DOCKETED

Docket Number:	16-AFC-01
Project Title:	Stanton Energy Reliability Center
TN #:	214207-9
Document Title:	Appendix 3A - Interconnection Request Studies
Description:	Application for Certification Vol. 2
Filer:	Sabrina Savala
Organization:	Stanton Energy Reliability Center, LLC
Submitter Role:	Applicant
Submission Date:	10/27/2016 10:23:29 AM
Docketed Date:	10/26/2016

Appendix 3A
Interconnection Request Studies

Appendix 3A-1
Phase II Interconnection Study Report

Queue Cluster 7 Phase II Interconnection Study Report

SCE Metro Bulk Area Report

Final Report

11/24/2015

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

Appendices

A. Introduction

In accordance with the California Independent System Operator (CAISO) Generator Interconnection and Deliverability Allocation Procedures (GIDAP) Tariff Appendix DD, this Queue Cluster 7 (QC7) Phase II Study was performed to determine the combined impact of all the QC7 Phase II projects on the CAISO Controlled Grid.

There were 19 QC7 Phase II generation projects in Southern California Edison (SCE) and Valley Electric Association's (VEA) service territory modeled in the Phase II Study. Five (5) general study areas were formed based on the electrical impact among the generation projects: Northern Area, Eastern Bulk Area, East of Pisgah (EOP) Bulk Area, North of Lugo (NOL) Bulk Area and Metro Area. In the Metro Area, there are no QC7 Phase II projects interconnecting to the CAISO Controlled Grid. This report focuses on the Metro Bulk Area, which covers the LA Basin but focuses on the Orange County area encompassed by Alamitos, Del Amo, Center, Lewis, Serrano, Chino, Viejo, Santiago, Johanna, and Ellis Substations. This report provides the following:

- Transmission system impacts caused by the addition of QC7 Phase II projects requesting interconnection in the area,
- System reinforcements necessary to mitigate the adverse impacts under various system conditions of the QC7 Phase II projects requesting interconnection in the area,
- A list of required facilities and maximum cost responsibility for Reliability Network Upgrades (RNUs) and Local Delivery Network Upgrades (LDNUs) assigned to each QC7 Interconnection Request (IR),
- A cost estimate of Area Delivery Network Upgrades (ADNUs) for each QC7 IR that has selected Option (B),
- A good faith estimate of the Interconnection Facilities cost,
- A good faith estimate of time to construct the Network Upgrades and Interconnection Facilities (IF) for each QC7 IR.

To determine the system impacts caused by QC7 Phase II projects, the following studies were performed:

- Steady State Power Flow Analyses
- Short Circuit Duty (SCD) Analyses
- Transient Stability Analyses
- Post-Transient Voltage Analyses
- Deliverability Assessment
- Service Date and Commercial Operation Date Assessment

A.1 QC7 Phase II Generation Project Interconnection Information

A total of five (5) generation projects made up of a total of 266.8 MW seeking interconnection into the QC7 Phase II Metro Area. All five generation projects are seeking distribution interconnections to facilities served out of the SCE's Non-CAISO controlled Barre and Johanna Sub-transmission systems. Table A.1 lists all the new generator projects in the Metro Area with essential data obtained from the SCE WDAT Generation Queue.

Table A.1: SCE QC7 Phase II Projects (Metro Sub-transmission Systems)

#	SCE#	Deliverability	Fuel Type	Project Size (MW)	Point of Interconnection (CAISO Delivery Point)	COD
1	WDT1185	Full Capacity	BESS	20 MW	Two (2) Chestnut 12 kV circuits (Johanna 220 kV Switchrack)	12/01/2019
2	WDT1188	Full Capacity	Natural Gas	47 MW	Johanna 66 kV switchrack (Johanna 220 kV Switchrack)	12/01/2020
3	WDT1189	Full Capacity	Natural Gas	150 MW	Barre 66 kV switchrack (Barre 220 kV Switchrack)	06/01/2018
4	WDT1192	Full Capacity	BESS	40 MW	Johanna-Cabrillo 66 kV line (Johanna 220 kV Switchrack)	12/31/2018
5	WDT1206	Full Capacity	BESS	9.8 MW	One (1) Johanna 12 kV circuit (Johanna 220 kV Switchrack)	6/01/2016
TOTAL = 266.8 MW (5 Projects)						

A.2 Study Objectives

This QC7 Phase II deliverability assessment was performed in accordance with Section 8.1 of Appendix DD of the CAISO Tariff, which states the Phase II Interconnection Study shall:

i. Update, as necessary, analyses performed in the Phase I Interconnection Studies to account for the withdrawal of IRs from the current Queue Cluster;
ii. Identify final RNUs needed to physically and reliably interconnect the Generating Facilities and provide final cost estimates;
iii. Identify final LDNUs needed to interconnect those Generating Facilities selecting Full Capacity or Partial Capacity Deliverability Status and provide final cost estimates;
iv. Identify final ADNUs for Interconnection Customers selecting Option (B), as provided below and provide revised cost estimates;
v. Identify, for each IR, the Participating TO's Interconnection Facilities for the final Point of Interconnection (POI) and provide a +/-20% cost estimate; and
vi. Coordinate in-service timing requirements based on operational studies in order to facilitate achievement of the Commercial Operation Dates of the Generating Facilities.

In order to achieve the above objectives, this same Section 8.1 explains what specific studies need to be done:

> The Phase II Interconnection Study report shall set forth the applicable cost estimates for RNUs, LDNUs, ADNUs and Participating TOs Interconnection Facilities that shall be the basis for Interconnection Financial Security Postings under Section 11.2 and 11.3 Where the cost estimations applicable to the total of RNUs and LDNUs are based upon the Phase I Interconnection Study (because the cost estimation for the subtotal of RNUs and LDNUs were lower and so establish maximum cost responsibility under Section 10.1), the Phase II Interconnection Study report shall recite this fact.

The Phase II Study analysis was performed to identify the conceptual IF, Plan of Service RNUs, RNUs, LDNUs, ADNUs, and Distribution Upgrades necessary to safely and reliably interconnect the QC7 Phase II projects and provide the requested deliverability. An estimated cost and construction schedule for these facilities is provided in this report.

B. Study Assumptions

B.1 Load and Intertie Flow Assumptions

The 2019 On-Peak reliability cases modeled 26,013 MW load (1-in-10 load forecast). The 2019 Off-Peak reliability cases modeled 15,498 MW, approximately 60% of On-Peak load.

The Deliverability Assessment On-Peak case modeled a 24,331 MW load (1-in-5 load forecast) in the SCE system with an import target as shown in Table 3-1 of Appendix B.

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 area.

B.2 Generation Dispatch Assumptions

Generation assumptions for the area are shown in the tables[1] provided in Appendix B.

Generation dispatch assumptions in Deliverability Assessment can be found at:
http://www.caiso.com/Documents/On-PeakDeliverabilityAssessmentMethodology.pdf.
In the On-Peak Deliverability Assessment, the existing Full Capacity generators in the Metro area are modeled for their net qualifying capacities. The generators seeking interconnection with Full Capacity Deliverability Status in the Metro are modeled for the requested maximum net outputs.

In both the On-Peak and the Off-Peak Reliability Assessment, all generation is dispatched at 100% for the study area or sub-areas.

B.3 Transmission System Assumptions

The QC7 Phase II Study included the modeling of all CAISO-approved transmission projects in the area base cases that are not yet fully constructed and placed into service. This includes the following CAISO-approved transmission projects:

[1] These tables reflect the latest project information at the time the study was performed and may not reflect the numerous changes to the queue (i.e. withdraws, project size reductions, etc.) that have taken place during the course of the study.

B.3.1 Upgrades Identified through the Generation Interconnection Process which are included in an executed LGIA

i. The Tehachapi Renewable Transmission Project (TRTP)

All of the Tehachapi Renewable Transmission Project ("TRTP") overhead transmission has been constructed enabling in-servicing the segments listed above. The remaining TRTP construction involves the underground work in Chino Hills and is necessary to enable in-servicing of the Mira Loma-Vincent 500 kV transmission line. This work is currently estimated to be completed in 2016.

ii. Previously Identified Vincent SCD Mitigation

The need to replace the following four 50 kA 500 kV circuit breakers to increase the rated interrupting current was identified as part of the QC3&4 studies:

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

B.3.2 Upgrades Identified Through the 2013-2014 CAISO Transmission Plan

Studies performed under the CAISO 2013-2014 Transmission Plan have identified the need for transmission upgrades to enable the grid infrastructure to serve load in a reliable manner. Approved transmission upgrades include the following:

i. Harry Allen – Eldorado 500 kV Project

The project consists of constructing a new 500 kV transmission line from Harry Allen to Eldorado.

ii. Delany-Colorado River 500 kV (DLCR) Project

The project consists of constructing a new 500 kV transmission line from Delaney 500 kV Substation located in Arizona to SCE's Colorado River 500 kV Substation.

iii. Eldorado Line Swap Project

The project consists of reconfiguring the Eldorado – Moenkopi and Eldorado – Mohave 500 kV T/Ls to eliminate the adjacent circuit transmission corridor contingency of the Eldorado – Lugo and Eldorado – Mohave 500 kV T/Ls per WECC regional criteria which drives an overload problem.

iv. Eldorado-Lugo Series Capacitor Project

The project consists of upgrading the series capacitor banks located at Eldorado and Lugo Substations on the Eldorado – Lugo 500 kV T/L to a rating of 3,800 A (normal) and 4,000 A (emergency). The project also includes equipping the Eldorado – Lugo 500 kV T/L terminating positions at Eldorado and Lugo Substations with 4,000 A rated equipment.

v. **Lugo-Mohave Series Capacitor Project**

The project consists of upgrading the series capacitor banks located at Mohave Substations on the Lugo – Mohave 500 kV T/L to a rating of 3,800 A (normal) and 4,000 A (emergency). The project also includes equipping the Lugo-Mohave 500 kV T/L terminating positions at Lugo and Mohave Substations with 4,000 A rated equipment.

vi. **Mesa Loop-In Project**

The project consists upgrading the substation to include a 500 kV switchrack and three 500/220 kV transformer banks served by looping the Vincent-Mira Loma 500 kV transmission line, Rio Hondo-Laguna Bell 220 kV transmission line and Goodrich-Laguna Bell 220 kV transmission line in-and-out of the Mesa substation. In addition, the project includes upgrading the Laguna Bell-Mesa No.1. These upgrades are expected to be completed in 2020.

vii. **Laguna Bell Corridor Upgrade Project**

The project upgrades Mesa – Laguna Bell No. 1 and No. 2 and Mesa – Lighthipe 220 kV lines to their conductor ratings. The project includes upgrading the Laguna Bell-Mesa No.1, southern portion of the Laguna Bell-Rio Hondo (portion that will become the future Laguna Bell-Mesa No.2 220 kV) and the Mesa-Lighthipe 220 kV lines to their conductor rating by replacing terminal equipment at Laguna Bell and Lighthipe Substations and removing transmission line clearance limitations on one span each of the Laguna Bell – Mesa No. 1 and Lighthipe – Mesa 220 kV lines. These upgrades are expected to be completed in 2020.

viii. **Victor Loop-In Project**

The project consists of looping the existing Kramer-Lugo No.1 and No.2 220 kV transmission lines into the existing Victor Substation in order to mitigate transient voltage dip concerns identified under loss of both the existing Lugo-Victor No.1 and No.2 220 kV transmission lines. As part of the Project, both the Mojave Desert SPS and HDPP SPS described below will be modified to reflect the system topology. Upon completion of the project, the existing Kramer-Lugo No.1 and No.2 220 kV transmission lines will become the Kramer-Victor No.1 and No.2 220 kV lines and the Lugo-Victor No.3 and No.4 220 kV transmission lines.

Due to the construction requirements of the upgrades discussed above, queued generation projects may be subject to increased exposure to congestion management, i.e. generation curtailments while upgrades are under construction. The extent of congestion is dependent on many factors including the actual in-service date of queued generation projects.

B.4 Existing Special Protection Systems (SPS) and Operating Procedures

Existing System Operating Bulletins (SOB) and Operating Procedures (OP) may be relevant for QC7 Study analysis in the SCE Metro System. These include, but are not limited to, the following:

- Critical System Voltage
- System Voltage Control

Additionally operating procedures, which may include curtailing the output of the QC7 Phase II projects during planned or extended forced outages may be required for reliable operation of the transmission system. These procedures, if needed, will be developed before the projects' COD.

B.5 Upgrades Identified through the Generation Interconnection Process which are not included in an executed LGIA

i. Barre – Del Amo Line Upgrade

The upgrade will remove existing clearance limitation on the Barre – Del Amo 220kV transmission line and increase the line emergency rating to 3360 amps.

ii. Previously Identified Del Amo SCD Mitigation

As part of the QC6 Phase II studies, the need to install nine (9) sets of TRV capacitors to increase the rated interrupting current on the following six circuit breakers were identified:

- Pos. No. 4 CB4042 and CB6042
- Pos. No. 6 CB4062 and CB6062
- Pos. No. 8 CB4082 and CB6082

B.6 Pre-QC7 Affected System Transmission Upgrades

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

B.7 Power Flow Base Cases

The QC7 Phase II Study power flow cases were developed from the CAISO approved transmission expansion base case series representing year 2019 load forecast (On-Peak and Off-Peak load conditions). These power flow study cases included all CAISO approved transmission projects impacting SCE's service territory, as well as all earlier queued Serial Group and cluster generation projects with associated Network Upgrades regardless of the in service date.

The following power flow cases were used for the reliability analysis in the area QC7 Phase II Study:

2019 On-Peak Full Loop Power Flow Case:

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

2019 Off-Peak Full Loop Power Flow Case:

Power flow analyses were also performed using the Off-Peak full loop base case in order to evaluate system performance due to the addition of Phase I generation projects during light load conditions. The Off-Peak load was modeled approximately 60% of the On-Peak load level.

B.8 Deliverability Base Cases

B.8.1 Master Deliverability Assessment Base Case

A master base case was developed for the QC7 Phase II On-Peak deliverability assessment which modeled all the Pre-QC7 Phase II and QC7 Phase II generation projects. The resources in the master base case are dispatched as follows:

- Existing capacity resources are dispatched at 80% of their summer peak Net Qualified Capacity (NQC).
- Proposed full capacity resources are dispatched to balance load and maintain expected imports, but not exceeding 80% of their summer peak NQC.
- Energy-Only (EO) resources are considered off-line.
- Imports are at the maximum summer peak simultaneous historical level by branch group as shown in Table 3-1 in Appendix B.
- Non-pump load is at the 1-in-5 peak load level for CAISO.
- Pump load is dispatched within expected range for summer peak load hours.

B.8.2 SCE Metro Area Deliverability Assessment Base Case

The SCE Metro Area deliverability assessment base case was developed from the master base case by dispatching all proposed full capacity resources in the Metro Area to 80% of their NQC.

C. Reliability Standards, Criteria and Methodology

C.1 Reliability Standards and Criteria

The generator interconnection studies were 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.

C.1.1 NERC Reliability Standards

The studies analyzed 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 ISO, 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[2]:

- FAC-001: Facility Connection Requirements[3]
- FAC-002: Coordination of Plans for New Facilities[4]
- TPL-001-4: Transmission System Planning Performance Requirements[5]

C.1.2 WECC Regional Criteria

The WECC System Performance TPL-001-WECC-CRT-2.1[6] Regional Criteria are applicable to the ISO as a planning authority and set forth additional requirements that must be met under a varied but specific set of operating conditions.[7]

C.1.3 California ISO Planning Standards

The California ISO Planning Standards specify the grid planning criteria to be used in the planning of ISO transmission facilities.8 The objectives of these standards are to:

- 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 ISO Controlled Grid; and to
- identify whether specific criteria should be adopted that are more stringent than the NERC standards or WECC regional criteria.

C.1.4 Contingencies

The system performance with the addition of the generation projects will be evaluated under normal conditions (**Category P0**) and following loss of single or multiple BES elements as defined by the applicable reliability standards and criteria. Refer to Appendix C for a complete list of specific contingencies evaluated.

Single contingency (Category P1)

The assessment will consider all possible Category P1 contingencies based upon the following:

- 3Φ Fault with loss of one generator (P1.1)[9]
- 3Φ Fault with loss of one transmission circuit (P1.2)

---

[2] http://www.nerc.com/pa/stand/Pages/ReliabilityStandardsUnitedStates.aspx?jurisdiction=United States

[3] http://www.nerc.com/files/FAC-001-1.pdf; FAC-001 is applicable to the PTOs, but not to the ISO

[4] http://www.nerc.com/files/FAC-002-2.pdf

[5] http://www.nerc.com/files/TPL-001-4.pdf; FAC-002 requires the assessment being performed in accordance with TPL-001 through TPL-003, which are replaced by TPL-001-4. Analysis of Extreme Events is not performed in the Phase II study as it is not included in TPL-001 through TPL-003.

[6] https://www.wecc.biz/Reliability/TPL-001-WECC-CRT-2.1.pdf

[7] http://compliance.wecc.biz/application/ContentPageView.aspx?ContentId=71

[8] http://www.caiso.com/Documents/FinalISOPlanningStandards-April12015_v2.pdf

[9] Includes per California ISO Planning Standards – Loss of Combined Cycle Power Plant Module as a Single Generator Outage Standard.

- 3Φ Fault with loss of one transformer (P1.3)
- 3Φ Fault with loss of one shunt device (P1.4)
- SLG Fault with loss of a single pole of DC lines (P1.5)

Notes:

1. The purpose of generation interconnection studies is to evaluate stressed system conditions due to the addition of new generators. Because Category P1.1 would not provide for such stressed conditions, the study results would not properly identify potential impacts corresponding to the projects seeking interconnection. As such, Category P1.1 was not evaluated as part of the Phase II studies but is addressed as part of SCE's Annual Expansion Studies performed in coordination with the CAISO.

2. Category P1.5 is not applicable in the Metro Area as no DC lines exist within this area. Category P1.5 was examined as part of the QC7 GIP studies performed for the East of Pisgah Area (Intermountain DC line) and Northern Area (Pacific DC Intertie).

Single contingency (Category P2)

The assessment will consider all Category P2 contingencies based upon the following:

- Loss of one transmission line section without a fault (P2.1)
- SLG Fault with loss of one bus section (P2.2)
- SLG Fault with loss of one breaker (internal fault) (non-bus-tie-breaker) (P2.3)
- SLG Fault with loss of one breaker (internal fault) (bus-tie-breaker) (P2.4)

Notes:

1. Category P2.1 is not applicable for the Metro Bulk area as there are no multi-segmented bulk transmission lines.

2. Category P2.2 is only applicable at the Alamitos, Huntington Beach, Mira Loma, Mesa (future), San Onofre, Santiago, and Walnut Substations in the Metro area bulk system; however, all of the aforementioned substation designs are such that loss of one bus section does not result in any additional P2.2 impacts that are not already addressed as part of Category P1.

3. All of the Metro area bulk substations are designed as either double-bus, double-breaker or breaker-and-a-half configuration. Such design configuration results in Category P2.3 power flow conditions to be the same as Category P4. For stability, Category P4 would experience more severe performance due to the associated delayed clearing. As such, Category P2.3 will be examined as part of Category P4 power flow. Under stability analysis, if criteria violation is identified with delayed clearing, normal clearing will also be reviewed.

4. With the exception of the Walnut Substation, the substation design in this Metro area is such that loss of one bus-tie breaker does not result in any additional impact that is not already addressed as part of Category P1. As a result, the only Category P2.4 contingency requiring evaluation in the Metro area is loss of the SCE either the North bus section at Walnut, or the South bus section.

Multiple contingency (Category P3)

The assessment will consider selected Category P3 contingencies with the loss of a ***generator unit*** followed by system adjustments and the loss of the following:

- 3Φ Fault with loss of one generator (P3.1)[10]
- 3Φ Fault with loss of one transmission circuit (P3.2)
- 3Φ Fault with loss of one transformer (P3.3)
- 3Φ Fault with loss of one shunt device (P3.4)
- SLG Fault with loss of a single pole of DC lines (P3.5)
- SLG Fault with loss of both poles of the Pacific DC Intertie (WECC exemption)

Notes:
1. The purpose of generation interconnection studies is to evaluate stressed system conditions due to the addition of new generators. Because Category P3 would not provide for such stressed conditions, the study results would not properly identify potential impacts corresponding to the projects seeking interconnection. As such, none of Category P3 was not evaluated as part of the Phase II studies but is addressed as part of SCE's Annual Expansion Studies performed in coordination with the CAISO.

Multiple contingency (Category P4)

The assessment will consider selected Category P4 contingencies with the loss of multiple elements caused by a stuck breaker (non-bus-tie-breaker for P4.1-P4.5 and bus-tie-breaker for P4.6) attempting to clear a SLG fault on one of the following:

- generator (P4.1)
- transmission circuit (P4.2)
- transformer (P4.3)
- shunt device (P4.4)
- bus section (P4.5)
- loss of multiple elements caused by stuck breaker (bus-tie-breaker) attempting to clear a fault on associated bus (P4.6)

Notes:

E. The purpose of generation interconnection studies are to evaluate stressed system conditions due to the addition of new generators. Because Category P4.1 would not provide for such stressed conditions, the study results would not properly identify potential impacts corresponding to the projects seeking interconnection. In addition, the CAISO utilizes market re-dispatch protocols to ensure that adequate generation dispatch conditions are implemented following loss of any transmission element in Category P4 in order to maintain system performance within standards in anticipation of the next contingency. This re-dispatch may involve curtailment of the generation resources, including those studied as part of this queue cluster. As such, Category P4.1 was not evaluated as part of the GIP studies but is addressed as part of SCE's Annual Expansion Studies performed in coordination with the CAISO.

[10] Includes per California ISO Planning Standards – Loss of Combined Cycle Power Plant Module as a Single Generator Outage Standard.

2. Within the Metro Area impacting Orange County (QC7 sphere of influence), shunt devices are installed at Barre, Chino Johanna, Laguna Bell, Olinda, Santiago, Viejo, Villa Park, Walnut, and Mira Loma substations. Except for Johanna, all substations are designed as a double-bus, double-breaker or breaker-and-a-half with all elements on bus which connects shunt device fully equipped with circuit breakers. This Category P4.4 power flow conditions are therefore the same as Category P1.4 power flow conditions for all stations except Johanna.

3. Category P4.5 (loss of multiple elements/bus section caused by a stuck breaker attempting to clear a fault on associated bus) results in the same power flow performance as Category P2.4 for the substations in the Metro area and therefore addressed under Category P2.4.

4. Category P4.6 (loss of multiple elements/bus-tie breaker caused by a stuck breaker) results in the same power flow performance as Category P2.2 and/or P2.4 for the substations in the Metro area and therefore addressed under Category P2.2 and/or P2.4.

Multiple contingency (Category P5)

The assessment will consider selected Category P5 contingencies with delayed fault clearing due to the failure of a non-redundant relay protecting the faulted element to operate as designed, for one of the following:

- SLG Fault with loss of one generator (P5.1)
- SLG Fault with loss of one transmission circuit (P5.2)
- SLG Fault with loss of one transformer (P5.3)
- SLG Fault with loss of one shunt device (P5.4)
- SLG Fault with loss of one bus section (P5.5)

Notes:

1. The purpose of generation interconnection studies is to evaluate stressed system conditions due to the addition of new generators. Because Category P5.1 would not provide for such stressed conditions, the study results would not properly identify potential impacts corresponding to the projects seeking interconnection. As such, Category P5.1 was not evaluated as part of the GIP studies but is addressed as part of SCE's Annual Expansion Studies performed in coordination with the CAISO

2. Category P5 power flow conditions to be exactly the same as Category P4.1 (back-up protection results in delayed removal of faulted element) or the same as Category P4 (Zone 2 protection behaves similar to stuck breaker protection). As such, power flow will address Category P5 under Category P1 or Category P4 analysis.

Multiple contingency (Category P6)

Because the CAISO implements congestion management protocols that curtail generation resources under loss of a system element in preparation for the next contingency, the assessment assumed that the new generations could be curtailed following the first contingency as needed. Therefore, the assessment did not consider Category P6 contingencies which involves the loss of two or more (non-generator unit) elements with system adjustment between them. However, Category P6 is addressed as part of SCE's Annual Transmission Planning Process which ensures system is adequate to maintain appropriate level of service to load demand.

Multiple contingency (Category P7)

The assessment will consider all possible Category P7 contingencies for the SLG fault with the loss of a common structure as follows:

- Any two adjacent circuits on common structure[11] (P7.1)
- Loss of a bipolar DC lines (P7.2)

Notes:
Category P7.2 is not applicable in the Metro Area as no DC lines exist within this area. Category P7.2 was examined as part of the QC7 GIP studies performed for the East of Pisgah Area (Intermountain DC line) and Northern Area (Pacific DC Intertie).

WECC Regional Criteria Adjacent Circuits

The assessment will consider all possible contingencies for the SLG fault with

- Loss of two Adjacent Transmission Circuits[12] per WECC regional criteria

The same performance criteria applicable to P7 contingencies are applied to WECC regional criteria adjacent circuit outages in Sections 4.2 to 4.5.

All possible P1 except for P1.1, P2, P7 and WECC adjacent circuit contingencies are studied. Contingencies in Categories P3 through P6 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

C.2 Steady State Study Criteria

C.2.1 Normal Overloads

Normal overloads are those that exceed 100 percent of normal facility rating under Category P0 normal conditions (no contingency). Normal overloads are identified in deliverability assessment and reliability study power flow analyses in accordance with Reliability Standard TPL-001-4. It is required that loading of all transmission system facilities be within their normal ratings under the Category P0 conditions.

C.2.2 Emergency Overloads

Emergency overloads are those that exceed 100 percent of emergency ratings under Category P1 to P7 contingency conditions. Emergency overloads are identified in the deliverability assessment and reliability study power flow analyses in accordance with Reliability Standards TPL-001-4. It is

[11] Excludes circuits that share a common structure or common right-of-way for 1 mile or less.
[12] https://www.wecc.biz/_layouts/15/WopiFrame.aspx?sourcedoc=/Reliability/WECC Glossary and Naming Conventions Updated 8-11-2014.pdf&action=default&DefaultItemOpen=1

required that loading of all transmission system facilities be within their emergency ratings under the Category P1 to P7 contingency conditions.

C.2.3 Voltage Criteria

All buses within the ISO Controlled Grid that cannot meet the requirement in Table C.2 will be further investigated. Exceptions to this voltage standard granted by the ISO will be observed in the Phase II Study.

Table C.2: Voltage Criteria
(Bus voltages are relative to the nominal bus voltages of the system under study)

Voltage level	Normal Conditions* (P0)		Contingency Conditions (P1 ~ P7)		Voltage Deviation	
	Vmin (pu)	Vmax (pu)	Vmin (pu)	Vmax (pu)	P1 ~ P3	P4 ~ P7
≤ 200 kV	0.95	1.05	0.90	1.1	≤5%	≤10%
200 kV ~ 500kV	0.95	1.05	0.90	1.1	≤5%	≤10%
≥ 500 kV	1.0	1.05	0.90	1.1	≤5%	≤10%

*Real-time operating system voltages in this area range from 520 – 530 kV for 500 kV systems and 220 – 228 kV for 220 kV systems.

C.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. Transient stability studies are performed to ensure system stability following severe system disturbances.

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

- 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);
- A stability simulation will be deemed to exhibit positive damping if a curve defined by the peaks of the machine relative rotor angle swing curves tends to intersect a second curve defined by the valleys of the relative rotor angle swing curves with the passing of time. Corresponding lines on bus voltage swing curves will likewise tend to intersect. A stability simulation, which satisfies these conditions, will be defined as stable;
- Duration of a stability simulation run will be ten (10) seconds unless a longer time is required to ascertain damping;
- The transient performance analysis will start immediately after the fault clearing and conclude at the end of the simulation and;
- 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.

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

Table C.3: WECC Disturbance-Performance Table of Allowable Effects on Other Systems
(in addition to NERC requirements) [13]

Performance Level	Disturbance	Transient Voltage Dip Criteria	Minimum Transient Frequency
P1 and P2.1	Generator	Max V Dip – 25% Max Duration of V Dip Exceeding 20% - 20 cycles Not to exceed 30% at non-load buses.	59.6 Hz for 6 cycles or more at a load bus.
	Circuit		
	Transformer		
	Shunt Device		
	Single pole of a DC line		
	PDCI		
P2[14]-P7	Bus Section Fault	Max V Dip – 30% at any bus. Max Duration of V Dip Exceeding 20% - 40 cycles at load buses	59.0 Hz for 6 cycles or more at a load bus.
	Internal Breaker Fault		
	Multiple contingency events		

C.4 Post-Transient Voltage Deviation Criteria

Contingencies that showed significant voltage deviations in the power flow studies will be selected for further analysis using WECC standard of 5% voltage deviation for single contingencies and 10% voltage deviation for contingencies involving multiple elements.

C.5 Power Factor Criteria

Table C.5 summarizes the power factor criteria per the CAISO tariff for the projects.

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

Generation Type	Power Factor Criteria
Asynchronous Generator[15]	0.95 lagging to 0.95 leading at the POI[16]
Synchronous Generator	0.90 lagging to 0.95 leading at generator terminals

[13] Table 3 represents CAISO's interpretation of how NERC categories B and C would relate to the contingency categories defined in TPL-001-4. WECC Regional Criterion that addresses TPL_001-4 is currently under development. For disturbances not included in the WECC Category B, e.g. shunt device outages, the criteria is used to screen potential performance issues for further investigation.

[14] Performance level for P2.1 is to be the same as P1.

[15] An induction, doubly-fed, or electronic power generating unit(s) that produces 60 Hz (nominal) alternating current, such as solar PV, wind, battery storage generator, etc.

[16] The CAISO Tariff requires that projects be able to meet power factor requirements of 0.95 lagging and 0.95 leading at the POI, if studies identify the need based on meeting reliability and safety requirements.

C.6 Short Circuit Duty Assessment Criteria

C.6.1 Reliability Standards and 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.

SCE uses the following policy to determine breaker replacement responsibility for cluster projects that overstress or increase overstress on existing circuit breakers:

- The fault duties are calculated before and after current cluster projects to identify any equipment overstress conditions. Three-phase (3PH) and single line-to-ground (SLG) faults are simulated without the current cluster projects and with the current cluster projects including the identified Reliability and Local Delivery Network Upgrades from the power flow analysis.

- All bus locations where the current cluster 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 identified. These are examined further to determine if any equipment is overstressed as a result of the current cluster interconnections and corresponding network upgrades.

- Thereafter, the fault duties are then calculated with the addition of ADNUs for current cluster Option (B) projects.

If any equipment is overstressed as a result of the ADNUs, the responsibility to finance circuit breaker upgrades associated with the ADNUs shall be assigned to the projects requiring the ADNU based on the same factors used to allocate the ADNU. The responsibility to finance short circuit related Reliability Network Upgrades identified shall be assigned to all contributing Irs (projects) pro rata based on their short-circuit duty contribution. Furthermore, if a proposed network upgrade triggers an adverse short circuit impact, the responsibility to finance such short circuit related RNU shall be assigned to the projects contributing to the network upgrade based on the same factors used to allocate the proposed network upgrade cost.

C.6.2 Application Queue Post QC7 Phase II Projects

Application queue short circuit duty (SCD) studies were performed to determine the impact on circuit breakers with the interconnection of QC7 Phase II projects to the transmission system. The application queue considered all existing and higher queued generation interconnection projects and corresponding upgrades into the starting base cases as a pre-condition prior to adding the QC7 Phase II projects. In addition, the application queue included all CAISO approved transmission projects and all SCE approved non-CAISO upgrades and system modifications (such as open Mira Loma AA-Bank) into the starting base case as a pre-condition prior to adding the QC7 Phase II projects. The fault duties were calculated to identify any equipment overstress conditions. Three-phase (3PH) and single-line-to-ground (SLG) faults were simulated without the QC7 Phase II projects to establish the starting base line.

The QC7 Phase II projects, including the identified Reliability and Local and Area Delivery Network Upgrades from the power flow and stability analysis, were added to the starting base line and the fault duties were recalculated to identify the incremental impacts associated with the inclusion of the QC7 Phase II projects.

C.6.3 Ground Grid Evaluation of SCE Substations

The short circuit studies identified substations where the QC7 Phase II projects increased the substation ground grid duty by 0.25 kA or more. The SCE substations flagged to have ground grid duty concerns are disclosed in Section D.5 of the QC7 Phase II area group report.

C.7 Deliverability Methodology

C.7.1 On-Peak Deliverability Assessment Methodology

The assessment was performed following the On-Peak Deliverability Assessment methodology (http://www.caiso.com/Documents/On-PeakDeliverabilityAssessmentMethodology.pdf).

The main steps of the On-Peak deliverability assessment are described below.

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.

C.7.2 Local Deliverability Constraints and Area Delivery Constraints

In the Phase II 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 characteristics:

- 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 characteristics:

- 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 II 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 Irs 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 versus 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.

C.7.3 Identification of Area Delivery Network Upgrades

The CAISO performs a second round of the deliverability assessment to identify facilities necessary to provide deliverability for Option (B) projects beyond the level of Transmission Plan (TP) Deliverability for each Area Deliverability Constraint.

In the round 2 of the deliverability assessment, all LDNUs and RNUs identified in the round 1 study will be modeled. For each area deliverability constraint, an amount of generation that fully utilizes the TP Deliverability will be identified. Then Option (B) projects will be added to the generation fully utilizing TP Deliverability. ADNUs are identified to provide deliverability for all the Option (B) projects.

C.8 In-Service Date & Commercial Operating Date Assessment Methodology

The QC7 Phase II operational studies examined the following:

- In-service date feasibility evaluation for Plan of Service
- Generation Sequencing Implementation (GSI) short circuit duty evaluation
- Commercial Operation Date (COD) based operational deliverability assessment

C.8.1 In-Service Date Feasibility Evaluation for Plan of Service

The in-service date feasibility evaluation for each project's Plan of Service upgrades are provided in the corresponding Appendix A.

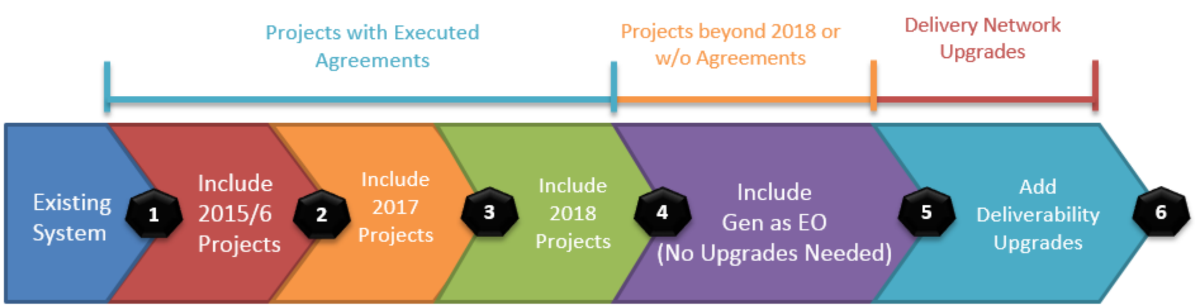
C.8.2 Generation Sequencing Implementation (GSI) SCD Evaluation

The GSI SCD evaluations are broken down into three categories. The description of each of the three categories and their corresponding study assumption is described below:

1. Short term (next 3 years): models generation projects with an executed Interconnection Agreement in good standing (not suspended) and approved transmission projects and network upgrades according to their CODs (3 base cases, one for each year)
2. Mid-term: models all generation projects and transmission without the long-lead-time DNUs. Generation projects requiring long-lead-time DNUs are interim EO. (one base case)
3. Long term: will model the long-lead-time DNUs of top of the mid-term DNUs. (one base case)

The GSI short circuit duty evaluation was performed to identify the timing for the need of short-circuit duty mitigations. The evaluation considered seven different scenarios as shown below in Figure C.1. The details on the GSI short circuit duty assessment are provided in Appendix G.

Figure C.1 –GSI SCD Evaluation



C.8.3 Commercial Operating Date (COD) Based Operational Delivery Assessment

The operational Deliverability Assessment follows the On-Peak Deliverability Assessment methodology. The key components of the operational Deliverability Assessments are discussed below.

Generation Interconnection Project Commercial Operation Date

The assessment models all the active generation projects according to their COD. The latest COD information will be collected as specified below:

- The COD in the Generator Interconnection Agreement (GIA) for executed GIAs or those GIAs that were filed unexecuted at FERC;
- The estimated COD in an approved modification request;
- The estimated COD in the latest study report for projects that have completed the interconnection studies but have not executed the GIA; or
- The requested COD for projects in the current cluster.

The COD will be further scrutinized for feasibility and adjusted if deemed infeasible. Factors used to adjust the COD include:

- Status and progress of the interconnection study or GIA negotiation.
- The estimated time for the Participating TO to complete the Interconnection Facilities and Network Facilities required for the generator interconnection.
- Other information provided by the Interconnection Customer (IC), such as notice to proceed with development of Interconnection Facilities or Network Facilities, and the Generating Facility's permitting, financing and construction status.

The adjusted COD will be used in the operational Deliverability Assessment. In particular, projects that have not signed GIAs or are not under construction are not considered as reasonable to have COD in the next year. The COD for such projects will be adjusted to a later future year based on the factors listed above.

Study Years

The operational Deliverability Assessment will be performed for each applicable future year until the year before all the required Delivery Network Upgrades are scheduled to be in service for the study group.

Modeling Requirements

For each study year, the operational Deliverability Assessment will model the generation projects with adjusted COD in or before the study year and Network Upgrade components that are projected to be in service in or before the study year. In case a generation project will be implemented in phases as defined in the executed GIA, the phasing of the project will be modeled.

The resources, including generation, load, and import, will be modeled in accordance with the On-Peak Deliverability Assessment methodology.

Method for Allocating Deliverable Partial Capacity

Assuming the system conditions cannot accommodate the full deliverability of all generators in the study area that will be in Commercial Operation for the study year, the partial deliverability of each generator is allocated as a function of the Queue Position, generator size, and generator flow impact on the transmission constraint that is binding in the deliverability power flow. For each deliverability constraint facility, the available capacity without the generation projects being tested is allocated to projects in the order from earlier queued projects to later queued projects until it is depleted. The projects in the same cluster are considered to have the same queue position. If there is available partial capacity for projects in the same cluster, the capacity is allocated using a weighted least square optimization.

The optimization allocation is formulated as:

$$Min \sum_{i=1}^{N} \frac{1}{\overline{D_i}} (\overline{D_i} - D_i)^2$$

$$s.t. \quad \sum_{i=1}^{N} D_i \cdot SF_{il} \le C_l, \quad l = 1, \cdots, L$$

$$0 \le D_i \le \overline{D_i}, \quad i = 1, \cdots, N$$

Where

N: number of generators

D_i: Deliverable MW of generator i

$\overline{Di}$: Upper limit of NQC[17] of generator i

L: number of deliverability constraints

C_l: available capacity on the deliverability constraint l

SF_{il}: shift factor of generator i output on deliverability constraint l

D. Reliability Assessment Results

D.1 Steady State Reliability Assessment

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

Power flow analysis and reactive power deficiency analysis were performed to ensure that SCE's transmission system remains in full compliance with North American Reliability Corporation (NERC) current reliability standards TPL-001, 002 and 003 and new TPL-001-4, as well as other NERC/WECC reliability standards, with the proposed interconnection. The results of these analyses will serve as documentation that an evaluation of the reliability impact of new facilities and their connections on interconnected transmission systems is performed. The reactive power deficiency analysis also determines whether the asynchronous facilities proposed by the interconnection projects are required to provide 0.95 leading/lagging power factor at the POI.

[17] For intermittent generation, a range of output levels between the 20% and 50% production exceedance during On-Peak load hours are studied.

The study results for this QC7 Phase II Study will be communicated to neighboring entities that may be impacted, for coordination and incorporation of its transmission assessments. Input from neighboring entities is solicited to ensure coordination of transmission systems.

While it is impractical to study all combinations of system load and generation levels during all seasons and at all times of the day, the base cases were developed to represent stressed scenarios of loading and generation conditions for the study group area. The CAISO and SCE cannot guarantee that the QC7 Phase II generation 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 this Phase II study.

D.1.1 Bulk[18] System Steady State Study (Category P0-P7)

i. Power Flow Study Results

Based on the assumptions listed above, the addition of the QC7 Phase II projects did not trigger any thermal overloads or create voltage violations on the Bulk system in the Metro area. Base Case power flow plots illustrating flow conditions are provided in Appendix D.

ii. Power Flow Study Observations & Notes

(a) Reactive Power Deficiency

There were no projects seeking interconnection in the Metro area bulk system in QC7 Phase II. The subtranmission VAR requirements are addressed in the Subtranmission Assessment report. Please refer to the Subtransmission Assessment Report included in your QC7 PII report package for further information related to the 66 kV system area study.

(b) Metro Area Constraints

In areas where transmission capacity is limited, generation resources will be in competition for available transmission capacity with other resources in queue and/or already interconnected and generation market bid prices will dictate which generators actually get to generate and which are curtailed.

Both Full Capacity Deliverability projects and Energy Only Deliverability projects could be subjected to curtailment if the total amount of generation that ultimately materializes is in excess of the available transmission capacity. Pursuant to CAISO Tariff, Appendix DD, section 2.4.2, “Interconnection Service does not in and of itself convey any right to deliver electricity to any specific customer or point of delivery or rights to any specific MW of available capacity on the CAISO Controlled Grid.”

iii. Reliability Assessment Mitigations

Based on the study assumptions, no upgrades are triggered by the QC7 Phase II projects to mitigate thermal overloads.

D.1.2 66 kV System Steady State Study

A separate Subtransmission Assessment Report was developed that strictly focuses on the analysis conducted for projects interconnecting at the 66 kV level (Non-CAISO controlled facilities) within the Metro Area. Please refer to the Subtransmission Assessment Report included in your QC7 PII report package for further information related to the 66 kV system area steady state study.

D.2 Transient Stability Assessment

The transient stability study in QC7 Phase I concluded that there were no impacts to transient stability with the addition of a larger number of project in the Metro area. Generators proceeding into QC7 Phase II represent a subset of the Phase I generators previously studied; and as such were found to not have an adverse impact on transient stability.

D.3 Post Transient Voltage Stability Assessment and Results

A post-transient voltage stability analysis in QC7 Phase II concluded that there were no impacts to post-transient voltage stability with the addition of a larger number of projects in the Metro area. Generators proceeding into QC7 Phase II represent a subset of the Phase I generators previously studied; and as such were found to not have an adverse impact on the post-transient voltage stability.

D.4 Energy Storage Charging Analysis

There were no projects seeking interconnection in the Metro area bulk system in QC7 Phase II that involved energy storage. A separate Subtransmission Assessment Report was developed that strictly focuses on the analysis conducted for projects interconnecting at the 66 kV level (Non-CAISO controlled facilities) within the Metro Area. Please refer to the Subtransmission Assessment Report included in your QC7 PII report package for further information related to the 66 kV energy storage charging analysis, if applicable.

Similarly, for projects interconnecting at the distribution level (33kV and below, Non-CAISO controlled facilities), the energy storage charging analysis information is provided as separate attachments to the Appendix A report, if applicable.

D.5 Short Circuit Duty Assessment Results

D.5.1 Application Queue SCD Results

The QC7 Phase II SCD results, provided in Appendix H, and corresponding circuit breaker evaluations identified that the inclusion of the Phase II projects triggers the need for SCD mitigations. The tables below illustrate the effective three-phase-to-ground and single-phase-to-ground duties for those transmission, subtransmission, and/or distribution substations that required mitigation.

1. Application Queue SCD Results – Transmission

The QC7 Phase II SCD results and corresponding circuit breaker evaluations identified that the inclusion of the Phase II projects triggers the need for SCD mitigation at the following transmission substations: Barre 220 kV, and Vista 220 kV. The effective three-phase-to-ground and single-phase-to-ground duties are shown in Table D.5.1.1 and Table D.5.1.2 respectively. The mitigation requirements are discussed below.

Table D.5.1.1
Effective Three-Phase-to-Ground Duties at Transmission Locations
Requiring SCD Mitigation by QC7 Phase II

Substation	Voltage	Pre QC7 Phase II			Post QC7 Phase II			Cluster Impact	
		kA	X/R	Eff kA*	kA	X/R	Eff kA*	kA	Eff kA*
Barre	220	62.2	20.3	62.8	64.0	20.7	64.6	1.8	1.8
Vista	220	49.5	20.5	50.0	49.6	20.5	50.1	0.1	0.1

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

Table D.5.1.2
Effective Single-Phase-to-Ground Duties at Transmission Locations
Requiring SCD Mitigation by QC7 Phase II

Substation	Voltage	Pre QC7 Phase II			Post QC7 Phase II			Cluster Impact	
		kA	X/R	Eff kA*	kA	X/R	Eff kA*	kA	Eff kA*
Barre	220	47.8	13.2	47.8	48.5	13.2	48.5	0.7	0.7
Vista	220	44.5	16.0	44.5	44.6	16.0	44.6	0.1	0.1

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

2. Application Queue SCD Results – Subtransmission

The QC7 Phase II SCD results and corresponding circuit breaker evaluations identified that the inclusion of the Phase II projects triggers the need for SCD mitigation at the following subtransmission substations – Barre 66 kV and Villa Park 66 kV. The effective three-phase-to-ground and single-phase-to-ground duties are shown in Table D.5.1.3 and Table D.5.1.4 respectively. A detailed discussion of the upgrade requirements is provided in section A.1.2.

Table D.5.1.3
Effective Three-Phase-to-Ground Duties at Subtransmission Locations
Requiring SCD Mitigation by QC7 Phase II

Substation	Voltage	Pre QC7 Phase II			Post QC7 Phase II			Cluster Impact	
		kA	X/R	Eff kA*	kA	X/R	Eff kA*	kA	Eff kA*
Barre	66	23.7	46.5	29.4	30.0	50.3	37.5	6.3	8.1
Villa Park	66	32.7	43.4	39.9	33.0	43.5	40.3	0.3	0.4

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

Table D.5.1.4
Effective Single-Phase-to-Ground Duties at Subtransmission Locations
Requiring SCD Mitigation by QC7 Phase II

Substation	Voltage	Pre QC7 Phase II	Post QC7 Phase II	Cluster Impact

		kA	X/R	Eff kA*	kA	X/R	Eff kA*	kA	Eff kA*
Barre	66	16.8	29.8	19.3	28.7	27.7	32.7	11.9	13.4
Villa Park	66	10.3	33.7	12.1	10.3	33.7	12.1	0.0	0.0

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

3. Application Queue SCD Results – Distribution

The QC7 Phase II SCD results and corresponding circuit breaker evaluations identified that the inclusion of the Phase II projects did not trigger the need for SCD mitigation at any SCE distribution substations (33kV and below).

D.5.2 SCD Mitigation Discussion

As discussed above, studies identified overstressed breaker conditions at the Barre 220 kV, Barre 66 kV, Villa Park 66 kV and Vista 220 kV Substations. Drivers for the Barre 220 kV SCD include assumptions corresponding to existing repowers of units classified as Once-Through-Cooling (OTC) as well as interconnection of new generation resources. Detailed discussion addressing the operational aspects corresponding to the Barre 220 kV breakers in Appendix I. The QC7 Phase II SCD mitigations required at Barre 66 kV, Villa Park 66 kV and Vista 220 kV are the following:

1. **Transmission**
   Vista 220 kV Substation – Upgrade fourteen (14) circuit breakers

2. **Subtrasmission**
   Barre 66 kV Substation – Replace twenty-seven (27) circuit breakers
   Villa Park 66 kV Substation – Replace one (1) circuit breaker

Refer to Attachment 2 of the Appendix A report for the project allocated costs associated with the upgrades mentioned above.

D.5.3 Ground Grid Evaluation of SCE Substations Results

The results of the application queue SCD studies were also utilized to identify any SCE substations (CAISO controlled) that may have duty problems on the existing substation ground grid due to the inclusion of the QC7 Phase II projects. The application queue ground grid analysis flagged for further review all existing substations where the QC7 Phase II Projects increased the substation ground grid duty by at least 0.25 kA. The following locations will require a detailed ground grid analysis to be performed in support of QC7 Phase II projects:

- Goleta
- Huntington Beach
- Lewis

The approximate one-time cost for such study is $43k per substation. These costs will be allocated to the generation projects with significant SCD contributions or the group of generation projects if the SCD contribution is the result of an upgrade assigned to a specific group of projects. Specifically, the costs for the ground grid study of each flagged substation is assigned to project(s) in the area I which the flagged substation resides. For example, if Devers 220 kV substation, which is an SCE substation in the Eastern Area, is flagged for a ground grid study, the associated costs for the ground grid study will be assigned to each QC7 PII project in the Eastern Area.

Refer to applicable Appendix A report for additional costs details, if applicable.

D.5.4 Generation Sequencing Implementation (GSI) Short Circuit Duty Assessment Results

The GSI Short Circuit Duty Assessment Results Discussion is provided in Appendix G of this report.

D.5.5 In-Service Date and Commercial Operating Assessment

The assessment results of the project are identified in Section F of the Phase II Appendix A report.

E. Delivery Assessment Results

E.1 On-Peak Deliverability Assessment

E.1.1 Deliverability Constraints to be mitigated by SPS

There are no deliverability constraints identified for the QC7 Phase II projects in the Metro Area.

E.1.2 Local Deliverability Constraints and LDNUs

There are no local deliverability constraints identified for the QC7 Phase II projects in the Metro Area.

E.1.3 Area Deliverability Constraints and ADNUs

There are no area deliverability constraints identified for the QC7 Phase II projects in the Metro Area.

E.1.4 Deliverability Assessment Mitigation

There are no upgrades triggered by QC7 Phase II projects in the Metro Area in the on-peak deliverability assessment.

E.2 COD Based Deliverability Assessment

Based on the Operational Dates of the required Network Upgrades, the COD based operational deliverability assessment was performed for 2016 and 2018. The transmission and generation assumptions are listed in Table E.2 and E.3. SPS's were assumed to be installed before they are needed.

Table E.2: Transmission Assumptions for Area Operational Deliverability Assessment[19]

[19] Transmission upgrades that are already in-service are not listed as they are part of the existing system.

Project	Type	First Year Modeled
Mesa loop-in	Approved transmission project	2020
Laguna Bell Corridor upgrade	Approved transmission project	2020
Barre – Del Amo upgrade	Network Upgrade	2018

Table E.3: Generation Assumptions for Area Operational Deliverability Assessment[20]

Queue Position	MW	Point of Interconnection	First Year of Study
702	435	El Segundo 220kV	2018
960	59.32	Ellis 220kV	2020
990	910	Center – Mesa and Center – Olinda 220kV lines	2018

Based on the operational dates assumed above, there are no deliverability constraints identified.

F. Scope of Network and Distribution Upgrades

The mitigation requirements triggered by QC7 Phase II projects, based on the results described in Sections above, are as follows:

F.1 Plan of Service Reliability Network Upgrades

There are no Plan of Service Reliability Network Upgrades for projects seeking interconnection are discussed in detail in each individual project report (Appendix A).

F.2 Reliability Network Upgrades

Assumed scopes for the Reliability Network Upgrades in the Metro Bulk area are discussed below.

F.2.1 Short Circuit Duty (SCD) Mitigation – RNU

The Network SCD mitigations required are the following:

i. Substation

Vista 220 kV Substation – Upgrade the following fourteen (14) circuit breakers by installing TRV capacitors

- Pos. No.3 CB4032 and CB6032
- Pos. No.4 CB4042 and CB6042
- Pos. No.7 CB4072 and CB6072
- Pos. No.8 CB4082 and CB6082
- Pos. No.9 CB4092 and CB6092
- Pos. No.10 CB4102 and CB6102

[20] Generation projects that have been completed and are operational are not listed in the table as they are part of the existing system.

- Pos. No.11 CB4112 and CB6112

ii. Corporate Environmental Health & Safety

Perform all required activities to support Network SCD mitigations required.

F.3 Local Delivery Network Upgrades

There is no identified Local Delivery Network Upgrade for QC7 Phase II projects in the Metro area.

F.4 Area Delivery Network Upgrades

There is no identified Area Delivery Network Upgrade for QC7 Phase II projects in the Metro area.

F.5 Distribution Upgrades

F.5.1 Short Circuit Duty (SCD) Mitigation

i. Substation

Barre 66 kV Substation - Replace twenty-eight (28) circuit breakers

- Pos. No.3 CB61 and CB62
- Pos. No.8 CB51 and CB52
- Pos. No.16 CB19 and CB20
- Pos. No.18 CB23 and CB24
- Pos. No.20 CB27 and CB28
- Pos. No.23 CB33 and CB34
- Pos. No.24 CB35 and CB36
- Pos. No.25 CB37 and CB38
- Pos. No.27 CB41 and CB42
- Pos. No.28 CB43 and CB44
- Pos. No.30 CB47 and CB48
- Pos. No.31 CB49 and CB50
- No. 1 CAP Bank CB100
- No. 4 CAP Bank CB66
- No. 6 CAP Bank CB67
- West Bus Sectionalizing CB5

Villa Park 66 kV Substation - Replace one (1) circuit breaker

- Pos. No.12 CB95

ii. Corporate Environmental Health & Safety

Perform all required activities to support Network SCD mitigations required

F.6 Additional Scope – Ground Grid

A detailed ground grid was not performed as part of this assessment for the substations identified in D. Such analysis requires field crews to take soil samples in order to determine adequate soil resistivity values, which are used to ascertain adequacy the adequacy of the existing ground grid. As a result, additional scope will be included as part of the final engineering for the project at the PTO substations whose ground grids were flagged with duty concerns. Each IC is receiving a separate Appendix A report, specific only to that generation project, outlining the appropriate substations requiring ground grid analysis.

G. Cost and Construction Duration Estimates for Upgrades

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 the QC7 Phase II are dependent on the completed construction and energizing of the identified Network Upgrades. Without these upgrades, the new generators may be subject to CAISO's congestion management, including generation tripping. Based on the needed time for permitting, design, and construction, it may not be feasible to complete all the upgrades needed for this cluster before the requested Commercial Operation Dates.

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 total estimated cost of the system upgrades allocated to the Metro area projects are provided in Appendix E.

H. Affected Systems Coordination

The CAISO cannot study comprehensively the impacts of the Generating Facility on the transmission systems of Affected System operators. The CAISO does not have detailed information about Affected Systems on a transmission-element level, nor does the CAISO know the details of the various reliability and operating criteria applicable to the Affected Systems. In addition, because the operation of transmission systems and NERC reliability standards change over time, the CAISO cannot presume to know all of the impacts of these changes on Affected Systems. As such, the CAISO contacted all Potentially Affected Systems[21] to inquire whether they are impacted by the Generating Facility's interconnection to the CAISO Controlled Grid. The CAISO is providing notice to the Interconnection Customer of the Identified Affected Systems[22] for this Generating Facility. To ensure a safe and reliable interconnection to the CAISO Controlled Grid, six (6) months before the Initial Synchronization Date of the Generating Facility, the Interconnection Customer shall provide documentation to the CAISO, in accordance with the

[21] "Potentially Affected System" shall mean an electric system in electric proximity to the CAISO's controlled grid that may be an Affected System.

[22] "Identified Affected System" shall mean an Affected System operator who either stated that it should be considered an Affected System or whose electric system has been identified by the CAISO as potentially impacted by a generator interconnection through the applicable study process.

Generation Interconnection and Deliverability Allocation Procedure (GIDAP) Section 3.7, and GIDAP Business Practice Manual (BPM) Section 6.1.4, confirming that the Identified Affected System operators have been contacted by the Interconnection Customer, and (i) that any system reliability impacts have been addressed (or that there are no system impacts), or (ii) that the Interconnection Customer has taken all reasonable steps to address potential reliability system impacts with the Identified Affected System operator but has been unsuccessful.

H.1. Potential Affected System – Power Flow Results

The addition of all QC7 Phase II projects in the Metro area does not adversely impact power flows on Affected Systems that are within the Metro Area as these affected systems (City of Anaheim and City of Vernon) are radially connected to SCE. Because these systems are radially connection, power flows to these system is determined based on affected system load demand less internal generation within these systems.

H.2. Potential Affected System – SCD Results

The Generation Interconnection Studies identified that the QC7 Phase II Projects increase SCD throughout the system. The tables below show the SCD increment to neighboring utilities due to the addition of all QC7 Phase II projects:

Three-Phase Short-Circuit Duty Evaluation of Adjacent Facilities Impacted by QC7 Phase II

Substation	Voltage	Entity	Cluster Impact (kA)
Eldorado	525	SCE	0.2
Lugo	525	SCE	0.2
McCullough	525	LADWP	0.2
Mead	525	WALC	0.1
Midway	525	PG&E	0.5
Moenkopi	525	APS	0
Mohave	525	Joint	0
Palo Verde	525	APS	0.5
Victorville	525	LADWP	0
Bob tap	230	VEA	0.4
Eldorado	230	Joint	0.1
Eldorado	230	SCE	0.8
Inyo	230	LADWP	0
Julian Hinds	230	MWD	0.1
Laguna Bell	230	SCE/City of Vernon	0.1
Lewis	230	SCE/City of Anaheim	0.6
Magnolia	230	Nevada	0
Merchant	230	SDG&E	0.1
Mirage	230	IID	0
NSO	230	Nevada	0.1
Sylmar	230	LADWP	0
Wildlife	230	City of Riverside	0
Blythe	161	WALC	0

Single line-to-ground Short-Circuit Duty Evaluation of Adjacent Facilities Impacted by QC7 Phase II

Substation	Voltage	Entity	Cluster Impact (kA)
Eldorado	525	SCE	0.3
Lugo	525	SCE	0
McCullough	525	LADWP	0.4
Mead	525	WALC	0.1
Midway	525	PG&E	0.1
Moenkopi	525	APS	0
Mohave	525	Joint	0
Palo Verde	525	APS	0.5
Victorville	525	LADWP	0
Bob tap	230	VEA	0.8
Eldorado	230	Joint	0.1
Eldorado	230	SCE	1.4
Inyo	230	LADWP	0
Julian Hinds	230	MWD	0
Laguna Bell	230	SCE/City of Vernon	0.1
Lewis	230	SCE/City of Anaheim	0.4
Magnolia	230	Nevada	0
Merchant	230	SDG&E	0.1
Mirage	230	IID	0
NSO	230	Nevada	0
Sylmar	230	LADWP	0
Wildlife	230	City of Riverside	0
Blythe	161	WALC	0

I. Environmental Evaluation, Permitting, and Licensing

Environmental Evaluation, Permitting, and Licensing information is provided in Appendix K of this report.

J. Items Not Covered in this Report

J.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 Final Engineering and Design.

J.2 Customer's Technical Data

The study accuracy and results for the QC7 Phase II Study are contingent upon the accuracy of the technical data provided by the IC. Any changes from the data provided could void the Study results.

J.3 Study Impacts on Neighboring Utilities

Results or consequences of this QC7 Phase II 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, etc. Refer to Affected Systems Coordination Section for further details.

J.4 Use of Participating TO Facilities

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

J.5 Participating Transmission Owner Interconnection Handbook

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

J.6 Western Electricity Coordinating Council (WECC) Policies

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

J.7 System Protection Coordination

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

J.8 Standby Power and Temporary Construction Power

The QC7 Phase II Study does not address any requirements for standby power or temporary construction power that the Project may require prior to the in-service date of the Interconnection Facilities. Should the Project require standby power or temporary construction power from 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 service.

J.9 Licensing Cost and Estimated Time to Construct Estimate (Duration)

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.

J.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 PTO substation. Due to uncertainties related to telecommunication upgrades for the numerous projects in queue ahead of QC7 Phase II, 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 QC7 Phase II may be reduced. Any changes in these assumptions may affect the cost and schedule for the identified telecommunication facilities.

J.11 Ground Grid Analysis

A detailed ground grid analysis may be required as part of the final engineering for the project at the PTO substations whose ground grids were flagged with duty concerns.

J.12 Subsynchronous Interaction Evaluations

Certain generators or inverter based generators when interconnected within electrical proximity of series capacitor banks on the transmission system are susceptible to Sub-Synchronous Interaction (SSI) conditions which must be evaluated. Subsynchronous Interaction evaluations include Subsynchronous Resonance (SSR) and Subsynchronous Torsional Interactions (SSTI) for conventional generation units, and Subsynchronous Control Instability (SSCI) for inverter based generators using power electronic devices (e.g. Solar PV and Wind Turbines).

A study will need to be performed to evaluate the SSI between generating facilities and the transmission system for projects interconnecting close electrical proximity of series capacitor banks on the transmission system to ensure that the Project does not damage SCE's control systems.

The SSCI study will require that the IC provide a detailed PSCAD model of its Generating Facility and associated control systems, along with the manufacturer representative's contact information. The study will identify any mitigation(s) that will be required prior to initial synchronization of the Generating Facility. The study and the proposed mitigation(s) shall be at the expense of the IC.

It is the IC's responsibility to select, purchase, and install turbine/inverter based generators that are compatible with the series compensation in the area.

Each IC is receiving a separate Appendix A report, specific only to that generation project, defining if the project is required to undertake this additional analysis. Each identified IC is 100% responsible for any studies related to the SSR or SSTI. The only study that SCE will perform (at the IC's expense) is for SSCI.

J.13 Applicability

This document has been prepared to identify the impact(s) contributions of the Project on the PTO electrical system; as well as establish the technical requirements to interconnect the Project to the POI that was evaluated in the QC7 Phase II study for the Project. Nothing in this report is intended to supersede or establish terms/ conditions specified in interconnection agreements agreed to by PTO, CAISO and the IC.

J.14 Potential Changes in Cost Responsibility

The IC is hereby placed on notice that interconnection of its 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. In accordance with Section 14.2.2 of CAISO Tariff Appendix DD Generator Interconnection and Deliverability Allocation Procedures (GIDAP), should Network Upgrades required for queued-ahead projects be 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 Network Upgrades required by earlier queued generating facilities are not subject to an executed GIA (or unexecuted GIA filed at FERC) the financial responsibility for such upgrades may fall to the IC. The details of the estimated cost that may be reallocated to each proposed project under such circumstances is included in the Appendix A Section Q.14.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. Changes in costs allocated to the IC could also arise as the result of the CAISO's reassessment process described in Section 7.4 of the GIDAP. SCE encourages the IC to review Sections 7.4 and 14.2.2 of the GIDAP for the rules and processes under which the financial responsibility might be reapportioned to the IC. Potential changes in the IC's cost responsibility resulting from application of the provisions of these Sections of GIDAP are not included in this Phase II study, nor are the potential impacts to the IC's maximum cost responsibility outlined in this Phase II study.

K. Definitions

ADNU	Area Delivery Network Upgrade
BES	Bulk Electric System
CAISO	California Independent System Operator Corporation
CDWR	California Department of Water Resources
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
GIDAP	Generator Interconnection and Deliverability Allocation Procedures
IC	Interconnection Customer
IID	Imperial Irrigation District
LDNU	Local Delivery Network Upgrade
LFBs	Local Furnishing Bonds
LGIA	Large Generator Interconnection Agreement
NERC	North American Electric Reliability Corporation
NQC	Net Qualifying Capacity as modeled in the Deliverability Assessment:
PG&E	Pacific Gas and Electric Company
Phase II	Study QC7 Phase II Study
PMax	Maximum generation output
PTO	Participating Transmission Owner
RAS	Remedial Action Scheme (also known as SPS)
POI	Point of Interconnection
POS	Plan of Service
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
SVP	Silicon Valley Power
TPP	CAISO's Transmission Planning Process
TPD	Transmission Plan Deliverability: Deliverability supported by the CAISO's Transmission Plan
VEA	Valley Electric Association
WAPA	Western Area Power Administration
WDT	Wholesale Distribution Tariff
WECC	Western Electricity Coordinating Council

Appendix A

Individual Project Report

Please refer to separate document

Appendix B

System Assumptions

Please refer to separate document

Appendix C

Contingency Lists for Outages

Please refer to separate document

Appendix D

Power Flow Plots

Please refer to separate document

Appendix E

Cost and Construction Duration Estimates for Upgrades

Please refer to separate document

Appendix F

Not Used

Appendix G

Generation Sequencing Implementation (GSI) Short Circuit Duty Evaluation Discussion

Please refer to separate document

Appendix H

Short Circuit Calculation Study Results

Please refer to separate document

Appendix I

Barre 220 kV Short-Circuit Duty Operational Analysis

Appendix J

Not Used

Appendix K

Environmental Evaluation, Permitting, and Licensing

Please refer to separate document

Appendix A – WDT1189

Wellhead Power Development, LLC

Stanton Energy Center

QUEUE CLUSTER 7 PHASE II REPORT

November 24, 2015

This study has been completed in coordination with the California Independent System Operator Corporation (CAISO) per CAISO Tariff Appendix DD Generator Interconnection and Deliverability Allocation Procedures (GIDAP)

Table of Contents

Attachments:

1. Interconnection Facilities, Network Upgrades and Distribution Upgrades
2. Escalated Cost and Time to Construct for Interconnection Facilities, Reliability Network Upgrades, Delivery Network Upgrades, and Distribution Upgrades
3. Allocation of Network Upgrades for Cost Estimates and Maximum Network Upgrade Cost Responsibility
4. Distribution Provider Interconnection Handbook
5. Short Circuit Calculation Study Results (see Appendix H of the Area Report)
6. Customer Provided Dynamic Data
7. Not Used
8. Subtransmission Assessment Report (if applicable)

A. Introduction

Wellhead Power Development, LLC, the Interconnection Customer (IC), has submitted a completed Interconnection Request (IR) to Southern California Edison Company (SCE) for their proposed Stanton Energy Center (Project). The project requested a Point of Interconnection (POI) is Southern California Edison Company's (SCE) Barre 66 kV Switchrack located in Orange County, CA. The Project has a CAISO delivery point at Barre 220 kV Substation bus. The IC elected that the project be Option A with Full Capacity Deliverability Status, and desires an In-Service Date (ISD) and Commercial Operation Date (COD) of March 30, 2018 and June 1, 2018 respectively. Such dates are specified in the Project Attachment B. Actual ISD and COD will depend on design and construction requirements to interconnect for the Project.

In accordance with Federal Energy Regulatory Commission (FERC) approved CAISO Tariff Appendix DD Generator Interconnection and Deliverability Allocation Procedures (GIDAP) of Attachment I of SCE's Wholesale Distribution Access Tariff (WDAT), the Project was grouped with Queue Cluster 7 (QC7) Phase II projects to determine the impacts of the group.

Please note that the discussion related to the combined impacts at the transmission and subtransmission levels of the group resides in the Area and Subtransmission Assessment Reports; both are included in the QC7 PII report package. This report focuses only on the impacts or impact contributions of the Project at the local Distribution System, and it is not intended to supersede any contractual terms or conditions specified in a Generator Interconnection Agreement (GIA).

The report provides the following:

1. Transmission and/or Subtransmission 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 to construct[1] these facilities. Such information is provided in Attachment 1 and Attachment 2 as separate documents in the Appendix A Project report package.

All the equipment and facilities comprising the Project located in Stanton, California, as disclosed by the IC in its IR, as may have been amended during the Interconnection Study process, which consists of (i) three (3) synchronous generator units rated at 50.6 MW each for a combined output of 151.6 MW as measured at the generator terminals; (ii) the associated infrastructure and step-up transformers, (iii) meters and metering equipment, (iv) appurtenant equipment and (v) 1.8 MW of auxiliary load.

Based on the technical data provided for the main step-up transformer banks, internal generation facility losses were found to be 0.7 MW resulting in a net output, as measured at the high-side of the main transformer banks, of 149.3 MW when taking the auxilary loads and internal facility losses into account. Losses on the 0.34 mile 3000 copper XLP UG generation tie-line were found to be 0.1 MW resulting in an estimated capacity delivery of 149.2 MW at the Point of Interconnection.

The Project shall consist of the Generating Facility and the IC's Interconnection Facilities as illustrated below in Figure A-1. Similarly, the Project information is summarized in Table A.1 below The location of

[1] It should be noted that construction is only part of the duration of months specified in the study, includes detailed engineering, licensing, etc, and other activities required to bring such facilities into service. 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.

the Project was assumed as specified in the IR provided by the IC. The Project shall not exceed the total net output.

Figure A.1: Project IC Facilities One-Line Diagram

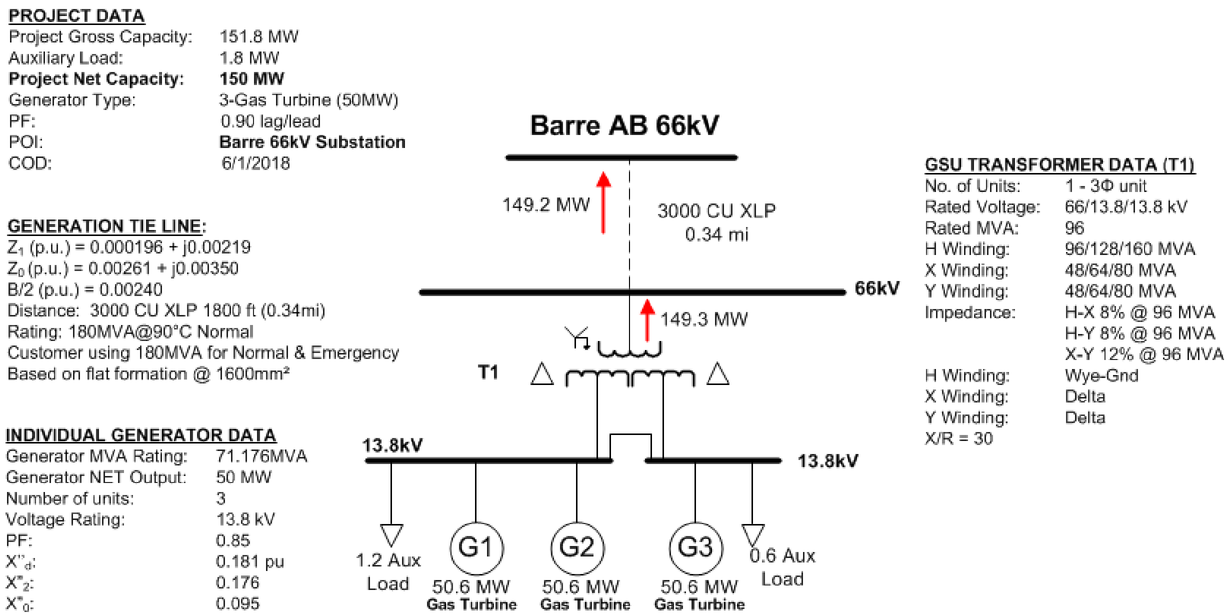


Figure A.2: Project IC Facilities Site Location

Table A.1: Project General Information

Project Location	10711 Dale Street Stanton, CA 90680 Orange County GPS Coordinates: Latitude: 33.807053, Longitude: -117.985299
Distribution Provider's Planning Area	SCE Metro Bulk system
Number and Types of Generators	3 Synchronous Generators (50.6 MW each)
Interconnection Voltage	66 kV
Maximum Generator Output (At Generator Terminals)	151.8 MW (gross)
Generator Auxiliary Load	1.8 MW
Internal Generation Facility Losses	0.7 MW
Maximum Net Output at Generation Facility (High-Side of Main Transformer)	149.3 MW
Power Factor Range	Lead 0.90 / Lag 0.90 at POI per interconnection application
Step-up Transformer(s)	Main Transformers (T1) 66/13.8/13.8 kV (YG-D-D), H-Winding: 96/128/160 MVA, X-Winding: 48/64/80 MVA, Y-Winding: 48/64/80 MVA, H-X Impedance Value: 8% @ 96 MVA H-Y Impedance Value: 8% @ 96 MVA X-Y Impedance Value 12% @ 96 MVA
Gen-Tie	0.34 miles, 3000 CU XLP
POI	Distribution Provider's Barre 66 kV Switchrack
Estimated Losses on Gen-Tie Facilities (All Gen-Tie Facilities used to deliver to POI)	0.1 MW
IC Requested COD	6/01/2018

B. Study Assumptions

For detailed assumptions regarding the group cluster delivery analysis, please refer to the applicable QC7 Phase II SCE Area Report and for detailed assumptions regarding the group cluster analysis at the subtransmission level, please refer to the applicable QC7 Phase II Subtransmission Assessment Report. Below are the assumptions specific to the Project:

1. The following is the Plan of Service (POS) assumed for the Project in the Phase II Study:

   The project was modeled as via one 66 kV generation tie-line (gen-tie) to SCE's Barre 66 kV Substation.

2. The following facilities will be installed by SCE and **are included** in this Phase II Study:

   - The new 66 kV position at Barre Switchrack.
   - The segment of a 66 kV generation tie-line inside the Barre 66 kV substation property line.
   - The extensions of each of the two generator – owned fiber optic cables inside the Barre Substation property line.
   - Lightwave, channel bank(s) and associated equipment at Barre Substation and at the Generating Facility.
   - The required revenue load meters.

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

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

   - The 66 kV generation tie-line from the Generating Facility to the last structure outside the Barre Substation property line.
   - The fiber optic cables to provide two diversely routed telecommunication paths required for the line protection relays.
   - The required CAISO metering equipment (voltage and current transformers and CAISO meters) and metering cabinet for SCE revenue meter.

     NOTE: The metering voltage and current transformers installed for the CAISO metering will also be used for the SCE owned revenue meters.

   - The following 66 kV line protection relays to be installed at the Generating Facility end of the 66 kV generation tie-line:
     - One (1) G.E. L90 current differential relay with dual dedicated digital communication channels on diverse paths to Barre Substation.
     - One (1) SEL 311L current differential relay with dual dedicated digital communication channels on diverse paths to Barre Substation.

C. Reliability Standards, Study Criteria and Methodology

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. Refer to Section C of the Area Report for details of the applicable reliability standards, study criteria and methodology.

D. Power Flow Reliability Assessment Results

I. Steady State Power Flow Analysis Results – 220 kV and above

The study did not identify any power flow issues on the Bulk Electric System not addressed via the use of CAISO Congestion Management or via already approved transmission upgrades. Consequently, the Project is not allocated cost for any Network Upgrades identified to address power flow issues. The details of the power flow analysis are provided in Section D of the Area Report.

II. Steady State Power Flow Analysis Results - 66 kV

1. Thermal Overloads

The study did not identify any power flow issues on the Barre 66 kV Subtransmission System. The details of the power flow analysis are provided in the Subtransmission Assessment Report.

2. Voltage Performance

The Project is required to provide power factor regulation capability (0.95 lead/lag at POI for asynchronous generation and 0.90 lagging to 0.95 leading at generator terminals for synchronous generators) to alleviate power flow non-convergence and maintain the Transmission transfer capability.

3. Required Mitigations

No power flow mitigations on the Subtransmission System were identified to be required by the Project.

E. Short Circuit Duty Results

Short circuit studies were performed to determine the fault duty impact of adding the QC7 Phase II projects to the Transmission system and to ensure system coordination. The fault duties were calculated with and without the projects to identify any equipment overstress conditions. Once overstressed circuit breakers are identified, the fault current contribution from each individual project in QC7 Phase II is determined. Each project in the cluster will be responsible for its share of the upgrade cost based on the rules set forth in CAISO Tariff Appendix DD.

1. Short Circuit Duty Study Input Data

"Synchronous Gen" Data for each generation unit:

X"1 - positive sequence subtransient reactance: 0.181 PU
X"2 - negative sequence subtransient reactance: 0.176 PU
X"0 - zero sequence subtransient reactance: 0.095 PU

Generation tie-line:

Length:	1,800 feet
Conductor:	3000 CU XLP
Z1(p.u.) conductor impedance information:	0.000196 R, 0.00219 X, 0.0048 B
Z0(p.u.) conductor impedance information:	0.00261 R, 0.00350 X, 0.0048 B

Main Generation Step-Up Transformer technical details are provided above in Table A-1.

2. Short Circuit Duty Study Results

All bus locations where the QC7 Phase II projects increase the short-circuit duty by 0.1 kA or more and where duty was found to be in excess of 60% of the minimum breaker nameplate rating are listed in the Area Report (Appendix H). These values have been used to determine if any equipment is overstressed as a result of the inclusion of QC7 Phase II interconnections and corresponding network upgrades, if any.

As discussed in Section D.5.2 of the Area Report and Appendix I, short circuit duty at Barre 220 kV was found to exceed the maximum nameplate ratings of all existing 220 kV breakers. Physical upgrades would necessitate replacement of all circuit breakers with a currently non-SCE standard higher rated 220 kV breaker which will necessitate in excess of $70 million and require over 48 months to implement. Because the need is currently viewed as temporary in nature and is impacted by timing of the ultimate disposition of the existing OTC units, the recommended mitigation involves implementing an operating procedure which would restrict the number of generation units that can operate (i.e., “spin”) to ensure duties at Barre 220 kV are maintained within the maximum Barre SCD ratings of 63 kA. Since most of the duty increase is attributed to the Project and the Project was selected to replace the OTC generators, operation of the Project will be limited if sufficient OTC units do not retire to lower SCD below maximum breaker capability by the time the Project desires to interconnect. .

The responsibility to finance short circuit related Reliability Network Upgrades identified through a Group Study shall be assigned to all Interconnection Requests in that Group Study pro rata on the basis of short circuit duty contribution of each Generating Facility.

Please refer to the QC7 Phase II Area Report for the QC7 Phase II breaker evaluation identified overstressed circuit breakers at the SCE buses, and Attachment 2 for the pro-rata allocation with corresponding estimated costs (if any) for the Project, based on SCD contribution at each location.

3. SCE Substations with Ground Grids Duty Concerns

The short circuit studies flagged SCE substations beyond the Project POI with ground grid duty concerns that necessitate a ground grid study. The Project’s contribution to the Huntington Beach 220 kV, Lewis 220 kV, Apollo 66 kV, Bolsa 66 kV, Fullerton 66 kV, Gilbert 66 kV, Kindler 66 kV, La Palma 66 kV, Lampson 66 kV, Marion 66 kV, Shawnee 66 kV, Sunny Hills 66 kV, Team 66 kV, and Trask 66 kV Substations were found to be significant and will require the project to fund the cost of performing ground grid studies at these locations.

4. Preliminary Protection Requirements

   Protection requirements are designed and intended to protect the Distribution Provider's system only. The preliminary protection requirements were based upon the interconnection plan as shown in the one-line diagram depicted in line item #7 in Attachment 1.

   The IC is responsible for the protection of its own system and equipment and must meet the requirements in the Distribution Provider Interconnection Handbook provided in Attachment 4.

F. Transient Stability Evaluation

With the Project providing 0.95 power factor correction as measured at the POI and including the required mitigation identified above, transient stability performance was found to be acceptable. Refer to enclosed Area Report and Subtransmission Assessment Report in the QC7 Phase II report package, for the QC7 Phase II transient stability evaluation criteria and assessment results.

G. Power Factor Requirements

Based on the results of the Study, the Project will need to be designed to maintain a composite power delivery at continuous rated power at the POI at a power factor within the range of 0.95 lead/lag at POI for asynchronous generation and 0.90 lagging to 0.95 leading at generator terminals for synchronous generators. Additionally, the generation system must be designed to accommodate a VAR schedule provided by SCE. SCE will determine if the VAR schedule is necessary based on future re-arrangements of SCE's Transmission.

H. Deliverability Assessment Results

1. **On Peak Deliverability Assessment**

   The Project does not contribute to any deliverability constraint.

2. **Off Peak Deliverability Assessment**

   There is no wind generators in the study area. The off-peak deliverability assessment is not performed.

3. **Required Mitigations**

   No Delivery Network Upgrades are required.

I. In-Service Date and Commercial Operation Date Assessment

The latest information provided by the IC has indicated that the requested generator ISD is March 30, 2018 and a COD of June 1, 2018. To determine if these dates could be met, an In-Service Date and Commercial Operation Date Assessment was performed which considered both the QC7 Phase II process timelines as well as the following facilities needed to provide for reliable energy only interconnection of the Project. Timing of the upgrades required to provide for the requested Full Capacity Deliverability Status are discussed in the section below:

1. QC7 Interconnection Process Timelines

   To enable physical interconnection, a Generator Interconnection Agreement (GIA) is required. As part of the QC7 interconnection process, a GIA is not scheduled to be tendered until after completion of the CAISO's Reassessment and Transmission Planning Deliverability (TPD)

Allocation Study Process which does not commence until late January or early February 2016. The TPD Allocation is scheduled to be completed by April and if no changes to scope requirements are identified, a letter is provided at the end of April outlining the TPD Allocation results. However, if changes are identified, updates to scope, costs and schedules are developed and updated reports are issued by the end of July. The GIA negotiations commences after either the issuance of the letter outlining the TPD allocation results at the end of April or upon issuance of the updated reports at the end of July. Provided the Project does not elect to Park, the letter or updated reports are used as the basis to proceed with the GIA negotiations. Assuming a three month timeframe for GIA negotiations, a GIA is not expected until either early August 2016 or early November 2016 depending on TPD study results and decision to Park or proceed.

2. System Upgrade Timelines for Reliable Interconnection

The Operational Studies identified that the following facilities are required in order to provide for an energy only interconnection:

a. Distribution Provider's Interconnection Facilities

As described in Section 1.b of Attachment 1, line protection, telecomm, and SCE portion of 66 kV gen-tie among other items will be required to terminate the IC gen-tie at the SCE Johanna Substation. Preliminary durations estimated to install the Distribution Provider's Interconnection Facilities is 27 months.

b. Reliability Network Upgrades – Short-Circuit Duty (SCD) Mitigation

Short circuit duty operational mitigation was identified taking into account new generation projects which have executed GIAs, approved transmission system upgrades fully permitted and under construction, and new generation projects including QC7 Phase II Projects which do not yet have an executed GIA. The study results for these operational studies are provided in Section II of the Generation Sequencing Implementation (GSI) Short Circuit Duty evaluation (Appendix G). Based on the study results, the following upgrades/mitigation are required to be in place in order to enable energy only interconnection of this Project:

- Reconfiguration of the system to operate one Mira Loma AA-Bank on the east side as normally open (requires simply opening AA-Bank so no duration identified)
- Vincent 220 kV bus-split which has an estimated in-service date of July 2016

In addition to the above mitigation requirements which already have established in-service dates, the following additional SCD mitigations may be needed in order to enable energy only interconnection. It is important to note that projects to undertake the work have not been initiated since the timing of need is dependent on development of queued generation projects, including QC7, which have not yet executed a GIA.

- Replacement of four (4) Vincent 500 kV circuit breakers (triggered by QC3&4)
- Upgrade fourteen (14) Vista 220 kV circuit breakers by installing TRV Caps (triggered by QC7)
- CAISO Operating Procedure which limits the number of generation units operating and "spinning" to ensure duties at Barre 220 kV are maintained within the maximum Barre SCD ratings of 63 kA (triggered by QC7)

The identification of need was based on the assumption that all queued generation projects actually materialize and are interconnected (as energy only). Timing to implement the first two SCD mitigations are currently estimated at 27 months from the date the need is identified. These additional SCD mitigations will be continuously evaluated as part of ongoing GIA negotiations and ongoing studies to properly define the time when actual need to undertake these mitigations is required based on the actual GIA negotiations with corresponding requested in-service dates. Once the actual need is triggered, project development will commence. Timing to implement the recommended CAISO Operating Procedure will depend on OTC unit operations and timing of actual development of the Stanton Energy Project.

c. Voltage Support Mitigation

No voltage support upgrades were identified to be required to enable this project to interconnect.

d. Distribution Upgrades

i. Plan of Service

As described in Section 3.b of Attachment 1, a new 66 kV line position equipped as a double-bus double-breaker configuration is required as the Distribution Plan of Service to interconnect the project to the SCE Barre Substation. Preliminary duration estimated to install the Distribution Provider's Distribution Upgrades is 27 months.

ii. Short-Circuit Duty Mitigation

The studies identified that several QC7 Phase II Projects, including this project, contributes to the overstressing of one 66 kV circuit breaker at Villa Park and that this project alone drives the need for replacement of twenty-eight (28) 66 kV circuit breakers at Barre. Preliminary duration estimated to replace the 66 kV circuit breakers at Barre and Villa Park is 27 months.

3. Conclusion

Based on the standard timelines, the requested IC In-Service Date of March 30, 2018 cannot be met due to the following reasons:

- The QC7 Interconnection Process Timelines will not yield a Generator Interconnection Agreement until either early August 2016 or early November 2016 depending on TPD study results which is beyond the requested IC In-Service Date.

- Timelines required to construct the Distribution Provider's Interconnection Facilities and Distribution Upgrades are estimated at 27 months from the date the GIA is executed, payments are made, and notice to proceed with interconnection is provided. Following the standard process, this would result in a best case in-service date of December 2018 or March 2019 depending on TPD study results. It should be noted that the ability to meet a best case in-service date is tied directly to the IC's timely execution of the Interconnection Agreement, submittal of payments, and notice to proceed.

- Potential need to replace four (4) Vincent 500 kV and upgrade fourteen (14) Vista 220 kV circuit breakers which would require an estimated 27 months to complete from the day a project is initiated to commence the upgrade at each location.

It is also important to note that once interconnected, the ability to operate the unit (even in spinning reserve) is contingent on further developments and operating status of existing OTC units. With all OTC units currently in operating either as generator or synchronous condenser, the Barre 220 kV circuit breakers will be overstressed with the addition of this project. To address this issue, an Operating Procedure is recommended that will limit certain generation unit operations.

J. Timing of Full Capacity Deliverability Status, Interim Deliverability, Area Constraints, and Operational Information

The IC elected that the Project be Option A with Full Capacity Deliverability Status (FCDS). Timing of obtaining the requested FCDS is dependent on the completion of Delivery Network Upgrades. Until such time that the Delivery Network Upgrades are completed and placed into service, the Project may experience additional congestion exposure due to transmission limitations or may be granted Interim Deliverability Status based on annual system availability. The sections below provide a discussion of the timing of Full Capacity Deliverability Status, Interim Deliverability, Area Constraints, and Operational Information.

1. System Upgrades Required for Full Capacity Deliverability Status

   No upgrades have been identified to be required (either previously triggered or triggered with the addition of QC7 Projects) for this project to obtain the requested FCDS.

2. Interim Operational Deliverability Assessment for Information Only

   The operational deliverability assessment was performed for study years 2018 and 2020 by modeling the Transmission and generation in service in the corresponding study year. For details of the Transmission and generation assumption, refer to Section E.2 of the Area Report. There are no deliverability constraints identified. The Project will have the deliverability status as granted by the Transmission Plan Deliverability allocation.

3. Conclusion

   Since no upgrades have been identified to be required to obtain FCDS, the requested Full Capacity Deliverability Status could be achieved upon interconnection.

K. Interconnection Facilities, Network Upgrades, and Distribution Upgrades

Please see **Attachment 1** for the Interconnection Facilities, Reliability Network Upgrades, Delivery Network Upgrades and Distribution Upgrades allocated to the Project. Please note that SCE will not "reserve" the identified Interconnection Facilities (IF's) for the proposed POI. The identified scope/facilities will be allocated to the project upon the successful execution of the Generator

Interconnection Agreement (GIA) and SCE has completed the detailed design and engineering of the facilities according to tariff timelines.

L. Cost and Construction Duration Estimates

To determine the cost responsibility of each generation project in QC7 Phase II, the CAISO developed cost allocation factors (Attachment 3) for Reliability Network Upgrades, Local Delivery Network Upgrades and Area Delivery Network Upgrades. Attachment 2 provides the 'constant' 2015 dollars and their escalation to the estimated COD year for Interconnection Facilities, Reliability Network Upgrades, Delivery Network Upgrades, and Distribution Upgrades which the Project was allocated cost.

For the QC7 Phase II Study, the estimated COD is derived by assuming the duration of the work element will begin in December 2016, which accounts for the CAISO tariff scheduled completion date of the QC7 Phase II study plus: the TP Deliverability (TPD)[2] allocation, Annual Reassessment effort, and the interconnection agreement signing period and submittal of required funds by the IC.

The IC should note that any Local Delivery Network Upgrades and Area Delivery Network Upgrades allocated to the Project may be assessed 35% Income Tax Component of Contribution (ITCC) pending the results of the TPD allocation Process several months after the QC Phase II Study Reports are released, in addition to the 35% ITCC assessed for the IFs, DUs, and RNUs above the $60K/MW repayment cap allocated to the Project. For your information, Attachment 2 contains a potential ITCC estimate[3] based on the Phase II cost in this study. It does not represent the “maximum ITCC exposure” of the Project. Attachment 3 provides an estimated non-reimbursable RNU cost that would be subject to ITCC, taking into account the Network Upgrade maximum cost responsibility. The maximum ITCC warranted by the Project will be addressed, calculated, and included during the Interconnection Agreement development phase once the IC submits the TPD Affidavit confirming the acceptance, partial acceptance, or denial of awarded deliverability assigned to the Project.

M. SCE Technical Requirements

The IC is responsible for the protection of its own system and equipment and must meet the requirements in the Distribution Provider Interconnection Handbook provided in Attachment 4.

It is the IC’s responsibility to select, purchase, and install turbine/inverter based generators that are compatible with the series compensation in the area.

N. Sub Synchronous Interaction Evaluations

Certain generators or inverter based generators when interconnected within electrical proximity of series capacitor banks on the transmission system are susceptible to Sub-Synchronous Interaction (SI) conditions which must be evaluated. Subsynchronous Interaction evaluations include Subsynchronous

[2] Transmission Plan Deliverability: Deliverability supported by the CAISO’s Transmission Plan

[3] The maximum ITCC exposure applies ITCC (35%) to assigned IF and DU facilities, Network Upgrades that are not subject to transmission credits incremental to a repayment $/MW cap or an award of 0 MW TPD Allocation, and that SCE will own the facilities in question. The maximum ITCC exposure is calculated by applying the following formula: (IF*35%)+ ((RNU Costs – (Project MW * ($60k/MW)))*35%)+(LDNU*35%)+(ADNU*35%)+(DU*35%)

Resonance (SSR) and Subsynchronous Torsional Interactions (SSTI) for conventional generation units, and Subsynchronous Control Instability (SSCI) for inverter based generators using power electronic devices (e.g. Solar PV and Wind Turbines).

For projects interconnecting at the 220 kV voltage level and above in close electrical proximity of series capacitor banks on the transmission system a study will need to be performed to evaluate the SI between generating facilities and the transmission system.

The IC is 100% responsible for any studies related to the SSR or SSTI. The only study that SCE will perform (at the IC's expense) is for SSCI; to ensure that the Project does not damage SCE's control systems.

The SSCI study will require that the IC provide a detailed PSCAD model of its Generating Facility and associated control systems, along with the manufacturer representative's contact information. The study will identify any mitigation(s) that will be required as part project execution and need to be completed prior to initial synchronization of the Generating Facility. The study and the proposed mitigation(s) shall be at the expense of the IC.

It is the IC's responsibility to select, purchase, and install turbine/inverter based generators that are compatible with the series compensation in the area.

O. Environmental Evaluation, Permitting, and Licensing

Please see Appendix K of the QC7 Phase II Area Report.

P. Affected Systems Coordination

Please see Section H of the QC7 Phase II Area Report.

Q. 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 detailed engineering and design.

2. IC's Technical Data

   The study accuracy and results for the QC7 Phase II Study are contingent upon the accuracy of the technical data provided by the IC. Any changes from the data provided could void the study results.

3. Study Impacts on Neighboring Utilities

   Results or consequences of this QC7 Phase II 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).

   Refer to Affected Systems Coordination section of the Area Report.

4. Use of Distribution Provider Facilities

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

5. Distribution Provider Interconnection Handbook

   The IC shall be required to adhere to all applicable requirements in the Distribution Provider 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 IC 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 Distribution Provider-owned protection and generator-owned protection. If adequate protection coordination cannot be achieved, then modifications to the generator-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 QC7 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 Distribution Provider prior to the In-Service Date of the Interconnection Facilities, the IC is responsible to make appropriate arrangements with Distribution Provider to receive and pay for such revenue service.

9. Licensing Cost and Estimated Time to Construct Estimate (Duration)

   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 generation tie line, 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 Distribution Provider substation. Due to uncertainties related to telecommunication upgrades for the numerous projects in queue ahead of QC7 Phase II, 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 QC7 Phase II may be reduced. Any changes in these assumptions may affect the cost and schedule for the identified telecommunication facilities.

11. Ground Grid Analysis

    A detailed ground grid analysis will be required as part of the detailed engineering for the Project at the SCE substations whose ground grids were flagged with duty concerns.

12. 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 POI that was evaluated in the QC7 Phase II Study for the Project. Nothing in this report is intended to supersede or establish terms/conditions specified in interconnection agreements agreed to by SCE, CAISO and the IC.

13. Process for synchronization/trial operations and commercial operations of the Project

    The IC is reminded that the CAISO has implemented a New Resource Implementation (NRI) process that ensures that a generation resource meets all requirements before synchronization/trial operations and commercial operations. The NRI uses a bucket system for deliverables from the IC that are required to be approved by the CAISO. The first step of this process is to submit an "ISO Initial Contact Information Request form" at least 7 months in advance of the planned initial synchronization. Subsequently an NRI project number will be assigned to the project for all future communications with the CAISO. The Distribution Providers have no involvement in this NRI process except to inform the IC of this process requirement. Further information on the NRI process can be obtained from the CAISO Website using the following links:

    New Resource Implementation webpage:
    http://www.caiso.com/participate/Pages/NewResourceImplementation/Default.aspx

    NRI Checklist:
    http://www.caiso.com/Documents/NewResourceImplementationChecklist.xls

    NRI Guide:
    http://www.caiso.com/Documents/NewResourceImplementationGuide.doc

14. Potential Changes in Cost Responsibility

    The IC hereby placed on notice that interconnection of its 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. Section 14.2.2 of the GIDAP provides that should Network Upgrades required for queued-ahead projects be 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 Distribution Provider. However, if the Network Upgrades required by earlier queued generating facilities are not subject to an executed GIA (or unexecuted GIA filed at FERC) at the time of withdrawal of the earlier queued generating facilities, the financial responsibility for such upgrades may fall to the IC[4]. 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. Changes in costs allocated to the IC could also arise as the result of the CAISO's reassessment process described in Section 7.4 of the GIDAP. SCE encourages the IC to review Sections 7.4 and 14.2.2 of the GIDAP for the rules and processes under which the financial responsibility might be reapportioned to the IC. Potential changes in the IC's cost responsibility resulting from application of the provisions of these Sections of GIDAP are not included in this Phase II study, nor are the potential impacts to the IC's maximum cost responsibility outlined.

15. Additional limitations may occur in the future under future base case overloads.

16. Please note that SCE has made its best efforts to convey as much information possible based on information provided by the IC about its proposed project. The information contained herein may indicate to ICs that a project of its magnitude may be better suited to interconnect at higher voltage levels, or downsize as to not incur significant amount of restrictions. Any determination to change POIs or downsize is purely at the IC's discretion and would be subject to a SCE material modification review pursuant to the tariff.

[4] Such circumstance was not identified for the Project in the Study.

Attachment 1

Interconnection Facilities, 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

Please refer to separate document.

Attachment 3

Allocation of Network Upgrades for Cost Estimates

	Project Allocation(%)	Total Upgrade Cost (2015 $k)		Allocated Cost (2015 $k)		Allocated Cost (Escalated $k)	
RNU							
Vista 220kV CB upgrade	3.16%	$	2,359	$	75	$	85
Vista 220kV CB upgrade grid ground study	100.00%	$	43	$	43	$	49
RNU Total		**$**	**2,403**	**$**	**118**	**$**	**134**
Grand Total				**$**	**118**	**$**	**134**

Attachment 4

Distribution Provider Interconnection Handbook

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

Please refer to separate document.

Attachment 5

Short Circuit Calculation Study Results

Please refer to the Appendix H of the Area Report.

Attachment 6

Customer Provided Project Dynamic Data

The following data was submitted by the IC for Dynamic simulation:

genrou 96694 "WDT1189G " 13.80 "1 " : #9 mva=71.176 "tpdo" 9.67 "tppdo" 0.05 "tpqo" 2.95 "tppqo" 0.05 "h" 0.97 "d" 0.0 "ld" 2.35 "lq" 2.15 "lpd" 0.245 "lpq" 0.35 "lppd" 0.181 "ll" 0.13 "s1" 0.094 "s12" 0.507 "ra" 0.0053 "rcomp" 0 "xcomp" 0 "accel" 0.5

exac2 96694 "WDT1189G " 13.80 "1 " : #9 "tr" 0.028 "tb" 1.0 "tc" 1.0 "ka" 889.0 "ta" 0.02 "vamax" 166.0 "vamin" -166.0 "kb" 1.0 "vrmax" 41.5 "vrmin" 0.0 "te" 0.5 "kl" 1.51 "kh" 0.0 "kf" 0.0303 "tf" 1.0 "kc" 0.0 "kd" 0.0 "ke" 1.0 "vlr" 50.08 "e1" 1.5 "se1" 0.19 "e2" 2.0 "se2" 0.67 "limflg" 0.0

pss2a 96694 "WDT1189G " 13.80 "1 " : #9 "j1" 1 "k1" 0 "j2" 3 "k2" 0 "tw1" 2 "tw2" 2 "tw3" 2 "tw4" 0 "t6" 0 "t7" 2 "ks2" 1.03 "ks3" 1 "ks4" 1 "t8" 0.5 "t9" 0.1 "n" 1 "m" 5 "ks1" 10.0 "t1" 0.25 "t2" 0.04 "t3" 0.2 "t4" 0.03 "vstmax" 0.1 "vstmin" -0.1 "a" 1 "ta" 0 "tb" 0

ggov1 96694 "WDT1189G " 13.80 "1 " : #9 mwcap=51.0 "r" 0.05 "rselect" 1.0 "tpelec" 1.0 "maxerr" 0.023 "minerr" -0.023 "kpgov" 3.6 "kigov" 1.65 "kdgov" 0.0 "tdgov" 1.0 "vmax" 1.0 "vmin" 0.24 "tact" 0.4 "kturb" 2.7 "wfnl" 0.2587 "tb" 0.1 "tc" 0.0 "flag" 0.0 "teng" 0.0 "tfload" 0.3 "kpload" 1.0 "kiload" 3.3 "ldref" 1.0902 "dm" 0.0 "ropen" 99.0 "rclose" -99.0 "kimw" 0.0 "pmwset" 0.0 "aset" 99.0 "ka" 10.0 "ta" 0.1 "db" 0.0 "tsa" 1.0 "tsb" 1.0 "rup" 99.0 "rdown" -99.0

genrou 96695 "WDT1189G2 " 13.80 "2 " : #9 mva=71.176 "tpdo" 9.67 "tppdo" 0.05 "tpqo" 2.95 "tppqo" 0.05 "h" 0.97 "d" 0.0 "ld" 2.35 "lq" 2.15 "lpd" 0.245 "lpq" 0.35 "lppd" 0.181 "ll" 0.13 "s1" 0.094 "s12" 0.507 "ra" 0.0053 "rcomp" 0 "xcomp" 0 "accel" 0.5

exac2 96695 "WDT1189G2 " 13.80 "2 " : #9 "tr" 0.028 "tb" 1.0 "tc" 1.0 "ka" 889.0 "ta" 0.02 "vamax" 166.0 "vamin" -166.0 "kb" 1.0 "vrmax" 41.5 "vrmin" 0.0 "te" 0.5 "kl" 1.51 "kh" 0.0 "kf" 0.0303 "tf" 1.0 "kc" 0.0 "kd" 0.0 "ke" 1.0 "vlr" 50.08 "e1" 1.5 "se1" 0.19 "e2" 2.0 "se2" 0.67 "limflg" 0.0

pss2a 96695 "WDT1189G2 " 13.80 "2 " : #9 "j1" 1 "k1" 0 "j2" 3 "k2" 0 "tw1" 2 "tw2" 2 "tw3" 2 "tw4" 0 "t6" 0 "t7" 2 "ks2" 1.03 "ks3" 1 "ks4" 1 "t8" 0.5 "t9" 0.1 "n" 1 "m" 5 "ks1" 10.0 "t1" 0.25 "t2" 0.04 "t3" 0.2 "t4" 0.03 "vstmax" 0.1 "vstmin" -0.1 "a" 1 "ta" 0 "tb" 0

ggov1 96695 "WDT1189G2 " 13.80 "2 " : #9 mwcap=51.0 "r" 0.05 "rselect" 1.0 "tpelec" 1.0 "maxerr" 0.023 "minerr" -0.023 "kpgov" 3.6 "kigov" 1.65 "kdgov" 0.0 "tdgov" 1.0 "vmax" 1.0 "vmin" 0.24 "tact" 0.4 "kturb" 2.7 "wfnl" 0.2587 "tb" 0.1 "tc" 0.0 "flag" 0.0 "teng" 0.0 "tfload" 0.3 "kpload" 1.0 "kiload" 3.3 "ldref" 1.0902 "dm" 0.0 "ropen" 99.0 "rclose" -99.0 "kimw" 0.0 "pmwset" 0.0 "aset" 99.0 "ka" 10.0 "ta" 0.1 "db" 0.0 "tsa" 1.0 "tsb" 1.0 "rup" 99.0 "rdown" -99.0

genrou 96695 "WDT1189G2 " 13.80 "3 " : #9 mva=71.176 "tpdo" 9.67 "tppdo" 0.05 "tpqo" 2.95 "tppqo" 0.05 "h" 0.97 "d" 0.0 "ld" 2.35 "lq" 2.15 "lpd" 0.245 "lpq" 0.35 "lppd" 0.181 "ll" 0.13 "s1" 0.094 "s12" 0.507 "ra" 0.0053 "rcomp" 0 "xcomp" 0 "accel" 0.5

exac2   96695 "WDT1189G2   " 13.80 "3 " : #9 "tr" 0.028 "tb" 1.0 "tc" 1.0 "ka" 889.0 "ta" 0.02 "vamax" 166.0 "vamin" -166.0 "kb" 1.0 "vrmax" 41.5 "vrmin" 0.0 "te" 0.5 "kl" 1.51 "kh" 0.0 "kf" 0.0303 "tf" 1.0 "kc" 0.0 "kd" 0.0 "ke" 1.0 "vlr" 50.08 "e1" 1.5 "se1" 0.19 "e2" 2.0 "se2" 0.67 "limflg" 0.0

pss2a   96695 "WDT1189G2   " 13.80 "3 " : #9 "j1" 1 "k1" 0 "j2" 3 "k2" 0 "tw1" 2 "tw2" 2 "tw3" 2 "tw4" 0 "t6" 0 "t7" 2 "ks2" 1.03 "ks3" 1 "ks4" 1 "t8" 0.5 "t9" 0.1 "n" 1 "m" 5 "ks1" 10.0 "t1" 0.25 "t2" 0.04 "t3" 0.2 "t4" 0.03 "vstmax" 0.1 "vstmin" -0.1 "a" 1 "ta" 0 "tb" 0

ggov1   96695 "WDT1189G2   " 13.80 "3 " : #9 mwcap=51.0 "r" 0.05 "rselect" 1.0 "tpelec" 1.0 "maxerr" 0.023 "minerr" -0.023 "kpgov"   3.6 "kigov"   1.65 "kdgov" 0.0 "tdgov" 1.0 "vmax"   1.0 "vmin" 0.24 "tact" 0.4 "kturb"   2.7 "wfnl" 0.2587 "tb" 0.1 "tc" 0.0 "flag" 0.0 "teng" 0.0 "tfload" 0.3 "kpload" 1.0 "kiload"   3.3 "ldref" 1.0902 "dm" 0.0 "ropen" 99.0 "rclose" -99.0 "kimw" 0.0 "pmwset" 0.0 "aset" 99.0 "ka" 10.0 "ta" 0.1 "db" 0.0 "tsa" 1.0 "tsb" 1.0 "rup" 99.0 "rdown" -99.0

Attachment 7

Not Used.

Attachment 8

Subtransmission Assessment Report for Generation Reliability Study

Please refer to separate document.

Addendum to Appendix A – WDT1189

Wellhead Power Development, LLC

Stanton Energy Center Project

Addendum #1

Cluster 7 Phase II Final Report

December 28, 2015

This study has been completed in coordination with the California Independent System Operator Corporation (CAISO) per CAISO Tariff Appendix DD Generator Interconnection and Deliverability Allocation Procedures (GIDAP)

Project No.		No	Date	Document Title	Description of Document
WDT1189	Stanton Energy Center Project	2	12/28/2015	Addendum #1 to Queue Cluster 7 Phase II Appendix A Final Report	The purpose of this report is to publish the written comments provided by the IC to SCE in accordance with the timelines stated per Section 4.6.10 in GIP
WDT1189	Stanton Energy Center Project	1	11/24/2015	Queue Cluster 7 Phase II Appendix A Final Report	Report to disclose results of QC7 Phase II cluster.

Executive Summary

Wellhead Power Development, LLC, an Interconnection Customer (IC), received a Queue Cluster 7 Phase II (QC7 Phase II) study report dated November 24, 2015 for its Interconnection Request (IR) to Southern California Edison (SCE) for their proposed Stanton Energy Center Project (Project), queue position WDT1189.

Subsequent to the distribution of the report, to comply with GIP obligation to IC's written comments on interconnection studies as modified by FERC Order 792, SCE is publishing any written comments submitted by the IC per Section 4.6.10:

- Within ten (10) Business Days of receipt of the QC7 PII report, but in no event less than three (3) Business Days before the Results Meeting conducted to discuss the report; and/or

- Additional comments on the final QC7 Phase II Interconnection Study report up to (3) Business Days following the Results Meeting

This addendum report discloses below the written comments provided by the IC to SCE in accordance with the timelines stated in GIP for QC7 Phase II study report dated November 24, 2015. The Phase II study report is unaffected by this addendum report.

QC7 Phase II – WDAT1189 – Stanton Energy Center Project

1. Written comments provided by IC within ten (10) Business Days of receipt of the QC7 PII report

   a. None

2. Written comments provided by IC three (3) Business Days following the Results Meeting

   a. None

Appendix A – WDT1189

Wellhead Power Development, LLC

Stanton Energy Center

QUEUE CLUSTER 7 PHASE II REPORT

Addendum #1 to the Final Phase II Study Report

June 24, 2016

This study has been completed in coordination with the California Independent System Operator Corporation (CAISO) per CAISO Tariff Appendix DD Generator Interconnection and Deliverability Allocation Procedures (GIDAP)

Table of Contents

Attachments:

1. Interconnection Facilities, Network Upgrades and Distribution Upgrades
2. Escalated Cost and Time to Construct for Interconnection Facilities, Reliability Network Upgrades, Delivery Network Upgrades, and Distribution Upgrades
3. Not Used
4. Distribution Provider Interconnection Handbook
5. Short Circuit Calculation Study Results (see Appendix H of the Bulk Area Report)
6. Customer Provided Dynamic Data
7. Subtransmission Assessment Report – Barre 66 kV System

A. Introduction

Wellhead Power Development, LLC, the Interconnection Customer (IC), has submitted a completed Interconnection Request (IR) to Southern California Edison Company (SCE) for their proposed Stanton Energy Center (Project). The project requested a Point of Interconnection (POI) is Southern California Edison Company's (SCE) Barre 66 kV Switchrack located in Orange County, CA. The Project has a CAISO delivery point at Barre 220 kV Substation bus. The IC elected that the project be Option A with Full Capacity Deliverability Status, and desires an In-Service Date (ISD) and Commercial Operation Date (COD) of March 30, 2018 and June 1, 2018 respectively. Such dates are specified in the Project Attachment B. Actual ISD and COD will depend on design and construction requirements to interconnect for the Project.

In accordance with Federal Energy Regulatory Commission (FERC) approved CAISO Tariff Appendix DD Generator Interconnection and Deliverability Allocation Procedures (GIDAP) of Attachment I of SCE's Wholesale Distribution Access Tariff (WDAT), the Project was grouped with Queue Cluster 7 (QC7) Phase II projects to determine the impacts of the group.

Please note that the discussion related to the combined impacts at the Transmission and Subtransmission levels of the group resides in the SCE Metro Bulk Area and Barre Subtransmission Assessment Reports; both are included in the QC7 PII report package. This report focuses only on the impacts or impact contributions of the Project at the local Distribution system, and it is not intended to supersede any contractual terms or conditions specified in an Interconnection Agreement.

The report provides the following:

1. Transmission and/or Subtransmission 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 to construct[1] these facilities. Such information is provided in Attachment 1 and Attachment 2 as separate documents in the Appendix A Project report package.

All the equipment and facilities comprising the Project located in Stanton, California, as disclosed by the IC in its IR, as may have been amended during the Interconnection Study process, which consists of (i) three (3) synchronous generator units rated at 50.6 MW each for a combined output of 151.6 MW as measured at the generator terminals; (ii) the associated infrastructure and step-up transformers, (iii) meters and metering equipment, (iv) appurtenant equipment and (v) 1.8 MW of auxiliary load.

Based on the technical data provided for the main step-up transformer banks, internal generation facility losses were found to be 0.7 MW resulting in a net output, as measured at the high-side of the main transformer banks, of 149.3 MW when taking the auxilary loads and internal facility losses into account. Losses on the 0.34 mile 3000 copper XLP UG generation tie-line were found to be 0.1 MW resulting in an estimated capacity delivery of 149.2 MW at the Point of Interconnection.

The Project shall consist of the Generating Facility and the IC's Interconnection Facilities as illustrated below in Figure A-1. Similarly, the Project information is summarized in Table A.1 below The location of

[1] It should be noted that construction is only part of the duration of months specified in the study, includes final engineering, licensing, etc, and other activities required to bring such facilities into service. These durations are from the execution of the Interconnection Agreement, receipt of: all required information, funding, and written authorization to proceed from the IC as will be specified in the Interconnection Agreement to commence the work.

the Project was assumed as specified in the IR provided by the IC. The Project shall not exceed the total net output.

Figure A.1: Project IC Facilities One-Line Diagram

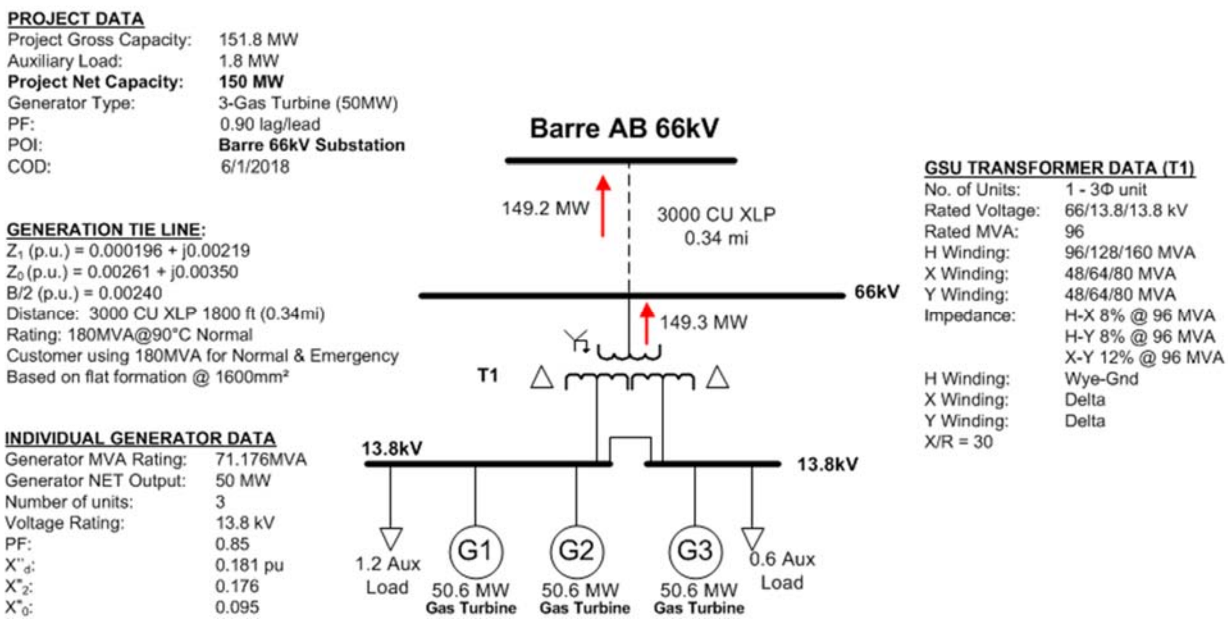


Figure A.2: Project IC Facilities Site Location

Table A.1: Project General Information

Project Location	10711 Dale Street Stanton, CA 90680 Orange County GPS Coordinates: Latitude: 33.807053, Longitude: -117.985299
Distribution Provider's Planning Area	SCE Metro Bulk system
Number and Types of Generators	3 Synchronous Generators (50.6 MW each)
Interconnection Voltage	66 kV
Maximum Generator Output (At Generator Terminals)	151.8 MW (gross)
Generator Auxiliary Load	1.8 MW
Internal Generation Facility Losses	0.7 MW
Maximum Net Output at Generation Facility (High-Side of Main Transformer)	149.3 MW
Power Factor Range	Lead 0.90 / Lag 0.90 at POI per interconnection application
Step-up Transformer(s)	Main Transformers (T1) 66/13.8/13.8 kV (YG-D-D), H-Winding: 96/128/160 MVA, X-Winding: 48/64/80 MVA, Y-Winding: 48/64/80 MVA, H-X Impedance Value: 8% @ 96 MVA H-Y Impedance Value: 8% @ 96 MVA X-Y Impedance Value 12% @ 96 MVA
Gen-Tie	0.34 miles, 3000 CU XLP
POI	Distribution Provider's Barre 66 kV Switchrack
Estimated Losses on Gen-Tie Facilities (All Gen-Tie Facilities used to deliver to POI)	0.1 MW
IC Requested COD	6/01/2018

B. Study Assumptions

For detailed assumptions regarding the group cluster delivery analysis, please refer to the applicable QC7 Phase II SCE Metro Area Deliverability Assessment and for detailed assumptions regarding the group cluster analysis at the Subtransmission level, please refer to the applicable QC7 Phase II Subtransmission Assessment Report. Below are the assumptions specific to the Project:

1. The following is the Plan of Service (POS) assumed for the Project in the Phase II Study:

   The project was modeled as via one 66 kV generation tie-line (gen-tie) to SCE's Barre 66 kV Substation.

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

   - The new 66 kV position at Barre Switchrack.
   - The segment of a 66 kV generation tie-line inside the Barre 66 kV substation property line.
   - The extensions of each of the two generator – owned fiber optic cables inside the Barre Substation property line.
   - Lightwave, channel banks and associated equipment at Barre Substation and at the Generating Facility.
   - The required retail load meters.

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

3. The following facilities are to be installed by the Interconnection Customer and **<u>are not included</u>** in this Phase II Study:

   - The 66 kV generation tie-line from the Generating Facility to the last structure outside the Barre Substation property line.
   - The fiber optic cables to provide two diversely routed telecommunication paths required for the line protection relays.
   - The required CAISO metering equipment (voltage and current transformers and CAISO meters) and metering cabinet for SCE revenue meter.

     NOTE: The metering voltage and current transformers installed for the CAISO metering will also be used for the SCE owned retail meters.

   - The following 66 kV line protection relays to be installed at the Generating Facility end of the 66 kV generation tie-line:
     - One (1) G.E. L90 current differential relay with dual dedicated digital communication channels on diverse paths to Barre Substation.
     - One (1) SEL 311L current differential relay with dual dedicated digital communication channels on diverse paths to Barre Substation.

C. Reliability Standards, Study Criteria and Methodology

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. Refer to Section C of the Bulk Area Report for details of the applicable reliability standards, study criteria and methodology.

D. Power Flow Reliability Assessment Results

I. Steady State Power Flow Analysis Results – 220 kV and above

The study did not identify any power flow issues on the Bulk Electric System not addressed via the use of CAISO Congestion Management or via already approved transmission upgrades. Consequently, the Project is not allocated cost for any Network Upgrades identified to address power flow issues. The details of the power flow analysis are provided in Section D of the Metro Area Report.

II. Steady State Power Flow Analysis Results - 66 kV

1. Thermal Overloads

The study did not identify any power flow issues on the Barre 66 kV Subtransmission System. The details of the power flow analysis are provided in the Subtransmission Assessment Report.

2. Voltage Performance

   The Project is required to provide power factor regulation capability (0.95 lead/lag at POI for asynchronous generation and 0.90 lagging to 0.95 leading at generator terminals for synchronous generators) to alleviate power flow non-convergence and maintain the Transmission transfer capability.

3. Required Mitigations

   No power flow mitigations on the subtransmission system were identified to be required by the Project.

E. Short Circuit Duty Results

Short circuit studies were performed to determine the fault duty impact of adding the QC7 Phase II projects to the Transmission system and to ensure system coordination. The fault duties were calculated with and without the projects to identify any equipment overstress conditions. Once overstressed circuit breakers are identified, the fault current contribution from each individual project in QC7 Phase II is determined. Each project in the cluster will be responsible for its share of the upgrade cost based on the rules set forth in CAISO Tariff Appendix DD.

1. Short Circuit Duty Study Input Data

   “Synchronous Gen” Data for each generation unit:

   X"1 - positive sequence subtransient reactance: 0.181 PU
   X"2 - negative sequence subtransient reactance: 0.176 PU
   X"0 - zero sequence subtransient reactance: 0.095 PU

Generation tie-line:

Length:	1,800 feet
Conductor:	3000 CU XLP
Z1(p.u.) conductor impedance information:	0.000196 R, 0.00219 X, 0.0048 B
Z0(p.u.) conductor impedance information:	0.00261 R, 0.00350 X, 0.0048 B

Main Generation Step-Up Transformer

Technical details are provided above in Table A-1.

2. Short Circuit Duty Study Results

All bus locations where the QC7 Phase II projects increase the short-circuit duty by 0.1 kA or more and where duty was found to be in excess of 60% of the minimum breaker nameplate rating are listed in the Bulk Area Report (Appendix H). These values have been used to determine if any equipment is overstressed as a result of the inclusion of QC7 Phase II interconnections and corresponding network upgrades, if any.

As discussed in Section D.5.2 of the Area Report and Appendix I, short circuit duty at Barre 220 kV was found to exceed the maximum nameplate ratings of all existing 220 kV breakers. Physical upgrades would necessitate replacement of all circuit breakers with a currently non-SCE standard higher rated 220 kV breaker which will necessitate in excess of $70 million and require over 48 months to implement. Because the need is currently viewed as temporary in nature and is impacted by timing of the ultimate disposition of the existing OTC units, the recommended mitigation involves implementing an operating procedure which would restrict the number of generation units that can operate (i.e., "spin") to ensure duties at Barre 220 kV are maintained within the maximum Barre SCD ratings of 63 kA. Such restrictions may impact day-to-day operations of this project as well as those existing OTC units which provide significant short-circuit duty contribution to the Barre 220 kV bus.

The responsibility to finance short circuit related Reliability Network Upgrades identified through a Group Study shall be assigned to all Interconnection Requests in that Group Study pro rata on the basis of short circuit duty contribution of each Generating Facility.

Please refer to the QC7 Phase II Area Report for the QC7 Phase II breaker evaluation identified overstressed circuit breakers at the SCE buses, and Attachment 2 for the pro-rata allocation with corresponding estimated costs (if any) for the Project, based on SCD contribution at each location. Note that the list of Barre 66 kV circuit breakers shown in the QC7 Phase II Area Report has been adjusted as discussed in the Subtransmission Assessment Report (Queue Cluster 7 Phase II Attachment 8). In addition, the 2016 Reassessment Study efforts has determined that the need to upgrade fourteen (14) circuit breakers at Vista 220 kV Substation for short-circuit duty mitigation is no longer required.

3. SCE Substations with Ground Grids Duty Concerns

The short circuit studies flagged SCE-owned substations beyond the Project POI with ground grid duty concerns that necessitate a ground grid study. The Project's contribution to the Huntington Beach 220 kV, Lewis 220 kV, Apollo 66 kV, Bolsa 66 kV, Fullerton 66 kV, Gilbert 66 kV, Kindler 66 kV, La Palma 66 kV, Lampson 66 kV, Marion 66 kV, Shawnee 66 kV, Sunny Hills 66 kV, Team 66 kV, and Trask 66 kV Substations were found to be signification and will require the project to fund the cost of performing ground grid studies at these locations.

4. Preliminary Protection Requirements

   Protection requirements are designed and intended to protect the Distribution Provider's system only. The preliminary protection requirements were based upon the interconnection plan as shown in the one-line diagram depicted in line item #7 in Attachment 1.

   The IC is responsible for the protection of its own system and equipment and must meet the requirements in the Distribution Provider Interconnection Handbook provided in Attachment 4.

F. Transient Stability Evaluation

With the Project providing 0.95 power factor correction as measured at the POI and including the required mitigation identified above, transient stability performance was found to be acceptable. Refer to enclosed Bulk Area Report and Subtransmission Assessment Report in the QC7 Phase II report package, for the QC7 Phase II transient stability evaluation criteria and assessment results.

G. Power Factor Requirements

Based on the results of the Study, the Project will need to be designed to maintain a composite power delivery at continuous rated power at the POI at a power factor within the range of 0.95 lead/lag at POI for asynchronous generation and 0.90 lagging to 0.95 leading at generator terminals for synchronous generators. Additionally, the generation system must be designed to accommodate a VAR schedule provided by SCE. SCE will determine if the VAR schedule is necessary based on future re-arrangements of SCE's Transmission.

H. Deliverability Assessment Results

1. **On Peak Deliverability Assessment**

   The Project does not contribute to any deliverability constraint.

2. **Off Peak Deliverability Assessment**

   There is no wind generators in the study area. The off-peak deliverability assessment is not performed.

3. **Required Mitigations**

   No Delivery Network Upgrades are required.

I. In-Service Date and Commercial Operation Date Assessment

The latest information provided by the IC has indicated that the requested generator ISD is March 30, 2018 and a COD of June 1, 2018. To determine if these dates could be met, an In-Service Date and Commercial Operation Date Assessment was performed which considered both the QC7 Phase II process timelines as well as the following facilities needed to provide for reliable energy only interconnection of the Project. Timing of the upgrades required to provide for the requested Full Capacity Deliverability Status are discussed in the section below:

1. QC7 Interconnection Process Timelines

To enable physical interconnection, a Generation Interconnection Agreement (GIA) is required. As part of the QC7 interconnection process, a GIA is not scheduled to be tendered until after completion of the Reassessment and Transmission Planning Deliverability (TPD) Allocation Study Process which does not commence until late January or early February 2016. The TPD Allocation is scheduled to be completed by April and if no changes to scope requirements are identified, a letter is provided at the end of April outlining the TPD Allocation results. However, if changes are identified, updates to scope, costs and schedules are developed and updated reports are issued by the end of July. The GIA negotiations commences after either the issuance of the letter outlining the TPD allocation results at the end of April or upon issuance of the updated reports at the end of July. Provided the Project does not elect to Park, the letter or updated reports are used as the basis to proceed with the GIA negotiations. Assuming a three month timeframe for GIA negotiations, a GIA is not expected until either early August 2016 or early November 2016 depending on TPD study results and decision to Park or proceed.

2. System Upgrade Timelines for Reliable Interconnection

   The Operational Studies identified that the following facilities are required in order to provide for an energy only interconnection:

   a. Distribution Provider's Interconnection Facilities

      As described in Section 1.b of Attachment 1, line protection, telecomm, and SCE portion of 66 kV gen-tie among other items will be required to terminate the IC gen-tie at the SCE Johanna Substation. Preliminary durations estimated to install the Distribution Provider's Interconnection Facilities is 27 months.

   b. Reliability Network Upgrades – Short-Circuit Duty (SCD) Mitigation

      Short circuit duty operational mitigation was identified taking into account new generation projects which have executed GIAs, approved transmission system upgrades fully permitted and under construction, and new generation projects including QC7 Phase II Projects which do not yet have an executed GIA. The study results for these operational studies are provided in Section II of the Generation Sequencing Implementation (GSI) Short Circuit Duty evaluation (Appendix G). Based on the QC7 Phase II and taking into account 2016 Reassessment study results, the following upgrades/mitigation are required to be in place in order to enable energy only interconnection of this Project:

      - Reconfiguration of the system to operate one Mira Loma AA-Bank on the east side as normally open (requires simply opening AA-Bank so no duration identified)
      - Vincent 220 kV bus-split which has an estimated in-service date of July 2016

      In addition to the above mitigation requirements which already have established in-service dates, the following additional SCD mitigations may be needed in order to enable energy only interconnection. It is important to note that projects to undertake the work have not been initiated since the timing of need is dependent on development of queued generation projects, including QC7, which have not yet executed a GIA.

      - Replacement of four (4) Vincent 500 kV circuit breakers (triggered by QC3&4)
      - ~~Upgrade fourteen (14) Vista 220 kV circuit breakers by installing TRV Caps (triggered by QC7)~~

- o CAISO Operating Procedure which limits the number of generation units operating and "spinning" to ensure duties at Barre 220 kV are maintained within the maximum Barre SCD ratings of 63 kA (triggered by QC7)

The identification of need was based on the assumption that all queued generation projects actually materialize and are interconnected (as energy only). Timing to implement the first two SCD mitigations are currently estimated at 27 months from the date the need is identified. These additional SCD mitigations will be continuously evaluated as part of ongoing GIA negotiations and ongoing studies to properly define the time when actual need to undertake these mitigations is required based on the actual GIA negotiations with corresponding requested in-service dates. Once the actual need is triggered, project development will commence. Timing to implement the recommended CAISO Operating Procedure will depend on OTC unit operations and timing of actual development of the Stanton Energy Project.

c. Voltage Support Mitigation

No voltage support upgrades were identified to be required to enable this project to interconnect.

d. Distribution Upgrades

i. Plan of Service

As described in Section 3.b of Attachment 1, a new 66 kV line position equipped as a double-bus double-breaker configuration is required as the Distribution Plan of Service to interconnect the project to the SCE Barre Substation. Preliminary duration estimated to install the Distribution Provider's Distribution Upgrades is 27 months.

ii. Short-Circuit Duty Mitigation

The studies identified that several QC7 Phase II Projects, including this project, contributes to the overstressing of one (1) 66 kV circuit breaker at Villa Park and that this project alone would drive the need for replacement of twenty-eight (28) 66 kV circuit breakers at Barre under a conditions when the bus-sectionalizing 66 kV circuit breakers are closed. However, the number of CB's requiring replacement is reduced to twenty-one (21) with an operating procedure which to disconnect the Project (WDAT 1189) during the condition when the bus-sectionalizing breakers are closed as discussed in the Subtransmission Assessment Report (Queue Cluster 7 Phase II Attachment 8). Preliminary duration estimated to replace the 66 kV circuit breakers at Barre and Villa Park is 27 months.

3. Conclusion

Based on the standard timelines, the requested IC In-Service Date of March 30, 2018 cannot be met due to the following reasons:

- o The QC7 Interconnection Process Timelines will not yield a Generation Interconnection Agreement until either early August 2016 or early November 2016 depending on TPD study results which is beyond the requested IC In-Service Date.

- Timelines required to construct the Distribution Provider's Interconnection Facilities and Distribution Upgrades are estimated at 27 months from the date the GIA is executed, payments are made, and notice to proceed with interconnection is provided. Following the standard process, this would result in a best case in-service date of December 2018 or March 2019 depending on TPD study results. It should be noted that the ability to meet a best case in-service date is tied directly to the IC's timely execution of the Interconnection Agreement, submittal of payments, and notice to proceed.
- Potential need to replace four (4) Vincent 500 kV ~~and upgrade fourteen (14) Vista 220 kV~~ circuit breakers which would require an estimated 27 months to complete from the day a project is initiated to commence the upgrade~~ at each location~~.

It is also important to note that once interconnected, the ability to operate the unit (even in spinning reserve) is contingent on further developments and operating status of existing OTC units. With all OTC units currently in operating either as generator or synchronous condenser, the Barre 220 kV circuit breakers will be overstressed with the addition of this project. To address this issue, an Operating Procedure is recommended that will limit certain generation unit operations.

J. Timing of Full Capacity Deliverability Status, Interim Deliverability, Area Constraints, and Operational Information

The IC elected that the Project be Option A with Full Capacity Deliverability Status (FCDS). Timing of obtaining the requested FCDS is dependent on the completion of Delivery Network Upgrades. Until such time that the Delivery Network Upgrades are completed and placed into service, the Project may experience additional congestion exposure due to transmission limitations or may be granted Interim Deliverability Status based on annual system availability. The sections below provide a discussion of the timing of Full Capacity Deliverability Status, Interim Deliverability, Area Constraints, and Operational Information.

1. System Upgrades Required for Full Capacity Deliverability Status

   No upgrades have been identified to be required (either previously triggered or triggered with the addition of QC7 Projects) for this project to obtain the requested FCDS.

2. Interim Operational Deliverability Assessment for Information Only

   The operational deliverability assessment was performed for study years 2018 and 2020 by modeling the Transmission and generation in service in the corresponding study year. For details of the Transmission and generation assumption, refer to Section E.2 of the Area Report. There are no deliverability constraints identified. The Project will have the deliverability status as granted by the Transmission Plan Deliverability allocation.

3. Conclusion

   Since no upgrades have been identified to be required to obtain FCDS, the requested Full Capacity Deliverability Status could be achieved upon interconnection.

K. Interconnection Facilities, Network Upgrades, and Distribution Upgrades

Please see **Attachment 1** for the Interconnection Facilities, Reliability Network Upgrades, Delivery Network Upgrades and Distribution Upgrades allocated to the Project. Please note that SCE will not "reserve" the identified IF's for the proposed POI. The identified scope/facilities will be allocated to the project upon the successful execution of the Generation Interconnection Agreement and SCE has completed the final design and engineering of the facilities according to tariff timelines.

L. Cost and Construction Duration Estimates

To determine the cost responsibility of each generation project in QC7 Phase II, the CAISO developed cost allocation factors (Attachment 3) for Reliability Network Upgrades, Local Delivery Network Upgrades and Area Delivery Network Upgrades. Attachment 2 provides the 'constant' 2014 dollars and their escalation to the estimated COD year for Interconnection Facilities, Reliability Network Upgrades, Delivery Network Upgrades, and Distribution Upgrades which the Project was allocated cost.

For the QC7 Phase II Study, the estimated COD is derived by assuming the duration of the work element will begin in December 2016, which accounts for the CAISO tariff scheduled completion date of the QC7 Phase II study plus: the TP Deliverability (TPD)[2] allocation, Annual Reassessment effort, and the interconnection agreement signing period and submittal of required funds by the IC.

The IC should note that any Local Delivery Network Upgrades and Area Delivery Network Upgrades allocated to the Project may be assessed 35% Income Tax Component of Contribution (ITCC) pending the results of the TPD allocation Process several months after the QC Phase II Study Reports are released, in addition to the 35% ITCC assessed for the IFs, DUs, and RNUs above the $60K/MW repayment cap allocated to the Project. For your information, Attachment 2 contains a potential ITCC estimate[3] based on the Phase I cost in this study. It does not represent the "maximum ITCC exposure" of the Project. Attachment 3 provides an estimated non-reimbursable RNU cost that would be subject to ITCC, taking into account the Network Upgrade maximum cost responsibility. The maximum ITCC warranted by the Project will be addressed, calculated, and included during the Interconnection Agreement development phase once the IC submits the TPD Affidavit confirming the acceptance, partial acceptance, or denial of awarded deliverability assigned to the Project.

M. SCE Technical Requirements

The IC is responsible for the protection of its own system and equipment and must meet the requirements in the Distribution Provider Interconnection Handbook provided in Attachment 4.

It is the IC's responsibility to select, purchase, and install turbine/inverter based generators that are compatible with the series compensation in the area.

---

[2] Transmission Plan Deliverability: Deliverability supported by the CAISO's Transmission Plan

[3] The maximum ITCC exposure applies ITCC (35%) to assigned IF and DU facilities, Network Upgrades that are not subject to transmission credits incremental to a repayment $/MW cap or an award of 0 MW TPD Allocation, and that SCE will own the facilities in question. The maximum ITCC exposure is calculated by applying the following formula: (IF*35%)+ ((RNU Costs – (Project MW * ($60k/MW)))*35%)+(LDNU*35%)+(ADNU*35%)+(DU*35%)

N. Sub Synchronous Interaction Evaluations

Certain generators or inverter based generators when interconnected within electrical proximity of series capacitor banks on the transmission system are susceptible to Sub-Synchronous Interaction (SI) conditions which must be evaluated. Subsynchronous Interaction evaluations include Subsynchronous Resonance (SSR) and Subsynchronous Torsional Interactions (SSTI) for conventional generation units, and Subsynchronous Control Instability (SSCI) for inverter based generators using power electronic devices (e.g. Solar PV and Wind Turbines).

For projects interconnecting at the 220 kV voltage level and above in close electrical proximity of series capacitor banks on the transmission system a study will need to be performed to evaluate the SI between generating facilities and the transmission system.

The IC is 100% responsible for any studies related to the SSR or SSTI. The only study that SCE will perform (at the IC's expense) is for SSCI; to ensure that the Project does not damage SCE's control systems.

The SSCI study will require that the IC provide a detailed PSCAD model of its Generating Facility and associated control systems, along with the manufacturer representative's contact information. The study will identify any mitigation(s) that will be required as part project execution and need to be completed prior to initial synchronization of the Generating Facility. The study and the proposed mitigation(s) shall be at the expense of the IC.

It is the IC's responsibility to select, purchase, and install turbine/inverter based generators that are compatible with the series compensation in the area.

O. Environmental Evaluation, Permitting, and Licensing

Please see Appendix K of the QC7 Phase II Bulk Area Report.

P. Affected Systems Coordination

Please see Section H of the QC7 Phase II Bulk Area Report.

Q. 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 final engineering and design.

2. IC's Technical Data

   The study accuracy and results for the QC7 Phase II Study are contingent upon the accuracy of the technical data provided by the IC. Any changes from the data provided could void the study results.

3. Study Impacts on Neighboring Utilities

   Results or consequences of this QC7 Phase II 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).

Refer to Affected Systems Coordination section of the Bulk Area Report.

4. Use of Distribution Provider Facilities

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

5. Distribution Provider Interconnection Handbook

   The IC shall be required to adhere to all applicable requirements in the Distribution Provider 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 IC 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 Distribution Provider-owned protection and generator-owned protection. If adequate protection coordination cannot be achieved, then modifications to the generator-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 QC7 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 Distribution Provider prior to the In-Service Date of the Interconnection Facilities, the IC is responsible to make appropriate arrangements with Distribution Provider to receive and pay for such retail service.

9. Licensing Cost and Estimated Time to Construct Estimate (Duration)

   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 generation tie line, 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 Distribution Provider substation. Due to uncertainties related to telecommunication upgrades for the numerous projects in queue ahead of QC7 Phase II, 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 QC7 Phase II may be reduced. Any changes in these assumptions may affect the cost and schedule for the identified telecommunication facilities.

11. Ground Grid Analysis

    A detailed ground grid analysis will be required as part of the final engineering for the Project at the SCE substations whose ground grids were flagged with duty concerns.

12. 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 POI that was evaluated in the QC7 Phase II Study for the Project. Nothing in this report is intended to supersede or establish terms/conditions specified in interconnection agreements agreed to by SCE, CAISO and the IC.

13. Process for synchronization/trial operations and commercial operations of the Project

    The IC is reminded that the CAISO has implemented a New Resource Implementation (NRI) process that ensures that a generation resource meets all requirements before synchronization/trial operations and commercial operations. The NRI uses a bucket system for deliverables from the IC that are required to be approved by the CAISO. The first step of this process is to submit an "ISO Initial Contact Information Request form" at least 7 months in advance of the planned initial synchronization. Subsequently an NRI project number will be assigned to the project for all future communications with the CAISO. The Distribution Providers have no involvement in this NRI process except to inform the IC of this process requirement. Further information on the NRI process can be obtained from the CAISO Website using the following links:

    New Resource Implementation webpage:
    http://www.caiso.com/participate/Pages/NewResourceImplementation/Default.aspx

    NRI Checklist:
    http://www.caiso.com/Documents/NewResourceImplementationChecklist.xls

    NRI Guide:
    http://www.caiso.com/Documents/NewResourceImplementationGuide.doc

14. Potential Changes in Cost Responsibility

    The IC hereby placed on notice that interconnection of its 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. Section 14.2.2 of the GIDAP provides that should Network Upgrades required for queued-ahead projects be 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 Distribution Provider. However, if the Network Upgrades required by earlier queued generating facilities are not subject to an executed GIA (or unexecuted GIA filed at FERC) the financial responsibility for such upgrades may fall to the IC. 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. Changes in costs allocated to the IC could also arise as the result of the CAISO's reassessment process described in Section 7.4 of the GIDAP. SCE encourages the IC to review Sections 7.4 and 14.2.2 of the GIDAP for the rules and processes under which the financial responsibility might be reapportioned to the IC. Potential changes in the IC's cost responsibility resulting from application of the provisions of these Sections of GIDAP are not included in this Phase II study, nor are the potential impacts to the IC's maximum cost responsibility outlined

15. Additional limitations may occur in the future under future base case overloads

16. Please note that SCE has made its best efforts to convey as much information possible based on information provided by the IC about its proposed project. The information contained herein may indicate to ICs that a project of its magnitude may be better suited to interconnect at higher voltage levels, or downsize as to not incur significant amount of restrictions. Any determination to change POIs or downsize is purely at the IC's discretion and would be subject to a SCE material modification review pursuant to the tariff.

Attachment 1

Interconnection Facilities, Network Upgrades and Distribution Upgrades

Please refer to separate document.

Queue Cluster 7 Phase II - Attachment 1
WDT1189– Stanton Energy Center Project
Interconnection Facilities, Network Upgrades and Distribution Upgrades

Addendum #1 to the Final Phase II Study Report

June 24, 2016

To determine the cost responsibility of each project in QC7, the California Independent System Operator Corporation (CAISO) developed cost allocation factors (Attachment 3) 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, Network Upgrades, and Distribution Upgrades allocated to the project are listed below[1].

1. Interconnection Facilities.

(a) **Interconnection Customer's Interconnection Facilities.** The Interconnection Customer shall:

(i) Install a substation with one (1) 66/13.8/13.8 kV main step-up transformer with H-X, H-Y, and X-Y windings with a 8, 8, and 12 percent impendences on a 95 MVA base.

(ii) Install a new underground 0.34 mile 66 kV generation tie-line from the Facility to a position designated by the Distribution Provider, outside of the Distribution Provider's Barre Substation, where Interconnection Customer shall install a structure designed and engineered in accordance with the Distribution Provider's specifications ("Last Structure"). This generation tie-line will be referred to as the Barre - WDT1189 66 kV Line. The right-of-way for Barre - WDT1189 66 kV Line shall extend up to the edge of the Barre Substation property line.

(Note: The Barre - WDT1189 66 kV Line name is subject to change by the Distribution Provider based upon its transmission line naming criteria. Should the Barre - WDT1189 66 kV Line name be changed, this GIA may be amended to reflect such change.)

(iii) The normal rating of the Interconnection Customer's 66 kV equipment that is part of the generation tie-line is 1574.59 A and the emergency rating is 1574.59 A.

(iv) Install appropriate single-mode fiber optic cable on Barre - WDT1189 66 kV Line to a point designated by the Distribution Provider near the Distribution Provider's Barre Substation to provide one of two telecommunication paths required for the line protection scheme, and the Remote Terminal Units ("RTU"). A minimum of eight (8) strands within the single-mode fiber optic cable shall be provided for the Distribution Provider's exclusive use into Barre Substation.

(v) Install appropriate fiber optic cable from the Facility to a point designated by the Distribution Provider near the Distribution Provider's Barre Substation to provide the second telecommunication path required for the line protection scheme. A minimum of eight (8) strands within the fiber

[1] Such descriptions are subject to modification to reflect the actual facilities that are constructed and installed following the Distribution Provider's final engineering and design, identification of field conditions, and compliance with applicable environmental and permitting requirements.

optic cable shall be provided for the Distribution Provider's exclusive use. The telecommunication path shall meet the Applicable Reliability Standards criteria for diversity.

(vi) Own, operate and maintain both telecommunication paths (including the fiber optic cables and appurtenant facilities), with the exception of the terminal equipment at both Barre Substation and at the Facility, which terminal equipment will be installed, owned, operated and maintained by the Distribution Provider.

(vii) Allow the Distribution Provider to review the Interconnection Customer's telecommunication equipment design and perform inspections to ensure compatibility with the Distribution Provider's terminal equipment and protection engineering requirements; allow the Distribution Provider to perform acceptance testing of the telecommunication equipment and the right to request and/or to perform correction of installation deficiencies.

(viii) Provide required data signals, make available adequate space, facilities, and associated dedicated electrical circuits within a secure building having suitable environmental controls for the installation of the Distribution Provider's RTU in accordance with the Interconnection Handbook.

(ix) Make available adequate space, facilities, and associated dedicated electrical circuits within a secure building having suitable environmental controls for the installation of the Distribution Provider's telecommunications terminal equipment in accordance with the Interconnection Handbook.

(x) Extend the fiber optic cables for the two telecommunication paths to an Interconnection Customer provided and installed patch panel located adjacent to the Distribution Provider's telecommunications terminal equipment specified above.

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

(xii) Install a revenue and wholesale metering cabinet and revenue and wholesale metering equipment (typically, voltage and current transformers) at the Facility to meter the Facility revenue and wholesale load, as specified by the Distribution Provider. The metering cabinet must be placed at a location that would allow twenty-four hour access for the Distribution Provider's metering personnel.

(xiii) Allow the Distribution Provider to install, in the revenue and wholesale metering cabinet provided by the Interconnection Customer, revenue and wholesale meters and appurtenant equipment required to meter the revenue and wholesale load at the Facility.

(xiv) Install relay protection to be specified by the Distribution Provider to match the relay protection used by the Distribution Provider at Barre Substation, in order to protect the Barre - WDT1189 66 kV Line, as follows:

1. Two (2) current differential relays connected via diversely routed dedicated digital communication channels to Barre Substation. The make and type of current differential relays will be specified by the

Distribution Provider during final engineering of the Distribution Provider’s Interconnection Facilities.

(xv) Install all equipment necessary to comply with the power factor requirements of Article 9.6.1 of the GIA, including the ability to automatically regulate the power factor to a schedule (VAR schedule) in accordance with the Interconnection Handbook.

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

(b) **Distribution Provider’s Interconnection Facilities.** The Distribution Provider shall**:**

(i) **Barre Substation.**

1. Install the interconnection facilities portion for a new 66 kV position to terminate the Barre - WDT1189 66 kV Line. This work includes the following:
   a. One (1) dead-end substation structure.
   b. Three (3) 66 kV potential transformers with steel pedestal support structures.
   c. Three (3) 66 kV line drops.
2. Install the following relays to protect the Barre - WDT1189 66 kV Line:
   a. Two (2) current differential relays connected via diversely routed dedicated digital communications channels to the Generating Facility.

(ii) **Barre - WDT1189 66 kV Line.**

Install an appropriate number of 66 kV sub-transmission structures including insulator/hardware assemblies between the Last Structure and the dead-end substation structure at Barre Substation. The actual number and location of the sub-transmission structures and spans of conductor will be determined by the Distribution Provider following completion of final engineering of the Distribution Provider’s Interconnection Facilities. The Phase II Interconnection Study assumed two (2) sub-transmission TSP risers, approximately 600 feet of 954 SAC conductor, 12,000 feet of 3000 kcmil underground Cu cable, and 3 vaults.

(iii) **Telecommunications.**

1. Install all required lightwave, channel, and associated equipment (including terminal equipment), supporting protection and SCADA requirements at the Facility and Barre Substation for the interconnection of the Facility. Notwithstanding that certain telecommunication equipment, including the telecommunications terminal equipment, will be located on the Interconnection Customer’s side of the Point of Change of Ownership, the Distribution Provider

shall own, operate and maintain such telecommunication equipment as part of the Distribution Provider's Interconnection Facilities.

2. Install appropriate length of fiber optic cable, including conduit and vaults, from the point designated by the Distribution Provider near the Distribution Provider's Barre Substation to extend the fiber optic cable into the communication room at Barre Substation. The actual location and length of fiber optic cable and conduit, and location and number of vaults, will be determined during final engineering of the Distribution Provider's Interconnection Facilities. The Phase II Interconnection Study assumed the installation of approximately 2,000 feet of underground fiber optic cable inside 5-inch conduit, and one (1) vault to extend the fiber optic cable into the communication room at Barre Substation.
3. Install appropriate length of fiber optic cable, including conduit and vaults, to extend the Interconnection Customer's diverse telecommunications from the point designated by the Distribution Provider near the Distribution Provider's Barre Substation into the communication room at Barre Substation. The actual location and length of fiber optic cable and conduit, and location and number of vaults, will be determined during final engineering of the Distribution Provider's Interconnection Facilities. The Phase II Interconnection Study assumed the installation of approximately 3,800 feet of underground fiber optic cable inside 5-inch conduit, and one (1) vault to extend the fiber optic cable into the communication room at Barre Substation.

(iv) **Real Properties, Transmission Project Licensing, and Corporate Environmental Health and Safety.**
Obtain easements and/or acquire land, obtain licensing and permits, and perform all required environmental activities for the installation of the Distribution Provider's Interconnection Facilities, including any associated telecommunication equipment for the Barre - WDT1189 66 kV Line.

(v) **Metering.**
Install revenue and wholesale meters and appurtenant equipment required to meter the revenue and wholesale load at the Facility. Notwithstanding that the meters and appurtenant equipment will be located on the Interconnection Customer's side of the Point of Change of Ownership, the Distribution Provider shall own, operate and maintain such facilities as part of the Distribution Provider's Interconnection Facilities.

(vi) **Power System Control.**
Install one (1) RTU at the Facility to monitor typical battery storage elements such as MW, MVAR, terminal voltage and circuit breaker status for the Facility and plant auxiliary load, and transmit the information received thereby to the Distribution Provider's grid control center.

Notwithstanding that the RTU will be located on the Interconnection Customer's side of the Point of Change of Ownership, the Distribution Provider shall own, operate and maintain the RTU as part of the Distribution Provider's Interconnection Facilities.

2. Network Upgrades.

(a) **Stand Alone Network Upgrades.**
None identified in the Phase II Study.

(b) **Other Network Upgrades.**

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

~~1. **Short Circuit Duty (SCD) Mitigation – (RNU)**~~
~~a. Vista 220 kV Substation~~
~~i. Upgrade fourteen (14) Circuit Breakers by installing fifteen (15) sets of TRV Capacitors.~~
~~ii. Perform ground grid study.~~
~~b. Real Properties, Transmission Project Licensing, and Corporate Environmental Health and Safety~~
~~Obtain easements and/or acquire land, obtain licensing and permits, and perform all required environmental activities for the installation of the TRV's.~~

2. **Ground grid studies.**
Perform ground grid studies at Huntington Beach 220 kV and Lewis 220 kV Substations.

(ii) **Distribution Provider's Delivery Network Upgrades See Area Report**
1. **Area Delivery Network Upgrades.**
None identified in the Phase II Study.
2. **Local Delivery Network Upgrades.**
None identified in the Phase II Study.

3. Distribution Upgrades. The Distribution Provider shall
(a) **Barre Substation.**
(i) Install the distribution facilities portion for a new 66 kV position to terminate the Barre - WDT1189 66 kV Line. This work includes the following:
a. Two (2) 66 kV circuit breakers.
b. Four (4) sets of 66 kV disconnect switches.
c. Perform ground grid study

(b) **Power Systems Controls.**

(i) Substation Automation System (SAS) point additions to the existing Barre SAS to accommodate new relay protection, status, and alarm.

(c) **Real Properties, Transmission Project Licensing, and Corporate Environmental Health and Safety.**

(i) Obtain easements and/or acquire land, obtain licensing and permits, and perform all required environmental activities for the installation of the Distribution Upgrades.

(d) **Short Circuit Duty (SCD) Mitigation – DU**

(i) Barre 66 kV Substation

a. Replace a total of twenty-one (21) Circuit Breakers and upgrade their bus positions accordingly.
b. Replace twelve (12) spans of 66 kV lines.
c. Perform ground grid study.
d. Real Properties, Transmission Project Licensing, and Corporate Environmental Health and Safety.
e. Obtain easements and/or acquire land, obtain licensing and permits, and perform all required environmental activities for replacement of the Circuit Breakers and Line Spans.

(ii) Villa Park 66 kV Substation

a. Replace ine Circuit Breaker.
b. Perform ground grid study.
c. Real Properties, Transmission Project Licensing, and Corporate Environmental Health and Safety.
d. Obtain easements and/or acquire land, obtain licensing and permits, and perform all required environmental activities for replacement of the Circuit Breaker.

(e) **Ground Grid Studies**

Perform ground grid studies at ~~Apollo 66 kV, Bolsa 66 kV,~~ Fullerton 66 kV, Gilbert 66 kV, Kindler 66 kV, La Palma 66 kV, Lampson 66 kV, Marion 66 kV and ~~, Shawnee 66 kV,~~ Sunny Hills 66 kV~~, Team 66 kV, and Trask 66 kV~~ Substations.

4. Affected System Upgrades

Not used.

5. Point of Change of Ownership.

(a) Barre - WDT1189 66 kV Line: The Point of Change of Ownership shall be the point where the conductors of the Barre - WDT1189 66 kV Line are attached to the Last Structure, which will be connected on the side of the Last Structure facing Barre Substation. The Interconnection Customer shall own and maintain the Last Structure, the conductors, insulators and jumper loops from such Last

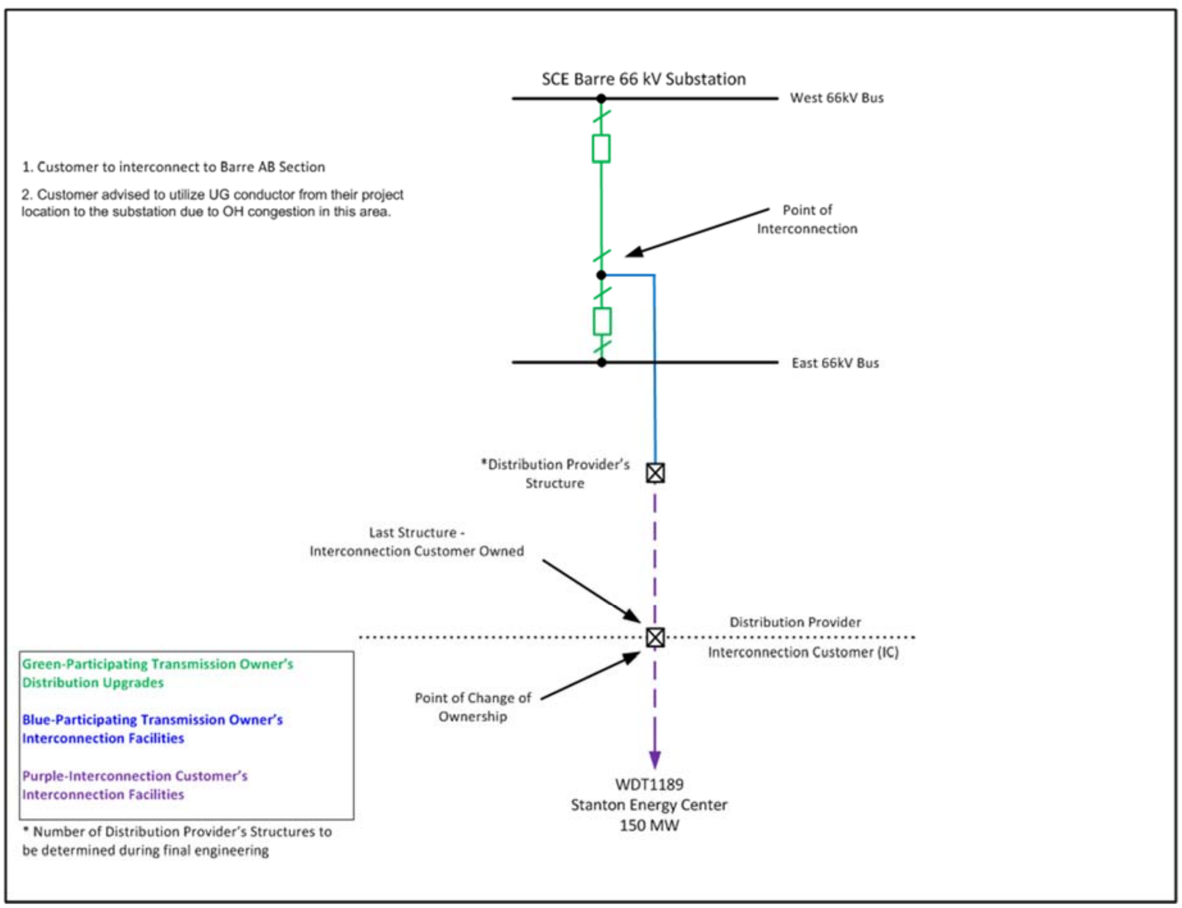
Structure to the Interconnection Customer's Facility. The Distribution Provider will own and maintain Barre Substation, as well as all circuit breakers, disconnects, relay facilities and metering within Barre Substation, together with the line drop, in their entirety, from the Last Structure to Barre Substation. The Distribution Provider will own the insulators that are used to attach the Distribution Provider-owned conductors to the Last Structure.

(b) Telecommunication single mode fiber optic cable: The Point of Change of Ownership shall be the point at a Distribution Provider owned vault, where the Interconnection Customer's fiber-optic cable is connected to the Distribution Provider's fiber optic cable.

(c) Telecommunication diverse fiber optic cable: The Point of Change of Ownership shall be the point at a Distribution Provider owned vault, where the Interconnection Customer's fiber-optic cable is connected to the Distribution Provider's fiber optic cable.

6. **Point of Interconnection.** The Distribution Provider's Barre 66 kV Substation at the 66 kV switchrack.

7. **One-Line Diagram of Interconnection to Barre 66 kV Substation.**



Attachment 2

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

Please refer to separate document.

Queue Cluster 7 Phase II - Attachment 2
Escalated Cost and Time to Construct for Interconnection Facilities, Reliability Network Upgrades, Delivery Network Upgrades, and Distribution Upgrades

Addendum #1 to the Final Phase II Study Report

June 24, 2016

QC7 Phase II Study Report Attachment #2

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

Project #: WDT1189

Cost Category	Costs per Category w/o ITCC (A)	One Time Costs (Note 1) (B)	Total Costs w/o ITCC (C=A+B)	Total Escalated Costs w/o ITCC	Estimated Time to Construct (Months)	COD Dollar Escalation Duration (Months)
	Constant 2016 Dollar in $1000s (Estimate)	Constant 2016 Dollar in $1000s (Estimate)	Constant 2016 Dollar in $1000s (Estimate)	Escalated to OD Year in $1000s	(Note 3,4,5, 9, & 10)	(Note 3,4,5, 9, & 10)
Interconnection Facilities						
Transmission	$0	$0	$0	$0	27	42
Sub-Transmission	$2,901	$0	$2,901	$3,295	27	42
Substation	$1,210	$0	$1,210	$1,374	27	42
Real Properties	$123	$0	$123	$140	27	42
Metering Services	$35	$0	$35	$40	27	42
Telecommunication	$725	$0	$725	$823	27	42
Edison Carrier Solutions	$168	$0	$168	$191	27	42
Corporate Environmental	$137	$0	$137	$156	27	42
Licensing	$0	$0	$0	$0	27	42
Power System Control	$74	$0	$74	$84	27	42
Interconnection Facilities Total	**$5,374**	**$0**	**$5,374**	**$6,103**	**27**	**42**
Reliability Network Upgrades						
Ground Grid Study						
Ground Grid Study for Bulk System(Huntington Beach and Lewis)	$0	$89	$89	$101	27	42
Reliability Network Upgrades Total	**$0**	**$89**	**$89**	**$101**	**27**	**42**
Distribution Upgrades						
Substation	$2,196	$45	$2,241	$2,545	27	42
Corporate Environmental	$57	$0	$57	$65	27	42
Power System Control	$0	$27	$27	$31	27	42
Short Circuit Duty Mitigation						
Barre 66 kV SCD	$16,397	$0	$16,397	$18,621	42	42
Villa Park 66 kV SCD	$397	$0	$397	$451	27	42
Ground Grid Study to support Barre 66 kV SCD	$0	$45	$45	$51	27	42
Ground Grid Study to support Villa Park 66 kV SCD	$0	$45	$45	$51	27	42
Ground Grid Study						
Ground Grid Study for Barre System (Apollo, Bolsa, Fullerton, Gilbert, Kindler, La Palma, Lampson, Marion, Shawnee, Sunny Hills, Team, Trask)	$0	$490	$490	$557	27	42
Distribution Upgrades Total	**$19,048**	**$651**	**$19,699**	**$22,370**	**42**	**42**

WDT1189 **Project MW: 10**

Income Tax Component of Contribution (ITCC) Potential		
Element	**ITCC @ 35% Constant Dollar in $1000s (2016)**	**ITCC @ 35% Escalated Dollar in $1000s (OD)**
IF (Calculation: (IF+SPS IF) * 35%)	**$1,881**	**$2,136**
RNU Refer to Note 11 below for Calculation	**$0**	**$0**
LDNU Refer to Note 12 below for ITCC treatment	**N/A**	**N/A**
DU (Calculation: DU* 35%)	**$6,667**	**$7,571**
ADNU Refer to Note 12 below for details on ITCC treatment	**N/A**	**N/A**

Max Duration for ITCC Calculation	**42**

Note 1: The one time costs item(s) will be treated as applicable per the specified upgrade classification. They may be reimburseable depending on their classification.

Note 2: Distribution upgrades are not reimbursable. Allocated costs may change if all projects responsible for these upgrades do not execute Generator Interconnection Agreements.

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

Note 4: Each Upgrade category may contain multiple work element construction durations. The longest construction duration is shown under the C.O.D Dollar Duration column.

Note 5: SCE's Phase II cost estimating is done in 'constant' dollars 2016 and then escalated to the estimated O.D.year. For the QC7 study, the estimated C.O.D. Dollar is derived by assuming the duration of the work element will begin in December 2016, which is the CAISO tariff scheduled completion date of the QC7 Phase II study plus: the TPD Allocation, Annual Reassessment Effort , and the interconnection agreement signing period and submittal of required funds by the IC. For instance, if a work element is estimated to take a total of 24 months (final engineering, design, procurement, licensing and construction), then the estimated C.O.D. would be December 2018. If an IC's requested C.O.D. is beyond the estimated C.O.D. of a work element, the IC's requested C.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 above may be subject to change.

Note 6: Individual O&M charges for the above construction costs will be identified and communicated during the Interconnection Agreement process.

Note 7: The Estimated Time to Construct (duration in months) is the schedule for the PTO to complete final engineering, design, procurement, licensing, and construction, etc., and other activities needed to construct and bring the facilities into service. Such activities are from the execution of the Generator Interconnection Agreements, and receipt of: all required information, funding, and written authorization to proceed from the IC, as will be specified in the Interconnection Agreement, to commence work. The estimated schedule does not take into account unanticipated delays or difficulties securing necessary permits, licenses or other approvals; construction difficulties or potential delays in the project implementation process; or unanticipated delays or difficulties in obtaining and receiving necessary clearances for interconnection of the project to the transmission system.

Note 8: Estimated Time to Construct durations are from completion of any preceding facilities required.

Note 9: The C.O.D. Dollar for the IF and RNU/Dist. Plan of Service facilities was escalated using the requested Project C.O.D when the requested Project C.O.D was beyond the identified ETC of the IF and RNU/Dist. Plan of Service facilities. In such instances there is a different duration (months) in the ETC and C.O.D. Dollar escalation duration columns.

Note 10: RNUs are subject to ITCC on funds above the repayment maximum ($60 k/MW) of the Project.The ITCC corresponding to the RNUs, when applicable, was calculated by applying the following formula:
[Total Project allocated RNU Costs – {(Project MW Size)* ($60k)}]*35%

Note 11: LDNUs and ADNUs may be assessed 35% ITCC. However, presently the ITCC corresponding to LDNUs and ADNUs cannot be quantified due to their dependency on TPD allocation awarded to the Project and accepted by the Interconnection Customer ("IC") several months after the Phase II studies are complete. Consequently, the maximum ITCC warranted by the Project will be addressed, calculated, and included during the Interconnection Agreement development phase once the IC submits the TPD Affidavit confirming acceptance, waiver (parking), or denial of awarded deliverability to the Project.

Attachment 3

Not Used

Attachment 4

Distribution Provider Interconnection Handbook

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

Please refer to separate document.

Attachment 5

Short Circuit Calculation Study Results

Please refer to the Appendix H of the Bulk Area Report.

Attachment 6

Customer Provided Project Dynamic Data

The following data was submitted by the IC for Dynamic simulation:

genrou 96694 "WDT1189G " 13.80 "1 " : #9 mva=71.176 "tpdo" 9.67 "tppdo" 0.05 "tpqo" 2.95 "tppqo" 0.05 "h" 0.97 "d" 0.0 "ld" 2.35 "lq" 2.15 "lpd" 0.245 "lpq" 0.35 "lppd" 0.181 "ll" 0.13 "s1" 0.094 "s12" 0.507 "ra" 0.0053 "rcomp" 0 "xcomp" 0 "accel" 0.5

exac2 96694 "WDT1189G " 13.80 "1 " : #9 "tr" 0.028 "tb" 1.0 "tc" 1.0 "ka" 889.0 "ta" 0.02 "vamax" 166.0 "vamin" -166.0 "kb" 1.0 "vrmax" 41.5 "vrmin" 0.0 "te" 0.5 "kl" 1.51 "kh" 0.0 "kf" 0.0303 "tf" 1.0 "kc" 0.0 "kd" 0.0 "ke" 1.0 "vlr" 50.08 "e1" 1.5 "se1" 0.19 "e2" 2.0 "se2" 0.67 "limflg" 0.0

pss2a 96694 "WDT1189G " 13.80 "1 " : #9 "j1" 1 "k1" 0 "j2" 3 "k2" 0 "tw1" 2 "tw2" 2 "tw3" 2 "tw4" 0 "t6" 0 "t7" 2 "ks2" 1.03 "ks3" 1 "ks4" 1 "t8" 0.5 "t9" 0.1 "n" 1 "m" 5 "ks1" 10.0 "t1" 0.25 "t2" 0.04 "t3" 0.2 "t4" 0.03 "vstmax" 0.1 "vstmin" -0.1 "a" 1 "ta" 0 "tb" 0

ggov1 96694 "WDT1189G " 13.80 "1 " : #9 mwcap=51.0 "r" 0.05 "rselect" 1.0 "tpelec" 1.0 "maxerr" 0.023 "minerr" -0.023 "kpgov" 3.6 "kigov" 1.65 "kdgov" 0.0 "tdgov" 1.0 "vmax" 1.0 "vmin" 0.24 "tact" 0.4 "kturb" 2.7 "wfnl" 0.2587 "tb" 0.1 "tc" 0.0 "flag" 0.0 "teng" 0.0 "tfload" 0.3 "kpload" 1.0 "kiload" 3.3 "ldref" 1.0902 "dm" 0.0 "ropen" 99.0 "rclose" -99.0 "kimw" 0.0 "pmwset" 0.0 "aset" 99.0 "ka" 10.0 "ta" 0.1 "db" 0.0 "tsa" 1.0 "tsb" 1.0 "rup" 99.0 "rdown" -99.0

genrou 96695 "WDT1189G2 " 13.80 "2 " : #9 mva=71.176 "tpdo" 9.67 "tppdo" 0.05 "tpqo" 2.95 "tppqo" 0.05 "h" 0.97 "d" 0.0 "ld" 2.35 "lq" 2.15 "lpd" 0.245 "lpq" 0.35 "lppd" 0.181 "ll" 0.13 "s1" 0.094 "s12" 0.507 "ra" 0.0053 "rcomp" 0 "xcomp" 0 "accel" 0.5

exac2 96695 "WDT1189G2 " 13.80 "2 " : #9 "tr" 0.028 "tb" 1.0 "tc" 1.0 "ka" 889.0 "ta" 0.02 "vamax" 166.0 "vamin" -166.0 "kb" 1.0 "vrmax" 41.5 "vrmin" 0.0 "te" 0.5 "kl" 1.51 "kh" 0.0 "kf" 0.0303 "tf" 1.0 "kc" 0.0 "kd" 0.0 "ke" 1.0 "vlr" 50.08 "e1" 1.5 "se1" 0.19 "e2" 2.0 "se2" 0.67 "limflg" 0.0

pss2a 96695 "WDT1189G2 " 13.80 "2 " : #9 "j1" 1 "k1" 0 "j2" 3 "k2" 0 "tw1" 2 "tw2" 2 "tw3" 2 "tw4" 0 "t6" 0 "t7" 2 "ks2" 1.03 "ks3" 1 "ks4" 1 "t8" 0.5 "t9" 0.1 "n" 1 "m" 5 "ks1" 10.0 "t1" 0.25 "t2" 0.04 "t3" 0.2 "t4" 0.03 "vstmax" 0.1 "vstmin" -0.1 "a" 1 "ta" 0 "tb" 0

ggov1 96695 "WDT1189G2 " 13.80 "2 " : #9 mwcap=51.0 "r" 0.05 "rselect" 1.0 "tpelec" 1.0 "maxerr" 0.023 "minerr" -0.023 "kpgov" 3.6 "kigov" 1.65 "kdgov" 0.0 "tdgov" 1.0 "vmax" 1.0 "vmin" 0.24 "tact" 0.4 "kturb" 2.7 "wfnl" 0.2587 "tb" 0.1 "tc" 0.0 "flag" 0.0 "teng" 0.0 "tfload" 0.3 "kpload" 1.0 "kiload" 3.3 "ldref" 1.0902 "dm" 0.0 "ropen" 99.0 "rclose" -99.0 "kimw" 0.0 "pmwset" 0.0 "aset" 99.0 "ka" 10.0 "ta" 0.1 "db" 0.0 "tsa" 1.0 "tsb" 1.0 "rup" 99.0 "rdown" -99.0

genrou 96695 "WDT1189G2 " 13.80 "3 " : #9 mva=71.176 "tpdo" 9.67 "tppdo" 0.05 "tpqo" 2.95 "tppqo" 0.05 "h" 0.97 "d" 0.0 "ld" 2.35 "lq" 2.15 "lpd" 0.245 "lpq" 0.35 "lppd" 0.181 "ll" 0.13 "s1" 0.094 "s12" 0.507 "ra" 0.0053 "rcomp" 0 "xcomp" 0 "accel" 0.5

exac2 96695 "WDT1189G2 " 13.80 "3 " : #9 "tr" 0.028 "tb" 1.0 "tc" 1.0 "ka" 889.0 "ta" 0.02 "vamax" 166.0 "vamin" -166.0 "kb" 1.0 "vrmax" 41.5 "vrmin" 0.0 "te" 0.5 "kl" 1.51 "kh" 0.0 "kf" 0.0303 "tf" 1.0 "kc" 0.0 "kd" 0.0 "ke" 1.0 "vlr" 50.08 "e1" 1.5 "se1" 0.19 "e2" 2.0 "se2" 0.67 "limflg" 0.0

pss2a 96695 "WDT1189G2 " 13.80 "3 " : #9 "j1" 1 "k1" 0 "j2" 3 "k2" 0 "tw1" 2 "tw2" 2 "tw3" 2 "tw4" 0 "t6" 0 "t7" 2 "ks2" 1.03 "ks3" 1 "ks4" 1 "t8" 0.5 "t9" 0.1 "n" 1 "m" 5 "ks1" 10.0 "t1" 0.25 "t2" 0.04 "t3" 0.2 "t4" 0.03 "vstmax" 0.1 "vstmin" -0.1 "a" 1 "ta" 0 "tb" 0

ggov1 96695 "WDT1189G2 " 13.80 "3 " : #9 mwcap=51.0 "r" 0.05 "rselect" 1.0 "tpelec" 1.0 "maxerr" 0.023 "minerr" -0.023 "kpgov" 3.6 "kigov" 1.65 "kdgov" 0.0 "tdgov" 1.0 "vmax" 1.0 "vmin" 0.24 "tact" 0.4 "kturb" 2.7 "wfnl" 0.2587 "tb" 0.1 "tc" 0.0 "flag" 0.0 "teng" 0.0 "tfload" 0.3 "kpload" 1.0 "kiload" 3.3 "ldref" 1.0902 "dm" 0.0 "ropen" 99.0 "rclose" -99.0 "kimw" 0.0 "pmwset" 0.0 "aset" 99.0 "ka" 10.0 "ta" 0.1 "db" 0.0 "tsa" 1.0 "tsb" 1.0 "rup" 99.0 "rdown" -99.0

Attachment 7

Subtransmission Assessment Report for Generation Reliability Study

Please refer to separate document.

Queue Cluster 7 Phase II

Attachment 7

Subtransmission Assessment Report

Addendum #1 to the Final Phase II Study Report

Barre 66 kV System

June 24, 2016

Table of Contents

1. Purpose

Impacts of QC7 Projects on the CAISO controlled transmission grid are addressed in the Metro Area Group Report. Because one (1) QC7 project is seeking to interconnect to the Barre 66 kV AB bus section, which is not under CAISO control, additional analysis is required to evaluate the 66 kV subtransmission system performance. The Individual project details are provided in the project's corresponding Appendix A. This additional analyses focuses on the QC7 interconnection request in the Barre 66 kV Subtransmission System and considers minimum levels of load demand with maximum generation dispatch as this would represent the most stressed condition for the project seeking interconnection to the Barre 66 kV AB bus section.

The purpose of this study is to determine the adequacy of SCE's electrical subtransmission system to accommodate the interconnection request and to identify system limitations that would require Distribution Upgrades on the subtransmission system to mitigate any identified impacts. The study included all existing and queued ahead generation projects in the Barre 66 kV Subtransmission System, regardless of the in-service dates of such prior queued generation projects. Results of the study will be used as the basis to determine appropriate cost allocation for the identified Distribution Upgrades taking into account every project in this cluster. An operational study was also performed, as required, to determine timing need of any identified upgrade. Such timing need is directly related to actual projects moving forward as not all queued ahead generation projects have progressed towards project execution. It is important to note that withdrawals of projects in this cluster could result in reallocating costs among the remaining projects.

The accuracy of the subtransmission assessment results are contingent on the accuracy of the technical data provided as part of the interconnection request. Any changes from the data provided could void the study results. The study report provides detailed study assumptions and conditions of the Barre AB 66 kV Subtransmission System in which the study was performed. The single QC7 interconnection request seeking interconnection to subtransmission facilities served out of the Barre AB 66 kV Subtransmission System progressed into Phase II. This project consists of a gas turbine power plant requesting to interconnect to the Barre 66 kV AB bus section.

This Subtransmission study report provides the following:

- Subtransmission system impacts caused by the addition of the QC7 Phase II project requesting interconnection in the Barre AB 66 kV Subtransmission System;
- A good faith estimate of the cost of any identified subtransmission level Distribution Upgrades

To determine the system impacts caused by the QC7 Phase II project seeking interconnection in the Barre 66 kV AB Subtransmission System, the following studies were performed:

- Steady State Power Flow Analyses
- Subtransmission level Short Circuit Duty Analyses

2. QC7 Phase II Generation Project Interconnection Information

The single QC7 interconnection request, totaling 150 MW, seeking interconnection to the Barre 66 kV subtransmission system progressed into Phase II. Table 2 summarizes the new QC7 generator project with essential data obtained from the SCE WDAT Generation Queue.

Table 2: SCE QC7 Phase II Project at Barre 66 kV System

CAISO Queue	Point of Interconnection (CAISO Delivery Point)	Full Capacity Energy Only	Fuel	Max MW
WDT 1189	Barre AB 66 kV Switchrack	FC	Gas	150
			Total QC7 Generation	**150**

3. System Assumptions

3.1 Planning Criteria

The generator interconnection studies were conducted utilizing SCE's Reliability Planning Criteria. More specifically, the main criteria applicable to this study are as follows:

Power Flow Analysis

Since the QC7 interconnection request, totaling 150 MW, is seeking interconnection directly to the Barre AB 66 kV bus section, the only contingency applicable for this study is loss of a single 220/66 kV Transformer Bank (A-Bank) at the Barre Substation.

- Single Contingencies (N-1) – Loss of one line or one A-bank

The following reliability criteria was used to evaluate loss of A-Bank:

Subtransmission Lines 220/66 kV Transformer banks (A-banks)	Base Case	Limiting Component Normal Rating
	N-1 and N-2	Limiting Component Emergency Rating
	Base Case	Normal Loading Rating*
	Long Term Emergency Loading Limit (LTELL) & Short Term Emergency Loading Limit (STELL)	As defined by SCE Operating Bulletin

3.1.1. Normal Overloads

Normal overloads are those that exceed 100 percent of normal facility rating with all facilities in-service (base case). Mitigation will be required to address any identified normal overload triggered by the inclusion of QC7 Phase II projects.

3.1.2. Contingency Overloads

Contingency overloads are those that exceed 100 percent of emergency ratings under outage conditions. Mitigation will be required to address any identified contingency overload triggered by the inclusion of QC7 Phase II projects.

3.1.3. Voltage Criteria

Voltage performance under single and double outage conditions will be limited to 5 percent and 10 percent deviation respectively.

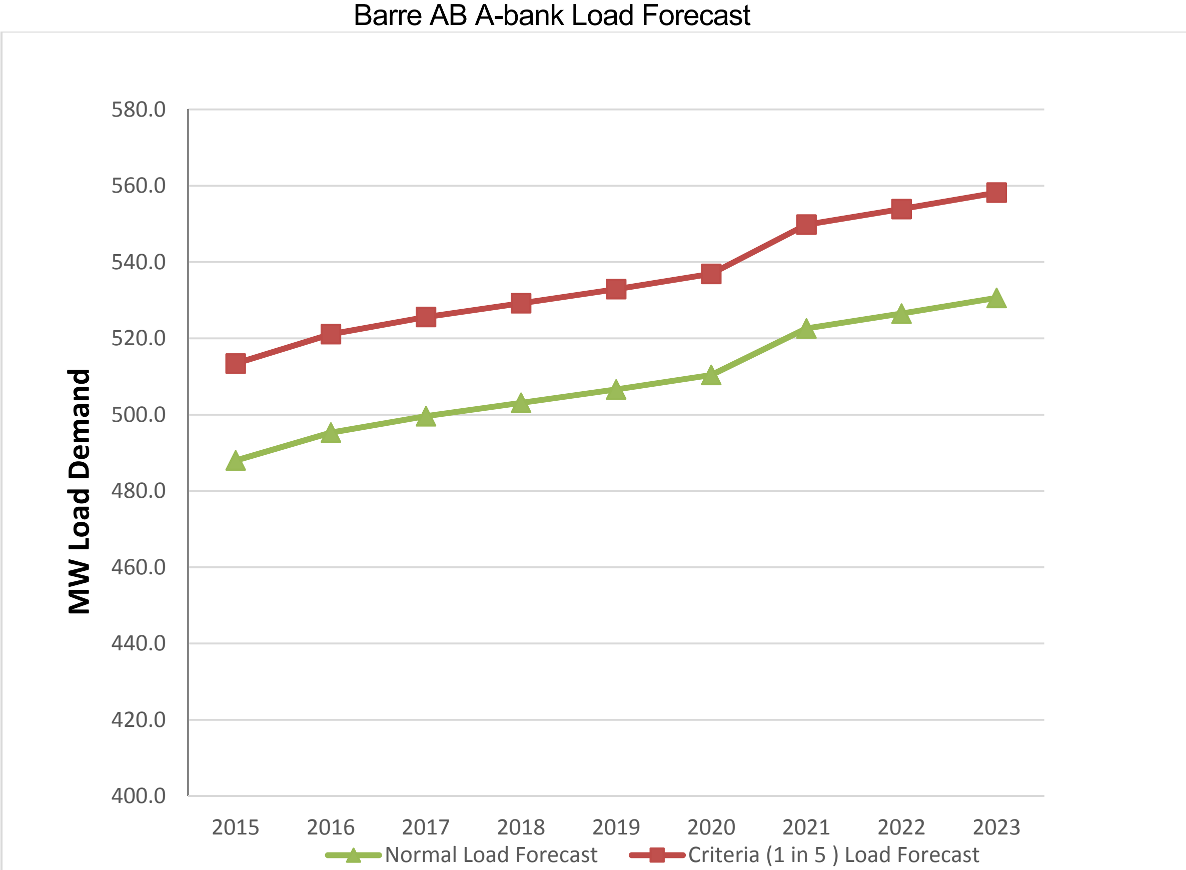
3.1.4. Power Factor Criteria

All projects will need to comply with SCE's Interconnection Handbook requirements.

3.2 Load Assumptions

The load assumptions used for local subtransmission system initially considered a 2019 load forecast. The 2019 load forecast was derived using SCE's Distribution Engineering A-bank Planning load forecast as well as the individual load serving substation (B-bank) load forecast for 2015-2023. Figure 3.2.1 below provides the local subtransmission load forecast values at the A-bank level under Normal (1-in-2 year) and Criteria (1-in-5 year) Planning assumptions.

Figure 3.2.1
Barre AB A-bank Load Forecast



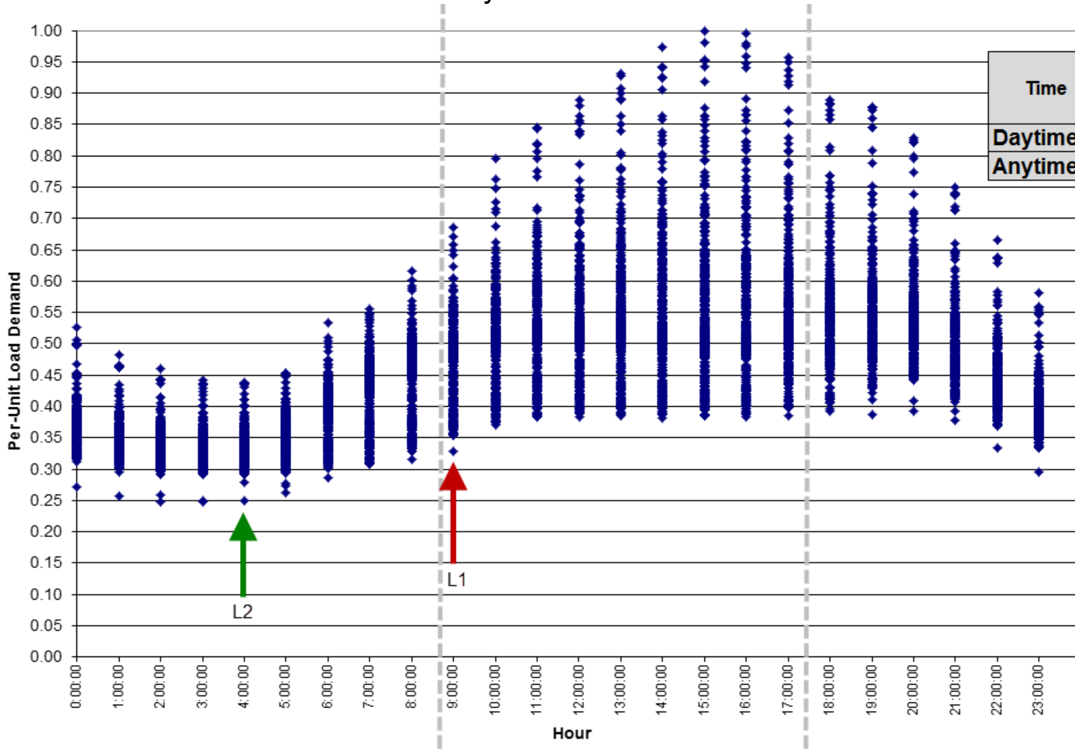
The A-bank Normal and Criteria load forecast was distributed to each individual B-bank substation (lower voltage substations served from the 220/66 kV substation) on a pro-rata basis. The resulting individual B-bank substation values are shown below in Table 3.2.1 and were used as the basis for evaluating subtransmission system performance.

Table 3.2.1
Local Subtransmission System Load Assumptions

Barre System Load Serving Substations	**2019**	
	Normal (1-in-2)	**Criteria (1-in-5)**
Barre 5&6 (D)	78.5	82.6
Ely (D)	68.2	71.8
Fullerton (D) 12kV	72.6	76.4
Fullerton (D) 4kV	5.0	5.2
Gilbert (D)	74.5	78.3
La Palma (D)	52.1	54.8
Lampson (D)	74.3	78.2
Marion (D)	77.0	81.0
Large Customers	4.4	4.7
Barre AB-Section Total	**506.6**	**532.9**

To model year 2019 hourly forecast load performance, historical year 2013 A-bank data was obtained and normalized (maximum historical load = 1.0). This was done in order to provide a means for scaling to reflect comparable hourly performance with a year 2019 load forecast. Shown below, Figure 3.2.2, is the normalized local subtransmission system A-bank hourly load performance as measured at the 220/66 kV transformer banks.

Figure 3.2.2
Normalized Local Subtransmission System
A-bank Hourly Load Performance



Time	Min Per Unit Value
Daytime	0.33
Anytime	0.25

The assessment evaluating the most stressed system condition pertaining to maximum generation output. This condition involves identifying issues that arise under minimum load and maximum generation for the study. Utilizing the normalized hourly load performance shown above in Figure 3.2.2, the lowest per-unit load was applied to define two maximum generation output scenarios. The first scenario would use the minimum per-unit load during the daytime (shown as L1) while the second scenario would use the minimum value identified at any time of the day (shown as L2).

These per-unit values were used to define the specific load distribution assumptions at each load serving substation. These values were used in the base cases developed for each load scenario. The base cases multiplied the per-unit value identified for the respective load scenario, L1 and L2, with the “Normal” load distribution shown in Table 3.2.1. The resulting minimum load distribution used in the power flow study at each individual B-bank substation is provided below in Table 3.2.2.

Table 3.2.2
B-bank Load Distribution

Barre System Load Serving Substations	Minimum Load	
	0.33 PU	0.25 PU
	L1	L2
Barre 5&6 (D)	25.9	20.6
Ely (D)	22.5	17.9
Fullerton (D) 12kV	24.0	19.1
Fullerton (D) 4kV	1.6	1.3
Gilbert (D)	24.6	19.6
La Palma (D)	17.2	13.7
Lampson (D)	24.5	19.5
Marion (D)	25.4	20.2
Large Customers	1.4	1.2
Barre AB-Section Total Load	**167.2**	**133.2**

3.3 Generation Assumptions

There were no queued ahead generation projects in the Barre AB Subtransmission System.

3.4 Subtransmission System Assumptions

The QC7 Phase II Study modeled the existing Barre AB 66 kV Bus Section without any additional upgrades as no such upgrades have been triggered. The study considered existing system operating bulletins/procedures that transfer system load from bus one section to the adjacent bus section by closing the sectionalizing breaker under the loss of one A-Bank.

3.5 Study Methodology

3.5.1. Power Flow Study

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. This assessment is comprised of power flow study scenarios that represents load conditions reflected in Table 3.2.2. A pre case without the inclusion of the QC7 projects and a Post-case with the inclusion of QC7 projects were modeled for each of the load conditions reflected in Table 3.2.2. Mitigation measures will be recommended for any power flow criteria violation identified to be triggered with the inclusion of QC7 projects. The outage conditions evaluated are provided below in Table 3.5.1.

Table 3.5.1
List of Contingencies Evaluated

#	Contingency Type	Contingency Description
1	Base Case	No Outage
2	N-1	Loss of Barre 1A 230/66 kV
3	N-1	Loss of Barre 3A 230/66 kV

The contingency study did not consider loss of lines internal to the Barre 66 kV System as the project does not impact flows on these lines since it is connected directly to the source bus.

3.5.2. Post Transient Voltage Study

The power flow study voltage results were used as a screen to identify those contingencies that may require additional post-transient voltage studies. Contingencies identified in the power flow to have a voltage drop in excess of 5% were selected for post-transient voltage analysis. The Post-transient voltage studies compare voltage deviations to the reliability requirements for single and double contingency outages on the subtransmission system. Mitigation measures will be recommended for any criteria violation identified to be triggered with the inclusion of QC7 projects.

3.5.3. Short Circuit Duty Study

To determine the impact on short-circuit duty within the subtransmission system after inclusion of all QC7 projects (application queue), the study calculated the maximum symmetrical three-phase-to-ground (3PH) and single-line-to-ground (SLG) short-circuit duties. Generation and transformer data represented in the generator and transformer data sheets provided by the customers were utilized. Bus locations where short-circuit duty is increased with the inclusion of all QC7 projects by at least 0.1 kA and the duty is in excess of 60% of the minimum breaker nameplate rating are flagged for further review. Upon completion of the detailed circuit breaker review, circuit breakers exposed to fault currents in excess of 100 percent of their interrupting capacities will need to be replaced or upgraded, whichever is appropriate. Cost for breaker upgrades or replacements will be allocated to QC7 projects if the study identifies QC7 as the triggering entity. It is important to note that costs for upgrades triggered by queued ahead projects may ultimately be allocated if the triggering entity ultimately withdraws and the need for the upgrades is still required and triggered by QC7 following any such withdrawals. Additional review was performed which evaluated the potential use of operating scheme and/or procedure to disconnect the Project anytime the Barre 66 kV sectionalizing bus breakers are closed. Such procedure will result in excluding Project SCD impacts on the Barre C 66 kV circuit breakers.

In addition to the application queue short-circuit duty study, an operational short-circuit duty study is performed, as required, as a means to identify timing of any identified circuit breaker upgrades or replacements. The operational studies will involve short-circuit duty review of the following scenarios:

- Years 2015/2016, 2017, and 2018 with inclusion of all new generation projects that have an executed interconnection agreement and which are scheduled to be in-service during those timeframes;

- All other generation projects will be modeled as energy only under a 2019 base case. Any identified distribution and network upgrade needed to enable physical energy-only interconnection and allow flow of energy to reach the CAISO point of delivery will also be assumed to be in place as part of this scenario

- A final short-circuit duty review will be perform which adds all network upgrades identified to be triggered for Full Capacity Deliverability Status (FCSD) and which are not yet under development or which will be placed into service after year 2019.

The short circuit studies also identified substations within the subtransmission where the QC7 Phase II projects increased the substation ground grid duty by 0.25 kA or more.

4. Power Flow Results

4.1 Maximum Generation Coupled with Minimum Load Conditions

Based on the assumptions listed above, the addition of the QC7 Phase II project did not trigger any base case or single contingency subtransmission overloads under maximum generation with minimum load study conditions.

4.2 Maximum Energy Storage Coupled with Minimum Local Subtransmission Generation Conditions

No QC7 projects in this system involve energy storage. As such there is no identified subtransmission assessment mitigation

4.3 Power Flow Study Observations, Notes, and Restriction to Energy Storage

(a) Metro Bulk Area Export Limits
Please refer to the Metro Bulk Area Report Section for impacts on the CAISO controlled system

(b) N-1-1 Outages
Loss of two A-Banks is beyond planning criteria. However, under such conditions, the ability continue to operate will depend on real-time operating conditions. It is important to note that under such potential conditions, curtailment of generation output will be implemented under real-time operation of the system, if required, in advance of the second outage to ensure potential overload is properly mitigated. Because all interconnection agreements contain a provision to enable such generation curtailment, no additional physical upgrades were identified to be required under such outage conditions.

(c) Energy Storage
No energy storage projects in this section.

4.4 Subtransmission Assessment Mitigations

(a) Maximum Generation Coupled with Minimum Load Conditions

There were no impacts identified to the Barre AB Subtransmission System that would necessitate mitigation.

(b) Maximum Energy Storage Coupled with Minimum Local Subtransmission Generation Conditions

There were no QC7 Projects in this system that involved energy storage.

5. Post Transient Voltage Stability Assessment Results

Review of the power flow study results identified that no voltage deviation exceeded the criteria discussed above. As a result,, no further post-transient voltage stability analysis was performed. Please refer to the Metro Bulk Area Report for the post-transient analysis performed on the bulk system.

6. Short Circuit Duty Results

6.1 Application Queue

The application queue three-phase-to-ground and single-phase-to-ground fault currents for the Barre 66 kV AB Subtransmission System are shown below in Table 6.1.1 and Table 6.1.2 respectively.

Table 6.1.1
Application Queue Three-Phase-To-Ground Short-Circuit Duty Results
Barre AB Subtransmission System

Bus Name	Bus kV	Pre-Case			Post-Case			Delta kA
		X/R	kA	Eff kA	X/R	kA	Eff kA	
~~Apollo (D)~~	~~66~~	~~8.8~~	~~12.7~~	~~12.7~~	~~8.1~~	~~14~~	~~14.0~~	~~1.3~~
Barre (D)	66	50.4	26.0	32.5	53.5	32.3	40.7	8.2
~~Bolsa (D)~~	~~66~~	~~6.9~~	~~11.2~~	~~11.2~~	~~6.4~~	~~12.2~~	~~12.2~~	~~1.0~~
Ely (D)	66	9.5	15.3	15.3	8.6	17.2	17.2	1.9
Fullerton (D)	66	6.2	13.2	13.2	5.7	14.6	14.6	1.4
Gilbert (D)	66	5.8	11.1	11.1	5.4	12.1	12.1	1.0
Kinder (C)	66	4.4	7.7	7.7	4.2	8.2	8.2	0.5
La Palma (D)	66	12.6	17.0	17.9	11.5	19.5	20.5	2.6
Lampson (D)	66	4.8	9.9	9.9	4.5	10.7	10.7	0.8
Marion (D)	66	12.2	16.3	17.1	11.1	17.6	18.5	1.4
Peaker (D)	66	23.7	25.0	27.5	21.0	30.7	32.8	5.3
~~Shawnee (D)~~	~~66~~	~~12.2~~	~~15.6~~	~~15.6~~	~~11.1~~	~~17.6~~	~~17.6~~	~~2.0~~
Sunnyhills (C)	66	5.7	9.3	9.3	5.3	10.0	10.0	0.7
~~Team (D)~~	~~66~~	~~7.4~~	~~10.8~~	~~10.8~~	~~6.9~~	~~11.7~~	~~11.7~~	~~0.9~~
~~Trask (D)~~	~~66~~	~~14.9~~	~~18.2~~	~~18.2~~	~~13.5~~	~~21.1~~	~~21.1~~	~~2.9~~

Table 6.1.2
End-of-Queue Single-Phase-To-Ground Short-Circuit Duty Results
Barre AB Subtransmission System

Bus Name	Bus kV	Pre-Case			Post-Case			Delta kA
		X/R	kA	Eff kA	X/R	kA	Eff kA	
~~Apollo (D)~~	~~66~~	~~8.7~~	~~9.5~~	~~9.5~~	~~8.1~~	~~10.2~~	~~10.2~~	~~0.7~~
Barre (D)	66	40.5	23.5	28.4	34.2	33.2	39.2	10.8
~~Bolsa (D)~~	~~66~~	~~7.8~~	~~10.0~~	~~10.0~~	~~7.3~~	~~10.7~~	~~10.7~~	~~0.7~~
Ely (D)	66	10.3	10.7	11.1	9.2	12.0	12.5	1.4
Fullerton (D)	66	6.9	8.1	8.1	6.3	9.0	9.0	0.9
Gilbert (D)	66	6.6	6.8	6.8	6.1	7.3	7.3	0.5
Kinder (C)	66	4.8	4.8	4.8	4.6	5.1	5.1	0.3
La Palma (D)	66	10.4	11.2	11.6	9.3	12.9	13.4	1.8
Lampson (D)	66	5.1	6.3	6.3	4.7	6.8	6.8	0.5
Marion (D)	66	10.7	11.4	12.0	9.5	13.1	13.8	1.8
Peaker (D)	66	21.4	22.8	24.4	15.2	31.7	31.7	7.3
~~Shawnee (D)~~	~~66~~	~~10.6~~	~~11.6~~	~~11.6~~	~~9.6~~	~~13.0~~	~~13.0~~	~~1.4~~
Sunnyhills (C)	66	6.5	5.4	5.4	6.1	5.8	5.8	0.4
~~Team (D)~~	~~66~~	~~6.8~~	~~7.6~~	~~7.6~~	~~6.4~~	~~8.1~~	~~8.1~~	~~0.5~~
~~Trask (D)~~	~~66~~	~~13.3~~	~~15.6~~	~~15.6~~	~~11.7~~	~~17.9~~	~~17.9~~	~~2.3~~

The QC7 Phase II breaker evaluations identified that the inclusion of QC7 projects triggers the need for SCD mitigation at the Barre 66 kV. The corresponding mitigation ~~is~~ shown in the Metro Area Bulk Report includes identification of 66 kV circuit breakers on the Barre C Section under an assumption that the Barre 66 kV sectionalizing circuit breakers were closed (during loss of A-Bank) with the Project in-service and operational. The total number of 66 kV circuit breaker upgrades triggered by the inclusion is reduced to twenty-one (21) breakers located on the Barre AB Section with the use of an Operating Procedure to disconnect the Project anytime the Barre 66 kV sectionalizing bus breakers are closed. The circuit breakers outlined in Section F.5.1.i of the Metro Area Bulk Report that are no longer required circuit breaker upgrades, with this operating procedure, includes CB5, CB6, CB51, CB52, CB61, CB62, and CB65. Project cost allocations are shown in Appendix G of the Metro Area Bulk Report. Section D.5.2 and Section F.5.1.i of

6.2 Sensitivity Study – Define Projects that Drive Need for SCD Mitigation at Barre 66 kV

A sensitivity study was performed to properly identify the QC7 Phase II project(s) which materially drive the need for the Barre 66 kV breaker upgrades. The sensitivity study considered two additional scenarios beyond Application Queue analysis. The first scenario modeled every QC7 Phase II project except for those projects seeking interconnection to distribution facilities served out of the Barre 66 kV Subtransmission System. The second scenario modeled those QC7 Phase II projects seeking interconnection to distribution facilities served out of the Barre 66 kV Subtransmission System without the rest of the QC7 Phase II projects.

6.2.1 Scenario 1: QC7 Phase II Projects External to Barre 66 kV System excluding QC7 Phase II Projects Internal to Barre 66 kV System

The three-phase-to-ground and single-phase-to-ground fault currents for the Barre 66 kV Subtransmission System under Scenario 1 resulted in no identified substations within the Barre System where SCD contribution was increased by at least 0.1 kA where the resulting SCD required a need for short-circuit duty mitigation. Such finding results in the conclusion that the need for circuit breaker upgrades internal to the Barre 66 kV Subtransmission System are completely driven by the addition of QC7 Projects seeking interconnection to distribution served by the Barre 66 kV Subtransmission System.

6.2.2 Scenario 2: QC7 Phase II Projects Internal to Barre 66 kV System excluding QC7 Phase II Projects External to Barre 66 kV System

The three-phase-to-ground and single-phase-to-ground fault currents for the Barre 66 kV Subtransmission System under Scenario 2 are shown below in Table 6.2.1.1 and Table 6.2.1.2 respectively.

Table 6.2.2.1
Three-Phase-To-Ground Short-Circuit Duty Results
QC7 Phase II Projects Excluding QC7 Phase II Projects External to Barre 66 kV System

Bus Name	Bus kV	Pre-Case			Post-Case			Delta kA
		X/R	kA	Eff kA	X/R	kA	Eff kA	
~~Apollo (D)~~	~~66~~	~~8.8~~	~~12.7~~	~~12.7~~	~~8.1~~	~~14.0~~	~~14.0~~	~~1.3~~
Barre (D)	66	50.4	26.0	32.5	53.5	32.2	40.6	8.1
~~Bolsa (D)~~	~~66~~	~~6.9~~	~~11.2~~	~~11.2~~	~~6.4~~	~~12.2~~	~~12.2~~	~~1.0~~
Ely (D)	66	9.5	15.3	15.3	8.6	17.2	17.2	1.9
Fullerton (D)	66	6.2	13.2	13.2	5.7	14.6	14.6	1.4
Gilbert (D)	66	5.8	11.1	11.1	5.4	12.1	12.1	1.0
Kinder (C)	66	4.4	7.7	7.7	4.2	8.2	8.2	0.5
La Palma (D)	66	12.6	17.0	17.9	11.5	19.5	20.5	2.6
Lampson (D)	66	4.8	9.9	9.9	4.5	10.7	10.7	0.8
Marion (D)	66	12.2	16.3	17.1	11.1	17.6	18.5	1.4
Peaker (D)	66	23.7	25.0	27.5	21.0	30.7	32.8	5.3
~~Shawnee (D)~~	~~66~~	~~12.2~~	~~15.6~~	~~15.6~~	~~11.1~~	~~17.6~~	~~17.6~~	~~2.0~~
Sunnyhills (C)	66	5.7	9.3	9.3	5.3	10.0	10.0	0.7
~~Team (D)~~	~~66~~	~~7.4~~	~~10.8~~	~~10.8~~	~~6.9~~	~~11.7~~	~~11.7~~	~~0.9~~
~~Trask (D)~~	~~66~~	~~14.9~~	~~18.2~~	~~18.2~~	~~13.5~~	~~21.1~~	~~21.1~~	~~2.9~~

Table 6.2.2.2
Single-Phase-To-Ground Short-Circuit Duty Results
QC7 Phase II Projects Excluding QC7 Phase II Projects External to Barre 66 kV System

Bus Name	Bus kV	Pre-Case			Post-Case			Delta kA
		X/R	kA	Eff kA	X/R	kA	Eff kA	
~~Apollo (D)~~	~~66~~	~~8.7~~	~~9.5~~	~~9.5~~	~~8.1~~	~~14.0~~	~~14~~	~~4.5~~
Barre (D)	66	40.5	23.5	28.4	53.5	32.3	40.7	12.3
~~Bolsa (D)~~	~~66~~	~~7.8~~	~~10.0~~	~~10.0~~	~~6.4~~	~~12.2~~	~~12.2~~	~~2.2~~
Ely (D)	66	10.3	10.7	11.1	8.6	17.2	17.9	6.8
Fullerton (D)	66	6.9	8.1	8.1	5.7	14.6	14.6	6.5
Gilbert (D)	66	6.6	6.8	6.8	5.4	12.1	12.0	5.2
Kinder (C)	66	4.8	4.8	4.8	4.2	8.2	8.2	3.4
La Palma (D)	66	10.4	11.2	11.6	11.5	19.5	20.2	8.6
Lampson (D)	66	5.1	6.3	6.3	4.5	10.7	10.7	4.4
Marion (D)	66	10.7	11.4	12.0	11.1	17.6	18.5	6.5
Peaker (D)	66	21.4	22.8	24.4	21.0	30.7	32.8	8.4
~~Shawnee (D)~~	~~66~~	~~10.6~~	~~11.6~~	~~11.6~~	~~11.1~~	~~17.6~~	~~17.6~~	~~6.0~~
Sunnyhills (C)	66	6.5	5.4	5.4	5.3	10.0	10.0	4.6
~~Team (D)~~	~~66~~	~~6.8~~	~~7.6~~	~~7.6~~	~~6.9~~	~~11.7~~	~~11.7~~	~~4.1~~
~~Trask (D)~~	~~66~~	~~13.3~~	~~15.6~~	~~15.6~~	~~13.5~~	~~21.1~~	~~21.1~~	~~5.5~~

Based on the study results, the inclusion of all application queue projects except the eighteen QC7 Phase II projects external to the Barre 66 kV Subtransmission System resulted in a need for breaker upgrades at the 66 kV voltage level. Such conclusion indicates that the single project seeking interconnection to distribution facilities served out of the Barre 66 kV Subtransmission System drives the need for the circuit breaker upgrades at Barre 66 kV Subtransmission System identified in the Metro Area Group Report.

6.3 Operational Study

Based on the conclusion that the need for Barre 66 kV breaker upgrades is directly linked to the development of the single project seeking interconnection to distribution facilities served out of the Barre 66 kV Subtransmission System, an operational study was performed to determine timing of need for such circuit breaker upgrades. The operational study evaluated the impacts associated with the incremental addition of generation units from the single project seeking interconnection to distribution facilities served out of the Barre 66 kV Subtransmission System.

6.3.1 Addition of one unit from WDT1189

The operational three-phase-to-ground and single-phase-to-ground fault currents for the Barre 66 kV Subtransmission System with the addition of only one unit from WDT1189 are shown below in Table 6.2.3.1 and Table 6.2.3.2 respectively.

Table 6.3.1.1
Three-Phase-To-Ground Short-Circuit Duty Results
QC7 Phase II Projects Excluding QC7 Phase II Projects External to Barre 66 kV System

Bus Name	Bus kV	Pre-Case			Post-Case			Delta kA
		X/R	kA	Eff kA	X/R	kA	Eff kA	
~~Apollo (D)~~	~~66~~	~~8.8~~	~~12.7~~	~~12.7~~	~~8.5~~	~~13.3~~	~~13.3~~	~~0.6~~
Barre (D)	66	50.4	26.0	32.5	54.0	28.8	36.6	4.1
~~Bolsa (D)~~	~~66~~	~~6.9~~	~~11.2~~	~~11.2~~	~~6.7~~	~~11.7~~	~~11.7~~	~~0.5~~
Ely (D)	66	9.5	15.3	15.3	9.1	16.2	16.2	0.9
Fullerton (D)	66	6.2	13.2	13.2	6.0	13.9	13.9	0.7
Gilbert (D)	66	5.8	11.1	11.1	5.6	11.6	11.6	0.5
Kinder (C)	66	4.4	7.7	7.7	4.3	8.0	8.0	0.3
La Palma (D)	66	12.6	17.0	17.9	12.1	18.1	19.0	1.1
Lampson (D)	66	4.8	9.9	9.9	4.6	10.3	10.3	0.4
Marion (D)	66	12.2	16.3	17.1	11.8	17.3	18.2	1.1
Peaker (D)	66	23.7	25.0	27.5	22.8	27.5	30.0	2.5
~~Shawnee (D)~~	~~66~~	~~12.2~~	~~15.6~~	~~15.6~~	~~11.7~~	~~16.5~~	~~16.5~~	~~0.9~~
Sunnyhills (C)	66	5.7	9.3	9.3	5.5	9.7	9.7	0.4
~~Team (D)~~	~~66~~	~~7.4~~	~~10.8~~	~~10.8~~	~~7.2~~	~~11.3~~	~~11.3~~	~~0.5~~
~~Trask (D)~~	~~66~~	~~14.9~~	~~18.2~~	~~18.2~~	~~14.3~~	~~19.5~~	~~19.5~~	~~1.3~~

Table 6.3.1.2
Single-Phase-To-Ground Short-Circuit Duty Results
QC7 Phase II Projects Excluding QC7 Phase II Projects External to Barre 66 kV System

Bus Name	Bus kV	Pre-Case			Post-Case			Delta kA
		X/R	kA	Eff kA	X/R	kA	Eff kA	
~~Apollo (D)~~	~~66~~	~~8.7~~	~~9.5~~	~~9.5~~	~~8.2~~	~~10.0~~	~~10.0~~	~~0.5~~
Barre (D)	66	40.5	23.5	28.4	35.3	30.7	36.2	7.8
~~Bolsa (D)~~	~~66~~	~~7.8~~	~~10.0~~	~~10.0~~	~~7.5~~	~~10.4~~	~~10.4~~	~~0.4~~
Ely (D)	66	10.3	10.7	11.1	9.5	11.6	12.1	1.0
Fullerton (D)	66	6.9	8.1	8.1	6.4	8.8	8.8	0.7
Gilbert (D)	66	6.6	6.8	6.8	6.2	7.2	7.2	0.4
Kinder (C)	66	4.8	4.8	4.8	4.6	5.0	5.0	0.2
La Palma (D)	66	10.4	11.2	11.6	9.5	12.5	13.0	1.4
Lampson (D)	66	5.1	6.3	6.3	4.8	6.7	6.7	0.4
Marion (D)	66	10.7	11.4	12.0	9.7	12.7	13.3	1.3
Peaker (D)	66	21.4	22.8	24.4	16.2	29.4	29.7	5.3
~~Shawnee (D)~~	~~66~~	~~10.6~~	~~11.6~~	~~11.6~~	~~9.9~~	~~12.6~~	~~12.6~~	~~1.0~~
Sunnyhills (C)	66	6.5	5.4	5.4	6.2	5.7	5.7	0.3
~~Team (D)~~	~~66~~	~~6.8~~	~~7.6~~	~~7.6~~	~~6.5~~	~~8.0~~	~~8.0~~	~~0.4~~
~~Trask (D)~~	~~66~~	~~13.3~~	~~15.6~~	~~15.6~~	~~12.2~~	~~17.1~~	~~17.1~~	~~1.5~~

Results corresponding to the addition of one unit from WDT1189 indicates that short-circuit duty values at Barre increase beyond duty capability of a number of existing circuit breakers. Such results conclude that the breaker upgrades at the Barre 66 kV need to be in place prior to allowing synchronization of the first unit from WDT1189.

6.3.2 Addition of two units from WDT1189

The operational three-phase-to-ground and single-phase-to-ground fault currents for the Barre 66 kV Subtransmission System with the addition of two units from WDT1189 are shown below in Table 6.2.3.1 and Table 6.2.3.2 respectively.

Table 6.3.2.1
Three-Phase-To-Ground Short-Circuit Duty Results
QC7 Phase II Projects Excluding QC7 Phase II Projects External to Barre 66 kV System

Bus Name	Bus kV	Pre-Case			Post-Case			Delta kA
		X/R	kA	Eff kA	X/R	kA	Eff kA	
~~Apollo (D)~~	~~66~~	~~8.8~~	~~12.7~~	~~12.7~~	~~8.3~~	~~13.7~~	~~13.7~~	~~1.0~~
Barre (D)	66	50.4	26.0	32.5	54.3	30.8	39.1	6.6
~~Bolsa (D)~~	~~66~~	~~6.9~~	~~11.2~~	~~11.2~~	~~6.5~~	~~12.0~~	~~12.0~~	~~0.8~~
Ely (D)	66	9.5	15.3	15.3	8.8	16.8	16.8	1.5
Fullerton (D)	66	6.2	13.2	13.2	5.8	14.3	14.3	1.1
Gilbert (D)	66	5.8	11.1	11.1	5.5	11.9	11.9	0.8
Kinder (C)	66	4.4	7.7	7.7	4.3	8.1	8.1	0.4
La Palma (D)	66	12.6	17.0	17.9	11.8	18.9	19.8	1.9
Lampson (D)	66	4.8	9.9	9.9	4.5	10.5	10.5	0.6
Marion (D)	66	12.2	16.3	17.1	11.4	17.2	18.1	1.0
Peaker (D)	66	23.7	25	27.5	21.9	29.3	31.6	4.1
~~Shawnee (D)~~	~~66~~	~~12.2~~	~~15.6~~	~~15.6~~	~~11.4~~	~~17.2~~	~~17.2~~	~~1.6~~
Sunnyhills (C)	66	5.7	9.3	9.3	5.4	9.9	9.9	0.6
~~Team (D)~~	~~66~~	~~7.4~~	~~10.8~~	~~10.8~~	~~7.0~~	~~11.5~~	~~11.5~~	~~0.7~~
~~Trask (D)~~	~~66~~	~~14.9~~	~~18.2~~	~~18.2~~	~~13.8~~	~~20.4~~	~~20.4~~	~~2.2~~

Table 6.3.2.2
Single-Phase-To-Ground Short-Circuit Duty Results
QC7 Phase II Projects Excluding QC7 Phase II Projects External to Barre 66 kV System

Bus Name	Bus kV	Pre-Case			Post-Case			Delta kA
		X/R	kA	Eff kA	X/R	kA	Eff kA	
~~Apollo (D)~~	~~66~~	~~8.7~~	~~9.5~~	~~9.5~~	~~8.1~~	~~10.1~~	~~10.1~~	~~0.6~~
Barre (D)	66	40.5	23.5	28.4	34.8	32.2	38.0	9.6
~~Bolsa (D)~~	~~66~~	~~7.8~~	~~10.0~~	~~10.0~~	~~7.4~~	~~10.6~~	~~10.6~~	~~0.6~~
Ely (D)	66	10.3	10.7	11.1	9.3	11.8	12.3	1.2
Fullerton (D)	66	6.9	8.1	8.1	6.3	8.9	8.9	0.8
Gilbert (D)	66	6.6	6.8	6.8	6.1	7.3	7.3	0.5
Kinder (C)	66	4.8	4.8	4.8	4.6	5.1	5.1	0.3
La Palma (D)	66	10.4	11.2	11.6	9.4	12.7	13.2	1.6
Lampson (D)	66	5.1	6.3	6.3	4.7	6.8	6.8	0.5
Marion (D)	66	10.7	11.4	12.0	9.6	12.9	13.5	1.5
Peaker (D)	66	21.4	22.8	24.4	15.6	30.7	30.7	6.3
~~Shawnee (D)~~	~~66~~	~~10.6~~	~~11.6~~	~~11.6~~	~~9.7~~	~~12.8~~	~~12.8~~	~~1.2~~
Sunnyhills (C)	66	6.5	5.4	5.4	6.1	5.7	5.7	0.3
~~Team (D)~~	~~66~~	~~6.8~~	~~7.6~~	~~7.6~~	~~6.5~~	~~8.1~~	~~8.1~~	~~0.5~~
~~Trask (D)~~	~~66~~	~~13.3~~	~~15.6~~	~~15.6~~	~~11.9~~	~~17.6~~	~~17.6~~	~~2.0~~

Results corresponding to the addition of two units from WDT1189 are for information purposes only as circuit breaker upgrades at Barre are required to be in place prior to allowing synchronization of the first unit from WDT1189.

6.4 Ground Grid Evaluation

As shown above in Table 6.1.2, the addition of the QC7 Phase II projects seeking interconnection to distribution facilities served out of the Barre 66 kV Subtransmission System were found to significantly increase single line-to-ground short circuit duty. The study identified the following SCE Substations served out of the Barre System where the single line-to-ground fault contribution from the QC7 projects increased duty in excess of 0.25 kA and exceeded the currently documented ground grid single line-to-ground short circuit duty value (excludes Ely and Johanna as current documentation indicates no issues).

- ~~Apollo~~
- Barre
- ~~Bolsa~~
- Fullerton
- Gilbert
- Kinder
- La Palma
- Lampson
- Marion
- ~~Shawnee~~
- Sunnyhills
- ~~Team~~
- ~~Trask~~

These locations will require a detailed ground grid analysis to be performed in support of projects seeking interconnection to distribution facilities served out of the Barre 66 kV Subtransmission System. The approximate one-time cost for such study is $35k per substation. These costs will be allocated to the generation projects identified to significantly increase SCD contributions and are identified in the appropriate Appendix A

7. Scope of Subtransmission Level Distribution Upgrades

Please refer to the Attachment 1 of the applicable Appendix A report for the scope of any subtransmission upgrades

8. Network Constraints

Please refer to the Metro Area Bulk Report for information pertaining to any network related constraints.

Queue Cluster 7 Phase II - Attachment 1
WDT1189– Stanton Energy Center Project
Interconnection Facilities, Network Upgrades and Distribution Upgrades

Distribution Provider's Interconnection Facilities, Network Upgrades and Distribution Upgrades described below are based on the Distribution Provider's preliminary engineering and design. Such descriptions are subject to modification to reflect the actual facilities that are constructed and installed following the Distribution Provider's detailed engineering and design, identification of field conditions, and compliance with applicable environmental and permitting requirements[1].

1. Interconnection Facilities.

(a) **Interconnection Customer's Interconnection Facilities.** The Interconnection Customer shall:

(i) Install a substation with one (1) 66/13.8/13.8 kV main step-up transformer with H-X, H-Y, and X-Y windings with a 8, 8, and 12 percent impendences on a 95 MVA base.

(ii) Install a new underground 0.34 mile 66 kV generation tie-line from the Facility to a position designated by the Distribution Provider, outside of the Distribution Provider's Barre Substation, where Interconnection Customer shall install a structure designed and engineered in accordance with the Distribution Provider's specifications ("Last Structure"). This generation tie-line will be referred to as the Barre - WDT1189 66 kV Line. The right-of-way for Barre - WDT1189 66 kV Line shall extend up to the edge of the Barre Substation property line.

(Note: The Barre - WDT1189 66 kV Line name is subject to change by the Distribution Provider based upon its transmission line naming criteria. Should the Barre - WDT1189 66 kV Line name be changed, this GIA may be amended to reflect such change.)

(iii) The normal rating of the Interconnection Customer's 66 kV equipment that is part of the generation tie-line is 1574.59 A and the emergency rating is 1574.59 A.

(iv) Install appropriate single mode fiber optic cable on Barre - WDT1189 66 kV Line to a point designated by the Distribution Provider near the Distribution Provider's Barre Substation to provide one of two telecommunication paths required for the line protection scheme, and the Remote Terminal Units ("RTU"). A minimum of eight (8) strands within the single mode fiber optic cable shall be provided for the Distribution Provider's exclusive use into Barre Substation.

(v) Install appropriate fiber optic cable from the Facility to a point designated by the Distribution Provider near the Distribution Provider's Barre Substation to provide the second telecommunication path required for the line protection scheme. A minimum of eight (8) strands within the fiber

[1] Such descriptions are subject to modification to reflect the actual facilities that are constructed and installed following the Distribution Provider's detailed engineering and design, identification of field conditions, and compliance with applicable environmental and permitting requirements.

optic cable shall be provided for the Distribution Provider’s exclusive use. The telecommunication path shall meet the Applicable Reliability Standards criteria for diversity.

(vi) Own, operate and maintain both telecommunication paths (including the fiber optic cables and appurtenant facilities), with the exception of the terminal equipment at both Barre Substation and at the Facility, which will be installed, owned, operated and maintained by the Distribution Provider.

(vii) Allow the Distribution Provider to review the Interconnection Customer’s telecommunication equipment design and perform inspections to ensure compatibility with the Distribution Provider’s terminal equipment and protection engineering requirements; allow the Distribution Provider to perform acceptance testing of the telecommunication equipment and the right to request and/or to perform correction of installation deficiencies.

(viii) Provide required data signals, make available adequate space, facilities, and associated dedicated electrical circuits within a secure building having suitable environmental controls for the installation of the Distribution Provider’s RTU in accordance with the Interconnection Handbook.

(ix) Make available adequate space, facilities, and associated dedicated electrical circuits within a secure building having suitable environmental controls for the installation of the Distribution Provider’s telecommunications terminal equipment in accordance with the Interconnection Handbook.

(x) Extend the fiber optic cables for the two telecommunication paths to an Interconnection Customer provided and installed patch panel located adjacent to the Distribution Provider’s telecommunications terminal equipment specified above.

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

(xii) Install retail metering cabinet and metering equipment (typically, voltage and current transformers) at the Facility to meter the Facility retail load, as specified by the Distribution Provider. The metering cabinet must be placed at a location that would allow twenty-four hour access for the Distribution Provider’s metering personnel.

(xiii) Allow the Distribution Provider to install, in the retail metering cabinet provided by the Interconnection Customer, revenue meters and appurtenant equipment required to meter the retail load at the Facility.

(xiv) Install relay protection to be specified by the Distribution Provider to match the relay protection used by the Distribution Provider at Barre Substation, in order to protect the Barre - WDT1189 66 kV Line, as follows:

1. Two (2) current differential relays connected via diversely routed dedicated digital communication channels to Barre Substation. The make and type of current differential relays will be specified by the Distribution Provider during detailed engineering of the Distribution Provider’s Interconnection Facilities.

(xv) Install all equipment necessary to comply with the power factor requirements of Article 9.6.1 of the GIA, including the ability to automatically regulate the power factor to a schedule (VAR schedule) in accordance with the Interconnection Handbook.

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

(b) **Distribution Provider's Interconnection Facilities.** The Distribution Provider shall**:**

(i) **Barre Substation.**

1. Install the interconnection facilities portion for a new 66 kV position to terminate the Barre - WDT1189 66 kV Line. This work includes the following:
   a. One (1) dead-end substation structure.
   b. Three (3) 66 kV potential transformers with steel pedestal support structures.
   c. Three (3) 66 kV line drops.
2. Install the following relays to protect the Barre - WDT1189 66 kV Line:
   a. Two (2) current differential relays connected via diversely routed dedicated digital communications channels to the Generating Facility.

(ii) **Barre - WDT1189 66 kV Line.**

Install an appropriate number of 66 kV sub-transmission structures including insulator/hardware assemblies between the Last Structure and the dead-end substation structure at Barre Substation. The actual number and location of the sub-transmission structures and spans of conductor will be determined by the Distribution Provider following completion of detailed engineering of the Distribution Provider's Interconnection Facilities. The Phase II Interconnection Study assumed two (2) sub-transmission TSP risers, approximately 600 feet of 954 SAC conductor, 12,000 feet of 3000 kcmil underground Cu cable, and 3 vaults.

(iii) **Telecommunications.**

1. Install all required lightwave, channel bank(s), and associated equipment (including terminal equipment), supporting protection and SCADA requirements at the Facility and Barre Substation for the interconnection of the Facility. Notwithstanding that certain telecommunication equipment, including the telecommunications terminal equipment, will be located on the Interconnection Customer's side of the Point of Change of Ownership, the Distribution Provider shall own, operate and maintain such telecommunication equipment as part of the Distribution Provider's Interconnection Facilities.
2. Install appropriate length of fiber optic cable, including conduit and vaults, from the point designated by the Distribution Provider near the Distribution Provider's Barre Substation to extend the fiber optic cable

into the communication room at Barre Substation. The actual location and length of fiber optic cable and conduit, and location and number of vaults, will be determined during detailed engineering of the Distribution Provider's Interconnection Facilities. The Phase II Interconnection Study assumed the installation of approximately 2,000 feet of underground fiber optic cable inside 5-inch conduit, and one (1) vault to extend the fiber optic cable into the communication room at Barre Substation.

3. Install appropriate length of fiber optic cable, including conduit and vaults, to extend the Interconnection Customer's diverse telecommunications from the point designated by the Distribution Provider near the Distribution Provider's Barre Substation into the communication room at Barre Substation. The actual location and length of fiber optic cable and conduit, and location and number of vaults, will be determined during detailed engineering of the Distribution Provider's Interconnection Facilities. The Phase II Interconnection Study assumed the installation of approximately 3,800 feet of underground fiber optic cable inside 5-inch conduit, and one (1) vault to extend the fiber optic cable into the communication room at Barre Substation.

(iv) **Real Properties, Transmission Project Licensing, and Corporate Environmental Health and Safety.**
Obtain easements and/or acquire land, obtain licensing and permits, and perform all required environmental activities for the installation of the Distribution Provider's Interconnection Facilities, including any associated telecommunication equipment for the Barre - WDT1189 66 kV Line.

(v) **Metering.**
Install revenue meters and appurtenant equipment required to meter the retail load at the Facility. Notwithstanding that the meters and appurtenant equipment will be located on the Interconnection Customer's side of the Point of Change of Ownership, the Distribution Provider shall own, operate and maintain such facilities as part of the Distribution Provider's Interconnection Facilities.

(vi) **Power System Control.**
Install one (1) RTU at the Facility to monitor typical battery storage elements such as MW, MVAR, terminal voltage and circuit breaker status for the Facility and plant auxiliary load, and transmit the information received thereby to the Distribution Provider's grid control center. Notwithstanding that the RTU will be located on the Interconnection Customer's side of the Point of Change of Ownership, the Distribution Provider shall own, operate and maintain the RTU as part of the Distribution Provider's Interconnection Facilities.

2. Network Upgrades.

(a) **Stand Alone Network Upgrades.**
None identified in the Phase II Study.

(b) **Other Network Upgrades.**

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

1. **Short Circuit Duty (SCD) Mitigation – RNU**
    a. Vista 220 kV Substation
        i. Upgrade fourteen (14) Circuit Breakers by installing fifteen (15) sets of TRV Capacitors.
        ii. Perform ground grid study.
    b. Real Properties, Transmission Project Licensing, and Corporate Environmental Health and Safety
    Obtain easements and/or acquire land, obtain licensing and permits, and perform all required environmental activities for the installation of the TRV's.

2. **Ground grid studies.**
Perform ground grid studies at Huntington Beach 220 kV and Lewis 220 kV Substations.

(ii) **Distribution Provider's Delivery Network Upgrades**

1. **Area Delivery Network Upgrades.**
None identified in the Phase II Study.
2. **Local Delivery Network Upgrades.**
None identified in the Phase II Study.

3. Distribution Upgrades. The Distribution Provider shall

(a) **Barre Substation.**

(i) Install the distribution facilities portion for a new 66 kV position to terminate the Barre - WDT1189 66 kV Line. This work includes the following:
    a. Two (2) 66 kV circuit breakers.
    b. Four (4) sets of 66 kV disconnect switches.
    c. Perform ground grid study

(b) **Power Systems Controls.**

(i) Substation Automation System (SAS) point additions to the existing Barre SAS to accommodate new relay protection, status, and alarm.

(c) **Real Properties, Transmission Project Licensing, and Corporate Environmental Health and Safety.**

(i) Obtain easements and/or acquire land, obtain licensing and permits, and perform all required environmental activities for the installation of the Distribution Upgrades.

(d) **Short Circuit Duty (SCD) Mitigation – DU**

(i) Barre 66 kV Substation

a. Replace a total of twenty-seven (27) Circuit Breakers and upgrade their bus positions accordingly.
b. Replace twelve (12) spans of 66 kV Lines.
c. Perform ground grid study.
d. Real Properties, Transmission Project Licensing, and Corporate Environmental Health and Safety.
e. Obtain easements and/or acquire land, obtain licensing and permits, and perform all required environmental activities for replacement of the Circuit Breakers and Line Spans.

(ii) Villa Park 66 kV Substation.

a. Replace one Circuit Breaker.
b. Perform ground grid study.
c. Real Properties, Transmission Project Licensing, and Corporate Environmental Health and Safety.
d. Obtain easements and/or acquire land, obtain licensing and permits, and perform all required environmental activities for replacement of the Circuit Breaker.

(e) **Ground Grid Studies.**

Perform ground grid studies at Apollo 66 kV, Bolsa 66 kV, Fullerton 66 kV, Gilbert 66 kV, Kindler 66 kV, La Palma 66 kV, Lampson 66 kV, Marion 66 kV, Shawnee 66 kV, Sunny Hills 66 kV, Team 66 kV, and Trask 66 kV Substations.

4. Affected System Upgrades

Not used.

5. Point of Change of Ownership.

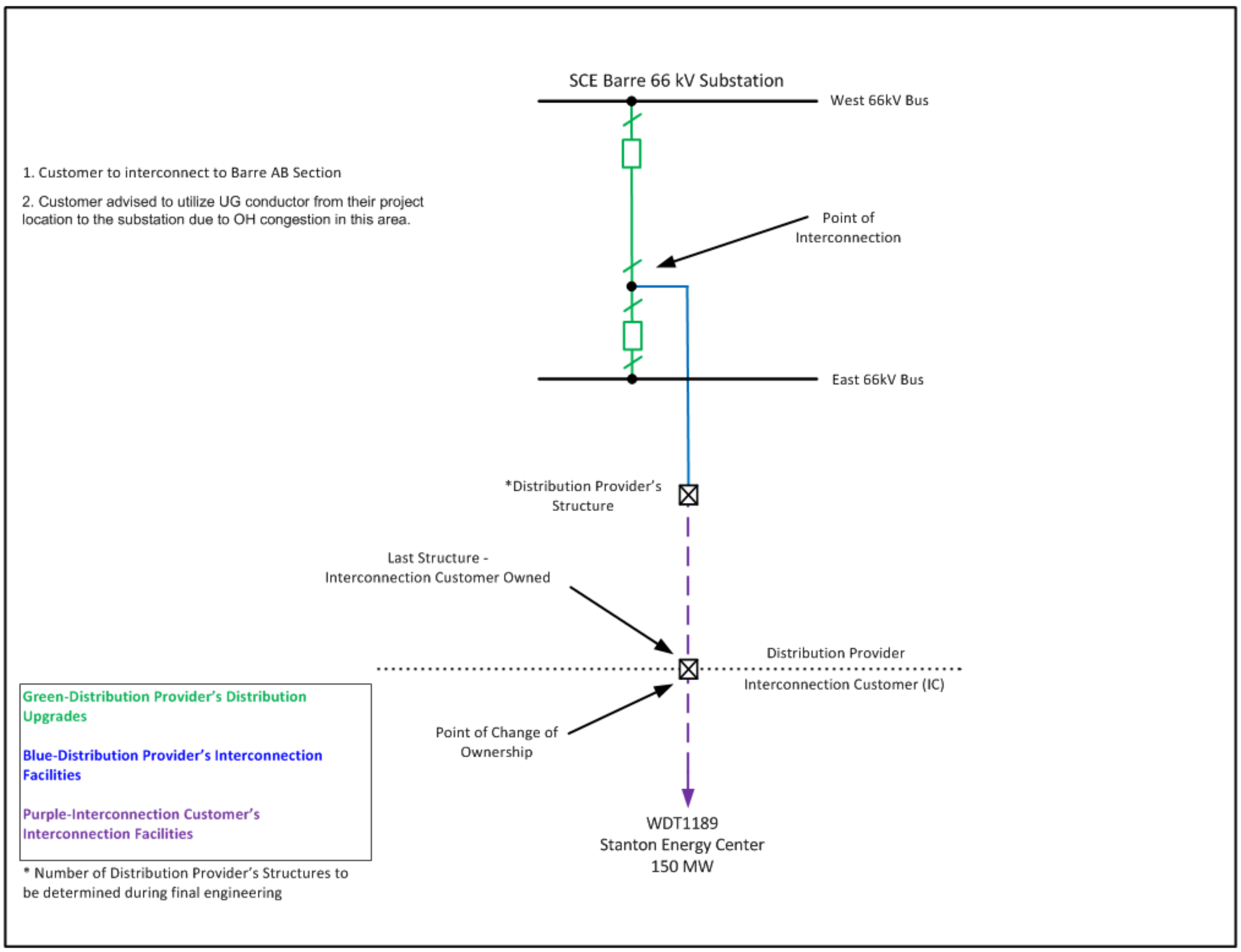
(a) Barre - WDT1189 66 kV Line: The Point of Change of Ownership shall be the point where the conductors of the Barre - WDT1189 66 kV Line are attached to the Last Structure, which will be connected on the side of the Last Structure facing Barre Substation. The Interconnection Customer shall own and maintain the Last Structure, the conductors, insulators and jumper loops from such Last Structure to the Interconnection Customer's Facility. The Distribution Provider will own and maintain Barre Substation, as well as all circuit breakers, disconnects, relay facilities and metering within Barre Substation, together with the line drop, in their entirety, from the Last Structure to Barre Substation. The Distribution Provider will own the insulators that are used to attach the Distribution Provider-owned conductors to the Last Structure.

(b) Telecommunication single mode fiber optic cable: The Point of Change of Ownership shall be the point at a Distribution Provider owned vault, where the Interconnection Customer's fiber optic cable is connected to the Distribution Provider's fiber optic cable.

(c) Telecommunication diverse fiber optic cable: The Point of Change of Ownership shall be the point at a Distribution Provider owned vault, where the Interconnection Customer's fiber optic cable is connected to the Distribution Provider's fiber optic cable.

6. **Point of Interconnection.** The Distribution Provider's Barre 66 kV Substation at the 66 kV switchrack.

7. **One-Line Diagram of Interconnection to Barre 66 kV Substation.**



QC7 Phase II Study Report Attachment #2

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

Project #: WDT1189

Cost Category	Costs per Category w/o ITCC (A)	One Time Costs (Note 1) (B)	Total Costs w/o ITCC (C=A+B)	Total Escalated Costs w/o ITCC	Estimated Time to Construct (Months)	COD Dollar Escalation Duration (Months)
	Constant 2015 Dollar in $1000s (Estimate)	Constant 2015 Dollar in $1000s (Estimate)	Constant 2015 Dollar in $1000s (Estimate)	Escalated to OD Year in $1000s	(Note 3,4,5, 9, & 10)	(Note 3,4,5, 9, & 10)
Interconnection Facilities						
Transmission	$0	$0	$0	$0	27	42
Sub-Transmission	$2,830	$0	$2,830	$3,213	27	42
Substation	$1,180	$0	$1,180	$1,340	27	42
Real Properties	$120	$0	$120	$137	27	42
Metering Services	$35	$0	$35	$39	27	42
Telecommunication	$707	$0	$707	$803	27	42
Edison Carrier Solutions	$164	$0	$164	$186	27	42
Corporate Environmental	$134	$0	$134	$152	27	42
Licensing	$0	$0	$0	$0	27	42
Power System Control	$72	$0	$72	$82	27	42
Interconnection Facilities Total	**$5,242**	**$0**	**$5,242**	**$5,953**	**27**	**42**
Reliability Network Upgrades						
Short Circuit Duty Mitigation						
Vista 220 kV SCD	$923	$0	$923	$1,048	27	42
Ground Grid Study to support Vista 220 kV SCD	$0	$43	$43	$49	27	42
Ground Grid Study						
Ground Grid Study for Bulk System(Huntington Beach and Lewis)	$0	$87	$87	$99	27	42
Reliability Network Upgrades Total	**$923**	**$130**	**$1,053**	**$1,196**	**27**	**42**
Distribution Upgrades						
Substation	$2,142	$43	$2,185	$2,482	27	42
Corporate Environmental	$56	$0	$56	$64	27	42
Power System Control	$0	$27	$27	$30	27	42
Short Circuit Duty Mitigation						
Barre 66 kV SCD	$18,821	$0	$18,821	$21,373	42	42
Villa Park 66 kV SCD	$387	$0	$387	$440	27	42
Ground Grid Study to support Barre 66 kV SCD	$0	$43	$43	$49	27	42
Ground Grid Study to support Villa Park 66 kV SCD	$0	$43	$43	$49	27	42
Ground Grid Study						
Ground Grid Study for Barre System (Apollo, Bolsa, Fullerton, Gilbert, Kindler, La Palma, Lampson, Marion, Shawnee, Sunny Hills, Team, Trask)	$0	$522	$522	$592	27	42
Distribution Upgrades Total	**$21,406**	**$679**	**$22,084**	**$25,079**	**42**	**42**
Grand Total	**$27,570**	**$809**	**$28,379**	**$32,228**	**42**	**42**

WDT1189	**Project MW:**	**150**
Income Tax Component of Contribution (ITCC) Potential		
Element	**ITCC @ 35% Constant Dollar in $1000s (2015)**	**ITCC @ 35% Escalated Dollar in $1000s (OD)**
IF (Calculation: (IF+SPS IF) * 35%)	**$1,835**	**$2,083**
RNU **Refer to Note 11 below for Calculation**	**$0**	**$0**
LDNU **Refer to Note 12 below for ITCC treatment**	**N/A**	**N/A**
DU (Calculation: DU* 35%)	**$7,492**	**$8,508**
ADNU **Refer to Note 12 below for details on ITCC treatment**	**N/A**	**N/A**

Max Duration for ITCC Calculation	**42**

Note 1: The one time costs item(s) will be treated as applicable per the specified upgrade classification. They may be reimburseable depending on their classification.

Note 2: Distribution upgrades are not reimbursable. Allocated costs may change if all projects responsible for these upgrades do not execute Generator Interconnection Agreements.

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

Note 4: Each Upgrade category may contain multiple work element construction durations. The longest construction duration is shown under the C.O.D Dollar Duration column.

Note 5: SCE's Phase II cost estimating is done in 'constant' dollars 2015 and then escalated to the estimated O.D.year. For the QC7 study, the estimated C.O.D. Dollar is derived by assuming the duration of the work element will begin in December 2016, which is the CAISO tariff scheduled completion date of the QC7 Phase II study plus: the TPD Allocation, Annual Reassesment Effort , and the interconnection agreement signing period and submittal of required funds by the IC. For instance, if a work element is estimated to take a total of 24 months (final engineering, design, procurement, licensing and construction), then the estimated C.O.D. would be December 2018. If an IC's requested C.O.D. is beyond the estimated C.O.D. of a work element, the IC's requested C.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 above may be subject to change.

Note 6: Individual O&M charges for the above construction costs will be identified and communicated during the Interconnection Agreement process.

Note 7: The Estimated Time to Construct (duration in months) is the schedule for the PTO to complete final engineering, design, procurement, licensing, and construction, etc., and other activities needed to construct and bring the facilities into service. Such activities are from the execution of the Generator Interconnection Agreements, and receipt of: all required information, funding, and written authorization to proceed from the IC, as will be specified in the Interconnection Agreement, to commence work. The estimated schedule does not take into account unanticipated delays or difficulties securing necessary permits, licenses or other approvals; construction difficulties or potential delays in the project implementation process; or unanticipated delays or difficulties in obtaining and receiving necessary clearances for interconnection of the project to the transmission system.

Note 8: The escalation factors to convert the estimated cost (in 'constant' 2015 dollars) to the estimated C.O.D. are found in the posted SCE 2015 Per Unit Cost Guide on the CAISO website:
http://www.caiso.com/informed/Pages/StakeholderProcesses/ParticipatingTransmissionOwnerPerUnitCosts.aspx

Note 9: Estimated Time to Construct durations are from completion of any preceding facilities required.

Note10: The C.O.D. Dollar for the IF and RNU/Dist. Plan of Service facilities was escalated using the requested Project C.O.D when the requested Project C.O.D was beyond the identified ETC of the IF and RNU/Dist. Plan of Service facilities. In such instances there is a different duration (months) in the ETC and C.O.D. Dollar escalation duration columns.

Note11: RNUs are subject to ITCC on funds above the repayment maximum ($60 k/MW) of the Project.The ITCC corresponding to the RNUs, when applicable, was calculated by applying the following formula:
[Total Project allocated RNU Costs – ((Project MW Size)* ($60k))]*35%

Note12: LDNUs and ADNUs may be assessed 35% ITCC. However, presently the ITCC corresponding to LDNUs and ADNUs cannot be quantified due to their dependency on TPD allocation awarded to the Project and accepted by the Interconnection Customer ("IC") several months after the Phase II studies are complete. Consequently, the maximum ITCC warranted by the Project will be addressed, calculated, and included during the Interconnection Agreement development phase once the IC submits the TPD Affidavit confirming acceptance, waiver (parking), or denial of awarded deliverability to the Project.

QC7 Phase II Study Report Attachment 2A

Project # WDT1189

Application Queue Short Circuit Duty (SCD) Analysis Results - Project Allocations

RNU

Reliability Network Upgrades - SCD Mitigations

Project	Vista 230 kV	
	%	Allocated Cost (x1000) 2015 Dollars
WDT1189	39.11%	$ 923

Duration (months)	27

Total Constant Dollars ($1000) (2015)	Total COD Escalted Duration
$923	27

Ground Grid Study Costs: $43

DU

Distribution Upgrades - SCD Mitigations

Project	Villa Park 66kV		Barre 66kV	
	%	Allocated Cost (x1000) 2015 Dollars	%	Allocated Cost (x1000) 2015 Dollars
WDT1189	82.08%	$ 387	100.00%	$ 18,821
Duration (months)	27		27	

Total Constant Dollars ($1000) (2015)	Total COD Escalated Duration
$19,208	27

Ground Grid Study Costs: $43

Note: The estimated cost for the SCD Upgrades for the Metro area are highly conceptual and are subject to chage to circumstances out of SCE's control such as licensing and enviromal permitting requirements; which could potentially impact the costs allocation to the Project associated with this upgrade.

Queue Cluster 7 Phase II

Attachment 8

Subtransmission Assessment Report

Barre 66 kV System

November 24, 2015

Table of Contents

1. Purpose

Impacts of QC7 Projects on the CAISO controlled transmission grid are addressed in the Metro Area Group Report. Because one (1) QC7 project is seeking to interconnect to the Barre 66 kV AB bus section, which is not under CAISO control, additional analysis is required to evaluate the 66 kV Subtransmission System performance. The Individual project details are provided in the project's corresponding Appendix A. These additional analyses focus on the QC7 interconnection request in the Barre 66 kV Subtransmission System and consider minimum levels of load demand with maximum generation dispatch as this would represent the most stressed condition for the project seeking interconnection to the Barre 66 kV AB bus section.

The purpose of this study is to determine the adequacy of SCE's electrical Subtransmission System to accommodate the interconnection request and to identify system limitations that would require Distribution Upgrades on the Subtransmission System to mitigate any identified impacts. The study included all existing and queued ahead generation projects in the Barre 66 kV Subtransmission System, regardless of the in-service dates of such prior queued generation projects. Results of the study will be used as the basis to determine appropriate cost allocation for the identified Distribution Upgrades taking into account every project in this cluster. An operational study was also performed, as required, to determine timing need of any identified upgrade. Such timing need is directly related to actual projects moving forward as not all queued ahead generation projects have progressed towards project execution. It is important to note that withdrawals of projects in this cluster could result in reallocating costs among the remaining projects.

The accuracy of the subtransmission assessment results are contingent on the accuracy of the technical data provided as part of the interconnection request. Any changes from the data provided could void the study results. The study report provides detailed study assumptions and conditions of the Barre AB 66 kV Subtransmission System in which the study was performed. The single QC7 interconnection request seeking interconnection to subtransmission facilities served out of the Barre AB 66 kV Subtransmission System progressed into Phase II. This project consists of a gas turbine power plant requesting to interconnect to the Barre 66 kV AB bus section.

This Subtransmission Assessment Report provides the following:

- Subtransmission System impacts caused by the addition of the QC7 Phase II project requesting interconnection to the Barre AB 66 kV Subtransmission System;
- A good faith estimate of the cost of any identified subtransmission level Distribution Upgrades

To determine the system impacts caused by the QC7 Phase II project seeking interconnection to the Barre 66 kV AB Subtransmission System, the following studies were performed:

- Steady State Power Flow Analyses
- Subtransmission level Short Circuit Duty Analyses

2. QC7 Phase II Generation Project Interconnection Information

The single QC7 interconnection request, totaling 150 MW, seeking interconnection to the Barre 66 kV Subtransmission System progressed into Phase II. Table 2 summarizes the new QC7 generator project with essential data obtained from the SCE WDAT Generation Queue.

Table 2: SCE QC7 Phase II Project at Barre 66 kV System

CAISO Queue	Point of Interconnection (CAISO Delivery Point)	Full Capacity Energy Only	Fuel	Max MW
WDT 1189	Barre AB 66 kV Switchrack	FC	Gas	150
			Total QC7 Generation	**150**

3. System Assumptions

3.1 Planning Criteria

The generator interconnection studies were conducted utilizing SCE's Reliability Planning Criteria. More specifically, the main criteria applicable to this study are as follows:

Power Flow Analysis

Since the QC7 interconnection request, totaling 150 MW, is seeking interconnection directly to the Barre AB 66 kV bus section, the only contingency applicable for this study is loss of a single 220/66 kV Transformer Bank (A-Bank) at the Barre Substation.

- Single Contingencies (N-1) – Loss of one line or one A-bank

The following reliability criteria were used to evaluate loss of A-Bank:

Subtransmission Lines 220/66 kV Transformer banks (A-banks)	Base Case	Limiting Component Normal Rating
	N-1 and N-2	Limiting Component Emergency Rating
	Base Case	Normal Loading Rating*
	Long Term Emergency Loading Limit (LTELL) & Short Term Emergency Loading Limit (STELL)	As defined by SCE Operating Bulletin

3.1.1. Normal Overloads

Normal overloads are those that exceed 100 percent of normal facility rating with all facilities in-service (base case). Mitigation will be required to address any identified normal overload triggered by the inclusion of QC7 Phase II projects.

3.1.2. Contingency Overloads

Contingency overloads are those that exceed 100 percent of emergency ratings under outage conditions. Mitigation will be required to address any identified contingency overload triggered by the inclusion of QC7 Phase II projects.

3.1.3. Voltage Criteria

Voltage performance under single and double outage conditions will be limited to 5 percent and 10 percent deviation, respectively.

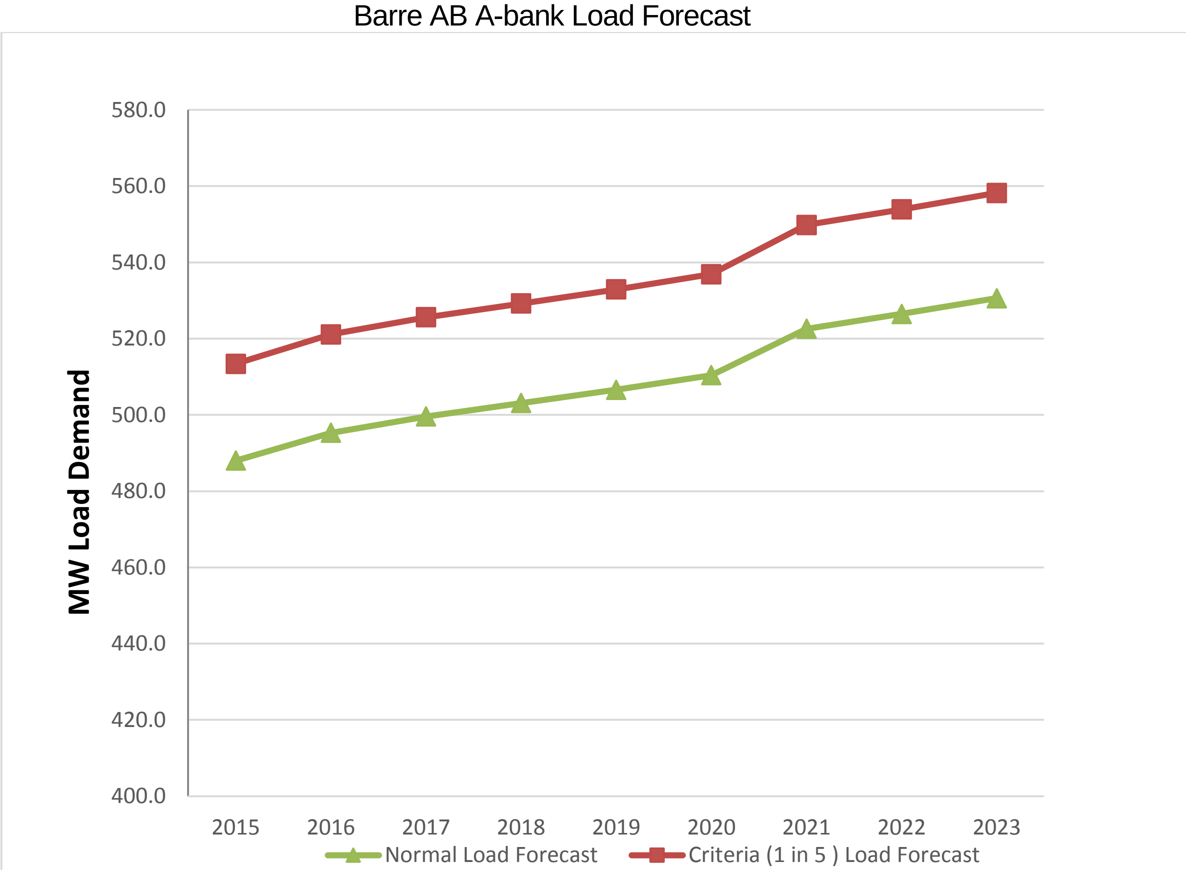
3.1.4. Power Factor Criteria

All projects will need to comply with SCE's Interconnection Handbook requirements.

3.2 Load Assumptions

The load assumptions used for local Subtransmission System initially considered a 2019 load forecast. The 2019 load forecast was derived using SCE's Distribution Engineering A-bank Planning load forecast as well as the individual load serving substation (B-bank) load forecast for 2015-2023. Figure 3.2.1 below provides the local subtransmission load forecast values at the A-bank level under Normal (1-in-2 year) and Criteria (1-in-5 year) Planning assumptions.

Figure 3.2.1
Barre AB A-bank Load Forecast



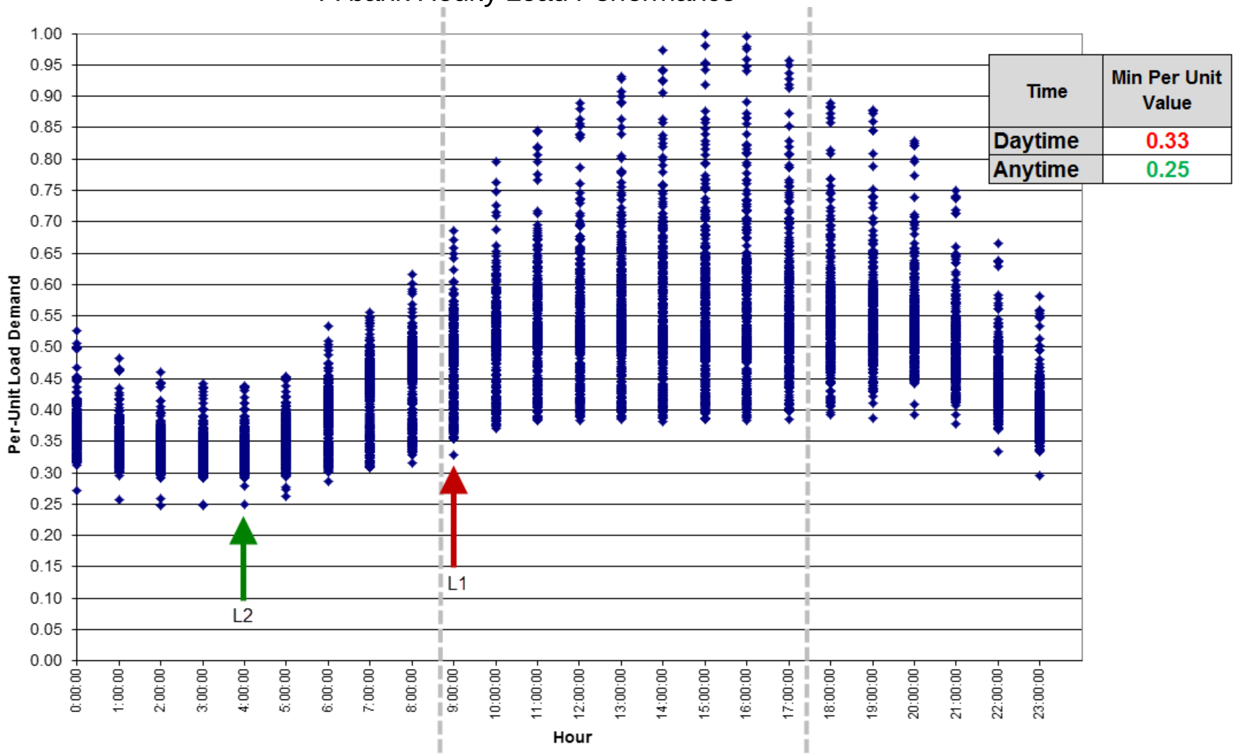
The A-bank Normal and Criteria load forecast was distributed to each individual B-bank substation (lower voltage substations served from the 220/66 kV substation) on a pro-rata basis. The resulting individual B-bank substation values are shown below in Table 3.2.1 and were used as the basis for evaluating Subtransmission System performance.

Table 3.2.1
Local Subtransmission System Load Assumptions

Barre System Load Serving Substations	2019	
	Normal (1-in-2)	Criteria (1-in-5)
Barre 5&6 (D)	78.5	82.6
Ely (D)	68.2	71.8
Fullerton (D) 12kV	72.6	76.4
Fullerton (D) 4kV	5.0	5.2
Gilbert (D)	74.5	78.3
La Palma (D)	52.1	54.8
Lampson (D)	74.3	78.2
Marion (D)	77.0	81.0
Large Customers	4.4	4.7
Barre AB-Section Total	**506.6**	**532.9**

To model year 2019 hourly forecast load performance, historical year 2013 A-bank data was obtained and normalized (maximum historical load = 1.0). This was done in order to provide a means for scaling to reflect comparable hourly performance with a year 2019 load forecast. Shown below, Figure 3.2.2, is the normalized local Subtransmission System A-bank hourly load performance as measured at the 220/66 kV transformer banks.

Figure 3.2.2
Normalized Local Subtransmission System
A-bank Hourly Load Performance



The assessment evaluating the most stressed system condition pertaining to maximum generation output. This condition involves identifying issues that arise under minimum load and maximum generation for the study. Utilizing the normalized hourly load performance shown above in Figure 3.2.2, the lowest per-unit load was applied to define two maximum generation output scenarios. The first scenario would use the minimum per-unit load during the daytime (shown as L1) while the second scenario would use the minimum value identified at any time of the day (shown as L2).

These per-unit values were used to define the specific load distribution assumptions at each load serving substation. These values were used in the base cases developed for each load scenario. The base cases multiplied the per-unit value identified for the respective load scenario, L1 and L2, with the “Normal” load distribution shown in Table 3.2.1. The resulting minimum load distribution used in the power flow study at each individual B-bank substation is provided below in Table 3.2.2.

Table 3.2.2
B-bank Load Distribution

Barre System Load Serving Substations	Minimum Load	
	0.33 PU	0.25 PU
	L1	L2
Barre 5&6 (D)	25.9	20.6
Ely (D)	22.5	17.9
Fullerton (D) 12kV	24.0	19.1
Fullerton (D) 4kV	1.6	1.3
Gilbert (D)	24.6	19.6
La Palma (D)	17.2	13.7
Lampson (D)	24.5	19.5
Marion (D)	25.4	20.2
Large Customers	1.4	1.2
Barre AB-Section Total Load	**167.2**	**133.2**

3.3 Generation Assumptions

There were no queued ahead generation projects in the Barre AB Subtransmission System.

3.4 Subtransmission System Assumptions

The QC7 Phase II Study modeled the existing Barre AB 66 kV Bus Section without any additional upgrades as no such upgrades have been triggered. The study considered existing system operating bulletins/procedures that transfer system load from one bus section to the adjacent bus section by closing the sectionalizing breaker under the loss of one A-Bank.

3.5 Study Methodology

3.5.1. Power Flow Study

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. This assessment is comprised of power flow study scenarios that represent load conditions reflected in Table 3.2.2. A pre case without the inclusion of the QC7 projects and a Post-case with the inclusion of QC7 projects were modeled for each of the load conditions reflected in Table 3.2.2. Mitigation measures will be recommended for any power flow criteria violation identified to be triggered with the inclusion of QC7 projects. The outage conditions evaluated are provided below in Table 3.5.1.

Table 3.5.1
List of Contingencies Evaluated

#	Contingency Type	Contingency Description
1	Base Case	No Outage
2	N-1	Loss of Barre 1A 230/66 kV
3	N-1	Loss of Barre 3A 230/66 kV

The contingency study did not consider loss of lines internal to the Barre 66 kV System as the project does not impact flows on these lines since it is connected directly to the source bus.

3.5.2. Post Transient Voltage Study

The power flow study voltage results were used as a screen to identify those contingencies that may require additional post-transient voltage studies. Contingencies identified in the power flow to have a voltage drop in excess of 5% were selected for post-transient voltage analysis. The Post-transient voltage studies compare voltage deviations to the reliability requirements for single and double contingency outages on the Subtransmission System. Mitigation measures will be recommended for any criteria violation identified to be triggered with the inclusion of QC7 projects.

3.5.3. Short Circuit Duty Study

To determine the impact on short-circuit duty within the Subtransmission System after inclusion of all QC7 projects (application queue), the study calculated the maximum symmetrical three-phase-to-ground (3PH) and single-line-to-ground (SLG) short-circuit duties. Generation and transformer data represented in the generator and transformer data sheets provided by the customers were utilized. Bus locations where short-circuit duty is increased with the inclusion of all QC7 projects by at least 0.1 kA and the duty is in excess of 60% of the minimum breaker nameplate rating are flagged for further review. Upon completion of the detailed circuit breaker review, circuit breakers exposed to fault currents in excess of 100 percent of their interrupting capacities will need to be replaced or upgraded, whichever is appropriate. Cost for breaker upgrades or replacements will be allocated to QC7 projects if the study identifies QC7 as the triggering entity. It is important to note that costs for upgrades triggered by queued ahead projects may ultimately be allocated if the triggering entity ultimately withdraws and the need for the upgrades is still required and triggered by QC7 following any such withdrawals.

In addition to the application queue short-circuit duty study, an operational short-circuit duty study is performed, as required, as a means to identify timing of any identified circuit breaker upgrades or replacements. The operational studies will involve short-circuit duty review of the following scenarios:

- Years 2015/2016, 2017, and 2018 with inclusion of all new generation projects that have an executed interconnection agreement and which are scheduled to be in-service during those timeframes;

- All other generation projects will be modeled as energy only under a 2019 base case. Any identified distribution and network upgrade needed to enable physical energy-only interconnection and allow flow of energy to reach the CAISO point of delivery will also be assumed to be in place as part of this scenario;

- A final short-circuit duty review will be performed which adds all network upgrades identified to be triggered for Full Capacity Deliverability Status (FCDS) and which are not yet under development or which will be placed into service after year 2019.

The short circuit studies also identified substations within the subtransmission where the QC7 Phase II projects increased the substation ground grid duty by 0.25 kA or more.

4. Power Flow Results

4.1 Maximum Generation Coupled with Minimum Load Conditions

Based on the assumptions listed above, the addition of the QC7 Phase II project did not trigger any base case or single contingency subtransmission overloads under maximum generation with minimum load study conditions.

4.2 Maximum Energy Storage Coupled with Minimum Local Subtransmission Generation Conditions

No QC7 projects in this system involve energy storage. As such, there is no identified subtransmission assessment mitigation.

4.3 Power Flow Study Observations, Notes, and Restriction to Energy Storage

(a) Metro Bulk Area Export Limits
Please refer to the Metro Bulk Area Report Section for impacts on the CAISO controlled system.

(b) N-1-1 Outages
Loss of two A-Banks is beyond planning criteria. However, under such conditions, the ability to continue to operate will depend on real-time operating conditions. It is important to note that under such potential conditions, curtailment of generation output will be implemented under real-time operation of the system, if required, in advance of the second outage to ensure potential overload is properly mitigated. Because all interconnection agreements contain a provision to enable such generation curtailment, no additional physical upgrades were identified to be required under such outage conditions.

(c) Energy Storage
No energy storage projects in this section.

4.4 Subtransmission Assessment Mitigations

(a) Maximum Generation Coupled with Minimum Load Conditions

There were no impacts identified to the Barre AB Subtransmission System that would necessitate mitigation.

(b) Maximum Energy Storage Coupled with Minimum Local Subtransmission Generation Conditions

There were no QC7 Projects in this system that involved energy storage.

5. Post Transient Voltage Stability Assessment Results

Review of the power flow study results identified that no voltage deviation exceeded the criteria discussed above. As a result, no further post-transient voltage stability analysis was performed. Please refer to the Metro Bulk Area Report for the post-transient analysis performed on the bulk system.

6. Short Circuit Duty Results

6.1 Application Queue

The application queue three-phase-to-ground and single-phase-to-ground fault currents for the Barre 66 kV AB Subtransmission System are shown below in Table 6.1.1 and Table 6.1.2, respectively.

Table 6.1.1
Application Queue Three-Phase-To-Ground Short-Circuit Duty Results
Barre Subtransmission System

Bus Name	Bus kV	Pre-Case			Post-Case			Delta kA
		X/R	kA	Eff kA	X/R	kA	Eff kA	
Apollo (D)	66	8.8	12.7	12.7	8.1	14	14.0	1.3
Barre (D)	66	50.4	26.0	32.5	53.5	32.3	40.7	8.2
Bolsa (D)	66	6.9	11.2	11.2	6.4	12.2	12.2	1.0
Ely (D)	66	9.5	15.3	15.3	8.6	17.2	17.2	1.9
Fullerton (D)	66	6.2	13.2	13.2	5.7	14.6	14.6	1.4
Gilbert (D)	66	5.8	11.1	11.1	5.4	12.1	12.1	1.0
Kinder (C)	66	4.4	7.7	7.7	4.2	8.2	8.2	0.5
La Palma (D)	66	12.6	17.0	17.9	11.5	19.5	20.5	2.6
Lampson (D)	66	4.8	9.9	9.9	4.5	10.7	10.7	0.8
Marion (D)	66	12.2	16.3	17.1	11.1	17.6	18.5	1.4
Peaker (D)	66	23.7	25.0	27.5	21.0	30.7	32.8	5.3
Shawnee (D)	66	12.2	15.6	15.6	11.1	17.6	17.6	2.0
Sunnyhills (C)	66	5.7	9.3	9.3	5.3	10.0	10.0	0.7
Team (D)	66	7.4	10.8	10.8	6.9	11.7	11.7	0.9
Trask (D)	66	14.9	18.2	18.2	13.5	21.1	21.1	2.9

Table 6.1.2
End-of-Queue Single-Phase-To-Ground Short-Circuit Duty Results
Barre Subtransmission System

Bus Name	Bus kV	Pre-Case			Post-Case			Delta kA
		X/R	kA	Eff kA	X/R	kA	Eff kA	
Apollo (D)	66	8.7	9.5	9.5	8.1	10.2	10.2	0.7
Barre (D)	66	40.5	23.5	28.4	34.2	33.2	39.2	10.8
Bolsa (D)	66	7.8	10.0	10.0	7.3	10.7	10.7	0.7
Ely (D)	66	10.3	10.7	11.1	9.2	12.0	12.5	1.4
Fullerton (D)	66	6.9	8.1	8.1	6.3	9.0	9.0	0.9
Gilbert (D)	66	6.6	6.8	6.8	6.1	7.3	7.3	0.5
Kinder (C)	66	4.8	4.8	4.8	4.6	5.1	5.1	0.3
La Palma (D)	66	10.4	11.2	11.6	9.3	12.9	13.4	1.8
Lampson (D)	66	5.1	6.3	6.3	4.7	6.8	6.8	0.5
Marion (D)	66	10.7	11.4	12.0	9.5	13.1	13.8	1.8
Peaker (D)	66	21.4	22.8	24.4	15.2	31.7	31.7	7.3
Shawnee (D)	66	10.6	11.6	11.6	9.6	13.0	13.0	1.4
Sunnyhills (C)	66	6.5	5.4	5.4	6.1	5.8	5.8	0.4
Team (D)	66	6.8	7.6	7.6	6.4	8.1	8.1	0.5
Trask (D)	66	13.3	15.6	15.6	11.7	17.9	17.9	2.3

The QC7 Phase II breaker evaluations identified that the inclusion of QC7 projects triggers the need for SCD mitigation at the Barre 66 kV. The corresponding mitigation is shown in the Metro Area Bulk Report. Project cost allocations are shown in Appendix G of the Metro Area Bulk Report.

6.2 Sensitivity Study – Define Projects that Drive Need for SCD Mitigation at Barre 66 kV

A sensitivity study was performed to properly identify the QC7 Phase II project(s) which materially drive the need for the Barre 66 kV breaker upgrades. The sensitivity study considered two additional scenarios beyond Application Queue analysis. The first scenario modeled every QC7 Phase II project except for those projects seeking interconnection to distribution facilities served out of the Barre 66 kV Subtransmission System. The second scenario modeled those QC7 Phase II projects seeking interconnection to distribution facilities served out of the Barre 66 kV Subtransmission System without the rest of the QC7 Phase II projects.

6.2.1 Scenario 1: QC7 Phase II Projects External to Barre 66 kV System excluding QC7 Phase II Projects Internal to Barre 66 kV System

The three-phase-to-ground and single-phase-to-ground fault currents for the Barre 66 kV Subtransmission System under Scenario 1 resulted in no identified substations within the Barre System where SCD contribution was increased by at least 0.1 kA where the resulting SCD required a need for short-circuit duty mitigation. Such findings result in the conclusion that the need for circuit breaker upgrades internal to the Barre 66 kV Subtransmission System are completely driven by the addition of QC7 Projects seeking interconnection to distribution served by the Barre 66 kV Subtransmission System.

6.2.2 Scenario 2: QC7 Phase II Projects Internal to Barre 66 kV System excluding QC7 Phase II Projects External to Barre 66 kV System

The three-phase-to-ground and single-phase-to-ground fault currents for the Barre 66 kV Subtransmission System under Scenario 2 are shown below in Table 6.2.1.1 and Table 6.2.1.2, respectively.

Table 6.2.2.1
Three-Phase-To-Ground Short-Circuit Duty Results
QC7 Phase II Projects Excluding QC7 Phase II Projects External to Barre 66 kV System

Bus Name	Bus kV	Pre-Case			Post-Case			Delta kA
		X/R	kA	Eff kA	X/R	kA	Eff kA	
Apollo (D)	66	8.8	12.7	12.7	8.1	14.0	14.0	1.3
Barre (D)	66	50.4	26.0	32.5	53.5	32.2	40.6	8.1
Bolsa (D)	66	6.9	11.2	11.2	6.4	12.2	12.2	1.0
Ely (D)	66	9.5	15.3	15.3	8.6	17.2	17.2	1.9
Fullerton (D)	66	6.2	13.2	13.2	5.7	14.6	14.6	1.4
Gilbert (D)	66	5.8	11.1	11.1	5.4	12.1	12.1	1.0
Kinder (C)	66	4.4	7.7	7.7	4.2	8.2	8.2	0.5
La Palma (D)	66	12.6	17.0	17.9	11.5	19.5	20.5	2.6
Lampson (D)	66	4.8	9.9	9.9	4.5	10.7	10.7	0.8
Marion (D)	66	12.2	16.3	17.1	11.1	17.6	18.5	1.4
Peaker (D)	66	23.7	25.0	27.5	21.0	30.7	32.8	5.3
Shawnee (D)	66	12.2	15.6	15.6	11.1	17.6	17.6	2.0
Sunnyhills (C)	66	5.7	9.3	9.3	5.3	10.0	10.0	0.7
Team (D)	66	7.4	10.8	10.8	6.9	11.7	11.7	0.9
Trask (D)	66	14.9	18.2	18.2	13.5	21.1	21.1	2.9

Table 6.2.2.2
Single-Phase-To-Ground Short-Circuit Duty Results
QC7 Phase II Projects Excluding QC7 Phase II Projects External to Barre 66 kV System

Bus Name	Bus kV	Pre-Case			Post-Case			Delta kA
		X/R	kA	Eff kA	X/R	kA	Eff kA	
Apollo (D)	66	8.7	9.5	9.5	8.1	14.0	14	4.5
Barre (D)	66	40.5	23.5	28.4	53.5	32.3	40.7	12.3
Bolsa (D)	66	7.8	10.0	10.0	6.4	12.2	12.2	2.2
Ely (D)	66	10.3	10.7	11.1	8.6	17.2	17.9	6.8
Fullerton (D)	66	6.9	8.1	8.1	5.7	14.6	14.6	6.5
Gilbert (D)	66	6.6	6.8	6.8	5.4	12.1	12.0	5.2
Kinder (C)	66	4.8	4.8	4.8	4.2	8.2	8.2	3.4
La Palma (D)	66	10.4	11.2	11.6	11.5	19.5	20.2	8.6
Lampson (D)	66	5.1	6.3	6.3	4.5	10.7	10.7	4.4
Marion (D)	66	10.7	11.4	12.0	11.1	17.6	18.5	6.5
Peaker (D)	66	21.4	22.8	24.4	21.0	30.7	32.8	8.4
Shawnee (D)	66	10.6	11.6	11.6	11.1	17.6	17.6	6.0
Sunnyhills (C)	66	6.5	5.4	5.4	5.3	10.0	10.0	4.6
Team (D)	66	6.8	7.6	7.6	6.9	11.7	11.7	4.1
Trask (D)	66	13.3	15.6	15.6	13.5	21.1	21.1	5.5

Based on the study results, the inclusion of all application queue projects, except the eighteen QC7 Phase II projects external to the Barre 66 Subtransmission System, resulted in a need for breaker upgrades at the 66 kV voltage level. Such a conclusion indicates that the single project seeking interconnection to distribution facilities served out of the Barre 66 Subtransmission System drives the need for the circuit breaker upgrades at Barre 66 kV identified in the Metro Area Group Report.

6.3 Operational Study

Based on the conclusion that the need for Barre 66 kV breaker upgrades is directly linked to the development of the single project seeking interconnection to distribution facilities served out of the Barre 66 Subtransmission System, an operational study was performed to determine timing of need for such circuit breaker upgrades. The operational study evaluated the impacts associated with the incremental addition of generation units from the single project seeking interconnection to distribution facilities served out of the Barre 66 Subtransmission System.

6.3.1 Addition of one unit from WDT1189

The operational three-phase-to-ground and single-phase-to-ground fault currents for the Barre 66 kV Subtransmission System with the addition of only one unit from WDT1189 are shown below in Table 6.2.3.1 and Table 6.2.3.2 respectively.

Table 6.3.1.1
Three-Phase-To-Ground Short-Circuit Duty Results
QC7 Phase II Projects Excluding QC7 Phase II Projects External to Barre 66 kV System

Bus Name	Bus kV	Pre-Case			Post-Case			Delta kA
		X/R	kA	Eff kA	X/R	kA	Eff kA	
Apollo (D)	66	8.8	12.7	12.7	8.5	13.3	13.3	0.6
Barre (D)	66	50.4	26.0	32.5	54.0	28.8	36.6	4.1
Bolsa (D)	66	6.9	11.2	11.2	6.7	11.7	11.7	0.5
Ely (D)	66	9.5	15.3	15.3	9.1	16.2	16.2	0.9
Fullerton (D)	66	6.2	13.2	13.2	6.0	13.9	13.9	0.7
Gilbert (D)	66	5.8	11.1	11.1	5.6	11.6	11.6	0.5
Kinder (C)	66	4.4	7.7	7.7	4.3	8.0	8.0	0.3
La Palma (D)	66	12.6	17.0	17.9	12.1	18.1	19.0	1.1
Lampson (D)	66	4.8	9.9	9.9	4.6	10.3	10.3	0.4
Marion (D)	66	12.2	16.3	17.1	11.8	17.3	18.2	1.1
Peaker (D)	66	23.7	25.0	27.5	22.8	27.5	30.0	2.5
Shawnee (D)	66	12.2	15.6	15.6	11.7	16.5	16.5	0.9
Sunnyhills (C)	66	5.7	9.3	9.3	5.5	9.7	9.7	0.4
Team (D)	66	7.4	10.8	10.8	7.2	11.3	11.3	0.5
Trask (D)	66	14.9	18.2	18.2	14.3	19.5	19.5	1.3

Table 6.3.1.2
Single-Phase-To-Ground Short-Circuit Duty Results
QC7 Phase II Projects Excluding QC7 Phase II Projects External to Barre 66 kV System

Bus Name	Bus kV	Pre-Case			Post-Case			Delta kA
		X/R	kA	Eff kA	X/R	kA	Eff kA	
Apollo (D)	66	8.7	9.5	9.5	8.2	10.0	10.0	0.5
Barre (D)	66	40.5	23.5	28.4	35.3	30.7	36.2	7.8
Bolsa (D)	66	7.8	10.0	10.0	7.5	10.4	10.4	0.4
Ely (D)	66	10.3	10.7	11.1	9.5	11.6	12.1	1.0
Fullerton (D)	66	6.9	8.1	8.1	6.4	8.8	8.8	0.7
Gilbert (D)	66	6.6	6.8	6.8	6.2	7.2	7.2	0.4
Kinder (C)	66	4.8	4.8	4.8	4.6	5.0	5.0	0.2
La Palma (D)	66	10.4	11.2	11.6	9.5	12.5	13.0	1.4
Lampson (D)	66	5.1	6.3	6.3	4.8	6.7	6.7	0.4
Marion (D)	66	10.7	11.4	12.0	9.7	12.7	13.3	1.3
Peaker (D)	66	21.4	22.8	24.4	16.2	29.4	29.7	5.3
Shawnee (D)	66	10.6	11.6	11.6	9.9	12.6	12.6	1.0
Sunnyhills (C)	66	6.5	5.4	5.4	6.2	5.7	5.7	0.3
Team (D)	66	6.8	7.6	7.6	6.5	8.0	8.0	0.4
Trask (D)	66	13.3	15.6	15.6	12.2	17.1	17.1	1.5

Results corresponding to the addition of one unit from WDT1189 indicates that short-circuit duty values at Barre increase beyond duty capability of a number of existing circuit breakers. Such results conclude that the breaker upgrades at the Barre 66 kV need to be in place prior to allowing synchronization of the first unit from WDT1189.

6.3.2 Addition of two units from WDT1189

The operational three-phase-to-ground and single-phase-to-ground fault currents for the Barre 66 kV Subtransmission System, with the addition of two units from WDT1189, are shown below in Table 6.2.3.1 and Table 6.2.3.2, respectively.

Table 6.3.2.1
Three-Phase-To-Ground Short-Circuit Duty Results
QC7 Phase II Projects Excluding QC7 Phase II Projects External to Barre 66 kV System

Bus Name	Bus kV	Pre-Case			Post-Case			Delta kA
		X/R	kA	Eff kA	X/R	kA	Eff kA	
Apollo (D)	66	8.8	12.7	12.7	8.3	13.7	13.7	1.0
Barre (D)	66	50.4	26.0	32.5	54.3	30.8	39.1	6.6
Bolsa (D)	66	6.9	11.2	11.2	6.5	12.0	12.0	0.8
Ely (D)	66	9.5	15.3	15.3	8.8	16.8	16.8	1.5
Fullerton (D)	66	6.2	13.2	13.2	5.8	14.3	14.3	1.1
Gilbert (D)	66	5.8	11.1	11.1	5.5	11.9	11.9	0.8
Kinder (C)	66	4.4	7.7	7.7	4.3	8.1	8.1	0.4
La Palma (D)	66	12.6	17.0	17.9	11.8	18.9	19.8	1.9
Lampson (D)	66	4.8	9.9	9.9	4.5	10.5	10.5	0.6
Marion (D)	66	12.2	16.3	17.1	11.4	17.2	18.1	1.0
Peaker (D)	66	23.7	25	27.5	21.9	29.3	31.6	4.1
Shawnee (D)	66	12.2	15.6	15.6	11.4	17.2	17.2	1.6
Sunnyhills (C)	66	5.7	9.3	9.3	5.4	9.9	9.9	0.6
Team (D)	66	7.4	10.8	10.8	7.0	11.5	11.5	0.7
Trask (D)	66	14.9	18.2	18.2	13.8	20.4	20.4	2.2

Table 6.3.2.2
Single-Phase-To-Ground Short-Circuit Duty Results
QC7 Phase II Projects Excluding QC7 Phase II Projects External to Barre 66 kV System

Bus Name	Bus kV	Pre-Case			Post-Case			Delta kA
		X/R	kA	Eff kA	X/R	kA	Eff kA	
Apollo (D)	66	8.7	9.5	9.5	8.1	10.1	10.1	0.6
Barre (D)	66	40.5	23.5	28.4	34.8	32.2	38.0	9.6
Bolsa (D)	66	7.8	10.0	10.0	7.4	10.6	10.6	0.6
Ely (D)	66	10.3	10.7	11.1	9.3	11.8	12.3	1.2
Fullerton (D)	66	6.9	8.1	8.1	6.3	8.9	8.9	0.8
Gilbert (D)	66	6.6	6.8	6.8	6.1	7.3	7.3	0.5
Kinder (C)	66	4.8	4.8	4.8	4.6	5.1	5.1	0.3
La Palma (D)	66	10.4	11.2	11.6	9.4	12.7	13.2	1.6
Lampson (D)	66	5.1	6.3	6.3	4.7	6.8	6.8	0.5
Marion (D)	66	10.7	11.4	12.0	9.6	12.9	13.5	1.5
Peaker (D)	66	21.4	22.8	24.4	15.6	30.7	30.7	6.3
Shawnee (D)	66	10.6	11.6	11.6	9.7	12.8	12.8	1.2
Sunnyhills (C)	66	6.5	5.4	5.4	6.1	5.7	5.7	0.3
Team (D)	66	6.8	7.6	7.6	6.5	8.1	8.1	0.5
Trask (D)	66	13.3	15.6	15.6	11.9	17.6	17.6	2.0

Results corresponding to the addition of two units from WDT1189 are for informational purposes only as circuit breaker upgrades at Barre are required to be in place prior to allowing synchronization of the first unit from WDT1189.

6.4 Ground Grid Evaluation

As shown above in Table 6.1.2, the addition of the QC7 Phase II projects seeking interconnection to distribution facilities served out of the Barre 66 kV Subtransmission System were found to significantly increase single line-to-ground short circuit duty. The study identified the following SCE Substations served out of the Barre System where the single line-to-ground fault contribution from the QC7 projects increased duty in excess of 0.25 kA and exceeded the currently documented ground grid single line-to-ground short circuit duty value (excludes Ely and Johanna as current documentation indicates no issues).

- Apollo
- Barre
- Bolsa
- Fullerton
- Gilbert
- Kinder
- La Palma
- Lampson
- Marion
- Shawnee
- Sunnyhills
- Team
- Trask

These locations will require a detailed ground grid analysis to be performed in support of projects seeking interconnection to distribution facilities served out of the Barre 66 kV Subtransmission System. The approximate one-time cost for such study is $35k per substation. These costs will be allocated to the generation projects identified to significantly increase SCD contributions and are identified in the appropriate Appendix A.

7. Scope of Subtransmission Level Distribution Upgrades

Please refer to the Attachment 1 of the applicable Appendix A report for the scope of any subtransmission upgrades.

8. Network Constraints

Please refer to the Metro Bulk Area Report for information pertaining to any network related constraints.

Queue Cluster 7 Phase II – Appendix B

SCE Metro Area - System Assumptions

Appendix B: System Assumptions

1. Generation Assumption Tables

Generation assumptions for SCE's Metro System are shown in Table 1.1 (Existing Generation), Table 1.2 Pre Queue Cluster 1 and 2 Phase II SGIP projects (Pre QC1&2 Phase II SGIPs), Table 1.3 Pre QC3&4 Phase II projects (Pre QC3&4 Phase II SGIPs), Table 1.4 Queue Cluster 3 and 4 Phase II projects (QC3&4 Phase II), Table 1.5 Queue Cluster 5 Phase II projects (QC5 Phase II), Table 1.6A Queue Cluster 6 Phase II projects (QC6 Phase II), Table 1.6B Queue Cluster 6 Phase II projects (Deliverability Only) for projects studied for interconnection under Independent Study Process and for deliverability in Cluster 6 , and Table 1.7 summarizes the Rule 21 projects in the area.

Table 1.1: Existing Generation

Locations	Type	Size (MW)
Alamitos	Steam	1902.86
Anaheim	Simple Cycle-GT	50
Barre Peaker	Simple Cycle-GT	47.0
Broadway	Steam	65
Center Peaker	Simple cycle-GT	47
Clearwater	Combined Cycle	28
Chevmain	Other	76
El Segundo	Steam	544
Etiwanda	Steam	640
Etiwanda Peaker	Simple Cycle-GT	46
Harbor Cogen	Other	110
Huntington Beach	Steam	498.97
Inland Empire Energy Center	Combined Cycle	810
Long Beach	Simple Cycle-GT	224
Malburg	Combined Cycle	134.1
MiraLoma Peaker	Simple Cycle-GT	46.0
Redondo	Steam	475.7
Walnut Creek Energy Park	Simple Cycle - GT	500.5
	Total (Existing)	**6,245.13**

Appendix B: System Assumptions

Table 1.2: Pre QC1&2 Phase II SGIPs Interconnection Request

#	CAISO Queue #	SCE Project ID	Interconnection Point	Size (MW)
1	WDAT	WDT426	Mosquito (Chino) 12 kV	1.5
2	WDT	WDT240	Brea Power II-Olinda Alpha Landf (Olinda 230/66 kV)	18.4
3	WDT	WDT268	Brea Power II - 9MW Increase (Olinda 230/66 kV)	9.0
4	WDT	WDT125	CSDLA Puente Hills 2 (Rio Hondo 230/66 kV)	8.0
5	WDT	WDT292	Bowerman Landfill (Santiago 230/66 kV)	19.6
			Total	**56.5**

Table 1.3: Pre QC3&4 Phase II SGIPs Interconnection Requests

#	CAISO QUEUE #	SCE Project ID	Interconnection Point	Size (MW)
1	WDAT	WDT473	Earnhardt (Padua) 12 kV	1.75
2	WDAT	WDT482	Orchardale (Del Amo) 12 kV	1.33
3	WDAT	WDT483	Loftus (Del Amo) 12 kV	1.25
4	WDAT	WDT484	Loftus (Del Amo) 12 kV	1.5
5	WDAT	WDT485	Loftus (Del Amo) 12 kV	1
6	WDAT	WDT486	Orchardale (Del Amo) 12 kV	1.75
			Total	**8.58**

Table 1.4: QC3&4 Phase II Interconnection Request

#	CAISO QUEUE #	SCE Project ID	Interconnection Point	Size (MW)
1	702	TOT560	El Segundo 220 kV	435
			Total	**435**

Appendix B: System Assumptions

Table 1.5: QC5 Phase II Interconnection Request

#	CAISO QUEUE #	SCE Project ID	Interconnection Point	Size (MW)
1	893	TOT642	Ellis 220 kV	938.61
			Total	**938.61**

Table 1.6A: QC6 Phase II Interconnection Requests

#	CAISO QUEUE #	SCE Project ID	Interconnection Point	Size (MW)
1	960	TOT665	Ellis 220 kV	59.33
2	990	TOT663	Looping the Center-Mesa & Center Olinda 220 kV T/Ls	910
			Total	**969.33**

Table 1.6B: QC6 Phase II Interconnection Requests (Deliverability Only)

#	SCE QUEUE #	SCE Project ID	Interconnection Point	Size (MW)
1	WDT1003ISP	WDT1003	Brea 66 kV Substation (Olinda 230/66 kV)	5.0
			Total	**5.0**

Appendix B: System Assumptions

Table 1.7: Rule 21 Interconnection Requests

#	CAISO QUEUE #	SCE Project ID	System	Size (MW)
1	Rule 21	GFID	Alamitos 220/66 kV	6.25
2	Rule 21	GFID	Barre 220/66 kV	9.62
3	Rule 21	GFID	Center 220/66 kV	14.4
4	Rule 21	GFID	Chino 220/66 kV	2.65
5	Rule 21	GFID	Del Amo 220/66 kV	5.78
6	Rule 21	GFID	Ellis 220/66 kV	4.26
7	Rule 21	GFID	El Nido 230/66 kV	35.75
8	Rule 21	GFID	Hinson 220/66 kV	1.37
9	Rule 21	GFID	La Cienega 220/66 kV	5.9
10	Rule 21	GFID	La Fresa 220/66 kV	3.6
11	Rule 21	GFID	Laguna Bell 230/66 kV	0.87
12	Rule 21	GFID	Lighthipe 220/66 kV	7.6
13	Rule 21	GFID	Mesa 230/66 kV	0.2
14	Rule 21	GFID	Mira Loma 220/66 kV	23.4
15	Rule 21	GFID	Padua 220/66 kV	1.44
16	Rule 21	GFID	Santiago 220/66 kV	13.38
17	Rule 21	GFID	Walnut 220/66 kV	3.1
18	Rule 21	GFID	Walnut 220/66 kV	3.4
			Total	**142.97**

2. Modeling and Dispatch Assumptions

In the on-peak and off-peak Reliability Assessments, generation dispatch assumptions were developed with the goal of stressing the transmission facilities that will ultimately deliver the output of the QC7 projects into the load centers of Orange County. In order for the output of the QC7 projects (located mostly in Orange County) to fully stress the impacted transmission lines, the LA basin generation was redispatched. The capacities of coastal generators that utilize Once-Through Cooling (OTC) were chosen to be reduced in anticipation of future restrictions that may be placed on these generators. This dispatch allowed for the proper reliability assessment of existing transmission facilities in the vicinity of the proposed QC7 project locations.

Appendix B: System Assumptions

3. Deliverability Study

Commented [MS1]: Updated table from CAISO's Table B.1 in QC7-P2 Metro Area Deliverability report

Table B-1: On-Peak Deliverability Assessment Import Target

Branch Group Name	Direction	Net Import MW	Import Unused ETC & TOR MW
Lugo-Victorville_BG	N-S	1,237	3
COI_BG	N-S	3,770	548
BLYTHE_BG	E-W	68	0
CASCADE_BG	N-S	80	0
CFE_BG	S-N	-169	0
ELDORADO_MSL	E-W	838	0
IID-SCE_BG	E-W	702	0
IID-SDGE_BG	E-W		
LAUGHLIN_BG	E-W	-44	0
MCCULLGH_MSL	E-W	0	316
MEAD_MSL	E-W	952	428
NGILABK4_BG	E-W	-114	168
NOB_BG	N-S	1,544	0
PALOVRDE_MSL	E-W	2,514	185
PARKER_BG	E-W	113	19
SILVERPK_BG	E-W	6	0
SUMMIT_BG	E-W	25	0
SYLMAR-AC_MSL	E-W	225	342
Total		11,707	2,009

QC7 Phase II Metro Bulk Area .otg
#
Contingency Selection Criteria: From area 24; zone 0 to 999; 200 kV to 999 kV
#
#Category P1
#The purpose of Generation Interconnection Process (GIP) studies are to evaluate stressed generation conditions on the system.
#Because Category P1.1 would not provide for such stressed conditions, the study results would not properly identify potential
#impacts corresponding to the projects seeking interconnection.
#As such, Category P1.1 was not evaluated as part of the GIP studies but is addressed as part of SCE's Annual Expansion Studies
#performed in coordination with the CAISO.
#
#Category P1.2 Fault with loss of one Transmission Circuit
#

```
line_1201                "Line MIRALOMA    500.0 to SERRANO     500.0 Circuit 1"   1.000
 line "MIRALOMA    500.00"  "SERRANO     500.00"  "1 "  1 0
0
line_1202                "Line MIRALOMA    500.0 to SERRANO     500.0 Circuit 2"   1.000
 line "MIRALOMA    500.00"  "SERRANO     500.00"  "2 "  1 0
0
line_1203                "Line RANCHVST    500.0 to SERRANO     500.0 Circuit 1"   1.000
 line "RANCHVST    500.00"  "MIRA81X2    500.00"  "1 "  1 0
 line "MIRA81X2    500.00"  "SERRANO     500.00"  "1 "  1 0
0
line_1204                "Line MIRALOMA    500.0 to MESA CAL    500.0 Circuit 1"   1.000
 line "MIRALOMA    500.00"  "EAST TS     500.00"  "1 "  1 0
 line "EAST TS     500.00"  "WEST TS     500.00"  "1 "  1 0
 line "WEST TS     500.00"  "MESA CAL    500.00"  "1 "  1 0
0
line_1205                "Line ALBERHIL    500.0 to SERRANO     500.0 Circuit 1"   1.000
 line "ALBERHIL    500.00"  "SERRANO     500.00"  "1 "  1 0
0
line_1206                "Line BARRE       230.0 to ELLIS       230.0 Circuit 1"   1.000
 line "BARRE       230.00"  "ELLIS       230.00"  "1 "  1 0
0
line_1207                "Line BARRE       230.0 to ELLIS       230.0 Circuit 2"   1.000
 line "BARRE       230.00"  "ELLIS       230.00"  "2 "  1 0
0
line_1208                "Line BARRE       230.0 to ELLIS       230.0 Circuit 3"   1.000
 line "BARRE       230.00"  "ELLIS       230.00"  "3 "  1 0
0
line_1209                "Line BARRE       230.0 to ELLIS       230.0 Circuit 4"   1.000
 line "BARRE       230.00"  "ELLIS       230.00"  "4 "  1 0
0
line_1210                "Line ELLIS       230.0 to HUNTGBCH    230.0 Circuit 1"   1.000
 line "ELLIS       230.00"  "HUNTGBCH    230.00"  "1 "  1 0
0
line_1211                "Line ELLIS       230.0 to HUNTGBCH    230.0 Circuit 3"   1.000
 line "ELLIS       230.00"  "HUNTGBCH    230.00"  "3 "  1 0
0
line_1212                "Line ELLIS       230.0 to HUNTBCH1    230.0 Circuit 2"   1.000
 line "ELLIS       230.00"  "HUNTBCH1    230.00"  "2 "  1 0
0
line_1213                "Line ELLIS       230.0 to HUNTBCH1    230.0 Circuit 4"   1.000
 line "ELLIS       230.00"  "HUNTBCH1    230.00"  "4 "  1 0
0
line_1214                "Line ELLIS       230.0 to JOHANNA     230.0 Circuit 1"   1.000
 line "ELLIS       230.00"  "JOHANNA     230.00"  "1 "  1 0
0
line_1215                "Line ELLIS       230.0 to SANTIAGO    230.0 Circuit 1"   1.000
 line "ELLIS       230.00"  "SANTIAGO    230.00"  "1 "  1 0
0
line_1216                "Line JOHANNA     230.0 to SANTIAGO    230.0 Circuit 1"   1.000
 line "JOHANNA     230.00"  "SANTIAGO    230.00"  "1 "  1 0
0
line_1217                "Line S.ONOFRE    230.0 to SANTIAGO    230.0 Circuit 1"   1.000
```

line "S.ONOFRE 230.00" "SANTIAGO 230.00" "1 " 1 0
0
line_1218 "Line S.ONOFRE 230.0 to SANTIAGO 230.0 Circuit 2" 1.000
line "S.ONOFRE 230.00" "SANTIAGO 230.00" "2 " 1 0
0
line_1219 "Line S.ONOFRE 230.0 to SERRANO 230.0 Circuit 1" 1.000
line "S.ONOFRE 230.00" "SERRANO 230.00" "1 " 1 0
0
line_1220 "Line VIEJOSC 230.0 to S.ONOFRE 230.0 Circuit 1" 1.000
line "VIEJOSC 230.00" "S.ONOFRE 230.00" "1 " 1 0
0
line_1221 "Line VIEJOSC 230.0 to CHINO 230.0 Circuit 1" 1.000
line "VIEJOSC 230.00" "CHINO 230.00" "1 " 1 0
0
line_1222 "Line CHINO 230.0 to SERRANO 230.0 Circuit 1" 1.000
line "CHINO 230.00" "SERRANO 230.00" "1 " 1 0
0
line_1223 "Line SERRANO 230.0 to VILLA PK 230.0 Circuit 1" 1.000
line "SERRANO 230.00" "VILLA PK 230.00" "1 " 1 0
0
line_1224 "Line SERRANO 230.0 to VILLA PK 230.0 Circuit 2" 1.000
line "SERRANO 230.00" "VILLA PK 230.00" "2 " 1 0
0
line_1225 "Line LEWIS 230.0 to SERRANO 230.0 Circuit 1" 1.000
line "LEWIS 230.00" "SERRANO 230.00" "1 " 1 0
0
line_1226 "Line LEWIS 230.0 to SERRANO 230.0 Circuit 2" 1.000
line "LEWIS 230.00" "SERRANO 230.00" "2 " 1 0
0
line_1227 "Line LEWIS 230.0 to VILLA PK 230.0 Circuit 1" 1.000
line "LEWIS 230.00" "VILLA PK 230.00" "1 " 1 0
0
line_1228 "Line BARRE 230.0 to VILLA PK 230.0 Circuit 1" 1.000
line "BARRE 230.00" "VILLA PK 230.00" "1 " 1 0
0
line_1229 "Line BARRE 230.0 to LEWIS 230.0 Circuit 1" 1.000
line "BARRE 230.00" "LEWIS 230.00" "1 " 1 0
0
line_1230 "Line ALMITOSE 230.0 to BARRE 230.0 Circuit 1" 1.000
line "ALMITOSE 230.00" "BARRE 230.00" "1 " 1 0
0
line_1231 "Line ALMITOSW 230.0 to BARRE 230.0 Circuit 2" 1.000
line "ALMITOSW 230.00" "BARRE 230.00" "2 " 1 0
0
line_1232 "Line DELAMO 230.0 to BARRE 230.0 Circuit 1" 1.000
line "DELAMO 230.00" "BARRE 230.00" "1 " 1 0
0
line_1233 "Line ALMITOSW 230.0 to LITEHIPE 230.0 Circuit 1" 1.000
line "ALMITOSW 230.00" "LITEHIPE 230.00" "1 " 1 0
0
line_1234 "Line ALMITOSE 230.0 to CENTER S 230.0 Circuit 1" 1.000
line "ALMITOSE 230.00" "CENTER S 230.00" "1 " 1 0
0
line_1235 "Line DELAMO 230.0 to CENTER S 230.0 Circuit 1" 1.000
line "DELAMO 230.00" "CENTER S 230.00" "1 " 1 0
0
line_1236 "Line HINSON 230.0 to DELAMO 230.0 Circuit 1" 1.000
line "HINSON 230.00" "DELAMO 230.00" "1 " 1 0
0
line_1237 "Line DELAMO 230.0 to LAGUBELL 230.0 Circuit 1" 1.000
line "DELAMO 230.00" "LAGUBELL 230.00" "1 " 1 0
0
line_1238 "Line LITEHIPE 230.0 to MESA CAL 230.0 Circuit 1" 1.000
line "LITEHIPE 230.00" "MESA CAL 230.00" "1 " 1 0
0

```
line_1239 "Line LA FRESA 230.0 to LAGUBELL 230.0 Circuit 1" 1.000
 line "LA FRESA 230.00" "LAGUBELL 230.00" "1 " 1 0
0
line_1240 "Line MESA CAL 230.0 to REDONDO 230.0 Circuit 1" 1.000
 line "MESA CAL 230.00" "REDONDO 230.00" "1 " 1 0
0
line_1241 "Line LAGUBELL 230.0 to MESA CAL 230.0 Circuit 1" 1.000
 line "LAGUBELL 230.00" "MESA CAL 230.00" "1 " 1 0
0
line_1242 "Line LAGUBELL 230.0 to MESACALS 230.0 Circuit 2" 1.000
 line "LAGUBELL 230.00" "MESACALS 230.00" "2 " 1 0
0
line_1243 "Line CENTER S 230.0 to TOT663TAP 230.0 Circuit 1" 1.000
 line "CENTER S 230.00" "TOT663TAP 230.00" "1 " 1 0
0
line_1244 "Line CENTER S 230.0 to TOT663TAP 230.0 Circuit 2" 1.000
 line "CENTER S 230.00" "TOT663TAP 230.00" "2 " 1 0
0
line_1245 "Line TOT663TAP 230.0 to MESA CAL 230.0 Circuit 1" 1.000
 line "TOT663TAP 230.00" "MESA CAL 230.00" "1 " 1 0
0
line_1246 "Line TOT663TAP 230.0 to OLINDA 230.0 Circuit 1" 1.000
 line "TOT663TAP 230.00" "OLINDA 230.00" "1 " 1 0
0
line_1247 "Line MESACALS 230.0 to WALNUT 230.0 Circuit 1" 1.000
 line "MESACALS 230.00" "WALNUT 230.00" "1 " 1 0
0
line_1248 "Line OLINDA 230.0 to WALNUT 230.0 Circuit 1" 1.000
 line "OLINDA 230.00" "WALNUT 230.00" "1 " 1 0
0
line_1249 "Line MIRALOMW 230.0 to WALNUT 230.0 Circuit 1" 1.000
 line "MIRALOMW 230.00" "WALNUT 230.00" "1 " 1 0
0
line_1250 "Line MIRALOME 230.0 to OLINDA 230.0 Circuit 1" 1.000
 line "MIRALOME 230.00" "OLINDA 230.00" "1 " 1 0
0
line_1251 "Line CHINO 230.0 to MIRALOMW 230.0 Circuit 1" 1.000
 line "CHINO 230.00" "MIRALOMW 230.00" "1 " 1 0
0
line_1252 "Line CHINO 230.0 to MIRALOMW 230.0 Circuit 2" 1.000
 line "CHINO 230.00" "MIRALOMW 230.00" "2 " 1 0
0
line_1253 "Line CHINO 230.0 to MIRALOME 230.0 Circuit 3" 1.000
 line "CHINO 230.00" "MIRALOME 230.00" "3 " 1 0
0
#
#Category P1.3 Fault with loss of one transformer
#
tran_1301 "Tran MIRALOMA 500.00 to MIRALOMW 230.00 Circuit 1MIRLOM1T 13.80" 1.000
 tran "MIRALOMA 500.00" "MIRALOMW 230.00" "1 " 0 "MIRLOM1T 13.80"
0
tran_1302 "Tran MIRALOMA 500.00 to MIRALOMW 230.00 Circuit 2MIRLOM2T 13.80" 1.000
 tran "MIRALOMA 500.00" "MIRALOMW 230.00" "2 " 0 "MIRLOM2T 13.80"
0
tran_1303 "Tran MIRALOMA 500.00 to MIRALOME 230.00 Circuit 3MIRLOM3T 13.80" 1.000
 tran "MIRALOMA 500.00" "MIRALOME 230.00" "3 " 0 "MIRLOM3T 13.80"
0
tran_1304 "Tran MIRALOMA 500.00 to MIRALOME 230.00 Circuit 4MIRLOM4T 13.80" 1.000
 tran "MIRALOMA 500.00" "MIRALOME 230.00" "4 " 0 "MIRLOM4T 13.80"
0
tran_1305 "Tran SERRANO 500.00 to SERRANO 230.00 Circuit 1SERRAN1T 13.80" 1.000
 tran "SERRANO 500.00" "SERRANO 230.00" "1 " 0 "SERRAN1T 13.80"
0
tran_1306 "Tran SERRANO 500.00 to SERRANO 230.00 Circuit 2SERRAN2T 13.80" 1.000
 tran "SERRANO 500.00" "SERRANO 230.00" "2 " 0 "SERRAN2T 13.80"
```

```
0
tran_1307             "Tran SERRANO    500.00 to SERRANO    230.00 Circuit 3          0.00"   1.000
 tran "SERRANO    500.00"  "SERRANO    230.00"  "3 "  0 "           0.00"
0
tran_1308             "Tran MESA CAL    500.00 to MESA CAL    230.00 Circuit 2MESA2T      13.80"   1.000
 tran "MESA CAL    500.00"  "MESA CAL    230.00"  "2 "  0 "MESA2T      13.80"
0
tran_1309             "Tran MESA CAL    500.00 to MESACALS    230.00 Circuit 3MESA3T      13.80"   1.000
 tran "MESA CAL    500.00"  "MESACALS    230.00"  "3 "  0 "MESA3T      13.80"
0
tran_1310              "Tran MESA CAL    500.00 to MESACALS    230.00 Circuit 4MESA4T      13.80"   1.000
 tran "MESA CAL    500.00"  "MESACALS    230.00"  "4 "  0 "MESA4T      13.80"
0
#
# Category P.1.4 Fault with the loss of one shunt device
#
lshunt_1401      "Line shunt @ MIRALOMA"
 lshunt "EAST TS    500.00"  "MIRALOMA    500.00"  "t"  1  1  0
0
svd_1402        "SVD MIRALOMA   500.00" 1.000
 svd "MIRALOMA   500.00" "ei" 0
0
svd_1403        "SVD BARRE     230.00" 1.000
 svd "BARRE     230.00" "ei" 0
0
svd_1404        "SVD JOHANNA   230.00" 1.000
 svd "JOHANNA   230.00" "ei" 0
0
svd_1405        "SVD SANTIAGO   230.00" 1.000
 svd "SANTIAGO   230.00" "ei" 0
0
svd_1406        "SVD VIEJOSC   230.00" 1.000
 svd "VIEJOSC   230.00" "ei" 0
0
svd_1407        "SVD VILLA PK   230.00" 1.000
 svd "VILLA PK   230.00" "ei" 0
0
svd_1408        "SVD LAGUBELL   230.00" 1.000
 svd "LAGUBELL   230.00" "ei" 0
0
svd_1409        "SVD MESA CAL   230.00" 1.000
 svd "MESA CAL   230.00" "ei" 0
0
svd_1410        "SVD WALNUT    230.00" 1.000
 svd "WALNUT    230.00" "ei" 0
0
svd_1411        "SVD OLINDA    230.00" 1.000
 svd "OLINDA    230.00" "ei"
0
svd_1412        "SVD CHINO     230.00" 1.000
 svd "CHINO     230.00" "ei" 0
0
svd_1413        "SVD MIRALOME   230.00" 1.000
 svd "MIRALOME   230.00" "ei" 0
0
svd_1414        "SVD MIRALOMW   230.00" 1.000
 svd "MIRALOMW   230.00" "ei" 0
0
# P.1.5 Category P1.5 is not applicable in the Metro Area as no DC lines exist within this area. This category
# was examined as part of the QC7 GIP studies performed for the East of Pisgah Area (Intermountain DC line) and
# Northern Area (Pacific DC Intertie).
#
#
# Category P2s (Single Contingencies)
#
```

```
# Category P2.1: Loss of one transmission line section without a fault
#
# Note: Category P2.1 is not applicable for the Metro Bulk area as there are no multi-segmented bulk transmission lines.
#
# Category P2.2: SLG Fault with loss of one bus section
#
# Note: In the Metro Area, sectionalizing bus ties exist (or will exist) only at Alamitos, Huntington Beach, Mira
# Loma, Mesa (future), San Onofre, Santiago, and Walnut. All Metro Area Substation designs are such that loss of
# one bus section does not result in any additional P2.2 impacts that are not already addressed as part of Category P1.
#
#
# Category P2.3: SLG Fault with loss of one breaker (internal fault) (non-bus-tie-breaker)
#
# Note: All Metro Area Substation designs are such that loss of one breaker (internal fault on non-bus-tie-breaker)
# does not result in any additional P2.3 impacts that are not already addressed as part of Category P1.
#
# Category P2.4: SLG fault with loss of one breaker (internal fault) (bus-tie-breaker)
#
# Note 2: Except for Walnut, the substation design in this area is such that loss of one bus-tie breaker does not
# result in any additional impact that is not already addressed as part of Category P1.
#
bus_2401          "WALNUT NORTH 230 KV BUS" 1.000
 line "MESACALS     230.00"  "WALNUT       230.00"  "1 "  1 0
 tran "WALNUT       230.00"  "WALNUT        66.00"  "3 "  0 "              0.00"
0
bus_2402          "WALNUT SOUTH 230 KV BUS" 1.000
 svd  "WALNUT       230.00" "ei" 0
 tran "WALNUT       230.00"  "WALNUT        66.00"  "4 "  0 "              0.00"
0
#
# Category P3 (Multiple Contingencies)
#
# The assessment will consider selected Category P3 contingencies with the loss of a generator unit followed by system
# adjustments and the loss of the following:
#            3F Fault with loss of one generator (P3.1)
#            3F Fault with loss of one transmission circuit (P3.2)
#            3F Fault with loss of one transformer (P3.3)
#            3F Fault with loss of one shunt device (P3.4)
#            SLG Fault with loss of a single pole of DC lines (P3.5)
#            SLG Fault with loss of both poles of the Pacific DC Intertie (WECC exemption)
#
# Notes:
# The purpose of Generation Interconnection Process (GIP) studies is to evaluate stressed generation conditions on the system.
# Because Category P3 would not provide for such stressed conditions, the study results would not properly identify potential
# impacts corresponding to the projects seeking interconnection. As such, none of Category P3 was evaluated as part of the GIP
# studies but is addressed as part of SCE’s annual reliability assessment performed in coordination with the CAISO.
#
# Category P4 (Multiple Contingencies)
#
# The assessment will consider selected Category P4 contingencies with the loss of multiple elements caused by a stuck breaker
# (non-bus-tie-breaker for P4.1-P4.5 and bus-tie-breaker for P4.6) attempting to clear a SLG fault on one of the following:
#
#P4.1 Generators is not applicable for the Metro Area
#
#
#P4.2 Transmission Circuit
#
bay_4201                        "MESA 500kV POS.5T STUCK CB"
 line "VINCENT      500.00"  "MESA CAL     500.00"  "1 "  1 0
 tran "MESA CAL     500.00"  "MESACALS     230.00"  "4 "  0 "MESA4T        13.80"
0
bay_4202                        "MIRA LOMA 500kV POS.1XN STUCK CB"
 line "RANCHVST     500.00"  "MIRA81X2     500.00"  "1 "  1 0
 tran "MIRALOMA     500.00"  "MIRALOME     230.00"  "3 "  0 "MIRLOM3T      13.80"
 svd  "MIRALOMA     500.00"  "ei" 0
```

```
0
bay_4203                        "MIRA LOMA 500kV POS.1XT STUCK CB"
 line "RANCHVST     500.00"  "MIRA81X2     500.00"  "1 "  1 0
 line "MIRA81X2     500.00"  "SERRANO      500.00"  "1 "  1 0
0
bay_4204                        "MIRA LOMA 500kV POS.1XS STUCK CB"
 line "MIRA81X2     500.00"  "SERRANO      500.00"  "1 "  1 0
 svd  "MIRALOMA     500.00"  "ei" 0
0
bay_4205                        "MIRA LOMA 500kV POS.1N STUCK CB"
 line "MIRALOMA     500.00"  "SERRANO      500.00"  "2 "  1 0
 tran "MIRALOMA     500.00"  "MIRALOME     230.00"  "3 "  0 "MIRLOM3T      13.80"
 svd  "MIRALOMA     500.00"  "ei" 0
0
bay_4206                        "MIRA LOMA 500kV POS.1T STUCK CB"
 line "MIRALOMA     500.00"  "SERRANO      500.00"  "2 "  1 0
 svd  "MIRALOMA     500.00"  "ei" 0
0
bay_4207                        "MIRA LOMA 500kV POS.2N STUCK CB"
 line "LUGO         500.00"  "MIRALOMA     500.00"  "2 "  1 0
 tran "MIRALOMA     500.00"  "MIRALOME     230.00"  "3 "  0 "MIRLOM3T      13.80"
 svd  "MIRALOMA     500.00"  "ei" 0
0
bay_4208                        "MIRA LOMA 500kV POS.2T STUCK CB"
 line "LUGO         500.00"  "MIRALOMA     500.00"  "2 "  1 0
 tran "MIRALOMA     500.00"  "MIRALOMW     230.00"  "1 "  0 "MIRLOM1T      13.80"
0
bay_4209                        "MIRA LOMA 500kV POS.6N STUCK CB"
 line "LUGO         500.00"  "MIRALOMA     500.00"  "3 "  1 0
 tran "MIRALOMA     500.00"  "MIRALOME     230.00"  "3 "  0 "MIRLOM3T      13.80"
 svd  "MIRALOMA     500.00"  "ei" 0
0
bay_4209                        "MIRA LOMA 500kV POS.6T STUCK CB"
 line "LUGO         500.00"  "MIRALOMA     500.00"  "3 "  1 0
 tran "MIRALOMA     500.00"  "MIRALOME     230.00"  "4 "  0 "MIRLOM4T      13.80"
0
bay_4210                        "SERRANO 500kV POS.1T STUCK CB"
 line "MIRALOMA     500.00"  "SERRANO      500.00"  "1 "  1 0
 tran "SERRANO      500.00"  "SERRANO      230.00"  "1 "  0 "SERRAN1T      13.80"
0
bay_4211                        "SERRANO 500kV POS.2T STUCK CB"
 line "MIRALOMA     500.00"  "SERRANO      500.00"  "2 "  1 0
# line "RANCHVST     500.00"  "MIRA81X2     500.00"  "1 "  1 0
# line "MIRA81X2     500.00"  "SERRANO      500.00"  "1 "  1 0
 tran "SERRANO      500.00"  "SERRANO      230.00"  "2 "  0 "SERRAN2T      13.80"
0
bay_4212                        "SERRANO 500kV POS.3T STUCK CB"
 line "ALBERHIL     500.00"  "SERRANO      500.00"  "1 "  1 0
 tran "SERRANO      500.00"  "SERRANO      230.00"  "3 "  0 "               0.00"
0
bay_4213                        "BARRE 230kV POS.4S STUCK CB"
 line "DELAMO       230.00"  "BARRE        230.00"  "1 "  1 0
 svd  "BARRE        230.00"  "ei" 0
0
bay_4214                        "BARRE 230kV POS.6S STUCK CB"
 line "BARRE        230.00"  "LEWIS        230.00"  "1 "  1 0
 svd  "BARRE        230.00"  "ei" 0
0
bay_4215                        "BARRE 230kV POS.7S STUCK CB"
 line "BARRE        230.00"  "VILLA PK     230.00"  "1 "  1 0
 svd  "BARRE        230.00"  "ei" 0
0
bay_4216                        "BARRE 230kV POS.8S STUCK CB"
 line "BARRE        230.00"  "ELLIS        230.00"  "4 "  1 0
 svd  "BARRE        230.00"  "ei" 0
```

```
0
bay_4217                    "BARRE 230kV POS.9S STUCK CB"
 line "ALMITOSW     230.00"  "BARRE        230.00"  "2 "  1 0
 svd  "BARRE        230.00"  "ei" 0
0
bay_4218                    "BARRE 230kV POS.10S STUCK CB"
 line "ALMITOSE     230.00"  "BARRE        230.00"  "1 "  1 0
 svd  "BARRE        230.00"  "ei" 0
0
bay_4219                    "BARRE 230kV POS.11S STUCK CB"
 line "BARRE        230.00"  "ELLIS        230.00"  "3 "  1 0
 svd  "BARRE        230.00"  "ei" 0
0
bay_4220                    "BARRE 230kV POS.12S STUCK CB"
 line "BARRE        230.00"  "ELLIS        230.00"  "2 "  1 0
 svd  "BARRE        230.00"  "ei" 0
0
bay_4221                    "BARRE 230kV POS.13S STUCK CB"
 line "BARRE        230.00"  "ELLIS        230.00"  "1 "  1 0
 svd  "BARRE        230.00"  "ei" 0
0
bay_4222                    "ELLIS 230kV POS.1T STUCK CB"
 line "BARRE        230.00"  "ELLIS        230.00"  "2 "  1 0
 line "ELLIS        230.00"  "SANTIAGO     230.00"  "1 "  1 0
0
bay_4223                    "ELLIS 230kV POS.2T STUCK CB"
 line "BARRE        230.00"  "ELLIS        230.00"  "1 "  1 0
 line "ELLIS        230.00"  "JOHANNA      230.00"  "1 "  1 0
0
bay_4224                    "ELLIS 230kV POS.3T STUCK CB"
 line "ELLIS        230.00"  "HUNTBCH1     230.00"  "4 "  1 0
 tran "ELLIS        230.00"  "ELLIS         66.00"  "1 "  1 0
0
bay_4225                    "ELLIS 230kV POS.4T STUCK CB"
 line "ELLIS        230.00"  "HUNTGBCH     230.00"  "3 "  1 0
 tran "ELLIS        230.00"  "ELLIS         66.00"  "2 "  1 0
0
bay_4226                    "JOHANNA 230kV POS.1W STUCK CB"
 line "ELLIS        230.00"  "JOHANNA      230.00"  "1 "  1 0
 tran "JOHANNA      230.00"  "JOHANNA       66.00"  "4 "  1 0
 svd  "JOHANNA      230.00"  "ei" 0
0
bay_4227                    "JOHANNA 230kV POS.2W STUCK CB"
 line "JOHANNA      230.00"  "SANTIAGO     230.00"  "1 "  1 0
 tran "JOHANNA      230.00"  "JOHANNA       66.00"  "4 "  1 0
 svd  "JOHANNA      230.00"  "ei" 0
0
bay_4228                    "SANTIAGO 230kV POS.3N STUCK CB"
 line "JOHANNA      230.00"  "SANTIAGO     230.00"  "1 "  1 0
 svd  "SANTIAGO     230.00"  "ei" 0
0
bay_4229                    "SANTIAGO 230kV POS.3T STUCK CB"
 line "JOHANNA      230.00"  "SANTIAGO     230.00"  "1 "  1 0
 tran "SANTIAGO     230.00"  "SANTIAGO      66.00"  "2 "  1 0
0
bay_4230                    "SANTIAGO 230kV POS.5N STUCK CB"
 line "S.ONOFRE     230.00"  "SANTIAGO     230.00"  "1 "  1 0
 svd  "SANTIAGO     230.00"  "ei" 0
0
bay_4231                    "SANTIAGO 230kV POS.5T STUCK CB"
 line "S.ONOFRE     230.00"  "SANTIAGO     230.00"  "2 "  1 0
 line "ELLIS        230.00"  "SANTIAGO     230.00"  "1 "  1 0
0
bay_4232                    "SANTIAGO 230kV POS.7N STUCK CB"
 line "S.ONOFRE     230.00"  "SANTIAGO     230.00"  "1 "  1 0
```

```
 svd  "SANTIAGO     230.00"  "ei" 0
0
bay_4233                        "VIEJO 230kV POS.1N STUCK CB"
 line "S.ONOFRE     230.00"  "SANTIAGO     230.00"  "1 "  1 0
 svd  "SANTIAGO     230.00"  "ei" 0
0
bay_4234                        "VIEJO 230kV POS.3S STUCK CB"
 line "VIEJOSC      230.00"  "CHINO        230.00"  "1 "  1 0
 svd  "SANTIAGO     230.00"  "ei" 0
0
bay_4235                        "VIEJO 230kV POS.3T STUCK CB"
 line "VIEJOSC      230.00"  "CHINO        230.00"  "1 "  1 0
 tran "VIEJOSC      230.00"  "VIEJOSC       66.00"  "2 "  1 0
0
bay_4236                        "VIEJO 230kV POS.3S OR 3N STUCK CB"
 line "VIEJOSC      230.00"  "S.ONOFRE     230.00"  "1 "  1 0
 svd  "SANTIAGO     230.00"  "ei" 0
0
bay_4237                        "SERRANO 230kV POS.1T STUCK CB"
 line "CHINO        230.00"  "SERRANO      230.00"  "1 "  1 0
 line "LEWIS        230.00"  "SERRANO      230.00"  "1 "  1 0
0
bay_4238                        "SERRANO 230kV POS.2T STUCK CB"
 line "LEWIS        230.00"  "SERRANO      230.00"  "2 "  1 0
 line "S.ONOFRE     230.00"  "SERRANO      230.00"  "1 "  1 0
0
bay_4239                        "SERRANO 230kV POS.3T STUCK CB"
 line "SERRANO      230.00"  "VILLA PK     230.00"  "2 "  1 0
 tran "SERRANO      500.00"  "SERRANO      230.00"  "1 "  0 "SERRAN1T      13.80"
0
bay_4240                        "SERRANO 230kV POS.4T STUCK CB"
 line "SERRANO      230.00"  "VILLA PK     230.00"  "1 "  1 0
 tran "SERRANO      500.00"  "SERRANO      230.00"  "2 "  0 "SERRAN2T      13.80"
0
bay_4241                        "LEWIS 230kV POS.5T STUCK CB"
 line "LEWIS        230.00"  "VILLA PK     230.00"  "1 "  1 0
 line "LEWIS        230.00"  "SERRANO      230.00"  "1 "  1 0
0
bay_4242                        "LEWIS 230kV POS.6T STUCK CB"
 line "BARRE        230.00"  "LEWIS        230.00"  "1 "  1 0
 line "LEWIS        230.00"  "SERRANO      230.00"  "2 "  1 0
0
bay_4243                        "VILLA PARK 230kV POS.2T STUCK CB"
 line "LEWIS        230.00"  "VILLA PK     230.00"  "1 "  1 0
 tran "VILLA PK     230.00"  "VILLA PK      66.00"  "1 "  1 0
0
bay_4244                        "VILLA PARK 230kV POS.2S STUCK CB"
 line "LEWIS        230.00"  "VILLA PK     230.00"  "1 "  1 0
 tran "VILLA PK     230.00"  "VILLA PK      66.00"  "2 "  1 0
0
bay_4245                        "VILLA PARK 230kV POS.6T STUCK CB"
 line "SERRANO      230.00"  "VILLA PK     230.00"  "2 "  1 0
 tran "VILLA PK     230.00"  "VILLA PK      66.00"  "3 "  1 0
0
bay_4246                        "VILLA PARK 230kV POS.6S STUCK CB"
 line "SERRANO      230.00"  "VILLA PK     230.00"  "2 "  1 0
 tran "VILLA PK     230.00"  "VILLA PK      66.00"  "2 "  1 0
0
bay_4247                        "VILLA PARK 230kV POS.8N STUCK CB"
 line "SERRANO      230.00"  "VILLA PK     230.00"  "1 "  1 0
 svd  "VILLA PK     230.00"  "ei" 0
0
bay_4248                        "VILLA PARK 230kV POS.8T STUCK CB"
 line "SERRANO      230.00"  "VILLA PK     230.00"  "1 "  1 0
 line "BARRE        230.00"  "VILLA PK     230.00"  "1 "  1 0
```

```
0
bay_4249                    "VILLA PARK 230kV POS.8S STUCK CB"
 line "BARRE       230.00"  "VILLA PK     230.00"  "1 "  1 0
 tran "VILLA PK    230.00"  "VILLA PK      66.00"  "2 "  1 0
0
bay_4250                    "LAGUNA BELL 230kV POS.5N/5S STUCK CB"
 line "LAGUBELL    230.00"  "MESACALS     230.00"  "2 "  1 0
 svd  "LAGUBELL    230.00"  "ei" 0
0
bay_4251                    "LAGUNA BELL 230kV POS.6N/6S STUCK CB"
 line "DELAMO      230.00"  "LAGUBELL     230.00"  "1 "  1 0
 svd  "LAGUBELL    230.00"  "ei" 0
0
bay_4252                    "LAGUNA BELL 230kV POS.11N/11S STUCK CB"
 line "LAGUBELL    230.00"  "MESA CAL     230.00"  "1 "  1 0
 svd  "LAGUBELL    230.00"  "ei" 0
0
bay_4253                    "LAGUNA BELL 230kV POS.12N/12S STUCK CB"
 line "LA FRESA    230.00"  "LAGUBELL     230.00"  "1 "  1 0
 svd  "LAGUBELL    230.00"  "ei" 0
0
bay_4254                    "WALNUT 230KV POS.7N STUCK CB"
 line "MIRALOMW    230.00"  "WALNUT       230.00"  "1 "  1 0
 tran "WALNUT      230.00"  "WALNUT        66.00"  "3 "  0 "              0.00"
0
bay_4255                    "WALNUT 230KV POS.7S STUCK CB"
 line "MIRALOMW    230.00"  "WALNUT       230.00"  "1 "  1 0
 tran "WALNUT      230.00"  "WALNUT        66.00"  "4 "  0 "              0.00"
0
bay_4256                    "WALNUT 230KV POS.8N STUCK CB"
 line "OLINDA      230.00"  "WALNUT       230.00"  "1 "  1 0
 tran "WALNUT      230.00"  "WALNUT        66.00"  "3 "  0 "              0.00"
0
bay_4257                    "WALNUT 230KV POS.8S STUCK CB"
 line "OLINDA      230.00"  "WALNUT       230.00"  "1 "  1 0
 tran "WALNUT      230.00"  "WALNUT        66.00"  "4 "  0 "              0.00"
0
bay_4258                    "OLINDA 230KV POS.2W STUCK CB"
 line "TOT663TAP   230.00"  "OLINDA       230.00"  "1 "  1 0
 svd  "OLINDA      230.00"  "ei"
0
bay_4259                    "OLINDA 230KV POS.6W STUCK CB"
 line "OLINDA      230.00"  "WALNUT       230.00"  "1 "  1 0
 svd  "OLINDA      230.00"  "ei"
0
bay_4260                    "OLINDA 230KV POS.6T STUCK CB"
 line "MIRALOME    230.00"  "OLINDA       230.00"  "1 "  1 0
 line "OLINDA      230.00"  "WALNUT       230.00"  "1 "  1 0
0
bay_4261                    "OLINDA 230KV POS.6W STUCK CB"
 line "OLINDA      230.00"  "WALNUT       230.00"  "1 "  1 0
 svd  "OLINDA      230.00"  "ei"
0
bay_4262                    "CHINO 230KV POS.5E STUCK CB"
 line "CHINO       230.00"  "MIRALOMW     230.00"  "2 "  1 0
 tran "CHINO       230.00"  "CHINO         66.00"  "1 "  0 "              0.00"
 svd  "CHINO       230.00"  "ei"
0
bay_4263                    "CHINO 230KV POS.5T STUCK CB"
 line "CHINO       230.00"  "MIRALOMW     230.00"  "2 "  1 0
 tran "CHINO       230.00"  "CHINO         66.00"  "3 "  0 "              0.00"
0
bay_4264                    "CHINO 230KV POS.7E STUCK CB"
 line "CHINO       230.00"  "MIRALOME     230.00"  "3 "  1 0
 tran "CHINO       230.00"  "CHINO         66.00"  "1 "  0 "              0.00"
```

```
 svd  "CHINO        230.00"  "ei"
0
bay_4265                       "CHINO 230KV POS.7T STUCK CB"
 line "CHINO        230.00"  "MIRALOME     230.00"  "3 "  1 0
 tran "CHINO        230.00"  "CHINO         66.00"  "2 "  0 "               0.00"
0
bay_4266                        "CHINO 230KV POS.10E STUCK CB"
 line "CHINO        230.00"  "SERRANO      230.00"  "1 "  1 0
 tran "CHINO        230.00"  "CHINO         66.00"  "1 "  0 "               0.00"
 svd  "CHINO        230.00"  "ei"
0
bay_4267                        "CHINO 230KV POS.10T STUCK CB"
 line "CHINO        230.00"  "SERRANO      230.00"  "1 "  1 0
 line "VIEJOSC      230.00"  "CHINO        230.00"  "1 "  1 0
0
bay_4268                        "CHINO 230KV POS.10S STUCK CB"
 line "VIEJOSC      230.00"  "CHINO        230.00"  "1 "  1 0
 line "CHINO        230.00"  "MIRALOMW     230.00"  "1 "  1 0
0
bay_4269                        "MIRA LOMA(W) 230KV POS.2T STUCK CB"
 line "CHINO        230.00"  "MIRALOMW     230.00"  "1 "  1 0
 svd  "MIRALOMW     230.00"  "ei" 0
0
bay_4270                        "MIRA LOMA(W) 230KV POS.3T STUCK CB"
 line "CHINO        230.00"  "MIRALOMW     230.00"  "2 "  1 0
 line "MIRALOMW     230.00"  "WALNUT       230.00"  "1 "  1 0
0
bay_4271                        "MIRA LOMA(W) 230KV POS.3S STUCK CB"
 line "MIRALOMW     230.00"  "WALNUT       230.00"  "1 "  1 0
 svd  "MIRALOMW     230.00"  "ei" 0
0
bay_4272                        "MIRA LOMA(W) 230KV POS.5T STUCK CB"
 line "MIRALOMW     230.00"  "WILDLIFE     230.00"  "1 "  1 0
 tran "MIRALOMW     230.00"  "MIRALOMA      66.00"  "5 "  0 "               0.00"
0
bay_4273                        "MIRA LOMA(E) 230KV POS.14N STUCK CB"
 line "CHINO        230.00"  "MIRALOME     230.00"  "3 "  1 0
 svd  "MIRALOME     230.00"  "ei" 0
0
bay_4274                        "MIRA LOMA(E) 230KV POS.14T STUCK CB"
 line "CHINO        230.00"  "MIRALOME     230.00"  "3 "  1 0
 line "MIRALOME     230.00"  "OLINDA       230.00"  "1 "  1 0
0
bay_4275                        "MIRA LOMA(E) 230KV POS.15T STUCK CB"
 line "MIRALOME     230.00"  "VSTA         230.00"  "2 "  1 0
 tran "MIRALOMA     500.00"  "MIRALOME     230.00"  "4 "  0 "MIRLOM4T      13.80"
0
bay_4276                        "MIRA LOMA(E) 230KV POS.16N STUCK CB"
 line "RANCHVST     230.00"  "MIRALOME     230.00"  "2 "  1 0
 svd  "MIRALOME     230.00"  "ei" 0
0
bay_4277                        "MIRA LOMA(E) 230KV POS.16T STUCK CB"
 line "RANCHVST     230.00"  "MIRALOME     230.00"  "2 "  1 0
 line "RANCHVST     230.00"  "MIRALOME     230.00"  "1 "  1 0
0
#
# P4.3: Transformer
#
bay_4301                         "MIRA LOMA 500kV POS.2S STUCK CB"
 tran "MIRALOMA     500.00"  "MIRALOMW     230.00"  "1 "  0 "MIRLOM1T      13.80"
 svd  "MIRALOMA     500.00"  "ei" 0
0
bay_4302                         "MIRA LOMA 500kV POS.4N STUCK CB"
 tran "MIRALOMA     500.00"  "MIRALOMW     230.00"  "2 "  0 "MIRLOM2T      13.80"
 tran "MIRALOMA     500.00"  "MIRALOME     230.00"  "3 "  0 "MIRLOM3T      13.80"
```

```
 svd  "MIRALOMA     500.00"  "ei" 0
0
bay_4303                       "MIRA LOMA 500kV POS.4S STUCK CB"
 tran "MIRALOMA     500.00"  "MIRALOMW     230.00"  "2 "  0 "MIRLOM2T      13.80"
 svd  "MIRALOMA     500.00"  "ei" 0
0
bay_4304                       "MIRA LOMA 500kV POS.6S STUCK CB"
 tran "MIRALOMA     500.00"  "MIRALOME     230.00"  "4 "  0 "MIRLOM4T      13.80"
 svd  "MIRALOMA     500.00"  "ei" 0
0
bay_4305                       "MIRA LOMA(W) 230KV POS.4S STUCK CB"
 tran "MIRALOMA     500.00"  "MIRALOMW     230.00"  "1 "  0 "MIRLOM1T      13.80"
 svd  "MIRALOMW     230.00"  "ei" 0
0
bay_4306                       "MIRA LOMA(W) 230KV POS.5S STUCK CB"
 tran "MIRALOMW     230.00"  "MIRALOMA      66.00"  "5 "  0 "              0.00"
 svd  "MIRALOMW     230.00"  "ei" 0
0
bay_4307                       "MIRA LOMA(W) 230KV POS.6S STUCK CB"
 tran "MIRALOMW     230.00"  "MIRALOMA      66.00"  "6 "  0 "              0.00"
 svd  "MIRALOMW     230.00"  "ei" 0
0
bay_4308                       "MIRA LOMA(W) 230KV POS.7S STUCK CB"
 tran "MIRALOMA     500.00"  "MIRALOMW     230.00"  "2 "  0 "MIRLOM2T      13.80"
 svd  "MIRALOMW     230.00"  "ei" 0
0
bay_4309                       "MIRA LOMA(W) 230KV POS.8S STUCK CB"
 tran "MIRALOMW     230.00"  "MIRALOMA      66.00"  "7 "  0 "              0.00"
 svd  "MIRALOMW     230.00"  "ei" 0
0
bay_4310                       "MIRA LOMA(E) 230KV POS.10N STUCK CB"
 tran "MIRALOMA     500.00"  "MIRALOME     230.00"  "3 "  0 "MIRLOM3T      13.80"
 svd  "MIRALOME     230.00"  "ei" 0
0
bay_4311                       "MIRA LOMA(E) 230KV POS.15N STUCK CB"
 tran "MIRALOMA     500.00"  "MIRALOME     230.00"  "4 "  0 "MIRLOM4T      13.80"
 svd  "MIRALOME     230.00"  "ei" 0
0
bay_4312                       "SANTIAGO 230kV POS.1N STUCK CB"
 tran "SANTIAGO     230.00"  "SANTIAGO      66.00"  "1 "  1 0
 svd  "SANTIAGO     230.00"  "ei" 0
0
bay_4313                       "SANTIAGO 230kV POS.6N STUCK CB"
 tran "SANTIAGO     230.00"  "SANTIAGO      66.00"  "3 "  1 0
 svd  "SANTIAGO     230.00"  "ei" 0
0
bay_4314                       "SANTIAGO 230kV POS.8N STUCK CB"
 tran "SANTIAGO     230.00"  "SANTIAGO      66.00"  "4 "  1 0
 svd  "SANTIAGO     230.00"  "ei" 0
0
bay_4315                       "VIEJO 230kV POS.1N OR 1S STUCK CB"
 tran "VIEJOSC      230.00"  "VIEJOSC       66.00"  "1 "  1 0
 svd  "VIEJOSC      230.00"  "ei" 0
0
bay_4316                       "VIEJO 230kV POS.3N STUCK CB"
 tran "VIEJOSC      230.00"  "VIEJOSC       66.00"  "2 "  1 0
 svd  "VIEJOSC      230.00"  "ei" 0
0
bay_4317                       "VILLA PARK 230kV POS.2N STUCK CB"
 tran "VILLA PK     230.00"  "VILLA PK      66.00"  "1 "  1 0
 svd  "VILLA PK     230.00"  "ei" 0
0
bay_4318                       "VILLA PARK 230kV POS.2N STUCK CB"
 tran "VILLA PK     230.00"  "VILLA PK      66.00"  "3 "  1 0
 svd  "VILLA PK     230.00"  "ei" 0
```

```
0
bay_4319                    "LAGUNA BELL 230kV POS.3N/3S STUCK CB"
 tran "LAGUBELL    230.00"  "LAGUBELL     66.00"  "1 "  1 0
 svd  "LAGUBELL    230.00"  "ei" 0
0
bay_4320                    "LAGUNA BELL 230kV POS.4N/4S STUCK CB"
 tran "LAGUBELL    230.00"  "LAGUBELL     66.00"  "2 "  1 0
 svd  "LAGUBELL    230.00"  "ei" 0
0
bay_4321                    "LAGUNA BELL 230kV POS.9N/9S STUCK CB"
 tran "LAGUBELL    230.00"  "LAGUBELL     66.00"  "1 "  1 0
 svd  "LAGUBELL    230.00"  "ei" 0
0
bay_4322                    "LAGUNA BELL 230kV POS.10N/10S STUCK CB"
 tran "LAGUBELL    230.00"  "LAGUBELL     66.00"  "2 "  1 0
 svd  "LAGUBELL    230.00"  "ei" 0
0
bay_4323                    "WALNUT 230KV POS.3N STUCK CB"
 tran "WALNUT      230.00"  "WALNUT       66.00"  "2 "  0 "            0.00"
 line "MESACALS    230.00"  "WALNUT      230.00"  "1 "  1 0
0
bay_4324                    "WALNUT 230KV POS.3S STUCK CB"
 tran "WALNUT      230.00"  "WALNUT       66.00"  "2 "  0 "            0.00"
 svd  "WALNUT      230.00"  "ei" 0
0
bay_4325                    "OLINDA 230KV POS.1W STUCK CB"
 tran "OLINDA      230.00"  "OLINDA       66.00"  "1 "  1 0
 svd  "OLINDA      230.00"  "ei"
0
bay_4326                    "OLINDA 230KV POS.3W STUCK CB"
 tran "OLINDA      230.00"  "OLINDA       66.00"  "2 "  1 0
 svd  "OLINDA      230.00"  "ei"
0
bay_4327                    "OLINDA 230KV POS.7W STUCK CB"
 tran "OLINDA      230.00"  "OLINDA       66.00"  "4 "  1 0
 svd  "OLINDA      230.00"  "ei"
0
bay_4328                    "CHINO 230KV POS.5W STUCK CB"
 tran "CHINO       230.00"  "CHINO        66.00"  "3 "  1 0
 line "CHINO       230.00"  "MIRALOMW    230.00"  "1 "  1 0
0
bay_4329                    "CHINO 230KV POS.7W STUCK CB"
 tran "CHINO       230.00"  "CHINO        66.00"  "2 "  1 0
 line "CHINO       230.00"  "MIRALOMW    230.00"  "1 "  1 0
0
#
# P4.4: Shunt Device
#
# Notes:
# Within the Metro Area impacting Orange County (QC7 sphere of influence), shunt devices are installed at Barre, Chino Johanna,
# Laguna Bell, Olinda, Santiago, Viejo, Villa Park, Walnut, and Mira Loma. Except for Johanna, all substations are designed as a
# double-bus, double-breaker or breaker-and-a-half with all elements on bus which connects shunt device fully equipped with circuit
# breakers. This Category P4.4 power flow conditions are therefore the same as Category P1.4 power flow conditions for all stations
# except Johanna.
#
bay_4401                    "JOHANA 230KV POS.8W STUCK CB"
 svd  "JOHANNA     230.00"  "ei" 0
 tran "JOHANNA     230.00"  "JOHANNA      66.00"  "4 "  1 0
0
#
# P4.5: Bus Section results in the same power flow performance as Category P2.2 and is therefore addressed under Category P2.2.
#
# P4.6: Bus-Tie Breaker results in the same power flow performance as Category P2.4 and is therefore addressed under Category
# P2.4.
#
```

```
# Multiple contingency (Category P5)
# The assessment will consider selected Category P5 contingencies with delayed fault clearing due to the failure of a non-redundant
# relay protecting the faulted element to operate as designed, for one of the following:
#       SLG Fault with loss of one generator (P5.1)
#       SLG Fault with loss of one transmission circuit (P5.2)
#       SLG Fault with loss of one transformer (P5.3)
#       SLG Fault with loss of one shunt device (P5.4)
#       SLG Fault with loss of one bus section (P5.5)
#
# Notes:
# 1. The purpose of Generation Interconnection Process (GIP) studies are to evaluate stressed generation conditions on the
# system. Because Category P5.1 would not provide for such stressed conditions, the study results would not properly identify
# potential impacts corresponding to the projects seeking interconnection. As such, Category P5.1 was not evaluated as part of the
# GIP studies but is addressed as part of SCE's Annual Expansion Studies performed in coordination with the CAISO
#
# 2. Category P5 power flow conditions are exactly the same as Category P1 (back-up protection results in delayed removal of
# faulted element) or the same as Category P4 (Zone 2 protection behaves similar to stuck breaker protection). As such, Category
# P5 is addressed as part of Category P1 or Category P4.
#
#
# Category P6 (Multiple Contingencies)
#
# Notes:
# Because the CAISO implements congestion management protocols that curtail generation resources under loss of a system
# element in preparation for the next contingency, the assessment did not consider Category P6 contingencies which involves the
# loss of two or more (non-generator unit) elements with system adjustment between them. However, Category P6 is addressed as
# part of SCE's annual reliability assessment performed in coordination with the CAISO which ensures system is adequate to
# maintain appropriate level of service to load demand.
#
# Category P7 (Multiple Contingencies)
#
# Category P7.1 Any two adjacent circuits on common structure
#
#
line_7101            "Line MIRALOMA    500.0 to SERRANO     500.0 Circuit 1 & Line MIRALOMA    500.0 to SERRANO
500.0 Circuit 2"   1.000
 line "MIRALOMA    500.00"  "SERRANO     500.00"  "1 "  1 0
 line "MIRALOMA    500.00"  "SERRANO     500.00"  "2 "  1 0
 #line "RANCHVST    500.00"  "MIRA81X2    500.00"  "1 "  1 0
 #line "MIRA81X2    500.00"  "SERRANO     500.00"  "1 "  1 0
0
line_7102            "Line BARRE       230.0 to ELLIS       230.0 Circuit 1 & Line BARRE       230.0 to ELLIS       230.0
Circuit 2"   1.000
 line "BARRE       230.00"  "ELLIS       230.00"  "1 "  1 0
 line "BARRE       230.00"  "ELLIS       230.00"  "2 "  1 0
0
line_7103            "Line BARRE       230.0 to ELLIS       230.0 Circuit 3 & Line BARRE       230.0 to ELLIS       230.0
Circuit 4"   1.000
 line "BARRE       230.00"  "ELLIS       230.00"  "3 "  1 0
 line "BARRE       230.00"  "ELLIS       230.00"  "4 "  1 0
0
line_7104            "Line ELLIS       230.0 to HUNTGBCH    230.0 Circuit 1 & Line ELLIS       230.0 to HUNTBCH1    230.0
Circuit 2"   1.000
 line "ELLIS       230.00"  "HUNTGBCH    230.00"  "1 "  1 0
 line "ELLIS       230.00"  "HUNTBCH1    230.00"  "2 "  1 0
0
line_7105            "Line ELLIS       230.0 to HUNTGBCH    230.0 Circuit 3 & Line ELLIS       230.0 to HUNTBCH1    230.0
Circuit 4"   1.000
 line "ELLIS       230.00"  "HUNTGBCH    230.00"  "3 "  1 0
 line "ELLIS       230.00"  "HUNTBCH1    230.00"  "4 "  1 0
0
line_7106            "Line ELLIS       230.0 to SANTIAGO    230.0 Circuit 1 & Line JOHANNA     230.0 to SANTIAGO
230.0 Circuit 1"   1.000
 line "ELLIS       230.00"  "SANTIAGO    230.00"  "1 "  1 0
 line "JOHANNA     230.00"  "SANTIAGO    230.00"  "1 "  1 0
```

0
line_7107 "Line ELLIS 230.0 to JOHANNA 230.0 Circuit 1 & Line ELLIS 230.0 to SANTIAGO 230.0 Circuit 1" 1.000
line "ELLIS 230.00" "JOHANNA 230.00" "1 " 1 0
line "ELLIS 230.00" "SANTIAGO 230.00" "1 " 1 0
0
line_7108 "Line S.ONOFRE 230.0 to SANTIAGO 230.0 Circuit 1 & Line S.ONOFRE 230.0 to SANTIAGO 230.0 Circuit 2" 1.000
line "S.ONOFRE 230.00" "SANTIAGO 230.00" "1 " 1 0
line "S.ONOFRE 230.00" "SANTIAGO 230.00" "2 " 1 0
0
line_7109 "Line VIEJOSC 230.0 to S.ONOFRE 230.0 Circuit 1 & Line S.ONOFRE 230.0 to SERRANO 230.0 Circuit 1" 1.000
line "VIEJOSC 230.00" "S.ONOFRE 230.00" "1 " 1 0
line "S.ONOFRE 230.00" "SERRANO 230.00" "1 " 1 0
0
line_7110 "Line VIEJOSC 230.0 to CHINO 230.0 Circuit 1 & Line S.ONOFRE 230.0 to SERRANO 230.0 Circuit 1" 1.000
line "VIEJOSC 230.00" "CHINO 230.00" "1 " 1 0
line "S.ONOFRE 230.00" "SERRANO 230.00" "1 " 1 0
0
line_7111 "Line CHINO 230.0 to SERRANO 230.0 Circuit 1 & Line VIEJOSC 230.0 to CHINO 230.0 Circuit 1" 1.000
line "CHINO 230.00" "SERRANO 230.00" "1 " 1 0
line "VIEJOSC 230.00" "CHINO 230.00" "1 " 1 0
0
line_7112 "Line CHINO 230.0 to SERRANO 230.0 Circuit 1 & Line S.ONOFRE 230.0 to SERRANO 230.0 Circuit 1" 1.000
line "CHINO 230.00" "SERRANO 230.00" "1 " 1 0
line "S.ONOFRE 230.00" "SERRANO 230.00" "1 " 1 0
0
line_7114 "Line CHINO 230.0 to MIRALOMW 230.0 Circuit 1 & Line CHINO 230.0 to MIRALOMW 230.0 Circuit 2" 1.000
line "CHINO 230.00" "MIRALOMW 230.00" "1 " 1 0
line "CHINO 230.00" "MIRALOMW 230.00" "2 " 1 0
0
line_7115 "Line SERRANO 230.0 to VILLA PK 230.0 Circuit 1 & Line SERRANO 230.0 to VILLA PK 230.0 Circuit 2" 1.000
line "SERRANO 230.00" "VILLA PK 230.00" "1 " 1 0
line "SERRANO 230.00" "VILLA PK 230.00" "2 " 1 0
0
line_7116 "Line LEWIS 230.0 to SERRANO 230.0 Circuit 1 & Line LEWIS 230.0 to SERRANO 230.0 Circuit 2" 1.000
line "LEWIS 230.00" "SERRANO 230.00" "1 " 1 0
line "LEWIS 230.00" "SERRANO 230.00" "2 " 1 0
0
line_7117 "Line BARRE 230.0 to VILLA PK 230.0 Circuit 1 & Line LEWIS 230.0 to VILLA PK 230.0 Circuit 1" 1.000
line "BARRE 230.00" "VILLA PK 230.00" "1 " 1 0
line "LEWIS 230.00" "VILLA PK 230.00" "1 " 1 0
0
line_7118 "Line BARRE 230.0 to VILLA PK 230.0 Circuit 1 & Line BARRE 230.0 to LEWIS 230.0 Circuit 1" 1.000
line "BARRE 230.00" "VILLA PK 230.00" "1 " 1 0
line "BARRE 230.00" "LEWIS 230.00" "1 " 1 0
0
line_7119 "Line ALMITOSE 230.0 to BARRE 230.0 Circuit 1 & Line ALMITOSW 230.0 to BARRE 230.0 Circuit 2" 1.000
line "ALMITOSE 230.00" "BARRE 230.00" "1 " 1 0
line "ALMITOSW 230.00" "BARRE 230.00" "2 " 1 0
0
line_7120 "Line DELAMO 230.0 to BARRE 230.0 Circuit 1 & Line ALMITOSW 230.0 to BARRE 230.0 Circuit 2" 1.000
line "DELAMO 230.00" "BARRE 230.00" "1 " 1 0
line "ALMITOSW 230.00" "BARRE 230.00" "2 " 1 0

0
line_7121 "Line ALMITOSE 230.0 to CENTER S 230.0 Circuit 1 & Line ALMITOSW 230.0 to LITEHIPE 230.0 Circuit 1" 1.000
line "ALMITOSE 230.00" "CENTER S 230.00" "1 " 1 0
line "ALMITOSW 230.00" "LITEHIPE 230.00" "1 " 1 0
0
line_7122 "Line DELAMO 230.0 to CENTER S 230.0 Circuit 1 & Line ALMITOSE 230.0 to CENTER S 230.0 Circuit 1" 1.000
line "DELAMO 230.00" "CENTER S 230.00" "1 " 1 0
line "ALMITOSE 230.00" "CENTER S 230.00" "1 " 1 0
0
line_7123 "Line HINSON 230.0 to DELAMO 230.0 Circuit 1 & Line ALMITOSW 230.0 to LITEHIPE 230.0 Circuit 1" 1.000
line "HINSON 230.00" "DELAMO 230.00" "1 " 1 0
line "ALMITOSW 230.00" "LITEHIPE 230.00" "1 " 1 0
0
line_7124 "Line DELAMO 230.0 to LAGUBELL 230.0 Circuit 1 & Line LITEHIPE 230.0 to MESA CAL 230.0 Circuit 1" 1.000
line "DELAMO 230.00" "LAGUBELL 230.00" "1 " 1 0
line "LITEHIPE 230.00" "MESA CAL 230.00" "1 " 1 0
0
line_7125 "Line LA FRESA 230.0 to LAGUBELL 230.0 Circuit 1 & Line MESA CAL 230.0 to REDONDO 230.0 Circuit 1" 1.000
line "LA FRESA 230.00" "LAGUBELL 230.00" "1 " 1 0
line "MESA CAL 230.00" "REDONDO 230.00" "1 " 1 0
0
line_7126 "Line MESA CAL 230.0 to REDONDO 230.0 Circuit 1 & Line LAGUBELL 230.0 to MESA CAL 230.0 Circuit 1" 1.000
line "MESA CAL 230.00" "REDONDO 230.00" "1 " 1 0
line "LAGUBELL 230.00" "MESA CAL 230.00" "1 " 1 0
0
line_7127 "Line LAGUBELL 230.0 to MESACALS 230.0 Circuit 2 & Line LITEHIPE 230.0 to MESA CAL 230.0 Circuit 1" 1.000
line "LAGUBELL 230.00" "MESACALS 230.00" "2 " 1 0
line "LITEHIPE 230.00" "MESA CAL 230.00" "1 " 1 0
0
line_7128 "Line CENTER S 230.0 to TOT663TAP 230.0 Circuit 1 & Line CENTER S 230.0 to TOT663TAP 230.0 Circuit 2" 1.000
line "CENTER S 230.00" "TOT663TAP 230.00" "1 " 1 0
line "CENTER S 230.00" "TOT663TAP 230.00" "2 " 1 0
0
line_7129 "Line MESACALS 230.0 to WALNUT 230.0 Circuit 1 & Line TOT663TAP 230.0 to MESA CAL 230.0 Circuit 1" 1.000
line "MESACALS 230.00" "WALNUT 230.00" "1 " 1 0
line "TOT663TAP 230.00" "MESA CAL 230.00" "1 " 1 0
0
line_7130 "Line MESACALS 230.0 to WALNUT 230.0 Circuit 1 & Line TOT663TAP 230.0 to OLINDA 230.0 Circuit 1" 1.000
line "MESACALS 230.00" "WALNUT 230.00" "1 " 1 0
line "TOT663TAP 230.00" "OLINDA 230.00" "1 " 1 0
0
line_7131 "Line MIRALOMW 230.0 to WALNUT 230.0 Circuit 1 & Line OLINDA 230.0 to WALNUT 230.0 Circuit 1" 1.000
line "MIRALOMW 230.00" "WALNUT 230.00" "1 " 1 0
line "OLINDA 230.00" "WALNUT 230.00" "1 " 1 0
0
line_7132 "Line OLINDA 230.0 to WALNUT 230.0 Circuit 1 & Line TOT663TAP 230.0 to OLINDA 230.0 Circuit 1" 1.000
line "OLINDA 230.00" "WALNUT 230.00" "1 " 1 0
line "TOT663TAP 230.00" "OLINDA 230.00" "1 " 1 0
0
line_7133 "Line MIRALOMW 230.0 to WALNUT 230.0 Circuit 1 & Line MIRALOME 230.0 to OLINDA 230.0 Circuit 1" 1.000
line "MIRALOMW 230.00" "WALNUT 230.00" "1 " 1 0
line "MIRALOME 230.00" "OLINDA 230.00" "1 " 1 0

0
Category P7.2 Loss of a bipolar DC Lines is not applicable in the Metro Area as no DC lines exist within this area.
end
End of Contingency List

Queue Cluster 7 Phase II – Appendix D

SCE Metro Area – Power Flow Plots

Appendix D: Power Flow Plots

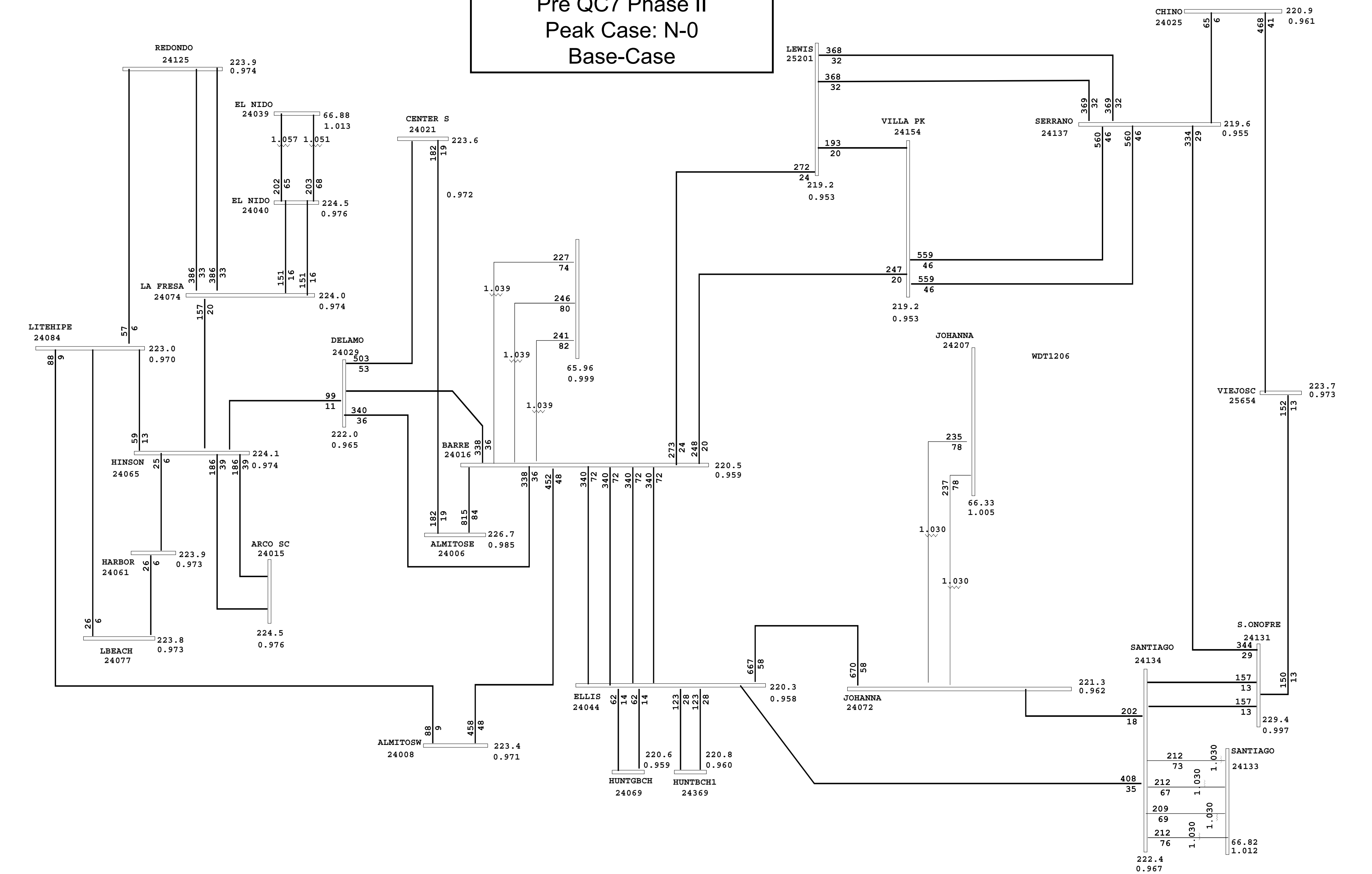
Pre QC7 Phase II: Peak Case Power Flow Plots	
Case	Contingency Description
1	No Contingency (Base-Case)

Post QC7 Phase II: Peak Case Power Flow Plots	
Case	Contingency Description
2	No Contingency (Base-Case)
3	Barre-Ellis No. 2 230 kV line
4	Ellis-Johanna 230 kV line
5	Ellis-Johanna & Ellis-Santiago 230 kV lines
6	Ellis-Johanna & Johanna-Santiago 230 kV lines
7	Ellis- Santiago & Johanna-Santiago 230 kV lines
8	Barre-Ellis No. 2 & Barre-Ellis No. 3 230 kV lines

Pre QC7 Phase II: Off-Peak Case Power Flow Plots	
Case	Contingency Description
9	No Contingency (Base-Case)

Post QC7 Phase II: Off-Peak Case Power Flow Plots	
Case	Contingency Description
10	No Contingency (Base-Case)
11	Barre-Ellis No. 2 230 kV line
12	Ellis-Johanna 230 kV line
13	Ellis-Johanna & Ellis-Santiago 230 kV lines
14	Ellis-Johanna & Johanna-Santiago 230 kV lines
15	Ellis- Santiago & Johanna-Santiago 230 kV lines
16	Barre-Ellis No. 2 & Barre-Ellis No. 3 230 kV lines

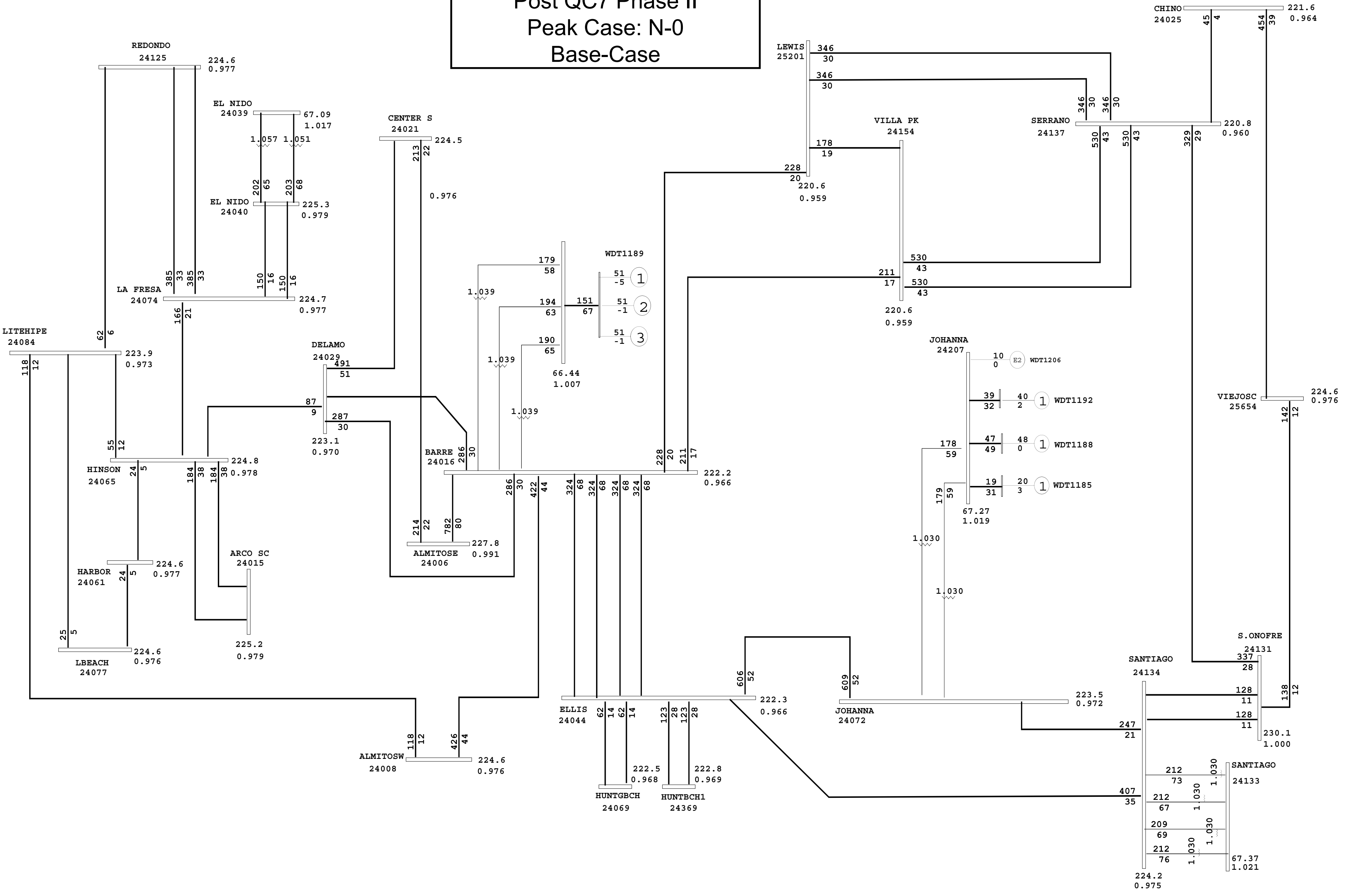
Power Flow Plot
Pre QC7 Phase II
Peak Case: N-0
Base-Case



General Electric International, Inc.   PSLF Program   Fri Sep 11 15:23:56 2015   SSTOOLSV6\cases\19p-Metro-PreQC7P2.sav

GE	EC&R CAISO 20 MW EQUIV. COLLECTION SYSTEM, 66 KV GEN-TIE CASE NAME:C:\GIP\Projects\Clusters\QC7\BaseCases\19p-Metro-PreQC7P2_r6.sav SCE [LOAD 26020 XCHGE-10786 GEN 16397][AA 0V 0M 0D 0VA]MW	[0MW][0MW][NORTHERN NEW MEXICO (NM2) 1978MW][EAST OF COLORADO RIVER (EO [SYLMAR 7564][VIC-LUGO 904][0][0][0]MW	MVA/%rate C:\GIP\Projects\Clust Rating = 1

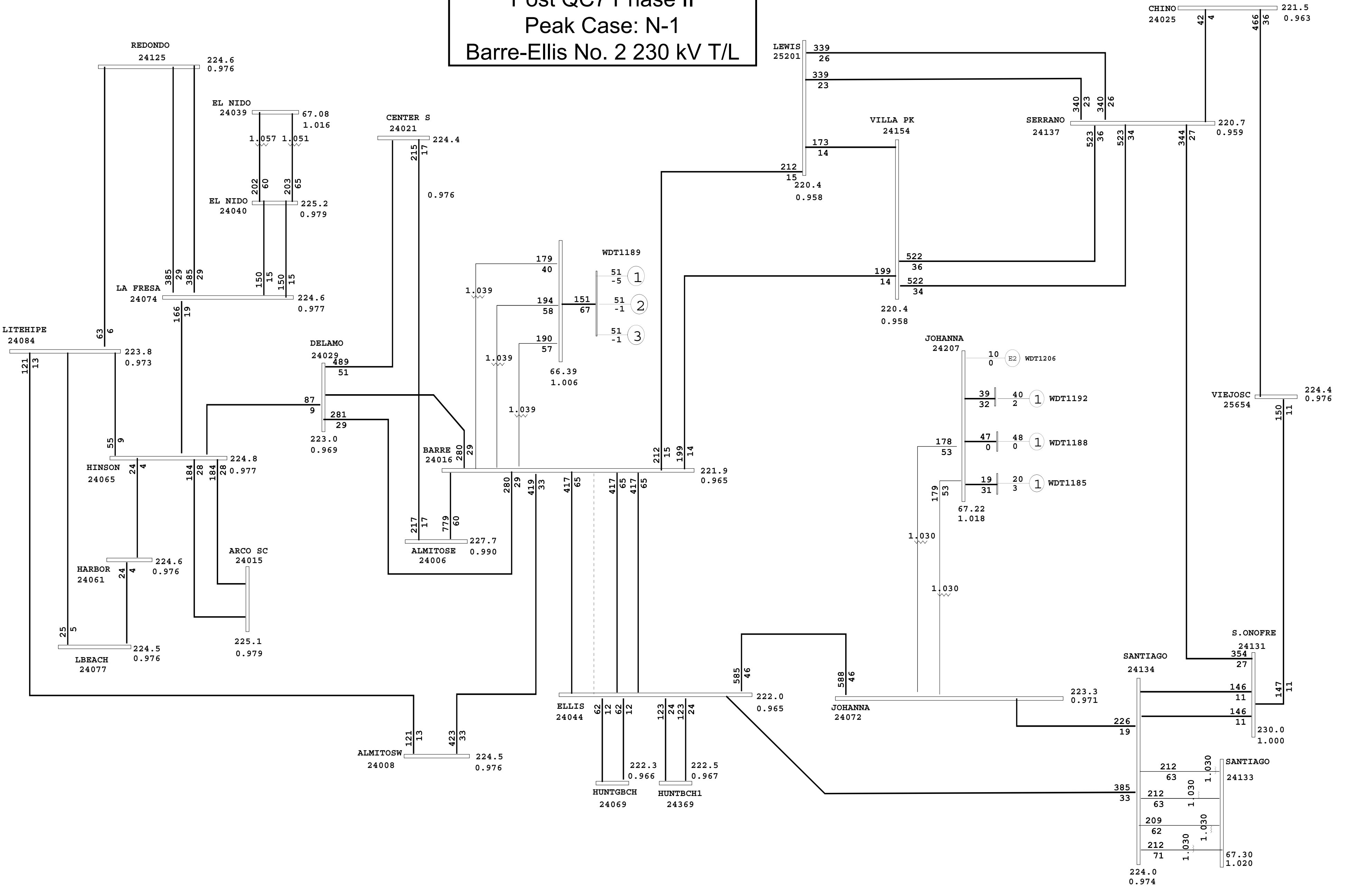
Power Flow Plot
Post QC7 Phase II
Peak Case: N-0
Base-Case



General Electric International, Inc. PSLF Program Thu Aug 27 10:45:12 2015 SSTOOLSV6\cases\19p-Metro-PstQC7P2.sav

EC&R CAISO 20 MW EQUIV. COLLECTION SYSTEM, 66 KV GEN-TIE CASE NAME:cases\19p-Metro-PstQC7P2.sav SCE [LOAD 26020 XCHGE-10787 GEN 16382][AA 0V 0M 0D 0VA]MW	[0MW][0MW][NORTHERN NEW MEXICO (NM2) 1978MW][EAST OF COLORADO RIVER (EO [SYLMAR 7550][VIC-LUGO 923][0][0][0]MW	MVA/%rate C:\GIP\Projects\Clust Rating = 1

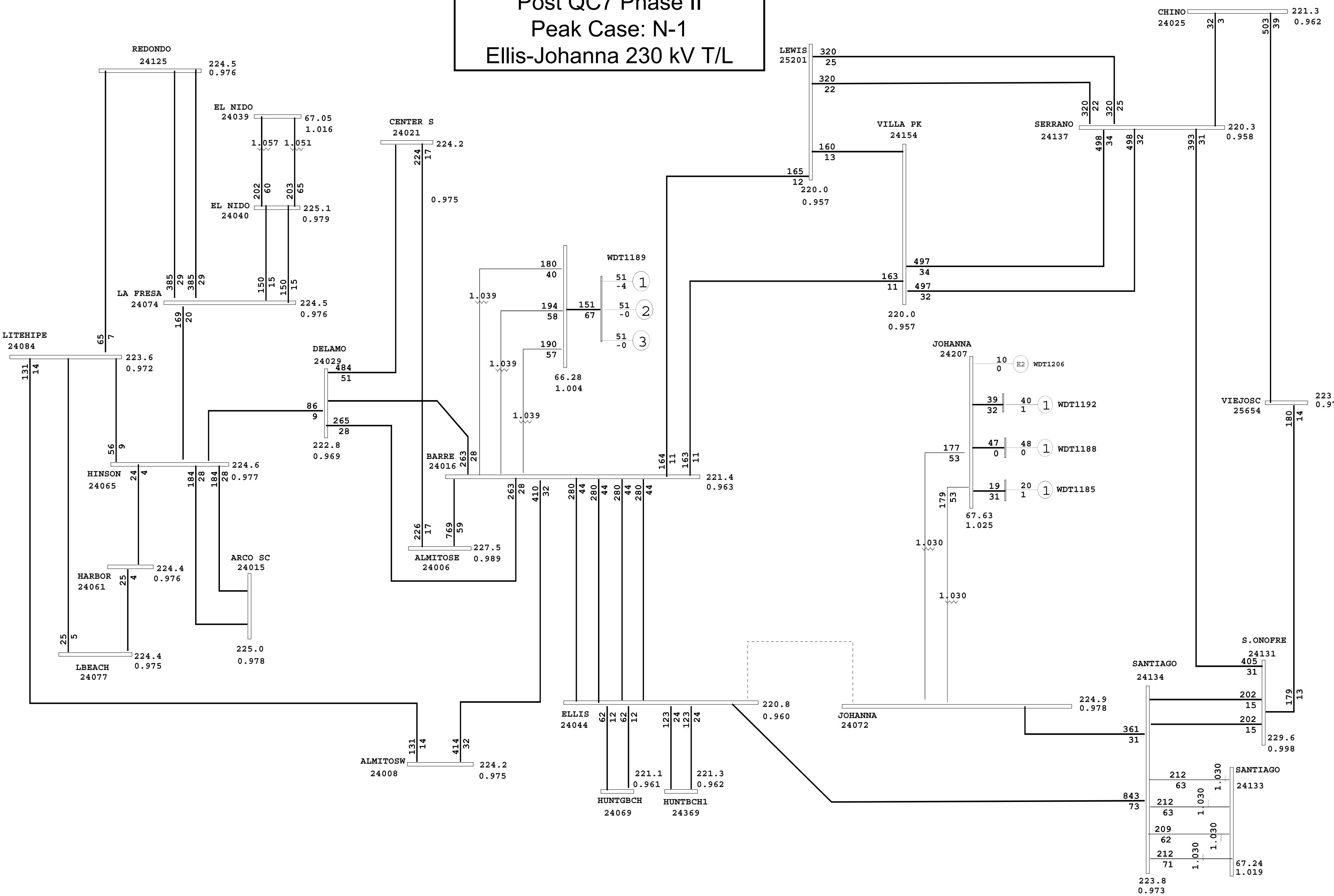
Power Flow Plot
Post QC7 Phase II
Peak Case: N-1
Barre-Ellis No. 2 230 kV T/L



General Electric International, Inc.   PSLF Program   Thu Aug 27 10:46:22 2015   SSTOOLSV6\cases\19p-Metro-PstQC7P2.sav

EC&R CAISO 20 MW EQUIV. COLLECTION SYSTEM, 66 KV GEN-TIE	[0MW][0MW][NORTHERN NEW MEXICO (NM2) 1978MW][EAST OF COLORADO RIVER (EO		MVA/%rate
CASE NAME:cases\19p-Metro-PstQC7P2.sav	[SYLMAR 7550][VIC-LUGO 923][0][0][0]MW		C:\GIP\Projects\Clust
SCE [LOAD 26020 XCHGE-10787 GEN 16382][AA 0V 0M 0D 0VA]MW			Rating = 2

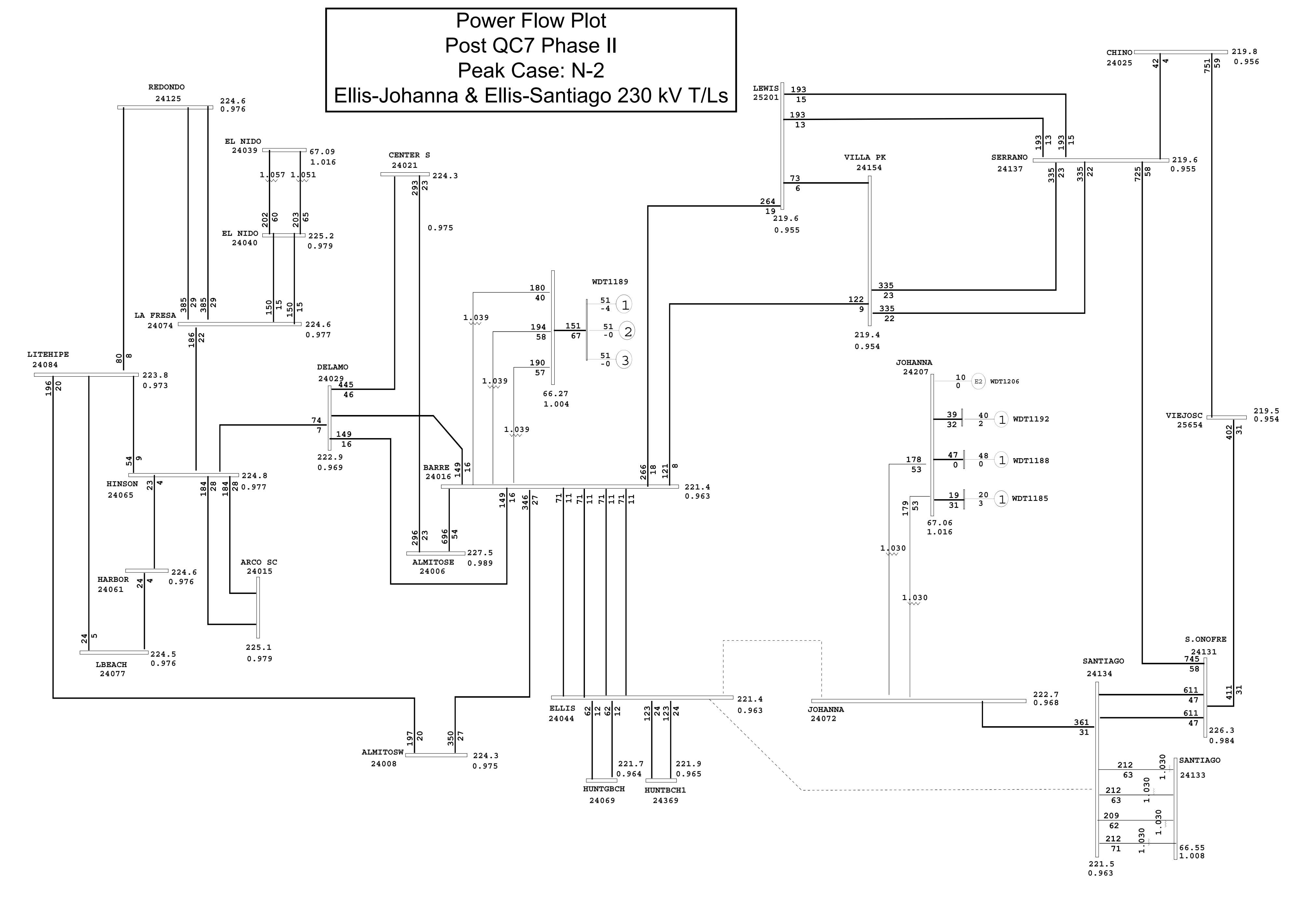
Power Flow Plot
Post QC7 Phase II
Peak Case: N-1
Ellis-Johanna 230 kV T/L



General Electric International, Inc. PSLF Program Thu Aug 27 10:52:27 2015 SSTOOLSV6\cases\19p-Metro-PstQC7P2.sav

GE	EC&R CAISO 20 MW EQUIV. COLLECTION SYSTEM, 66 KV GEN-TIE CASE NAME:cases\19p-Metro-PstQC7P2.sav SCE [LOAD 26020 XCHGE-10787 GEN 16382][AA 0V 0M 0D 0VA]MW	[0MW][0MW][NORTHERN NEW MEXICO (NM2) 1978MW][EAST OF COLORADO RIVER (EO [SYLMAR 7550][VIC-LUGO 923][0][0][0]MW	MVA/%rate gediworkScan.drw Rating = 2

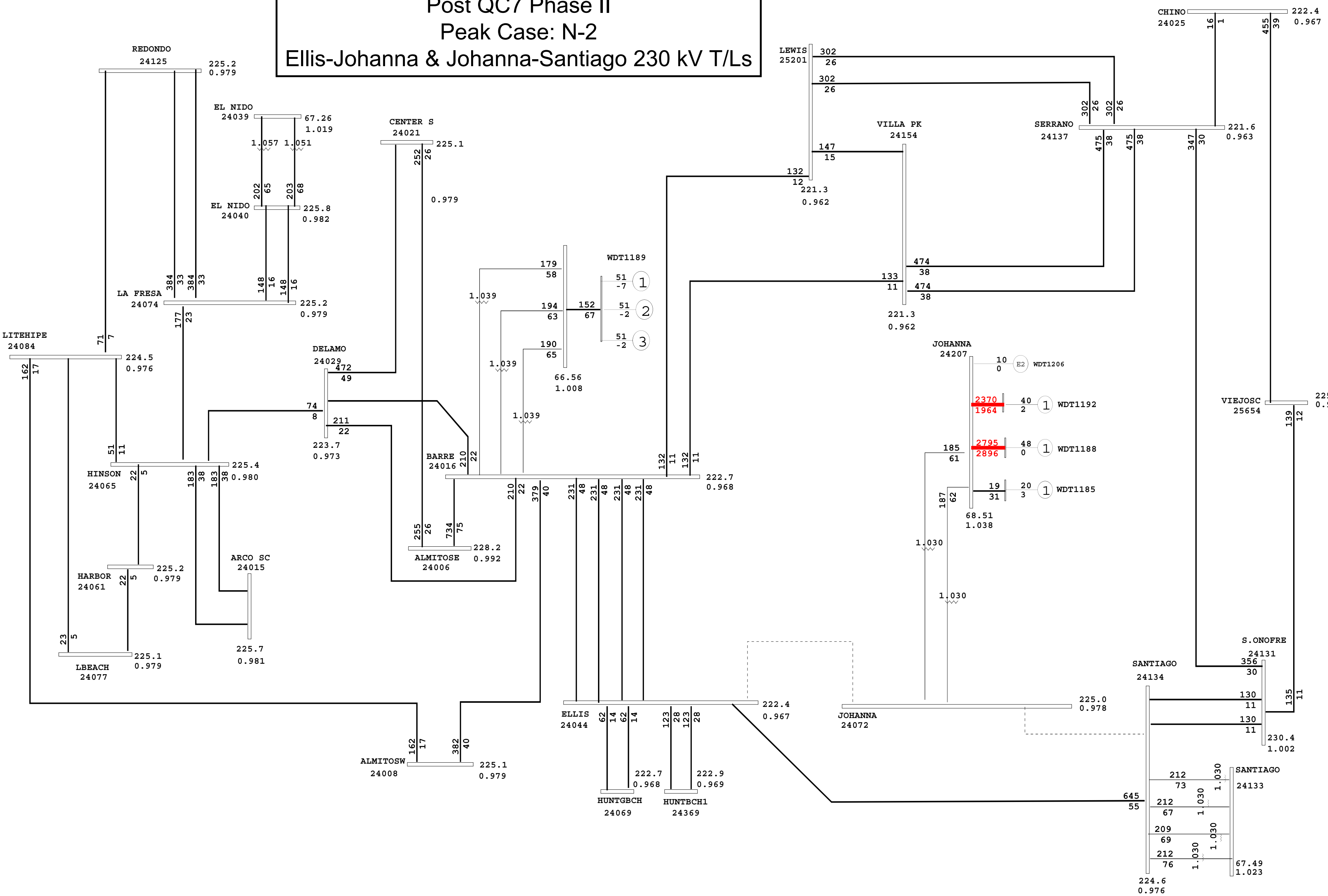
Power Flow Plot
Post QC7 Phase II
Peak Case: N-2
Ellis-Johanna & Ellis-Santiago 230 kV T/Ls



General Electric International, Inc. PSLF Program Thu Aug 27 10:59:21 2015 SSTOOLSV6\cases\19p-Metro-PstQC7P2.sav

EC&R CAISO 20 MW EQUIV. COLLECTION SYSTEM, 66 KV GEN-TIE CASE NAME:cases\19p-Metro-PstQC7P2.sav SCE [LOAD 26020 XCHGE-10787 GEN 16382][AA 0V 0M 0D 0VA]MW	[0MW][0MW][NORTHERN NEW MEXICO (NM2) 1978MW][EAST OF COLORADO RIVER (EO [SYLMAR 7550][VIC-LUGO 923][0][0][0]MW	MVA/%rate gediworkScan.drw Rating = 2

Power Flow Plot
Post QC7 Phase II
Peak Case: N-2
Ellis-Johanna & Johanna-Santiago 230 kV T/Ls



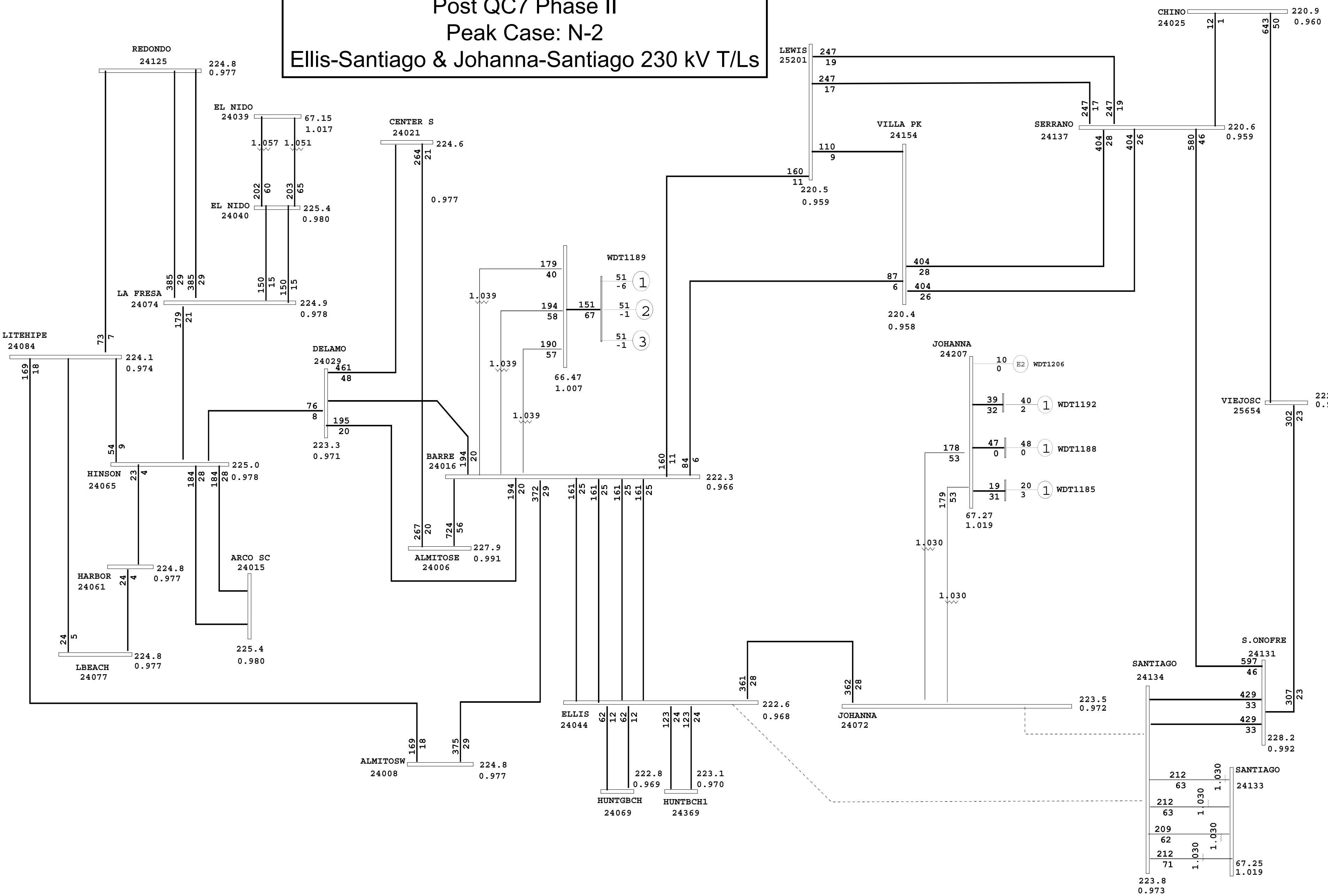
General Electric International, Inc. PSLF Program Thu Aug 27 10:57:37 2015 SSTOOLSV6\cases\19p-Metro-PstQC7P2.sav

EC&R CAISO 20 MW EQUIV. COLLECTION SYSTEM, 66 KV GEN-TIE
CASE NAME:cases\19p-Metro-PstQC7P2.sav
SCE [LOAD 26020 XCHGE-10787 GEN 16382][AA 0V 0M 0D 0VA]MW

[0MW][0MW][NORTHERN NEW MEXICO (NM2) 1978MW][EAST OF COLORADO RIVER (EO
[SYLMAR 7550][VIC-LUGO 923][0][0][0]MW

MVA/%rate
gediworkScan.drw
Rating = 1

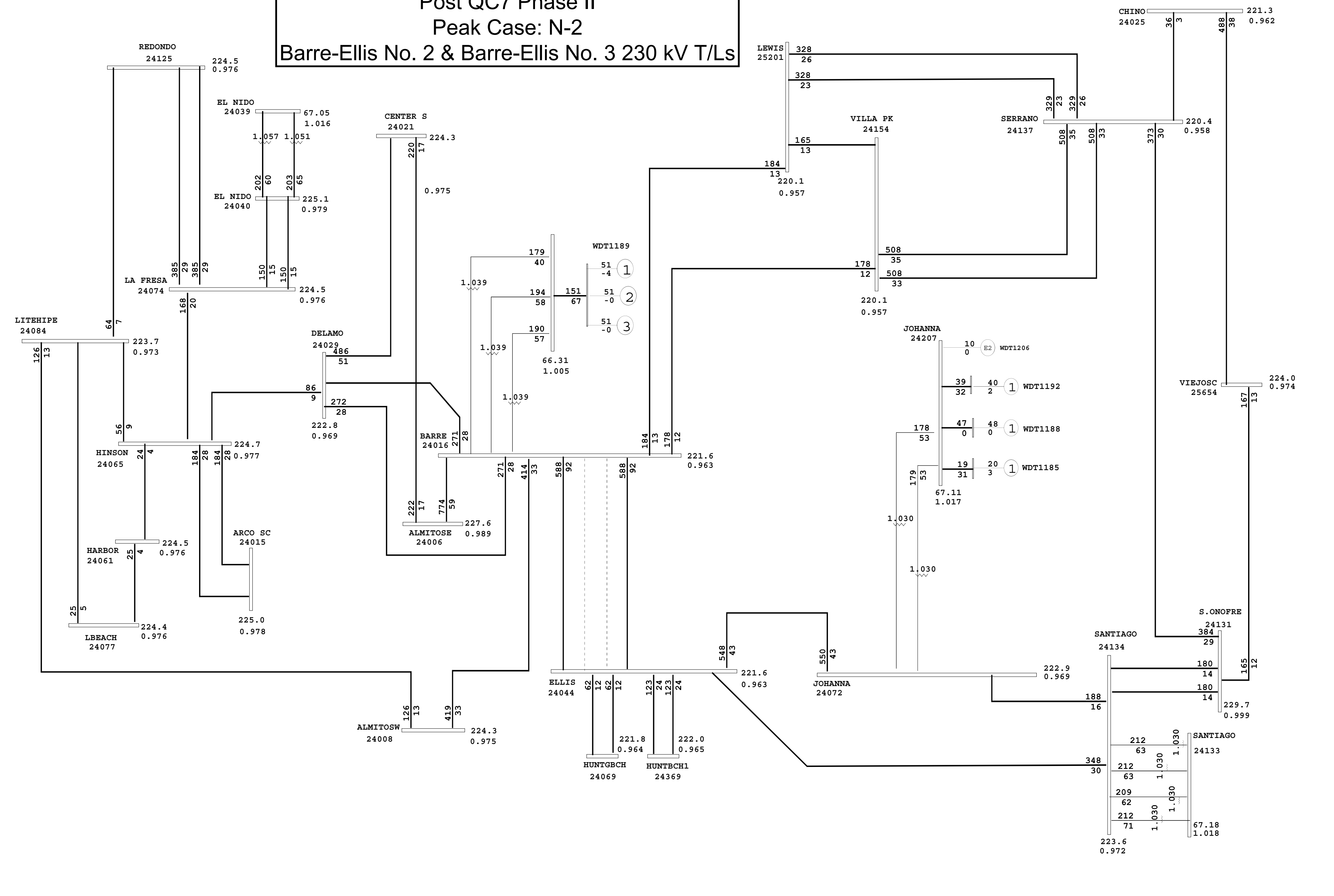
Power Flow Plot
Post QC7 Phase II
Peak Case: N-2
Ellis-Santiago & Johanna-Santiago 230 kV T/Ls



General Electric International, Inc.   PSLF Program   Thu Aug 27 10:55:33 2015   SSTOOLSV6\cases\19p-Metro-PstQC7P2.sav

EC&R CAISO 20 MW EQUIV. COLLECTION SYSTEM, 66 KV GEN-TIE CASE NAME:cases\19p-Metro-PstQC7P2.sav SCE [LOAD 26020 XCHGE-10787 GEN 16382][AA 0V 0M 0D 0VA]MW	[0MW][0MW][NORTHERN NEW MEXICO (NM2) 1978MW][EAST OF COLORADO RIVER (EO [SYLMAR 7550][VIC-LUGO 923][0][0][0]MW	MVA/%rate gediworkScan.drw Rating = 2

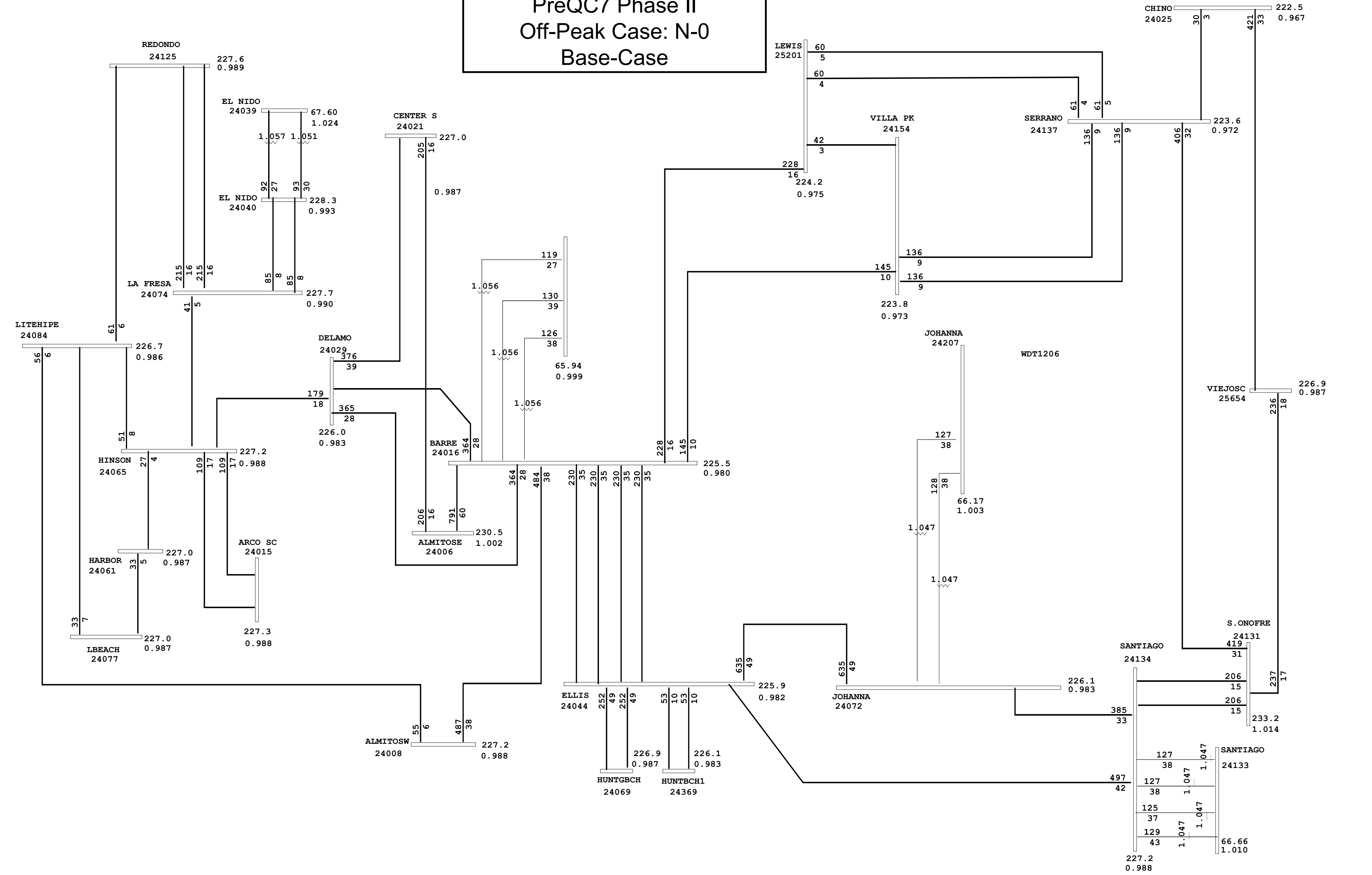
Power Flow Plot
Post QC7 Phase II
Peak Case: N-2
Barre-Ellis No. 2 & Barre-Ellis No. 3 230 kV T/Ls



General Electric International, Inc.   PSLF Program   Thu Aug 27 10:50:39 2015   SSTOOLSV6\cases\19p-Metro-PstQC7P2.sav

EC&R CAISO 20 MW EQUIV. COLLECTION SYSTEM, 66 KV GEN-TIE	[0MW][0MW][NORTHERN NEW MEXICO (NM2) 1978MW][EAST OF COLORADO RIVER (EO	MVA/%rate
CASE NAME:cases\19p-Metro-PstQC7P2.sav	[SYLMAR 7550][VIC-LUGO 923][0][0][0]MW	gediworkScan.drw
SCE [LOAD 26020 XCHGE-10787 GEN 16382][AA 0V 0M 0D 0VA]MW		Rating = 2

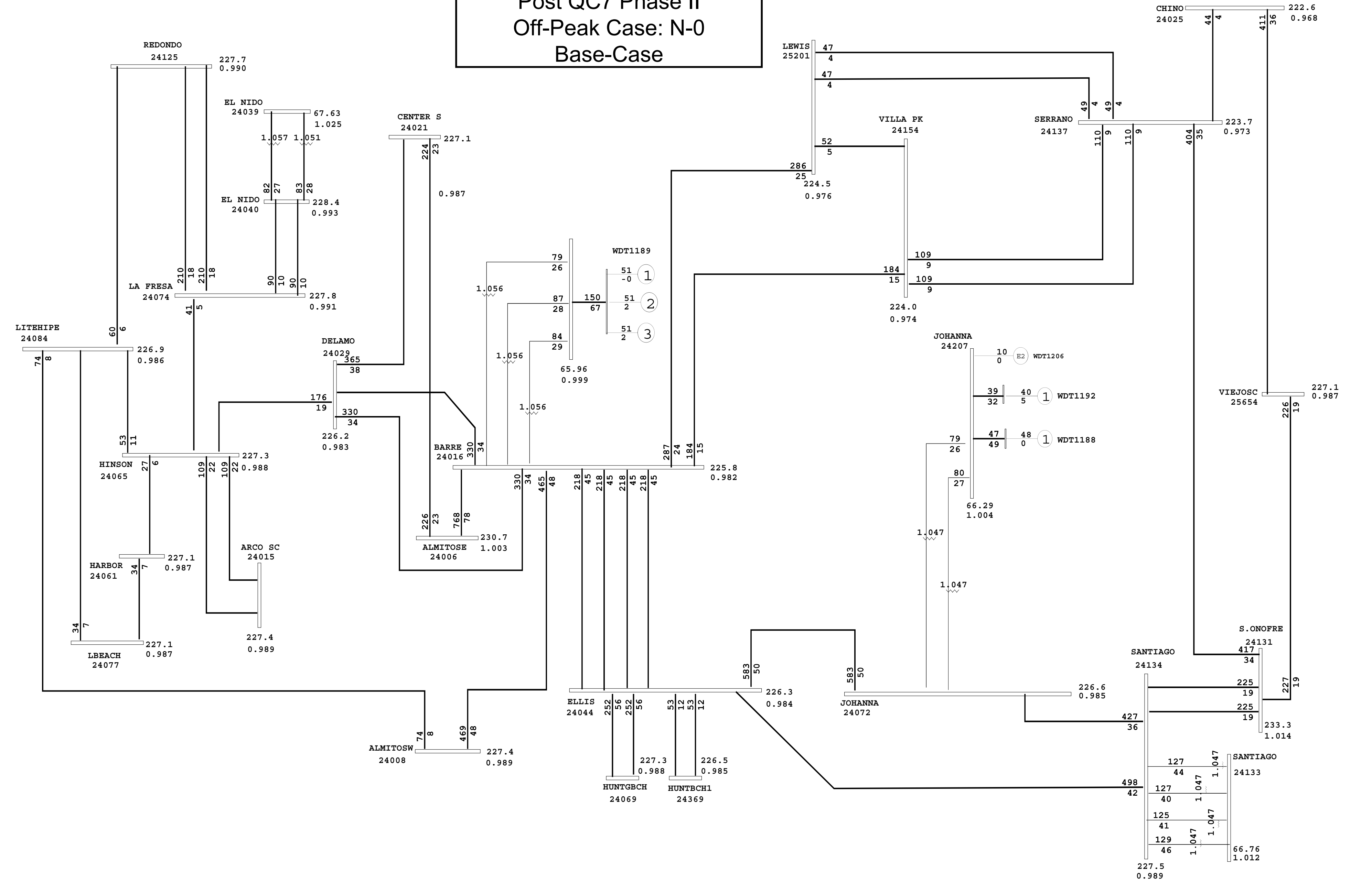
Power Flow Plot
PreQC7 Phase II
Off-Peak Case: N-0
Base-Case



General Electric International, Inc. PSLF Program Fri Sep 11 15:25:13 2015 SSTOOLSV6\cases\19op-Metro-PreQC7P2.sav

2014 SCE ATRA BASE CASE	[0MW][0MW][NORTHERN NEW MEXICO (NM2) 1647MW][EAST OF COLORADO RIVER (EO		MVA/%rate
CASE NAME:C:\GIP\Projects\Clusters\QC7\BaseCases\19op-Metro-PreQC7P2_R6.sav	[SYLMAR-1678][VIC-LUGO 250][0][0][0]MW		C:\GIP\Projects\Clust
SCE [LOAD 15502 XCHGE -76 GEN 16459][AA 0V 0M 0D 0VA]MW			Rating = 2

Power Flow Plot
Post QC7 Phase II
Off-Peak Case: N-0
Base-Case



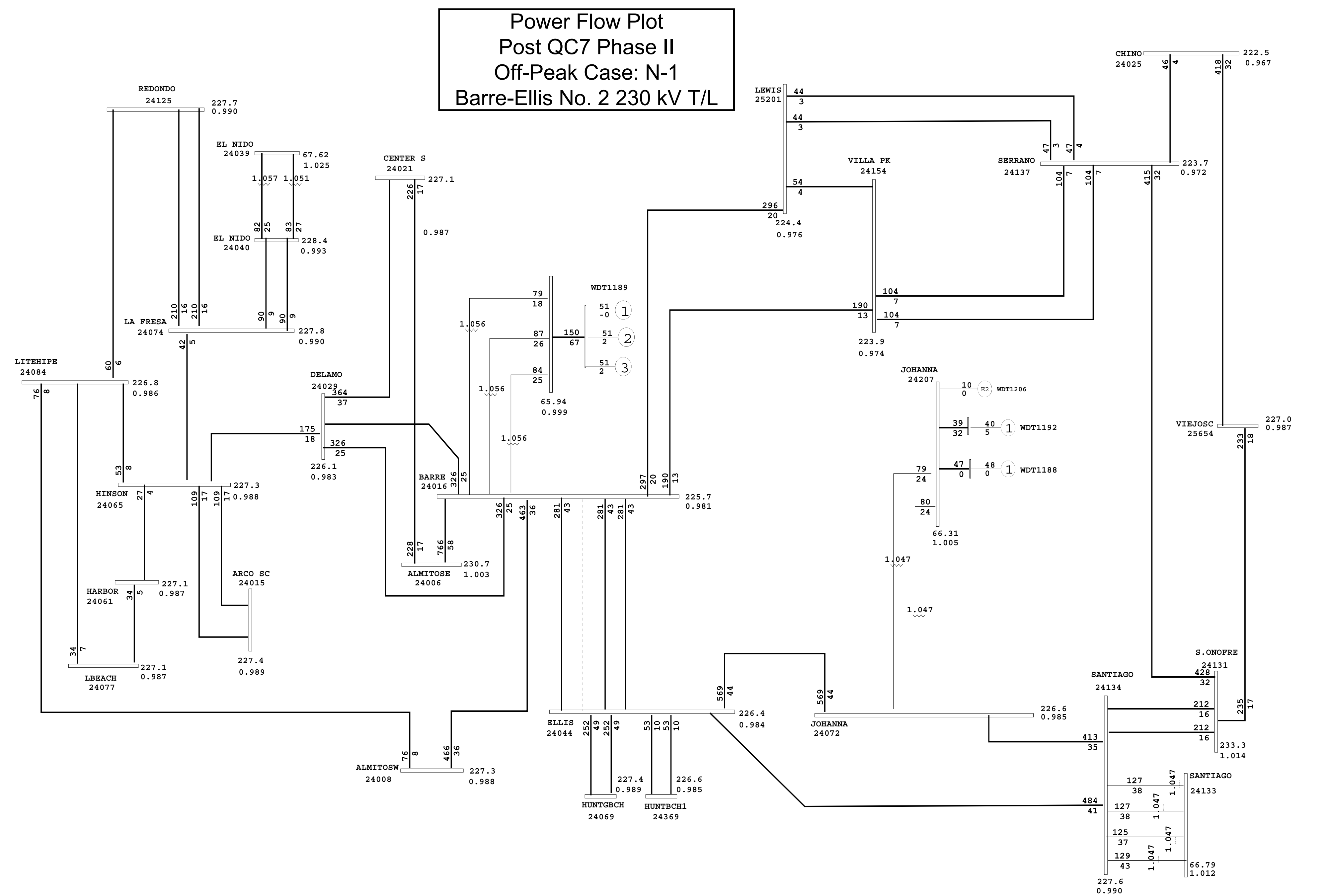
General Electric International, Inc. PSLF Program Thu Aug 27 11:08:39 2015 SSTOOLSV6\cases\19op-Metro-PstQC7P2.sav

2014 SCE ATRA BASE CASE
CASE NAME:C:\GIP\Projects\Clusters\QC7\BaseCases\Dynamics\cases\19op-Metro-PstQ
SCE [LOAD 15505 XCHGE -21 GEN 16514][AA 0V 0M 0D 0VA]MW

[0MW][0MW][NORTHERN NEW MEXICO (NM2) 1647MW][EAST OF COLORADO RIVER (EO
[SYLMAR-1767][VIC-LUGO 251][0][0][0]MW

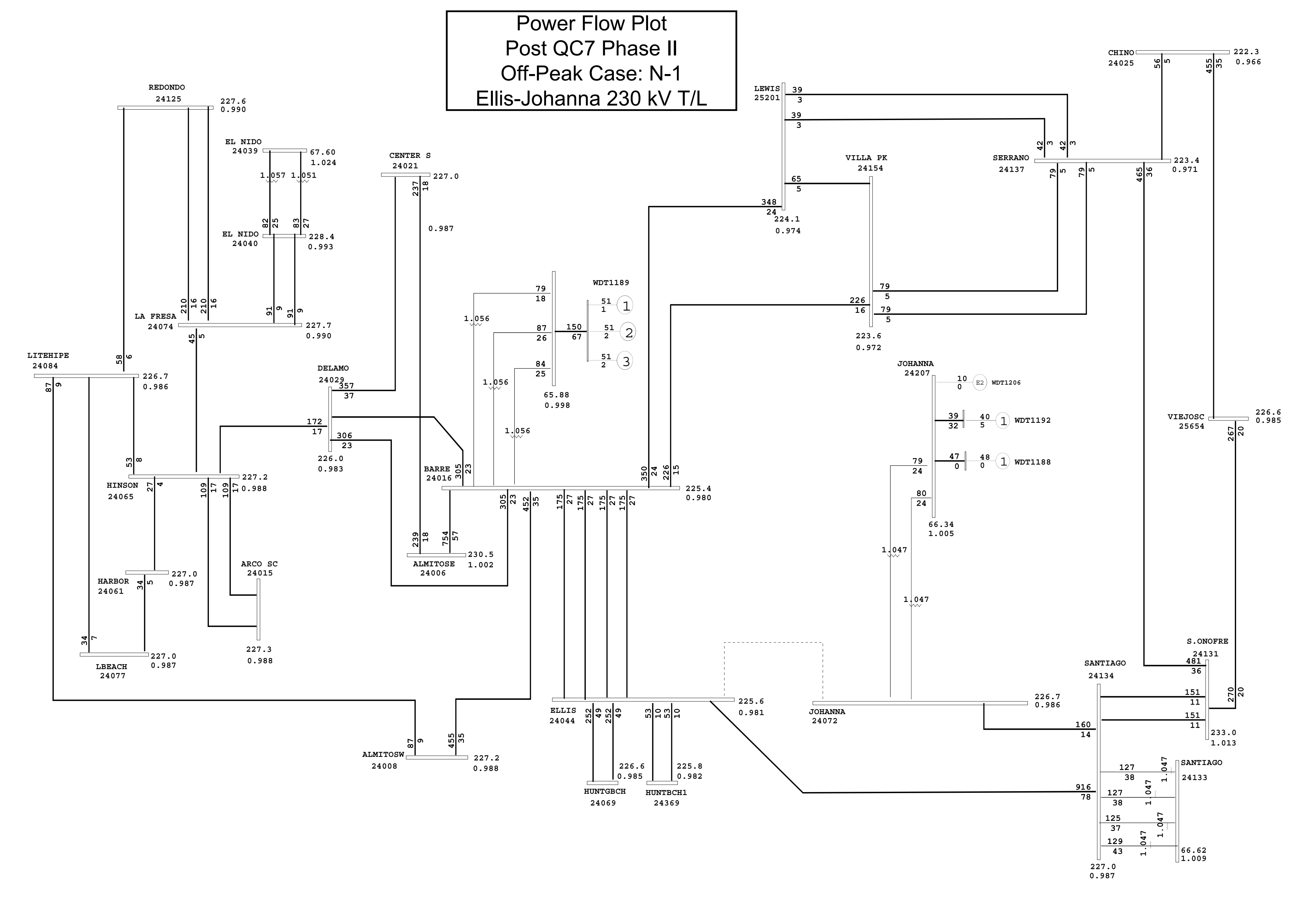
MVA/%rate
gediworkScan.drw
Rating = 1

Power Flow Plot
Post QC7 Phase II
Off-Peak Case: N-1
Barre-Ellis No. 2 230 kV T/L



General Electric International, Inc.   PSLF Program   Thu Aug 27 11:13:59 2015   SSTOOLSV6\cases\19op-Metro-PstQC7P2.sav

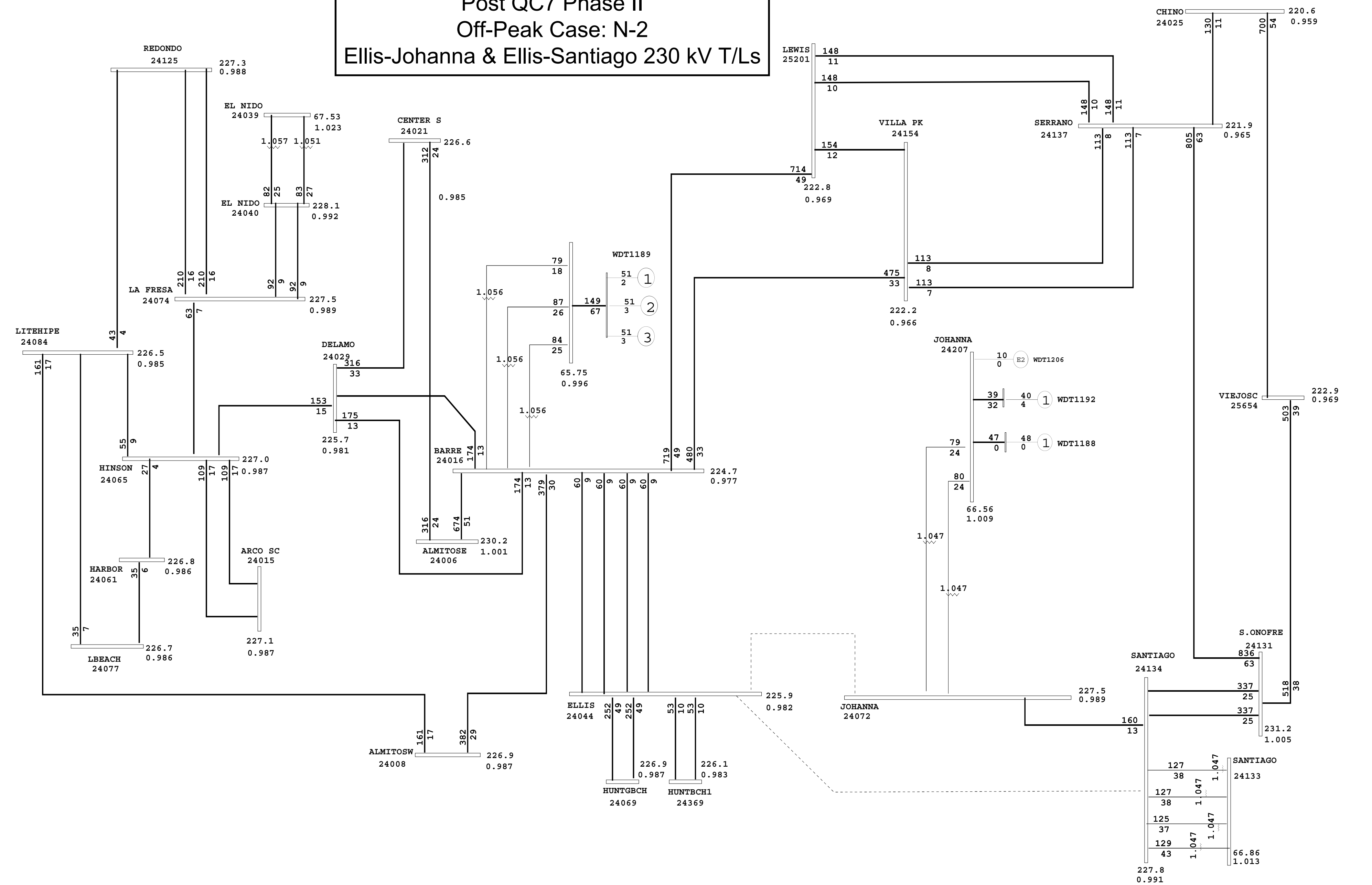
	2014 SCE ATRA BASE CASE CASE NAME:C:\GIP\Projects\Clusters\QC7\BaseCases\Dynamics\cases\19op-Metro-PstQ SCE [LOAD 15505 XCHGE -21 GEN 16514][AA 0V 0M 0D 0VA]MW	[0MW][0MW][NORTHERN NEW MEXICO (NM2) 1647MW][EAST OF COLORADO RIVER (EO [SYLMAR-1767][VIC-LUGO 251][0][0][0]MW	MVA/%rate gediworkScan.drw Rating = 2



General Electric International, Inc. PSLF Program Thu Aug 27 11:01:10 2015 SSTOOLSV6\cases\19op-Metro-PstQC7P2.sav

2014 SCE ATRA BASE CASE CASE NAME:C:\GIP\Projects\Clusters\QC7\BaseCases\Dynamics\cases\19op-Metro-PstQ SCE [LOAD 15505 XCHGE -21 GEN 16514][AA 0V 0M 0D 0VA]MW	[0MW][0MW][NORTHERN NEW MEXICO (NM2) 1647MW][EAST OF COLORADO RIVER (EO [SYLMAR-1767][VIC-LUGO 251][0][0][0]MW	MVA/%rate gediworkScan.drw Rating = 2

Power Flow Plot
Post QC7 Phase II
Off-Peak Case: N-2
Ellis-Johanna & Ellis-Santiago 230 kV T/Ls



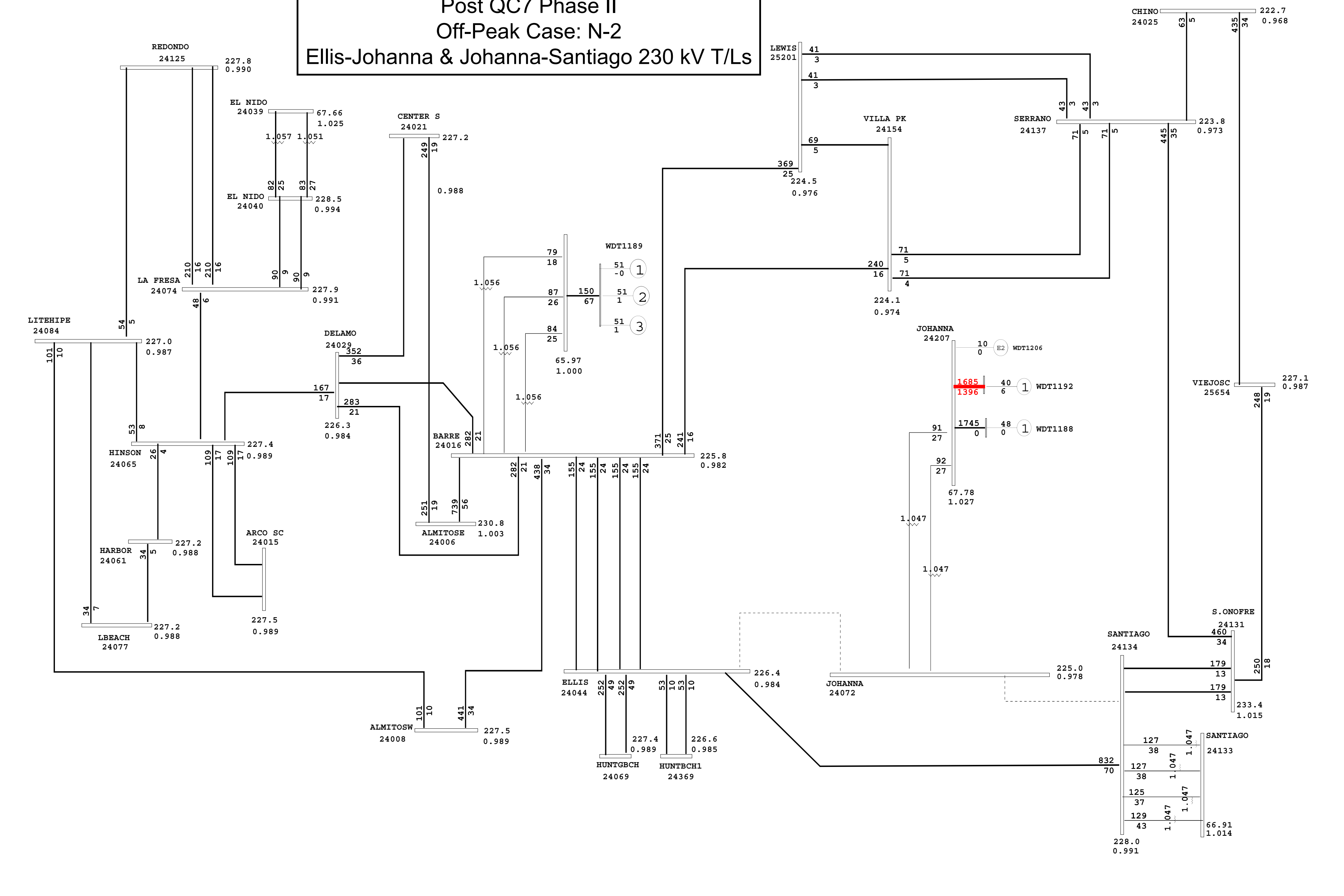
General Electric International, Inc.   PSLF Program   Thu Aug 27 11:05:39 2015   SSTOOLSV6\cases\19op-Metro-PstQC7P2.sav

2014 SCE ATRA BASE CASE
CASE NAME:C:\GIP\Projects\Clusters\QC7\BaseCases\Dynamics\cases\19op-Metro-PstQ
SCE [LOAD 15505 XCHGE -21 GEN 16514][AA 0V 0M 0D 0VA]MW

[0MW][0MW][NORTHERN NEW MEXICO (NM2) 1647MW][EAST OF COLORADO RIVER (EO
[SYLMAR-1767][VIC-LUGO 251][0][0][0]MW

MVA/%rate
gediworkScan.drw
Rating = 2

Power Flow Plot
Post QC7 Phase II
Off-Peak Case: N-2
Ellis-Johanna & Johanna-Santiago 230 kV T/Ls



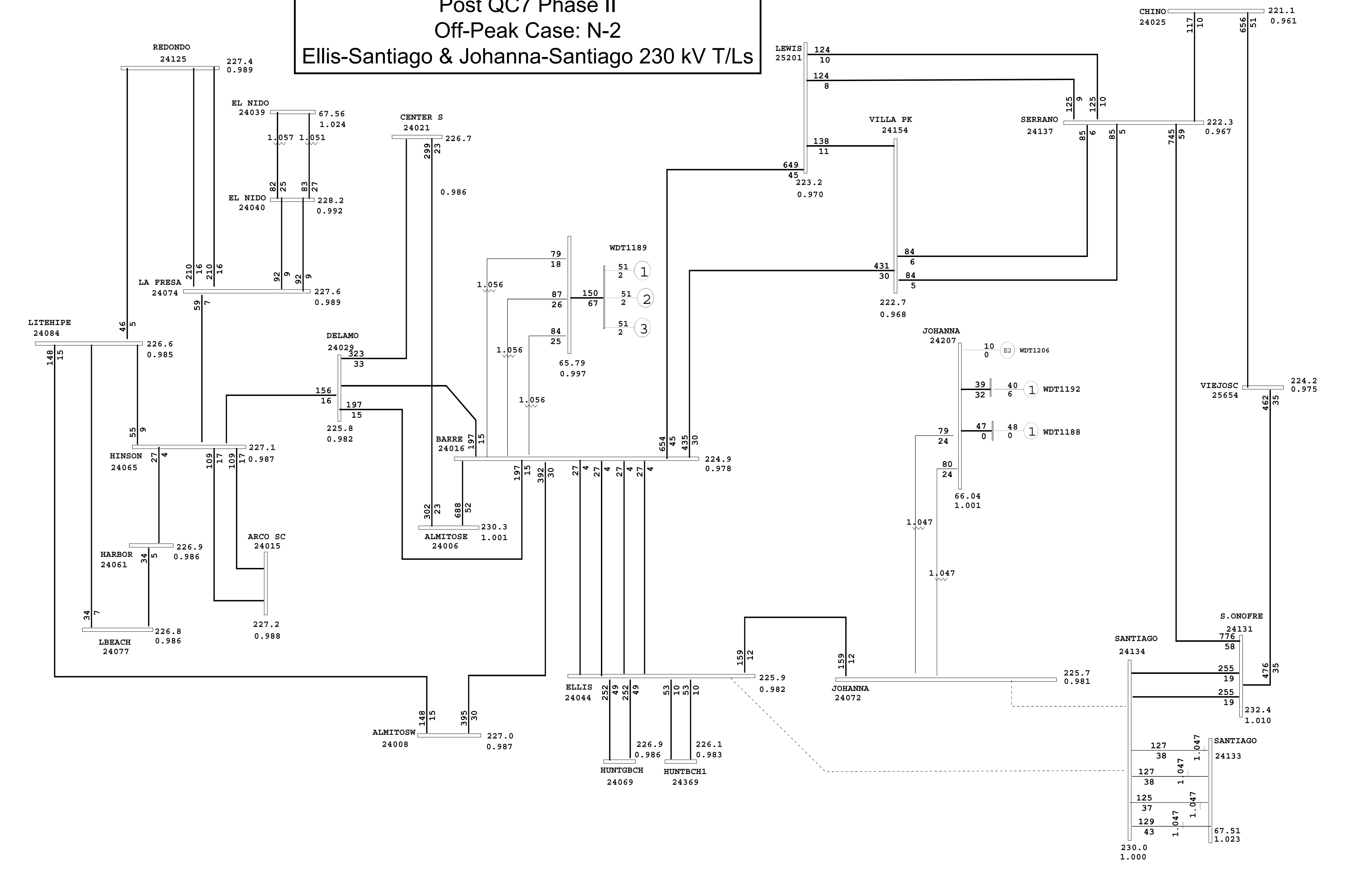
General Electric International, Inc.   PSLF Program   Thu Aug 27 11:04:31 2015   SSTOOLSV6\cases\19op-Metro-PstQC7P2.sav

2014 SCE ATRA BASE CASE
CASE NAME:C:\GIP\Projects\Clusters\QC7\BaseCases\Dynamics\cases\19op-Metro-PstQ
SCE [LOAD 15505 XCHGE -21 GEN 16514][AA 0V 0M 0D 0VA]MW

[0MW][0MW][NORTHERN NEW MEXICO (NM2) 1647MW][EAST OF COLORADO RIVER (EO
[SYLMAR-1767][VIC-LUGO 251][0][0][0]MW

MVA/%rate
gediworkScan.drw
Rating = 2

Power Flow Plot
Post QC7 Phase II
Off-Peak Case: N-2
Ellis-Santiago & Johanna-Santiago 230 kV T/Ls



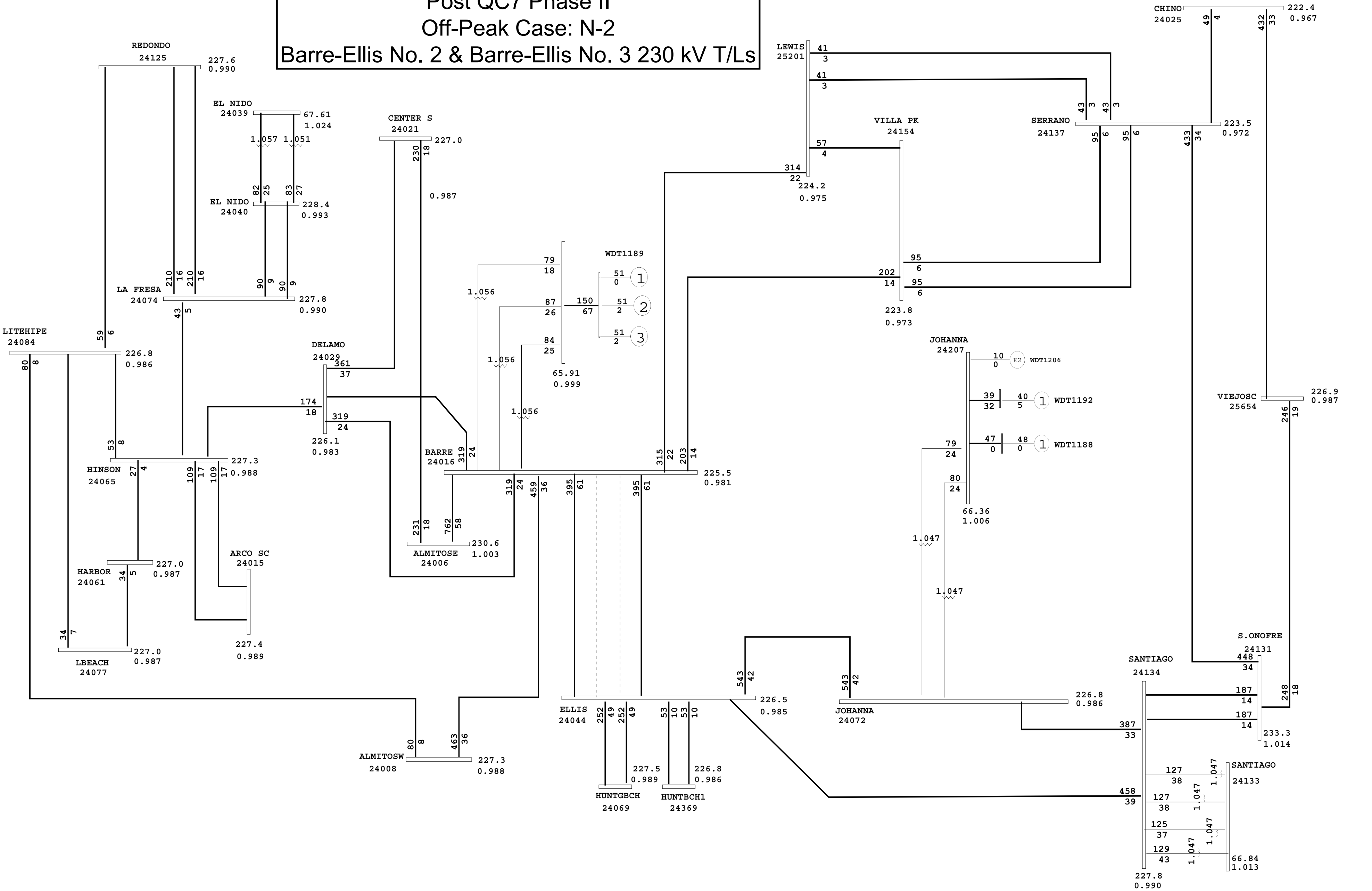
General Electric International, Inc. PSLF Program Thu Aug 27 11:06:59 2015 SSTOOLSV6\cases\19op-Metro-PstQC7P2.sav

2014 SCE ATRA BASE CASE
CASE NAME:C:\GIP\Projects\Clusters\QC7\BaseCases\Dynamics\cases\19op-Metro-PstQ
SCE [LOAD 15505 XCHGE -21 GEN 16514][AA 0V 0M 0D 0VA]MW

[0MW][0MW][NORTHERN NEW MEXICO (NM2) 1647MW][EAST OF COLORADO RIVER (EO
[SYLMAR-1767][VIC-LUGO 251][0][0][0]MW

MVA/%rate
gediworkScan.drw
Rating = 2

Power Flow Plot
Post QC7 Phase II
Off-Peak Case: N-2
Barre-Ellis No. 2 & Barre-Ellis No. 3 230 kV T/Ls



General Electric International, Inc. PSLF Program Thu Aug 27 11:14:45 2015 SSTOOLSV6\cases\19op-Metro-PstQC7P2.sav

2014 SCE ATRA BASE CASE	[0MW][0MW][NORTHERN NEW MEXICO (NM2) 1647MW][EAST OF COLORADO RIVER (EO	MVA/%rate
CASE NAME:C:\GIP\Projects\Clusters\QC7\BaseCases\Dynamics\cases\19op-Metro-PstQ	[SYLMAR-1767][VIC-LUGO 251][0][0][0]MW	gediworkScan.drw
SCE [LOAD 15505 XCHGE -21 GEN 16514][AA 0V 0M 0D 0VA]MW		Rating = 2

Queue Cluster 7 Phase II – Appendix H

Short Circuit Calculation Study Results

NOVEMBER 24, 2015

Table H.3.1a: Existing System with the inclusion of Projects in 2015 Three-Phase-to-ground Fault Analysis

Bus Name	Bus KV	PRE CASE		POST CASE		DELTA KA
		X/R	KA	X/R	KA	
Antelope	525	20.5	32.1	20.8	32.8	0.7
Colorado River	525	18.5	13.4	19	13.8	0.4
Eldorado	525	12.1	46.7	12.3	47.5	0.8
Lugo	525	21.7	45.9	21.8	46.1	0.2
Red Bluff	525	18.6	14.7	18.9	15	0.3
Vincent	525	18.7	40.7	18.9	42.1	1.4
Whirlwind	525	21	29.9	21.3	30.7	0.8
Antelope	230	24.3	36.3	24.6	36.6	0.3
Arcogen	230	16.7	35.5	16.6	35.7	0.2
Barre	230	22.1	58.8	22	59.1	0.3
Center	230	14.9	41.3	14.9	41.7	0.4
Chino	230	14.9	36.5	17.5	47.5	11
Colorado River	230	39.1	14.5	41.2	15.6	1.1
Del Amo	230	16.7	45.2	16.6	45.5	0.3
Devers	230	21.1	37.7	21.2	38	0.3
El Nido	230	17.8	38.1	17.7	38.2	0.1
El Segundo	230	18	33.4	18	33.5	0.1
Ellis	230	17.3	41.6	17.2	41.7	0.1
Etiwanda	230	25.8	55	25.2	56.9	1.9
Gould	230	15	16.1	12.5	23.5	7.4
Highwind	230	22	15.6	22	15.7	0.1
Hinson	230	17.6	40.6	17.6	40.8	0.2
La Fresa	230	22.4	44.4	22.3	44.7	0.3
Laguna Bell	230	15.4	35	15.1	36	1
Lewis	230	21.5	48.7	21.4	49	0.3
Lighthipe	230	17	42.8	17.1	43.2	0.4
Long Beach	230	12.3	27.4	12.2	27.5	0.1
Mesa	230	15.5	49.5	16.1	52.8	3.3
Mira Loma A	230	22.3	47.6	20.5	52.1	4.5
Mira Loma B	230	24.7	54.3	22.4	61.5	7.2
Olinda	230	14.7	30	14.7	30.2	0.2
Ormond Beach	230	32.6	31.4	32.4	31.6	0.2
Pardee	230	15.9	55.1	15.6	57.1	2
Pearblossom	230	5.6	9.9	5.5	10.1	0.2
Rancho	230	26.1	55.9	25.4	57.9	2
Redondo	230	23.3	44.3	23.3	44.6	0.3
Rio Hondo	230	14.5	31.2	14.4	31.4	0.2
San Bernardino	230	20.1	36.4	20	36.5	0.1
Serrano	230	26.4	56.9	26.3	57.3	0.4
Sylmar (SCE)	230	15.3	60.6	15.2	61.4	0.8
Villa Park	230	24.8	50	24.7	50.3	0.3
Vincent A	230	22.6	54.3	20.9	60.4	6.1
Vincent B	230	22.6	54.3	20.9	60.4	6.1
Vista	230	16.3	45.8	16.2	46	0.2
Walnut	230	15.9	34.9	15.9	35.2	0.3
Altwind	115	11.3	15.9	11.1	16.1	0.2

Buckwind	115	15.3	18.4	15.1	18.7	0.3
Devers	115	39.9	24.1	39.1	24.5	0.4
Farrell	115	10.1	13.1	10	13.3	0.2
Garnet	115	18	18	17.7	18.2	0.2
Sanwind	115	9.9	13.6	9.8	14	0.4
Terawind	115	16.6	20	16.3	20.3	0.3
Tiffanywind	115	14	18.3	13.8	18.5	0.2
Venwind	115	6.2	15.2	6.1	15.3	0.1
Cal Cement	66	18.1	18.6	18.1	18.7	0.1
Chino_A	66	45.9	29.8	55.7	31.3	1.5
Chino_B	66	45.9	29.8	55.7	31.3	1.5
Del Sur	66	8.8	19.2	8.8	19.5	0.3
Gould	66	26.4	11	26.4	11.8	0.8
Laguna Bell AB	66	42.2	21.9	42.1	22	0.1
Laguna Bell DE	66	34.6	27.7	34.5	27.8	0.1
Mesa	66	38.3	32	39.6	32.4	0.4
Mira Loma	66	41.4	37.7	41	38.3	0.6
Oasis	66	5.5	9.2	5.7	9.5	0.3
Padua	66	32	25.6	31.9	25.7	0.1
Ritter Ranch	66	7.7	11.6	7.7	11.7	0.1
Saugus_A	66	34.1	38	34.1	38.2	0.2
Saugus_C	66	34.1	38	34.1	38.2	0.2
Viejo	66	31.9	17.6	32.7	17.8	0.2
Windhub66_A	66	45.1	25.1	45.5	25.2	0.1
Windhub66_B	66	45.1	25.1	45.5	25.2	0.1
Antelope	66	29.4	32.6	29.4	33.2	0.6

Table H.3.1b: Existing System with the inclusion of Projects in 2015 Single-Phase-to-ground Fault Analysis

Bus Name	Bus KV	PRE CASE		POST CASE		DELTA KA
		X/R	KA	X/R	KA	
Antelope	525	18.3	28.4	18.4	28.8	0.4
Colorado River	525	13.2	10.9	13.5	11.3	0.4
Eldorado	525	10.7	37.4	11.4	39.9	2.5
Lugo	525	11.8	35.8	11.8	36	0.2
Mira Loma	525	12.1	31.2	12.2	31.3	0.1
Red Bluff	525	11.7	12.4	11.7	12.6	0.2
Vincent	525	15.6	33.7	15.8	34.5	0.8
Whirlwind	525	16.3	26.8	16.3	27.3	0.5
Antelope	230	25.7	40.9	26	41.2	0.3
Barre	230	13.9	46.4	13.9	46.5	0.1
Center	230	14.8	34	14.8	34.2	0.2
Chino	230	11.5	32.5	12.6	41.2	8.7
Colorado River	230	26.8	15.7	27.7	16.9	1.2
Del Amo	230	11.3	42	11.3	42.2	0.2
Devers	230	18.7	42.7	18.7	43	0.3
El Nido	230	16.7	37.3	16.6	37.4	0.1
Etiwanda	230	18.1	55.7	17.8	57	1.3
Hinson	230	19.4	36.3	19.4	36.5	0.2

La Fresa	230	19.7	42.5	19.7	42.7	0.2
Laguna Bell	230	12.9	32.6	12.5	33.2	0.6
Lewis	230	15.5	44.9	15.4	45.1	0.2
Lighthipe	230	11.7	39.4	11.6	39.7	0.3
Mesa	230	11.4	41.6	11.2	43.8	2.2
Mira Loma A	230	15.7	49.3	14.8	52.6	3.3
Mira Loma B	230	16	53.9	15.4	60.1	6.2
Moorpark	230	24.1	29.8	23.9	30	0.2
Olinda	230	12.6	26	12.6	26.1	0.1
Pardee	230	13.8	40.5	13.5	41.5	1
Rancho	230	18.5	57.8	18.1	59.3	1.5
Redondo	230	29.6	40.5	29.5	40.7	0.2
Rio Hondo	230	16.1	26.6	16	26.7	0.1
Sylmar (SCE)	230	12.6	66.7	12.5	67.4	0.7
Villa Park	230	17.4	44.3	17.4	44.4	0.1
Vincent A	230	19.7	55.3	18.9	59.8	4.5
Vincent B	230	19.7	55.3	18.9	59.8	4.5
Walnut	230	16.7	33.5	16.7	33.7	0.2
Altwind	115	9.2	13.4	9.1	13.5	0.1
Buckwind	115	11.6	16.8	11.5	16.9	0.1
Devers	115	35.3	27.8	34.6	28.3	0.5
Garnet	115	13.5	17	13.3	17.1	0.1
Terawind	115	12.6	19	12.5	19.3	0.3
Tiffanywind	115	10.9	16.7	10.8	16.8	0.1
ANTELOPE	66	24	21.9	23	22.7	0.8
Chino_A	66	29.2	18.7	30.4	19.1	0.4
Chino_B	66	29.2	18.7	30.4	19.1	0.4
Gould	66	25.3	10	25.2	10.4	0.4
Mira Loma	66	29.5	28.7	29.3	28.9	0.2
Ritter Ranch	66	9.1	5.4	9	5.5	0.1

Table H.3.2a: Inclusion of Projects in 2016 Three-Phase-to-ground Fault Analysis

Bus Name	Bus KV	PRE CASE		POST CASE		DELTA KA
		X/R	KA	X/R	KA	
Antelope	525	20.8	32.8	21.2	35.5	2.7
Colorado River	525	19.0	13.8	19.5	14.4	0.6
Eldorado	525	12.3	47.5	11.8	50.4	2.9
Lugo	525	21.8	46.1	18.8	49.7	3.6
Mira Loma	525	24.1	34.2	22.4	38.4	4.2
Red Bluff	525	18.9	15.0	19.2	15.4	0.4
Serrano	525	25.5	30.8	24.5	32.2	1.4
Vincent	525	18.9	42.1	18.9	46.9	4.8
Whirlwind	525	21.3	30.7	21.7	33.1	2.4
Antelope	230	24.6	36.6	25.9	38.9	2.3
Barre	230	22.0	59.1	21.9	59.5	0.4
Center	230	14.9	41.7	14.9	41.8	0.1
Chino	230	17.5	47.5	17.2	48.9	1.4
Colorado River	230	41.2	15.6	31.9	21.6	6.0

Del Amo	230	16.6	45.5	16.6	45.6	0.1
Devers	230	21.2	38.0	21.4	38.4	0.4
Eldorado	230	17.4	56.1	17.3	56.7	0.6
Eldorado_2	230	43.5	19	43.7	19.1	0.1
Ellis	230	17.2	41.7	17.1	41.9	0.2
Etiwanda	230	25.2	56.9	24.7	58.4	1.5
Highwind	230	22.0	15.7	21.7	16.4	0.7
Hunt. Beach. A	230	16.8	36.7	16.8	36.8	0.1
Hunt. Beach. B	230	16.8	36.7	16.8	36.8	0.1
Kramer	230	16.2	18.0	15.9	18.8	0.8
Lewis	230	21.4	49.0	21.2	49.6	0.6
Lugo	230	27.9	39.8	27.6	40.5	0.7
Luz	230	19.5	10.4	19.3	10.6	0.2
Mesa	230	16.1	52.8	16.2	53.1	0.3
Mira Loma A	230	20.5	52.1	20.4	54.1	2.0
Mira Loma B	230	23.7	60.8	23.5	63.3	2.5
Olinda	230	14.7	30.2	14.6	30.4	0.2
Pardee	230	15.6	57.1	15.5	57.7	0.6
Rancho	230	25.4	57.9	24.8	59.5	1.6
Red Bluff	230	38.1	14.1	30.5	20.1	6.0
San Bernardino	230	20.0	36.5	19.8	36.8	0.3
Serrano	230	26.3	57.3	26.0	58.5	1.2
Sylmar (SCE)	230	15.2	61.4	15.2	61.7	0.3
Victor	230	15.7	23.8	18.2	32.5	8.7
Villa Park	230	24.7	50.3	24.5	51.0	0.7
Vista	230	16.2	46.0	16.0	46.7	0.7
Walnut	230	15.9	35.2	15.8	35.4	0.2
Whirlwind	230	38.9	31.2	36.0	40.1	8.9
Whirlwind_2	230	38.9	31.2	36.0	40.1	8.9
Buckwind	115	15.1	18.7	15.1	18.8	0.1
Devers	115	39.1	24.5	39.4	24.7	0.2
Terawind	115	16.3	20.3	16.4	20.4	0.1
Tiffanywind	115	13.8	18.5	13.8	18.6	0.1
Lewis	69	30.4	44.7	30.4	44.8	0.1
Antelope	66	29.4	33.2	30.3	34.0	0.8
Cal Cement	66	18.1	18.7	18.1	18.9	0.2
Chino_A	66	55.7	31.3	55.9	31.4	0.1
Chino_B	66	55.7	31.3	55.9	31.4	0.1
Del Sur	66	8.8	19.5	8.9	20.0	0.5
Mira Loma	66	41.0	38.3	41.3	38.5	0.2
Ritter Ranch	66	7.7	11.7	7.7	11.8	0.1
Windhub66_A	66	45.5	25.2	46.3	25.7	0.5
Windhub66_B	66	45.5	25.2	46.3	25.7	0.5

Table H.3.2b: Inclusion of Projects in 2016 Single-Phase-to-ground Fault Analysis

Bus Name	Bus KV	PRE CASE		POST CASE		DELTA KA
		X/R	KA	X/R	KA	
Antelope	525	18.4	28.8	18.2	30.8	2.0
Colorado River	525	13.5	11.3	16.3	13.5	2.2
Eldorado	525	11.4	39.9	11.1	41.3	1.4
Lugo	525	11.8	36.0	10.9	37.5	1.5
Mira Loma	525	12.2	31.3	11.3	34.6	3.3
Red Bluff	525	11.7	12.6	14.1	14.6	2.0
Serrano	525	14.0	27.4	13.6	28.1	0.7
Vincent	525	15.8	34.5	14.7	37.8	3.3
Whirlwind	525	16.3	27.3	17.3	30.3	3.0
Antelope	230	26.0	41.2	27.0	43.8	2.6
Barre	230	13.9	46.5	13.8	46.7	0.2
Chino	230	12.6	41.2	12.3	42.0	0.8
Colorado River	230	27.7	16.9	25.8	24.5	7.6
Devers	230	18.7	43.0	18.9	43.4	0.4
El Segundo	230	18.0	32.9	18.2	33.1	0.2
Eldorado	230	16.0	52.7	15.9	53.1	0.4
Eldorado_2	230	40.7	21.4	40.8	21.6	0.2
Etiwanda	230	17.8	57.0	17.3	58.1	1.1
Kramer	230	11.1	15.5	10.2	16.5	1.0
Lewis	230	15.4	45.1	15.3	45.4	0.3
Lugo	230	22.4	40.6	18.4	41.0	0.4
Mesa	230	11.2	43.8	11.2	44.0	0.2
Mira Loma A	230	14.8	52.6	14.0	54.4	1.8
Mira Loma B	230	15.9	59.5	16.3	61.3	1.8
Pardee	230	13.5	41.5	13.4	41.7	0.2
Rancho	230	18.1	59.3	17.6	60.5	1.2
Red Bluff	230	26.6	15.2	24.3	22.7	7.5
San Bernardino	230	18.5	38.6	18.4	38.8	0.2
Serrano	230	19.1	58.9	18.9	59.7	0.8
Sylmar (SCE)	230	12.5	67.4	12.5	67.6	0.2
Victor	230	12.1	20.8	6.6	26.3	5.5
Villa Park	230	17.4	44.4	17.3	44.8	0.4
Vista	230	13.2	41.2	13.0	41.6	0.4
Whirlwind	230	31.7	34.1	29.6	44.6	10.5
Whirlwind_2	230	31.7	34.1	29.6	44.6	10.5
Devers	115	34.6	28.3	34.8	28.5	0.2
Kramer	115	13.1	23.9	12.9	24.3	0.4
Terawind	115	12.5	19.3	12.5	19.4	0.1
Victor	115	18.7	24.7	17.7	26.7	2.0
Antelope	66	23.0	22.7	23.2	22.9	0.2
Windhub66_A	66	21.2	17.5	21.2	17.6	0.1
Windhub66_B	66	21.2	17.5	21.2	17.6	0.1

Table H.3.3a: Inclusion of Projects in 2017 Three-Phase-to-ground Fault Analysis

Bus Name	Bus KV	PRE CASE		POST CASE		DELTA KA
		X/R	KA	X/R	KA	
Antelope	525	21.6	35.2	21.4	36	0.8
Colorado River	525	19.5	14.4	19.7	14.6	0.2
Eldorado	525	12.3	47.5	11.9	50.8	3.3
Lugo	525	21.9	46.6	18.8	49.6	3
Mira Loma	525	23.9	36.5	22.5	37.5	1
Red Bluff	525	19.2	15.4	19.4	15.5	0.1
Serrano	525	25.4	31.7	24.5	32.2	0.5
Vincent	525	19.4	46.2	19	47.3	1.1
Whirlwind	525	22	32.9	22.1	33.9	1
Alamitos B	230	15.8	30.7	15.7	30.8	0.1
Antelope	230	26	38.8	26.1	39	0.2
Barre	230	22	59.4	21.7	60.4	1
Center	230	14.9	41.7	14.8	41.9	0.2
Chino	230	17.4	48.3	17.2	48.7	0.4
Colorado River	230	31.9	21.6	32.6	22.2	0.6
Del Amo	230	16.6	45.5	16.5	45.8	0.3
Devers	230	21.4	38.3	21.4	38.4	0.1
Eldorado	230	17.4	56.1	16.9	57.2	1.1
Eldorado_2	230	43.5	19	16.3	27.2	8.2
Ellis	230	17.2	41.8	17.4	43.3	1.5
Etiwanda	230	25.4	56.2	25	56.7	0.5
Highwind	230	21.8	16.4	21.5	16.6	0.2
Ivanpah	230	26.5	10.9	19.8	12.6	1.7
Lewis	230	21.4	49.4	21.1	50	0.6
Lugo	230	28.3	39.9	27.7	40.4	0.5
Mesa	230	16.2	53	16.1	53.2	0.2
Mira Loma A	230	20.8	53.6	20.5	54.2	0.6
Mira Loma B	230	23.1	56.7	22.7	57.2	0.5
Rancho	230	25.7	57.2	25.1	57.7	0.5
Santiago	230	17.7	26.3	18.4	28.7	2.4
Serrano	230	26.4	58.1	25.9	58.9	0.8
Victor	230	18.5	32.3	18.2	32.5	0.2
Villa Park	230	24.7	50.8	24.4	51.4	0.6
Vincent A	230	27.6	41.3	27.5	41.6	0.3
Vincent B	230	23.1	45.1	23	45.4	0.3
Vista	230	16.4	45.9	16.2	46.1	0.2
Whirlwind	230	36.3	40	37.2	42.1	2.1
Whirlwind_2	230	36.3	40	37.2	42.1	2.1
Ivanpah	115	29.4	17.2	27.4	18.1	0.9
Lewis	69	30.5	44.8	30.4	44.9	0.1
Ellis A	66	34.1	28.6	34.3	28.7	0.1
Johanna	66	43.9	20.5	45	20.7	0.2
Santiago A	66	45.8	22.9	48.1	23.3	0.4
Santiago B	66	35.7	22	36.9	22.4	0.4

Table H.3.3b: Inclusion of Projects in 2017 Single-Phase-to-ground Fault Analysis

Bus Name	Bus KV	PRE CASE		POST CASE		DELTA KA
		X/R	KA	X/R	KA	
Antelope	525	18.4	30.7	18.3	31.2	0.5
Colorado River	525	16.3	13.5	16.4	13.6	0.1
Eldorado	525	11.4	39.9	11.1	41.7	1.8
Lugo	525	11.6	36	10.9	37.3	1.3
Mira Loma	525	10.5	32.2	10.2	32.7	0.5
Serrano	525	13.9	27.8	13.7	28	0.2
Vincent	525	15	37.5	14.8	38.1	0.6
Whirlwind	525	17.5	30.2	17.7	31.2	1
Antelope	230	27.1	43.7	27.2	43.9	0.2
Barre	230	13.9	46.7	13.7	47.1	0.4
Chino	230	12.5	41.4	12.4	41.6	0.2
Colorado River	230	25.8	24.5	26	24.9	0.4
Del Amo	230	11.3	42.2	11.3	42.3	0.1
Eldorado	230	15.9	52.7	15.7	53.4	0.7
Eldorado_2	230	40.7	21.4	17.7	28.9	7.5
Ellis	230	18.2	36.3	18	37.1	0.8
Etiwanda	230	17.9	56.4	17.7	56.7	0.3
Ivanpah	230	21.7	9.6	12.2	12.8	3.2
Lewis	230	15.4	45.3	15.3	45.6	0.3
Lugo	230	18.6	40.6	18.3	40.9	0.3
Mira Loma A	230	13.9	53.6	13.8	54	0.4
Mira Loma B	230	13.9	50.8	13.8	51.2	0.4
Pardee	230	13.4	41.7	14.4	44.5	2.8
Rancho	230	18.2	58.6	18	59	0.4
Santiago	230	18.3	25.4	18.1	29	3.6
Serrano	230	19.1	59.4	18.8	59.9	0.5
Victor	230	6.7	26.2	6.6	26.3	0.1
Villa Park	230	17.4	44.7	17.2	45	0.3
Vincent A	230	23.9	42.3	23.9	42.5	0.2
Vincent B	230	19.7	45.8	19.6	46	0.2
Vista	230	13.2	41.1	13.1	41.3	0.2
Whirlwind	230	29.8	44.5	30.4	47.3	2.8
Whirlwind_2	230	29.8	44.5	30.4	47.3	2.8
Ivanpah	115	26.3	19.4	23.5	20.8	1.4
Santiago A	66	39.8	20.8	40	21	0.2
Santiago B	66	23.5	16.2	23.5	16.4	0.2

Table H.3.4a: Inclusion of Projects in 2018 Three-Phase-to-ground Fault Analysis

Bus Name	Bus KV	PRE CASE		POST CASE		DELTA KA
		X/R	KA	X/R	KA	
Colorado Rvr	525	19.7	14.6	21.9	16.8	2.2
Red Bluff	525	19.4	15.5	20.6	16.9	1.4
Serrano	525	24.5	32.2	24.5	32.4	0.2
Colorado Rvr	230	32.6	22.2	37.5	23.8	1.6
Devers	230	21.4	38.4	21.9	39.5	1.1

Mirage	230	10.1	18.1	10.1	18.3	0.2
Red Bluff	230	30.7	20.2	33.3	21.1	0.9
Serrano	230	25.9	58.9	26	59	0.1
Altwind	115	11.1	16.1	10.9	16.6	0.5
Buckwind	115	15.1	18.8	14.9	19.4	0.6
Devers	115	39.4	24.7	40.8	25.9	1.2
Farrell	115	9.9	13.3	9.8	13.6	0.3
Garnet	115	17.7	18.3	17.4	18.9	0.6
Sanwind	115	9.8	14	9.7	14.4	0.4
Terawind	115	16.4	20.5	16.2	21.3	0.8
Tiffanywind	115	13.8	18.6	13.6	19.3	0.7
Venwind	115	6.1	15.4	6	15.8	0.4
Banducci	66	0	0	3.3	2.9	2.9

Table H.3.4b: Inclusion of Projects in 2018 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	16.4	13.6	18.1	16.5	2.9
Red Bluff	525	14.1	14.6	14.1	15.8	1.2
Colorado Rvr	230	26	24.9	30	27.2	2.3
Devers	230	18.9	43.4	19.2	44.4	1
Red Bluff	230	24.4	22.8	25.3	23.7	0.9
Altwind	115	9.1	13.5	9	13.8	0.3
Buckwind	115	11.4	17	11.3	17.5	0.5
Devers	115	34.8	28.5	36.3	29.9	1.4
Farrell	115	9.7	12.6	9.6	12.8	0.2
Garnet	115	13.3	17.2	13.1	17.6	0.4
Terawind	115	12.5	19.4	12.4	20	0.6
Tiffanywind	115	10.8	16.9	10.6	17.4	0.5
Valley AB	115	48.5	25.6	48.7	25.7	0.1
Banducci	66	0	0	4.3	1.8	1.8

Table H.3.5a: Inclusion of Energy Only Projects Post 2018 Three-Phase-to-ground Fault Analysis

Bus Name	Bus KV	PRE CASE		POST CASE		DELTA KA
		X/R	KA	X/R	KA	
Alberhil	525	0	0	23.5	23.2	23.2
Antelope	525	21.4	36	21.9	36.8	0.8
Colorado River	525	21.9	16.8	22.8	18.7	1.9
Eldorado	525	11.9	50.8	11.9	51.5	0.7
Lugo	525	18.8	49.7	18.9	51.2	1.5
Mira Loma	525	22.5	37.5	22.4	39	1.5
Red Bluff	525	20.6	16.9	21.6	19.9	3
Serrano	525	24.5	32.4	24.2	35.2	2.8
Valley A	525	26	19.3	25.7	24.4	5.1
Valley B	525	26	19.3	25.7	24.4	5.1
Vincent	525	19	47.3	19.5	48.8	1.5
Whirlwind	525	22.1	33.9	22.6	34.7	0.8

Antelope	230	26.1	39	26.4	39.4	0.4
Barre	230	21.7	60.5	21	63.2	2.7
Center	230	14.8	41.9	15.5	45.7	3.8
Chino	230	17.2	48.8	17.5	49.5	0.7
Colorado River	230	37.5	23.8	40.3	26.1	2.3
Del Amo	230	16.5	45.8	16.5	47	1.2
Devers	230	21.9	39.5	22.7	41.7	2.2
Eldorado	230	16.9	57.3	16.9	57.6	0.3
Eldorado_2	230	16.3	27.2	16.6	28.2	1
Ellis	230	17.4	43.3	16.6	45.5	2.2
Etiwanda	230	24.9	56.8	25.2	58	1.2
Hunt. Beach. A	230	16.8	37.8	15.9	39.2	1.4
Hunt. Beach. B	230	16.8	37.8	15.9	39.2	1.4
Jasper	230	0	0	12.6	9	9
Kramer	230	15.9	18.8	15.8	19.5	0.7
Lewis	230	21.1	50.1	20.7	52	1.9
Lugo	230	27.7	40.5	28.2	41.3	0.8
Luz	230	19.3	10.6	20.7	11.7	1.1
Mesa	230	16.1	53.2	16.6	57.4	4.2
Mira Loma B	230	22.7	57.3	22.7	59.1	1.8
Olinda	230	14.6	30.3	14.9	33.6	3.3
Pardee	230	15.5	57.6	15.5	58.1	0.5
Pastoria	230	13.5	30.2	13.8	30.7	0.5
Primm	230	18.9	12.1	19	12.2	0.1
Rancho	230	25.1	57.8	25.4	59.1	1.3
Red Bluff	230	33.3	21.1	37.7	26.9	5.8
Rio Hondo	230	14.8	30.9	14.8	31.4	0.5
San Onofre	230	17.9	27.5	14	43.4	15.9
Santiago	230	18.4	28.7	17.3	31.6	2.9
Serrano	230	26	59	25.7	62	3
Sylmar (SCE)	230	15.2	61.7	15.2	62	0.3
Victor	230	18.2	32.5	18.1	33	0.5
Villa Park	230	24.4	51.5	24	53.7	2.2
Vincent A	230	27.5	41.6	27.9	45.5	3.9
Vincent B	230	23	45.4	23.3	46	0.6
Walnut	230	15.8	35.4	16	36.7	1.3
Whirlwind	230	37.2	42.1	38.5	43.9	1.8
Wildlife	230	0	0	14.7	24.1	24.1
Alberhil	115	0	0	60.8	19.9	19.9
Altwind	115	10.9	16.6	10.9	16.8	0.2
Buckwind	115	14.9	19.4	14.8	19.7	0.3
Devers	115	40.8	25.9	41.9	26.4	0.5
Farrell	115	9.8	13.6	9.8	13.8	0.2
Garnet	115	17.4	18.9	17.5	19.1	0.2
Kramer	115	13.9	23.9	14	24.2	0.3
Sanwind	115	9.7	14.4	9.6	14.5	0.1
Terawind	115	16.2	21.3	16.2	21.6	0.3
Tiffanywind	115	13.6	19.3	13.5	19.5	0.2

Venwind	115	6	15.8	5.9	16	0.2
Lewis	69	30.4	44.9	30.4	45.3	0.4
Antelope	66	30.4	34.1	30.4	34.5	0.4
Barre AB	66	47.1	23.6	50.3	30	6.4
Center B	66	22.3	27.5	22.8	27.8	0.3
Del Sur	66	8.9	20	8.9	20.2	0.2
Ellis A	66	34.3	28.7	34.2	28.9	0.2
Johanna	66	45	20.7	46.3	22.7	2
Mesa	66	39.8	32.5	41	32.9	0.4
Olinda	66	37	22.6	38.5	23.1	0.5
Rio Hondo	66	24.8	32.3	24.8	32.5	0.2
Santiago A	66	48.1	23.3	48.1	23.7	0.4
Santiago B	66	36.9	22.4	36.7	22.8	0.4
Viejo	66	32.8	17.9	32.8	18.3	0.4
Villa Park	66	43.5	32.7	43.5	32.9	0.2
Walnut	66	31.6	30.3	32	30.6	0.3
Wilderness	66	0	0	32.9	27.3	27.3

Table H.3.5b: Inclusion of Energy Only Projects Post 2018 Single-Phase-to-ground Fault Analysis

Bus Name	Bus KV	PRE CASE		POST CASE		DELTA
		X/R	KA	X/R	KA	KA
Alberhil	525	0	0	14	23.5	23.5
Antelope	525	18.3	31.2	18.3	31.7	0.5
Colorado Rvr	525	18.1	16.5	18.6	18.2	1.7
Eldorado	525	11.1	41.7	11.1	42.5	0.8
Lugo	525	10.9	37.3	10.9	38.1	0.8
Mira Loma	525	10.2	32.7	10	33.5	0.8
Red Bluff	525	14.1	15.8	14.9	18.4	2.6
Serrano	525	13.6	28.1	12.4	30.6	2.5
Valley A	525	15.2	19.7	13.8	24.8	5.1
Valley B	525	15.2	19.7	13.8	24.8	5.1
Vincent	525	14.8	38.1	15	39.1	1
Whirlwind	525	17.7	31.2	17.9	32.2	1
Antelope	230	27.2	43.9	27.4	44.3	0.4
Barre	230	13.7	47.1	13.3	48.2	1.1
Center	230	14.8	34.3	14.3	39.1	4.8
Chino	230	12.4	41.6	12.5	41.9	0.3
Colorado Rvr	230	30	27.2	31.2	30.4	3.2
Del Amo	230	11.3	42.4	11.2	43	0.6
Devers	230	19.2	44.4	19.4	46.4	2
El Segundo	230	17.9	33	19.2	33.6	0.6
Eldorado	230	15.7	53.4	15.7	53.7	0.3
Eldorado_2	230	17.7	28.9	17.9	30.4	1.5
Ellis	230	18	37.1	17.1	39.5	2.4
Etiwanda	230	17.7	56.8	17.7	57.6	0.8
Hunt. Bch. A	230	19.9	29	18.9	33.6	4.6
Hunt. Bch. B	230	19.9	29	18.9	33.6	4.6
Jasper	230	0	0	10.5	6.7	6.7

Kramer	230	10.2	16.5	9.6	17.1	0.6
Lewis	230	15.2	45.7	14.9	46.8	1.1
Lugo	230	18.3	40.9	18.5	41.8	0.9
Luz	230	12.7	9.8	15.8	11.5	1.7
McCullough	230	13.6	51	13.6	51.2	0.2
Mesa	230	11.1	44	11.2	48.6	4.6
Mira Loma B	230	13.8	51.2	14	52	0.8
Olinda	230	12.5	26.2	11.4	29.5	3.3
Pardee	230	14.4	44.5	14.3	44.7	0.2
Pastoria	230	13.2	27.6	14.7	32.5	4.9
Rancho	230	18	59.1	18	60	0.9
Red Bluff	230	25.3	23.7	27.8	30.6	6.9
Rio Hondo	230	16.3	26.5	16.2	26.7	0.2
Santiago	230	18.1	29	17.5	31	2
Serrano	230	18.8	60	17.8	62.9	2.9
Victor	230	6.6	26.3	6.6	26.6	0.3
Villa Park	230	17.2	45	16.7	46.3	1.3
Vincent A	230	23.9	42.5	23.9	46.1	3.6
Vincent B	230	19.6	46	19.7	46.6	0.6
Walnut	230	16.6	33.8	16.6	34.6	0.8
Whirlwind	230	30.4	47.3	30	50.1	2.8
Whirlwind_2	230	30.4	47.3	30	50.1	2.8
Wildlife	230	0	0	15.9	18.5	18.5
Alberhil	115	0	0	49.7	24.8	24.8
Altwind	115	9	13.8	9	13.9	0.1
Buckwind	115	11.3	17.5	11.3	17.7	0.2
Devers	115	36.3	29.9	36.8	30.4	0.5
Garnet	115	13.1	17.6	13.3	17.9	0.3
Kramer	115	12.9	24.3	12.7	24.5	0.2
Terawind	115	12.4	20	12.3	20.2	0.2
Tiffanywind	115	10.6	17.4	10.6	17.5	0.1
Valley AB	115	48.7	25.7	50.7	26.7	1
Valley D	115	50.3	23.9	32.2	39.3	15.4
Victor	115	17.7	26.7	17.7	26.8	0.1
Antelope	66	23.2	22.9	23.2	23	0.1
Barre AB	66	29.9	16.8	27.7	28.7	11.9
Center B	66	24.1	20.9	24.4	21	0.1
Johanna	66	30.6	13.2	34.6	15.7	2.5
Mesa	66	29.5	20	29.7	20.1	0.1
Olinda	66	26.7	15.1	27	15.2	0.1
Santiago A	66	40	21	40.1	21.2	0.2
Viejo	66	28	12.3	28	12.5	0.2
Wilderness	66	0	0	11.5	23.2	23.2

Table H.3.6a: Inclusion of In-Flight upgrades and All Other Pending Deliverability Network Upgrades Three-Phase-to-ground Fault Analysis

Bus Name	Bus KV	PRE CASE		POST CASE		DELTA
		X/R	KA	X/R	KA	KA
Alberhil	525	23.5	23.2	23.2	23.7	0.5
Antelope	525	21.9	36.8	22	37.4	0.6
Colorado River	525	22.8	18.7	21.7	22.6	3.9
Eldorado	525	11.9	51.5	11.9	51.6	0.1
Lugo	525	18.9	51.2	19.2	52.4	1.2
Mesa	525	0	0	24.8	29.3	29.3
Mira Loma	525	22.4	39	23	41	2
Red Bluff	525	21.6	19.9	21.4	22.2	2.3
Valley A	525	25.7	24.4	25.6	25.2	0.8
Valley B	525	25.7	24.4	25.6	25.2	0.8
Vincent	525	19.5	48.8	19.6	50.3	1.5
Whirlwind	525	22.6	34.7	22.6	35.2	0.5
Alamitos A	230	22.4	32.8	22.2	33	0.2
Alamitos B	230	14.3	29.5	14.2	29.7	0.2
Antelope	230	26.4	39.4	26.6	39.6	0.2
Arcogen	230	16.4	35.2	16.3	35.9	0.7
Barre	230	21	63.2	20.7	63.8	0.6
Center	230	15.5	45.7	15.4	46.7	1
Chino	230	17.5	49.5	17.7	50.1	0.6
Colorado River	230	40.3	26.1	41.9	28.3	2.2
Del Amo	230	16.5	47	16.1	49.4	2.4
Devers	230	22.7	41.7	25.2	49.1	7.4
El Casco	230	11.2	11.7	18.4	17.6	5.9
El Nido	230	17.6	36.5	17.6	37.3	0.8
El Segundo	230	18.4	32.8	18.4	33.4	0.6
Ellis	230	16.6	45.5	16.5	45.8	0.3
Etiwanda	230	25.2	58	27.5	59.8	1.8
Goodrich	230	13.3	21.9	14.3	27.8	5.9
Gould	230	12.5	23.7	12.9	25.3	1.6
Hinson	230	17.3	40.2	17.2	41	0.8
Hunt. Beach A	230	15.9	39.2	15.8	39.4	0.2
Hunt. Beach B	230	15.9	39.2	15.8	39.4	0.2
La Fresa	230	20.3	41.3	20.5	42.6	1.3
Laguna Bell	230	14.9	36	16.8	56.8	20.8
Lewis	230	20.7	52	20.6	52.2	0.2
Lighthipe	230	16.7	42.3	16.6	42.9	0.6
Long Beach	230	12.2	27.2	12.1	27.6	0.4
Lugo	230	28.2	41.3	28.5	41.5	0.2
Mesa	230	16.6	57.4	18.9	60.1	2.7
Mesa_2	230	0	0	19.3	63.6	63.6
Mira Loma A	230	20.8	53.4	21.1	54.1	0.7
Mira Loma B	230	22.7	59.1	24	60.5	1.4
Olinda	230	14.9	33.6	14.9	33.8	0.2
Ramon	230	9.9	18.3	9.8	19.1	0.8
Rancho	230	25.4	59.1	27.6	60.9	1.8

Red Bluff	230	37.7	26.9	38.8	28.2	1.3
Redondo	230	19.5	38.8	19.6	39.5	0.7
Rio Hondo	230	14.8	31.4	15.9	32.9	1.5
San Benardino	230	20.1	36.3	25	41.2	4.9
San Onofre	230	14	43.4	14.3	47.3	3.9
Santiago	230	17.3	31.6	17.3	32	0.4
Serrano	230	25.7	62	25.7	62.5	0.5
Villa Park	230	24	53.7	24	53.9	0.2
Vincent B	230	23.3	46	23.3	46.3	0.3
Vista	230	16.3	43.6	20.5	47.9	4.3
Walnut	230	16	36.7	16.1	37	0.3
Westwing	230	15.8	62.4	15.9	62.7	0.3
Whirlwind	230	38.5	43.9	38.7	44.2	0.3
Whirlwind_2	230	38.5	43.9	38.7	44.2	0.3
Wildlife	230	14.7	24.1	15.2	24.7	0.6
Altwind	115	10.9	16.8	10.8	17.2	0.4
Buckwind	115	14.8	19.7	14.9	20.2	0.5
Devers	115	41.9	26.4	44.9	27.3	0.9
Farrell	115	9.8	13.8	9.7	14	0.2
Garnet	115	17.5	19.1	17.5	19.5	0.4
Sanwind	115	9.6	14.5	9.6	14.8	0.3
Terawind	115	16.2	21.6	16.3	22.1	0.5
Tiffanywind	115	13.5	19.5	13.5	20	0.5
Venwind	115	5.9	16	5.9	16.3	0.3
Vista	115	26.9	19.6	28.7	19.9	0.3
Del Amo	66	57.5	23.1	57.9	23.2	0.1
Etiwanda B	66	52.2	15.5	53.3	26.5	11
Gould	66	26.4	11.8	26.9	11.9	0.1
La Fresa B	66	39.8	26.1	40	26.2	0.1
Lag. Bell AB	66	41.8	22	49.6	23.4	1.4
Lag. Bell DE	66	34.4	27.8	38.4	29.4	1.6
Mesa	66	41	32.9	44.4	33.4	0.5
Rio Hondo	66	24.8	32.5	25.9	32.9	0.4
San Benardino	66	38.5	30.7	43	31.6	0.9
Vista A	66	38	26.9	40.6	27.1	0.2
Vista C	66	22.7	25.8	23.5	26.1	0.3
Wilderness	66	32.9	27.3	33.6	27.5	0.2

Table H.3.6b Inclusion of In-Flight upgrades and All Other Pending Deliverability Single-Phase-to-ground Fault Analysis

Bus Name	Bus KV	PRE CASE		POST CASE		DELTA KA
		X/R	KA	X/R	KA	
Alberhil	525	14	23.5	13.9	23.9	0.4
Antelope	525	18.3	31.7	18.1	32.1	0.4
Colorado River	525	18.6	18.2	17.4	21	2.8
Lugo	525	10.9	38.1	10.7	38.7	0.6
Mesa	525	0	0	13.9	25.1	25.1

Mira Loma	525	10	33.5	10.3	35.3	1.8
Red Bluff	525	14.9	18.4	14.5	19.8	1.4
Serrano	525	12.4	30.6	12.2	30.9	0.3
Valley A	525	13.8	24.8	13.7	25.4	0.6
Valley B	525	13.8	24.8	13.7	25.4	0.6
Vincent	525	15	39.1	14.1	40.4	1.3
Whirlwind	525	17.9	32.2	17.8	32.5	0.3
Alamitos A	230	15.2	31.3	15.1	31.4	0.1
Antelope	230	27.4	44.3	27.5	44.4	0.1
Arcogen	230	17.1	29.9	17.1	30.2	0.3
Barre	230	13.3	48.2	13.2	48.4	0.2
Center	230	14.3	39.1	14.2	39.7	0.6
Chino	230	12.5	41.9	13.6	44.3	2.4
Colorado River	230	31.2	30.4	31.6	32.5	2.1
Del Amo	230	11.2	43	10.7	44.3	1.3
Devers	230	19.4	46.4	21.9	52	5.6
El Casco	230	6.6	10.2	12.7	12.6	2.4
El Nido	230	16.6	36.2	16.5	36.7	0.5
El Segundo	230	19.2	33.6	19.1	33.9	0.3
Ellis	230	17.1	39.5	17.1	39.7	0.2
Etiwanda	230	17.7	57.6	19.1	60.7	3.1
Hinson	230	19.1	36.1	19.2	36.5	0.4
Hunt. Beach A	230	18.9	33.6	18.9	33.7	0.1
Hunt. Beach B	230	18.9	33.6	18.9	33.7	0.1
La Fresa	230	18.8	39	18.4	39.7	0.7
Laguna Bell	230	12.2	33.3	3.3	39.2	5.9
Lewis	230	14.9	46.8	14.9	46.9	0.1
Lugo	230	18.5	41.8	18.5	42	0.2
Mesa	230	11.2	48.6	13.5	50.6	2
Mesa_2	230	0	0	13.3	63.4	63.4
Mira Loma A	230	14	53.1	14.8	54.1	1
Mira Loma B	230	14	52	13.9	53.4	1.4
Mirage	230	10.6	16.5	10.6	17	0.5
Olinda	230	11.4	29.5	11.3	29.7	0.2
Rancho	230	18	60	18.9	62.5	2.5
Red Bluff	230	27.8	30.6	28.1	31.7	1.1
Rio Hondo	230	16.2	26.7	14	30.1	3.4
San Benardino	230	18.5	38.5	24.4	41.3	2.8
San Onofre	230	8	30.7	8.6	47.8	17.1
Santiago	230	17.5	31	17.6	31.3	0.3
Serrano	230	17.8	62.9	17.8	63.3	0.4
Villa Park	230	16.7	46.3	16.7	46.4	0.1
Vincent A	230	23.9	46.1	23.6	46.3	0.2
Vincent B	230	19.7	46.6	18.1	46.7	0.1
Vista	230	13.2	40.8	15.8	43.7	2.9
Walnut	230	16.6	34.6	16.4	35	0.4
Westwing	230	12	57.9	12	58.1	0.2
Whirlwind	230	30	50.1	30	50.3	0.2

Whirlwind_2	230	30	50.1	30	50.3	0.2
Wildlife	230	15.9	18.5	16.3	18.8	0.3
Altwind	115	9	13.9	8.9	14.1	0.2
Buckwind	115	11.3	17.7	11.3	17.9	0.2
Devers	115	36.8	30.4	39.1	31.2	0.8
Farrell	115	9.6	12.9	9.5	13	0.1
Garnet	115	13.3	17.9	13.3	18.2	0.3
Terawind	115	12.3	20.2	12.3	20.6	0.4
Tiffanywind	115	10.6	17.5	10.6	17.8	0.3
Valley AB	115	50.7	26.7	51.1	26.9	0.2
Valley D	115	32.2	39.3	32.4	39.5	0.2
Vista	115	24.6	22	26.1	22.2	0.2
Etiwanda B	66	31.8	12.8	31.6	19.9	7.1
Lag. Bell AB	66	27.5	15.6	28.5	16.1	0.5
Lag. Bell DE	66	22	22	22.6	22.7	0.7
Mesa	66	29.7	20.1	30.4	20.3	0.2
Rio Hondo	66	18.2	19.3	18.4	19.4	0.1
San Bernardino	66	26.3	23.3	27.1	23.6	0.3
Vista A	66	26.3	21.9	26.9	22	0.1
Vista C	66	13.7	20.4	13.9	20.5	0.1

Queue Cluster 7 Phase II – Appendix H

Short Circuit Calculation Study Results

NOVEMBER 24, 2015

Table H.3.1a: Existing System with the inclusion of Projects in 2015 Three-Phase-to-ground Fault Analysis

Bus Name	Bus KV	PRE CASE		POST CASE		DELTA KA
		X/R	KA	X/R	KA	
Antelope	525	20.5	32.1	20.8	32.8	0.7
Colorado River	525	18.5	13.4	19	13.8	0.4
Eldorado	525	12.1	46.7	12.3	47.5	0.8
Lugo	525	21.7	45.9	21.8	46.1	0.2
Red Bluff	525	18.6	14.7	18.9	15	0.3
Vincent	525	18.7	40.7	18.9	42.1	1.4
Whirlwind	525	21	29.9	21.3	30.7	0.8
Antelope	230	24.3	36.3	24.6	36.6	0.3
Arcogen	230	16.7	35.5	16.6	35.7	0.2
Barre	230	22.1	58.8	22	59.1	0.3
Center	230	14.9	41.3	14.9	41.7	0.4
Chino	230	14.9	36.5	17.5	47.5	11
Colorado River	230	39.1	14.5	41.2	15.6	1.1
Del Amo	230	16.7	45.2	16.6	45.5	0.3
Devers	230	21.1	37.7	21.2	38	0.3
El Nido	230	17.8	38.1	17.7	38.2	0.1
El Segundo	230	18	33.4	18	33.5	0.1
Ellis	230	17.3	41.6	17.2	41.7	0.1
Etiwanda	230	25.8	55	25.2	56.9	1.9
Gould	230	15	16.1	12.5	23.5	7.4
Highwind	230	22	15.6	22	15.7	0.1
Hinson	230	17.6	40.6	17.6	40.8	0.2
La Fresa	230	22.4	44.4	22.3	44.7	0.3
Laguna Bell	230	15.4	35	15.1	36	1
Lewis	230	21.5	48.7	21.4	49	0.3
Lighthipe	230	17	42.8	17.1	43.2	0.4
Long Beach	230	12.3	27.4	12.2	27.5	0.1
Mesa	230	15.5	49.5	16.1	52.8	3.3
Mira Loma A	230	22.3	47.6	20.5	52.1	4.5
Mira Loma B	230	24.7	54.3	22.4	61.5	7.2
Olinda	230	14.7	30	14.7	30.2	0.2
Ormond Beach	230	32.6	31.4	32.4	31.6	0.2
Pardee	230	15.9	55.1	15.6	57.1	2
Pearblossom	230	5.6	9.9	5.5	10.1	0.2
Rancho	230	26.1	55.9	25.4	57.9	2
Redondo	230	23.3	44.3	23.3	44.6	0.3
Rio Hondo	230	14.5	31.2	14.4	31.4	0.2
San Bernardino	230	20.1	36.4	20	36.5	0.1
Serrano	230	26.4	56.9	26.3	57.3	0.4
Sylmar (SCE)	230	15.3	60.6	15.2	61.4	0.8
Villa Park	230	24.8	50	24.7	50.3	0.3
Vincent A	230	22.6	54.3	20.9	60.4	6.1
Vincent B	230	22.6	54.3	20.9	60.4	6.1
Vista	230	16.3	45.8	16.2	46	0.2
Walnut	230	15.9	34.9	15.9	35.2	0.3
Altwind	115	11.3	15.9	11.1	16.1	0.2

Buckwind	115	15.3	18.4	15.1	18.7	0.3
Devers	115	39.9	24.1	39.1	24.5	0.4
Farrell	115	10.1	13.1	10	13.3	0.2
Garnet	115	18	18	17.7	18.2	0.2
Sanwind	115	9.9	13.6	9.8	14	0.4
Terawind	115	16.6	20	16.3	20.3	0.3
Tiffanywind	115	14	18.3	13.8	18.5	0.2
Venwind	115	6.2	15.2	6.1	15.3	0.1
Cal Cement	66	18.1	18.6	18.1	18.7	0.1
Chino_A	66	45.9	29.8	55.7	31.3	1.5
Chino_B	66	45.9	29.8	55.7	31.3	1.5
Del Sur	66	8.8	19.2	8.8	19.5	0.3
Gould	66	26.4	11	26.4	11.8	0.8
Laguna Bell AB	66	42.2	21.9	42.1	22	0.1
Laguna Bell DE	66	34.6	27.7	34.5	27.8	0.1
Mesa	66	38.3	32	39.6	32.4	0.4
Mira Loma	66	41.4	37.7	41	38.3	0.6
Oasis	66	5.5	9.2	5.7	9.5	0.3
Padua	66	32	25.6	31.9	25.7	0.1
Ritter Ranch	66	7.7	11.6	7.7	11.7	0.1
Saugus_A	66	34.1	38	34.1	38.2	0.2
Saugus_C	66	34.1	38	34.1	38.2	0.2
Viejo	66	31.9	17.6	32.7	17.8	0.2
Windhub66_A	66	45.1	25.1	45.5	25.2	0.1
Windhub66_B	66	45.1	25.1	45.5	25.2	0.1
Antelope	66	29.4	32.6	29.4	33.2	0.6

Table H.3.1b: Existing System with the inclusion of Projects in 2015 Single-Phase-to-ground Fault Analysis

Bus Name	Bus KV	PRE CASE		POST CASE		DELTA KA
		X/R	KA	X/R	KA	
Antelope	525	18.3	28.4	18.4	28.8	0.4
Colorado River	525	13.2	10.9	13.5	11.3	0.4
Eldorado	525	10.7	37.4	11.4	39.9	2.5
Lugo	525	11.8	35.8	11.8	36	0.2
Mira Loma	525	12.1	31.2	12.2	31.3	0.1
Red Bluff	525	11.7	12.4	11.7	12.6	0.2
Vincent	525	15.6	33.7	15.8	34.5	0.8
Whirlwind	525	16.3	26.8	16.3	27.3	0.5
Antelope	230	25.7	40.9	26	41.2	0.3
Barre	230	13.9	46.4	13.9	46.5	0.1
Center	230	14.8	34	14.8	34.2	0.2
Chino	230	11.5	32.5	12.6	41.2	8.7
Colorado River	230	26.8	15.7	27.7	16.9	1.2
Del Amo	230	11.3	42	11.3	42.2	0.2
Devers	230	18.7	42.7	18.7	43	0.3
El Nido	230	16.7	37.3	16.6	37.4	0.1
Etiwanda	230	18.1	55.7	17.8	57	1.3
Hinson	230	19.4	36.3	19.4	36.5	0.2

La Fresa	230	19.7	42.5	19.7	42.7	0.2
Laguna Bell	230	12.9	32.6	12.5	33.2	0.6
Lewis	230	15.5	44.9	15.4	45.1	0.2
Lighthipe	230	11.7	39.4	11.6	39.7	0.3
Mesa	230	11.4	41.6	11.2	43.8	2.2
Mira Loma A	230	15.7	49.3	14.8	52.6	3.3
Mira Loma B	230	16	53.9	15.4	60.1	6.2
Moorpark	230	24.1	29.8	23.9	30	0.2
Olinda	230	12.6	26	12.6	26.1	0.1
Pardee	230	13.8	40.5	13.5	41.5	1
Rancho	230	18.5	57.8	18.1	59.3	1.5
Redondo	230	29.6	40.5	29.5	40.7	0.2
Rio Hondo	230	16.1	26.6	16	26.7	0.1
Sylmar (SCE)	230	12.6	66.7	12.5	67.4	0.7
Villa Park	230	17.4	44.3	17.4	44.4	0.1
Vincent A	230	19.7	55.3	18.9	59.8	4.5
Vincent B	230	19.7	55.3	18.9	59.8	4.5
Walnut	230	16.7	33.5	16.7	33.7	0.2
Altwind	115	9.2	13.4	9.1	13.5	0.1
Buckwind	115	11.6	16.8	11.5	16.9	0.1
Devers	115	35.3	27.8	34.6	28.3	0.5
Garnet	115	13.5	17	13.3	17.1	0.1
Terawind	115	12.6	19	12.5	19.3	0.3
Tiffanywind	115	10.9	16.7	10.8	16.8	0.1
ANTELOPE	66	24	21.9	23	22.7	0.8
Chino_A	66	29.2	18.7	30.4	19.1	0.4
Chino_B	66	29.2	18.7	30.4	19.1	0.4
Gould	66	25.3	10	25.2	10.4	0.4
Mira Loma	66	29.5	28.7	29.3	28.9	0.2
Ritter Ranch	66	9.1	5.4	9	5.5	0.1

Table H.3.2a: Inclusion of Projects in 2016 Three-Phase-to-ground Fault Analysis

Bus Name	Bus KV	PRE CASE		POST CASE		DELTA KA
		X/R	KA	X/R	KA	
Antelope	525	20.8	32.8	21.2	35.5	2.7
Colorado River	525	19.0	13.8	19.5	14.4	0.6
Eldorado	525	12.3	47.5	11.8	50.4	2.9
Lugo	525	21.8	46.1	18.8	49.7	3.6
Mira Loma	525	24.1	34.2	22.4	38.4	4.2
Red Bluff	525	18.9	15.0	19.2	15.4	0.4
Serrano	525	25.5	30.8	24.5	32.2	1.4
Vincent	525	18.9	42.1	18.9	46.9	4.8
Whirlwind	525	21.3	30.7	21.7	33.1	2.4
Antelope	230	24.6	36.6	25.9	38.9	2.3
Barre	230	22.0	59.1	21.9	59.5	0.4
Center	230	14.9	41.7	14.9	41.8	0.1
Chino	230	17.5	47.5	17.2	48.9	1.4
Colorado River	230	41.2	15.6	31.9	21.6	6.0

Del Amo	230	16.6	45.5	16.6	45.6	0.1
Devers	230	21.2	38.0	21.4	38.4	0.4
Eldorado	230	17.4	56.1	17.3	56.7	0.6
Eldorado_2	230	43.5	19	43.7	19.1	0.1
Ellis	230	17.2	41.7	17.1	41.9	0.2
Etiwanda	230	25.2	56.9	24.7	58.4	1.5
Highwind	230	22.0	15.7	21.7	16.4	0.7
Hunt. Beach. A	230	16.8	36.7	16.8	36.8	0.1
Hunt. Beach. B	230	16.8	36.7	16.8	36.8	0.1
Kramer	230	16.2	18.0	15.9	18.8	0.8
Lewis	230	21.4	49.0	21.2	49.6	0.6
Lugo	230	27.9	39.8	27.6	40.5	0.7
Luz	230	19.5	10.4	19.3	10.6	0.2
Mesa	230	16.1	52.8	16.2	53.1	0.3
Mira Loma A	230	20.5	52.1	20.4	54.1	2.0
Mira Loma B	230	23.7	60.8	23.5	63.3	2.5
Olinda	230	14.7	30.2	14.6	30.4	0.2
Pardee	230	15.6	57.1	15.5	57.7	0.6
Rancho	230	25.4	57.9	24.8	59.5	1.6
Red Bluff	230	38.1	14.1	30.5	20.1	6.0
San Bernardino	230	20.0	36.5	19.8	36.8	0.3
Serrano	230	26.3	57.3	26.0	58.5	1.2
Sylmar (SCE)	230	15.2	61.4	15.2	61.7	0.3
Victor	230	15.7	23.8	18.2	32.5	8.7
Villa Park	230	24.7	50.3	24.5	51.0	0.7
Vista	230	16.2	46.0	16.0	46.7	0.7
Walnut	230	15.9	35.2	15.8	35.4	0.2
Whirlwind	230	38.9	31.2	36.0	40.1	8.9
Whirlwind_2	230	38.9	31.2	36.0	40.1	8.9
Buckwind	115	15.1	18.7	15.1	18.8	0.1
Devers	115	39.1	24.5	39.4	24.7	0.2
Terawind	115	16.3	20.3	16.4	20.4	0.1
Tiffanywind	115	13.8	18.5	13.8	18.6	0.1
Lewis	69	30.4	44.7	30.4	44.8	0.1
Antelope	66	29.4	33.2	30.3	34.0	0.8
Cal Cement	66	18.1	18.7	18.1	18.9	0.2
Chino_A	66	55.7	31.3	55.9	31.4	0.1
Chino_B	66	55.7	31.3	55.9	31.4	0.1
Del Sur	66	8.8	19.5	8.9	20.0	0.5
Mira Loma	66	41.0	38.3	41.3	38.5	0.2
Ritter Ranch	66	7.7	11.7	7.7	11.8	0.1
Windhub66_A	66	45.5	25.2	46.3	25.7	0.5
Windhub66_B	66	45.5	25.2	46.3	25.7	0.5

Table H.3.2b: Inclusion of Projects in 2016 Single-Phase-to-ground Fault Analysis

Bus Name	Bus KV	PRE CASE		POST CASE		DELTA KA
		X/R	KA	X/R	KA	
Antelope	525	18.4	28.8	18.2	30.8	2.0
Colorado River	525	13.5	11.3	16.3	13.5	2.2
Eldorado	525	11.4	39.9	11.1	41.3	1.4
Lugo	525	11.8	36.0	10.9	37.5	1.5
Mira Loma	525	12.2	31.3	11.3	34.6	3.3
Red Bluff	525	11.7	12.6	14.1	14.6	2.0
Serrano	525	14.0	27.4	13.6	28.1	0.7
Vincent	525	15.8	34.5	14.7	37.8	3.3
Whirlwind	525	16.3	27.3	17.3	30.3	3.0
Antelope	230	26.0	41.2	27.0	43.8	2.6
Barre	230	13.9	46.5	13.8	46.7	0.2
Chino	230	12.6	41.2	12.3	42.0	0.8
Colorado River	230	27.7	16.9	25.8	24.5	7.6
Devers	230	18.7	43.0	18.9	43.4	0.4
El Segundo	230	18.0	32.9	18.2	33.1	0.2
Eldorado	230	16.0	52.7	15.9	53.1	0.4
Eldorado_2	230	40.7	21.4	40.8	21.6	0.2
Etiwanda	230	17.8	57.0	17.3	58.1	1.1
Kramer	230	11.1	15.5	10.2	16.5	1.0
Lewis	230	15.4	45.1	15.3	45.4	0.3
Lugo	230	22.4	40.6	18.4	41.0	0.4
Mesa	230	11.2	43.8	11.2	44.0	0.2
Mira Loma A	230	14.8	52.6	14.0	54.4	1.8
Mira Loma B	230	15.9	59.5	16.3	61.3	1.8
Pardee	230	13.5	41.5	13.4	41.7	0.2
Rancho	230	18.1	59.3	17.6	60.5	1.2
Red Bluff	230	26.6	15.2	24.3	22.7	7.5
San Bernardino	230	18.5	38.6	18.4	38.8	0.2
Serrano	230	19.1	58.9	18.9	59.7	0.8
Sylmar (SCE)	230	12.5	67.4	12.5	67.6	0.2
Victor	230	12.1	20.8	6.6	26.3	5.5
Villa Park	230	17.4	44.4	17.3	44.8	0.4
Vista	230	13.2	41.2	13.0	41.6	0.4
Whirlwind	230	31.7	34.1	29.6	44.6	10.5
Whirlwind_2	230	31.7	34.1	29.6	44.6	10.5
Devers	115	34.6	28.3	34.8	28.5	0.2
Kramer	115	13.1	23.9	12.9	24.3	0.4
Terawind	115	12.5	19.3	12.5	19.4	0.1
Victor	115	18.7	24.7	17.7	26.7	2.0
Antelope	66	23.0	22.7	23.2	22.9	0.2
Windhub66_A	66	21.2	17.5	21.2	17.6	0.1
Windhub66_B	66	21.2	17.5	21.2	17.6	0.1

Table H.3.3a: Inclusion of Projects in 2017 Three-Phase-to-ground Fault Analysis

Bus Name	Bus KV	PRE CASE		POST CASE		DELTA KA
		X/R	KA	X/R	KA	
Antelope	525	21.6	35.2	21.4	36	0.8
Colorado River	525	19.5	14.4	19.7	14.6	0.2
Eldorado	525	12.3	47.5	11.9	50.8	3.3
Lugo	525	21.9	46.6	18.8	49.6	3
Mira Loma	525	23.9	36.5	22.5	37.5	1
Red Bluff	525	19.2	15.4	19.4	15.5	0.1
Serrano	525	25.4	31.7	24.5	32.2	0.5
Vincent	525	19.4	46.2	19	47.3	1.1
Whirlwind	525	22	32.9	22.1	33.9	1
Alamitos B	230	15.8	30.7	15.7	30.8	0.1
Antelope	230	26	38.8	26.1	39	0.2
Barre	230	22	59.4	21.7	60.4	1
Center	230	14.9	41.7	14.8	41.9	0.2
Chino	230	17.4	48.3	17.2	48.7	0.4
Colorado River	230	31.9	21.6	32.6	22.2	0.6
Del Amo	230	16.6	45.5	16.5	45.8	0.3
Devers	230	21.4	38.3	21.4	38.4	0.1
Eldorado	230	17.4	56.1	16.9	57.2	1.1
Eldorado_2	230	43.5	19	16.3	27.2	8.2
Ellis	230	17.2	41.8	17.4	43.3	1.5
Etiwanda	230	25.4	56.2	25	56.7	0.5
Highwind	230	21.8	16.4	21.5	16.6	0.2
Ivanpah	230	26.5	10.9	19.8	12.6	1.7
Lewis	230	21.4	49.4	21.1	50	0.6
Lugo	230	28.3	39.9	27.7	40.4	0.5
Mesa	230	16.2	53	16.1	53.2	0.2
Mira Loma A	230	20.8	53.6	20.5	54.2	0.6
Mira Loma B	230	23.1	56.7	22.7	57.2	0.5
Rancho	230	25.7	57.2	25.1	57.7	0.5
Santiago	230	17.7	26.3	18.4	28.7	2.4
Serrano	230	26.4	58.1	25.9	58.9	0.8
Victor	230	18.5	32.3	18.2	32.5	0.2
Villa Park	230	24.7	50.8	24.4	51.4	0.6
Vincent A	230	27.6	41.3	27.5	41.6	0.3
Vincent B	230	23.1	45.1	23	45.4	0.3
Vista	230	16.4	45.9	16.2	46.1	0.2
Whirlwind	230	36.3	40	37.2	42.1	2.1
Whirlwind_2	230	36.3	40	37.2	42.1	2.1
Ivanpah	115	29.4	17.2	27.4	18.1	0.9
Lewis	69	30.5	44.8	30.4	44.9	0.1
Ellis A	66	34.1	28.6	34.3	28.7	0.1
Johanna	66	43.9	20.5	45	20.7	0.2
Santiago A	66	45.8	22.9	48.1	23.3	0.4
Santiago B	66	35.7	22	36.9	22.4	0.4

Table H.3.3b: Inclusion of Projects in 2017 Single-Phase-to-ground Fault Analysis

Bus Name	Bus KV	PRE CASE		POST CASE		DELTA KA
		X/R	KA	X/R	KA	
Antelope	525	18.4	30.7	18.3	31.2	0.5
Colorado River	525	16.3	13.5	16.4	13.6	0.1
Eldorado	525	11.4	39.9	11.1	41.7	1.8
Lugo	525	11.6	36	10.9	37.3	1.3
Mira Loma	525	10.5	32.2	10.2	32.7	0.5
Serrano	525	13.9	27.8	13.7	28	0.2
Vincent	525	15	37.5	14.8	38.1	0.6
Whirlwind	525	17.5	30.2	17.7	31.2	1
Antelope	230	27.1	43.7	27.2	43.9	0.2
Barre	230	13.9	46.7	13.7	47.1	0.4
Chino	230	12.5	41.4	12.4	41.6	0.2
Colorado River	230	25.8	24.5	26	24.9	0.4
Del Amo	230	11.3	42.2	11.3	42.3	0.1
Eldorado	230	15.9	52.7	15.7	53.4	0.7
Eldorado_2	230	40.7	21.4	17.7	28.9	7.5
Ellis	230	18.2	36.3	18	37.1	0.8
Etiwanda	230	17.9	56.4	17.7	56.7	0.3
Ivanpah	230	21.7	9.6	12.2	12.8	3.2
Lewis	230	15.4	45.3	15.3	45.6	0.3
Lugo	230	18.6	40.6	18.3	40.9	0.3
Mira Loma A	230	13.9	53.6	13.8	54	0.4
Mira Loma B	230	13.9	50.8	13.8	51.2	0.4
Pardee	230	13.4	41.7	14.4	44.5	2.8
Rancho	230	18.2	58.6	18	59	0.4
Santiago	230	18.3	25.4	18.1	29	3.6
Serrano	230	19.1	59.4	18.8	59.9	0.5
Victor	230	6.7	26.2	6.6	26.3	0.1
Villa Park	230	17.4	44.7	17.2	45	0.3
Vincent A	230	23.9	42.3	23.9	42.5	0.2
Vincent B	230	19.7	45.8	19.6	46	0.2
Vista	230	13.2	41.1	13.1	41.3	0.2
Whirlwind	230	29.8	44.5	30.4	47.3	2.8
Whirlwind_2	230	29.8	44.5	30.4	47.3	2.8
Ivanpah	115	26.3	19.4	23.5	20.8	1.4
Santiago A	66	39.8	20.8	40	21	0.2
Santiago B	66	23.5	16.2	23.5	16.4	0.2

Table H.3.4a: Inclusion of Projects in 2018 Three-Phase-to-ground Fault Analysis

Bus Name	Bus KV	PRE CASE		POST CASE		DELTA KA
		X/R	KA	X/R	KA	
Colorado Rvr	525	19.7	14.6	21.9	16.8	2.2
Red Bluff	525	19.4	15.5	20.6	16.9	1.4
Serrano	525	24.5	32.2	24.5	32.4	0.2
Colorado Rvr	230	32.6	22.2	37.5	23.8	1.6
Devers	230	21.4	38.4	21.9	39.5	1.1

Mirage	230	10.1	18.1	10.1	18.3	0.2
Red Bluff	230	30.7	20.2	33.3	21.1	0.9
Serrano	230	25.9	58.9	26	59	0.1
Altwind	115	11.1	16.1	10.9	16.6	0.5
Buckwind	115	15.1	18.8	14.9	19.4	0.6
Devers	115	39.4	24.7	40.8	25.9	1.2
Farrell	115	9.9	13.3	9.8	13.6	0.3
Garnet	115	17.7	18.3	17.4	18.9	0.6
Sanwind	115	9.8	14	9.7	14.4	0.4
Terawind	115	16.4	20.5	16.2	21.3	0.8
Tiffanywind	115	13.8	18.6	13.6	19.3	0.7
Venwind	115	6.1	15.4	6	15.8	0.4
Banducci	66	0	0	3.3	2.9	2.9

Table H.3.4b: Inclusion of Projects in 2018 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	16.4	13.6	18.1	16.5	2.9
Red Bluff	525	14.1	14.6	14.1	15.8	1.2
Colorado Rvr	230	26	24.9	30	27.2	2.3
Devers	230	18.9	43.4	19.2	44.4	1
Red Bluff	230	24.4	22.8	25.3	23.7	0.9
Altwind	115	9.1	13.5	9	13.8	0.3
Buckwind	115	11.4	17	11.3	17.5	0.5
Devers	115	34.8	28.5	36.3	29.9	1.4
Farrell	115	9.7	12.6	9.6	12.8	0.2
Garnet	115	13.3	17.2	13.1	17.6	0.4
Terawind	115	12.5	19.4	12.4	20	0.6
Tiffanywind	115	10.8	16.9	10.6	17.4	0.5
Valley AB	115	48.5	25.6	48.7	25.7	0.1
Banducci	66	0	0	4.3	1.8	1.8

Table H.3.5a: Inclusion of Energy Only Projects Post 2018 Three-Phase-to-ground Fault Analysis

Bus Name	Bus KV	PRE CASE		POST CASE		DELTA KA
		X/R	KA	X/R	KA	
Alberhil	525	0	0	23.5	23.2	23.2
Antelope	525	21.4	36	21.9	36.8	0.8
Colorado River	525	21.9	16.8	22.8	18.7	1.9
Eldorado	525	11.9	50.8	11.9	51.5	0.7
Lugo	525	18.8	49.7	18.9	51.2	1.5
Mira Loma	525	22.5	37.5	22.4	39	1.5
Red Bluff	525	20.6	16.9	21.6	19.9	3
Serrano	525	24.5	32.4	24.2	35.2	2.8
Valley A	525	26	19.3	25.7	24.4	5.1
Valley B	525	26	19.3	25.7	24.4	5.1
Vincent	525	19	47.3	19.5	48.8	1.5
Whirlwind	525	22.1	33.9	22.6	34.7	0.8

Antelope	230	26.1	39	26.4	39.4	0.4
Barre	230	21.7	60.5	21	63.2	2.7
Center	230	14.8	41.9	15.5	45.7	3.8
Chino	230	17.2	48.8	17.5	49.5	0.7
Colorado River	230	37.5	23.8	40.3	26.1	2.3
Del Amo	230	16.5	45.8	16.5	47	1.2
Devers	230	21.9	39.5	22.7	41.7	2.2
Eldorado	230	16.9	57.3	16.9	57.6	0.3
Eldorado_2	230	16.3	27.2	16.6	28.2	1
Ellis	230	17.4	43.3	16.6	45.5	2.2
Etiwanda	230	24.9	56.8	25.2	58	1.2
Hunt. Beach. A	230	16.8	37.8	15.9	39.2	1.4
Hunt. Beach. B	230	16.8	37.8	15.9	39.2	1.4
Jasper	230	0	0	12.6	9	9
Kramer	230	15.9	18.8	15.8	19.5	0.7
Lewis	230	21.1	50.1	20.7	52	1.9
Lugo	230	27.7	40.5	28.2	41.3	0.8
Luz	230	19.3	10.6	20.7	11.7	1.1
Mesa	230	16.1	53.2	16.6	57.4	4.2
Mira Loma B	230	22.7	57.3	22.7	59.1	1.8
Olinda	230	14.6	30.3	14.9	33.6	3.3
Pardee	230	15.5	57.6	15.5	58.1	0.5
Pastoria	230	13.5	30.2	13.8	30.7	0.5
Primm	230	18.9	12.1	19	12.2	0.1
Rancho	230	25.1	57.8	25.4	59.1	1.3
Red Bluff	230	33.3	21.1	37.7	26.9	5.8
Rio Hondo	230	14.8	30.9	14.8	31.4	0.5
San Onofre	230	17.9	27.5	14	43.4	15.9
Santiago	230	18.4	28.7	17.3	31.6	2.9
Serrano	230	26	59	25.7	62	3
Sylmar (SCE)	230	15.2	61.7	15.2	62	0.3
Victor	230	18.2	32.5	18.1	33	0.5
Villa Park	230	24.4	51.5	24	53.7	2.2
Vincent A	230	27.5	41.6	27.9	45.5	3.9
Vincent B	230	23	45.4	23.3	46	0.6
Walnut	230	15.8	35.4	16	36.7	1.3
Whirlwind	230	37.2	42.1	38.5	43.9	1.8
Wildlife	230	0	0	14.7	24.1	24.1
Alberhil	115	0	0	60.8	19.9	19.9
Altwind	115	10.9	16.6	10.9	16.8	0.2
Buckwind	115	14.9	19.4	14.8	19.7	0.3
Devers	115	40.8	25.9	41.9	26.4	0.5
Farrell	115	9.8	13.6	9.8	13.8	0.2
Garnet	115	17.4	18.9	17.5	19.1	0.2
Kramer	115	13.9	23.9	14	24.2	0.3
Sanwind	115	9.7	14.4	9.6	14.5	0.1
Terawind	115	16.2	21.3	16.2	21.6	0.3
Tiffanywind	115	13.6	19.3	13.5	19.5	0.2

Venwind	115	6	15.8	5.9	16	0.2
Lewis	69	30.4	44.9	30.4	45.3	0.4
Antelope	66	30.4	34.1	30.4	34.5	0.4
Barre AB	66	47.1	23.6	50.3	30	6.4
Center B	66	22.3	27.5	22.8	27.8	0.3
Del Sur	66	8.9	20	8.9	20.2	0.2
Ellis A	66	34.3	28.7	34.2	28.9	0.2
Johanna	66	45	20.7	46.3	22.7	2
Mesa	66	39.8	32.5	41	32.9	0.4
Olinda	66	37	22.6	38.5	23.1	0.5
Rio Hondo	66	24.8	32.3	24.8	32.5	0.2
Santiago A	66	48.1	23.3	48.1	23.7	0.4
Santiago B	66	36.9	22.4	36.7	22.8	0.4
Viejo	66	32.8	17.9	32.8	18.3	0.4
Villa Park	66	43.5	32.7	43.5	32.9	0.2
Walnut	66	31.6	30.3	32	30.6	0.3
Wilderness	66	0	0	32.9	27.3	27.3

Table H.3.5b: Inclusion of Energy Only Projects Post 2018 Single-Phase-to-ground Fault Analysis

Bus Name	Bus KV	PRE CASE		POST CASE		DELTA
		X/R	KA	X/R	KA	KA
Alberhil	525	0	0	14	23.5	23.5
Antelope	525	18.3	31.2	18.3	31.7	0.5
Colorado Rvr	525	18.1	16.5	18.6	18.2	1.7
Eldorado	525	11.1	41.7	11.1	42.5	0.8
Lugo	525	10.9	37.3	10.9	38.1	0.8
Mira Loma	525	10.2	32.7	10	33.5	0.8
Red Bluff	525	14.1	15.8	14.9	18.4	2.6
Serrano	525	13.6	28.1	12.4	30.6	2.5
Valley A	525	15.2	19.7	13.8	24.8	5.1
Valley B	525	15.2	19.7	13.8	24.8	5.1
Vincent	525	14.8	38.1	15	39.1	1
Whirlwind	525	17.7	31.2	17.9	32.2	1
Antelope	230	27.2	43.9	27.4	44.3	0.4
Barre	230	13.7	47.1	13.3	48.2	1.1
Center	230	14.8	34.3	14.3	39.1	4.8
Chino	230	12.4	41.6	12.5	41.9	0.3
Colorado Rvr	230	30	27.2	31.2	30.4	3.2
Del Amo	230	11.3	42.4	11.2	43	0.6
Devers	230	19.2	44.4	19.4	46.4	2
El Segundo	230	17.9	33	19.2	33.6	0.6
Eldorado	230	15.7	53.4	15.7	53.7	0.3
Eldorado_2	230	17.7	28.9	17.9	30.4	1.5
Ellis	230	18	37.1	17.1	39.5	2.4
Etiwanda	230	17.7	56.8	17.7	57.6	0.8
Hunt. Bch. A	230	19.9	29	18.9	33.6	4.6
Hunt. Bch. B	230	19.9	29	18.9	33.6	4.6
Jasper	230	0	0	10.5	6.7	6.7

Kramer	230	10.2	16.5	9.6	17.1	0.6
Lewis	230	15.2	45.7	14.9	46.8	1.1
Lugo	230	18.3	40.9	18.5	41.8	0.9
Luz	230	12.7	9.8	15.8	11.5	1.7
McCullough	230	13.6	51	13.6	51.2	0.2
Mesa	230	11.1	44	11.2	48.6	4.6
Mira Loma B	230	13.8	51.2	14	52	0.8
Olinda	230	12.5	26.2	11.4	29.5	3.3
Pardee	230	14.4	44.5	14.3	44.7	0.2
Pastoria	230	13.2	27.6	14.7	32.5	4.9
Rancho	230	18	59.1	18	60	0.9
Red Bluff	230	25.3	23.7	27.8	30.6	6.9
Rio Hondo	230	16.3	26.5	16.2	26.7	0.2
Santiago	230	18.1	29	17.5	31	2
Serrano	230	18.8	60	17.8	62.9	2.9
Victor	230	6.6	26.3	6.6	26.6	0.3
Villa Park	230	17.2	45	16.7	46.3	1.3
Vincent A	230	23.9	42.5	23.9	46.1	3.6
Vincent B	230	19.6	46	19.7	46.6	0.6
Walnut	230	16.6	33.8	16.6	34.6	0.8
Whirlwind	230	30.4	47.3	30	50.1	2.8
Whirlwind_2	230	30.4	47.3	30	50.1	2.8
Wildlife	230	0	0	15.9	18.5	18.5
Alberhil	115	0	0	49.7	24.8	24.8
Altwind	115	9	13.8	9	13.9	0.1
Buckwind	115	11.3	17.5	11.3	17.7	0.2
Devers	115	36.3	29.9	36.8	30.4	0.5
Garnet	115	13.1	17.6	13.3	17.9	0.3
Kramer	115	12.9	24.3	12.7	24.5	0.2
Terawind	115	12.4	20	12.3	20.2	0.2
Tiffanywind	115	10.6	17.4	10.6	17.5	0.1
Valley AB	115	48.7	25.7	50.7	26.7	1
Valley D	115	50.3	23.9	32.2	39.3	15.4
Victor	115	17.7	26.7	17.7	26.8	0.1
Antelope	66	23.2	22.9	23.2	23	0.1
Barre AB	66	29.9	16.8	27.7	28.7	11.9
Center B	66	24.1	20.9	24.4	21	0.1
Johanna	66	30.6	13.2	34.6	15.7	2.5
Mesa	66	29.5	20	29.7	20.1	0.1
Olinda	66	26.7	15.1	27	15.2	0.1
Santiago A	66	40	21	40.1	21.2	0.2
Viejo	66	28	12.3	28	12.5	0.2
Wilderness	66	0	0	11.5	23.2	23.2

Table H.3.6a: Inclusion of In-Flight upgrades and All Other Pending Deliverability Network Upgrades
Three-Phase-to-ground Fault Analysis

Bus Name	Bus KV	PRE CASE		POST CASE		DELTA
		X/R	KA	X/R	KA	KA
Alberhil	525	23.5	23.2	23.2	23.7	0.5
Antelope	525	21.9	36.8	22	37.4	0.6
Colorado River	525	22.8	18.7	21.7	22.6	3.9
Eldorado	525	11.9	51.5	11.9	51.6	0.1
Lugo	525	18.9	51.2	19.2	52.4	1.2
Mesa	525	0	0	24.8	29.3	29.3
Mira Loma	525	22.4	39	23	41	2
Red Bluff	525	21.6	19.9	21.4	22.2	2.3
Valley A	525	25.7	24.4	25.6	25.2	0.8
Valley B	525	25.7	24.4	25.6	25.2	0.8
Vincent	525	19.5	48.8	19.6	50.3	1.5
Whirlwind	525	22.6	34.7	22.6	35.2	0.5
Alamitos A	230	22.4	32.8	22.2	33	0.2
Alamitos B	230	14.3	29.5	14.2	29.7	0.2
Antelope	230	26.4	39.4	26.6	39.6	0.2
Arcogen	230	16.4	35.2	16.3	35.9	0.7
Barre	230	21	63.2	20.7	63.8	0.6
Center	230	15.5	45.7	15.4	46.7	1
Chino	230	17.5	49.5	17.7	50.1	0.6
Colorado River	230	40.3	26.1	41.9	28.3	2.2
Del Amo	230	16.5	47	16.1	49.4	2.4
Devers	230	22.7	41.7	25.2	49.1	7.4
El Casco	230	11.2	11.7	18.4	17.6	5.9
El Nido	230	17.6	36.5	17.6	37.3	0.8
El Segundo	230	18.4	32.8	18.4	33.4	0.6
Ellis	230	16.6	45.5	16.5	45.8	0.3
Etiwanda	230	25.2	58	27.5	59.8	1.8
Goodrich	230	13.3	21.9	14.3	27.8	5.9
Gould	230	12.5	23.7	12.9	25.3	1.6
Hinson	230	17.3	40.2	17.2	41	0.8
Hunt. Beach A	230	15.9	39.2	15.8	39.4	0.2
Hunt. Beach B	230	15.9	39.2	15.8	39.4	0.2
La Fresa	230	20.3	41.3	20.5	42.6	1.3
Laguna Bell	230	14.9	36	16.8	56.8	20.8
Lewis	230	20.7	52	20.6	52.2	0.2
Lighthipe	230	16.7	42.3	16.6	42.9	0.6
Long Beach	230	12.2	27.2	12.1	27.6	0.4
Lugo	230	28.2	41.3	28.5	41.5	0.2
Mesa	230	16.6	57.4	18.9	60.1	2.7
Mesa_2	230	0	0	19.3	63.6	63.6
Mira Loma A	230	20.8	53.4	21.1	54.1	0.7
Mira Loma B	230	22.7	59.1	24	60.5	1.4
Olinda	230	14.9	33.6	14.9	33.8	0.2
Ramon	230	9.9	18.3	9.8	19.1	0.8
Rancho	230	25.4	59.1	27.6	60.9	1.8

Red Bluff	230	37.7	26.9	38.8	28.2	1.3
Redondo	230	19.5	38.8	19.6	39.5	0.7
Rio Hondo	230	14.8	31.4	15.9	32.9	1.5
San Benardino	230	20.1	36.3	25	41.2	4.9
San Onofre	230	14	43.4	14.3	47.3	3.9
Santiago	230	17.3	31.6	17.3	32	0.4
Serrano	230	25.7	62	25.7	62.5	0.5
Villa Park	230	24	53.7	24	53.9	0.2
Vincent B	230	23.3	46	23.3	46.3	0.3
Vista	230	16.3	43.6	20.5	47.9	4.3
Walnut	230	16	36.7	16.1	37	0.3
Westwing	230	15.8	62.4	15.9	62.7	0.3
Whirlwind	230	38.5	43.9	38.7	44.2	0.3
Whirlwind_2	230	38.5	43.9	38.7	44.2	0.3
Wildlife	230	14.7	24.1	15.2	24.7	0.6
Altwind	115	10.9	16.8	10.8	17.2	0.4
Buckwind	115	14.8	19.7	14.9	20.2	0.5
Devers	115	41.9	26.4	44.9	27.3	0.9
Farrell	115	9.8	13.8	9.7	14	0.2
Garnet	115	17.5	19.1	17.5	19.5	0.4
Sanwind	115	9.6	14.5	9.6	14.8	0.3
Terawind	115	16.2	21.6	16.3	22.1	0.5
Tiffanywind	115	13.5	19.5	13.5	20	0.5
Venwind	115	5.9	16	5.9	16.3	0.3
Vista	115	26.9	19.6	28.7	19.9	0.3
Del Amo	66	57.5	23.1	57.9	23.2	0.1
Etiwanda B	66	52.2	15.5	53.3	26.5	11
Gould	66	26.4	11.8	26.9	11.9	0.1
La Fresa B	66	39.8	26.1	40	26.2	0.1
Lag. Bell AB	66	41.8	22	49.6	23.4	1.4
Lag. Bell DE	66	34.4	27.8	38.4	29.4	1.6
Mesa	66	41	32.9	44.4	33.4	0.5
Rio Hondo	66	24.8	32.5	25.9	32.9	0.4
San Benardino	66	38.5	30.7	43	31.6	0.9
Vista A	66	38	26.9	40.6	27.1	0.2
Vista C	66	22.7	25.8	23.5	26.1	0.3
Wilderness	66	32.9	27.3	33.6	27.5	0.2

Table H.3.6b Inclusion of In-Flight upgrades and All Other Pending Deliverability Single-Phase-to-ground Fault Analysis

Bus Name	Bus KV	PRE CASE		POST CASE		DELTA KA
		X/R	KA	X/R	KA	
Alberhil	525	14	23.5	13.9	23.9	0.4
Antelope	525	18.3	31.7	18.1	32.1	0.4
Colorado River	525	18.6	18.2	17.4	21	2.8
Lugo	525	10.9	38.1	10.7	38.7	0.6
Mesa	525	0	0	13.9	25.1	25.1

Mira Loma	525	10	33.5	10.3	35.3	1.8
Red Bluff	525	14.9	18.4	14.5	19.8	1.4
Serrano	525	12.4	30.6	12.2	30.9	0.3
Valley A	525	13.8	24.8	13.7	25.4	0.6
Valley B	525	13.8	24.8	13.7	25.4	0.6
Vincent	525	15	39.1	14.1	40.4	1.3
Whirlwind	525	17.9	32.2	17.8	32.5	0.3
Alamitos A	230	15.2	31.3	15.1	31.4	0.1
Antelope	230	27.4	44.3	27.5	44.4	0.1
Arcogen	230	17.1	29.9	17.1	30.2	0.3
Barre	230	13.3	48.2	13.2	48.4	0.2
Center	230	14.3	39.1	14.2	39.7	0.6
Chino	230	12.5	41.9	13.6	44.3	2.4
Colorado River	230	31.2	30.4	31.6	32.5	2.1
Del Amo	230	11.2	43	10.7	44.3	1.3
Devers	230	19.4	46.4	21.9	52	5.6
El Casco	230	6.6	10.2	12.7	12.6	2.4
El Nido	230	16.6	36.2	16.5	36.7	0.5
El Segundo	230	19.2	33.6	19.1	33.9	0.3
Ellis	230	17.1	39.5	17.1	39.7	0.2
Etiwanda	230	17.7	57.6	19.1	60.7	3.1
Hinson	230	19.1	36.1	19.2	36.5	0.4
Hunt. Beach A	230	18.9	33.6	18.9	33.7	0.1
Hunt. Beach B	230	18.9	33.6	18.9	33.7	0.1
La Fresa	230	18.8	39	18.4	39.7	0.7
Laguna Bell	230	12.2	33.3	3.3	39.2	5.9
Lewis	230	14.9	46.8	14.9	46.9	0.1
Lugo	230	18.5	41.8	18.5	42	0.2
Mesa	230	11.2	48.6	13.5	50.6	2
Mesa_2	230	0	0	13.3	63.4	63.4
Mira Loma A	230	14	53.1	14.8	54.1	1
Mira Loma B	230	14	52	13.9	53.4	1.4
Mirage	230	10.6	16.5	10.6	17	0.5
Olinda	230	11.4	29.5	11.3	29.7	0.2
Rancho	230	18	60	18.9	62.5	2.5
Red Bluff	230	27.8	30.6	28.1	31.7	1.1
Rio Hondo	230	16.2	26.7	14	30.1	3.4
San Benardino	230	18.5	38.5	24.4	41.3	2.8
San Onofre	230	8	30.7	8.6	47.8	17.1
Santiago	230	17.5	31	17.6	31.3	0.3
Serrano	230	17.8	62.9	17.8	63.3	0.4
Villa Park	230	16.7	46.3	16.7	46.4	0.1
Vincent A	230	23.9	46.1	23.6	46.3	0.2
Vincent B	230	19.7	46.6	18.1	46.7	0.1
Vista	230	13.2	40.8	15.8	43.7	2.9
Walnut	230	16.6	34.6	16.4	35	0.4
Westwing	230	12	57.9	12	58.1	0.2
Whirlwind	230	30	50.1	30	50.3	0.2

Whirlwind_2	230	30	50.1	30	50.3	0.2
Wildlife	230	15.9	18.5	16.3	18.8	0.3
Altwind	115	9	13.9	8.9	14.1	0.2
Buckwind	115	11.3	17.7	11.3	17.9	0.2
Devers	115	36.8	30.4	39.1	31.2	0.8
Farrell	115	9.6	12.9	9.5	13	0.1
Garnet	115	13.3	17.9	13.3	18.2	0.3
Terawind	115	12.3	20.2	12.3	20.6	0.4
Tiffanywind	115	10.6	17.5	10.6	17.8	0.3
Valley AB	115	50.7	26.7	51.1	26.9	0.2
Valley D	115	32.2	39.3	32.4	39.5	0.2
Vista	115	24.6	22	26.1	22.2	0.2
Etiwanda B	66	31.8	12.8	31.6	19.9	7.1
Lag. Bell AB	66	27.5	15.6	28.5	16.1	0.5
Lag. Bell DE	66	22	22	22.6	22.7	0.7
Mesa	66	29.7	20.1	30.4	20.3	0.2
Rio Hondo	66	18.2	19.3	18.4	19.4	0.1
San Bernardino	66	26.3	23.3	27.1	23.6	0.3
Vista A	66	26.3	21.9	26.9	22	0.1
Vista C	66	13.7	20.4	13.9	20.5	0.1

I. Introduction

As discussed in Section D.5.2 of the Metro Area Report, the QC7 Phase II application queue short-circuit duty study identified that the addition of new generation in the LA Basin results in overstressing all existing Barre 220 kV circuit breakers beyond their current 63 kA ratings. It is important to note that the 63 kA rating represents SCE's maximum 220 kV circuit breaker design standard. The overstressed condition is impacted by timing of and ultimate disposition to the existing once-through cooling (OTC) units as well as timing of new generation interconnections in the basin. To determine the appropriate mitigation, a detail evaluation was performed that considered current OTC status, timing and cost for potential system upgrades, and potential use of operating procedures as alternative mitigation.

II. Once-Through Cooling Units

On May 4, 2010, the State Water Resources Control Board (SWRCB) adopted a statewide policy on the use of coastal and estuarine waters for power plant cooling. The policy established uniform, technology-based standards to implement federal Clean Water Act section 316(b), which requires that the location, design, construction and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact. The policy was approved by the Office of Administrative Law on September 27, 2010 and became effective on October 1, 2010. It required owners or operators of existing non-nuclear fossil fuel power plants using once-through cooling to submit an implementation plan to the SWRCB by April 1, 2011. The following provides an update of active Once-Through Cooling (OTC) plants located in the SCE service territory which contribute Basin Area short-circuit duty to the Barre 220 kV circuit breakers.

A. Alamitos Generating Station

The existing Alamitos Generating Station consists of a total of seven generation units, which have a net generating capacity of 1950 MWs. The Alamitos Generating Station Units 1 through 6 are currently in operation, whereas unit 7 has been retired and will be demolished. On December 27, 2013, AES Southland Development, LLC (AES-SLD) filed an Application for Certification (AFC)[1] to construct the Alamitos Energy Center to replace the existing Alamitos Generating Station to the California Energy Commission (CEC). In addition, a Permit to Construct and Title V modification to the South Coast Air Quality Management District (SCAQMD) was also submitted in December, 2013. The proposed Alamitos Energy Center, as described in the AFC, will be a natural-gas-fired, air-cooled, combined-cycle generator with a net generating capacity of 1,936 MW and gross generating capacity of 1,995 MW. The commission accepted the AFC submittal as adequate on March 12, 2014.

On April 23, 2015 AES Southland submitted a letter to the SWRCB[2] outlining an implementation plan for the Alamitos Energy Center. In the letter AES states that the existing six generating units are fully contracted through May 31, 2018 and will remain operational at least until then. The table below outlines the implementation plan and impacts to Units 1 through 6 in chronological order based on the implementation plan

[1] http://www.energy.ca.gov/sitingcases/alamitos/
[2] http://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/powerplants/alamitos/docs/aes_042915.pdf

submitted by AES to the CEC as outlined in the letter. It is important to note that the implementation plan reflects best intentions, which are subject to change as future market developments and decisions by other state agencies will influence the ultimate actions and their timing.

Table I-1
AES Alamitos Implementation Plan

Unit #	Capacity (MW)	Compliance Approach	Target Date	Comments
Unit 6	495	Retirement	07/31/2019	Accommodate new CCGT at H. Beach
Unit 5	498	Retirement	11/30/2019	Accommodate new CCGT at Alamitos
Unit 1	175	Retirement	12/31/2020	OTC Policy Compliance
Unit 2	175	Retirement	12/31/2020	OTC Policy Compliance
Unit 3	332	Retirement	12/31/2020	OTC Policy Compliance
Unit 4	335	Retirement	12/31/2020	OTC Policy Compliance

B. Huntington Beach Generating Station

On June 27, 2012 AES Southland, LLC submitted an Application for Certification (AFC) to the California Energy Commission seeking permission to construct and operate the Huntington Beach Energy Project (HBEP). To enable construction of the new natural-gas fired, combined-cycle, air-cooled, 939-megawatt (MW) electrical generating facility,[3] removal of the existing units, including Unit 3 and Unit 4 currently operated as synchronous condensers under RMR Agreement, would be required. Pursuant to the agreement, the CAISO was required to provide the hours of operation of the synchronous condensers until they are no longer deemed necessary due to changed circumstances. The latest CAISO filing was submitted on June 10, 2015.[4]

The Application for Certification (AFC) was granted by the California Energy Commission (CEC) on October 29, 2014, but the application is currently on hold pending a major amendment to reflect recent PPA configuration among other issues.

C. El Segundo Generating Station

On December 21, 2000, EL Segundo Power II LLC filed an Application for Certification (AFC) seeking approval from the California Energy Commission to replace the existing El Segundo Generating Station (ESGS) Units 1 and 2 in the City of El Segundo with Units 5, 6, 7, and 8 which are a natural gas-fired combined cycle electric generation facility[5]. The existing ESGS Units 3 and 4 located adjacent to Units 1 and 2 will not be modified by this project. The new combined cycle facility is expected to generate 630 megawatts (MW) under nominal conditions. This is 291 MW more than the old Units 1 and 2 were capable of generating when operating.

On February 7, 2001, the AFC was accepted and on February 2, 2005[6] the Commission's Final Decision was released. On August 1, 2013 El Segundo's units 5, 6, 7, and 8 were deemed operational and producing power.

[3] http://www.energy.ca.gov/sitingcases/huntington_beach_energy/
[4] http://www.caiso.com/Documents/Jun10_2015_InformationalFiling_AESHuntingtonBeach_HoursofOperation_ER13-351.pdf
[5] http://www.energy.ca.gov/sitingcases/elsegundo/
[6] http://www.energy.ca.gov/2005publications/CEC-800-2005-001/CEC-800-2005-001-CMF.PDF

On April 23, 2013, NRG filed a Petition to Amend (PTA)[7] the California Energy Commission License for ESEC (Docket #00-AFC-14C). The amendment, also known as the El Segundo Power Facility Modification (ESPFM) or the ESEC amendment, proposes the demolition of Units 3 and 4, to be replaced with Units 9, 10, 11, and 12, and the replacement of a once-through seawater cooling system with dry-cooling technology. The purpose of the PTA is to decommission Unit 4 (Unit 3 previously decommissioned) demolish two units (Units 3 and 4), and add fast-start and dispatch flexibility capabilities through the installation of 435 MW net (449 MW gross) of more efficient generation. The PTA proposes the replacement of steam boilers scheduled to retire by December 31, 2015 to meet the state's OTC policy compliance deadline for the ESEC. This amendment would result in a total ESEC generating capacity of 1,022 MW gross. The Final Staff Assessment was released on August 27, 2015.

D. Redondo Beach Generating Station

The existing Redondo Beach Generating Station currently has four operating steam-generating units (Units 5-8) and auxiliary boiler no. 17, and four retired units (units 1-4). On November 20, 2012 AES Southland, LLC submitted an Application for Certification (AFC) to the California Energy Commission seeking permission to construct and operate the Redondo Beach Energy Project (RBEP), located at 1100 North Harbor Drive in the City of Redondo Beach, Los Angeles County.[8] The RBEP is a proposed natural-gas fired, combined-cycle, air-cooled electrical generating facility with a net generating capacity of 496 megawatt (MW), which will replace, and be constructed on the site of the AES Redondo Beach Generating Station. RBEP will consist of one three-on-one, combined-cycle gas turbine power block with three natural-gas-fired combustion turbine generators (CTG), three supplemental-fired heat recovery steam generators (HRSG), one steam turbine generator (STG), an air-cooled condenser, and related ancillary equipment. The existing Redondo Beach Generating Station Units 1 through 8 and auxiliary boiler no. 17 will be demolished as part of the project. On August 20, 2014, Applicant filed a "Notice of Suspension of Application for Certification" (TN202962) (Applicant's Notice). On May 5, 2015, the CEC filed a Scheduling Order, with Evidentiary Hearings set in November 2015 and a final CEC decision expected mid-2016.

III. Barre 220 kV SCD Assessment

As with all identified circuit breaker impacts, timing of need for mitigation is determined by performing a Generation Sequencing Implementation (GSI) short-circuit duty evaluation. The methodology used in performing this GSI is discussed in Section I of Appendix G. The methodology for the initial years (2015-2018) takes into account only generation projects which have an executed Generation Interconnection Agreement (GIA) which would exclude all of QC7 Phase 2 Projects. GSI impacts corresponding with QC7 Phase 2 Projects are considered in the scenario that adds all generation resources as energy only since it excludes all major long-lead time network upgrades not expected to be in-service by 2018.

---

[7] http://docketpublic.energy.ca.gov/PublicDocuments/Compliance/00-AFC-14C/2013/TN%2070442%2004-23-13%20El%20Segundo%20Energy%20Center%20Petition%20to%20Amend.pdf

[8] http://www.energy.ca.gov/sitingcases/redondo_beach/

Appendix I
Barre 220 kV Short Circuit Duty Evaluation

As discussed in Section II.5 of Appendix G, the GSI evaluation of the scenario that includes all generation resources through QC7 as energy only, identified overstressed Barre 220 kV circuit breakers. Application queue short-circuit duty results identified these breakers to be triggered with the inclusion of QC7 Projects. In order to fully understand the extent of the Barre 220 kV circuit breaker impacts, a detailed assessment was performed, which analyzed a number of possibilities. Below is a discussion of the various years that were analyzed and the assumptions that were made for the OTC generation projects, as well as individual unit contributions to Barre 220 kV fault duty.

1. 2015-2018 Barre Short-Circuit Duty with existing OTC

The existing system which includes OTC units still in operation, as shown below in Table I-2, was modified to add all new generation projects with executed GIA's and all transmission upgrades that are currently in flight and expected to be completed by 2018. The new generation projects were added to the year based on their identified commercial operation date as reflected in the most current GIA filed at FERC. Transmission upgrades were added to the year where they are expected to be placed into service.

Table I-2
OTC Units with Corresponding MW Output as Defined by CAISO Master Control List

Alamitos	Unit 1	Unit 2	Unit 3	Unit 4	Unit 5	Unit 6
	174.56	175	332.18	335.67	497.97	495
Huntington Beach	Unit 1	Unit 2	Unit 3	Unit 4		
	225.75	225.8	Synchronous Condensers			
Redondo Beach	Unit 5	Unit 6	Unit 7	Unit 8		
	178.87	175	505.96	495.9		
El Segundo	Unit 4					
	335					

Under this scenario, three-phase-to-ground and single-phase-to-ground short-circuit duty results at Barre are provided below in Table I-3 and Table I-4 respectively.

Table I-3
Three-Phase-to-Ground Short-Circuit Duty at Barre 220 kV

Bus Name	Bus kV	End 2015		End 2016		End 2017		End 2018	
		X/R	kA	X/R	kA	X/R	kA	X/R	kA
Barre	220	22.0	59.1	21.9	59.5	21.7	60.4	21.7	60.5

Table I-4
Single-Phase-to-Ground Short-Circuit Duty at Barre 220 kV

Bus Name	Bus kV	End 2015		End 2016		End 2017		End 2018	
		X/R	kA	X/R	kA	X/R	kA	X/R	kA
Barre	220	13.9	46.5	13.8	46.7	13.7	47.1	13.7	47.1

As can be observed, a three-phase-to-ground fault condition yields a higher short-circuit duty value. Consequently, all remaining analysis will focus on three-phase-to-ground short-circuit duty as will appropriate mitigation.

Detailed review of the circuit breakers at Barre concluded that the breakers are subject to a multiplier factor as defined by IEEE Standards. The product of the multiplier factor to the short-circuit duty kA is the effective duty seen by the circuit breaker. Results of applying the appropriate multiplier yields a maximum fault duty of 60.7 kA, 61.6 kA and 61.7 kA for year 2016, 2017, and 2018 respectively. These values are within the 63 kA nameplate rating value of all existing circuit breaker.

2. Inclusion of Generation Projects without GIA (existing OTC)

The inclusion of new generation projects that are not part of the 2015-2018 GSI cases were included into a case that assumes all these new generation resources through QC7 as energy only. The new generation projects are the same as those itemized in Table I.B.1 of Appendix G but exclude TOT560 (CAISO Queue #702), TOT638 (CAISO Queue #939), and TOT642 (CAISO Queue #893). No additional network upgrades beyond those needed to interconnect projects as energy-only were included into this scenario and all existing OTC units were assumed to remain in place and operational. This evaluation differs from the “Energy Only” evaluation performed and discussed in Section II.5 of Appendix G with results provided in Appendix H. The difference involves the status of OTC unit repowers. Study results presented in Appendix G and Appendix H assume OTC unit repowers are in place consistent with requests received by current plant owners; this evaluation models the OTC units prior to being repowered.

As part of these additional studies, which exclude the OTC repowers, short-circuit duty at the Barre 220 kV substation was found to increase. The increase is attributed to the fact that the OTC units contribute more fault duty as compared to the repower units for certain repower proposals. To adequately capture expected impacts beyond 2018 while existing OTC units are still in service, all new generation projects not included in the 2016-2018 cases were subdivided into several categories. The first category involved the addition of those new Pre-QC7 generation projects that can be conceivably placed in-service by 2019 if a GIA were executed in the very near term and if the corresponding interconnection customer has not identified a desired in-service date that is beyond 2019. A second category consists of the addition of QC7 Phase 2 projects in the vicinity of the Barre Substation and a third category consists of the addition of everyone else as energy only. A discussion of the study results for each of these studies is provided below.

(a) Inclusion of Pre-QC7 Generation Projects that could conceivably be placed in-Service in 2019 With Existing OTC

Under this scenario, short circuit duty at Barre 220 kV was identified to be within the maximum 63 kA allowable limit. The short circuit duty results for Barre 220 kV was found to be 61.0 kA with an X/R ratio of 21.0. Applying the appropriate multiplier yields a maximum fault duty of 61.6 kA.

(b) Inclusion of QC7 Generation Projects With Existing OTC

Under this scenario, short circuit duty at Barre 220 kV was identified to be in excess of the maximum 63 kA allowable limit. The short circuit duty results for Barre 220 kV was found to be 62.5 kA with an X/R ratio of 22.0. Applying the appropriate multiplier yields a maximum fault duty of 64.4 kA. Most of the duty increase is attributed to a single QC7 Phase II project seeking to interconnect to SCE's Barre Substation at the 66 kV voltage level.

(c) Inclusion of QC7 Generation Projects that are not expected to be placed in-Service until after current OTC timeframe

While the current timeframes are such OTC repowers need to be in place by 2020, an extension to the current timeframes could result in a condition where additional resources are interconnection prior to OTC repowers being in place. Under this scenario, short circuit duty at Barre 220 kV would continue to grow in excess of the maximum 63 kA allowable limit. The short circuit duty results for Barre 220 kV under this condition was found to be 63.5 kA with an X/R ratio of 22.0. Applying the appropriate multiplier yields a maximum fault duty of 65.4 kA. Most of the incremental duty increase is attributed to a single QC6 project seeking to interconnect to transmission serving SCE's Center Substation as SCE's Center Substation is only two busses away from Barre.

It is important to note that any changes internal to SDG&E electric system could have an adverse impact on Barre's SCD. If duties internal to SDG&E are increased, the increase would result in an increase at Barre. Specific incremental amounts are dependent on the nature of changes to the system equivalent which is driven by both electric system topology and the number of fault duty sources internal to SDG&E. As a result, a concerted effort will be undertaken with the CAISO to review and develop appropriate operational SCD models for SDG&E system as such models will aid in the determination of potentially earlier need for mitigation.

3. Unit Contribution to Barre Fault Duty

Based on the study findings above, it is clear that need for mitigation of the Barre 220 kV circuit breakers is primarily driven by fault duty provided by local area generation projects. Such finding indicates that the need for actual mitigation is highly dependent on the coordination of replacement and disposition of OTC units, particularly those units which are electrically closer to the Barre Substation, as well as the timing of such coordination. Review of all available data indicates that all OTC units desire to operate up to their allowable compliance requirement date prior to taking OTC units off-line. Such outcome introduces a potential for overstress circuit breakers at Barre 220 kV that appears to potentially resolve itself in the long-term as OTC units are taken off-line and repowered.

IV. Mitigation Options

Two fundamental options exist to address the Barre 220 kV short-circuit duty issue. The first option involves increasing fault duty capability by replacing existing equipment with equipment that can withstand higher short-circuit duty values. The second option involves lowering the amount of short-circuit duty seen at the Barre 220 kV bus.

1. Mitigation Option #1 - Increase Fault Duty Capacity

SCE's current standards provide for a maximum 220 kV circuit breaker rating of 63 kA for open-air substation designs. SCE is currently reviewing the potential to increase 220 kV design capability to enable more than 63 kA for open-air substation designs. For existing substation, detailed engineering review is required to determine if physical space is available as breakers that are rated higher than 63 kA will require more physical space. In addition to the 220 kV voltage level, increases to allowable short-circuit duty at the 220 kV voltage level will result in increases to the fault duty at the 66 kV voltage level. SCE's current 66 kV design allows for a maximum 40 kA rated circuit breaker at the 66 kV voltage level. Increases to fault duty at the 220 kV level may limit the amount of new generation that can be interconnected at the 66 kV voltage level or may necessitate the need to also modify the current 66 kV design standards to allow for higher short-circuit duty. Lastly, increases to fault duty at the 66 kV level may limit the amount of new generation that can be interconnected at the low voltage distribution level (i.e., 12 kV) or may necessitate the need to also modify the current low voltage design standards to allow for higher short-circuit duty. As can be appreciated, a decision to increase short-circuit duty capability beyond current design standards at the 220 kV voltage level should be undertaken with consideration to downstream (lower voltage) implications.

An initial review of the Barre Substation suggests that adequate space is available to support replacement of existing circuit breakers with breakers that are rated greater than 63 kA. The upgrade scope would involve replacement of all twenty-four existing circuit breakers with higher rated 220 kV circuit breaker. The estimated cost is in excess of $70 million and time to implement such upgrades would involve over 48 months. Such option would therefore not be in-service until after all of the OTC units are expected to comply with the SWRCB adopted statewide policy on the use of coastal and estuarine waters for power plant cooling.

2. Mitigation Option #2 - Lower Fault Duty at Barre

An alternative to increasing the station's short-circuit capability is to lower fault duty at Barre to below the current 63 kA design limits. The focus of studies performed under GIP are geared towards identifying system impacts of adding new generation. As a result, the option to lower fault duty at Barre under GIP focused on evaluating the amount of duty reduction gained by turning off generation resources in the Metro Area near the Barre Substation as identified in the individual project's Appendix A report.

V. Recommendation

The recommended mitigation involves mitigation option #2 – lower fault duty at Barre by developing operating procedures that would limit the operation of Metro Area generation near the Barre Substation as identified in the individual project's Appendix A report. The basis for the recommendation is due to the time durations associated with implementing physical upgrades and corresponding temporary nature of the problem due to expected net unit retirements following OTC compliance.

Queue Cluster 7 Phase II – Appendix K

Environmental Evaluation, Permitting, and Licensing

NOVEMBER 24, 2015

Appendix K
Environmental Evaluation and Permitting/Licensing Requirements for Generation Interconnection Projects
Prepared by CEHS/RP&A/Law/MPO on October 10, 2013

The Interconnection Customer may be required to complete environmental impact studies and obtain permits for the construction, operation, and maintenance of the Generating Facility and Interconnection Customer's Interconnection Facilities. Such activities would be the responsibility of the Interconnection Customer.

SCE may also be required to complete environmental studies and obtain permits/licenses for the construction, operation, and maintenance of its facilities, including its Interconnection Facilities and Upgrades. SCE implements procedures to ensure compliance with all applicable federal and state laws and regulations. Depending on the project, SCE's activities may be subject to the jurisdiction of several agencies, such as the California Public Utilities Commission (CPUC), California Department of Fish and Wildlife, U.S. Fish and Wildlife Service, State Water Resources Control Board or Regional Water Quality Control Board, U.S. Army Corps of Engineers, California Coastal Commission, Bureau of Land Management, and U.S. Forest Service.

As both SCE and the Interconnection Customer may be subject to similar requirements for performing environmental studies, it may be beneficial to combine portions of the environmental study processes. However, close coordination with SCE during the study process would be needed to ensure the final study/report/product meets SCE environmental requirements.

I. CPUC Licensing Requirements Pursuant to General Order 131-D

As an electric public utility, SCE is regulated by the CPUC. The CPUC's General Order 131-D (GO 131-D) sets forth rules related to the planning and construction of electric generation, transmission, power, and distribution line facilities and substations located in California. The CPUC issued GO 131-D to be responsive to: the California Environmental Quality Act (CEQA); the need for public notice and the opportunity for affected parties to be heard by the Commission; and the obligations of the utilities to serve their customers in a timely and efficient manner.

Section III of GO 131-D specifies the type of authorization required for the construction of electric facilities to be constructed by electric public utilities subject to the CPUC's jurisdiction. The requirements for a Certificate of Public Convenience and Necessity (CPCN) apply to the construction of major electric transmission line facilities designed for immediate or eventual operation at 200 kV or more (Section III.A). The requirements for a Permit to Construct (PTC) apply to the construction of electric power line facilities designed for immediate or eventual operation at a voltage between 50 kV and 200 kV, or new or upgraded substations with high side voltage equal to or exceeding 50 kV (Section III.B). Sections III.A and III.B.1 provide exemptions from CPUC CPCN and PTC requirements when certain conditions exist. An application for a CPCN or PTC must include a Proponent's Environmental Assessment (PEA) or equivalent information on the environmental impact of the project in accordance with the provisions of CEQA and the CPUC's Rules of Practice and Procedure for the CPUC's review (Section IX). CEQA requires that the CPUC consider the environmental consequences before acting upon or approving a project for which SCE has filed an application for a PTC or CPCN; accordingly, construction cannot begin on such projects until the CPUC Commissioners issue a Decision to approve the project and certify the final CEQA document issued by the CPUC.

Generally, SCE takes approximately 18 to 24 months to assemble a CPCN or PTC application, the majority of which time is attributed to developing the PEA and performing related environmental surveys. The CPUC review of such applications may take an additional18 to 48 months depending on the specific issues.

For a copy of GO 131-D, please go to:

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

A more detailed discussion of PTC and CPCN requirements and certain exemptions from such requirements are provided below:

A. Certificate of Public Convenience and Necessity (CPCN)

Section III.A of GO 131-D requires electric public utilities to obtain a CPCN from the CPUC for the construction of major electric transmission line facilities that are designed for immediate or eventual operation at 200 kV or more except for the following[1]:

- the replacement of existing power line facilities or supporting structures with equivalent facilities or structures,
- the minor relocation of existing power line facilities,
- the conversion of existing overhead lines to underground, or
- the placing of new or additional conductors, insulators, or their accessories on or replacement of supporting structures already built.

1. "Expedited" CPCN[2]

Unlike the rules for PTCs described later in this document, there is no provision in GO 131-D that exempts from CPCN requirements major electric transmission facilities over 200 kV that have undergone environmental review pursuant to CEQA as part of a larger project. Accordingly, if major electric line facilities have

[1] Note, unlike PTC exemptions discussed later in this document, which are enumerated with specific exemption classifications (e.g., Exemption f), GO 131-D does not enumerate CPCN exemptions in the same manner. Instead, CPCN exemptions are discussed in a lengthy sentence in Section III.A in which the GO states that CPCNs are required "except for" the situations discussed in the bullets above. SCE has bulletized these CPCN exemption references for the purposes of providing clarity in this document.

[2] Note, the word "expedited" is not a defined term in GO 131-D. SCE uses this term when it files a CPCN (or PTC) application and anticipates that the CPUC will not be required to undergo separate CEQA review, and accordingly assumes the schedule for the CPUC's review may be "expedited" due the fact the CPUC would likely not have to conduct CEQA review of the application.

already undergone environmental review pursuant to CEQA by the lead agency that permitted the Generating Facility and the Interconnection Customer's Interconnection Facilities, SCE would proceed under an "expedited" CPCN application by attaching the final CEQA document in lieu of a PEA. Based on past experience, SCE anticipates that an "expedited" CPCN typically may take from six to nine months for the CPUC to process.

B. Permit to Construct (PTC)

Section III.B of GO 131-D requires electric public utilities to obtain a PTC from the CPUC for the construction of electric power line facilities which are designed for immediate or eventual operation at any voltage between 50 kV and 200 kV, or new or upgraded substations with high side voltage equal to or exceeding 50 kV unless one of the listed exemptions under Section III.B.1 (exemptions a through h) applies. Note, though, that exemptions a through h shall not apply when any of the conditions specified in CEQA Guidelines §15300.2 regarding exceptions to categorical exemptions exist (Section III.B.2).

1. PTC Exemptions

Section III.B.1 of GO 131-D discusses the conditions under which certain projects may proceed exempt from PTC requirements. These include:

Exemption b[3].: The replacement of existing power line facilities or supporting structures with equivalent facilities or structures,

Exemption c.: The minor relocation of existing power line facilities up to 2,000 feet in length, or the intersetting of additional support structures between existing support structures,

Exemption d.: The conversion of existing overhead lines to underground,

Exemption e.: The placing of new or additional conductors, insulators, or their accessories on supporting structures already built,

Exemption f.: Power lines or substations to be relocated or constructed which have undergone environmental review pursuant to CEQA as part of a larger project, and for which the final CEQA document (Environmental Impact Report (ElR) or Negative Declaration) finds no significant unavoidable environmental impacts caused by the proposed line or substation,

[3] PTC Exemption a. is no longer in use; it was a "grandfather" exemption used when GO 131-D was implemented in the mid-1990s to provide an exemption for projects that had an in-service date of January 1, 1996.

Exemption g.: Power line facilities or substations to be located in an existing franchise, road-widening setback easement, or public utility easement; or in a utility corridor designated, precisely mapped and officially adopted pursuant to law by federal, state, or local agencies for which a final Negative Declaration or EIR finds no significant unavoidable environmental impacts,

Exemption h.: The construction of projects that are statutorily or categorically exempt pursuant CEQA.

2. PTC Exemption f

As noted above, exemption f of GO 131-D (Section III.B.1.f), in particular, exempts the need for a PTC for power lines or substations to be relocated or constructed which 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.

SCE may be eligible to use exemption f after the Interconnection Customer's lead agency approves a final CEQA document that finds no significant unavoidable environmental impacts caused by SCE's proposed scope of work. While, in some cases, other exemptions discussed above may be applicable, Exemption f is often the likely or preferred exemption to use when there is a larger project driving the SCE scope of work.

To use exemption f, SCE would follow certain noticing requirements, including filing an informational advice letter with the CPUC, posting a notice on-site and off-site at the project location, advertising once a week for two weeks successively in a local newspaper at least 45 days prior to construction, and providing notice to the director for each county or city in which the project would be located and the executive director of the California Energy Commission. As part of an agreement with the CPUC Energy Division, SCE would informally provide a copy of the final CEQA document to the CPUC Energy Division for reference when the advice letter is pending before the CPUC.

The CPUC rules for advice letters consider an advice letter to be in effect on the 30th calendar day after the filing date. Typically, SCE may proceed with construction 45 days after noticing and posting unless a protest is filed and/or the CPUC suspends the advice letter. If a protest is filed with the CPUC, the protestant must address whether SCE has properly claimed the exemption. SCE would have five business days to respond to the protest, and the CPUC would typically take a minimum of 30 days to review the protest and SCE's response. The CPUC would either dismiss the protest or require SCE to file an application for a PTC. Note that SCE would have no control over the time it takes the CPUC to respond when protests arise.

3. "Expedited" PTC[4]

For power lines or substations that have undergone environmental review pursuant to CEQA as part of a larger project but do not qualify for exemption f (final CEQA document finds significant unavoidable environmental impacts caused by the proposed line or substation), SCE may be able to file for an "expedited" PTC by attaching the larger project's final CEQA document to its application in lieu of a PEA. The schedule for the CPUC's review of such an "expedited PTC" could depend on many factors, including issues not resolved in the larger project's CEQA document and/or whether the CPUC would need to issue a Statement of Overriding Considerations. Although SCE assumes such review would not take as long as a "regular" PTC application, a schedule estimate would need to be provided on a case-by-case basis after consultation with the CPUC.

If construction does not qualify for an expedited PTC or an exemption to a PTC, SCE would likely be required to file a PTC application with a PEA. As discussed earlier in this document with respect to the timing for CPCN applications, SCE would typically take 18 – 24 months to develop the PTC application and PEA, and the CPUC's review of the PTC may take 18 – 48 months as the CPUC would need to conduct its own environmental review pursuant to CEQA by issuing an Initial Study and Negative Declaration/Mitigated Negative Declaration or Environmental Impact Report.

C. Projects on Federal Land

If an Interconnection Customer is seeking approvals for the Generating Facility and Interconnection Customer's Interconnection Facilities from only a federal agency and not from a state agency, the federal lead agency would generally prepare an environmental document pursuant to the National Environmental Policy Act (NEPA). Note that the provisions of GO 131-D do not allow for the use of exemption f, expedited PTC, or expedited CPCN when the environmental review is conducted only pursuant to NEPA and not to CEQA requirements. SCE may consult with the CPUC on a case-by-case basis to determine whether the CPUC would allow for the project to proceed exempt from CPUC permitting requirements or would expedite the PTC/CPCN application process if SCE were to submit the final NEPA document in lieu of a PEA.

D. Projects Not Subject to CPUC GO 131-D Permitting

[4] *ibid*

Section III.C of GO 131-D does not require issuance of a CPCN or PTC from the CPUC for the construction of electric distribution (under 50 kV) line facilities, or substations with a high side voltage under 50 kV, or substation modification projects which increase the voltage of an existing substation to the voltage for which the substation has been previously rated within the existing substation boundaries. Note, though, that the construction of facilities under 50 kV may affect and require work on facilities over 50 kV.

In cases where permits are not required from the CPUC, SCE may be required to obtain permits from other regulatory agencies. For additional information, please see section III below (Permitting Requirements by Resource Agencies).

II. CPUC Approval Requirements Pursuant to Section 851

Since SCE is subject to the jurisdiction of the CPUC, it must also comply with Public Utilities Code Section 851. Among other requirements, this code provision requires SCE to obtain CPUC approval of transfers of SCE property, including leases and rights-of-way granted to third parties for Interconnection Facilities. Obtaining CPUC approval for a Section 851 application or advice letter can take several months, and requires compliance with CEQA. SCE recommends that Section 851 issues be identified as early as possible so that the necessary application or advice letter can be prepared and processed. As with GO 131-D compliance, SCE recommends that the project proponent include an analysis of any environmental impacts resulting from transfers of SCE property that may be subject to Section 851 in the lead agency's CEQA review so that the CPUC does not need to undertake additional CEQA review in connection with its Section 851 approval.

III. Permitting Requirements by Resource Agencies

For both projects that are subject to and projects that are not subject to CPUC permitting, 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 before commencement of construction activities. Resource agencies such as California Department of Fish and Wildlife, U.S. Fish and Wildlife Service, State Water Resources Control Board or Regional Water Quality Control Board, U.S. Army Corps of Engineers, California Coastal Commission, and U.S. Forest Service are required to comply with CEQA or NEPA, as applicable, when issuing permits. Therefore, in order to secure permits from such agencies, SCE's work may require environmental surveys/studies/reports even if no license is required from the CPUC.

Although the necessity for environmental permits is oftentimes unknown during the initial stages of project development, it is recommended that the Interconnection Customer and SCE combine portions of their environmental study processes.

A. CEQA/NEPA Documentation

If the Interconnection Customer incorporates SCE's scope of work into its environmental study reports, it is recommended for the Interconnection Customer to closely coordinate with SCE during the environmental review process to ensure that SCE's scope of work is being adequately described, and to ensure that environmental studies are being performed to industry standard. If the resulting environmental documents do not adequately describe SCE's scope of work or do not adequately analyze the environmental impacts caused by SCE's scope of work, SCE and/or the permitting agencies may not be able to rely on such documents and additional environmental documents may need to be prepared, resulting in delays to the project schedule.

B. Permit Applications

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. Therefore, SCE (not the Interconnection Customer) shall be the permit holder for all such permits. It is SCE's experience that securing such permits may take from six 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 Endangered Species Act 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 prepare plans to adequately address agency requirements.

IV. Recommendations

For the reasons stated above, it is recommended that the Interconnection Customer identity and include all of SCE's Interconnection Facilities, Distribution Upgrades, and Plan of Service Network Upgrades (including facilities agreed upon by all parties and permitted by the tariff to be constructed by others and deeded to SCE) in the Interconnection Customer's environmental study reports submitted to the lead agency permitting the Generating Facility and the Interconnection Customer's Interconnection Facilities (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 lead agency(ies) review the potential environmental impacts associated with SCE's scope of work in any environmental document prepared. Doing so may enable SCE to proceed "exempt" from CPUC permitting requirements or under an "expedited" PTC or CPCN. SCE may also be required to obtain other authorizations for its Interconnection Facilities and Upgrades. However, depending on certain circumstances, the CPUC may still require SCE to undergo a standard PTC or CPCN for the facilities associated with the Interconnection Customer's Generating Facility. Hence, SCE's facilities needed for the project interconnection could require an additional four to six years, or more, to develop the application and secure CPUC approval.

Appendix K
Environmental Evaluation and Permitting/Licensing Requirements for Generation Interconnection Projects
Prepared by CEHS/RP&A/Law/MPO on October 10, 2013

Appendix 3A-1
Phase II Interconnection Study Report

APPENDIX 3A-1A

Addendum 1 to the Interconnection Study Report

This appendix is provided on CD-ROM.

Appendix 3A-1b
Appendix H to the Interconnection Study Report

APPENDIX 3A-1B

Appendix H to the Interconnection Study Report

This appendix is provided on CD-ROM.