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2015 Ten Year Assessment

Grid Planning

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Introduction

Introduction

The Sacramento Municipal Utility District (SMUD), established in 1946, is the nation's sixth largest community-owned electric utility in terms of customers served (approximately 625,000) and covers a 900 square mile area that includes Sacramento County and a small portion of Placer County. SMUD's all-time peak demand of 3,299 MW occurred on July 24, 2006.

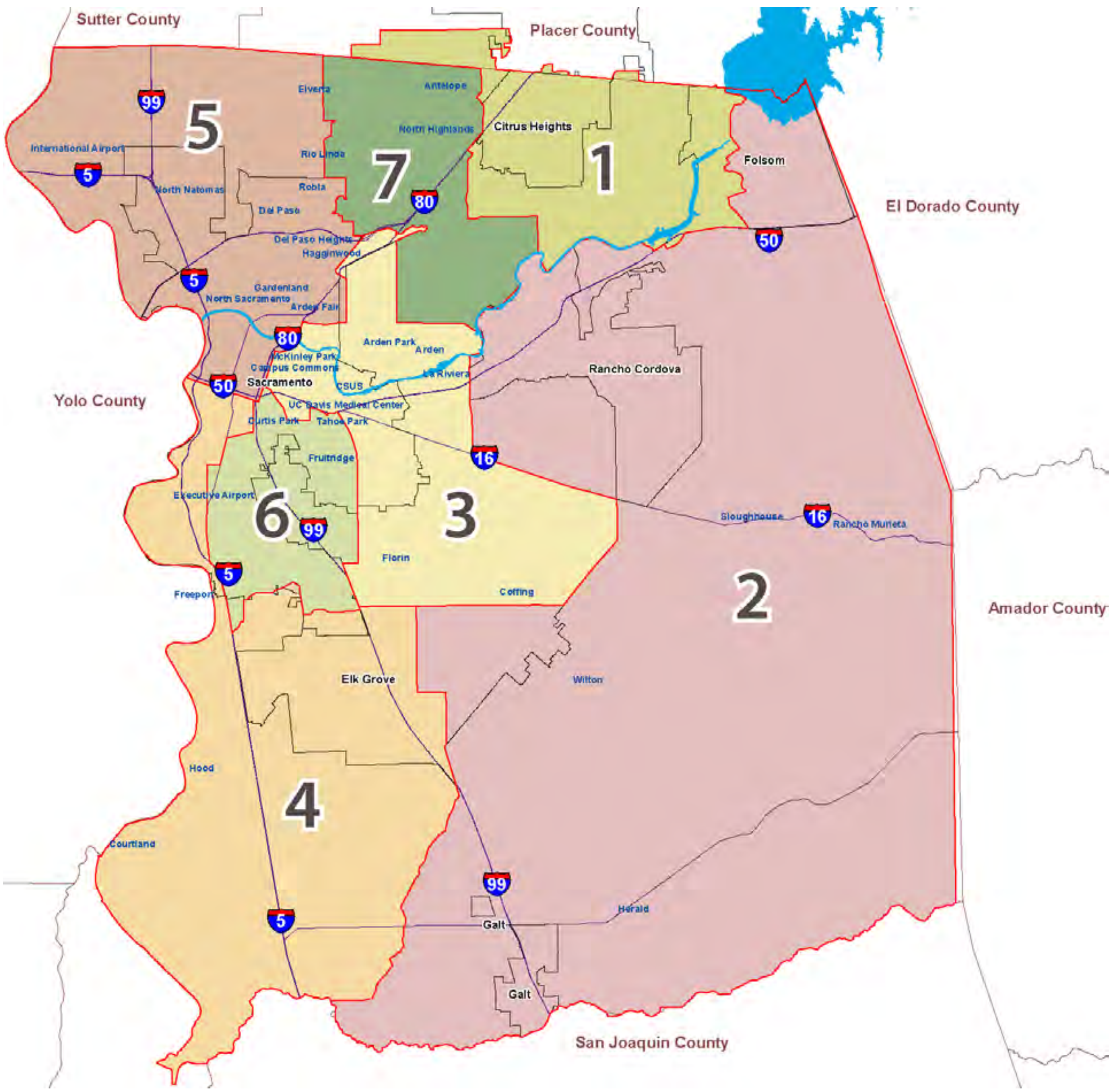

Figure 1: SMUD Service Territory and Ward Areas[1]

[1] https://www.smud.org/en/about-smud/company-information/board-of-directors/ward-map.htm

Changes to NERC Planning Standard (TPL)

Effective January 1, 2016, NERC Reliability Standard TPL-001-4 consolidates four TPL Reliability Standards into a single standard. Additionally, TPL-001-4 introduces significant revisions by requiring:

- More detailed description of system conditions modeled
- Transmission maintenance outages
- Annual short circuit assessment
- Sensitivity cases around varying assumptions (i.e. demand forecasts, resource availability)
- Spare equipment strategy
- Restrictions on load shedding
- Documentation of reliability criteria

NERC updated the contingency categories with the consolidation of the previous four TPL Reliability Standards. Table 1 details a comparison of the "new" and "old" contingency categories.

Table 1: Comparison of Old Contingencies vs. New Contingencies

Old TPL[2]	New TPL[3]	Description
Category A	P0	All Facilities In-Service (N-0)
Category B	P1	Single Outage
Category C1, C2	P2	Single event that may result in multi-facility outage
Category C3	P3	Loss of Generator unit, system adjustment, followed by P1. (No load shed allowed)
Category C	P4	Fault plus stuck breaker
N/A	P5	Fault plus delayed clearing due to relay component failure
Category C	P6	Overlapping Outages (No Generation Facilities)
Category C4, C5	P7	Common structure outages
Category D	Prefix "ES(S)"	Extreme contingencies

[2] Old TPL is comprised of TPL-001-0.1, -002-0b,-003-0b,-004-0a
[3] TPL-001-4

Ten Year Assessment of the SMUD Transmission System

A comprehensive multi-year assessment of SMUD's transmission system is performed annually to ensure that NERC/WECC Reliability Standards are met each year of the ten year planning horizon. This assessment includes the near-term (2016 through 2020) and the long-term (2021 through 2025) planning horizons. This assessment addresses: SMUD's Bulk Electric System (BES), its Load Serving Capability (LSC), and the ability to operate reliably over a broad spectrum of system conditions following a wide range of probable contingencies. In addition, it also evaluates the reliability impacts resulting from extreme BES disturbances.

The 2015 Pacific Gas and Electric (PG&E) Expansion Plan Central Valley power flow base cases were used as seed cases for this assessment. These base cases incorporate a 1-in-10 year adverse peak demand for both SMUD and the surrounding Sacramento valley area and have all projected firm transfers modeled. These cases include: recent demand forecasts, expected generation patterns, and in-service updates for project proposals. In addition, no Capacity Benefit Margin (CBM) amount is used in the ten year planning horizon.

This Ten-Year Assessment focuses on adverse weather peak system conditions in addition to off-peak conditions including steady state (thermal), voltage stability and transient stability analyses.

Executive Summary

Executive Summary

This assessment complies with NERC Standard TPL-001-4. As an internal controls mechanism, each specific requirement within the TPL-001-4 standard is included in the applicable section heading to ensure a complete transition to the new planning standard.

Compliance with NERC Reliability Standard TPL-001-4

All applicable contingency categories (P0 - P7) were simulated to ensure compliance with NERC/WECC planning standards and identify any reliability concerns on the SMUD transmission system.

The 2015 Ten-Year Assessment has identified no reliability violations based on performed steady state power flow, voltage stability (QV), and transient stability analyses.

SMUD Load Serving Capability (LSC) Study

The Load Serving Capability (LSC) is the maximum demand that can be served with all facilities in service while meeting all applicable reliability standards. For the near and long-term planning horizons, years 2016 through 2025, power flow studies demonstrate that SMUD will be able to reliably serve peak demand.

The LSC is limited by the WECC reactive margin criteria at the Natomas 230 kV bus for loss of the Sutter-O'Banion 230 kV Line (N-1). Figure 2 provides a graphical representation of SMUD's LSC compared to the managed base growth demand.

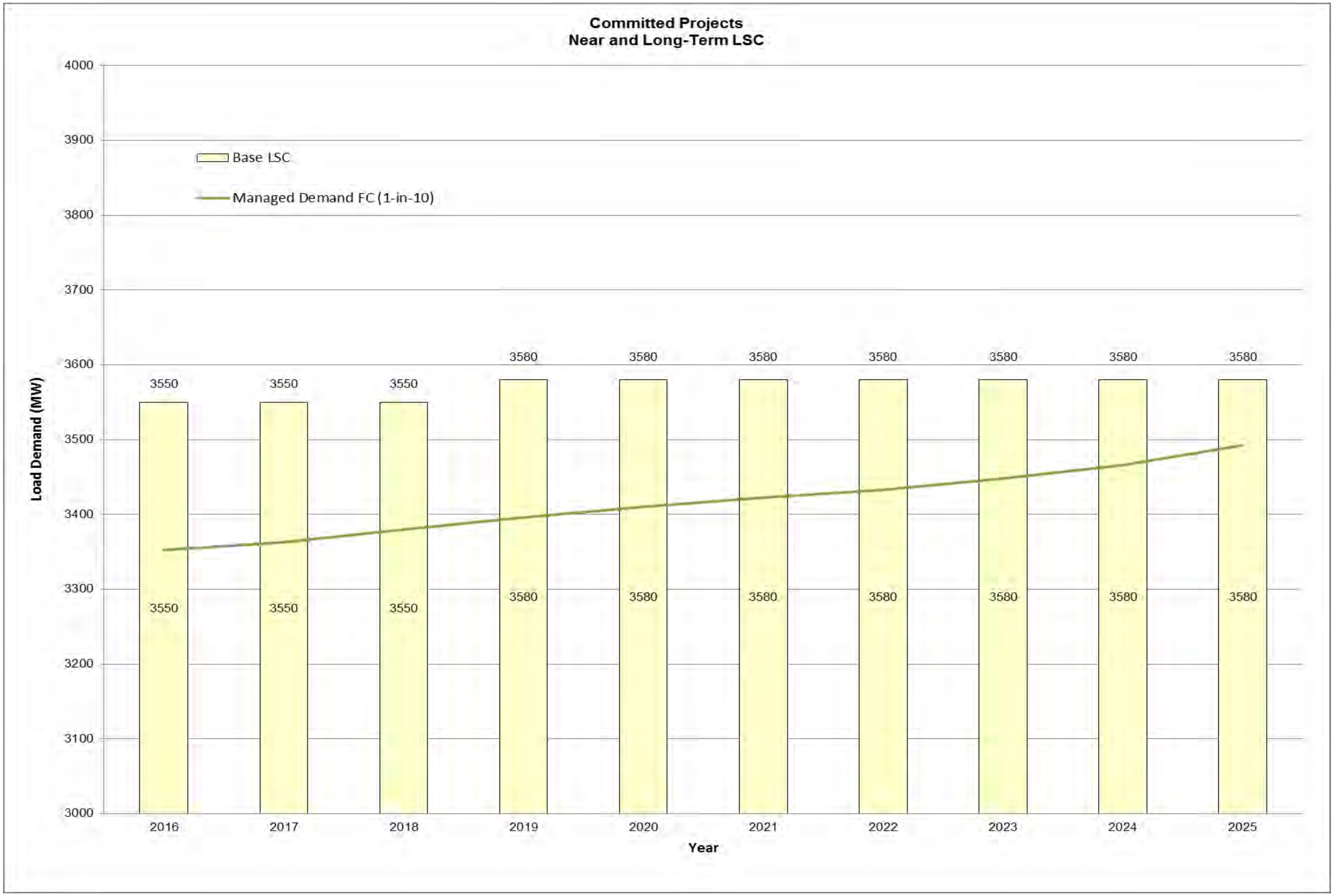

Figure 2: Committed Projects (Near-Term and Long-Term LSC)

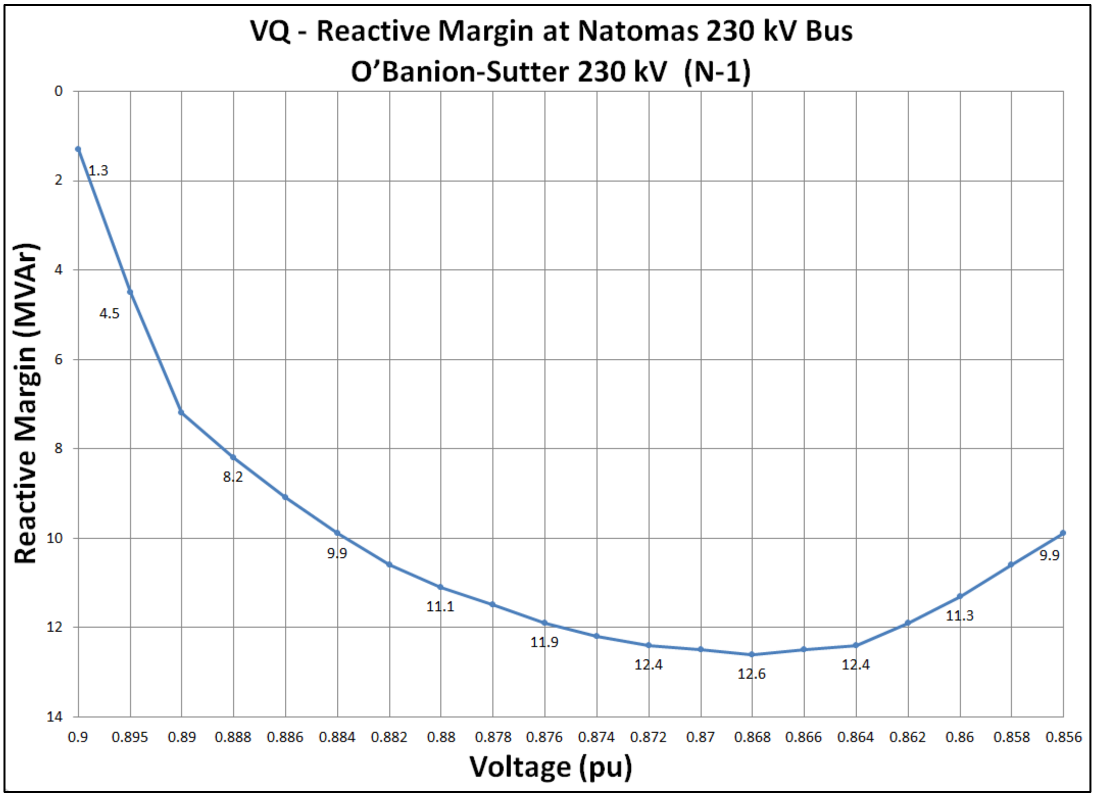

Figure 3: 2016 VQ Reactive Margin

Table 2: SMUD's Load Serving Capbility

Year	Limiting Contingency	Limiting Facility	LSC (MW)
2016	O'Banion-Sutter 230 kV (N-1)	WECC Reactive Margin Criteria at Natomas 230 kV Bus	3550
2017	O'Banion-Sutter 230 kV (N-1)	WECC Reactive Margin Criteria at Natomas 230 kV Bus	3550
2018	O'Banion-Sutter 230 kV (N-1)	WECC Reactive Margin Criteria at Natomas 230 kV Bus	3550
2019	O'Banion-Sutter 230 kV (N-1)	WECC Reactive Margin Criteria at Natomas 230 kV Bus	3580
2020	O'Banion-Sutter 230 kV (N-1)	WECC Reactive Margin Criteria at Natomas 230 kV Bus	3580
2021	O'Banion-Sutter 230 kV (N-1)	WECC Reactive Margin Criteria at Natomas 230 kV Bus	3580
2022	O'Banion-Sutter 230 kV (N-1)	WECC Reactive Margin Criteria at Natomas 230 kV Bus	3580
2023	O'Banion-Sutter 230 kV (N-1)	WECC Reactive Margin Criteria at Natomas 230 kV Bus	3580
2024	O'Banion-Sutter 230 kV (N-1)	WECC Reactive Margin Criteria at Natomas 230 kV Bus	3580
2025	O'Banion-Sutter 230 kV (N-1)	WECC Reactive Margin Criteria at Natomas 230 kV Bus	3580

Peak Demand Forecast Reduction

The 2015 long-term peak demand forecast shows annual decreases compared to last year's demand forecast. Generally, a lower peak demand forecast requires less Load Serving Capability (LSC) projects and also results in a reduced likelihood of reliability related concerns. A full description of the peak demand forecast can be in the Demand Forecast section.

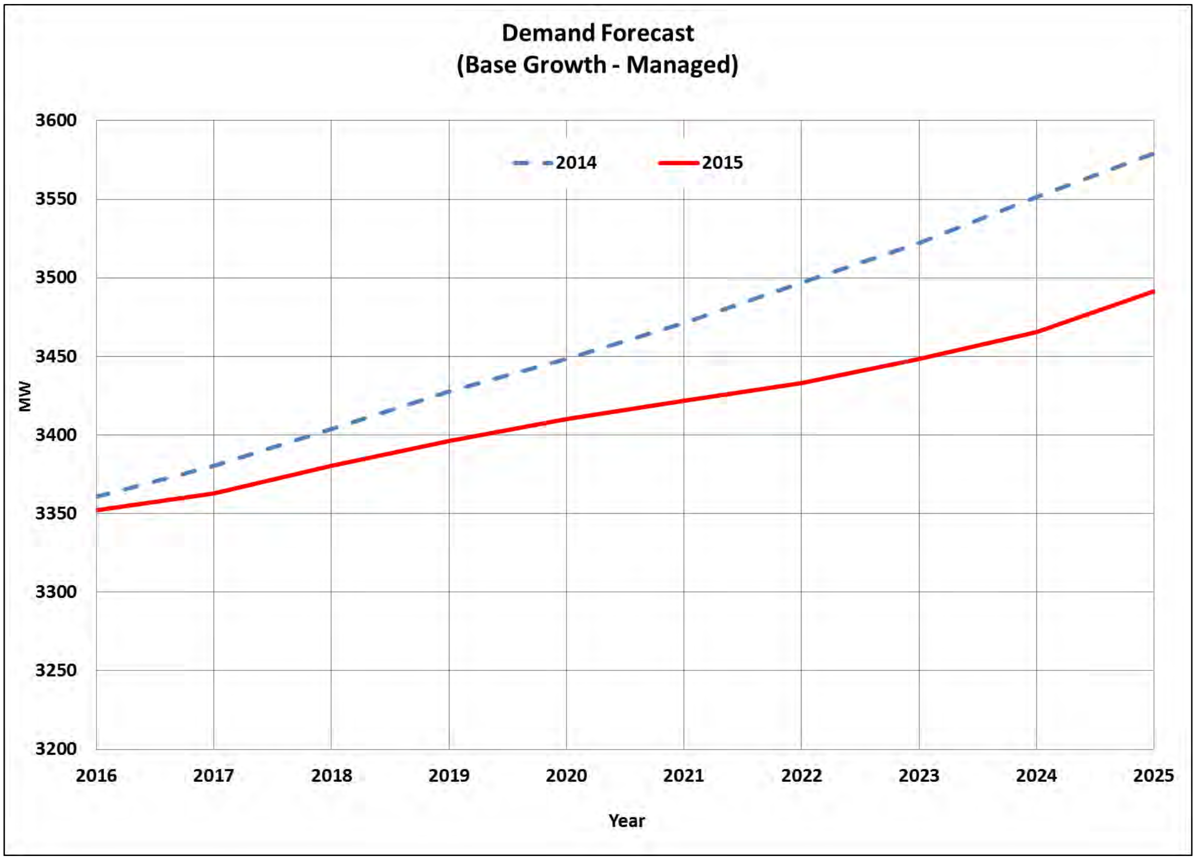

Figure 4: Demand Forecast Comparison 2014 vs. 2015

Cosumnes Power Plant (CPP) Reactive Capability

SMUD's LSC is voltage stability limited; therefore, reactive power resources in the SMUD system have a direct effect on the LSC. With this in mind, Grid Planning (GP) staff analyzed results from the Western Electricity Coordinating Council (WECC) reactive power capability tests[4] that were performed at the CPP in January 2005, May 2010, and May 2015.

Due to the variations[5] in the test results and to meet the NERC standard, MOD-025-2[6], GP staff collaborated with Grid Operations, Power Generation, and the plant operator, Ethos Energy, to stage a retest in September 2015. The successful retest replicated the maximum reactive capability resulting in a LSC increase of ~50 MW over the 2010 test values.

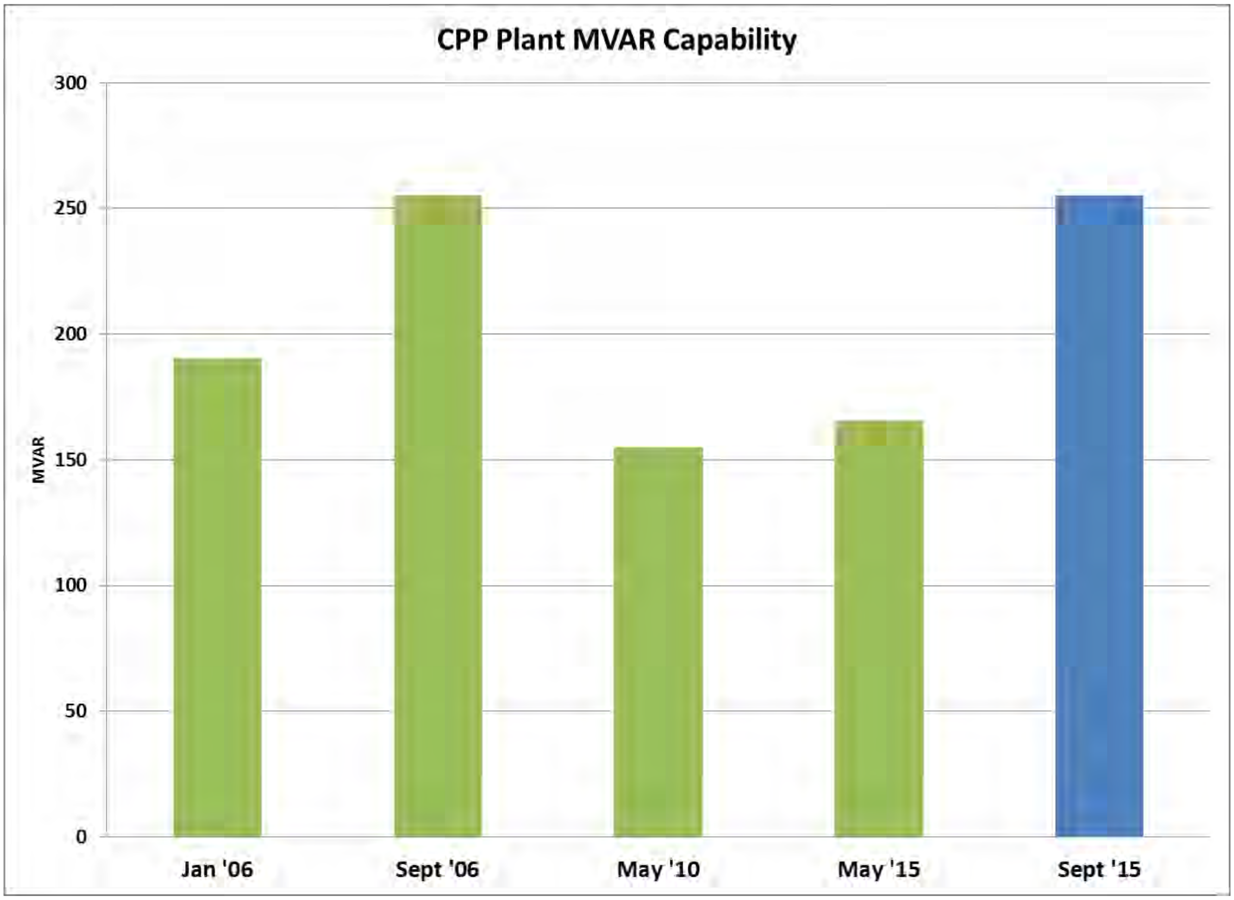

Figure 5: CPP Plant MVAR Capability

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[4] The September 2006 test was informal and did not meet the requirements of the WECC testing process.

[5] It was determined that the testing was performed under unfavorable system voltage conditions resulting in underrated CPP reactive power capability.

[6] MOD-025-2 Verification of Generator Real and Reactive Power Capability requires verification of reactive output for a minimum of one hour.

Transmission Projects

Completed Transmission Projects

Foothill Capacitor Bank

IN-SERVICE DATE

November 01, 2015

PROJECT SCOPE

The scope of this project was to install a 50 MVAR 230 kV transmission capacitor bank at Foothill Substation.

BACKGROUND

Due to feasibility constraints, this capacitor installation was relocated from Hurley to the Foothill substation.

SYSTEM IMPACTS

The installation of transmission capacitors reduces system losses, improves the 230 kV voltage profile, supplies substation reactive demand, provides reactive support for high import levels and system disturbances, improves operating flexibility, and simplifies reactive device coordination with SMUD's distribution system. In addition, the capacitors increase the SMUD's LSC.

Cosumnes Power Plant Maximum Reactive Capability

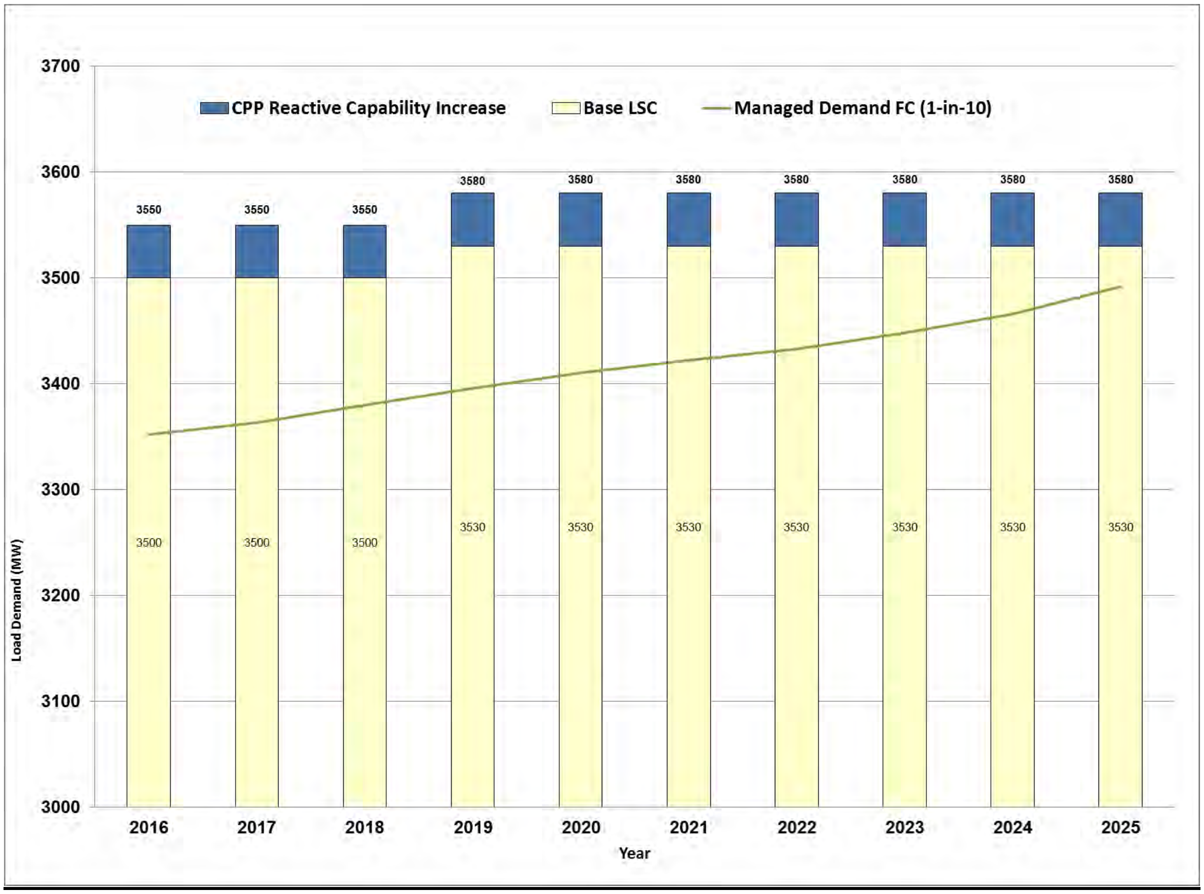

Figure 6: LSC Comparison of Previous CPP Reactive Values vs. New Reactive Values

IN-SERVICE DATE

September 22, 2015

PROJECT SCOPE

The maximum reactive power (Q_{max}) on all three units at the Cosumnes Power Plant (CPP) was tested by boosting each of the units, one at a time, and held for 60 minutes at that maximum MVAR output.

BACKGROUND

SMUD's previous reactive capability tests have been limited by high system voltages.

SYSTEM IMPACTS

There is a ~50 MW LSC increase from this change.

Planned Transmission Projects

The committed projects identified in Table 3 provide margin above LSC requirements to meet the 1-in-10 year demand forecasts and comply with the NERC/WECC Reliability Standards for years 2016 through 2025. Funds have been approved for their construction in order to meet the planned in-service dates described in the table.

Table 3: Near Term Transmission Projects

Project Name	Project Description	Project Status	Expected IS Date
Foothill 50 MVAR Shunt Capacitor	Install Transmission Capacitors	Completed	November 01, 2015
Station E	North City Rebuild	Committed	May 31, 2017
Franklin 230/69kV Substation	New Distribution Substation	Committed	May 31, 2019

For planning and modeling purposes only, the projects in Table 4 are shown with in-service dates to be determined (TBD), as no final decision has been made as to the timing, reliability need, or staging of these projects. SMUD will evaluate the need and timing of these projects and make a recommendation in future assessments.

Table 4: Long-Term Transmission Projects

Project Name	Project Description	Project Status	Expected IS Date
CoSu 500 kV Project	New 500 kV Line from COTP to SMUD	Under Evaluation	TBD
Iowa Hill Pumped Storage Facility & 4th UARP Line	New Hydro Plant and Transmission Line in the UARP	Delayed	TBD
Lake-Folsom-Orangevale 230 kV re-conductoring	Re-conductor 230 kV Line	Delayed	TBD

Franklin 230/69kV Substation

EXPECTED IN-SERVICE DATE

May 31, 2019

PROJECT SCOPE

This project will construct a new bulk substation with a breaker and a half bus configuration. In addition, the Rancho Seco – Pocket 230 kV No. 1 and No. 2 lines will be looped into the substation and two 16.2 MVAr of capacitor banks will be installed on the 69 kV bus. The substation will include eight 230 kV circuit breakers and a single 230/69 kV transformer, rated at 224 MVA.

BACKGROUND

The Franklin 230/69 kV substation site is located near the intersection of Franklin Boulevard and Bilby Road. The substation is adjacent to the Rancho Seco - Pocket 230 kV Double Circuit Transmission Line (DCTL).

SYSTEM IMPACTS

There are no NERC Reliability Standard violations associated with the construction of this substation. Primarily, Franklin Substation off loads the Pocket and Elk Grove substations and meets customer demand growth.

ONE-LINE DIAGRAMS

- Figure 7: Conceptual Franklin One-Line Diagram

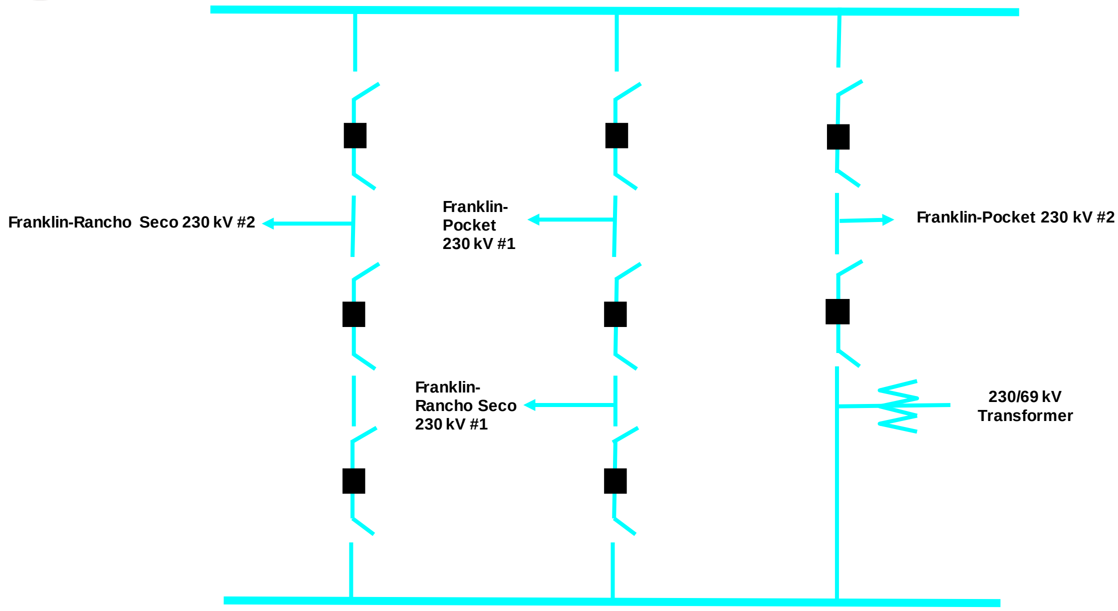

Figure 7: Conceptual Franklin One-Line Diagram

New Transmission Projects under Evaluation

Colusa Sutter 500 kV Transmission Line Proposal

SMUD and the Western Area Power Administration – Sierra Nevada Region (Western) propose to construct a 500 kV transmission project interconnecting the California Oregon Intertie Project (COTP) near the existing Maxwell 500 kV series capacitor station to a new 500/230 kV substation near the existing O'Banion 230 kV station. The project name is Colusa Sutter Transmission Line or CoSu.

SMUD and Western are not seeking a formal Western Electricity Coordinating Council (WECC) Path Rating using the WECC Path Rating Process. However, due to the proximity of the project proposal to the existing WECC Path 66, all technical studies were performed with the California Oregon Intertie (COI) at its rating of 4800 MW to ensure there are no adverse impacts to the existing COI rating.

A primary objective for this new transmission project is to provide SMUD full transmission access to its current rights on the COTP, which it currently cannot fully utilize. To address this need, SMUD requested additional capacity on Western's transmission system between the COTP and the SMUD system. Western did not have sufficient available transmission capacity to meet the request and the SMUD and Western agreed to initiate discussions to evaluate a jointly developed project that could accomplish the objective.

SMUD and Western have formed a project coordination review group within WECC that is currently studying the impacts, if any, to neighboring transmission systems and existing WECC rated paths.

It is important to note that the SMUD Board has only approved an agreement that allows initiation of an environmental review and to begin regional transmission review activities. Hence, no final decision has been made regarding the project.

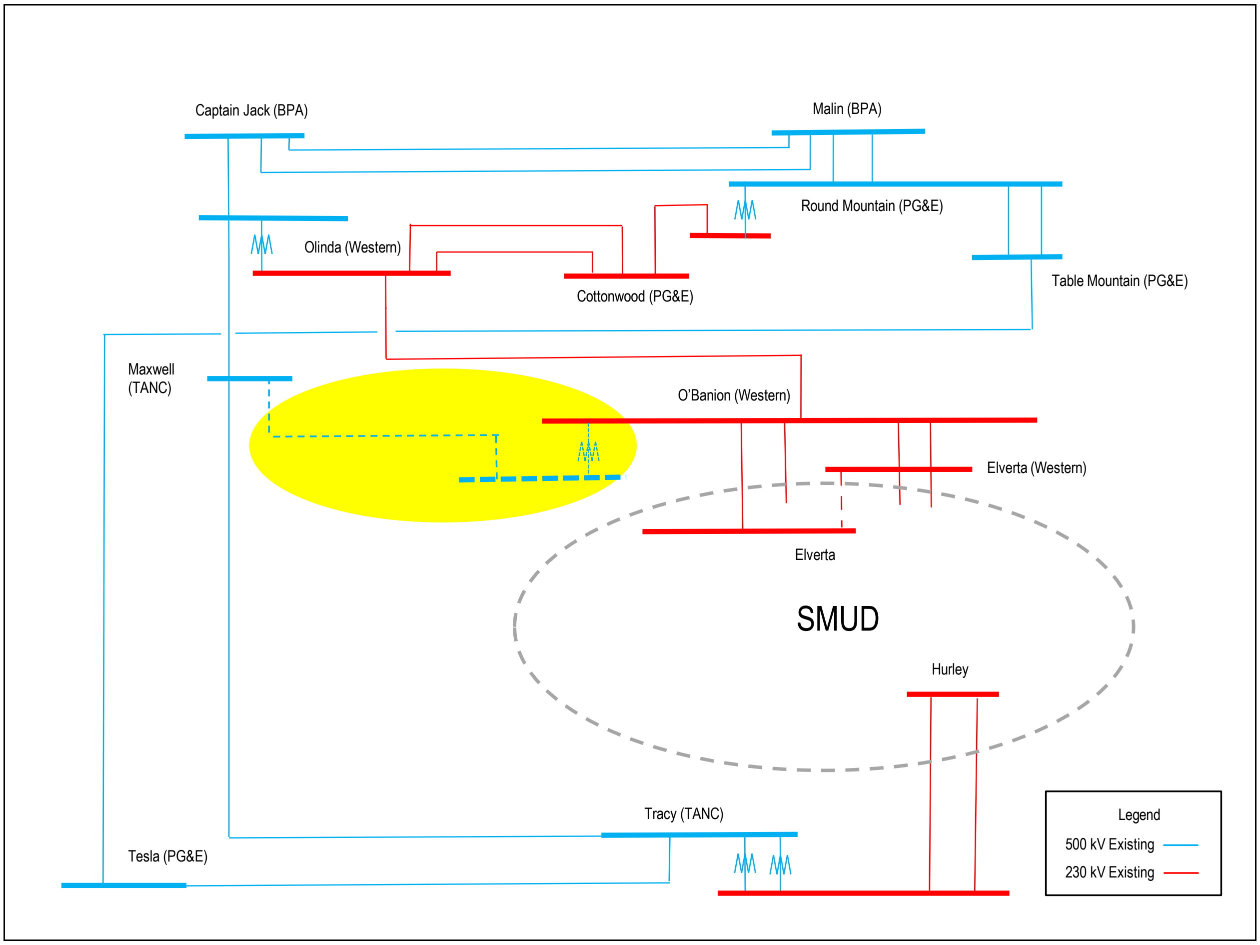

Figure 8: Conceptual Interconnection Diagram

Balancing Authority Projects

This section details transmission projects within the Balancing Authority of Northern California (BANC).

Elverta 230kV Line Swap

BACKGROUND

This is the Western Area Power Administration's (WAPA) project to move the O'Banion-Elverta 230 kV line #2 to the Roseville-Elverta 230 kV line position and the Roseville-Elverta 230 kV line to the O'Banion-Elverta 230 kV line position at Elverta Substation. This project addresses loading issues on the Elverta-Hurley 230 kV #2 line following the Elverta 1182 stuck breaker failure and mitigates the need to limit Sutter Energy Center output under certain operating conditions.

ONE-LINE DIAGRAM

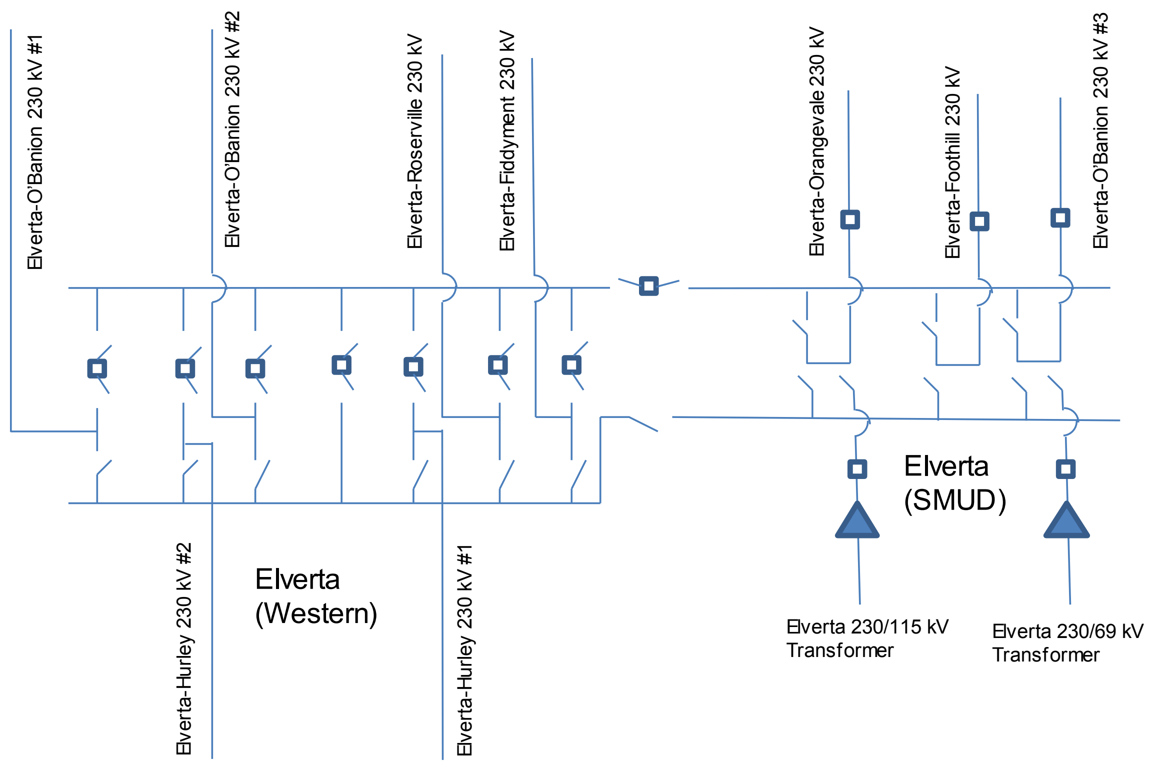

Figure 9: Existing Elverta Substation

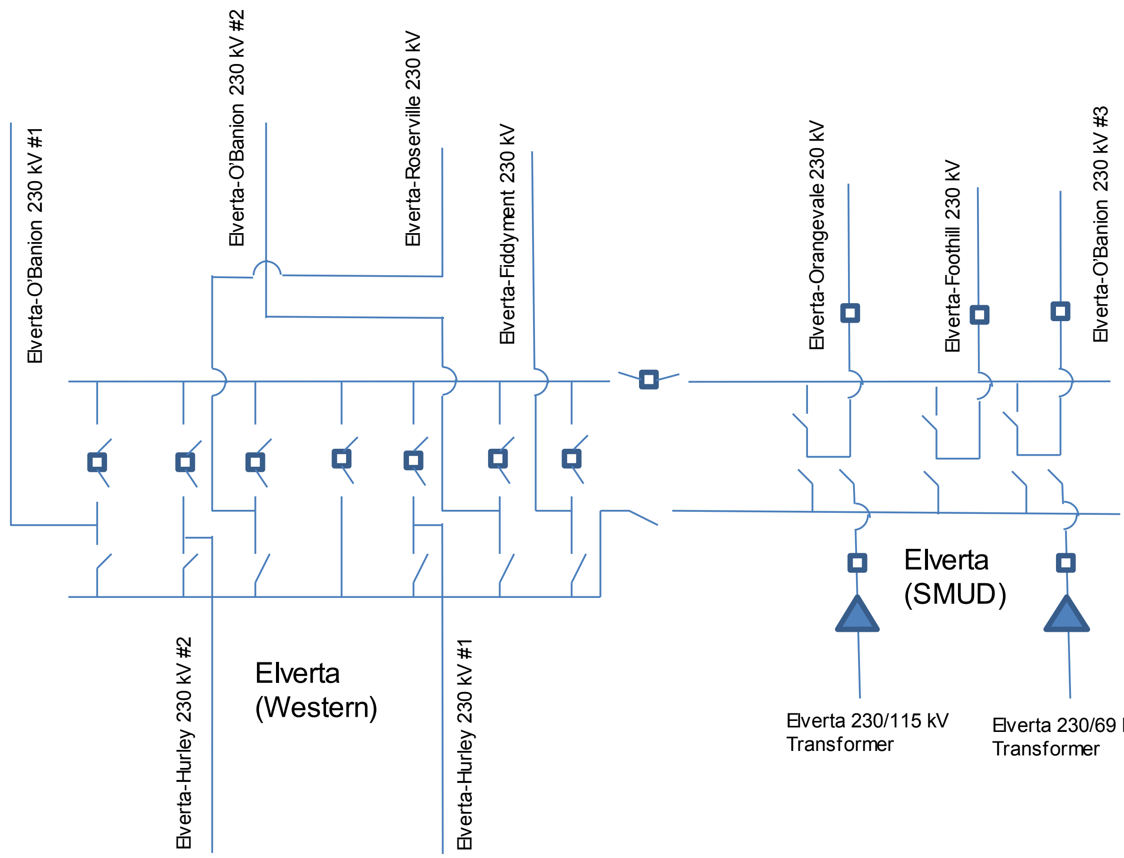

Figure 10: Elverta 230 kV Line Swap

SMUD Studies

115 kV BES Exclusion Awaiting Approval by NERC

The North American Electric Reliability Corporation (NERC) definition of the Bulk Electric System (BES) generally includes facilities that are operated at greater than 100 kV. However, there may be instances the BES definition may classify certain elements as BES that are not necessary for the reliable operation of the BES. For these situations, NERC has developed evaluation criteria for specific situations, allowing exclusion from the BES. SMUD applied under the criteria for Exclusion 3 to remove its 115 kV Downtown Network from the BES.

SMUD provided evidence that real power (MW) does not flow from the 115 kV network into the BES, the total generation within the 115 kV network is less than the 75 MVA Inclusion limit, there are no black start units within the 115 kV network, and the 115 kV network is not part of any major WECC transfer path or flow gate.

SMUD submitted all the evidence to NERC through the BESNet tool and has been reviewed and approved for submittal by WECC and is currently under NERC review.

Transmission System High Voltage Study

SMUD's transmission system generally experiences higher voltages[7] in the early morning hours during the spring and winter months under minimum demand conditions. Increases in energy efficiency and distributed generation are expected to lessen the minimum demand even further putting upward pressure on transmission voltage levels.

There have been no instances of SOL violations related to system voltages. However, 230 kV bus voltages are approaching their limits. The addition of shunt reactors would enhance the Power System Operator (PSO) voltage control capabilities.

Without the shunt reactors, PSO may be required to commit additional generation units or extend their schedules and/or remove transmission lines from service to maintain the voltage under the System Operating Limit (SOL).

To avoid this additional cost and prevent the wear and tear on the circuit breakers, increase reliability, and maintain compliance with NERC reliability standards, additional shunt reactors could be installed on the 12 kV tertiary of existing 230/69 kV transformers to help reduce voltage levels.

SMUD has identified several candidate sites for 12 kV shunt reactor installations including: Carmichael, Elk Grove, Hedge, Natomas and Pocket substations. Since most of the high voltages occurred in the SMUD's northern territory, Carmichael, followed by Natomas are the most effective sites in reducing the 230 kV voltage. The other three sites are more effective reducing voltage in the southern territory.

Power flow studies demonstrate that a 25 MVAR shunt reactor can maintain the 230 kV voltages below the 242 kV maximum, but provided little margin. Additional voltage margin to keep the voltage near 240 kV would require three 25 MVAR shunt reactors (75 MVAR total). For reliability purposes, each shunt reactor would be placed at different locations (Carmichael, Natomas, and Hedge). An outage of one reactor would leave enough shunt reactor capacity to avoid switching transmission circuits under most light load conditions.

Figures 11 and 12 show the minimum loads and associated high voltages from 2011 to 2014.

[7] SMUD's Operating Procedure PSE 104 – Voltage and Reactive Control provide System Operating Limits (SOL). The voltage limit SOLs for the 230 kV and 115 kV systems are 242 kV and 124 kV, respectively.

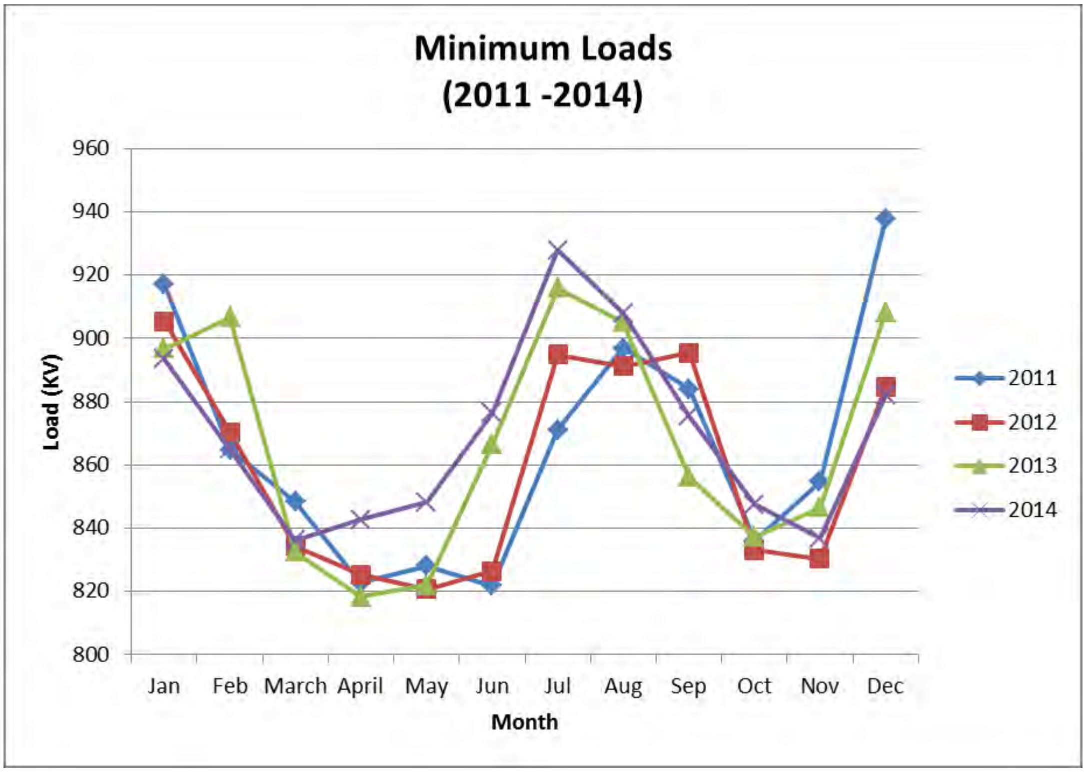

Figure 11: Minimum System Loads

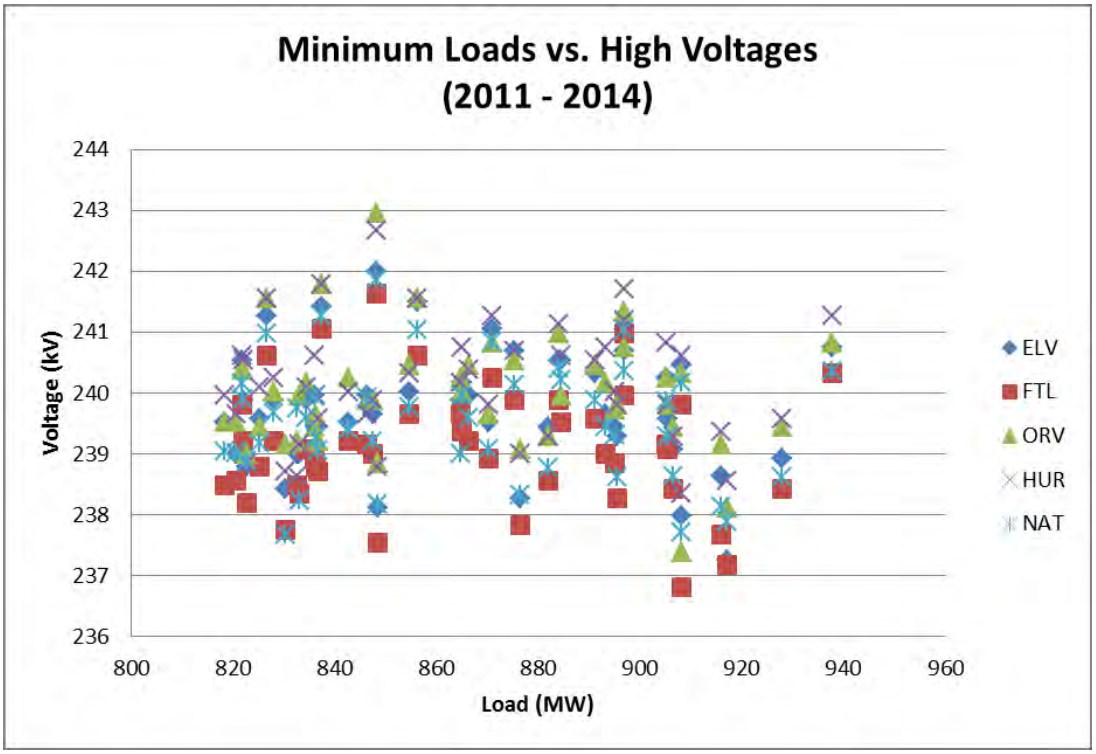

Figure 12: Bus Voltages at the Minimum System Loads

Demand Forecast

SMUD's Resource Planning and Pricing Department provides annual demand forecast updates. A base customer growth scenario combined with summer heat storm conditions is used for reliability planning. The reduced demand forecast reflects SMUD's significant investment in customer energy efficiency programs and expected SB1 solar installations and is referred to as the "managed" peak. Grid Planning uses the 1-in-10 managed demand forecast to more accurately reflect the historical customer growth experienced over the past several years.

The managed base growth forecast includes a portion of SMUD's energy efficiency and solar goals which are projected from planned expansion of existing energy efficiency programs and new subsidized rooftop solar generation programs. The forecast excludes future energy efficiency, demand reduction, and distributed generation programs that have not yet been designed. SMUD staff develops the load forecast to ensure sufficient reliability projects are identified to meet the NERC/WECC reliability criteria considering risks related to future loads including: higher than expected load growth, less than expected peak demand reductions from energy efficiency and distributed generation programs, and potential delays in siting of major transmission related facilities.

Table 5 provides the year by year demand forecasts used in this study.

Table 5: 1 in 10 Peak Demand Load Forecast

Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Demand Forecast (MW)	3,352	3,363	3,380	3,396	3,410	3,422	3,433	3,448	3,466	3,492

Figure 13 is a graphical representation of the demand forecasts for the past three years.

Figure 14 compares previous peaks to managed forecasted demand.

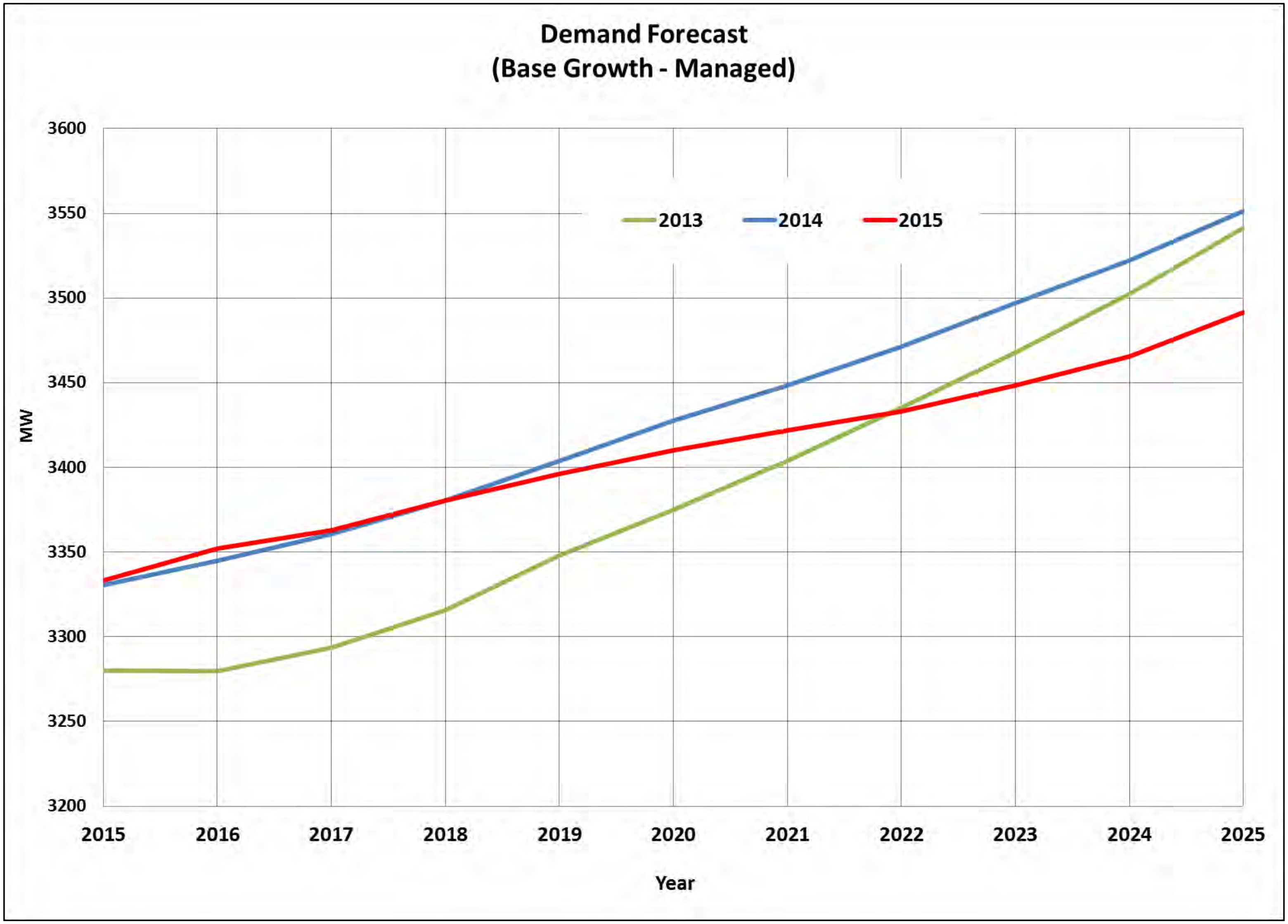

Figure 13: Historical Load Forecasts

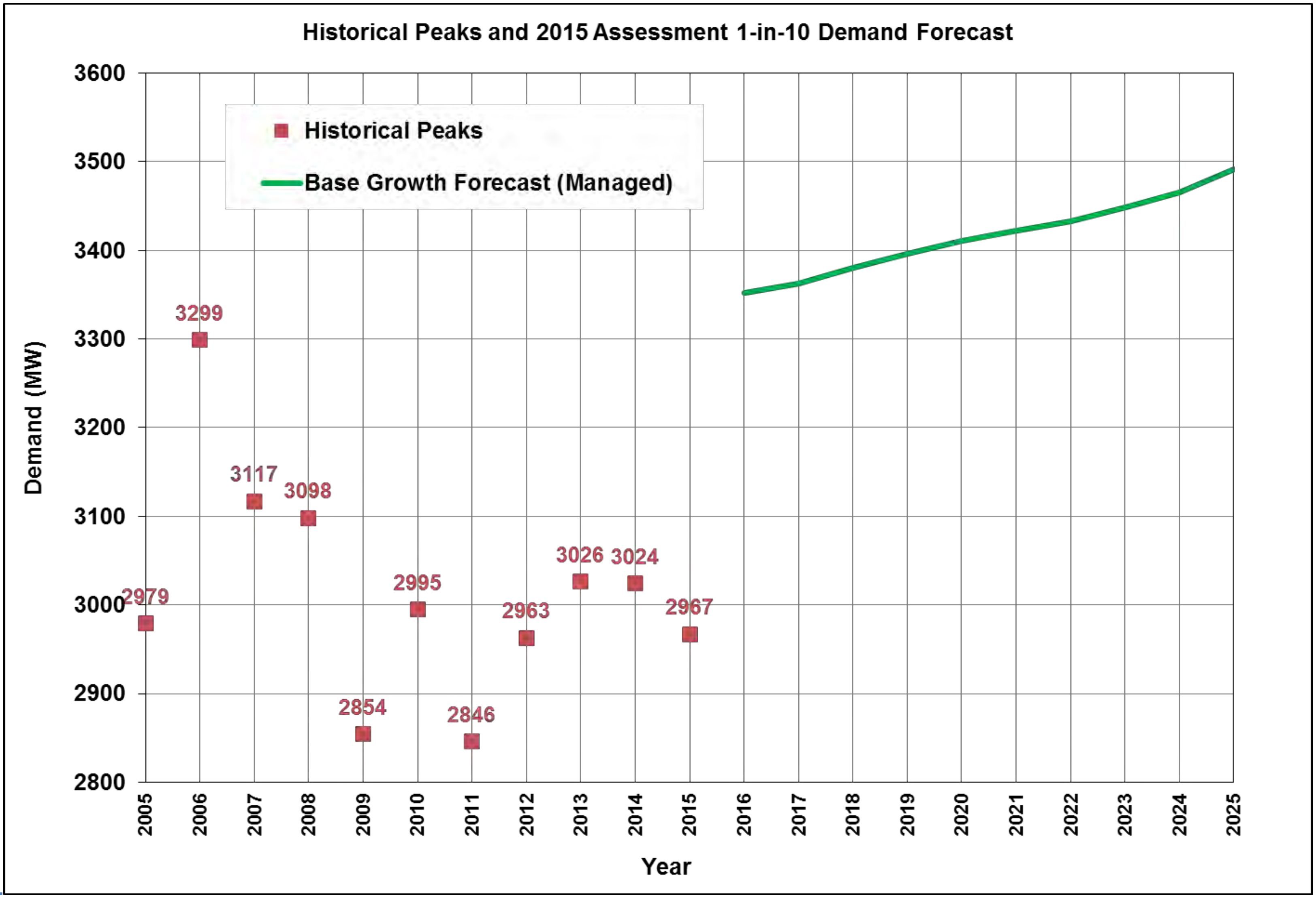

Figure 14: Historical and Forecast Peak Demand

Demand Side Management Programs

SMUD's current Demand Side Management (DSM) programs are not typically used for transmission planning purposes as they are used for economics, during emergencies, or for proposed mitigation in the event that transmission or generation projects are delayed. However, DSM programs are currently being evaluated for re-design to allow for more frequent use and implementation and being coordinated with a new two-way metering system and communication infrastructure. SMUD is evaluating a long-term commitment to these programs along with other demand and supply alternatives which may increase both transmission and distribution grid reliability. Once the new programs have been implemented, they will be evaluated for inclusion in SMUD's transmission planning or as a reduction to peak demand.

TPL-001-4

Reliability Assessment

A comprehensive electric transmission system assessment of the Sacramento area is performed annually to ensure that NERC Reliability Standards are met each year. The power flow base cases used for this assessment include existing and planned facilities. This assessment is based on all contingencies applicable to Categories P0-P7 as well as extreme contingencies, which includes SMUD owned transmission lines, generators, and transformers, and select key facilities owned by neighboring utilities due to their proximity to the SMUD system. In addition, it includes the most severe double line outages that have historically limited SMUD's import and load serving capability.

The assessment results were performed using the demand forecasts described in the Demand Forecast section. The following paragraphs provide an assessment of SMUD's system under adverse weather peak conditions and off-peak conditions including steady state (thermal), voltage stability (QV) and transient stability analyses.

System Models: [R1]

SMUD's system models use data consistent with what is provided under the MOD-032-1 standard as well as supplemented data to model projected projects and changes to SMUD's system.

System Models Represent [R1 - 1.1]

- Existing facilities and any changes to the existing facilities
- New and future planned facilities
- Real and reactive load forecasts
- Known outages of generation and transmission facilities with a duration of at least six months
- Known commitments for Firm Transmission Service and Interchange
- Resources required to serve SMUD's demand

Planning Assessment Assumptions [R2]

SMUD, as the registered Transmission Planner (TP) and Planning Coordinator (PC) prepared an annual planning assessment (2015 Ten Year Assessment) for its portion of the BES. This planning assessment uses the most current studies performed, documented assumptions, and summarizes the results of steady state, short circuit, and stability analyses. The assumptions in this study are detailed below.

Reactive Power Assumption

The electric demand modeled in the base cases represents a 0.983 lagging power factor at the distribution level based on historical data.

There are approximately 900 MVAr of 230 kV, 69 kV, 21 kV and 12 kV capacitors modeled in the base cases that are used by transmission and distribution operators to maintain voltages on both the transmission and distribution systems. Typically, new capacitors are installed at the low side of 230 kV or 115 kV step down transformers when new substations are completed or when the MVAr flow through the transformer becomes excessive and capacitors on the distribution system cannot be installed.

SMUD has begun to install transmission shunt capacitors at the 230 kV level. These capacitors provide operating flexibility, help maintain 230 kV voltages, compensate for reactive flows from the transmission system to the distribution system, and supply the reactive losses on intertie lines during peak periods with high import levels. In addition, as part of the SmartSacramento project, SMUD installed additional distribution line capacitors and the functionality for Volt-VAr optimization.

There are also 70 MVAr of shunt reactors located in the SMUD's transmission system and modeled in the power flow cases. These reactors are located at Hurley, Orangevale, and Pocket substations and are used to help lower bus voltages during off-peak conditions. During summer peak conditions, these reactors are switched out of service.

Generation Assumption

Table 6 indicates the output level assumptions (based on historical data) for the generating units in the SMUD transmission system.

Table 6: SMUD Area Generation Assumptions

Generation Type	SMUD Generation	Rated Capacity (MW)[8]	Power Flow Output Level (MW)
Hydro	Camino	156	100
	Jaybird	153	120
	Jones Fork	10	10
	Loon Lake	79	70
	Robbs Peak	26	20
	Union Valley	47	40
	White Rock	249	160
	Total Hydro Dispatch	*720*	*520*
Thermal	Campbell Soup	168	160
	McClellan	70	60
	Procter and Gamble	190	150
	Carson Ice	108	90
	Cosumnes	592	485
	UC Davis Medical Center	25	25
	Kiefer Land Fill[9]	15	15
	Total Thermal Dispatch	*1168*	*985*
Total Generation Dispatch		**1888**	**1505**

In addition, there is approximately 100 MW of solar photovoltaic generation[10] (Feed-In Tariff) in the area. This assessment study maintains approximately 200 MW of operating reserves of internal SMUD generation under normal conditions.

Near Term Steady State Planning Assessment [R2 - 2.1]

For Near-Term steady state system performance, the transmission assessment for the SMUD transmission planning area used adverse summer peak conditions as well as off peak conditions for analyses. SMUD also used past annual studies or other qualified studies (where needed) to support this assessment as indicated in Requirement R2, Part 2.6 of the new TPL-001-4 standard.

Steady State Base Cases [R2-2.1.1. & 2.1.2]

[8] Rated Capacity is the aggregated peak output of generating stations, and does not reflect penstock flow limitations, etc. These limitations are accounted for in generation dispatch in the GE-PSLF powerflow models.
[9] Kiefer Land Fill is located on the distribution system and is represented as individual generator power flow model on 69 kV buses
[10] Solar PV from FIT on-peak capacity factor is assumed at 65% and is represented as aggregated solar generators in the power flow model.

The Near-Term steady state portion requires qualifying studies to cover at least two different system conditions:

- System Peak Load Year one or two and year five. This assessment used the following cases:
    - 2016 Heavy Summer
    - 2020 Heavy Summer

- System Off-Peak Load for one of the five years. SMUD chose to conduct studies for two of the five year near-term planning horizon.
    - 2016 Light Summer
    - 2020 Heavy Winter

Planned / Known Outages [R2-2.1.3]

System peak and off peak cases were updated to reflect any known outages for durations of over six months. Supporting data was retrieved from SMUD's Transmission Outage Application (TOA) and analyzed to determine which elements of the transmission system and generation units, if any, met this minimum threshold.

- It was determined that the Loon Lake Power plant will be de-rated from its peak generating capacity of 79 MW to 76 MW due to high stator currents at 79 MW rating. As such, SMUD ensured that the power flow models for Loon Lake were adjusted accordingly.
-

Table 7: P1 Events with Known Outages/Derates of Over Six Months – For 2016

NERC Category	Limiting Contingency	Affected Facility (Element)	% Overload Before Mitigation Action	Mitigating Action
P1	None	None	None	None

Steady State Sensitivity Case(s) [R2-2.1.4]

SMUD created three sensitivity cases for each of the studies described under Requirements R2, Parts 2.1.1 and 2.1.2. Year one (1) and year five (5) peak load studies include a sensitivity to simulate a 1 in 20 demand forecast compared to the 1 in 10 demand forecast used for Part 2.1.1.

- 2016 1 in 20 load forecast, 3509 MW
- 2020 1 in 20 load forecast, 3677 MW

- The 1 in 20 load forecast for the 2020 year is beyond SMUD's LSC based on QV limitations, these results were studied to find potential future thermal limitations.

The system off-peak sensitivity case was created to simulate the effect of an ongoing drought by significantly reducing SMUD's UARP hydro generation. The reduced output from UARP generation is a 520 MW reduction to the SMUD transmission system.

Spare Equipment Strategy [R2-2.1.5]

SMUD reviewed previous lead times for major transmission equipment identifying facilities with a lead time of one year or more and then compared it to SMUD's spare equipment strategy. SMUD identified two scenarios where the loss of an element would result in the loss of major transmission equipment for duration extending longer than one year due to the long lead time.

There are three generator step-up transformers at Cosumnes Power Plant (CPP). Two 18/230 kV transformers are used to connect each of the plants CTG's and a 16.5/230 kV transformer to connect the STG. The loss of one of the 18/230 kV transformers would result in the loss of a CTG and the plant would have to be operated in 1 on 1 mode, effectively reducing the plant's output in half (250 MW drop in output). The loss of the 16.5/230 kV transformer would result in the plant not being able to use the STG, due to the lack of bypass ability this would result in the loss of CPP. Losing the STG due to the failure of the 16.5/230 kV transformer is the most severe scenario for SMUD due to the transformer's long lead time. This results in a 500 MW generation loss.

The loss of CPP could cause adverse operational conditions for SMUD. However, SMUD's Power Operations Engineering group studies CPP outages for both the loss of one generator and for a complete outage of CPP. Regular studies and procedures can be found in SMUD procedure PSE-107 - Sacramento Area DLT, SPS, and Nomogram Operations.

Steady State Long-Term Planning Assessment [R2-2.2]

For the Planning Assessment, the Long-Term Planning Horizon portion of the steady state analysis, SMUD assess year ten annually and the analysis is supported by the following annual current study, or supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:

Steady State Years [R2-2.2.1]

Year 2025 Heavy Summer was chosen as the long-term steady state study year. This year represents the last long-term year studied to ensure early identification of any long-term reliability issues. 2025 is also the last year studied to determine SMUD's LSC.

Short Circuit Analysis [R2-2.3]

Short circuit (SC) analysis was performed on the 2015 and proposed 2020 systems to review the near-term planning horizon for changes to the SMUD system. Short circuit fault currents were calculated at all of the BES buses and compared to their rated short circuit values. Any short circuit values that exceed 80% of the rated value are deemed to require further evaluation.

2015 Short Circuit Results

Results from the 2015 study found that the 230 kV breakers at the Hurley substation, (CB 5814, CB 5820, CB 5828 and CB 5834) exceed 80% of their interrupting ratings. These breakers will continued to be monitored and if they exceed 90% of the interrupting ratings in future studies a corrective action plan will be made.

On the 115 kV network, it was found that Breakers (CB 124, CB 128, CB 132, CB 162, CB 166 and CB 192) at Hedge Substation exceed their rated interrupting and momentary ratings. The Corrective Action Plan (CAP) is described in section R2. – R2.8.

115 kV breakers at the North City substation (CB 5010, CB 5020, CB 5060 and 5080) are within 5% of their interrupting rating. Circuit breakers (CB 5050 and CB 5070) are currently within 7% of their interrupting ratings.

2020 Short Circuit Results

The 2020 study did not find an increase in short circuit values that would require additional circuit breakers to be monitored or replaced. Some circuit breakers that are noted in the 2015 study are marked for replacement in the short circuit Corrective Action Plan (CAP), shown in section R2-2.8, may still be in service in 2020 per the CAP schedule they are on.

Stability Near-Term [R2-2.4]

For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis is assessed annually and is supported by current or past studies as qualified in Requirement R2, Part 2.6 as necessary. The following studies were required:

Peak Load with consideration of induction motor Loads [R2-2.4.1]

System Peak load is required for one of the five years. SMUD used the following cases and utilized the WECC composite load model (CMPLDW) to represent the expected dynamic behavior of the system loads:

- 2016 Heavy Summer
- 2020 Heavy Summer

Off-Peak Load [R2-2.4.2]

System Off-Peak is required for one of the five years. SMUD opted to study the following two years:

- 2016 Heavy Winter
- 2020 Heavy Winter

Stability Sensitivity Case(s) [R2-2.4.3]

SMUD performed sensitivity studies for the cases used in accordance with Requirement R2, Parts 2.4.1 and 2.4.2. To create a sensitivity case for 2.4.1 the case was adjusted from a 1 in 10 to a 1 in 20 demand forecast. To create a sensitivity study for requirement 2.4.2 the off-peak heavy winter case was adjusted so that it represented an extended drought and SMUD's UARP hydro system was only available as spinning reserve, removing 520 MW of generation from the SMUD area.

- 2016 1 in 20 load forecast, 3509 MW
- 2020 1 in 20 load forecast, 3677 MW
    - The 1 in 20 demand forecast for the 2020 year is beyond SMUD's LSC based on QV limitations, these results were studied to find potential future stability limitations.

Stability Long-Term [R2-2.5]

For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the stability analysis was assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, Part 2.6 and if needed, included documentation to support the technical rationale for determining material changes.

- Year 2025 Heavy Summer was chosen as the Long-Term Stability year studied for the 2015 Planning Assessment. This year represents the SMUD system 10 years out. The 10th year is also the last long-term year studied in past planning assessments. This represents continuity in studies even though the TPL standards have changed. Year 2025 is also the last year studied to determine SMUD's LSC.

Past Studies Used [R2-2.6]

For requirement R2, part 2.1.5, this study relied on previous studies for the contingency analysis and load serving capability for the SMUD area. The study utilized SMUD's PSE 107 for operating capabilities during Abnormal or Emergency system conditions for CPP being off-line. The operating limits are based on the most extreme contingencies and the ability to provide reliable operational regions for the next generator, single, or credible double transmission line outage.

For the short circuit portion of this report, separate short circuit studies were completed. Two separate reports were used, one for the 230 kV system and one for the 115 kV system. The two reports were:

- Assessment Of Interruption Capabilities of 230kV Circuit Breaker, SMUD 12/31/15
- Assessment Of Interruption Capabilities of 115 kV Circuit Breaker/Circuit Switcher, SMUD 6/30/2015

Past Studies are five years old or newer [R2-2.6.1]

No studies greater than five years old were used in this Assessment.

No Material changes have occurred to the system since the Past Studies [R2-2.6.2]

No material changes have occurred in or around the SMUD system for the previous studies used.

Corrective Action Plans (CAP) [R2-2.7]

The steady state and stability studies did not indicate inabilities of the system to meet performance requirements in Table 1 (Table 19 in this report). As such, Requirements R2-2.7.1, R2-2.7.2, R2-2.7.3, and R2-2.7.4 are currently not applicable to SMUD.

Short Circuit Corrective Action Plans [R2-2.8]

The short circuit study revealed two areas within SMUD's 115 kV network that require a Corrective Action Plan (CAP):

- Hedge 115 kV Circuit Breakers
- North City 115 kV Circuit Breakers

SMUD's CAP includes a replacement project for the overstressed Hedge breakers that exceed their interrupt capability. SMUD will replace one breaker a year until all affected breakers are replaced. Design work is scheduled to begin in 2016 with construction in 2017.

The North City 115 kV breakers are nearing their interrupt capabilities. SMUD's CAP includes a complete replacement (Station E) of North City with an expected in service date of 2017.

Circuit breaker 5828 at Hurley 230 kV substation is scheduled to be replaced in 2016 for reliability reasons.

Steady State Results [R3]

For the Steady State portion of the Planning Assessment, SMUD performed studies for the Near-Term and Long-Term Transmission Planning Horizons listed in R2, Parts 2.1 and 2.2. The studies were based on data provided in R1 and were conducted using computer simulation models in General Electric – Positive Sequence Load Flow (GE-PSLF) software.

Steady State BES Performance [R3-3.1]

SMUD performed studies for planning events to determine whether the BES meets the performance requirements in Table 1 based on the contingency list created in requirement R3, Part 3.4. The results of the powerflow simulations are shown below.

The study results showed that there were no observed overloads of any transmission element for contingencies in categories P1-P5. For the more severe P6 and higher categories, the steady state results and system impacts are described in the tables below. These tables summarize the results for all peak and off-peak cases studies.

Table 8: 2016 Summer Peak Steady State Study Results

NERC Cat.	Limiting Contingency	Affected Facility (Element)	% Overload (Before Mitigating Actions)	Mitigating Action	%Overload (After Mitigating Actions)
P0-P5	None	None	None	None	None
P6	Carmichael-Hurley 230 kV TL outage and Orangevale-White Rock 230 kV TL outage	Orangevale – Folsom 230 kV #1	100	System Adjustments : Re-dispatch UARP Generation	Less than 100% of Normal Rating
P6	Cordova-White Rock 230 kV TL outage and Orangevale-White Rock 230 kV TL outage	Camino – Lake 230 kV #1	137	System Adjustments : Re-dispatch UARP Generation	Less than 100% of Normal Rating
P6	North City-Station A #1 115 kV TL outage and Station B-Station D 115 kV TL outage	North City – Station A 115 kV #2	136	Non Consequential Load Loss Allowed per Standard	Less than 100% of Normal Rating
P6	North City-Station A #2 115 kV TL outage and Station B-Station D 115 kV TL outage	North City – Station A 115 kV #1	136	Non Consequential Load Loss Allowed per Standard	Less than 100% of Normal Rating
P7	Camino-Lake & Cordova-White Rock 230 kV line outage	Orangevale – White Rock 230 kV #1	137	UARP SPS	Less than 100% of Normal Rating

NERC Cat.	Limiting Contingency	Affected Facility (Element)	% Overload (Before Mitigating Actions)	Mitigating Action	%Overload (After Mitigating Actions)
P7	Camino-Lake & Camino-White Rock 230 kV line outage	Jaybird – White Rock 230 kV #1	101	UARP SPS	Less than 100% of Normal Rating
P7	Camino-Lake & Camino-White Rock 230 kV line outage	Jaybird – White Rock 230 kV #1	101	UARP SPS	Less than 100% of Normal Rating
ESS2a	Loss of transmission line tower 303	Carmichael – Hurley 230 kV #1	153	Carmichael SPS	102% of Emergency Rating
ESS2b	Loss of all lines north of Lake 230 kV station	Orangevale – White Rock 230 kV #1	137	UARP SPS	Less than 100% of Normal Rating
ESS2b	Loss of all lines south of Elk Grove 230 kV station	Campbell – Hedge 230 kV #1	109	Non Consequential Load Loss Allowed per Standard	Less than 100% of Normal Rating
ESS2b	Loss of all lines west of Rancho Seco 230 kV station	Hedge – Procter 230 kV #1	139	Procter SPS	Less than 100% of Normal Rating
		Hurley – Procter 230 kV #1	101		Less than 100% of Normal Rating
	PROCTER SPS triggered post Contingency	Hedge – Cordova #1	108	Non Consequential Load Loss Allowed per Standard	Less than 100% of Normal Rating
		Lake – Cordova #1	125		Less than 100% of Normal Rating
		North City – Station B #1	106		Less than 100% of Normal Rating
		North City – Station B #2	106		Less than 100% of Normal Rating
ESS2b	Loss of all lines west of Fiddyment 230 kV station	Carmichael – Hurley 230 kV #1	104	Carmichael SPS	Less than 100% of Normal Rating
ESS2b	Loss of all lines north of Orangevale 230 kV station	Carmichael – Hurley 230 kV #1	153	Carmichael SPS	102% of Emergency Rating
ESS2b	Loss of all lines west of Folsom 230 kV station	Carmichael – Hurley 230 kV #1	104	Carmichael SPS	Less than 100% of Normal Rating

NERC Cat.	Limiting Contingency	Affected Facility (Element)	% Overload (Before Mitigating Actions)	Mitigating Action	%Overload (After Mitigating Actions)
ESS2c	Rancho Seco 230 kV switching station outage	Hedge – Procter 230 kV #1	140	Procter SPS	Less than 100% of Normal Rating
		Hurley – Procter 230 kV #1	102		Less than 100% of Normal Rating
	PROCTER SPS triggered post Contingency	Hedge – Cordova #1	108	Non Consequential Load Loss Allowed per Standard	Less than 100% of Normal Rating
		Lake – Cordova #1	124		Less than 100% of Normal Rating
		North City – Station B #1	107		Less than 100% of Normal Rating
		North City – Station B #2	107		Less than 100% of Normal Rating
ESS3a	Hurley-Tracy #1 & #2 and Bellota-Rancho Seco #1 & #2 230 kV line outage	Goldhill – Lake 230 kV #1	116	Non Consequential Load Loss Allowed per Standard	Less than 100% of Normal Rating

Table 9: 2016 Summer Off-Peak Steady State Study Results

NERC Cat.	Limiting Contingency	Affected Facility (Element)	% Overload (Before Mitigating Actions)	Mitigating Action	%Overload (After Mitigating Actions)
P0-P7	None	None	None	None	None

Table 10: 2020 Adverse Summer Peak Steady State Study Results

NERC Cat.	Limiting Contingency	Affected Facility (Element)	% Overload (Before Mitigating Actions)	Mitigating Action	%Overload (After Mitigating Actions)
P0-P5	None	None	None	None	None

NERC Cat.	Limiting Contingency	Affected Facility (Element)	% Overload (Before Mitigating Actions)	Mitigating Action	%Overload (After Mitigating Actions)
P6	Cordova-White Rock 230 kV TL outage and Orangevale-White Rock 230 kV TL outage	Camino – Lake 230 kV #1	137	System Adjustments : Re-dispatch UARP Generation	Less than 100% of Normal Rating
P6	North City-Station A #1 115 kV TL outage and Station B-Station D 115 kV TL outage	North City – Station A 115 kV #2	124	Non Consequential Load Loss Allowed per Standard	Less than 100% of Normal Rating
P6	North City-Station A #2 115 kV TL outage and Station B-Station D 115 kV TL outage	North City – Station A 115 kV #1	124	Non Consequential Load Loss Allowed per Standard	Less than 100% of Normal Rating
P7	Camino-Lake & Cordova-White Rock 230 kV line outage	Orangevale – White Rock 230 kV #1	136	UARP SPS	Less than 100% of Normal Rating
P7	Camino-Lake & Camino-White Rock 230 kV line outage	Jaybird – White Rock 230 kV #1	101	UARP SPS	Less than 100% of Normal Rating
ESS2a	Loss of transmission line tower 303	Carmichael – Hurley 230 kV #1	145	Carmichael SPS	Less than 100% of Normal Rating
ESS2b	Loss of all lines north of Lake 230 kV station	Orangevale – White Rock 230 kV #1	136	UARP SPS	Less than 100% of Normal Rating
ESS2b	Loss of all lines south of Elk Grove 230 kV station	Campbell – Hedge 230 kV #1	101	Non Consequential Load Loss Allowed per Standard	Less than 100% of Normal Rating
ESS2b	Loss of all lines west of Fiddyment 230 kV station	Carmichael – Hurley 230 kV #1	100	Carmichael SPS	Less than 100% of Normal Rating
ESS2b	Loss of all lines north of Orangevale 230 kV station	Carmichael – Hurley 230 kV #1	145	Carmichael SPS	Less than 100% of Normal Rating
ESS3a	Hurley-Tracy #1 & #2 and Bellota-Rancho Seco #1 & #2 230 kV line outage	Goldhill – Lake 230 kV #1	125	Non Consequential Load Loss Allowed per Standard	Less than 100% of Normal Rating

Table 11: 2020 Summer Off-Peak Steady State Study Results

NERC Cat.	Limiting Contingency	Affected Facility (Element)	% Overload (Before Mitigating Actions)	Mitigating Actions	%Overload (After Mitigating Actions)
ESS3a	Hurley-Tracy #1 & #2 and Bellota-Rancho Seco #1 & #2 230 kV line outage	Goldhill – Lake 230 kV #1	115	Non Consequential Load Loss Allowed per Standard	Less than 100% of Normal Rating

Table 12: 2025 Adverse Summer Peak Steady State Study Results

NERC Cat.	Limiting Contingency	Affected Facility (Element)	% Overload (Before Mitigating Actions)	Mitigating Actions	%Overload (After Mitigating Actions)
P0-P5	None	None	None	None	None
P6	Cordova-White Rock 230 kV TL outage and Orangevale-White Rock 230 kV TL outage	Camino – Lake 230 kV #1	137	System Adjustments : Re-dispatch UARP Generation	Less than 100% of Normal Rating
P6	North City-Station A #1 115 kV TL outage and Station B-Station D 115 kV TL outage	North City – Station A 115 kV #2	150	Non Consequential Load Loss Allowed per Standard	Less than 100% of Normal Rating
P6	North City-Station A #2 115 kV TL outage and Station B-Station D 115 kV TL outage	North City – Station A 115 kV #1	150	Non Consequential Load Loss Allowed per Standard	Less than 100% of Normal Rating
P7	Camino-Lake & Cordova-White Rock 230 kV line outage	Orangevale – White Rock 230 kV #1	136	UARP SPS	Less than 100% of Normal Rating
P7	Camino-Lake & Camino-White Rock 230 kV line outage	Jaybird – White Rock 230 kV #1	101	UARP SPS	Less than 100% of Normal Rating
ESS2a	Loss of transmission line tower 303	Carmichael – Hurley 230 kV #1	138	Carmichael SPS	Less than 100% of Normal Rating
ESS2b	Loss of all lines north of Lake 230 kV station	Orangevale – White Rock 230 kV #1	137	UARP SPS	Less than 100% of Normal Rating
ESS2b	Loss of all lines north of Lake 230 kV station	Hedge – Procter 230 kV #1	105	Procter SPS	Less than 100% of Normal Rating

NERC Cat.	Limiting Contingency	Affected Facility (Element)	% Overload (Before Mitigating Actions)	Mitigating Actions	%Overload (After Mitigating Actions)
ESS2b	Loss of all lines south of Elk Grove 230 kV station	Campbell – Hedge 230 kV #1	105	Non Consequential Load Loss Allowed per Standard	Less than 100% of Normal Rating
ESS2b	Loss of all lines west of Fiddyment 230 kV station	Carmichael – Hurley 230 kV #1	100	Carmichael SPS	Less than 100% of Normal Rating
ESS2b	Loss of all lines north of Orangevale 230 kV station	Carmichael – Hurley 230 kV #1	138	Carmichael SPS	Less than 100% of Normal Rating
ESS3a	Hurley-Tracy #1 & #2 and Bellota-Rancho Seco #1 & #2 230 kV line outage	Goldhill – Lake 230 kV #1	143	Non Consequential Load Loss Allowed per Standard	Less than 100% of Normal Rating

Table 13: 2016 Heavy Summer 1 in 20 Load Forecast, Sensitivity Study Results

NERC Cat.	Limiting Contingency	Affected Facility (Element)	% Overload (Before Mitigating Actions)	Mitigating Action	%Overload (After Mitigating Actions)
P0-P5	None	None	None	None	None
P6	Carmichael-Hurley 230 kV TL outage and Orangevale-White Rock 230 kV TL outage	Orangevale – Folsom 230 kV #1	106	System Adjustments : Re-dispatch UARP Generation	Less than 100% of Normal Rating
P6	Cordova-White Rock 230 kV TL outage and Orangevale-White Rock 230 kV TL outage	Camino – Lake 230 kV #1	137	System Adjustments : Re-dispatch UARP Generation	Less than 100% of Normal Rating
P6	North City-Station A #1 115 kV TL outage and Station B-Station D 115 kV TL outage	North City – Station A 115 kV #2	144	Non Consequential Load Loss Allowed per Standard	Less than 100% of Normal Rating
P6	North City-Station A #2 115 kV TL outage and Station B-Station D 115 kV TL outage	North City – Station A 115 kV #1	144	Non Consequential Load Loss Allowed per Standard	Less than 100% of Normal Rating
P6	Folsom-Orangevale 230 kV TL outage and Orangevale – White Rock 230 kV TL outage	Carmichael – Hurley 230 kV #1	102	Carmichael SPS	Less than 100% of Normal Rating
P7	Common Structure, Camino –Lake 230 kV TL and Cordova – White Rock 230 kV TL	Orangevale – White Rock 230 kV #1	137	System Adjustments : Re-dispatch UARP	Less than 100% of Normal Rating

				Generation	
P7	Common Structure, Camino – Lake 230 kV TL and Camino – White Rock 230 kV TL	Jay Bird – White Rock 230 kV #1	101	System Adjustments : Re-dispatch UARP Generation	Less than 100% of Normal Rating

Table 14: 2016 Light Summer, No UARP, Sensitivity Study Results

NERC Cat.	Limiting Contingency	Affected Facility (Element)	% Overload (Before Mitigating Actions)	Mitigating Action	%Overload (After Mitigating Actions)
P0-P7	None	None	None	None	None

Table 15: 2020 Heavy Summer 1 in 20 Load Forecast, Sensitivity Study Results

NERC Cat.	Limiting Contingency	Affected Facility (Element)	% Overload (Before Mitigating Actions)	Mitigating Action	%Overload (After Mitigating Actions)
P0-P5	None	None	None	None	None
P6	Carmichael-Hurley 230 kV TL outage and Orangevale-White Rock 230 kV TL outage	Orangevale – Folsom 230 kV #1	106	System Adjustments : Re-dispatch UARP Generation	Less than 100% of Normal Rating
P6	Cordova-White Rock 230 kV TL outage and Orangevale-White Rock 230 kV TL outage	Camino – Lake 230 kV #1	138	System Adjustments : Re-dispatch UARP Generation	Less than 100% of Normal Rating
P6	North City-Station A #1 115 kV TL outage and Station B-Station D 115 kV TL outage	North City – Station A 115 kV #2	150	Non Consequential Load Loss Allowed per Standard	Less than 100% of Normal Rating
P6	North City-Station A #2 115 kV TL outage and Station B-Station D 115 kV TL outage	North City – Station A 115 kV #1	150	Non Consequential Load Loss Allowed per Standard	Less than 100% of Normal Rating
P6	Folsom-Orangevale 230 kV TL outage and Orangevale – White Rock 230 kV TL outage	Carmichael – Hurley 230 kV #1	108	Carmichael SPS	Less than 100% of Normal Rating
P7	Common Structure, Camino –Lake 230 kV TL and Cordova – White Rock 230 kV TL	Orangevale – White Rock 230 kV #1	137	System Adjustments : Re-dispatch UARP Generation	Less than 100% of Normal Rating
P7	Common Structure, Camino – Lake 230 kV TL and Camino – White Rock 230 kV TL	Jay Bird – White Rock 230 kV #1	101	System Adjustments : Re-dispatch UARP	Less than 100% of Normal Rating

				Generation	

Impact of Extreme Events [R3-3.2]

SMUD performed studies to assess the impact of the extreme events which are identified by the list created in R3, Part 3.5. Results of these studies that result in the potential for negative impact are shown in the tables listed under section R3 – 3.1.

Contingency Analyses [R3-3.3]

Contingency analyses for requirement R3, Parts 3.1 & 3.2 were performed according to the criteria listed in R3-3.3.1 and R3-3.3.2

Protection System [R3-3.3.1]

SMUD simulated the removal of all elements that the Protection System and other automatic controls that are expected to disconnect for each contingency without operator intervention.

Voltage Ride Through [R3-3.3.1.1]

SMUD simulated the tripping of generators where simulations showed generator bus voltages or high side of the GSU voltages were less than known or assumed minimum generator steady state or ride through voltage limitations. Instances where GSU voltages dropped below .95 PU were investigated.

Relay Loadability Limits [R3-3.3.1.2]

Transmission elements were tripped where loadability limits were exceeded.

Automatic Operation of Equipment [R3-3.3.2]

SMUD simulated the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities, such as special protection systems (SPS). The impacts of such operations were analyzed as part of the assessment.

Steady State Events [R3-3.4]

Planning events expected to produce more severe system impacts on SMUD's BES were identified, and a list of those contingencies were evaluated for system performance in R3, Part 3.1. These contingencies were selected as they have historically been deemed as credible severe contingencies, and were included in past studies.

External Contingencies [R3-3.4.1]

SMUD coordinated with Pacific Gas & Electric (PG&E), the California Independent System Operator (CAISO), and Western Area Power Administration – Sierra Nevada Region (WASN) to create a list of contingencies external to SMUD which may negatively impact SMUD's system. These contingencies were included in the list of contingencies for the assessment.

Steady State Extreme Events [R3-3.5]

Extreme events in Table 1 that were expected to produce more severe system impacts were identified and a list created of those events were evaluated in Requirement R3, Part 3.2. These contingencies were selected as they have historically been deemed as credible severe contingencies, and were included in past studies. These events were previously known as Category D events.

Stability Results [R4]

SMUD performed contingency analyses for the stability portion of the assessment as described in Requirement R2, Parts 2.4 and 2.5. The studies were based on data provided in R1 and were conducted via computer simulation models in General Electric – Positive Sequence Load Flow (GE-PSLF) software.

Stability BES Performance [R4-4.1]

SMUD performed studies for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.

Synchronism P1 [R4-4.1.1]

For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System in not considered pulling out of synchronism.

- SMUD performed P1 stability simulations; the results of the simulations verified that no P1 event would cause a generating unit to fall out of synch.

Synchronism P2-P7 [R4-4.1.2]

For planning events P2-P7:When a generator pulls out of synch in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected facilities.

- SMUD performed P2-P7 stability simulations and found no synchronism violations.

Power Oscillations P1-P7 [R4-4.1.3]

For planning events P1-P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

- SMUD performed P1-P7 stability simulations and found no power oscillation violations.

Stability Extreme Events [R4-4.2]

SMUD performed stability studies to assess the impact of extreme events identified by the contingency list developed for Requirement R4, Part 4.5.

- SMUD performed extreme stability simulations and found no powerflow violations.

Contingency Analyses [R4-4.3]

Contingency analyses for Requirement R4, Parts 4.1 and 4.2 were performed according to the criteria listed in R4-4.3.1 and R4-4.3.2

Protection System [R4-4.3.1]

SMUD simulated the removal of all elements that the protection system and other automatic controls are expected to disconnect for each Contingency without operator intervention.

Successful High Speed Reclosing [R4-4.3.1.1]

SMUD simulated events with successful high speed reclosing and unsuccessful high speed reclosing (P5 events that simulate fault plus relay failure to operate) into a fault were high speed reclosing is utilized.

Voltage Ride Through [R4-4.3.1.2]

SMUD simulated the tripping of generators where simulations showed generator bus voltages or high side of the GSU voltages were less than known or assumed minimum generator steady state or ride through voltage limitations.

Line Tripping [R4-4.3.1.3]

SMUD simulated the tripping of lines appropriately when transient swings caused Protection System operation based on generic or actual relay models.

Protection System [R4-4.3.2]

SMUD simulated the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities, such as SMUD's

Under Voltage Direct Load Shedding (UVDLS) and Under Frequency Load Shedding (UFLS). The impacts of such operations were analyzed as part of the assessment.

Stability Events [R4-4.4]

Planning events expected to produce more severe system impacts on SMUD's BES were identified, and a list of those contingencies were evaluated for system performance in R4, Part 4.1. These contingencies were selected as they have historically been deemed as credible severe contingencies, and were included in past studies.

External Contingencies [R4-4.4.1]

SMUD coordinated with Pacific Gas & Electric (PG&E), California Independent System Operator (CAISO), and Western Area Power Administration – Sierra Nevada Region (WASN) to create a list of contingencies external to SMUD which may negatively impact SMUD's system. These contingencies were included in the list of contingencies for the assessment.

Stability Extreme Events [R4-4.5]

Extreme events in Table 1 that were expected to produce more severe system impacts were identified and a list created of those events were evaluated in Requirement R4, Part 4.2. These contingencies were selected as they have historically been deemed as credible severe contingencies, and were included in past studies. These events were known in the past as Category D events.

Appendices

0: FAC-013-2 Assessment of Transfer Capability for the Near-Term Planning Horizon

SMUD performs a Transfer Capability Study to comply with NERC Reliability Standard FAC-013-2 "Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon" in conjunction with SMUD's 2015 Ten-Year Transmission Assessment Plan. SMUD's "Transfer Capability" represents the ability to import power across the SMUD transmission system through the transmission interties. Since SMUD is typically importing power, there were no exporting reliability concerns. The reliability criteria and assumptions used to determine SMUD's transfer capability are consistent with the SMUD 2015 Ten-Year Transmission Assessment Plan criteria.

A 2015 heavy summer base case of the near-term planning horizon was used as a starting point to determine the SMUD transfer capability. The import transfer capability is **2,250 MW**. The limiting facility is the Hurley – Tracy 230 kV lines following the Rancho Seco – Bellota #1 and #2 230 kV common structure outage (Category P7 of the new NERC TPL-001-4 Standard).

This Transfer Capability study applied the same reliability criteria used in the SMUD's 2015 Ten-Year Assessment Plan which is the NERC/WECC Planning Standards, the WECC reactive margin criteria, and study methodology and guidelines.

A 2015 heavy summer base case of the near-term planning horizon was used as a starting point to determine the SMUD transfer capability. To determine the import transfer limit, in this case, internal generating resources and demand were modified until a reliability limit was observed.

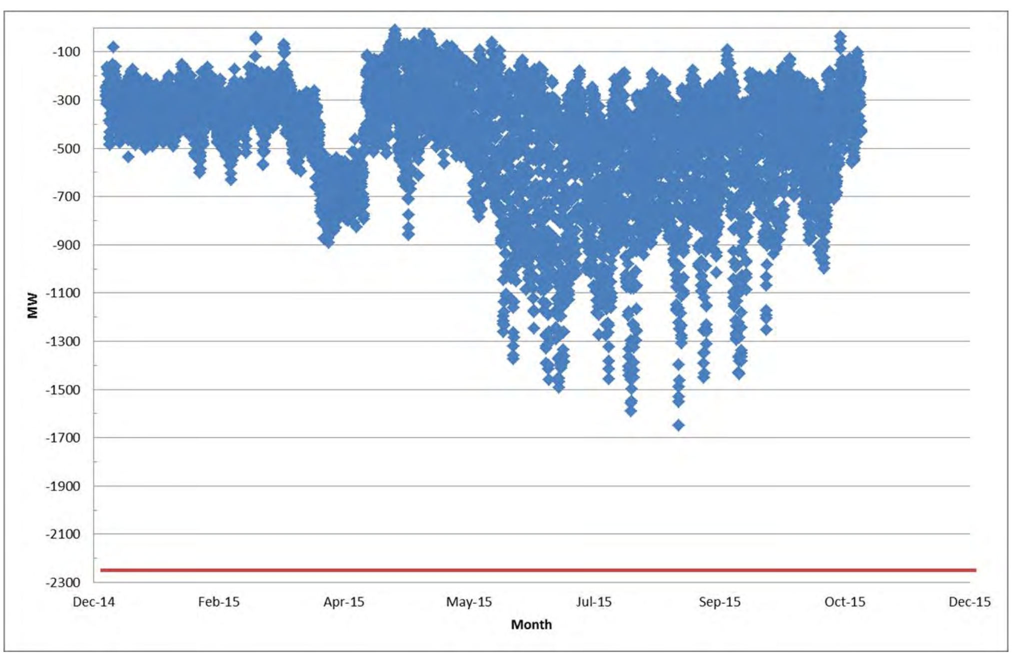

Figure 15: Actual Transfer Values, 2015

1: Special Protection Systems (SPS)

There are several Special Protection Systems (SPS) in the Sacramento Area designed to protect equipment and/or to maintain system reliability in the event of severe contingencies.

Sutter Special Protection System (SPS)

Refer to WASN's OP-61 Special Protection Schemes for Sutter Special Protection Scheme, under Section b on page 5.

Procter Special Protection System (SPS)

The Procter SPS will trip the Hurley-Procter 230 kV Line in the event that a disturbance causes the Procter-Hedge 230 kV Line to overload. A worst-case scenario (CPP off-line) for this is the double contingency loss of the Rancho Seco-Bellota 230 kV lines and all SPS actions associated with the contingency occurred at the same time.

SMUD Direct Load Tripping (DLT)

The SMUD DLT is an automated Load Shedding application on the SMUD EMS. The scheme is available to be armed by SMUD dispatchers under certain scenarios. EMS must be operating for SMUD DLT to be activated since both detection and activation are performed by EMS.

The SMUD DLT monitors the line status on the following three 230 kV tie-line group:

1. N-2: Rancho Seco-Bellota #1 and #2
2. N-2: Tracy-Hurley #1 and #2
3. N-4: Elverta-O'Banion #1 & #2 & #3, and Natomas-O'Banion

In addition, voltages at Elverta, Hurley, Rancho Seco, Pocket, and Lake are also monitored. The scheme implements a dispatcher specified amount of load shed in approximately 10 seconds upon the detection of the loss of any one of the three tie-line groups listed above, or if the majority of the monitored voltages (4 out of 6 buses or more) drop to less than 212 kV for 10 consecutive seconds.

The Load Shedding scheme consists of individual 12 kV distribution substation feeders that have SCADA control. The scheme receives real-time information on the loading and status of each of these distribution feeders and determines the number of feeders to trip to give the desired amount of Load Shedding. The application opens just enough feeder breakers to shed the desired load amount. Interrupting smaller increments of load at the 12 kV levels, instead of shedding load at the bulk transformer or 69 kV feeder level gives better control in shedding the specified amount of load, and limits the amount of excess load shedding.

Under Voltage Direct Load Shedding Scheme (UVDLS)

SMUD also has an UVDLS located at several substations. This scheme is armed continuously and acts as an added safety net to shed load automatically for severe contingencies.

The UVDLS Timer will reset when the 230 kV system voltages recovers above 218 kV for 6 cycles or at 220 kV instantaneously. That is, UVDLS will operate when the 230 kV system voltages at local substations drops below 212 kV and stays below 218 kV for 15 consecutive seconds. See the diagram below for more details.

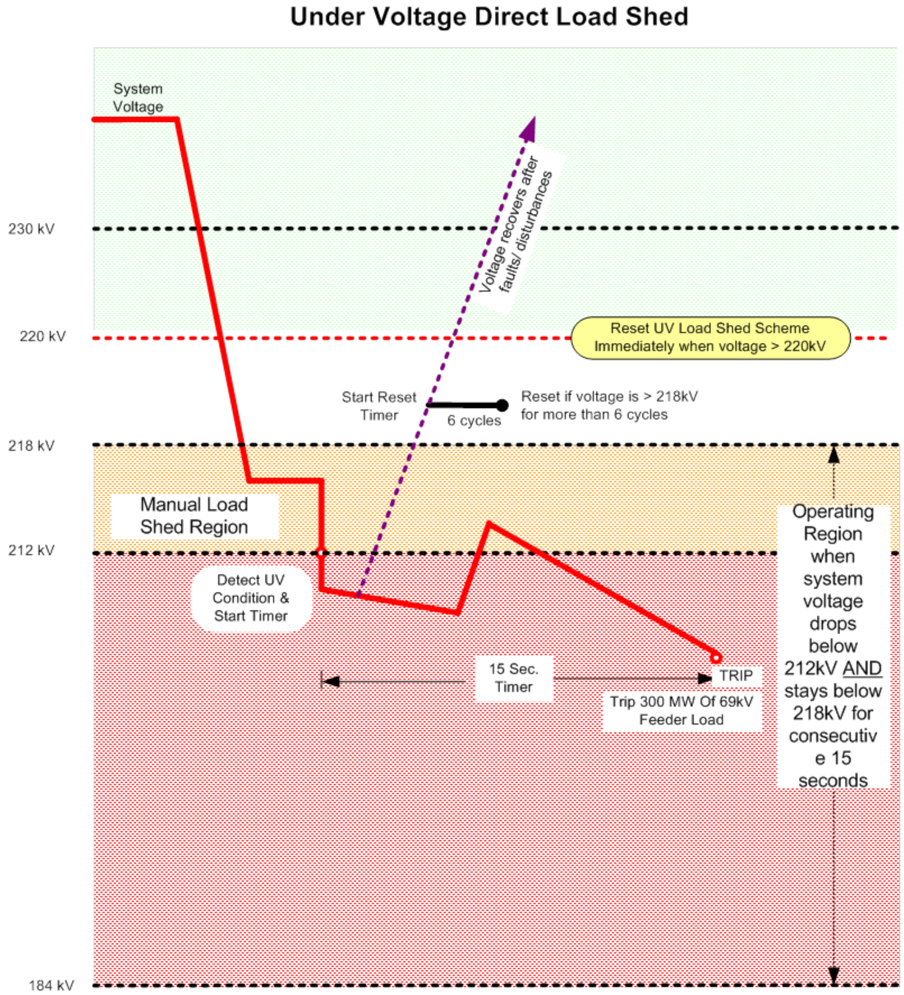

Figure 16: Diagram of SMUD's UVLS settings

UARP Special Protection System (SPS)

A Special Protection System (SPS) has been installed to eliminate overloads due to high UARP generation levels for loss of double line outages. This scheme monitors the current for the White Rock -Orangevale and Jaybird–White Rock lines. The SPS is normally armed at all times and will runback Camino Generators 1 & 2 and White Rock Generators 1 & 2, as necessary, to mitigate potential thermal overloads on the White Rock-Orangevale and Jaybird–White Rock 230 kV lines, depending on the SPS seasonal setting.

Carmichael Special Protection System (SPS)

The Carmichael-Hurley 230 kV line has two sections: an overhead line section and a pipe-type underground cable section. The 230 kV line is limited by the underground cable section for normal conditions and limited by the overhead section during emergency conditions.

The SPS is to protect the 230 kV line under the following double line outage: the Folsom-Orangevale and Orangevale-White Rock 230 kV lines.

The SPS consists of non-directional overcurrent relays installed at Carmichael that monitor the current through the Carmichael-Hurley 230 kV line. The SPS will be always in service, but deployed only when line ampacity is above the summer emergency rating of 925 Amps (368 MVA).

2: NERC/WECC Reliability Standards

SMUD utilizes the NERC/WECC Reliability Standards, the WECC reactive margin criteria and study methodology, and study guidelines unique to the Sacramento Area and SMUD's reliability needs.

Voltage Criteria [R5.]

Steady State Voltage Limits

Operating procedure PSE-104 – Voltage and Reactive Control provides System Operating Limits (SOL). The steady state voltage limit SOLs are tabulated below:

Table 16: SMUD Voltage Operating Limits

	SOL (kV)	
Nominal Voltage (kV)	High	Low
230	242	218
115	124	110

Post Contingency Voltage Deviations

WECC members are developing new post contingency criteria for steady state analysis but it has not been approved. As such, SMUD used the previous approved criteria and matched the new P category outages as shown in the tables below.

Table 17: Post Contingency Voltage Deviations

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

Table 18: Comparison of old TPL contingencies with new TPL contingencies.

Old TPL	New TPL	Description
Category A	P0	All Facilities In-Service (N-0)
Category B	P1	Single Outage
Category C1, C2	P2	Single event that may result in multi-facility outage
Category C3	P3	Loss of Generator unit, system adjustment, followed by P1. (No load shed allowed)
Category C	P4	Fault plus stuck breaker
N/A	P5	Fault plus delayed clearing due to relay component failure
Category C	P6	Overlapping Outages (No Generation Facilities)
Category C4, C5	P7	Common structure outages
Category D	Prefix "ES(S)"	Extreme contingencies

Transient Voltage Response

To demonstrate that the post-transient voltages recover and become stable, voltage dip criteria shall meet the WECC "finger diagram" with a requirement for at least a 20 percent dip recovery within 20 second of the fault clearing.

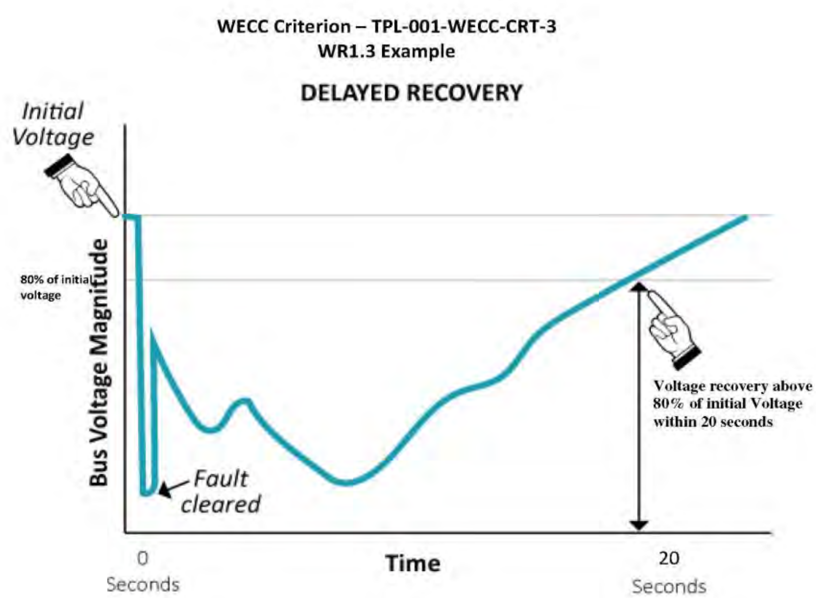

Figure 17: Voltage Performance Diagram

Methodology used to Identify System Instability [R6.]

Cascading Outages

The assessment assumed the definition of cascading outages to be the uncontrolled successive loss of system elements triggered by an incident at any location and which results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.

Instability

The assessment assumed the definition of power system stability as the ability of an electric power system, for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a physical disturbance, with most system variables bounded so that practically the entire system remains intact[11].

Power system stability can be classified into three types of stability: rotor angle stability, voltage stability, and frequency stability. Rotor angle stability is the ability of the power system to maintain synchronism when subjected to a disturbance. Voltage stability is the ability of the power system to maintain acceptable voltages when subjected to a disturbance. Frequency stability is the ability of the power system to maintain steady frequency when subjected to a disturbance. For this assessment, a station was deemed unstable if one of the following criteria was met:

- Rotor angle oscillations that were undamped as demonstrated by peak-to-peak magnitudes that did not decrease with time (rotor angle instability).
- Loss of synchronism between one machine and the rest of the system or between groups of generators (rotor angle instability).
- Bus voltage oscillations that were undamped as demonstrated by peak-to-peak magnitudes that did not decrease with time (voltage instability).
- Bus voltage magnitudes that did not recover to 80% of their pre-disturbance voltages within 20 seconds of the disturbance (voltage instability).

Islanding

The assessment assumed the definition of uncontrolled islanding to be the unplanned and uncontrolled splitting of a power system into two or more islands. Severe disturbances may cause uncontrolled separation by causing a group of generators in one area to swing against a group of generators in a different area of an interconnection.

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[11] P. Kundur *et al.*, "Definition and Classification of Power System Stability," *IEEE Trans. Power Syst.*, vol. 19, no. 2, pp. 1387-1392, May 2004.

Responsibilities for Performing the Planning Assessment [R7.]

SMUD, as the registered Planning Coordinator (PC) and Transmission Planner (TP), is responsible for performing all required studies for this assessment. There are no other TPs within the SMUD PC footprint.

NERC/WECC Reliability Standards

The NERC/WECC Reliability Standards state that Transmission System Planning Performance assessments shall be conducted on an annual basis to establish that the BES will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

The fundamental purpose of the interconnected transmission system is to move electric power from areas of generation to areas of customer load. The transmission system must be planned, designed, constructed, and operated so that it is capable of reliably performing this function over a wide range of system conditions. The transmission system must be capable of withstanding both common contingencies and the less probable extreme contingencies. The transmission system is planned so that it should be able to operate within thermal, voltage, and stability limits during normal and emergency conditions.

The NERC Reliability Standards define the measures needed to maintain reliability of the interconnected bulk electric systems using the following two terms:

Adequacy - The ability of the electric systems to supply the aggregate electrical demand and energy requirements of their customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.

Security - The ability of the electric system to withstand a sudden disturbance such as an electric short circuit or the unanticipated loss of a system element.

The NERC/WECC Reliability Standards for System Planning Performance and are summarized in Table 19 & 20. System performance assessments shall indicate that the system limits are met for all planned facilities in service (P0), loss of a single element (P1), loss of two or more elements (P2 – P7), and extreme events resulting in two or more elements removed or cascading out of service. Extreme contingencies measure the robustness of the transmission system and should be reviewed for reliability and evaluated for risks and consequences.

The ability of the interconnected transmission systems to withstand probable and extreme contingencies must be determined by both Planning and Operating studies. Assessments should also include the effects of existing and planned protection schemes, backup or redundant protection schemes, and control devices to ensure that protection systems and control devices are sufficient to meet the system performance criteria as defined in Table 4. The transmission system must be capable of meeting P1-P7requirements while accommodating the planned outage of any bulk electric equipment (including protection systems or their components) at all demand levels for which planned outages are performed.

Table 19: TPL-001-4 Transmission System Planning Performance Requirements

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.
b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.
c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.
d. Simulate Normal Clearing unless otherwise specified.
e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.
g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.
h. Planning event P0 is applicable to steady state only.
i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event	Fault Type	BES Level	Interruption of Firm Transmission Service Allowed	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device	3Ø	EHV, HV	No	No
		5. Single Pole of a DC line	SLG			
P2 Single	Normal System	1. Opening of a line section w/o fault	N/A	EHV, HV	No	No
		2. Bus Section Fault	SLG	EHV	No	No
				HV	Yes	Yes
		3. Internal Breaker Fault (non-Bus-tie Breaker)	SLG	EHV	No	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker)	SLG	EHV, HV	Yes	Yes
P3 Multiple Contingency	Loss of generator unit followed by System adjustments	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device	3Ø	EHV, HV	No	No
		5. Single Pole of a DC line	SLG			

P4 Multiple Contingency (Fault plus stuck breaker)	Normal System	Loss of multiple elements caused by a stuck breaker (no-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device 5. Bus Section	SLG	EHV	No	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency (Fault plus relay failure to operate)	Normal System	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: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device 5. Bus Section	SLG	EHV	No	No
				HV	Yes	Yes
P6 Multiple Contingency (Two overlapping singles)	Loss of one of the following followed by system adjustments: 1. Transmission Circuit 2. Transformer 3. Shunt Device 4. Single Pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer 3. Shunt Device	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG			
P7 Multiple Contingency (Common Structure)	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on a common structure 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

Table 20: TPL-001-4 Transmission System Planning Performance Requirements for Extreme Events

<table>
<tr><th colspan="2">Table 1 -Steady State & Stability Performance Extreme Events</th></tr>
<tr><td colspan="2">Steady State & Stability
For all extreme events evaluated:
a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency
b. Simulate Normal Clearing unless otherwise specified</td></tr>
<tr><td>Steady State
1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to system adjustments.
2. Local area events affecting the Transmission System such as:
a. Loss of tower line with three or more circuits.
b. Loss of all Transmission lines on a common Right-of-Way.
c. Loss of a switching station or substation (loss of one voltage level plus transformers).
d. Loss of all generating units at a generating station.
e. Loss of a large Load or major Load center.
3. Wide area events affecting Transmission System based System topology such as:
a. Loss of two generating station resulting from conditions such as:
i. Loss of large gas pipeline into a region or multiple regions that significant gas-fired generation.
ii. Loss of the use of a large body of water as the cooling source for generation
iii. Wildfires
iv. Severe weather, e.g. hurricanes, tornadoes, etc.
v. A successful cyber-attack.
vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants.
b. Other events based upon operating experience that may result in wide area disturbances.</td>
<td>Stability
1. With an initial condition of a single generator, Transmission circuit, singe pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.
2. Local or wide area events affecting the Transmission System such as:
a. 3Ø fault on generator with stuck breaker or relay failure resulting in Delayed Fault Clearing
b. 3Ø fault on Transmission circuit with stuck breaker or a relay failure resulting in Delayed Fault Clearing
c. 3Ø fault on transformer with stuck breaker or relay failure resulting in Delayed Fault Clearing.
d. 3Ø fault on bus section with stuck breaker or relay failure resulting in Delayed Fault Clearing.
e. 3Ø internal breaker fault.
f. Other events based upon operating experience, such as consideration of initiating events that experience suggest may result in wide area disturbances.</td></tr>
</table>

WECC Disturbance Performance and Reactive Margin Criteria

The NERC/WECC Reliability Standards discussed in the previous section do not specifically address the criteria or study methodology required to ensure reliability for the more severe contingencies involving transient stability or voltage collapse. As a result, WECC has developed criteria and a methodology for conducting transient and voltage stability studies. The WECC criteria and methodology are aligned with the NERC disturbance categories and specify limits for voltage, frequency, damping, and real/reactive power margins.

Transient stability analysis is typically performed from the initiation of a disturbance to approximately 10 seconds after the disturbance. Voltage stability criteria and real/reactive power margins address the period after transient stability oscillations have damped out and before manual actions to adjust generation or interchange schedules can be implemented. This is typically in the period between 10 seconds to 3 minutes after a disturbance. An area susceptible to voltage collapse can be identified by a power flow contingency analysis. Cases that exhibit large voltage deviations or fail to converge to a solution are typically at or near a voltage unstable operating point. Note that voltage collapse typically occurs after the VAR capability of the region is depleted.

There are two types of analysis typically conducted to address voltage collapse. These include Power-Voltage (PV) and Voltage-Reactive Power (QV). Both PV and QV analysis should be assessed to determine the reactive margin. Either method may be used for a general voltage stability evaluation, but more detailed studies should demonstrate adequate voltage stability margin for both PV and QV analysis. Sole reliance on either PV or QV analysis is not sufficient to assess voltage stability and the proximity to voltage collapse. The system must be planned and operated to maintain minimum levels of margin. This margin is required to account for uncertainties in data, equipment performance, and differences in the transmission network conditions. In addition, PV and QV analysis can be used to determine the required amounts of undervoltage load shedding and to address the proper combination of static and dynamic reactive power support.

QV Analysis

QV analysis is a study technique that relates VAR margin at a point in the transmission network to the voltage at that point in the network. The benefit of this methodology is that it provides an indication of the proximity to voltage collapse due to a shortage of VAR resources at a specific point in the system. With this technique, a fictitious VAR device is modeled at a critical point in the transmission system. The voltage of this device is set to a desired value, and the VAR output required maintaining this voltage is recorded. As the voltage is decreased, the VAR device must produce more VARs to maintain the desired voltage. The point of voltage collapse is reached when an incremental decrease in voltage also causes a decrease in the VAR output of the device. The output of the VAR device represents the amount of reactive power deficiency at that point of the system. The VAR deficiency at any point in the system must be less than the margin determined from the WECC VQ methodology.

The WECC criteria for performing QV analysis are as following:

- The most reactive deficient bus must have adequate reactive power margin for the most severe Category B disturbance (N-1) to satisfy the following conditions;
    - A 5% increase beyond the maximum forecasted load or interface flows.
- A Category C disturbance (N-2) requires a 2.5% increase beyond the maximum load forecast load or interface flow.

Assessment Report Distribution List [R8.]

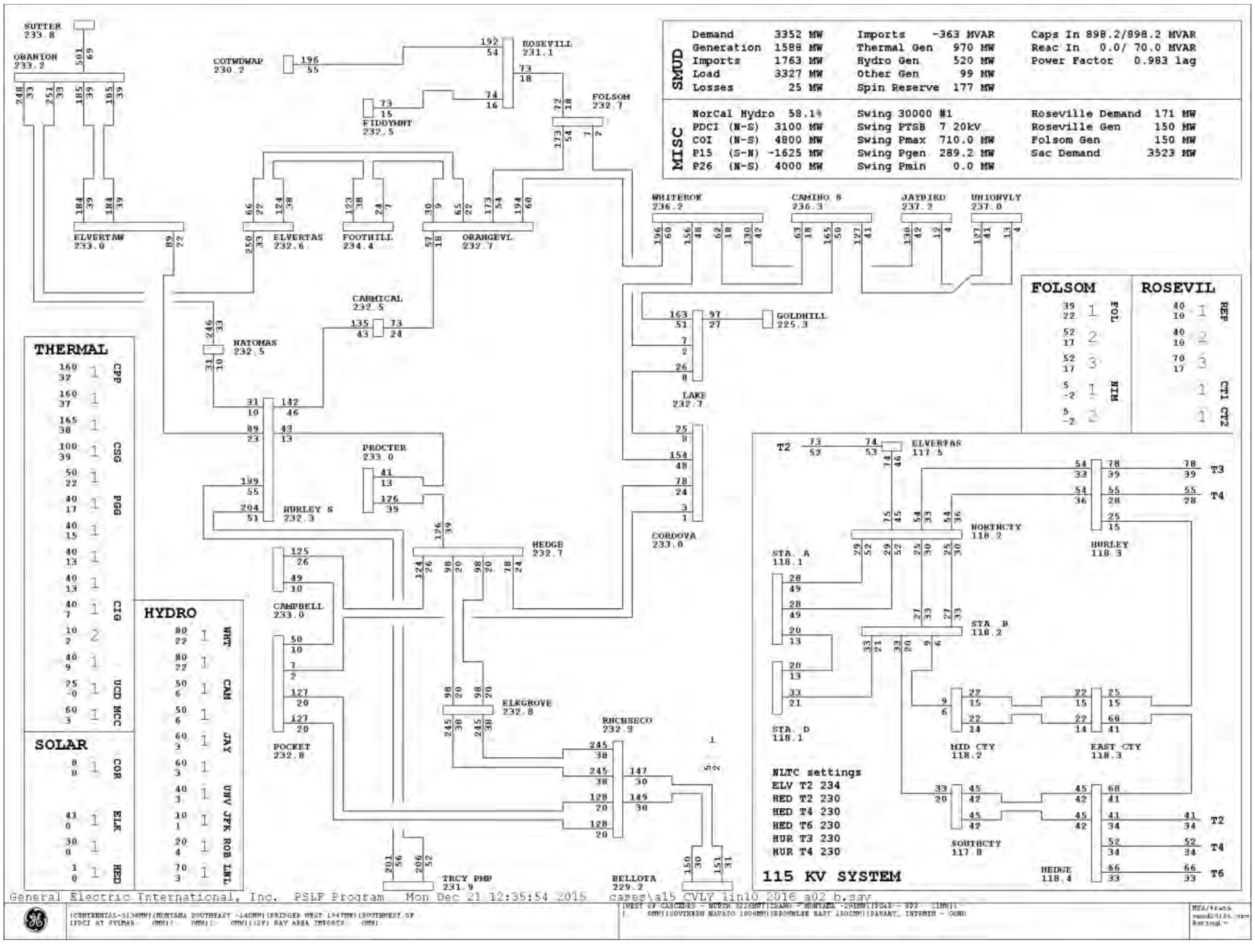
SMUD, as the Planning Coordinator and Transmission Planner, will distribute this planning assessment results to adjacent planning coordinators and adjacent transmission planners within 90 calendar days of completing the planning assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. SMUD maintains an assessment distribution list in order to facilitate quicker distribution of the annual assessment report.

Assessment Report Comments [R8-8.1]

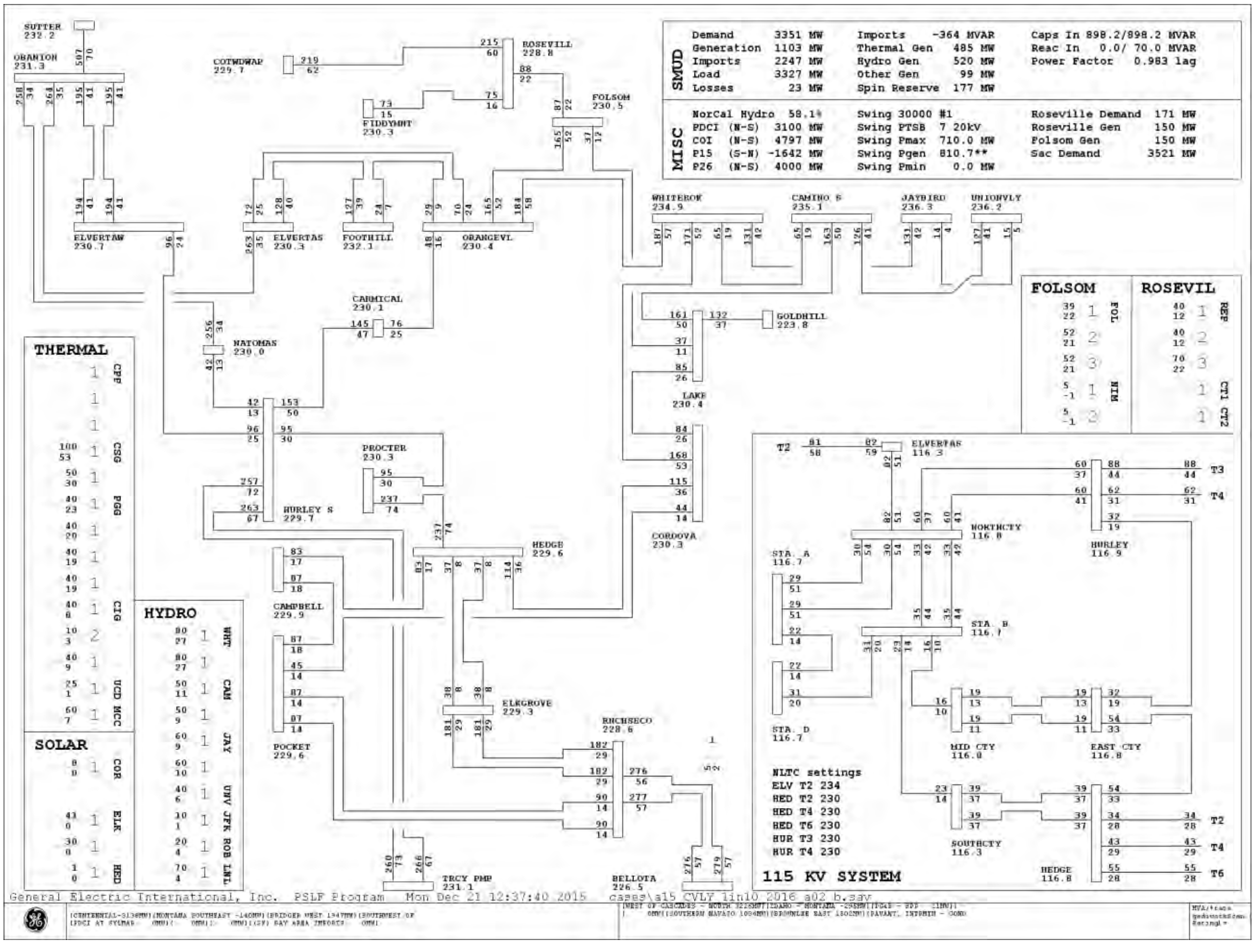
If a recipient of the Planning Assessment results provides documented comments on the results, SMUD shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

3: Steady State Power Flow Diagrams

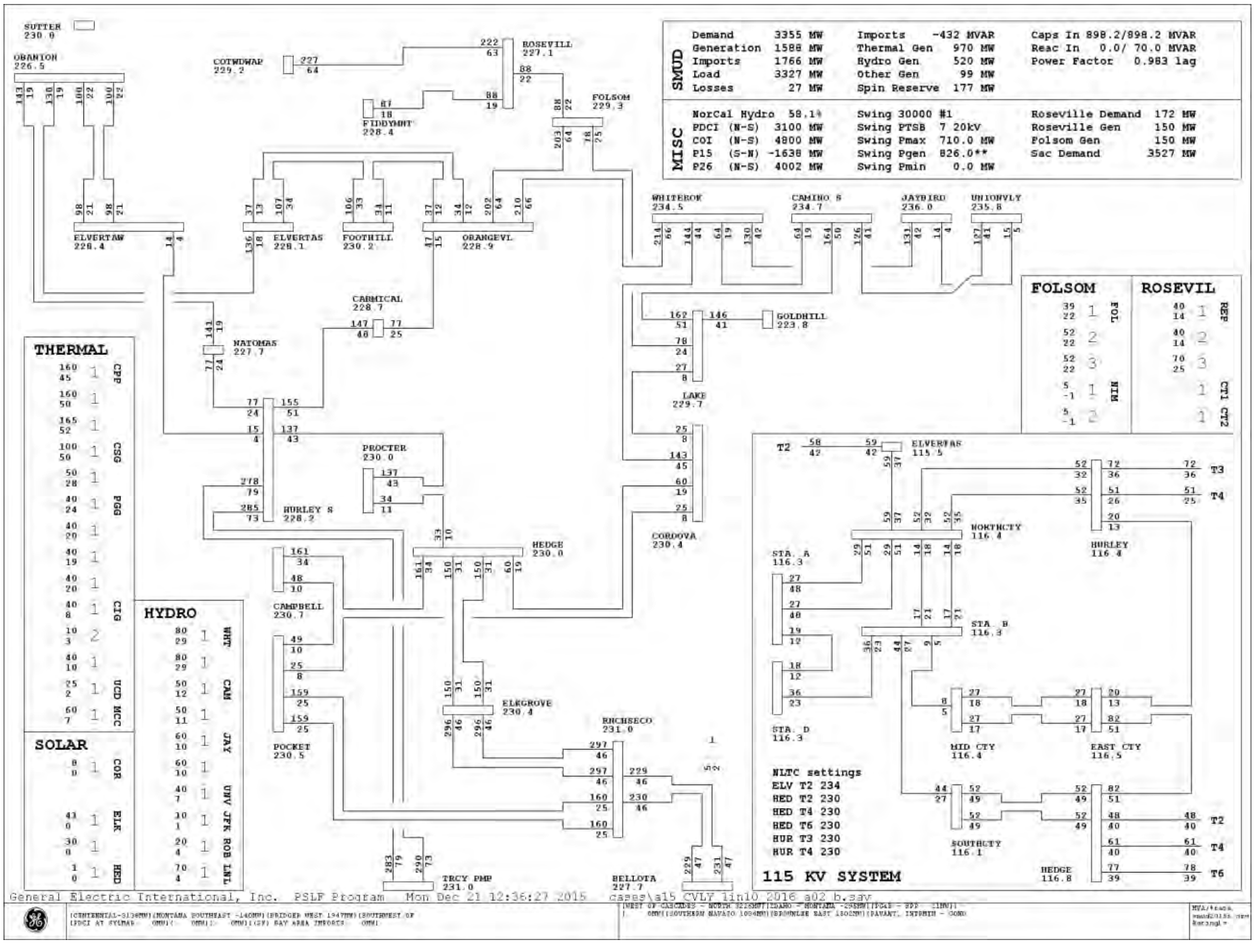
Below is a selection of steady state power flow diagrams which show pre contingency and post contingency results. More steady state diagrams can be made available upon request.



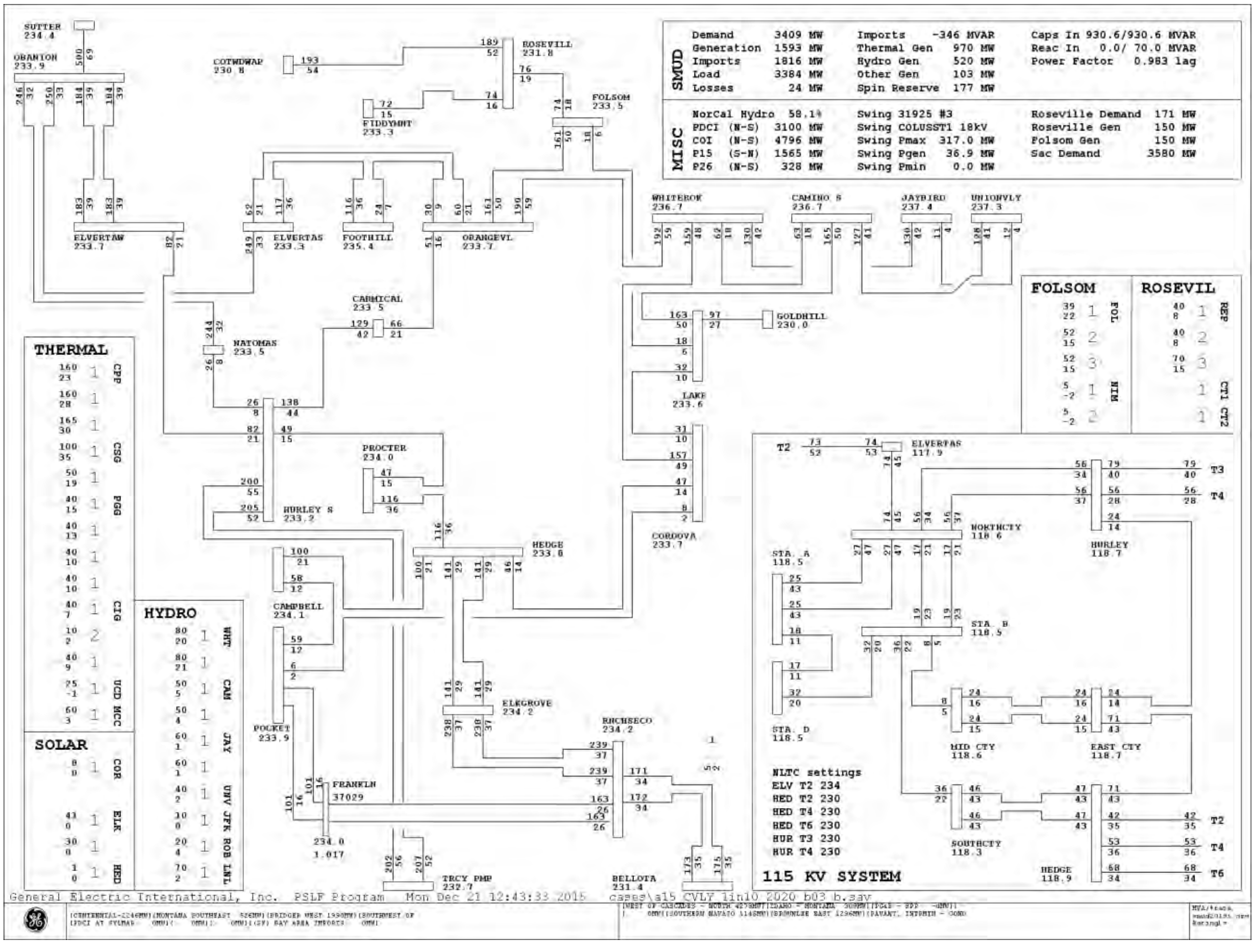
2016 Steady State – No Contingency



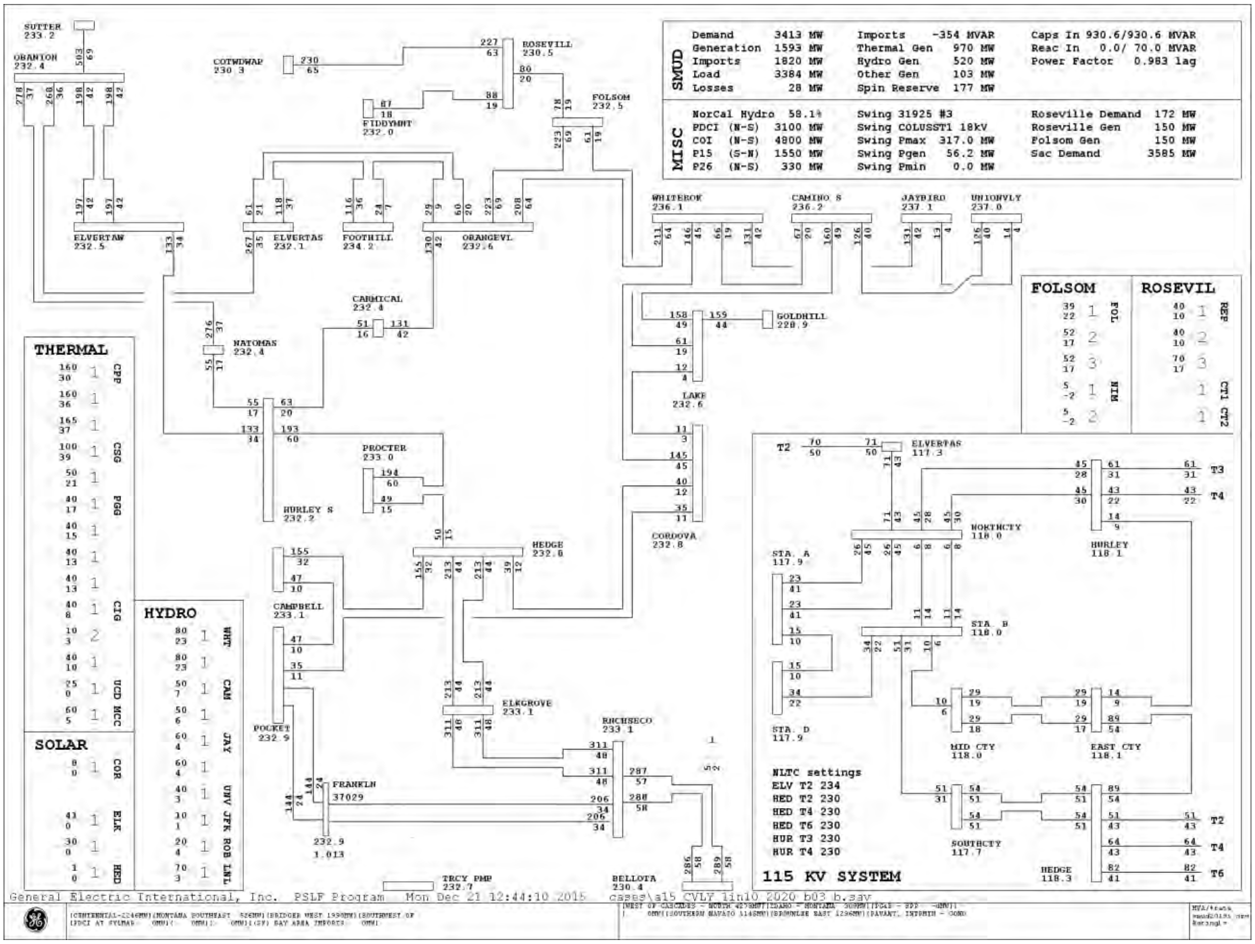
2016 Steady State – CPP Plant Outage



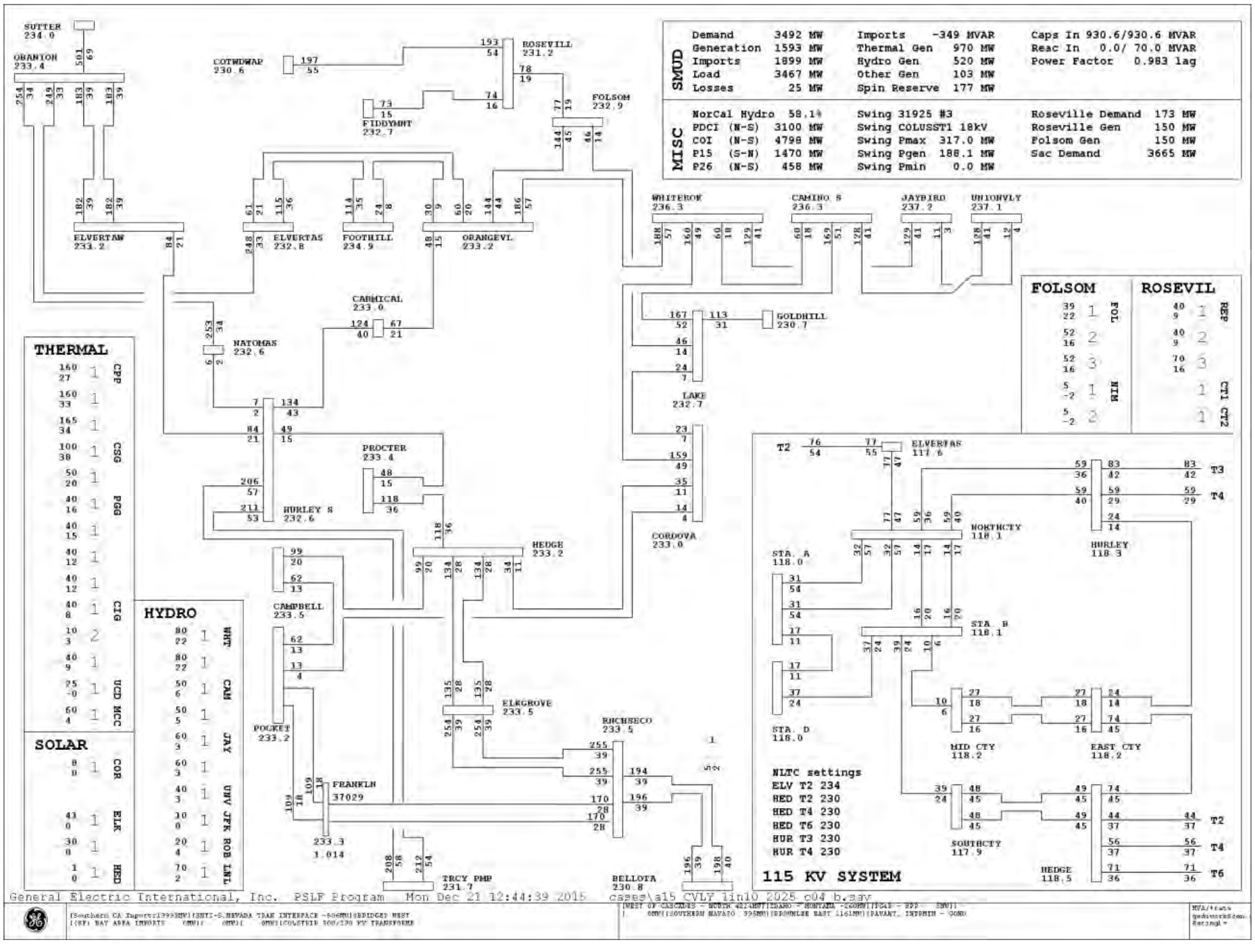
2016 Steady State – O'Banion – Sutter (N-1) Outage



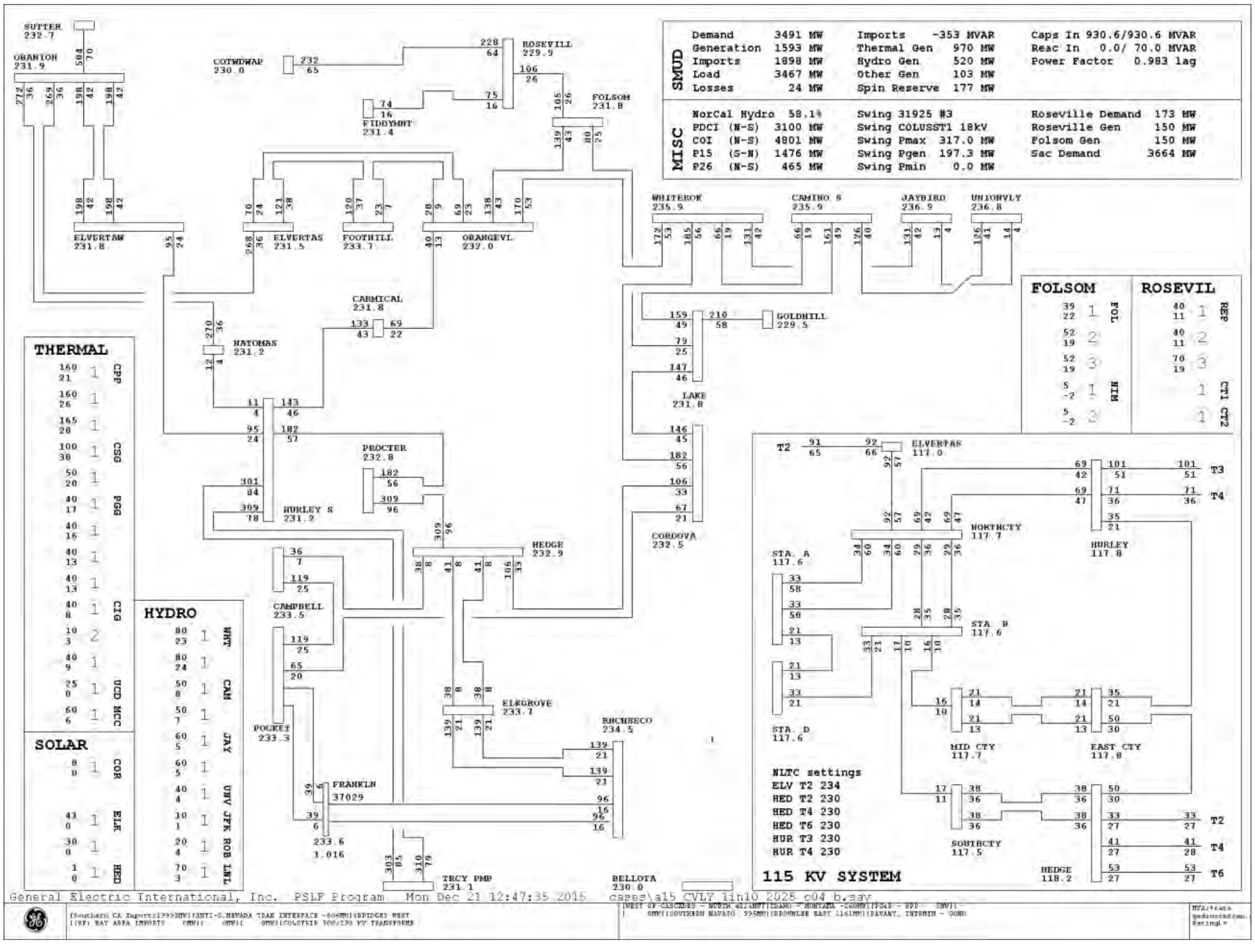
2020 Steady State – No Contingency



2020 Steady State – Tracy – Hurley (N-2) Outage



2025 Steady State – No Contingency



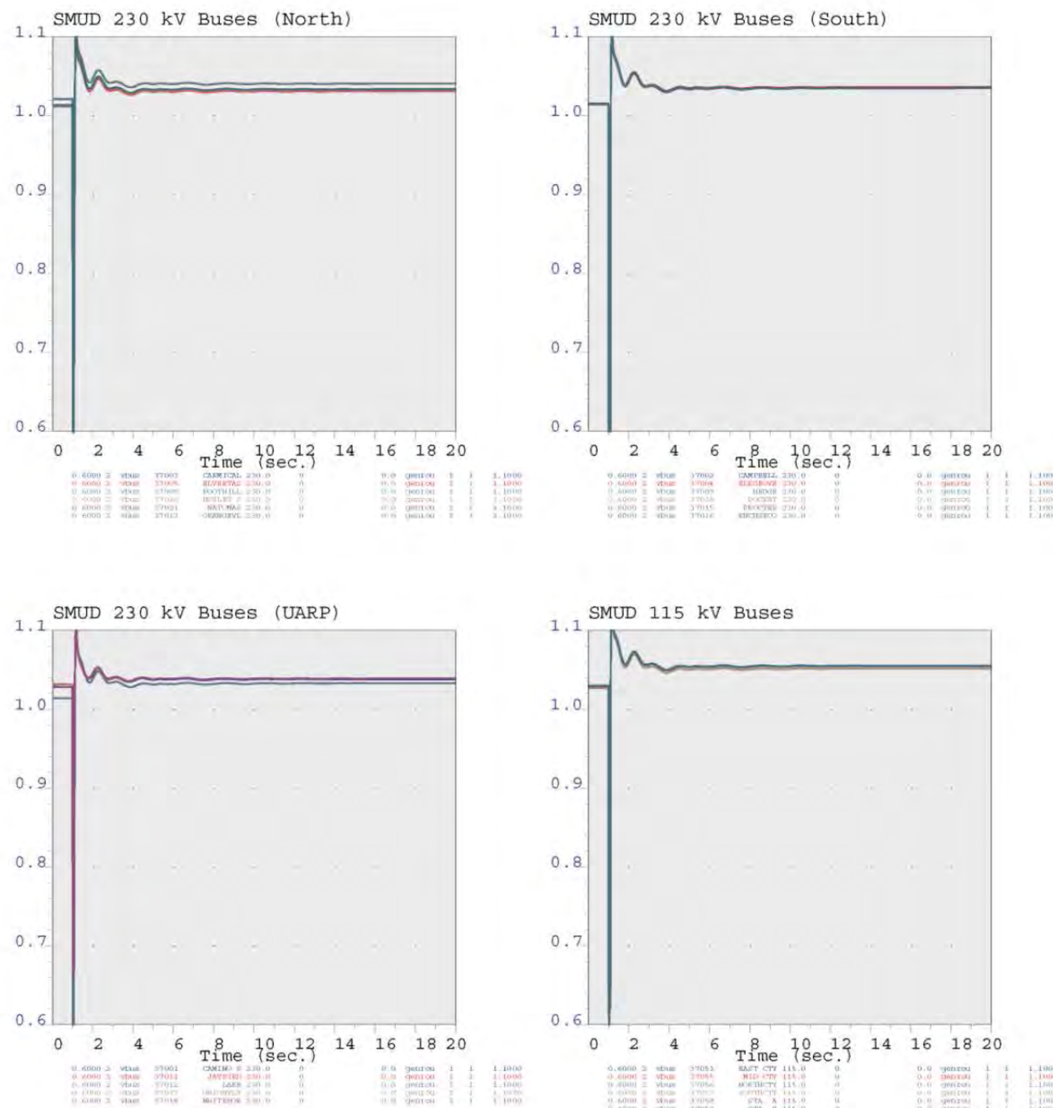
2025 Steady State – Rancho Seco – Bellota (N-2) Outage

4: Dynamic Stability Plots

Below is a selection of dynamic stability power flow plots which show stability results. More dynamic plots can be made available upon request.

The following are plots for contingencies on the 2016 Adverse Summer Peak case.

2015 Ten Year Plan Assessment - 2016 Summer Peak



16HS3_10_Bellota-RanchoSeco-Camanch-dlo
2016 HS3 OPERATING CASE
AUGUST 25, 2015
COMMENTS DUE TO AREA COORDINATORS BY SEPTEMBER 8, 2015
COMMENTS FROM AREA COORDINATORS DUE TO STAFF BY SEPTEMBER 15, 2014

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16HS3_10_Bellota-RanchoSeco-Camanch-dlo.chf

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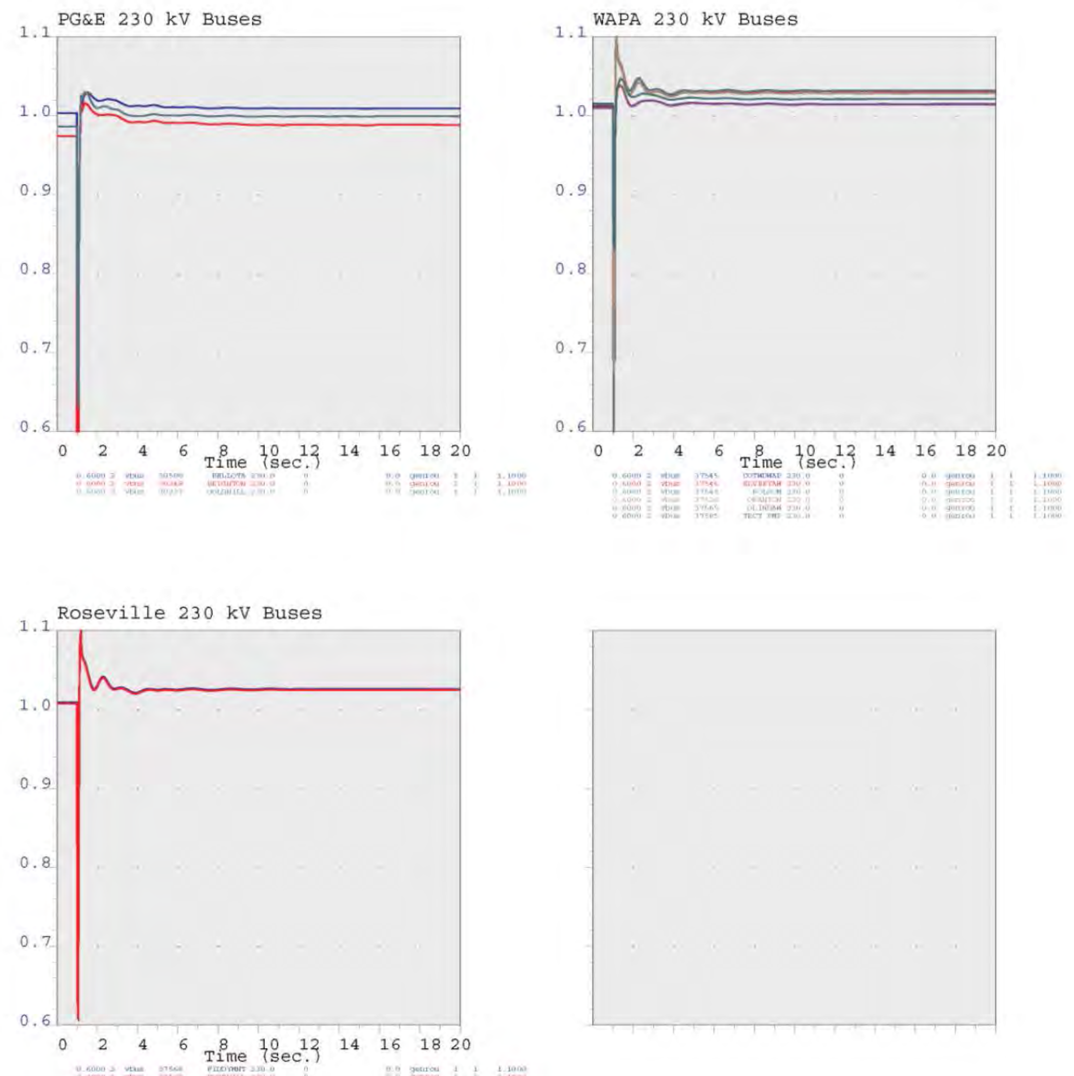
2015 Ten Year Plan Assessment - 2016 Summer Peak



16HS3_10_Bellota-RanchoSeco-Camanch-dlo
2016 HS3 OPERATING CASE
AUGUST 25, 2015
COMMENTS DUE TO AREA COORDINATORS BY SEPTEMBER 8, 2015
COMMENTS FROM AREA COORDINATORS DUE TO STAFF BY SEPTEMBER 15, 2014

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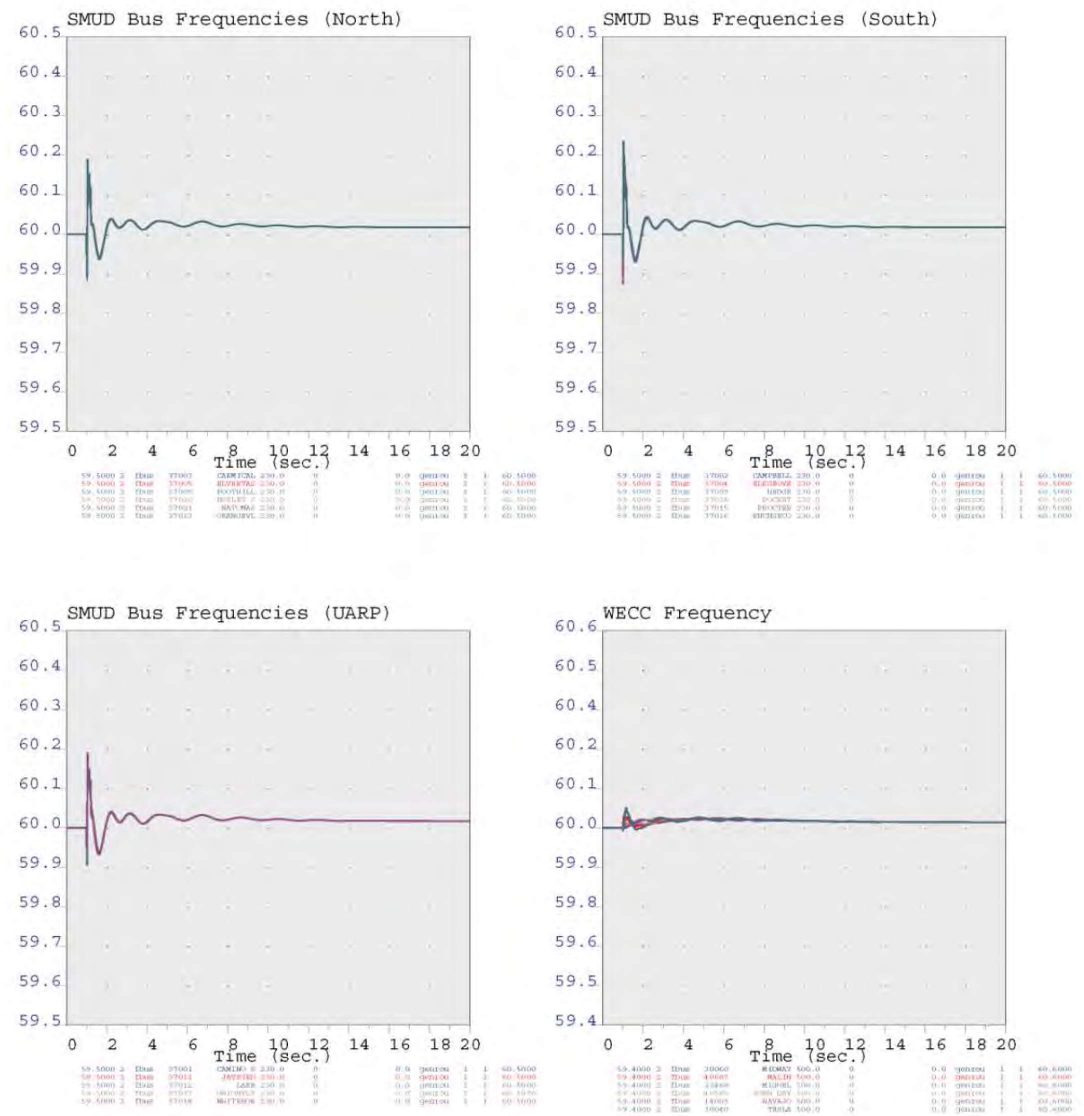
16HS3_10_Bellota-RanchoSeco-Camanch-dlo.chf

Tue Oct 27 11:09:13 2015

2015 Ten Year Plan Assessment - 2016 Summer Peak



16HS3_10_Bellota-RanchoSeco-Camanch-dlo
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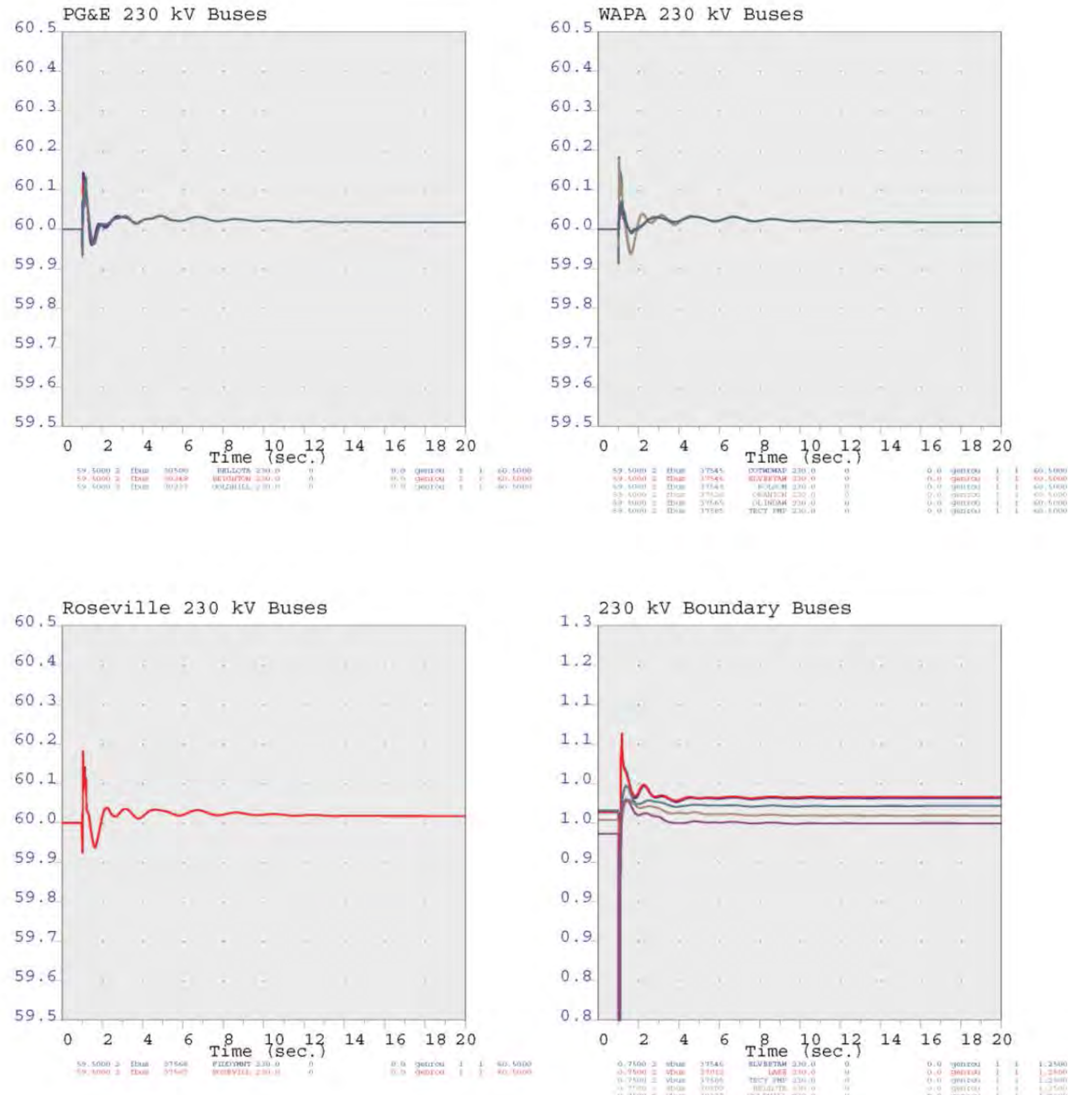
16HS3_10_Bellota-RanchoSeco-Camanch-dlo.chf

Tue Oct 27 11:09:13 2015

2015 Ten Year Plan Assessment - 2016 Summer Peak



16HS3_10_Bellota-RanchoSeco-Camanch-dlo
2016 HS3 OPERATING CASE
AUGUST 25, 2015
COMMENTS DUE TO AREA COORDINATORS BY SEPTEMBER 8, 2015
COMMENTS FROM AREA COORDINATORS DUE TO STAFF BY SEPTEMBER 15, 2014

Page 4

16HS3_10_Bellota-RanchoSeco-Camanch-dlo.chf

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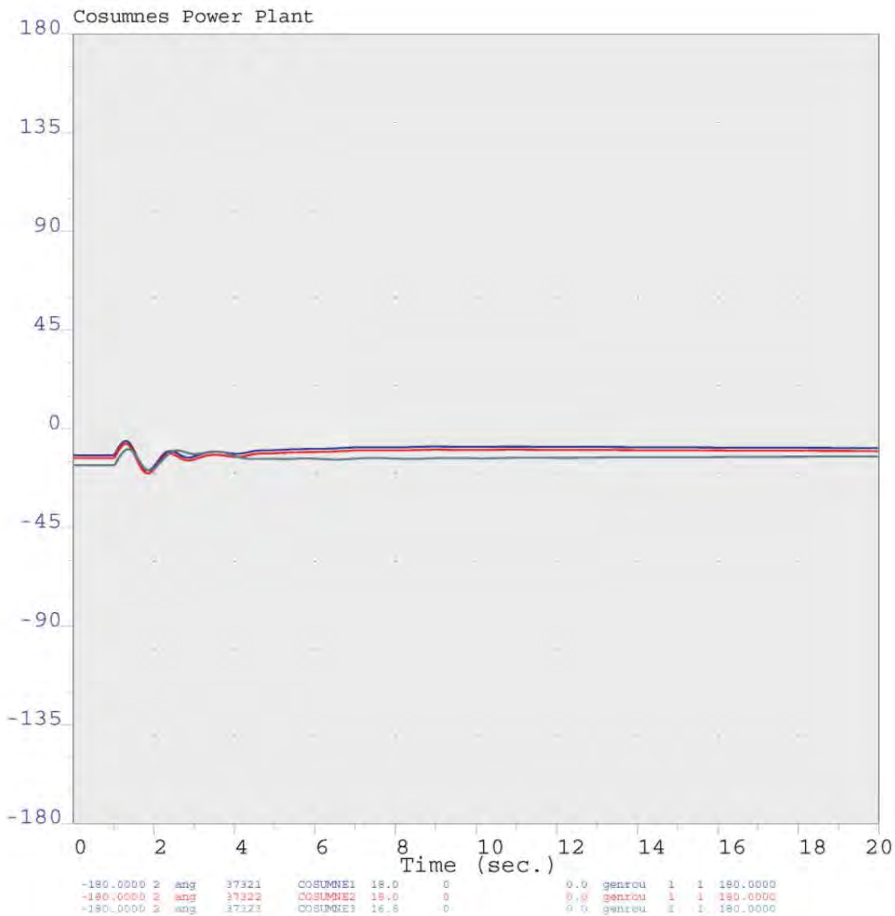
2015 Ten Year Plan Assessment - 2016 Summer Peak



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2016 HS3 OPERATING CASE
AUGUST 25, 2015
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16HS3_10_Bellota-RanchoSeco-Camanch-dlo.chf

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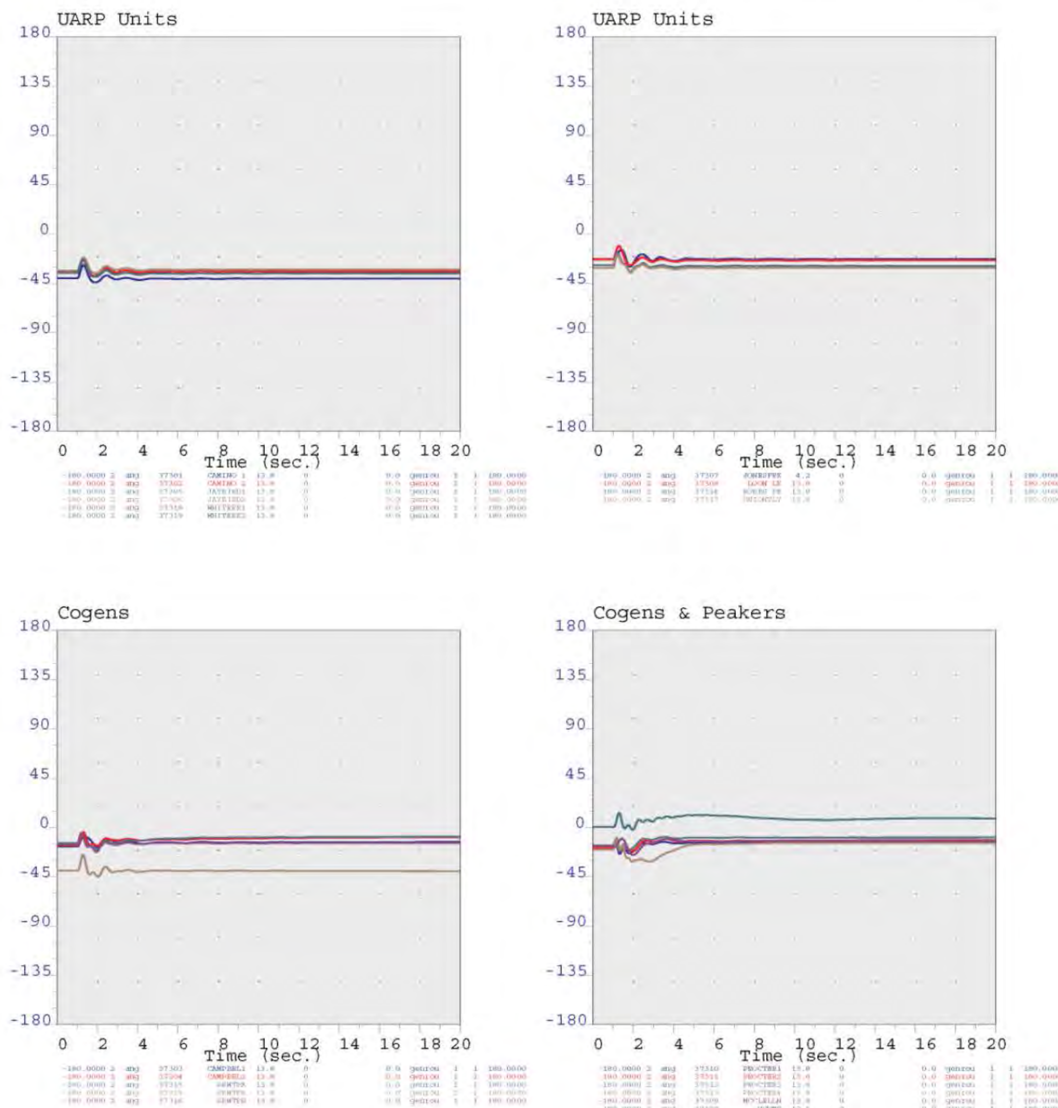
2015 Ten Year Plan Assessment - 2016 Summer Peak



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16HS3_10_Bellota-RanchoSeco-Camanch-dlo.chf

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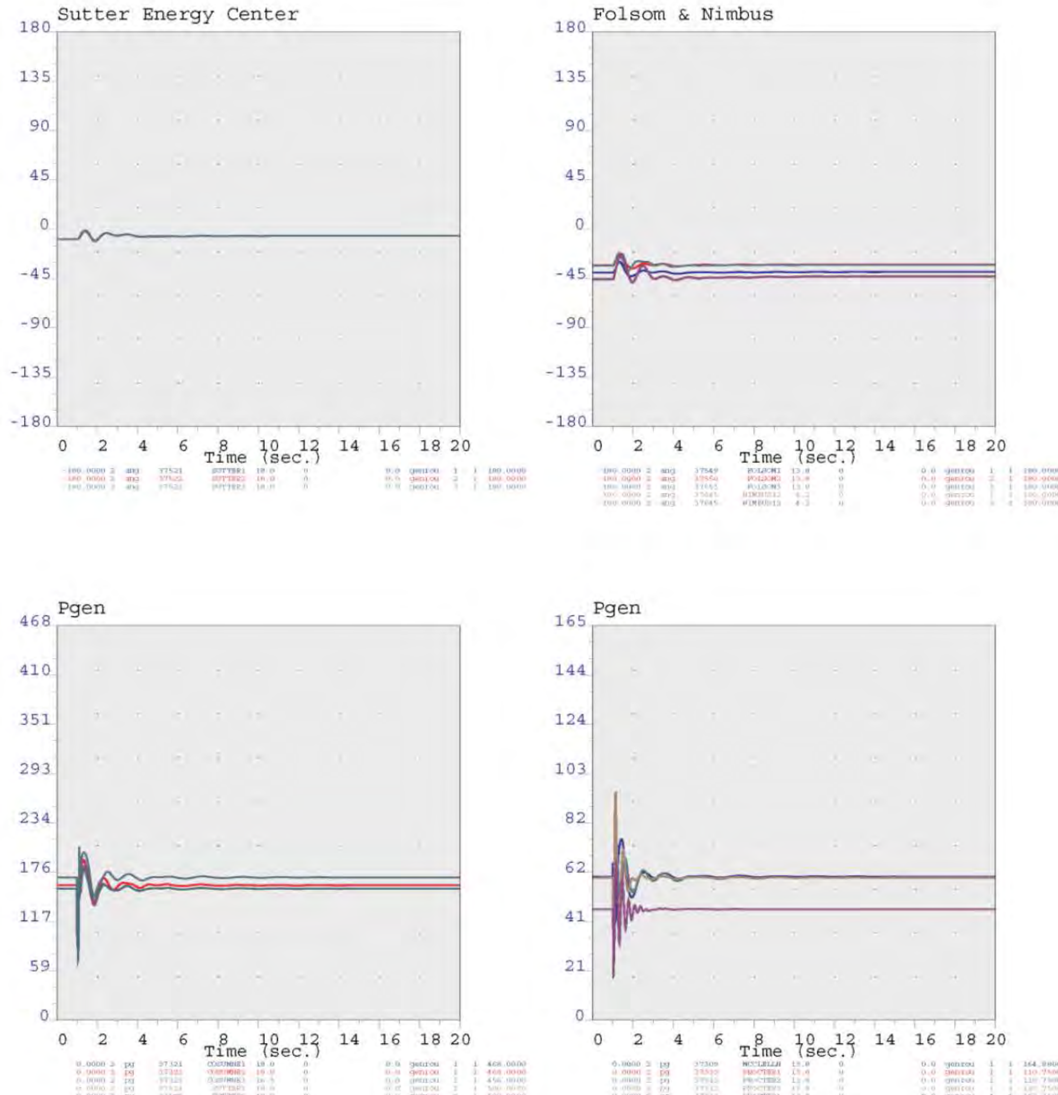
2015 Ten Year Plan Assessment - 2016 Summer Peak



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AUGUST 25, 2015
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16HS3_10_Bellota-RanchoSeco-Camanch-dlo.chf | .
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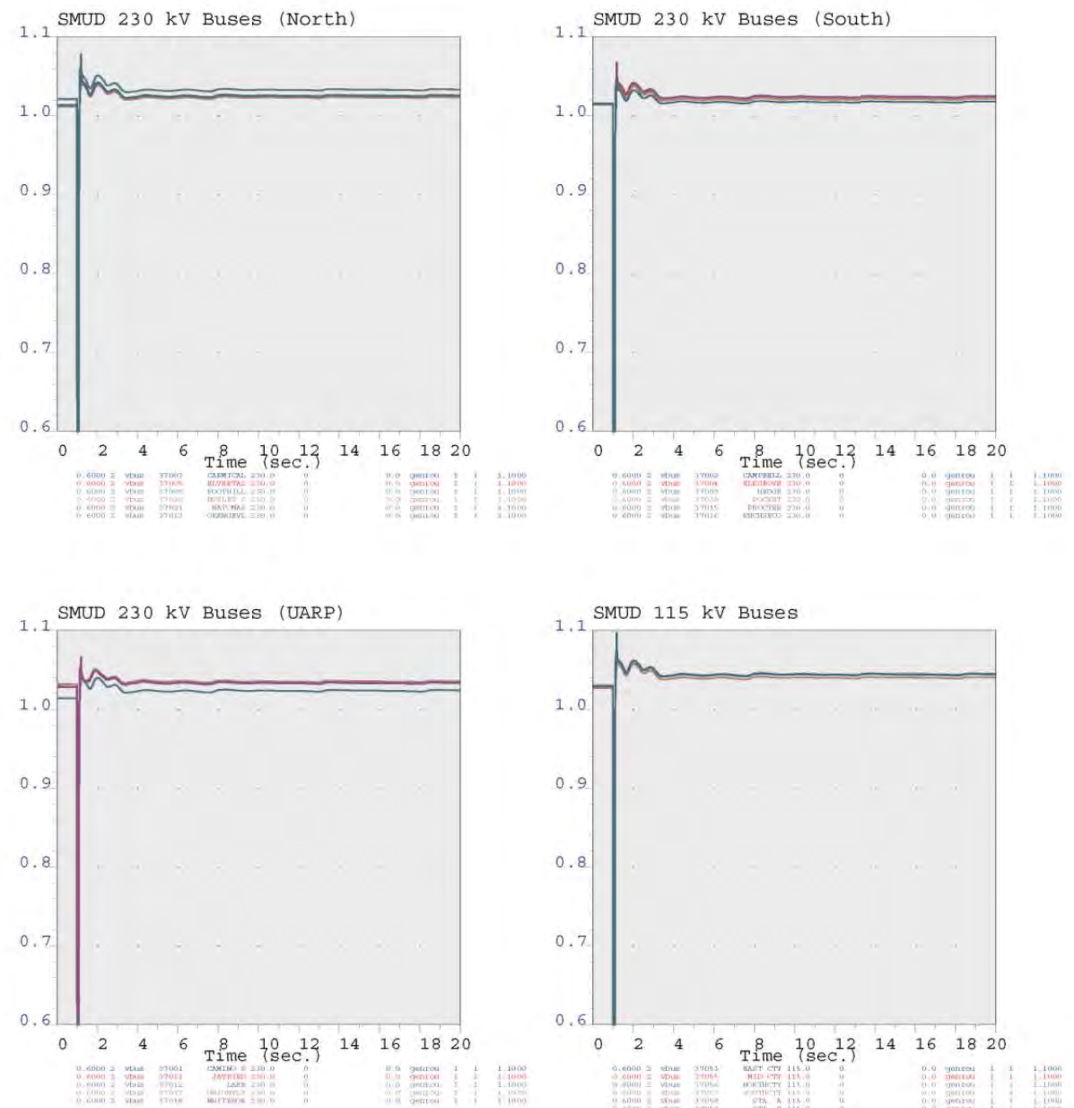
2015 Ten Year Plan Assessment - 2016 Summer Peak



16HS3_10_Cosumnes-pp
2016 HS3 OPERATING CASE
AUGUST 25, 2015
COMMENTS DUE TO AREA COORDINATORS BY SEPTEMBER 8, 2015
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16HS3_10_Cosumnes-pp.chf

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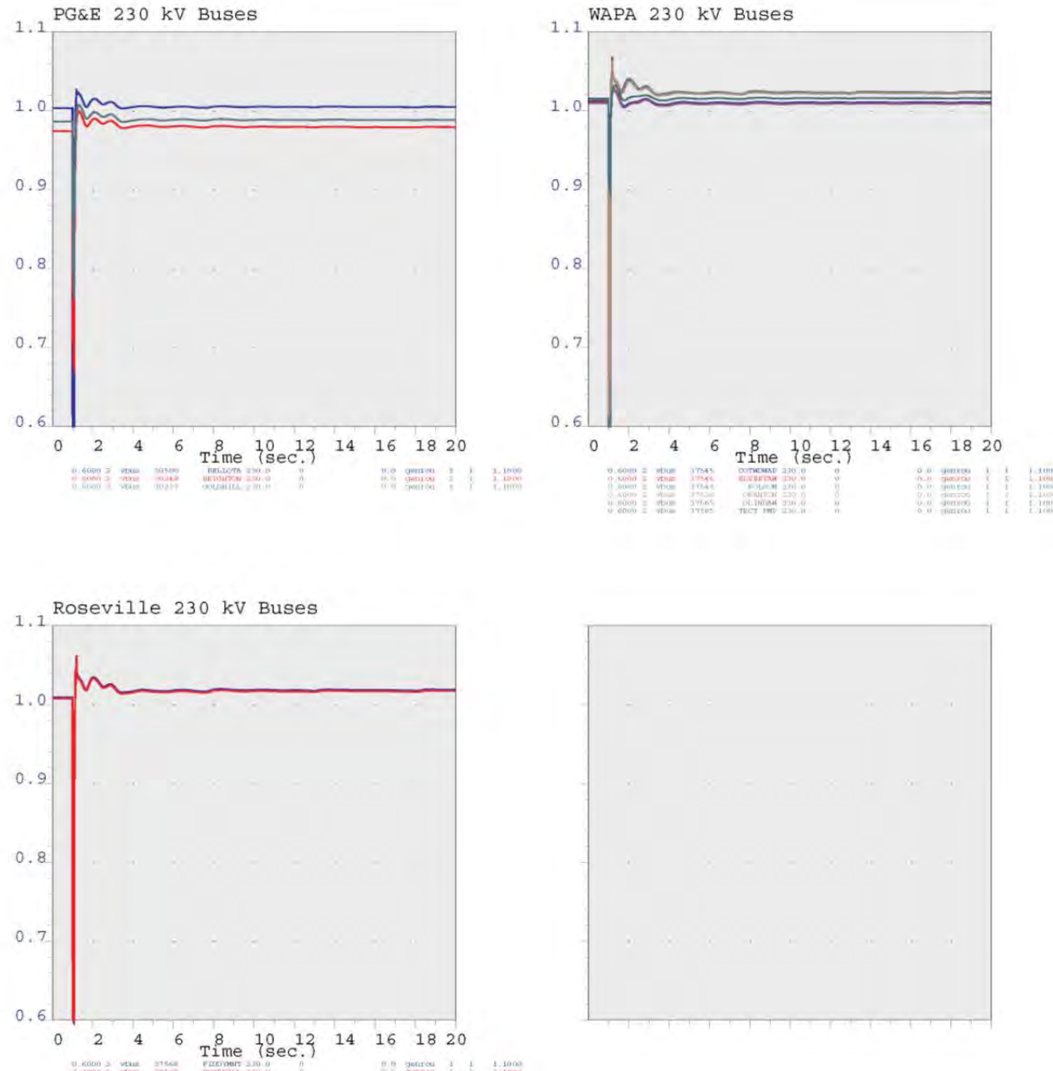
2015 Ten Year Plan Assessment - 2016 Summer Peak



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2016 HS3 OPERATING CASE
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COMMENTS DUE TO AREA COORDINATORS BY SEPTEMBER 8, 2015
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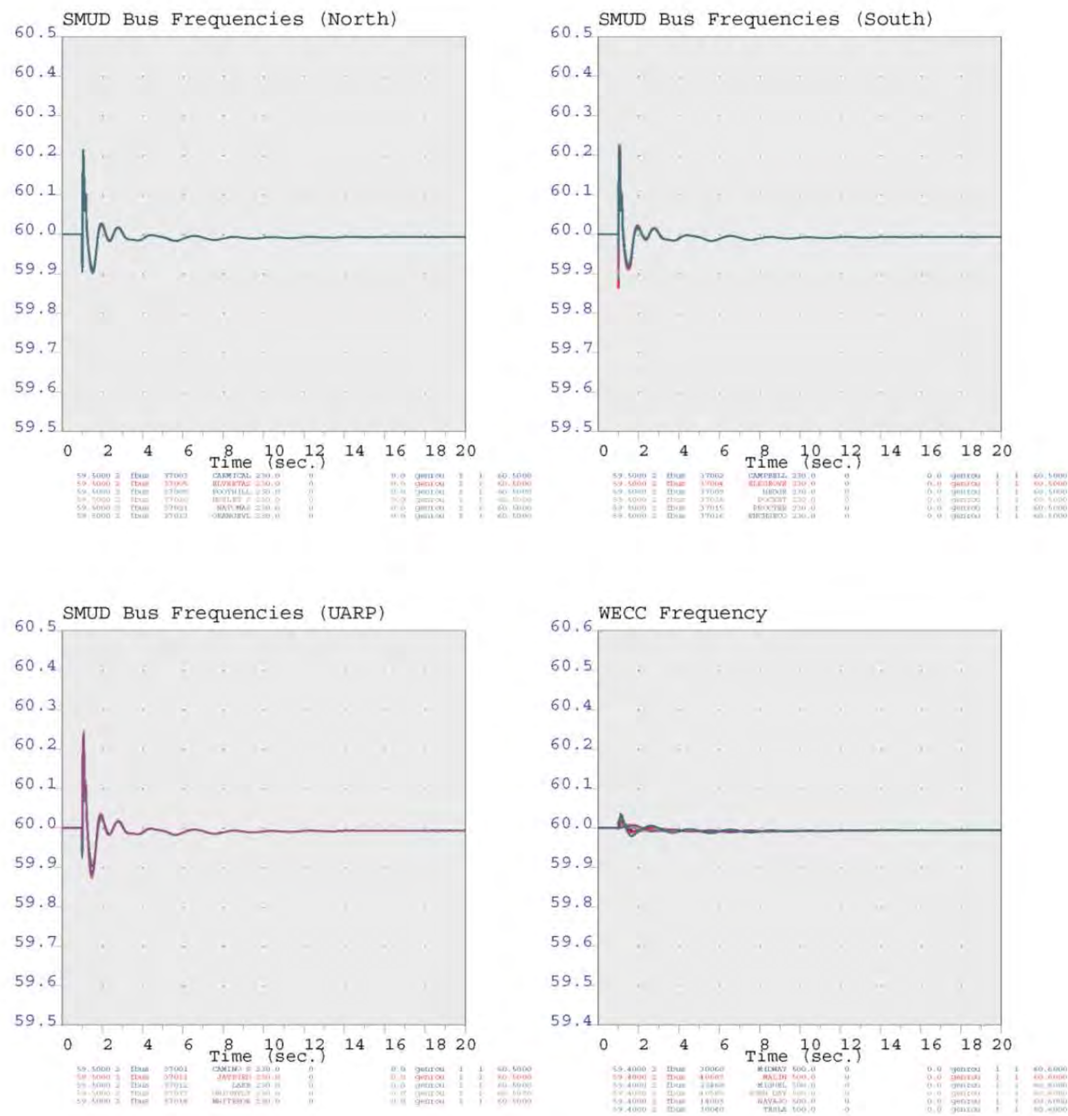
2015 Ten Year Plan Assessment - 2016 Summer Peak



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2016 HS3 OPERATING CASE
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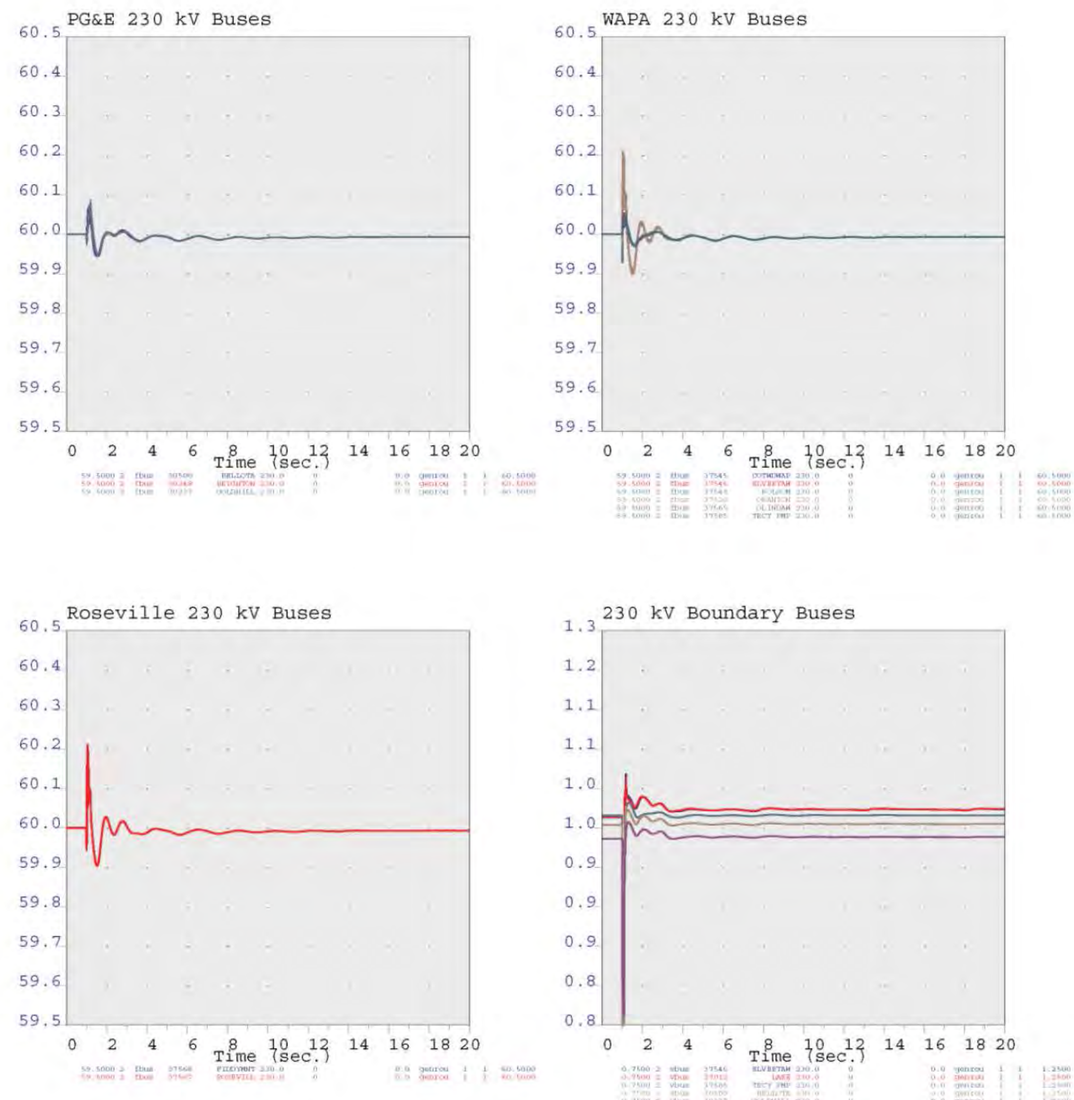
2015 Ten Year Plan Assessment - 2016 Summer Peak



16HS3_10_Cosumnes-pp
2016 HS3 OPERATING CASE
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16HS3_10_Cosumnes-pp.chf

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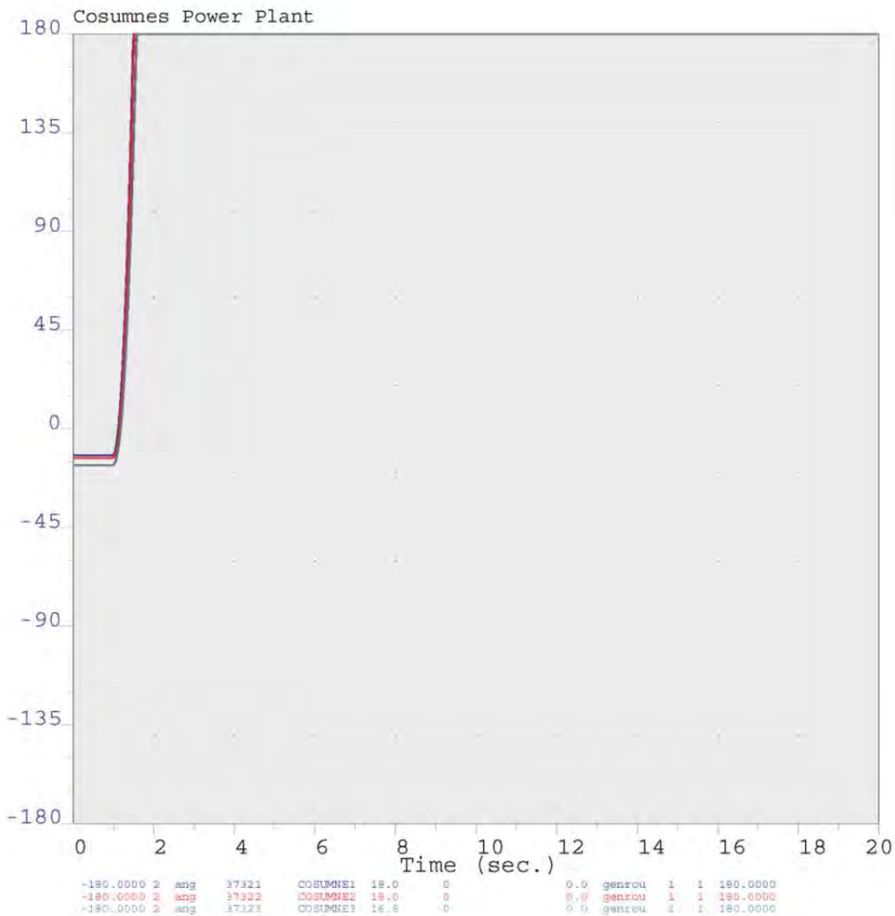
2015 Ten Year Plan Assessment - 2016 Summer Peak



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2016 HS3 OPERATING CASE
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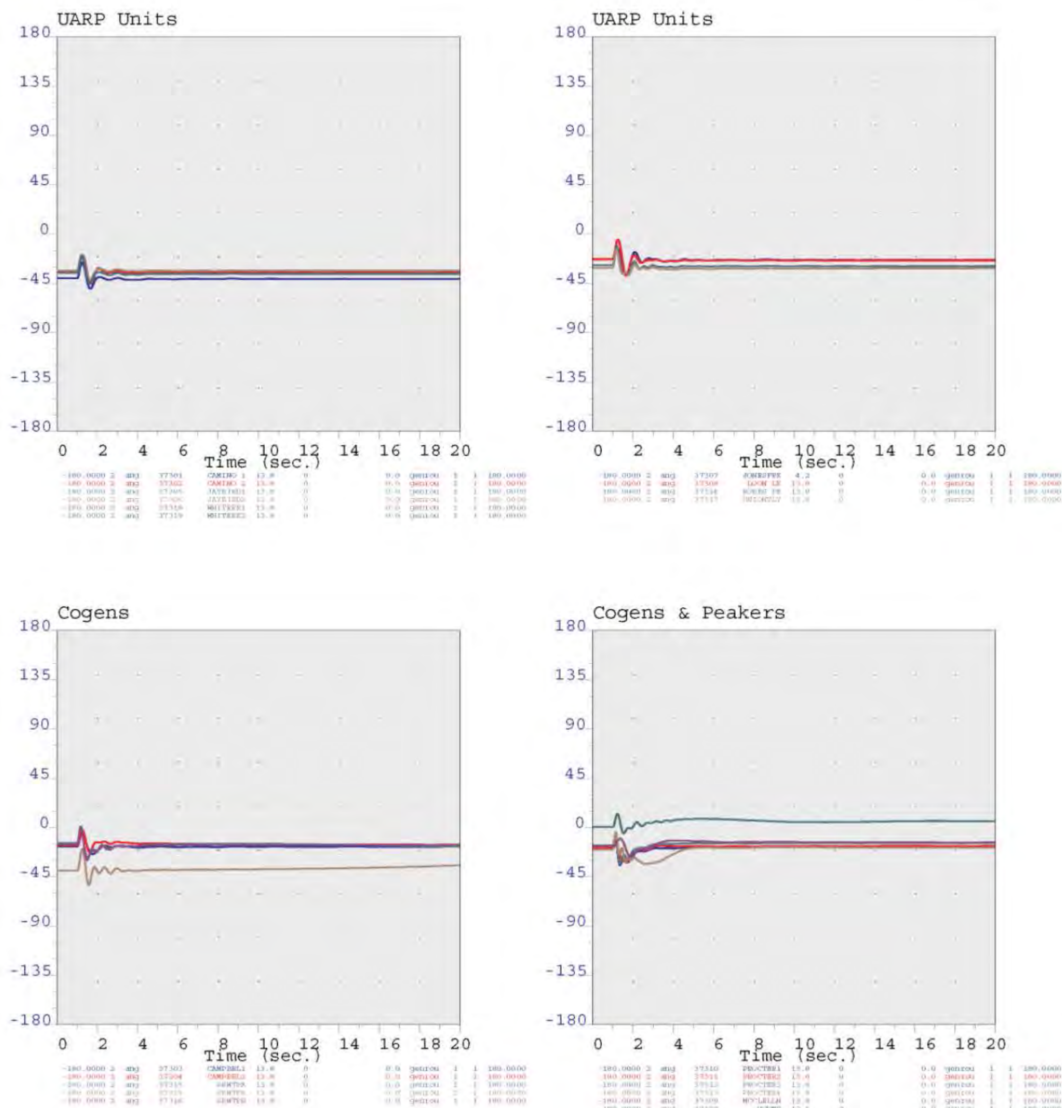
2015 Ten Year Plan Assessment - 2016 Summer Peak



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2016 HS3 OPERATING CASE
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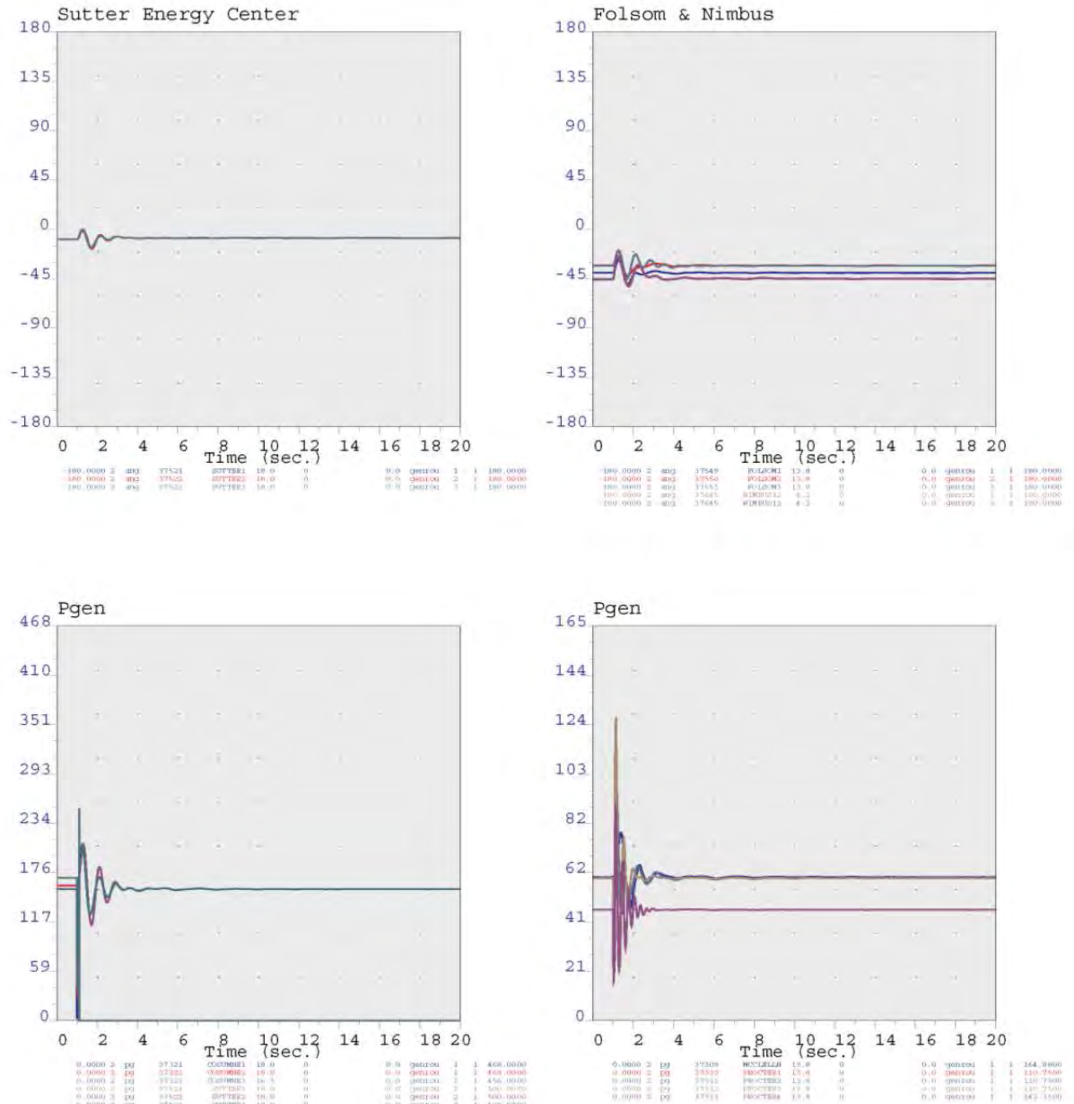
2015 Ten Year Plan Assessment - 2016 Summer Peak



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16HS3_10_Cosumnes-pp.chf

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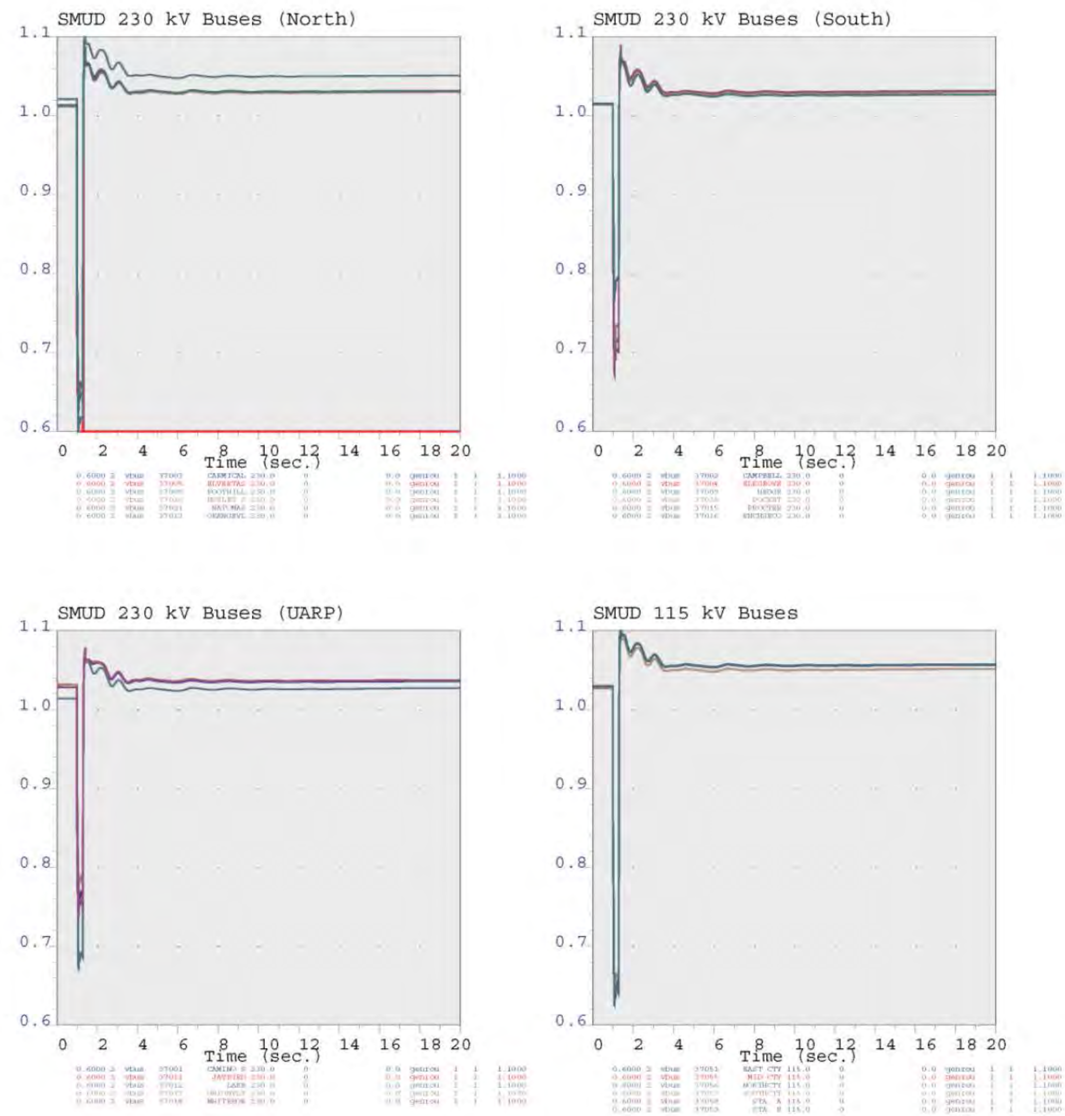
2015 Ten Year Plan Assessment - 2016 Summer Peak



16HS3_10_Elverta_bkr1182_18cycles
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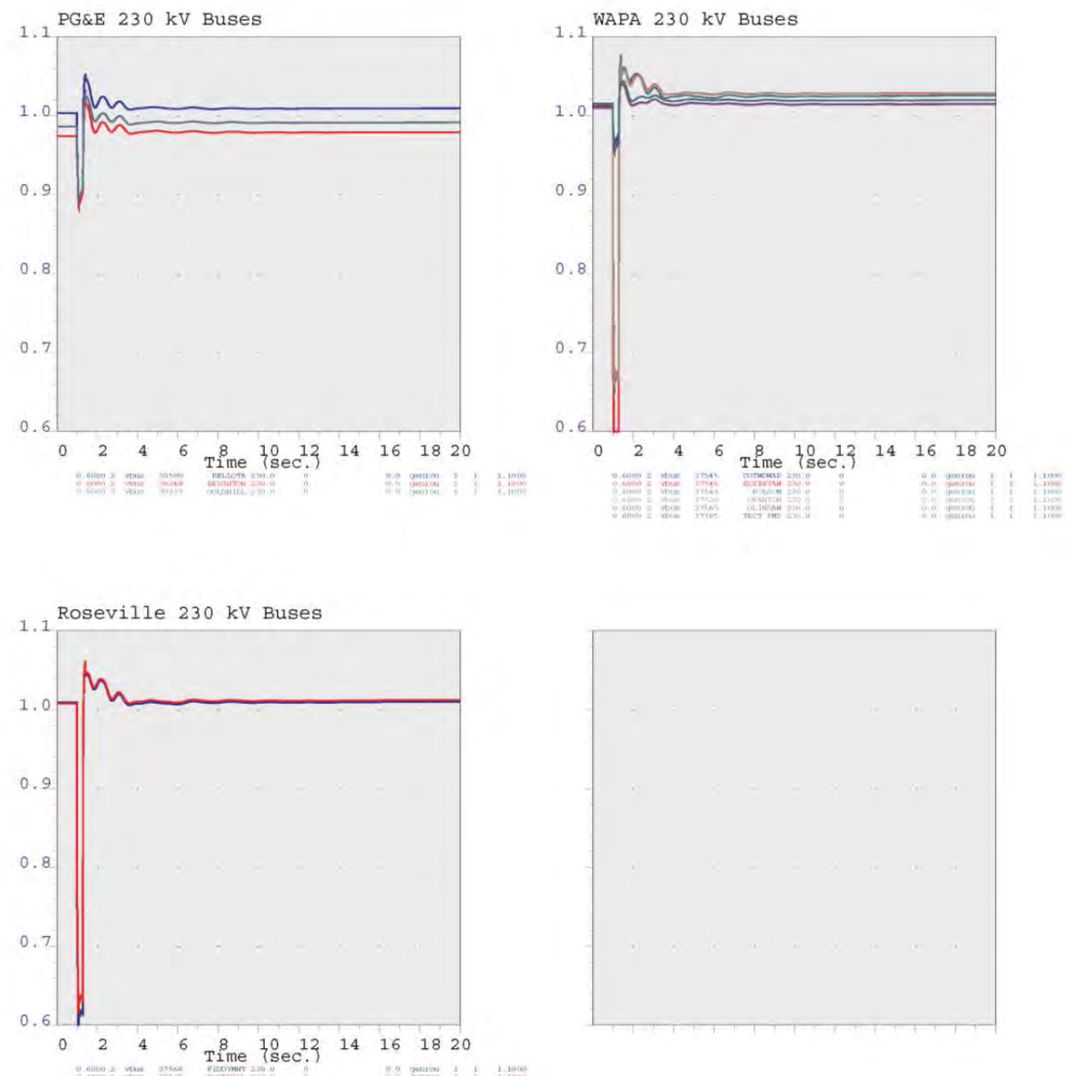
2015 Ten Year Plan Assessment - 2016 Summer Peak



16HS3_10_Elverta_bkr1182_18cycles
2016 HS3 OPERATING CASE
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16HS3_10_Elverta_bkr1182_18cycles.chf

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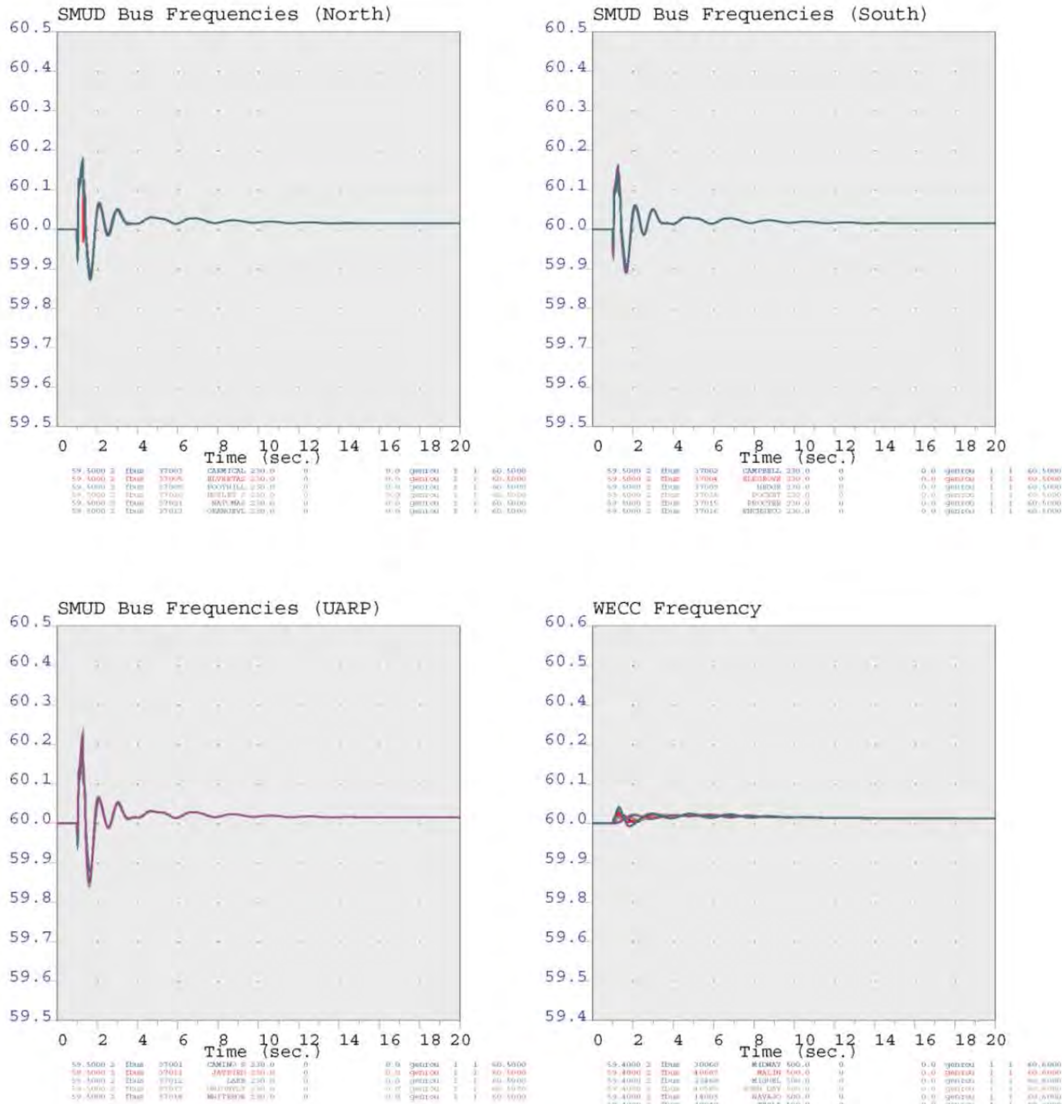
2015 Ten Year Plan Assessment - 2016 Summer Peak



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2016 HS3 OPERATING CASE
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16HS3_10_Elverta_bkr1182_18cycles.chf

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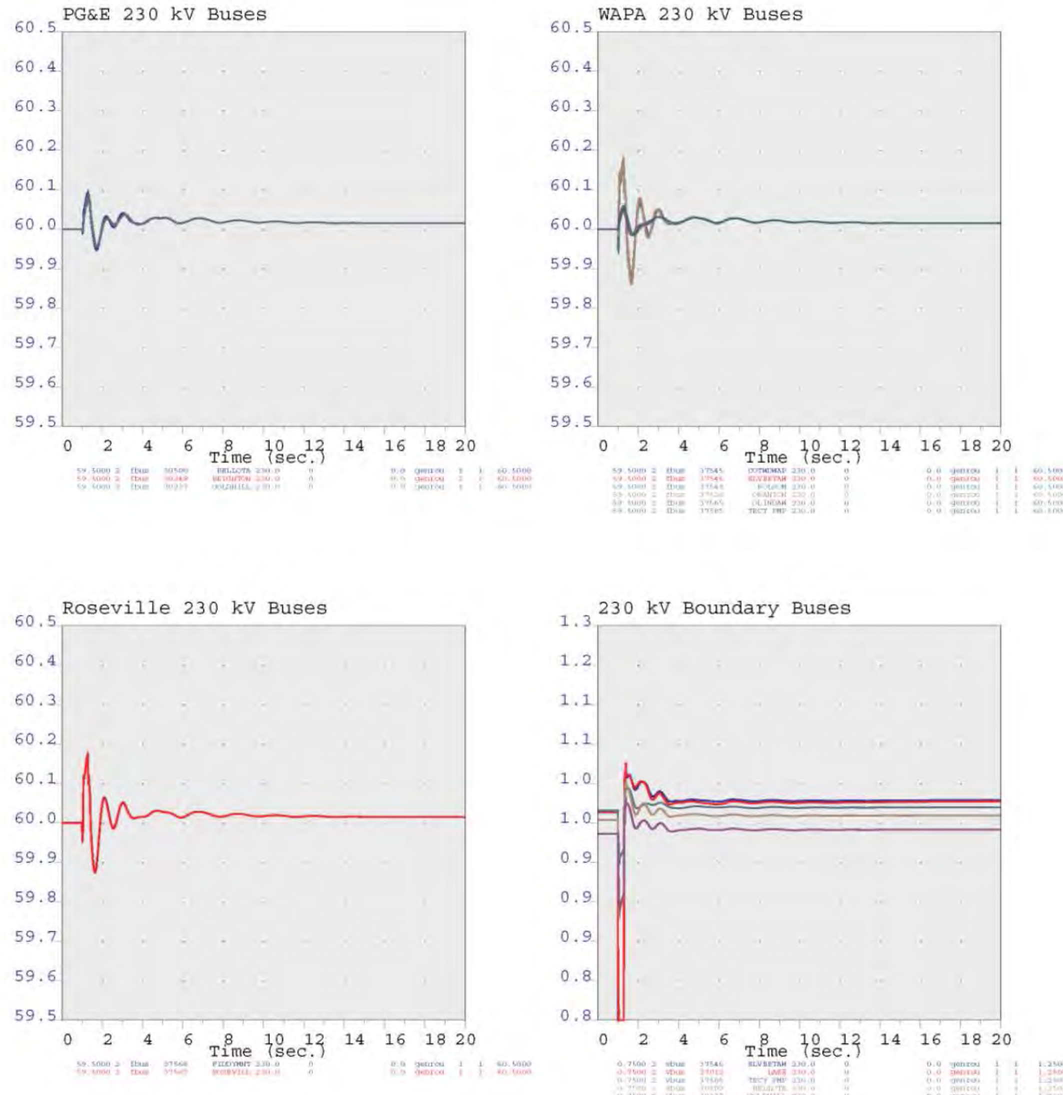
2015 Ten Year Plan Assessment - 2016 Summer Peak



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2016 HS3 OPERATING CASE
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16HS3_10_Elverta_bkr1182_18cycles.chf

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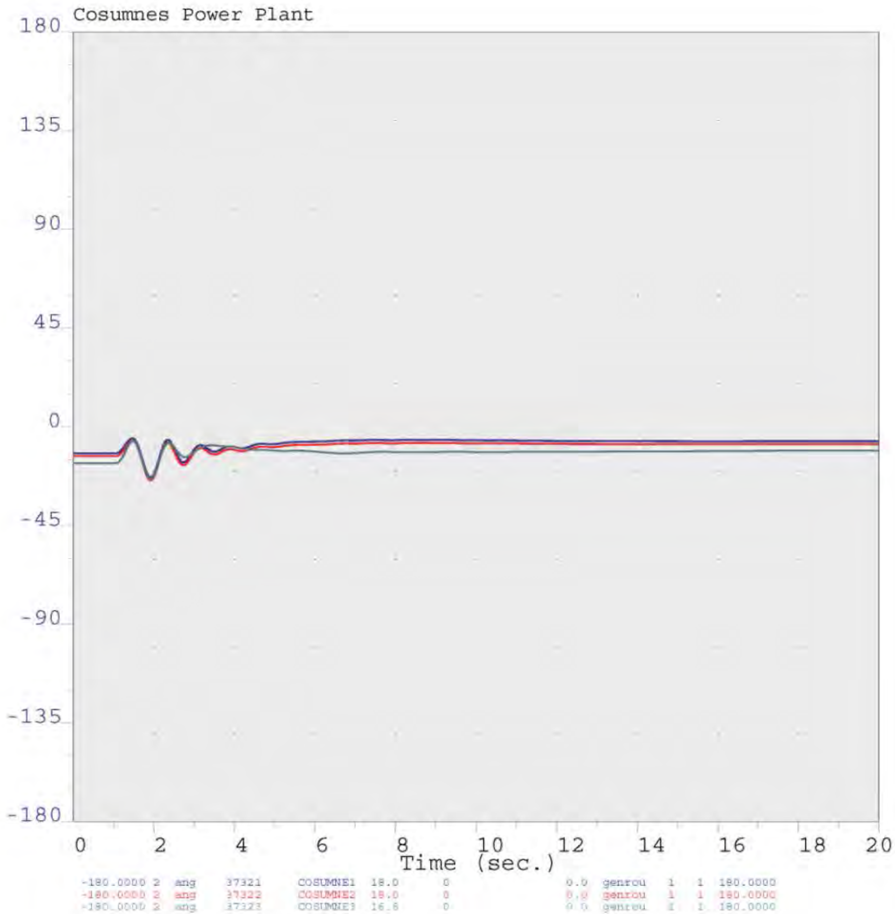
2015 Ten Year Plan Assessment - 2016 Summer Peak



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16HS3_10_Elverta_bkr1182_18cycles.chf

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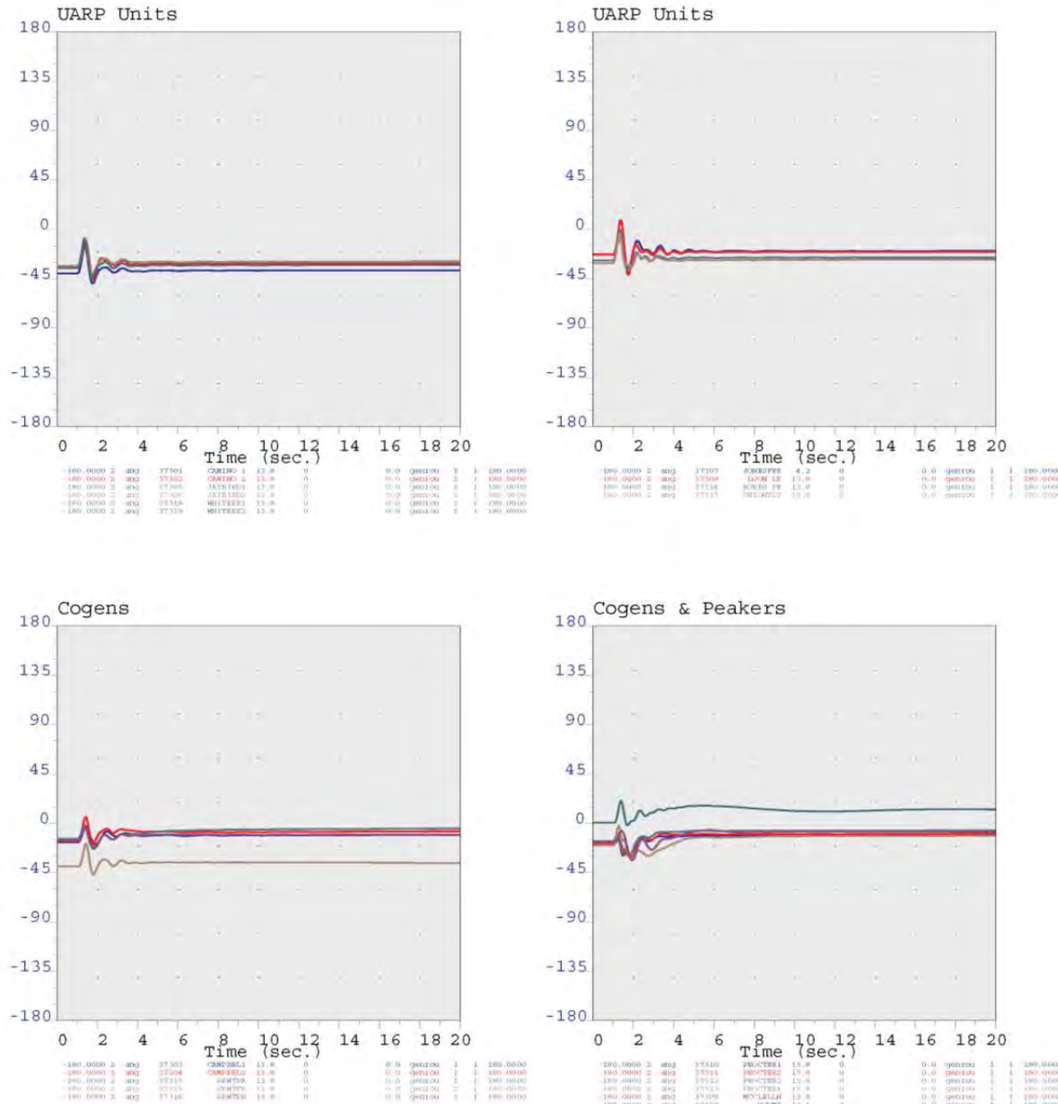
2015 Ten Year Plan Assessment - 2016 Summer Peak



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16HS3_10_Elverta_bkr1182_18cycles.chf

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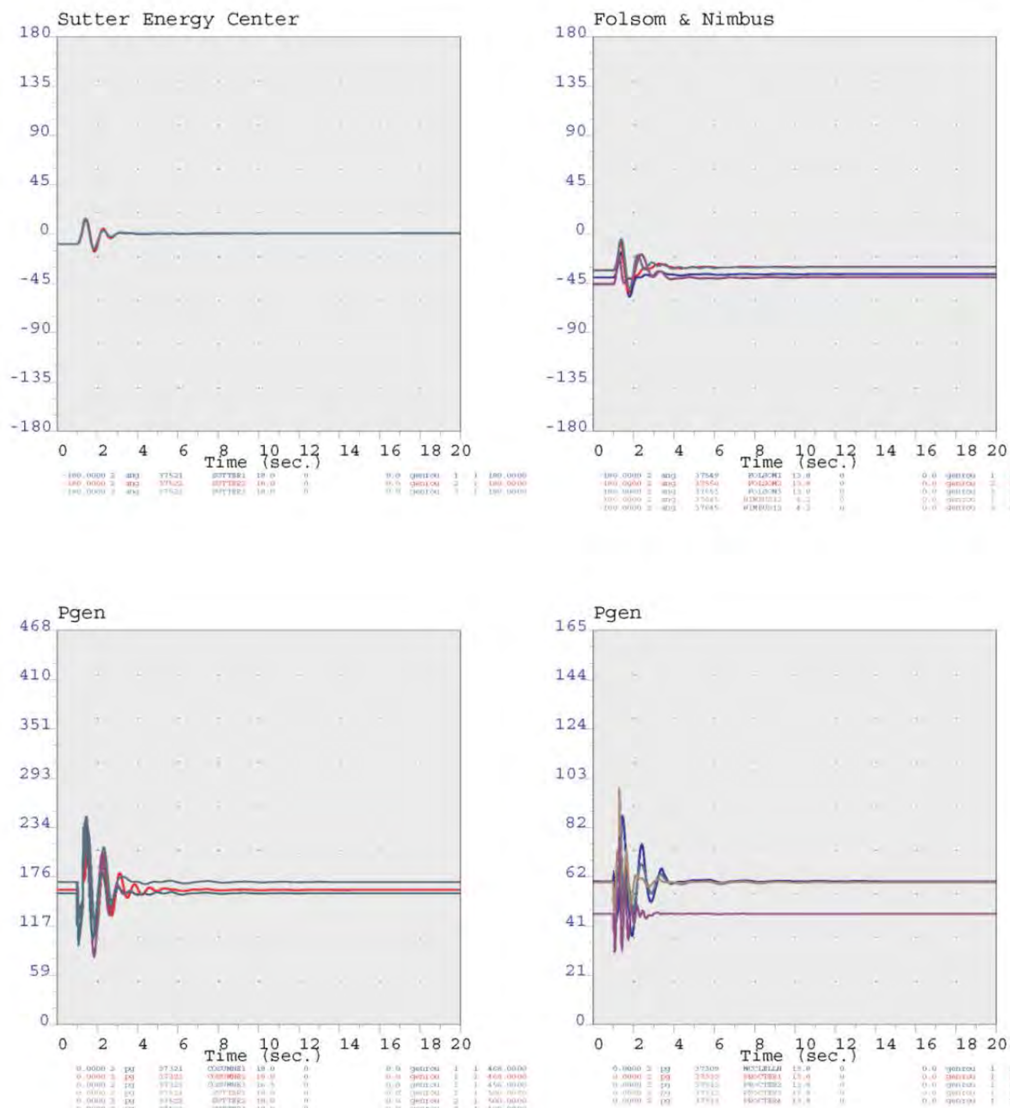
2015 Ten Year Plan Assessment - 2016 Summer Peak



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2016 HS3 OPERATING CASE
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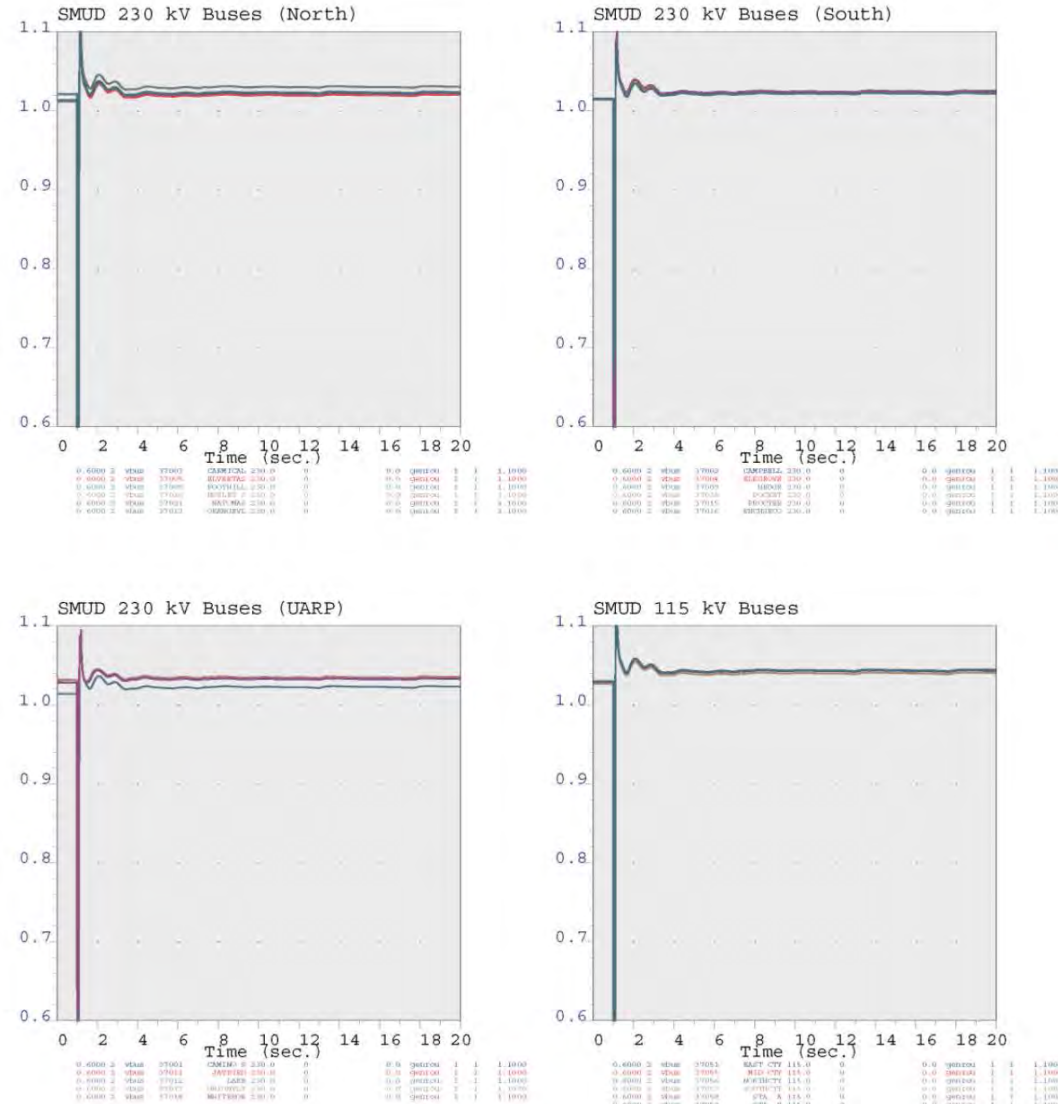
2015 Ten Year Plan Assessment - 2016 Summer Peak



16HS3_10_Obanion-Sutter-slo
2016 HS3 OPERATING CASE
AUGUST 25, 2015
COMMENTS DUE TO AREA COORDINATORS BY SEPTEMBER 8, 2015
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Page 1

16HS3_10_Obanion-Sutter-slo.chf

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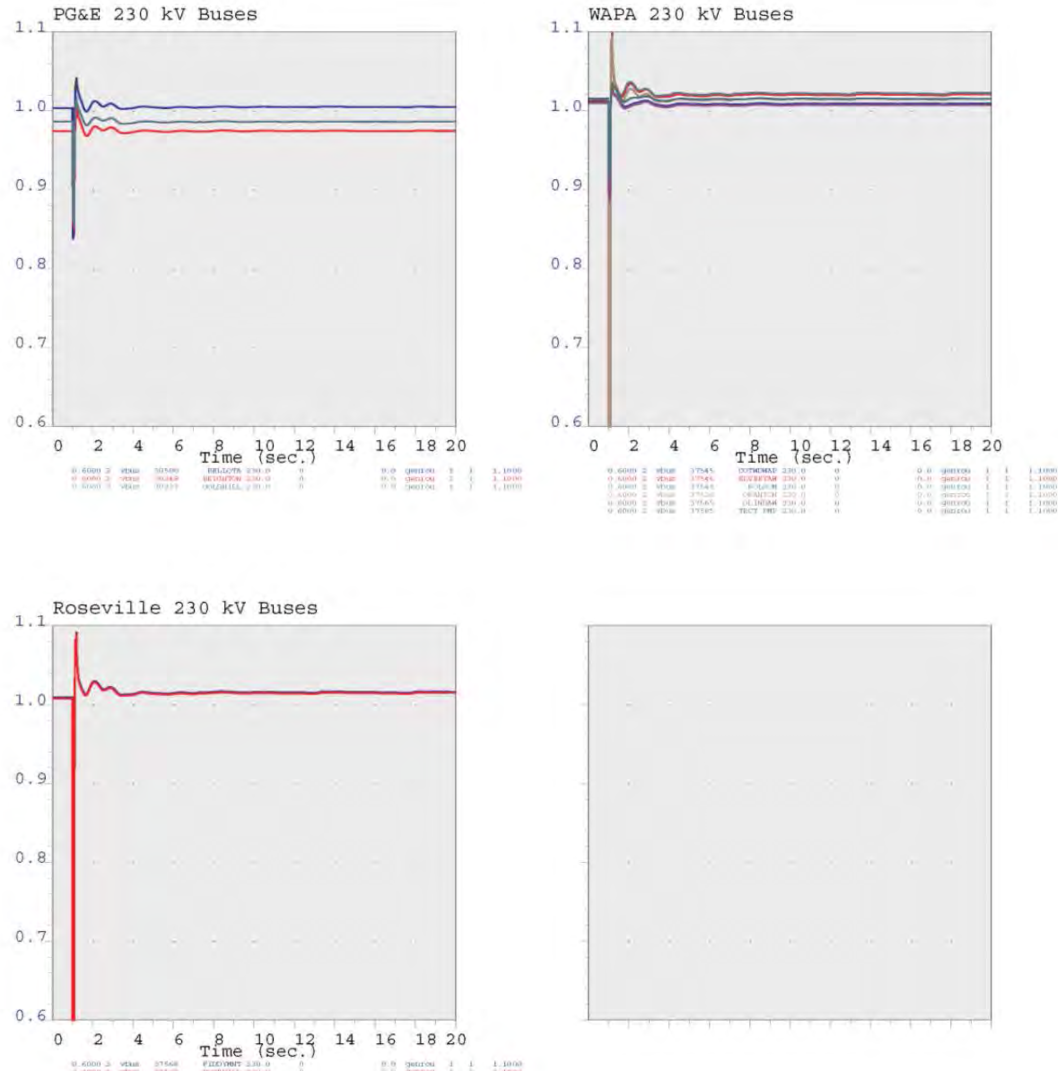
2015 Ten Year Plan Assessment - 2016 Summer Peak



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2016 HS3 OPERATING CASE
AUGUST 25, 2015
COMMENTS DUE TO AREA COORDINATORS BY SEPTEMBER 8, 2015
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16HS3_10_Obanion-Sutter-slo.chf

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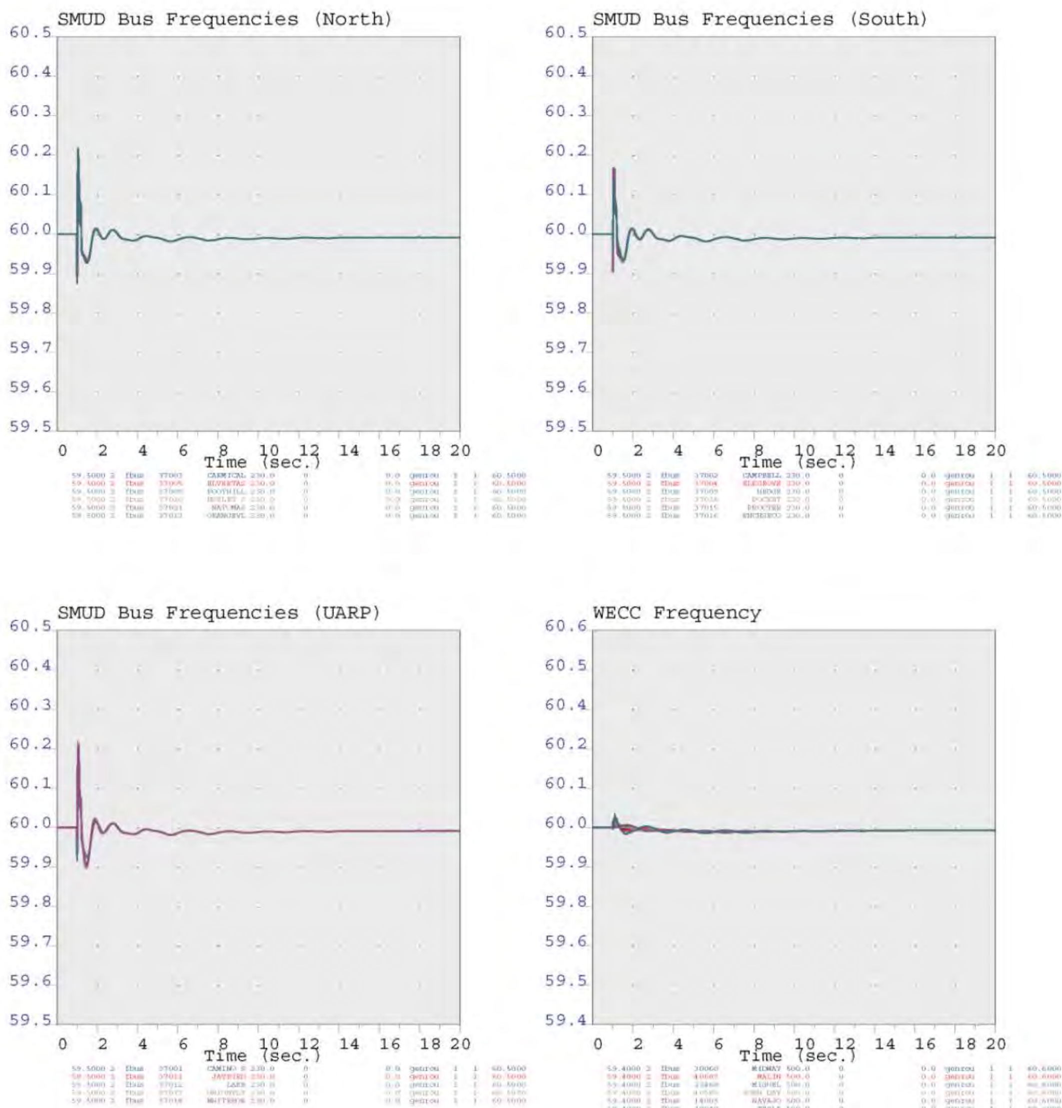
2015 Ten Year Plan Assessment - 2016 Summer Peak



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2016 HS3 OPERATING CASE
AUGUST 25, 2015
COMMENTS DUE TO AREA COORDINATORS BY SEPTEMBER 8, 2015
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16HS3_10_Obanion-Sutter-slo.chf

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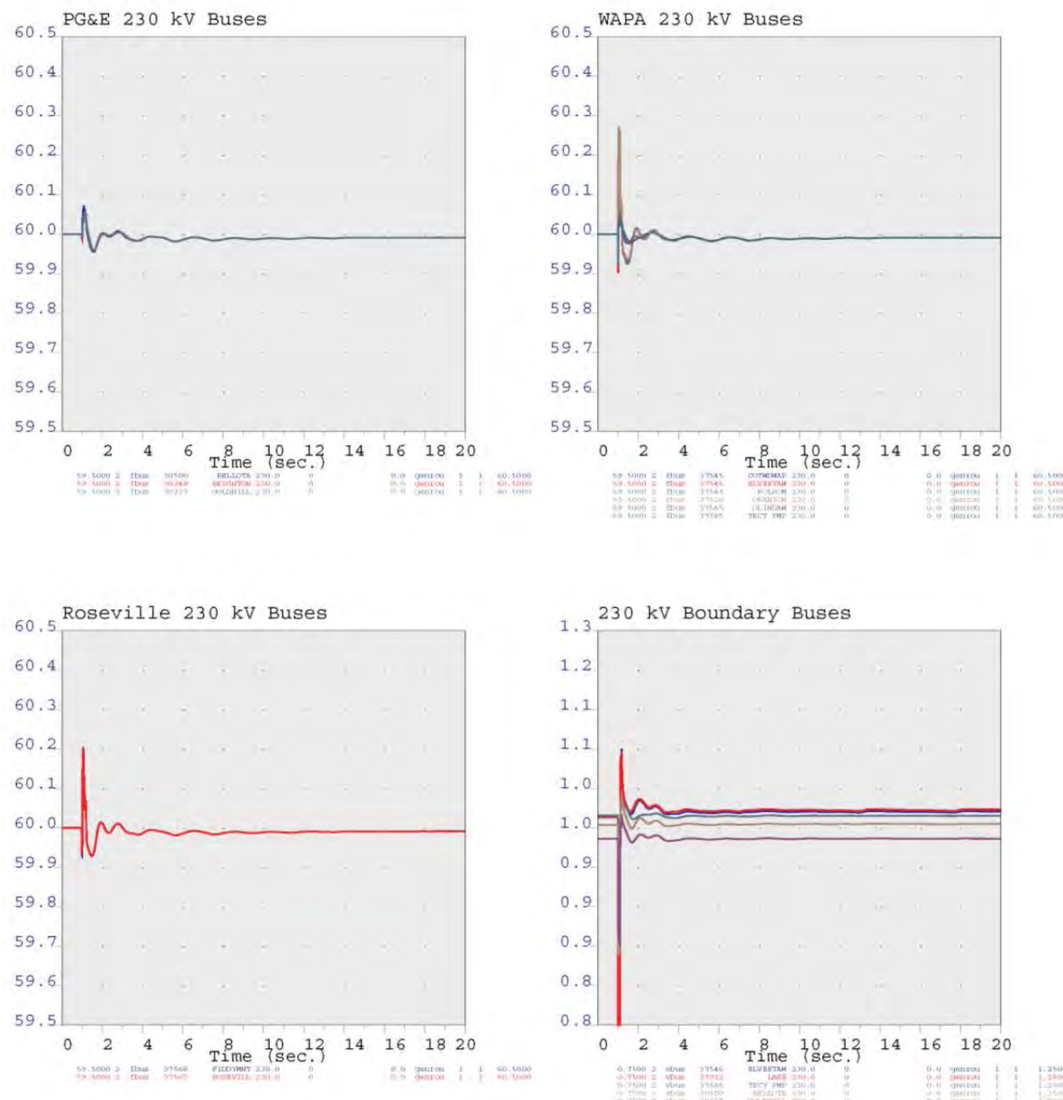
2015 Ten Year Plan Assessment - 2016 Summer Peak



16HS3_10_Obanion-Sutter-slo
2016 HS3 OPERATING CASE
AUGUST 25, 2015
COMMENTS DUE TO AREA COORDINATORS BY SEPTEMBER 8, 2015
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16HS3_10_Obanion-Sutter-slo.chf

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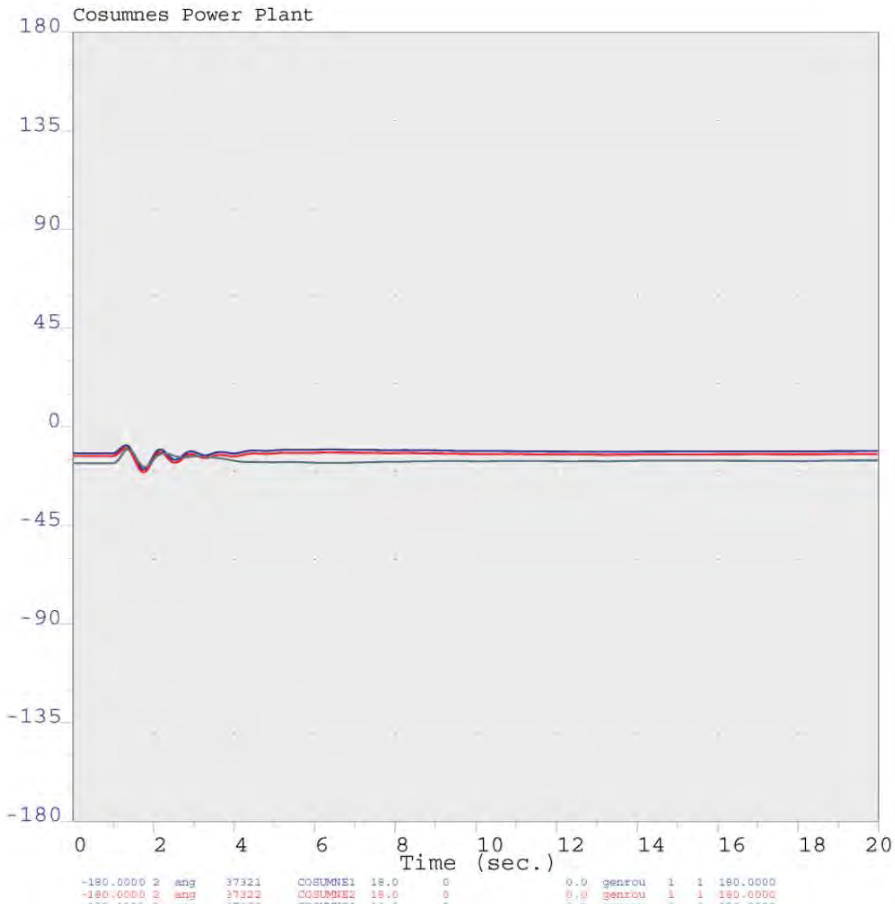
2015 Ten Year Plan Assessment - 2016 Summer Peak



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2016 HS3 OPERATING CASE
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16HS3_10_Obanion-Sutter-slo.chf

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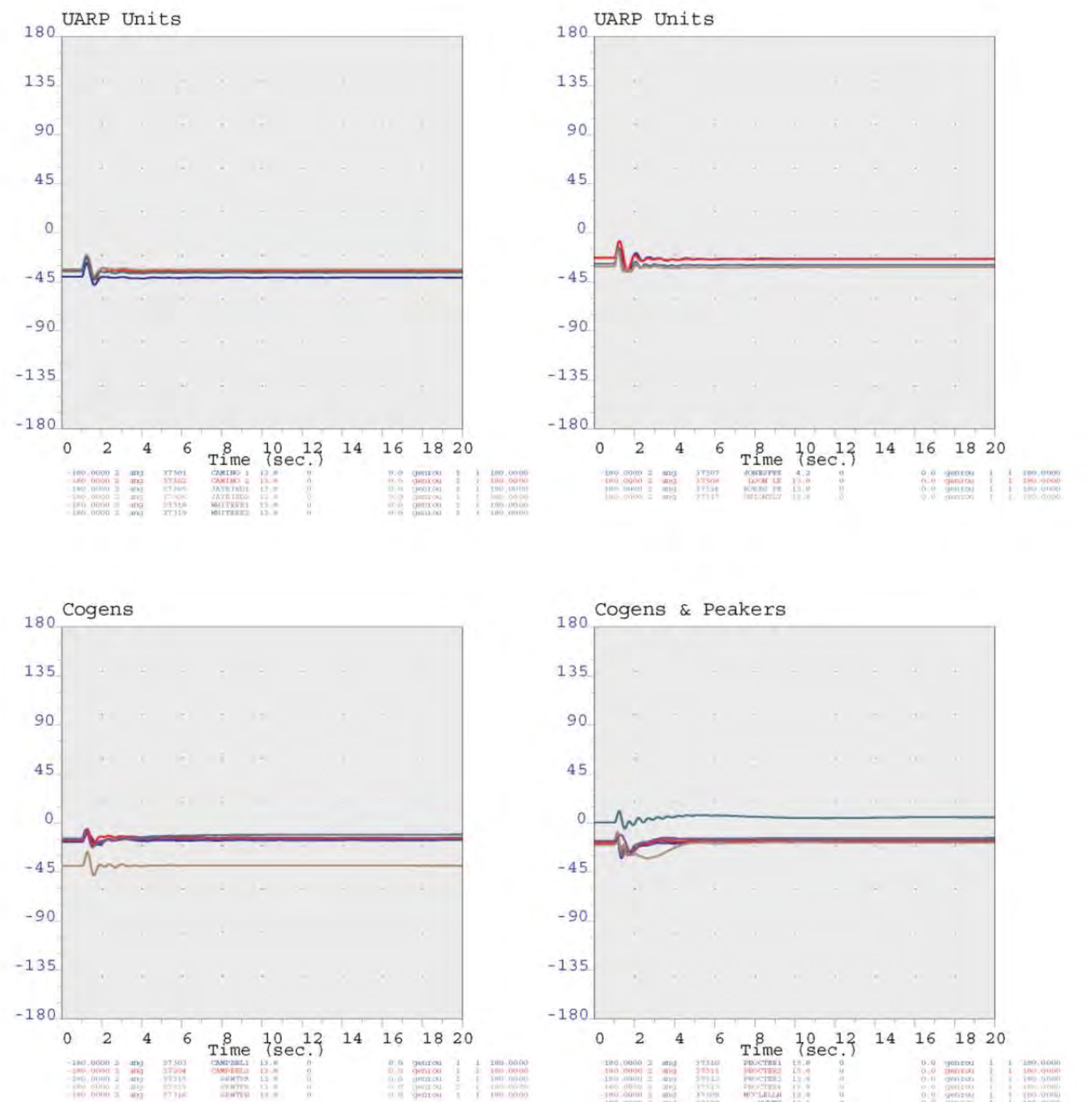
2015 Ten Year Plan Assessment - 2016 Summer Peak



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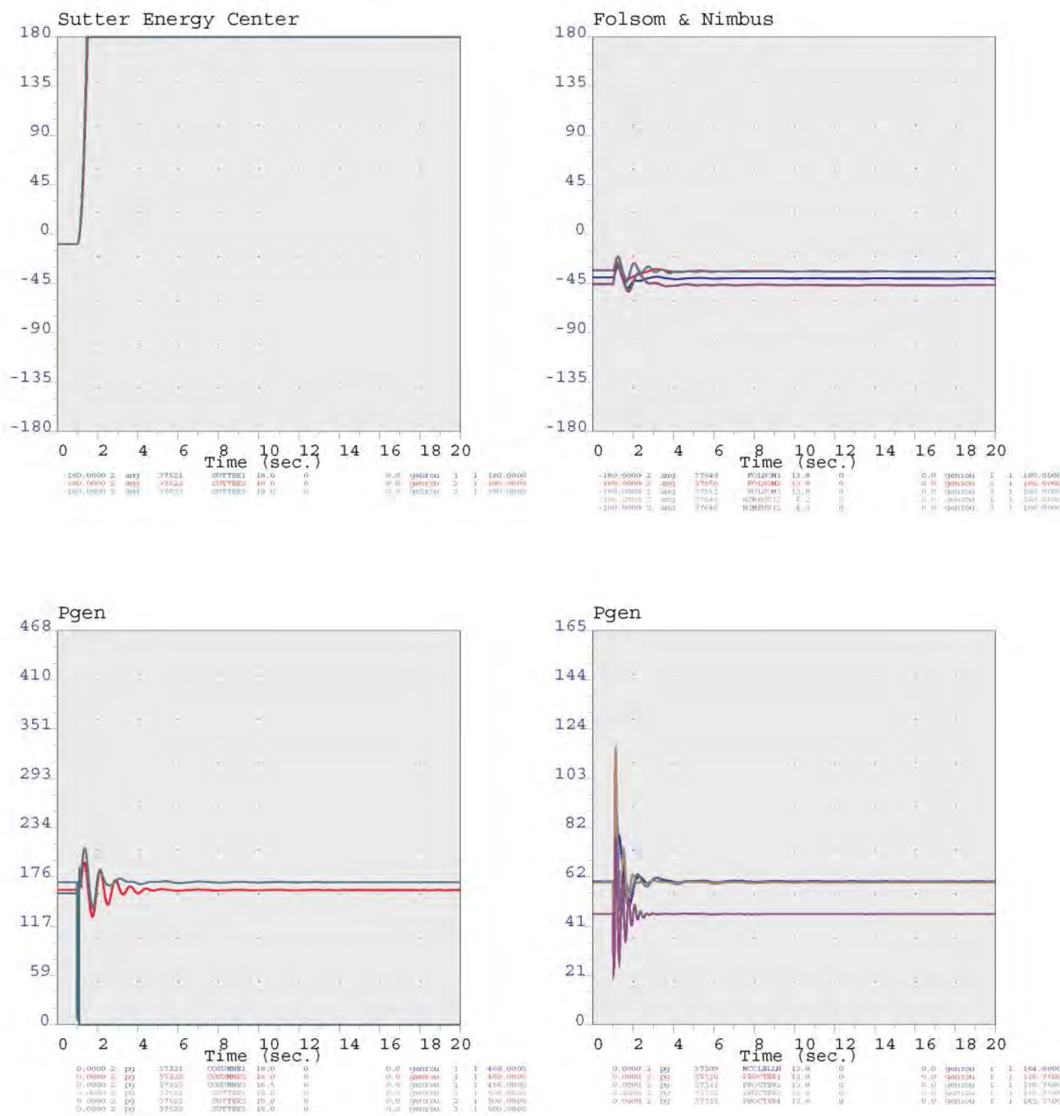
GE	16HS3_10_Obanion-Sutter-slo.chf	. Tue Oct 27 11:37:54 2015

2015 Ten Year Plan Assessment - 2016 Summer Peak



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2016 HS3 OPERATING CASE
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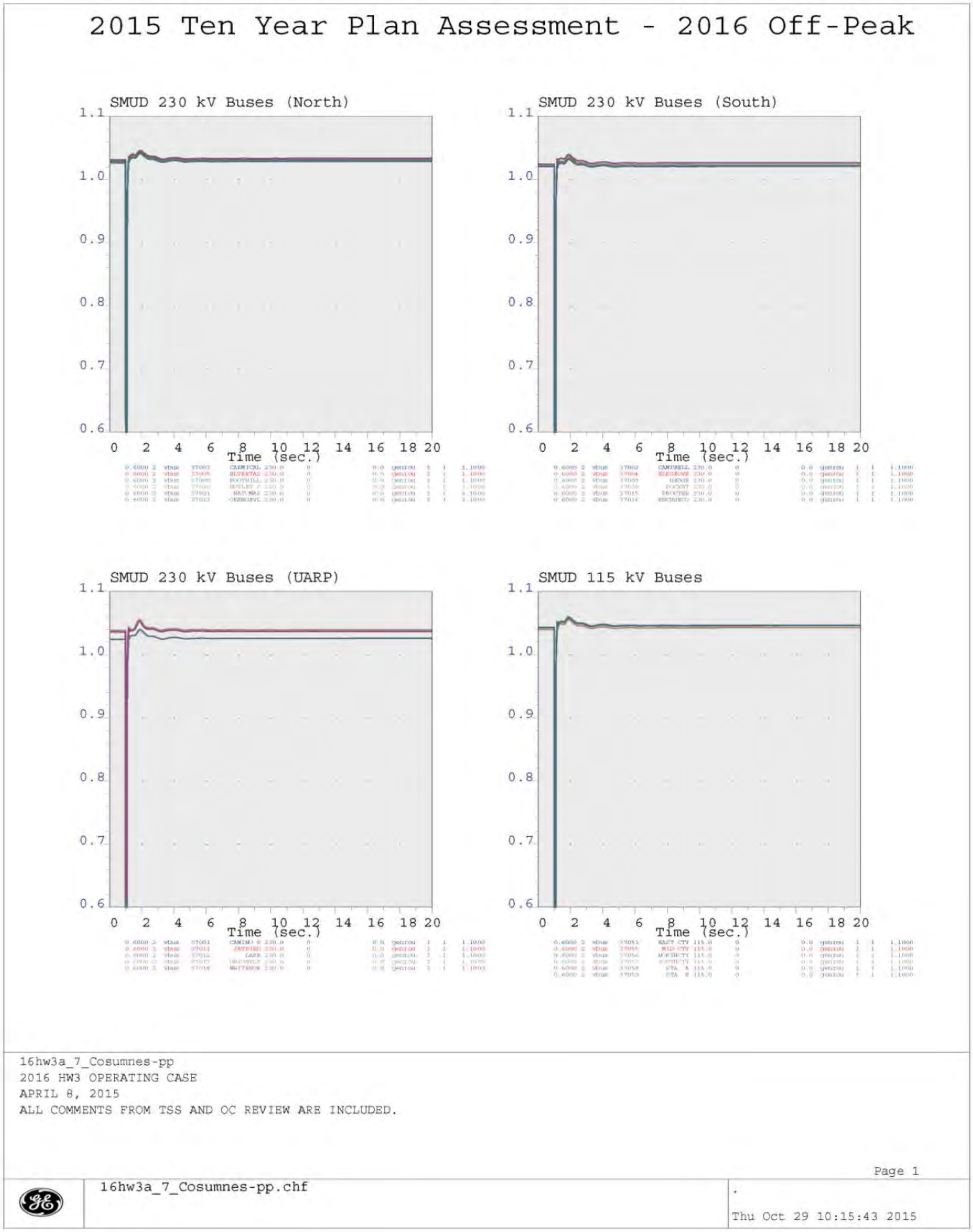
16HS3_10_Obanion-Sutter-slo.chf

Tue Oct 27 11:37:54 2015

The following are plots for contingencies on the 2016 Summer Off-Peak case.


2015 Ten Year Plan Assessment - 2016 Off-Peak
SMUD 230 kV Buses (North)
SMUD 230 kV Buses (South)
SMUD 230 kV Buses (UARP)
SMUD 115 kV Buses
1.1
1.0
0.9
0.8
0.7
0.6
0 2 4 6 8 10 12 14 16 18 20
Time (sec.)
16hw3a_7_Cosumnes-pp
2016 HW3 OPERATING CASE
APRIL 8, 2015
ALL COMMENTS FROM TSS AND OC REVIEW ARE INCLUDED.
Page 1
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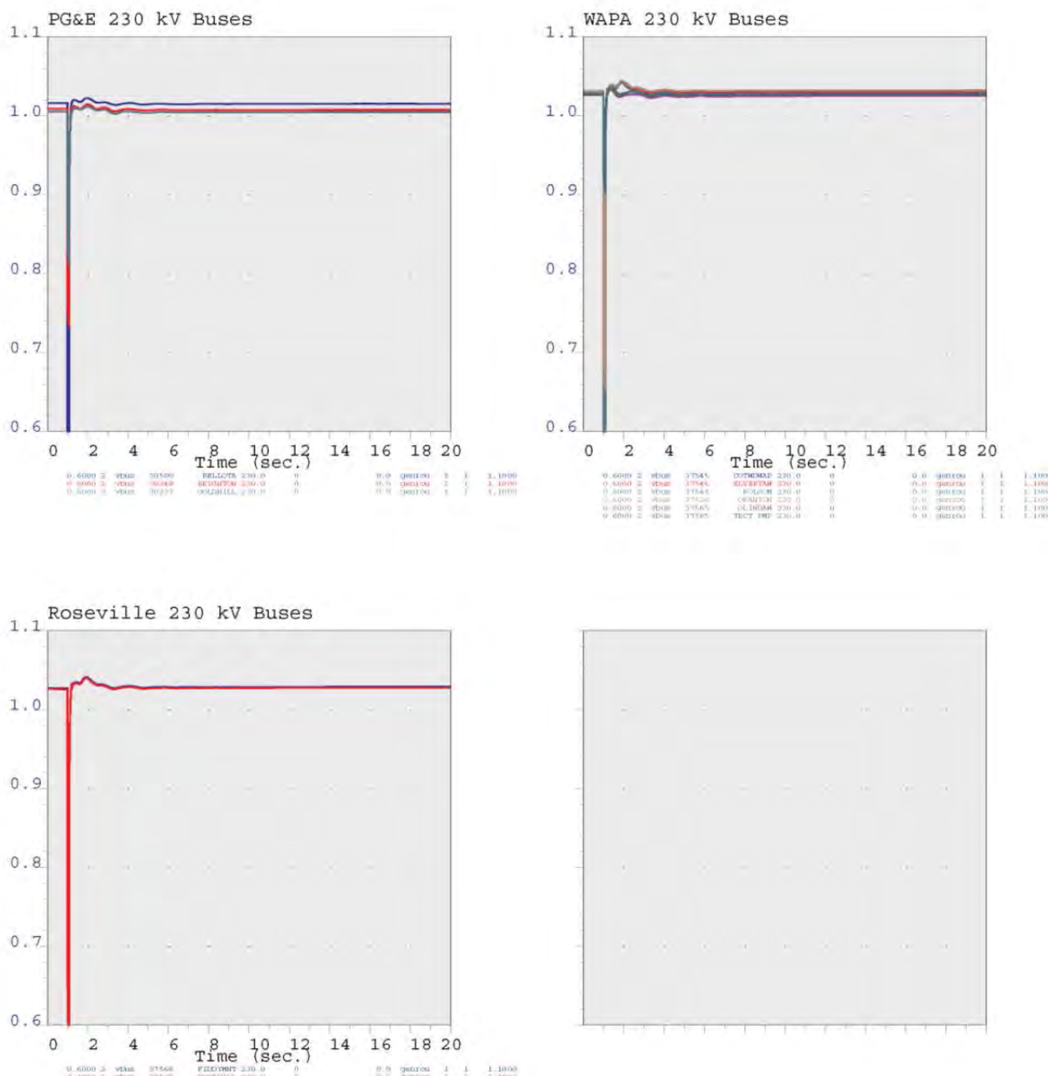
Thu Oct 29 10:15:43 2015

2015 Ten Year Plan Assessment - 2016 Off-Peak



16hw3a_7_Cosumnes-pp
2016 HW3 OPERATING CASE
APRIL 8, 2015
ALL COMMENTS FROM TSS AND OC REVIEW ARE INCLUDED.

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16hw3a_7_Cosumnes-pp.chf

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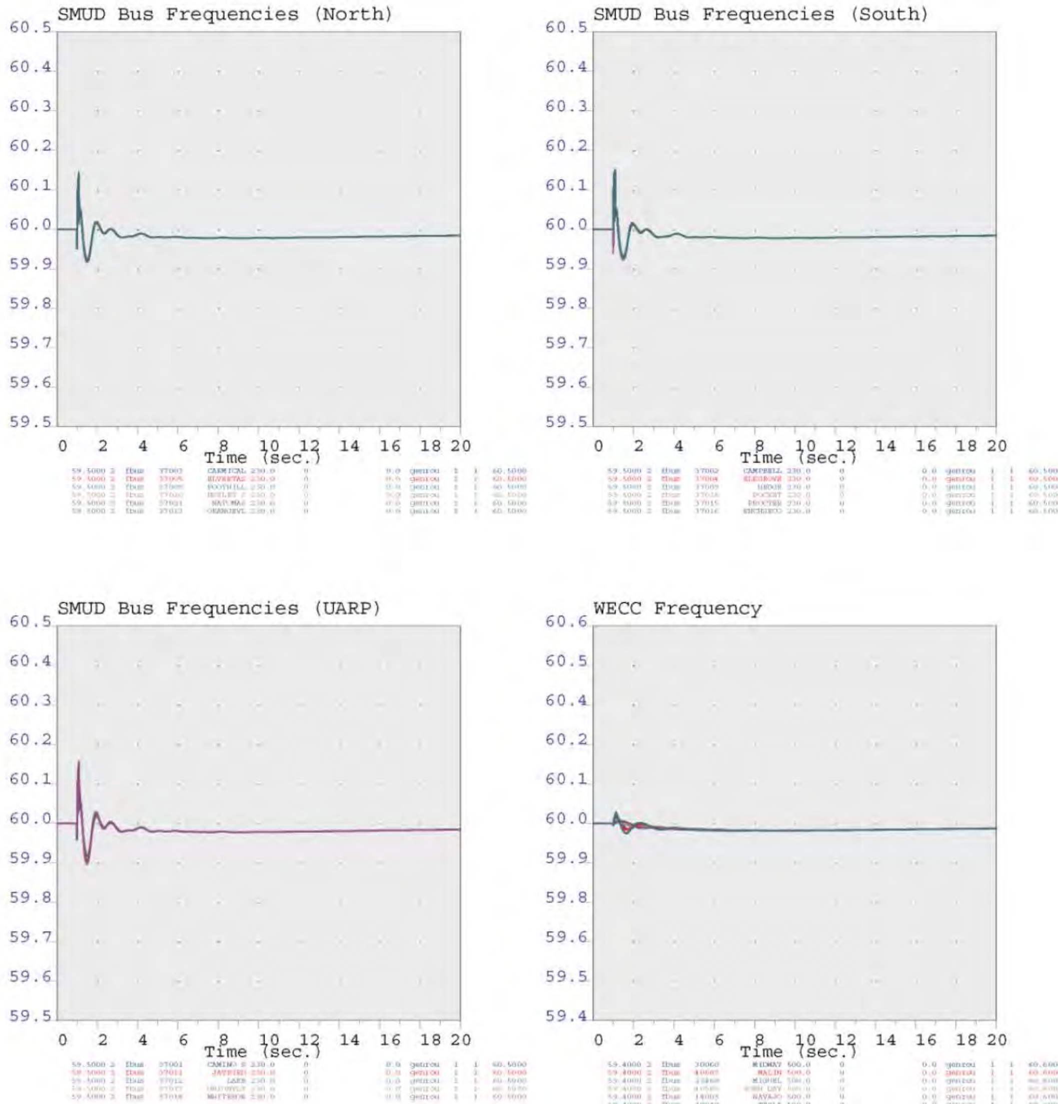
2015 Ten Year Plan Assessment - 2016 Off-Peak



16hw3a_7_Cosumnes-pp
2016 HW3 OPERATING CASE
APRIL 8, 2015
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16hw3a_7_Cosumnes-pp.chf

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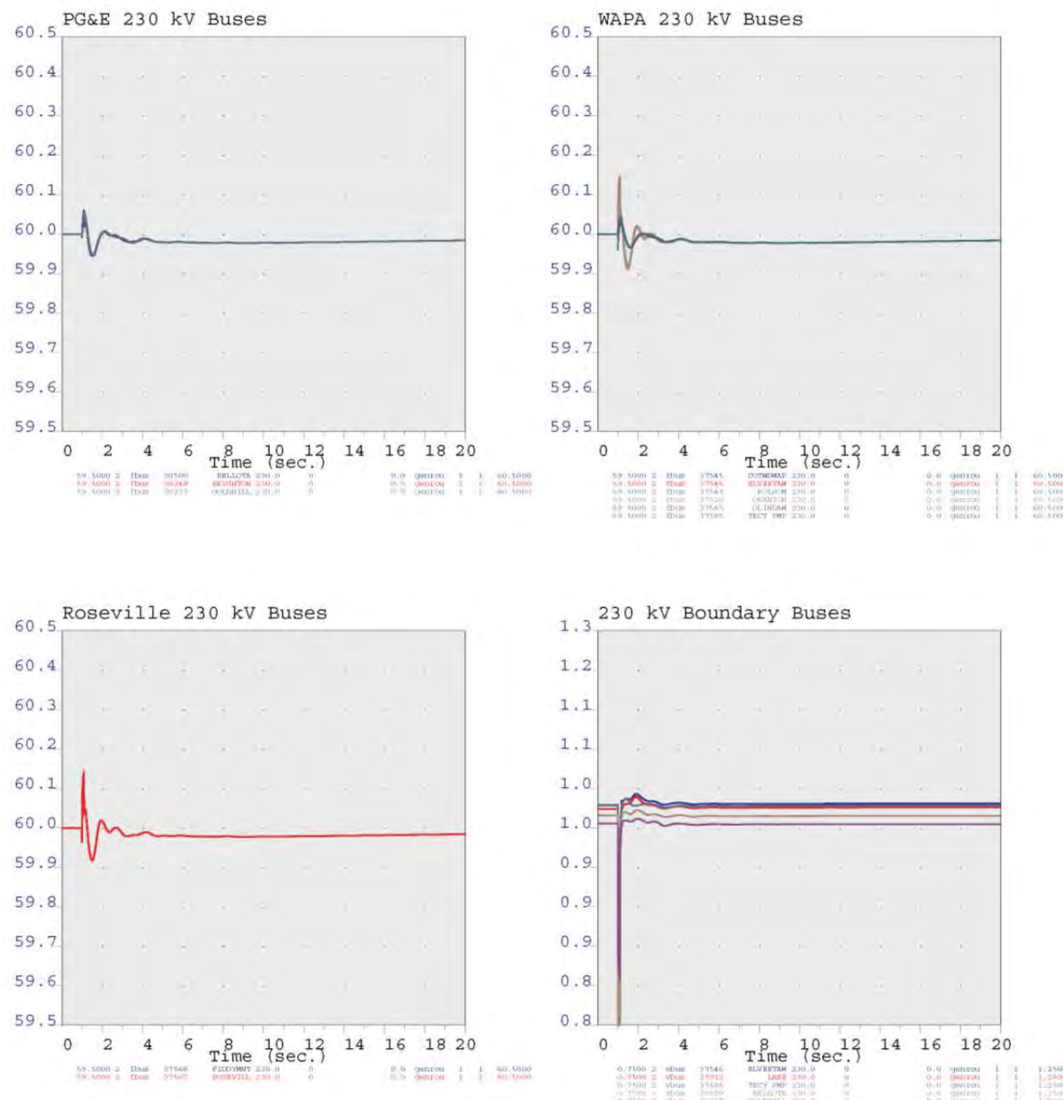
2015 Ten Year Plan Assessment - 2016 Off-Peak



16hw3a_7_Cosumnes-pp
2016 HW3 OPERATING CASE
APRIL 8, 2015
ALL COMMENTS FROM TSS AND OC REVIEW ARE INCLUDED.

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16hw3a_7_Cosumnes-pp.chf

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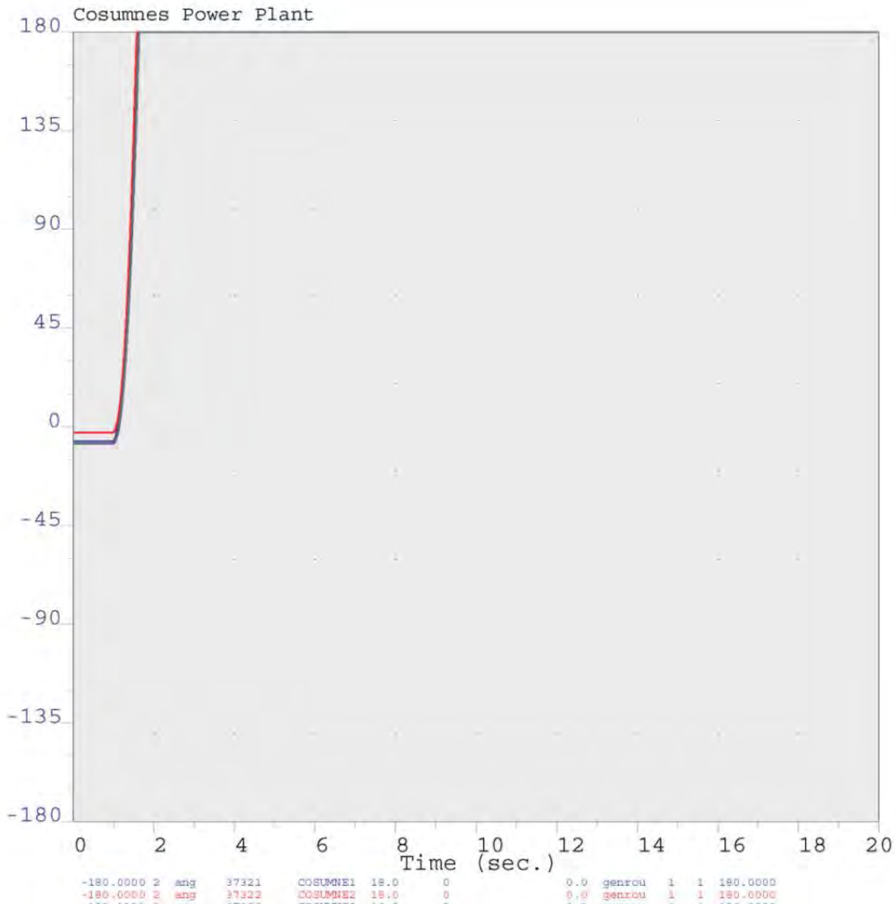
2015 Ten Year Plan Assessment - 2016 Off-Peak



16hw3a_7_Cosumnes-pp
2016 HW3 OPERATING CASE
APRIL 8, 2015
ALL COMMENTS FROM TSS AND OC REVIEW ARE INCLUDED.

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16hw3a_7_Cosumnes-pp.chf

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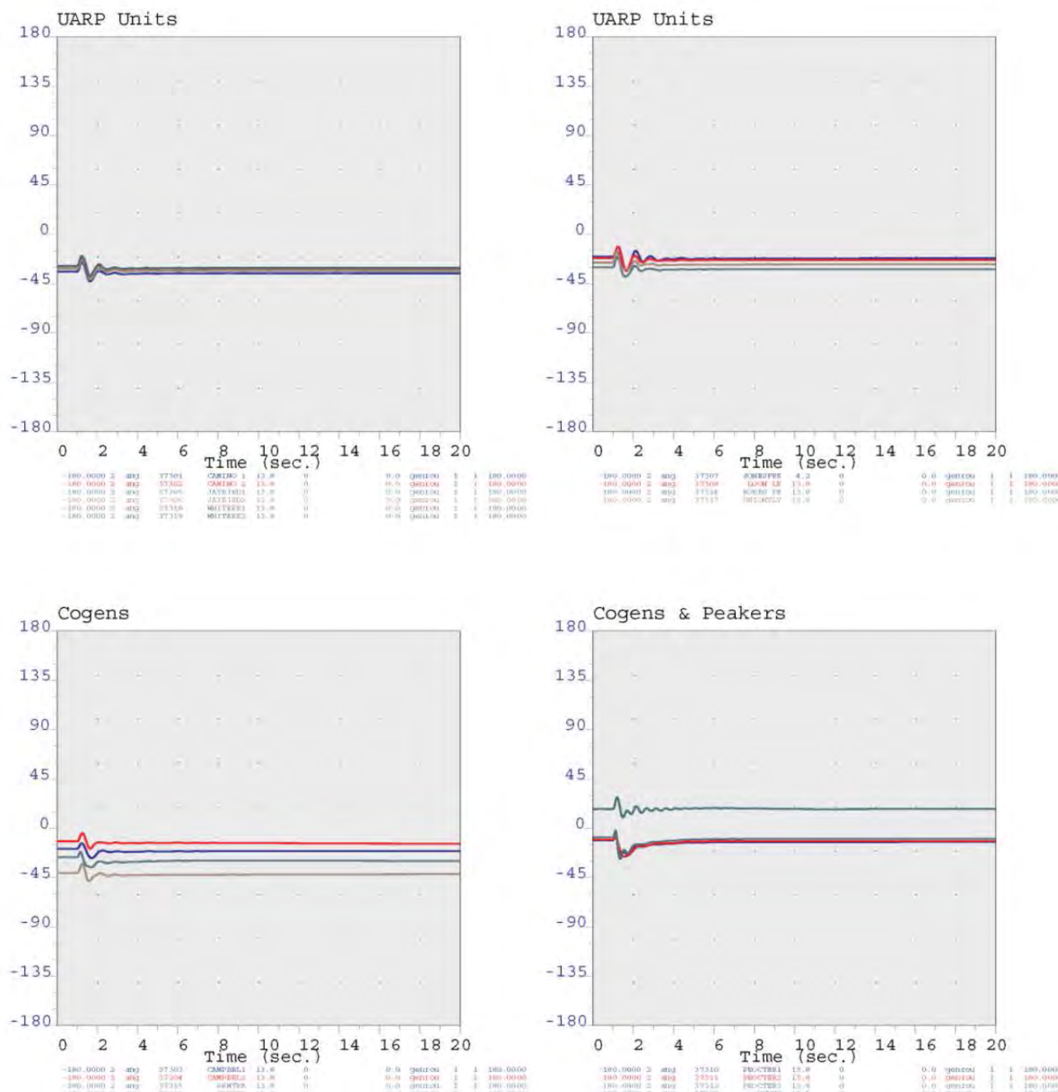
2015 Ten Year Plan Assessment - 2016 Off-Peak



16hw3a_7_Cosumnes-pp
2016 HW3 OPERATING CASE
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16hw3a_7_Cosumnes-pp.chf

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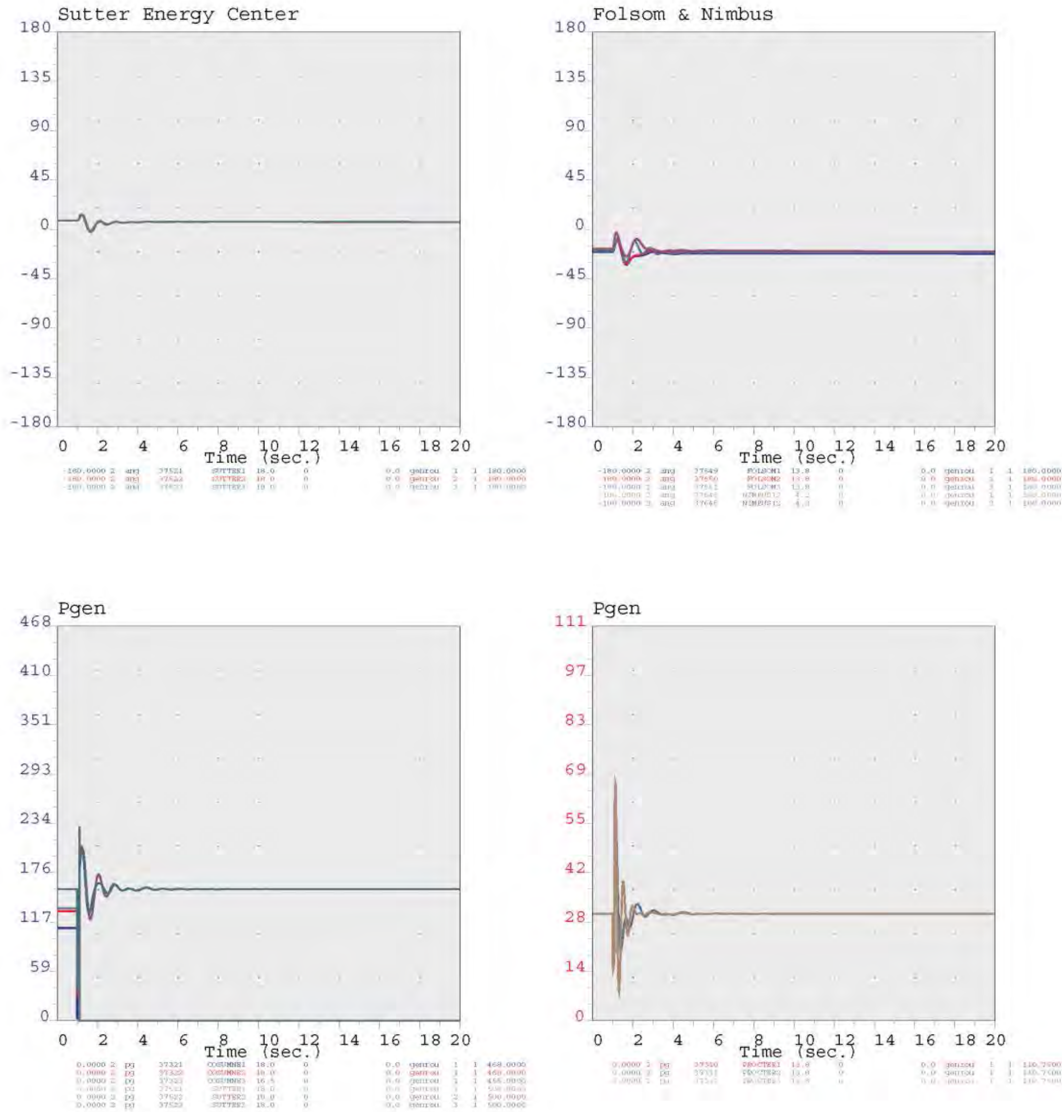
2015 Ten Year Plan Assessment - 2016 Off-Peak



16hw3a_7_Cosumnes-pp
2016 HW3 OPERATING CASE
APRIL 8, 2015
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16hw3a_7_Cosumnes-pp.chf

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The following are plots for contingencies on the 2020 Adverse Summer Peak case.

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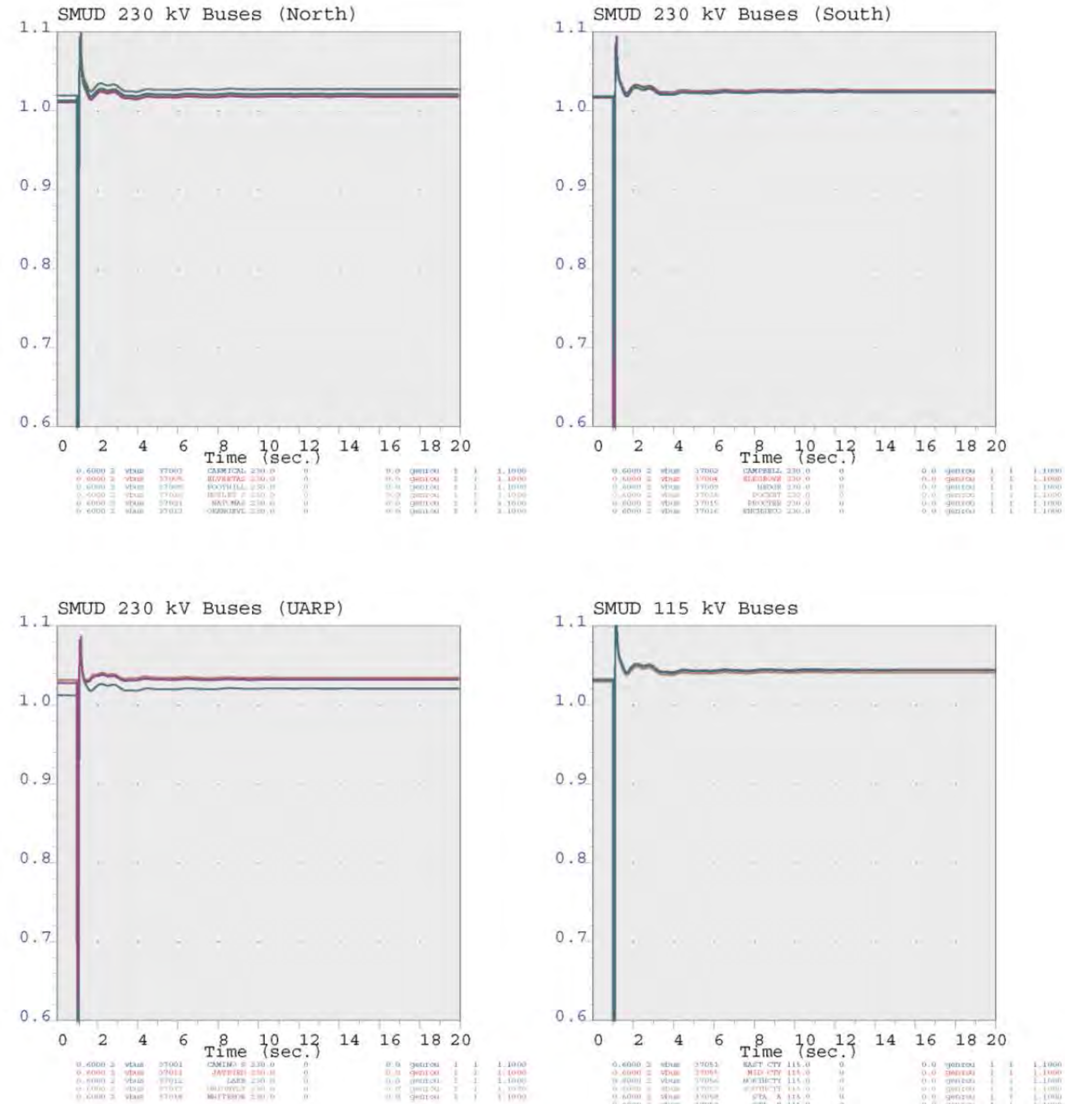

20hs2a_7_SMUD-Obanion-Sutter
2020 HEAVY SUMMER 2 PLANNING CASE
SEPTEMBER 23, 2014

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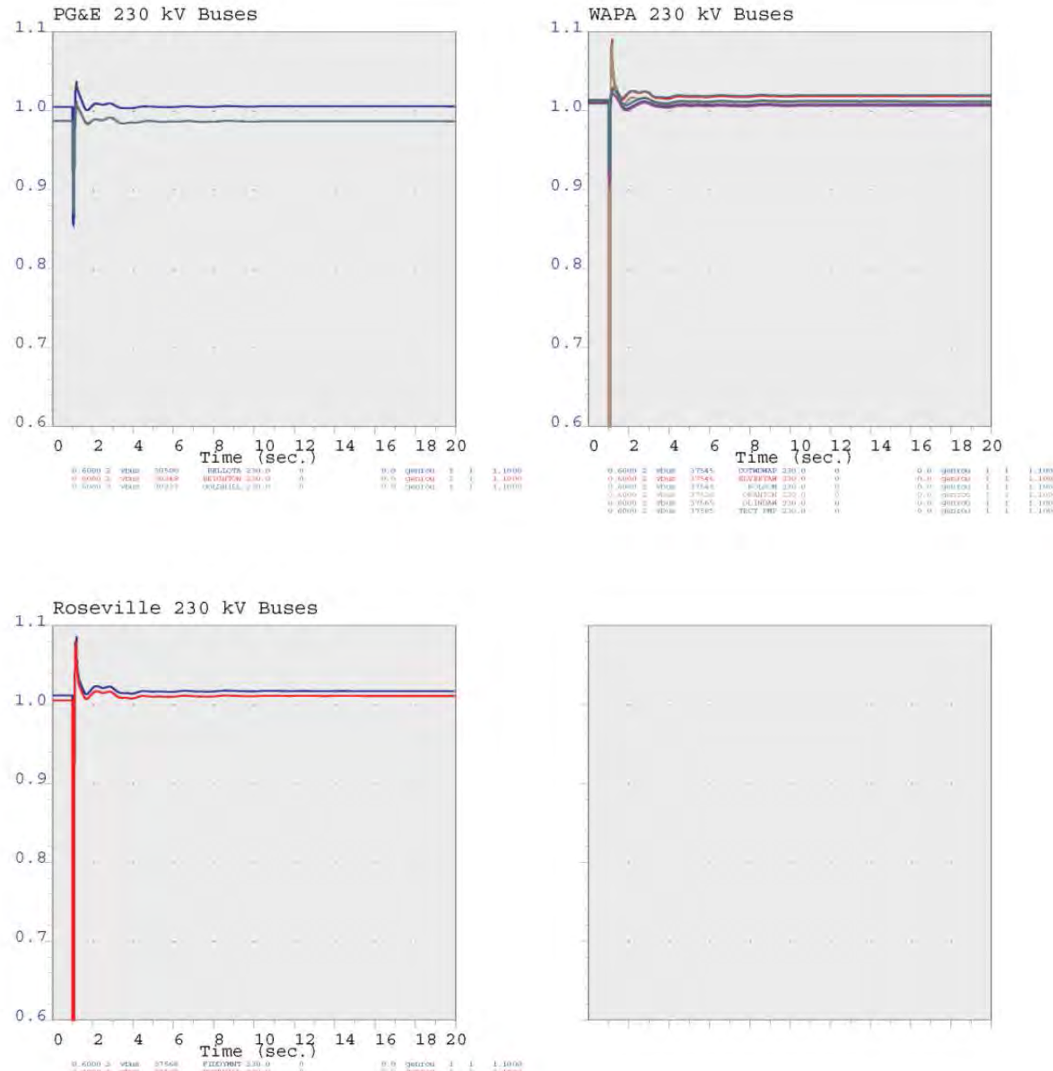
20hs2a_7_SMUD-Obanion-Sutter.chf

Fri Nov 06 09:03:01 2015

2015 Ten Year Plan Assessment - 2020 Summer Peak



20hs2a_7_SMUD-Obanion-Sutter
2020 HEAVY SUMMER 2 PLANNING CASE
SEPTEMBER 23, 2014

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20hs2a_7_SMUD-Obanion-Sutter.chf

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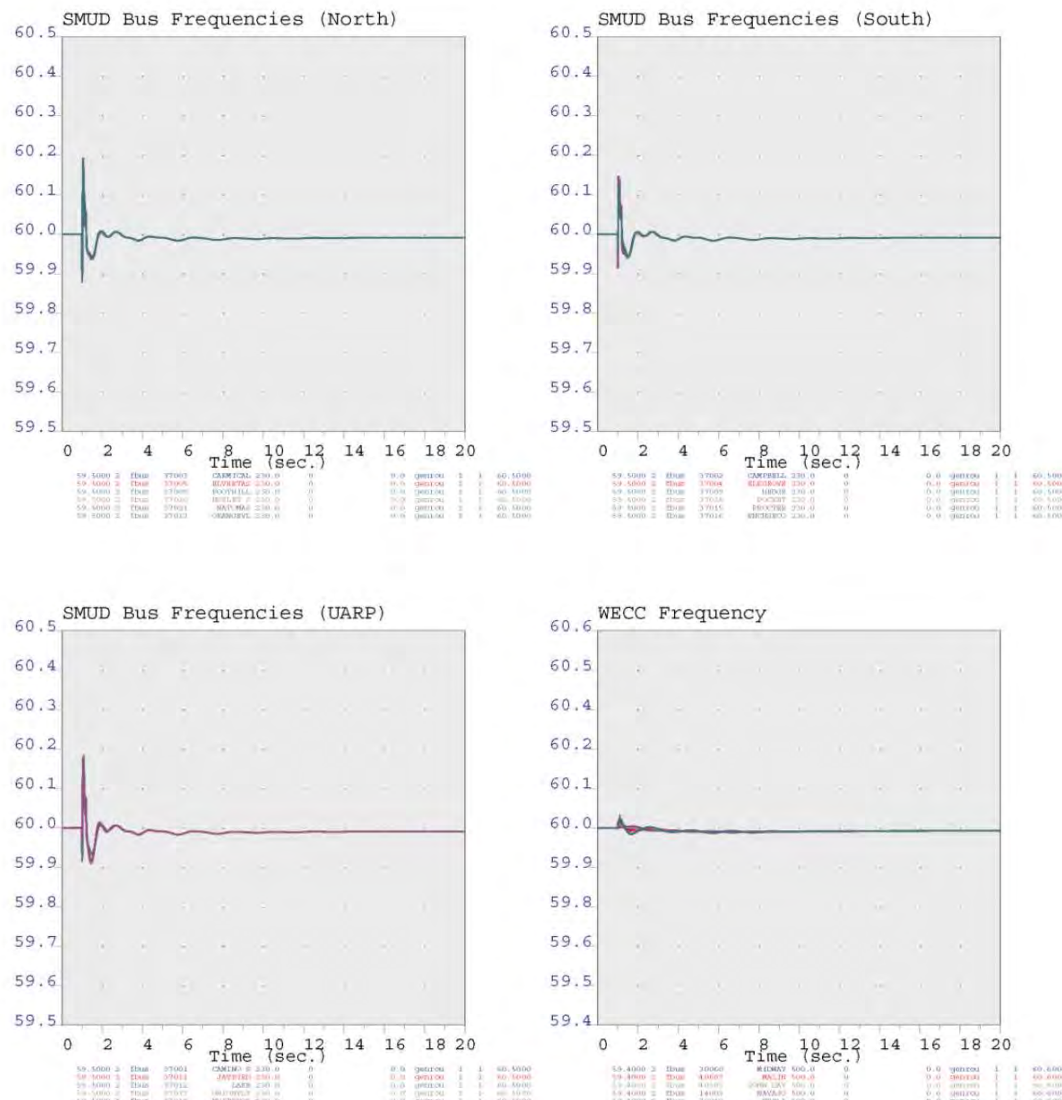
2015 Ten Year Plan Assessment - 2020 Summer Peak



20hs2a_7_SMUD-Obanion-Sutter
2020 HEAVY SUMMER 2 PLANNING CASE
SEPTEMBER 23, 2014

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20hs2a_7_SMUD-Obanion-Sutter.chf

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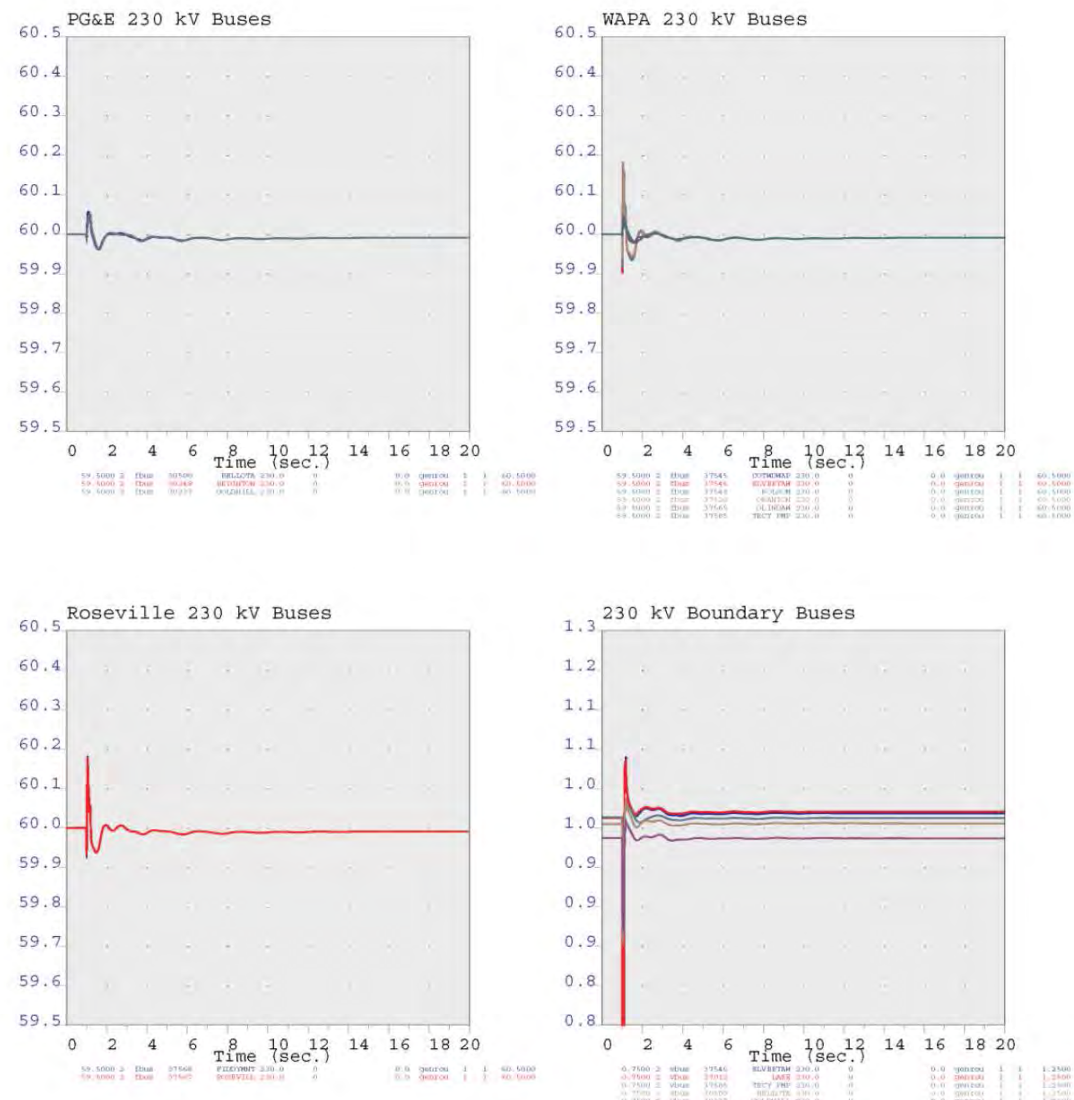
2015 Ten Year Plan Assessment - 2020 Summer Peak



20hs2a_7_SMUD-Obanion-Sutter
2020 HEAVY SUMMER 2 PLANNING CASE
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20hs2a_7_SMUD-Obanion-Sutter.chf

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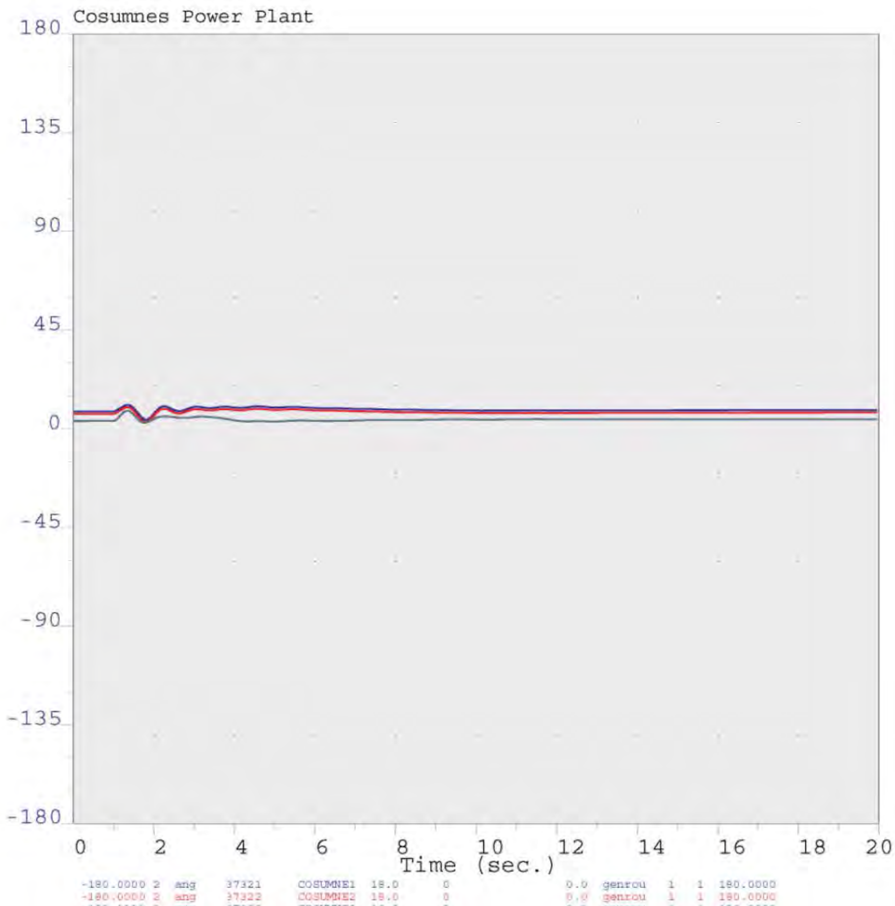
2015 Ten Year Plan Assessment - 2020 Summer Peak



20hs2a_7_SMUD-Obanion-Sutter
2020 HEAVY SUMMER 2 PLANNING CASE
SEPTEMBER 23, 2014

Page 5

20hs2a_7_SMUD-Obanion-Sutter.chf

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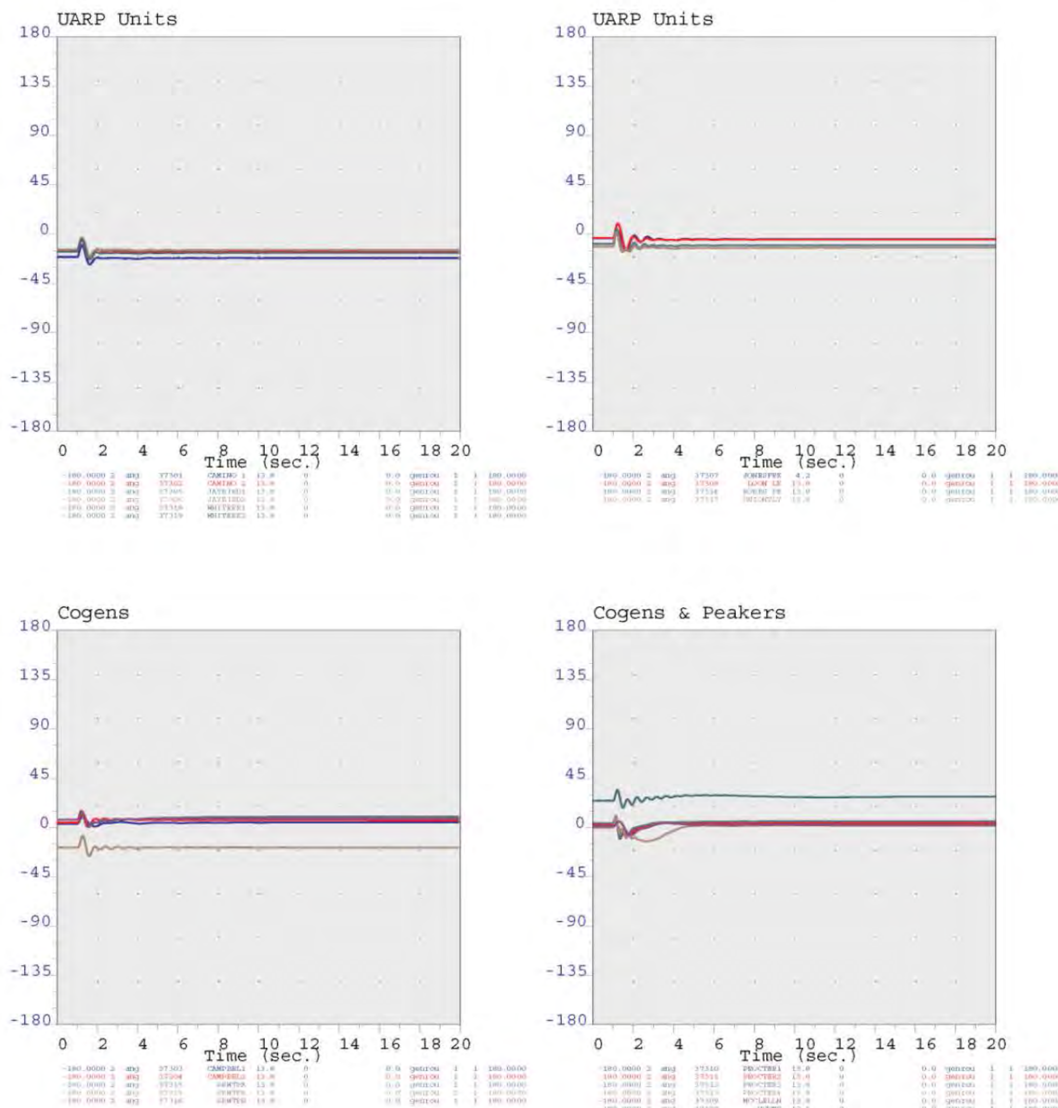
Fri Nov 06 09:03:01 2015

2015 Ten Year Plan Assessment - 2020 Summer Peak



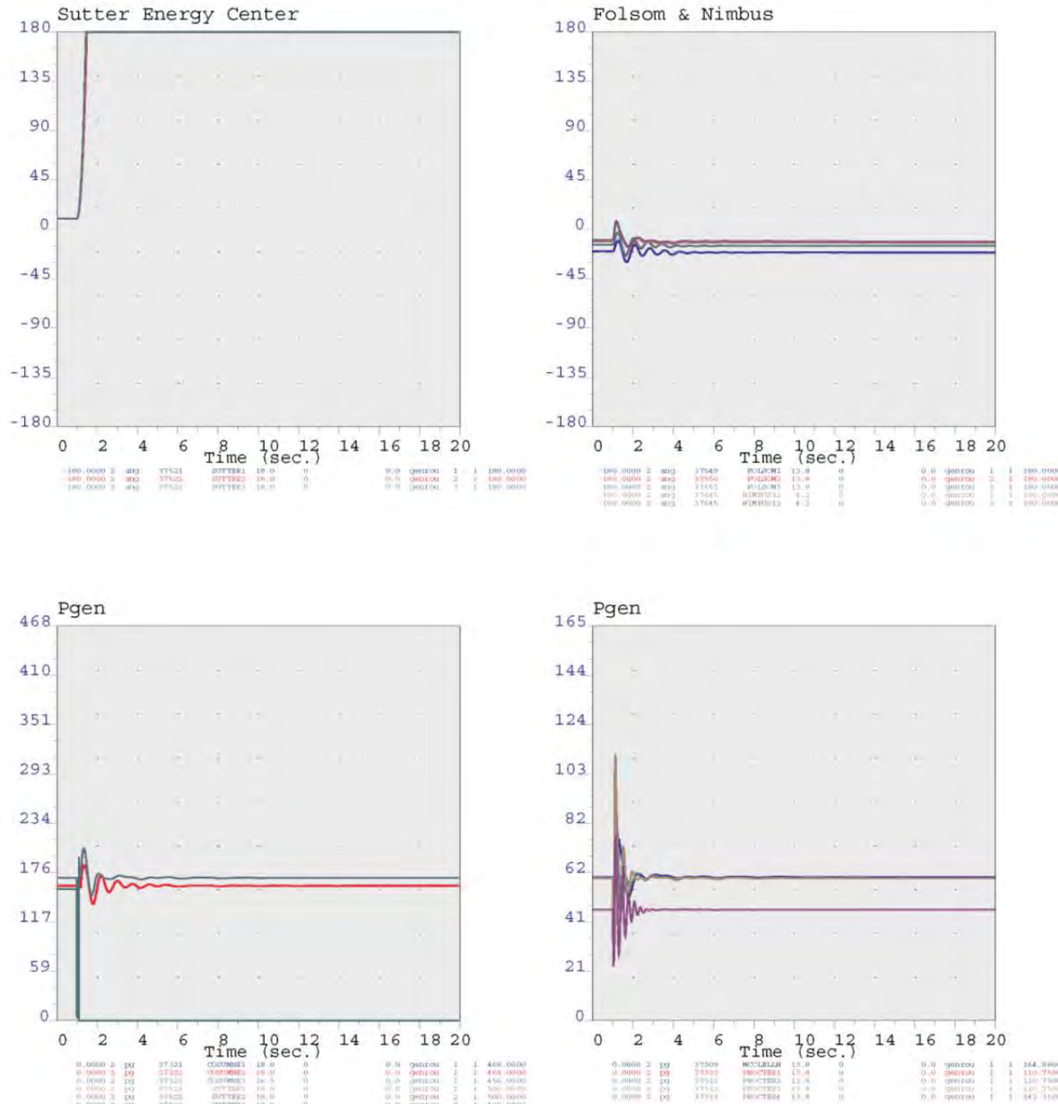
20hs2a_7_SMUD-Obanion-Sutter
2020 HEAVY SUMMER 2 PLANNING CASE
SEPTEMBER 23, 2014

Page 6

20hs2a_7_SMUD-Obanion-Sutter.chf

Fri Nov 06 09:03:01 2015

2015 Ten Year Plan Assessment - 2020 Summer Peak



20hs2a_7_SMUD-Obanion-Sutter
2020 HEAVY SUMMER 2 PLANNING CASE
SEPTEMBER 23, 2014

Page 7

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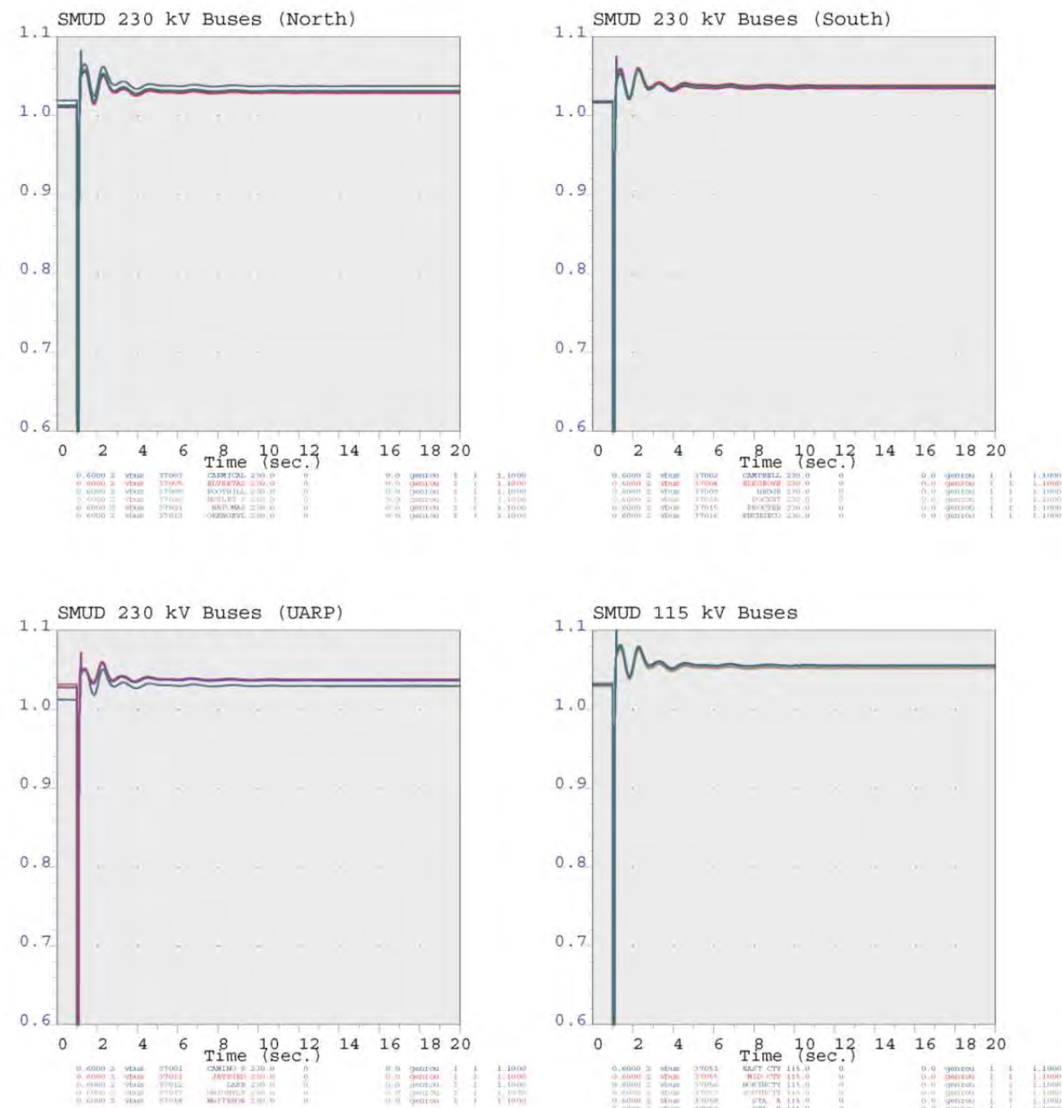
2015 Ten Year Plan Assessment - 2020 Summer Peak



20hs2a_7_SMUD-RSeco-Bellota-dlo
2020 HEAVY SUMMER 2 PLANNING CASE
SEPTEMBER 23, 2014

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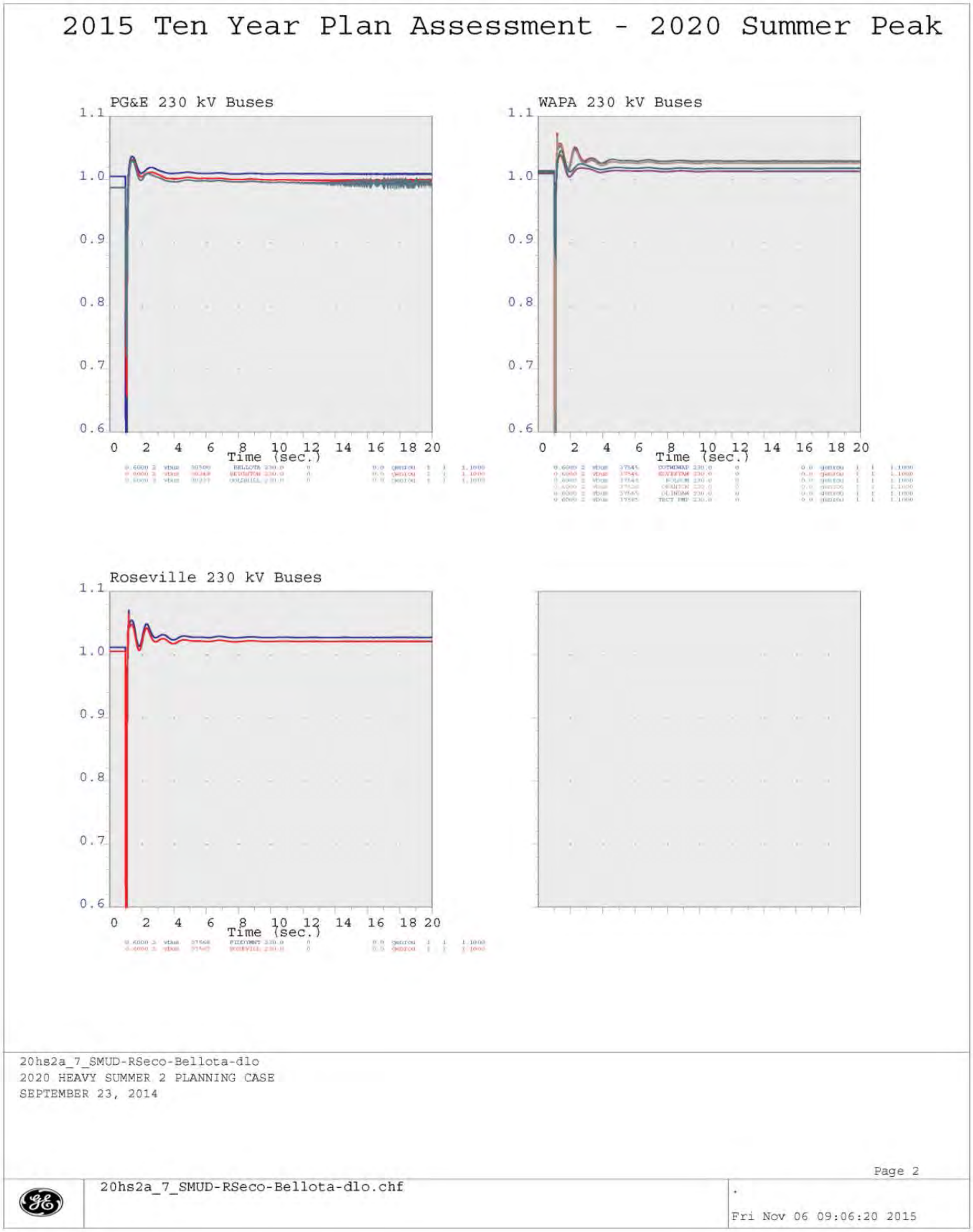
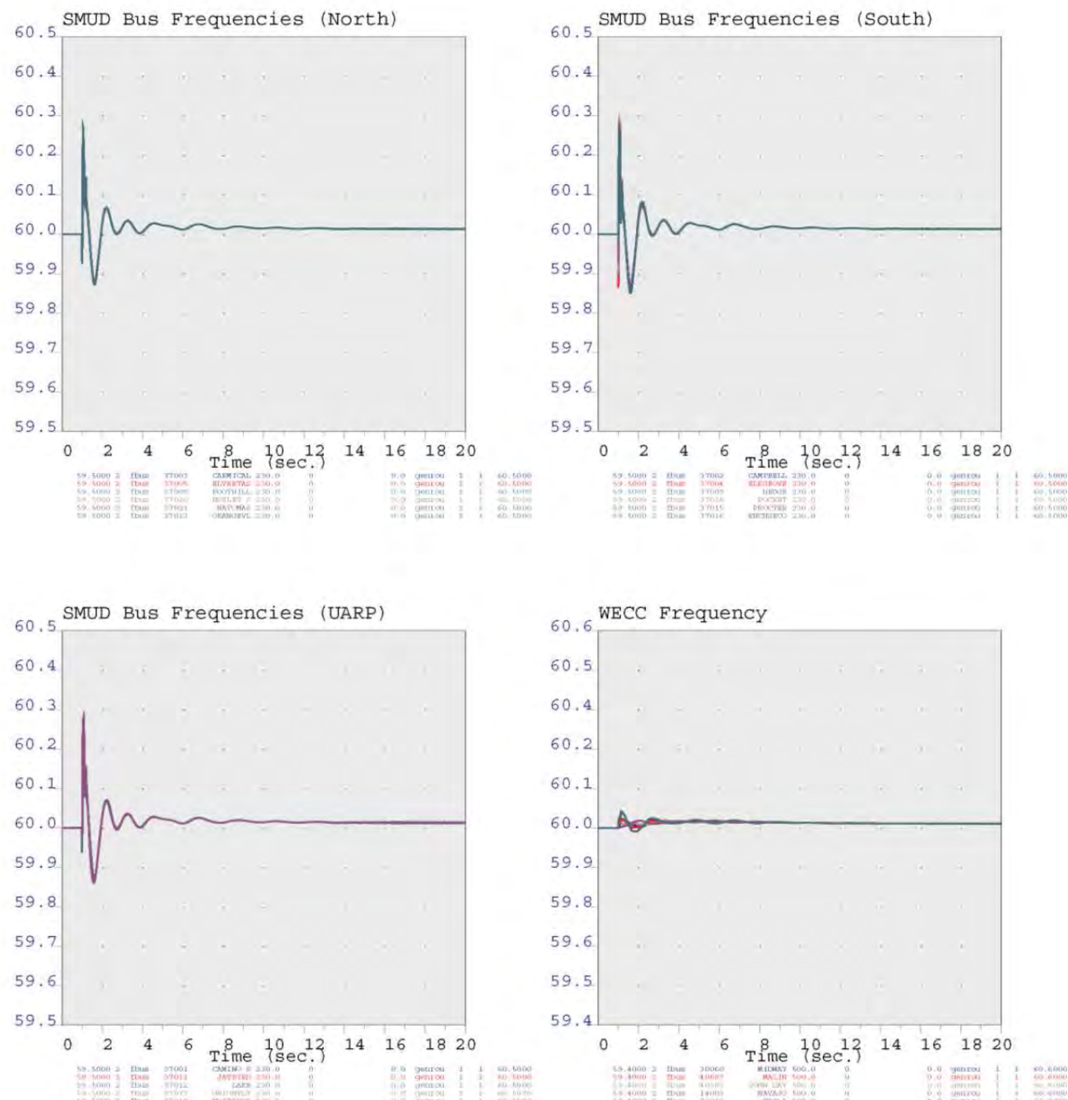
Fri Nov 06 09:06:20 2015


2015 Ten Year Plan Assessment - 2020 Summer Peak
PG&E 230 kV Buses
WAPA 230 kV Buses
Roseville 230 kV Buses
Time (sec.)
20hs2a_7_SMUD-RSeco-Bellota-dlo
2020 HEAVY SUMMER 2 PLANNING CASE
SEPTEMBER 23, 2014
Page 2
20hs2a_7_SMUD-RSeco-Bellota-dlo.chf
Fri Nov 06 09:06:20 2015

2015 Ten Year Plan Assessment - 2020 Summer Peak



20hs2a_7_SMUD-RSeco-Bellota-dlo
2020 HEAVY SUMMER 2 PLANNING CASE
SEPTEMBER 23, 2014

Page 3

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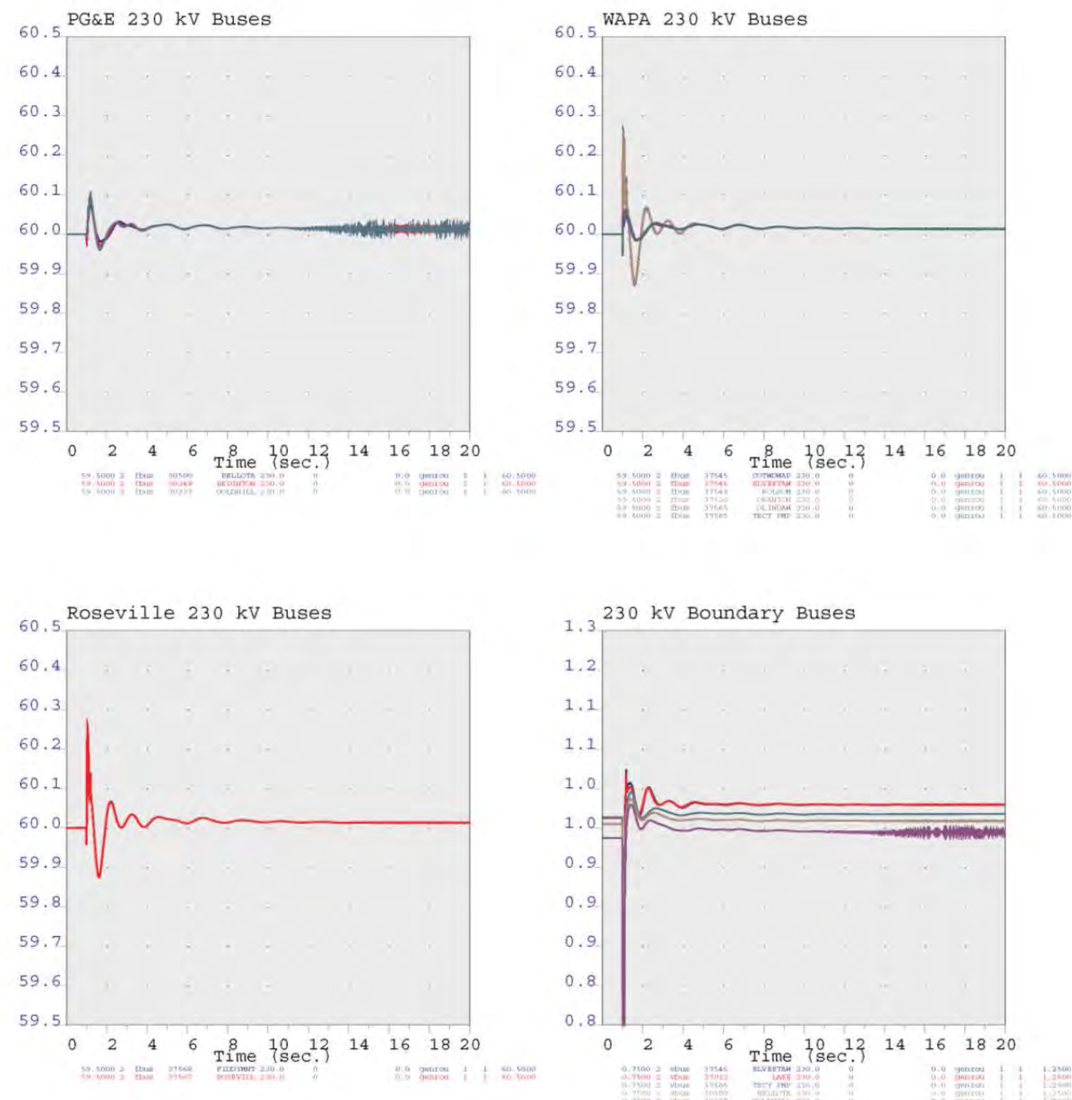
2015 Ten Year Plan Assessment - 2020 Summer Peak



20hs2a_7_SMUD-RSeco-Bellota-dlo
2020 HEAVY SUMMER 2 PLANNING CASE
SEPTEMBER 23, 2014

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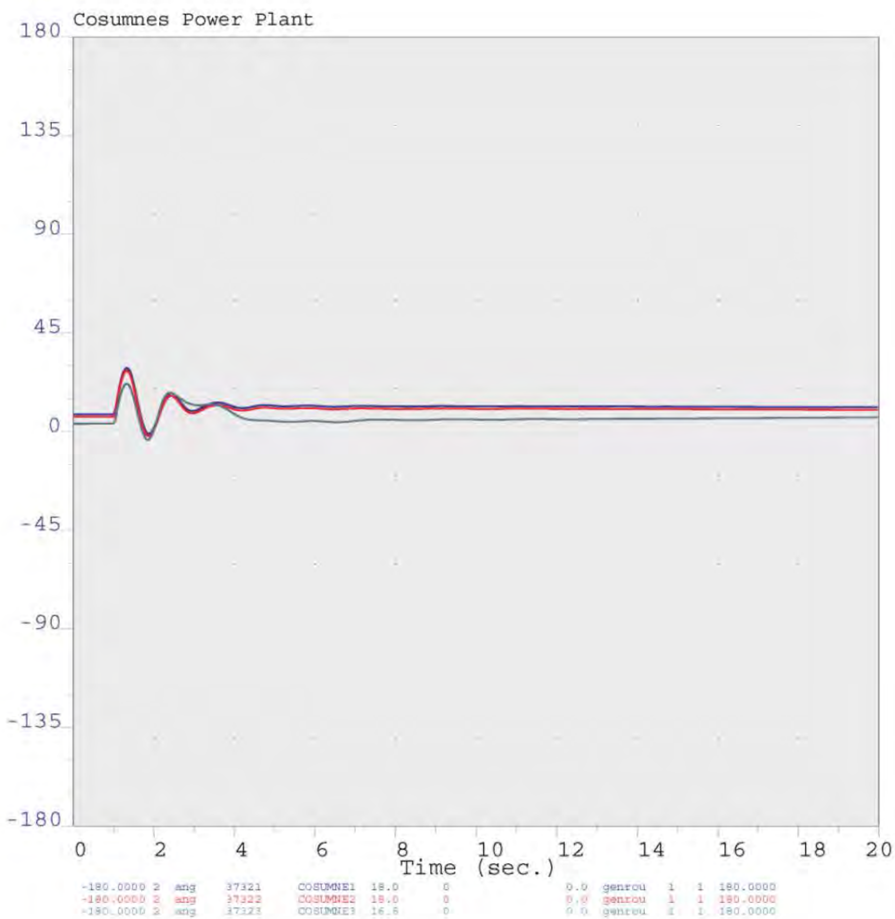
Fri Nov 06 09:06:21 2015

2015 Ten Year Plan Assessment - 2020 Summer Peak



20hs2a_7_SMUD-RSeco-Bellota-dlo
2020 HEAVY SUMMER 2 PLANNING CASE
SEPTEMBER 23, 2014

Page 5

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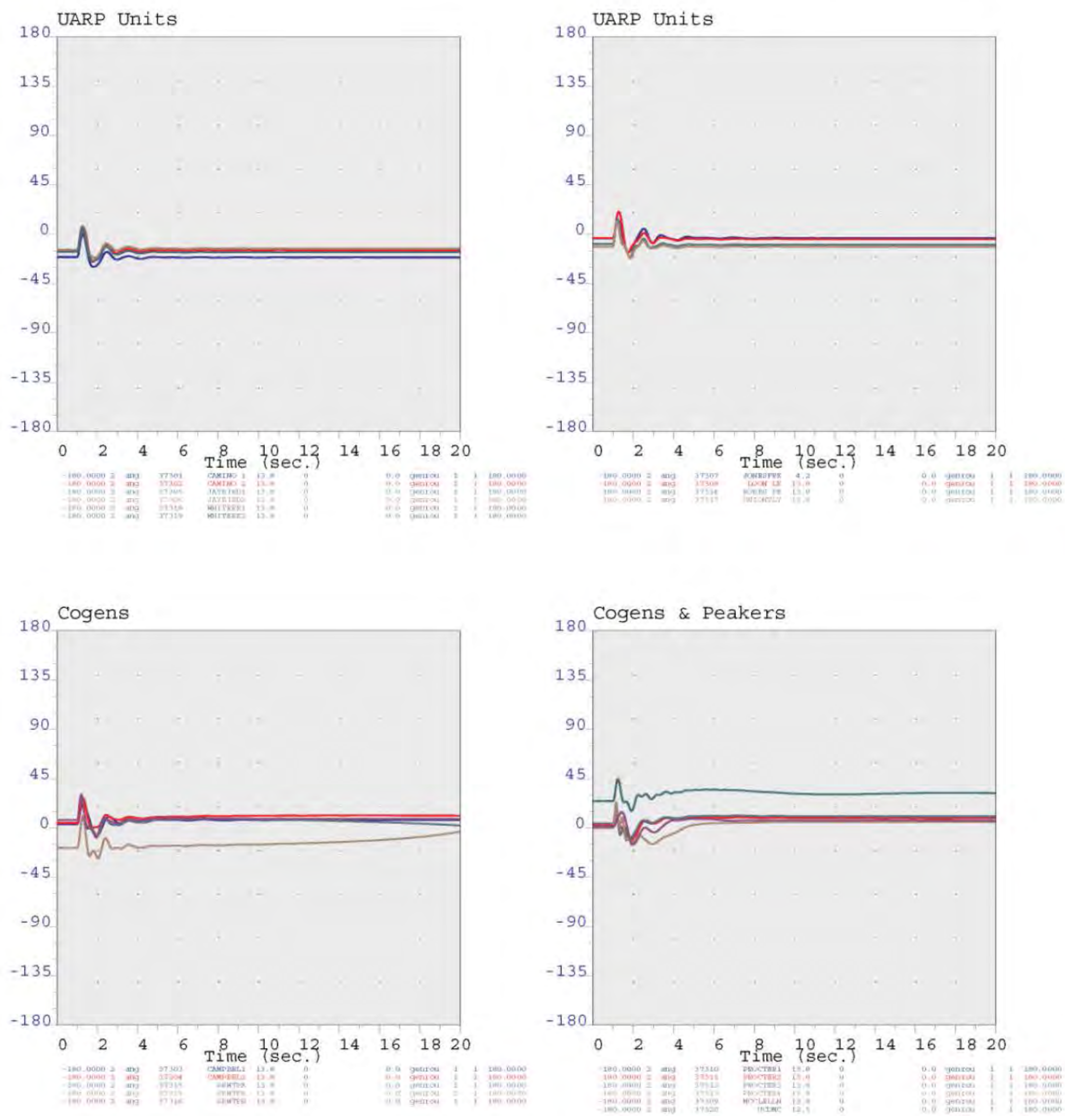
2015 Ten Year Plan Assessment - 2020 Summer Peak



20hs2a_7_SMUD-RSeco-Bellota-dlo
2020 HEAVY SUMMER 2 PLANNING CASE
SEPTEMBER 23, 2014

Page 6

20hs2a_7_SMUD-RSeco-Bellota-dlo.chf

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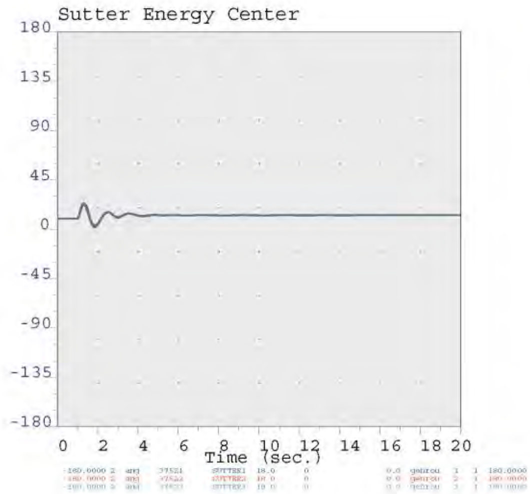
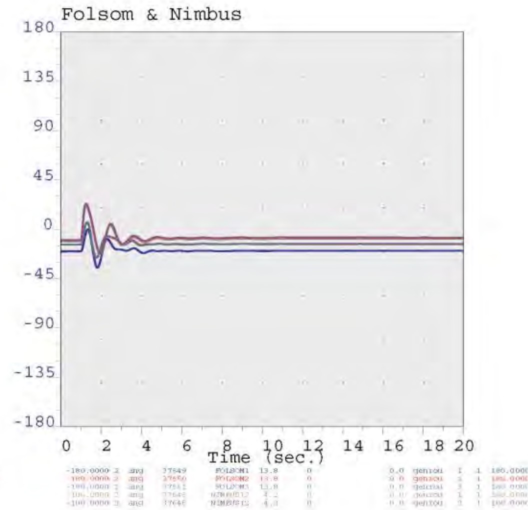
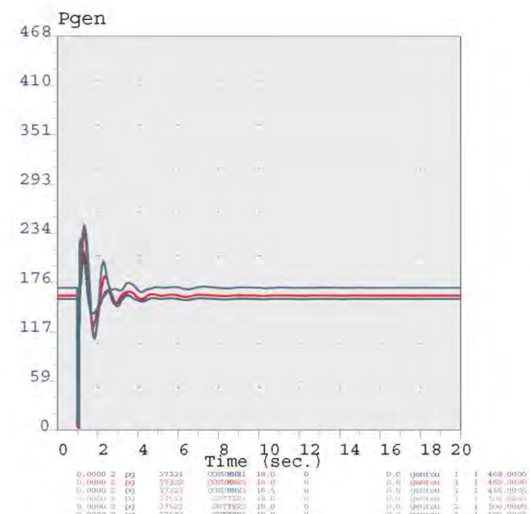
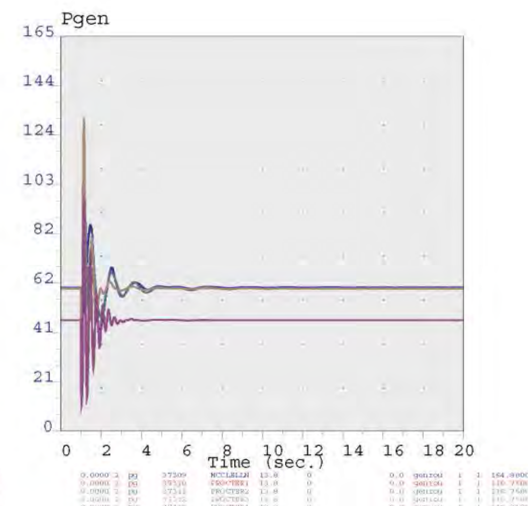
2015 Ten Year Plan Assessment - 2020 Summer Peak









20hs2a_7_SMUD-RSeco-Bellota-dlo
2020 HEAVY SUMMER 2 PLANNING CASE
SEPTEMBER 23, 2014

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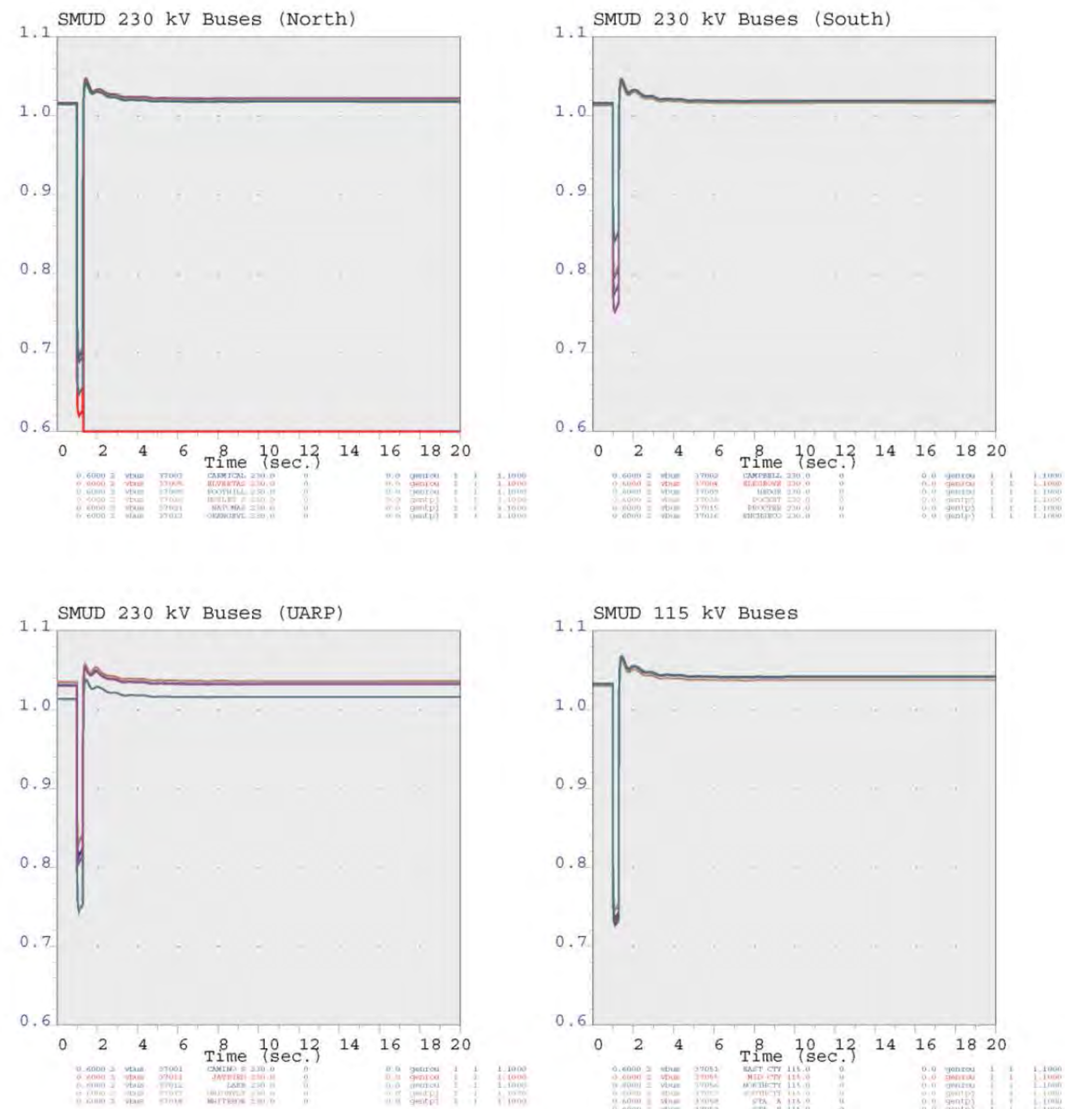
20hs2a_7_SMUD-RSeco-Bellota-dlo.chf

Fri Nov 06 09:06:21 2015

The following are plots for contingencies on the 2020 Adverse Summer Off-Peak case.

2015 Ten Year Plan Assessment - 2020 Off Peak



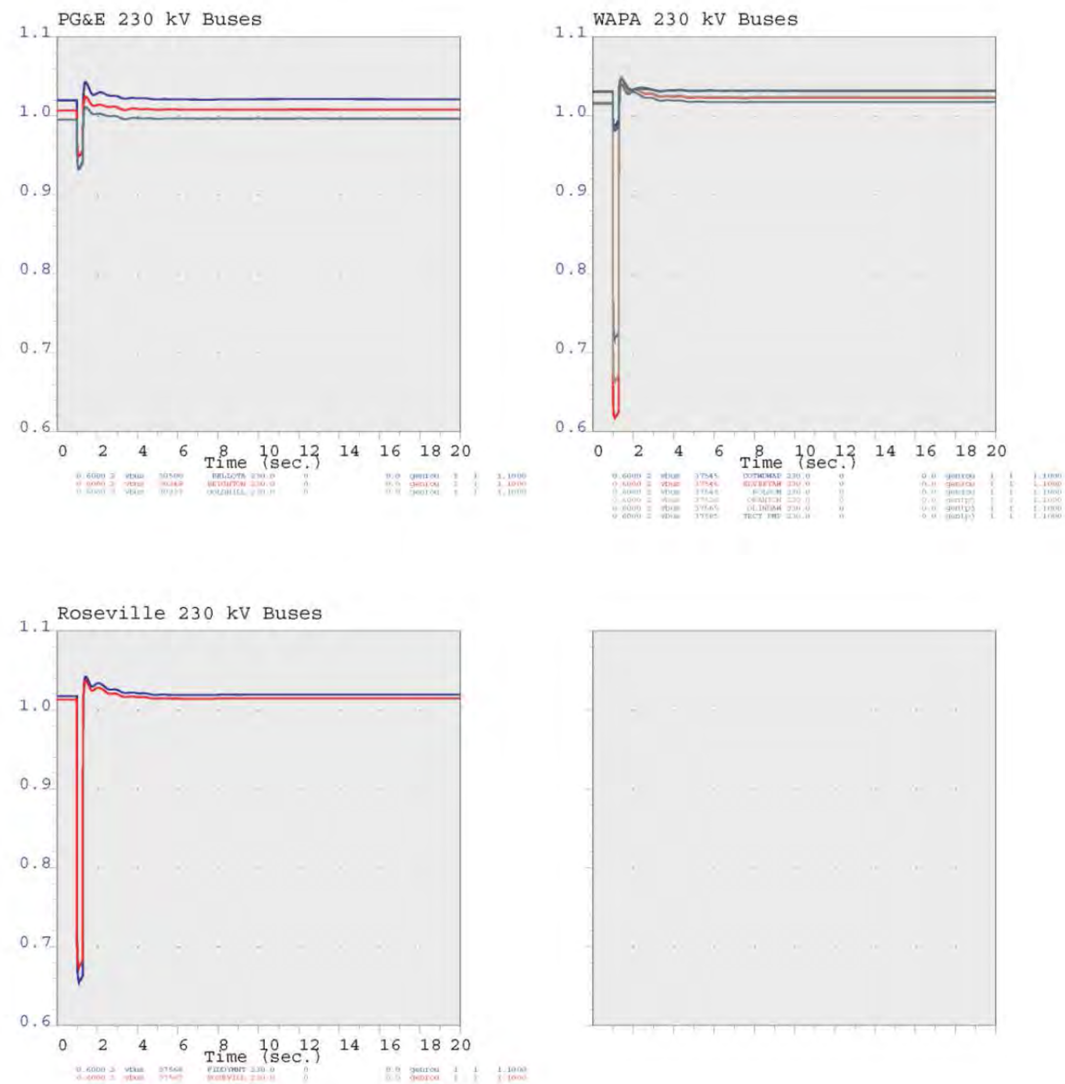
20hw1a_7_Elverta_bkr1182_18cycles
2019-20HW1 BASE CASE
AUGUST 12, 2014
ALL COMMENTS FROM TSS REVIEW ARE INCLUDED.

Page 1

20hw1a_7_Elverta_bkr1182_18cycles.chf

Tue Oct 27 11:31:30 2015

2015 Ten Year Plan Assessment - 2020 Off Peak



20hw1a_7_Elverta_bkr1182_18cycles
2019-20HW1 BASE CASE
AUGUST 12, 2014
ALL COMMENTS FROM TSS REVIEW ARE INCLUDED.

Page 2

20hw1a_7_Elverta_bkr1182_18cycles.chf

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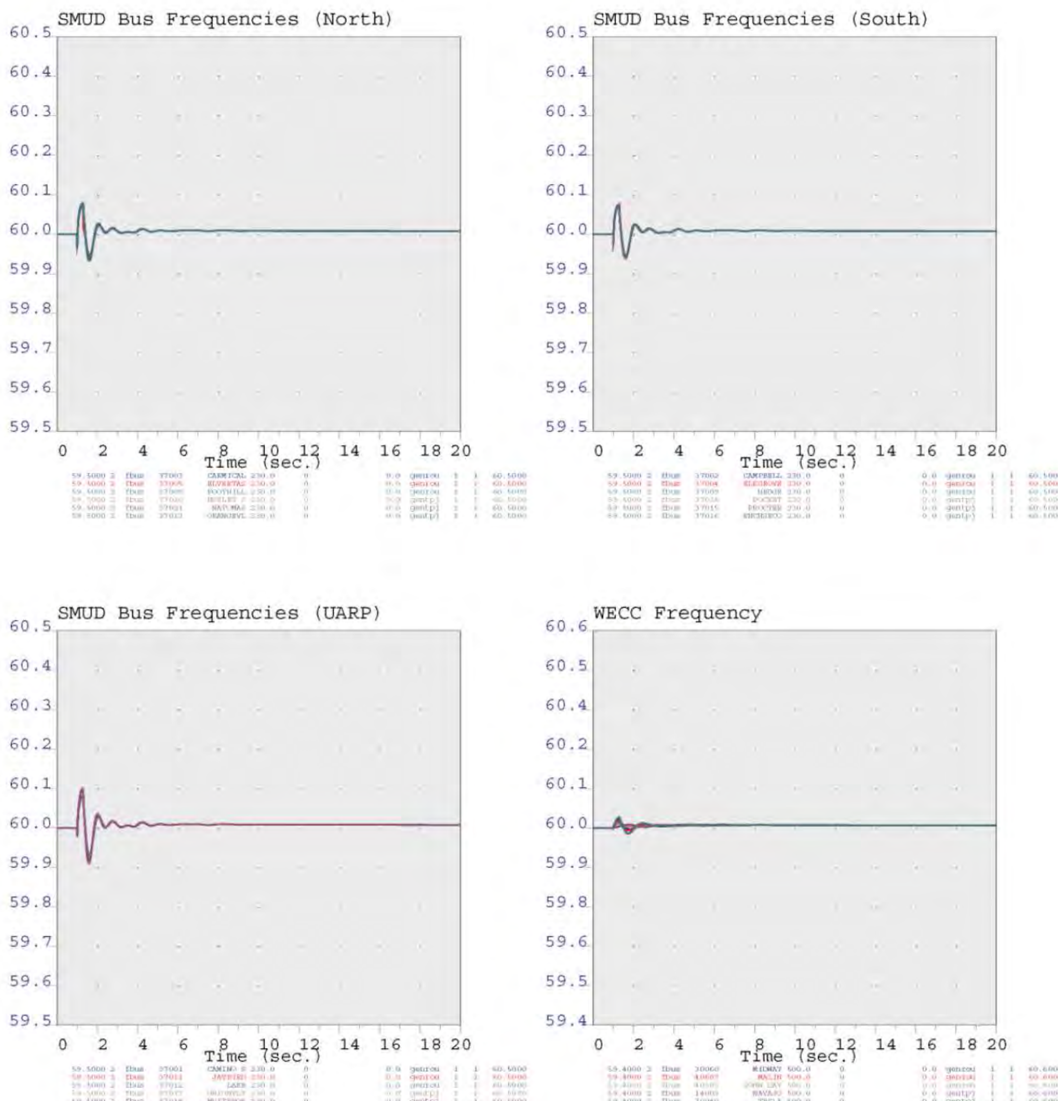
2015 Ten Year Plan Assessment - 2020 Off Peak



20hw1a_7_Elverta_bkr1182_18cycles
2019-20HW1 BASE CASE
AUGUST 12, 2014
ALL COMMENTS FROM TSS REVIEW ARE INCLUDED.

Page 3

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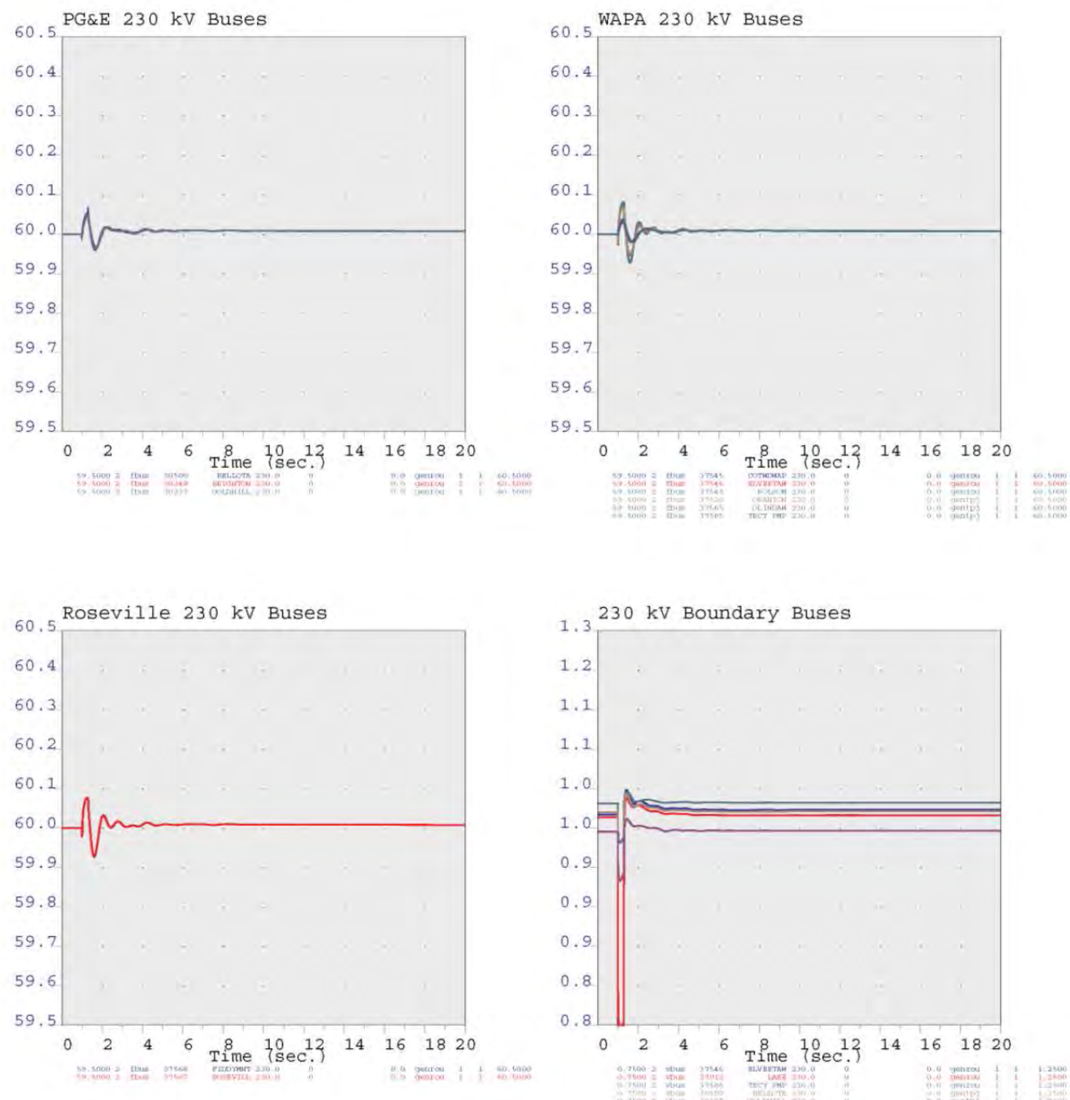
2015 Ten Year Plan Assessment - 2020 Off Peak



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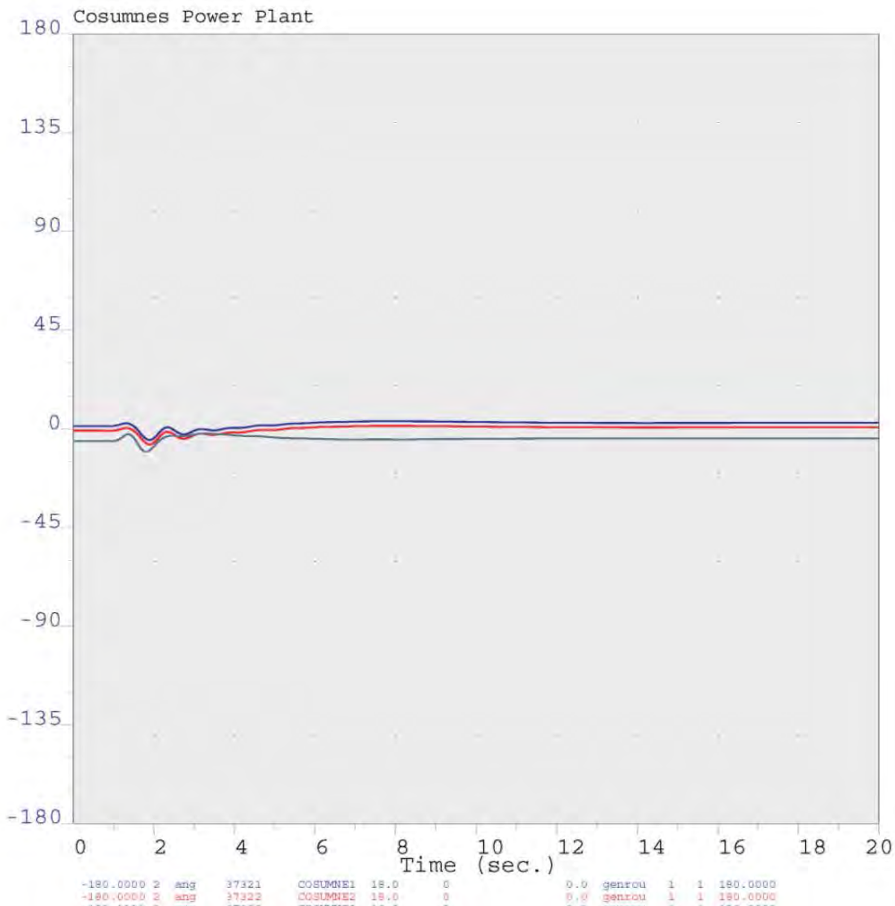
2019-20HW1 BASE CASE
AUGUST 12, 2014
ALL COMMENTS FROM TSS REVIEW ARE INCLUDED.

Page 4

20hw1a_7_Elverta_bkr1182_18cycles.chf

Tue Oct 27 11:31:30 2015

2015 Ten Year Plan Assessment - 2020 Off Peak



20hw1a_7_Elverta_bkr1182_18cycles
2019-20HW1 BASE CASE
AUGUST 12, 2014
ALL COMMENTS FROM TSS REVIEW ARE INCLUDED.

Page 5

20hw1a_7_Elverta_bkr1182_18cycles.chf

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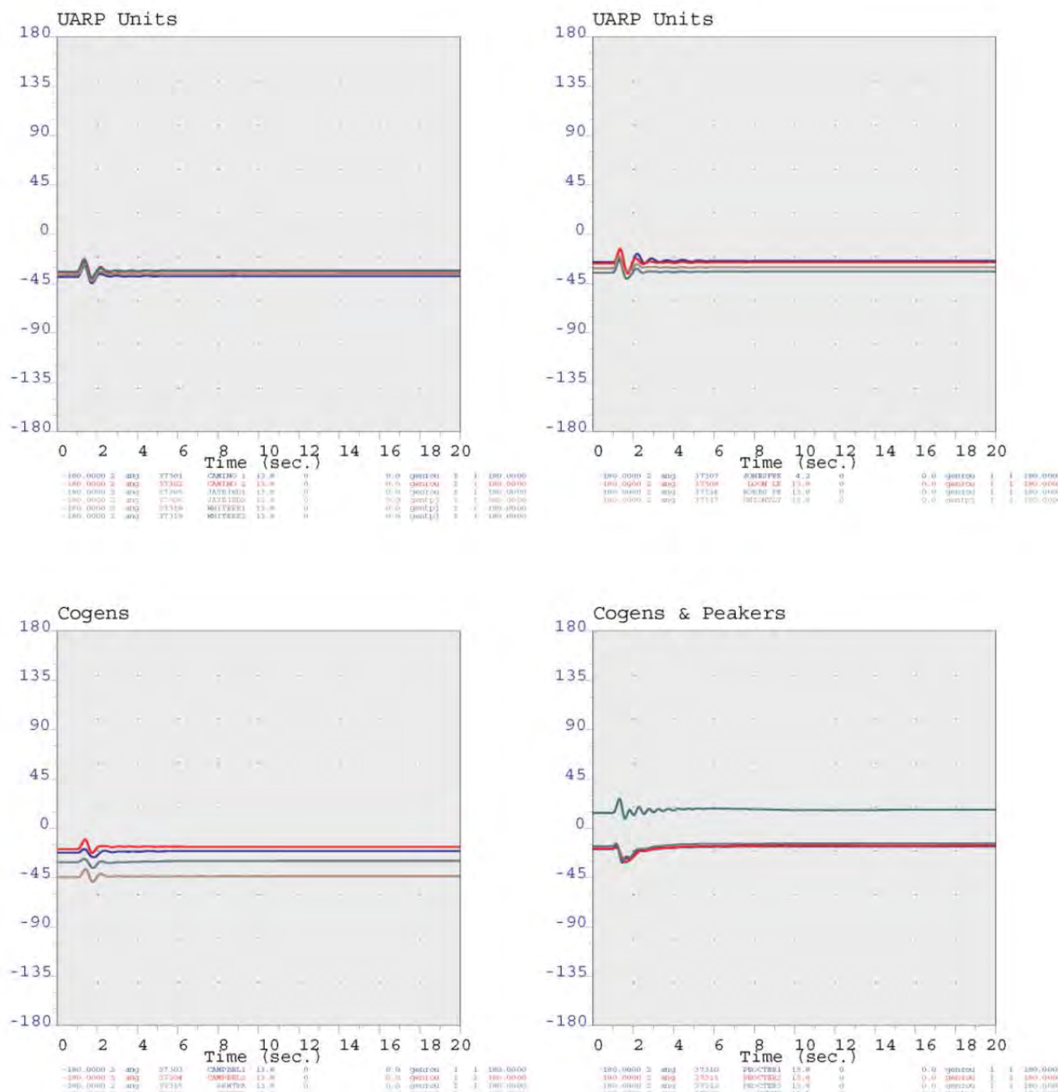
2015 Ten Year Plan Assessment - 2020 Off Peak



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2019-20HW1 BASE CASE
AUGUST 12, 2014
ALL COMMENTS FROM TSS REVIEW ARE INCLUDED.

Page 6

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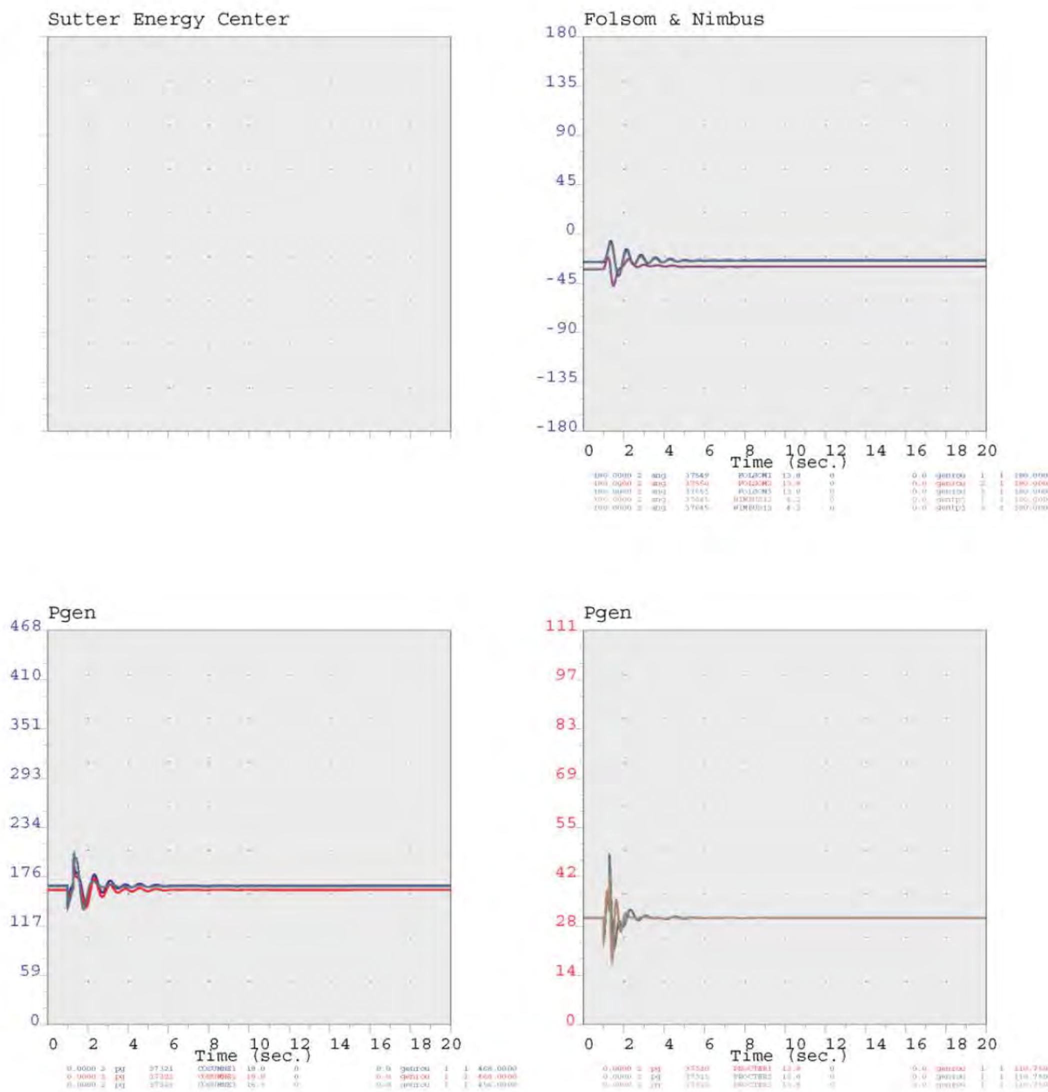

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2019-20HW1 BASE CASE
AUGUST 12, 2014
ALL COMMENTS FROM TSS REVIEW ARE INCLUDED.

Page 7

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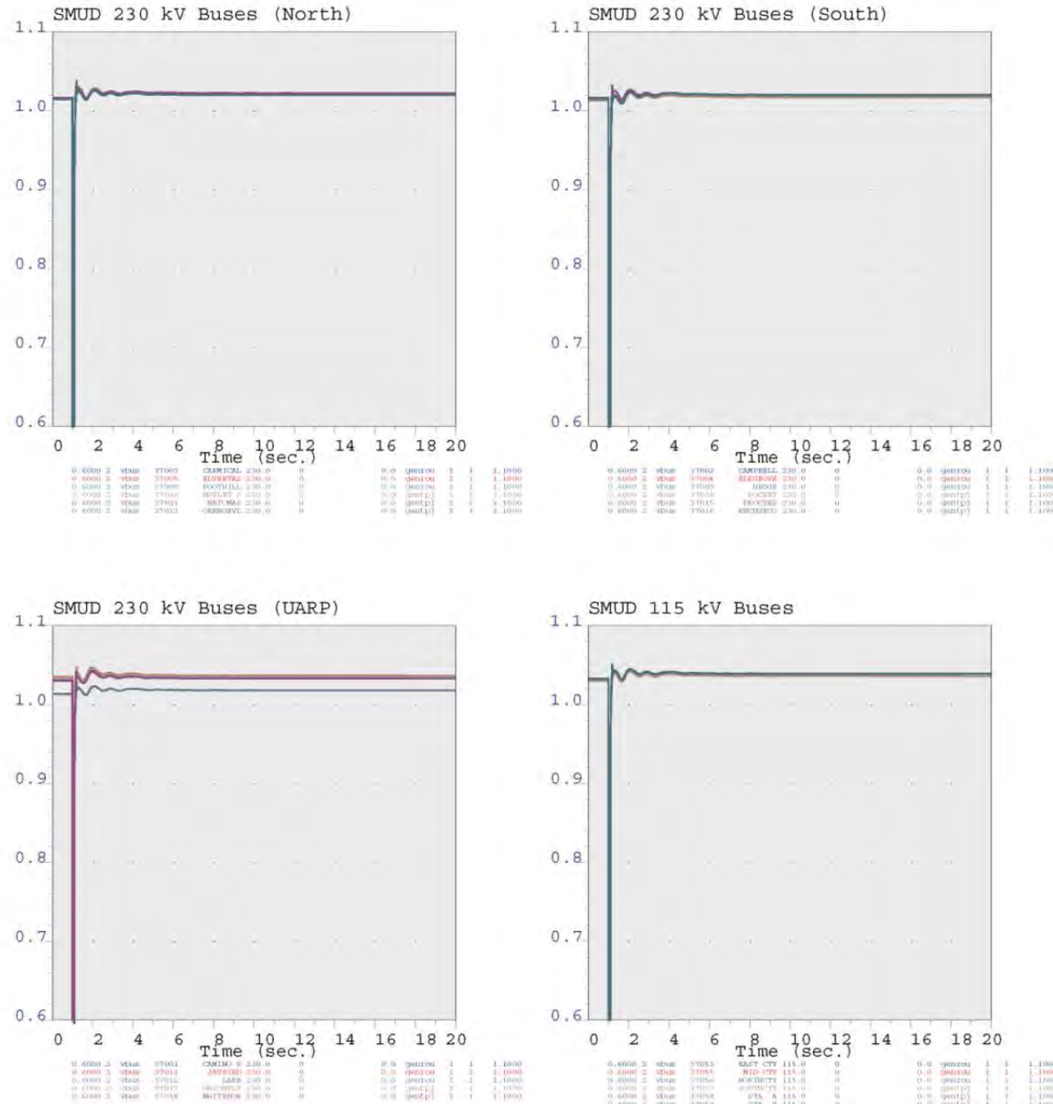
2015 Ten Year Plan Assessment - 2020 Off Peak



20hw1a_7_RSeco-Pocket_RSeco-Frank-dctl
2019-20HW1 BASE CASE
AUGUST 12, 2014
ALL COMMENTS FROM TSS REVIEW ARE INCLUDED.

Page 1

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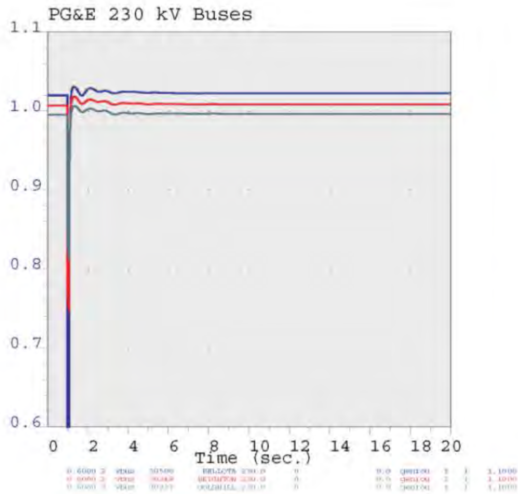
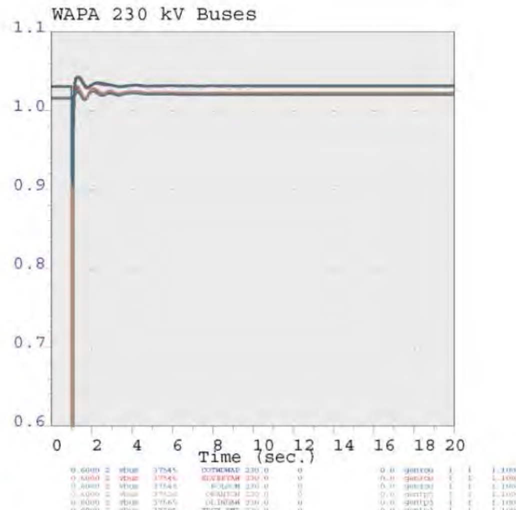
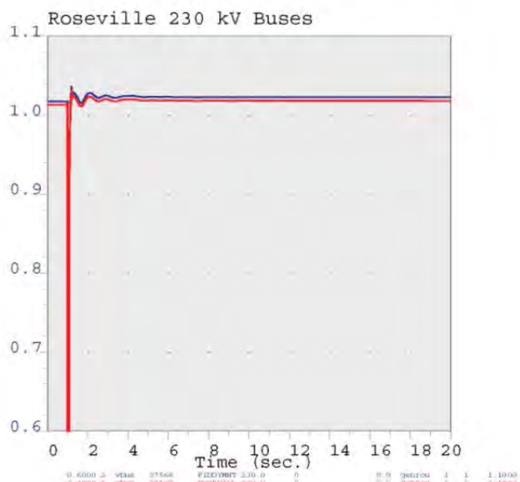
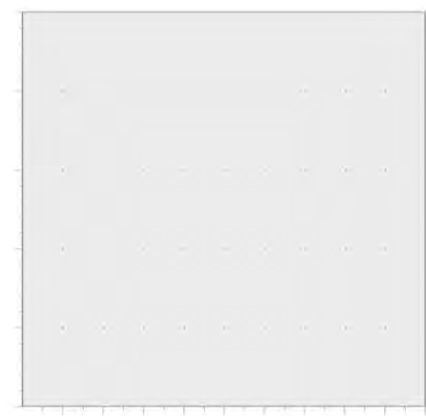
Tue Oct 27 11:50:20 2015

2015 Ten Year Plan Assessment - 2020 Off Peak









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2019-20HW1 BASE CASE
AUGUST 12, 2014
ALL COMMENTS FROM TSS REVIEW ARE INCLUDED.

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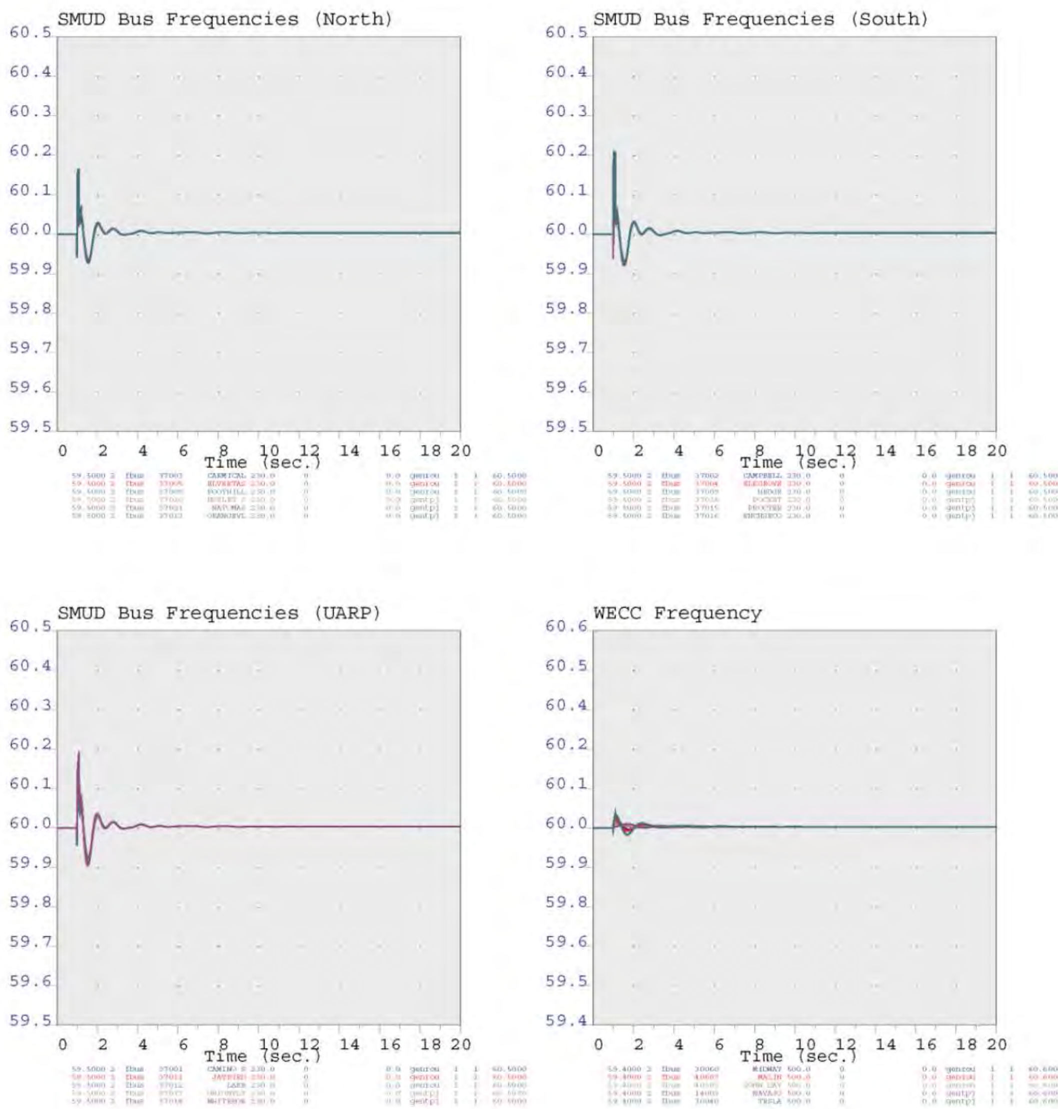
2015 Ten Year Plan Assessment - 2020 Off Peak



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2019-20HW1 BASE CASE
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ALL COMMENTS FROM TSS REVIEW ARE INCLUDED.

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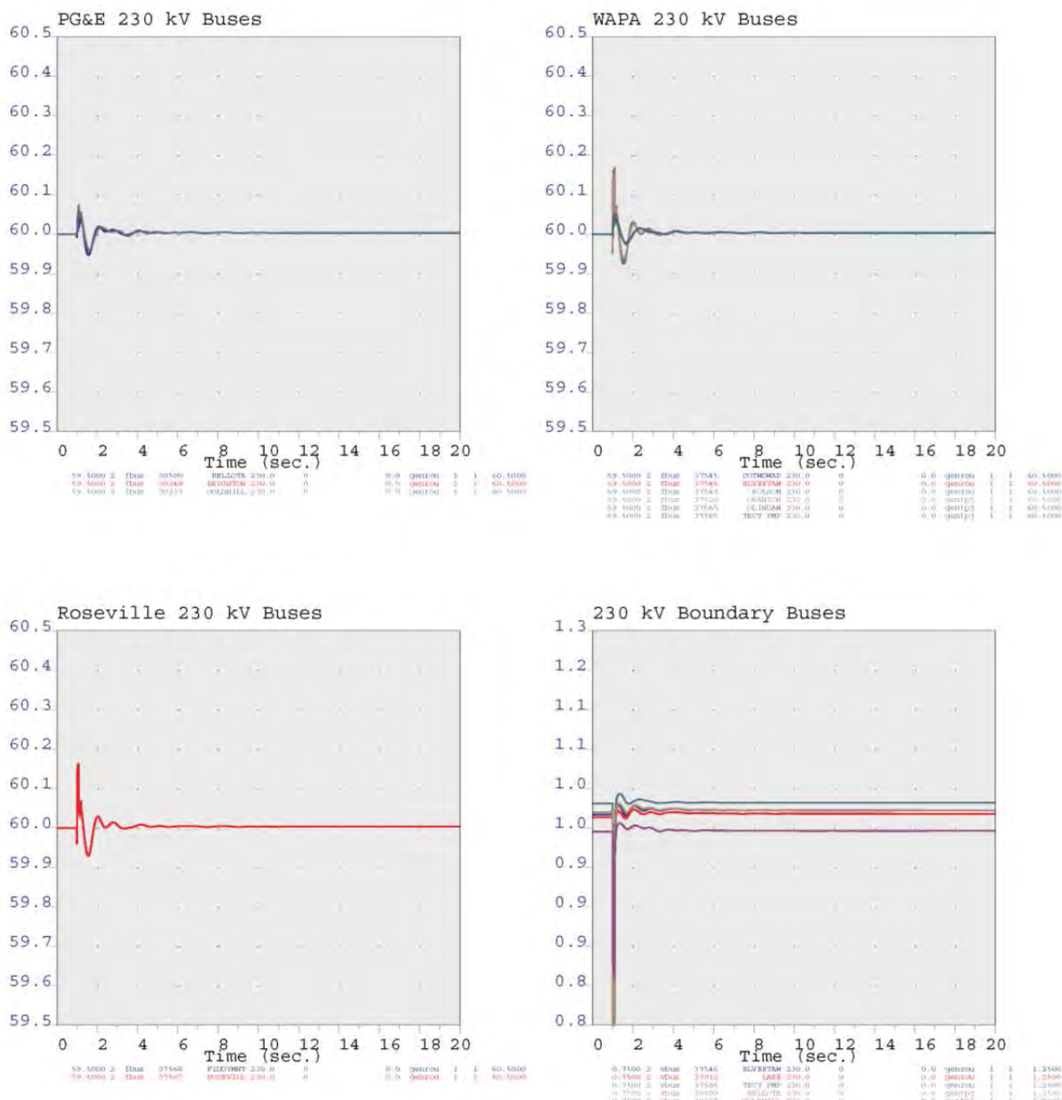
2015 Ten Year Plan Assessment - 2020 Off Peak



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AUGUST 12, 2014
ALL COMMENTS FROM TSS REVIEW ARE INCLUDED.

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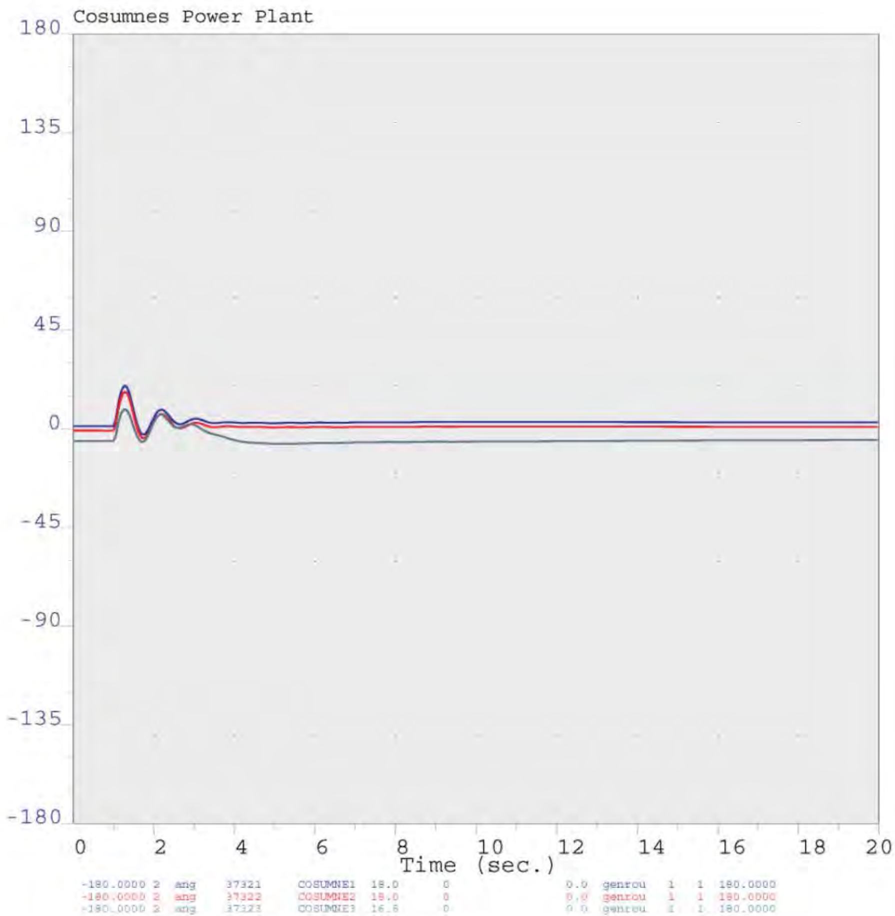
2015 Ten Year Plan Assessment - 2020 Off Peak



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2019-20HW1 BASE CASE
AUGUST 12, 2014
ALL COMMENTS FROM TSS REVIEW ARE INCLUDED.

Page 5

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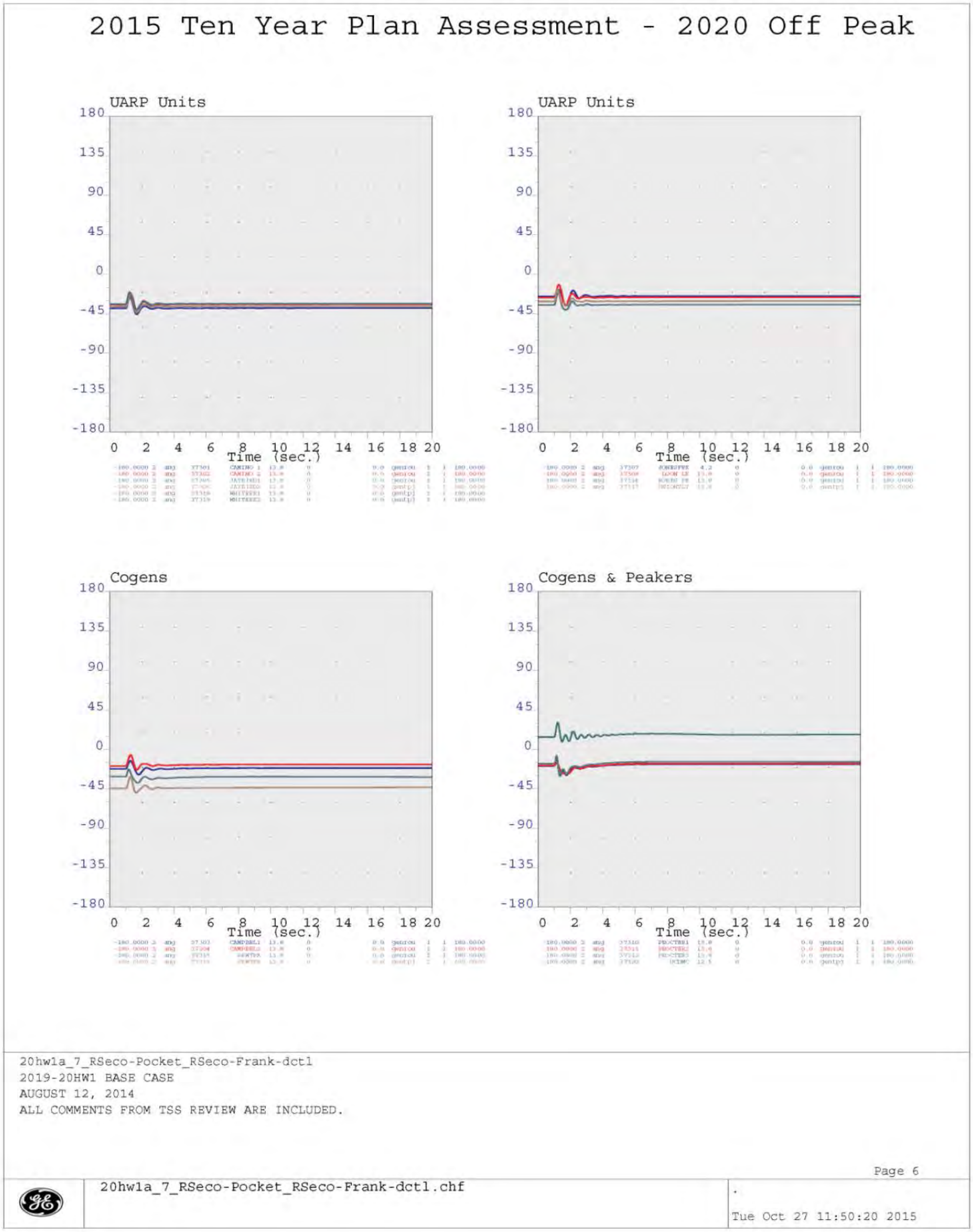
2015 Ten Year Plan Assessment - 2020 Off Peak
UARP Units
UARP Units
Cogens
Cogens & Peakers
180
135
90
45
0
-45
-90
-135
-180
0 2 4 6 8 10 12 14 16 18 20
Time (sec.)
20hw1a_7_RSeco-Pocket_RSeco-Frank-dctl
2019-20HW1 BASE CASE
AUGUST 12, 2014
ALL COMMENTS FROM TSS REVIEW ARE INCLUDED.
Page 6
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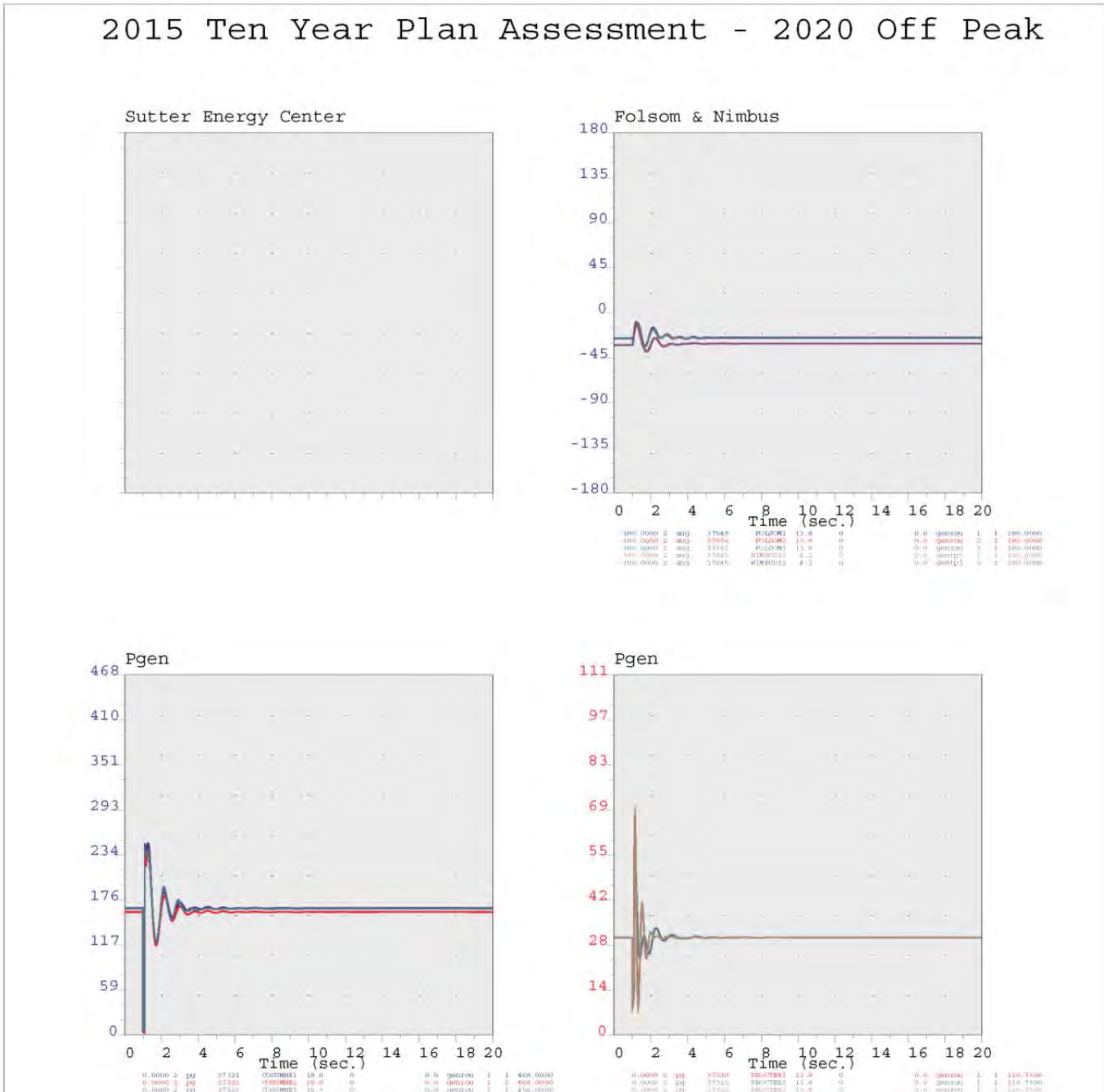

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2019-20HW1 BASE CASE
AUGUST 12, 2014
ALL COMMENTS FROM TSS REVIEW ARE INCLUDED.

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20hw1a_7_RSeco-Pocket_RSeco-Frank-dctl.chf

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5: Contingency List

Please refer to formal contingency document created by Grid Planning. This can be made available upon request.