SMUD
SACRAMENTO MUNICIPAL UTILITY DISTRICT
The Power To Do More.℠
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December 22, 2008
SOR08-167

California Energy Commission
Docket Unit
Attn: Docket 09-IEP-1D
1516 Ninth Street, MS-4
Sacramento, CA 95814-5512

Attached is the Sacramento Municipal Utility District's (SMUD) annual long-term transmission plan.

The attached Ten-Year Plan Report outlines the timing and need for reliability-based system improvements that would allow the District to meet the 1-in-10 adverse load forecasts. These are SMUD staff proposals and are not intended to indicate SMUD management or Board approval. Please note that these proposed transmission projects require coordination with neighboring entities and notification to applicable parties will take place following internal SMUD approvals.

If you have any questions, please contact Craig Cameron at (916) 732-5363 or ccamero@smud.org.

Sincerely,

Vicken E. Kasarjian
Director, System Operations and Reliability
Sacramento Municipal Utility District

SMUD
2008 Ten-Year Transmission Plan Assessment

FINAL

November 18, 2008

Sacramento Municipal Utility District

Prepared by: ______________________ Date: 11/18/08
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Executive Summary

Sacramento Municipal Utility District (SMUD), established in 1946, is the nation's sixth largest community-owned electric utility in terms of customers served.

SMUD service territory covers a 900 square miles area that includes Sacramento County and a small portion of Placer County. Within this service territory, SMUD owns 473 miles of transmission lines and 9,784 miles of distribution lines that provide electric service to approximately 590,000 customers.

SMUD service territory is a summer peaking area and experienced a record peak demand of 3,299 megawatts (MW) on July 24, 2006.

NERC/WECC Reliability Standards require SMUD to perform an annual electric transmission system assessment to ensure that SMUD's transmission facilities continue to meet all applicable reliability standards for near-term (years one through five) and long-term (years six though ten) planning horizons.

For this report, SMUD performed:

- *A ten year planning assessment of the SMUD transmission system*

  A comprehensive electric transmission system assessment of the Sacramento Area was performed to ensure that NERC Reliability Standards could be met through the ten year planning horizon. This year's assessment focused on years 2009 through 2018 that addressed the bulk electric system issues that impact both the LSC and the local area. In addition, it also evaluated the system impacts resulting from extreme bulk electric system disturbances.

- *An annual SMUD load serving capability (LSC) study*

  The LSC is the maximum load with all facilities in service that can be served while meeting all applicable reliability standards.

  For the near-term planning horizon (2009 through 2013) with the committed projects described in Table E-1, studies have shown that the District will be able to reliably serve load in all years.

  Several project alternatives provide margin above load serving requirements for the long-term planning horizon (2014 through 2018). A brief description of these projects is provided in Table E-2. For planning and modeling purposes only, the projects in Table E-2 are shown with a preliminary in-service date. No final decision has been made as to the timing or staging of these projects.

The District will evaluate the need and timing of these projects and make a recommendation in future assessments.

- *System reliability risk studies based on WECC/NERC planning standards*

  SMUD used the 2008 Pacific Gas and Electric (PG&E) Expansion Plan power flow base cases as a basis for this assessment. These cases incorporated a 1-in-10 year adverse peak load for both SMUD and the surrounding Sacramento Area. The base cases were then run against all contingencies applicable to Categories A, B, C, and D to identify any reliability concerns within the SMUD Area.

- *Transmission upgrade proposals to address reliability risks*

  Planning analysis identified the proposed Iowa Hill Project overloading the Folsom-Orangevale and Lake-Folsom 230 kV lines under Category C contingencies. SMUD proposes to reconductor the Orangevale-Folsom-Lake 230 kV circuit to mitigate the overload observed with the proposed Iowa Hill facility under Category C conditions.

- *Summarized planned transmission projects*

  The following projects identified in Table E-1 provide margin above LSC requirements to meet the 1-in-10 year load forecasts and meet the NERC Reliability Standards for years 2009-2013. These projects are committed and funds have been approved for their construction in order to meet the in-service date described in the table. A more detailed discussion of these projects can be found in Chapter 4 of this report.

Table E-1: Near-Term (Years 1-5) Planned Transmission Projects

Project Name	Project Description	Project Status	Expected In-Service Date
Second Hurley 230/115 kV Transformer	Install a second 230/115 kV Bank at Hurley Substation	Committed	December 20, 2008
Folsom Loop Project	Loop the Orangevale-Lake 230 kV into Folsom Substation	Committed	December 20, 2009
Cordova 230/69 kV Substation	New Distribution Substation	Committed	May 31, 2010
Upgrade SMUD Cogeneration Fleet	Upgrade turbine equipments	Committed	May 31, 2008 – May 31, 2010
Install 150 MVAr of Transmission Capacitors	Install transmission capacitors	Committed	May 31, 2009 – May 31, 2011
O'Banion-Elverta /Natomas230 kV Project	New 230 kV DCTL between O'Banion and Elverta/Natomas Substations	Committed	May 31, 2011

The following proposed projects identified in Table E-2 provide margin above the 1-in-10 year load forecasts and meet the NERC Reliability Standards for study years 2014 through 2018. A more detailed discussion of these projects can be found in Chapters 4 and 5 of the report. Subsequent to the technical studies performed for this ten-year assessment, three local resource initiatives have emerged as future alternatives. These include solar-thermal augmentation of the CPP plant, utility scale photovoltaic plants, and a solar-thermal powered plant in the southern part of the service area. These resources will be included in next year's ten-year assessment.

Table E-2: Long-Term (Years 6-10) Planned Transmission Projects

Project Name	Project Description	Project Status	Expected In-Service Date
Franklin 230/69 kV Substation	New Distribution Substation	Proposed	May 31, 2014
Tracy-Hurley 230 kV Interconnection (Project Zeta Phase I)	Interconnect a 230 kV source from Tracy into SMUD's system	Proposed	May 31, 2014
O'Banion-Sutter 230 kV DCTL Conversion	Add circuit breakers to convert O'Banion-Sutter line to double circuit tower line	Proposed	May 31, 2016
Iowa Hill Pump Storage Facility	New Hydro Plant in the UARP	Proposed	May 31, 2017
Install 200 MVAr of transmission capacitors	Install transmission capacitors	Proposed	May 31, 2017
Project Zeta (Phase II)	Interconnect a 500 kV source from Tracy into SMUD's system	Proposed	May 31, 2017

The Tracy-Hurley 230 kV Interconnection Project is a subset of Project Zeta being evaluated by Transmission Agency of Northern California (TANC) to provide transmission access for renewable resources located in northern California and northwestern Nevada regions.

The study results outlined in this report were based on the 1-in-10 load forecasts in Table 1-1 which were developed earlier this year and do not account for recent slowdown in the housing market and economic recession. Also, it does not include the full impact of the SMUD Board of Director's aggressive energy efficiency programs which are currently being redesigned to meet these goals. The long term load impacts of the current economic conditions and the load reductions from SMUD's redesigned energy efficiency programs will be captured in future assessments. Those studies will determine the impacts, if any, on the timing of the proposed projects.

Figure E-1 provides a graphical representation of the District's LSC compared to the High, Base and Energy Efficiency Potential load forecasts. The graph depicts LSC with all the committed and proposed projects and in-service dates described in Tables E-1 and E-2.

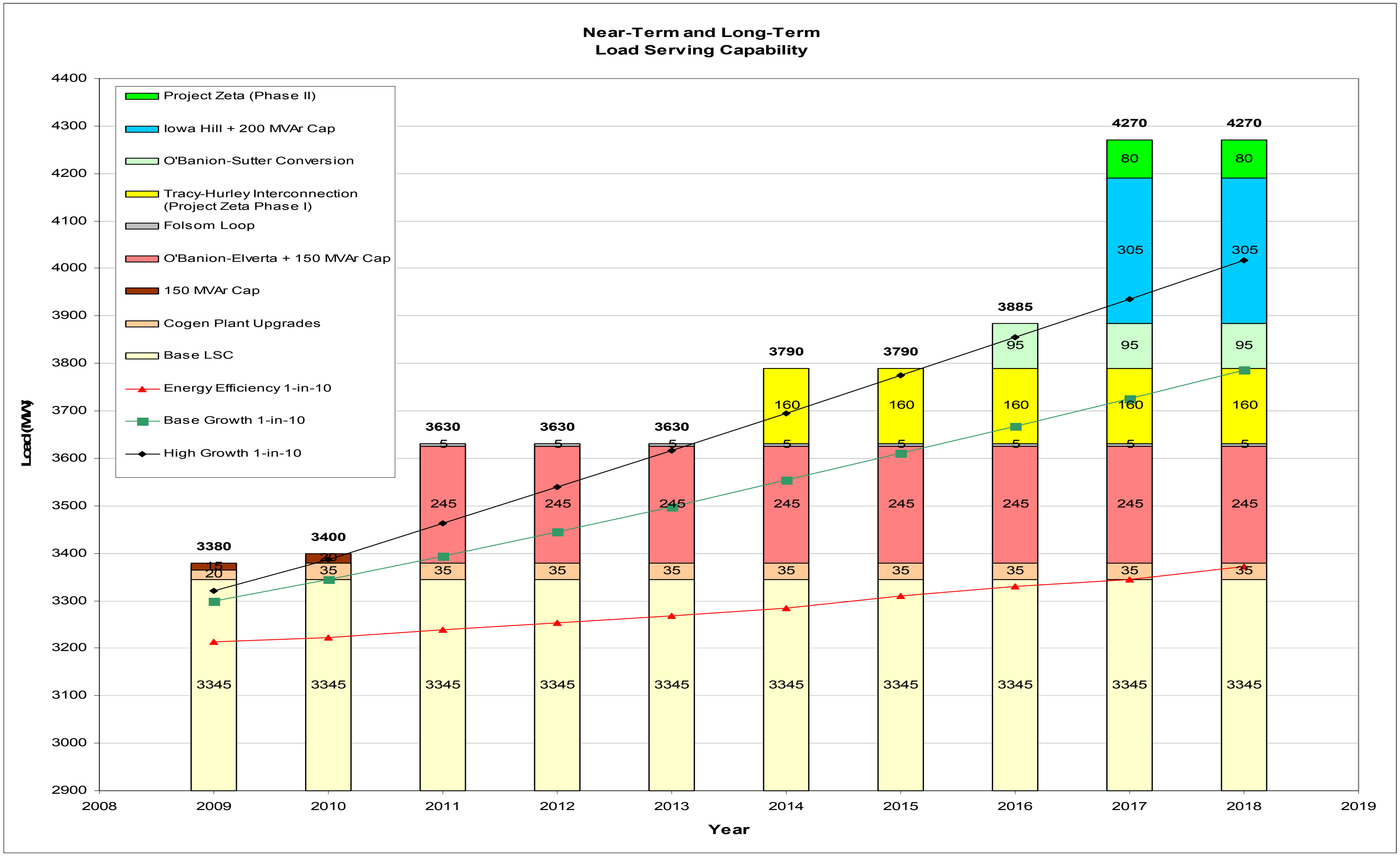

Figure E-1: LSC

Chapter 1: Introduction

1 Introduction

A comprehensive year-by-year electric transmission system assessment of the District's transmission system is performed annually to ensure that NERC Reliability Standards are met each year of the ten year planning horizon. This assessment includes the near-term (years 2009 through 2013) and the long-term (years 2014 through 2018) planning horizons.

The 2008 Pacific Gas and Electric (PG&E) Expansion Plan power flow base cases were used as a basis for this assessment. These cases incorporated a 1-in-10 year adverse peak load for both SMUD and the surrounding Sacramento Area and have all projected firm transfers modeled. These cases are modified to include recent load forecast revisions, reflect expected generation patterns, or include updates for project additions or deletions.

Besides peak system conditions, per NERC Reliability Standards (TPL-001 through TPL-004), a transient stability analysis along with an assessment of the District's system under off-peak conditions are studied and documented separately.

1.1 Reliability Criteria and Guidelines

SMUD used the NERC/WECC Planning Standards, the WECC reactive margin criteria and study methodology and study guidelines to assess the SMUD transmission system. See Appendix 3: NERC/WECC Reliability Standards for details.

1.2 Load Forecasts

The SMUD load forecast information is provided by the SMUD Business Planning and Budget Department. Load forecasts are updated annually and typically developed for a normal, 1-in-2 probability peak load, a 1-in-5 probability peak load, and an adverse, 1-in-10 probability peak load.

Currently, Power System Assessment (PSA) performs local Sacramento Area transmission assessment studies with the 1-in-10 adverse customer load growth forecast to ensure that NERC/WECC reliability standards are maintained.

Three load growth scenarios are provided: the High growth case, the Base customer load growth case and the Energy Efficiency Potential case.

The High growth case increases at an average rate of 77 MW per year (2.1%). The load is based on historical load growth between 2000 and 2006. This case does not include the planned expansions of SMUD energy efficiency programs and does not reflect the decline in customer growth in 2008.

The Base customer growth case increases at an average rate of 54 MW per year (1.5%). This scenario was based on population projections in Sacramento County from Global Insight Inc. and the California Department of Finance, Population and Demographic Unit in 2007. This case does not include the planned expansions of SMUD's energy efficiency programs and does not reflect the decline in customer growth in 2008.

The Energy Efficiency Potential case reflects a reduction in energy use due to SMUD energy efficiency programs. Based on a recent study completed for SMUD which quantifies the potential load reductions based on the current stock energy efficient end-use appliances, SMUD energy efficiency programs will have a positive impact on energy use. The impact level is included in the forecasts; however, only half of the goals adopted by SMUD 's Board of Directors in 2007. The adopted goals include benefits of future energy efficiency technologies and programs which have yet to be designed and offered to customers. Based on these assumptions, the Energy Efficiency Potential growth case increases at an average rate of 18 MW per year (0.5%).

Table 1-1 provides the year by year load projections for the High Growth, Base Growth and Energy Efficiency Potential load forecasts. Figure 1-1 is a graphical representation of the load forecast scenarios shown in Table 1-1 along with recorded historical peaks.

Table 1-1: Demand Load Forecasts

1-in-10 Forecast	2009 (MW)	2010 (MW)	2011 (MW)	2012 (MW)	2013 (MW)	2014 (MW)	2015 (MW)	2016 (MW)	2017 (MW)	2018 (MW)	Average Rate (MW /Year)	Average Rate (%/ Year)
High Growth	3,321	3,387	3,463	3,539	3,616	3,695	3,774	3,854	3,935	4,017	77	2.1
Base Growth	3,299	3,344	3,393	3,445	3,498	3,553	3,610	3,668	3,726	3,785	54	1.5
Energy Efficiency Potential Growth	3,214	3,223	3,238	3,253	3,269	3,285	3,311	3,331	3,345	3,373	18	0.5

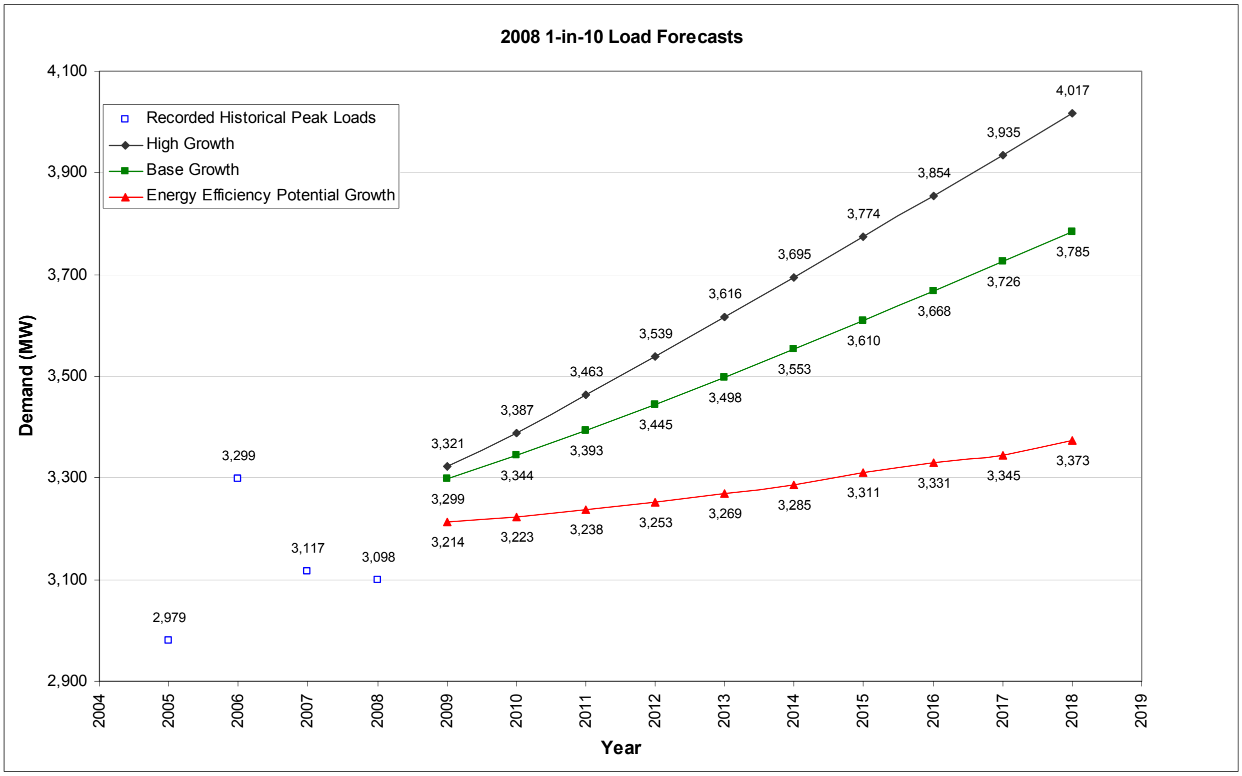

Figure 1-1: Load Forecasts (2009-2018)

The load forecasts in Table 1-1 were developed earlier this year and does not account for the recent slowdown in the housing market and current economic conditions. The long term load impacts of current economic conditions and forecasts of the load reductions from SMUD's redesigned energy efficiency programs will be captured in subsequent reliability assessments. Needs and timing of the proposed reliability base projects and new project initiatives will be included in these assessments.

1.3 Demand Side Management Programs

The District's current Demand Side Management (DSM) programs are not typically used for transmission planning purposes[1]. They allow for limited use during emergencies only. However, they may be used operationally during emergencies or for proposed mitigation in the event that transmission or generation projects are delayed. The use of existing DSM as mitigation in planning assessment studies should only be conducted in the near-term and approved as a valid mitigation by Operations Engineering.

The District currently maintains about 200 MW of Demand Side Management programs. There are two types of DSM: dispatchable and non-dispatchable.

[1] PSA recommend DSM be modeled discretely for evaluation of impact on the bulk electric system.

There is currently about 150 MW of dispatchable load management. This type of DSM consists of the SMUD Air Conditioning Load Management (ACLM) Program. The ACLM can be triggered easily by dispatchers within ten minutes and can be used during emergencies or to provide non-spinning reserves.

There is currently about 50 MW of non-dispatchable DSM Programs. This type of DSM consists of large customers that voluntarily reduce their load in exchange for a lower energy rate. To utilize this type of DSM, the District must give an appropriate notice to allow time for the customers to voluntarily reduce their load. This type of DSM could be used to reduce peak load if customers are given appropriate notice, but could not be depended on operationally in the event of an emergency.

DSM programs are currently being evaluated for re-design to allow for more frequent use and implementation being coordinated with a new two-way metering system and communication infrastructure. The District 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.

1.4 Reactive Power Assumption

The electric demand modeled in the base cases represents a 0.975 power factor based on input from Operation and real-time data.

Distribution Engineering evaluates transformer reactive loading and determines the appropriate locations to install distribution capacitors. There are approximately 1,500 MVAr of capacitors currently installed at distribution substations or out on the distribution feeders. These capacitors are included as part of the power flow load model.

Currently, there are approximately 695 MVAr of 69 kV, 21 kV and 12 kV capacitors that are used by transmission and distribution operators to maintain voltages on the bulk transmission system. Typically, new capacitors are installed at the low side of 230 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.

The District is also planning to install capacitors at the 230 kV level in the future. 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.

There are also 70 MVAr of shunt reactors located in the District’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.

1.5 Generation Assumption

Table 1-2 indicates the output level assumptions for the generating units in the SMUD transmission system.

Table 1-2: SMUD Area Generation Assumptions

Generation Type	SMUD Generation	Net Dependable Capacity (MW)	Power Flow Output Level (MW)
Hydro	Camino	150	100
	Jaybird	146	120
	Jones Fork	10	10
	Loon Lake	82	70
	Robbs Peak	20	20
	Union Valley	46	40
	White Rock	225	160
	Total Hydro Dispatch	*679*	*520*
Thermal	Campbell Soup	150	150
	McClellan	72	60
	Procter and Gamble	160	150
	Carson Ice	92	90
	Cosumnes	500	500
	UC Davis Medical Center	25	25
	Kiefer Land Fill[2]	0	0
	Total Thermal Dispatch	*1,016*	*975*
Total Generation Dispatch		**1,695**	**1,495**

1.6 Proposed and Planned Transmission Projects List

Table 1-3 lists the planned transmission projects that have an impact on the District's transmission network. This table lists only those projects that the District has committed to fund and construct. Some of these projects are very near completion while others are still in the design stage. A more detailed discussion of these projects can be found in Chapter 4 of the report.

Table 1-3: Near-Term Planned Transmission Projects

Project Name	Project Description	Year Proposal	Project Status	Expected Lead Time (Year)	Expected In-Service Date
Second Hurley 230/115 kV Transformer	Install a second 230/115 kV Bank at Hurley Substation	2006	Committed	2	December 20, 2008
Folsom Loop Project	Loop the Orangevale-Lake 230 kV into	2004	Committed	1	December 20, 2009

[2] Kiefer Land Fill is located on the distribution system and is not included in the power flow model.

Project Name	Project Description	Year Proposal	Project Status	Expected Lead Time (Year)	Expected In-Service Date
	Folsom Substation				
Cordova 230/69 kV Substation	New Distribution Substation	2004	Committed	4	May 31, 2010
Upgrade SMUD Cogeneration Fleet	Upgrade turbine equipments	2007	Committed	2	May 31, 2008 – May 31, 2010
Install 150 MVAr of Transmission Capacitors	Install transmission capacitors	2006	Committed	1	May 31, 2009 – May 31, 2011
O'Banion-Elverta/Natomas Project[3]	New 230 kV DCTL between O'Banion and Elverta Substations	2001	Committed	9	May 31, 2011

Table 1-4 lists the proposed transmission projects that have an impact on the District's ability to reliably serve the long-term load forecast. These projects have been identified as being required in the 2014 through 2017 time frame for load serving requirements with the high load growth scenario described in Section 1.2. As discussed in Section 1.2, timing for these projects are being reviewed as the high growth load forecast is being updated to reflect the slowdown in customer growth seen with the current economic conditions and demand reductions achievable with SMUD's aggressive energy efficiency goals. In addition, re-design of demand response programs may further reduce 1-in-10 peak demands. A more detailed discussion of these projects can be found in Chapters 4 and 5 of the report.

Table 1-4: Long-Term Proposed Transmission Projects

Project Name	Project Description	Year Proposal	Project Status	Expected Lead Time (Year)	Expected In-Service Date
Franklin 230/69 kV Substation	New Distribution Substation	2005	Proposed	6	May 31, 2014
Tracy-Hurley 230 kV Interconnection (Project Zeta Phase I)	Interconnect a 230 kV source from Tracy into SMUD's system	2008	Proposed	6	May 31, 2014
O'Banion-Sutter 230 kV DCTL Conversion	Add circuit breakers to convert O'Banion-Sutter line to double circuit tower line	2007	Proposed	1	May 31, 2016
Iowa Hill Pump Storage Facility[4]	New Hydro Plant in the UARP	TBD	Proposed	8	May 31, 2017
Install 200 MVAr of transmission capacitors	Install transmission capacitors	2007	Proposed	2	May 31, 2017
Project Zeta (Phase II)	Interconnect a 500 kV source from Tracy into SMUD's system	TBD	Proposed	TBD	May 31, 2017

[3] With the project environmental analysis taken longer than expected, the O'Banion-Elverta/Natomas 230 kV Project in-service date has been delayed to May 31, 2011.
[4] Giving the lengthy process of the UARP license approval, the Iowa Hill Project in-service date has been delayed to May 31, 2017.

Chapter 2: Load Serving Capability

2 Load Serving Capability

SMUD's LSC is the maximum load with all facilities in service that can be served while meeting all applicable reliability standards. The LSC is compared against the adverse peak load forecast to determine potential reliability constraints and the need for transmission or generation projects. The LSC should be larger than the forecast load and operating reserve requirements to ensure bulk transmission system reliability.

2.1 Near-Term Load Serving Capability

The near-term planning horizon is defined as years one through five in the NERC Reliability Standards. Studies have shown that the District will be able to reliably serve load in years 2009 through 2013 with the committed transmission projects identified in Table E-1 in service.

The LSC is limited by a thermal limitation for loss of the O'Banion-Elverta 230 kV #1 or #2 Line for years 2009 and 2010. Once the O'Banion-Elverta/Natomas 230 kV Project is in service (May 31, 2011), the LSC is limited by the WECC reactive margin criteria for loss of N-1 or N-2 of the Sutter-O'Banion 230 kV lines.

2.2 Long-Term Load Serving Capability

The long-term planning horizon is defined as years six through ten in the NERC Reliability Standards.

Figure 2-1 illustrates the LSC if all the committed and proposed projects described in Tables E-1 and E-2 are constructed.

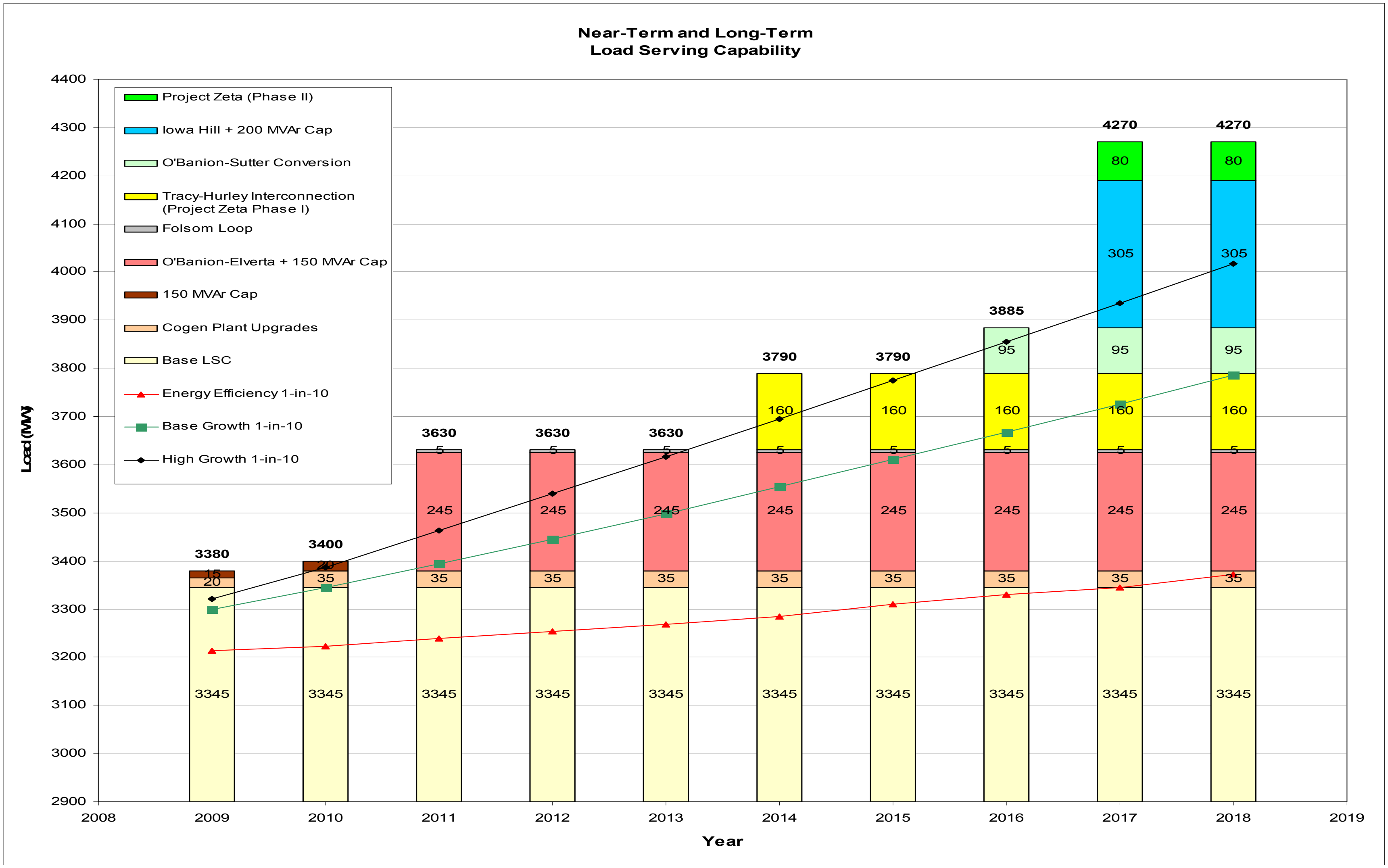

Figure 2-1: LSC

Chapter 3: Reliability Assessment Results

3 Reliability Assessment Results

A comprehensive year-by-year electric transmission system assessment of the Sacramento Area is performed annually to ensure that NERC Reliability Standards are met each year. In addition to the required minimum five year planning horizon, SMUD also performed analysis for up to ten years. The power flow base cases used for this assessment include existing and planned facilities. This assessment is based on all contingencies applicable to Categories A, B, C, and D. Refer to Table 3.1 and the following paragraphs for a review of the assessment results.

The assessment results were performed modeling the load growth scenarios described in Section 1.2. As described in that section, current load growth scenarios are lower and identified transmission requirements will be further reviewed to determine reliability based needs through the 2009 Ten-Year Assessment Plan.

3.1 Near-Term System Performance

The transmission assessment for the SMUD Area has demonstrated that there are no normal or emergency overloads for the near-term.

Category A – Normal Conditions

None

Category B – Loss of a Single Bulk Electric System Element

None

Category C – Loss of Two or More Bulk Electric System Elements

None

Category D – Extreme Events Resulting Loss of Two or More Bulk Electric System Elements

System performance following extreme events that remove multiple elements were evaluated for risks and consequences. Only the most severe contingencies were conducted as part of the reliability assessment. The documented results are given for informational purposes only and to be provided to WECC, as the Regional Reliability Organization (RRO), as required by the RRO.

3.2 Long-Term System Performance

The intention of the long-term analysis is more of a screening level and it is meant to identify transmission facilities where longer term review may be required to ensure the transmission system continues to meet all applicable reliability standards. Although, the long-term results are documented, future studies are still needed to verify the actual load demand and generation conditions. Therefore, the documented long-term results are given for informational purposes only until further studies are conducted.

The transmission assessment for the SMUD Area has demonstrated that there were no normal overloads for the long-term planning horizon. However, the analysis has identified a few 230 kV lines overloading under emergency conditions as follow:

Category A – Normal Conditions

None

Category B – Loss of a Single Bulk Electric System Element

Tracy-Hurley 230 kV #1 Line

The Tracy-Hurley 230 kV #1 Line is a critical import transmission line to serve the District's load and it has lower line ratings than the No.2 line. By 2014, either outage of the Tracy-Hurley 230 kV #2 Line with one of the Cosumnes Units offline or the Rancho Seco-Bellota 230 kV lines overload the Tracy-Hurley 230 kV #1.

Category C – Loss of Two or More Bulk Electric System Elements

Folsom-Orangevale and Lake-Folsom 230 kV Lines

With the operation of Iowa Hill Pump Storage Plant by year 2017, the Folsom-Orangevale and Lake-Folsom 230 kV lines (Folsom Loop Project in-service) exceed its emergency ratings by 6% and 1% respectively under DCTL outages. Reconductor of the Orangevale-Folsom-Lake 230 kV circuit will be necessary to mitigate the overload observed with the Iowa Hill facility.

Category D – Extreme Events Resulting Loss of Two or More Bulk Electric System Elements

Not required for long-term planning horizon

Table 3-1 provides detailed documentation of the overloads discovered over the near and long-term planning horizons.

Table 3-1: Assessment Results

NERC	Contingency	Affected Facility	Facility Rating SE (Amps)	2009 (%)	2010 (%)	2011 (%)	2012 (%)	2013 (%)	2014 (%)	2015 (%)	2016 (%)	2017 (%)	2018 (%)	Mitigation Plan
Normal Conditions														
A	Normal Overload	None												
Loss of a Single Bulk Electric System Element														
B2	Tracy-Hurley 230 kV #2 with one Cosumnes Unit Offline (L-1/G-1)	Tracy-Hurley 230 kV #1	992	< 95	< 95	< 95	< 95	< 95	**102** / <95[5]	**107** / < 95	**115** / < 95	99 / <95	**107** / <95	Tracy-Hurley 230 kV Project
Loss of Two or More Bulk Electric System Elements														
C5	Rancho Seco-Bellota 230 kV (PG&E) [Procter RAS] (N-2)	Tracy-Hurley 230 kV #1	992	< 95	< 95	< 95	< 95	96	**105** / < 95	**114** / < 95	**122** / < 95	**101** / < 95	**109** / < 95	Tracy-Hurley 230 kV Project
C5	Orangevale-Elverta and Orangevale-White Rock 230 kV (N-2)	Folsom-Orangevale 230 kV	879	< 95	< 95	< 95	< 95	< 95	< 95	< 95	< 95	**106** / < 95	**107** / < 95	Folsom-Orangevale 230 kV Reconductoring
C5	Camino-Lake and White Rock-Cordova 230 kV (N-2)	Lake-Folsom 230 kV	879	< 95	< 95	< 95	< 95	< 95	< 95	< 95	< 95	**101** / < 95	**103** / < 95	Lake-Folsom 230 kV Reconductoring
Extreme Event Resulting Loss of Two or More Bulk Electric System Elements														
C1[6]	Elverta 230 kV East Bus Section Outage (Western)	Elverta-Hurley 230 kV #2	1,205	154	166	< 95	< 95	< 95	Not Required for Long-Term Planning Horizon					Load and/or Generation Curtailment is allowed per NERC/WECC Planning Standards
C1	Elverta 230 kV West Bus Section Outage (Western)	Tracy-Hurley 230 kV #1	992	97	107	< 95	< 95	< 95						
C2	Elverta 230 kV Breaker 1182 Internal Fault or Failure (Western)	Elverta-Hurley 230 kV #2	1,205	148	160	100	100	101						
C2	Elverta 230 kV Breaker 182 Internal Fault or Failure [SEC RAS] (Western)	Folsom-Orangevale 230 kV	879	109	< 95	< 95	< 95	< 95						

[5] Post project thermal line loadings.
[6] NERC Transmission Standards Table A3-1 lists bus section outage and breaker failure under both the C and D categories.

NERC	Contingency	Affected Facility	Facility Rating SE (Amps)	2009 (%)	2010 (%)	2011 (%)	2012 (%)	2013 (%)	2014 (%)	2015 (%)	2016 (%)	2017 (%)	2018 (%)	Mitigation Plan
C2	Elverta 230 kV Breaker 182 Internal Fault or Failure [SEC RAS] (Western)	Tracy-Hurley 230 kV #1	992	102	< 95	< 95	< 95	< 95	Not Required for Long-Term Planning Horizon					Load and/or Generation Curtailment is allowed per NERC/WECC Planning Standards
C2	O'Banion 230 kV Breaker 2082 Internal Fault or Failure (Western)	Tracy-Hurley 230 kV #1	992	< 95	< 95	< 95	99	105						
D7	Elverta-Orangevale 230 kV Corridor Section 1 [with SEC RAS]	Folsom-Orangevale 230 kV	879	104	99	< 95	< 95	< 95						
D7	Elverta-Orangevale 230 kV Corridor Section 1 [with SEC RAS]	Tracy-Hurley 230 kV #1	992	102	110	< 95	< 95	< 95						
D7	Hurley-Procter 230/115 kV Corridor Section 1	Folsom-Orangevale 230 kV	879	102	99	95	98	102						
D7	Hurley-Procter 230/115 kV Corridor Section 1	Hedge-South City 115 kV #1and #2	580	103	100	100	104	109						
D7	Hurley-Procter 230/115 kV Corridor Section 1	South City-Station B 115 kV	880	102	98	98	104	111						
D7	UARP 230 kV Corridor Section 5	Orangevale-White Rock 230 kV	880	146	146	145	145	146						
D8	Loss of O'Banion 230 Substation	Tracy-Hurley 230 kV #1	992	98	110	112	115	117						
D8	Loss of O'Banion 230 Substation	Tracy-Hurley 230 kV #2	1,204	< 95	< 95	< 95	97	100						
D8	Loss of White Rock Substation	Lake-Camino 230 kV	880	102	102	101	101	101						

Chapter 4: Planned Transmission Projects

4 Planned Transmission Projects

The projects listed in this chapter are proposed projects from previous assessments that were included in the base assessment assumption. This chapter provides detailed information on the planned transmission projects:

4.1 Second Hurley 230/115 kV Transformer

EXPECTED IN-SERVICE DATE

December 20, 2008

PROJECT SCOPE

The scope of this project is to install a second Hurley 230/115 kV Transformer, rated at 200 MVA.

BACKGROUND

Currently, there is a single 230/115 kV transformer bank at Hurley Substation. Hurley Substation, a 230/115/70 kV substation, is located in the Arden Park Area. This substation is one of the three key substations that supplies electric service to downtown Sacramento. The other two substations serving downtown Sacramento are Hedge and Elverta.

SYSTEM IMPACTS

Planning analysis has demonstrated a reliability standard violation under double contingency for the existing Hurley 230/115 kV Transformer. The addition of the second Hurley 230/115 kV Transformer reduces loadings on the existing bank and Carmichael-Hurley, Hurley-Procter, and Procter-Hedge 230 kV lines.

ONE-LINE DIAGRAM

- Figure 4-1: Second Hurley 230/115 kV Transformer One-Line Diagram

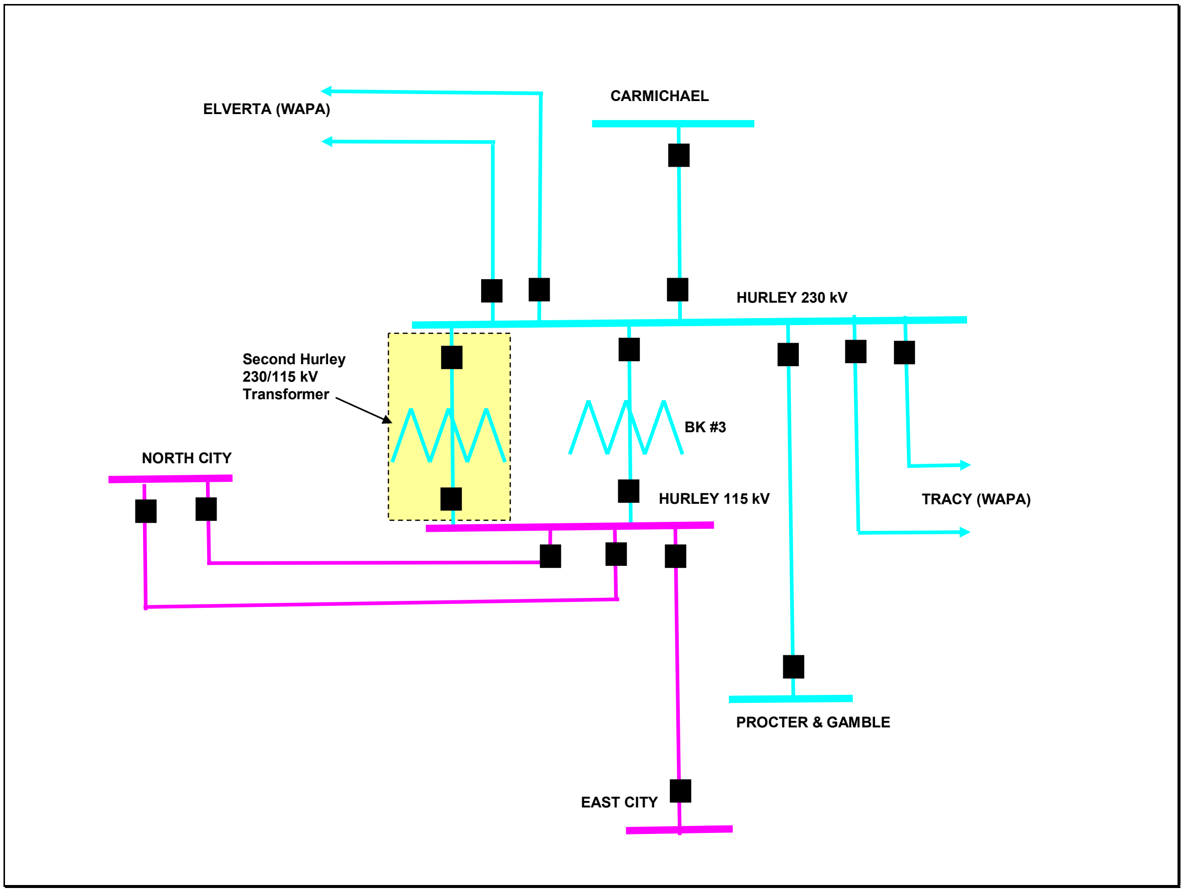

Figure 4-1: Second Hurley 230/115 kV Bank One-Line Diagram

4.2 Cordova 230/69 kV Substation

EXPECTED IN-SERVICE DATE

May 31, 2010

PROJECT SCOPE

This project is to construct a new distribution substation with a breaker and a half bus configuration consisting of 3 bays and 8-230 kV circuit breakers. One open 230 kV breaker position will be available for future substation expansion. In addition, 16 MVAr of capacitors are to be installed on the 69 kV low voltage bus and loop the White Rock-Hedge and Lake-Pocket 230 kV DCTL into the substation.

BACKGROUND

The Cordova (also know as Douglas) 230/69 kV Substation site is located in Rancho Cordova north of Grant Line Road. The substation is adjacent to the White Rock-Hedge and Lake-Pocket 230 kV DCTL.

SYSTEM IMPACTS

There are no NERC Reliability Standard violations associated with the construction of this substation. Primarily, Cordova Substation off loads the Hedge, Carmichael, and Lake substations.

ONE-LINE DIAGRAMS

- Figure 4-2: Cordova Substation One-Line Diagram
- Figure 4-3: Cordova Substation Location Diagram

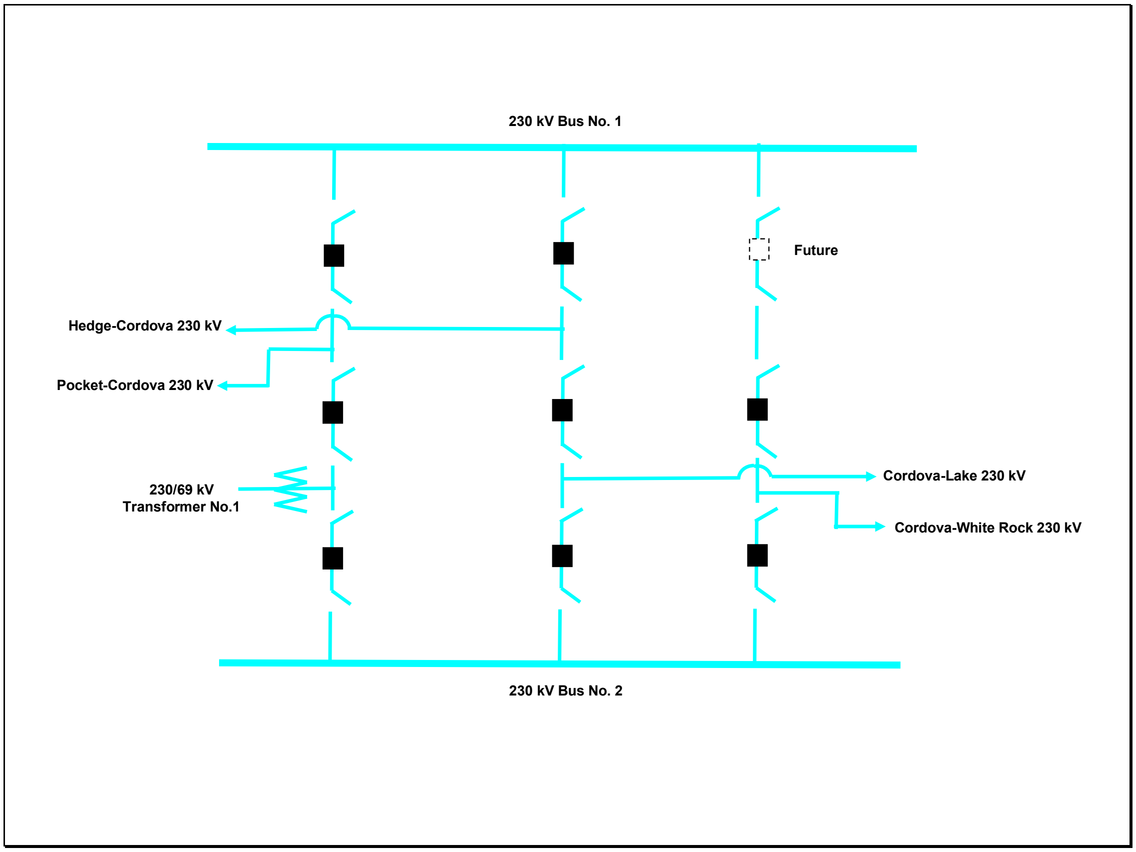

Figure 4-2: Cordova Substation One-Line Diagram

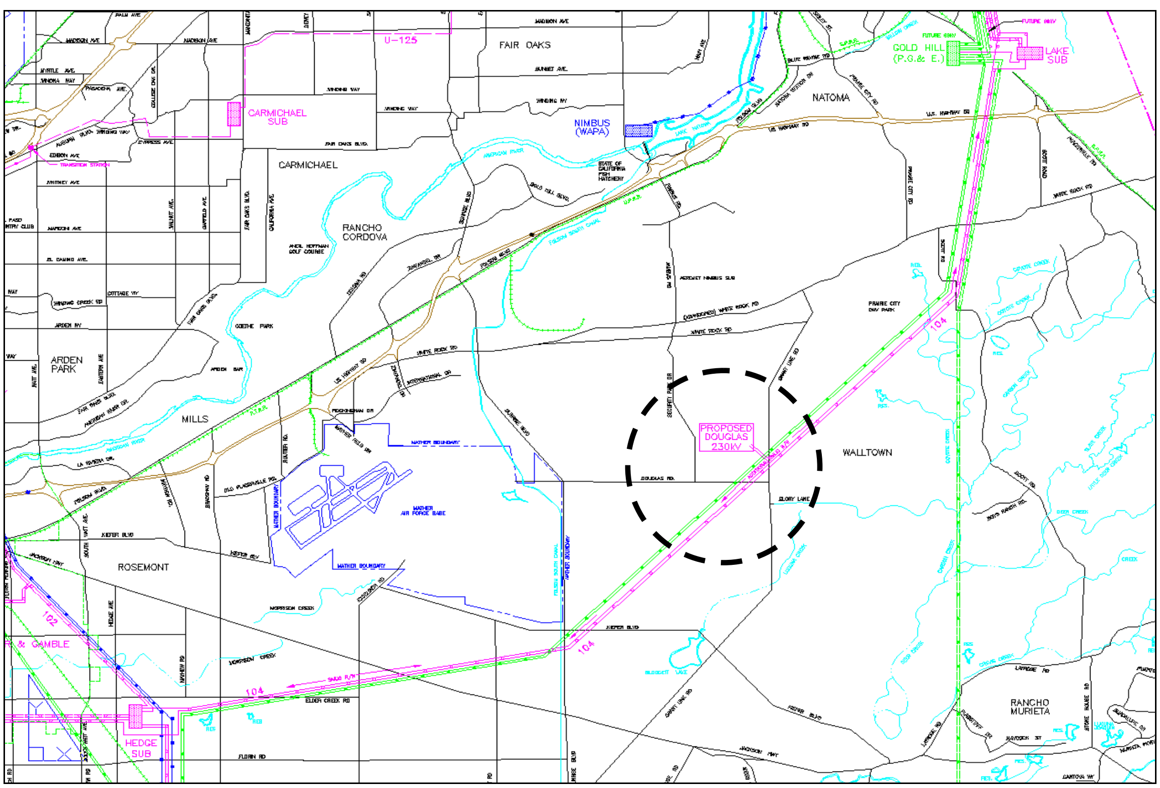

Figure 4-3: Cordova Substation Location Diagram

4.3 Folsom Loop Project

EXPECTED IN-SERVICE DATE

December 20, 2009

PROJECT SCOPE

This project requires looping SMUD's Orangevale-Lake 230 kV Line into Western's Folsom Substation. In addition, extending Folsom's main and transfer bus and installing two new 230 kV circuit breakers along with associated control and protection equipment will be required.

BACKGROUND

Since the City of Folsom Annexation and the removal of the Folsom-Gold Hill Line in 1987, the Folsom and Nimbus generation plants are connected radially via a single transmission line, namely the Folsom-Roseville 230 kV Line. Recently, due to the construction/relocation of the Folsom Bridge, the Orangevale-Lake 230 kV Line was re-routed directly adjacent to the Folsom Substation. The relocation of the 230 kV line provides an excellent opportunity for the interconnection.

SYSTEM IMPACTS

This project improves reliability by limiting the exposures on the Hurley-Carmichael 230 kV Underground Cable and mitigating overloads on the Elverta-Hurley and Elverta-Natomas 230 kV circuits for Category C contingencies. There will be an SPS installed and released to service by the end of this year to protect the Hurley-Carmichael UG Cable. In addition, the Folsom Loop Project provides operational stability to both the City of Roseville and Folsom and a redundant outlet for the Folsom and Nimbus generation thus eliminating them as a potential Most Severe Single Contingency (MSSC) for operating reserves.

ONE-LINE DIAGRAM

- Figure 4-4: Folsom Loop Project One-Line Diagram

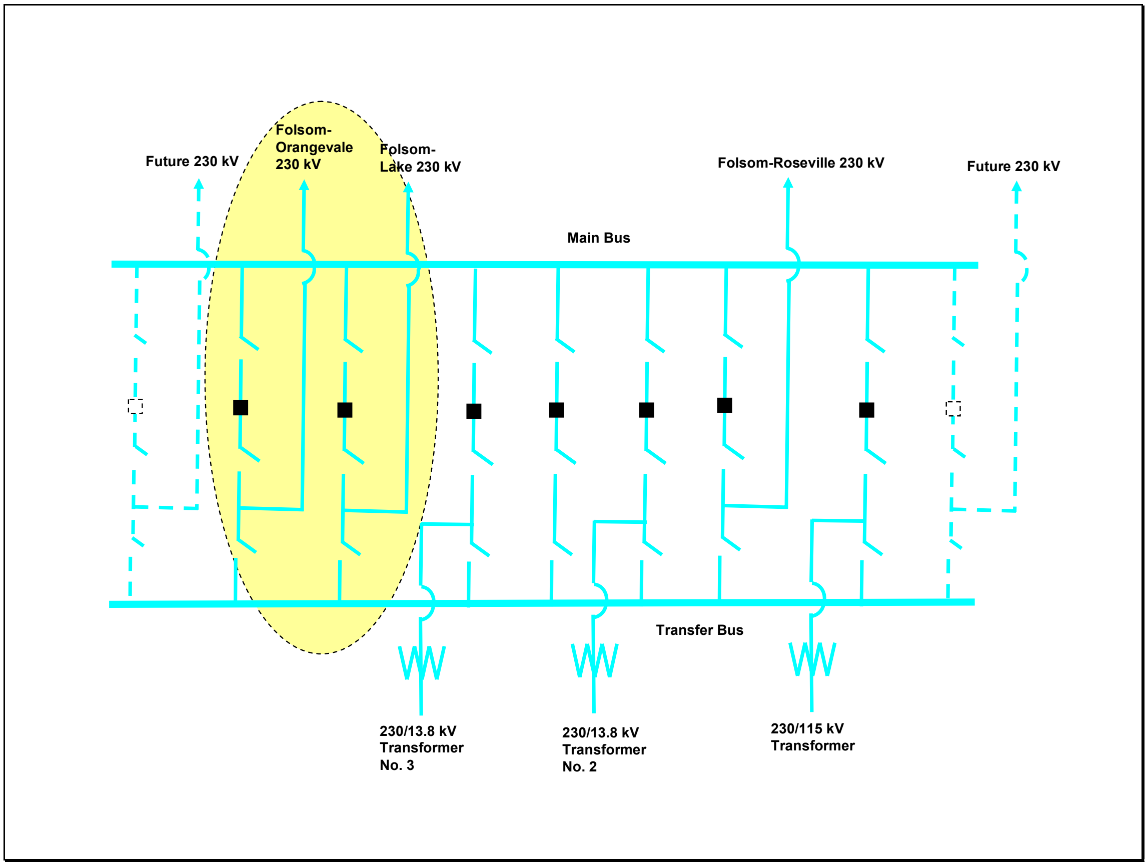

Figure 4-4: Folsom Loop Project One-Line Diagram

4.4 Cogeneration Plant Upgrades

EXPECTED IN-SERVICE DATE

May 31, 2008 – May 31, 2010

PROJECT SCOPE

The scope of this project is to upgrade the LM6000 fleet at Procter and Gamble and Carson Ice. The following is the anticipated schedule:

- Procter and Gamble LM6000 Upgrade (between May 31, 2008 and December 20, 2009) – upgrade to PC SPRINT/EFS (water injected for NOx control) to the combined cycle and peaker combustion
- Carson Ice LM6000 Upgrade (May 31, 2010) – upgrade to PC SPRINT/EFS (water injected for NOx control) to the combined cycle and peaker combustion.

BACKGROUND

The plant upgrades add generating capacity for high ambient temperature conditions. It is anticipated that an increase of approximately 32 MW can be achieved for the currently approved projects during high ambient temperature peak conditions. Planning studies have identified that the increase plant capacities at each facility improve the District's LSC and the operating efficiency of the existing generating units.

Procter and Gamble LM6000 Upgrade

The Procter and Gamble plant consists of a 2x1 combined cycle with fired duct burners and a peaker unit. The current maximum output is 164 MW and an increase of about 23 MW may be achieved with an upgrade to PC SPRINT/EFS (water injected for NOx control) to the combined cycle and peaker combustion turbines. The combined cycle engines are currently PA models of the LM6000 engine. The peaker, which was installed in 2001, is a PC model of the LM6000 engine. Upgrading the units to PC SPRINT/EFS adds hardware, water injection in the compressor section, an exhaust diffuser, and variable inlet guide vanes.

There are no NERC Reliability Standard violations associated with this upgrade.

Carson Ice LM6000 Upgrade

The Carson Ice plant consists of a combined cycle with a fired duct burner and a peaker unit. The current maximum output is 100 MW and an increase of about 9 MW may be achieved with a PA to PC SPRINT/EFS upgrade (water injected for NOx control) to the combined cycle combustion turbines.

There are no NERC Reliability Standards violations associated with this Plant upgrade.

The upgrades for three Procter and Gamble LM6000 units and one Carson Ice LM6000 units have been approved.

SYSTEM IMPACTS

There are no NERC Reliability Standard violations associated with the plant upgrades.

ONE-LINE DIAGRAM

- Figure 4-5: Location Diagram

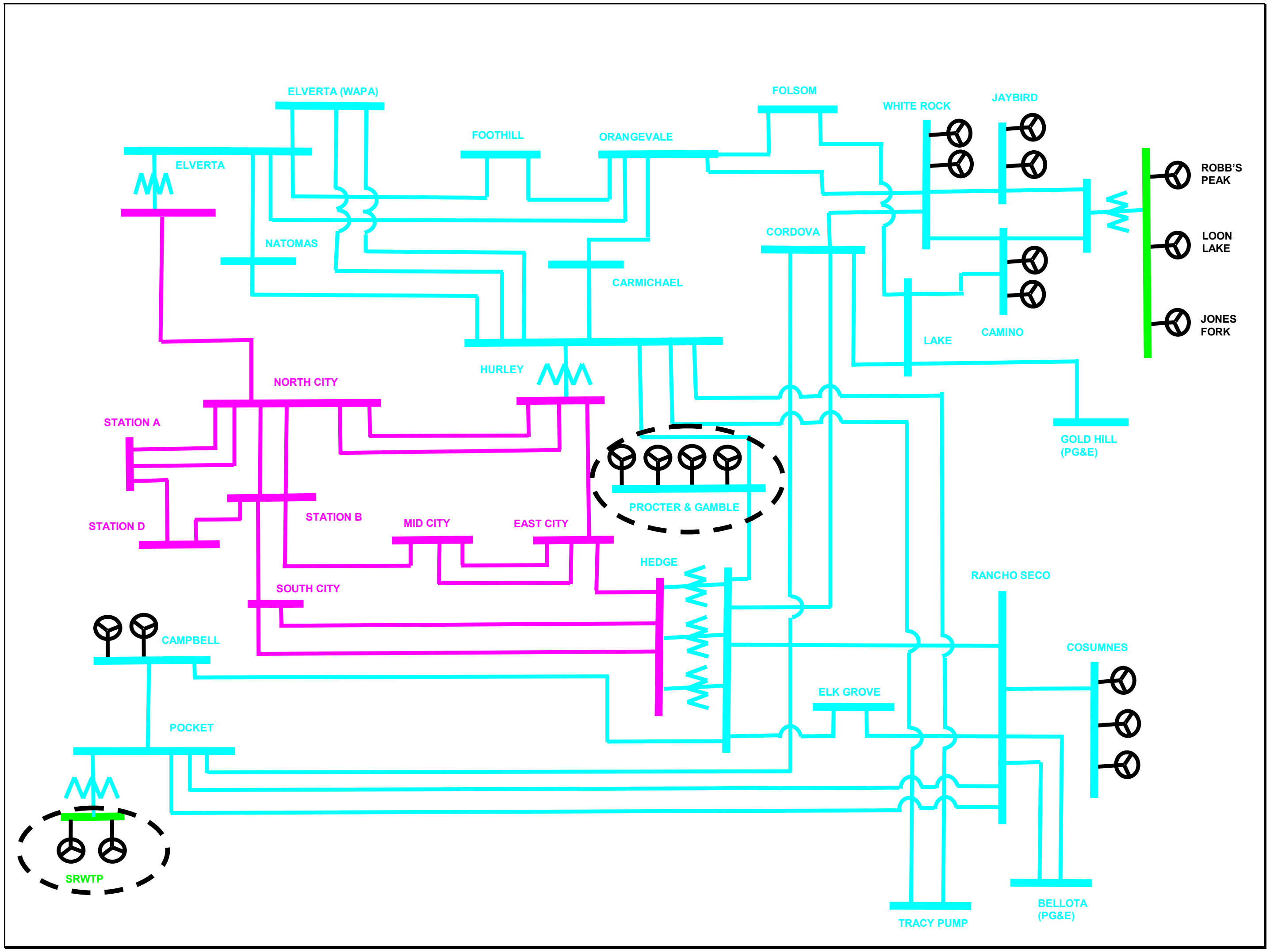

Figure 4-5: Location Diagram

4.5 150 MVAr Transmission Capacitor Bank

EXPECTED IN-SERVICE DATE

May 31, 2009 – May 31, 2011

PROJECT SCOPE

The scope of this project is to install a total of 150 MVAr of 230 kV transmission capacitors at the following substations:

- 50 MVAr at Elk Grove Substation (May 31, 2009)
- 50 MVAr at Pocket Substation (May 31, 2010)
- 50 MVAr at Hurley Substation (May 31, 2011).

BACKGROUND

The locations currently selected for transmission capacitor installations are Hurley, Elk Grove, and Pocket substations. These locations were selected primarily by evaluating the substation reactive load, voltage response to severe NERC Category C contingencies and the proximity to interconnection points with other utilities.

SYSTEM IMPACTS

The installation of 150 MVAr 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 distribution. The capacitors can also significantly increase the District's LSC once the O'Banion-Elverta/Natomas Project is in service.

ONE-LINE DIAGRAMS

- Figure 4-6: Location Diagram

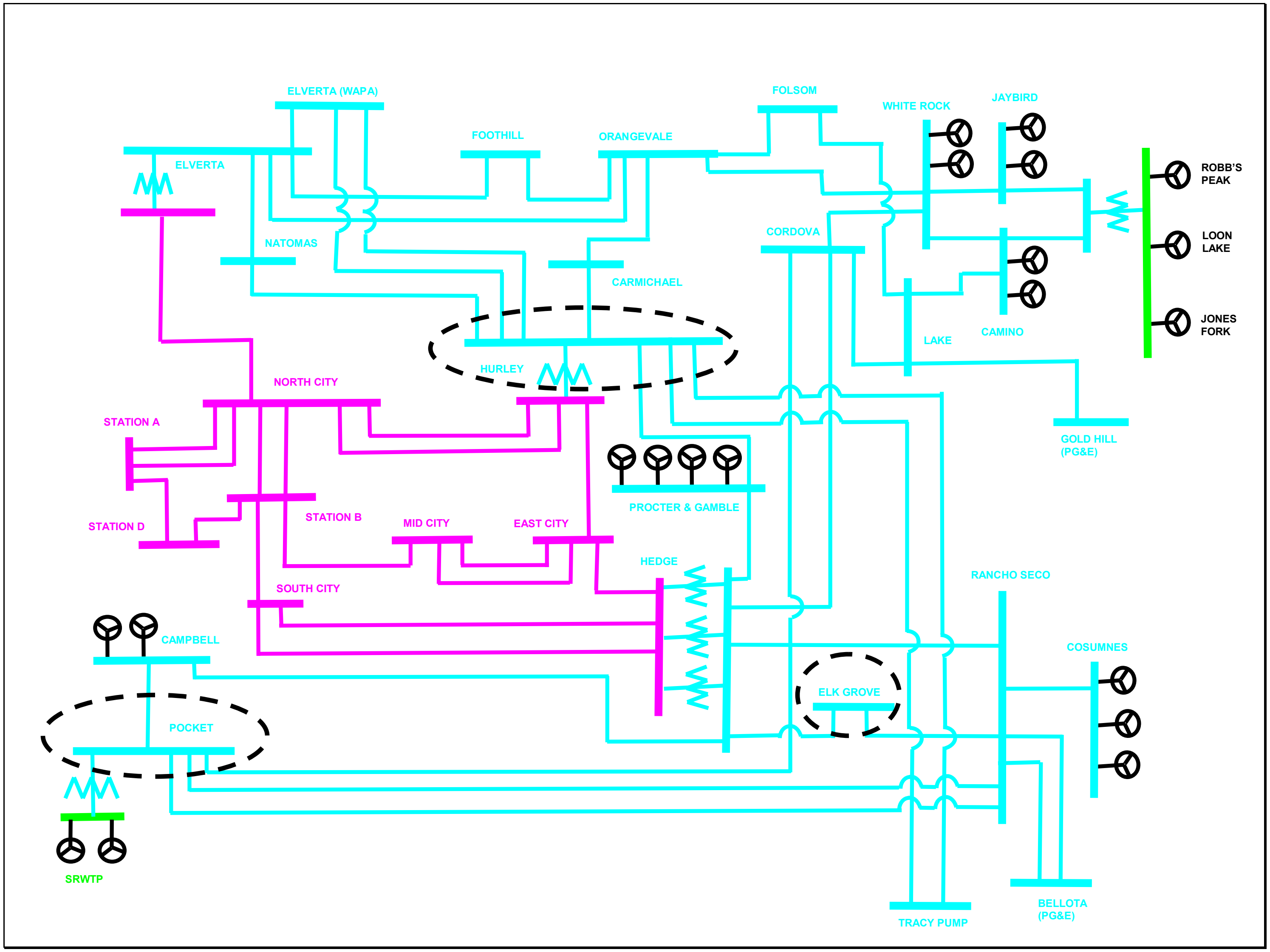

Figure 4-6: Location Diagram

4.6 O'Banion-Elverta/Natomas 230 kV Project

EXPECTED IN-SERVICE DATE

May 31, 2011

PROJECT SCOPE

The project involves opening and extending SMUD's existing Elverta-Natomas 230 kV line into Western's O'Banion Substation. The project will consist of constructing approximately 25 miles of a new double circuit transmission line from a point on the Elverta-Natomas right-of-way (ROW) into the O'Banion Substation. The project creates two new transmission circuits out of O'Banion, namely the O'Banion-Elverta 230 kV and O'Banion-Natomas 230 kV lines while eliminating the existing Elverta-Natomas 230 kV Line.

BACKGROUND

The O'Banion-Elverta/Natomas 230 kV Project is also known as the Sacramento Voltage Support (SVS) Project and provides significant reliability benefits. The main benefits are summarized as follows:

- Eliminates the most severe single and double contingencies that impact the reliability of the area
- Increases the ability of load serving entities in the Sacramento Area to reliably serve load
- Virtually eliminates the reliance on the operation of the Sutter Energy Center SPS to maintain reliability following a disturbance on the transmission system.

SYSTEM IMPACTS

The reliability and LSC of the current transmission system is limited by the loss of one of the parallel O'Banion-Elverta 230 kV lines. The system is limited by thermal overloads on the remaining O'Banion-Elverta line following the operation of the SEC SPS and subsequent trip of the 500 MW Sutter Power Plant. The O'Banion-Elverta/Natomas Project adds two more transmission circuits to this path and eliminates this contingency as a limiting factor.

ONE-LINE DIAGRAM

- Figure 4-7: O'Banion-Elverta/Natomas 230 kV Project One-Line Diagram

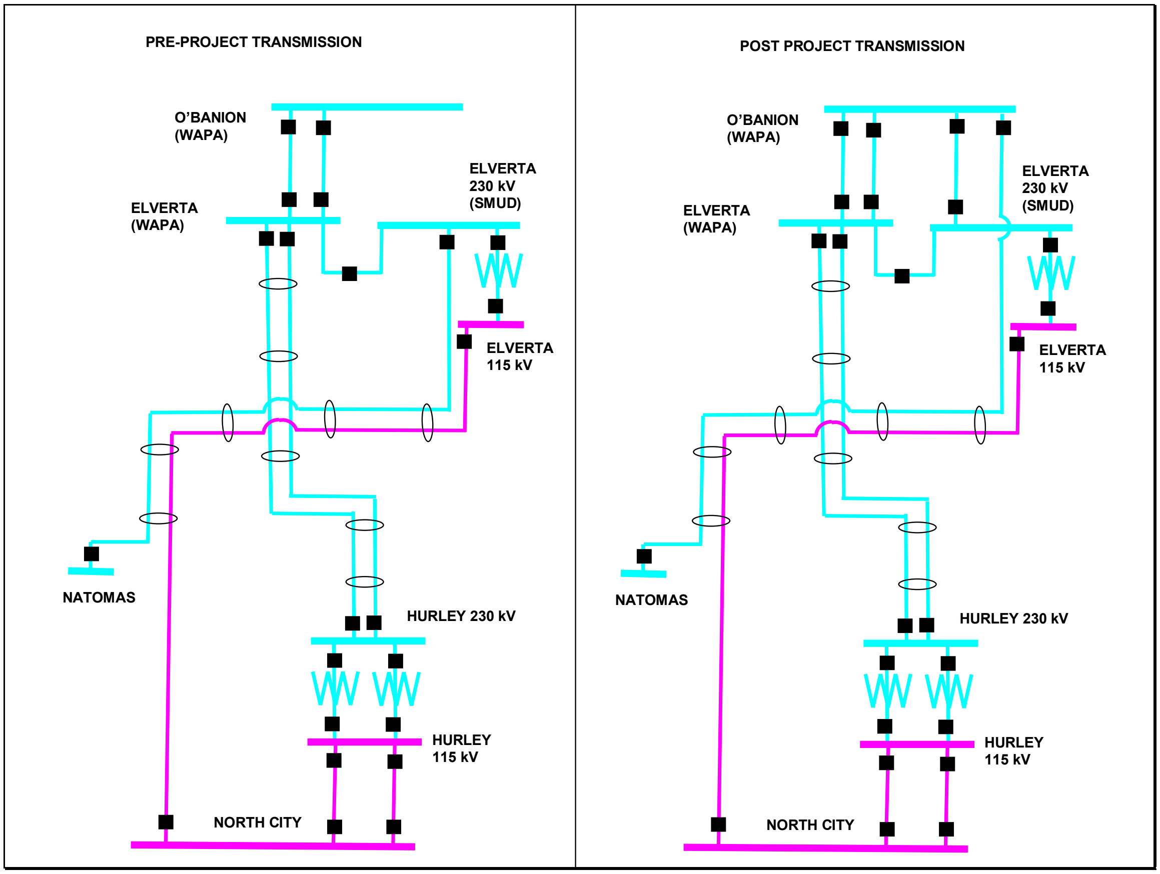

Figure 4-7: O'Banion-Elverta/Natomas 230 kV Project One-Line Diagram

4.7 Franklin 230/69 kV Substation

EXPECTED IN-SERVICE DATE

May 31, 2014

PROJECT SCOPE

This project will construct a new distribution substation with a breaker and a half bus configuration, operated as a ring bus. In addition, the Rancho Seco-Pocket 230 kV No. 1 Line will be looped into the substation and 2-16.2 MVAr of capacitor banks will be installed. The substation will include 5-230 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 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.

ONE-LINE DIAGRAMS

- Figure 4-8: Conceptual Franklin One-Line Diagram
- Figure 4-9: Franklin Location Diagram

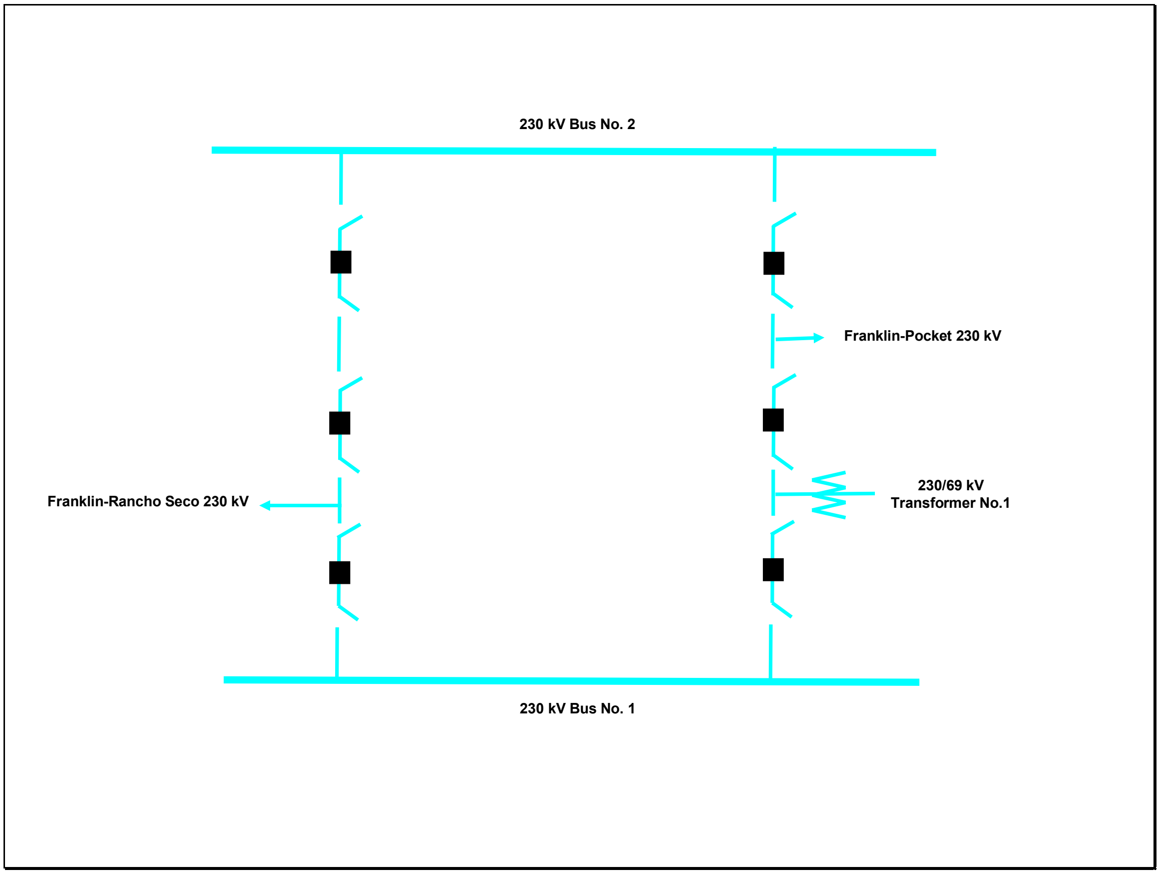

Figure 4-8: Conceptual Franklin One-Line Diagram

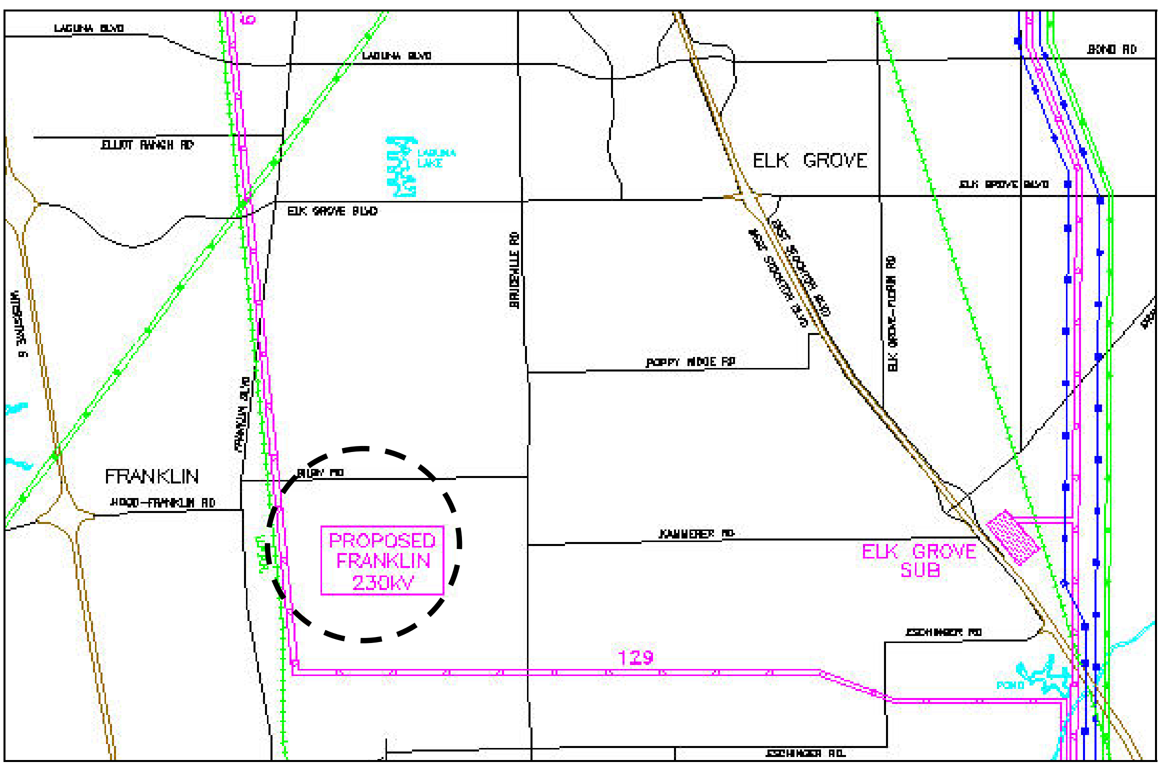

Figure 4-9: Franklin Location Diagram

4.8 Sutter-O'Banion 230 kV Conversion

EXPECTED IN-SERVICE DATE

May 31, 2016

PROJECT SCOPE

The scope of this project is to convert the Sutter-O'Banion 230 kV Line to a double circuit line by untying the 230 kV line into two separate lines and adding a circuit breaker at Sutter Station.

BACKGROUND

The Sutter-O'Banion 230 kV Line, 4 miles long, connects the Sutter generation to the Sacramento load center. This line was constructed as a double circuit, but only one circuit breaker was originally provided at each end of the line, and it is currently operated as a single circuit.

The O'Banion-Elverta/Natomas 230 kV Project already includes a second breaker at O'Banion Substation.

SYSTEM IMPACTS

Converting the Sutter-O'Banion 230 kV transmission line to a DCTL improves system reliability by eliminating the loss of 500 MW of generation for NERC Category B contingencies. After the O'Banion-Elverta/Natomas Project is in service, the District's LSC will be limited by WECC reactive margin requirements for a NERC Category B contingency of Sutter-O'Banion. Converting this line to a double circuit eliminates this single contingency as being a limitation. A gain in LSC is achieved because the next limiting contingency is a NERC Category C contingency and the WECC reactive margin requirements are reduced for this level of contingency.

ONE-LINE DIAGRAM

- Figure 4-10: Sutter-O'Banion 230 kV Conversion One-Line Diagram

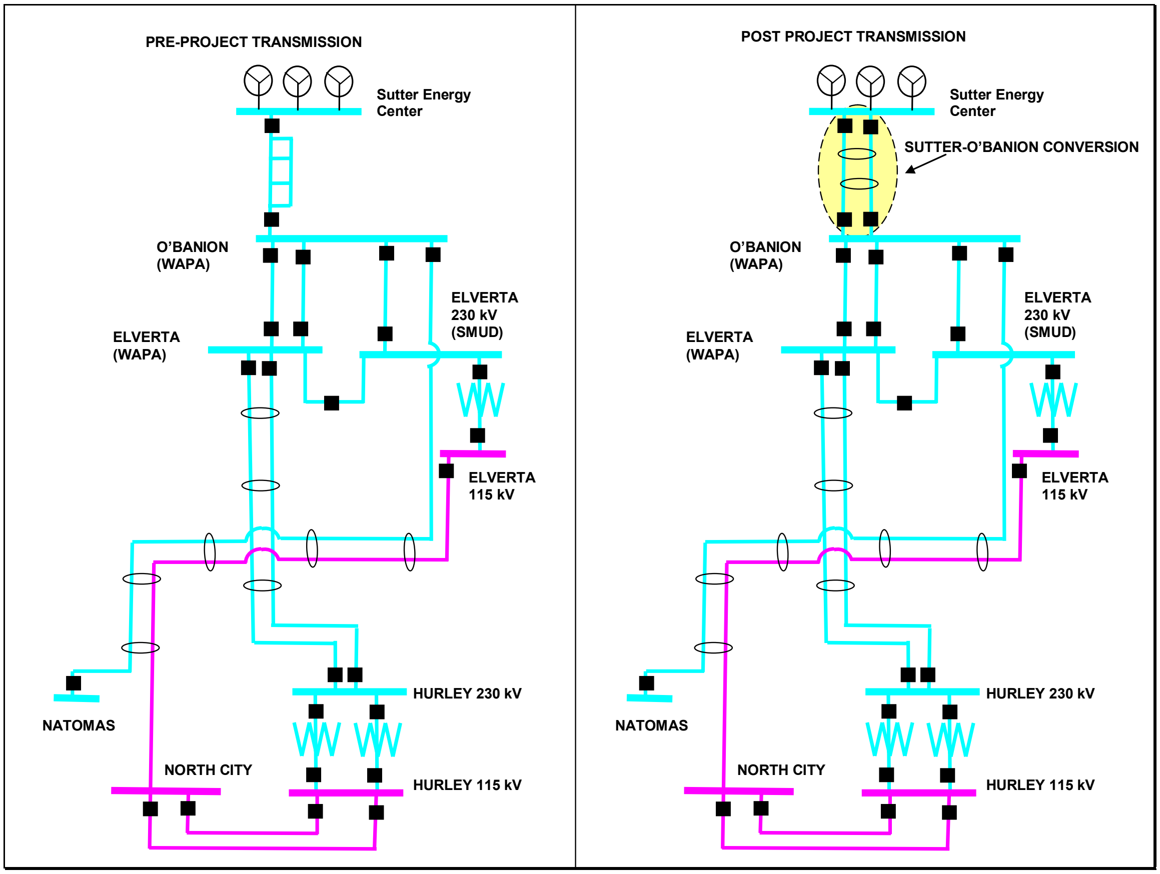

Figure 4-10: Sutter-O'Banion 230 kV Conversion One-Line Diagram

4.9 Iowa Hill Pump Storage Hydro Plant

EXPECTED IN-SERVICE DATE

May 31, 2017

PROJECT SCOPE

The scope of this project is to construct a 400 MW Iowa Hill Pump Storage Hydro Plant within the District's Upper American River Project (UARP). The plant is expected to interconnect to the White Rock–Camino 230kV Line through a new 230 kV switchyard and a 2 miles long double circuit 230 kV transmission line.

In addition, reconductoring the following UARP 230 kV lines with high ampacity 954 ACSS conductors will be necessary:

- White Rock-Orangevale 230 kV
- White Rock-Cordova (Hedge) 230 kV
- Camino-Lake 230 kV
- Camino-White Rock (Iowa Hill) 230 kV
- Jay Bird-White Rock 230 kV

The 954 ACSS conductor has a normal and emergency rating of 1,714 amps.

BACKGROUND

The Iowa Hill site is adjacent to the existing Slab Creek reservoir within the District's UARP. Iowa Hill would pump during low load periods and generate during peak load conditions.

The addition of 400 MW of additional generation in the UARP will require transmission reinforcement to allow delivery of the full output from Iowa Hill. Table 4-1 lists the existing UARP transmission lines.

Table 4-1: Existing UARP 230 kV Lines

Transmission Facility	Conductor Type	Ratings (SN/SE)	Line Length (Mile)
White Rock-Orangevale 230 kV	954 AAC	760/880	31
White Rock-Hedge 230 kV	954 AAC	760/880	40
Camino-Lake 230 kV	954 AAC	760/880	32
Camino-White Rock 230 kV	954 ACSR	770/900	10

Transmission Facility	Conductor Type	Ratings (SN/SE)	Line Length (Mile)
Jay Bird-White Rock 230 kV	795 ACSR	700/820	16
Jay Bird-Union Valley 230 kV	795 ACSR	700/820	6
Camino-Union Valley 230 kV	954 ACSR	770/900	12

Previous analysis indicated that there would be strong opposition in obtaining right of way to build a fourth circuit through a 7 mile section of the El Dorado Hills Area to accommodate this project. As a result, the current proposal consists of reconductoring some of the existing 230 kV lines with high ampacity 954 kcmil ACSS conductor.

Reconductoring the UARP 230 kV transmission lines with high ampacity 954 ACSS conductor allows the Iowa Hill plant to deliver 400 MW to the SMUD load center. However, the high ampacity conductor does not allow a corresponding 400 MW increase in the District's LSC during peak conditions. The reason for this is that ACSS conductor has a higher resistance, so an increase in resistance will increase the I^2R losses and will increase the line impedance; therefore, increasing the voltage drop along the line.

SYSTEM IMPACTS

In addition, the Iowa Hill Project causes thermal overloads on the Folsom-Orangevale and Lake-Folsom 230 kV lines following NERC Category C contingencies (with Folsom Loop Project in service). A possible reinforcement plan is to reconductor these 230 kV lines.

ONE-LINE DIAGRAMS

- Figure 4-11 : Iowa Hill One-Line Diagram
- Figure 4-12 : Iowa Hill Location within UARP

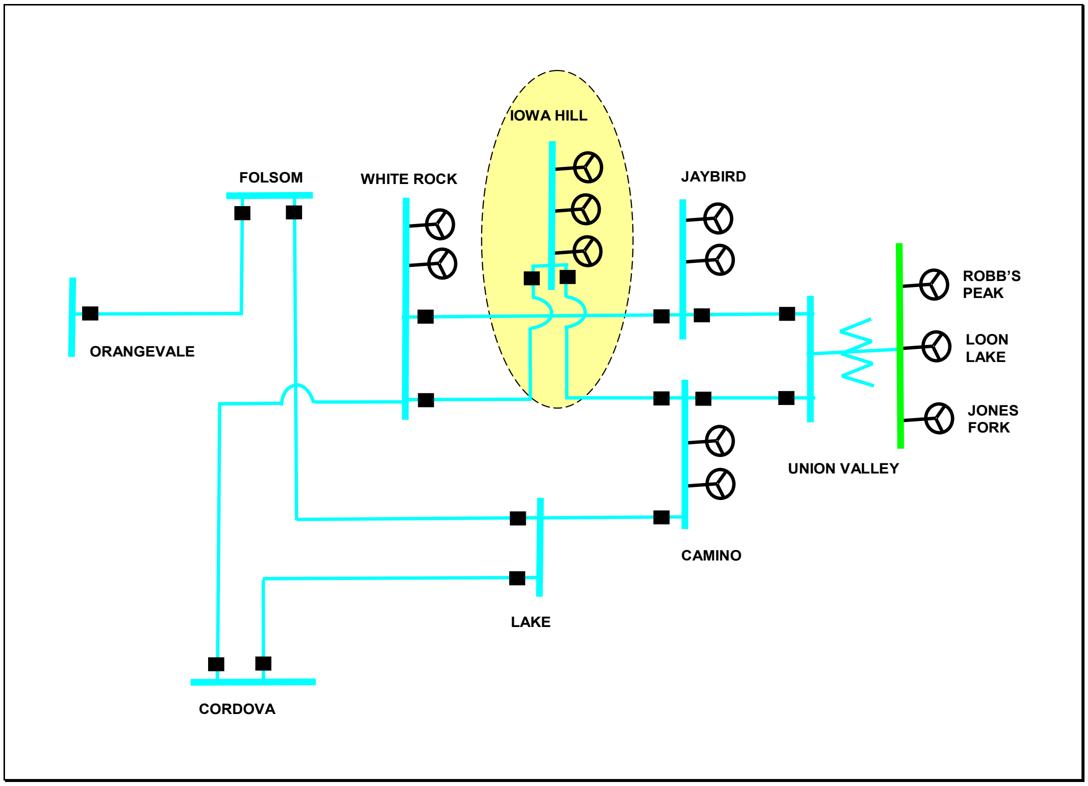

Figure 4-11: Iowa Hill One-Line Diagram

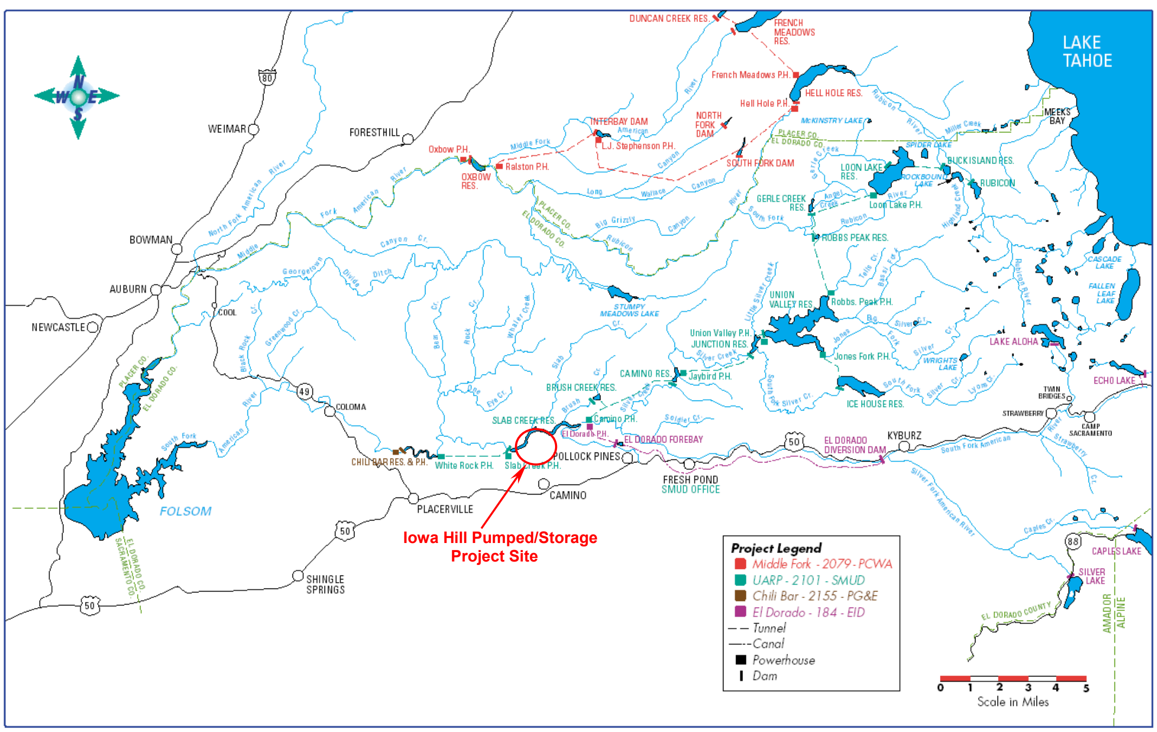

Figure 4-12: Iowa Hill Location within UARP

4.10 200 MVAr Capacitor Bank

EXPECTED IN-SERVICE DATE

May 31, 2017

PROJECT SCOPE

The scope of this project is to install 200 MVAr transmission or distribution capacitor banks (in conjunction with Iowa Hill Hydro Plant Project) to provide a gain in LSC equal to the plant capacity.

BACKGROUND

The 400 MW Iowa Hill Pump Storage Plant provides many reliability benefits and increases the District's ability to reliability serve load. However, it does not provide the desired increase in LSC.

Possible locations selected for transmission capacitor installation include Lake, Orangevale, Cordova, and Elverta substations. These locations were selected because they are substations where the UARP transmission lines terminate or are important interconnection points with other utilities:

- Lake 230 kV 50 MVAr
- Orangevale 230 kV 50 MVAr
- Cordova 230 kV 50 MVAr
- Elverta 230 kV 50 MVAr

SYSTEM IMPACTS

A combination of adding transmission and distribution capacitors may allow this 400 MW plant to be near 100% effective in increasing LSC. In addition, the capacitors will compensate for the increased system reactive losses.

ONE-LINE DIAGRAM

None

Chapter 5: Transmission Projects Needing Further Analysis

5 Transmission Projects Needing Further Analysis

The projects listed in this chapter are transmission projects that require further analysis. This chapter provides details for each transmission projects:

5.1 Tracy-Hurley 230 kV Interconnection

BACKGROUND

The Tracy-Hurley 230 kV interconnection alternatives add transmission system infrastructure to increase the SMUD LSC. Currently, these project alternatives are in the conceptual phase. Western should be consulted about equipment ratings, conductor sag requirements, and the transmission system design for these alternatives. There may be various other alternatives to be taken into consideration after input from Western.

The Tracy-Hurley 230 kV Interconnection is also a subset of Project Zeta which is being evaluated by TANC to provide a transmission path for renewable resources in northern California and northwestern Nevada to be delivered to central California.

At this point in time, Alternative 5 is the preferred plan of service as it relieves the overload seen on the Tracy-Hurley 230 kV lines and will increase LSC by 160 MW. The Tracy-Hurley 230 kV Project will be required by May 31, 2014.

ALTERNATIVES

- Status Quo
- Alternative 1: Reconductor Tracy-Hurley 230 kV Lines
- Alternative 2: Reconductor and Loop Tracy-Hurley 230 kV Line No. 2
- Alternative 3: Reconductor and Loop Tracy-Hurley 230 kV Lines
- Alternative 4: Construct a Switching Station
- Alternative 5: Reconductor the Tracy-Hurley 230 kV Lines and Construct a new 230 kV Line

Status Quo

The existing Tracy-Hurley 230 kV lines are approximately 62 miles in length and are strung with ACSR conductor types as follows:

Facility	*Facility Rating (SN/SE) MVA*	*Conductor Type*	*Distance (miles)*
Tracy-Hurley 230 kV #1	360/395	795/1,272 ACSR	58.3/3.4
Tracy-Hurley 230 kV #2	435/480	954/1,272 ACSR	7.0/54.4

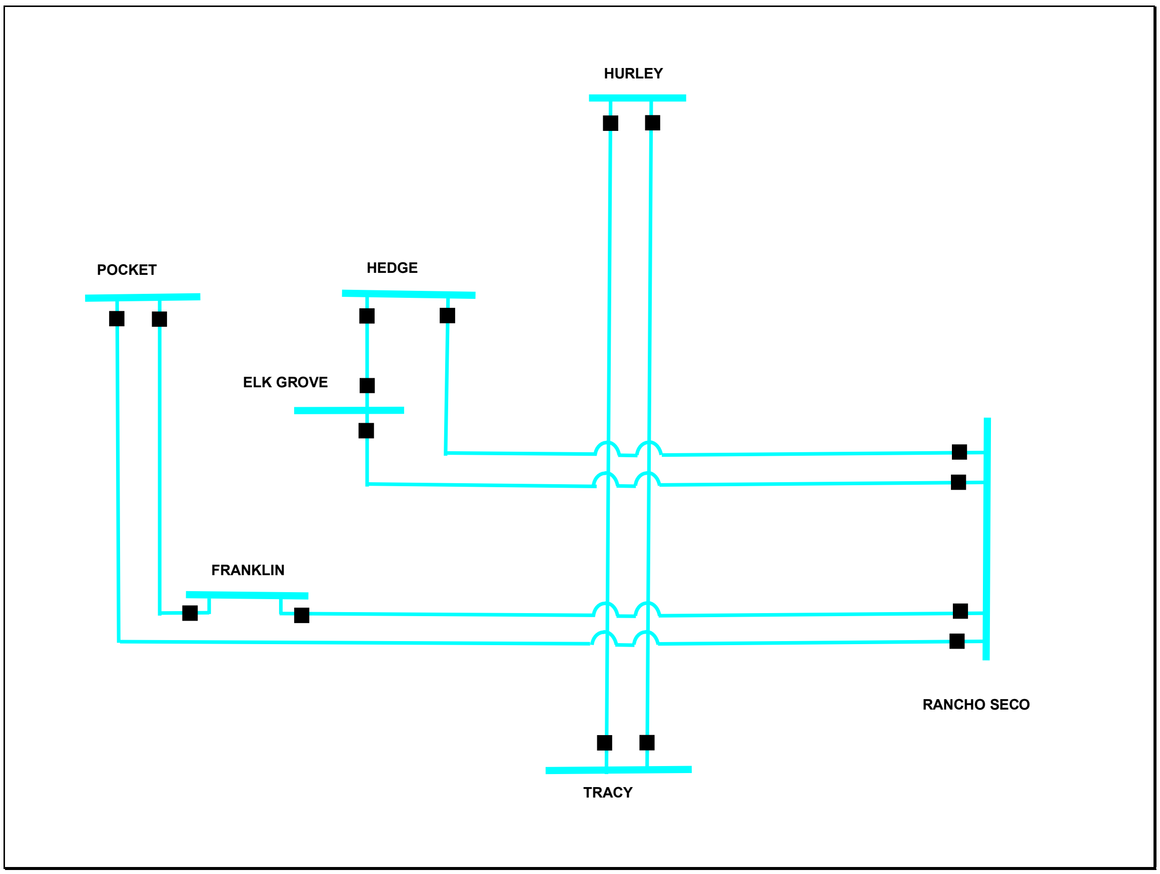

Figure 5-1: Existing System Configuration

Alternative 1: Reconductor Tracy-Hurley 230 kV Lines

This alternative involves in reconductoring the Tracy-Hurley 230 kV lines with high ampacity 1,272 ACSS conductor type. Alternative 1 could increase the LSC by approximately 35 MW.

Facility	*Facility Rating (SN/SE) MVA*	*Conductor Type*	*Distance (miles)*
Tracy-Hurley 230 kV #1	876/876	1,272 ACSS	62
Tracy-Hurley 230 kV #2	876/876	1,272 ACSS	62

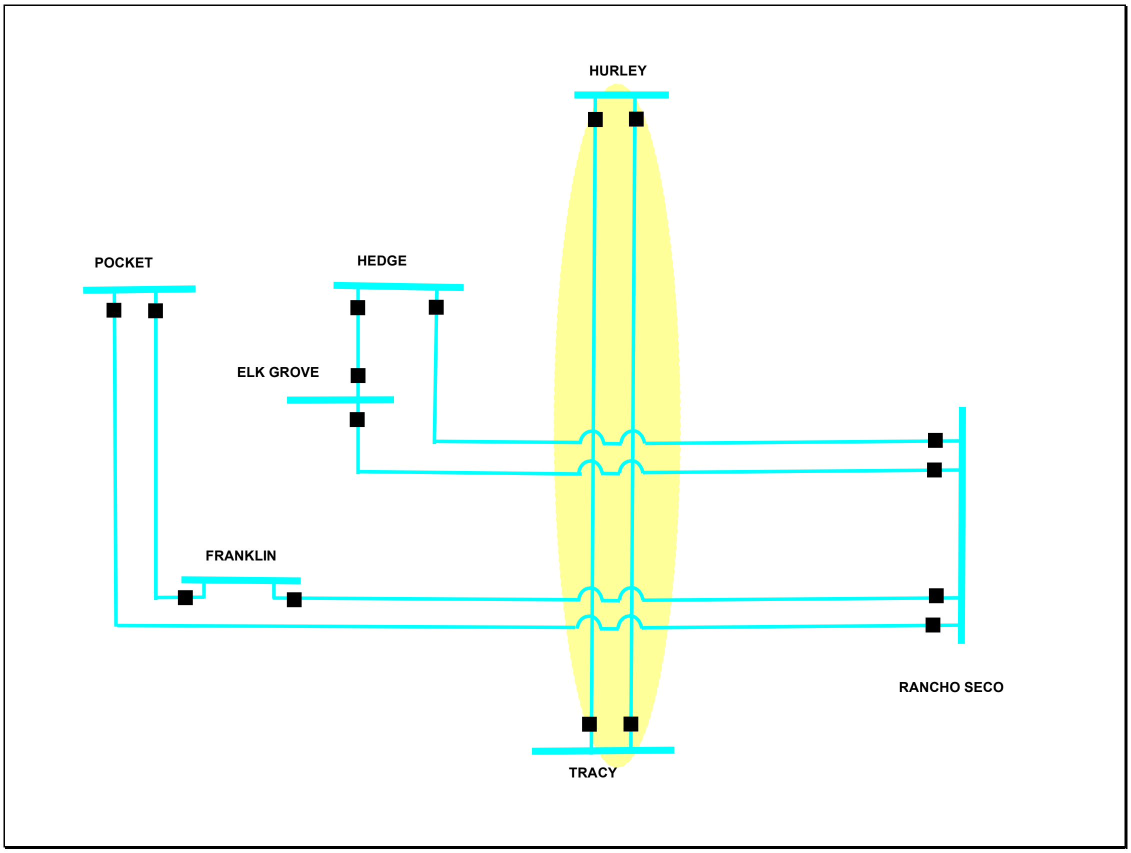

Figure 5-2: Alternative 1

Alternative 2: Reconductor and Loop Tracy-Hurley 230 kV Line No. 2

This alternative consists of looping the Tracy-Hurley 230 kV No. 2 Line into Elk Grove Substation and reconductoring the Tracy-Hurley 230 kV No. 1 and the Tracy-Elk Grove 230 kV (Tracy-Hurley 230 kV No. 2) lines. The existing conductor sizes are not changed for the Elk Grove-Hurley section of Tracy-Hurley 230 kV #2. It appears that the existing bus bays and circuit breakers at Elk Grove Substation could accommodate the looping. This alternative could increase the LSC by approximately 50 MW.

Facility	*Facility Rating (SN/SE) MVA*	*Conductor Type*	*Distance (miles)*
Tracy-Hurley 230 kV #1	876/876	1,272 ACSS	62
Tracy-Elk Grove 230 kV	876/876	1,272 ACSS	46
Elk Grove-Hurley 230 kV	435/480	954/1,272 ACSR	7/9

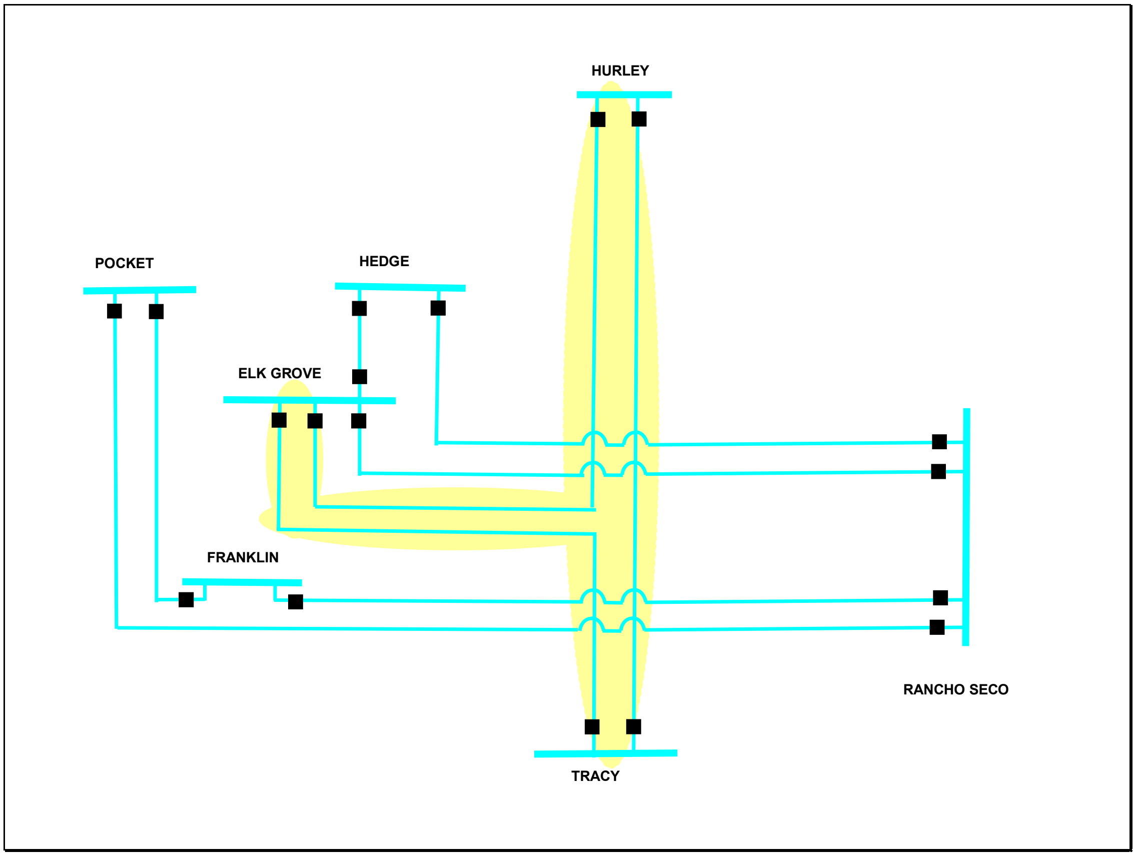

Figure 5-3: Alternative 2

Alternative 3: Reconductor and Loop Tracy-Hurley 230 kV Lines

This alternative consists of looping both Tracy-Hurley 230 kV circuits into Elk Grove Substation. In addition, the Tracy-Elk Grove 230 kV lines would need to be reconductored. It appears that the existing bus bays and circuit breakers at Elk Grove Substation could be utilized to connect two new circuits. New bus bay positions with breakers would be required for the other two 230 kV lines. This alternative could increase the LSC by approximately 50 MW.

Facility	*Facility Rating (SN/SE) MVA*	*Conductor Type*	*Distance (miles)*
Tracy-Elk Grove 230 kV #1	876/876	1,272 ACSS	46
Tracy-Elk Grove 230 kV #2	876/876	1,272 ACSS	46
Elk Grove-Hurley 230 kV #1	360/395	795 ACSR	16
Elk Grove-Hurley 230 kV #2	435/480	954/1,272 ACSR	7/9

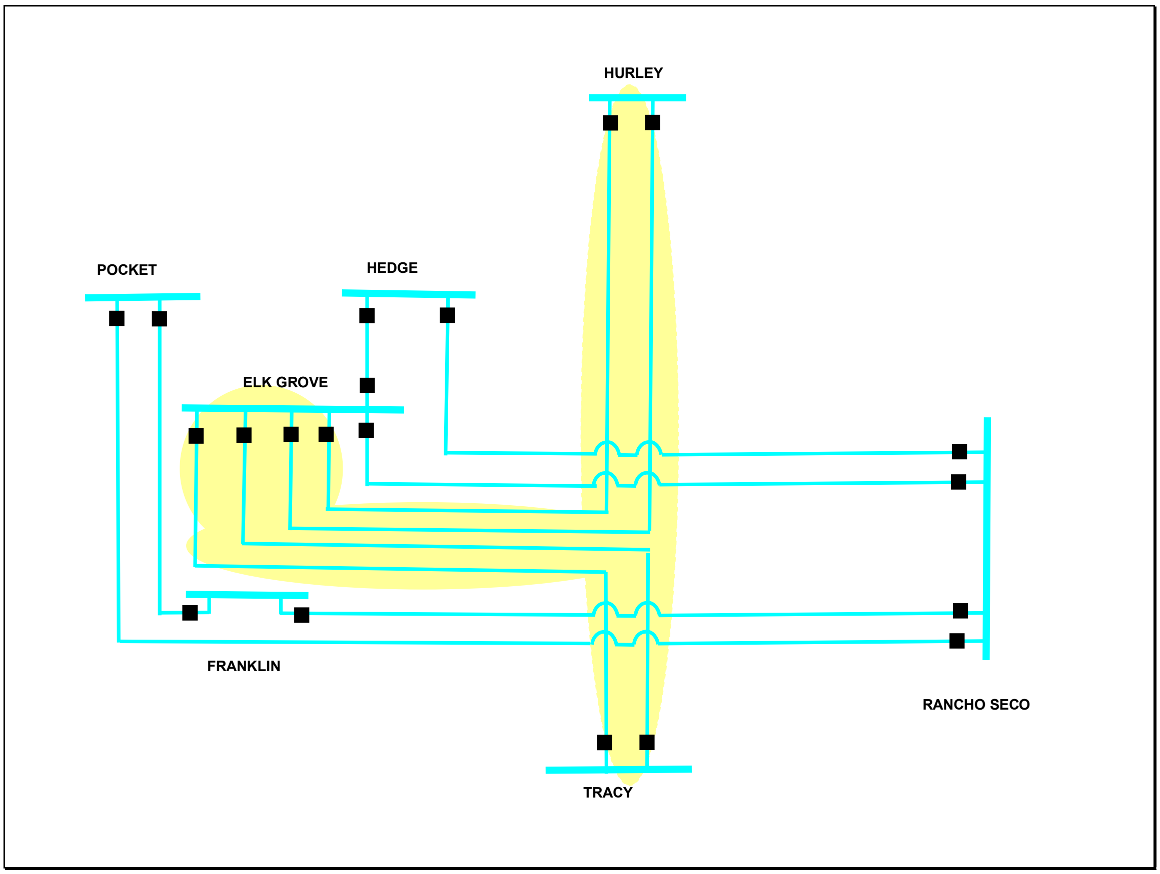

Figure 5-4: Alternative 3

Alternative 4: Construct a Switching Station

This alternative involves constructing a Switching Station just south of Elk Grove Substation and looping the Tracy-Hurley, Rancho Seco-Pocket, and Rancho Seco-Franklin 230 kV lines into the Switching Station. Alternative 4 does not provide an increase in LSC.

Facility	***Facility Rating (SN/SE) MVA***	***Conductor Type***	***Distance (miles)***
Tracy-Sw. Sta 230 kV #1	360/395	795/1,272 ACSR	39.6/3.4
Tracy-Sw. Sta 230 kV #2	435/480	1,272 ACSR	43
Sw. Sta-Hurley 230 kV #1	360/395	795 ACSR	16
Sw. Sta-Hurley 230 kV #2	435/480	954/1,272 ACSR	7/9

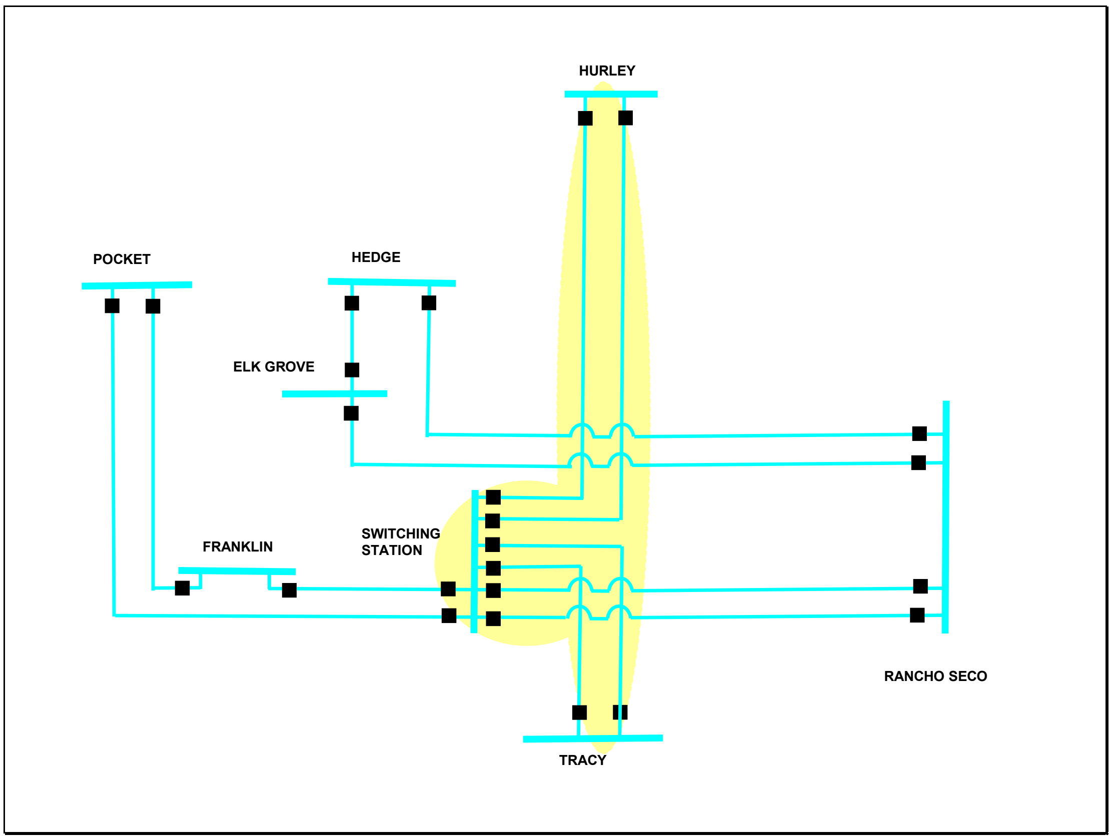

Figure 5-5: Alternative 4

Alternative 5: Reconductor Tracy-Hurley 230 kV Lines and Construct a new Line

This alternative involves looping the Tracy-Hurley 230 kV No. 2 into Elk Grove Substation and constructing a new transmission line from Tracy to Elk Grove. The new line will be built as a 500 kV line (energized at 230 kV level). In addition, majority of the existing 230 kV lines from Tracy to Hurley Substation would need to be reconductored. It appears that the existing bus bays and circuit breakers at Elk Grove Substation could accommodate two of the three circuits. Another bus bay position and circuit breakers would be required for the third 230 kV circuit. This alternative increases the LSC by approximately 160 MW.

Facility	*Facility Rating (SN/SE) MVA*	*Conductor Type*	*Distance (miles)*
Tracy-Hurley 230 kV #1	683/683	954 ACSS	62
Tracy-Elk Grove 230 kV #1	683/683	954 ACSS	46
Tracy-Elk Grove 230 kV #2	683/683	954 ACSS	46
Elk Grove-Hurley 230 kV	435/480	954/1,272 ACSR	7/9

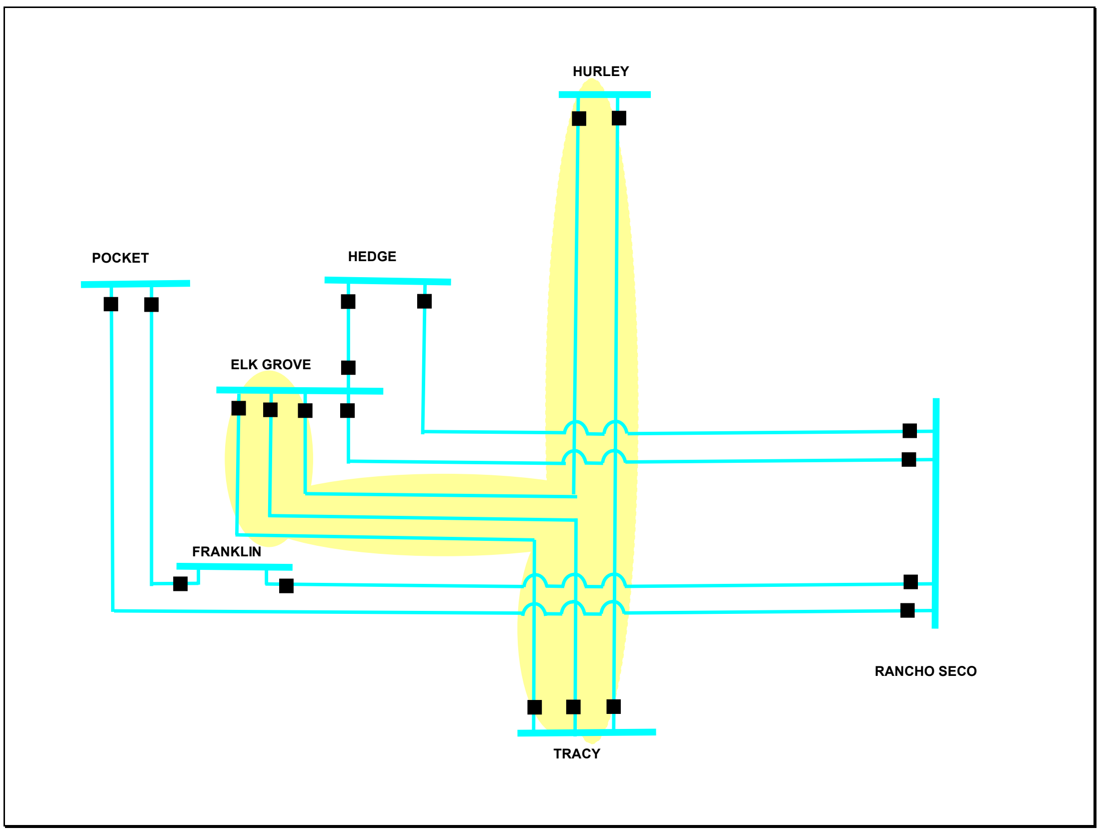

Figure 5-6: Alternative 5

5.2 Project Zeta (TANC)

BACKGROUND

TANC's Project Zeta adds transmission system infrastructure to increase SMUD LSC. Currently, Project Zeta is still in the conceptual phase and the purpose of this project is to tap the renewable resources in the northern California and northwestern Nevada and deliver the power to central California. One of the delivery points is within SMUD's territory just south of the City of Elk Grove (referred to as Dillard Road Substation in this report).

There were three alternatives examined. All alternatives included the following:

- New 500/230 kV Dillard Road Substation
- New 500 kV line from Tracy to Dillard Road Substation.

Alternative 1 also included looping the Rancho Seco-Franklin 230 kV Line and the Rancho Seco-Pocket 230 kV Line into the Dillard Road Substation. Refer to Figure 5-7.

Alternative 2 included looping the Rancho Seco-Franklin 230 kV Line and the Rancho Seco-Hedge 230 kV Line into the Dillard Road Substation. Refer to Figure 5-8.

Alternative 3 included looping the Rancho Seco-Hedge 230 kV Line into the Dillard Road Substation and the construction of a new Dillard-Hurley 230 kV Line. Refer to Figure 5-9.

The analyses evaluated the system impacts on the District's transmission system with the addition of the 500 kV source. In addition, there may be various other alternatives to be taken into consideration once Project Zeta is solidified.

SYSTEM IMPACTS

Power flow analyses performed on all three alternatives indicated that Alternatives 1 and 2 would not be desirable due to the impacts which it would have on the SMUD 230 kV and 115 kV transmission lines, specifically:

- Campbell-Hedge 230 kV Line
- Hurley-Procter 230 kV Line
- Hedge-South City 115 kV Lines
- Hedge-East City 115 kV Line.

On the other hand, Alternative 3 demonstrated that there would be no overloads for DCTL contingencies and provided an increase of approximately 240 MW of LSC. Therefore, Alternative 3 would be the desirable alternative.

Since Alternative 3 requires a long implementation lead time, the project will be built in stages. The project stages will be included in future assessments.

Table 5.1 shows the comparison of power flow results between the three alternatives.

Table 5-1: Power Flow Results Comparison

Contingency	Affected Facility	Facility Rating (Amps)	2017 (%)			
			Pre-Project	A1	A2	A3
Rancho Seco-Elk Grove and Rancho Seco-Hedge 230 kV (N-2)	Campbell Soup-Hedge 230 kV	1,380	83	118	N/A	N/A
Tracy-Hurley 230 kV (N-2)	Hurley-Procter 230 kV	880	77	105	109	63
Procter-Hurley 230 kV and Hedge-East City 115 kV (N-2)	Hedge-South City 115 kV #1 and #2	580	75	100	102	82
Hedge-South City 115 kV (N-2)	Hedge-East City 115 kV	880	87	103	104	93

ONE-LINE DIAGRAMS

- Figure 5-7: Alternative 1
- Figure 5-8: Alternative 2
- Figure 5-9: Alternative 3

Alternative 1: Loop Rancho Seco-Franklin and Rancho Seco-Pocket 230 kV Lines into Dillard Road Substation

This alternative involves looping the Rancho Seco-Franklin and Rancho Seco-Pocket 230 kV lines into the new Dillard Road Substation.

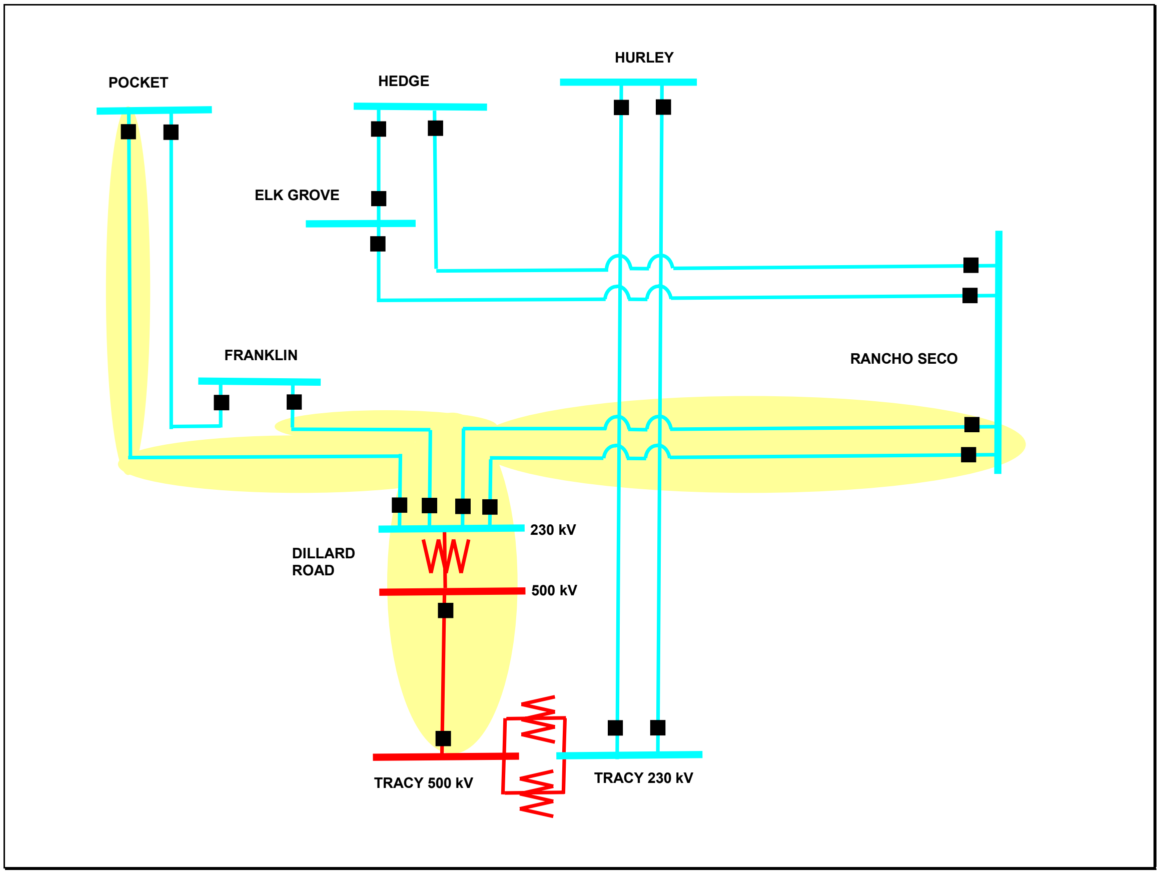

Figure 5-7: Alternative 1

Alternative 2: Loop Rancho Seco-Franklin and Rancho Seco-Hedge 230 kV Lines into Dillard Road Substation

This alternative involves looping the Rancho Seco-Franklin and Rancho Seco-Hedge 230 kV lines into the new Dillard Road Substation.

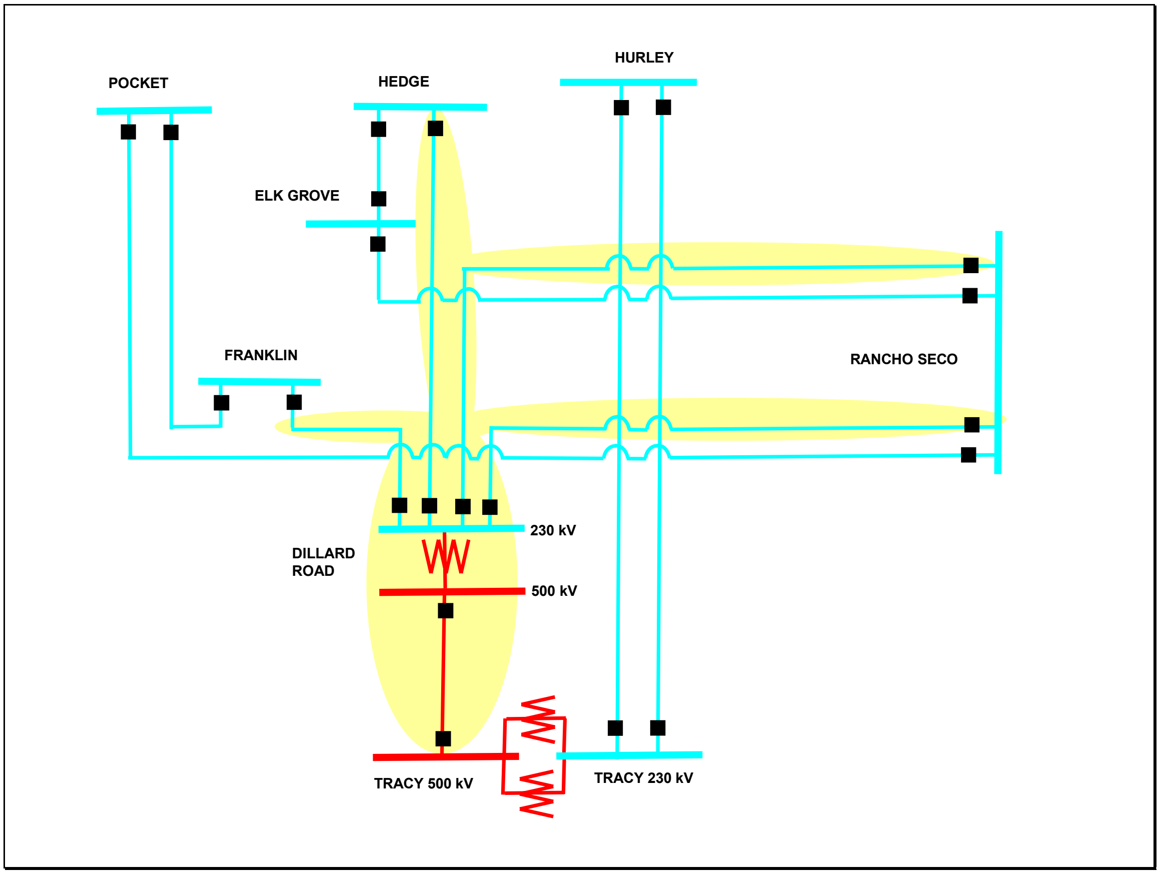

Figure 5-8: Alternative 2

Alternative 3: Loop Rancho Seco-Hedge 230 kV Line into Dillard Road Substation and construct a new Dillard-Hurley 230 kV Line

This alternative involves looping the Rancho Seco-Hedge 230 kV lines into the new Dillard Road Substation and constructing a new Dillard-Hurley 230 kV Line.

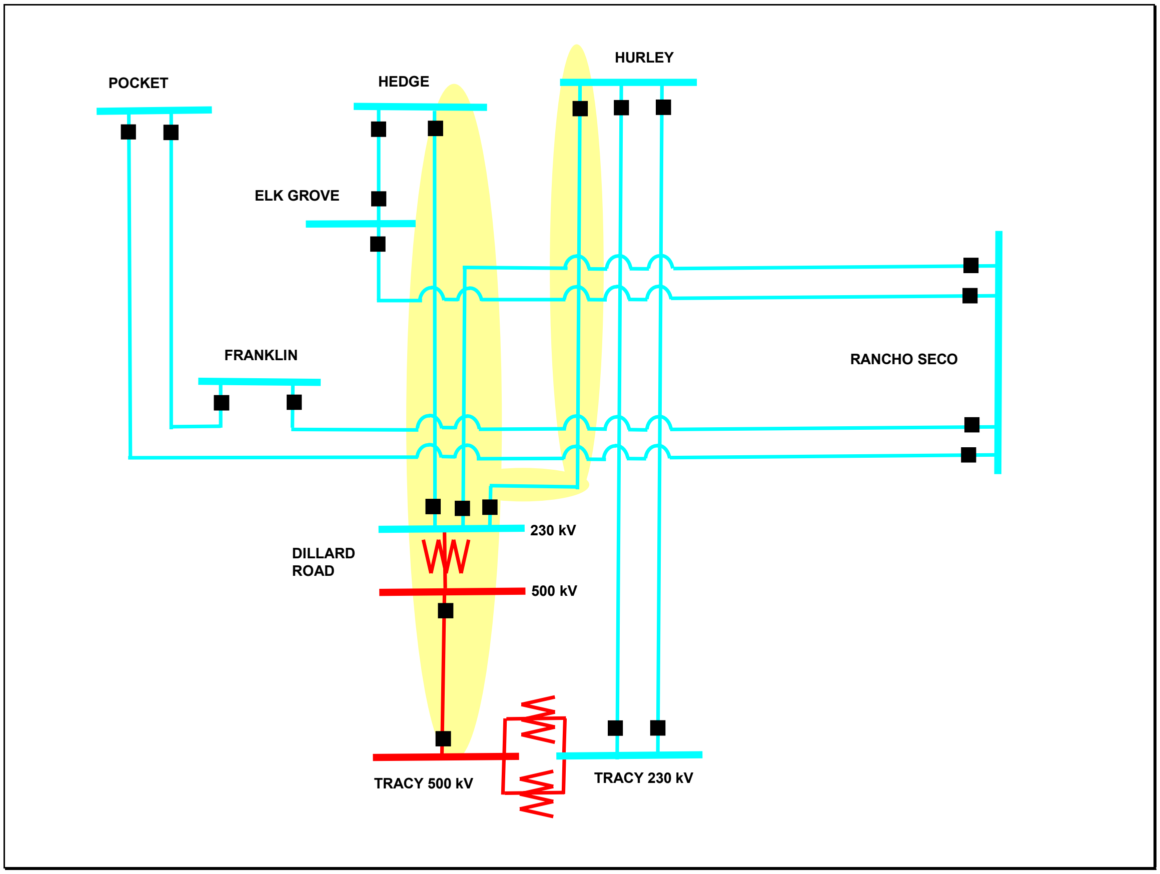

Figure 5-9: Alternative 3

Chapter 6: New Transmission Project Proposals

6 New Transmission Project Proposals

This chapter lists the new transmission project proposals for the 2008 transmission assessment. In addition, this chapter provides details for each new transmission project proposals.

6.1 Folsom-Orangevale 230 kV Reconductoring

EXPECTED IN-SERVICE DATE

May 31, 2017

PROJECT SCOPE

The scope of this project is to reconductor the Folsom-Orangevale 230 kV Line (in conjunction with Iowa Hill) with a higher ampacity conductor (1,174 Amps summer emergency). If necessary, an upgrade of associated line terminal equipments to accommodate the new ratings may be required.

BACKGROUND

The Iowa Hill Pump Storage Plant provides many reliability benefits and increases the District's ability to reliability serve load. However, it causes thermal overloads on the 230 kV circuits which bring UARP power into the SMUD load center. One of the 230 kV circuits is the Folsom-Orangevale 230 kV Line (with Folsom Loop Project operational).

The Folsom-Orangevale 230 kV Line is approximately 6 miles long and consists of 954 AAC conductor. It has a normal conductor rating of 758 Amps and an emergency rating of 879 Amps.

By 2018, the Folsom-Orangevale 230 kV Line overloads by 7% following the loss of DCTL of Orangevale-Elverta and Orangevale-White Rock 230 kV lines. This will necessitate the need to reconductor the 230 kV circuit.

ONE-LINE DIAGRAMS

- Figure 6-1: Lake-Orangevale Area Diagram
- Figure 6-2: DCTL Outage of Orangevale-Elverta and Orangevale-White Rock 230 kV (Pre-Project)
- Figure 6-3: DCTL Outage of Orangevale-Elverta and Orangevale-White Rock 230 kV (Post Project)

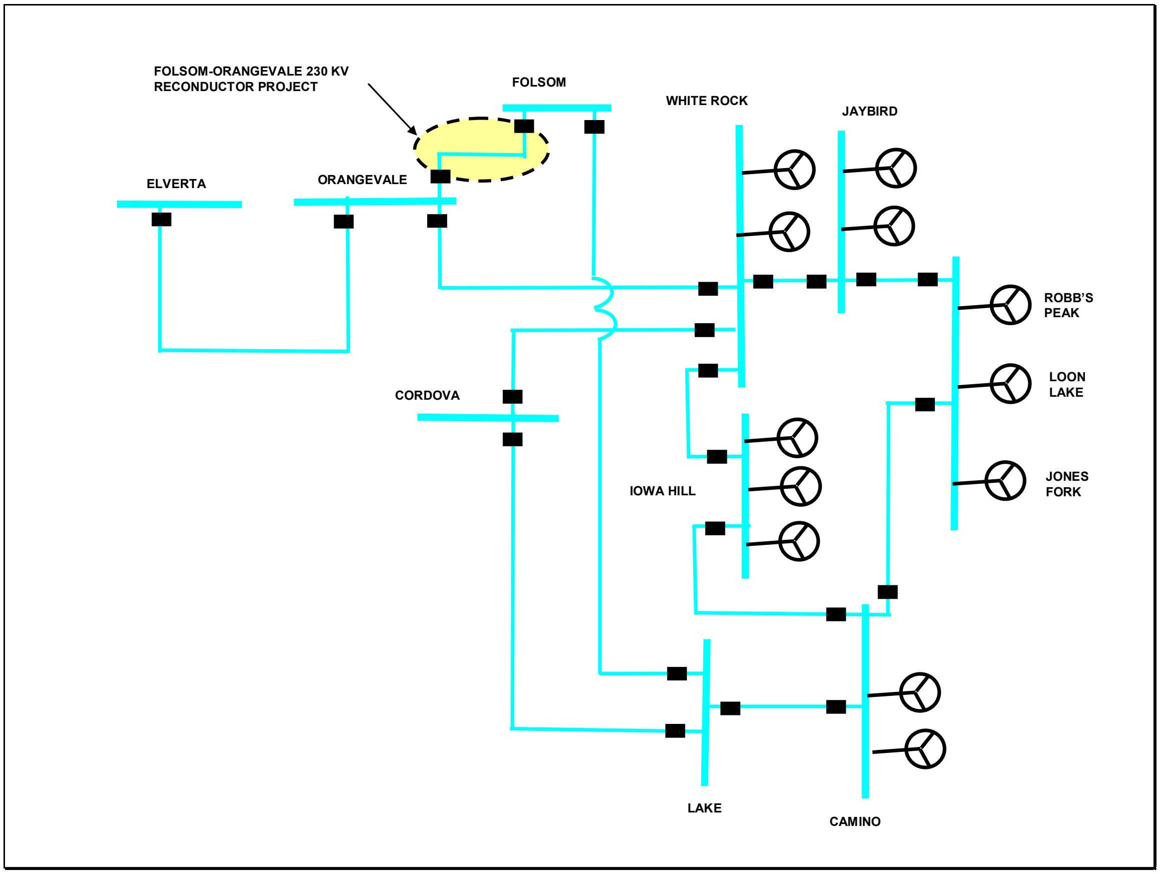

Figure 6-1: Lake-Orangevale Area Diagram

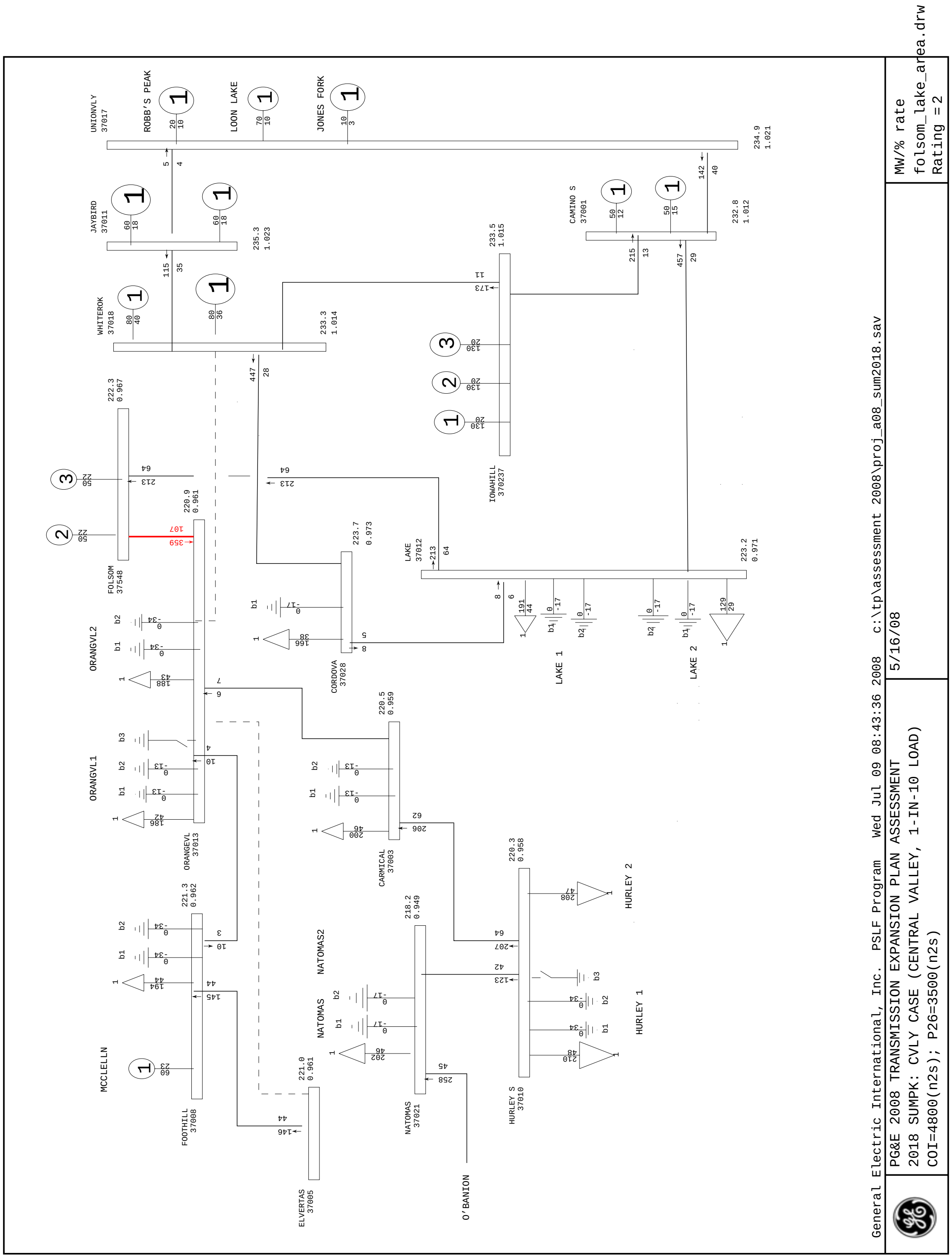

Figure 6-2: DCTL Outage of Orangevale-Elverta and Orangevale-White Rock 230 kV Lines (Pre-Project)

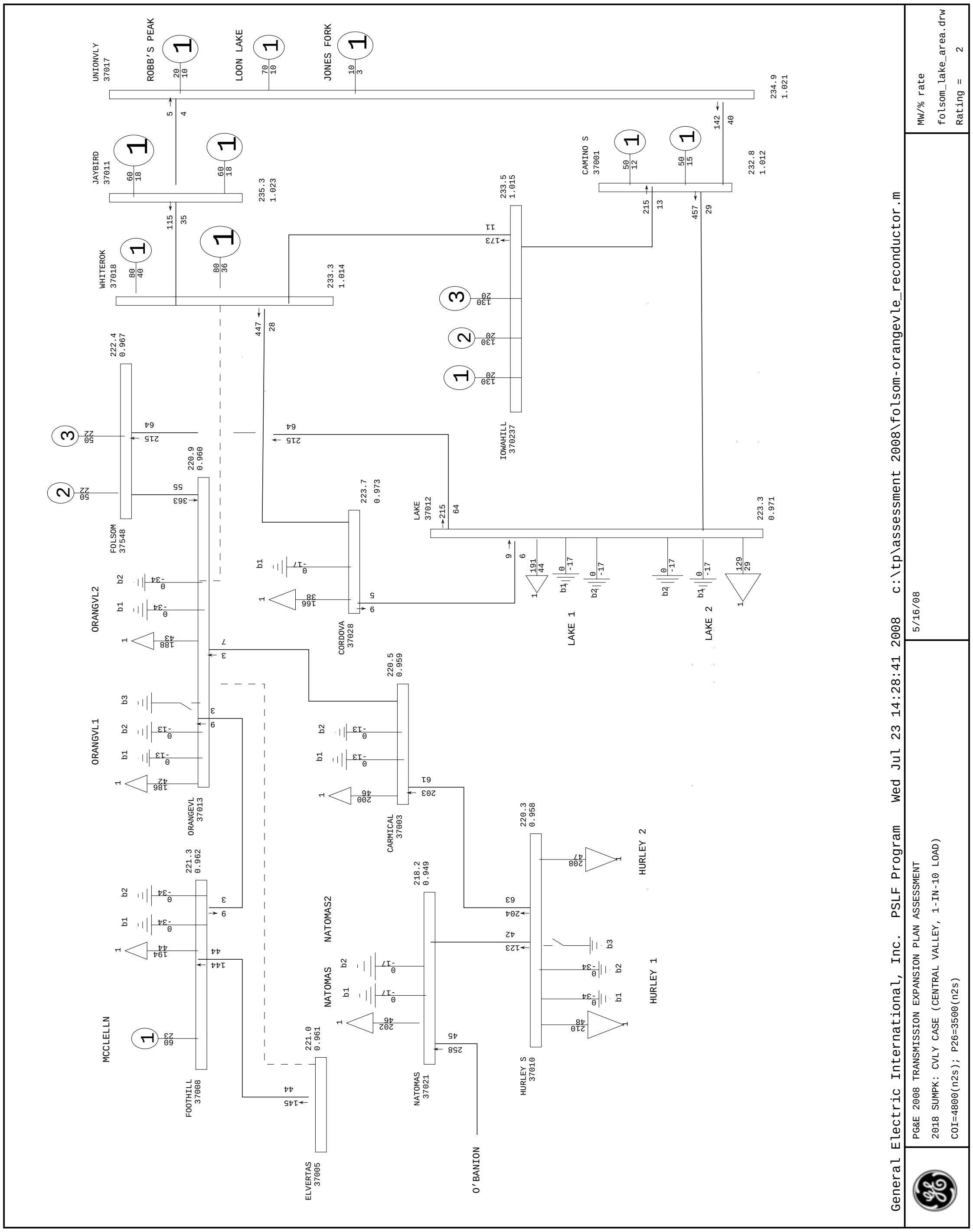

Figure 6-3: DCTL Outage of Orangevale-Elverta and Orangevale-White Rock 230 kV Lines (Post Project)

6.2 Lake-Folsom 230 kV Reconductoring

EXPECTED IN-SERVICE DATE

May 31, 2017

PROJECT SCOPE

The scope of this project is to reconductor the Lake-Folsom 230 kV Line (in conjunction with Iowa Hill) with a higher ampacity conductor (1,174 Amps summer emergency). If necessary, an upgrade of associated line terminal equipments to accommodate the new ratings may be required.

BACKGROUND

The Iowa Hill Pump Storage Plant provides many reliability benefits and increases the District's ability to reliability serve load. However, it causes thermal overloads on the 230 kV circuits. One of the overloaded 230 kV circuits is the Lake-Folsom 230 kV Line (with Folsom Loop Project operational).

The Lake-Folsom 230 kV Line is approximately 4 miles long and consists of 954 AAC conductor. It has a normal conductor rating of 758 Amps and an emergency rating of 879 Amps.

By 2018, the Lake-Folsom 230 kV Line overloads by 3% following the loss of DCTL of Camino-Lake and White Rock-Cordova 230 kV lines. This overload will drive the need for the line reconductor.

ONE-LINE DIAGRAMS

- Figure 6-4: Lake-Orangevale Area Diagram
- Figure 6-5: DCTL Outage of Camino-Lake and White Rock-Cordova 230 kV (Pre-Project)
- Figure 6-6: DCTL Outage of Camino-Lake and White Rock-Cordova 230 kV (Post Project)

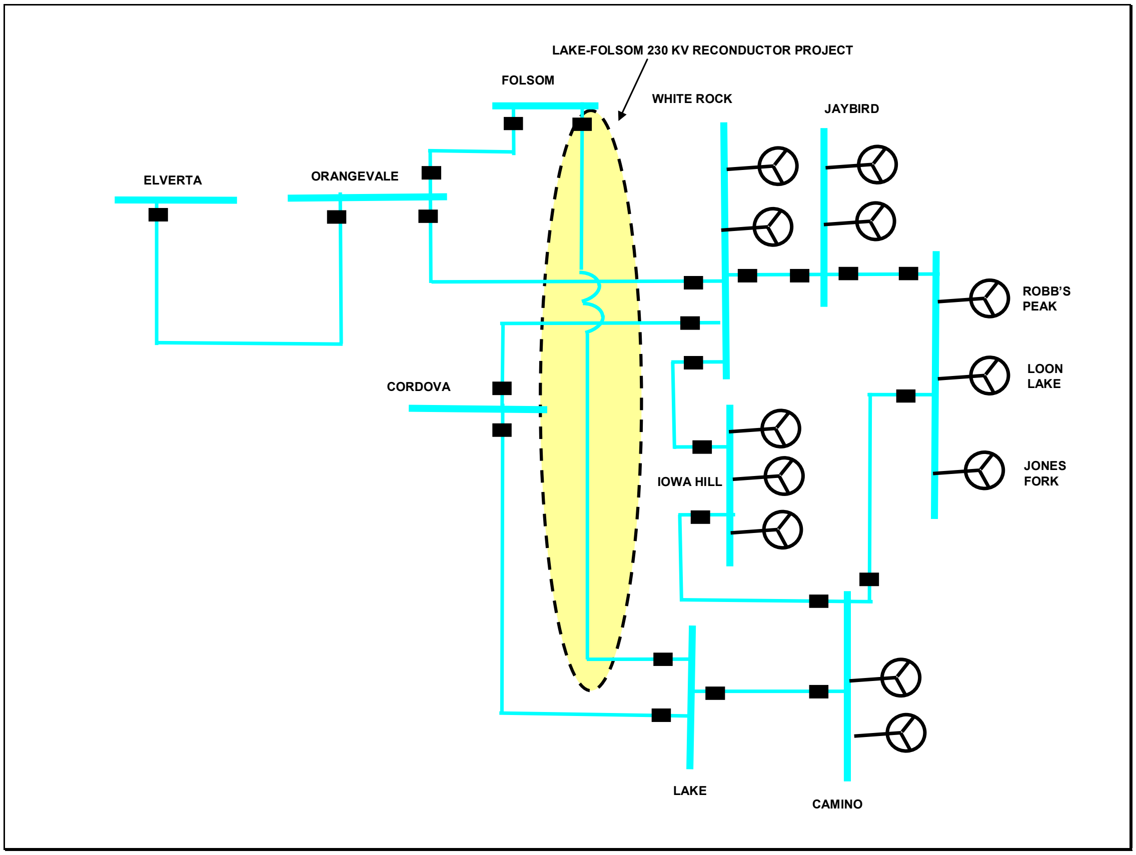

Figure 6-4: Lake-Orangevale Area Diagram

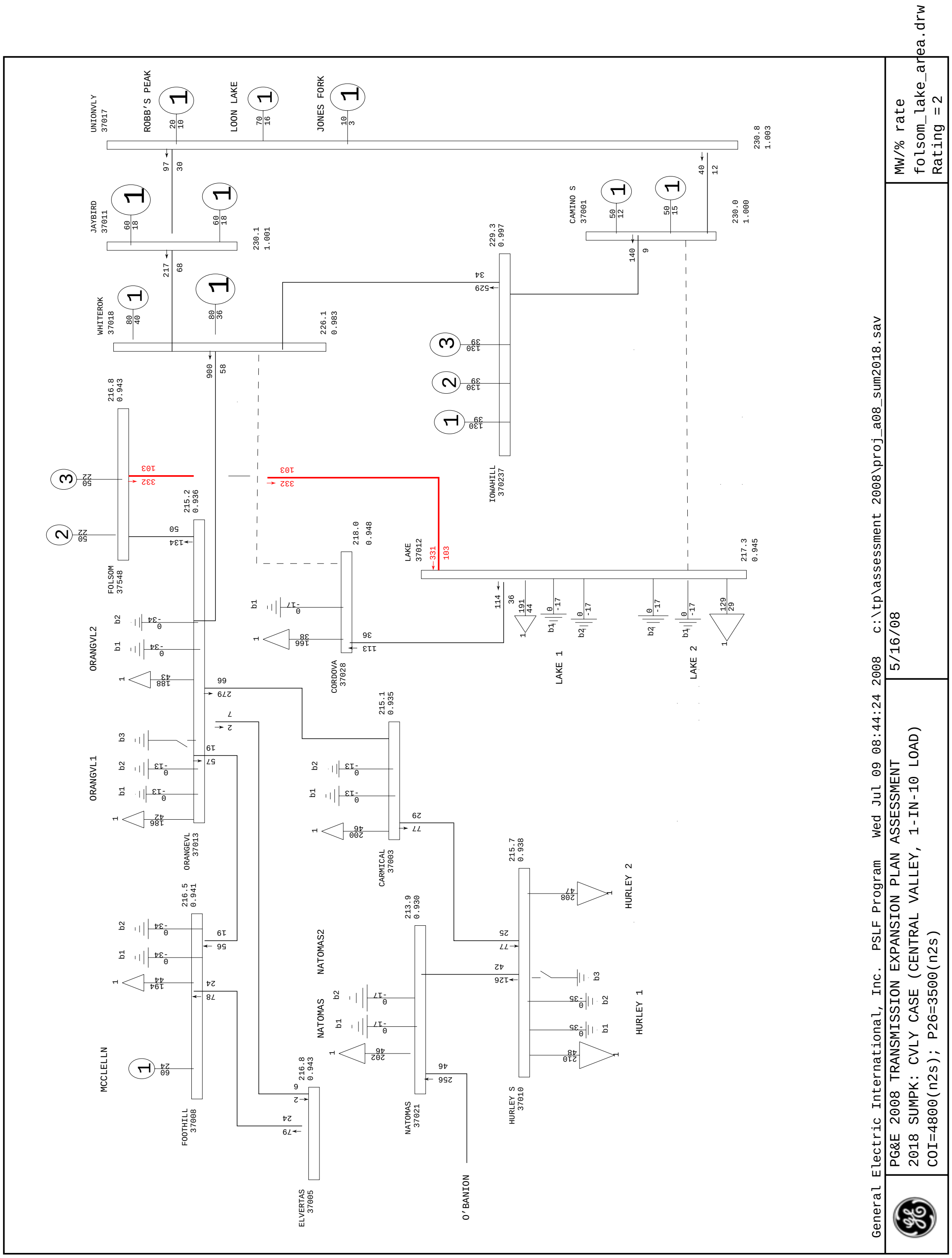

Figure 6-5: DCTL Outage of Camino-Lake and White Rock-Cordova 230 kV Lines (Pre-Project)

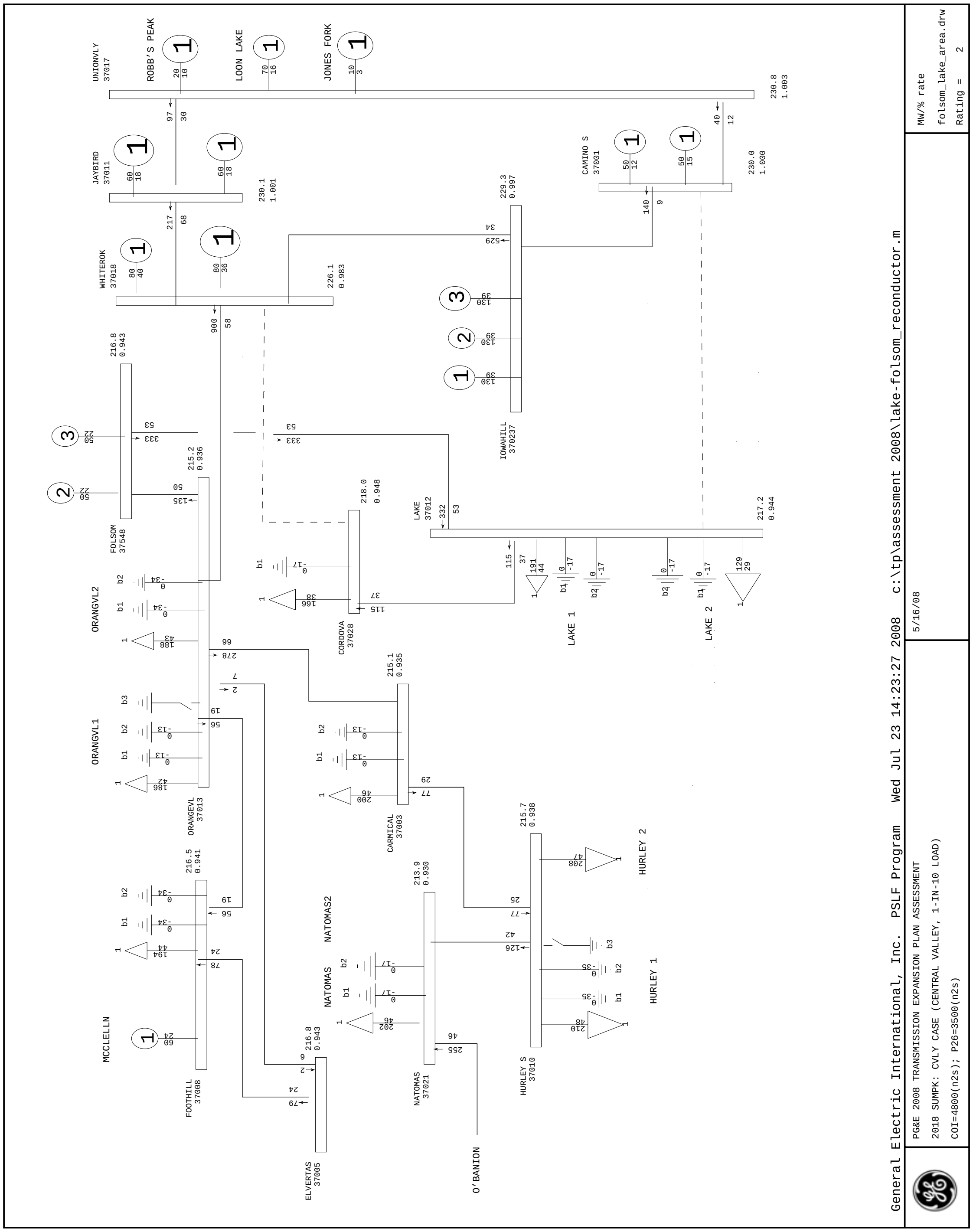

Figure 6-6: DCTL Outage of Camino-Lake and White Rock-Cordova 230 kV Lines (Post Project)

Appendices

Appendix 1: Special Protection Systems

There are several Special Protection Systems (SPS) and Overload Protection Schemes (OPS) 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)

The Sutter SPS is based on monitoring the current flow on the O'Banion-Elverta #1 & #2 lines and the O'Banion-Sutter line. The scheme recognizes the season-adjusted line ratings based on a summer or winter operating season. There are two functions within the season-dependent thermal overload modules and one function within the season-independent stability module.

Module 1 is a thermal overload module of the Sutter SPS and can be initiated during normal conditions with high levels of Sutter Power Plant output in combination with high Western CVP Northern California hydro generation levels and/or high SMUD Area imports. If any one of the phases of either O'Banion-Elverta #1 or #2 is loaded more than the seasonal SPS trip setting for more than 10 seconds, SPS will send a "Ramp Down" signal to Sutter Power Plant.

Module 2 is a thermal overload module of the Sutter SPS and can be initiated during emergency conditions for high Sutter Power Plant output in combination with various single and double contingency outages south of O'Banion. If any one of the phases of either O'Banion-Elverta #1 or #2 is loaded more than the seasonal SPS trip setting for more than 60 seconds, SPS will send a signal to Sutter Power Plant to "Trip one unit" and start the "Ramp Down" on the other two units. If the overload remains above the seasonal trip setting for 10 minutes the Sutter-O'Banion line will be tripped by the SPS to prevent damage to the line.

Module 3 is the stability module of the Sutter SPS and can be initiated If all three phases of both O'Banion-Elverta lines are loaded to less than 35 Amp (14MVA, indication that both lines are open), and the flow on at least two of three phases of Sutter-O'Banion is more than 1159 Amp (462 MVA), SPS will send a signal to Sutter to trip one unit (instantaneous).

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 for this is the double contingency loss of the Rancho Seco – Bellota 230 kV line. The Procter SPS will take from about 10 minutes to 1 hour to open the line. In most cases, SMUD dispatch should have sufficient time to mitigate the overload prior to the SPS action.

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 flows on the following seven 230 kV lines: Rancho Seco-Bellota #1 and #2, Tracy-Hurley #1 and #2, O'Banion-Elverta #1 and #2, and Gold Hill-Lake. 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 two or more of the SMUD Area tie lines (MW flow on each line below the set-point of 10 MW for 10 consecutive seconds), 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 scheme is set to trip 69 kV feeders automatically when the voltage at the local 230 kV bus is below 212 kV for 15 seconds. The scheme operates independently of system frequency or the SMUD DLT scheme. The estimated value of 308.5 MW load shed is for 2007 peak load forecast conditions.

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 N-2 DLOs. 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.

Hurley-Carmichael Special Protection System (SPS)

The Hurley-Carmichael 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.

To protect the cable under the following double line outage: the Elverta- Foothill and Elverta-Orangevale 230 kV, or the Orangevale-Lake and Orangevale-White Rock 230 kV, a SPS will be installed by the end of 2008.

The SPS consists of non-directional overcurrent relays installed at Carmichael that monitor the current through the Hurley-Carmichael 230 kV UG Cable. The SPS is set to trip and lockout the Carmichael 69 kV feeders when the cable ampacity is above the 100-hr summer emergency rating of 825 Amps (329 MVA). Tripping will occur within seconds, with only enough delay to ride through short duration power swings or faults.

Appendix 2: Contingency List

The complete Category A, B, C and D contingency list is available upon request

Appendix 3: NERC/WECC Reliability Standards

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

NERC/WECC Reliability Standards

The NERC/WECC Reliability Standards state that transmission system performance assessments shall be conducted on an annual basis and that future study years and critical system conditions are studied as deemed appropriate by the responsible entity.

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 Adequacy and Security address these concepts and are summarized in Table A3-1. System performance assessments shall indicate that the system limits are met for all planned facilities in service (Category A), loss of a single element (Category B), loss of two or more elements (Category C), and extreme events resulting in two or more elements removed or cascading out of service (Category D). 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 Categories C and D of Table A3-1. The transmission system must be capable of meeting Category C and D requirements 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 A3-1: Transmission System Standards - Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating*	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A. No Contingencies	All Facilities in Service	Yes	No	No
B. Event resulting in the loss of a single element	Single Line Ground (SLG) or 3Phase (3∅Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault	Yes	No[b]	No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more multiple elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker(Failure or internal Fault)	Yes	Planned/ Controlled[c]	No
	SLG or 3∅ Fault, with Normal Clearing[e], Manual system Adjustments, followed by another SLG or 3∅ Fault, with Normal Clearing[e]: 3. Category B (B1,B2,B3 or B4) contingency, manual System adjustments, followed by another Category B (B1,B2,B3, or B4) Contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3∅), with Normal Clearing[e]: 5. Any tow circuits of a Multiple circuit towerline[f]	Yes	Planned/ Controlled[c]	No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes	Planned/ Controlled[c]	No
D[d] Extreme Event resulting in two or more (multiple elements removed or Cascading out of service.	3∅ Fault, with delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transformer 3. Transmission Circuit 4. Bus Section	• May involve substantial loss of customer Demand and generation in a widespread area or areas. • Portions or all of the interconnected systems may not achieve a new, stable operating point. • Evaluation of these events may require joint studies with neighboring systems.		
	3∅ Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault).			

	1. Loss of towerline with three or more circuits 2. All Transmission lines on a common right-of-way 3. Loss of a substation (one voltage plus transformers) 4. Loss of switching station (one voltage level plus transformers) 5. Loss of all generating units at a station 6. Loss of a large Load or major Load center 7. Failure of a fully redundant Special Protection (or remedial action scheme) to operate when required 8. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in a response to an event or abnormal system condition for which it was not intended to operate 9. Impact of severe power swings or oscillations from disturbances in another Regional Reliability Organization.	

a) Applicable rating refers to the applicable Normal and Emergency facility thermal rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruptions of electric supply to radial customers or some local Network customers connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to Customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-callable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemptions criteria.

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. This supplementary WECC criterion is summarized in Table A3-2.

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 (VQ). Both PV and VQ 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 VQ analysis. Sole reliance on either PV or VQ 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 VQ 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[7].

PV Analysis

PV analysis is a study technique that relates voltage at a point in the transmission network to either of the following:

- A load within a defined region, or
- A power transfer across a transmission interface.

The benefit of this methodology is that it provides an indication of the proximity to voltage collapse throughout a range of load levels or power transfers on an interface path. With this technique, the load or transmission interface power transfers are increased and the critical voltage points are recorded at each load level. As the load or power transfers into a region are increased, the voltage profile of the region will become lower until an incremental increase in the load or power transfer causes the voltage to increase rather than decrease. When this occurs, the point of voltage collapse is reached.

The WECC criteria for performing PV analysis are indicated in Table A3.2. As indicated in the table, the maximum load or transfer limit operating point should be the lower of the following:

- 5.0% below the load or interface path flow at the voltage collapse point on the PV curve for Category B disturbances (N-1).
- 2.5% below the load or interface path flow at the voltage collapse point on the PV curve for Category C disturbances (N-2).
- At or below the load or interface path flow at the voltage collapse point on the PV curve for Category D disturbances.

[7] This reactive margin criterion was developed in May of 1998 by the WECC Reactive Power Reserve Work Group (RRWG). The document describing these criteria is entitled “Voltage Stability Criteria, Undervoltage load shedding strategy, and Reactive Power Reserve Monitoring”.

VQ Analysis

VQ 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 VQ analysis are indicated in Table A3.2. As indicated in the table, the maximum VAR margin for a given load level or transfer limit should be greater than the 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
    - A 5% increase beyond the maximum allowable interface flows.

- A Category C disturbance (N-2) requires 50% of the reactive power margin requirement of a Category B disturbance (a 2.5% increase beyond the maximum load forecast load or interface flow).
- A Category D disturbance requires a reactive power margin greater than 0.

Table A3-2: Summary of the WECC Disturbance Performance and Reactive Margin Criteria

Category	Outage Frequency (Outages/year)	Transient Voltage Dip Standard [2, 3, 4, 5, 7, 11]	Minimum Transient Frequency Standard [4, 5, 6, 7]	Post-Transient voltage deviation [3, 4, 7, 11]	P-V Margin Criteria [7, 9, 10, 11, 12]	V-Q Margin Criteria [7, 9, 11, 12, 13]
A - All Facilities in Service	Not Applicable	Nothing in addition to NERC	Nothing in addition to NERC	Nothing in addition to NERC	> 5% of Area Load at Voltage Collapse Point	Not Applicable
B – Event resulting in the loss of a single element	>= 0.33	<= 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	>= 5% of Area Load at Voltage Collapse Point	Worst Case Scenario (8)[8]
C – Event(s) resulting in the loss of two or more elements[8]	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	>= 2.5% of Area Load at Voltage Collapse Point	50% of Margin Requirement in Level B
D – Extreme event resulting in two or more (multiple) elements removed or cascading out of service [8]	< 0.033	Nothing in addition to NERC	Nothing in addition to NERC	Nothing in addition to NERC	>0	> 0

Notes for Table A3-2

1. The WECC Disturbance-Performance Table applies equally to either a system with all elements in service, or a system with one element removed and the system adjusted.
2. As an example in applying the WECC Disturbance-Performance Table, a Category B disturbance in one system shall not cause a transient voltage dip in another system that is greater than 20% for more than 20 cycles at load buses, or exceed 25% at load buses or 30% at non-load buses at any time other than during the fault.
3. Additional voltage requirements associated with voltage stability are also specified. If it can be demonstrated that post transient voltage deviations that are less than the values in the table will result in voltage instability, the system in which the disturbance originated and the affected system(s) should cooperate in mutually resolving the problem.
4. Refer to Figure W-1 of the NERC/WECC Planning Standards for voltage performance parameters.
5. Load buses include generating unit auxiliary loads.
6. To reach the frequency categories shown in the WECC Disturbance-Performance Table for Category C disturbances, it is presumed that some planned and controlled islanding has occurred. Underfrequency load shedding is expected to arrest this frequency decline and assure continued operation within the resulting islands.
7. For simulation test cases, the interconnected transmission system steady state loading conditions prior to a disturbance should be appropriate to the case. Disturbances should be simulated at locations on the system that result in maximum stress on other systems. Relay action, fault clearing time, and reclosing practice should be represented in simulations according to the planning and operation of the actual or planned systems. When simulating post transient conditions, actions are limited to automatic devices and no manual action is to be assumed.

[8] The most reactive deficient bus must have adequate reactive power margin for the worst single contingency to satisfy either of the following conditions, whichever is worse: (i) a 5% increase beyond maximum forecasted loads or (ii) a 5% increase beyond maximum allowable interface flows. The worst single contingency is the one that causes the largest decrease in the reactive power margin.

8. For application of these criteria within a member system, controlled load shedding is allowed to meet Performance Level C and D
9. Margin for N-0 (Performance Level) conditions must be greater than the margin for Performance Levels B, C, and D.
10. Maximum operating point on the P axis must have a MW margin equal to or greater than the values in this table as measured from the nose point of the P-V curve for each Performance Level.
11. Post-transient analysis techniques shall be utilized in applying the criteria.
12. Each member system should consider, as appropriate, the uncertainties in determining the required margin for its system.
13. The most reactive deficient bus must have adequate reactive power margin for the worst single contingency to satisfy either of the following conditions, whichever is worse:
    (i) A 5% increase beyond maximum forecasted loads or
    (ii) A 5% increase beyond maximum allowable interface flows.

The worst single contingency is the one that causes the largest decrease in the reactive power margin.

Appendix 4: Assessment Of System Operating Limits

The District's transmission system has historically been limited by WECC reactive margin criteria. Current operating and near-term planning horizon, the transmission system is limited by thermal overloads for a single transmission line contingency. When this limitation is mitigated in the near future, the transmission system is again limited by the WECC reactive margin criteria. To capture the reliability requirements and limits for the District's transmission system, an overall System Operating Limit (SOL) is determined. Both the NERC Reliability Standards and the WECC reactive margin criteria are applied to determine this SOL.

This section addresses the District's overall System Operating Limit (SOL) and describes the methodology used to assess this limit. An assessment of the SOL must be conducted annually to ensure that the Bulk Electric System (BES) reliability requirements are maintained for the ten year planning horizon. The requirements used to determine an SOL are described in the following standard:

FAC-010 System Operating Limits Methodology for the Planning Horizon

The District does not currently have SOL's that qualify as an Interconnection Reliability Operating Limits (IROL). The WECC operating philosophy is to operate only in conditions that have been studied. Therefore, SMUD does not report IROL conditions.

Methodology for the Sacramento Area SOL

Since the mid 1990's, the potential for voltage collapse has been the main reliability issue in the Sacramento Area. All of the utilities in the area have collaborated and contributed to improve this situation. The boundary of the Sacramento Area was originally defined by minimizing the amount of undervoltage load shedding required to prevent potential voltage collapse for a NERC Category C5 contingency. Since that time, many changes have occurred on the system. However, the basic characteristics of how the system works, and the boundary of the Sacramento Area has essentially remained the same. The Sacramento Municipal Utility District and the City of Roseville are the only load serving entities within this boundary. All of the generation embedded within these entities as well as the Western Area Power Administration Folsom generation is also included within the SOL boundary.

The District determines the System Operating Limit (SOL) for each study year in the ten year planning horizon to ensure reliable planning of the Bulk Electric System (BES). A methodology has been established to determine the overall SOL for the Sacramento Area transmission system.

The SOL is determined by the application of the following assessment assumptions:

- Utilize appropriate power flow cases with a detailed model of the Northern California transmission system

- Apply 1-in10 Load Forecast load for SMUD, the City of Roseville, and the surrounding Sacramento Area

- Ensure that Sacramento Area generation does not exceed the maximum dependable output level and includes appropriate operating reserves

- Maintain 200 MW capacity of operating reserves of internal SMUD generation

- Limit Sacramento imports to maintain reliability standards for:
  - NERC Category A - System Performance Under Normal Conditions
  - NERC Category B - System Performance Following Loss of a Single BES Element
  - NERC Category C - System Performance Following Loss of Two or More BES Elements
  - WECC reactive margin requirements

- Apply existing Protection Mitigation Systems or Remedial Action Plans if necessary

The WECC reactive margin criteria are applied to the most severe Category B and C contingencies. These contingencies are selected by evaluating the contingencies with large voltage deviations or those that produce a solution divergence. PV analysis is conducted to determine the load level at the voltage collapse point. The LSC is determined by calculating the load level that includes the applicable reactive margin as defined in the WECC criteria. The WECC reactive margin criterion is discussed in more detail in Appendix 3.

When evaluating the Load Serving Capability, system performance should be consistent with the following for all contingencies:

- All facilities are operating within their applicable Post-Contingency thermal, frequency, and voltage limits
- Cascading outages do not occur
- Uncontrolled separation of the system does not occur
- The system demonstrates transient, dynamic, and voltage stability.

In addition, for NERC Category C or D contingencies, the following also apply:

- Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems
- Interruption of firm transfer, load, or system reconfiguration is permitted through manual or automatic control or protection actions
- To prepare for the next contingency, system adjustments are permitted, including changes to generation, load, and the transmission system topology when determining limits