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Subject**: NEXTERA: REDACTED PHASE II STUDIES**
GENESIS SOLAR ENERY PROJECT
DOCKET NO. (09-AFC-8)

Enclosed for filing with the California Energy Commission is the original of **NEXTERA: REDACTED PHASE II STUDIES**, for the Genesis Solar Energy Project (09-AFC-8).

Sincerely,

Ashley Y Garner

Ashley Garner

Transition Cluster Phase II Interconnection Study Report

Group Report in SCE's Eastern Bulk System

Final Report

California ISO
Your Link to Power

July 08, 2010

This study has been completed in coordination with SCE per CAISO Tariff Appendix Y Large Generator Interconnection Procedures (LGIP) for Interconnection Requests in a Queue Cluster Window

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Definitions

AVR	Automatic Voltage Regulation
Borrego Cluster	Group of Transition Cluster projects located in the Borrego area
CAISO	California Independent System Operator Corporation
COD	Commercial Operation Date
Deliverability Assessment	CAISO’s Deliverability Assessment
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	Transition Cluster Phase I Study
Phase II Study	Transition 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
TC	Transition Cluster
TPP	CAISO’s Transmission Planning Process
WECC	Western Electricity Coordinating Council

1. Executive Summary

In accordance with the Federal Energy Regulatory Commission (FERC) approved Large Generator Interconnection Procedures (LGIP) for Interconnection Requests in a Queue Cluster Window (CAISO Appendix Y), this Transition Cluster Phase II Study was initiated to determine the combined impact of all the Transition Cluster projects on SCE's electrical system, including that portion of SCE's electrical system that is part of the CAISO Controlled Grid.

There are thirty-five generation projects in the Transition Cluster in SCE's service territory for the Phase II Study. Four general groups are formed based on the electrical impact among the generation projects: Northern Bulk System, Eastern Bulk System, East of Lugo Bulk System and Metro System. This study report provides the following:

1. Transmission system impacts caused by the addition of five Transition Cluster projects requesting interconnection in the Eastern Bulk System;

2. System reinforcements necessary to mitigate the adverse impacts of the five Transition Cluster projects requesting interconnection in the Eastern Bulk System under various system conditions; and

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 Transition Cluster 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

The results of above studies indicated that Transition Cluster projects are responsible for the overloading of several transmission facilities and overstressing of several circuit breakers at a number of substations in the

SCE service territory. Network Upgrades[1] to mitigate identified problems corresponding to the five Transition Cluster 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 and Distribution Upgrades along with an estimated cost.

Table A – Plan of Service Reliability Network Upgrades

1	Various (see individual Appendix A reports)	
	TOTAL	**$ (redacted)**

Table B – Reliability Network Upgrades

1	Loop the Colorado River-Devers 500 kV #2 line into Red Bluff Sub	
2	Upgrade Line Drop on Mira Loma-Vista 220 kV #2 Line at Vista Substation	
3	Colorado River Sub Expansion -- #1 AA Bank	
4	New SPS to Trip 1400 MW Phase II projects by Loss of Devers-Red Bluff 500 kV #1 and #2 Lines	
5	New SPS to Trip 500 MW Phase II projects by Loss of one of AA Bank at Colorado River Sub	
TOTAL		**$ (redacted)**

Table C – Delivery Network Upgrades

1	West of Devers 220 kV Upgrades Project	
2	Colorado River Sub Expansion -- #2 AA Bank	
TOTAL		**$ (redacted)**

Table D – Distribution Upgrades

1	None	
TOTAL		**$0**

These upgrades do not include Interconnection Facilities which are the obligation of each Interconnection Customer to finance. Interconnection facilities relating to each individual project are discussed in the corresponding Appendix A. Distribution Upgrades identified in Table D are not Network Upgrades and are non-refundable.

Given the magnitude of the above upgrades, a good faith estimate of the time required to engineer, license, procure, and construct all facilities identified in the above tables could be up to 84 months from LGIA execution. Timelines required to engineer, license, procure, and construct facilities necessary for

[1] 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.

interconnection and/or delivery of each individual project are discussed in Appendix A.

2. Transition Cluster Interconnection Information

A total of five generation projects totaling a maximum output of 2,199.5 MW are included in the SCE Transition Cluster. Table 2.1 lists all the generator projects with essential data obtained from the CAISO Generation queue.

Table 2.1: SCE Transition Cluster Projects (Eastern Bulk System)

CAISO Queue	Point of Interconnection	Full Capacity Energy Only	Fuel	Max MW	Proposed On-Line Date (as requested by IC)
193	Colorado River 220 kV	FC	Solar	500	07/01/2013
421	Blythe-Eagle Mountain 161 kV Line	FC	Solar	49.5	02/01/2012
294	Colorado River 220 kV	FC	Solar	1,000	07/01/2013
365	Red Bluff 220 kV	FC	Solar	500	07/01/2013
431	Colorado River 220 kV	FC	Solar	150	07/01/2014
Total Phase II Transition Cluster Generation				**2,199.5**	

Note that significant changes occurred between Phase I and Phase II in the Transition Cluster queue for the Eastern Bulk System including:

- Withdrawal of 10 projects (7,490 MW)
- Change in POI for Q294 (moved from Colorado River 500 kV to Colorado River 220 kV for Phase II Study)
- Q365 reduced from 750 MW to 500 MW
- Q431 reduced from 250 MW to 150 MW

3. 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 Large 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 Large Generating Facilities selecting Full Capacity Deliverability Status;

(v) assign responsibility for financing Delivery Network Upgrades needed to interconnect those Large 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 Large 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 Large 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 Large 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 Transition Cluster projects into the CAISO Controlled Grid. An estimated cost and construction schedule for these facilities has also been provided in this report.

4. Study Assumptions

4.1 Power flow base cases

The Phase II Study used four power flow base cases; two for Deliverability Assessment and two for Reliability Assessment, representing 2013 peak load and 2013 off-peak system conditions. These base cases included all CAISO approved transmission projects, as well as higher queue serial generation projects with associated Network Upgrades and Special Protection Systems.

4.2 Load and Import

The Deliverability Assessment On-Peak case modeled a 26243 MW load (1-in-5 load forecast) in SCE system with an import target as shown in Table 4.2. The Off-Peak case modeled a 16082 MW load in SCE system.

Table 4.2: On-Peak Deliverability Assessment Import Target

Branch Group (BG) Name	BG Import Direction	Net Import MW	Import Unused ETC MW
Lugo_victrville_BG	N-S	1047	523
COI_BG	N-S	3770	548
BLYTHE_BG	E-W	106	0
CASCADE_BG	N-S	23	0
CFE_BG	S-N	-154	0
ELDORADO_BG	E-W	935	0
IID-SCE_BG	E-W	268	0
IID-SDGE_BG	E-W	-174	163
INYO_BG	E-W	0	0
LAUGHLIN_BG	E-W	0	0
MCCULLGH_BG	E-W	-15	316
MEAD_BG	E-W	539	516
MERCHANT_BG	E-W	425	0
N.GILABK4_BG	E-W	-170	168
NOB_BG	N-S	1449	0
PALOVRDE_BG	E-W	2984	233
PARKER_BG	E-W	66	52
SILVERPK_BG	E-W	9	0
SUMMIT_BG	E-W	-32	15
SYLMAR-AC_BG	E-W	-351	471
Total		**10726**	**3005**

The Reliability Assessment 2013 peak load case modeled a 26,262 MW load (1-in-10 load forecast). The off-peak load case represented about 60% of 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.

4.3 Generation Dispatch

Generation assumptions for SCE's Eastern Bulk System are shown in Table 4.3.1 (existing) and 4.3.2 (active queued ahead serial).

Generation dispatch assumptions in Deliverability Assessment can be found at http://www.caiso.com/1c44/1c44b5c31cce0.html. In the on-peak Deliverability Assessment, the Summer 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.

In the Reliability Assessment, the generation is dispatched at PMax as listed in Tables 4.3.1 and 4.3.2..

Table 4.3.1
Existing Eastern Bulk Generation

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

Table 4.3.2
Eastern Bulk Serial Interconnection Requests

CAISO Queue Position	Type	Project Size (MW)
1	Wind	16.5
3	N-Gas	850
17	N-Gas	520
49	Wind	100.5
72	Hydro	500
136	N-Gas	300
138	Wind	150
146	Solar	150
147	Solar	400
219	N-Gas	50
	Total	**3,037**

4.4 New Transmission Projects

This 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 serial generation projects in the Eastern Bulk System were modeled in order to determine if additional facilities would be needed to support the Transition Cluster projects.

The Transition Cluster Phase II Study pre-project base cases assume for modeling purposes that the California Portion of DPV2, namely Devers-Colorado River project (DCR) including the proposed 500kV Switchyard at Colorado River, has been constructed and placed in service by SCE. Based on this modeling assumption, DCR costs have not been included in this Phase II Study nor has any portion of DCR been allocated to the Transition Cluster Phase II Study Projects. However, if required regulatory approvals are not granted, modeling assumption will need to be re-examined.

- 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.

- The Red Bluff 500/220 kV Substation

  There are two-(2) solar projects in the Serial Group, totaling 550 MW, which proposed to interconnect in SCE/MWD's J. Hinds and Eagle Mountain area. This injection capacity would result in overloading MWD's 220kV system and would cause costly system upgrades and interruption of the MWD's pump services during the construction of the system upgrades.

  Based on the mutual agreement among CAISO, SCE, and affected Interconnection Customers (the ICs), the Red Bluff Substation was proposed to interconnect these projects directly into SCE's existing Palo Verde – Devers 500 kV line (DPV1 Line) by looping-in the Red Bluff Substation 2 miles East of the CA series caps on the DPV1 line (final substation location is subject to regulatory approvals).

- Devers – Colorado River Project

  Construct a 500 kV Colorado River switchyard. Construct a new 125.4 mile 500kV T/L from the proposed Colorado River switchyard to Devers Substation. Construct a new 42 miles 500 kV T/L between Devers Substation and Valley Substation.

- West-of-Devers SPS (Temporary)

- Blythe I Generation SPS

- MWD Cross Tripping SPS

4.5 Other SPSs and Operator Actions

4.5.1 All new SPSs and modifications to existing ones are subject to review by affected parties and members of the WECC Remedial Action Scheme Reliability Subcommittee (RASRS).

- LEAPS Generation Dynamic SPS

4.5.2 Operating Procedures

Operating procedures, which may include curtailing the output of the Transition Cluster 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.

4.6 Queued Ahead Triggered Circuit Breaker Upgrades, Replacement or Mitigation Requirements

This TC Phase II Study assumed that all previously triggered short-circuit duty impacts would be mitigated by the corresponding triggering project. Consequently, this study evaluated the incremental impacts associated with the addition of the Transition Cluster projects, including appropriate transmission upgrades as identified in this study, in an effort to cost allocate the incremental upgrades associated with the addition of the Transition Cluster projects. However, it should be clear that for reliability reasons it may be necessary to implement mitigation upgrades previously triggered by queued ahead generation projects prior to allowing interconnection of Transition Cluster generation projects.

A determination of such mitigation upgrade needs will be based on the study results of the Operational Studies undertaken for each of the Transition Cluster generation projects. Should an impact to circuit breakers be identified in the Operational Study to require the implementation of mitigation upgrades, such upgrades will need to be advanced by the corresponding projects in Operational Queue order to enable interconnection.

The following provide the mitigation details of all previously triggered short-circuit duty impacts.

Upgrade the following three 500 kV circuit breakers at Lugo Substation from 50 kA to 63 kA by installing Transient Recovery Voltage (TRC) Capacitors:

4.6.1 Lugo 500 kV

Upgrade the following three 500 kV circuit breakers at Lugo Substation from 50 kA to 63 kA by installing Transient Recovery Voltage (TRC) Capacitors:

- Lugo CB762
- Lugo CB922
- Lugo CB852

4.6.2 Mira Loma 500 kV

Upgrade the following six 500 kV circuit breakers at Mira Loma Substation from 40 kA to 50 kA by recertifying breaker capability:

- Mira Loma CB712 and CB812
- Mira Loma CB822
- Mira Loma CB742 and CB942
- Mira Loma CB962

4.6.3 Vincent 500 kV

Upgrade the following four 500 kV circuit breakers at Vincent Substation from 40 kA to 50 kA by recertifying breaker capability:

- Vincent CB812 and CB912
- Vincent CB852
- Vincent CB862

4.6.4 Antelope 220 kV

Upgrade or replace the following eleven 40 kA 220 kV circuit breakers at Antelope Substation to 63 kA:

- Antelope CB61X2 (Replace with 63kA)
- Antelope CB4022 (Replace with 63kA) and CB6022 (Replace with 63kA)
- Antelope CB4032 (Install TRV) and CB6032 (Replace with 63kA)
- Antelope CB4042 (Replace with 63kA) and CB6042 (Replace with 63kA)
- Antelope CB4062 (Replace with 63kA) and CB6062 (Replace with 63kA)
- Antelope CB4072 (Replace with 63kA)
- Antelope CB4082 (Replace with 63kA)

4.6.5 Chino 220 kV

Upgrade the following 220 kV circuit breaker at Chino Substation from 50 kA to 63 kA by installing Transient Recovery Voltage (TRC) Capacitors:

- Chino CB6072

4.6.6 Devers 220 kV

Upgrade or replace the following nine 220 kV circuit breakers at Devers Substation to 63 kA:

- Devers CB42X2 (Replace with 63 kA) and CB62X2 (Replace with 63 kA)
- Devers CB5022 (Replace with 63 kA) and CB6022 (Replace with 63 kA)
- Devers CB4032 (Install TRV Caps)

- Devers CB4082 (Replace with 63 kA) and CB6082 (Install TRV Caps)
- Devers CB4092 (Replace with 63 kA) and CB6092 (Replace with 63 kA)

4.6.7 Etiwanda 220 kV

Implement mitigation measures to address impacts on the following twenty-four 220 kV circuit breakers at the Etiwanda Substation:

- Etiwanda CB43E2 and Etiwanda CB63E2
- Etiwanda CB4022 and Etiwanda CB6022
- Etiwanda CB41E2 and Etiwanda CB42E2
- Etiwanda CB45E2 and Etiwanda CB61E2
- Etiwanda CB62E2 and Etiwanda CB65E2
- Etiwanda CB4032 and Etiwanda CB6032
- Etiwanda CB4042 and Etiwanda CB6042
- Etiwanda CB4052 and Etiwanda CB6052
- Etiwanda CB4092 and Etiwanda CB6092
- Etiwanda CB4102 and Etiwanda CB6102
- Etiwanda CB4072 and Etiwanda CB6072
- Etiwanda CB4082 and Etiwanda CB6082

4.6.8 Mesa 220 kV

Upgrade the following two 220 kV circuit breakers at Mesa Substation from 50 kA to 63 kA by installing Transient Recovery Voltage (TRC) Capacitors:

- Mesa CB4132 and CB6132

4.6.9 Mira Loma East 220 kV

Implement mitigation measures to address impacts on the following twelve 220 kV circuit breakers at the Mira Loma Substation East Section:

- Mira Loma CB4102, CB6102 and CB4172
- Mira Loma CB4142, CB4152 and CB4162
- Mira Loma CB5142, CB5152 and CB5162
- Mira Loma CB6142, CB6152 and CB6162

4.6.10 Villa Park 220 kV

Upgrade the following two 220 kV circuit breakers at Villa Park Substation from 50 kA to 63 kA by installing Transient Recovery Voltage (TRV) Capacitors:

- Villa Park CB4N062
- Villa Park CB4062

4.6.11 Vincent 220 kV

Implement mitigation measures to address impacts on the following twenty-one 220 kV circuit breakers at the Vincent Substation:

- Vincent CB41X2, CB51X2 and CB61X2
- Vincent CB412, CB512 and CB612
- Vincent CB422, CB522 and CB622
- Vincent CB432, CB532 and CB632
- Vincent CB452 and CB652
- Vincent CB462, CB562 and CB662
- Vincent CB472, CB572 and CB672
- Vincent CB682

4.6.12 Devers 115 kV

Replace the following fourteen 115 kV circuit breakers at Devers Substation to 40 kA:

- Devers CB3N, CB3S and CB3T
- Devers CB4N and CB4S
- Devers CB6N and CB6S
- Devers CB7N and CB7S
- Devers CB10N and C10S
- Devers CB11N and C11S
- Devers CB CAP4

4.6.13 Inyokern 115 kV

Replace the following two 115 kV circuit breakers at Inyokern Substation to 40 kA:

- Inyokern CB13 and CB14

4.6.14 Terawind 115 kV

Replace the following 115 kV circuit breaker at Terawind Substation to 40 kA:

- Terawind CB1

4.6.15 Antelope 66 kV

Replace the following thirty-eight 66 kV circuit breaker at Antelope Substation to 40 kA:

- Antelope CB1E and CB1W
- Antelope CB2E and CB2W
- Antelope CB3E and CB3W
- Antelope CB4E and CB4W
- Antelope CB5E and CB5W
- Antelope CB7E and CB7W
- Antelope CB8E and CB8W
- Antelope CB9E and CB9W
- Antelope CB10E and CB10W
- Antelope CB12E and CB12W
- Antelope CB14E and CB14W
- Antelope CB18E and CB18W

- Antelope CB20E and CB20W
- Antelope CB22E and CB22W
- Antelope CB23E and CB23W
- Antelope CB24E and CB24W
- Antelope CB25E and CB25W
- Antelope CB26E and CB26W
- Antelope CB CAP1
- Antelope CB CAP3

4.6.16 Ellis 66 kV

Replace the following forty-five 66 kV circuit breaker at Ellis Substation to
40 kA:

- Ellis CB1XN and CB1XS
- Ellis CB1N and CB1S
- Ellis CB2N and CB2S
- Ellis CB4N and CB4S
- Ellis CB5N and CB5S
- Ellis CB6N and CB6S
- Ellis CB7N and CB7S
- Ellis CB8N and CB8S
- Ellis CB9N and CB9S
- Ellis CB10N and CB10S
- Ellis CB11N and CB11S
- Ellis CB12N and CB12S
- Ellis CB14N and CB14S
- Ellis CB15N and CB15S
- Ellis CB23N and CB23S
- Ellis CB24N and CB24S
- Ellis CB25N and CB25S
- Ellis CB26N and CB26S
- Ellis CB27N and CB27S
- Ellis CB28N and CB28S
- Ellis CB30N and CB30S
- Ellis CB CAP1
- Ellis CB CAP2
- Ellis CB CAP4

4.6.17 Hinson 66 kV

Replace the following thirty-one 66 kV circuit breaker at Hinson Substation to
40 kA:

- Hinson CB2N, CB2S and CB2T
- Hinson CB3N and CB3S
- Hinson CB4N, CB4S and CB4T
- Hinson CB5N, CB5S and CB5T
- Hinson CB6N, CB6S and CB6T
- Hinson CB7N and CB7S
- Hinson CB8N, CB8S and CB8T

- Hinson CB13N, CB13S and CB13T
- Hinson CB14N, CB14S and CB14T
- Hinson CB16N and CB16S
- Hinson CB CAP1
- Hinson CB CAP2
- Hinson CB CAP3
- Hinson CB CAP4

4.6.18 Neenach 66 kV

Replace the following two 66 kV circuit breakers at Neenach Substation to
40 kA:

- Neenach CB2 and CB3

4.6.19 San Bernardino 66 kV

Replace the following eighteen 66 kV circuit breakers at the San Bernardino Substation to 40 kA:

- San Bernardino CB7N, CB7S and CB7T
- San Bernardino CB8S and CB8T
- San Bernardino CB10N and CB10S
- San Bernardino CB13N, CB13S and CB13T
- San Bernardino CB15N and CB15S
- San Bernardino CB16N and CB16S
- San Bernardino CB19N and CB19S
- San Bernardino CB CAP1
- San Bernardino CB CAP2

4.6.20 Saugus 66 kV

Implement mitigation measures to address impacts on the following thirty-eight 66 kV circuit breakers at the Saugus Substation:

- Saugus CB1E and CB1W
- Saugus CB2E, CB2W and CB2T
- Saugus CB3E and CB3W
- Saugus CB4E, CB4W and CB4T
- Saugus CB5E, CB5W and CB5T
- Saugus CB6E, CB6W and CB6T
- Saugus CB8E and CB8W
- Saugus CB9E, CB9W and CB9T
- Saugus CB10E, CB10W and CB10T
- Saugus CB11E, CB11W and CB11T
- Saugus CB12E and CB12W
- Saugus CB13E and CB13W
- Saugus CB14E and CB14W
- Saugus CB CAP1
- Saugus CB CAP3
- Saugus CB CAP4
- Saugus CB CAP5
- Saugus CB CAP7

4.6.21 Vista "A" 66 kV

Replace the following twelve 66 kV circuit breakers at the Vista "A" Substation to 40 kA:

- Vista "A" CB3XE, CB3XW and CB3XT
- Vista "A" CB4XE, CB4XW and CB4XT
- Vista "A" CB5XE and CB5XW
- Vista "A" CB0BE and CB0BW
- Vista "A" CAP 4
- Vista "A" CAP 6

4.6.22 Vista "C" 66 kV

Replace the following twelve 66 kV circuit breakers at the Vista "C" Substation to 40 kA:

- Vista "C" CB9E and CB9W
- Vista "C" CB10E and CB10W
- Vista "C" CB17E and CB17W
- Vista "C" CB19E and CB19W
- Vista "C" CAP 1
- Vista "C" CAP 2
- Vista "C" CAP 3
- Vista "C" CAP 5

5. Study Criteria and Methodology

The applicable reliability criteria, which incorporate the Western Electricity Coordinating Council (WECC) , the North American Electric Reliability Council (NERC) planning criteria, and the CAISO Planning Standards were used to evaluate the impact of Transition Cluster projects on the CAISO Controlled Grid.

5.1 Steady State Study Criteria

5.1.1 Normal Overloads

Normal overloads are those that exceed 100 percent of normal facility ratings. The CAISO Controlled Grid Reliability Criteria requires the loading of all transmission system facilities be within their normal ratings. Normal overloads refer to overloads that occur during normal operating conditions (no contingency).

5.1.2 Emergency Overloads

Emergency overloads are those that exceed 100 percent of emergency ratings. Emergency overloads refer to overloads that occur during single element contingencies (Category “B”) and multiple element contingencies (Category “C”).

5.1.3 Voltage Violations

Voltage violations will occur if voltage deviations exceed +/-7% of the pre-disturbance level for Category B contingencies and +/ -10% for Category C contingencies.

5.1.4 Contingencies

The contingencies used in this analysis are provided in Appendix C. Various categories of contingencies are summarized in Table 5-1:

Table 5-1: Power flow contingencies

Contingencies	Description
CAISO Category “A” (No contingency)	All facilities in service – Normal Conditions
CAISO Category “B”	• B1 - All single generator outages. • B2 - All single transmission circuit outages. • B3 - All single transformer outages. • Selected overlapping single generator and transmission circuit outages.
CAISO Category “C”	• C1 - SLG Fault, with Normal Clearing: Bus outages (60-230 kV) • C2 - SLG Fault, with Normal Clearing: Breaker failures (excluding bus tie and sectionalizing breakers) at the same bus section above. • C3 - Combination of any two-generator/transmission line/transformer outages. • C4 - Bipolar (dc) Line • C5 - Outages of double circuit tower lines (60-230 kV) • C6 - SLG Fault, with Delayed Clearing: Generator • C7 - SLG Fault, with Delayed Clearing: Transmission Line • C8 - SLG Fault, with Delayed Clearing: Transformer • C9 - SLG Fault, with Delayed Clearing: Bus Section

Although most of the CAISO Category “C” contingencies were considered as part of this study, it is impractical to study all possible combinations of any two elements throughout the system. Therefore, as allowed under NERC standard TPL-003-0 R1.3.1, only selected critical Category C contingencies (C1 – C9) that were deemed most severe were evaluated in this study.

5.2 Short Circuit Duty Criteria

Short circuit studies are performed to determine the maximum fault duty on the adjacent buses to the Transition Cluster projects in the SCE service territory. This study determines the impact of increased fault current resulting from Transition Cluster projects. Short circuit results will allocate costs for overstressed breakers to each cluster, which are formed from generation projects with a fault contribution above a threshold value. The Computer Aided Protection Engineering (CAPE) software is used to conduct the detailed short circuit studies with three phase (3PH) and single-line-to-ground (SLG) faults.

To determine the impact on short-circuit duty within SCE’s electrical system, after inclusion of the Transition Cluster generation projects, the study calculated the maximum 3PH and SLG short-circuit duties. Generation, transformer, and generation tie-line data provided by each Transition Cluster Interconnection Customer was utilized. Bus locations where short-circuit duty is increased with the proposed Transition Cluster projects by at least 0.1 kA and the duty is in excess of 60% of the minimum breaker nameplate rating are flagged for further review. Upon completion of the detailed circuit breaker review, circuit breakers exposed to fault currents in excess of 100 percent of their interrupting capacities will need to be replaced or upgraded, whichever is appropriate. It should be noted that other WECC entities may request specific information within the WECC process to evaluate potential impact within their respective systems of this project addition.

5.3 Transient Stability Criteria

Transient stability analysis is a time-based 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.

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 WECC Reliability Criteria and the NERC Planning Standards.

Table 5.3 illustrates the NERC/WECC Reliability Criteria. The reliability and performance criteria are applied to the entire WECC transmission system.

Table 5.3

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 (see Note 3)
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.

Note 3:SCE applies a 7% post-transient criteria for Category "B" disturbances on the SCE system.

5.4 Post-Transient Voltage Stability Criteria

The last column of the above Table 5.3 illustrates the Post-Transient Voltage Stability Criteria. For some large generator contingencies, the governor power flow is utilized to test for the post-transient voltage deviation criteria.

5.5 Reactive Margin Criteria

Table 5.5 summarizes the voltage support and reactive power criteria in the NERC/WECC Planning Standards.

The system performance will be evaluated according to the NERC/WECC planning criteria.

Table 5.5: Reactive Margin Analysis Criteria Summary

Performance Level/Category	Disturbance	Reactive Power Deficiency Criteria
B	Generator One Circuit One Transformer DC Single Pole Block	Governor power flow to reach convergence at 105% of load level or operational transfer capability
C	Two Generators Two Circuits DC Bipolar Block	Governor power flow to reach convergence at 102.5% of load level or operational transfer capability

5.6 Power Factor Criteria

Table 5.6 summarizes the power factor criteria per the CAISO tariff. The voltage at the POI must be within criteria under normal and contingency conditions. Additional requirements may also be imposed by the CAISO Tariff or by the SCE Interconnection Handbook.

Table 5.6: Power Factor Analysis Criteria Summary

Generation Type	Power Factor Criteria
Wind Generator	0.95 lagging to 0.95 leading at the POI
All other Generator Types	0.90 lagging to 0.95 leading at Generator terminals

6. Deliverability Assessment

This assessment is comprised of on-peak and off-peak deliverability assessments for the Transition Cluster projects in the Eastern Bulk System. Both SCE system and SDG&E bulk system were monitored for any adverse impacts.

6.1 On-Peak Deliverability Assessment

The assessment was performed following the on-peak Deliverability Assessment methodology (http://www.caiso.com/23d7/23d7e41c14580.pdf). The study results are summarized in Table 6.1.

Table 6.1: On-Peak Deliverability Assessment for Eastern Bulk System

Contingency	Overloaded Facilities	Rating	Max Flow
Devers – Valley 500 kV #1 and #2	Devers – TOT185HS 230 kV #1	1150 Amps	1258 Amps/ 109%
	Devers –El Casco 230 kV #1	1150 Amps	1693 Amps/ 147%
	Devers-VSTA 230 kV #2	1240 Amps	1485 Amps / 120%
	Devers-SANBRDNO 230 kV #1	796 Amps	1286 Amps / 162%
Basecase	Colorado River 500/230 kV transformers #2	1120 MVA	1948 MVA

The Colorado River substation is originally triggered by a project in the Serial Group and only a 500 kV switchyard is required. For the TC Phase II projects, it is needed to expand the Colorado River switchyard to a 500/230 kV substation with two transformers.

There are multiple contingencies that cause West of Devers 230kV lines (as shown in Table 6.1) overloaded. The Devers – Valley 500 kV N-2 is the most critical contingencies for this overload.

6.2 Off-Peak Deliverability Assessment

There is no off-peak deliverability assessment is required by the Deliverability Assessment methodology (http://www.caiso.com/23d7/23d7e41c14580.pdf) for the Eastern Bulk area since there are all solar projects in this area.

7. Steady State Assessment

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

Power flow analysis was performed to ensure that SCE's transmission system remains in full compliance with North American Reliability Corporation (NERC) reliability standards TPL-001, 002, 003 and 004 with the proposed interconnection. The results of these power flow analyses will serve as documentation that an evaluation of the reliability impact of new facilities and their connections on interconnected transmission systems is performed. If a NERC reliability problem exists as a result of this interconnection, it is SCE's responsibility to identify the problem and develop an appropriate corrective action plan to comply with NERC reliability standards and the CAISO's responsibility to review and approve such corrective action plan.

As part of SCE's obligations with NERC as the registered Transmission Owner for the SCE transmission system, the study results for this interconnection will be communicated to the CAISO, or other neighboring entities that may be impacted, for coordination and incorporation of its transmission assessments. Input from the CAISO and other neighboring entities are 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 Transition Cluster 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 Transition Cluster Phase II Study.

The following power flow base cases were used for the analysis in the Phase II Study:

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

  Power flow analyses were performed using SCE's summer 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 Transition Cluster generation projects during light load conditions. The spring load was modeled at about 60% of the summer peak load.

The base cases modeled all CAISO approved SCE transmission projects. The base cases also modeled all proposed generation projects that were higher than the Transition Cluster projects in the CAISO generation queue. These generation projects were modeled along with their identified transmission upgrades necessary for their interconnection and/or delivery.

The detail power flow study results were discussed in the sections below. Table 7-1 and 7-2 listed the overloaded lines under studied contingencies:

7.1 Study Results

The overloads caused by Transition Cluster Group projects and associated power flow plots are shown in Appendix D.

1. Normal Overloads (Category "A")

Under projected 2013 peak load conditions, Phase II projects caused two (2) Category "A" normal overloads. Under projected off-peak load conditions, Phase II projects caused the same two (2) normal overloads which are also found in the peak load conditions.

All identified base case overloads occurred on the two (2) 220 kV lines in the West of Devers Area.

2. Emergency Overloads (Category "B")

Under projected 2013 peak load conditions, Phase II projects caused three (3) Category "B" overload. Under projected 2013 off-peak load conditions, Phase II projects caused the same three (3) Category "B" overloads.

All identified N-1 overloads occurred on the three (3) 220 kV lines in the West of Devers Area.

3. Emergency Overloads (Category "C")

Under the projected 2013 peak load conditions, Phase II projects caused four (4) new Category "C" overload. Under the projected 2013 off peak load conditions, Phase II projects caused total of four (4) Category "C" overloads: the same three (3) overloads as in the peak case and one (1) new overload.

The identified base case overloads occurred on the four (4) 220 kV lines in the West of Devers Area.

Table 7-1 Peak Load Load, Category “A”, “B", and “ C” Overloads

Overload Facility	Rating	Loading (Amps)		Contingency
		Pre	Post	
San Bernardino – Devers 230 kV line No. 1	796 Amp (N) 796 Amp (E)	769	896	Base Case
Devers – El Casco 230 kV line No. 1	1150 Amp (N) 1150 Amp (E)	1143	1282	Base Case
Devers – Vista 230 kV line No. 2	1240 Amp (N) 1240 Amp (E)	1207	1388	Cabawind – Vista 230 kV line No. 1
San Bernardino – Devers 230 kV line No. 1	796 Amp (N) 796 Amp (E)	896	1042	DEVERS 230.0 to VSTA 230.0 Circuit 2
Devers – El Casco 230 kV line No. 1	1150 Amp (N) 1150 Amp (E)	1279	1439	DEVERS 230.0 to VSTA 230.0 Circuit 2
San Bernardino – Devers 230 kV line No.1	1150 Amp(N) 1150 Amp(E)	1361	1692	Devers – Valley 500kV lines No. 1 and No. 2
Devers – Vista 230 kV line No. 2	1150 Amp(N) 1150 Amp(E)	1617	1982	Devers – Valley 500kV lines No. 1 and No. 2
Devers – El Casco 230 kV line No. 1	1150 Amp(N) 1150 Amp(E)	1783	2156	Devers – Valley 500kV lines No. 1 and No. 2
San Bernardino – El Casco 230 kV line No. 1	1150 Amp (N) 1150 Amp (E)	917	1248	Devers – Valley 500kV lines No. 1 and No. 2

Table 7-2: Off Peak Load, Category "A", "B", and "C" Overloads

Overload Facility	Rating	Loading (Amps)		Contingency
		Pre	Post	
Devers – San Bernardino 230kV line No. 1	796 Amp (N) 796 Amp (E)	755	952	Base Case
Devers – El Casco 230 kV line No. 1	1150 Amp(N) 1150 Amp(E)	1049	1265	Base Case
Devers – Vista 230 kV line No. 2	1240 Amp (N) 1240 Amp (E)	1142	1384	Vista – San Bernardino 230 kV line No. 2
Devers – El Casco 230 kV line No. 1	1150 Amp(N) 1150 Amp(E)	1193	1447	DEVERS 230.0 to VSTA 230.0 Circuit 2
Devers – San Bernardino 230kV line No. 1	1150 Amp (N) 1150 Amp (E)	890	1123	DEVERS 230.0 to VSTA 230.0 Circuit 2
Devers – San Bernardino 230kV line No. 1	1150 Amp(N) 1150 Amp(E)	719	917	DEVERS 230.0 to MIRAGE 230.0 Circuit 1, DEVERS 230.0 to MIRAGE
Devers – Vista 230 kV line No. 2	1240 Amp(N) 1240 Amp(E)	1465	1791	ETIWANDA 230.0 to SANBRDNO 230.0 Circuit 1, VSTA 230.0 to SANBRDNO
Devers – El Casco 230 kV line No. 1	1240 Amp(N) 1240 Amp(E)	1420	1746	DEVERS to VSTA 230 ck 2, SANBRDNO to DEVERS 230 ck 1
Mira Loma – Vista 230kV line No. 2	2299 Amp (N) 3110 Amp (E)	2693	3214	Etiwanda – San Bernardino 230 kV line No. 1 & Etiwanda – Vista 230 kV line

8. Short Circuit Duty Assessment

Short circuit studies were performed to determine the impact on circuit breakers with the interconnection of Transition Cluster Phase II projects to the transmission system. The fault duties were calculated before and after Phase II projects to identify any equipment overstress conditions. Three-phase (3PH) and single-line-to-ground (SLG) faults were simulated without the Phase II projects and with the Phase II projects including the identified Reliability and Delivery Network Upgrades from the power flow analysis.

8.1 SCD Results

All bus locations where the Transition Cluster 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. These values have been used to determine if any *additional* equipment, beyond what has previously been identified to be overstressed due to queued ahead serial projects, is triggered with the addition of the Transition Cluster Phase II interconnections and corresponding network upgrades. The Transition Cluster Phase II breaker evaluation identified the following additional overstressed circuit breakers which are triggered by the Transition Cluster Projects:

8.1.1 Vincent 500 kV Substation

The study identified that the addition of the Transition Cluster projects results in increasing SCD at SCE's Vincent 500 kV Substation beyond the breaker capabilities. Such duty increases were identified to impact a total of eleven 500 kV circuit breakers including four circuit breakers (see Section 4.6.3) which were previously identified to be triggered by serial interconnection projects but whose upgrade did not create sufficient capacity to accommodate the Transition Cluster Projects.

- Vincent 500 kV CB712, CB812 and CB912
- Vincent 500 kV CB722 and CB822
- Vincent 500 kV CB752, CB852 and CB952
- Vincent 500 kV CB762, CB862 and CB962

8.1.2 Kramer 220 kV Substation

The study identified that the addition of the Transition Cluster projects results in increasing SCD at SCE's Kramer 220 kV Substation beyond the breaker capabilities. Such duty increases were identified to impact a total of five 220 kV circuit breakers.

- Kramer 220 kV CB6012
- Kramer 220 kV CB4022 and CB6022
- Kramer 220 kV CB4082
- Kramer 220 kV CB4102

8.1.3 Windhub 220 kV Substation

The study identified that the addition of the Transition Cluster projects results in increasing SCD at SCE's Windhub 220 kV Substation beyond the breaker capabilities with the Windhub Substation operating with four 500/220 kV transformer banks in parallel. Such duty increases were identified to impact a total of nine 220 kV circuit breakers.

- Windhub 220 kV CB4102 and CB6102
- Windhub 220 kV CB4122 and CB6122
- Windhub 220 kV CB4112 and CB6112
- Windhub 220 kV CB2132, CB4132 and CB6132

8.1.4 Antelope 66 kV Substation

The study identified that the addition of the Transition Cluster projects results in increasing SCD at SCE's Antelope 66 kV Substation. Such duty increases were identified to impact a total of forty 66 kV circuit breakers including thirty-eight circuit breakers which were previously identified to be triggered by serial interconnection projects (see Section 4.6.19). The incremental duty contributions will result in duty which is in excess of the previous mitigation for the thirty-eight circuit breakers previously identified. As a result, mitigation for all identified forty circuit breakers will be required.

- Antelope CB1E and CB1W
- Antelope CB2E and CB2W
- Antelope CB3E and CB3W
- Antelope CB4E and CB4W
- Antelope CB5E and CB5W
- Antelope CB7E and CB7W
- Antelope CB8E and CB8W
- Antelope CB9E and CB9W
- Antelope CB10E and CB10W
- Antelope CB12E and CB12W
- Antelope CB14E and CB14W
- Antelope CB18E and CB18W
- Antelope CB20E and CB20W
- Antelope CB21E and CB21W
- Antelope CB22E and CB22W
- Antelope CB23E and CB23W
- Antelope CB24E and CB24W
- Antelope CB25E and CB25W
- Antelope CB26E and CB26W
- Antelope CB CAP1
- Antelope CB CAP3

8.2 SCD Mitigation Measures

To mitigate these identified overstressed circuit breakers, the following upgrades are recommended:

- Replace seven CBs and upgrade four CBs to achieve 63 kA rating on overstressed Vincent 500 kV CBs
- Replace five CBs to achieve 50 kA rating on overstressed Kramer 220 kV CBs
- Sectionalize Windhub 220 kV bus

- Operating procedure[2] to reduce Antelope 66 kV SCD

The responsibility to finance short circuit related Reliability Network Upgrades identified through a Group Study shall be assigned to all Interconnection Requests in that Group Study pro rata on the basis of the maximum megawatt electrical output of each proposed new Large Generating Facility or the amount of megawatt increase in the generating capacity of each existing Generating Facility. The pro rata allocation of each Transition Cluster Project to the circuit breaker upgrades listed above is provided in each individual report (Appendix A).

9. Transient Stability Analysis

Transient stability analysis was conducted using both the summer peak and spring full loop base cases to ensure that the transmission system remains stable with the addition of Transition Cluster generation projects. The generator dynamic data used for the study is confidential in nature and is provided with each individual project report

9.1 Transient Stability Study Scenarios

Disturbance simulations were performed for a study period of 10 seconds to determine whether the Transition Cluster 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).

9.2 Transient Stability Results

The study identified total of 39 SCE buses showing poor performance in the on-peak cases for the worst contingency of N-2 of Devers-Red Bluff 500 kV line #1 and #2. After implementing the proposed system upgrades, the results showed acceptable system stability with no criteria violations.

The study results of the off-peak load condition showed lower EOR and WOR path flow may be needed to achieve acceptable system stability performance with all proposed system upgrades.

Transient stability plots for on-peak and off-peak conditions and spring load conditions are provided in Appendix F.

[2] SCE anticipates that the appropriate long-term mitigation of the Antelope 66 kV SCD problem involves sectionalization of the Antelope 66 kV bus, but may also involve pre-Transition Cluster system SCD mitigation for Vincent 220 kV and Mira Loma 220 kV SCD problems. As an interim mitigation measure until the appropriate upgrades can be identified, an operating procedure to de-loop or de-energize sufficient transmission facilities to keep Antelope 66 kV SCD below 40 KA will be required.

10. Post-Transient Voltage Stability Analysis

The post-transient voltage stability results indicate no criteria violations by adding Phase II projects. The study concluded that the Phase II projects would not cause the transmission system to go unstable under Category "B" and Category "C" outages.

11. Mitigation of Transition Cluster Project Impacts

The mitigation requirements triggered by Transition Cluster projects, based on the results described in Sections 6-10 above, are as follows.

11.1 Plan of Service Reliability Network Upgrades

Plan of Service Reliability Network Upgrades for Transition Cluster projects in the Eastern Bulk System are discussed in detail in each individual project report (Appendix A).

11.2 Reliability Network Upgrades

Assumed scope for the Reliability Network Upgrades for Transition Cluster projects in the Eastern Bulk System are listed below.

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

Devers – Colorado River No.2 500kV Transmission Line
Loop the proposed line into Red Bluff Substation and form the two new Devers – Red Bluff no.2 and Colorado River – Red Bluff No.2 500kV T/Ls.

This work requires the installation of approximately 1 Circuit Mile of 2-2156KCMIL ACSR Conductors and OPGW, four Dead End 500kV Lattice Steel Structures and thirty Insulator / Hardware Assemblies.

Red Bluff 500/220kV Substation
Install two new Double Breaker Line Positions within the existing 500kV Switchyard to terminate the two new Colorado River No.2 and Devers No.2 500kV T/Ls.

Existing Control Room
Install the following Protection Relays:

500kV Transmission Lines

- Four GE C60 Breaker Management Relays
- Two G.E. D60 Distance Relay (Digital Communication

Channel)

- Two G.E. L90 Current Differential Relay (Digital Communication Channel)
- Two SEL-421 Current Differential Relay with RFL 9780 on PLCC.
- Two additional RFL 9780 Direct Transfer Trip on PLCC
- Two RFL 9745 Direct transfer trip on PLCC

11.2.2 Colorado River Substation Expansion – No. 1 AA-Bank

Expand the existing station, presently configured as a 500kV Switchyard, to a 1120MVA 500/220kV Substation by installing one 1120MVA 500/220kV Transformer Bank with corresponding 500kV and 220kV Bank Positions and installing a new 220kV Switchyard.

Scope Detail:
Install the following equipment:

- One 500kV Double Breaker Bank Position to connect the No.1AA Tr. Bk.
- One additional 500kV Circuit breaker and two Disconnect Switches on existing 500kV Two-Breaker Position connect the No.2AA Tr. Bk.
- Two 1120MVA 500/220kV No.1AA and No.2AA Transformer Banks consisting of seven 373MVA Single-Phase Units (Includes one spare unit)
- Two 220KV Operating Buses covering eight positions
- One 220kV Double Breaker Bank Position to connect the No.1AA Tr. Bk.
- One 220kV Double Breaker Bank Position to connect the No.2AA Tr. Bk.

500kV Switchyard:
Position 3
Install the following equipment for a Double Breaker Bank Position on a Breaker-and a-Half Configuration to connect the No.1AA 500/220kV Tr. Bk.:

- One 108 Ft. High by 90 Ft. Wide Dead-End Structure
- Two 500kV – 4000A – 50kA Circuit Breakers
- Four 500kV Horizontal-Mounted Group-Operated Disconnect Switches – One of them equipped with Grounding Attachments.
- Fifteen 500kV Bus Supports
- 2-1590KCMIL ACSR Conductors

500/220kV Transformer Bank:
Install one 1120MVA 500/161-220kV Transformer Banks as follows:

- Four 373MVA 500/161-220kV Single-Phase units, including one spare unit.

- Three 500kV Surge Arresters
- Three 220kV Surge Arresters
- One standard seven-position transformer structure with all the required 500kV and 220kV bus-work to allow for the Grounded Wye / Delta connection of the Single-Phase units and placement of the spare unit.
- One 13.8kV Tertiary Bus equipped as follows:
- Five 13.8kV – 2000A – 17kA Circuit Breakers
- Fifteen 13.8kV Hook-Stick Disconnect Switches
- Five 13.8kV 45MVAR Reactors
- One Ground Bank Detector (3 - 5kVA 14400-120/240V Transformers)
- One 14400-120V Voltmeter Potential Transformer
- One Voltmeter
- Three 40E Standard Size 4 S&C Type Fuses
- Approximately 700 Circuit Ft. of 2-1590KCMIL ACSR Conductors for the 500kV and 220kV Transformer Leads

220kV Switchyard:
Operating Buses

Install the following equipment required for a new 220kV Switchyard:

- Six 60 Ft High x 90 Ft Wide Bus Dead End Structures
- Twenty four Bus Dead-End Insulator Assemblies
- Six 220kV Potential Devices
- Approximately 920 Circuit Ft. of 21590KCMIL ACSR Bus Conductors

Position 5:

Install the following equipment for a Double Breaker Bank Position on a Breaker-and-a-Half Configuration to connect the No.1AA 500/220kV Tr. Bk.:

- One 80 Ft. High by 50 Ft, Wide Dead-End Structure
- Two 220kV 3000A – 50kA Circuit Breakers
- Four 220kV 3000A – 80kA Horizontal-Mounted Group-Operated Disconnect Switches
- One Grounding Switch Attachment
- Eighteen 220kV Bus Supports with associated steel pedestals
- 2-1590KCMIL ACSR Conductors

Existing Control Room

Install the following Protection Relays:

500/220kV Transformer Banks

- Four GE C60 Breaker Management Relays
- One GE T60 Bank Differential Relay
- One SEL-387 Bank Differential Relay
- Four GE C30 Sudden Pressure Aux Relay

- Five GE F60 Reactor Bank Relays (one per reactor)
- Two SEL-351 Ground Detector Bank Relay
- Twelve GE SBD11B 220kV Bus Differential Relays

11.2.3 Upgrade Mira Loma – Vista No.2 220 kV T/L Line Drops at Vista Substation to Emergency Rating of 3,500 A or Higher

Vista Substation:
Replace the existing 2-1033KCMIL ACSR Conductors (N – 2 Rating of 3,150A) on the Mira – Loma No.2 220kV line Position at Vista Substation with new 2-1590KCMIL ACSR Conductors (N – 2 Rating of 4,100A)

11.2.4 New SPS to Trip up to 1,400 MW of Generation Under the Devers – Red Bluff No.1 and No.2 Double Contingency

Red Bluff Substation

Install the following SPS Relays at each location:

- Two N60 relays (One each for SPS A and B) for Line Monitoring
- One SEL – 2407 Satellite Synchronized Clock.

Colorado River Bluff Substation

Install the following SPS Relays:

- Four N60 relays (Two each for SPS A and B) for Logic Central Processing and sending of tripping signals to Generators.
- One SEL – 2407 Satellite Synchronized Clock.

Telecommunications
Install the following equipment and channels to support the SPS:

- Devers Substation: Two Channel Banks (One each for SPS A and B)

Power System Control
Install Dual RTU's for SPS arming, control and status and alarm indications at Colorado River Substation.

Expand existing RTU's Devers and Red Bluff Substations to install additional points required to support the SPS.

11.2.5 New SPS to Trip up to 500 MW of Generation Connected to Colorado River Substation Under Either No.1AA or No.2AA Transformer Bank Single Contingency

Colorado River Bluff Substation
Install the following SPS Relays:

- Four N60 relays (Two each for SPS A and B) for Banks Monitoring

The four N60 relays for Logic Central Processing and sending of tripping signals to Generators installed for SPS described on Item 11.2.3 will also support this additional SPS.

Telecommunications
No additional equipment required.
All equipment installed for SPS described on Item 3 will also support this additional SPS.

Power System Control
Also expand existing RTU's Devers and Red Bluff Substations to install additional points required to support the SPS.

11.3 Delivery Network Upgrades

Details of the scope for the Delivery Network Upgrades of the Phase II projects in the Eastern Bulk System are listed below.

11.3.1 West of Devers Upgrades

Upgrade the following 220kV transmission Lines to 3,000A Rating by replacing all existing conductors with new 2-1590KCMIL ACSR conductors per phase and replacing all substations terminal equipment with 3,000A rated elements:

- Devers – San Bernardino No.1 220kV T/L – 43 Circuit Miles
- Devers – San Bernardino No.2 220kV T/L – 43 Circuit Miles
- Devers – Vista No.1 220kV T/L – 45 Circuit Miles
- Devers – Vista No.2 220kV T/L – 45 Circuit Miles
- Devers Substation: Upgrade four 220kV line Positions
- San Bernardino G.S.: Upgrade two 220kV line Positions
- Vista Substation: Upgrade two 220kV line Positions

Note:

Prior to this upgrade the existing Devers – San Bernardino No.2 220kV T/L will be looped into the new El Casco Substation forming the two new Devers – El Casco and El Casco – San Bernardino 220kV T/Ls.

After this line re-configuration the existing Devers – San Bernardino No.1 220kVT/L will be re-named Devers – San Bernardino 220kV T/L.

The Devers and San Bernardino 220kV Line Positions at the new El Casco Substation will be rated 3,000A and would not require any upgrades.

11.3.2. Colorado River Substation Expansion – No. 2 AA Bank

Increase the 500/220kV station capacity from 1120MVA to 2240MVA by installing an additional No.2AA 1120MVA 500/220kV Transformer Bank with corresponding 500kV and 220kV Bank Positions.

Scope Detail:
500 kV Switchyard:

Position 5:
Install the following equipment on the existing 2-CB Line Position to expand to a 3-CB Line / Bank Position as required to connect the No.2AA Tr. Bk.:

- One 108 Ft. High by 90 Ft. Wide Dead-End Structure
- One 500kV 4000A – 50kA Circuit Breaker
- Two 500kV 4000A – 80kA Horizontal-Mounted Group-Operated Disc. Switches
- One Grounding Switch Attachments
- Also <u>remove</u> twelve 500kV Bus Supports and corresponding steel pedestals and foundations.

500/220 kV Transformer Bank:
Install one 1120MVA 500/161-220kV Transformer Bank as follows:

- Three 373MVA 500/161-220kV Single-Phase units.
- Three 500kV Surge Arresters
- Three 220kV Surge Arresters
- One 13.8kV Tertiary Bus equipped as follows:
- Five 13.8kV – 2000A – 17kA Circuit Breakers
- Fifteen 13.8kV Hook-Stick Disconnect Switches
- Five 13.8kV 45MVAR Reactors
- One Ground Bank Detector (3 - 5kVA 14400-120/240V Transformers)
- One 14400-120V Voltmeter Potential Transformer
- One Voltmeter

- Three 40E Standard Size 4 S&C Type Fuses
- Approximately 700 Circuit Ft. of 2-1590KCMIL ACSR Conductors for the 500kV and 220kV Transformer Leads

220kV Switchyard:
Position 7:
Install the following equipment for a Double Breaker Bank Position on a Breaker-and-a-Half Configuration to connect the No.2AA 500/220kV Tr. Bk.:

- One 80 Ft. High by 50 Ft, Wide Dead-End Structure
- Two 220kV 3000A – 50kA Circuit Breakers
- Four 220kV 3000A – 80kA Horizontal-Mounted Group-Operated Disconnect Switches
- One Grounding Switch Attachment
- Eighteen 220kV Bus Supports with associated steel pedestals
- 2-1590KCMIL ACSR Conductors

Existing Control Room
Install the following Protection Relays:

500/220kV Transformer Banks
- Four GE C60 Breaker Management Relays
- One GE T60 Bank Differential Relay
- One SEL-387 Bank Differential Relay
- Three GE C30 Sudden Pressure Aux Relays
- Five GE F60 Reactor Bank Relays (one per reactor)
- Two SEL-351 Ground Detector Bank Relay

12. Environmental Evaluation / Permitting

12.1 CPUC General Order 131-D

The California Public Utilities Commission's (CPUC) General Order 131-D (GO 131-D) sets for 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 facilities between 50 and 200 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 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 6-18 months to assemble a CPCN or PTC application, the majority of which time is involves by developing a required Proponent's Environmental Assessment (PEA). The CPUC review of such applications may take anywhere from 8 – 36 months depending on the specific.

12.2 CPUC General Order 131-D – Permit to Construct/Exemptions

GO 131-D provides for certain exemptions from the CPUC PTC requirements for facilities between 50 and 200 kV. For example, Exemption f of GO 131-D (Section III.B.1.f) exempts from CPUC PTC permitting requirements power lines or substations between 50 - 200 kV 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 exemption 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 jurisdicition(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 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 4-6 months to process.

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

When SCE's transmission lines 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 transmission lines 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 the project 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 4-6 months for the CPUC to process.

12.4 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 assumed that the Interconnection Customer will include SCE's Interconnection Facilities and Network Upgrades work scope (including facilities to be constructed by others and deeded to SCE) in the Interconnection Customer's environmental reports/applications submitted to the lead agency permitting the Interconnection Customer's larger generator project (e.g., California Energy Commission or applicable local, state or federal permitting agency, such as the Bureau of Land Management), and that such agencies will 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, the SCE's facilities needed for the project interconnection could require an additional two years, or more, to license and permit. The cost for obtaining any of this type of permitting is not included in the cost estimates.

Please see General Order 131-D. This document can be found in the CPUC's web page at:

http://www.cpuc.ca.gov/PUBLISHED/GENERAL_ORDER/589.htm

12.5 CPUC Section 851

Because 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.

12.6 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 will follow the requirements of all applicable environmental laws and regulations and issue an in-house environmental clearance before commencement of construction activities.

13. Upgrades, Cost and Time to Construct Estimates

The cost estimates are based on initial engineering scope as described in Section 11 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 Transition Cluster 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 Large 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 Deliverability Status based on the flow impact of each such Large Generating Facility on the Delivery Network Upgrades as determined by the generation distribution factor methodology.

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

The estimated costs of **Distribution Upgrades** and **non-CAISO transmission upgrades, if applicable,** 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 Large 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 13.1 Upgrades, Estimated Costs, and Estimated Time to Construct Summary

Type of Upgrade	Upgrade	Description	Estimated Cost x 1,000	Estimated Time to Construct
Plan of Service Reliability Network Upgrades	Plan of Service Reliability Network Upgrades for TC Phase II projects in the Eastern Bulk System are discussed in detail in each individual project report (Appendix A).		$(redacted)	See Appendix A
Reliability Network Upgrades	Loop the Colorado River – Devers 500 kV No. 2 Transmission Line into Red Bluff Substation	Loop the Colorado River – Devers 500 kV No. 2 line into Red Bluff Substation and form the two new Devers – Red Bluff No.2 and Colorado River – Red Bluff No.2 500kV T/Ls. Install two new Double Breaker Line Positions within the existing 500kV Switchyard to terminate the two new Colorado River No.2 and Devers No.2 500kV T/Ls.	$ (redacted)	36 months
	Colorado River Substation Expansion – No. 1 AA Bank	Expand the existing station, presently configured as a 500kV Switchyard, to a 1120MVA 500/220kV Substation by installing one 1120MVA 500/220kV Transformer Banks with corresponding 500kV and 220kV Bank Positions and installing a new 220kV Switchyard.		
	Upgrade Mira Loma – Vista No.2 220 kV T/L Line Drops at Vista Substation to Emergency Rating of 3,500 A or Higher	Replace the existing 2-1033KCMIL ACSR Conductors (N – 2 Rating of 3,150A) on the Mira – Loma No.2 220kV line Position at Vista Substation with new 2-1590KCMIL ACSR Conductors (N – 2 Rating of 4,100A)		
	New SPS To Trip up to 1,400 MW of Generation Under the Devers – Red Bluff No.1 and No.2 Double Contingency	Trip Generation under the Double Contingency caused by the simultaneous outages of Devers – Red Bluff No.1 and No.2 500kV T/Ls.		
	New SPS to Trip up to 500 MW of Generation Connected to Colorado River Substation Under Either No.1AA or No.2AA Transformer Bank Single Contingency	Trip Generation under the Single Contingency caused by the individual outage of either one of the Colorado River No.1AA or No.2AA Transformer Bank.		
Delivery Network Upgrades	West of Devers 220 kV Upgrades	Upgrade the following 220kV transmission Lines to 3,000A Rating by replacing all existing conductors with new 2-1590KCMIL ACSR conductors per phase and replacing all substations terminal equipment with 3,000A rated elements: Devers – San Bernardino No.1 220kV T/L – 35 Circuit Miles Devers – San Bernardino No.2 220kV T/L – 35 Circuit Miles Devers – Vista No.1 220kV T/L – 37 Circuit Miles Devers – Vista No.2 220kV T/L – 37 Circuit Miles Devers Substation: Upgrade four 220kV line Positions San Bernardino G.S.: Upgrade two 220kV line Positions Vista Substation: Upgrade two 220kV line Positions	$ (redacted)	84 months
	Colorado River Substation Expansion – No. 2 AA Bank	Increase the 500/220kV station capacity from 1120MVA to 2240MVA by installing an additional No.2AA 1120MVA 500/220kV Transformer Bank with corresponding 500kV and 220kV Bank Positions		
Distribution Upgrades	None		$0	N/A
Total			**$ (redacted)**	**84 Months**

The non-binding construction schedule to engineer and construct the facilities identified in this report will be project-specific and will be based upon the assumption that the environmental permitting obtained by the IC is adequate for permitting all SCE activities.

It is assumed that the IC will include the SCE's Interconnection Facilities and Network Upgrades work scope, as they apply to work within public domains, in its environmental impact report to the CPUC. However, note that CPUC may still require SCE to obtain a Permit to Construct (PTC) or a Certificate of Public Convenience and Necessity (CPCN) for the Interconnection Facilities and Network Upgrades work associated with the project. Hence, the facilities needed for the project interconnection could require an additional two to three years to complete. The cost for obtaining any of this type of permitting is not included in the above estimates.

14. Coordination with Affected Systems

ISO LGIP tariff Appendix Y section 3.7 requires coordinating with any affected systems that have any potential impact of Transition Cluster projects. CAISO will coordinate the review of the Phase II reports with potentially Affected Systems, such as: MWD, IID, WAPA, APS…, etc to verify the conclusions and recommendations of this Phase II report. Depending on the outcome of such review, it may be necessary for the Interconnection Customer to enter into separate study agreements with the potentially affected system owner(s), at the cost of the Interconnection Customer, to analyze the impacts to the affected system(s). Any such analysis may identify additional upgrades on the affected system(s) for which mitigation would be the responsibility of the Interconnection Customer.

Appendix A - Q #193

NextEra Energy Resources

Desert Center Blythe Generation Project

(Genesis Solar Energy Project)

Final Report

California ISO
Your Link to Power

July 08, 2010

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

Table of Contents

Attachments:

1. **Generator Machine Dynamic Data**
2. **Dynamic Stability Plots (see Appendix F)**
3. **SCE Interconnection Handbook**
4. **Short Circuit Calculation Study Results (see Appendix H)**
5. **Deliverability Assessment Results**
6. **Allocation of Network Upgrades for Cost Estimates**
7. **Results of Operational Studies (Removed)**

1 Executive Summary

NextEra Energy Resources (NextEra), an Interconnection Customer (IC), has submitted a completed Interconnection Request (IR) to the California Independent System Operator Corporation (CAISO) for their proposed Desert Center Blythe Generation Project (Project), interconnecting to the CAISO Controlled Grid. The Project is a solar thermal trough technology plant with an output of 500 MW to the Point of Interconnection (POI) which is at Southern California Edison Company's (SCE) proposed Colorado River Substation in Blythe, California. The IC has proposed a Commercial Operation Date of July 1, 2013 for the Project.

In accordance with Federal Energy Regulatory Commission (FERC) approved Large Generator Interconnection Procedures (LGIP) for Interconnection Requests in a Queue Cluster Window (ISO Appendix Y), the Project was grouped with Transition Cluster projects in a Phase II Interconnection Study to determine the impacts of the group as well as impacts of the Project on the CAISO Controlled Grid.

The group report has been prepared separately identifying the combined impacts of all projects in the group on the CAISO Controlled Grid. This individual report focuses only on the impacts associated with the Project.

The report provides the following:

1. Transmission system impacts caused by the Project;

2. System reinforcements necessary to mitigate the adverse impacts caused by the Project under various system conditions; and

3. A list of required facilities and a non-binding, good faith estimate of the Project's cost responsibility and time to permit, engineer, design, procure and construct these facilities.

The Phase II Study results have determined that the Project contributes to overloading of transmission facilities for which mitigation plans have been proposed. A combination of congestion management for base case and contingency overloads, West-of-Devers Upgrades Project, looping the 2nd 500 kV T/L into the Red Bluff Substation, Colorado River substation expansion with two 500/230 kV transformers, and the use of SPS under identified contingency outage conditions is required to mitigate the power flow impacts of the project described above. See the group report for additional details.

The non-binding costs to interconnect the Project are:

Interconnection Facilities[1]	**$ (redacted)**	including ITCC[2];
Network Upgrades[3]	**$ (redacted)**	

[1] The transmission facilities necessary to physically and electrically interconnect the Project to the CAISO Controlled Grid at the point of interconnection. These costs are not reimbursable.
[2] Income Tax Component of Contribution.

Distribution Upgrades[4] **$ (redacted)**

The anticipated time to construct the facilities associated with the Project is approximately 84 months from the signing of the Large Generator Interconnection Agreement (LGIA). In addition there may be operational constraints related to the construction of upgrades to accommodate projects ahead in queue. See Section 9 "Operational Studies" for additional details.

2 Project and Interconnection Information

Table 2-1 provides general information about the Project as modeled in the Phase II Study.

Table 2-1: Desert Center Blythe Project General Information

Project Location	Blythe, California
SCE Planning Area	Eastern Bulk System
Number and Type of Generators	4 Siemens synchronous steam generator using parabolic trough field technology
Interconnection Voltage	220 kV
Maximum Generator Output	570MW
Generator Auxiliary Load	70 MW
Maximum Net Output to Grid	500 MW
Power Factor Range	0.90 Lagging to 0.90 Leading
Step-up Transformer	Four 3-phase transformer rated for 220/13.8 kV, 150 MVA, with 9% impedance on a 90 MVA base
Point of Interconnection	Connect to the proposed Colorado River 500/220 kV Substation
Commercial Operation Date	July 1, 2013 (customer requested date
Significant Individual Project Appendix B Changes between Phase I and Phase II	None

Figure 2-1 provides the map for the Project and the transmission facilities in the vicinity. Figure 2-2 shows the conceptual single line diagram of the Project as modeled in the Phase II Study.

[3] 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.

[4] These upgrades are not part of the CAISO Controlled Grid and are not reimbursable

Redacted Photo for CEII Purposes

Figure 2-1 : Map of the Project

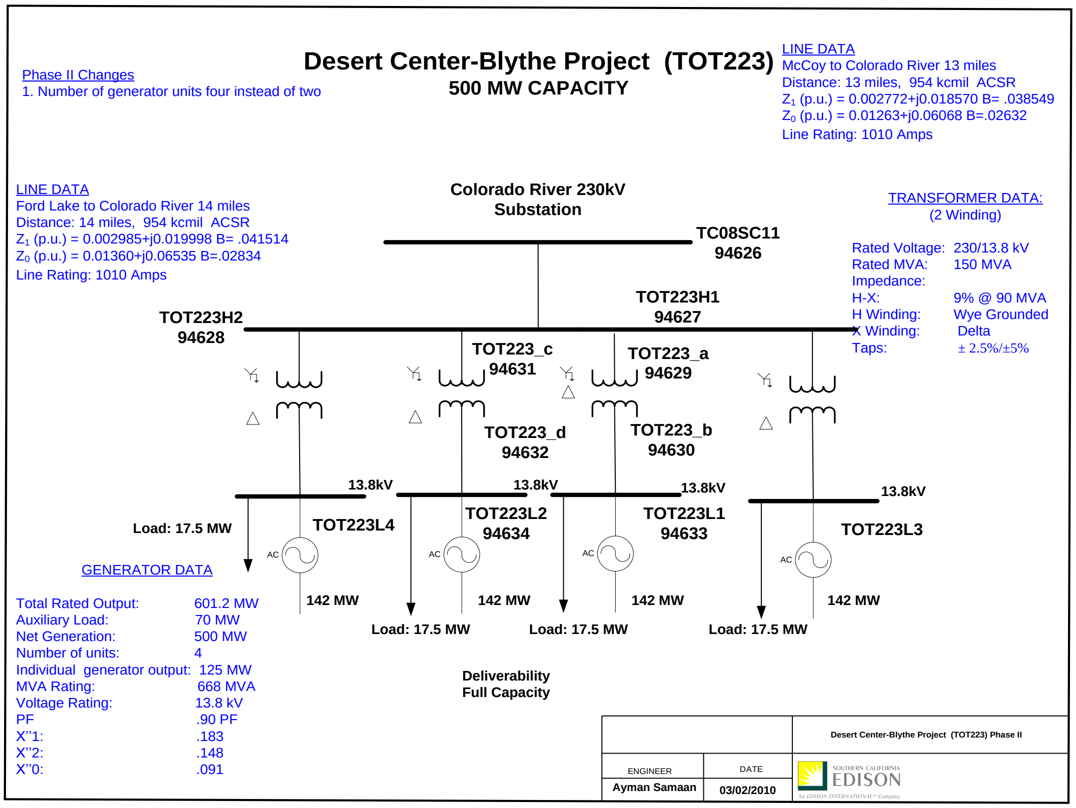

Figure 2-2: Proposed Single Line Diagram as modeled in the Phase II Study

3 Study Assumptions

For details about the Transition Cluster interconnection information and the group study assumptions, including relevant changes between the Phase I and Phase II studies, see the group report Sections 2 and 4.

The Transition Cluster Phase II Study pre-project base cases assume for modeling purposes that the California Portion of DPV2, namely Devers-Colorado River project (DCR) including the proposed 500kV Switchyard at Colorado River, has been constructed and placed in service by SCE. Based on this modeling assumption, DCR costs have not been included in this Phase II Study nor has any portion of DCR been allocated to the Transition Cluster Phase II Study Projects. However, if required regulatory approvals are not granted, modeling assumption will need to be re-examined.

The following design assumptions are applicable to the Project:

A. The following Facilities were estimated and included in the Phase II Study:

- The second telecommunication path from the generating facility to the Colorado River Substation will be installed by SCE.
- All telecommunication terminal equipment at the end of the gen tie line (on the IC's side), which will interface with the generator-owned line protection relays and the special protection system (SPS) relays, will be installed by SCE.
- It is assumed SCE would be required to install one additional dead-end structure and a total of two spans to reach the 220 kV switchyard.
- The required revenue metering cabinet and retail load meters to be installed at the generating facility will be installed by SCE.
- The required remote terminal unit (RTU) to be installed at the generating facility will be installed by SCE.

B. The following Facilities were not included in the Phase II Study:

- The Queue #193 220 kV gen tie Line from the generating facility to the last structure outside the Colorado River Substation property line will be installed by the Generator.
- The 220 kV gen tie line Right of Way should extend up to the edge of the Colorado River Substation property line
- The Queue #193 220 kV gen tie line must be equipped with optical ground wire (OPGW) to provide the telecommunication path required for the line protection scheme and <u>one of the two</u> telecommunication paths required for the SPS.
- The cost of the OPGW will be included in the cost of the gen tie line to be installed by the Generator.
- All required CAISO metering equipment at the generating facility will be provided by the Generator.
- All required revenue metering equipment to meter the generating facility retail load will be specified by SCE and installed by the Generator.
- The following 220 kV gen tie line protection and SPS relays to be installed at the Generating Facility will be specified by SCE and provided by the Generator:
    - One G.E. L90 current differential relay with telecommunication channel to Colorado River Substation via the 220 kV gen tie line OPGW.
    - One SEL 311C current differential relay. No telecommunication channels required.
    - Two N60 relays (one each for SPS A and B) to trip the Generator breakers.
    - One SEL – 2407 satellite synchronized clock.

4 Power Flow Analysis

The group study indicated that this project is contributing into overloading of the following transmission facilities. The details of the analysis and overload levels are provided in the group study.

4.1 Overloaded Transmission Facilities

Category "A"

- Devers-San Bernardino 220 kV No.1 and No.2 lines
- Devers-Vista 220 kV line No.1

Category "B"

- Devers-Vista 220 kV No.2 line
- Devers-San Bernardino 220 kV No.1 and No.2 lines
- Devers-Vista 220 kV line No.1

Category "C"

- Devers-Vista 220 kV No.2 line
- Devers-San Bernardino 220 kV No.1 and No.2 lines
- Devers-Vista 220 kV line No.1
- Mira Loma – Vista 220 kV No.2 line

4.2 Power Flow Non-Convergence

None

4.3 Recommended Mitigations

The Phase II Study results have determined that the Project contributes to overloading of transmission facilities for which mitigation plans have been proposed. A combination of congestion management for base case and contingency overloads, West-of-Devers Upgrades Project, looping the 2nd 500 kV T/L into the Red Bluff Substation, and the use of SPS under identified contingency outage conditions is required to mitigate the power flow impacts of the project described above. See the group report for additional details.

5 Short Circuit Analysis

Short circuit studies were performed to determine the fault duty impact of adding the Phase II Projects to the transmission system. The fault duties were calculated with and without the Projects to identify any equipment overstress conditions.

The cost responsibility of each individual project was determined based on the methodology applied in the Phase I Study once overstressed circuit breakers were identified. Costs of replacing and/or upgrading circuit breakers located within a Transition Cluster Group were allocated among all generation projects located within that Group. Costs of replacing and/or upgrading circuit breakers not located within a particular Transition Cluster Group were allocated over the entire Transition Cluster. Costs were allocated pro rata on the basis of the maximum megawatt electrical output of each proposed new Large Generating Facility or the amount of megawatt increase in the generating capacity of each existing Generating Facility.

5.1 Short Circuit Study Input Data

The following input data provided by the IC was used in this study:

Siemens Synchronous Generator Short Circuit Data @ 500 MVA Base:

Positive Sequence subtransient reactance (X''1) = 0.183 p.u.

Negative Sequence subtransient reactance (X''2) = 0.148 p.u.

Zero Sequence subtransient reactance (X''0) = 0.091 p.u.

Station Step-up Transformer

The four (4) transformers are each three-phase 220/18 kV rated for 150 MVA with an impedance of 9% at 90MVA base.

Generation Tie Line

The IC has two generation facilities that will be consolidated at a ring bus to connect a single 14 mile, 954 ACSR, 230 kV gen tie to Colorado River Substation, assuming the ring bus is located at the McCoy location.

5.2 Results

All bus locations where the Phase II Projects increase the short-circuit duty by 0.1 kA or more and where duty is in excess of 60% of the minimum breaker nameplate rating are listed in the Appendix H of the Group Report. These values have been used to determine if any equipment is overstressed as a result of the Phase II interconnections and corresponding network upgrades, if any. The Phase II breaker evaluation identified the following overstressed circuit breakers:

- Vincent 500 kV Substation: 500 kV CB962, CB862, CB852, CB812, CB912, CB 952, CB 722, CB 712, CB752, CB762, and CB822
- Kramer 220 kV Substation: 220 kV CB4022, CB6022, CB6012, CB4082, and CB4102
- Windhub 220 kV Substation: 220 kV CB4102, CB4122, CB6102, CB6122, CB4122, CB4132, CB2132, CB6112, and CB6132
- Antelope 66 kV Substation: 66 kV CB21E and CB 21W

Based on the cost assignment methodology applied in the Phase II Study, the Project will have the assigned cost responsibility for mitigation of the short-circuit duty results described above. The total cost responsibility allocated to the Project is provided in Attachment 6.

5.3 Preliminary Protection Requirements

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

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

6 Reactive Power Deficiency Analysis

Reactive power deficiency analysis was performed in the group study. The reactive power deficiency analysis included power flow sensitivity analysis in the eastern bulk system. The study found no reactive deficiency from this project to the SCE bulk system. For additional details, please see the group report.

7 Transient Stability Evaluation

Transient Stability studies were conducted using the full loop base cases to ensure that the transmission system remains in operating equilibrium, as well as operating in a coordinated fashion, through abnormal operating conditions after the Phase II projects begin operation. The generator dynamic data used in the study for this Project is shown in Attachment 1.

7.1 Transient Stability Study Scenarios

Disturbance simulations were performed for a study period of 10 seconds to determine whether the Phase II projects will create any system instability during a variety of line and generator outages. The most critical single contingency and double contingency outage conditions in the east and west of Devers area within the overall SCE Eastern Bulk System were evaluated. For the list of specific line and generator outages evaluated, see the group report.

7.2 Results

Stability analysis was performed for the Eastern Bulk systems to identify the stability impacts of this Phase II Study queued generation project.

In the stability analysis performed in the 500 kV, 220 kV and 115 kV systems with the upgrades in place to mitigate base case and outage related overload problems, system instability was identified from the worse Category "C" outage. A proposed SPS to trip up to 1400 MW Phase II Study project capacity including tripping this project mitigated the system impact. Stability plots are shown in Appendix F of the group report.

8 Deliverability Assessment

8.1 On Peak Deliverability Assessment

CAISO performed a 2013 On-Peak Deliverability Assessment. The detail on-peak deliverability assessment results can be found in the group report for the Eastern Bulk system.

8.2 Off- Peak Deliverability Assessment

There is no off-peak deliverability assessment required by the Deliverability Assessment methodology (http://www.caiso.com/23d7/23d7e41c14580.pdf) for the Eastern Bulk area since there are all solar projects in this area.

9 Operational Studies

9.1 IC Proposed Project Timelines

The latest information provided by the IC has indicated that the proposed date for the generator step-up transformer to receive back feed power is May 1, 2013 and the proposed Commercial Operation Date for the entire 500 MW project is July 1, 2013. Due to the modular nature of the solar facilities, the IC has indicated that construction of this project will commence on January 1, 2011 with the initial block to be ready for testing on May 14, 2013.

9.2 System Upgrade Timelines

The Project involves the installation of the following Interconnection Facilities:

1. A dead-end structure and one dedicated double breaker position at the planned Colorado River 220 kV substation to bring in the Project generation tie lines;
2. An RTU at the Project Facility; and
3. The installation of telecommunications equipment to provide diverse protection and data transfer capability to the RTU, and SCADA data recording equipment.

The anticipated time to construct these interconnection facilities is 24 months following execution of the LGIA. However, start of construction of such interconnection facilities cannot commence until SCE receives all appropriate regulatory approvals, permitting approvals, licenses allowing the construction of the Colorado River (CR) 500 kV switchyard which is part of the Devers-Colorado River (DCR) project, the Colorado River Substation expansion, and required telecommunication facilities to support an initial "Energy Only" interconnection.

This Phase II Study assumed that all previously triggered short-circuit duty impacts would be mitigated by the corresponding triggering project. Consequently, this study evaluated the incremental impacts associated with the addition of the Transition Cluster projects, including appropriate transmission upgrades as identified in this study, in an effort to cost allocate the incremental upgrades associated with the addition of the Transition Cluster projects. However, it should be clear that for reliability reasons it may be necessary to implement mitigation upgrades previously triggered by queued ahead generation projects prior to allowing interconnection of Transition Cluster generation projects.

The circuit breaker upgrades that were triggered by queued-ahead projects are identified in Section 4.6 of the group report. The Operational Study undertaken as part of this Phase II Study identified the required timing for circuit breaker upgrades triggered by queued-ahead generation projects. The Table below identifies the first year that circuit breaker upgrades triggered by queued-ahead projects were found to be required in this Operational Study at each substation location.

Table 9-1: Circuit Breaker Upgrades Triggered by Queued-ahead Projects

Year	Location

2010	Devers 115 kV Ellis 66 kV Etiwanda 220 kV Inyokern 115 kV Vincent 220 kV Antelope 66 kV Neenach 66 kV
2011	Terawind 115 kV
2012	Mira Loma 220 kV Villa Park 220 kV
2013	Antelope 220 kV Chino 220 kV Devers 220 kV Lugo 500 kV Mesa 220 kV Vincent 500 kV
2014	Mira Loma 500 kV Vincent 220 kV
2015	None
2016	None

This Phase II Study assumed that the timelines for construction of the upgrades listed in Table 9-1 to accommodate queued-ahead projects will also be sufficient to accommodate the operational requirements for the Transition Cluster projects. In the event that the Transition Cluster projects will need to accelerate these upgrades, the projects will need to do so via a separate agreement. Operational studies will be conducted on an annual basis or more frequently as needed to identify such requirements.

The circuit breaker upgrades that were triggered by Transition Cluster projects are identified in Section 8.2 of the group report. The Operational Study undertaken as part of this Phase II Study identified the required timing for circuit breaker upgrades triggered by Transition Cluster projects. The Table below identifies the first year that circuit breaker upgrades triggered by Transition Cluster projects were found to be required in this Operational Study at each substation location.

Table 9-2: Circuit Breaker Upgrades Triggered by Transition Cluster Projects

Year	Location
2013	Antelope 66 kV
2014	None
2015	Vincent 500 kV Windhub 220 kV
2016	Kramer 220 kV

9.2.1 Reliability Network Upgrade Timelines

To balance power flow on the Colorado River – Red Bluff – Devers 500 kV line and the Colorado River – Devers 500 kV, Phase II Study identified that the inclusion of all the Eastern area projects located within the Blythe – Area and the Desert Center – Area Project will require looping of the Colorado River – Devers 500kV No.2 T/L into the Red Bluff Substation. The anticipated time to construct this reliability network upgrade is 36 months upon execution of LGIA. The new proposed Colorado River 500 kV switchyard is a part of the Devers-Colorado River (DCR) project. The anticipated time to construct the Colorado River Substation and DCR is 36 months following receipt of all regulatory approvals appropriate approvals for the DCR project.

The Phase II Study identified that the inclusion of all Eastern area Projects located within the Blythe area triggered the need for SCE-owned Colorado River 220 kV switchyard with one new SCE-owned 500/220 kV transformer bank and expansion of the Colorado River 500 kV switchyard. The anticipated time to construct this Reliability Network Upgrade is 36 months following execution of the LGIA. It is important to note that the start of construction of such Reliability Network Upgrades cannot commence until SCE receives all appropriate permitting approvals and licenses for the Colorado River Substation expansion and the looping-in of DCR to Red Bluff Substation.

The Phase II Study identified that the inclusion of all Eastern area Projects triggered the need for upgrading the Mira Loma – Vista No.2 220 kV T/L drops at Vista Substation to mitigate the overload under certain 220 kV outages. The anticipated time to construct this reliability network upgrade is 12 months following execution of the LGIA.

Additionally, the Phase II Study identified that the inclusion of all the projects located in the Blythe Area triggered the need for a new SPS to mitigate the losses of one AA bank at Colorado River Substation. The Project will need to be added to the SPS at the new Colorado River Substation. The anticipated time to construct this Reliability Network Upgrade is 24 months following execution of the LGIA. As previously stated, construction of such Reliability Network Upgrades cannot commence until SCE receives all appropriate approvals and licenses for Colorado River Substation and DCR.

Lastly, to maintain system reliability the Phase II Study identified that the inclusion of all Eastern area Projects located within the Blythe area and the Desert Center area triggered the need for a new SPS to address impacts on the SCE system under certain 500 kV outages. The anticipated time to construct this Reliability Network Upgrade is 24 months following execution of LGIA. This project will be added to this new SPS once the project is placed into service

9.2.2 Delivery Network Upgrade Timelines

To provide the requested Full Delivery, the Phase II Study identified the need for significant Delivery Network Upgrades. Specifically, the project has been identified to contribute to the need for upgrading the four 220kV T/L in the West of Devers area to mitigate the base case overload. The anticipated time to construct all of these Delivery Network Upgrades associated with "Full Delivery" Interconnection is 84 months following execution of LGIA.

The Phase II Study identified that the inclusion of all Eastern area Projects located within the Blythe area triggered the need for the second AA-Bank at the Colorado River Substation. The anticipated time to construct this Delivery Network Upgrade is 36 months following execution of LGIA. It is important to note that the start of construction of such Delivery Network Upgrade cannot commence until SCE receives all appropriate permitting approvals and licenses for the Colorado River Substation expansion.

9.2.3 Distribution Upgrade Timelines

The Phase II Study concluded that the Project was not allocated any Distribution Upgrades.

9.3 Conclusion

Based on information available at this time, assuming an anticipated LGIA execution date of September 2010, there are potential operational constraints to the Project associated with base case congestion exposure under an interim "Energy Only" Interconnection.

The current schedule for the Reliability Network Upgrades indicate a 36-month time duration to construct the SCE-owned Colorado River 220 kV switchyard with one new SCE-owned 500/220 kV transformer bank and expansion of the Colorado River 500 kV switchyard after execution of the LGIA. This schedule suggests that the facilities needed to interconnect the Project, under an initial "Energy Only" arrangement, cannot be constructed by the requested transformer back feed date of May 1, 2013. The earliest date possible to interconnect the Project under an Energy Only arrangement would be September 2013 provided all regulatory approvals are received.

The project interim "Energy Only" status would remain until all the Delivery Network Upgrades are constructed. Based on the current schedules, this condition could exist for up to 84 months, and possibly longer depending on actual permitting and construction timelines of the Delivery Network Upgrades.

These conclusions are based on the estimated time for engineering, licensing, procurement, and construction of a typical project. Schedule durations may change due to the number of projects approved and release dates to construct the project. The ability to meet the IC proposed operating date is subject to constraints such as resource availability, system outage availability, and environmental windows for construction.

10 Environmental Evaluation/Permitting

Please see Section 12 of group report.

11 Upgrades, Cost Estimates and Construction schedule estimates

To determine the cost responsibility of each generation project in Phase II Study, the CAISO developed cost allocation factors based on the individual contribution of each project (Attachment 6). The cost allocation for the Interconnection Facilities and Network Upgrades for which this Project is solely responsible is as follows:

PTO'S INTERCONNECTION FACILITIES

1. Transmission:

Install one 220 kV dead-end structure, two spans of conductors and OPGW and twelve dead end insulator / hardware assemblies between the last generator-owned structure and the Substation dead – end rack at the Colorado River 220 kV switchyard.

2. Substations:

Colorado River 500/220 kV Substation

Install the following Interconnection Facilities components to terminate the new 220 kV gen tie line at a dedicated double breaker position.

- One dead-end structure (60 ft. high x 50 ft. wide)
- Three 220 kV coupling capacitor voltage transformers
- One G.E. L90 current differential relay with telecommunication channel to the Generating Facility via the 220 kV gen tie line OPGW.
- One SEL 311C current differential relay. No telecommunication channels required.

3. Metering Services Organization

Install a revenue metering cabinet and revenue meters required to meter the retail load at the generating facility. The Generator will provide the required metering equipment (voltage and current transformers).

4. Power System Control

Install one RTU at the generating facility to monitor the typical generation elements such as MW, MVAR, terminal voltage and circuit breaker status at each generating unit and the plant auxiliary load and transmit this information to the SCE Grid Control Center.

5. Telecommunications

Install approximately 28 miles of new All Dielectric Self Supported (ADSS) Fiber Optic Cable from the Colorado River Substation to the generating facility to meet the diverse routing requirements for the SPS relays.

Also install all required light-wave, channel and related terminal equipment at each end of the gen tie line.

Note: Telecommunication is required for both generation sites due to SPS requirements under an N-2 condition to trip 375 MW (total of 3 units). It was assumed that a total of 28 miles of telecommunication would be required from Colorado Substation to connect both generation sites.

6. Real Properties, Transmission Project Licensing, and Environmental Health and Safety

Obtain easements and/or acquire land, obtain licensing and permits, and perform all required environmental activities for the installation of the 28 miles of telecommunication and the SCE portion of the Project gen tie line and telecommunication route.

PLAN OF SERVICE RELIABILITY NETWORK UPGRADES

Colorado River 500/220 kV Substation

Install the following equipment for a dedicated 220 kV double breaker line position on a breaker-and-a-half configuration to terminate the Queue #193 220 kV gen tie Line.

- Two 220 kV 3000A – 50 kA Circuit Breakers
- Four 220 kV 3000A – 80 kA Horizontal-Mounted Group-Operated Disconnect Switches
- One Grounding Switch Attachment
- Eighteen 220 kV Bus Supports with associated steel pedestals
- 2-1590 KCMIL ACSR Conductors
- Two GE C60 Breaker Management Relays inside existing Control Room

Power System Control

Expand the existing RTU to install additional points required for the Queue #193 220 kV gen tie line position.

RELIABILITY NETWORK UPGRADES

Below is a list of Reliability Network Upgrades with costs that have been allocated to the Project. See group report section 11 for scope details.

- Loop the 2nd 500 kV line between Red Bluff Sub and Colorado River Sub into the Red Bluff 500/220 kV Substation
- Replace Line Riser on Mira Loma – Vista 220 kV No.2 T/L at Vista Substation
- Colorado River Substation Expansion - No.1 AA-Bank

- Develop a SPS for N-2 of Devers-Red Blufff 500 kV T/Ls
- Develop a SPS for N-1 of Colorado River AA-Bank

DELIVERY NETWORK UPGRADES

Below is a list of Delivery Network Upgrades with costs that have been allocated to the Project. See group report section 11 for scope details.

- West of Devers 220 kV Line Upgrade Project
- Colorado River Substation Expansion - No.2 AA-Bank

DISTRIBUTION UPGRADES

None

Table 11.1: Upgrades, Estimated Costs, and Estimated Time to Construct Summary

Type of Upgrade	Upgrade (May include the following)	Description	Estimated Cost x 1000	Estimated Time to Construct *(Note 3)*
PTO's Interconnection Facilities *(Note 1)*	Transmission, Substations, Metering Services Organization, Power System Control, Telecommunications, Real Properties, Transmission Projects Licensing, and Environmental Health and Safety	Non-network facilities needed to enable interconnection	$(redacted)	24 Months
Plan of Service Reliability Network Upgrades	Substation, Power System Control	Direct Assigned Network upgrades needed to enable interconnection.	$(redacted)	24 Months
Reliability Network Upgrades	Transmission, Substations, Metering Services Organization, Power System Control, Telecommunications, Real Properties, Transmission Projects Licensing, and Environmental Health and Safety	Allocated Network upgrades needed to maintain system Reliability	$(redacted)	36 Months
Delivery Network Upgrades	Transmission, Substations, Metering Services Organization, Power System Control, Telecommunications, Real Properties, Transmission Projects Licensing, and Environmental Health and Safety	Network upgrades needed to support Full Delivery, if requested	$(redacted)	84 Months
Distribution Upgrades *(Note 2)*	None	Non-CAISO SCE Distribution Facilities	$0	N/A
Total			**$(redacted)**	**84 Months**

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

Note 2: These upgrades are not part of the CAISO Controlled Grid , and are not reimbursable.

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

12 Study Caveats

12.1 Plan of Service

The Plan of Service developed for the Project is based on the data submittals provided for each specific project in the cluster group and will serve as the basis for developing the LGIA and for permitting purposes. However, the final Plan of Service is subject to change based upon completion of preliminary and final engineering, identification of field conditions, and compliance with applicable environmental and permitting requirements.

12.2 Customer's Technical Data

The study accuracy and results for the Phase II Study are contingent upon the accuracy of the technical data provided by the Interconnection Customer. Any changes from the data provided could void the study results.

12.3 Study Impacts on Neighboring Utilities

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

12.4 Relocations and Other Use of SCE Facilities

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

12.5 SCE Interconnection Handbook

The Interconnection Customer shall be required to adhere to all applicable requirements in the SCE Interconnection Handbook. These include, but are not limited to, all applicable protection, voltage regulation, VAR correction, harmonics, switching and tagging, and metering requirements.

12.6 Western Electricity Coordinating Council (WECC) Policies

The Interconnection Customer shall be required to adhere to all applicable WECC policies including, but not limited to, the WECC Generating Unit Model Validation Policy.

12.7 System Protection Coordination

Adequate Protection coordination will be required between SCE-owned protection and Interconnection Customer-owned protection. If adequate protection coordination cannot be achieved, then modifications to the Interconnection Customer-owned facilities (i.e., Generation tie line or Substation modifications) may be required to allow for ample protection coordination.

12.8 Standby Power and Temporary Construction Power

The Phase II Study does not address any requirements for standby power or temporary construction power that the Project may require prior to the in-service date of the interconnection facilities. Should the Project require standby power or temporary construction power from SCE prior to the in-service date of the interconnection facilities, the IC is responsible to make appropriate arrangements with SCE to receive and pay for such retail service.

12.9 Construction Schedule

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

12.10 Telecommunication Assumptions

The cost for telecommunication facilities that were identified as part of the IC's Interconnection Facilities was based on an assumption that these facilities would be sited, licensed, and constructed by SCE as opposed to the IC doing this work. In addition, the telecommunication requirements for SPS were assumed based on tripping of the generator breaker as opposed to tripping the circuit breakers at the SCE substation. Any changes in these assumptions may affect the cost and schedule for the identified telecommunication facilities.

Attachment 1

Generator Machine Dynamic Data

#TOT223 Desert Center Blythe 500MW connected to Colorado River 220kV bus
genrou 94634 "TOT223L2" 18.00 "1 " : #9 mva=587 "Tpdo" 6.310 "Tppdo" 0.037 "Tpqo" 0.507 "Tppqo" 0.073 "H" 3.710 "D" 0 "Ld" 1.772 "Lq" 1.691 "Lpd" 0.258 "Lpq" 0.454 "Lppd" 0.200 "Ll" 0.151 "S1" 0.051 "S12" 0.0462 "Ra" 0.0025 "Rcomp" 0.0 "Xcomp" 0.0
exst4b 94634 "TOT223L2" 18.00 "1 " : #9 "tr" 0.0 "kpr" 3.99 "kir" 3.99 "ta" 0.01 "vrmax" 1 "vrmin" -0.870 "kpm" 1.0 "kim" 0.0 "vmmax" 1.0 "vmmin" -0.870 "kg" 0.0 "kp" 5.01 "angp" 0.0 "ki" 0.0 "kc" 0.08 "xl" 0.0 "vbmax" 6.27
pss2a 94634 "TOT223L2" 18.00 "1 " : #9 "j1" 1 "k1" 0 "j2" 3 "k2" 0 "tw1" 2 "tw2" 2 "tw3" 2 "tw4" 0 "t6" 0 "t7" 2 "ks2" 0.35 "ks3" 1 "ks4" 1 "t8" 0.5 "t9" 0.1 "n" 1 "m" 5 "ks1" 10 "t1" 0.25 "t2" 0.04 "t3 " 0.20 "t4" 0.03 "vstmax" 0.1 "vstmin" -0.1
tgov1 94634 "TOT223L2" 18.50 "1 " : #9 0.050 0.5 1.0 0.0 3.0 10.0 0.0
genrou 94633 "TOT223L1" 18.00 "1 " : #9 mva=587 "Tpdo" 6.310 "Tppdo" 0.037 "Tpqo" 0.507 "Tppqo" 0.073 "H" 3.710 "D" 0 "Ld" 1.772 "Lq" 1.691 "Lpd" 0.258 "Lpq" 0.454 "Lppd" 0.200 "Ll" 0.151 "S1" 0.051 "S12" 0.0462 "Ra" 0.0025 "Rcomp" 0.0 "Xcomp" 0.0
exst4b 94633 "TOT223L1" 18.00 "1 " : #9 "tr" 0.0 "kpr" 3.99 "kir" 3.99 "ta" 0.01 "vrmax" 1 "vrmin" -0.870 "kpm" 1.0 "kim" 0.0 "vmmax" 1.0 "vmmin" -0.870 "kg" 0.0 "kp" 5.01 "angp" 0.0 "ki" 0.0 "kc" 0.08 "xl" 0.0 "vbmax" 6.27
pss2a 94633 "TOT223L1" 18.00 "1 " : #9 "j1" 1 "k1" 0 "j2" 3 "k2" 0 "tw1" 2 "tw2" 2 "tw3" 2 "tw4" 0 "t6" 0 "t7" 2 "ks2" 0.35 "ks3" 1 "ks4" 1 "t8" 0.5 "t9" 0.1 "n" 1 "m" 5 "ks1" 10 "t1" 0.25 "t2" 0.04 "t3 " 0.20 "t4" 0.03 "vstmax" 0.1 "vstmin" -0.1
tgov1 94633 "TOT223L1" 18.50 "1 " : #9 0.050 0.5 1.0 0.0 3.0 10.0 0.0

Attachment 2

Dynamic Stability Plots

Attachment 3

SCE Interconnection Handbook

Attachment 4

Short Circuit Calculation Study Results

Attachment 5

Deliverability Assessment Results

The deliverability assessment results can be found in the Transition Cluster Phase II group report for the Eastern Bulk system.

Attachment 6

Allocation of Network Upgrades for Cost Estimates

Type	Upgrades	Needed For	Cost factor	Cost Share ($1000)
Delivery	West of Devers 220kV upgrades: Reconductoring four 230kV lines of West of Devers.	Normal and contingency overload	21.35%	$ (redacted)
Delivery	Expand Colorado River (CR) Substation: add the second 500/220 AA transformer banks, rated at 1120 MVA as normal rating.	Normal overload on the first Colorado River 500/230 kV transformer	30.30%	$ (redacted)
Reliability	Expand Colorado River (CR) Substation: Build CR 500/220 kV Substation with a new 500/220 AA transformer banks, rated at 1120 MVA as normal rating.	Interconnect the new generators at Colorado River 230 kV bus	30.30%	$ (redacted)
Reliability	Loop-in the Red Bluff (RB) 500/220 kV Substation into the Colorado - Devers 500 kV #2 line	To balance power flow on DPV 1 and DPV 2 lines	23.26%	$ (redacted)
Reliability	Replace the line raiser on Mira Loma – Vista 220 kV #2 line to 3500amps or higher	Emergency overload in off-peak reliability study	22.73%	$ (redacted)
Reliability	Develop a SPS to trip 1400MW TC2 generation to mitigate dynamic voltage violations under the N-2 of Devers – RedBluff No.1 and No.2 500 kV lines.	Dynamic voltage violation under N-2 contingency	23.26%	$ (redacted)
Reliability	Develop a SPS to trip 500 MW TC2 generation at the Colorado River 500/220 kV substation to mitigate the overload by on one AA bank for the loss of another AA bank (T-1 contingency)	Emergency overload	30.30%	$ (redacted)
Plan of Service Reliability Network Upgrade	Substation, Power System Control	Direct Assigned Network upgrades needed to enable interconnection.	100.00%	$ (redacted)
			Total:	$ (redacted)

Attachment 7

Results of Operational Studies

BEFORE THE ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION OF THE STATE OF CALIFORNIA
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APPLICATION FOR CERTIFICATION FOR THE
GENESIS SOLAR ENERGY PROJECT

Docket No. 09-AFC-8

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(Revised 7/23/10)

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DECLARATION OF SERVICE

I, Ashley Garner, declare that on July 23, 2010, I served and filed copies of the attached **: NEXTERA: REDACTED PHASE II STUDIES** dated **July 8, 2010.** The original document, filed with the Docket Unit, is accompanied by a copy of the most recent Proof of Service list, located on the web page for this project at: **[http://ww.energy.ca.gov/sitingcases/genesis_solar].**

The documents have been sent to both the other parties in this proceeding (as shown on the Proof of Service list) and to the Commission's Docket Unit, in the following manner:
(***Check all that Apply***)

FOR SERVICE TO ALL OTHER PARTIES:

__X__ sent electronically to all email addresses on the Proof of Service list;

_____ by personal delivery;

__X__ by delivering on this date, for mailing with the United States 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 **NOT** marked "email preferred."

AND

FOR FILING WITH THE ENERGY COMMISSION:

__X__ sending an original paper copy and one electronic copy, mailed and emailed respectively, to the address below (***preferred method***);

OR

______ depositing in the mail an original and 12 paper copies, as follows:

CALIFORNIA ENERGY COMMISSION
Attn: Docket No. 09-AFC-8
1516 Ninth Street, MS-4
Sacramento, CA 95814-5512

docket@energy.state.ca.us

I declare under penalty of perjury 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.

Ashley Y Garner
Ashley Garner