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September 24, 2013

VIA ELECTRONIC DOCKETING

Ms. Felicia Miller, Project Siting Manager
California Energy Commission
1516 Ninth Street
Sacramento, California 95814

Re: Huntington Beach Energy Project (12-AFC-02)
California Independent System Operator's Phase I Interconnection Study Report (Transmission System Engineering)

Dear Ms. Miller:

Enclosed herein please find Applicant AES Southland Development, LLC's Phase I Interconnection Study Report by the California Independent System Operator for the Huntington Beach Energy Project. Please contact me if you have any questions regarding this submittal.

Respectfully submitted,

Melissa A. Foster

MAF:jmw
Enclosures

Alaska California Idaho
Minnesota Oregon Utah Washington
and Washington, D.C.

Queue Cluster 5 Phase I Interconnection Study Report

Group Report in SCE's Metro System

Final Report

January 31, 2013

This study has been completed in coordination with SCE per CAISO Tariff Appendix DD Generator Interconnection and Deliverability Allocation Procedures (GIDAP)

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Appendices:

K. Operational Requirement (not provided in the Phase I Study)

Definitions

ADNU	Area Delivery Network Upgrade
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
GIP	Generator Interconnection Procedures
IC	Interconnection Customer
IID	Imperial Irrigation District
LADWP	Los Angeles Department of Water and Power
LDNU	Local Delivery Network Upgrade
LFBs	Local Furnishing Bonds
LGIA	Large Generator Interconnection Agreement
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	QC5 Phase I Study
Phase II Study	QC5 Phase II Study
PTO	Participating Transmission Owner
RAS	Remedial Action Scheme (also known as SPS)
POI	Point of Interconnection
POS	Plan of Service
QC5	Queue Cluster 5
RNU	Reliability Network Upgrade
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric Company
SPS	Special Protection System (also known as RAS)
SVC	Static VAr Compensator
TPP	CAISO's Transmission Planning Process
TP Deliverability	Deliverability supported by the CAISO's Transmission Plan
TWRA	Tehachapi Wind Resource Area
TRTP	Tehachapi Renewable Transmission Project
WECC	Western Electricity Coordinating Council

A. Executive Summary

In accordance with the Federal Energy Regulatory Commission (FERC) approved Generator Interconnection and Deliverability Allocation Procedures (GIDAP) (CAISO Tariff Appendix DD), this Queue Cluster 5 Phase I (QC5) study was initiated to determine the combined impact of all the QC5 projects on the CAISO Controlled Grid.

There are forty-five (45) generation projects in QC5 in SCE's service territory modeled in the Phase I Study. Five general study areas[1] are formed based on the electrical impact among the generation projects: Northern System, Eastern System, East of Pisgah System, North of Lugo System and Metro System. This study report provides the following:

1. Transmission system impacts caused by the addition of QC5 projects requesting interconnection in the Metro System,
2. System reinforcements necessary to mitigate the adverse impacts under various system conditions of the two (2) QC5 projects requesting interconnection in the Metro System,
3. A list of required facilities and maximum cost responsibility for Reliability Network Upgrades (RNUs) and Local Delivery Network Upgrades (LDNUs) assigned to each Interconnection Request
4. A cost estimate of Area Delivery Network Upgrades (ADNUs) for each Interconnection Request
5. A good faith estimate of the Interconnection Facilities cost
6. A good faith estimate of time to construct the Network Upgrades and Interconnection Facilities for each Interconnection Request.

To determine the system impacts caused by QC5 projects, the following studies were performed:

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

The results of above studies indicate that QC5 projects are responsible for the overloading of transmission facilities and overstressing of circuit breakers in SCE's service territory. Network Upgrades[2] and Distribution Upgrades to mitigate identified problems corresponding to the QC5 projects requesting interconnection in the Metro System have been proposed in this report. The following tables show a summary of the proposed Network Upgrades along with an estimated cost.

[1] Precise electrical groupings were created during the deliverability study for Delivery Network cost allocation purposes.
[2] The additions, modification, and upgrades to the CAISO Controlled Grid required at or beyond the Point of Interconnection to accommodate the interconnection of the Generating Facility to the CAISO Controlled Grid. Network Upgrades shall consist of Delivery Network Upgrades and Reliability Network Upgrades. Network Upgrades do not include Distr bution Upgrades.

Table A – Plan of Service Reliability Network Upgrades ($ 1,000)[3]

1	Various (see individual Appendix A reports)	
	TOTAL	[redacted]

Table B – Reliability Network Upgrades ($ 1,000)[3]

1	None	[redacted]
	TOTAL	[redacted]

Table C – Local Delivery Network Upgrades ($ 1,000)[4]

1	None	[redacted]
	TOTAL	[redacted]

Table D – Area Delivery Network Upgrades ($ 1,000)[5]

1	None	[redacted]
	TOTAL	[redacted]

Table E – Distribution Upgrades ($ 1,000) [6,7]

1	None	[redacted]
	TOTAL	[redacted]

The upgrades in the Tables above do not include Interconnection Facilities and Non-Network Non-CAISO Transmission Upgrades, which are the obligation of each Interconnection Customer to finance. The interconnection facilities relating to each individual project are discussed in the corresponding Appendix A Individual Project Reports.

Given the magnitude of the above upgrades, a non-binding estimate to engineer, license, procure, and construct the facilities identified in the above Tables could be up to 44 months from execution of the Generator Interconnection Agreement, receipt of: all required information, funding, and written authorization to proceed from the IC as will be specified in the Generator Interconnection Agreement to commence the work.

The Phase II Study for QC5 will evaluate potential operational constraints associated with the network upgrades required for the Serial Group and/or clusters queue-ahead and not allocated to QC5 but which either help support or are required to interconnect the QC5 projects. These Serial Group and/or cluster upgrades may impact the individual generation requested In-Service Dates.

[3] The SCE transmission facili ies, other than Interconnection Facilities, at or beyond the point of interconnection necessary to physically and electrically interconnect the Project, needed to maintain system integrity and reliability.

[4] The SCE transmission facili ies, other than Interconnection Facilities, at or beyond the point of interconnec ion necessary to physically and electrically interconnect the Project , which are specific to the loca ion of an individual generation project or a small group of genera ion projects located very close together electrically, and needed to support Full Capacity Deliverability Status, if requested.

[5] The SCE transmission facili ies, other than Interconnection Facilities, at or beyond the point of interconnec ion necessary to physically and electrically interconnect the Project , which provide deliverability to load from a specified quantity of new generation in an electrical area of the grid, and needed to support Full Capacity Deliverability Status, if requested. These upgrades are not capped.

[6] For distribu ion cost associated to upgrades in the Lugo Hub Subarea area (below 115 kV), Antelope-Bailey distribution system (below 66 kV), and Eastern distribu ion system (below 115 kV) please see WDAT Appendix A reports.

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

Facility In-Service Dates will be further evaluated as part of the QC5 Phase II Study in order to evaluate potential options for interconnection prior to the required Delivery Network Upgrades.

B. QC5 Interconnection Information

A total of two (2) generation projects make up the QC5 Metro Area Cluster.

There are two (2) generation projects totaling a maximum output of 1414.3 MW that are included in the QC5 Metro System. Table B.1 lists all the new generator projects in the Metro System with essential data obtained from the CAISO Generation Queue.

Table B.1: SCE QC5 Projects (Metro System)

CAISO Queue	Point of Interconnection	Full Capacity Energy Only	Fuel	Max MW	Proposed COD (as filed with IR)
893	Huntington Beach 220 kV Substation	FC	CC	938.612	6/01/2020
941	Redondo Beach 220 kV Substation	FC	CC	475.72	12/31/2018
Total QC5 Generation (Metro System)				**1414.329**	

C. Study Objectives

This QC5 Interconnection study was performed in accordance with Section 6.2 of Appendix DD of the CAISO tariff, which states:

The Phase I Interconnection Study shall:

(i) evaluate the impact of all Interconnection Requests received during the Cluster Application Window for a particular year on the CAISO Controlled Grid,

(ii) preliminarily identify all LDNU and RNU needed to address the impacts on the CAISO Controlled Grid of the Interconnection Requests,

(iii) preliminarily identify for each Interconnection Request required Interconnection Facilities,

(iv) assess the Point of Interconnection selected by each Interconnection Customer and potential alternatives to evaluate potential efficiencies in overall transmission upgrades costs,

(v) establish the maximum cost responsibility for LDNUs and RNUs assigned to each Interconnection Request, until the issuance of the Phase II Interconnection Study report,

(vi) provide a good faith estimate of the cost of Interconnection Facilities for each Interconnection Request, and

(vii) provide a cost estimate of ADNUs for each Generating Facility in a Queue Cluster Group Study.

In order to achieve the above objectives, this same Section 6.2 explains what specific studies need to be done:

“The Phase I Interconnection Study will consist of a short circuit analysis, a stability analysis to the extent the CAISO and applicable Participating TO(s) reasonably expect transient or voltage stability concerns, a power flow analysis, including Off-Peak analysis, and an On-Peak Deliverability Assessment (and Off-Peak Deliverability Assessment which will be for informational purposes only) for the purpose of identifying LDNUs and estimating the cost of ADNUs, as applicable.

The Phase I Interconnection Study will state for each Group Study or Interconnection Request studied individually (i) the assumptions upon which it is based, (ii) the results of the analyses, and (iii) the requirements or potential impediments to providing the requested Interconnection Service to all Interconnection Requests in a Group Study or to the Interconnection Request studied individually.

The Phase I Interconnection Study will provide, without regard to the requested Commercial Operation Dates of the Interconnection Requests, a list of RNUs and LDNUs to the CAISO Controlled Grid that are preliminarily identified as required as a result of the Interconnection Requests in a Group Study or as a result of any Interconnection Request studied individually and Participating TO’s Interconnection Facilities associated with each Interconnection Request, the estimated costs of ADNUs, if applicable and an estimate of any other financial impacts (i.e., on Local Furnishing Bonds).

The Phase I Study analysis was performed to identify the conceptual Interconnection Facilities, Plan of Service Reliability Network Upgrades, Reliability Network Upgrades, Local Delivery Network Upgrades, incremental Area Delivery Network Upgrades, and Distribution Upgrades necessary to safely and reliably interconnect the QC5 projects. An estimated cost and construction schedule for these facilities is provided in this report.

D. Study Assumptions

D.1 Power flow base cases

The QC5 Study base cases were developed from the WECC base case and PTO’s transmission expansion base case series representing Peak and Off-Peak load conditions. The QC5 studies were based on a 2016 load forecast. These base cases included all CAISO approved transmission projects, as well as earlier queued Serial Group and cluster generation projects with associated Network Upgrades and Special Protection Systems.

D.2 Load and Import

The Deliverability Assessment On-Peak case modeled a 24,862 MW load (1-in-5 load forecast) in the SCE system with an import target as shown in Table 4.2. The Off-Peak case modeled a 16364 MW load in the SCE system.

Table D.2.1: On-Peak Deliverability Assessment Import Target

Branch Group Name	Direction	Net Import MW	Import Unused ETC & TOR MW
Lugo-Victorville-BG	N-S	1432	141
COI_BG	N-S	3770	548
BLYTHE_BG	E-W	45	0
CASCADE_BG	N-S	36	0
CFE_BG	S-N	-119	0
ELDORADO_MSL	E-W	1213	0
IID-SCE_BG	E-W	1000	0
IID-SDGE_BG	E-W	500	0
LAUGHLIN_BG	E-W	-38	0
MCCULLGH_MSL	E-W	7	316
MEAD_MSL	E-W	938	455
NGILABK4_BG	E-W	-131	168
NOB_BG	N-S	1208	0
PALOVRDE_MSL	E-W	2872	168
PARKER_BG	E-W	126	28
SILVERPK_BG	E-W	0	0
SUMMIT_BG	E-W	6	0
SYLMAR-AC_MSL	E-W	-164	368
Total		12599	2192

The Metro System Reliability Assessment Peak case modeled a 26,429 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.

D.3 Generation Dispatch Assumptions

Generation assumptions for SCE's Metro System are shown in Table D.3.1 (Existing Generation), Table D.3.2 (Active Queued Ahead Serial), Table D.3.3 (Transition Cluster), Table D.3.4 Pre Queue Cluster 1 and 2 Phase II SGIP projects (Pre QC1&2 Phase II SGIPs), Table D.3.5 QC1&2 Phase II projects (QC1&2 Phase II), Table D.3.6 Pre QC3&4 Phase II projects (Pre QC3&4 Phase II SGIPs), Table D.3.7 Queue Cluster 3 and 4 Phase II projects (QC3&4 Phase II), and Table D.3.8 summarizes the Rule 21 projects in the area .
Generation dispatch assumptions in Deliverability Assessment can be found at http://www.caiso.com/Documents/Deliverability assessment methodologies. In the Peak Deliverability Assessment, the Peak Qualified Capacity (QC) for proposed Full Capacity generation projects is set to 64% of the requested PMax for wind generation and 100% of the requested PMax for solar generation initially. The Peak QC may be adjusted to 40% of the

requested PMax for wind generation and 85% for solar generation if a mix of different fuel type generations is identified in the Deliverability Assessment as the 5% DFAX group for a transmission limitation. In the Off-Peak Deliverability Assessment, the proposed Full Capacity wind generation is dispatched at its maximum nameplate output and solar generation at 85% of its nameplate output.

In the Reliability Assessment, the generation is initially dispatched at maximum nameplate output as listed in Tables D.3.1, D.3.2, D.3.3, D.3.4, D.3.5, D.3.6, D.3.7, and D.3.8. Additional generation dispatch assumptions in the reliability assessment are discussed in the power flow results section of this report.

Table D.3.1: Existing Generation

Generation unit	Type	Size (MW)
Agua Mansa	Simple Cycle -GT	47
Alamitos	Steam	1950
Anaheim	Simple Cycle-GT	50
Barre Peaker	Simple Cycle-GT	47
Broadway	Steam	65
Center Peaker	Simple cycle-GT	47
Century	Simple Cycle-GT	47
Clearwater	Combined Cycle	32
Chevmain	Other	76
Drews	Simple Cycle-GT	47
El Segundo	Steam	670
Etiwanda	Steam	640
Etiwanda Peaker	Simple Cycle-GT	47
Harbor Cogen	Other	110
Huntington Beach	Steam	870
Indigo Peaker	Simple Cycle-GT	182
Inland Empire Energy Center	Combined Cycle	810
Long Beach	Simple Cycle-GT	283
Malburg	Combined Cycle	136
MiraLoma Peaker	Simple Cycle-GT	50
Redondo	Steam	1280
Riverside 1 &2	Simple Cycle-GT	96
San Onofre	Nuclear	2150
Springs	Other	44
	Total (Existing)	9,776

Table D.3.2: Active Queued Ahead Serial Group Interconnection Requests

CAISO Queue Position	Type	Size (MW)
CAISO Queue #7	Combined Cycle	560
CAISO Queue #66	Gas Turbines	500.5
CAISO Queue #252	Gas Turbines	12.7
SCE WDAT #086	Combined Cycle	8
SCE WDAT #229	Gas	47.1
SCE WDAT #236	Gas	47.9
SCE WDAT #240	Landfill Gas	25
SCE WDAT #268	Landfill Gas	9
	Total	**1,210.2**

Table D.3.3: Transition Cluster Interconnection Requests

CAISO Queue Position	Type	Size (MW)
CAISO Queue #383	Combined Cycle	85
	Total	**85**

Table D.3.4: Pre QC1&2 Phase II SGIPs Interconnection Request

CAISO Queue Position	Type	Size (MW)
SCE WDAT #327	Solar	1
SCE WDAT #356	Solar	1
SCE WDAT #358	Solar	2
SCE WDAT #359	Solar	2
SCE WDAT #364	Solar	0.5
SCE WDAT #426	Solar	2
SCE WDAT #427	Solar	0.75
SCE WDAT #428	Solar	1.5
SCE WDAT #429	Solar	1.5
	Total	**12.25**

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

CAISO Queue Position	Type	Size (MW)
CAISO Queue #494	Nuclear	48
	Total	**48**

Table D.3.6: Pre QC3&4 Phase II SGIPs Interconnection Request

CAISO Queue Position	Type	Size (MW)
SCE WDAT #444	Solar	1.6
SCE WDAT #450	Solar	1
SCE WDAT #451	Solar	1
SCE WDAT #463	Solar	1
SCE WDAT #464	Solar	0.5
SCE WDAT #466	Solar	0.5
SCE WDAT #467	Solar	0.75
SCE WDAT #471	Solar	0.75
SCE WDAT #473	Solar	1.75
SCE WDAT #474	Solar	1
SCE WDAT #475	Solar	0.75
SCE WDAT #476	Solar	1.25
SCE WDAT #478	Solar	0.5
SCE WDAT #479	Solar	0.5
SCE WDAT #480	Solar	1.16
SCE WDAT #481	Solar	1.25
SCE WDAT #482	Solar	1.33
SCE WDAT #483	Solar	1.25
SCE WDAT #484	Solar	1.5
SCE WDAT #485	Solar	1
SCE WDAT #486	Solar	1.75
SCE WDAT #487	Solar	1.25
SCE WDAT #489	Solar	2
SCE WDAT #525	Solar	1
SCE WDAT #589	Solar	1
SCE WDAT #766	Solar	1
SCE WDAT #621	Solar	0.5
	Total	**28.84**

Table D.3.7: QC3&4 Phase II Interconnection Request

CAISO Queue Position	Type	Size (MW)
CAISO Queue #702	Combine Cycle	435
	Total	**435**

Table D.3.8: Rule 21 Interconnection Request

CAISO Queue Position	Type	Size (MW)
GFID 2819	Natural Gas	0.75
GFID 5277	Solar	1.5
GFID 5468	Solar	1.5
GFID 5475	Solar	0.25
GFID4203	Combustion Turbine	0.35
GFID2849		0.003
GFID7188		0.8
GFID5827	Solar	3.31
GFID2848	Diesel	21.88
GFID5858	Solar PV	1.5
GFID7194	Combustion Turbine	1.45
GFID2732		0.06
GFID2861	Natural Gas	7.5
GFID5948	Solar	1.5
GFID7143	Solar	0.66
GFID5142	Solar	0.37
GFID7197	Fuel Cell	0.1
GFID2875	Natural Gas	2.3
GFID2721		13.38
GFID2851	Diesel	1.2
GFID2858	Diesel	6.25
GFID2860	Combustion Turbine	3.1
GFID7153	Combustion Turbine	2.81
GFID7195	Micro Turbine	1
GFID2857	Solar	0.07
GFID4215	Hydro	0.2
GFID2844	Combustion Turbine	0.15
	Total	**73.943**

D.4 New Transmission Projects

This QC5 study included the modeling of all CAISO-approved transmission projects in the Metro System base cases. In addition, a number of transmission upgrades that are needed to support queued ahead Serial Group and cluster generation projects in the Metro System were modeled in order to determine if additional facilities would be needed to support the QC5 projects.

D.4.1 Previously Triggered Area SPS

The interconnection of a higher queued project required the implementation of a SPS to protect for thermal overload on the El Nido-La Cienega 220 kV line for the N-2 outage of the El Nido-La Fresa 3 & 4 220 kV lines.

D.4.2 Del Amo-Ellis Loop-in Project

Loop-in the Del Amo-Ellis 220 kV transmission line into Barre 220 kV Substation in order to prevent long term outage of Santiago Substation with the shutdown of Huntington Beach 3 & 4 generation units.

D.5 Other SPSs and Operator Actions

Existing System Operating Bulletins (SOB), Operating Procedures (OP), and Special Protection Systems (SPS) may be relevant for QC5 Study analysis in the SCE Metro System. These include, but are not limited to, the following:

- SOB-013 (Critical System Voltage)
- SOB-017 (System Voltage Control)
- SOB-292 (Santiago N-2 Remedial Action Scheme)
- SOB-293 (El Nido N-2 Remedial Action Scheme)

D.5.1 Other Operating Procedures

Operating procedures, which may include curtailing the output of the QC5 projects during planned or extended forced outages may be required for reliable operation of the transmission system. These procedures, if needed, will be developed before the projects' Commercial Operation Date.

D.6 Transmission Upgrades outside the CAISO Controlled Grid

No transmission upgrades outside the CAISO controlled grid were identified as in the previous generation interconnection studies for the SCE Eastern system. However, neighboring utilities may identify need for physical upgrades within their system not identified in the studies.

E. Study Criteria and Methodology

E.1 Reliability Standards and Criteria

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

E.1.1 NERC Reliability Standards

The CAISO will analyze the need for transmission upgrades and additions in accordance with NERC reliability standards, which set forth criteria for system performance requirements that must be met under a varied but specific set of operating conditions. The following NERC reliability standards are applicable to the CAISO, as a registered NERC planning authority, and the PTOs, as Transmission Planners, and are the primary standards for the interconnection of new facilities and system performance[8]:

- FAC-001: Facility Connection Requirements[9]
- FAC-002: Coordination of Plans for New Facilities

[8] http://www.nerc.com/page.php?cid=2%7C20
[9] http://www.nerc.com/files/FAC-001-1.pdf; FAC-001 is applicable to PTOs, but not to the ISO

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

E.1.2 WECC Regional Criteria

The WECC TPL system performance criteria are applicable to the CAISO as a planning authority and set forth additional requirements that must be met under a varied but specific set of operating conditions.[10]

E.1.3 California ISO Planning Standards

The California ISO Planning Standards specify the grid planning criteria to be used in the planning of CAISO transmission facilities.[11] These standards cover the following:

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

E.1.4 Contingencies

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

Table E.1.4.1 summarizes the contingencies per NERC Reliability Standards WECC Regional Criteria and CAISO Planning Standards.

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

Table E.1.4.1: Contingencies

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

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

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

E.2 Steady State Study Criteria

E.2.1 Normal Overloads

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

E.2.2 Emergency Overloads

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

E.2.3 Voltage Violations

All buses within the CAISO controlled grid that cannot meet the requirement in Table E.2.3.1 will be further investigated.

Table E.2.3.1: Voltage Criteria

(Voltages are relative to the nominal voltage of the system studied)

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

*Most of the 500 kV buses have specific requirements.

E.3 Transient Stability Criteria

Transient stability analysis is a time-domain simulation that assesses the performance of the power system during (and shortly following) a system disturbance. A transient stability study is performed to ensure system stability following critical disturbances on the system.

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

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

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

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

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

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

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

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

Table E.3.1 illustrates the WECC reliability criteria. The reliability and performance criteria are applied to the entire WECC transmission system.

Table E.3.1: 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 1)
A	Not Applicable	Nothing in Addition to NERC		
B	≥ 0.33	Not to exceed **25%** at load buses or **30%** at non-load buses. Not to exceed **20% for more than 20 cycles** at load buses.	Not below **59.6 Hz** for 6 cycles or more at a load bus	Not to exceed **5%** at any bus
C	0.033 – 0.33	Not to exceed 30% at any bus. Not to exceed **20% for more than 40 cycles** at load buses.	Not below **59.0 Hz** for 6 cycles or more at a load bus	Not to exceed **10%** at any bus
D	< 0.033	Nothing in Addition to NERC		

Note 1: As an example in applying the WECC Disturbance-Performance Table, Category B disturbance in one system shall not cause a transient voltage dip in another system that is greater than 20% for more than 20 cycles at load buses, or exceed 25% at load buses or 30% at non-load buses at any time other than during the fault.

E.4 Post-Transient Voltage Stability Criteria

The last column of the above Table E.3.1 illustrates the post-transient voltage stability criteria. The governor power flow is utilized to test for the post-transient voltage deviation criteria.

E.5 Reactive Margin Criteria

Table E.5.1 summarizes the voltage support and reactive power criteria of requirement R3 of the WECC Regional Criterion TPL-001-WECC-CRT-2. The system performance will be evaluated accordingly.

Table E.5.1: Reactive Margin Analysis Criteria Summary

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

E.6 Power Factor Criteria

Table E.6.1 summarizes the power factor criteria per the CAISO tariff for the projects.

Table E.6.1: CAISO Tariff Power Factor Analysis Criteria Summary

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

E.7 Short Circuit Criteria

The short circuit analysis will be performed by simulating single-line-to-ground (1LG) and three-phase (3LG) bus faults as the worst case in a study area, which represents the worst-case conditions to determine the maximum available fault current. Criteria to determine if circuit breakers are overstressed are specific to each study area and will be outlined in the final Interconnection Study reports.

F. Deliverability Assessment

This assessment is comprised of Peak and Off-Peak deliverability assessments for the QC5 projects in the Northern Bulk System. Both SCE and PG&E bulk systems were monitored for any adverse impacts.

F.1 On-Peak Deliverability Assessment Methodology

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

Master Deliverability Assessment Base Case

A master base case was developed for the Cluster 3 Peak deliverability assessment which modeled all the queued generation projects up to Cluster 3. The resources in the master base case are dispatched as follows:

- Existing capacity resources are dispatched at 80% of Peak net qualified capacity (NQC).
- Proposed full capacity resources are dispatched to balance load and maintain expected imports, but not exceeding 80% of Peak NQC.
- Energy Only resources are set off-line.
- Imports are at the maximum Peak simultaneous historical level by branch group as shown in Table D.2.1.
- Non-pump load is at the 1 in 5 Peak load level for CAISO.
- Pump load is dispatched within expected range for Peak load hours.

Northern Bulk Group Deliverability Assessment Base Case

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

Screening for Potential Deliverability Problems Using DC Power Flow Tool

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

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

  or

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

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

Verifying and Refining the Analysis Using AC Power Flow Tool

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

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

F.2 Local Deliverability Constraints and Area Deliverability Constraints

In the Phase I Study, the CAISO performed two rounds of deliverability assessments to, first, identify any transmission system operating limits that constrain the deliverability of the modeled generators, and second, determine LDNUs and ADNUs to relieve those constraints. The first round of the deliverability assessment modeled all the generation projects requesting Full Capacity or Partial Capacity Deliverability Status in accordance with the On-Peak Deliverability Assessment Methodology. The transmission system operating limits identified during the assessment are divided into two categories: local deliverability constraints and area deliverability constraints.

Local deliverability constraints tend to have the following attributes:

- The generators whose deliverability they constrain (generators inside the 5% DFAX circle) are all located on a few buses electrically close to each other.
- Relieving these constraints does not trigger high cost upgrades.

Area Deliverability Constraints tend to have the following attributes:

- The generators whose deliverability they constrain (generators inside the 5% DFAX circle) are spread over at least one and possibly more grid study areas or resource areas identified in a resource portfolio used in the TPP.
- In the first round of the Phase I deliverability assessment, relieving these constraints may trigger high cost upgrades, driven by excessively large MW amounts of new generation behind the area deliverability constraint.
- In some potential situations the ISO may classify as an area deliverability constraint a constraint that constrains the deliverability of generators electrically close to each other and is triggered by an exceptionally large volume of generation. This could occur, for example, when there is an exceptionally large volume of Interconnection Requests in a relatively smaller local sub-area within one of the resource development areas identified in the TPP portfolios and relieving the constraint requires expensive upgrades. This

potential situation was raised as a concern by some stakeholders, and we determined that in such cases, if they occur, the appropriate remedy would be to reclassify the constraint as an area deliverability constraint based on the recognition that it would serve a substantial volume of generation projects within the study area.

The categorization of ADNU vs. LDNU is based on the deliverability constraint that triggers the need of the DNU. With the exception of SPS mitigating deliverability constraints, ADNUs are transmission upgrades or additions to relieve Area Deliverability Constraints and LDNUs are to relieve Local Deliverability Constraints.

F.3 Identification of Area Delivery Network Upgrades

The CAISO performed the second round of the deliverability assessment to identify facilities necessary to provide the incremental deliverability between the level of TP Deliverability and additional amount necessary for the MW capacity amount of generation targeted in the Phase I Study. The additional amount is referred as Phase I Incremental MW in the report.

For each Area Deliverability Constraint, a base case was developed such that the TP Deliverability is fully utilized. Then the Phase I Incremental MW was added. The ADNUs were then identified to support the deliverability of the Phase I Incremental MW.

F.4 On-Peak Deliverability Assessment Results

F.4.1 Deliverability Constraints to be Mitigated by SPS

None

F.4.2 Local Deliverability Constraints and LDNUs

None

F.4.3 Area Deliverability Constraints and ADNUs

None

G. Steady State Assessment

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

Power flow analysis was performed to ensure that CAISO Controlled Grid 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.

The study results for this interconnection will be communicated to neighboring entities that may be impacted, for coordination and incorporation of its transmission assessments. Input from 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 QC5 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 QC5 study.

The following power flow base cases were used for the analysis in the QC5 Study:

- **Peak Full Loop Base Case:**

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

- **Off-Peak 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 QC5 generation projects during light load conditions. The Off-Peak load was modeled at about 65% of the 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 QC5 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 power flow study included a preliminary power flow study, which modeled all QC5 projects in the Metro System with plans of service as originally requested. This preliminary study served as a "screening analysis" to identify potential reliability issues in the original plans of service requested by the developers in QC5. The power flow study also included a modified power flow study, which reflected system changes based on the findings of the preliminary study.

G.1 Bulk System Steady State Study

G.1.1 Preliminary Power Flow Study Assumptions

The preliminary study modeled all Metro System QC5 projects with the customer requested plans of service and no system upgrades. All generating units in the Metro System are dispatched at PMax in the preliminary study. This preliminary study was intended to find whether plan of service issues with QC5 projects would require changes to the customer requested plans of service or points of interconnection.

G.1.2 Preliminary Power Flow Study Results

(a) Preliminary Voltage and VAR Study Results

There were no voltage and VAR issues identified with the addition of the QC5 projects in the Metro System.

(b) Preliminary Power Flow Study Results (Category "A", "B" and "C")

Based on the assumptions listed above, the power flow analysis results for Peak and Off-Peak conditions are shown in Table G.1.3.1 and Table G.1.3.2 below.

Table G.1.3.1: Peak Conditions Power Flow Overloads

Over Loaded Component	Rating (Amps)	Pre-Project Loading (Amps / %Rating)	Post-Project Loading (Amps / %Rating)	% Change from Pre-Project Loading	Comment
Category A (N-0) Overloads – Peak					
None					
Category B (N-1) Overloads – Peak					
None					
Category C (N-2) Overloads – Peak					
None					

Table G.1.3.2: Off-Peak Conditions Power Flow Overloads

Over Loaded Component	Rating (Amps)	Pre-Project Loading (Amps / %Rating)	Post-Project Loading (Amps / %Rating)	% Change from Pre-Project Loading	Comment
Category A (N-0) Overloads – Off-Peak					
None					
Category B (N-1) Overloads – Off-Peak					
None					
Category C (N-2) Overloads – Off-Peak					
None					

G.1.3 Bulk System Steady State Study Conclusions

Based on the findings of the steady state study, the following conclusions were reached

(a) Reactive Power Deficiency
There were no reactive power deficiencies identified with the addition of the QC5 Phase I projects in the Metro System.

(b) Voltage Performance
There were no voltage violations identified with the addition of the QC5 Phase I projects in the Metro System.

H. Short Circuit Duty Assessment

H.1 Short Circuit Duty Analysis Results

Application Queue Short circuit studies were performed to determine the impact on circuit breakers with the interconnection of QC5 projects to the transmission system. The fault duties were calculated before and after QC5 projects to identify any equipment overstress conditions. Three-phase (3PH) and single line-to-ground (SLG) faults were simulated without the QC5 projects and with the QC5 projects including the identified Reliability and Delivery Network Upgrades from the power flow analysis.

All bus locations where the QC5 projects increases 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 equipment is overstressed as a result of the QC5 interconnections and corresponding network upgrades.

(a) Application Queue with RNUs Analysis Results

Fault duties were calculated with the inclusion of the QC5 projects and the identified RNUs to identify the incremental impacts associated with these facilities. The QC5 breaker evaluations identified the following overstressed circuit breakers:

- Twenty-one (21) 50 kA, 220 kV CBs at Vista Substation

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

- Replace/Upgrade twenty-one (21) 220 kV CBs at Vista Substation

(b) Application Queue with RNUs and LDNUs Analysis Results

Fault duties were re-calculated to include the QC5 projects and the identified RNUs and LDNU's from the power flow and stability analysis to identify the incremental impacts associated with these facilities. The QC5 breaker evaluation did not identify any additional overstressed circuit breakers on top of what was identified in Application Queue with RNUs analysis.

(c) Application Queue with RNUs, LDNUs, & ADNUs Analysis Results

A preliminary SCD run was performed include the QC5 projects and the identified RNUs, LDNUs, and ADNUs to identify the incremental impacts associated with these ADNU Facilities. The preliminary results identified the following overstressed circuit breakers on top of what has been identified above in application Queue with RNUs and LDNUs analysis:

- Twenty-four (24) 63 kA, 220 kV CBs at Mira Loma (W) Substation
- Eight (8) 40 kA, 115 kV CBs at Valley A Substation
- Six (6) 40 kA, 115 kV CBs at Valley B Substation

To mitigate these identified overstressed circuit breakers, the following upgrades are recommended in addition to what has been identified above in application Queue with RNUs and LDNUs analysis:

- Reconfigure the Mira Loma – Vista No.1 and No.2 and Mira Loma – Rancho Vista No.1 and No.2 220 kV lines at Mira Loma Substation to lower 220 kV short-circuit duty at Mira Loma.
- Upgrade eight (8) 115 kV circuit breakers due to increased duty at Valley A Substation.
- Upgrade six (6) 115 kV circuit breakers due to increased duty at Valley B Substation.

The responsibility to finance short circuit RNUs identified through a Group Study shall be assigned to all Interconnection Requests in that Group Study pro rata on the basis of short-circuit duty contribution of each Generating Facility. In addition, the SCD impact of the associated LDNUs was allocated to each Generating Facility using the same percentage assigned for the triggered LDNUs. The pro rata contribution corresponding to each QC5 project to the circuit breaker upgrades listed above is provided in each individual report (Appendix A). The short circuit upgrades associated with ADNUs are ADNUs, which will be further evaluated in the Phase II Interconnection study. The cost of the short circuit ADNUs are not included in the Phase I study and not assigned to QC5 projects.

H.2 Application Queue: Ground Grid Analysis

It should be noted that the Phase II Study will utilize the results of the application queue SCD studies of the Phase II cluster study to identify any SCE substations (CAISO-controlled) that may have duty problems on the existing substation ground grid due to the inclusion of the QC5 Phase II projects.

I. Transient Stability Analysis

Transient stability analysis was conducted using both the Peak and Off-Peak base cases to ensure that the transmission system remains stable with the addition of QC5 generation projects. The generator dynamic data used for the study is confidential in nature and is provided with each individual project report.

I.1 Bulk System Steady State Study

I.1.1 Transient Stability Study Scenarios

Disturbance simulations were performed for a study period of 10 seconds to determine whether the QC5 projects will create any system instability during a variety of line and generator outages. For SCE's Metro System, selected line and generator outages within the Metro System were evaluated. The outages were consistent with Category B and Category C requirements (single element and multiple element outages).

In the analysis, power flow cases from the preliminary power flow assessment were used, and VARS required for power flow base-case convergence were converted to equivalent load impedances for dynamic simulation purposes.

I.1.2 Transient Stability Results

The transient stability study concluded that with the addition of the QC5 Phase I projects and proposed system upgrades in place, the transient stability performance of the system is acceptable.

J. Post-Transient Voltage Stability Analysis

A post-transient voltage stability analysis was performed for this QC5 Phase I Study. The post-transient analysis focused on evaluating the system after the inclusion of all transmission upgrades and the use of the identified SPS, assuming all new generation projects meeting the power factor requirements. Under such conditions, the post-transient study showed acceptable system performance.

K. Mitigation of QC5 Project Impacts

The mitigation requirements triggered by QC5 projects, based on the results described in Sections F-J above, are as follows.

K.1 Plan of Service Reliability Network Upgrades

Plan of Service Reliability Network Upgrades for QC5 projects in the Metro System are discussed in detail in each individual project report (Appendix A).

K.2 Reliability Network Upgrades

The Reliability Network Upgrades for the Metro System QC5 Phase I projects are identified in the individual Appendix A reports.

K.3 Local Delivery Network Upgrades

No Local Delivery Network Upgrades were identified as part of this QC5 Phase I Study for the Metro area.

K.4 Area Delivery Network Upgrades

No Area Delivery Network Upgrades were identified as part of this QC5 Phase I Study for the Metro area.

K.5 Distribution Upgrades

No Distribution Upgrades were identified.

L. Environmental Evaluation / Permitting

L.1 CPUC General Order 131-D

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

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

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

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

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

GO 131-D provides for certain exemptions from the CPUC PTC requirements for electric power line facilities between 50 and 200 kV and new or upgraded substations with a high side voltage exceeding 50 kV. For example, Exemption f of GO 131-D (Section III.B.1.f) exempts from CPUC PTC permitting requirements power lines or substations to be constructed or relocated that have undergone environmental review pursuant to CEQA as part of a larger project, and for which the final CEQA document (Environmental Impact Report or Negative Declaration) finds no significant unavoidable environmental impacts caused by the proposed line or substation. Note, GO 131-D, Section III.B.2, discusses the conditions under which PTC exemptions shall not apply (consistent with CEQA Guidelines).

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

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

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

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

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

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

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

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

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

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

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

L.5 CPUC Section 851

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

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

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

Resource agencies are required to comply with CEQA and/or NEPA (as applicable) when issuing their permits; however, the necessity for environmental permits is oftentimes unknown during the initial stages of project development. Therefore, it is recommended that the Interconnection Customer identifies all project components, including SCE's

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

M. Upgrades, Cost and Time to Construct Estimates

The cost estimates are based on the published unit costs, when applicable. Customized costs were developed when the unit costs did not reflect the unique circumstances of a project. The customized costs may include: anticipated purchase of land rights, licensing, environmental mitigation, looping lines into substations, new switchyards, substation upgrades not included in unit costs, and SCE's Interconnection Facilities.

Regardless of the requested Commercial Operating Date, the actual Commercial Operation Dates of the generation projects in QC5 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.

Costs for each generation project are confidential and are not published in the main body of this report. Each IC is receiving a separate Appendix A report, specific only to that generation project, containing the details of the IC's cost responsibilities.

The estimated cost of Reliability Network Upgrades identified in this Group Study is assigned to all Interconnection Requests in that Group Study according to the following rules: (a) short circuit related Reliability Network Upgrades will be assigned pro rata on the basis of the short circuit duty contribution of each Generating Facility and associated proposed Network Upgrades, (b) for all other Reliability Network Upgrades, the cost will be assigned pro rata on the basis of the maximum megawatt electrical output of each proposed new Generating Facility or the amount of megawatt increase in the generating capacity of each existing Generating Facility as listed by the Interconnection Customer in its Interconnection Request. Plan of Service Reliability Upgrades are 100% allocated to the particular IC and are detailed in each IC's Appendix A report.

The estimated cost of all Local Delivery Network Upgrades identified in the Deliverability Assessment are assigned to all Interconnection Requests selecting Full or Partial Capacity

Deliverability Status based on the flow impact of each such Generating Facility on the Delivery Network Upgrades as determined by the generation distribution factor methodology.

The estimated cost of an Area Delivery Network Upgrade divided by the Phase I Incremental MW for the Area Deliverability Constraint establishes the ADNU cost rate for the QC5 projects whose deliverability are constrained by the Area Deliverability Constraint.

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

The estimated cost of Distribution Upgrades and Non-Network Non-CAISO Transmission Upgrades are developed by SCE and are not mandated by the ISO Tariff. These costs are not reimbursable.

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

Type of Upgrade	Upgrade	Description	Estimated Cost x 1,000 (Note 4)	Estimated Cost x 1,000 Constant Dollar (OD Year) (Note 4)	Estimated Time to Construct in Months (Note 1) (Note 3)
Plan of Service Reliability Network Upgrades	Plan of Service Reliability Network Upgrades for QC1 projects in the North of Lugo Bulk System are discussed in detail in each individual project report (Appendix A).		**See Appendix A**		
Reliability Network Upgrades	No Reliability Network Upgrades were identified for the Metro System in the QC5 Phase I study				
Local Delivery Network Upgrades	No Local Delivery Network Upgrades were identified for the Metro System in the QC5 Phase I study				
Distribution Upgrades (Note 2)	No Distribution Upgrades were identified for the Metro System in the QC5 Phase I study				
Total			NA	NA	**NA**

Note1: The estimated licensing cost and durations applied to this project are based on the project scope details presented in this study. These estimates are subject to change as project environmental and real estate elements are further defined. Upon execution of the Interconnection Agreement, additional evaluation including but not limited to preliminary engineering, environmental surveys, and property right checks may enable licensing cost and/or duration updates to be provided.
Note 2: These upgrades are not identified in the ISO tariff, and are not reimbursable. Allocated costs may change if all projects respons ble for these upgrades do not execute Interconnection Agreements.
Note 3: Each Upgrade category may contain multiple scope durations. The longest duration is shown under the Estimated Time to Construct.
Note 4: SCE's Phase I cost estimating is done in 'constant' dollars 2012 and then escalated to the estimated O.D..year. For the Phase I Study, the estimated O.D. is derived by assuming the duration of the work element will begin in March 2014, which is the CAISO tariff scheduled completion date of the QC5 Phase II study plus 90 days for the Interconnection Agreement signing period. For instance, if a work element is estimated to take a total of 24 months (permitting, design, procurement, and construction), then the estimated O.D. would be March 2016. If an IC's requested O.D.(in- service) is beyond the estimated O.D. of a work element, the IC's requested O.D. is used. However, should the Generator Interconnection Agreement not be executed, or the necessary information, funding, and written authorization to proceed is not provided by the IC, in time for the Participating TO to perform the work within these time frames, the information provided in Table D.1 may be subject to change.

Table M.2 ADNU Cost Rate

Upgrade	Total Cost	Phase I Incremental MW	ADNU Cost Rate (O.D. Year)	Estimated Time to Construct in Months
NA	NA	NA	NA	NA

N. Coordination with Affected Systems

ISO GIP tariff Appendix Y Section 3.7 requires coordinating with any affected systems that have any potential impact of QC5 projects.

Revised Appendix A – Q893

AES North America Development, LLC

Huntington Beach

Queue Cluster 5 Phase I Report

August 12, 2013

This study has been completed in coordination with Southern California Edison per CAISO Tariff Appendix DD Generator Interconnection and Deliverability Allocation Procedures (GIDAP)

Table of Contents

A. Executive Summary

AES North America Development, LLC, the Interconnection Customer (IC), received a Queue Cluster 5 Phase I Study (Phase I) Appendix A report dated January 31, 2013 for their Interconnection Request (IR) to the California Independent System Operator Corporation (CAISO) for their proposed Huntington Beach (Project), Q893.

Since the issuance of the Appendix A report dated January 31, 2013, it was learned that the existing Facilities of the Project have an existing “Radial Line Agreement” (RLA) and “Facilities Study Agreement” (FSA) that impact the classification of the upgrades identified in the QC5 Phase I report provided to the IC. In addition, it was also identified that facilities beyond those identified in the QC5 Phase I report are needed for the interconnection and operation of the Project. As a result, the Appendix A report is being reissued to rectify the classification of the facilities and address the additional facilities required to interconnect the Project. This reissue of the Appendix A report for Q893 is effective upon its issuance date and supersedes the previously issued Appendix A report. For additional information on the changes, refer to Section E.

For the purposes of this report, prior to the repower of the Interconnection Customer’s Huntington Beach Generating Facility, the Participating TO owned Huntington Beach 220kV Substation consisted of a double bus-double breaker 220kV Substation, whereby the Huntington Beach Generating Facilities units 1, 2, 3 and 4 were connected directly to the Huntington Beach 220kV Substation buses via motor operated disconnects. As a result of the proposed re-powering of the Huntington Beach Generating Facility and as pursuant to the Participating TO’s interconnection standards for new and repowered generating facilities, any and all new or repowered generating facilities must include the following:

1. High side circuit breakers and disconnects at the generating facility capable of isolating the generating facility from the Participating TO’s electrical system and the CAISO grid.

2. All generating tie lines interconnecting into the Participating TO’s substation must be terminated with circuit breakers and disconnects.

3. All generating tie lines interconnecting into the Participating TO’s substation must terminate using either double bus-double breaker, breaker and a half or other configuration as determined by the ISO and Participating TO.

In the particular case of this Project, the interconnection configuration must be reconfigured from termination directly to the 220kV buses to termination to a double bus-double breaker configuration. Therefore, the need to remove the existing geneation tie lines and motor operated disconnects currently connecting the generation tie lines to the 220kV buses directly and reconfiguring the terminations to a double bus-double breaker configuration.

The Project is a Full Capacity Deliverability Status, Combined Cycle Plant with a total rated output of 938.612 MW to the proposed Point of Interconnection (POI) at Southern California Edison Company’s (SCE) Ellis 220[1] kV Bus in Orange County, California. The customer has requested a proposed In-Service Date of January 01, 2017 and a proposed Commercial Operation Date of June 30, 2018.

In accordance with Federal Energy Regulatory Commission (FERC) approved Generator Interconnection and Deliverability Allocation Procedures (GIDAP) (CAISO Tariff Appendix DD), the Project was grouped with Queue Cluster 5 Phase I (QC5) study projects to determine the impacts of the group as well as impacts of the Project on the CAISO Controlled Grid.

[1] Identification of facility voltages (220 kV or 500 kV) in this Phase I Study are shown consistent with SCE System Opera ing Bulletin 123. However, all studies were predicated on the base voltages reflected in the Western Electricity Coordinating Council (WECC) base cases. For the SCE bulk power system, the WECC base cases reflect 230 kV and 500 kV base voltages; consequently, all per-unit calcula ions presented were based on 230 kV and 500 kV voltages.

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

The report provides the following:

1. Transmission system impacts caused by the Project;

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

3. A list of required facilities and a good faith estimate of the Project's cost responsibility and time required to construct and bring these facilities into service.

The QC5 study has determined that the Project contributes to various reliability and/or deliverability problems for which mitigation plans have been proposed. These mitigation plans are detailed in Section C of this report. The cost responsibility and estimated time to construct[2] the facilities required for the Project are summarized below.

The good faith cost estimates (in 2012 constant dollars) of PTO and Interconnection Customer Interconnection Facilities[3] (IF) and Distribution Upgrades[4] to interconnect the Project are:

PTO Interconnection Facilities	[redacted]
ITCC for PTO Interconnection Facilities	[redacted]
Interconnection Customer Interconnection Facilities	[redacted]
ITCC for Interconnection Customer Interconnection Facilities	[redacted]
Distribution Upgrades	[redacted]
ITCC for Distribution Upgrades	[redacted]

The non-binding cost estimate of PTO Interconnection Facilities (IF) and Distribution Upgrades to interconnect the Project is approximately [redacted] including ITCC[5]. Similarly, the good faith cost estimate for the allocated Interconnection Customer Interconnection Facilities necessary to interconnect the project is [redacted].

There were no Reliability Network Upgrades[6] (RNUs), Distribution Upgrades, Local Delivery Network Upgrades[7] (LDNUs) and Area Delivery Network Upgrades[8,9] (ADNUs) identified or allocated in this Phase I study in order to provide the Full Capacity Deliverability Status requested in the Interconnection Request.

[2] Construction is only part of he duration of months specified in the study, includes final engineering, licensing, etc, and other activi ies required to bring such facilities into service.

[3] The transmission facilities identified between the generation facility and the point of interconnection necessary to physically and electrically interconnect he Project to the CAISO-Controlled Grid.

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

[5] Income Tax Component of Contribu ion. The ITCC included in his cost es imate was computed using a 35% rate.

[6] The SCE transmission facilities, other han Interconnection Facili ies, at or beyond he point of interconnection necessary to physically and electrically interconnect the Project, needed to maintain system integrity and reliability.

[7] The SCE transmission facilities, other han Interconnection Facili ies, at or beyond he point of interconnection necessary to physically and electrically interconnect the Project, and are network upgrades built to address local deliverability constraints for projects that request Full or Partial Capacity Deliverability Status

[8] The SCE transmission facilities, other han Interconnection Facili ies, at or beyond he point of interconnection necessary to physically and electrically interconnect the Project, and are network upgrades built to address area deliverability constraints for projects that request Full or Partial Capacity Deliverability Status.

[9] The SCE transmission facilities, other han Interconnection Facili ies, at or beyond he point of interconnection necessary to physically and electrically interconnect the Project, and are network upgrades built to address area deliverability constraints for projects that request Full or Partial Capacity Deliverability Status.

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

Facility Type	**Duration (Months)**[10]
PTO Interconnection Facilities	44
Interconnection Customer Interconnection Facilities	44
Reliability Network Upgrades	NA
Local Delivery Network Upgrades	NA
Area Delivery Network Upgrades	NA
Distribution Upgrades	NA

These durations are from the execution of the Generator Interconnection Agreement, receipt of: all required information, funding, and written authorization to proceed from the IC as will be specified in the Generator Interconnection Agreement to commence the work.

B. Project and Interconnection Information

The Project's general information, as stated in the IR provided by the IC, and Interconnection Facilities are illustrated below in Table B.1, Figure B.1 provides the map for the Project and the transmission facilities in the vicinity, and Figure B.2 shows the conceptual single line diagram of the Project as modeled in the study.

[10] The dura ion specified reflects the approximate estimated time of completion for these facilities and is different than he dura ion amount specified for these facilities in Attachment #2 due to the fact that he duration amounts in Attachment #2 are pushed out to synch with the requested OD for the Project.

Table B.1: Project General Information

Project Location	21730 Newland St. Huntington Beach, CA Orange County
Participating TO's Planning Area	SCE Metro Area
Number and Type of Generators	Two Combine Cycle (3X113.825 MW Gas Turbine & 1X145.148 MW Steam Turbine)
Interconnection Voltage	220 kV
Maximum Generator Output	973.246 MW
Generator Auxiliary Load	34.634 MW
Maximum Net Output to Grid	938.612 MW
Power Factor Range	Lead 0.95 / Lag 0.90
Step-up Transformer(s)	**Combine Cycle Gas Turbine Transformer:** 220/13.8 kV (YG -D), 73/96/120 MVA H-X Impedance Value: 10 % @ 73 MVA **Combine Cycle Steam Turbine Transformer:** 220/13.8 (YG -D), 93/123/153 MVA H-X Impedance Value: 10 % @ 93 MVA
Point of Interconnection	Participating TO's Ellis 220 kV Substation
Interconnection Customer Requested Commercial Operation Date	June 30, 2018

Figure B.1: Map of the Project

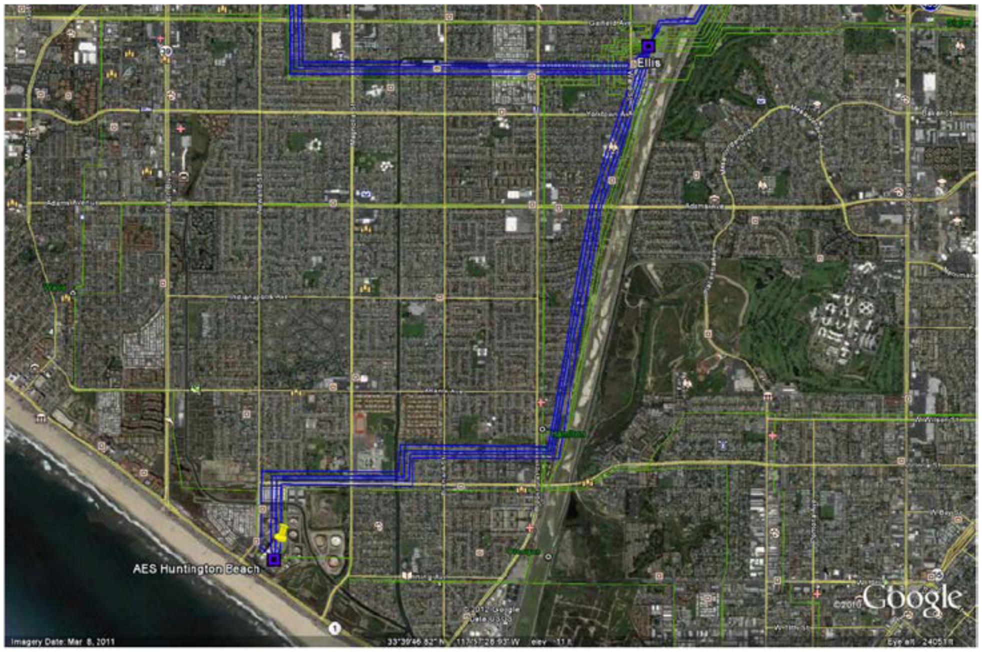
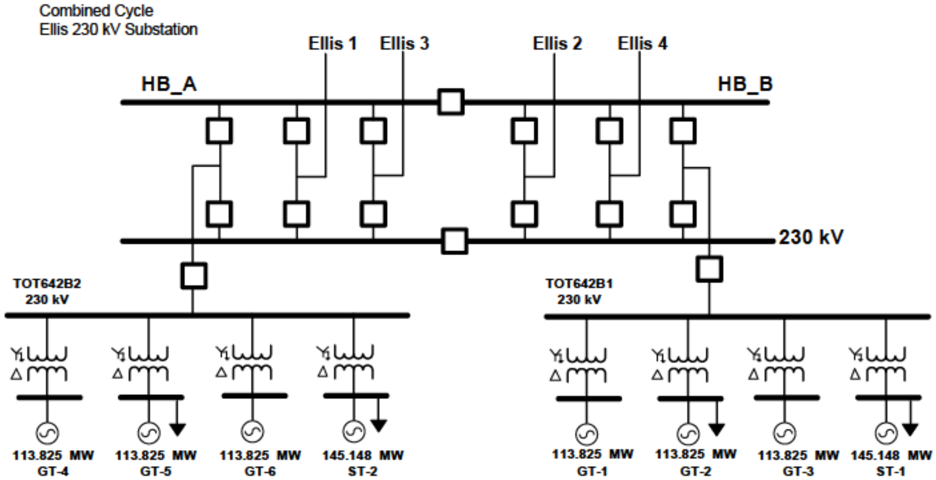


Figure B.2: Proposed Single Line Diagram

PROJECT DATA

Project Rated Output:	973.246 MW
Auxiliary Load:	34.634 MW
Project Net Capacity:	938.612 MW
Generator Type:	Combined Cycle
POI:	Ellis 230 kV Substation

TOT642 - Huntington Beach (Q893)
938.612 MW Full Capacity



EQUIVALENT GENERATOR DATA (GT)

Equivalent Rated Output:	682.95 MW
MVA Rating:	718.89 MVA
Voltage Rating:	13.8 kV
PF Regulation Range:	0 95

INDIVIDUAL GENERATOR DATA (6 units)

Individual generator output:	113.825 MW
MVA Rating:	119.815 MVA
Voltage Rating:	13.8 kV
PF Regulation Range:	0 95
X"1:	0.121 p.u.
X0 :	0.082 p.u.

INDIVIDUAL GT TRANSFORMER DATA (6 unit)

Rated Voltage:	230/13.8 kV
Rated MVA:	120 MVA
H-X:	10% @ 73 MVA
H Winding:	Wye-GND
X Winding:	Delta

EQUIVALENT GENERATOR DATA (ST)

Equivalent Rated Output:	290.296 MW
MVA Rating:	305.574 MVA
Voltage Rating:	13.8 kV
PF Regulation Range:	0.95

INDIVIDUAL GENERATOR DATA (2 units)

Individual generator output:	145.148 MW
MVA Rating:	152.787 MVA
Voltage Rating:	13.8 kV
PF Regulation Range:	0.95
X"d:	0.14 p u.
X0 :	0.091 p.u.

INDIVIDUAL ST TRANSFORMER DATA (2 unit)

Rated Voltage:	230/13.8 kV
Rated MVA:	153 MVA
H-X:	10% @ 93 MVA
H Winding:	Wye-GND
X Winding:	Delta

Gen-Tie Line Data B1

Distance: 0.22 miles, 1033.5 ACSR
Z_1 (p.u.) = 0.000038 R, 0.000308 X
Z_0 (p.u.) = 0.000157 R, 0.001064 X

Gen-Tie Line Data B2

Distance: 0.16 miles, 1033.5 ACSR
Z_1 (p.u.) = 0 000027 R, 0.000224 X
Z_0 (p.u.) = 0 000114 R, 0.000774 X

C. PTO Interconnection Facilities, Network Upgrades, and Interconnection Customer Interconnection Facilities

To determine the cost responsibility of each generation project in QC5, the CAISO developed cost allocation factors (Attachment 1) for Reliability Network Upgrades and Local Delivery Network Upgrades. The CAISO developed the $/MW cost rate for incremental Area Delivery Network Upgrades. The cost rate multiplied by the requested deliverable MW capacity provides the cost estimate for the Area Delivery Network Upgrades. The Interconnection Facilities are the sole cost responsibility of the Project. The Interconnection Facilities and Network Upgrades are listed below:

PTO'S INTERCONNECTION FACILITIES

1. **Transmission**

   Q893220 kV Generation Tie Line

   Install one (1) span of conductor and OPGW between the last generator owned structure and the substation dead-end rack at the 220 kV switchyard for each of the generation blocks (for a total of two).

2. **Substation**

   Huntington Beach Substation: The Participating TO owned 220kV Substation configured in a double bus-double breaker configuration.

   Install the following interconnection facility components of a new dedicated double breaker 220 kV line position to terminate both of the generation blocks:

   - Two (2) dead-end structures (one for each generation block).
   - Six (6) 220 kV coupling capacitor voltage transformers (three for each generation block)
   - Two(2) sets of two (2) line current differential protection relays with dedicated, diverse digital communication channels:
     (1) One G.E. L90 current differential relay, or its equivalent successor, with dual dedicated digital communication channels to the generation tie line main breaker (one for each generation block).
     (2) One SEL 311L current differential relay, or its equivalent successor, with dual dedicated digital communication channels to the generation tie line main breaker (one for each generation block).
   - One MEER building - the construction of this MEER building will house all relays for Huntington Beach Substation when the demolition of the existing MEER at the customer site takes place.
   - Four 220 kV circuit breakers (two for each block)
   - Eight sets of 220 kV disconnect switches (four for each block)
   - Two grounding switch attachment (one for each block)
   - Thirty six bus supports (eighteen for each block)
   - Upgrade cable trench.

3. **Telecommunications**

   Extend the fiber optic (FO) and OPGW provided by the customer to the Huntington Beach Substation communications room to meet the diverse routing requirements for each of the 220 kV generation blocks protection and SPS relays.

   Also, install all required light wave, channel and related terminal equipment at each end of both FO paths to interface with the required line protection relays and RTU.

- Install two (2) diverse FO cables into a new communications room in new MEER from existing communications room.
- Construct DACS, light wave, channel & associated equipment in new communications room.
- Construct a new communications room with DC power system and common equipment

4. **Metering Services Organization**

   Install revenue meters required to meter the retail load at the generating facility (One per block for a total of two)

   The customer will provide the required metering equipment (voltage and current transformers and metering cabinet).

5. **Power System Controls**

   Install one RTU at the generating facility to monitor typical generation elements such as MW, MVAR, terminal voltage and circuit breaker status of each generating unit and the plant auxiliary load and transmit this information to the SCE grid control center. Add points to the existing RTU at Huntington Beach Substation

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

   Obtain licensing, permits, easements and perform all required environmental activities for the installation of the following project elements if applicable:

   - Segment of 220 kV generation tie line within the Huntington Beach Substation property
   - Two (2) segments of FO and OPGW within the Huntington Beach Substation property
   - Access easements

INTERCONNECTION CUSTOMER INTERCONNECTION FACILITIES

1. **Substation**

   Huntington Beach Substation

   The PTO shall remove the following equipment at the 66 kV switchyard:

   - Remove two (2) 66 kV circuit breakers with associated foundations in position 2
   - Remove four (4) sets of 66 kV disconnect switches with associated foundations in position 2).
   - Remove three 66 kV (3) PTs with associated foundation (pos. \2)
   - Remove approximately 310' of 1590 MCM ACSR conductor (pos. 2) for the CBs

   The PTO shall remove the following equipment at the 220 kV switchyard:

   - Remove four (4) 220 kV Motor Operated Disconnect (MOD) switches (units 1, 2, 3 & 4) with associated structures.

PLAN OF SERVICE RELIABILITY NETWORK UPGRADES

No Plan of Service Reliability Network Upgrades were identified as part of this QC5 Phase I study for Project.

RELIABILITY NETWORK UPGRADES (RNU)

No Reliability Network Upgrades (non-Plan of Service) were identified as part of this QC5 Phase I study for Project.

LOCAL DELIVERY NETWORK UPGRADES (LDNU)

No Local Delivery Network Upgrades were identified as part of this QC5 Phase I study for Project.

AREA DELIVERY NETWORK UPGRADES (ADNU) USED TO DERIVE DOLLAR-PER-MW VALUE

No Area Delivery Network Upgrades were identified as part of this QC5 Phase I study for Project.

DISTRIBUTION UPGRADES

No Distribution Upgrades identified as part of this QC5 Phase I study for Project.

D. Cost and Construction Duration Estimates

To determine the cost responsibility of each generation project in QC5, the CAISO developed cost allocation factors (Attachment 1) for Reliability Network Upgrades and Local Delivery Network Upgrades. The CAISO developed the $/MW cost rate for incremental Area Delivery Network Upgrades. The cost rate multiplied by the requested deliverable MW capacity provides the cost estimate for the Area Delivery Network Upgrades. Attachment 2 provides the 'constant' 2012 dollars and their escalation to the estimated operating date year for Interconnection Facilities, Reliability Network Upgrades, Delivery Network Upgrades, and Distribution Upgrades which the Project was allocated cost. For the QC5 study, the estimated O.D. is derived by assuming the duration of the work element will begin in March 2014, which is the CAISO tariff scheduled completion date of the QC5 Phase II study plus 90 days for the interconnection agreement signing period.

E. Study Assumptions and Additional Scope Discussion

I. Study Assumptions

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

1. For the purposes of this report, prior to the repower of the Interconnection Customer's Huntington Beach Generating Facility, the Participating TO owned Huntington Beach 220kV Substation consisted of a double bus-double breaker 220kV Substation, whereby the Huntington Beach Generating Facilities units 1, 2, 3 and 4 were connected directly to the Huntington Beach 220kV Substation buses via motor operated disconnects. As a result of the proposed re-powering of the Huntington Beach Generating Facility and as pursuant to the Participating TO's interconnection standards for new and repowered generating facilities, any and all new or repowered generating facilities must include the following:

   a) High side circuit breakers and disconnects at the generating facility capable of isolating the generating facility from the Participating TO's electrical system and the CAISO grid.

   b) All generating tie lines interconnecting into the Participating TO's substation must be terminated with circuit breakers and disconnects.

   c) All generating tie lines interconnecting into the Participating TO's substation must terminate using either double bus double breaker, breaker and a half or other configuration as determined by the ISO and Participating TO.

2. In the particular case of this Project, the interconnection configuration must be reconfigured from termination directly to the 220kV buses to termination to a double bus-double breaker configuration. Therefore, the need to remove the existing generation tie lines and motor operated disconnects currently connecting the generation tie lines to the 220kV buses directly and reconfiguring the terminations to a double bus-double breaker configuration.

   3. The following facilities will be installed by SCE and <u>are included</u> in this Phase I Study:

   - The segment of the 220 kV generation tie line from customer last structure into and within Huntington Beach Substation property lines.
   - The segments of the telecommunication paths inside Huntington Beach Substation property line.
   - The required remote terminal unit (RTU) to be installed at the generating facility will be installed by SCE.
   - The required retail load meters.

     NOTE: SCE installation <u>does not</u> include metering voltage and current transformers. The SCE meters will be connected to the generator – owned voltage and current transformers to be installed for their CAISO metering.

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

   - The 220 kV generation tie line from the Generating Facility to the last structure outside the Huntington Beach Substation property line.
   - The 220 kV generation tie line optical ground wire (OPGW) and an additional FO path to provide two diverse telecommunication paths required for the line protection relays.
   - One high side circuit breaker per generation block at the customer's facility in accordance with SCE's Interconnection Handbook.
   - The customer will demolish and remove all existing facilities including the buildings and 66 kV substation. This assumes that all of the relays and associated equipment in the existing

control room will be relocated into the new MEER at Huntington Beach Substation This work will be completed under the existing FSA and no relocation costs are included in this study.

- This study did not take into account phasing of the project.

- The required CAISO metering equipment (voltage and current transformers, and CAISO meters).
- The metering cabinet to house the required SCE retail meters.

  NOTE: Based on a single CAISO resource metering point for an entire block, the metering voltage and current transformers installed for the CAISO metering will also be used for the SCE owned retail meters. (PT's and CT's to meet SCE specifications.) In the event that a single CAISO resource meter point is not provided, interconnection customer will provide block level single point dedicated retail metering voltage and current transformers, associated disconnects and dedicated enclosure in accordance with SCE standards.
- The following line protection relays to be installed at the Generating Facility end of each 220 kV generation tie line:
  - One G.E. L90 current differential relay, or its equivalent successor, with dual dedicated digital communication channels to Huntington Beach Substation.
  - One SEL 311L current differential relay, or its equivalent successor, with dual dedicated digital communication channels to Huntington Beach Substation.

II. Additional Scope Discussion

As previously mentioned, and demonstrated in Section C in this Revised Appendix A report, there are additional facilities required for interconnection of the Project beyond those identified in the original QC5 Phase I report dated January 31, 2013. Specifically the facilities are:

- Removal of the 66 kV circuit breakers, disconnect switches, and potential transformers.
- Upgrading the existing cable trenches inside Huntington Beach Substation.

The new generators will provide auxiliary power eliminating the need for the existing 66 kV feeds and the need to remove the 66 kV position within SCE's substation that is currently providing auxiliary power.

New cables will need to be installed from the new 220 kV circuit breakers to the new MEER. In order to provide a safe environment for the SCE personnel to install these new cables, the existing cable trenches at Huntington Beach Substation need to be upgraded/repaired.

The POI was determined to be Ellis Substation. The previously defined Plan of Service Reliability Network Upgrades were moved to the PTO's Interconnection Facilities to reflect the correct POI. The motor operated disconnect switches were determined to be under a FSA and owned by the IC. The scope and cost to remove the motor operated disconnect switches was moved to the IC Interconnection Facilities section.

F. Deliverability Assessment

See Section F in the group report.

G. Power Flow Analysis

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

(a) Overloaded Transmission Facilities

Category "A"

- None

Category "B"

- None

Category "C"

- None

(b) Power Flow Non-Convergence

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

(c) Voltage Performance

There were no voltage issues identified by the addition of this project.

(d) Required Mitigations

With the modeling of all CAISO-approved transmission projects and a number of transmission upgrades needed to support queued ahead Serial Group and Cluster projects in the Metro System, the study identified that the Metro System has sufficient transmission capability to accommodate the QC5 Phase I projects without any additional upgrades.

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

See the group report for additional details.

H. Short Circuit Analysis

Short circuit studies were performed to determine the fault duty impact of adding the QC5 projects to the Participating TO system and to ensure system coordination. The fault duties were calculated with and without the projects to identify any equipment overstress conditions. Once overstressed circuit breakers are identified, the fault current contribution from each individual project in QC5 is determined. Each project in QC5 will be responsible for its share of the upgrade cost based on the rules set forth in CAISO Tariff Appendix DD.

III. Short Circuit Study Input Data

The following input data provided by the Interconnection Customer and was used in this study:

Individual Combined Cycle Steam Turbine Units (x2):

- X"1 – positive sequence subtransient reactance: 0.140 PU
- X2 – negative sequence subtransient reactance: 0.182 PU
- X0 – zero sequence subtransient reactance: 0.091 PU

Individual Combined Cycle Gas Turbine Units (x6):

- X"1 – positive sequence subtransient reactance: 0.121 PU
- X2 – negative sequence subtransient reactance: 0.150 PU
- X0 – zero sequence subtransient reactance: 0.082 PU

Individual Combine Cycle Steam Turbine Transformer (x2)
Each transformer is a three-phase, 220/13.8 kV (YG-D), 93//123/153 MVA with the following impedance information:

- H-X: 10% @ 93 MVA

Individual Combine Cycle Gas Turbine Transformer (x6)
Each transformer is a three-phase, 220/13.8 kV (YG-D), 73/96/120 MVA with the following impedance information:

- H-X: 10% @ 73 MVA

Generation Tie Line

The generation tie line was assumed to be negligible.

IV. Short Circuit Duty Study Results

All bus locations where the QC5 projects increase the short-circuit duty by 0.1 kA or more and where duty is in excess of 60% of the minimum breaker nameplate rating are listed in the group report Appendix H. These values have been used to determine if any equipment is overstressed as a result of the QC5 interconnections and corresponding network upgrades, if any.

The responsibility to finance short circuit related upgrades identified through a group study shall be assigned to all Interconnection Requests in that group study pro-rata on the basis of short circuit duty contribution of each Generating Facility. In addition, the SCD impact of the associated proposed Network Upgrades was allocated to each Generating Facility using the same percentage assigned for the triggered Network Upgrade.

(a) Application Queue with RNUs and LDNUs Analysis Results

Fault duties were calculated with the inclusion of the QC5 projects and the identified RNUs and LDNUs to identify the incremental impacts associated with these Facilities. As discussed in Section H of the group report, under this scenario the QC5 study breaker evaluation identified overstressed circuit breakers. The following is the pro-rata cost allocation for this project, based on SCD contribution at each location.

SCD Mitigation - Table of Network Breaker Replacements (RNU)

NA

(b) Application Queue with RNUs, LDNUs, & ADNUs Analysis Results

Fault duties were re-calculated to include the QC5 projects and the identified RNUs, LDNUs, and ADNUs from the power flow and stability analysis to identify the incremental impacts associated with these Facilities. As discussed in Section H of the group report, under this scenario the QC5 study breaker evaluation identified overstressed circuit breakers at Mira Loma and Valley. As part of this Phase I cost estimates for mitigation of short circuit duty impacts under this scenario are not included. As part of Phase II if this mitigation is identified to still be required, cost estimates and corresponding pro-rata cost allocation will be determined

(c) Application Queue Distribution Analysis Results

Fault duties were calculated for the QC5 projects on the distribution system. Under this scenario the QC5 study breaker evaluation identified overstressed circuit breakers at the following distribution substations. The following is the pro-rata cost allocation for this project, based on SCD contribution at each location.

SCD Mitigation -Table of Distribution Breaker Replacements

NA

V. Preliminary Protection Requirements

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

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

I. Project Power Factor Requirements

This Project consist of synchronous generators and are required to operate within a 0.95 leading to 0.90 lagging power factor as measured at the generator terminals.

J. Transient Stability Evaluation

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

(a) Transient Stability Study Scenarios

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

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

(b) Transient Stability Study Results

Limited stability analysis was performed for the Metro System to identify "relative" as opposed to "absolute" conclusions regarding the stability impacts of the QC5 queued generation projects. In the limited stability analysis performed there were no transient stability problems identified with the addition of the QC5 Phase I projects in the Metro System. Stability plots are shown in Appendix F of the group report.

K. Environmental Evaluation/Permitting

Please see Section L of the QC5 group report.

L. Items not covered in this study

1. Conceptual Plan of Service

The results provided in this study are based on conceptual engineering and a preliminary plan of service and are not sufficient for permitting of facilities. The Plan of Service is subject to change as part of the Phase II Interconnection Study.

2. **Customer's Technical Data**

   Additional technical data related to the Interconnection Customer's project may be required as part of the Phase II study. The study accuracy and results for the QC5 Phase I Study are contingent upon the accuracy of the technical data provided by the Interconnection Customer. Any changes from the data provided could void the Study results.

3. **Study Impacts on Neighboring Utilities**

   Results or consequences of this QC5 Phase I Study and/or to-be-performed Phase II Interconnection Study may require additional studies, facility additions, and/or operating procedures to address impacts to neighboring utilities and/or regional forums. For example, impacts may include but are not limited to WECC Path Ratings, short circuit duties outside of the CAISO Controlled Grid, and sub-synchronous resonance (SSR).

4. **Use of Participating TO Facilities**

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

5. **Participating TO Interconnection Handbook**

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

6. **Western Electricity Coordinating Council (WECC) Policies**

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

7. **System Protection Coordination**

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

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

   The QC5 Phase I Study does not address any requirements for standby power or temporary construction power that the Project may require prior to the In-Service Date of the Interconnection Facilities. Should the Project require standby power or temporary construction power from Participating TO prior to the In-Service Date of the Interconnection Facilities, the IC is responsible to make appropriate arrangements with Participating TO to receive and pay for such retail.

9. **Licensing Cost and Duration Estimate (Estimated Construction Schedule)**

   The estimated licensing cost and durations applied to this project are based on the project scope details presented in this study. These estimates are subject to change as project environmental and real estate elements are further defined. Upon execution of the Interconnection Agreement, additional evaluation including but not limited to preliminary engineering, environmental surveys, and property right checks may enable licensing cost and/or duration updates to be provided.

10. Network/Non-Network Classification of Telecommunication Facilities

The cost for telecommunication facilities that were identified as part of the IC's Interconnection Facilities was based on an assumption that these facilities would be sited, licensed, and constructed by the IC. The IC will own, operate, maintain, and construct diverse telecommunication paths associated with the IC's gen tie, excluding terminal equipment at both ends. In addition, the telecommunication requirements for SPS were assumed based on tripping of the generator breaker as opposed to tripping the circuit breakers at the Participating TO substation. Due to uncertainties related to telecommunication upgrades for the numerous projects in queue ahead of QC5 Phase I, telecommunication upgrades for higher queued projects were not considered in this study. Depending on the outcome of interconnection studies for higher queued projects, the telecommunication upgrades identified for QC5 Phase I may be reduced. Any changes in these assumptions may affect the cost and schedule for the identified telecommunication facilities.

11. Applicability

This document has been prepared to identify the impact(s) contributions of the Project on the SCE electrical system; as well as establish the technical requirements to interconnect the Project to the Point of Interconnection that was evaluated in the QC5 Phase I Study for the Project. Nothing in this report is intended to supersede or establish terms/conditions specified in interconnection agreements agreed to by SCE, CAISO and the Interconnection Customer.

12. Cost Responsibility Declaration

The interconnection customer is hereby placed on notice that attainment of Full Capacity Deliverability status, or Partial Capacity Deliverability status, as such terms are defined in the CAISO GIDAP, for the proposed generating facility may be dependent upon certain network upgrades which are currently the cost responsibility of projects ahead of the proposed generating facility in the interconnection application queue. According to Appendix DD, Section 14.2.2 of the CAISO GIDAP, if such upgrades required for queued-ahead projects are included in an executed GIA (or unexecuted GIA filed at FERC) at the time of withdrawal of the earlier queued generating facility, and the upgrades are determined to still be needed by later queued generating facilities, the financial responsibility for such upgrades falls to the Participating Transmission Owner. However, if the upgrades required by earlier queued generating facilities not subject to an executed GIA (or unexecuted GIA filed at FERC) the financial responsibility for such upgrades may fall to the interconnection customer. SCE encourages the interconnection customer to review Section 14.2.2 for the rules and processes under which the financial responsibility might be reapportioned to the interconnection customer. Section 14.2.2 also discusses how network upgrades required by interconnection customers selecting Option (B) might be required to be reapportioned among interconnection customers selecting Option (B) in the case of withdrawals of earlier queued generating facilities. This potential cost responsibility is not included in this Phase I study, nor is it subject to the maximum cost responsibility outlined in this Phase I study.

Attachment 1

AES North America Development, LLC

Huntington Beach

Sensitivity Assessment

PREPARED BY
AMIR MOHAMMEDNUR

SCE received a request from AES to perform a high level assessment to evaluate the potential impacts on SCE's transmission system as a result of increasing their Queue Cluster 5 Phase I Huntington Beach project from 938.612 MW to 1000 MW. Additionally, AES requested SCE to assess the short circuit duty impacts associated with paralleling the Huntington Beach 220 kV bus. This analysis was performed using the Queue Cluster 5 Phase I power flow and short circuit duty base cases. After performing the analysis, SCE did not identify any thermal overloads or any short circuit duty issues. It's important to note that the results disclosed in this high level analysis are for informational purposes only and are not intended to guarantee a certain level of deliverability status. If AES decides to proceed forward with the additional MW they will have to apply under the formal interconnection process.

Attachment 2

Escalated Cost and Time to Construct for PTO Interconnection Facilities, Interconnection Customer Interconnection Facilities, Reliability Network Upgrades, Delivery Network Upgrades, and Distribution Upgrades

Please refer to separate document.

Attachment 2: Escalated Cost and Time to Construct for Interconnection Facilities, Reliability Network Upgrades, Delivery Network Upgrades, and Distribution Upgrades

Element	Interconnection Facilities Costs x 1,000 Constant Dollar (2012)	Reliability Network Upgrades Costs x 1,000 Constant Dollar (2012)	Delivery Network Upgrades Costs x 1,000 Constant Dollar (2012)	Distribution Upgrades Costs x 1,000 Constant Dollar (2012)	One Time Costs x 1,000 Constant Dollar (2012)	Total Estimated Costs w/o ITCC x 1,000 Constant Dollar (2012)	Total Estimated Costs w/o ITCC x 1,000 Escalated Constant Dollars (OD Year)	"ITCC* x 1,000 Constant Dollar (2012)	Total Estimated Costs w ITCC x 1,000 Constant Dollar (2012)	Total Estimated Costs w ITCC x 1,000 Escalated Constant Dollar (OD Year)	Estimated Time to Construct (Months) (Note 3,4, and 5)
PTO's Interconnection Facilities (Note 1)											
Transmission/Subtransmission	[redacted]							[redacted]			
Substation - MEER Building - Equip two dedicated double breaker positions - Repair 220 kV cable trench	[redacted]				[redacted]			[redacted]			
Telecommunications/Edison Carrier Solutions	[redacted]							[redacted]			
Corporate Enviromental Services	[redacted]							[redacted]			
Licensing	[redacted]							[redacted]			
Real Properties	[redacted]							[redacted]			
Metering Services	[redacted]							[redacted]			
Power System Controls – Generating Facility	[redacted]				[redacted]			[redacted]			
Subtotal	[redacted]				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	84
IC's Interconnection Facilities (Note 1)											
Transmission/Subtransmission											
Substation - Remove 4 - 220 kV MOD DSW - Remove 66 kV Equipment	[redacted]										
Telecommunications/Edison Carrier Solutions											
Corporate Enviromental Services - Support the IC's Interconnect Facilities removal of MOD, DSW, CBs, etc	[redacted]										
Licensing											
Real Properties											
Metering Services											
Power System Controls – Generating Facility											
Subtotal	[redacted]					[redacted]	[redacted]		[redacted]	[redacted]	84
PTO's Reliability Network Upgrades											
Short Circuit Mitigation - None											
Plan of Service											
Substation											
Transmission/Subtransmission											
Corporate Enviromental Services											
Licensing											
Real Properties											
Power System Controls											
Telecommunications											
Subtotal											
PTO's Local Delivery Network Upgrades											
None											
Subtotal											
Distribution Upgrades (Note 2)											
None											
Subtotal											
Total	[redacted]		NA	NA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	84
AREA DELIVERY NETWORK UPGRADES COST ALLOCATION											
PTO's Area Delivery Network Upgrades											
None											
Total	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Project Total	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Q893

Note 1: The Interconnection Customer (IC) is obligated to fund these upgrades, and the IC will not be reimbursed for these upgrade costs.

Note 2: The Interconnection Customer is obligated to fund these upgrades, and the IC will not be reimbursed for these upgrade costs. Allocated costs may change if all projects responsible for these upgrades do not execute Interconnection Agreements.

Note 3: The estimated licensing cost and construction durations applied to this project are based on the project scope details presented in this study. These estimates are subject to change after project environmental and real estate elements are further defined. After execution of the Interconnection Agreement, additional evaluation, including but not limited to, preliminary engineering, environmental surveys, and property right checks may result in licensing cost and/or construction duration updates which will be provided to the IC.

Note 4: SCE's Phase I cost estimating is done in 'constant' dollars 2012 and then escalated to the estimated O.D. year. For the Phase I Study, the estimated O.D. is derived by assuming the duration of the work element will begin in March 2014, which is the CAISO tariff scheduled completion date of the QC5 Phase II Study plus 90 calendar days for the Interconnection Agreement negotiations/execution. For instance, if a work element is estimated to take a total of 24 months for permitting, design, procurement, and construction, then the estimated O D. would be March 2016. If an IC's requested O.D. (In-Service Date) is beyond the estimated O D. of a work element, the IC's requested O.D. is used. However, should the Generator Interconnection Agreement not be executed, or if the necessary information, funding, and written authorization to proceed is not provided by the IC in time for the Participating TO to perform the work within these time frames, then the information provided in Table D.1 may be subject to change.

Note 5: The Estimated Time to Construct (ETC) duration specified synchs with the requested O.D. for the Project. The ETC of the Interconnection Facilities is estimated to be approximately 44 months.

Attachment 3

Participating TO Interconnection Handbook

Preliminary Protection Requirements for Interconnection Facilities are outlined in the Participating TO Interconnection Handbook.

Attachment 4

Short Circuit Calculation Study Results

Please refer to the Appendix H of the group report.

Attachment 5

Not Used

Attachment 6

Customer Provided Project Dynamic Data

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

models

genrou 96315 "BLK1_GT-1 " 13.80 "G1" : #9 mva=119.82 "tpdo" 13.1000 "tppdo" 0.0500 "tpqo" 4.0000 "tppqo" 0.0500 "h" 1.28 "d" 0.0000 "ld" 2.12 "lq" 1.94 "lpd" 0.169 "lpq" 0.2 "lppd" 0.121 "ll" 0.078 "s1" 0.1579 "s12" 0.5697 "ra" 0.00082 "rcomp" 0.0000 "xcomp" 0.0000 "accel" 0.0000

esst1a 96315 "BLK1_GT-1 " 13.80 "G1" : #9 "tr" 0.0 "vimax" 999.00 "vimin" -999.00 "tc" 1.000000 "tb" 10.0000 "ka" 190.00 "ta" 0.020000 "vrmax" 6.9210 "vrmin" -6.7000 "kc" 0.050000 /

"kf" 0.0 "tf" 1.000000 "tc1" 0.0 "tb1" 0.0 "vamax" 999.00 "vamin" -999.00 "ilr" 0.0 "klr" 0.0 "uelin" 0.0 "pssin" 0.0

gast 96315 "BLK1_GT-1 " 13.80 "G1" : #9 mwcap=113.825 "r" 0.040000 "t1" 0.100000 "t2" 1.000000 "t3" 5.0000 "lmax" 1.000000 "kt" 3.1250 "vmax" 1.000000 "vmin" 0.050000 "dturb" 0.0 "fidle" 0.0 "rmax" 99.0000 "linc" 99.0000 "tltr" 99.0000 "ltrat" 99.0000 "a" 0.0 "b" 1.000000 "db1" 0.0 "eps" 0.0 "db2" 0.0 "gv1" 0.0 "pgv1" 0.0 "gv2" 0.0 "pgv2" 0.0 "gv3" 0.0 "pgv3" 0.0 "gv4" 0.0 "pgv4" 0.0 "gv5" 0.0 "pgv5" 0.0 "gv6" 0.0 "pgv6" 0.0 "ka" 1.000000 "t4" 0.0 "t5" 0.0

pss2b 96315 "BLK1_GT-1 " 13.80 "G1" : #9 "j1" 1.000000 "k1" 96315 "j2" 3.0000 "k2" 96315 "vsi1max" 999.00 "vsi1min" -999.00 "tw1" 2.0000 "tw2" 2.0000 "vsi2max" 999.00 "vsi2min" -999.00 "tw3" 2.0000 "tw4" 2.0000 "t6" 0.020000 "t7" 2.0000 "ks2" 0.200000 "ks3" 1.000000 "t8" 0.0 "t9" 1.000000 "n" 1.000000 "m" 5.0000 "ks1" 5.0000 "t1" 0.200000 "t2" 0.040000 "t3" 0.360000 "t4" 0.120000 "t10" 0.010000 "t11" 0.010000 "vstmax" 999.00 "vstmin" -999.00 "a" 1.000000 "ta" 0.0 "tb" 0.0 "ks4" 1.000000

genrou 96316 "BLK1_GT-2 " 13.80 "G2" : #9 mva=119.82 "tpdo" 13.1000 "tppdo" 0.0500 "tpqo" 4.0000 "tppqo" 0.0500 "h" 1.28 "d" 0.0000 "ld" 2.12 "lq" 1.94 "lpd" 0.169 "lpq" 0.2 "lppd" 0.121 "ll" 0.078 "s1" 0.1579 "s12" 0.5697 "ra" 0.00082 "rcomp" 0.0000 "xcomp" 0.0000 "accel" 0.0000

esst1a 96316 "BLK1_GT-2 " 13.80 "G2" : #9 "tr" 0.0 "vimax" 999.00 "vimin" -999.00 "tc" 1.000000 "tb" 10.0000 "ka" 190.00 "ta" 0.020000 "vrmax" 6.9210 "vrmin" -6.7000 "kc" 0.050000 /

"kf" 0.0 "tf" 1.000000 "tc1" 0.0 "tb1" 0.0 "vamax" 999.00 "vamin" -999.00 "ilr" 0.0 "klr" 0.0 "uelin" 0.0 "pssin" 0.0

gast 96316 "BLK1_GT-2 " 13.80 "G2" : #9 mwcap=113.825 "r" 0.040000 "t1" 0.100000 "t2" 1.000000 "t3" 5.0000 "lmax" 1.000000 "kt" 3.1250 "vmax" 1.000000 "vmin" 0.050000 "dturb" 0.0 "fidle" 0.0 "rmax" 99.0000 "linc" 99.0000 "tltr" 99.0000 "ltrat" 99.0000 "a" 0.0 "b" 1.000000 "db1" 0.0 "eps" 0.0 "db2" 0.0 "gv1" 0.0 "pgv1" 0.0 "gv2" 0.0 "pgv2" 0.0 "gv3" 0.0 "pgv3" 0.0 "gv4" 0.0 "pgv4" 0.0 "gv5" 0.0 "pgv5" 0.0 "gv6" 0.0 "pgv6" 0.0 "ka" 1.000000 "t4" 0.0 "t5" 0.0

pss2b 96316 "BLK1_GT-2 " 13.80 "G2" : #9 "j1" 1.000000 "k1" 96316 "j2" 3.0000 "k2" 96316 "vsi1max" 999.00 "vsi1min" -999.00 "tw1" 2.0000 "tw2" 2.0000 "vsi2max" 999.00 "vsi2min" -999.00 "tw3" 2.0000 "tw4" 2.0000 "t6" 0.020000 "t7" 2.0000 "ks2" 0.200000 "ks3" 1.000000 "t8" 0.0 "t9" 1.000000 "n" 1.000000 "m" 5.0000 "ks1" 5.0000 "t1" 0.200000 "t2" 0.040000 "t3" 0.360000 "t4" 0.120000 "t10" 0.010000 "t11" 0.010000 "vstmax" 999.00 "vstmin" -999.00 "a" 1.000000 "ta" 0.0 "tb" 0.0 "ks4" 1.000000

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esst1a 96317 "BLK1_GT-3 " 13.80 "G3" : #9 "tr" 0.0 "vimax" 999.00 "vimin" -999.00 "tc" 1.000000 "tb" 10.0000 "ka" 190.00 "ta" 0.020000 "vrmax" 6.9210 "vrmin" -6.7000 "kc" 0.050000 /

"kf" 0.0 "tf" 1.000000 "tc1" 0.0 "tb1" 0.0 "vamax" 999.00 "vamin" -999.00 "ilr" 0.0 "klr" 0.0 "uelin" 0.0 "pssin" 0.0

gast 96317 "BLK1_GT-3 " 13.80 "G3" : #9 mwcap=113.825 "r" 0.040000 "t1" 0.100000 "t2" 1.000000 "t3" 5.0000 "lmax" 1.000000 "kt" 3.1250 "vmax" 1.000000 "vmin" 0.050000 "dturb" 0.0 "fidle" 0.0 "rmax" 99.0000 "linc" 99.0000 "tltr" 99.0000 "ltrat" 99.0000 "a" 0.0 "b" 1.000000 "db1" 0.0 "eps" 0.0 "db2" 0.0 "gv1" 0.0 "pgv1" 0.0 "gv2" 0.0 "pgv2" 0.0 "gv3" 0.0 "pgv3" 0.0 "gv4" 0.0 "pgv4" 0.0 "gv5" 0.0 "pgv5" 0.0 "gv6" 0.0 "pgv6" 0.0 "ka" 1.000000 "t4" 0.0 "t5" 0.0

pss2b 96317 "BLK1_GT-3 " 13.80 "G3" : #9 "j1" 1.000000 "k1" 96317 "j2" 3.0000 "k2" 96317 "vsi1max" 999.00 "vsi1min" -999.00 "tw1" 2.0000 "tw2" 2.0000 "vsi2max" 999.00 "vsi2min" -999.00 "tw3" 2.0000 "tw4" 2.0000 "t6" 0.020000 "t7" 2.0000 "ks2" 0.200000 "ks3" 1.000000 "t8" 0.0 "t9" 1.000000 "n" 1.000000 "m" 5.0000 "ks1" 5.0000 "t1" 0.200000 "t2" 0.040000 "t3" 0.360000 "t4" 0.120000 "t10" 0.010000 "t11" 0.010000 "vstmax" 999.00 "vstmin" -999.00 "a" 1.000000 "ta" 0.0 "tb" 0.0 "ks4" 1.000000

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esst1a 96319 "BLK1_GT-4 " 13.80 "G4" : #9 "tr" 0.0 "vimax" 999.00 "vimin" -999.00 "tc" 1.000000 "tb" 10.0000 "ka" 190.00 "ta" 0.020000 "vrmax" 6.9210 "vrmin" -6.7000 "kc" 0.050000 /

"kf" 0.0 "tf" 1.000000 "tc1" 0.0 "tb1" 0.0 "vamax" 999.00 "vamin" -999.00 "ilr" 0.0 "klr" 0.0 "uelin" 0.0 "pssin" 0.0

gast 96319 "BLK1_GT-4 " 13.80 "G4" : #9 mwcap=113.825 "r" 0.040000 "t1" 0.100000 "t2" 1.000000 "t3" 5.0000 "lmax" 1.000000 "kt" 3.1250 "vmax" 1.000000 "vmin" 0.050000 "dturb" 0.0 "fidle" 0.0 "rmax" 99.0000 "linc" 99.0000 "tltr" 99.0000 "ltrat" 99.0000 "a" 0.0 "b" 1.000000 "db1" 0.0 "eps" 0.0 "db2" 0.0 "gv1" 0.0 "pgv1" 0.0 "gv2" 0.0 "pgv2" 0.0 "gv3" 0.0 "pgv3" 0.0 "gv4" 0.0 "pgv4" 0.0 "gv5" 0.0 "pgv5" 0.0 "gv6" 0.0 "pgv6" 0.0 "ka" 1.000000 "t4" 0.0 "t5" 0.0

pss2b 96319 "BLK1_GT-4 " 13.80 "G4" : #9 "j1" 1.000000 "k1" 96319 "j2" 3.0000 "k2" 96319 "vsi1max" 999.00 "vsi1min" -999.00 "tw1" 2.0000 "tw2" 2.0000 "vsi2max" 999.00 "vsi2min" -999.00 "tw3" 2.0000 "tw4" 2.0000 "t6" 0.020000 "t7"

2.0000 "ks2" 0.200000 "ks3" 1.000000 "t8" 0.0 "t9" 1.000000 "n" 1.000000 "m" 5.0000 "ks1" 5.0000 "t1" 0.200000 "t2" 0.040000 "t3" 0.360000 "t4" 0.120000 "t10" 0.010000 "t11" 0.010000 "vstmax" 999.00 "vstmin" -999.00 "a" 1.000000 "ta" 0.0 "tb" 0.0 "ks4" 1.000000

genrou 96320 "BLK1_GT-5 " 13.80 "G5" : #9 mva=119.82 "tpdo" 13.1000 "tppdo" 0.0500 "tpqo" 4.0000 "tppqo" 0.0500 "h" 1.28 "d" 0.0000 "ld" 2.12 "lq" 1.94 "lpd" 0.169 "lpq" 0.2 "lppd" 0.121 "ll" 0.078 "s1" 0.1579 "s12" 0.5697 "ra" 0.00082 "rcomp" 0.0000 "xcomp" 0.0000 "accel" 0.0000

esst1a 96320 "BLK1_GT-5 " 13.80 "G5" : #9 "tr" 0.0 "vimax" 999.00 "vimin" -999.00 "tc" 1.000000 "tb" 10.0000 "ka" 190.00 "ta" 0.020000 "vrmax" 6.9210 "vrmin" -6.7000 "kc" 0.050000 /

"kf" 0.0 "tf" 1.000000 "tc1" 0.0 "tb1" 0.0 "vamax" 999.00 "vamin" -999.00 "ilr" 0.0 "klr" 0.0 "uelin" 0.0 "pssin" 0.0

gast 96320 "BLK1_GT-5 " 13.80 "G5" : #9 mwcap=113.825 "r" 0.040000 "t1" 0.100000 "t2" 1.000000 "t3" 5.0000 "lmax" 1.000000 "kt" 3.1250 "vmax" 1.000000 "vmin" 0.050000 "dturb" 0.0 "fidle" 0.0 "rmax" 99.0000 "linc" 99.0000 "tltr" 99.0000 "ltrat" 99.0000 "a" 0.0 "b" 1.000000 "db1" 0.0 "eps" 0.0 "db2" 0.0 "gv1" 0.0 "pgv1" 0.0 "gv2" 0.0 "pgv2" 0.0 "gv3" 0.0 "pgv3" 0.0 "gv4" 0.0 "pgv4" 0.0 "gv5" 0.0 "pgv5" 0.0 "gv6" 0.0 "pgv6" 0.0 "ka" 1.000000 "t4" 0.0 "t5" 0.0

pss2b 96320 "BLK1_GT-5 " 13.80 "G5" : #9 "j1" 1.000000 "k1" 96320 "j2" 3.0000 "k2" 96320 "vsi1max" 999.00 "vsi1min" -999.00 "tw1" 2.0000 "tw2" 2.0000 "vsi2max" 999.00 "vsi2min" -999.00 "tw3" 2.0000 "tw4" 2.0000 "t6" 0.020000 "t7" 2.0000 "ks2" 0.200000 "ks3" 1.000000 "t8" 0.0 "t9" 1.000000 "n" 1.000000 "m" 5.0000 "ks1" 5.0000 "t1" 0.200000 "t2" 0.040000 "t3" 0.360000 "t4" 0.120000 "t10" 0.010000 "t11" 0.010000 "vstmax" 999.00 "vstmin" -999.00 "a" 1.000000 "ta" 0.0 "tb" 0.0 "ks4" 1.000000

genrou 96321 "BLK1_GT-6 " 13.80 "G6" : #9 mva=119.82 "tpdo" 13.1000 "tppdo" 0.0500 "tpqo" 4.0000 "tppqo" 0.0500 "h" 1.28 "d" 0.0000 "ld" 2.12 "lq" 1.94 "lpd" 0.169 "lpq" 0.2 "lppd" 0.121 "ll" 0.078 "s1" 0.1579 "s12" 0.5697 "ra" 0.00082 "rcomp" 0.0000 "xcomp" 0.0000 "accel" 0.0000

esst1a 96321 "BLK1_GT-6 " 13.80 "G6" : #9 "tr" 0.0 "vimax" 999.00 "vimin" -999.00 "tc" 1.000000 "tb" 10.0000 "ka" 190.00 "ta" 0.020000 "vrmax" 6.9210 "vrmin" -6.7000 "kc" 0.050000 /

"kf" 0.0 "tf" 1.000000 "tc1" 0.0 "tb1" 0.0 "vamax" 999.00 "vamin" -999.00 "ilr" 0.0 "klr" 0.0 "uelin" 0.0 "pssin" 0.0

gast 96321 "BLK1_GT-6 " 13.80 "G6" : #9 mwcap=113.825 "r" 0.040000 "t1" 0.100000 "t2" 1.000000 "t3" 5.0000 "lmax" 1.000000 "kt" 3.1250 "vmax" 1.000000 "vmin" 0.050000 "dturb" 0.0 "fidle" 0.0 "rmax" 99.0000 "linc" 99.0000 "tltr" 99.0000 "ltrat" 99.0000 "a" 0.0 "b" 1.000000 "db1" 0.0 "eps" 0.0 "db2" 0.0 "gv1" 0.0 "pgv1" 0.0 "gv2" 0.0 "pgv2" 0.0 "gv3" 0.0 "pgv3" 0.0 "gv4" 0.0 "pgv4" 0.0 "gv5" 0.0 "pgv5" 0.0 "gv6" 0.0 "pgv6" 0.0 "ka" 1.000000 "t4" 0.0 "t5" 0.0

pss2b 96321 "BLK1_GT-6 " 13.80 "G6" : #9 "j1" 1.000000 "k1" 96321 "j2" 3.0000 "k2" 96321 "vsi1max" 999.00 "vsi1min" -999.00 "tw1" 2.0000 "tw2" 2.0000 "vsi2max" 999.00 "vsi2min" -999.00 "tw3" 2.0000 "tw4" 2.0000 "t6" 0.020000 "t7"

2.0000 "ks2" 0.200000 "ks3" 1.000000 "t8" 0.0 "t9" 1.000000 "n" 1.000000 "m" 5.0000 "ks1" 5.0000 "t1" 0.200000 "t2" 0.040000 "t3" 0.360000 "t4" 0.120000 "t10" 0.010000 "t11" 0.010000 "vstmax" 999.00 "vstmin" -999.00 "a" 1.000000 "ta" 0.0 "tb" 0.0 "ks4" 1.000000

genrou 96318 "BLK1_ST-1 " 13.80 "S1" : #9 mva=152.7870 "tpdo" 12.4000 "tppdo" 0.0500 "tpqo" 3.8000 "tppqo" 0.0500 "h" 1.0900 "d" 0.0000 "ld" 2.2700 /

"lq" 2.0700 "lpd" 0.1930 "lpq" 0.2300 "lppd" 0.1400 "ll" 0.0770 "s1" 0.1200 "s12" 0.4791 "ra" 0.0007 "rcomp" 0.0000 "xcomp" 0.0000 "accel" 0.0000

esac7b 96318 "BLK1_ST-1 " 13.80 "S1" : #9 "tr" 0.0 "kpr" 15.0000 "kir" 1.8800 "kdr" 0.0 "tdr" 0.005000 "vrmax" 3.2000 "vrmin" -3.2000 "kpa" 48.3800 "kia" 0.0 "vamax" 28.1400 /

"vamin" -23.3200 "kp" 1.000000 "kl" 10000.00 "te" 1.4000 "vfemax" 13.9000 "vemin" 0.0 "ke" 1.000000 "kc" 0.470000 "kd" 0.920000 "kf1" 0.0 /

"kf2" 0.150000 "kf3" 0.020000 "tf" 1.5000 "e1" 6.9000 "se1" 0.150000 "e2" 9.2000 "se2" 2.0700 "spdmlt" 0.0

ieeeg1 96318 "BLK1_ST-1 " 13.80 "S1" : #9 mwcap=142.0000 "k" 20.0000 "t1" 0.004000 "t2" 0.020000 "t3" 0.350000 "uo" 99.0000 "uc" -99.0000 "pmax" 1.000000 "pmin" 0.0 "t4" 0.060000 "k1" 1.000000 /

"k2" 0.0 "t5" 0.0 "k3" 0.0 "k4" 0.0 "t6" 0.0 "k5" 0.0 "k6" 0.0 "t7" 0.0 "k7" 0.0 "k8" 0.0 /

"db1" 0.0 "eps" 0.0 "db2" 0.0 "gv1" 0.0 "pgv1" 0.0 "gv2" 0.0 "pgv2" 0.0 "gv3" 0.0 "pgv3" 0.0 "gv4" 0.0 /

"pgv4" 0.0 "gv5" 0.0 "pgv5" 0.0 "gv6" 0.0 "pgv6" 0.0

pss2b 96318 "BLK1_ST-1 " 13.80 "S1" : #9 "j1" 1.000000 "k1" 96322 "j2" 3.0000 "k2" 96322 "vsi1max" 999.00 "vsi1min" -999.00 "tw1" 2.0000 "tw2" 2.0000 "vsi2max" 999.00 "vsi2min" -999.00 /

"tw3" 2.0000 "tw4" 2.0000 "t6" 0.020000 "t7" 2.0000 "ks2" 0.200000 "ks3" 1.000000 "t8" 0.0 "t9" 1.000000 "n" 1.000000 "m" 5.0000 /

"ks1" 5.0000 "t1" 0.200000 "t2" 0.040000 "t3" 0.360000 "t4" 0.120000 "t10" 0.010000 "t11" 0.010000 "vstmax" 999.00 "vstmin" -999.00 "a" 1.000000 /

"ta" 0.0 "tb" 0.0 "ks4" 1.000000

genrou 96322 "BLK1_ST-2 " 13.80 "S2" : #9 mva=152.7870 "tpdo" 12.4000 "tppdo" 0.0500 "tpqo" 3.8000 "tppqo" 0.0500 "h" 1.0900 "d" 0.0000 "ld" 2.2700 /

"lq" 2.0700 "lpd" 0.1930 "lpq" 0.2300 "lppd" 0.1400 "ll" 0.0770 "s1" 0.1200 "s12" 0.4791 "ra" 0.0007 "rcomp" 0.0000 "xcomp" 0.0000 "accel" 0.0000

esac7b 96322 "BLK1_ST-2 " 13.80 "S2" : #9 "tr" 0.0 "kpr" 15.0000 "kir" 1.8800 "kdr" 0.0 "tdr" 0.005000 "vrmax" 3.2000 "vrmin" -3.2000 "kpa" 48.3800 "kia" 0.0 "vamax" 28.1400 /

"vamin" -23.3200 "kp" 1.000000 "kl" 10000.00 "te" 1.4000 "vfemax" 13.9000 "vemin" 0.0 "ke" 1.000000 "kc" 0.470000 "kd" 0.920000 "kf1" 0.0 /

"kf2" 0.150000 "kf3" 0.020000 "tf" 1.5000 "e1" 6.9000 "se1" 0.150000 "e2" 9.2000 "se2" 2.0700 "spdmlt" 0.0

ieeeg1 96322 "BLK1_ST-2 " 13.80 "S2" : #9 mwcap=142.0000 "k" 20.0000 "t1" 0.004000 "t2" 0.020000 "t3" 0.350000 "uo" 99.0000 "uc" -99.0000 "pmax" 1.000000 "pmin" 0.0 "t4" 0.060000 "k1" 1.000000 /

"k2" 0.0 "t5" 0.0 "k3" 0.0 "k4" 0.0 "t6" 0.0 "k5" 0.0 "k6" 0.0 "t7" 0.0 "k7" 0.0 "k8" 0.0 /

"db1" 0.0 "eps" 0.0 "db2" 0.0 "gv1" 0.0 "pgv1" 0.0 "gv2" 0.0 "pgv2" 0.0 "gv3" 0.0 "pgv3" 0.0 "gv4" 0.0 /

"pgv4" 0.0 "gv5" 0.0 "pgv5" 0.0 "gv6" 0.0 "pgv6" 0.0

pss2b 96322 "BLK1_ST-2 " 13.80 "S2" : #9 "j1" 1.000000 "k1" 96322 "j2" 3.0000 "k2" 96322 "vsi1max" 999.00 "vsi1min" -999.00 "tw1" 2.0000 "tw2" 2.0000 "vsi2max" 999.00 "vsi2min" -999.00 /

"tw3" 2.0000 "tw4" 2.0000 "t6" 0.020000 "t7" 2.0000 "ks2" 0.200000 "ks3" 1.000000 "t8" 0.0 "t9" 1.000000 "n" 1.000000 "m" 5.0000 /

"ks1" 5.0000 "t1" 0.200000 "t2" 0.040000 "t3" 0.360000 "t4" 0.120000 "t10" 0.010000 "t11" 0.010000 "vstmax" 999.00 "vstmin" -999.00 "a" 1.000000 /

"ta" 0.0 "tb" 0.0 "ks4" 1.000000

Metro Area Single Contingencies (N-1)

No.	Contingency Description
1.	SANLUSRY to S.ONOFRE 230.0 kV No.1
2.	SANLUSRY to S.ONOFRE 230.0 kV No.2
3.	SANLUSRY to S.ONOFRE 230.0 kV No.3
4.	TALEGA to S.ONOFRE 230.0 kV No.1
5.	TALEGA to S.ONOFRE 230.0 kV No.1B
6.	TALEGA to S.ONOFRE 230.0 kV No.2
7.	TALEGA to S.ONOFRE 230.0 kV No.2B
8.	ALMITOSE to BARRE 230.0 kV No.1
9.	ALMITOSE to CENTER S 230.0 kV No.1
10.	ALMITOSW to BARRE 230.0 kV No.2
11.	ALMITOSW to LITEHIPE 230.0 kV No.1
12.	ARCO SC to HINSON 230.0 kV No.1
13.	ARCO SC to HINSON 230.0 kV No.2
14.	BARRE to ELLIS 230.0 kV No.1
15.	BARRE to VILLA PK 230.0 kV No.1
16.	BARRE to LEWIS 230.0 kV No.1
17.	CAMINO to MEAD S 230.0 kV No.E
18.	CAMINO to MEAD S 230.0 kV No.W
19.	CAMINO to GENE 230.0 kV No.1
20.	CENTER S to MESA CAL 230.0 kV No.1
21.	CENTER S to OLINDA 230.0 kV No.1
22.	CHINO to MIRALOMW 230.0 kV No.1
23.	CHINO to MIRALOMW 230.0 kV No.2
24.	CHINO to SERRANO 230.0 kV No.1
25.	CHINO to MIRALOME 230.0 kV No.3
26.	DELAMO to CENTER S 230.0 kV No.1
27.	DELAMO to ELLIS 230.0 kV No.1
28.	DELAMO to LAGUBELL 230.0 kV No.1
29.	EAGLROCK to GOULD 230.0 kV No.1
30.	EAGLROCK to MESA CAL 230.0 kV No.1
31.	EAGLROCK to PARDEE 230.0 kV No.1
32.	EAGLROCK to SYLMAR S 230.0 kV No.1
33.	EL NIDO to LA FRESA 230.0 kV No.3
34.	EL NIDO to LA FRESA 230.0 kV No.4
35.	EL NIDO to LCIENEGA 230.0 kV No.1
36.	EL NIDO to CHEVMAIN 230.0 kV No.1
37.	ELLIS to HUNTGBCH 230.0 kV No.1

38.	ELLIS to HUNTGBCH 230.0 kV No.3
39.	ELLIS to JOHANNA 230.0 kV No.1
40.	ELLIS to SANTIAGO 230.0 kV No.1
41.	ELLIS to HUNTBCH1 230.0 kV No.2
42.	ELLIS to HUNTBCH1 230.0 kV No.4
43.	ELSEGNDO to EL NIDO 230.0 kV No.1
44.	ELSEGNDO to CHEVMAIN 230.0 kV No.1
45.	ETIWANDA to MIRALOME 230.0 kV No.1
46.	HARBOR to HINSON 230.0 kV No.1
47.	HARBOR to LBEACH 230.0 kV No.1
48.	HINSON to DELAMO 230.0 kV No.1
49.	JOHANNA to SANTIAGO 230.0 kV No.1
50.	LA FRESA to HINSON 230.0 kV No.1
51.	LA FRESA to LAGUBELL 230.0 kV No.1
52.	LA FRESA to REDONDO 230.0 kV No.1
53.	LA FRESA to REDONDO 230.0 kV No.2
54.	LAGUBELL to RIOHONDO 230.0 kV No.1
55.	LBEACH to LITEHIPE 230.0 kV No.1
56.	LCIENEGA to LA FRESA 230.0 kV No.1
57.	LITEHIPE to HINSON 230.0 kV No.1
58.	LITEHIPE to MESA CAL 230.0 kV No.1
59.	MESA CAL to REDONDO 230.0 kV No.1
60.	MESA CAL to RIOHONDO 230.0 kV No.1
61.	MESA CAL to VINCENT 230.0 kV No.2
62.	MESA CAL to WALNUT 230.0 kV No.1
63.	MIRALOMA to SERRANO 500.0 kV No.1
64.	MIRALOMA to SERRANO 500.0 kV No.2
65.	MIRALOMW to WALNUT 230.0 kV No.1
66.	MIRALOMW to VSTA 230.0 kV No.1
67.	MOORPARK to ORMOND 230.0 kV No.1
68.	MOORPARK to ORMOND 230.0 kV No.2
69.	MOORPARK to ORMOND 230.0 kV No.3
70.	MOORPARK to ORMOND 230.0 kV No.4
71.	OLINDA to WALNUT 230.0 kV No.1
72.	REDONDO to LITEHIPE 230.0 kV No.1
73.	RIOHONDO to VINCENT 230.0 kV No.2
74.	S.ONOFRE to SANTIAGO 230.0 kV No.1
75.	S.ONOFRE to SANTIAGO 230.0 kV No.2
76.	S.ONOFRE to SERRANO 230.0 kV No.1
77.	SERRANO to VILLA PK 230.0 kV No.1
78.	SERRANO to VILLA PK 230.0 kV No.2

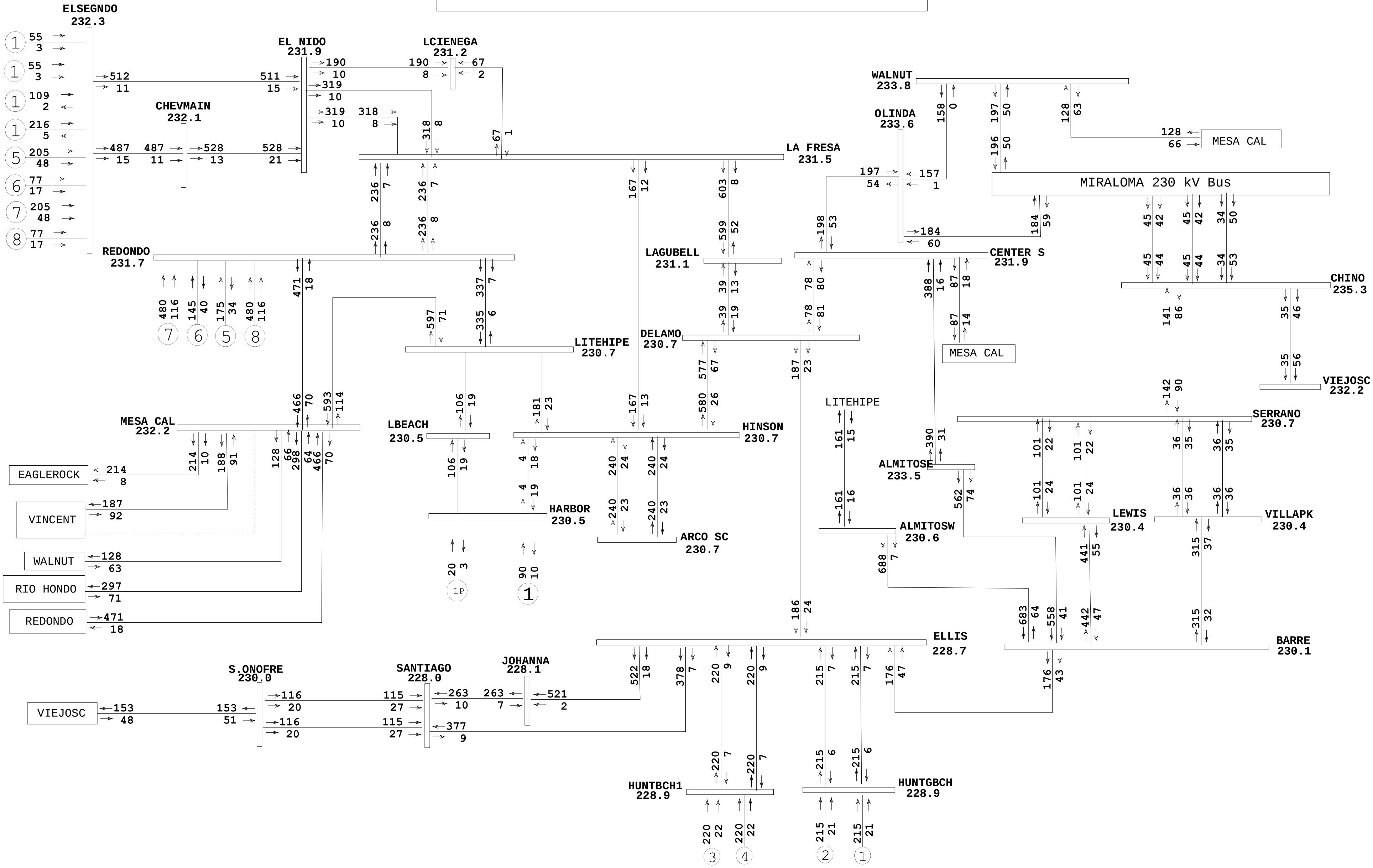
79.	SERRANO to VALLEYSC 500.0 kV No.1
80.	SYLMAR S to GOULD 230.0 kV No.1
81.	VINCENT to MESA CAL 230.0 kV No.1
82.	VINCENT to RIOHONDO 230.0 kV No.1
83.	VINCENT to S.CLARA 230.0 kV No.1
84.	VINCENT to MIRALOMA 500.0 kV No.1
85.	VINCENT to VINCTSVC 500.0 kV No.1
86.	RANCHVST to SERRANO 500.0 kV No.1
87.	RANCHVST to MIRALOME 230.0 kV No.1
88.	RANCHVST to MIRALOME 230.0 kV No.2
89.	GOODRICH to GOULD 230.0 kV No.1
90.	GOODRICH to LAGUBELL 230.0 kV No.1
91.	LEWIS to SERRANO 230.0 kV No.1
92.	LEWIS to SERRANO 230.0 kV No.2
93.	LEWIS to VILLA PK 230.0 kV No.1
94.	VIEJOSC to CHINO 230.0 kV No.1
95.	VIEJOSC to S.ONOFRE 230.0 kV No.1
96.	MIRALOME to OLINDA 230.0 kV No.1
97.	MIRALOME to PADUA 230.0 kV No.1
98.	MIRALOME to VSTA 230.0 kV No.2
99.	SYLMAR1 to SYLMAR S 230.0 kV No.1
100.	SERRANO to ALBERHL5 500.0 kV No.1
101.	ALBERHL5 to VALLEYSC 500.0 kV No.1
102.	ALBERHL5 to LEAPS-MP 500.0 kV No.1

Metro Area Single Contingencies (N-2)

No.	Contingency Description
1.	ALMITOSE to BARRE 230.0 kV No.1 & ALMITOSW to BARRE 230.0 kV No.2
2.	ALMITOSE to CENTER S 230.0 kV No.1 & ALMITOSW to BARRE 230.0 kV No.2
3.	ALMITOSE to CENTER S 230.0 kV No.1 & ALMITOSW to LITEHIPE 230.0 kV No.1
4.	ALMITOSE to CENTER S 230.0 kV No.1 & DELAMO to CENTER S 230.0 kV No.1
5.	ALMITOSW to BARRE 230.0 kV No.2 & DELAMO to ELLIS 230.0 kV No.1
6.	ALMITOSW to LITEHIPE 230.0 kV No.1 & HINSON to DELAMO 230.0 kV No.1
7.	BARRE to ELLIS 230.0 kV No.1 & DELAMO to ELLIS 230.0 kV No.1
8.	BARRE to VILLA PK 230.0 kV No.1 & BARRE to LEWIS 230.0 kV No.1
9.	BARRE to VILLA PK 230.0 kV No.1 & LEWIS to VILLA PK 230.0 kV No.1
10.	CENTER S to MESA CAL 230.0 kV No.1 & CENTER S to OLINDA 230.0 kV No.1
11.	CENTER S to MESA CAL 230.0 kV No.1 & MESA CAL to WALNUT 230.0 kV No.1
12.	CENTER S to OLINDA 230.0 kV No.1 & MESA CAL to WALNUT 230.0 kV No.1
13.	CENTER S to OLINDA 230.0 kV No.1 & OLINDA to WALNUT 230.0 kV No.1
14.	CHINO to MIRALOMW 230.0 kV No.1 & CHINO to MIRALOMW 230.0 kV No.2
15.	CHINO to MIRALOMW 230.0 kV No.2 & CHINO to MIRALOME 230.0 kV No.3
16.	CHINO to SERRANO 230.0 kV No.1 & S.ONOFRE to SERRANO 230.0 kV No.1
17.	CHINO to SERRANO 230.0 kV No.1 & VIEJOSC to CHINO 230.0 kV No.1
18.	DELAMO to LAGUBELL 230.0 kV No.1 & HINSON to DELAMO 230.0 kV No.1
19.	DELAMO to LAGUBELL 230.0 kV No.1 & LITEHIPE to MESA CAL 230.0 kV No.1
20.	EL NIDO to LA FRESA 230.0 kV No.3 & EL NIDO to LA FRESA 230.0 kV No.4
21.	EL NIDO to LCIENEGA 230.0 kV No.1 & LCIENEGA to LA FRESA 230.0 kV No.1
22.	EL NIDO to CHEVMAIN 230.0 kV No.1 & ELSEGNDO to EL NIDO 230.0 kV No.1
23.	ELLIS to HUNTGBCH 230.0 kV No.1 & ELLIS to HUNTBCH1 230.0 kV No.2
24.	ELLIS to HUNTGBCH 230.0 kV No.3 & ELLIS to HUNTBCH1 230.0 kV No.2
25.	ELLIS to HUNTGBCH 230.0 kV No.3 & ELLIS to HUNTBCH1 230.0 kV No.4
26.	ELLIS to JOHANNA 230.0 kV No.1 & ELLIS to SANTIAGO 230.0 kV No.1
27.	ELLIS to SANTIAGO 230.0 kV No.1 & JOHANNA to SANTIAGO 230.0 kV No.1
28.	ELSEGNDO to EL NIDO 230.0 kV No.1 & ELSEGNDO to CHEVMAIN 230.0 kV No.1
29.	HARBOR to HINSON 230.0 kV No.1 & LBEACH to LITEHIPE 230.0 kV No.1
30.	HINSON to DELAMO 230.0 kV No.1 & LA FRESA to HINSON 230.0 kV No.1
31.	HINSON to DELAMO 230.0 kV No.1 & LITEHIPE to HINSON 230.0 kV No.1
32.	LA FRESA to HINSON 230.0 kV No.1 & LA FRESA to LAGUBELL 230.0 kV No.1
33.	LA FRESA to HINSON 230.0 kV No.1 & REDONDO to LITEHIPE 230.0 kV No.1
34.	LA FRESA to LAGUBELL 230.0 kV No.1 & LITEHIPE to MESA CAL 230.0 kV No.1
35.	LA FRESA to LAGUBELL 230.0 kV No.1 & MESA CAL to REDONDO 230.0 kV No.1
36.	LA FRESA to LAGUBELL 230.0 kV No.1 & REDONDO to LITEHIPE 230.0 kV No.1
37.	LA FRESA to REDONDO 230.0 kV No.1 & LA FRESA to REDONDO 230.0 kV No.2

38.	LA FRESA to REDONDO 230.0 kV No.2 & MESA CAL to REDONDO 230.0 kV No.1
39.	LAGUBELL to RIOHONDO 230.0 kV No.1 & LITEHIPE to MESA CAL 230.0 kV No.1
40.	LAGUBELL to RIOHONDO 230.0 kV No.1 & MESA CAL to RIOHONDO 230.0 kV No.1
41.	LBEACH to LITEHIPE 230.0 kV No.1 & LITEHIPE to HINSON 230.0 kV No.1
42.	LITEHIPE to MESA CAL 230.0 kV No.1 & GOODRICH to LAGUBELL 230.0 kV No.1
43.	MESA CAL to REDONDO 230.0 kV No.1 & REDONDO to LITEHIPE 230.0 kV No.1
44.	MESA CAL to REDONDO 230.0 kV No.1 & GOODRICH to LAGUBELL 230.0 kV No.1
45.	MESA CAL to RIOHONDO 230.0 kV No.1 & MESA CAL to WALNUT 230.0 kV No.1
46.	MESA CAL to WALNUT 230.0 kV No.1 & OLINDA to WALNUT 230.0 kV No.1
47.	MIRALOMA to SERRANO 500.0 kV No.1 & MIRALOMA to SERRANO 500.0 kV No.2
48.	MIRALOMA to SERRANO 500.0 kV No.1 & MIRALOME to OLINDA 230.0 kV No.1
49.	MIRALOMW to WALNUT 230.0 kV No.1 & OLINDA to WALNUT 230.0 kV No.1
50.	MIRALOMW to WALNUT 230.0 kV No.1 & MIRALOME to OLINDA 230.0 kV No.1
51.	MOORPARK to ORMOND 230.0 kV No.1 & MOORPARK to ORMOND 230.0 kV No.2
52.	MOORPARK to ORMOND 230.0 kV No.2 & MOORPARK to ORMOND 230.0 kV No.3
53.	MOORPARK to ORMOND 230.0 kV No.3 & MOORPARK to ORMOND 230.0 kV No.4
54.	OLINDA to WALNUT 230.0 kV No.1 & MIRALOME to OLINDA 230.0 kV No.1
55.	RIOHONDO to VINCENT 230.0 kV No.2 & VINCENT to RIOHONDO 230.0 kV No.1
56.	S.ONOFRE to SANTIAGO 230.0 kV No.1 & S.ONOFRE to SANTIAGO 230.0 kV No.2
57.	S.ONOFRE to SANTIAGO 230.0 kV No.2 & S.ONOFRE to SERRANO 230.0 kV No.1
58.	S.ONOFRE to SERRANO 230.0 kV No.1 & SERRANO to VALLEYSC 500.0 kV No.1
59.	S.ONOFRE to SERRANO 230.0 kV No.1 & VIEJOSC to CHINO 230.0 kV No.1
60.	S.ONOFRE to SERRANO 230.0 kV No.1 & VIEJOSC to S.ONOFRE 230.0 kV No.1
61.	SERRANO to VILLA PK 230.0 kV No.1 & SERRANO to VILLA PK 230.0 kV No.2
62.	SERRANO to VILLA PK 230.0 kV No.2 & LEWIS to SERRANO 230.0 kV No.2
63.	RANCHVST to MIRALOME 230.0 kV No.1 & RANCHVST to MIRALOME 230.0 kV No.2
64.	LEWIS to SERRANO 230.0 kV No.1 & LEWIS to SERRANO 230.0 kV No.2
65.	LEWIS to SERRANO 230.0 kV No.1 & LEWIS to VILLA PK 230.0 kV No.1

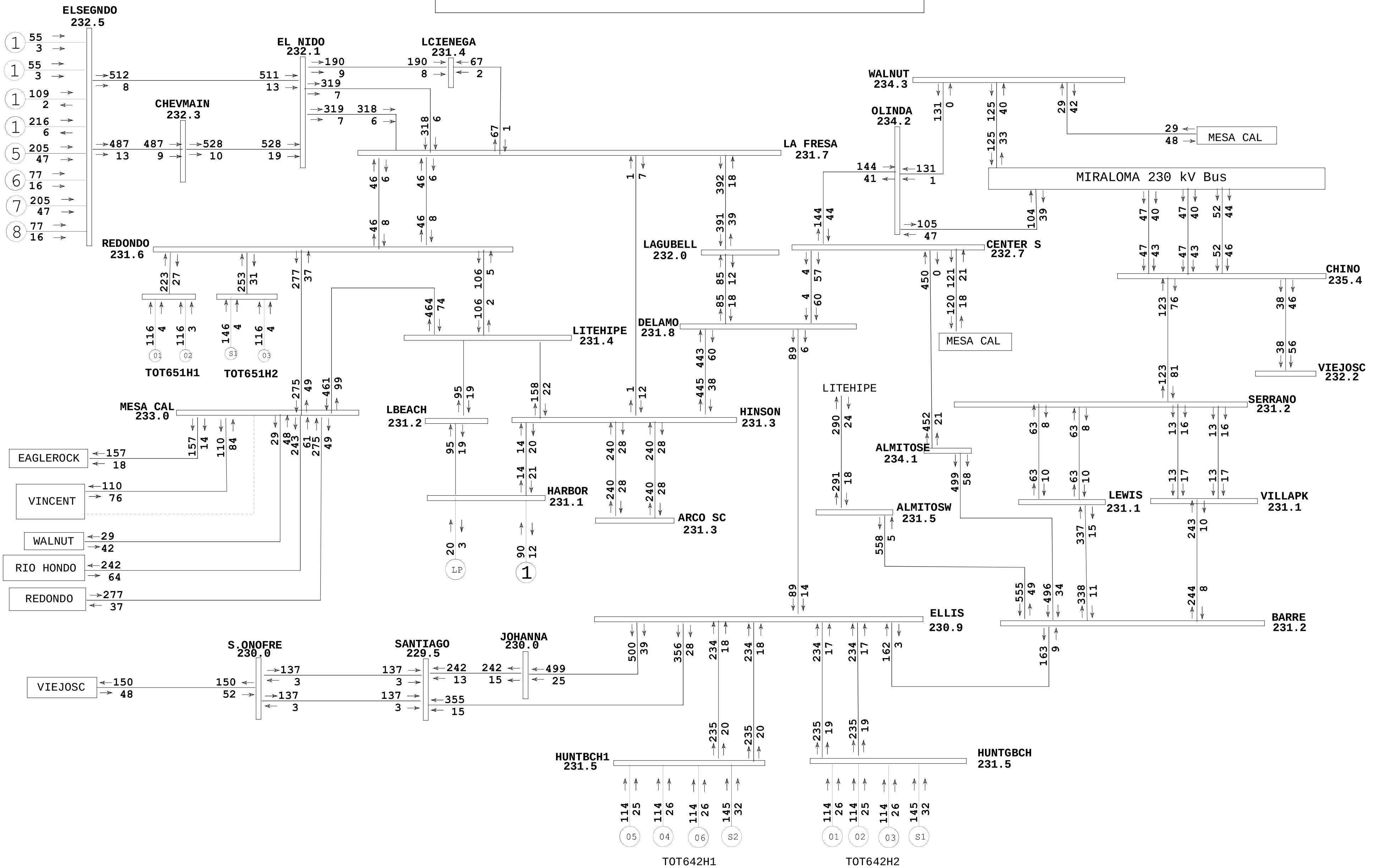
SCE Metro Area 230 kV System



General Electric International, Inc. PSLF Program Mon Jan 07 15:38:04 2013 c:\projects\18\metro-qc5\stability\Pre-16op-Metro_QC5P1-4.sav

2016 Off Peak Base Case SCE Metro Bulk System Study, Queue Cluster 5 Phase 1 Case		MW/MVAR Rating = 1

SCE Metro Area 230 kV System



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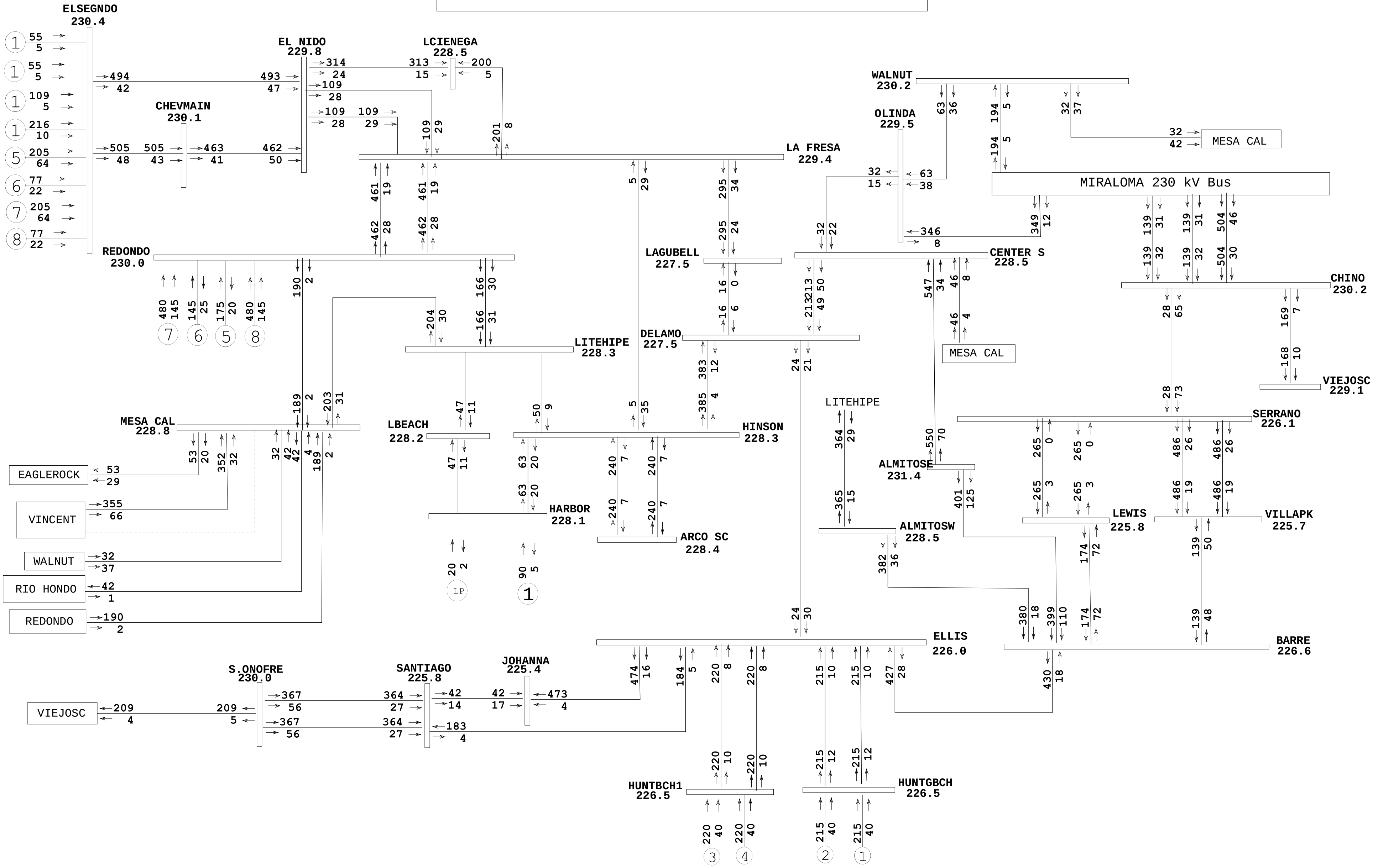
2016 Off Peak Base Case

SCE Metro Bulk System Study, Queue Cluster 5 Phase 1 Case

MW/MVAR

Rating =   1

SCE Metro Area 230 kV System



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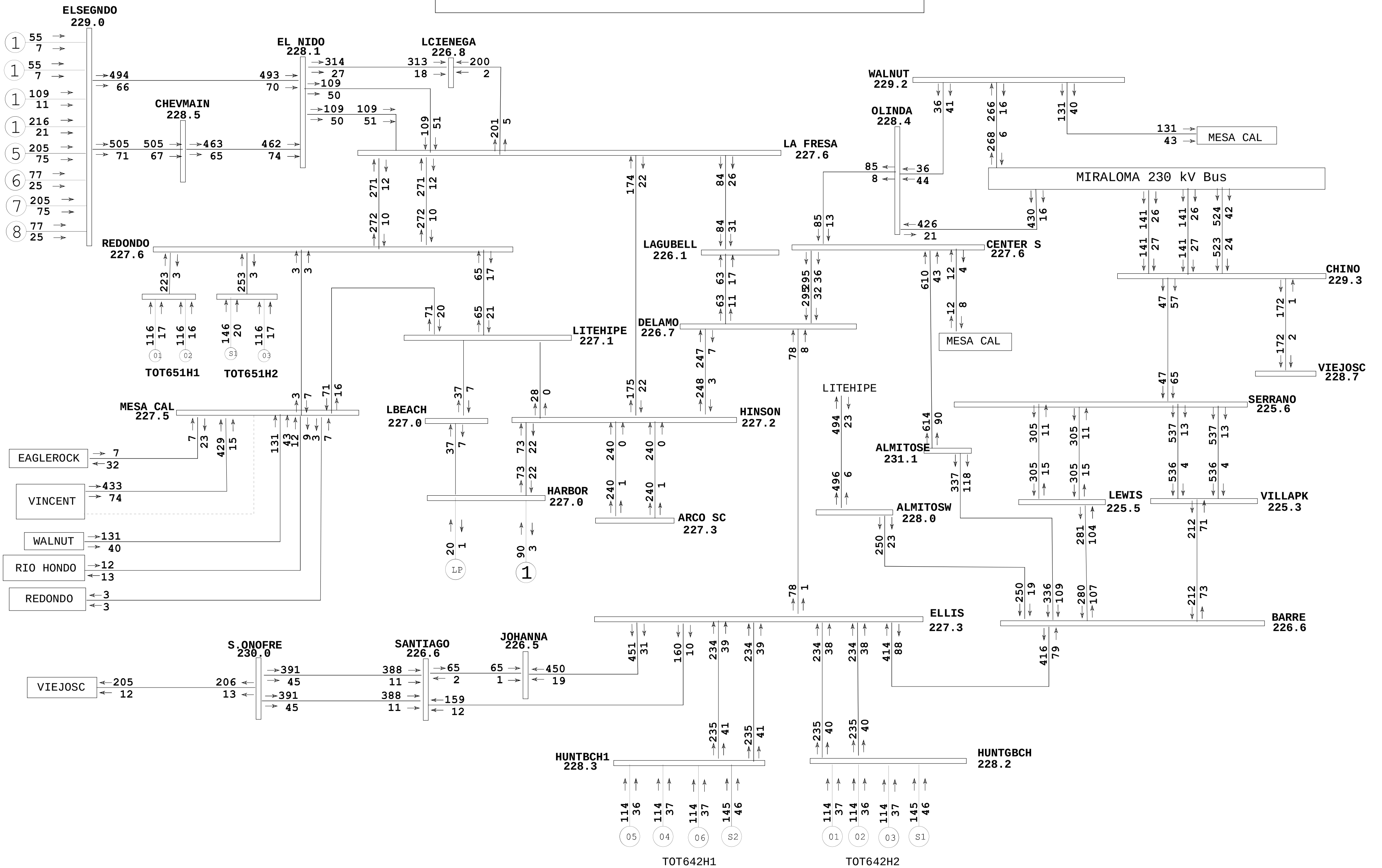
2016 Peak Base Case

SCE Metro Bulk System Study, Queue Cluster 5 Phase 1 Case

MW/MVAR

Rating = 1

SCE Metro Area 230 kV System



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2016 Peak Base Case

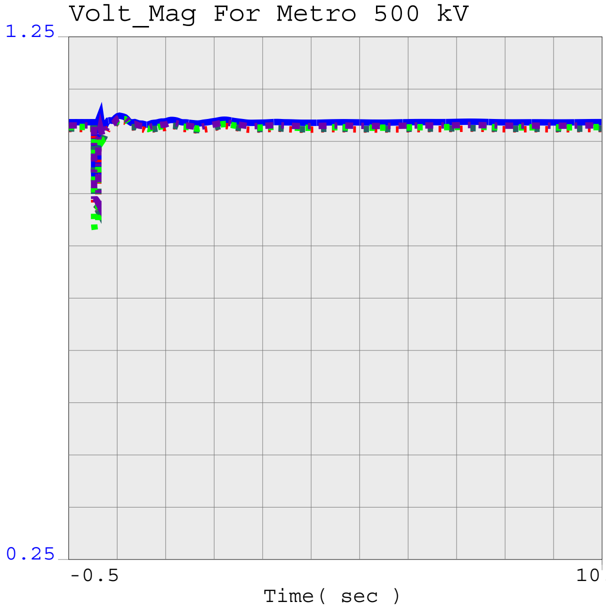
SCE Metro Bulk System Study, Queue Cluster 5 Phase 1 Case

MW/MVAR

Rating = 1

QUEUE CLUSTER 5 PHASE 1 TRANSIENT STABILITY

Volt_Mag For Metro 500 kV



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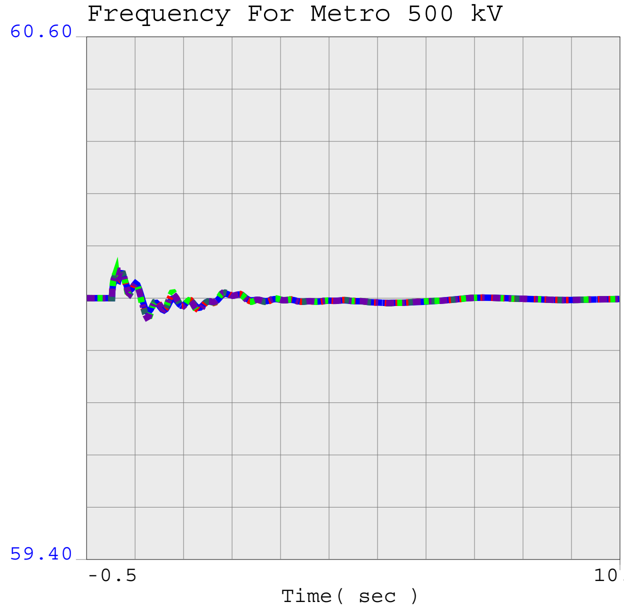
0.2500	vbus	24092	MIRALOMA 500.0	0	0.0	1	1	1.2500
0.2500	vbus	24236	RANCHVST 500.0	0	0.0	1	1	1.2500
0.2500	vbus	24138	SERRANO 500.0	0	0.0	1	1	1.2500
0.2500	vbus	24151	VALLEYSC 500.0	0	0.0	1	1	1.2500

Frequency For Metro 500 kV



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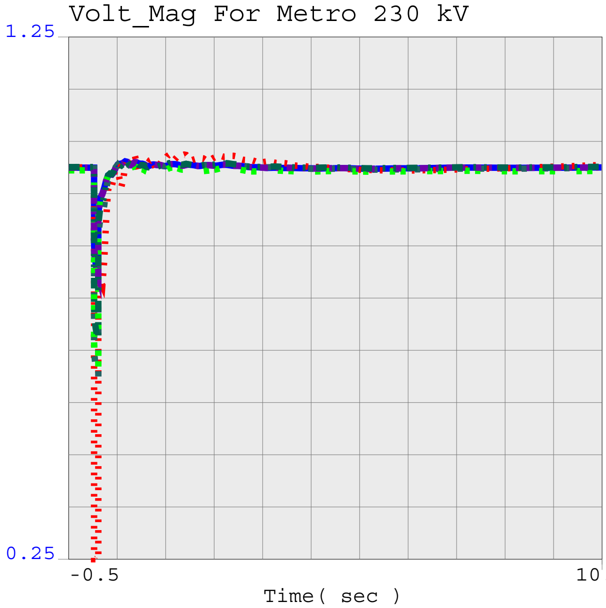
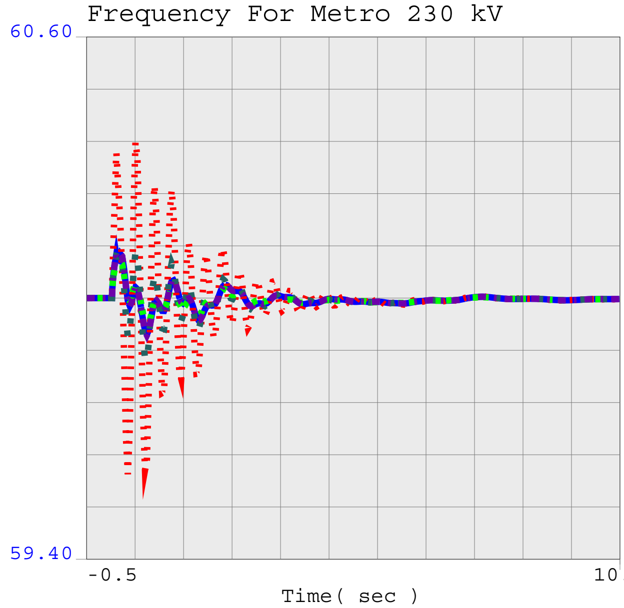
59.4000	fbus	24092	MIRALOMA 500.0	0	0.0	1	1	60.6000
59.4000	fbus	24236	RANCHVST 500.0	0	0.0	1	1	60.6000
59.4000	fbus	24138	SERRANO 500.0	0	0.0	1	1	60.6000
59.4000	fbus	24151	VALLEYSC 500.0	0	0.0	1	1	60.6000

Volt_Mag For Metro 230 kV



0.2500	vbus	24125	REDONDO 230.0	0	0.0	1	1	1.2500
0.2500	vbus	24044	ELLIS 230.0	0	0.0	1	1	1.2500
0.2500	vbus	24029	DELAMO 230.0	0	0.0	1	1	1.2500
0.2500	vbus	25201	LEWIS 230.0	0	0.0	1	1	1.2500
0.2500	vbus	24074	LA FRESA 230.0	0	0.0	1	1	1.2500
0.2500	vbus	24021	CENTER S 230.0	0	0.0	1	1	1.2500

Frequency For Metro 230 kV



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59.4000	fbus	24029	DELAMO 230.0	0	0.0	1	1	60.6000
59.4000	fbus	25201	LEWIS 230.0	0	0.0	1	1	60.6000
59.4000	fbus	24074	LA FRESA 230.0	0	0.0	1	1	60.6000

QC5 METRO AREA
Heavy Spring Conditions

QC5-hsp-pst-v4_Barre-Ellis-slo.chf

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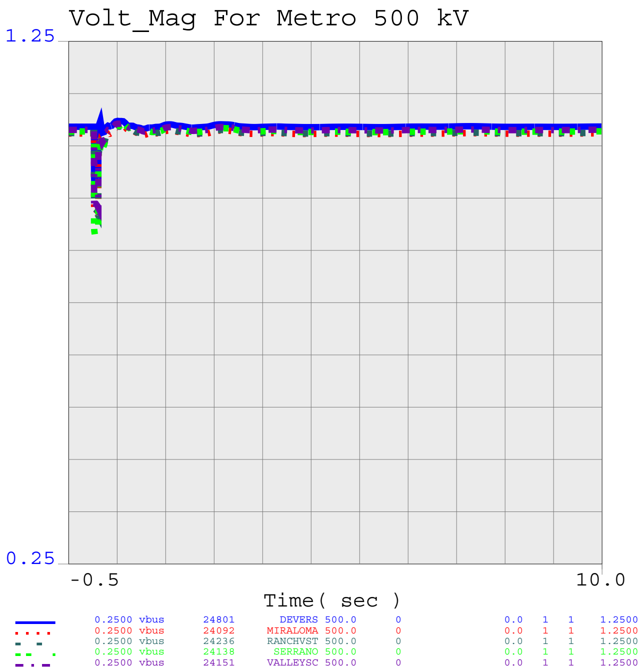
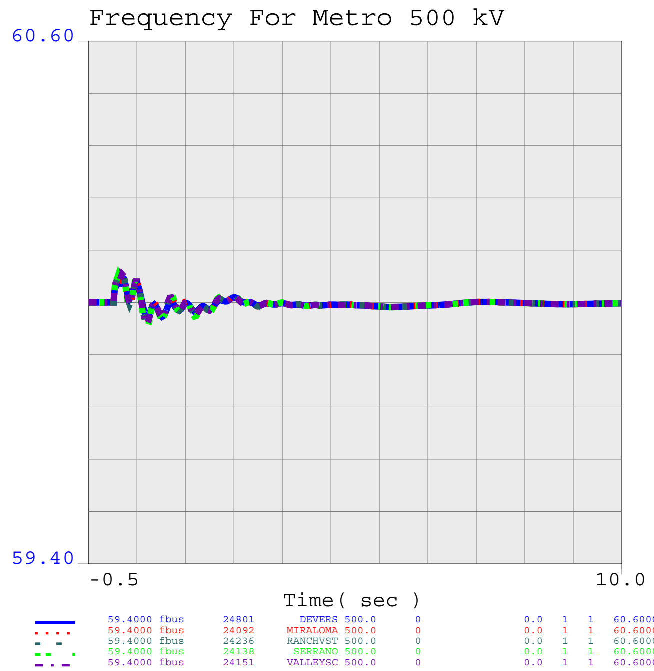
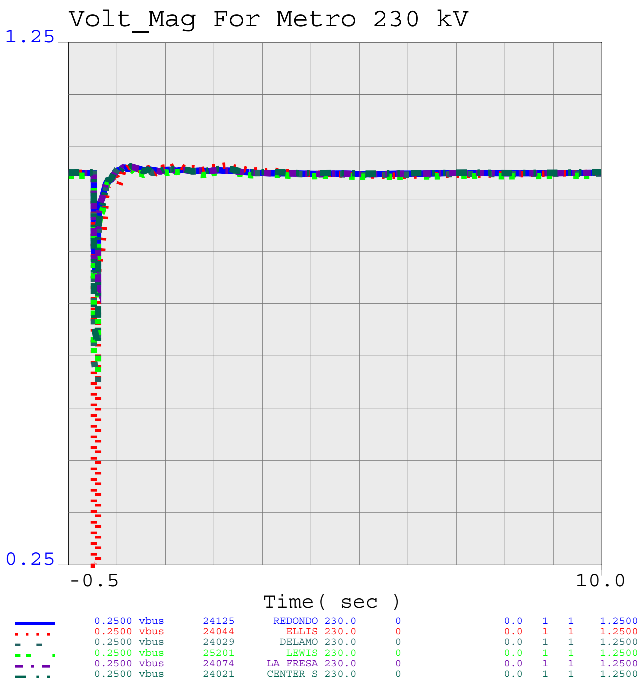
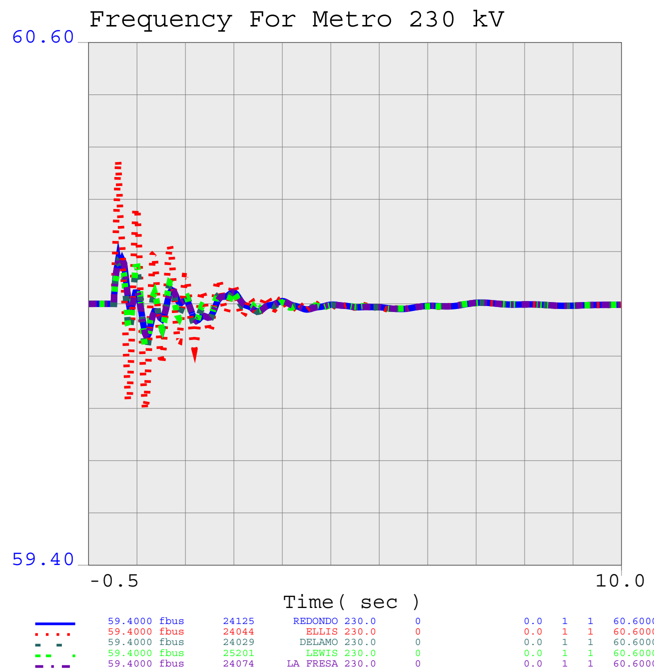
Thu Jan 17 11:05:13 2013

QUEUE CLUSTER 5 PHASE 1 TRANSIENT STABILITY









QC5 METRO AREA
Heavy Spring Conditions

QC5-hsp-pst-v4_Ellis-Huntgbch-1.chf

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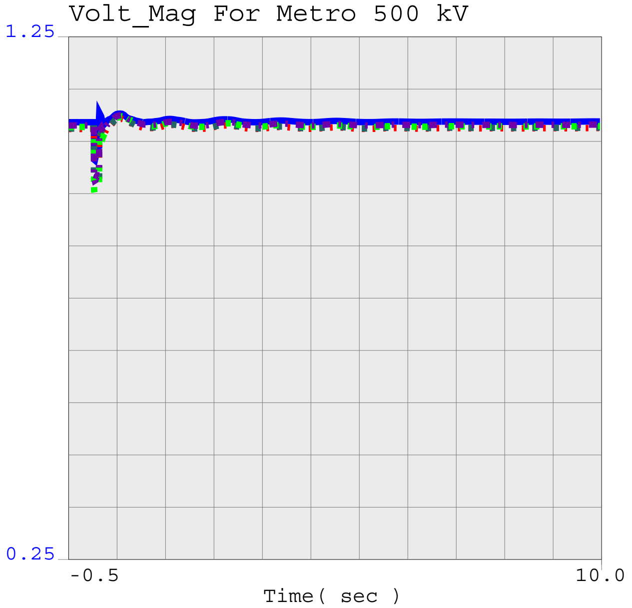
Thu Jan 17 10:54:24 2013

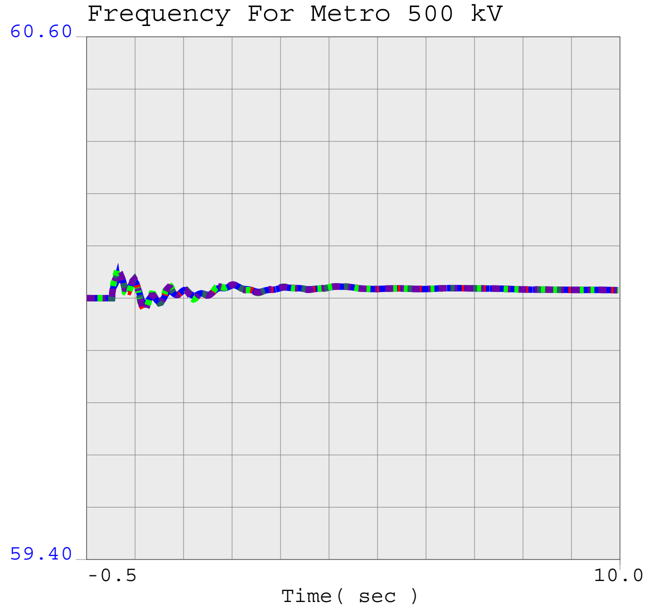
QUEUE CLUSTER 5 PHASE 1 TRANSIENT STABILITY

Volt_Mag For Metro 500 kV



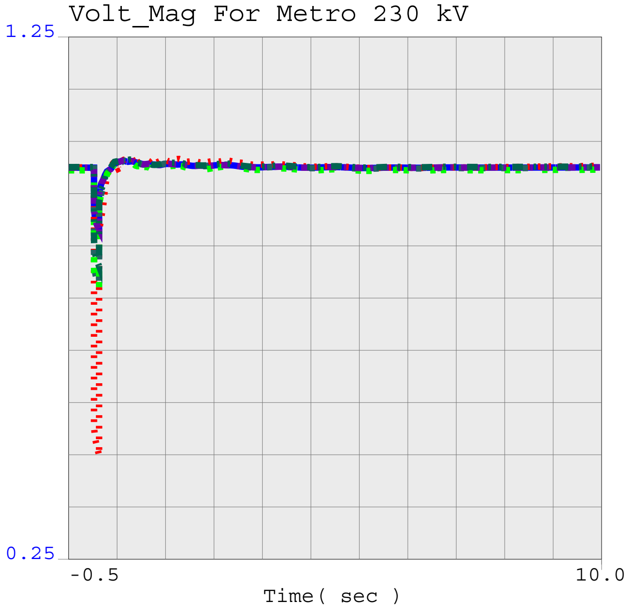
0.2500 vbus 24801 DEVERS 500.0 0 0.0 1 1 1.2500
0.2500 vbus 24092 MIRALOMA 500.0 0 0.0 1 1 1.2500
0.2500 vbus 24236 RANCHVST 500.0 0 0.0 1 1 1.2500
0.2500 vbus 24138 SERRANO 500.0 0 0.0 1 1 1.2500
0.2500 vbus 24151 VALLEYSC 500.0 0 0.0 1 1 1.2500

Frequency For Metro 500 kV



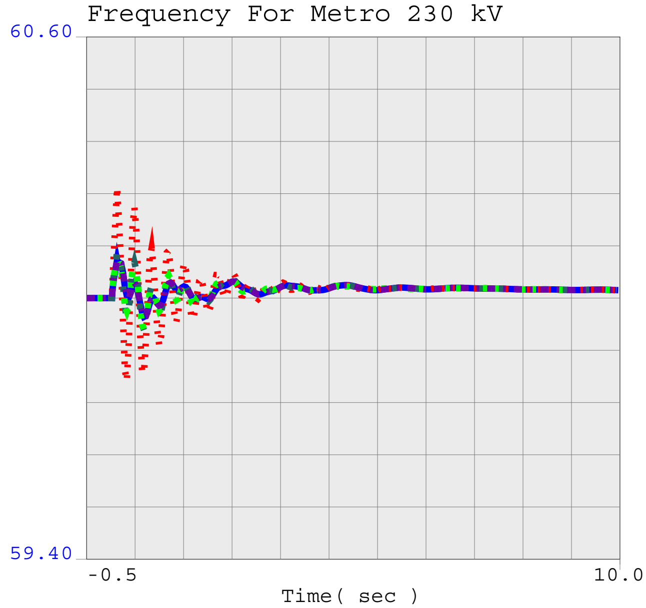
59.4000 fbus 24801 DEVERS 500.0 0 0.0 1 1 60.6000
59.4000 fbus 24092 MIRALOMA 500.0 0 0.0 1 1 60.6000
59.4000 fbus 24236 RANCHVST 500.0 0 0.0 1 1 60.6000
59.4000 fbus 24138 SERRANO 500.0 0 0.0 1 1 60.6000
59.4000 fbus 24151 VALLEYSC 500.0 0 0.0 1 1 60.6000

Volt_Mag For Metro 230 kV



0.2500 vbus 24125 REDONDO 230.0 0 0.0 1 1 1.2500
0.2500 vbus 24044 ELLIS 230.0 0 0.0 1 1 1.2500
0.2500 vbus 24029 DELAMO 230.0 0 0.0 1 1 1.2500
0.2500 vbus 25201 LEWIS 230.0 0 0.0 1 1 1.2500
0.2500 vbus 24074 LA FRESA 230.0 0 0.0 1 1 1.2500
0.2500 vbus 24021 CENTER S 230.0 0 0.0 1 1 1.2500

Frequency For Metro 230 kV



59.4000 fbus 24125 REDONDO 230.0 0 0.0 1 1 60.6000
59.4000 fbus 24044 ELLIS 230.0 0 0.0 1 1 60.6000
59.4000 fbus 24029 DELAMO 230.0 0 0.0 1 1 60.6000
59.4000 fbus 25201 LEWIS 230.0 0 0.0 1 1 60.6000
59.4000 fbus 24074 LA FRESA 230.0 0 0.0 1 1 60.6000

QC5 METRO AREA
Heavy Spring Conditions

QC5-hsp-pst-v4_Ellis-Santiago-Johanna-dlo.chf

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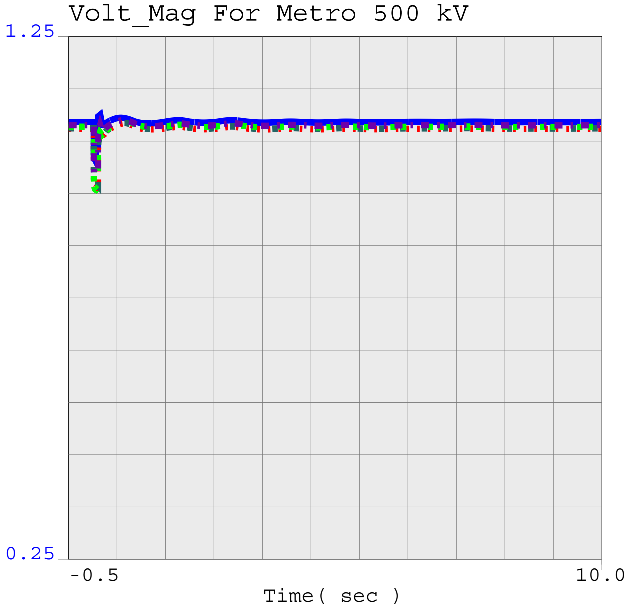
Thu Jan 17 10:55:51 2013

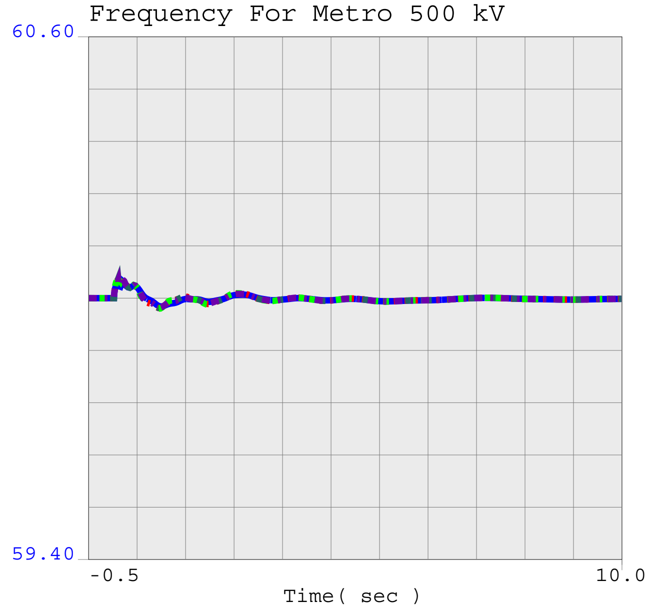
QUEUE CLUSTER 5 PHASE 1 TRANSIENT STABILITY

Volt_Mag For Metro 500 kV



0.2500	vbus	24801	DEVERS 500.0	0	0.0	1	1	1.2500
0.2500	vbus	24092	MIRALOMA 500.0	0	0.0	1	1	1.2500
0.2500	vbus	24236	RANCHVST 500.0	0	0.0	1	1	1.2500
0.2500	vbus	24138	SERRANO 500.0	0	0.0	1	1	1.2500
0.2500	vbus	24151	VALLEYSC 500.0	0	0.0	1	1	1.2500

Frequency For Metro 500 kV



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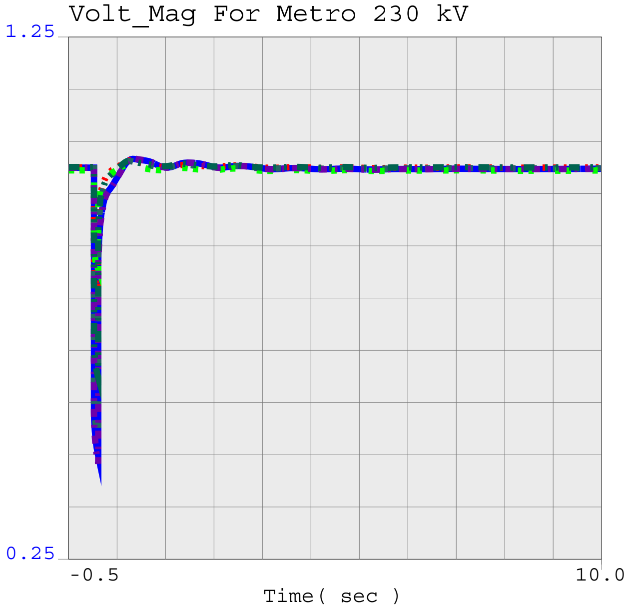
59.4000	fbus	24236	RANCHVST 500.0	0	0.0	1	1	60.6000
59.4000	fbus	24138	SERRANO 500.0	0	0.0	1	1	60.6000
59.4000	fbus	24151	VALLEYSC 500.0	0	0.0	1	1	60.6000

Volt_Mag For Metro 230 kV



0.2500	vbus	24125	REDONDO 230.0	0	0.0	1	1	1.2500
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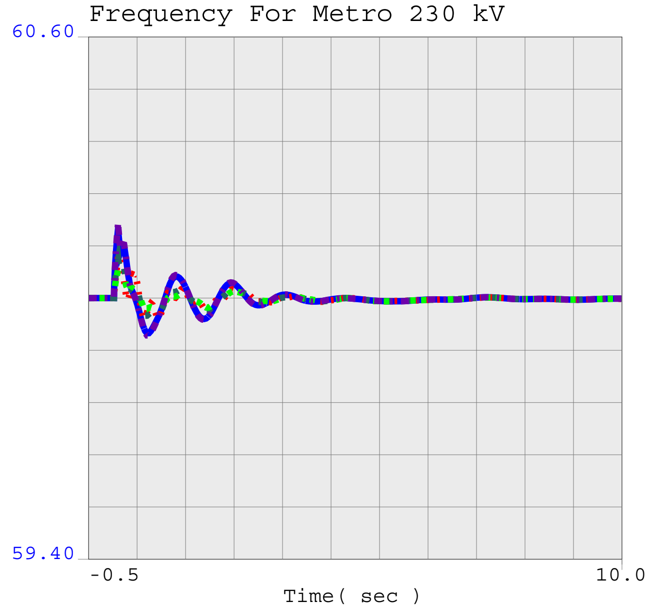
0.2500	vbus	24029	DELAMO 230.0	0	0.0	1	1	1.2500
0.2500	vbus	25201	LEWIS 230.0	0	0.0	1	1	1.2500
0.2500	vbus	24074	LA FRESA 230.0	0	0.0	1	1	1.2500
0.2500	vbus	24021	CENTER S 230.0	0	0.0	1	1	1.2500

Frequency For Metro 230 kV



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59.4000	fbus	24029	DELAMO 230.0	0	0.0	1	1	60.6000
59.4000	fbus	25201	LEWIS 230.0	0	0.0	1	1	60.6000
59.4000	fbus	24074	LA FRESA 230.0	0	0.0	1	1	60.6000

QC5 METRO AREA
Heavy Spring Conditions

QC5-hsp-pst-v4_Hinson-Hinson-DelAmo-Litehipe-Hinson.chf

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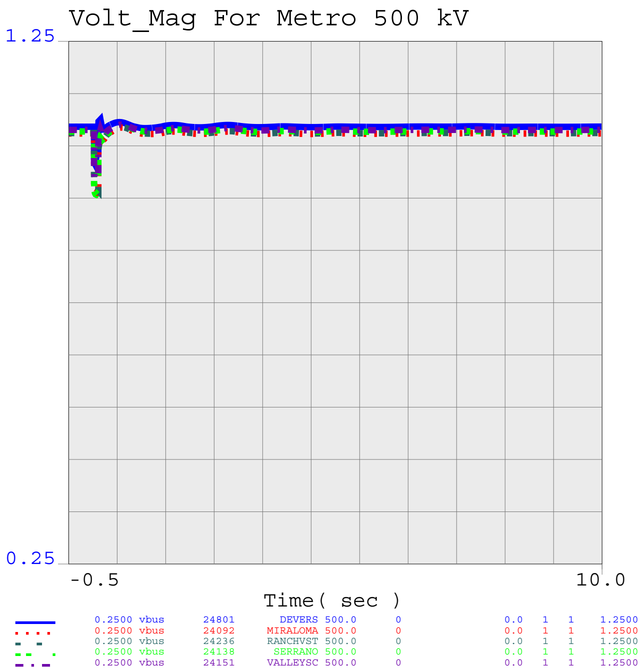
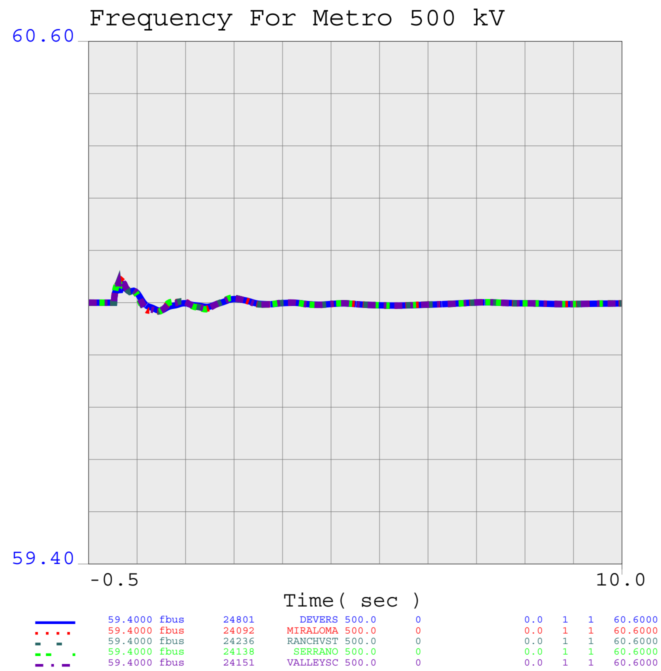
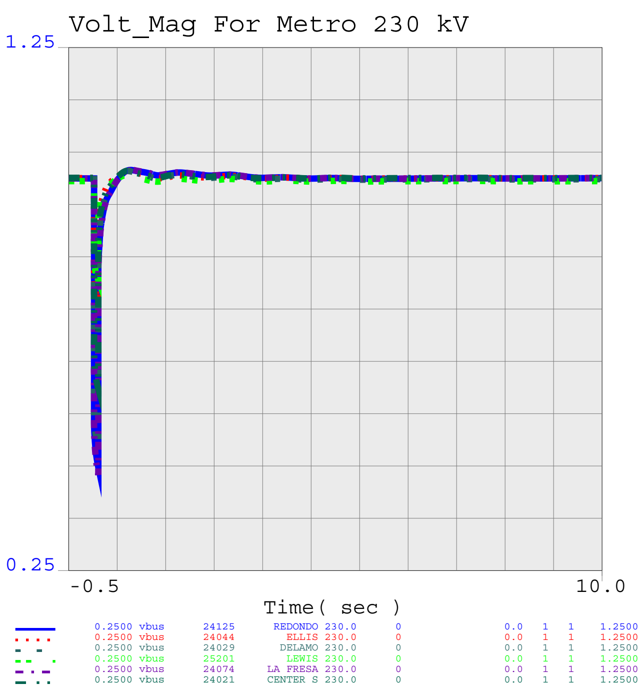
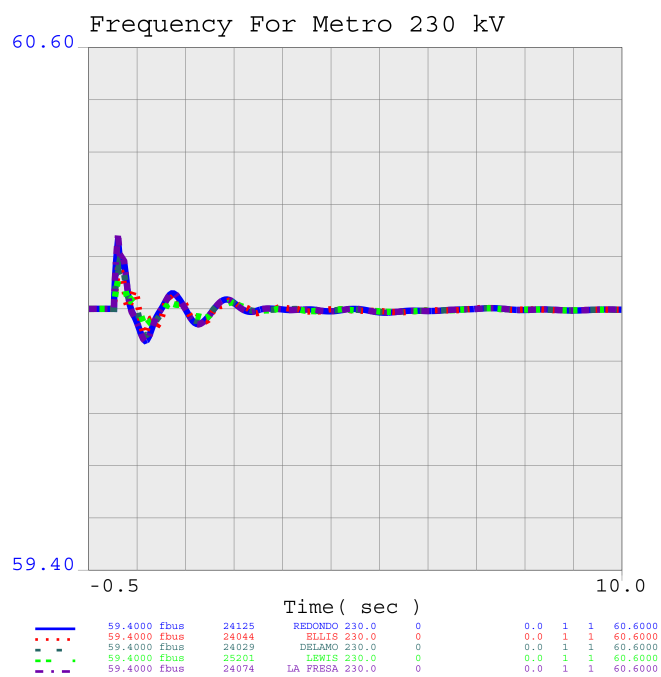
Thu Jan 17 10:57:14 2013

QUEUE CLUSTER 5 PHASE 1 TRANSIENT STABILITY





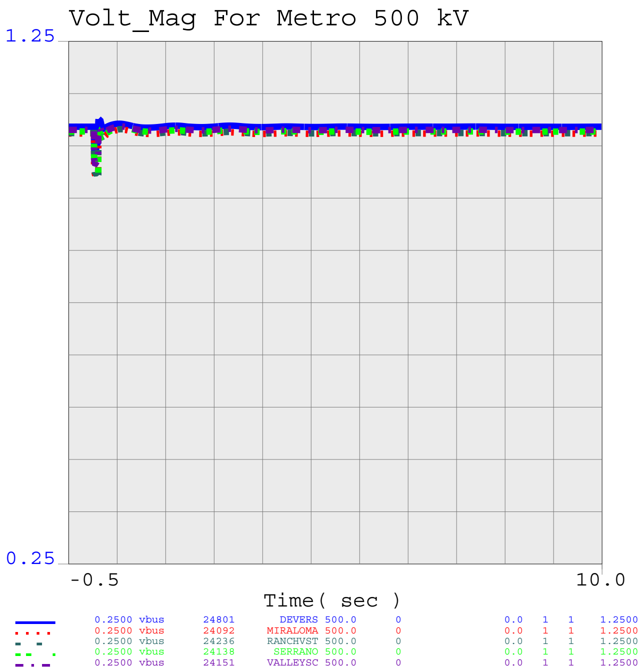


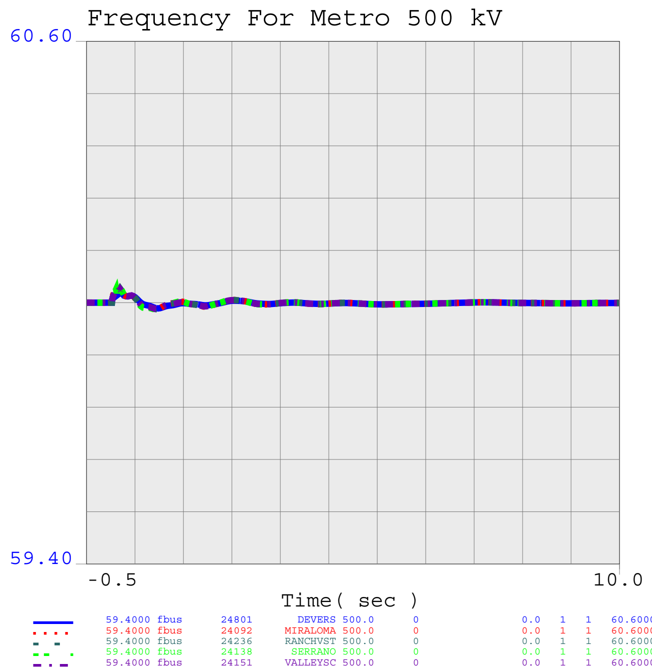


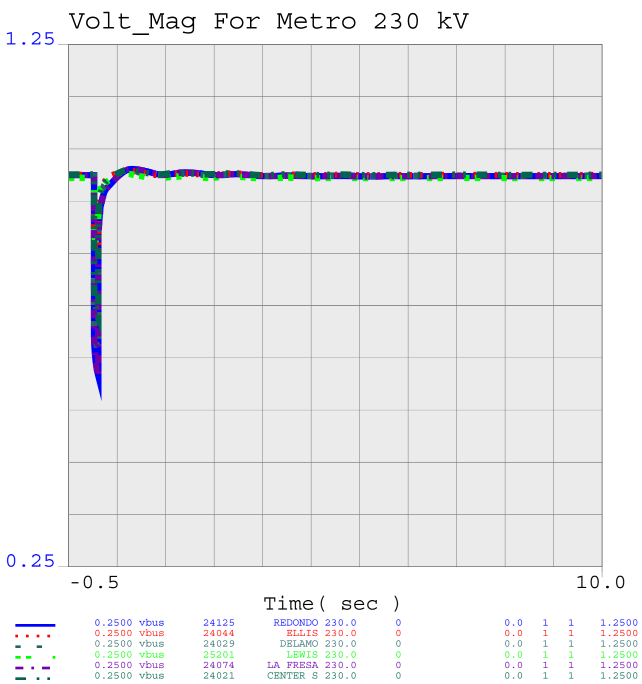
QC5 METRO AREA
Heavy Spring Conditions

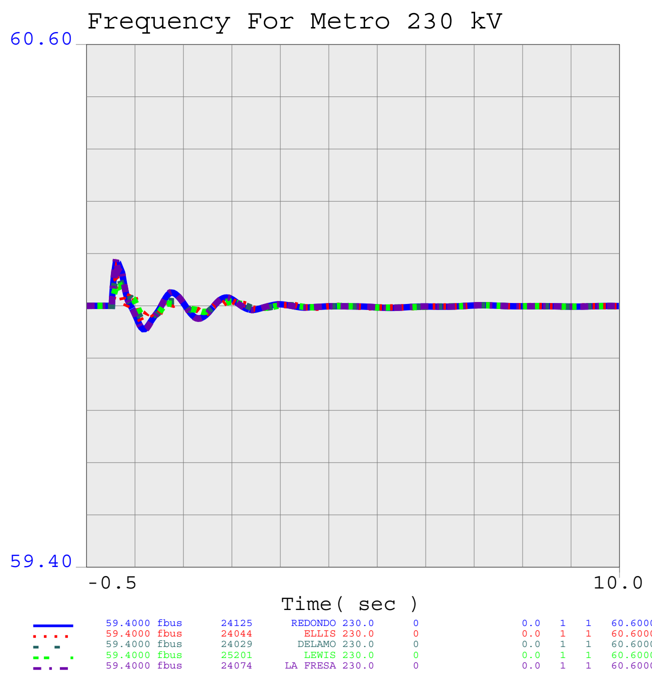
	QC5-hsp-pst-v4_Hinson-LaFresa-Hinson-slo.chf	. Thu Jan 17 10:58:38 2013

QUEUE CLUSTER 5 PHASE 1 TRANSIENT STABILITY









QC5 METRO AREA
Heavy Spring Conditions

QC5-hsp-pst-v4_LBeach-Hinson-DelAmo-Lbeach-Litehipe.chf

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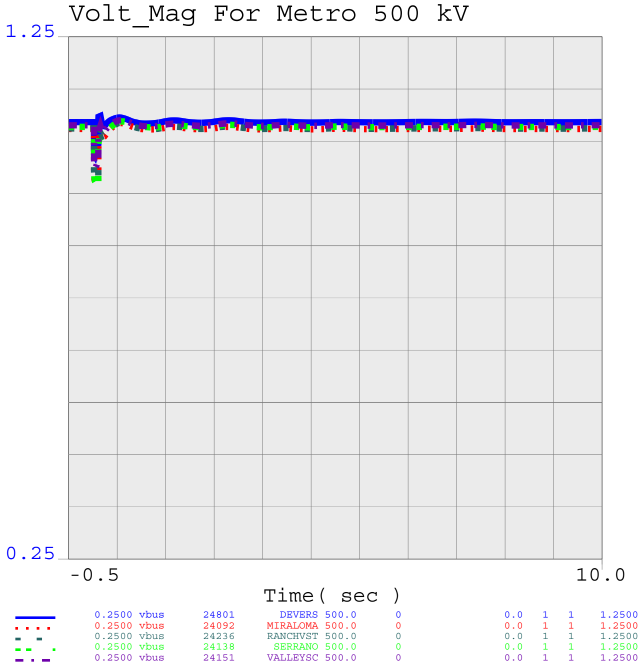
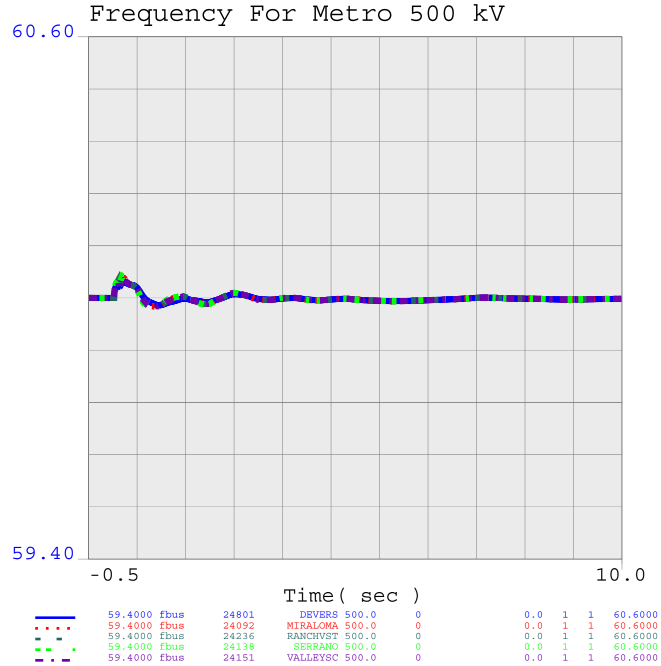
Thu Jan 17 11:00:00 2013

QUEUE CLUSTER 5 PHASE 1 TRANSIENT STABILITY

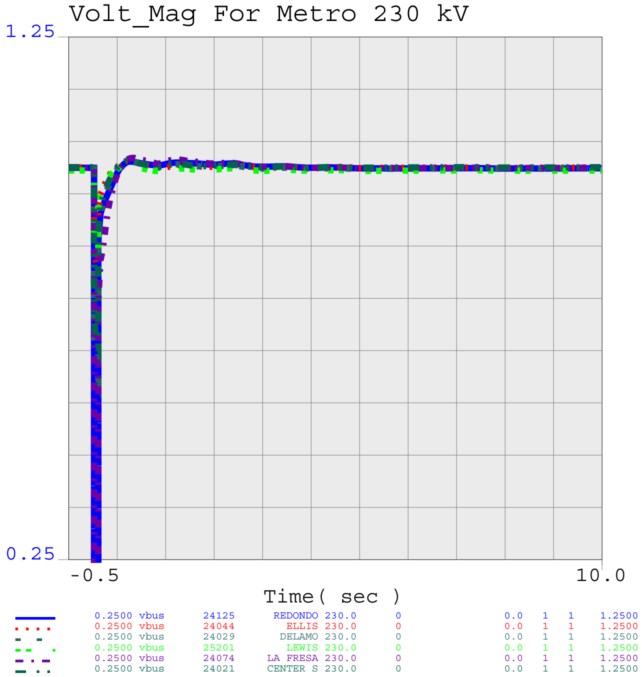
Volt_Mag For Metro 500 kV



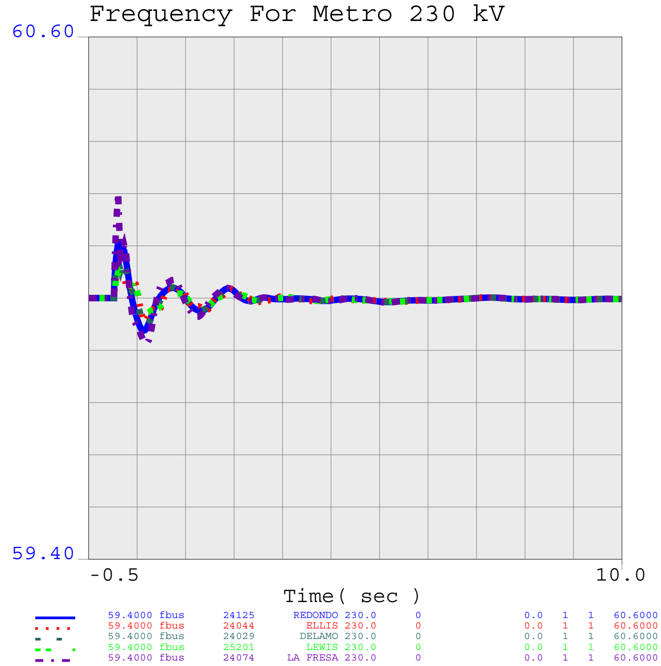
Frequency For Metro 500 kV



Volt_Mag For Metro 230 kV



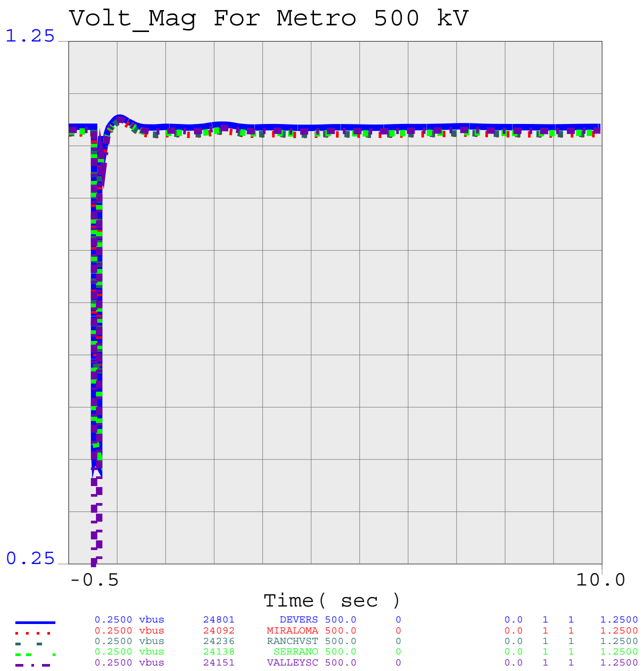
Frequency For Metro 230 kV

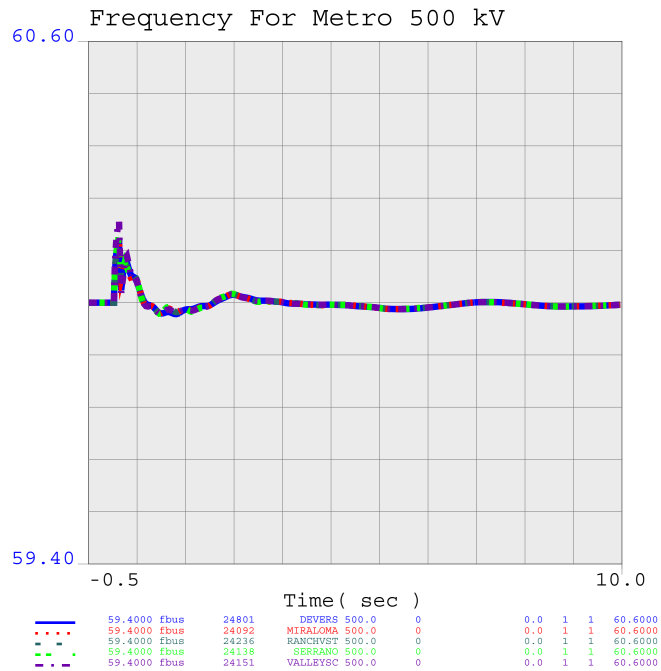


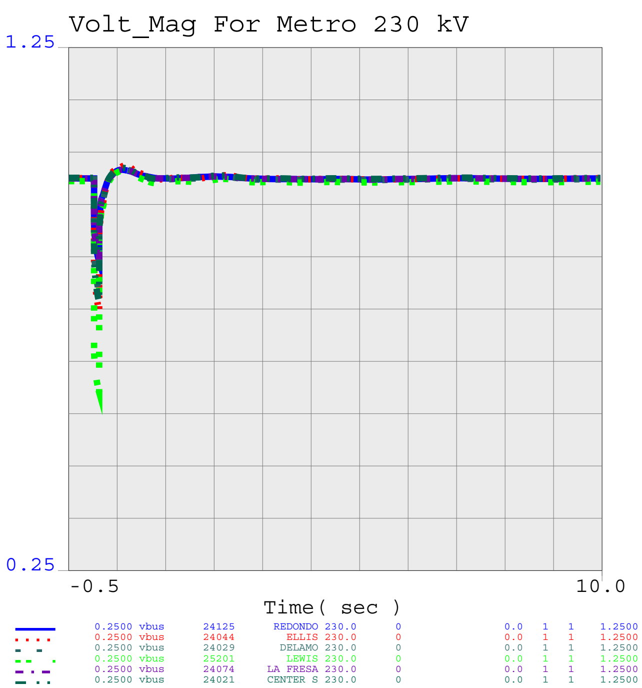
QC5 METRO AREA
Heavy Spring Conditions

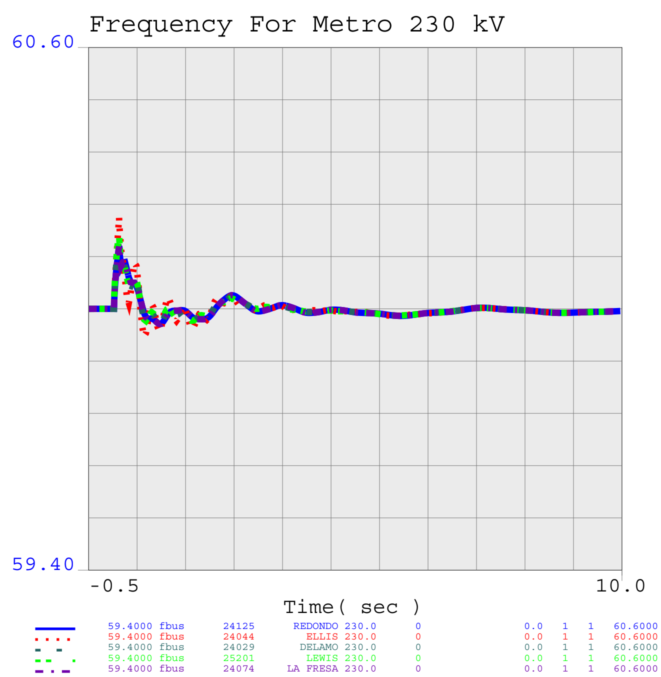
	QC5-hsp-pst-v4_LFesa-Redondo-dlo.chf	. Thu Jan 17 11:01:16 2013

QUEUE CLUSTER 5 PHASE 1 TRANSIENT STABILITY









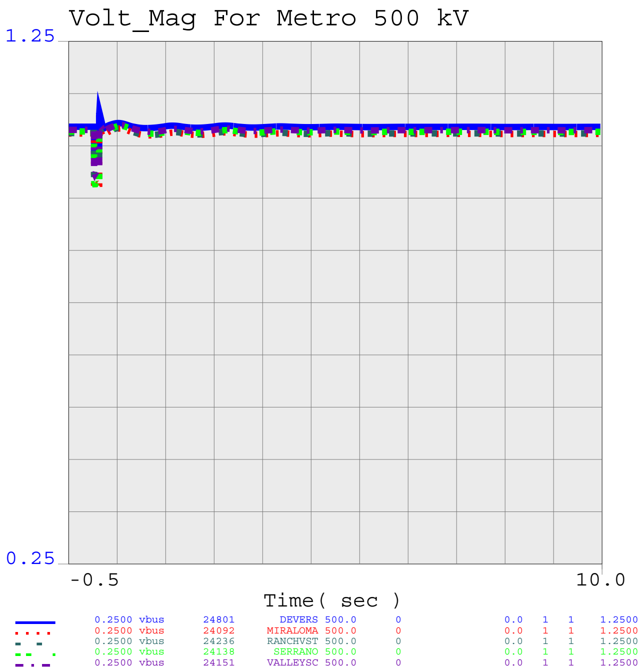
QC5 METRO AREA
Heavy Spring Conditions

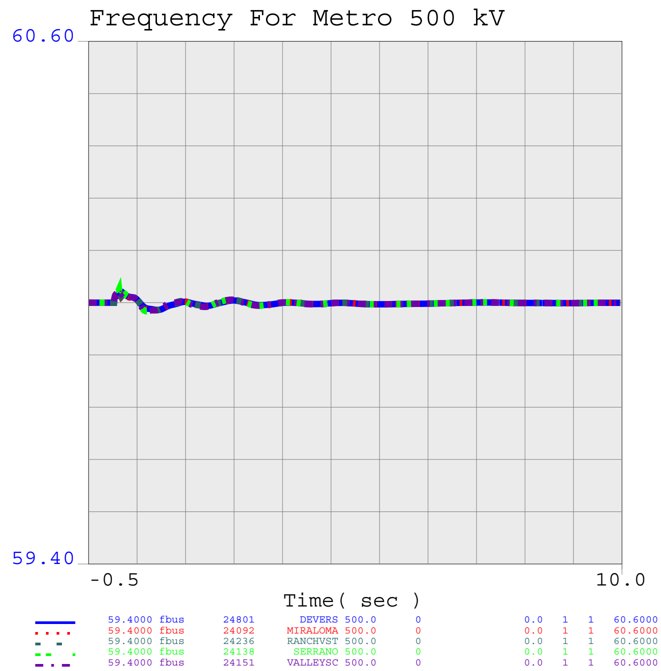
QC5-hsp-pst-v4_Valley-Serrano-slo.chf

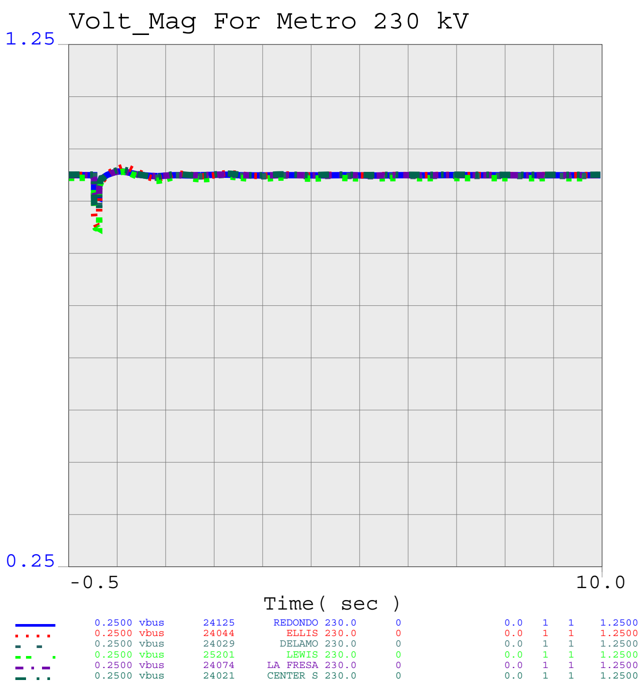
.

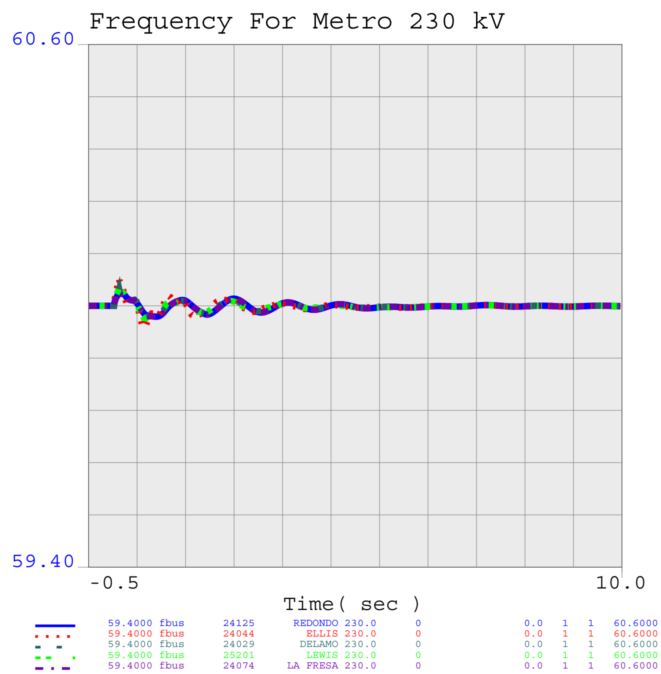
Thu Jan 17 11:02:38 2013

QUEUE CLUSTER 5 PHASE 1 TRANSIENT STABILITY









QC5 METRO AREA
Heavy Spring Conditions

QC5-hsp-pst-v4_Viejo-songs-slo.chf

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Thu Jan 17 11:03:52 2013

QC5 Phase I

Appendix H – Distribution Short Circuit Duty Results

Three-Phase-to-Ground Fault Analysis

Substation Name	Bus Voltage	Pre QC3&4 Phase II kA	Pre QC3&4 Phase II X/R	Post QC3&4 Phase II kA	Post QC3&4 Phase II X/R	Delta (kA)
Alerhill	115	19.8	68.6	20.4	72.3	0.6
AULD	115	17.7	11.7	17.8	11.6	0.2
Battle	115	15.1	10.5	15.2	10.4	0.1
BUNKER	115	11.6	8.6	11.7	8.5	0.1
Elsinore	115	9.1	8.7	9.2	8.6	0.1
Fogarty	115	10.4	10.4	10.6	10.3	0.2
Ivyglen	115	13.7	16.9	14.0	16.7	0.3
MWD Eastside	115	11.3	9.9	11.4	9.8	0.1
NELSON	115	11.0	9.3	11.1	9.3	0.1
Skylark	115	9.3	9.6	9.4	9.5	0.1
STETSON	115	11.0	9.2	11.2	9.1	0.1
SUNCITY	115	16.3	10.8	16.4	10.7	0.2
Valley_AB	115	22.1	70.9	22.7	72.0	0.6
Valley_C	115	11.0	77.9	11.2	78.6	0.2
Valley_D	115	32.5	78.3	33.1	79.2	0.6
ARROYO	66	11.4	12.1	11.7	12.2	0.3
Dairymans	66	4.9	3.9	6.5	4.6	1.6
Elcans	66	9.0	6.9	9.4	6.7	0.4
Etiwanda A	66	23.6	68.8	23.8	70.6	0.2
Etiwanda B	66	27.0	159.2	27.2	170.7	0.2
Goshen	66	9.3	6.5	9.9	6.3	0.6
GOULD	66	16.2	33.9	16.9	38.5	0.7
Grapeland	66	23.0	27.8	23.1	27.9	0.2
Haagen	66	6.3	4.6	8.0	5.4	1.8
Hanford	66	5.8	5.4	6.5	5.3	0.6
ISABELLA	66	2.4	5.5	2.6	5.9	0.2
KERN RIVER 3	66	4.2	4.9	4.4	5.0	0.2
KERNVILLE	66	4.1	4.7	4.2	4.8	0.1
LA CANADA	66	11.4	11.3	11.8	11.4	0.3
LAKEGEN	66	2.5	5.7	2.6	6.0	0.2
Laurel	66	6.7	3.3	7.0	3.2	0.4
Liberty	66	13.4	8.4	14.5	8.4	1.1
Lourich	66	4.4	2.4	4.6	2.3	0.2
Mascot	66	6.2	5.8	7.4	5.9	1.2
MiraLoma	66	38.2	59.2	38.4	61.2	0.2
Oakgrove	66	9.6	7.1	10.0	7.0	0.4
Octol	66	4.2	2.3	4.4	2.3	0.2
Padua	66	26.1	46.3	26.3	47.1	0.2
Pipe	66	21.7	18.1	21.8	18.1	0.1
Protein	66	5.3	4.0	7.1	5.1	1.9
Rector	66	21.5	11.8	22.9	11.5	1.4
Riverway	66	8.8	7.0	9.0	6.8	0.3
Rolling	66	16.8	12.6	16.9	12.6	0.1
San Bernardino	66	31.9	43.0	32.1	43.5	0.1

Strip	66	16.7	12.6	16.8	12.6	0.1
Tipton	66	4.5	2.6	4.8	2.5	0.2
Tulare	66	10.4	6.4	12.1	6.7	1.6
Venice_Hill	66	6.7	3.1	6.8	3.1	0.1
Venida	66	8.4	4.3	8.6	4.2	0.2
VESTAL	66	25.8	11.2	26.4	11.2	0.6
Villa Park	66	32.4	46.3	32.5	46.1	0.1
Visalia	66	12.9	6.5	13.4	6.3	0.5
WELDON	66	1.4	3.5	1.6	3.9	0.2
Bartsow East	34.5	5.6	7.7	6.0	8.1	0.4
CalNev	34.5	3.7	2.9	3.9	2.9	0.1
Coal Gas	34.5	5.7	6.0	6.1	6.2	0.4
Edwards	34.5	4.2	5.0	4.6	5.8	0.4
Gale	34.5	6.4	7.4	6.8	7.8	0.4
Garnet	34.5	13.8	14.5	14.0	14.3	0.2
Inyokern	34.5	10.7	15.1	11.0	16.3	0.3
Kerr Westend	34.5	6.4	6.1	6.7	6.6	0.3
Lime Rock	34.5	6.5	6.4	7.6	5.5	1.0
North Muroc	34.5	2.9	2.6	3.0	2.7	0.2
Pinnacles	34.5	7.0	8.8	7.3	10.0	0.3
Rancho	34.5	4.2	4.9	4.6	4.4	0.4
Searles	34.5	7.7	13.6	8.1	19.4	0.4
SEGS 1	34.5	4.4	6.6	4.6	6.7	0.2
Southbase	34.5	2.4	6.3	2.5	7.0	0.1
Tortilla	34.5	7.7	15.9	8.1	16.2	0.4
Victor	34.5	12.5	30.8	17.5	32.1	5.0
Victorville	34.5	7.1	6.7	8.3	5.8	1.2
Water Well	34.5	3.2	3.5	3.3	3.5	0.1
Barstow	12.47	4.1	9.1	5.3	11.5	1.2
Carodean	12.47	8.7	5.3	9.0	6.0	0.3
Dairymans	12.47	7.2	9.7	7.6	12.1	0.5
Goshen	12.47	10.8	31.4	11.0	32.3	0.1
Hanford_2	12.47	12.9	11.4	13.4	11.8	0.5
Hanford_3	12.47	12.1	8.4	12.6	8.5	0.5
Laurel	12.47	13.1	7.5	13.3	7.5	0.3
Liberty	12.47	15.6	17.5	15.8	17.7	0.3
Liberty	12.47	15.5	17.9	15.7	18.2	0.3
Marasch_1	12.47	15.2	20.8	15.7	21.5	0.5
Mascot12	12.47	12.5	11.2	13.3	11.9	0.8
Minneola	12.47	7.2	4.1	7.4	4.1	0.2
Oakgrove_1	12.47	14.2	11.4	14.4	11.4	0.2
Oakgrove_2	12.47	14.6	11.4	14.7	11.3	0.2
Octol_1	12.47	9.0	6.2	9.1	6.2	0.2
Pinnacles	12.47	15.3	35.6	15.4	42.0	0.2
Protein	12.47	7.4	15.8	7.9	24.9	0.5
Rancho	12.47	7.9	5.9	8.3	5.6	0.4
Rector	12.47	23.4	19.1	23.7	19.1	0.3

Riverway	12.47	13.9	23.4	14.1	23.5	0.1
Roadway	12.47	21.0	19.3	21.5	19.8	0.5
Savage	12.47	17.5	18.7	17.7	19.0	0.2
Tipton	12.47	8.7	6.1	8.9	6.2	0.2
Tortilla	12.47	14.3	15.6	14.4	15.8	0.1
Tulare_#1	12.47	14.6	16.0	15.1	17.5	0.5
Tulare_#2	12.47	16.6	26.3	17.2	30.9	0.6
Victorville	12.47	7.5	17.9	7.9	17.1	0.4
Visalia	12.47	15.9	17.7	16.0	17.7	0.1
WELDON	12.47	3.4	8.2	3.5	9.7	0.1
Yermo	12.47	5.2	3.9	5.3	3.9	0.1
Yucca	12.47	13.0	6.6	13.2	7.1	0.2
LAKEGEN	6.9	12.2	17.7	12.5	19.5	0.2
Haagen	4.16	9.9	10.2	10.1	10.7	0.2
Tulare	4.16	12.9	20.5	13.1	21.3	0.1
Victorville	4.16	9.5	18.9	9.7	18.5	0.2

Single-Phase-to-Ground Fault Analysis

Substation Name	Bus Voltage	Pre QC3&4 Phase II kA	Pre QC3&4 Phase II X/R	Post QC3&4 Phase II kA	Post QC3&4 Phase II X/R
Alerhill	115	24.9	52.5	25.6	54.5
AULD	115	17.9	12.5	18.1	12.4
Battle	115	12.8	9.9	12.8	9.9
BUNKER	115	11.1	8.7	11.2	8.6
Elsinore	115	9.5	9.7	9.6	9.6
Fogarty	115	9.9	9.6	10.0	9.5
Ivyglen	115	11.7	11.4	11.8	11.3
MWD Eastside	115	10.0	10.6	10.1	10.5
NELSON	115	11.3	10.5	11.4	10.4
Skylark	115	9.0	10.3	9.0	10.2
STETSON	115	10.6	9.8	10.7	9.7
SUNCITY	115	13.2	9.5	13.3	9.4
Valley_AB	115	28.0	53.6	28.7	54.4
Valley_C	115	13.6	63.3	13.8	64.0
Valley_D	115	40.2	59.9	40.9	60.6
ARROYO	66	8.0	12.9	8.1	13.0
Dairymans	66	2.7	5.0	4.6	5.6
Elcans	66	5.5	7.0	5.6	6.9
Etiwanda A	66	16.8	144.7	16.9	149.2
Etiwanda B	66	20.4	99.5	20.5	101.5
Goshen	66	5.6	6.7	5.9	6.5
GOULD	66	12.3	56.2	12.6	63.3
Grapeland	66	17.7	32.0	17.8	32.1
Haagen	66	3.5	5.7	5.6	6.2
Hanford	66	3.2	5.9	3.6	5.8
ISABELLA	66	2.2	5.5	2.3	8.3
KERN RIVER 3	66	4.1	4.9	4.2	6.9
KERNVILLE	66	3.9	4.7	4.0	6.5
LA CANADA	66	7.8	11.7	7.9	11.8
LAKEGEN	66	2.2	5.7	2.3	8.4
Laurel	66	4.2	3.9	4.4	3.8
Liberty	66	8.5	8.6	9.2	8.6
Lourich	66	3.1	2.8	3.3	2.8
Mascot	66	3.5	6.1	4.2	6.1
MiraLoma	66	29.2	57.5	29.2	58.5
Oakgrove	66	5.9	7.2	6.1	7.1
Octol	66	3.6	2.4	3.7	2.4
Padua	66	18.3	99.3	18.3	101.2
Pipe	66	16.2	19.9	16.3	19.9
Protein	66	2.9	5.2	5.3	6.1
Rector	66	20.0	15.4	21.1	15.1
Riverway	66	5.3	7.3	5.4	7.3
Rolling	66	10.7	12.8	10.7	12.7
San Bernardino	66	23.8	44.2	23.8	44.4

Strip	66	10.6	13.1	10.6	13.1
Tipton	66	3.1	3.0	3.3	3.0
Tulare	66	6.7	6.2	8.3	6.3
Venice_Hill	66	3.9	4.2	4.0	4.1
Venida	66	5.1	5.2	5.2	5.2
VESTAL	66	20.3	11.2	21.0	11.4
Villa Park	66	10.3	218.4	10.3	218.3
Visalia	66	8.8	7.1	9.0	7.0
WELDON	66	1.0	3.5	1.0	5.1
Bartsow East	34.5	2.9	12.4	3.0	12.8
CalNev	34.5	2.1	4.6	2.3	4.4
Coal Gas	34.5	3.4	9.3	3.8	9.4
Edwards	34.5	2.2	14.9	2.2	18.1
Gale	34.5	3.9	12.0	4.5	12.7
Garnet	34.5	3.3	71.7	3.4	71.5
Inyokern	34.5	2.6	93.5	2.6	102.5
Kerr Westend	34.5	1.4	28.5	1.4	30.9
Lime Rock	34.5	4.1	6.8	4.3	6.4
North Muroc	34.5	1.5	5.3	1.6	5.5
Pinnacles	34.5	1.4	38.6	1.4	42.4
Rancho	34.5	2.3	5.8	2.4	5.6
Searles	34.5	1.5	106.2	1.5	158.8
SEGS 1	34.5	4.0	10.5	4.2	10.4
Southbase	34.5	1.6	13.7	1.7	15.6
Tortilla	34.5	4.2	43.9	4.3	46.2
Victor	34.5	10.5	52.8	12.5	63.6
Victorville	34.5	4.6	7.0	4.9	6.6
Water Well	34.5	1.8	5.3	1.9	5.2
Barstow	12.47	4.5	9.2	5.7	11.4
Carodean	12.47	11.4	5.8	11.9	6.5
Dairymans	12.47	7.9	11.3	8.3	13.7
Goshen	12.47	11.5	44.3	11.6	45.8
Hanford_2	12.47	14.8	13.5	15.3	13.9
Hanford_3	12.47	13.9	9.2	14.3	9.3
Laurel	12.47	14.8	9.1	15.0	9.1
Liberty	12.47	16.7	19.2	16.9	19.4
Liberty	12.47	16.6	19.7	16.8	20.0
Marasch_1	12.47	18.2	26.1	18.6	27.2
Mascot12	12.47	14.3	12.9	15.0	13.7
Minneola	12.47	10.1	4.4	10.4	4.4
Oakgrove_1	12.47	15.7	12.2	15.8	12.2
Oakgrove_2	12.47	15.9	12.0	16.1	12.0
Octol_1	12.47	10.8	6.9	10.9	6.9
Pinnacles	12.47	0.0	1.0	0.0	1.0
Protein	12.47	8.1	21.6	8.5	34.8
Rancho	12.47	10.0	6.2	10.5	5.9
Rector	12.47	24.8	27.0	25.1	27.1

Riverway	12.47	15.5	31.7	15.6	31.9
Roadway	12.47	21.3	26.0	21.6	26.7
Savage	12.47	22.6	21.4	22.8	21.7
Tipton	12.47	10.0	7.4	10.1	7.4
Tortilla	12.47	16.7	17.0	16.8	17.2
Tulare_#1	12.47	16.0	18.7	16.5	20.2
tulare_#2	12.47	18.5	35.4	18.9	42.0
Victorville	12.47	8.6	23.5	8.9	22.8
Visalia	12.47	17.3	20.3	17.4	20.3
WELDON	12.47	3.9	8.2	4.1	12.5
Yermo	12.47	7.0	4.3	7.1	4.3
Yucca	12.47	16.0	7.5	16.2	8.1
LAKEGEN	6.9	0.0	17.7	0.0	1.0
Haagen	4.16	0.0	1.0	0.0	1.0
Tulare	4.16	13.3	21.8	13.4	22.4
Victorville	4.16	10.0	21.0	10.2	20.7

Delta (kA)
0.7
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Table H.1

With the inclusion of the proposed RNU and LDNU

Three – Phase-to-Ground Fault Analysis

Bus Name	Bus KV	PRE CASE		POST CASE		DELTA KA
		X/R	KA	X/R	KA	
Eldorado	500	14	46.7	14.4	47.6	0.9
Serrano	500	25	32.7	25.2	32.9	0.2
Whirlwind	500	23.8	37.8	24.2	38	0.2
Chino	230	16.1	50.9	16.1	51.3	0.4
Cool Water	230	20.8	15.8	20.8	16	0.2
Colorado River_2	230	0	0	51.8	24.6	24.6
Devers	230	25.9	52.1	25.9	52.5	0.4
Eldorado	230	17	56.2	17.1	56.4	0.2
Eldorado_2	230	20.1	40.5	20.8	42	1.5
Etiwanda	230	25.1	55.3	25.7	58.8	3.5
Highwind_230	230	21.5	18.6	24	22.1	3.5
Inyokern	230	6.2	11	6.3	11.3	0.3
Jasper	230	12.3	15	12.9	15.5	0.5
Kramer	230	14.8	20.8	15.5	21.7	0.9
Mira Loma A	230	20.2	54.4	20.1	54.6	0.2
Mira Loma B	230	21.8	59.3	21.8	60.9	1.6
Pardee	230	15.5	61.1	15.5	61.2	0.1
Pastoria	230	13.3	30.8	13.4	31.2	0.4
Rancho	230	25	56	25.6	59.3	3.3
San Ber_dino	230	24.8	41.5	24.7	42	0.5
Serrano	230	25	57.5	25.1	57.6	0.1
Vista	230	20.3	49.4	20.3	50.5	1.1
Wildlife	230	15.2	24.9	15.2	25.1	0.2
Devers_B	115	0	0	23.3	24.8	24.8
Farrell	115	9.5	14.5	9.2	15.1	0.6
Garnet	115	17.3	20.7	15.9	22.9	2.2
Indigo	115	16.1	19.7	14.8	21	1.3
Inyokern	115	5.7	12.7	6	13.8	1.1
Kramer	115	11.9	25.7	12.9	27.1	1.4
Leatherneck	115	0	0	3.1	2.1	2.1
Mogen	115	3.1	6.3	5	10.3	4
Rocket Test	115	3.1	5.6	3.1	5.7	0.1
US Borax	115	3.2	6.3	5.3	10.3	4
Victor	115	18.5	24.1	18.6	24.3	0.2
ANTELOPE	66	44.1	39.8	44.4	40.2	0.4
CAL CEMENT	66	20.6	19.3	20.5	19.6	0.3
DEL SUR	66	12.4	27	12.5	27.2	0.2
Etiwanda A	66	41	23.8	41.4	23.9	0.1
GREAT LAKES	66	3	6.4	3.2	6.7	0.3
Highwin66	66	0	0	50	12.7	12.7
Padua	66	31.8	25.6	31.9	25.8	0.2
Rector	66	12.5	20.7	12.2	22.2	1.5

ROSAMOND	66	3.8	9.1	5	9.9	0.8
Vestal	66	12.6	22.4	12.6	22.9	0.5
Windhub66_A	66	48	24.7	48.9	25.2	0.5
Windhub66_B	66	63.2	14.5	63.8	14.7	0.2

Table H.2

With the inclusion of the proposed RNU and LDNU

Single-Phase-to-Ground Fault Analysis

Bus Name	Bus KV	PRE CASE		POST CASE		DELTA KA
		X/R	KA	X/R	KA	
Colorado Rvr	525	22.3	23.8	23.9	24.9	1.1
Eldorado	525	12.7	41.7	13	42.6	0.9
Red Bluff	525	14.9	20.9	14.9	21	0.1
Serrano	525	12.9	29.2	12.9	29.3	0.1
Vincent	525	14.8	40.2	15.6	40.6	0.4
Whirlwind	525	18.4	34.9	18.4	35.1	0.2
Chino	230	13.7	42.6	13.7	42.8	0.2
Cool Water	230	21.6	16	21.4	16.1	0.1
Colorado River _2	230	0	0	45.9	29.7	29.7
Devers	230	22.2	56.7	22.3	57.4	0.7
Eldorado	230	15.9	53.3	16.1	53.5	0.2
Eldorado_2	230	20.6	45.3	21	48.1	2.8
Ellis	230	17.8	36.8	17.1	37.9	1.1
Etiwanda	230	16.8	55.5	17	59	3.5
Highwind_230	230	14.3	14.7	19	20.7	6
Inyokern	230	7.4	8.6	7.6	8.7	0.1
Jasper	230	9.2	10.6	11.3	13.2	2.6
Kramer	230	10.4	18.1	10.5	18.5	0.4
Mira Loma A	230	11.8	55.1	11.7	55.3	0.2
Mira Loma B	230	10	54.4	9.9	55.3	0.9
Pastoria	230	13.1	28	14.4	32.9	4.9
Pearblossom	230	6.5	8.2	6.9	8.4	0.2
Rancho	230	16.4	56.9	16.5	60	3.1
San Ber_dino	230	24.2	41.6	24.2	41.9	0.3
Vincent A	230	19.6	66.4	19.8	66.7	0.3
Vincent B	230	19.6	66.4	19.8	66.7	0.3
Vista	230	15.6	44.3	15.4	45.1	0.8
Whirlwind	230	31.4	58.1	31.6	58.2	0.1
Whirlwind_2	230	31.4	58.1	31.6	58.2	0.1
Windhub_A	230	42.2	36.6	39.4	39.6	3
Windhub_B	230	46.3	36.1	46.9	40.7	4.6
Devers_B	115	0	0	23	27.2	27.2
Farrell	115	9.3	13.4	9.1	13.7	0.3
Garnet	115	12.1	19.4	11.3	21	1.6
Inyokern	115	6.8	13.9	7.4	14.7	0.8
Kramer	115	11.9	25.5	12.5	27	1.5
Leatherneck	115	0	0	4.1	2.1	2.1
Mogen	115	4	5.2	5.3	8.3	3.1
Rocket Test	115	4.3	4.5	4.3	4.6	0.1
US Borax	115	3.9	4.9	5.2	7.8	2.9
Victor	115	17.9	26.8	17.9	26.9	0.1
ANTELOPE	66	26.8	24.2	25.1	25.1	0.9

Etiwanda A	66	43.8	22.9	44.1	23	0.1
GREAT LAKES	66	4.2	3.4	4.3	3.8	0.4
Highwin66	66	0	0	21.8	9.7	9.7
Rector	66	13.1	21.7	12.8	23	1.3
Vestal	66	11.9	18.8	11.6	19.5	0.7
Windhub66_A	66	27.3	15.3	27.3	15.4	0.1

Table H.3

With the inclusion of the proposed RNU, LDNU and ADNU

Three – Phase-to-Ground Fault Analysis

Bus Name	Bus Voltage	PRE QC5 Phase 1		Post QC5 Phase 1		DELTA KA
		X/R	KA	X/R	KA	
Windhub_500	500	26.1	27.6	27.3	30.3	2.7
ALBH500	500	24	22.6	24.3	27.1	4.5
Red Bluff	500	23.4	23.3	23.3	27.3	4
Kramer	500	0	0	25.2	13	13
Llano	500	0	0	24.7	30.2	30.2
Mesa	500	0	0	23.2	35	35
Antelope	500	22.9	39.2	23.4	42.6	3.4
Colorado Rvr	500	26.6	24	25.9	26.5	2.5
Eldorado	500	14	46.7	14.4	48.1	1.4
Lugo	500	22.3	47.7	22.9	49.9	2.2
Mira Loma	500	24.1	39.4	24.3	45.6	6.2
Serrano	500	25	32.7	25.2	34.9	2.2
Valley A	500	26.9	25.3	25.8	29.8	4.5
Valley B	500	26.9	25.3	25.8	29.8	4.5
Vincent	500	20	51.1	20.6	58.6	7.5
Antelope	230	28.4	41.9	29.2	42.8	0.9
Barre	230	18.9	51.8	19	52	0.2
Center	230	14.8	42.8	15	43.2	0.4
Chino	230	16.1	50.9	16.2	52.5	1.6
Cool Water	230	20.8	15.8	20.2	16.6	0.8
Colorado River_ 2	230	0	0	52.5	25.7	25.7
Del Amo	230	14.8	42.9	14.7	43.2	0.3
Devers	230	25.9	52.1	26	53.1	1
El Casco	230	18.4	17.8	18.4	17.9	0.1
Eldorado	230	17	56.2	17.1	56.6	0.4
Eldorado_2	230	20.1	40.5	20.8	42.2	1.7
Etiwanda	230	25.1	55.3	26	59.8	4.5
Gould	230	12.5	23.7	14	29.9	6.2
Highwind_230	230	21.5	18.6	24	22.3	3.7
Inyokern	230	6.2	11	5.8	13	2
Kramer	230	14.8	20.8	19.4	31	10.2
Lewis	230	19.9	47	20	47.6	0.6
Lighthipe	230	16.9	45.5	16.8	45.7	0.2
Lugo	230	29.8	42.3	29	43.2	0.9
Mira Loma A	230	20.2	54.4	20.7	56.4	2
Mira Loma B	230	21.8	59.3	22.2	62.4	3.1

Olinda	230	14.7	31.3	14.8	31.4	0.1
Pastoria	230	13.3	30.8	13.4	31.2	0.4
Rancho	230	25	56	25.8	60.3	4.3
San Ber_dino	230	24.8	41.5	24.6	42.2	0.7
San Onofre	230	21.6	56.9	21.5	57.1	0.2
Serrano	230	25	57.5	25.5	58.9	1.4
Sylmar (SCE)	230	15.2	62.9	15.3	63.7	0.8
Victor	230	15.8	25.1	15.6	25.4	0.3
Villa Park	230	23	49.4	23.2	50.3	0.9
Vista	230	20.3	49.4	20.3	50.9	1.5
Walnut	230	16	36.7	16.3	36.9	0.2
Wildlife	230	15.2	24.9	15.2	25.2	0.3
Whirlwind	230	41.3	50.5	42.6	51.9	1.4
Red Bluff	230	39.5	30.2	41.3	32	1.8
Jasper	230	12.3	15	12.8	15.7	0.7
Mesa_2	230	0	0	20	58.2	58.2
Whirlwind_2	230	41.3	50.5	42.6	51.9	1.4
Devers	115	42.9	28.9	42.7	29.2	0.3
Inyokern	115	5.7	12.7	6.1	14.2	1.5
Kramer	115	11.9	25.7	13.6	29.1	3.4
Victor	115	18.5	24.1	18.4	24.5	0.4
ALBH115	115	61	19.8	64.6	20.5	0.7
Tiffanywind	115	13.2	21.1	13.1	21.2	0.1
Terawind	115	15.6	23.3	15.5	23.5	0.2
Indigo	115	16.1	19.7	16	19.9	0.2
Garnet	115	17.3	20.7	17.2	20.8	0.1
Altwind	115	10.6	18	10.5	18.1	0.1
Venwind	115	6	17	6	17.1	0.1
Leatherneck	115	0	0	3.1	2.1	2.1
Mogen	115	3.1	6.3	5	10.5	4.2
Rocket Test	115	3.1	5.6	3.1	5.8	0.2
US Borax	115	3.2	6.3	5.2	10.5	4.2
Lewis	69	32.1	40.1	32.2	40.2	0.1
ANTELOPE	66	44.1	39.8	44.9	40.4	0.6
Etiwanda A	66	41	23.8	41.5	24	0.2
Gould	66	26.4	11.8	28.1	12.2	0.4
Highwin66	66	0	0	50	12.7	12.7
Mira Loma	66	41.2	38.5	41.8	38.7	0.2
Padua	66	31.8	25.6	32	25.9	0.3
Rector	66	12.5	20.7	12.2	22.2	1.5
San Ber_dino	66	43.3	32.1	43.4	32.2	0.1

Vestal	66	12.6	22.4	12.6	22.9	0.5
CAL CEMENT	66	20.6	19.3	20.5	19.7	0.4
DEL SUR	66	12.4	27	12.5	27.3	0.3
QUARTZ HILL	66	10	19.8	9.9	19.9	0.1
ROSAMOND	66	3.8	9.1	5	9.9	0.8
GREAT LAKES	66	3	6.4	3.2	6.7	0.3
Windhub66_A	66	48	24.7	49	25.3	0.6
Windhub66_B	66	63.2	14.5	64	14.7	0.2

Table H.4

With the inclusion of the RNU, LDNU and ADNU

Single-Phase-to-Ground Fault Analysis

Substation Name	Bus Voltage	PRE QC5 Phase 1		Post QC5 Phase 1		DELTA KA
		X/R	KA	X/R	KA	
Alberhill	500	14.5	22.7	13.7	27.3	4.6
Red Bluff	500	14.9	20.9	13.5	25.1	4.2
Kramer	500	0	0	14.9	10.5	10.5
Llano	500	0	0	13.5	23	23
Mesa	500	0	0	14.2	29.2	29.2
Antelope	500	18.2	33	17.9	35.1	2.1
Colorado Rvr	500	22.3	23.8	23	28.2	4.4
Eldorado	500	12.7	41.7	13	42.9	1.2
Lugo	500	12.3	36.2	13	39.3	3.1
Mira Loma	500	10.3	34	10.2	38.8	4.8
Serrano	500	12.9	29.2	12.4	30.5	1.3
Valley	500	14.5	25.6	13.7	30.4	4.8
Vincent	500	14.8	40.2	14.4	48.2	8
Antelope	230	28.7	46.1	29.3	46.9	0.8
Barre	230	13.9	42.5	13.8	42.6	0.1
Center	230	14.9	34.6	13.8	35.9	1.3
Chino	230	13.7	42.6	13.7	43.5	0.9
Cool Water	230	21.6	16	21	16.6	0.6
Colorado River A	230	0	0	46.8	31.1	31.1
Del Amo	230	10.4	40	10.3	40.2	0.2
Devers	230	22.2	56.7	22.1	57.5	0.8
Eldorado	230	15.9	53.3	16.1	53.6	0.3
Eldorado_2	230	20.6	45.3	21	48.2	2.9
Ellis	230	17.8	36.8	17.1	38	1.2
Etiwanda	230	16.8	55.5	16.7	59.7	4.2
Gould	230	9.2	19	8.8	24.1	5.1
Highwind_230	230	14.3	14.7	19	20.8	6.1
Inyokern	230	7.4	8.6	7.2	9.7	1.1
Kramer	230	10.4	18.1	14.6	29.9	11.8
Lewis	230	15.1	43.9	15.1	44.3	0.4
Lighthipe	230	11.4	40.9	11.2	41.6	0.7
Lugo	230	23.1	42.5	23.5	43.7	1.2
Mira Loma A	230	11.8	55.1	12	57.1	2
Mira Loma B	230	10	54.4	9.8	56.7	2.3

Pastoria	230	13.1	28	14.4	32.9	4.9
Rancho	230	16.4	56.9	16.2	60.9	4
San Ber_dino	230	24.2	41.6	24.2	42.1	0.5
Serrano	230	18.1	59.7	18	60.8	1.1
Sylmar (SCE)	230	12.5	68.6	12.5	69.2	0.6
Villa Park	230	16.8	44.1	16.8	44.5	0.4
Vista	230	15.6	44.3	15.4	45.3	1
Walnut	230	16.7	34.6	15.5	35.5	0.9
Whirlwind	230	31.4	58.1	31.7	59.4	1.3
Red Bluff	230	26.9	34.1	27.5	36.4	2.3
Jasper	230	9.2	10.6	11.2	13.3	2.7
Mesa_2	230	0	0	16.2	56.2	56.2
Whirlwind_2	230	31.4	58.1	31.7	59.4	1.3
Windhub_B	230	46.3	36.1	47.4	41.2	5.1
Wildlife	230	16.2	18.8	16.2	19	0.2
Windhub_A	230	42.2	36.6	39.6	40	3.4
Alberhill	115	50	24.7	52.2	25.5	0.8
Devers	115	35.9	32.9	35.4	33.2	0.3
Inyokern	115	6.8	13.9	7.5	15.1	1.2
Kramer	115	11.9	25.5	13.9	29.7	4.2
Valley AB	115	53.2	28.2	54.6	28.8	0.6
Valley C	115	50.2	44.5	51.1	45.2	0.7
Victor	115	17.9	26.8	17.8	27.1	0.3
Tiffanywind	115	10.3	18.4	10.2	18.5	0.1
Terawind	115	11.8	21.3	11.7	21.5	0.2
Garnet	115	12.1	19.4	12	19.5	0.1
Leatherneck	115	0	0	4.1	2.2	2.2
Mogen	115	4	5.2	5.3	8.4	3.2
Rocket Test	115	4.3	4.5	4.3	4.7	0.2
US Borax	115	3.9	4.9	5.1	7.9	3
Great Lake	66	4.2	3.4	4.3	3.8	0.4
Windhub66_A	66	27.3	15.3	27.3	15.4	0.1
Antelope	66	26.8	24.2	25.2	25.2	1
Etiwanda A	66	43.8	22.9	44.2	23	0.1
Gould	66	25.2	10.4	26.1	10.6	0.2
Highwin66	66	0	0	21.8	9.7	9.7
Rector	66	13.1	21.7	12.8	23	1.3
Vestal	66	11.9	18.8	11.6	19.5	0.7

Table H.5

With the proposed RNU

Three – Phase-to-Ground Fault Analysis

Bus Name	Bus KV	PRE QC5 Phase 1		POST QC5 Phase 1		DELTA KA
		X/R	KA	X/R	KA	
Colorado River	500	26.6	24	27	24.4	0.4
Eldorado	500	14	46.7	14.4	47.6	0.9
Serrano	500	25	32.7	25.2	32.9	0.2
Red Bluff	500	23.4	23.3	23.5	23.5	0.2
Chino	230	16.1	50.9	16.1	51.3	0.4
Colorado Rvr	230	39.8	46	40.8	47.5	1.5
Cool Water	230	20.8	15.8	20.8	16	0.2
Devers	230	25.9	52.1	25.9	52.6	0.5
Eldorado	230	17	56.2	17.1	56.4	0.2
Eldorado_2	230	20.1	40.5	20.8	42	1.5
Etiwanda	230	25.1	55.3	25.7	58.8	3.5
Highwind_230	230	21.5	18.6	24	22.1	3.5
Inyokern	230	6.2	11	6.3	11.3	0.3
Kramer	230	14.8	20.8	15.5	21.7	0.9
Merchant_2	230	16.4	50.9	16.5	51.1	0.2
Mira Loma A	230	20.2	54.4	20.1	54.6	0.2
Mira Loma B	230	21.8	59.3	21.8	60.9	1.6
Pardee	230	15.5	61.1	15.5	61.2	0.1
Pastoria	230	13.3	30.8	13.4	31.2	0.4
Rancho	230	25	56	25.6	59.3	3.3
San Ber_dino	230	24.8	41.5	24.7	42	0.5
Serrano	230	25	57.5	25.1	57.6	0.1
Vista	230	20.3	49.4	20.3	50.5	1.1
Wildlife	230	15.2	24.9	15.2	25.1	0.2
Jasper	230	12.3	15	12.9	15.5	0.5
Devers_B	115	0	0	23.3	24.8	24.8
Inyokern	115	5.7	12.7	6	13.8	1.1
Kramer	115	11.9	25.7	12.9	27.1	1.4
Victor	115	18.5	24.1	18.6	24.3	0.2
Farrell	115	9.5	14.5	9.2	15.1	0.6
Indigo	115	16.1	19.7	14.8	21	1.3
Garnet	115	17.3	20.7	15.9	22.9	2.2
Leatherneck	115	0	0	3.1	2.1	2.1
Mogen	115	3.1	6.3	5	10.3	4
Rocket Test	115	3.1	5.6	3.1	5.7	0.1
US Borax	115	3.2	6.3	5.3	10.3	4
ANTELOPE	66	44.1	39.8	43.1	40.2	0.4
Etiwanda A	66	41	23.8	41.4	23.9	0.1
Highwin66	66	0	0	50	12.7	12.7
Padua	66	31.8	25.6	31.9	25.8	0.2
Rector	66	12.5	20.7	12.2	22.2	1.5
Vestal	66	12.6	22.4	12.6	22.9	0.5
CAL CEMENT	66	20.6	19.3	20.5	19.6	0.3

DEL SUR	66	12.4	27	12.3	27.2	0.2
ROSAMOND	66	3.8	9.1	3.9	9.4	0.3
GREAT LAKES	66	3	6.4	3	6.6	0.2
Windhub66_A	66	48	24.7	48.9	25.2	0.5
Windhub66_B	66	63.2	14.5	63.8	14.7	0.2

Table H.6
With the proposed RNU
Single-Phase-to-Ground Fault Analysis

Bus Name	Bus KV	PRE QC5 Phase 1		POST QC5 Phase 1		DELTA KA
		X/R	KA	X/R	KA	
Colorado Rvr	500	22.3	23.8	23	24.4	0.6
Eldorado	500	12.7	41.7	13	42.6	0.9
Red Bluff	500	14.9	20.9	14.9	21	0.1
Serrano	500	12.9	29.2	12.9	29.3	0.1
Vincent	500	14.8	40.2	15.6	40.6	0.4
Chino	230	13.7	42.6	13.7	42.8	0.2
Colorado Rvr	230	29.5	52.5	30.5	55.6	3.1
Cool Water	230	21.6	16	21.4	16.1	0.1
Devers	230	22.2	56.7	22.3	57.4	0.7
Eldorado	230	15.9	53.3	16.1	53.5	0.2
Eldorado_2	230	20.6	45.3	21	48.1	2.8
Ellis	230	17.8	36.8	17.1	37.9	1.1
Etiwanda	230	16.8	55.5	17	59	3.5
Highwind_230	230	14.3	14.7	19	20.7	6
Inyokern	230	7.4	8.6	7.6	8.7	0.1
Jasper	230	9.2	10.6	11.3	13.2	2.6
Kramer	230	10.4	18.1	10.5	18.5	0.4
Lebec	230	12	23.1	16.6	30.3	7.2
Merchant_2	230	14.5	47.4	14.6	47.5	0.1
Mira Loma A	230	11.8	55.1	11.7	55.3	0.2
Mira Loma B	230	10	54.4	9.9	55.4	1
Pastoria	230	13.1	28	14.4	32.9	4.9
Rancho	230	16.4	56.9	16.5	60	3.1
San Ber_dino	230	24.2	41.6	24.2	41.9	0.3
Vincent A	230	19.6	66.4	19.8	66.7	0.3
Vincent B	230	19.6	66.4	19.8	66.7	0.3
Vista	230	15.6	44.3	15.4	45.1	0.8
Whirlwind	230	31.4	58.1	31.6	58.2	0.1
Whirlwind_2	230	31.4	58.1	31.6	58.2	0.1
Windhub_A	230	42.2	36.6	39.4	39.6	3
Windhub_B	230	46.3	36.1	46.9	40.7	4.6
Devers_B	115	0	0	23	27.2	27.2
Inyokern	115	6.8	13.9	7.4	14.7	0.8
Kramer	115	11.9	25.5	12.5	27	1.5
Victor	115	17.9	26.8	17.9	26.9	0.1
Farrell	115	9.3	13.4	9.1	13.7	0.3
Garnet	115	12.1	19.4	11.3	21	1.6
Leatherneck	115	0	0	4.1	2.1	2.1
Mogen	115	4	5.2	5.3	8.3	3.1
Rocket Test	115	4.3	4.5	4.3	4.6	0.1
US Borax	115	3.9	4.9	5.2	7.8	2.9
ANTELOPE	66	26.8	24.2	24.7	25.1	0.9
Etiwanda A	66	43.8	22.9	44.1	23	0.1

Highwin66	66	0	0	21.8	9.7	9.7
Rector	66	13.1	21.7	12.8	23	1.3
Vestal	66	11.9	18.8	11.6	19.5	0.7
GREAT LAKES	66	4.2	3.4	4.2	3.7	0.3
Windhub66_A	66	27.3	15.3	27.3	15.4	0.1