Project are identified in Section D of your corresponding Appendix A report.

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.

Table D – Distribution Upgrades[6,7]

1	SCD Mitigation	$1,211, 000
	TOTAL	**$1,211,000**

Table E – Other[8]

1	Ground Grid Analysis for flagged SCE Substations	
	TOTAL	NA

These upgrades do not include Interconnection Facilities, which are the obligation of each Interconnection Customer to fund. It should be noted that for each project interconnecting directly to an SCE substation, cost for a ground grid study were incorporated as part of the Interconnection Facilities. For projects requesting interconnection to new substations, such cost was not applied as the ground grid design at these substations would enable for a maximum 63 kA for 500 kV and 220 kV Substation open-air design. The Interconnection Facilities relating to each individual project are discussed in the corresponding Appendix A. Distribution upgrades identified in Table D are non-refundable.

Given the magnitude of above upgrades, a good faith estimate to engineer, license, procure, and construct all facilities identified in the above tables could be up to 84 months from Interconnection Agreement execution. Timelines required to engineer, license, procure, and construct facilities necessary for interconnection and/or delivery of each individual project are discussed in Appendix A.

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6 These upgrades are not part of the CAISO Controlled Grid, and are not reimbursable, and subject to Income Tax Component of Contribution (ITCC). The ITCC included is this cost estimate was computed using a 35% rate.

7 For distribution cost associated to upgrades in the Blythe and Colorado River corridor please see applicable individual Appendix A report, similarly for distribution cost for project in the Eastern area (below 115 kV) see WDAT Appendix A reports..

8 These are one-time cost that correspond with the results of the application queue ground grid analysis, please refer to Section H.1.3 and Section K for details.

B. Phase II Interconnection Information

A total of sixteen (16) generation projects made up the QC3&4 Phase II Eastern Area Cluster.

There are five (5) generation projects totaling a maximum output of 2,061 MW included in QC3&4 Phase II Study for the Eastern Bulk System. Table B.1 lists all the new generator projects in the Eastern Bulk System with essential data obtained from the CAISO Generation Queue.

Additonally, nine (9) generation projects totaling a maximum output of 67.78 MW are included in QC3&4 Phase II study for the SCE Eastern distrubution system. Table B.2 lists all these new generator projects with essential data obtained from the SCE WDAT Generation Queue.

Lastly, there are two (2) projects totaling a maximum output of 25.0 MW, that elected the one-time Full Capacity Deliverability status option within the QC4 Application Window.Table B.3 lists these 2 projects.

Table B.1: SCE QC3&4 Phase II Projects (Eastern Bulk System)

Project Number	Point of Interconnection	Full Capacity/ Energy Only	Fuel	Max MW
CAISO Q643AE	Red Bluff Substation 220 kV	FC	PV	150
CAISO Q643AC	Colorado River Substation 220 kV	FC	Solar Thermal	750
CAISO Q797	Red Bluff Substation 220 kV	FC	Solar	400
CAISO Q831	Colorado River Substation 220 kV	FC	Solar Thermal	540
CAISO Q798	Colorado River Substation 220 kV	EO	PV	221
			Total Generation	**2,061**

Table B.2: SCE QC3&4 Phase II Projects (Eastern Distribution System)

Project Number	Point of Interconnection	Full Capacity/ Energy Only	Fuel	Max MW
WDT492	Lena 12 kV ckt out of Cardiff 66/12 kV substation (San Bernardino 220/66 kV System)	EO	PV	1.6
WDT493	Lena 12 kV ckt out of Cardiff 66/12 kV substation (San Bernardino 220/66 kV System)	EO	PV	0.5
WDT590	Limonite 33 kV ckt out of Calelectric 115/33 kV substation (Vista 220/66 kV System)	EO	PV	8.18
WDT609	Sprague 12 kV ckt out of Mayberry 115/12 kV substation (Valley 500/115 kV System)	EO	PV	5
WDT668	Lauda 33 kV ckt out of Nelson 115/33 kV substation (Valley 500/115 kV System)	EO	PV	20
WDT689	Durox 12 kV ckt out of Timoteo 66/12 kV substation (San Bernardino 220/66 kV System)	EO	PV	1.5
WDT764	Autry 12 kV ckt out of Farrell 15/12 kV (Devers 220/115 kV System)	EO	PV	6
WDT786	Resort 33 kV ckt out of Nelson 115/33 kV substation (Valley 500/115 kV System)	FC	PV	20
WDT787	Corsair 12 kV ckt out of Stetson 115/12 kV substation (Valley 500/115 kV System)	EO	PV	5
			Total Generation	**67.78**

Table B.3: SCE QC3&4 Phase II Energy Only to Full Capacity Interconnection Requests

Project Number	Point of Interconnection	Full Capacity/ Energy Only	Fuel	Max MW
WDT357DS	Cheslor 33 kV ckt % Blythe (WALC) 161/33 kV substation (Blythe 161/33 kV System)	FC	PV	20
WDT440DS	Tram 33 kV ckt % Garnet 115/33 kV substation (Devers 220/115 kV System)	FC	PV	5
			Total Generation	**25**

C. Study Objectives

This Phase II Interconnection study was performed in accordance with Section 7.1 of Appendix Y of the CAISO tariff, which states:

The Phase II Interconnection study shall:

(i) update, as necessary, analyses performed in the Phase I Interconnection Studies to account for the withdrawal of Interconnection Requests,

(ii) identify final Reliability Network Upgrades needed to physically interconnect the Generating Facilities,

(iii) assign responsibility for financing the identified final Reliability Network Upgrades,

(iv) identify, following coordination with the CAISO's Transmission Planning Process, final Delivery Network Upgrades needed to interconnect those Generating Facilities selecting Full Capacity Deliverability status;

(v) assign responsibility for financing Delivery Network Upgrades needed to interconnect those Generating Facilities selecting Full Capacity Deliverability status;

(vi) identify for each Interconnection Request final Point of Interconnection and Participating TO's Interconnection Facilities;

(vii) provide a +/-20% estimate for each Interconnection Request of the final Participating TO's Interconnection Facilities;

(viii) optimize in-service timing requirements based on operational studies in order to maximize achievement of the Commercial Operation Dates of the Generating Facilities; and

(ix) if it is determined that the Delivery Network Upgrades cannot be completed by the Interconnection Customer's identified Commercial Operation Date, provide that operating procedures necessary to allow the Generating Facility to interconnect as an energy-only resource, on an interim-only basis, will be developed and utilized until the Delivery Network Upgrades for the Generating Facility are completed and placed into service.

This same section continues and further states that the Phase II Interconnection study shall:

(x) specify and estimate the cost of the equipment, engineering, procurement and construction work, including the financial impacts (i.e., on Local Furnishing Bonds), if any, and schedule for effecting remedial measures that address such financial impacts, needed on the CAISO Controlled Grid to implement the conclusions of the updated Phase II Interconnection study technical analyses in accordance with Good Utility Practice to physically and electrically connect the Interconnection Customer's Interconnection Facilities to the CAISO Controlled Grid; and

(xi) also identify the electrical switching configuration of the connection equipment, including, without limitation: the transformer, switchgear, meters, and other station equipment; the nature and estimated cost of any Participating TO's Interconnection Facilities and Network Upgrades necessary to accomplish the interconnection; and an estimate of the time required to complete the construction and installation of such facilities.

The Phase II study analysis was performed to identify the Interconnection Facilities, Plan of Service Reliability Network Upgrades, Reliability Network Upgrades, Delivery Network Upgrades and Distribution Upgrades necessary to safely and reliably interconnect the Phase II projects into the CAISO Controlled Grid. An estimated cost and construction schedule for these facilities have also been provided in this report.

D. Study Assumptions

D.1 Power flow base cases

The QC3&4 Phase II Study used power flow base cases representing peak 2015 and off-peak 2015 system conditions in the SCE service territory. These base cases included all CAISO approved transmission projects, as well as higher queued generation projects with associated Network Upgrades and Special Protection Systems.

D.2 Load and Import

The Deliverability Assessment On-Peak case modeled a 24,718 MW load in SCE system with an import target as shown in Table D.2. The Off-Peak case modeled a 16,140 MW load in SCE system.

Table D.2: On-Peak Deliverability Assessment Import Target

BG Iface #	Branch Group Name	Direction	Net Import MW	Import Unused ETC & TOR MW
911	Lugo-Victorville-BG	N-S	1306	171
904	COI_BG	N-S	3770	548
901	BLYTHE_BG	E-W	90	0
902	CASCADE_BG	N-S	17	0
903	CFE_BG	S-N	-95	0
905	ELDORADO_MSL	E-W	1011	0
907	IID-SCE_BG	E-W	1500	0
908	IID-SDGE_BG	E-W		0
910	LAUGHLIN_BG	E-W	-41	0
921	MCCULLGH_MSL	E-W	14	316
912	MEAD_MSL	E-W	350	585
914	NGILABK4_BG	E-W	-105	168
PDCI	NOB_BG	N-S	1283	0
916	PALOVRDE_MSL	E-W	2899	124
917	PARKER_BG	E-W	123	22
919	SILVERPK_BG	E-W	0	0
920	SUMMIT_BG	E-W	-8	0
915	SYLMAR-AC_MSL	E-W	-72	459
Total			12042	2393

The Reliability Assessment Summer Peak Case modeled a 27,028 MW load. The off-peak load case represented about 60% of summer peak load.

While it is impractical to study all combinations of system load and generation levels during all seasons and at all times of the day, the base cases were developed to represent stressed scenarios of loading and generation conditions for the study group area.

D.3 Generation Assumptions

Generation assumptions for SCE's Eastern Bulk System[9] are shown in Table D.3.1 (Existing Generation), Table D.3.2 (Active Queued Ahead Serial), Table D.3.3 (Transition Cluster), Table D.3.4 Pre Queue Cluster 1 and 2 Phase II SGIP Projects (Pre QC1&2 Phase II SGIPs), Table D.3.5 QC1&2 Phase II Projects (QC1&2 Phase II), Table D.3.6 Pre QC3&4 Phase II Projects (Pre QC3&4 Phase II SGIPs), and Table D.3.7 which summarizes the Rule 21 projects in the area.

[9] Only SCE's Northern Bulk System generation (including Big Creek Corridor and Ventura areas) is shown in the provided tables.

Generation dispatch assumptions in Deliverability Assessment can be found at http://www.caiso.com/Documents/Deliverability%20assessment%20methodologies. In the on-peak Deliverability Assessment, the Peak Qualified Capacity for proposed Full Capacity generation projects is set to 64% of the requested PMax for wind generation and 100% of the requested PMax for Solar generation initially. The Summer Peak QC may be adjusted to 40% of the requested PMax for wind generation and 85% for solar generation if a mix of different fuel type generations is identified in the Deliverability Assessment as the 5% DFAX group for a transmission limitation. In the off-peak Deliverability Assessment, the proposed Full Capacity wind generation is dispatched at its requested PMax and solar generation at 85% of its requested PMax.

In the Reliability Assessment, the generation is dispatched at PMax.

Table D.3.1: Existing Generation

Locations	Type	Size (MW)
Devers Area	Wind	873
East of Devers Area	N-Gas	520
Eastern Bulk	QF	472
	Total	1,865

Table D.3.2: Active Queued Ahead Serial Interconnection Requests

#	CAISO Queue #	SCE Project ID	Interconnection Point	Size (MW)
1	A.39	TOT015	Tiffanywind 115 kV)	45
2	A.39	TOT004	San Bernardino 230 kV	1,000
3	WDAT	WDT042	Seawind 115 kV)	40
4	A.39	TOT019	Mountwind 115 kV)	44.4
5	A.39	TOT021	Mountwind 115 kV)	22.2
6	A.39	TOT051	Mountwind 115 kV)	22.4
7	A.39	TOT048	Indigo 115 kV	45.3
8	A.39	TOT056	Indigo 115 kV	90.6
9	WDAT	WDT073	Colton 66 kV (Out of Vista)	80
10	WDAT	WDT075	Eastside 115 kV (Out of Valley)	39.6
11	WDAT	WDT080	Colton Cement 66 kV (Out of Vista)	28.5
12	WDAT	WDT053	Banwind 115 kV	42.6
13	WDAT	WDT092	Sanwind 115 kV	66
14	WDAT	WDT098	Vista 66 kV	40
15	WDAT	WDT019	City of Colton (Out of Vista)	40
16	3	TOT032	Devers 220 kV Bus	850
17	17	TOT079	Colorado River 500 kV Bus	520
18	23	TOT109	San Bernardino 220 kV	72
19	49	TOT120	Devers 115 kV Bus	100.5
20	WDAT	WDT177	City of Riverside (Out of Vista)	96
21	50	TOT037	Valley 500 kV	800
22	WDAT	WDT179	Colton-Bloomington 66 kV Line	49.9

23	WDAT	WDT182	Valley 115 kV	507.5
24	72	TOT132	Alberhill 500 kV	500
25	WDAT	WDT213	Blast 115 kV	49
26	WDAT	WDT230	Eitwanda 66 kV	44.6
27	138	TOT185	Devers-Vista No.2 220 kV T/L (via new Substation)	150
28	146	TOT198	Red Bluff 220 kV Bus	150
29	147	TOT199	Red Bluff 220 kV Bus	400
30	219	TOT237	Colorado River 500 kV Bus	50
31	WDAT	WDT263	Blythe 33 kV	21
			TOTAL	6,007

Table D.3.3: Transition Cluster Interconnection Requests

#	CAISO Queue #	SCE Project ID	Interconnection Point	Size (MW)
1	193	TOT233	Colorado River 220 kV Bus	500
3	294	TOT276	Colorado River 220 kV Bus	1,000
4	365	TOT321	Red Bluff 220 kV Bus	500
2	421	TOT349	Blythe-Eagle Mountain 161 kV T/L (via new substation)	49.5
			TOTAL	2,050

Table D.3.4: Pre-QC1&2 Phase II Serial SGIP Interconnection Requests

#	CAISO Queue #	SCE Project ID	Interconnection Point	Size (MW)
1	WDAT	WDT011	Renwind 12 kV	9
2	WDAT	WDT034	Garnet 33 kV	2.1
3	WDAT	WDT016	Garnet 33 kV	11.6
4	A.39	TOT023	Buckwind 115 kV	3.8
5	1	TOT022	Buckwind 115 kV	16.5
6	WDAT	WDT176	Garnet 33 kV	6.5
8	WDT	WDT401	Venwind 115 kV	20
10	WDT	WDT334	Hi Desert 115 kV	20
11	WDT	WDT357	Blythe 33 kV	20
13	WDT	WDT423	Hi Desert 33 kV	2
14	WDT	WDT458	Hi Desert 33 kV	10
15	WDT	WDT459	Hi Desert 33 kV	9
			TOTAL	131

Table D.3.5: QC1&2 Phase II Interconnection Requests

#	CAISO Queue #	SCE Project ID	Interconnection Point	Size (MW)
1	576	TOT446	Colorado River 220 kV	485
2	588	TOT453	Red Bluff 220 kV	200
3	WDAT	WDT400	Pan Aero 115 kV	30
4	632AA	TOT476	Devers - Farrell 115 kV	13
			TOTAL	728

Table D.3.6: Pre-QC3&4 Phase II Serial SGIP Interconnection Requests

#	CAISO QUEUE #	SCE Project ID	Interconnection Point	Size (MW)
1	WDAT	WDT440	Tram (Devers) 33 kV	5
2	WDAT	WDT450	Bacardi (Mira Loma) 12 kV	1
3	WDAT	WDT451	Bacardi (Mira Loma) 12 kV	1
4	WDAT	WDT463	Metro (Padua) 12 kV	1
5	WDAT	WDT464	Absolut (Mira Loma) 12 kV	0.5
6	WDAT	WDT466	Redlabel (Mira Loma) 12 kV	0.5
7	WDAT	WDT471	Andretti (Padua) 12 kV	0.75
8	WDAT	WDT473	Earnhardt (Padua) 12 kV	1.75
9	WDAT	WDT462ISP		7.95
			TOTAL	19.45

Table D.3.7: Area Rule 21 Projects

#	CAISO QUEUE #	SCE Project ID	System	Size (MW)
1	Rule 21	GFID	Devers 230/115 kV	82.79
2	Rule 21	GFID	Eagle Rock 230/66 kV	4.5
3	Rule 21	GFID	Parker 161/66 kV	10.5
4	Rule 21	GFID	San Bernardino 230/66 kV	1.3
5	Rule 21	GFID	Valley 500/115 kV	8.13
6	Rule 21	GFID	Vista 230/115 kV	11.65
			Total	118.87

D.4 New Transmission Projects

This QC3&4 Phase II study included the modeling of all CAISO-approved transmission projects in the Eastern Bulk System base cases. In addition, a number of transmission upgrades are needed to support queued ahead generation projects in the Eastern Bulk System were modeled in order to determine if additional facilities would be needed to support the Phase II projects.

D.4.1 Devers – Mirage Split Project

SCE's Devers and Mirage 115 kV systems are operated in parallel with the local 220 kV systems. Such configuration caused peak time overloads on the 115 kV systems. Reconfiguring the Devers 115 kV and Mirage 115 kV systems to be operated radial from the 220 kV system will mitigate the identified overloads and increase local reliability to serve load. The Devers-Mirage Split Project has received final approval from the CPUC.

D.4.2 Devers – Colorado River Project (DCR)

SCE has obtained the Certification of Public Convenience and Necessity for the DCR Project. The DCR Project consists of a new Colorado River 500 kV switchyard (CRS), a new 125.4 mile 500 kV transmission line from the proposed Colorado River 500 kV switchyard to the existing Devers Substation, and a new 42 mile 500 kV transmission line between the Devers Substation and Valley Substation. As part of this project, the existing Devers-Palo Verde 500 kV transmission line will be looped in-and-out of CRS forming the new Colorado River-Devers 500 kV and new Colorado River-Palo Verde 500 kV transmission lines. The DCR Project is in the construction phase.

D.4.3 Red Bluff 500/220 kV Substation

Two solar projects in the Serial Group, totaling 550 MW, proposed to interconnect in to SCE'/MWD's J. Hinds and Eagle Mountain area. These two projects would result in overloading the Metropolitan Water District's 220 kV system and would cause costly system upgrades and interruption of the MWD's pump services during the construction of the system upgrades. To provide for the interconnection of these two projects, the Red Bluff Substation was proposed as the most viable alternative to interconnect these two projects directly into SCE's existing Palo Verde – Devers 500 kV line (DPV1 Line). The Red Bluff Substation, to be located approximately two miles east of the DPV1 California series capacitors s on the DPV1 line, will be connected to the existing DPV1 500 kV transmission line by looping the line in-and-out of the substation creating a new Devers-Red Bluff No.1 500 kV and new Colorado River-Red Bluff No.1 500 kV transmission lines.

D.4.4 Loop the Colorado River – Devers 500 kV No.2 Transmission Line into Red Bluff Substation

As part of the Transition Cluster, generation projects located in the Eastern Area triggered the need to loop the new Devers - Colorado River No.2 500 kV T/L, proposed as part of the DCR Project, into Red Bluff Substation forming the new Devers-Red Bluff No.2 500 kV and new Colorado River-Red Bluff No.2 500 kV transmission lines.

D.4.5 Colorado River Substation Expansion

As part of the Transition Cluster, generation projects seeking interconnection to the Colorado River Substation triggered the need to expand the substation. The expansion involves the installation of a 220 kV switch rack with two 500/220 kV 1120MVA transformer banks. The timing of the 2nd AA-Bank upgrade is contingent upon the development of generation projects interconnecting at Colorado River Substation 220 kV bus.

D.4.6 Red Bluff Substation Expansion

As part of the Queue Cluster 2, generation projects seeking interconnection to the Red Bluff Substation triggered the need for the second 500/220 kV 1120MVA transformer bank. The timing of this upgrade is contingent upon the development of Queue Cluster 2 generation projects interconnecting to Red Bluff Substation 220 kV bus. In the event, the Queue Cluster 3&4 Phase II generation projects interconnecting to the Red Bluff Substation 220 kV bus require an earlier operating date or advance into an interconnection agreement in advance of the Queue Cluster 2 project, the QC3&4 Phase II projects would require the advancement of the second AA bank installation. Under such condition, QC3&4 Phase II projects would be required to provide the advancement cost of the second AA bank at Red Bluff.

In addition, the Queue Cluster 2 generation projects that triggered the need for the second 500/220 kV transformer at Red Bluff have not executed an LGIA yet. Therefore, at the time of publishing this report, the cost responsibility for this transformer was uncertain. If these projects were to choose to not execute their LGIA, then funding for the transformer would not exist. Because, Queue Cluster 3&4 generation projects would trigger this project in this scenario, Queue Cluster 3&4 projects have been assigned the cost of this transformer. When the Queue Cluster 2 generation executes an LGIA, then the Queue Cluster 3&4 cost responsibility for the second 500/220 kV transformer at Red Bluff will be removed from the Phase II study results for the Queue Cluster 3&4 projects.

D.4.7 Upgrade Mira Loma – Vista No.2 220 kV T/L Line Drops at Vista Substation

As part of the Transition Cluster, generation projects located in the Eastern Area triggered the need to replace the existing 2-1033KCMIL ACSR conductors on the existing Mira Loma-Vista No.2 220 kV line position at Vista Substation with new 2-1590KCMIL ACSR Conductors.

D.4.8 West Of Devers Upgrades

As part of the Transition Cluster, generation projects located in the Eastern Area triggered the need upgrade the following 220 kV transmission lines by replacing all existing infrastructure with new structures that can support bundled 1590 KCMIL ACSR conductors. In addition, all substations terminal equipment will need to be upgraded to 3,000A rated elements:

- Devers – San Bernardino No.1 230 kV T/L
- Devers – San Bernardino No.2 230 kV T/L
- Devers – Vista No.1 230 kV T/L
- Devers – Vista No.2 230 kV T/L

The completion date for this upgrade was initially estimated to be early 2018. However, the initial estimated in-service date predicated upon obtaining transmission rights-of-way across the Morongo Reservation in sufficient time to allow SCE to submit its Application for a Certificate of Public Convenience and Necessity to the CPUC by October 2012. Despite diligent efforts, SCE has yet to obtain the critical rights-of-way that would secure a project route location, which has impacted the ability to complete preliminary engineering and environmental surveys as well as license/permits for the route. In addition, SCE's recent experience with other large transmission projects indicates that the time to obtain regulatory approvals will likely take longer than originally anticipated, and that complying with environmental mitigation measures that may be imposed by the regulatory authorities could cause further delays to construction. As such, SCE has a reasonable expectation that the activities required for completion of West of Devers will be delayed by at least a year, and possibly longer.

D.5 Other SPSs and Operator Actions

All new SPSs and modifications to existing ones will be designed with consideration of CAISO SPS guidelines and are subject to review by Affected Parties and members of the WECC Remedial Action Scheme Reliability Subcommittee (RASRS).

D.5.1 Blythe Energy RAS

The Blythe Energy RAS is designed to prevent transmission line overloads as well as system instability in the Julian Hinds area. These problems could occur during high generation conditions under certain transmission conditions. The following outlines the RAS functionality:

- Mitigate thermal overload on Julian Hinds-Mirage 230 kV line
- Mitigate thermal overload on MWD section of the Julian Hinds 230 kV Operating or Transfer Bus
- Address System instability

D.5.2 Proposed Colorado River Corridor SPS

As part of the Transition Cluster, generation projects located in the Eastern Area triggered the need for a new Colorado River Corridor SPS. This SPS involves tripping up to 1,400 MW of the new generation projects under double outage or 1150 MW under single outage conditions. Specifically, the new SPS is envisioned to monitor line status for various outage conditions among the following lines:

- Red Bluff – Devers 500 kV T/L No.1
- Red Bluff – Devers 500 kV T/L No.2
- Colorado River – Red Bluff 500 kV T/L No.1
- Colorado River – Red Bluff 500 kV T/L No.2
- Devers – Valley 500 kV T/L No.1
- Devers – Valley 500 kV T/L No.2

If outage of the monitored lines occurs, generation projects interconnected at Colorado River and/or Red Bluff Substation will be tripped to prevent transmission line or transformer bank overloads as well as system instability.

D.5.3 Proposed Colorado River Substation SPS

As part of the Transition Cluster, generation projects seeking interconnection to the Colorado River Substation triggered the need for a new Colorado River substation SPS. SPS involves tripping new generation projects under loss of one 500/220 kV transformer bank at Colorado River Substation to prevent a thermal overload on the remaining transformer banks planned to be added as part of the CRS expansion.

D.5.4 Proposed LEAPS SPS

The SPS was proposed from LEAPS SIS Re-Study and will be placed into service concurrent with LEAPS.

D.5.5 Operating Procedures

Operating procedures, which may include curtailing the output of the QC3&4 Phase II projects during planned or extended forced outages, may be required for reliable operation of the transmission system. These procedures, if needed, will be developed before the projects' Commercial Operation Date.

D.6 Queued Ahead Triggered Circuit Breaker Upgrades, Replacement or Mitigation Requirements

This QC3&4 Phase II Study evaluated both the pre-QC3&4 and post-QC3&4 conditions to properly identify all queue-ahead triggered short-circuit duty mitigations and properly assign mitigation for those impacts that are triggered by the addition of QC3&4. It is important to recognize that previous studies may have identified mitigation requirements which are now different due to the number of project withdrawals that have occurred since the queued-ahead studies were completed. As a result, it is possible that the mitigation previously defined in a queued ahead project's study is now assigned to projects as part of this QC3&4 Phase II Study. Section H provides both a list of previously triggered short-circuit duty mitigations based on most current interconnection queue as well as short-circuit duty mitigations triggered with the addition of the projects that are part of this QC3&4 Phase II Study.

D.7 Transmission Upgrades outside the CAISO Controlled Grid

No transmission upgrades outside the CAISO controlled grid were identified as in the previous generation interconnection studies for the SCE Eastern System.

E. Study Criteria and Methodology

E.1 Reliability Standards and Criteria

The generator interconnection studies will be conducted to ensure the CAISO-controlled-grid is in compliance with the North American Electric Reliability Corporation (NERC) reliability standards, WECC regional criteria, and the CAISO planning standards.

E.1.1 NERC Reliability Standards

The CAISO will analyze the need for transmission upgrades and additions in accordance with NERC reliability standards, which set forth criteria for system performance requirements that must be met under a varied but specific set of operating conditions. The following NERC reliability standards are applicable to the CAISO as a registered NERC planning authority and are the primary standards for the interconnection of new facilities and system performance[10]:

- FAC-002: Coordination of Plans for New Facilities

[10] http://www.nerc.com/page.php?cid=2%7C20

- TPL-001: System Performance Under Normal Conditions (category A);
- TPL-002: System Performance Following Loss of a Single Bulk Electric System (BES) Element (category B); and
- TPL-003:System Performance Following Loss of Two or More BES Elements
  (category C)

E.1.2 WECC Regional Criteria

The WECC TPL system performance criteria are applicable to the CAISO as a planning authority and set forth additional requirements that must be met under a varied but specific set of operating conditions.[11]

E.1.3 California ISO Planning Standards

The California ISO Planning Standards specify the grid planning criteria to be used in the planning of CAISO transmission facilities.[12] These standards cover the following:

- address specifics not covered in the NERC reliability standards and WECC regional criteria;
- provide interpretations of the NERC reliability standards and WECC regional criteria specific to the CAISO-controlled grid; and
- identify whether specific criteria should be adopted that are more stringent than the NERC standards or WECC regional criteria.

E.1.4 Contingencies

The system performance with the addition of the generation projects will be evaluated under normal conditions and following loss of single or multiple BES elements as defined by the applicable reliability standards and criteria.

Table E.1 summarizes the contingencies per NERC Reliability Standards WECC Regional Criteria and CAISO Planning Standards.

[11] http://compliance.wecc.biz/application/ContentPageView.aspx?ContentId=71
[12] http://www.caiso.com/Documents/TransmissionPlanningStandards.pdf

Table E.1: Contingencies

Contingencies	Description
NERC TPL-001 NERC Category A (No contingency)	All facilities in service – Normal Conditions
NERC TPL-002 Category B	■ B1 –SLG or 3Φ Fault, with Normal Clearing: single generator outage ■ B2 –SLG or 3Φ Fault, with Normal Clearing: single transmission circuit outage ■ B3 –SLG or 3Φ Fault, with Normal Clearing: single transformer outage ■ B4 –Single Pole Block, with Normal Clearing: single pole (dc) line outage
CAISO Planning Standard Category B	■ II.2. – Selected overlapping single generator and transmission circuit outages ■ II.5. –Loss of combined cycle power plant module
NERC TPL-003 Category C	■ C1 –SLG Fault, with Normal Clearing: Bus outages ■ C2 –SLG Fault, with Normal Clearing: Breaker failures ■ C3 –SLG or 3Φ Fault, Combination of any two-generator/transmission line/transformer outages except these in CAISO Category B ■ C4 –Bipolar Block, with Normal Clearing: Bipolar (dc) Line ■ C5 –Outages of double circuit tower lines ■ C6 –SLG Fault, with Delayed Clearing: Generator ■ C7 –SLG Fault, with Delayed Clearing: Transformer ■ C8 –SLG Fault, with Delayed Clearing: Transmission Circuit ■ C9 –SLG Fault, with Delayed Clearing: Bus Section
WECC Regional Criteria TPL-001-WECC-CRT-2 Category C	■ R1.1 –SLG Fault, with Normal Clearing: two adjacent transmission circuits (greater than 300 kV) on separate towers

In the QC3&4 Phase II study, all Categories B, C4 C5, WECC R1.1, as well as the worst Categories C1 ~ C3 and C6 ~ C9 outages, in the electrical vicinity of the general study area are analyzed. The worst Category C outages are selected by taking into account the following factors:

- Amount of generation lost immediately following the outage
- Normal condition loading of a transmission facility
- Bus outages and breaker failures that cause disconnection of the entire bus during the transient period

E.2 Steady State Study Criteria

E.2.1 Normal Overloads

Normal overloads are those that exceed 100 percent of normal facility rating under NERC Category A conditions (no contingency). Normal overloads are identified in deliverability assessment and reliability power flow analysis in accordance with Reliability Standard TPL-001. It is required that loading of all transmission system facilities be within their normal ratings under the Category A conditions.

E.2.2 Emergency Overloads

Emergency overloads are those that exceed 100 percent of emergency ratings under NERC/WECC/ CAISO Category B and Category C outage conditions. Emergency overloads are identified in deliverability assessment and reliability power flow analysis in accordance with Reliability Standards TPL-002 and TPL-003. It is required that loading of all transmission system facilities be within their emergency ratings under the Category B and Category C outage conditions.

E.2.3 Voltage Violations

Voltage violations will occur if voltage deviations or voltage exceeds the limit specified in Table E.2.

Table E.2: Voltage Criteria
(Voltages are relative to the nominal voltage of the system studied)

Voltage level	Normal Conditions (TPL-001)		Contingency Conditions (TPL-002 & TPL-003)		Voltage Deviation	
	Vmin (pu)	Vmax (pu)	Vmin (pu)	Vmax (pu)	TPL-002	TPL-003
≤ 200 kV	0.95	1.05	0.90	1.1	≤5%	≤10%
≥ 200 kV	0.95	1.05	0.90	1.1	≤5%	≤10%
≥ 500 kV	1.0	1.05	0.90	1.1	≤5%	≤10%

E.3 Transient Stability Criteria

Transient stability analysis is a time-domain simulation that assesses the performance of the power system during (and shortly following) a contingency. Transient stability studies are performed to ensure system stability following critical faults on the system.

The system is considered stable if the following conditions are met:

1. All machines in the WECC interconnected system must remain in synchronism as demonstrated by relative rotor angles (unless modeling problems are identified and concurrence is reached that a problem does not really exist);

2. A stability simulation will be deemed to exhibit positive damping if a line defined by the peaks of the machine relative rotor angle swing curves tends to intersect a second line connecting the valleys of the curves with the passing of time;

3. Corresponding lines on bus voltage swing curves will likewise tend to intersect. A stability simulation, which satisfies these conditions, will be defined as stable;

4. Duration of a stability simulation run will be ten seconds unless a longer time is required to ascertain damping;

5. The transient performance analysis will start immediately after the fault clearing and conclude at the end of the simulation and;

6. A case will be defined as marginally stable if it appears to have zero percent damping and the voltage dips are within (or at) the WECC Reliability Criteria limits.

Performance of the transmission system is measured against the NERC Reliability Standards and WECC Regional Criteria. NERC TPL-001, TPL-002 and TPL-003 require no loss of demand or curtailed firm transfers under Category A and Category B conditions, and planned/controlled loss of demand or curtailed firm transfers under Category C outages. Category A, B and C outages should not result in cascading outages.

Table E.3 illustrates the WECC reliability criteria. The reliability and performance criteria are applied to the entire WECC transmission system.

Table E.3: WECC Disturbance-Performance Table of Allowable Effects on Other Systems
(in addition to NERC requirements)

NERC and WECC Categories	Outage Frequency Associated with the Performance Category (Outage/Year)	Transient Voltage Dip Standard	Minimum Transient Frequency Standard	Post-Transient Voltage Deviation Standard (See Note 2)
A	Not Applicable	Nothing in Addition to NERC		
B	≥ 0.33	Not to exceed **25%** at load buses or **30%** at non-load buses. Not to exceed **20% for more than 20 cycles** at load buses.	Not below **59.6 Hz** for 6 cycles or more at a load bus	Not to exceed **5%** at any bus
C	0.033 – 0.33	Not to exceed 30% at any bus. Not to exceed **20% for more than 40 cycles** at load buses.	Not below **59.0 Hz** for 6 cycles or more at a load bus	Not to exceed **10%** at any bus
D	< 0.033	Nothing in Addition to NERC		

Note 2: As an example in applying the WECC Disturbance-Performance Table, Category B disturbance in one system shall not cause a transient voltage dip in another system that is greater than 20% for more than 20 cycles at load buses, or exceed 25% at load buses or 30% at non-load buses at any time other than during the fault.

E.4 Post-Transient Voltage Stability Criteria

The last column of the above Table E.3 illustrates the post-transient voltage stability criteria. The governor power flow is utilized to test for the post-transient voltage deviation criteria.

E.5 Reactive Margin Criteria

Table E.4 summarizes the voltage support and reactive power criteria of requirement R3 of the WECC Regional Criterion TPL-001-WECC-CRT-2. The system performance will be evaluated accordingly.

Table E.4: Reactive Margin Analysis Criteria Summary

Contingency Category	Reactive Power Criteria
B	Voltage stability is required at 105% of load level or transfer path rating
C	Voltage stability is required at 102.5% of load level or transfer path rating

E.6 Power Factor Criteria

Table E.5 summarizes the power factor criteria per the CAISO tariff for the QC3&4 Phase II projects.

Table E.5: CAISO Tariff Power Factor Analysis Criteria Summary

Generation Type	Power Factor Criteria
Asynchronous Generator	0.95 lagging to 0.95 leading at the POI if identified in the study
Synchronous Generator	0.90 lagging to 0.95 leading at the generator terminal

E.7 Operational Study

The QC3&4 Phase II operational studies examined the following:

- Plan of service COD feasibility evaluation
- Operational power factor requirement
- Operational short circuit duty evaluation

The operational studies were broken down into three categories. The description of each of the three categories and their corresponding study assumption is described below:

1. Short term (next 3 years): models generation projects with executed interconnection agreement and approved transmission projects and network upgrades according to their CODs (3 base cases, one for each year)

2. Mid-term: models all generation projects and transmission without the long-lead-time DNUs. Generation projects requiring long-lead-time DNUs are interim EO. (one base case)

3. Long term: will model the long-lead-time DNUs of top of the mid-term DNUs. (one base case)

F. Deliverability Assessment

This assessment is comprised of on-peak and off-peak deliverability assessments for the Phase II projects in the Northern Bulk System. Both SCE and PG&E bulk systems were monitored for any adverse impacts.

F.1 On-Peak Deliverability Assessment

The assessment was performed following the on-peak Deliverability Assessment methodology (http://www.caiso.com/Documents/On-PeakDeliverabilityAssessmentMethodology.pdf). The main steps of the on-peak deliverability assessment are described below.

Master Deliverability Assessment Base Case

A master base case was developed for the on-peak deliverability assessment which modeled all the queued generation projects up to Phase II. The resources in the master base case are dispatched as follows:

- Existing capacity resources are dispatched at 80% of summer peak net qualified capacity (NQC).
- Proposed full capacity resources are dispatched to balance load and maintain expected imports, but not exceeding 80% of summer peak NQC.
- Energy-only resources are set off-line.
- Imports are at the maximum summer peak simultaneous historical level by branch group as shown in Table 4.1.
- Non-pump load is at the 1 in 5 peak load level for CAISO.
- Pump load is dispatched within expected range for summer peak load hours.

Eastern Bulk Group Deliverability Assessment Base Case

The Eastern Bulk group deliverability assessment base case was developed from the master base case by dispatching all proposed full capacity resources in the Eastern Bulk System to 80% of the NQC.

Screening for Potential Deliverability Problems Using DC Power Flow Tool

A DC transfer capability/contingency analysis tool was used to identify potential deliverability problems. For each analyzed facility, an electrical circle was drawn which includes all generating units including unused Existing Transmission Contract (ETC) injections that have a 5% or greater

- Distribution factor (DFAX) = △ flow on the analyzed facility / △ output of the generating unit *100%

  or

- Flow impact = DFAX * NQC / Applicable rating of the analyzed facility *100%.

Load flow simulations were performed, which study the worst-case combination of generator output within each 5% Circle.

Verifying and Refining the Analysis Using AC Power Flow Tool

The outputs of capacity units in the 5% Circle were increased starting with units with the largest impact on the transmission facility. No more than twenty units were increased to their maximum output. In addition, no more than 1500 MW of generation was increased. All remaining generation within the Control Area was proportionally displaced, to maintain a load and resource balance.

When the 20 units with the highest impact on the facility can be increased more than 1500 MW, the impact of the remaining amount of generation to be increased was considered using a Facility Loading Adder. The Facility Loading Adder was calculated by taking the remaining MW amount available from the 20 units with the highest impact times the DFAX for each unit. An equivalent MW amount of generation with negative DFAXs was also included in the Facility Loading Adder, up to 20 units. If the net impact from the Facility Loading Adders was negative, the impact was set to zero and the flow on the analyzed facility without applying Facility Loading Adders was reported.

F.2 On-Peak Deliverability Assessment Results

In the on-peak deliverability assessment, the Phase II projects were identified to contribute to overloads, which are listed in Table F.1.

Table F.1: On-Peak Deliverability Assessment Results for Eastern Bulk System

Contingency	Overload facilities	Overload (%)
Basecase	Lugo – Victorville 500 kV	108%
	MCCULLGH – Victorville 500 kV No. 1	104%
	Valley – Alberhill 500 kV	117%
	Alberhill – Serrano 500 kV	102%
	Red Bluff-Devers 500 kV No. 1	101%
	Red Bluff-Devers 500 kV No. 1	101%
	Colorado 500/230kV bank No. 1 & 2	146%
Red Bluff 500/2230 kV transformer N-1	The remaining Red Bluff 500/230 kV transformer	107%
Red Bluff - Devers 500kV No. 1	Red Bluff - Devers 500kV No. 2	136%
Red Bluff - Devers 500kV No. 2	Red Bluff - Devers 500kV No. 1	136%
Colorado River - Palo Verde 500kV No. 1	Alberhill – Serrano 500 kV	102%

El Dorado – Mohave 500 kV	Lugo – Victorville 500 kV	127%
Red Bluff - Devers 500kV No. 1 & No. 2	Lugo - Victorville 500kV	160%
	Moenkopi - Eldorado 500kV	111%
	Mead – Marketplace 500 kV No. 1	100%
	El Dorado – Lugo 500 kV	144%
	Colorado River - Palo Verde 500kV No. 1	138%
	Hassy AZ 230 – HassyTap 230 kV #1	116%
	Mirage – J. Hinds 230kV No. 1	142%
	NILAND – CVSUB 161 kV	108%
Colorado River – Red Bluff 500kV No. 1 & 2	Lugo – Victorville 500kV	141%
	El Dorado – Lugo 500 kV	128%
	Mirage – J. Hinds 230kV No. 1	120%
El Dorado – Lugo 500kV No. 1	Lugo – Victorville 500kV	139%
	Alberhill – Serrano 500 kV	106%
	Valley – Alberhill 500 kV	121%
El Dorado – Mohave 500 kV	El Dorado – Lugo 500 kV	116%
	Valley - Alberhill 500 kV	119%
	Alberhill – Serrano 500 kV	104%
	Lugo – Victorville 500 kV	127%
Mohave – Lugo 500 kV	El Dorado – Lugo 500 kV	116%
	Valley – Alberhill 500 kV	120%
	Lugo – Victorville 500 kV	126%
Eldorado – Lugo & Eldorado – Mahve	Lugo – Victorville 500kV	168%
	Alberhill – Serrano 500 kV	110%
	Valley-Alberhill 500 kV	125%
Lugo – Victorville 500 kV	Valley – Alberhill 500 kV	123%
	Alberhill – Serrano 500 kV	107%
	El Dorado – Lugo 500 kV	137%
N.Gila – Imperial Valley 500 kV	Valley – Alberhill 500 kV	121%
	Alberhill – Serrano 500 kV	106%
	El Dorado – Lugo 500 kV	112%

In order to mitigate all overloads listed in Table F.1, a comprehensive approach is used instead of mitigating them one by one. At the end, the following upgrades were proposed together to mitigate all above overloads.

- Build a new 500 kV line from Colorado River to Valley through RedBluff. The segment between RedBluff and Valley has 70% compensation.

- Build a new 500 kV line from Valley to Serrano through Alberhill

- Add the third 500/230 kV transformer at Colorado River substation

- Upgrade Devers – Red Bluff 500 kV No.1 line rating

- Expand the proposed Colorado River Corridor SPS to trip generation at Colorado River and RedBluff after contingencies of RedBluff – Devers 500 kV lines, or Devers – Valley 500 kV lines; and to trip generation at Colorado River after contingencies Colorado River – Red Bluff 500 kV lines

- Expand the proposed Colorado River Substation SPS to trip generation at Colorado River after contingencies of Colorado River transformers

- Add a new SPS at Red Bluff substation to trip generation at Red Bluff after contingencies of Red Bluff substation

- Upgrade the two series caps and the terminal equipments on El Dorado – Lugo 500 kV line and switch them in under normal condition

- Upgrade the series cap and the terminal equipment on Mohave – Lugo 500 kV line at Mohave end and switch series caps at both Mohave and Lugo ends in under normal condition

- Re-route of Eldorado – Lugo 500 kV transmission line

The C3C4 Phase II study identified that there is approximately 7900, and up to 11700 MW, of new generation can be accommodated by the transmission system without the new 500 kV lines from Colorado River to Valley through RedBluff, and from Valley to Serrano through Alberhill as discussed above. The higher number was based on the assumption that new generators with smaller distribution factors to the overloaded facilities would be built. The renewable portfolios under study in the 2012/2013 CAISO Transmission Planning Process have approximately 7000 MW of generation that contributes to the identified deliverability constraints listed in Table F.1. As comparison, there are about 17152 MW of new generation in the queues up to Clusters 3 and 4 Phase II, as listed in Table F.2, that contributes to the deliverability constraints. This demonstrates that the new 500 kV lines from Colorado River to Valley through Red Bluff and from Valley to Serrano through Alberhill are not needed in the current transmission plan.

Each of these two 500 kV line upgrades has the estimated cost over $200 million according to the reports of Clusters 1 and 2 Phase II and Cluster 3 Phase 1. They would be removed from the Phase II Study results since they are not needed in the current transmission plan and satisfies at least one of the following criteria:

a. The network upgrade consists of new transmission lines 200 kV or above, and has capital costs of $100 million or greater; or
b. The network upgrade has a capital cost of $200 million or more.

The remaining upgrades as discussed above do not satisfy these two criteria, increase the amount of available deliverability without the upgrades removed, and will stay in the Phase II Study results.

Table F.2. Generation Projects Contributing to the Desert Area Deliverability Constraints

Generation Projects Contributing to the SCE Area Deliverability Constraints			
Project Q#	POI	Pmax	CREZ
17	Colorado River 500kV	520	Riverside East (500 kV)
32	Boulevrd 138 kV	201	San Diego South
58	Control 115 kV	62	Kramer
68	Pisgah 230kV	850	Pisgah
103	Border 69 kV	27	SDG&E Non-CREZ
124	Imperial Valley 230 kV	600	Imperial – SDG&E
126	Nipton 230kV	500	Mountain Pass
131	Ivanpah 230kV	100	Mountain Pass
135	Jasper 230kV	60	San Bernardino - Lucerne
146	Redbluff 230 kV	150	Riverside East (500 kV)
147	Redbluff 230 kV	400	Riverside East (500 kV)
150	Border 69 kV	47.4	SDG&E Non-CREZ
156	Jasper 230kV	201	San Bernardino - Lucerne
162	Ivanpah 230kV	114	Mountain Pass
163	Ivanpah 230kV	300	Mountain Pass
193	Colorado River 230kV	500	Riverside East (500 kV)
219	Colorado River 500kV	50	Riverside East (500 kV)
233	Ivanpah 230kV	200	Mountain Pass
240	Pisgah 230kV	400	Pisgah
241	Pisgah 230kV	400	Pisgah
294	Colorado River 230kV	1000	Riverside East (500 kV)
297	Neenach 66 kV	66	Tehachapi 230kV
365	Redbluff 230 kV	500	Riverside East (500 kV)
421	Blythe 161 kV	49.5	Riverside East (161 kV)
429	Imperial Valley 230 kV	100	Imperial - SDG&E
442	Imperial Valley 230 kV	125	Imperial - SDG&E
467	Primm 230kV	230	Mountain Pass
493	IV - Central 500kV	299	Imperial - SDG&E
502	Primm 230kV	20	Mountain Pass
503	Eldorado 230kV	155	Mountain Pass
510	Imperial Valley 230 kV	200	Imperial - SDG&E
512	Neenach 66 kV	26	Tehachapi 230kV
552	Jasper 230kV	60	San Bernardino - Lucerne
561	Imperial Valley 230 kV	200	Imperial - SDG&E
565	Miguel - Sycamore 230 kV	100	SDG&E Non-CREZ
574	Otay Mesa 230 kV	308	SDG&E Non-CREZ

576	Colorado River 230kV	485	Riverside East (500 kV)
588	Redbluff 230 kV	200	Riverside East (500 kV)
590	Imperial Valley 230 kV	150	Imperial - SDG&E
593	Mohave 500kV	310	Mountain Pass
608	Imperial Valley 230 kV	250	Imperial - SDG&E
106A	Boulevrd 138 kV	160	San Diego South
WDT190	Vestal 66 kV	49.9	SCE Non-CREZ
WDT235	Goleta 66 kV	49.9	SCE Non-CREZ
WDT315	Casa Diablo 34 kV	40.7	Kramer
WDT425	Vestal 66 kV	51	SCE Non-CREZ
WDT433	Vestal 66 kV	40	SCE Non-CREZ
159A	ECO 230 kV	400	San Diego South
643AE	Red Bluff Substation 220 kV	150	Riverside East
643AC	Colorado River Substation 220 kV	750	Riverside East
797	Red Bluff Substation 220 kV	400	Riverside East
831	Colorado River Substation 220 kV	540	Riverside East
WDT786	Resort 33 kV ckt out of Nelson 115/33 kV substation (Valley 500/115 kV System)	20	NonCrez
WDT357DS	Cheslor 33 kV ckt % Blythe (WALC) 161/33 kV substation (Blythe 161/33 kV System)	20	Riverside East
WDT440DS	Tram 33 kV ckt % Garnet 115/33 kV subtation (Devers 220/115 kV System)	5	Palm Springs
643T	Hassayampa-North Gila 500 kV Line	1250 / 700	Imperial
643AP	Sunrise Powerlink 500 kV Line	16.1	Imperial
667	Imperial Valley Substation 230 kV Bus	150	Imperial
781	Barrett-Cameron 69 kV Line	20	San Diego South
789	Boulevard East Substation 69 kV Bus	80	San Diego South
794	Boulevard East Substation 138 kV Bus	45	San Diego South
837	ECO Substation 138 kV Bus	20	San Diego South
838	Imperial Valley Substation 230 kV Bus	100	Imperial
644A	ECO Substation 138 kV Bus	20	San Diego South
653ED	Boulevard East Substation 69 kV Bus	20	San Diego South
205	SCE-Owned Eldorado 220 kV Switchyard	300	El Dorado
714	VEA System	540	El Dorado

740	VEA System	270	El Dorado
643AI	SCE-Owned Eldorado 220 kV Switchyard	300	El Dorado
855	SDG&E-Owned Merchant 230 kV Switchyard	92	El Dorado
WDT707	SCE Rector 66 kV	4	SCE-NonCrez
WDT273	SCE Saugus 66 kV	20	SCE-NonCrez
W7	Boulevard 12 kV bus	5	San Diego South
W17	Boulevard C444 12 kV	5	San Diego South
W21	Boulevard C445 12 kV	3	San Diego South
Total MW		17152.5	

As conclusion, the following upgrades identified in the Cluster 3 and Cluster 4 Phase II on-peak deliverability assessment would be counted in the cost allocation to Cluster 3 and Cluster 4 Phase II projects. Details of cost and cost allocations can be found in Section M of the group report and Attachment 1 in the individual reports.

- Add the third 500/230 kV transformer at Colorado River substation
- Upgrade Devers – Red Bluff 500 kV No.1 line rating
- Expand the proposed Colorado River Corridor SPS to trip generation at Colorado River and RedBluff after contingencies of RedBluff – Devers 500 kV lines, or Devers – Valley 500 kV lines; and to trip generation at Colorado River after contingencies Colorado River – Red Bluff 500 kV lines
- Expand the proposed Colorado River Substation SPS to trip generation at Colorado River after contingencies of Colorado River transformers
- Add a new SPS at Red Bluff substation to trip generation at Red Bluff after contingencies of Red Bluff substation
- Upgrade the two series caps and the terminal equipments on El Dorado – Lugo 500 kV line and switch them in under normal condition
- Upgrade the series cap and the terminal equipment on Mohave – Lugo 500 kV line at Mohave end and switch series caps at both Mohave and Lugo ends in under normal condition
- Re-route of Eldorado – Lugo 500 kV transmission line

F.3 Operational Deliverability Assessment

The tariff allows the Generating Facilities to interconnect as an energy-only resource on an interim-only basis before all the required Delivery Network Upgrades are in service. In the Phase II study, the CAISO performed the operational deliverability assessment to provide information on the interim deliverability for the Phase II projects requesting Full Capacity deliverability status. Such interim and partial deliverability is for information only.

The operational deliverability assessment follows the same on-peak deliverability assessment methodology as described in Section 6. The key components of the operational deliverability assessments are discussed below.

Study Years

The assessment for the Eastern Bulk System was performed for 2013 to 2022

Assumptions for Generation Interconnection Projects

The Phase II projects and generation projects queued ahead of Cluster 3 and Cluster 4 are modeled in the operational deliverability assessment according to the latest Commercial Operation Date (COD) information available. A project is modeled in a study year if the COD of the project is before the summer of the study year.

Table F.3 Generation Projects in SCE Eastern Bulk System Modeled in the Operational Deliverability Assessment

Queue Position	PMAX	Point of Interconnection	First Operational Deliverability Study Year
A.39	45	Tiffanywind 115 kV)	In operation
A.39	1,000	San Bernardino 230 kV	In operation
WDAT042	40	Seawind 115 kV)	In operation
A.39	44.4	Mountwind 115 kV)	In operation
A.39	22.2	Mountwind 115 kV)	In operation
A.39	22.4	Mountwind 115 kV)	In operation
A.39	45.3	Indigo 115 kV	In operation
A.39	90.6	Indigo 115 kV	In operation
WDAT073	80	Colton 66 kV (Out of Vista)	In operation
WDAT075	39.6	Eastside 115 kV (Out of Valley)	In operation
WDAT080	28.5	Colton Cement 66 kV (Out of Vista)	In operation
WDAT053	42.6	Banwind 115 kV	In operation
WDAT092	66	Sanwind 115 kV	In operation
WDAT098	40	Vista 66 kV	In operation
WDAT019	40	City of Colton (Out of Vista)	In operation
3	850	Devers 220 kV Bus	2013
17	520	Colorado River 500 kV Bus	2013
23	72	San Bernardino 220 kV	In operation

49	100.5	Devers 115 kV Bus	2012
WDAT177	96	City of Riverside (Out of Vista)	In operation
50	800	Valley 500 kV	In operation
WDAT179	49.9	Colton-Bloomington 66 kV Line	In operation
WDAT182	507.5	Valley 115 kV	2012
72	500	Alberhill 500 kV	2012
WDAT213	49	Blast 115 kV	2011
WDAT230	44.6	Eitwanda 66 kV	2012
138	150	Devers-Vista No.2 220 kV T/L(via new Substation)	2012
146	150	Red Bluff 220 kV Bus	2015
147	400	Red Bluff 220 kV Bus	2015
219	50	Colorado River 500 kV Bus	2013
WDAT263	21	Blythe 33 kV	In operation
193	500	Colorado River 220 kV Bus	2013
294	1,000	Colorado River 220 kV Bus	2013
365	500	Red Bluff 220 kV Bus	2013
576	485	Colorado River 230 kV	2014
588	200	Red Bluff 230 kV	2013
WDT786	20	Resort 33 kV ckt out of Nelson 115/33 kV substation (Valley 500/115 kV System)	2013
CAISO Q643AE	150	Red Bluff Substation 220 kV	2014
CAISO Q643AC	750	Colorado River Substation 220 kV	2015
CAISO Q797	400	Red Bluff Substation 220 kV	2014
CAISO Q831	540	Colorado River Substation 220 kV	2014

<u>Assumptions for Transmission Upgrades</u>

Transmission upgrades are modeled in the operational deliverability assessment based on their estimated COD. A transmission upgrade is modeled in a study year if the estimated COD is before the summer of the study year. All the required SPSs are assumed to be in-service when the associated generation project is in commercial operation.

Table F.4 Transmission Upgrades in SCE Eastern Bulk System Modeled in the Operational Deliverability Assessment

Transmission Upgrade	First Operational Deliverability Study Year
The new Colorado River – Devers – Valley 500 kV line	2013
Colorado River #2 and #3 transformer	2014 (See Section D.4.5)
Red Bluff #2 transformer	2015 (See Section D.4.6)
West of Devers upgrades	2019 (See Section D.4.8)

Method for Determining Deliverable Partial Capacity

Assuming the system conditions cannot accommodate the full deliverability of all generators in the study area that will be in commercial operation for the study year, the partial deliverability of each generator is determined from the amount of its power output that can be accommodated on a portion of the transmission constraint that is binding in the deliverability power flow. For each generator, the portion of the binding transmission constraint is calculated as a function of the queue position, generator's size and its flow impact on the constraint.

For each deliverability constraint facility, the available capacity without the generation projects being tested is allocated to projects in the order from higher queued projects to lower queued projects until it is depleted. The projects in the same cluster are considered to have the same queue position. If there is available partial capacity for projects in the same cluster, each project's partial deliverability capacity is determined based on the generator's size and its flow impact.

Operational Deliverability Assessment Results

Deliverability constraints identified for Eastern Bulk projects are summarized in Table F.5. Deliverability of the cluster projects are provided in Table F.6. Deliverable MW for each project is provided in the Appendix A. The operational deliverability assessment results are non-binding and for information only.

Table F.5: Deliverability Constraints Affecting Eastern Bulk Projects

Overloaded Facilities	Contingency	Active During Study Years	Group of Generators Constrained
West of Devers 230 kV lines	Devers - Valley 500 kV lines No. 1 & No. 2	2015 ~ 2018	SCE Eastern
Lugo - Victorville 500 kV line	Eldorado - Lugo 500 kV line No. 1 & Eldorado - Mohave 500 kV line No. 1	2015 ~ 2021	SCE Eastern Blythe SCE East of Pisgah SCE North of Lugo SCE Northern 230 kV SDGE
Lugo - Victorville 500 kV line	Red Bluff - Colorado River 500 kV lines No. 1 & No. 2	2015 ~2016	SCE Eastern SCE East of Pisgah SDGE East of Miguel
Lugo - Victorville 500 kV line	Devers - Red Bluff 500 kV lines No. 1 & No. 2	2015 ~2016	SCE Eastern SCE East of Pisgah SDGE East of Miguel
Lugo - Eldorado 500 kV line	Devers - Red Bluff 500 kV lines No. 1 & No. 2	2015 ~	SCE Eastern SCE East of Pisgah SDGE East of Miguel
Lugo - Victorville 500 kV line	Lugo - Eldorado 500 kV line No. 1	2015 ~	SCE East of Pisgah SCE North of Lugo SCE Northern 230 kV
Colorado River - Palo Verde 500 kV line	Devers - Red Bluff 500 kV lines No. 1 & No. 2	2015 ~	SCE Eastern Red Bluff SCE Eastern Colorado River

Table F.6: Eastern Bulk Projects Deliverability by Queue Order

	2013	2014	2015~2018	2019	2020
Serial Group	100%	FCDS	FCDS	FCDS	FCDS
Transition Cluster	100%	100%	Partial	FCDS	FCDS
QC 1 & QC 2	N/A	N/A	0	FCDS	FCDS
QC 3 & QC 4	N/A	N/A	0	0	FCDS

QC 3 & 4 projects could achieve Full Capacity Deliverability Status once all required and assumed network upgrades are in-service after the generation project is in commercial operation. However, the NQC may be subject to curtailment because certain high-cost and long lead-time Delivery Network Upgrades have been removed in the Desert area per methodology in the Revised Technical Bulletin: Deliverability Requirements for Queue Clusters 1-4 and Determination of Net Qualifying Capacity. Such Delivery Network Upgrades are driven by a large amount of generation exceeding what is needed to meet renewable targets and load growth, therefore are most likely not be needed.

G. Steady State Assessment

This assessment is comprised of Power Flow Analysis and Reactive Power Deficiency Analysis.

Power flow analysis and **reactive power deficiency analysis** were performed to ensure that SCE's transmission system remains in full compliance with North American Reliability Corporation (NERC) reliability standards TPL-001, 002 and 003, as well as other NERC/WECC reliability standards, with the proposed interconnection. The results of these analyses will serve as documentation that an evaluation of the reliability impact of new facilities and their connections on interconnected transmission systems is performed. The reactive power deficiency analysis also determines whether the asynchronous facilities proposed by the interconnection projects are required to provide 0.95 leading/lagging power factor at the Point of Interconnection.

The study results for this QC3&4 Phase II study will be communicated to neighboring entities that may be impacted, for coordination and incorporation of its transmission assessments. Input from neighboring entities is solicited to ensure coordination of transmission systems.

While it is impractical to study all combinations of system load and generation levels during all seasons and at all times of the day, the base cases were developed to represent stressed scenarios of loading and generation conditions for the study group area. The CAISO and SCE cannot guarantee that the QC3&4 Phase II projects can operate at maximum rated output 24 hours a day, year round, without adverse system impacts, nor can the CAISO and SCE guarantee that these projects would not have adverse system impacts during the times and seasons not studied in the QC3&4 Phase II study.

The following power flow base cases were used for the analysis in the QC3&4 Phase II study:

- **Peak Full Loop Base Case:**

  Power flow analyses were performed using SCE's peak full loop base case (in General Electric Power Flow format). This base case was developed from base cases that were used in the SCE annual transmission expansion plan studies. It has a 1-in-10 year adverse weather load level for the SCE service territory.

- **Off-Peak Full Loop Base Case:**

  Power flow analyses were also performed using the off-peak full loop base case in order to evaluate system performance due to the addition of Phase II generation projects during light load conditions. The off-peak load was modeled at about 65% of the peak load level.

The base cases modeled all CAISO approved SCE transmission projects. The base cases also modeled all proposed generation projects that were higher queued than the generation projects included in this QC3&4 Phase II study. These generation projects were modeled along with their identified transmission upgrades necessary for their interconnection and/or delivery.

The power flow study included a bulk system power flow analysis, which modeled all QC3&4 Phase II projects in the Eastern Bulk System with plans of service as originally requested, but without any network upgrades identified in their Cluster 3 or Cluster 4 Phase I Studies. This power flow study, discussed in Section G.1 and Section G.2 below, was used to identify potential impacts on SCE's 220 and 500 kV system. This power flow study is discussed in Section G3 and G.4. Section G.3 provides the study conclusions associated with inclusion of the projects but without any upgrades beyond the method of service facilities needed to interconnect the project. Section G.4 provides the study conclusions after inclusion of the facility upgrades identified as part of the initial study.

G.1 Bulk System Steady State Study

The study modeled all existing generators and generator projects up to Cluster 4, approved transmission projects, and any network upgrades required for generator projects queued earlier than the QC3&4 Phase II projects. This assessment was intended to identify the delivery and reliability network upgrade requirements for the QC3&4 Phase II projects. The assessment was also intended to help identify problems in the plan of service requested by developers in the QC3&4 Phase II study that would require modifications to the customer requested plans of service or points of interconnection.

G.1.1 Modeling and Generation Dispatch Assumptions

The reliability assessment was performed assuming all generation resources in the Eastern Bulk System were dispatched irrespective of the requested level of transmission service. This was done to identify if any new congestion exposure is created with the additional generation resources in Phase II.

G.1.2 Power Flow Results (Category "A", "B", and "C")

In the Eastern Bulk System with both Energy Only and Full Capacity generation resources dispatched at full output in the starting base case, the preliminary power flow analysis identified that under summer conditions there are base case (Category "A", "B", and "C") overloads on the following:

Table G.1.2: Power Flow Overloads

Over Loaded Component	Rating Amps (MVA)	Pre- Project Loading(Amps |%Rating)		Post- Project Loading(Amps |%Rating)		% Change from Pre-Project Loading	Comment/ Contingency
Category A, B and C Overloads							
Future Colorado River No.1 & No. 2 500/220 kV transformers	(1120)	992.5	89%	1748	156%	67%	Category A
Red Bluff – Devers No.1 500 kV T/L	2700	2015	75%	2788	103%	28%	Category A
Red Bluff – Devers No.2500 kV T/L	2700	2015	75%	2788	103%	28%	Category A
Valley – Alberhilll 500 kV T/L	3950	3014	76%	3995	102%	26%	Category A
Alberhill – Serrano 500 kV T/L	3950	3129	79%	4122	104%	28%	Category A
Mira Loma -Olinda 220 kV T/L	2480	2274	92%	2662	107%	15%	Rancho Vista – Mira Loma 230 kV T/L

The base case diverged under the following contingences:

- Coachella Valley – Mirage 220 kV T/L And Ramon – Mirage 220 kV T/L
- Etiwanda – Vista 220 kV T/L and Devers – Vista 220 kV T/L
- Devers – Valley No. 1 &2 500 T/L
- Devers – Red Bluff No. 1 &2 500 T/L
- Colorado River – Red Bluff No. 1 &2 500 T/L
- Devers – Mirage No.1 &2 220 kV T/L
- Devers – Vista No 1&2 230 kV T/L
- Hassyamp – N.Gila 500 ck 1
- Alberhill – Valley 500 T/L
- Alberhill – Serrano 500 T/L
- Lewis - Serrano No.1 &2 230 kV T/L

G.1.3 Power Flow Study Conclusions

With the inclusion of the QC3&4 Phase II projects there are a total of 5866 MW of generation interconnection requests at both Colorado River and Red Bluff Substations as shown in the table below. The QC3&4 Phase II study results indicated that without an additional 500 kV T/L in the Eastern area to provide the capacity needed to accommodate QC3&4 Phase II interconnection requests, the maximum Colorado River and Red Bluff 500 kV system capability is limited to approximately 3800 to 4000 MW. Therefore, generation curtailments would be required due to the system capacity limitation. This total represents a 30% curtailment of total active queued generation in the Eastern area. Identified overloads above in Table G.1.2 with the exception of Colorado River transformer overloads, are mitigated if the flow is maintained within the MW range specified above.

Per the directions from the CAISO, with the exception of Colorado River transformer overloads, overloads identified in Section G.1 were assumed to be mitigated by congestion management.

	Queue Projects		
	Red Bluff	Colorado River	Cumulative Total
Serial	550	570	1120
Transition Cluster	500	1500	3120
Queue Cluster 1	0	0	3120
Queue Cluster 2	200	485	3805
Queue Cluster 3	150	750	4705
Queue Cluster 4	400	761	5866

G.1.4 Colorado River AA-Bank No.3 500/220 kV

There are three QC3&4 Phase 2 generation projects that are requesting interconnection to Colorado River substation 220 kV bus. The study identified the need for the third and the fourth AA –Bank to mitigate base case overload. However, due to the fact that one of the three projects is energy only, SCE and CAISO are recommending the installation of the third AA-Bank only, assuming that congestion managements would be utilized to maintain the flow within AA-Bank rating.

G.1.5 Eastern Bulk System SPS (Various)

The need for new SPS in the Eastern Bulk has been identified as part of studies performed for Phase II generation project studies. The SPS involves tripping the new generation projects under the outage conditions:

1. Expand previously identified Colorado River corridor SPS to trip additional Phase II generation projects in the Eastern Bulk under the N-2 or N-1 outage of the following lines:

    - Colorado River – Red Bluff No.1 and/or No.2 500 kV T/Ls
    - Devers – Red Bluff No.1 and/or 2 500 kV T/Ls
    - Devers – Valley 500 kV No. 1 and/or No.2 T/Ls

2. Expand previously identified Colorado River Substation SPS to trip additional Phase II generation projects connected at Colorado River under N-1 outage of ant AA – Bank at Colorado River Sub

3. Implement new Red Bluff Substation SPS to trip QC3&4 Phase II projects connected at Red Bluff 220 kV Bus under N-1 outage of AA – Bank at Red Bluff Substation

G.1.6 Devers – Red Bluff No.1 500 kV T/L

The study determined that the total amount of QC3&4 Phase II generation projects seeking interconnection in the Eastern bulk system overload both the existing Devers – Red Bluff 500 kV No.1 T/L and the proposed Devers – Red Bluff 500 kV No.2 T/L base case and under contingency. As a result, SCE has recommended upgrading for the existing Devers – Red Bluff 500 kV T/L No.1 to normal line rating to 3800 A.

G.1.7 East Of Devers Flow Limits

The QC3&4 Phase II study results indicated that with the inclusion of Devers – Colorado River project (DCR) and WOD projects, the maximum Colorado River and Red Bluff 500 kV system capability is limited to approximately 3800 to 4000 MW of generation.

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 and reactive power support provided by the interconnection customers.

G.1.8 Reactive Power Deficiency Analysis

The contingency analysis identified power flow non-convergence issues under several 500 kV N-1 and N-2 contingency conditions, as shown above. The non-convergence issues are associated with the excessive power flows that lack necessary reactive support from the asynchronous generation projects seeking interconnection in this area.

The QC3&4 Phase II study results identified the need to install a total of two (2) 150 MVAR 500 kV shunt capacitor banks at Red Bluff and one 550 MVAR (500 kV Voltage Base) SVC at the 500 kV bus at Colorado River Substation to address low voltage performance and stability issues triggered by the addition of QC3&4 Phase II generation projects. However, with all the projects in the Eastern Bulk System, including those interconnecting to the Colorado River and Red Bluff Substations, providing necessary reactive capability, the reactive deficiency problems can be mitigated by tripping generation and maintaining the capacity at Colorado River and Red Bluff 500 kV system below approximately 3800 to 4000 MW of generation. Per the directions from the CAISO, the voltage problems identified above were assumed to be mitigated by congestion management.

Therefore, all Phase II projects in the Eastern Bulk System are required to provide reactive capability in consistence with the tariff requirement. In particular, the asynchronous facilities must provide 0.95 leading/lagging power factor at the POI.

The study concluded that all asynchronous generating facilities in the Eastern Bulk System are required to provide 0.95 leading/lagging power factor at the Point of Interconnection.

G.2 Operational Study Results

The Operational Study results for the project are identified in Section K of the Phase II Appendix A report.

H. Short-Circuit Duty Assessment

H.1 Application Queue Analysis

H.1.1 Application Queue: Pre QC3&4 Phase II Projects

Application queue short circuit duty (SCD) studies were performed to determine the impact on circuit breakers with the interconnection of QC3&4 Phase II projects to the transmission system. The application queue considered all existing and higher queued generation interconnection projects and corresponding upgrades into the starting base cases as a pre-condition prior to adding the QC3&4 Phase II projects. In addition, the application queue included all CAISO approved transmission projects and all SCE approved non-CAISO upgrades and system modifications (such as open Mira Loma AA-Bank) into the starting base case as a pre-condition prior to adding the QC3&4 Phase II projects. The fault duties were calculated to identify any equipment overstress conditions. Three-phase (3PH) and single-line-to-ground (SLG) faults were simulated without the QC3&4 Phase II projects to establish the starting base line.

The following provide the mitigation details of all identified previously triggered short-circuit duty impacts at locations where duty contributions were increased without the addition of the QC3&4 Phase II projects.

H.1.1.1 Mira Loma 500 kV – Implement internal cap insertion interrupter modifications on the following two 40 kA 500 kV circuit breakers:

- Pos. No.1 CB812
- Pos. No.6 CB962

H.1.1.2 Vincent 500 kV – Replace the following four 50 kA 500 kV circuit breakers:

- Pos. No.2 CB722
- Pos. No.5 CB852 and CB952
- Pos. No.6 CB862

H.1.1.3 Antelope 220 kV – Upgrade or replace the following nine 40 kA 220 kV circuit breakers at Antelope Substation to achieve 63 kA rating:

- Pos. No.2 CB4022 (Replace) and CB6022 (Replace)
- Pos. No.3 CB6032 (Upgrade)
- Pos. No.4 CB4042 (Replace) and CB6042 (Replace)
- Pos. No.6 CB4062 (Replace) and CB6062 (Replace)
- Pos. No.7 CB4072 (Upgrade)
- Cap Bank CB61X2 (Replace)

H.1.1.4 Devers 220 kV – Upgrade or replace the following nine 220 kV circuit breakers at Devers Substation to achieve 63 kA rating:

- Cap Bank No.3 CB42X2 (Replace)
- Cap Bank No.1 CB62X2 (Replace)
- Pos. No.2 CB5022 (Replace) and CB6022 (Replace)
- Pos. No.3 CB4032 (Upgrade)
- Pos. No.8 CB4082 (Replace) and CB6082 (Upgrade)
- Pos. No.9 CB4092 (Replace) and CB6092 (Replace)

H.1.1.5 Vincent 220 kV – Implement system mitigation measures to address impacts on all 220 kV circuit breakers at the Vincent Substation

H.1.1.6 Inyokern 115 kV – Replace the following two 115 kV circuit breakers at Inyokern Substation to 40 kA:

- Inyokern CB13 and CB14

H.1.2 Application Queue: Post QC3&4 Phase II Projects

The QC3&4 Phase II projects including the identified Reliability and Delivery Network Upgrades from the power flow and stability analysis were added to the starting base line and the fault duties were recalculated to identify the incremental impacts associated with the inclusion of the QC3&4 Phase II projects. The responsibility to finance short circuit related Reliability Network Upgrades identified through a Group Study shall be assigned to all Interconnection Requests in the QC3&4 Phase II study pro rata on the basis of SCD contribution of each proposed Generating Facility. In addition, the SCD impact of the associated Network Upgrades was allocated to each Generating Facility using the same percentage assigned for the triggered Network Upgrade. The pro rata contribution corresponding to each QC3&4 Phase II project to the circuit breaker upgrades listed above is provided in each individual report (Appendix A). However, it should be clear that for reliability reasons it may be necessary to implement operational mitigation of the upgrades previously triggered by queued ahead generation projects prior to allowing interconnection of QC3&4 Phase II generation projects. A determination of such mitigation upgrade needs will be based on the study results of the Operational

SCD Studies undertaken for these Phase II generation projects. Should an impact to circuit breakers be identified in the Operational Study that requires the implementation of mitigation upgrades, such upgrades will need to be advanced by the corresponding projects in Operational Queue order to enable interconnection of the project. To support advancing breaker upgrades triggered by queued ahead projected, the cost allocation defined in this study for breaker upgrades triggered by the QC3&4 Projects will be used to support advancement of such corresponding work in order to ensure in-service dates can be met.

All bus locations where the QC3&4 Phase II projects increased 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 Appendix H, as well as Table H.1.1 (three-phase-to-ground) and Table H.1.2 (single-phase-to-ground). These values have been used to determine if any *additional* equipment, beyond what has previously been identified to be overstressed due to queued ahead projects, is triggered with the addition of the QC3&4 Phase II interconnections and corresponding network upgrades.

The QC3&4 Phase II breaker evaluations identified that the inclusion of the Phase II projects triggers the need for SCD mitigation at Vincent 500 kV, Colorado River 220 kV and Antelope 220 kV. The effective three-phase-to-ground and single-phase-to-ground duties are shown below in Table H.1.1 and Table H.1.2 respectively. A detailed discussion of the upgrade requirements is provided below.

Table H.1.1
Effective Three-Phase-to-Ground Duties at Locations Requiring Phase II Triggered SCD Mitigation

Substation	Voltage	Pre-Phase II			Post-Phase II			Phase II Impact	
		kA	X/R	Eff kA*	kA	X/R	Eff kA*	kA	Eff kA*
Vincent	500	49.6	20.5	50.1	51.6	20.1	51.6	2.0	1.5
Antelope	220	39.5	27.3	42.7	42.1	28.4	45.9	2.6	3.2
Colorado River	220	31.5	38.9	35.9	44.7	40.9	51.4	13.2	15.5

***** Effective kA is the value that is used to determine breaker adequacy consistent with IEEE Standards

Table H.1.2
Effective Single-Phase-to-Ground Duties at Locations Requiring Phase II Triggered SCD Mitigation

Substation	Voltage	Pre-Phase II			Post-Phase II			Phase II Impact	
		kA	X/R	Eff kA*	kA	X/R	Eff kA*	kA	Eff kA*
Vincent	500	39.4	15.0	39.4	40.4	14.8	40.4	1.0	1.0
Antelope	220	42.9	27.8	46.3	46.2	28.6	50.4	3.3	4.1
Colorado River	220	35.6	28.7	38.8	52.2	32.0	57.9	16.6	19.1

***** Effective kA is the value that is used to determine breaker adequacy consistent with IEEE Standards

H.1.2.1 Vincent 500 kV – Upgrade the following four 500 kV circuit breakers at Vincent Substation installing TRV Caps to achieve 63 kA rating

- Pos. No.2 CB722 and CB822
- Pos. No.5 CB752

- Pos. No.6 CB762

H.1.2.2 Antelope 220 kV – Replace the following 50 kA 220 kV circuit breaker at Antelope Substation with a new 63 kA rated breaker

- Pos. No.3 CB4032

H.1.2.3 Colorado River 220 kV – Upgrade the following six 220 kV circuit breakers at Colorado River Substation installing TRV Caps to achieve 63 kA rating

- Pos. No.1 CB4012 and CB6012
- Pos. No.5 CB4052 and CB6052
- Pos. No.7 CB4072 and CB6072

H.1.3 Application Queue: Ground Grid Analysis

H.1.3.1 Substations Flagged for Review

The results of the application queue SCD studies were also utilized to identify any SCE substations (CAISO controlled) that may have duty problems on the existing substation ground grid due to the inclusion of the QC3&4 Phase II projects. The application queue ground grid analysis flagged for further review all existing substations where the QC3&4 Phase II Projects increased the substation ground grid duty by at least 0.5 kA. New substations were not flagged for review as the ground grid design at these substations would enable for a maximum 63 kA for 500 kV and 220 kV Substation open-air design.

- Antelope 220 kV
- El Segundo 220 kV
- El Nido 220 kV
- Kramer 220 kV
- La Fresa 220 kV
- Redondo Beach 220 kV
- Inyokern 115 kV
- Antelope 66 kV
- Del Sur 66 kV
- Quartz Hill 66 kV

H.1.3.2 Substations Requiring Ground Grid Analysis

Further review of the above substation identified that previous Ground Grid Studies exist for the Antelope 220 kV, El Nido 220 kV, and Antelope 66 kV which would obviate the need to perform a Ground Grid Study. The previous Ground Grid Studies identify that the existing ground grid at these locations is adequate for the total fault current identified with the inclusion of QC3&4 Phase II Projects in support of QC3&4 Phase 2 Projects. As a result, the following locations will require a detailed ground grid analysis to be performed in support of QC3&4 Phase II Projects:

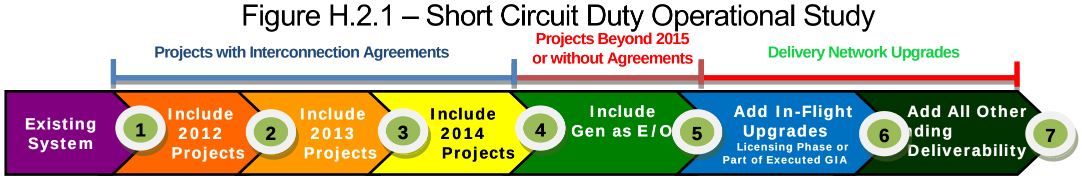
- El Segundo 220 kV
- Kramer 220 kV
- La Fresa 220 kV
- Redondo Beach 220 kV
- Inyokern 115 kV
- Del Sur 66 kV
- Quartz Hill 66 kV

The approximate one-time cost for such study is $10,500 per substation. These costs will be allocated to the generation projects with significant SCD contributions or the group of generation projects if the SCD contribution is the result of an upgrade assigned to a specific group of projects.

H.2 Operational Analysis: Study Methodology

The Operational short-circuit duty studies were performed to identify timing of need for short-circuit duty mitigations. The operational study considered seven different scenarios as shown below in Figure H.2.1. These scenarios were selected as the most appropriate operational study conditions.

Figure H.2.1 – Short Circuit Duty Operational Study



Three-phase (3PH) and single-line-to-ground (SLG) faults were simulated for the existing system condition to establish the starting operational base line conditions. Generation projects with an active Interconnection Agreement (LGIA, SGIA, GIA or Letter Agreement) filed at FERC were added for years 2012, 2013 and 2014 based on dates provided for in the Interconnection Agreement and as modified by the project execution team, if appropriate. In addition, transmission upgrades already licensed and permitted which are under construction or scheduled to be in-service by the end of 2014 were included into the 2012, 2013, and 2014 operational studies. The list of new generation projects with executed agreements are summarized below in Table H.2.1, Table H.2.2 and Table H.2.3 for years 2012, 2013, and 2014 respectively and the list of transmission upgrades scheduled to be in-service by the end of 2014 are summarized below in Table H.2.4.

Table H.2.1
Generation Projects with Executed Agreement Expected to be In-Service in End of 2012

CAISO Number	SCE Project Number	Queue Date	Point of Interconnection	Project Size (MW)
Basin Area				
7	TOT041	10/06/00	El Segundo 230 kV	564
66	TOT135	05/06/05	Walnut 230 kV	500.5
WDAT	WDT240	10/19/06	Brea 66 kV (Olinda System)	25
WDAT	WDT268	04/02/08	Brea 66 kV (Olinda System)	9
Eastern Area: Bulk				
3	TOT032	06/14/00	Devers 230 kV (Sentinel Project)	200[13]
Eastern Area: Devers-Mirage 115 kV System				
WDAT	WDT042	01/07/00	Devers-Banning-Windpark 115 kV line	40
Eldorado/Ivanpah				
162	TOT210	01/05/07	Ivanpah 115 kV	126
Lugo Hub				
WDAT	WDT372	08/25/09	Victor 115/33 kV	20
Northern Area: Bulk				
95	TOT162	03/01/06	Windhub 230 kV	130[14]
119	TOT173	03/01/06	Windhub 230 kV	168[15]
132	TOT179	09/27/06	Highwind 230 kV	160[16]
412	TOT345	07/31/08	Whirlwind 230 kV	110[17]
602	TOT455	02/01/10	Whirlwind 230 kV	50[18]
Northern Area: Antelope-Bailey 66 kV System				
297	TOT278	07/31/08	Neenach 66 kV	66
Northern Area: North of Magunden				
WDAT	WDT190	06/17/05	Tap into 66 kV line into Browning Substation	49.9
Northern Area: Saugus 66 kV System				
WDAT	WDT273	03/26/08	Saugus 66 kV System	20

Table H.2.2
Generation Projects with Executed Agreement Expected to be In-Service in End 2013

CAISO Number	SCE Project Number	Queue Date	Point of Interconnection	Project Size (MW)
Eastern Area: Bulk				
3	TOT032	06/14/00	Devers 230 kV (Sentinel Project)	650[19]
146	TOT198	11/16/06	New Red Bluff 230 kV	150
147	TOT199	11/16/06	New Red Bluff 230 kV	400
193	TOT223	07/31/08	Colorado River 230 kV	250[20]
Eldorado/Ivanpah				
131	TOT180	09/25/06	Ivanpah 115 kV	133
233	TOT242	06/27/07	Ivanpah 115 kV	133

Table H.2.2
Generation Projects with Executed Agreement Expected to be In-Service in End of 2013

[13] This figure reflects partial interconnection of 200 MW of the 850 MW Project in 2012.
[14] This figure reflects installing the remaining 130 MW of the 550 MW Project in 2012.
[15] This figure reflects partial interconnection of 168 MW of the 500 MW Project in 2012.
[16] This figure reflects partial interconnection of 160 MW of the 297 MW Project in 2012.
[17] This figure reflects partial interconnection of 110 MW of the 250 MW Project in 2012.
[18] This figure reflects partial interconnection of 50 MW of the 150 MW Project in 2012.
[19] This figure reflects installing the remaining 650 MW of the 850 MW Project in 2013.
[20] This figure reflects partial interconnection of 250 MW of the 500 MW Project in 2013.

(Continued)

CAISO Number	SCE Project Number	Queue Date	Point of Interconnection	Project Size (MW)
North of Kramer				
125	TOT175	08/22/06	Water Valley 230 kV	250
Northern Area: Bulk				
73	TOT148	06/27/05	Whirlwind 230 kV	110[21]
132	TOT179	09/27/06	Highwind 230 kV	137[22]
407	TOT340	05/30/08	Whirlwind 230 kV	120[23]
408	TOT341	05/30/08	Whirlwind 230 kV	50[24]
412	TOT345	07/31/08	Whirlwind 230 kV	140[25]
602	TOT455	02/01/10	Whirlwind 230 kV	60[26]
Northern Area: Antelope-Bailey 66 kV System				
522A	TOT416	08/19/09	Rosamond 66 kV	20
531A	TOT427	10/29/09	Antelope-Del Sur 66 kV	20
651A	TOT508	02/01/10	Antelope 66 kV	20
653H	TOT516	02/01/10	Antelope 66 kV	20
660	TOT522	02/01/10	Antelope 66 kV	20
WDAT	WDT453	01/31/10*	Palmdale 66/12 kV	5
Northern Area: Ventura				
WDAT	WDT661	06/09/11	Estero-Remac 16 kV (Santa Clara System)	11.2[27]
Northern Area: Windhub 66 kV System				
WDAT	WDT368	08/20/09	Goldtown 66/12 kV	4.9

Table H.2.3
Generation Projects with Executed Agreement Expected to be In-Service by End 2014

CAISO Number	SCE Project Number	Queue Date	Point of Interconnection	Project Size (MW)
Lugo Hub				
WDAT	WDT323	12/16/08	Cottonwood 115/33 kV	20
Northern Area: Bulk				
93	TOT161	03/01/06	Windhub 230 kV	138[28]
119	TOT173	08/08/06	Windhub 230 kV	90[29]
407	TOT340	05/30/08	Whirlwind 230 kV	160[30]
408	TOT341	05/30/08	Whirlwind 230 kV	140[31]

[21] This figure reflects installing the remaining 110 MW of the 250 MW Project in 2013.
[22] This figure reflects installing the remaining 137 MW of the 297 MW Project in 2013.
[23] This figure reflects partial interconnection of 120 MW of the 325 MW Project in 2013.
[24] This figure reflects partial interconnection of 50 MW of the 325 MW Project in 2013.
[25] This figure reflects installing the remaining 140 MW of the 250 MW Project in 2013.
[26] This figure reflects installing an additional 60 MW of the 150 MW Project increasing installed amount to 110 MW in 2013.
[27] This figure reflects installing the remaining 11.2 MW of the 13.2 MW Project in 2013.
[28] This figure reflects partial interconnection of 138 MW of the 220 MW Project in 2014
[29] This figure reflects installing an additional 90 MW of the 500 MW Project increasing installed amount to 258 MW in 2014.
[30] This figure reflects installing an additional 160 MW of the 325 MW Project increasing installed amount to 280 MW in 2014.
[31] This figure reflects installing an additional 140 MW of the 325 MW Project increasing installed amount to 190 MW in 2014.

Table H.2.4
Transmission Upgrades with a Well Defined In-Service Date Prior to End of 2014

System Upgrade	OD
Highwind 230 kV Substation (TRTP Segment 3B)	2012
Windhub-Highwind 230 kV T/L (TRTP Segment 3B)	2012
Windhub No.1 and No.2 500/230 kV Transformer Banks (Segment 9)	2012
Antelope-Vincent No.1 500 kV T/L (TRTP Segment 5)	2012
New Eldorado-Merchant No.2 with Merchant Tie CBs Operated as Normally Closed	2012
Loop Magnolia-NSO 230 kV T/L into Eldorado and reconfigure to operate Merchant No.1 and No.2 230 kV T/L as radial gen-ties	2012
DC-R: Colorado River 500/230 kV Substation with one AA-Bank	2013
DC-R: Devers-Colorado River 500 kV T/L with Series Comp	2013
DC-R: Devers-Valley No.2 500 kV T/L	2013
Devers-Mirage 115 kV System Split	2013
EITP: Ivanpah 230 kV Substation with two A-Banks	2013
EITP: Eldorado-Ivanpah 230 kV No. 1 and No. 2 Lines with SCE-owned new Eldorado 220 kV temporarily connected to existing Joint-Owned Eldorado 220 kV	2013
EKWRA: Move Sequence I through IX	2013
El Casco 220/115 kV (Phase II – Subtransmission System)	2013
Path 42: Devers-Coachella 230 kV Loop into Mirage	2013
TRTP: Chino-Mira Loma No.3 500 kV Operated at 230 kV (Segment 8B)	2013
TRTP: Rio Hondo-Vincent No.2 220 kV Replacement (Segment 6 and 7)	2013
Red Bluff 500/230 kV Substation with one AA-Bank	2013
Saugus No.3 220/66 kV Transformer Bank	2013
Water Valley Substation (loops the Kramer-Cool Water No.1 220 kV T/L)	2013
West-of-Devers Interim Project (Line Reactors)	2013
EKWRA: Remaining Portion of EKWRA	2014
TRTP: Mira Loma-Vincent 500 kV (Segments 6, 7, and 8)	2014
TRTP: Rio Hondo-Vincent No.2 220 kV Replacement (TRTP 6, 7)	2014
San Joaquin Cross Valley Loop	2014
Whirlwind No.3 500/230 kV Transformer Bank (second AA-Bank)	2014[32]
Vestal A-Bank Replacement #1	2014

[32] Installation of second AA-Bank at Whirlwind Substation is required when total amount of generation projects interconnecting exceed initial bank capability. Based on executed or near executed agreements (Serial and Transition Cluster), this date is currently identified to be 2014.

H.2.2 Projects with Executed Agreements but In-Service Date after 2014 and All Other Generation Projects Assumed To Be Interconnected as Energy Only

In order to provide a preview of additional circuit breaker upgrade or replacement requirements that could materialize as more and more generation projects are interconnected, the operational study considered the inclusion of all other generation projects. This includes both generation projects with executed agreements but in-service dates beyond 2014 and generation projects that do not yet have an executed agreement in place assuming they could be interconnected as Energy Only resource. These projects were added to the 2014 operational study scenario together with already permitted transmission upgrades that will be in-service beyond 2014. While the interconnection customers may be requesting an earlier in-service dates, this operational study method will define all of the circuit breaker upgrades and/or replacements needed to interconnect every single generation project that can be interconnected as Energy Only. For those projects that requested Full Delivery status, impacts to short circuit duty associated with the Delivery Network Upgrades is covered by subsequent study scenarios.

The study did not take into account permitting timeframes associated with construction of the facilities needed to support the Energy Only interconnection and simply assumed such facilities would be in place. The objective of this Operational Study scenario is to identify locations where additional circuit breaker upgrade or replacement requirements could materialize as interconnection agreements are executed so that resource requirements could be identified in order to enable interconnection of any generation project. While some of these generation projects have articulated a desire for an earlier in-service date, there is no executed agreement in place committing to such interconnection timeframes. Consequently, the study performed grouped all of these projects together. The list of the generation projects and transmission upgrades modeled in this operational study scenario are summarized below in Table H.2.5 and Table H.2.6 respectively.

Table H.2.5
Generation Project with Executed Agreements But In-Service Date After 2014 and All Other Generation Projects Assumed To Be Interconnected as Energy Only

CAISO Number	SCE Project Number	Queue Date	Point of Interconnection	Project Size (MW)
Basin Area				
WDAT	WDT292	04/10/08	Irvine Substation (Out of Santiago System)	19.6
383	TOT327	07/31/08	Arco-Hinson 230 kV	85
490	TOT412	07/31/09	San Onofre 230 kV	48
702	TOT560	03/31/11	El Segundo 230 kV	435
Eastern Area: Bulk				
17	TOT079	04/22/03	Colorado River 500 kV	520
72	TOT132	06/16/05	Alberhill 500 kV (Previously Lee Lake)	500
219	TOT237	05/23/07	Colorado River 500 kV	50

Table H.2.5
Generation Project with Executed Agreements But In-Service Date After 2014 and All Other Generation Projects Assumed To Be Interconnected as Energy Only (Continued)

CAISO Number	SCE Project Number	Queue Date	Point of Interconnection	Project Size (MW)
Eastern Area: Bulk (Continued)				
193	TOT223	07/31/08	Colorado River 230 kV	250[33]
294	TOT276	07/31/08	Colorado River 230 kV	1000
365	TOT321	07/31/08	Red Bluff 230 kV	500
576	TOT446	02/01/10	Colorado River 230 kV	485
588	TOT453	02/01/10	Red Bluff 230 kV	200
643AE	TOT486	07/31/10	Red Bluff 230 kV	150
643AC	TOT496	07/31/10	Colorado River 230 kV	750
797	TOT566	03/31/11	Red Bluff 230 kV	400
798	TOT528	03/31/11	Colorado River 230 kV	221
831	TOT583	03/31/11	Colorado River 230 kV	540
Eastern Area: Blythe				
421	TOT349	07/31/08	Blythe-Eagle Mountain 161 kV T/L	49.5
WDAT	WDT357	08/17/09	Blythe 33 kV Distribution	20
Eastern Area: Devers-Mirage 115 kV System				
WDAT	WDT011	03/23/98	Renwind 115/12 kV	9
WDAT	WDT016	07/09/98	Garnet 115/33 kV	11.57
1	TOT022	09/30/98	Buckwind 115 kV	16.5
N/A	TOT023	01/22/99	Buckwind 115 kV	2.4[34]
49	TOT120	12/14/04	Devers 115 kV	100.5
WDAT	WDT334	06/09/09	Hi Desert 115/33 kV	18.5
WDAT	WDT401	10/08/08	Venwind 115 kV	20
WDAT	WDT458	01/31/10*	Hi Desert 115/33 kV	10
WDAT	WDT459	01/31/10*	Hi Desert 115/33 kV	9
632AA	TOT476	02/01/10	Devers-Farrell 115 kV Line	10
WDAT	WDT400	02/01/10	Pan Aero 115 kV	30
WDAT	WDT011	03/23/98	Renwind 115/12 kV	9
WDAT	WDT016	07/09/98	Garnet 115/33 kV	11.57
Eastern Area: San Bernardino 66 kV System				
WDAT	WDT492	03/31/11	Cardiff 12 kV	2
WDAT	WDT493	03/31/11	Cardiff 12 kV	1
WDAT	WDT689	03/31/11	Timoteo 12 kV	1.5
Eastern Area: Valley 115 kV System				
WDAT	WDT182	05/06/05	Valley 115 kV	507.5
WDAT	WDT609	03/31/11	Mayberry 115/12 kV	10
WDAT	WDT668	03/31/11	Nelson 115/33 kV	26

[33] This figure reflects installing the remaining 250 MW increasing the total project installed amount to 500 MW.
[34] This figure reflects installing 2.4 MW of Solar increasing the total project amount to 3.82 MW.

WDAT	WDT787	03/31/11	Stetson 115/12 kV	9
WDAT	WDT786	03/31/11	Nelson 115/33 kV	20

Table H.2.5
Generation Project with Executed Agreements But In-Service Date After 2014 and All Other Generation Projects Assumed To Be Interconnected as Energy Only (Continued)

CAISO Number	SCE Project Number	Queue Date	Point of Interconnection	Project Size (MW)
Eastern Area: Vista 115 kV and 66 kV Systems				
WDAT	WDT179	03/18/05	Colton-Bloomington 66 kV Line	49.9
WDAT	WDT590	03/31/11	Calectric 115/33 kV	8.18
Eldorado/Ivanpah/Mohave/Pisgah/Jasper Corridor				
68	TOT131	05/11/05	Pisgah 230 kV	850[35]
135	TOT183	10/10/06	Jasper 230 kV (Looping Lugo-Pisgah No.1)	60
163	TOT211	07/31/08	Ivanpah 230 kV	300
240	TOT250	07/12/07	Pisgah 230 kV	400
241	TOT245	07/12/07	Pisgah 230 kV	400
205	TOT226	07/31/08	SCE-owned new Eldorado 220 kV	300
467	TOT381	07/31/08	Primm 230 kV (Loop Eldorado-Ivanpah)	230
502	TOT405	07/31/09	Primm 230 kV (Loop Eldorado-Ivanpah)	20
503	TOT404	07/31/09	SCE-owned new Eldorado 220 kV	155
593	TOT448	02/01/10	Mohave 500 kV	310
643AI	TOT487	07/31/10	SCE-owned Eldorado 230 kV	300
714	TOT564	03/31/11	VEA System 230 kV	540
741	TOT572	03/31/11	VEA System 230 kV	270
855	TOT581	03/31/11	Merchant 220 kV (non SCE-owned)	150
Lugo Hub				
WDAT	WDT371	08/25/09	Cottonwood-Savage 115 kV	20
WDAT	WDT409	12/09/09	Cottonwood 115/33 kV Distribution	10
WDAT	WDT421	01/25/10	Cottonwood 115/33 kV Distribution	20
WDAT	WDT491	01/25/10	Victor 115/33 kV Distribution	20
WDAT	WDT508	01/25/10	Apple Valley 115/12 kV Distribution	0.98
552	TOT438	02/01/10	Jasper 230 kV	60
589	TOT452	02/01/10	Victor 115 kV	60
WDAT	WDT406	02/24/10	Cottonwood 115/33 kV Distribution	3
WDAT	WDT531	06/22/10	Apple Valley 115/12 kV Distribution	1.56
WDAT	WDT532	06/22/10	Apple Valley 115/12 kV Distribution	1.56
WDAT	WDT533	06/22/10	Apple Valley 115/12 kV Distribution	1.56
WDAT	WDT618	09/07/10	Victor 115/12 kV Distribution	2
WDAT	WDT642	09/07/10	Cottonwood-Savage 115 kV	20
WDAT	WDT646	09/09/10	Victor 115/12 kV Distribution	5

[35] This project has a suspended LGIA which calls for partial installation of 275 MW (Phase I) and final 575 MW as a second phase following completion of Lugo-Pisgah 500 kV. Since LGIA is suspended, full project was modeled as Energy Only

WDAT	WDT647	09/09/10	Victor 115/33 kV Distribution	5
WDAT	WDT648	09/13/10	Victor 115/12 kV Distribution	2
WDAT	WDT649	09/13/10	Victor 115/12 kV Distribution	5

Table H.2.5
Generation Project with Executed Agreements But In-Service Date After 2014 and All Other Generation Projects Assumed To Be Interconnected as Energy Only (Continued)

CAISO Number	SCE Project Number	Queue Date	Point of Interconnection	Project Size (MW)
Lugo Hub (Continued)				
WDAT	WDT650	09/13/10	Victor 115/12 kV Distribution	5
WDAT	WDT651	09/13/10	Victor 115/33 kV Distribution	2
WDAT	WDT617	03/31/11	Victor 115/33 kV Distribution	2
WDAT	WDT788	03/31/11	Victor 115/33 kV Distribution	10
WDAT	WDT791	03/31/11	Victor 115/33 kV Distribution	20
North of Kramer				
WDT	WDT164	10/21/04	Gale-Pole Switch 52 115 kV	80
58	TOT127	02/22/05	Control 115 kV	62
142	TOT192	11/06/06	Kramer 220 kV	80
WDAT	WDT315	07/31/08	Casa Diablo 115 kV	40.7
695	TOT556	03/31/11	Control 115 kV	38
Northern: Bulk				
20	TOT108	09/04/03	Whirlwind 230 kV	111[36]
84	TOT151	12/01/05	Whirlwind 230 kV	340
86A	TOT155	04/01/10	Vincent 230 kV	34
92	TOT154	10/01/12	Vincent 230 kV	570
93	TOT161	06/30/12	Windhub 230 kV	82[37]
94	TOT164	06/30/12	Highwind 230 kV	180
97	TOT165	06/30/12	Whirlwind 230 kV	160
119	TOT173	08/08/06	Windhub 230 kV	242[38]
153	TOT200	11/22/06	Whirlwind 230 kV	100
154	TOT203	07/31/08	Windhub 230 kV	250
175	TOT215	07/31/08	Whirlwind 230 kV	650
407	TOT340	07/31/08	Whirlwind 230 kV	45[39]
408	TOT341	07/31/08	Whirlwind 230 kV	135[40]
188	TOT219	07/31/08	Windhub 230 kV	200
494	TOT398	07/31/09	Windhub 230 kV	350
506	TOT411	07/31/09	Whirlwind 230 kV	300
513	TOT409	07/31/09	Whirlwind 230 kV	141
537A	TOT430	11/23/09	Highwind 230 kV	19.5

[36] This figure reflects the balance of the 300 MW Interconnection Request.
[37] This figure reflects the balance of the 220 MW Interconnection Request.
[38] This figure reflects the balance of the 500 MW Interconnection Request.
[39] This figure reflects the balance of the 325 MW Interconnection Request.
[40] This figure reflects the balance of the 325 MW Interconnection Request.

602	TOT455	02/01/10	Whirlwind 230 kV	40[41]
643AA	TOT480	07/31/10	Antelope 230 kV	200.1

Table H.2.5
Generation Project with Executed Agreements But In-Service Date After 2014 and All Other Generation Projects Assumed To Be Interconnected as Energy Only (Continued)

CAISO Number	SCE Project Number	Queue Date	Point of Interconnection	Project Size (MW)
Northern: Bulk (Continued)				
643	TOT497	07/31/10	Whirlwind 230 kV	153
643AJ	TOT494	07/31/10	Whirlwind 230 kV	100
746	TOT573	03/31/11	Whirlwind 230 kV	175
768	TOT585	03/31/11	Antelope 230 kV	330
795	TOT544	03/31/11	Whirlwind 230 kV	20
796	TOT545	03/31/11	Whirlwind 230 kV	20
Northern: Antelope-Bailey 66 kV System				
86B	TOT156	06/01/09	Canwind 66 kV	33
342	TOT307	07/31/08	Del Sur 66 kV	50
WDAT	WDT270	07/31/08	Little Rock-Wilsona 66 kV	33
512	TOT410	07/31/09	Antelope 66 kV	94
522B	TOT417	08/19/09	Rosamond 66 kV	20
WDAT	WDT361	08/20/09	Great Lakes 66/12 kV	5
WDAT	WDT404	11/30/09	Little Rock-Wilsona 66 kV	10
540	TOT431	12/22/09	Lancaster-Little Rock-Piute 66 kV Line	20
546	TOT437	01/06/10	Piute-Redman 66 kV Line	15
547	TOT436	01/06/10	Lancaster-Purify-Redman 66 kV Line	20
617A	TOT465	01/31/10*	Piute-Redman 66 kV	20
628	TOT471	02/01/10	Antelope-Cal Cement-Rosamond 66 kV Line	20
649C	TOT499	02/01/10	Antelope-Cal Cement-Rosamond 66 kV Line	20
650AA	TOT501	02/01/10	Antelope-Del Sur-Rosamond 66 kV Line	15
649B	TOT502	02/01/10	Antelope-Del Sur-Rosamond 66 kV Line	20
650A	TOT521	02/01/10	Antelope 66 kV	20
658	TOT523	02/01/10	Antelope-Lancaster-Lanpri-Shuttle 66 kV Line	20
659	TOT524	02/01/10	Antelope 66 kV	20
661	TOT525	02/01/10	Antelope-Rosamond 66 kV Line	20
WDAT	WDT504	04/13/10	Del Sur 66/12 kV	10
WDAT	WDT527	04/26/10	Redman 66/12 kV	5
WDAT	WDT554	07/08/10	Little Rock 66/12 kV	5
WDAT	WDT625	09/07/10	Little Rock 66/12 kV	2
WDAT	WDT626	09/07/10	Little Rock 66/12 kV	2
WDAT	WDT628	09/07/10	Rosamond 66/12 kV	5
WDAT	WDT638	09/07/10	Del Sur 66/12 kV	5

[41] This figure reflects the balance of the 150 MW Interconnection Request.

WDAT	WDT639	09/07/10	Del Sur 66/12 kV	5
WDAT	WDT640	09/07/10	Little Rock 66/12 kV	5
WDAT	WDT641	09/07/10	Little Rock 66/12 kV	5
WDAT	WDT643	09/07/10	Little Rock-Wilsona 66 kV Line	20

Table H.2.5
Generation Project with Executed Agreements But In-Service Date After 2014 and All Other Generation Projects Assumed To Be Interconnected as Energy Only (Continued)

CAISO Number	SCE Project Number	Queue Date	Point of Interconnection	Project Size (MW)
Northern: Antelope-Bailey 66 kV System				
WDAT	WDT665	09/09/10	Little Rock-Wilsona 66 kV Line	20
WDAT	WDT672	09/13/10	Little Rock-Wilsona 66 kV Line	20
670	TOT542	03/31/11	Antelope-Del Sur-Rosamond 66 kV Line	20
671	TOT543	03/31/11	Antelope-Lancaster-Lanpri-Shuttle 66 kV Line	20
738	TOT571	03/31/11	Oasis 66 kV	20
769	TOT586	03/31/11	Antelope-Del Sur-Rosamond 66 kV Line	40
778	TOT559	03/31/11	Antelope 66 kV	20
856	TOT591	03/31/11	Monolith 66 kV	8
WDAT	WDT619	03/31/11	Del Sur 66/12 kV	1
WDAT	WDT620	03/31/11	Piute 66/12 kV	2
WDAT	WDT621	03/31/11	Piute 66/12 kV	2
WDAT	WDT623	03/31/11	Del Sur 66/12 kV	2
WDAT	WDT624	03/31/11	Del Sur 66/12 kV	2
WDAT	WDT659	03/31/11	Little Rock-Wilsona 66 kV Line	8.5
Northern: North of Magunden				
WDAT	WDT390	10/19/09	Vestal 66 kV Subtransmission	20
WDAT	WDT603	06/30/10	Vestal 66 kV Subtransmission	20
WDAT	WDT407	01/31/10*	Rector Distribution	20
WDAT	WDT391	10/19/09	Rector 66 kV Subtransmission	20
WDAT	WDT392	10/19/09	Vestal 66 kV Subtransmission	20
WDAT	WDT394	10/19/09	Vestal 66 kV Subtransmission	20
WDAT	WDT353	12/03/09	Vestal 66 kV Subtransmission	20
WDAT	WDT439	05/20/10	Vestal 66 kV Subtransmission	20
WDAT	WDT425	02/01/10	Weldon 66 kV	37.5
WDAT	WDT433	02/01/10	Vestal-Glenville 66 kV	40
WDAT	WDT707	03/31/11	Rector 66/12 kV	4
WDAT	WDT763	03/31/11	Vestal 66/12 kV	7
WDAT	WDT789	03/31/11	Vestal 66/12 kV	5
Northern: Ventura				
WDAT	WDT768	03/31/11	Santa Clara 66/16 kV	2
Northern: Windhub 66 kV System				
348	TOT313	07/31/08	Windhub 66 kV	40
349	TOT314	07/31/08	Windhub 66 kV	100

WDAT	WDT402	11/25/09	Goldtown 66/12 kV	10
WDAT	WDT435	01/31/10*	Windhub 66 kV	20
521	TOT419	02/01/10**	Corum-Goldtown 66 kV Line	19.9
522	TOT420	02/01/10**	Corum-Goldtown-Rosamond 66 kV Line	20

* Date adjusted as a result of the FERC approved Generation Interconnection Procedure modifications

Table H.2.6
Transmission Upgrades Already Licensed but Expected to Be In-Service After 2014

System Upgrade	OD
Colorado River No.2 500/230 kV Transformer Bank	2015[42]
TRTP: Pardee-Vincent No.2 220 kV (Segment 11)	2015
TRTP: Vincent-Mesa No.2 220 kV(Segment 11)	2015
TRTP: Eagle Rock-Gould 220 kV (Segment 11)	2015
Wildlife 230 kV Substation (City of Riverside MOS)	2015
Vestal A-Bank Replacement #2	2016
Whirlwind No.4 500/230 kV Transformer Bank (third AA-Bank)	2016[43]

H.2.3 Inclusion of All Long-term Deliverability Network Upgrades

The Operational Study included a final scenario that added all of the long-term Deliverability Upgrades needed to provide for the requested Full Capacity Deliverability status level of service to all generation projects in queue including the Phase II project requests.

H.3 Operational Analysis: Study SCD Results

H.3.1 Existing System with the inclusion of projects in 2012

All bus locations where the inclusion of projects in 2012 increased 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 Appendix H Table H.3.1a (three-phase-to-ground) and Table H.3.1b (single-phase-to-ground). These values were used to determine which SCD mitigation needs to be placed into service by the end of 2012.

The 2012 Operational Study breaker evaluation identified the need for SCD mitigation at the following location:

[42] Installation of second AA-Bank at Colorado River Substation is required when total amount of generation projects interconnecting exceed initial bank capability. Based on executed or near executed agreements (Serial and Transition Cluster), this date is currently identified to be 2015.

[43] Installation of second AA-Bank at Whirlwind Substation is required when total amount of generation projects interconnecting exceed initial bank capability. Based on executed or near executed agreements (Serial and Transition Cluster), this date is currently identified to be 2014.

H.3.1.1 Antelope 220 kV

With the construction of TRTP, short-circuit duties have been increased beyond the 40 kA capability of the nine 220 kV circuit breakers. To mitigate the overstressed breakers, SCE has initiated a project which will replace five 40 kA rated breakers with 63 kA rated breakers, upgrade two 50 kA breakers to increase capability to 63 kA, and remove two 40 kA breakers that are no longer needed following the operation of the Antelope-Windhub 500 kV Transmission Line at 500 kV voltage level (previously operated at 220 kV). The following lists the breakers that require mitigation:

- Cap Bank No.2 CB 61X2 (Replace)
- Pos. No.2 CB 4022 (Replace) and CB 6022 (Replace)
- Pos. No.3 CB 6032 (Upgrade)
- Pos. No.4 CB 4042 (Replace) and CB 6042 (Replace)
- Pos. No.6 CB 4062 (Remove) and CB 6062 (Remove)
- Pos. No.7 CB 4072 (Upgrade)

The current in-service date for this mitigation is December 31, 2013. Since the duties are overstressed in 2012, an operating procedure is being implemented which will open a 500/220 kV transformer bank at Antelope as a means of lower short-circuit duty until such time that the permanent mitigation is in place.

H.3.1.2 Mesa 220 kV

With the addition of new generation resources, short-circuit duties have been increased beyond the 50 kA capability of three 220 kV circuit breakers. To mitigate the overstressed breakers, SCE has initiated a project which will upgrade these three 50 kA rated breakers in 2012 to increase capability to 63 kA. The following lists the breakers that require mitigation:

- Pos. No.13 CB 4132 and CB 6142
- Pos. No.14 CB 6142

H.3.1.3 Vincent 220 kV

With the construction of TRTP, short-circuit duties have been increased beyond the 40 kA capability of the 220 kV circuit breaker connecting Cap Bank No.1 (CB682). Mitigation is required to address this impact. To mitigate the overstressed breaker, SCE will need to replace it with a 63 kA rated circuit breaker.

H.3.2 Inclusion of projects in 2013

All bus locations where the inclusion of projects in 2013 increased 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 Appendix H Table H.3.2a (three-phase-to-ground) and Table H.3.2b (single-phase-to-ground). These values were used to determine which incremental SCD mitigation needs to be placed into service by the end of 2013.

H.3.2.1 Devers 220 kV

The 2013 Operational Study breaker evaluation identified the need for SCD mitigation at the Devers 220 kV Substation. With the inclusion of new generation and transmission projects scheduled to be on-line by the end of 2013, short-circuit duties have been increased beyond the capabilities of nine 220 kV circuit breaker s. To mitigate the overstressed breakers, SCE has initiated a project which will replace seven 40 kA rated breakers with 63 kA rated breakers and upgrade two
50 kA breakers to increase capability to 63 kA. The following lists the breakers that require mitigation

- Cap Bank No.1 CB42X2 (Replace)
- Cap Bank No.3 CB62X2 (Replace)
- Pos. No.2 CB 5022 (Replace) and CB 6022 (Replace)
- Pos. No.3 CB 6032 (Upgrade)
- Pos. No.8 CB 4082 (Replace) and CB 6082 (Upgrade)
- Pos. No.9 CB 4092 (Replace) and CB 6092 (Replace)

H.3.2.2 Mira Loma 220 kV

The 2013 Operational Study breaker evaluation identified the need for SCD mitigation at the Mira Loma 220 kV Substation East Bus Section. With the inclusion of new generation and transmission projects scheduled to be on-line by the end of 2013, short-circuit duties have been increased beyond the capabilities of five 220 kV 63 kA circuit breakers. These breakers are subject to a multiplier factor as defined by IEEE Standards. As a result, three-phase-to-ground duties identified in this operational study determined that the three-phase-to-ground duty on these five specific breakers was increased from an effective 56.7 kA to an effective 64.1 kA. To mitigate the overstressed breakers, an operational procedure will be implemented which will operate one existing 500/220 kV transformer bank on the Mira Loma East Bus Section as normally open and will only be closed when the other bank is unavailable. This mitigation will lower short-circuit duties to within existing circuit breaker limits.

H.3.3 Inclusion of projects in 2014

All bus locations where the inclusion of projects in 2014 increased 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 Appendix H Table H.3.3a (three-phase-to-ground) and Table H.3.3b (single-phase-to-ground). These values were used to determine which incremental SCD mitigation needs to be placed into service by the end of 2014.

The 2014 Operational Study breaker evaluation identified the need for SCD mitigation at the Serrano 220 kV Substation. With the inclusion of new generation and transmission projects scheduled to be on-line by the end of 2014, short-circuit duties have been increased beyond the capabilities of all fourteen 220 kV 63 kA circuit breakers. These breakers are subject to a multiplier factor as defined by IEEE Standards. As a result, three-phase-to-ground duties identified in this operational study determined that the three-phase-to-ground duty on these specific breakers was increased from an effective 62.3 kA to an effective 63.1 kA. Mitigation will need to be developed to address these overstressed circuit breakers.

H.3.4 Inclusion of all Generation Projects Without an Executed Interconnection Agreement or With an Executed Agreement that Provides for an In-Service Date Beyond 2014 and Inclusion of CPUC Approved Transmission Upgrades Scheduled to be In-Service after 2014.

All bus locations where the inclusion of all remaining generation projects and inclusion of already licensed transmission projects that have a completion date after 2014 increased 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 Appendix H, as well as Table H.3.4a (three-phase-to-ground) and Table H.3.4b (single-phase-to-ground). These values were used to determine which incremental SCD mitigation will need to be placed into service to support all of these generation projects and completion of the already licensed transmission projects.

With the inclusion of all new remaining generation assumed to be interconnected as Energy Only but no upgrades modeled and the inclusion of all remaining licensed transmission projects scheduled to be on-line after 2014, short-circuit duties have been increased beyond the capabilities of all twenty-four 220 kV 63 kA circuit breakers at Vincent Substation. Mitigation will need to be developed to address these overstressed circuit breakers. The mitigation will involve reconfiguration of the 220 kV Line and Bus Arrangement at Vincent and splitting of the bus as a means to lower short-circuit duty. The actual need for this work is based on the number of projects that ultimately interconnect and the corresponding fault duty contributions. At this point in time, it is unknown when such mitigation will actually be required. Additional Operational Short-Circuit Duty studies will need to be performed as more projects near execution of an interconnection agreement to identify actual timing need for such short-circuit duty mitigation.

H.3.5 Inclusion of all Pending Deliverability Network Upgrades.

All bus locations where the inclusion of pending Deliverability Network Upgrades increased 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 Appendix H, as well as Table H.3.5a (three-phase-to-ground) and Table H.3.5b (single-phase-to-ground). These values were used to determine which incremental SCD mitigation needs to be placed into service to provide for the requested Full Capacity Deliverability service.

The Operational Study which layered all pending Deliverability Network Upgrades, either previously triggered but not yet in project licensing or triggered by the inclusion of QC3&4 Projects, identified five substation locations which required SCD mitigation. To mitigate the overstressed breakers, breaker upgrades or replacements will be required as Network Deliverability Upgrades are placed into service. Some of the overstressed breakers may undergo upgrade followed by replacement as short-circuit duties continue to rise. The following provides a summary of each location requiring short-circuit duty mitigation:

H.3.5.1 Mira Loma 500 kV

- Pos. No.1 CB812
- Pos. No.6 CB962

H.3.5.2 Vincent 500 kV – Replace the following seven 500 kV circuit breakers with 63 kA:

- Pos. No.2 CB722 and CB822
- Pos. No.5 CB752, CB852 and CB952
- Pos. No.6 CB762 and CB862

H.3.5.3 Antelope 220 kV – Replace the following 50 kA 220 kV circuit breaker at Antelope Substation with a new 63 kA rated breaker

- Pos. No.3 CB4032

H.3.5.4 Colorado River 220 kV – Upgrade the following six 220 kV circuit breakers at Colorado River Substation installing TRV Caps to achieve 63 kA rating

- Pos. No.1 CB4012 and CB6012
- Pos. No.5 CB4052 and CB6052
- Pos. No.7 CB4072 and CB6072

H.3.5.5 Inyokern 115 kV – Replace the following two 115 kV circuit breakers at Inyokern Substation to 40 kA:

- Inyokern CB13 and CB14

Actual timing of replacement of the above circuit breakers is closely tied with the in-servicing of additional Deliverability Network Upgrades. As a result, it is anticipated that these breakers will be scheduled concurrently with the corresponding Deliverability Network Upgrades that ultimately drives the timing need for the upgrade.

H.4 Additional SCD Discussion

The Phase II Study has shown significant increases in SLG short-circuit duty with the addition of numerous grounded interconnection transformers. For details, see Appendix H. It is strongly recommended that Phase II generation projects, to the extent possible, install transformers that limit each project's contribution to SLG SCD on the SCE system. This may be accomplished by installing transformers with delta-connected high side windings or with "impedance-grounded" wye-connected high side windings.

I. Transient Stability Analysis

Transient stability analysis was conducted using both the peak and off-peak full loop base cases to ensure that the transmission system remains stable with the addition of QC3&4 Phase II generation projects. The generator dynamic data used for the study is confidential in nature and is provided with each individual project report.

Disturbance simulations were performed for a study period of 10 seconds to determine whether the QC3&4 Phase II projects will create any system instability during a variety of line and generator outages. For SCE's Eastern Bulk System, selected line and generator outages within the Eastern Bulk System were evaluated. The outages were consistent with Category B and Category C requirements (single element and multiple element outages).

The transient stability study concluded that with the addition of the QC1&2PII projects proposed system upgrades in place as well as assuming each project can provide 0.95 power factor correction at their POI, the transient stability performance of the system is acceptable. Transient stability plots for summer peak and off-peak load conditions are provided in Appendix F.

J. Post-Transient Voltage Stability Analysis

The reactive deficiency analysis in Section G concluded that the asynchronous generating facilities are required to provide 0.95 leading/lagging power factor correction at the POI.

A post-transient voltage stability analysis was performed for this QC3&4 Phase II study. The post-transient analysis focused on evaluating the system after the inclusion of all transmission upgrades and the use of the identified SPS, assuming all new generation projects meeting the power factor requirements. Under such conditions, the post-transient study showed unacceptable system performance.

To maintain acceptable system performance, the maximum capacity of the 500 kV System supporting Colorado River and Red Bluff Substations was identified to range between 3800 to 4000 MW provided local area solar thermal generation is dispatched and local area solar PV is fully equipped with power factor correction. The system capacity will be lowered if solar thermal projects in the Eastern Bulk System are not dispatched. As part of the operational study, a scenario was evaluated which considered PV solar dispatch only and identified unacceptable transient stability performance if PV generation dispatch at Colorado River and Red Bluff substation exceeds 3100MW. Per the directions from the CAISO, the transient stability issues, including the 3100 MW lower limit associated with the PV solar dispatch, would be mitigated by congestion management.

K. Mitigation of Phase II Project Impacts

The mitigation requirements triggered by QC3&4 Phase II projects, based on the results described in Sections F-J above, are as follows:

K.1 Plan of Service Reliability Network Upgrades

Plan of Service Reliability Network Upgrades for QC3&4 Phase II projects in the Eastern Bulk System are discussed in detail in each individual project report (Appendix A).

K.2 Reliability Network Upgrades

Assumed scope for the Reliability Network Upgrades for QC3&4 Phase II projects in the Eastern Bulk System are discussed below.

K.2.1 Expansion of the proposed Colorado River Corridor SPS

Include the five new interconnections to Colorado River and Red Bluff Substations into the existing (Pre-Project) Colorado River Corridor SPS to trip the new generation under either one of the two the following single contingencies:

- N – 1 Outage of Devers – Red Bluff No.1 or No.2 500 kV T/L's.
- N – 1 Outage of Colorado River – Red Bluff No.1 or No.2 500 kV T/L's.
- N – 1 Outage of Devers – Valley No.1 or No.2 500 kV T/L's.

The existing Colorado River Corridor SPS already monitors the four single contingencies addressed above so there is no need for additional line monitoring relays.

Additional Requirements:
Install six additional N60 relays at Red Bluff Substation (Three for SPS A and three for SPS B) to transmit tripping signals to the five new Generating Facilities.

K.2.2 New Red Bluff Substation SPS

Install a new SPS to trip the two new interconnections to the Red Bluff Substation under the single contingency caused by the outage of either one of the two Red Bluff No.1AA or No.2AA transformer banks.

Additional Requirements:
Install four additional N60 relays at Colorado River (Two for SPS A and two for SPS B) for No.3AA transformer bank monitoring and to transmit tripping signals to the two new Generating Facilities.

K.2.3 Expansion of the proposed Colorado River Substation SPS

Include the three new interconnections to Colorado River Substation into the existing (Pre-Project) Colorado River Substation SPS to trip the new generation under the single contingency caused by the outage of any one of the three Colorado River No.1AA or No.2AA or No.3AA 500/220 kV transformer banks.

New Requirements:
The existing Colorado River Substation SPS already monitors the existing No.1AA and No.2AA transformer banks. and trips all existing interconnections.

Monitoring of the new No.3AA transformer bank will be added.

Additional Requirements:
Install two additional N60 relays at Colorado River (One for SPS A and one for SPS B) for No.3AA transformer bank. monitoring and to transmit tripping signals to the three new Generating Facilities.

K.3 Telecommunications

Dual Channels from the Colorado River and Red Bluff Substations to each one of the five Generating Facilities have already been accounted for within the Interconnection Facilities Section of each particular Interconnection.

K.3.1 Additional Telecommunications Elements

- Install Channel Banks and Cross Connects at each one of the five Generating Facilities
- Install Channel Banks and Digital Cross Connects at Colorado River and Red Bluff Substations
- Install Channel Banks at Grid Control Center (GCC) facility

K.3.2 Power System Controls

- Expand the existing set of SPS Twin RTU’s at Colorado River Substation and modify the arming program to support the two new Colorado River Corridor and Colorado River Substation SPS’s.
- Install one set of SPS Twin RTU’s at Red Bluff Substation to support the new Red Bluff Substation SPS
- Expand existing RTU at Red Bluff Substation to include monitoring and control of the new 500 kV Shunt Capacitor Bank Circuit Breakers
- Expand existing RTU at Colorado River Substation to include monitoring and control of the new No.3AA Transformer Bank 500 kV and 220 kV Circuit Breakers

K.4 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 six 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 ten sets of TRV capacitors to mitigate the increased duty on six circuit breakers, and perform ground grid analysis for substation.

Antelope 220 kV Substation
Upgrade/replace one 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 as well as completion of corresponding Deliverability Network Upgrades. Additional review of these upgrades will be performed as projects execute interconnection agreements to identify need and schedule installation of these upgrades.

K.5 Delivery Network Upgrades

K.5.1 Colorado River AA-Bank No.3 500/220 kV

Increase the 500/220 kV station capacity from 2,240 MVA to 3,360 MVA by installing a new No.3AA 1120 MVA 500/220 kV Transformer Bank with corresponding 500 kV and 220 kV Bank Positions.

This work requires the installation of the following equipment:

- One Circuit Breaker and two Disconnect Switches at the existing 500 kV Line Double Breaker Position 8 presently terminating the Red Bluff No.2 500 kV T/L to convert it into a Line / Bank position arranged in a Breaker and a Half Configuration connecting to the new No.3AA transformer bank.
- Extensions of existing 220 kV North and South Buses eight positions to the West.
- Two Bus Sectionalizing Disconnect Switches and associated support structures
- One 220 kV Double Breaker Bank Position to connect the new No.3AA transformer bank.
- One No.3AA 1,120MVA 500/220 kV Transformer Bank equipped with four 373 MVA Single Phase Units (Includes Spare Unit) and 13.8 kV Tertiary Buses and corresponding Reactors.

K.5.2 Devers – Red Bluff No.1 500 kV T/L

Transmission Line:
Eliminate line clearances restrictions to upgrade the continuous rating of the line to 3,800A.

This upgrade requires the replacement of ninety existing Transmission Structures with taller structures and the installation of two additional Intersect Structures.

The installation of an Intersect Structure on the No.1 Line requires the additional installation of an Intersect Structure on the adjacent No.2 line to eliminate the possibility of the conductors of the No.2 line swinging into the Intersect Structure of the No.1 Line.

Devers 500/220 kV Substation:
Replace all equipment on the existing Palo Verde (Future Red Bluff No.1) 500 kV Line Position to upgrade the position to 4,000A Rating.

K.5.3 Red Bluff Substation 500/220 kV Capacity Increase

Red Bluff No.2 500/220 kV Transformer Banks

Increase the 500/220 kV station capacity from 1,120 MVA to 2,240 MVA by installing a new No.2AA 1120 MVA 500/220kV transformer bank with corresponding 500 kV and 220 kV bank positions. This expansion requires the following work:

- Extend the existing 500kV North and South Buses.
- Extend the existing 220kV North and South Buses.
- Install a 500kV double breaker bank position to connect the new 500/220kV transformer bank.
- Install a 220kV double breaker bank position to connect the new 500/220kv transformer bank.
- Install the No.2AA 1,120MVA 500/220kV transformer bank equipped with three 373 MVA single phase units and 13.8 kV tertiary buses.

Power System Control

Expand existing RTU at Red Bluff Substation to include monitoring and control of the new 500kV and 220kV transformer bank T/L circuit breakers.

K.6 East of Pisgah Delivery Network Upgrades allocated to Eastern Projects

The following Delivery Network Upgrades were identified to be triggered by the QC3&4 Phase II projects in the Eastern and East of Pisgah Bulk systems.

K.6.1 Upgrade Eldorado-Lugo 500 kV T/L series caps to 3,800 Amps at each end

Upgrade the existing 500 kV Line Series Capacitors on the Eldorado-Lugo 500 kV T/L to 3,800A Continuous Rating.

K.6.2 Upgrade Lugo-Eldorado 500 kV T/L terminal equipment to above 3800 amps

Eldorado Substation
Replace two circuit breakers, four disconnect switches and all conductors on the existing Lugo 500 kV Line Position with new 4,000A rated equipment to upgrade the position to 4,000A Rating.

Lugo Substation
Replace three circuit breakers, six disconnect switches and all conductors on the existing Eldorado 500 kV Line Position with new 4,000A rated equipment to upgrade the position to 4,000A Rating.

K.6.3 Upgrade Lugo - Mohave 500 kV T/L series cap at Mohave to 3800 amps

Upgrade the existing 500 kV line Series Capacitors on the Lugo 500 kV T/L to 3,800A Continuous Rating.

K.6.4 Equip Lugo line position at Mohave with 4000 Amps rated equipment

Install two Circuit Breakers, four Disconnect Switches and all required conductors to upgrade the existing Lugo 500 kV Line Position to comply with the present Line and Bus Criteria. All new equipment will be rated 4,000A.

NOTE: The existing configuration connects the line directly to one of the two buses via a disconnect switch. This configuration violates the present Line and bus criteria.

K.7 Distribution Upgrades

K.7.1 Blythe and Colorado River Corridor Distribution Upgrades

See applicable Appendix A WDAT report.

K.7.2 Short Circuit Duty (SCD) Mitigation

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

Stetson 12 kV Substation
Upgrade/replace five (5)12 kV circuit breakers, 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

K.7.3 Eastern Area Distribution Upgrades (Below 115 kV level)

See individual Appendix A WDAT reports

K.8 Other

Detailed ground grid analysis at the following SCE-owned substations that were flagged to have ground grid duty concerns by the QC3&4 Phase II application queue ground grid analysis:

Substations:

- None

L. Environmental Evaluation / Permitting

L.1 CPUC General Order 131-D

The California Public Utilities Commission's (CPUC) General Order 131-D (GO 131-D) sets forth the permitting requirements for certain electrical and generation facilities. GO 131-D was established by the CPUC to be responsive to: the requirements of the California Environmental Quality Act (CEQA); the need for public notice and the opportunity for affected parties to be heard by the CPUC; and the obligations of the utilities to serve their customers in a timely and efficient manner.

Electric power line facilities between 50 and 200 kV and new or upgraded substations with a high side voltage exceeding 50 kV are subject to the CPUC's Permit to Construct (PTC) review specified in GO 131-D, Section III.B. For facilities subject to PTC review, or for over 200 kV electric transmission line facilities subject to Certificate of Public Convenience and Necessity (CPCN) requirements specified in GO 131-D, Section III.A, the CPUC reviews utility PTC or CPCN applications pursuant to CEQA and serves as Lead Agency under CEQA. Section IX of GO 131-D discusses the requirements for PTC and CPCN applications.

Generally, SCE takes approximately a minimum of 18-24 months to assemble a CPCN or PTC application, the majority of which time is attributed to developing a required Proponent's Environmental Assessment (PEA). The CPUC review of such applications may take anywhere from 18 – 48 months depending on the specific issues.

For more details, please see General Order 131-D. This document can be found in the CPUC's web page at the CPUC's web page:
http://www.cpuc.ca.gov/PUBLISHED/GENERAL_ORDER/589.htm

L.2 CPUC General Order 131-D – Permit to Construct/Exemptions

GO 131-D provides for certain exemptions from the CPUC PTC requirements for electric power line facilities between 50 and 200 kV and new or upgraded substations with a high side voltage exceeding 50 kV. For example, Exemption f of GO 131-D

(Section III.B.1.f) exempts from CPUC PTC permitting requirements power lines or substations to be constructed or relocated that have undergone environmental review pursuant to CEQA as part of a larger project, and for which the final CEQA document (Environmental Impact Report or Negative Declaration) finds no significant unavoidable environmental impacts caused by the proposed line or substation. Note, GO 131-D, Section III.B.2, discusses the conditions under which PTC exemptions shall not apply (consistent with CEQA Guidelines).

After lead agency approval of the final CEQA document which confirms there are no significant environmental impacts associated with the SCE scope of work, SCE may be eligible to use Exemption f, and in doing so would follow certain limited public noticing requirements, including filing an informational Advice Letter at the CPUC, posting the project site/route, providing notice to the local jurisdiction(s) planning director and the executive director of the California Energy Commission (CEC), and advertising the project notice, for once a week for two weeks successively in a local newspaper. As part of an agreement with the CPUC Energy Division, SCE informally provides a copy of the final CEQA document to the CPUC Energy Division for reference when the Advice Letter is pending before the CPUC.

Note, the CPUC rules for Advice Letters consider an Advice Letter to be in effect on 30th calendar day after the date filed, and GO 131-D specifies a minimum period of 45 days between advertising the notice for the project and when construction can occur.

Typically, SCE may proceed with construction 45 days after it has filed its Advice Letter and has posted and advertised the project notice unless a protest is filed and/or CPUC staffs suspend the Advice Letter. If protests are filed, they must address whether SCE has properly claimed the exemption. SCE has 5 business days to respond to the protest and the CPUC will typically take a minimum of 30 days to review the protest and SCE's response, and either dismiss the protests or require SCE to file for a Permit to Construct. SCE has no control over the time it takes the CPUC to respond when issues arise. If the protest is granted, SCE may then need to apply for a formal permit to construct the project (i.e., Permit to Construct).

If SCE facilities are not included in the larger project's CEQA review, or if the project does not qualify for the exemption due to significant, unavoidable environmental impacts, or if the exemption is subject to the "override" provision in GO 131-D, Section III.B.2, SCE may need to seek approval from the CPUC (i.e., Permit to Construct) taking as much as 18 months or more since the CPUC would need to conduct its own environmental evaluation (i.e., Mitigated Negative Declaration or Environmental Impact Report).

Note, for projects undergoing no CEQA review but instead only undergoing a review under the National Environmental Policy Act (NEPA) due to the lead agency being a federal agency (such as the BLM), GO 131-D technically does not allow for the use of Exemption f when the environmental review is conducted only pursuant to NEPA and does not have a CEQA component. As such, SCE would need to review such projects on a case-by-case basis with the CPUC to determine if the CPUC would allow the project to proceed under Exemption f or instead allow SCE to proceed under an "expedited" PTC application by attaching the NEPA document in lieu of a PEA.

For projects that are not eligible for Exemption f, but have already undergone CEQA or NEPA review, SCE may be able to file an “expedited” PTC application, which typically takes the CPUC approximately 6-9 months to process.

L.3 CPUC General Order 131-D – Certificate of Public Convenience & Necessity (CPCN) Exceptions

When SCE’s T/Ls are designed for immediate or eventual operation at 200 kV or more, GO 131-D requires SCE to obtain a Certificate of Pubic Convenience and Necessity (CPCN) from the CPUC unless one of the following exceptions applies: the replacement of existing power line facilities or supporting structures with equivalent facilities or structures, the minor relocation of existing facilities, the conversion of existing overhead lines (greater than 200 kV) to underground, or the placing of new or additional conductors, insulators, or their accessories on or replacement of supporting structures already built.

Unlike Exemption f relating to the exemptions allowed from a Permit to Construct for electric facilities between 50 – and 200 kV, no such exemption exists for electric facilities over 200 kV T/Ls that have undergone environmental review pursuant to CEQA as part of a larger project, and for which the final CEQA document finds no significant unavoidable environmental impacts caused by the proposed line or substation. Accordingly, SCE would need to consult on a case-by-case basis with the CPUC for such projects CPUC would allow to proceed “exempt” or instead allow SCE to proceed under an “expedited” CPCN application by attaching the final CEQA document in lieu of a SCE Proponent’s Environmental Assessment. Such an expedited CPCN with the environmental review already completed by the lead agency that permitted the Interconnection Customer’s generator project, typically may take from only 6-9 months for the CPUC to process.

L.4 CPUC General Order 131-D – General Comments Relating to Environmental Review of SCE Scope of Work as Part of the Larger Generator Project

For the benefits and reasons stated above, it is recommended that the Interconnection Customer includes SCE’s Interconnection Facilities, Distribution, and Plan of Service Network Upgrades work scope (including facilities to be constructed by others and deeded to SCE) in the Interconnection Customer's environmental reports and applications for project approval submitted to the lead agency permitting the Interconnection Customer’s larger generator project (e.g., California Energy Commission, Bureau of Land Management, city, county, or other applicable local, state or federal permitting agency). It is also recommended that such agencies review the potential environmental impacts associated with SCE’s work scope in any environmental document issued. This may enable SCE to proceed “exempt” from CPUC permitting requirements or under an “expedited” PTC or CPCN. However, depending on certain circumstances, the CPUC may still require SCE to undergo a standard PTC or CPCN for the generator tie line and Network Upgrades work associated with the Interconnection Customer's Project. SCE may also be required to obtain other authorizations for its interconnection facilities and network upgrades.

Hence, SCE's facilities needed for the project interconnection could require an additional two years, or more, to license and permit.

L.5 CPUC Section 851

Since SCE is subject to the jurisdiction of the CPUC, it must also comply with Public Utilities Code Section 851. Among other things, this code provision requires SCE to obtain CPUC approval of leases and licenses to use SCE property, including rights-of-way granted to third parties for Interconnection Facilities. Obtaining CPUC approval for a Section 851 application can take several months, and requires compliance with the California Environmental Quality Act (CEQA). SCE recommends that Section 851 issues be identified as early as possible so that the necessary application can be prepared and processed. As with GO 131-D compliance, SCE recommends that the project proponent include any facilities that may be affected by Section 851 in the lead agency CEQA review so that the CPUC does not need to undertake additional CEQA review in connection with its Section 851 approval.

L.6 SCE scope of work NOT subject to CPUC General Order 131-D

Certain SCE facilities and scope of work may not be subject to CPUC's G.O. 131-D. In such instances, SCE must ensure that requirements of all applicable environmental laws and regulations are addressed, necessary environmental surveys and studies are performed, and all required State and federal environmental permits are applied for and secured from various resource agencies (e.g., those permits resulting from State or federal application of the Endangered Species Act, Clean Water Act, Section 106 of the National Historic Preservation Act, etc.) before commencement of construction activities.

Resource agencies are required to comply with CEQA and/or NEPA (as applicable) when issuing their permits; however, the necessity for environmental permits is oftentimes unknown during the initial stages of project development. Therefore, it is recommended that the Interconnection Customer identifies all project components, including SCE's Interconnection Facilities and Plan of Service Network Upgrades supporting the interconnection of the Project, in environmental reports and applications for project approval submitted to the agencies permitting the Interconnection Customer's larger generator project (e.g., California Energy Commission, Bureau of Land Management, Department of Energy, city, county, or other applicable local, state or federal permitting agencies). It is also recommended that the agencies review the potential environmental impacts associated with SCE's work scope in any environmental document issued. In the event that permits are required from resource agencies, the CEQA/NEPA documents issued by the lead agency(ies) may potentially be utilized to show compliance with CEQA/NEPA requirements, reducing delays to the project schedule. Please note applications for permits from resource agencies (i.e. Streambed Alteration Agreements or Incidental Take Permits) shall be submitted by SCE for all SCE project components. It is SCE's experience that securing such permits may take from 6 to 12 months, depending on the permit type, from the time complete permit applications are submitted by SCE to the resource agencies for agencies to process. More complex permitting such as ESA Section 10 Habitat Conservation Plans and Bald and Golden Eagle Protection Act permitting are more laborious and may require more than a year (in some cases, multiple years) to perform surveys and plan preparation to adequately address agency requirements.

M. Upgrades, Cost and Time to Construct Estimates

The cost estimates are based on initial engineering scope as described in Section K of this report. Costs for each generation project are confidential and are not published in the main body of this report. Each IC is receiving a separate report, specific only to that generation project, containing the details of the IC's cost responsibilities.

Regardless of the requested Commercial Operating Date, the actual Commercial Operation Dates of the generation projects in the QC3&4 Phase II are dependent on the completed construction and energizing of the identified Network Upgrades. Without these upgrades, the new generators may be subject to CAISO's congestion management, including generation tripping. Based on the needed time for permitting, design, and construction, it may not be feasible to complete all the upgrades needed for this cluster before the requested Commercial Operation Dates.

The estimated cost of **Reliability Network Upgrades** identified in this Group Study is assigned to all Interconnection Requests in that Group Study pro rata on the basis of the maximum megawatt electrical output of each proposed new Generating Facility or the amount of megawatt increase in the generating capacity of each existing Generating Facility as listed by the Interconnection Customer in its Interconnection Request.

The estimated cost of all **Delivery Network Upgrades** identified in the Deliverability Assessment are assigned to all Interconnection Requests selecting Full Capacity or Partial Deliverability status based on the flow impact of each such Generating Facility on the Delivery Network Upgrades as determined by the generation distribution factor methodology.

The estimated cost of all **Interconnection Facilities** is assigned to each Interconnection Request individually. The cost estimates for the Interconnection Facilities are all site specific and details are provided in each individual project report.

The estimated costs of **Distribution Upgrades** and **non-CAISO transmission upgrades** are assigned to all Interconnection Requests in that Group Study pro rata on the basis of the maximum megawatt electrical output of each proposed new Generating Facility or the amount of megawatt increase in the generating capacity of each existing Generating Facility as listed by the Interconnection Customer in its Interconnection Request. Distribution Upgrades and non-CAISO transmission upgrades are non-refundable.

Table M.1: Upgrades, Estimated Costs, and Estimated Time to Construct Summary

Each Upgrade category may contain multiple scope durations. The longest duration is shown under the Estimated Time to Construct.

Type of Upgrade	Upgrade	Description	Estimated Cost x 1,000 (Note 4)	Estimated Cost x 1,000 Constant Dollar (OD Year) (Note 4)		Estimated Time to Construct in Months *(Note 1)* *(Note 3)*
Plan of Service Reliability Network Upgrades	Plan of Service Reliability Network Upgrades for QC3&4 Phase II projects in the Eastern Bulk System are discussed in detail in each individual project report (Appendix A).		See Appendix A			
Reliability Network Upgrades	Expansion of the proposed Colorado River Corridor SPS	Expand the proposed Colorado River SPS to trip QC3&4 Generation Projects.	$1,044	$1,132	2015	24
	New Red Bluff Substation SPS (N-1)	Trip QC3&4 generation projects at Red Bluff Substation under (N-1) Single Contingency caused by the outage of any of Red Bluff 500/220 kV Transformer banks	$1,205	$1,306	2015	24
	Expansion of the proposed Colorado River Substation SPS	Expand the proposed Colorado River SPS to trip QC3&4 Generation Projects under (N-1) Single Contingency caused by the outage of any of Colorado River 500/220 kV Transformer banks	$1,172	$1,271	2015	24
	Short-Circuit Duty (SCD) Mitigation	See Section K for description	$1,713	$1,857	2015	24
Delivery Network Upgrades	Colorado River AA-Bank No.3 500/220 kV	Install No.3 500/220 kV AA-Bank at Colorado River Substation	$60,626	$65,734	2015	24
	Devers – Red Bluff No.1 500 kV T/L	Replace existing structures as required to eliminate the present Line-to-Ground clearance restrictions and Restore the line rating to 3,800A.	$86,827	$108,858	2020	84[44] Note 6

[44] The proposed Devers – Red Bluff upgrade requires increasing the height of 90 or more 500kV towers. Without detail studies such as: tower location, area of ground disturbance, property rights, environmental clearance, GO131D evaluation etc., the duration for this upgrade is assumed to take 84 month. The schedule will be adjusted once additional detailed information is known.

	Red Bluff 500/220 kV Substation Capacity Increase	Install No.2 500/220 kV AA-Bank at Red Bluff Substation	**$ 60,626**	**$69,259**	**2017**	**48**
East of Pisgah Delivery Network Upgrades allocated to Eastern Projects	Re-route of Eldorado – Lugo 500 kV transmission line		**$35,882**	**$44,160**	**2020**	**84 Note 6**
	Upgrade Lugo-Eldorado 500 kV T/L series caps to 3800		**$96,756**	**$107,762**	**2016**	**40**
	Upgrade Lugo-Eldorado 500 kV T/L terminal equipment to		**$24,063**	**$26,800**	**2015**	**40**
	Upgrade Lugo - Mohave 500 kV T/L series cap at Mohave to 3800 amps		**$48,378**	**$53,881**	**2016**	**40**
	Equip Lugo line position at Mohave with 4000 Amps rated equipment		**$12,065**	**$13,438**	**2016**	**40**
Distribution Upgrades *(Note 2)*	SCD Mitigation	See Section K for description	**$1,211**	**$1,313**	**2015**	**24**
Other (Note 5)	Ground Grid Analysis for flagged SCE Substations	See Section K for description	**NA**	**NA**	**NA**	**NA**
Total			**$431,568**	**$496,771**	**2020**	**84 Note 6**

Note1: 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 2: These upgrades are not part of the CAISO Controlled Grid and are not reimbursable
Note 3: Each Upgrade category may contain multiple scope durations. The longest duration is shown under the Estimated Time to Construct.
Note 4: SCE's Phase II cost estimating is done in 'constant' dollars 2012 and then escalated to the estimated O.D. year. For the 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 Participating TO to perform the work within these time frames, the information provided in Table D.1 may be subject to change
Note 5: These cost estimates are a one-time cost and are not reimbursable.
Note 6: These are preliminary schedules that are being reviewed. Updated schedules will be released when available.

N. Coordination with Affected Systems

CAISO LGIP tariff Appendix Y section 3.7 requires coordinating with any affected systems that have any potential impact of QC3&4 Phase II projects. Potential affected systems were notified of the generation interconnection requests in the Eastern Bulk System. The study plan and base cases used in the analysis were provided to potential affected systems. Comments from the potential affected systems have been incorporated.

BEFORE THE ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION OF THE STATE OF CALIFORNIA
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APPLICATION FOR CERTIFICATION FOR THE RIO MESA SOLAR ELECTRIC GENERATING FACILITY

DOCKET NO. 11-AFC-04
PROOF OF SERVICE
(Revised 11/2/12)

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DECLARATION OF SERVICE

I, Kwame Thompson, declare that on December 7, 2012, I served a copy of the attached document QC3 and QC4 Phase II Interconnection Study Repot. This document is accompanied by the most recent Proof of Service list, located on the web page for this project at: http://www.energy.ca.gov/sitingcases/riomesa/index.html.

The document has been sent to the other parties in this proceeding (as shown on the Proof of Service list) and to the Commission's Docket Unit or Chief Counsel, as appropriate, in the following manner:

(C*heck all that Apply*)

For service to all other parties:

_X_ Served electronically to all e-mail addresses on the Proof of Service list;

____ Served by delivering on this date, either personally, or for mailing with the U.S. Postal Service with first-class postage thereon fully prepaid, to the name and address of the person served, for mailing that same day in the ordinary course of business; that the envelope was sealed and placed for collection and mailing on that date to those addresses marked *"hard copy required" or where no e-mail address is provided.

AND

For filing with the Docket Unit at the Energy Commission:

_X_ by sending electronic copies to the e-mail address below (preferred method); *OR*

____ by depositing an original and 12 paper copies in the mail with the U.S. Postal Service with first class postage thereon fully prepaid, as follows:

CALIFORNIA ENERGY COMMISSION – DOCKET UNIT
Attn: Docket No. 11-AFC-04
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OR, if filing a Petition for Reconsideration of Decision or Order pursuant to Title 20, § 1720:

____ Served by delivering on this date one electronic copy by e-mail, and an original paper copy to the Chief Counsel at the following address, either personally, or for mailing with the U.S. Postal Service with first class postage thereon fully prepaid:

California Energy Commission
Michael J. Levy, Chief Counsel
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I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct, that I am employed in the county where this mailing occurred, and that I am over the age of 18 years and not a party to the proceeding.

Original Signed by:
Kwame Thompson

*indicates change