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2016 Transmission System Planning Assessment

TPL-001-4 Compliance Documentation

Grid Planning Department
Sacramento Municipal Utility District
December 30, 2016

Executive summary

An annual assessment was performed in 2016 to demonstrate that the Sacramento Municipal Utility District (SMUD) portion of the Bulk Electric System meets all performance requirements specified in the TPL-001-4 NERC Reliability Standard for the years 2017 through 2026 (planning years one through ten).

Steady state, short circuit, and stability analyses were performed as part of this assessment. A spare equipment unavailability analysis and sensitivities for the steady state and stability analyses were also performed. The short circuit analysis was supported by qualified past studies, whereas the steady state and stability analyses were supported by current studies.

The steady state analysis identified the need for the four corrective action plans listed in Table I. The other analyses (i.e. the short circuit, stability, spare equipment unavailability, and sensitivity analyses) did not identify any system deficiencies or produce any recommendations.

The corrective action plans consist of the installation of remedial action schemes (RAS). Only one RAS is needed to mitigate the two contingencies that impact the Hurley–Procter 230 kV line. If approved, the proposed CoSu Project mitigates all of the identified issues. Other mitigation measures will be evaluated. With these corrective action plans, the SMUD system meets all performance requirements specified in TPL-001-4.

Table I: Summary of corrective action plans to meet performance requirements

Contingency	Overloaded facilities	Corrective Action Plan	Year needed	Year in-service
Folsom–Lake & Orangevale–White Rock 230 kV lines (P7)	Hurley–Procter 230 kV line	• Install a RAS to shed firm load • Proposed CoSu Project	2020	2018 2024
Tracy–Hurley #1 & #2 230 kV lines (P7)	Hurley–Procter 230 kV line	• Install a RAS to shed firm load • Proposed CoSu Project	2022	2018 2024
Various faults at Rancho Seco 230 kV station (P2.3, P4)	Rancho Seco–Bellota #2 230 kV line	• Install a RAS to shed firm load • Proposed CoSu Project	2022	2022 2024
Rancho Seco–Bellota #1 & #2 230 kV lines (P7)	Tracy–Hurley #1 & #2 230 kV lines and Gold Hill–Lake 230 kV line	• Proposed CoSu Project • Install a RAS to shed firm load	2026	2024 2026

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1 Introduction

An annual assessment was performed in 2016 to demonstrate that the Sacramento Municipal Utility District (SMUD) portion of the Bulk Electric System (BES) meets all performance requirements specified in the TPL-001-4 NERC Reliability Standard [1][1] for the years 2017 through 2026 (planning years one through ten). This report documents the assessment.

To help demonstrate that this assessment fully complied with [1], two tables were developed to assist in the reviewing of this report. The first table, Table 1.1 below, lists the various types of analyses that were performed as part of this assessment and the study years that were selected for each analysis.

Table 1.1: Analysis matrix showing the studies performed in this assessment

		Near-term horizon year					Far-term horizon year				
		1	2	3	4	5	6	7	8	9	10
Analysis	Load	2017	’18	’19	’20	2021	2022	’23	’24	’25	2026
Steady state	Peak	-	X	-	-	X	-	-	-	-	X
	Off-peak	-	-	-	-	X					
Steady state sensitivity	Peak	-	X	-	-	X					
	Off-peak	-	-	-	-	X					
Steady state spare equipment unavailability	Peak	-	X	-	-	-					
	Off-peak	-	-	-	-	X					
Short circuit	Peak	X	-	-	X	-					
Stability	Peak	-	X	-	-	-					
	Off-peak	-	-	-	-	X					
Stability sensitivity	Peak	-	X	-	-	-					
	Off-peak	-	-	-	-	X					

The second table, Table A.1 in Appendix A, lists every requirement in [1] along with the associated report sections that are intended to demonstrate compliance.

The remainder of this report is structured as follows:

- Section 2 provides the scope of this assessment
- Section 3 provides a brief description of the SMUD transmission system
- Section 4 provides the methodology and assumptions with which this assessment was performed
- Section 5 provides the results of this assessment

2 Scope

This assessment measured the system performance of the SMUD 230-kV system for the years 2017 through 2026 (planning years one through ten) with the specific goal of demonstrating compliance with [1].

[1]This report uses the IEEE convention in citing references. All references are listed in the References section on page 15.

3 System Description

SMUD, established in 1946, is the nation's sixth largest community-owned electric utility in terms of customer accounts with approximately 624,000 residential and business accounts. With a workforce of 2,000 employees, it provides electricity to a population of 1.4 million people in its 900-square-mile service territory covering Sacramento County and small portions of Placer and Yolo Counties.

SMUD is a summer-peaking utility and its all-time peak load is 3,299 MW. This peak occurred on July 24, 2006, a day in which local temperatures reached 108 °F.

The SMUD transmission system is a network of 230-kV transmission lines. SMUD also has a 115-kV network that primarily serves the Downtown Sacramento area, though this network was officially approved as non-BES as of June 14, 2016 by NERC via a Self-Determined Notice of Exclusion.

The SMUD transmission system is interconnected to two adjacent systems: the Pacific Gas & Electric (PG&E) system and the Western Area Power Administration (WAPA) system. The interties connecting SMUD to these systems are listed in Table 3.1.

Table 3.1: SMUD interties

Adjacent system	Intertie
PG&E	Rancho Seco–Bellota #1 230 kV line Rancho Seco–Bellota #2 230 kV line Gold Hill–Lake 230 kV line
WAPA	Elverta 230 kV substation (bus bar) Folsom–Orangevale 230 kV line Lake–Folsom 230 kV line Hurley–Tracy #1 230 kV line Hurley–Tracy #2 230 kV line O'Banion–Elverta #3 230 kV line O'Banion–Natomas 230 kV line Elverta–Hurley #1 230 kV line Elverta–Hurley #2 230 kV line

SMUD is registered with the North American Electric Reliability Corporation (NERC) as a Planning Coordinator (PC) and as a Transmission Planner (TP). SMUD is the only TP in the SMUD PC Area.

4 Methodology and Assumptions

The methodology and assumptions used in this assessment are detailed in the sections that follow.

4.1 Year one

Year one was defined as calendar year 2017 in this assessment. This meets the definition of Year One that was approved by NERC in its *Glossary of Terms Used in NERC Reliability Standards*. The other years in the planning horizon can be referenced in Table 4.1 on page 4.

4.2 System model representations

This assessment utilized accurate system models of the SMUD portion of the BES. The models used are maintained by SMUD and submitted to the WECC for use in the compilation of basecases for various study years and scenarios. These models use data consistent with that provided in accordance with all relevant modeling data reliability standards and are supplemented with data from other sources as necessary.

4.2.1 Existing facilities

The system models used in this assessment represented all existing facilities.

4.2.2 Extended duration outages

The system models used in this assessment did not represent any known outages of generation or transmission facilities with a duration of at least six months because there are no such known outages.

4.2.3 New planned facilities

The system models used in this assessment represented all new planned facilities. The only new planned facility is the Franklin 230 kV substation that will be interconnected between the Pocket and Rancho Seco 230 kV stations in early 2019.

4.2.4 Changes to existing facilities

As there are no planned changes to SMUD's existing facilities, the SMUD portion of the system models used in this assessment did not model any facility modifications.

4.2.5 Real and reactive load forecasts

The system models used in this assessment represented the most recent real power load forecasts described in [2]. The real power load forecasts assumed a coincident system peak for the SMUD system on a Wednesday in July with a high temperature of 110 °F. This high temperature corresponds to a 1-in-10 peak load forecast. The load forecast data from [2] is listed in Table 4.1 on page 4 for reference[2]. Except for the sensitivity analyses described in Sections 4.3.5.1 and 4.3.5.2, all peak loads referred to in this assessment are 1-in-10 peak load forecasts.

The reactive power load forecast assumed for this assessment was a 0.983 lagging power factor for all loads across all years. This forecast is based on the calculated power factor from SMUD's historical peak load.

4.2.6 Firm transmission service and interchange commitments

Firm transmission service and interchanges were not represented in this assessment since SMUD does not have any existing or projected commitments.

[2] The 1-in-10 load forecast values were taken from the "Managed with Scenarios" column of Table 13 in [2].

Table 4.1: 1-in-10 peak load forecast

Planning Year	Calendar Year	Load forecast (MW)
1	2017	3284
2	2018	3189
3	2019	3204
4	2020	3223
5	2021	3242
6	2022	3259
7	2023	3284
8	2024	3306
9	2025	3335
10	2026	3359

4.2.7 Resources required for load

The system models used in this assessment represented the supply side resources and their assumed dispatches for the peak and off-peak load conditions as listed in Table 4.2.

Table 4.2: Supply side resources and assumed dispatch by load condition

		Dispatch (Gross MW)	
Type	Plant	Peak	Off-peak
Hydro	Camino	100	20
	Jaybird	120	20
	Jones Fork	10	5
	Loon Lake	70	20
	Robbs Peak	20	5
	Union Valley	40	20
	White Rock	160	40
Thermal	Campbell Soup	150	150
	Carson Ice	90	-
	Cosumnes	485	485
	Kiefer Land Fill	15	-
	McClellan	60	-
	Procter & Gamble	150	-
	UCD Medical Center	25	-
	Total	1495	765

The system models represented the demand side resources in the peak load forecast via reduced load.

4.3 Steady state analysis

A steady state analysis was performed as part of this assessment to determine whether the SMUD portion of the BES meets the performance requirements in Table 1 of [1]. The analysis was also performed to assess the impact of extreme events identified in Table 1 of [1]. This analysis was supported by current studies.

4.3.1 Simulation software

All simulations performed for the steady state portion of this assessment were performed using the General Electric Positive Sequence Load Flow (PSLF) version 19.0_01 power flow software. This software is widely used throughout the WECC.

4.3.2 Peak load years studied

This assessment included a steady state analysis of peak loads for planning years two, five, and ten (i.e. 2018, 2021, 2026). Years two and five were selected for inclusion in this assessment. Year one was not selected since the summer peak load for year one will be only 6 months away when this report is finalized and since the peak load study cases jointly developed by the regional entities were developed for year two. Year ten was selected for inclusion because it is the year in the far-term planning horizon that is most stressed due to the higher peak load.

Peak load refers to the load forecast described in Section 4.2.5.

4.3.3 Off-peak load years studied

This assessment included a steady state analysis of off-peak loads for planning year five (i.e. 2021).

In this assessment, off-peak load refers to a minimum load scenario during the early morning hours on a day where the system load is at a very low level, voltages are higher than normal, and spinning generation is at a minimum. The forecasted minimum load used in this assessment, which was 900 MW, was determined using engineering judgment and load data from 2011 to the present day.

4.3.4 Extended duration outages

As noted in Section 4.2.2 above, there are no known outages with a duration of at least six months. As such, this assessment did not include a steady state analysis of P1 events from Table 1 in [1] with any known "extended duration" outages.

4.3.5 Sensitivity analysis

This assessment included two sensitivity analyses to demonstrate the impact of changes to basic assumptions used in the system models to the steady state reliability. Sensitivity cases for the peak and off-peak loads cases were developed by varying the certain conditions in such a way as to stress the system within a range of credible conditions that demonstrated a measurable change in system response. These sensitivity cases are described in the subsections below.

4.3.5.1 Real power load forecast sensitivity

A sensitivity analysis was performed on the peak load years described in Section 4.3.2 by using the extreme 1-in-20 peak load forecast in [2] instead of the 1-in-10 peak load forecast. This extreme forecast can be referenced in Appendix B. In general, the 1-in-20 peak load forecasts are 3 percent higher in load than the 1-in-10 peak load forecasts and are representative of a Wednesday in July with a high temperature of 112 °F.

The reactive power peak loads in these sensitivity cases were assumed to remain the same at a 0.983 lagging power factor.

4.3.5.2 Generation dispatch sensitivity

A sensitivity analysis was performed on the off-peak load year noted in Section 4.3.3 by changing the assumed generation dispatch. The sensitivity case used in this analysis was stressed by assuming the Cosumnes Power Plant was out of service, resulting in an increase in system imports and a decrease in online, spinning generation.

4.3.6 Spare equipment unavailability

SMUD's spare equipment strategy could result in the unavailability of the following major transmission equipment for one year or more:

- 50-MVAR 230 kV bus shunt capacitor at Elk Grove 230 kV substation
- 50-MVAR 230 kV bus shunt capacitor at Foothill 230 kV substation
- 50-MVAR 230 kV bus shunt capacitor at Natomas 230 kV substation

A steady state analysis was performed for years two and five of the peak load cases and for year five of the off-peak load case to assess the impact of the possible unavailability of the long lead time equipment noted above. The steady analysis included the evaluation of the P0, P1, and P2 category contingencies identified in Table 1 from [1].

All other major transmission equipment not listed above is either not used by SMUD or can be replaced or repaired in less than one year.

4.3.7 Contingencies studied

The steady state analysis was performed using contingencies listed in Table 1 from [1]. Only those planning events in Table 1 in [1] that were expected to produce more severe impacts on the SMUD portion of the BES were identified and included in this assessment. In addition, extreme events in Table 1 in [1] were identified and included in this analysis. The rationale for selecting the contingencies for the steady state analysis was based on engineering judgment, past studies, and knowledge of the SMUD and surrounding portions of the BES.

All contingencies simulated the removal of all elements that the protection system and other automatic controls are expected to disconnect without operator intervention. Generators with post-contingency steady state bus voltages below 0.95 voltage per unit were investigated to determine if the generators should be manually tripped to reflect actual protection equipment settings and generator limits. Transmission facilities were tripped when simulations showed post-contingency currents that exceeded 150 percent of their respective winter emergency ratings.

There are no existing or planned devices in the SMUD system that are designed to provide steady state control of electrical system quantities. All load tap changing transformers in the SMUD system are distribution transformers that are designed to automatically control the load side voltage. These load tap changers were not modeled in this assessment since they were assumed to operate outside of the post-transient time frames.

Table 4.3: Number of contingencies evaluated in the planning year two case

Category	Steady state	Stability
P0	1	1
P1.1	22	1
P1.2	135	17
P1.3	75	10
P1.4	3	0
P2.2	115	10
P2.3	195	9
P2.4	4	4
P3	1,793	4
P4.1	23	0
P4.2	351	12
P4.3	133	3
P4.4	3	0
P4.5	285	4
P4.6	2	1
P5.3	8	0
P5.5	12	12
P6	2,485	2
P7	107	8
Extreme 2a	1	-
Extreme 2b	21	-
Extreme 2c	3	-
Extreme 2d	7	3
Extreme 2e	1	-
Extreme 3ai	3	-
Extreme 3aiv	1	-
Extreme 3av	2	-
Total	5,791	101

A summary of the contingencies included in the steady state analysis of the planning year two case is shown in Table 4.3. The number of contingencies included for planning years five and ten differs due to the addition of the Franklin 230 kV substation described in Section 4.2.3.

The list of contingencies used in this analysis was coordinated with all adjacent Planning Coordinators and Transmission Planners to ensure that contingencies on adjacent systems which may impact the SMUD system were included in this assessment.

4.3.8 Performance requirements

The steady state analysis results for category P0 through P7 contingencies included in the analysis were evaluated against the performance requirements in Table 1 in [1]. These performance requirements can be summarized as:

- The system shall remain stable.
- Cascading and uncontrolled islanding shall not occur.

- Applicable facility ratings shall not be exceeded.
- Steady state voltages and post-contingency voltage deviations shall be within acceptable limits as established SMUD.
- Non-consequential load loss is not allowed for category P1, P2.1, and P3 contingencies.

For the steady state analysis, SMUD, which is its own Planning Coordinator and Transmission Planner, defined the acceptable limits for steady state voltages and post-contingency voltage deviations as those default limits defined in WR1 of [3]. Specifically, these limits are defined at all applicable BES buses as:

- Steady state voltages shall stay within 95 to 105 percent of nominal for the P0 event (system normal pre-contingency powerflow).
- Steady state voltages shall stay within 90 to 110 percent of nominal for P1 through P7 events (post-contingency powerflow).
- For P1 events, post-contingency steady state voltage deviations at each applicable BES bus serving load shall not exceed 8 percent of the pre-contingency voltage.

The results for the extreme contingencies were assessed for their impact to the system. If the results showed cascading caused by the occurrence of an extreme event, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the events was conducted.

In order to identify system instability, SMUD assumed the following definitions:

Cascading – 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.

Voltage instability – The violation of any of the low voltage criteria defined herein at any BES bus.

Uncontrolled islanding – The unplanned and uncontrolled splitting of the 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 the power system.

Events that resulted in cascading, voltage instability, or uncontrolled islanding, as defined above, were deemed unstable.

4.4 Short circuit analysis

A short circuit analysis was performed for this assessment to determine whether circuit breakers have adequate interrupting capability for faults they will be expected to interrupt. This analysis was supported by past studies [4] and [5] that are qualified per [1] since the past studies meet the following criteria:

- They are less than five calendar years old.
- No material changes have occurred to the SMUD system since the past studies were performed (i.e. SMUD has not added any transmission or significant generation facilities that would render the past studies invalid).

The qualified past studies modeled the system in 2015 and 2020, which is both before and after the Franklin 230 kV substation enters service. The Franklin substation is the only new planned facility in the planning horizon.

4.4.1 Simulation software

The short circuit analysis portion of this assessment was supported by studies that utilized the ASPEN Oneliner and Breaker Rating Module software program. This software program is widely used throughout the WECC.

4.4.2 Peak load years studied

The short circuit analysis was performed for years one and four in order to span the near-term transmission planning horizon.

4.4.3 Rating criteria

The criteria used in the short circuit analysis are based on industry standards developed and approved by the Institute of Electrical and Electronics Engineers in [6] and [7].

4.5 Stability analysis

A stability analysis was performed as part of this assessment to assess the performance of the SMUD system. This analysis was supported by current studies.

4.5.1 Simulation software

All simulations performed for the stability portion of this assessment were performed using the General Electric Positive Sequence Load Flow (PSLF) version 19.0_01 power flow software.

4.5.2 Peak load years studied

This assessment included a stability analysis of the peak load for planning year two. The rationale for selecting year two instead of year one is the same rationale described in Section 4.3.2.

4.5.3 Off-peak load years studied

This assessment included a stability analysis of the off-peak load for planning year five.

4.5.4 Sensitivity analysis

Similar to the steady state sensitivity analysis, two stability sensitivity analyses were performed to demonstrate the impact of changes to basic assumptions used in the system models to the stability of the system. Sensitivity cases for the peak and off-peak loads cases were developed by varying the certain conditions in such a way as to stress the system within a range of credible conditions that demonstrated a measurable change in system response. These sensitivity cases are described in the subsections below.

4.5.4.1 Real power load forecast sensitivity

As part of the stability assessment portion of this assessment, a sensitivity analysis was performed for the real power load forecast sensitivity described in Section 4.3.5.1.

4.5.4.2 Generation dispatch sensitivity

A stability sensitivity analysis was also performed for the generation dispatch sensitivity described in Section 4.3.5.2.

4.5.5 Impact of proposed material generation changes

A stability analysis was not performed for the far-term planning horizon since there are no planned material generation additions or changes in this planning horizon.

4.5.6 Contingencies studied

A stability analysis was performed using contingencies listed in Table 1 from [1]. Those planning events in Table 1 in [1] that were expected to produce more severe *stability* impacts on the SMUD portion of the BES were identified and included in this assessment. Extreme events were identified and included in the analysis as well.

The rationale for selecting the contingencies for the stability analysis was based on engineering judgment, past studies, and knowledge of the SMUD and surrounding portions of the BES.

All contingencies simulated the removal of all elements that the protection system and other automatic controls are expected to disconnect without operator intervention. Since high speed reclosing is not utilized for 3-phase faults in the SMUD system, it was not included in any of the events with 3-phase faults. Generators were tripped if simulations showed generator bus voltages or high side of the generator step-up voltages below the ride-through voltage limitations specified in the PRC-024 NERC Reliability Standard. Transmission lines and transformers were tripped when transient swings showed the potential to cause protection system operation based on generic relay models.

All existing devices that are designed to provide dynamic control of electrical system quantities, such as generator excitation systems, were simulated.

A summary of the stability contingencies evaluated in the stability analysis for planning year one is shown in Table 4.3 on page 7.

The list of contingencies used in this analysis was coordinated with all adjacent Planning Coordinators and Transmission Planners to ensure that contingencies on adjacent systems which may impact the SMUD system were included in this assessment.

4.5.7 Performance requirements

The stability analysis results for category P0 through P7 contingencies included in this analysis were evaluated against the performance requirements in Table 1 in [1]. These performance requirements can be summarized as:

- The system shall remain stable.
- Cascading and uncontrolled islanding shall not occur.
- Transient voltage response shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.[3]
- Non-consequential load loss is not allowed for category P1, P2.1, and P3 contingencies on the SMUD 230 kV system.
- For P1 events, no generating unit shall pull out of synchronism.

[3] SMUD is registered with NERC as both a Planning Coordinator and a Transmission Planner.

- For P2 through P7 events, generators that pull out of synchronism shall not cause apparent impedance swings that trip transmission system elements other than the generator unit and its directly connected facilities.
- For P1 through P7 events, power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and the Transmission Planner.

The results for the extreme contingencies were assessed for their impact to the system and not evaluated against any criteria. If the results showed cascading caused by the occurrence of an extreme event, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the events was conducted.

For this stability analysis, SMUD, which is its own Planning Coordinator and Transmission Planner, defined the acceptable limits for transient voltage response for the SMUD system as those limits defined in WR1 of [3]. Specifically, these limits were defined as follows:

- For all P1 through P7 events, voltages shall recover to 80 percent voltage of the pre-contingency voltage within 20 seconds of the initiating event for each applicable BES bus serving load.
- For all P1 through P7 events, following fault clearing and voltage recovery above 80 percent, voltage at each applicable BES bus serving load shall neither dip below 70 percent of pre-contingency voltage for more than 30 cycles nor remain below 80 percent of pre-contingency voltage for more than two seconds.

SMUD defined acceptable damping for power oscillations as that defined in WR1.6, which is that all oscillations must show positive damping within 30 seconds after the start of the event. Oscillations that did not meet this criterion were deemed unstable.

The criteria used to identify system instability is listed in Section 4.3.8.

4.6 System deficiencies

Corrective action plans were developed for those analyses that indicated an inability of the system to meet the respective performance requirements. Each corrective action plan included the associated actions needed to achieve the required system performance.

5 Results

The results of the steady state, short circuit, and stability analyses are described in the sections that follow.

5.1 Steady state

The results for the peak load cases identified the need for four corrective action plans to resolve thermal overloads across the near and far-term planning horizons. These corrective action plans are described below in detail and are also summarized in Table 5.1. The proposed CoSu Project referenced below is a project involving a new 500-kV transmission line that would originate somewhere along the Olinda–Tracy 500 kV line and terminate either north of or in the Sacramento region.

A sample of the steady state thermal results can be referenced in Appendix E on page 25.

It should be noted that although non-consequential load loss was utilized in the corrective action plans to mitigate various multiple contingencies, it was not utilized under “Footnote 12” in [1] to mitigate any P1, P2.1, or P3 contingencies.

Folsom–Lake & Orangevale–White Rock 230 kV lines out (P7) This n-2 contingency overloads the Hurley–Procter 230 kV line by 10 and 19 percent in the peak load year five and ten cases respectively. The corrective action plan for this contingency is to install a RAS by the summer of 2018 that would shed up to 85 MW of load at the Hurley 230 kV substation. If approved, the proposed CoSu Project would mitigate this overload in 2024 and eliminate the need for a RAS. Alternatives to the CoSu Project, such as a Hurley–Procter 230 kV line rerate, reconductor or rebuild project, will be explored by staff in 2017.

Tracy–Hurley #1 & #2 230 kV lines out (P7) This n-2 contingency also overloads the Hurley–Procter 230 kV line by 18 percent in the year ten peak load case. The corrective action plan for this contingency is to use the same RAS as the RAS described in the previous corrective action plan to shed up to 125 MW of load at the Hurley 230 kV substation. If approved, the proposed CoSu Project would mitigate this overload in 2024 and eliminate the need for a RAS. Alternatives to the CoSu Project, such as a Hurley–Procter 230 kV line rerate, reconductor or rebuild project, will be explored by staff in 2017.

Various faults at the Rancho Seco 230 kV station Four contingencies (of types P2 and P4) at the Rancho Seco 230 kV switchyard that all result in reduced generation at the Cosumnes Power Plant and the forced outage of the Rancho Seco–Bellota #1 230 kV line overload the remaining Rancho Seco–Bellota #2 230 kV line by 12 percent in the year ten peak load case. The corrective action plan for this contingency is to install a RAS by the summer of 2022 that would shed up to 170 MW of load at the Elk Grove 230 kV substation. If approved, the proposed CoSu Project would mitigate this overload in 2024 and eliminate the need for a RAS. Alternatives to the CoSu Project and the RAS will be explored by staff in 2017.

Rancho Seco–Bellota #1 & #2 230 kV lines out (P7) This n-2 contingency overloads the Tracy–Hurley 230 kV #1 & #2 230 kV lines as well as the Gold Hill–Lake 230 kV line in the peak load year ten case by up to 4 percent. If approved, the proposed CoSu Project would be in service before this contingency could potentially cause overloads. The corrective action plan for this contingency, should the CoSu Project be delayed or not be approved, is to install a RAS by the summer of 2026 that would shed up to 125 MW of load across at the Hurley 230 kV substation. Alternatives to the CoSu Project and the RAS will be explored by staff in 2017.

These corrective action plans are summarized in Table 5.1 on page 13.

The results for the off-peak load case did not identify any thermal overloads or voltage issues. There are no additional corrective action plans resulting from the steady state off-peak analysis.

5.1.1 Impact of extreme contingencies

Many extreme contingencies were simulated in this assessment, most of which produced severe results. Though extreme contingencies are very high impact, they have an extremely low probability of occurring.

The results showed the potential for cascading for some of the extreme contingencies included in the analysis. As such, an evaluation of possible actions to reduce the likelihood or mitigate the consequences was conducted. All possible actions considered were deemed too expensive and not justified given the probabilities of occurrence for the extreme contingencies.

Table 5.1: Summary of corrective action plans to meet performance requirements

Contingency	Impacted facilities	Corrective Action Plan	Year needed	Year in-service
Folsom–Lake & Orangevale–White Rock 230 kV lines (P7)	Hurley–Procter 230 kV line overload	• Install a RAS to shed firm load • Proposed CoSu Project	2020	2018 2024
Tracy–Hurley #1 & #2 230 kV lines (P7)	Hurley–Procter 230 kV line overload	• Install a RAS to shed firm load • Proposed CoSu Project	2022	2018 2024
Various faults at Rancho Seco 230 kV station (P2.3, P4)	Rancho Seco–Bellota #2 230 kV line overload	• Install a RAS to shed firm load • Proposed CoSu Project	2022	2022 2024
Rancho Seco–Bellota #1 & #2 230 kV lines (P7)	Tracy–Hurley #1 & #2 230 kV lines and Gold Hill–Lake 230 kV line	• Proposed CoSu Project • Install a RAS to shed firm load	2026	2024 2026

5.1.2 Sensitivity analysis

The peak load sensitivity analysis identified the same overloads as those identified with the 1-in-10 peak load cases.

The off-peak load sensitivity analysis did not identify any performance deficiencies.

There are no additional corrective action plans resulting from the steady state sensitivity analysis.

5.1.3 Spare equipment unavailability analysis

The results of the spare equipment unavailability analysis showed no performance deficiencies. As such, there are no recommendations for the spare equipment strategy.

5.2 Short circuit

The results of the short circuit analysis show that all circuit breakers in the SMUD system have adequate short circuit current interrupting capabilities. No corrective action plans are necessary to meet the performance requirements in [1]. However, Hurley circuit breakers 5814, 5820, 5828, and 5834 should be reviewed in the next assessment due to their high interrupting duties of 80 to 85 percent.

Tabulated results of the interrupting duties for all SMUD breakers can be referenced in Appendix C.

5.3 Stability

The stability analysis results did not identify any system deficiencies. All stability performance criteria defined in Section 4.5.7 were met for both the peak and off-peak load cases. No corrective action plans are necessary to meet the performance requirements in [1].

Sample output can be referenced in Appendix D.

5.3.1 Sensitivity analysis

The peak load and off-peak load stability sensitivity analyses did not identify any stability performance deficiencies; all performance criteria were met.

References

[1] *Transmission System Planning Performance Requirements*. NERC Reliability Standard TPL-001-4. May 7, 2014.

[2] *SMUD Load Forecast and Methodology 2016-2035*. Sacramento Municipal Utility District. May 2016.

[3] *WECC Criterion TPL-001-WECC-CRT-3 Transmission System Planning Performance*. Western Electricity Coordinating Council. September 21, 2016.

[4] *Assessment of Interruption Capability of 230 kV Circuit Breaker*. Sacramento Municipal Utility District. November 6, 2015.

[5] *Assessment of Interruption Capability of 230 kV Circuit Breaker Addendum*. Sacramento Municipal Utility District. December 18, 2015.

[6] *IEEE Application Guide for AC High-Voltage Circuit Breakers Rating on a Symmetrical Current Basis*. IEEE Std. C37.010-1999 (R2005).

[7] *IEEE Standard Rating Structure for AC High-Voltage Circuit Breakers*. IEEE Std. C37.04-1999.

Appendix A Requirements matrix

The table below lists the requirements in [1] and the associated sections in this assessment that demonstrate compliance.

Table A.1: Compliance requirements and their corresponding sections and pages

Requirement	Section	Page
R1	4.2	3
R1.1	-	-
R1.1.1	4.2.1	2
R1.1.2	4.2.2	2
R1.1.3	4.2.3	2
R1.1.3	4.2.4	3
R1.1.4	4.2.5	3
R1.1.5	4.2.6	3
R1.1.6	4.2.7	4
R2	-	-
R2.1	4.3	5
R2.1.1	4.3.2	5
R2.1.2	4.3.3	5
R2.1.3	4.3.4	5
R2.1.4	4.3.5	5
R2.1.5	4.3.6	6
R2.2	4.3.2	5
R2.2.1	4.3.2	5
R2.3	4.4	8
R2.4	4.5	9
R2.4.1	4.5.2	9
R2.4.2	4.5.3	9
R2.4.3	4.5.4	9
R2.5	4.5.5	10
R2.6	-	-
R2.6.1	-	-
R2.6.2	-	-
R2.7	4.6	11
R2.7.1	5.1	12
R2.7.2	-	-
R2.7.3	-	-
R2.7.4	-	-
R2.8	5.2	13
R2.8.1	-	32
R2.8.2	-	-
R3	4.3	4
R3.1	4.3.7	6
R3.2	4.3.7	6
R3.3	4.3.7	6

Continued on next page

Table A.1: *Continued from previous page*

Requirement	Section	Page
R3.3.1	4.3.7	6
R3.3.1.1	4.3.7	6
R3.3.1.2	4.3.7	6
R3.3.2	4.3.7	6
R3.4	4.3.7	6
R3.4.1	4.3.7	7
R3.5	4.3.7	6
R4	4.5	9
R4.1	4.5.6	10
R4.1.1	4.5.7	10
R4.1.2	4.5.7	10
R4.1.3	4.5.7	10
R4.2	4.5.6	10
R4.3	4.5.6	10
R4.3.1	4.5.6	10
R4.3.1.1	4.5.6	10
R4.3.1.2	4.5.6	10
R4.3.1.3	4.5.6	10
R4.3.2	4.5.6	10
R4.4	4.5.6	10
R4.4.1	4.5.6	10
R4.5	4.5.6	10
R5	4.3.8	7
R5	4.4.3	9
R5	4.5.7	10
R6	4.3.8	7
R7	3	2
R8	-	-
R8.1	-	-

Appendix B Peak loads

The differences between the 1-in-10 and 1-in-20 peak load forecasts are shown in the table below.

The 1-in-20 peak loads were derived from Table 13 and Table 14 in [2] by adding the “Station” and “Net Metered” columns in Table 13 to the 1-in-20 values in Table 14.

Table B.1: Peak load comparison

		Peak load (MW)	
Planning Year	Calendar Year	1-in-10	1-in-20
1	2017	3284	3396
2	2018	3189	3302
3	2019	3204	3318
4	2020	3223	3338
5	2021	3242	3358
6	2022	3259	3376
7	2023	3284	3402
8	2024	3306	3425
9	2025	3335	3456
10	2026	3359	3481

Appendix C Short circuit analysis data

The table below lists the interrupting duties of the SMUD circuit breakers.

Table C.1: Circuit breaker duties

		Interrupting Duty (%)	
Station	Breaker	2015	2020
Camino	330	30.6	30.6
Camino	340	30.6	30.6
Camino	350	31.0	31.0
Camino	360	31.0	31.0
Camino	370	29.0	29.0
Campbell Soup	4002	52.8	52.8
Campbell Soup	4008	40.8	40.8
Campbell Soup	4014	52.8	52.8
Carmichael	5900	36.6	36.6
Carmichael	5920	36.6	36.6
Carmichael	5930	53.8	53.8
Cordova	4202	53.9	53.9
Cordova	4208	50.2	50.2
Cordova	4214	53.9	53.9
Cordova	4220	53.9	53.9
Cordova	4226	53.5	53.5
Cordova	4232	53.9	53.9
Cordova	4244	53.9	53.9
Cordova	4250	53.9	53.9
Elk Grove	5402	48.6	48.6
Elk Grove	5408	43.5	43.5
Elk Grove	5414	48.6	48.6
Elk Grove	5420	59.7	59.7
Elk Grove	5426	53.3	53.3
Elk Grove	5432	59.7	59.7
Elk Grove	5438	59.7	59.7
Elk Grove	5444	59.7	59.7
Elk Grove	5456	59.7	59.7
Elk Grove	5462	59.7	59.7
Elverta	2	61.8	61.8
Elverta	6	61.1	61.1
Elverta	10	59.8	59.8
Elverta	14	60.3	60.3
Elverta	24	60.1	60.1
Foothill	5100	22.6	22.6
Foothill	5110	21.0	21.0

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Table C.1: *Continued from previous page*

		Interrupting Duty (%)	
Station	Breaker	2015	2020
Foothill	5122	30.8	30.8
Jaybird	460	21.5	21.5
Jaybird	470	18.4	18.4
Jaybird	480	21.3	21.3
Hedge	20	68.8	68.8
Hedge	28	68.8	68.8
Hedge	34	64.8	65.0
Hedge	40	68.8	68.8
Hedge	48	68.8	68.8
Hedge	54	56.6	56.9
Hedge	60	56.6	56.9
Hedge	68	55.9	55.9
Hedge	74	55.2	55.4
Hurley	5802	66.6	66.6
Hurley	5808	68.5	68.8
Hurley	5814	85.5	85.8
Hurley	5820	83.5	83.8
Hurley	5828	80.5	81.0
Hurley	5834	85.5	85.9
Hurley	5840	63.7	63.7
Hurley	5860	64.2	64.5
Hurley	5870	67.0	67.3
Hurley	5880	68.0	68.3
Hurley	5890	55.6	55.8
Lake	5202	44.5	44.5
Lake	5206	44.5	44.5
Lake	5210	54.7	54.7
Lake	5214	54.7	54.7
Lake	5220	54.7	54.7
Lake	5226	44.5	44.5
Lake	5230	54.7	54.7
Lake	5236	49.2	49.2
Lake	5242	54.7	54.7
Natomas	400	42.3	42.3
Natomas	410	35.2	35.2
Natomas	420	42.3	42.3
Natomas	470	42.3	42.3
Natomas	480	42.3	42.3
Orangevale	5702	67.1	67.1

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Table C.1: *Continued from previous page*

		Interrupting Duty (%)	
Station	Breaker	2015	2020
Orangevale	5708	46.2	46.2
Orangevale	5714	53.7	53.7
Orangevale	5718	55.7	55.7
Orangevale	5722	61.7	61.7
Orangevale	5728	63.2	63.2
Orangevale	5734	43.9	43.9
Pocket	5602	46.3	46.3
Pocket	5606	39.9	39.9
Pocket	5610	51.4	51.4
Pocket	5618	51.4	55.1
Pocket	5620	42.4	44.7
Pocket	5628	42.4	44.7
Procter & Gamble	5402	59.9	59.9
Procter & Gamble	5408	59.9	59.9
Procter & Gamble	5414	59.9	59.9
Procter & Gamble	5420	59.9	59.9
Rancho Seco	200	71.7	71.1
Rancho Seco	210	68.3	68.3
Rancho Seco	220	71.1	71.1
Rancho Seco	230	71.5	72.0
Rancho Seco	240	71.5	72.0
Rancho Seco	250	68.3	68.3
Rancho Seco	300	73.9	73.9
Rancho Seco	310	73.9	73.9
Rancho Seco	320	73.9	73.9
Rancho Seco	330	73.9	73.9
Rancho Seco	340	73.9	73.9
Rancho Seco	350	73.9	73.9
Union Valley	570	23.0	23.0
Union Valley	580	23.1	23.1
Union Valley	590	24.4	24.4
White Rock	230	46.9	46.9
White Rock	240	46.9	46.9
White Rock	250	46.9	46.9
White Rock	260	46.7	46.7
White Rock	270	43.1	43.1
White Rock	280	46.9	46.9

Appendix D Sample stability simulation output

The graphs below are a sample of the stability simulation output. The contingency shown is one with more severe results.

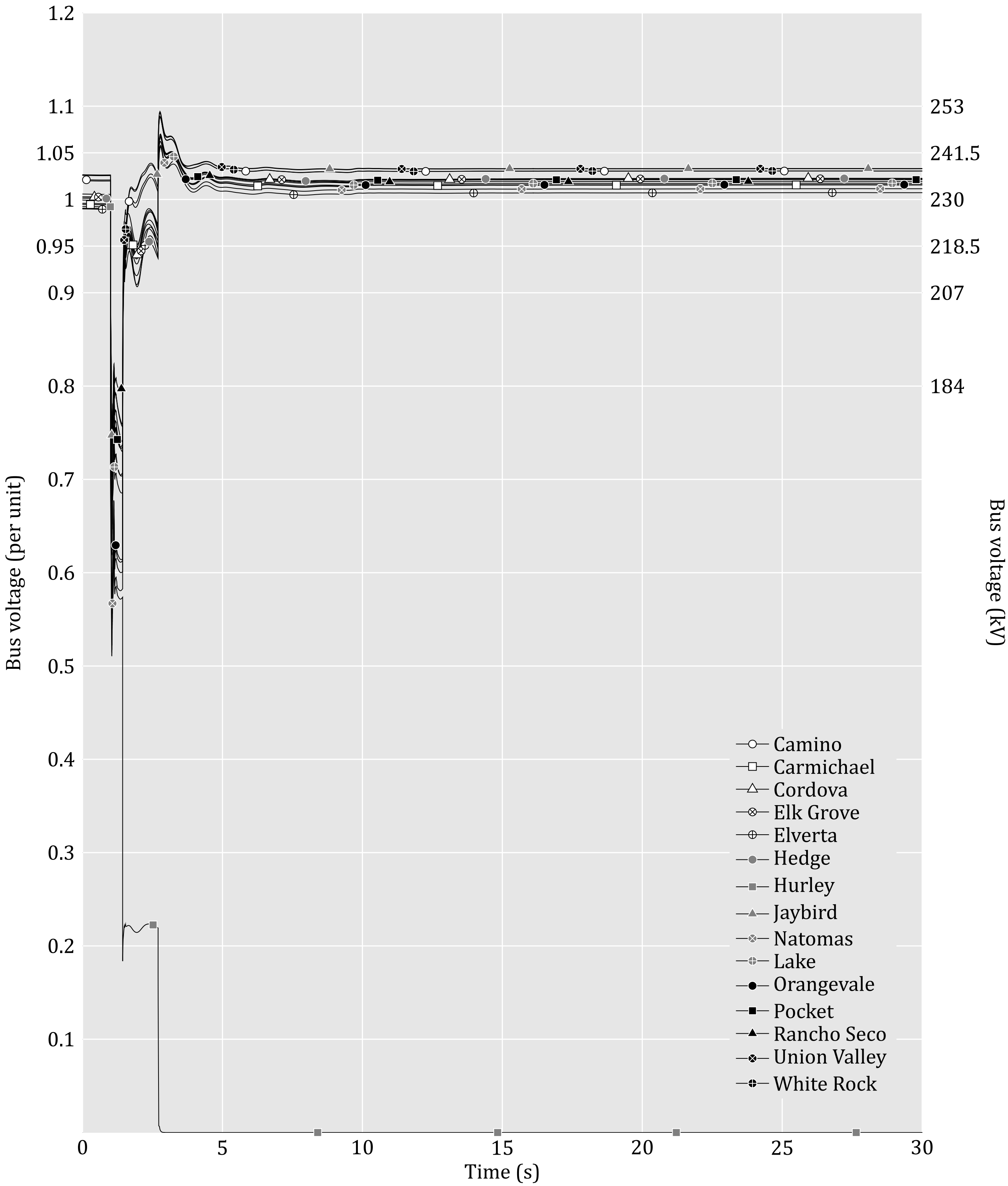

Figure D.1: Bus voltages following a Lake 230 kV 1-ϕ bus fault with relay failure in the peak year two case

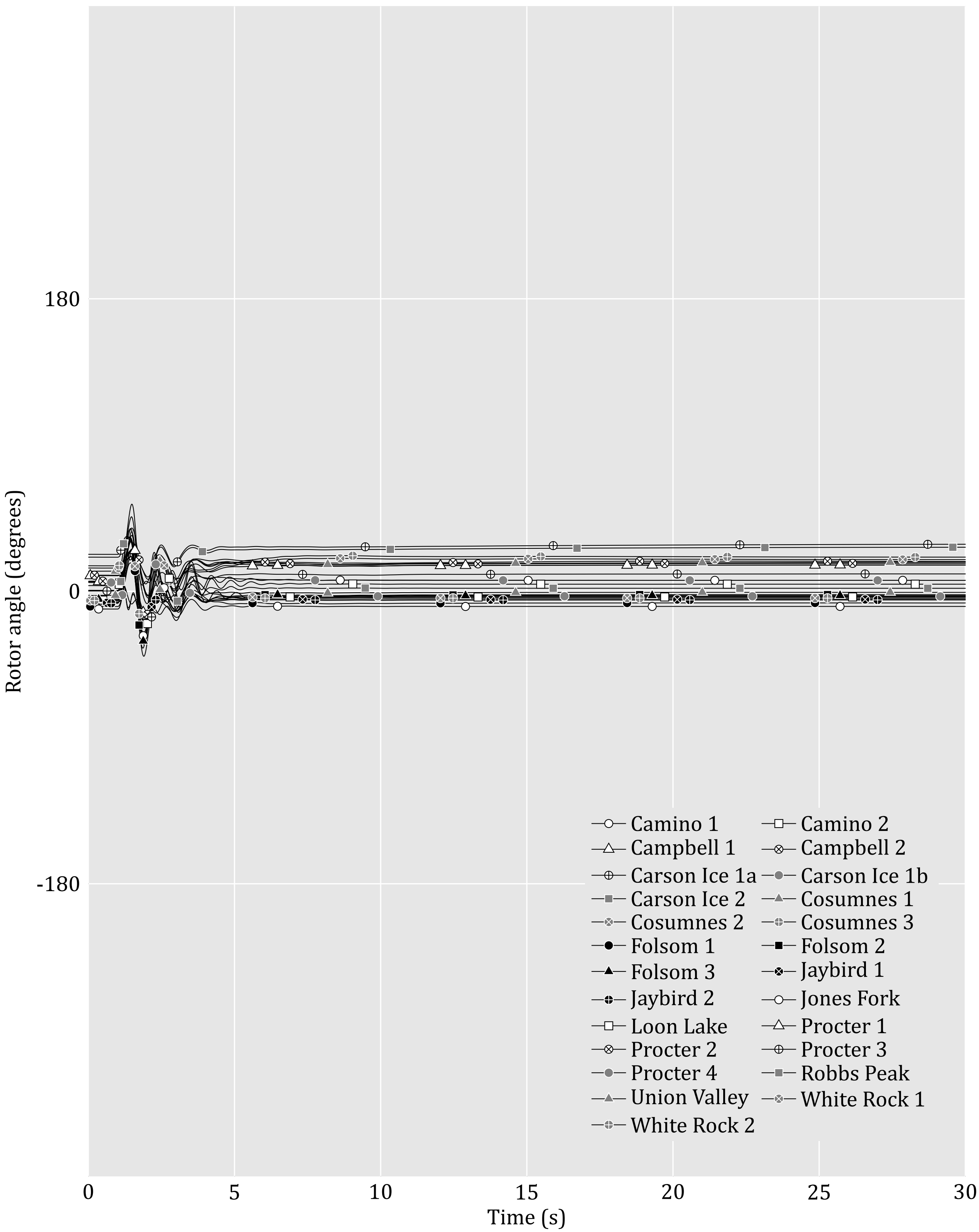

Figure D.2: Rotor angles following a Lake 230 kV 1-ϕ bus fault with relay failure in the peak year two case

Appendix E Sample steady state output

Table E.1: Sample steady state thermal loading results for the peak load years studied (only results with post-contingency loadings above 95 percent of summer emergency rating are shown)

			% of Emergency Rating		
Type	Contingency	Impacted Facility	18HS	21HS	26HS
P7	Folsom–Lake and Orangevale–White Rock 230 kV line outage	Hurley–Procter 230 kV #1 line	95	110	119
P7	Tracy–Hurley #1 and #2 230 kV line outage	Hurley–Procter 230 kV #1 line	<95	100	118
P2.3	Rancho Seco 230 kV breaker fault (1LG in BKR 210)	Rancho Seco–Bellota 230 kV #2 line	<95	95	112
P4.2	Rancho Seco–Bellota #1 230 kV line outage with stuck breaker (1LG fault with RAN BKR 210 stuck)	Rancho Seco–Bellota 230 kV #2 line	<95	95	112
P4.5	Rancho Seco 230 kV bus fault (1LG fault with BKR 210 stuck)	Rancho Seco–Bellota 230 kV #2 line	<95	95	112
P4.3	Cosumnes STG1 230/16.5 kV GSU transformer outage with stuck breaker (1LG fault with BKR 210 stuck)	Rancho Seco–Bellota 230 kV #2 line	<95	95	112
P7	Rancho Seco–Bellota #1 and #2 230 kV line outage	Tracy–Hurley 230 kV #2 line	<95	<95	104
P7	Rancho Seco–Bellota #1 and #2 230 kV line outage	Gold Hill–Lake 230 kV #1 line	<95	<95	102
P7	Rancho Seco–Bellota #1 and #2 230 kV line outage	Tracy–Hurley 230 kV #1 line	<95	<95	101
P2.3	Rancho Seco 230 kV breaker fault (1LG in BKR 250)	Rancho Seco–Bellota 230 kV #1 line	<95	<95	100
P3	Cosumnes CTG2 generator outage and Rancho Seco–Bellota #2 230 kV line outage	Rancho Seco–Bellota 230 kV #1 line	<95	<95	100
P3	Cosumnes CTG3 generator outage and Rancho Seco–Bellota #2 230 kV line outage	Rancho Seco–Bellota 230 kV #1 line	<95	<95	100
P4.2	Rancho Seco–Bellota #2 230 kV line outage with stuck breaker (1LG fault with RAN BKR 250 stuck)	Rancho Seco–Bellota 230 kV #1 line	<95	<95	100
P4.3	Cosumnes CTG3 230/18 kV GSU transformer outage with stuck breaker (1LG fault with BKR 250 stuck)	Rancho Seco–Bellota 230 kV #1 line	<95	<95	100
P4.5	Rancho Seco 230 kV bus fault (1LG fault with BKR 250 stuck)	Rancho Seco–Bellota 230 kV #1 line	<95	<95	100

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Table E.1: *Continued from previous page*

			% of Emergency Rating		
Type	Contingency	Impacted Facility	18HS	21HS	26HS
P6	Rancho Seco–Bellota #2 230 kV line outage and Tracy–Hurley #1 230 kV line outage	Rancho Seco–Bellota 230 kV #1 line	<95	<95	100
P3	Cosumnes CTG2 generator outage and Rancho Seco–Bellota #1 230 kV line outage	Rancho Seco–Bellota 230 kV #2 line	<95	<95	100
P3	Cosumnes CTG3 generator outage and Rancho Seco–Bellota #1 230 kV line outage	Rancho Seco–Bellota 230 kV #2 line	<95	<95	100
P6	Rancho Seco–Bellota #1 230 kV line outage and Tracy–Hurley #1 230 kV line outage	Rancho Seco–Bellota 230 kV #2 line	<95	<95	100
P6	Rancho Seco–Bellota #1 230 kV line outage and Tracy–Hurley #1 230 kV line outage	Rancho Seco–Bellota 230 kV #2 line	<95	<95	99
P6	Rancho Seco–Bellota #2 230 kV line outage and Gold Hill–Lake 230 kV line outage	Rancho Seco–Bellota 230 kV #1 line	<95	<95	98
P6	Rancho Seco–Bellota #1 230 kV line outage and Gold Hill–Lake 230 kV line outage	Rancho Seco–Bellota 230 kV #2 line	<95	<95	98
P7	Elk Grove–Rancho Seco #1 and #2 230 kV line outage	Campbell–Hedge 230 kV #1 line	<95	<95	98
P6	Tracy–Hurley #2 230 kV line outage and Orangevale–White Rock 230 kV line outage	Hurley–Procter 230 kV #1 line	<95	<95	97
P5.3	White Rock #1 230/13.8 kV GSU transformer outage with relay failure	Camino–Lake 230 kV #1 line	96	96	97
P5.3	White Rock #2 230/13.8 kV GSU transformer outage with relay failure	Camino–Lake 230 kV #1 line	96	96	97
P6	Tracy–Hurley #2 230 kV line outage and O'Banion–Olinda 230 kV line outage	Hurley–Procter 230 kV #1 line	<95	<95	96
P6	Tracy–Hurley #1 230 kV line outage and Orangevale–White Rock 230 kV line outage	Hurley–Procter 230 kV #1 line	<95	<95	95