Pacific Gas and Electric Company™

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April 16, 2009

DOCKET	
09-IEP-1D	
DATE	April 16 2009
RECD.	April 16 2009

California Energy Commission
Docket Office, MS-4
Attn: Docket No. 09-IEP-1D
1516 Ninth Street
Sacramento, CA 95814

Re: Docket No. 09-IEP-1D – Transmission Planning

Docket Office:

Attached, on compact disk, is our submittal for the 2009 IEPR transmission data request – PG&E's 2009 Grid Expansion Plan as submitted to the ISO on March 5, 2009. It is our understanding that the CEC staff received this 8MB document on March 6 in their role as stakeholders in the ISO process, but by this submittal we hope to assure that other staff working in this area has this resource in the development of the IEPR.

PG&E is not requesting confidential treatment for this material, but please note that it is sensitive information and PG&E keeps a log of those receiving its filing.

Please feel free to call me with any questions or concerns

Sincerely,

Kathy Trel

Kathy Treleven

Enclosure

PG&E's
2009 Electric Transmission Grid Expansion Plan

(Formerly the 2008 Electric Transmission Grid Expansion Plan)

Pacific Gas and Electric Company®

March 5, 2009

Executive Summary

The need for longer-term, integrated, transmission planning activities has become increasingly important over the last several years. There are various planning initiatives targeted at improving transmission system reliability, interconnecting renewable resources, and developing long-term transmission plans to serve future demand needs. The need to integrate these transmission planning activities are particularly important because the lack of integration may lead to higher risks of service interruptions for electric customers or the inability to deliver on the interconnection of generation resources that are needed to service the grid.

A priority for Pacific Gas and Electric Company (PG&E) is to develop a plan that not only focuses on the replacement and expansion of its electric facilities, but also ensures that the electrical transmission system is compliant with all applicable standards and is able to accept delivery of new renewable resources in order to meet California's current and future renewable energy targets.

PG&E's 2009 Electric Transmission Grid Expansion Plan (Transmission Plan) summarizes PG&E's plan for transmission upgrades. Specifically, this Transmission Plan is a ten year plan, which is expected to cost between $4 billion and $6 billion. This Transmission Plan aims at accomplishing the following, but not limited to:

- NERC compliance
- Improving transmission system access for renewable generation to meet Renewable Portfolio Standard (RPS) goals and targets
- Improving service reliability for end users
- Coordinating long term plans for PG&E's transmission system

About PG&E

Pacific Gas and Electric Company (PG&E), incorporated in California in 1905, is one of the largest combination natural gas and electric utilities in the United States. Based in San Francisco, PG&E is a wholly owned subsidiary of PG&E Corporation.

PG&E serves approximately 15 million people throughout a 70,000 square mile service area in northern and central California. Within this service territory, PG&E provides electric service through 123,054 circuit miles of electric distribution lines and 18,610 circuit miles of interconnected transmission lines. These interconnected electric facilities form an electric grid that interconnects power generation facilities and delivers electric power to end users. In addition, PG&E has approximately 40,123 miles of natural gas distribution pipelines and 6,136 miles of transportation pipelines for natural gas service.

PG&E's electric service area stretches from Eureka in the north to Bakersfield in the south, and from the Pacific Ocean in the west to the Sierra Nevada in the east. Within this area, some of the larger metropolitan areas that receive electric service from PG&E include Bakersfield, Stockton, Fresno, Oakland, San Francisco, San Jose, Santa Rosa, and the Silicon Valley.

NERC Compliance

As the registered Transmission Planner for PG&E's transmission system, PG&E must demonstrate that its transmission system complies with all applicable NERC reliability planning standards. In addition, as the registered Transmission Planner, PG&E must also fulfill the following responsibilities: maintenance of transmission system models, collection of required information for planning purposes, evaluation and documentation of transmission plans and coordination with other neighboring plans. The registered Transmission Planner is expected to coordinate and jointly plan with other Transmission Planners, as appropriate, to ensure new facilities do not adversely affect the reliability of neighboring transmission systems. A copy of NERC's reliability planning standards as well as the roles and responsibilities within NERC's Reliability Functional Model can be reviewed under NERC's website (www.nerc.com).

On an annual basis, PG&E performs studies that test the transmission system's performance against the applicable NERC reliability planning standards. These transmission studies form the foundation for the transmission projects that are proposed in this transmission plan. Assumptions that are taken into account when performing such planning assessments include, but are not limited to: 1) near and long-term electric demand forecasts, 2) generation outlook of existing and planned generation facilities, 3) development of planned transmission facilities. These transmission assessment reports are located within this plan under Appendix 6.

Since this plan was developed under the CAISO's transmission planning stakeholder process, interested market participants were also involved in the development of this plan. This transmission plan serves as PG&E's NERC Compliance documentation of its planned transmission projects, as well as its documentation of coordination with neighboring utility plans.

Improving Transmission Access for Renewable Generation

There are a number of areas in California, and in the WECC region, with resources that could potentially enable California to meet its resource needs and also enable PG&E to meet its near and long-term RPS goals.

On a regional basis, PG&E has participated in other planning forums that could improve access to resource areas through potential major network upgrades. Since 2003, PG&E has conducted a number of planning studies that focus on identifying transmission facilities that are needed to connect renewable resources and deliver the associated capacity and energy to load centers in California.

Chapter 7 and Chapter 8 of this plan discuss some of the recent activities that PG&E is pursuing in meeting its near-term and long-term procurement goals to achieve California's renewable energy targets of 20% by 2010 – 2013 on a delivered basis and to consider expanded renewable energy goals. Additionally, these two chapters include transmission upgrades needed to access renewable resources and deliver the energy to the load centers. Some of the projects within this transmission plan that are expected to facilitate access for renewable resources and help meet established and future RPS goals are listed below and discussed in greater detail within this plan:

- San Luis Obispo Solar Switching Station No. 3
- Morro Bay-Midway 230 kV Line Nos. 1 and 2 Reconductoring
- Atlantic - Rio Oso - Gold Hill 230 kV Lines
- Central California Clean Energy Transmission Project (C3ETP)
- Bay Area Bulk Transmission
- Canada - Pacific Northwest - Northern CA Transmission
- Vaca-Dixon – Birds Landing 230 kV Reconductoring
- Palermo – Rio Oso 115 kV Reconductoring
- South of Birds Landing 230 kV Reconductoring

Chapter 8 covers conceptual 500 kV transmission projects that are projected to supply load growth and to accommodate expected renewable resources as well as for the future need to allow for the shut-down of once-through cooling generators. A major project discussed in this chapter is the Canada/Pacific Northwest – Northern California Transmission Project for which PG&E recently completed a regional planning project review with the Western Electricity Coordinating Council (WECC). This proposed project will allow access to significant renewable resources in British Columbia, Alberta and the Pacific Northwest.

Improving Service Reliability

This transmission plan also includes several projects that are expected to improve the overall level of service reliability for end users. Specifically, these projects are targeting improvements in various electric service reliability metrics, such as System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), and Customer Average Interruption Duration Index (CAIDI), among others.

These service reliability improvement projects can involve installation of redundant transmission facilities to mitigate extended service interruptions, as well as the installation of equipment that facilitate a quicker service restoration process following a power outage. Specifically, these projects may involve constructing new transmission lines, installing additional transformers, installing Supervisory Control and Data Acquisition (SCADA) equipment or reconfiguring an electric network to provide greater redundancy.

Coordinating Long Term Plans for PG&E’s Transmission System

For ease of discussion, PG&E’s assessment and identified long-term transmission plans are described by geographical location within PG&E’s service territory in Appendix 6, “Reliability Assessment Study Report”. Specifically, these areas are:

- Greater Bay Area
- Northern Valley
- Central Valley
- San Joaquin Valley
- Central Coast and Los Padres
- 500 kV Transmission System

Within each of these areas, PG&E has developed various transmission proposals that are coordinated in the near and long-term horizons for the overall purpose of meeting end user needs. This year’s transmission plan includes a total of 151 transmission projects. These include 93 new project proposals that were submitted into the CAISO’s Request Window, detailed description of each project is found on Chapters 4 – 6 of this plan. Furthermore, this transmission plan includes brief descriptions of 58 projects that have been previously approved by the CAISO, which are listed in Chapter 3.

In summary, PG&E’s transmission plan is a ten-year plan that translates the near and long-term investment plans into a program of improvements to be implemented over the coming years. With this transmission plan, PG&E attempts to select the most cost effective investments for end users, while taking into account NERC compliance, service reliability, as well as related environmental and economic sustainability issues.

Table of Contents

CHAPTER 1

PG&E's Electric Transmission Expansion Plan

PG&E's Electric Transmission Grid Expansion Plan is more than just a collection of transmission projects bundled together to form a plan. This transmission plan serves as a road map towards PG&E's integrated transmission plan that encompasses, but not limited to the following:

- NERC Compliance
- Improving transmission system access for renewable generation to meet Renewable Portfolio Standard (RPS) goals and targets
- Improving service reliability for end users
- Integrating the above in a coordinated long term plans for PG&E

As the registered Transmission Planner for PG&E's transmission system, PG&E must demonstrate that its transmission system complies with all applicable NERC[1] reliability planning standards. In addition, as the registered Transmission Planner, PG&E must also fulfill the following responsibilities include: maintenance of transmission system models, collection of required information for planning purposes, evaluation and documentation of transmission plans that meet reliability standards and coordinate with other neighboring plans. A copy of NERC's reliability planning standards as well as the roles and responsibilities within NERC's Reliability Functional Model can be reviewed under NERC's website (www.nerc.com). This transmission plan serves as PG&E's documentation of transmission plans that meet applicable reliability standards, as well as coordination with neighboring utility plans.

Development of this transmission plan is coordinated in accordance with the California Independent System Operator's (CAISO's) Tariff, Section 24, as well as the business rules set forth in the CAISO Business Practice Manual for the Transmission Planning Process (TPP) in which PG&E is required to participate, which also align with FERC's Order 890 protocol. The CAISO's Transmission Planning Process is an annual integrated, open, participatory and transparent process that focuses on ensuring reliable, economically efficient, and nondiscriminatory use of the transmission system.

As such, in March 2008, PG&E embarked on the development of this year's transmission plan by participating in the first stage of the process in the development of Unified Planning Assumptions and CAISO Study Plan.

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[1] Effective January 1, 2007, the North American Electric Reliability Council and the North American Electric Reliability Corporation merged, with NERC Corporation being the surviving entity. NERC Corporation was certified as the "electric reliability organization" by the Federal Energy Regulatory Commission on July 20, 2006.
NERC's mission is to improve the reliability and security of the bulk power system in North America. To achieve that, NERC develops and enforces reliability standards; monitors the bulk power system; assesses future adequacy; audits owners, operators, and users for preparedness; and educates and trains industry personnel. NERC is a self-regulatory organization that relies on the diverse and collective expertise of industry participants. As the Electric Reliability Organization, NERC is subject to audit by the U.S. Federal Energy Regulatory Commission and governmental authorities in Canada.

Stakeholders were provided the opportunity to review and comment on the Unified Planning Assumptions prior to incorporation into the final Study Plan by the CAISO.

With both the Unified Planning Assumptions and the CAISO Study Plan developed the second stage of the process that is the assessment of system reliability begins. In 2008, PG&E performed the reliability assessment of its transmission facilities. The reliability assessment followed all assumptions agreed upon as well as any applicable planning standards. PG&E follows the CAISO Grid Planning Standards which encompasses both the NERC Planning Standards (FAC 001, FAC 002, and TPL 001 – TPL 004) and the WECC Reliability Standards to ensure the transmission system performance maintains acceptable performance.

PG&E’s 2008 Assessment Report (Appendix 6) documents the results of the reliability assessment as well as it identifies short and long-term needs at locations where potential transmission expansion is required. The reliability assessment evaluates the performance and robustness of the entire PG&E transmission system, which consists of facilities with nominal voltages of 500 kilovolts (kV), 230 kV, 115 kV, 70 kV and 60 kV. In addition, due to different climates and loading profiles, when conducting the reliability assessment, the transmission system is divided into eight distinct planning areas. The assessment is conducted for the ten-year planning horizon, years 2009, 2010, 2011, 2012, 2013 and 2018. The assessment for the year 2018 is necessary to identify longer lead time projects or facility needs that may have some bearing on transmission decisions that are being made in the near-term.

With the reliability assessment results PG&E then participates in the third stage of the CAISO’s TPP, which is project approval and development of the CAISO Transmission Plan. In this phase PG&E uses its assessment results to identify system reliability risks and in turn develop mitigation plans to reliably serve electric customers during normal and contingency conditions. New reliability transmission project proposals are then submitted for CAISO approval through the Request Window.

On an annual basis, PG&E performs studies that test the transmission system’s performance against the applicable NERC Planning Standards. These transmission assessments form the base foundation of the transmission plans that are proposed in this transmission plan. These transmission assessment reports are located within this plan under Appendix 6.

Summary of PG&E's Transmission Plan

PG&E's Transmission Plan consists of the projects shown in Tables 1-1, 1-2, 1-3 and 1-4. Table 1-1 shows the projects that have received CAISO approval in previous years and are being implemented. There are fifty-eight projects that have received prior approval.

Table 1-1: Projects Previously Approved by the CAISO

No.	Project Title	Purpose and Benefit	County	Project Scope	Cost Range ($)	Targeted In-Service Date
1	Humboldt – Harris 60 kV Reconductoring	NERC Compliance	Humboldt	Reconductor 60 kV Line	1M - 5M	2008
2	Martin 115/60 kV Transformer Replacement	NERC Compliance	San Francisco	Transformer Replacement	5M - 10M	2008
3	Weber #1 60 kV Line	NERC Compliance	San Joaquin	Reconductor and reconfigure the Weber #1 60 kV Line	1M - 5M	2009
4	Monta Vista 115/60 kV Transformer	NERC Compliance	Santa Clara	Install a 115/60 kV transformer at Monta Vista Substation	5M - 10M	2009
5	Plainfield Substation Capacity Increase	Interconnect Customer	Yolo	Distribution Substation Interconnection	5M - 10M	2009
6	Potrero Bus Parallel Circuit Breaker	NERC Compliance	San Francisco	Add a second parallel breaker	1M - 5M	2009
7	Martin – Hunters Point 115 kV Cable	NERC Compliance	San Francisco	Construct New Underground Cable	50M - 100M	2009
8	Borden – Madera 70 kV Reinforcement	NERC Compliance	Madera	Install 70 kV Breaker and Construct Additional Line	5M - 10M	2009
9	Brighton 230/115 kV Transformer Replacement	NERC Compliance	Sacramento	Transformer Replacement	5M – 10M	2009
10	Contra Costa – Las Positas 230 kV Line	NERC Compliance	Contra Costa	Reconductor the Contra Costa – Las Positas and Contra Costa – Lone Tree 230 kV Lines	10M – 20M	2009
11	Gold Hill – Clarksville 115 kV Line Reconductoring	NERC Compliance	El Dorado	Reconductor 115 kV Lines	1M - 5M	2009

No.	Project Title	Purpose and Benefit	County	Project Scope	Cost Range ($)	Targeted In-Service Date
12	Lakeville 230/60 kV Transformer Capacity Increase	NERC Compliance	Sonoma	Install Second 230/60 kV Transformer	5M - 10M	2009
13	Placer – Gold Hill 115 kV Line Reinforcement	NERC Compliance	Placer	Reconductor Placer - Gold Hill 115 kV Lines	10M – 20M	2009
14	West Sacramento – Brighton 115 kV Reconductoring	NERC Compliance	Yolo	Reconductor 115 kV Lines	10M – 20M	2009
15	Humboldt Reactive Support	NERC Compliance	Humboldt	Install SVC at Humboldt Substation	10M - 20M	2009
16	Moss Landing – Salinas – Soledad 115 kV Reconductoring	NERC Compliance	Monterey	Line Reconductor	10M – 15M	2009
17	Pease – Marysville 60 kV Line	NERC Compliance	Yuba and Sutter	Construct New 60 kV Line	10M - 20M	2009
18	7th Standard Substation Capacity Increase	Interconnect Customer	Kern	Distribution Substation Interconnection	1M - 5M	2010
19	Atlantic – Lincoln Transmission	NERC Compliance	Placer	Convert 60 kV Facilities to 115 kV and Construct New 115 kV Line	50M – 100M	2010
20	Bay Meadows 115 kV Reconductoring	NERC Compliance	San Mateo	Reconductor 115 kV Lines	5M – 10M	2010
21	Hollister 115 kV Reconductoring	NERC Compliance	San Benito	Line Reconductor	20M – 50M	2010
22	Mendocino Coast Reactive Support	NERC Compliance	Mendocino	Install 10 to 15 MVArs of reactive support at Fort Bragg or Big River 60 kV Substations	5M – 10M	2010
23	Menlo 60 kV Switch Upgrade	NERC Compliance	San Mateo	Replace 60 kV switches at Menlo 60 kV Substation	<1M	2010
24	Mesa 115 kV Shunt Capacitors	NERC Compliance	Santa Barbara	Install Shunt Capacitors	1M - 5M	2010
25	Missouri Flat – Gold Hill 115 kV Line	NERC Compliance	Calaveras	Line Reconductor	10M – 20M	2010

No.	Project Title	Purpose and Benefit	County	Project Scope	Cost Range ($)	Targeted In-Service Date
26	Newark – Ravenswood 230 kV Line	NERC Compliance	San Mateo and Alameda	Reconductor Newark – Ravenswood and Tesla – Ravenswood 230 kV Line	10M – 20M	2010
27	Oakland Underground Cable	NERC Compliance	Alameda	Construct New Underground Cable	50M - 100M	2010
28	Palermo – Rio Oso 115 kV Line Reconductoring	NERC Compliance	Yuba and Sutter	Line Reconductor	50M- 60M	2010
29	Pittsburg – Tesla 230 kV Reconductoring	NERC Compliance	Contra Costa	Increase 230 kV Capacity	10M – 20M	2010
30	South of Birds Landing 230 kV Reconductoring	NERC Compliance	Solano	Line Reconductor	30M – 40M	2010
31	Stone Substation Capacity Increase	Interconnect Customer	Yolo	Distribution Substation Interconnection	1M - 5M	2010
32	Table Mountain – Rio Oso 230 kV Line Reconductor and Tower Raises	NERC Compliance	Yuba and Sutter	Increase substation equipment capacity	1M - 5M	2010
33	Tesla 115 kV Capacity Increase	NERC Compliance	San Joaquin	Increase Transmission Capacity	10M – 20M	2010
34	West Fresno Reactive Support	NERC Compliance	Fresno	Install Caps At West Fresno	1M – 5M	2010
35	Gregg 230 kV Reactor	NERC Compliance	Madera	Install Shunt Reactors	5M - 10M	2010
36	West Point – Valley Springs 60 kV Line	NERC Compliance	Calaveras	Reconductor 60 kV Line	5M – 10M	2010
37	Crazy Horse Switching Station	NERC Compliance	San Benito	Construct New Switching Station	20M - 50M	2010
38	Cooley Landing 115/60 kV Transformer Capacity Upgrade	NERC Compliance	San Mateo	Replace Cooley Landing 115/60 kV Transformer No. 1 by 2010 and No. 2	10M - 20M	2011
39	Cortina 60 kV Reliability	NERC Compliance	Colusa	Install Additional Transformer	5M – 10M	2011

No.	Project Title	Purpose and Benefit	County	Project Scope	Cost Range ($)	Targeted In-Service Date
40	East Nicolaus 115 kV Area Reinforcement	NERC Compliance	Sutter	Increase 115 kV Transmission Capacity	10M – 20M	2011
41	Half Moon Bay Reactive Support	NERC Compliance	San Mateo	Increase 60 kV Transmission Capacity	5M – 10M	2011
42	Moraga Transformer Capacity Increase	NERC Compliance	Contra Costa	Replace Moraga 230/115 kV Banks	10M – 20M	2011
43	Pittsburg 230/115 kV Transformer Capacity Increase	NERC Compliance	Contra Costa	Install a third 230/115 kV transformer at Pittsburg	10M - 20M	2011
44	Soledad 115/60 kV Transformer Capacity	NERC Compliance	Monterey	Replace transformers at Soledad Substation with 200 MVA Transformers	10M - 20M	2011
45	South of San Mateo Capacity Increase	NERC Compliance	San Mateo	Increase 115 kV Transmission Capacity	10M - 20M	2011
46	Tesla – Newark 230 kV Path Upgrade	NERC Compliance	Contra Costa	Increase 230 kV Capacity	5M – 10M	2011
47	Vaca Dixon – Birds Landing 230 kV Reconductoring	NERC Compliance	Solano	Reconductor 230 kV Lines	20M - 50M	2011
48	Wheeler Ridge 230/70 kV Transformer	NERC Compliance	Kern	Add a Second 230/70 kV Bank	5M – 10M	2011
49	Lakeville – Ignacio #2 230 kV Line	NERC Compliance	Sonoma	Re-establish the Lakeville – Ignacio #2 230 kV Line	1M – 5M	2011
50	Metcalf – Evergreen 115 kV	NERC Compliance	Santa Clara	Reconductor 115 kV Lines	5M - 10M	2012
51	Metcalf – Piercy & Swift and Newark – Dixon Landing 115 kV Upgrade	NERC Compliance	Santa Clara	Reconductor 115 kV Lines	5M - 10M	2012
52	Monta Vista – Los Altos 60 kV Reconductoring	NERC Compliance	Santa Clara	Reconductor 60 kV Line	1M – 5M	2012
53	Rio Oso 230/115 kV Transformer Upgrades	NERC Compliance	Sutter	Transformer Replacements	10M - 20M	2012

No.	Project Title	Purpose and Benefit	County	Project Scope	Cost Range ($)	Targeted In-Service Date
54	Contra Costa – Moraga 230 kV Line Reconductoring	NERC Compliance	Contra Costa	Reconductor 230 kV Lines	10M - 20M	2013
55	Ignacio – San Rafael and Ignacio – Las Gallinas 115 kV Reconductoring	NERC Compliance	Marin	Reconductor 115 kV Lines	5M - 10M	2013
56	Vaca Dixon - Lakeville 230 kV Reconductoring	NERC Compliance	Solano	Line Reconductor	50M - 100M	2013
57	San Leandro – Oakland J 115 kV Line Reconductoring	NERC Compliance	Contra Costa	Reconductor San Leandro - Oakland J 115 kV Line	10M - 20M	2015
58	Woodward 115 kV Reinforcement	NERC Compliance	Fresno	Reconductor 115 kV Lines	5M - 10M	2016

Table 1-2 lists the projects with a cost of less than $50 million that PG&E is submitting for CAISO approval this year. The evaluations of the scopes of the projects are complete. PG&E requests that the CAISO review these projects and approve them. There are fifty-three projects costing less than $50 million seeking CAISO approval this year.

Table 1-2: Projects <$50M Needing Approval this Year by CAISO

No.	Project Title	Purpose and Benefit	County	Project Scope	Cost Range ($)	Targeted In-Service Date
1	Camden 70 kV Breaker Installation	NERC Compliance and Operational Flexibility	Fresno	Install SCADA and circuit breakers	2M – 4M	2009
2	Higgins 115 kV Circuit Breaker Installation	Operational Flexibility	Nevada	Replace Switch Nos. 146 and 156 with a circuit breakers	1M – 5M	2009
3	Ignacio 115 kV Bus Reconfiguration	Operational Flexibility	Marin	Extend 115 kV bus and relocate transformer	5M – 6M	2009
4	Larkin Circuit Breaker No. 192	Operational Flexibility	San Francisco	Upgrade protection equipment at Larkin	1M - 3M	2009
5	Wilson – Oro Loma 115 kV Line Reconductor	NERC Compliance	Merced	Line Reconductor	2M – 3M	2009
6	230 kV Solar Switching Station	Interconnect Customer	San Luis Obispo	New 230 kV Switching Station	25M – 35M	2010
7	Burns Reliability	Operational Flexibility	Santa Cruz	Install a breaker and SCADA at Burns Substation	5M – 8M	2010
8	Carbona Reliability	NERC Compliance and Operational Flexibility	San Joaquin	Line Reconductor and circuit breaker addition	1M – 5M	2010
9	Cassidy 70 kV Breaker Installation	NERC Compliance and Operational Flexibility	Madera	Install SCADA and circuit breakers	1M – 2M	2010
10	Daly City Bus Reconfiguration Project	Operational Flexibility	San Mateo	Install breakers and SCADA at Daly City	1M - 5M	2010

No.	Project Title	Purpose and Benefit	County	Project Scope	Cost Range ($)	Targeted In-Service Date
11	Herndon 115 kV Circuit Breaker Replacement	NERC Compliance	Fresno	Replace circuit breaker No. 122 rated at 2,000 amps or larger	1M – 2M	2010
12	Humboldt 115/60 kV Transformer Nos. 1 & 2 Replacement	NERC Compliance	Humboldt	Transformer Replacement	10M – 15M	2010
13	Kyoho Manufacturing California 115 kV Interconnection	Tariff and Compliance	San Joaquin	Interconnect KHMCA's Substation by tapping off the Stockton "A" - Lockeford - Bellota #2 115 kV Line	1M – 5M	2010
14	Lakeville No. 2 60 kV Line Switch Upgrade	NERC Compliance	Sonoma	Replace limiting switch	< 1M	2010
15	Lodi-Industrial 60 kV Line Switch Upgrade	NERC Compliance	San Joaquin	Replace limiting switches with larger ones	< 1M	2010
16	Menlo Area 60 kV System Upgrade	NERC Compliance	San Mateo	Reconductor 60 kV Line	5M – 15M	2010
17	Mosher Transmission	NERC Compliance and Operational Flexibility	San Joaquin	Replace switches with circuit breakers at Mosher Substation and Reconductor Lockeford #1 60 kV Line	10M – 20M	2010
18	Newburg Second 60 kV Tap and SCADA Installation	Operational Flexibility	Humboldt	Construct a new 60 kV tap line and add SCADA at Newburg Substation	1M – 2M	2010
19	Occidental of Elk Hills 230 kV Interconnection	Interconnect Customer	Kern	Interconnect Occidental's new substation	< 1M	2010
20	Palermo 115 kV Circuit Breaker and Switch Replacements	NERC Compliance	Butte	Circuit breaker replacement	1M – 5M	2010
21	Salado-Newman 60 kV Line No. 2 Reconductor	NERC Compliance	Stanislaus	Line Reconductor	< 1M	2010
22	Sanger – California Ave. 70 kV to 115 kV Voltage Conversion	NERC Compliance	Fresno	70 to 115 kV Conversion	5M – 10M	2010

No.	Project Title	Purpose and Benefit	County	Project Scope	Cost Range ($)	Targeted In-Service Date
23	Sanger – Reedley Area Reinforcement	NERC Compliance	Fresno	70 to 115 kV Conversion	20M – 25M	2010
24	Tri-Valley Voltage Control	NERC Compliance	Alameda	Add shunt reactors at Vineyard and North Dublin Substation	10M - 15M	2010
25	Caribou 60 kV Line No. 2 Reconductor	NERC Compliance	Plumas	Line Reconductor	5M – 10M	2011
26	Garberville Reactive Support	NERC Compliance	Humboldt	Install reactive support at Garberville Substation	5M – 10M	2011
27	Gold Hill – Horseshoe 115 kV Reinforcement	NERC Compliance	Sacramento and Placer	Line Reconductor	5M – 10M	2011
28	Guernsey – Henrietta 70 kV Line Reconductor	NERC Compliance	Kings	Line Reconductor	1M – 5M	2011
29	Hartley 60 kV Breakers Installation	Operational Flexibility	Lake	Replace Hartley switch Nos. 57 and 59 with SCADA controlled circuit breakers	2M - 3M	2011
30	Herndon 230/115 kV Transformer Installation	NERC Compliance	Fresno	Install a 3rd 230/115 kV Transformer at Herndon Substation	10M – 15M	2011
31	Kern – Old River Line Reconductor	NERC Compliance	Kern	Line Reconductor	15M – 25M	2011
32	Maple Creek Reactive Support	NERC Compliance	Humboldt	Install reactive support at Maple Creek Substation	2M – 5M	2011
33	Morro Bay – Midway 230 kV Line Reconductor	NERC Compliance	San Luis Obispo and Kern	Line Reconductor	35M – 45M	2011
34	San Justo Distribution Substation	NERC Compliance	San Benito	Construct a new substation and line loop	5M – 10M	2011
35	Santa Cruz 115 kV Reinforcement	NERC Compliance	Santa Cruz	Rebuild the Green Valley-Rob Roy line into a double-circuit line and install reactive support at Camp Evers	10M – 15M	2011

No.	Project Title	Purpose and Benefit	County	Project Scope	Cost Range ($)	Targeted In-Service Date
36	Shepherd Substation Interconnection	NERC Compliance	Fresno	New Substation and Line Loop	8M – 10M	2011
37	West Fresno 115 kV Bus Upgrade	Operational Flexibility	Fresno	Create a ring bus design	3M – 5M	2011
38	Caruthers – Kingsburg 70 kV Line Reconductor	NERC Compliance and Operational Flexibility	Fresno	Line Reconductor and New Line	10M – 15M	2012
39	Clearlake 60 kV System Reinforcement	NERC Compliance	Lake	New 115 kV line and new 115/60 kV transformer	20M - 30M	2012
40	Cressey – Gallo 115 kV Line Installation	Operational Flexibility	Merced	New Line	15M – 25M	2012
41	Del Monte – Fort Ord 60 kV Reinforcement	NERC Compliance	Monterey	Line Reconductor	5M – 10M	2012
42	Evergreen-Mabury Conversion	NERC Compliance	Santa Clara	60 to 115 kV Conversion	10M – 15M	2012
43	Ignacio-Mare Island 115 kV System Reinforcement	NERC Compliance	Mare Island	Line Reconductor	20M - 25M	2012
44	Metcalf-Morgan Hill 115 kV Reinforcement	NERC Compliance	Santa Clara	Line Reconductor and loop	10M - 20M	2012
45	Midway – Renfro 115 kV Line Reconductor	NERC Compliance	Kern	Line Reconductor	17M – 22M	2012
46	Natividad Distribution Substation	NERC Compliance	Monterey	Construct a new substation, line reconductor and line loop	15M – 20M	2012
47	Ravenswood-Cooley Landing 115 kV Reconductoring Project	NERC Compliance	San Mateo and Santa Clara	Line Reconductor	5M – 10M	2012
48	Valley Springs 230/60 kV Transformer Addition	NERC Compliance and Operational Flexibility	San Joaquin	Add a second Valley Springs Transformer rated at 200 MVA	8M – 10M	2012
49	Watsonville Voltage Conversion	NERC Compliance	Santa Cruz	60 to 115 kV Conversion	20M – 25M	2012

No.	Project Title	Purpose and Benefit	County	Project Scope	Cost Range ($)	Targeted In-Service Date
50	Cooley Landing-Los Altos 60 kV Reconductoring	NERC Compliance	Santa Clara	Line Reconductor	5M – 10M	2013
51	Fulton-Fitch Mountain 60 kV Line Reconductoring	NERC Compliance	Sonoma	Line Reconductor	3M – 5M	2013
52	Glenn 60 kV Line No. 1 Reconductor	NERC Compliance	Glenn	Line Reconductor	6M – 8M	2013
53	San Mateo-Bair 60 kV Reconductoring	NERC Compliance	San Mateo	Line Reconductor	5M – 10M	2013

Table 1-3 lists the projects with a cost greater than $50 million that PG&E is submitting for CAISO approval this year. The evaluations of the scopes of the projects are complete. PG&E requests that the CAISO review these projects and approve them. There is one project costing greater than $50 million seeking CAISO approval this year.

Table 1-3: Projects >$50M Needing Approval this Year by CAISO

No.	Project Title	Purpose and Benefit	County	Project Scope	Cost Range ($)	Targeted In-Service Date
1	Embarcadero-Potrero 230 kV Cable	NERC Compliance	San Francisco	Build new 230 kV underground cable	100M – 150M	2012

PG&E develops projects to resolve potential NERC reliability issues, increase reliability to customers, allow for the import of renewable and conventional generation, among other rationales. Projects that are proposed may require further evaluation and development prior to seeking CAISO approval. Table 1-4 shows projects that have been proposed that need further analysis before CAISO approval is required. There are thirty-nine projects that require further analysis.

Table 1-4: Projects Requiring Further Analysis

No.	Project Title	Purpose and Benefit	County	Project Scope	Cost Range ($)	Targeted In-Service Date
1	Country Club 60 kV Bus Upgrade	NERC Compliance	San Joaquin	Bus Reconductor and Line Reconductor	1M – 5M	2010
2	Atlantic – Rio Oso – Gold Hill 230 kV Lines	NERC Compliance	Placer	Line Reconductor	30M – 40M	2012
3	Cascade Area Reinforcement	NERC Compliance	Shasta	Install a second 115/60 kV Transformer	7M – 12M	2012
4	Manteca 60 kV Area Reinforcement	Operational Flexibility	San Joaquin	Install a second 115/60 kV Transformer or 60 to 115 kV Conversion	15M – 30M	2012
5	Missouri Flat Expansion	NERC Compliance and Operational Flexibility	El Dorado	Convert Missouri Flat into a Ring Bus	1M – 5M	2012
6	Rio Oso 115 kV Reactive Support	NERC Compliance and Operational Flexibility	Sutter	Install reactive support at Rio Oso Substation	25M – 35M	2012
7	Vaca Dixon - Sobrante - Moraga 230 kV Reinforcement	Access Resource	Solano and Contra Costa	Increase Transmission Capacity to Access Resources	100M – 200M	2012
8	Valley Springs No. 1 60 kV Line Reinforcement	NERC Compliance	San Joaquin	Line Reconductor	8M – 10M	2012
9	Brighton - Davis 115 kV Reconductoring	NERC Compliance	Sacramento and Yolo	Line Reconductor	5M – 10M	2013

No.	Project Title	Purpose and Benefit	County	Project Scope	Cost Range ($)	Targeted In-Service Date
10	Central California Clean Energy Project	NERC Compliance and Access to Resource	Fresno, Kings and Kern	New 500 kV Substation, New 500 kV DCTL and Voltage Support	1,000M	2013
11	Drum – Grass Valley – Weimar 60 kV Line	NERC Compliance	Nevada	Line Reconductor	10M – 20M	2013
12	Essex Jct – Arcata – Fairhaven 60 kV Line Reconductoring	NERC Compliance	Humboldt	Line Reconductor	1M – 2M	2013
13	Table Mountain – Vaca Dixon 230 kV Reinforcement	Access Resource	Shasta, Tehama, Glenn, Colusa, Yolo, and Solano	Increase Transmission Capacity to Access Resources	50M – 200M	2013
14	Eagle Rock and Mendocino 115 kV Capacity Increase Project	NERC Compliance	Colusa and Lake	Line Reconductor and New 230/115 kV Transformer	50M – 100M	2014
15	Eight Mile Road-Tesla 230 kV Lines Reconductor	NERC Compliance	Stockton	Line Reconductor	30M – 50M	2014
16	Lockeford – Lodi 60 kV Reconductoring	NERC Compliance	San Joaquin	Line Reconductor	10M – 20M	2014
17	Oakhurst 115 kV Tap Reinforcement	NERC Compliance	Madera	Line Reconductor or New Line	10M – 40M	2014
18	Oakland Pocket Capacity Upgrade	NERC Compliance	Alameda	New Oakland J-Oakland C 115 kV cable	100M – 200M	2014
19	South of Palermo 115 kV Reinforcement	NERC Compliance	Butte	Line Reconductor	50M – 60M	2014
20	Vaca Dixon – Davis 115 kV Conversion	NERC Compliance	Sacramento and Yolo	60 to 115 kV Conversion	80M – 100M	2014
21	Valley Springs - Martell 60 kV Line Reconductor	NERC Compliance	Calaveras, Amador	Line Reconductor	15M – 25M	2014
22	Ashlan – Gregg and Ashlan – Herndon 230 kV Reconductor	NERC Compliance	Fresno, Madera	Line Reconductor	5M – 10M	2015
23	Atlantic - Placer Voltage Conversion	NERC Compliance	Placer	60 to 115 kV Conversion	50M – 60M	2015

No.	Project Title	Purpose and Benefit	County	Project Scope	Cost Range ($)	Targeted In-Service Date
24	Bay Area Bulk Transmission Project	NERC Compliance	Bay Area Counties	New 500 kV Substation	400M - 700M	2015
25	Kern - Lamont Area Reinforcement	NERC Compliance	Kern	Line Reconductor	5M – 8M	2015
26	San Mateo and Moraga Synchronous Condenser Replacements	NERC Compliance	San Mateo and Contra Costa	Replace San Mateo and Moraga Synchronous Condensers	10M – 20M	2015
27	San Vicente 230/115 kV Substation	NERC Compliance	Monterey	Construct a new 230/115 kV substation	50M – 60M	2015
28	Borden – Coppermine - Wishon 70 kV Upgrade	NERC Compliance	Fresno	Convert Borden Coppermine 70 kV Line	25M – 40M	2016
29	Contra Costa Substation Reliability Improvement Plan	Operational Flexibility	Contra Costa	Loop the Contra Costa PP-Moraga 230 kV No.1 Line Contra Costa Substation	10M – 15M	2016
30	Corcoran – Guernsey Area Reinforcement	NERC Compliance	Kings	70 to 115 kV Conversion	10M – 15M	2016
31	E1 Substation	NERC Compliance	Fresno	Construct a new 230/115/70 kV Substation in East Fresno	50M - 70M	2016
32	Lemoore Area Reinforcement	Operational Flexibility	Kings	70 to 115 kV Conversion and new 115 kV line	25M – 30M	2016
33	Paso Robles Area Reinforcement	NERC Compliance	San Luis Obispo	New 230/70 kV Transformer and New 70 kV Line	15M – 20M	2016
34	Renfro Area Reinforcement	NERC Compliance	Kern	New line and line reconductor	10M – 20M	2016
35	Exchequer – Yosemite 70 kV Line Reconductor	NERC Compliance	Mariposa	Line Reconductor	5M – 10M	2017
36	Los Banos-Oro Loma 70 kV Area Reinforcement	NERC Compliance	Merced	Line Reconductor	10M – 20M	2017

No.	Project Title	Purpose and Benefit	County	Project Scope	Cost Range ($)	Targeted In-Service Date
37	Arco – Twisselman Area Reinforcement	NERC Compliance	Kern	Install a second 230/70 kV Transformer at Arco Substation and Line Reconductor	17M – 25M	2018
38	East Bay – Potrero 230 kV Transmission	Operational Flexibility	Alameda, Contra Costa and San Francisco	New 230 kV Transmission Cable from the East Bay to San Francisco.	350M – 500M	2018
39	Monta Vista – Los Gatos - Evergreen 60 kV Project	NERC Compliance	Santa Clara	Line Reconductor	10M – 15M	2018

CHAPTER 2

Background of Electric Transmission Grid Expansion Plan Process

In accordance with the California Independent System Operator Corporation's (CAISO's Tariff, Section 24, as well as the business rules set forth in the CAISO Business Practice Manual, Pacific Gas and Electric Company (PG&E) is required to participate in the annual CAISO Transmission Planning Process (TPP). Additionally, PG&E is to perform NERC's Transmission Planner functions, including conducting local and bulk transmission planning studies of its service area under the direction of the CAISO for inclusion in the CAISO's TPP; propose new facilities; prepare meaningful cost estimates for proposed and alternative facilities; conduct interconnection studies, facility studies, participate in regional/sub-regional planning groups, and construct projects when designated under the CAISO tariff.

Development of PG&E's annual transmission grid expansion plan is coordinated within the CAISO's TPP, which encourages all interested market participants to participate and provide comments and input on PG&E's transmission plans. The CAISO's TPP is structured into three stages, these are:

- Development of Unified Planning Assumptions and CAISO Study Plan
- Performing technical studies for assessment of system reliability
- Documentation of technical study results and development of transmission plans proposals.

The second phase of the Transmission Planning Process is documenting the technical studies in the reliability assessment report. The report can be reviewed in Appendix 6, which is available upon request due to its large volume. Appendix 6 includes the identified transmission area concerns over the next ten years, along with the identified transmission upgrade projects.

The analyses conducted for this reliability assessment report included power flow, post-transient, transient stability and voltage stability studies. Over 2,000 planning contingencies were analyzed to evaluate the effect of single element and selected multiple element unavailability. The analyses covered the entire PG&E transmission system, which included 60, 70, 115, 230 and 500 kV transmission system facilities.

The final results from the assessment report will be used to initiate the expansion plan new project proposals seeking CAISO management and Board approval. In addition to the new project proposals, the Expansion Plan list the recently completed projects, provide a status update of the projects previously approved by the CAISO and the conceptual projects that need additional analyses because they lack a clear scope, cost and schedule.

Responsibilities and Objectives

As part of the CAISO Transmission Planning Process, PG&E performed the following with the assistance from the CAISO and Stakeholder Group:

- Developed transmission base cases that model forecast conditions
- Conducted a transmission system performance assessment of its facilities to maintain acceptable system voltages and thermal loadings
- Identified system reliability risks to comply with the CAISO Grid Planning Standards
- Developed mitigation plans to reliably serve electric customers during normal and contingency conditions for years 2009 to 2013
- Provide proposals, as appropriate, to reliably serve electric customers during normal and contingency conditions for years 2014 to 2018
- Consider lead times where necessary for successful implementation of the projects
- Addressed all CAISO recommendations identified in the CAISO Transmission Planning Process that relate to PG&E's transmission system
- Assess selected transmission upgrades proposed by the CAISO and stakeholders

Criteria and Guidelines

PG&E used the CAISO grid planning criteria to assess the PG&E transmission system. The CAISO Grid Planning Criteria encompasses the NERC[1] planning standards and the WECC[2] reliability criteria. The CAISO grid planning criteria are posted on the CAISO's web site at www.caiso.com.

[1] North American Electric Reliability Corporation
[2] Western Electricity Coordinating Council

Transmission Expansion Projects Completed in Year 2008

PG&E completed 14 transmission grid infrastructure upgrades in 2008. These upgrades included reconductoring of transmission lines, replacement of transformers, and construction of new line and substation facilities. The following table summarizes the completed projects.

Table 2-1: Completed Transmission Projects in 2008

No.	Project No.	Project Title	In-Service Date
1	T783B	Vaca Dixon 500/230 kV Transformer	Jan-08
2	T949	Del Monte 115/60 kV Transformer No. 4	Apr-08
3	T122	Herndon Bullard 115 kV Reconductoring	Apr-08
4	T1013	Merced 115 kV Bus Reconductoring	Apr-08
6	T680	Kasson - Lammers 115 kV Reconductoring	May-08
7	T847	Newark – Fremont 115 kV Reconductoring	May-08
8	T686B	Palermo 230/115 kV Transformer	May-08
5	T1012	Atwater SPS	May-08
9	T141	Lone Tree Substation	Jun-08
10	T923A	McCall 230/115 kV Transformer Replacement	Jun-08
12	T844	Stagg 230/60 kV Transformers	Jun-08
13	T966	Templeton – Atascadero 70 kV Reconductoring	Jun-08
11	T694	Metcalf - El Patio 115 kV Circuits Reinforcement	Jun-08
14	T177E	Davis 115 kV Circuit Breaker	Sep-08
15	T1095	Granite Venalis Interconnection	Oct-08
16	T776	Monta Vista 115/60 kV Transformer	Oct-08
17	T867	Metcalf - Moss Landing 230 kV Lines	Oct-08

Transmission Projects Placed Into Service in Year 2008

T783B: Vaca Dixon 500/230 kV Transformer

(In Service Date – January 2008)

PROJECT INFORMATION

This project installed a second 500/230 kV transformer at Vaca Dixon Substation. This transformer is sized with 3-single phase units with a total capacity of 1,122 MVA.

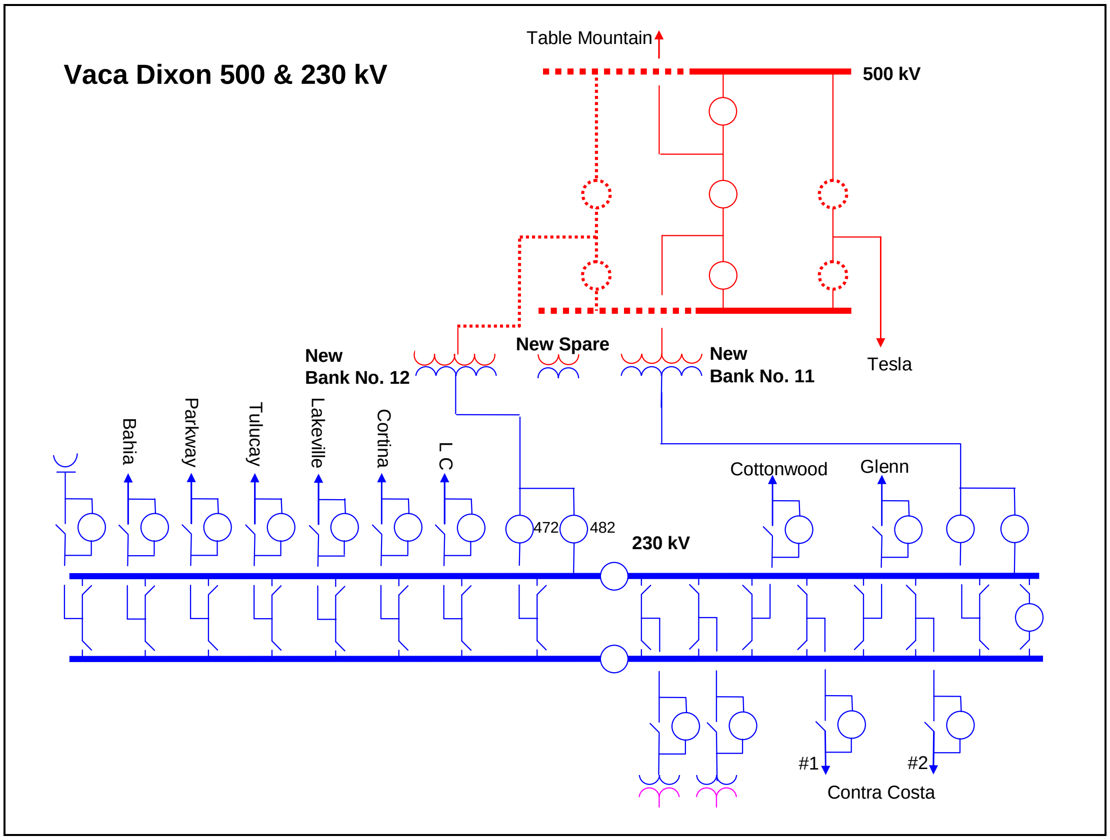


Figure 2-1: Scope Diagram

T949: Del Monte 115/60 kV Transformer Replacement
(In Service Date – April 2008)

PROJECT INFORMATION

This project replaced Del Monte 115/60 kV Transformer No. 4 with a larger capacity rated unit.

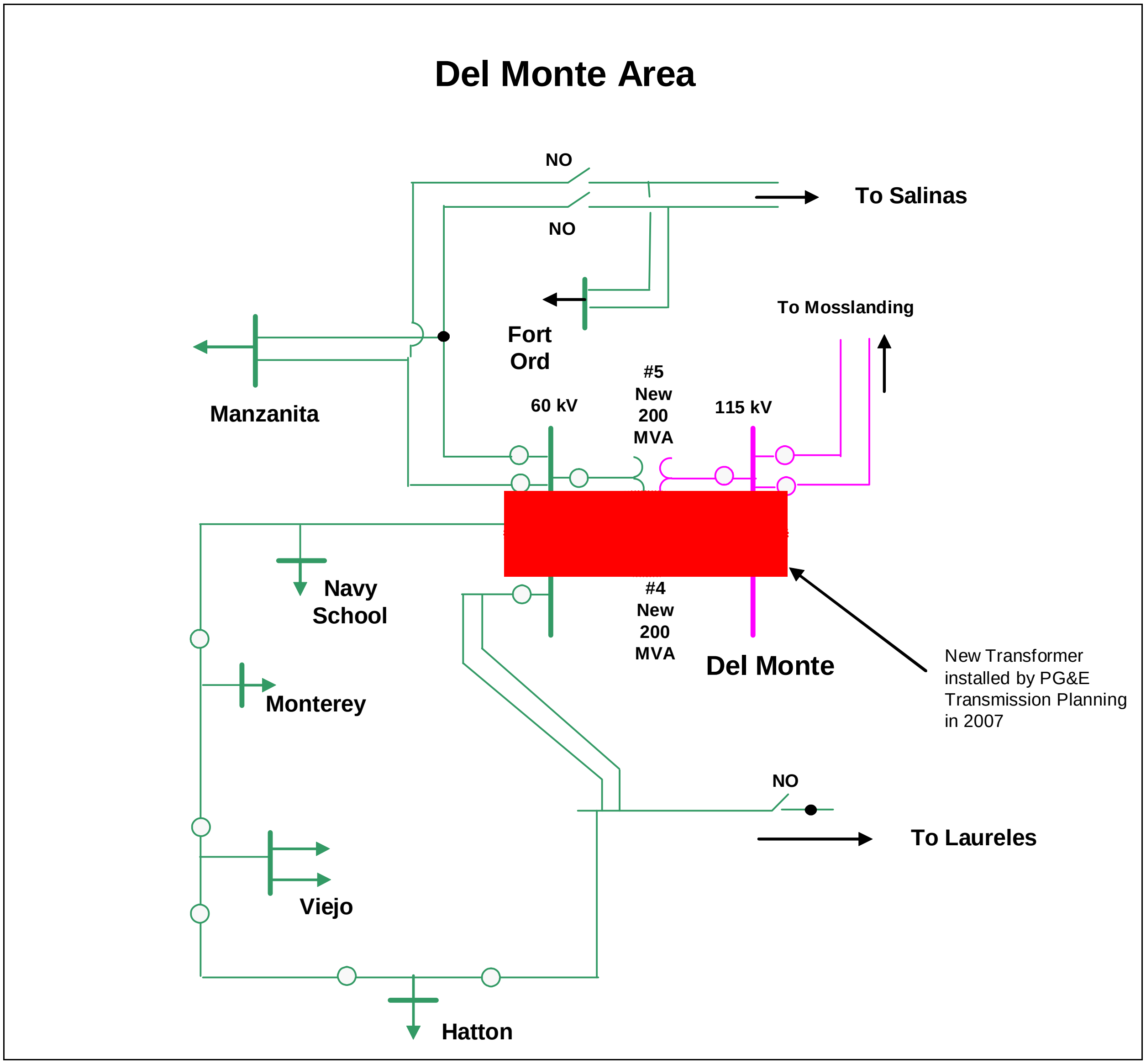


Figure 2-2: Scope Diagram

T122: Herndon – Bullard 115 kV Reconductoring

(In Service Date – April 2008)

PROJECT INFORMATION

The project reconductored the Herndon – Pinedale 115 kV sections (7.5 miles each section) of the Herndon – Bullard 115 kV Nos. 1 and 2 lines to 477 SSAC.

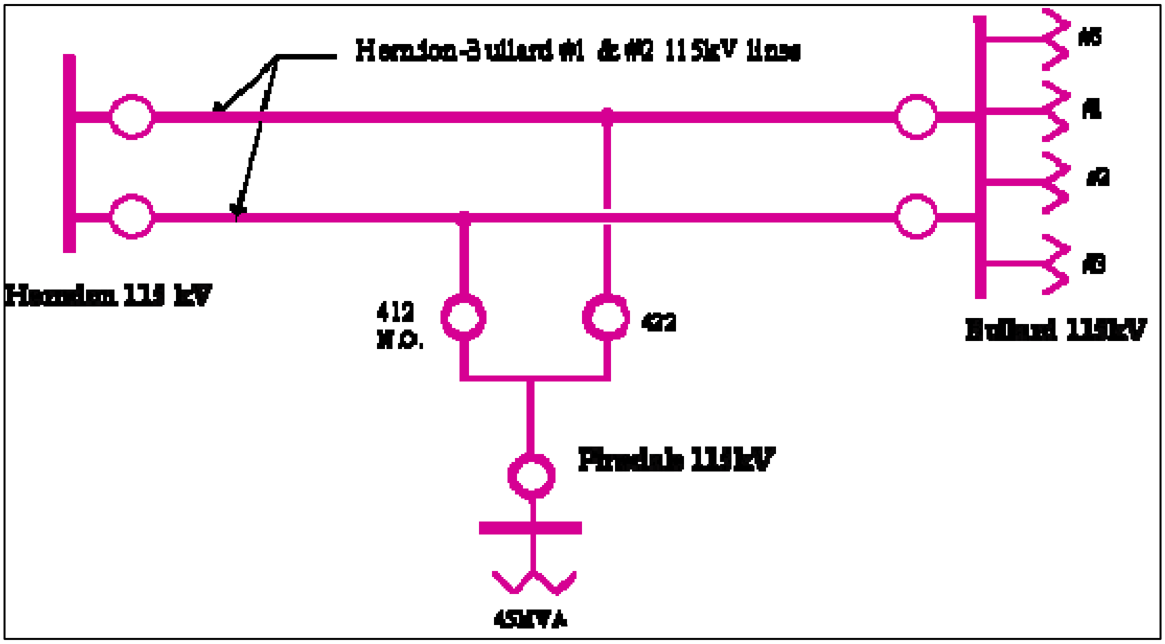


Figure 2-3: Scope Diagram

T1013: Merced 115 kV Bus Reconductoring

(In Service Date – April 2008)

PROJECT INFORMATION

The project reconductored 120 feet of the Merced Substation 115 kV Bus with a higher capacity rated conductor. The new conductor is rated for 820 Amps or greater to handle the higher loading.

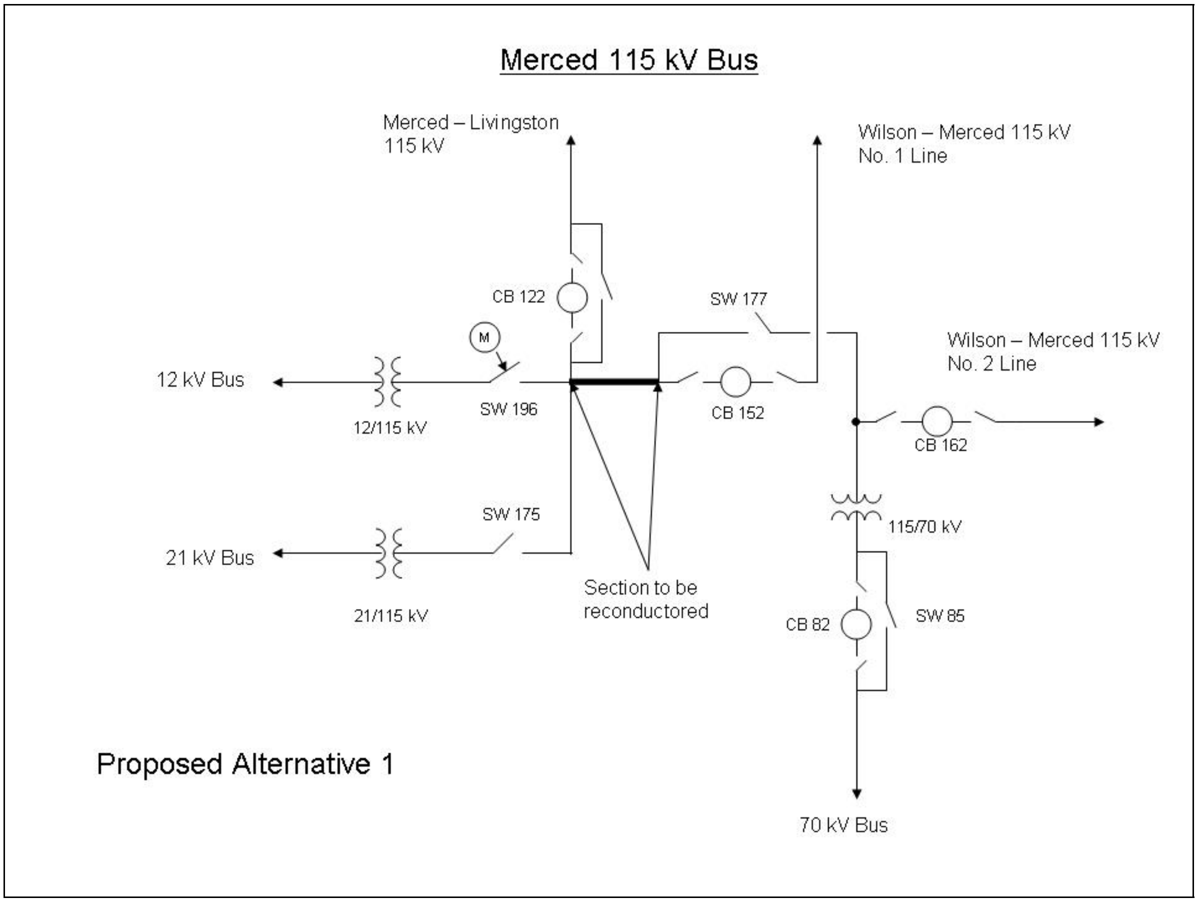


Figure 2-4: Scope Diagram

T680: Kasson – Lammers 115 kV Reconductoring

(Service Date – May 2008)

PROJECT INFORMATION

This project reconductored the Kasson – Lammers 115 kV line to 477 ACSS (1 mile).

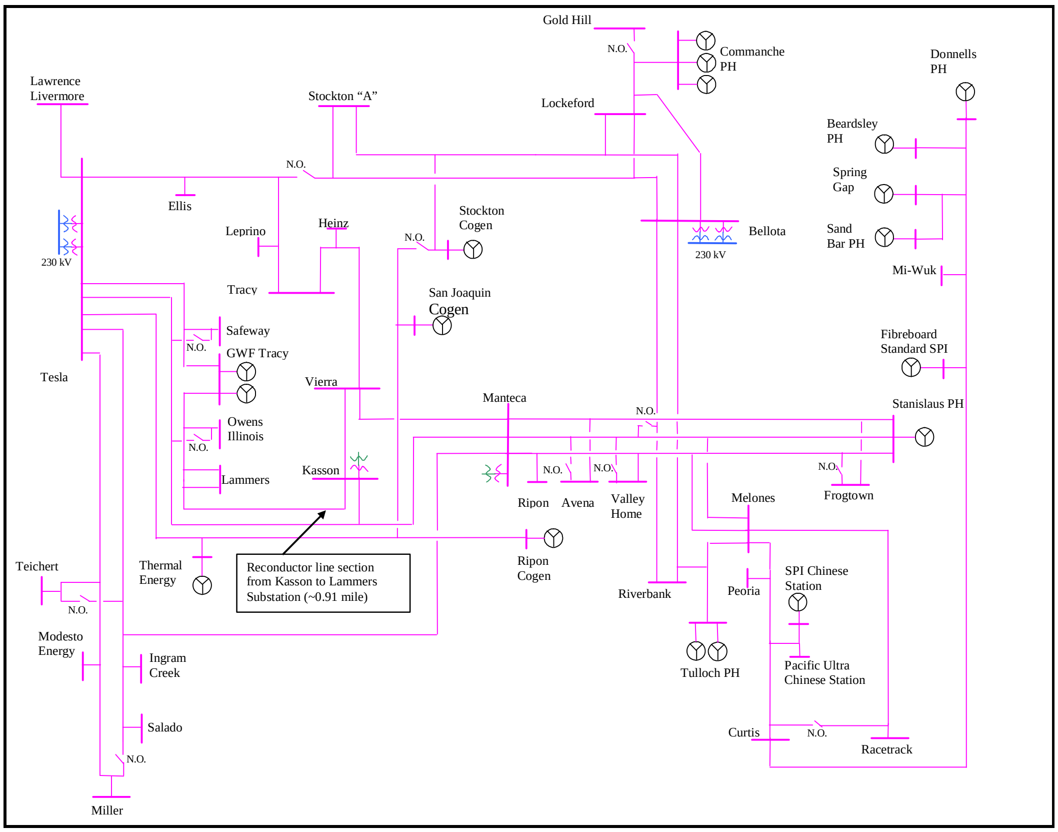


Figure 2-5: Scope Diagram

T847: Newark – Fremont 115 kV Reconductoring

(In Service Date – May 2008)

PROJECT INFORMATION

The project reconductored the Newark – Fremont 115 kV lines (about 4 miles each line) with 477 ACSS or equivalent.

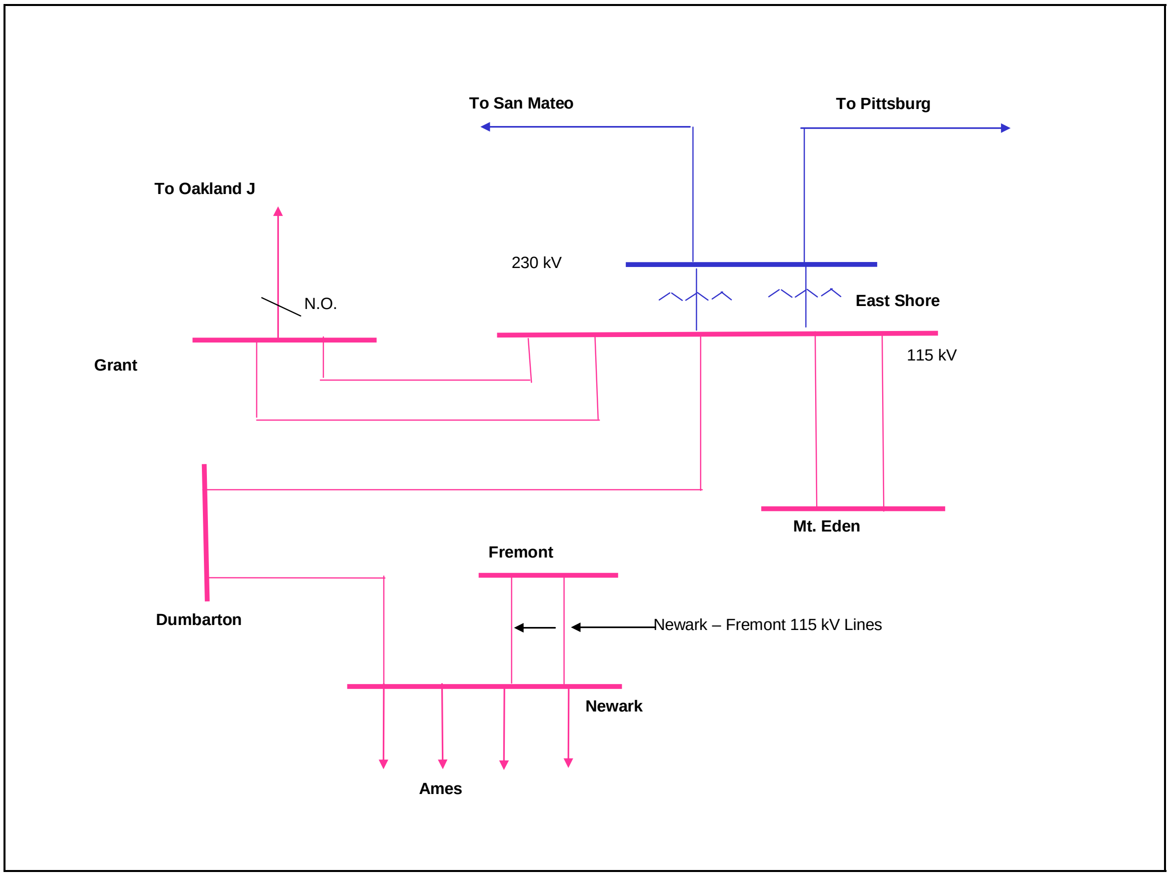


Figure 2-6: Scope Diagram

T686B: Palermo 230/115 kV Transformer

(In Service Date - May 2008)

PROJECT INFORMATION

This project installed a new three phase, 420 MVA, 230/115 kV transformer at Palermo Substation. The existing 230/115/60 kV transformer is disconnected from the 115 kV network and operated as a 230/60 kV transformer.

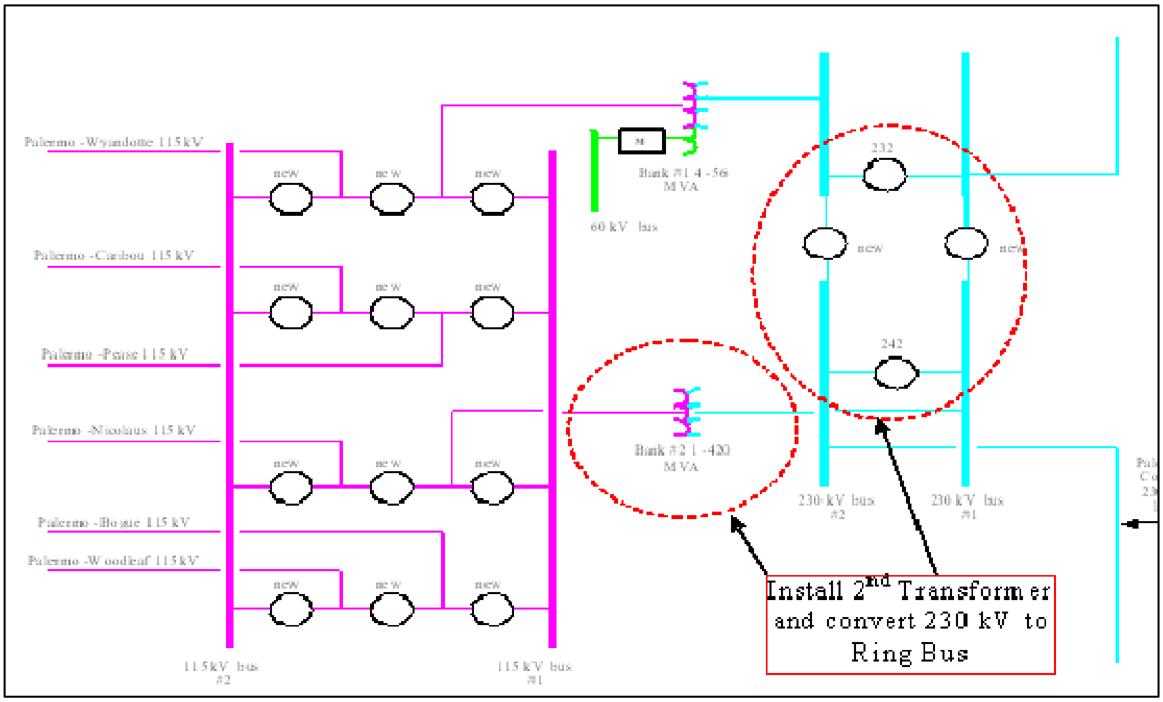


Figure 2-7: Scope Diagram

T1012: Atwater SPS
(In Service Date – May 2008

PROJECT INFORMATION

This project installed an SPS to open Atwater CB 132 (Atwater - El Capitan 115 kV Line) under the following conditions:

1. If Atwater CB 142 (Wilson - Atwater 115 kV Line) is open and
2. If Atwater CB 132 (Atwater - El Capitan 115 kV Line) shows 120 amps or more of directional power flow from Atwater Substation to El Capitan.

This SPS will result in dropping El Capitan Substation load (approximately 75MW in 2008) following the double-circuit outage.

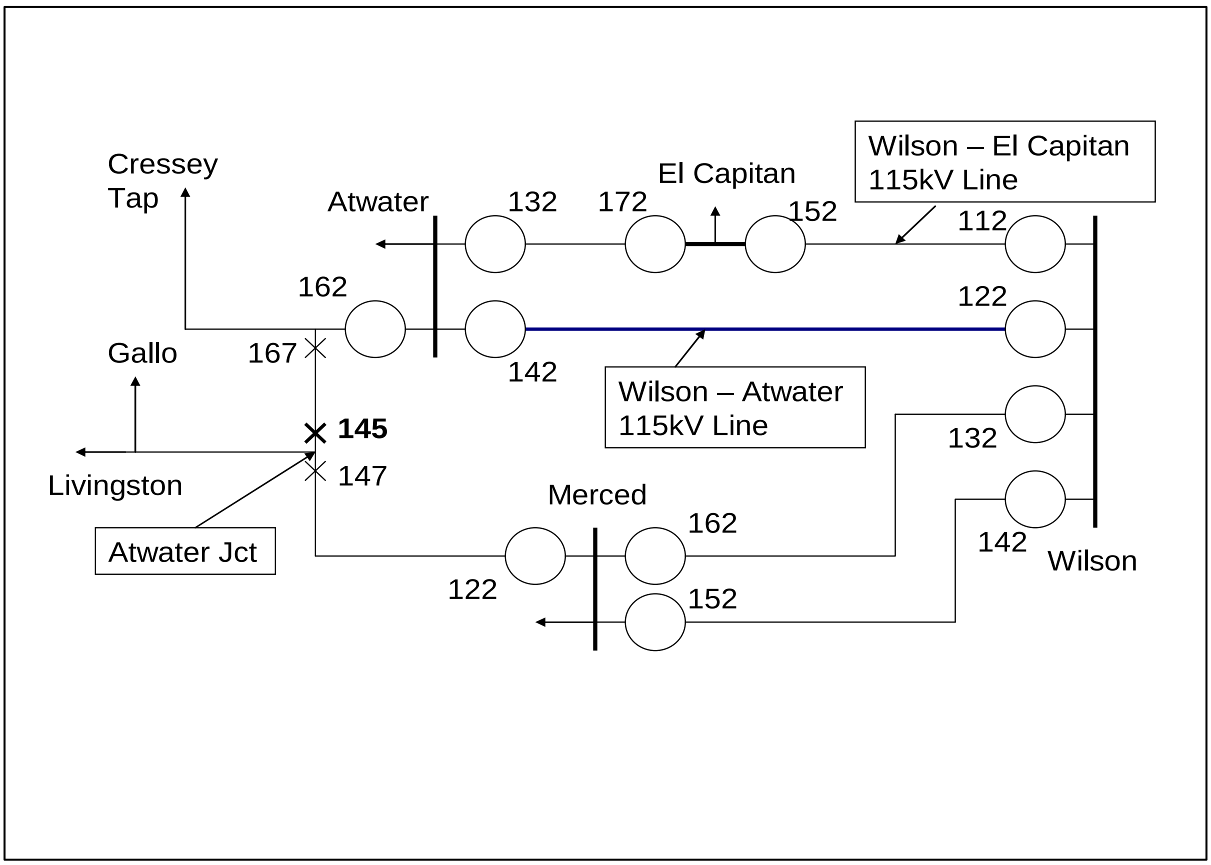


Figure 2-8: Scope Diagram

T141: Lone Tree Substation
(In Service Date – June 2008)

PROJECT INFORMATION

The Lone Tree Substation interconnected in a looped arrangement on the Contra Costa – Cayetano 230 kV Line.

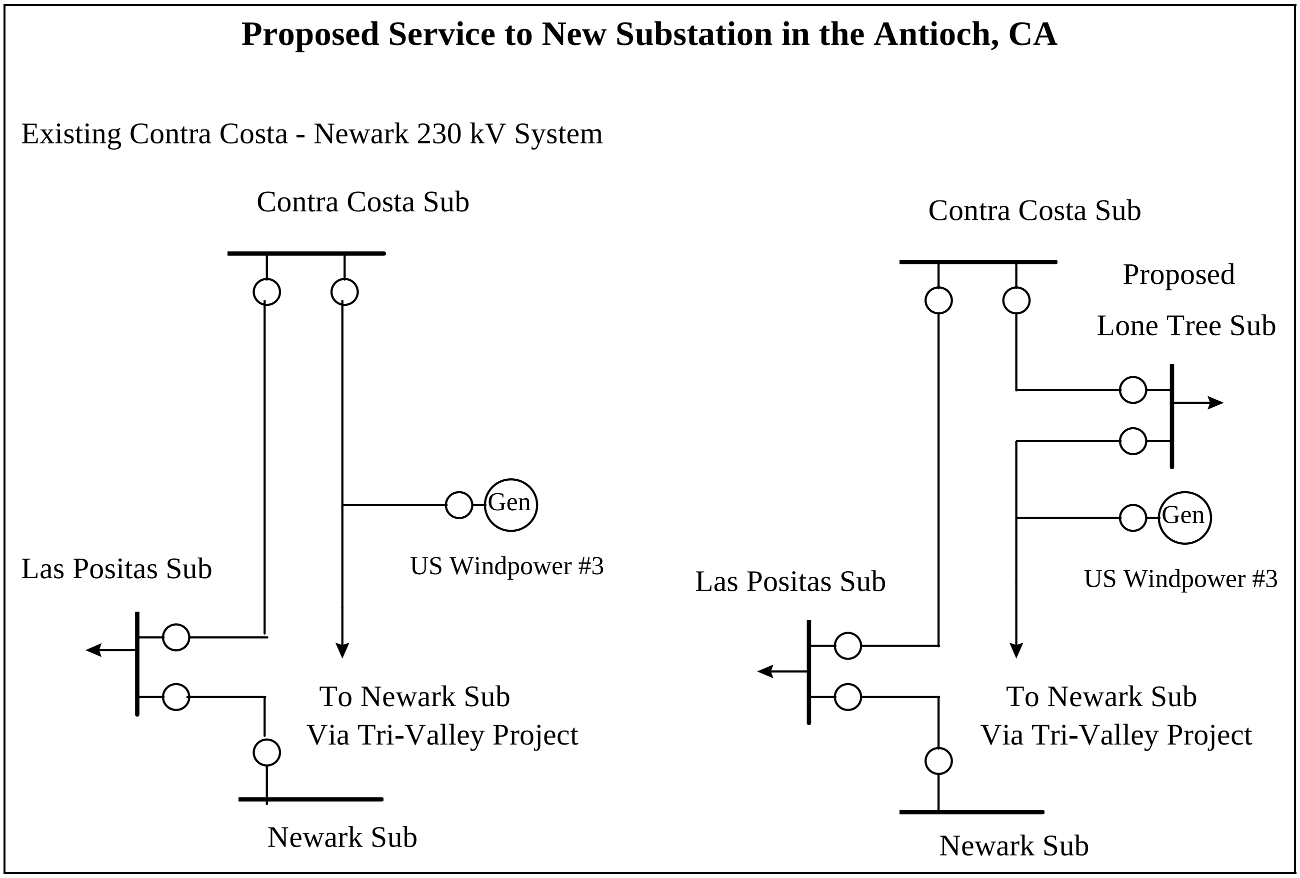


Figure 2-9: Scope Diagram

T923A: McCall 230/115 kV Transformer Replacement

(Service Date – June 2008)

This project replaced the McCall 230/115 kV Transformer No. 1 with a larger capacity unit.

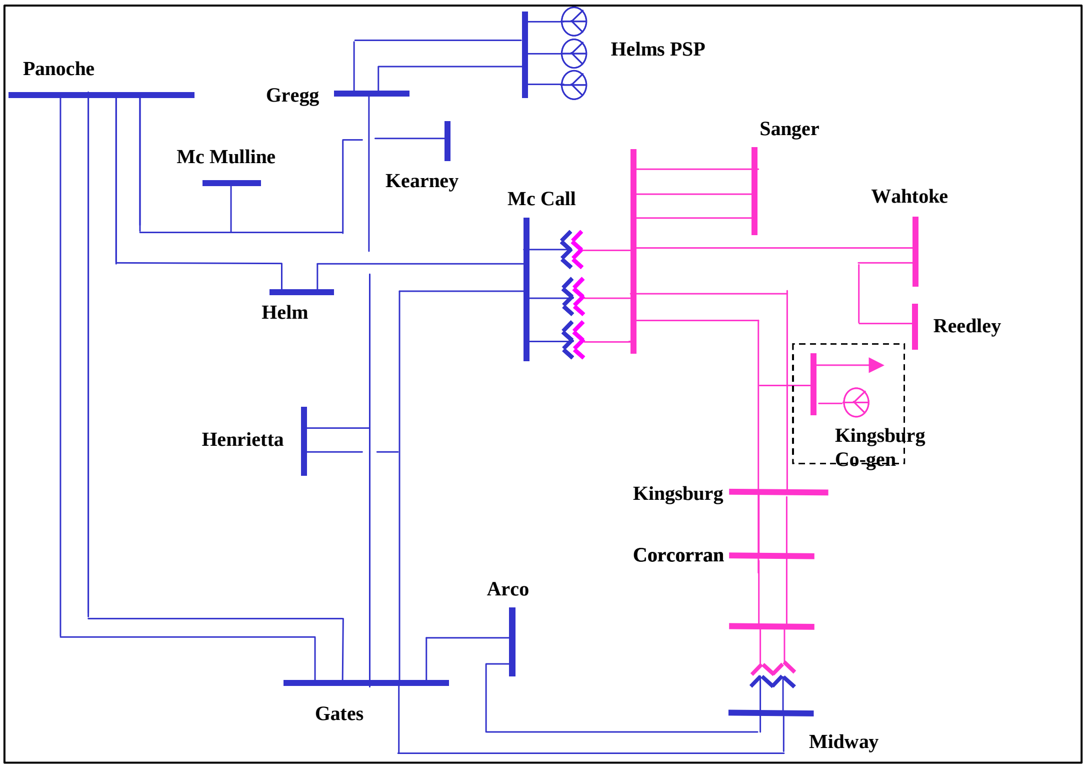


Figure 2-10: Scope Diagram

T844: Stagg 230/60 kV Transformers

(In Service Date – June 2008)

PROJECT INFORMATION

This project replaced the existing Stagg 230/60 kV transformers with two 300 MVA units.

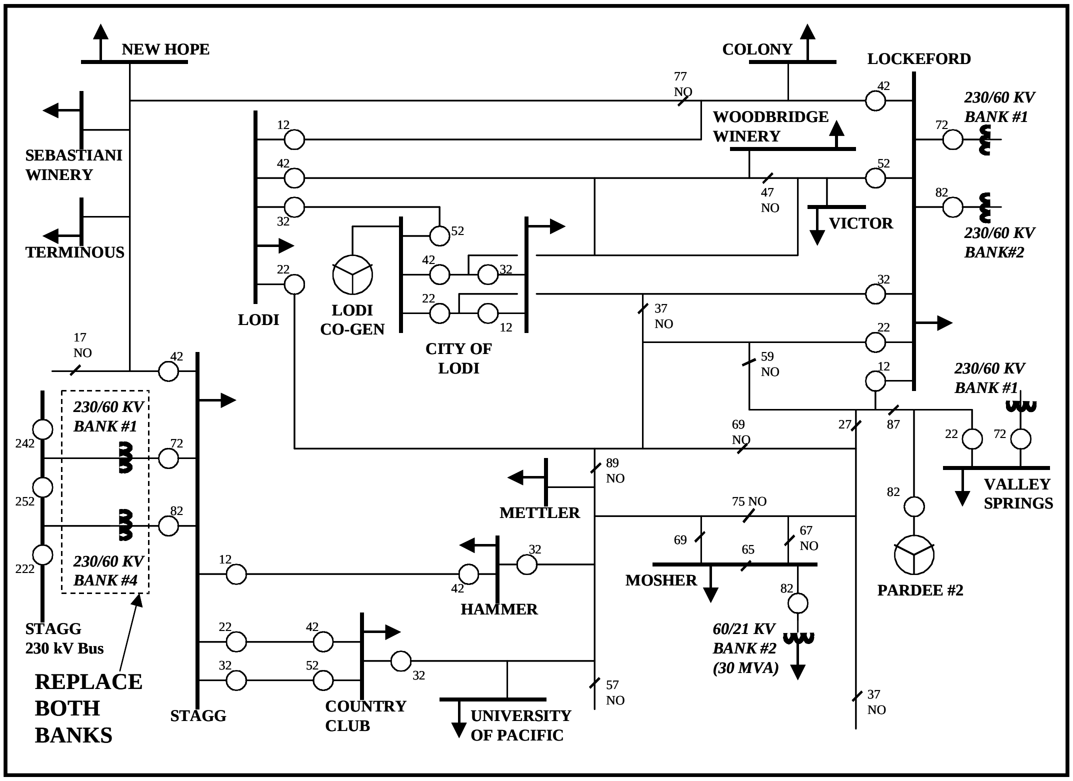


Figure 2-11: Scope Diagram

T966: Templeton – Atascadero 70 kV Reconductoring
(In Service Date – June 2008)

PROJECT INFORMATION

The project reconductored the limiting sections of the Templeton – Atascadero 70 kV Line.

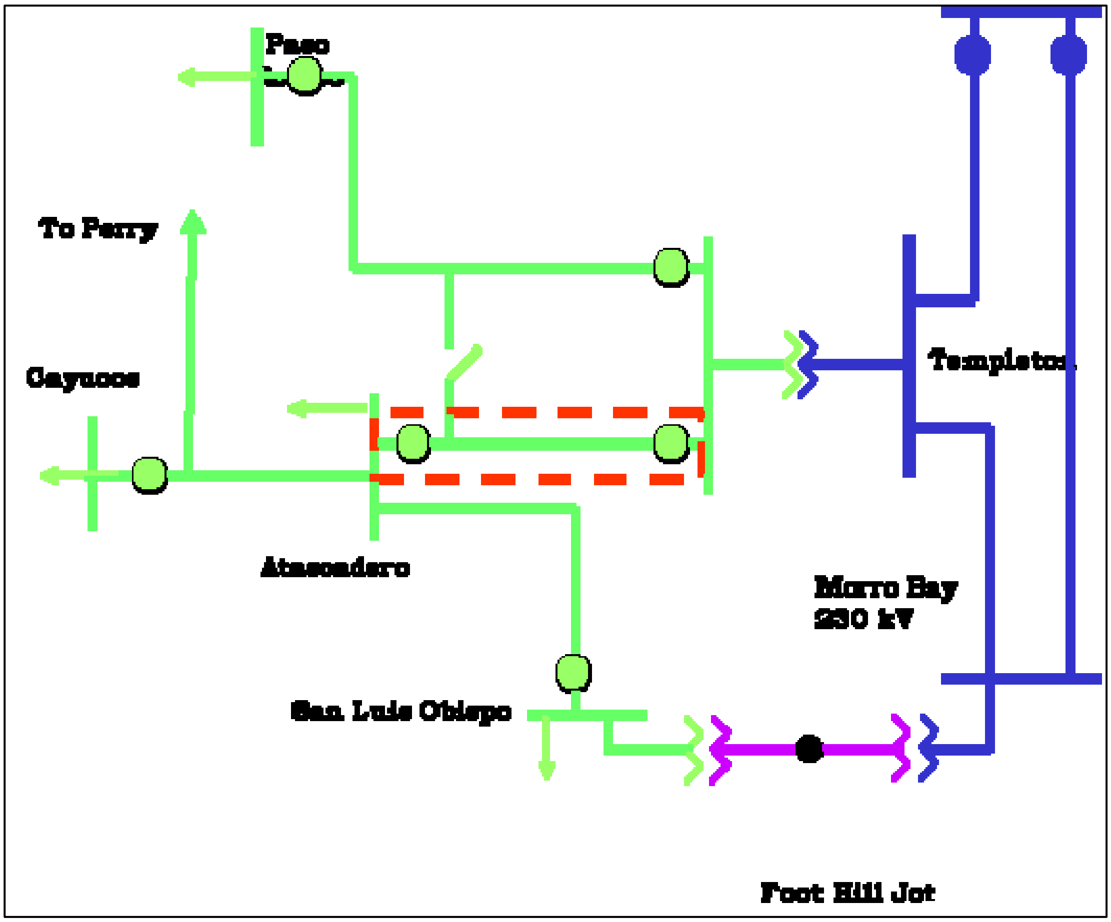


Figure 2-12: Scope Diagram

T694: Metcalf - El Patio 115 kV Circuits Reinforcement

(In Service Date – June 2008)

PROJECT INFORMATION

This project reconductored the Metcalf-El Patio Nos. 1 and 2 115 kV circuits with 477 kcmil ACSS conductors.

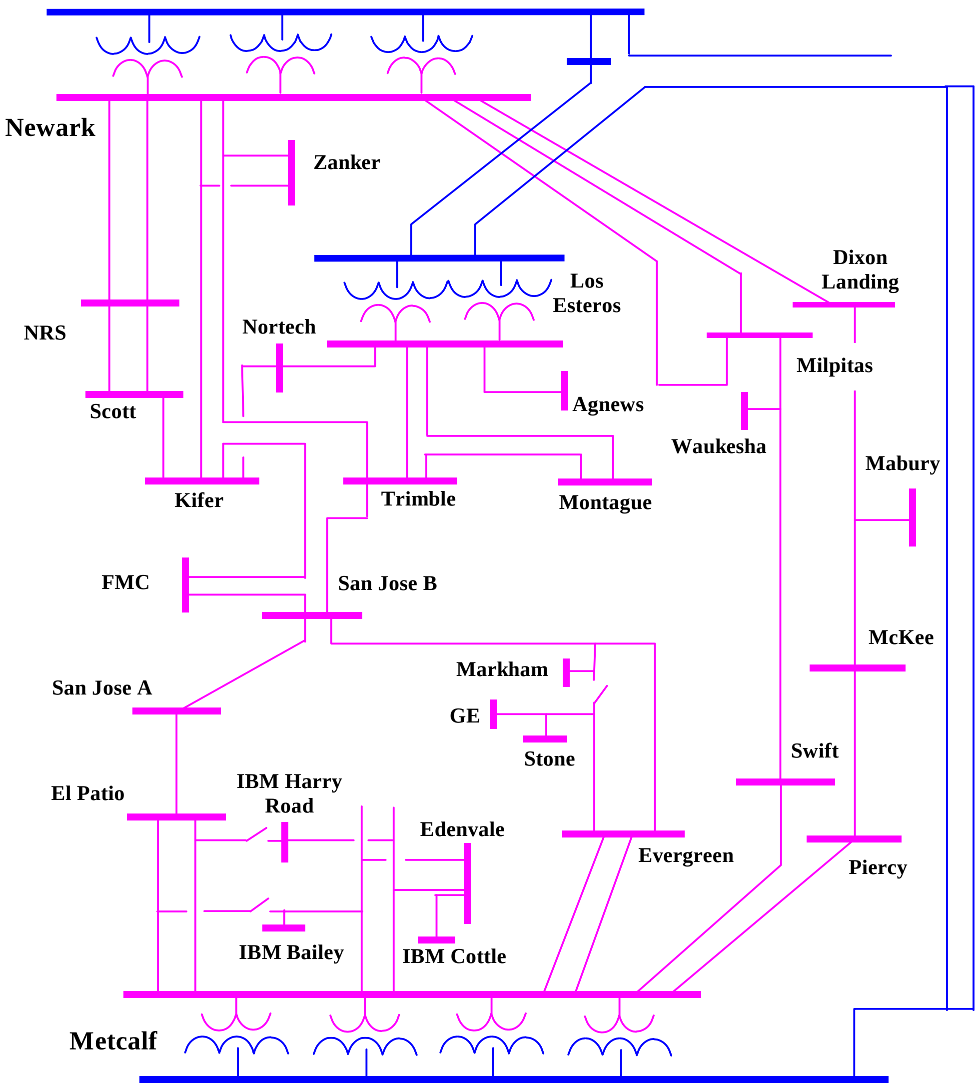


Figure 2-13: Scope Diagram

T177E: Davis 115 kV Circuit Breaker

(In Service Date – September 2008)

PROJECT INFORMATION

The project scope installed a new 115 kV circuit breaker to provide a direct connection to University of California Davis' (UCD) new substation.

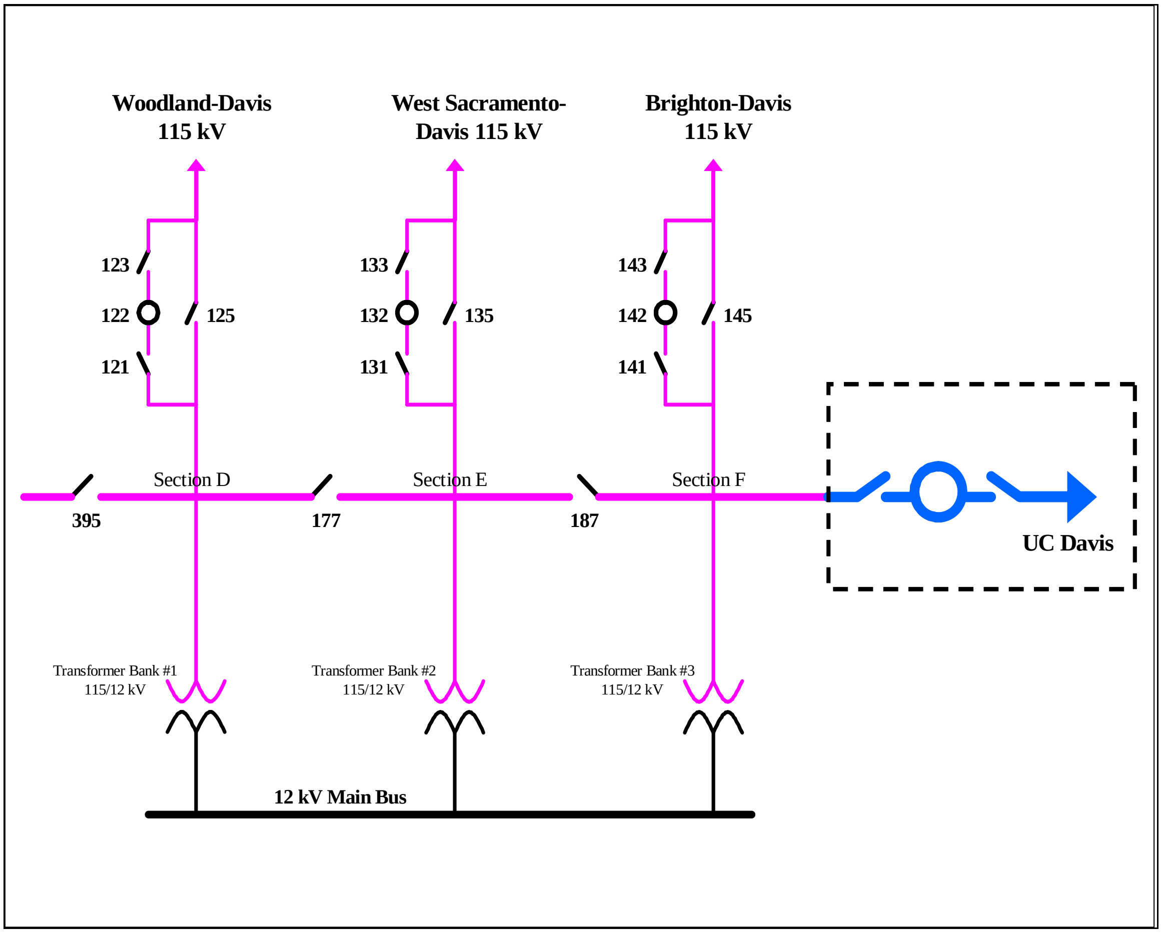


Figure 2-14: Scope Diagram

T1095E: Granite Vernalis
(In Service Date – October 2008)

PROJECT INFORMATION

The project scope is that Granite builds a new customer-owned substation to serve its expected load for its new plant. PG&E would construct, own and operate one short 115 kV tap line (approximately 500 feet) to interconnect to the new Granite Vernalis Substation.

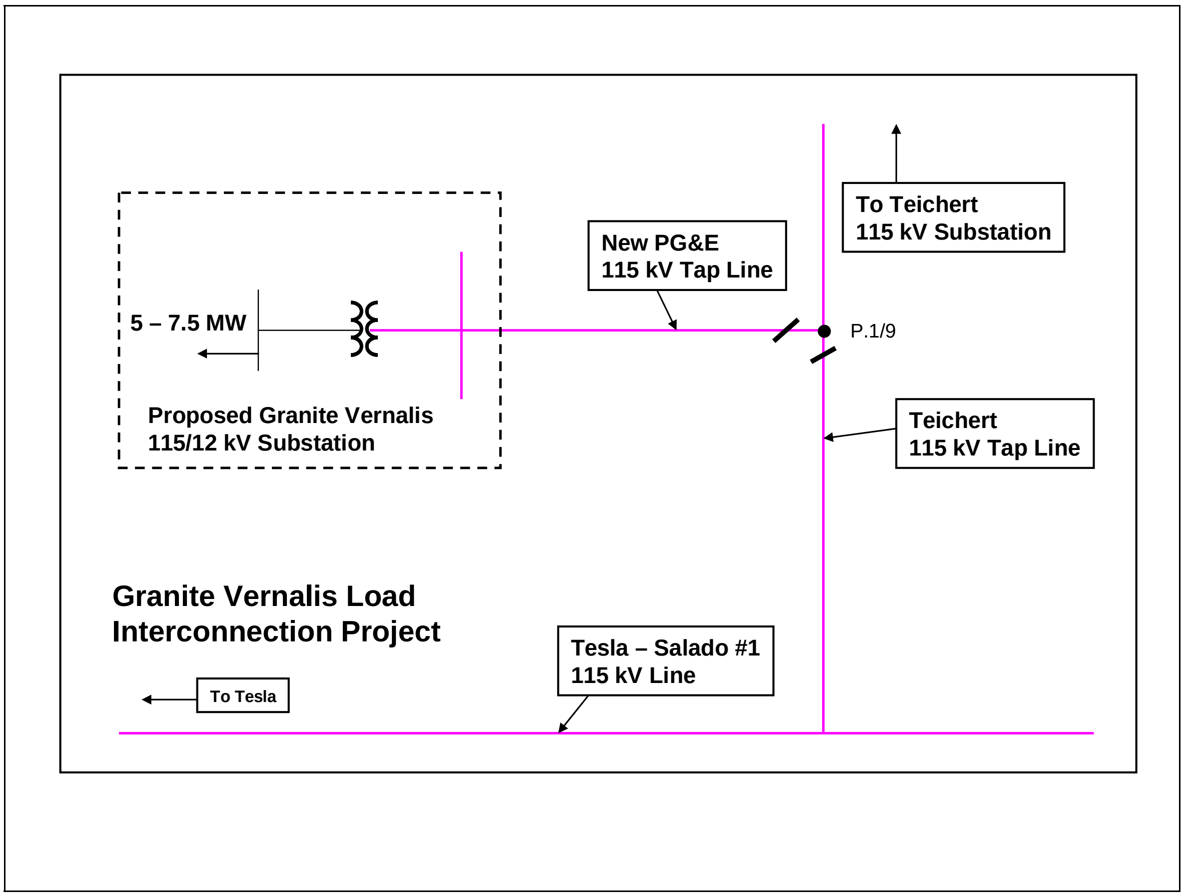


Figure 2-15: Scope Diagram

T776: Monta Vista 115/60 kV Transformer

(In Service Date – October 2008)

PROJECT INFORMATION

The project installed a 115/60 kV transformer at Monta Vista Substation. This transformer is sized at 200 MVA.

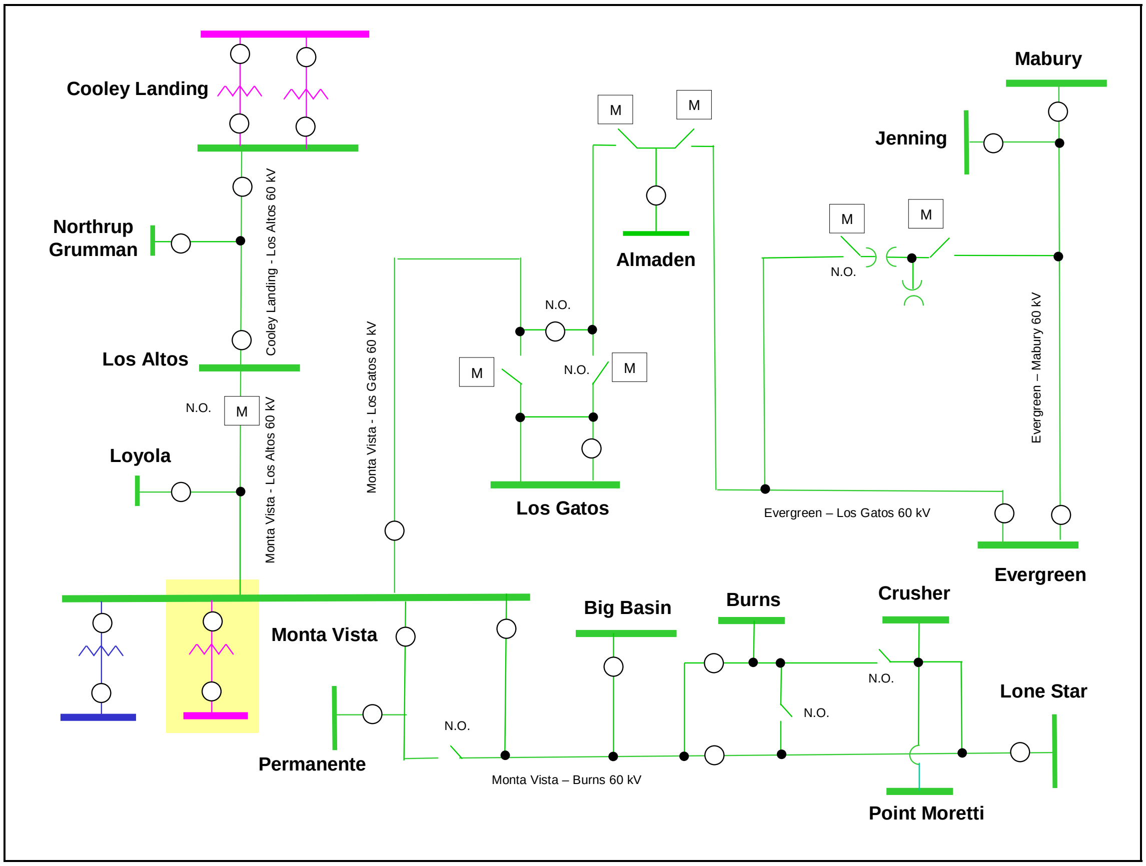


Figure 2-16: Scope Diagram

T867: Metcalf - Moss Landing 230 kV Lines
(In Service Date – October 2008)

PROJECT INFORMATION

This project reconductored the Metcalf – Moss Landing 230 kV Line Nos. 1 and 2 with 954 ACSS.

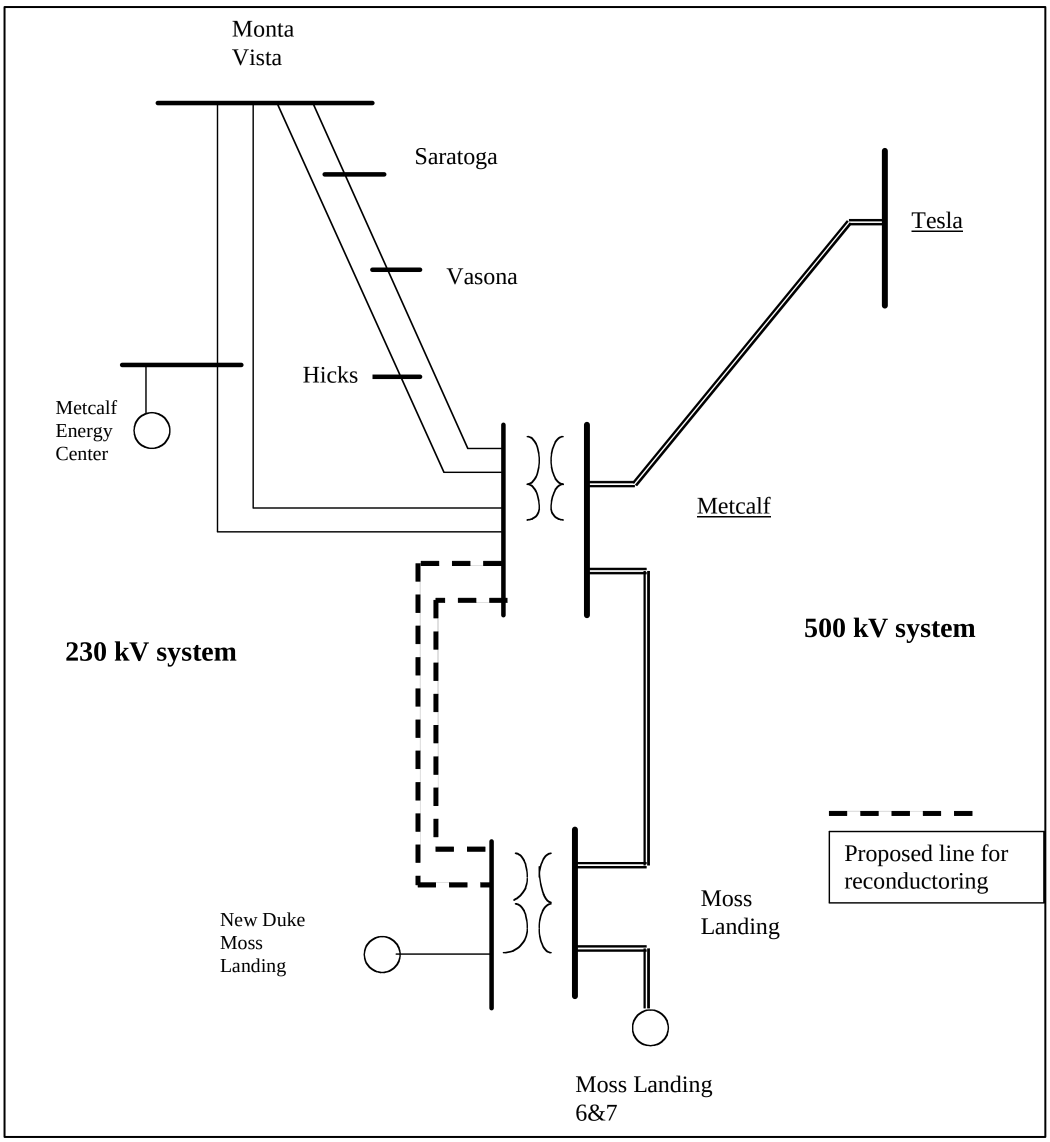


Figure 2-17: Scope Diagram

CHAPTER 3

Summary of Transmission Project Proposals

PG&E has seventy-two projects that have received approval from the CAISO. This chapter provides a brief summary of each transmission project that has been approved by the CAISO.

T958: Humboldt – Harris 60 kV Reconductoring

(Expected In Service Date – December 2008)

PROJECT INFORMATION

This project proposes to reconductor a 1-mile section between Humboldt and Harris substations with a conductor rated at 650 Amps or higher and to install SCADA on Switch Nos. 37 and 39 at Harris Substation.

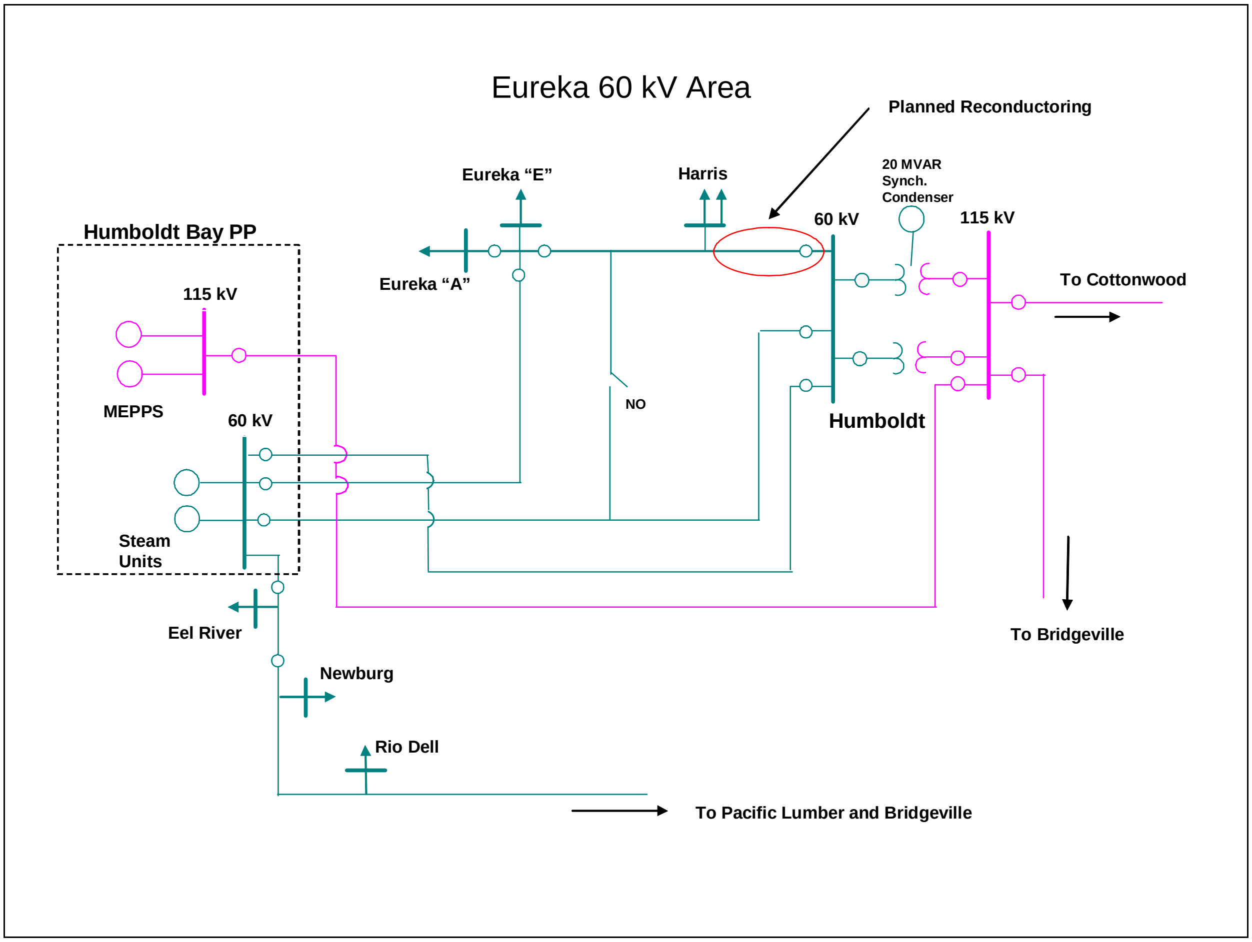


Figure 3-1: Scope Diagram

T980: Martin 115/60 kV Transformer Replacement

(Expected In Service Date – December 2008)

PROJECT INFORMATION

The project scope is to install a second Martin 115/60 kV transformer. This new transformer is rated to handle 200 MVA.

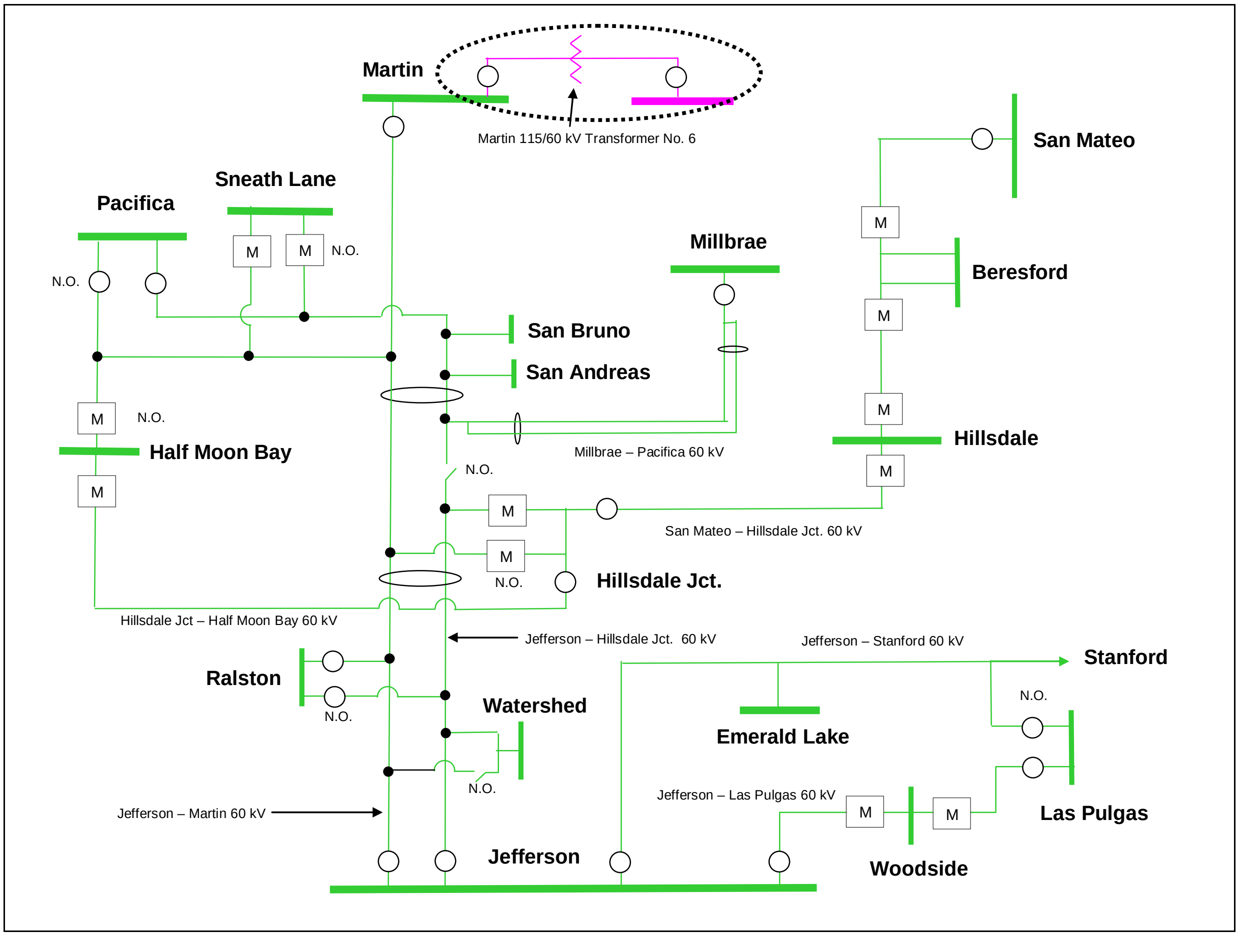


Figure 3-2: Scope Diagram

T997: Weber #1 60 kV Line

(Expected In Service Date – January 2009)

PROJECT INFORMATION

The scope is to reconfigure the Weber #1 Line by normally opening switch 79 and normally closing switch 77. In addition, reconductor a 1-mile 3/0 Al section between Stockton "A" and Charter Way with a higher capacity rated conductor that is capable of carrying a minimum summer normal capacity of 500 Amps or higher.

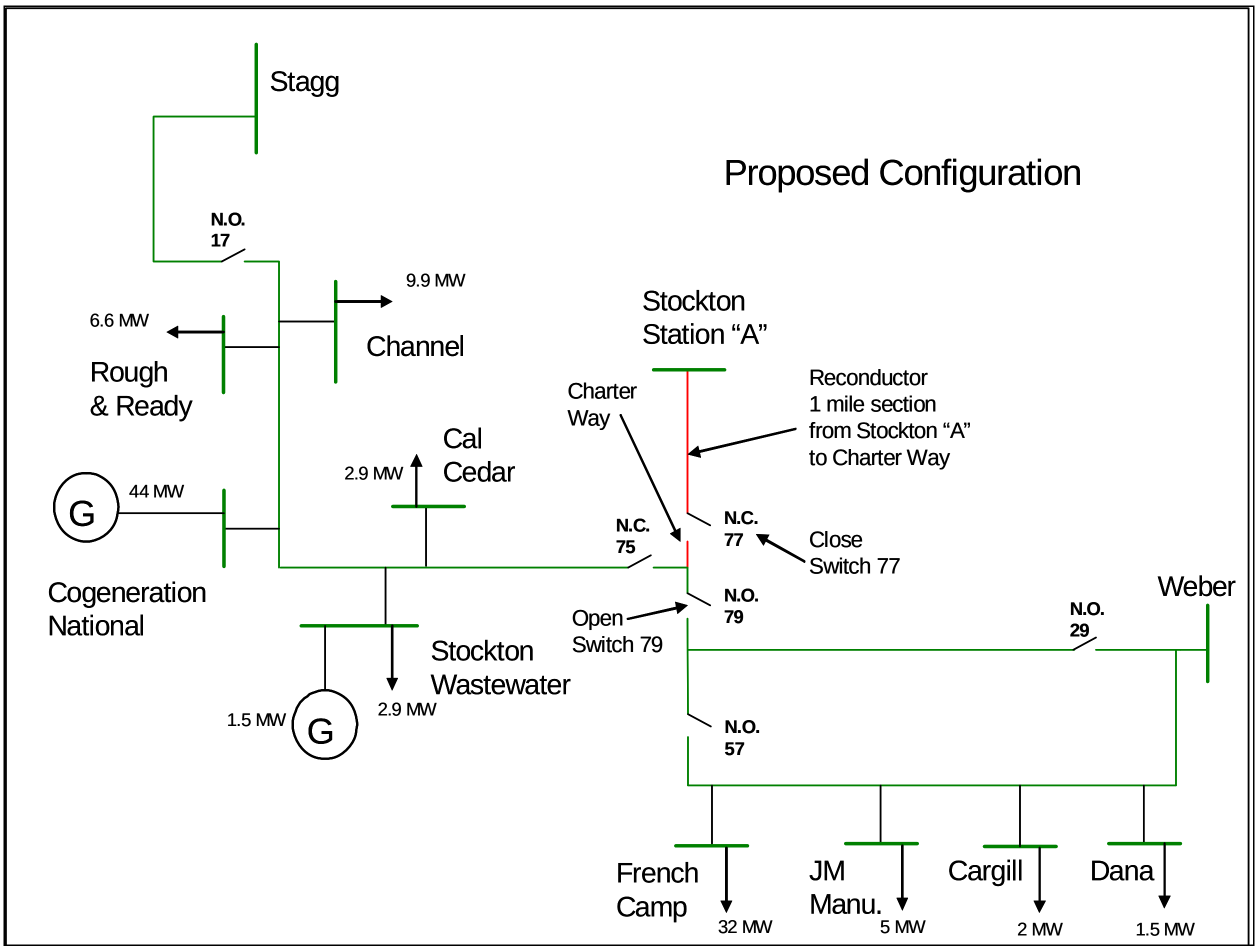


Figure 3-3: Scope Diagram

T776: Monta Vista 115/60 kV Transformer
(Expected In Service Date – March 2009)

PROJECT INFORMATION

The project scope is to install a 115/60 kV transformer at Monta Vista Substation. This transformer is planned to be sized at 200 MVA or higher.

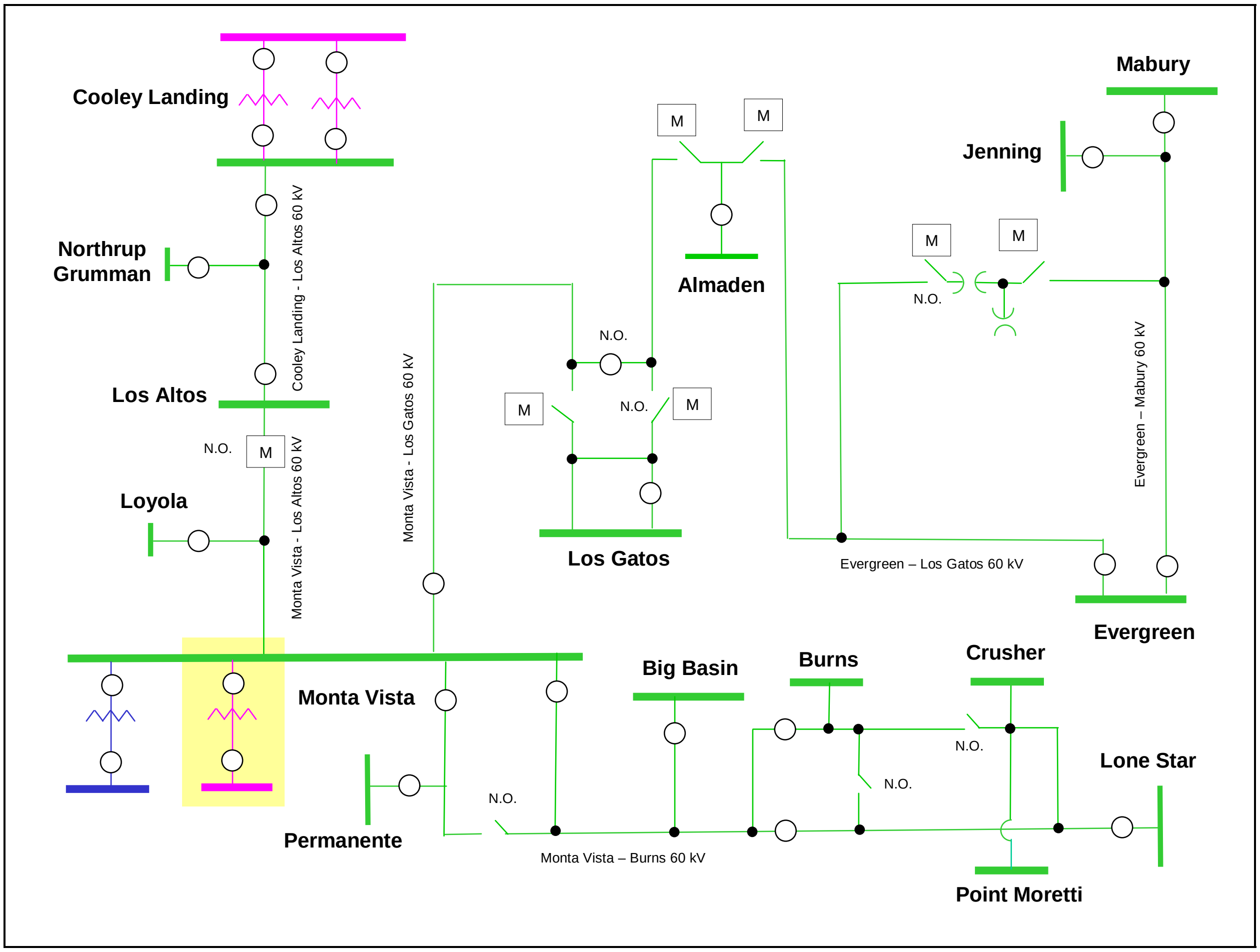


Figure 3-4: Scope Diagram

T776: Plainfield Substation Capacity Increase

(Expected In Service Date – March 2009)

PROJECT INFORMATION

The project scope is to rebuild the existing Plainfield 60 kV Tap Line to accommodate a double circuit arrangement and reconfigure Plainfield Substation into a flip-flop design.

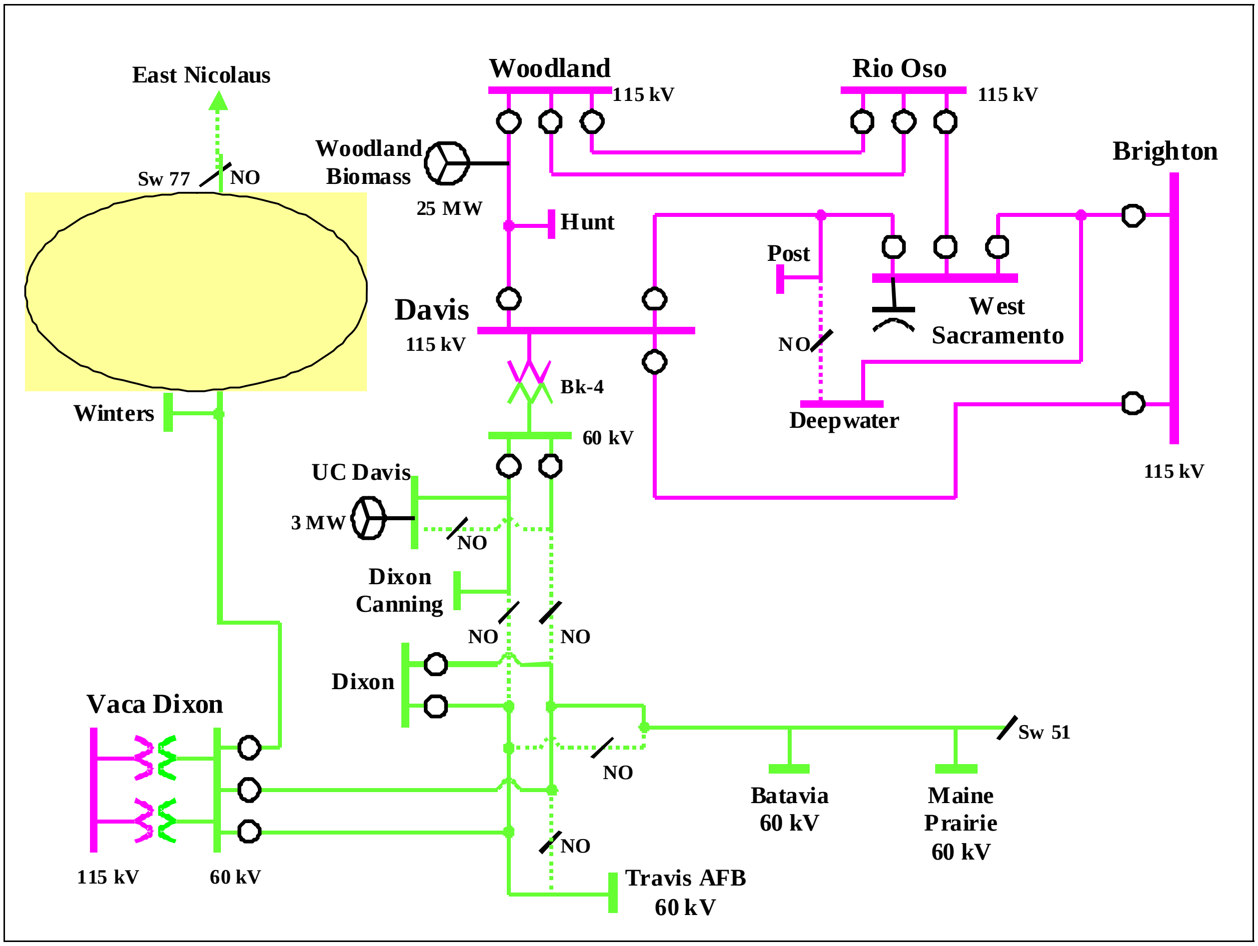


Figure 3-5: Scope Diagram

T998: Potrero Bus Parallel Circuit Breaker

(Expected In Service Date – March 2009)

PROJECT INFORMATION

The project scope is to install a 115 kV bus parallel breaker at Potrero Substation.

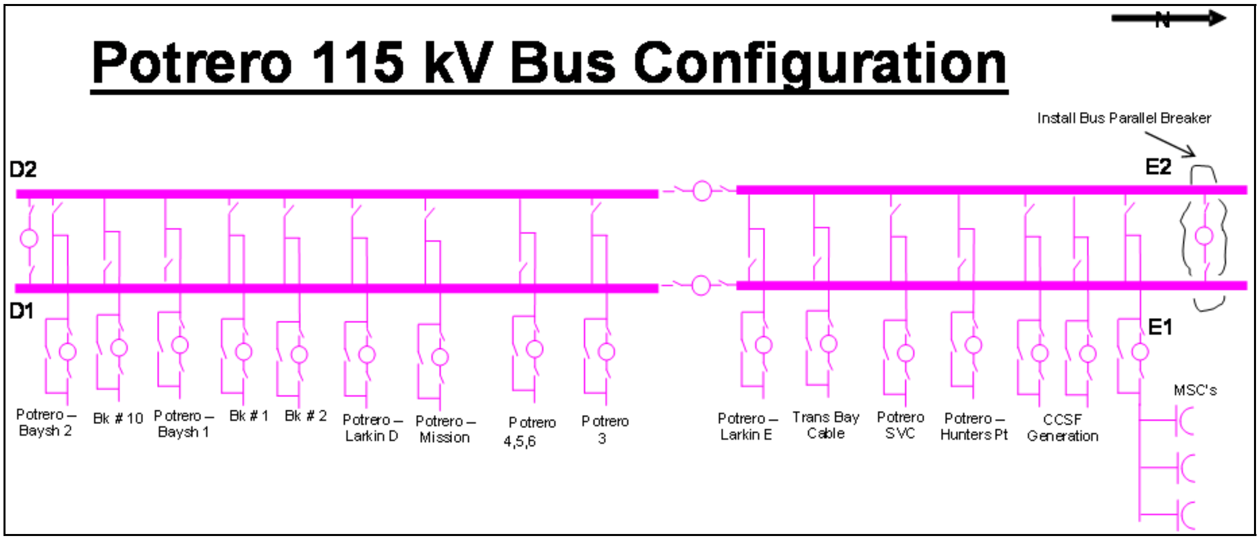


Figure 3-6: Scope Diagram

T897: Martin – Hunters Point 115 kV Cable

(Expected In Service Date – April 2009)

PROJECT INFORMATION

The project proposes to construct an additional 115 kV underground cable between Martin and Hunters Point substations.

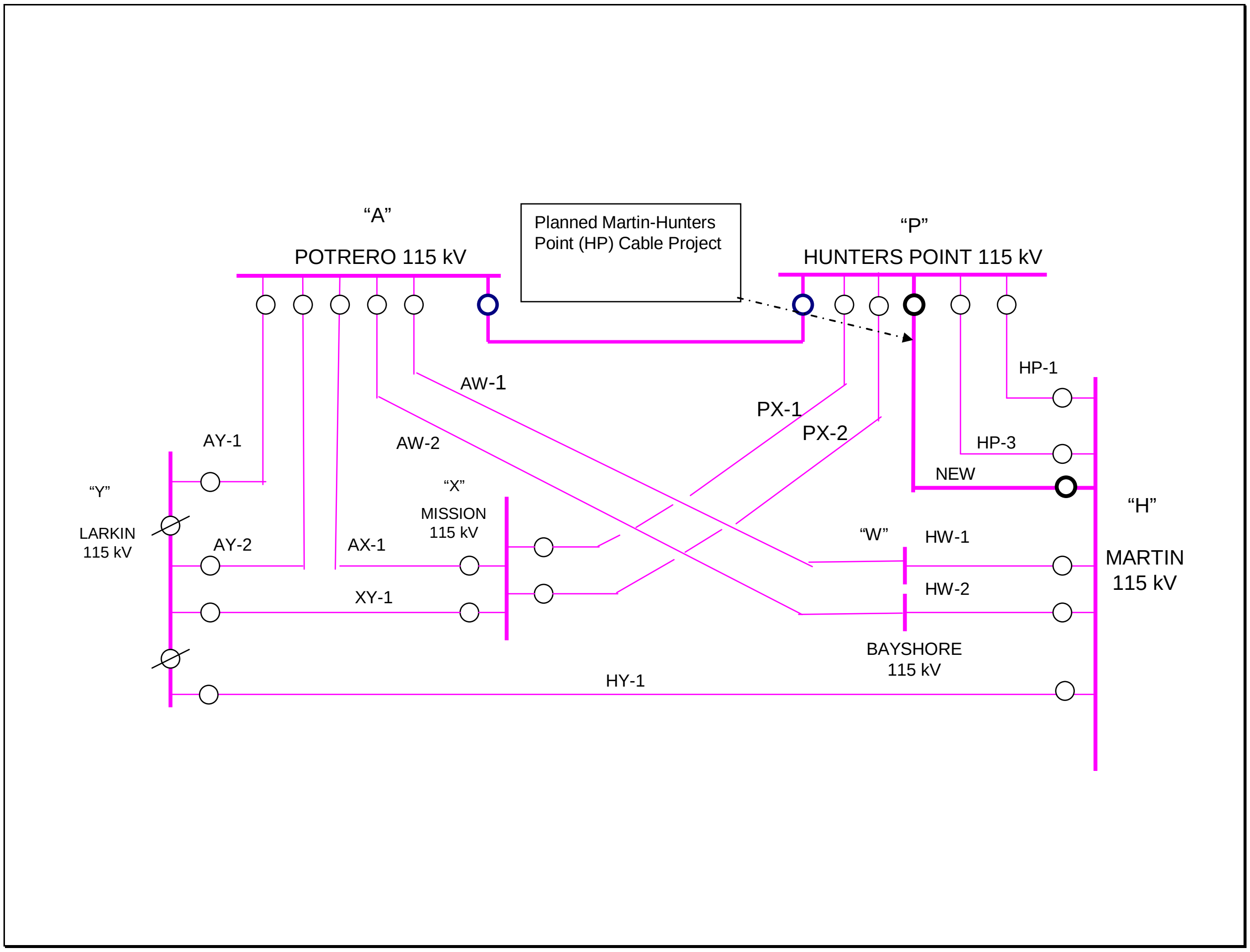


Figure 3-7: Scope Diagram

T964: Borden – Madera 70 kV Reinforcement
(Expected In Service Date – May 2009)

PROJECT INFORMATION

This project proposes to build a new 70 kV line from Borden Substation to Madera Substation with 715.5 kcmil AAC or equivalent, add a new 70 kV breaker at Borden Substation, re-conductor 10 miles with 715.5 kcmil AAC or equivalent, and re-configure lines to form new Borden-Glass and Glass-Biola-Madera 70 kV lines.

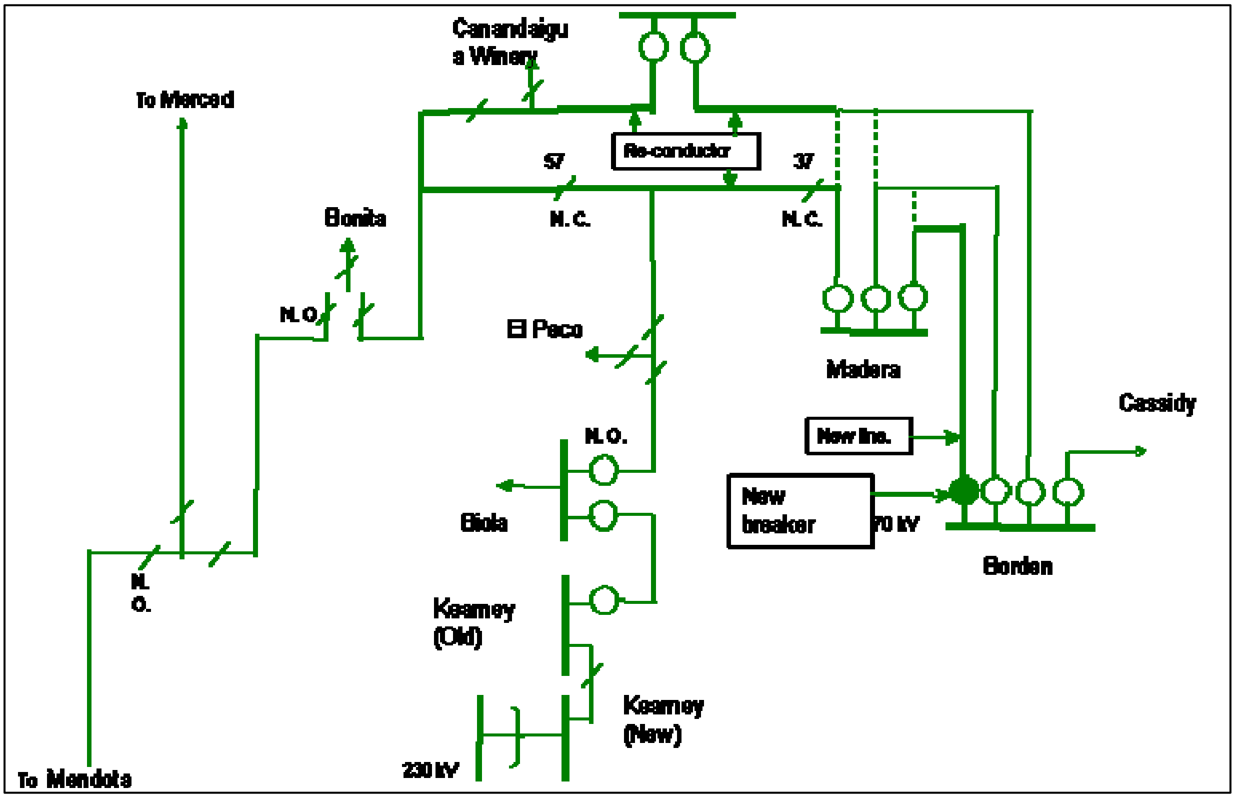


Figure 3-8: Scope Diagram

T758A: Brighton 230/115 kV Transformer Replacement

(Expected In Service Date – May 2009)

PROJECT INFORMATION

This project will replace the existing Brighton 230/115 kV Transformer Bank No. 9 with a new 420 MVA, 230/115 kV three-phase, load-tap-changer (LTC) transformer and install a new 230 kV Modular, Protection, Automation and Control (MPAC) building at Brighton Substation.

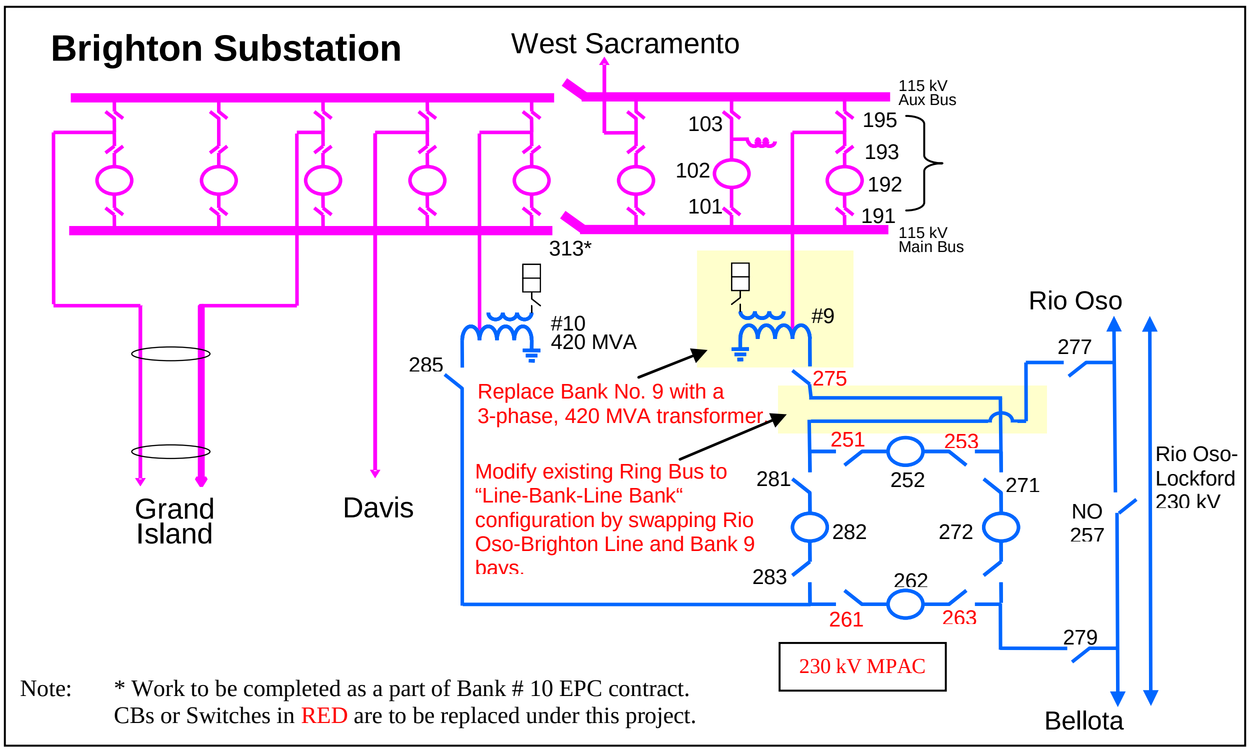


Figure 3-9: Scope Diagram

T772: Contra Costa – Las Positas 230 kV Line

(Expected In Service Date – May 2009)

PROJECT INFORMATION

The project proposes to reconductor 24 miles of the Contra Costa-Las Positas 230 kV and 5.3 miles of the Contra Costa-Lone Tree 230 kV lines with a conductor having an emergency rating of at least 1,500 Amps.

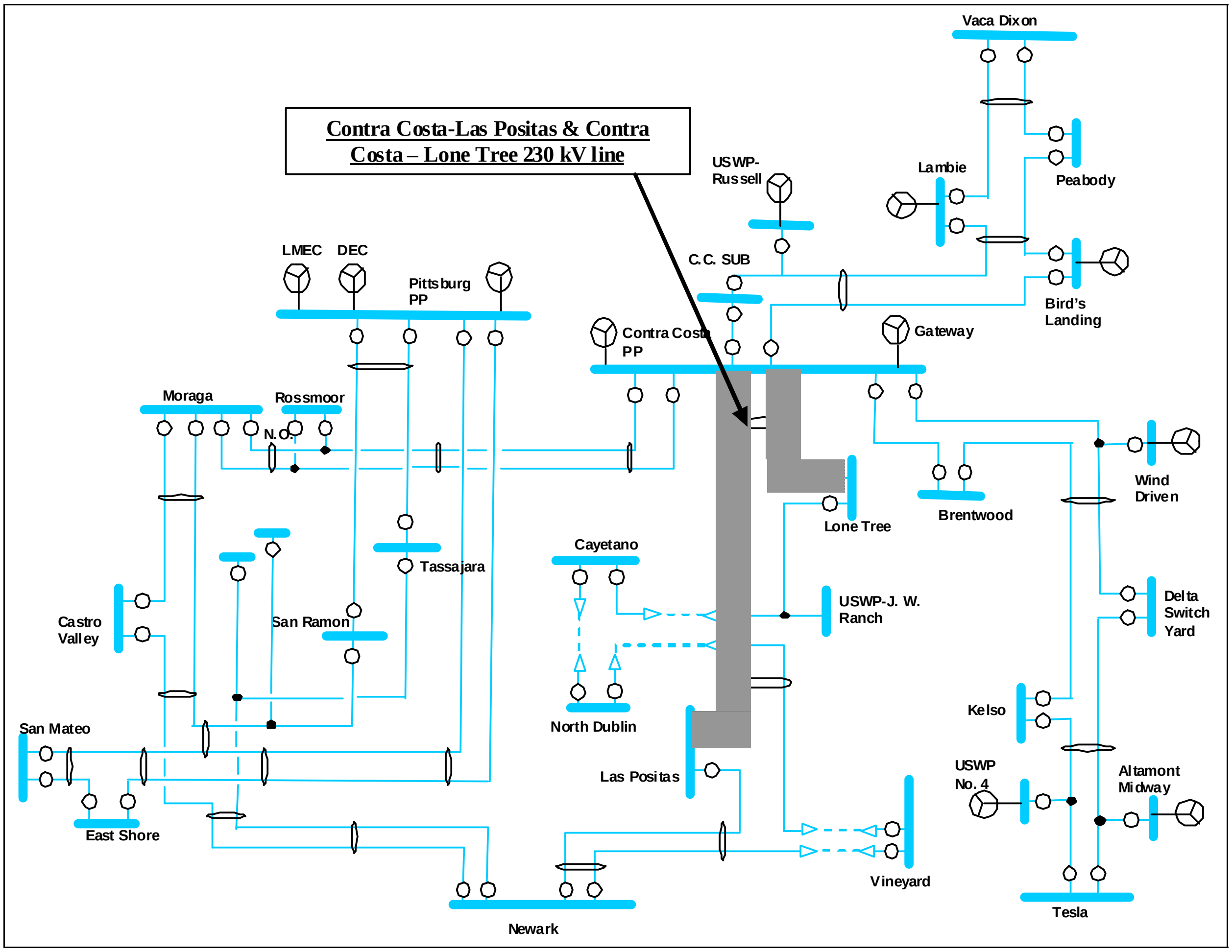


Figure 3-10: Scope Diagram

T444B: Gold Hill – Clarksville 115 kV Line Reconductoring

(Expected In Service Date – May 2009)

PROJECT INFORMATION

This project proposes to reconductor the Gold Hill – Clarksville 115 kV Line with 477 SSAC conductors.

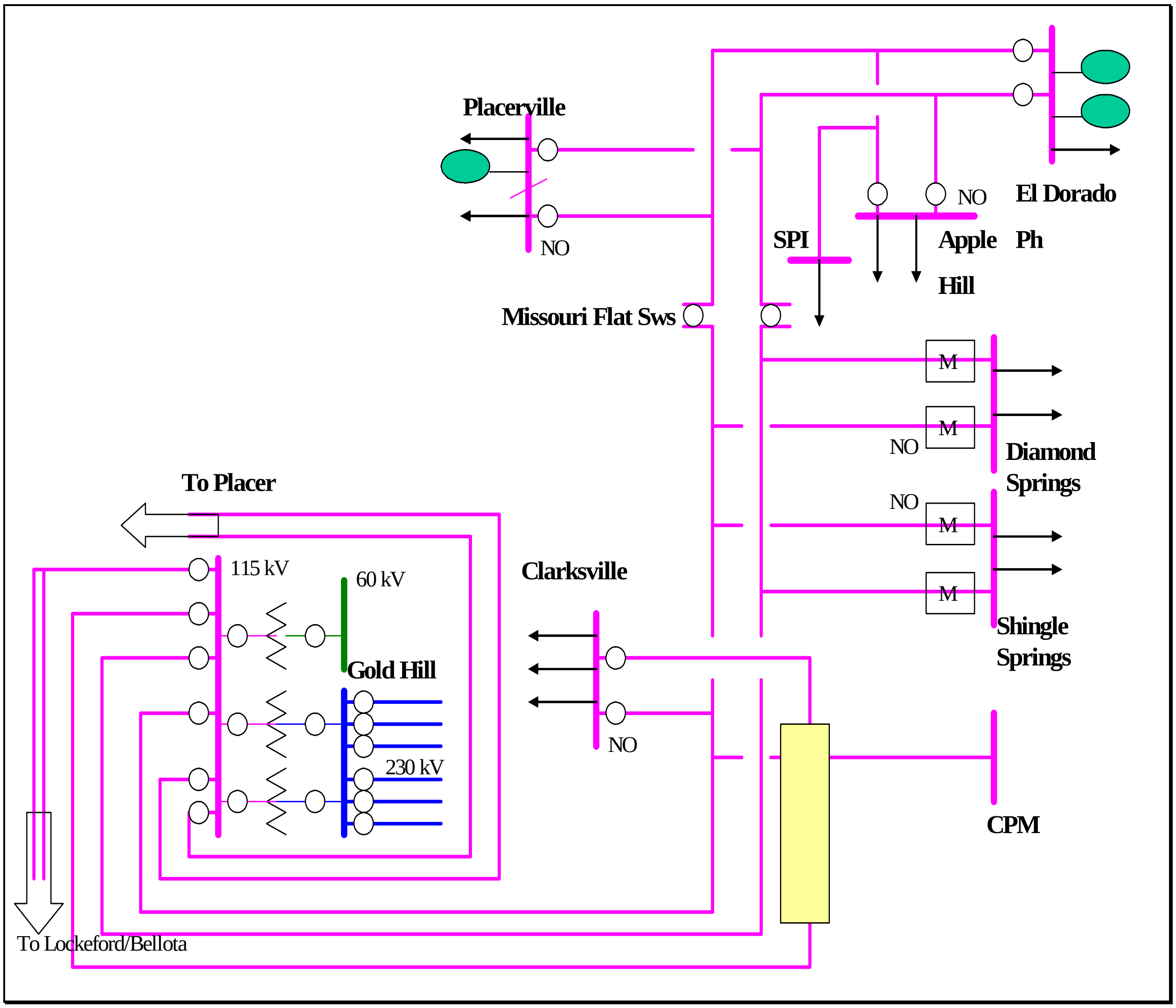


Figure 3-11: Scope Diagram

T571: Lakeville 230/60 KV Transformer Capacity Increase

(Expected In Service Date – May 2009)

PROJECT INFORMATION

This project proposes to install a second 230/60 kV transformer at Lakeville Substation. This new transformer will be rated at 200 MVA.

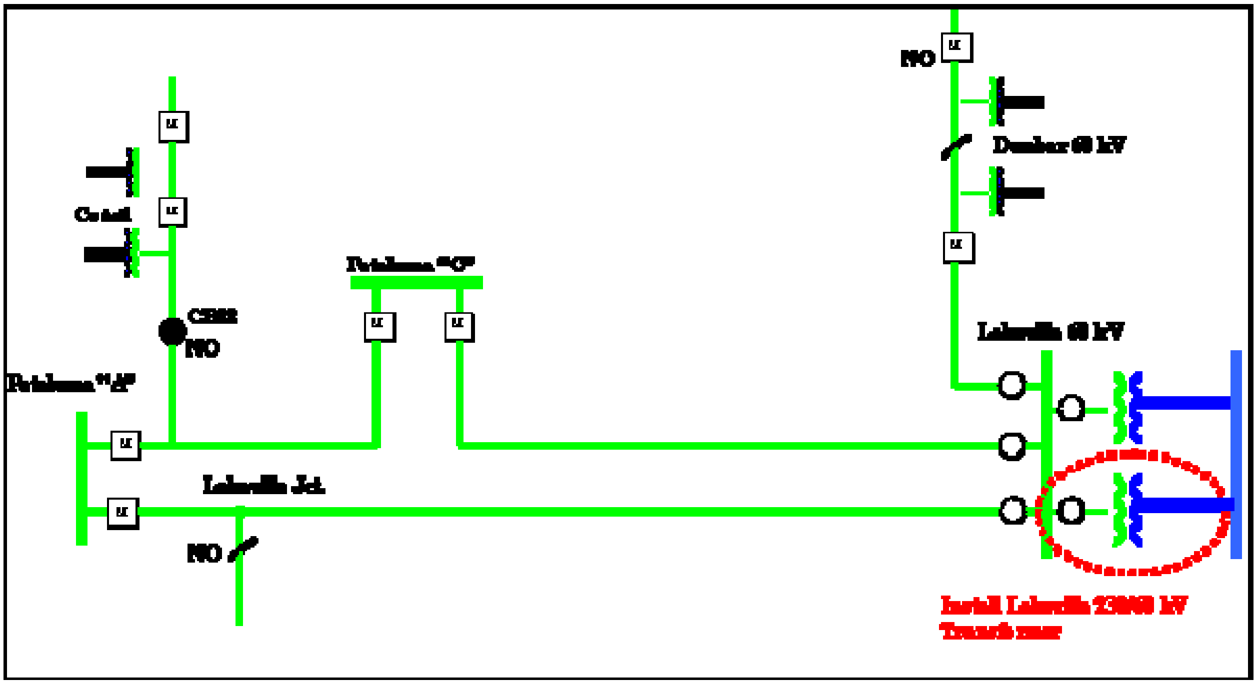


Figure 3-12: Scope Diagram

T444: Placer – Gold Hill 115 kV Reinforcement

(Expected In Service Date – May 2009)

PROJECT INFORMATION

The project scope is to reconductor the limiting conductors (24 miles) from Placer to Gold Hill substations on both Placer – Gold Hill 115 kV lines with 477 ACSS conductors.

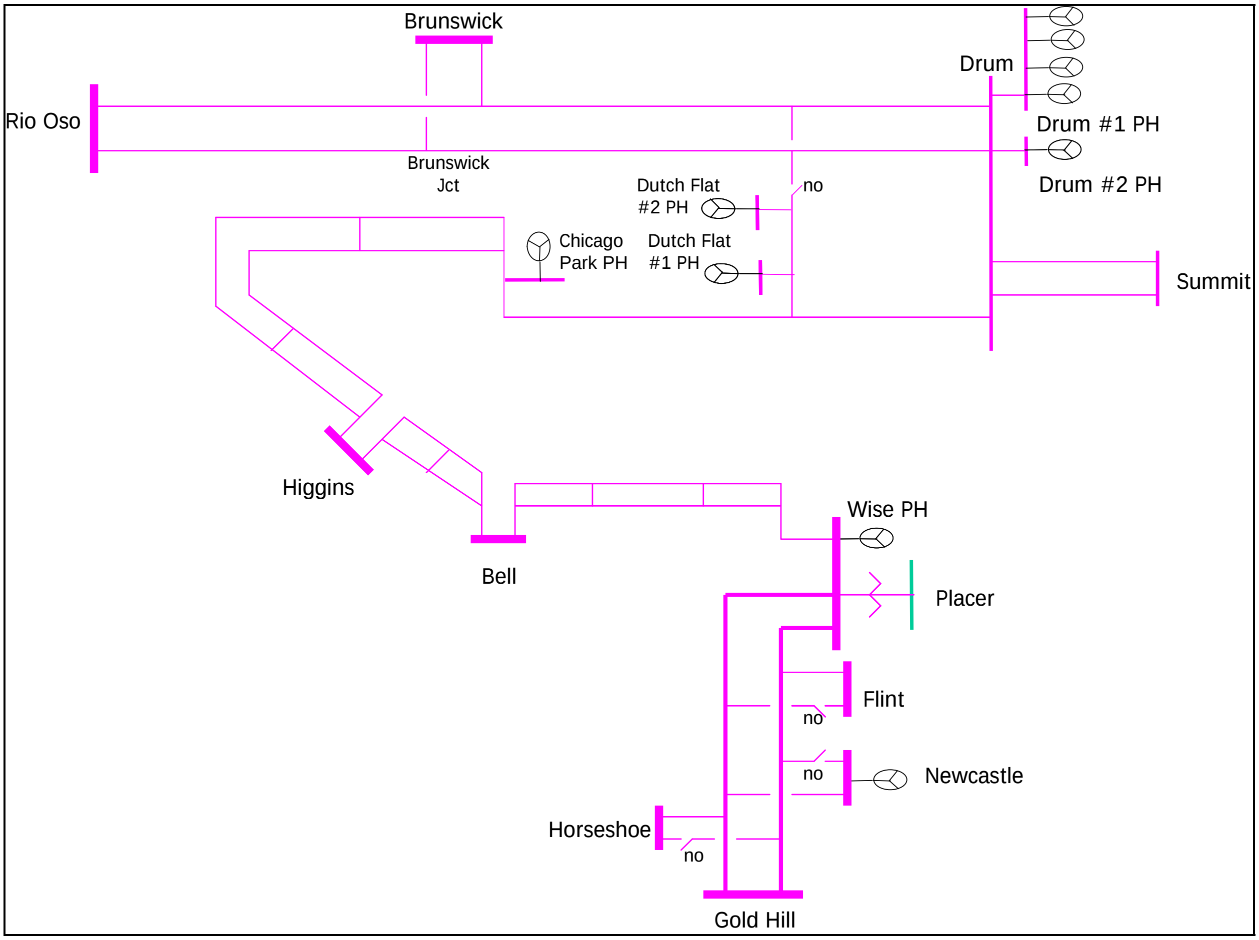


Figure 3-13: Scope Diagram

T177B: West Sacramento – Brighton 115 kV Reconductoring

(Expected In Service Date – May 2009)

PROJECT INFORMATION

This project proposes to reconductor 14 miles of the West Sacramento-Brighton 115 kV Line and the 14 miles of the Rio Oso-West Sacramento 115 kV Line with 477 SSAC conductors.

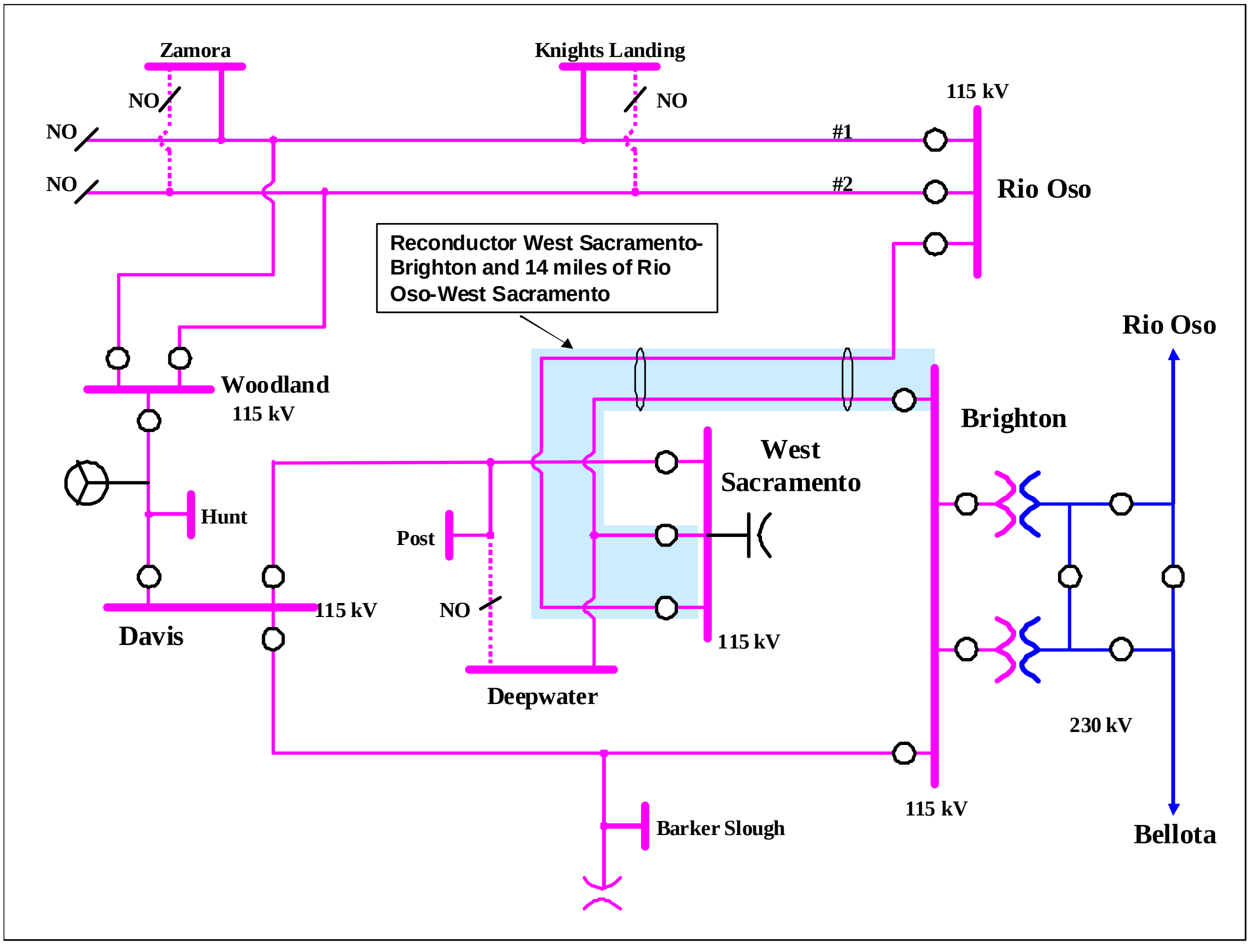


Figure 3-14: Scope Diagram

T945: Humboldt Reactive Support (SVC)

(Expected In Service Date – December 2009)

PROJECT INFORMATION

This project will replace the existing synchronous condenser at Humboldt Substation with a new Static VAr Compensator device (SVC) that is capable of producing -25/+50 megavolt amperes – reactive (MVArs).

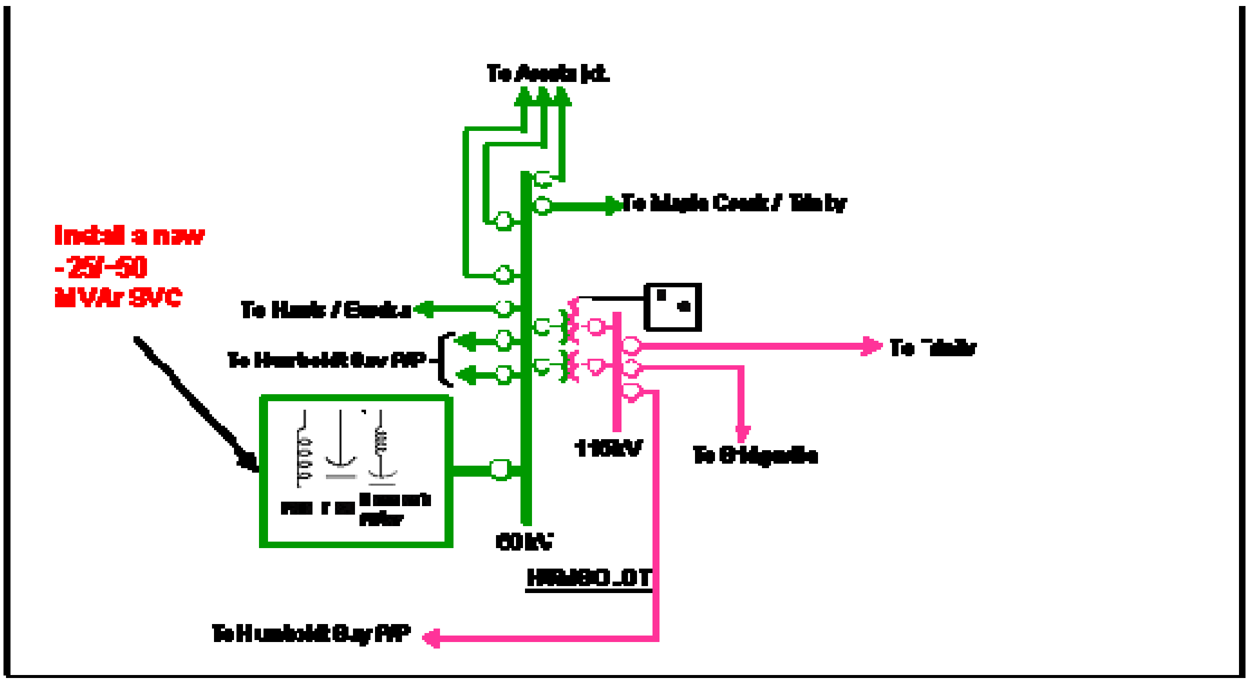


Figure 3-15: Scope Diagram

T970B: Moss Landing – Salinas – Soledad 115 kV Reconductoring

(Expected In Service Date – December 2009)

PROJECT INFORMATION

This project proposes to reconductor a 10.4-mile section of the Moss Landing-Salinas-Soledad Nos. 1 and 2 115 kV lines from Moss Landing to the Lagunitas Switches. Specifically, this project will: 1) Reconductor the line sections with 477 steel-supported aluminum conductor (SSAC) on both transmission lines, and 2) Replace 115 kV switches 413 and 415 and associated conductors at Moss Landing.

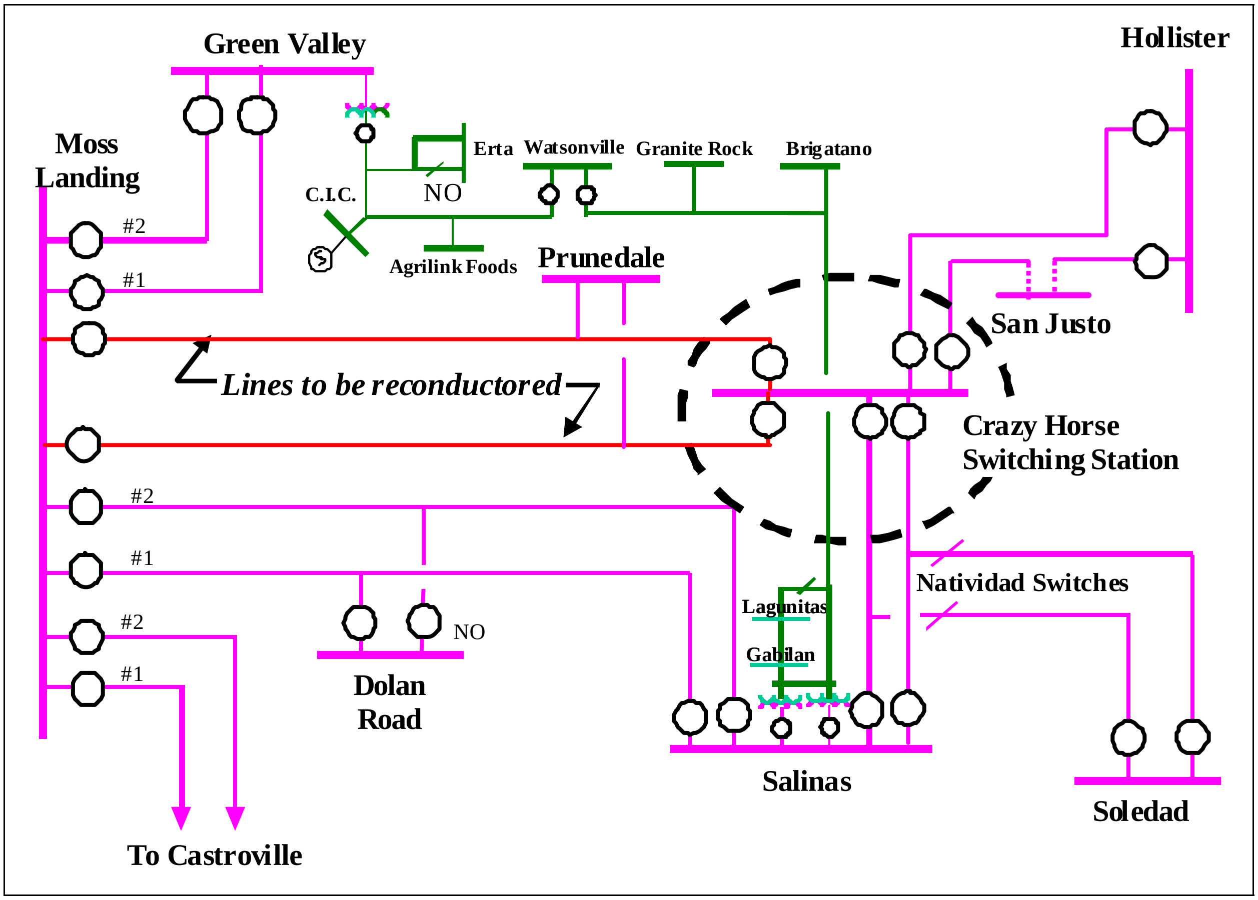


Figure 3-16: Scope Diagram

T815: Pease – Marysville 60 kV Line

(Expected In Service Date – December 2009)

PROJECT INFORMATION

This project proposes to utilize an existing right-of-way to construct a new 60 kV line (8 miles) between Pease and Marysville substations.

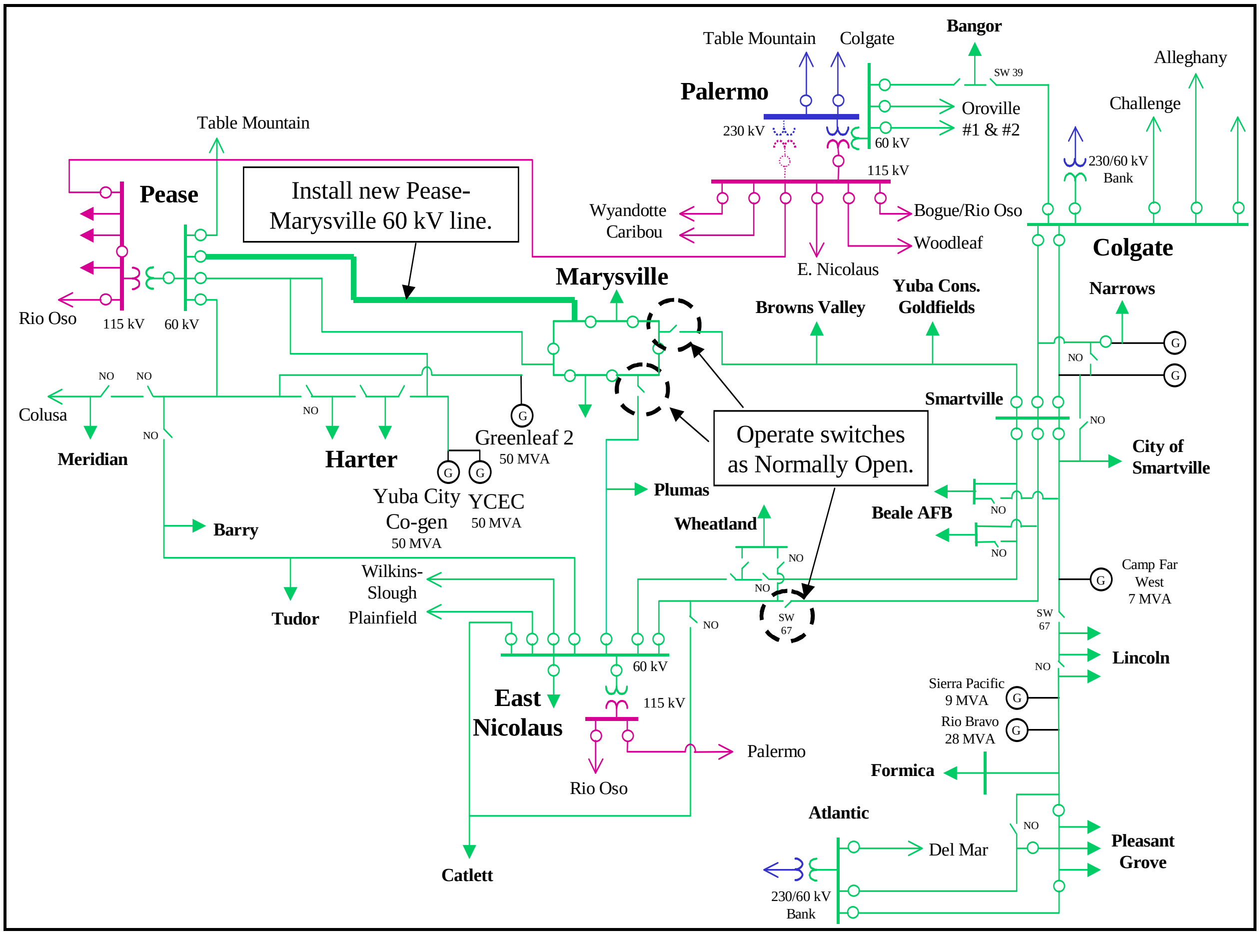


Figure 3-17: Scope Diagram

T1020: 7th Standard Substation Capacity Increase

(Expected In Service Date – May 2010)

PROJECT INFORMATION

The project scope is to loop the proposed 7th Standard Substation off the Kern-Lerdo-Kern Oil 115 kV Line. Looping the 7th Standard Substation would require building a new 115 kV double circuit tower line (3.5 miles long) from 7th Standard Substation to the Kern-Lerdo-Kern Oil 115 kV Line. The new double circuit tower line will be sized with 1113 Al conductors.

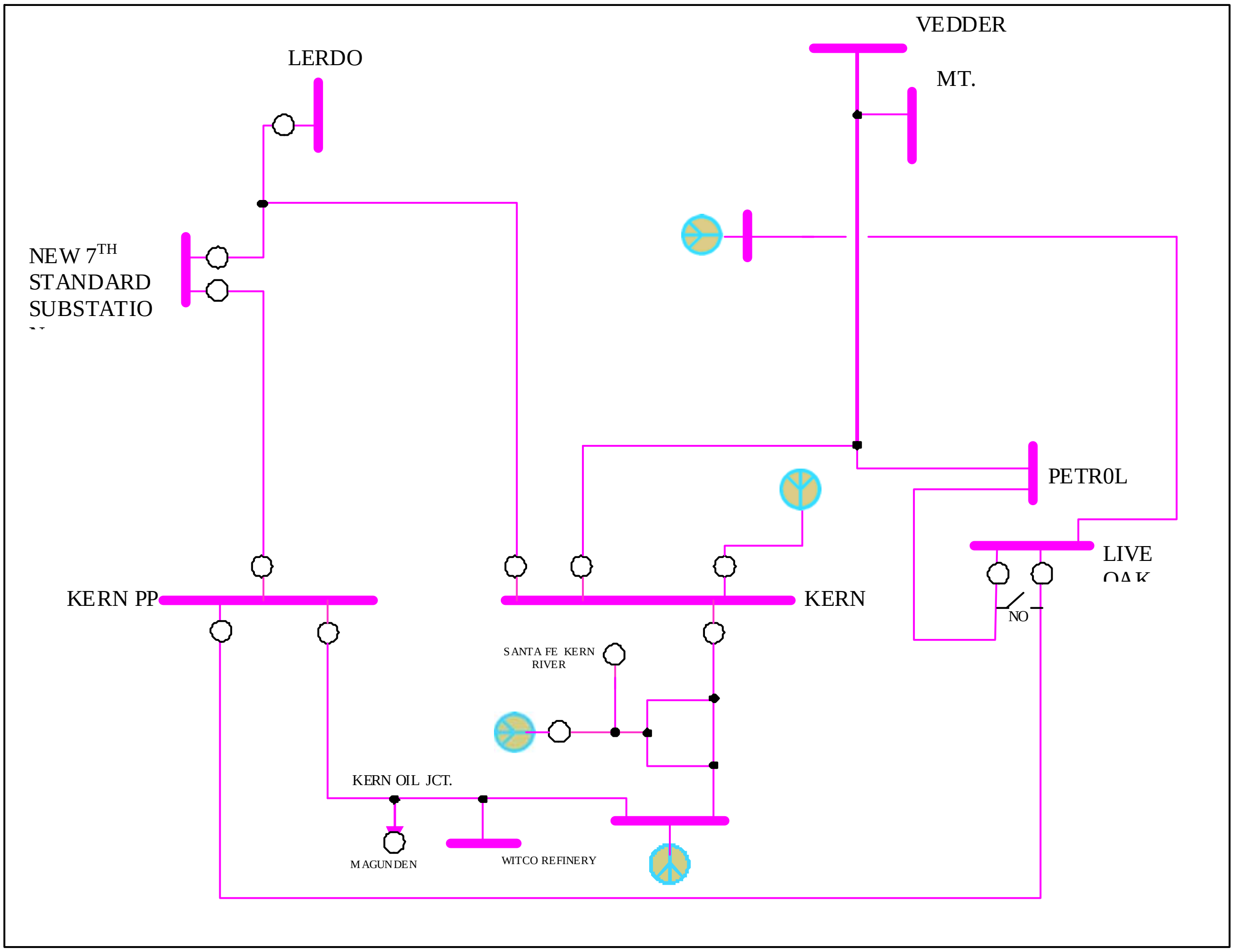


Figure 3-18: Scope Diagram

T759: Atlantic – Lincoln Transmission

(Expected In Service Date – May 2010)

PROJECT INFORMATION

The Atlantic – Lincoln Transmission plan includes three separate construction projects ("project components"). These project components are:

1st Project Component

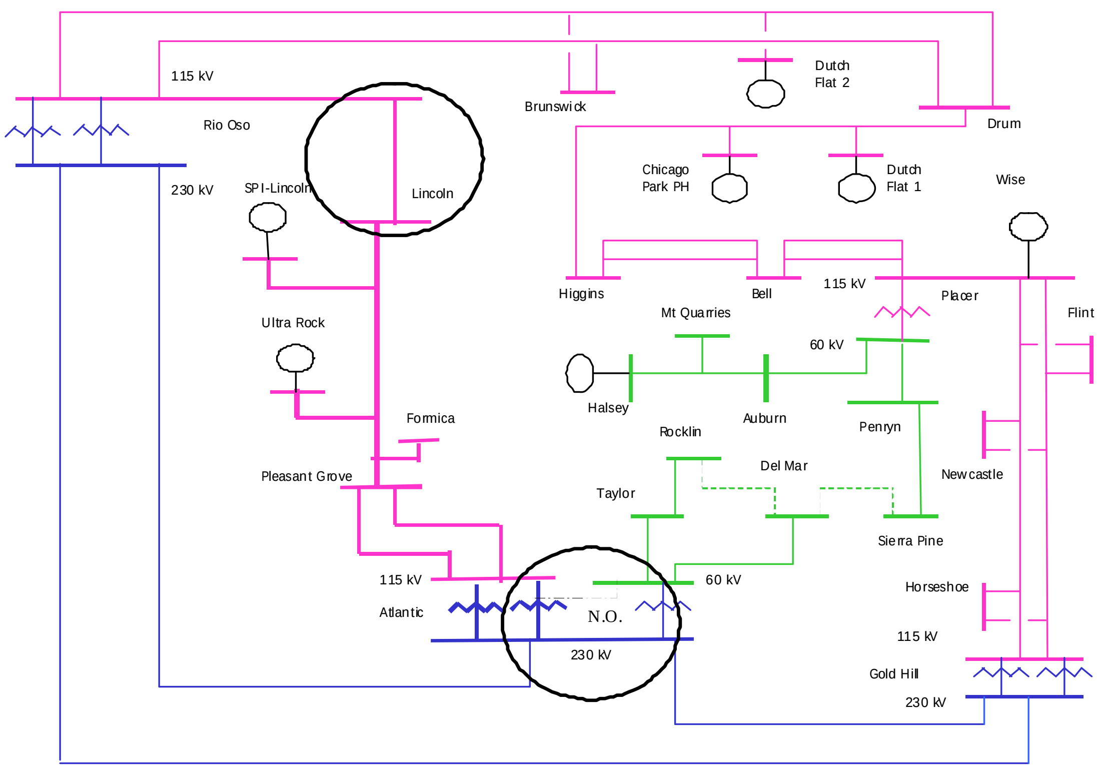
1. Reconductor the Atlantic – Pleasant Grove 60 kV No. 2 Line (about 6 miles) with 477 Aluminum Conductor Steel-Supported (ACSS) conductors, and
2. Reconductor the Lincoln – Pleasant Grove 60 kV Line (about 7 miles) with 477 ACSS conductors.

2nd Project Component

1. Convert and operate the Atlantic – Pleasant Grove Line Nos. 1 and 2 and the Lincoln – Pleasant Grove Line to 115 kV service,
2. Install a 230/115 kV transformer and associated equipment at Atlantic,
3. Replace the existing 230/60 kV transformer No. 2 at Atlantic with a 230/115 x 60 kV transformer and associated equipment, and
4. Replace the existing 60/12 kV transformer No. 2 at Lincoln with a 115/21 kV transformer and associated equipment.

3rd Project Component

1. Construct a new Rio Oso – Lincoln 115 kV Line with 477 ACSS conductors by replacing existing 60 kV and overbuilding existing 12 kV line facilities.



Atlantic – Lincoln Long Term Plan

Figure 3-19: Scope Diagram

T249: Bay Meadows 115 kV Reconductoring

(Expected In Service Date – May 2010)

PROJECT INFORMATION

This project proposes to reconductor the San Mateo – Bay Meadows 115 kV Nos. 1 and 2 lines (4.2 miles) with 477 ACSS conductors.

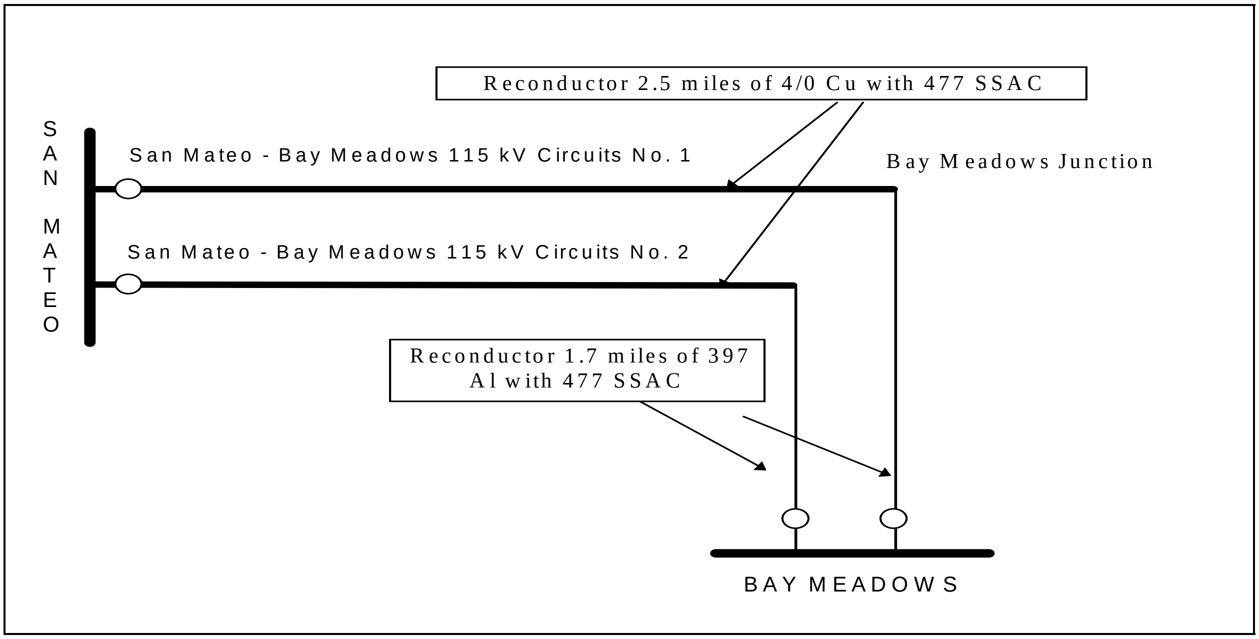


Figure 3-20: Scope Diagram

T458C: Hollister 115 kV Reconductoring

(Expected In Service Date – May 2010)

PROJECT INFORMATION

This project will reconductor the Hollister Taps sections of the Moss Landing – Salinas – Soledad Nos. 1 and 2 115 kV lines with 477 SSAC conductors.

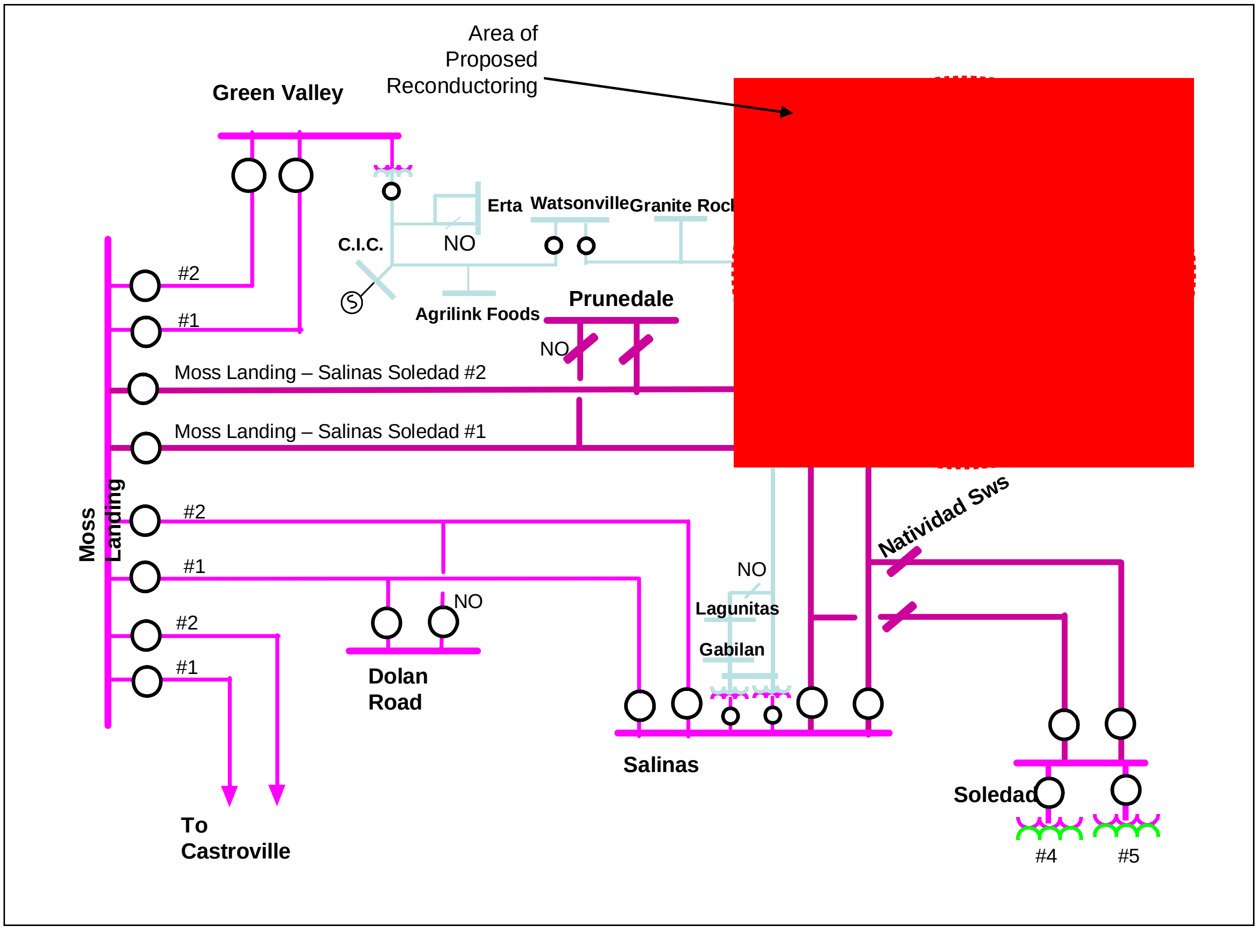


Figure 3-21: Scope Diagram

T993: Mendocino Coast Reactive Support
(Expected In Service Date – May 2010)

PROJECT INFORMATION

The preferred scope is to install between 10 MVArs and 15 MVArs of reactive support at Fort Bragg or Big River 60 kV substations.

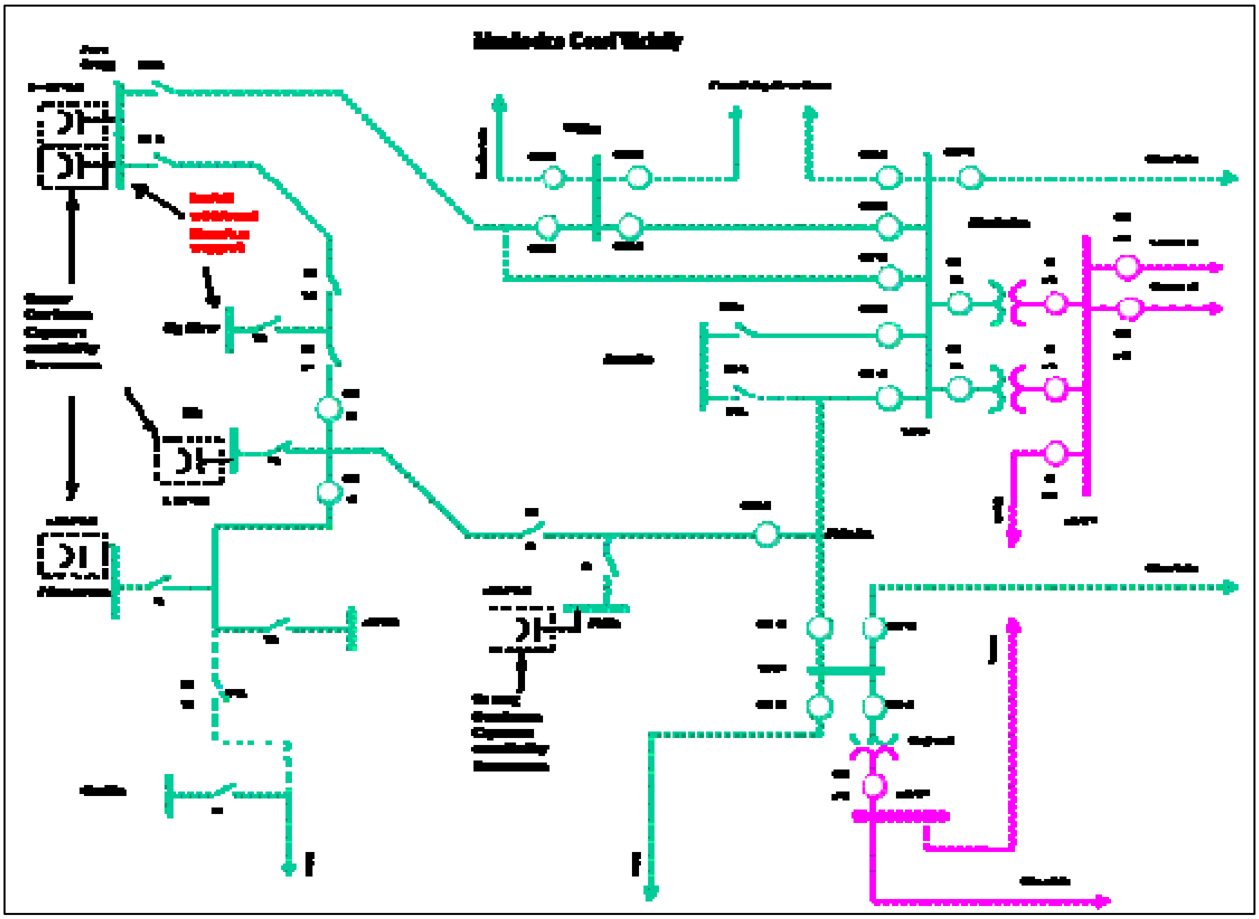


Figure 3-22: Scope Diagram

T1037: Menlo 60 kV Switch Upgrade

(Expected In Service Date –May 2010)

PROJECT INFORMATION

The project scope is to replace all 60 kV switches that have a rating of less then 800 Amps in Menlo 60 kV Substation with switches that have a capability of 800 Amps or greater.

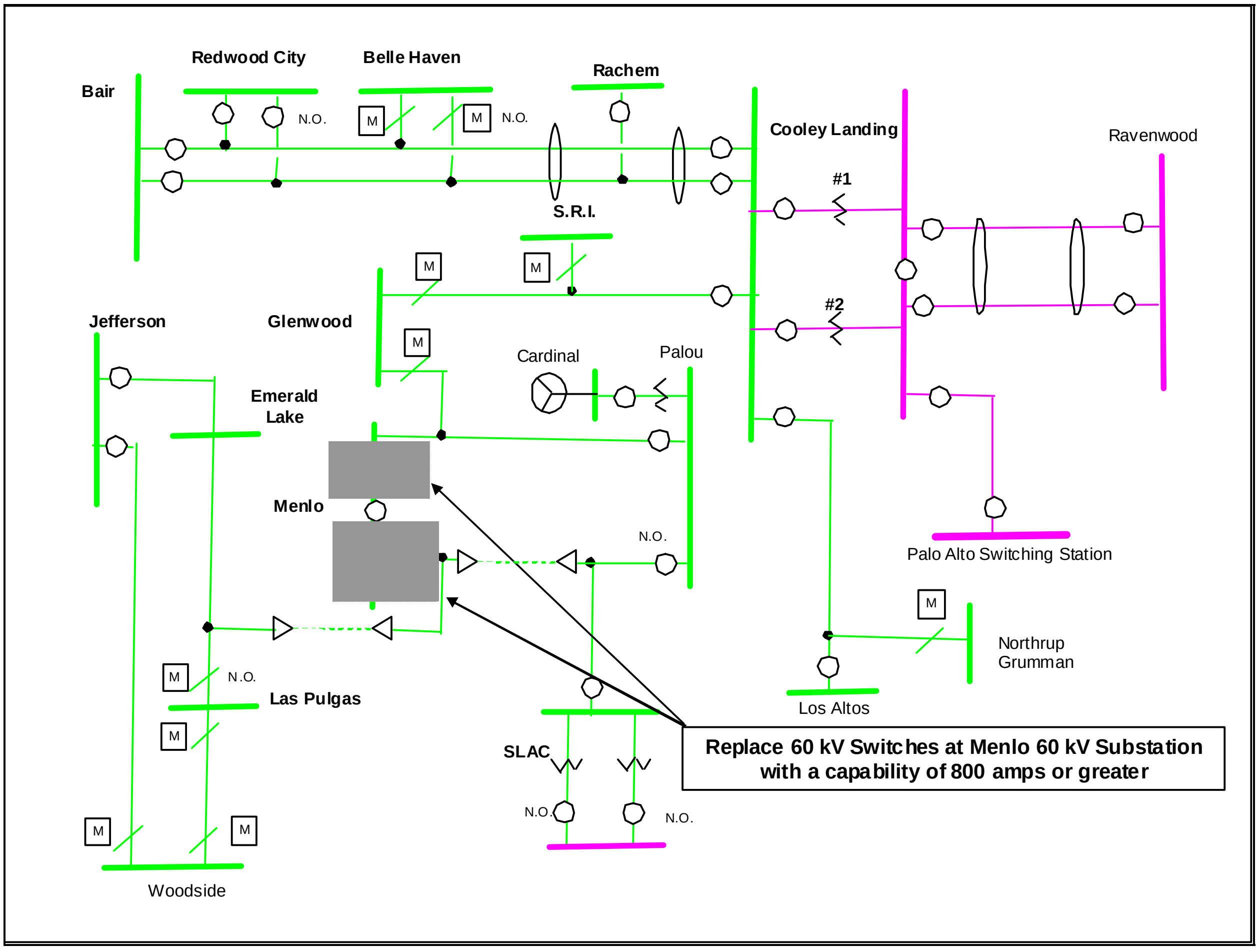


Figure 3-23: Scope Diagram

T965: Mesa 115 kV Shunt Capacitors
(Expected In Service Date – May 2010)

PROJECT INFORMATION

The project scope is to install an additional 2-25 MVArs of 115 kV shunt capacitors at Mesa Substation.

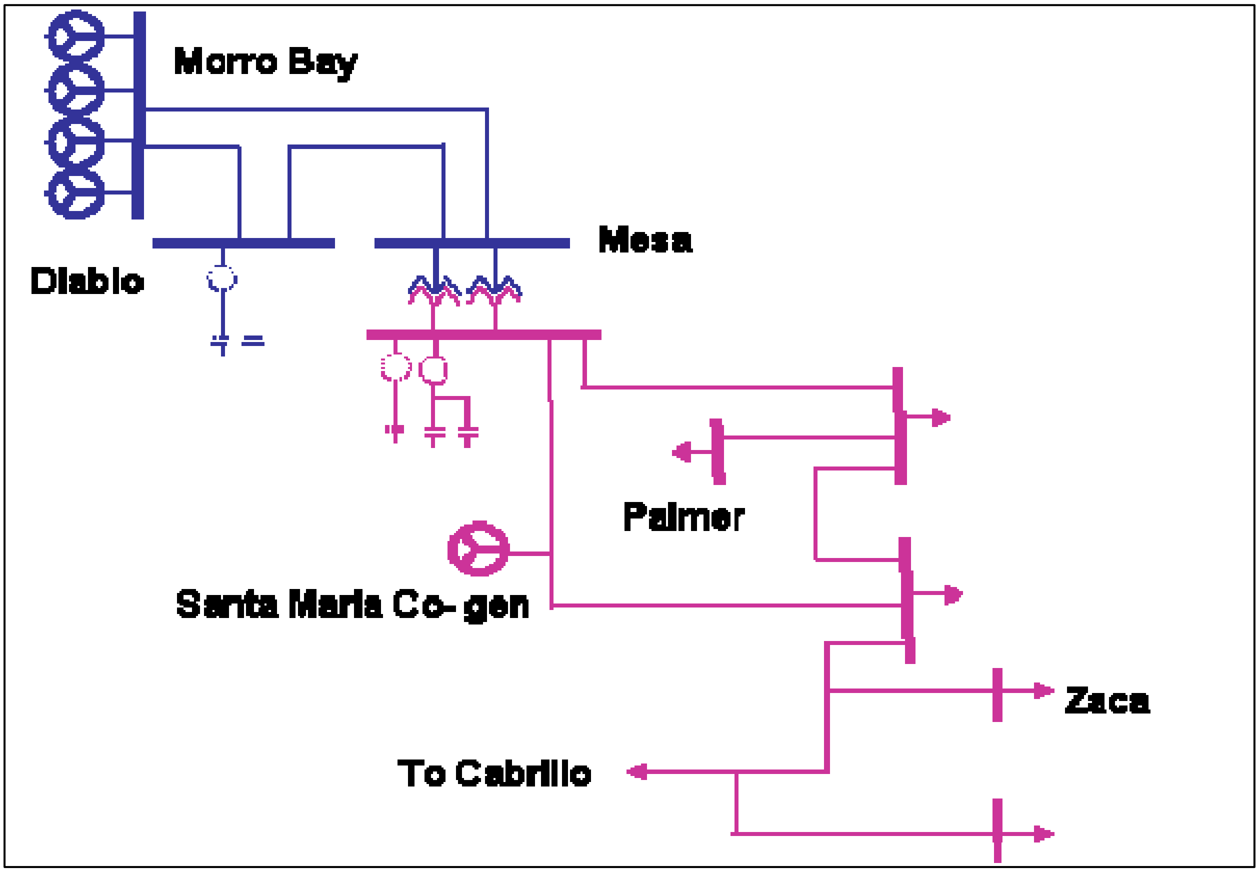


Figure 3-24: Scope Diagram

T444C: Missouri Flat – Gold Hill 115 kV Line

(Expected In Service Date – May 2010)

PROJECT INFORMATION

The project scope is to reconductor the Missouri Flat-Gold Hill 115 kV Nos. 1 and 2 lines between Gold Hill and Shingle Springs substations with higher capacity conductors that are rated to handle at least 1,100 Amps under emergency conditions.

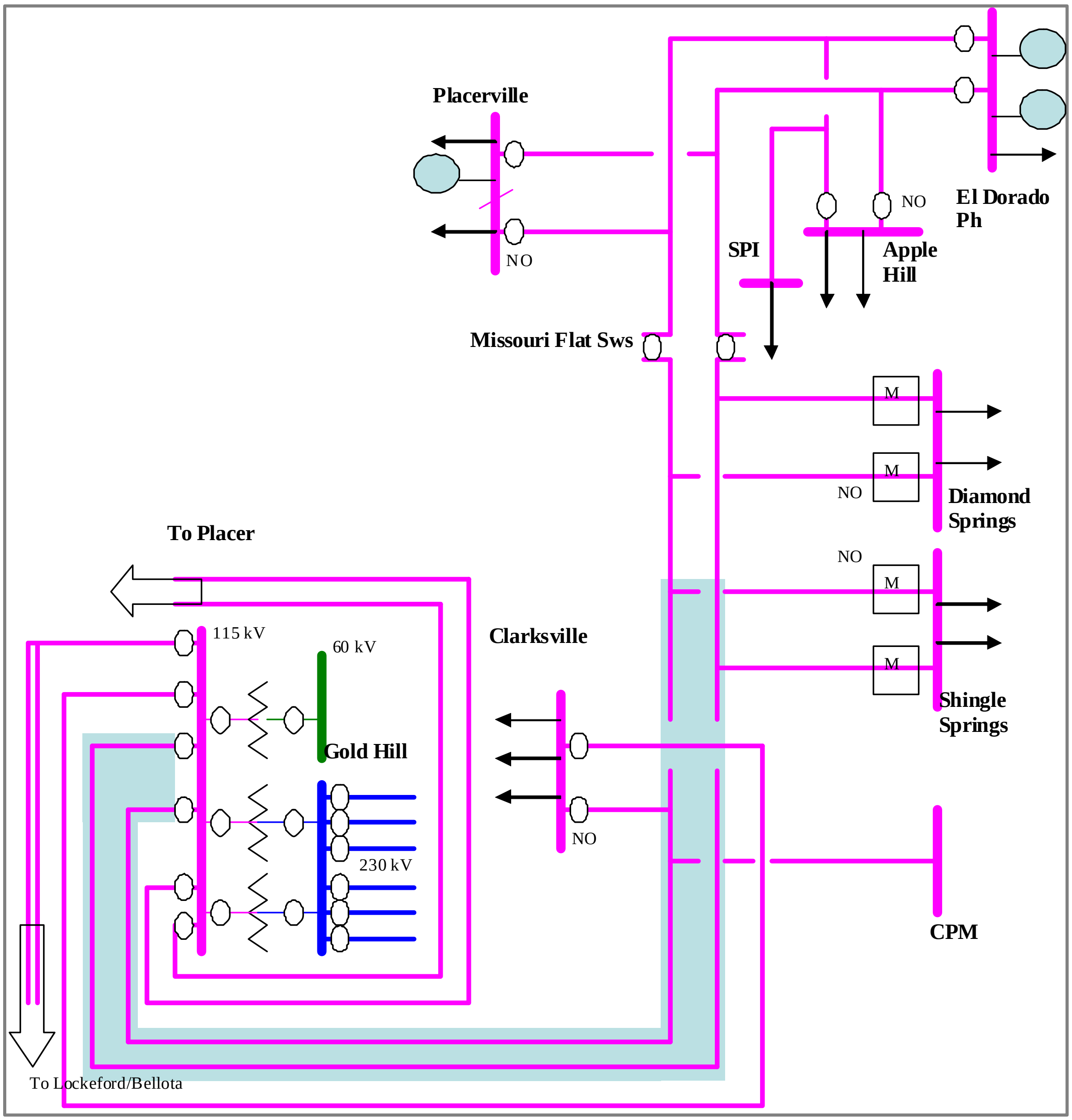


Figure 3-25: Scope Diagram

T982: Newark – Ravenswood 230 kV Line

(Expected In Service Date – May 2010)

PROJECT INFORMATION

The project scope is to reconductor the Newark-Ravenswood 230 kV Line (approximately 9 miles) and a section of the Tesla-Ravenswood 230 kV Line (approximately 9 miles), with a conductor having an emergency loading capability of at least 3,000 Amps. In addition, Newark 230 kV Circuit Breaker No. 610 and Ravenswood 230 kV Circuit Breaker No. 222 will be replaced with 3,000 Amp rated circuit breakers.

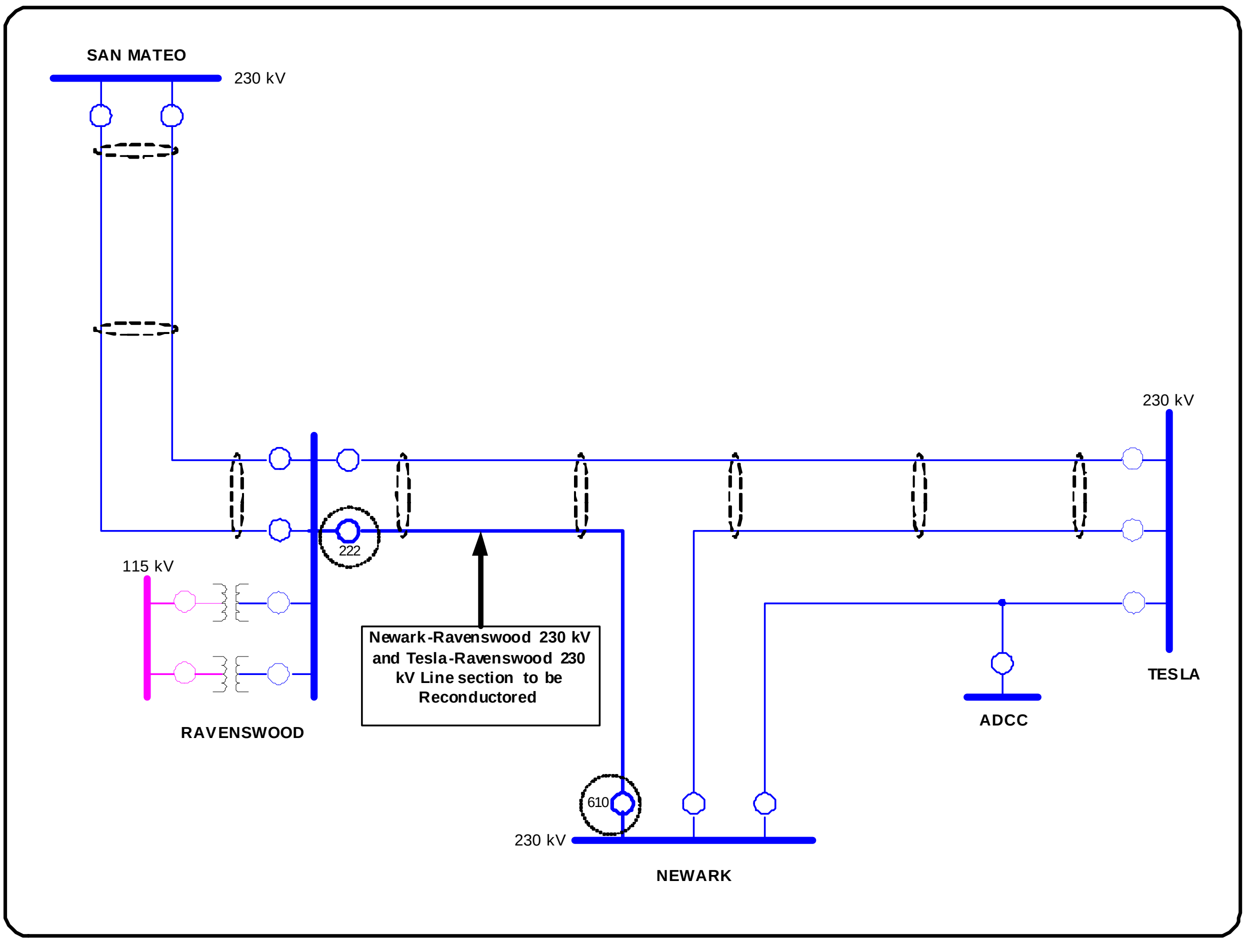


Figure 3-26: Scope Diagram

T983: Oakland Underground Cable

(Expected In Service Date – May 2010)

PROJECT INFORMATION

The project scope is to construct an additional Oakland C – X 115 kV underground cable (approximately 3.4 miles).

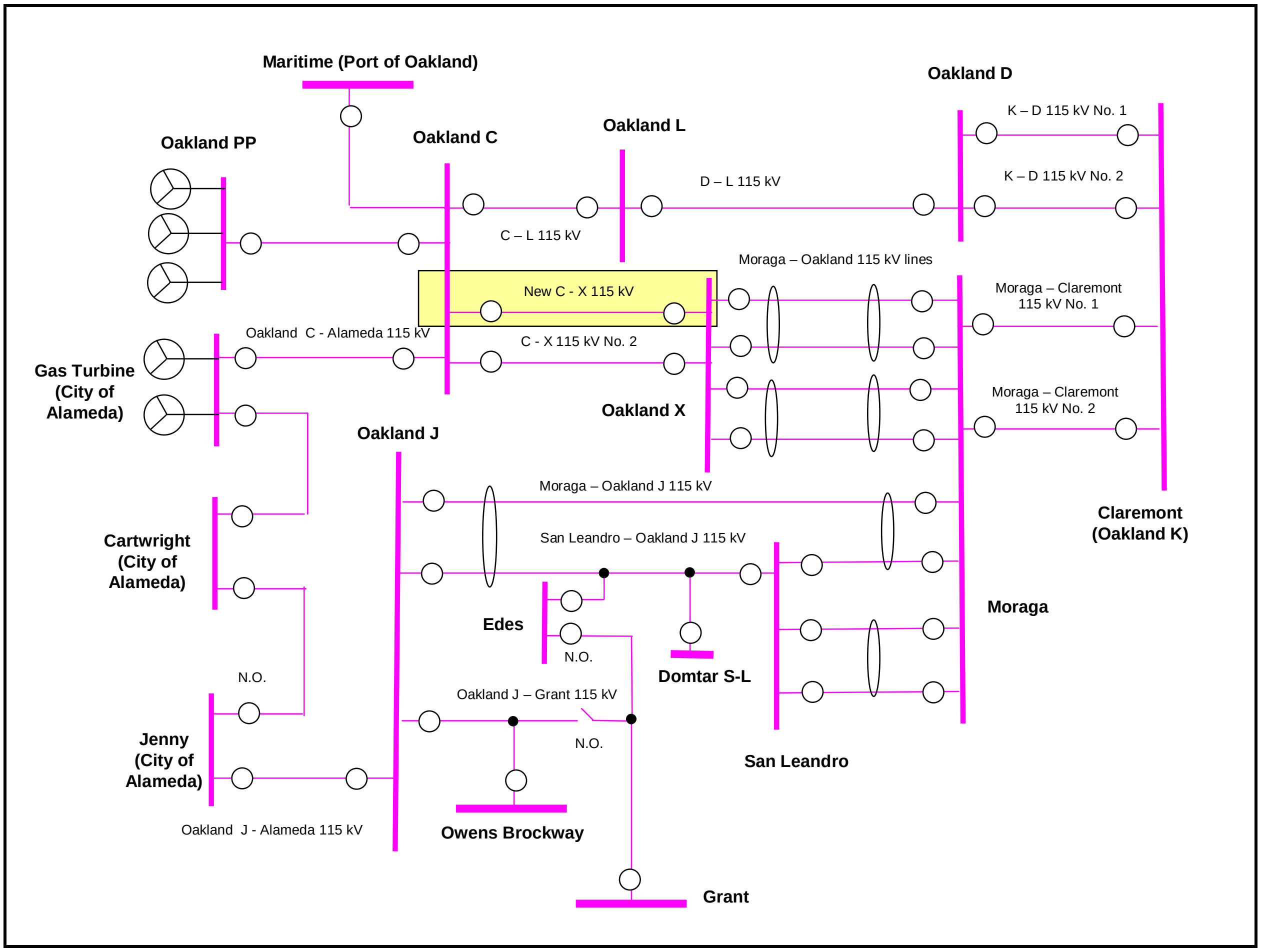


Figure 3-27: Scope Diagram

T258A: Palermo – Rio Oso 115 kV Line Reconductoring

(Expected In Service Date – May 2010)

PROJECT INFORMATION

The project scope is to re-construct sections of the existing Palermo-Rio Oso 115 kV double circuit tower line and re-conductor with 1,113 kcmil all aluminum conductor. This re-construction work would include a 40-mile section between Palermo and East Nicolaus substations. The re-conductor work would also include a 30-mile section between Palermo and Bogue Junction for a total of 70 circuit miles.

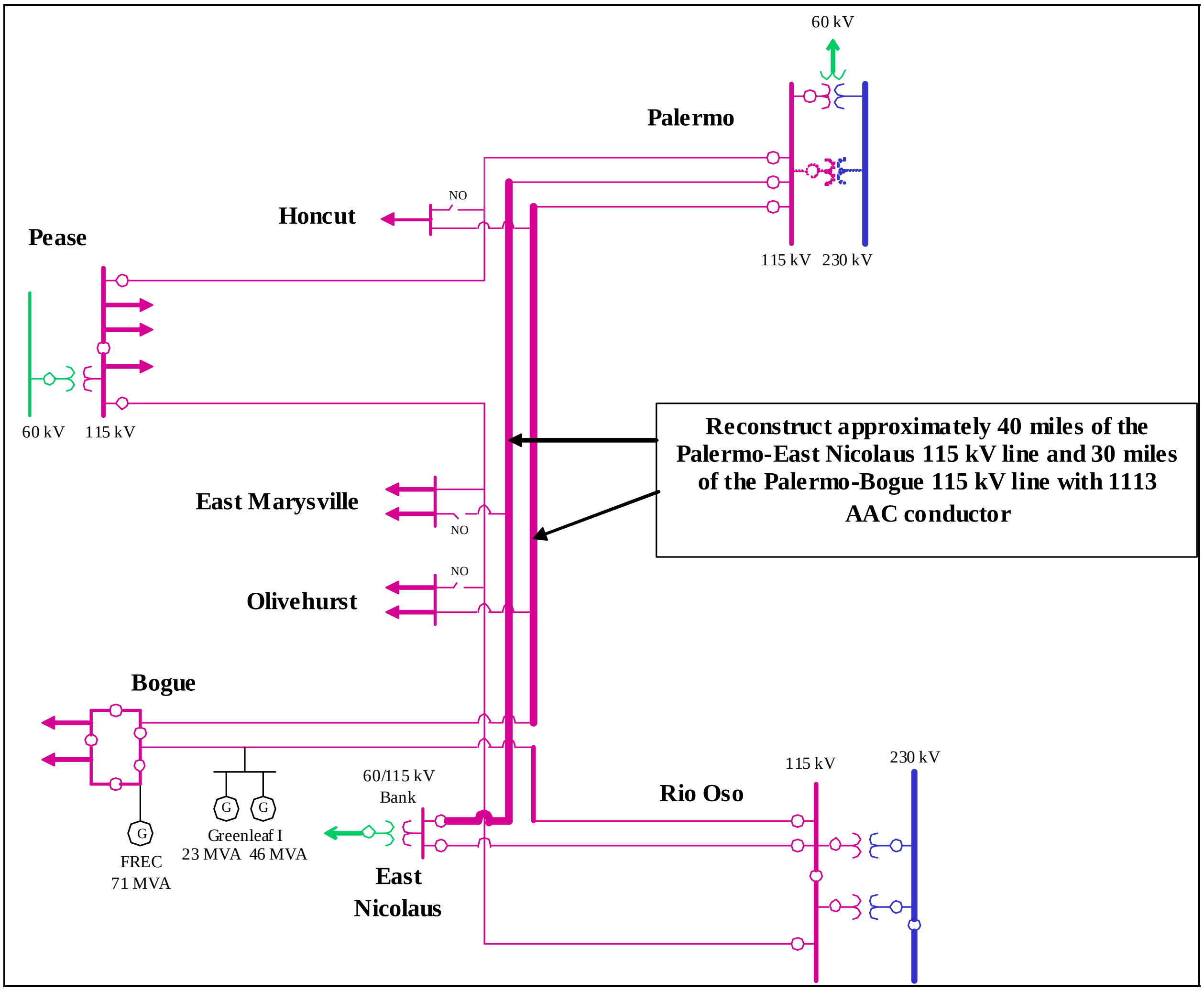


Figure 3-28: Scope Diagram

T984: Pittsburg – Tesla 230 kV Reconductoring

(Expected In Service Date –May 2010)

PROJECT INFORMATION

The project scope is to reconductor the Pittsburg – Tesla 230 kV lines with higher capacity rated conductors sized to handle 1,700 Amps or higher.

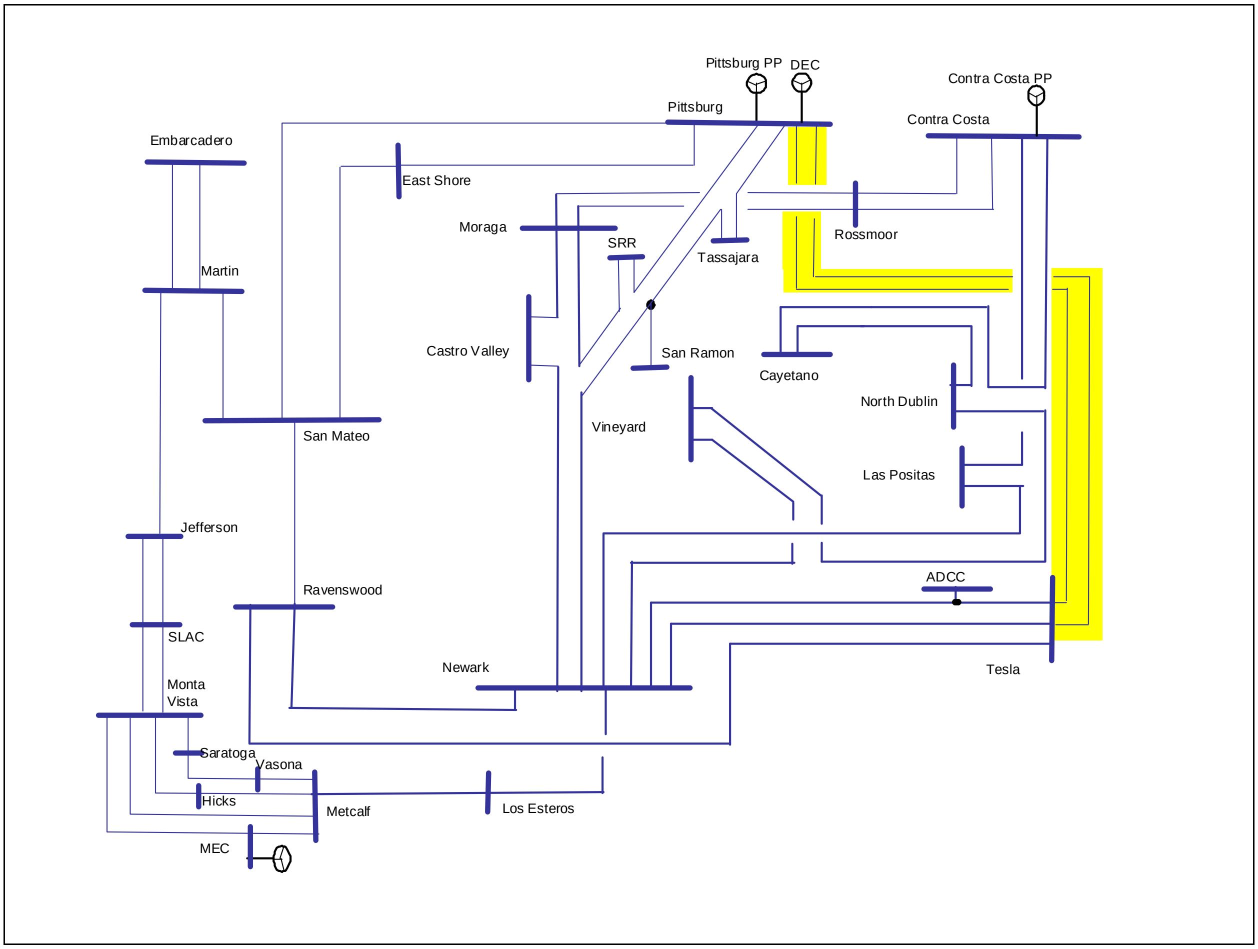


Figure 3-29: Scope Diagram

T972A: South of Birds Landing 230 kV Reconductoring

(Expected In Service Date – May 2010)

PROJECT INFORMATION

This project proposes the following work, which was previously approved under the CAISO's LGIP process:

- Expand Birds Landing Switching Station to a four bay, breaker-and-a-half, configuration and loop the Lambie-Contra Costa Substation 230 kV Line into Birds Landing Switching Station.
- Disconnect Russell Substation from Lambie-Contra Costa Substation 230 kV Line and reconnect Russell Substation to Birds Landing Switching Station.
- Reconductor 7-miles of the Birds Landing-Contra Costa Substation, 8.6-miles of the Birds Landing-Contra Costa Power Plant and 2 miles of the Contra Costa Substation-Contra Costa Power Plant 230 kV lines with 1113 ACSS conductors.
- Modify protection and communication equipment at Birds Landing, Lambie, Contra Costa Power Plant and Contra Costa substations.

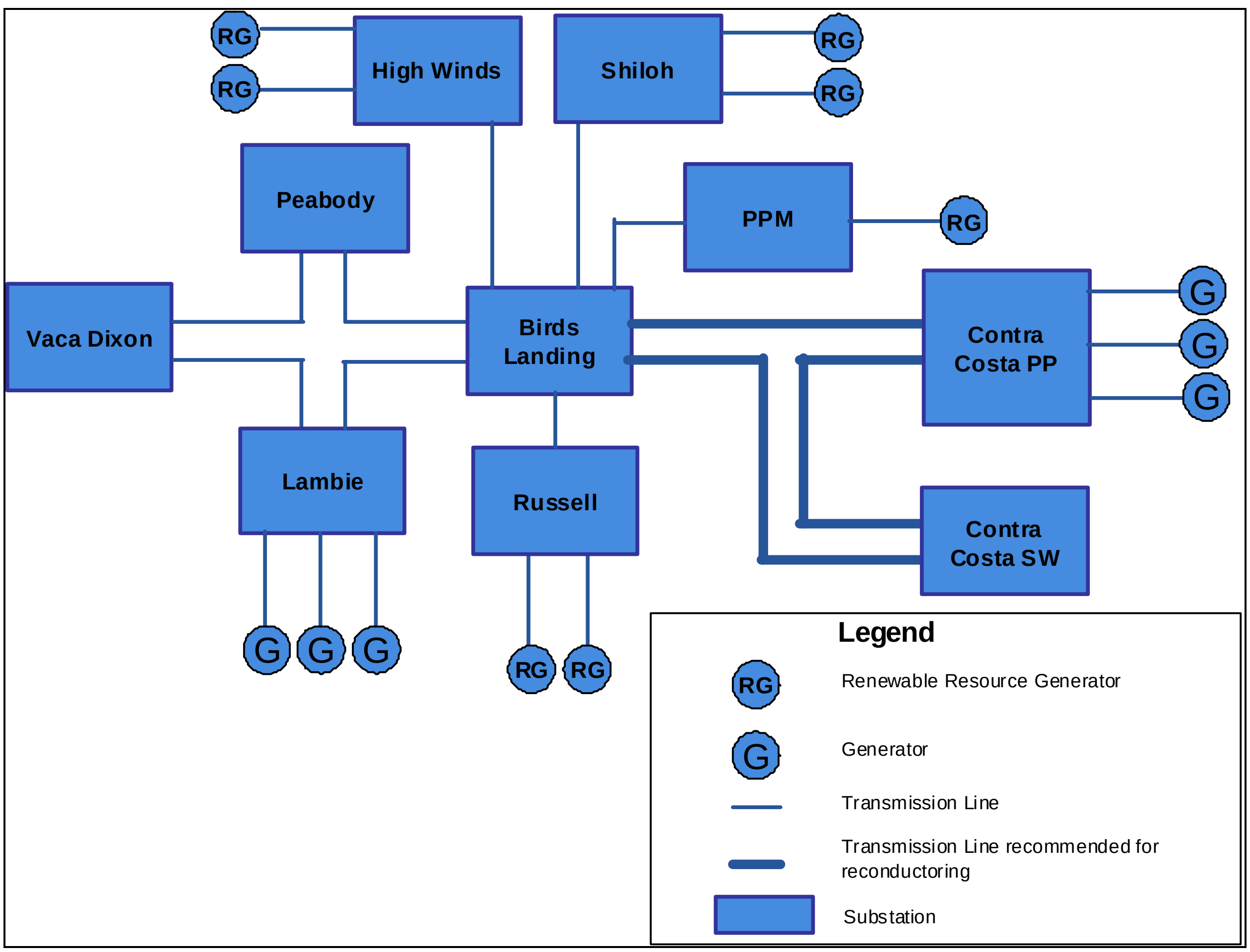


Figure 3-30: Scope Diagram

T444C: Stone Substation Capacity Increase

(Expected In Service Date – May 2010)

PROJECT INFORMATION

This project scope is to reconfigure the 115 kV connections into Stone Substation by creating a flip-flop configuration, which can be converted into a loop configuration in the future. This project will also involve installation of new 115 kV circuit breakers at Stone Substation.

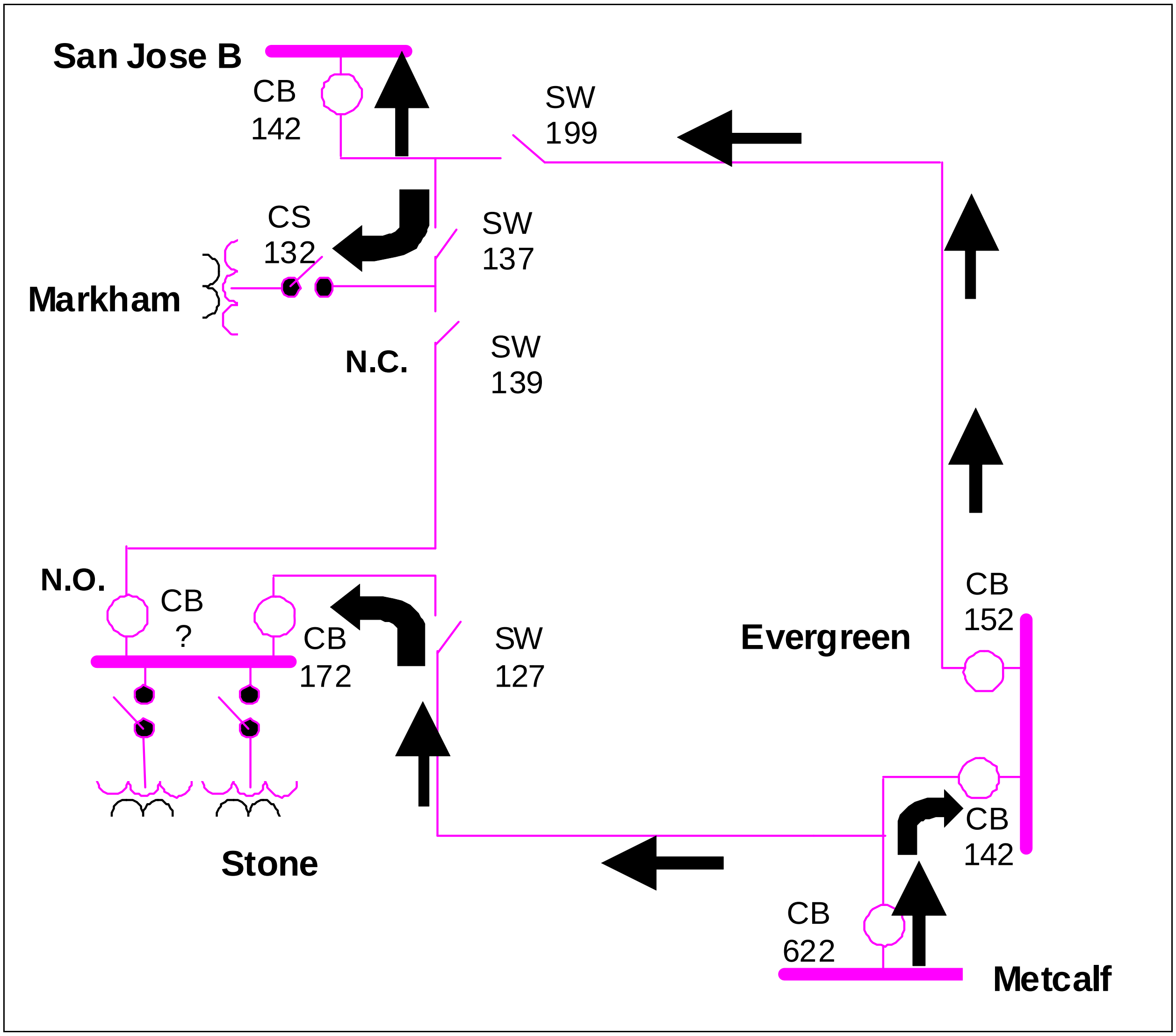


Figure 3-31: Scope Diagram

T1030: Table Mountain – Rio Oso 230 kV Reconductor and Tower Raises

(Expected In Service Date – May 2010)

PROJECT INFORMATION

The project scope is to replace the two existing 230 kV circuit breakers at Colgate Power House Switchyard with 2,000 Amp rated circuit breakers. Associated substation terminal equipment will be replaced and sized to handle the 2,000 Amp rated circuit breakers.

In addition, this project is being coordinated with a maintenance project that involves raising transmission line towers (103) on the Table Mountain-Rio Oso 230 kV double circuit tower lines (DCTL). This will also involve reconductoring 136 circuit miles on the Table Mountain-Rio Oso 230 kV DCTL with 795 SSAC conductors. The expected in-service date of this maintenance work is by May 2011.

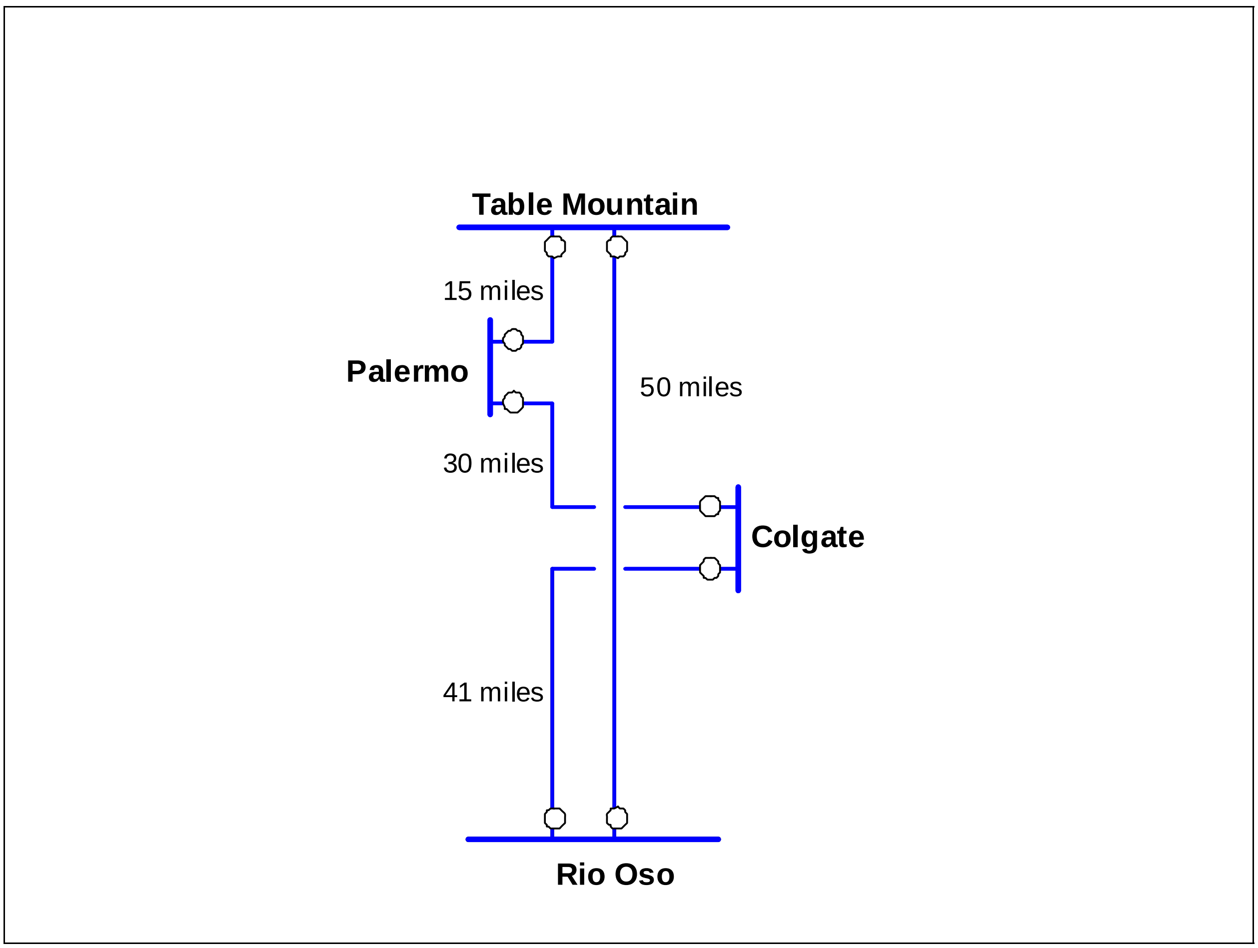


Figure 3-32: Scope Diagram

T680B: Tesla 115 kV Capacity Increase

(Expected In Service Date – May 2010)

PROJECT INFORMATION

This project proposes to reconductor the Tesla – Salado – Manteca 115 kV Line with a higher capacity conductor (443 Amps or greater) and the Schulte Sw Station – Lammers 115 kV Line (0.9 circuit miles) with a higher capacity conductor (1,430 Amps or greater).

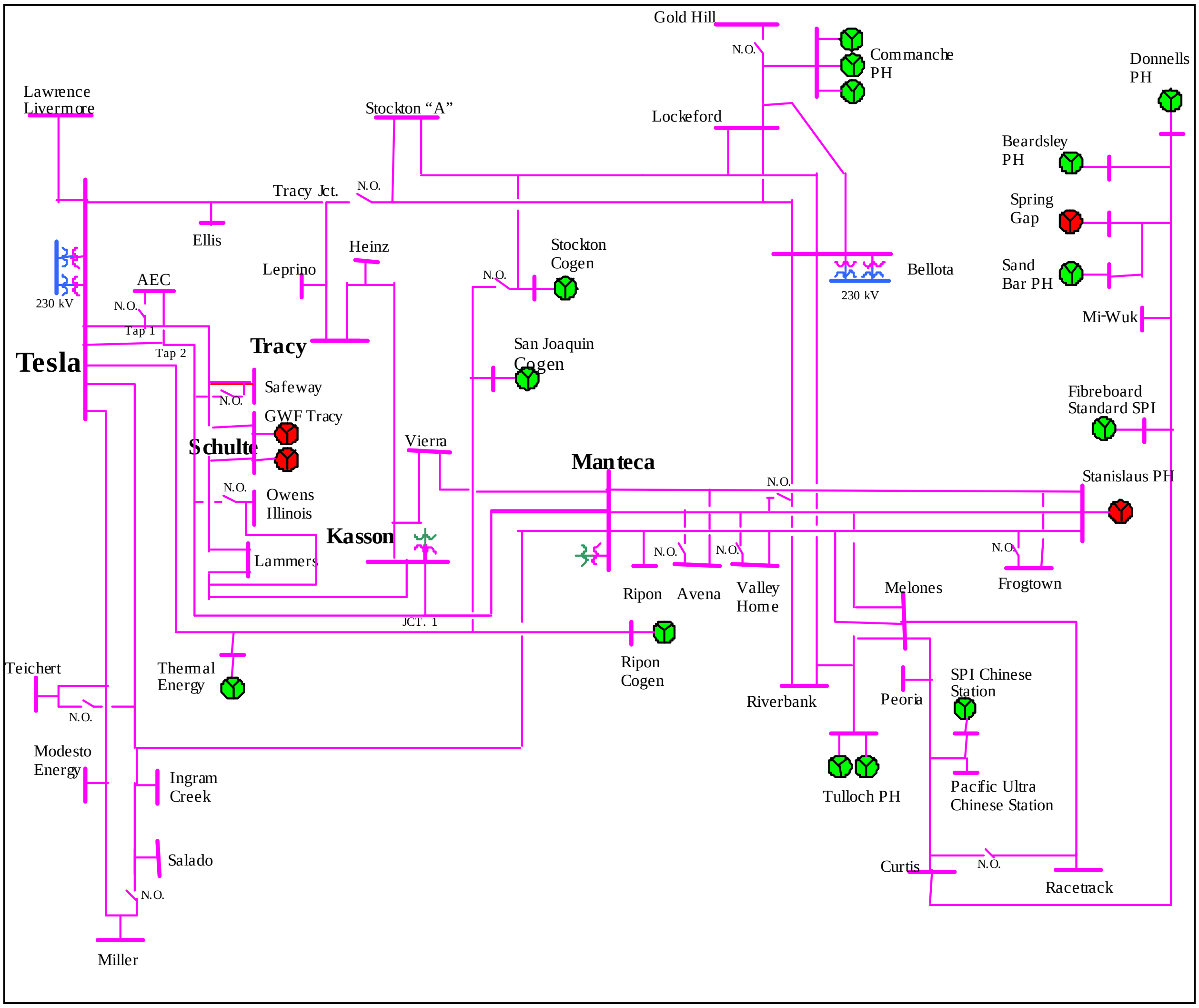


Figure 3-33: Scope Diagram

T1042: West Fresno Reactive Support

(Expected In Service Date – May 2010)

PROJECT INFORMATION

The project scope is to install 75 MVArs of shunt capacitors (three steps of 25 MVArs) at the West Fresno 115 kV Substation.

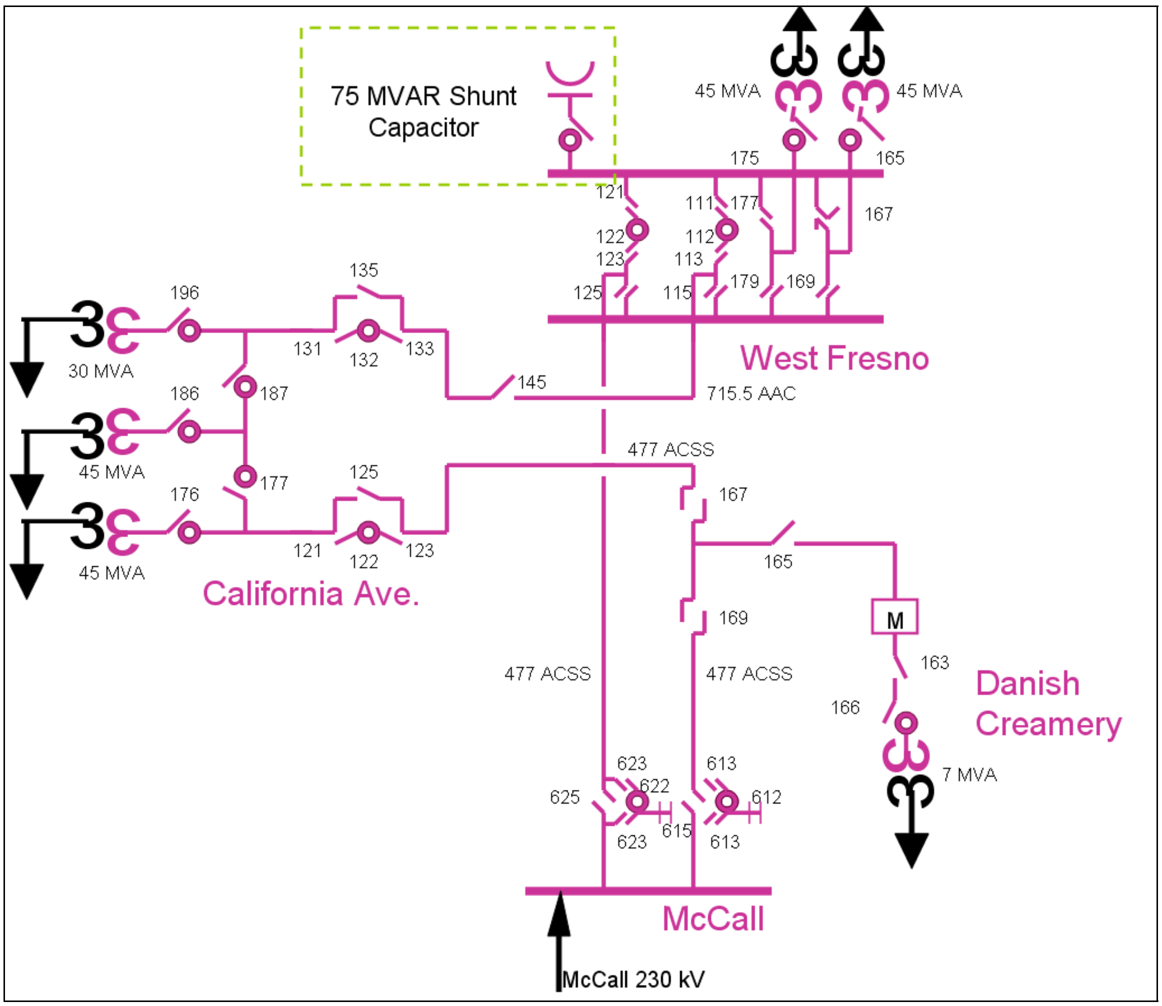


Figure 3-34: Scope Diagram

T258A: Gregg 230 kV Reactor

(Expected In Service Date – October 2010)

PROJECT INFORMATION

The project scope is to install 100 MVArs of 230 kV shunt reactors at Gregg Substation.

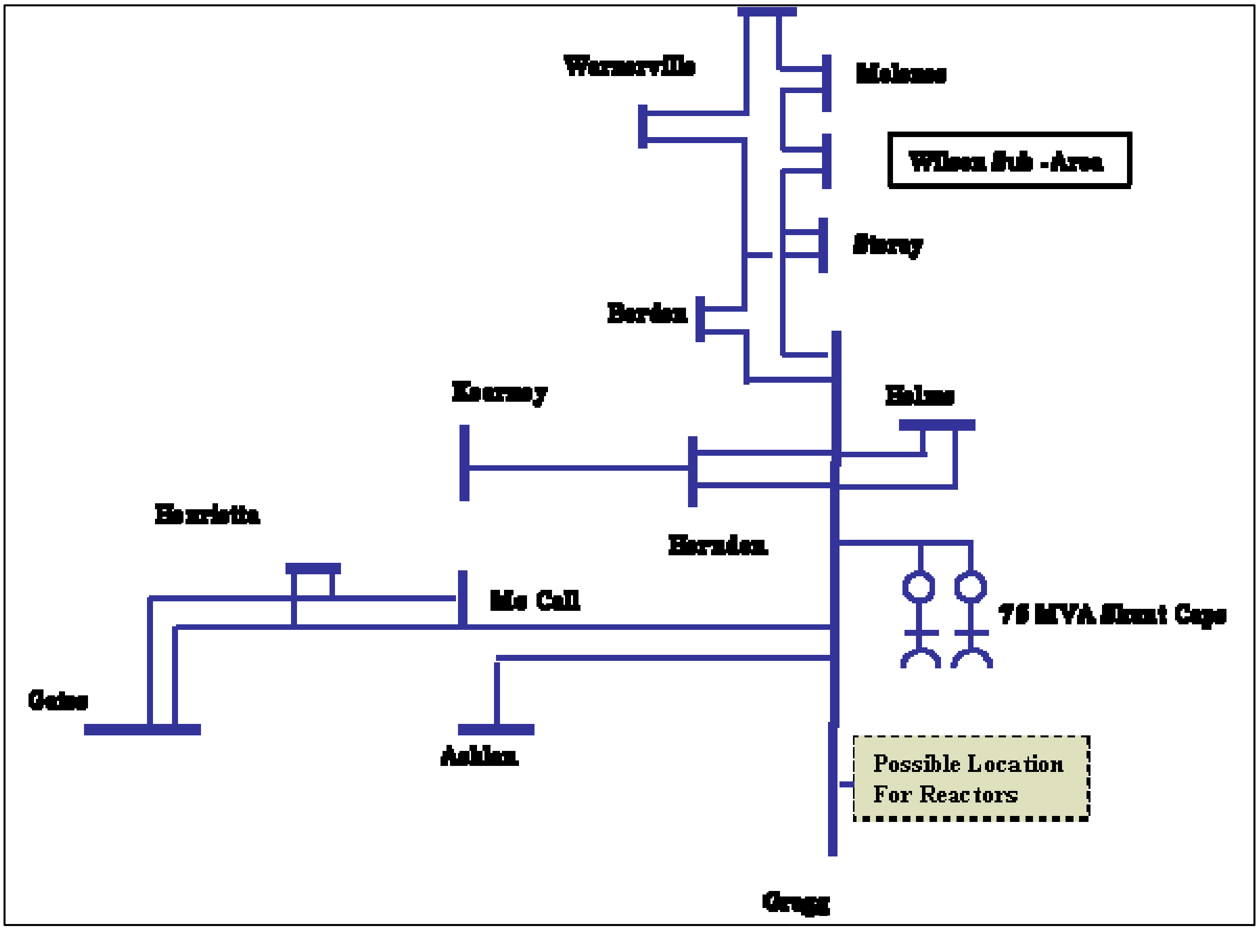


Figure 3-35: Scope Diagram

T880B: West Point – Valley Springs 60 kV Line

(Expected In Service Date - November 2010)

PROJECT INFORMATION

The project scope is to reconductor approximately 11 miles of the West Point – Valley Springs 60 kV Line with 795 ACSR conductors or larger.

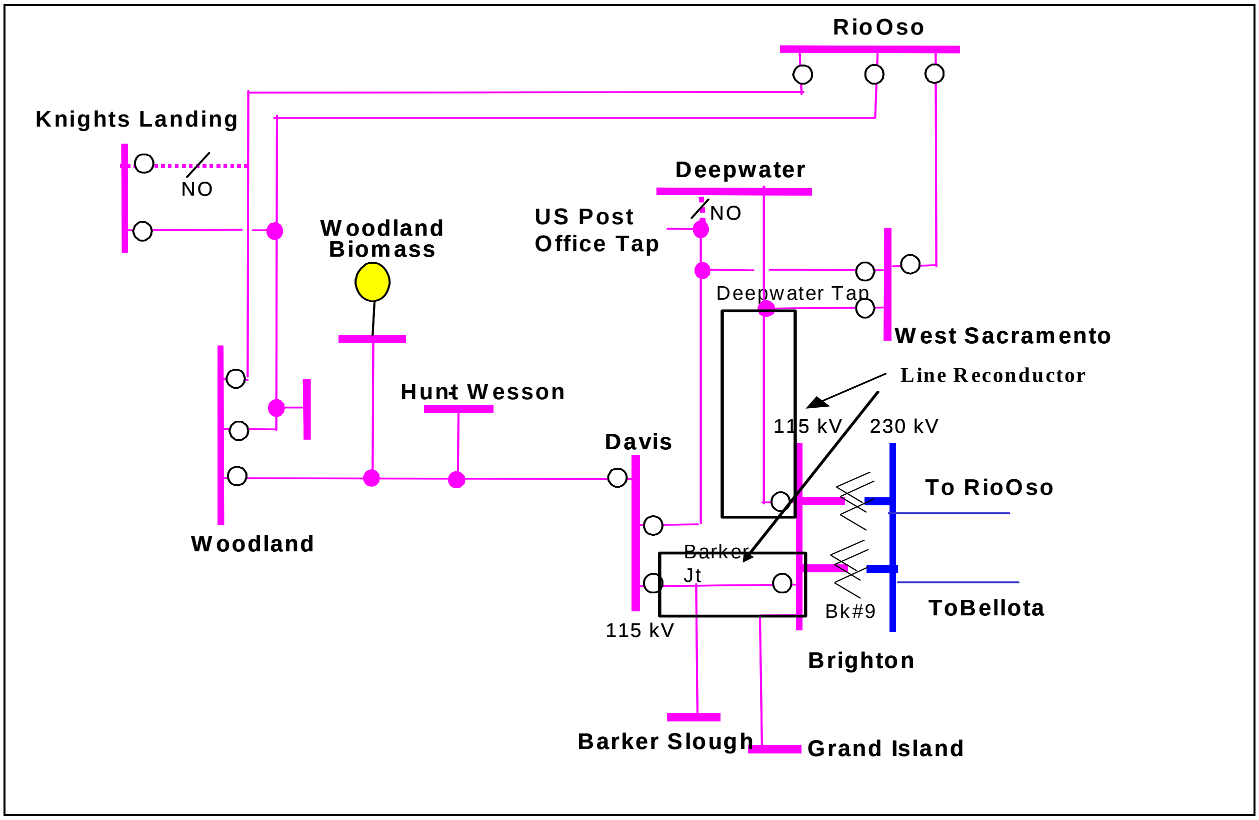


Figure 3-36: Scope Diagram

T970: Crazy Horse Switching Station

(Expected In Service Date – December 2010)

PROJECT INFORMATION

This project proposes to construct a new 115 kV switching station in the Central Coast Division.

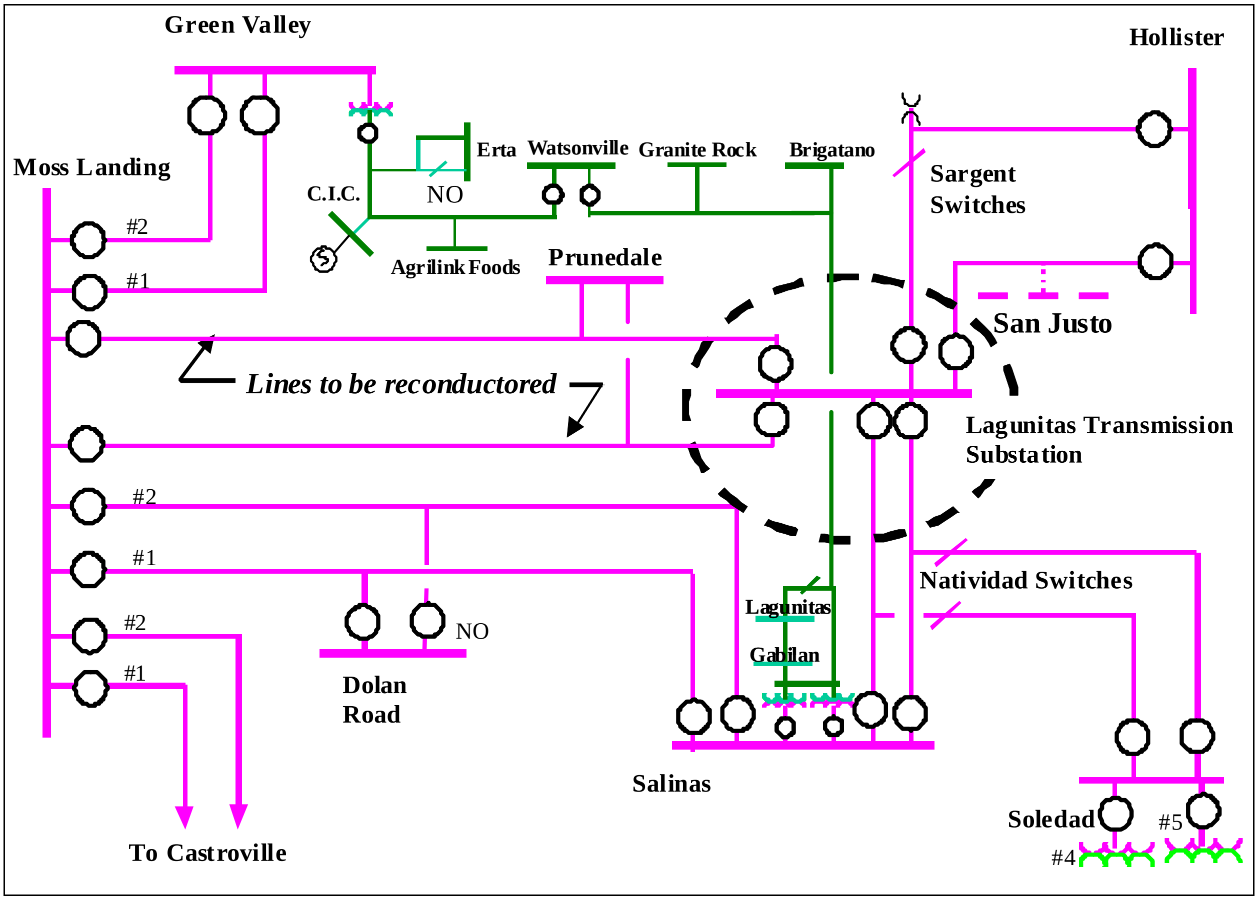


Figure 3-37: Scope Diagram

T1033: Cooley Landing 115/60 kV Transformer Capacity Uprade

(Expected In Service Date – May 2011)

PROJECT INFORMATION

This project scope is to replace Cooley Landing 115/60 kV Transformer No. 1 with four 60 MVA, single-phase units, and Cooley Landing 115/60 kV Transformer No. 2 with three 60 MVA, single-phase units by May 2011.

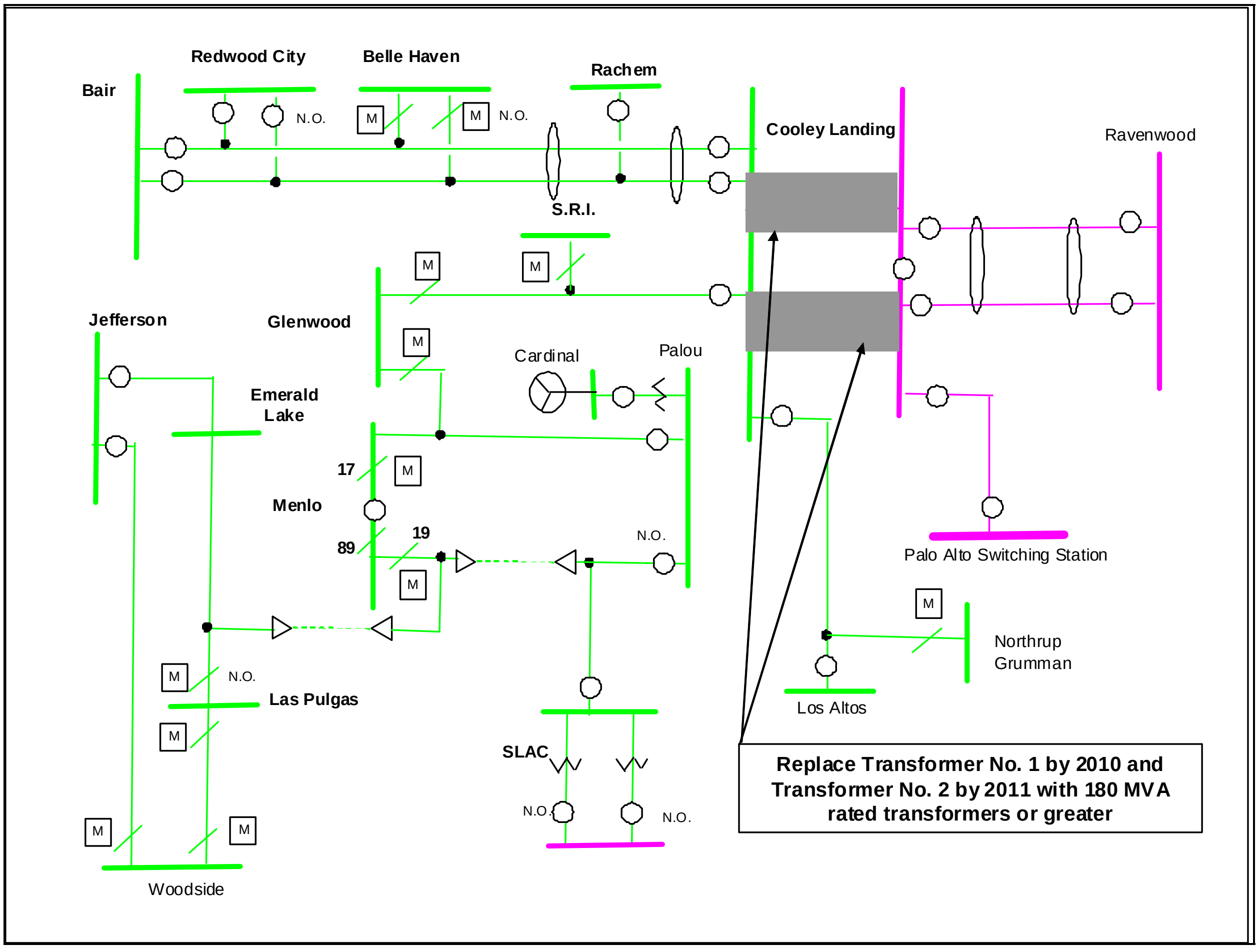


Figure 3-38: Scope Diagram

T346A: Cortina 60 kV Reliability
(Expected In Service Date - May 2011)

PROJECT INFORMATION

The project scope is to install an additional 230/60 kV or 115/60 kV transformer at Cortina Substation.

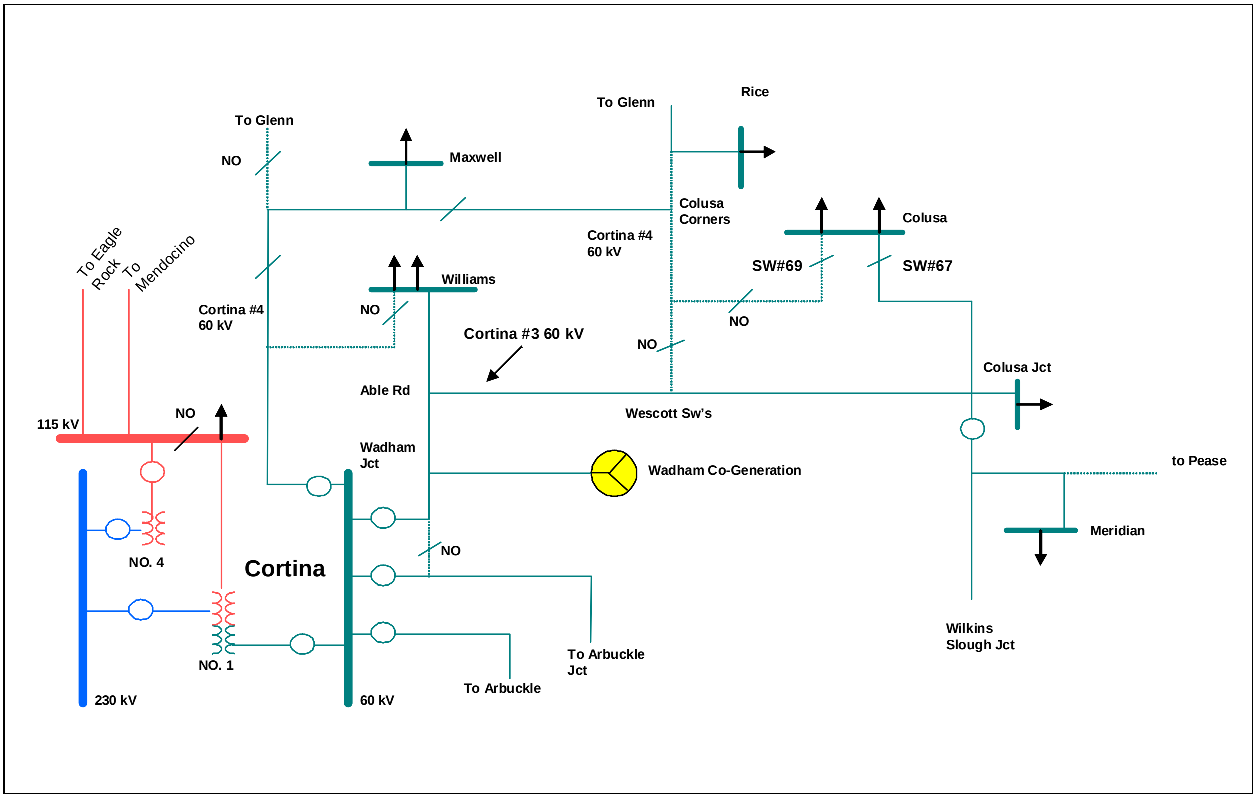


Figure 3-39: Scope Diagram

T1000: East Nicolaus 115 kV Area Reinforcement

(Expected In Service Date – May 2011)

PROJECT INFORMATION

The project scope is to replace the East Nicolaus 115/60 kV Transformer No. 2 with a transformer rated at 180 MVA or larger (four single phases, each rated at 60 MW per phase) and replace the adjacent voltage regulator.

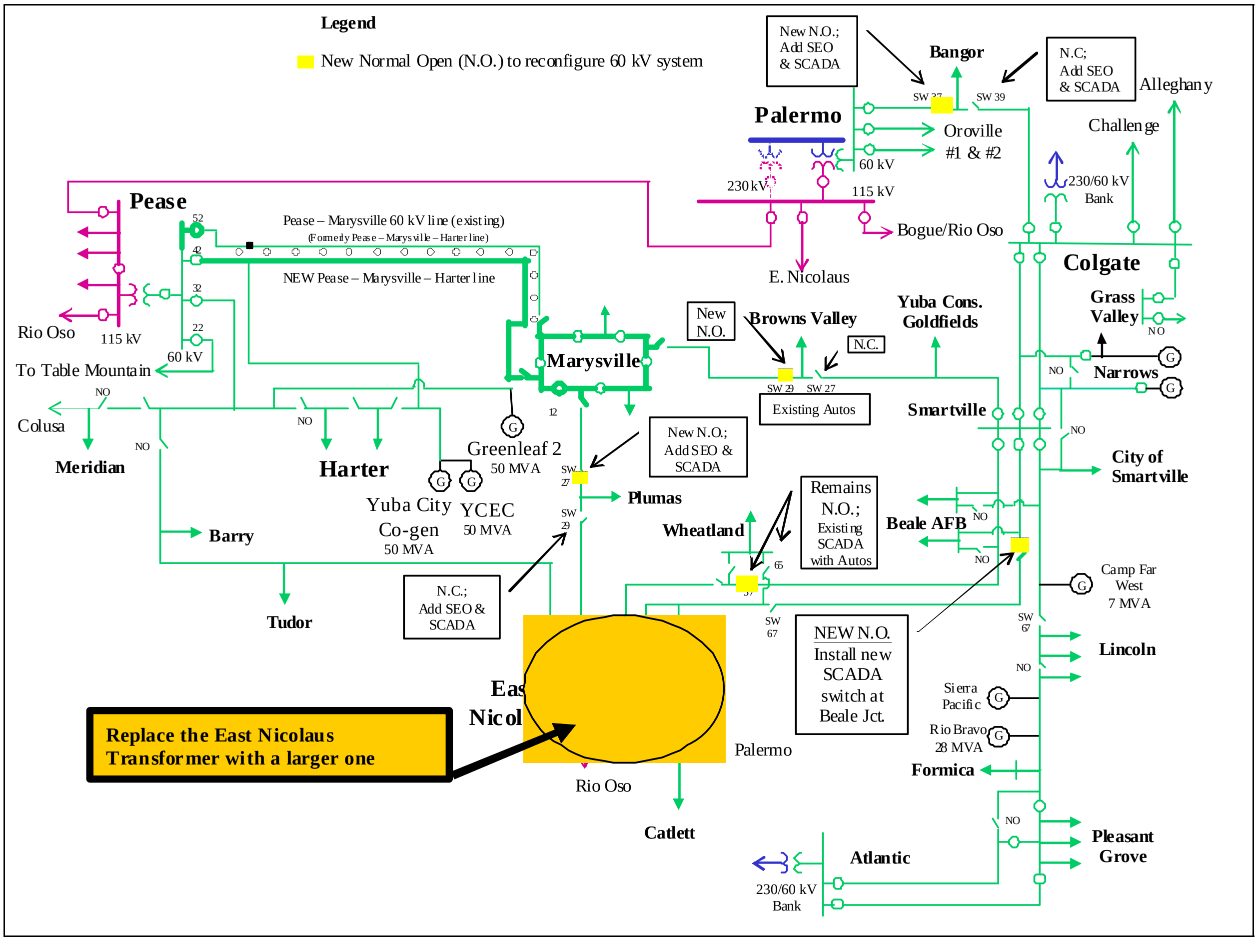


Figure 3-40: Scope Diagram

T979: Half Moon Bay Reactive Support

(Expected In Service Date May 2011)

PROJECT INFORMATION

The project scope is to install additional voltage support or to construct new 60 kV facilities into the Half Moon Bay area.

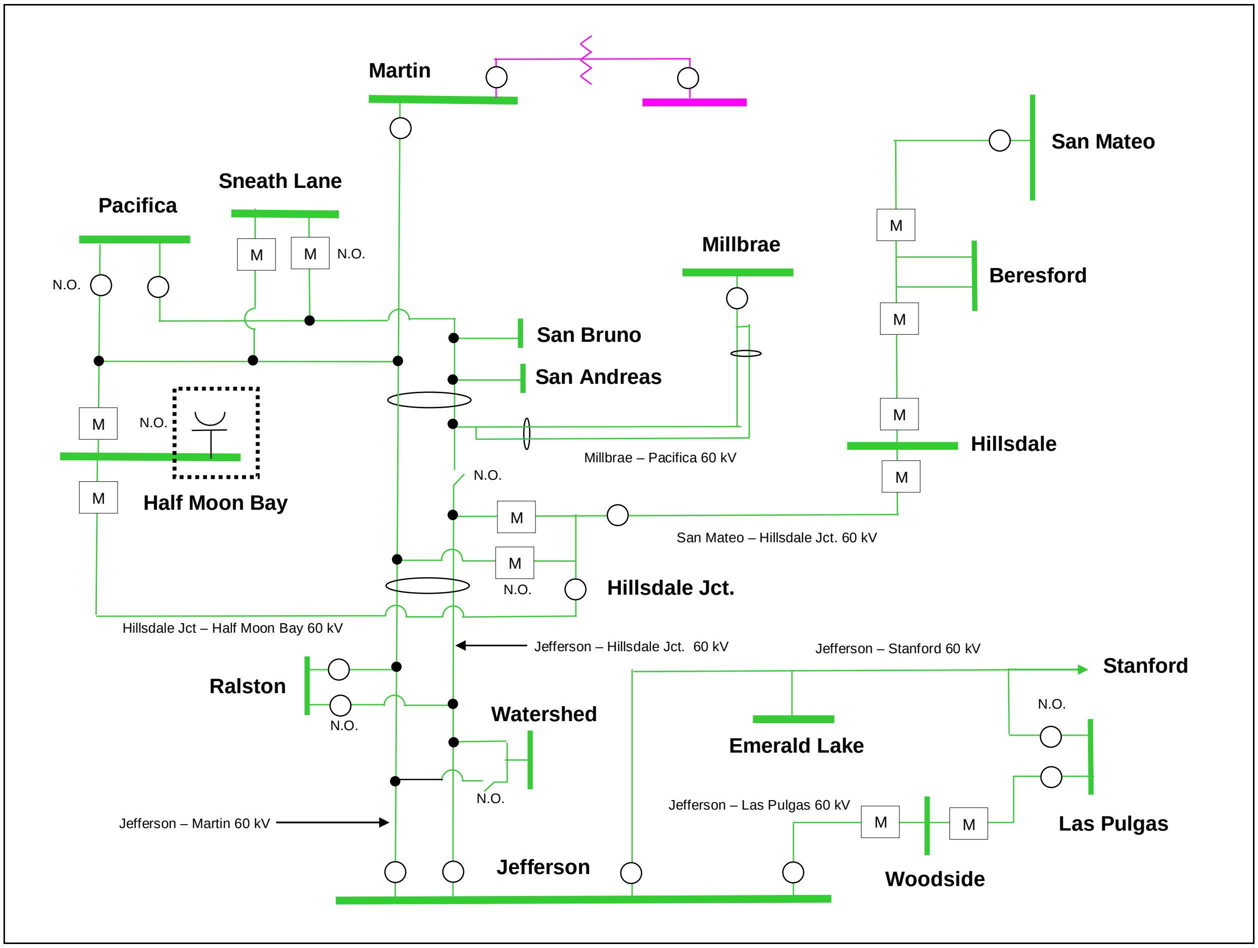


Figure 3-41: Scope Diagram

T990: Moraga Transformer Capacity Increase

(Expected In Service Date – May 2011)

PROJECT INFORMATION

The project scope is to replace Moraga Transformer Nos. 1 and 2 with transformers rated to each handle 420 MVA or higher.

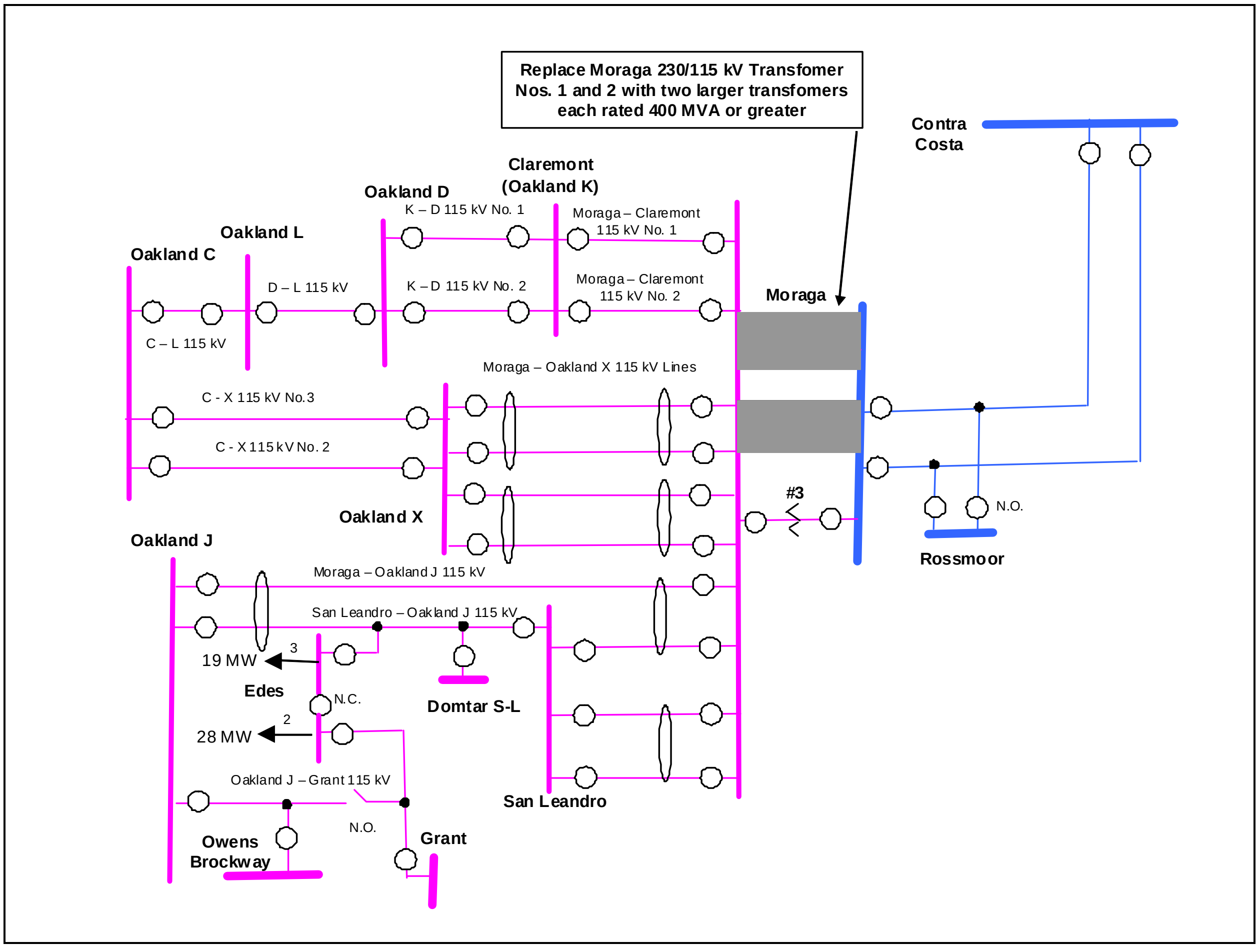


Figure 3-42: Scope Diagram

T999: Pittsburg 230/115 kV Transformer Capacity Increase

(Expected In Service Date - May 2011)

PROJECT INFORMATION

The project scope is to add a third Pittsburg transformer rated at 400 MVA or larger.

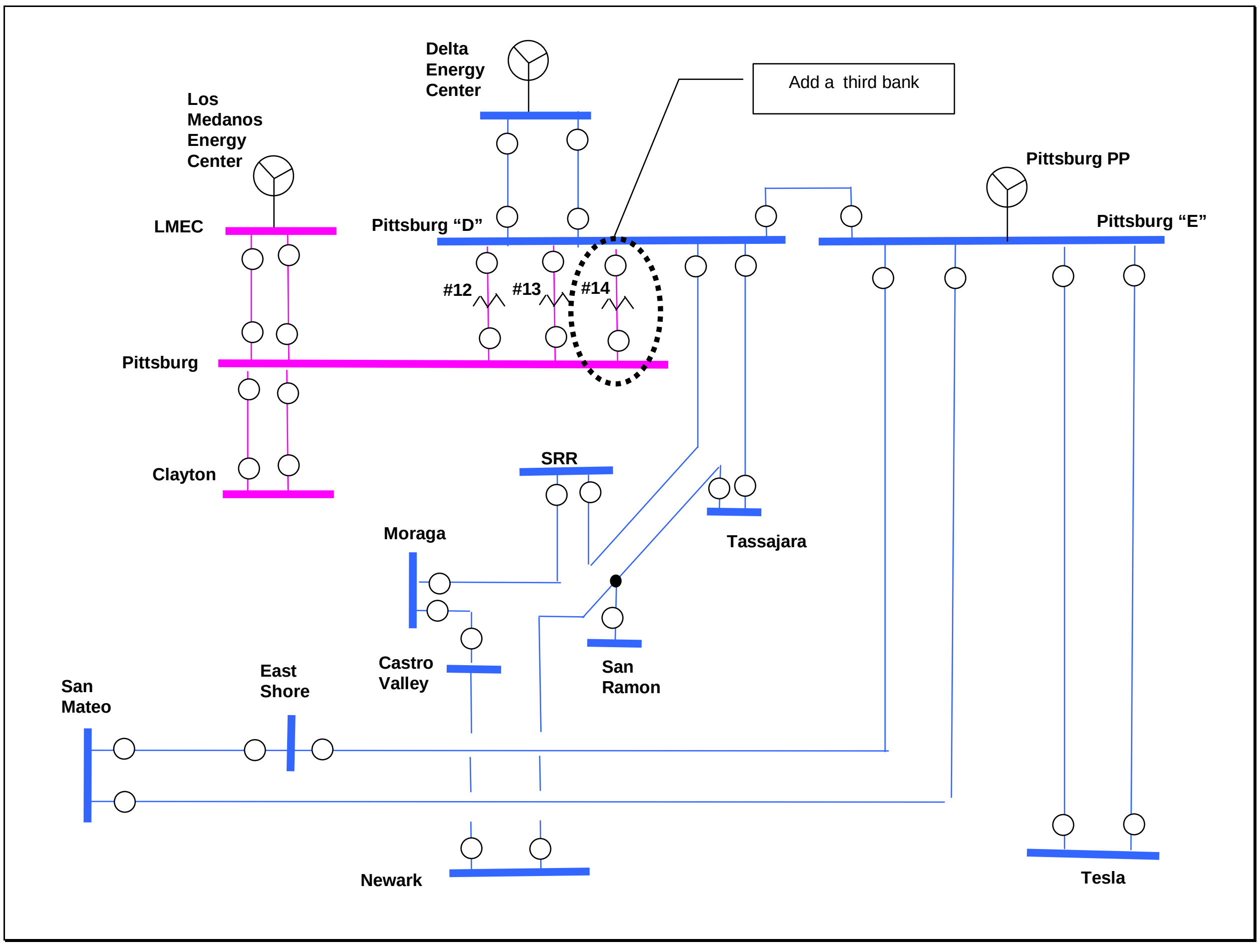


Figure 3-43: Scope Diagram

T996A: Soledad 115/60 kV Transformer Capacity

(Expected In Service Date - May 2011)

PROJECT INFORMATION

The preferred alternative is to replace the existing Soledad 115/60 kV Transformers Nos. 4 and 5 with two new 115/60 kV, 200 MVA transformers.

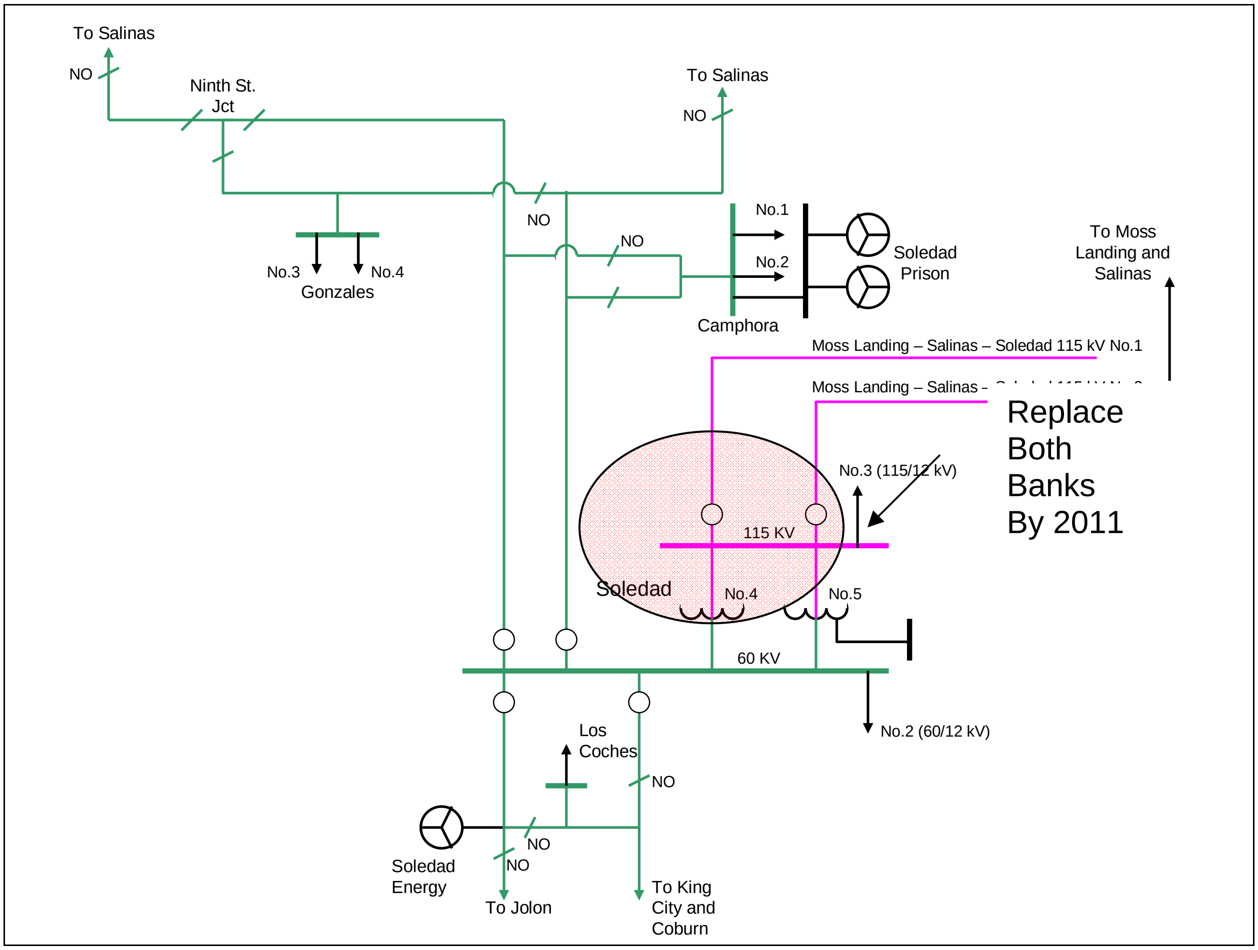


Figure 3-44: Scope Diagram

T920A: South of San Mateo Capacity Increase

(Expected In Service Date - May 2011)

PROJECT INFORMATION

The project scope is to upgrade the transmission facilities between Ames, Ravenswood and San Mateo. The completion of this project would reduce or eliminate the need for the existing automated protection scheme. Project options to be evaluated include upgrading existing and building new transmission facilities.

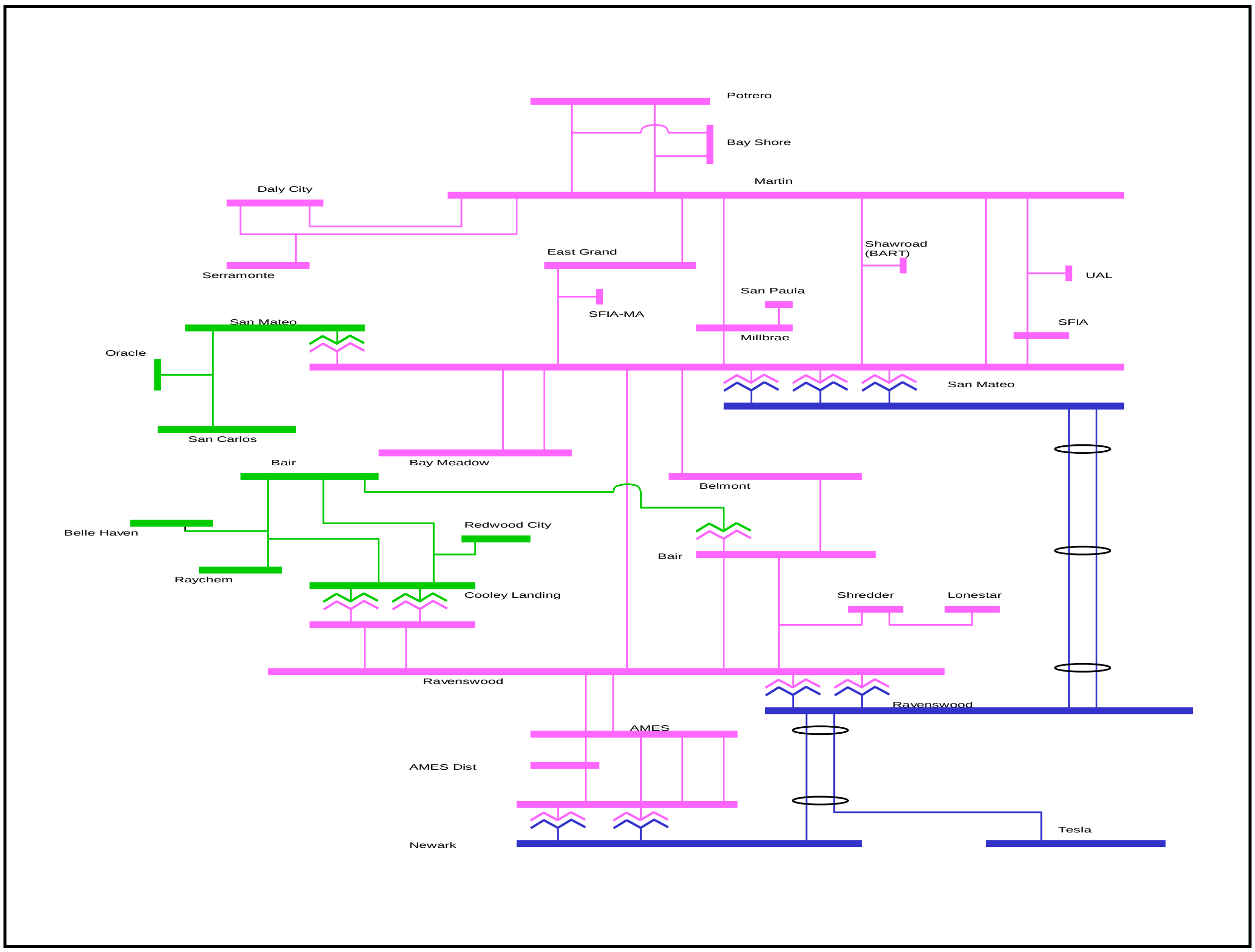


Figure 3-45: Scope Diagram

T670B: Tesla – Newark 230 kV Path Upgrade

(Expected In Service Date May 2011)

PROJECT INFORMATION

The project scope is to reconductor the limiting sections of the Tesla – Newark 230 kV No. 2 with larger capacity rated conductors. If necessary, associated line terminal equipment would be upgraded. In addition, the project scope would require obtaining any necessary environmental and land permits to complete the reconductoring work.

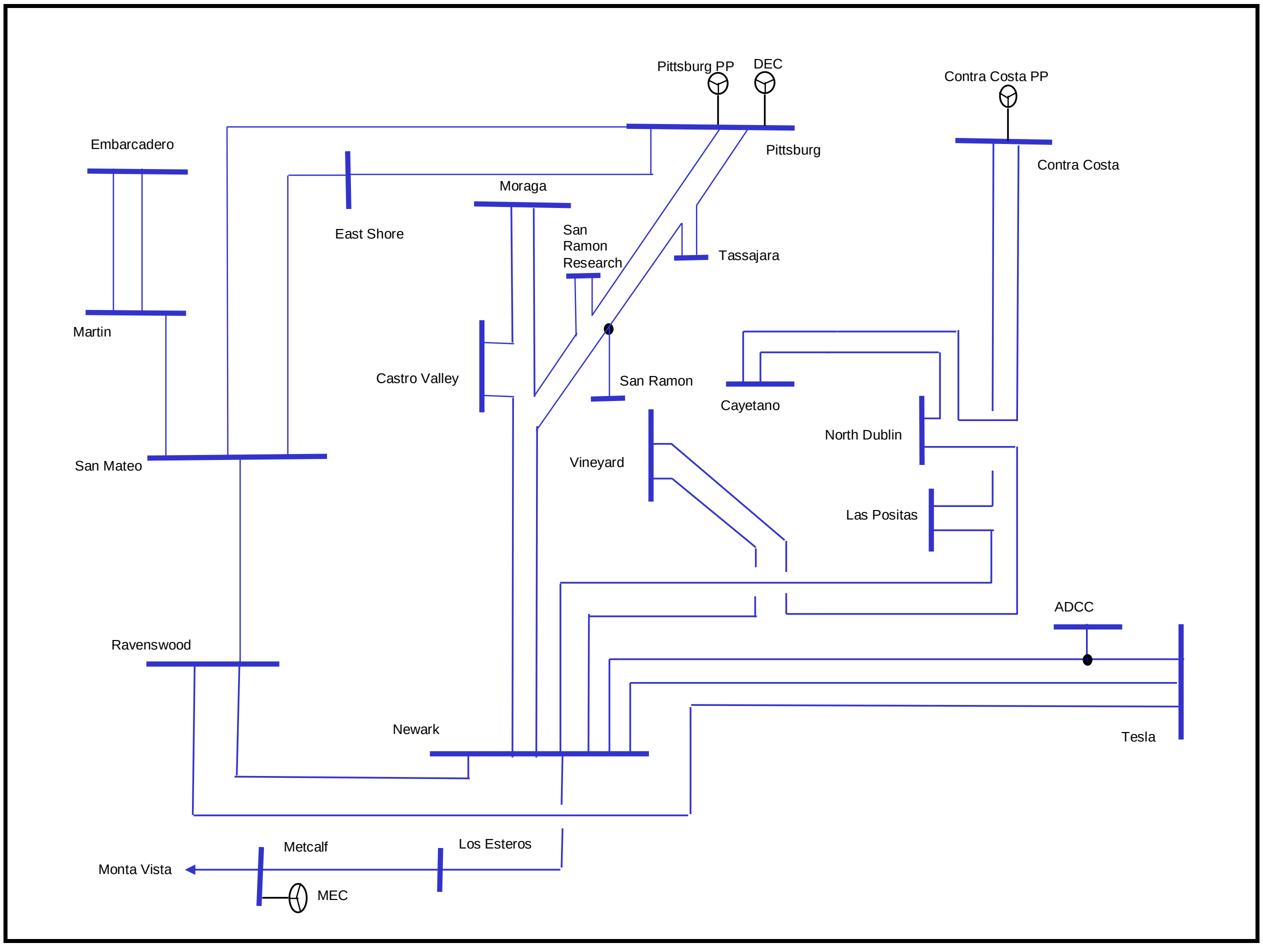


Figure 3-46: Scope Diagram

T972: Vaca Dixon – Birds Landing 230 kV Reconductoring

(Expected In Service Date – May 2011)

PROJECT INFORMATION

The project scope is to reconductor the Vaca Dixon – Peabody, Vaca Dixon – Lambie and Lambie – Birds Landing 230 kV lines with 1113 ACSS conductors.

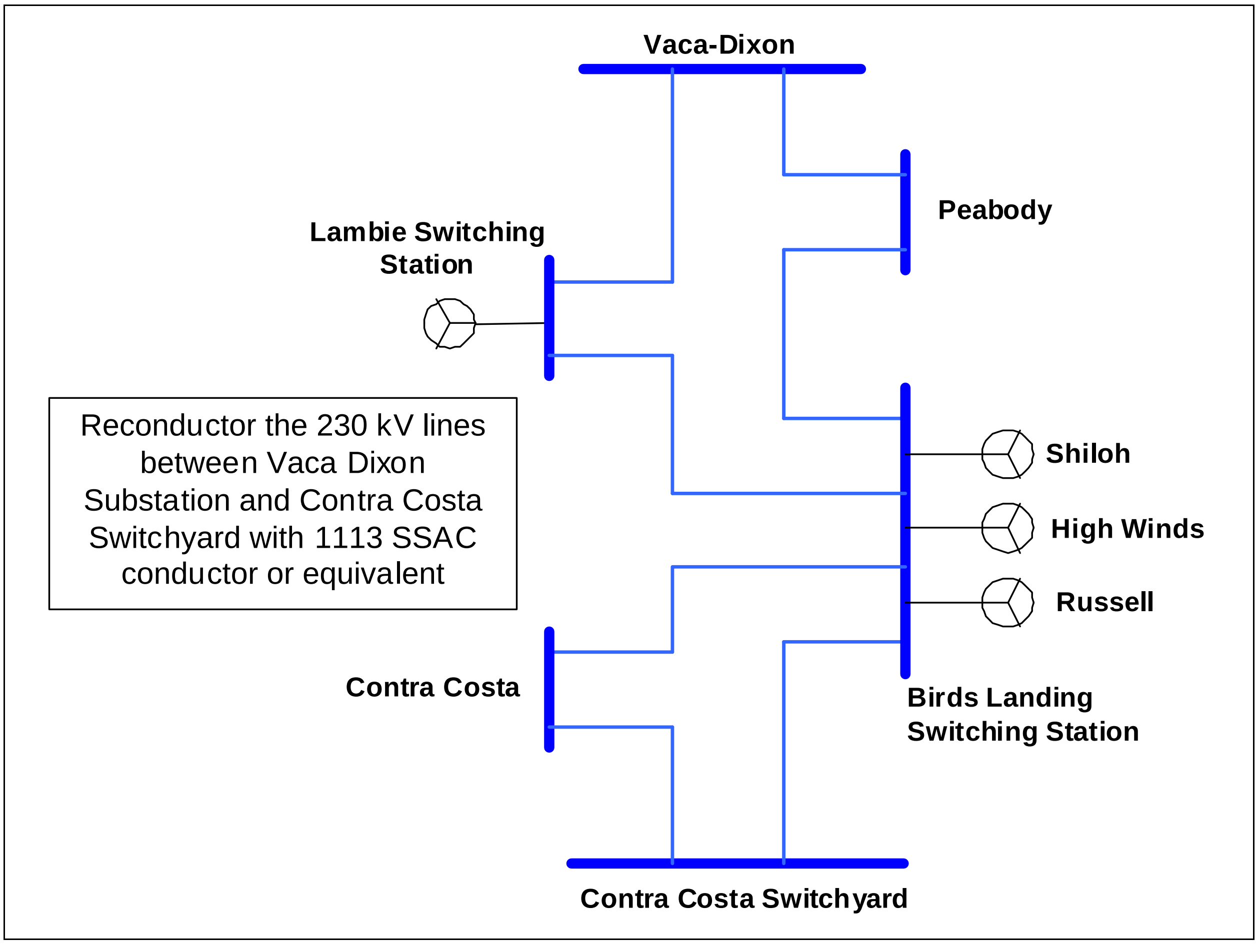


Figure 3-47: Scope Diagram

T1000: Wheeler Ridge 230/70 kV Transformer

(Expected In Service Date – May 2011)

PROJECT INFORMATION

The project scope is to install a second 230/70 kV transformer at Wheeler Ridge Substation. This transformer will be sized to handle a rating of 200 MVA or higher.

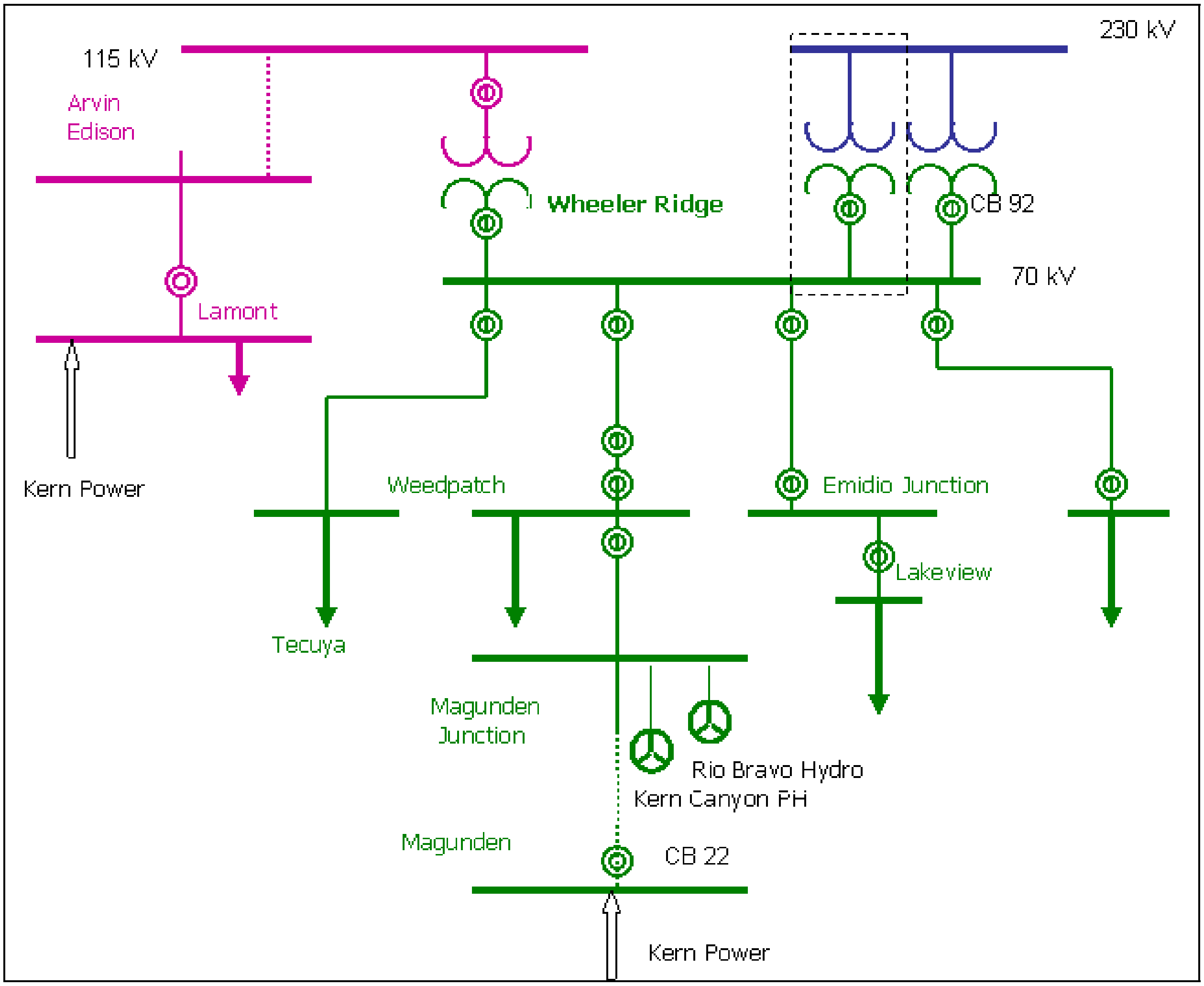


Figure 3-48: Scope Diagram

T994: Lakeville – Ignacio #2 230 kV Line

(Expected In Service Date – December 2011)

PROJECT INFORMATION

This project re-establishes a second 230 kV transmission line between Lakeville and Ignacio Substation.

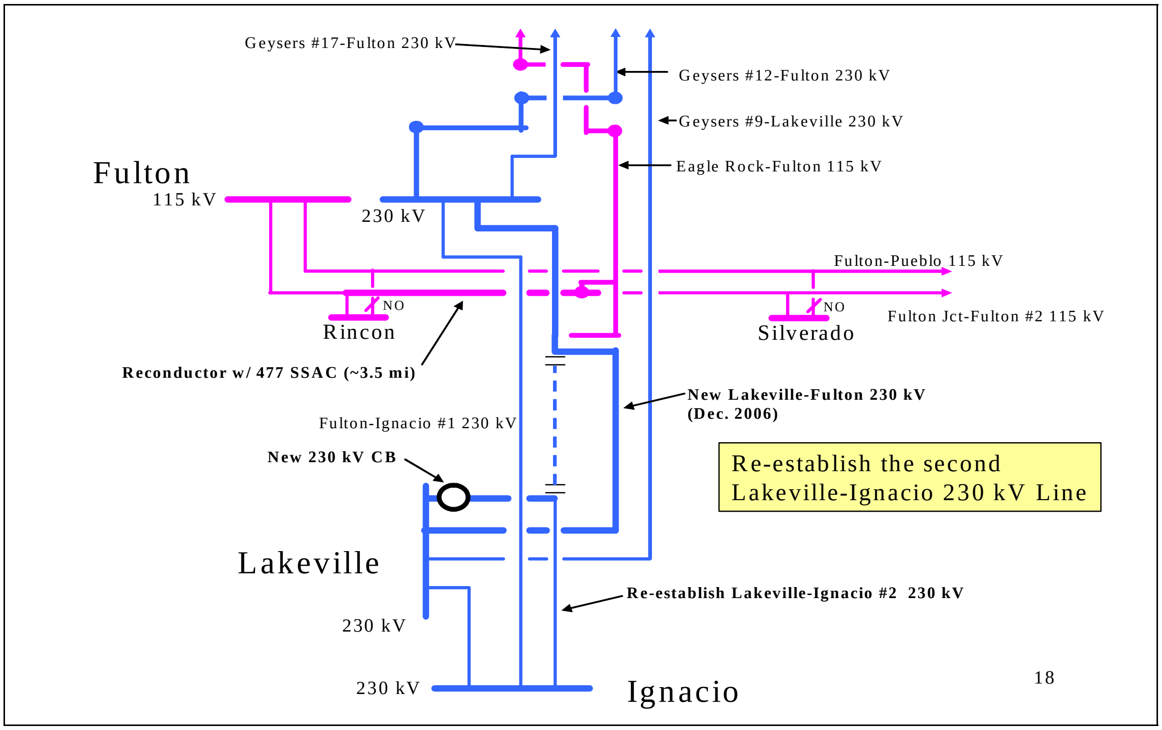


Figure 3-49: Scope Diagram

T854: Metcalf – Evergreen 115 kV

(Expected In Service Date – May 2012)

PROJECT INFORMATION

This project proposes to reconductor the Metcalf – Evergreen 115 kV lines with 477 ACSS conductors.

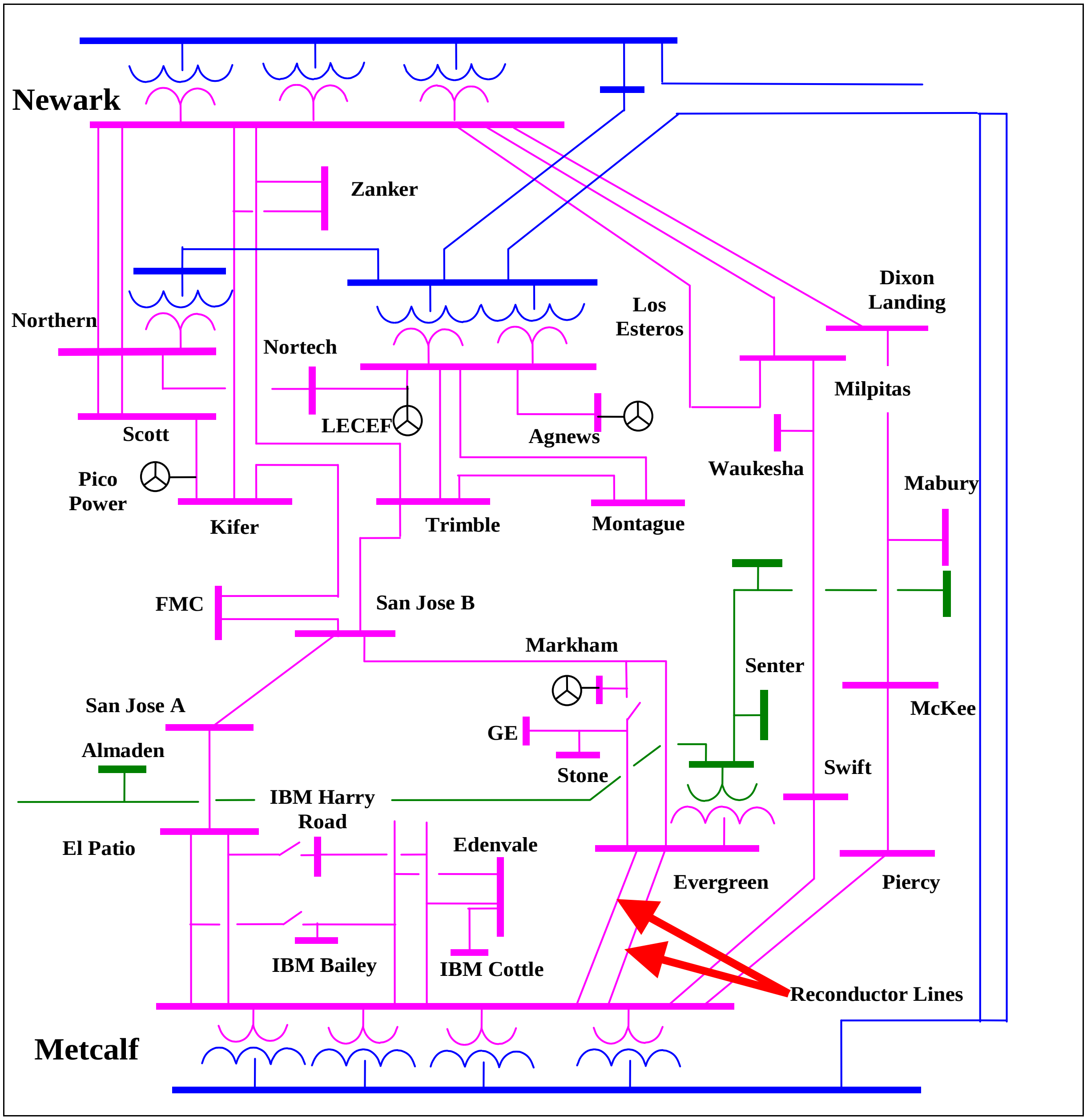


Figure 3-50: Scope Diagram

T692: Metcalf – Piercy & Swift – Metcalf and Newark – Dixon Landing 115 kV Upgrade

(Expected In Service Date – May 2012)

PROJECT INFORMATION

This project proposes to reconductor the Piercy/Swift – Metcalf and Newark – Dixon Landing 115 kV lines with 795 ACSS conductors or equivalent.

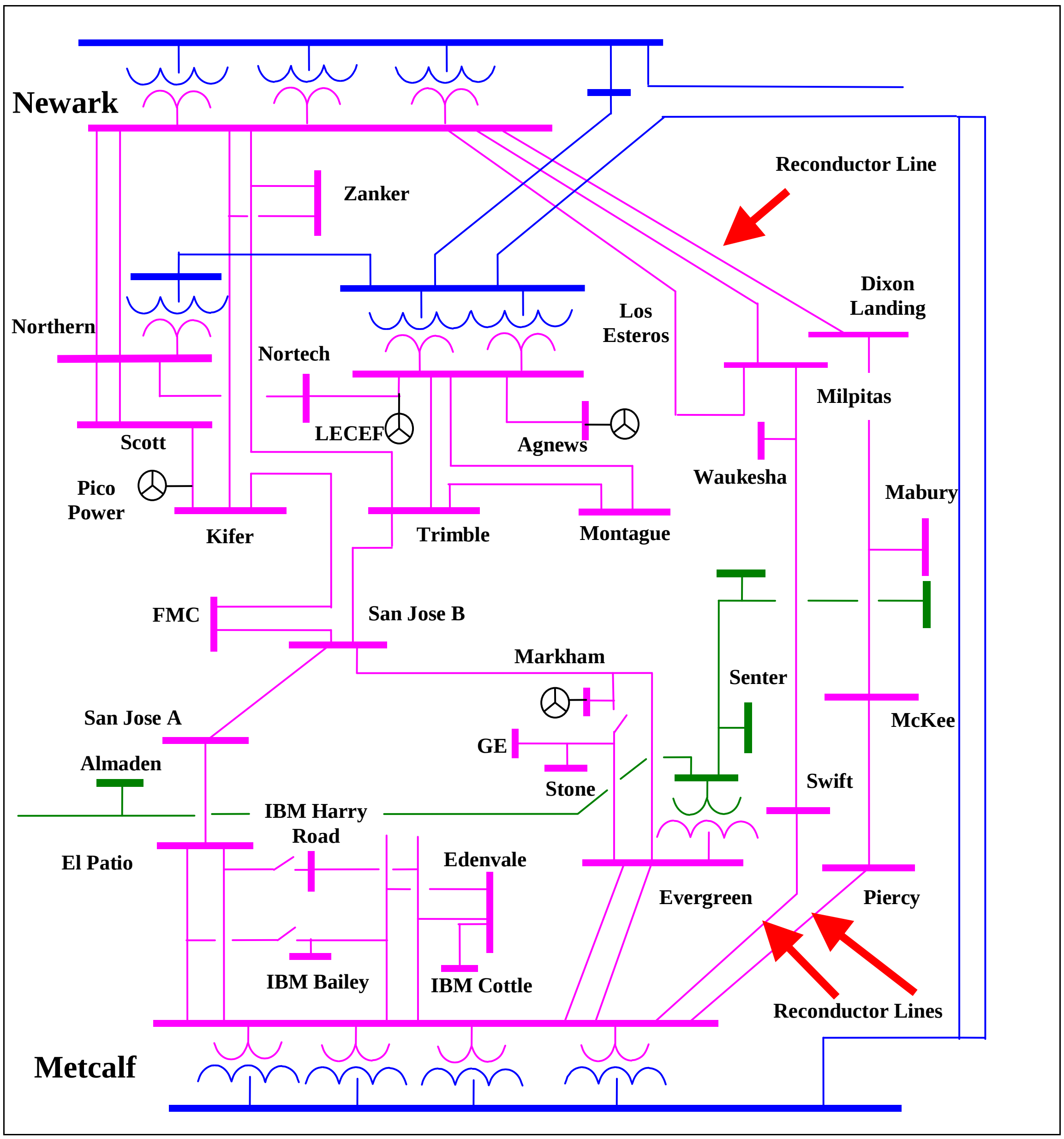


Figure 3-51: Scope Diagram

T981: Monta Vista – Los Altos 60 kV Reconductoring
(Expected In Service Date - May 2012)

PROJECT INFORMATION

The project scope is to transfer Palo Alto to be served from Monta Vista and reconductor 2 miles of the Monta Vista – Loyola section of the Monta Vista – Los Altos 60 kV Line with 715 Al conductors or larger. If necessary, the project scope may also include the upgrade of associated line terminal equipment to accommodate the higher rating. In addition, environmental and land permits may be required to complete the reconductoring work.

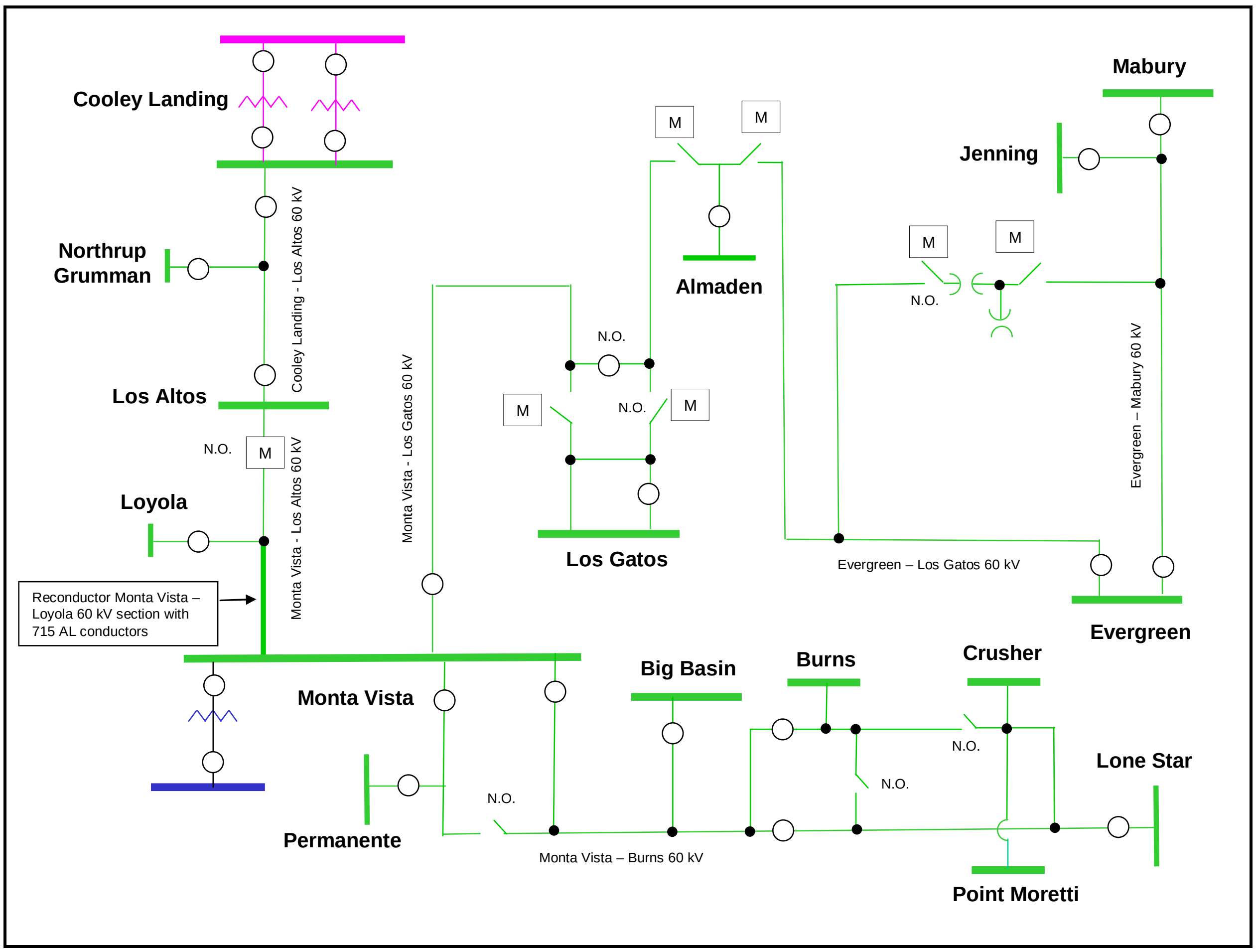


Figure 3-52: Scope Diagram

T985B: Rio Oso 230/115 kV Transformer Upgrades
(Expected In Service Date: May 2012)

PROJECT INFORMATION

The project scope is to replace the Rio Oso 230/115 kV transformers (Nos. 1 and 2) with three-phase, 420 MVA rated, transformer units.

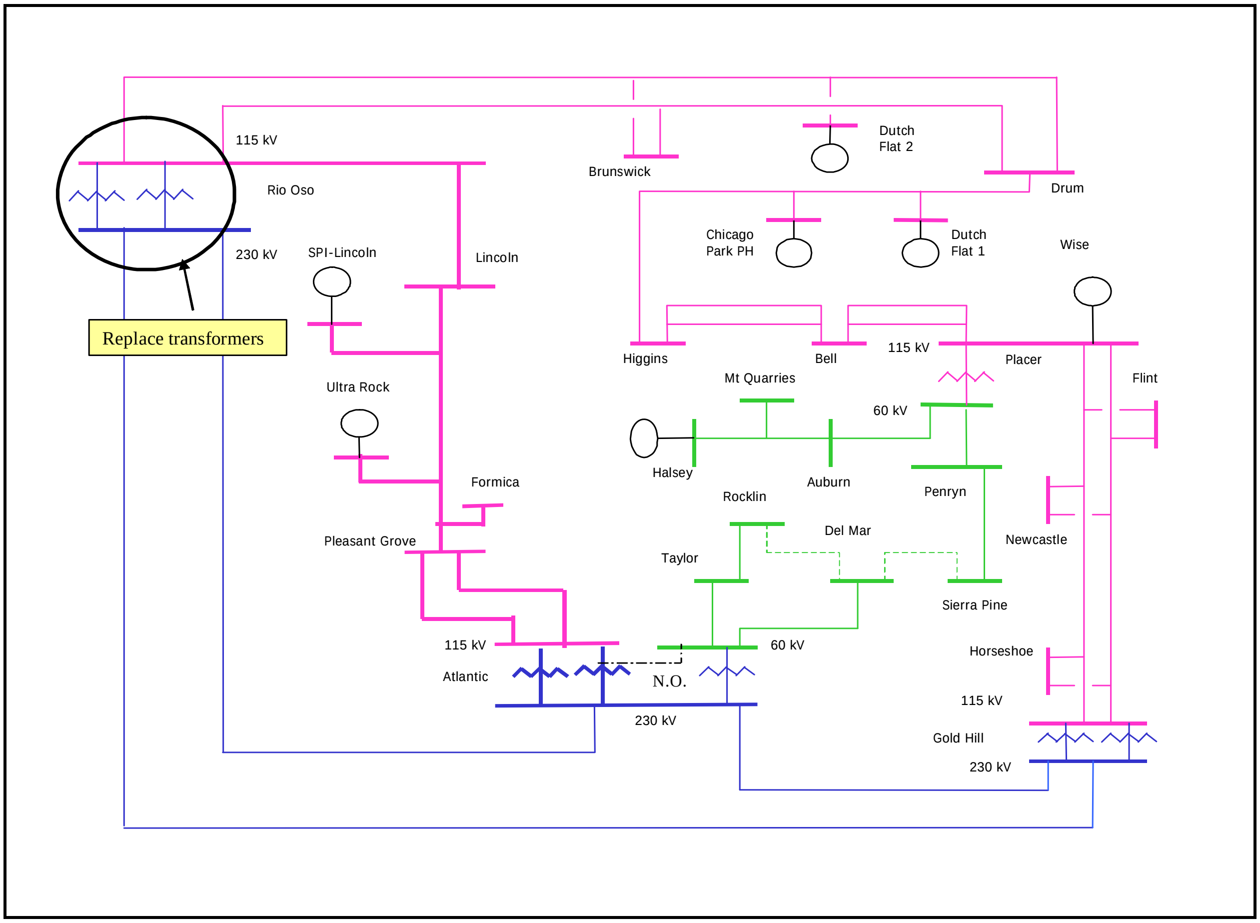


Figure 3-53: Scope Diagram

T991: Contra Costa – Moraga 230 kV Line Reconductoring

(Expected In Service Date –May 2013)

PROJECT INFORMATION

The project proposal is to reconductor the Contra Costa – Moraga 230 kV Line Nos. 1 and 2 (approximately 25 miles) with 954 ACSS conductors or equivalent.

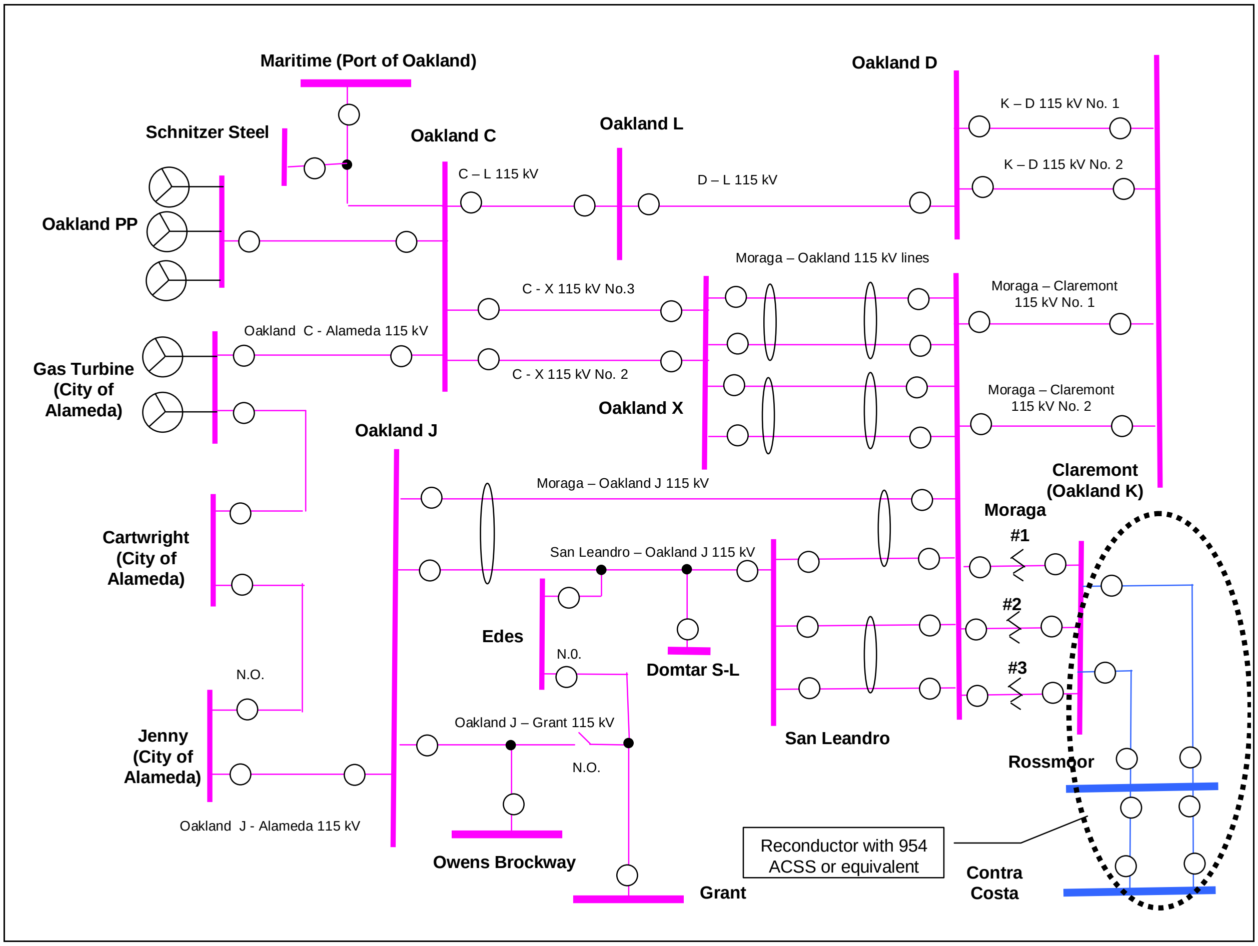


Figure 3-54: Scope Diagram

T197B: Ignacio – San Rafael and Ignacio – Las Gallinas 115 kV Reconductoring

(Expected In Service Date –May 2013)

PROJECT INFORMATION

The project scope is to reconductor the Ignacio – San Rafael 115 kV Nos. 1 and 3 lines with larger capacity rated conductors. If necessary, associated line terminal equipment would be upgraded. In addition, the project scope would require obtaining any necessary environmental and land permits to complete the reconductoring work.

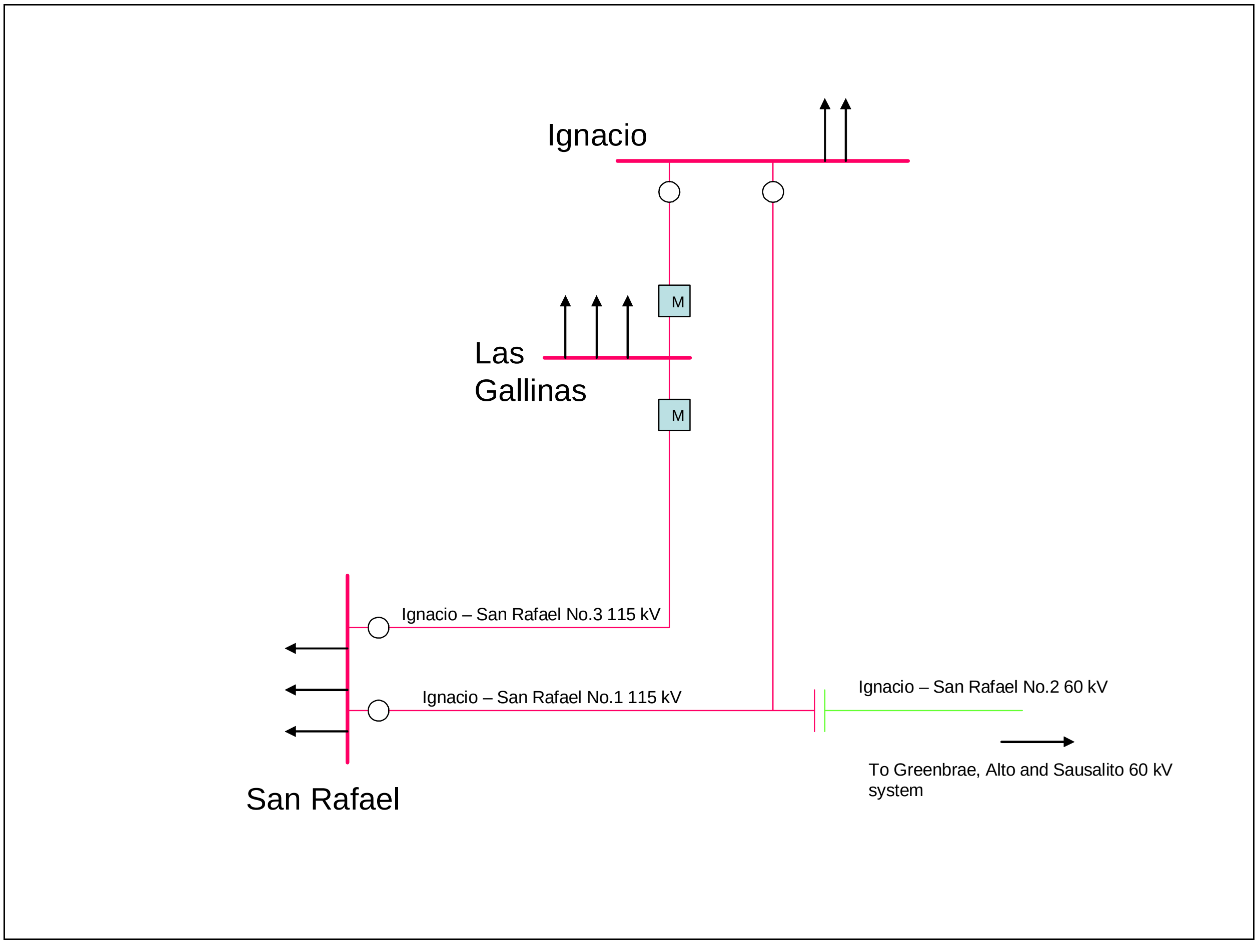


Figure 3-55: Scope Diagram

T603B: Vaca Dixon-Lakeville 230 kV Reconductoring

(Expected In Service Date - May 2013)

PROJECT INFORMATION

This project proposes to reconductor the Vaca-Lakeville and Tulucay-Vaca 230 kV Lines with a higher capacity conductor.

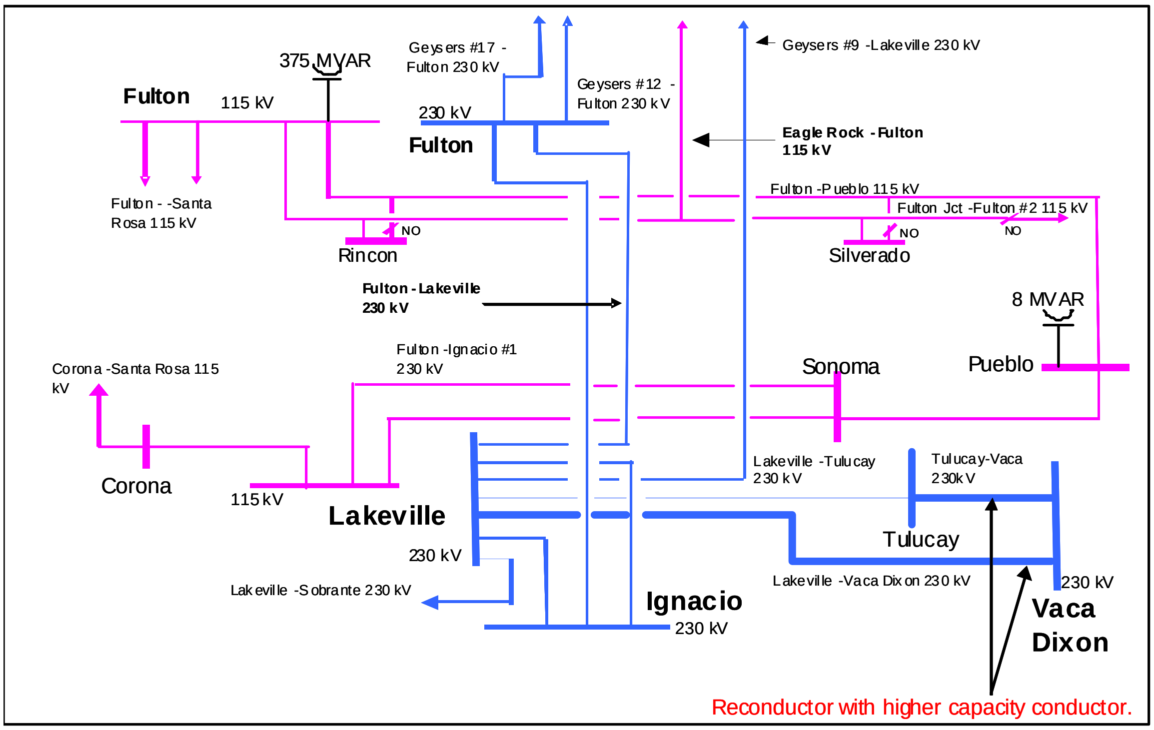


Figure 3-56: Scope Diagram

T992: San Leandro – Oakland "J" 115 kV Line Reconductoring
(Expected In Service Date –May 2015)

PROJECT INFORMATION

The project scope is to reconductor a section of the San Leandro – Oakland "J" 115 kV Line (approximately 6 miles) to 477 ACSS or equivalent.

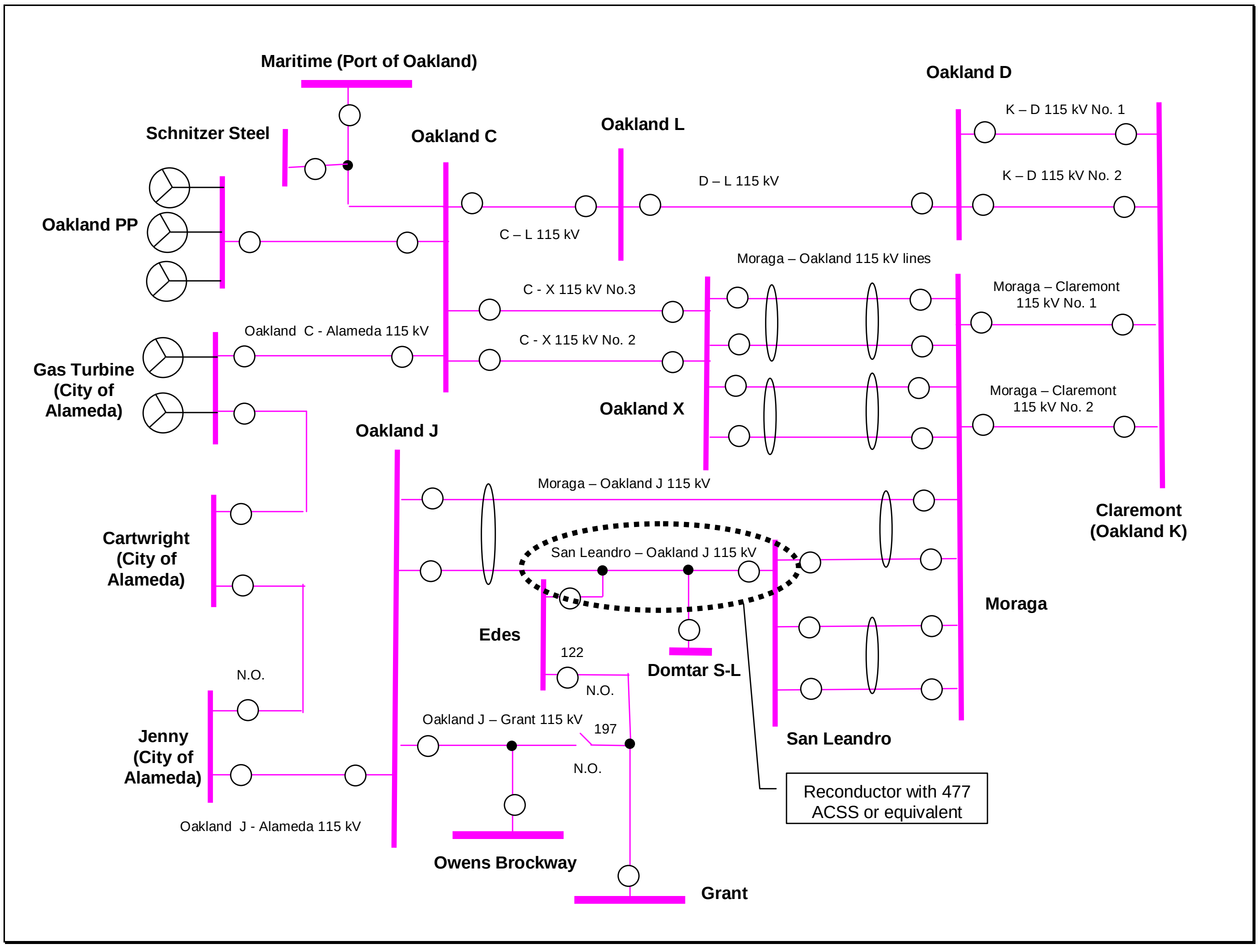


Figure 3-57: Scope Diagram

T986: Woodward 115 kV Reinforcement

(Expected In Service Date 2016)

PROJECT INFORMATION

This project proposes to reconductor the limiting sections of the Kerckhoff – Clovis – Sanger and the Herndon – Woodward 115 kV lines with larger capacity rated conductors

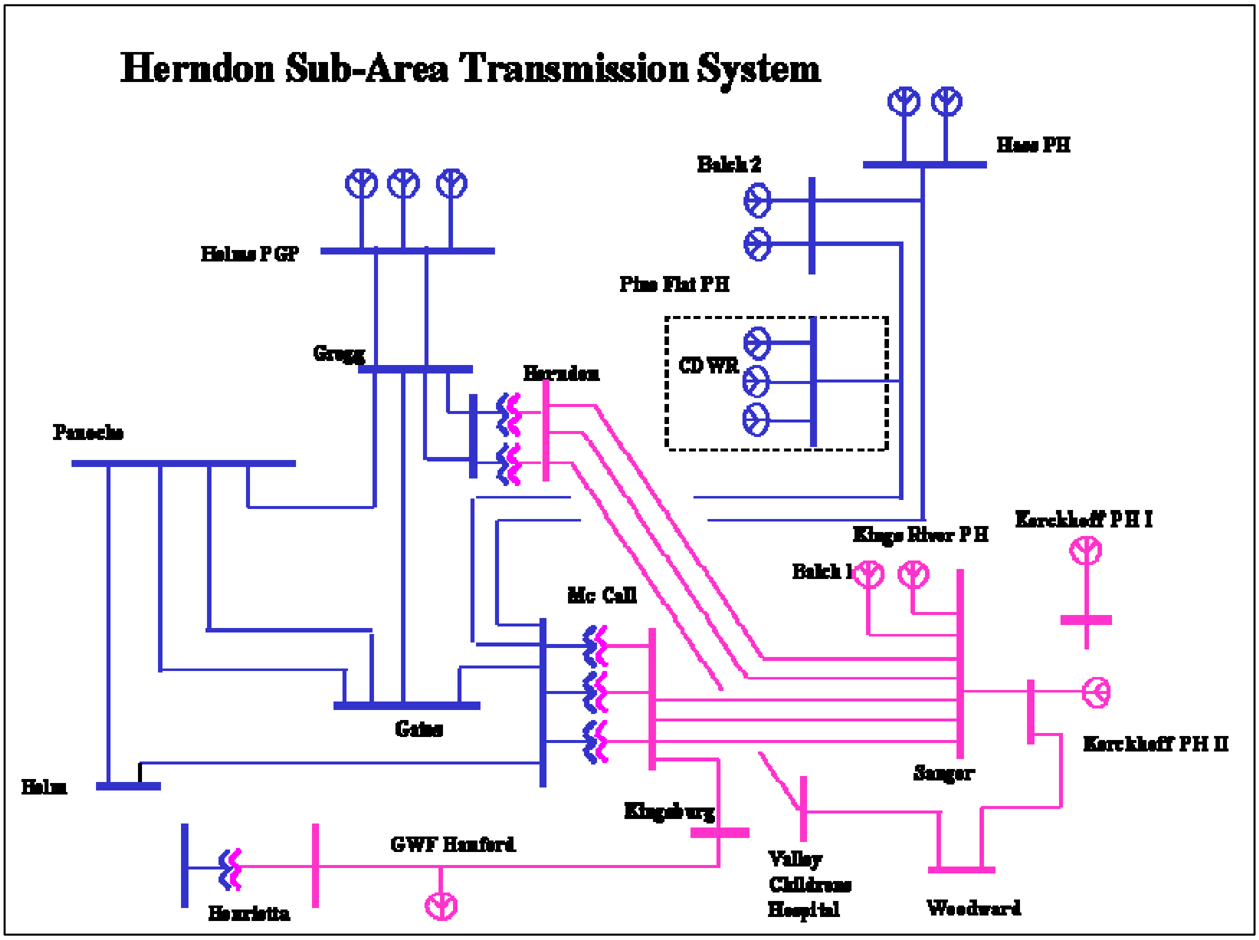


Figure 3-58: Scope Diagram

CHAPTER 4

Table of Contents

2009 Projects

Larkin Circuit Breaker No. 192

TARGETED IN-SERVICE DATE

March 2009

PURPOSE AND BENEFIT

Reliability – Operational Flexibility and CAISO Short Term Plan

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROJECT

The proposed project scope that is needed to operate Larkin CB 192 normally closed includes the following work:

- Install four sets (12) of "slip-on" current transformers, "doughnut" type 3000/5 MR, on Larkin distribution transformer banks Nos. 3, 4 and 6. And circuit breaker 172 for XY-1 cable at switch 171.
- Install (10) boxes of dual overcurrent SEL-501 relays on distribution bank Nos. 1, 2, 3, 4, and 6.
- Adjust current transformer ratios and metering replacement at Martin, Potrero and Mission Substations.

This project is expected to cost between $1M and $5M.

BACKGROUND

Over 60% of electric demand in the City of San Francisco ("The City") is supplied by a 115kV transmission network that is fed from Martin Substation. Larkin Substation, located at the corner of Larkin and Eddy Streets, is one of five substations connected to that network. Larkin is a six-bank distribution substation that roughly supplies about 25% of the demand in the City. Larkin is fed by four 115 kV underground transmission lines: the AY-1 and AY-2 Lines from Potrero P.P. Substation, the XY-1 Line from Mission Substation and the HY-1 Line from Martin Substation.

The 115 kV bus at Larkin that connects the four 115 kV lines and the six distribution transformers is configured in three sections (D, E and F). There are three sectionalizing circuit breakers along the 115 kV bus, with two breakers (Nos. 172 and 192) normally open. This configuration was developed due to concerns about high fault duties on both the transmission and distribution switchgear in the substation.

One major side effect of this "split bus" configuration is that there is a lower level of station reliability. Power flow on the HY-1 Line from Martin to Larkin is also reduced.

This line is one of five 115 kV "import" lines that deliver power from Martin up into the City.[1] With no generation on-line in the City during peak demand periods this year, the HY-1 Line would still only load to 60% of its normal rating, while the other four import lines would load to 95% to 101% of their normal ratings.

Preliminary engineering analyses have determined that normally closing 115 kV Circuit Breaker (CB) No. 192 at Larkin will not increase 115 kV fault duties to unacceptable levels, although some equipment modifications will be needed at several substations. Fault duties on the 12 kV distribution switchgear, which are already a concern, will increase less than 1% if CB No. 192 is closed.

Station reliability will improve with CB No. 192 normally closed. Also, while loading on the HY-1 Line will increase (by about 15%), loading on the four other import lines will decrease (by about 5% on each line). The decreased loading on other import lines results in less reliance on in-City generation. This is particularly helpful when performing maintenance on any of the other four import lines. Furthermore, closing in Larkin CB No. 192 will provide a large benefit towards increasing clearance windows with respect to Potrero generation requirements during the San Francisco 115 kV Recabling Project.

Based on the increased capability to provide network support to the San Francisco 115 kV transmission system and increased operating flexibility to perform clearances and routine bus maintenance, it is recommended to upgrade the protection equipment at Larkin, Martin, and Potrero P.P. Substations.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

[1] The four other import lines out of Martin are: the AHW-1 and AHW-2 lines to Potrero P.P. and Bayshore Substations and the HP-1 and HP-3 lines to Hunters Point Substation. These other four 115 kV underground lines are part of the San Francisco 115 kV Recabling Project.

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended. This alternative does not address the potential reliability concern.

PROJECT SCHEDULE

- Environmental and Permitting Processes – None
- Design – Start design July 2008. Complete design March 2009
- Major Equipment – Long lead time materials ordered June 2008. Long lead time materials received October 2008.
- Construction – Start October 2008, complete by March 2009
- Operation Date – March 2009

KEY ISSUES

- Land-Use Restrictions – None
- Environmental Concerns – None
- Special Metering or Protection – TBD
- Common Mode Exposure Items – None
- Interaction with other Projects – TBD

GEPSLF MODELING INFORMATION

```
# Closing Larkin CB 192, between bus section E and F
#CLOSE  "FBUS", "TOBUS", "CKT="
CLOSE   33201   33202     1
```

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagram
2. Power Flow Summary
3. Pre and Post Project Power Flow Plots

Attachment 1: Scope Diagram

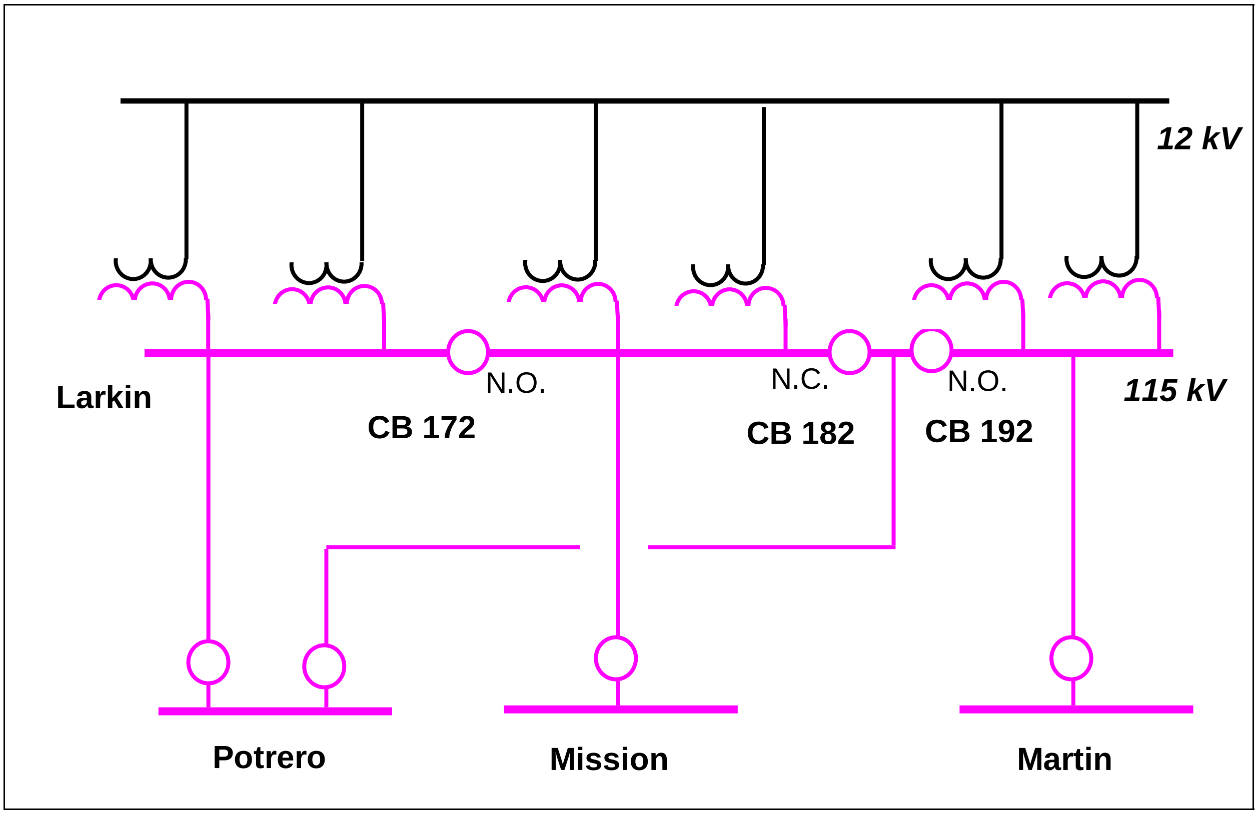


Figure 4-1: Schematic Diagram of Larkin Substation

Attachment 2: Power Flow Summary

Table 4-1: Power Flow Summary

Contingency	Facility Affected	Facility Rating (Post-Project)	2010 (Pre-Project)	2010 (Post-Project)
TBC and A-H-W # 1 out (L-1-1)	A-H-W # 2	SE Rating 844 Amps	105%	99%
TBC and Martin-Hunters Point # 1 or # 3 out (L-1-1)	HP-1 or HP-3	SE Rating 874 Amps	84%	79%

Attachment 3: Pre and Post Project Power Flow Plots

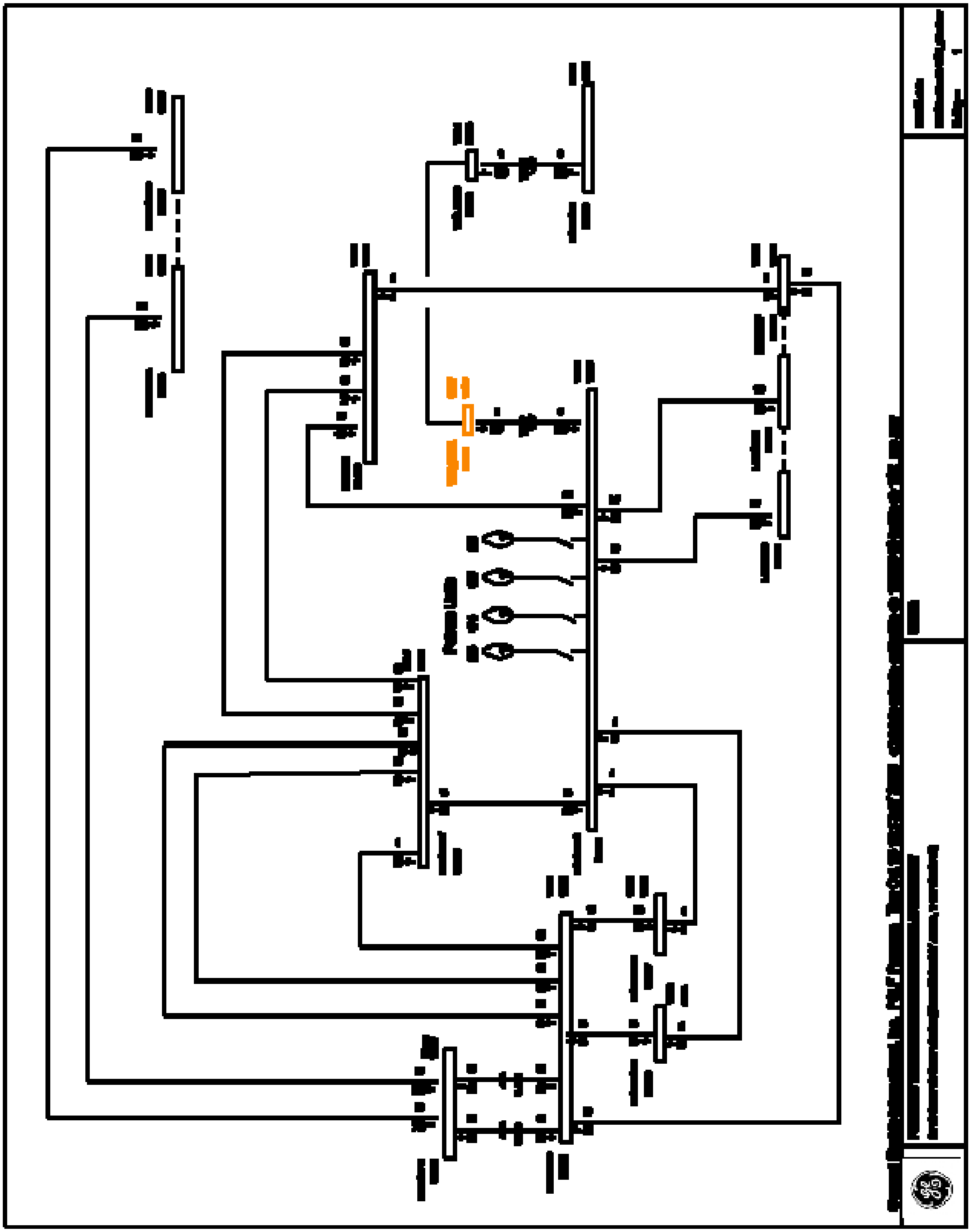


Figure 4-2: All Facilities In-Service, Year 2010 (Pre-Project)

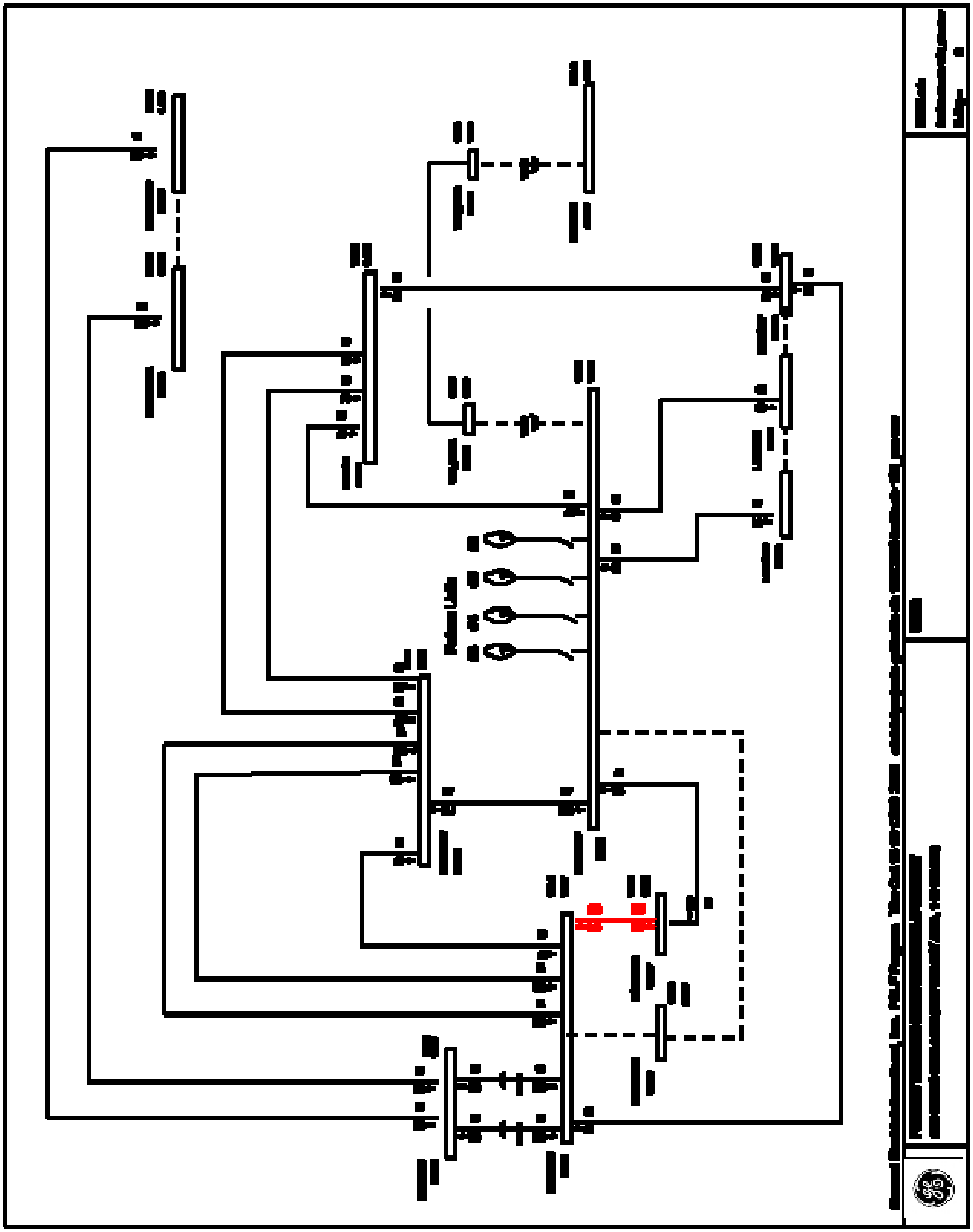


Figure 4-3: Outage of Trans Bay Cable and Martin-Bayshore-Potrero # 1 115 kV Cable (N-1-1), Year 2010 (Pre-Project)

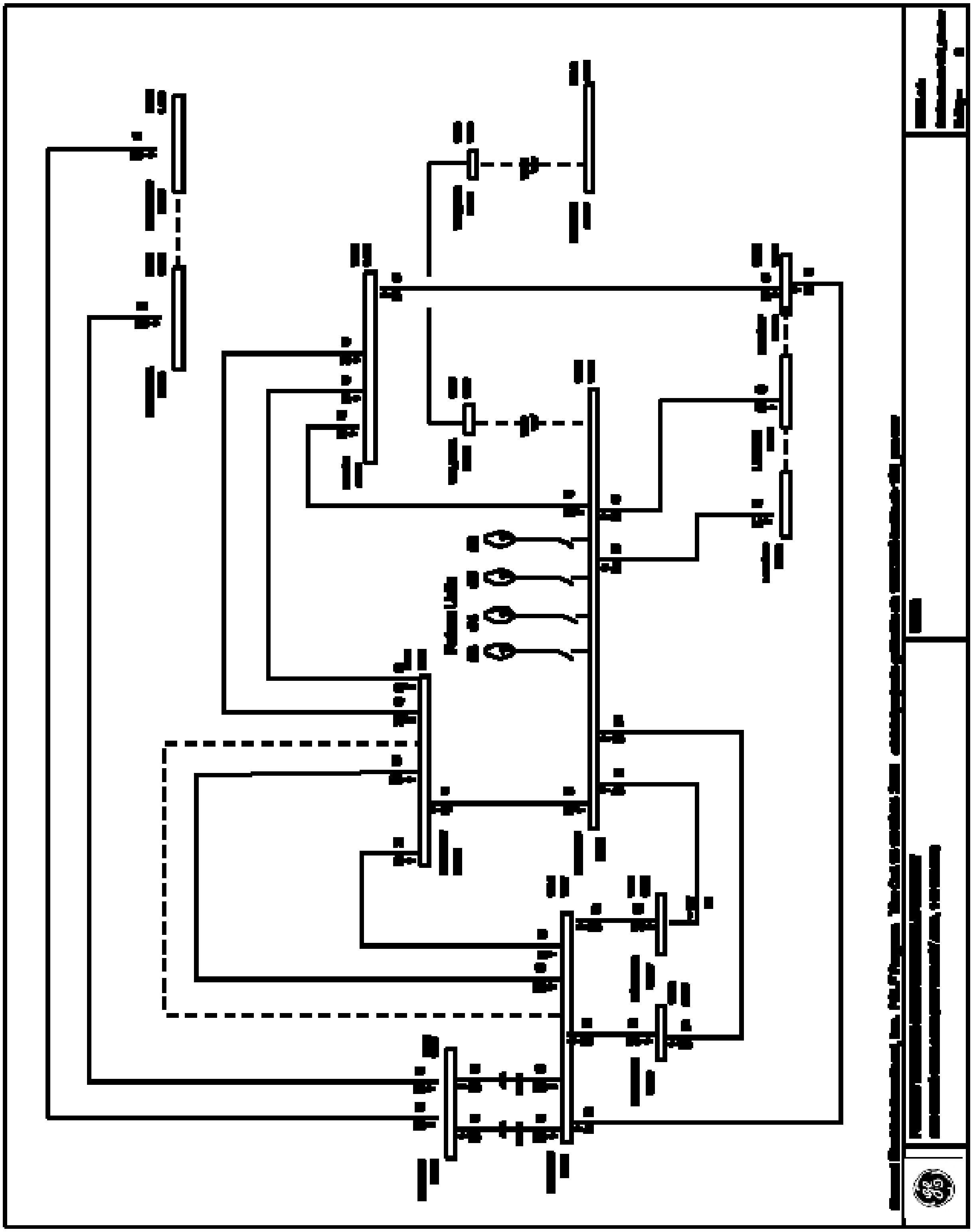


Figure 4-4: Outage of Trans Bay Cable and Martin-Hunters Point # 1 115 kV Cable (N-1-1), Year 2010 (Pre-Project)

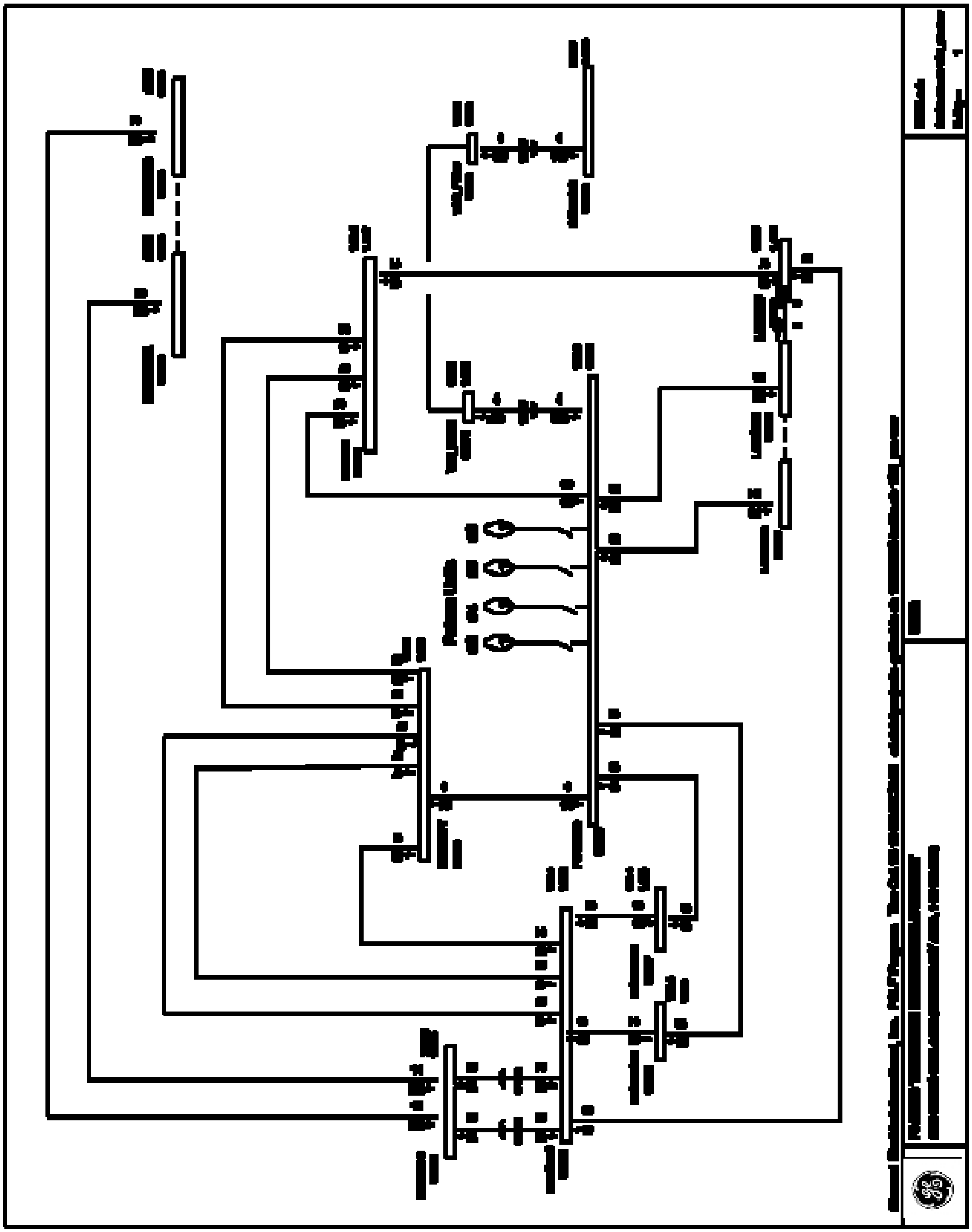


Figure 4-5: All Facilities In-Service, Year 2010 (Post-Project)

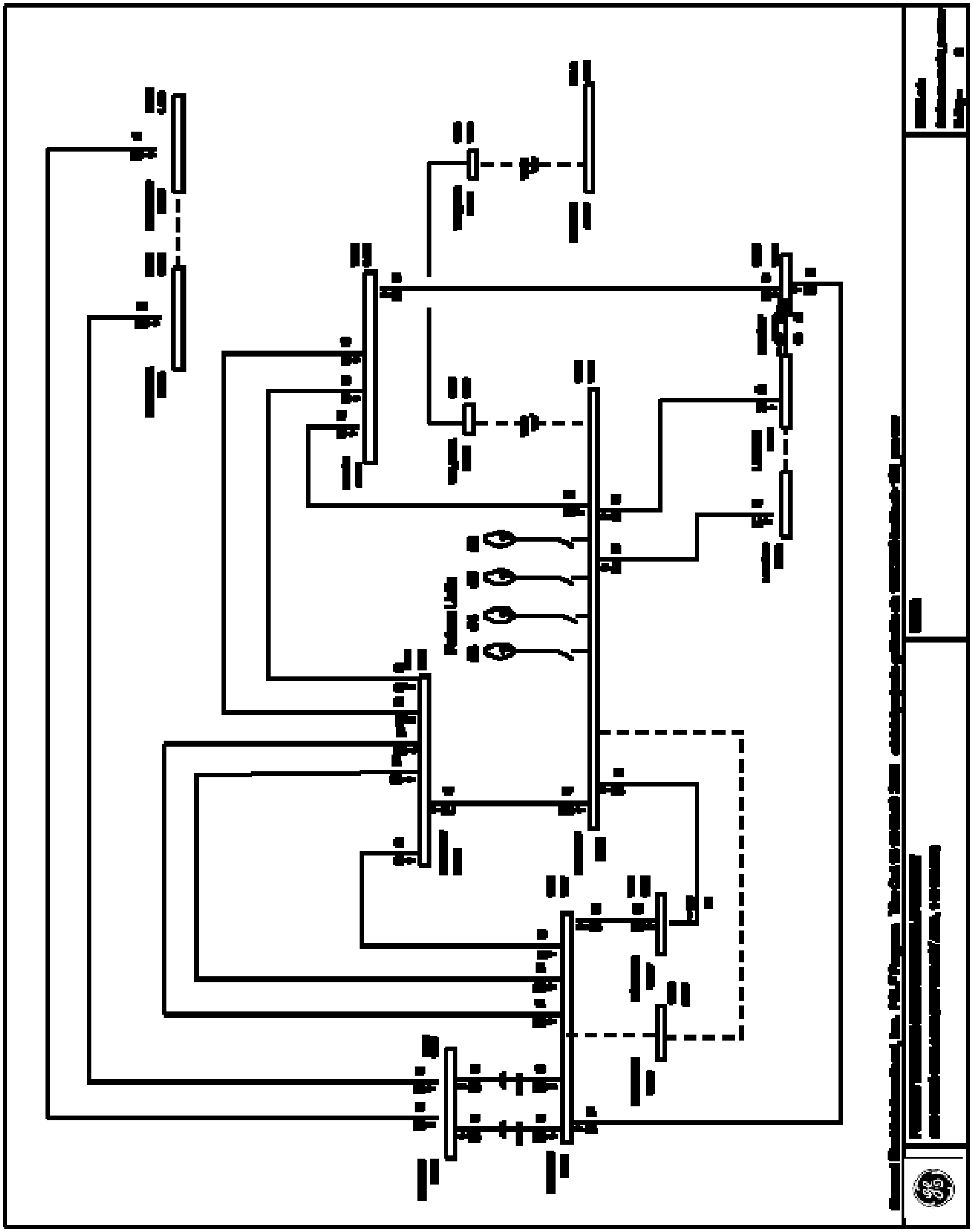


Figure 4-6: Outage of Trans Bay Cable and Martin-Bayshore-Potrero # 1 115 kV Cable (N-1-1), Year 2010 (Post-Project)

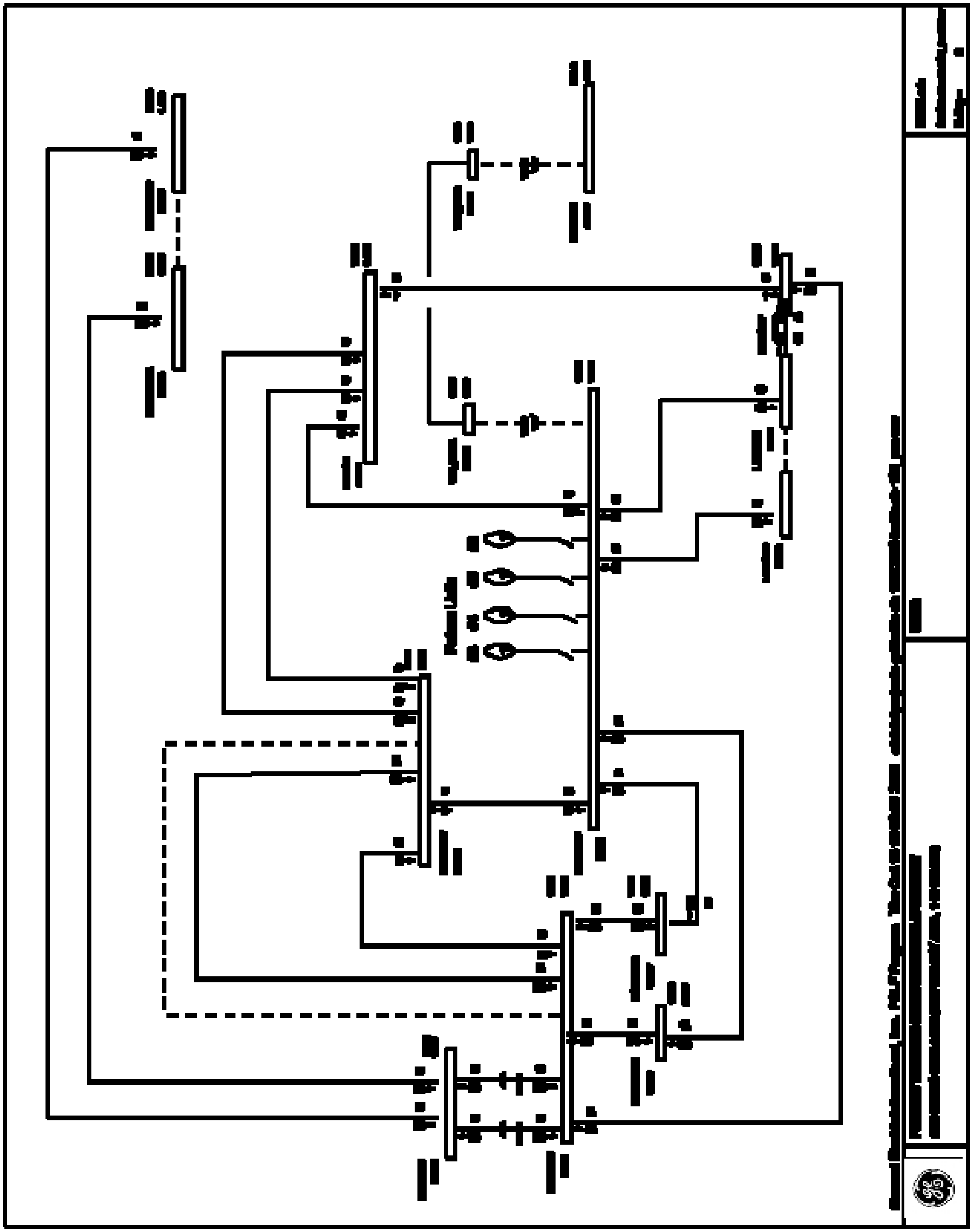


Figure 4-7: Outage of Trans Bay Cable and Martin-Hunters Point # 1 115 kV Cable (N-1-1), Year 2010 (Post-Project)

Ignacio 115 kV Bus Reconfiguration

TARGETED IN-SERVICE DATE

May 2009

PURPOSE AND BENEFIT

Reliability – Operational Flexibility

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROJECT

The project scope is to extend the existing Ignacio 115 kV bus by two bays, re-terminate a 115 kV line and a 115/60 kV transformer to new positions and to replace two existing 115 kV circuit breakers.

This project is expected to cost between $5M and $6M.

BACKGROUND

Ignacio Substation, located in northern Marin County, is connected to the transmission grid via four 230 kV power lines. Three of these lines import power from the Geysers generation area. The fourth 230 kV line connects Ignacio to Sobrante Substation in the Bay Area. Ignacio Substation is the key electric facility in serving electric customers in Marin and portions of Sonoma County. There are currently fifteen distribution substations served by Ignacio Substation.

The Ignacio 115 kV bus is comprised of a main and auxiliary bus with one bus sectionalizing breaker. Both 115/60 kV Transformers Nos. 1 and 3 are connected to the same bus section. Under this bus configuration, an outage of 115 kV bus section "E" will result in the loss of both 115/60 kV transformers, all connected 60 kV customer loads and some 115 kV connected customer loads. This outage would impact over 76,000 PG&E customers in Marin County.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO Grid Planning Criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended. It does not address a 115 kV bus outage which impacts over 76,000 electric customers served from Ignacio Substation.

PROJECT SCHEDULE

- Environmental and Permitting Processes – None
- Design – July 2008
- Major Equipment – March 2008
- Construction – November 2008
- Operation Date – May 2009

KEY ISSUES

- Land-Use Restrictions – None
- Environmental Concerns – None
- Special Metering or Protection – None
- Common Mode Exposure Items – None
- Interaction with other Projects – Ignacio 115 kV MPAC Project.

GEPSLF MODELING INFORMATION

N/A

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagram
2. Demand Forecast

Attachment 1: Scope Diagram

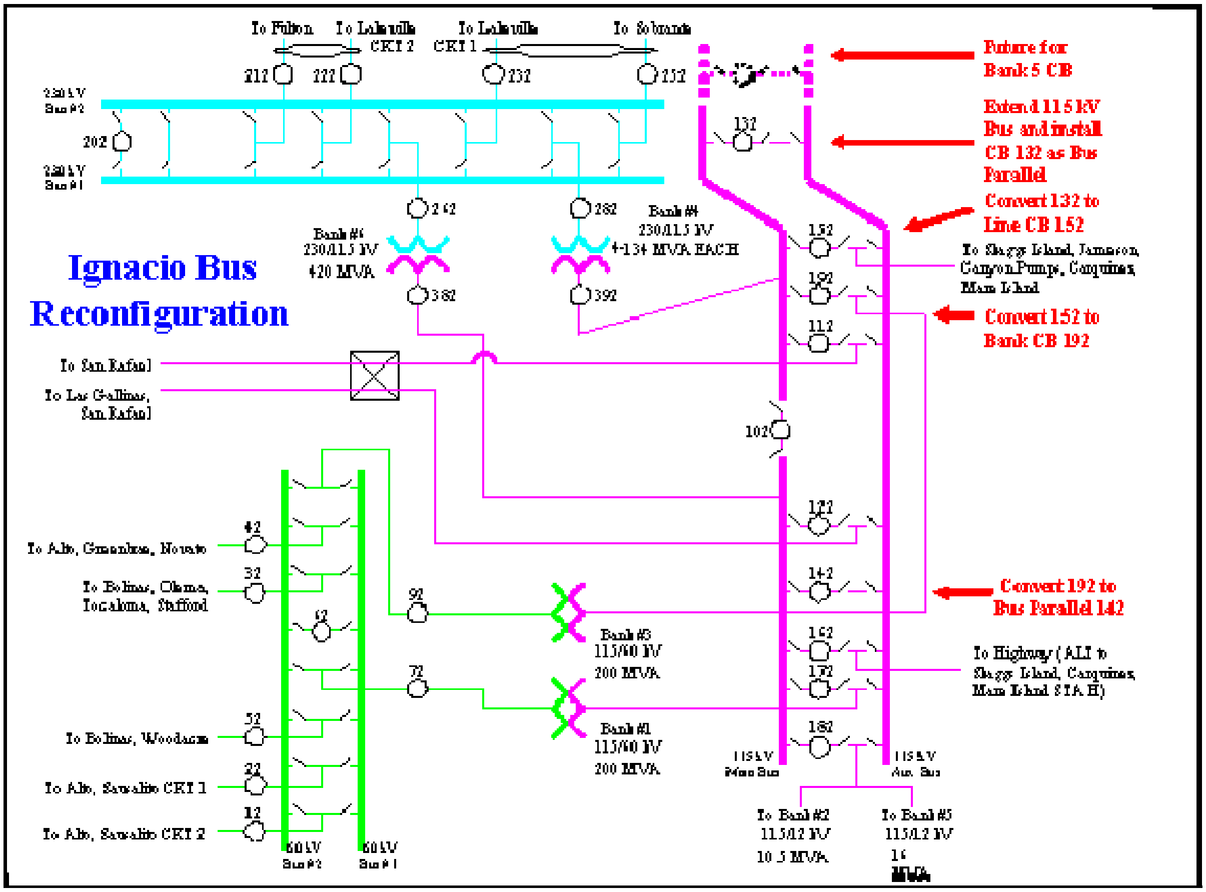


Figure 4-8: Ignacio Bus Configuration

Attachment 2: Demand Forecast

Table 4-2: Area Demand Forecast

Substation	2009 (MW)	2010 (MW)	2011 (MW)	2012 (MW)	2013 (MW)	Growth Rate (MW/Year)
Novato	21.0	21.2	21.5	21.7	21.9	0.2
Stafford	21.3	21.5	21.8	22.0	22.2	0.2
Olema	3.3	3.4	3.4	3.4	3.5	0.1
Bolinas	1.5	1.5	1.5	1.6	1.6	0.0
Woodacre	8.1	8.2	8.3	8.4	8.5	0.1
Greenbrae	23.7	24.0	24.2	24.5	24.8	0.3
Alto	36.5	36.9	37.4	37.8	38.2	0.4
Sausalito	11.2	11.3	11.4	11.6	11.7	0.1
San Rafael	71.5	72.2	73.1	73.9	74.7	0.8
Las Gallinas	36.2	36.5	37.0	37.4	37.8	0.4
Highway	46.1	46.7	47.5	48.3	49.3	0.8
Carquinez	24.5	24.8	25.3	25.7	26.2	0.4
Mare Island	4.2	4.2	4.2	4.2	4.2	0.0
Total	**309**	**312**	**317**	**321**	**325**	**3.9**

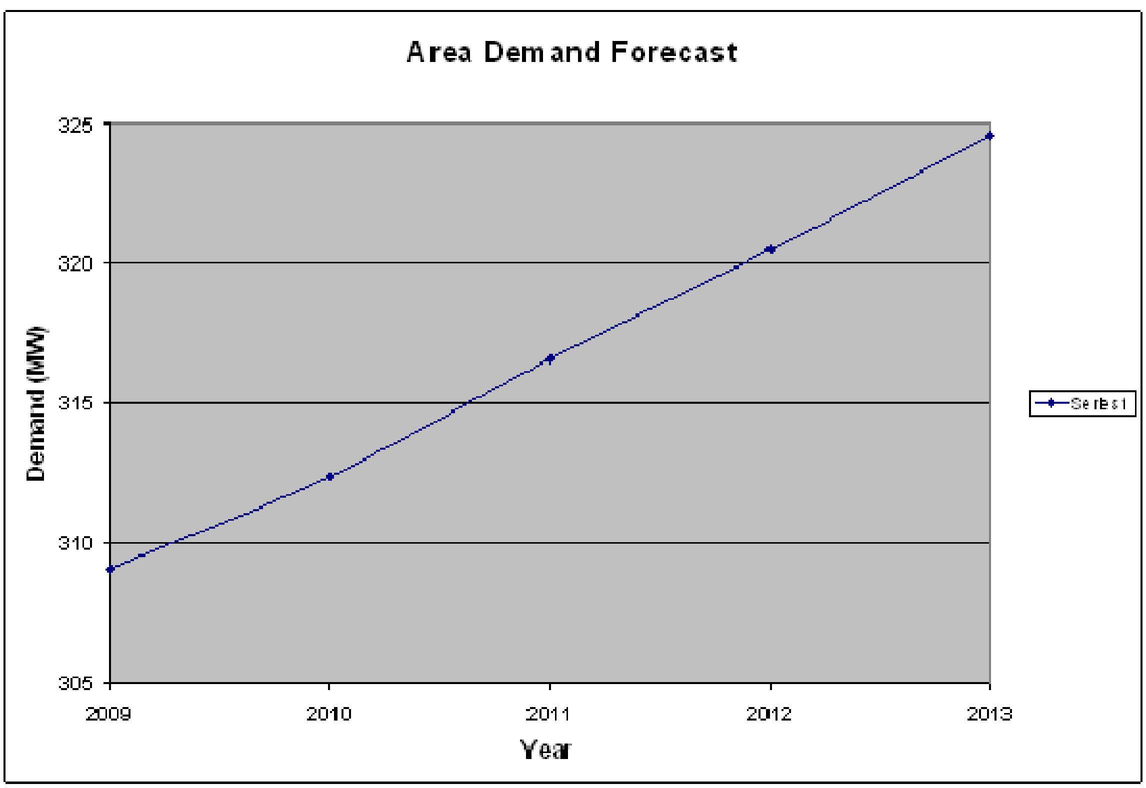


Figure 4-9: Plot of Area Forecast

Higgins 115 kV Circuit Breaker Installation

TARGETED IN-SERVICE DATE

March 2009

PURPOSE AND BENEFIT

Reliability – Operational Flexibility

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROPOSED PROJECT

The proposed project scope is to:

- Replace Higgins MOAS Nos. 146 and 156 with SCADA controlled circuit breakers.
- Build new 115 kV transfer bus.
- Upgrade Higgins Sw. 127 and 129 to SCADA switches.
- Install an SPS scheme to guard against a Placer-Gold Hill 115 kV Line overload.

The project is expected to cost between $1M and $5M.

BACKGROUND

Higgins Substation is located in the City of Lake of the Pines, within Nevada County, which is approximately 40 miles northeast of Sacramento. This distribution substation serves approximately 8,400 customers in the City of Lake of the Pines and the Alta Sierra community. Higgins is connected to the transmission grid via the Drum-Bell 115 kV Line and serves electric customers via three 115/12 kV distribution transformers. In 2006, Higgins reached an electric peak demand of 38 MW and is projected to annually increase at a rate of 0.8 MW or 2% per year.

The Drum-Bell 115 kV Line is comprised of 44 miles (including all tap lines) of various conductor sizes and is constructed mainly on lattice steel towers. Originating from Drum Substation, the 115 kV transmission line traverses in a northeast to southwest direction along Highways 80 and 49. Higgins 115 kV line protection is comprised of MOAS Nos. 146 and 156. Under this bus arrangement, the customers at Higgins experience all outages that affect the Drum-Bell 115 kV Line.

Review of the outage data collected by the Company's outage review process shows the Drum-Bell 115 kV Line is subjected to an average of 5 outages, which translates to 42 outage minutes per year. The installation of 115 kV circuit breakers will improve service reliability to customers served by Higgins Substation. It is also recommended to build a 115 kV transfer bus and relocate Higgins Switch No. 169. This will provide the operating flexibility to perform breaker maintenance work and conforms to substation standard requirements.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended because it does not address the capacity issues.

Alternative 2: Convert Higgins 115 kV bus to a ring bus configuration

In addition to upgrading Higgins MOAS Nos. 146 and 156 with 115 kV circuit breakers, this alternative would convert the Higgins 115 kV single bus to a ring bus arrangement by upgrading the Higgins Circuit Switcher Nos. 136 and 166 with circuit breakers. This alternative is projected to cost $6 million and is not recommended because of its high cost and incremental reliability benefits in comparison to the preferred alternative.

PROJECT SCHEDULE

- Environmental and Permitting Processes – Not Applicable
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – January 2009

KEY ISSUES

- Land-Use Restrictions – None
- Environmental Concerns – None
- Special Metering or Protection - TBD
- Common Mode Exposure Items – None
- Interaction with other Projects or Studies – None

GEPSLF MODELING INFORMATION

N/A

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagram
2. Project Power Flow Plots

Attachment 1: Scope Diagrams

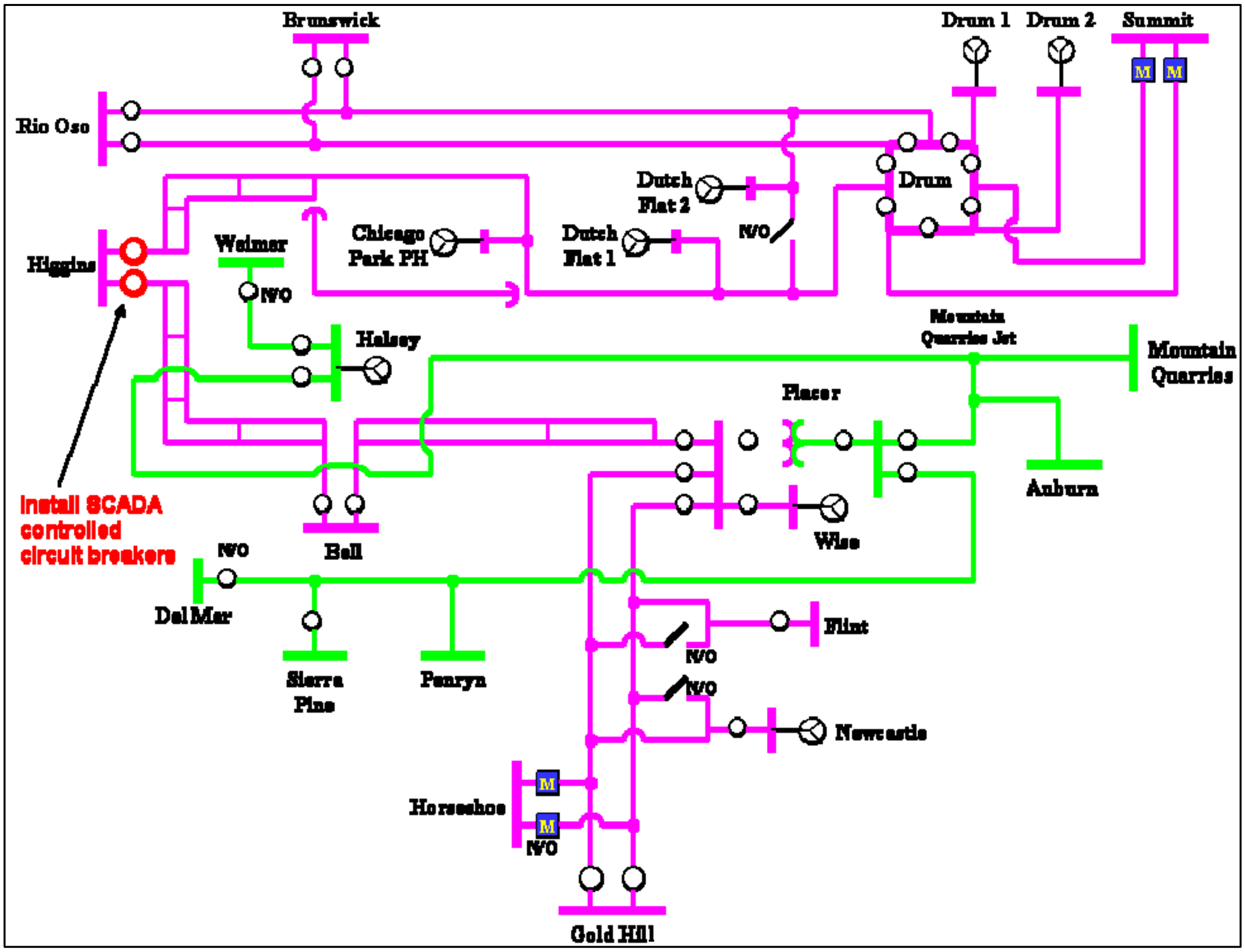


Figure 4-10: Scope Diagram

Attachment 2: Project Power Flow Plots

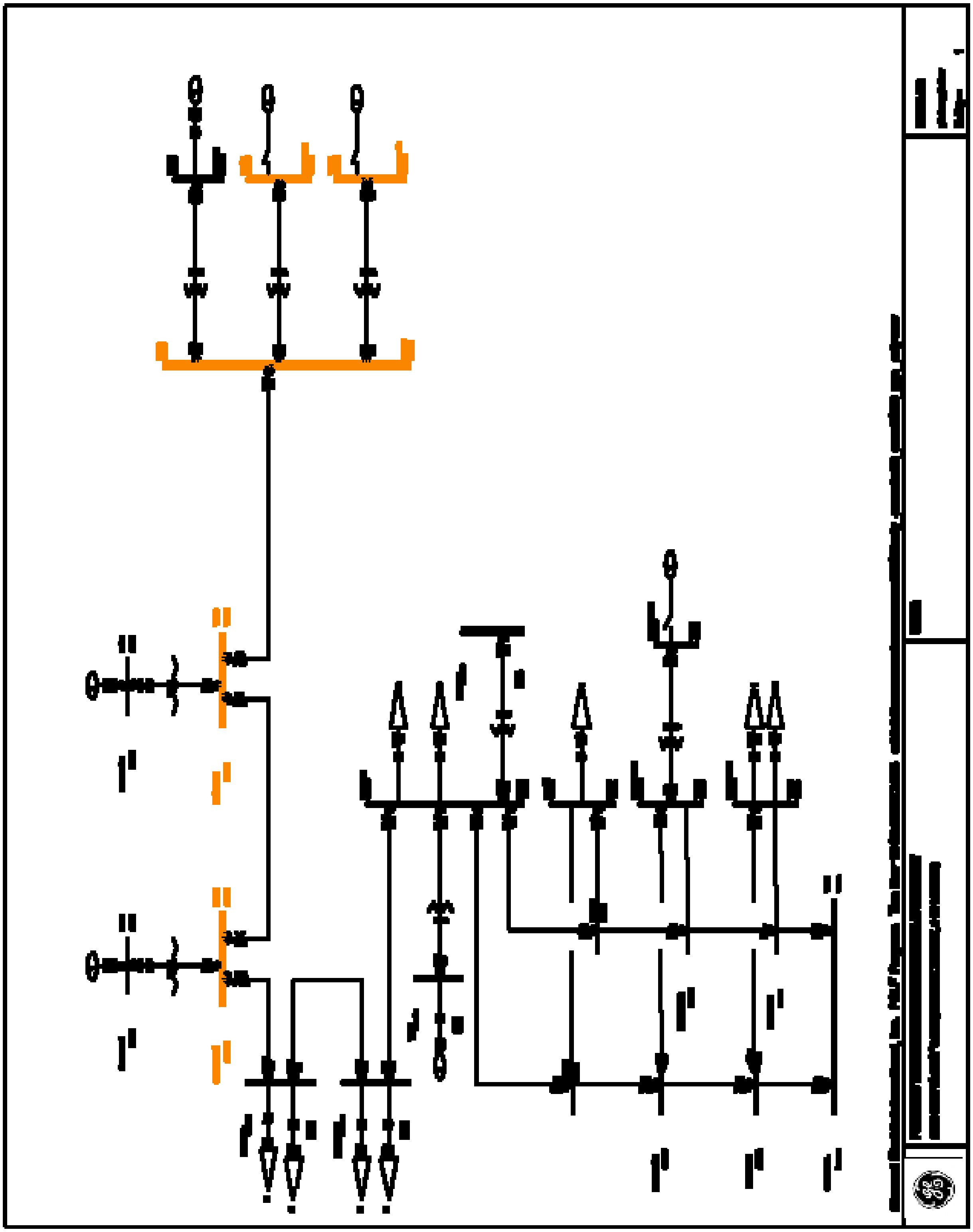


Figure 4-11: Pre and Post Project – Normal Conditions

Camden 70 kV Breaker Installation

TARGETED IN-SERVICE DATE

May 2009

PURPOSE AND BENEFIT

Reliability – NERC Compliance and Operational Flexibility

PROJECT CLASSIFICATION

This is a new project

DESCRIPTION AND SCOPE OF PROPOSED PROJECT

Install a 70 kV bus with circuit switcher with SCADA, and two 70 kV line circuit breakers with SCADA at Camden Substation.

The estimated cost for this alternative is between $2M and $4M.

BACKGROUND

Camden Substation, located near the city of Riverdale in Fresno County is approximately 20 miles south of Fresno on State Highway 41. It is a distribution substation that serves the greater Riverdale area load. Camden is connected to the transmission grid via the Caruthers-Kingsburg 70 kV Line. Camden Substation has two 70/12 kV transformer banks that support the Lemoore distribution planning area through four distribution feeders.

The Caruthers-Kingsburg 70 kV Line is comprised of approximately 40 circuit miles (including all tap lines) of various conductor sizes and is constructed mainly on single wood poles. Originating from Kingsburg Substation, the 70 kV transmission line traverses east to west along Davis Ave. The 70 kV transmission line then branches north from Camden Junction to a normally open Caruthers CB No. 22 and south to a normally open Lemoore NAS SW No. 55. The Caruthers-Kingsburg 70 kV Line serves Camden Substation, which had a projected electric peak demand of about 29.3 MW for the summer of 2008. Camden is tapped on the Caruthers-Kingsburg 70 kV Line and does not have 70 kV line sectionalizing capability. Under this arrangement, electric customers (3,617) served from Camden can experience all momentary and sustained outages on the Caruthers-Kingsburg 70 kV Line.

Review of the outage data collected by the Company's outage review process shows the Caruthers-Kingsburg 70 kV Line is subjected to an average of 5 outages and 614,000 outage minutes per year. Installing new 70 kV circuit breakers with SCADA at Camden will provide the sectionalizing capability to isolate a transmission line fault. As a result, transmission line caused outages which normally impact Camden will be significantly reduced. However, it will not eliminate all line outages as Camden will still be served on a radial line until the completion of the Caruthers-Kingsburg 70 kV Line Reconductor Project. This project will mitigate the impacts of a bus and bank outage.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended. It does not address a 70 kV line outage which impacts over 3,600 electric customers at Camden Substation.

Alternative 2: Install 70 kV ring bus configuration at Camden Substation

This alternative proposes to install a 70 kV ring bus configuration at Camden Substation. This would require four 70 kV circuit breakers with SCADA, and bus structures in excess of those required for Alternative 2. This alternative is projected to cost $6 million and is not recommended because of its high cost and incremental reliability benefits in comparison to the preferred alternative.

PROJECT SCHEDULE

- Environmental and Permitting Processes – None
- Design – Complete
- Major Equipment – Received
- Construction – In process
- Operation Date – May 2009

KEY ISSUES

- Land-Use Restrictions – None
- Environmental Concerns – None
- Special Metering or Protection – None
- Common Mode Exposure Items – None
- Interaction with other Projects or Studies – This project, by itself, will not eliminate all line outage impacts as Camden will still be served on a radial line until the completion of the Caruthers-Kingsburg 70 kV Line Reconductor Project.

GEPSLF MODELING INFORMATION

Not Applicable

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagram
2. Demand Forecast

Attachment 1: Scope Diagram

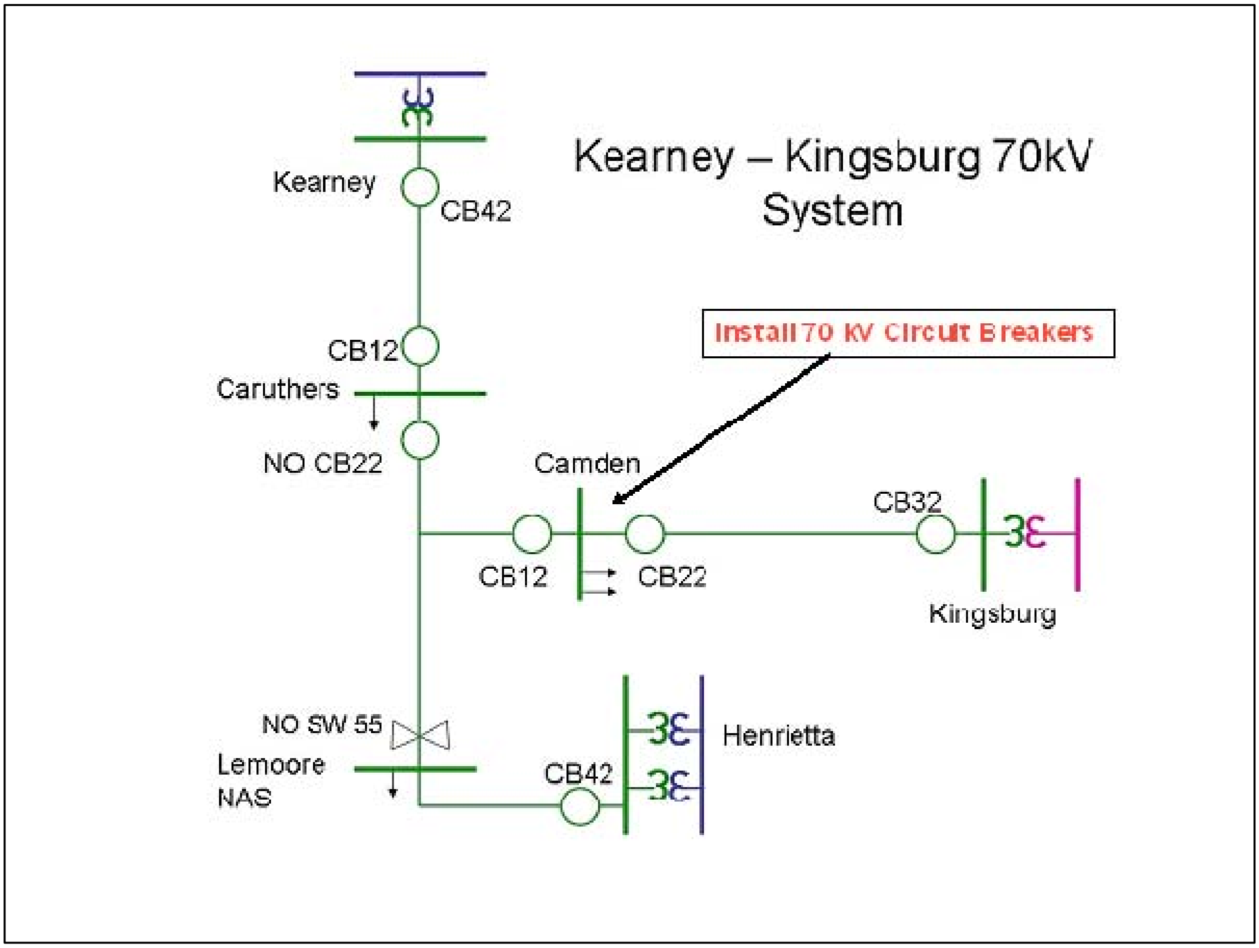


Figure 4-12: Proposed Scope Diagram

Attachment 2: Demand Forecast

Table 4-3: Area Load Demand Forecast

Substation/Bank	2009	2010	2011	2012	2013	Growth Rate(MW/yr)
Camden Bank 1	6.3	6.4	6.6	6.7	6.9	0.2
Camden Bank 2	10.0	10.2	10.5	10.7	10.9	0.2
Total Area Load	16.3	16.6	17.1	17.4	17.8	0.4

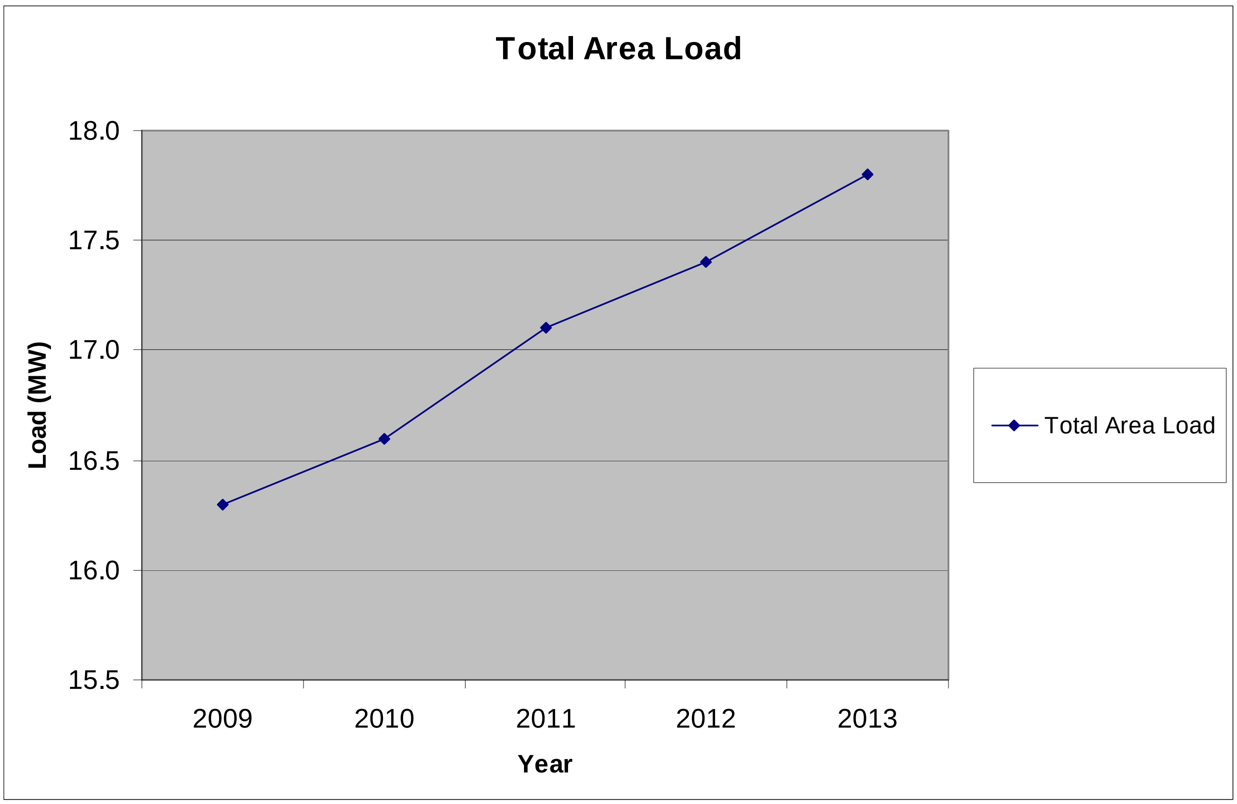


Figure 4-13: Area Load Demand Curve

Wilson – Oro Loma 115 kV Line Reconductor

TARGETED IN-SERVICE DATE

May 2009

PURPOSE AND BENEFIT

Reliability – NERC Compliance and LGIP Compliance. This network upgrade was also identified in the LGIP Process.

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROJECT

The project scope is to reconductor 5.25 miles of 115 kV line between Wilson Substation (Tower 2/4) and Le Grand Junction (Tower 8/2) with 715.5 AAC conductor or equivalent for a summer normal rating of 126 MVA and a summer emergency rating of 148 MVA. In addition, this work would also include modifying and upgrading relay protection at remote terminals located at Wilson and Oro Loma Substations. If necessary, this work will also include obtaining necessary land and environmental permitting to complete reconductoring work

The project is expected to cost between $2M and $3M.

BACKGROUND

Pacific Gas and Electric Company's Wilson Substation is located in Merced County on Yosemite Parkway near the junction of Highways 99 and 140. Wilson Substation has two 230/115 kV transformers. The power is stepped down to 115 kV and transmitted over two 115 kV transmission lines, Wilson – Oro Loma and Wilson – Le Grand. These two 115 kV lines travel to south and connect into Panoche Substation.

The Wilson – Oro Loma 115 kV Line is approximately 40 miles in length and is comprised of different conductors. The conductor ratings for the Wilson – Oro Loma 115 kV transmission lines are summarized in the table below.

Table 4-4: Wilson - Oro Loma 115 kV Line Characteristics

Line Sections	Conductor Type	Summer Normal Rating (Amps)	Summer Emergency Rating (Amps)	Winter Normal Rating (Amps)	Winter Emergency Rating (Amps)
Wilson Sub – Pole 2/4	2.73 miles of 336.4 ACSR	89	102	129	137
Pole 2/4 to Pole 2/8	5.25 miles of 266.8 AAC	68	80	103	110
Pole 2/8 to El Nido	6.51 miles of 397.5 AAC	88	102	133	142
El Nido – Oro Loma	25.9 miles of 397.5 AAC	88	102	133	142

Panoche Substation also has two 230/115 kV transformers and has access to power from major power plants. Panoche Energy Center, LLC, plans to install a 401 MW combined cycle generating facility (PEC), near the Company's Panoche Substation in Fresno County. PEC has obtained a CEC Permit and is under construction. The Company has executed an Interconnection Agreement with PEC to provide the interconnection services. The forecast commercial operation date is August 2009.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the CAISO in the LGIP process for interconnection of the Panoche Energy Center.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended as it does not address an emergency overload on the Wilson – Oro Loma 115 kV Line (section between Wilson Substation and Le Grand Junction).

Alternative 2: Install a Special Protection Scheme (SPS) at Herndon Substation

This alternative proposes to install the SPS at Herndon Substation to mitigate the overload on the Wilson – Oro Loma 115 kV Line resulting from the PEC generation interconnection at Panoche. This alternative is not recommended due to its higher cost.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2009

KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – TBD
- Special Metering or Protection - None
- Common Mode Exposure Items - None
- Interaction with other Projects or Studies – Panoche Energy Center Interconnection Project

GEPSLF MODELING INFORMATION

```
#Modifies the existing Wilson - Le Grand Junction section of the Wilson-Oro Loma 115 kV Line to account
#for the reconductoring of the 266.8 AAC segments to 715 AAC conductor.
OLDSECDD  34118, 34136, CKT=1, SEC=1, STATUS=1,+
        RPU=.01249, XPU=.044698, BPU=.0065895, MVA1=89, MVA2=102, MVA3=98, MVA4=109
```

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Single Line Diagrams
2. Power Flow Summary

Attachment 1: Scope Diagrams

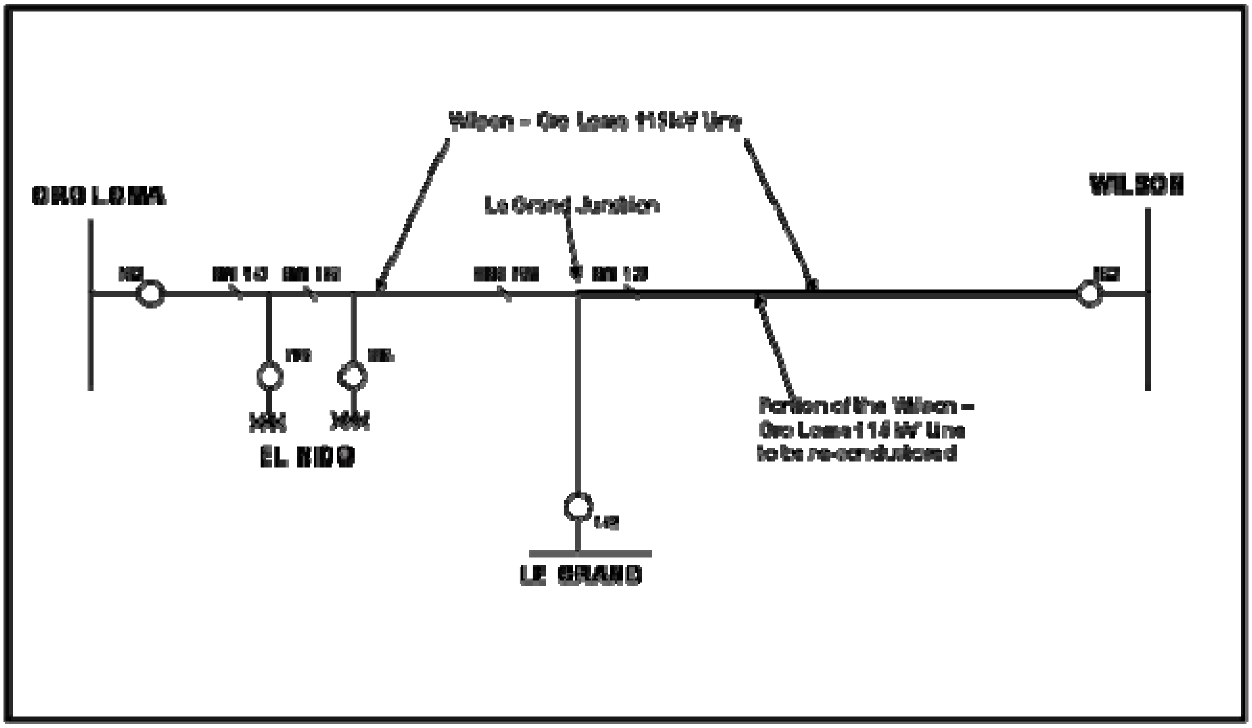


Figure 4-14: Proposed Single Line Diagram

Attachment 2: Power Flow Summary

Table 4-5: Power Flow Results from CAISO study "Planning for Second Dry Year Operation Reliability"

Double (N-2) Contingency Results (Overload > 130%)

	Contingency	Overload	Rating	Loading	%
North East	Table Mt-Rio Oso 230kV Palermo-Colgate 230kV	Pease-Rio Oso 115kV	507 A	747 A	147.4
North East	Gold Hill-Eight Mile 230kV Gold Hill-Lodi STIG 230kV	Table Mt-Palermo 230kV	976 A	1394 A	142.8
North East	Table Mt-Rio Oso 230kV Palermo-Colgate 230kV	Bogue-Rio Oso 115kV	512 A	693 A	135.4
North East	Table Mt-Rio Oso 230kV Table Mt-Palermo 230kV	Eight Mile-Tesla 230kV	976 A	1287 A	131.9
North East	Table Mt-Rio Oso 230kV Palermo-Colgate 230kV	Palermo-Bogue 115kV	417 A	546 A	131.5
Central Valley	Manteca-Vierra 115kV Tesla-Manteca 115kV	Tesla-Salado-Manteca 115kV	326 A	828 A	253.8
Central Valley	Schulte-Lammers 115kV Tesla-Manteca 115kV	Vierra-Tracy-Kasson 115kV	602 A	1299 A	215.6
Central Valley	Schulte-Lammers 115kV Tesla-Manteca 115kV	Tesla-Tracy 115kV	974 A	1915 A	196.6
Central Valley	Manteca-Vierra 115kV Tesla-Manteca 115kV	Kasson-Louise 60kV	385 A	718 A	186.5
Central Valley	Manteca-Vierra 115kV Tesla-Manteca 115kV	Kasson 115/60kV Bank	91 MVA	130 MVA	142.8
Central Valley	Stanislaus-Manteca #2 115kV Stanislaus-Melones-Manteca #1 115kV	Stanislaus-Melones-Manteca #3 115kV	326 A	457 A	140.2
Central Valley	Tesla-Manteca 115kV Tesla-Salado-Manteca 115kV	Schulte-Lammers 115kV	1125 A	1477 A	131.3
South Valley	Panoche-Kearney 230kV Panoche-Helm 230kV	Gates-McCall 230kV (Henrietta Tap-McCall)	975 A	1498 A	153.6
South Valley	**Herndon-Kearney 230kV Gates-Gregg 230kV**	**Wilson-Oro Loma 115kV (Wilson-Le Grand Jct)**	**398 A**	**582 A**	**146.2**
South Valley	Herndon-Kearney 230kV Gates-Gregg 230kV	Dairyland-Le Grand 115kV	398 A	554.6 A	162.7
South Valley	Herndon-Kearney 230kV Gates-Gregg 230kV	Wilson-Warnerville 230kV	793 A	1087.3 A	137.1
South Valley	Gregg-Herndon #1 & #2 230kV	Gregg-Ashlan 230kV (Gregg-Figarden Tap)	850 A	1160.4 A	136.5

2010 Projects

Burns Reliability

TARGETED IN-SERVICE DATE

May 2010

PURPOSE AND BENEFIT

Reliability – Operational Flexibility and Improved Service Restoration. This project will significantly reduce outage minutes for customers in the communities of Ben Lomand, Big Basin and Davenport.

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROPOSED PROJECT

This project scope is to install a 60 kV circuit breaker at Burns Substation on the 60 kV line up to Monta Vista. The Burns 60 kV bus will be reconfigured to accommodate the new breaker, and SCADA will be installed at Burns. The project will also install SCADA-operated switches at Big Basin Substation and at Lone Star Junction.

The cost of this project is estimated to range between $3M and $5M.

BACKGROUND

The communities of Ben Lomand, Big Basin and Davenport are served by a long 60 kV wood-pole transmission line out of Monta Vista Substation in Cupertino. At Burns Substation, there is a 60/21 kV "step-up" transformer that permits the distribution system out of Camp Evers Substation to supply the 60 kV distribution load.

However, the existing 60 kV system lacks SCADA, and without a breaker at Burns to help isolate faults up towards Monta Vista, restoring service to customers is a long, manual process that can take hours.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended because it does not reduce the customer outage minutes in this area.

PROJECT SCHEDULE

- Environmental and Permitting Processes – None
- Design – Summer 2009
- Major Equipment – Summer 2009
- Construction – Summer 2009 through Spring 2010
- Operation Date – May 2010

KEY ISSUES

- Land-Use Restrictions – None
- Environmental Concerns – None
- Special Metering or Protection – None
- Common Mode Exposure Items – None
- Interaction with other Projects – None

GEPSLF MODELING INFORMATION

No modeling changes in powerflow cases needed

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagram

Attachment 1: Scope Diagram

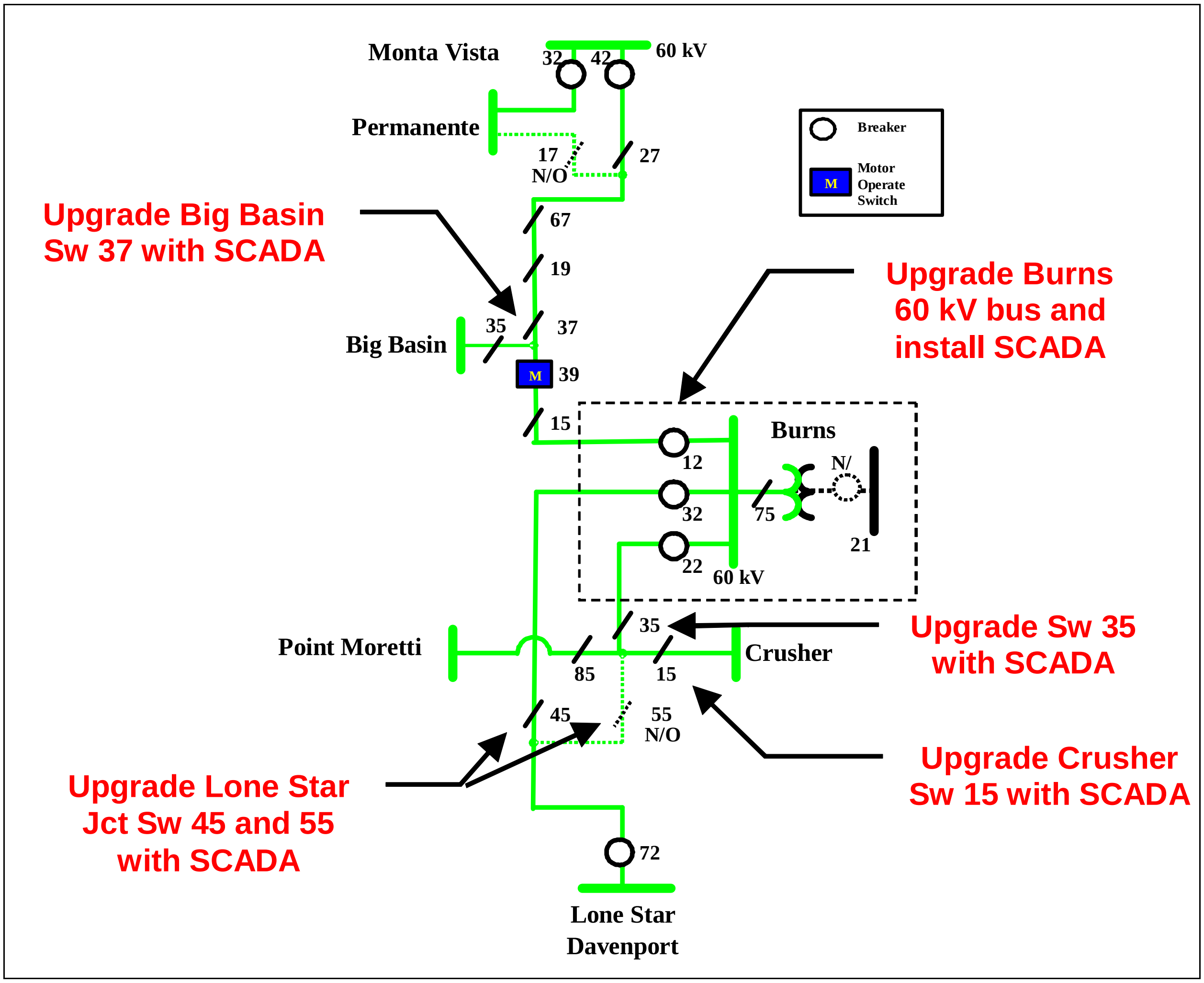


Figure 4-15: Project Scope for the Burns Reliability Project

Daly City Bus Reconfiguration

TARGETED IN-SERVICE DATE

December 2010

PURPOSE AND BENEFIT

Reliability – NERC Compliance

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROJECT

This project proposes to install two new 115 kV line circuit breakers with SCADA and a new low profile 115 kV bus at Daly City Substation by December 2010. This project also proposes to install two new 115 kV bus sectionalizing breakers with SCADA and disconnect switches.

This project is expected to cost between $5M and $10M.

BACKGROUND

Daly City Substation is located within the City of Daly City, San Mateo County. It is a distribution substation that serves the greater Daly City area load. Daly City is connected to the transmission grid via the San Mateo-Daly City Nos. 1 & 2 115 kV Lines. Daly City has two 115/12 kV distribution banks that supports the distribution planning area through twelve distribution feeders. Daly City has a recorded 2007 summer peak load of 80 MW and provides electric service to 40,000 customers.

Daly City is currently a looped substation with bus sectionalizing protection that meets the standard 2-bank station design. However, the existing 115 kV bus is not constructed in the traditional string bus arrangement. The 115 kV bus does not have the flexibility to meet the design standards of a 3-bank station. PG&E's Substation Maintenance department initiated a deteriorated facility project to replace Daly City Bank 1. PG&E initiated a capacity project install a third distribution bank at Daly City that would be completed concurrently. Connection of the third transformer to the existing 115 kV bus was the only feasible option. This direct connection would make the bus arrangement non-standard and significantly reduces the operating flexibility to perform clearances and maintenance. Under this bus arrangement, any maintenance clearance of the new Bank No. 3 would also require a clearance of the adjacent Bank No. 1 and vice versa. If the two banks can not be cleared at the same time then maintenance work would have to be deferred or customers would have to experience a planned outage. The direct connection also places the two banks at risk for a bus outage.

Because of the degrade in reliability that the direct connection of the new bank causes, it is recommended to build a standard low profile 115 kV bus. To retain a looped station configuration, it is recommended to install two new 115 kV line circuit breakers with SCADA. To reduce the impacts of a bus outage, it is recommended to install two new 115 kV bus sectionalizing circuit switchers with SCADA. Completion of this work retains the bus design standards for a 3-bank station and provides the necessary operating flexibility to perform routine clearances and maintenance.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended. This alternative does not address the potential overload issue.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – December 2010

KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – TBD
- Special Metering or Protection – TBD
- Common Mode Exposure Items – TBD
- Interaction with other Projects – TBD

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagram

Attachment 1: Scope Diagram

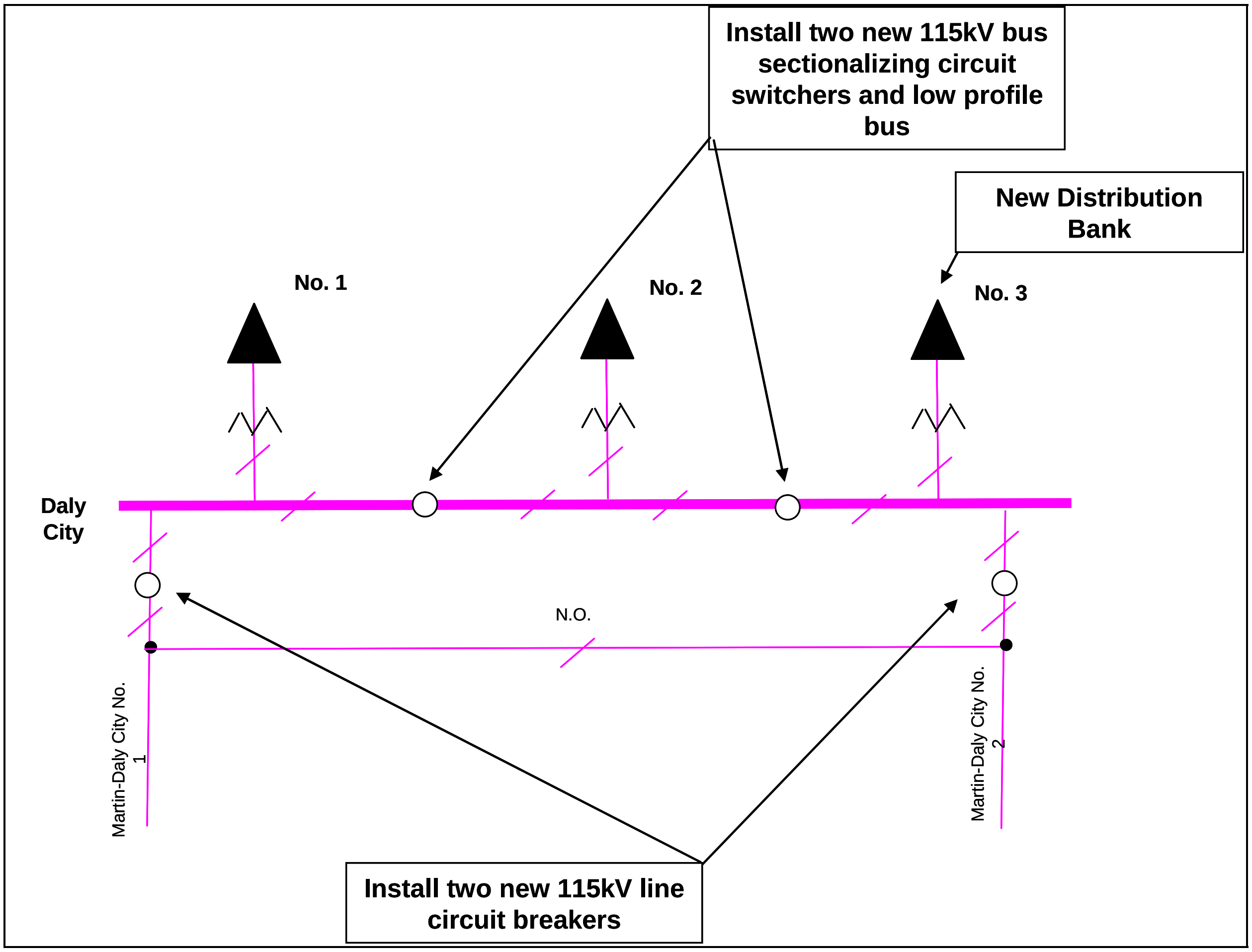


Figure 4-16: Scope Diagram

Menlo Area 60 kV System Upgrade

TARGETED IN-SERVICE DATE

May 2010

PURPOSE AND BENEFIT

Reliability – NERC Compliance

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROJECT

This project proposes to replace fifteen 600 Amp rated switches with 1,200 Amp rated switches and to upgrade the limiting components on the Jefferson-Stanford and Cooley Landing-Stanford 60 kV lines. The 60 kV buses at Glenwood and Menlo substations would be reconductored with bundled 1113 AAC conductor, and two breakers would be installed at Menlo Substation to improve transmission reliability. This project also proposes to reconductor the Glenwood-Menlo 60 kV line section with a conductor rated at 1100 Amps or greater (approximately 2 miles long).

This project is expected to cost between $5M and $10M.

BACKGROUND

Stanford University and the communities of Atherton and Menlo Park (approximately 15,490 electric customers) are served by two 60 kV transmission lines: one line emanates from Jefferson Substation; the other line from Cooley Landing Substation. The Jefferson-Stanford 60 kV Line is comprised of approximately 10 circuit miles of mainly 715.5 kcmil AAC conductor. This line primarily utilizes an overhead wood-pole construction, with two underground sections: 3,077 feet between Emerald Lake Junction and Menlo Junction and 4,520 feet between Menlo Junction and Stanford. The Cooley Landing-Stanford 60 kV Line is comprised of approximately 8 circuit miles of mainly 715.5 kcmil AAC conductor. This line primarily utilizes overhead wood-pole construction, with approximately 1.55 miles of line underground between Cooley Landing Substation and S.R.I Junction.

The capacity of these 60 kV lines emanating from Jefferson and Cooley Landing substations is limited by a 60 kV line section between Glenwood and Menlo substations, as well as fifteen 600-Amp switches at various locations on these 60 kV lines. The limiting switches are located at Emerald Lake, Las Pulgas, Menlo, Glenwood and SRI substations. Under peak 2009 conditions, planning studies conclude that the mentioned 600-Amp line switches could overload under an outage of either Jefferson-Stanford 60 kV or Cooley Landing-Stanford 60 kV Line while Stanford's Cardinal Cogeneration unit is offline. Another limiting component on the Cooley Landing-Stanford line is the Glenwood 60 kV bus. The bus consists of 250 kcmil Cu conductor.

Stanford's demand is currently about 40 MW, and the university has announced plans to increase their load to approximately 60 MW by 2020. If the Company had to supply its distribution load and the Stanford campus for these [L-1/G-1] contingencies, the 2009 emergency loadings mentioned above would increase by about 450 Amps, and the 2017 emergency loadings would increase by over 700 Amps. However, since a formal load-service agreement is not in place with the university, reinforcing the 60 kV system to enable Stanford to be served for these [L-1/G-1] contingencies is beyond the scope of this project. Transmission Planning is considering converting the 60 kV system to 115 kV, within the next five to ten years.

A fault on the Cooley Landing-Stanford 60 kV Line would result in outages of Menlo Transformer Nos. 2 and 4, and the distribution transformers at SRI, Glenwood and Stanford substations. A fault on the Jefferson-Stanford 60 kV Line would result in outages of Menlo Transformer Nos. 1 and 3 as well as Emerald Lake's distribution transformer bank.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO Grid Planning Criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended. This alternative does not address the potential overload and reliability issues.

Alternative 2: Rerate the fifteen 600-Amp Switches and Buses

This alternative proposes to re-rate the existing fifteen 600-Amps switches on the Jefferson-Stanford and Cooley Landing-Stanford 60 kV Lines as well as the Glenwood 60 kV Bus. Most of these switches are over 40 years old and they would require some maintenance in order to increase their capabilities, as well as the capability of the Glenwood Bus. These switches and Glenwood bus will still need to be replaced and reconductored a couple of years later since the re-rate will not provide adequate line capacity for the foreseeable future. This alternative is not recommended

PROJECT SCHEDULE

- Environmental and Permitting Processes – None
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2010

KEY ISSUES

- Land-Use Restrictions – None
- Environmental Concerns – None
- Special Metering or Protection – None
- Common Mode Exposure Items – None
- Interaction with other Projects – None
- Clearances during Construction – TBD

GEPSLF MODELING INFORMATION

```
# Menlo Area 60 kV Switch Replacements
# Description:
# This project will replace fifteen limiting switches in Menlo 60 kV Area
#****************************************************************************
#Replace Menlo 60 kV Switches with 1200 amp rated switches
#****************************************************************************
## Jefferson - Stanford 60 kV Line (Jefferson - Emerald Lake 60 kV Line)
# Emerald Lake Switch No. 37. Limiting is 600 Amp Switch.
OLDSECDD 33377, 33380, CKT=1, SEC=1, STATUS=1, MVA1=124.7, MVA2=124.7, MVA3=124.7, MVA4=124.7
## Jefferson - Stanford 60 kV Line (Emerald Lake - Las Pulgas Jct. 60 kV Line)
# Emerald Lake Switch No. 39 and Las Pulgas Jct Switch No. 57.  Limiting is 600 Amp Switch.
OLDSECDD 33377, 33393, CKT=1, SEC=1, STATUS=1, MVA1=124.7, MVA2=124.7, MVA3=124.7, MVA4=124.7
# # Jefferson - Stanford 60 kV Line (Las Pulgas Jct.- Menlo Jct. 60 kV Line)
# Las Pulgas Jct Switch No. 59 and Menlo Jct Switch No. 77. Limiting is 600 Amp Switch.
OLDSECDD 33393, 33385, CKT=1, SEC=1, STATUS=1, MVA1=124.7, MVA2=124.7, MVA3=124.7, MVA4=124.7
# # Jefferson - Stanford 60 kV Line (Menlo Jct - Menlo 60 kV Line)
# Menlo 60 kV Switches No. 19, 89 and 17. Limiting is 600 Amp Switch.
OLDSECDD 33383, 33385, CKT=1, SEC=1, STATUS=1, MVA1=124.7, MVA2=124.7, MVA3=124.7, MVA4=124.7
# # Cooley Landing - Stanford 60 kV Line (Cooley Landing - SRI 60 kV Line)
# SRI Switch No. 47 Limiting is 600 Amp Switch.
OLDSECDD 33375, 33382, CKT=1, SEC=1, STATUS=1, MVA1=124.7, MVA2=124.7, MVA3=124.7, MVA4=124.7
```

Cooley Landing - Stanford 60 kV Line (SRI - Glenwood 60 kV Line)
SRI Switch No. 49, Glenwood Switch Nos. 57, 77, 87, 59. Glenwood bus to be reconductored with bundled 1113 AL
OLDSECDD 33381, 33382, CKT=1, SEC=1, STATUS=1 , MVA1=124.7, MVA2=124.7, MVA3=124.7, MVA4=124.7
Cooley Landing - Stanford 60 kV Line (Glenwood - Menlo 60 kV Tap)
****
Reconductor Glenwood - Menlo 60 kV section
****
TL to be reconductor with 1113 AL.
OLDSECDD 33381, 33384, CKT=1, SEC=1, STATUS=1, MVA1=96, MVA2=110, MVA3=115, MVA4=130
Cooley Landing - Stanford 60 kV Line (Menlo 60 kV Tap - Menlo 60 kV)
TL to be reconductored with1113 AL
OLDSECDD 33384, 33390, CKT=1, SEC=1, STATUS=1, MVA1=96, MVA2=110, MVA3=115, MVA4=130
#END

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagram
2. Power Flow Summary
3. Pre and Post Project Power Flow Plots

Attachment 1: Scope Diagram

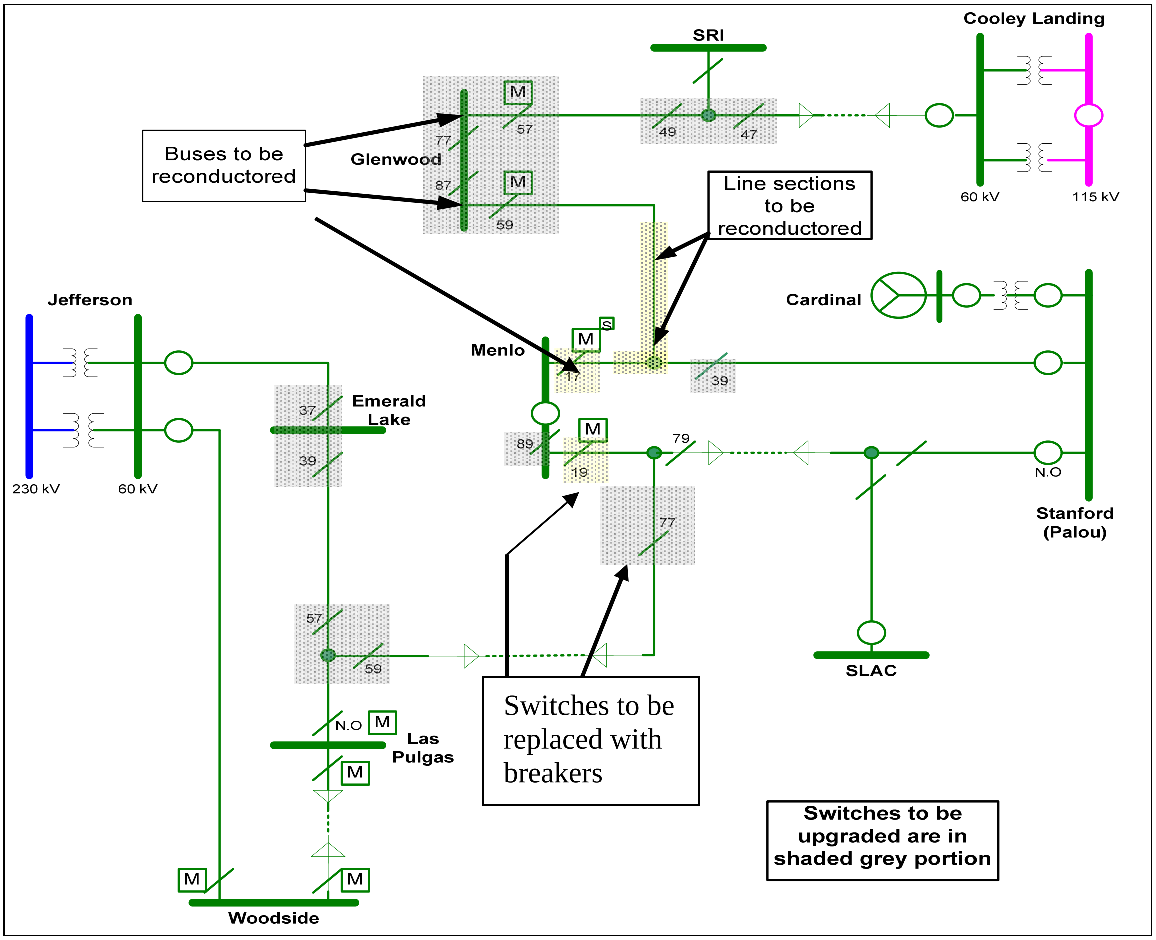


Figure 4-17: Menlo Area 60 kV Upgrade

Attachment 2: Power Flow Summary

Table 4-6: Power Flow Summary

Normal/Contingency	Facility Affected	2009 Pre-Project	2009 Post Project
Normal Conditions	Jefferson -Stanford 60 kV Line	56%	28%
Cooley Landing-Glenwood 60 kV Line Section		117%	59%
Normal Conditions	Cooley Landing -Stanford 60 kV	60%	23%
Jefferson-Emerald Lake 60 kV Line section		117%	55%

Attachment 3: Pre and Post Project Power Flow Plots

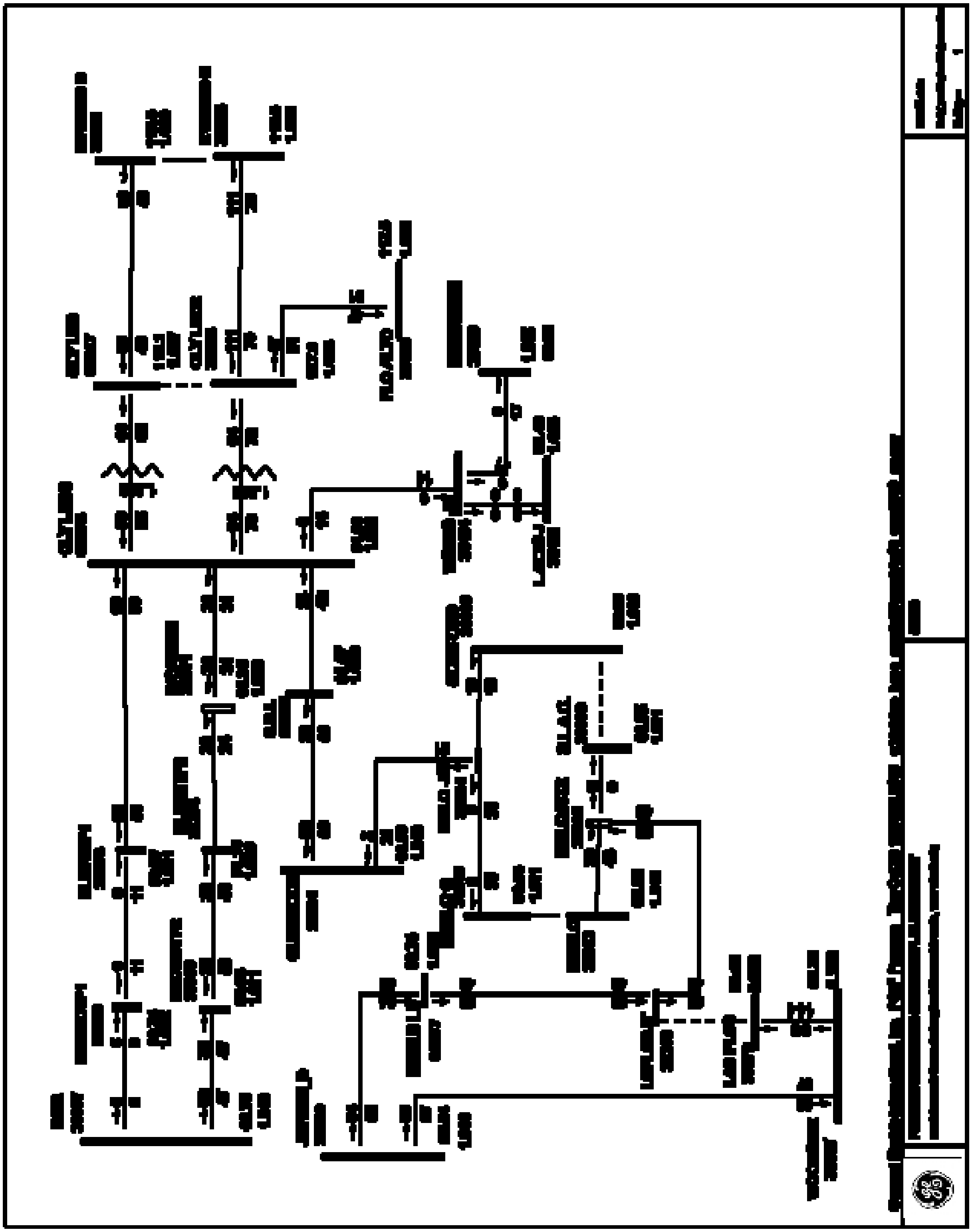


Figure 4-18: All Facilities in Service, Year 2009 (Pre-Project)

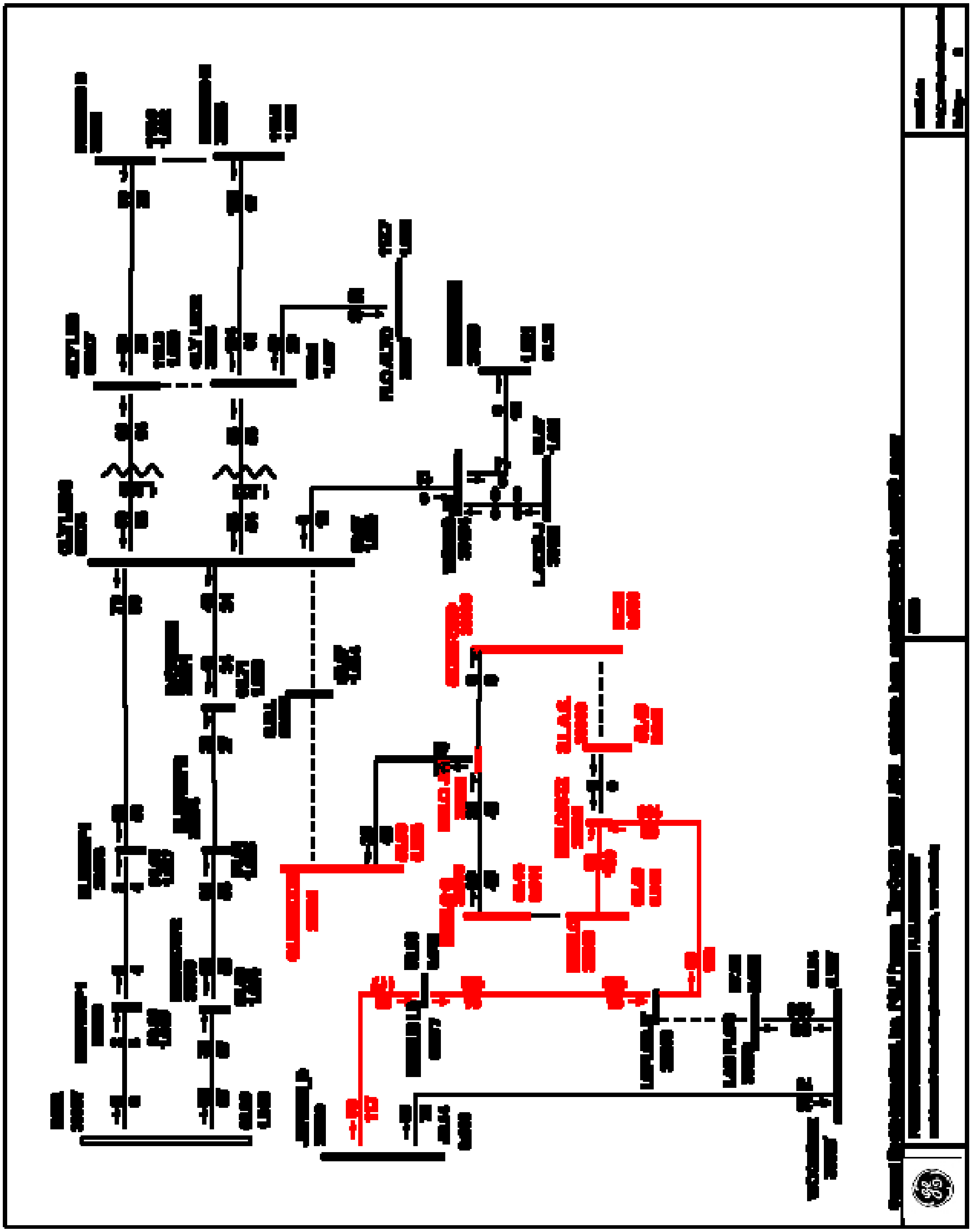


Figure 4-19: Outage of Cooley Landing-Glenwood section of Cooley Landing-Stanford 60 kV Line, overlapped with Cardinal Cogen offline (Stanford load dropped) Pre-Project

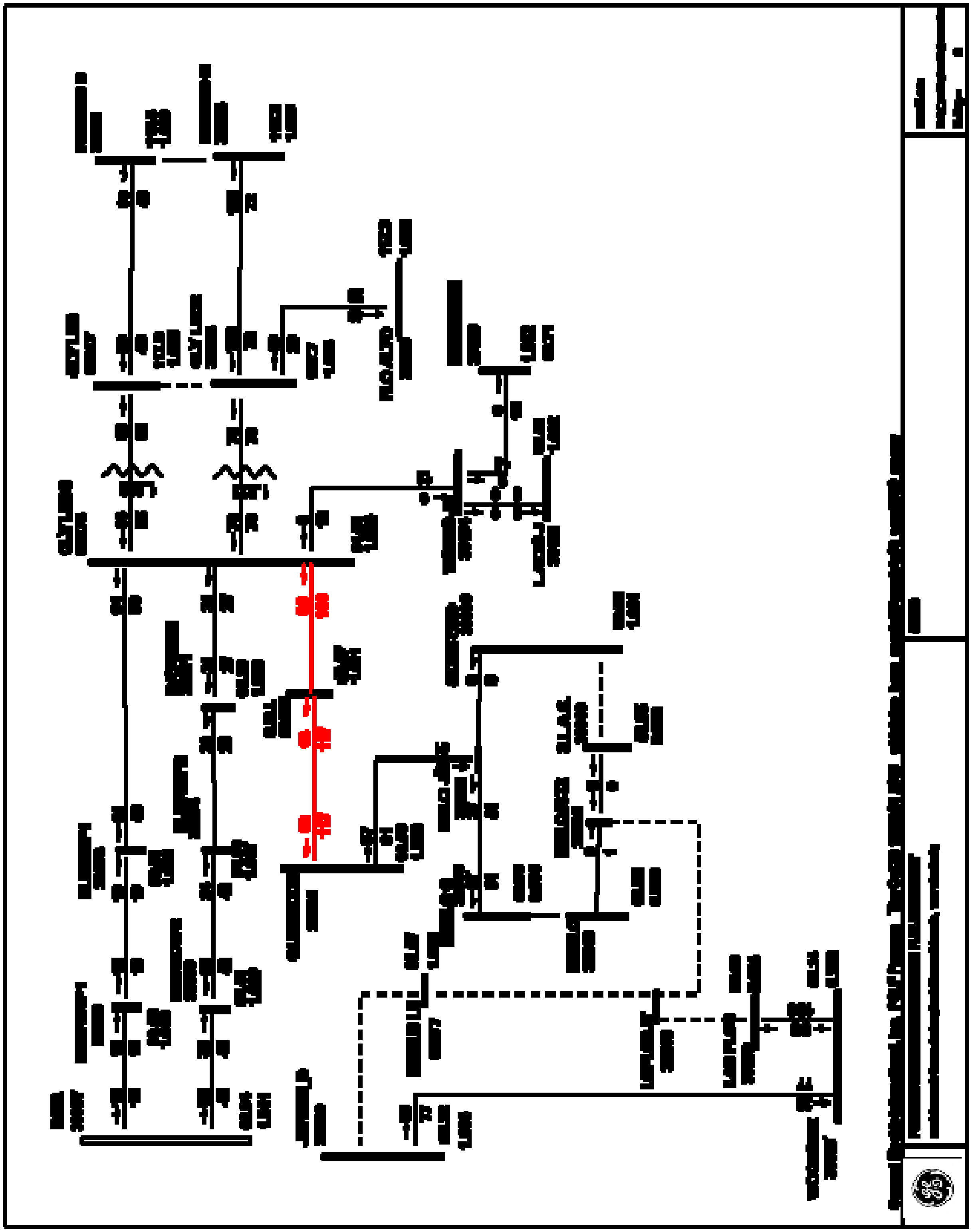


Figure 4-20: Outage of Jefferson-Menlo Junction section of the Jefferson-Stanford 60 kV Line, overlapped with Cardinal Cogen offline (Stanford load dropped) Pre-Project

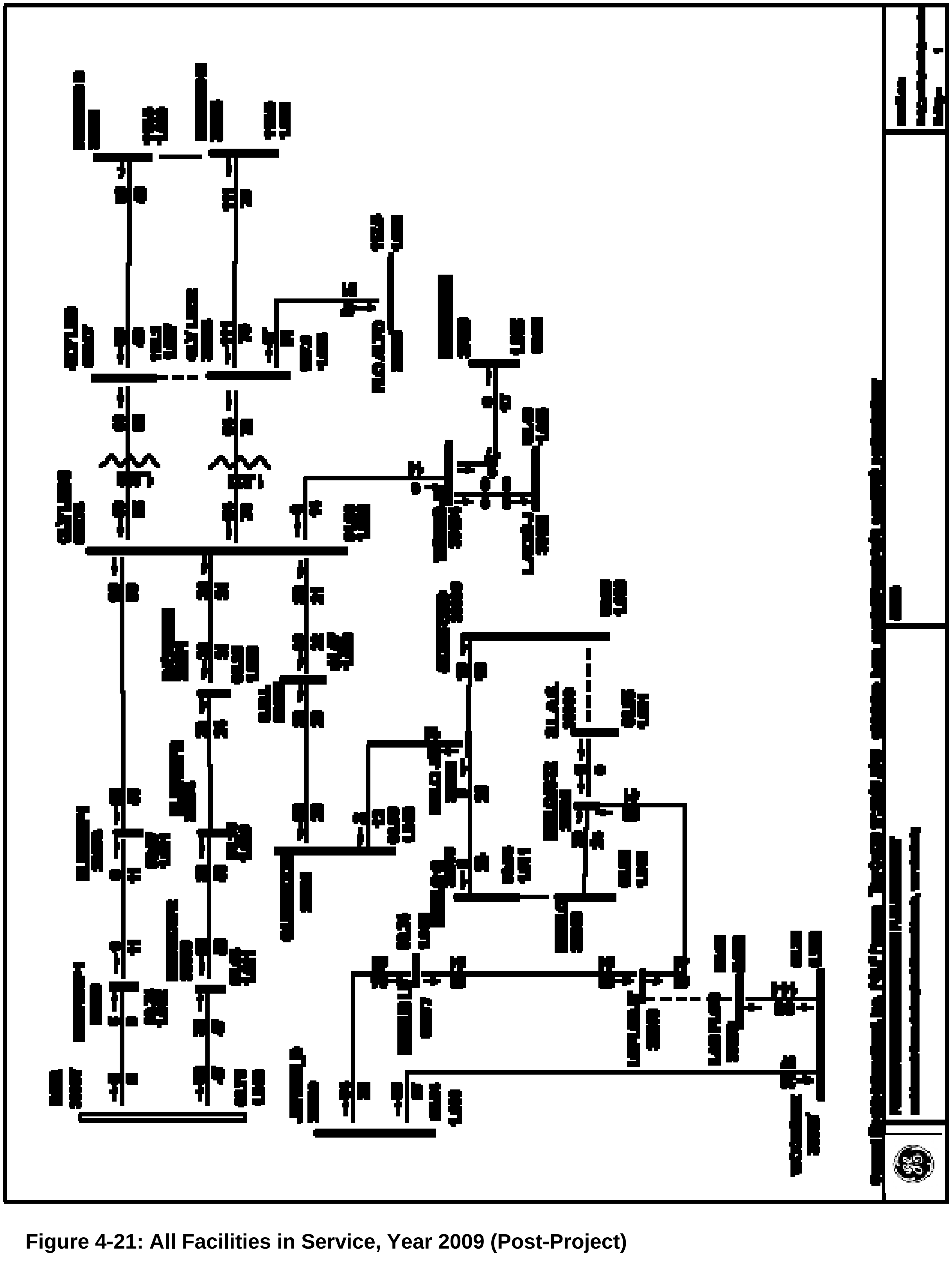


Figure 4-21: All Facilities in Service, Year 2009 (Post-Project)

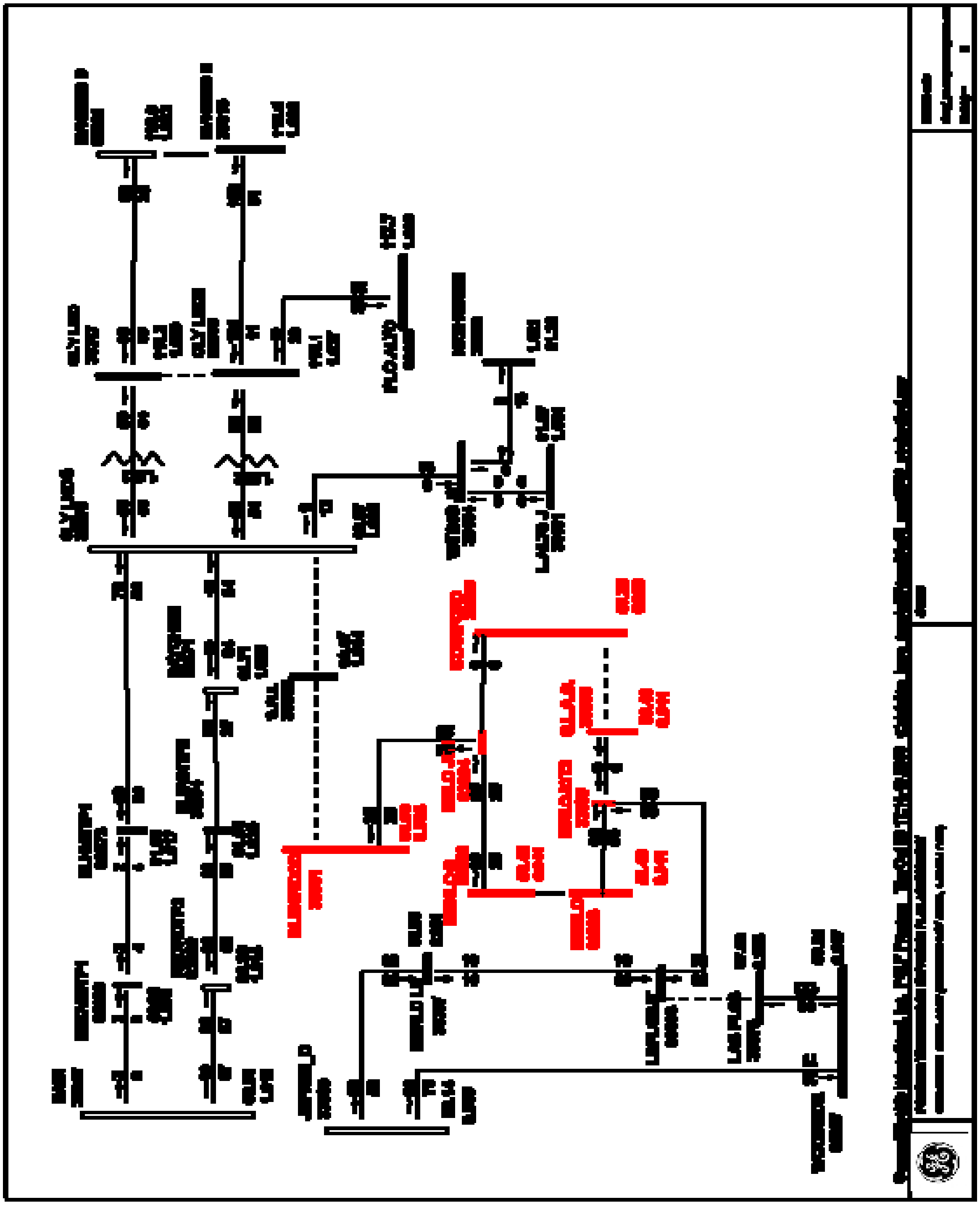


Figure 4-22: Outage of Cooley Landing-Glenwood section of Cooley Landing-Stanford 60 kV Line, overlapped with Cardinal Cogen offline (Stanford load dropped) - Post-Project.

Note: The voltage problems would be solved when Jefferson Bank 1 is installed by July 2009.

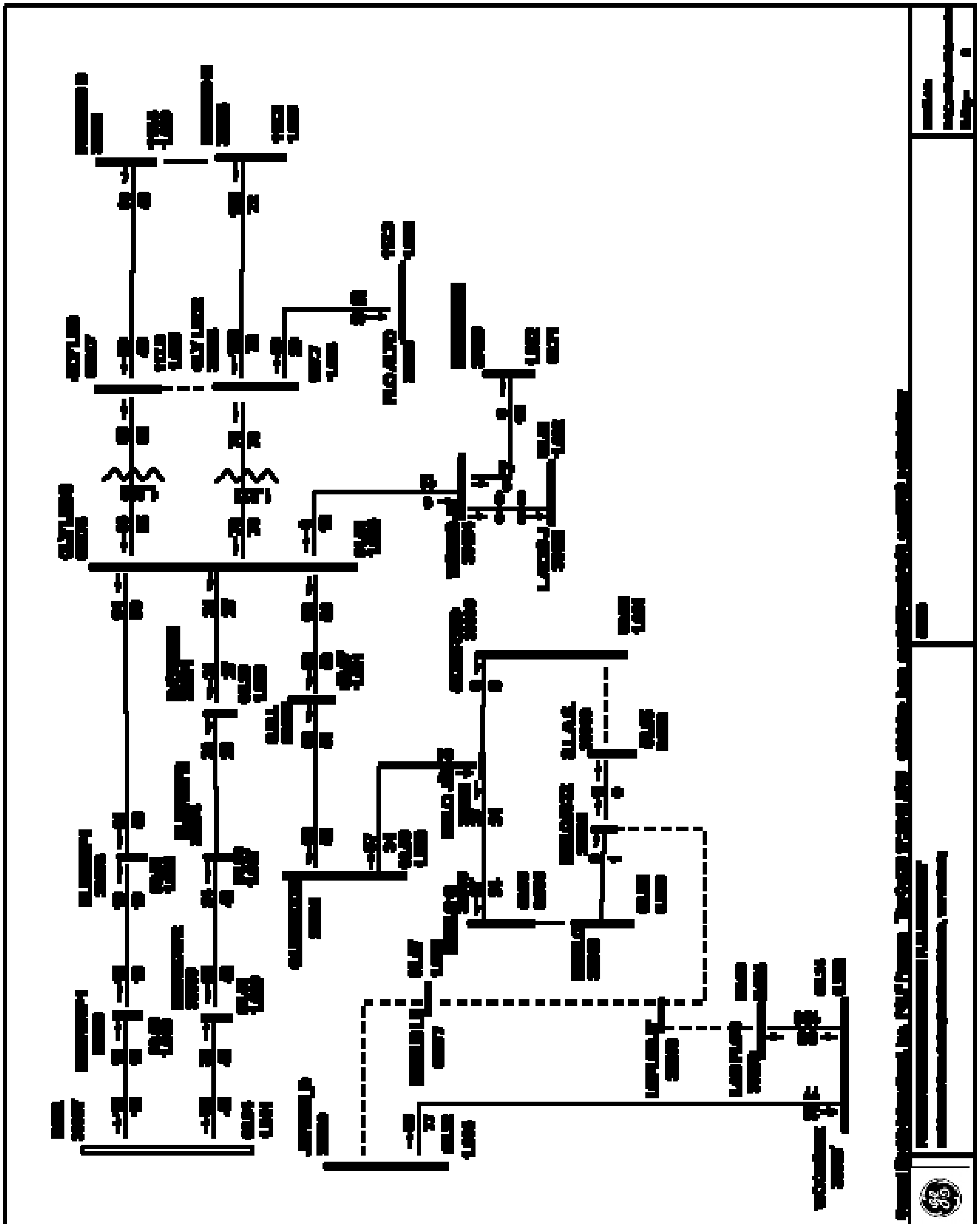


Figure 4-23: Outage of Jefferson-Menlo Junction section of the Jefferson-Stanford 60 kV Line, overlapped with Cardinal Cogen offline (Stanford load dropped) Post-Project

Tri-Valley Voltage Control

TARGETED IN-SERVICE DATE

November 2010

PURPOSE AND BENEFIT

Reliability – NERC Compliance and Operating Flexibility

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROJECT

The project scope is to install three 48 MVAR shunt reactors on the North Dublin-Vineyard 230 kV Line. The reactors will be installed on the line-side of the station circuit breakers at Vineyard Substation (2 shunt reactors) and North Dublin Substation (1 shunt reactor). All of the shunt reactors will be in-service except for the second shunt reactor at Vineyard Substation, which will serve as a spare. If necessary, the project scope may also include the upgrade of terminal equipment at North Dublin and Vineyard substations to accommodate the shunt reactors.

This project is expected to cost between $10M and $15M.

BACKGROUND

Several years ago, PG&E completed the Tri-Valley Electric Capacity Project, which constructed new 230 kV lines into Vineyard Substation and into new Cayetano and North Dublin substations. These substations serve over 19,000 customers in the cities of Pleasanton, Dublin and Livermore. Peak demand at these three substations is about 140 MW.

The Contra Costa-Newark No. 2 230 kV Line was used to loop into these three substations. As part of the Certificate of Public Convenience and Necessity (CPCN) for the Tri-Valley Project, the CPUC required that 22.4 miles of the new 230 kV lines be constructed underground. The underground sections are distributed as follows:

- Lone Tree-Cayetano 230 kV Line – 2.4 miles of underground cable,
- Cayetano-North Dublin 230 kV Line – 3.1 miles of underground cable,

- North Dublin-Vineyard 230 kV Line – 11.2 miles of underground cable, and
- Vineyard-Newark 230 kV Line – 5.7 miles of underground cable.

Due to the long length of underground cable in this 230 kV path, high levels of line charging currents exist in these cables, which can lead to high over-voltages on the cables should a long section of cable be “unloaded.”

Planning analysis shows that opening the Contra Costa-Cayetano-Newark 230 kV path at Newark or Contra Costa during off-peak, low-load conditions will result in the 230 kV voltages in the Tri-Valley area rising to 260 kV, or 13% over rated voltage. These voltage levels are well above operating guidelines.[2] Even during peak-load conditions, opening the path can result in voltages rising to 256 kV, or 12% over rated voltage.

Because of these potential over-voltages on opening the Contra Costa-Cayetano-Newark 230 kV path, clearances are risky and operating flexibility is very limited in this area. Furthermore, these over-voltages will affect the life expectancy of the underground cables. Southwire, the cable manufacturer for the North Dublin-Vineyard and Vineyard-Newark underground cable sections, had designed these cables to not exceed 245 kV for more than 15 minutes. Exceeding this limitation will lead to accelerated degradation of the cables and will jeopardize their warranties.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended because it does not eliminate the high voltage risk to equipment in the Tri-Valley 230 kV system. Operating flexibility is severely limited. In addition, degradation and possible failure of the Vineyard cables could result.

Alternative 2: Install a 150 MVAR Shunt Reactor at Underground-Overhead Transition on the North Dublin-Vineyard 230 kV Line

[2] Utility Standard UO S1036 and the California Independent System Operator Corporation’s (CAISO) Operating Procedure T-105 state that the 230 kV system voltages should be within the low- and high-operating limit of 224 kV and 242 kV, respectively.

This alternative proposes to install a 150 MVAR shunt reactor, comprised of three, 50 MVAR steps, on the North Dublin-Vineyard 230 kV Line at the location south of Vallecitos Road where the underground cables transition to overhead lines.

This is not recommended because of the potential permitting and land acquisition issues and the expected higher cost for this alternative. In addition, this alternative does not provide any redundancy should the new reactor be off-line for maintenance. The cost for this alternative is estimated to be over $10 million.

Alternative 3: Loop the North Dublin-Vineyard 230 kV Line into Las Positas Substation

This alternative proposes to loop the North Dublin-Vineyard 230 kV Line into Las Positas Substation.

The Las Positas Substation is a looped substation with six existing elements connected to its 230 kV bus. Bringing the North Dublin-Vineyard 230 kV Line into the substation will increase the number of elements to eight. The bus configuration will need to be upgraded to a breaker-and-a-half (BAAH) configuration to accommodate these new connections.

This alternative addresses the over-voltage problem and other local system issues. However, this alternative is expected to be much more costly than Alternative 2. And, given the potential time and costs needed to construct a new BAAH arrangement and loop the North Dublin-Vineyard line into Las Positas, a temporary reactor installation is needed to mitigate any over-voltage issues during construction. The project team is being requested to analyze the feasibility, timing and cost of this alternative, to determine if it is competitive with Alternative 2.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – November 2010

KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – TBD
- Special Metering or Protection – TBD
- Common Mode Exposure Items – TBD
- Interaction with other Projects – TBD

GEPSLF MODELLING INFORMATION

```
#A. SIMULATE THE NORTH DUBLIN CB 322 AND VINEYARD CB 212 ON THE NORTH DUBLIN-VINEYARD 230 KV LINE
#REMOVING THE ORIGNAL NORTH DUBLIN-VINYARD 230 KV LINE
PURGE 30537,35224,1,1
#SIMULATE THE NORTH DUBLIN CB 322
NEWBUSD   30538,NDBCB322,230,1,1.01,16,316,,,,,390
NEWSECDD  30537,30538,1,1,,0.005,,999,999,999,999,1,16,316,390
#SIMULATE THE VINEYARD CB 212
NEWBUSD   35228,VINCB212,230,1,1.01,16,316,,,,,390
NEWSECDD  35228,35224,1,1,,0.005,,999,999,999,999,1,16,316,390
#NEW NORTH DUBLIN-VINEYARD 230 KV LINE
NEWSECDD  30538,35228,1,1,0.003387,0.022391,0.679252,352,400,400,400,1,16,316,390
#B. INSTALLING SHUNT REACTORS AT NORTH DUBLIN AND VINEYARD SUBSTATION
#INSTALLING SHUNT REACTORS AT VINEYARD SUBSTATION
#NOTE: THE SECOND SHUNT REACTOR AT VINEYARD SUBSTATION IS A SPARE. IT IS NOT SHOWN IN THE MODEL.
#         INCREASE "B0" TO -96 IN MODELING THE SPARE
NEWSVD   35228 ID=v  ST=0 TYPE=0 VBAND=0.01  BINIT=0  N0=1  B0=-48  AREA=16 ZONE=316
#INSTALLING SHUNT REACTORS AT NORTH DUBLIN SUBSTATION
NEWSVD   30538 ID=v  ST=0 TYPE=0 VBAND=0.01  BINIT=0  N0=1  B0=-48  AREA=16 ZONE=316
#
#END
#
#NOTE: THE FOLLOWING CHANGE FILE IS TO SIMULATE THE OTHER CB ON THE CONTRA COSTA-LONETREE-
#   CAYETANO-NORTH DUBLIN-VINEYARD-NEWARK 230 KV PATH. THIS ADDITIONAL CHANGE FILE IS TO SIMULATE
#   OPEN ENDING THE 230 KV PATH
#
#****************************************************************************
# CONTRA COSTA-LONETREE 230 KV LINE
#TEMPORARY TURNING OFF ORIGNAL THE CONTRA COSTA-LONETREE 230 KV LINE
OLDSECDD  30525,30567,1,1,0,,,,,,,,,,,,
# LONETREE 2032 AND 2042
NEWBUSD   30572,LONECB1,230,1,1.01,8,308,,,,,390
NEWSECDD  30572,30567,1,1,,0.005,,999,999,999,999,1,8,308,390
#CONTRA COSTA CB 520
NEWBUSD   30524,COCOCB1,230,1,1.01,8,308,,,,,390
NEWSECDD  30525,30524,1,1,,0.005,,999,999,999,999,1,8,308,390
#CONTRA COSTA-LONETREE 230 KV LINE
NEWSECDD  30524,30572,1,1,0.001349,0.008246,0.016935,352,400,433,460,1,16,316,390
#
# LONETREE-CAYETANO 230 KV LINE WITH USP TAP
#TEMPORARY TURNING OFF ORIGNAL THE LONETREE-USP TAP 230 KV LINE
OLDSECDD  30567,30590,1,1,0,,,,,,,,,,,,
#TEMPORARY TURNING OFF ORIGNAL THE USP TAP-CAYETANO 230 KV LINE
OLDSECDD  30590,30530,1,1,0,,,,,,,,,,,,
# LONETREE CB 2012 AND 2022
NEWBUSD   30566,LONECB,230,1,1.01,8,308,,,,,390
NEWSECDD  30567,30566,1,1,,0.005,,999,999,999,999,1,16,316,390
# CAYETANO 272
NEWBUSD   30522,CYTCB1,230,1,1.01,16,316,,,,,390
NEWSECDD  30522,30530,1,1,,0.005,,999,999,999,999,1,16,316,390
#NEW LONETREE-USP TAP 230 KV LINE
NEWSECDD  30566,30590,1,1,0.003041,0.017729,0.036133,352,400,433,460,1,16,316,390
#NEW USP TAP-CAYETANO 230 KV LINE
NEWSECDD  30590,30522,1,1,0.000902,0.005691,0.143643,352,400,433,460,1,16,316,390
#
#CAYETANO-NORTH DUBLIN 230 KV LINE
#TEMPORARY TURNING OFF ORIGNAL THE CAYETANO-NORTH DUBLIN 230 KV LINE
OLDSECDD  30530,30537,1,1,0,,,,,,,,,,,,
#CAYETANO CB 292
NEWBUSD   30531,CYTCB,230,1,1.01,16,316,,,,,390
NEWSECDD  30530,30531,1,1,,0.005,,999,999,999,999,1,16,316,390
#NORTH DUBLIN CB 312
NEWBUSD   30532,NDBCB1,230,1,1.01,16,316,,,,,390
NEWSECDD  30532,30537,1,1,,0.005,,999,999,999,999,1,16,316,390
#NEW CAYETANO-NORTH DUBLIN 230 KV LINE
```

```
NEWSECDD  30531,30532,1,1,0.000715,0.005392,0.182050,400,400,400,400,1,16,316,390
#
#NEWARK-VINEYARD 230 KV LINE
#TEMPORARY TURNING OFF ORIGNAL THE NEWARK-VINEYARD 230 KV LINE
OLDSECDD  35219,30630,1,1,0,,,,,,,,,,,,
#NEWARK CB 540
NEWBUSD   30632,NEWKCB,230,1,1.01,16,316,,,,,390
NEWSECDD  30632,30630,1,1,,0.005,,999,999,999,999,1,16,316,390
#VINEYARD CB 222
NEWBUSD   35226,VINCB222,230,1,1.01,16,316,,,,,390
NEWSECDD  35219,35226,1,1,,0.005,,999,999,999,999,1,16,316,390
#NEW NEWARK-VINEYARD 230 KV LINE
NEWSECDD  35226,30632,1,1,0.003949,0.024491,0.378761,296,339,400,400,1,16,316,390
#END
```

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagram
2. Power Flow Summary
3. Pre and Post Project Power Flow Plots

Attachment 1: Scope Diagram

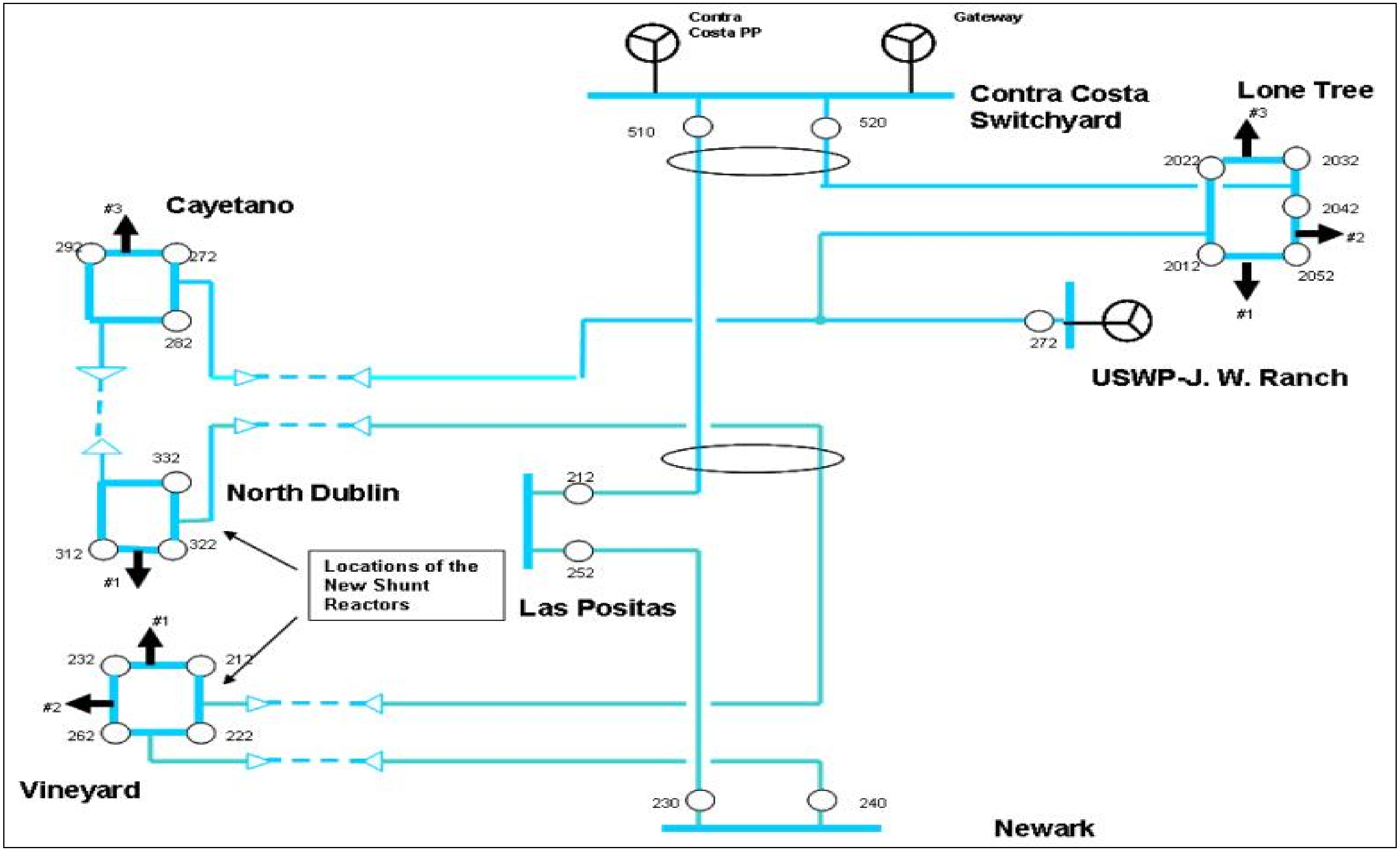


Figure 4-24: Scope Diagram

Attachment 2: Power Flow Summary

Table 4-7: 2009 Voltage Summary

Scenario	Monitored Facilities	Pre Project (kV, pu)		Post Project (kV, pu)	
Operating Conditions					
Normal	Newark 230 kV Bus	231 kV	1.00 pu	231 kV	1.00 pu
	Vineyard 230 kV Bus	235 kV	1.02 pu	230 kV	1.00 pu
	North Dublin 230 kV Bus	237 kV	1.03 pu	231 kV	1.01 pu
	Cayetano 230 kV Bus	236 kV	1.03 pu	232 kV	1.01 pu
	Lonetree 230 kV Bus	235 kV	1.02 pu	232 kV	1.01 pu
	USWP- JRW 9.1 kV Bus	9.4 kV	1.03 pu	9.2 kV	1.01 pu
Newark CB 340 open	Newark CB 340	256 kV	1.12 pu	235 kV	1.02 pu
	Vineyard 230 kV Bus	255 kV	1.11 pu	234 kV	1.02 pu
	North Dublin 230 kV Bus	251 kV	1.09 pu	234 kV	1.02 pu
	Cayetano 230 kV Bus	247 kV	1.07 pu	234 kV	1.02 pu
	USWP- JRW 9.1 kV Bus	9.7 kV	1.07 pu	9.3 kV	1.02 pu
Emergency Conditions					
Vineyard-Newark 230 kV Line	Vineyard 230 kV Bus	244 kV	1.06 pu	225 kV	0.98 pu
	North Dublin 230 kV Bus	244 kV	1.06 pu	228 kV	0.99 pu
	Cayetano 230 kV Bus	242 kV	1.06 pu	230 kV	1.00 pu
	USWP- JRW 9.1 kV Bus	9.5 kV	1.04 pu	9.1 kV	1.00 pu

Attachment 3: Pre and Post Project Power Flow Plots

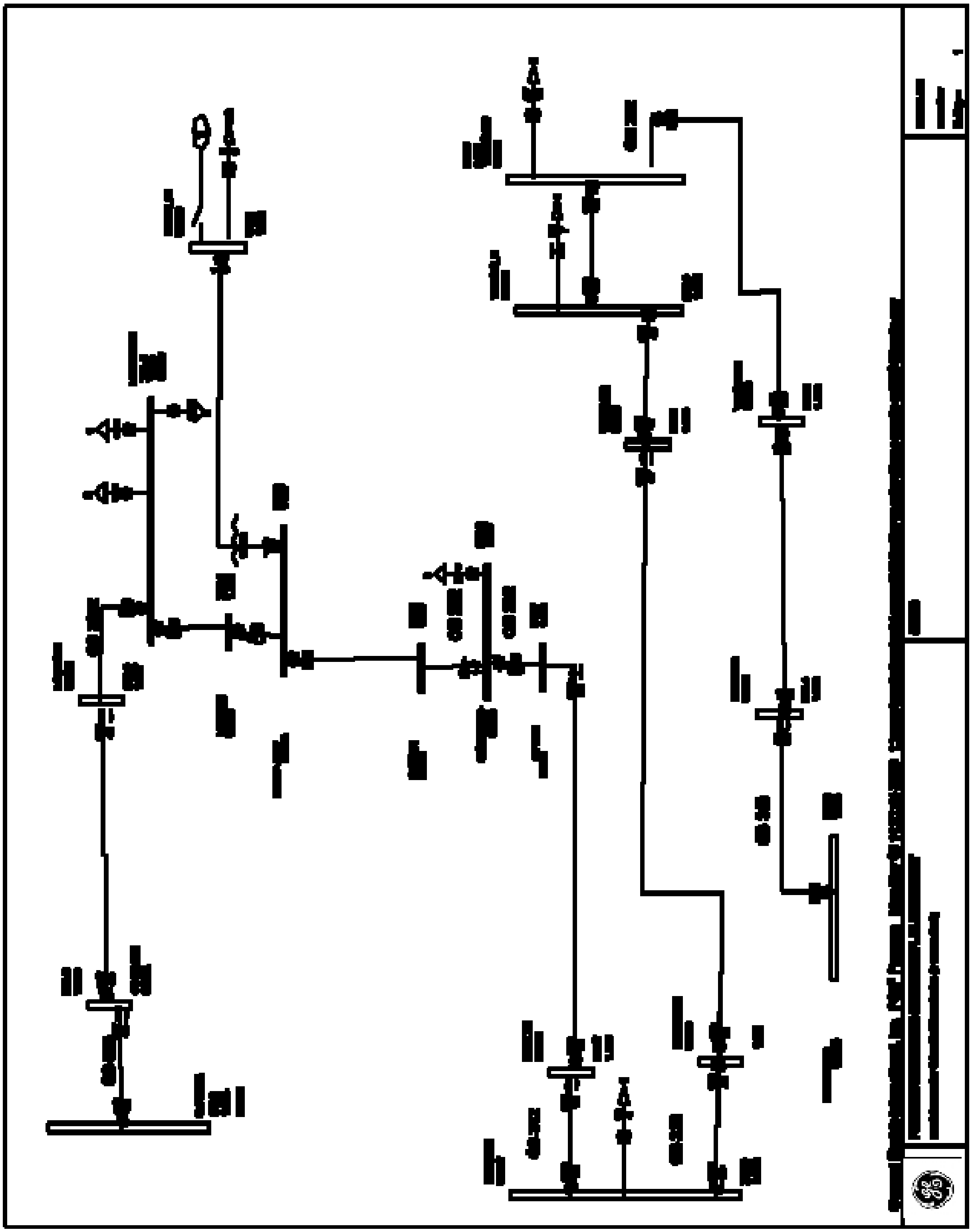


Figure 4-25: All Facilities in service, Year 2009 (Pre-Project)

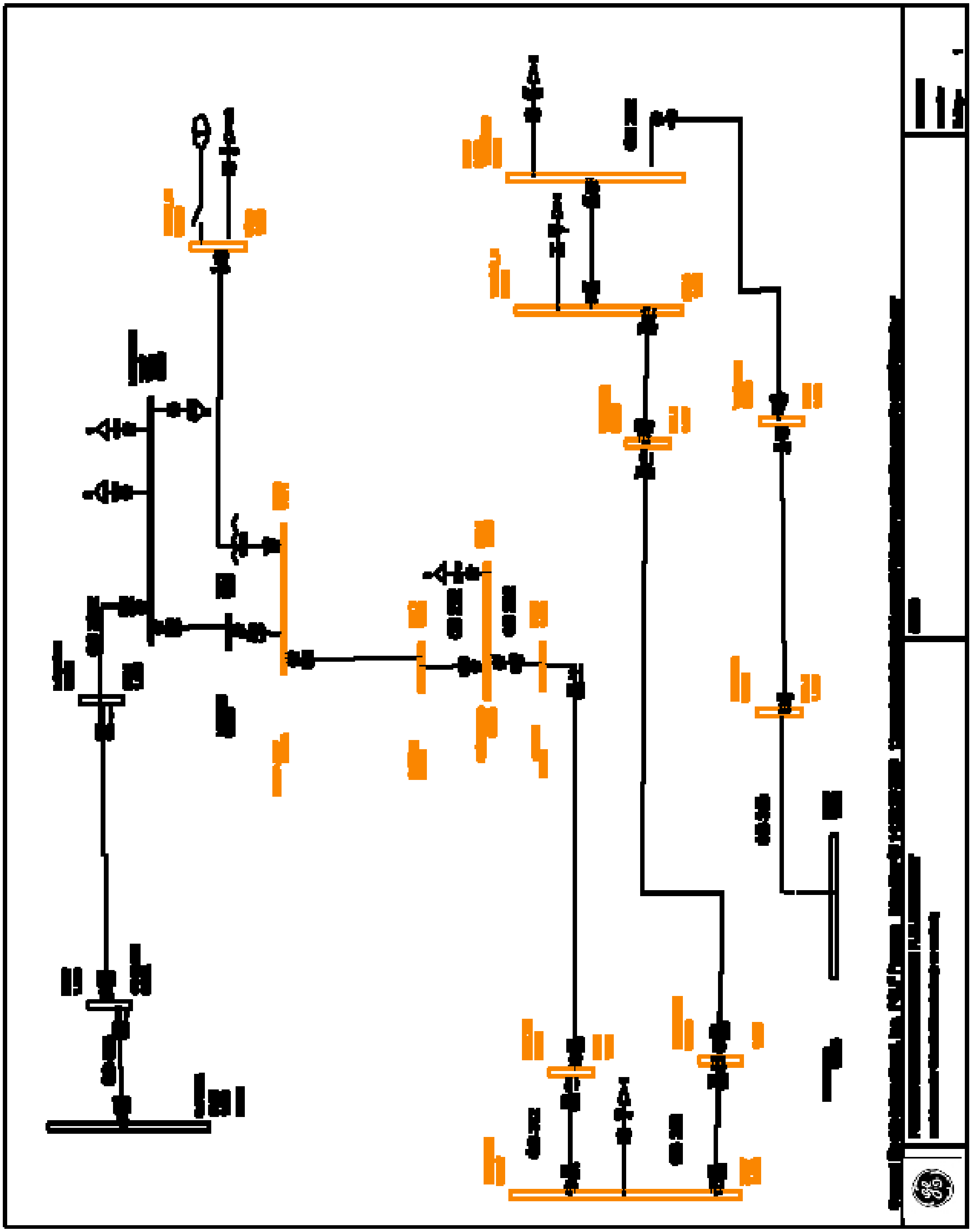


Figure 4-26: Newark CB 340, Year 2009 (Pre-Project)

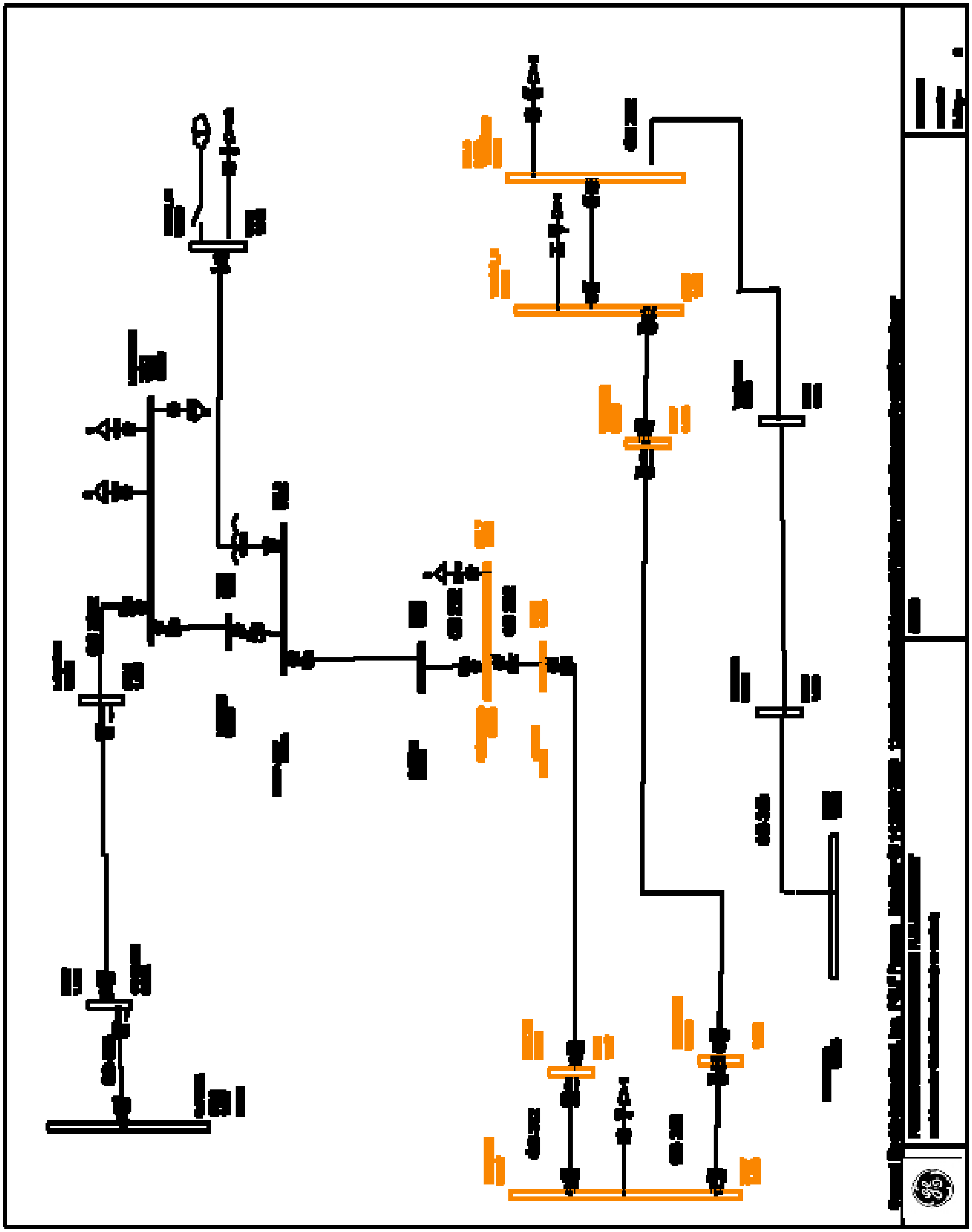


Figure 4-27: Outage of the Vineyard-Newark 230 kV Line, Year 2009 (Pre-Project)

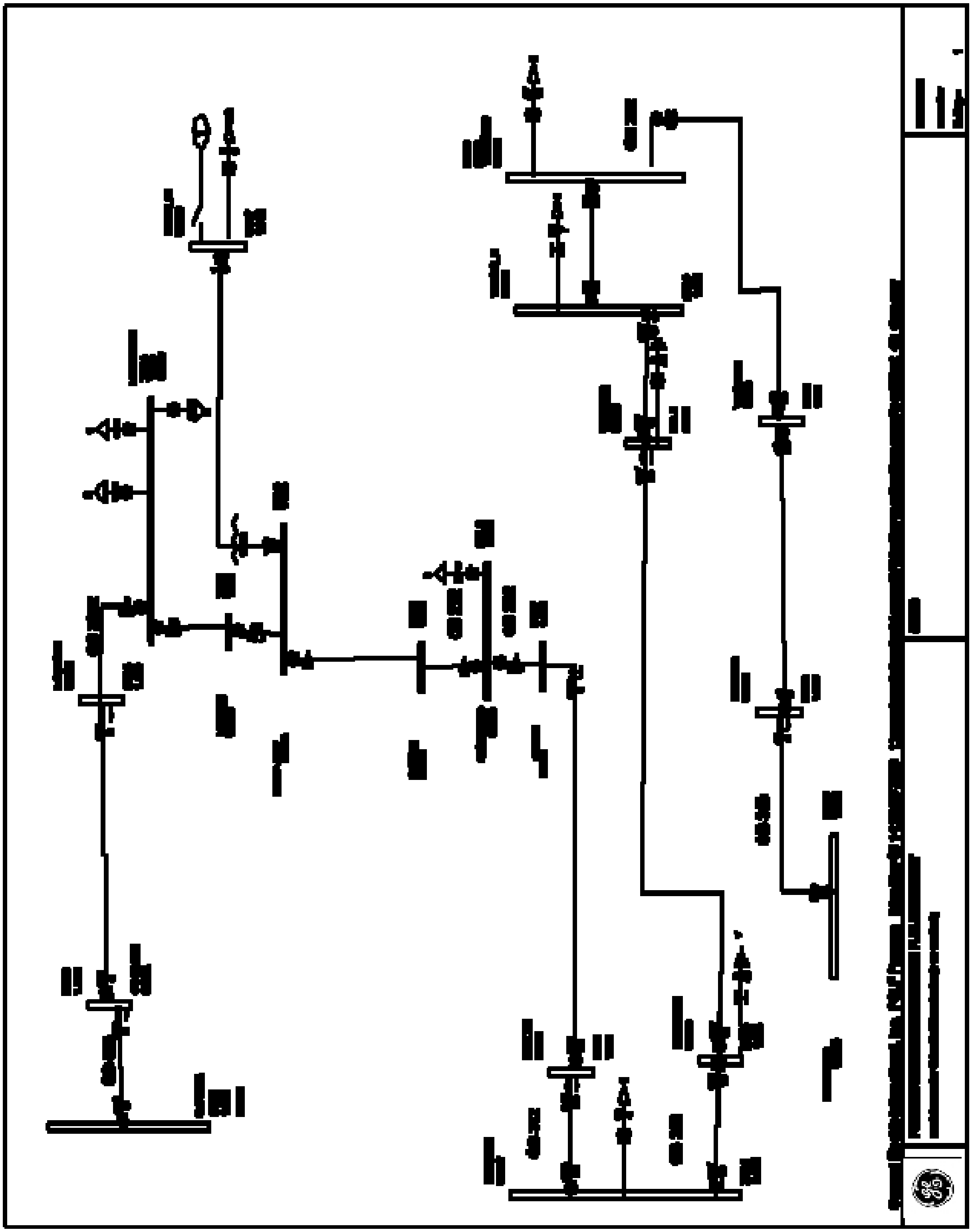


Figure 4-28: All Facilities in service, Year 2009 (Post-Project)

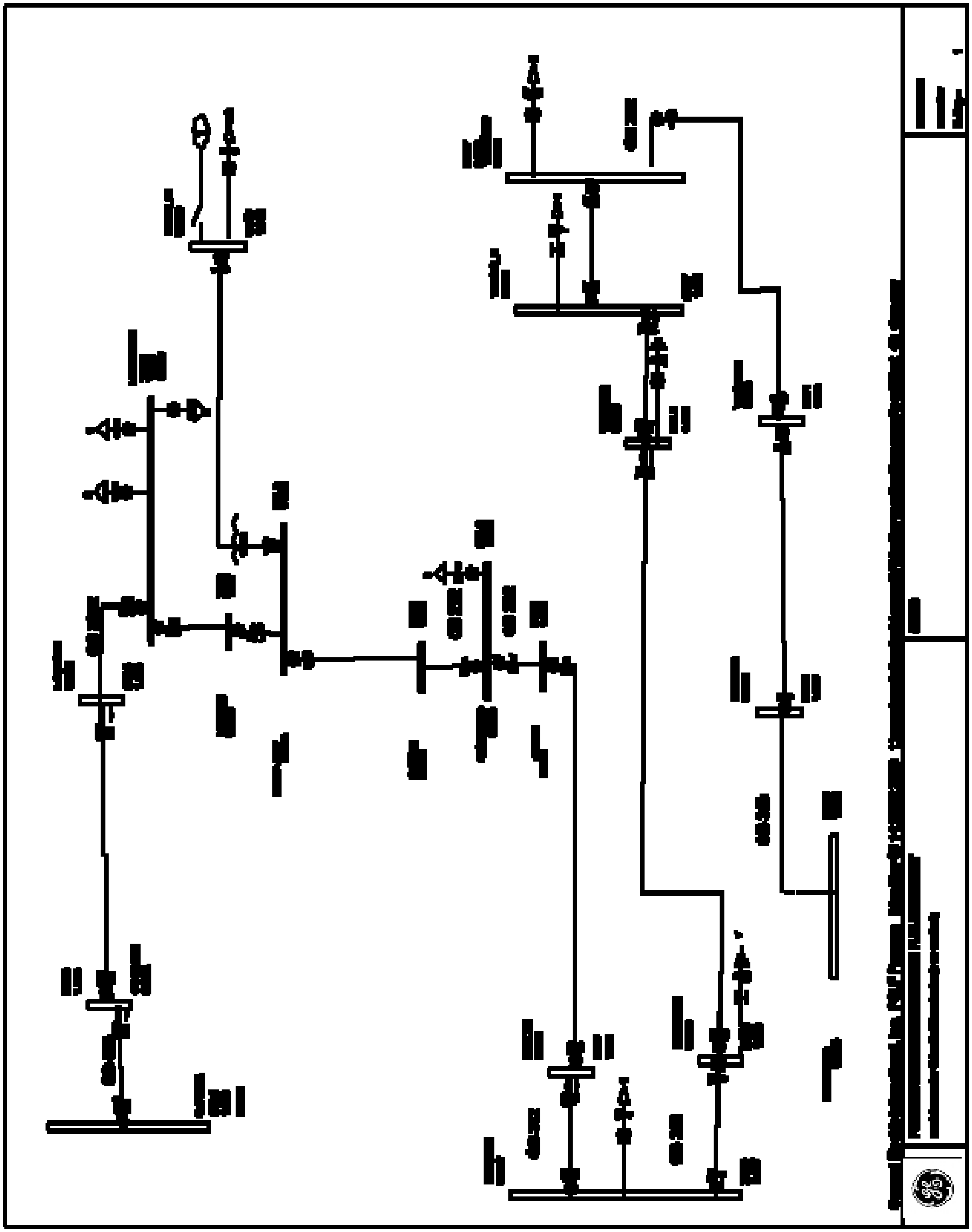


Figure 4-29: Newark CB 340, Year 2009 (Post-Project)

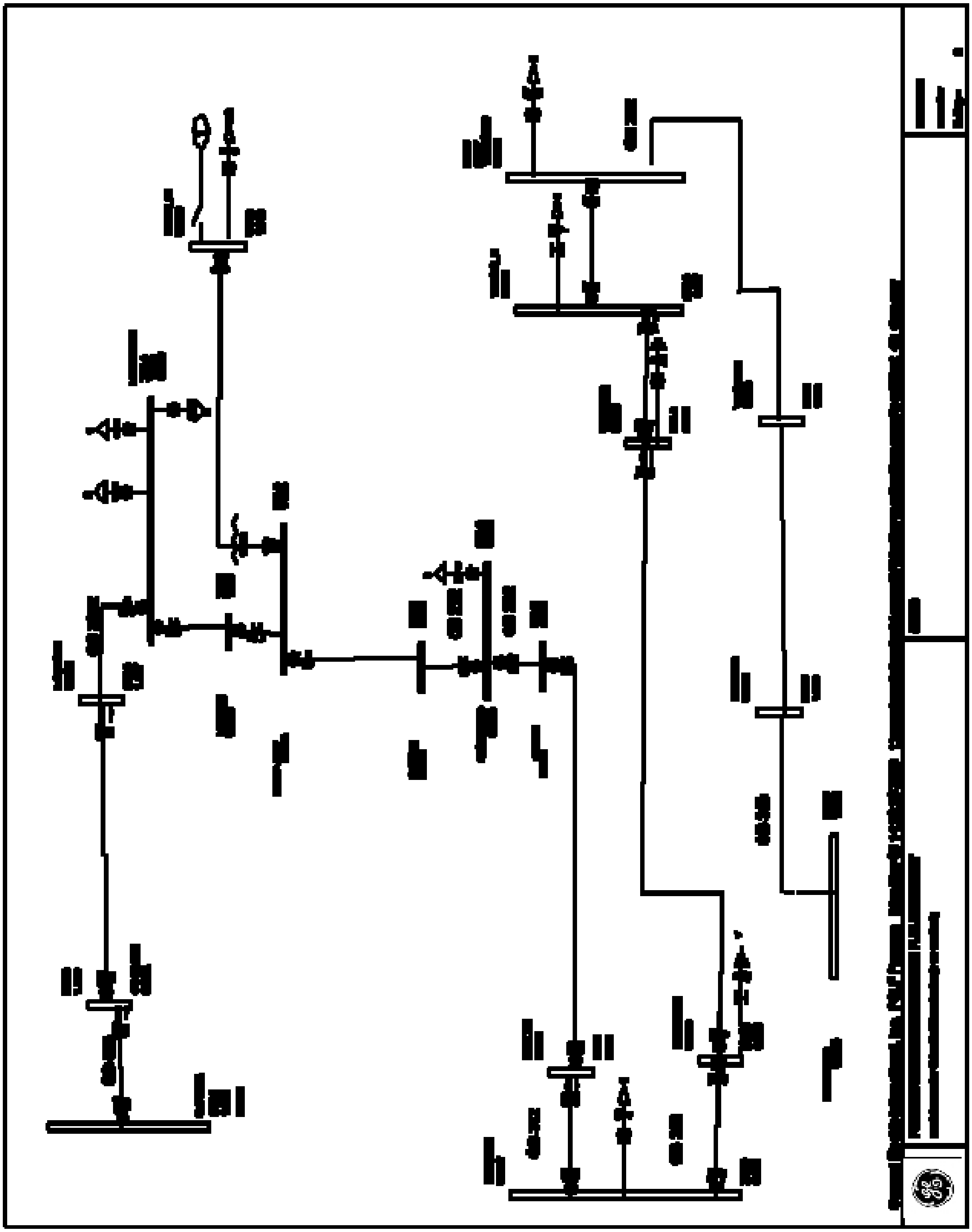


Figure 4-30: Outage of the Vineyard-Newark 230 kV Line, Year 2009 (Post-Project)

Humboldt 115/60 kV Transformer Replacements

TARGETED IN-SERVICE DATE

December 2010

PURPOSE AND BENEFIT

Reliability – NERC Compliance

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROJECT

The project scope is to replace Humboldt 115/60 kV Transformer Nos. 1 & 2 with 200 MVA rated, 115/60 kV transformers.

This project is expected to cost between $10M and $15M.

BACKGROUND

Humboldt County is located along California's northern Pacific coast. Electric customers in the Humboldt area are mainly served by the Company's network of 60 kV transmission lines and distribution substations. Presently, in order to meet the electricity needs of the area, Humboldt relies heavily on the local generation, a local synchronous condenser and power imported via four transmission lines. The Humboldt area demand is projected to reach about 197 MW in 2010 and is expected to increase at 1.2 MW per year.

The importing transmission lines include two 115 kV lines from Cottonwood Substation, one 60 kV line from Trinity Substation to the east and one 60 kV line from Mendocino Substation to the south. The 115 kV lines from Cottonwood are over 100 miles long and the 60 kV lines from Trinity and Mendocino are 55 and 80 miles long, respectively. Humboldt Substation currently has two 115/60 kV transformer banks, each with a normal rating of 36 MVA and a four-hour emergency rating of 45 MVA. Bank No. 1 is comprised of four single-phase 1947 55°C 12.5 MVA, 115/60 kV transformers (three in service, with a fourth spare unit), while Bank No. 2 is comprised of three single-phase 1951 55°C, 12.5 MVA, 115/60 kV transformers.

Planning analysis concluded that the Humboldt 115/60 kV Transformer Nos. 1 & 2 could potentially overload up to 10% above its winter emergency rating, for an outage of the one of the Humboldt Bay Power Plant (HBPP) generation tie line overlapped with one HBPP 60 kV unit during peak loading conditions in 2018.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended. This alternative does not address the potential overload issue.

PROJECT SCHEDULE

- Environmental and Permitting Processes – None
- Design – Started January 2008. Completed August 2008
- Major Equipment –Receive long lead time materials by March 2010
- Construction – TBD
- Operation Date – December 2010

KEY ISSUES

- Land-Use Restrictions – None
- Environmental Concerns – None
- Special Metering or Protection – None
- Common Mode Exposure Items – None
- Interaction with other Projects – Humboldt Reactive Support Project, Humboldt GIS BAAH 60 kV Bus Project.

GEPSLF MODELING INFORMATION

```
#*************************************************************************
#Humboldt 115/60 kV Transformers Replacements Project
#This project will replace existing 115/60 kV banks at Humboldt with two 200 MVA transformer.
#*************************************************************************
#
#Delete unit 1 & 2
OLD_TRAN  31080, 31000, 1, , , , , , , , , , , -1
OLD_TRAN  31080, 31000, 2, , , , , , , , , , , -1
#
#Install new 200 MVA transformers.
NEW_TRAN  31080, 31000, 1, 0.0022, 0.0353, -0.0001, 200, 220, 200, 220, 60, 115, 120, STAT=1, TYPE=1, TAPF=1, ANGLP=0,
REG=31080, VMAX=1.04, VMIN=1.0, STEPP=.00625, TMAX=1.1, TMIN=.9, TAPFP=1, TAPFS=1, GMAG=0.0004, AREA=1,
ZONE=301
NEW_TRAN  31080, 31000, 2, 0.0022, 0.0353, -0.0001, 200, 220, 200, 220, 60, 115, 120, STAT=1, TYPE=1, TAPF=1, ANGLP=0,
REG=31080, VMAX=1.04, VMIN=1.0, STEPP=.00625, TMAX=1.1, TMIN=.9, TAPFP=1, TAPFS=1, GMAG=0.0004, AREA=1,
ZONE=301
#END
```

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagram
2. Demand Forecast
3. Power Flow Summary
4. Pre and Post Project Power Flow Plots

Attachment 1: Scope Diagram

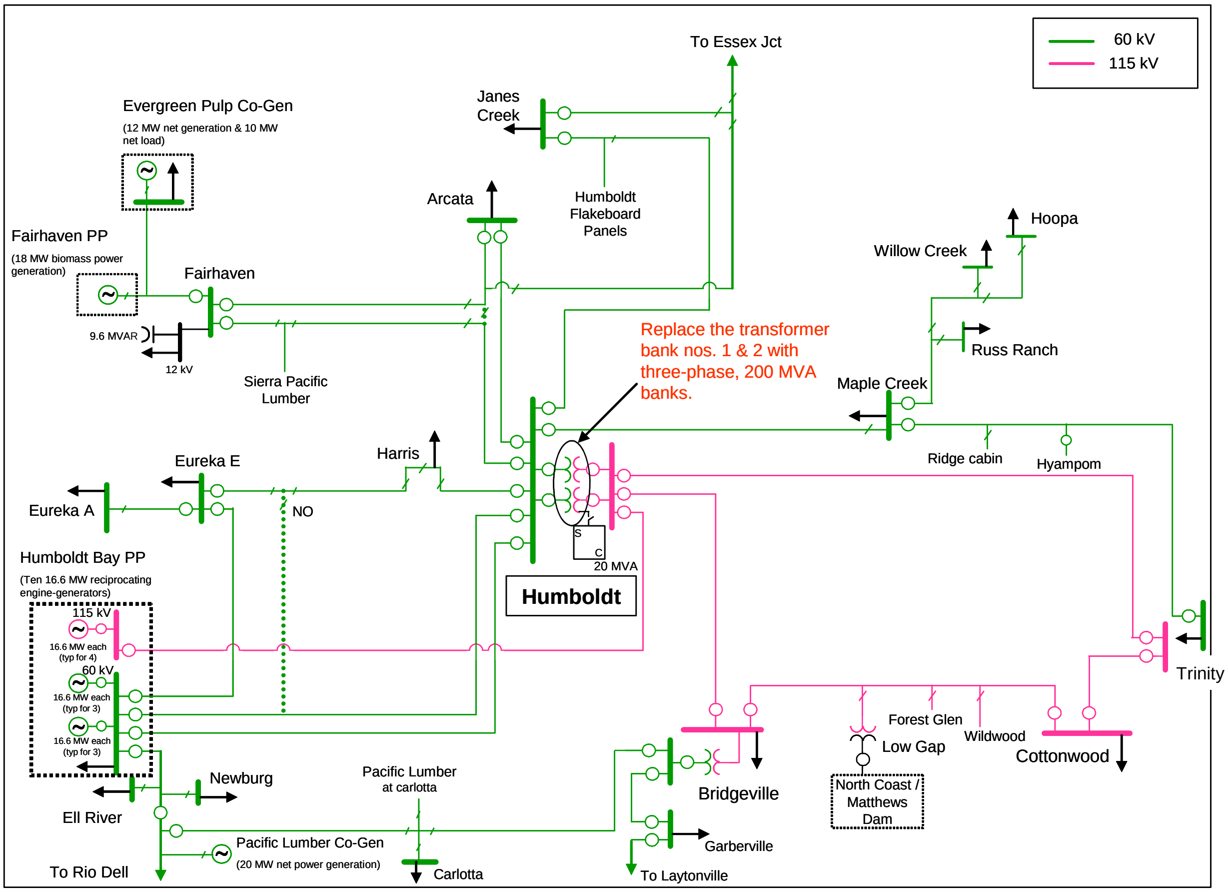


Figure 4-31: Humboldt Substation.

Attachment 2: Demand Forecast

Table 4-8: Area Demand Forecast

Substation	2009	2010	2011	2012	2013	Growth Rate (MW/Year)
Humboldt	194	197	200	203	206	3.0

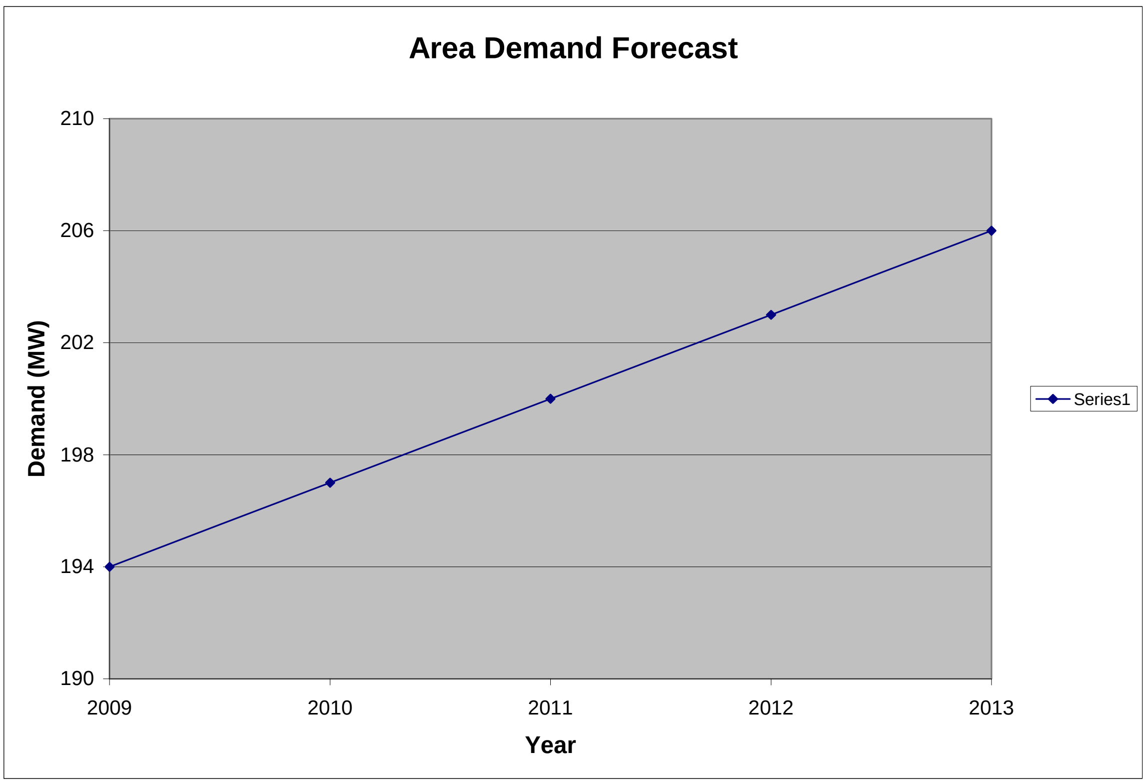


Figure 4-32: Plot of Area Forecast

Attachment 3: Power Flow Summary

Table 4-9: Power Flow Summary

Contingency	Facility Affected	2009 (Pre-Project)	2010 (Pre-Project)	2011 (Pre-Project)	2012 (Pre-Project)	2013 (Pre-Project)	2018 (Pre-Project)	2018 (Post-Project)
One HBPP GSU and one HBPP 60 kV Unit	Humboldt 115/60 kV Transformer Nos. 1 & 2	N/A	92%	94%	96%	98%	110%	22%

Attachment 4: Pre and Post Project Power Flow Plots

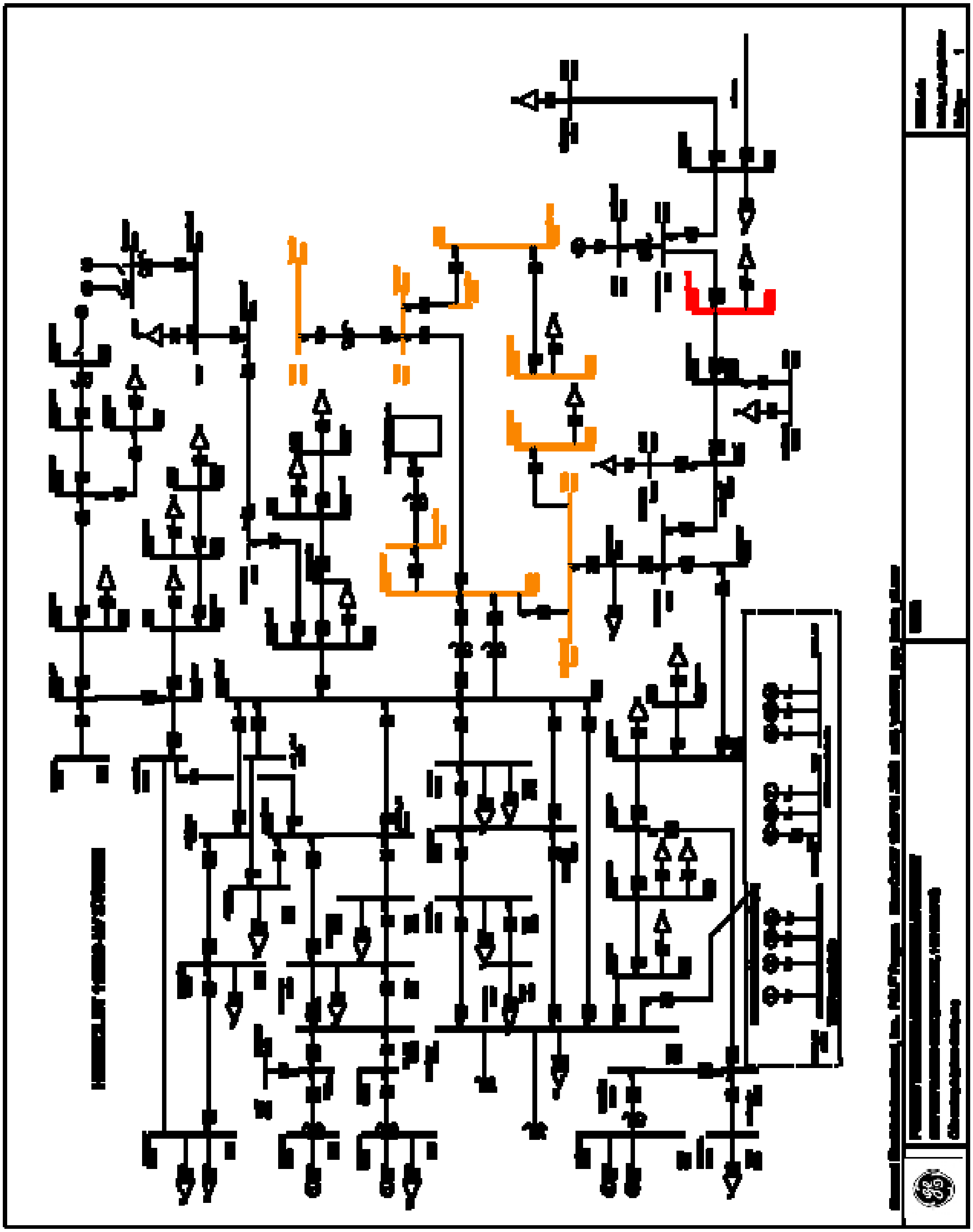


Figure 4-33: Pre Project - Normal Conditions (2018)

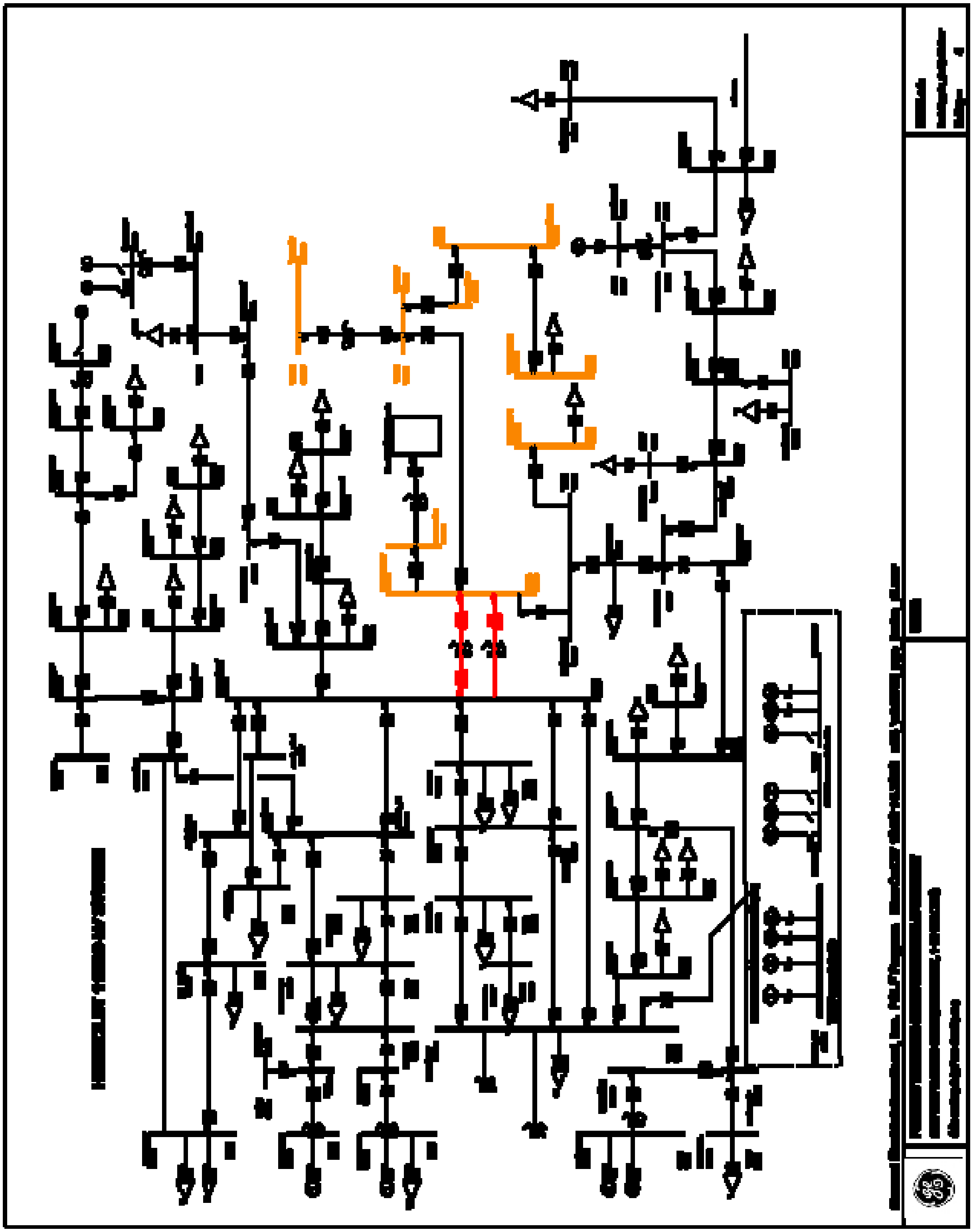


Figure 4-34: Pre Project - Loss of one HBPP gen tie line and one HBPP 60 kV unit (L-1/G-1). (2018)

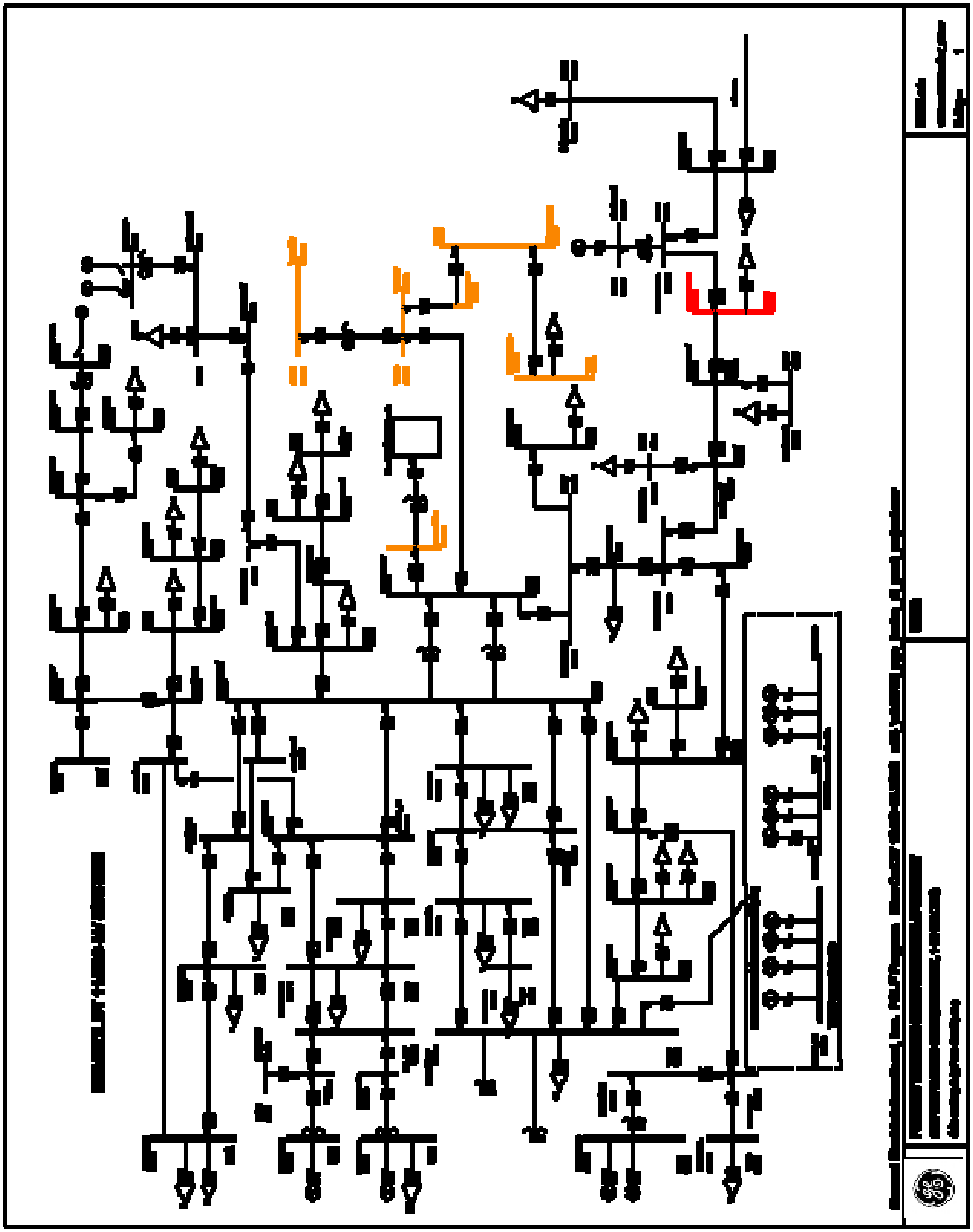


Figure 4-35: Post Project - Normal Conditions (2018)

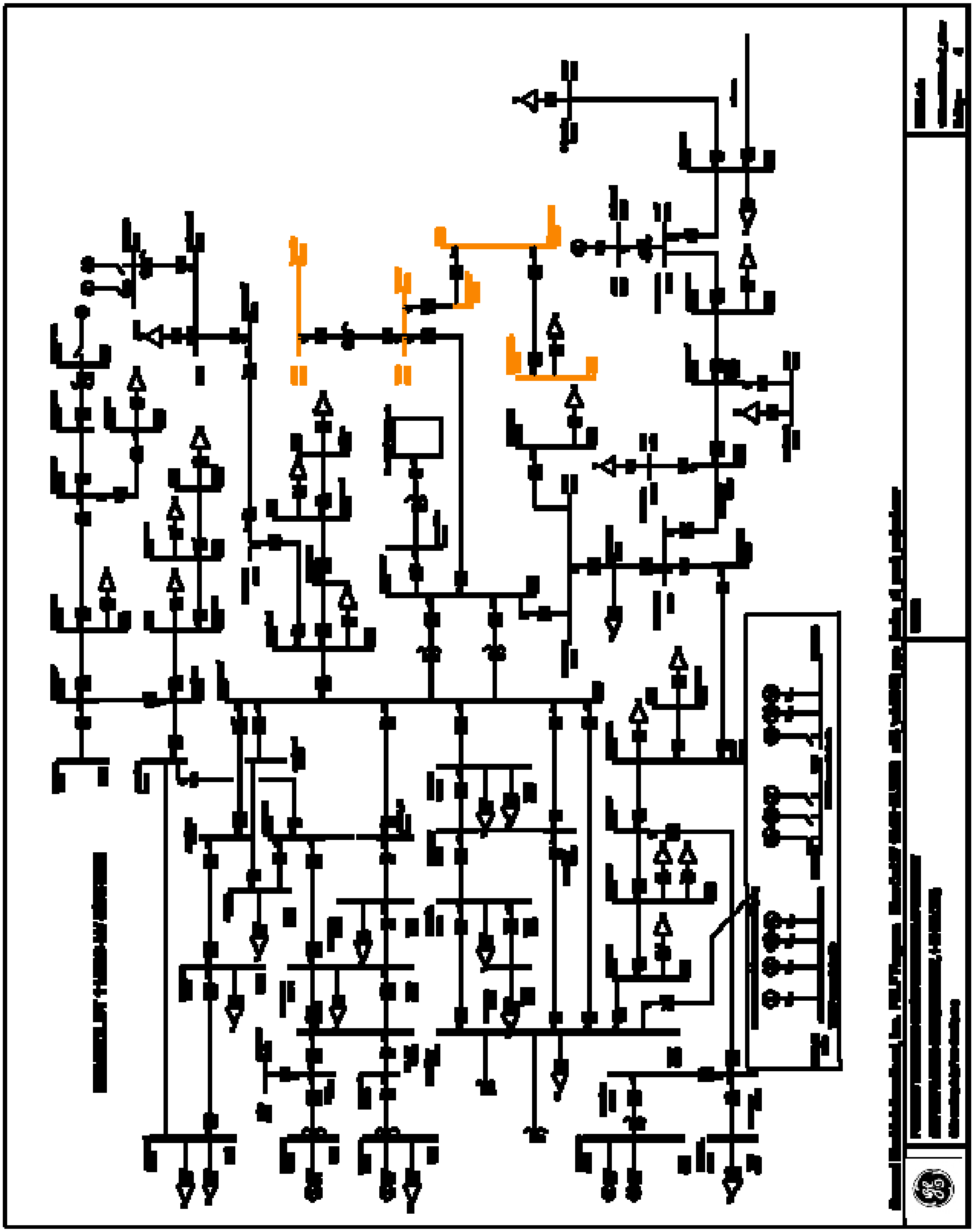


Figure 4-36: Post Project - Loss of the one HBPP gen tie line and one HBPP 60 kV unit (L-1/G-1). (2018)

Kyoho Manufacturing California 115 kV Interconnection

TARGETED IN-SERVICE DATE

June 2010

PURPOSE AND BENEFIT

Reliability – Tariff and Compliance

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROPOSED PROJECT

The preferred plan is to interconnect KHMCA's substation to the electric grid by tapping off PG&E's Stockton "A" – Lockeford – Bellota #2 115 kV Line.

This new tap line, which will be approximately 2 miles long, will be sized to handle a minimum of 40 amps during normal conditions. The new tap line will be tapped on the Stockton "A" – Lockeford – Bellota Line No. 2 near tower 11/80.

This project is estimated to cost between $1M and $5M.

BACKGROUND

The KHMCA automotive parts plant is located in the southern part Stockton. They plan to construct a new 115/12.47 kV substation to serve the 8 MW load, at 90 percent power factor, proposed at the new automotive parts plant.

PG&E has determined that interconnecting the automotive parts plant onto PG&E's 115 kV system is the recommended plan. This plan can be accomplished by building a two-mile 115 kV tap line from the KHMCA's new 115/12.47 kV substation to the Stockton "A" – Lockeford - Bellota Line No. 2. This tap line, which will be owned and operated by PG&E, will be connected near tower 11/80.

A Detailed Interconnection Study (DIS) for this interconnection was completed on August 11, 2008, which was later submitted to KHMCA on August 15, 2008. The DIS report indicated that it is feasible to connect the new KHMCA substation to the PG&E transmission grid and identified the needed interconnection facilities. A power flow assessment, utilizing the CAISO Grid Planning Criteria, was performed to determine the associated system impacts as a result of this interconnection. The reliability assessment results have identified no normal or emergency overloads, nor any voltage concerns, upon the interconnection of KHMCA's automotive parts plant.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

The status quo alternative is not recommended since PG&E has an obligation to serve within its service territory.

Alternative 2: Serve Kyoho from the Stockton "A" – Lockeford – Bellota 115 kV Line

The proposed tap line, which will be approximately 2 miles long, will be sized to handle a minimum of 40 amps during normal conditions. The new tap line will be tapped on the Stockton "A" – Lockeford – Bellota Line No. 2 near tower 11/80.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – June 2010

KEY ISSUES

- Land-Use Restrictions – None
- Environmental Concerns – None
- Special Metering or Protection – Install one set of 230 kV meters with associated CT's and PT's at Ky's substation.
- Common Mode Exposure Items – None

- Interaction with other Projects or Studies – None

GE PSLF MODELING INFORMATION

```
#Serve Kyoho load 8 MW from STCKTNJB-LCKFRDJB 115 kV, 7 miles from STCKTNJB (Stockton A - lockeford - bellota 115 kV #2
line)
#EDRO: June 2010

NEWBUSD   33590  "KYOHOTAP" BASKV=115  BUSTYPE=2 VSCHED=1.0  AREA=11 ZONE=311 VMAX=1.05 +
VMIN=.95 OWN=390
NEWSECDD  33552  33590     1    SEC=1 RPU=.007420 XPU=.036400 BPU=.005509 MVA1=125 MVA2=147 +
MVA3=193 MVA4=193 STATUS=0
NEWSECDD  33590  33558     1    SEC=1 RPU=.003180 XPU=.015600 BPU=.002361 MVA1=125 MVA2=147 +
MVA3=193 MVA4=193 STATUS=0
NEWLOAD   33590     1       PLOAD=8   PF=.9  ST=0  ZONE=311
SOLV

#Turn on lines and load

OLDSECDD  33552  33590    1  STAT=1
OLDSECDD  33590  33558    1  STAT=1
PURGE     33552  33558  1  1
OLDLOAD   33590  1  ST=1
SOLV
```

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagrams
2. Power Flow Summary
3. Pre and Post Project Power Flow Plots

Attachment 1: Scope Diagrams

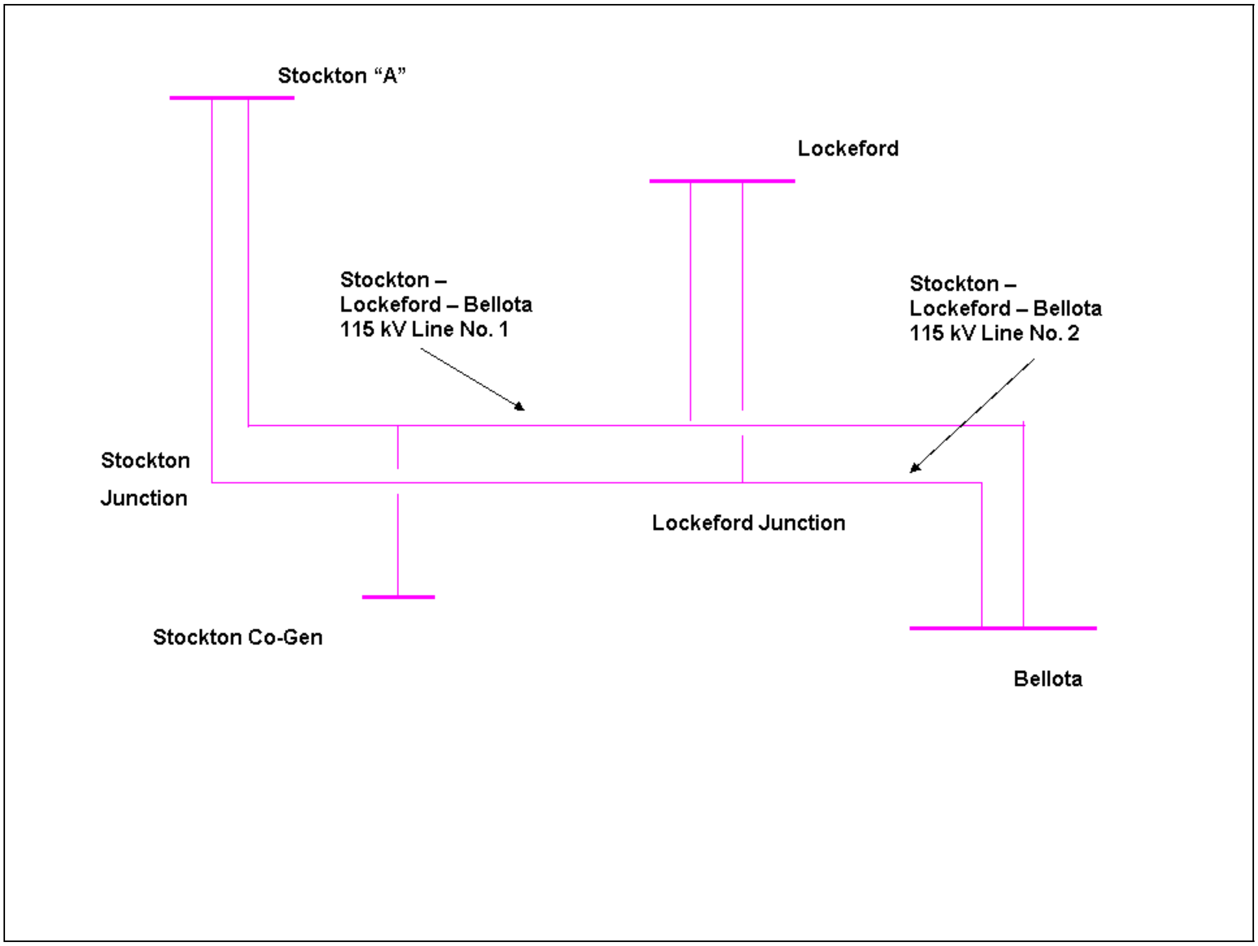


Figure 4-37: Existing Scope Diagram

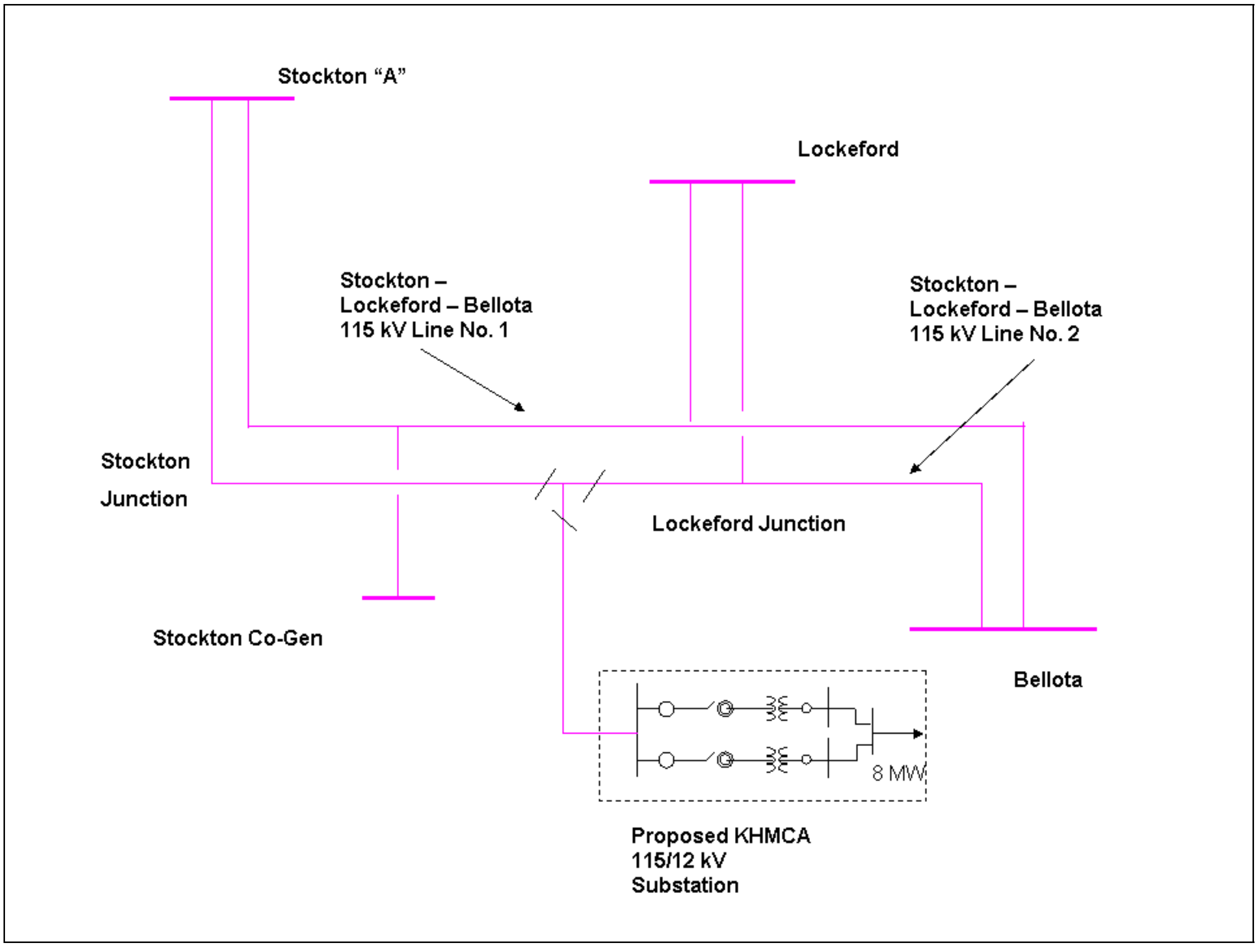


Figure 4-38: Proposed Scope Diagram

Attachment 2: Power Flow Summary

Table 4-10: Power Flow Summary

Contingency	Facility Affected	2013 (Pre-Project)	2013 (Post-Project)
Normal Conditions (N-0)	Stockton "A" – Lockeford – Bellota No. 1 (Stockton A – STN COGN)	65%	65%
	Stockton "A" – Lockeford – Bellota No. 2 (Lockeford Jct B – Bellota)	34%	40%
Stockton "A" – Lockeford – Bellota No. 1/Stockton Co-Gen (L-1/G-1)	Stockton "A" – Lockeford – Bellota No. 2 (Stockton B – Stockton Jct B)	92%	92%
	Stockton "A" – Lockeford – Bellota No. 2 (Lockeford Jct B – Bellota)	68%	74%

Attachment 3: Pre and Post Project Power Flow Plots

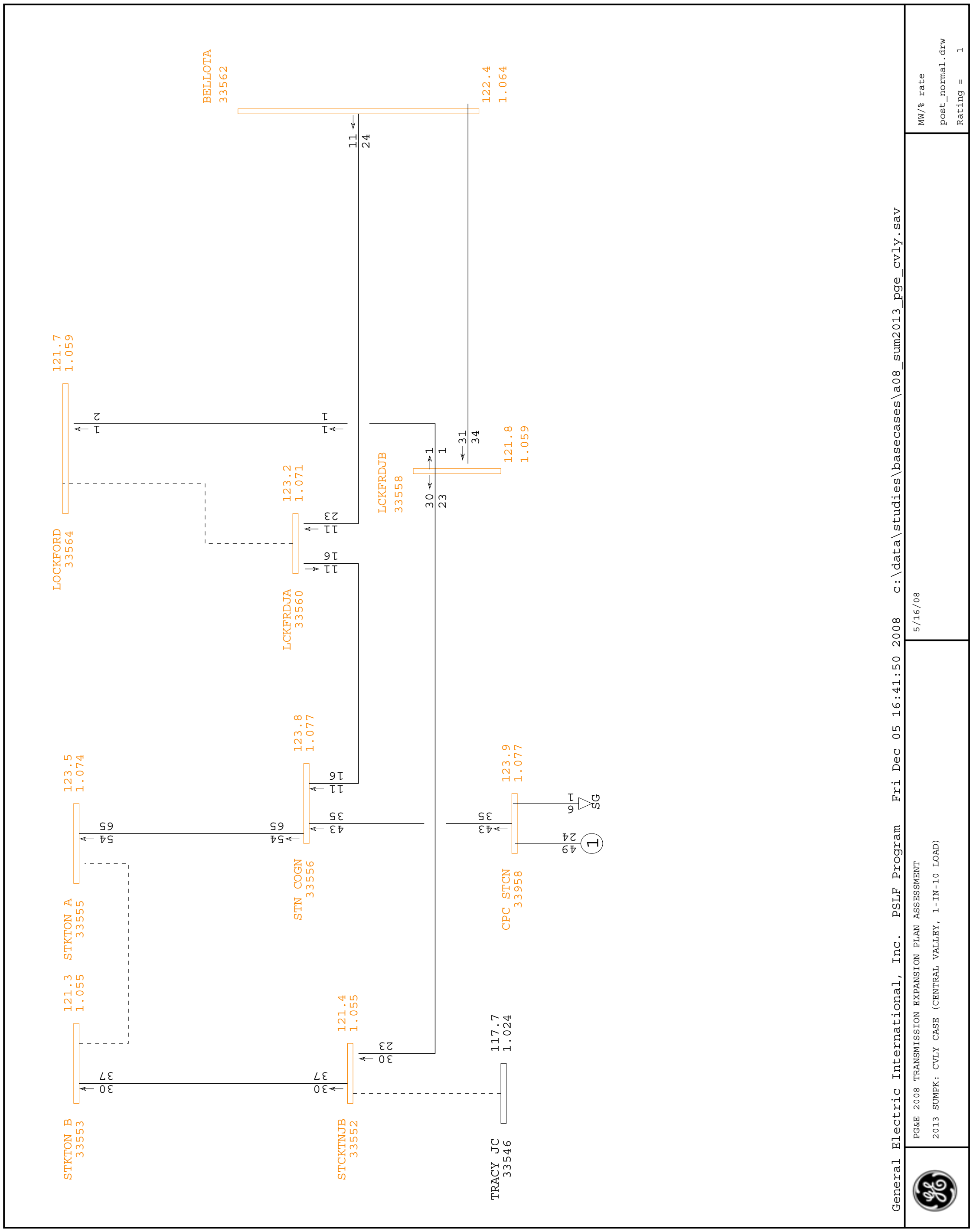


Figure 4-39: Pre-Project Power Flow Plot (Normal)

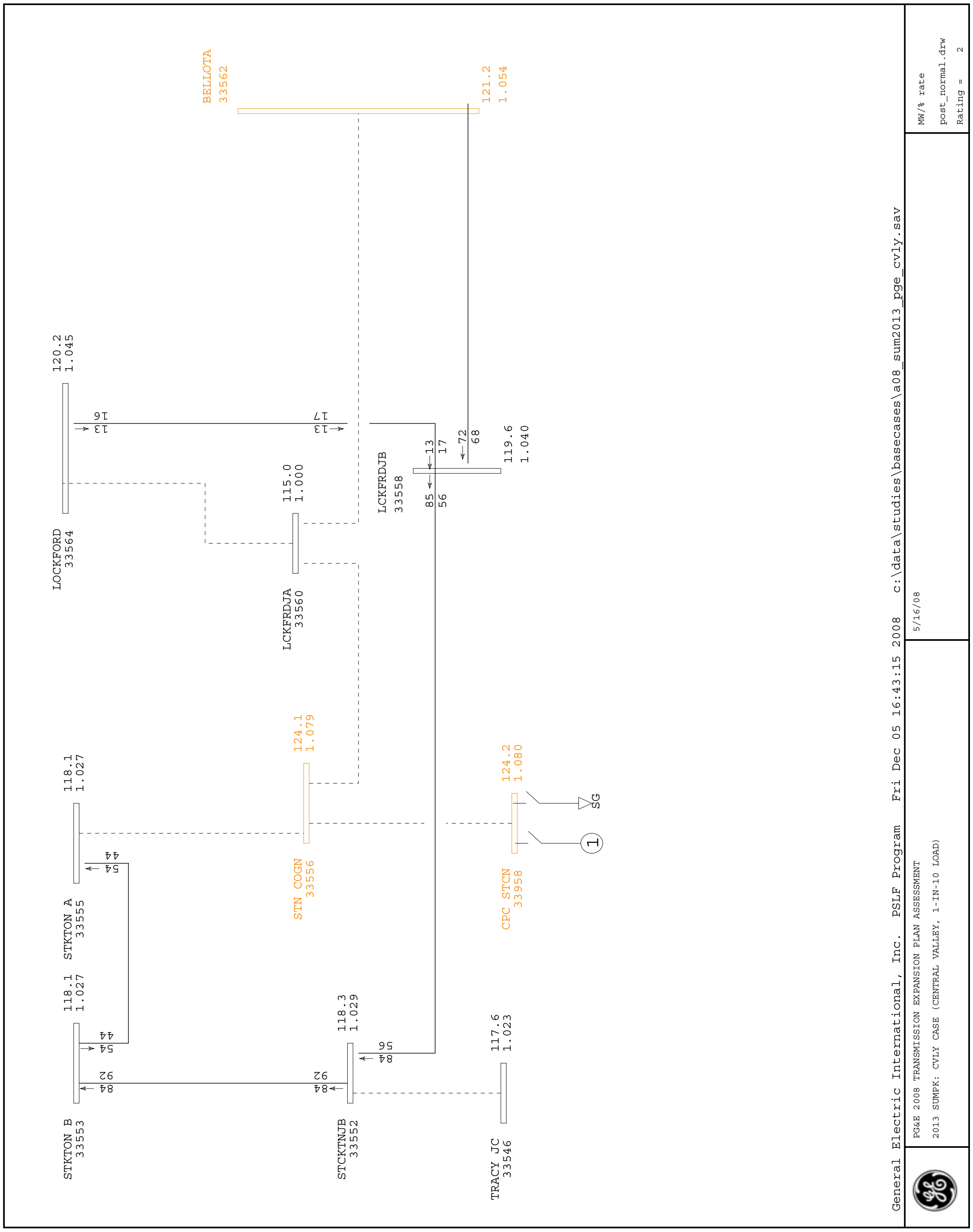


Figure 4-40: Pre-Project Power Flow Plot (Contingency 1: Loss of Stockton "A" – Lockeford – Bellota 115 kV Line No. 1 and loss of Stockton Co-Gen with Stockton A Bank 1 transferred to Stockton "A" – Lockeford – Bellota 115 kV Line No. 2)

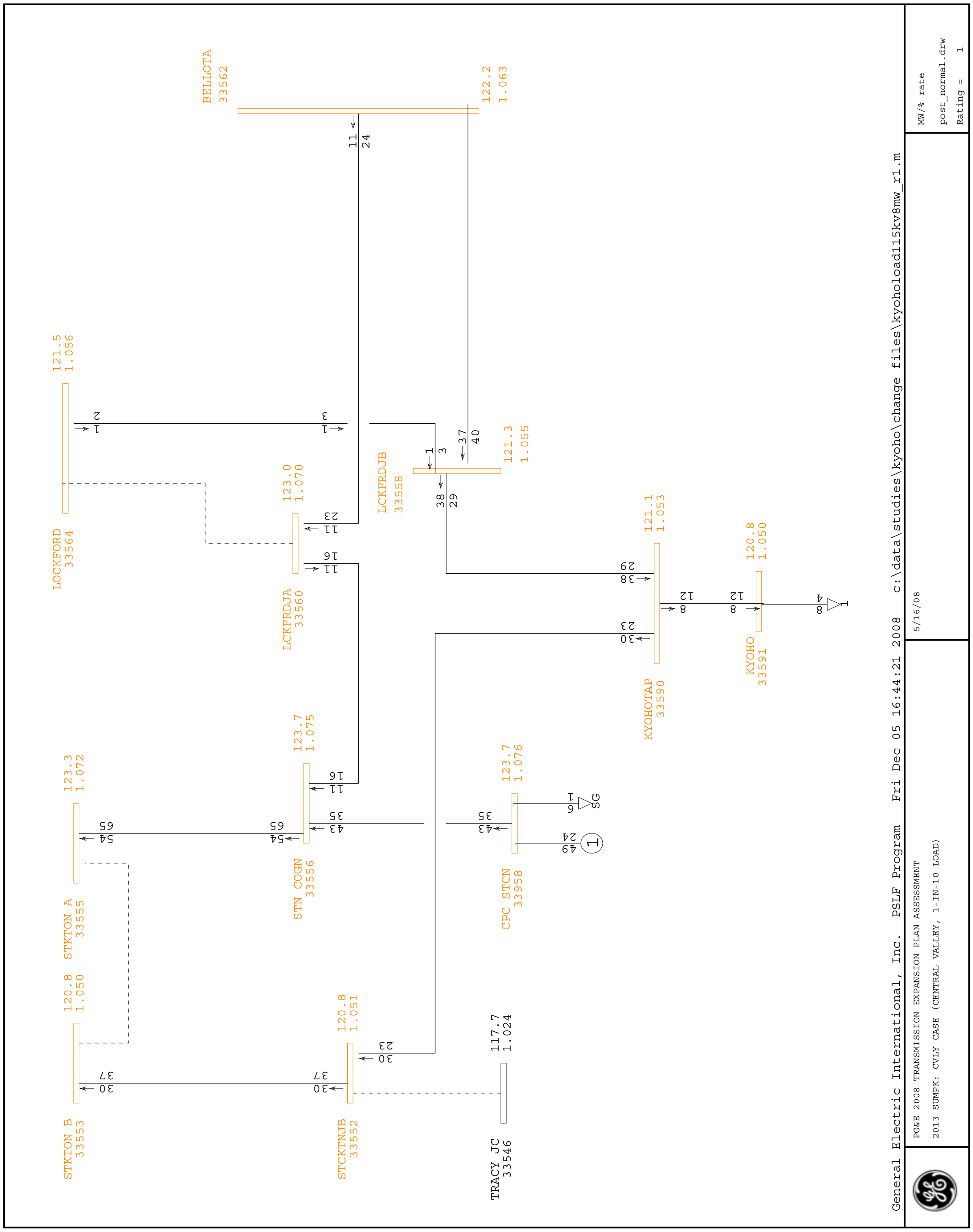


Figure 4-41: Post-Project Power Flow Plot (Normal)

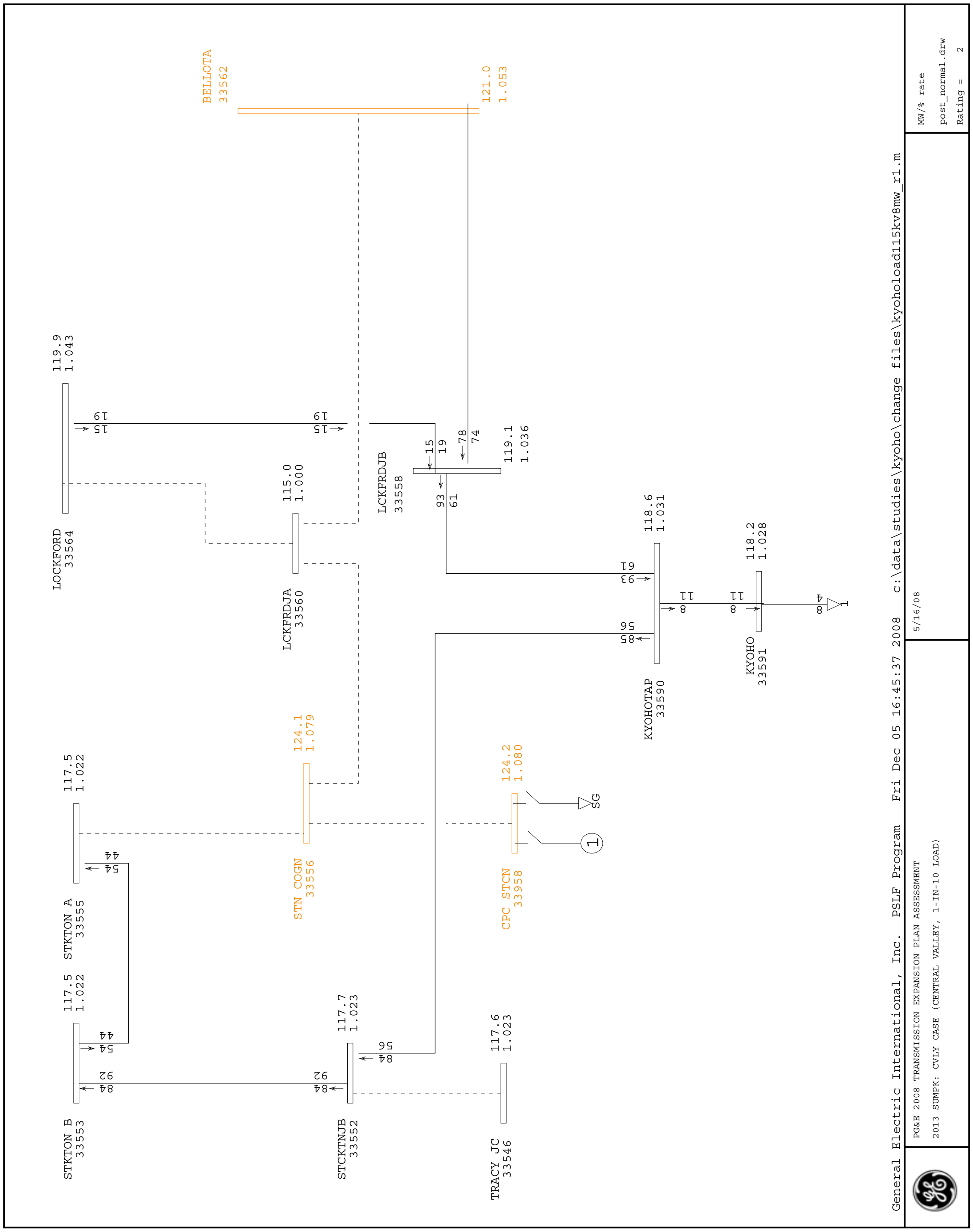


Figure 4-42: Post-Project Power Flow Plot (Contingency 1: Loss of Stockton "A" – Lockeford – Bellota 115 kV Line No. 1 and loss of Stockton Co-Gen with Stockton A Bank 1 transferred to Stockton "A" – Lockeford – Bellota 115 kV Line No. 2)

Lakeville No. 2 60 kV Line Switch Upgrade

TARGETED IN-SERVICE DATE

May 2010

PURPOSE AND BENEFIT

Reliability – NERC Compliance

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROJECT

The project scope is to replace the existing, 400 Amp rated, 60 kV line switch No. 57 on the Lakeville No. 2 60 kV Line. This new switch will be sized to handle a minimum rating of 600 Amps continuous current.

This project is expected to cost less then $1M.

BACKGROUND

The Lakeville No. 2 60 kV Line, located in Sonoma County, is approximately 22 miles long (including all taps). The Lakeville-Petaluma “A” section of this line is sized with 397 AAC conductors, which has a summer normal and emergency interior rating of 440 Amps and 514 Amps, respectively. However, the capacity of this line is currently limited to 400 Amps due to a limiting line switch (No. 57).

Under projected 2009 peak demand conditions, the Lakeville No. 2 60 kV Line could potentially overload by 7% following an outage of the Lakeville-Petaluma “C” 60 kV Line (L-1).

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO Grid Planning Criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended. This alternative does not address the potential overload issue.

PROJECT SCHEDULE

- Environmental and Permitting Processes – None
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2010

KEY ISSUES

- Land-Use Restrictions – None
- Environmental Concerns – None
- Special Metering or Protection – None
- Common Mode Exposure Items – None
- Interaction with other Projects – None

GEPSLF MODELING INFORMATION

```
#************************************************************************
# Lakeville No. 2 60 kV Line Switch Upgrade
# Description:
# This project will replace the limiting switch (No. 57) on the Lakeville No. 2 60 kV Line.
#*****************************************************************************
#
# Replace the Lakeville No. 2 60 kV Line with 600 amp CC rated switch
OLDSECDD  31390, 31394, CKT=1, SEC=1, STATUS=1,MVA1=46, MVA2=53, MVA3=69, MVA4=74
#END
```

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagram
2. Demand Forecast
3. Power Flow Summary
4. Pre and Post Project Power Flow Plots

Attachment 1: Scope Diagram

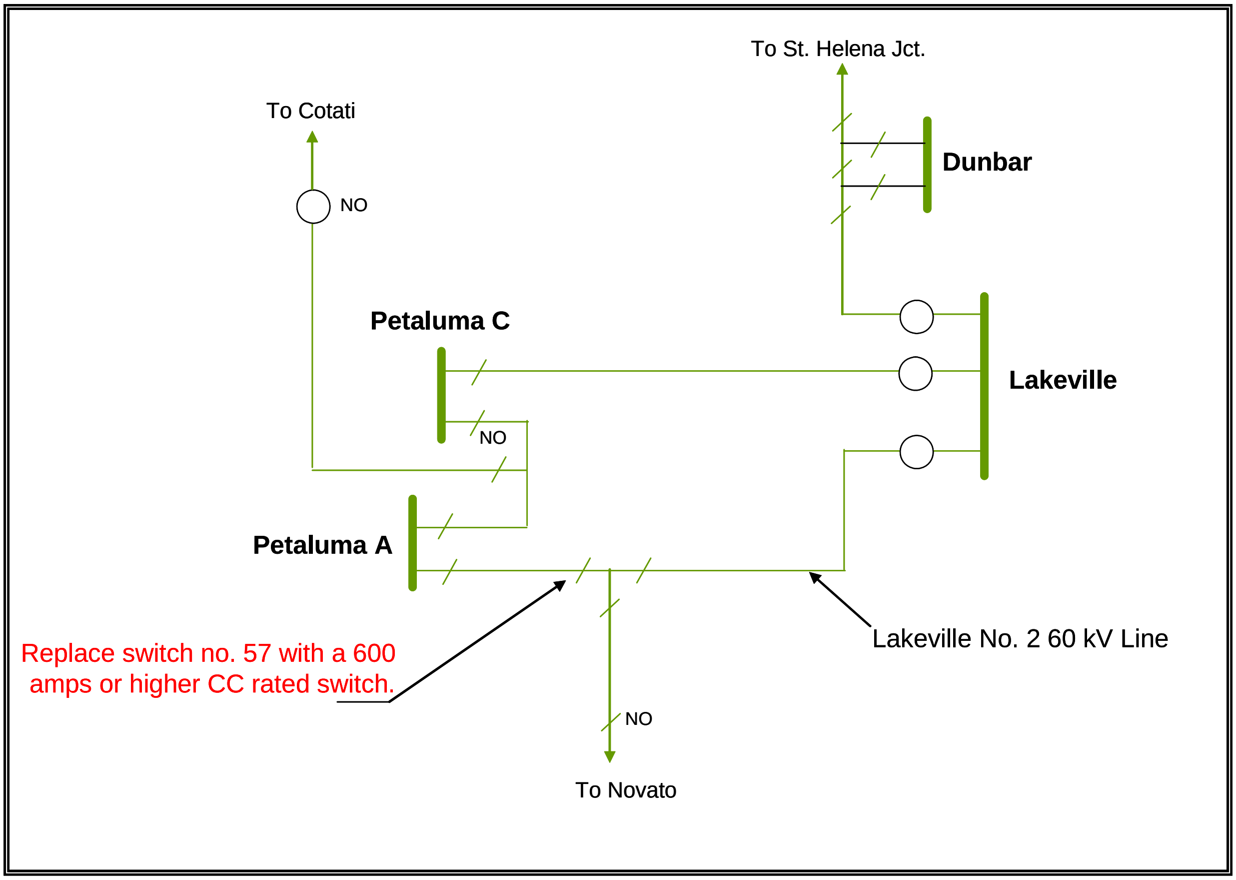


Figure 4-43: Lakeville 60 kV System

Attachment 2: Demand Forecast

Table 4-11: Area Demand Forecast

Substation	2009 (MW)	2010 (MW)	2011 (MW)	2012 (MW)	2013 (MW)	Growth Rate (MW/Year)
Petaluma A	2.8	2.9	3.0	3.0	3.1	0.1
Petaluma C	41.5	42.1	42.9	43.7	44.3	0.7
Totals	**44**	**45**	**46**	**47**	**47**	**0.8**

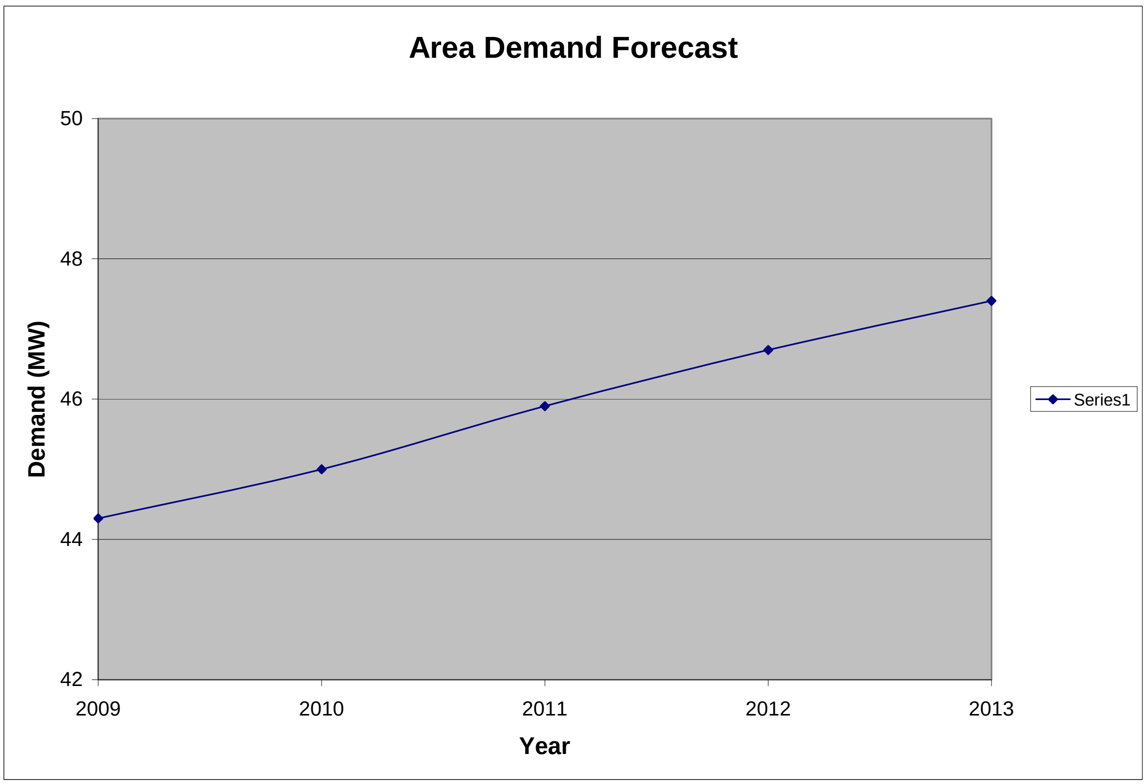


Figure 4-44: Plot of Area Forecast

Attachment 3: Power Flow Summary

Table 4-12: Power Flow Summary

Contingency	Facility Affected	2009 (Pre-Project)	2010 (Pre-Project)	2011 (Pre-Project)	2012 (Pre-Project)	2013 (Pre-Project)	2018 (Pre-Project)	2018 (Post-Project)
Lakeville No. 2 60 kV Line	Lakeville-Petaluma C 60 kV Line	107%	109%	111%	113%	115%	124%	97%

Attachment 4: Pre and Post Project Power Flow Plots

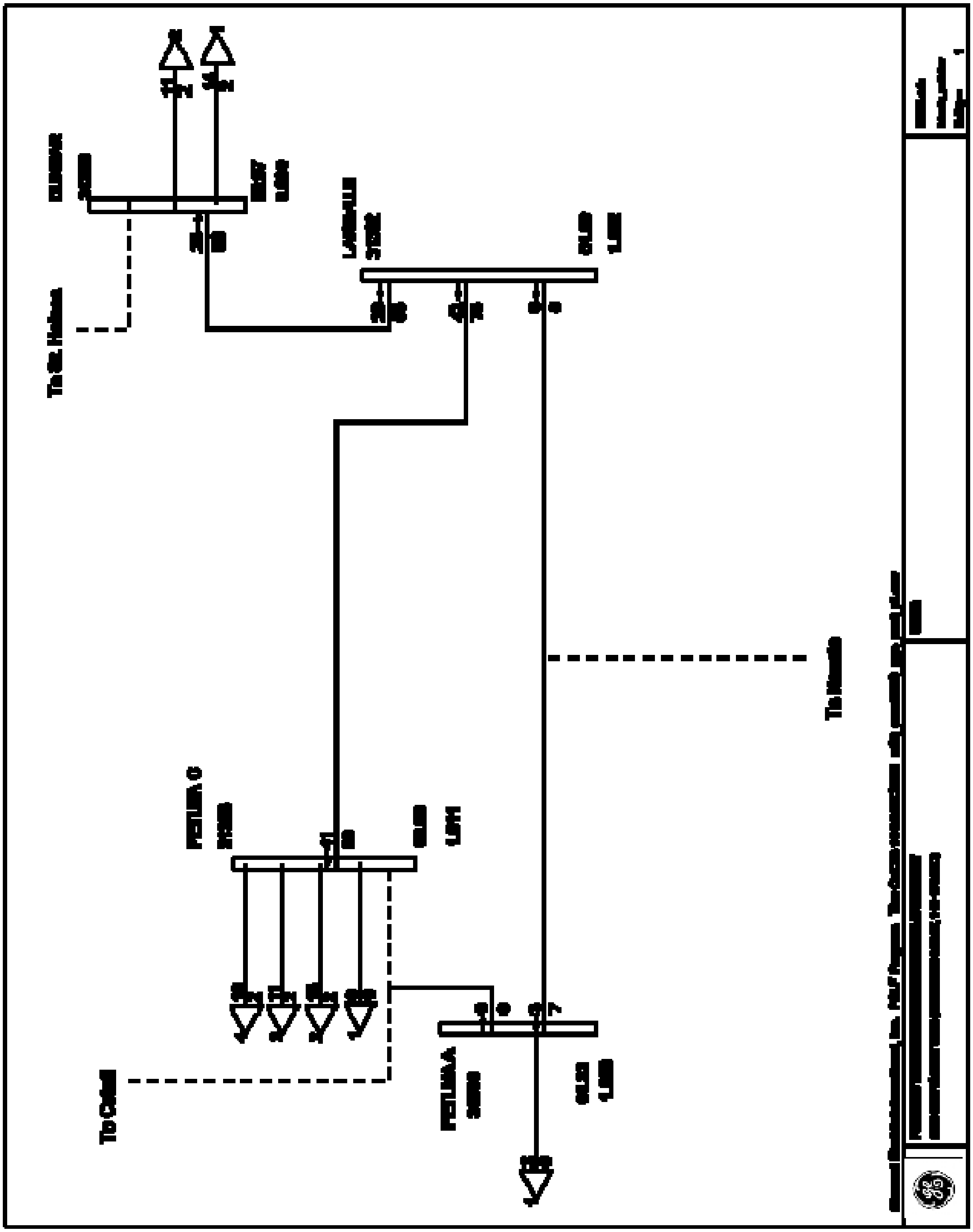


Figure 4-45: Pre-Project – Normal Conditions. (2009)

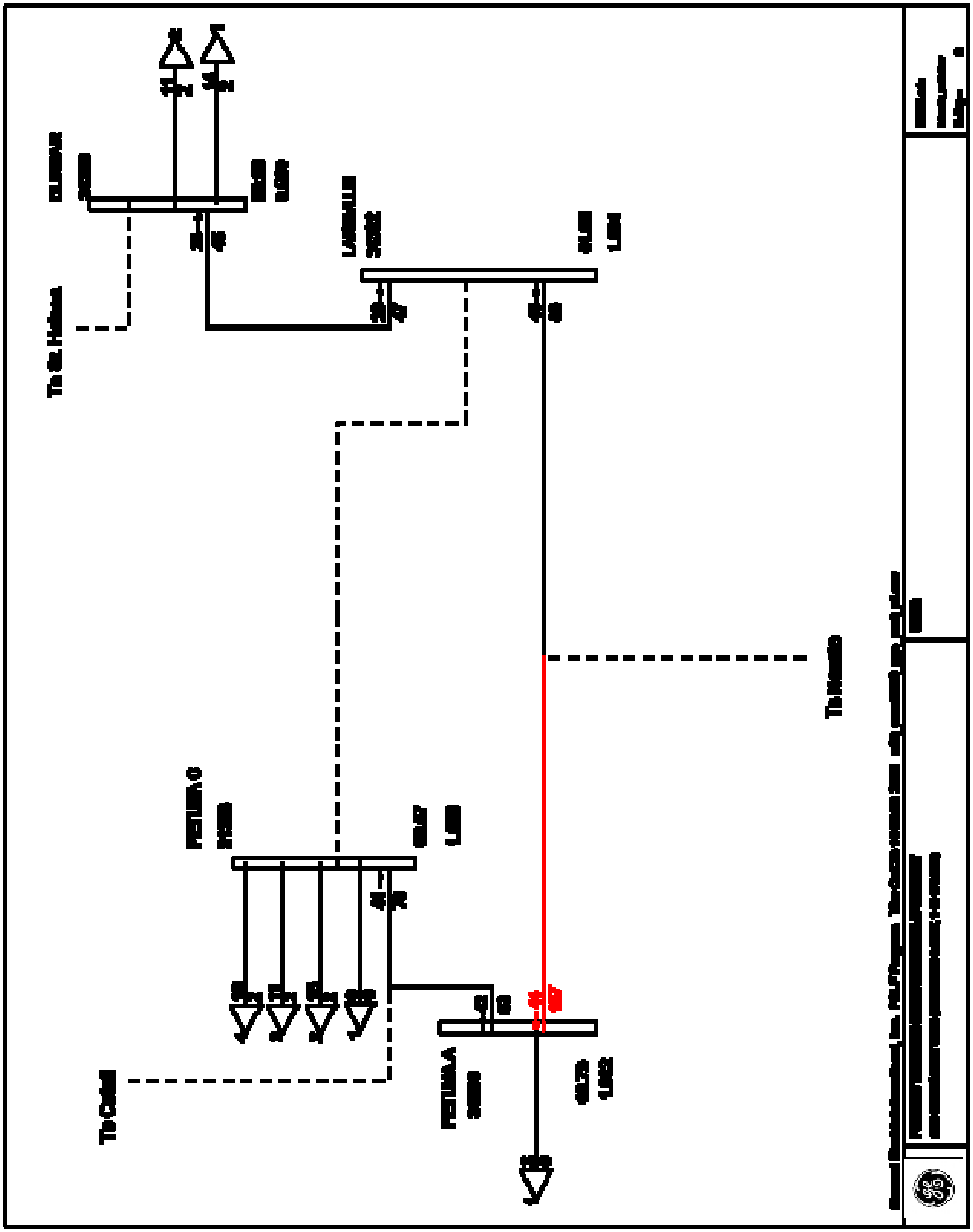


Figure 4-46: Pre-Project – Loss of the Lakeville-Petaluma C 60 kV Line (L-1). (2009)

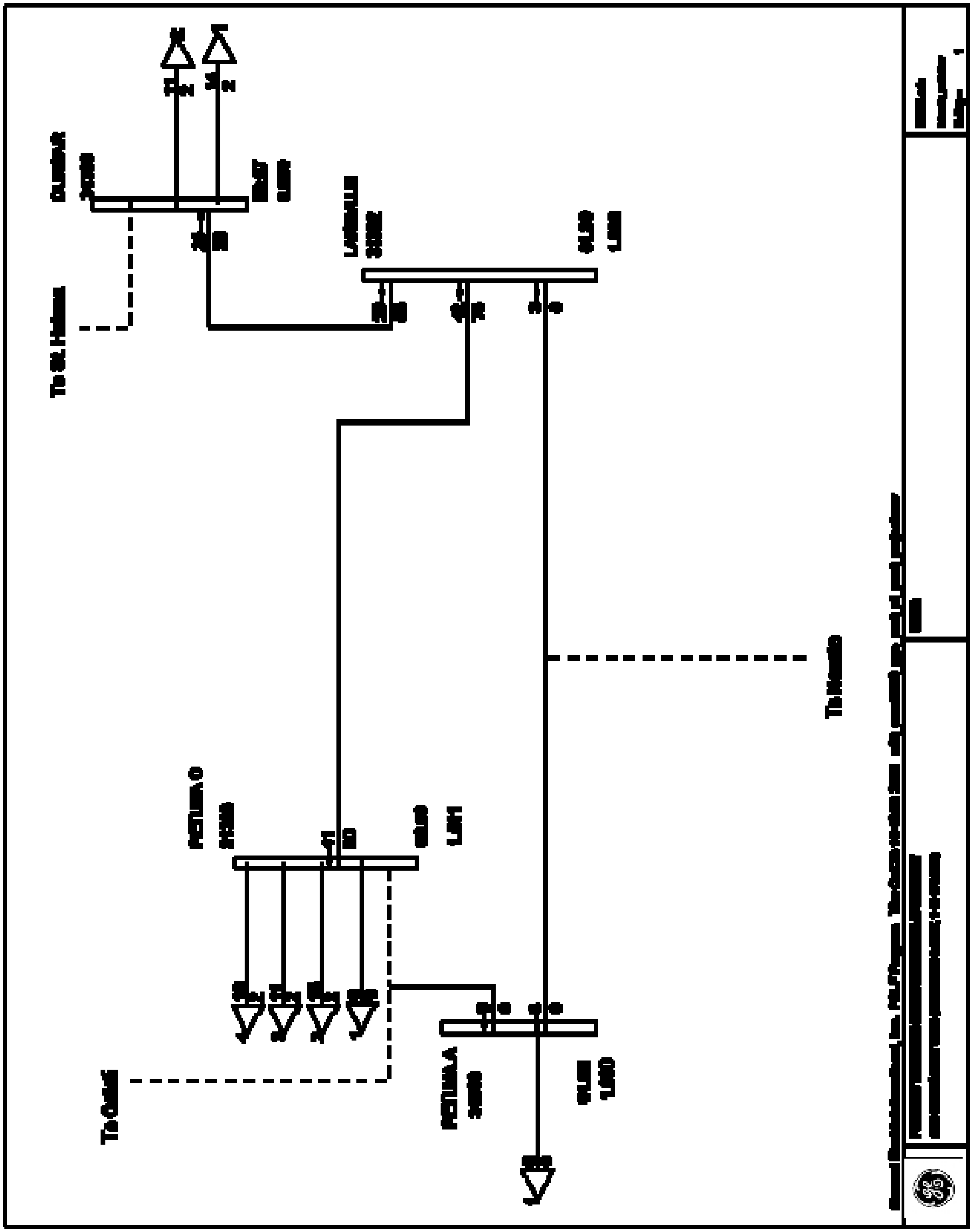


Figure 4-47: Post-Project – Normal Conditions. (2009)

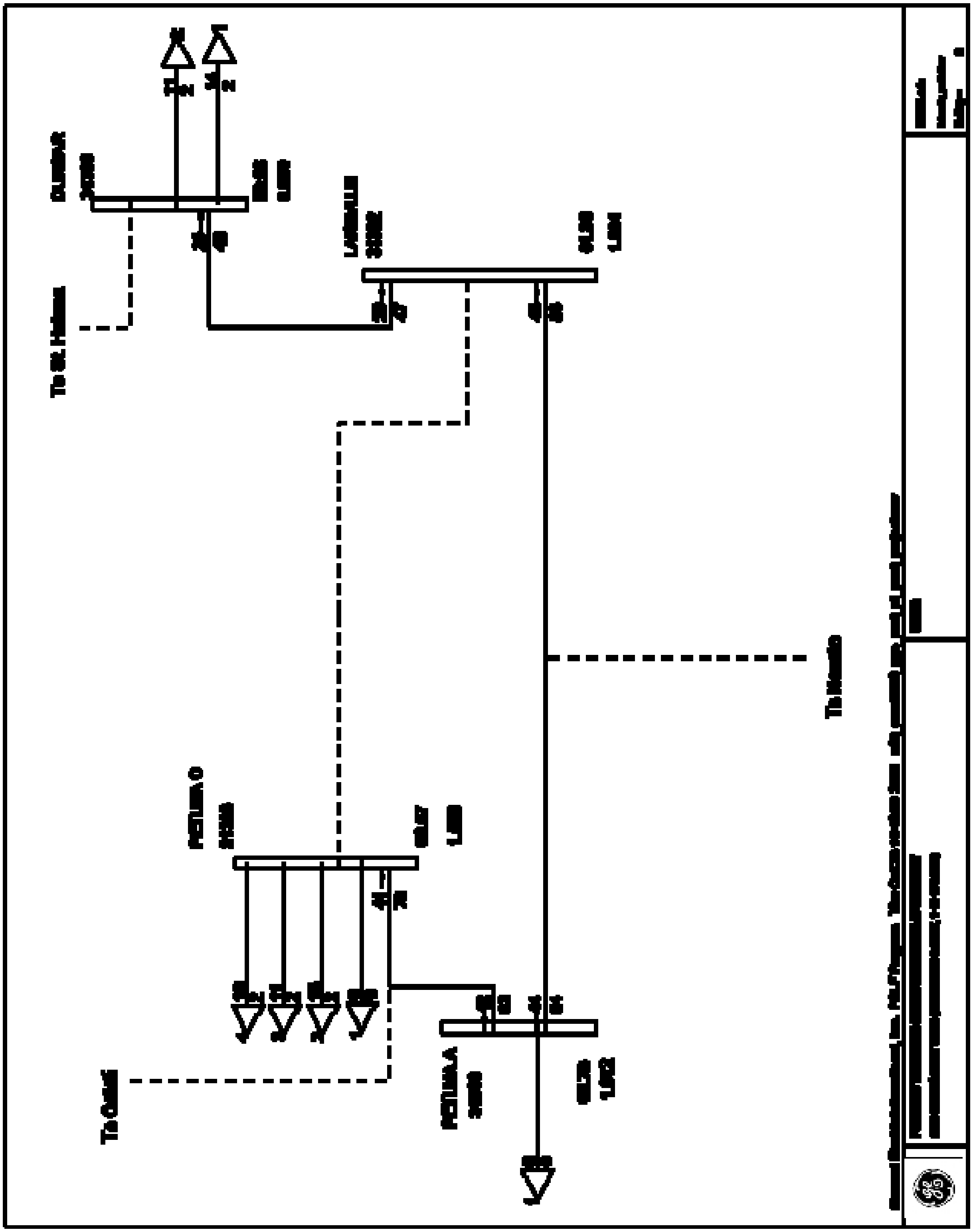


Figure 4-48 : Post-Project – Loss of the Lakeville-Petaluma C 60 kV Line (L-1). (2009)

Newburg Second 60 kV Tap and SCADA Installation

TARGETED IN-SERVICE DATE

May 2010

PURPOSE AND BENEFIT

Reliability – Operational Flexibility

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROJECT

The project scope is to install a second 60 kV tap to Newburg Substation off the Humboldt Bay-Rio Dell Junction 60 kV Line. This second tap will be constructed with conductors capable of carrying a minimum of 443 Amps under winter normal conditions and 473 Amps under winter emergency conditions. In addition, this project will also install SCADA capability to the two existing and one new 60 kV switches at Newburg Substation. Specifically these switches are switch Nos. 27, 29, and a new switch.

This project is expected to cost between $1M and $2M.

BACKGROUND

Newburg Substation, located near the City of Fortuna, is a distribution substation that serves the greater Fortuna area load. Newburg Substation has two 60/12 kV distribution banks and is connected to the transmission grid via the Humboldt Bay-Rio Dell Junction 60 kV Line.

The Humboldt Bay-Rio Dell Junction 60 kV Line is comprised of approximately 18 miles (including all tap lines) of various conductor sizes and is constructed mainly on single wood poles. Newburg Substation, which has an electric peak demand of about 8.5 MW, is served by a single tap off the Humboldt Bay-Rio Dell Junction 60 kV Line. Under this arrangement, over 6,000 customers at Newburg Substation experience all momentary and sustained outages on the Humboldt Bay-Rio Dell Junction 60 kV Line. Newburg's 60 kV line sectionalizing capability is comprised of MOAS Switches 27 and 29.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO Grid Planning Criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended. It does not address a 60 kV line outage which impacts over 6,000 electric customers served from Newburg Substation.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2010

KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – TBD
- Special Metering or Protection – None
- Common Mode Exposure Items – None
- Interaction with other Projects – None.

GEPSLF MODELING INFORMATION

N/A

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagram
2. Demand Forecast

Attachment 1: Scope Diagram

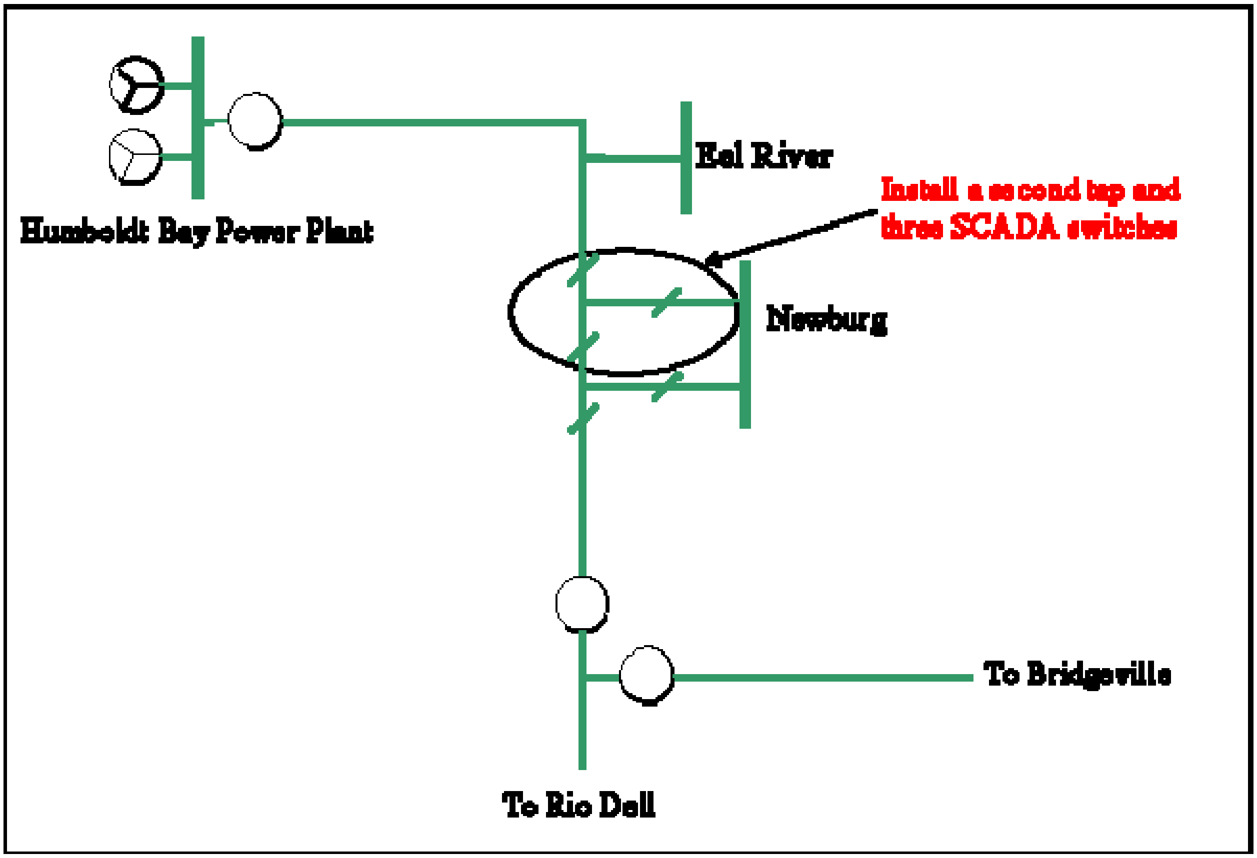


Figure 4-49: Project Scope Diagram

Attachment 2: Demand Forecast

Table 4-13: Area Demand Forecast

Substation	2009 (MW)	2010 (MW)	2011 (MW)	2012 (MW)	2013 (MW)	Growth Rate (MW/Year)
Eel River	11.8	12.0	12.2	12.4	12.5	0.2
Newburg	10.9	11.1	11.2	11.4	11.6	0.2
Totals	**22.7**	**23.1**	**23.4**	**23.8**	**24.1**	**0.4**

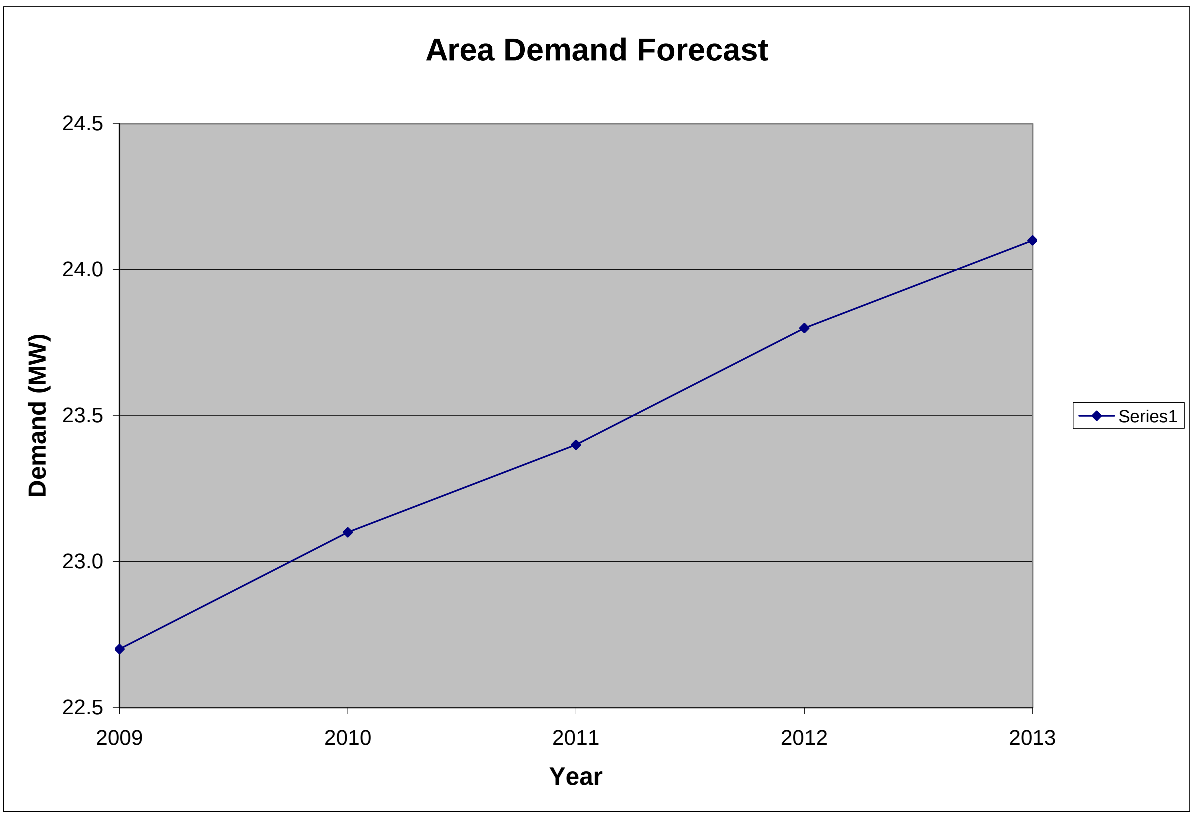


Figure 4-50: Plot of Area Forecast

Carbona Reliability

TARGETED IN-SERVICE DATE

May 2010

PURPOSE AND BENEFIT

Reliability – NERC Compliance and Operational Flexibility

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROJECT

The project scope is to:

- Install new 1,200 Amp 60 kV circuit breaker at Kasson Substation
- Reconfigure Carbona No. 1 60 kV Tap Line (300 feet new line section) to terminate at the new circuit breaker at Kasson Substation.
- Install two SCADA controlled transmission line switches on Carbona No. 1 and 2 60 kV Tap Lines by upgrading Carbona Switch Nos. 37 and 39
- Rerate the remaining portion (4.4 miles of #2/0 CU conductors) of the Carbona No. 1 60 kV Tap Line to 4 feet per second wind speed ratings of 336 Amps normal and 386 Amps emergency.

This project is expected to cost between $1M and $5M.

In addition, the following maintenance work will be completed along with the above project scope:

- Reconductor the Carbona No. 1 60 kV Tap Line from Pole # 11/85 to Carbona Substation (2.8 circuit miles of annealed #4 CU and 397.5 AAL conductors) with a higher capacity conductor (603 Amps or greater)

Completion of this project and the maintenance work will provide an alternative source to Carbona Substation with the ability to transfer the entire substation load remotely.

BACKGROUND

Carbona Substation serves electric customers in San Joaquin County. The 2008 projected peak load for this substation is approximately 32 MW and is forecast to increase at a rate of 0.5 MW or 1.6% per year. The majority of customers served from Carbona Substation are industrial customers. A sustained outage to Carbona Substation has a significant impact to the operations and production of major industrial customers with lost revenue totaling in the tens of thousands.

Electrically, this substation is interconnected onto to the Kasson No. 1 60 kV Line via two 60 kV transmission tap lines: Carbona No. 1 and 2 60 kV Tap Lines. Carbona No. 2 60 kV Tap Line serves as the primary source for Carbona Substation. Carbona No.1 60 kV Tap Line serves as an alternate emergency back-tie should Carbona No. 2 60 kV Tap Line be out of service. However, Carbona No. 1 60 kV Tap Line was identified to have several spans (2.8 miles) of annealed conductor. As a result of the annealed conductor, Carbona No. 1 60 kV Tap Line is not capable of serving the total peak demand at Carbona Substation under emergency conditions.

In addition, Carbona No.1 and 2 60 kV Tap Line are both directly connected to the Kasson No. 1 60 kV Line. An outage of the Kasson No. 1 60 kV Line will interrupt electric service to customers normally supplied by Carbona and Lyoth substations.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended because it does not mitigate the expected capacity constraints.

Alternative 2: Reconfigure and Reconductor Carbona No. 1 60 kV Tap Line, Loop Carbona Substation via Two New Circuit Breakers

This alternative proposes to replace the #4 AWG Cu conductor (2.8 miles) on the Carbona No. 1 60 kV Tap Line with a higher capacity conductor (603 Amps or greater), install one new 60 kV circuit breaker at Kasson Substation, reconfigure the Carbona

No. 1 60 kV Tap Line to interconnect at the Kasson 60 kV Bus via the new circuit breaker, and install two circuit breakers at Carbona Substation. The estimated cost for this project is $5 million. This alternative is not recommended because it is not feasible due to space constraints in Carbona Substation.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2010

KEY ISSUES

- Land-Use Restrictions – There are no land-use restrictions with this project.
- Environmental Concerns – TBD
- Special Metering or Protection – TBD
- Common Mode Exposure Items – None
- Interaction with other Projects or Studies – Maintenance work.

GEPSLF MODELING INFORMATION

```
#Reterminates the Carbona #1 60 kV Tap into Kasson Substation
#and reconductor 2.5 miles of the Carbona #1 60 kV Tap
#and rerate 4.4miles of the Carbona #1 60 kV Tap to 4fps
#Removes the Carbona #1 60 kV Tap from Banta Junction and Connects Carbona #1 60 kV Tap to Kasson Substation
MOVE_BRANCH  33762, 33760, CKT=1, NEW_TOBUS=33756
#Reconductor 2.5 miles of the Carbona #1 60 kV Tap with 715.5 AAC. From Carbona to Carbona Junction
#Impedance values per unit per mile: Rpu=0.004042, Xpu=0.020234, Bpu=0.000214
OLDSECDD 33764, 33763, CKT=1, RPU=0.010105, XPU=0.050585, BPU=0.000535, MVA1=66, MVA2=77, +
MVA3=101, MVA4=108=341, MVA3=373, MVA4=373, AREA=11, ZONE=311
#Rerate 4.4 miles of the Carbona #1 60 kV Tap to 4 fps
OLDSECDD 33762, 33763, CKT=1, MVA1=35, MVA2=40, MVA3=43, MVA4=46
OLDSECDD 33756, 33762, CKT=1, MVA1=35, MVA2=40, MVA3=43, MVA4=46
```

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagram
2. Demand Forecast
3. Power Flow Summary
4. Pre and Post Project Power Flow Plots

Attachment 1: Scope Diagram

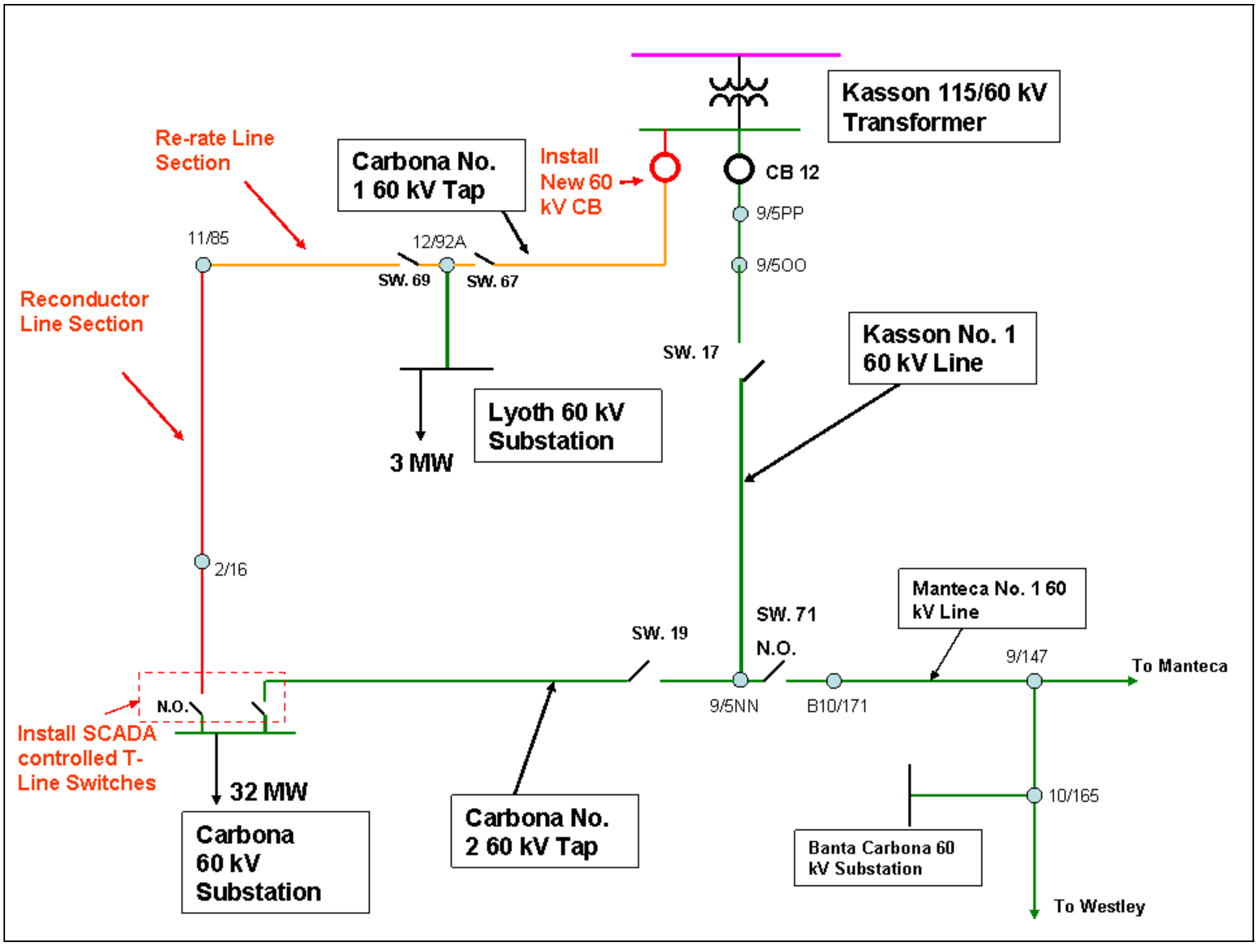


Figure 4-51: Single Line Diagram with Proposed Project and Maintenance Work

Attachment 2: Demand Forecast

Table 4-14: Demand Forecast

Substation	2009 (MW)	2010 (MW)	2011 (MW)	2012 (MW)	2013 (MW)	Growth Rate (MW/Year)
Carbona #1	23.3	23.6	24	24.5	24.8	0.38
Carbona #2	7.2	7.3	7.4	7.6	7.7	0.13
Lyoth	3	3	3	3	3	0
Totals	31	31	31	32	33	0.51

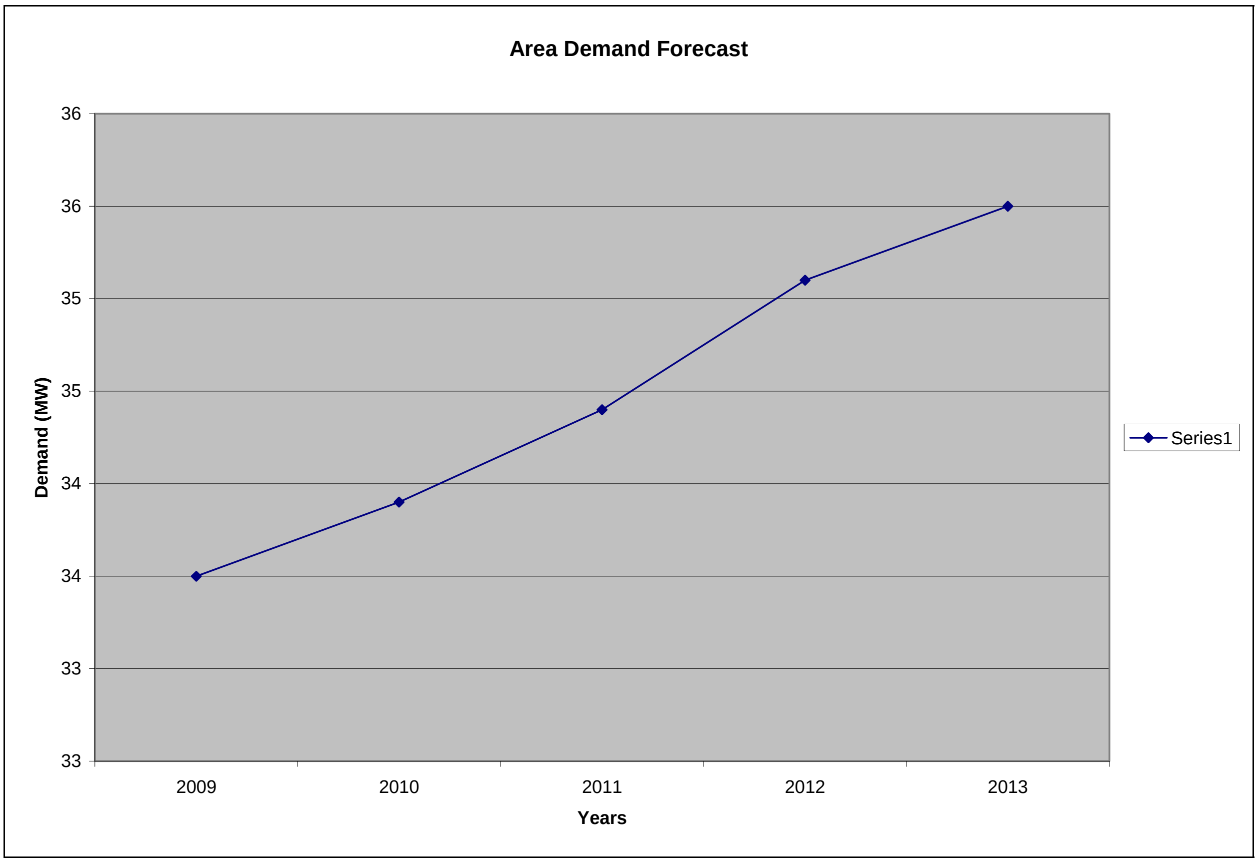


Figure 4-52: Plot of Demand Forecast

Attachment 3: Power Flow Summary

Table 4-15: Power Flow Summary

Contingency	Facility Affected	2009 (Pre-Project)	2010 (Pre-Project)	2011 (Pre-Project)	2012 (Pre-Project)	2013 (Pre-Project)	2013 (Post-Project)
Carbona No. 2 60 kV Tap (L-1)	Carbona No. 1 60 kV Tap (Carbona – Pole 11/85)	198%	202%	205%	210%	213%	42%
	Carbona No. 1 60 kV Tap (Pole 11/85 – Lyoth Tap)	93%	95%	97%	99%	100%	82%
	Carbona No. 1 60 kV Tap (Lyoth Tap – Kasson)	102%	104%	106%	108%	109%	89%

Attachment 3: Pre and Post Power Flow Plots Summary

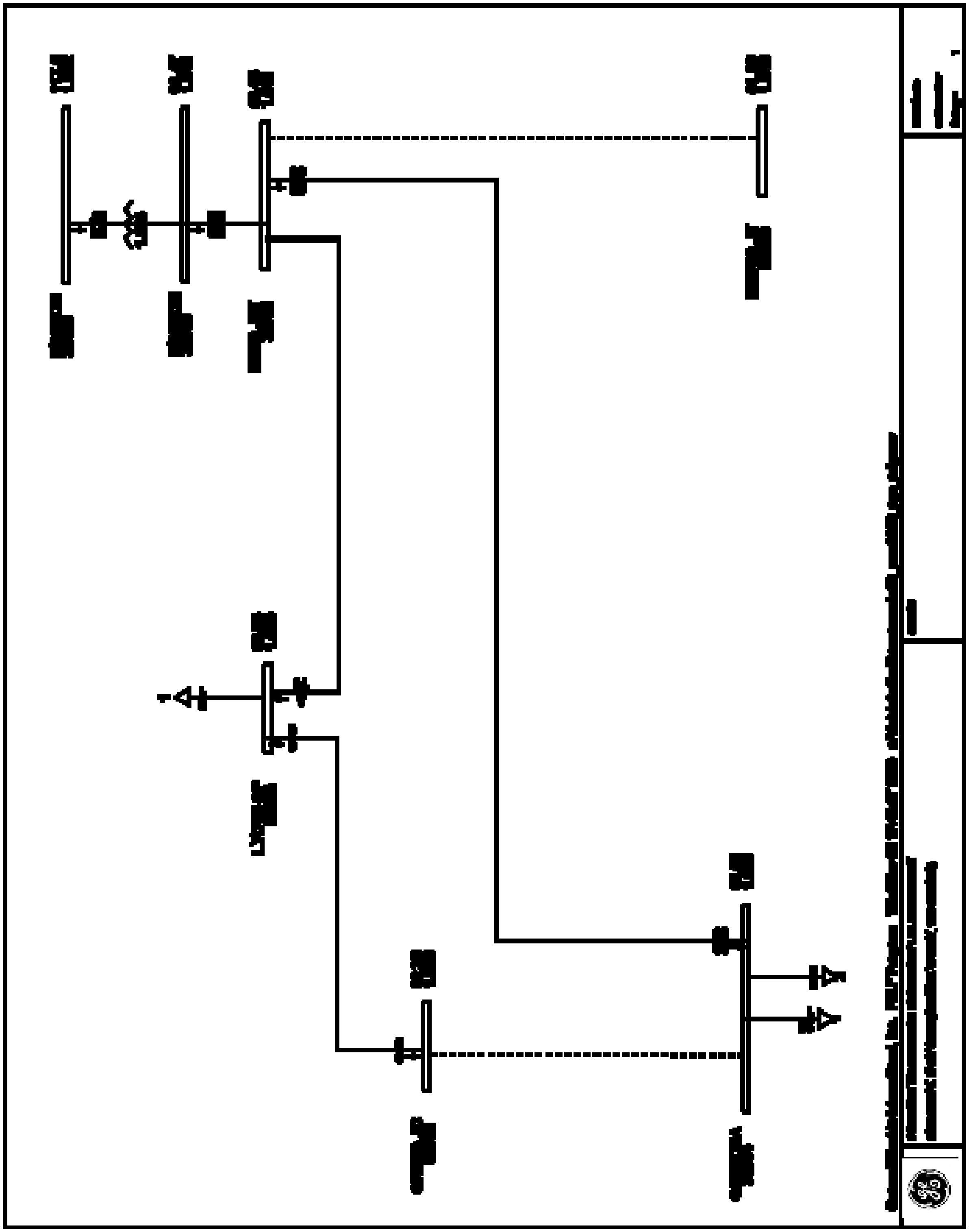


Figure 4-53: Pre-Project – Normal Conditions

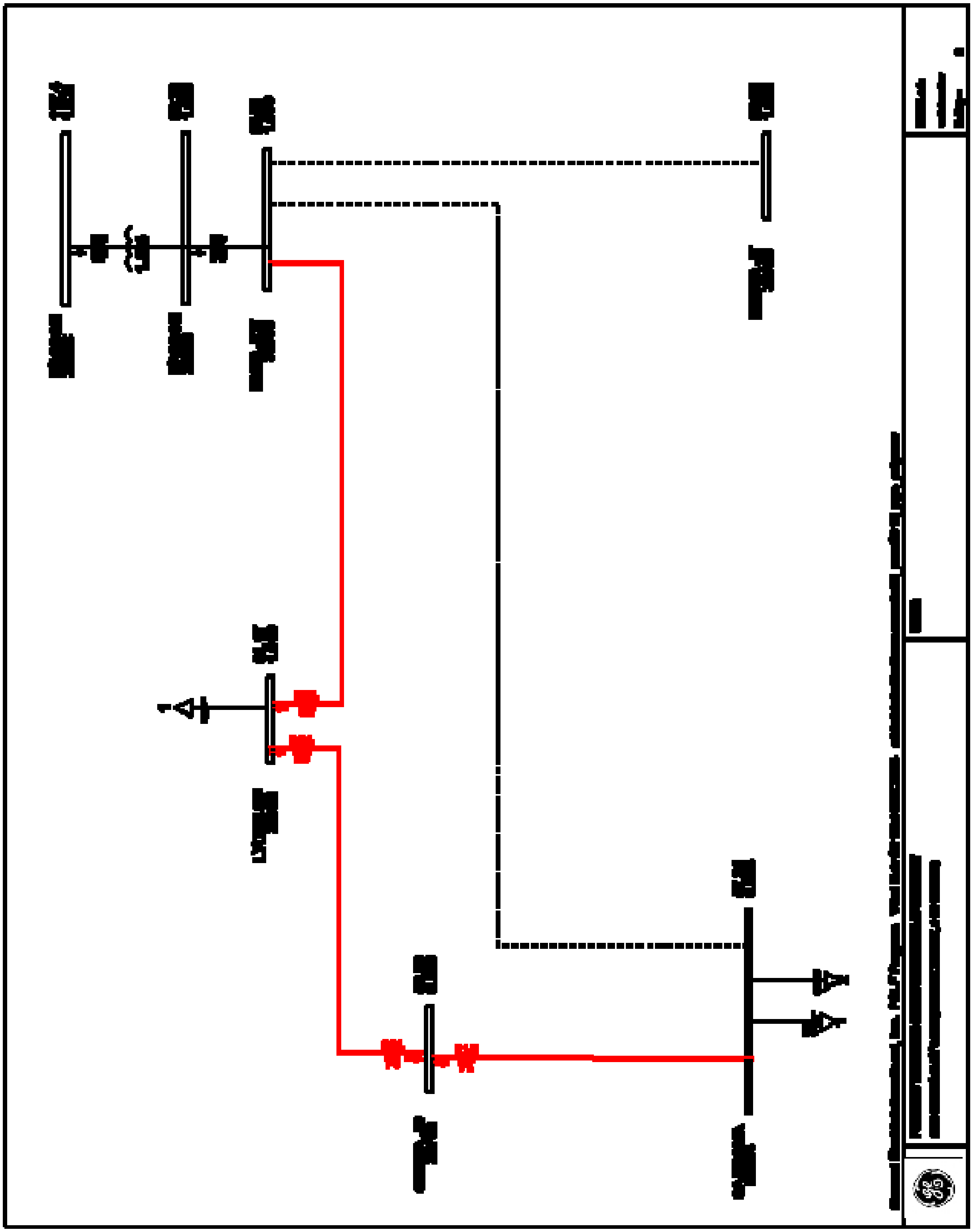


Figure 4-54: Pre-Project – Loss of the Carbona No. 2 60 kV Tap and the Carbona No. 1 60 kV Tap switched in

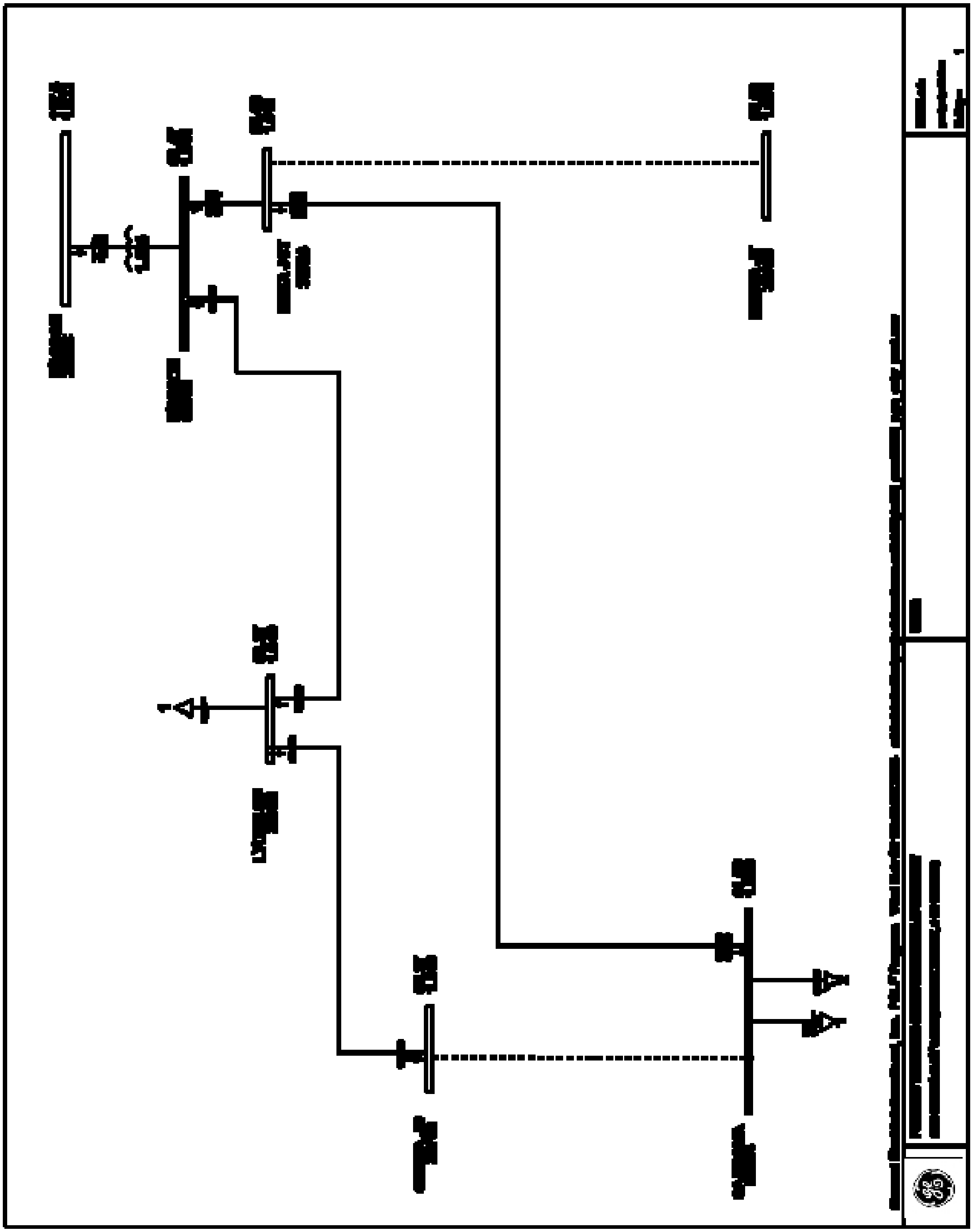


Figure 4-55: Post-Project – Normal Conditions

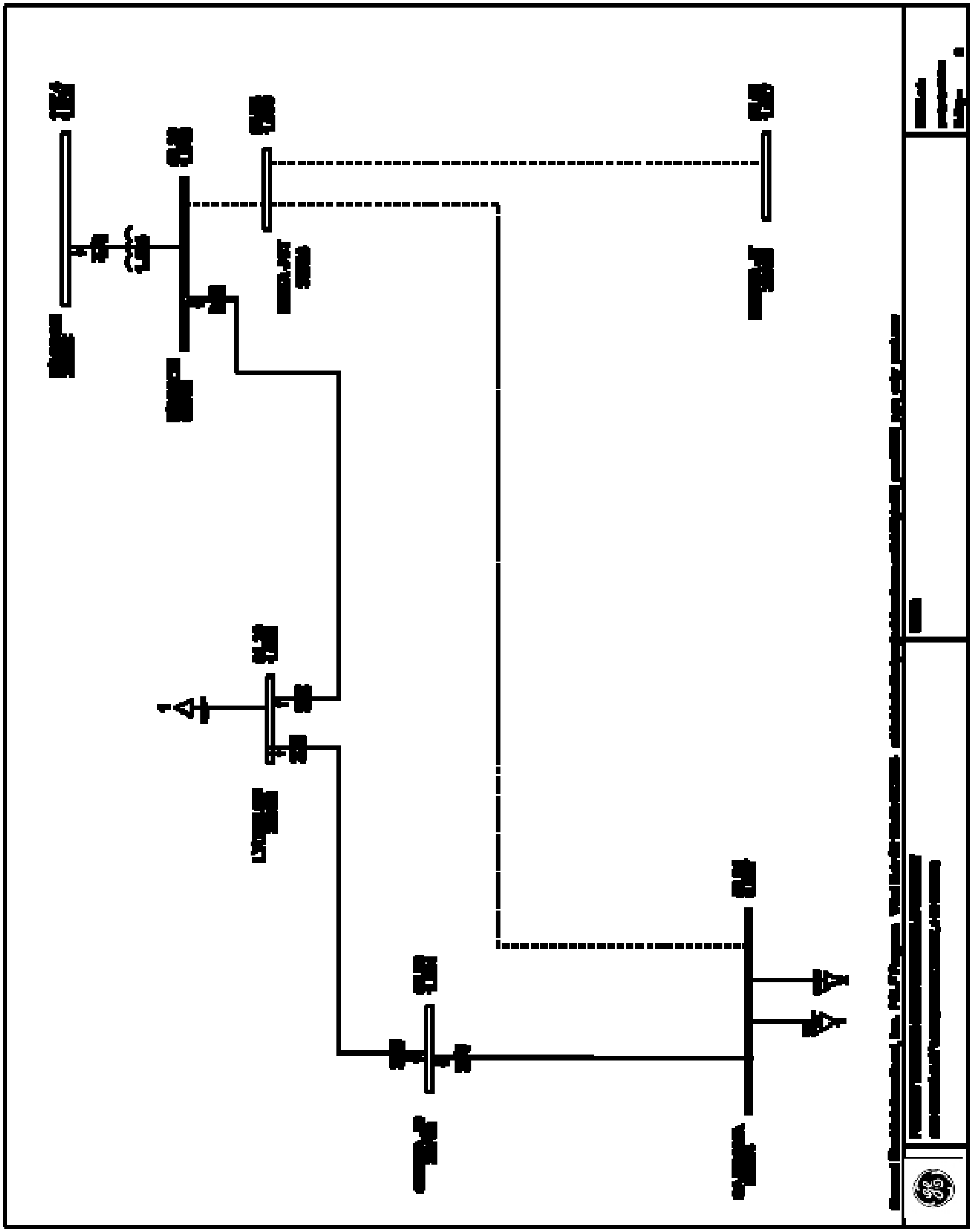


Figure 4-56: Post-Project – Loss of the Carbona No. 2 60 kV Tap and the Carbona No. 1 60 kV Tap switched in

Lodi – Industrial 60 kV Line Switch Upgrade

TARGETED IN-SERVICE DATE

May 2010

PURPOSE AND BENEFIT

Reliability – NERC Compliance

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROJECT

The project scope is to upgrade the 600 Amp rated switch (No. 29) on the Lodi-Industrial 60 kV Line with a switch rated to handle a minimum of 1,200 Amps.

This project is expected to cost less than $1M.

BACKGROUND

The Lockeford – Industrial, Lodi-Industrial and Lockeford – Lodi 60 kV Nos. 1, 2, and 3 lines are located in San Joaquin County, within the Central Valley area. These lines provide 60 kV transmission power from Lockeford Substation to serve local area customers in the Lockeford and Lodi areas.

This 60 kV system serves five substations that include Colony, Lodi, Victor, Mondavi, and Industrial (owned by the City of Lodi). The City of Lodi is a member of the Northern California Power Agency (NCPA) and is the largest city served from the PG&E 60 kV transmission network. Another key source to the local area load is through a 25 MW combustion turbine (Lodi CT owned by NCPA) located in Lodi. The load growth for the 60 kV systems is minimal, with the exception of the City of Lodi that is expected to grow at approximately 2 MW per year.

Planning analysis determined that loss of the Lockeford - Industrial 60 kV Line while the Lodi CT is offline is projected to overload the Lodi - Industrial 60 kV Line by 2% in 2012 and 12% in 2018. The limitation on the Lodi – Industrial 60 kV Line is Switch No. 29, rated at 600 Amps, and is located near Industrial Substation. The Lodi – Industrial 60 kV Line is strung with 715.5 AAL conductors rated at 631 Amps normal and 742 Amps emergency.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended. This alternative does not address the potential overload issue.

PROJECT SCHEDULE

- Environmental and Permitting Processes – None
- Design – TBD
- Major Equipment – None
- Construction – TBD
- Operation Date – May 2010

KEY ISSUES

- Land-Use Restrictions – None
- Environmental Concerns – None
- Special Metering or Protection – None
- Common Mode Exposure Items – None
- Interaction with other Projects or Studies – Lockeford-Lodi 60 kV Reinforcement

GEPSLF MODELING INFORMATION

```
#Lockeford-Lodi 60kV Line Switch Upgrade

OLDSECDD  FBUS=38060, TOBUS=33729, CKT=1, SEC=1, STATUS=1,+
        RPU=0.004, XPU=0.0185, BPU=0.00023, MVA1=66, MVA2=77, MVA3=101, MVA4=108
```

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagram
2. Demand Forecast
3. Power Flow Summary
4. Pre and Post Project Power Flow Plots

Attachment 1: Scope Diagram

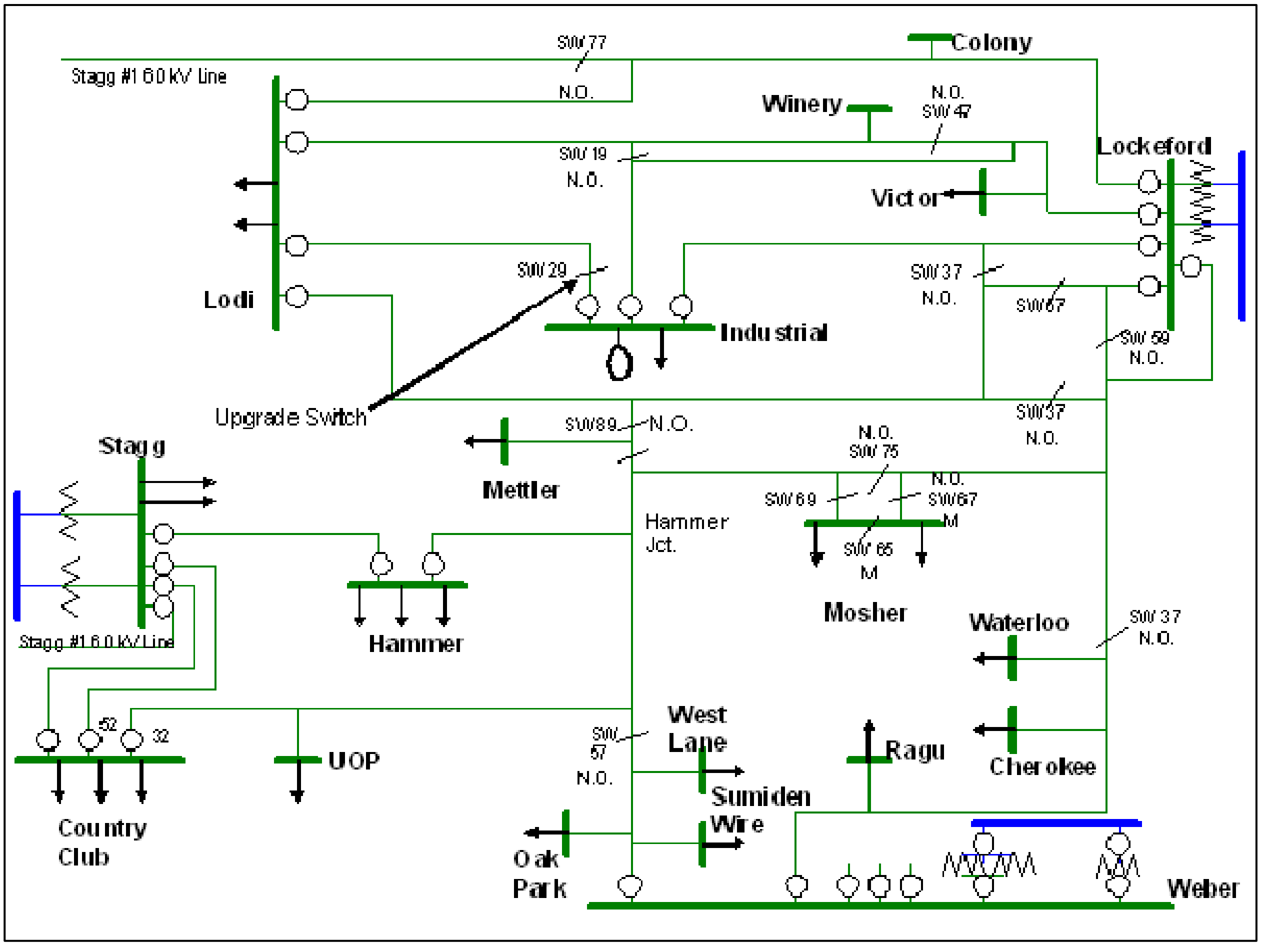


Figure 4-57: Scope Diagram

Attachment 2: Demand Forecast

Table 4-16: Demand Forecast and Growth Rate

Substation	2009	2010	2011	2012	2013	Growth Rate (MW/Year)
Colony	4.8	4.9	5.1	4.7	4.8	0.0
Lodi	20.3	20.9	21.6	19.9	20.3	0.0
Victor	3.8	3.9	4.0	3.8	3.9	0.0
City of Lodi	148.1	150.1	149.6	155.0	157.0	2.2
Mondavi	2.5	2.5	2.5	2.5	2.5	0.0
Totals	**179.5**	**182.3**	**182.8**	**185.9**	**188.4**	**2.2**

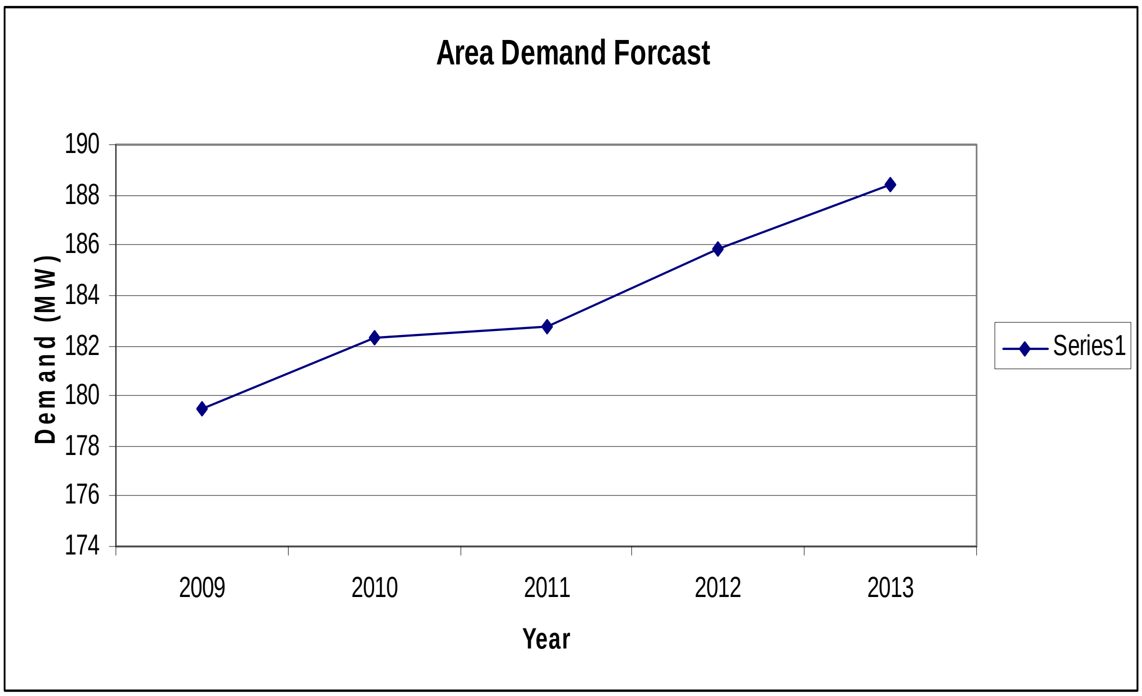


Figure 4-58: Forecasted Area Demand

Attachment 3: Power Flow Summary

Table 4-17: Power Flow Results

Contingency	Facility Affected	2009 (Pre-Project)	2010 (Pre-Project)	2011 (Pre-Project)	2012 (Pre-Project)	2013 (Pre-Project)	2013 (Post-Project)
Lockeford-Industrial 60kV Line	Lodi-Industrial 60kV Line	95%	98%	100%	103%	101%	95%

Attachment 4: Pre and Post Power Flow Plots

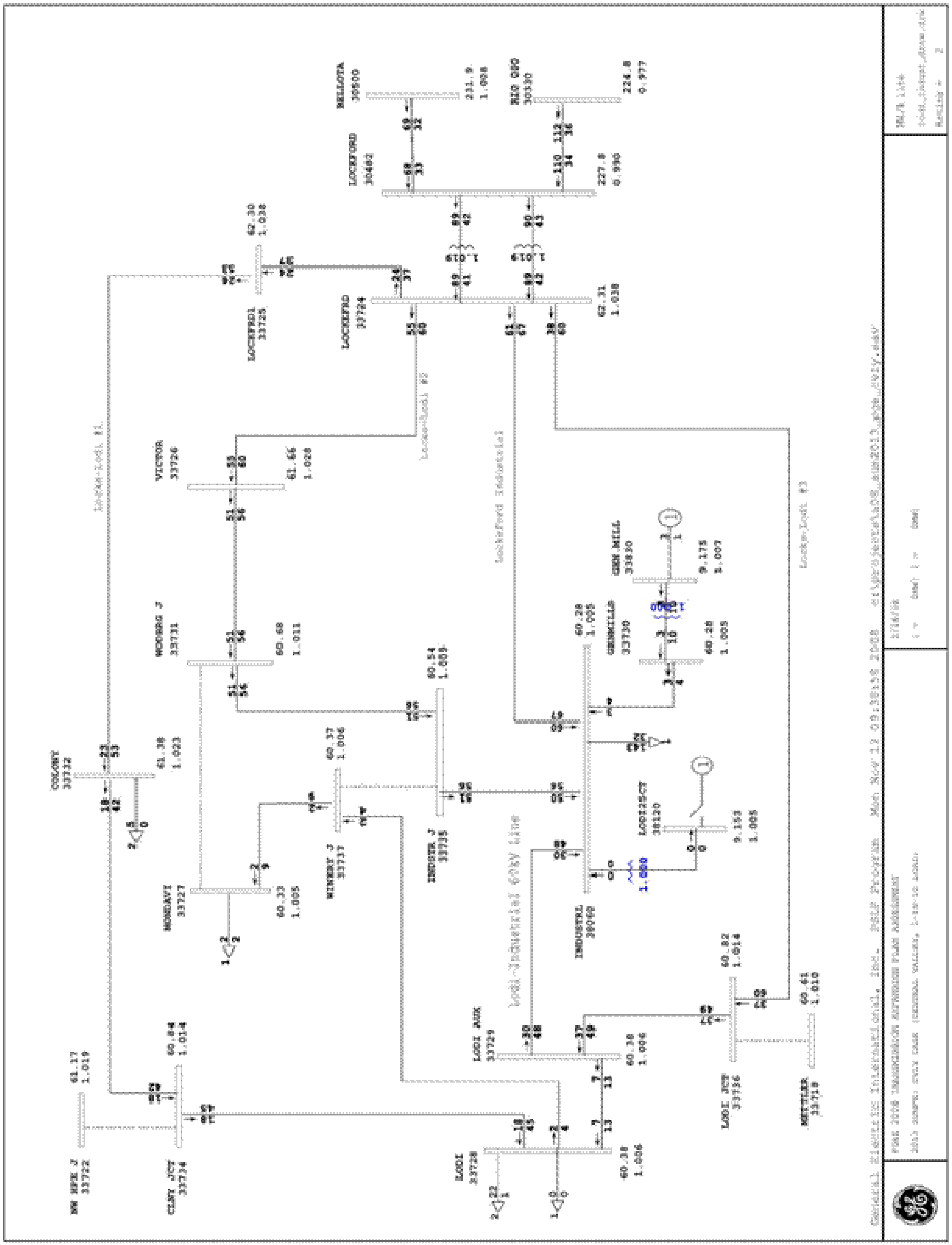


Figure 4-59: Pre-Project, All Lines In Service

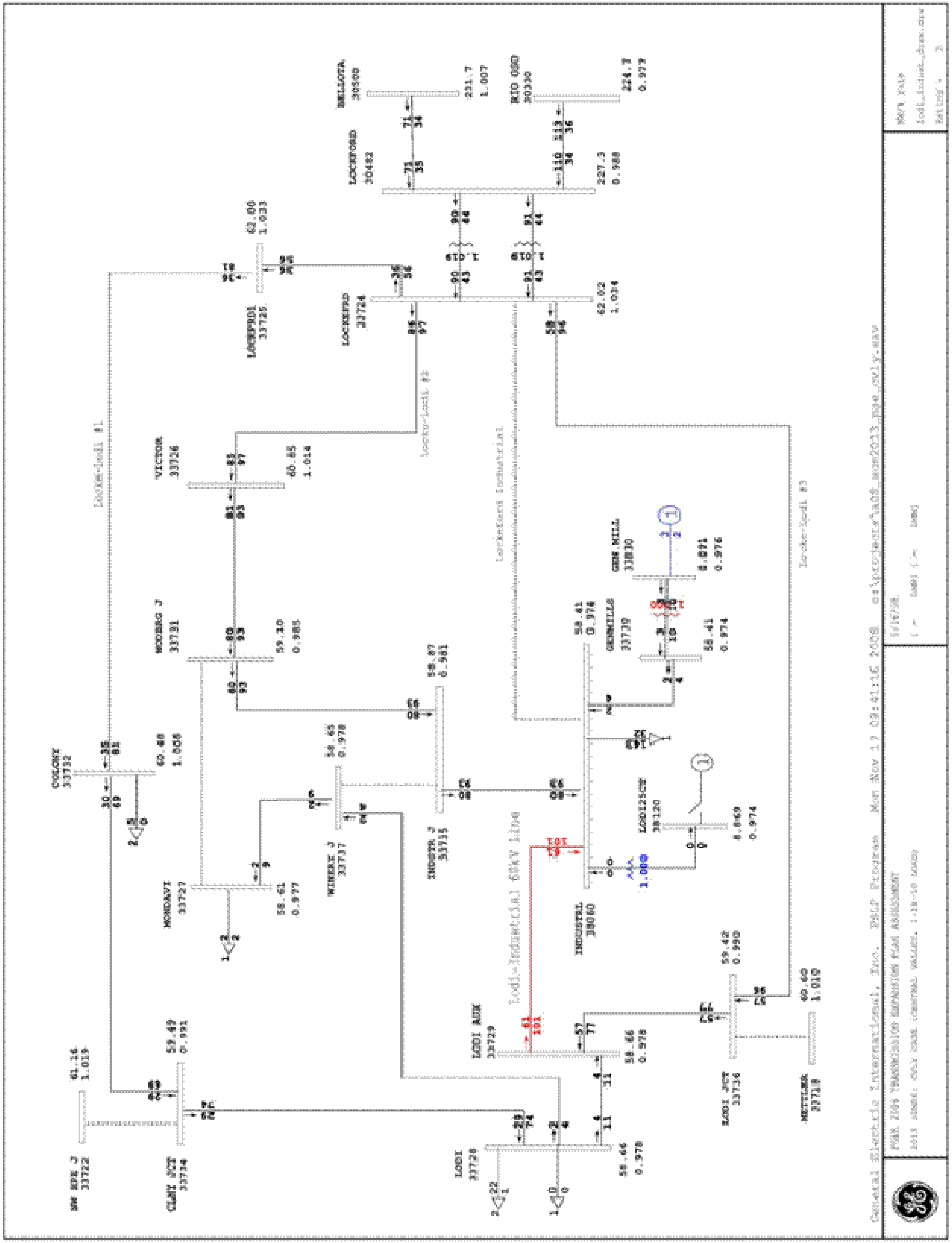


Figure 4-60: Pre-Project, Lockeford-Industrial 60kV Outage

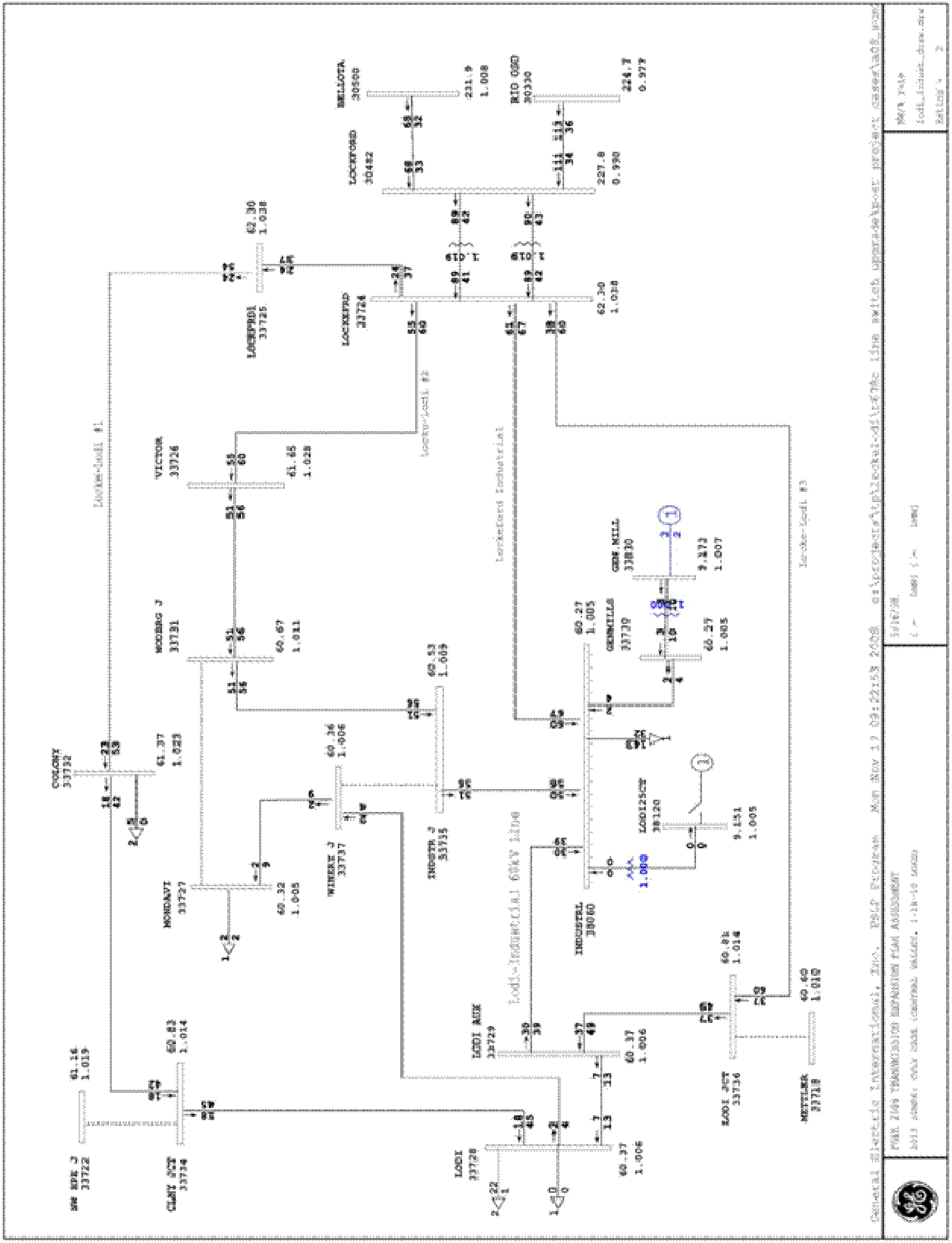


Figure 4-61: Post Project, Lockeford-Industrial 60kV Outage

Mosher Transmission Project

TARGETED IN-SERVICE DATE

May 2011

PURPOSE AND BENEFIT

Reliability – NERC Compliance

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROJECT

The project scope is to reconductor 11.6 miles of the Lockeford No. 1 60 kV Line with conductor rated to handle a minimum of 160 Amps for summer normal conditions and 650 Amps for summer emergency conditions. In addition this project scope also includes installation of two new 60 kV circuit breakers, rated to handle a minimum of 650 Amps, at Mosher Substation. All facilities will be sized for 115 kV for possible future voltage conversion.

This project is expected to cost between $10M and $20M.

BACKGROUND

PG&E's Mosher Substation is located in the northern part of Stockton, California. The substation contains motor operated air switches (MOAS) with SCADA and two 60/21 kV distribution transformers rated at 30 MVA each. The substation electric demand in 2008 was recorded at 56 MW and is expected to increase approximately 1.1 MW or 2% per year, which is in line with the area demand forecast.

Normally, Mosher Substation receives electric power from the Hammer – Country Club 60 kV Line. Typically, the Hammer – Country Club 60 kV Line experiences an outage 1.3 times a year with each occurrence lasting 4.4 minutes. The MOASs at Mosher Substation allow for a faster restoration following an outage of the Hammer – Country Club 60 kV Line.

During these abnormal conditions, the Lockeford No. 1 60 kV Line serves as a back up to the substation and is rated for 281 Amps normally and 326 Amps during emergency conditions.

Alone, the Lockeford No. 1 60 kV Line is not capable of serving the entire demand at Mosher Substation during summer peak conditions. As a result, only Mosher Transformer No. 2 is automatically transferred to the back up transmission line. Approximately, 2,500 customers on Mosher Transformer No. 1 are out of electric power.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended because it does not mitigate the expected capacity constraints.

Alternative 2: Mosher Substation Partial 115 kV Conversion plus Loop

The work included for this alternative is:

1. Install two 230/115 kV transformers at Lockeford Substation
2. Upgrade Industrial Substation (City of Lodi), Mettler, Victor, Winery and Mosher Substations to 115 kV
3. Convert the Lockeford – Lodi 60 kV Line No. 3 (up to Lodi Jct) to 115 kV
4. Convert the Lockeford No. 1 60 kV Line to 115 kV
5. Convert part of the Hammer – Country Club 60 kV Line to 115 kV (Mosher – Moranda Junction)

Connecting Mosher Substation to the Lockeford 115 kV system will be accomplished by utilizing the Lockeford No. 1 60 kV Line and the section from Mosher Substation to Lodi Junction, which will be insulated and operated at 115 kV. To complete the circuit, the Lodi to Lodi Junction section, of the Lockeford – Lodi #3 Line will re-terminate at Industrial Substation.

Alternative 3: Mosher Substation Full 115 kV Conversion

The work included for this alternative is:

1. Install two-230/115 kV Transformer at Lockeford Substation
2. Upgrade Victor, Winery, Colony, Industrial, Lodi and Mosher substations to 115 kV
3. Convert the Lockeford – Lodi Line Nos. 1, 2 and 3 to 115 kV
4. Convert the Lockeford – Industrial, Lodi – Industrial Lines to 115 kV
5. Convert the Industrial Tap to 115 kV

In addition, this alternative proposes to loop the Mosher Substation through the Lockeford No. 1 60 kV Line and the Hammer – Country Club 60 kV Line. The scope is to reinforce the Lockeford No. 1 60 kV Line and install two new circuit breakers at Mosher Substation.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2011

KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – TBD
- Special Metering or Protection - TBD
- Common Mode Exposure Items – None
- Interaction with other Projects or Studies – Lockeford – Lodi Area 60 kV Reconductoring

GEPSLF MODELING INFORMATION

```
#Mosher Transmission Project
#Reconductor the Lockeford #1 60 kV Line with 715 Al conductors and loop Mosher Substation
#
#  ____Section_______Miles______Construction____|R|____|X|____|B|
#  Lockeford to Waterloo Jct
#    Lckd-1/1            1.07     4/0 AL      0.004328  0.020910   0.000235
#    1/1-A10/231         5.50     2/0 Cu      0.022244  0.107481   0.001210
    #Total               6.57               0.026572  0.128391     0.001445
#  Waterloo Jct to Mosher
# WtJct (6/7A)-4/1       4.33     4/0 AL      0.017512  0.084617   0.000952
#    4/1-B3/69           0.02     715 Al      0.000081  0.000391   0.000004
#    4/2-Mosher          1.10     4/0 AL      0.004449  0.021496   0.000242
    #Total               5.45               0.022042  0.106504     0.001198
# ------------------------------------------------------------------------------
#ASPEN base:  R=0.1456 X=0.70351 B=0.016206 for 715 AL conductor
```

Lockeford - Waterloo Jct
OLDSECDD 33724, 33738, CKT=1 SEC=1 RPU=0.026572 XPU=0.128391 BPU=0.001445 MVA1=66 MVA2=77 MVA3=101 MVA4=108

Waterloo Jct - Mosher
OLDSECDD 33738, 33740, CKT=1 SEC=1 RPU=0.022042 XPU=0.106504 BPU=0.001198 MVA1=66 MVA2=77 MVA3=101 MVA4=108 STATUS=1

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagram
2. Demand Forecast
3. Power Flow Summary
4. Pre and Post Project Power Flow Plots

Attachment 1: Scope Diagram

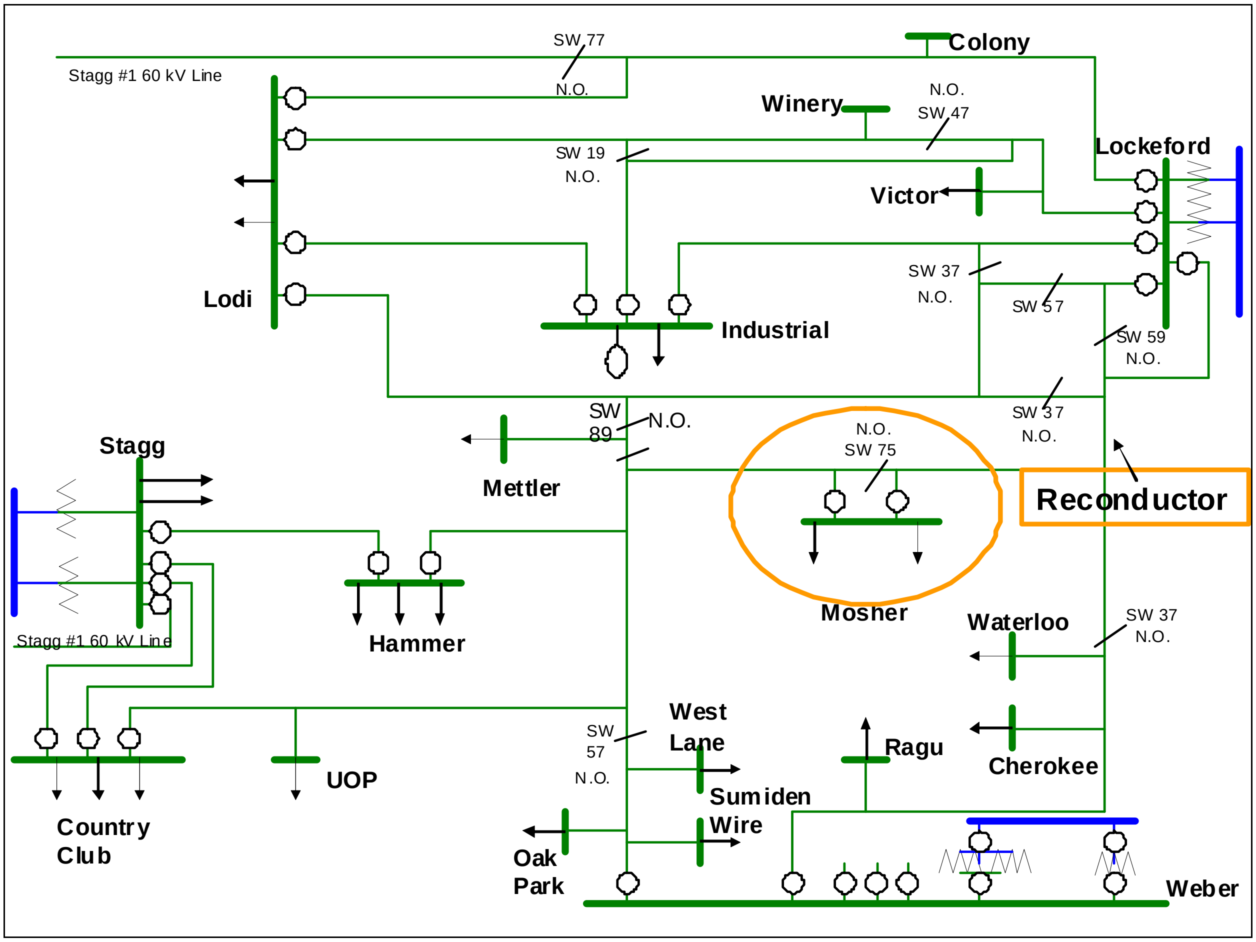


Figure 4-62: Single Line with Proposed Project

Attachment 2: Demand Forecast

Table 4-18: Demand Forecast

Substation	2008 (MW)	2009 (MW)	2010 (MW)	2011 (MW)	2012 (MW)	Growth Rate (MW/Year)
Lodi	20.3	20.9	21.5	19.8	22.3	0.5
Industrial	134.3	137.9	141.6	142.5	143.1	2.2
Mosher	51	52	53	54	55	1.1
Mettler	8.7	9	9.3	8.4	9.8	0.3
Colony	4.8	4.9	5.1	4.7	5.3	0.1
Winery	2.5	2.5	2.5	2.5	2.5	0.0
Victor	3.8	3.9	3.9	3.7	4	0.1
Hammer	53.5	54.6	56.1	57.7	58	1.1
Total	**279**	**286**	**293**	**294**	**300**	**5.3**

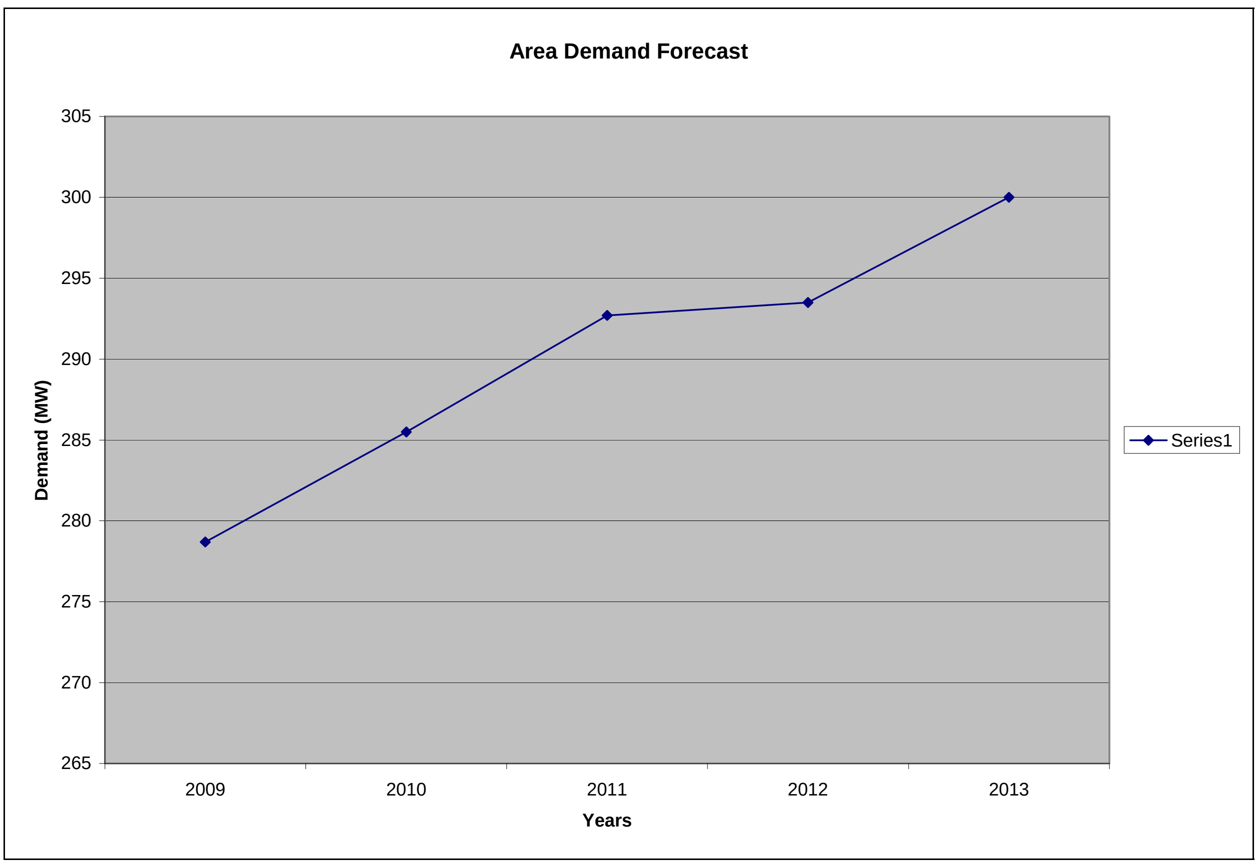


Figure 4-63: Plot of Demand Forecast

Attachment 3: Power Flow Summary

Table 4-19: Power Flow Summary

Contingency	Facility Affected	2009 (Pre-Project)	2010 (Pre-Project)	2011 (Pre-Project)	2012 (Pre-Project)	2013 (Pre-Project)	2013 (Post-Project)
Hammer – Country Club 60 kV Line (L-1) (Mosher Bank #2 Transferred)	Lockeford No. 1 60 kV Line (Lockeford – Waterloo Jct)	94%	96%	98%	101%	102%	44%
	Lockeford No. 1 60 kV Line (Waterloo Jct – Mosher)	60%	62%	63%	65%	66%	44%
Hammer – Country Club 60 kV Line (L-1) (Both Mosher Banks Transferred)	Lockeford No. 1 60 kV Line (Lockeford – Waterloo Jct)	157%	161%	163%	168%	172%	72%
	Lockeford No. 1 60 kV Line (Waterloo Jct – Mosher)	101%	103%	105%	108%	110%	72%

Attachment 4: Pre and Post Power Flow Plots

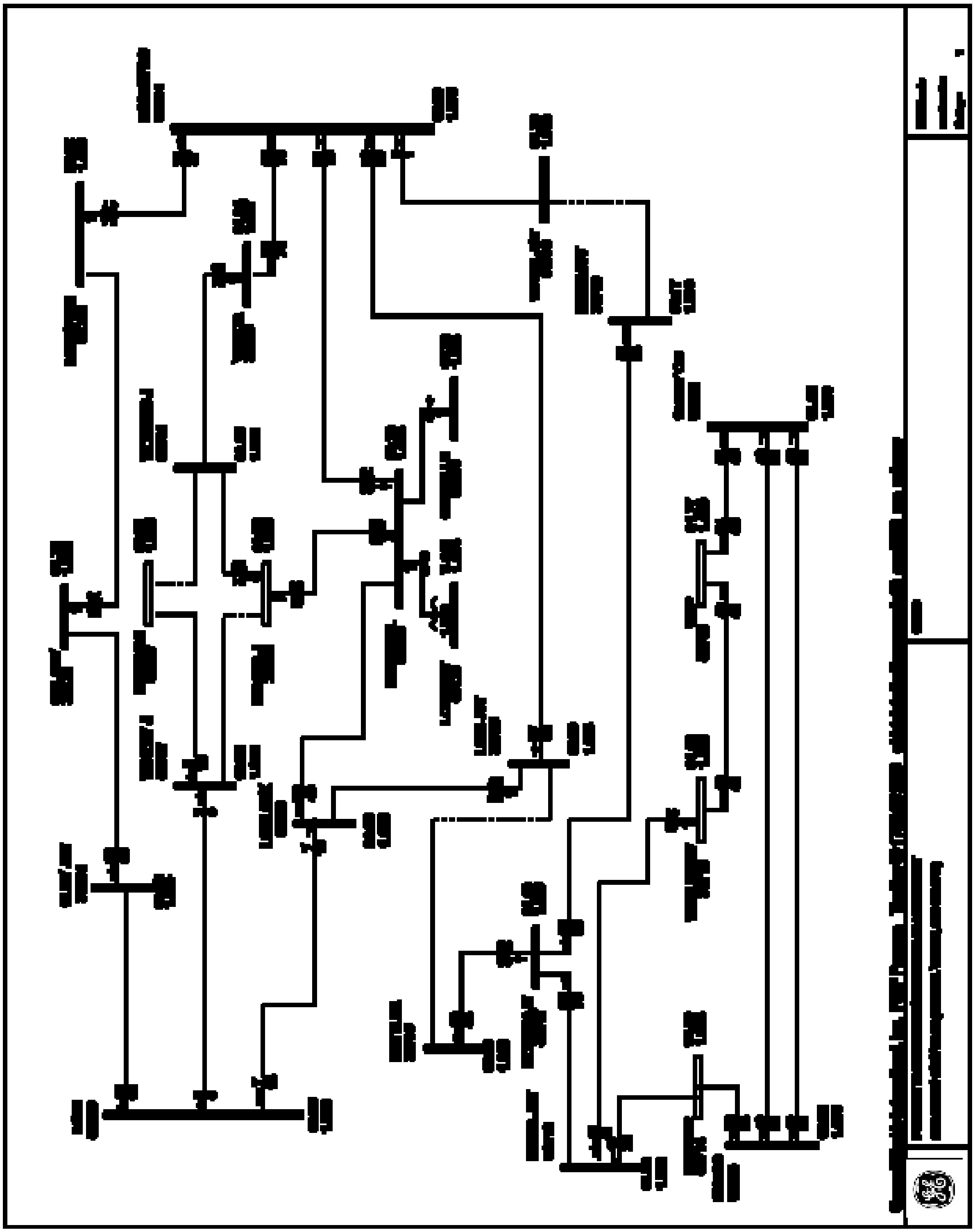


Figure 4-64: Pre Project - Normal Conditions

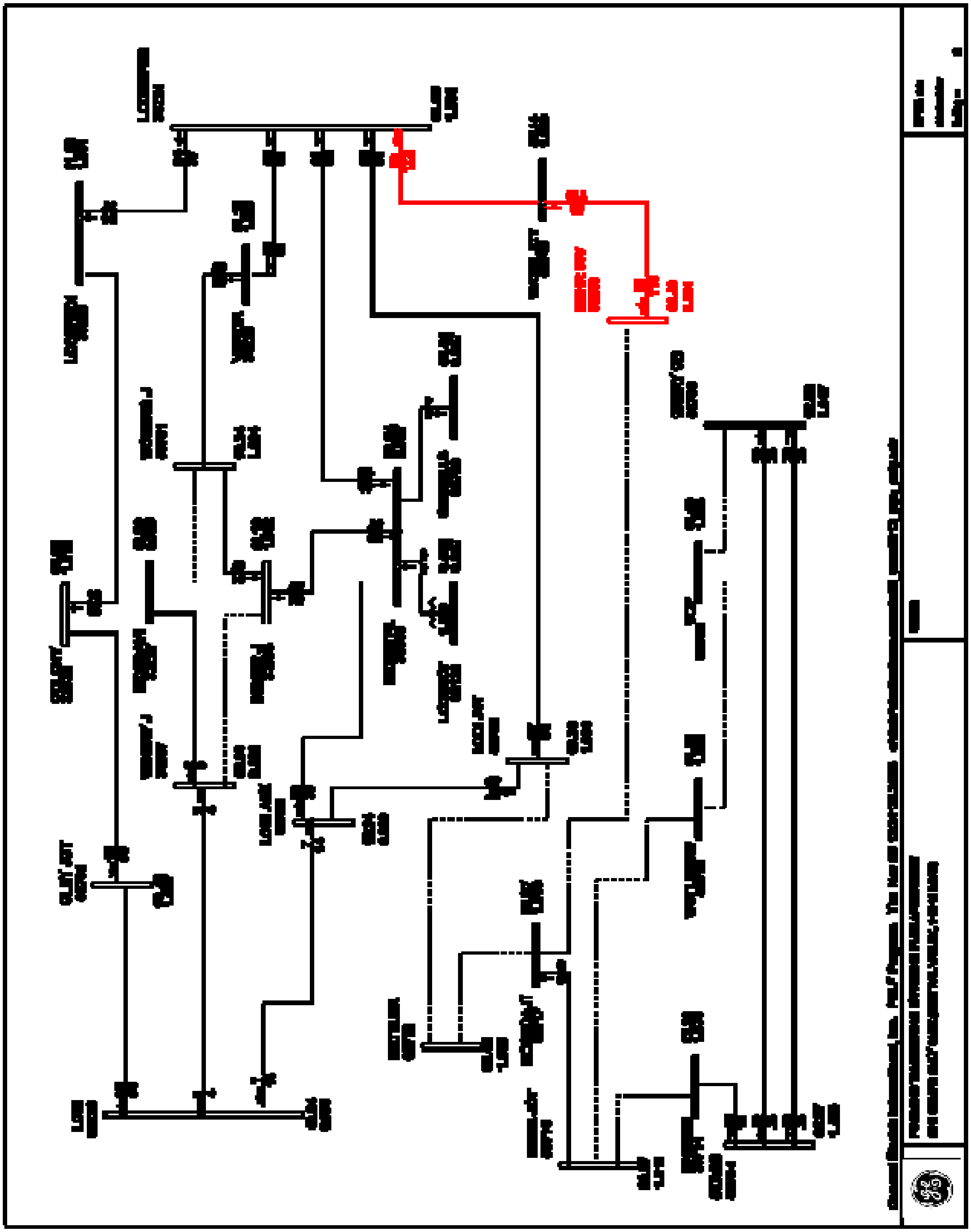


Figure 4-65: Pre Project – Loss of the Hammer – Country Club 60 kV Line

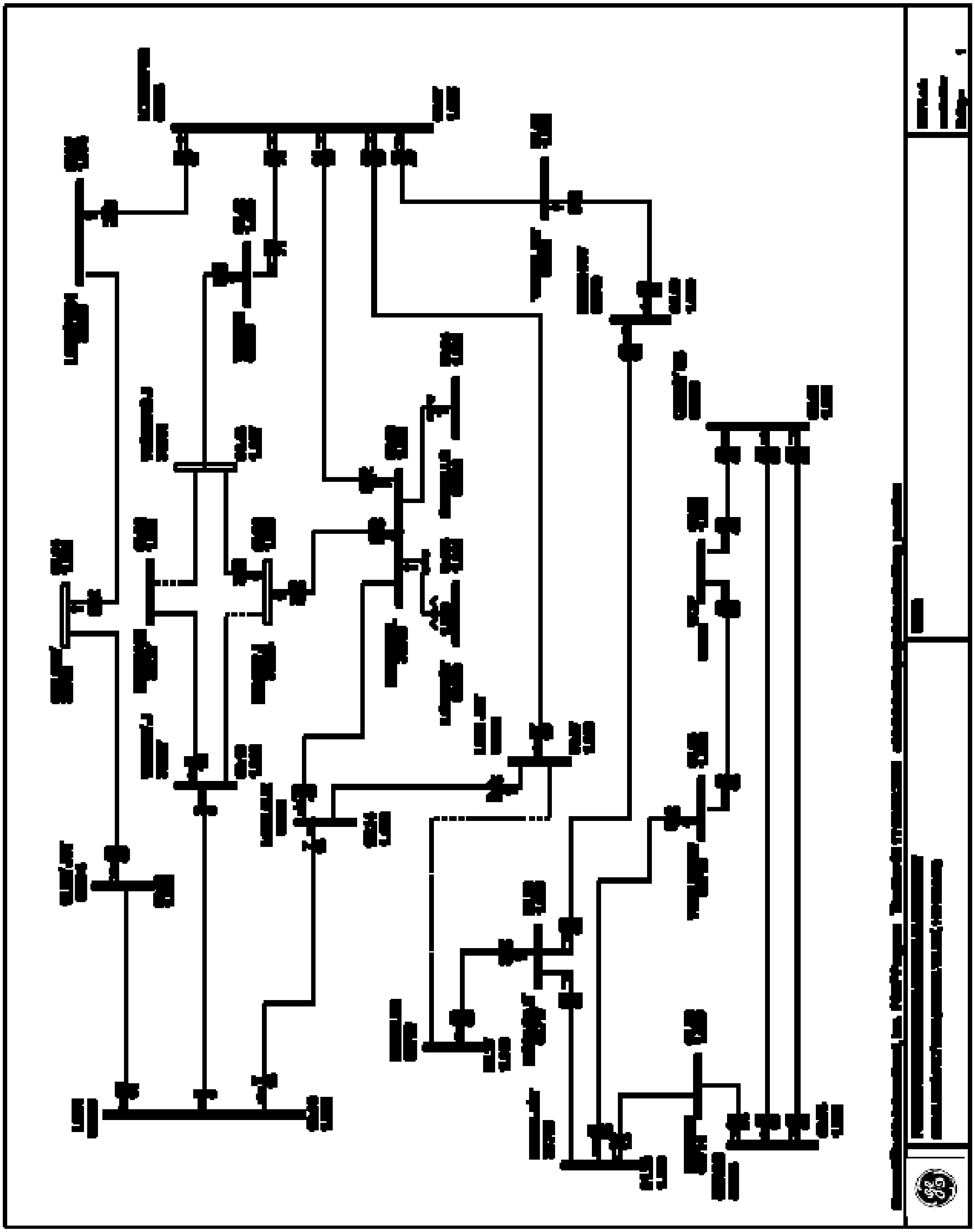


Figure 4-66: Post Project - Normal Conditions

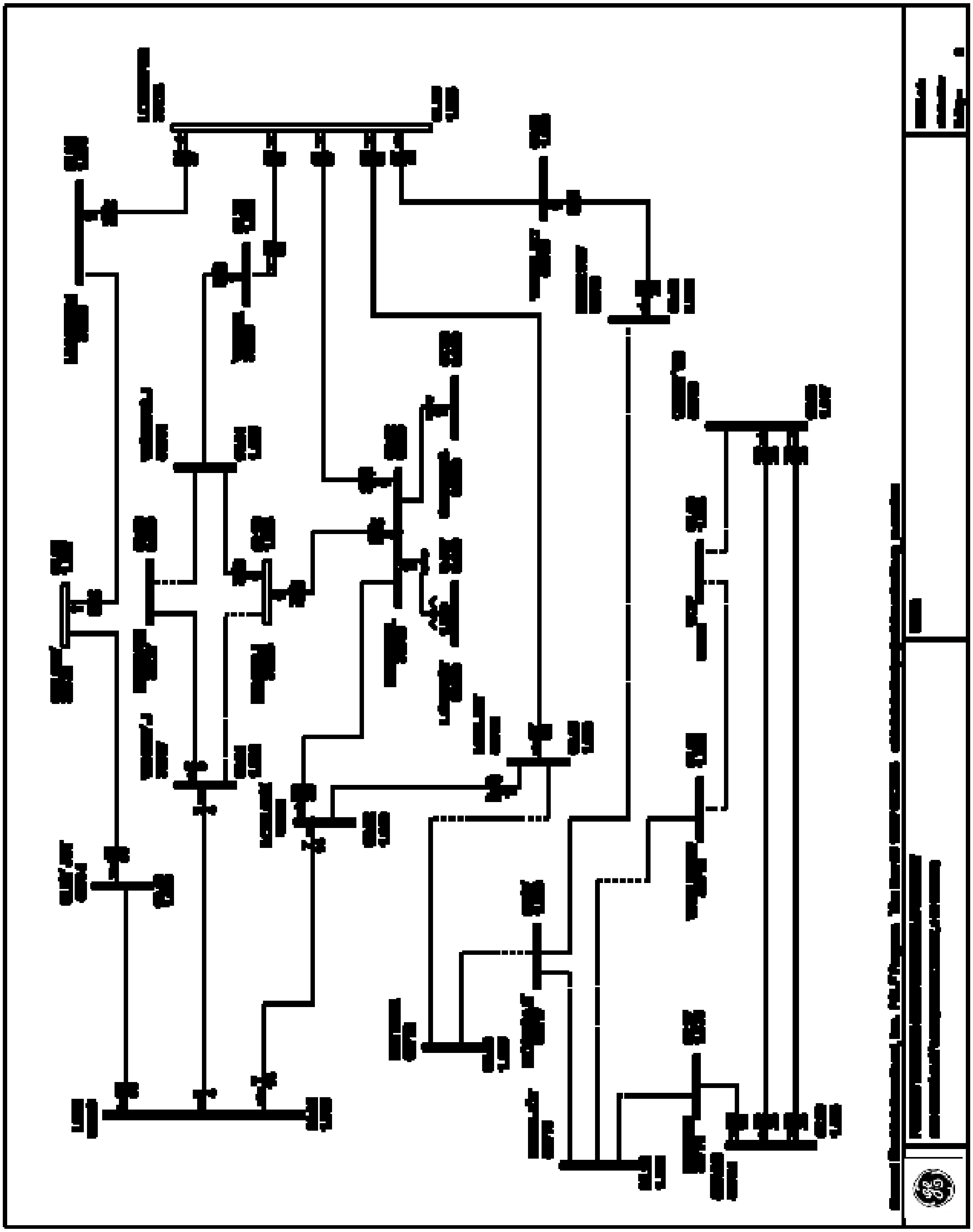


Figure 4-67: Post Project - Loss of the Hammer – Country Club 60 kV Line

Palermo 115 kV Circuit Breaker and Switch Replacements

TARGETED IN-SERVICE DATE

May 2010

PURPOSE AND BENEFIT

Reliability – NERC Compliance

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROPOSED PROJECT

The proposed project scope is to replace the Palermo 230/115 kV Transformer No. 2 circuit breaker (Palermo CB 182) and its associated switches with equipment rated to handle a minimum of 2,000 Amps.

This is the recommended plan for the area. The plan provides the needed transmission capacity and is pertinent in reducing the area's local capacity requirements.

The project is expected to cost between $1M and $5M.

BACKGROUND

PG&E's Palermo Substation is located in the south of Butte County near Oroville and helps serves power to local electric customers to the south in Sutter and Yuba counties. It is a key 230 kV power system facility that serves as a link for power flowing south along the California-Oregon Intertie (COI). At Palermo Substation, power is stepped down from
230 kV to 115 kV and 60 kV which is then transmitted over three 115 kV transmission lines and three 60 kV lines to serve the local area load.

In addition to providing 115 kV transmission power to local area electric customers, Palermo Substation also serve as a transmission path for bulk transmission power to travel. A large amount of this bulk transmission power is from nearby hydro generating facilities. There are several hydro power plants in the area, particularly along Feather River between Lake Almanor and Lake Oroville. A portion of the output from these power plants are transported to load centers in the Sacramento area through the three 115 kV transmission lines.

Located at Palermo Substation are 60 kV, 115 kV, and 230 kV facilities as well as two transmission transformers. Transformer No. 1 is a 230/115/60 kV unit with 168 MVA of capacity and provides only a small contribution (less than 1 MW) to the local 60 kV transmission system and primarily serves as a back-tie under normal conditions. Transformer No. 2 was recently installed in May 2008 and is a 230/115 kV unit with 420 MVA of capacity. However, Transformer No. 2 is currently limited by the low-side 115 kV circuit breaker which is capable of carrying 239 MVA under normal and emergency conditions.

Planning analysis concluded that during summer peak conditions an outage of the Feather River Energy Center and the Wood Leaf - Palermo 115 kV Line will overload the Transformer No. 2 circuit breaker by 2% in 2010.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended because it does not address the capacity issues.

PROJECT SCHEDULE

- Environmental and Permitting Processes – Not Applicable
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2010

KEY ISSUES

- Land-Use Restrictions – None.
- Environmental Concerns – None
- Special Metering or Protection – None
- Common Mode Exposure Items – None
- Interaction with other Projects or Studies – None

GEPSLF MODELING INFORMATION

```
# EDRO May 2010
#       Replace Palermo 230/115 kV Transformer No. 2 Circuit Breaker 182 with higher rated equipment
#-------------------------------------------------------------------------------------------
# OLD_TRAN  "FBUS=",       "TOBUS=",     "CKT=1", MVA1=,    MVA2=,    MVA3=,    MVA4=
#
# Replace Circuit Breaker 182 with higher rated equipment
  OLD_TRAN  "PALERMO  115" "PALERMO  230" CKT=2,  MVA1=420  MVA2=462  MVA3=420  MVA4=462
```

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagram
2. Demand Forecast
3. Generation Dispatch
4. Power Flow Summary
5. Pre and Post Project Power Flow Plots

Attachment 1: Scope Diagrams

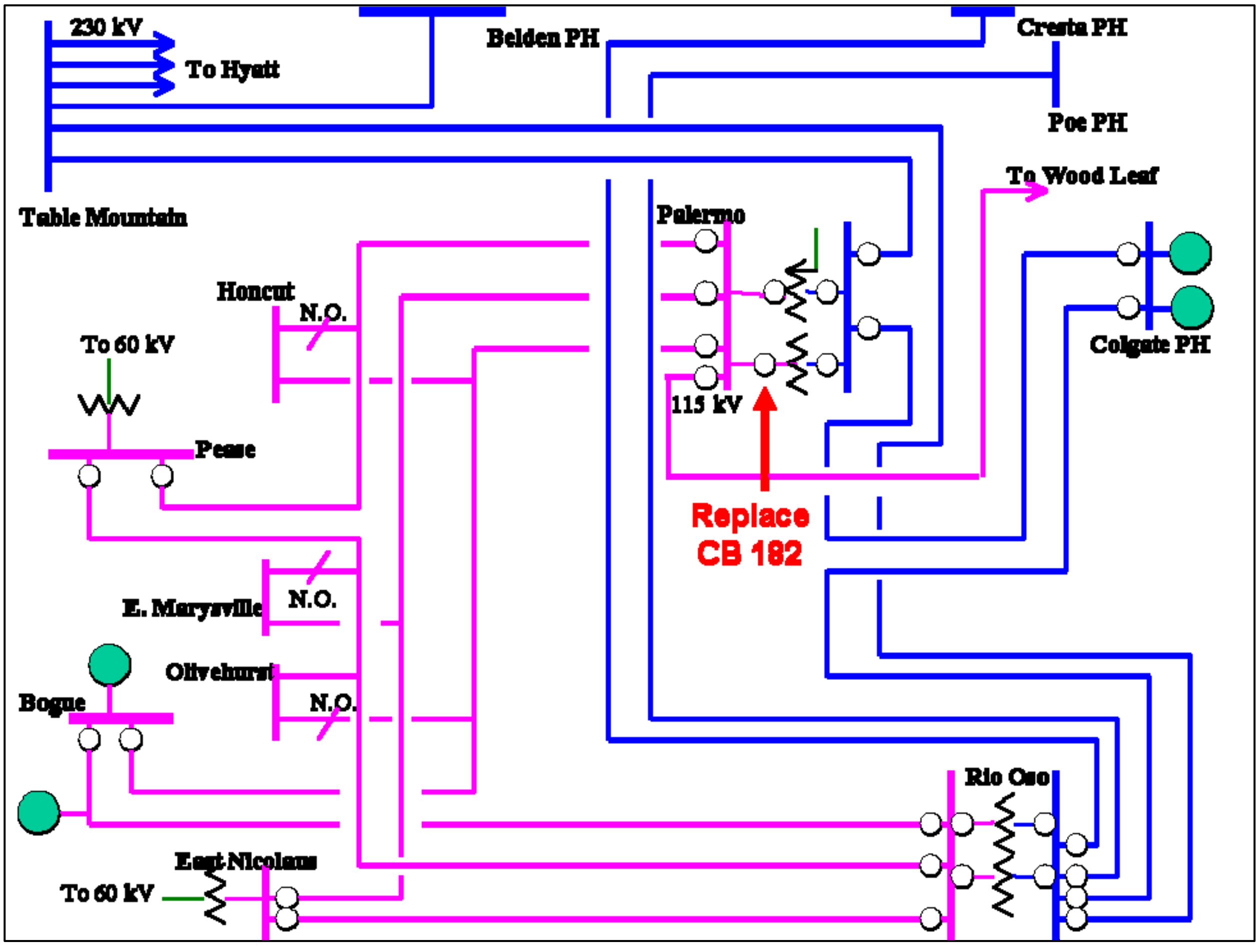


Figure 4-68: Scope Diagram

Attachment 2: Demand Forecast

Table 4-20: Palermo 115 kV Station Load (2008 Assessment)

Substation	2009 (MW)	2010 (MW)	2011 (MW)	2012 (MW)	2013 (MW)	Growth Rate (MW/Year)
East Marysville	19.6	19.8	20.2	20.4	20.7	0.3
Honcut	15.8	16.0	16.2	16.4	16.7	0.2
Olivehurst	27.2	27.5	27.9	28.3	28.6	0.4
Pease	29.1	29.7	30.3	30.9	31.4	0.6
Wyandotte	61.2	62.1	63.2	64.0	64.8	0.9
Total Load	**152.9**	**155.1**	**157.8**	**160.0**	**162.2**	**2.4**

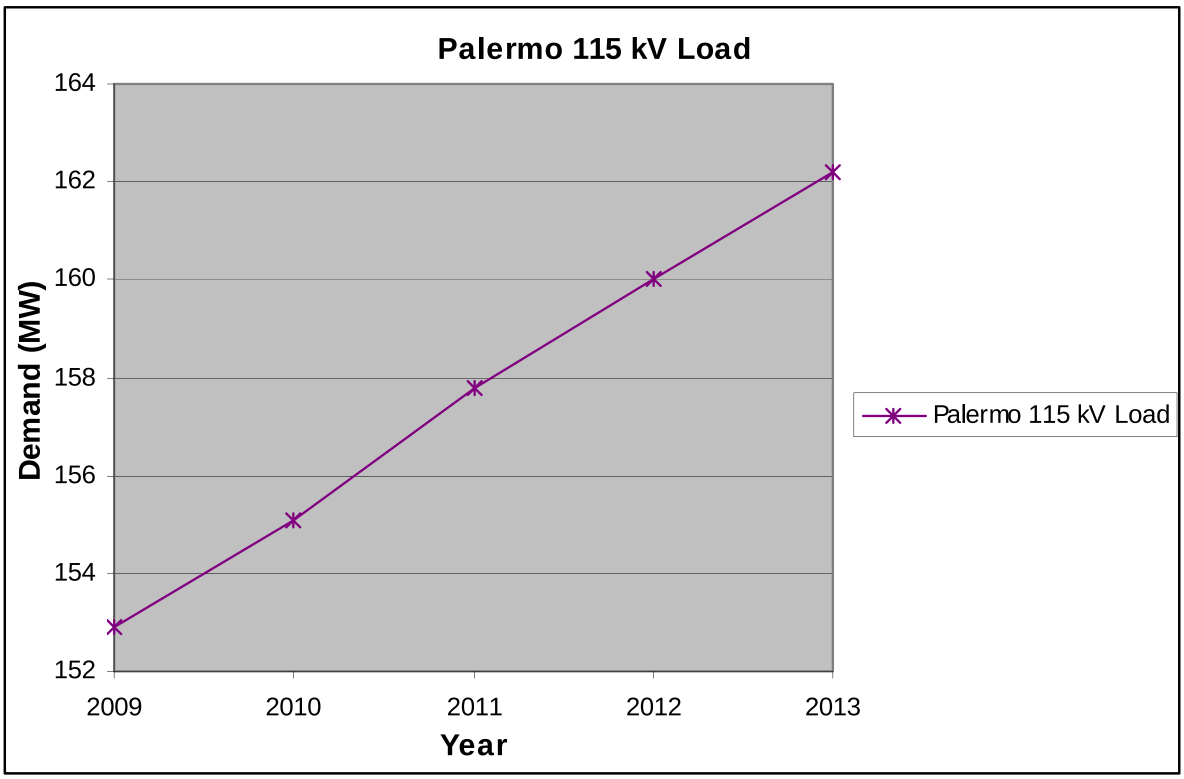


Figure 4-69: Palermo Area Demand Forecast

Attachment 3: Generation Dispatch

Table 4-21: Internal Generation – Wood Leaf - Palermo 115 kV Line

No.	Generation Facility	Generation Type	Generation	
			Dispatch	Rated
1	Wood Leaf	Hydro	55	60
2	Sly Creek	Hydro	9.5	13
3	Deadwood	Hydro	0	2
4	Forbestown	Hydro	30	39
Total			**95**	**114**

Attachment 4: Power Flow Summary

Table 4-22: Power Flow Summary

Contingency	Facility Affected	2009 (Pre-Project)	2010 (Pre-Project)	2010 (Post-Project)
Wood Leaf-Palermo 115 kV Line / FREC (L-1/G-1)	Palermo 230/115 kV Transformer No. 2	94%	102%	58%

Attachment 5: Pre and Post Project Power Flow Plots

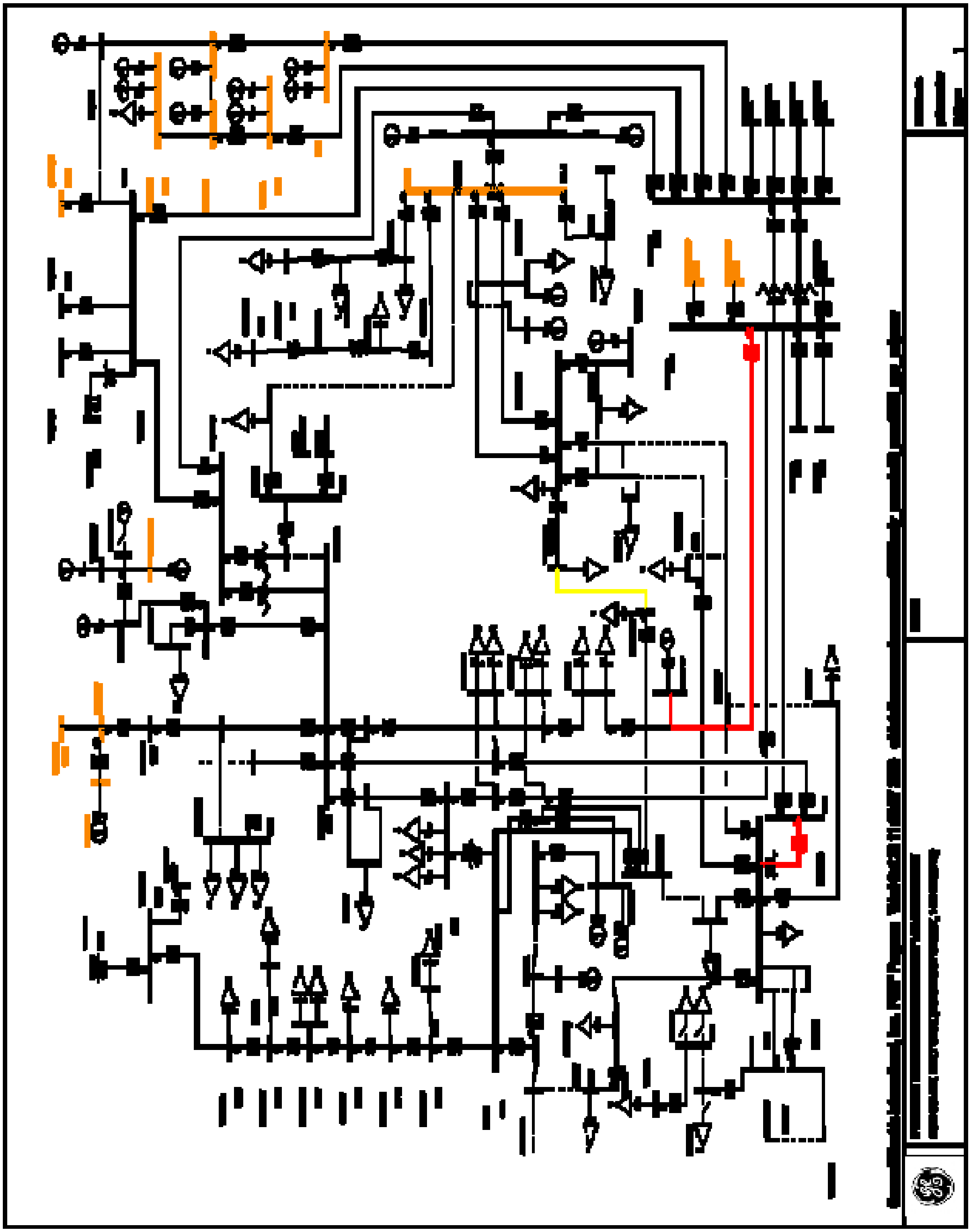


Figure 4-70: Pre Project – Normal Conditions

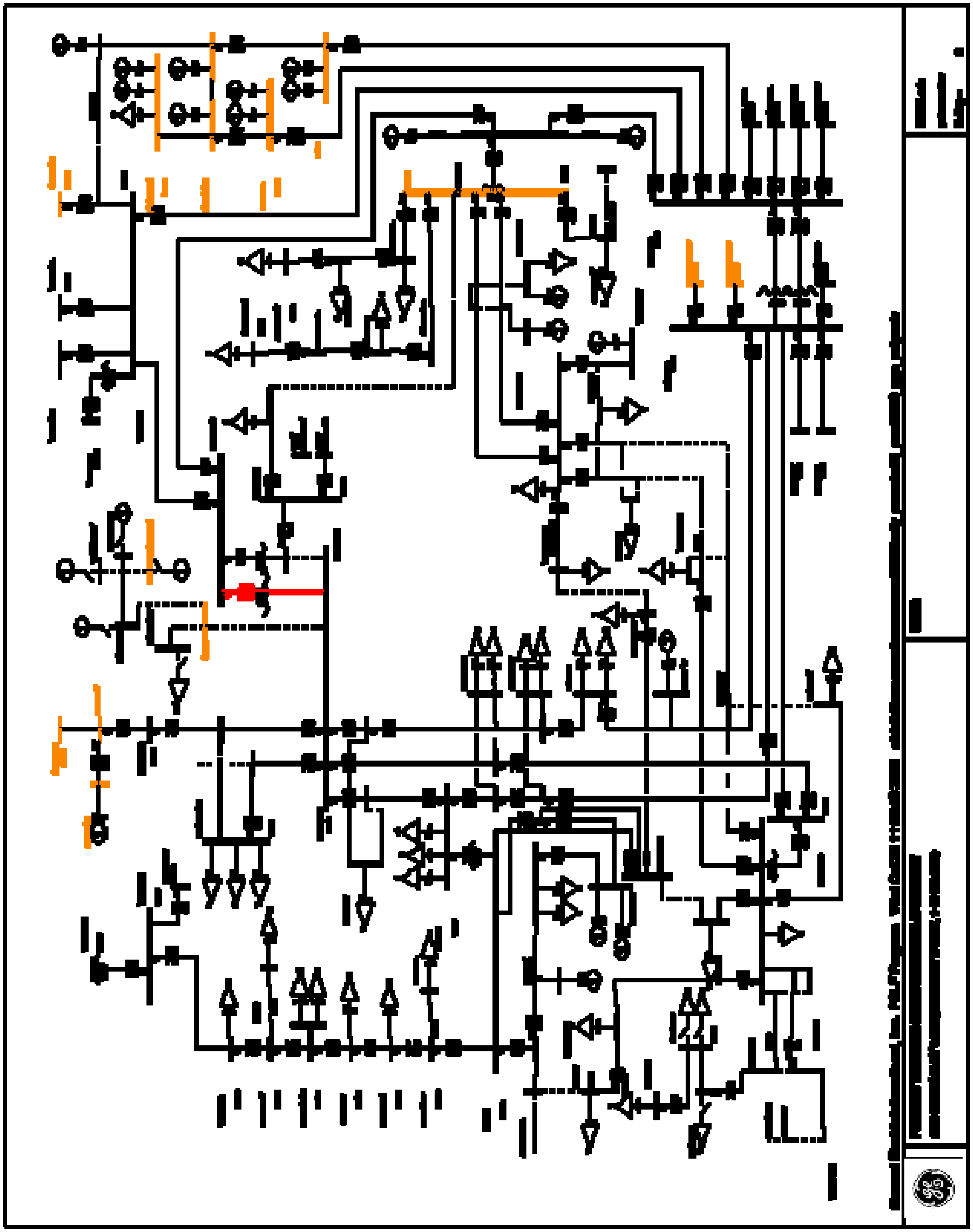


Figure 4-71: Pre Project – Loss of the Wood Lead – Palermo 115 kV Line overlapped with the Feather River Energy Center (L-1/G-1)

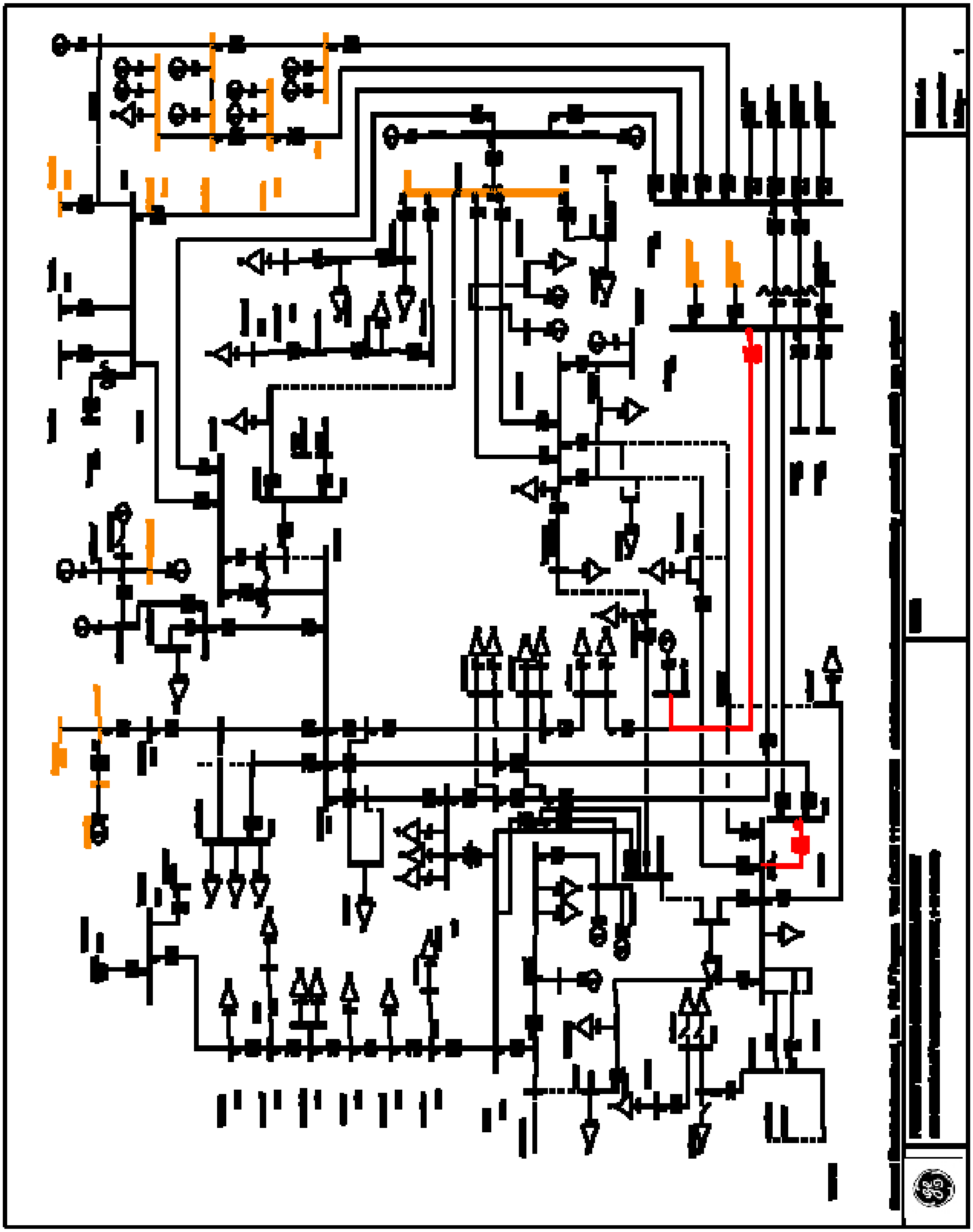


Figure 4-72: Post Project - Normal Conditions

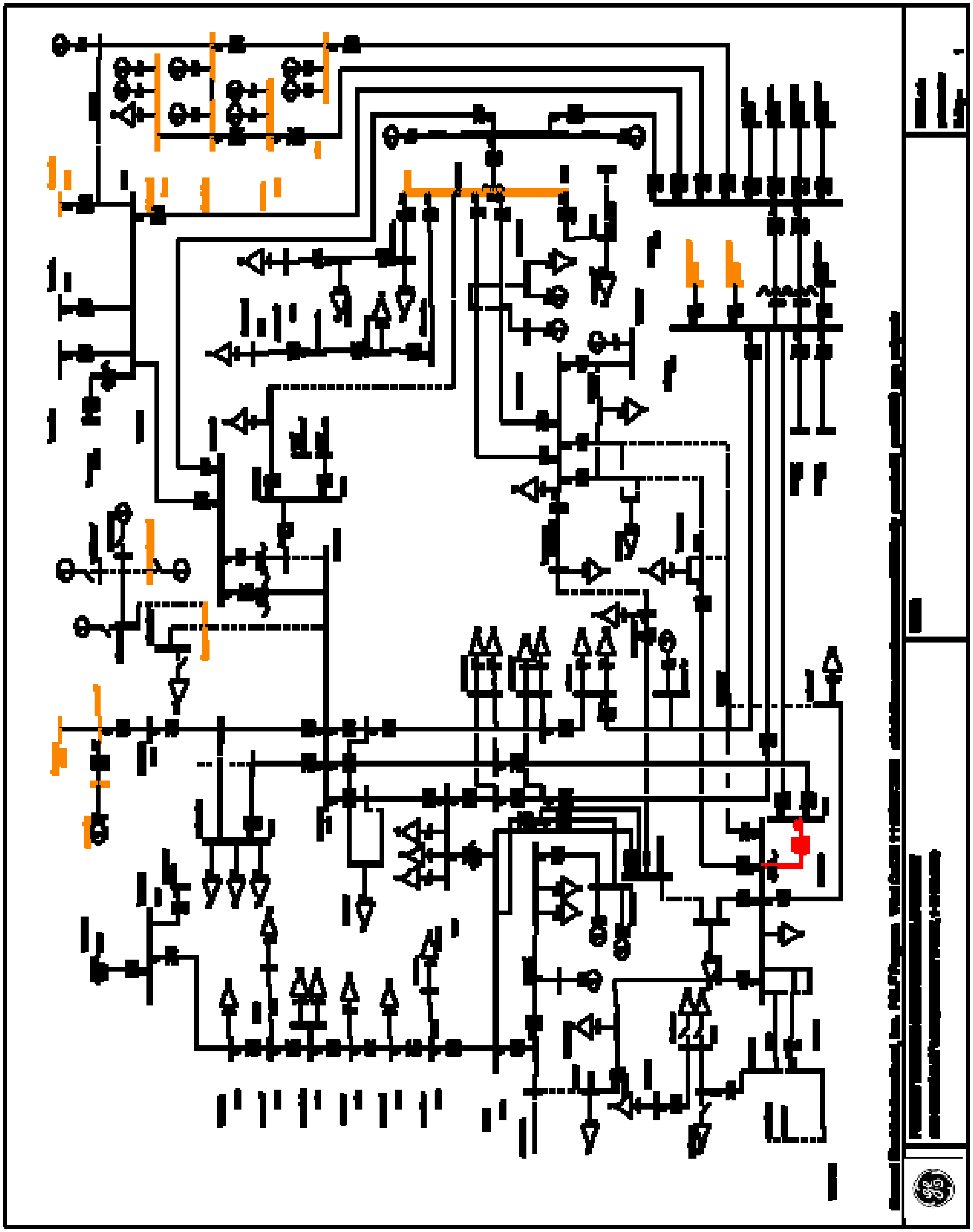


Figure 4-73: Post Project – Loss of the Wood Lead – Palermo 115 kV Line overlapped with the Feather River Energy Center (L-1/G-1)

Salado – Newman 60 kV Line No. 2 Reconductor

TARGETED IN-SERVICE DATE

May 2010

PURPOSE AND BENEFIT

Reliability – NERC Compliance

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROJECT

The project scope is to reconductor 6 spans (1,600 feet) of 266.8 AAL and #1/0 CU conductors on the Salado-Newman 60 kV No. 2 Line with conductors rated to handle a minimum of 631 Amps normal and 742 Amps emergency.

This project is expected to cost less than $1M.

BACKGROUND

The Salado – Newman 60 kV Nos. 1 and 2 Lines are located in the Stockton Division in Stanislaus County. They supply the Newman, Crows Landing and Gustine distribution substations and have a single connection to the transmission grid via a 115/60 kV transformer bank at Salado Substation. There Stanislaus Co. Resource Recovery generator (24 MW) is connected to the Salado – Newman 60 kV No. 1 Line and also serves the area.

The Salado – Newman 60 kV No.2 Line is strung with 715.5 AAL (6 circuit miles), 397.5 AAL (15.3 circuit miles), 266.8 AAL (0.1 circuit mile) and #1/0 CU (0.2 circuit mile) conductors.

The 2009 projected peak load for Newman, Crows Landing and Gustine substations is 45.2 MW and is forecast to increase at a rate of 0.9 MW or 2% per year.

Planning analysis identified that loss of the Salado – Newman 60 kV No. 1 Line (which also result in the loss of the Stanislaus Co. Resource Recovery generator) will overload the #1/0 CU section (Pole # 31/579 to Pole # 31/583) of the Salado – Newman 60 kV No. 2 Line by 14% in 2009 and 34% in 2018.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVE CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended because it does not mitigate the expected capacity constraints.

PROJECT SCHEDULE

- Environmental and Permitting Processes – None
- Design – TBD
- Major Equipment – None
- Construction – TBD
- Operation Date – May 2010

KEY ISSUES

- Land-Use Restrictions – There are no land-use restrictions with this project.
- Environmental Concerns – TBD
- Special Metering or Protection - TBD
- Common Mode Exposure Items – None
- Interaction with other Projects or Studies – None

GEPSLF MODELING INFORMATION

#There are 3-spans of 1/0 copper from 31/579 to 31/583. The newer 715 al. starts on the "ahead"
#side of 31/583 (TPD) toward Pole 31/584 (SW-17). Switches 17 and 19 are also rated at 600 amps.

#This line was re-conductored around 1997 or 1998. It is 715 Alum from Salado Sub to Patterson
#JCT up to Switch 17. From Switch 17 to Newman Sub it is 397.5 Alum.
#
Change File for Salado Reconductoring Project
#Reconductor 1/0 copper section with 715.5 AAL Conductors, limited by 397.5 AAC conductor section
#Section between Patterson and Patterson JCT
OLDSECDD 34004, 34006, CKT=1 SEC=1 MVA1=46 MVA2=53 MVA3=69 MVA4=74

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagram
2. Demand Forecast
3. Power Flow Summary
4. Pre and Post Project Power Flow Plots

Attachment 1: Scope Diagram

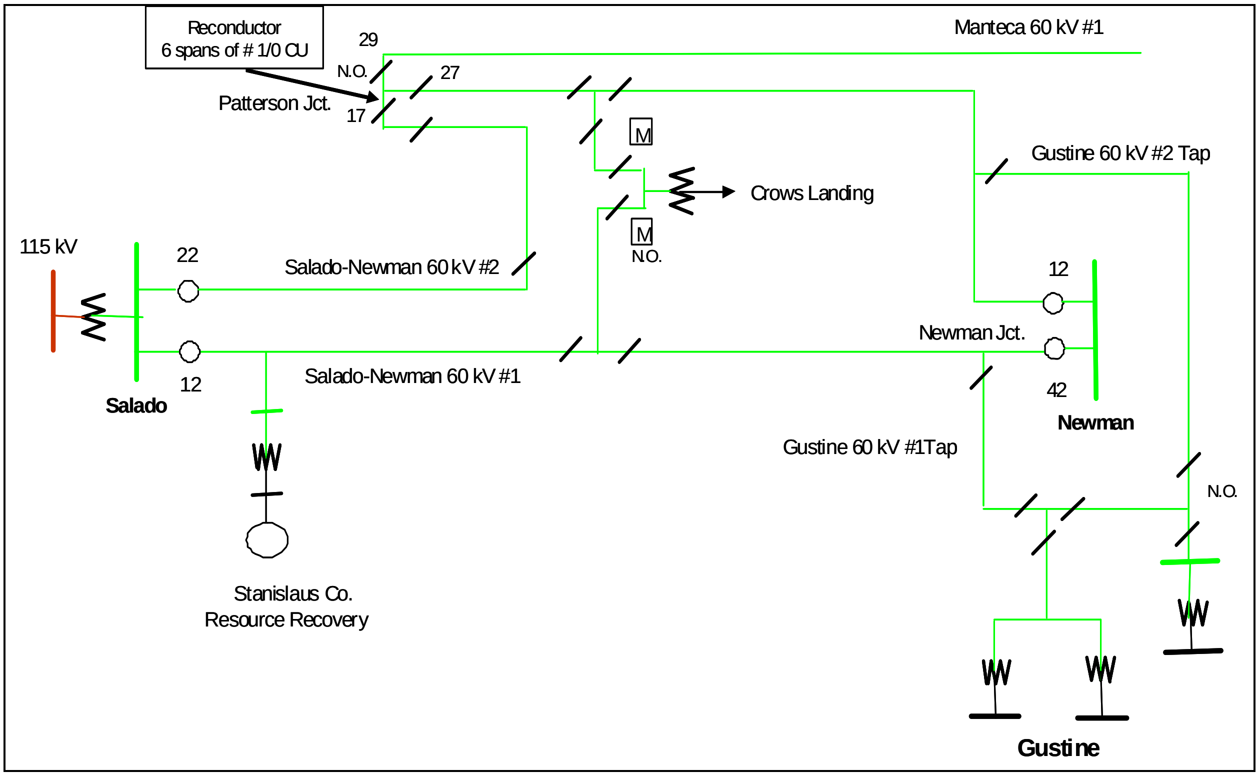


Figure 4-74: Scope Diagram

Attachment 2: Demand Forecast

Table 4-23: Demand Forecast

Substation	2009	2010	2011	2012	2013	Growth Rate (MW/Year)
Newman	20.4	20.8	21.1	21.5	21.9	0.4
Gustine	20.9	21.3	21.7	22.1	22.5	0.4
Crows Landing	3.9	4.0	4.1	4.2	4.3	0.1
Totals	**45.2**	**46.1**	**46.9**	**47.8**	**48.7**	**0.9**

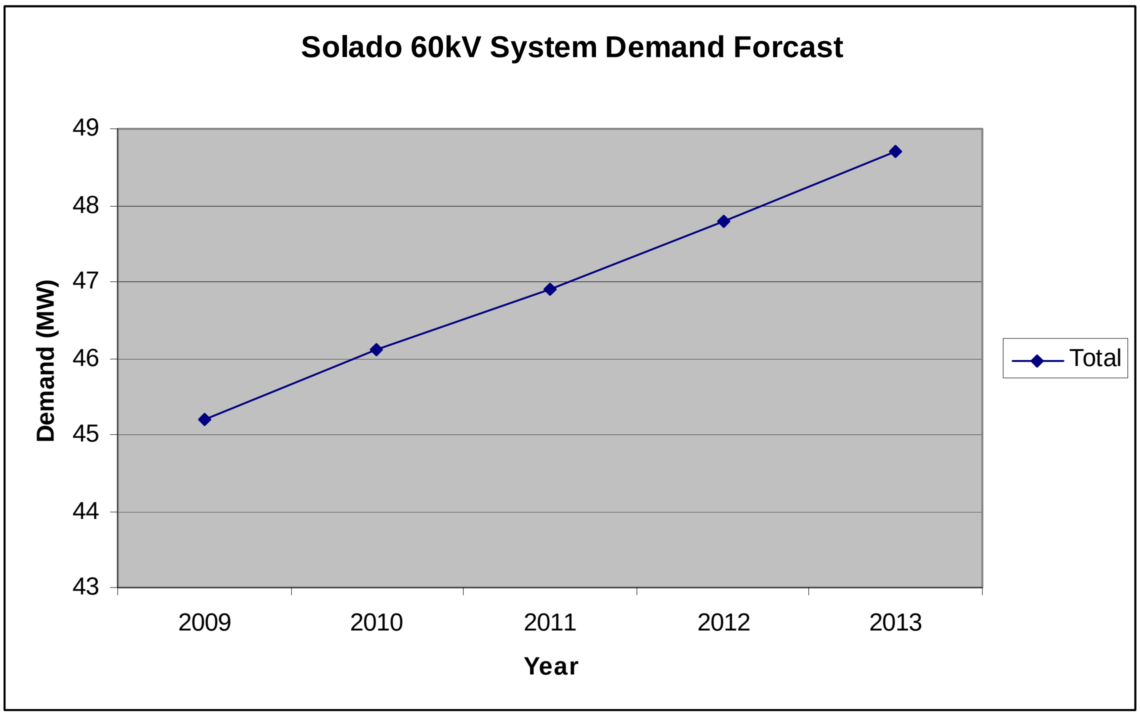


Figure 4-75: Plot of Demand Forecast

Attachment 3: Power Flow Summary

Table 4-24: Power Flow Summary

Contingency	Facility Affected	2009 (Pre-Project)	2010 (Pre-Project)	2011 (Pre-Project)	2012 (Pre-Project)	2013 (Pre-Project)	2013 (Post-Project)
Salado-Newman 60 kV #1 Line (L-1)	Salado-Newman 60 kV #2 Line	114%	116%	118%	120%	123%	60%

Attachment 4: Power Flow Summary

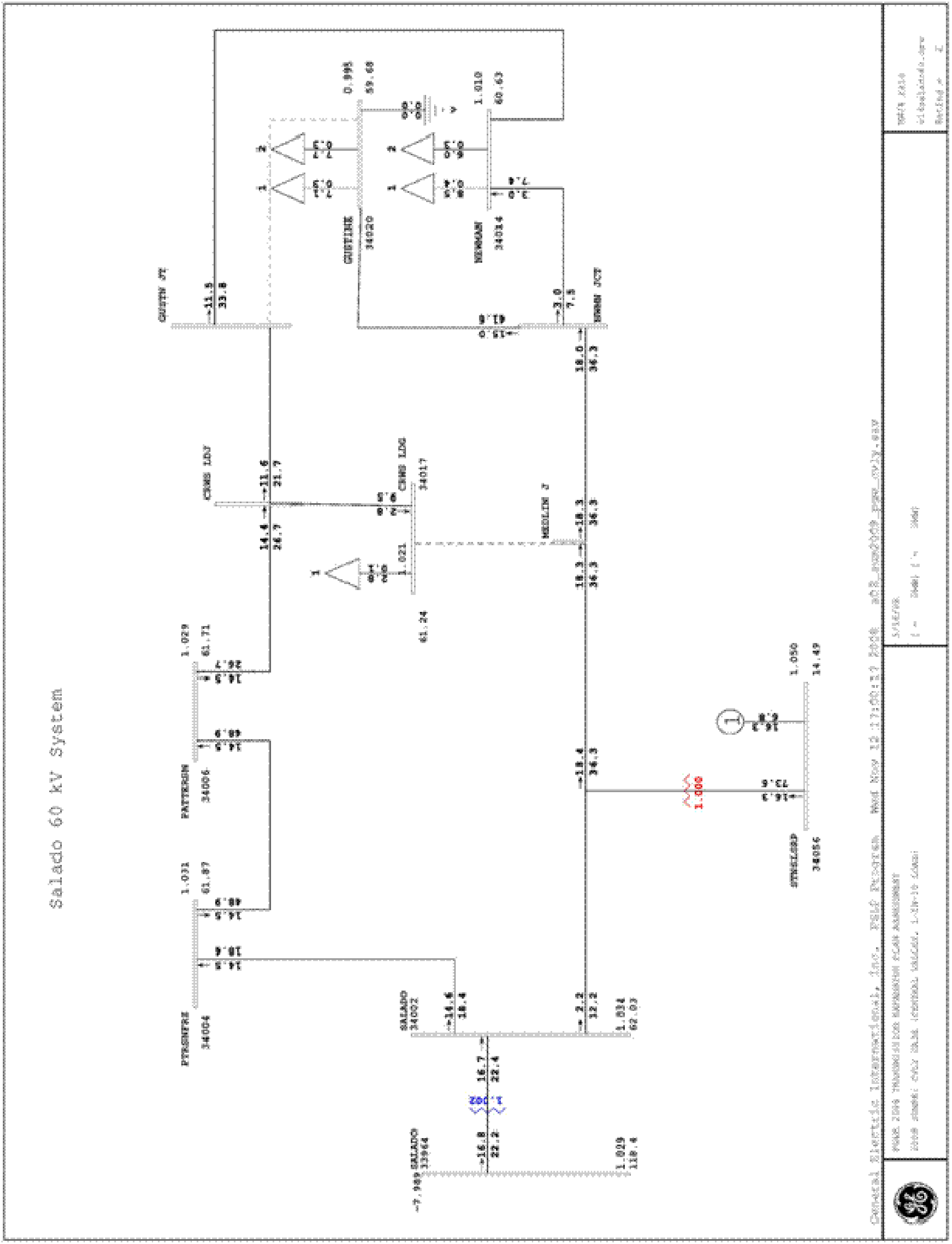


Figure 4-76: Pre Project - Normal Conditions

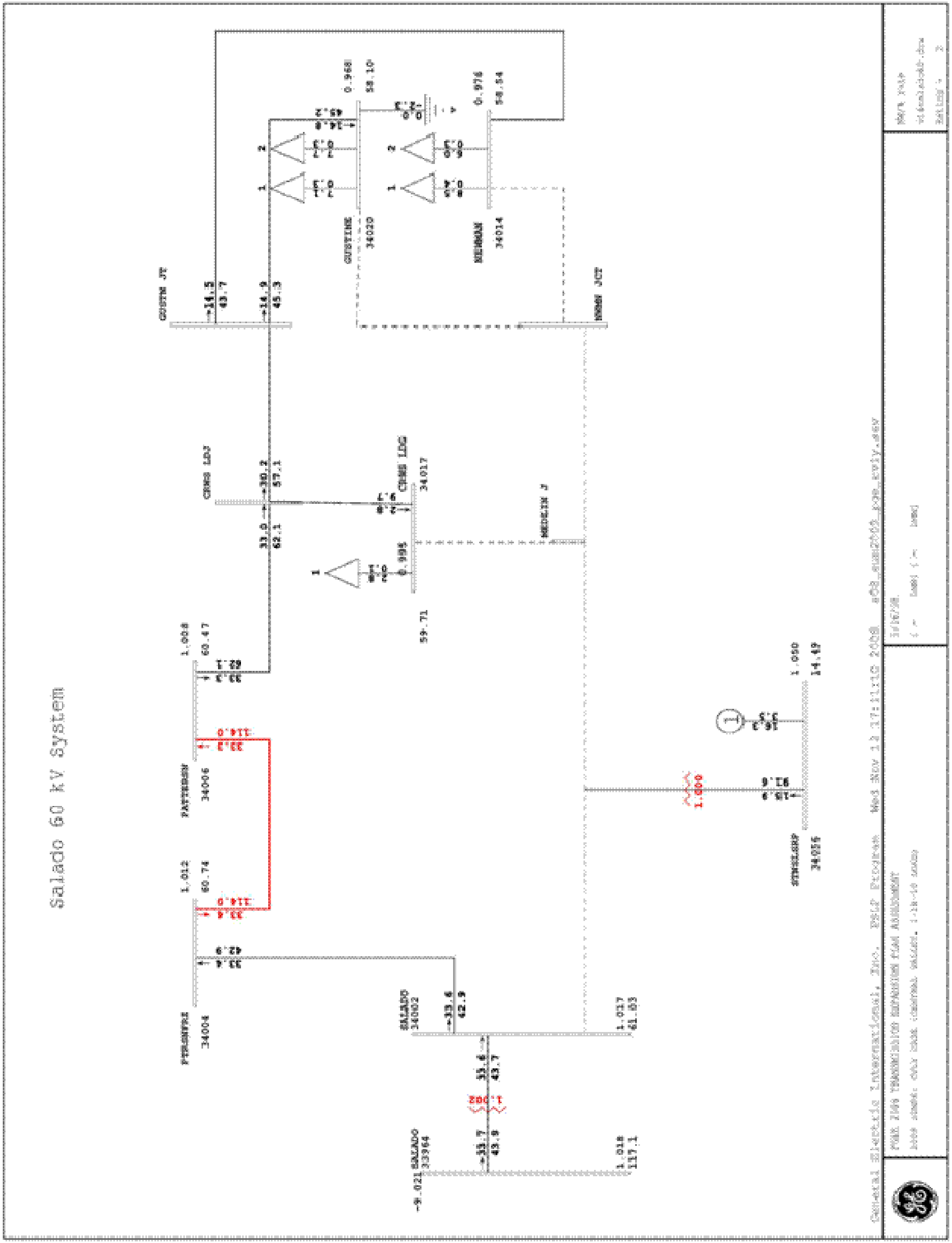


Figure 4-77: Pre Project Salado-Newman #1 Line Out of Service (L-1)

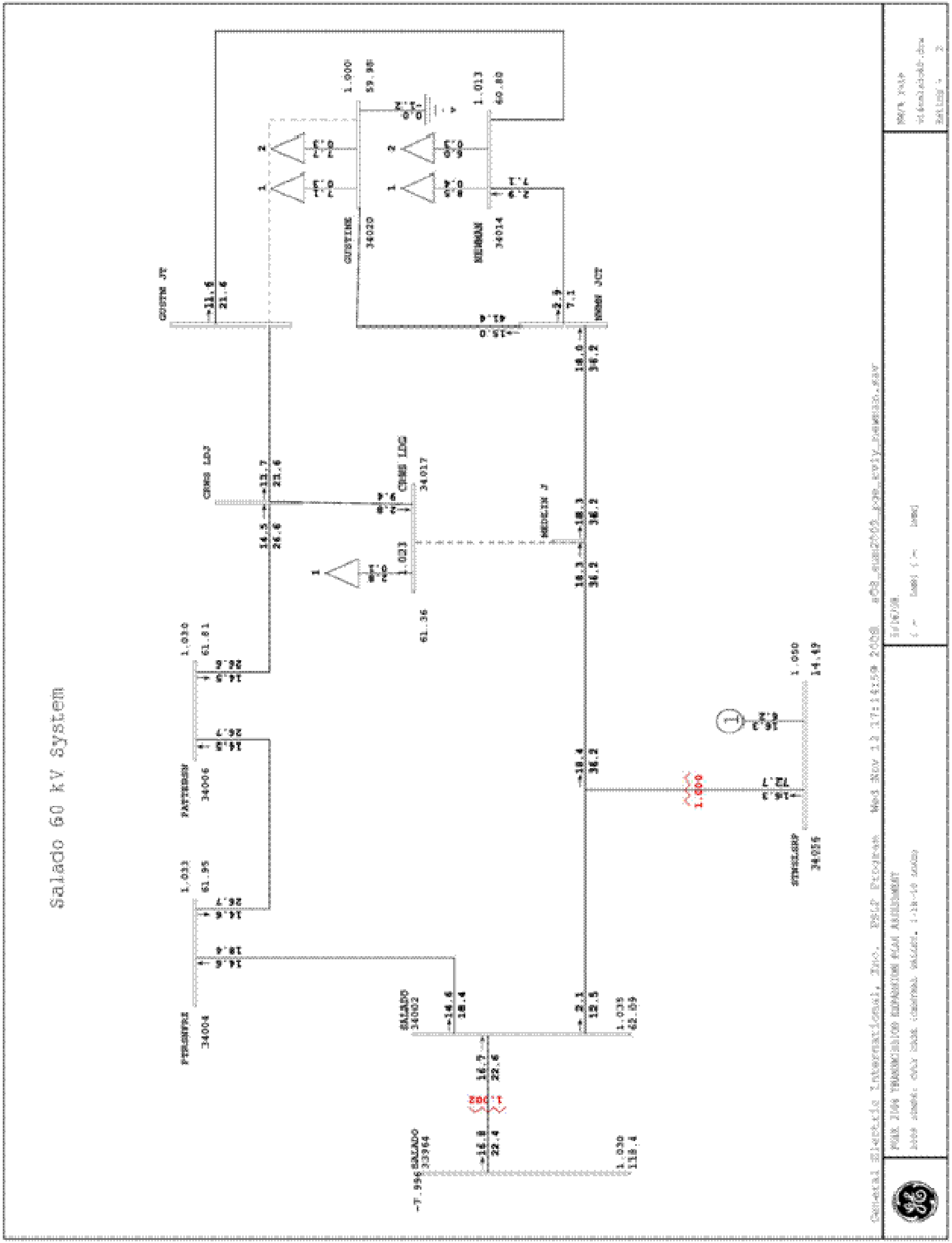


Figure 4-78: Post Project - Normal Conditions

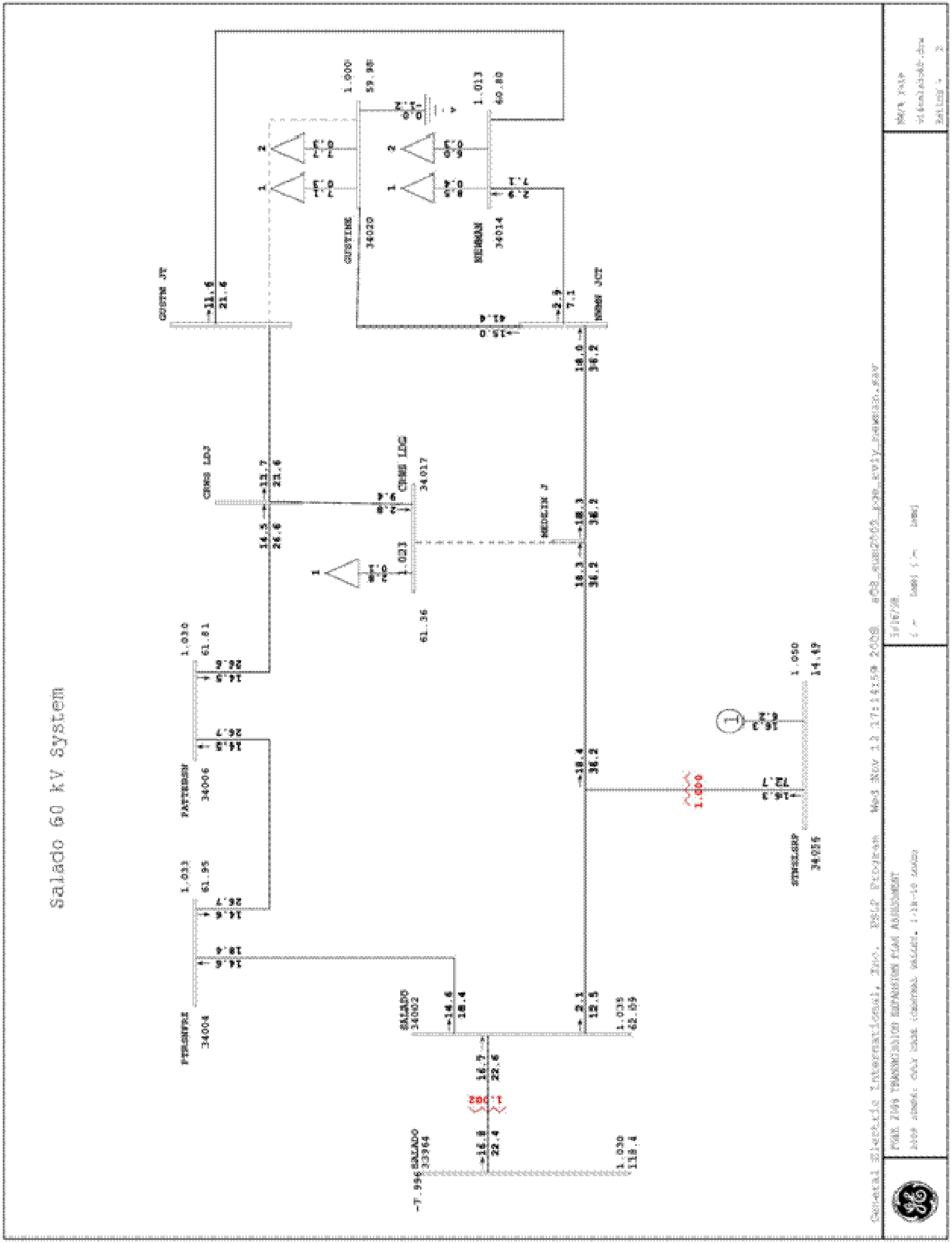


Figure 4-79: Post Project - Salado-Newman #1 Line Out of Service (L-1)

San Luis Obispo Switching Station #3

TARGETED IN-SERVICE DATE

December 2010

PURPOSE AND BENEFIT

Reliability and Renewable Resource Interconnection – NERC Compliance, Renewable Portfolio Standards and LGIP

PROJECT CLASSIFICATION

This is a new project. This project has two components: 1) Network Upgrade and 2) Direct Assignment.

This project serves as a Network Upgrade Project for generation interconnection project Q239, which is of renewable technology (solar). In addition, Project Q239 has a signed Power Purchase Agreements with PG&E.

PG&E has filed its advice letter on this Power Purchase Agreement, which can be reviewed under the following link:

http://www.pge.com/nots/rates/tariffs/tm2/pdf/ELEC_3318-E.pdf

DESCRIPTION AND SCOPE OF PROJECT

The project scope is to construct a new 230 kV switching station, electrically loop the Morro Bay – Midway 230 kV Nos. 1 and 2 into this new switching station and construct a generation tie line that interconnects solar generation into this new switching station. Specifically, this project scope has two components: Network Upgrades and Direct Assignment.

Network Upgrade Component:

- Construction of a new switching station that is configured in a Breaker-and-a-Half arrangement with two-3-breaker bays.
- Electrically loop this new switching station into the Morro Bay – Midway 230 kV Nos. 1 and 2 Lines.

Direct Assignment Component:

- Construction of a new 230 kV generation tie line (up to 2.5 miles long) from the site of Project Q239 to the new switching station

- Construction of a two-breaker-bay in the new switching station to interconnect the new 230 kV generation tie line

The Network Upgrade component of this project is expected to cost between $11M and $13M. The Network Upgrade component of this project will be owned and operated by PG&E. All Network Upgrade costs will be recovered in a future Transmission Owner rate case.

The Direct Assignment component of this project is expected to cost between $5M and $7M. The Direct Assignment component of this project will be owned, operated and funded by the generator developer for Q239.

The total cost for this project (Network Upgrade and Direct Assignment components) is between $16M and $20M.

BACKGROUND

PowerLight Corporation, a division of SunPower, an Interconnection Customer (IC), has submitted a completed Interconnection Request (IR) to the California Independent System Operator Corporation (CAISO) for their proposed Q239 Project. The Project is a solar generation project via polysilicon photovoltaic (PV) panels, with a maximum net output of 250 MW. The Project consists of two hundred 1.25 MW photovoltaic inverters with a 34.5 kV collection system. The proposed commercial operation date is December 1, 2011. The primary Point of Interconnection (POI) will be PG&E's Morro Bay – Midway 230 kV Nos. 1 and 2 lines.

Furthermore, timely interconnection of this solar power generation facility would help PG&E meet its energy procurement goals of procuring 20% of its energy from renewable resources.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO under the LGIP process.

STUDY CRITERIA

CAISO grid planning criteria

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – December 2010

KEY ISSUES

- Land-Use Restrictions – Permitting of new substation and generation tie line
- Environmental Concerns – Land for new substation and generation tie line
- Special Metering or Protection – None
- Common Mode Exposure Items – None
- Interaction with other Projects – Morro Bay – Midway 230 kV Line Reconductoring

GEPSLF MODELING INFORMATION

```
# 251.1 MW gross output (200 PV @ 1.255 MW each)
# 1.1  MW plant load
# 250 MW net to the grid
# Loop Morro Bay -  Midway #1 and #2 230 kV lines near Carrizo Plains
# Insert new buses for Q239 115, 12.47 and 0.48 kV
# NEWBUSD   BUSNO, "NAME=",   BASKV=,    BUSTYPE=, VSCHED=1,   AREA=,  ZONE=,   VMAX=,    VMIN=,
 NEWBUSD   30918  "Q239SWST" BASKV=230   BUSTYPE=1 VSCHED=1.0  AREA=30 ZONE=320 VMAX=1.05 VMIN=0.95
 NEWBUSD   30919  "Q239    " BASKV=230   BUSTYPE=1 VSCHED=1.0  AREA=30 ZONE=320 VMAX=1.05 VMIN=0.95
 NEWBUSD   36425  "Q239    " BASKV=34.5  BUSTYPE=1 VSCHED=1.0  AREA=30 ZONE=320 VMAX=1.05 VMIN=0.95
 NEWBUSD   36426  "Q239    " BASKV=0.48  BUSTYPE=2 VSCHED=1.0  AREA=30 ZONE=320 VMAX=1.05 VMIN=0.95
 SOLV
# insert 42.6 mile line with 1113 AAC interior line from Morro Bay - Q239SWST
# NEWSECDD  "FBUS"  "TOBUS"  "CKT=1"  SEC=1  RPU=  XPU=  BPU=  MVA1=    MVA2=    MVA3=    MVA4=    STATUS=1
 NEWSECDD   30915  30918     1    SEC=1 RPU=.007684 XPU=.063178 BPU=.124155 MVA1=329  MVA2=389  MVA3=513
MVA4=549  STATUS=0
 SOLV
 CLOSE     30915  30918     1
 SOLV
# insert 5 mile line with 1113 AAC interior line from Q239SWST - Q194
 NEWSECDD   30918  30916     1    SEC=1 RPU=.000902 XPU=.007415 BPU=.014572 MVA1=329  MVA2=389  MVA3=513
MVA4=549  STATUS=0
 SOLV
 CLOSE     30918  30916     1
 SOLV
# Remove Morro Bay - Q194 line section
 PURGE     30915  30916     1
 SOLV
# insert 16 mile line with 1113 AAC interior line from Q166P0701 - Q239SWST
 NEWSECDD   30920  30918     1    SEC=1 RPU=.002886 XPU=.023729 BPU=.046631 MVA1=329  MVA2=389  MVA3=513
MVA4=549  STATUS=0
 SOLV
 CLOSE     30920  30918     1
 SOLV
# insert 37 mile line with 1113 AAC interior line from Q239SWST - Midway
 NEWSECDD   30918  30970     1    SEC=1 RPU=.006673 XPU=.054873 BPU=.107834 MVA1=329  MVA2=389  MVA3=513
MVA4=549  STATUS=0
 SOLV
 CLOSE     30918  30970     1
```

```
 SOLV
# Remove Q166P0701 - Midway line section
 PURGE      30920  30970     1
 SOLV
# insert 100 ft line with min. Xpu to exceed jumper threshold with 795 ACSR from loop point to project
 NEWSECDD   30918  30919     1    SEC=1 RPU=.000005 XPU=.000300 BPU=.000061 MVA1=296  MVA2=339  MVA3=434
MVA4=460  STATUS=0
 SOLV
# Insert 2 new step up 34.5/230 kV 100 MVA transformers
# Rpu=.00306, Xpu=.09 @ 60 MVA base (set rating to 130 MVA each)
# available taps 2 @ +/- 2.5% on H winding
# NEW_TRAN   FBUS   TOBUS  CKT  ZR=,        ZX=,      BMAG=,      GMAG=       MVA1=,   MVA2=    MVA3=    MVA4=
# VNOMF=,     VNOMT=,     MVABASE=   REG=      TAPFP=1, TAPFS=1
 NEW_TRAN   36425  30919   1    ZR=.00306  ZX=.09    BMAG=.0000  GMAG=.0000  MVA1=130 MVA2=130 +
MVA3=130 MVA4=130  VNOMF=34.5  VNOMT=230   MVABASE=60 REG=30919 TAPFP=1.0  TAPFS=1.00 STAT=0
 SOLV
 NEW_TRAN   36425  30919   2    ZR=.00306  ZX=.09    BMAG=.0000  GMAG=.0000  MVA1=130 MVA2=130 +
MVA3=130 MVA4=130  VNOMF=34.5  VNOMT=230   MVABASE=60 REG=30919 TAPFP=1.0  TAPFS=1.00 STAT=0
 SOLV
# Insert 1 new 0.48/12.47 equivalent transformer (represents 200 individual step-up transformers)
# Rpu=.01008, Xpu=.0575 @ 1 MVA base (set rating to 250 MVA each)
# available taps 2 @ +/- 2.5% on H winding
 NEW_TRAN   36426  36425   1    ZR=.01008  ZX=.0575  BMAG=.0000  GMAG=.0000  MVA1=260 MVA2=260 +
MVA3=260 MVA4=260  VNOMF=0.48  VNOMT=34.5 MVABASE=200 REG=36425 TAPFP=1.0  TAPFS=1.00 STAT=0
 SOLV
# Insert 1 new equivalent generator representing 200 1.25 MW PV units
# units do not have any reactive capability
 NEWGENS    36426  UNIT=1   STAT=0  PGEN=251.1 QMAX=0.0  QMIN=0.0  VSCHED=1.00 BASEMVA=251.1 PMAX=251.1
PMIN=0
 SOLV
# Add 1.1 MW plant load @ .875 pf (power factor is assumed)
 NEWLOAD   36426      ss      PLOAD=1.1  PF=.875  ST=0  ZONE=360
 SOLV
# Add 60 MVAr capacitor to obtain unity power factor at POI
# NEW_BUS_SHUNT  "BUS=", BSH=,   STATUS=1, ID="b "
 NEW_BUS_SHUNT  36425   BSH=.60 STATUS=0  ID="b "
 SOLV
# Turn on all elements
# Close all lines and transformers
 CLOSE      30918  30919     1
 SOLV
 CLOSE      36425  30919   1
 SOLV
 CLOSE      36425  30919   2
 SOLV
 CLOSE      36426  36425   1
 SOLV
# Turn on gen, load
 OLDGENS    36426  1  STAT=1 PGEN=251.1
 OLDLOAD    36426  ss ST=1
 OLD_BUS_SHUNT   36425  BSH=.6  STATUS=1  ID="b "
 SOLV
```

MISCELLANEOUS DATA

- PG&E will construct, own, and operate the Network Upgrade component of this project
- The generation developer will provide initial funding for the Network Upgrade component of this project, which would later be reimbursed back to the developer once their generation project is placed into service and interconnected to the transmission grid.
- The generator developer will construct, own, and operate the Direct Assignment (Interconnection facilities) component of this project

ATTACHMENTS

1. Scope Diagram
2. Power Flow Drawing

Attachment 1: Scope Diagram

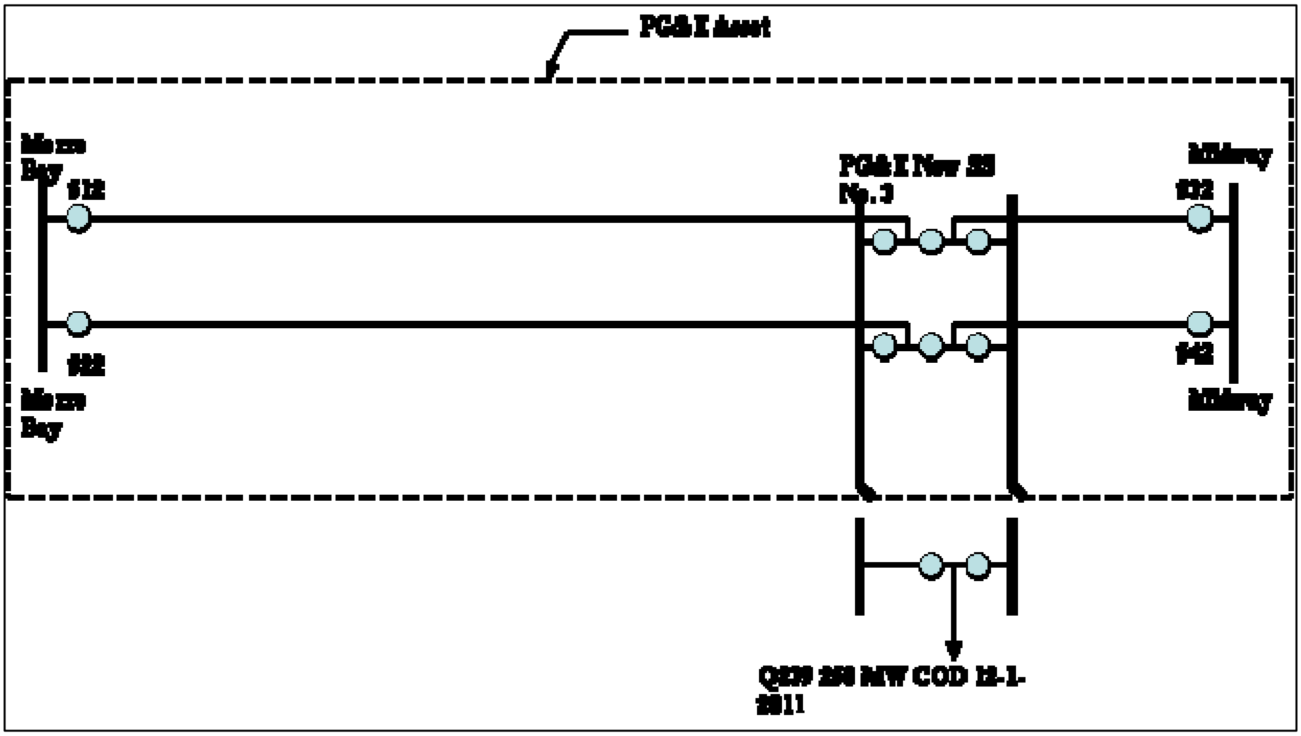


Figure 4-80: Proposed Scope Diagram

Attachment 2: Power Flow Drawing for Q239

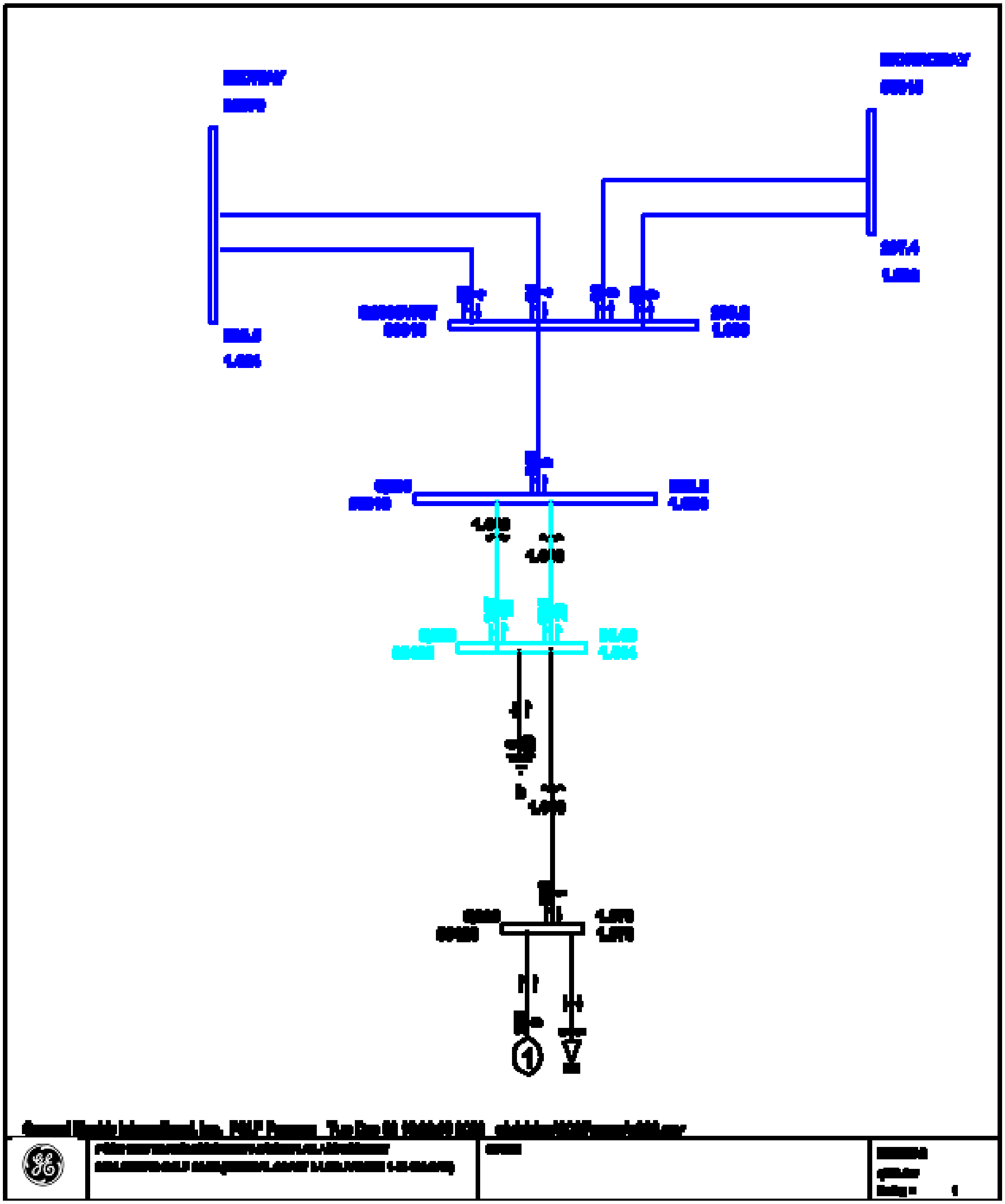


Figure 4-81: Post Project Q239

Cassidy 70 kV Breaker Installation

TARGETED IN-SERVICE DATE

May 2010

PURPOSE AND BENEFIT

Reliability – NERC Compliance and Operational Flexibility

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROJECT

The proposed project scope is to replace Cassidy 70 kV Substation switches (SW) Numbers (Nos.) 17 and 19 with circuit breakers. Automatics will be disabled on the Borden-Cassidy 70 kV line circuit breaker at Cassidy substation to guard against projected low voltages after an outage of the Borden-Cassidy 70 kV Line section.

The project is expected to cost between $1M and $2M.

BACKGROUND

Cassidy is a 70 kV distribution substation located in Madera County. Cassidy is comprised of one 70/12 kV, 12.5 MVA, transformer unit. Cassidy receives its transmission service via a single tap connection off the Borden-Coppermine 70 kV Line. Cassidy had a peak loading of 12.9 MW in 2008. A maintenance project has been initiated to replace Cassidy Distribution Bank No. 1 by May 2010. This project proposes to upgrade Cassidy Distribution Bank No. 1 to a 115x70/21 kV, 45 MVA, transformer unit.

The Borden-Coppermine 70 kV Line consists of approximately 20 circuit miles of 4/0 Copper, 397 Aluminum, 715.5 Aluminum, and 1113 Aluminum conductors. About 7 miles of this line is double circuited with 115 kV lines on tubular steel poles, while the rest of the line is hung from single wood poles. In addition to Cassidy Substation, River Rock Substation is also tapped off this line.

Currently, any outage along the Borden-Coppermine 70 kV Line drops both Cassidy and River Rock load. Installing breakers at Cassidy would significantly mitigate the impacts of a line outage. However, with circuit breakers, an outage of the Borden-

Cassidy 70 kV Line is projected to result in low voltage concerns at Cassidy under summer peak loading conditions. Therefore, automatics will be disabled for the Borden-Cassidy 70 kV circuit breaker at Cassidy substation in order to protect the system from low voltage conditions.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended since an outage of the Borden-Coppermine 70 kV line will still result in dropping Cassidy load.

Alternative 2: Borden-Coppermine 70 kV Upgrade

This alternative proposes to convert the Borden-Coppermine 70 kV Line for 115 kV operation by creating a new Herndon-Cassidy-Coppermine 115 kV Line. This would negate the need for a UVLS scheme, as the larger conductor would help support necessary voltage. However, by itself this project would not improve reliability at Cassidy. This alternative will be further studied in the long term.

PROJECT SCHEDULE

- Environmental and Permitting Processes – Not Applicable
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2010

KEY ISSUES

- Land-Use Restrictions – None
- Environmental Concerns – None
- Special Metering or Protection – None
- Common Mode Exposure Items – None
- Interaction with other Projects or Studies – None

GEPSLF MODELING INFORMATION

Not Applicable

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagram
2. Demand Forecast
3. Power Flow Summary
4. Pre and Post Project Power Flow Plots

Attachment 1: Scope Diagram

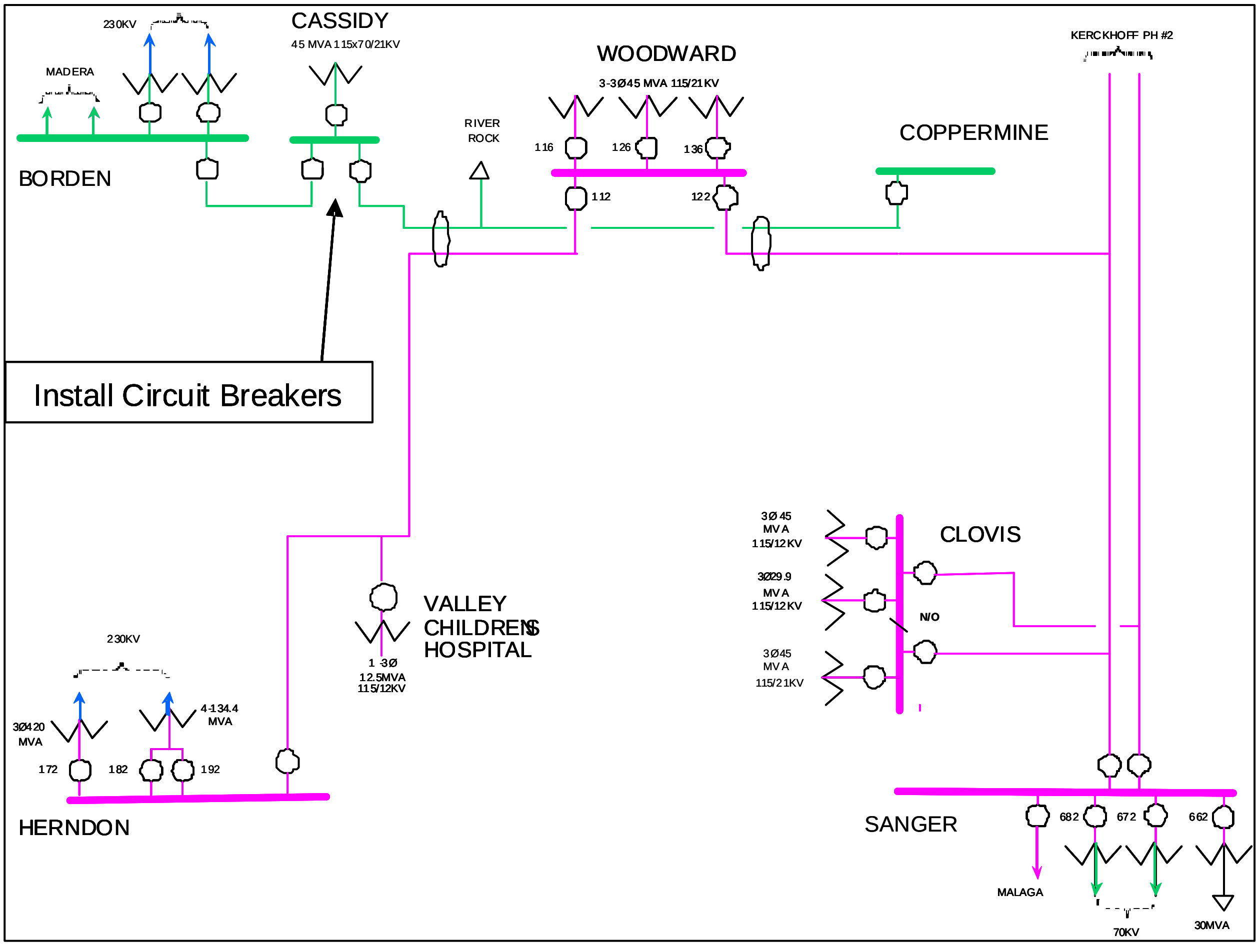


Figure 4-82: Proposed Scope Diagram

Attachment 2: Demand Forecast

Table 4-25 – Area Load Demand Forecast

Facility	*Projected Peak Load (MW)* 2009	2010	2011	2012	2013
70 kV System					
Cassidy Bank 1	13.8	13.9	14.2	14.4	14.6
River Rock Bank 1	2.3	2.3	2.3	2.3	2.3
Coppermine Bank 1	20.8	21.4	22	22.5	23.1
Total	**36.9**	**37.6**	**38.5**	**39.2**	**40**

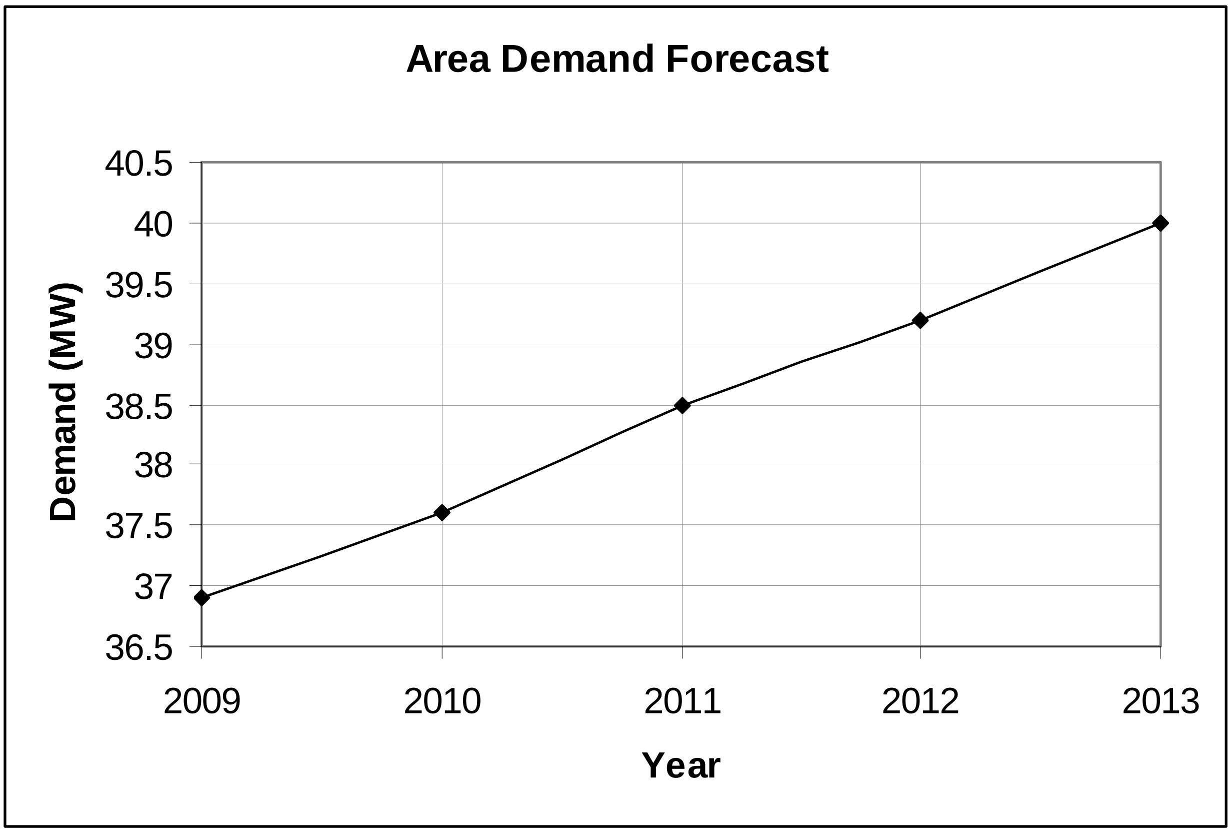


Figure 4-83: Area Load Demand Curve

Attachment 3: Power Flow Summary

Table 4-26: Power Flow Results without Disabled Circuit Breaker Automatics

		Voltage (pu)					
#	Facility	2009	2010	2011	2012	2013	Contingency
1	Cassidy 70 kV Substation	0.90	0.88	0.86	0.84	0.81	Borden-Cassidy 70 kV Line
2	River Rock 70 kV Substation	0.90	0.88	0.86	0.84	0.82	
3	Coppermine 70 kV Substation	-	0.89	0.87	0.85	0.83	
4	Auberry 70 kV Substation	0.89	0.87	0.85	0.82	0.80	
5	Wishon 70 kV Substation	0.90	0.88	0.86	0.83	0.81	
6	North Fork 70 kV Substation	0.87	0.85	0.83	0.80	0.78	
7	San Joaquin No. 2 70 kV Substation	0.88	0.86	0.84	0.81	0.78	
8	San Joaquin No. 3 70 kV Substation	0.87	0.84	0.82	0.79	0.77	
9	Friant 70 kV Substation	-	-	0.90	0.88	0.86	
		Loading (%)					
10	Tivy Valley - Reedley 70 kV Line	99.6	106	113	120	129	

Attachment 4: Pre and Post Project Power Flow Plots

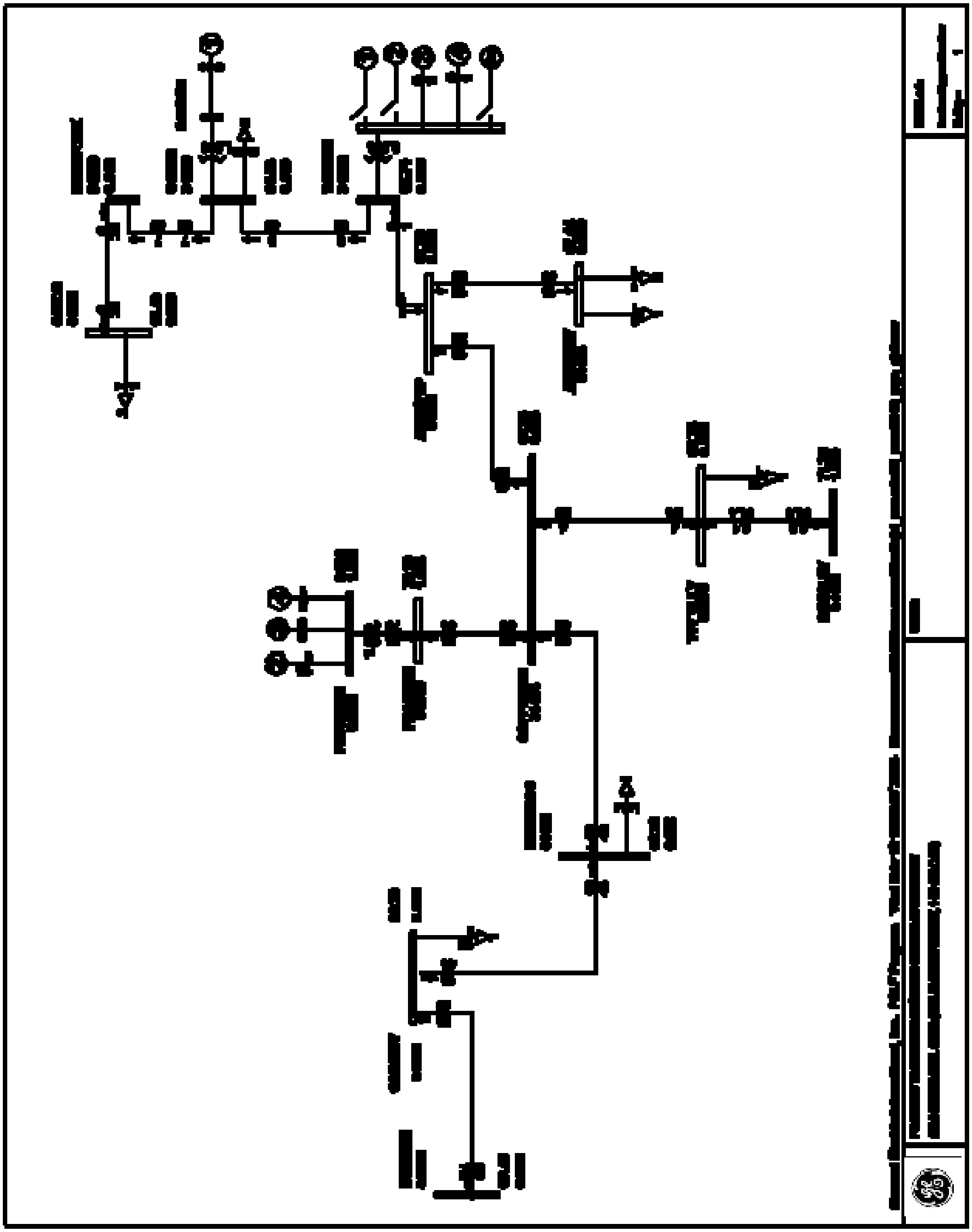


Figure 4-84: Pre Project – Normal Conditions

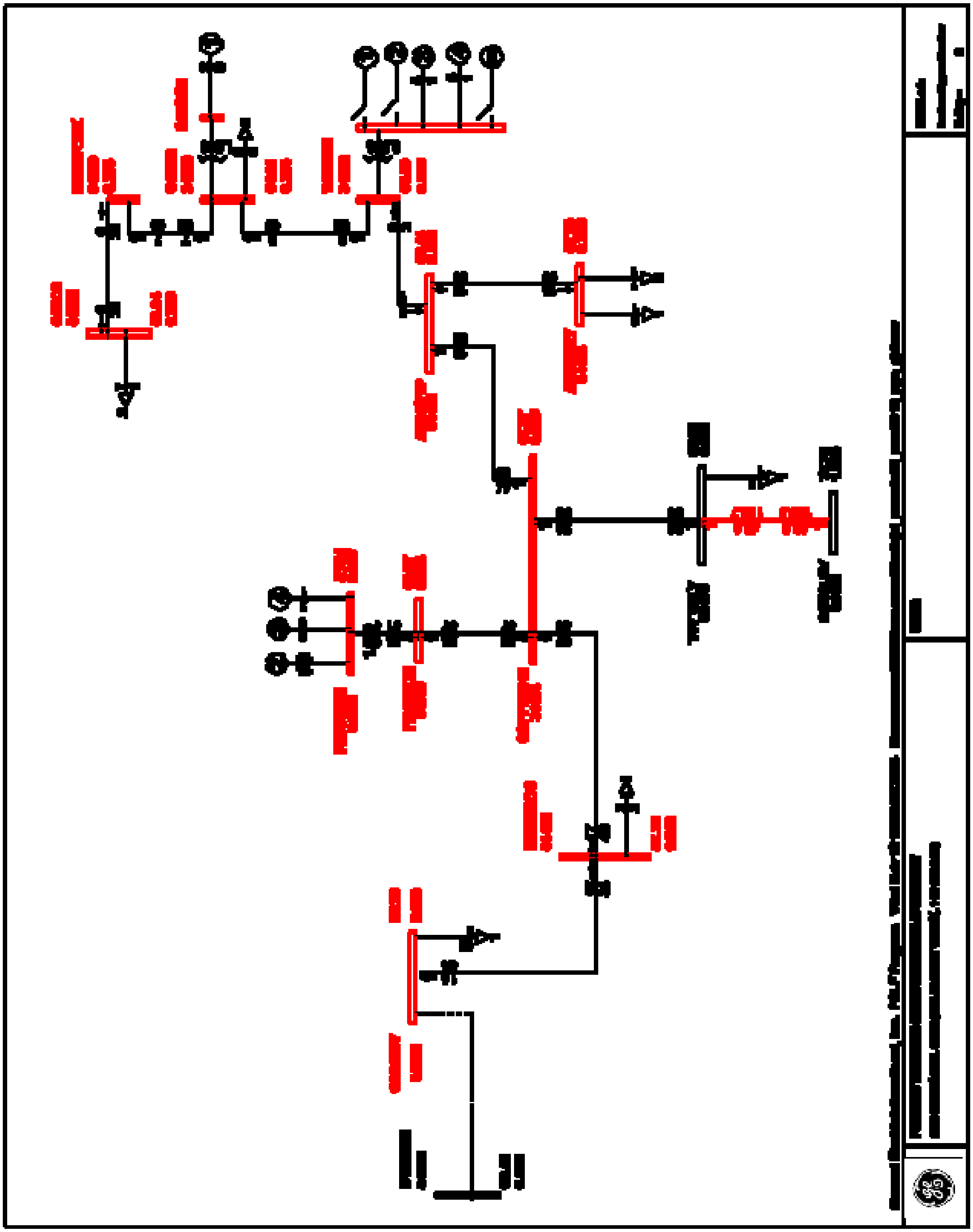


Figure 4-85: Post Project without Disabled Automatics – Loss of the Borden-Cassidy 70 kV Line: 2013

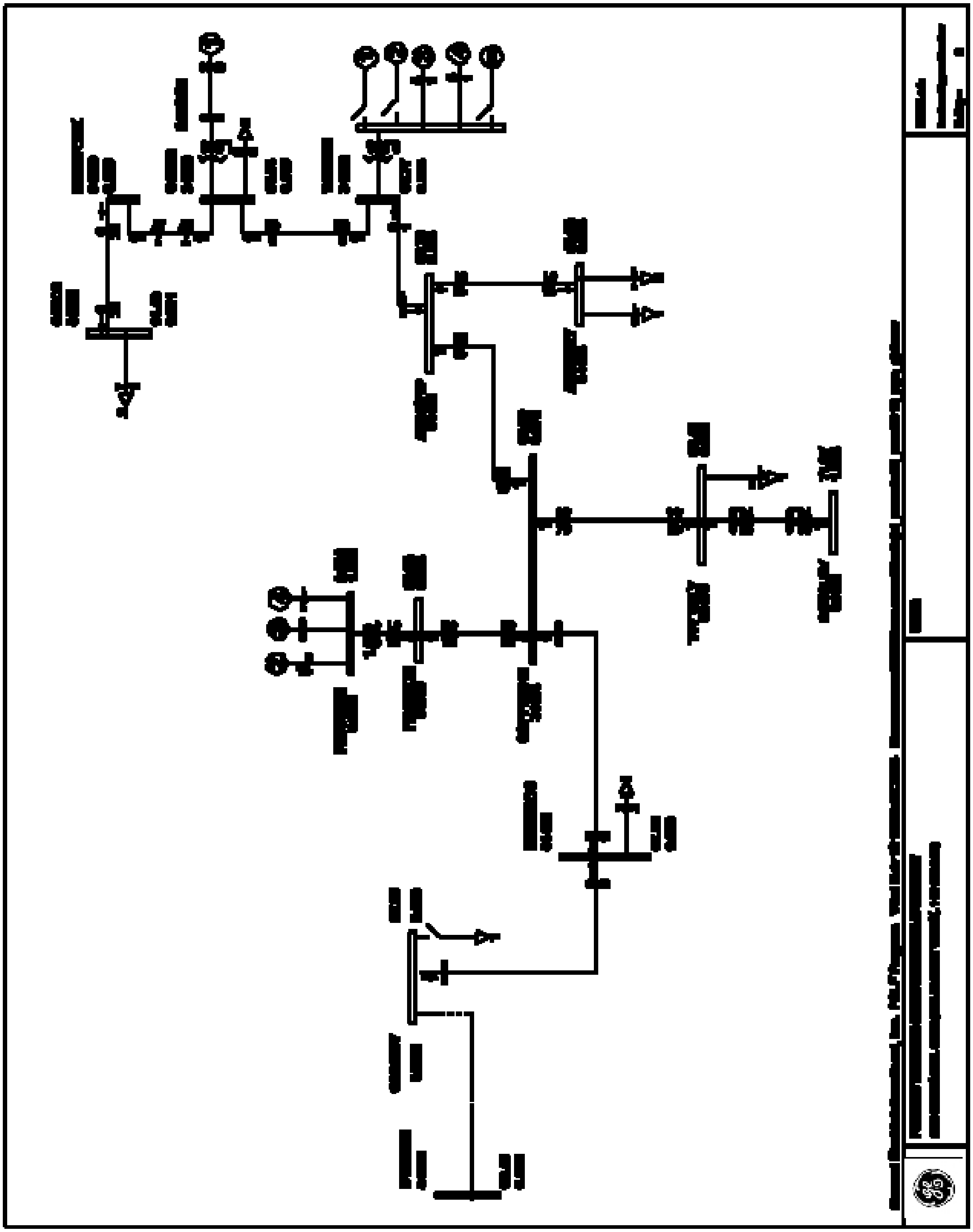


Figure 4-86: Post Project with Disabled Circuit Breaker Automatics – Loss of the Borden-Cassidy 70 kV Line: 2013

Herndon 115 kV Circuit Breaker Replacement

TARGETED IN-SERVICE DATE

May 2010

PURPOSE AND BENEFIT

Reliability – NERC Compliance

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROJECT

The proposed project scope is to replace Herndon circuit breaker (CB) number (No.) 122 with a 2,000 Amp-rated circuit breaker or larger and associated equipment at Herndon Substation. Completion of this project allows the Herndon-Bullard 115 kV No. 2 Line to serve up to 1,517 Amps under summer normal and emergency conditions.

The project is expected to cost between $1M and $2M.

BACKGROUND

Herndon Substation is located in Fresno County, and serves several 115 kV substations. Both Pinedale and Bullard are served from Herndon, and had a combined electric peak demand recorded at 220 MW in 2008.

The Herndon-Pinedale sections of the transmission lines are sized with 795 SSAC conductors, which are rated to handle 1,517 Amps under summer normal and emergency conditions. Although the Herndon-Bullard 115 kV lines are sized with 795 SSAC conductors, the lines are limited to handle a maximum of only 1,200 Amps due to circuit breaker and switch limitations at Herndon Substation. Specifically, Herndon CB No. 122, which protects the No. 2 Line, is rated to handle only 1,200 Amps. Herndon CB No. 122 is an oil-filled breaker that was installed in 1986. With this limitation, the outage of Herndon – Bullard Line No. 1 can result in overloaded conditions for the No. 2 line (and vice versa), given peak load conditions.

The Herndon-Bullard 115 kV No. 1 Line does not have any switch or CB limitations since CB No. 112 is rated to handle up to 2,000 Amps. There are, however, several disconnect and bus selection switches at Herndon that can further limit both lines to a

1,200 Amps normal, or 1,440 Amps emergency rating. These will be identified and replaced as needed.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended since an outage of the Herndon-Bullard 115 kV Line No. 1 or 2 is projected to load the remaining line above the ratings of Herndon CB No. 122 and switches.

PROJECT SCHEDULE

- Environmental and Permitting Processes – Not Applicable
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2010

KEY ISSUES

- Land-Use Restrictions – None
- Environmental Concerns – None
- Special Metering or Protection – None
- Common Mode Exposure Items – None
- Interaction with other Projects or Studies – None

GEPSLF MODELING INFORMATION

Not Applicable

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagram
2. Demand Forecast
3. Power Flow Summary
4. Pre and Post Project Power Flow Plots

Attachment 1: Scope Diagram

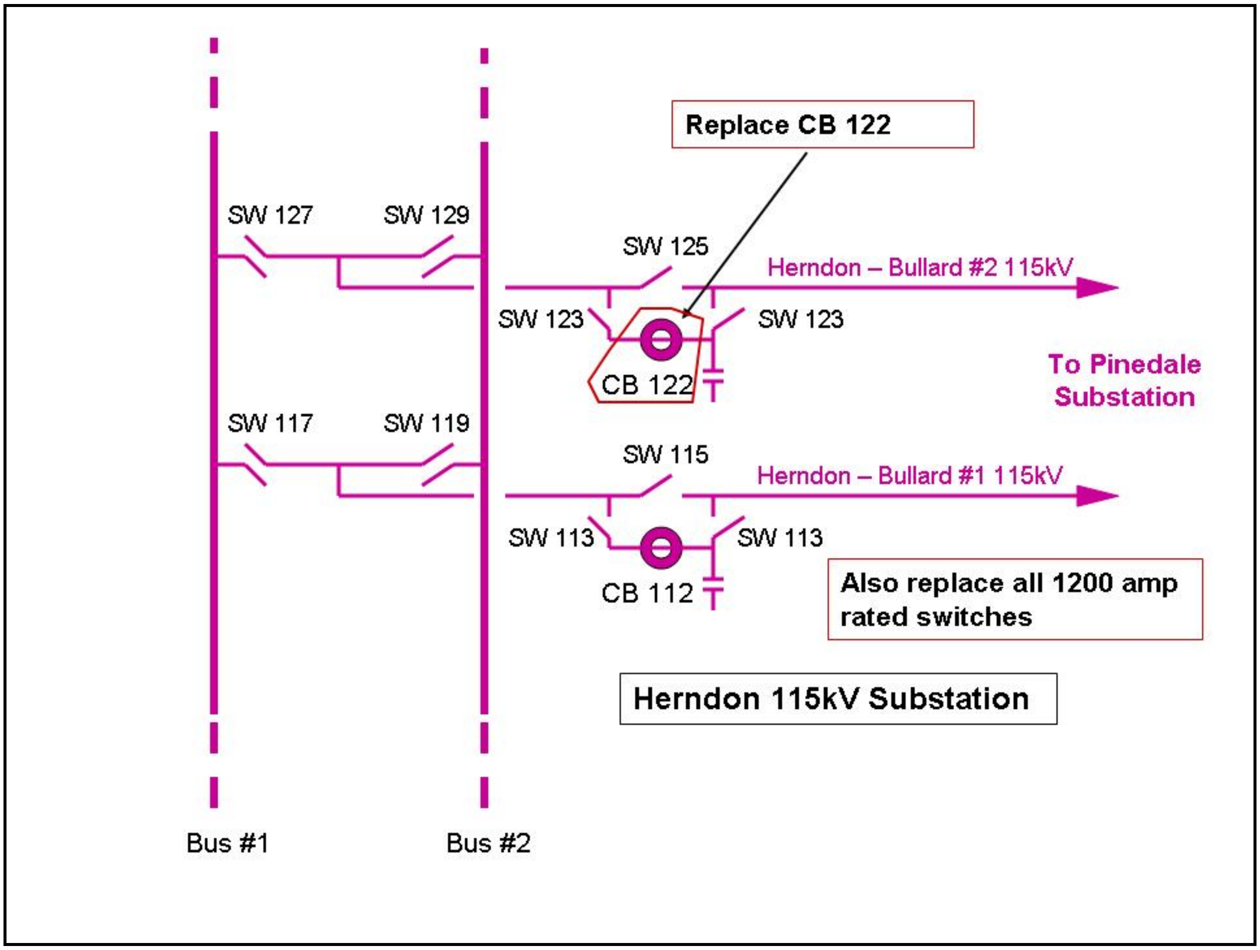


Figure 4-87: Proposed Scope Diagram

Attachment 2: Demand Forecast

Table 4-27: Area Load Demand Forecast

Facility	*Projected Peak Load (MW)*				
	2009	**2010**	**2011**	**2012**	**2013**
115 kV System					
Pinedale Bank 1	26.7	27.1	27.5	27.8	28.2
Pinedale Bank 2	28.5	29.1	29.6	30.1	30.7
Pinedale Bank 3	37.5	38.2	39	39.6	40.3
Bullard Bank 1	41.6	42.4	43.2	43.7	43.9
Bullard Bank 2	41.8	42.4	43.2	43.9	44.7
Bullard Bank 3	39.8	40.4	41.1	41.6	41.8
Total	**216**	**220**	**224**	**227**	**230**

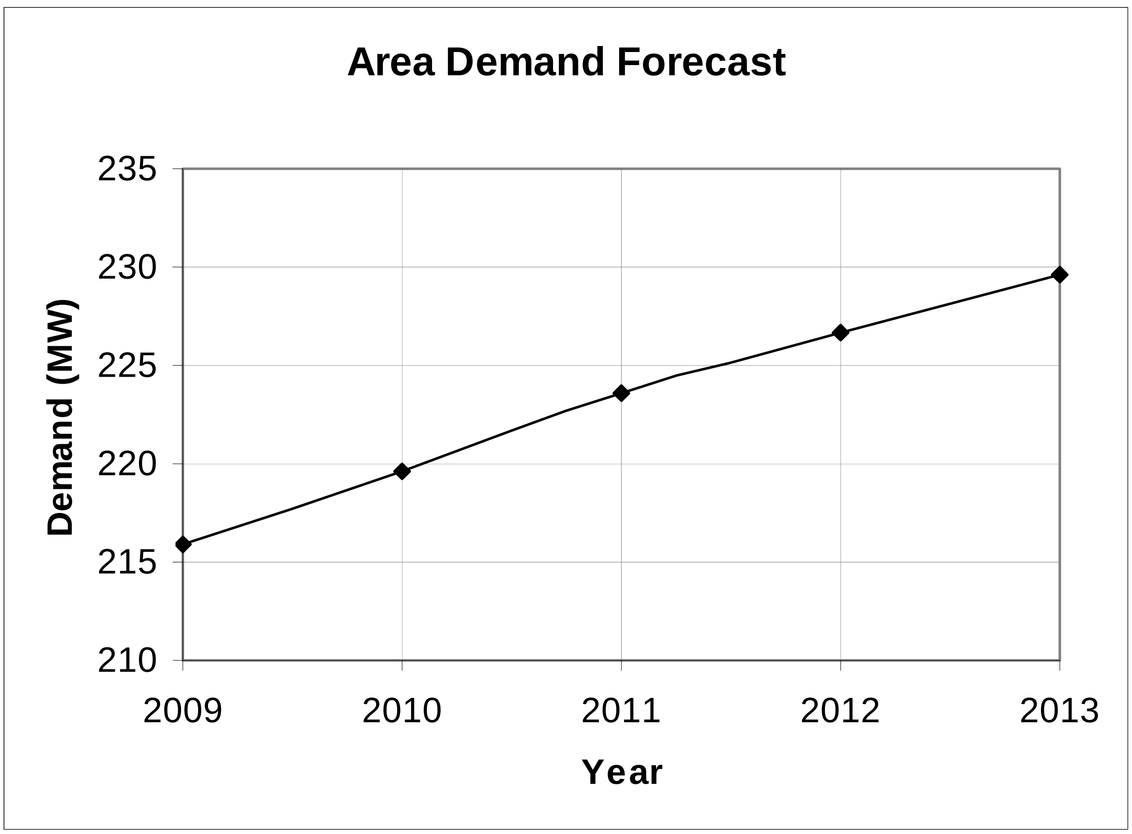


Figure 4-88: Area Load Demand Curve

Attachment 3: Power Flow Summary

Table 4-28: Power Flow Results

			Powerflow						
#	Facility	Facility Rating	2009	2010	2011	2012	2013	2018	Contingency
1	Herndon-Bullard 115 kV Line No. 1	1516 Amps (Limited to 1200 A)	-	-	1155 A (96%)	1176 A (98%)	1196 A (99.6%)	1296 A (108%)	Herndon-Bullard 115 kV Line No. 2
	Herndon-Bullard 115 kV Line No. 2								Herndon-Bullard 115 kV Line No. 1

Attachment 4: Pre and Post Project Power Flow Plots

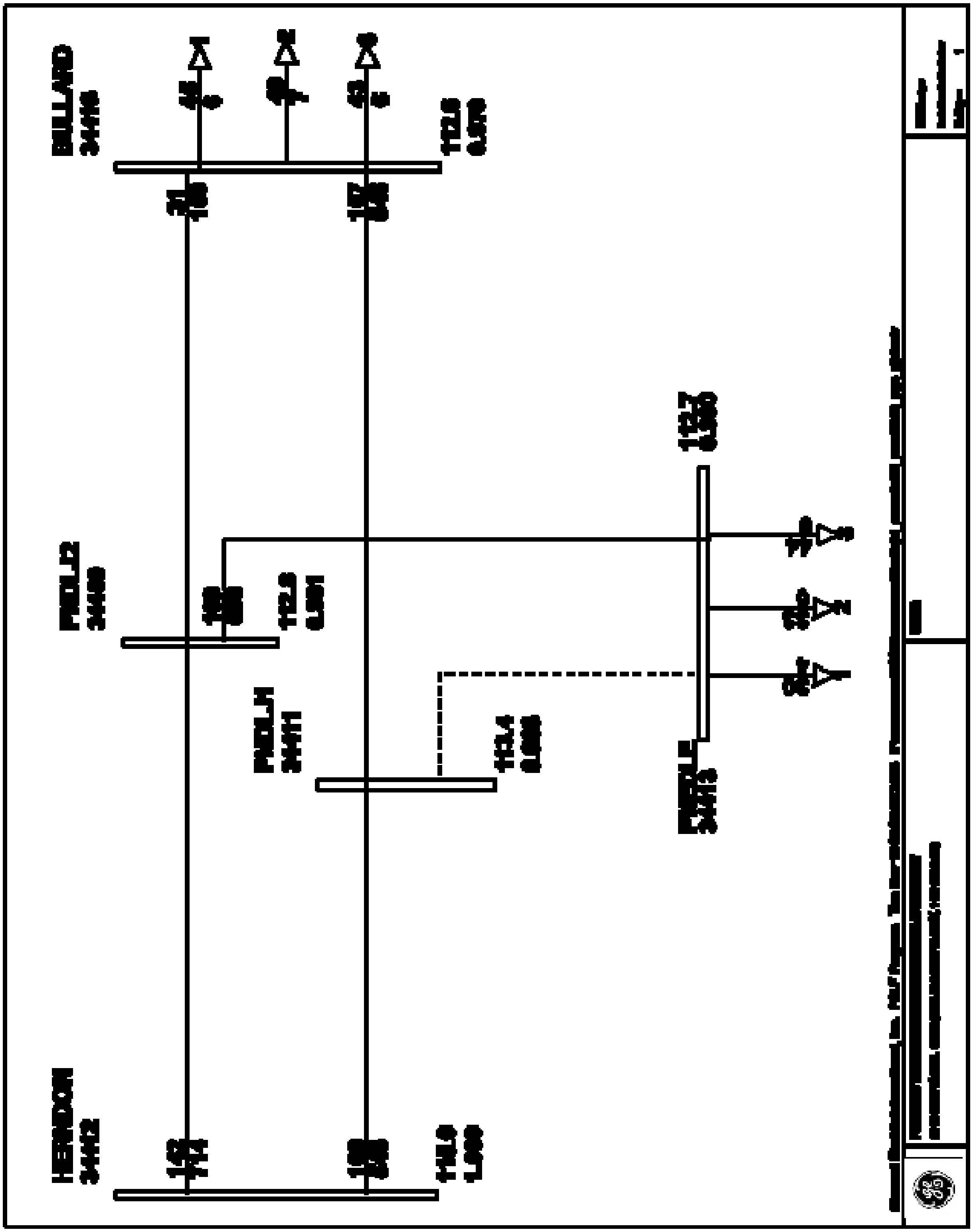


Figure 4-89: Pre-Contingency (2018)

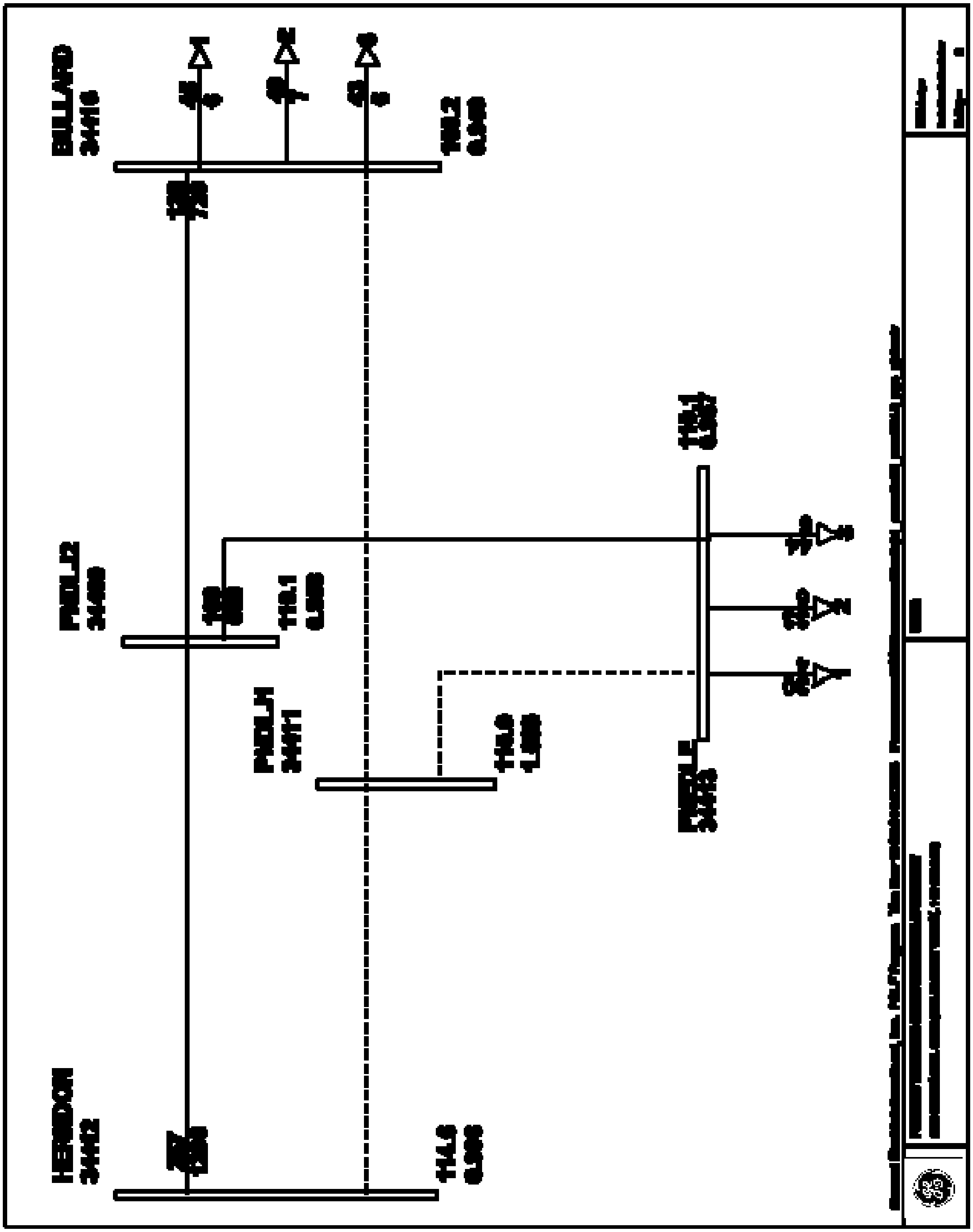


Figure 4-90: Post Contingency (Outage of Herndon-Bullard 115 kV Line No. 1: 2018)

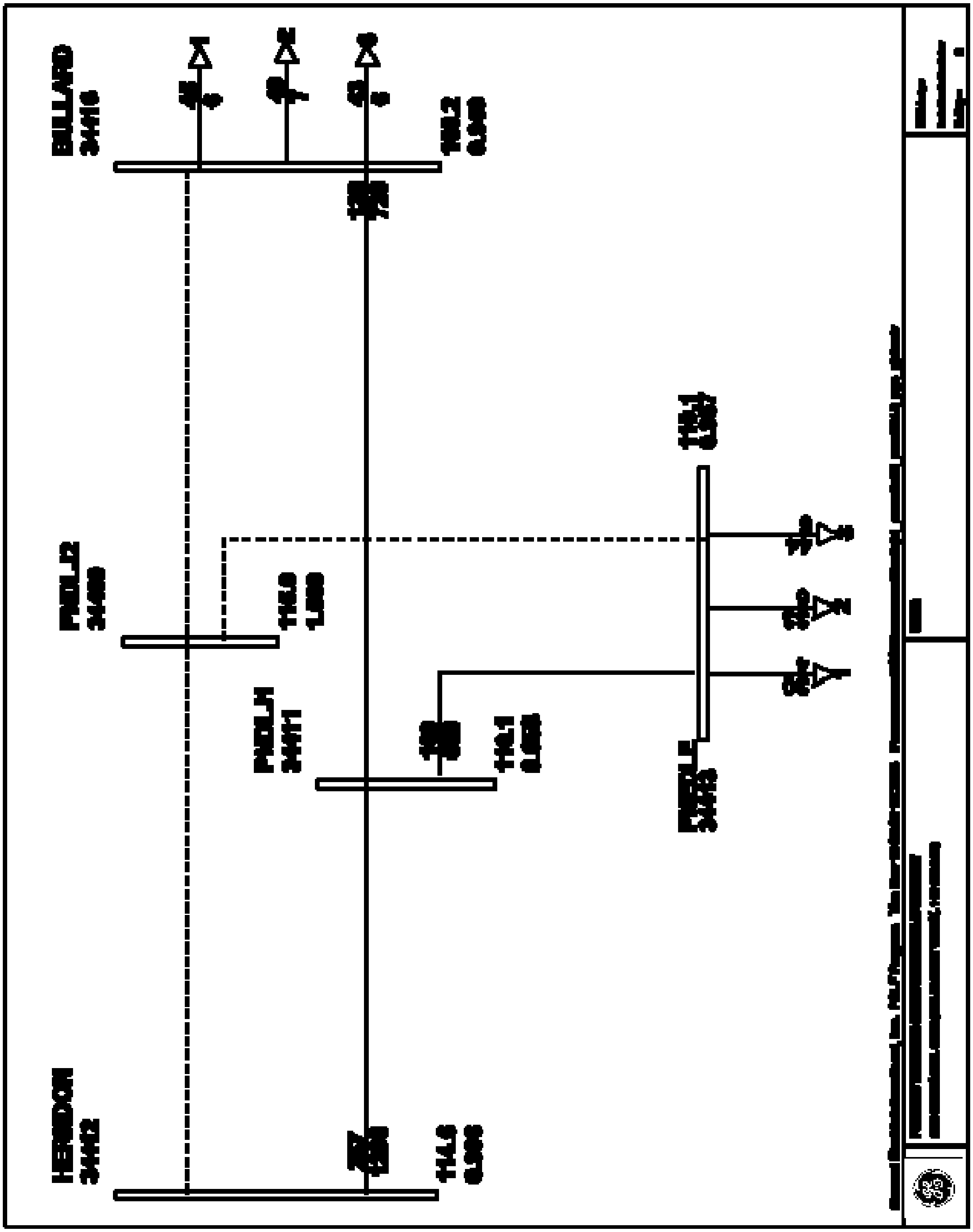


Figure 4-91: Contingency (Outage of Herndon-Bullard 115 kV Line No. 2: 2018)

Occidental of Elk Hills 230 kV Interconnection

TARGETED IN-SERVICE DATE

June 2010

PURPOSE AND BENEFIT

Reliability – Tariff and Compliance

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROPOSED PROJECT

The project scope to interconnect the new Occidental of Elk Hills' (Oxy) substation involves the following work:

1. Removal of existing interconnection service point off of the Midway-Taft 115 kV Line (including metering)
2. Install new meter at new customer owned substation

This project is expected to cost $400,000. This project will be financed by the customer.

BACKGROUND

Occidental of Elk Hills, Inc. (Oxy) located in Tupman is a transmission level customer served off of the Midway-Taft 115 kV Line. Oxy is requesting to transition its service point from 115 kV to its new 230/115 kV substation. In addition, Oxy is looking to increase its demand to 150 MW in 2010 and increase its level of service reliability. Oxy will build, construct, own, and operate its new 230/115 kV substation in close proximity to the Elk Hills Power Plant (Elk Hills Cogen Substation) currently owned and operated by Elk Hills Power. Oxy additionally plans to construct, own, and operate a new transmission line that will connect its new 230/115 kV substation to the Elk Hills Power 230 kV switchyard. It is Oxy's plan to obtain an undivided interest in the existing nine-mile 230 kV double circuit transmission line between the Utility's Midway substation and the Elk Hills Power Plant. Oxy will be served through these lines, the Midway-Elk Hills No. 1 and 2 230 kV lines.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases approved by the 2008 expansion plan study group and the CAISO. The Midway-Elk Hills No. 1 and 2 lines were assumed to consist of 1590 Aluminum Conductor Steel Reinforced (ACSR).

STUDY CRITERIA

CAISO Grid Planning Criteria

ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

The status quo alternative is not recommended since PG&E has an obligation to serve within its service territory.

Alternative 2: Continue to serve Oxy from its existing 115 kV service point

To provide an increased level of service reliability would require looping Oxy directly to Midway Substation. This would require upgrading the 115 kV bus at Midway to Breaker and a Half (BAAH) and building 2-8.25 miles transmission lines. This alternative was not Oxy's preferred option.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – June 2010

KEY ISSUES

- Land-Use Restrictions – None
- Environmental Concerns – None
- Special Metering or Protection – Install one set of 230 kV meters with associated CT's and PT's at Oxy's substation.
- Common Mode Exposure Items – None
- Interaction with other Projects or Studies – None

GE PSLF MODELING INFORMATION

```
#Occidental of Elk Hills 230kV Interconnection
#EDRO June 2010

# This change file removes Navy 35R (Oxy) from the existing 115kV service point
# and moves it to the new 230kV Oxy sub.
# This change file also increases the load per the customer to 150 MW at.95 PF

NEWBUSD   34817, NAME=OXY_230, BASKV=230, BUSTYPE=1, VSCHED=1, AREA=15, ZONE=345, OWN=360
NEWSECDD  30948, 34817, CKT=1, SEC=1, RPU=.00033887, XPU=.00240405, BPU=.00039574, +
        MVA1=164, MVA2=194, MVA3=256, MVA4=274, STATUS=1, AREA=15, ZONE=345, OWN=360
MOVE_BRANCH  35064, 34816,  CKT=1,  NEW_TOBUS=34817
MOVE_BRANCH  35064, 34816,  CKT=2,  NEW_TOBUS=34817
MOVE_LOAD  OLD_LOAD_BUS=34816 LOADID=SG TO_LOAD_BUS=34817 NEWLOADID=SG
OLD_TRAN  FBUS=35064, TOBUS=34817, CKT=1, VNOMF=9.11, VNOMT=230
OLD_TRAN  FBUS=35064, TOBUS=34817, CKT=2, VNOMF=9.11, VNOMT=230

OLDSECDD  FBUS=34774, TOBUS=34816, CKT=1, SEC=1, STATUS=-1
OLDSECDD  FBUS=34776, TOBUS=34816, CKT=1, SEC=1, STATUS=-1
NEWSECDD  34774, 34776, CKT=1, SEC=1, RPU=.02124063, XPU=.10291128, BPU=.01561158,+
        MVA1=126, MVA2=148, MVA3=194, MVA4=207, STATUS=1, AREA=15, ZONE=315, OWN=390
OLDLOAD  BUS=34817, LOADID=SG, PLOAD=150, PF=.95
EXTRACT   34816
```

MISCELLANEOUS DATA

- Occidental of Elk Hills, Inc. will construct, own, and finance the project
- Occidental of Elk Hills, Inc. will be the planned operator of the project

ATTACHMENTS

4. Scope Diagrams
5. Power Flow Summary
6. Pre and Post Project Power Flow Plots

Attachment 1: Scope Diagrams

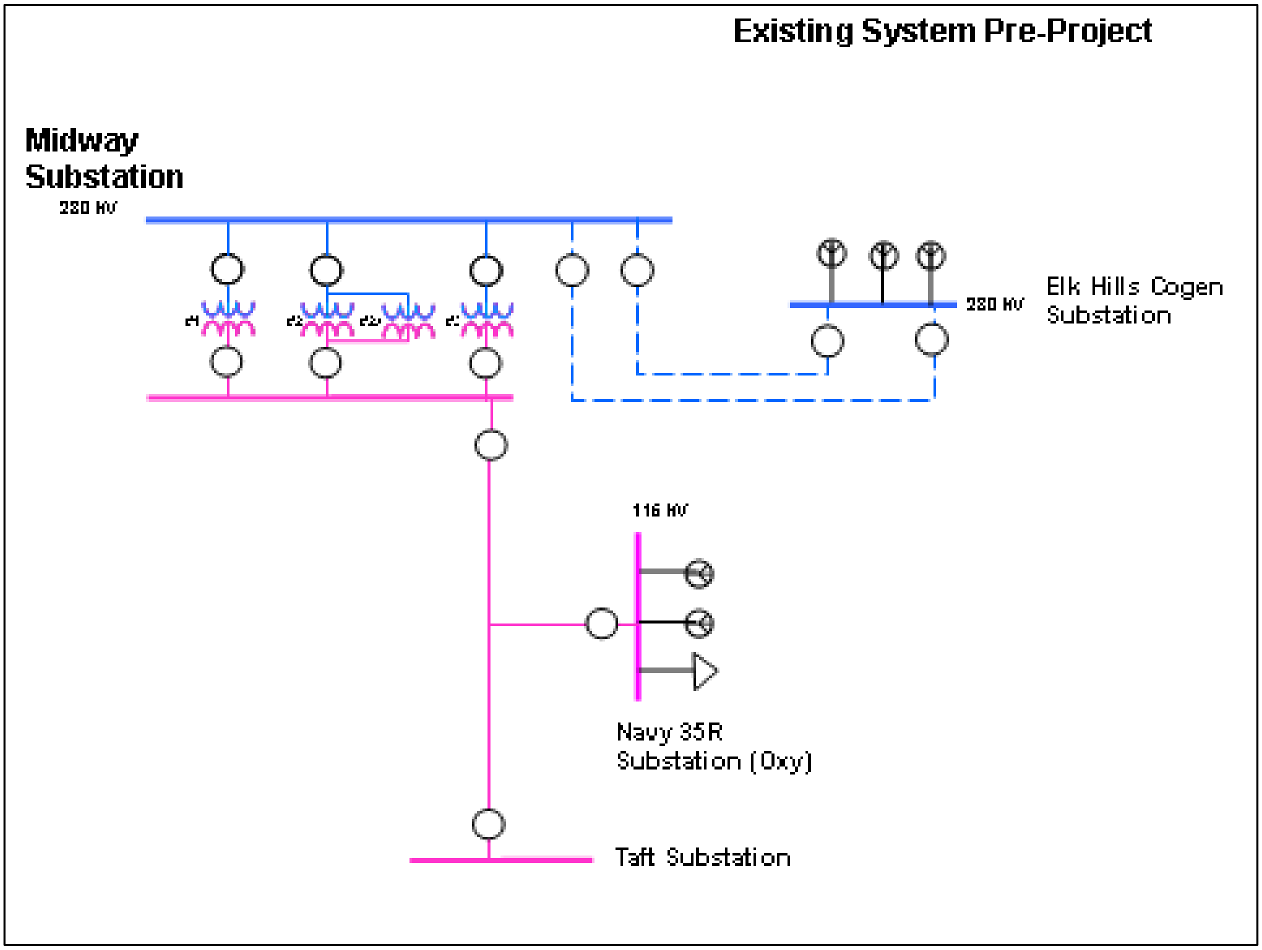


Figure 4-92: Existing Scope Diagram

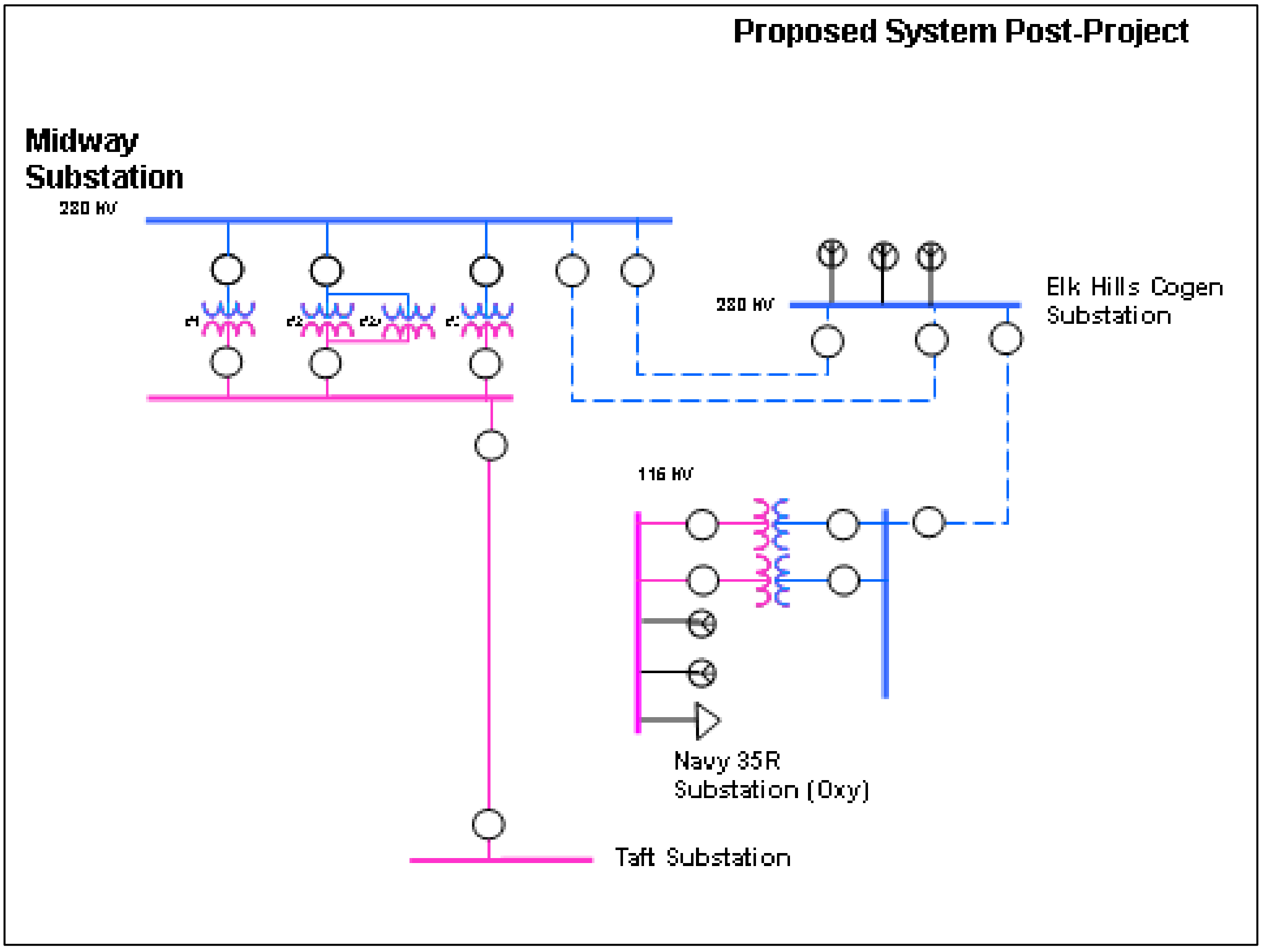


Figure 4-93: Proposed Scope Diagram

Attachment 2: Power Flow Summary

Table 4-29: Power Flow Summary

			Pre Project					Post Project	
#	Facility	Facility Rating	2009	2010	2011	2012	2013	2013	Contingency
1	Midway-Taft 115 kV Line	SE Rating 148 MVA	--	88%	88%	91%	91%	17%	Taft-Fellows 115 kV Line with University Cogen offline when Navy 35 R (OXY) gen offline (L-1/G-1)
2	Midway-Elk Hills No. 1 and 2 230 kV Lines	SE Rating 148 MVA	--	--	--	--	--	61%	Oxy-Elk Hills 230 kV Line
3	Midway-Elk Hills No. 1 and 2 230 kV Lines	SE Rating 148 MVA	--	0%	0%	0%	0%	0%	Either Midway-Elk Hills No. 1 or 2 230 kV Lines

Attachment 3: Pre and Post Project Power Flow Plots

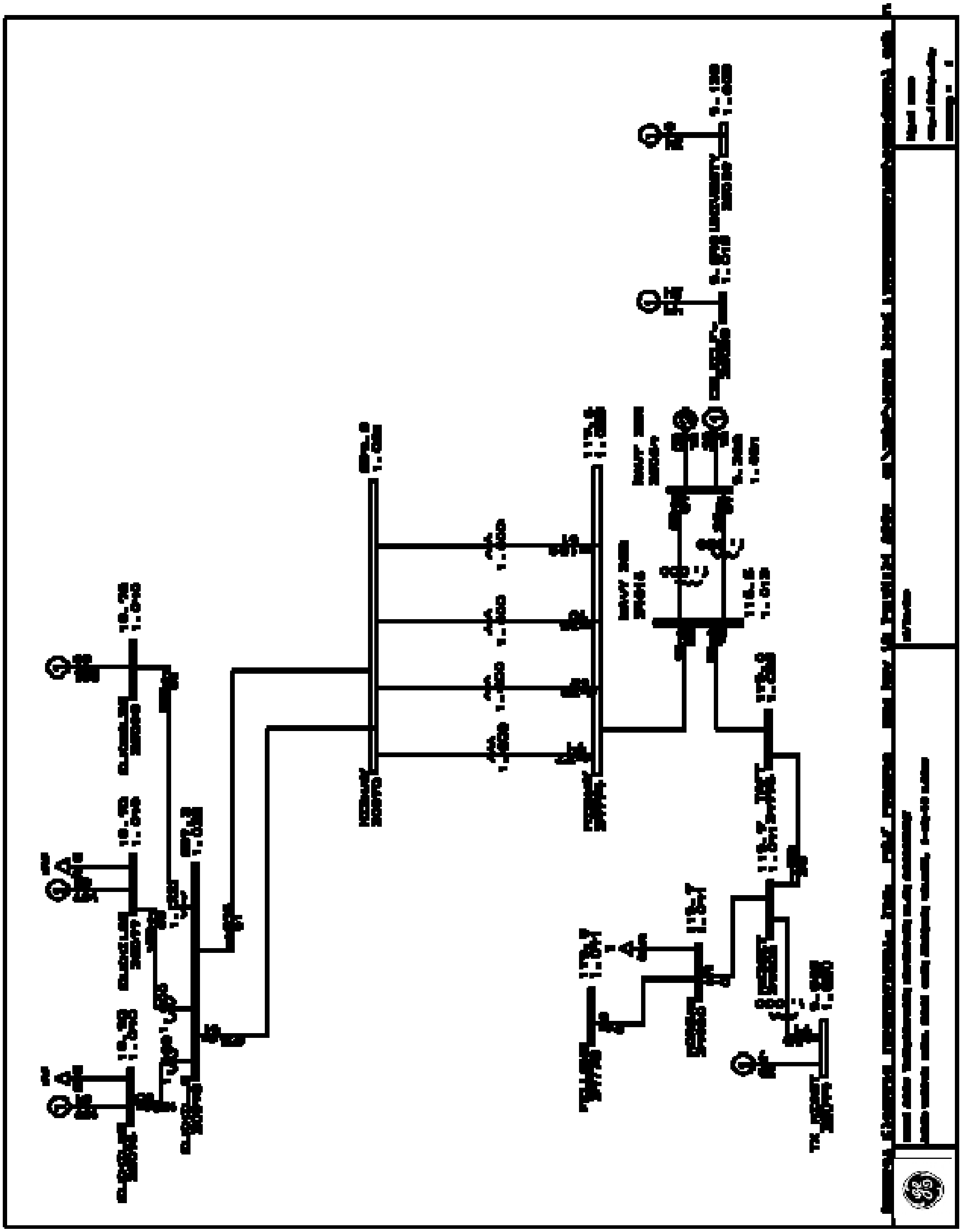


Figure 4-94: Pre-Project Power Flow Plot (Normal)

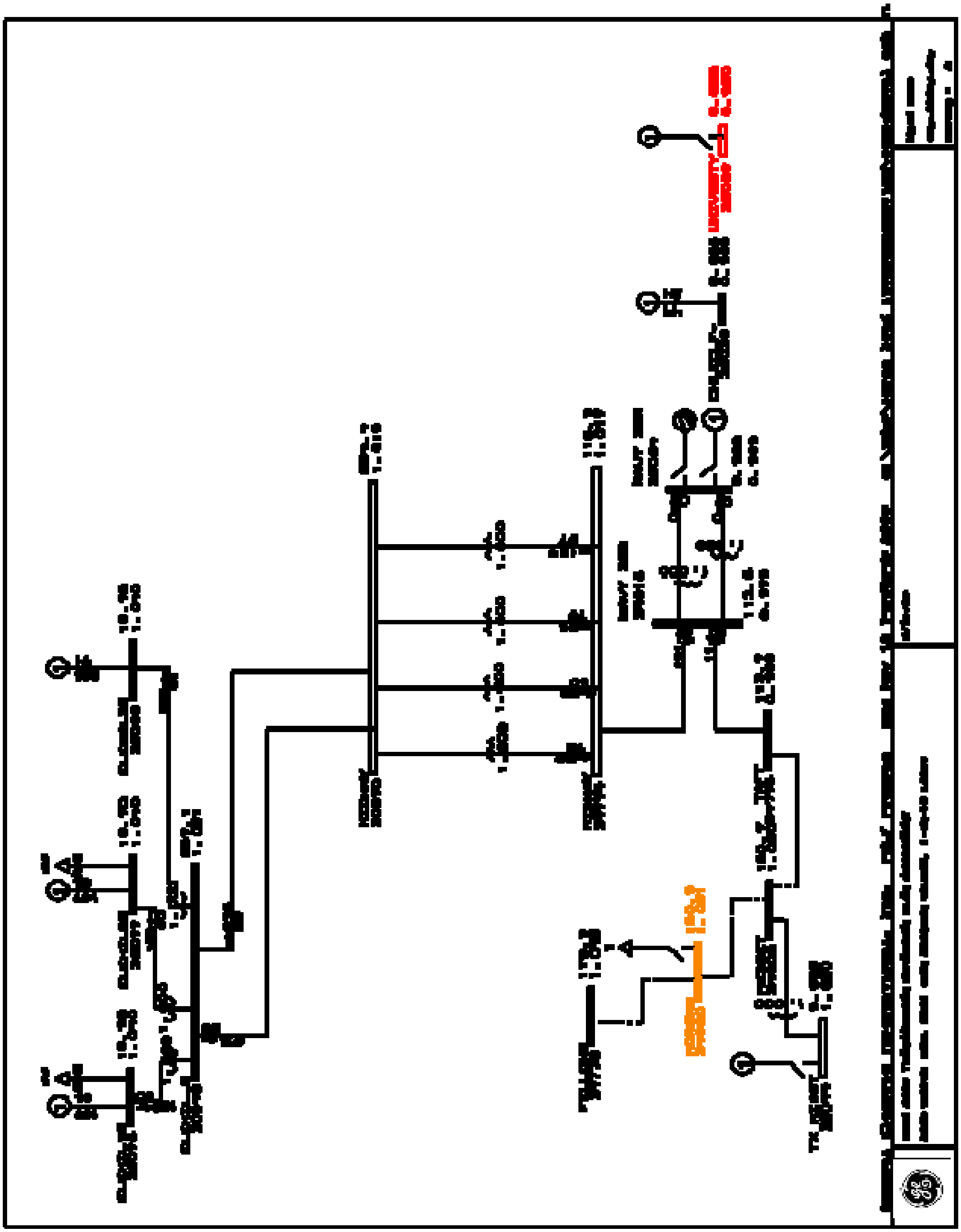


Figure 4-95: Pre-Project Power Flow Plot (Contingency 1: Taft-Fellows 115 kV with Navy 35R (Oxy) Gen and University Cogen offline)

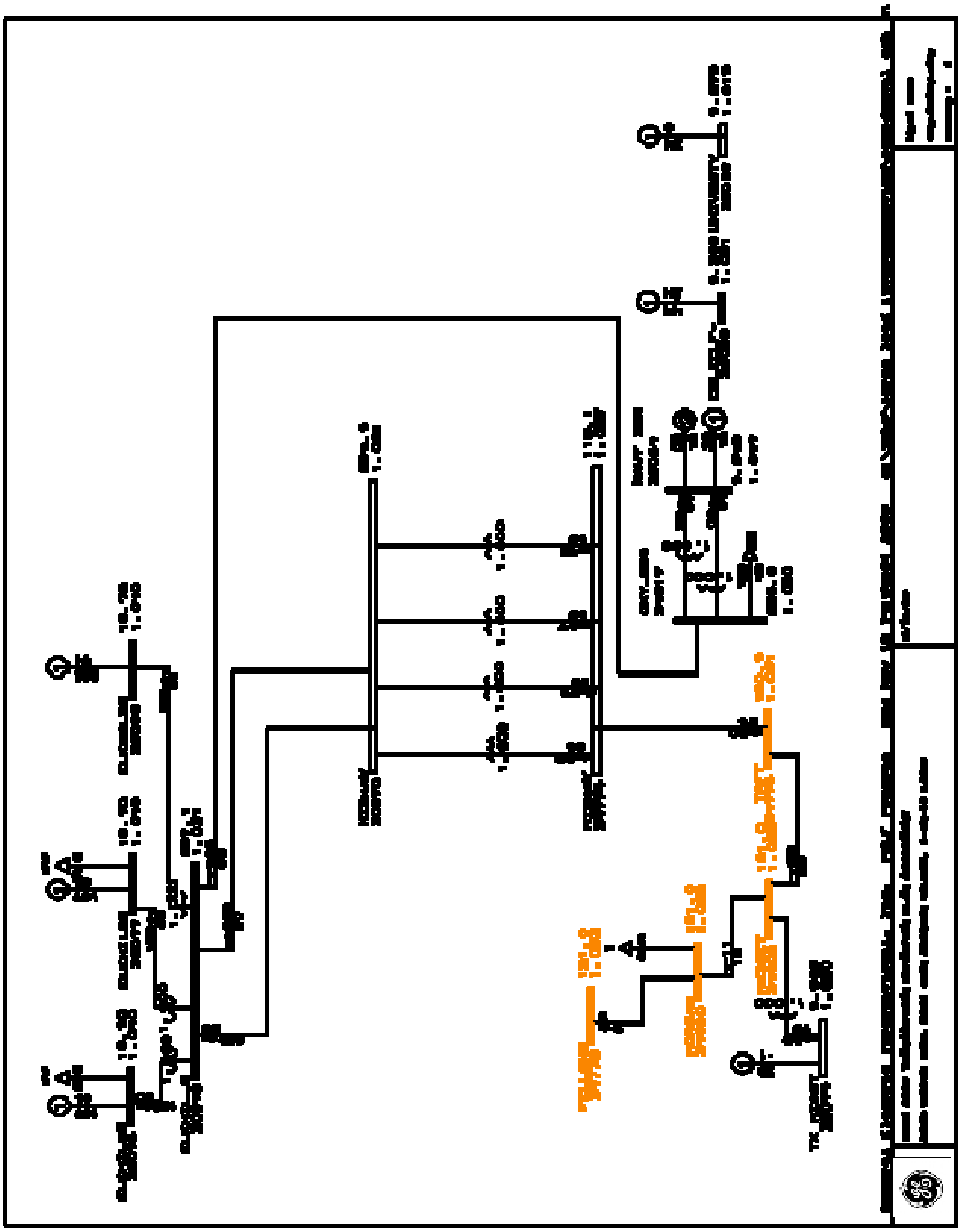


Figure 4-96: Post-Project Power Flow Plot (Normal)

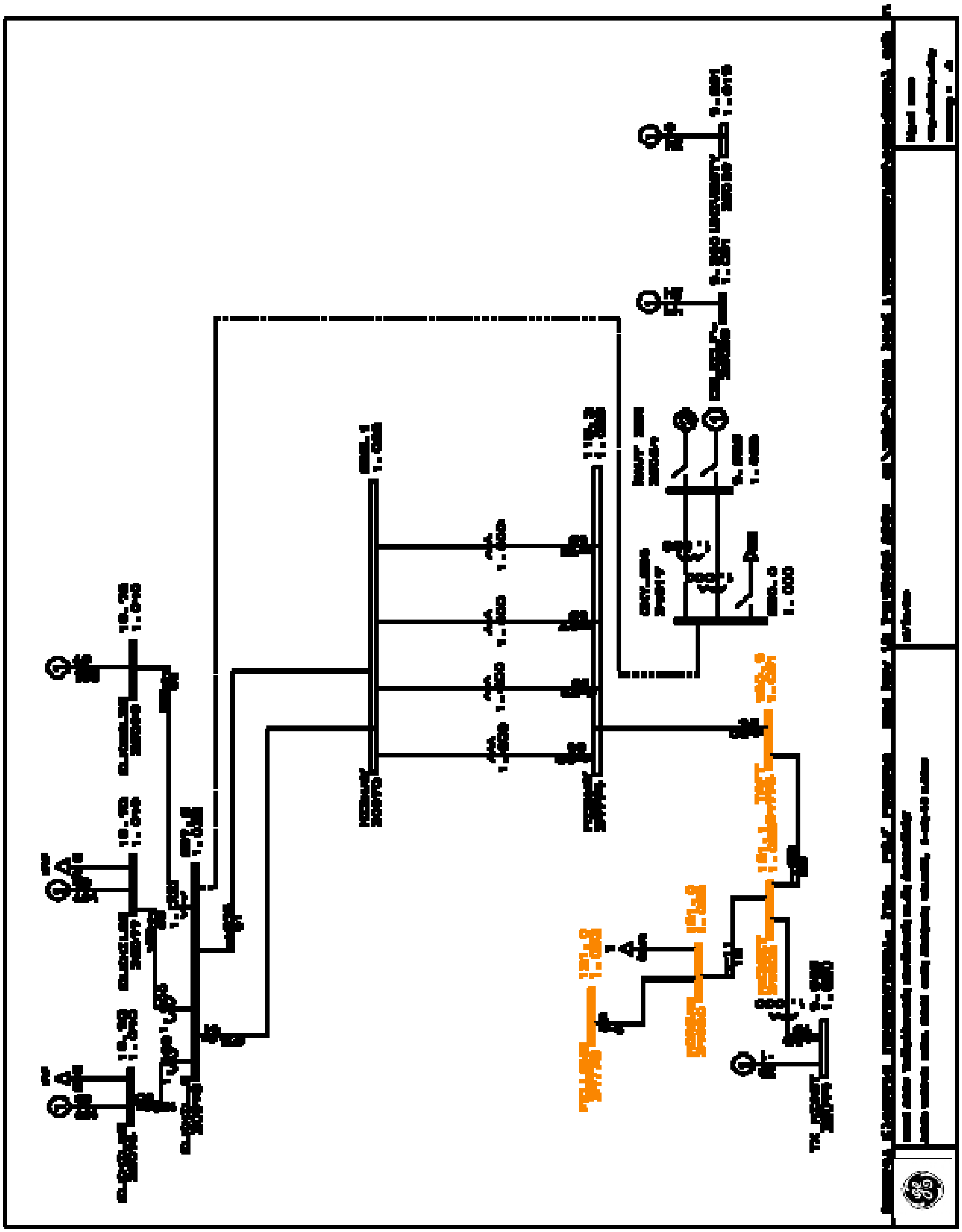


Figure 4-97: Post-Project Power Flow Plot (Contingency 2: Oxy-Elk Hills 230 kV)

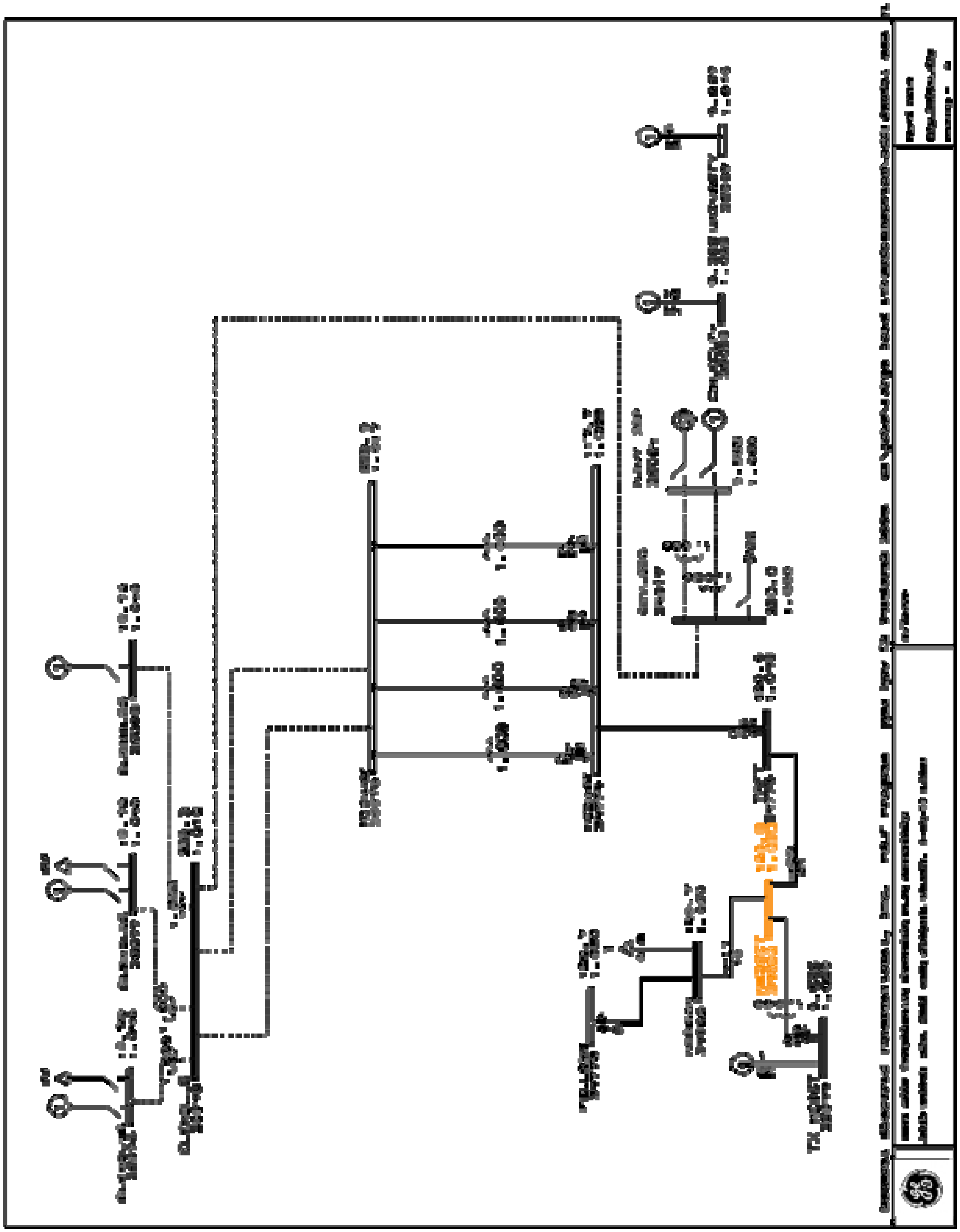


Figure 4-98: Post-Project Power Flow Plot (Contingency 4: Both Midway-Elk Hills No. 1 and 2 230 kV lines)

Note: The current transfer trip at Elk Hills takes both Midway-Elk hills No. 1 and 2 out of service for an outage of either line.

Sanger – California Ave 70 kV to 115 kV Voltage Conversion

TARGETED IN-SERVICE DATE

May 2011

PURPOSE AND BENEFIT

Reliability – NERC Compliance

PROJECT CLASSIFICATION

This is a previously approved project being re-submitted with a revised project scope. The project was previously submitted under the title “West Fresno Reactive Support”.

DESCRIPTION AND SCOPE OF PROPOSED PROJECT

The project scope is to convert the Sanger-California Ave 70 kV Line No. 2 for 115 kV operation and reconductor with a conductor capable of carrying a minimum of 900 Amps under emergency conditions. Associated substation terminal equipment will be added at California Ave and Sanger substations to accommodate this conversion. The project scope also includes obtaining any necessary land and environmental permits.

This project is expected to cost between $5M and $10M.

BACKGROUND

West Fresno and California Ave substations are located 3 miles apart in southwest Fresno County. These substations receive their electric power from McCall Substation to the south via the McCall-West Fresno and California Ave-McCall 115 kV lines. The two substations are also electrically connected via the West Fresno-California Ave 115 kV Line. California Dairies, a customer owned substation, is electrically tapped on the California Ave-McCall 115 kV Line. There are two idle 70 kV lines between California Ave and Sanger substations. Peak demand in this area is expected to increase at a rate of 2 MW per year.

Planning analysis for 2009 summer conditions has identified that an outage of the McCall-West Fresno 115 kV Line could drop 115 kV voltages at West Fresno Substation to 102 kV (0.88 per unit). Furthermore by 2018, an outage of the McCall-West Fresno 115 kV Line could overload the California Ave-McCall 115 kV Line by 2%.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended because it does not address the potential low voltage conditions at West Fresno Substation.

Alternative 2: Install shunt capacitors at West Fresno Substation

This alternative proposes to install 75 MVArs of shunt capacitors on the 115 kV bus at West Fresno Substation. This project is estimated to cost between $1M and $5M. This project is not recommended due to its limited transmission support for the area in the long term. Planning analysis has determined that additional reactive support could be required again at either West Fresno or California Ave within the next 10 years. In addition, the shunt capacitor installation does not mitigate the potential overload on the California Ave-McCall 115 kV Line.

PROJECT SCHEDULE

- Environmental and Permitting Processes – Notice of Construction required by May 2010; filing in January 2010
- Design – Start February 2010; Complete July 2010
- Major Equipment – Procurement start February 2010; Complete August 2010
- Construction – Start September 2010
- Operation Date – May 2011

KEY ISSUES

- Land-Use Restrictions – None
- Environmental Concerns – None
- Special Metering or Protection – West Fresno UVLS
- Common Mode Exposure Items – None
- Interaction with other Projects or Studies – Sanger-Reedley 70 to 115 kV Conversion Project

GEPSLF MODELING INFORMATION

#Reconductor Cal Ave-Sanger #2 to 115 kV (9.39 miles of 1113 AAC)
NEWSECDD 34402, 34366, CKT=1, SEC=1, RPU=0.0067089, XPU=0.049256, BPU=0.0076136,+
MVA1=164, MVA2=194, MVA3=183, MVA4=210, STATUS=1, AREA=14, ZONE=314, OWN=390

#Remove idle California Ave. - Sanger 70 kV #2
OLDSECDD 34486, 34488, CKT=2, STATUS=-1

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagram
2. Demand Forecast
3. Power Flow Summary
4. Pre and Post Project Power Flow Plots

Attachment 1: Scope Diagram

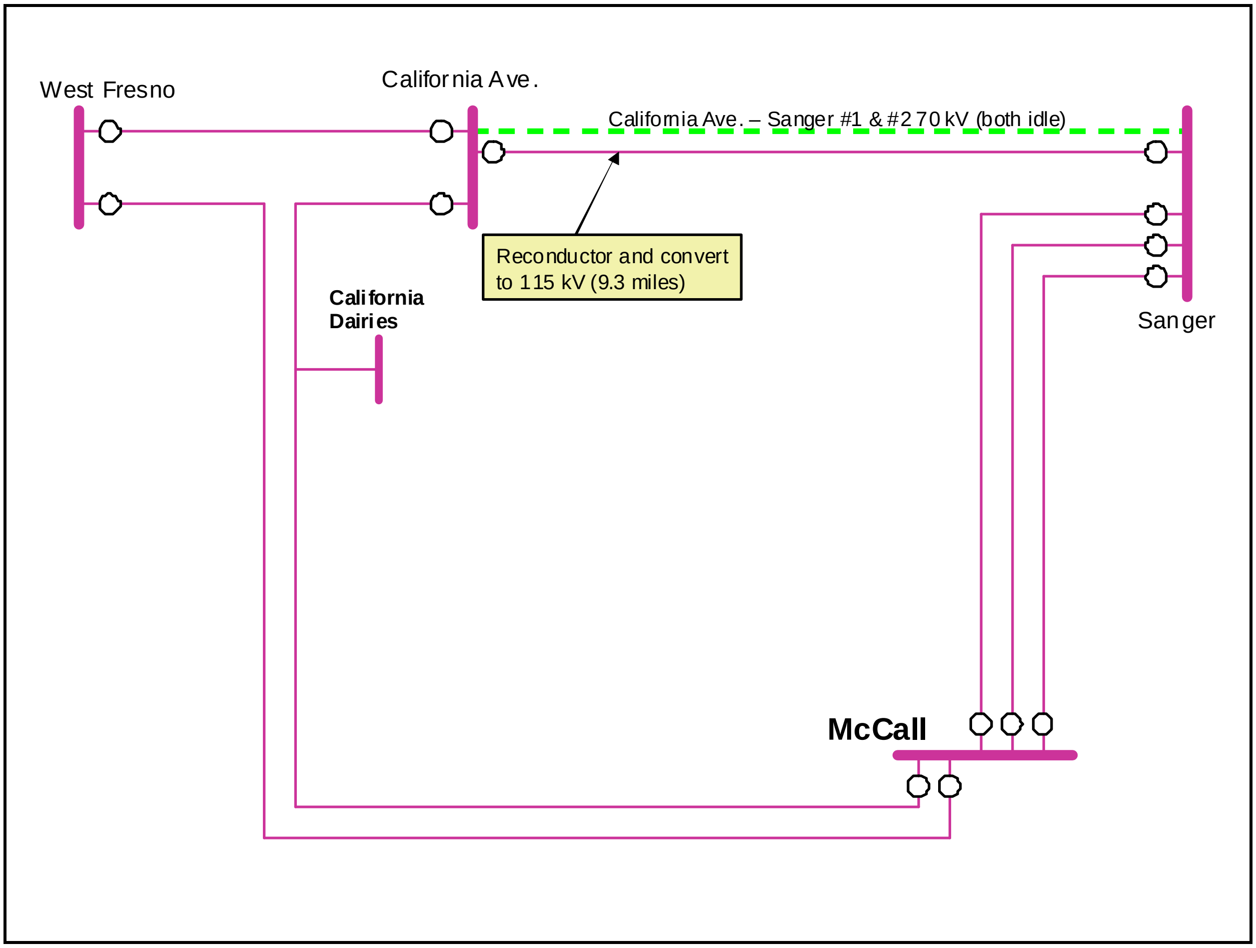


Figure 4-99: Proposed Scope Diagram

Attachment 2: Demand Forecast

Table 4-30: Area Load Demand Forecast

Substation/Bank	2009	2010	2011	2012	2013	Growth Rate(MW/yr)
West Fresno Bank 1	35.7	36.1	36.5	36.7	37.2	0.4
West Fresno Bank 2	37.1	37.5	37.9	38.2	38.6	0.4
West Fresno Bank 3	16.1	16.6	17.0	17.4	17.8	0.4
California Ave Bank 1	29.7	30.0	30.4	30.6	30.9	0.3
California Ave Bank 2	27.5	27.8	28.1	28.3	28.6	0.3
California Ave Bank 3	23.2	23.4	23.7	23.9	24.2	0.3
Danish Creamery	4.1	4.1	4.1	4.1	4.1	0.0
Total Area Load	173.4	175.5	177.7	179.2	181.4	2.0

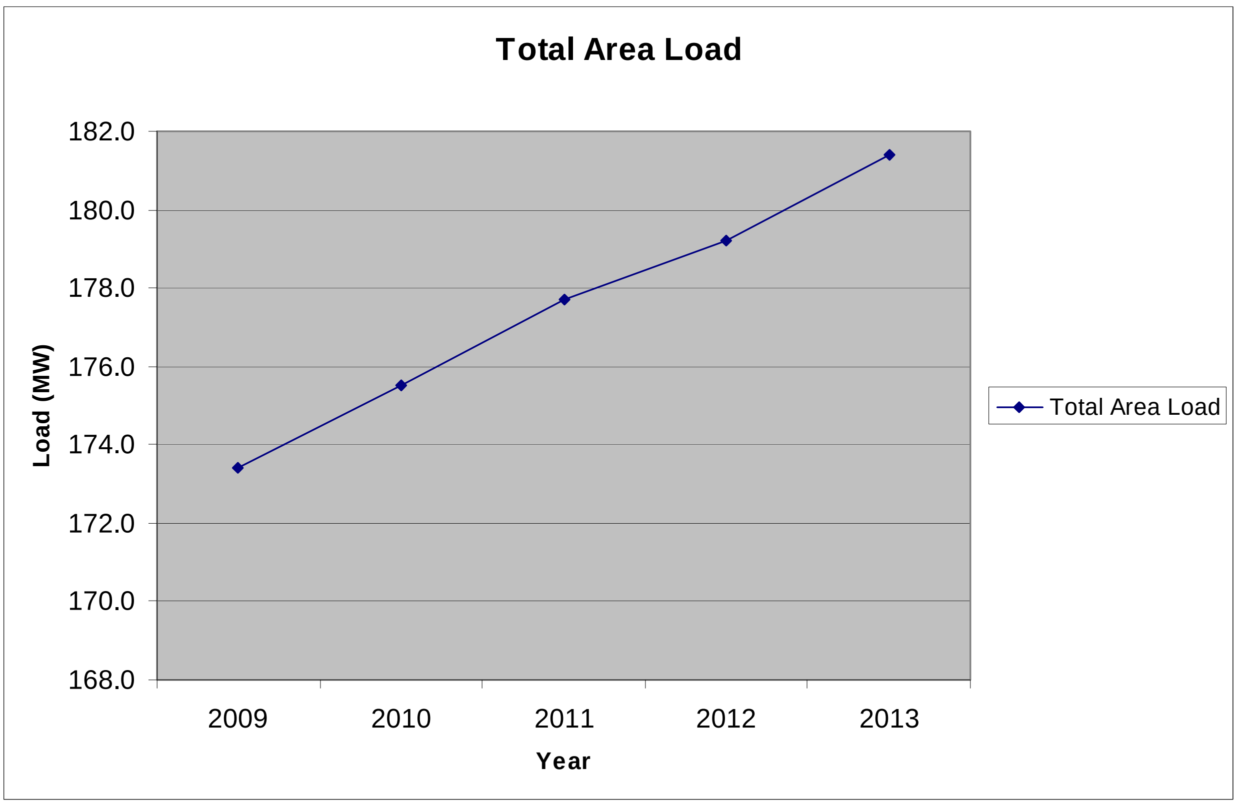


Figure 4-100: Area Load Demand Curve

Attachment 3: Power Flow Summary

Table 4-31: Power Flow Summary

			Pre Project						Post Project	
#	Facility	Facility Rating	2009	2010	2011	2012	2013	2018	2018	Contingency
1	West Fresno 115 kV Bus	115 kV (1.0 p.u.)	.88 p.u.	.88 p.u.	.88 p.u.	.87 p.u.	.87 p.u.	.84 p.u.	.988 p.u.	McCall-West Fresno 115 kV (L-1)
2	California Ave-McCall 115 kV Line	SE Rating 1126 Amps	--	--	--	--	--	102%	34%	McCall-West Fresno 115 kV (L-1)

Attachment 4: Pre and Post Project Power Flow Plots

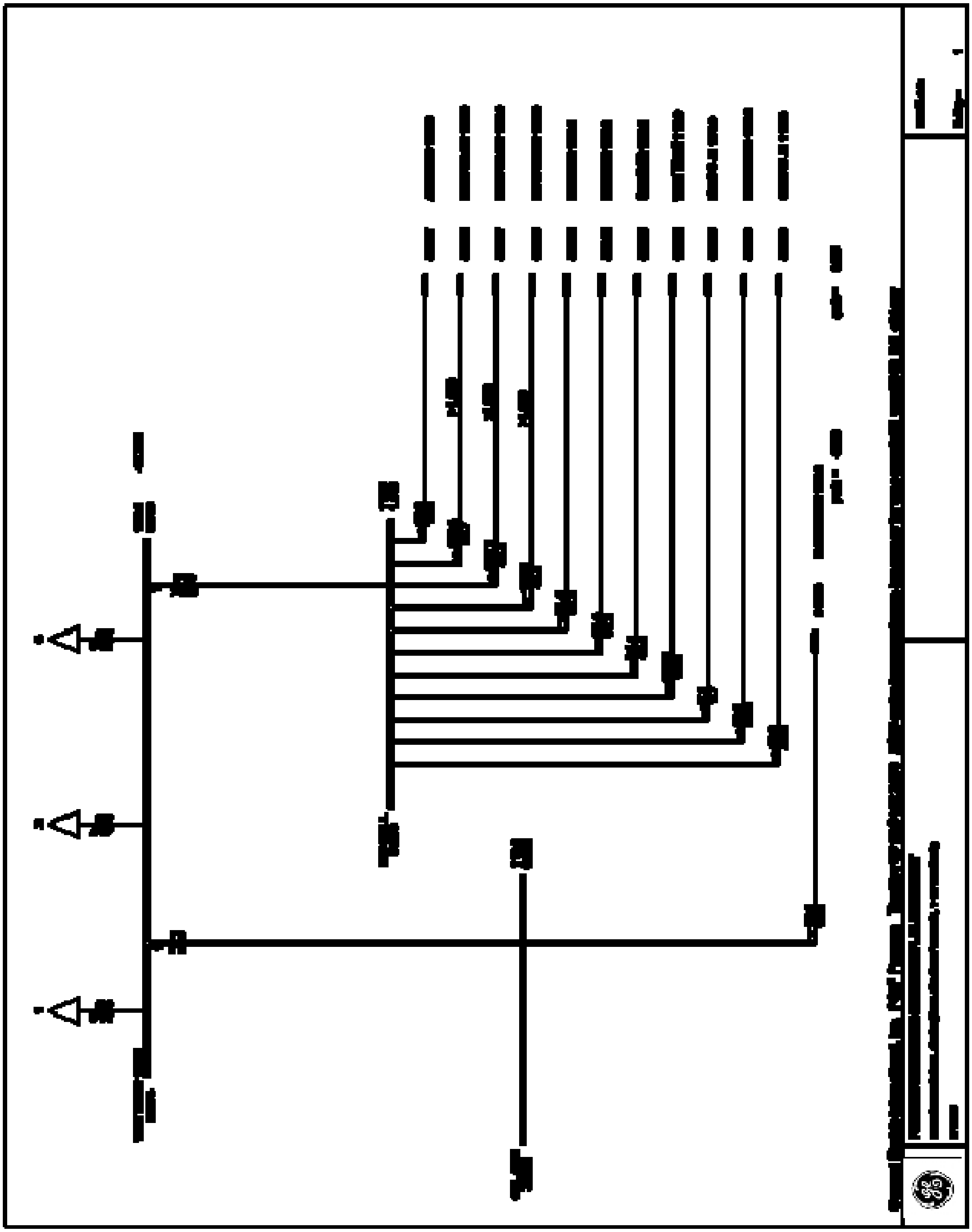


Figure 4-101: 2018 Pre Project – Normal

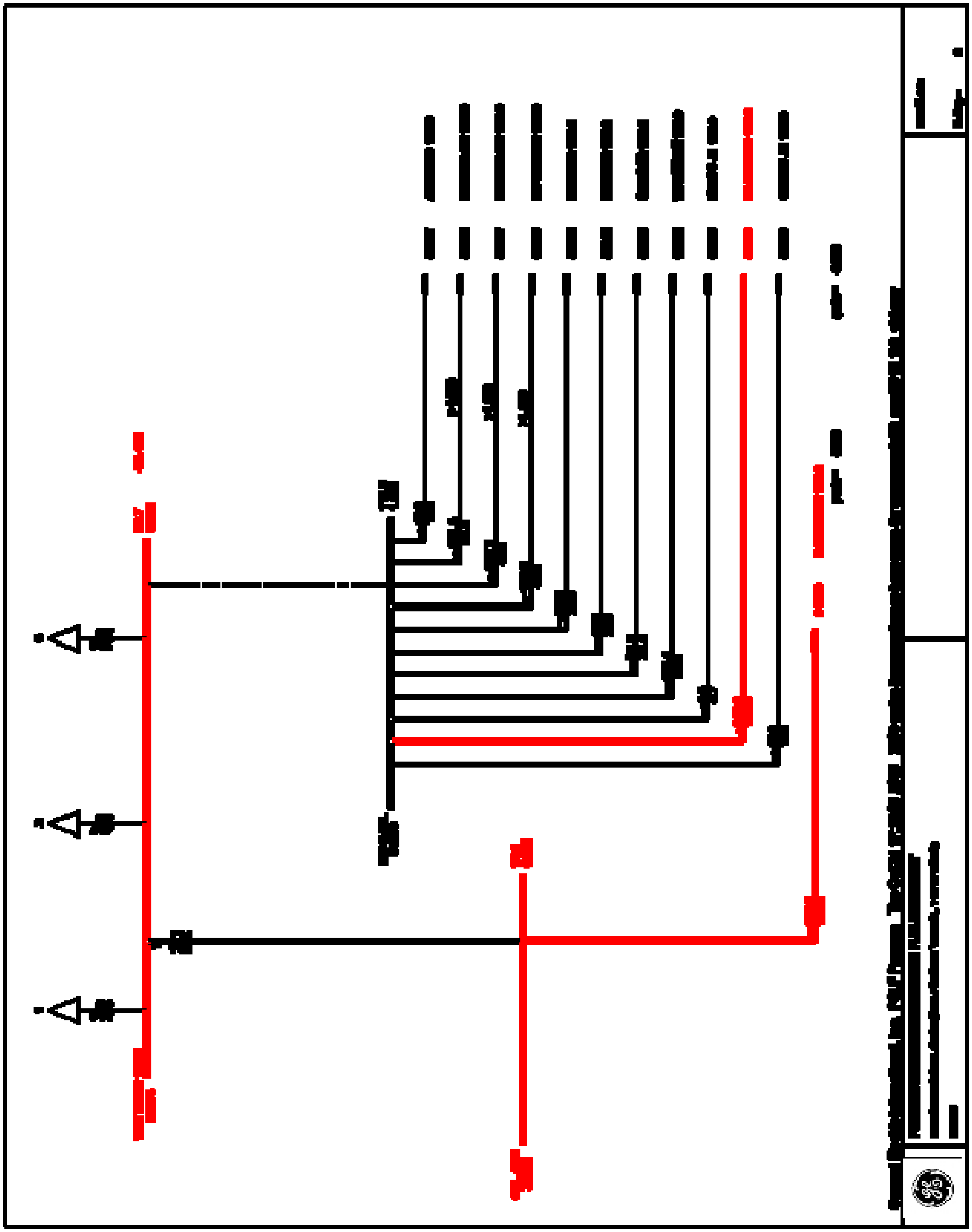


Figure 4-102: 2018 Pre Project - McCall-West Fresno 115 kV (L-1)

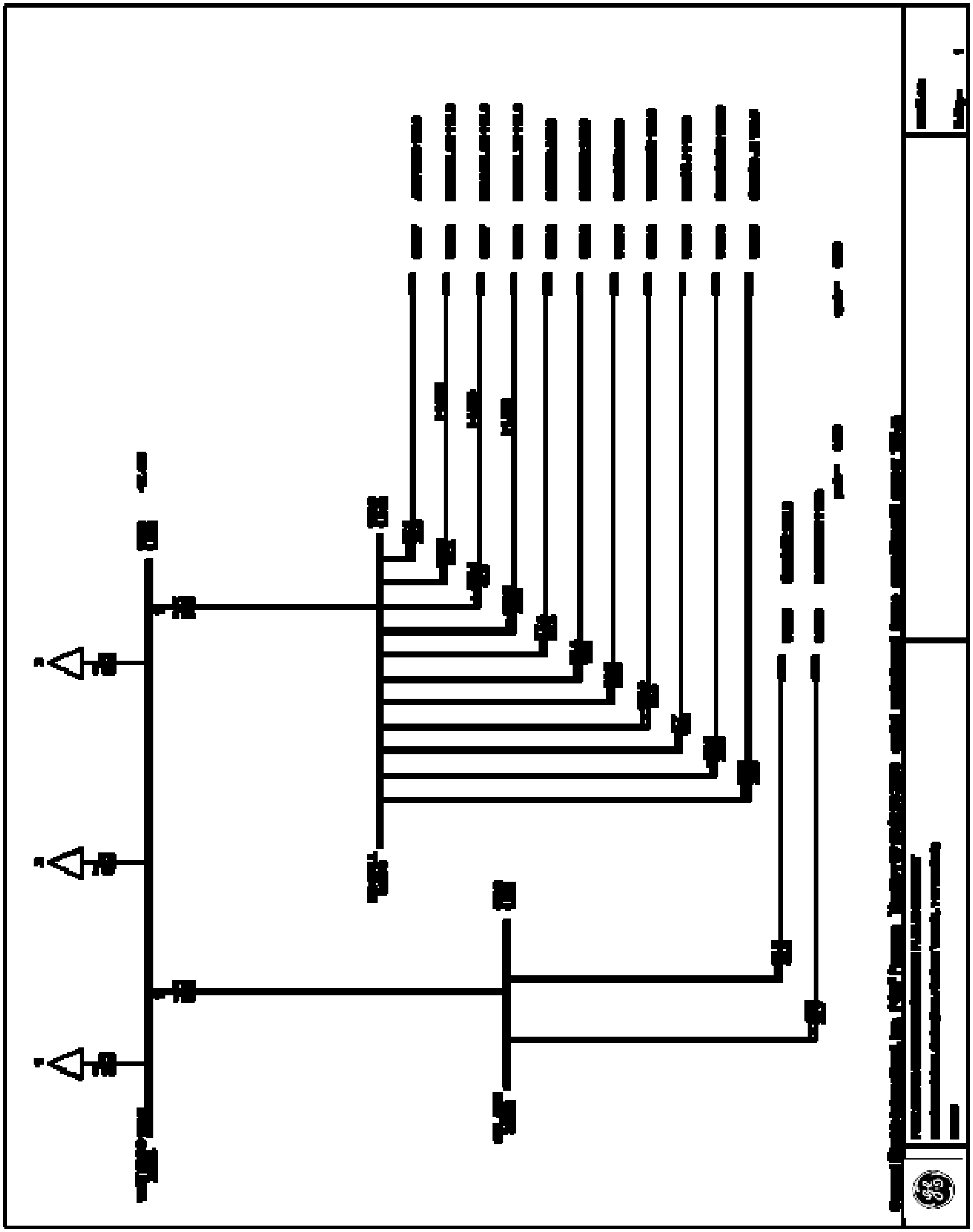


Figure 4-103: 2018 Post Project - Normal

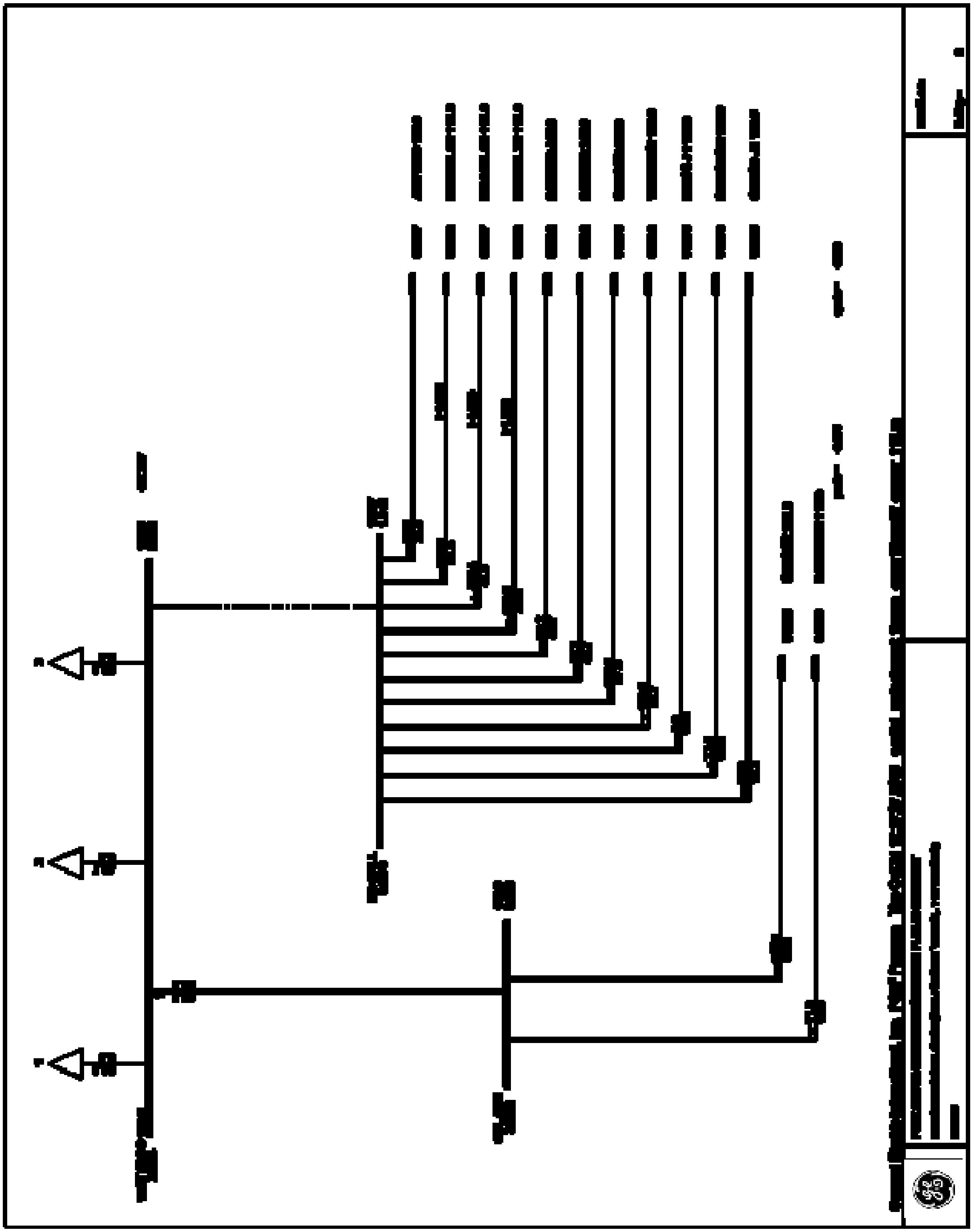


Figure 4-104: 2018 Post Project - McCall-West Fresno 115 kV (L-1)

Sanger – Reedley 70 kV to 115 kV Conversion

TARGETED IN-SERVICE DATE

May 2011

PURPOSE AND BENEFIT

Reliability – NERC Compliance and Operational Flexibility

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROPOSED PROJECT

The project scope is to convert the Sanger-Reedley 70 kV Line for 115 kV operation and reconductor with a conductor capable of carrying a minimum of 900 Amps under emergency conditions. In addition, Parlier Substation will be converted to 115 kV operation and the 115 kV bus at Reedley Substation will be upgraded to a breaker-and-a-half configuration. Sanger Cogen will be installing a 115 kV transformer and upgrading protection and metering equipment for 115 kV operation. All 70 kV equipment will be removed from Sanger Substation.

This project is expected to cost between $20M and $25M.

BACKGROUND

The Sanger-Reedley 70 kV Line is approximately 20 miles long and the electrical tie between Sanger and Reedley substations. The Sanger-Reedley 70 kV Line provide support to electric customers served by Dinuba, Orosi, Wahtoke, Parlier, Rainbow, Tivy Valley, Dunlap, Sand Creek, Sanger and Reedley substations. Parlier Substation and Sanger Cogen (owned by Algonquin Power Sanger LLC) are electrically tapped on the Sanger-Reedley 70 kV Line. The Sanger-Reedley 70 kV Line was re-rated to 4 feet per second wind speed (474 Amps under emergency conditions) in May 2004. This area is also supported by the Kings River-Sanger-Reedley 115 kV Line. The Kings River-Sanger-Reedley 115 kV Line spans from Sanger Substation to Piedra Switches, where one section connects to Kings River Powerhouse and the other to Reedley Substation. Rainbow Substation is electrically tapped on the Kings River-Sanger-Reedley 115 kV Line.

The 70 kV bus at Sanger Substation serves only the Sanger-Reedley 70 kV Line. The California Avenue-Sanger 70 kV Nos. 1 and 2 lines remain electrically connected to the bus but will be idled. California Avenue Substation was converted to a 115 kV station in 2005. Sanger Substation has three transformer banks. Sanger Bank No. 1 is a 115/12 kV transformer bank, Sanger Bank No. 2 is 115/70 kV transformer bank, and Sanger Bank No. 3 is a 115/70/12 kV transformer bank. In early 2008, Sanger Bank No. 3 failed and was subsequently replaced by a 115/12 kV transformer bank. This resulted in Sanger Bank No. 2 being the only transformer source to support the Sanger-Reedley 70 kV Line. To guard against a bank overload during normal and emergency conditions, Sanger Bank No. 2 was taken out of service by operating Sanger Circuit (CB) number (No.) 32 normally open. To guard against an overload to the Sanger-Reedley 70 kV Line (Parlier-Sanger Cogen line section), Sanger Cogen is limited to an output of 39 MW.

The Reedley SPS was installed in June 2008 to guard against potential overloads on the McCall-Reedley and Kings River-Sanger-Reedley 115 kV lines. It was projected that loss of either of the two 115 kV lines could cause an overload on the remaining line. The Reedley SPS is armed to drop four of the five distribution circuits at Reedley Substation under peak load conditions.

In addition to the problems listed above after the failure of Sanger Bank No. 3, planning studies for summer peak conditions have concluded that an overlapping outage of the McCall-Wahtoke 115 kV Line and Kings River Powerhouse offline could overload the Sanger-Reedley 70 kV Line (Sanger Cogen-Parlier line section) in 2010. The same outage is also projected to cause a thermal overload on the Kings River-Sanger-Reedley 115 kV Line (Sanger-Rainbow tap section) in 2013. In addition, under summer peak conditions, an overlapping outage of the McCall-Wahtoke 115 kV Line and Sanger Cogen, could overload the Kings River-Sanger-Reedley 115 kV Line (Reedley-Piedra Jct. line section) in 2010, and the Sanger-Reedley 70 kV Line (Sanger-Sanger Cogen Jct. line section) in 2018.

The proposed project allows the removal of all 70 kV equipment at Sanger. The Sanger-Reedley 70 to 115 kV Line Conversion Project will add capacity to the area that mitigates potential overloads on the Sanger-Reedley 70 kV Line and the Kings River-Sanger-Reedley 115 kV Line. It will also allow the removal of the Reedley SPS. Upon completion of this project, there will be sufficient capacity on the Sanger-Reedley 115 kV Line for Sanger Cogen to resume generation of the full 42 MW allowed in their Power Purchase Agreement (PPA) with PG&E.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended because it does not address the potential overload on sections of the Sanger-Reedley 70 kV Line, Kings River-Sanger-Reedley 115 kV Line, and Sanger Bank No. 2.

Alternative 2: Reconductor the limiting sections of the Sanger-Reedley 70 kV Line and Kings River-Sanger-Reedley 115 kV Line

This alternative proposes to replace with higher capacity conductor the limiting sections, totaling 47 circuit miles, of the Sanger-Reedley 70 kV Line and Kings River-Sanger-Reedley 115 kV Line. The estimated cost for this alternative is $25M to $30M and does not include the cost of installing a new 115/70 kV transformer bank to replace the failed Bank No. 2. This alternative does not provide the improved voltage levels and added reliability associated with the preferred 70 kV to 115 kV conversion alternative. In addition, the estimated cost is higher than the preferred alternative.

Alternative 3: Construct a new line from McCall Substation to Reedley Substation

This alternative proposes to construct a new 115 kV transmission line originating at McCall Substation and terminating at Reedley Substation. This new line would be located on the same towers as the McCall-Wahtoke 115 kV Line. This alternative is not recommended because it does not mitigate a single point of failure risk. A double circuit tower line outage of the McCall-Wahtoke and McCall-Reedley 115 kV lines is projected to overload the limiting sections of the Sanger-Reedley 70 kV Line, Kings River-Sanger-Reedley 115 kV Line, and Sanger Bank No.2.

PROJECT SCHEDULE

- Environmental and Permitting Processes – Notice of Construction to be filed Jan 2010, needed by May 2010
- Design – Start February 2010; Complete July 2010
- Major Equipment – Procurement start February 2010; Complete August 2010
- Construction – Start September 2010
- Operation Date – May 2011

KEY ISSUES

- Land-Use Restrictions – None
- Environmental Concerns – None
- Special Metering or Protection – Reedley SPS
- Common Mode Exposure Items – None
- Interaction with other Projects or Studies – Sanger-California Ave 70 kV to 115 kV Conversion Project

GEPSLF MODELING INFORMATION

```
#Convert the following 70kV Buses to 115kV Buses
OLDBUSD 34487, BASKV=115            #Sanger Jct 70 kV
OLDBUSD 34489, BASKV=115            #Sanger Co-gen
OLDBUSD 34490, BASKV=115            #Parlier

# Convert the existing Sanger - Parlier - Reedley 70 kV Line to 115kV @ 1113 AAC
#Sanger - Sanger JCT 115 kV Lines ( 4.33 mi)
#4.33 mile  0.0031236           0.022933 0.0035438
OLDSECDD 34488, 34487, CKT=1, SEC=1, RPU=0.0031236, XPU=0.022933, BPU=0.0035438, MVA1=164, MVA2=194,
MVA3=256 MVA4=274
MOVE_BRANCH  34487, 34488,  1,  34366

# Sanger JCT - Sanger Co-gen 115 kV Lines (5,000 ft)
#1 mile      0.00072139   0.0052963       0.00081836
OLDSECDD 34487, 34489, CKT=1, SEC=1, RPU=0.00072139,  XPU=0.0052963, BPU=0.00081836, MVA1=164, MVA2=194,
MVA3=256 MVA4=274

# Sanger Jct - Parlier 115 kV Lines (7.66 mi)
#7.66 miles            0.0055258             0.04057   0.006271
OLDSECDD 34487, 34490, CKT=1, SEC=1, RPU=0.0055258, XPU=0.04057, BPU=0.006271, MVA1=164, MVA2=194, MVA3=256
MVA4=274

# Parlier - Reedley 115 kV Lines (8.11 mi)
#8.1 miles  0.0058432           0.0429     0.0066312
OLDSECDD 34490, 34492, CKT=1, SEC=1, RPU=0.0058432,  XPU=0.0429, BPU=0.0066312, MVA1=164, MVA2=194, MVA3=256
MVA4=274
MOVE_BRANCH  34490, 34492,  1,  34380

# Sanger Cogen XFM
OLD_TRAN 34646, 34489, CKT=1, VNOMT=115

#Remove Sanger TB#2
OLD_TRAN    34366, 34488, CKT=2,  STAT=-1

#Remove Sanger TB#3, 115/70 portion. Load ID 3 remains on the 115 kV bus
OLD_TRAN    34366, 34488, CKT=3,  STAT=-1
```

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagrams
2. Demand Forecast
3. Power Flow Summary
4. Pre and Post Project Power Flow Plots

Attachment 1: Scope Diagrams

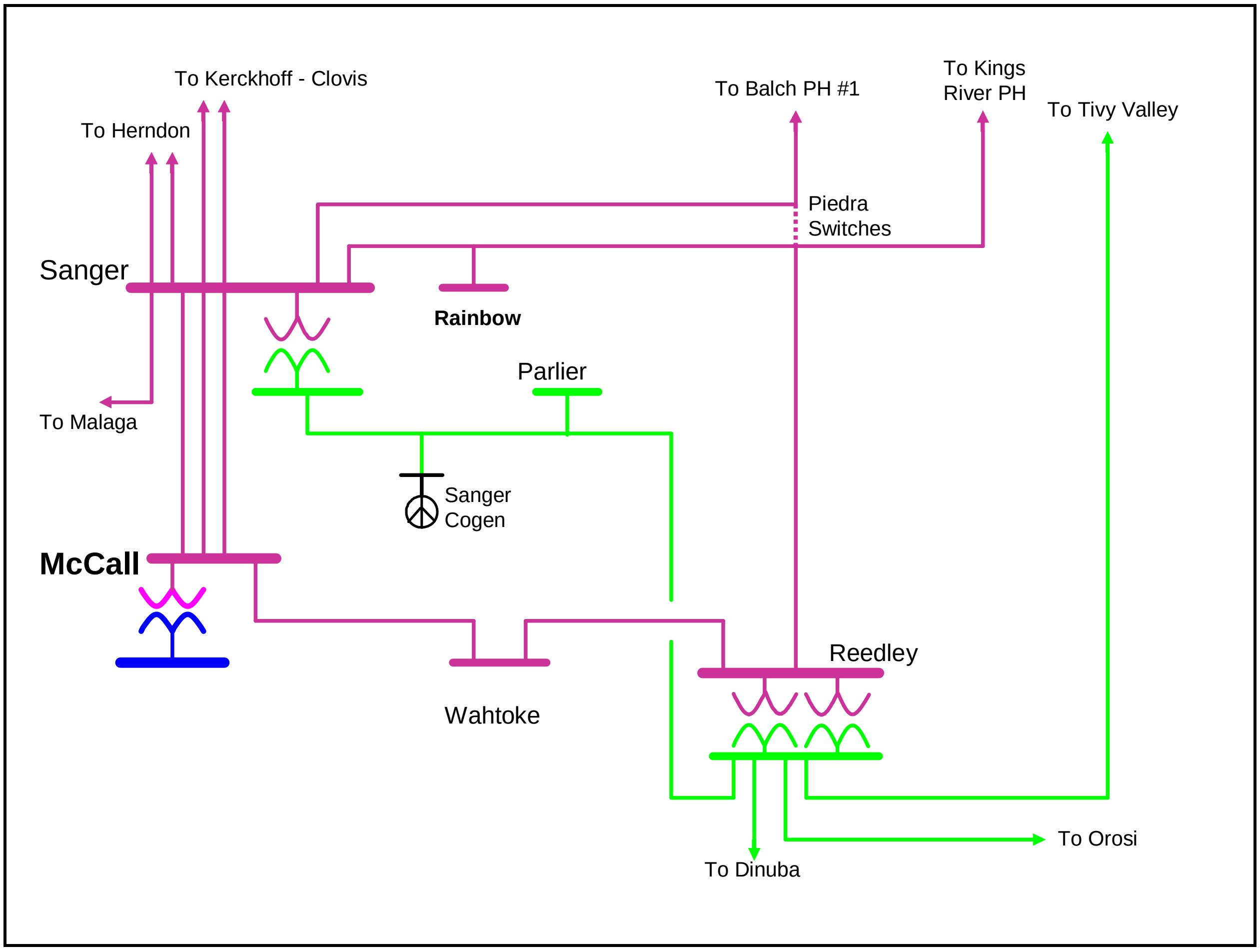


Figure 4-105: Existing Scope Diagram

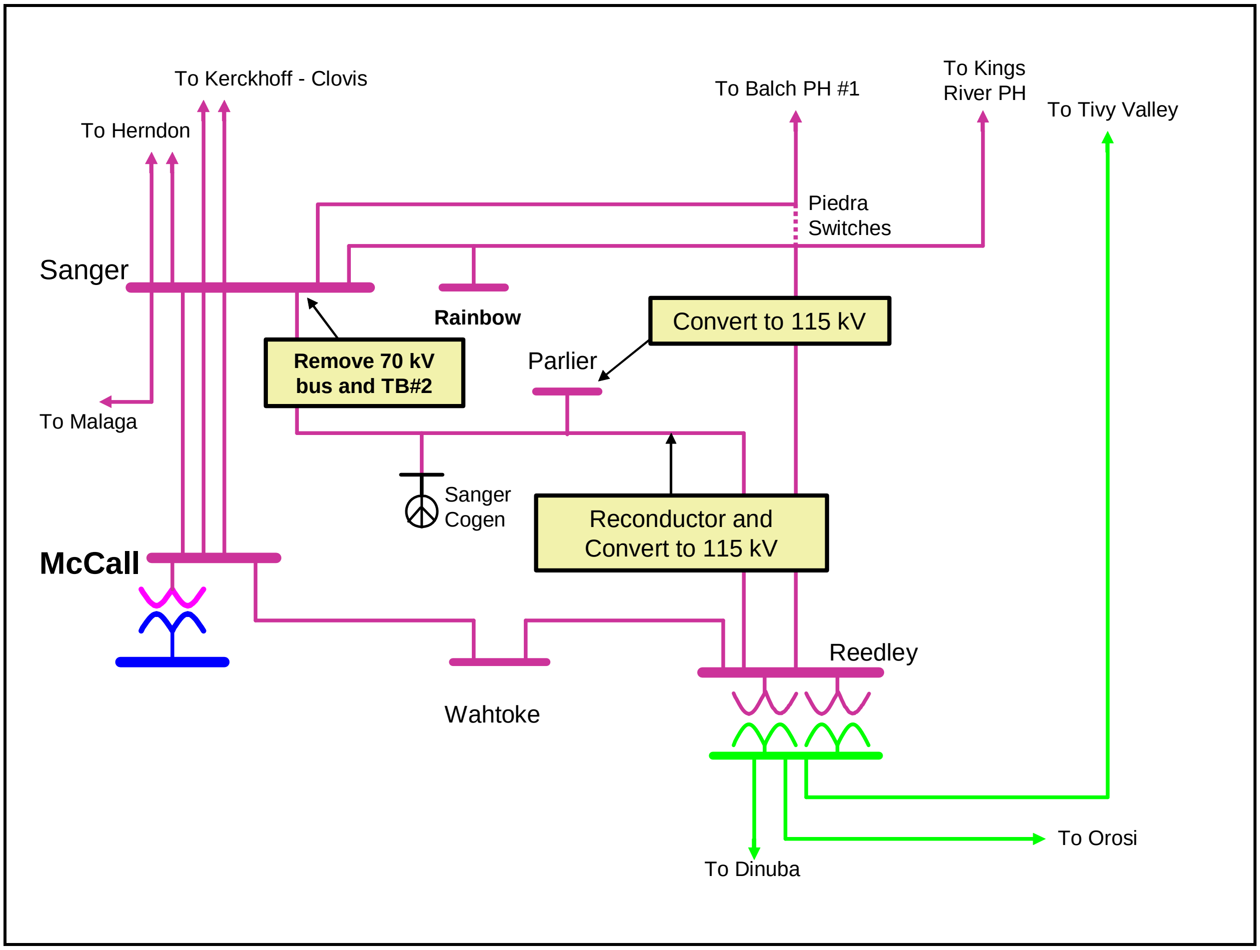


Figure 4-106: Proposed Scope Diagram

Attachment 2: Demand Forecast

Table 4-32: Area Load Demand Forecast

Substation/Bank	2009	2010	2011	2012	2013	Growth Rate(MW/yr)
Wahtoke Bank 2	28.2	28.7	29.3	29.7	30.3	0.5
Wahtoke Bank 3	19.4	19.7	20.1	20.4	20.8	0.4
Reedley Bank 3	24.3	24.8	25.2	25.6	26.1	0.5
Reedley Bank 1	16.2	16.5	16.8	17.0	17.4	0.3
Rainbow	15.1	15.4	15.6	15.9	16.1	0.3
Parlier	18.8	19.1	19.5	19.8	20.2	0.4
Dinuba Bank 1	8.7	8.8	9.0	9.1	9.3	0.2
Dinuba Bank 2	17.9	18.2	18.5	18.8	19.2	0.3
Orosi Bank 1	7.8	7.9	8.1	8.2	8.3	0.1
Orosi Bank 2	6.9	7.0	7.2	7.3	7.4	0.1
Sand Creek	2.8	2.9	3.0	3.1	3.2	0.1
Stone Corral Bank 2	3.3	3.3	3.3	3.3	3.3	0.0
Stone Corral Bank 3	2.7	2.6	2.6	2.6	2.6	0.0
Dunlap	4.0	4.1	4.3	4.4	4.5	0.1
Total Area Load	**176.1**	**179.0**	**182.5**	**185.2**	**188.7**	**3.1**

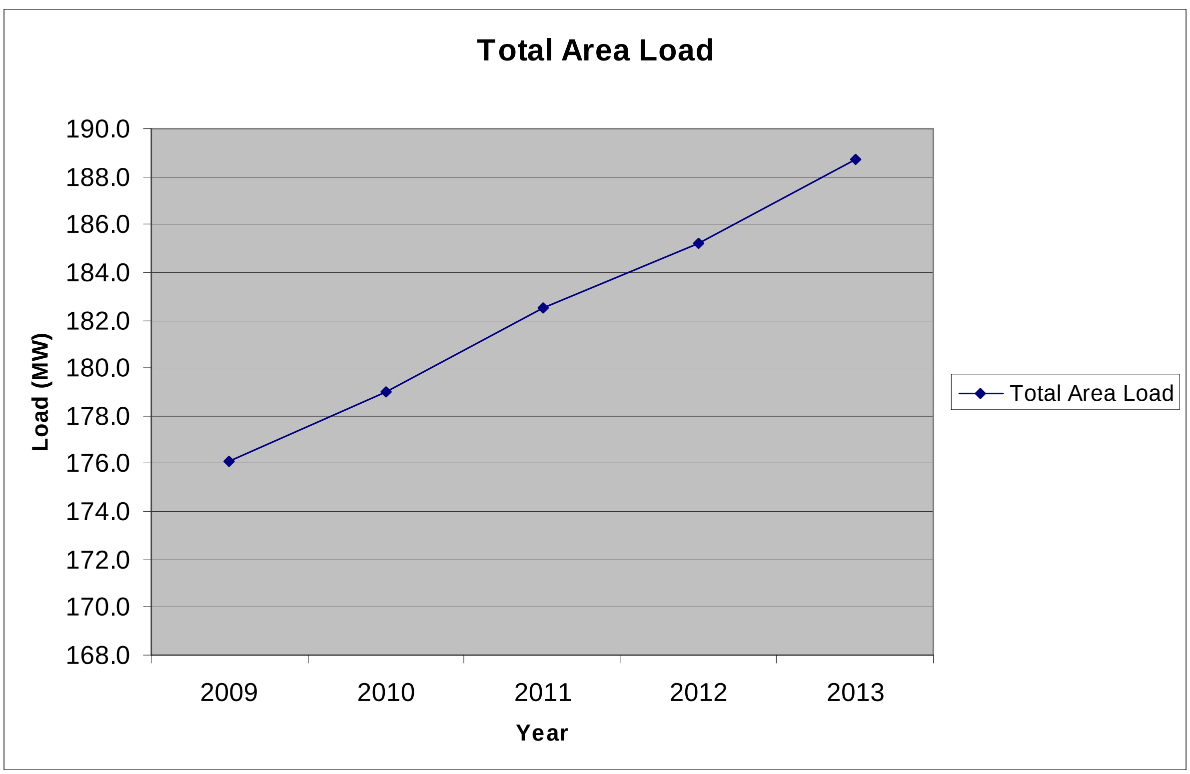


Figure 4-107: Area Load Demand Curve

Attachment 3: Power Flow Summary

Table 4-33: Power Flow Summary

			Pre Project						Post Project	
#	Facility	Facility Rating	2009	2010	2011	2012	2013	2018	2018	Contingency
1	Kings River-Sanger-Reedley 115 kV Line (Reedley-Piedra Jct)	SE Rating 597Amps	97%	100%	102%	104%	107%	121%	74%	Sanger Co-gen and McCall-Reedley (McCall Wahtoke) 115 kV (L-1/G-1)
2	Kings River-Sanger-Reedley 115 kV Line (Sanger-Rainbow Tap)	SE Rating 612 Amps	--	--	96%	98%	101%	115%	71%	Kings River PH and McCall-Reedley (McCall Wahtoke) 115 kV (L-1/G-1)
3	Sanger-Reedley 70 kV Line (Sanger Cogen Jct-Parlier)	SE Rating 470 Amps	--	100%	102%	103%	105%	117%	60%	Kings River PH and McCall-Reedley (McCall Wahtoke) 115 kV (L-1/G-1)
4	Sanger-Reedley 70 kV Line (Sanger Co-gen Jct-Sanger)	SE Rating 396 Amps	--	--	--	--	--	101%	52%	Sanger Co-gen and McCall-Reedley (McCall Wahtoke) 115 kV (L-1/G-1)

Attachment 4: Pre and Post Project Power Flow Plots

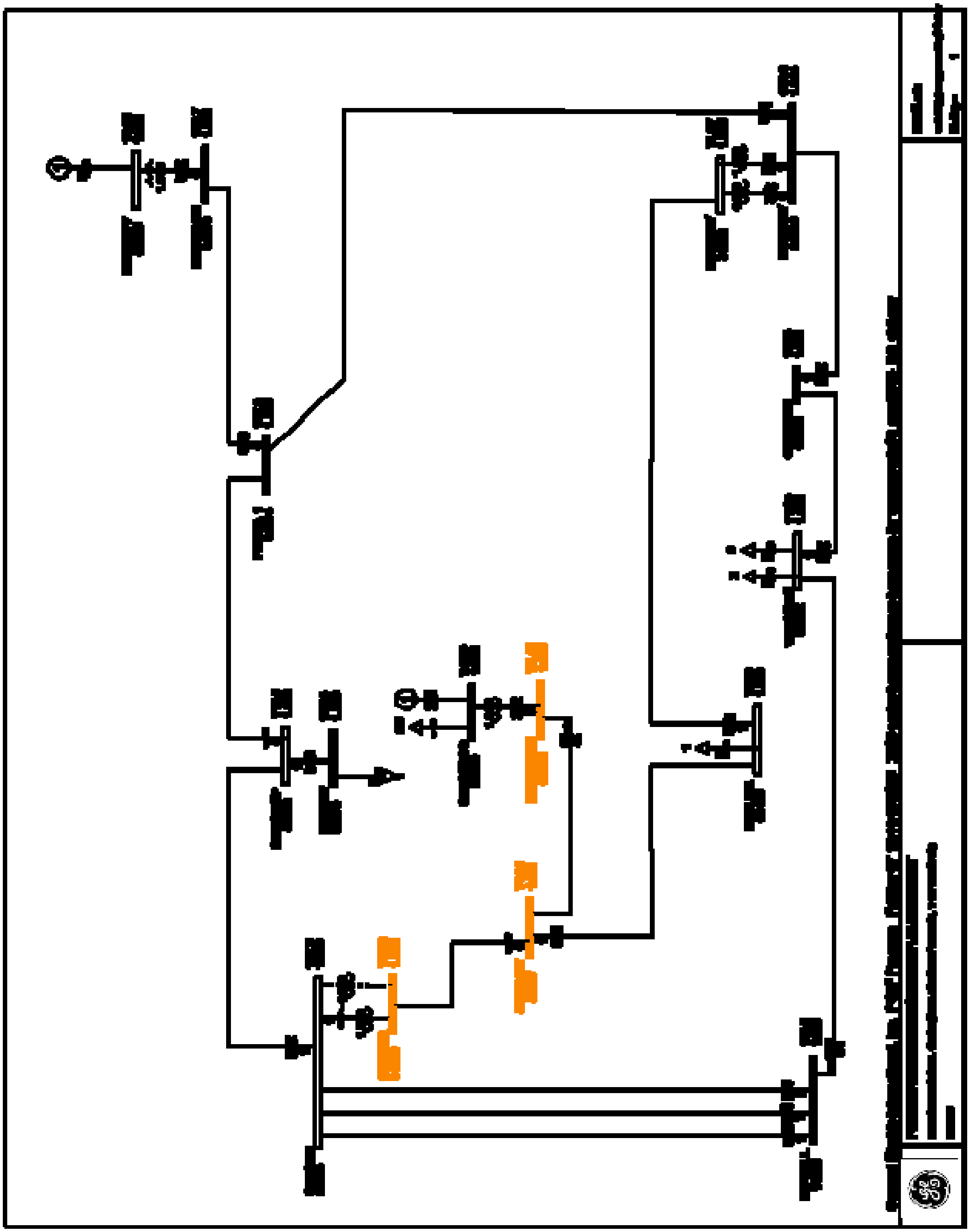


Figure 4-108: 2018 Pre Project – Normal

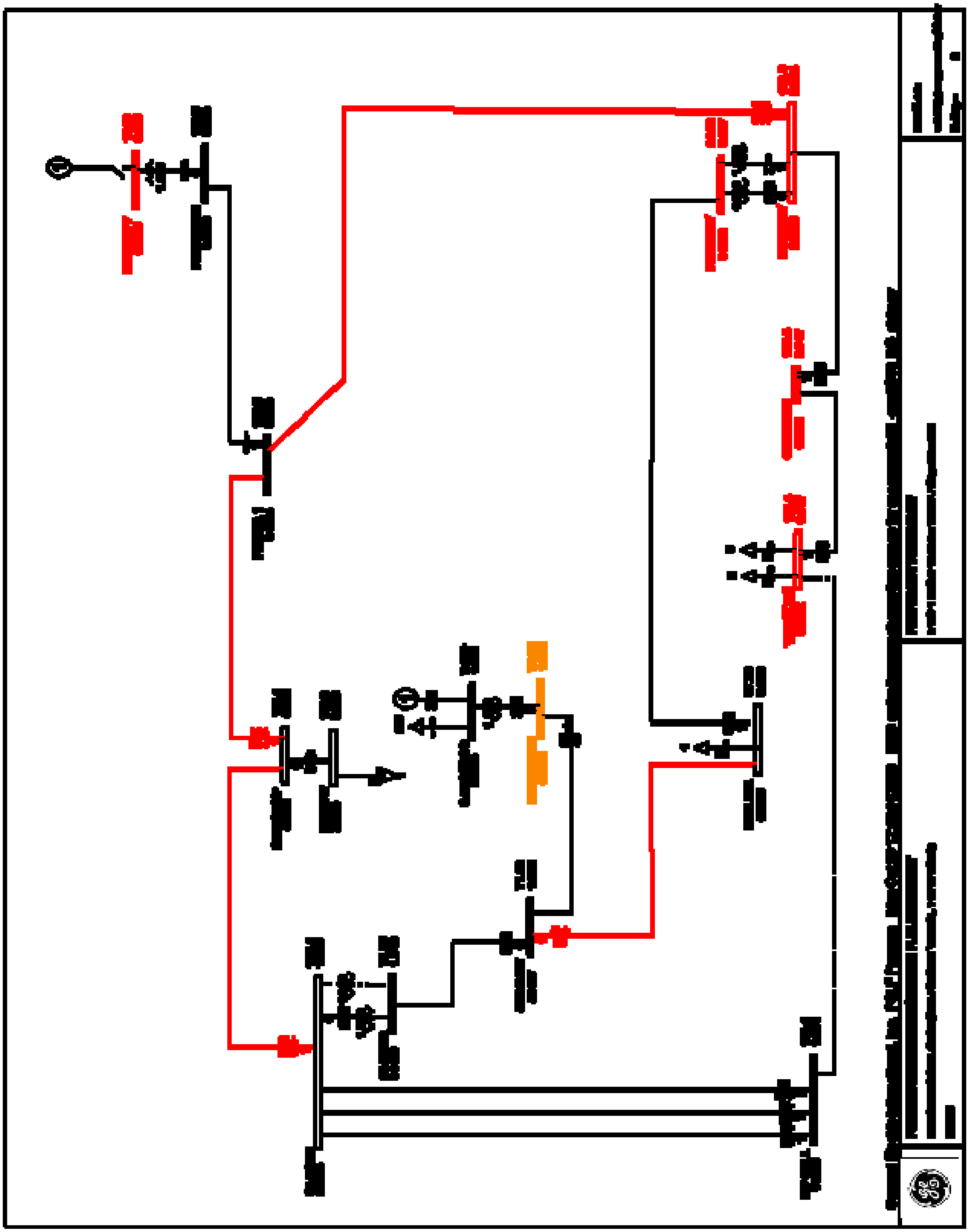


Figure 4-109: 2018 Pre Project – Loss of McCall-Wahtoke 115 kV and Kings River PH (L-1/G-1)

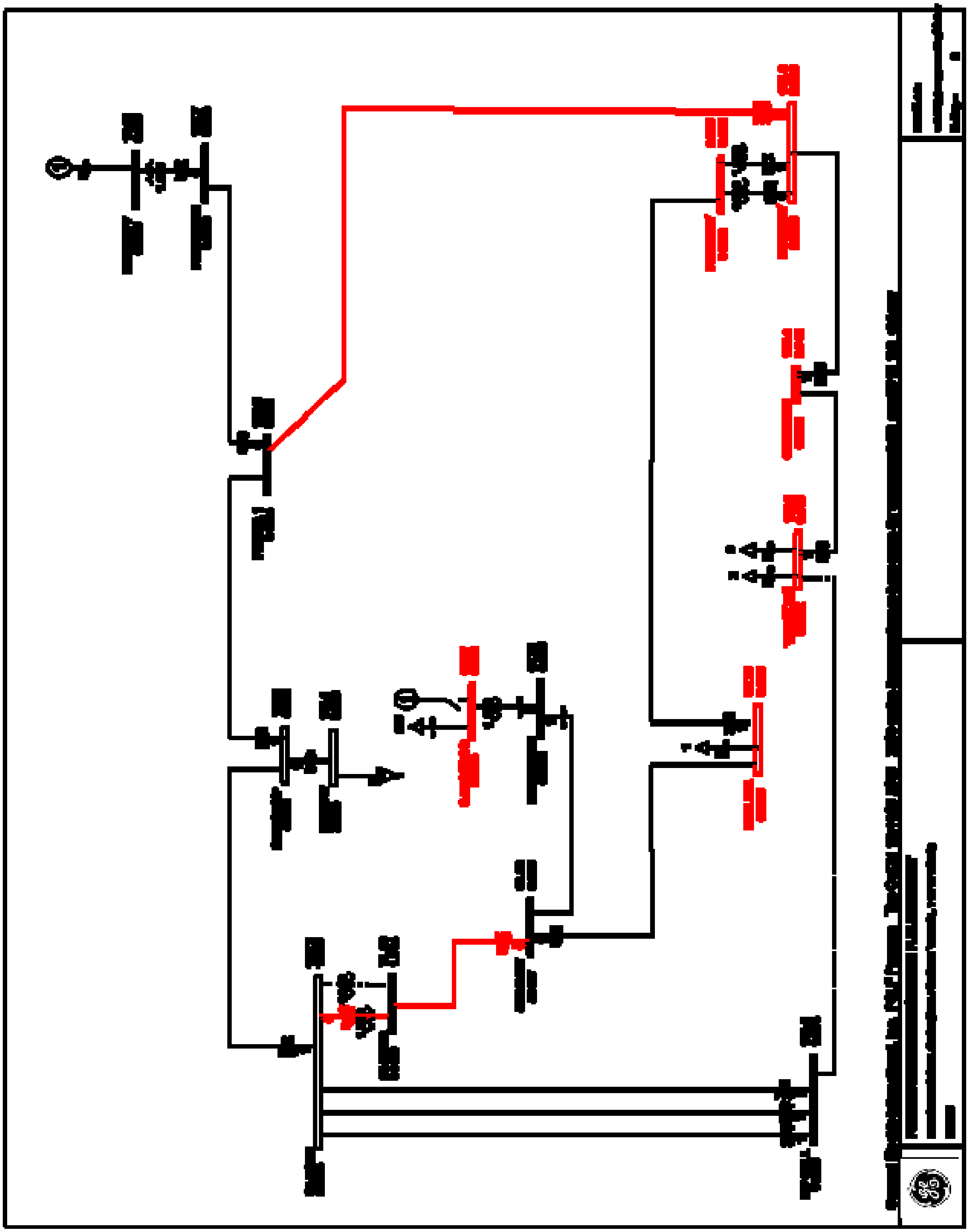


Figure 4-110: 2018 Pre Project - Loss of McCall-Wahtoke 115 kV Line and Sanger Cogen (L-1/G-1)

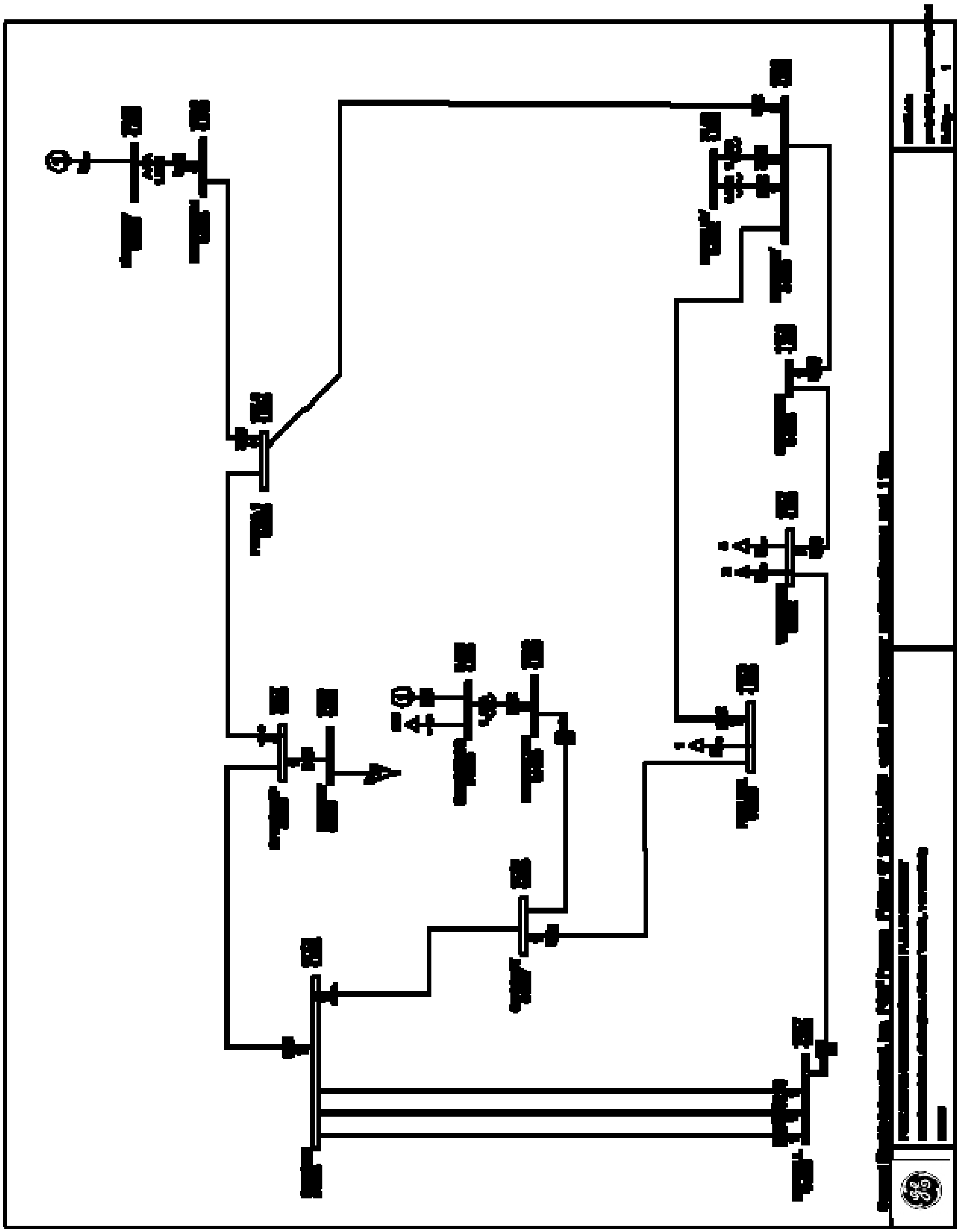


Figure 4-111: 2018 Post Project - Normal

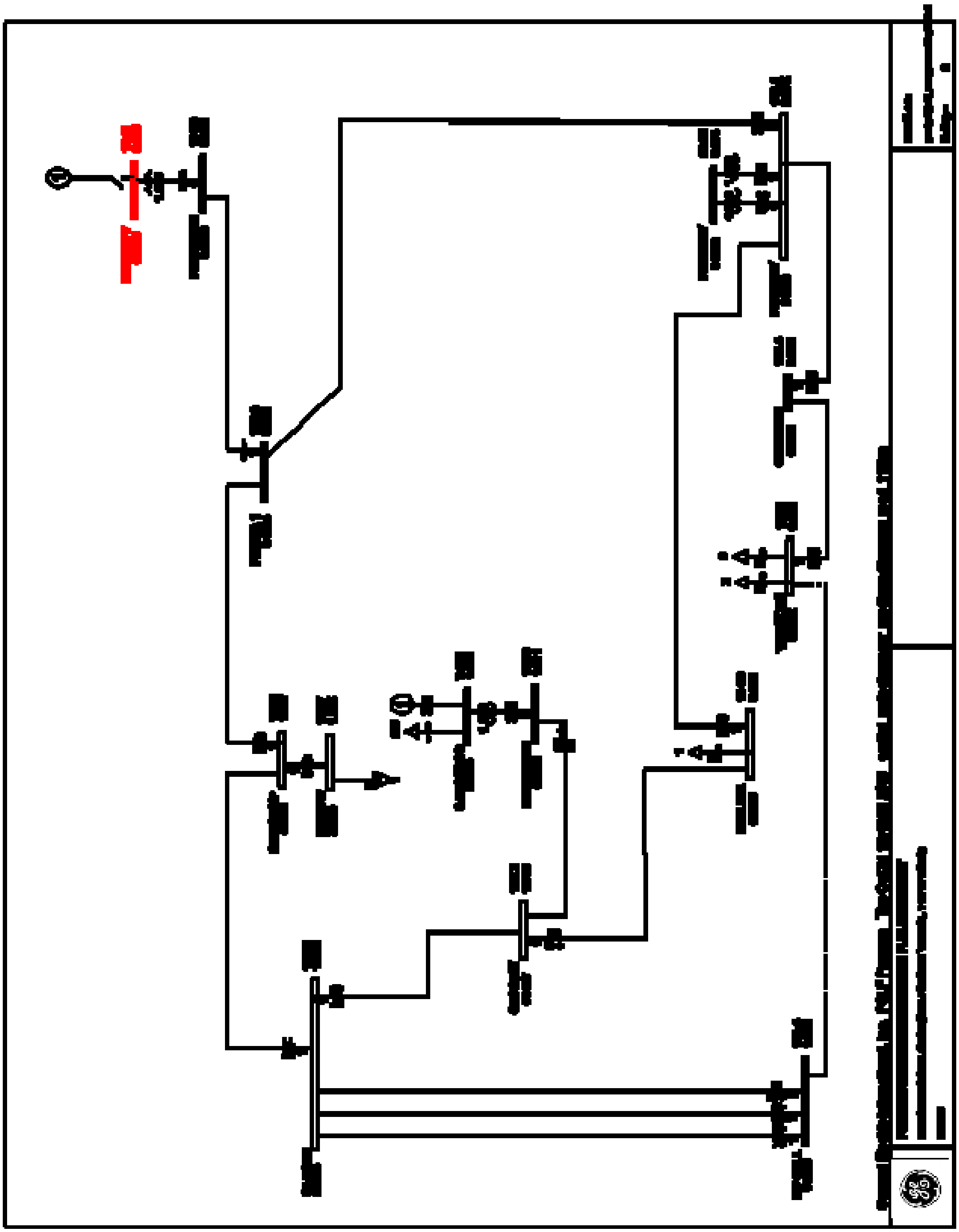


Figure 4-112: 2018 Post Project – Loss of McCall-Wahtoke 115 kV Line and Kings River PH (L-1/G-1)

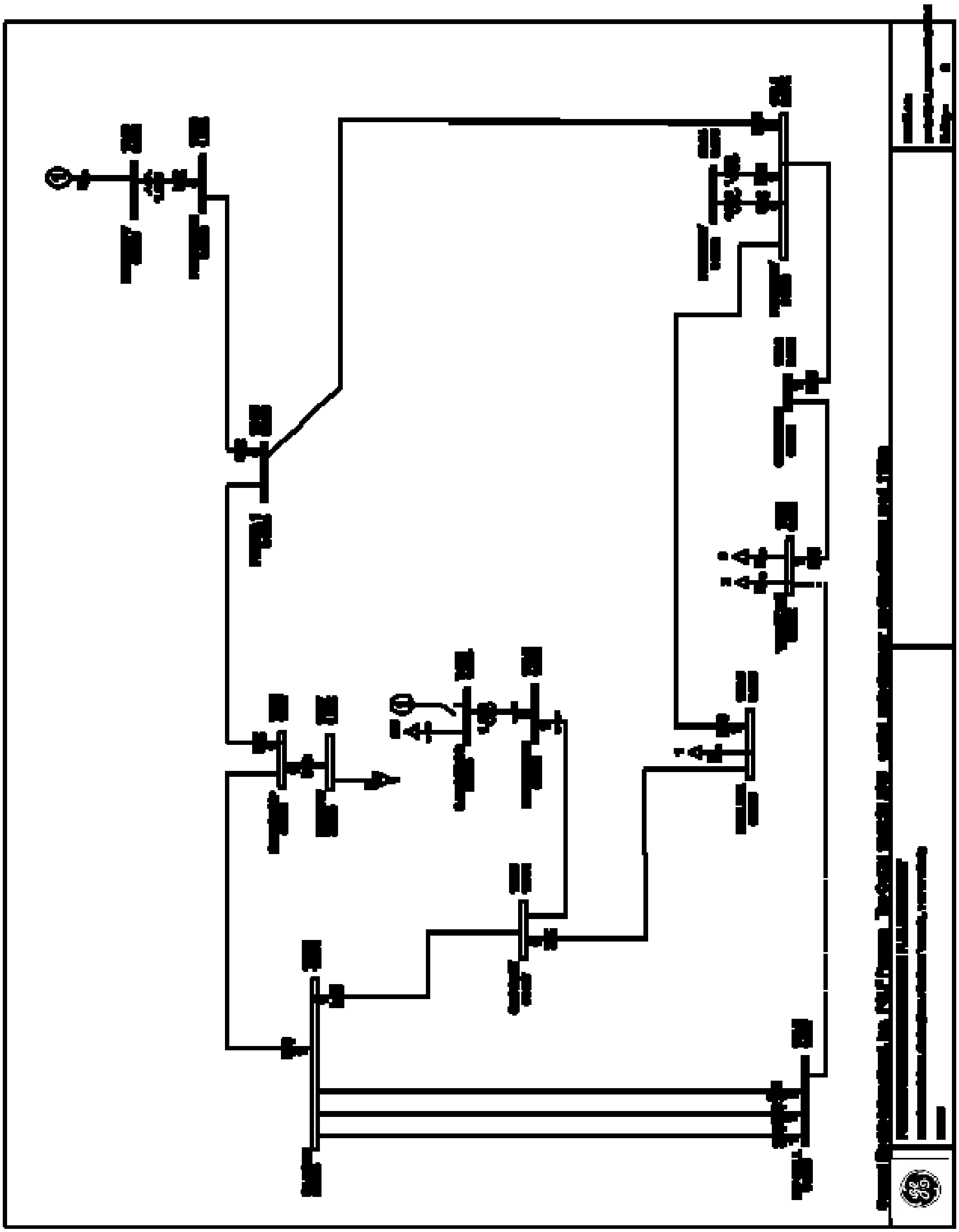


Figure 4-113: 2018 Post Project - Loss of McCall-Wahtoke 115 kV Line and Sanger Cogen (L-1/G-1)

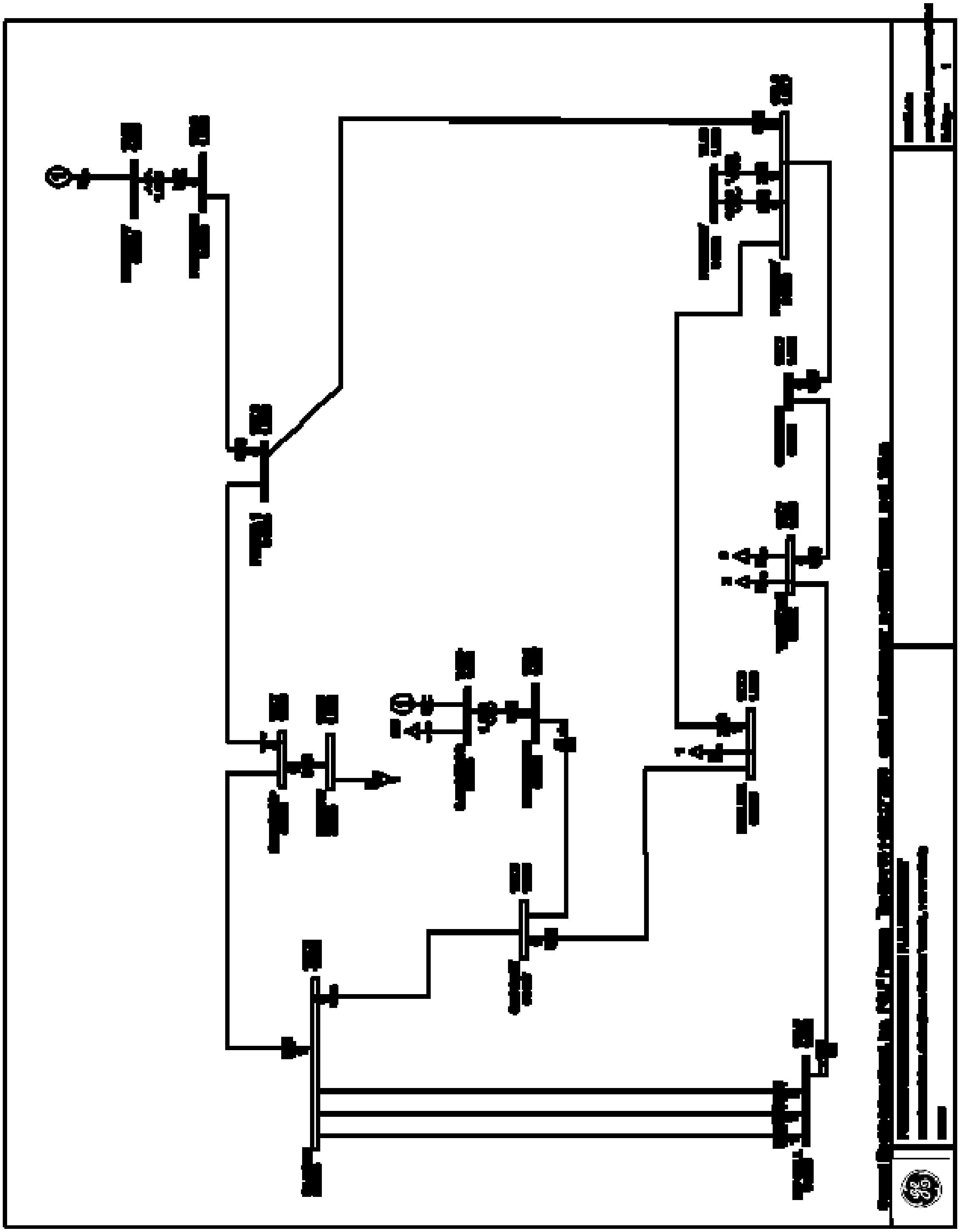


Figure 4-114: 2018 Post Project – Normal conditions, Sanger Cogen at Max Output of 42 MW

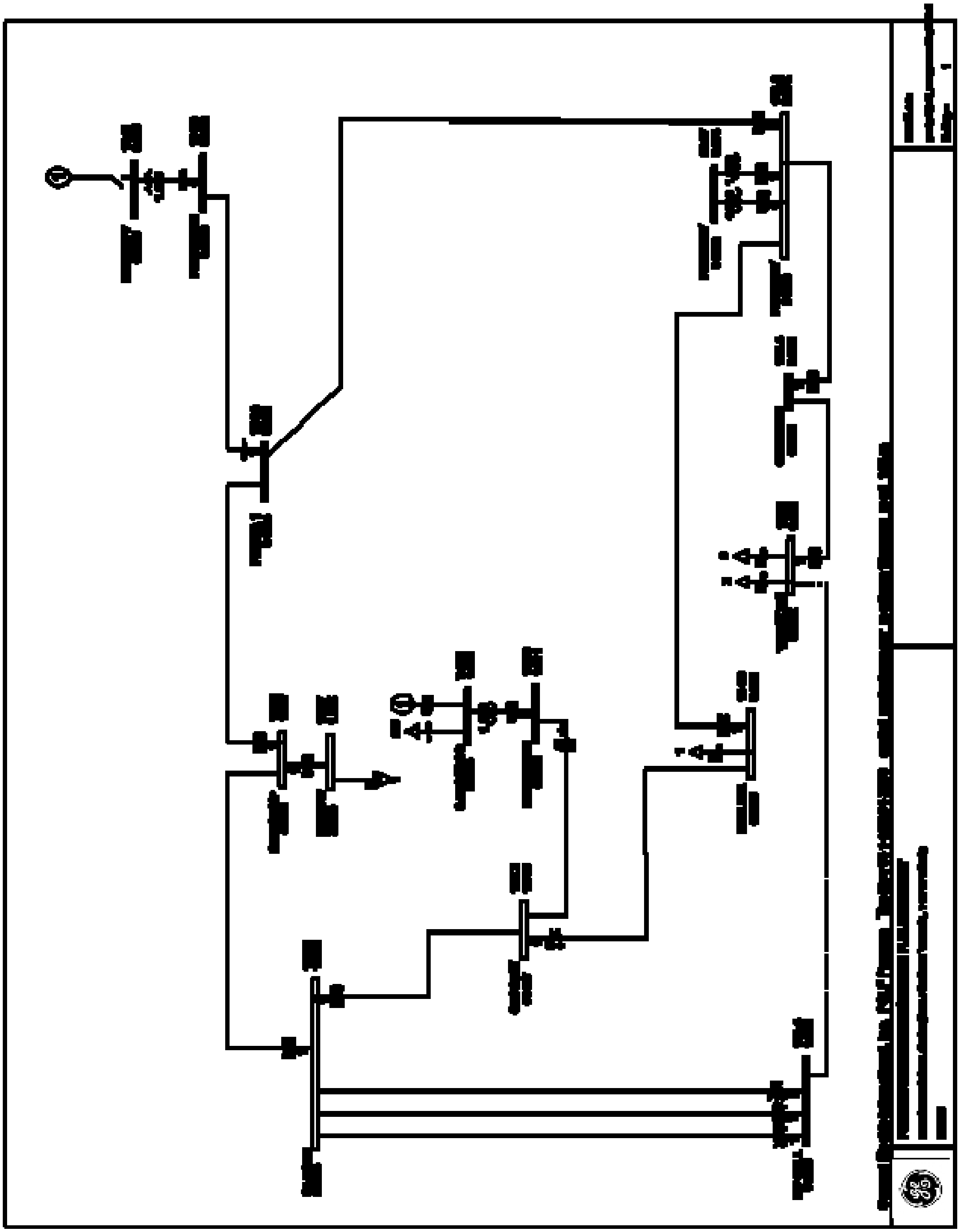


Figure 4-115: 2018 Post Project, Sanger Cogen at 42 MW – Loss of McCall-Wahtoke 115 kV and Kings River PH (L-1/G-1)

2011 Projects

San Justo Substation Interconnection

TARGETED IN-SERVICE DATE

May 2011

PURPOSE AND BENEFIT

Reliability – Tariff and Compliance

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROPOSED PROJECT

This project is proposing the transmission interconnection plan of service for a new distribution substation.

The project scope is to interconnect a new 115/21 kV distribution substation in San Juan Bautista. The 115 kV bus for this new substation (San Juan Substation) will be configured as a ring-bus. The Crazy Horse-Hollister No. 1 115 kV line will be looped into the new substation.

This project is expected to cost between $5M and $10M.

BACKGROUND

Distribution customers in San Juan Bautista are served by long distribution feeders out of Hollister Substation. These customers include several food-processing plants. There have been service reliability problems with the distribution system, and increasing load growth in the area is straining the distribution system.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO. PG&E also performed sensitivity studies for this local area using local system peak conditions.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended because it does not increase system capacity and it does not address the reliability concerns in San Juan Bautista.

PROJECT SCHEDULE

- Environmental and Permitting Processes – None
- Design – Fall 2010
- Major Equipment – Fall 2010
- Construction – Fall 2010 through Spring 2011
- Operation Date – May 2011

KEY ISSUES

- Land-Use Restrictions – None
- Environmental Concerns – None
- Special Metering or Protection – None
- Common Mode Exposure Items – None
- Interaction with other Projects – This project is dependent upon the completion of the Crazy Horse Switching Station Project

GEPSLF MODELING INFORMATION

```
#   Re-establish San Justo Substation
#
#     This change file will loop the new San Justo Substation into the new
#       Crazy Horse-Hollister No. 1 line. (The San Justo site is between
#       San Juan Highway and San Justo Road - less than 1 mile from Anzar Jct)
#
#   First, create the new San Justo Substation and model one new 10 MW
#     distribution bank load at the station
#
NEWBUSD 35945,"SANJUSTO",115.,1,1.00,19,319,,,1
NEWLOAD 35945,1,19,319,10.,2.5,,,,,,,,,1

#   Move the end of the Crazy Horse-Hollister No. 1 line from Hollister
#     to San Justo
MOVE_BRANCH  35910,35940,1,35945

#
#   Revise the line parameters from Crazy Horse to San Justo
#      - Use 2 fps coastal ratings
#      - This section will utilize mostly lattice towers with some self-supported TSP structures
```

```
#         1) Use Aspen model 2A-477 ACSS (ohms/mile) for now
#              values from Aspen: R=0.20755, X=0.740540, B=0.015388
#         2) Total line length = 7.47 miles
#
OLDSECDD 35910,35945,1,1,,0.011723,0.041829,0.005731,227.8,227.8,244.8,244.8,,,,,,

#   Create the new San Justo-Hollister No. 1 line
#      - Use 2 fps interior ratings
#      - This section will utilize self-supported TSP structures
#         1) Use Aspen model 2A-477 ACSS (ohms/mile) for now
#              values from Aspen: R=0.20755, X=0.740540, B=0.015388
#         2) Total line length = 8.25miles
#
NEWSECDD 35945,35940,1,1,0.012947,0.046196,0.006329,224.3,224.3,244.8,244.8,1

END
```

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagram
2. Pre and Post Project Power Flow Plots

Attachment 1: Scope Diagrams

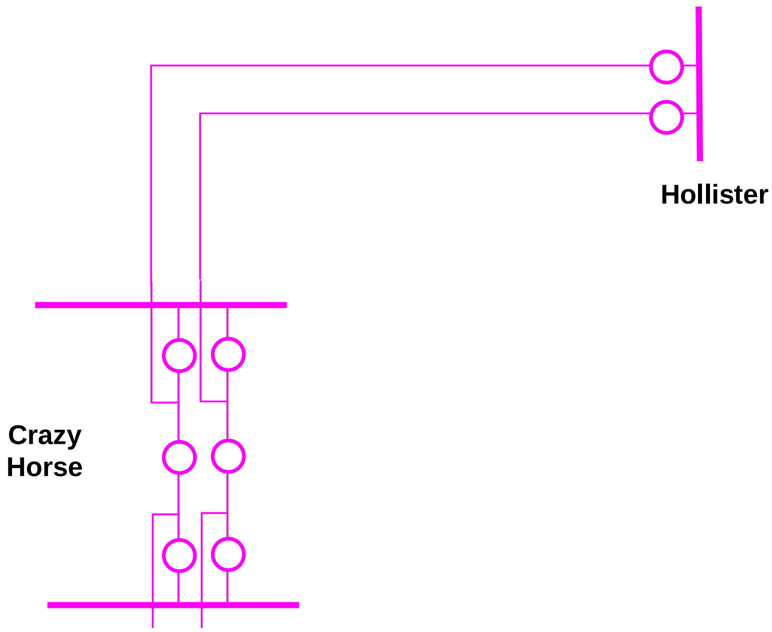


Figure 4-116: Pre-Project of Hollister 115 kV System

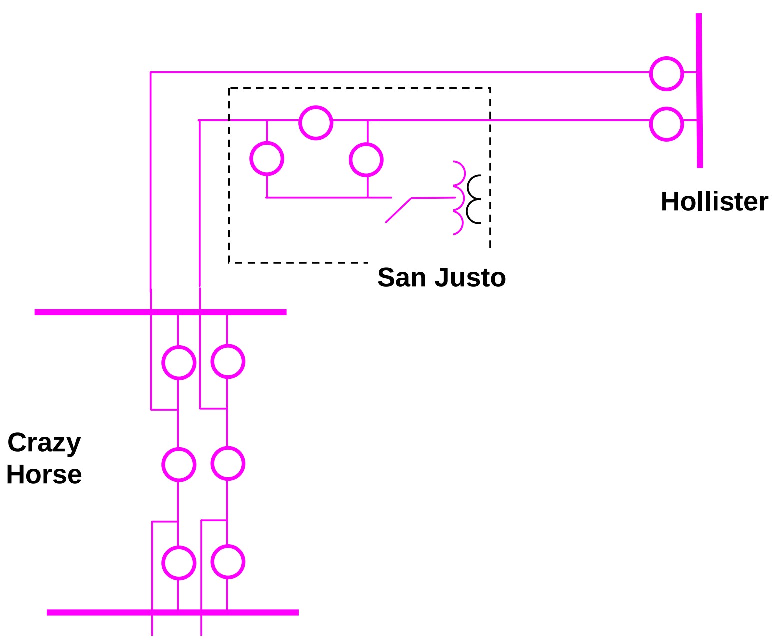


Figure 4-117: Post-Project of Hollister 115 kV System

Attachment 2: Pre- and Post-Project Power Flow Plots

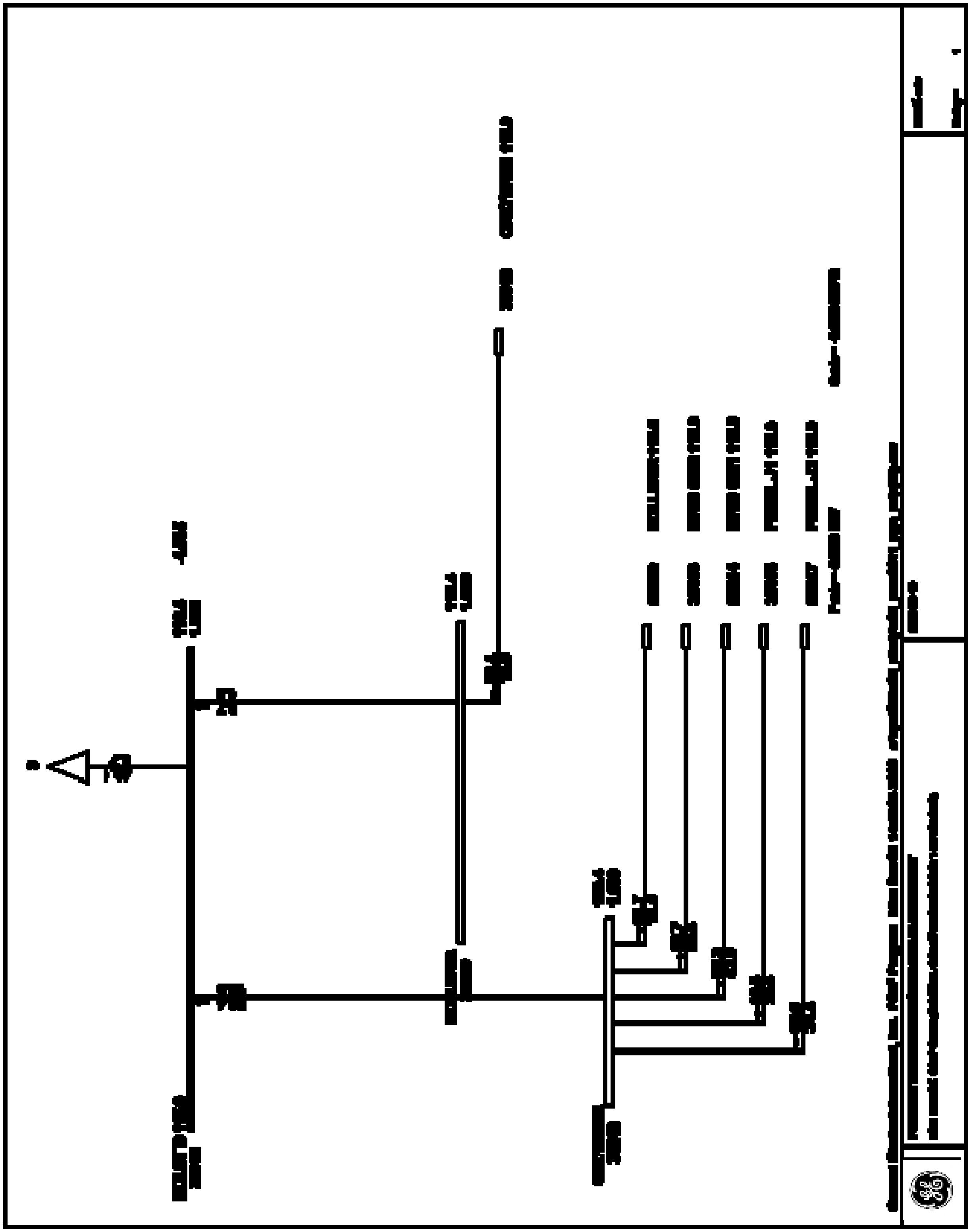


Figure 4-118: Pre-Project – Normal Conditions

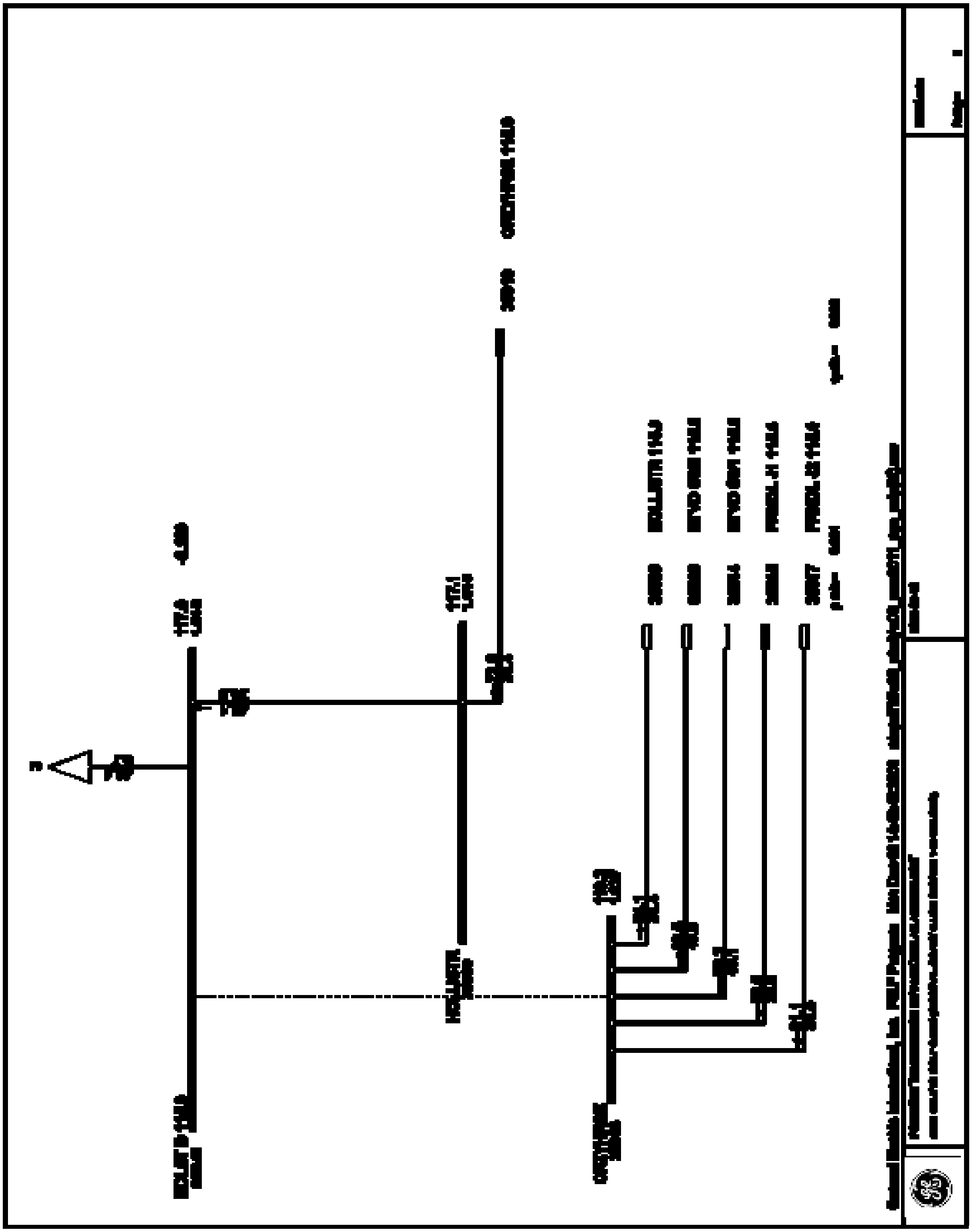


Figure 4-119: Pre-Project – Loss of the Crazy Horse - Hollister No. 1 115 kV Line (L-1)

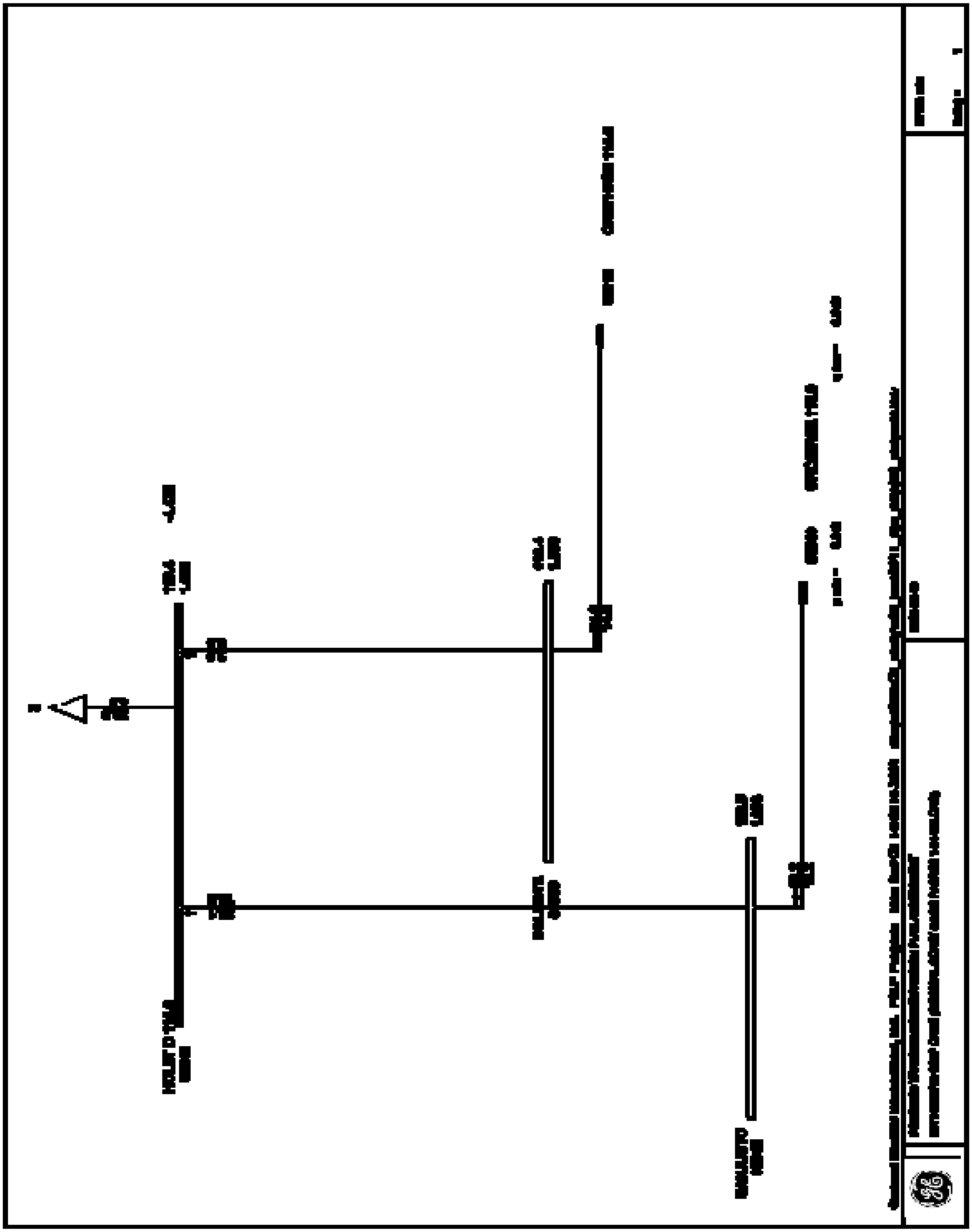


Figure 4-120: Post-Project - Normal Conditions

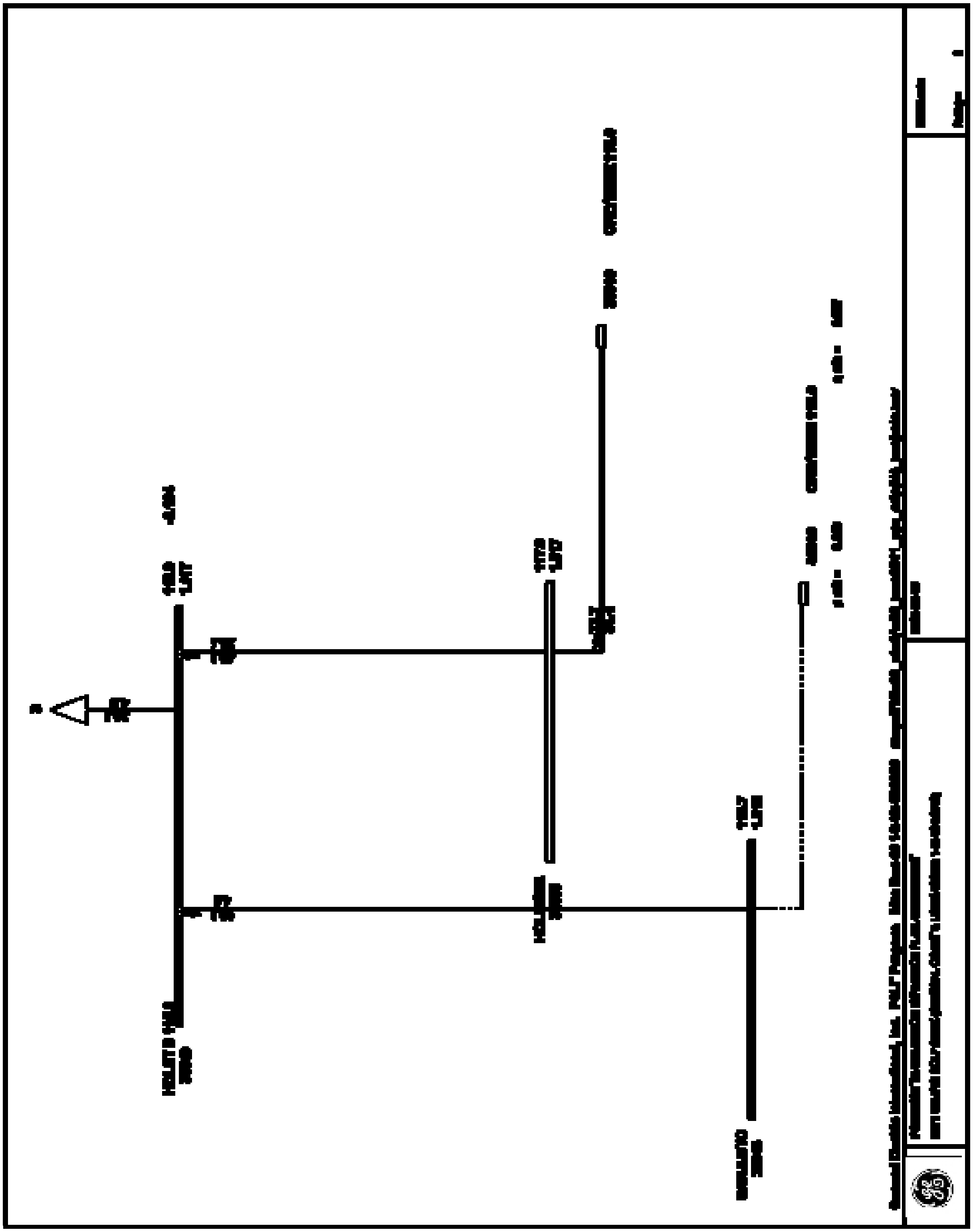


Figure 4-121: Post-Project – Loss of the Crazy Horse – San Justo 115 kV Line (L-1)

Santa Cruz 115 kV Reinforcement

TARGETED IN-SERVICE DATE

December 2011

PURPOSE AND BENEFIT

Reliability – NERC Compliance

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROPOSED PROJECT

This project scope is to rebuild the 7.5-mile Green Valley – Rob Roy section of the Green Valley – Paul Sweet 115 kV line into a double-circuit line, install three breakers at Rob Roy Substation and install 20 – 30 MVAR of reactive support at Camp Evers Substation. The rebuilt double-circuit line will be sized with conductors capable of handling a minimum of 700 Amps for summer normal conditions and 800 Amps for summer emergency conditions.

This project is expected to cost between $10M and $15M.

BACKGROUND

Paul Sweet, Camp Evers and Rob Roy Substations are supplied by two 115 kV lines from Green Valley Substation. These three distribution substations serve over 65,000 customers, with a wintertime peak demand of over 170 MW. A statcom device was installed at Paul Sweet Substation over 10 years ago to provide reactive support in the area.

By 2013, an outage of Green Valley – Rob Roy line section, combined with an outage of the Paul Sweet statcom, will result in the Green Valley – Camp Evers 115 kV line loading to over 90% of its winter emergency ratings and the 115 kV voltages at Paul Sweet and Rob Roy will be below 93%.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO. PG&E also performed sensitivity studies of this local area using local system peak conditions.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended because it does not increase system capacity and it does not address the reliability concerns in the Watsonville area.

PROJECT SCHEDULE

- Environmental and Permitting Processes – Spring 2011
- Design – Spring 2011
- Major Equipment – Summer 2011
- Construction – Summer 2011 through Fall 2011
- Operation Date – December 2011

KEY ISSUES

- Land-Use Restrictions – This project should qualify for a NOC.
- Environmental Concerns – None
- Special Metering or Protection – None
- Common Mode Exposure Items – None
- Interaction with other Projects – None

GEPSLF MODELING INFORMATION

```
#   Santa Cruz 115 kV Reinforcement Project
#
#     Create a double-circuit 115 kV line from Green Valley Sub to Rob Roy with 715 AAC conductor
#
#     Install 20 MVAR of shunt caps at Camp Evers Substation
#
#   Make the new 115 kV lines from Green Valley to Rob Roy
#        1) Used Aspen model TSP-715 AAC (ohms/mile)
#            values from Aspen: R=0.1455, X=0.70872, B=0.016389
```

```
#         2) Total line length = 7.55 miles
#         3) Use 2 fps coastal ratings
#
OLDSECDD 35901,35908,1,1,,0.008306,0.040460,0.006169,140.,160.,194.,207.,,,,,,,,,
NEWSECDD 35903,35908,2,1,0.008306,0.040460,0.006169,140.,160.,194.,207.,1,19,319,390

#
#   Install two 10 MVAR steps of shunt caps at Camp Evers
#
NEWSVD  35905,"v ",1,1,1.02,,,2,10.0,,,,,,,,,,,,,,,,,,,,19,319,,,390
```

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagram
2. Power Flow Summary
3. Pre and Post Project Power Flow Plots

Attachment 1: Scope Diagrams

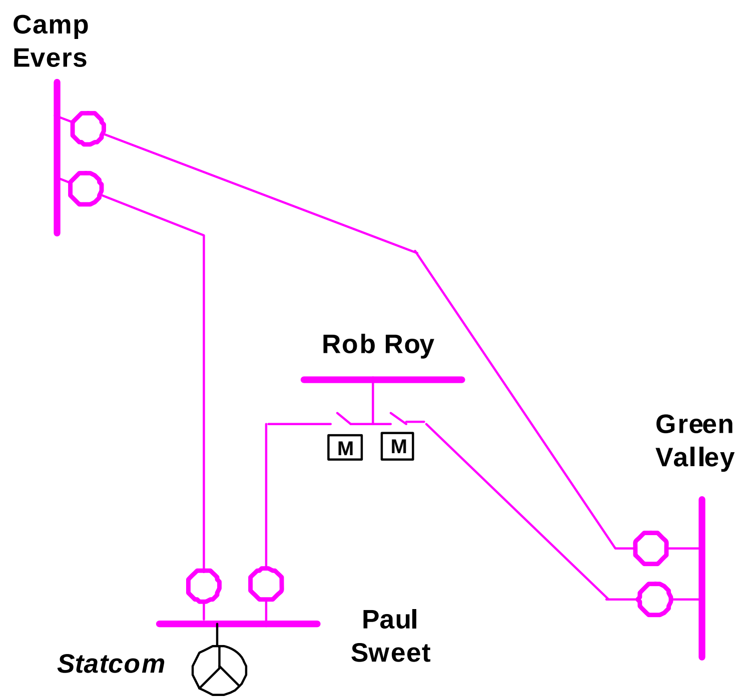


Figure 4-122: Pre-Project of Santa Cruz 115 kV System

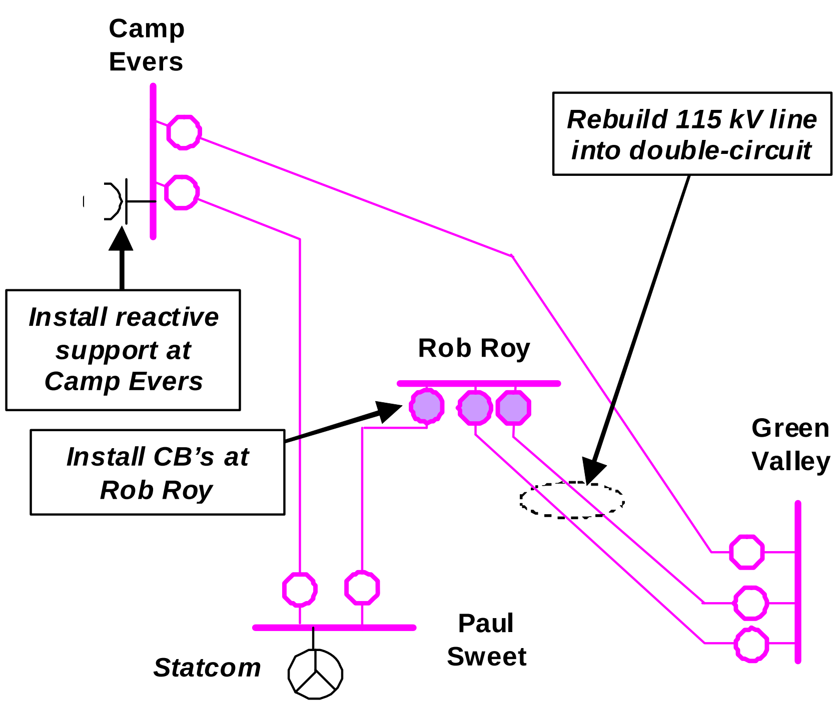


Figure 4-123: Post-Project of Santa Cruz 115 kV System

Attachment 2: Power Flow Summary

Table 4-34: Power Flow Summary

Contingency	Facility Affected	2013 (Pre-Project)	2018 (Pre-Project)	2010 (Post-Project)
Green Valley – Rob Roy 115 kV Line / Paul Sweet Statcom (L-1/G-1)	Rob Roy 115 kV Voltage	0.89	0.87	0.99
Green Valley – Camp Evers 115 kV Line / Paul Sweet Statcom (L-1/G-1)	Camp Evers 115 kV Voltage	0.93	0.92	0.97

Attachment 3: Pre and Post Project Power Flow Plots

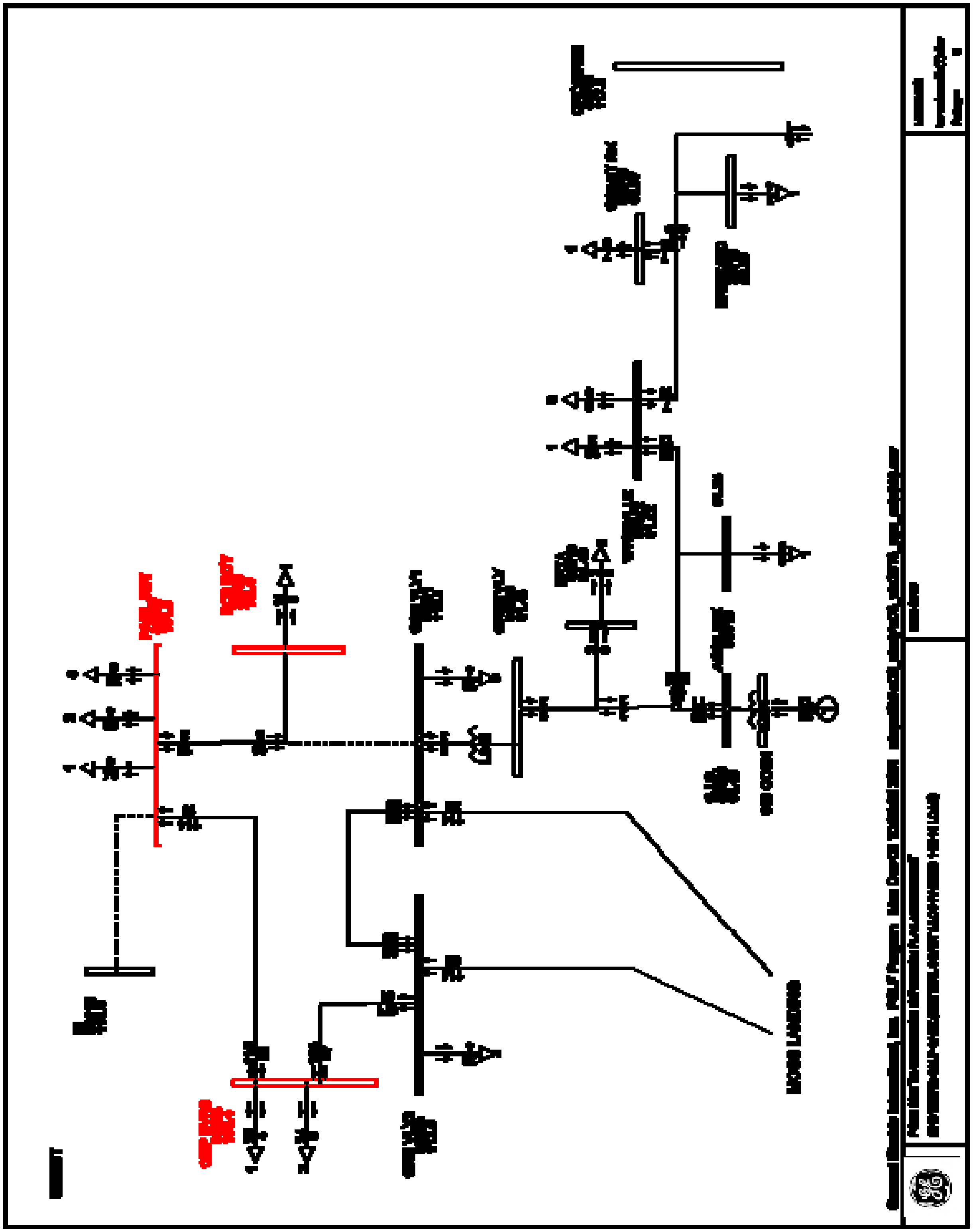


Figure 4-124: Pre-Project – Loss of Paul Sweet Statcom and Green Valley – Rob Roy 115 kV Line Section (L-1/G-1)

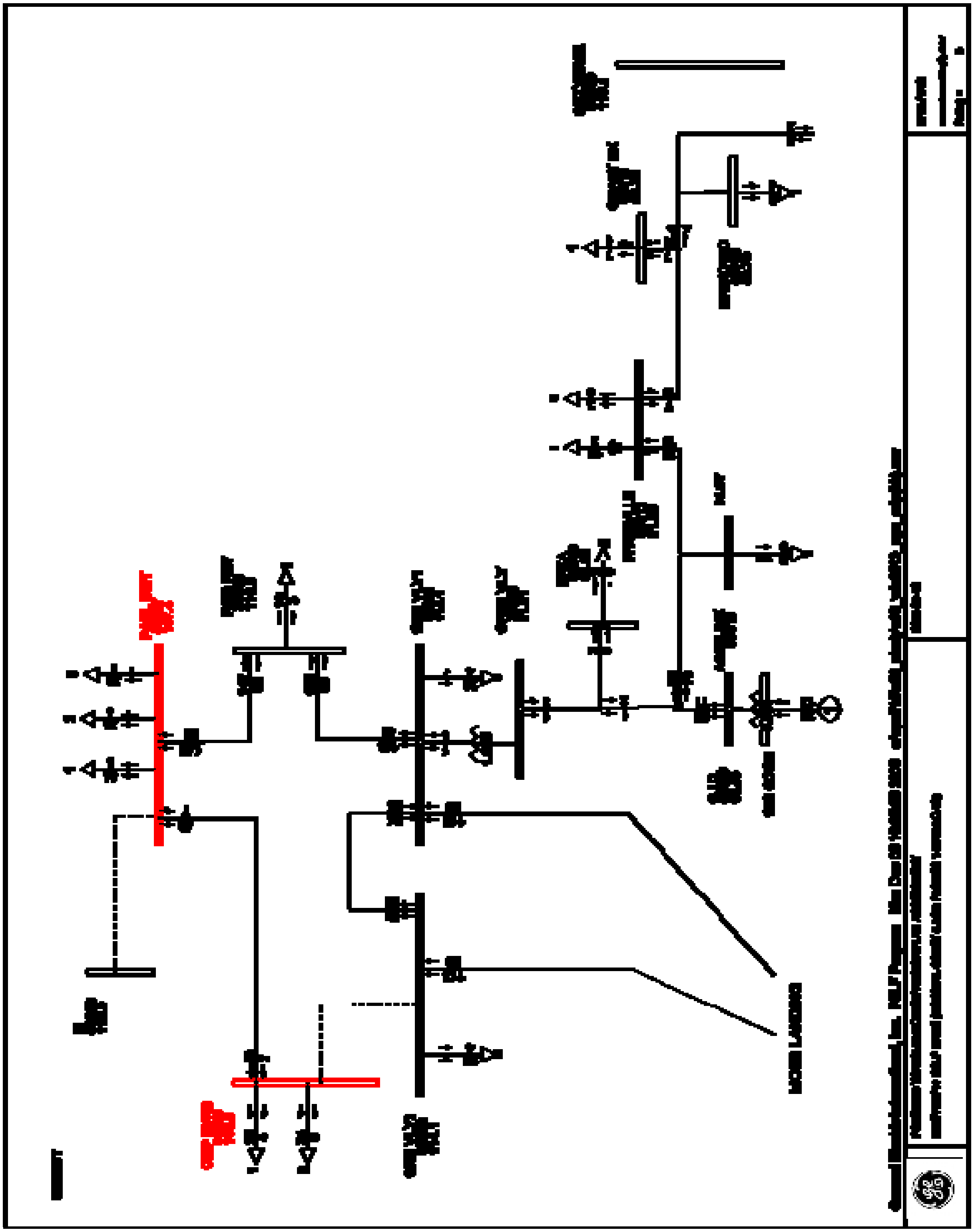


Figure 4-125: Pre-Project – Loss of Paul Sweet Statcom and Green Valley – Camp Evers 115 kV Line (L-1/G-1)

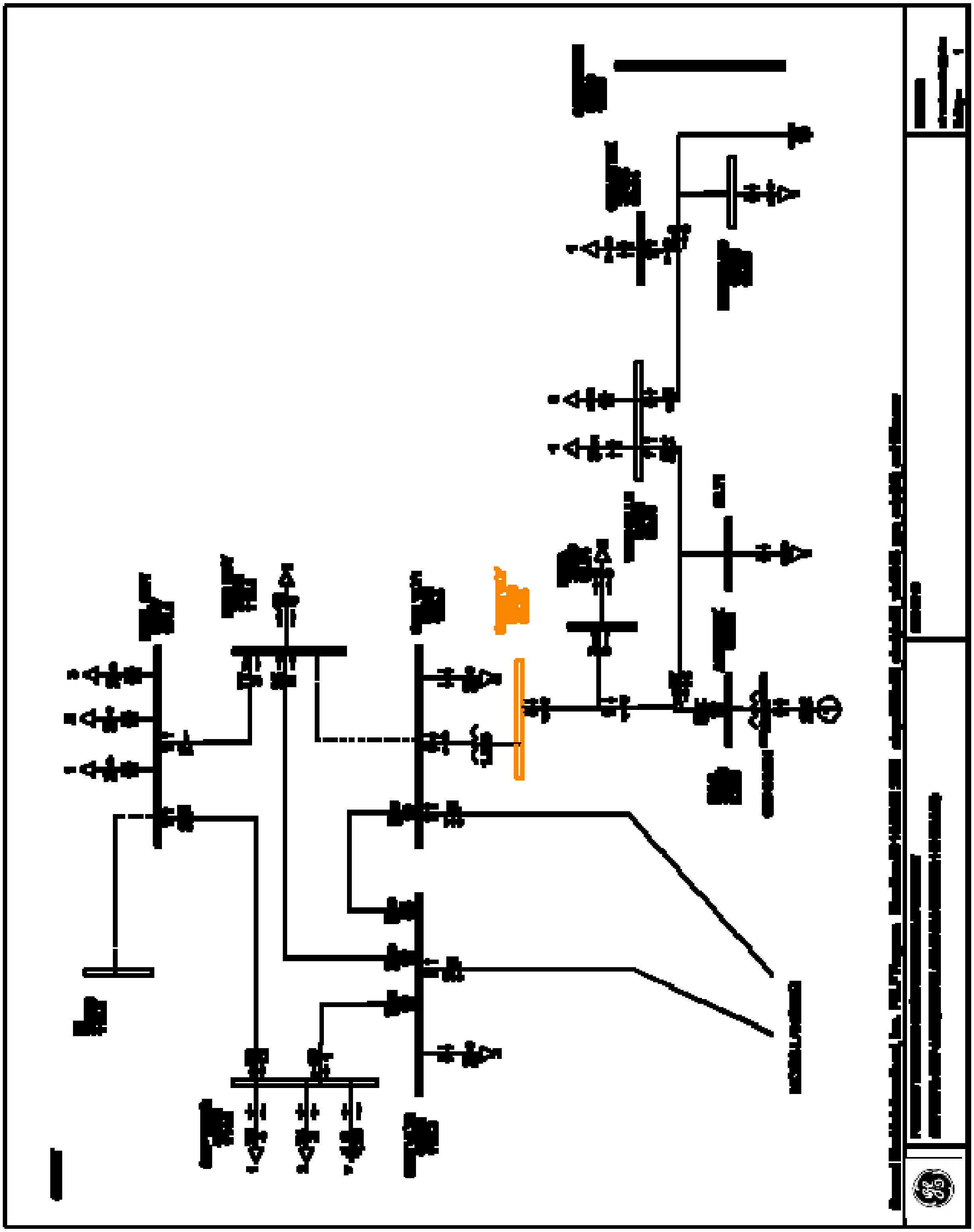


Figure 4-126: Post-Project - Loss of Paul Sweet Statcom and Green Valley – Rob Roy 115 kV Line Section (L-1/G-1)

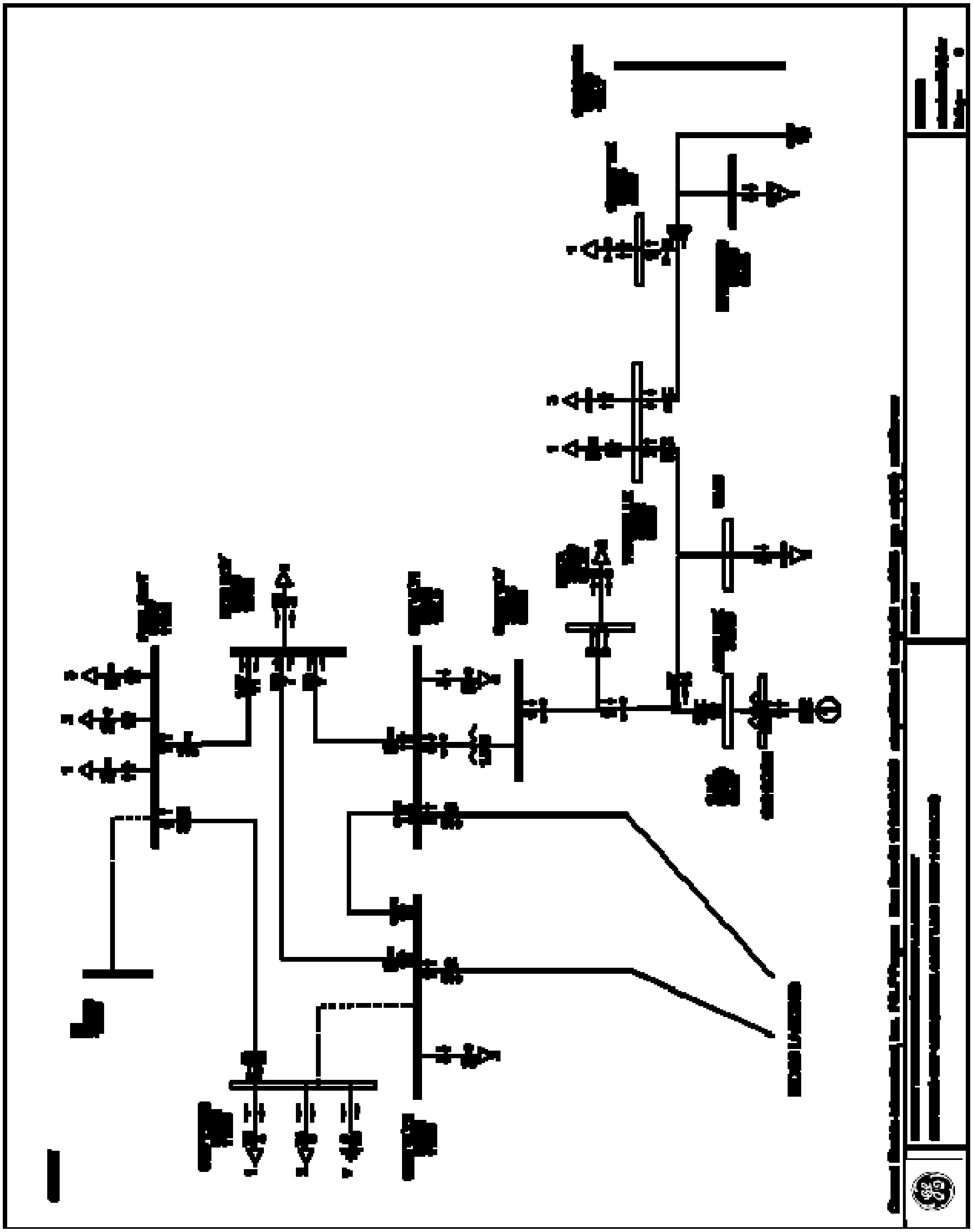


Figure 4-127: Post-Project – Loss of Paul Sweet Statcom and Green Valley – Camp Evers 115 kV Line (L-1/G-1)

Garberville Reactive Support

TARGETED IN-SERVICE DATE

May 2011

PURPOSE AND BENEFIT

Reliability – NERC Compliance

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROJECT

The project scope is to install a 20 MVAr reactive support device at Garberville Substation.

This project is expected to cost between $5M and $10M.

BACKGROUND

Garberville Substation is located in Humboldt County. Electric customers in this area are served by the Company's network of 60 kV transmission lines. Garberville Substation receives its power from both the Humboldt and Mendocino sources through the Bridgeville-Garberville and Garberville-Laytonville 60 kV lines respectively. The local area demand (includes Garberville, Fort Seward and Fruitland Substations) is projected to reach about 19.3 MW in 2011 and is expected to increase at 0.7 MW per year.

Planning studies have determined that under projected winter peak conditions, the voltage in the area 60 kV transmission system could potentially drop as low as 40% below its nominal voltage for an outage of the Bridgeville-Garberville 60 kV Line overlapped with Kekawaka offline.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended. This alternative does not address the potential low voltage issues.

PROJECT SCHEDULE

- Environmental and Permitting Processes – None
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2011

KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – None
- Special Metering or Protection – TBD
- Common Mode Exposure Items – None
- Interaction with other Projects or Studies – TBD

GEPSLF MODELING INFORMATION

```
#***********************************************************************
# Garberville Reactive Support Project
# Description:
# This project will install a 20 MVAr Reactive Support Device at Garberville Substation.
#****************************************************************************
NEWSVD   31116,v,1,2,0.02,31116,,1,20, AREA=1, ZONE=301
#END
```

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagram
2. Demand Forecast
3. Power Flow Summary
4. Pre and Post Project Power Flow Plots

Attachment 1: Scope Diagram

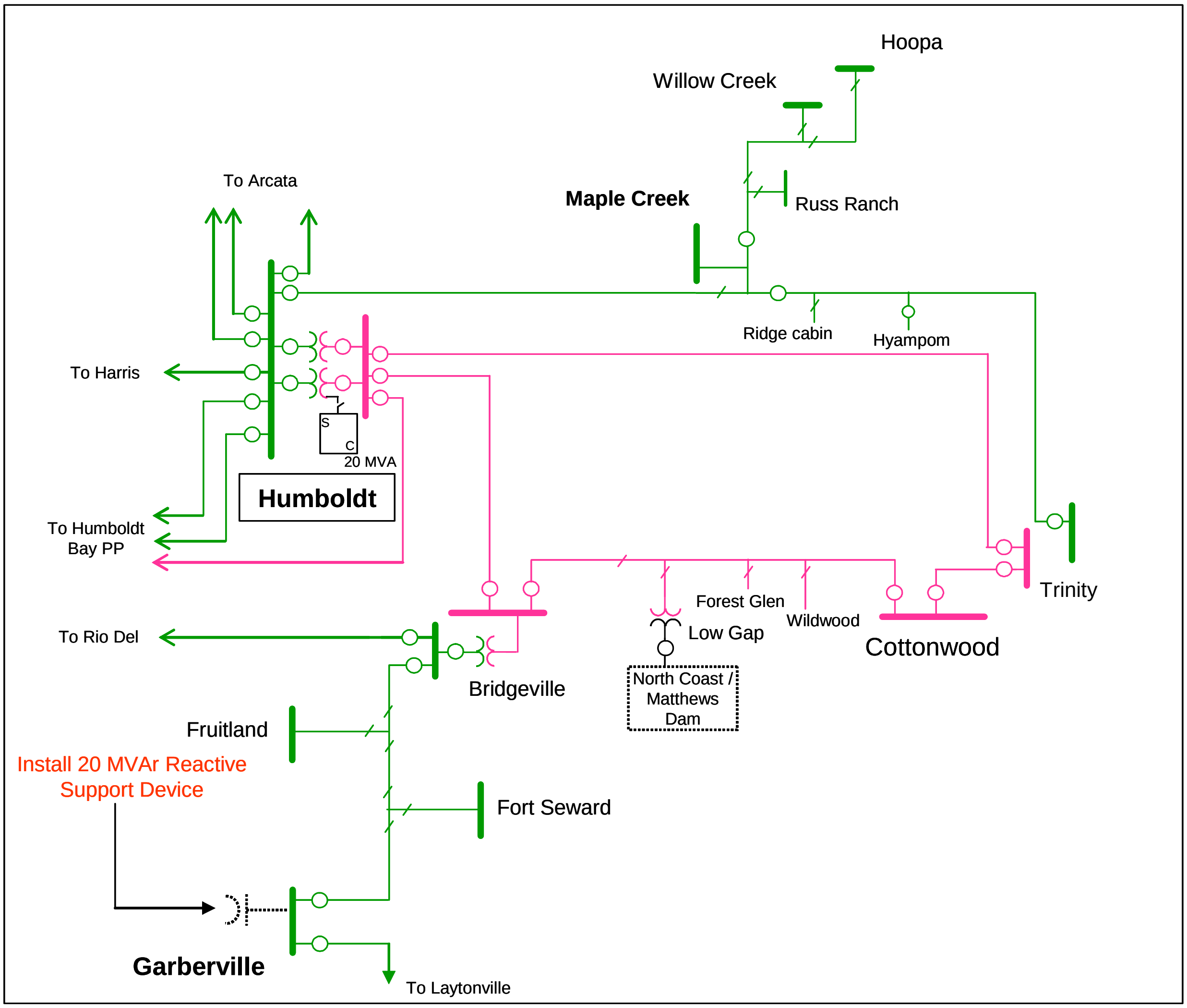


Figure 4-128: Humboldt Area Transmission System.

Attachment 2: Demand Forecast

Table 4-35: Area Demand Forecast

Substation	2009	2010	2011	2012	2013	Growth Rate (MW/Year)
Garberville	14.1	14.6	15.1	15.6	16.1	0.5
Fort Seward	0.5	0.6	0.6	0.6	0.6	0.1
Fruitland	3.4	3.5	3.6	3.8	3.9	0.1
Totals	**18.0**	**18.7**	**19.3**	**20.0**	**20.6**	**0.7**

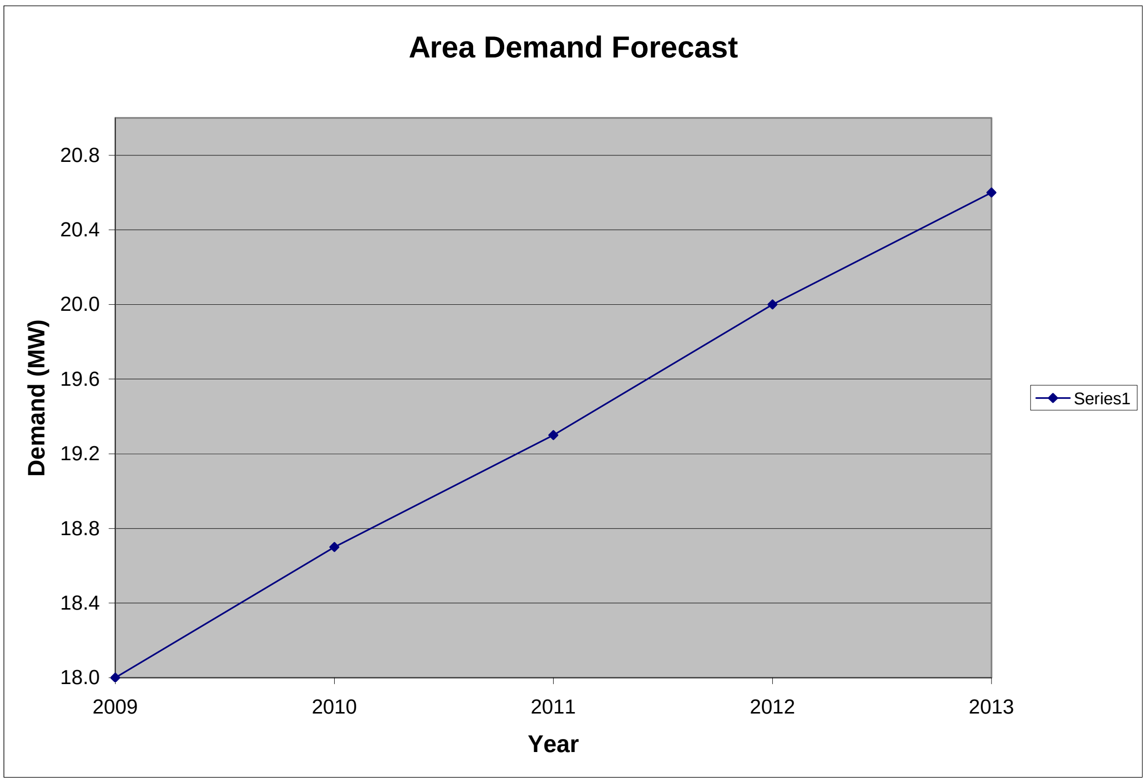


Figure 4-129: Plot of Area Forecast

Attachment 3: Power Flow Summary

Table 4-36: Power Flow Summary

Contingency	Facility Affected	2009 (Pre-Project)	2010 (Pre-Project)	2011 (Pre-Project)	2012 (Pre-Project)	2013 (Pre-Project)	2018 (Pre-Project)	2018 (Post-Project)
Bridgeville-Garberville 60 kV Line & Kekawaka offline	Garberville 60 kV voltage	0.80 p.u.	0.78 p.u.	0.73 p.u.	0.71 p.u.	0.70 p.u.	0.60 p.u.	0.98 p.u.

Attachment 4: Pre and Post Project Power Flow Plots

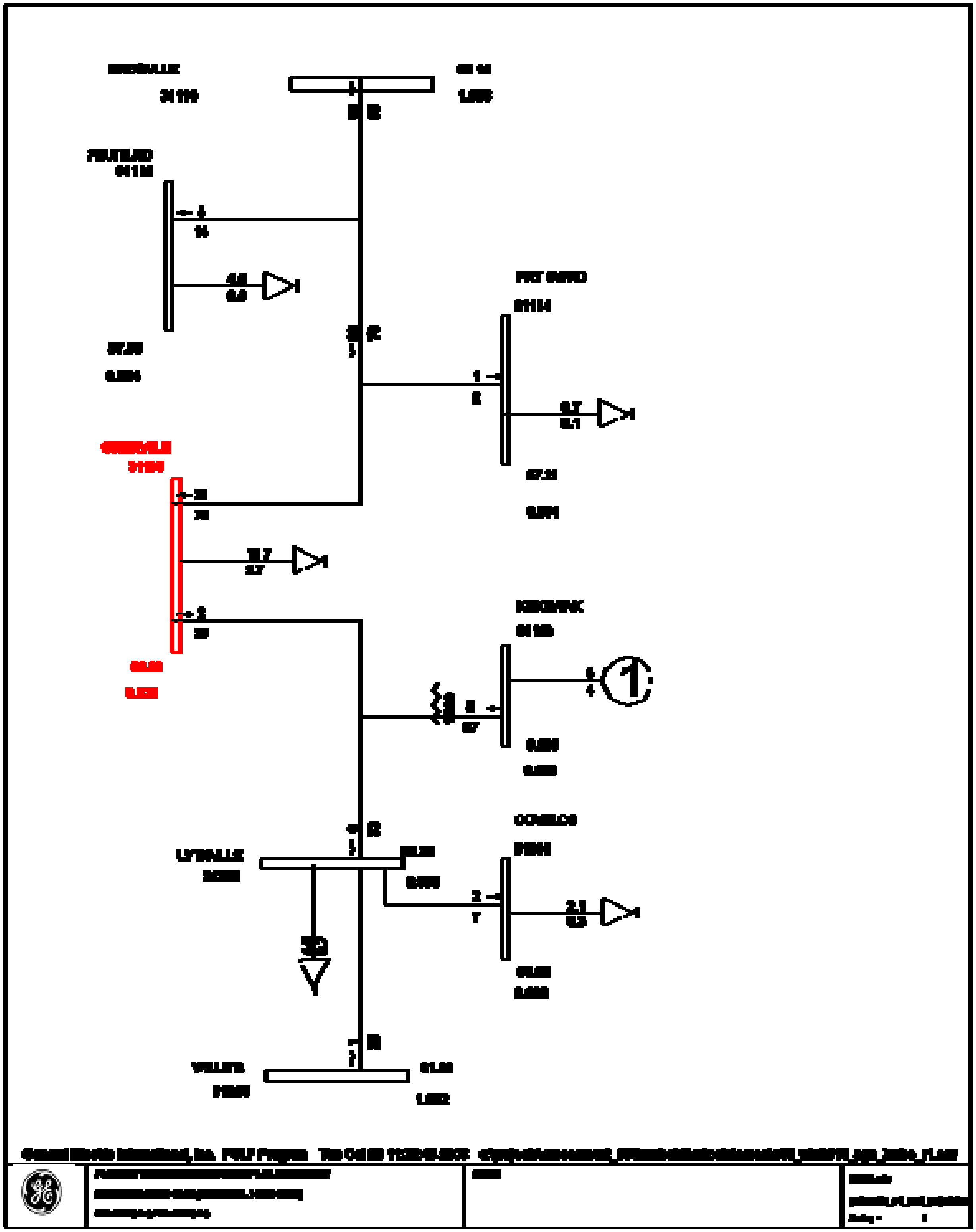


Figure 4-130: Pre Project - Normal Conditions (2018)

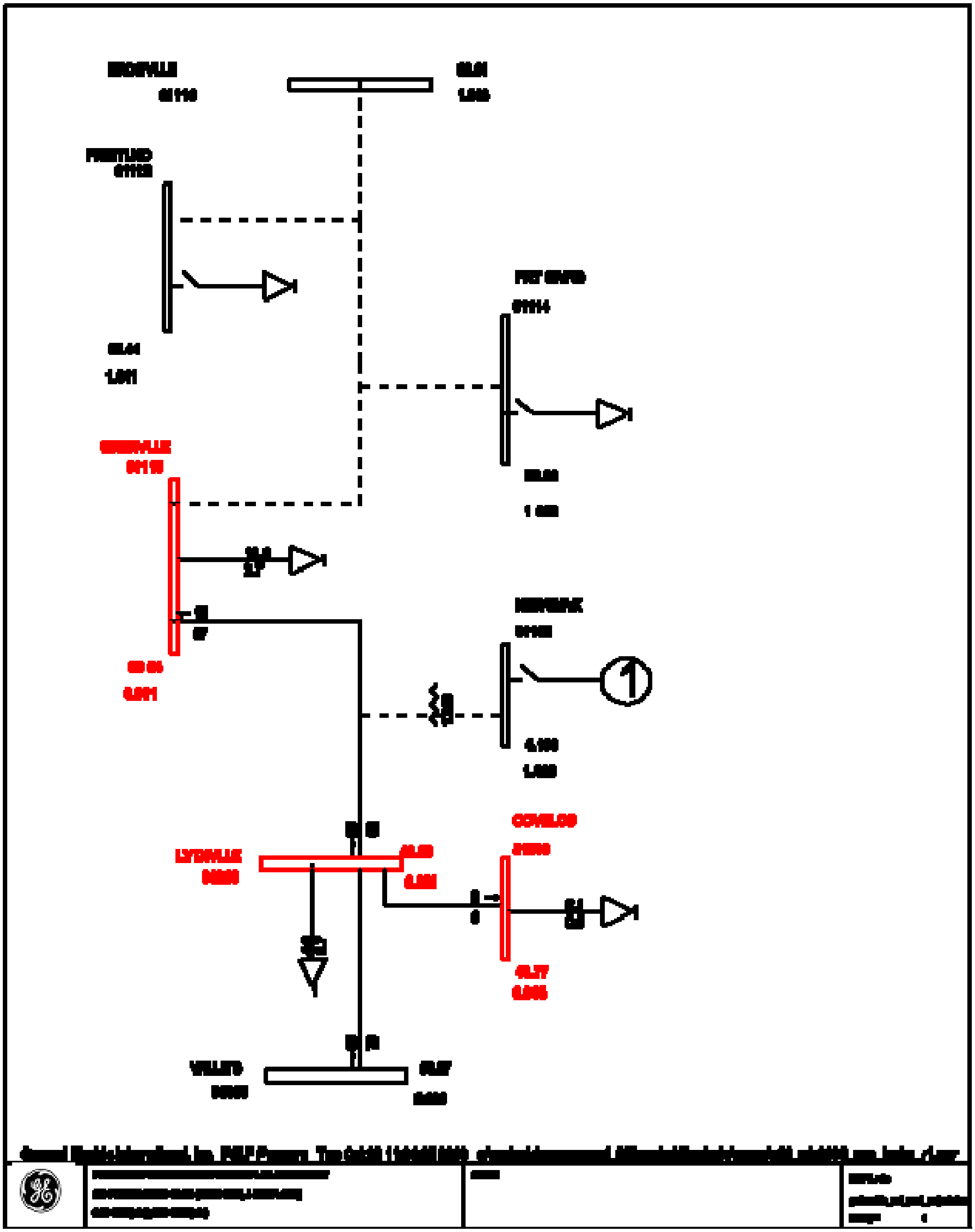


Figure 4-131: Pre Project – Loss of the Bridgeville-Garberville 60 kV Line overlapped with Kekawaka offline (L-1/G-1). (2018)

Note: Case solved by reducing load at Garberville

.

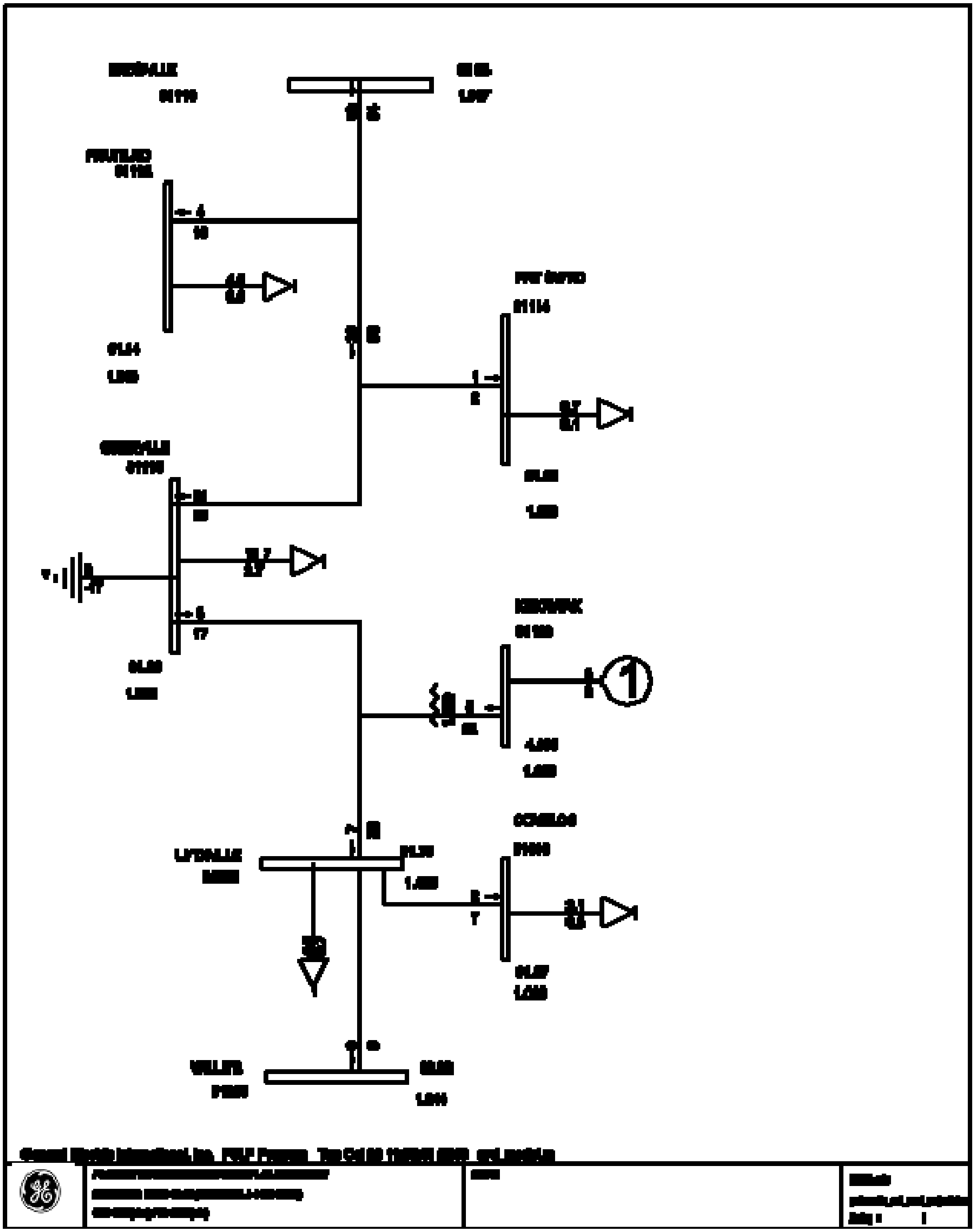


Figure 4-132: Post Project - Normal Conditions (2018)

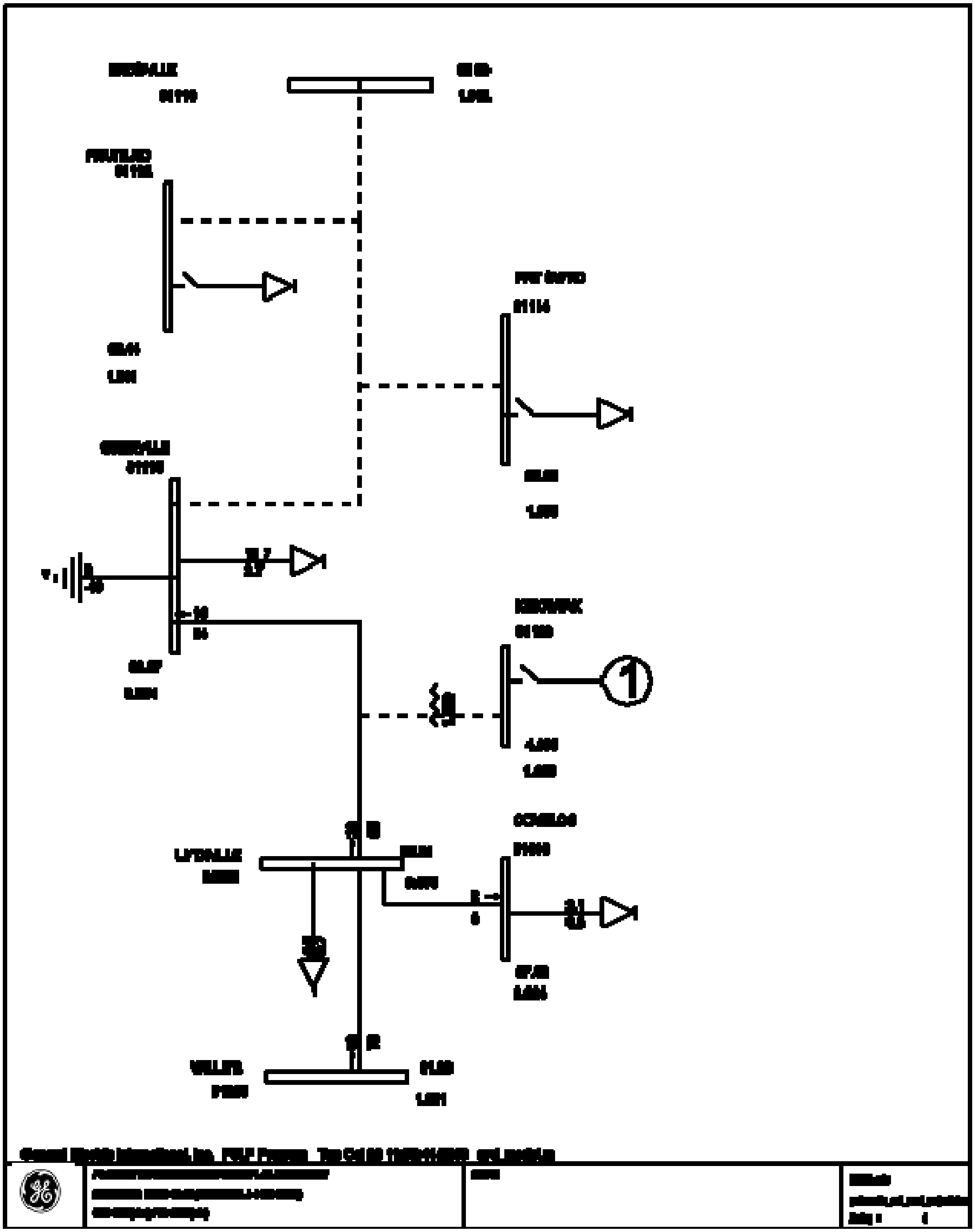


Figure 4-133: Post Project – Loss of the Bridgeville-Garberville 60 kV Line overlapped with Kekawaka offline (L-1/G-1). (2018)

Hartley 60 kV Breakers Installation

TARGETED IN-SERVICE DATE

May 2011

PURPOSE AND BENEFIT

Reliability – Operational Flexibility.

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROJECT

The project scope is to replace Hartley Substation 60 kV switches Nos. 57 and 59 with 60 kV circuit breakers that are rated to handle a minimum of 600 Amps.

This project is expected to cost between $2M and $3M.

BACKGROUND

Hartley is a distribution substation that is connected to the transmission grid via two taps off the Mendocino-Clear Lake 60 kV Line. Hartley Substation has two 60/12 kV distribution transformer banks that support the West Clear Lake distribution planning area.

Under the current arrangement at Hartley Substation, all outages on the Mendocino-Clear Lake 60 kV Line affect customers served from this substation.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO Grid Planning Criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended. It does not address a 60 kV line outage which impacts over 3,800 electric customers at Hartley Substation.

PROJECT SCHEDULE

- Environmental and Permitting Processes – None
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2011

KEY ISSUES

- Land-Use Restrictions – None
- Environmental Concerns – None
- Special Metering or Protection – None
- Common Mode Exposure Items – None
- Interaction with other Projects – None

GEPSLF MODELING INFORMATION

N/A

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagram
2. Demand Forecast

Attachment 1: Scope Diagram

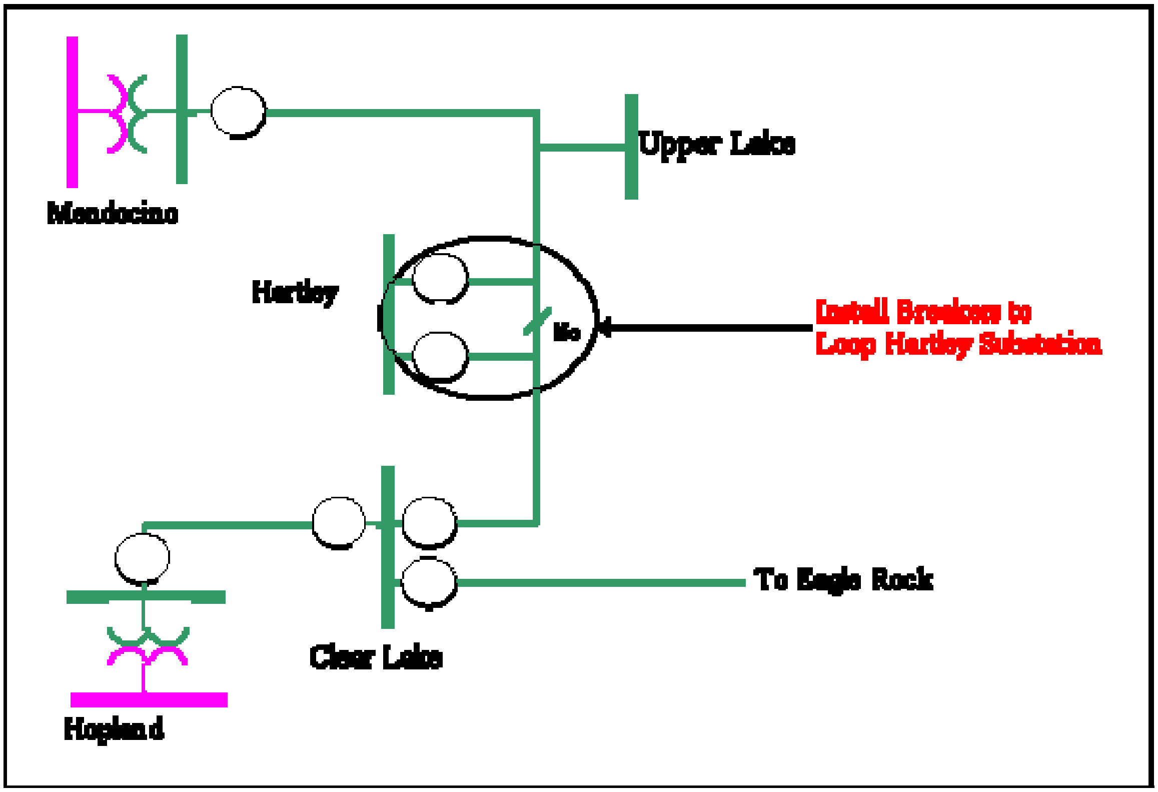


Figure 4-134: Clearlake 60 kV System

Attachment 2: Demand Forecast

Table 4-37: Area Demand Forecast

Substation	2009	2010	2011	2012	2013	Growth Rate (MW/Year)
Hartley	10.7	10.7	10.9	11.2	11.3	0.2
Upper Lake	3.5	3.6	3.6	3.7	3.7	0.1
Total	**14.2**	**14.3**	**14.5**	**14.9**	**15.0**	**0.3**

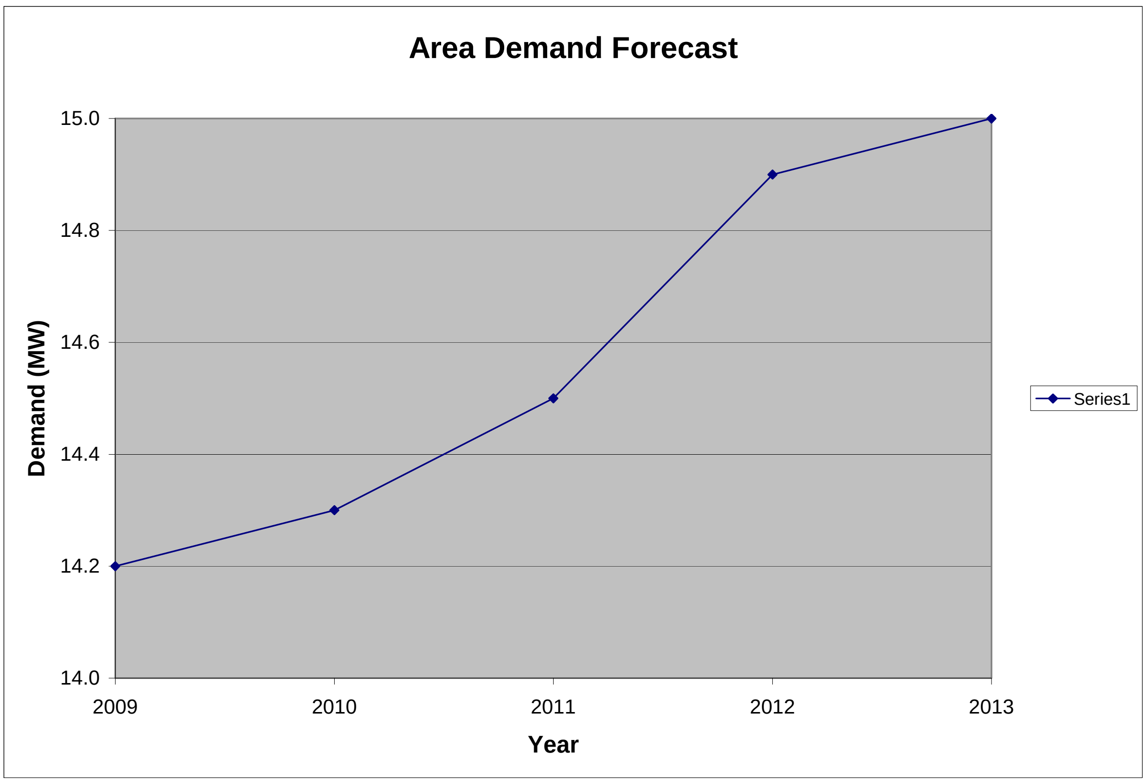


Figure 4-135: Plot of Area Forecast

Maple Creek Reactive Support

TARGETED IN-SERVICE DATE

May 2011

PURPOSE AND BENEFIT

Reliability – NERC Compliance

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROJECT

The project scope is to install a 10 MVAr reactive support device at Maple Creek Substation.

This project is expected to cost between $2M and $5M.

BACKGROUND

Maple Creek Substation is located in Humboldt County. Electric customers in this area are served by the Company's network of 60 kV transmission lines. Maple Creek Substation receives its power from both the Humboldt and Trinity sources through the Humboldt-Maple Creek and Trinity-Maple Creek 60 kV lines respectively. The local area demand (includes Maple Creek, Willow Creek and Hoopa Substations) is projected to reach about 11.5 MW in 2011 and is expected to increase at 0.2 MW per year.

Planning studies have determined that under projected winter peak conditions, the voltage in the area 60 kV transmission system could potentially drop to 30% below the nominal voltage for an outage of the Humboldt-Maple Creek 60 kV Line.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended. This alternative does not address the potential low voltage issues.

PROJECT SCHEDULE

- Environmental and Permitting Processes – None
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2011

KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – None
- Special Metering or Protection – TBD
- Common Mode Exposure Items – None
- Interaction with other Projects or Studies – None

GEPSLF MODELING INFORMATION

```
# Maple Creek Reactive Support Project
# Description:
# This project will install a 10 MVAr Reactive Support Device at Maple Creek Substation.
NEWSVD   31092,v,1,2,0.02,31092,,1,10, AREA=1, ZONE=301
#END
```

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagram
2. Demand Forecast
3. Power Flow Summary
4. Pre and Post Project Power Flow Plots

Attachment 1: Scope Diagram

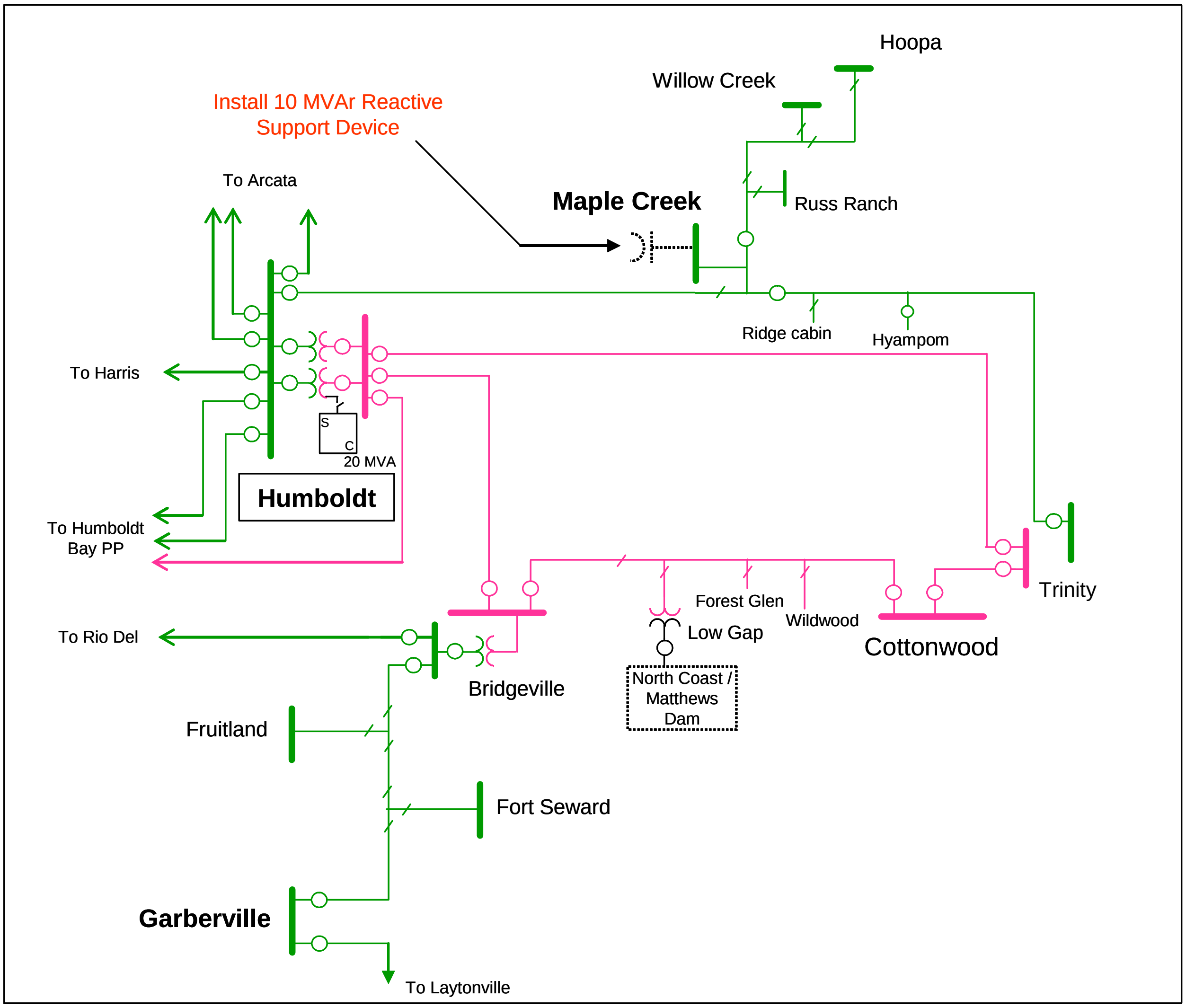


Figure 4-136: Humboldt Area Transmission System.

Attachment 2: Demand Forecast

Table 4-38: Area Demand Forecast

Substation	2009	2010	2011	2012	2013	Growth Rate (MW/Year)
Maple Creek	0.7	0.8	0.8	0.8	0.8	0.0
Willow Creek	5.6	5.7	5.8	5.9	6.0	0.1
Hoopa	4.7	4.8	4.9	4.9	5.0	0.1
Totals	**11.0**	**11.3**	**11.5**	**11.6**	**11.8**	**0.2**

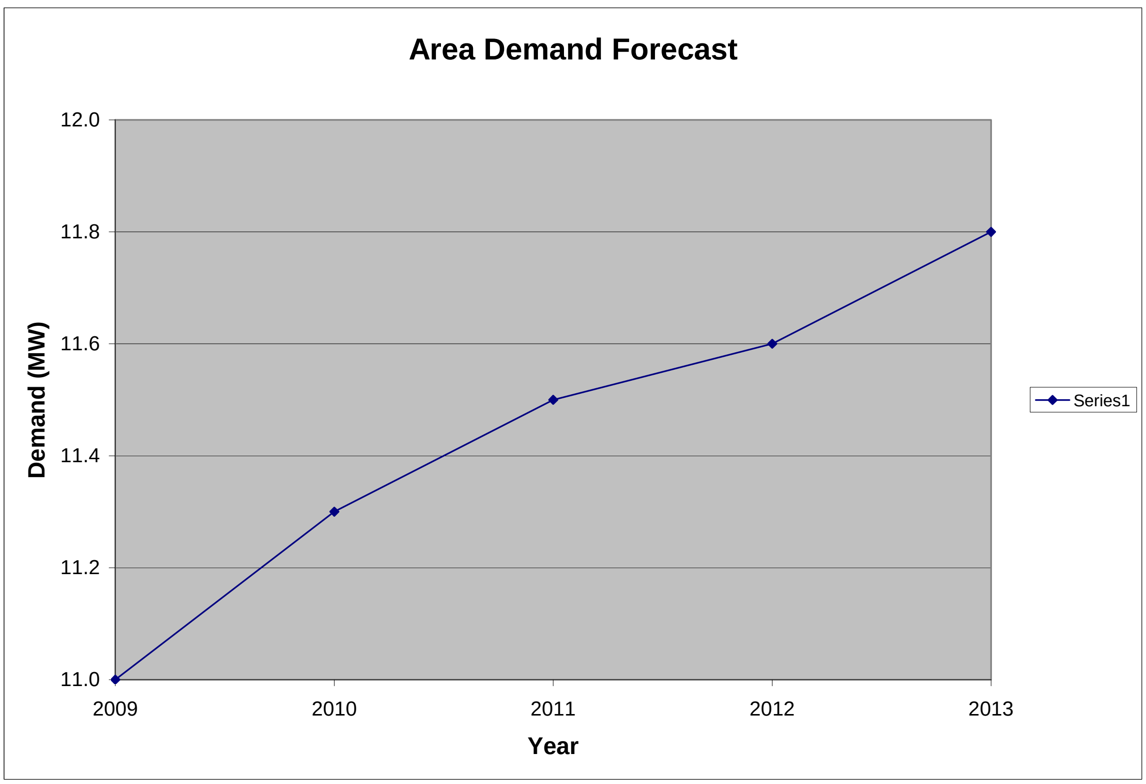


Figure 4-137: Plot of Area Forecast

Attachment 3: Power Flow Summary

Table 4-39: Power Flow Summary

Contingency	Facility Affected	2009 (Pre-Project)	2010 (Pre-Project)	2011 (Pre-Project)	2012 (Pre-Project)	2013 (Pre-Project)	2018 (Pre-Project)	2018 (Post-Project)
Humboldt-Maple Creek 60 kV Line	Maple Creek 60 kV voltage	0.85 p.u.	0.85 p.u.	0.85 p.u.	0.84 p.u.	0.83 p.u.	0.78 p.u.	1.03 p.u.
	Hoopa 60 kV Voltage	0.78 p.u.	0.78 p.u.	0.78 p.u.	0.77 p.u.	0.76 p.u.	0.70 p.u.	0.97 p.u.

Attachment 4: Pre and Post Project Power Flow Plots

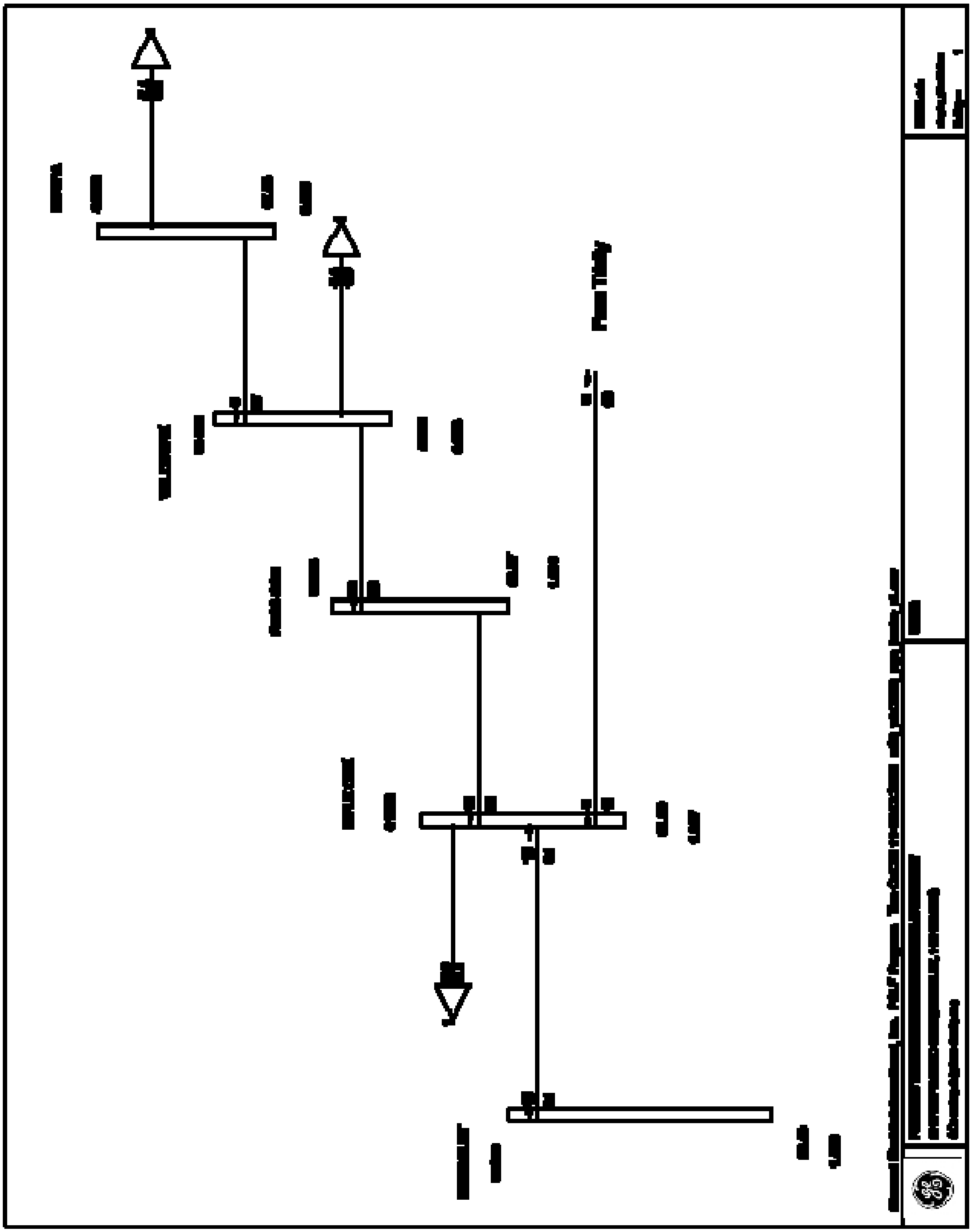


Figure 4-138: Pre Project - Normal Conditions (2018)

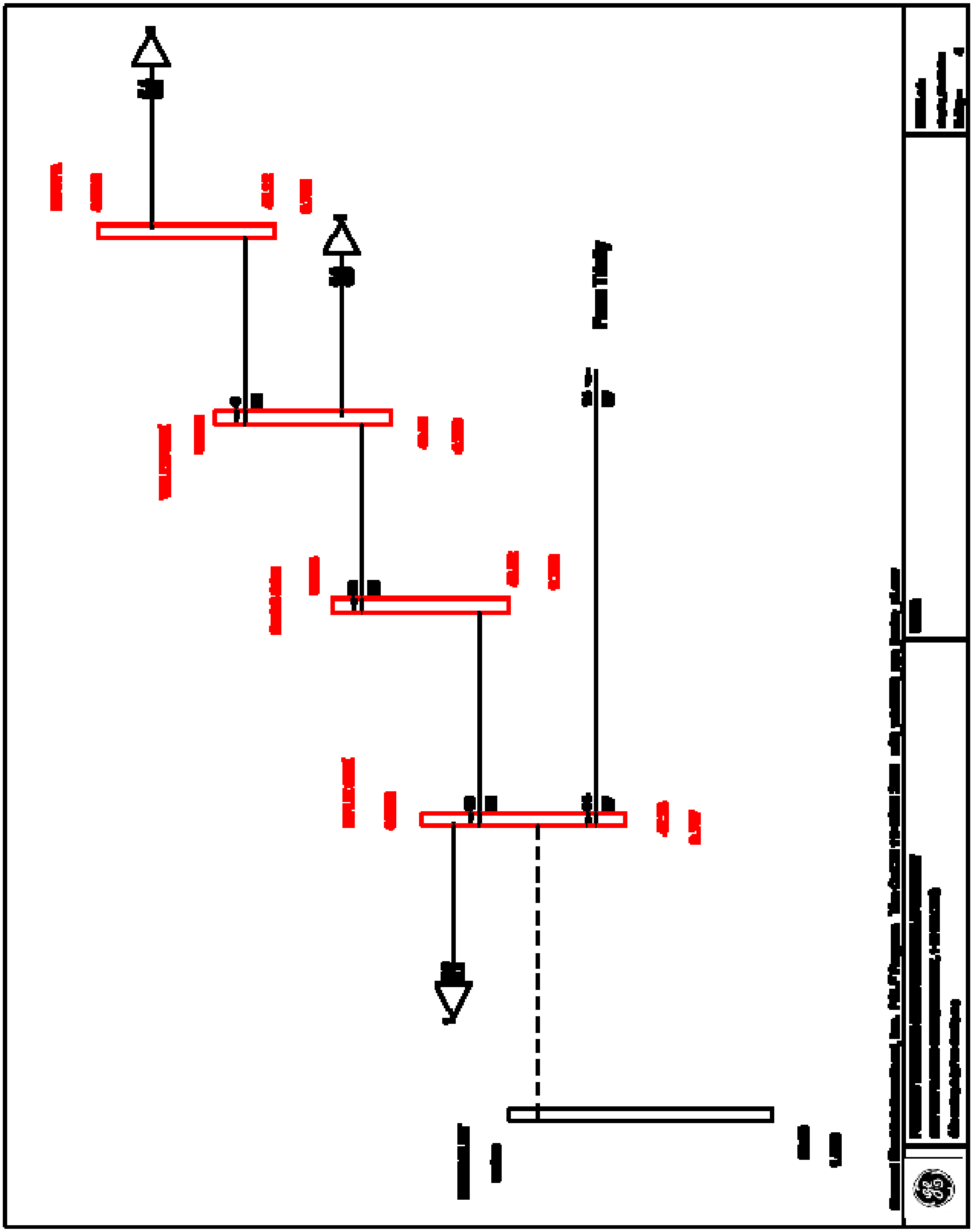


Figure 4-139: Pre Project – Loss of the Humboldt-Maple-Creek 60 kV Line (L-1). (2018)

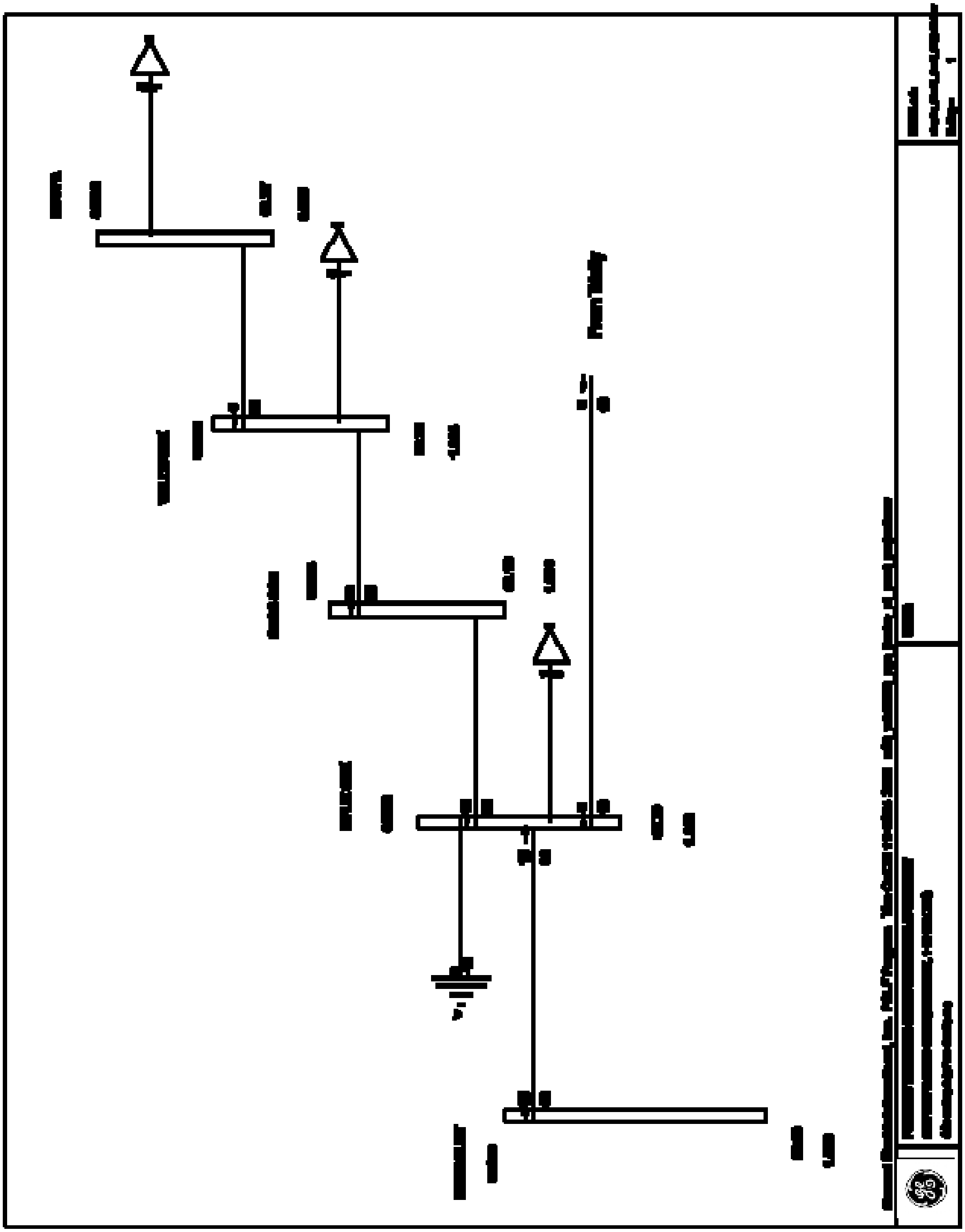


Figure 4-140: Post Project - Normal Conditions (2018)

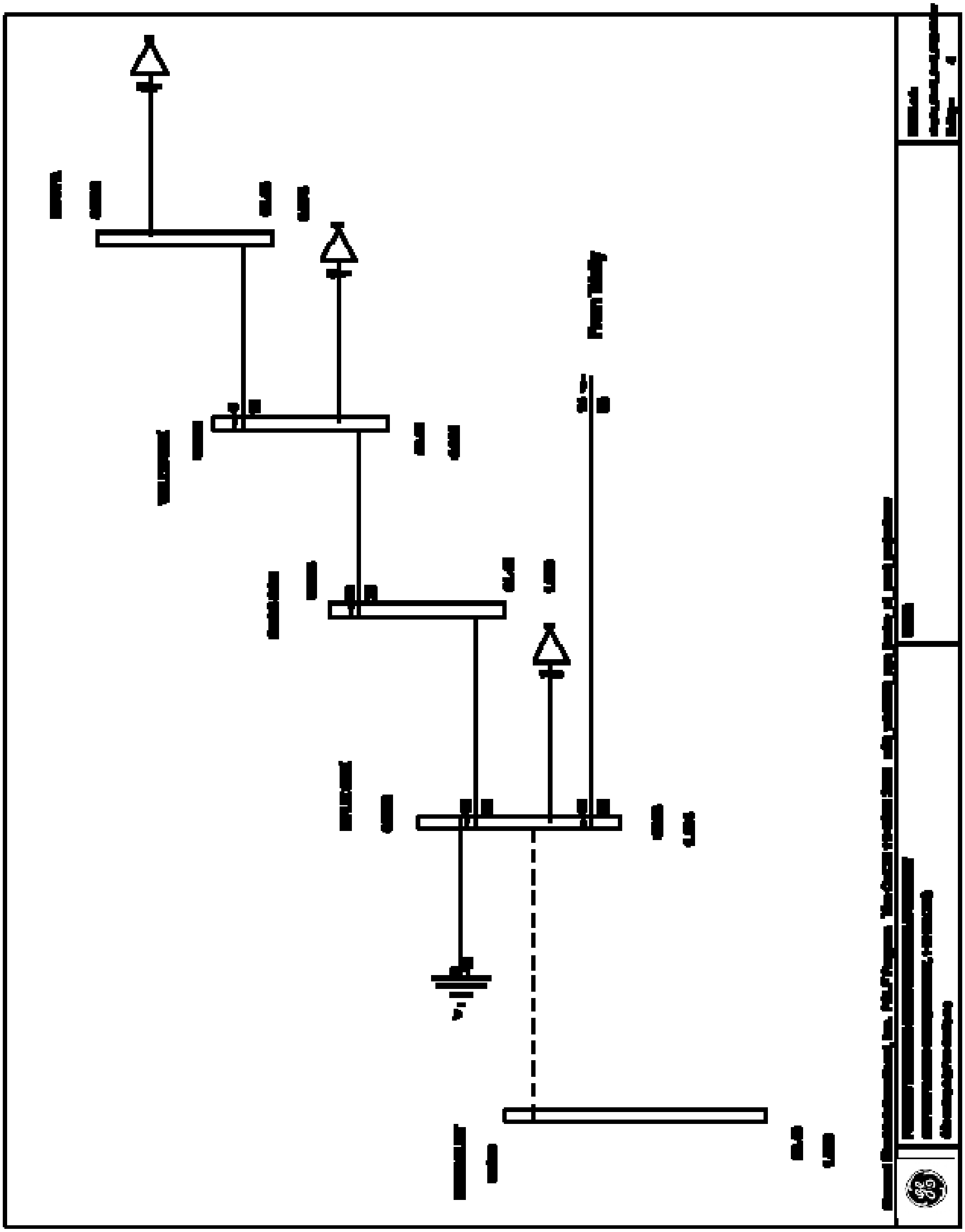


Figure 4-141: Post Project – Loss of the Humboldt-Maple Creek 60 kV Line (L-1). (2018)

Caribou 60 kV Line No. 2 Reconductor

TARGETED IN-SERVICE DATE

May 2011

PURPOSE AND BENEFIT

Reliability – NERC Compliance

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROPOSED PROJECT

The scope is to reconductor approximately 14 miles of the Caribou 60 kV Line No.2 from Caribou No.1 Power House (CB 42) to Switch 13 located near Grays Flat substation with a conductor rated to handle a minimum of 493 Amps under summer normal conditions.

The expected cost of this project is between $5M and $10M.

BACKGROUND

The Caribou 60 kV transmission system, located in PG&E's North Valley Division Area 6, serves about 4,250 electric customers in Plumas County. The Caribou 60 kV transmission system is served by two 60 kV lines: Caribou No.2 and Caribou-Plumas Jct. The Caribou 60 kV Line No.2 serves Grays Flat, Gansner, and Spanish Creek Substations. Grays Flat, Gansner, and Spanish Creek Substations have a recorded 2007 summer peak load of 4.7 MW and provide electric service to over 2,735 customers. The Caribou 60 kV Line No.2 is comprised of 42.5 miles (including all tap lines) of primarily two different sizes of conductors, 1/0 CU and 397.5 ACSR, and is constructed mainly on wooden poles. The Caribou 60 kV Line No.2 is limited by a 1/0 CU section and has a summer normal and emergency rating of 25 MVA and 29 MVA respectively.

The Caribou 60 kV Line No.2 does not have the line capability to support the clearance of the Caribou-Plumas Jct 60 kV line. In addition, the Caribou 60 kV Line No.2 does not have the line capability to support the restoration of East Quincy and Plumas-Sierra Substations under emergency conditions. This situation is aggravated when Sierra Pacific (Quincy) generation, with history of 11 outages per year, is out of service.

Based on the large customer impact of a Caribou-Plumas Jct. line outage and the limited flexibility to perform routine maintenance work, it is recommended to reconductor the approximately 14 miles long 1/0 Cu section on the Caribou 60 kV Line No.2 between Caribou No.1 PH and Switch No.13. It is recommended that the new conductor have the capability to provide 493 amps. This arrangement will provide the operating flexibility to perform routine clearance and maintenance work on the parallel Caribou-Plumas Jct Line.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended because it does not address the reliability or the capacity issue on the Caribou 60 kV Line No.2.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2011

KEY ISSUES

- Land-Use Restrictions – There are no land-use restrictions with this project.
- Environmental Concerns – TBD
- Special Metering or Protection - TBD
- Common Mode Exposure Items – None
- Interaction with other Projects or Studies – None

GEPSLF MODELING INFORMATION

#ASPEN base: RPU=0.007225 XPU=0.020790 BPU=0.000206 (397.5 ACSR)
#Caribou 60 kV Line #2, 14 miles
OLDSECDD 31690, 31676, CKT=2 SEC=1 RPU=0.10115 XPU=0.29106 BPU=0.002884 MVA1=51 MVA2=59 MVA3=74 MVA4=79

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagram
2. Customer Outage Minute Calculation
3. Demand Forecast
4. Power Flow Summary
5. Pre and Post Project Power Flow Plots

Attachment 1: Scope Diagram

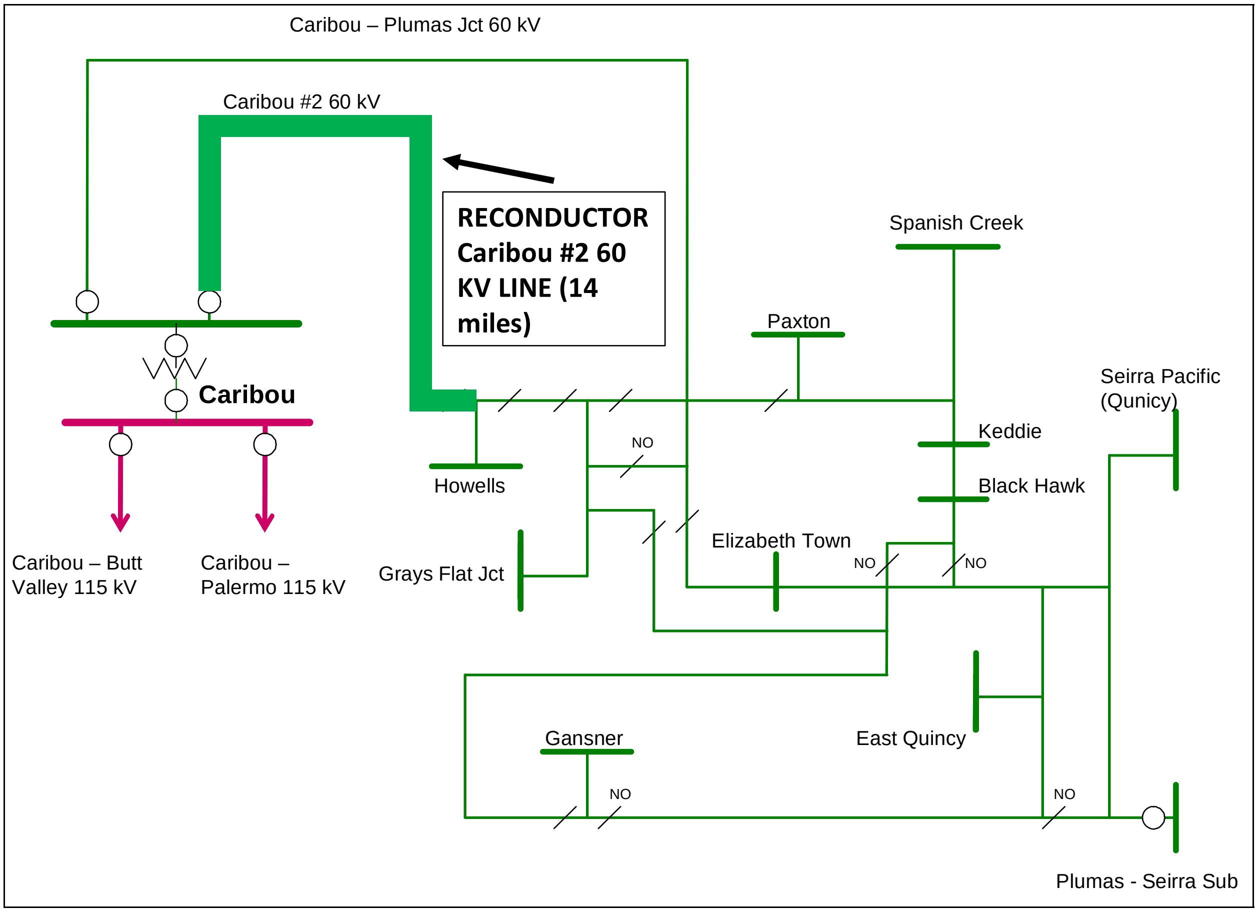


Figure 4-142: Scope Diagram

Attachment 2: Customer Outage Minutes Calculation

Table 4-40: Customer Outage Minutes for Caribou 60 kV Line No.2

Year	No of Outages	Customer Outage Minutes
2002	6	21,465
2003	10	4,766,585
2004	5	3,491,992
2005	7	141,669
2006	8	3,581,848
2007	7	2,062,726
2008	2	10,514
Total	**45**	**14,076,799**

Outages/Year - 9
Sustained Outages/Year - 3

Attachment 3: Demand Forecast

Table 4-41: Area Demand Forecast

Substation	2009	2010	2011	2012	2013	Growth Rate (MW/Year)
Gansner Bank 1	3.66	3.7	3.75	3.83	3.88	0.04
Spanish Crk Bk 1	1.2	1.22	1.24	1.26	1.28	0.02
Grays Flat Bank 1	0.12	0.12	0.12	0.12	0.12	0.00
Totals	**4.98**	**5.04**	**5.11**	**5.17**	**5.23**	**0.06**

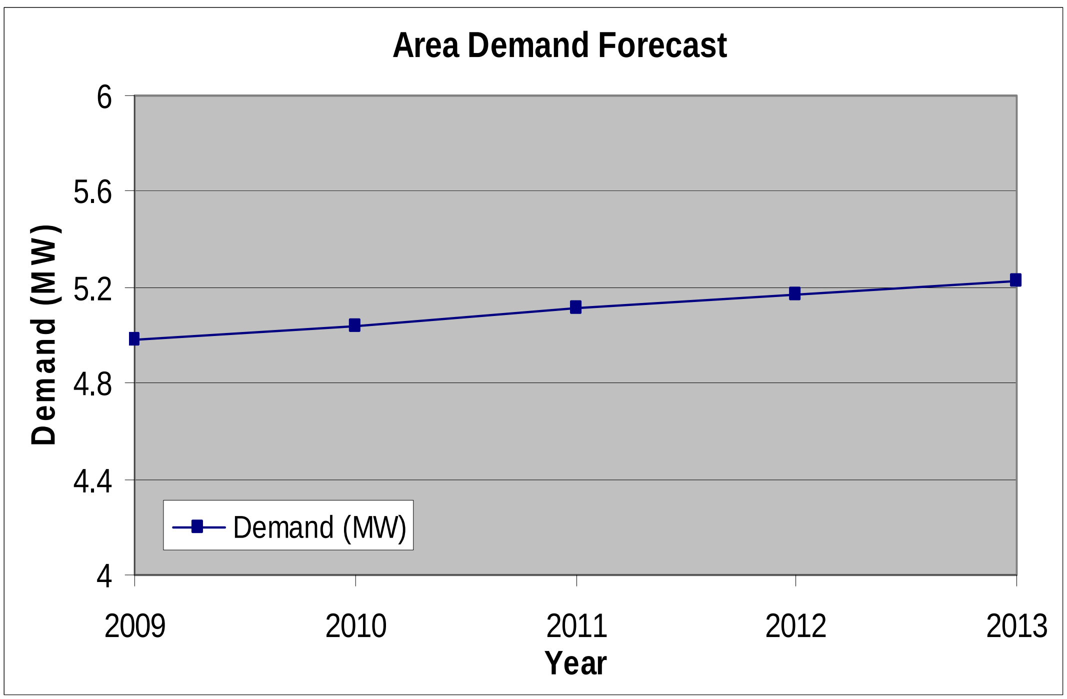


Figure 4-143: Plot of Demand Forecast

Attachment 4: Power Flow Summary

Table 4-42: Power Flow Summary

Contingency	Facility Affected	2009 (Pre-Project)	2010 (Pre-Project)	2011 (Pre-Project)	2011 (Post-Project)	2012 (Post-Project)	2013 (Post-Project)
Caribou - Plumas Jct 60 kV Line (Caribou - Grays Flat Jct Section) (L-1)	Caribou 60 kV Line No.2 (Caribou - Howells Section) (L-1)	104%	105%	111%	57%	58%	59%

Attachment 5: Pre and Post Project Power Flow Plots

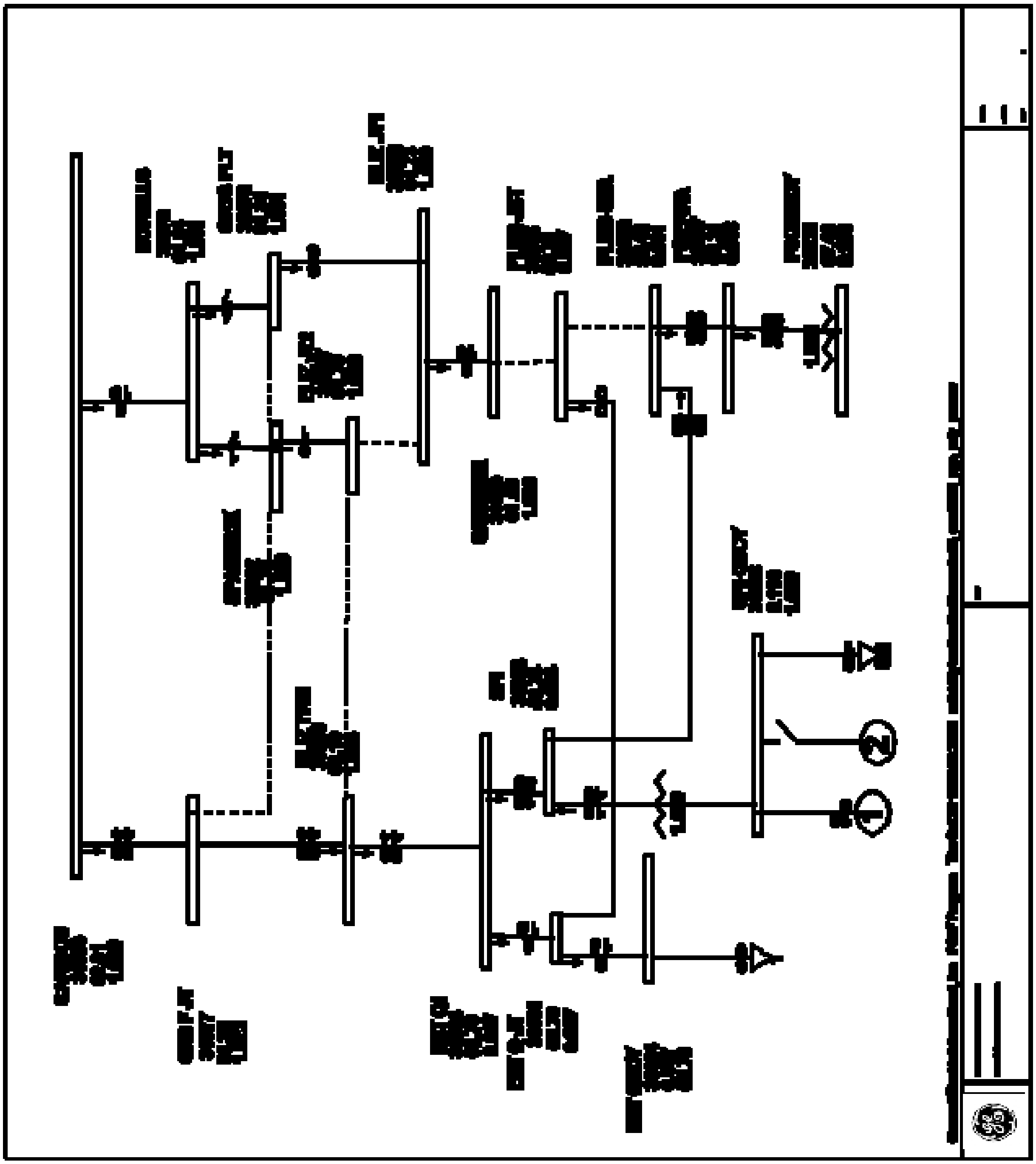


Figure 4-144: Pre Project - Normal Conditions

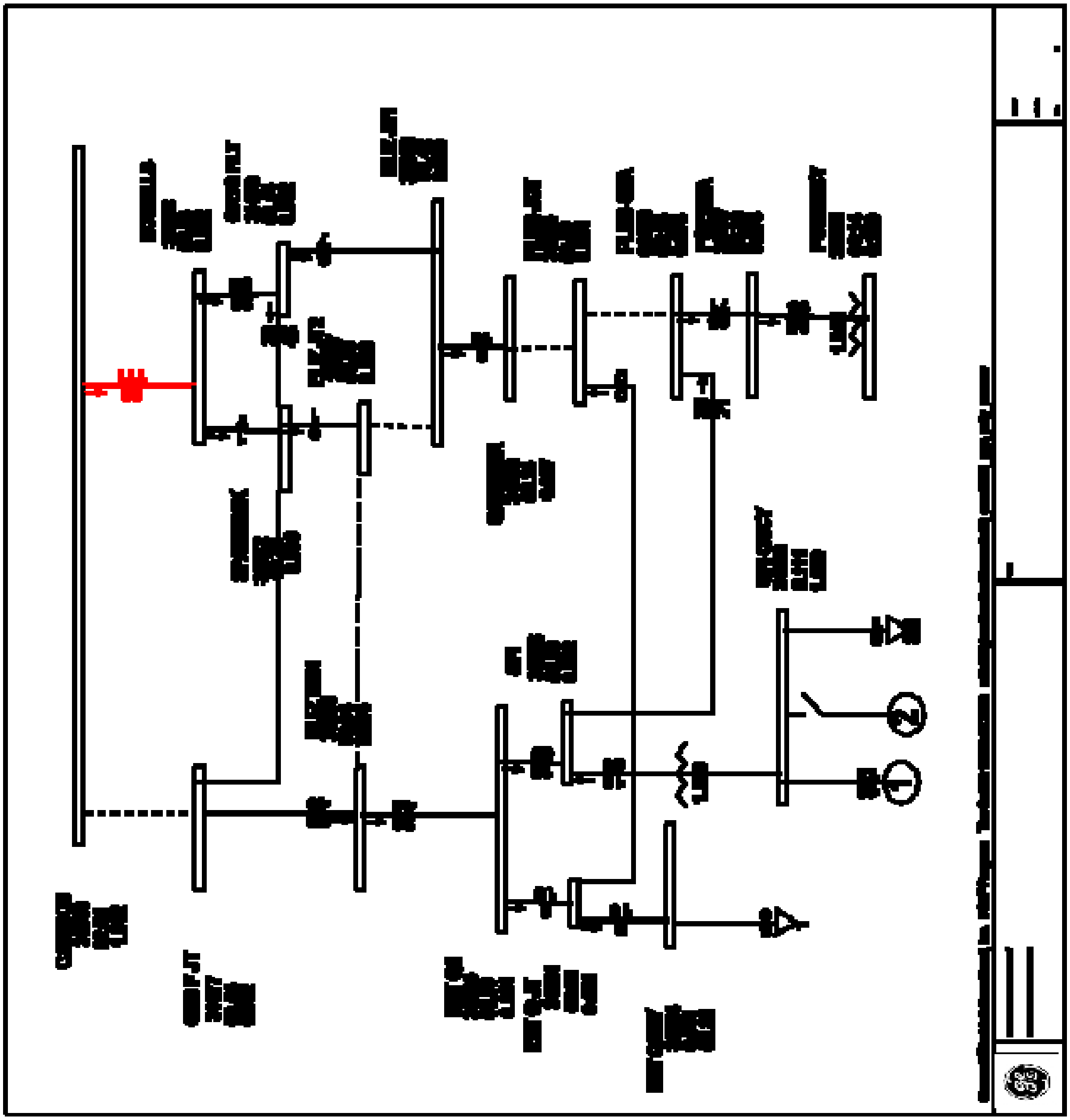


Figure 4-145: Pre Project - Loss of the Caribou - Grays Flat Jct 60 kV Line[3] (L-1)

[3] This overload is noticed only during the clearance conditions because the outage of Caribou - Grays Flat section would normally take out the entire Caribou - Plumas Jct 60 kV line. And the overload is based on the summer normal rating, assuming the emergency ratings could not be utilized.

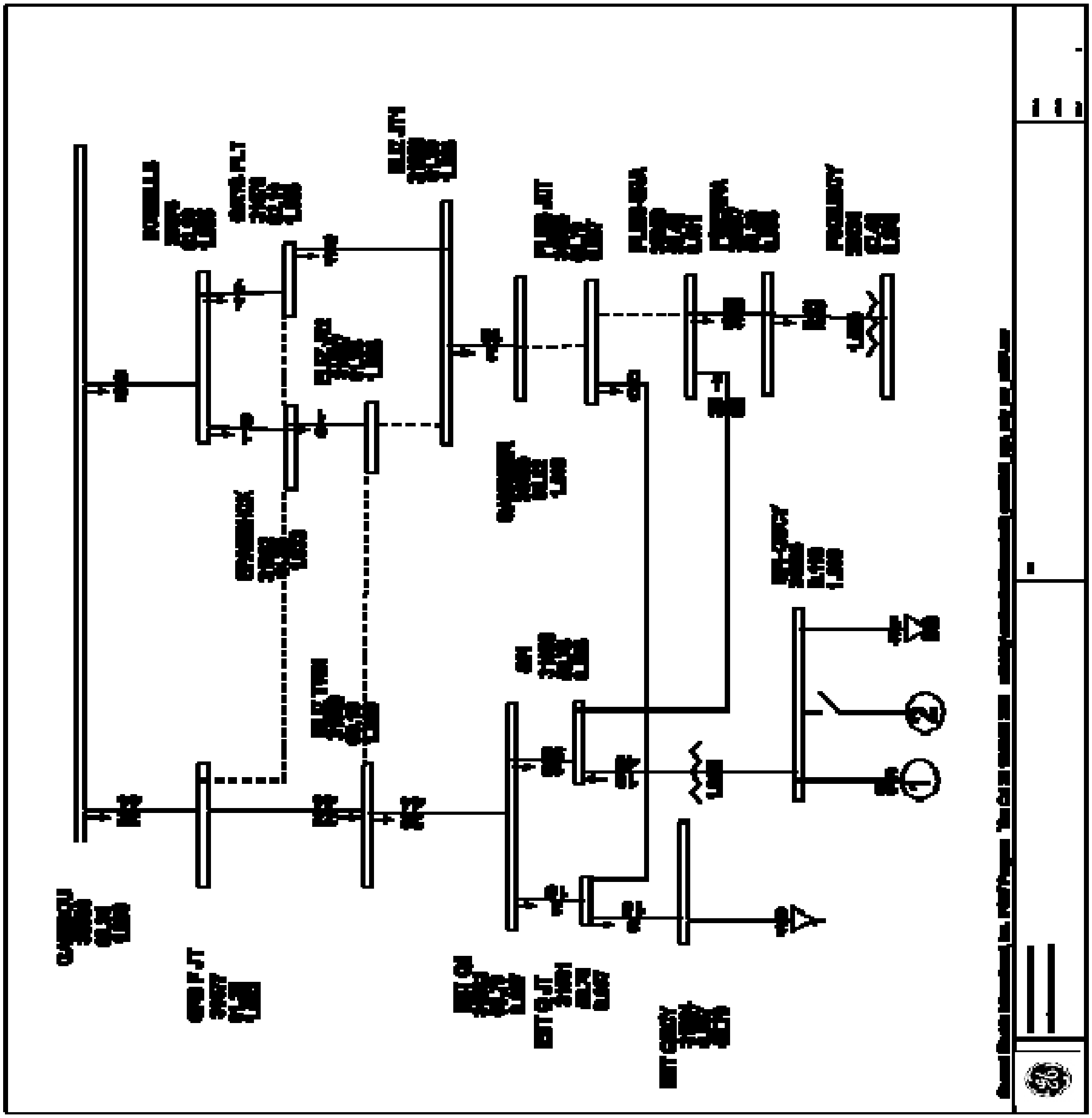


Figure 4-146: Post Project - Normal Conditions

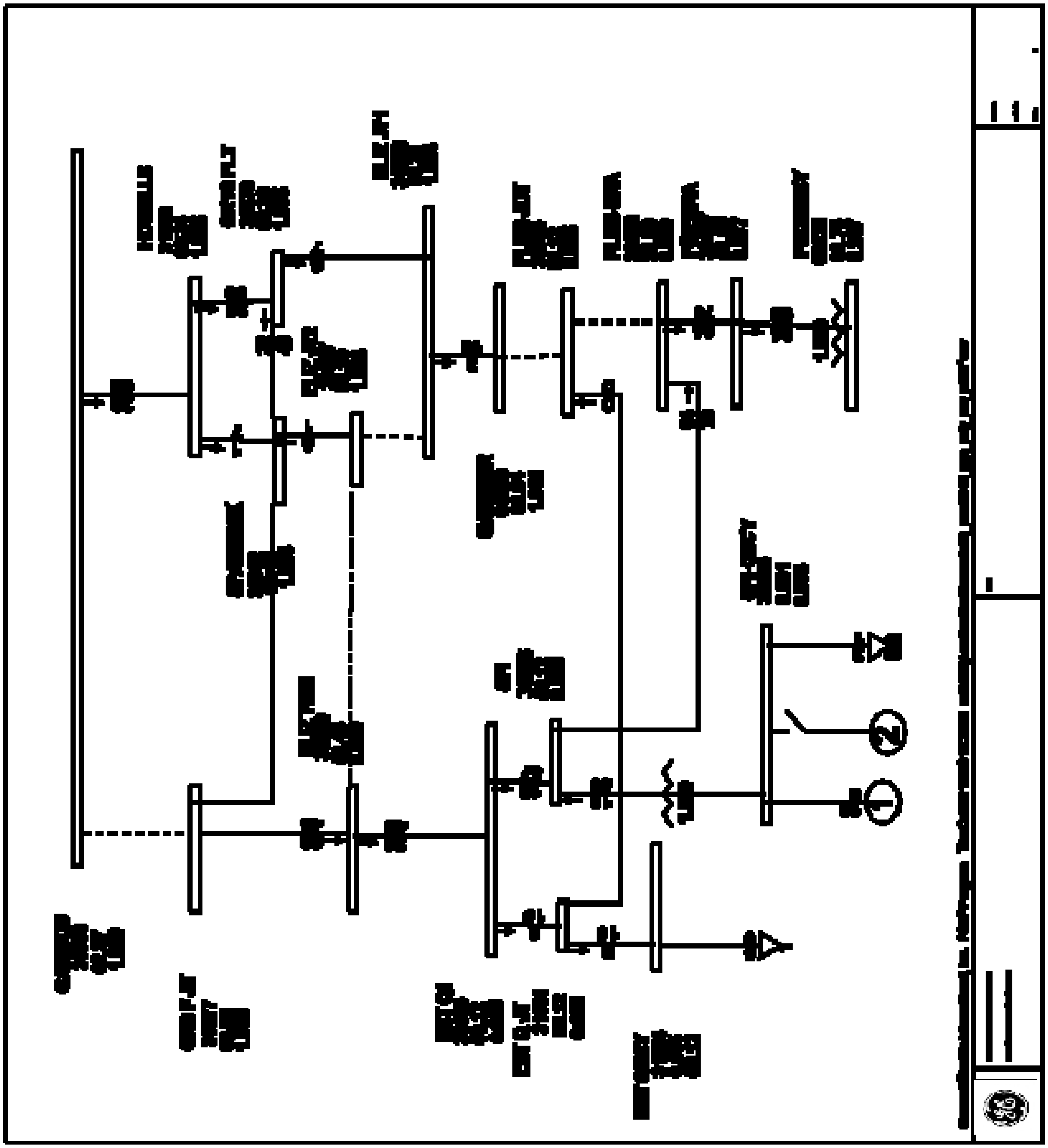


Figure 4-147: Post Project - Loss of the Caribou - Grays Flat Jct 60 kV Line (L-1)

Gold Hill – Horseshoe 115 kV Reinforcement

TARGETED IN-SERVICE DATE

May 2011

PURPOSE AND BENEFIT

Reliability – NERC Compliance

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROPOSED PROJECT

The proposed project scope is to reconductor the limiting conductors (16 miles) from Gold Hill to Horseshoe substations on both Placer – Gold Hill 115 kV Lines with conductors capable of carrying a minimum of 1,100 Amps for summer normal and emergency conditions.

The CAISO previously approved the northern portion of this project as part of the 2007 Expansion Plan process. The approved scope is to reconductor the limiting conductors (26 miles) from Placer to Horseshoe substations on both Placer – Gold Hill 115 kV Lines with conductors capable of carrying a minimum of 1,100 Amps under summer normal and emergency conditions. The expected in-service date for this work is May 2009. This is the recommended plan for the area. The plan provides the needed transmission capacity and is pertinent in reducing the area's local capacity requirements.

The project is expected to cost between $5M and $10M.

BACKGROUND

The Placer 60 kV and 115 kV transmission systems provide electric power to customers in Placer, El Dorado, and Nevada Counties. The 60 kV and 115 kV transmission systems together typically peak during the summer months. Peak demand is forecasted to grow at about 10 MW or 4% per year.

Power is imported into the Placer transmission system via two 115 kV lines from Gold Hill Substation and one 115 kV line from Drum Substation. They are the Placer – Gold

Hill Nos. 1 and 2 and Drum – Placer 115 kV Lines. The Placer transmission system is also supported by local hydro generation (Dutch Flat No. 1, Chicago Park, Wise Nos. 1 and 2, New Castle, and Halsey Powerhouses) that outputs 80 MW.

The Placer – Gold Hill 115 kV Nos. 1 and 2 Lines currently consist of 3/0 Cu and 715 Al conductors and are capable of carrying 65 MW normally and 83 MW under emergency conditions. The CAISO has approved a project to reconductor the 3/0 Cu sections of the Placer-Gold Hill 115 kV lines between Placer and Horseshoe substations with 477 ACSS conductor by May 2009, increasing the normal and emergency ratings for these sections to 1,126 Amps (224 MVA).

Planning analysis concluded that during summer peak conditions an outage of the Wise Powerhouse and the Placer – Gold Hill No. 1 115 kV Line will overload the 715 Al section of the parallel line by 2% in 2012[4].

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended because it does not address the capacity issues.

Alternative 2: Construct a third Placer – Gold Hill 115 kV Line

This alternative proposes to construct a new 115 kV line, from Placer to Gold Hill substations, with conductors capable of carrying a minimum of 1,100 Amps under summer normal and emergency conditions. The distance for this transmission line is approximately 21 miles.

The alternative is expected to cost around $30M to $50M.

Moreover, the new 115 kV line will require a specific permit from the California Public Utility Commission in order to site and construct the new transmission line. Although

[4] The planning analysis assumes that Sierra Pine is normally fed from the Placer source rather than the Atlantic area.

the allowance may be granted, PG&E may be required to construct the new transmission line a different route and location from those initially proposed resulting in a higher cost and a longer period to complete the project. Therefore, this alternative is not preferred due to its timing and higher cost.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2011

KEY ISSUES

- Land-Use Restrictions – None
- Environmental Concerns – TBD
- Special Metering or Protection - TBD
- Common Mode Exposure Items – None
- Interaction with other Projects or Studies – None

GEPSLF MODELING INFORMATION

```
# Reconductor Horseshoe-Gold Hill Nos. 1 & 2 115 kV Lines from 715 Al to 477 ACSS conductor
# Summer MVA1=Normal, MVA2=Summer Emergency MVA3=Winter Normal MVA4=Winter Emergency
# Circuit                    Fr Bus To Bus Conductor Distance  MVA1   MVA2   MVA3   MVA4
# -------------------------------- ------ ------ --------- -------- ------ ------ ------ ------
# Horseshoe Tap #1-Gold Hill        32018  32229  477 SSAC   8.3 mi  224.3  224.3  244.8  244.8
# Horseshoe Tap #2-Gold Hill        32018  32231  477 SSAC   8.3 mi  224.3  224.3  244.8  244.8
#-----------------------------------------------------------------------------------------
# OLDSECDD  "FBUS=",   "TOBUS=",   "CKT=1", SEC=1, RPU=,   XPU=,   BPU=,   MVA1=,   MVA2=,   MVA3=,
MVA4=
#
#Re-conductor the Placer-Gold Hill No. 1 115 kV Line between Horseshoe and Gold Hill (8 miles total) to 477 SSAC
  OLDSECDD  "HORSHE1  115" "GOLDHILL 115" CKT=1,  SEC=1, RPU=0.0130, XPU=0.0465, BPU=0.0064, MVA1=224.3
MVA2=224.3  MVA3=244.8  MVA4=244.8
#
#Re-conductor the Placer-Gold Hill No. 2 115 kV Line between Horseshoe and Gold Hill (8 miles total) to 477 SSAC
  OLDSECDD  "HORSHE2  115" "GOLDHILL 115" CKT=2,  SEC=1, RPU=0.0130, XPU=0.0465, BPU=0.0064, MVA1=224.3
MVA2=224.3  MVA3=244.8  MVA4=244.8
```

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagram
2. Demand Forecast
3. Generation Dispatch
4. Power Flow Summary
5. Pre and Post Project Power Flow Plots

Attachment 1: Scope Diagrams

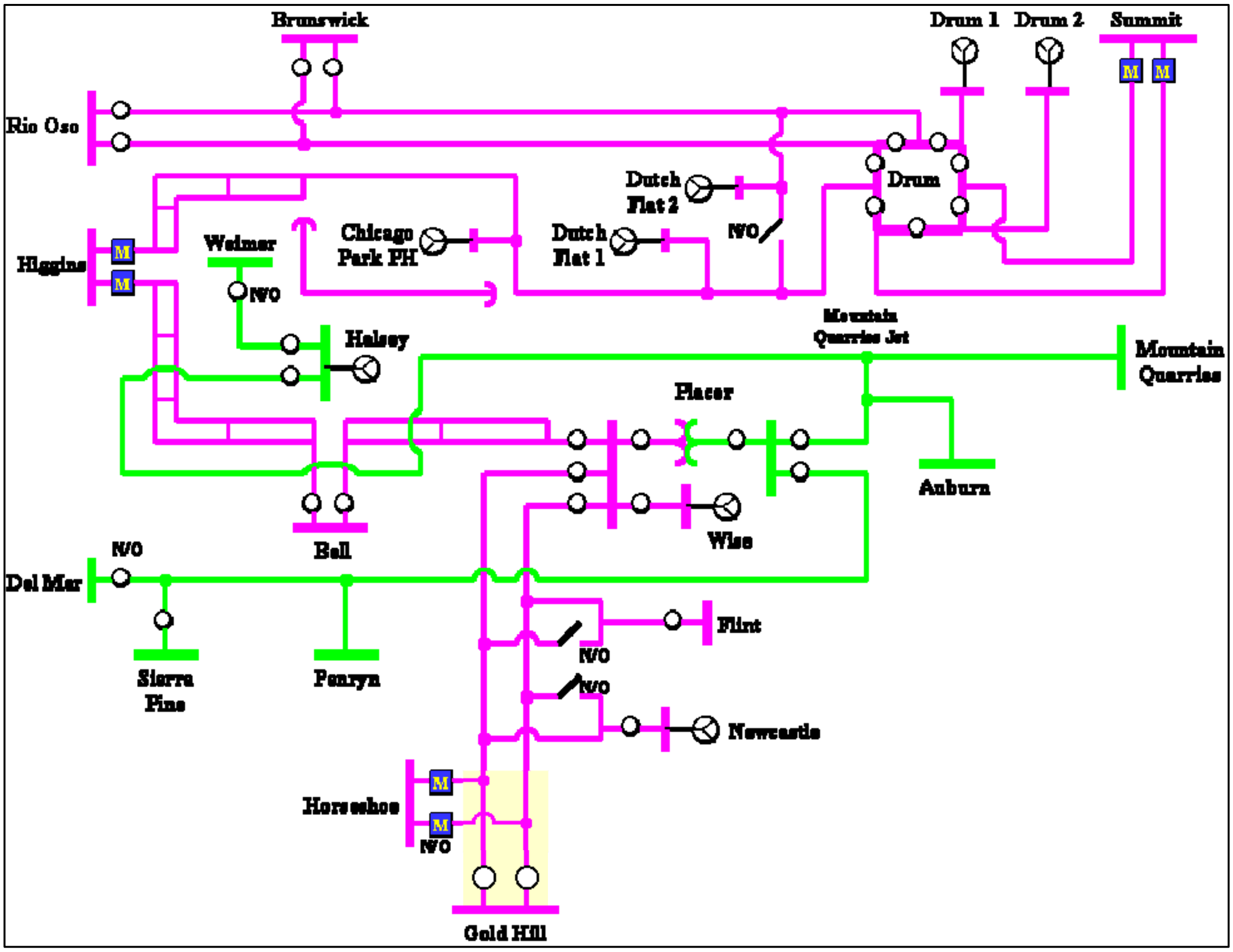


Figure 4-148: Scope Diagram

Attachment 2: Demand Forecast

Table 4-43: Placer System Area Load (2008 Assessment)

Area	2009	2010	2011	2012	2013	Growth Rate (MW/Year)
Placer System	285	290	298	304	311	6.5

Note: The Placer system area load is summed up by adding the Placer internal generation, located in attachment 3, and the line flows on following transmission lines:

- Placer – Gold Hill Nos. 1 and 2 115 kV Lines
- Drum – Bell 115 kV Line

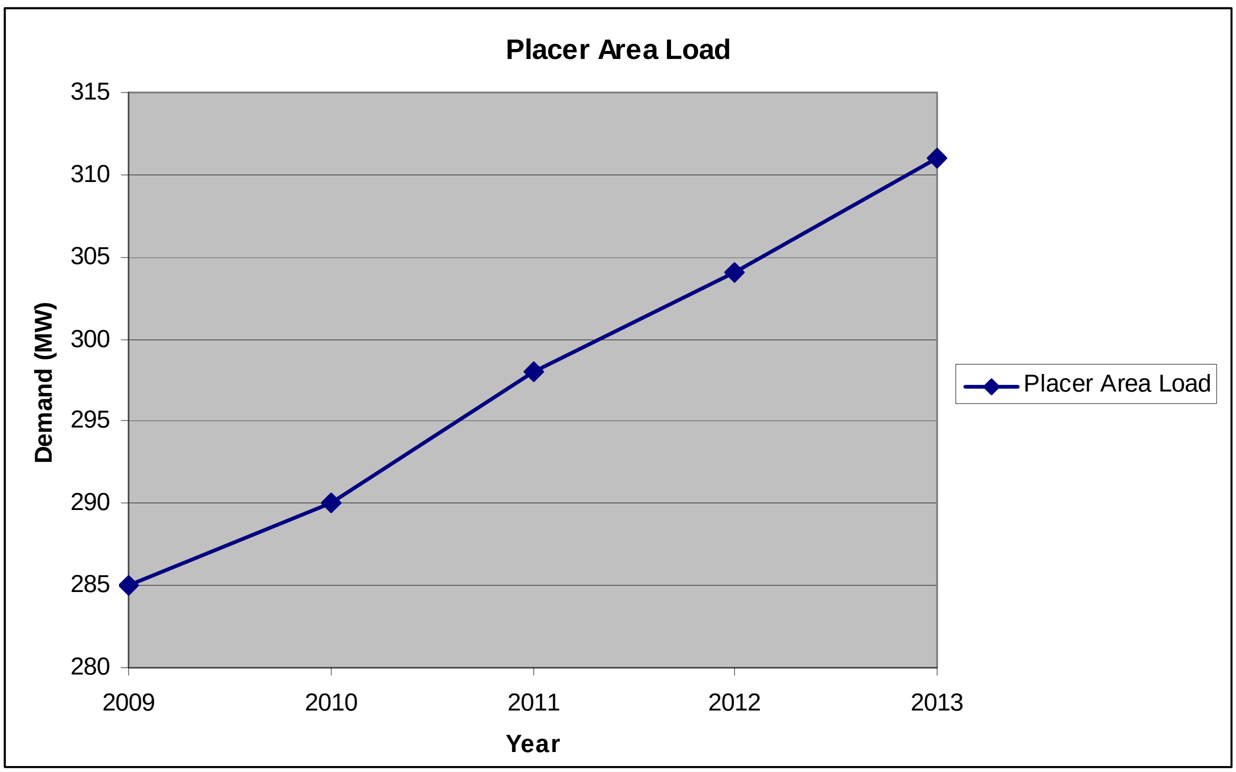


Figure 4-149: Placer System Area Load

Attachment 3: Generation Dispatch

Table 4-44: Placer System Internal Generation

No.	Generation Facility	Generation Type	Generation	
			Dispatch	Rated
1	Chicago Park	Hydro	38	40
2	Dutch Flat No. 1	Hydro	22	23
3	Halsey	Hydro	9	11
4	Newcastle	Hydro	0	14
5	Wise	Hydro	11	20
Total Placer System Internal Generation			**80**	**108**

Attachment 4: Power Flow Summary

Table 4-45: Power Flow Summary (2008 Assessment)

Contingency	Facility Affected	2009 (Pre-Project)	2010 (Pre-Project)	2011 (Pre-Project)	2012 (Pre-Project)	2012 (Post-Project)
Placer - Gold Hill 115 kV No. 1 Line/Wise Gen (L-1/G-1)	Placer - Gold Hill 115 kV No. 2 Line	93%	99%	98%	102%	67%
Placer - Gold Hill 115 kV No. 2 Line/Chicago Park Gen (L-1/G-1)	Placer - Gold Hill 115 kV No. 1 Line	100%	105%	104%	108%	71%

Attachment 5: Pre and Post Project Power Flow Plots

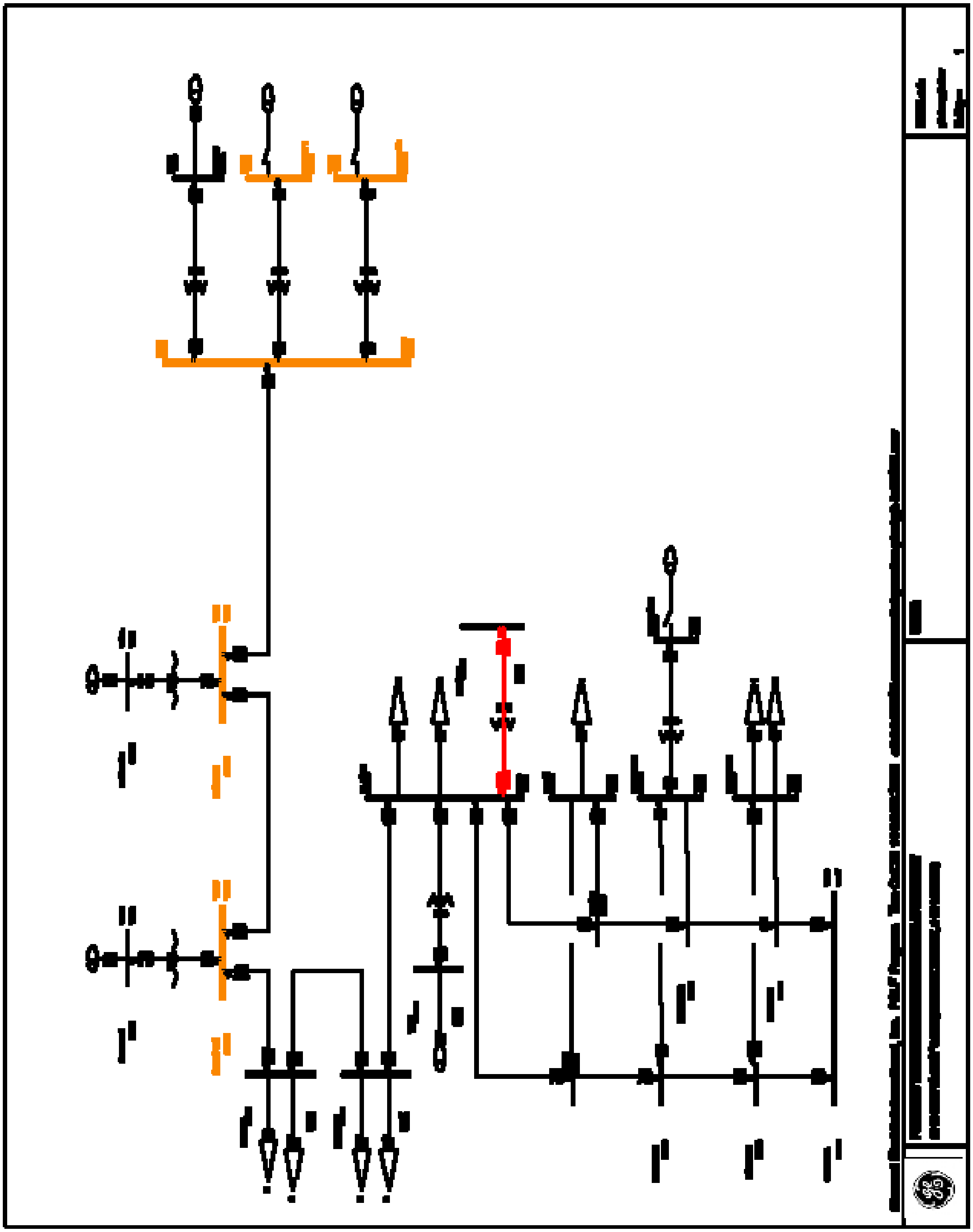


Figure 4-150: Pre Project – Normal Conditions

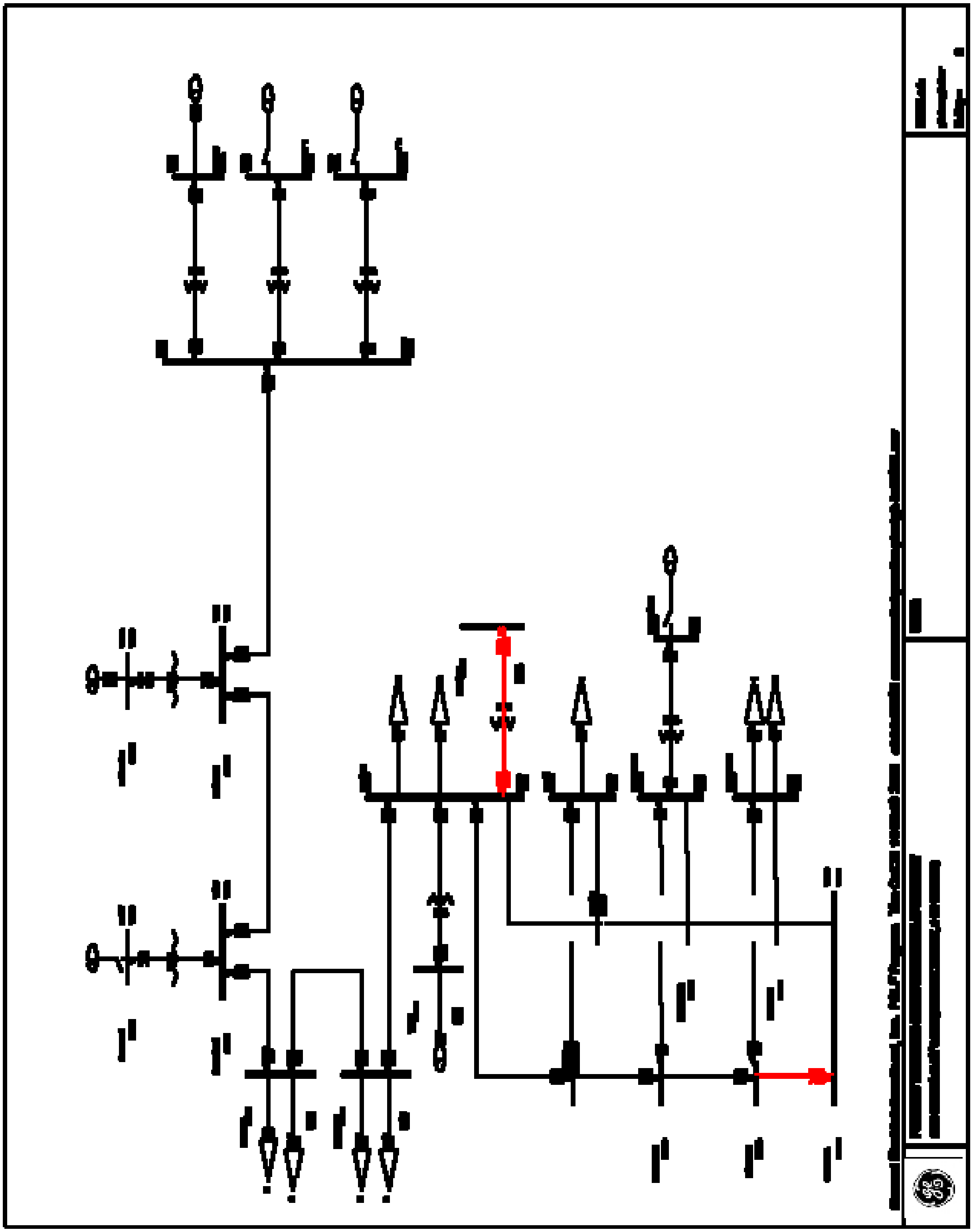


Figure 4-151: Pre Project – Loss of the Placer - Gold Hill 115 kV No. 2 Line overlapped with the Chicago Park Gen (L-1/G-1)

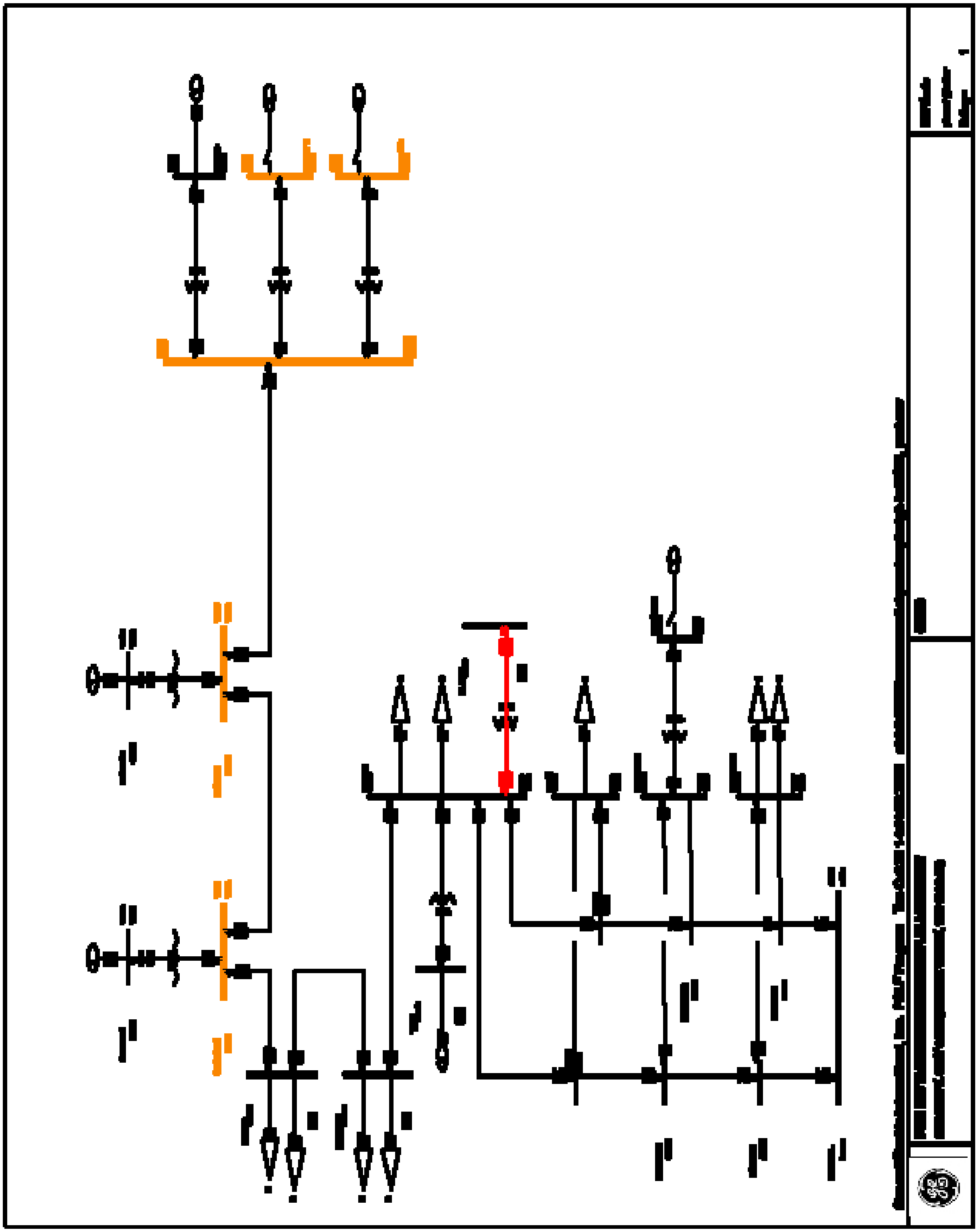


Figure 4-152: Post Project - Normal Conditions

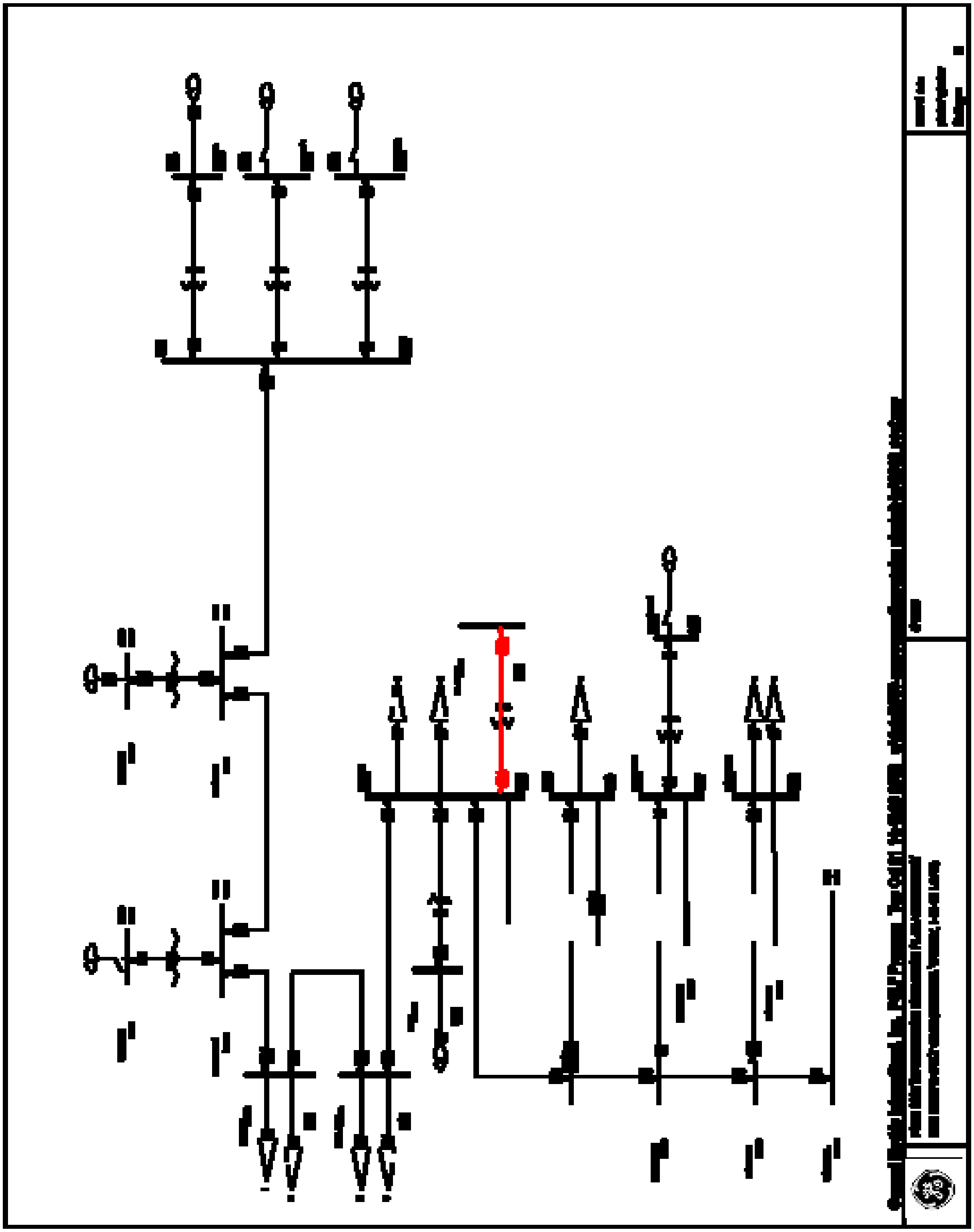


Figure 4-153: Post Project – Loss of the Placer - Gold Hill 115 kV No. 2 Line overlapped with the Chicago Park Gen (L-1/G-1)

Guernsey – Henrietta 70 kV Line Reconductor

IN-SERVICE DATE

May 2011

PURPOSE AND BENEFIT

Reliability – NERC Compliance

PROJECT CLASSIFICATION

This is a new project

DESCRIPTION AND SCOPE OF PROPOSED PROJECT

The project scope is to reconductor a three mile limiting section of the Guernsey-Henrietta 70 kV Line with a conductor capable of carrying a minimum capacity of 900 Amps under summer emergency conditions. Associated line terminal equipment will be upgraded, if necessary. The scope also includes obtaining any necessary environmental and land permits.

This project is expected to cost between $1M and $5M.

BACKGROUND

The Guernsey-Henrietta 70 kV Line provides radial service to Jacobs Corner, Guernsey, and Reserve Oil substations. It also provides service for GWF Hanford generation. Jacobs Corner Substation is comprised of two 70/12 kV transformer banks and is electrically connected to the Guernsey-Henrietta 70 kV Line via a double tap connection. Guernsey Substation is comprised of two 70/12 kV transformer banks and is electrically connected to the Guernsey-Henrietta 70 kV Line via a single tap connection. The Corcoran-Guernsey 70 kV Line serves as a back-tie to Guernsey Substation. The Guernsey-Henrietta 70 kV Line continues north from Guernsey Substation to Armstrong Switching Station. Both Reserve Oil Substation and GWF Hanford generation are electrically connected to Armstrong Switching Station. The Kingsburg-Lemoore 70 kV Line serves as a back-tie to Armstrong Switching Station. The Guernsey-Henrietta 70 kV Line primarily supports agricultural pumping loads. The line also provides electric service to the communities of Stratford and Hanford. The total peak demand for this area is expected to grow at a rate of just over 1% per year. A 4 ft/sec re-rate was granted for the Guernsey-Henrietta 70 kV Line in 2004.

Planning studies for 2013 summer peak conditions have concluded that with GWF Hanford generation offline, the Guernsey-Henrietta 70 kV Line could overload by 3%. This overload is projected to occur on the 3-mile segment of 266 Aluminum conductor between Henrietta and Jacobs Corner substations.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO. A new 70/12 kV 12 MVA distribution bank was installed at Guernsey Substation on January 2008. The additional distribution bank capacity was to support the high volume of processed applications by agriculture customers to convert their diesel pumps to electrical pumps. Guernsey Bank 2 was added to the load demand forecast to account for this new agriculture pumping load. In addition, the new pump interconnections utilize time-of-day metering. As a result, real time data has shown that new pumping loads typically operate during non-peak conditions and outside of the 4 ft/sec line re-rate window. Because of the reduced load diversity between peak and off-peak conditions, this study assumes a 2 ft/sec normal rating for the Guernsey-Henrietta 70 kV line.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended because it does not address the potential overload on the Guernsey-Henrietta 70 kV Line.

Alternative 2: Build a new 70 kV transmission line from Henrietta to Jacobs Corner

This alternative proposes to build a second 70 kV transmission line between Henrietta and Jacobs Corner substations. Five miles of the line originating at Henrietta Substation would need to be entirely new line and require the acquisition of new right-of-way, while the remaining three miles could be double circuited with the Guernsey-Henrietta 70 kV Line. This project has an estimated cost of $5M to $10M. This project is not recommended at this time due to the higher cost. This alternative will be considered in the long term to allow Jacobs Corner Substation to operate fully looped.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2011

KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – TBD
- Special Metering or Protection – TBD
- Common Mode Exposure Items – TBD
- Interaction with other Projects or Studies – None

GEPSLF MODELING INFORMATION

```
#Reconductor Henrietta to Jacobs Corner with 1113 AAC
OLDSECDD  34540, 34542, 1, SEC=1, STATUS=1, +
        RPU=0.015576, XPU=0.11436, BPU=0.0024266, MVA1=100, MVA2=118, MVA3=100, MVA4=118
```

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagram
2. Demand Forecast
3. Power Flow Summary
4. Pre and Post Project Power Flow Plots

Attachment 1: Scope Diagram

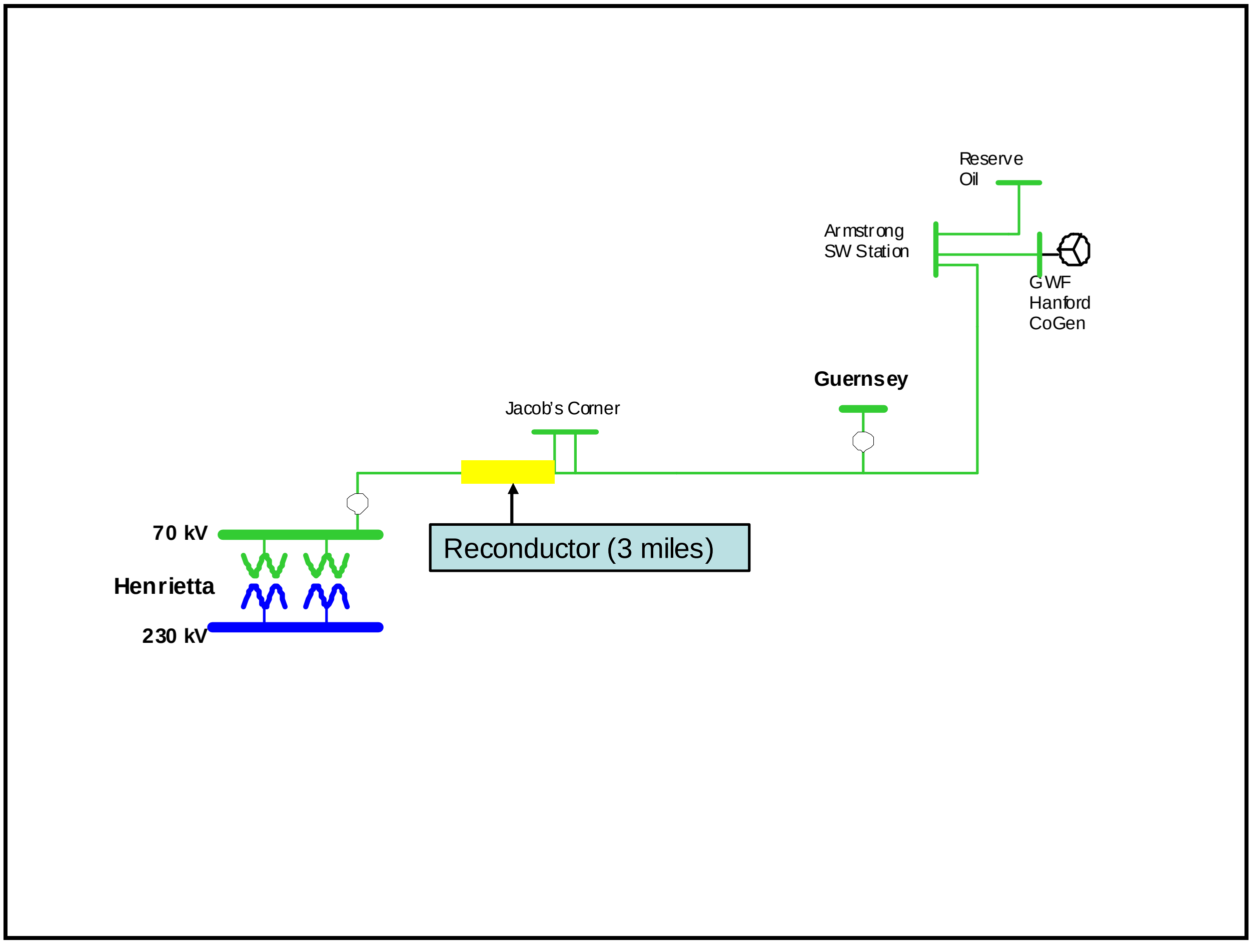


Figure 4-154: Proposed Scope Diagram

Attachment 2: Demand Forecast

Table 4-46: Area Load Demand Forecast

Substation/Bank	2009	2010	2011	2012	2013	Growth Rate(MW/yr)
Jacobs Corner Bank 1	11.8	11.8	11.8	11.8	11.8	0.0
Jacobs Corner Bank 2	9.3	9.3	9.4	9.3	9.4	0.0
Reserve Oil	2.0	2.0	2.0	2.0	2.0	0.0
Guernsey Bank 1	10.3	10.3	10.3	10.3	10.3	0.0
Guernsey Bank 2	7.6	8.2	8.8	9.4	10.0	0.6
Total Area Load	41.0	41.6	42.3	42.8	43.5	0.6

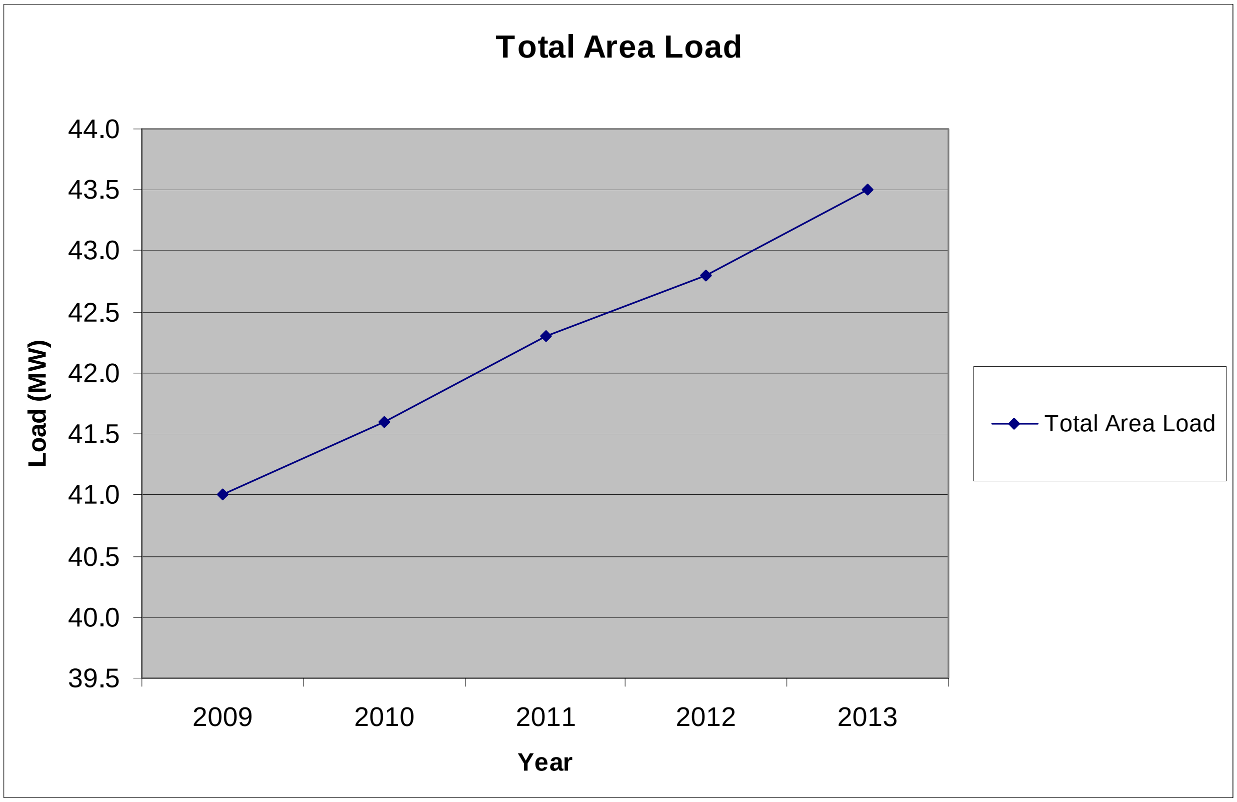


Figure 4-155: Area Load Growth

Attachment 3: Power Flow Summary

Table 4-47: Power Flow Results using Load Growth Projections

			Pre Project						Post Project	
#	Facility	Facility Rating	2009	2010	2011	2012	2013	2018	2018	Contingency
1	Guernsey-Henrietta 70 kV Line (Henrietta – Jacobs Corner)	SN Rating 343 Amps	96%	97%	99%	101%	102%	111%	46%	GWF Power (G-1)

Attachment 4: Pre and Post Project Power Flow Plots

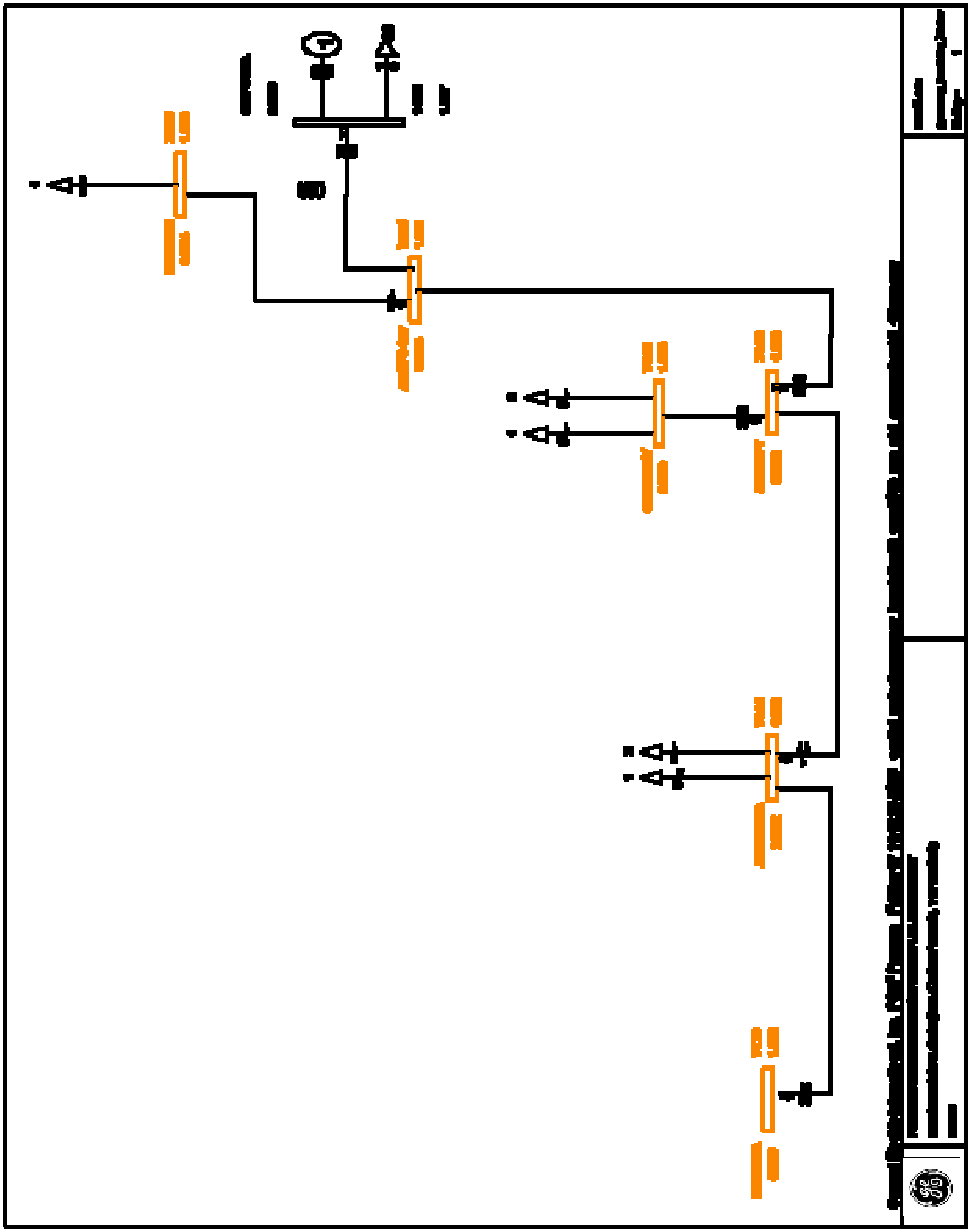


Figure 4-156: 2013 Pre Project – Normal

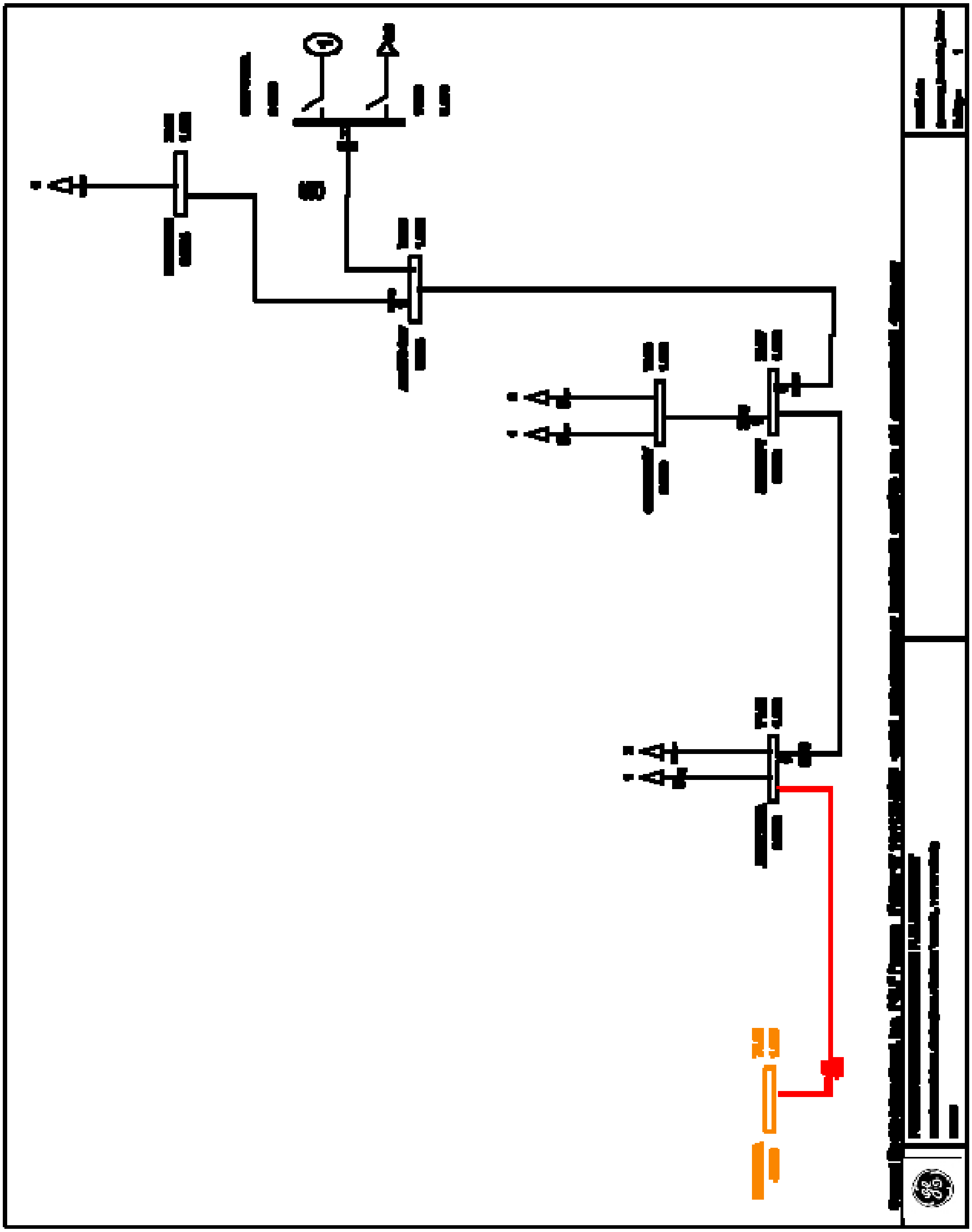


Figure 4-157: 2013 Pre Project – GWF Hanford offline (G-1)

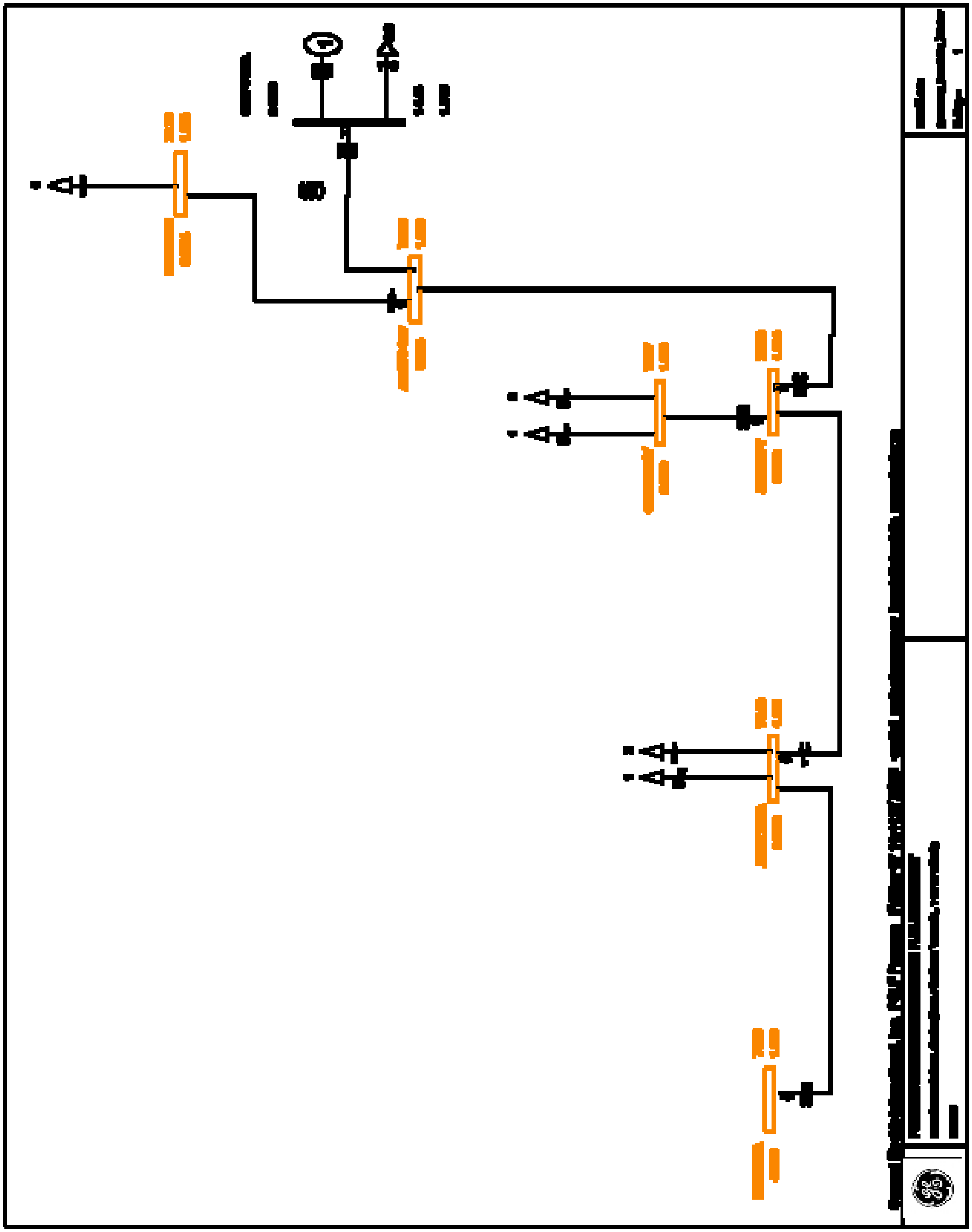


Figure 4-158: 2013 Post Project – Normal

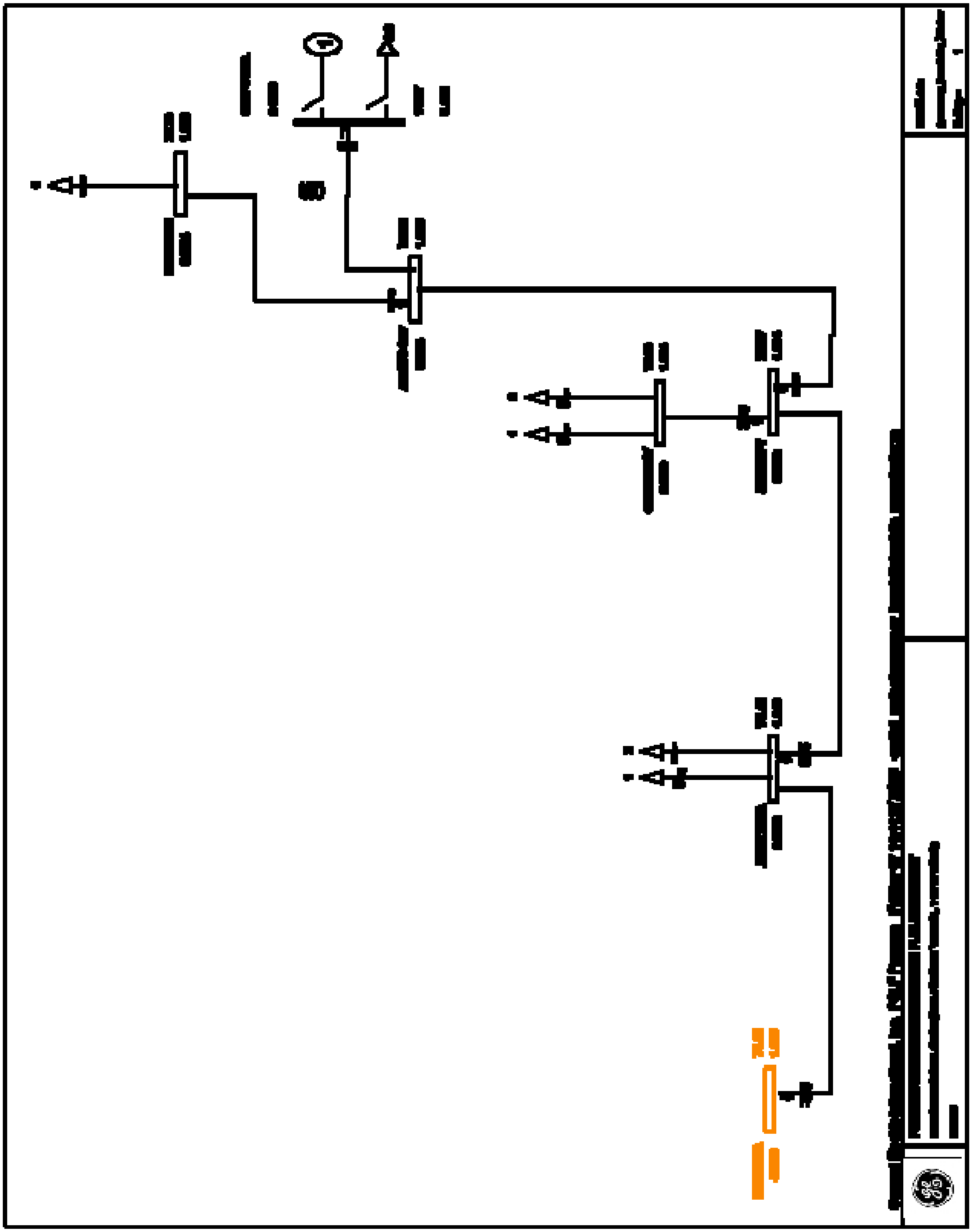


Figure 4-159: 2013 Post Project - GWF Hanford offline (G-1)

Herndon 230/115 kV Transformer

TARGETED IN-SERVICE DATE

May 2011

PURPOSE AND BENEFIT

Reliability – NERC Compliance and Local Capacity Requirements

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROJECT

The project scope is to install a third 230/115 kV transformer bank at Herndon Substation. This scope would include expanding the 115 kV and 230 kV buses and adding the necessary terminal equipment to interconnect this new transformer bank. This new transformer will be sized to handle at least 420 MVA.

This project is expected to cost between $10M and $15M.

BACKGROUND

Herndon Substation is located in Fresno County and is part of PG&E's San Joaquin Valley Area. Herndon Substation provides electrical support to the 115 kV network in the Greater Fresno Metropolitan area via two 230/115 kV, 420 MVA rated, transformer banks and through five 115 kV transmission lines. The Herndon 115 kV system, which serves approximately 110,000 electric customers, reaches peak demand levels around 522 MW. The growth rate for this area is approximately 3.0% per year.

The 230 kV system at Herndon is comprised of four 230 kV transmission lines: Gregg-Herndon 230 kV Nos. 1 and 2, the Herndon-Kearney 230 kV, and Herndon-Ashlan 230 kV lines. Herndon also provides voltage support via two 25 MVA synchronous condensers. The condensers are electrically connected to the tertiary windings of Herndon 230/115 kV Transformer Bank Nos. 1 and 2.

Planning studies for summer peak conditions have concluded that a failure of either Herndon 230/115 kV Transformer Bank No. 1 or 2,could load the remaining transformer bank to 100% of its emergency ratings by 2013. Additionally, the 2009 Local Capacity Requirements (LCR) assessment identified that an outage of Herndon 230/115 kV Bank

No. 1 overlapped with Kerckhoff II generator offline as the most critical contingency for the Herndon Sub-area. This condition coupled with less than 1,150 MW of local generation is projected to overload of Herndon 230/115 kV Bank No. 2 as early as 2009.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended. This alternative does not address load growth and reliability concerns.

Alternative 2: New Substation in Northern Fresno (E1)

This project scope is to construct a new 230/115 kV substation in Northern Fresno to help distribute bulk power to the underlying transmission systems. The new station will loop in both of the Gregg-Helms 230 kV lines, install two 230/115 kV transformers, loop in both Kerckhoff-Clovis-Sanger 115 kV lines, and direct connect the Shepherd-Woodward Jct 115 kV Line.

This alternative is not recommended because of timeline constraints.

PROJECT SCHEDULE

- Environmental and Permitting Processes – Not Applicable
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2011

KEY ISSUES

- Land-Use Restrictions – None
- Environmental Concerns – None
- Special Metering or Protection - None
- Common Mode Exposure Items - None
- Interaction with other Projects or Studies – E1 Substation

GEPSLF MODELING INFORMATION

```
#Adds third 420 MVA 230/115 kV Transformer at Herndon and fixes Herndon Bank 1&2 models
NEW_TRAN  30835, 34412, 3, ZR=0.0012, ZX=0.0564, BMAG=-0.0002, +
    MVA1=420, MVA2=462, MVA3=420, MVA4=462, VNOMF=235, VNOMT=120.70, MVABASE=252,+
    STAT=1, TYPE=1, TAPF=1, REG=34412, VMAX=1.5, VMIN=.51,+
    STEPP=.00625, TMAX=1.5, TMIN=.5, TAPFP=1, TAPFS=1, AREA=14, ZONE=314
```

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagrams
2. Demand Forecast
3. Power Flow Summary
4. Pre and Post Project Power Flow Plots

Attachment 1 Scope Diagrams

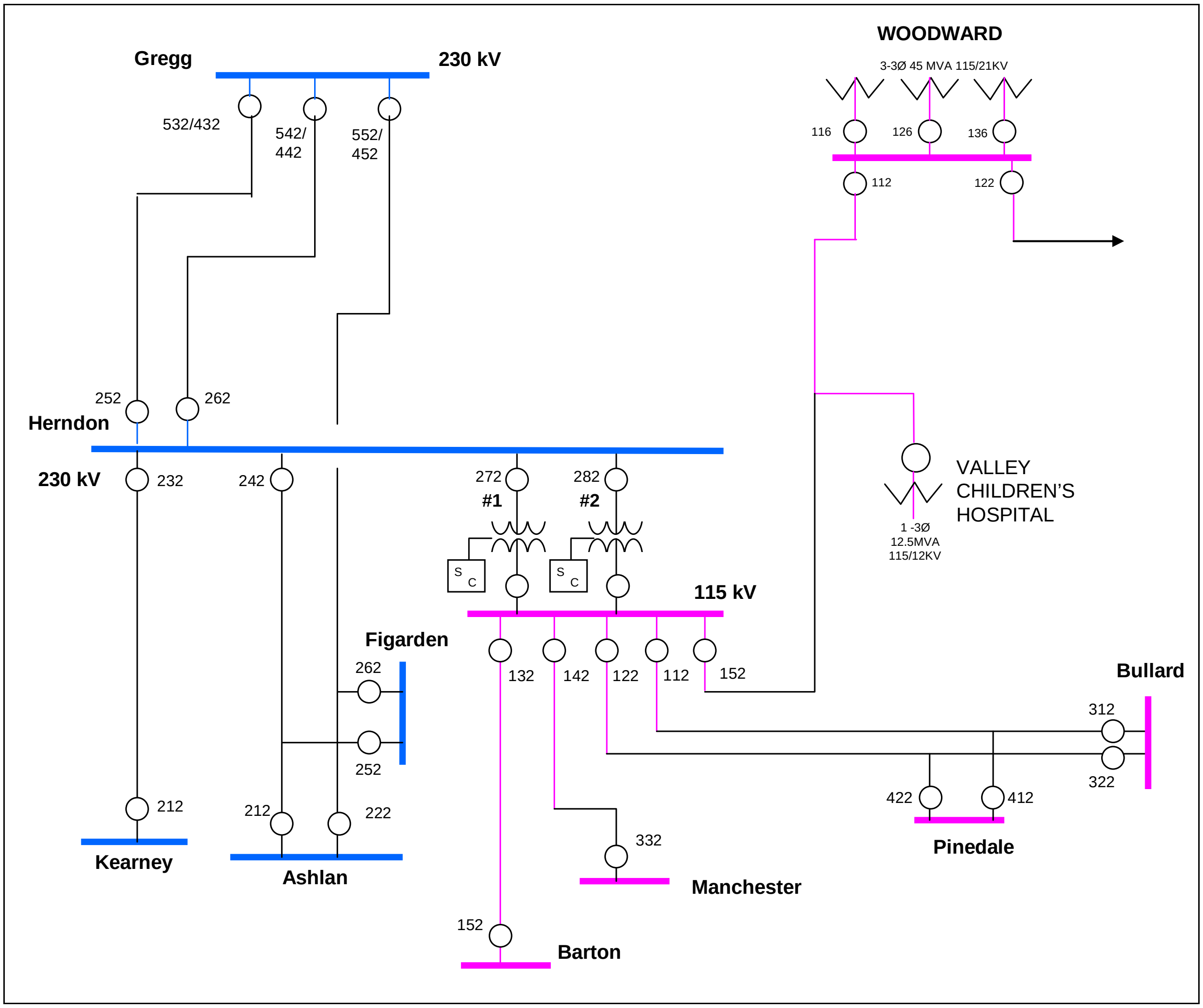


Figure 4-160: Existing Scope Diagram

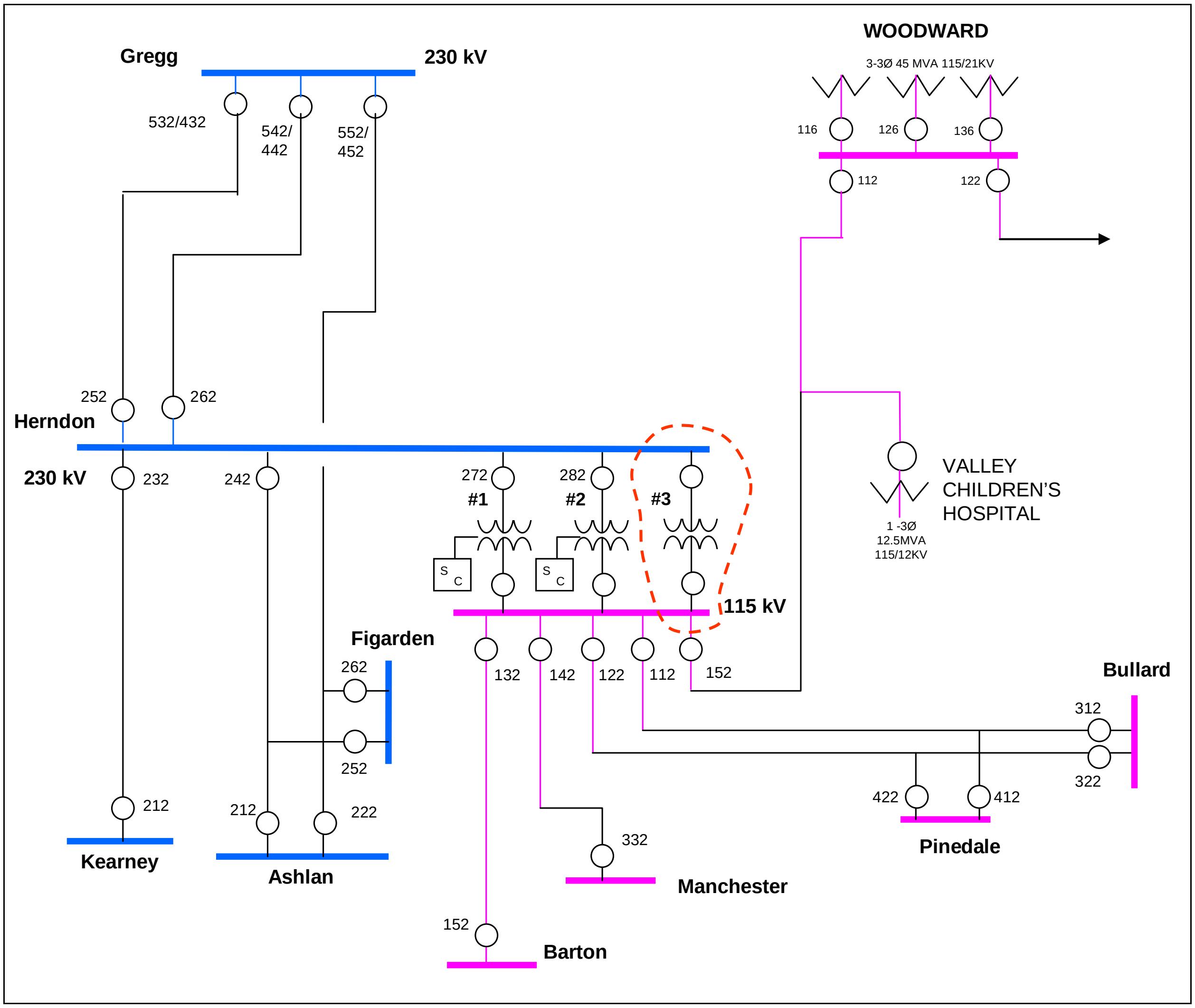


Figure 4-161: Proposed Scope Diagram

Attachment 2: Demand Forecast

Table 4-48: Load Demand Forecast

Substation/Bank	2009 (MW)	2010 (MW)	2011 (MW)	2012 (MW)	2013 (MW)	Growth Rate(MW/yr)
Bullard Bank 1	41.6	42.4	43.2	43.7	43.9	0.6
Bullard Bank 2	41.8	42.4	43.2	43.9	44.7	0.7
Bullard Bank 3	39.8	40.4	41.1	41.6	41.8	0.5
Pinedale Bank 1	26.7	27.1	27.5	27.8	28.2	0.4
Pinedale Bank 2	28.5	29.1	29.6	30.1	30.7	0.6
Pinedale Bank 3	37.5	38.2	39.0	39.6	40.3	0.7
Woodward Bank 1	39.2	39.9	40.7	41.3	42.1	0.7
Woodward Bank 2	48.9	49.8	50.8	51.6	52.5	0.9
Woodward Bank 3	40.9	41.7	42.5	43.1	44.0	0.8
Barton Bank 1	40.5	41.1	41.9	42.3	42.6	0.5
Barton Bank 2	34.8	35.3	35.9	36.4	36.5	0.4
Barton Bank 3	25.3	25.6	26.1	26.4	26.5	0.3
Manchester Bank 1	24.3	24.5	24.8	24.9	25.2	0.2
Manchester Bank 2	26.1	26.3	26.5	26.7	26.9	0.2
Manchester Bank 3	35.4	35.7	36.1	36.3	36.7	0.3
Total Area Load	531	540	549	556	563	8

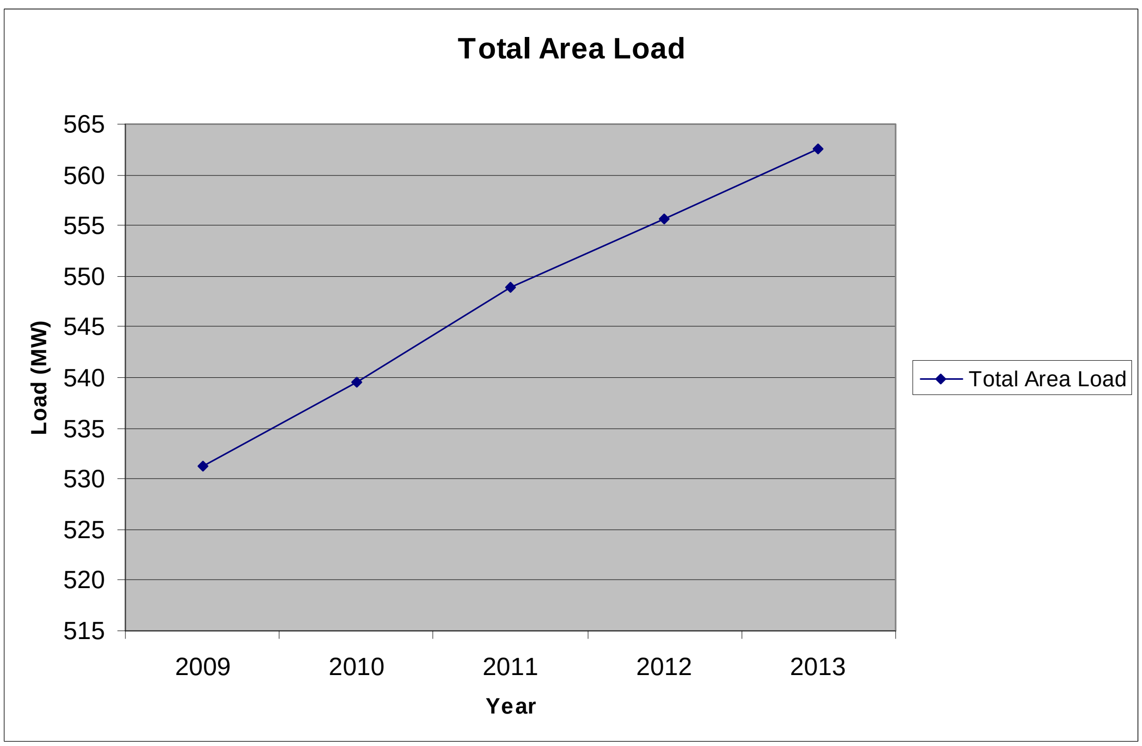


Figure 4-162: Area Load Demand Curve

Attachment 3: Power Flow Summary

Table 4-49: Power Flow Summary

			Pre Project						Post Project	
#	Facility	Facility Rating	2009	2010	2011	2012	2013	2018	2018	Contingency
1	Herndon 230/115 kV Bank No. 1 or 2	SE Rating 462 MVA	--	96%	96%	99%	100%	106%	59%	Herndon 230/115 kV Bank No. 1 or 2 (T-1)

Attachment 4: Pre and Post Project Power Flow Plots

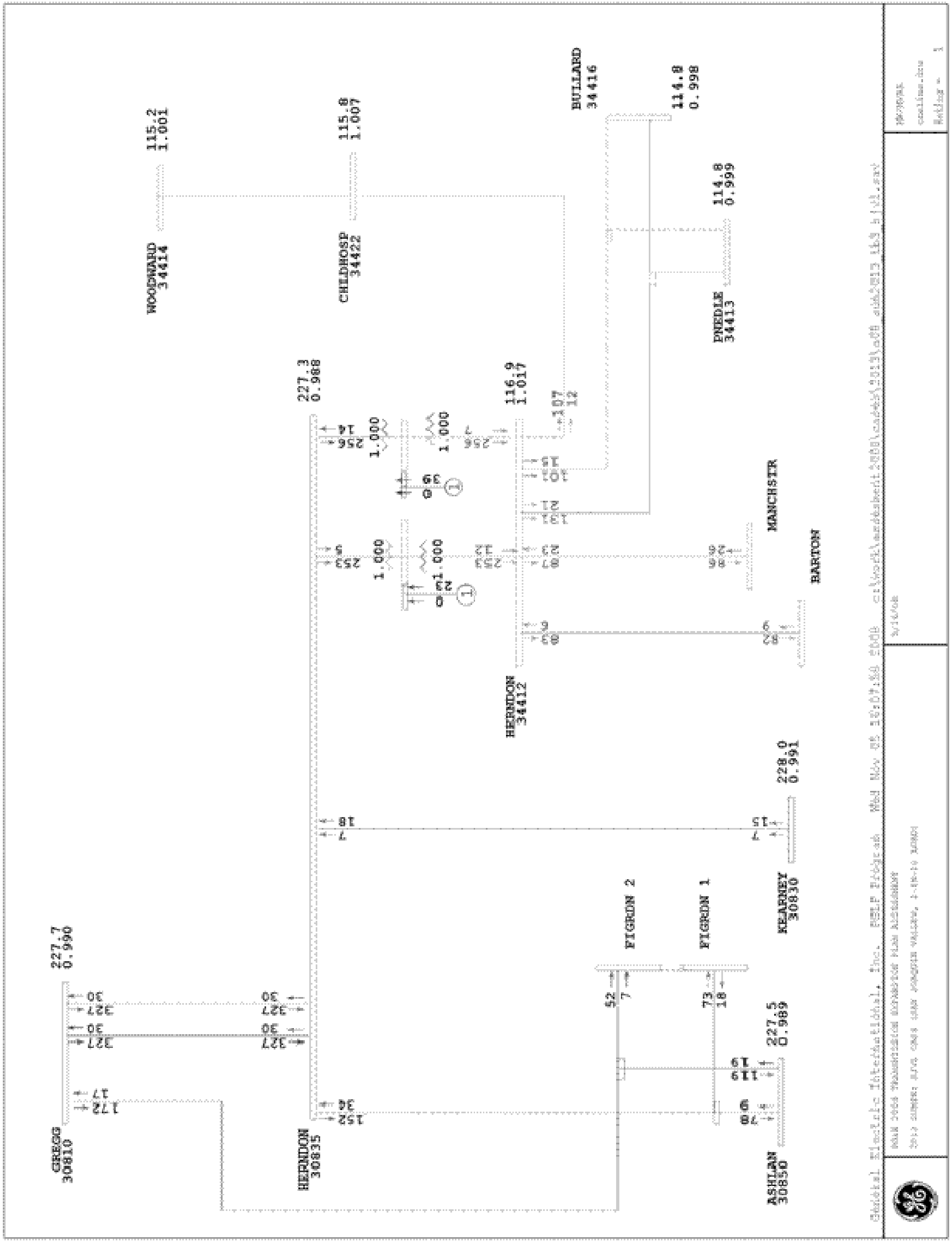


Figure 4-163: Pre Project – Normal Conditions

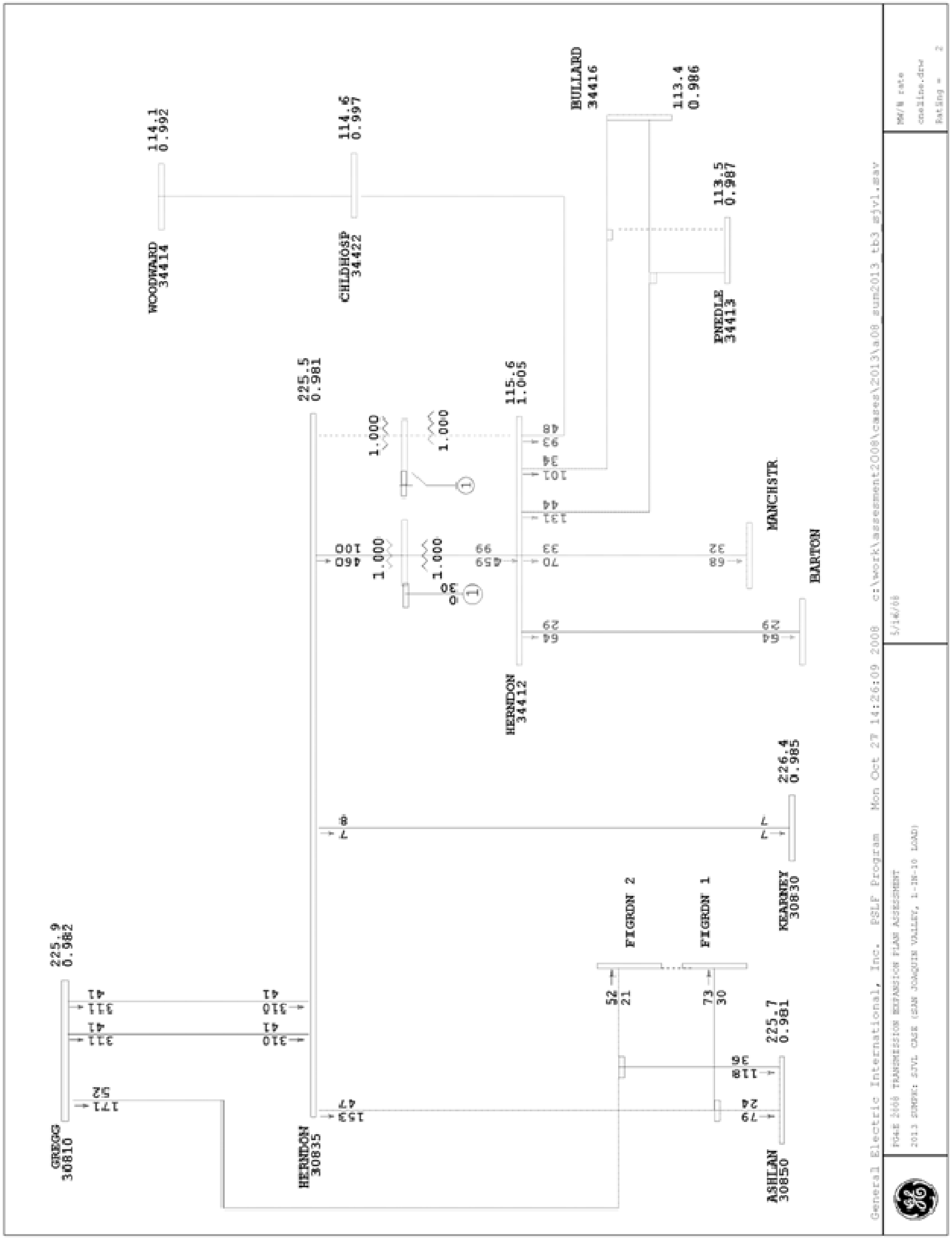


Figure 4-164: Pre Project – Herndon 230/115 kV Bank No. 2 Outage (T-1)

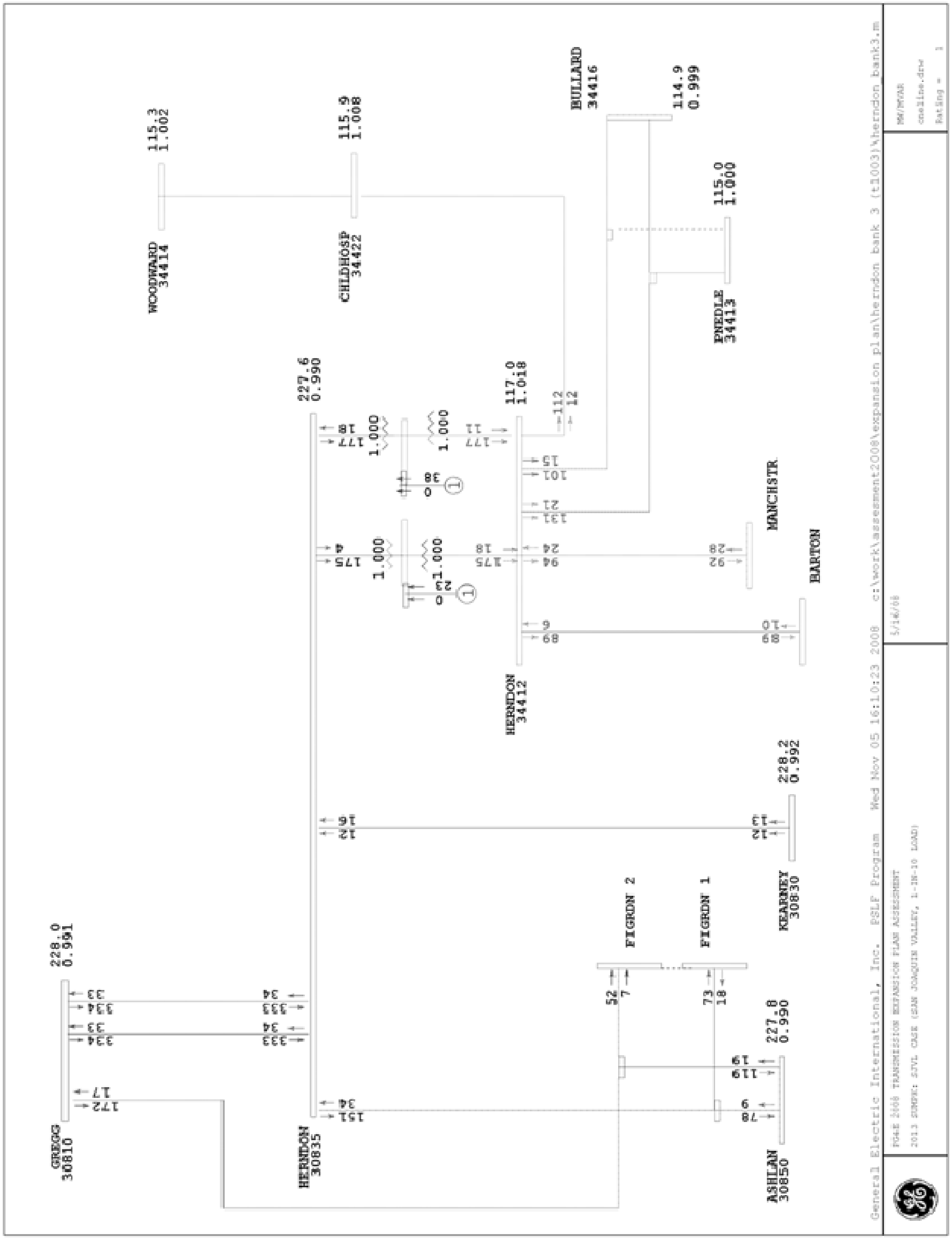


Figure 4-165: Post Project – Normal Conditions

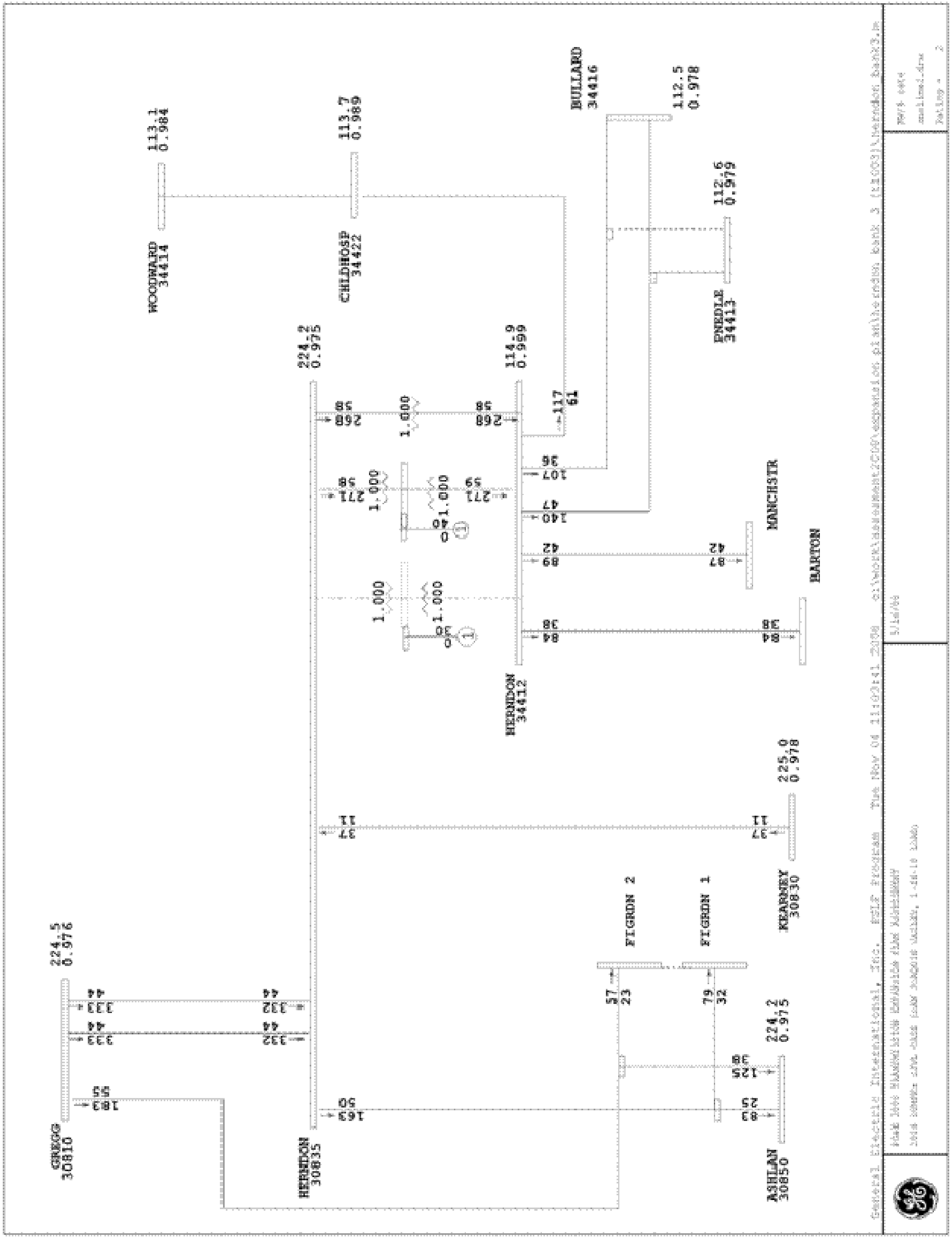


Figure 4-166: Post Project – Herndon 230/115 kV Bank No. 2 Outage (T-1)

Kern – Old River 70 kV Line Reconductor

TARGETED IN-SERVICE DATE

May 2011

PURPOSE AND BENEFIT

Reliability – NERC Compliance

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROJECT

The project scope is to reconductor approximately 35 miles of the Kern-Old River Nos. 1 and 2 70 kV lines with conductors capable of carrying a minimum of 825 Amps under summer normal and 975 Amps under summer emergency conditions. In addition, the project scope will upgrade line termination equipment at Kern and Old River substations, if necessary. This project will also obtain the necessary environmental and land permits to complete the reconductoring work.

This project is expected to cost between $15M and $25M.

BACKGROUND

Kern Power Plant Substation is located in Bakersfield and provides power to Panama and Old River substations via the Kern-Old River 70 kV Nos.1 and 2 lines. The Kern-Old River 70 kV No. 1 Line consists of 4/0 CU (Copper), 4/0 Al (Aluminum) and 397.5 Al (rated for 2 feet per second wind speed). The Kern-Old River 70 kV No. 2 Line consists of 3/0 CU, 336 Al, 1/0 CU, 397 Al, and 4/0 CU (rated for 4 feet per second wind speed).

Significant block load increases are anticipated for the Panama-Old River 70 kV area. This is based on the high volume of completed applications by agriculture customers to convert their diesel pumps to electrical pumps via the Agricultural Internal Combustion Engine Conversion (AG-ICE) Program. PG&E has initiated several distribution capacity increase projects for the area to support this new agriculture pumping load.

As a result of the increased loading, an outage of the Kern-Old River No. 2 70 kV Line (Kern-Panama line section) is projected to overload Kern-Old River No. 1 70 kV Line by 29% under 2010 summer peak conditions. In addition, this outage may cause voltages at Panama or Old River Substations to dip below .95 per unit value. A summer operating plan addresses this contingency by disabling the automatic restoration features at Panama.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases approved by the 2008 expansion plan study group and the CAISO. Ratings and impedances on the Kern-Old River No. 1 and 2 70 kV line were updated to reflect the limiting conductor (4/0 AL). Revised distribution load projections were used with non-coincidental peak bank values.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended. This alternative does not address load growth and voltage concerns.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2011

KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – None
- Special Metering or Protection – TBD
- Common Mode Exposure Items – None
- Interaction with other Projects – None

GEPSLF MODELING INFORMATION

```
# This Change file reconductors the Kern-Old River No. 1 and 2 Lines with 1113 AL

# line 2
# reconductoring Carnation to Kern
OLDSECDD  34908, 34918, CKT=1, SEC=1, STATUS=1, +
RPU=.008937, XPU=.065614, BPU=.013908, MVA1=100, MVA2=118, MVA3=156, MVA4=166
# reconductoring Panama to Carnation
OLDSECDD  34906, 34908, CKT=1, SEC=1, STATUS=1, +
RPU=.010261, XPU=.075335, BPU=.015968, MVA1=100, MVA2=118, MVA3=156, MVA4=167
# reconductoring  Union JCT to Panama
OLDSECDD  34905, 34906, CKT=1, SEC=1, STATUS=1, +
 RPU=.002122, XPU=.015582, BPU=.033303, MVA1=100, MVA2=118, MVA3=156, MVA4=167
# reconductoring Old River to Union JCT
OLDSECDD  34904, 34905, CKT=1, SEC=1, STATUS=1, +
RPU=.022449, XPU=.164821, BPU=.034936, MVA1=100, MVA2=118, MVA3=156, MVA4=167

# line 1
# reconductoring Old River to Kern
OLDSECDD  34904, 34914, CKT=1, SEC=1, STATUS=1, +
RPU=.023169, XPU=.170111, BPU=.036057, MVA1=100, MVA2=118, MVA3=156, MVA4=167
```

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagrams
2. Demand Forecast
3. Power Flow Summary
4. Pre and Post Project Power Flow Plots

Attachment 1: Scope Diagrams

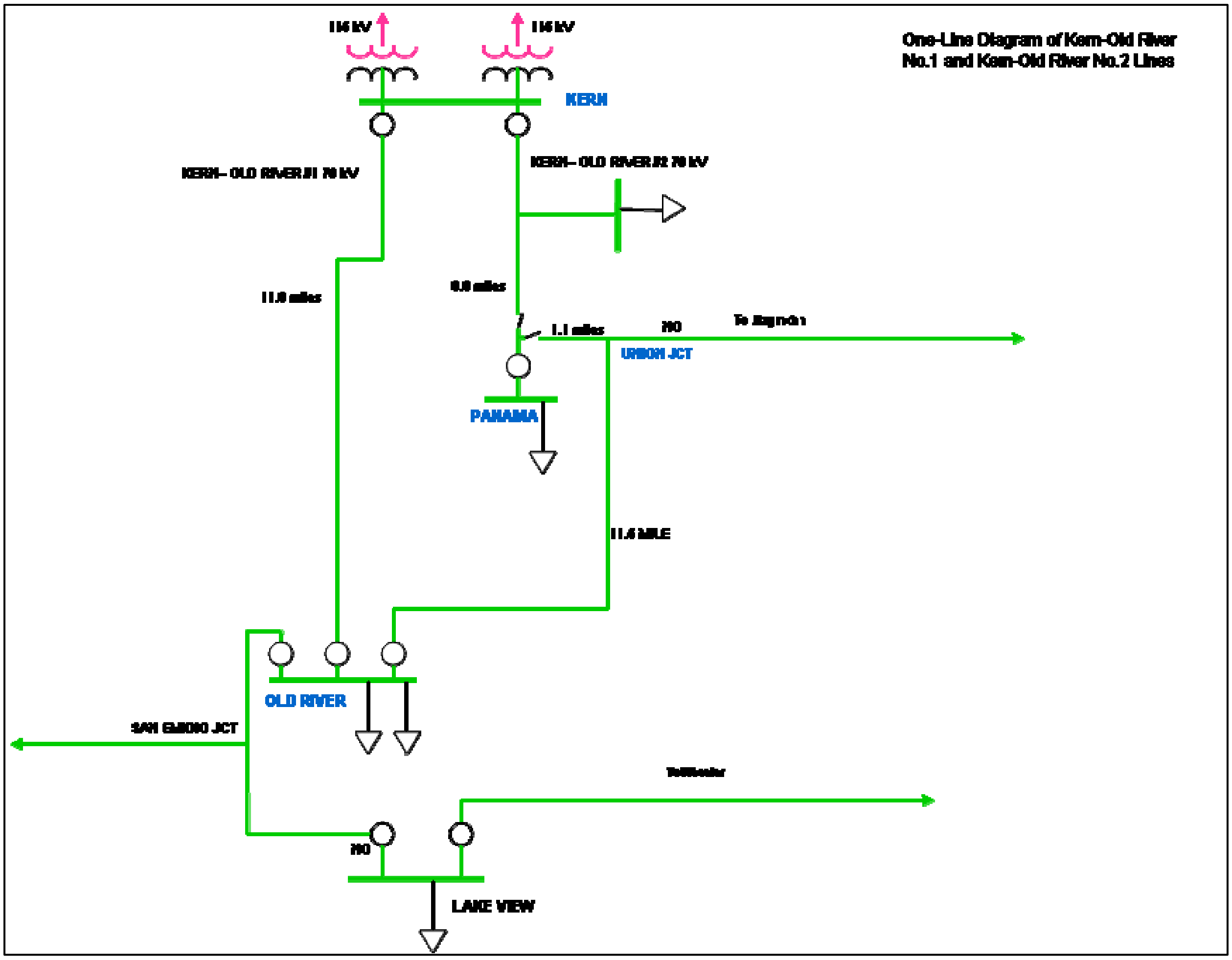


Figure 4-167: Existing Scope Diagram

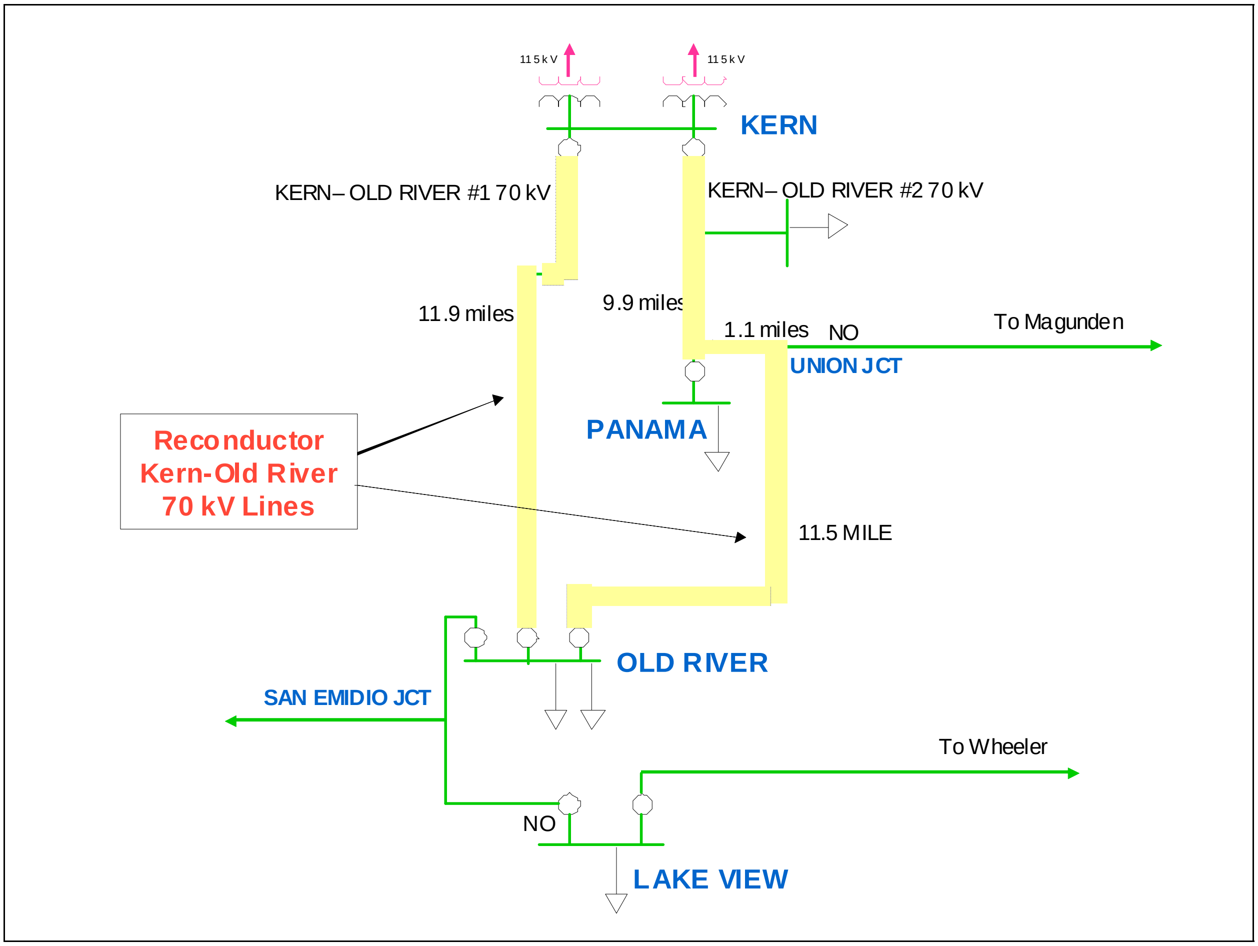


Figure 4-168: Proposed Scope Diagram

Attachment 2: Demand Forecast

Table 4-50: Area Load Demand Forecast

	2009 (MW)	2010 (MW)	2011 (MW)	2012 (MW)	2013 (MW)
Old River #1	11.8	11.9	12.0	12.0	12.3
Old River #2	15.2	15.3	15.5	15.6	15.6
Panama	36.7	37.0	39.0	41.3	43.8
Carnation	6.3	6.3	6.3	6.3	6.3
Copus	7.3	7.3	7.2	7.1	7.1
Total	**77**	**78**	**80**	**82**	**85**

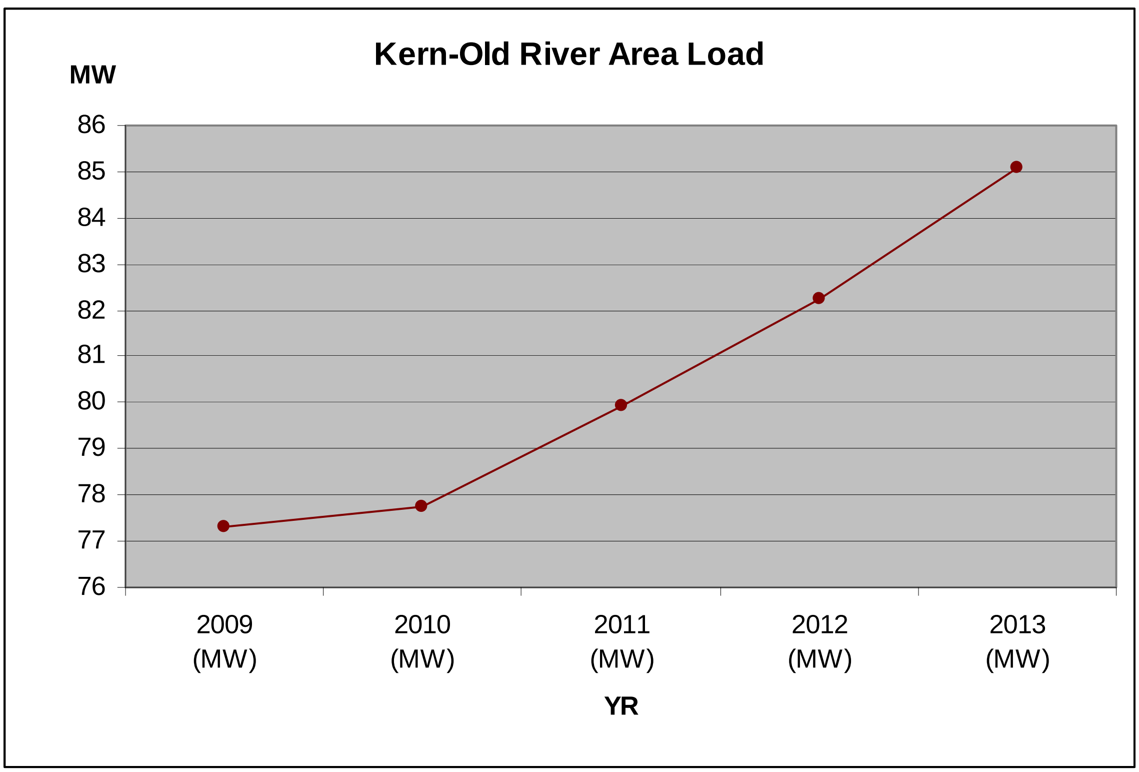


Figure 4-169: Area Load Demand Curve

Attachment 3: Power Flow Summary

Table 4-51: Power Flow Summary

			Pre Project					Post Project	
#	Facility	Facility Rating	2009	2010	2011	2012	2013	2013	Contingency
1	Kern-Old River No. 1	SE Rating 43 MVA	--	129%	135%	141%	148%	57%	Kern-Old River No. 2 (Kern-Panama Section (L-1)
	Kern-Old River No. 2	40 MVA	--	102%	109%	117%	126%	43%	
2	Kern-Old River No. 2	40 MVA	--	90%	93%	97%	101%	61%	Kern-Old River No. 1 (L-1)

Attachment 4: Pre and Post Project Power Flow Plots

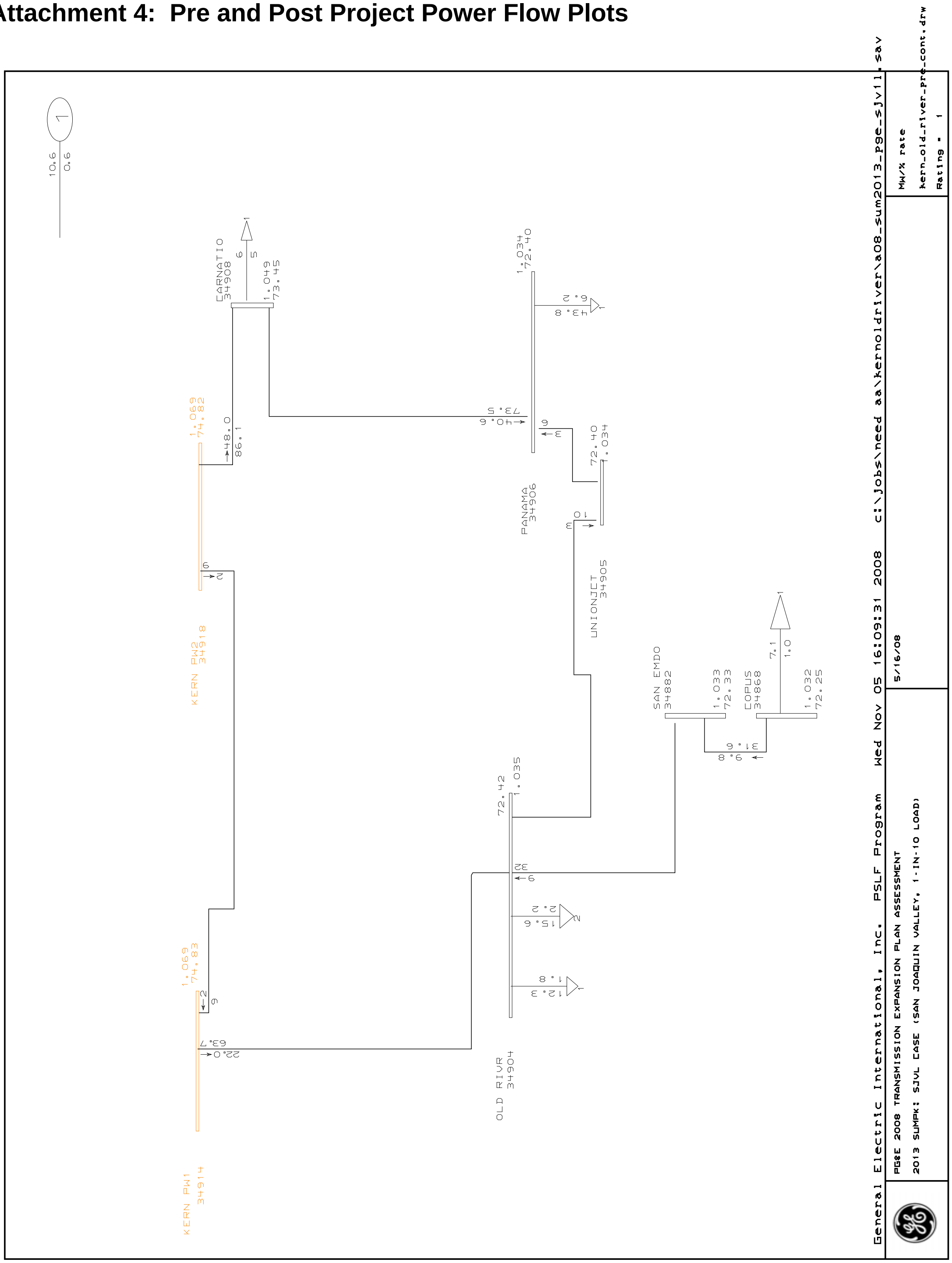


Figure 4-170: Pre Project – Normal Conditions

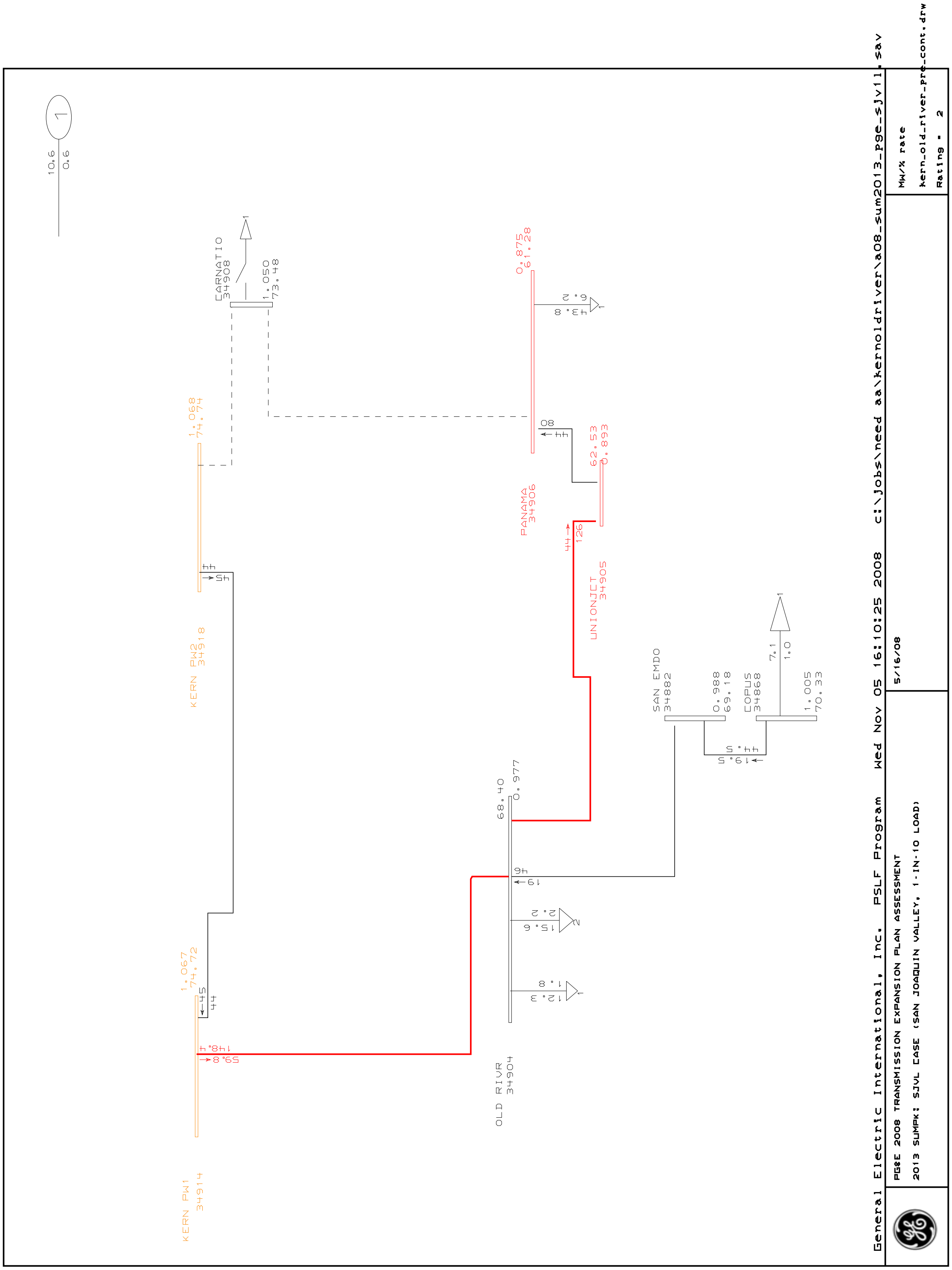


Figure 4-171: Pre Project-Contingency Outage of Kern-Old River No. 2 (Kern-Panama section)

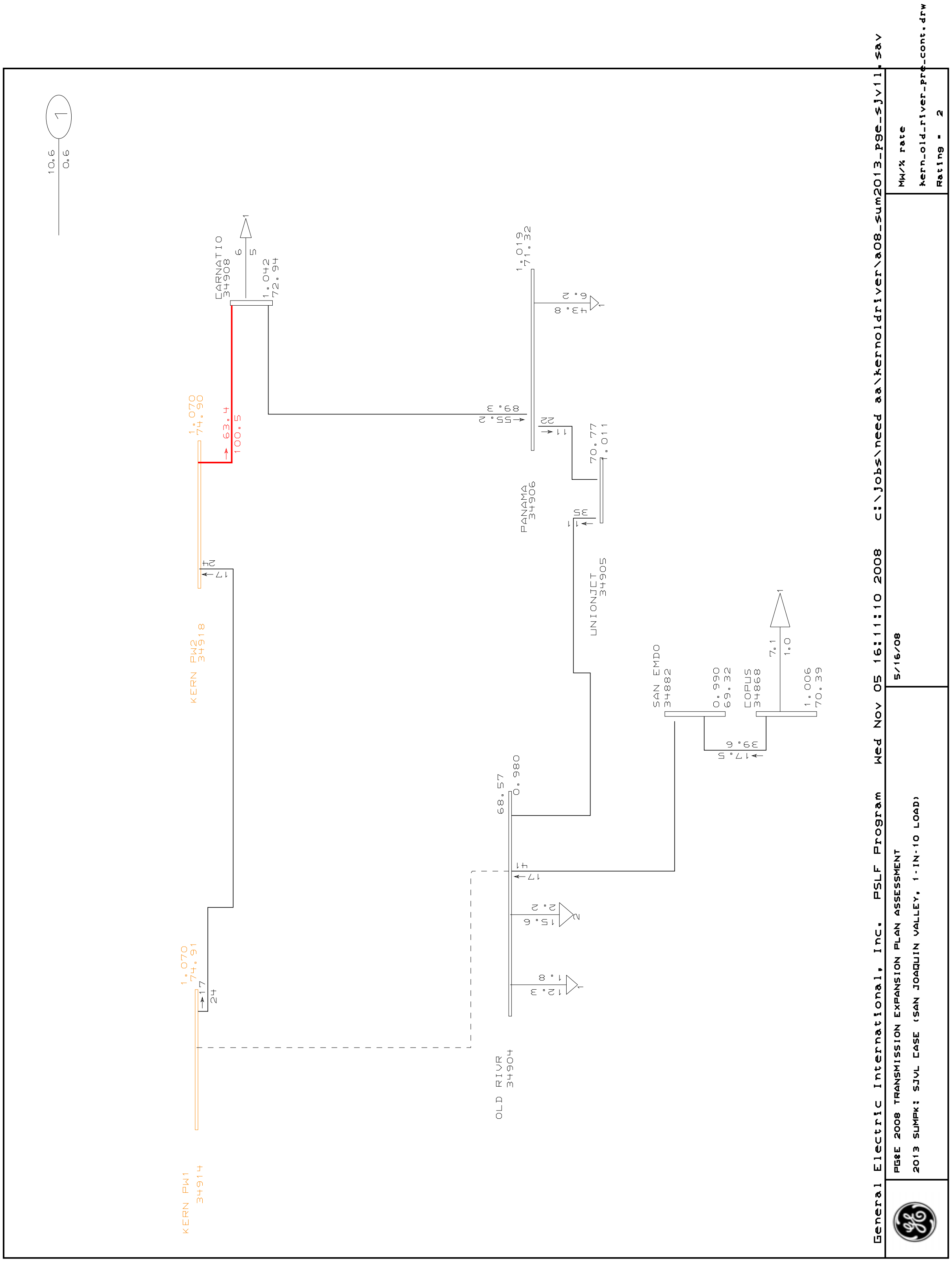


Figure 4-172: Pre Project-Contingency Outage of Kern-Old River No. 1

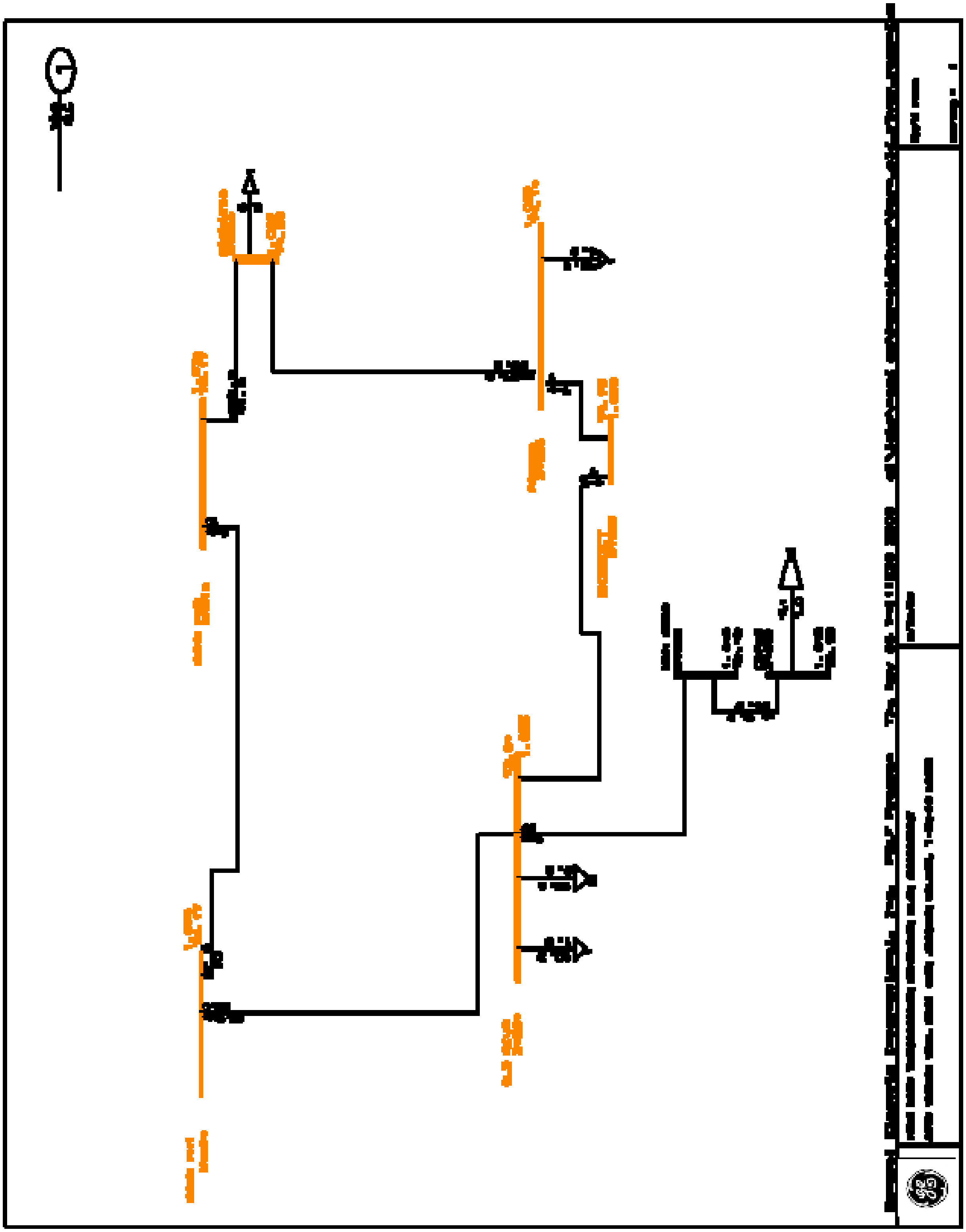


Figure 4-173: Post Project-Normal

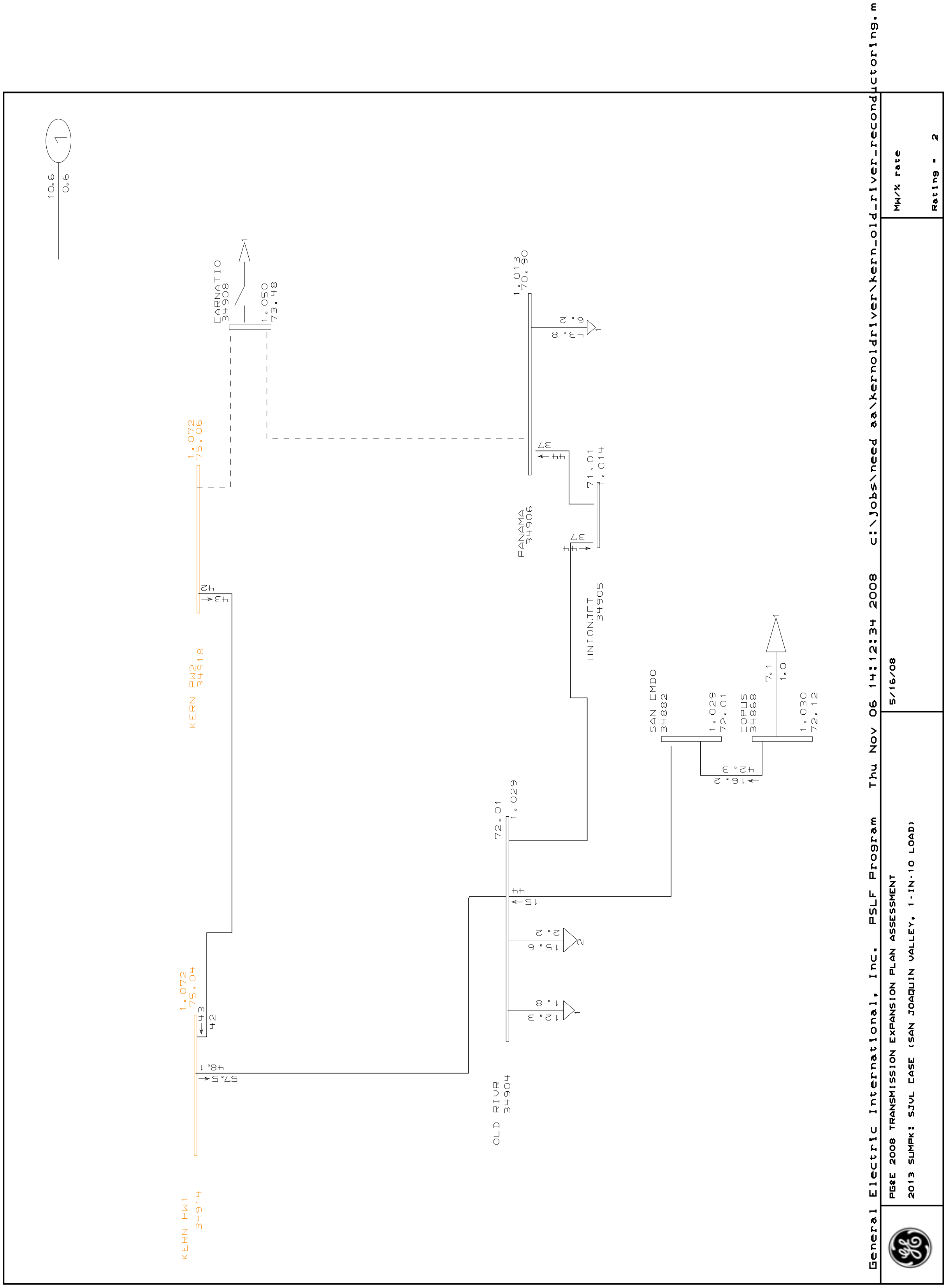


Figure 4-174: Post Project-Contingency Outage of Kern-Old River No. 2 (Kern-Panama section)

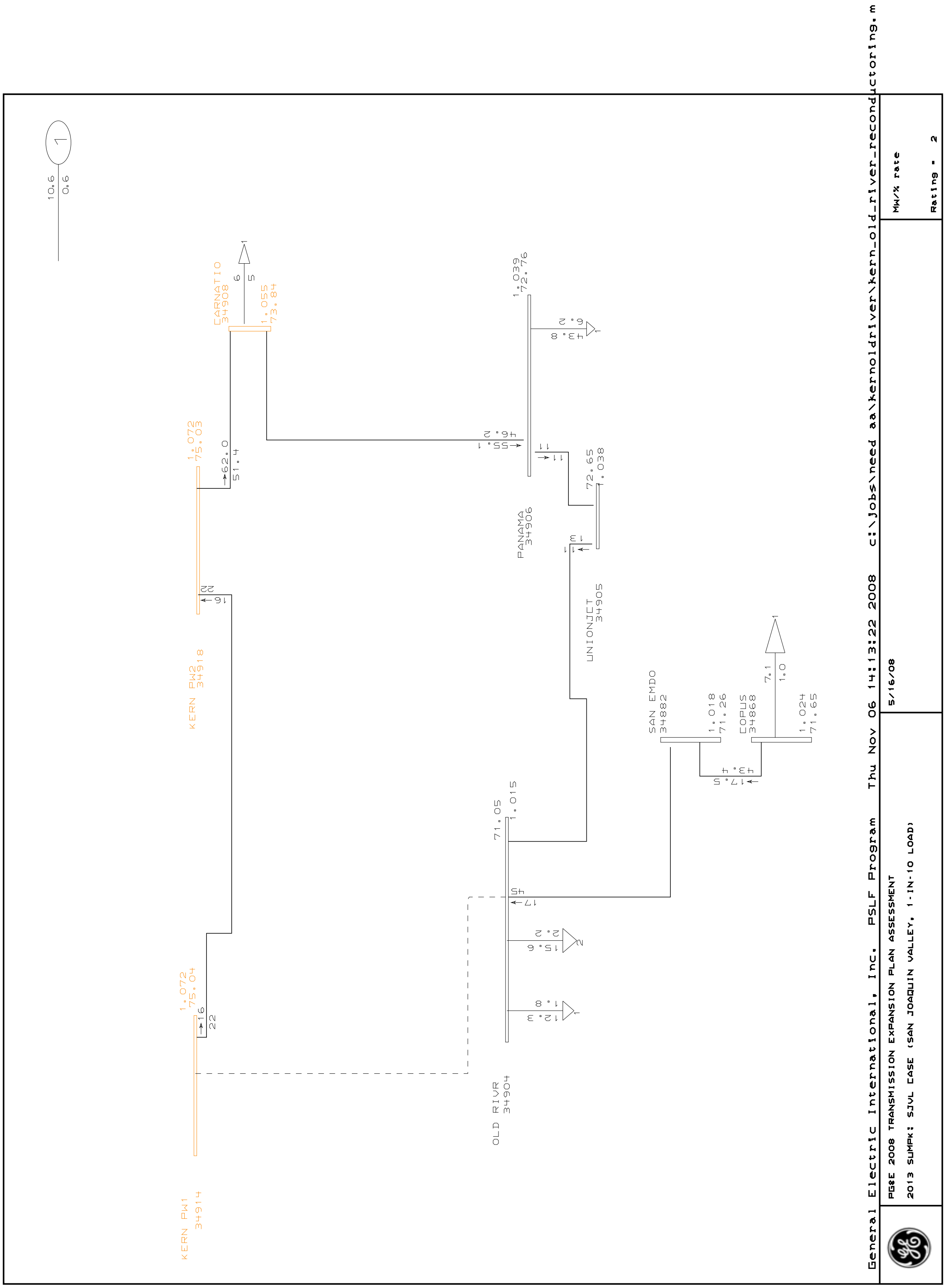


Figure 4-175: Post Project-Contingency Outage of Kern-Old River No. 1

Morro Bay – Midway 230 kV Line Nos. 1 and 2 Reconductoring

TARGETED IN-SERVICE DATE

May 2011

PURPOSE AND BENEFIT

Reliability and Renewable Resource Interconnection – NERC Compliance, Renewable Portfolio Standards for California and LGIP Network Upgrade

This project serves as a Network Upgrade Project for generation interconnection projects Q239 and Q242, which are both of renewable technology (solar). In addition, Q239 and Q242 have signed Power Purchase Agreements with PG&E.

PG&E has filed advice letters on these Power Purchase Agreements, which can be reviewed under the following links:

http://www.pge.com/nots/rates/tariffs/tm2/pdf/ELEC_3313-E.pdf
http://www.pge.com/nots/rates/tariffs/tm2/pdf/ELEC_3318-E.pdf

PROJECT CLASSIFICATION

This is a new project. This project is a Network Upgrade for solar generation in the Carrizo Plain area.

DESCRIPTION AND SCOPE OF PROJECT

The project scope is to reconductor 34 miles of the Morro Bay – Midway 230 kV Nos. 1 and 2 lines between the proposed San Luis Obispo Solar Switching Station #1 and Midway Substation with conductors capable of carrying a minimum of 1,700 Amps. In addition, this project scope will also include the upgrade of associated line terminal equipment to accommodate the higher conductor ratings.

This project is expected to cost between $35M and $45M.

BACKGROUND

Over the last few years, various solar power generation developers have approached the PG&E regarding electric interconnections to the local transmission network in the Carrizo Plain area. As a result, the Utility, California Independent System Operator (CAISO), and participating solar power generation developers have initiated various system studies to determine impacts and requirements for interconnecting solar power generation in this area. According to the CAISO's most current electric generation interconnection listing[5], three new solar power generation plants (650 MW) are planned to be constructed in this area by year 2011, while one additional solar power plant is planned to be constructed (390 MW) by year 2012. By year 2012, the Carrizo Plain area could interconnect as much as 1,040 MW of solar generation.

Electric transmission facilities that are located near the development of these solar power facilities are the Morro Bay-Midway 230 kV Nos. 1 and 2 lines, as well as the PG&E's Carrizo Plains Substation. In order to reliably interconnect the planned generation facilities, increasing capacity on the 230 kV lines between the solar switching station and Midway Substation would be required by May 2011 or earlier to allow the reliable full delivery of this solar power to the grid.

The Morro Bay – Midway 230 kV Nos. 1 and 2 lines are approximately 81 miles in length and comprised of 1113 all aluminum conductors (AAC) with Summer Normal rating of 825 Amps and Summer Emergency rating of 975 Amps

Furthermore, completion of this transmission line reconductoring project will help PG&E meet its energy procurement goals of procuring 20% of its energy from renewable resources.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended. This alternative does not address capacity and reliability concerns.

Alternative 2: Add a new 230 kV line between San Luis Solar Switching Station #1 and Morro Bay Substation

[5] The CAISO's Generation Interconnection Listing is a listing of the proposed generation interconnection projects that have an approved application for interconnection with the CAISO.

This alternative will propose to construct a new 230 kV line between Morro Bay and the San Luis Obispo Solar Switching Station #1 in the area to help support the full delivery of solar power to the grid.

Currently this alternative is not the most cost effective alternative in providing the full delivery of the solar generators by 2010. This alternative will be further evaluated in the long term to support the interconnection of additional solar power plants.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2011

KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – TBD
- Special Metering or Protection – None
- Common Mode Exposure Items – None
- Interaction with other Projects or Studies – Generation Interconnection Projects Q239 and Q242

GEPSLF MODELING INFORMATION

```
#Reconductor the section of the Morro Bay - Midway #1  ( 37 miles to Midway) with 954 ACSS
NEWSECDD  30970, 30916, CKT=1, SEC=1, RPU=.0093699, XPU=.048096, BPU=.10362,+
     MVA1=683, MVA2=683, MVA3=747, MVA4=747, STATUS=1, AREA=20, ZONE=320, OWN=390

#Reconductor the section of the Morro Bay - Midway # 2 ( 37 miles to Midway) with 954 ACSS
NEWSECDD  30970, 30916, CKT=2, SEC=1, RPU=.0093699, XPU=.048096, BPU=.10362,+
      MVA1=683, MVA2=683, MVA3=747, MVA4=747, STATUS=1, AREA=20, ZONE=320, OWN=390
```

MISCELLANEOUS DATA

- PG&E will construct and own the project
- PG&E will be the planned operator of the project
- The generation developers will provide initial funding for this project, which would later be reimbursed back to the developers once their generation projects are placed into service and interconnected to the transmission grid.

ATTACHMENTS

1. Scope Diagram
2. Power Flow Summary
3. Pre and Post Project Power Flow Plots

Attachment 1: Scope Diagram

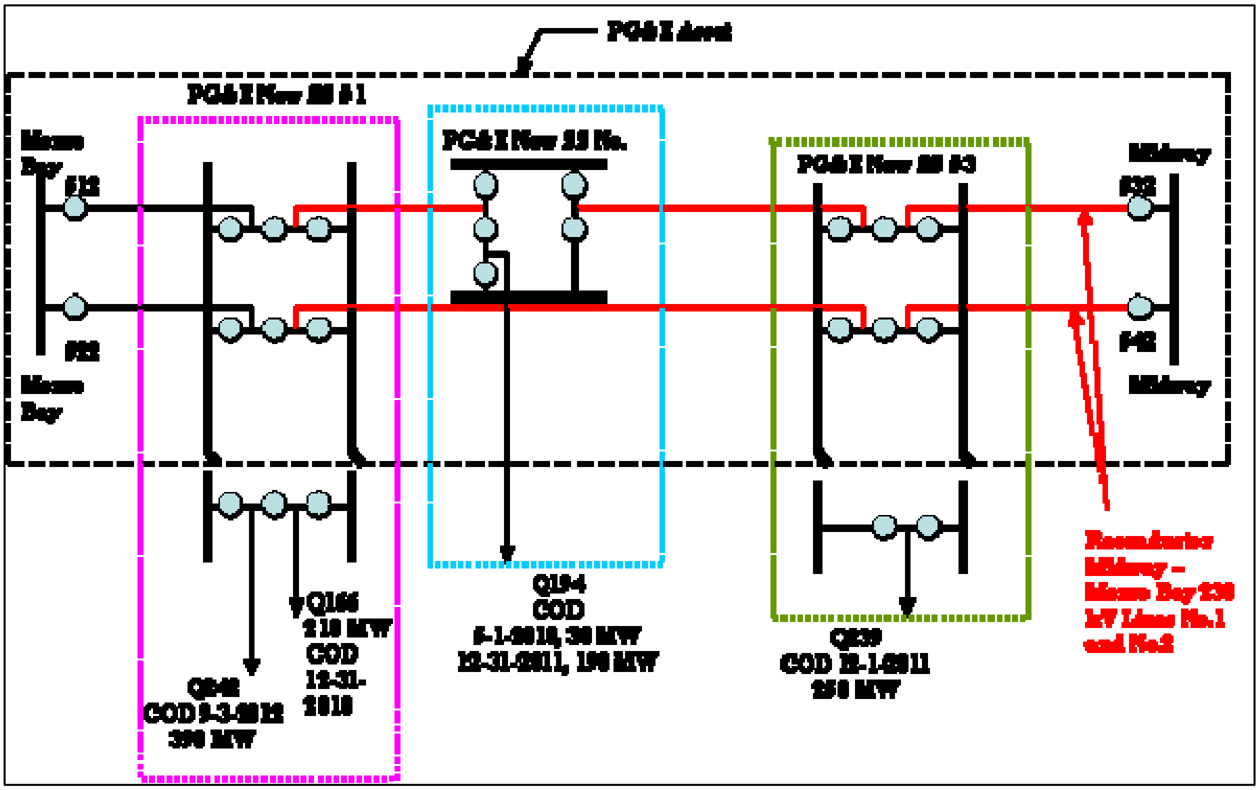


Figure 4-176: Proposed Scope Diagram

Attachment 2: Power Flow Summary

Table 4-52: Power Flow Summary

			Pre Project						Post Project	
#	Facility	Facility Rating	2009	2010	2011	2012	2013	2018	2018	Contingency
1	Morro Bay – Midway 230 kV Line	SN Rating 328 Amps	N.A.	52%	78%	117%	118%	121%	59%	Normal

Attachment 3: Pre and Post Power Flow Plots

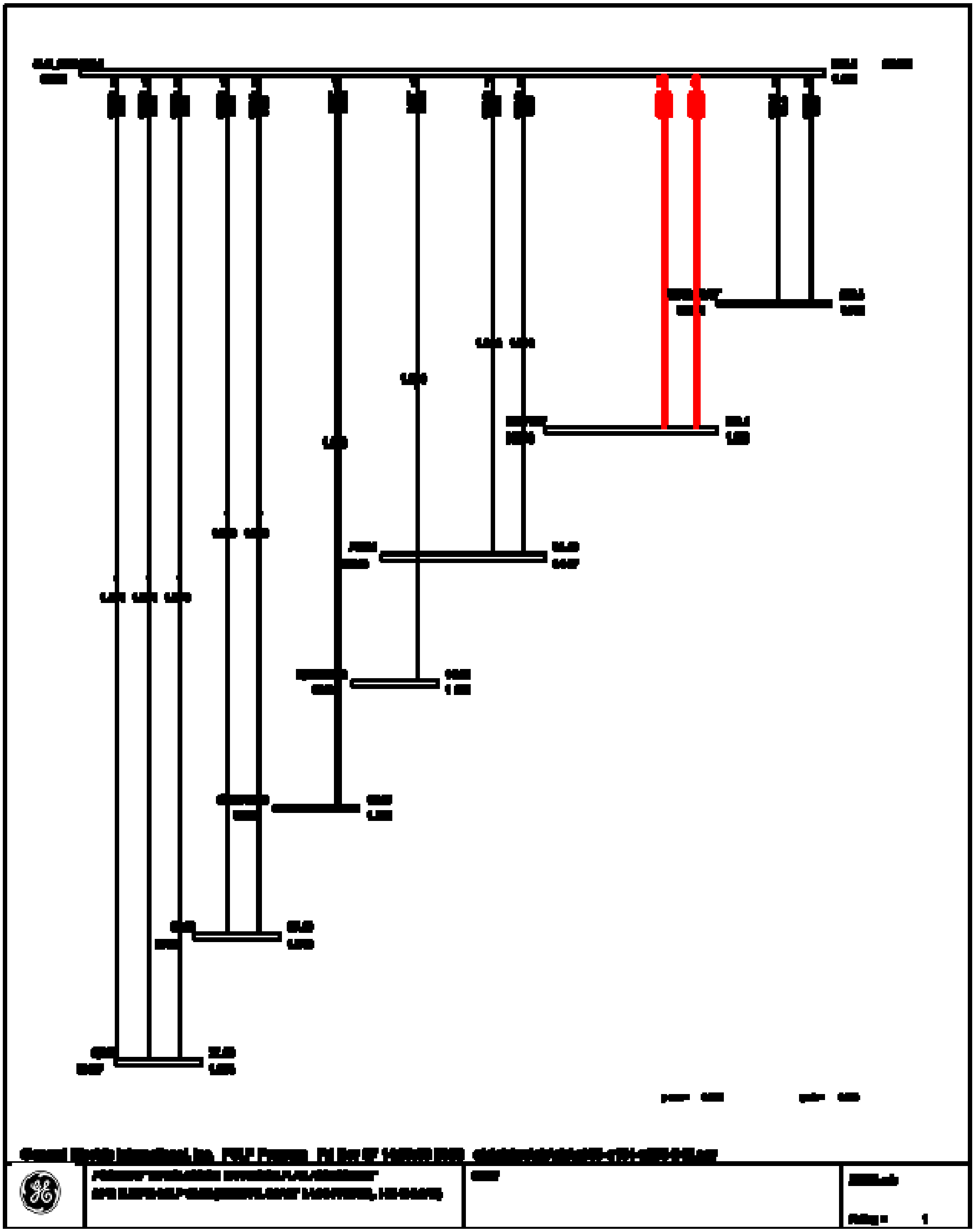


Figure 4-177: Pre Project – Normal Conditions

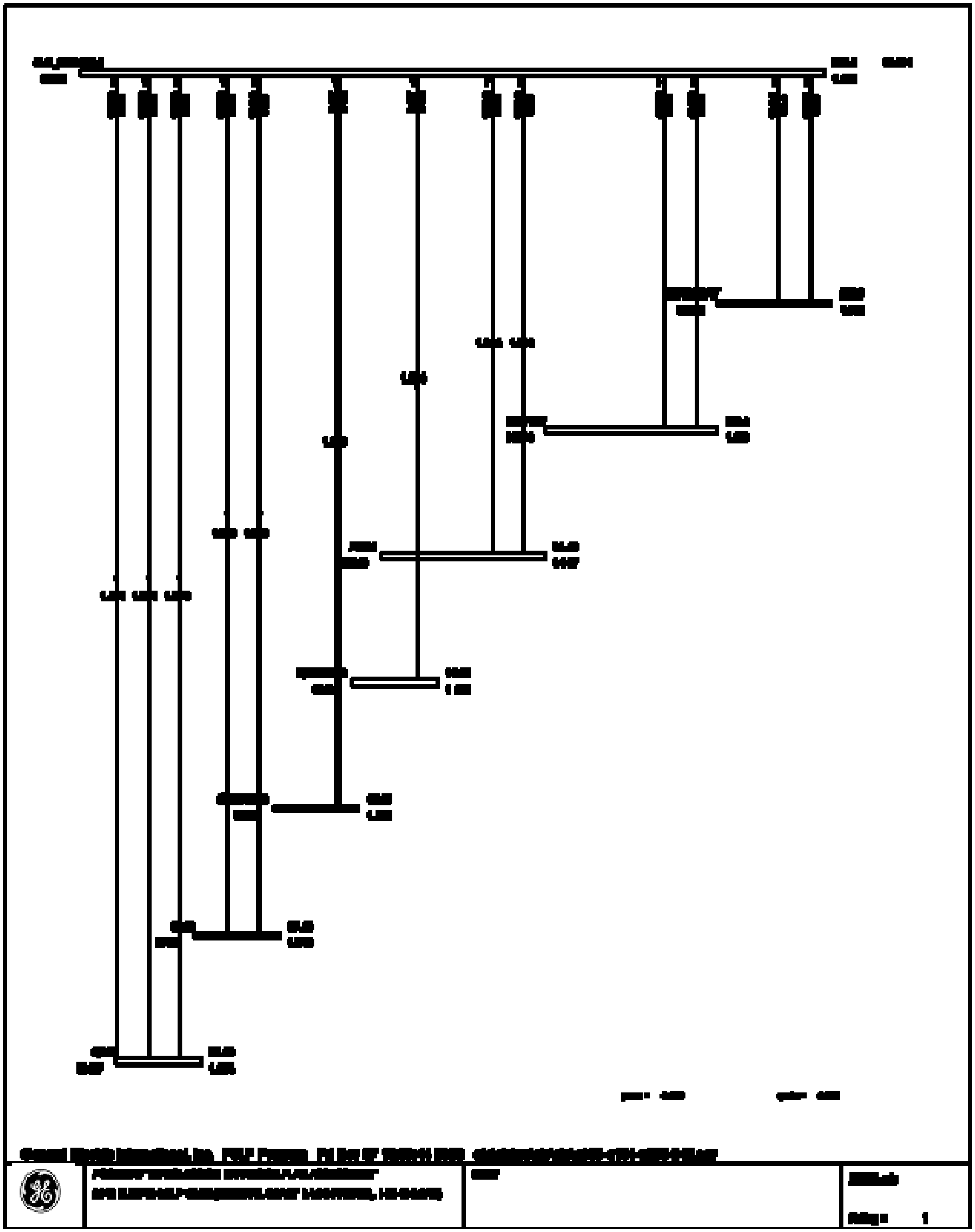


Figure 4-178: Post Project – Normal Condition

Shepherd Substation Interconnection

TARGETED IN-SERVICE DATE

May 2011

PURPOSE AND BENEFIT

Reliability – Tariff and Compliance

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROJECT

The project scope is to loop the proposed Shepherd Substation off the Kerckhoff-Clovis-Sanger No. 1 115 kV Line. Looping Shepherd Substation would require building a new 115 kV double circuit tower line (2 miles long) from Shepherd Substation to the Kerckhoff-Clovis-Sanger No. 1 115 kV Line. The new double circuit tower line conductor will be sized to handle a minimum capacity of 600 Amps for summer normal conditions and 1,355 Amps for summer emergency conditions. The scope of this project also includes the installation of 115 kV shunt capacitors at Shepherd Substation capable of providing 50 MVArs of reactive support.

This project is expected to cost between $8M and $10M.

BACKGROUND

PG&E is proposing to construct a new distribution substation (Shepherd Substation) to serve electric customers in Fresno County. This substation will be designed to serve up to 45 MVA of distribution transformers.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO. Forecasted loads not included in the 2008 series base cases were used to model the initial load interconnected at Shepherd Substation.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended. This alternative does not address load growth and reliability concerns.

Alternative 2: Connecting Shepherd Substation via a Flip-Flop Scheme

This alternative proposes to serve the new Shepherd Substation normally from the Kerckhoff-Clovis-Sanger No. 1 115 kV Line with an emergency source from Kerckhoff-Clovis-Sanger No. 2 115 kV Line. This alternative is not recommended as it does not address reliability concerns.

Alternative 3: Construct New Herndon-Woodward 115 kV Line

This alternative proposes to construct a second 115 kV Line from Herndon-Woodward. This project is not recommended due to time constraints related to permitting and land; however it will be considered for future capacity increases above a single 45 MVA distribution bank at Shepherd Substation.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2011

KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – None
- Special Metering or Protection – TBD
- Common Mode Exposure Items – A double circuit tower line outage of the new line using the Kerckhoff-Clovis-Sanger 115 kV Line would interrupt service to Shepherd Substation until one of the 115 kV lines was placed back into service.
- Interaction with other Projects – E1 Substation, and Borden-Coppermine 70 kV plan.

GEPSLF MODELING INFORMATION

```
#Creates New Shepherd Ave. Substation
NEWBUSD 34348, NAME=SHEPHERD, BASKV=115,BUSTYPE=1,VSCHED=1, AREA=14, ZONE=314, OWN=390
MOVE_BRANCH  34360, 34414,  1,  34348
#Shepard-Woodward Jct Line is made up of 5 miles of 1113AAC and 2 miles of 795 SSAC
OLDSECDD  34360, 34348, CKT=1, SEC=1, STATUS=1,+
        RPU=.00554678, XPU=.0359268, BPU=.0058599, MVA1=164, MVA2=194, MVA3=256, MVA4=274,+
        OWN=390, AREA=14, ZONE=314
#Shepard-Woodward Sub Line is made up of 3 miles of 1113AAC and 2 miles of 795 SSAC
NEWSECDD  34414, 34348, CKT=1, SEC=1, RPU=.004105, XPU=.0256968, BPU=.00417587,+
    MVA1=164, MVA2=194, MVA3=256, MVA4=274, STATUS=1, AREA=14, ZONE=314, OWN=390
#New SVD at Shepherd two steps of 25 MVAR
NEWSVD   34348, v, ST=1, TYPE=4, VBAND=.02, BINIT=50,  N0=2, B0=25,AREA=14, ZONE=314, OWN=390
#Distribution load from 2006 Woodward DPA for year 2011
NEWLOAD  34348, LOADID=1, AREA=14, ZONE=314, PLOAD=22.3, OWN=390, PF=.98, ST=1
```

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagrams
2. Demand Forecast
3. Power Flow Summary
4. Pre and Post Project Power Flow Plots

Attachment 1: Scope Diagrams

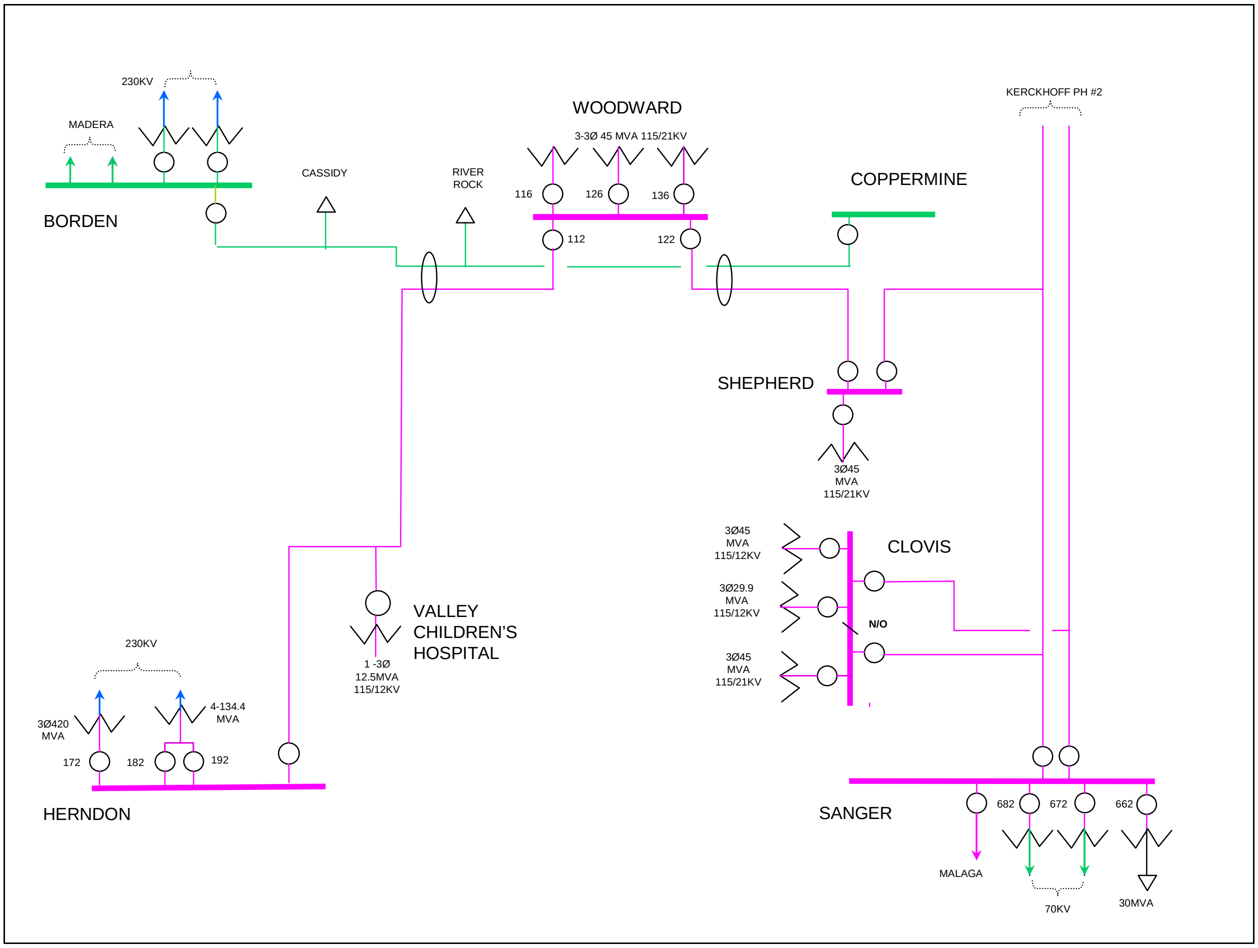


Figure 4-179: Shepherd Substation Interconnection Without MVAr Support

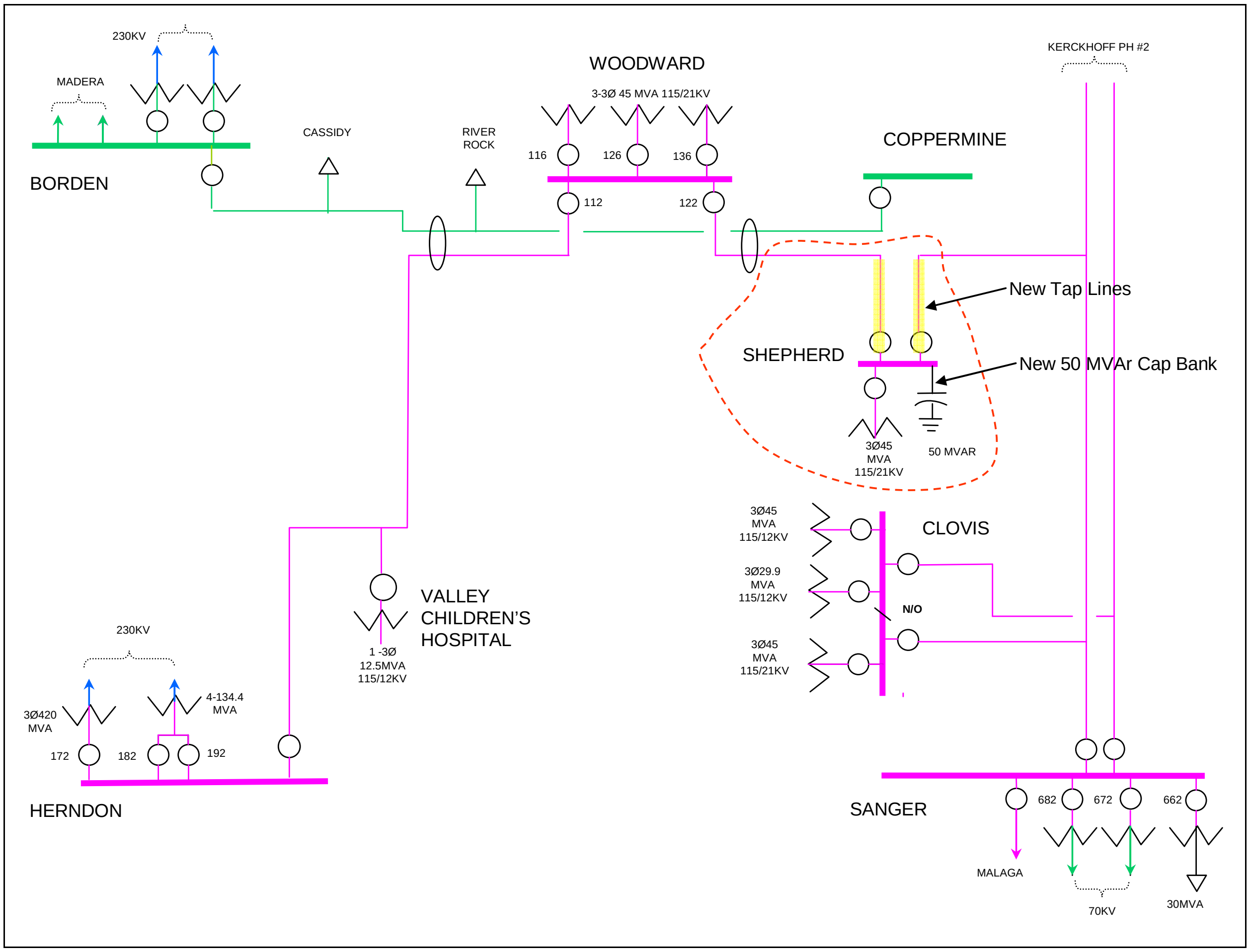


Figure 4-180: Proposed Scope Diagram

Attachment 2: Demand Forecast

Table 4-53: Area Load Demand Forecast

Substation/Bank	2009 (MW)	2010 (MW)	2011 (MW)	2012 (MW)	2013 (MW)	Growth Rate(MW/yr)
Clovis Bank 1	30.8	30.9	31.1	38.6	39.0	2.1
Clovis Bank 2	45.5	46.7	48.0	49.1	50.4	1.2
Clovis Bank 3	42.0	42.0	43.0	44.0	45.0	0.8
Shepherd	--	--	11.2	18.2	22.3	5.6
Woodward Bank 1	39.2	39.9	40.7	41.3	42.1	0.7
Woodward Bank 2	48.9	49.8	50.8	51.6	52.5	0.9
Woodward Bank 3	40.9	41.7	42.5	43.1	44.0	0.8
Total Area Load	**247**	**251**	**267**	**286**	**295**	**12**

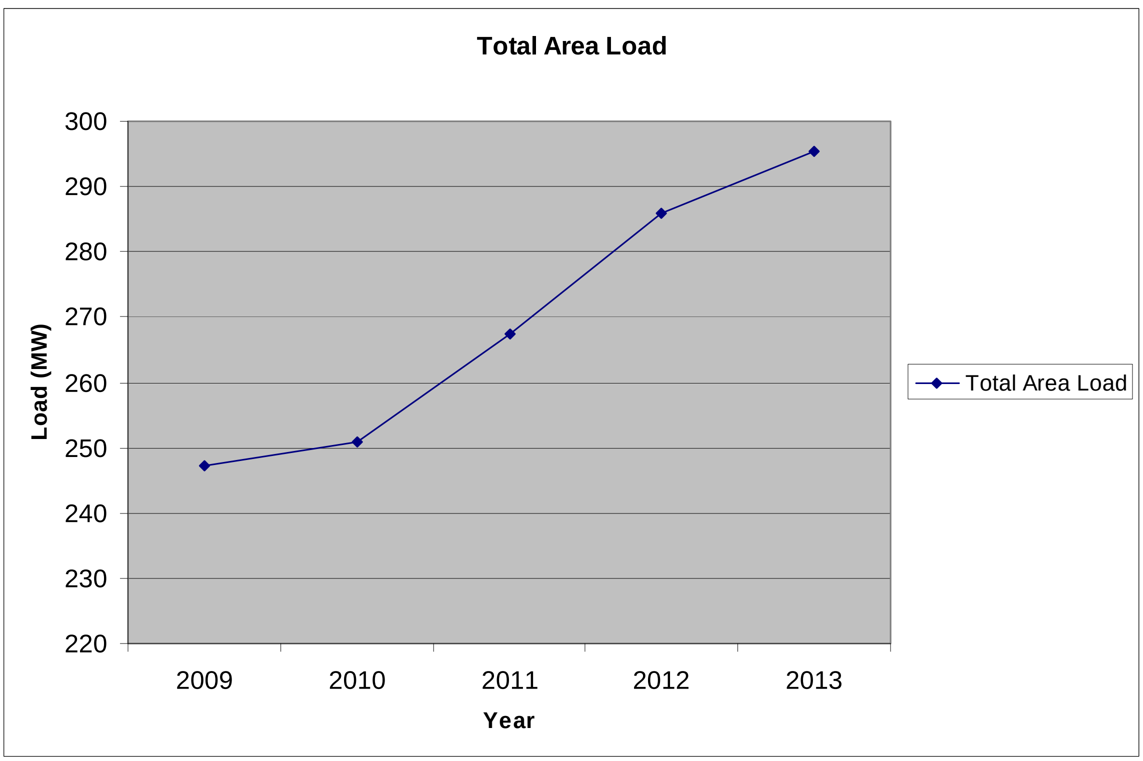


Figure 4-181: Area Load Demand Curve

Attachment 3: Power Flow Results

Table 4-54: Power Flow Results

			Pre-Project			Post Project	
#	Facility	Facility Rating	2011	2012	2013	2013	Contingency
1	Woodward 115 kV Bus	1.0 pu	0.93	0.92	0.91	0.98	Herndon-Woodward 115 kV Line and Kerchoff 2 (L-1/G-1)

Attachment 4: Pre and Post Power Flow Plots

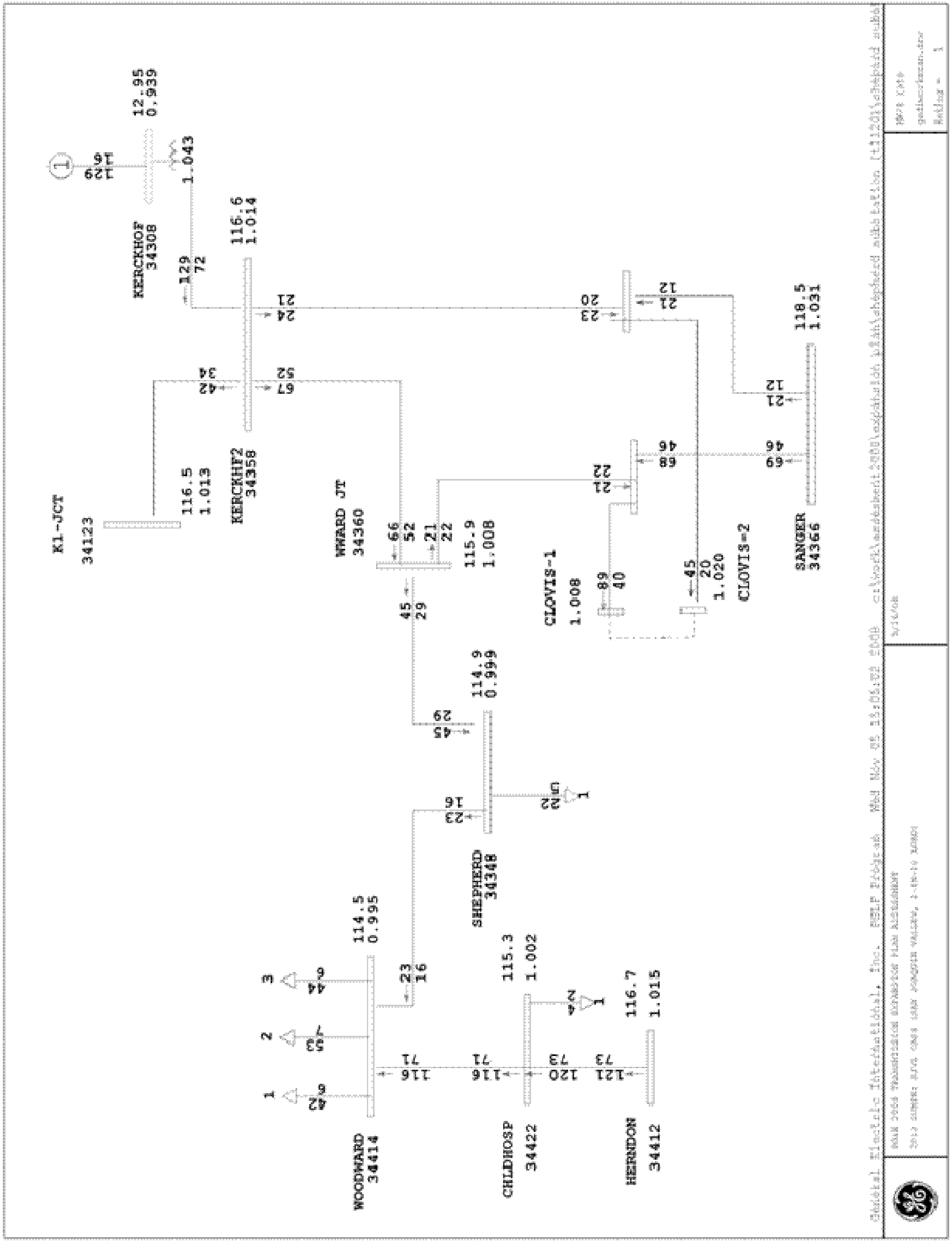


Figure 4-182: Pre Project – Normal Conditions

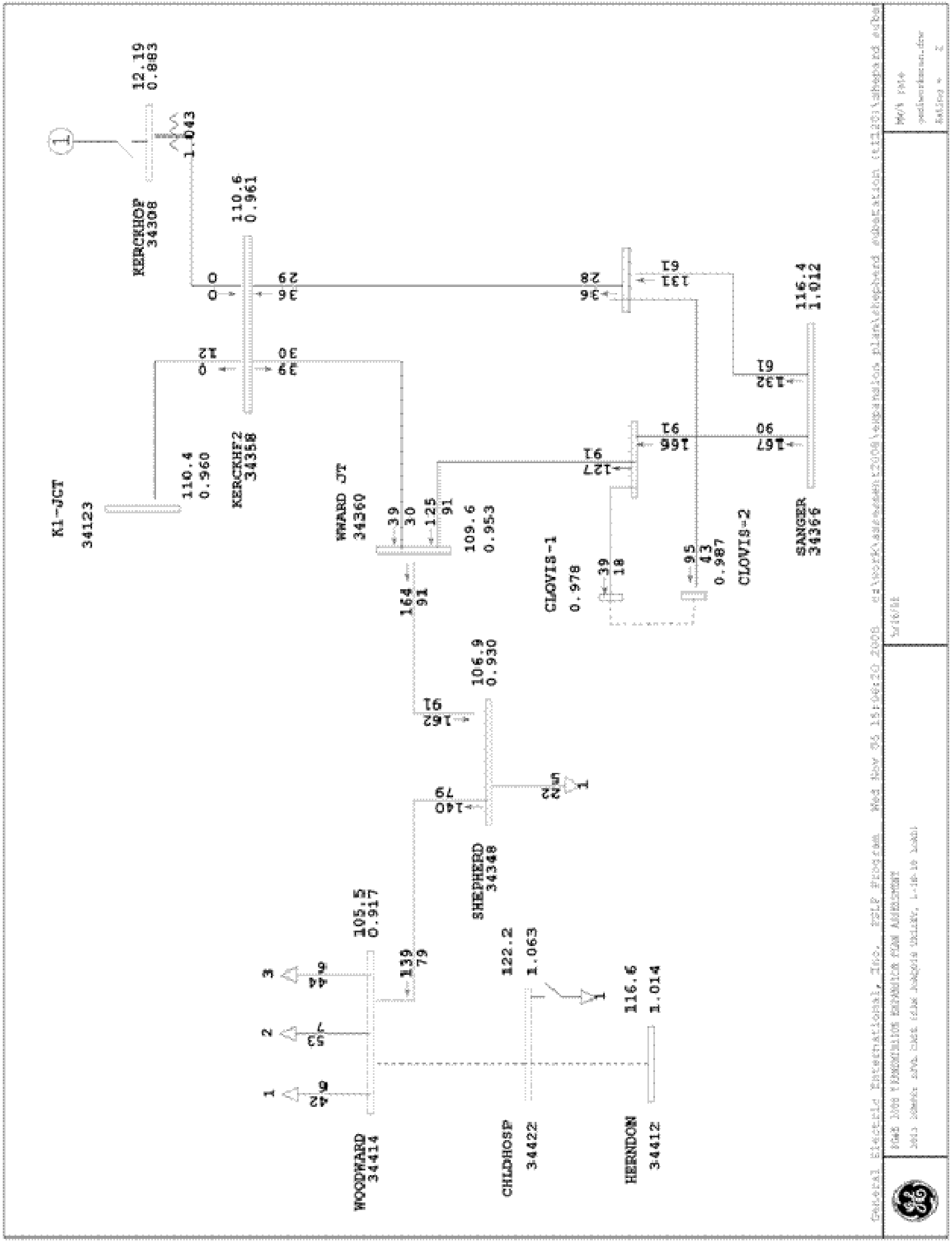


Figure 4-183: Pre Project – Herndon-Woodward 115 kV Line and Kerckhoff #2 Outage (L-1/G-1)

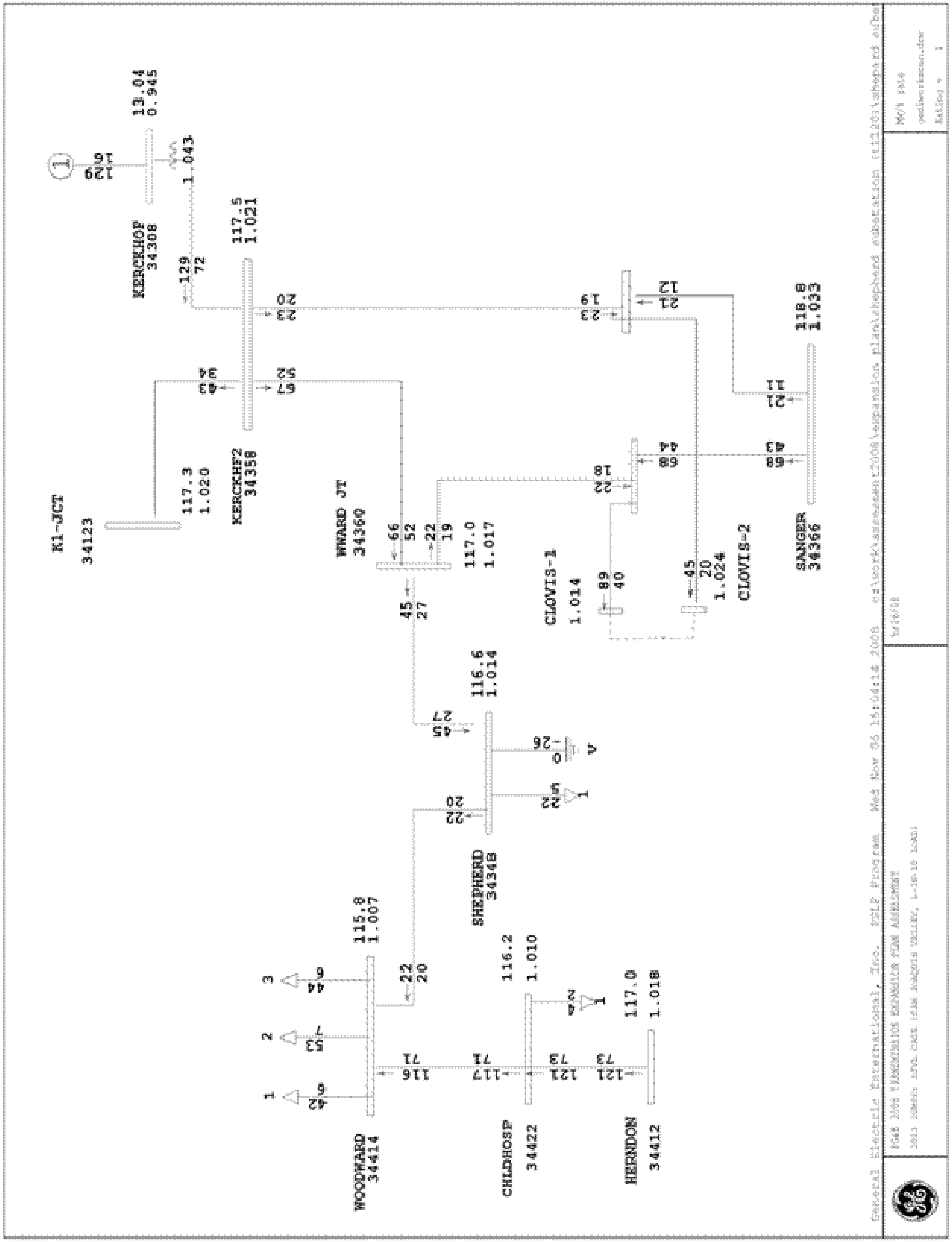


Figure 4-184: Post Project – Normal Conditions

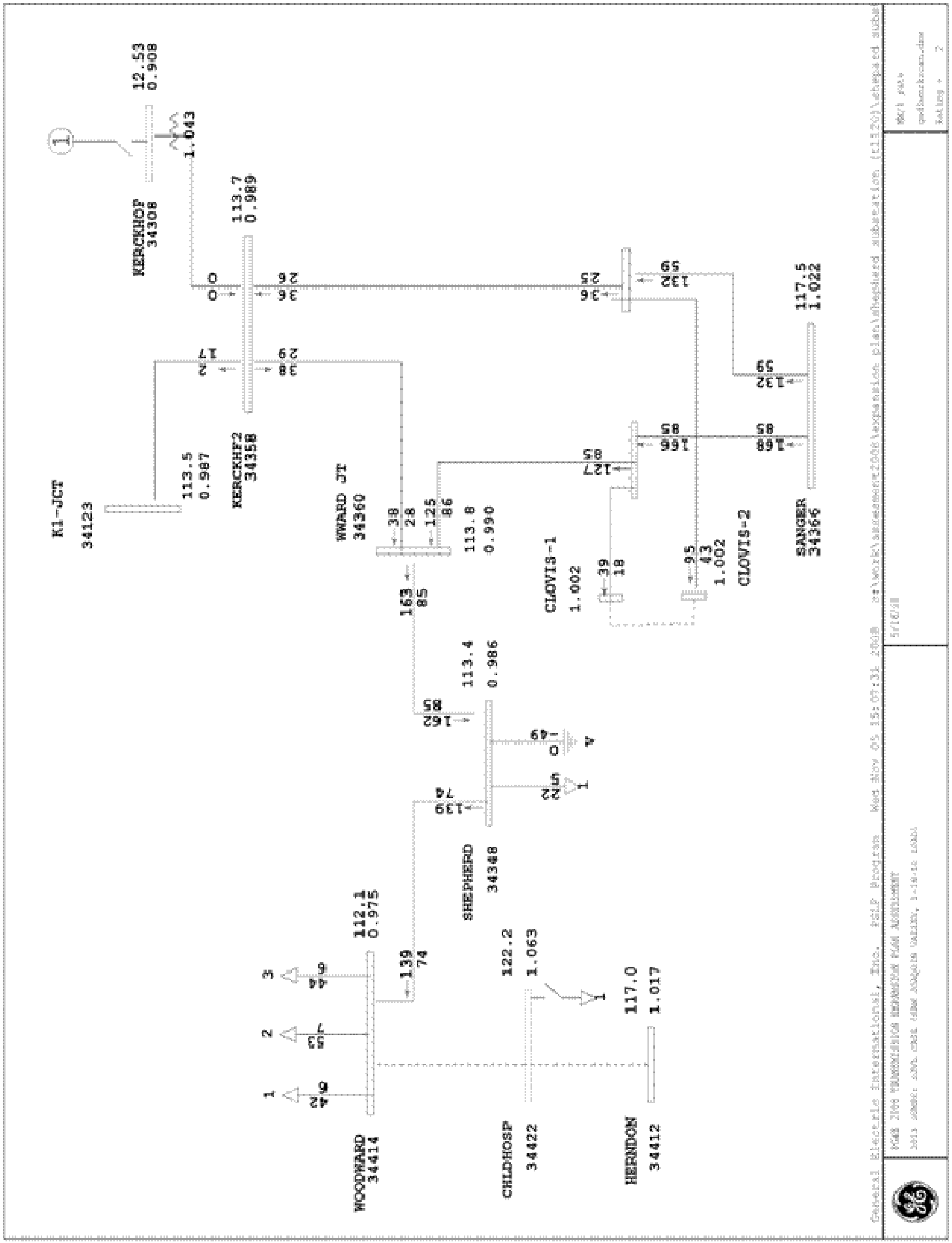


Figure 4-185: Post Project – Herndon-Woodward 115 kV Line and Kerchkoff #2 Outage (L-1/G-1)

West Fresno 115 kV Bus Upgrade

TARGETED IN-SERVICE DATE

May 2011

PURPOSE AND BENEFIT

Reliability – Operational Flexibility

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROJECT

The project scope is to convert the existing 115 kV main-aux bus arrangement at West Fresno Substation to a standard loop bus arrangement.

The project is expected to cost between $3M and $5M.

BACKGROUND

West Fresno Substation is a distribution station located within Fresno County. It connects to the transmission grid via the West Fresno-California Ave. and McCall-West Fresno No. 2 115 kV Lines. West Fresno has two 45 MVA, 115/12 kV distribution banks with a recorded 2008 summer peak load of 83.65 MW.

West Fresno Substation currently uses a main/aux bus configuration, with five elements. Under this bus arrangement, a bus or bank outage results in the loss of the entire substation. PG&E proposes to install a third 45 MVA distribution bank with circuit breaker protection by June 2009. This bank installation is Phase 1 of the looped configuration project; the new bank will connect directly to the main bus only. This project scope (Phase 2) will complete the transition to a looped station and provide improved reliability to the remaining distribution banks.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended since it does not provide any high side protection for West Fresno distribution banks No. 1 and No. 2.

PROJECT SCHEDULE

- Environmental and Permitting Processes – Not Applicable
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2011

KEY ISSUES

- Land-Use Restrictions – None
- Environmental Concerns – None
- Special Metering or Protection – None
- Common Mode Exposure Items – None
- Interaction with other Projects or Studies – None

GEPSLF MODELING INFORMATION

Not Applicable

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagrams
2. Demand Forecast

Attachment 1: Scope Diagrams

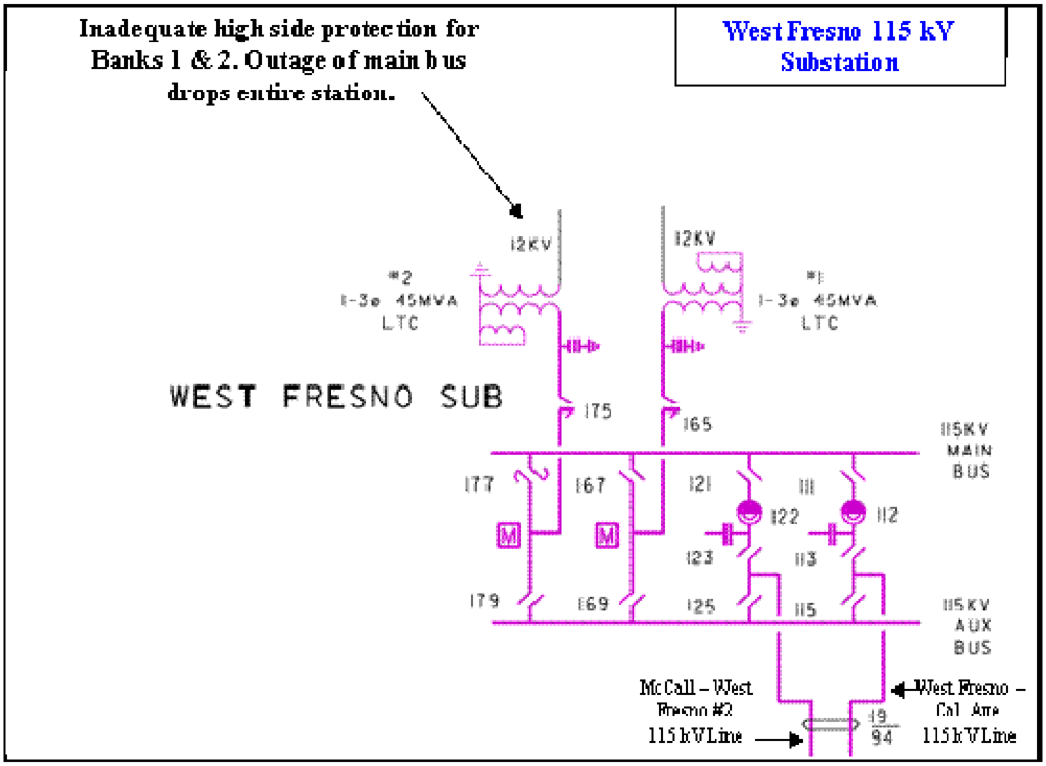


Figure 4-186: Existing Scope Diagram

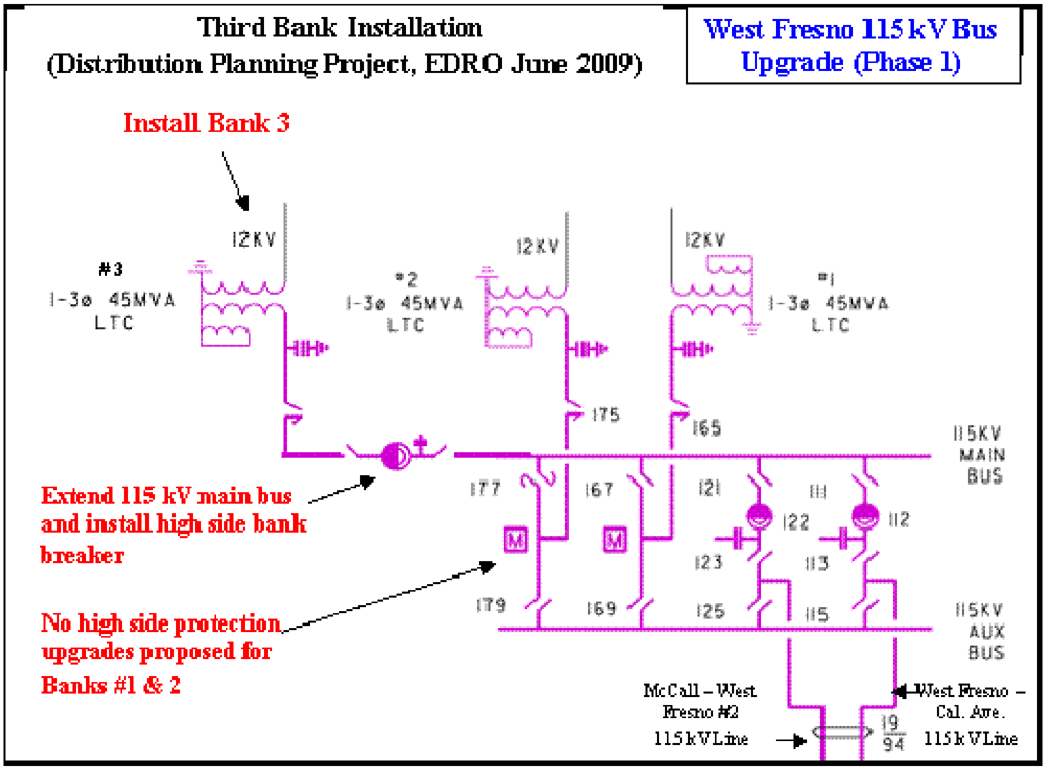


Figure 4-187: West Fresno Substation with 3rd bank Installation (2009 Installation)

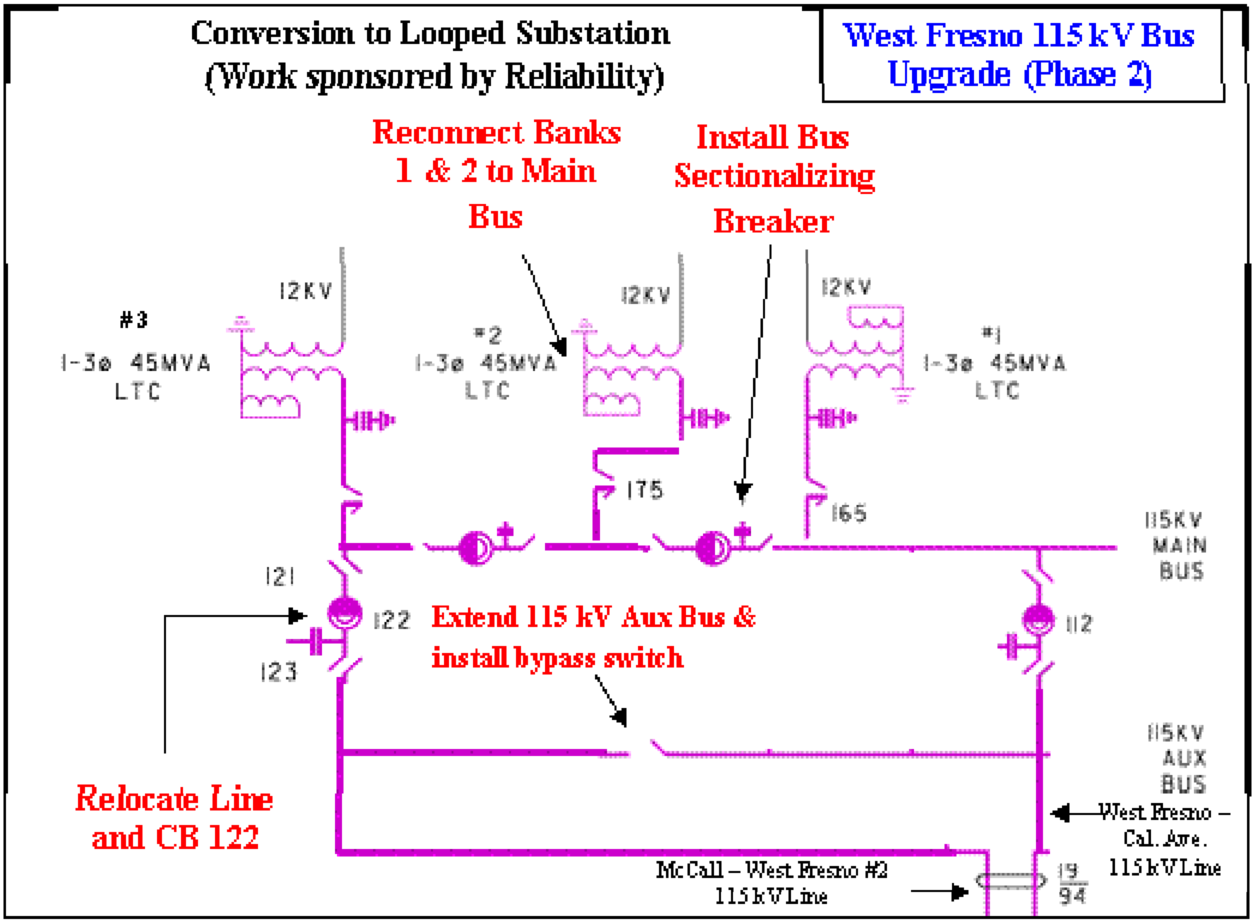


Figure 4-188: Proposed Scope Diagram

Attachment 2: Demand Forecast

Table 4-55: Area Load Demand Forecast

Facility	*Projected Peak Load (MW)*				
	2009	**2010**	**2011**	**2012**	**2013**
115 kV System					
West Fresno Bank 1	35.7	36.1	36.5	36.7	37.2
West Fresno Bank 2	37.1	37.5	37.9	38.2	38.6
West Fresno Bank 3	16.1	16.6	17	17.4	17.8
Total:	**89**	**90**	**91**	**92**	**94**

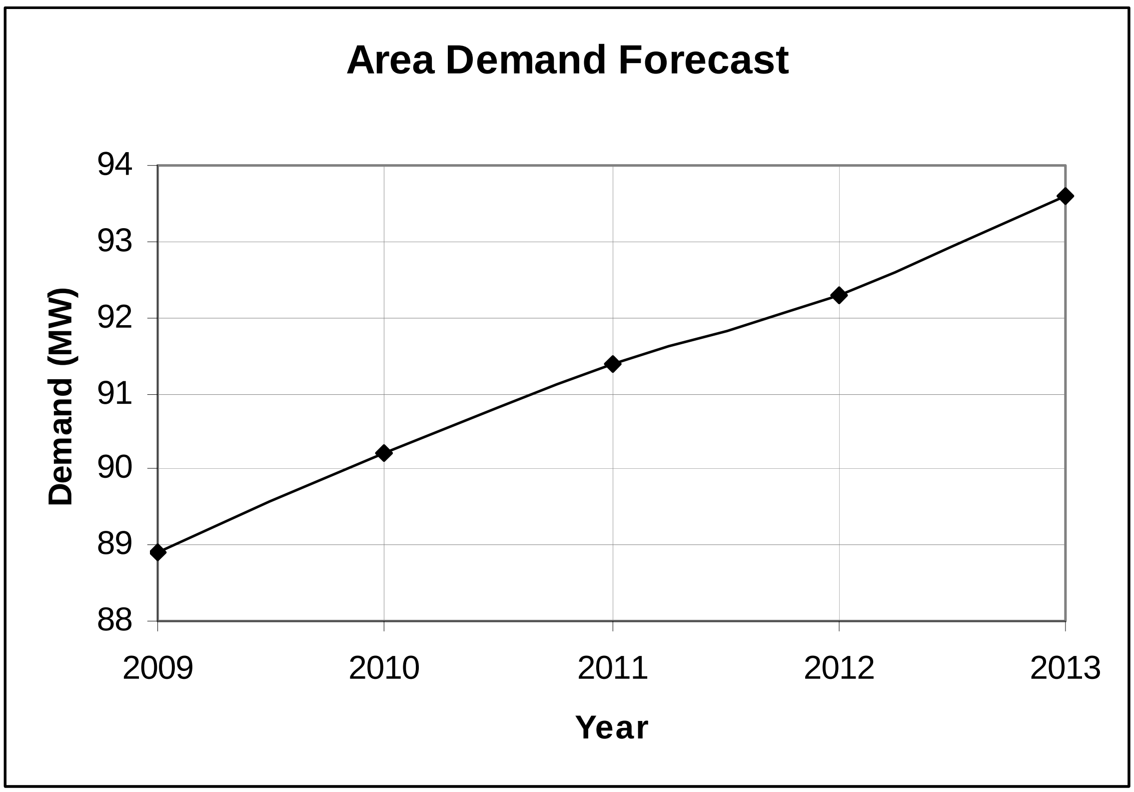


Figure 4-189: Area Load Demand Curve

2012 Projects

Evergreen – Mabury 60 kV to 115 kV Conversion

TARGETED IN-SERVICE DATE

May 2012

PURPOSE AND BENEFIT

Reliability – NERC Compliance

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROJECT

The project scope is to convert Mabury Substation to 115 kV and rebuild the Evergreen – Mabury 60 kV line (approximately 6 miles long) into a 115 kV circuit with conductors rated to handle a minimum of 700 Amps under summer normal conditions and a minimum of 800 Amps under summer emergency conditions.

This project is expected to cost between $10M and $15M.

BACKGROUND

Mabury Substation, located in Santa Clara County, supplies power to approximately 13,000 customers living in east San Jose. Approximately half of these customers are served from a 115/12 kV transformer, which is supplied via a tap into the McKee-Piercy 115 kV line. The other half are served from a 60/12 kV transformer, which is supplied via a radial line from Evergreen Substation. The McKee-Piercy 115 kV line is part of the old Newark-Metcalf No. 1 115 kV line, which serves over 80, 000 customers. The proposed extension of the BART system into downtown San Jose would connect a new traction power substation into this part of the 115 kV system.

The Evergreen-Mabury 60 kV line is approximately 6 miles long, and is composed of 4/0 CU, 336 AAC and 397 AAC conductors. The line is currently limited by the 4/0 CU conductor which is rated at 415 Amps normal and 470 Amps emergency.

Planning analysis has identified that an outage of either the 115 kV or 60 kV line into Mabury Substation would affect over 6,000 customers. In addition, continuing load growth in east San Jose will require the reconductoring of the ends of the Newark – Metcalf No. 1 115 kV line, specifically the Newark-Dixon Landing and the Metcalf-Piercy

115 kV Lines. This could require rebuilding of the lattice steel towers to accommodate the new conductor.

By converting the 60 kV portion of Mabury Substation to 115 kV and rebuilding the Evergreen-Mabury 60 kV line into a 115 kV circuit, the substation will be normally supplied via two 115 kV lines. This will improve reliability to customers served from Mabury Substation. In addition, the 115 kV connection from Evergreen will eliminate the future [L-1] overloads on the Newark-Metcalf No. 1 115 kV line and will help improve the post-contingency voltages.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended. This alternative does not address the potential overload issue.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2012

KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – TBD
- Special Metering or Protection – TBD
- Common Mode Exposure Items – TBD
- Interaction with other Projects – TBD

GEPSLF MODELLING INFORMATION

```
#  Convert 5.4 miles of 60kV line to 115kV with 954 AAC
#        1) Extract some buses (Evergreen Jct) and revise other buses as 115kV buses
#        2) Add Mabury 60kV load as Mabury 115kV load 1
#        3) Used Aspen models HH_715-954 along Senter Road and T1-954 remainder
#             HH_715-954 values from Aspen: R=0.1103, X=0.71044, B=0.016297
#             T1 values from Aspen: R=0.1103, X=0.68519, B=0.016653
#        4) Assume 2 fps normal and emergency ratings
#        5) Total line length = 1.48 miles of HH construction and then
#                          1.37 miles of T1 to Jennings Jct,
#                          2.70 miles of T1 from Jennings Jct to Mabury
#                      and  2.93 miles of T1 from Mabury to Mabury Jct

# Convert some 60 kV buses to 115 kV
#
OLDBUSD  35751,"JENNINGS",115.,,,,,,,,,,
OLDBUSD  35752,"JENING J",115.,,,,,,,,,,

# Move the Mabury 60 kV load to the Mabury 115 kV bus and the Jennings Jct-Mabury
#    secdd to the Mabury 115 kV bus
#
MOVE_LOAD 35750,1,35630,1
MOVE_BRANCH 35752,35750,1,35630

# Delete the Evergreen Junction and Mabury 60 kV buses
#
EXTRACT 35754 35750

# Reconductor the Evergreen-Jennings Jct 115 kV line section
#
NEWSECDD 35633,35752,1,1,0.002377,0.015048,0.002340,167,191,233,249,1,18,318,390

# Reconductor the Jennings Jct-Mabury 115 kV line section (T1 construction with 954 AAC)
OLDSECDD 35752,35630,1,1,1,0.002252,0.013989,0.002242,167,191,233,249,,,,,
# Reconductor the Mabury-Mabury Jct 115 kV line section (T1 construction with 954 AAC)
OLDSECDD 35629,35630,1,1,1,0.002444,0.015180,0.002433,167,191,233,249,,,,,

#END
```

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagram
2. Power Flow Summary
3. Pre and Post Project Power Flow Plots

Attachment 1: Scope Diagram

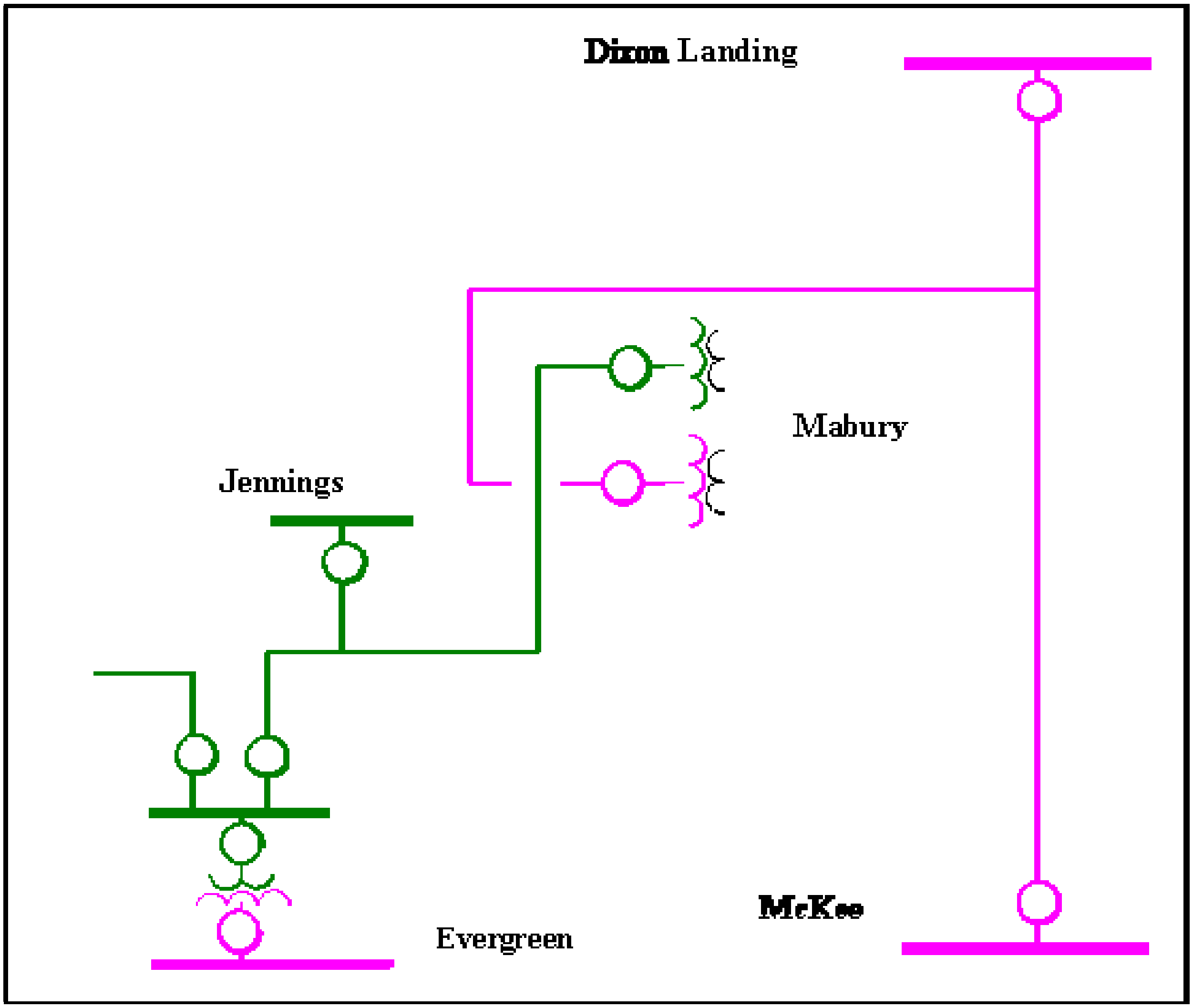


Figure 4-190: Scope Diagram (Existing)

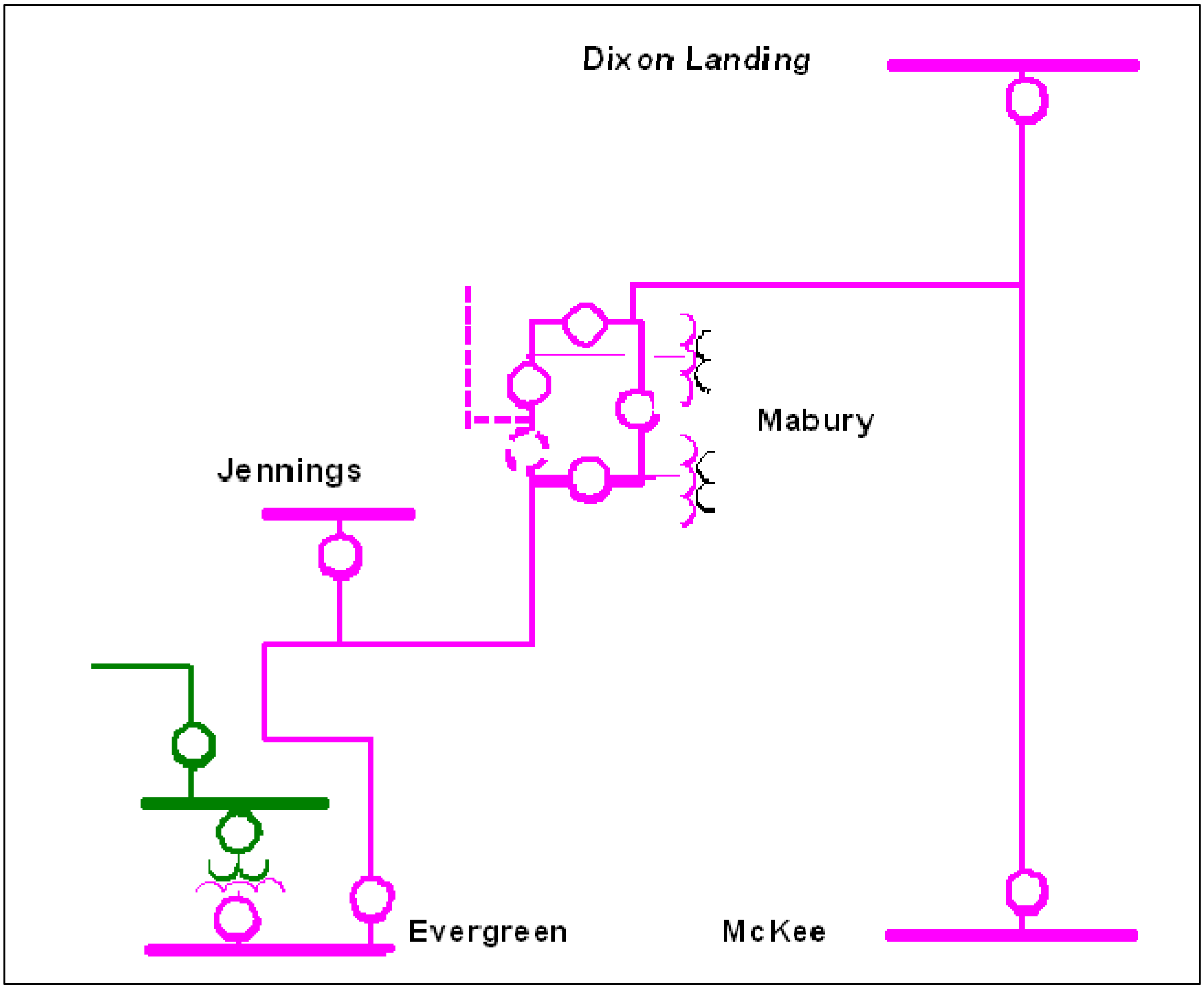


Figure 4-191: Scope Diagram (Proposed)

Attachment 2: Power Flow Summary

Table 4-56: Power Flow Summary

Normal/Contingency	Facility Affected	Facility Rating	2012 Pre-Project	2013 Pre-Project	2018 Pre-Project	2018 Post-Project
Normal Condition	Metcalf-Piercy 115 kV Line	SN Rating 1144 Amps	73%	74%	74%	72%
Newark-Dixon Landing 115 kV Line		SE Rating 1144 Amps	99%	100%	107%	83%
Normal Condition	Piercy 115 kV Substation	115 kV	1.02 p.u.	1.02 p.u.	1.02 p.u.	1.02 p.u.
Newark-Dixon Landing 115 kV Line			0.95 p.u.	0.95 p.u.	0.94 p.u.	0.98 p.u.
Normal Condition	Newark-Dixon Landing 115 kV Line	SN Rating 1144 Amps	28%	28%	30%	28%
Metcalf-Piercy 115 kV Line		SE Rating 1144 Amps	101%	102%.	105%	60%
Normal Condition	Dixon Landing 115 kV Substation	115 kV	1.02 p.u.	1.02 p.u.	1.02 p.u.	1.02 p.u.
Metcalf-Piercy 115 kV Line			0.94 p.u.	0.94 p.u	0.95 p.u.	0.97 p.u.

Attachment 3: Pre and Post Project Power Flow Plots

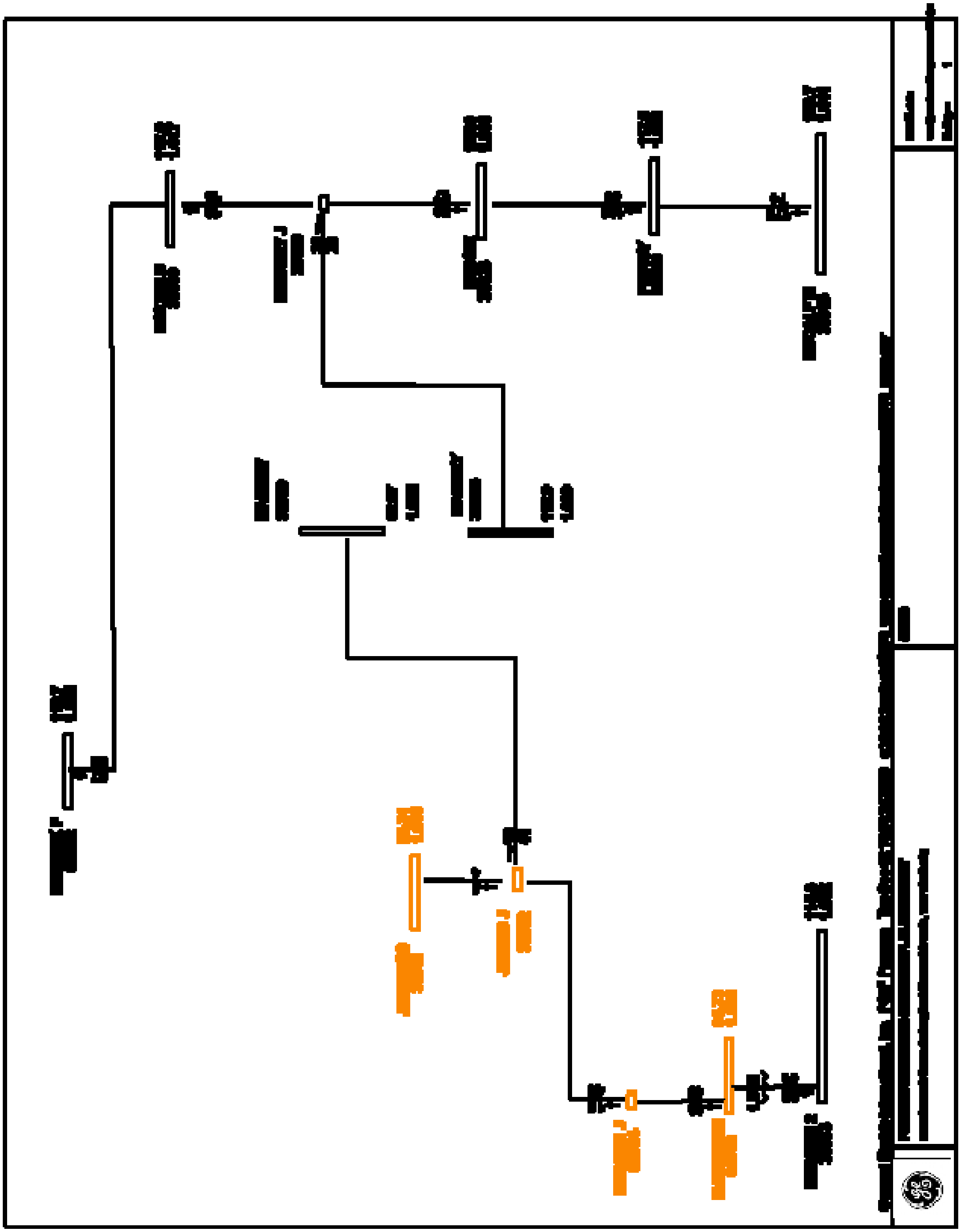


Figure 4-192: All Facilities in service, Year 2012 (Pre-Project)

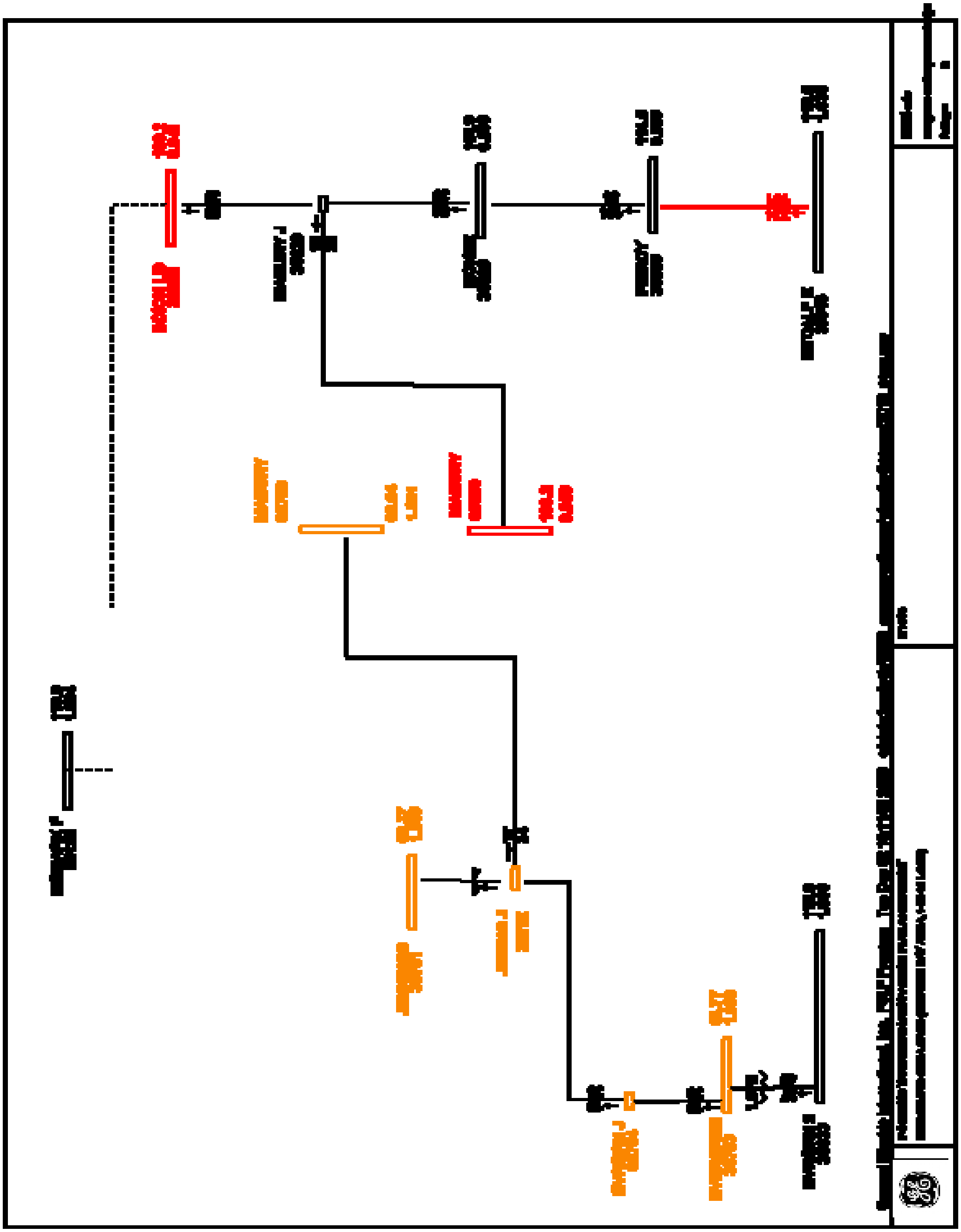


Figure 4-193: Outage of Newark-Dixon Landing 115 kV Line section, Year 2012 (Pre-Project)

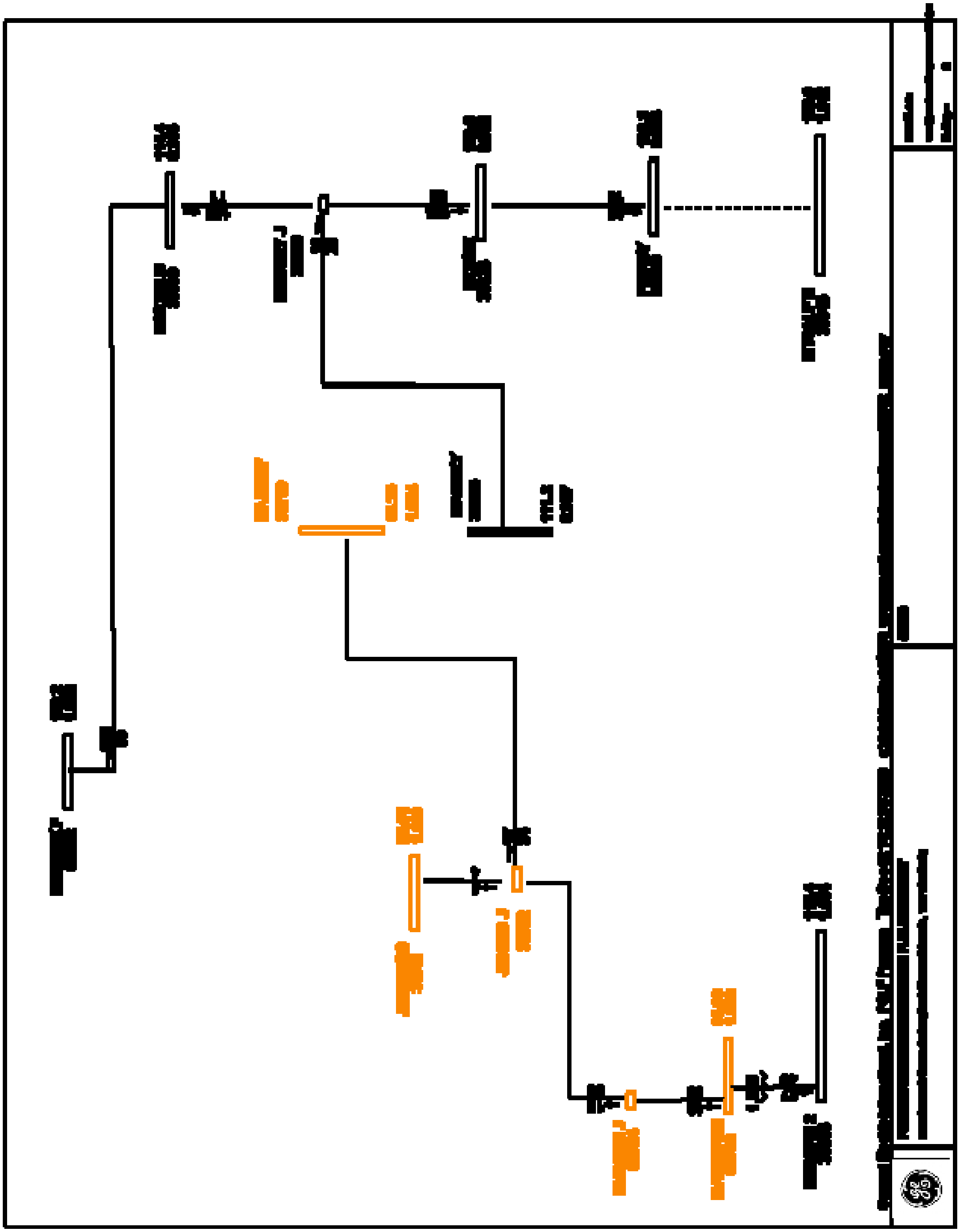


Figure 4-194: Outage of Metcalf-Piercy 115 kV Line section, Year 2012 (Pre-Project)

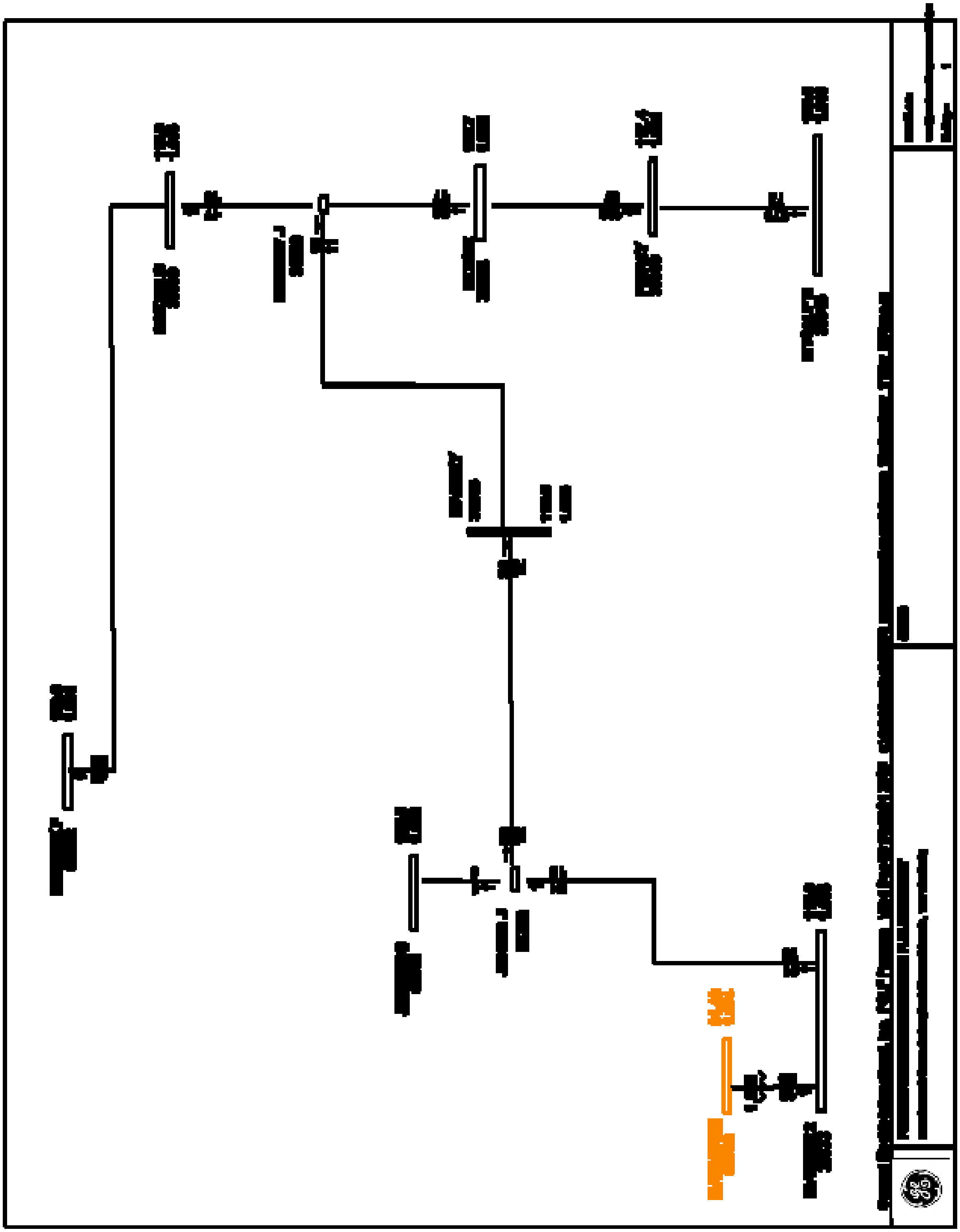


Figure 4-195: All Facilities in service, Year 2012 (Post-Project)

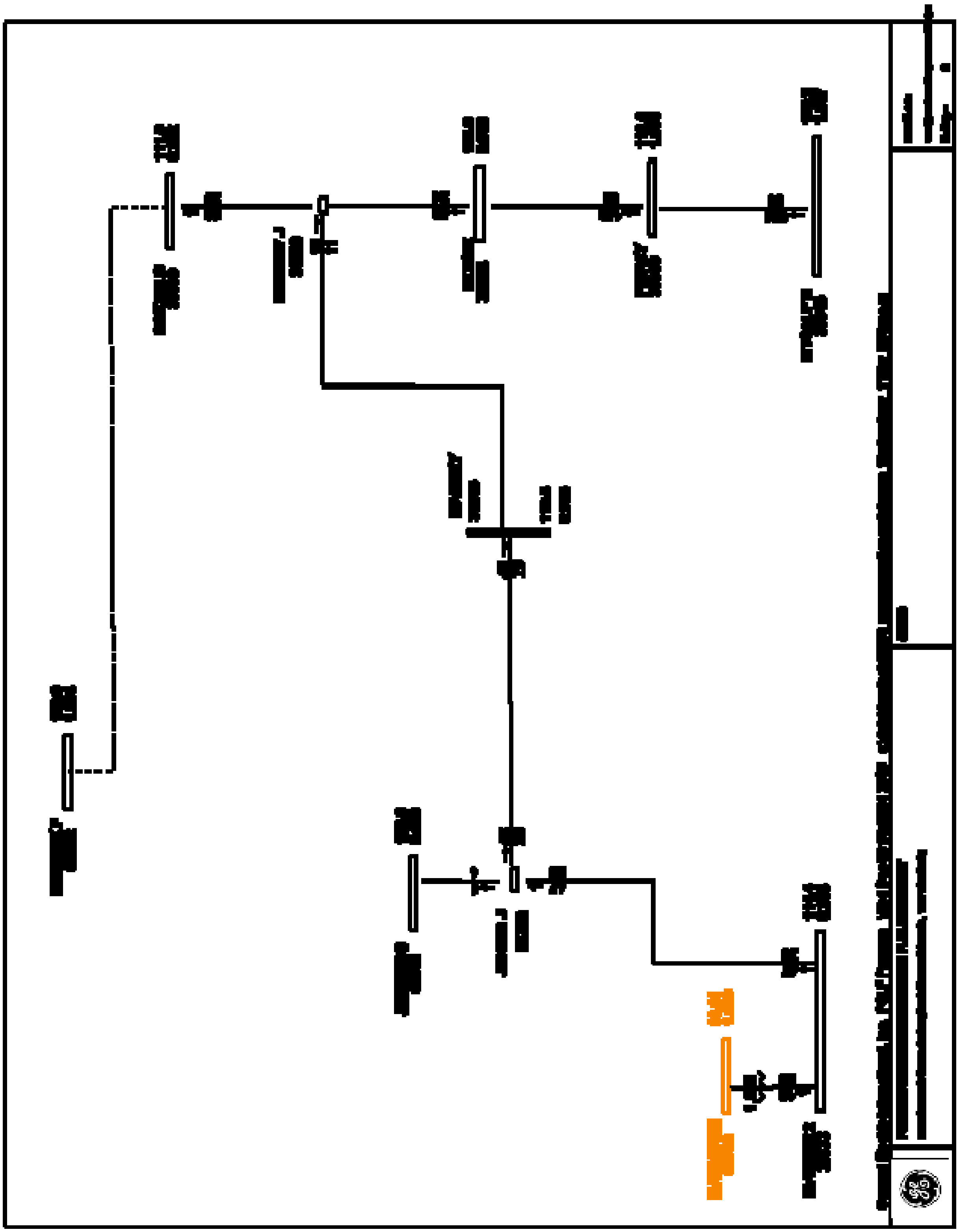


Figure 4-196: Outage of Newark-Dixon Landing 115 kV Line section, Year 2012 (Post-Project)

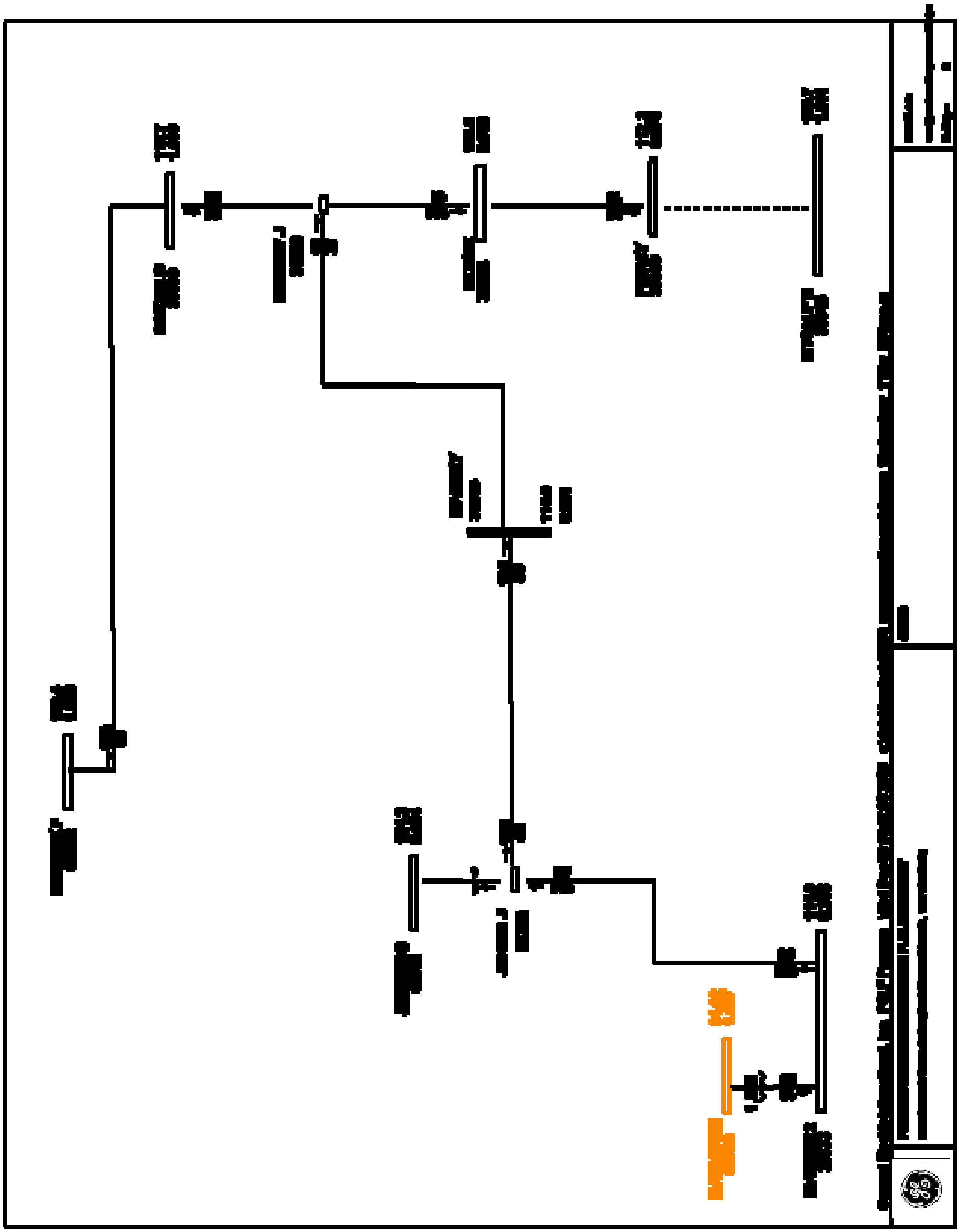


Figure 4-197: Outage of Metcalf-Piercy 115 kV Line section, Year 2012 (Post-Project)

Metcalf – Morgan Hill 115 kV Reinforcement

TARGETED IN-SERVICE DATE

May 2012

PURPOSE AND BENEFIT

Reliability – NERC Compliance and LCR Reduction

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROJECT

The recommended alternative is to loop Morgan Hill 115 kV Substation using the Metcalf – Llagas 115 kV Line and to reconductor the existing Metcalf – Morgan Hill 115 kV Line No. 1 and the new Metcalf – Morgan Hill 115 kV Line No. 2 with conductors rated to handle a minimum rating of 1500 Amps under summer normal conditions and summer emergency conditions.

This project is expected to cost between $10M and $20M.

BACKGROUND

Llagas pocket, located in Santa Clara County, has two 115 kV lines that are critical in serving electric customers in the area. The Metcalf – Llagas 115 kV Line, which comprises of sections from the Metcalf – Green Valley and Green Valley – Llagas 115 kV Line, is composed of 715 AAC conductor. The Metcalf – Green Valley section of the Metcalf – Llagas 115 kV Line is approximate 10 miles long and has a coastal Summer Normal/Emergency rating of 839/949 Amps, respectively. The Metcalf – Morgan Hill 115 kV Line is also composed of 715 AAC conductor and has a coastal Summer Normal/ Emergency rating of 839/949 Amps, respectively.

The Llagas pocket relies on both internal generation and transmission line imports to serve electric customer demand. Planning analysis has determined that an outage of Metcalf - Morgan Hill 115 kV Line results in reliance on local generation to prevent potential thermal/voltage concerns in the Llagas 115 kV area.

The proposed project is needed to meet future electric demand increase, improve grid operation efficiency, and reduce CAISO's local capacity requirements.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended. This alternative does not address the potential overload issue.

PROJECT SCHEDULE

- Environmental and Permitting Processes – None
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2012

KEY ISSUES

- Land-Use Restrictions – None
- Environmental Concerns – None
- Special Metering or Protection – TBD
- Common Mode Exposure Items – None
- Interaction with other Projects – TBD

GEPSLF MODELING INFORMATION

Reconductor Metcalf - Morgan Hill 115 kV Line No. 1 with 795 ACSS or Larger (9.67 Miles)
OLDSECDD 35642 35646 CKT=1 SEC=1 STATUS=1 RPU=0.015165 XPU=0.05414 BPU=0.0074225 MVA1=307 MVA2=307+
MVA3=330 MVA4=330

New Metcalf - Morgan Hill 115 kV Line No. 2 with 795 ACSS or Larger(9.67 Miles)
NEWSECDD 35642 35646 CKT=2 SEC=1 STATUS=1 RPU=0.015165 XPU=0.05414 BPU=0.0074225 MVA1=307 MVA2=307+
MVA3=330 MVA4=330
#
New Morgan Hill - Llagas 115 kV Line No. 2 with existing 715AAC (10.67 Miles)
NEWSECDD 35646 35648 CKT=2 SEC=1 STATUS=1 RPU=0.01197 XPU=0.05935 BPU=0.00848 MVA1=126 MVA2=148 +
MVA3=194 MVA4=207
#
Switch Metcalf - Green Valley 115 kV Line off
OLDSECDD 35642 35654 CKT=1 SEC=1 STATUS=0
Switch normally closed switch 179 open
OLDSECDD 35654 35655 CKT=1 SEC=1 STATUS=0
Switch the Green Valley - Llagas 115 kV Line off
OLDSECDD 35648 35655 CKT=1 SEC=1 STATUS=0

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagram
2. Power Flow Summary
3. Pre and Post Project Power Flow Plots

Attachment 1: Scope Diagram

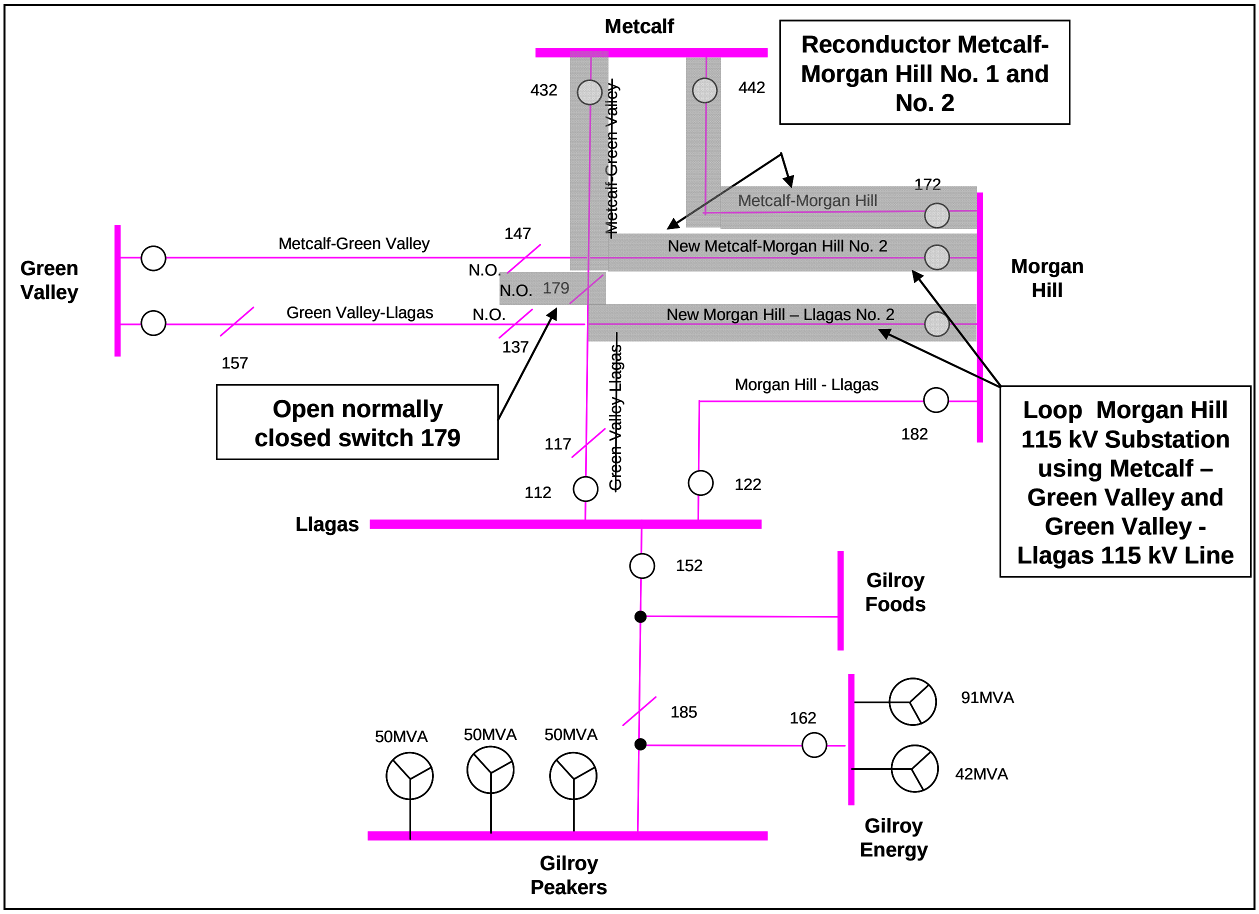


Figure 4-198: Metcalf 115 kV Area

Attachment 2: Power Flow Summary

Table 4-57: Power Flow Summary

Normal/Contingency	Facility Affected	2009 Pre-Project	2009 Post Project
Normal Conditions	Metcalf-Llagas 115 kV Line	48%	42%
Metcalf-Morgan Hill 115 kV Line		126%	83%

Attachment 3: Pre and Post Project Power Flow Plots

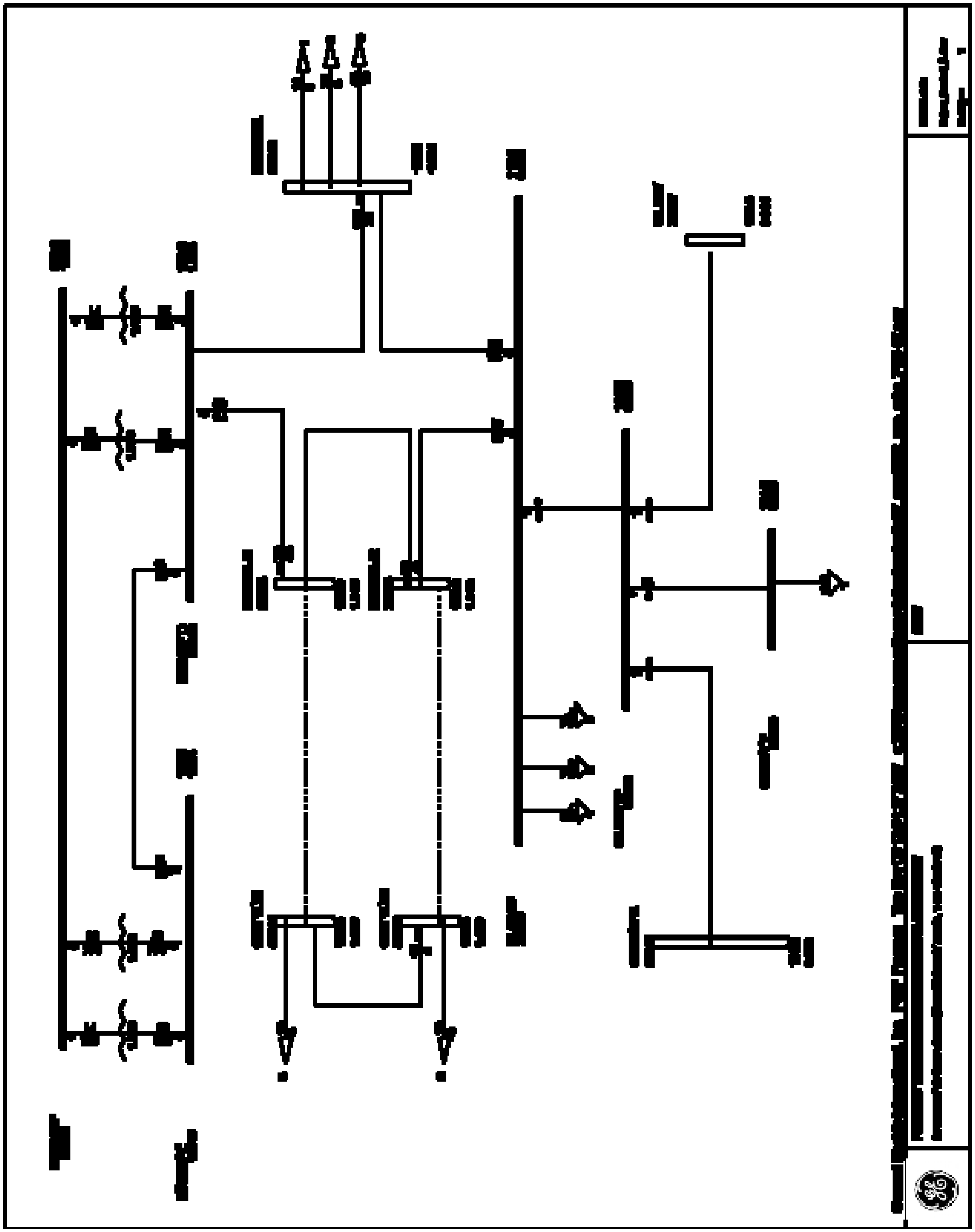


Figure 4-199: All Facilities In-Service, Year 2012 (Pre-Project)

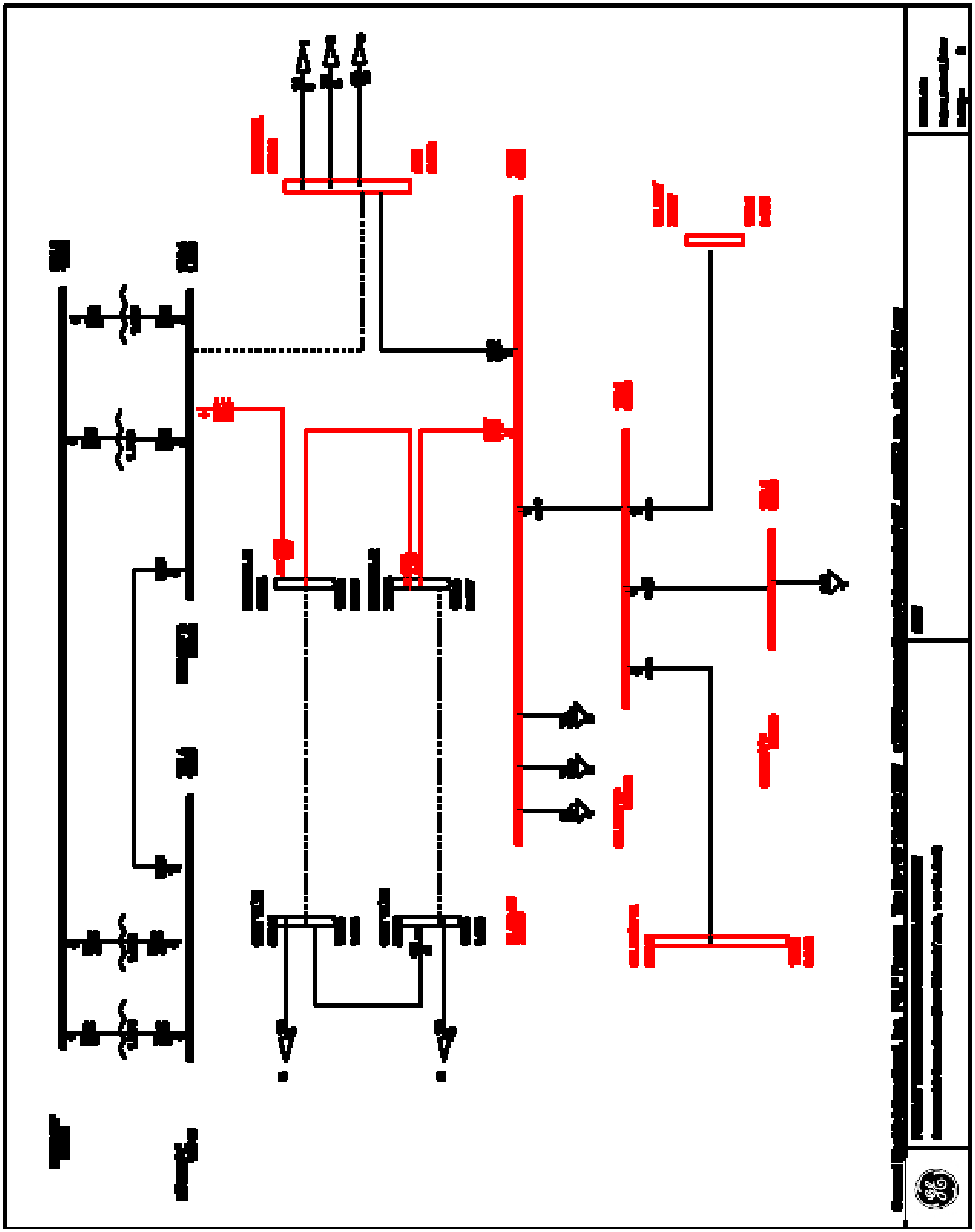


Figure 4-200: Outage of Metcalf – Morgan Hill 115 kV Line, Year 2012 (Pre-Project)

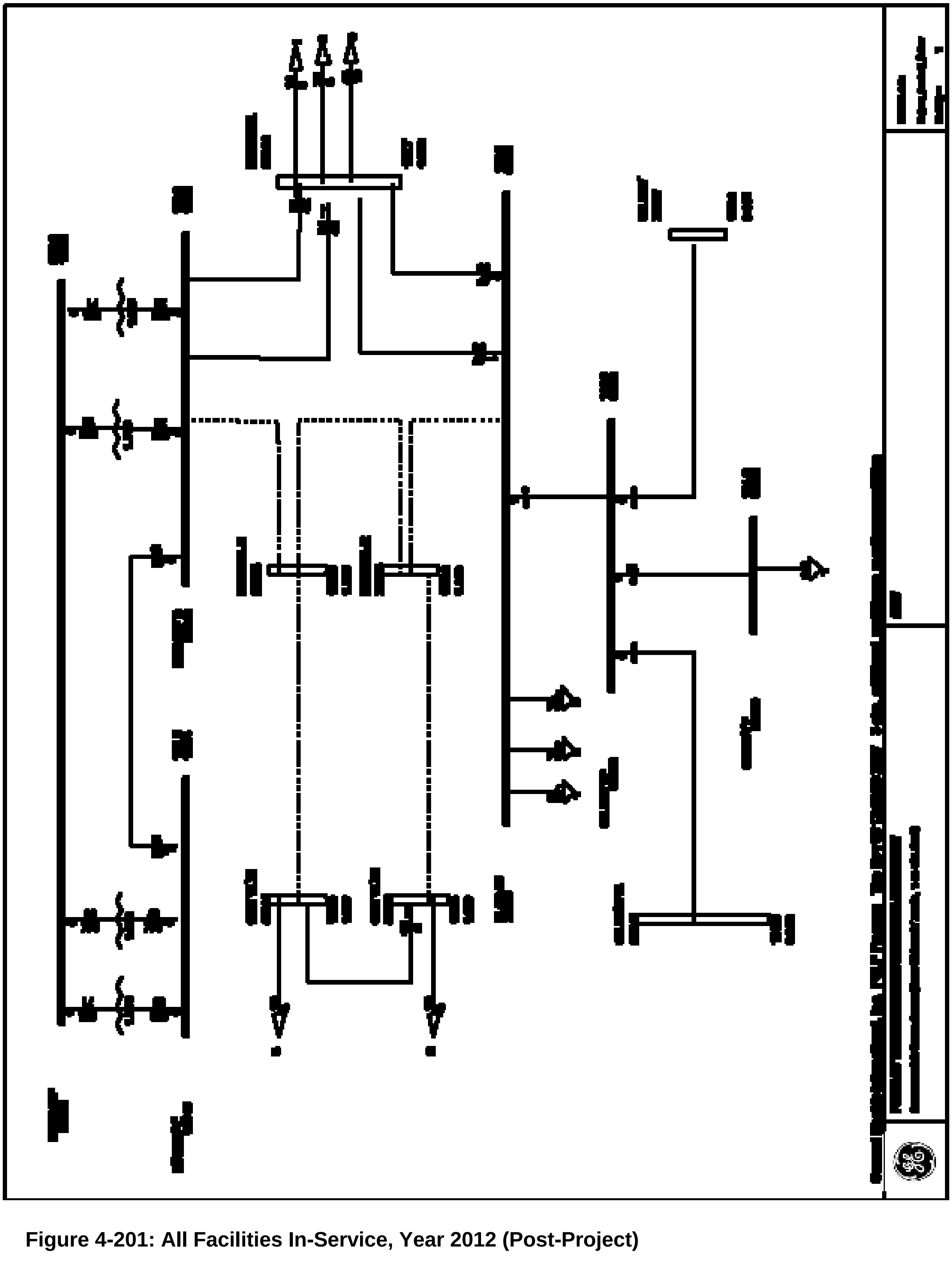


Figure 4-201: All Facilities In-Service, Year 2012 (Post-Project)

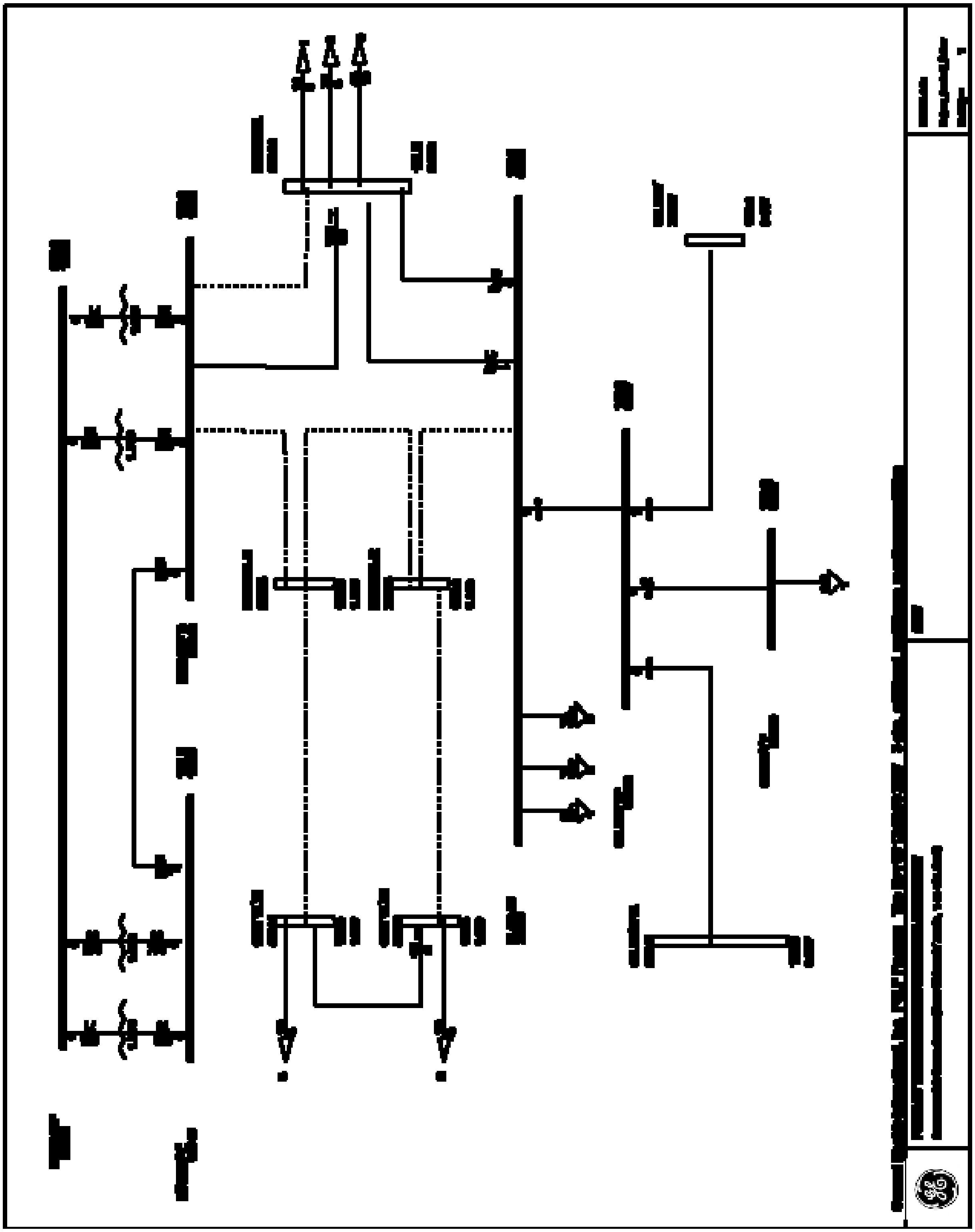


Figure 4-202: Outage of Metcalf – Morgan Hill 115 kV Line, Year 2012 (Post-Project)

Ravenswood – Cooley Landing 115 kV Reconductor

TARGETED IN-SERVICE DATE

May 2012

PURPOSE AND BENEFIT

Reliability – NERC Compliance

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROJECT

The project scope is to reconductor approximately 3.5 miles of the Ravenswood-Cooley Landing 115 kV Line Nos. 1 and 2 by 2012, with conductors rated to handle a minimum of 1,100 Amps under summer normal and emergency conditions. This alternative provides adequate line capacity for the foreseeable future.

This project is expected to cost between $5M and $10M.

BACKGROUND

Cooley Landing Substation, located in San Mateo County, has two critical 115 kV Lines providing power to over 38,000 electric customers in the area. Ravenswood – Cooley Landing 115 kV Lines Nos. 1 and 2 are double-circuit tower lines (DCTLs) composed of 715 AAC conductors with Summer Normal and Summer Emergency ratings of 780 amps and 885 amps, respectively.

The Jefferson 230/60 kV transformers help serve customers in this area. With Jefferson 230/60 kV Transformer No. 1 currently out of service, loadings turn to increase on the Ravenswood-Cooley Landing 115 kV lines. If this transformer is installed as planned in 2009, and the Cooley Landing 115 kV bus is converted to a BAAH arrangement as planned in 2011, loadings would decrease on the Ravenswood-Cooley Landing 115 kV lines.

Studies show that for 2012 summer peak conditions, the Ravenswood-Cooley Landing 115 kV Line Nos. 1 and 2 would overload by approximately 1% following an outage of its parallel line overlapped with Cardinal cogeneration offline (L-1/G-1).

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended. This alternative does not address the potential overload concerns.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2012

KEY ISSUES

- Land-Use Restrictions – None
- Environmental Concerns – None
- Special Metering or Protection – TBD
- Common Mode Exposure Items – None
- Interaction with other Projects – TBD

GEPSLF MODELING INFORMATION

```
# (1) *****For Ravenswood-Cooley Landing No. 1, Distance 1.8 miles (477 ACSS or larger)
#
#   CABLE           DISTANCE                IMPEDANCE
#   ACSS 477-24/7   per mile      RPU=0.001568 XPU=0.005987 BPU=0.000711
#   ACSS 477-27/7    1.8 miles    RPU=0.002822 XPU=0.010777 BPU=0.0012798
#
OLDSECDD 33317 33321 CKT=1  RPU=0.002822 XPU=0.010777 BPU=0.0012798 MVA1=228 MVA2=228 MVA3=245 MVA4=245
#
# (2) *****For Ravenswood-Cooley Landing No. 1, Distance 1.8 miles (477 ACSS or larger)
#
#   CABLE           DISTANCE                IMPEDANCE
#   ACSS 477-24/7   per mile      RPU=0.001568 XPU=0.005987 BPU=0.000711
#   ACSS 477-27/7    1.8 miles    RPU=0.002822 XPU=0.010777 BPU=0.0012798
#
OLDSECDD 33316 33315 CKT=2  RPU=0.002822 XPU=0.010777 BPU=0.0012798 MVA1=228 MVA2=228 MVA3=245 MVA4=245
# End
```

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagram
2. Power Flow Summary
3. Pre and Post Project Power Flow Plots

Attachment 1: Scope Diagram

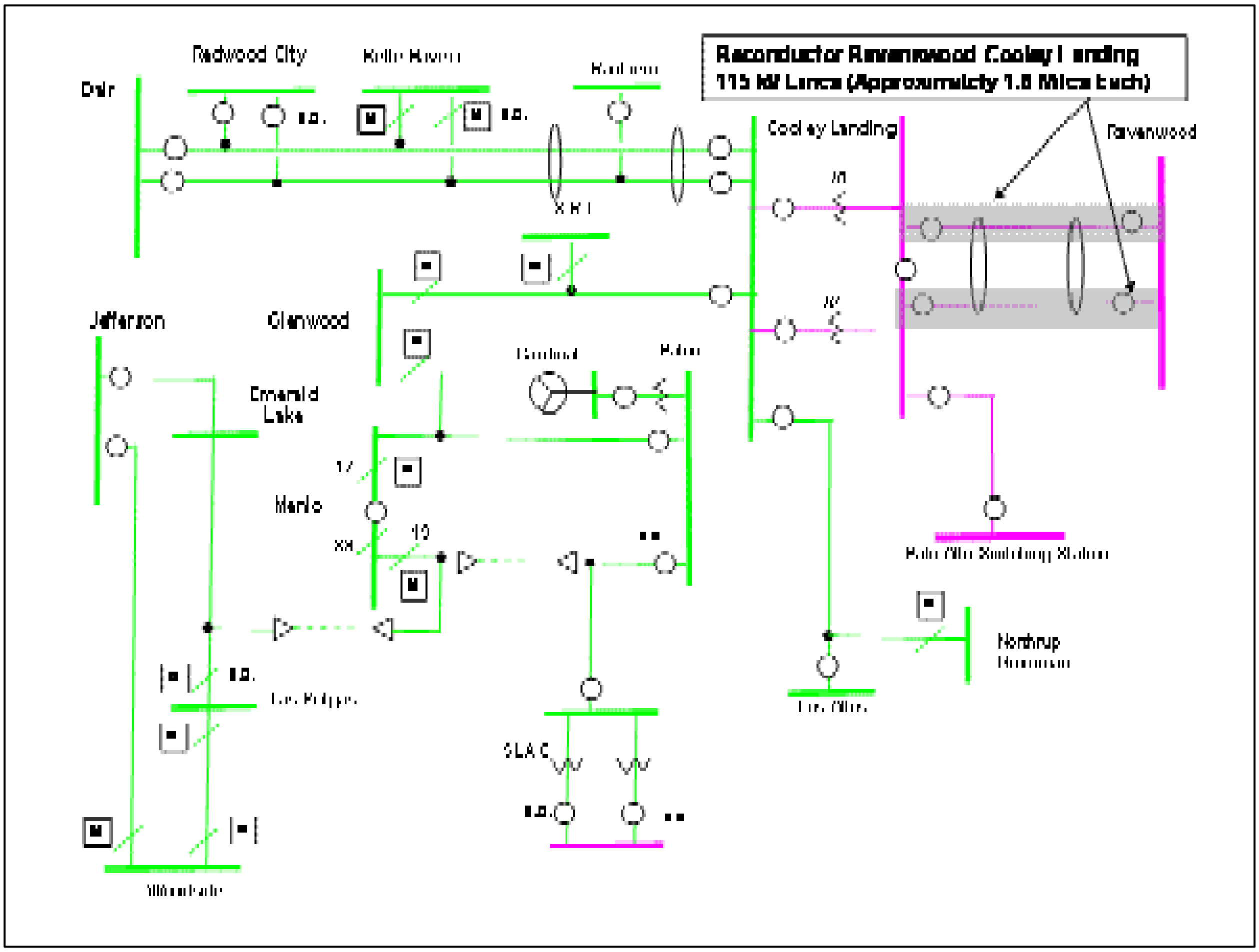


Figure 4-203: Cooley Landing 115/60 kV Area

Attachment 2: Power Flow Summary

Table 4-58: Power Flow Summary

Normal/Contingency	Facility Affected	2012 Pre-Project	2012 Post Project
Normal Conditions	Ravenswood-Cooley Landing 115 kV Line No. 1	60%	39%
Ravenswood-Cooley Landing 115 kV Line No. 2 with Cardinal cogen offline		99%	69%
Normal Conditions	Ravenswood-Cooley Landing 115 kV Line No. 2	62%	39%
Ravenswood-Cooley Landing 115 kV Line No. 1 with cardinal cogen offline		101%	70%

Attachment 3: Pre and Post Project Power Flow Plots

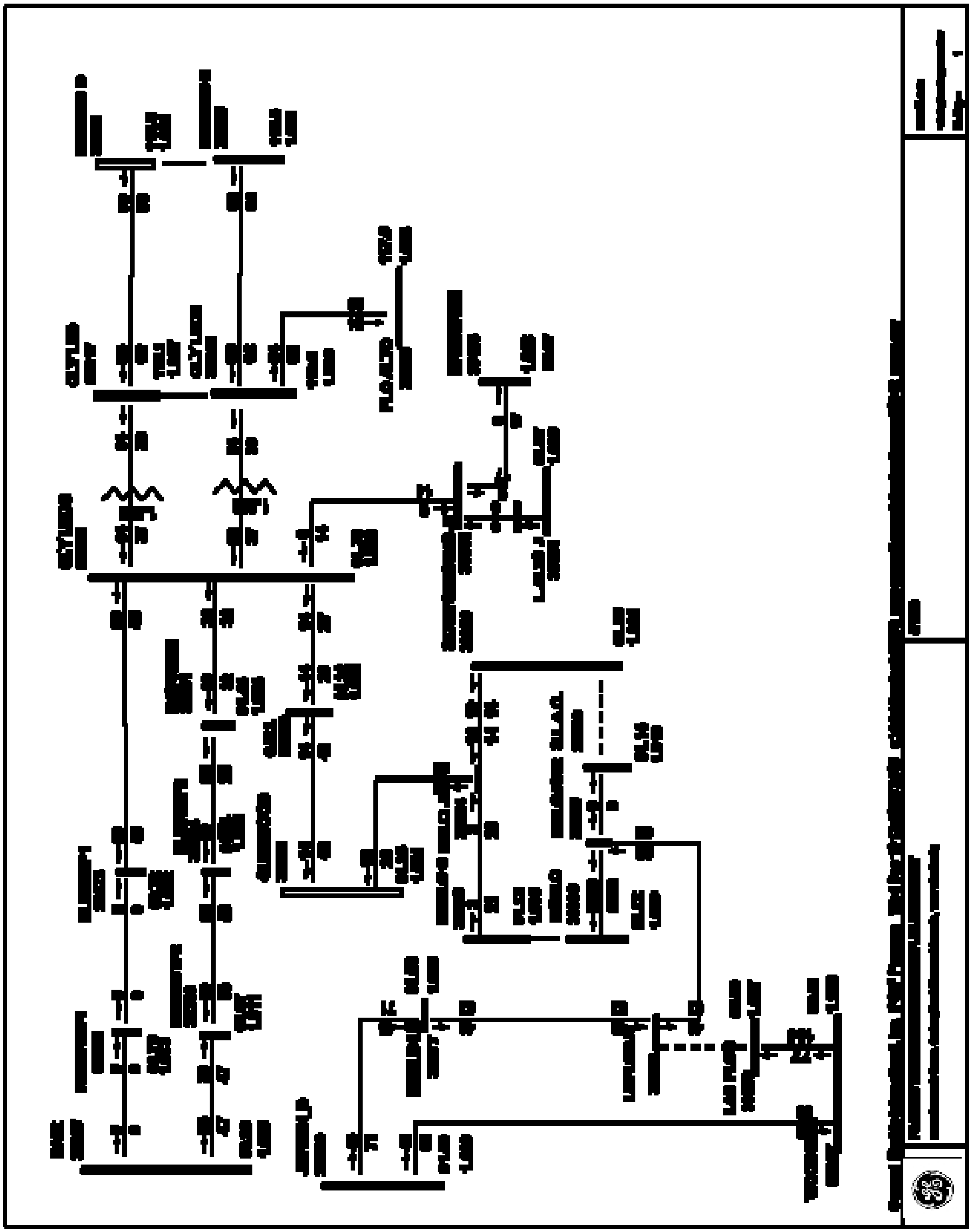


Figure 4-204: All Facilities In-Service, Year 2012 (Pre-Project)

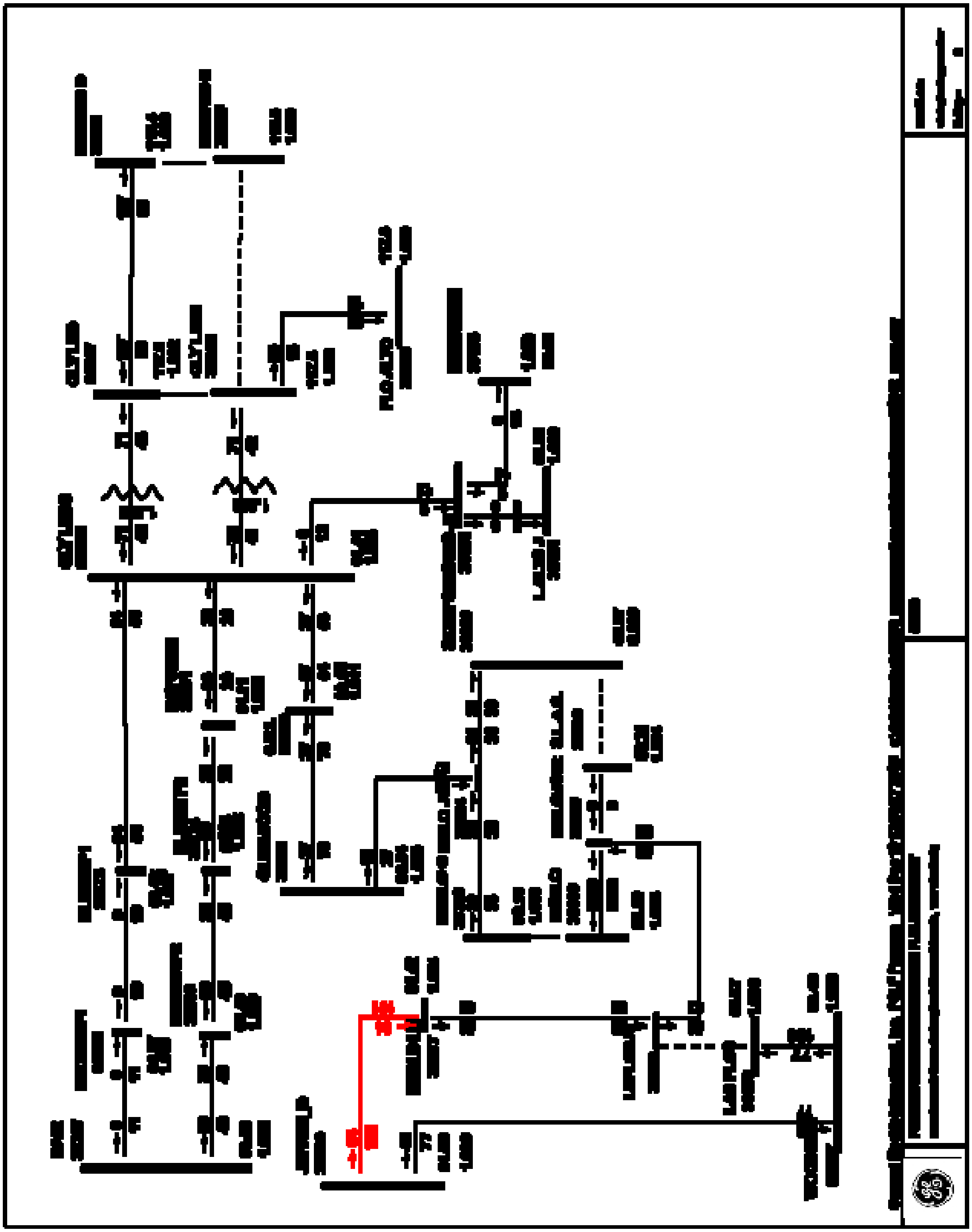


Figure 4-205: Outage of Ravenswood – Cooley Landing 115 kV Line overlapped with Cardinal Generation, Year 2012 (Pre-Project)

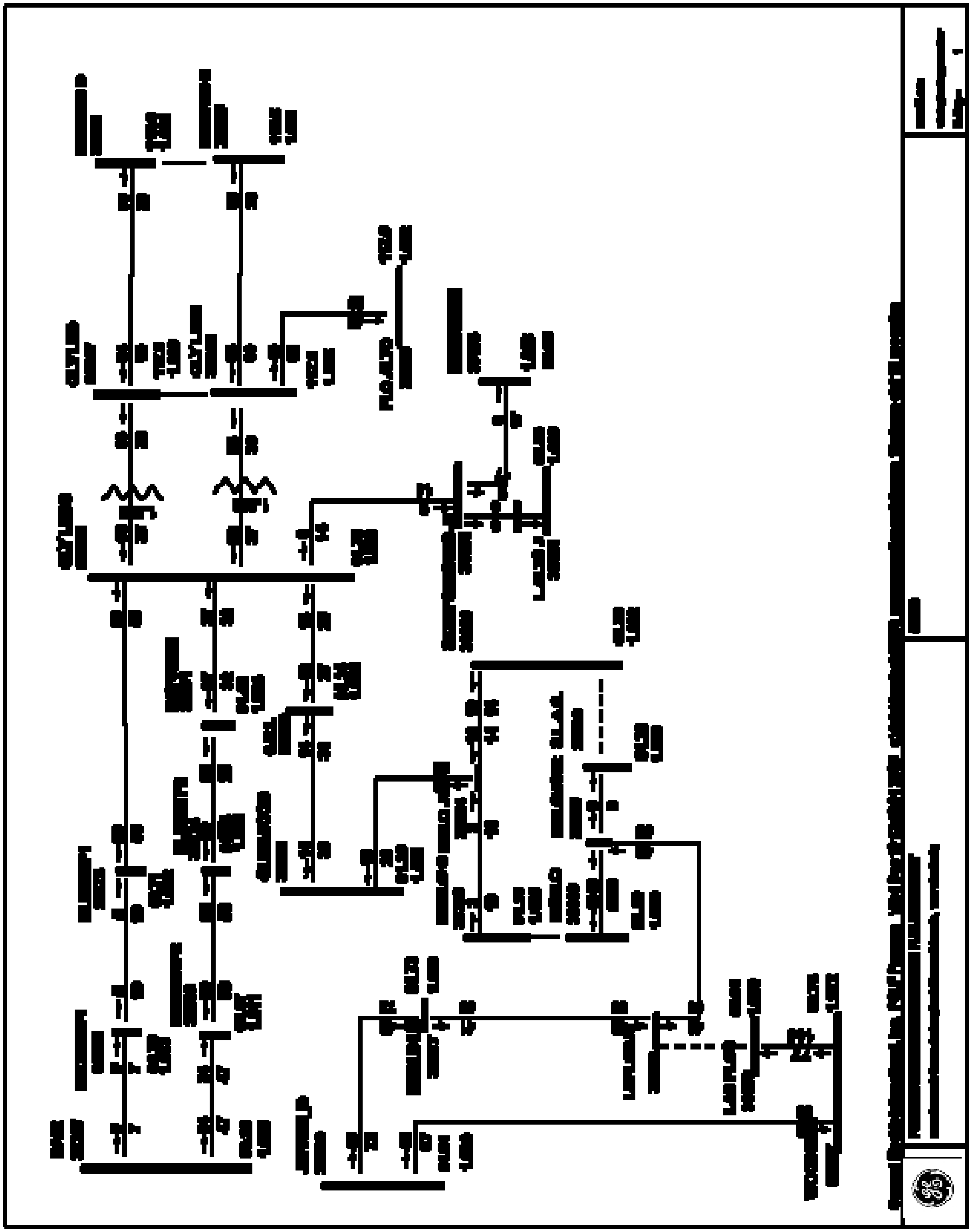


Figure 4-206: All Facilities In-Service, Year 2012 (Post-Project)

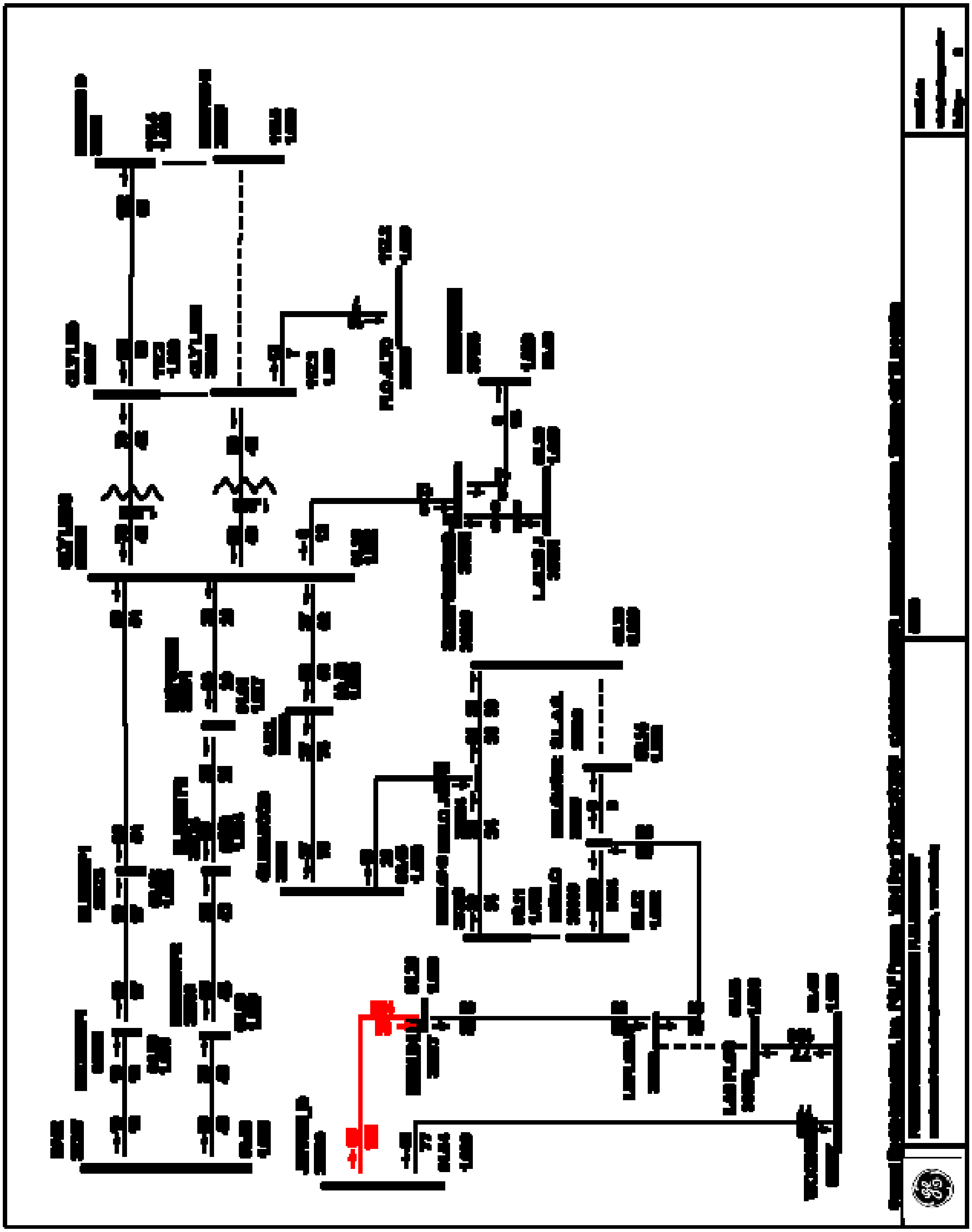


Figure 4-207: Outage of Ravenswood – Cooley Landing 115 kV Line overlapped with Cardinal Generation, Year 2012 (Post-Project)

Del Monte – Fort Ord 60 kV Reinforcement

TARGETED IN-SERVICE DATE

May 2010 & May 2012

PURPOSE AND BENEFIT

Reliability – NERC Compliance

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROPOSED PROJECT

This project is a multi-year project. The initial scope (Phase 1) is to be completed by May 2010 and includes the installation of two circuit breakers at Fort Ord Substation, so that Fort Ord is normally supplied by both the Del Monte Nos. 1 and 2 60 kV lines. These 60 kV circuit breakers will be rated to handle at least 1,000 Amps. Also, both lines will be re-rated to have 4 fps emergency ratings of 415 Amps. The Phase 2 scope of the project, to be completed by 2012, will be to reconductor both lines with a conductor having a summer normal ampacity of 700 Amps.

This project is expected to cost between $5M and $10M.

BACKGROUND

A new California State University (CSU) campus and several large housing developments are planned for the old Fort Ord military base in the town of Seaside. The electric demand at Fort Ord Substation is projected to grow from 19 MW to 35 MW by 2012 and, possibly, to 45 MW by 2018. The substation is currently served by one 60 kV line from Del Monte Substation, with a second line from Del Monte as a back-up source.

When electric demand at Fort Ord reaches 32 MW, the existing line supplying the substation will experience normal overloads. This demand level is expected to occur by 2010. Even if both 60 kV lines are used to supply Fort Ord, an outage of one line will overload the other line when demand at Fort Ord exceeds 35 MW. If Fort Ord demand does continue to increase, even a 4 fps emergency rating on both 60 kV lines will not be adequate to serve a peak demand of more than 40 MW following the loss of one line.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO. PG&E also performed sensitivity studies for this local area using local system peak conditions.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended because it does not increase system capacity and it does not address the reliability concerns at Fort Ord.

Alternative 2: Serve Fort Ord from the Moss Landing – Del Monte 115 kV Lines

This alternative would supply Fort Ord from the Moss Landing – Del Monte 115 kV lines, which are about one mile east of the substation. This is not recommended because it would be more costly and require much more time for permitting and construction.

PROJECT SCHEDULE

- Environmental and Permitting Processes – None
- Design – Spring 2010 (Phase 1) & Fall 2011 (Phase 2)
- Major Equipment – Spring 2010 (Phase 1) & Fall 2011 (Phase 2)
- Construction – Spring 2010 (Phase 1) & Spring 1012 (Phase 2)
- Operation Date – May 2012

KEY ISSUES

- Land-Use Restrictions – None
- Environmental Concerns – None
- Special Metering or Protection – None
- Common Mode Exposure Items – None
- Interaction with other Projects – None

GEPSLF MODELING INFORMATION

```
#
#   This change file for Phase 1 will close the normally open secdd between
#      Fort Ord Junction 2 (bus 36026) and Fort Ord (bus 36031)
#
#   With high loads at Fort Ord, simply status'ing ON the secdd may cause the case to diverge.
#   This change file will turn off the loads at Fort Ord first and then solve the case.  (This will
#   result in the voltages of the Jct 2 bus and the Fort Ord bus being closer together.
#
#  Status OFF the Fort Ord loads
#
OLDLOAD  36031,1,,,,,,,,,,,,0
OLDLOAD  36031,2,,,,,,,,,,,,0
#
#  Solve the case
SOLV
#
#  Status ON the secdd
#
OLDSECDD 36026,36031,1,1,1,,,,,,,,,,,,,
#
#  Solve the case
SOLV
#
#  Status ON the Fort Ord loads
#
OLDLOAD  36031,1,,,,,,,,,,,,1
OLDLOAD  36031,2,,,,,,,,,,,,1

-----------------------------------------------------------------
#
#   This change file for Phase 2 will reconductor the 60 kV Lines between Del Monte and Fort Ord Substations
#
#  Reconductor the No. 1 circuit
#
OLDSECDD 36034,36035,1,1,1,0.012009,0.056317,0.000683,73.,83.,101.,108.,,,,,,,
OLDSECDD 36024,36034,1,1,1,0.011923,0.059692,0.000636,73.,83.,101.,108.,,,,,,,
#
#  Reconductor the No. 2 circuit
#
OLDSECDD 36032,36035,1,1,1,0.010123,0.046248,0.000580,73.,83.,101.,108.,,,,,,,
OLDSECDD 36026,36032,1,1,1,0.011923,0.059692,0.000636,73.,83.,101.,108.,,,,,,,
#
#  Reconductor the drops into Fort Ord Substation (715 AAC)
#
OLDSECDD 36024,36031,1,1,1,,,,73.,83.,101.,108.,,,,,,,
OLDSECDD 36026,36031,1,1,1,,,,73.,83.,101.,108.,,,,,,,
```

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagram
2. Load Growth Forecast
3. Power Flow Summary
4. Pre and Post Project Power Flow Plots

Attachment 1: Scope Diagrams

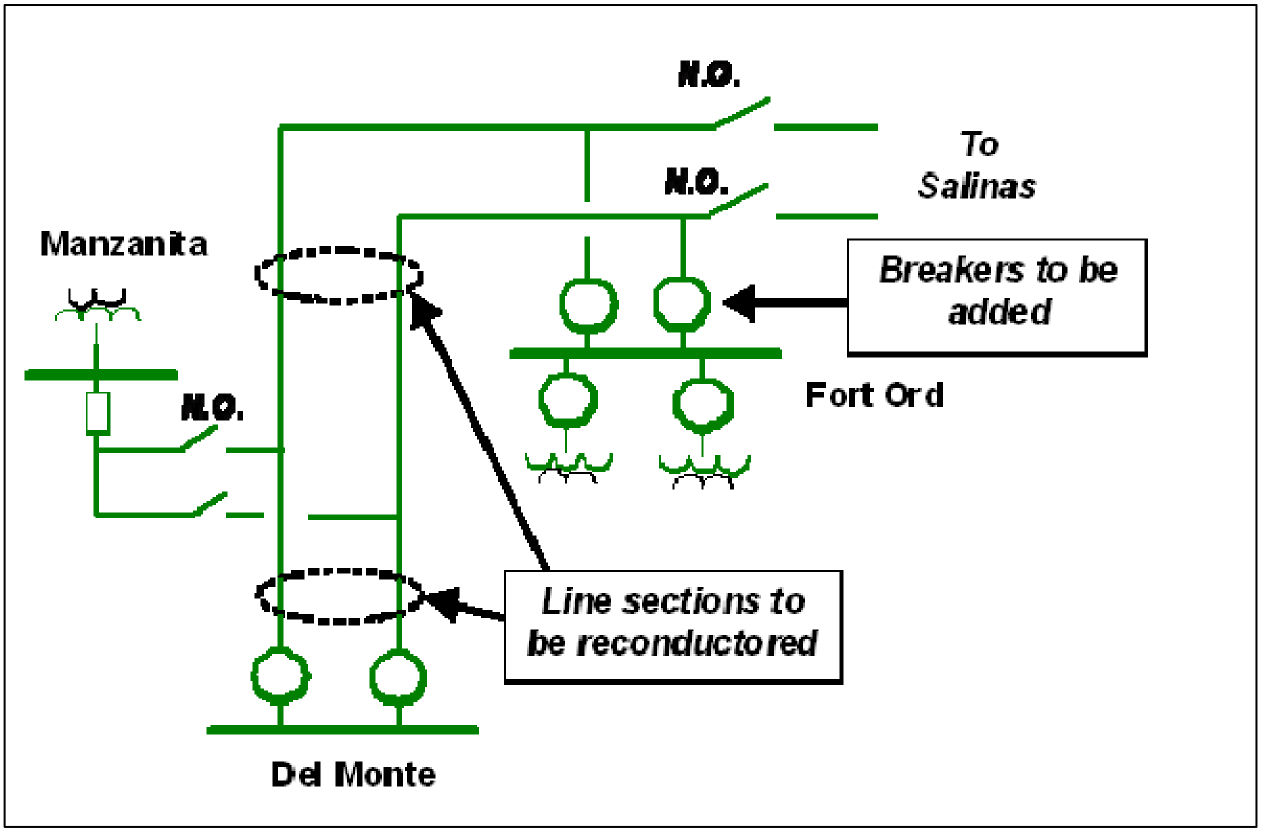
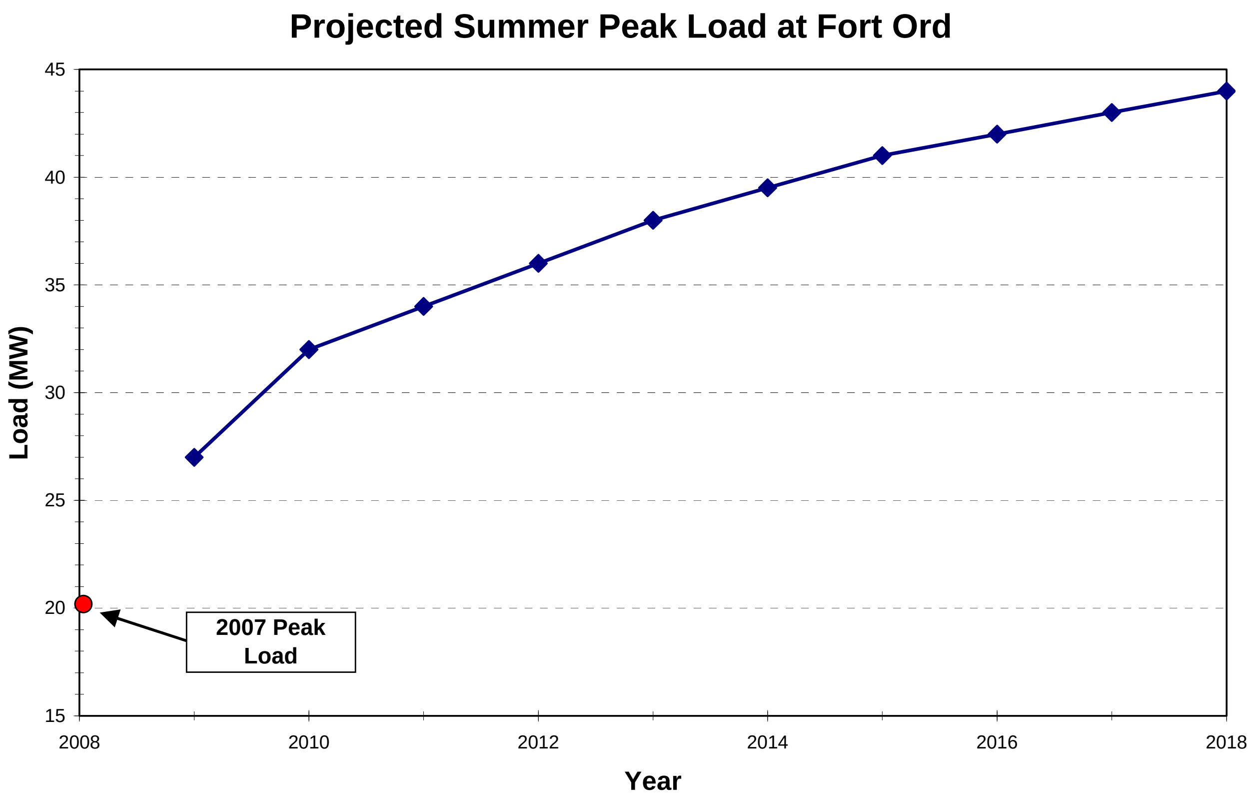


Figure 4-208: Project Scope for the Del Monte – Fort Ord 60 kV Reinforcement Project

Attachment 2: Load Growth Forecast



Attachment 4: Power Flow Summary

Table 4-59: Power Flow Summary

Contingency	Facility Affected	2011 (Pre-Project)	2013 (Pre-Project)	2013 (Post-Project)
Normal Conditions	Del Monte No. 1 60 kV Line	104%	121%	27%
Del Monte No. 1 60 kV Line (L-1)	Del Monte No. 2 60 kV Line	90%	104%	46%

Attachment 5: Pre- and Post-Project Power Flow Plots

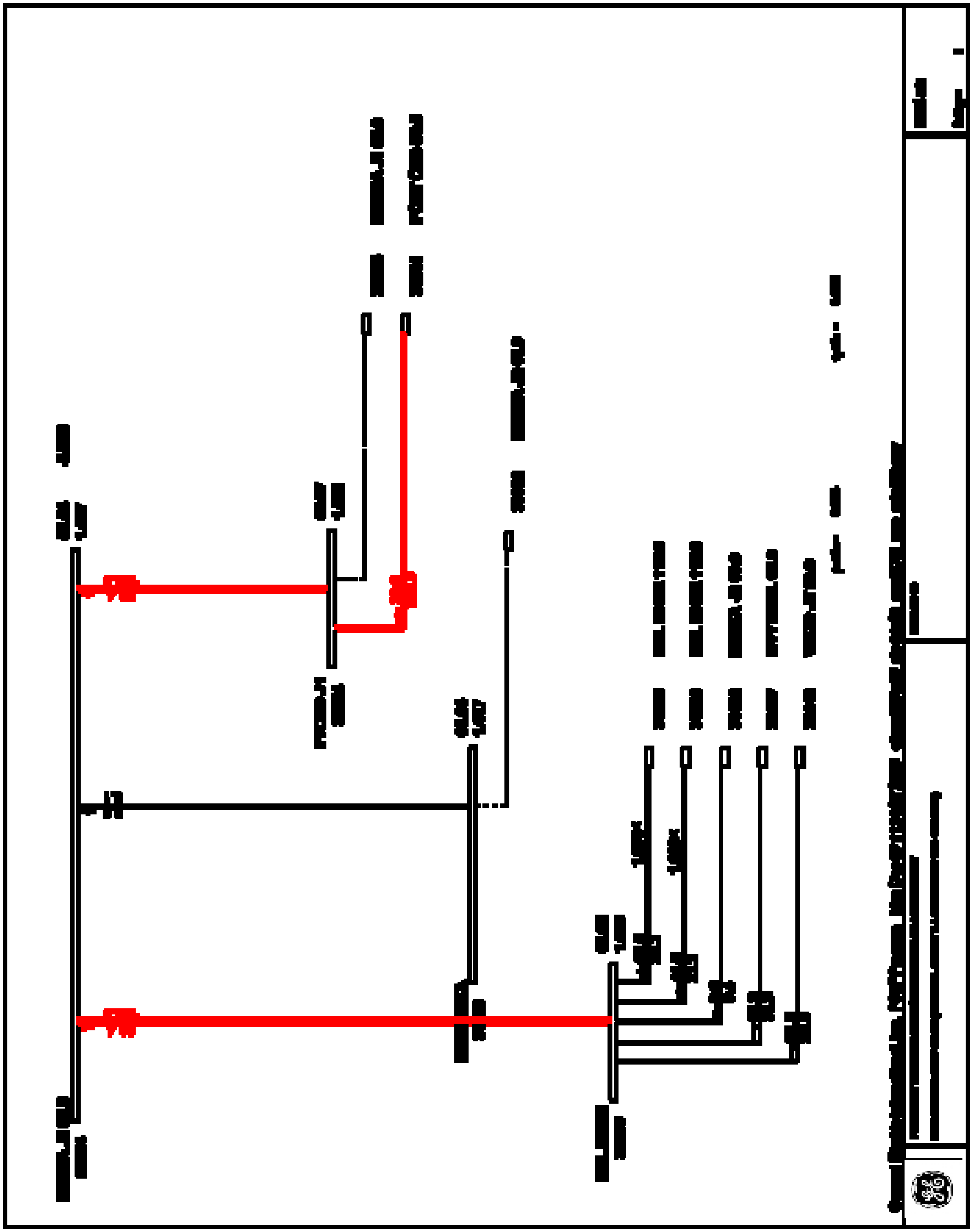


Figure 4-209: Pre-Project – Normal Conditions

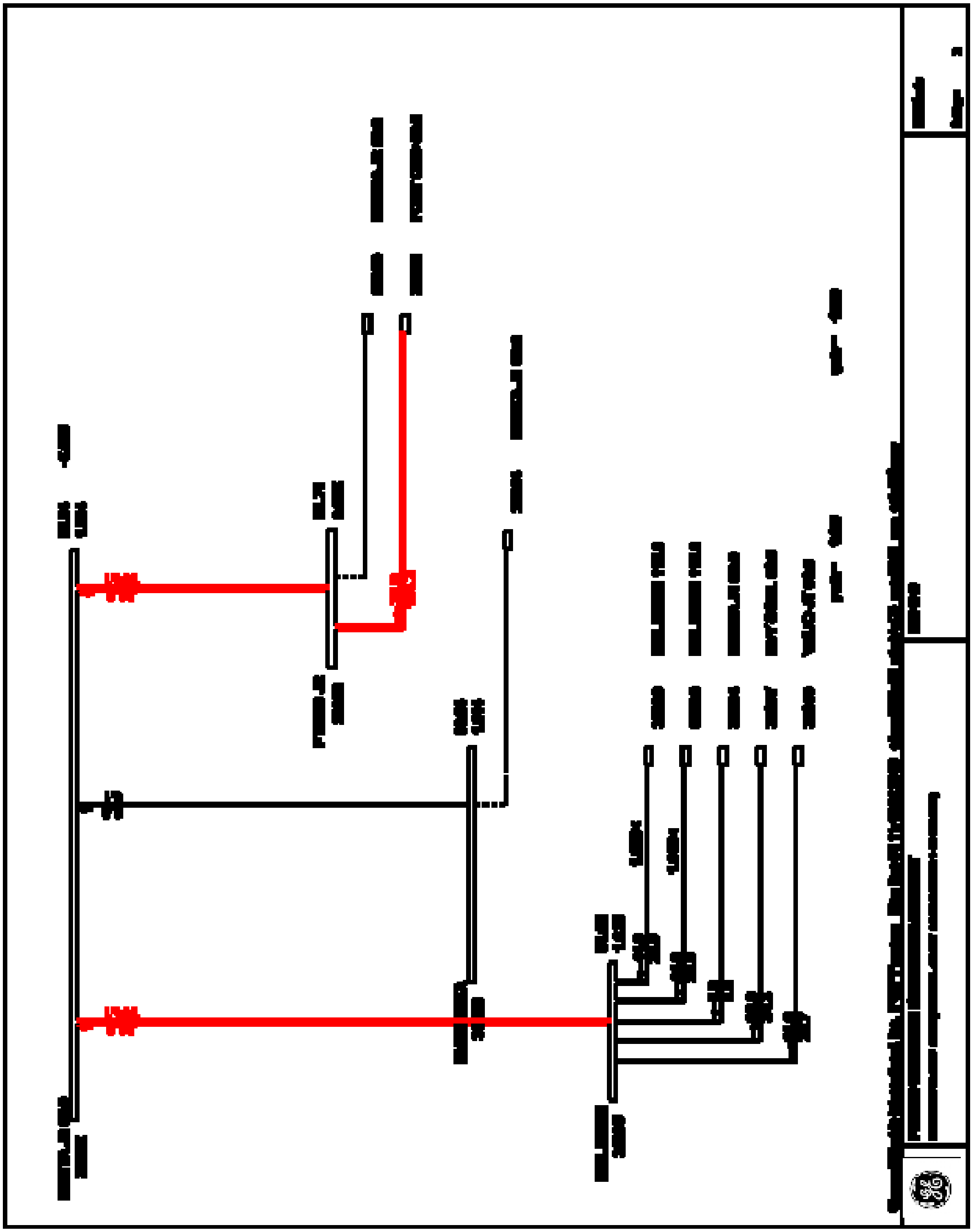


Figure 4-210: Pre-Project – Loss of the Del Monte No. 1 60 kV Line (L-1)

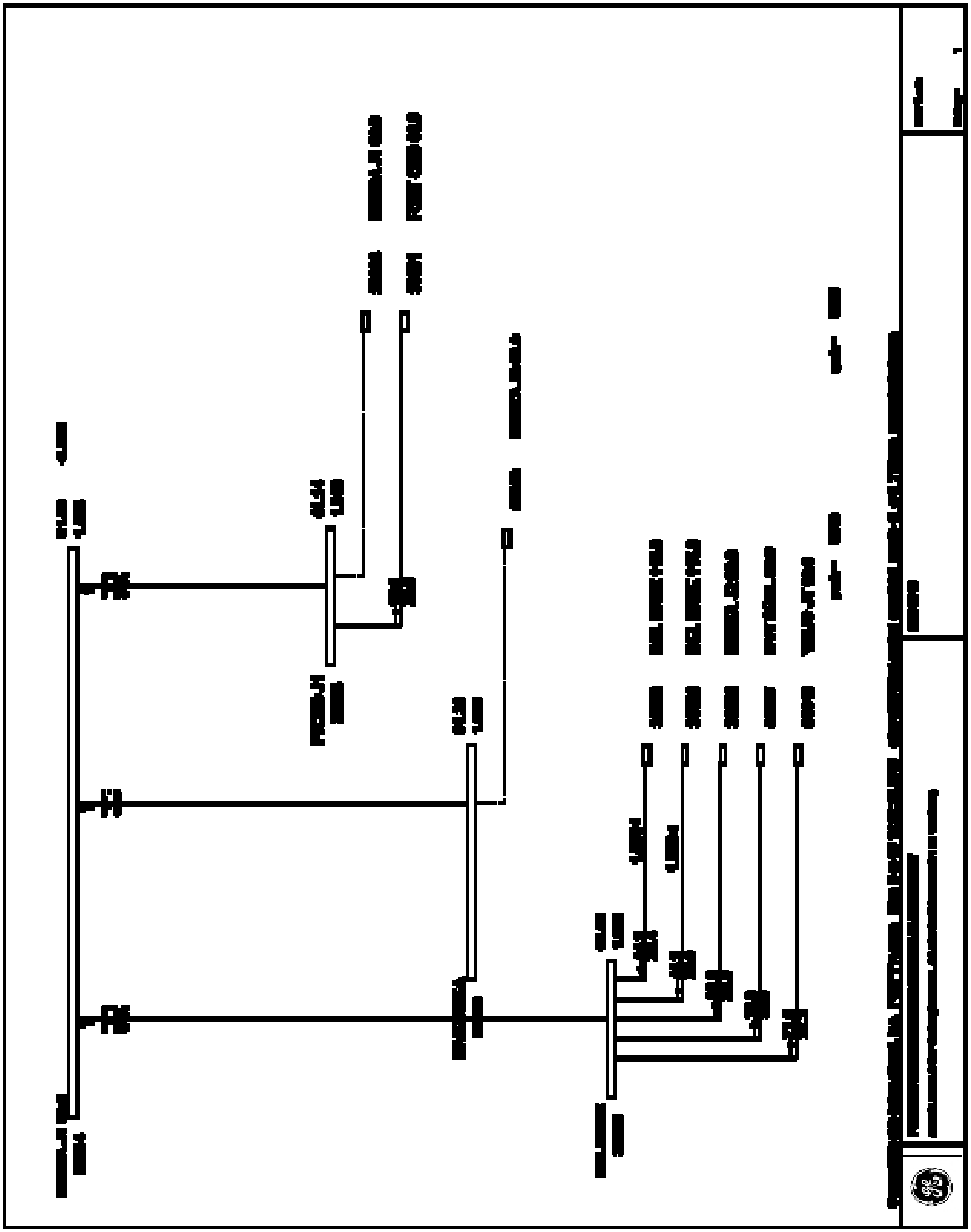


Figure 4-211: Post-Project - Normal Conditions

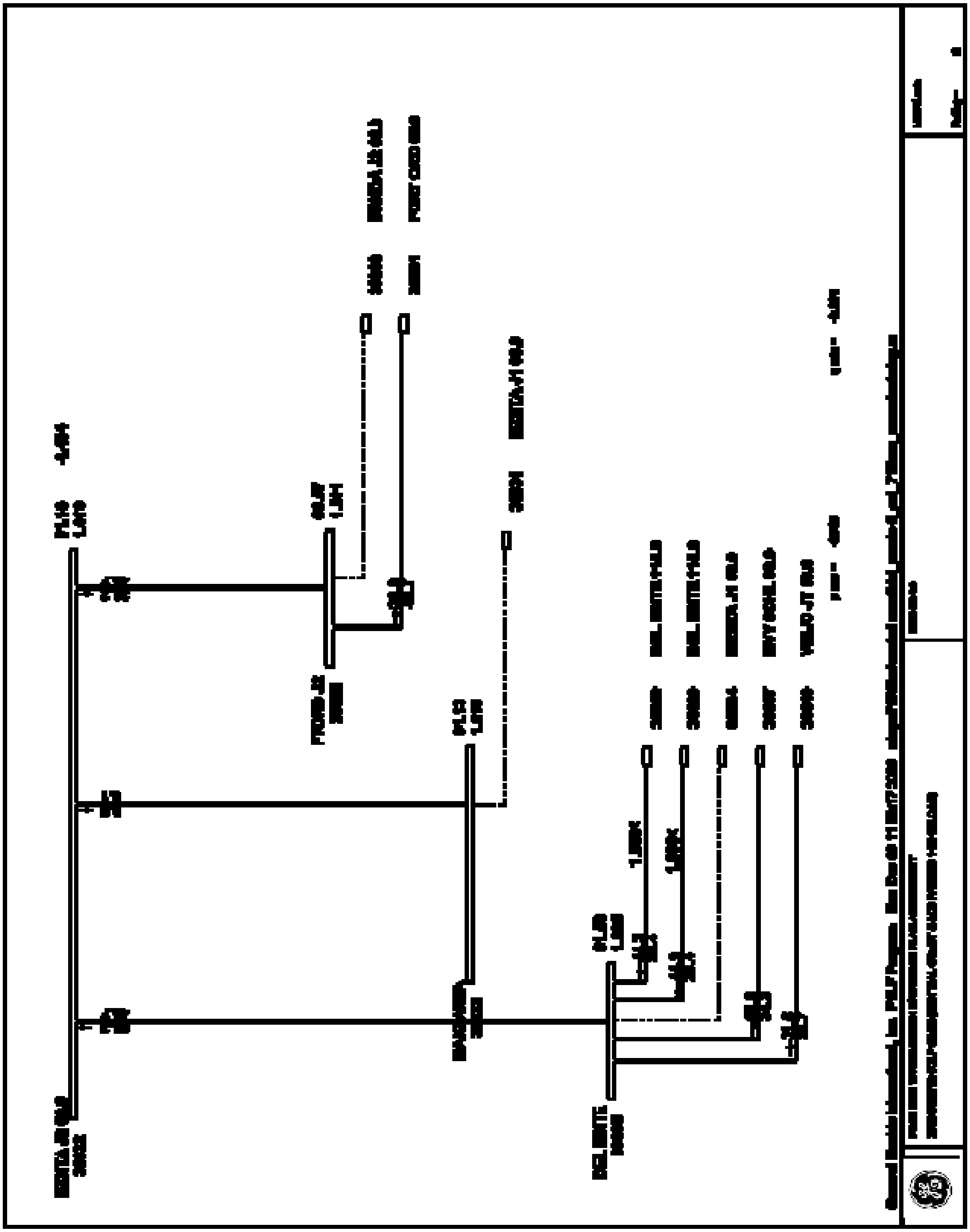


Figure 4-212: Post-Project – Loss of the Del Monte – Fort Ord No. 1 60 kV Line (L-1/G-1)

Natividad Substation Installation

TARGETED IN-SERVICE DATE

May 2012

PURPOSE AND BENEFIT

Reliability – Tariff and Compliance

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROPOSED PROJECT

This project is proposing the transmission interconnection plan of service for a new distribution substation.

The project scope is to interconnect a new distribution (Natividad) substation in the north Salinas area at the location of the Natividad Switches on the Crazy Horse-Salinas-Soledad Nos. 1 and 2 115 kV lines. The 115 kV bus at the Natividad Substation will be configured into a ring-bus. The local 115 kV lines in this area will be reconfigured so that the Crazy Horse-Salinas-Soledad 115 kV No. 1 line supplies Natividad Substation and the Crazy Horse-Salinas-Soledad 115 kV No. 2 line supplies Soledad Substation. The line sections (8.2 miles each for each line) from Crazy Horse to Salinas will also be reconductored with conductors capable of carrying a minimum of 900 Amps under summer normal conditions and 1,100 Amps under summer emergency conditions.

This project is expected to cost between $15M and $20M.

BACKGROUND

Large housing developments are planned in the future for the north Salinas area. Distribution capacity is very limited in this area, and a new distribution substation is needed in the area to serve the new load. PG&E is moving forward towards the development of a new distribution substation to serve future load growth in the north Salinas area.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO. PG&E also performed sensitivity studies for this local area using local system peak conditions.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended because it does not increase system capacity and it does not address the reliability concerns in the north Salinas area.

PROJECT SCHEDULE

- Environmental and Permitting Processes – None
- Design – Spring 2011
- Major Equipment – Spring 2011
- Construction – Spring 2011 through Spring 2012
- Operation Date – May 2012

KEY ISSUES

- Land-Use Restrictions – None
- Environmental Concerns – None
- Special Metering or Protection – None
- Common Mode Exposure Items – None
- Interaction with other Projects – This project is dependent upon the completion of the Crazy Horse Switching Station Project

GEPSLF MODELING INFORMATION

```
#   Natividad Distribution Substation
#
#    This change file:
#     1) Creates new Natividad 115 kV bus (35932)
#     2) Moves the Crazy Horse-Salinas-Soledad # 1 connections
#          over to the new bus (Crazy Horse, Salinas, Soledad)
#     3) Uses the Natividad Switches bus (35914) to loop Soledad
#          onto the Crazy Horse-Salinas-Soledad # 2 line (creating
```

```
#          a Crazy Horse-Soledad line and a Salinas-Soledad line)
#     4) Reconductor the lines from Crazy Horse to Salinas with 477 ACSS conductor
#
NEWBUSD  35932,"NATIVDAD",115.,1,1,19,319,,,,,390
NEWLOAD  35932,1,19,319,10.,2.5,,,,,,,,,1
MOVE_BRANCH  35910,35914,1,35932
MOVE_BRANCH  35919,35914,1,35932
MOVE_BRANCH  35920,35914,1,35932
MOVE_BRANCH  35919,35932,1,35914
MOVE_BRANCH  35918,35913,1,35914

#
#   Model the reconductoring of both 115 kV lines from Crazy Horse,
#    past Natividad, to Salinas Substation.
#      1) Lines are reconductored with 477 ACSS
#      2) The tower design is similar to Aspen model AH:477SSAC (ohms/mile)
#              R = 0.20755 ; X = 0.74054 ; B = 0.015391
#      3) Total line lengths are
#              Crazy Horse to Natividad = 4.1 miles
#              Natividad to Salinas = 4.0 miles
#      4) Use 2 fps coastal ratings for the lines
#
OLDSECDD 35910,35932,1,1,1,0.006434,0.022958,0.003146,228.,228.,245.,245.,1,19,319,
OLDSECDD 35910,35913,1,1,1,0.006434,0.022958,0.003146,228.,228.,245.,245.,1,19,319,
OLDSECDD 35932,35920,1,1,1,0.006278,0.022398,0.003069,228.,228.,245.,245.,1,19,319,
OLDSECDD 35914,35918,1,1,1,0.006278,0.022398,0.003069,228.,228.,245.,245.,1,19,319,
```

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagram
2. Pre and Post Project Power Flow Plots

Attachment 1: Scope Diagrams

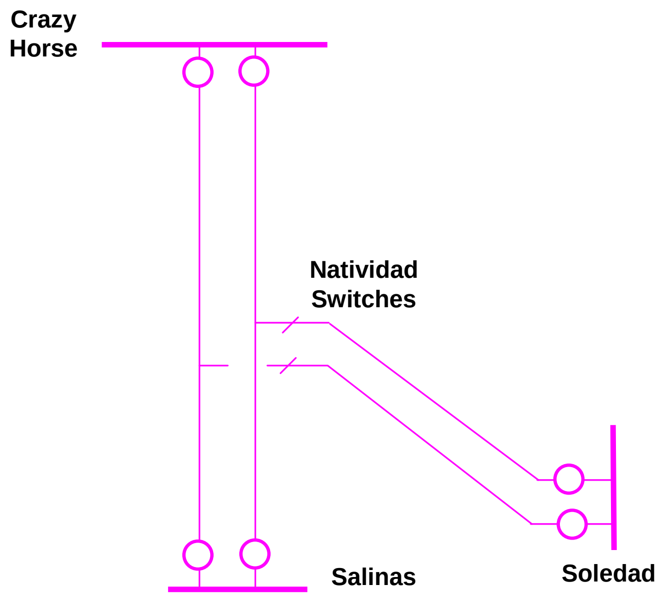


Figure 4-213: Pre-Project of Hollister-Salinas-Soledad 115 kV System

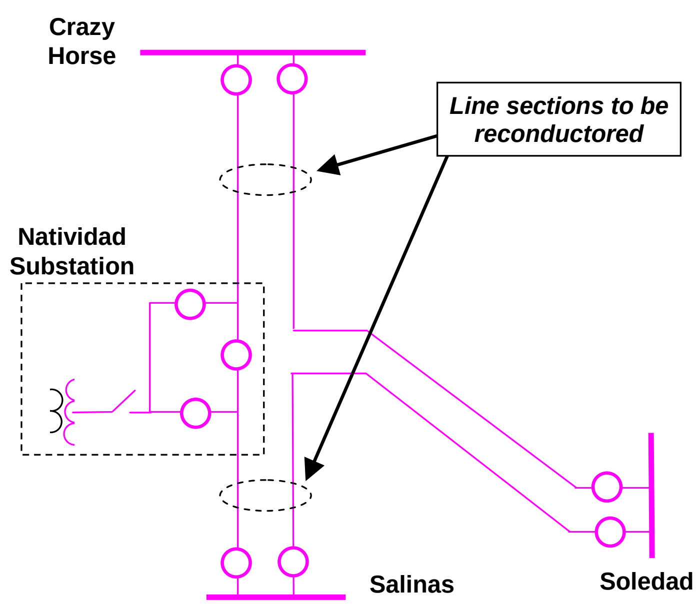


Figure 4-214: Post-Project of Hollister-Salinas-Soledad 115 kV System

Attachment 2: Pre- and Post-Project Power Flow Plots

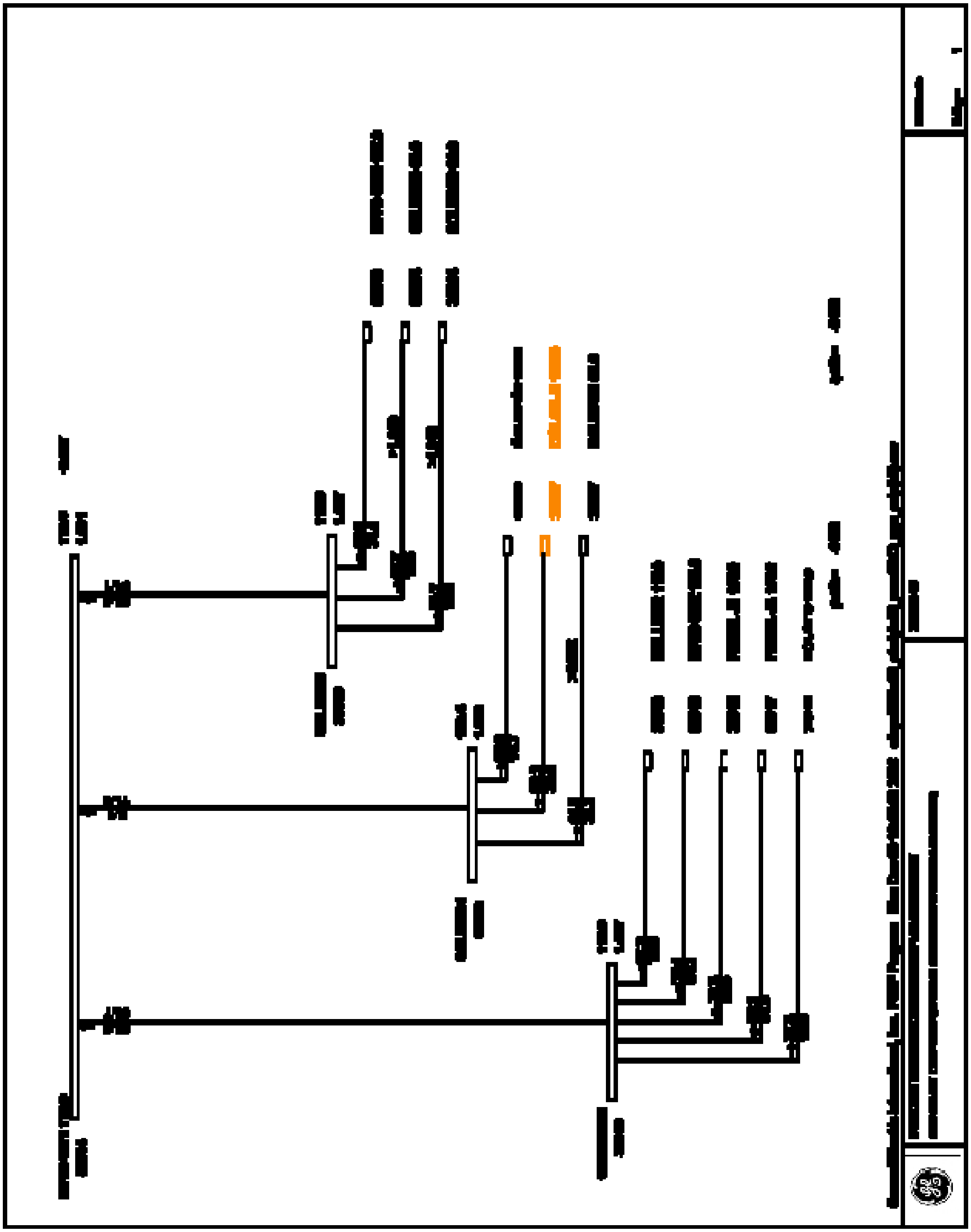


Figure 4-215: Pre-Project – Normal Conditions

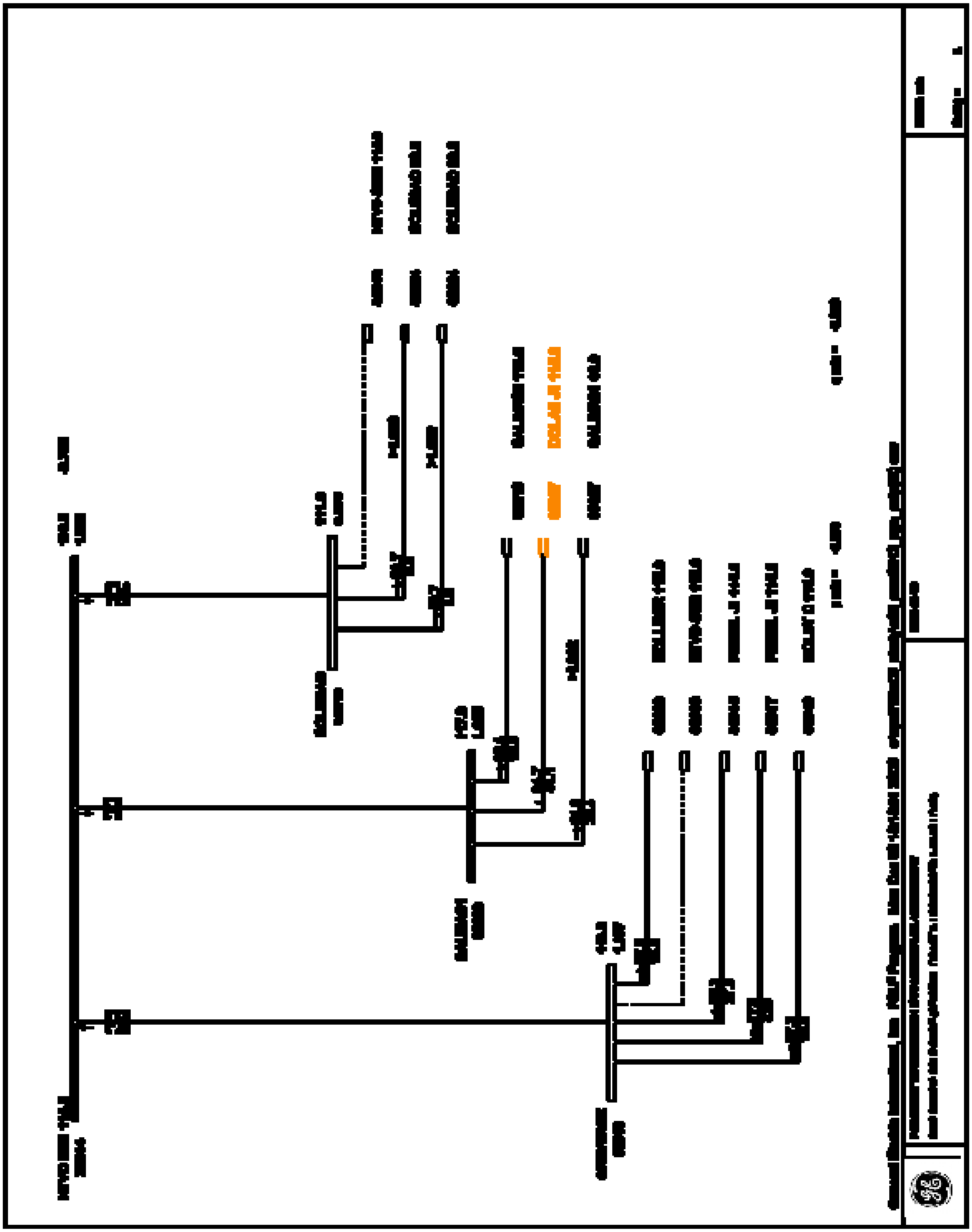


Figure 4-216: Pre-Project – Loss of the Crazy Horse – Salinas – Soledad No. 2 115 kV Line (L-1)

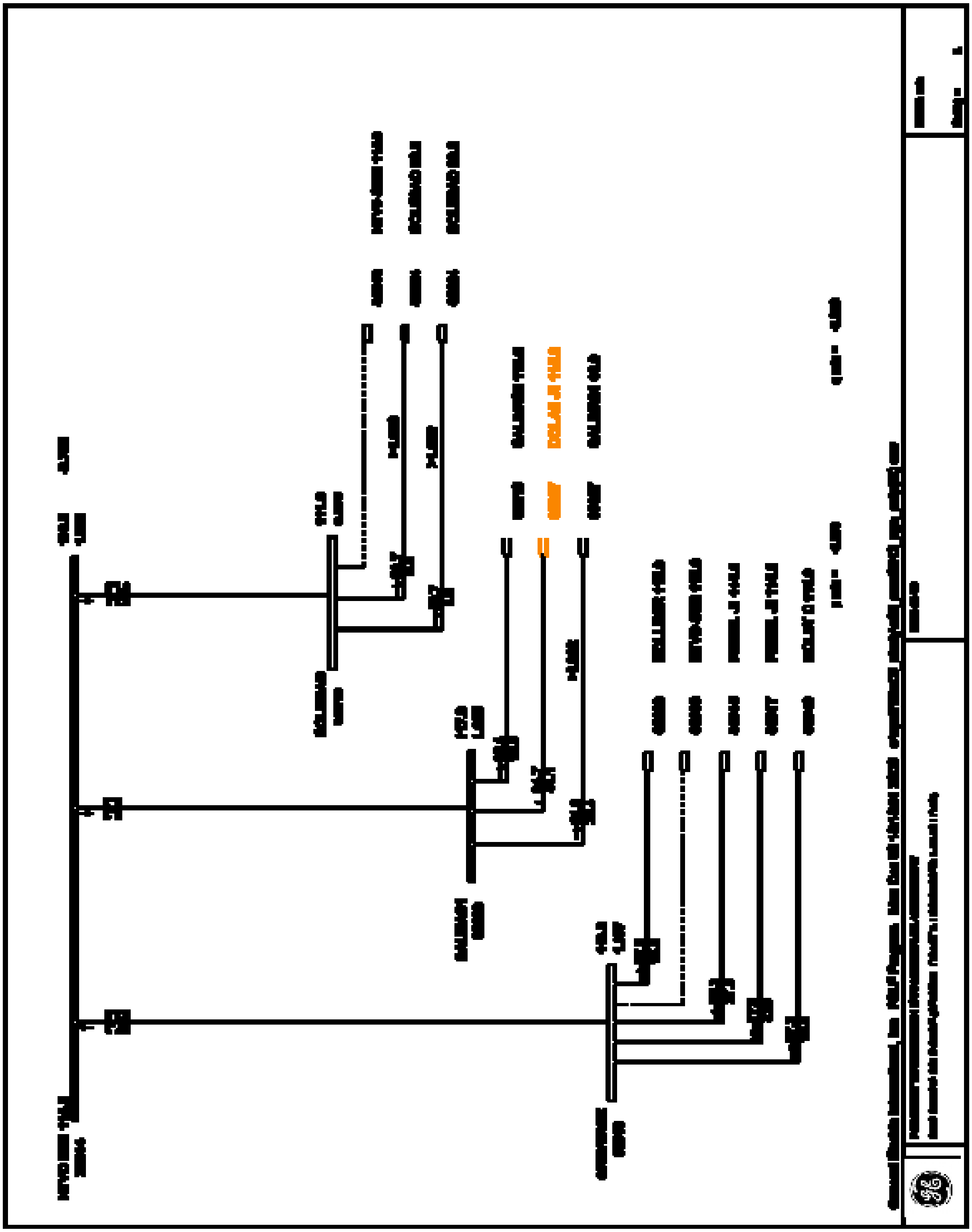


Figure 4-217: Pre-Project – Loss of the Moss Landing – Salinas Nos. 1 & 2 115 kV Lines (L-2)

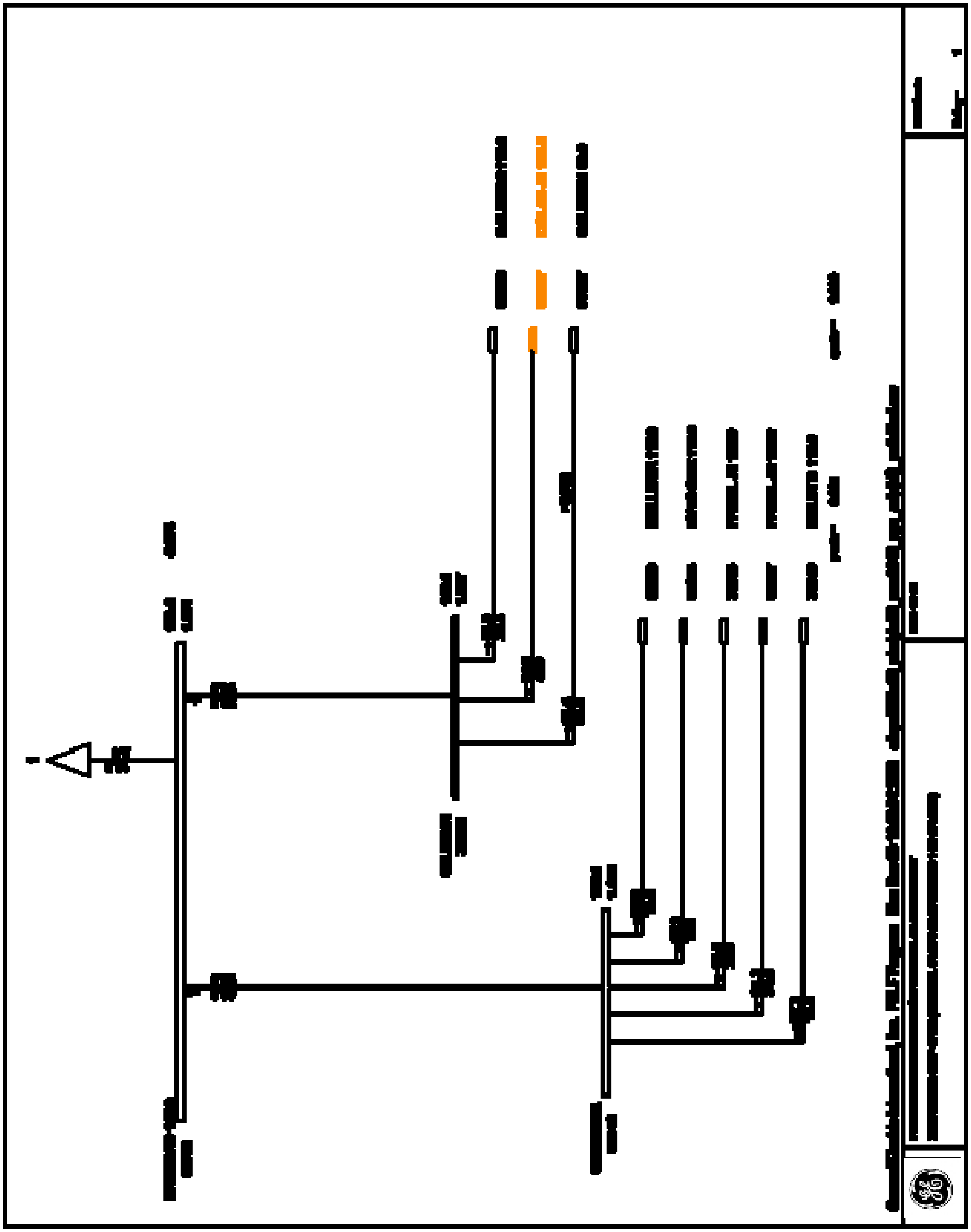


Figure 4-218: Post-Project - Normal Conditions

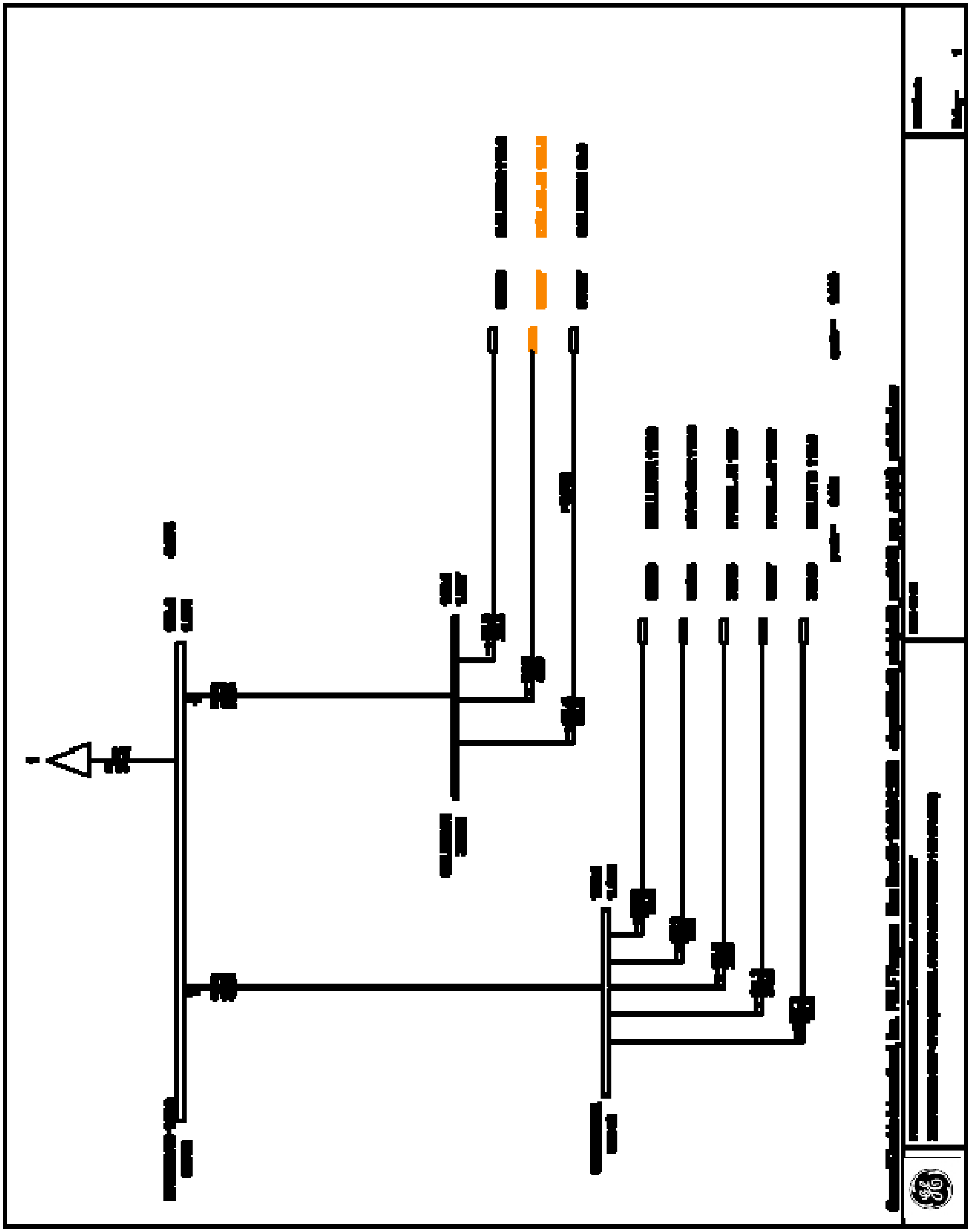


Figure 4-219: Post-Project – Loss of the Crazy Horse – Soledad 115 kV Line (L-1)

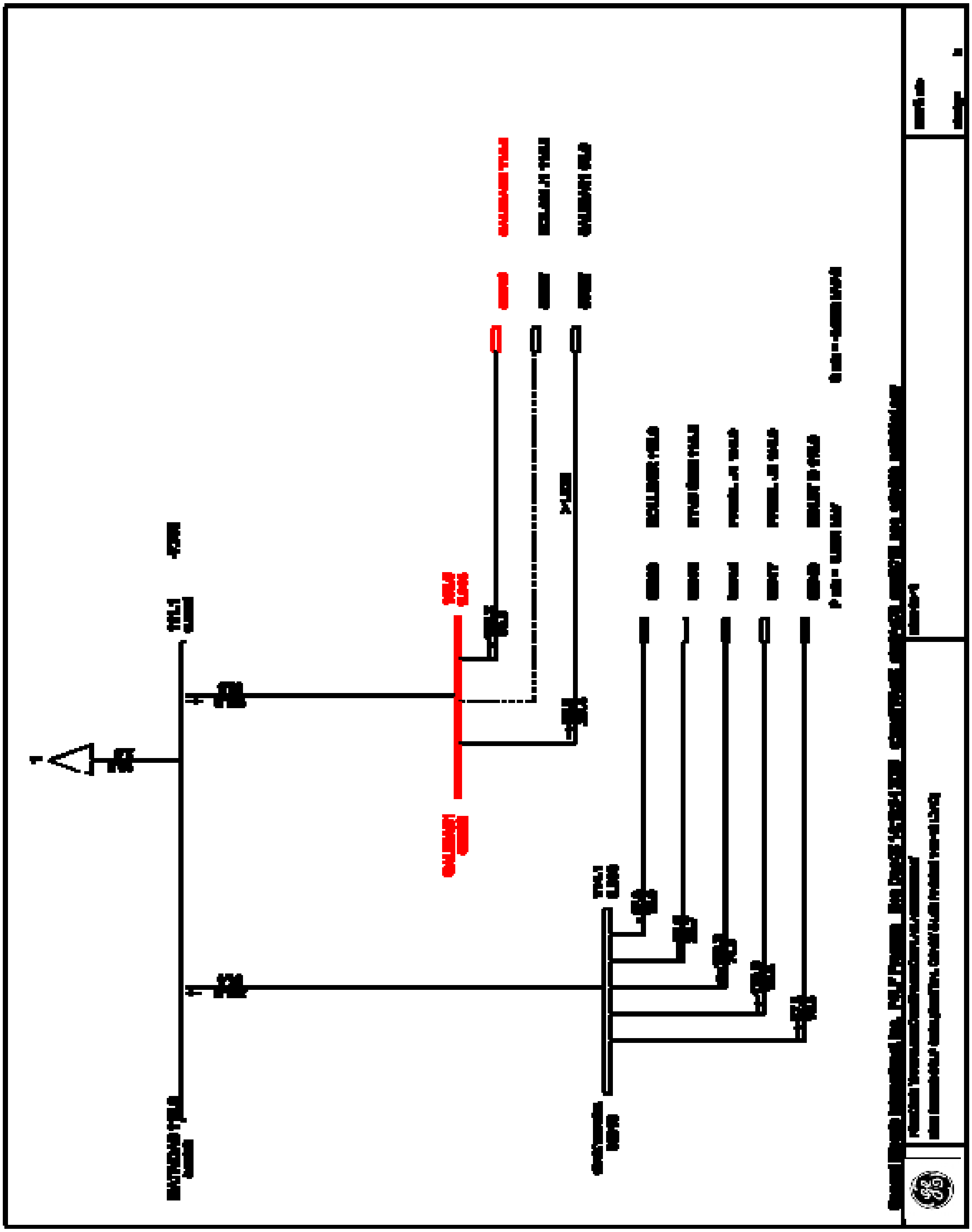


Figure 4-220: Post-Project – Loss of the Moss Landing – Salinas Nos. 1 & 2 115 kV Lines (L-2)

Watsonville 60 kV to 115 kV Voltage Conversion

TARGETED IN-SERVICE DATE

May 2012

PURPOSE AND BENEFIT

Reliability – NERC Compliance

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROPOSED PROJECT

This project scope is to convert the 60 kV system that serves Watsonville into a 115 kV system. The new system will connect into the Green Valley 115 kV buses (to be converted into a BAAH arrangement) and the Crazy Horse 115 kV buses.

The project cost is estimated to range between $25M and $30M.

BACKGROUND

The Watsonville 60 kV system serves approximately 5,000 customers. This system is primarily fed from Green Valley Substation, with a weak feed from Salinas Substation to the south. A UVLS scheme was installed several years ago to drop load to protect against low voltages following an outage of the Green Valley – Watsonville 60 kV Line.

By 2013, an outage of the Moss Landing – Green Valley 115 kV Line, combined with an outage of the CIC Cogen unit, will result in high loadings on the remaining Moss Landing – Green Valley Line and voltages below 95% in Santa Cruz.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO. PG&E also performed sensitivity studies of this local area using local system peak conditions.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended because it does not increase system capacity and it does not address the reliability concerns in the Watsonville area.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – Fall 2010
- Major Equipment – Summer 2011
- Construction – Fall 2011 through Spring 2012
- Operation Date – May 2012

KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – TBD
- Special Metering or Protection – None
- Common Mode Exposure Items – None
- Interaction with other Projects – This project is dependent upon the completion of the Crazy Horse Switching Station Project

GEPSLF MODELING INFORMATION

```
#   Conversion of Watsonville 60 kV System to 115 kV
#        Lines are converted to 115 kV with a connection into Crazy Horse Switching Station rather than down to Salinas
#       T1 wood-pole construction used, with 715 AAC conductor
#       Loop Lagunitas and Gabilan on Salinas lines
#
#   Delete the Green Valley 60 KV bus and remove the 60 kV line from Brigatano to Lagunitas Jct
#
EXTRACT 36008
OLDSECDD 36018,36022,1,,-1,,,,,,,,,,

#
#   Make the old 60 kV buses into 115 kV buses
#
OLDBUSD  36009,"C.I.C.  ",115.,,,,,,,,,,35949
OLDBUSD  36010,"ERTA    ",115.,,,,,,,,,,35950
OLDBUSD  36011,"CIC JCT ",115.,,,,,,,,,,35951
OLDBUSD  36012,"WTSNVLLE",115.,,,,,,,,,,35952
OLDBUSD  36013,"ERTA JCT",115.,,,,,,,,,,35953
OLDBUSD  36014,"GRANT JT",115.,,,,,,,,,,35954
OLDBUSD  36015,"GRANT RK",115.,,,,,,,,,,35955
```

```
OLDBUSD  36016,"AGRILINK",115.,,,,,,,,,,35956
OLDBUSD  36018,"BRIGTANO",115.,,,,,,,,,,35958

#
#   Replace the CIC 12.47/60 kV bank with a 12.47/115 kV bank
#
PURGE 36205 35949
NEW_TRAN  36205,35949,1,0.01000,0.24000,-
0.0007,40.,40.,40.,40.,12.47,115.,100,1,1,1,,,1.5,0.51,0.00625,1.5,0.5,1.000,1.000,,30,396

#
#   Make the new 115 kV connections to Green Valley and to Crazy Horse
#       - Use 2 fps ratings of 140 MVA and 160 MVA
#       - Make the Green Valley-Erta Jct line
#       - Make the Crazy Horse-Brigatano line
#
NEWSECDD 35901,35953,1,1,0.001815,0.008773,0.001334,140.,160.,194.,207.,1,19,319,390
NEWSECDD 35910,35958,1,1,0.010617,0.051310,0.007804,140.,160.,194.,207.,1,19,319,390

#
#   Redo the secdd values on the converted 60 kV system
#
OLDSECDD 35958,35954,1,1,1,0.000550,0.002660,0.000404,140.,160.,194.,207.,1,19,319,390
OLDSECDD 35952,35954,1,1,1,0.011772,0.056894,0.008654,140.,160.,194.,207.,1,19,319,390
OLDSECDD 35958,35954,1,1,1,0.000550,0.002660,0.000404,140.,160.,194.,207.,1,19,319,390
OLDSECDD 35958,35954,1,1,1,0.000550,0.002660,0.000404,140.,160.,194.,207.,1,19,319,390
OLDSECDD 35951,35953,1,1,1,0.002090,0.010103,0.001537,140.,160.,194.,207.,1,19,319,390
#
#   Status ON the 60 kV line section from Lagunitas Jct to Lagunitas and turn off the
#     remaining idled section of 60 kV line from Lagunitas Jct to Crazy Horse
#
OLDSECDD 36020,36022,1,1,1,,,,,,,,,,
NEWBUSD  36010,"CRYHSE60",60.,1,1,19,319,1.05,0.95,,1,390
NEWSECDD 36010,36022,1,1,0.023382,0.037390,0.000354,32.,36.,43.,46.,0,19,319,390

END
```

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagram
2. Power Flow Summary
3. Pre and Post Project Power Flow Plots

Attachment 1: Scope Diagrams

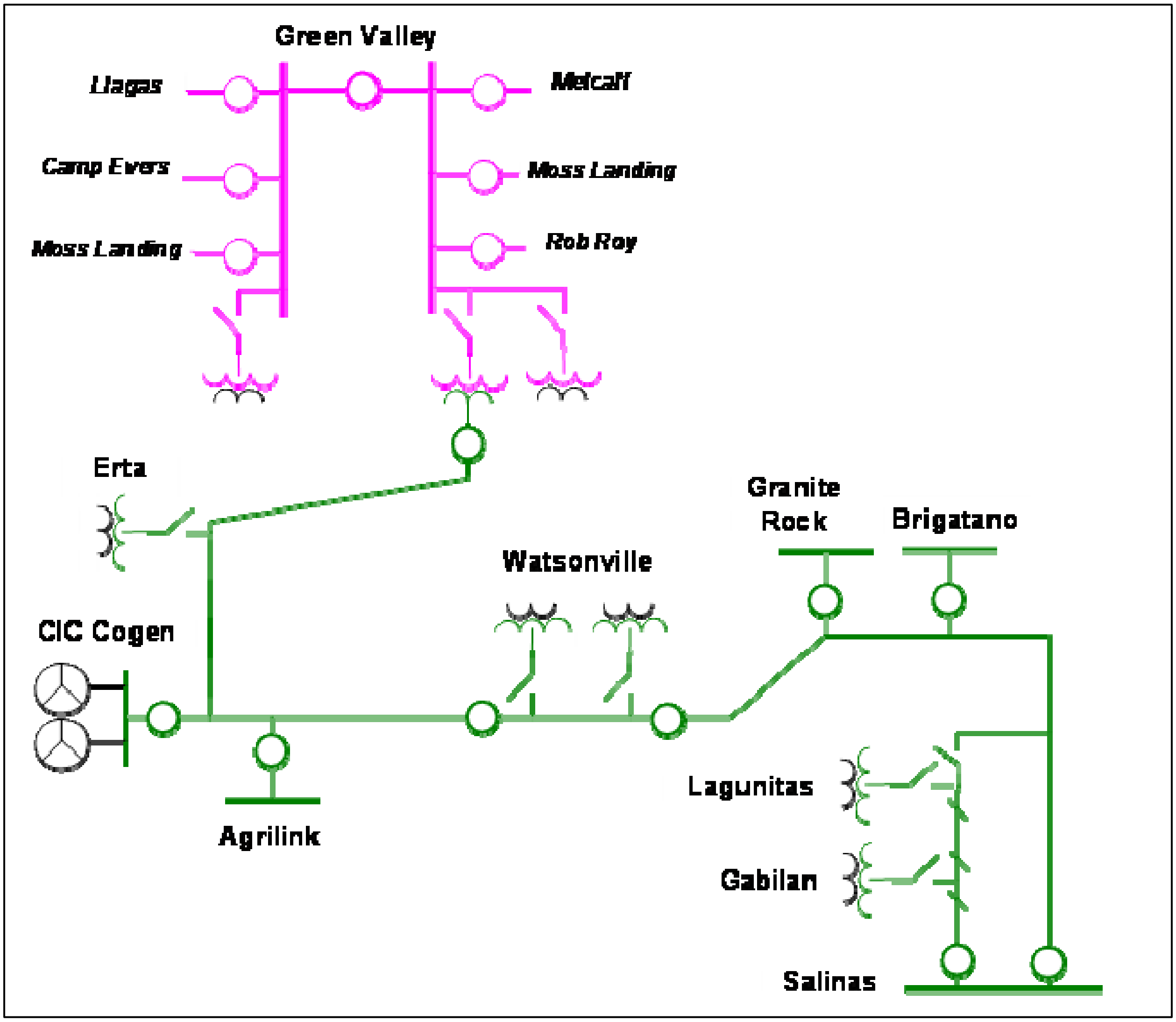


Figure 4-221: Pre-Project of Watsonville 60 kV Area

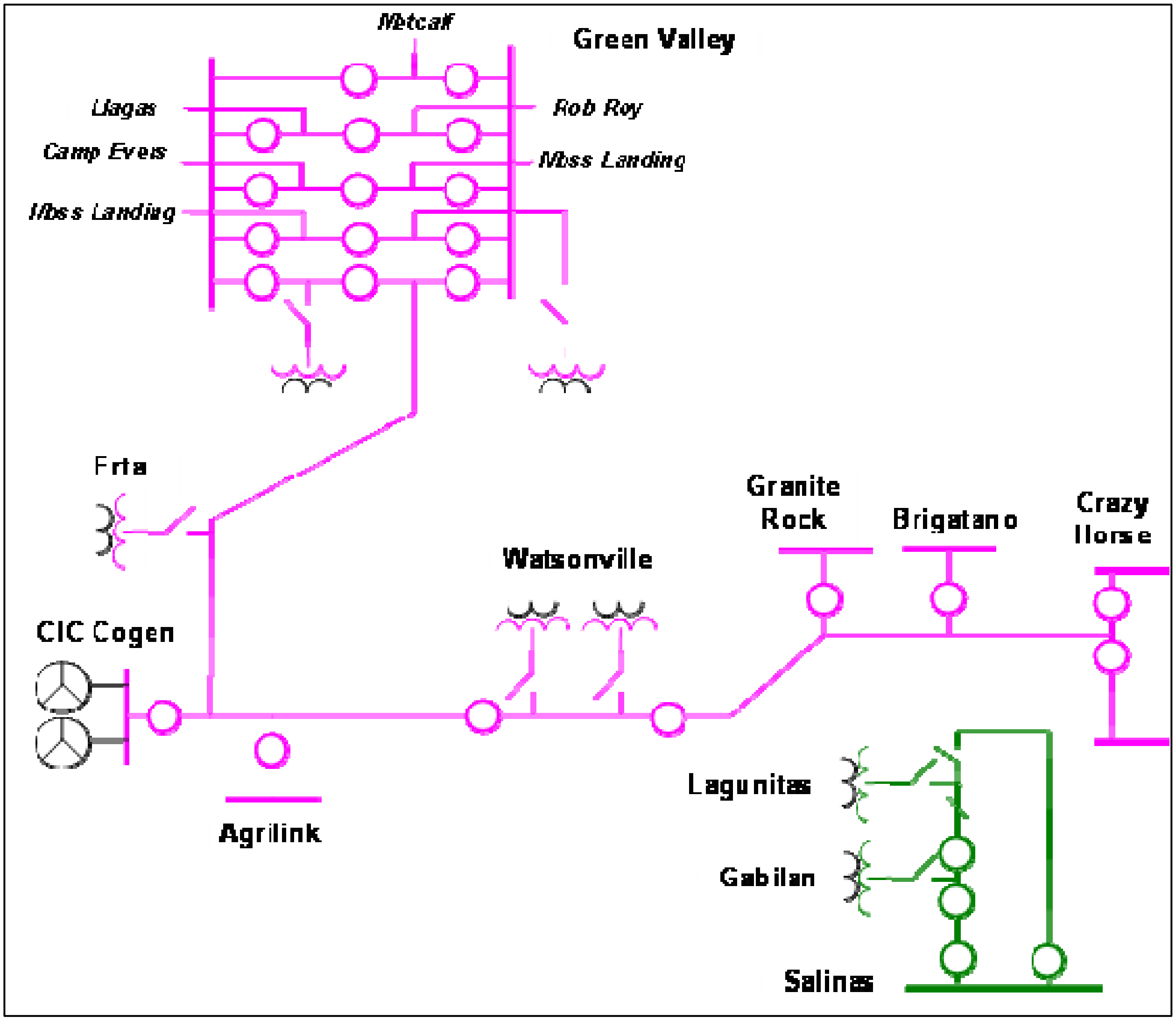


Figure 4-222: Post-Project of Watsonville Area

Attachment 2: Power Flow Summary

Table 4-60: Power Flow Summary

Contingency	Facility Affected	2009 (Pre-Project)	2013 (Pre-Project)	2013 (Post-Project)
Green Valley – Watsonville 60 kV Line (L-1)	Watsonville 60 kV Voltage	0.84	0.82	1.02
Moss Landing – Green Valley 115 kV Line / CIC Cogen Unit (L-1/G-1)	Other Moss Landing – Green Valley Line	97%	102%	75%
	Camp Evers 115 kV Voltage	0.96	0.95	0.99

Attachment 3: Pre- and Post-Project Power Flow Plots

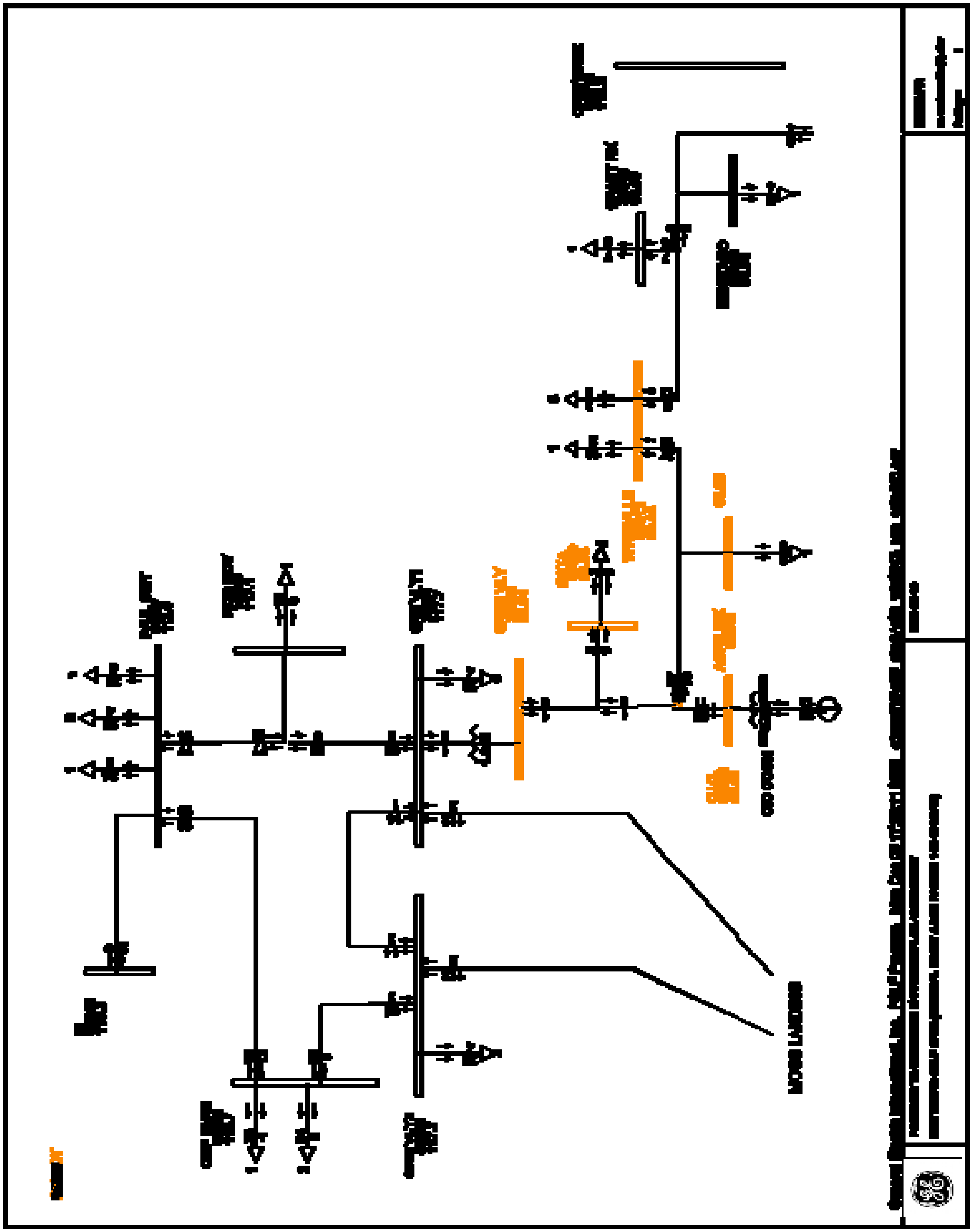


Figure 4-223: Pre-Project – Normal Conditions

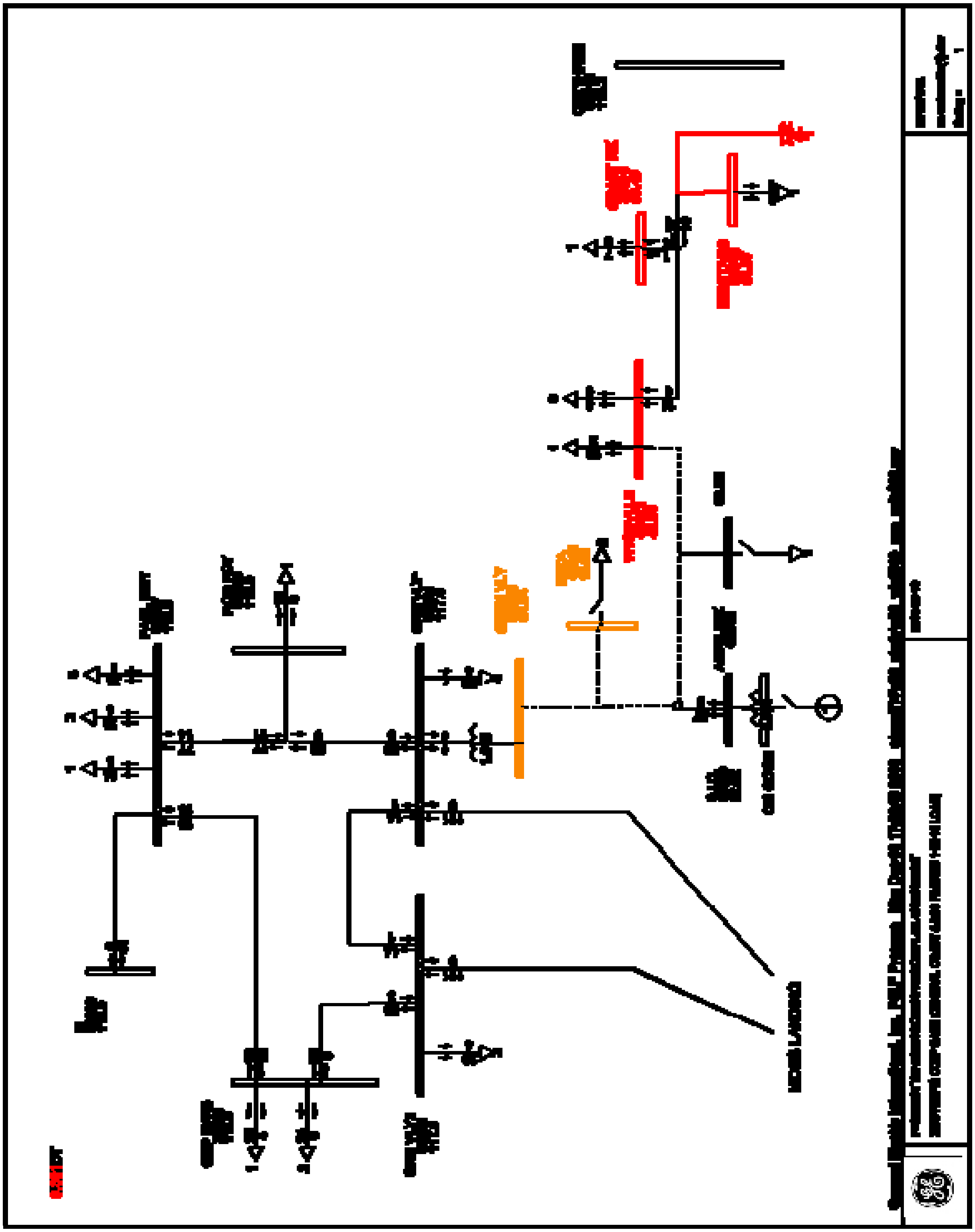


Figure 4-224: Pre-Project – Loss of the Green Valley – Watsonville 60 kV Line (L-1)

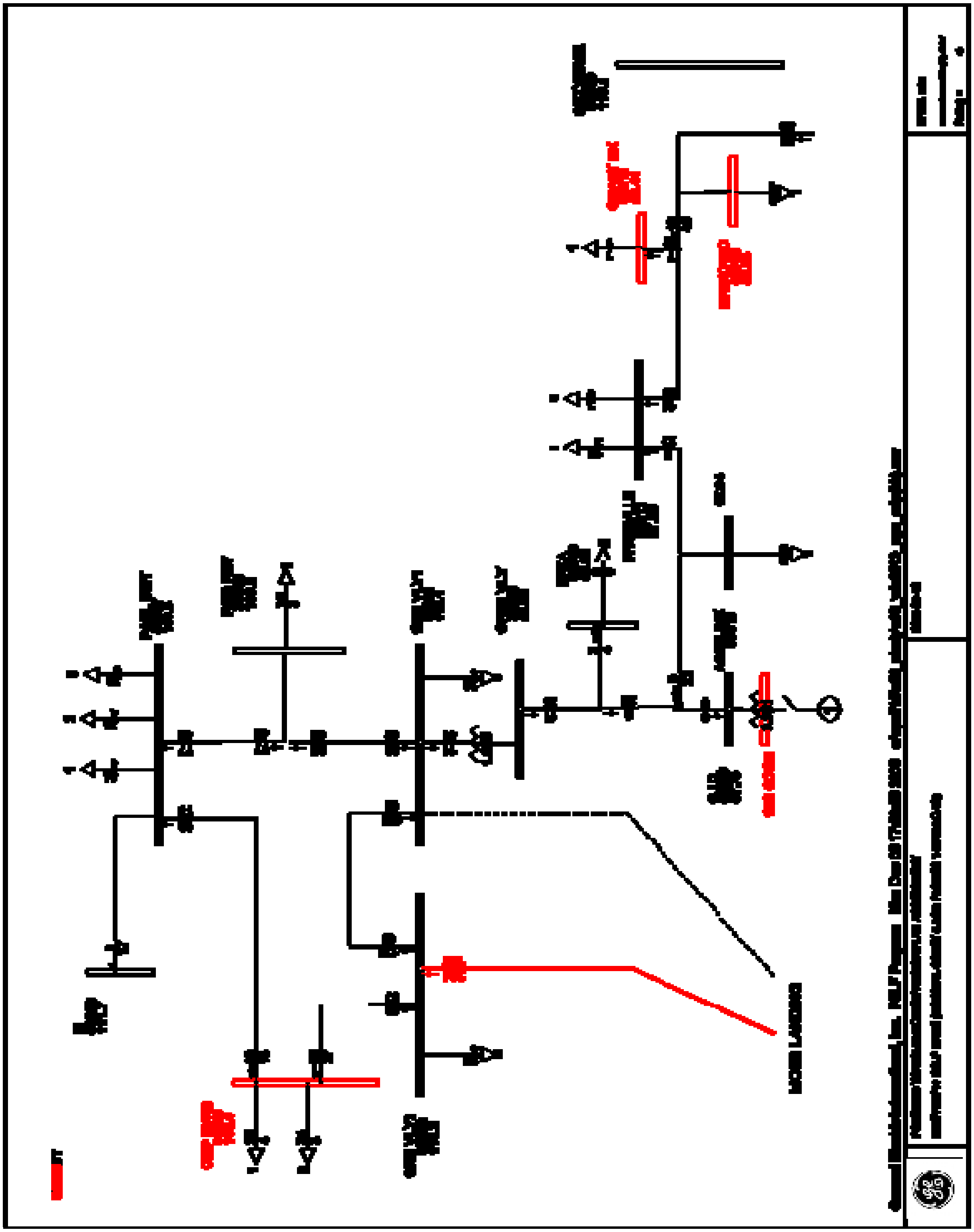


Figure 4-225: Pre-Project – Loss of the Moss Landing – Green Valley No. 1 115 kV Line and the CIC Cogen Unit (L-1/G-1)

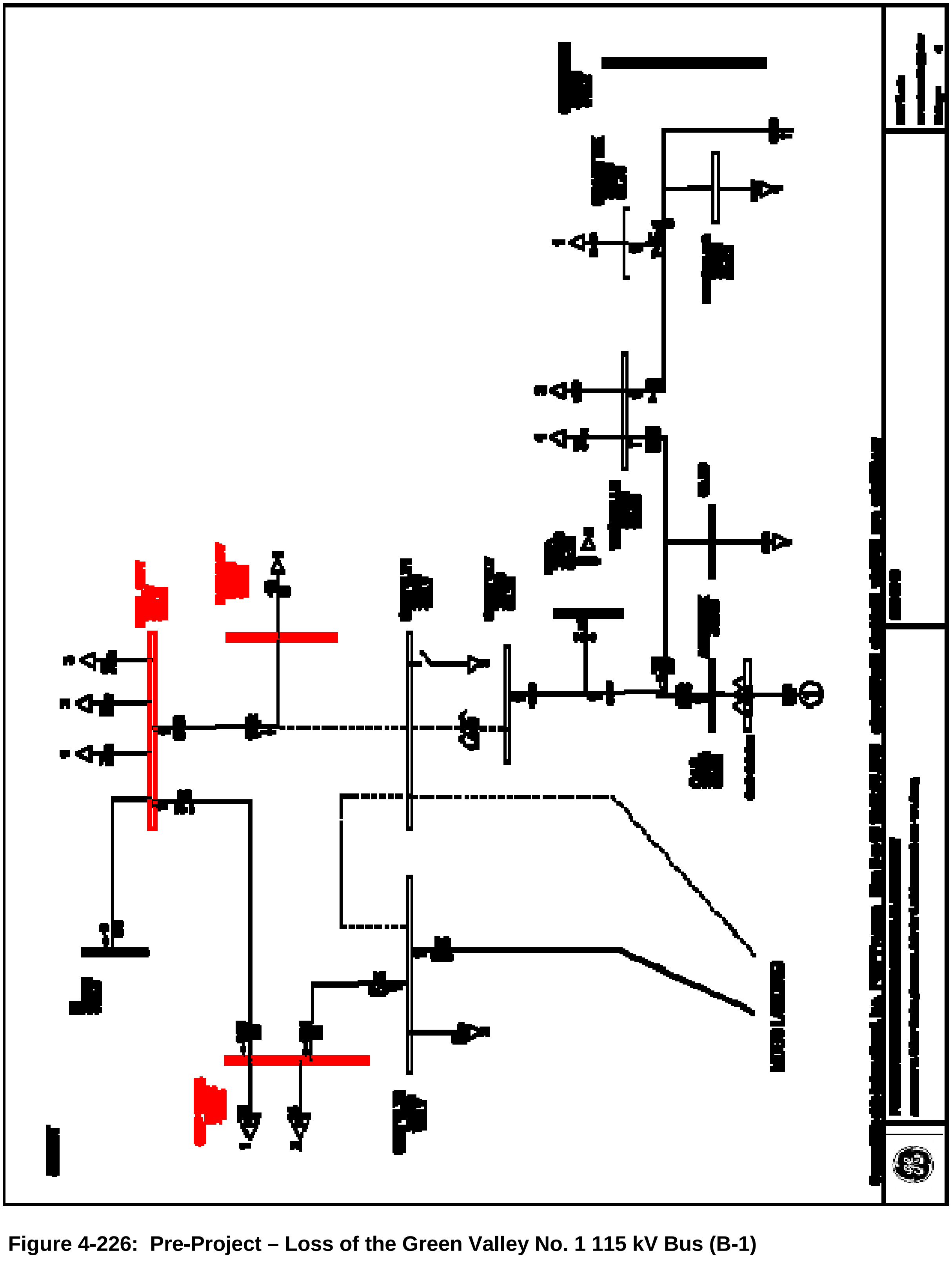


Figure 4-226: Pre-Project – Loss of the Green Valley No. 1 115 kV Bus (B-1)

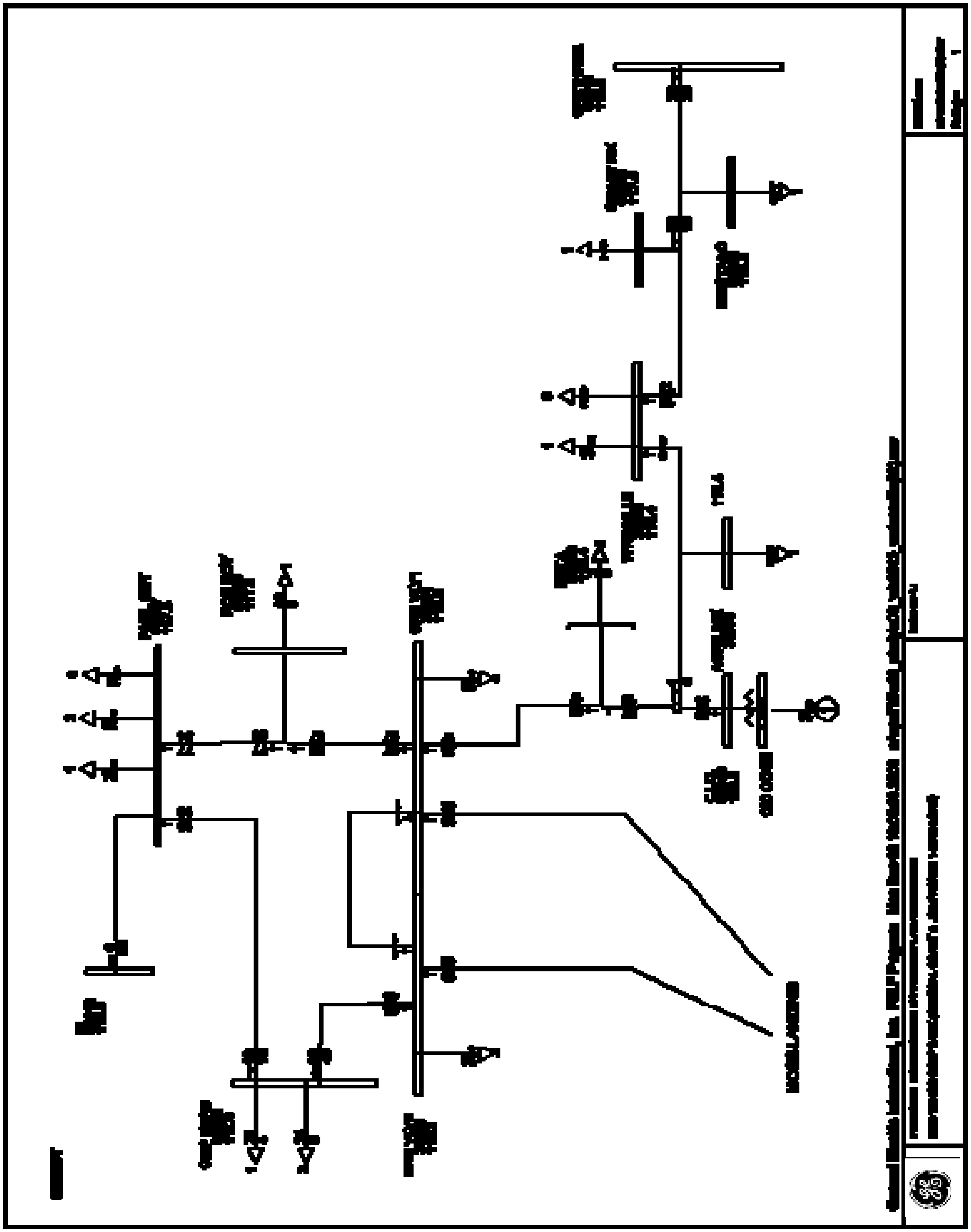


Figure 4-227: Post-Project - Normal Conditions

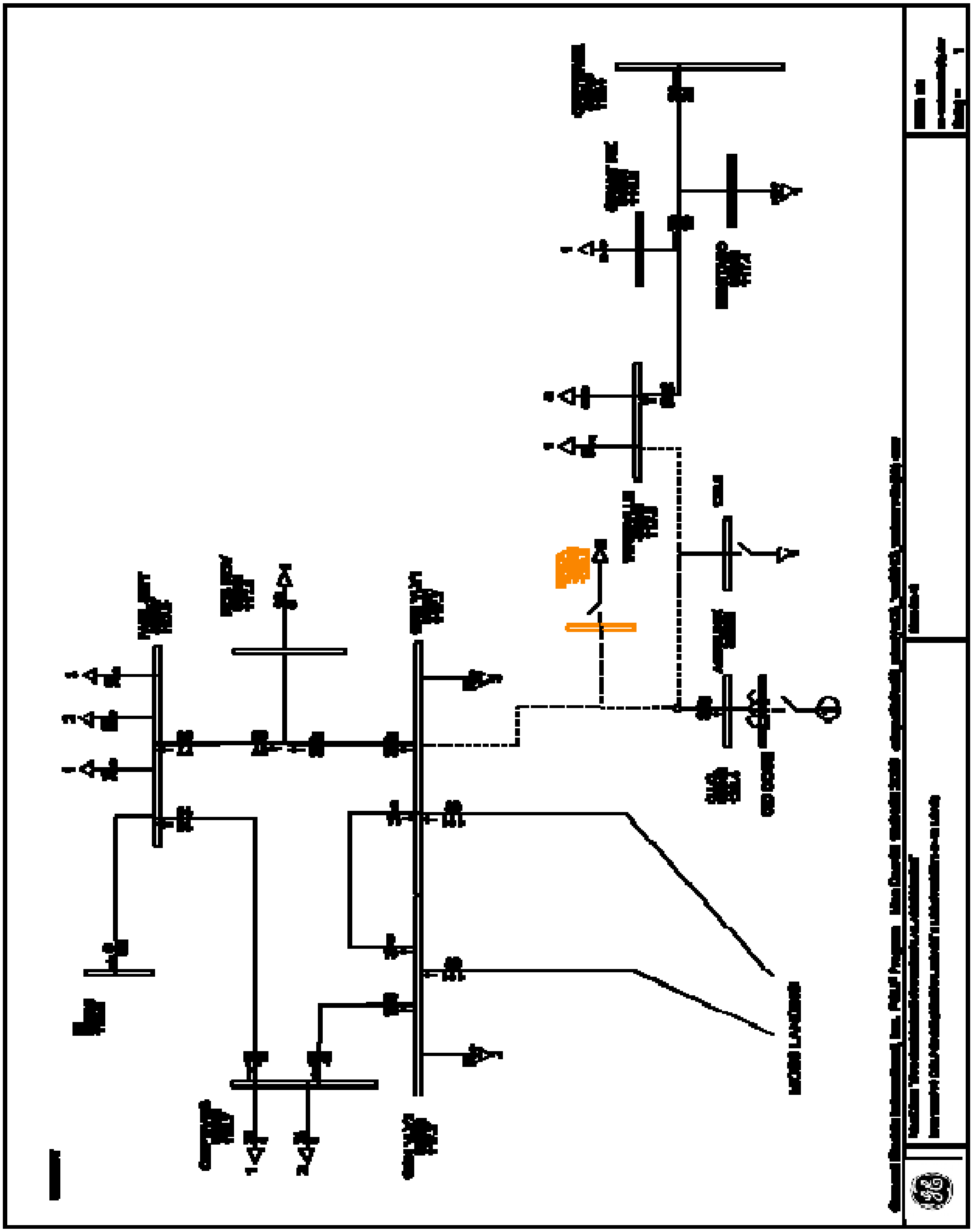


Figure 4-228: Post-Project – Loss of the Green Valley – Watsonville 60 kV Line (L-1)

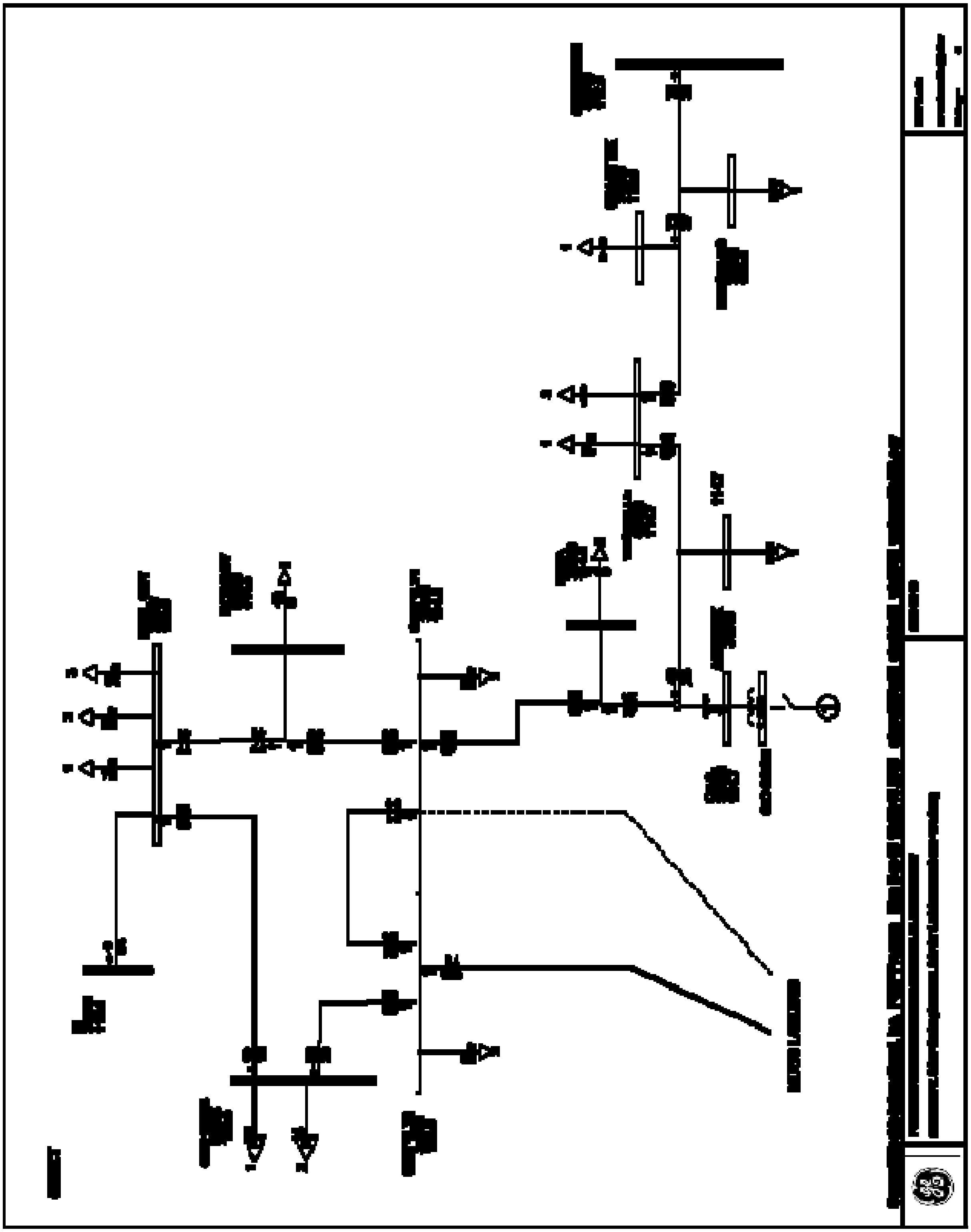


Figure 4-229: Post-Project – Loss of the Moss Landing – Green Valley No. 1 115 kV Line and the CIC Cogen Unit (L-1/G-1)

Clearlake 60 kV System Reinforcement

TARGETED IN-SERVICE DATE

May 2012

PURPOSE AND BENEFIT

Reliability – NERC Compliance

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROJECT

This project scope is to build a new 115 kV line, which is approximately 12 miles long, and is capable of carrying a minimum of 297 Amps under summer normal conditions and 345 Amps under summer emergency conditions. This new line will tap into the Eagle Rock-Cortina 115 kV Line and terminate at Middletown Substation. This project scope will also involve installation of a new 100 MVA rated or higher, 115/60 kV transformer at Middletown Substation.

This project is expected to cost between $20M and $30M.

In the 2007 Expansion Plan, PG&E included the Clearlake-Eagle Rock 60 kV Line Reconductoring Project as a project requiring further analysis. The project scope was to reconductor the 60 kV line section between Eagle Rock Substation and Konocti Junction. With this Clearlake 60 kV System Reinforcement Project, the Clearlake-Eagle Rock 60 kV Line Reconductoring Project is no longer needed.

BACKGROUND

The Clearlake 60 kV System mainly serves electric customers in Upper Lake, Lakeport, Kelseyville, Hidden Valley Lake and Middletown communities in Lake County. The 60 kV system is comprised of three 60 kV lines: Mendocino-Clearlake, Clearlake-Hopland, and Clearlake-Eagle Rock-Middletown and serves the area via five 60 kV substations: Upper Lake, Hartley, Clearlake, Konocti and Middletown. The combined local area demand is projected to reach about 70 MW in 2012 and is expected to increase at 1.4 MW per year.

The all three 60 kV lines consist of 4/0 Al conductor and has a normal and emergency rating of 297 Amps and 345 Amps. The Eagle Rock-Clearlake 60 kV line also has a section with 397 Al conductors between Eagle Rock and Konocti Substations. These 60 kV lines from Mendocino, Hopland and Eagle Rock to Clearlake are about 30, 12 and 20 miles long respectively.

The Middletown Substation is equipped with a special protection scheme (SPS), which drops load at Middletown when the voltage at station's 60 kV bus drops below an acceptable level.

The planning analysis has identified that the Clearlake 60 kV system could potentially experience thermal overloads and low voltages by 2012 even with Middletown SPS in place. The Clearlake-Eagle Rock 60 kV Line could overload by 1% above its rerated summer emergency rating in 2012 for an outage of the Geyser No. 3-Cloverdale 115 kV Line. Also, the Clearlake-Hopland 60 kV Line could overload by 6% above its emergency rating in 2018 for an outage of the Eagle Rock 115/60 kV transformer bank. The same outage could also create low voltage at Konocti in 2018.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO Grid Planning Criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended. This alternative does not address the potential thermal overloads and low voltages in the area even after the operation of the SPS at Middletown.

Alternative 2: Voltage Conversion to 115 kV

This alternative involves converting about 36 miles of 60 kV line and Middletown and Calistoga Substations to115 kV.

This alternative would also require some line reconductoring and bus work at terminal station's 115 kV buses to terminate the new 115 kV line.

This alternative is not preferred to address the potential thermal overloads and low voltages in the Clearlake 60 kV System because of the higher cost and extensive time required to implement the line and station conversions.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2012

KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – TBD
- Special Metering or Protection – TBD
- Common Mode Exposure Items – TBD
- Interaction with other Projects or Studies – Clearlake Long-Term Study

GEPSLF MODELING INFORMATION

```
#************************************************************************
# Clearlake 60 kV System Reinforcement
# Description:
# This project will install a new 115 kV line from Lowerlake to Middletown and a 115/60 kV bank at Middletown.
#*************************************************************************
# New Middletown 115 kV bus.
NEWBUSD   31343, MIDDLTWN, BASKV=115, BUSTYPE=1, VSCHED=1, AREA=2, ZONE=302
# New 115/60 kV Transformer at Middletown.
NEW_TRAN  31342, 31343, 1, 0.001450, 0.042000, 0, 67.5, 80, 67.5, 80, 60, 115, 45, STAT=1, TYPE=2, TAPF=0.9849,
ANGLP=0, REG=31342, VMAX=1.0583, VMIN=1.0333, STEPP=.00755, TMAX=1.0817, TMIN=0.9308, TAPFP=1, TAPFS=1,
GMAG=0, AREA=2, ZONE=302
# New 115 kV line from Lowerlake to Middletown.
NEWSECDD 31228, 31343, CKT=1, SEC=1, RPU=0.045521, XPU=0.076082, BPU=0.008787, MVA1=59, MVA2=69, STATUS=1
# Lowerlake-Middletown 60 kV line section Impedance change.
OLDSECDD 31340, 31342, CKT=1, SEC=1, STATUS=1, RPU=0.167228, XPU=0.279496, BPU=0.002392, MVA1=46, MVA2=53
#END
```

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagram
2. Demand Forecast
3. Power Flow Summary
4. Pre and Post Project Power Flow Plots

Attachment 1: Scope Diagram

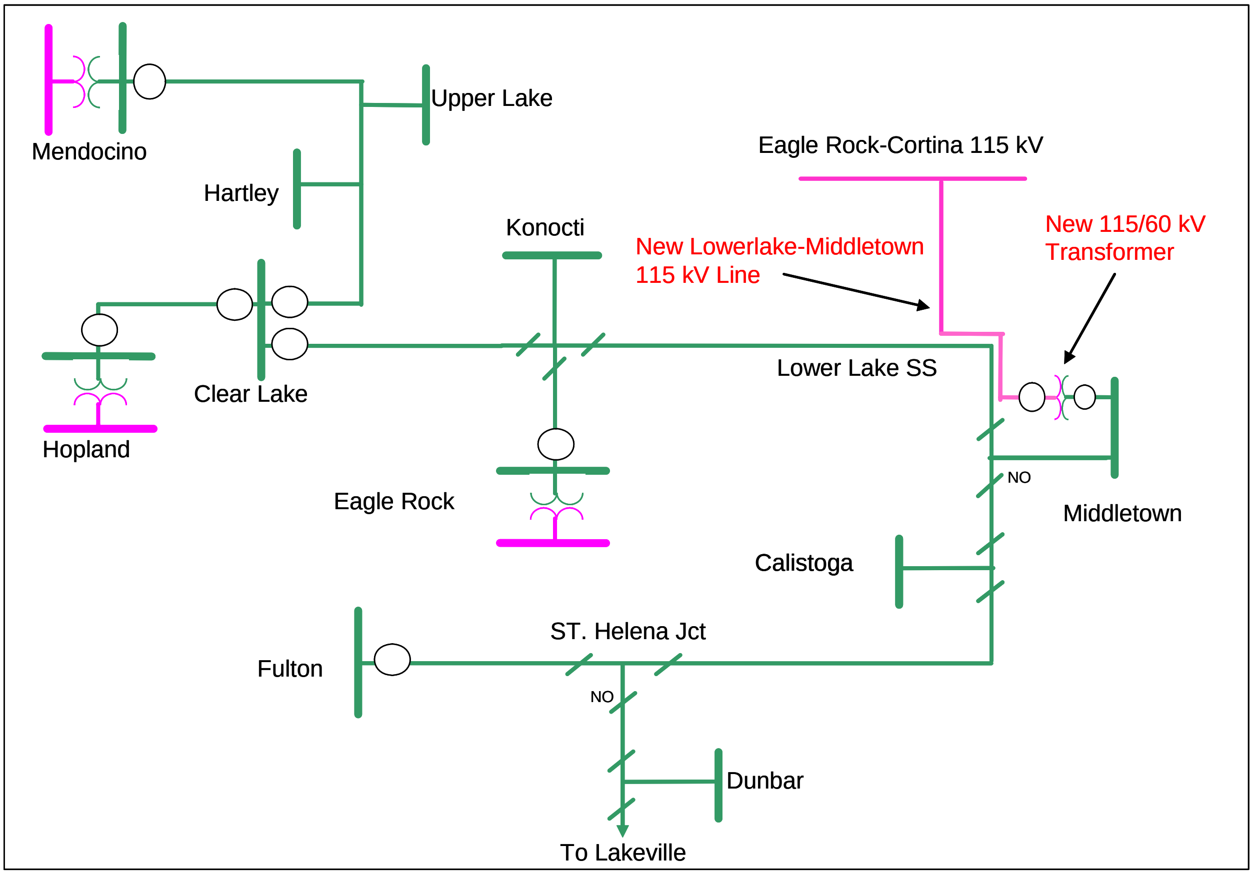


Figure 4-230: Clearlake 60 kV System

Attachment 2: Demand Forecast

Table 4-61: Area Demand Forecast

Substation	2009	2010	2011	2012	2013	Growth Rate (MW/Year)
Upper Lake	3.5	3.6	3.6	3.7	3.7	0.1
Hartley	10.7	10.7	10.9	11.2	11.3	0.2
Clearlake	19.0	19.3	19.6	19.9	20.2	0.3
Konocti	15.2	15.4	15.7	15.9	16.2	0.3
Middletown	17.0	17.6	18.2	18.9	19.5	0.6
Totals	**65**	**67**	**68**	**70**	**71**	**1.4**

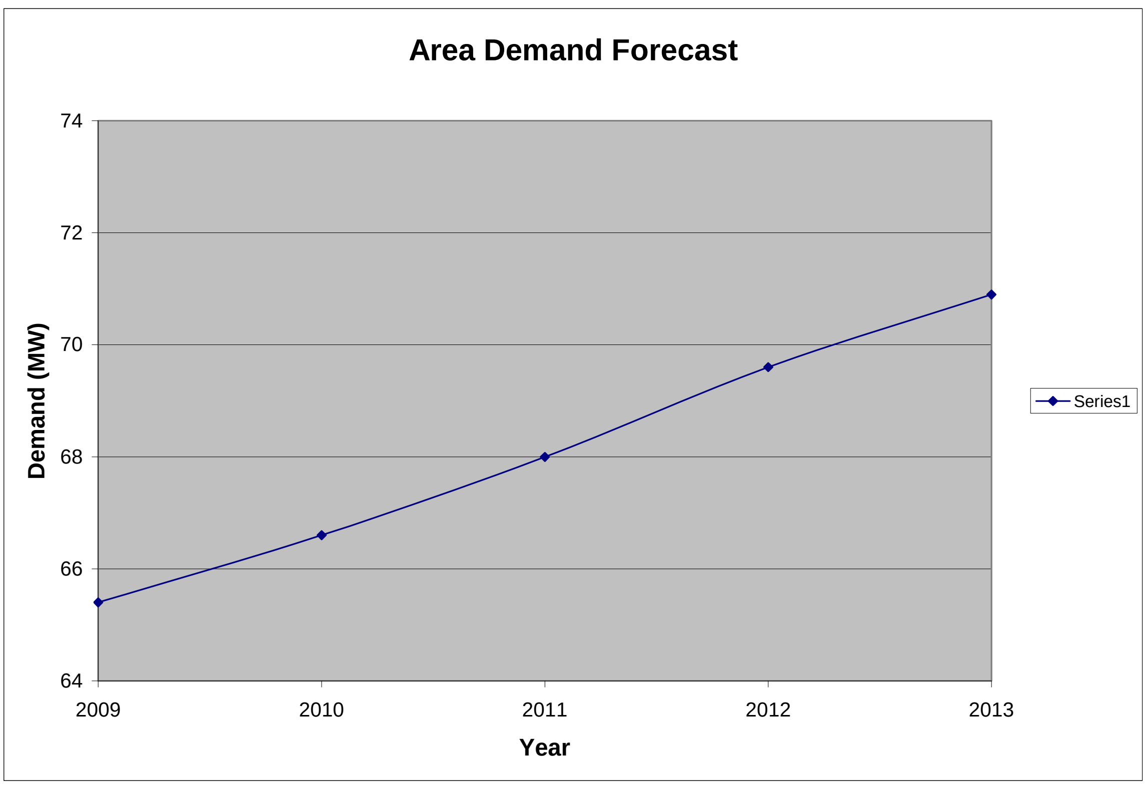


Figure 4-231: Plot of Area Forecast

Attachment 3: Power Flow Summary

Table 4-62: Power Flow Summary

Contingency	Facility Affected	2009 (Pre-Project)	2010 (Pre-Project)	2011 (Pre-Project)	2012 (Pre-Project)	2013 (Pre-Project)	2012 (Post-Project)
NERC Category A							
Middletown 60 kV Voltage	Normal	0.93 p.u.	0.93 p.u.	0.93 p.u.	0.93 p.u.	0.92 p.u.	1.04 p.u.
NERC Category B							
Clearlake-Eagle Rock 60 kV Line	Geyser No. 3-Cloverdale 115 kV Line	97%	97%	99%	101%	103%	63%

Contingency	Facility Affected	2009 (Pre-Project)	2010 (Pre-Project)	2011 (Pre-Project)	2012 (Pre-Project)	2013 (Pre-Project)	2018 (Pre-Project)	2018 (Post-Project)
Konocti 60 kV Voltage	Eagle Rock 115/60 kV Transformer	0.93 p.u.	0.93 p.u.	0.92 p.u.	0.92 p.u.	0.92 p.u.	0.88 p.u.	0.97 p.u.
Clearlake-Hopland 60 kV Line		90%	90%	91%	93%	95%	106%	58%

Attachment 4: Pre and Post Project Power Flow Plots

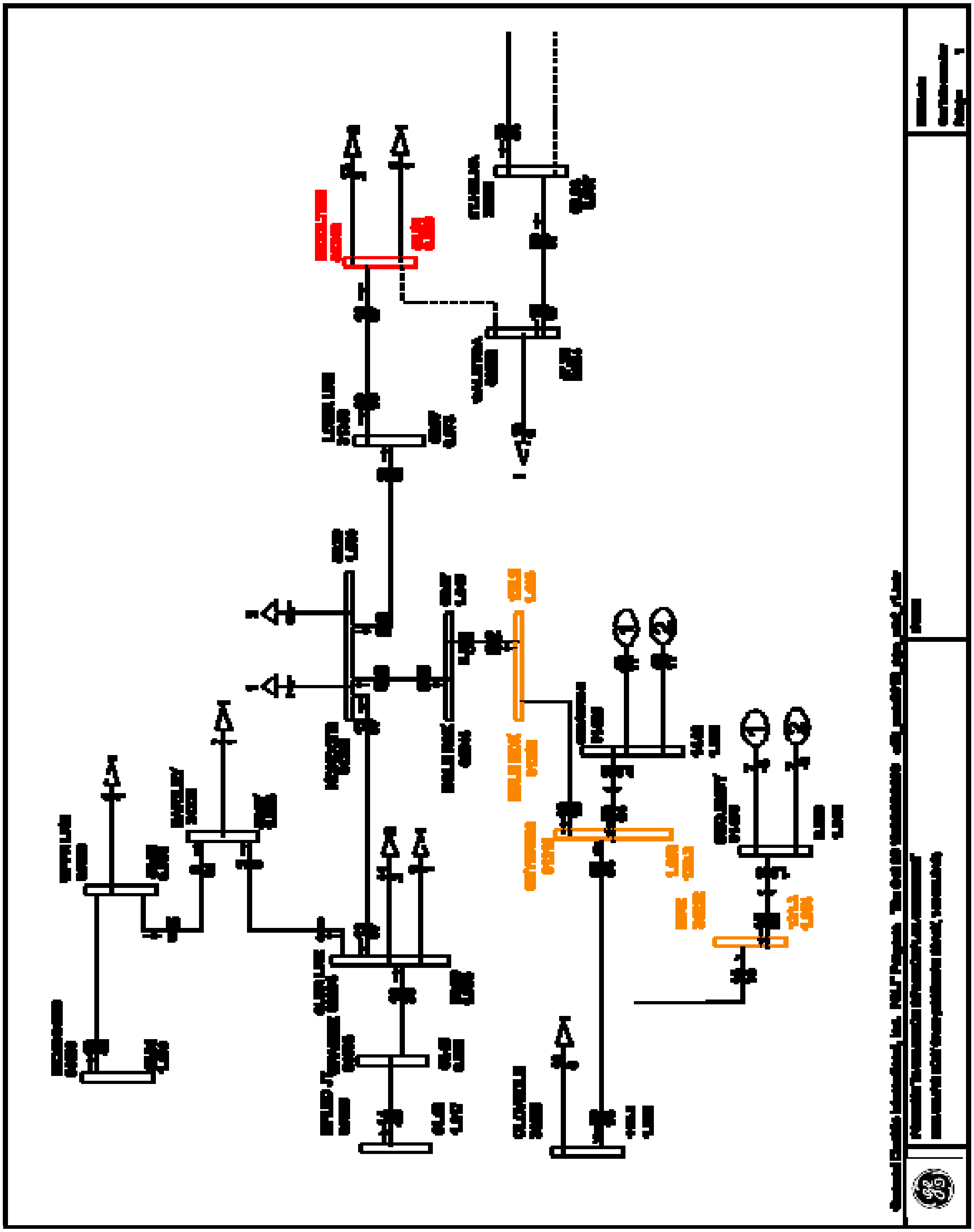


Figure 4-232: Pre Project – Normal Conditions (2012)

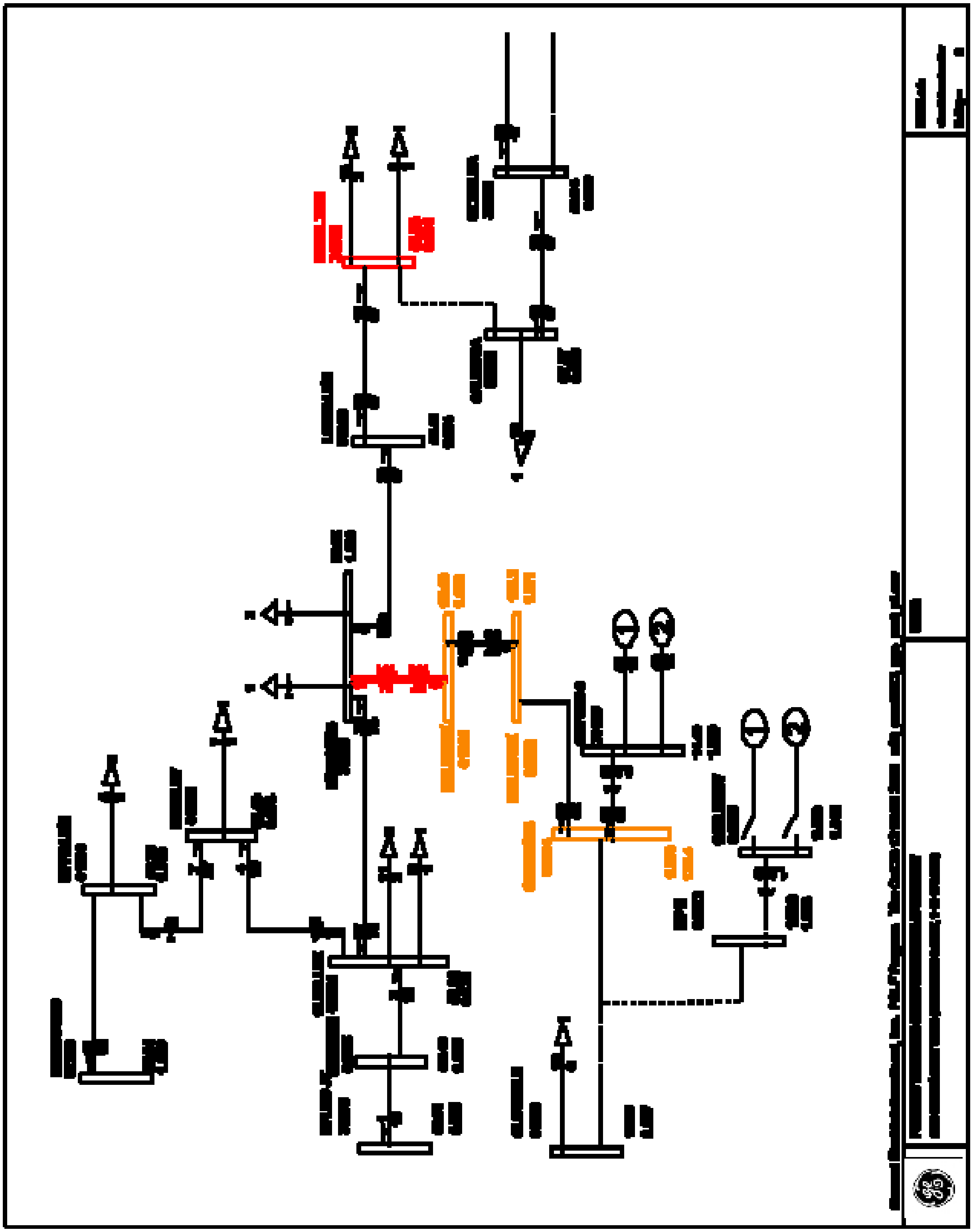


Figure 4-233: Pre-Project – Loss of Geyser No.3-Cloverdale 115 kV Line (L-1). (2012)

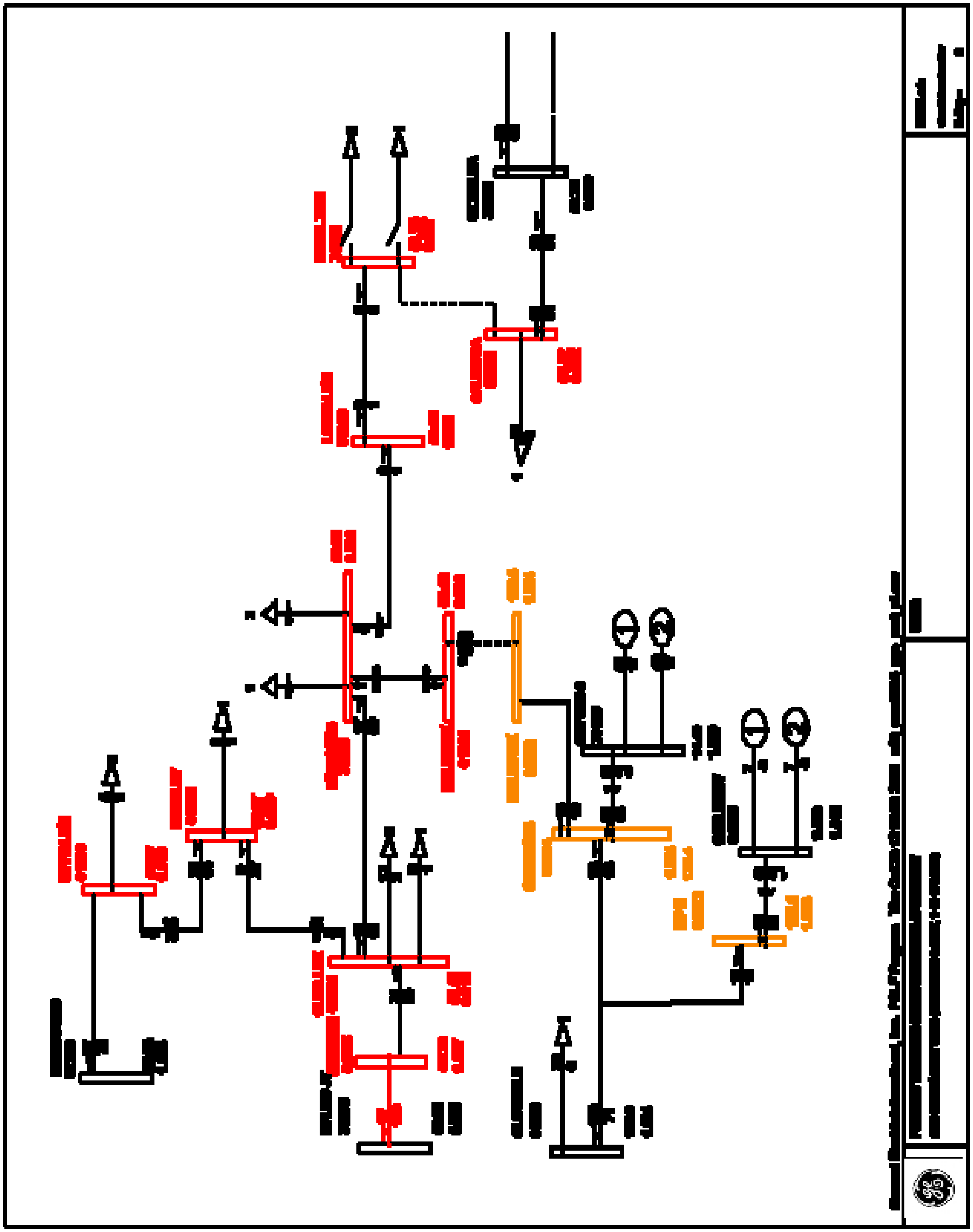


Figure 4-234: Pre-Project – Loss of Eagle Rock 115/60 kV Transformer (T-1). (2018)

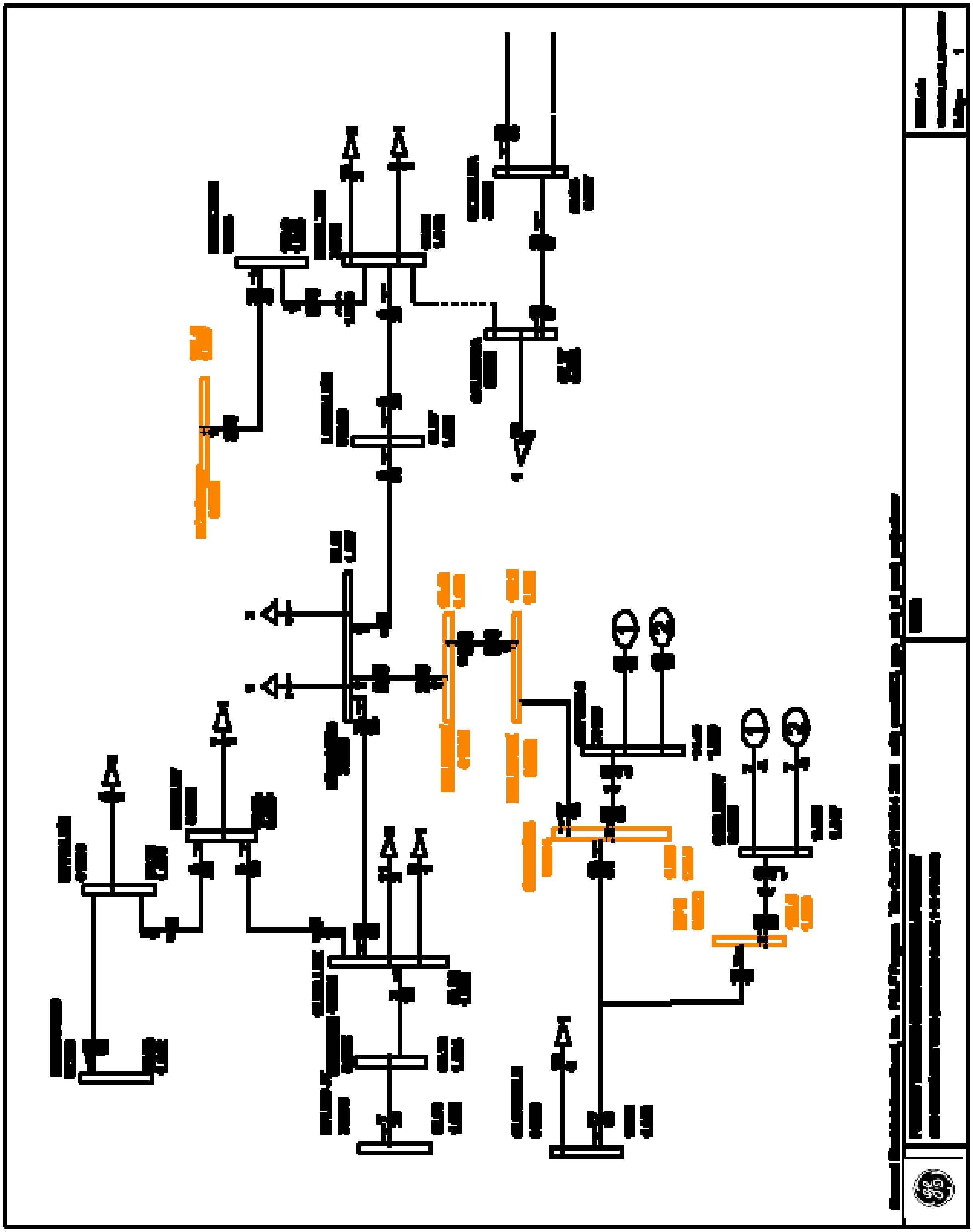


Figure 4-235: Post-Project – Normal Conditions. (2012)

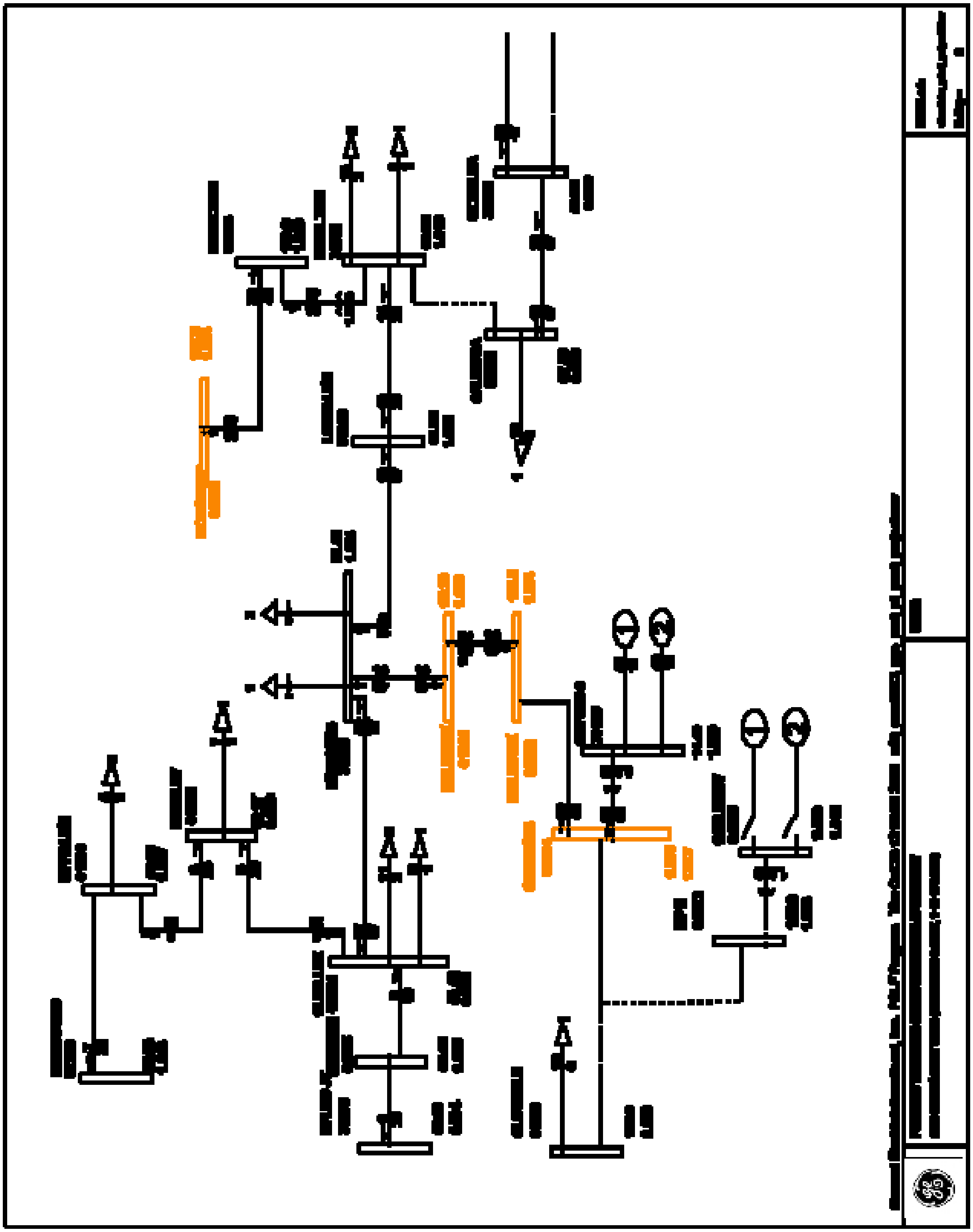


Figure 4-236: Post Project – Loss of Geyser No.3-Cloverdale 115 kV Line (L-1). (2012)

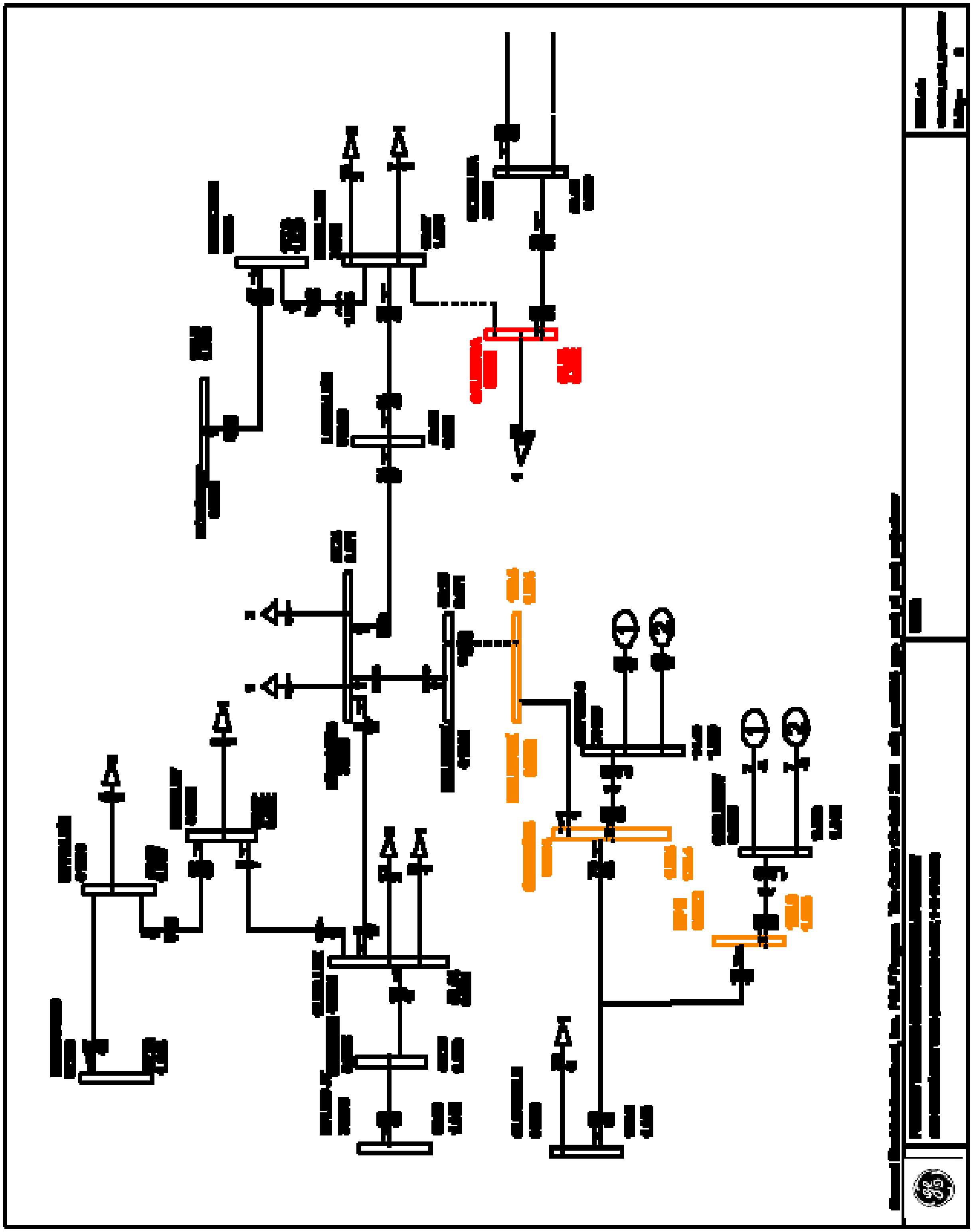


Figure 4-237: Post Project – Loss of Eagle Rock 115/60 kV Transformer (T-1). (2018)

Ignacio – Mare Island 115 kV System Reinforcement

TARGETED IN-SERVICE DATE

May 2012

PURPOSE AND BENEFIT

Reliability – NERC Compliance

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROJECT

The project scope is to reconductor about 19-mile section of the Ignacio-Mare Island Nos. 1 & 2 115 kV Lines with conductors rated to handle a minimum of 700 Amps for summer normal conditions and 800 Amps for summer emergency conditions. If necessary, associated line terminal equipment would be upgraded. In addition, the project scope would require obtaining any necessary environmental and land permits to complete the reconductoring work.

This project is expected to cost between $20M and $25M.

BACKGROUND

The Ignacio-Mare Island Nos. 1 & 2 115 kV Lines, located in Marin, Napa and Solano Counties, are the two lines that serve the electric customers in American Canyon and part of the City of Vallejo. The substations served from these transmission lines are Skaggs Island, Highway, Carquinez, Island Energy's Substation H and Hamilton wetlands (customer owned substation). The combined local area demand is projected to reach about 93 MW in 2012 and is expected to increase at 1.2 MW per year.

Both the Ignacio-Mare Island 115 kV Lines are about 40 miles in length (including tap lines) and are capable of carrying 359 Amps normally and 406 Amps under emergency conditions (between Ignacio and Highway substation). With the existing configuration, Skaggs Island, Carquinez and Station H Substations are served from the No. 1 line and Highway and Hamilton Wetlands Substations are served from the No. 2 line during the normal operating conditions. During an outage of the primary source, Highway, Carquinez and Station H Substations are automatically transferred to the alternate source.

The planning analysis has identified that the Ignacio-Mare Island Nos. 1 & 2 115 kV Lines could potentially overload for an outage of either line during peak loading conditions. The Nos. 1 & 2 lines could potentially load up to 117% and 102% of their emergency summer ratings respectively in 2012. To mitigate these thermal overload concerns in the short term, a request has been made recently to rerate these lines to 4 feet per second (fps) wind speed ratings. If the rerate is granted, these lines will have capacity of 428 Amps normally and 481 Amps under emergency conditions by 2009.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended. This alternative does not address the capacity deficiency of the Ignacio-Mare Island Nos. 1 & 2 115 kV Line.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2012

KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – TBD
- Special Metering or Protection – TBD
- Common Mode Exposure Items – TBD
- Interaction with other Projects or Studies – TBD

GEPSLF MODELING INFORMATION

```
#***************************************************************************
# Ignacio – Mare Island 115 kV System Reinforcement
# Description:
# This project will reconductor the limiting 19-mile section of the Ignacio-Mare Island Nos. 1 & 2 115 kV Lines.
#********************************************************************************
#
# Reconductor the Ignacio-Highway sections with 715 Al conductor.
OLDSECDD  32568, 32576, CKT=1, SEC=1, RPU=0.0132 XPU=0.066096 BPU=0.009444 MVA1=140 MVA2=160 MVA3=194 MVA4=207
OLDSECDD  32576, 32588, CKT=1, SEC=1, RPU=0.0077 XPU=0.038556 BPU=0.005509 MVA1=140 MVA2=160 MVA3=194 MVA4=207
OLDSECDD  32568, 32569, CKT=1, SEC=1, RPU=0.0011 XPU=0.005508 BPU=0.000787 MVA1=140 MVA2=160 MVA3=194 MVA4=207
OLDSECDD  32569, 32578, CKT=1, SEC=1, RPU=0.0121 XPU=0.060588 BPU=0.008657 MVA1=140 MVA2=160 MVA3=194 MVA4=207
OLDSECDD  32578, 32586, CKT=1, SEC=1, RPU=0.0077 XPU=0.038556 BPU=0.005509 MVA1=140 MVA2=160 MVA3=194 MVA4=207
#END
```

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagram
2. Demand Forecast
3. Power Flow Summary
4. Pre and Post Project Power Flow Plots

Attachment 1: Scope Diagram

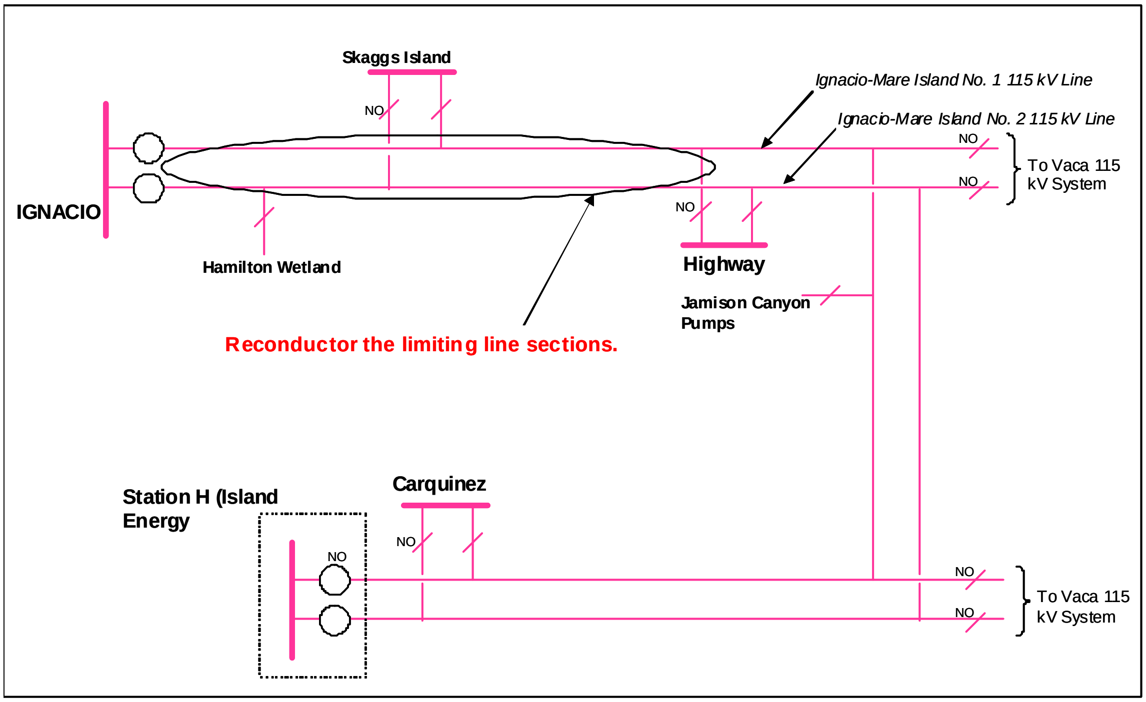


Figure 4-238: Ignacio – Mare Island 115 kV System.

Attachment 2: Demand Forecast

Table 4-63: Area Demand Forecast

Substation	2009	2010	2011	2012	2013	Growth Rate (MW/Year)
Highway	46.1	46.8	47.6	48.3	49.3	0.8
Carquinez	24.5	24.9	25.3	25.7	26.2	0.4
Station H	4.3	4.3	4.3	4.3	4.3	0.0
Hamilton Wetland	15.0	15.0	15.0	15.0	15.0	0.0
Skaggs Island	0.0	0.0	0.0	0.0	0.0	0.0
Totals	**90**	**91**	**92**	**93**	**95**	**1.2**

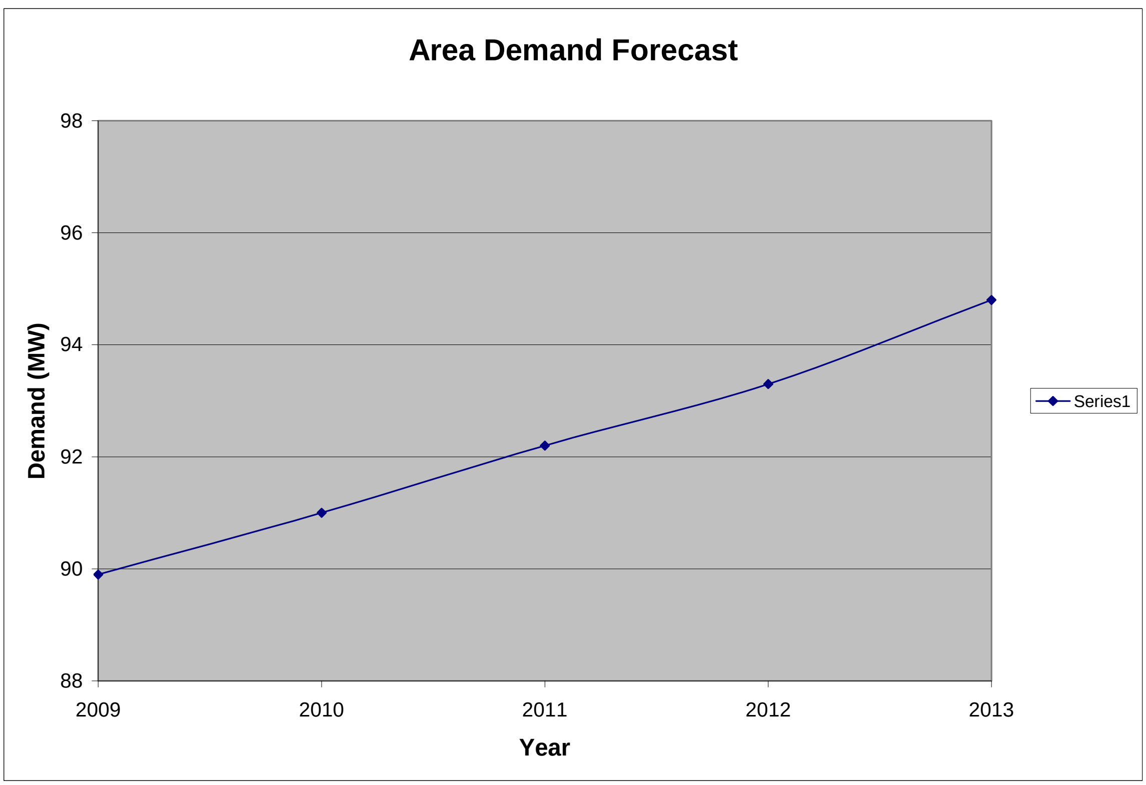


Figure 4-239: Plot of Area Forecast

Attachment 3: Power Flow Summary

Table 4-64: Power Flow Summary

Contingency	Facility Affected	2009 (Pre-Project)	2010 (Pre-Project)	2011 (Pre-Project)	2012 (Pre-Project)	2013 (Pre-Project)	2012 (Post-Project)
Ignacio-Mare Island No. 2 115 kV Line	Ignacio-Mare Island No. 1 115 kV Line	111%	113%	115%	117%	118%	60%
Ignacio-Mare Island No. 1 115 kV Line	Ignacio-Mare Island No. 2 115 kV Line	97%	99%	101%	102%	104%	50%

Attachment 4: Pre and Post Project Power Flow Plots

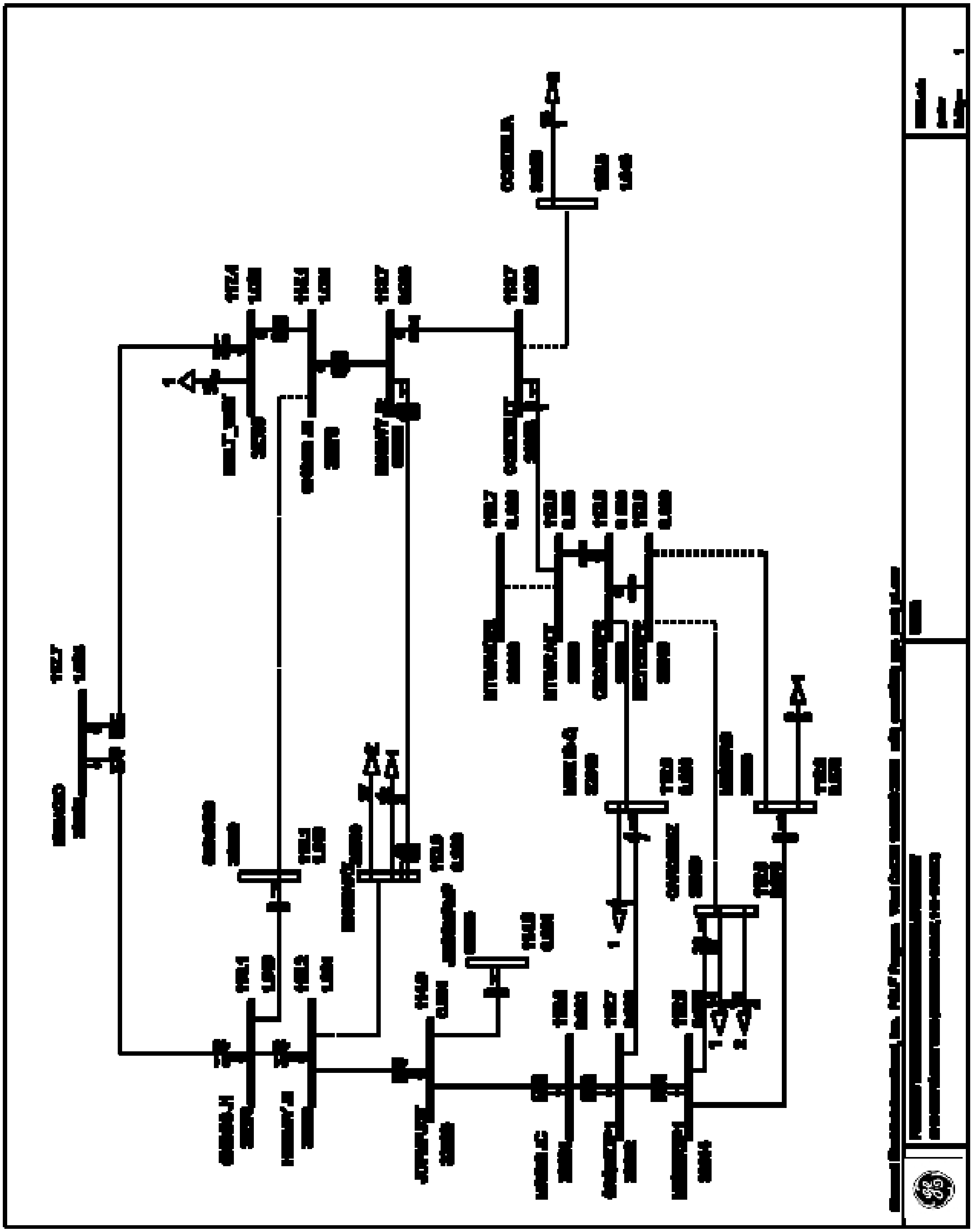


Figure 4-240: Pre Project - Normal Conditions (2012)

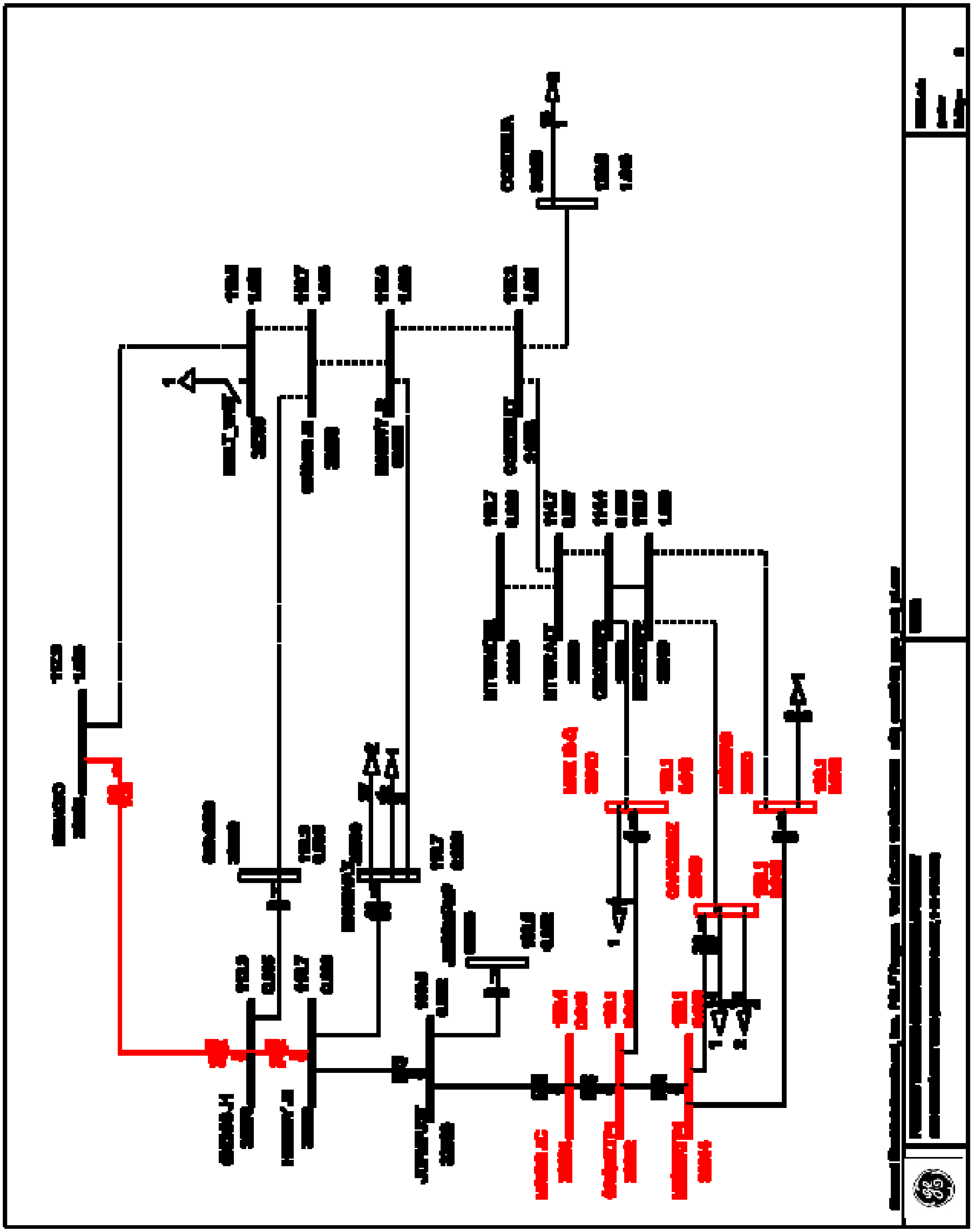


Figure 4-241: Pre Project - Loss of the Ignacio-Mare Island No. 2 115 kV Line (L-1). (2012)

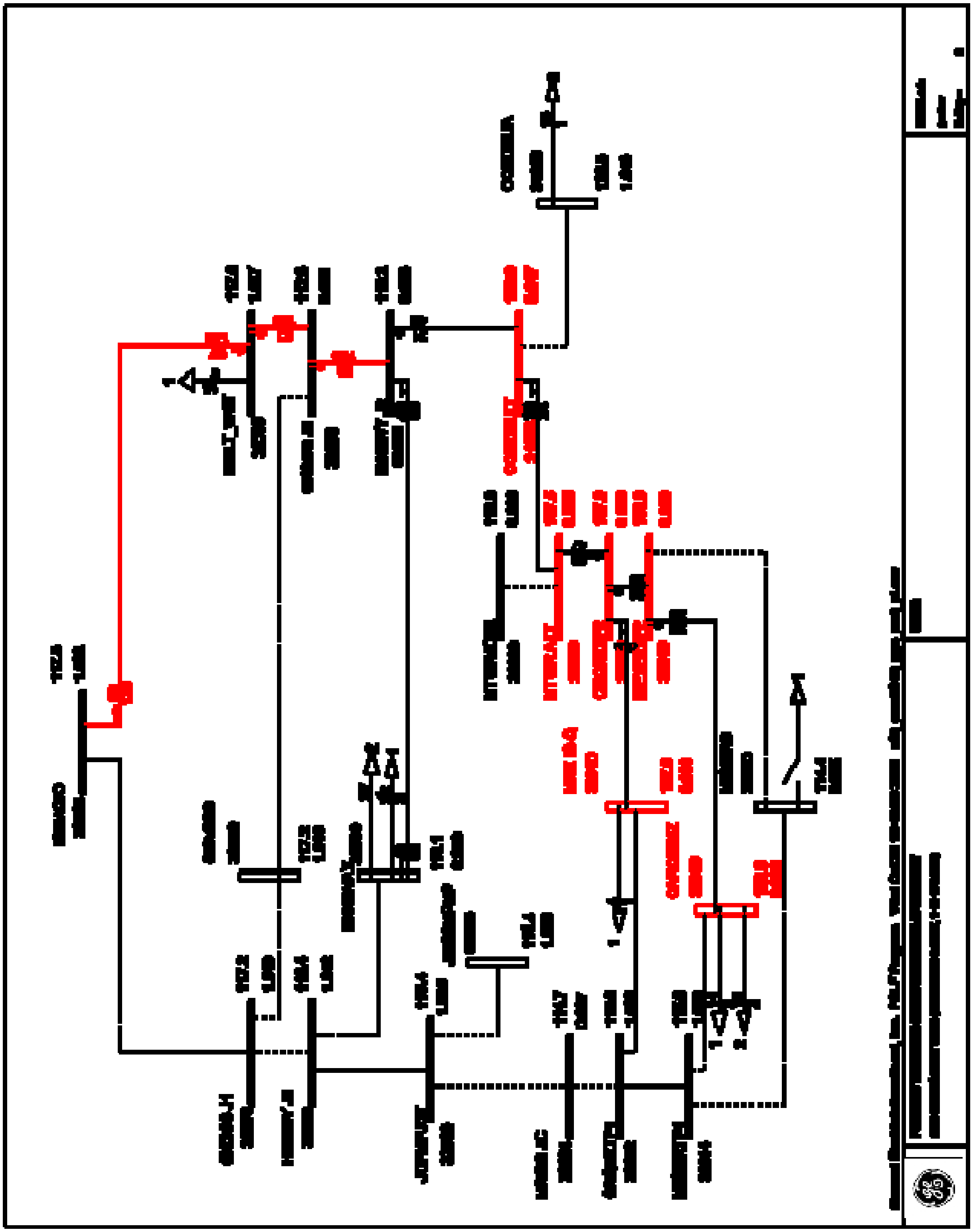


Figure 4-242: Pre Project - Loss of the Ignacio-Mare Island No. 1 115 kV Line (L-1). (2012)

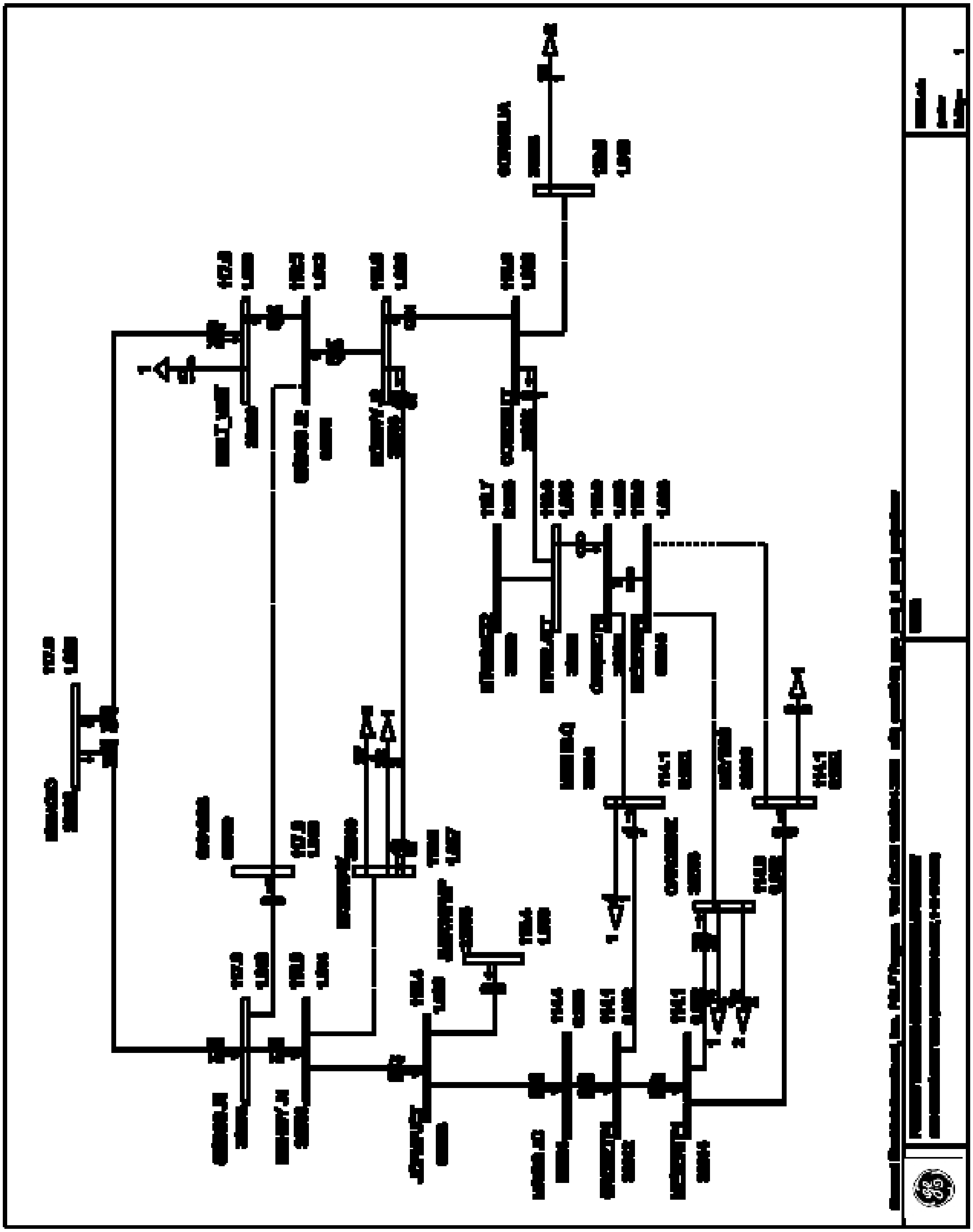


Figure 4- 243: Post Project - Normal Conditions (2012)

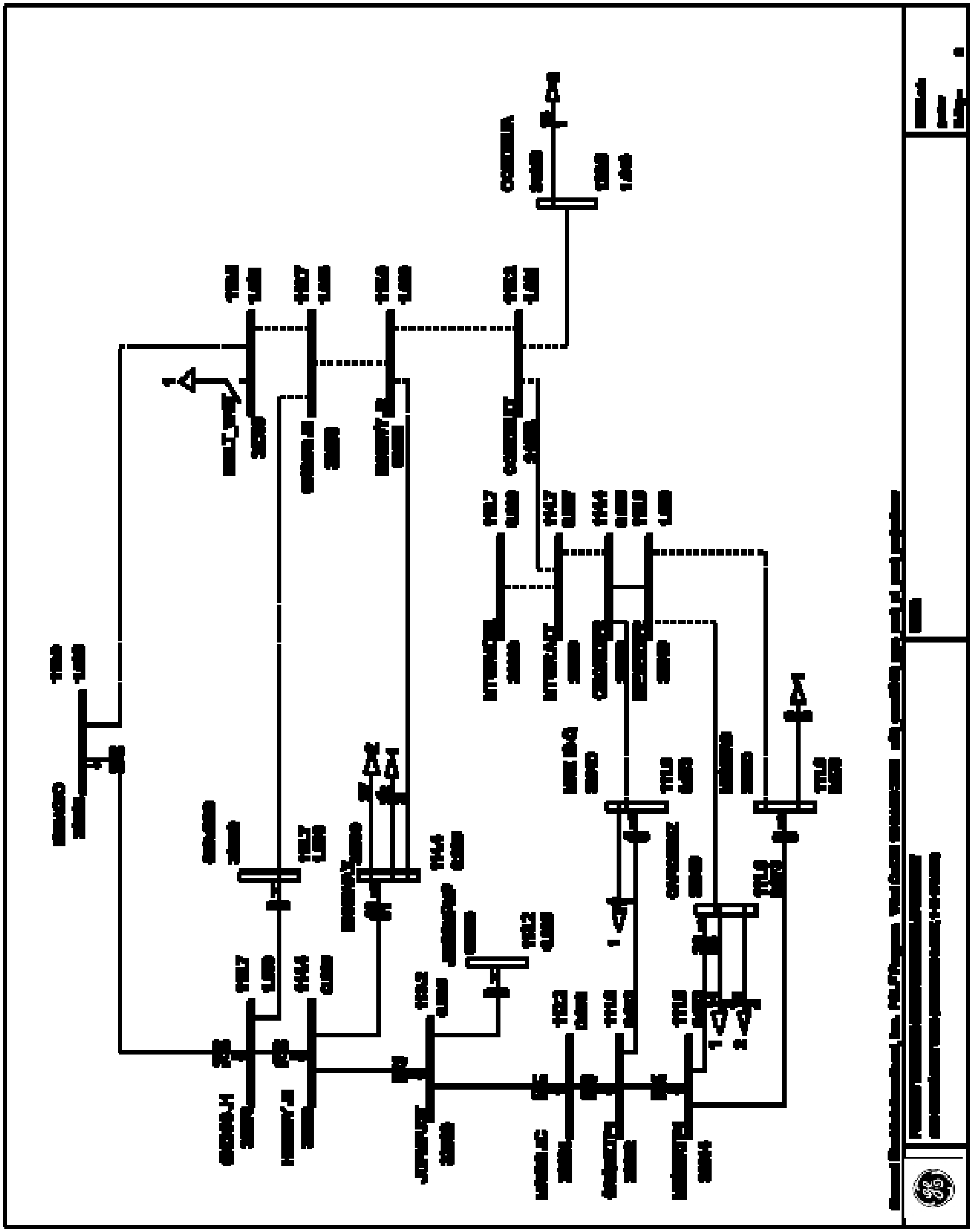


Figure 4-244: Post Project - Loss of the Ignacio-Mare Island No. 2 115 kV Line (L-1). (2012)

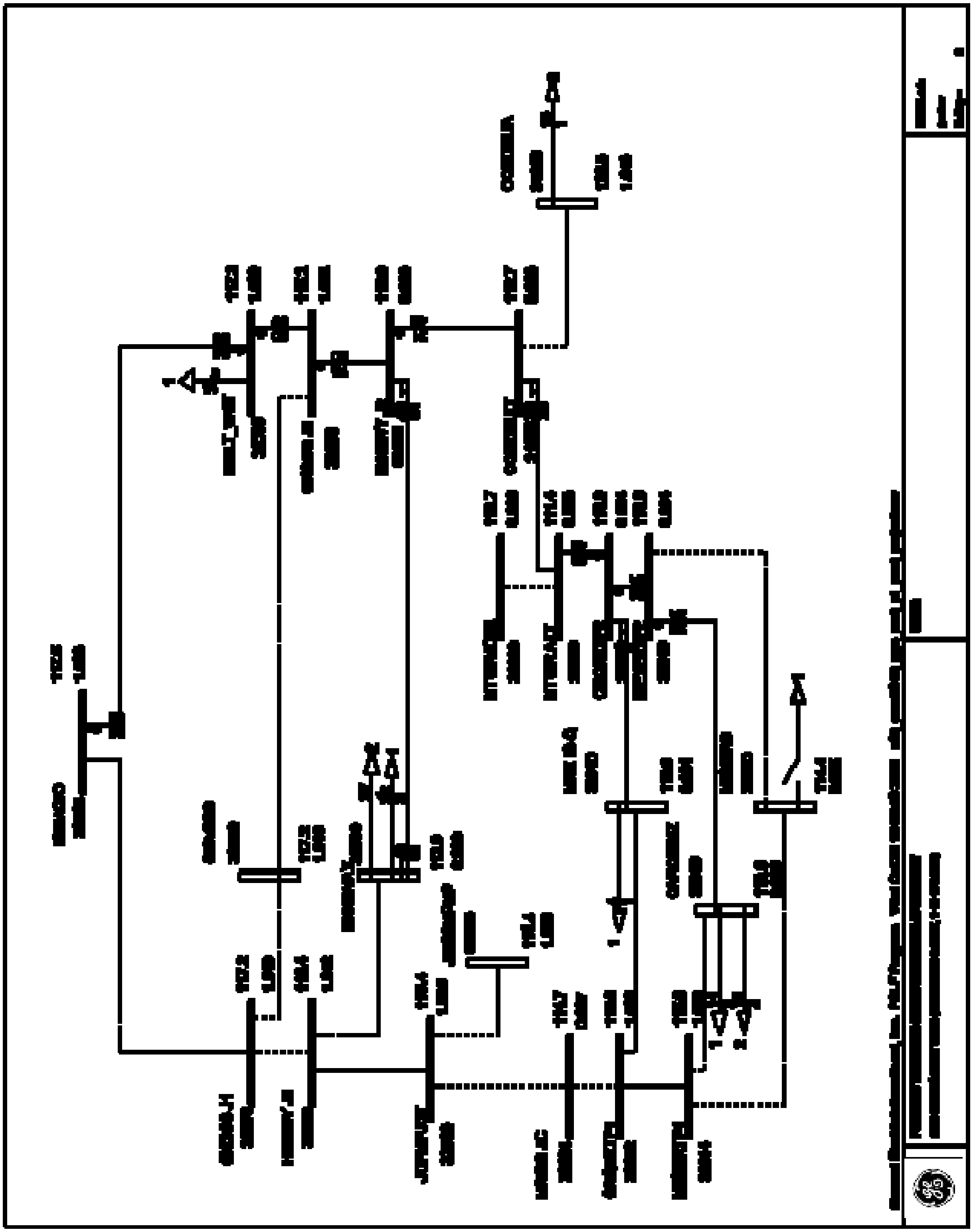


Figure 4-245: Post Project - Loss of the Ignacio-Mare Island No. 1 115 kV Line (L-1). (2012)

Valley Springs 230/60 kV Transformer Addition

TARGETED IN-SERVICE DATE

May 2012

PURPOSE AND BENEFIT

Reliability – NERC Compliance and Operational Flexibility

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROJECT

The recommended scope is to install an additional 230/60 kV three-phase transformer bank at Valley Springs with a normal rating of 200 MVA. It is also recommended to reconfigure the existing 230 kV bus to the standard breaker and a half (BAAH) arrangement for two transformer banks and two transmission lines.

This project is expected to cost between $8M and $10M

BACKGROUND

Valley Springs Substation is located east of the City of Valley Springs, Calaveras County and serves over 34,600 electric customers in the greater Valley Springs area. Valley Springs has one 230/60 kV transformer to provide support to the 60 kV transmission system through six 60 kV circuits. No distribution transformers are in operation at this facility. The 60 kV transmission system is comprised of Electra, Calaveras Cement, North Branch, Corral, West Point PH, Pine Grove, Clay, Ione, and Martell substations. Valley Springs Substation is looped into the transmission grid via two 230 kV lines: Tiger Creek-Valley Springs and Valley Springs-Bellota.

Valley Springs 230/60 kV Bank No. 1 is comprised of three single-phase 1974-vintage FPE 65°C, 44.8 MVA, 230/60 kV transformers. It has a normal rating of 134.4 MVA and an emergency rating of 161.3 MVA.

In 2007, the Valley Springs area reached an electric peak of 124 MW. Electric demand in this area is forecasted to grow at approximately 2 MW or 1.6 percent per year.

Planning analysis shows that the Valley Springs Bank No. 1 loads up to 110% in 2018 when West Point Powerhouse (P.H.) is out of service. Currently, the Valley Springs Bank No. 1 can not be cleared for maintenance due to the inability to off-load the 60 kV transmission system. As a result, operators have experienced warning signs for this bank when load is under the normal rating, meaning the bank may not be performing up to its nameplate rating. Also, the Valley Springs 60 kV transmission system is radial and over 34,600 customers in Calaveras County are at risk for a single transformer bank outage.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended. This alternative does not address load growth and reliability concerns.

PROJECT SCHEDULE

- Environmental and Permitting Processes – August 2008
- Design – TBD
- Major Equipment – August 2008
- Construction – TBD
- Operation Date – May 2012

KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – TBD
- Special Metering or Protection - None
- Common Mode Exposure Items - None
- Interaction with other Projects or Studies – Valley Springs 60 kV Reliability Project

GEPSLF MODELING INFORMATION

```
#New 230/60 kV 200 MVA Transformer at Valley Springs
NEW_TRAN  33610, 30490, 2, ZR=0.00377, ZX=0.09298, BMAG=-0.002,+
     MVA1=200, MVA2=220, MVA3=200, MVA4=220, VNOMF=60, VNOMT=230, MVABASE=100,+
     STAT=1, TYPE=2, TAPF=1, REG=33610, VMAX=1.0667, VMIN=1.0,+
     STEPP=.004910, TMAX=1.1264, TMIN=.9692, TAPFP=1, TAPFS=1, GMAG=.0006, AREA=11, ZONE=311
```

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Single Line Diagrams
2. Demand Forecast
3. Power Flow Summary
4. Pre and Post Project Power Flow Plots

Attachment 1: Scope Diagram

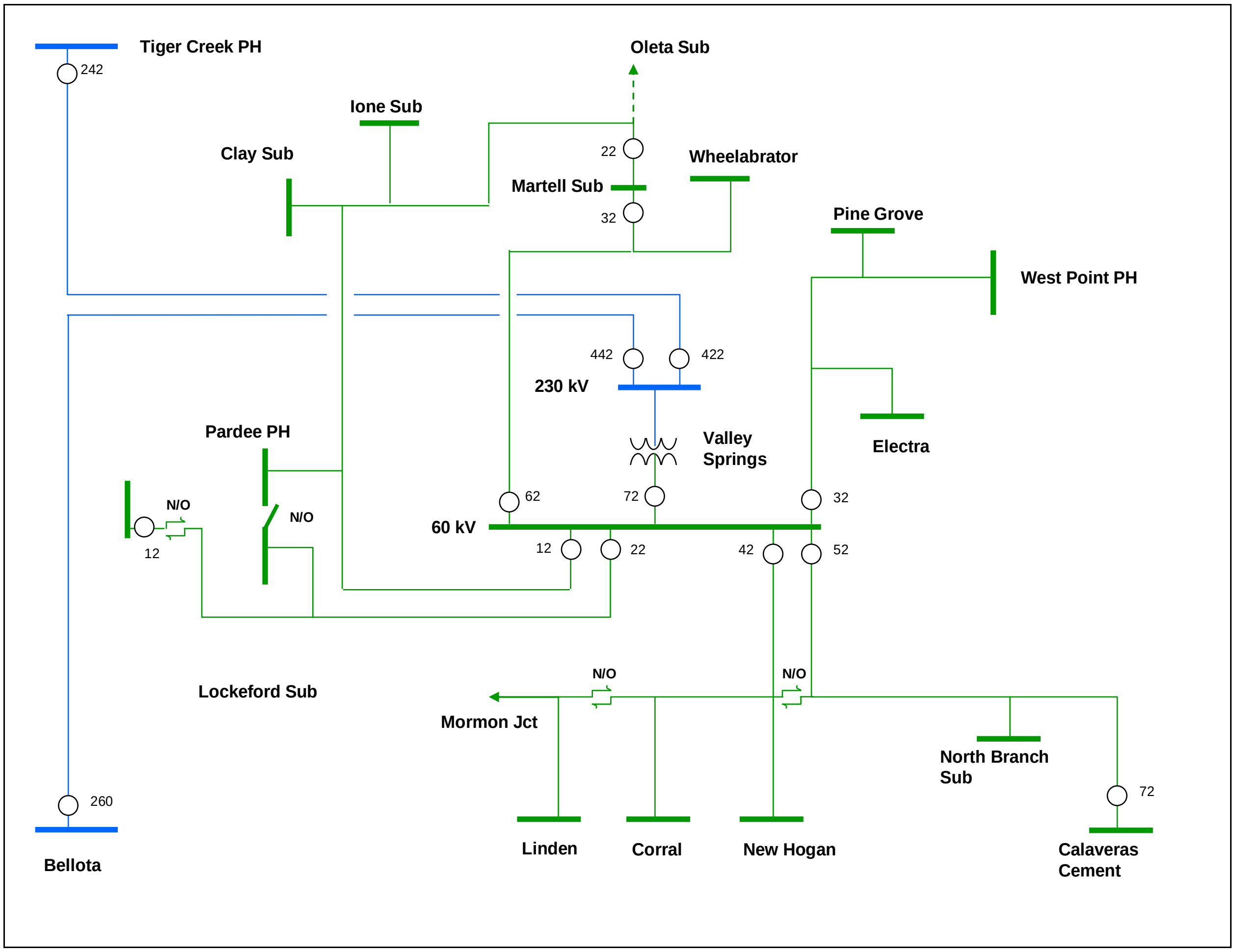


Figure 4-246: Existing Single Line Diagram

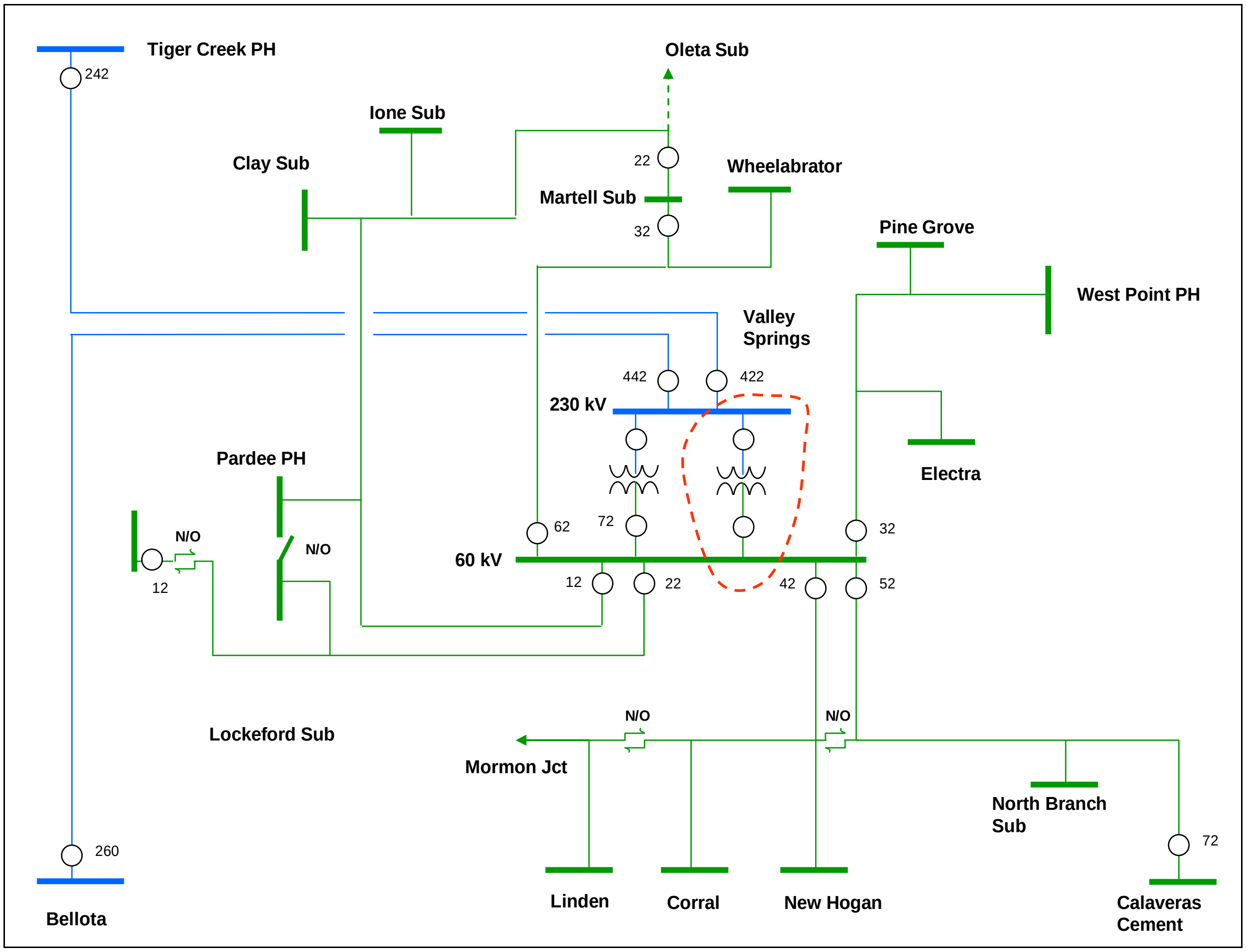


Figure 4-247: Single Line Diagram with proposed project

Attachment 2: Demand Forecast

Table 4-65: Demand Forecast

Substation/Bank	2009 (MW)	2010 (MW)	2011 (MW)	2012 (MW)	2013 (MW)	Growth Rate(MW/yr)
Cal Cement Bank 1	12.4	12.6	12.7	13.0	13.2	0.2
Clay Bank 1	12.7	13.0	13.3	13.7	13.9	0.3
Corral Bank 1	11.4	11.7	12.1	12.6	12.9	0.4
Corral Bank 2	14.9	15.4	15.9	16.5	16.9	0.5
Electra Bank 1	9.8	9.9	10.1	10.3	10.4	0.2
Ione Bank 1	11.7	11.9	12.2	12.5	12.7	0.3
Martell Bank 1	18.5	18.8	19.0	19.5	19.7	0.3
North Branch Bank 1	5.5	5.6	5.6	5.8	5.9	0.1
Pine Grove Bank 1	8.2	8.3	8.4	8.6	8.7	0.1
Pine Grove Bank 2	10.4	10.6	10.7	11.0	11.1	0.2
West Point Bank 2	4.5	4.6	4.6	4.7	4.8	0.1
West Point Bank 3	4.2	4.3	4.3	4.4	4.5	0.1
Total Area Load	**124**	**126**	**129**	**133**	**135**	**2**

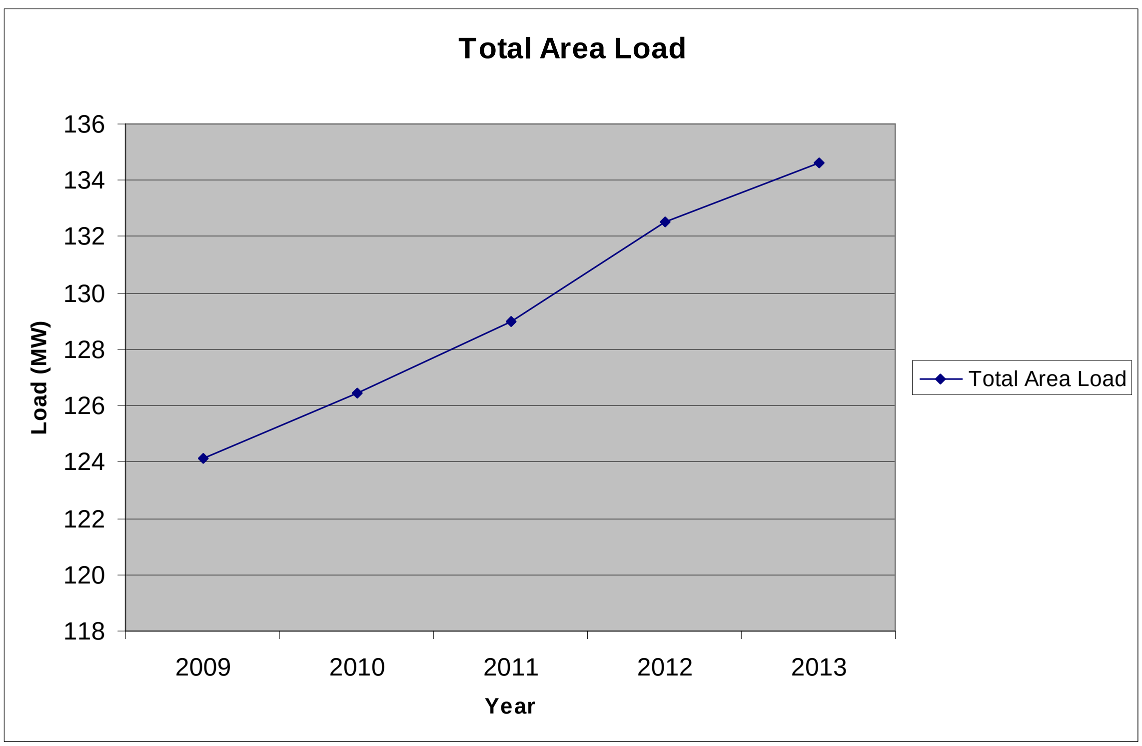


Figure 4-248: Plot of Demand Forecast

Attachment 3: Power Flow Summary

Table 4-66: Power Flow Results

			Pre Project						Post Project	
#	Facility	Facility Rating	2009	2010	2011	2012	2013	2018	2018	Contingency
1	Valley Springs 230/60 kV Bank No. 1	SN Rating 134 MVA	--	--	--	--	--	110%	67%	West Point PH (G-1)

Attachment 4: Pre and Post Project Power Flow Plots

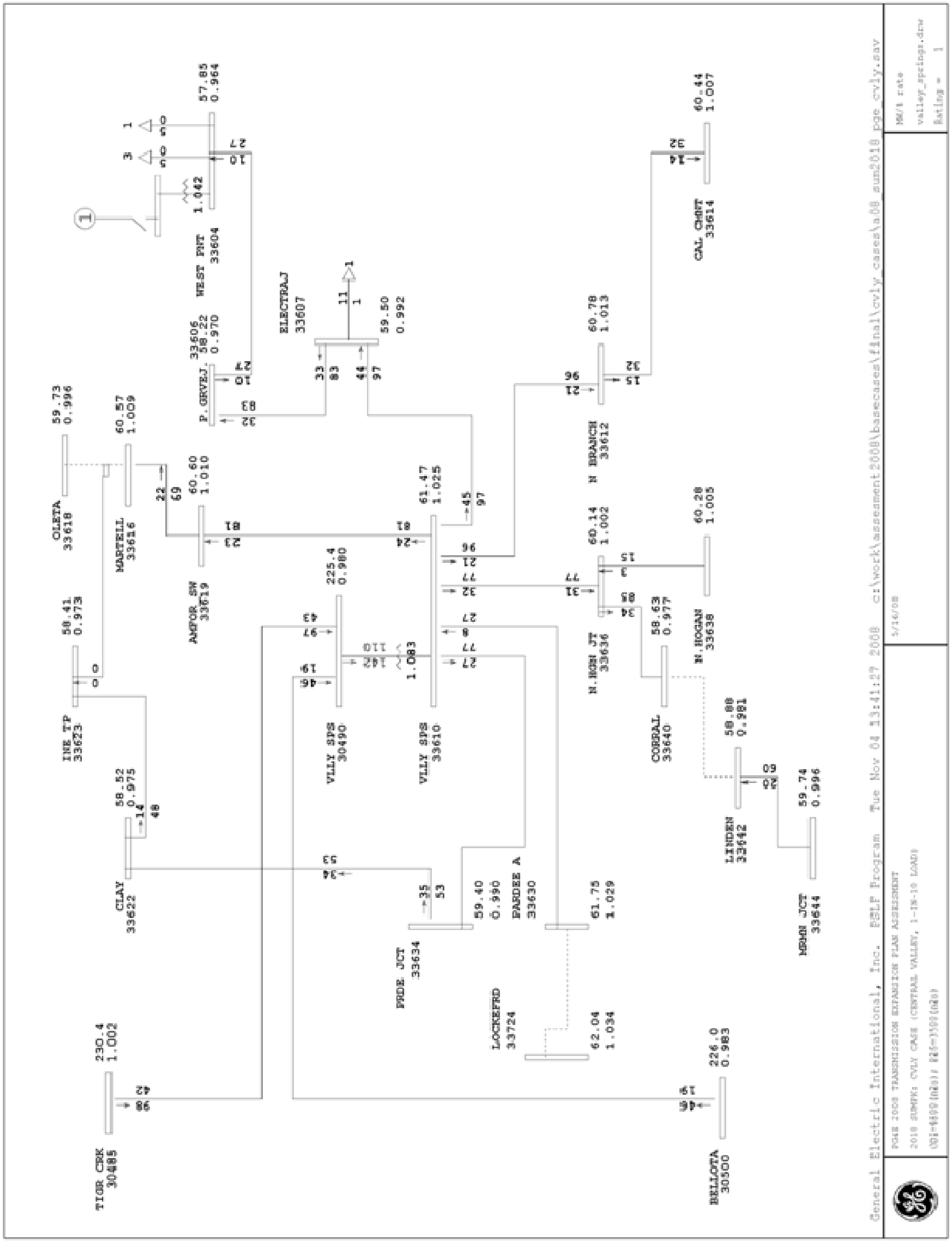


Figure 4-249: Pre Project – West Point PH Outage (G-1)

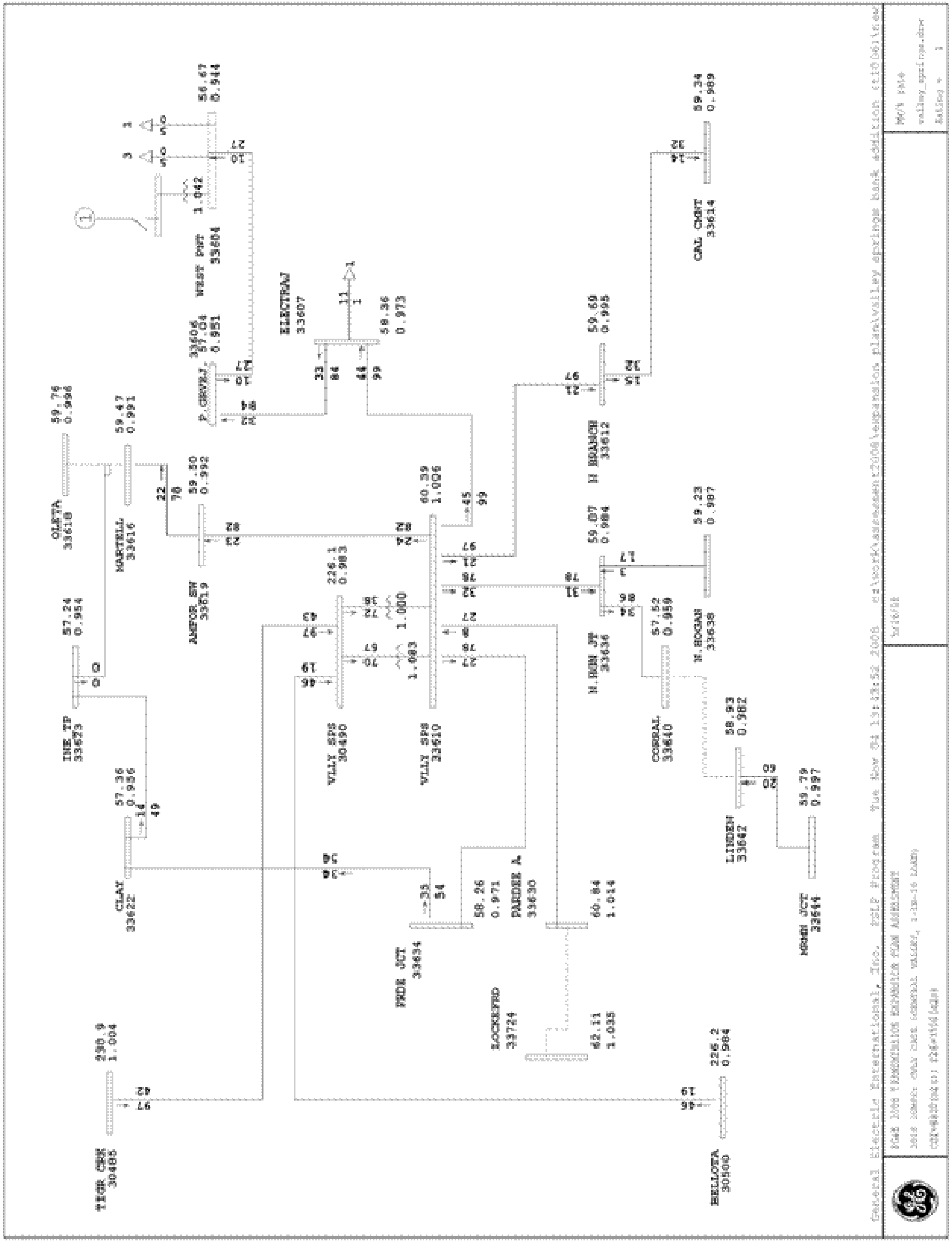


Figure 4-250: Post Project – West Point PH Outage (G-1)

Caruthers – Kingsburg 70 kV Line Reconductor

TARGETED IN-SERVICE DATE

May 2012

PURPOSE AND BENEFIT

Reliability – NERC Compliance and Operational Flexibility

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROJECT

The project scope is to reconductor Camden-Camden Junction, Camden Junction-Caruthers, and Camden Junction-Lemoore Naval Air Station (NAS) 70 kV line sections (approximately 25 miles in length). The new conductor will have a summer normal rating of at least 825 Amps and a summer emergency rating of 975 Amps. In addition, the 2 mile Henrietta-Lemoore NAS 70 kV line section will be double circuited to provide increased reliability. The project scope would also involve upgrading station terminal equipment and obtaining any necessary environmental and land permits to complete the reconductoring work.

The project is expected to cost between $10M and $15M.

BACKGROUND

The Caruthers-Kingsburg 70 kV Line is located in Fresno County, within PG&E's Fresno Division. The Camden-Caruthers area receives its transmission supply from three main sources: Kingsburg 115 kV substation to the East, Kearney 230 kV substation to the North, and the GWF Henrietta generator to the South. These sources feed three substations, Camden (40.5 MVA), Lemoore NAS (22 MVA) and Caruthers (20 MVA). Camden is comprised of two 70/12 kV distribution banks, number (No.) 1 at 30 MVA and No. 2 at 10.4 MVA. Caruthers is comprised of one 70/12 kV 20 MVA bank.

Significant block load increases are anticipated for the Camden-Caruthers area. This is based on the high volume of completed applications by agriculture customers to convert their diesel pumps to electrical pumps via the Agricultural Internal Combustion Engine Conversion (AG-ICE) Program. As a result, PG&E has initiated several distribution capacity increase projects for the area. Camden Distribution Bank 1 was recently upgraded from a 10.5 MVA bank to a 30 MVA bank on May 2008. Furthermore, a separate reliability project has been initiated to install 70 kV line circuit breakers at Camden by May 2009. A second 70/12 kV 30 MVA bank is being considered at Caruthers in 2010.

The Camden Junction-Lemoore NAS 70 kV Line consists of 9.5 miles of 1/0 Copper, and 3.5 miles of 3/0 Aluminum conductor on single wood poles. It has a summer normal rating of 243 Amps and a summer emergency rating of 282 Amps. The Camden-Camden Junction 70 kV Line is sized with 3/0 Aluminum conductor for 5.5 miles, rated for 257 Amps under normal conditions and 298 Amps for summer emergency conditions. The Camden Junction-Caruthers 70 kV Line is also comprised with 3/0 Aluminum conductor on single wood poles for 7 miles. The Henrietta-Lemoore NAS 70 kV Line has about 2 miles of 715 Aluminum conductor, which has a normal rating of 631 Amps and a summer emergency rating of 742 Amps. Under summer operating conditions, Caruthers circuit breaker (CB) Number (No.) 22 and Lemoore NAS line switch (SW) No. 55 are normally open, so each load has only one source with no connections to other lines.

Normally, an outage of a source line will isolate its respective radial substation load, since both Caruthers CB 22 and Camden Junction-Lemoore NAS 70 kV Line SW No. 55 are normally open. These are open during the summer since the sources are not capable of normally serving more than one substation. Analysis has concluded that an outage of the Camden-Kingsburg 70 kV line, with the normally open Lemoore NAS SW No. 55 closed, will result in a thermal overload of the Camden Junction-Lemoore NAS 70 kV Line. Completion of this project will allow Camden to operate as a looped station and Caruthers as a flip-flop station.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO. An exception occurs for the Camden Bank No. 1 load demand forecast. In May 2008, Camden Bank No. 1 was upgraded from a 10.5 MVA bank to a 30 MVA bank to account for the new agriculture pumping loads. This study assumed a growth rate of 2 MW/year for Camden Bank 1 to account for the projected agricultural pumping load increase.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended because an outage of the Kearny-Caruthers 70 kV Line or the Henrietta-Lemoore NAS 70 kV Line will still create thermal overloads on the Camden-Kingsburg 70 kV Line since the line cannot support the added load from Lemoore NAS or Caruthers.

Alternative 2: Reconductor from Kingsburg to Caruthers

This alternative would allow Kingsburg to normally serve both Camden and Caruthers provided Caruthers CB No. 12 was normally open. However, this alternative is not currently recommended since the Kingsburg 115/70 kV transformer bank No. 2 would become the next limiting factor for the source as the Camden and Caruthers load grows.

Alternative 3: Reconductor from Camden Junction to Kearney

This alternative would allow Kearney to normally serve both Caruthers and Camden, provided Camden CB No. 22 is open. This alternative is not recommended since future additional loading at Caruthers will cause the Kearney 230/70 kV transformer bank No. 2 to overload normally, therefore rendering it unable to also serve load at Camden.

PROJECT SCHEDULE

- Environmental and Permitting Processes – This work is expected to qualify for a Notice of Construction (NOC) exemption.
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2012

KEY ISSUES

- Land-Use Restrictions – This work is expected to qualify for a Notice of Construction (NOC) exemption.
- Environmental Concerns – None
- Special Metering or Protection – None
- Common Mode Exposure Items – None
- Interaction with other Projects or Studies – Camden 70 kV Breaker Installation

GEPSLF MODELING INFORMATION

#Reconductors Camden Jct-Lemoore NAS 70 kV line from 1/0 Cu (9.47 mi) and 3/0-7 Al (3.43 mi) to 1113 Al. 12.9 Miles.
OLDSECDD 34510, 34514, CKT=1, SEC=1, RPU=0.025116, XPU=0.184406, BPU=0.003909,+
MVA1=100, MVA2=118, MVA3=156, MVA4=167

#Reconductors Camden Jct-Camden 70 kV line from 3/0-7 Al to 1113 Al. 5.42 Miles.
OLDSECDD 34508, 34510, CKT=1, SEC=1, RPU=0.010553, XPU=0.077479, BPU=0.001642,+
MVA1=100, MVA2=118, MVA3=156, MVA4=167

#Reconductors Caruthers-Camden Jct 70 kV line from 3/0-7 Al to 1113 Al. 6.81 Miles.
OLDSECDD 34510, 34512, CKT=1, SEC=1, RPU=0.013259, XPU=0.097349, BPU=0.002063,+
MVA1=100, MVA2=118, MVA3=156, MVA4=167

#Reconductor Henrietta-Lemoore NAS 70 kV line from 715 Al to 1113 Al. 1.72 miles.
OLDSECDD 34514, 34540, CKT=1, SEC=1, RPU=0.003349, XPU=0.024587, BPU=0.000521,+
MVA1=100, MVA2=118, MVA3=156, MVA4=167

#Creates a new line section from Camden Jct-Lemoore NAS 70 kV SW 55 to Henrietta. 1.72 miles of 1113 Al.
LINETAP 34510, 34514, NEWBUS=34511, NEWNAME=LMOR_TAP, DIST_FBUS=.99, CKT=1, SEC=1

NEWSECDD 34540, 34511, CKT=1, SEC=1, RPU=.003349, XPU=.024587, BPU=.000521,+
MVA1=100, MVA2=118, MVA3=156, MVA4=167, STATUS=1, AREA=14, ZONE=314

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagrams
2. Demand Forecast
3. Power Flow Summary
4. Pre and Post Project Power Flow Plots

Attachment 1: Scope Diagrams

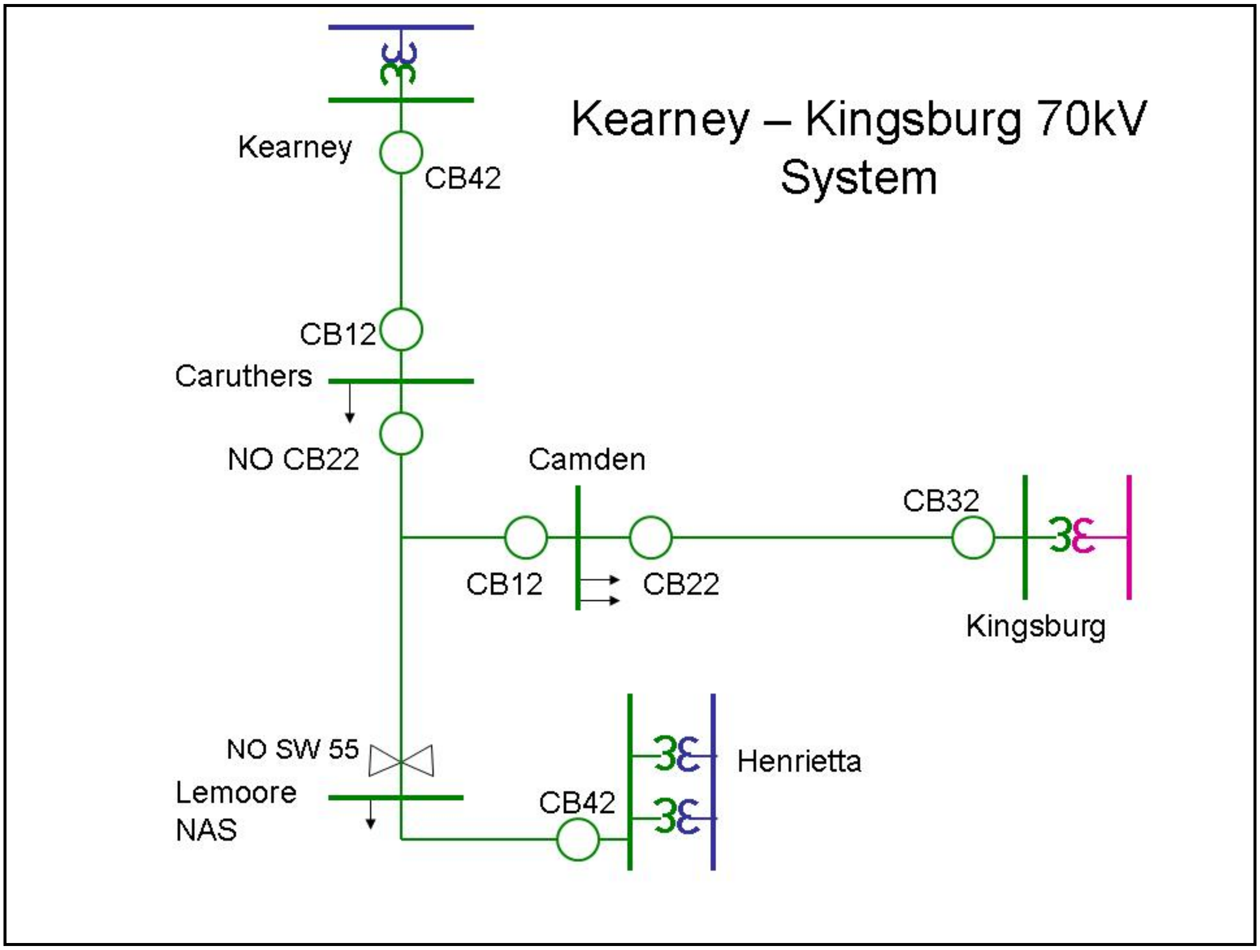


Figure 4-251: Existing Scope Diagram

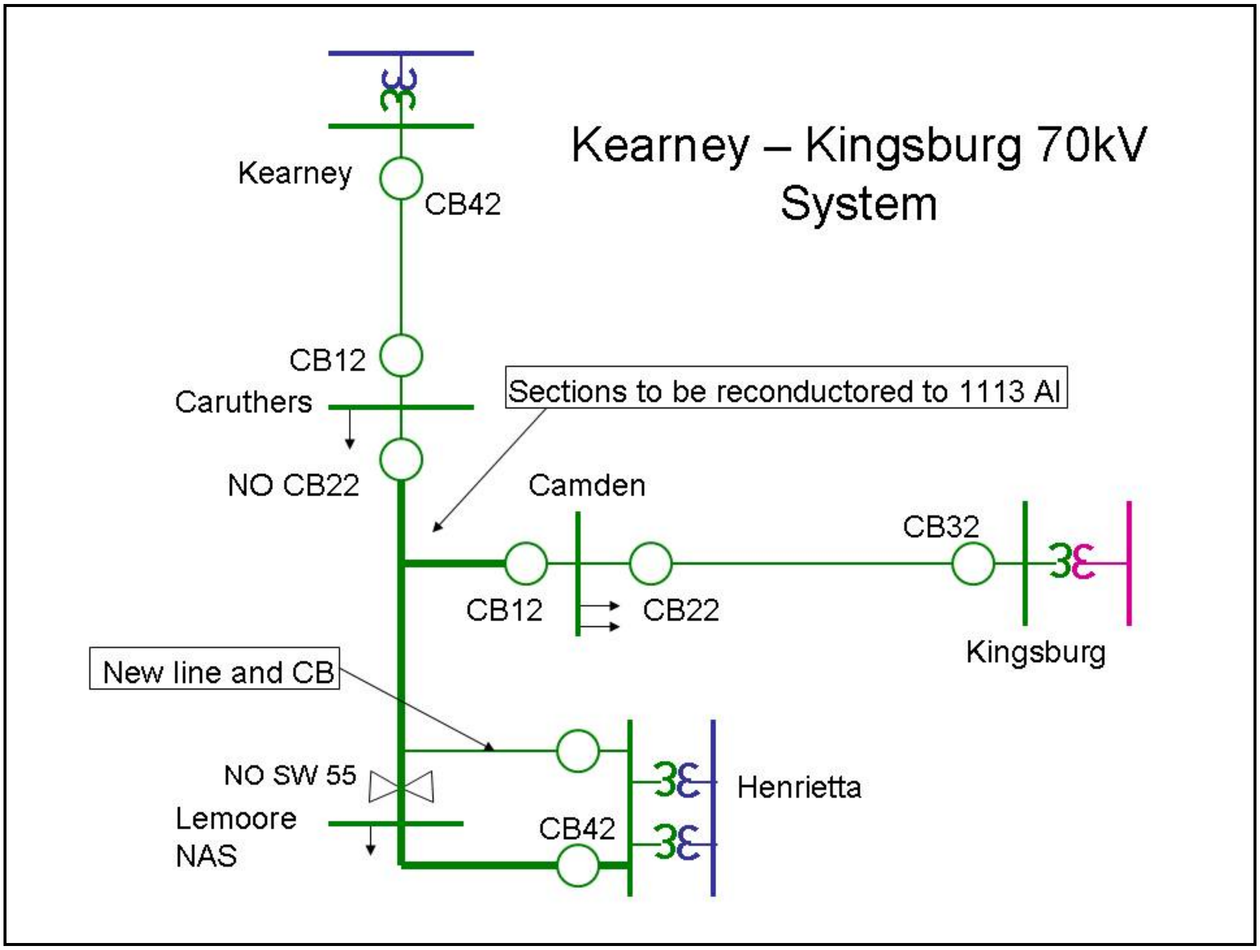


Figure 4- 252: Proposed Scope Diagram

Attachment 2: Demand Forecast

Table 4-67 – Area Load Demand Forecast

Facility	Actual Peak Load (MW)			Projected Peak Load (MW)				
	2006	2007	2008	2009	2010	2011	2012	2013
70 kV System								
Caruthers Bank 1	17.7	19.1	19.0	18.9	19.0	19.1	19.2	19.4
Camden Bank 2	10.0	10.5	10.5	10.5	10.5	10.5	10.5	10.5
Camden Bank 1 (Replaced with 30 MVA bank in 2008)	6.3	9.7	13.0	15.0	17.0	19.0	21.0	23.0
Lemoore NAS Bank 1	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0
Total:	**56**	**61**	**65**	**66**	**69**	**71**	**73**	**75**

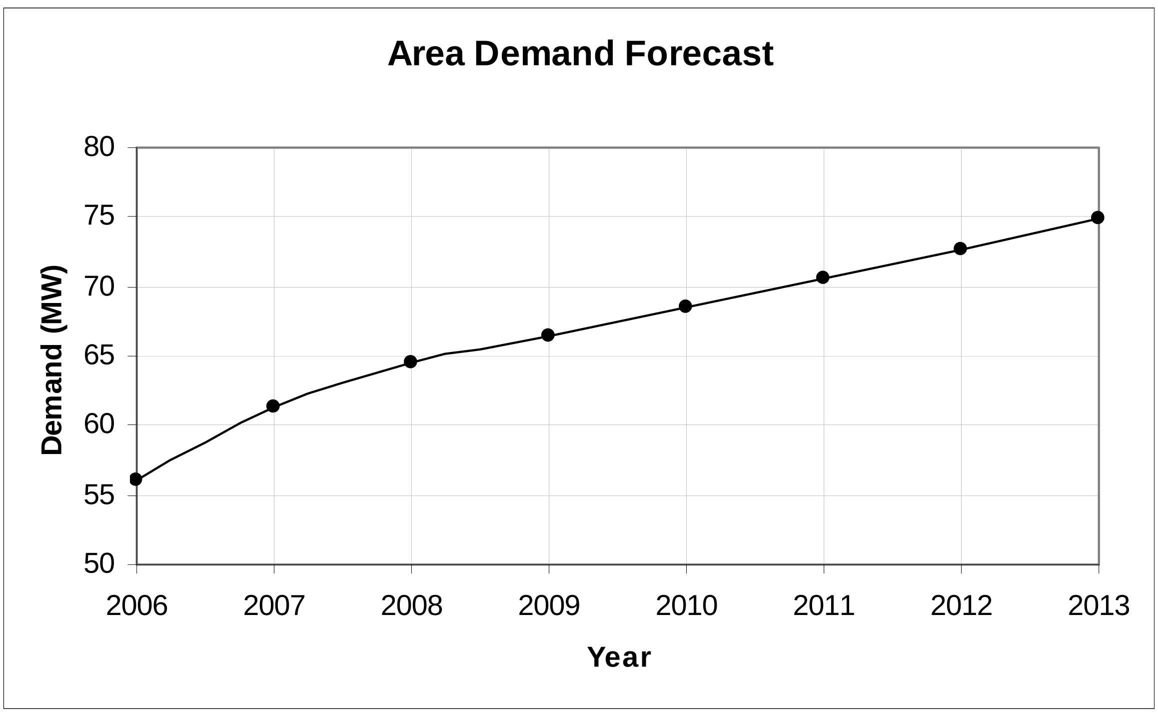


Figure 4-253 – Area Load Demand Curve

Attachment 3: Power Flow Summary

Table 4-68: Power Flow Results

			Pre Project						Post Project	
#	Facility	Facility Rating	2008	2009	2010	2011	2012	2013	2013	Contingency
1	Camden Junction-Lemoore NAS 70 kV Line	SE Rating 34 MVA	--	--	--	--	--	101 %	28%	Camden-Kingsburg 70 kV Line (L-1), with Camden Jct.-Lemoore NAS SW 55 closed to pick-up Camden load.

Attachment 4: Pre and Post Project Power Flow Plots

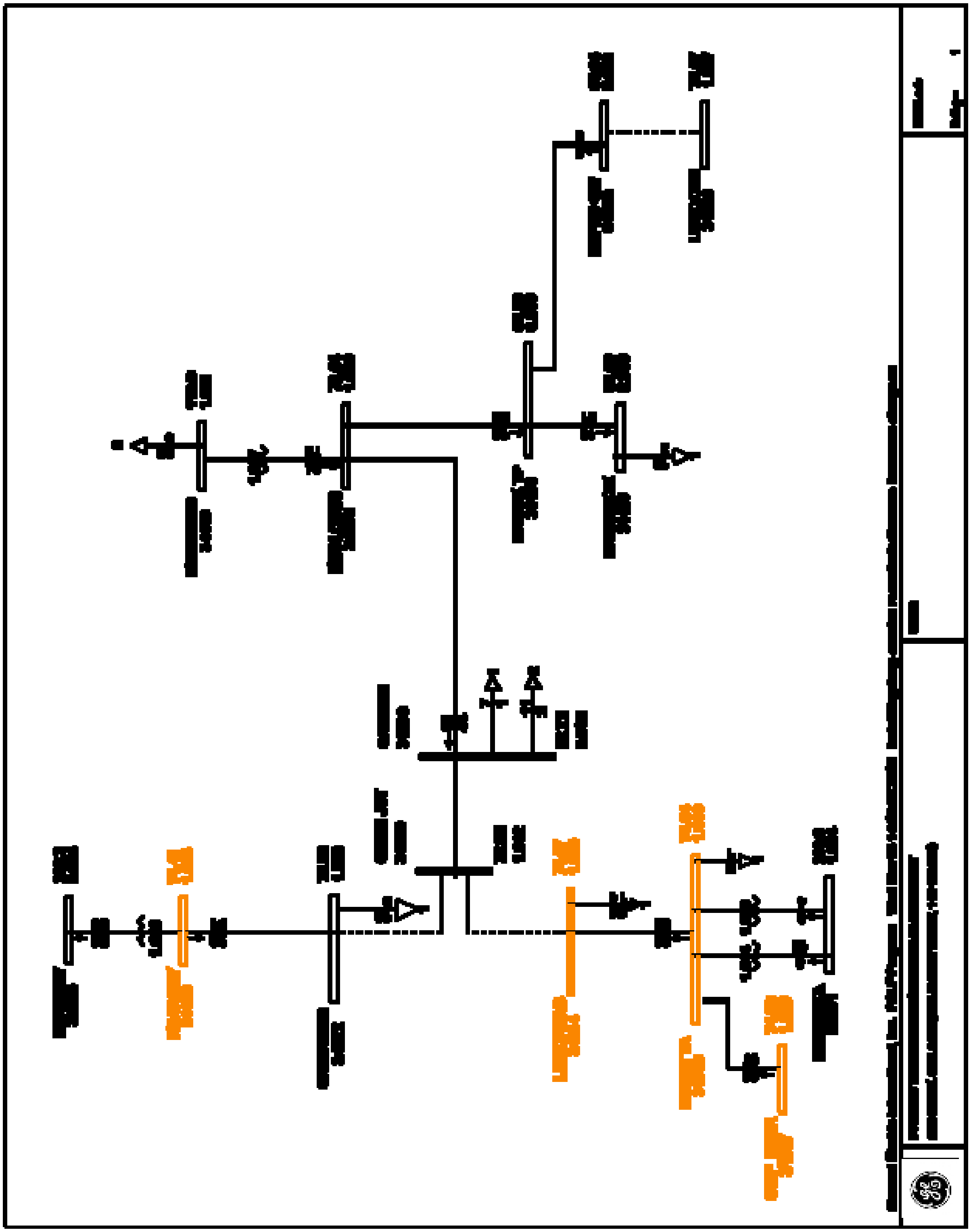


Figure 4-254 – Pre-Contingency Before Project

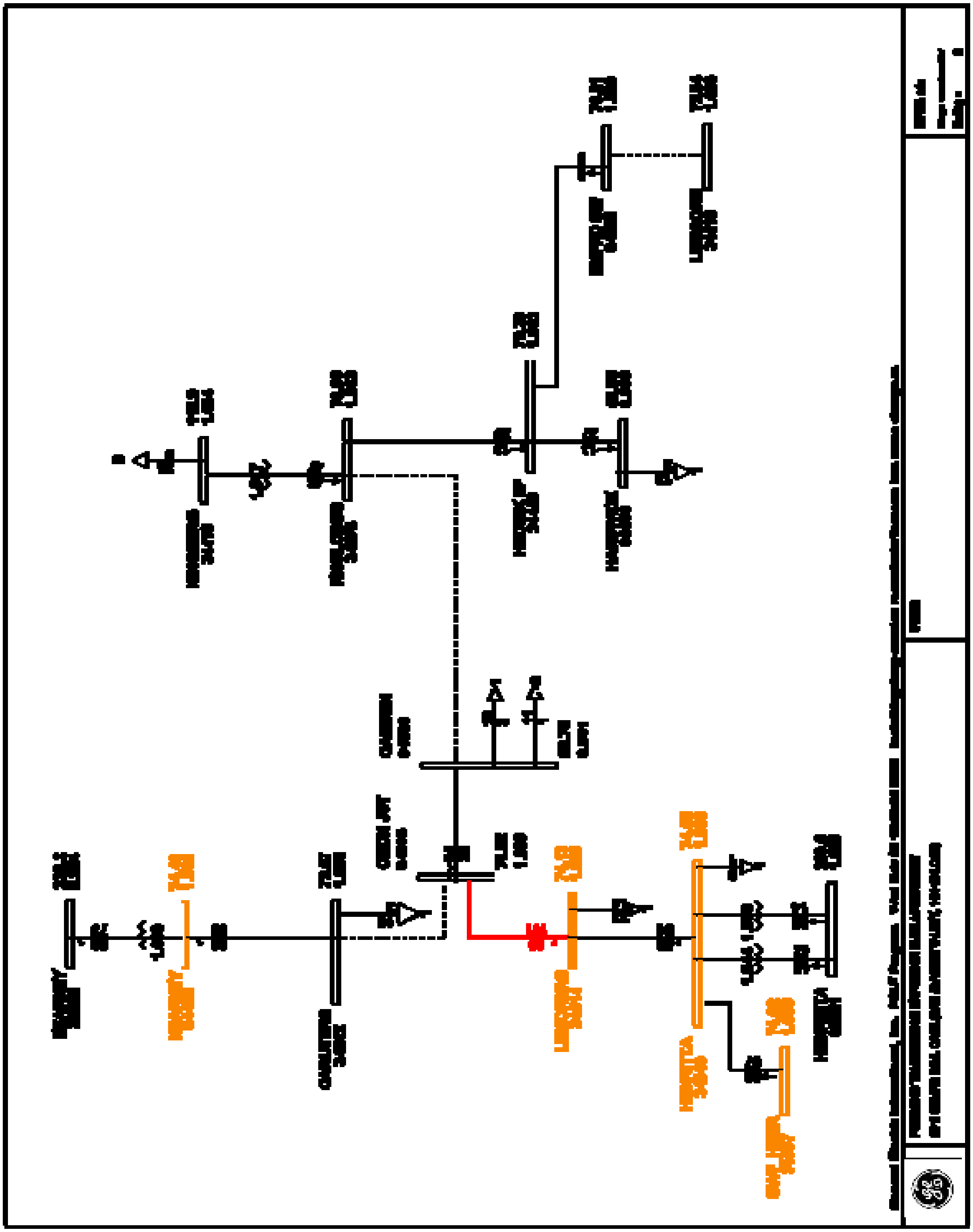


Figure 4-255 – Post Contingency Before Project (Outage of Camden-Kingsburg 70 kV line)

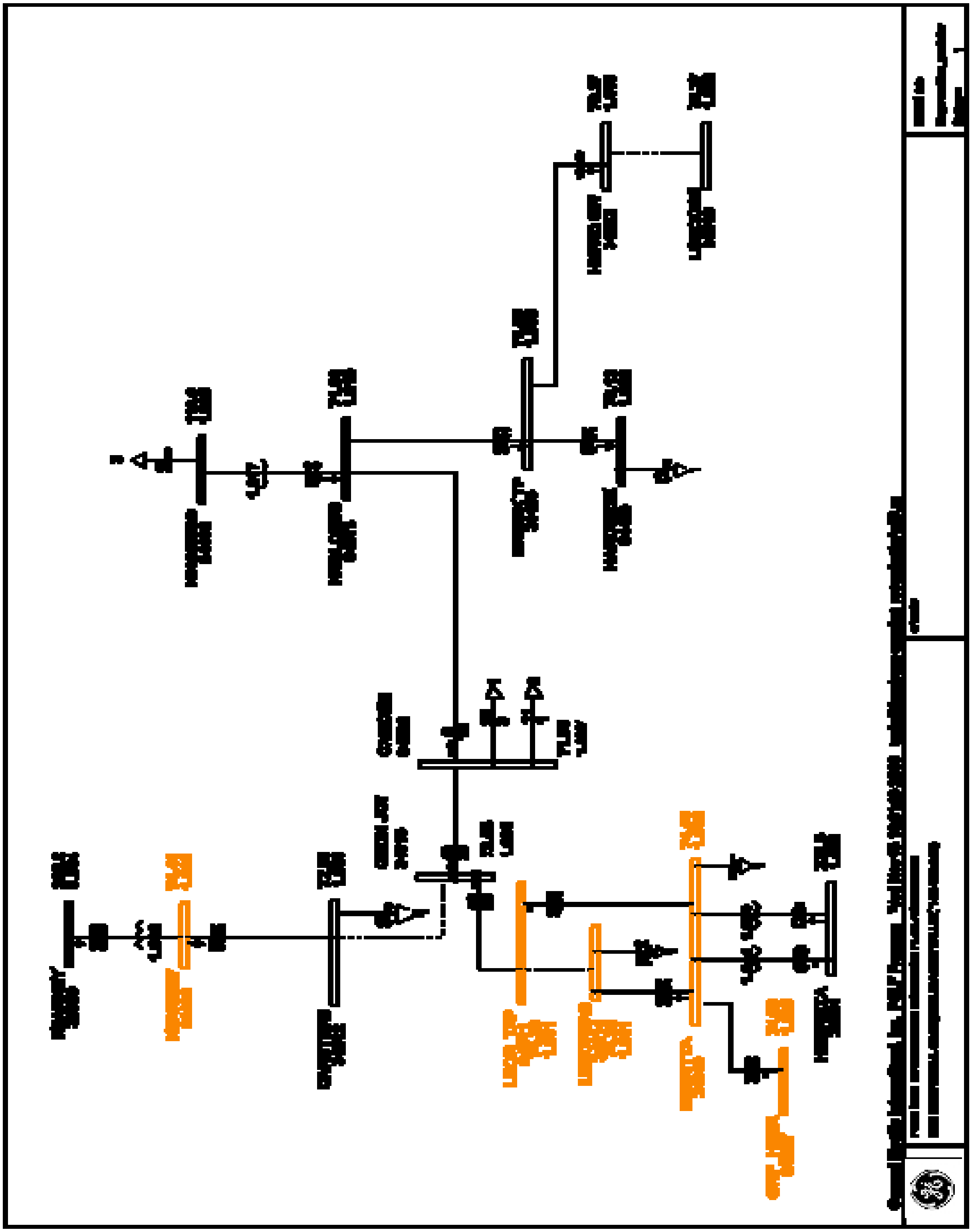


Figure 4-256 – Pre-Contingency After Project

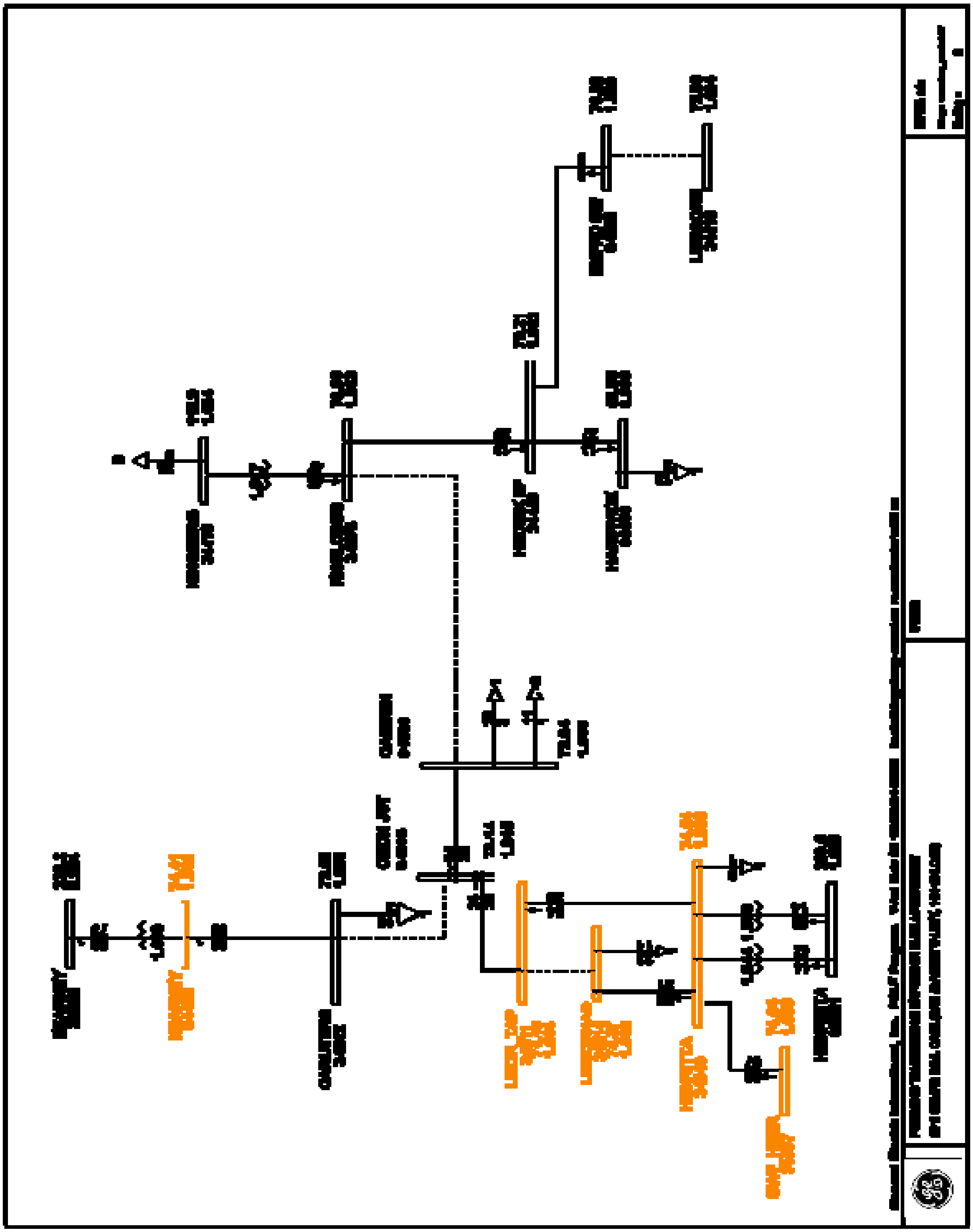


Figure 4-257 – Post Contingency After Project (Outage of Camden-Kingsburg 70 kV line)

Cressey – Gallo 115 kV Line

TARGETED IN-SERVICE DATE

December 2012

PURPOSE AND BENEFIT

Reliability – NERC Compliance and Operational Flexibility

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROJECT

The proposed project scope is to construct a new 115 kV transmission circuit (line) between Cressey and Gallo substations. As part of separate maintenance projects, Cressey and Livingston substations will have their 115 kV buses reconfigured into ring bus arrangements. Furthermore, Gallo's 115 kV bus will be converted into a 115 kV looped bus arrangement as part of a separate maintenance project.

This new 115 kV line, which will be 16 miles long, will be sized to handle 550 Amps under summer normal conditions and 650 Amps under summer emergency conditions. The 115 kV line will be constructed with 715 kcmil All Aluminum conductors (AAC) on wooden and tubular steel poles.

Completion of this project is expected to significantly improve the reliability to the customers in the greater Livingston and Cressey area with an annual SAIDI reduction of 614,000 customer outage minutes and an annual SAIFI reduction of 0.7 outages.

This project is expected to cost between $15M and $25M.

BACKGROUND

The Merced 115 kV transmission system, located in San Joaquin Valley, serves about 54,000 electric customers in northern Merced County. Communities in this area include Atwater, Cressey, Livingston, Merced, and Winton.

A critical transmission facility that connects the Merced 115 kV transmission system is the Atwater-Merced 115 kV Line. The Atwater-Merced 115 kV Line is comprised of 35 miles (including all tap lines) of various conductor sizes and is constructed mainly on wood poles. Originating from Atwater Substation, this 115 kV transmission line traverses in a north to south direction along Bert Crane Rd and then travels west to east along Dickenson Ferry Rd to Merced Substation. The Atwater-Merced 115 kV Line serves Livingston and Gallo substations via a 13-mile radial tap line from Atwater Junction. The Atwater-Merced 115 kV Line also serves Cressey and Dole Foods (formerly J.R. Woods) from a 6-mile radial tap line. The tap point is located one span away from Atwater Substation. The total number of electric customers served by these substations is 8,591. In 2006, the total peak demand at these substations was 58 MW. Demand in the area is expected to increase at an average of 1.5 MW per year.

Review of PG&E's outage data shows the Atwater – Merced 115 kV Line has experienced multiple sustained outages in the past three years. Every outage occurrence has had a big impact to major customers in the local area. The outages in October 2006 were especially significant to industrial customers that rely on electric service for the processing and crushing of grapes in order to the manufacture wine. Table 2 shows the line outage history for the past three years.

Table 4-69: Three Year Line Outage History for Atwater – Merced 115 kV Line

Date	Outage Type	Customer Minutes	Cause
8/15/2005	Sustained	991,494	Equipment Failure
10/30/2005	Momentary	0	Unknown
1/18/2006	Momentary	0	Weather
8/30/2006	Momentary	0	Third Party
10/1/2006	Sustained	3,859,240	Equipment Failure
10/1/2006	Sustained	527,990	Equipment Failure
10/25/2006	Sustained	1,993,640	Equipment Failure

The Atwater – Merced 115 kV Line experiences approximately 1.4 outages per year with an average duration of 5 hours per outage. Also, the line contributes an average of 2.5 million customer outage minutes per year. Based on the long length of line exposure, poor line performance, and large customer impacts to Cressey, Gallo, Livingston, and Dole Foods substations, it is recommended that reliability improvements be made to the Atwater-Merced 115 kV Line.

Several reliability projects have been implemented to provide immediate impacts to the customers in Merced County. A project to install transmission line SCADA switches at Atwater Jct. was completed in June 2007. A project to install SCADA to Atwater MOAS Sw. 167 and Merced CB 122 was completed by February 2008. A maintenance driven project to upgrade the Atwater 115 kV bus to a Breaker-and-a-Half (BAAH) bus configuration is expected to be completed by June 2009.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended since it will not resolve the reliability issues in Atwater-Merced pocket.

Alternative 2: Build a New Atwater to Livingston Transmission Line

This alternative proposes to loop the Atwater-Merced 115 kV Line into Livingston Substation to create the Atwater-Livingston and Livingston-Merced 115 kV lines. Preliminary analysis shows that a new transmission line could be built along Westside Blvd. up to tower 19/04, but 2.2 miles of wood poles would need to be reconfigured to accommodate two circuits. The cost estimate for this work is approximately $13 million

This alternative is not recommended because it will only mitigate the impacts of a line outage to Livingston Substation only. Gallo, JR Wood (Dole), and Cressey substations would still be served on radial taps and subjugated to all transmission line-related outages.

PROJECT SCHEDULE

- Environmental and Permitting Processes – A Proponent Environmental Assessment (PEA) is expected to be filed in January 2009 and is expected to be completed in July 2009. A Permit to Construct (PTC) is expected to be filed soon after the completion of the PEA.
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – December 2012

KEY ISSUES

- Environmental Concerns - A Proponent Environmental Assessment (PEA) is expected to be filed in January 2009 and is expected to be completed in July 2009.
- Land Use Restrictions - A Permit to Construct (PTC) is expected to be filed soon after the completion of the PEA.
- Special Metering or Protection – None
- Common Mode Exposure Items – None
- Interaction with other Projects or Studies – Maintenance Project - Atwater 115 kV Bus Conversion Project (EDRO May 2009)

GEPSLF MODELING INFORMATION

```
#Connect Gallo bus to Cressey bus (1, 715Al, 16 MILE)
NEWSECDD  34132, 34140, CKT=1, SEC=1, RPU=0.01760, XPU=0.08813, BPU=0.01256, +
          MVA1=126, MVA2=148, MVA3=207, STATUS=1, AREA=13, ZONE=343, OWN=390

#Remove Cressey Tap bus and all associated lines
EXTRACT 34108

#Add branch from Atwater JCT to Atwater (equivalent to the old ATWATR JCT - CRESEY T branch)
NEWSECDD  34110, 34104, CKT=1, SEC=1, RPU=0.005540, XPU=0.0155, BPU=0.00222, +
          MVA1=87, MVA2=102, MVA3=133, MVA4=133, STATUS=1, AREA=13, ZONE=313, OWN=390

#Add branch from Atwater to JRWD GEN  (equivalent to the old CRESEY T - JRWD GEN branch)
NEWSECDD  34104, 34114, CKT=1, SEC=1, RPU=0.00147, XPU=0.00411, BPU=0.00059, +
          MVA1=87, MVA2=102, MVA3=133, MVA4=133, STATUS=1, AREA=13, ZONE=313, OWN=390
```

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagrams
2. Atwater-Merced 115 kV Line Outage History
3. Pre and Post Power Flow Plots

Attachment 1: Scope Diagrams

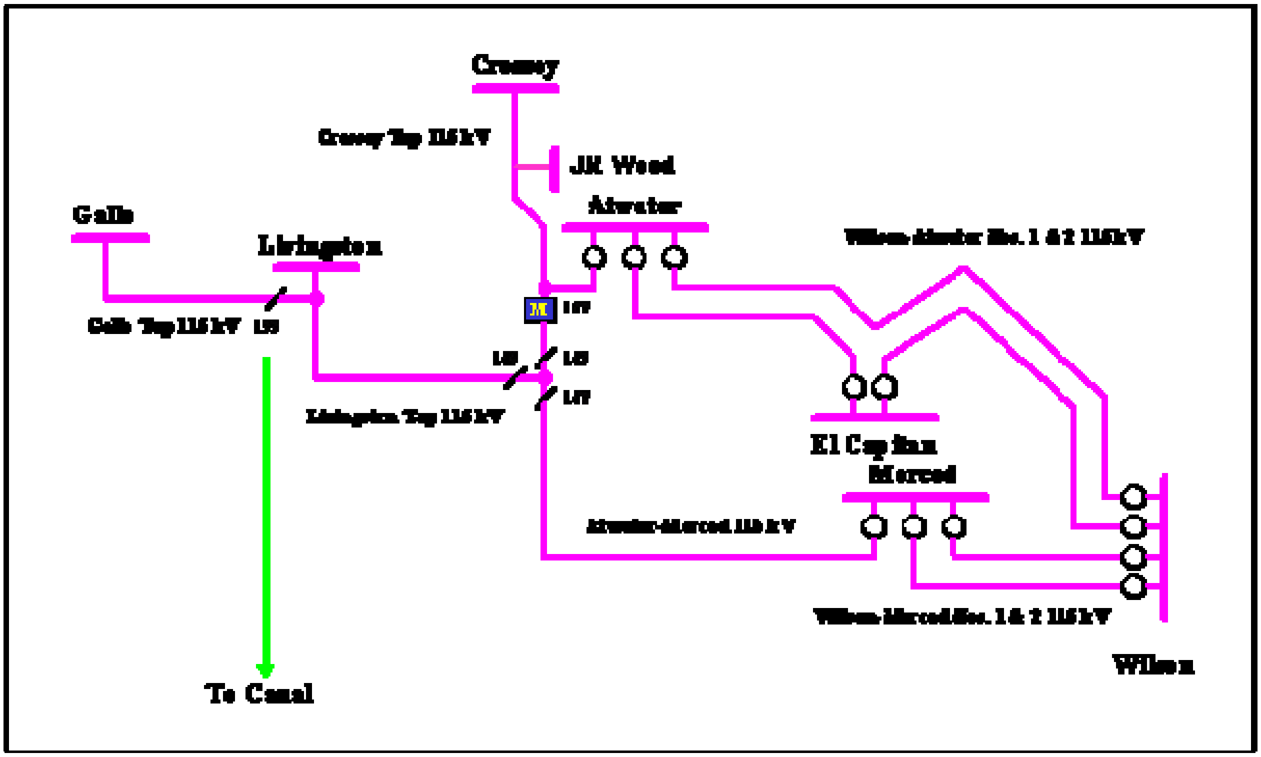


Figure 4-258: Existing Scope Diagram

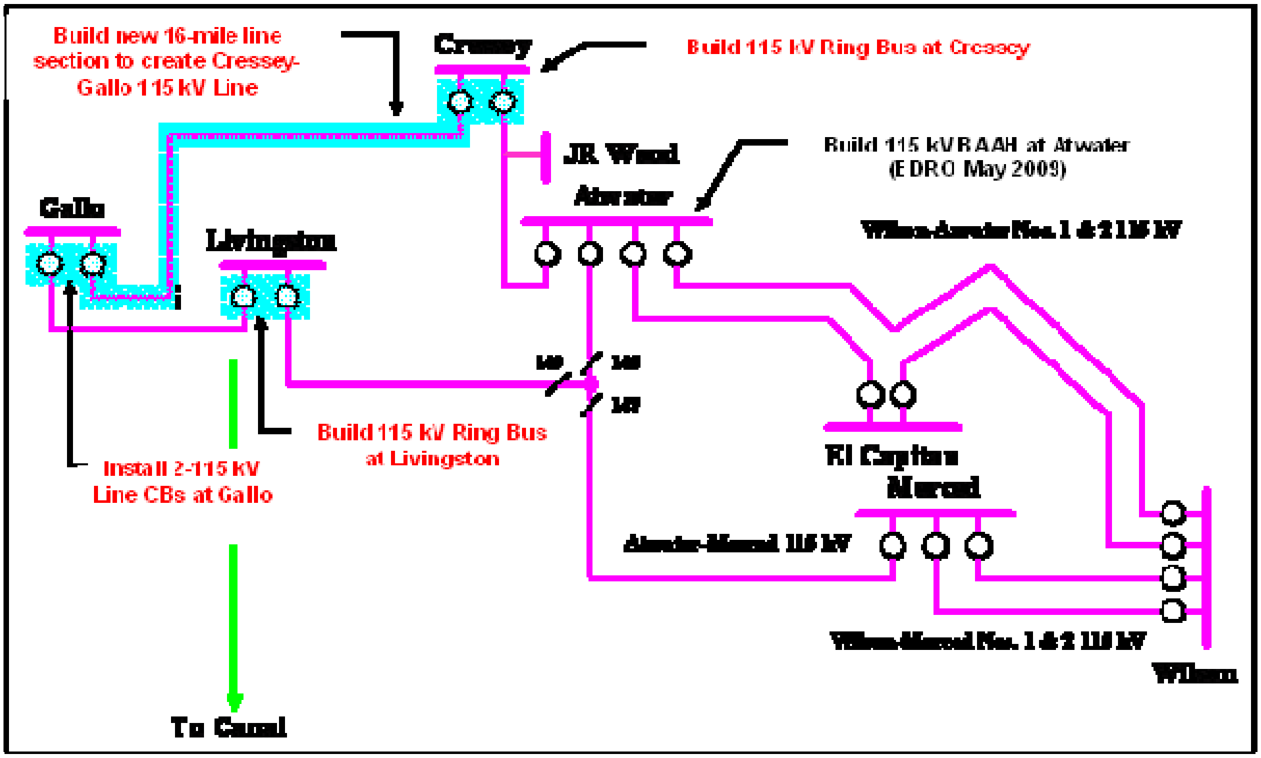


Figure 4-259: Proposed Scope Diagram

Attachment 2: Atwater-Merced 115 kV Line Outage History

Table 4-70: Atwater-Merced 115 kV Line Outage History

Yrs 2005-07 Outage History: Atwater-Merced 115 kV Line

Outage #	Date Out	Time Out	Date Restored	Time Restored	Line Outage Type	Cust Effected	Customer Outage Type	Duration of Outage	Customer Outage Minutes	Weather	Root Cause	Root Cause Detail
1	8/15/2005	22:07	8/16/2005	1:10	SUS	5,418	SUS	3Hrs 3Min	991,494	Lightning	Equipment Failure	Fire, pole
2	10/30/2005	12:55	10/30/2005	12:55	MOM	4,277	MOM	0Hrs 0Min	0	Clear	Unknown	Patrol - not conducted
3	1/18/2006	14:15	1/18/2006	14:15	MOM	8,278	MOM	0Hrs 0Min	0	Lightning	Weather	Lightning
4	8/30/2006	17:56	8/30/2006	17:56	MOM	5,179	MOM	0Hrs 0Min	0	Clear	Third Party	Vehicle
5	10/1/2006	22:50	10/2/2006	13:45	SUS	4,312	SUS	14Hrs 55Min	3,859,240	Rain	Equipment Failure	Fire, pole
6	10/1/2006	23:35	10/2/2006	2:40	SUS	2,854	SUS	3Hrs 5Min	527,990	Rain	Equipment Failure	Field structure
7	10/25/2006	12:38	10/25/2006	16:51	SUS	7,880	SUS	4Hrs 13Min	1,993,640	Clear	Equipment Failure	Field structure

Before Project					
Outages Total:	**7**	**Duration Total:**	**25Hrs 16Min**	**Cust Out Min Total:**	**7,372,364**
Outages / Year:	**1.4**	**Duration / Year:**	**5Hrs 3Min**	**Cust Out Min / Year:**	**2,457,455**
After Project (Phase 1 - Atwater Jct SCADA Switches)					
Outages / Year:	**1.4**	**Duration / Year :**	**2 Hrs 32Min**	**Cust Out Min / Year:**	**1,228,727**
After Project (Phase 2 - Atwater 115 kV BAAH Bus)					
Outages / Year:	**0.7**	**Duration / Year :**	**2 Hrs 32Min**	**Cust Out Min / Year:**	**614,364**
After Project (Phase 3 - new Gallo-Cressey 115 kV Line)					
Outages / Year:	**0.7**	**Duration / Year :**	**2 Hrs 32Min**	**Cust Out Min / Year:**	**106**

Attachment 3: Pre and Post Power Flow Plots

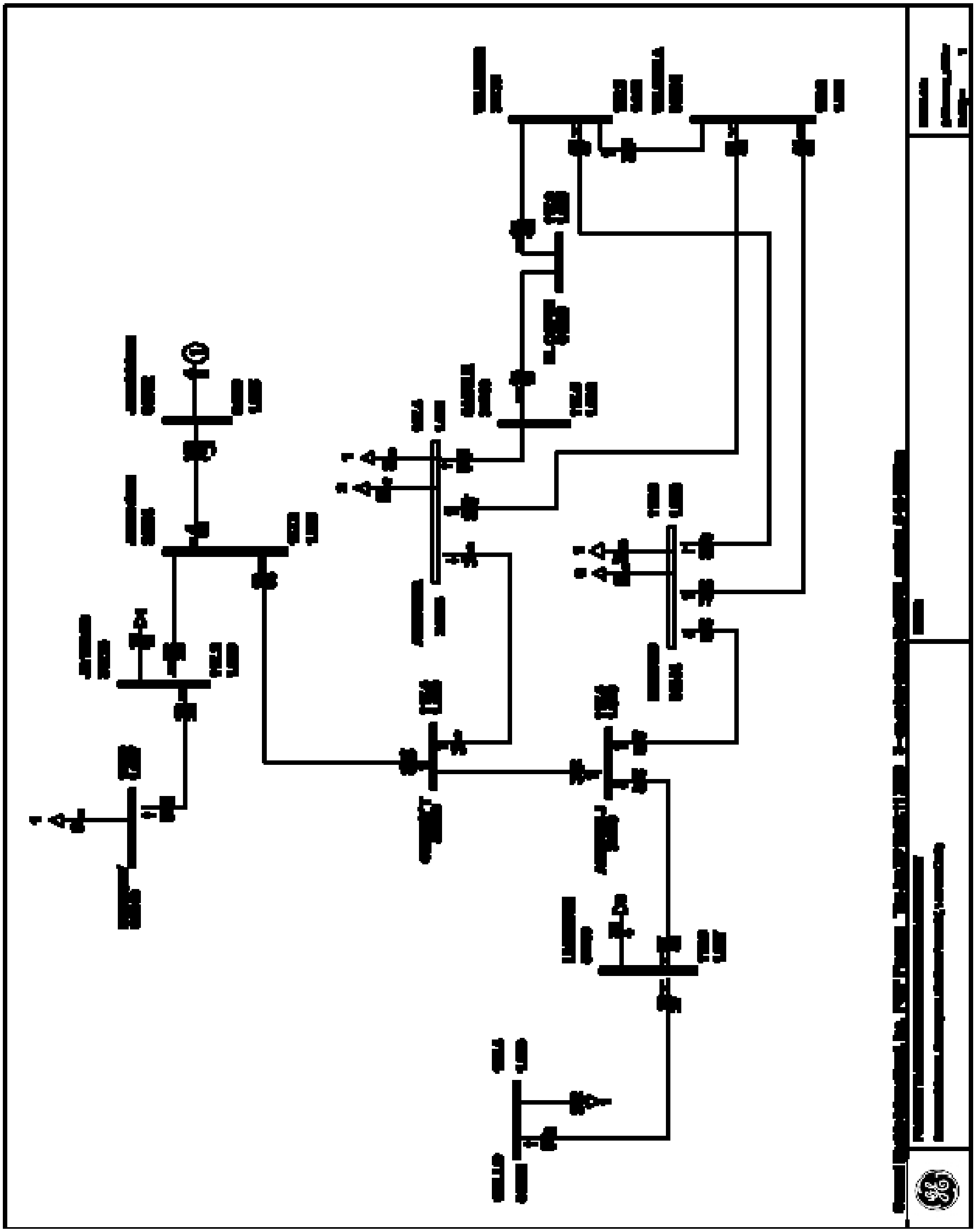


Figure 4-260: Pre Project – Normal Conditions

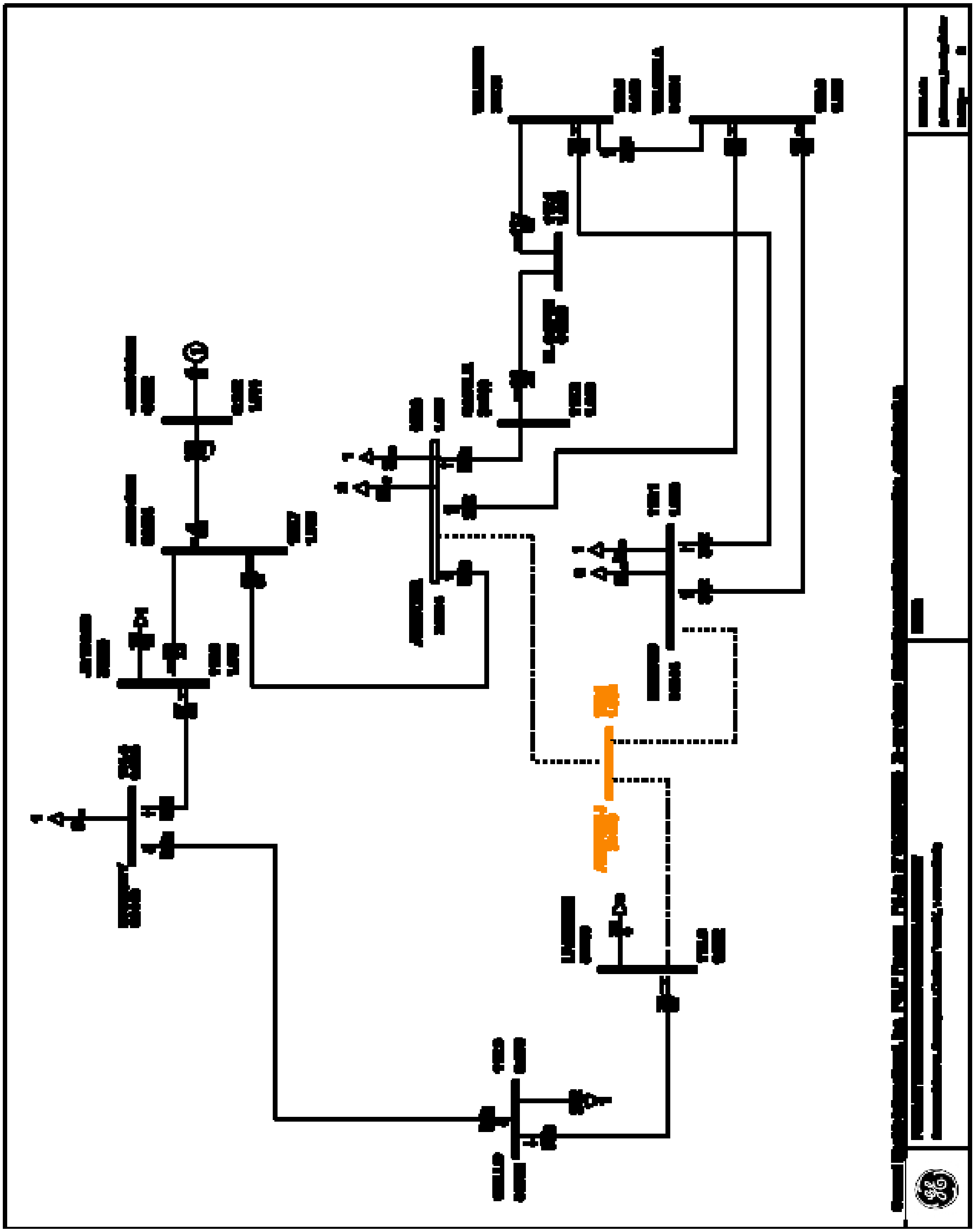


Figure 4-261: Post Project – Loss of the Atwater - Merced 115 kV Line

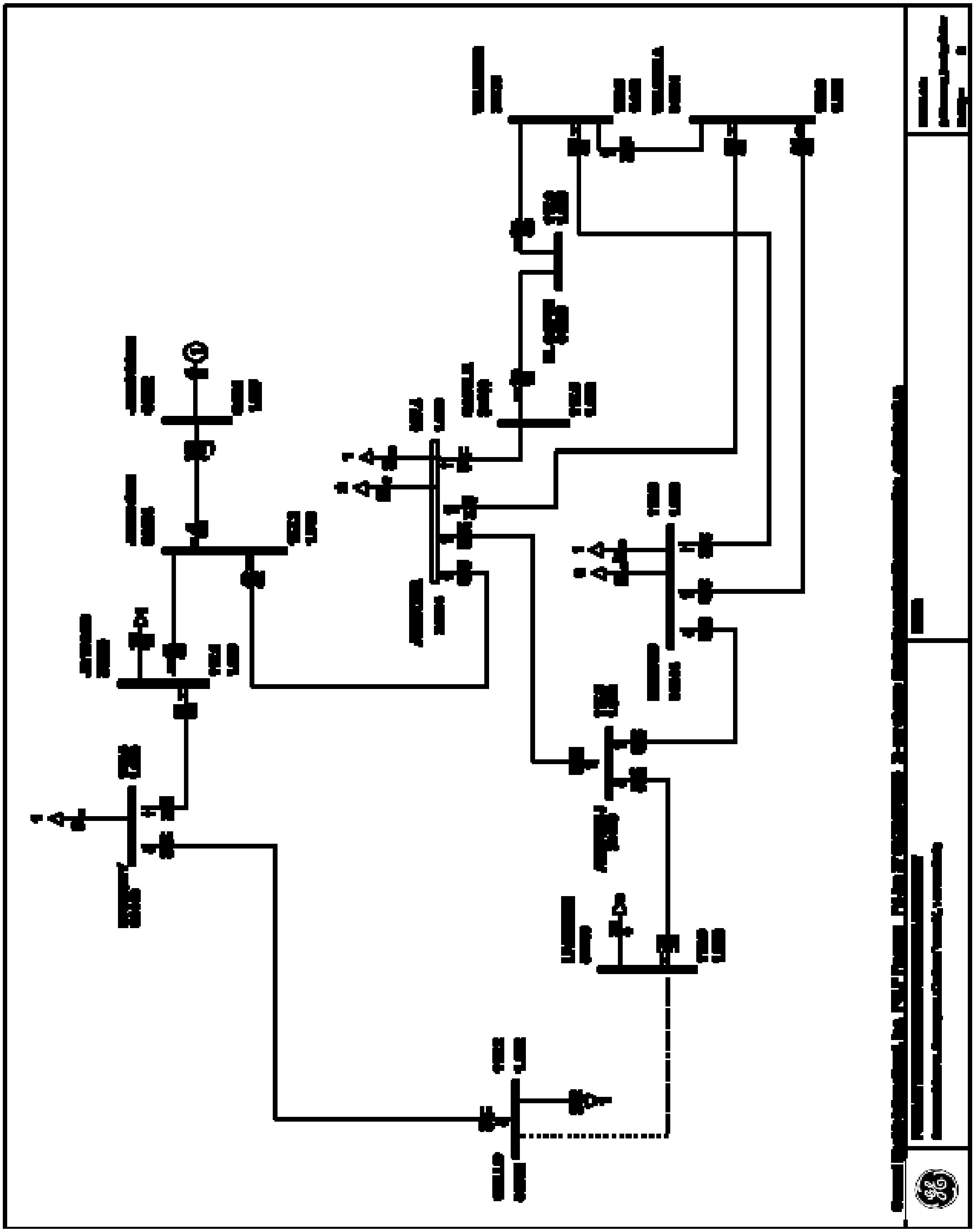


Figure 4-262: Post Project – Loss of Livingston - Gallo 115 kV Line

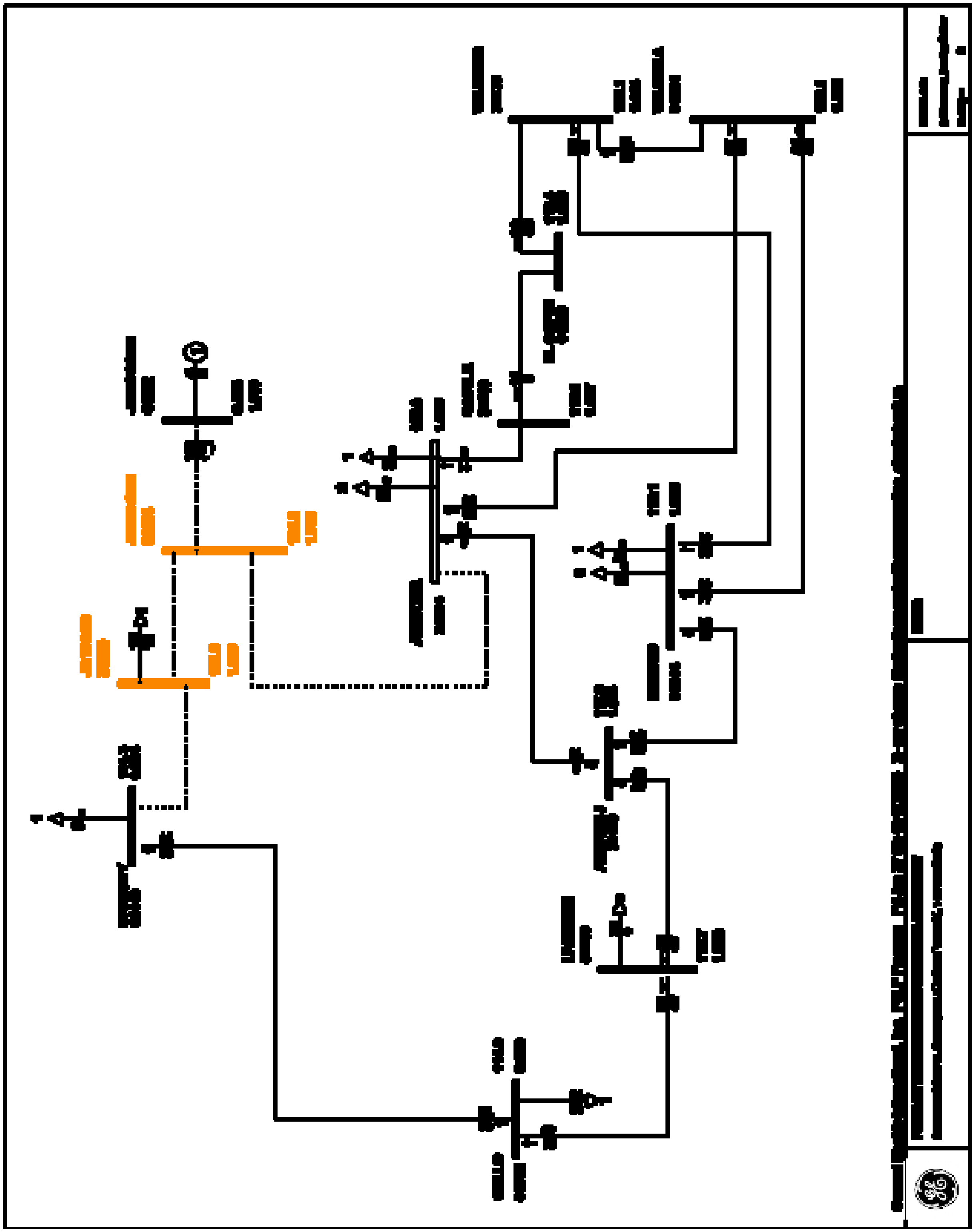


Figure 4-263: Post Project – Loss of Atwater - Cressey 115 kV Line

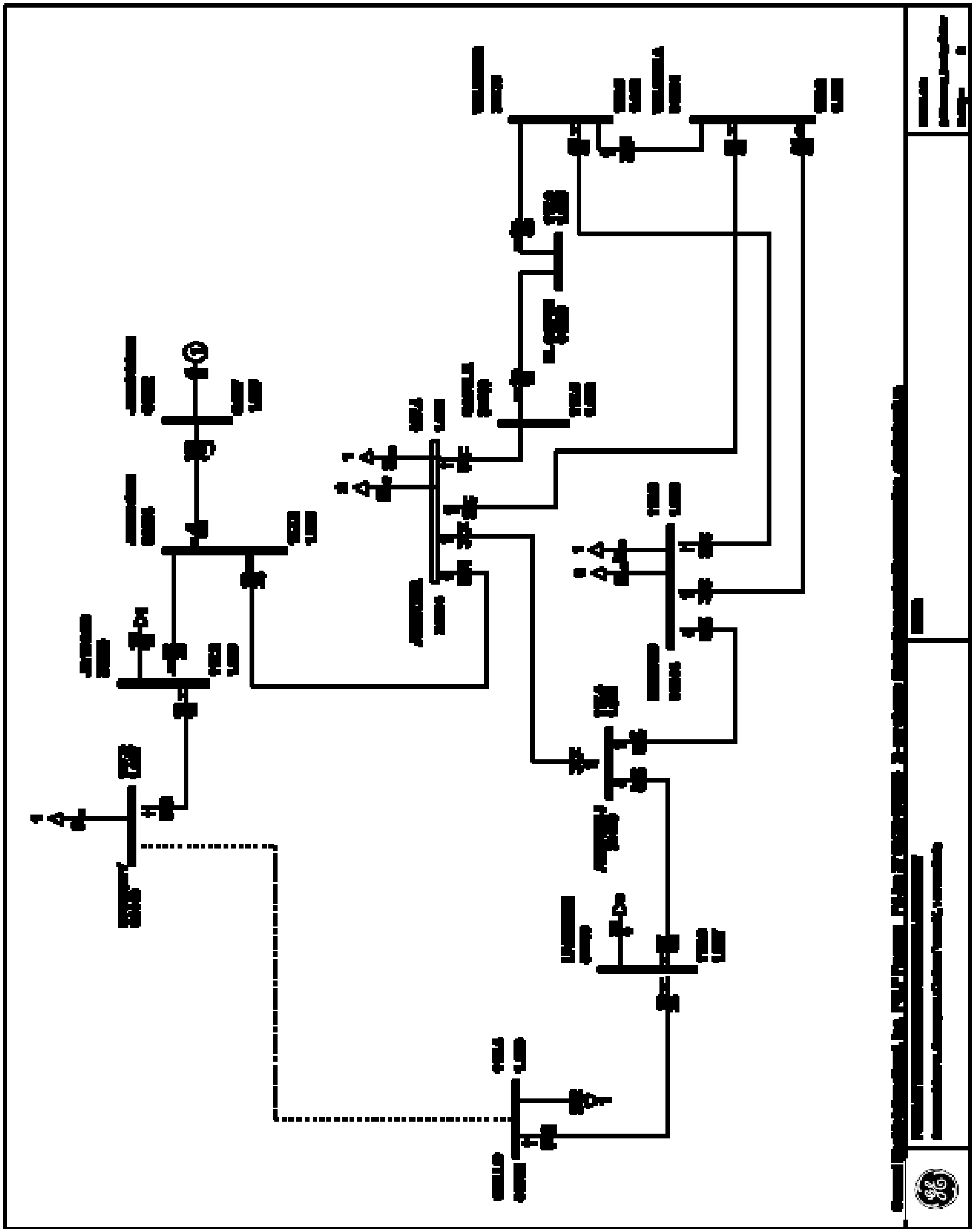


Figure 4-264: Post Project – Loss of the new Gallo - Cressey 115 kV Line

Midway – Renfro 115 kV Line Reconductor

TARGETED IN-SERVICE DATE

May 2012

PURPOSE AND BENEFIT

Reliability – NERC Compliance

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROJECT

The project scope is to reconductor the Midway-Renfo 115 kV Line (16 miles) and the Midway-Rio Bravo-Renfro 115 kV Line (16 miles) with conductors capable of carrying a minimum capacity of 1,517 Amps under both summer normal and emergency conditions. If necessary, associated line switches, and substation terminal equipment would be upgraded. In addition, the project scope would require obtaining any necessary environmental and land permits to complete the reconductoring work.

This project is expected to cost between $17M and $22M.

BACKGROUND

The Midway-Renfro and Midway-Rio Bravo-Renfro 115 kV double circuit tower lines are located in Kern County. It provides electric service to PG&E customers through Tupman, Rio Bravo, and Renfro 115 kV substations. Significant block load additions are anticipated in this area based on the large number of Agricultural Internal Combustion Engine Conversion (AG-ICE) electric service applications, and a new large load interconnection customer. PG&E initiated a distribution capacity increase project to install a new 115/12 kV, 45 MVA, transformer bank at Tupman Substation. The project will also upgrade the 115 kV bus to allow Tupman to be operated as a flip-flop substation. It is anticipated that the 2nd Tupman distribution bank would be installed by May 2009.

Transmission customer, Inergy, recently completed its large load interconnection application. Inergy's new substation was interconnected into PG&E's transmission system on November 2008.

Planning studies for summer peak conditions have concluded that an outage of the Midway-Renfro 115 kV Line will overload the Midway-Rio Bravo-Renfro 115 kV Line by 10% of its emergency rated capacity in 2011. A summer operating plan addresses this contingency by radializing service to Renfro and Tupman substations. A project has been initiated to re-rate the Midway-Renfro 115 kV lines to 3 ft/sec wind speed rating.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO. An exception occurs for the Inergy load demand forecast. A large load interconnection study has been completed for Inergy to increase its load demand to 14 MW by 2011. In addition, PG&E's Distribution Planning Department will install a 2nd 115/12 kV, 45 MVA, transformer bank at Tupman by May 2009 to support new agriculture pumping load. As part of this distribution project, the Tupman 115 kV bus will also be upgrade to allow Tupman to be operated as a flip-flop substation. Under this bus arrangement, Tupman, Norco, and Inergy substations would automatically transfer its service onto the Midway-Rio Bravo-Renfro 115 kV Line after an outage of the Midway-Renfro 115 kV Line.

STUDY CRITERIA

CAISO grid planning criteria.

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended. This alternative does not address the potential overload issue.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2012

KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – TBD
- Special Metering or Protection – None
- Common Mode Exposure Items – None
- Interaction with other Projects or Studies – TBD

GEPSLF MODELING INFORMATION

Reconductor Midway-Renfro 115 kV DCTL with 795 ACSS

```
# Midway-Renfro 115 kV Line (3 line sections)
# Existing: Midway-Tupman Jct #1              250 Cu   10.6 miles
#           Tupman Jct #1-Renfro Tap #1       250 Cu   5.8 miles
#           Renfro Tap #1-Renfro              715.5 Al  0.16 miles
#
# Reconductor to 795 ACSS: 16.6 miles total
# Midway-Tupman Jct #1
OLDSECDD 34774, 34749, 1, RPU=0.010292, XPU=0.056782, BPU=0.0085134, +
MVA1=302, MVA2=302, MVA3=302, MVA4=302
#Tupman Jct #1-Renfro Tap #1
OLDSECDD 34749, 34761, 1, RPU=0.0056313, XPU=0.031069, BPU=0.0046582, +
MVA1=302, MVA2=302, MVA3=302, MVA4=302
#Renfro Tap #1-Renfro
OLDSECDD  34761, 34762, 1, RPU=0.00015535, XPU=0.0001285,  BPU=0.0001285, +
MVA1=302, MVA2=302, + MVA3=302, MVA4=302

# Midway-Rio Bravo-Renfro 115 kV Line (6 line sections)
# Existing: #Midway-Rio Bravo Tomato              250 Cu    5.55 miles
#Rio Bravo Tomato-Frito Lay Tap                   250 Cu    1.90 miles
#Frito Lay Tap-Tupman Jct #2                      250 Cu    3.00 miles
#Tupman Jct #2-Renfro Jct                         250 Cu    0.77 miles
#Renfro-Jct-Renfro Tap #2                         250 Cu    5.16 miles
#Renfro Tap #2-Renfro                             715.5 Al  0.16 miles

# Reconductor to 795 ACSS: 16.5 miles total
#Midway-Rio Bravo Tomato
OLDSECDD 34774, 34811, 1, RPU=0.0053886, XPU=0.02973, BPU=0.0044575, +
MVA1=302, MVA2=302, MVA3=302, MVA4=302
#Rio Bravo Tomato-Frito Lay Tap
OLDSECDD 34811, 34813, 1, RPU=0.0018447, XPU=0.010178, BPU=0.001526, +
MVA1=302, MVA2=302, MVA3=302, MVA4=302
#Frito Lay Tap-Tupman Jct #2
OLDSECDD  34813, 34751, 1, RPU=0.0029127, XPU=0.01607, BPU=0.0024094, +
MVA1=302, MVA2=302, MVA3=302, MVA4=302
#Tupman Jct #2-Renfro Jct
OLDSECDD  34751, 34775, 1, RPU=0.0007476, XPU=0.0041247, BPU=0.00061842, +
MVA1=302, MVA2=302, MVA3=302, MVA4=302
#Renfro-Jct-Renfro Tap #2
OLDSECDD  34775, 34763, 1, RPU=0.0050099, XPU=0.027641, BPU=0.0041442, +
MVA1=302, MVA2=302, MVA3=302, MVA4=302
#Renfro Tap #2-Renfro
OLDSECDD  34763, 34767, 1, RPU=0.000155535, XPU=0.00085709, BPU=0.0001285, +
MVA1=302, MVA2=302, MVA3=302, MVA4=302
```

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagram
2. Demand Forecast
3. Power Flow Summary
4. Pre- and Post-Project Power Flow Plots

Attachment 1: Scope Diagram

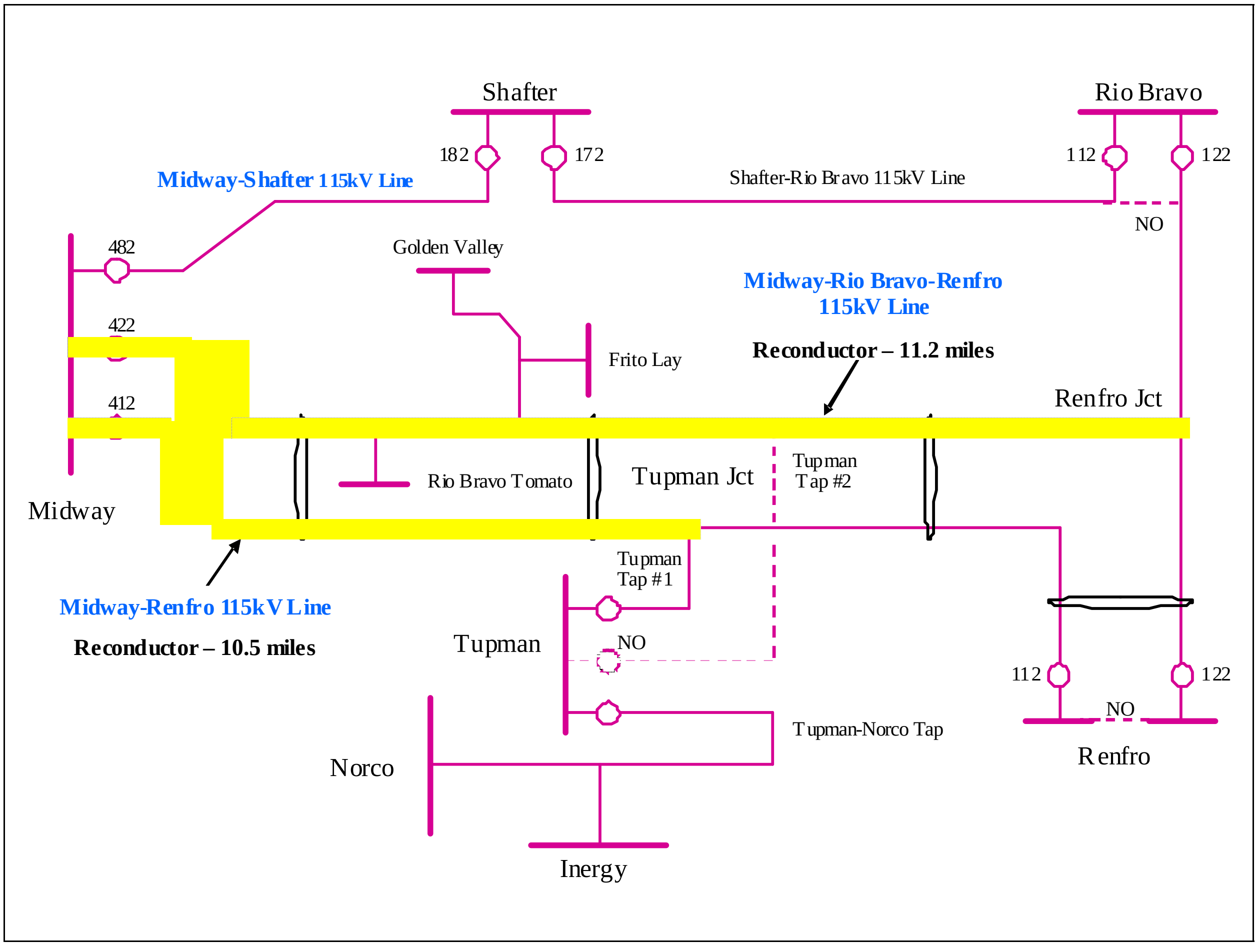


Figure 4-265: Proposed Scope Diagram

Attachment 2: Demand Forecast

Table 4-71: Load Demand Forecast

Substation	2009	2010	2011	2012	2013
Tupman	13.5	13.5	13.5	13.5	13.5
Renfro	58.4	59.4	60.5	60.7	61.8
Rio Bravo	17.7	17.8	17.9	17.7	17.8
Shafter	13.4	13.5	13.6	13.6	13.5
Inergy	10.0	10.0	14.0	14.0	14.0
Norco	4.2	4.2	4.2	4.2	4.2
Rio Bravo Tomato	5.1	5.1	5.1	5.1	5.1
Frito Lay	2.4	2.4	2.4	2.4	2.4
Golden Valley	5.7	5.7	5.7	5.7	5.7
TOTAL	**130**	**132**	**137**	**137**	**138**

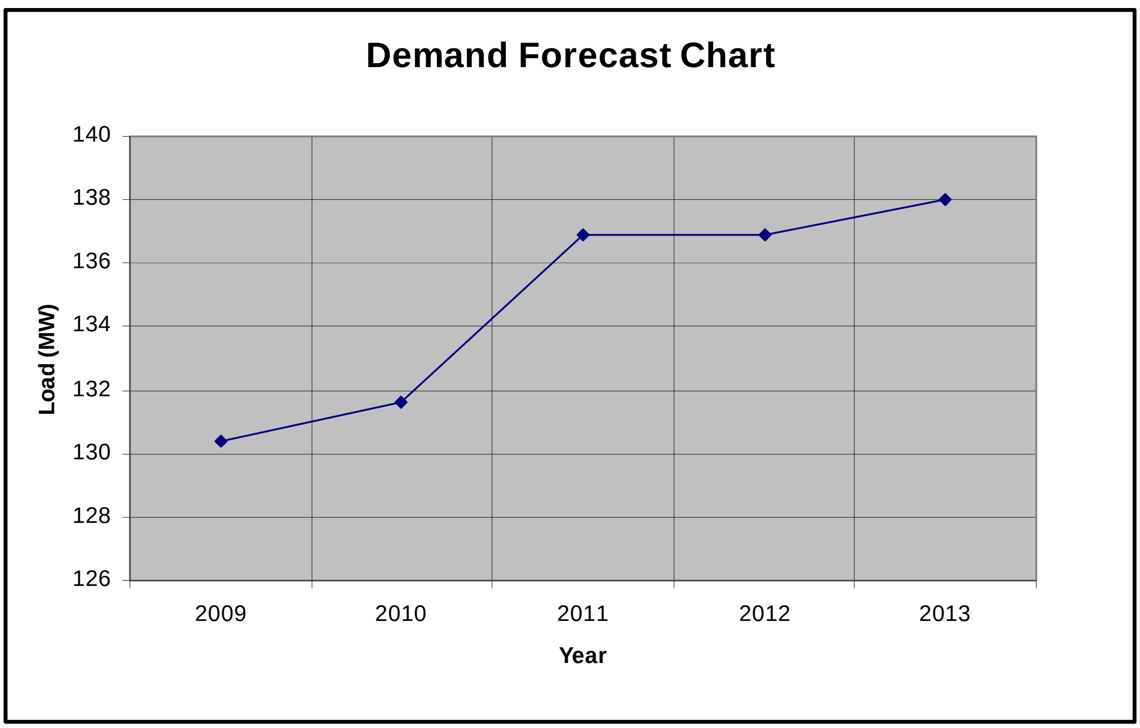


Figure 4-266: Area Load Demand Curve

Attachment 3: Power Flow Summary

Table 4-72: Power Flow Summary

Contingency	Facility Affected	2010 (Pre-Project)	2011 (Pre-Project)	2011 (Post-Project)	2012 (Post-Project)	2013 (Post-Project)
Midway-Renfro 115 kV Line (L-1)	Midway-Rio Bravo-Renfro 115 kV Line (Midway to Frito Lay Tap)	97%	110%	31%	31%	31%

Attachment 4: Pre and Post Project Power Flow Plots

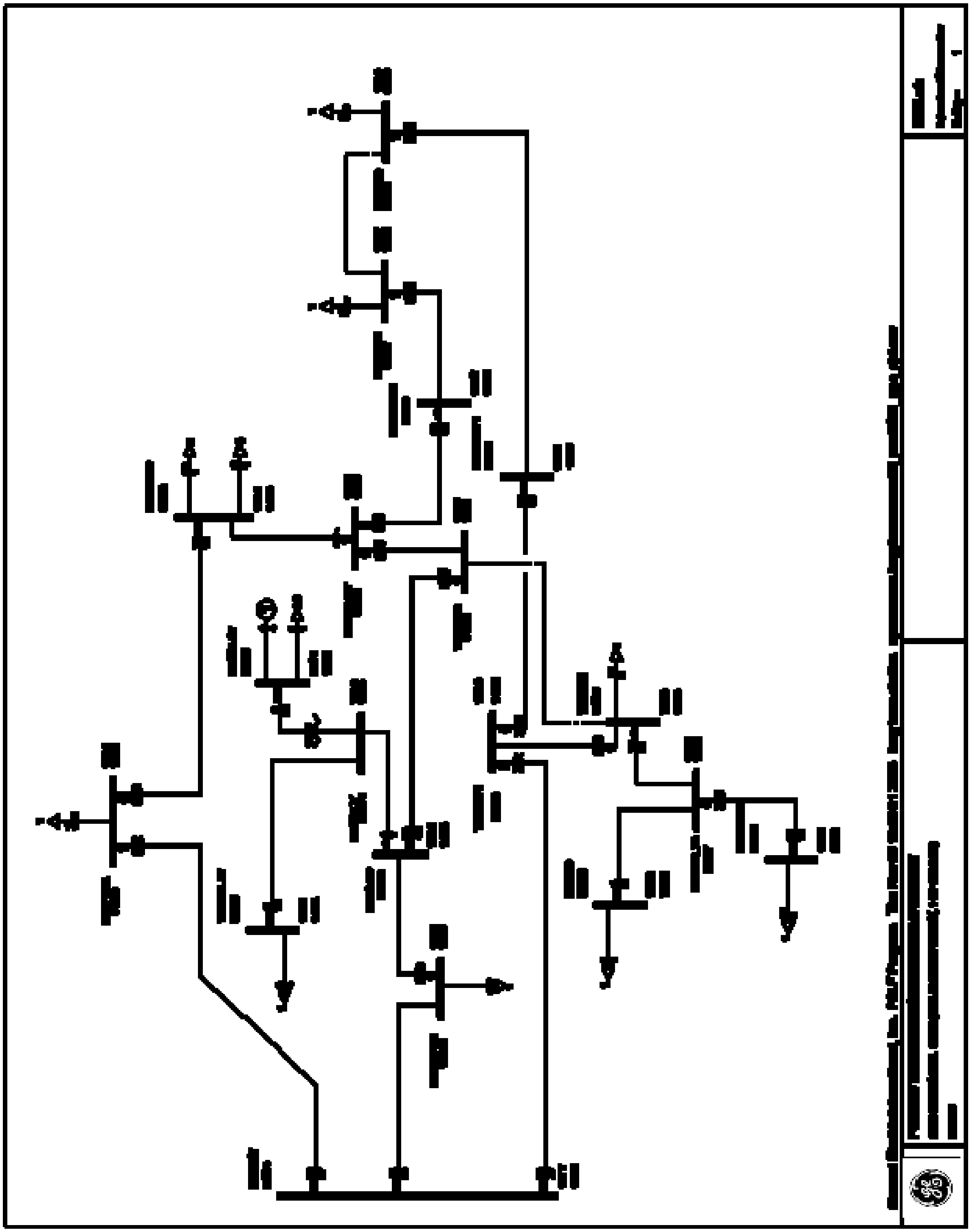


Figure 4-267: Pre-Project: Normal Conditions

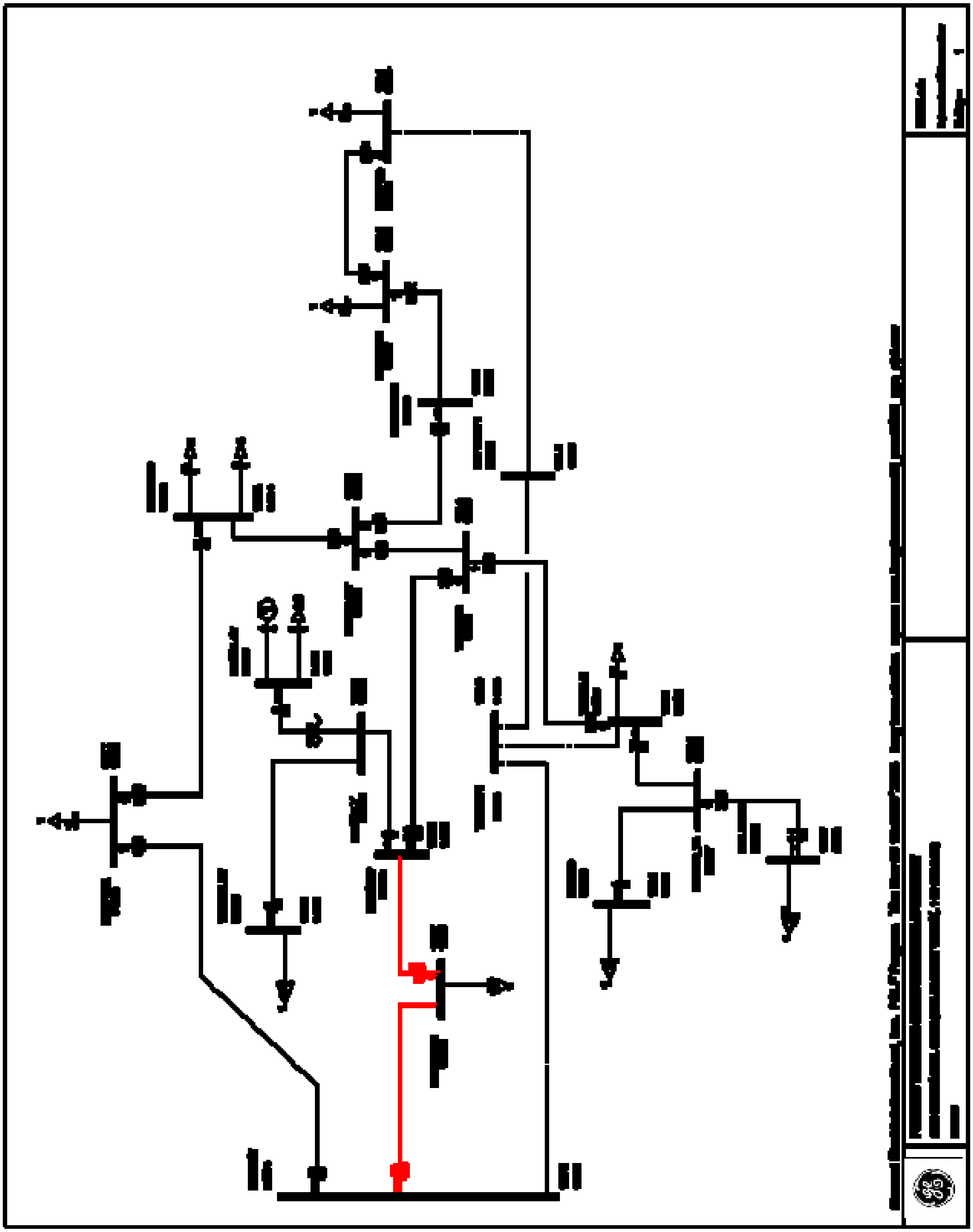


Figure 4-268: Pre-Project: Loss of Midway-Renfro 115 kV Line

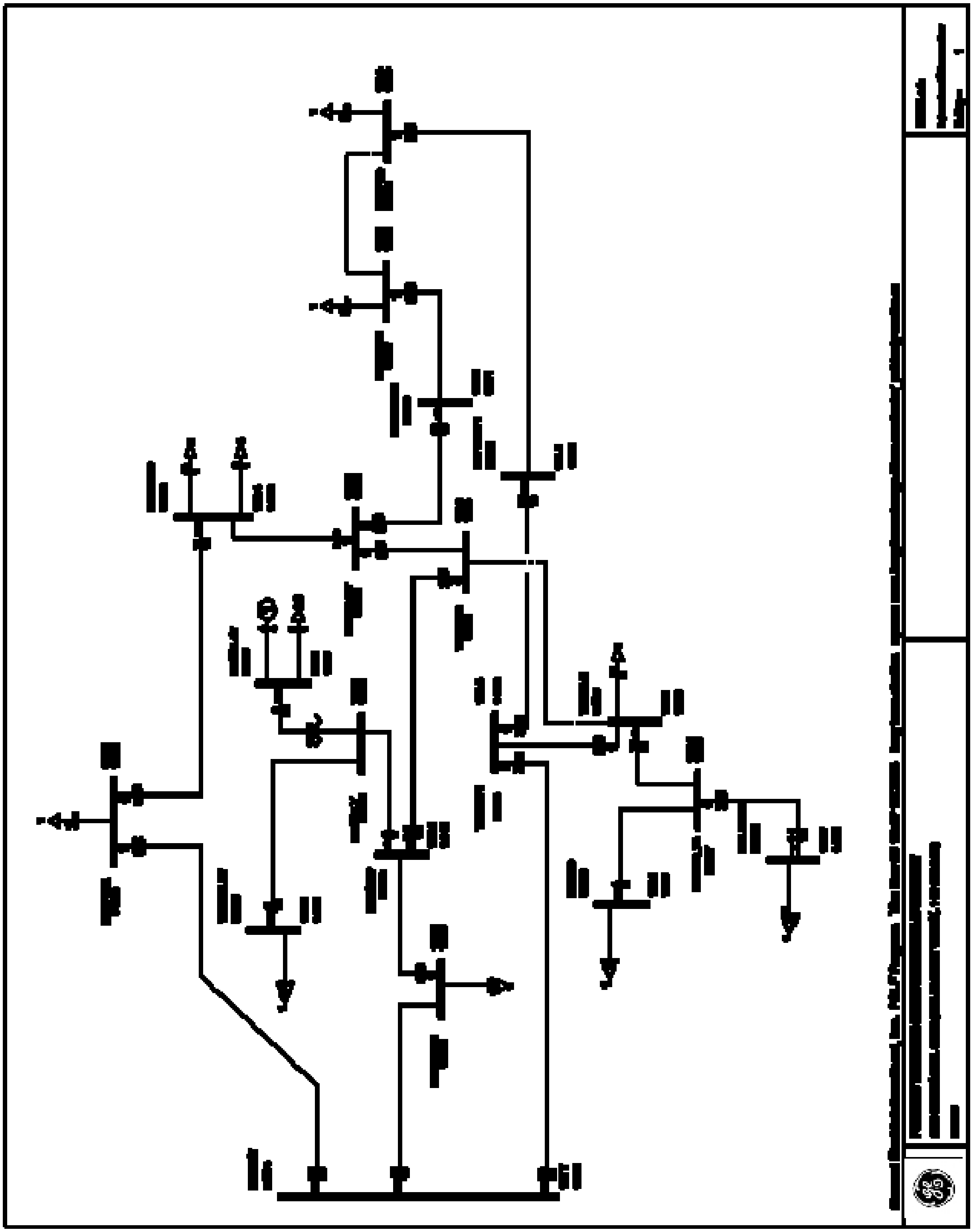


Figure 4-269: Post-Project: Normal Conditions

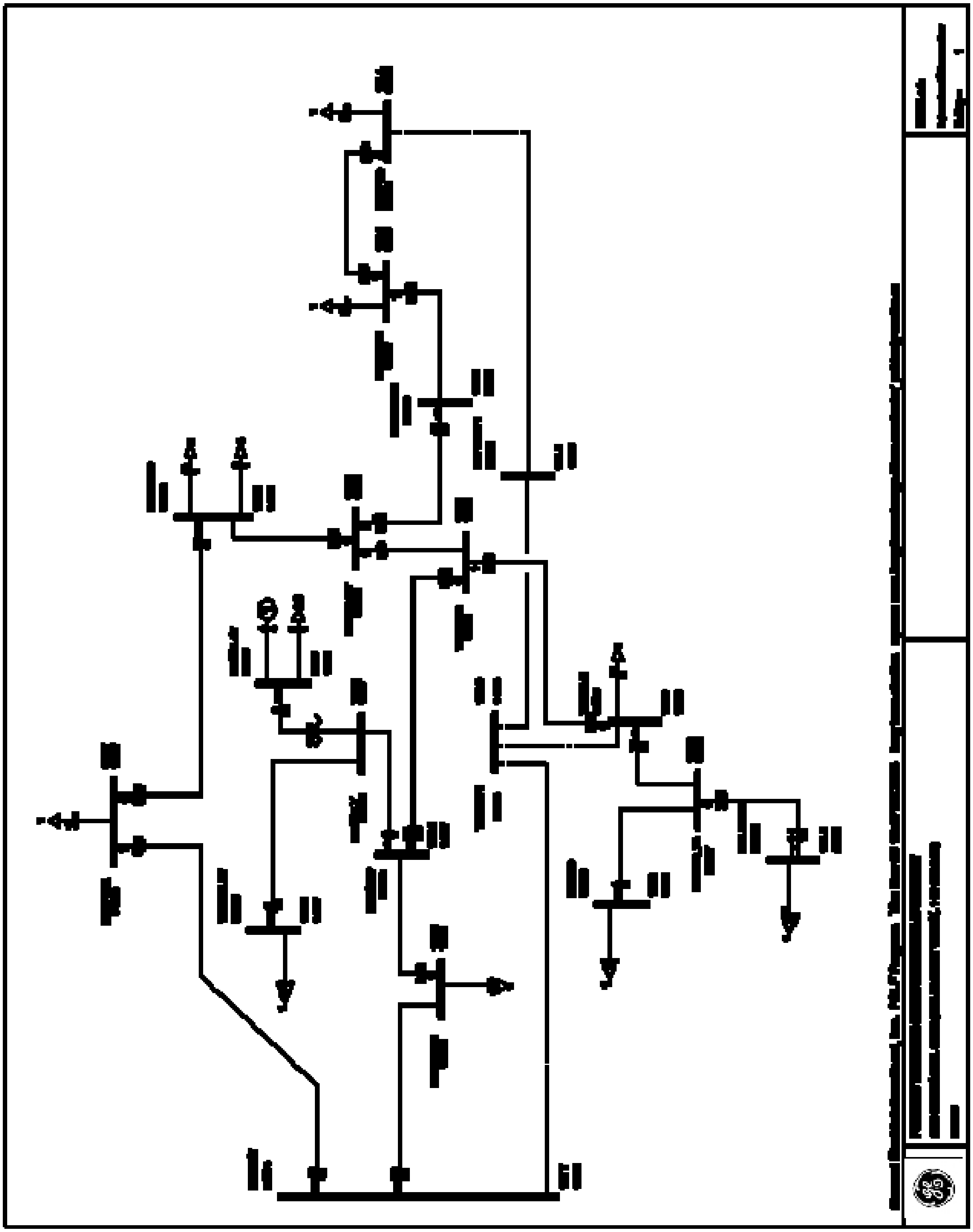


Figure 4-270: Post-Project: Loss of Midway-Renfo 115 kV Line

2013 Projects

Cooley Landing – Los Altos 60 kV Reconductor

TARGETED IN-SERVICE DATE

May 2013

PURPOSE AND BENEFIT

Reliability – NERC Compliance

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROJECT

The project scope is to reconductor the Cooley Landing-Los Altos (approximately 11 miles) 60 kV line with a conductor rated at 800 Amps or greater. If necessary, the project scope may also include the upgrade of associated line terminal equipment to accommodate the higher rating. In addition, environmental and land permits may be required to complete the reconductoring work.
This project is expected to cost between $5M and $10M.

BACKGROUND

The Los Altos and Loyola 60 kV substations are located in the Santa Clara County. The Los Altos Substation serves the City of Los Altos and the surrounding areas. These substations are normally supplied by the Monta Vista Substation. There is a backup connection from the Cooley Landing - Los Altos 60 kV line. An outage of the Monta Vista - Los Altos 60 kV line would cause the transfer of Los Altos load to the Cooley Landing 60 kV Line. In 2007, the recorded peak electric demand for Los Altos and Loyola was approximately at 42 MW. Load in this area is forecast to increase at a rate of 3.4% or 1.4 MW per year.

The Cooley Landing-Los Altos 60 kV Line is approximately 10 miles long, and consists of mainly 4/0 cu conductor. The line is currently rated at 495 Amps normal and 557 Amps emergency. This project would increase this line’s capability to 702 Amps normal and 802 Amps emergency.

Planning analysis has identified that the Cooley Landing – Los Altos 60 kV Line is projected to overload following an outage of the Monta Vista – Loyola 60 kV line section of the Monta Vista - Los Altos 60 kV Line.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended. This alternative does not address the potential overload issue.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2013

KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – TBD
- Special Metering or Protection – TBD
- Common Mode Exposure Items – TBD
- Interaction with other Projects – TBD

GEPSLF MODELING INFORMATION

RECONDUCTOR COOLEY LANDING-LOS ALTOS 60 kV
APPROXIMATELY 11 MILES WITH 715 AL CONDUCTOR
#
OLDSECDD 33375, 35454, CKT=1, SEC=1, RPU=0.02223, XPU=0.119135, BPU=0.001089, +
MVA1=73 MVA2=83, MVA3=101, MVA4=108
OLDSECDD 35454, 35451, CKT=1, SEC=1, RPU=0.00606, XPU=0.032492, BPU=0.000297, +
MVA1=73 MVA2=83, MVA3=101, MVA4=108
OLDSECDD 35451, 35450, CKT=1, SEC=1, RPU=0.01415, XPU=0.075814, BPU=0.000693, +
MVA1=73 MVA2=83, MVA3=101, MVA4=108
#

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagram
2. Power Flow Summary
3. Pre and Post Project Power Flow Plots

Attachment 1: Scope Diagram

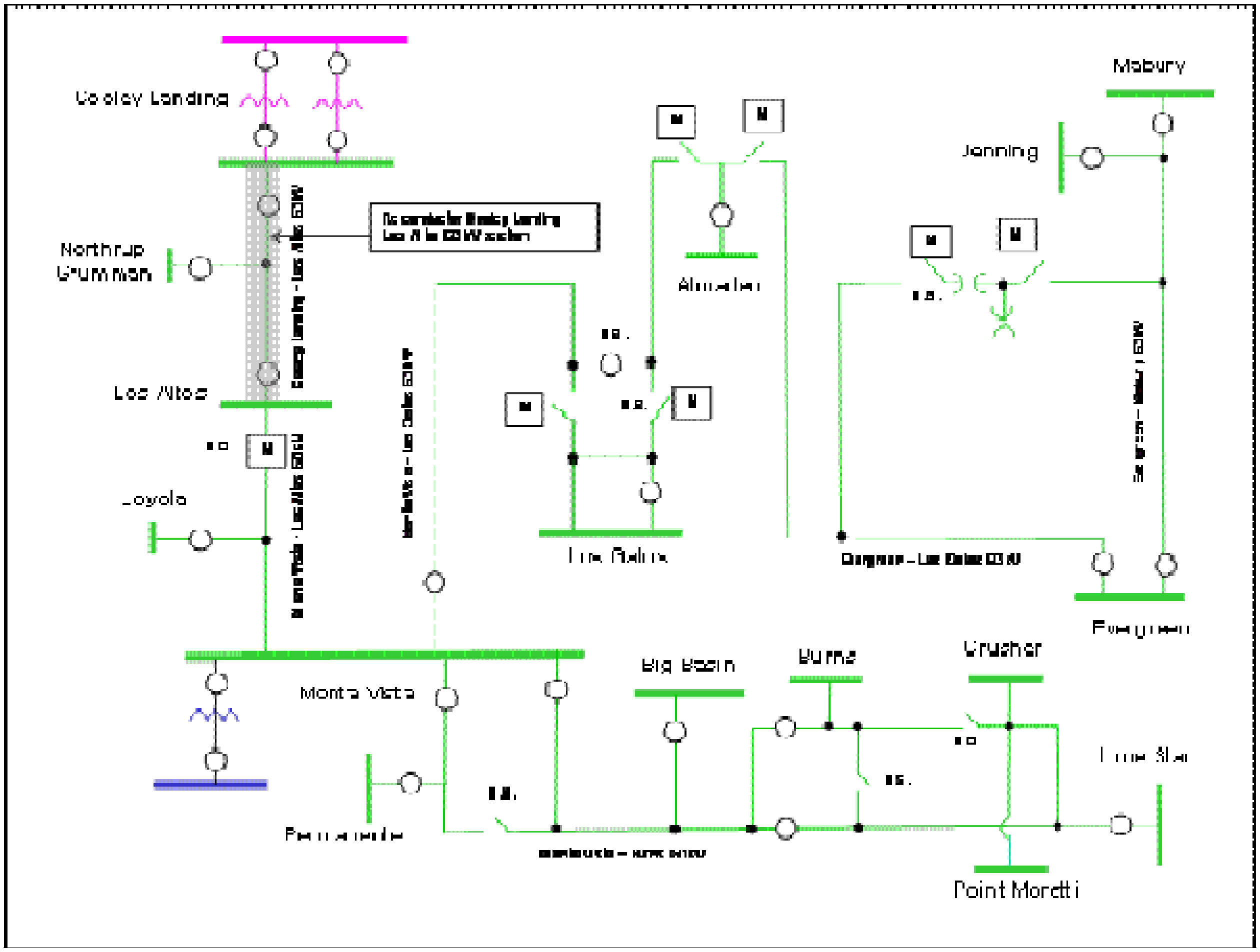


Figure 4-271: Scope Diagram

Attachment 2: Power Flow Summary

Table 4-73: Power Flow Summary

Normal/Contingency	Facility Affected	2009 Pre-Project	2010 Pre-Project	2011 Pre-Project	2012 Pre-Project	2013 Pre-Project	2013 Post-Project
Normal Conditions	Cooley Landing-Los Altos 60 kV Line	14%	14%	14%	14%	14%	10%
Monta Vista-Loyola 60 kV Line Section		93%	95%	97%	100%	102%	71%

Attachment 3: Pre and Post Project Power Flow Plots

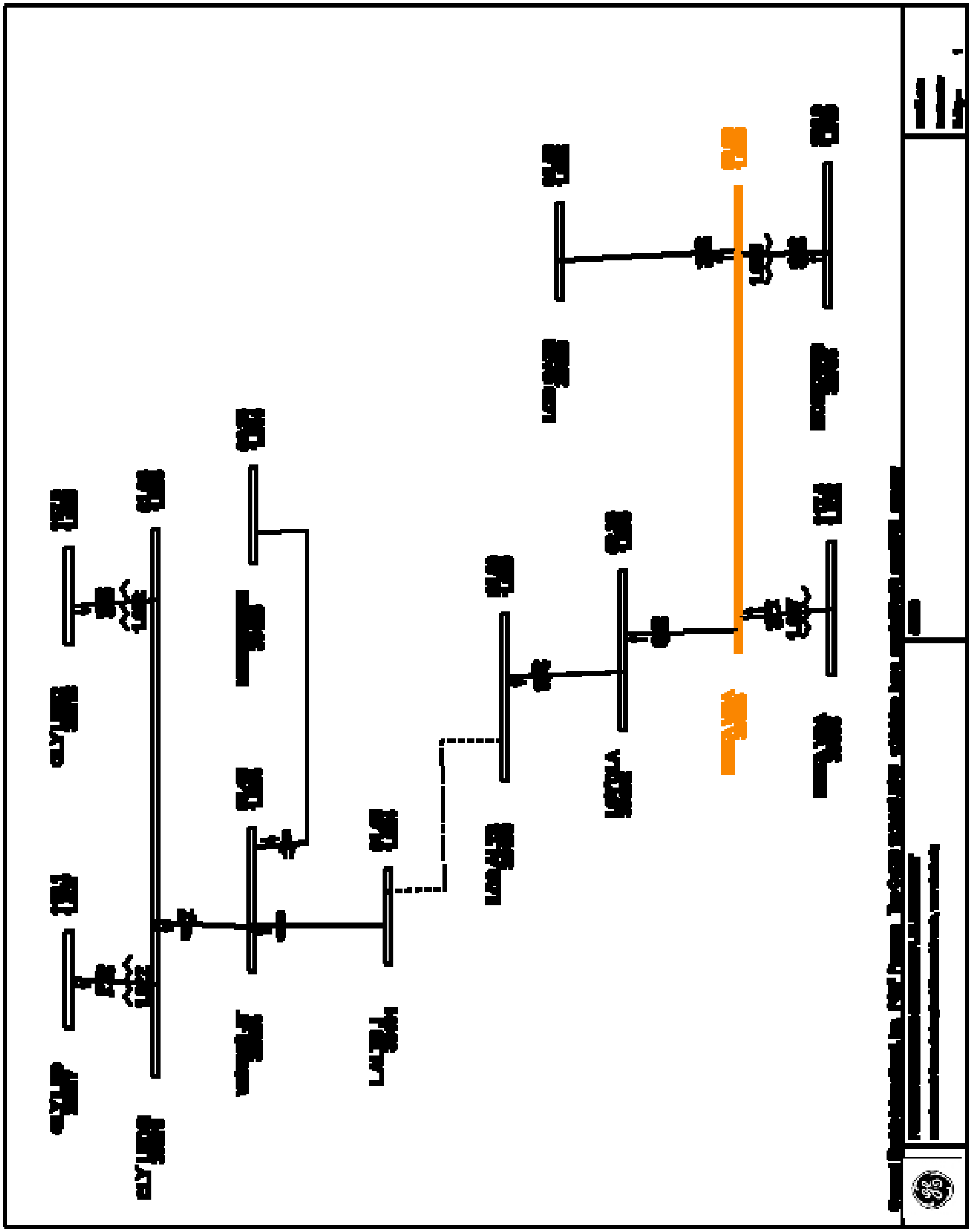


Figure 4-272: All Facilities in service, Year 2013 (Pre-Project)

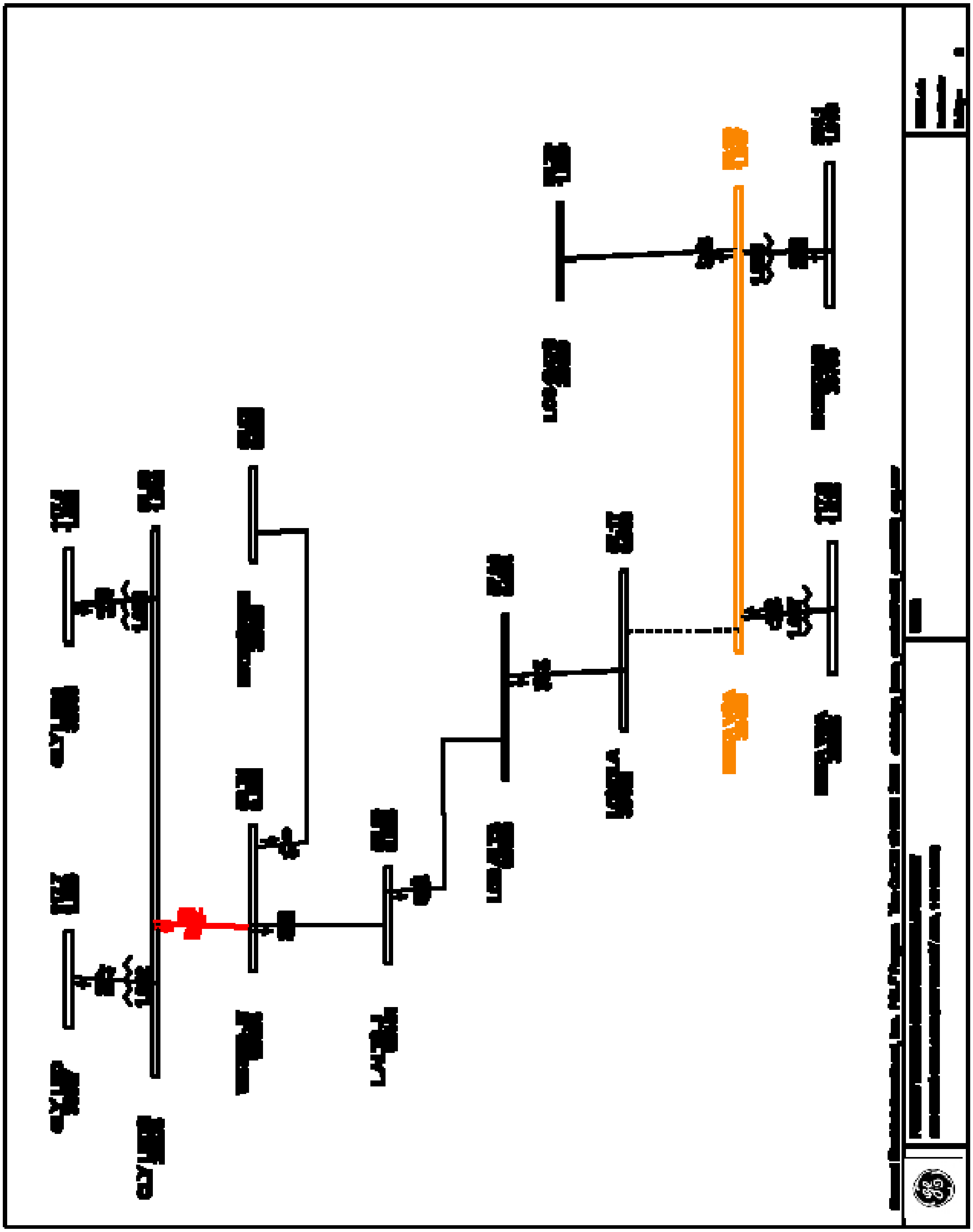


Figure 4-273: Outage of Monta Vista-Loyola 60 kV Line section, Year 2013 (Pre-Project)

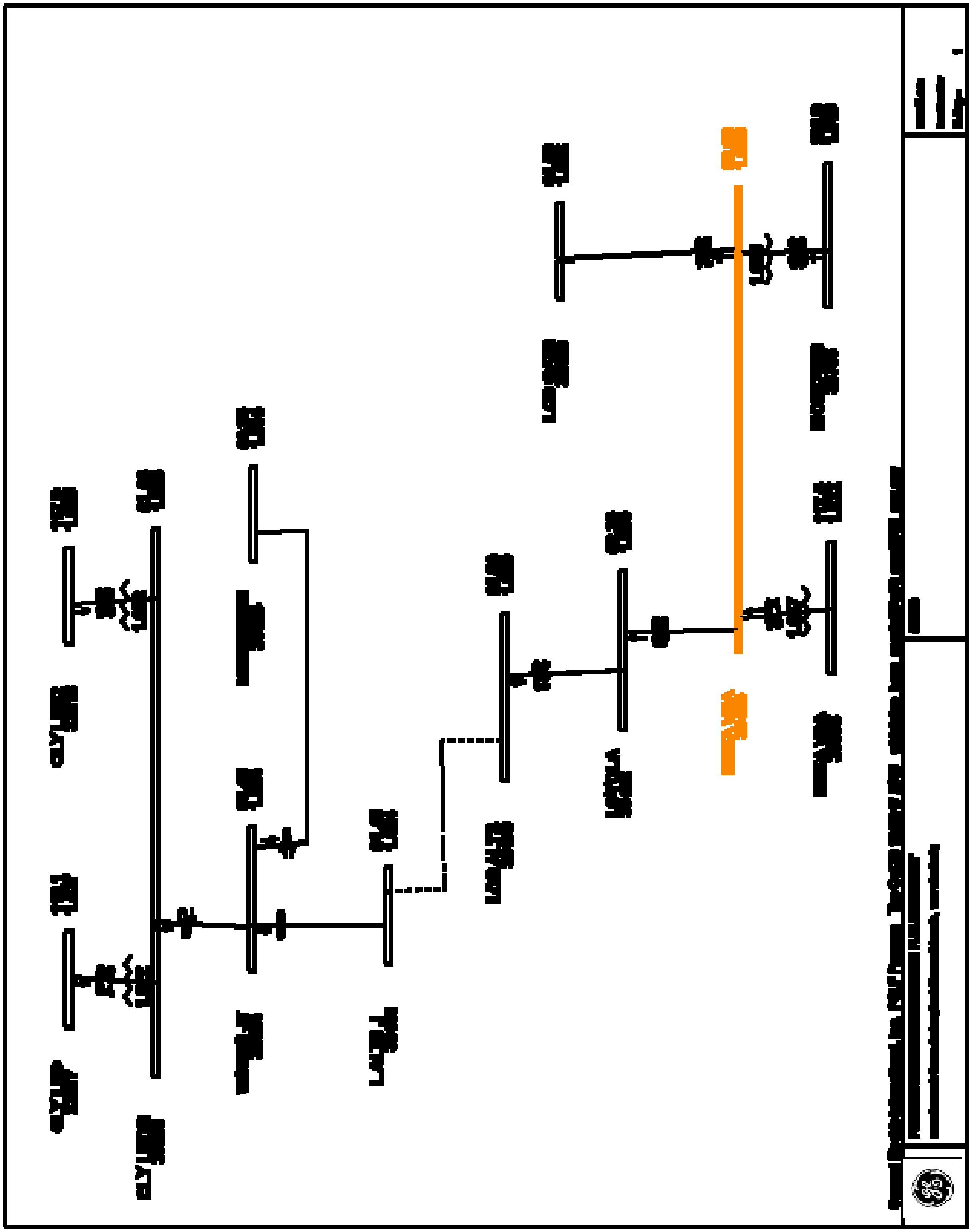


Figure 4-274: All Facilities in service, Year 2013 (Post-Project)

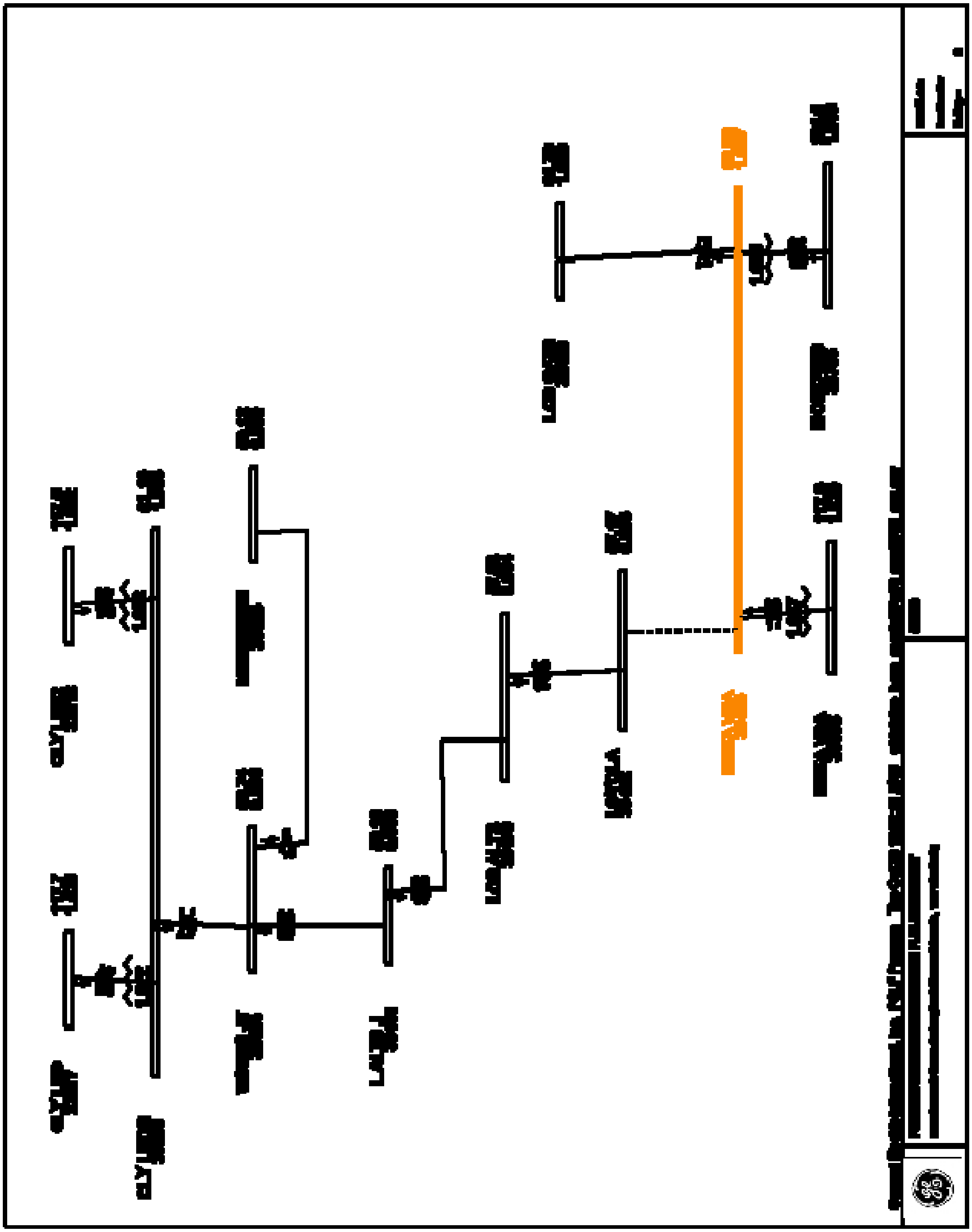


Figure 4-275: Outage of Monta Vista-Loyola 60kV Line section, Year 2013, (Post-Project)

San Mateo – Bair 60 kV Line Reconductor

TARGETED IN-SERVICE DATE

May 2013

PURPOSE AND BENEFIT

Reliability – NERC Compliance

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROJECT

The project scope is to reconductor the San Mateo-Bair 60 kV line (approximately 11 miles) with a conductor rated to handle a minimum of 1,100 Amps under summer normal and summer emergency conditions. In necessary, the project scope may also include the upgrade of associated line terminal equipment to accommodate the higher rating. In addition, environmental and land permits may be required to complete the reconductoring work.

This project is expected to cost between $5M and $10M.

BACKGROUND

The San Mateo and Bair 60 kV substations, located in San Mateo County serve the Oracle and San Carlos substations and the surrounding areas. An outage of the Bair-San Carlos 60 kV line section could overload the San Mateo-Oracle 60 kV line section. Also, an outage of the San Mateo-Oracle 60 kV line section could overload the Bair-San Carlos 60 kV line section. In 2007, the recorded peak electric demand for San Carlos was approximately 40 MW. Load in this area is forecast to increase at a rate of 1.1% per year.

The San Mateo - Bair 60 kV Line is approximately 10 miles long, and consists of mainly 4/0 cu conductor. The line is currently rated at 495 Amps normal and 557 Amps emergency. This project would increase this line’s capability to 1144 Amps normal and emergency.

Planning analysis has identified that the San Mateo – Oracle and Bair-San Carlos 60 kV Line sections are projected to overload following an outage of either of these line sections, on the San Mateo-Bair 60 kV Line.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended. This alternative does not address the potential overload issue.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2014

KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – TBD
- Special Metering or Protection – TBD
- Common Mode Exposure Items – TBD
- Interaction with other Projects – TBD

GEPSLF MODELLING INFORMATION

```
# RECONDUCTOR SAN MATEO-BAIR 60 kV LINE
# WITH 477 ACSS CONDUCTOR
#
OLDSECDD 33357, 33364, CKT=1, SEC=1, RPU=0.03457, XPU=0.12341, BPU=0.001254, +
MVA1=119 MVA2=119, MVA3=128, MVA4=128
OLDSECDD 33364, 33365, CKT=1, SEC=1, RPU=0.01728, XPU=0.06170, BPU=0.000627, +
MVA1=119 MVA2=119, MVA3=128, MVA4=128
OLDSECDD 33365, 33367, CKT=1, SEC=1, RPU=0.01152, XPU=0.04114, BPU=0.000418, +
MVA1=119 MVA2=119, MVA3=128, MVA4=128
#
#END
```

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagram
2. Power Flow Summary
3. Pre and Post Project Power Flow Plots

Attachment 1: Scope Diagram

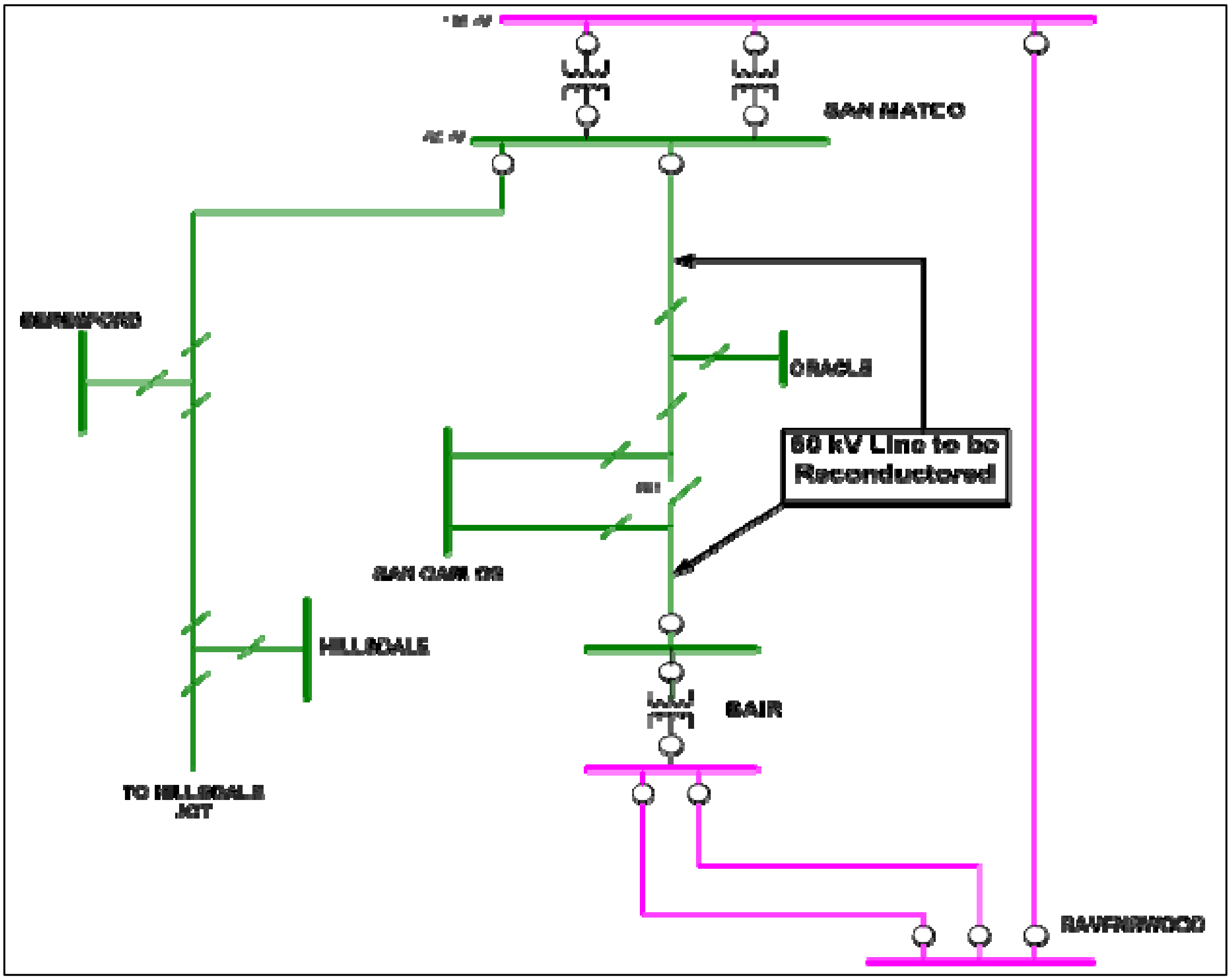


Figure 4-276: Scope Diagram

Attachment 2: Power Flow Summary

Table 4-74: Power Flow Summary

Normal/Contingency	Facility Affected	2009 Pre-Project	2010 Pre-Project	2011 Pre-Project	2012 Pre-Project	2013 Pre-Project	2014 Pre-Project	2014 Post-Project
Normal Conditions	San Mateo-Oracle 60 kV	62%	64%	64%	64%	65%	66%	28%
Bair-San Carlos 60 kV Line		96%	96%	97%	98%	100%	101%	49%
Normal Conditions	Bair-San Carlos 60 kV Line	47%	46%	47%	47%	48%	48%	21%
San Mateo-Oracle 60 kV		93%	94%	94%	95%	97%	98%	48%

Attachment 3: Pre and Post Project Power Flow Plots

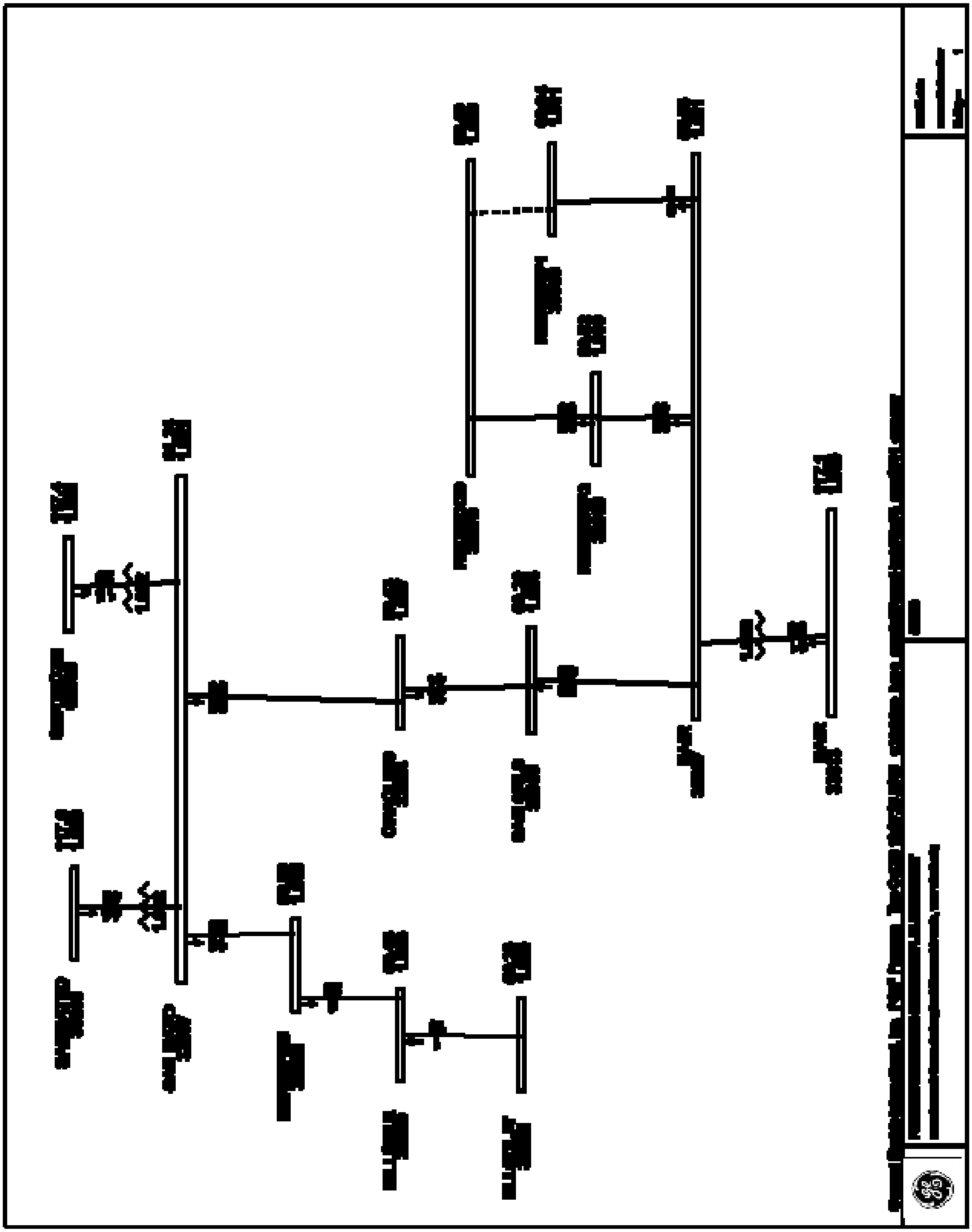


Figure 4-277: All Facilities in service, Year 2014 (Pre-Project)

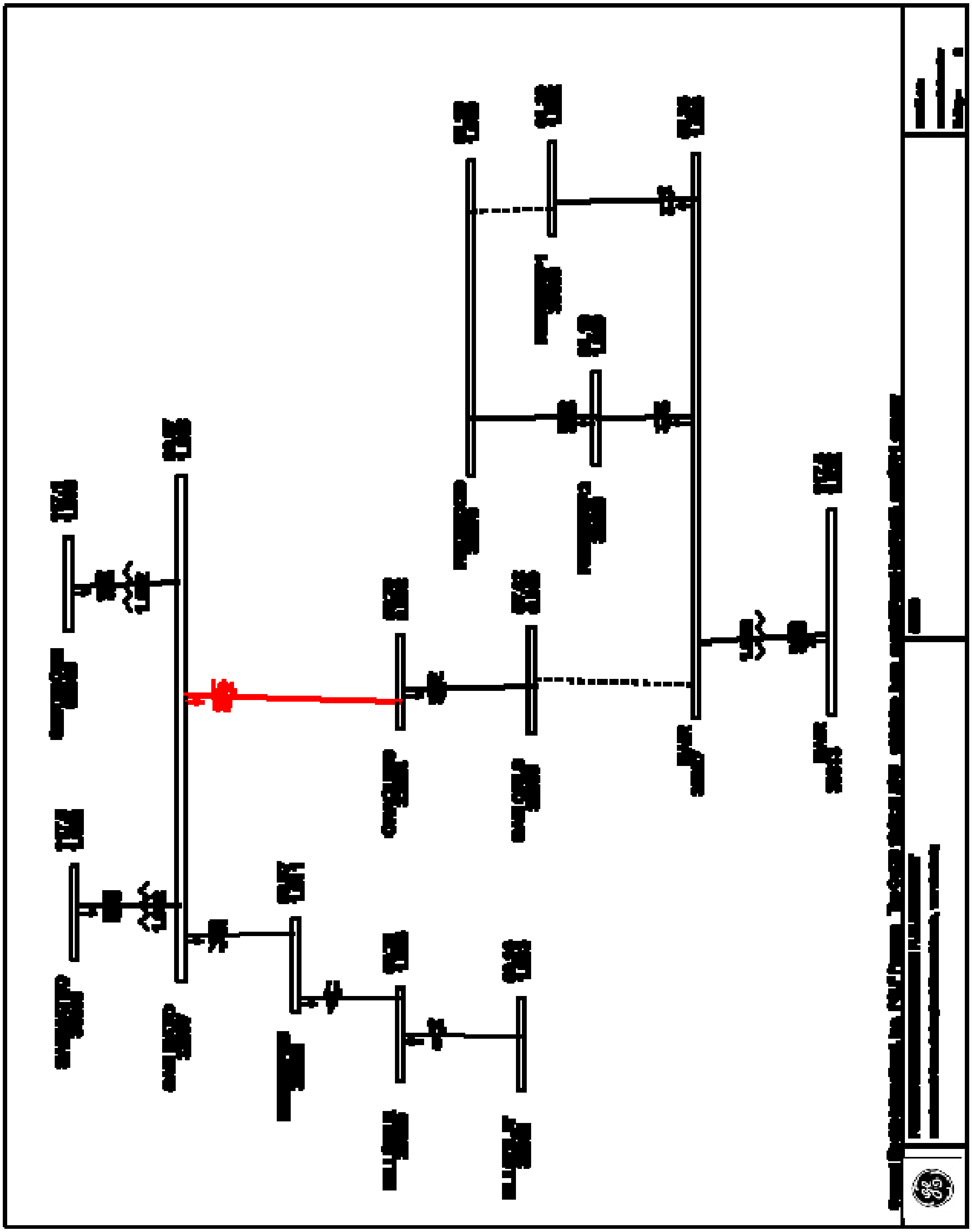


Figure 4-278: Outage of Bair-San Carlos 60 kV Line section, Year 2014 (Pre-Project)

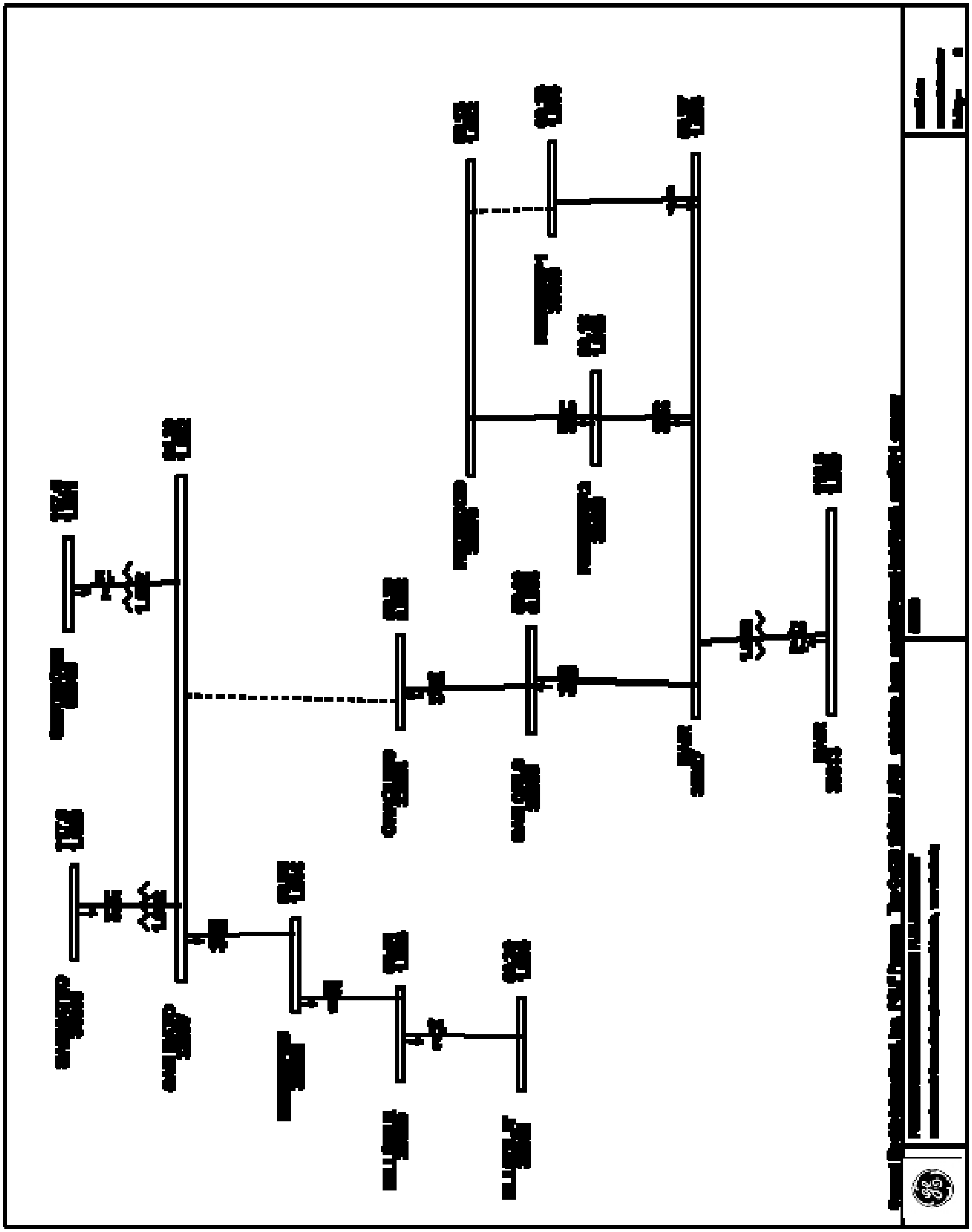


Figure 4-279: Outage of San Mateo-Oracle 60 kV Line section, Year 2014 (Pre-Project)

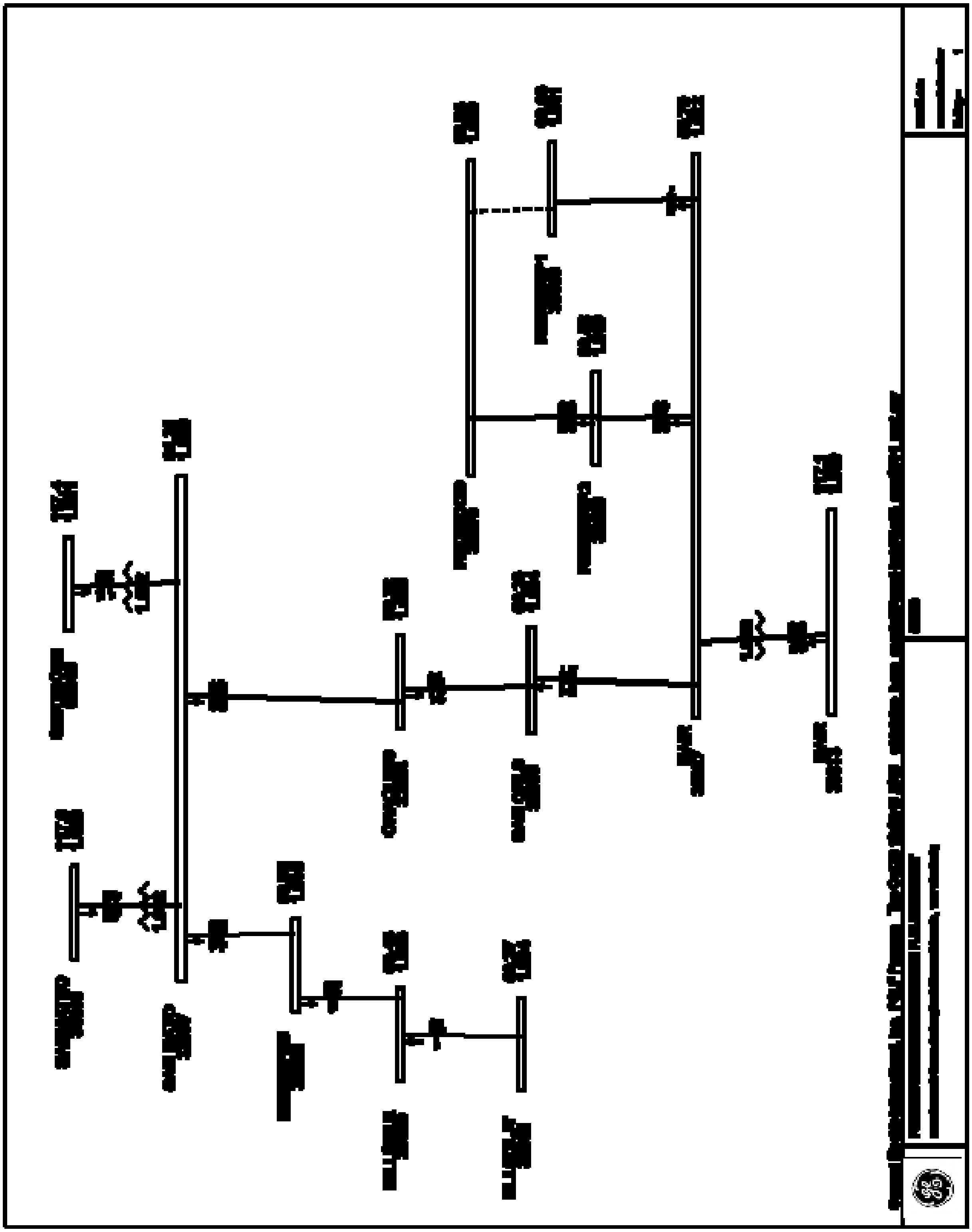


Figure 4-280: All Facilities in service, Year 2014 (Post-Project)

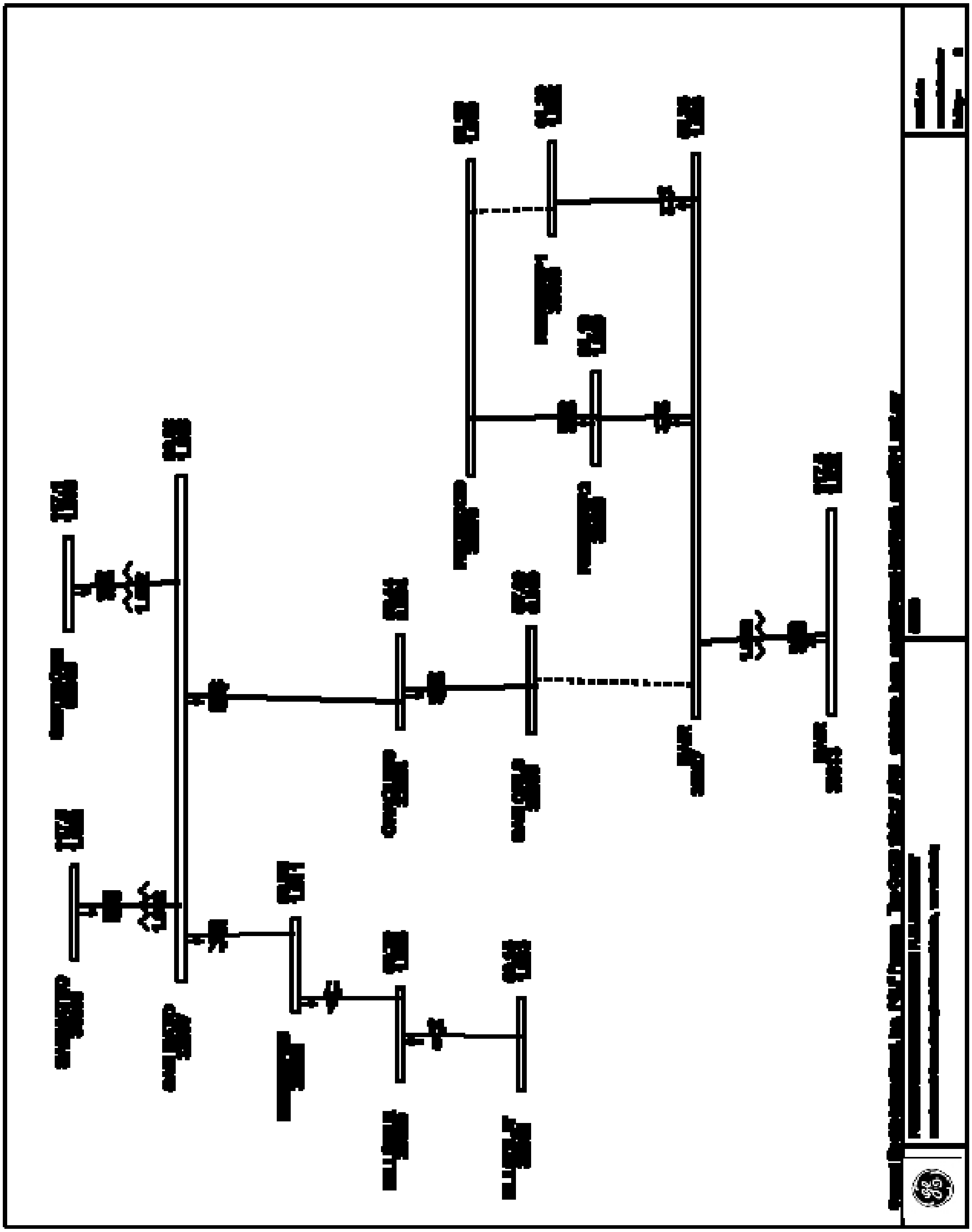


Figure 4-281: Outage of Bair-San Carlos 60 kV Line section, Year 2014 (Post-Project)

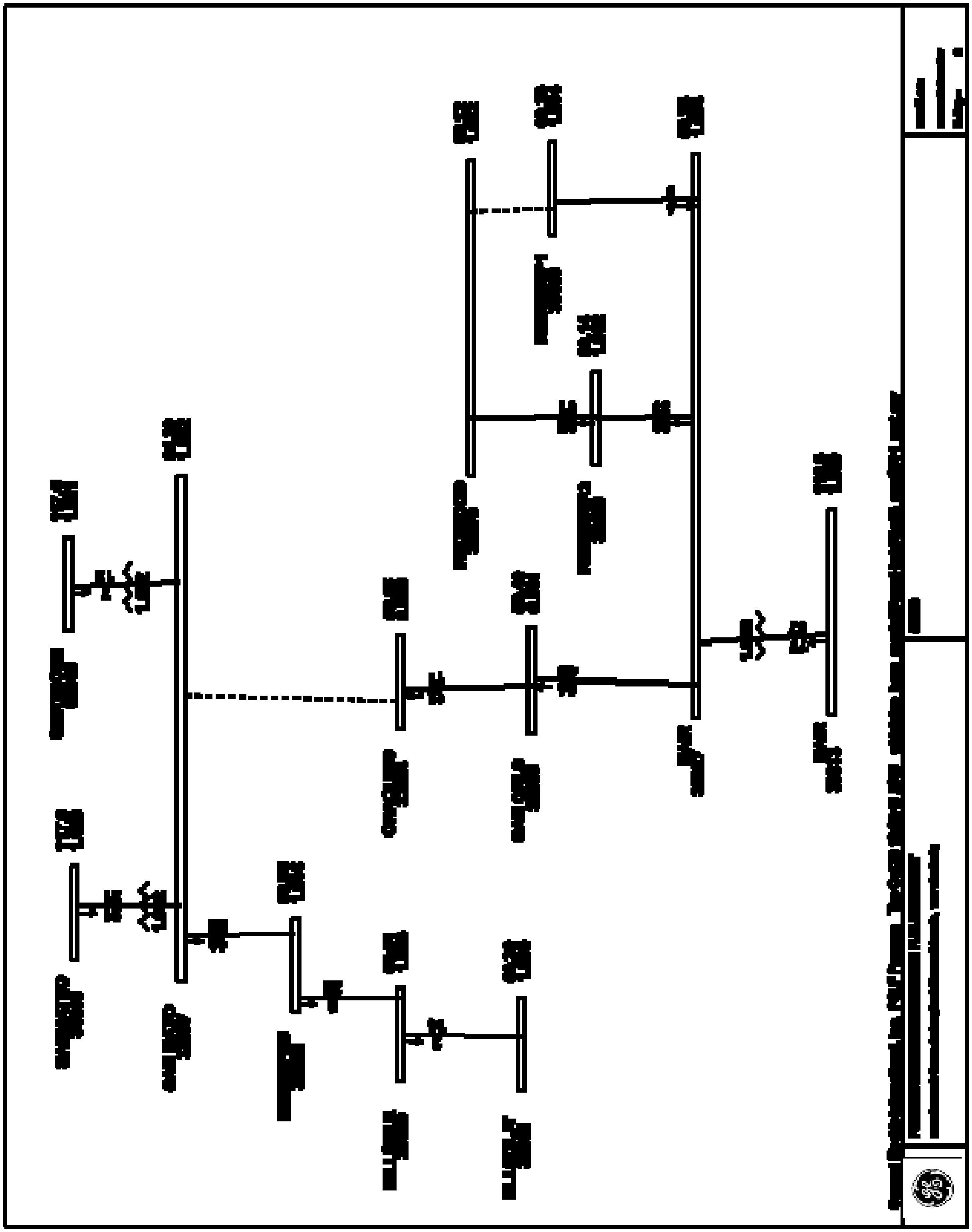


Figure 4-282: Outage of San Mateo-Oracle 60 kV Line section, Year 2014 (Post-Project)

Fulton – Fitch Mountain 60 kV Line Reconductor

TARGETED IN-SERVICE DATE

May 2013

PURPOSE AND BENEFIT

Reliability – NERC Compliance

PROJECT CLASSIFICATION

This is an existing project.

DESCRIPTION AND SCOPE OF PROJECT

The project scope is to reconductor an 8-mile section on the Fulton-Hopland 60 kV Line with a conductor rated to handle a minimum of 631 Amps under summer normal conditions and 742 Amps under summer emergency conditions. If necessary, associated line terminal equipment would be upgraded. In addition, the project scope would require obtaining any necessary environmental and land permits to complete the reconductoring work.

This project is expected to cost between $3M and $5M.

BACKGROUND

The Fulton-Hopland and Fulton No. 1 60 kV Lines, located in Sonoma County, are the two lines that serve electric customers in Healdsburg and Geyserville communities. The substations served by these transmission lines are Fitch Mountain, Geyserville and the City of Healdsburg's Badger Substation. The combined local area demand is projected to reach about 55 MW in 2009 and is expected to increase at 1 MW per year.

With the existing configuration, Geyserville Substation and the City of Healdsburg are served from the Fulton No. 1 60 kV Line and Fitch Mountain Substation is served from the Fulton-Hopland Line during the normal operating conditions. During an outage of the primary source, the City of Healdsburg and Fitch Mountain Substations are automatically transferred to the alternate source. However, Geyserville Substation is not transferred to the alternate source due to the potential thermal overload of the Fulton-Hopland 60 kV Line.

Planning analysis concluded that the Fulton-Hopland 60 kV Line could potentially overload up to 6% above its rerated summer emergency rating, for an outage of the Fulton No.1 60 kV Line during peak loading conditions in 2018. Transferring Geyserville to the Fulton-Hopland Line under these conditions could overload this line up to 4% above its rerated summer emergency rating in 2009.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended. This alternative does not address the capacity deficiency of the Fulton-Hopland 60 kV Line.

Alternative 2: Voltage Conversion

This alternative involves converting about 25 miles of 60 kV lines and Fitch Mountain, Geyserville and the City of Healdsburg's Badger Substations to115 kV.

This alternative would also require some line reconductoring and bus work at Fulton and Cloverdale 115 kV buses to terminate the new 115 kV line.

This alternative is not preferred to address the potential thermal overload of the Fulton-Hopland Line because of the higher cost and extensive time required to implement the station conversions.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2013

KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – TBD
- Special Metering or Protection – TBD
- Common Mode Exposure Items – None
- Interaction with other Projects or Studies – TBD

GEPSLF MODELING INFORMATION

```
#*********************************************************************
# Fulton-Hopland 60 kV Line Reconductor
# Description:  This project will reconductor the limiting 8-mile section of the Fulton-Hopland 60 kV Line.
#**************************************************************************
#
# Reconductor the Fulton-Fitch Mountain Tap section with 715 Al conductor.
OLDSECDD  31378, 31382, CKT=1, SEC=1, RPU=0.04042 XPU=0.20234 BPU=0.00214 +
MVA1=66 MVA2=77 MVA3=101 MVA4=108
#END
```

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagram
2. Demand Forecast
3. Power Flow Summary
4. Pre and Post Project Power Flow Plots

Attachment 1: Scope Diagram

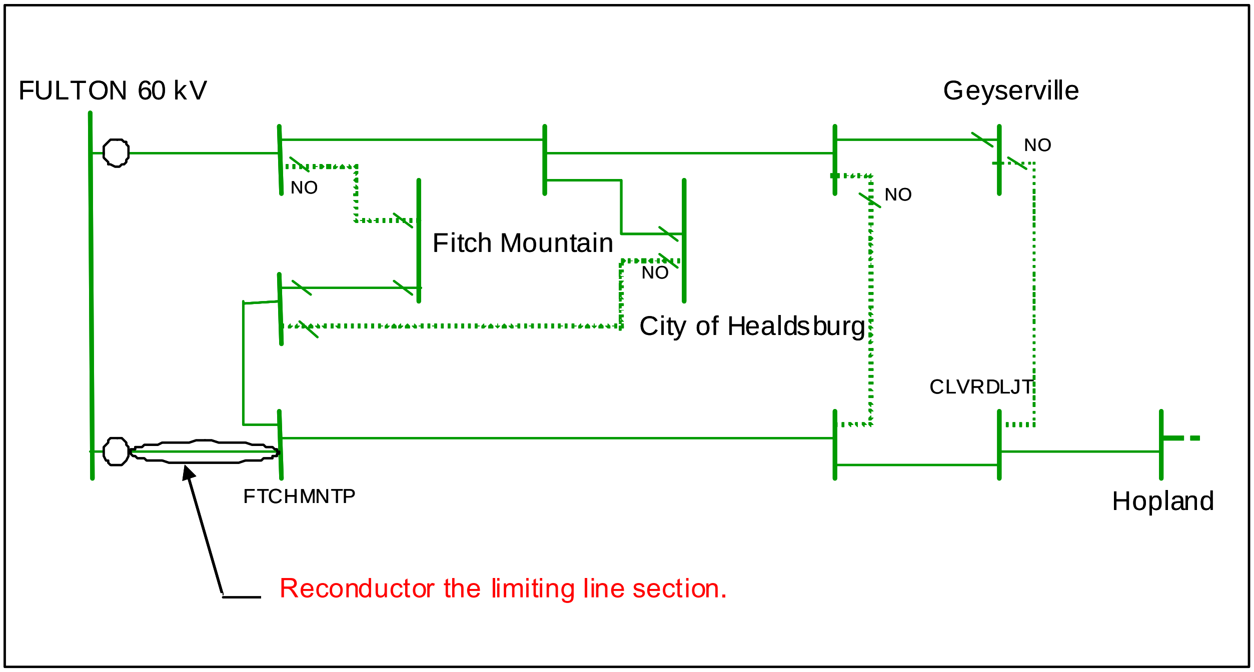


Figure 4-283: Healdsburg - Geyserville 60 kV System.

Attachment 2: Demand Forecast

Table 4-75: Area Demand Forecast

Substation	2009	2010	2011	2012	2013	Growth Rate (MW/Year)
Fitch Mountain	19.2	19.6	20.1	20.6	21.0	0.5
City of Healdsburg	21.7	22.1	22.5	22.5	22.5	0.1
Geyserville	13.9	14.3	14.7	15.1	15.4	0.4
Total	**55**	**56**	**57**	**58**	**59**	**1.0**

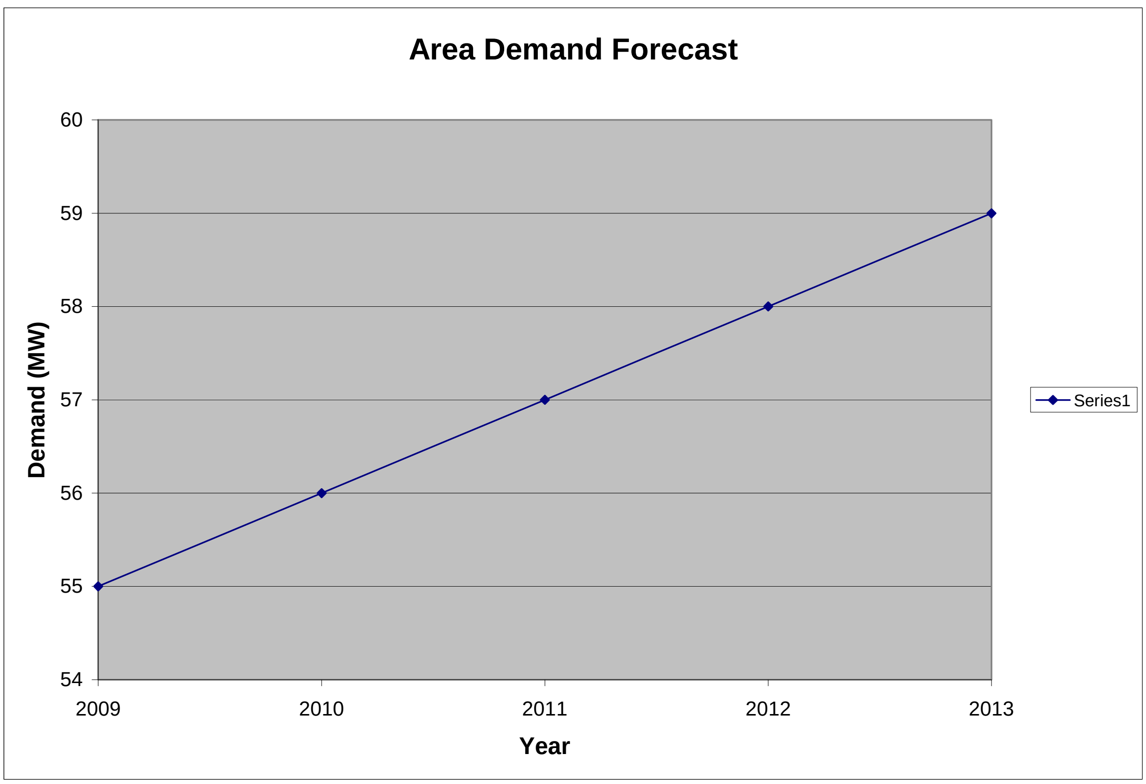


Figure 4-284: Plot of Area Forecast

Attachment 3: Power Flow Summary

Table 4-76: Power Flow Summary

Contingency	Facility Affected	2009 (Pre-Project)	2010 (Pre-Project)	2011 (Pre-Project)	2012 (Pre-Project)	2013 (Pre-Project)	2018 (Pre-Project)	2018 (Post-Project)
Fulton No. 1 60 kV Line	Fulton-Hopland 60 kV Line	95%	89%	92%	93%	95%	106%	55%

Attachment 4: Pre and Post Project Power Flow Plots

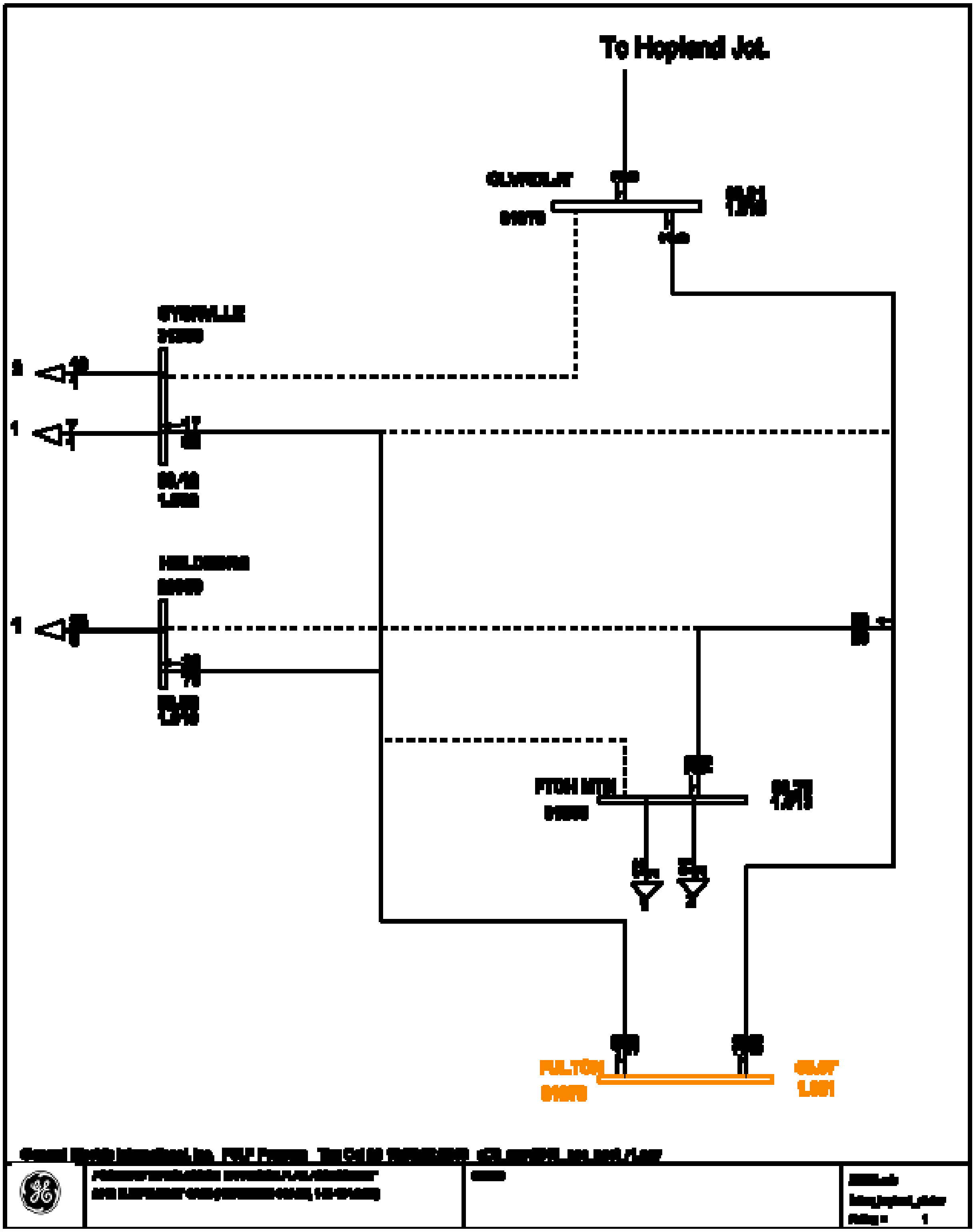


Figure 4-285: Pre Project - Normal Conditions (2018)

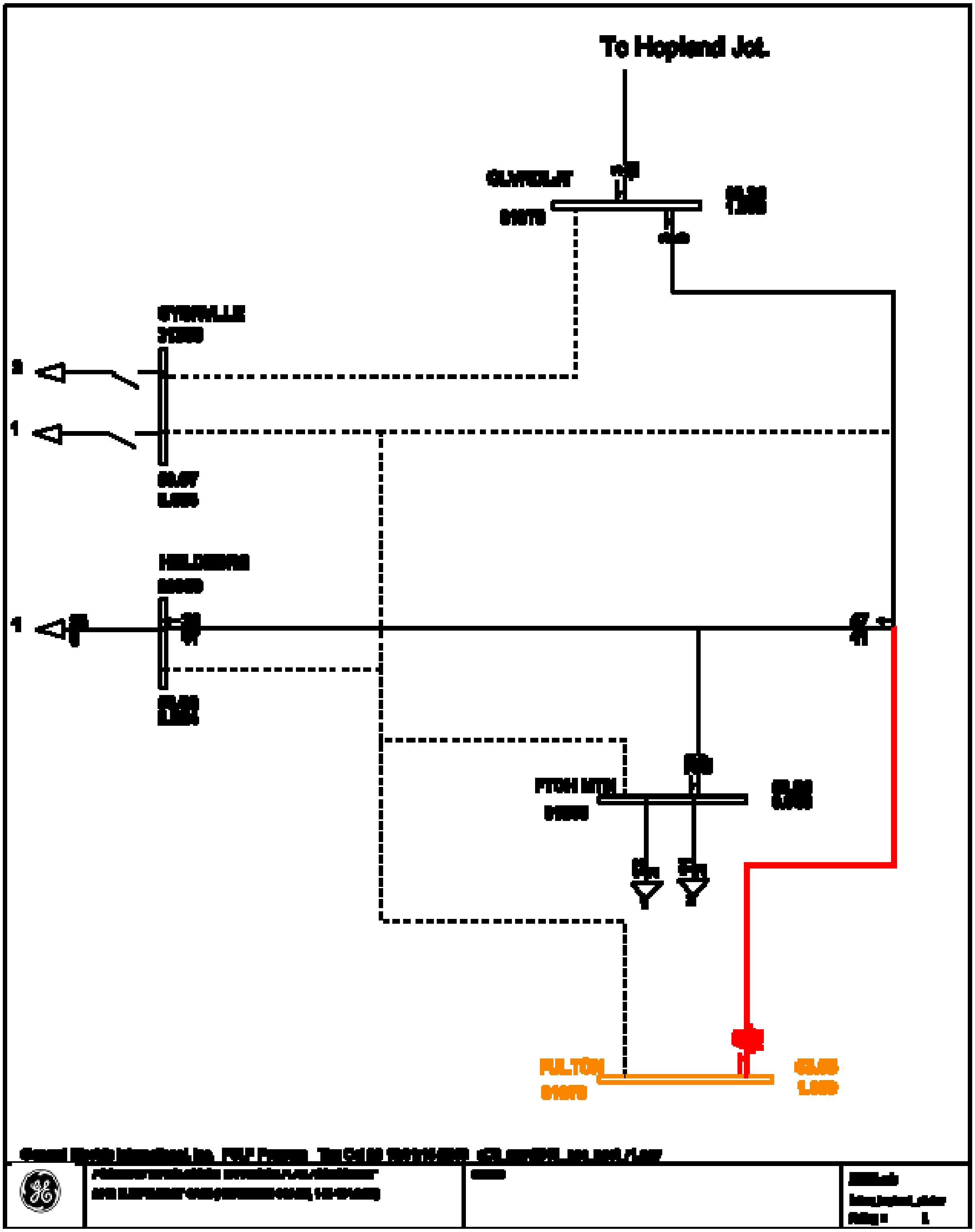


Figure 4-286: Pre Project - Loss of the Fulton No. 1 60 kV Line overlapped with Geyser 11 (L-1/G-1). (2018)

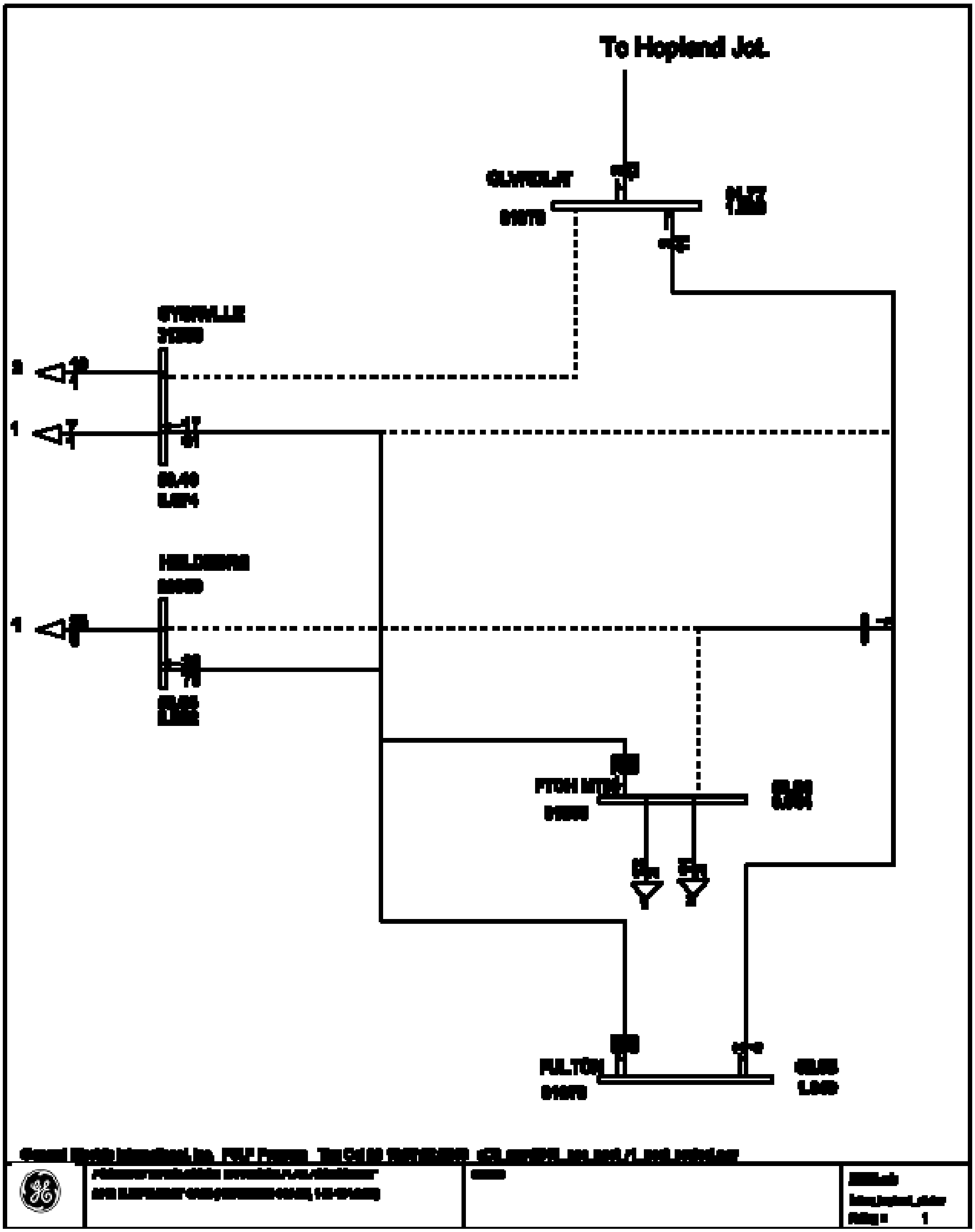


Figure 4-287: Post Project - Normal Conditions (2018)

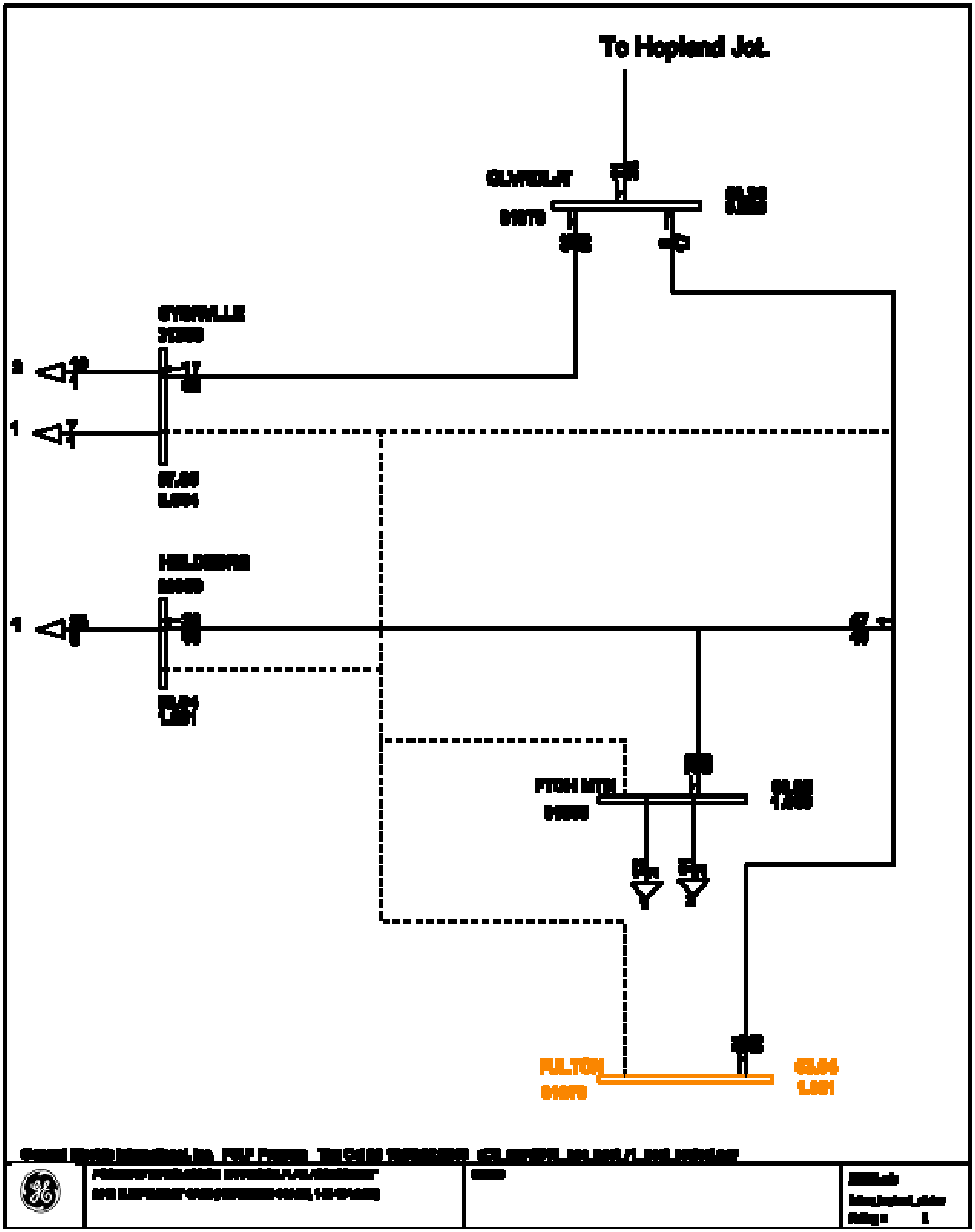


Figure 4-288: Post Project - Loss of the Fulton No. 1 60 kV Line overlapped with Geyser 11 (L-1/G-1). (Geyserville transferred to Fulton-Hopland line) (2018)

Glenn No.1 60 kV Line Reconductor

TARGETED IN-SERVICE DATE

May 2013

PURPOSE AND BENEFIT

Reliability – NERC Compliance

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROPOSED PROJECT

The scope is to reconductor the limiting section (5.5 miles) of the Glenn 60 kV Line No.1 between Glenn and Orland B Junction with a larger conductor rated to handle a minimum of 740 Amps under summer emergency conditions.

This project is expected to cost between $6M and $8M.

BACKGROUND

PG&E's Glenn Substation is located in the Glenn County of North Valley division and is connected to the transmission grid via two 230 kV lines and five 60 kV lines. Glenn Substation with its two 230/60 kV transformer banks is a key facility in serving the electric customers in Glenn County. Major communities in this region include Orland, Willows, Elk Creek, Hamilton, Corning, among others.

Peak electric demand for the substations normally served by Glenn 60 kV Line No.1 was recorded at 36 MW in 2007 and is expected to grow at 0.81 MW or 2.3% per year. Most of the load is resided at the Orland B substation. Peak demand for this substation is forecasted to grow at about 0.45 MW or 1.8 % per year.

The Glenn to Orland B section of Glenn 60 kV Line No.1 is capable of carrying up to 336 amps during normal and 386 amps during emergency conditions. These ratings reflect an increase in wind speed assumptions (4 feet per second wind speed ratings).

With the rerate in place, planning studies have identified that the loss of the Glenn 60 kV Line No.5 is projected to overload the Glenn to Orland B section of the Glenn 60 kV Line No.1 by 2% in 2013.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended because it does not address the potential overload issue on the Glenn 60 kV Line No.1.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2013

KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – TBD
- Special Metering or Protection - TBD
- Common Mode Exposure Items – None
- Interaction with other Projects or Studies – None

GEPSLF MODELING INFORMATION

```
#ASPEN base:    RPU=0.004042    XPU=0.020234    BPU=0.000214 (715-37 AAC)
#
#Glenn 60 kV Line No.1, 5.5 miles
OLDSECDD 31722, 31725, CKT=1 SEC=1 RPU=0.02223 XPU=0.11129 BPU=0.00118 +
MVA1=66 MVA2=77 MVA3=73 MVA4=83
```

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagram
2. Demand Forecast
3. Power Flow Summary
4. Pre and Post Project Power Flow Plots

Attachment 1: Scope Diagrams

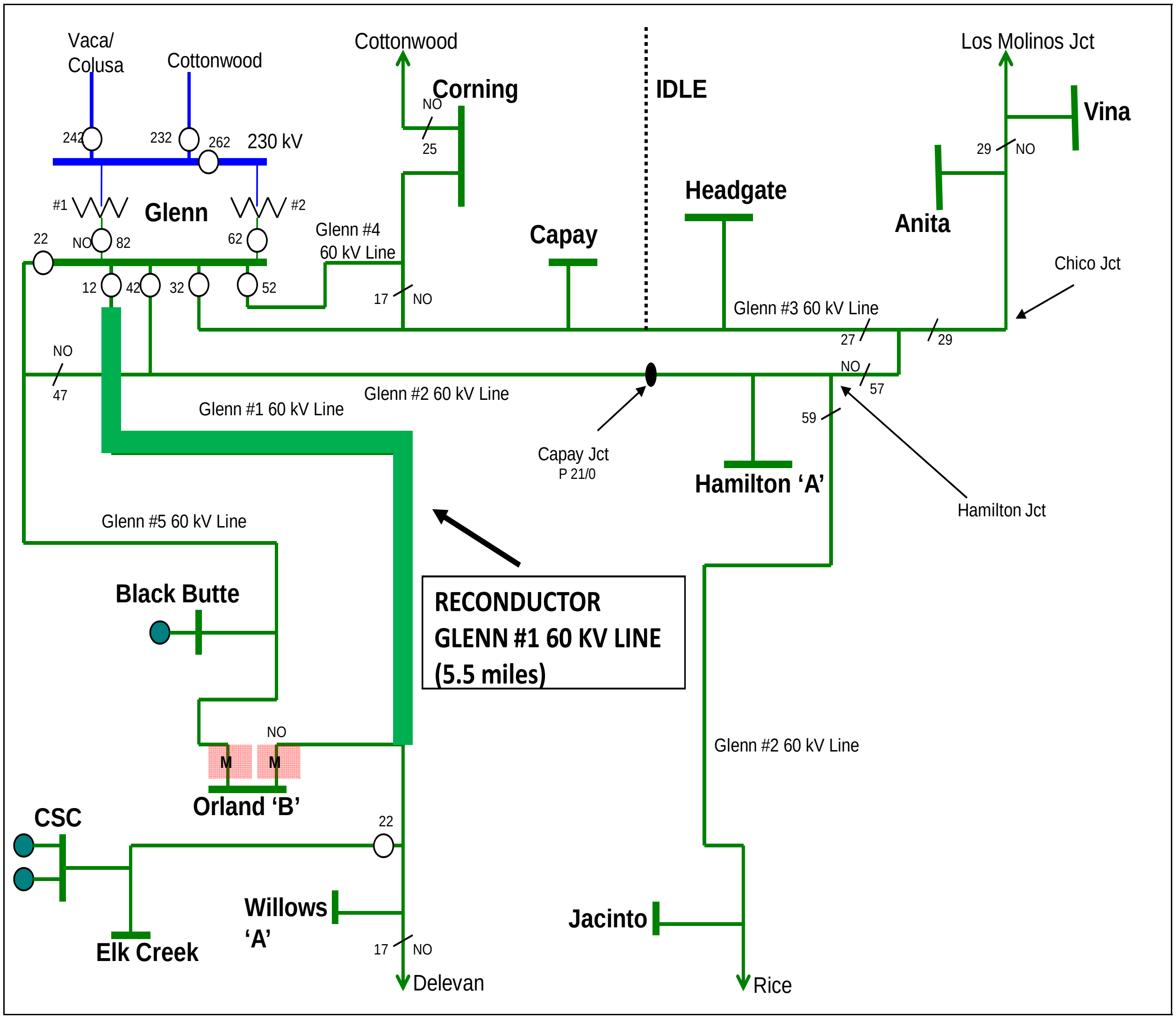


Figure 4-289: Scope Diagram

Attachment 2: Demand Forecast

Table 4-77: Area Demand Forecast

Substation	2009	2010	2011	2012	2013	Growth Rate (MW/Year)
Orland Bank 1	11	11.22	11.46	11.64	11.82	0.19
Orland Bank 2	14.37	14.65	14.96	15.2	15.44	0.25
Elk Creek Bank 1	2.61	2.71	2.81	2.91	3.01	0.1
Willows Bank 1	14.15	14.43	14.75	14.99	15.24	0.26
Totals	**42.13**	**43.01**	**43.98**	**44.74**	**45.51**	**0.81**

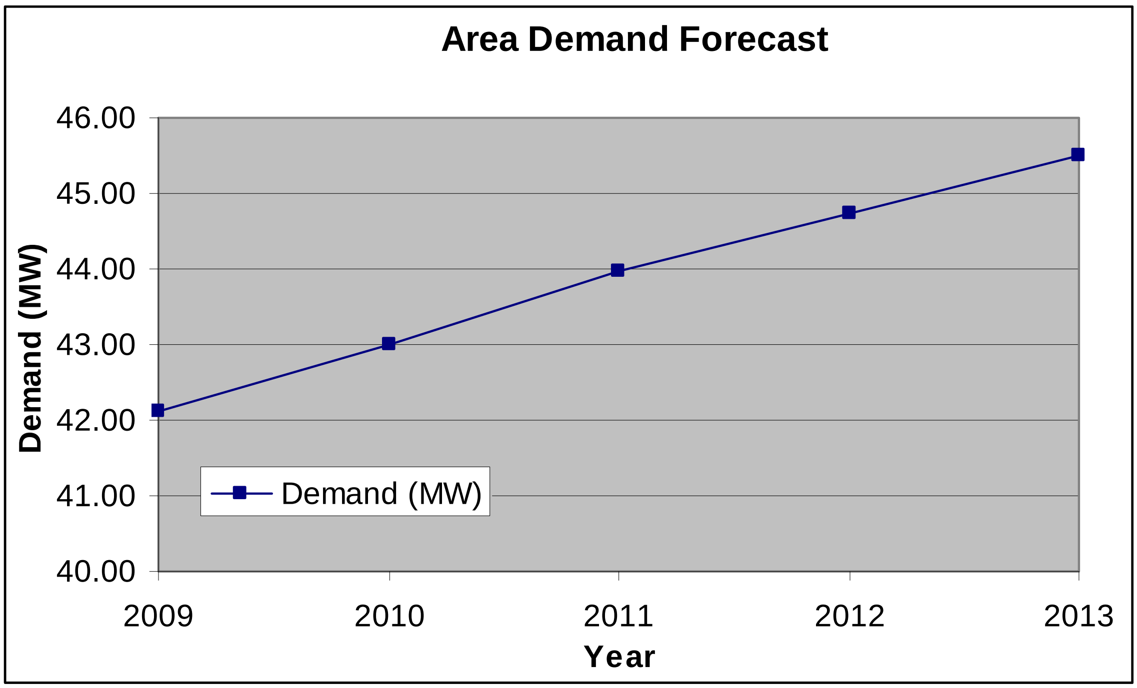


Figure 4-290: Plot of Demand Forecast

Attachment 3: Power Flow Summary

Table 4-78: Power Flow Summary

Contingency	Facility Affected	2009 (Pre-Project)	2010 (Pre-Project)	2011 (Pre-Project)	2012 (Pre-Project)	2013 (Pre-Project)	2013 (Post-Project)
Glenn 60 kV Line No.5 (L-1)	Glenn 60 kV Line No.1 (Glenn - Orland B Jct section)	96%	97%	99%	100%	102%	51%
Glenn 60 kV Line No.5 (L-1)	Glenn 60 kV Line No.1 (Orland B Jct - Elk creek Jct section)	45%	46%	47%	48%	48%	47%

Attachment 4: Pre and Post Project Power Flow Plots

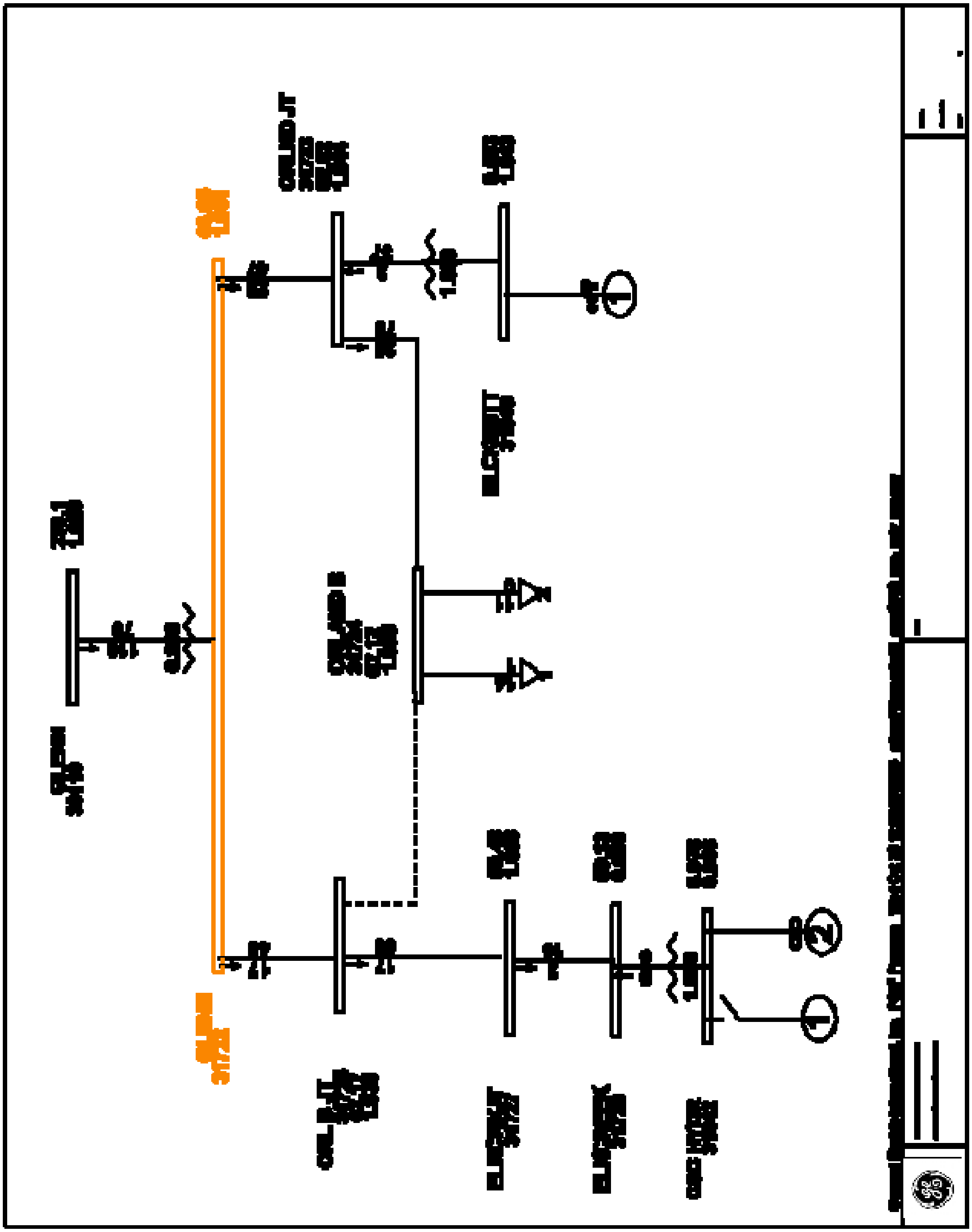


Figure 4-291: Pre Project - Normal Conditions

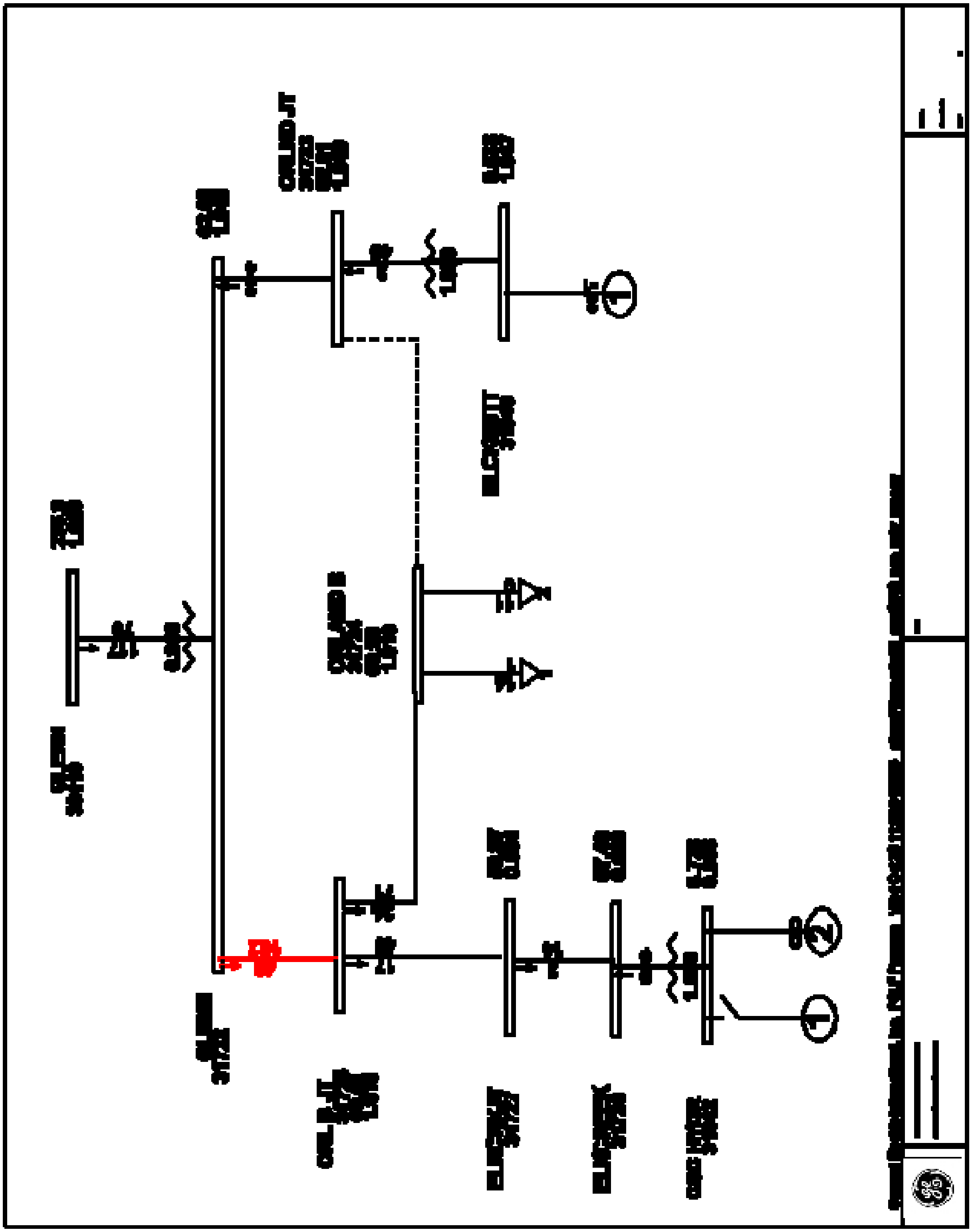


Figure 4-292: Pre Project - Loss of Glenn 60 kV Line No.5 (L-1)

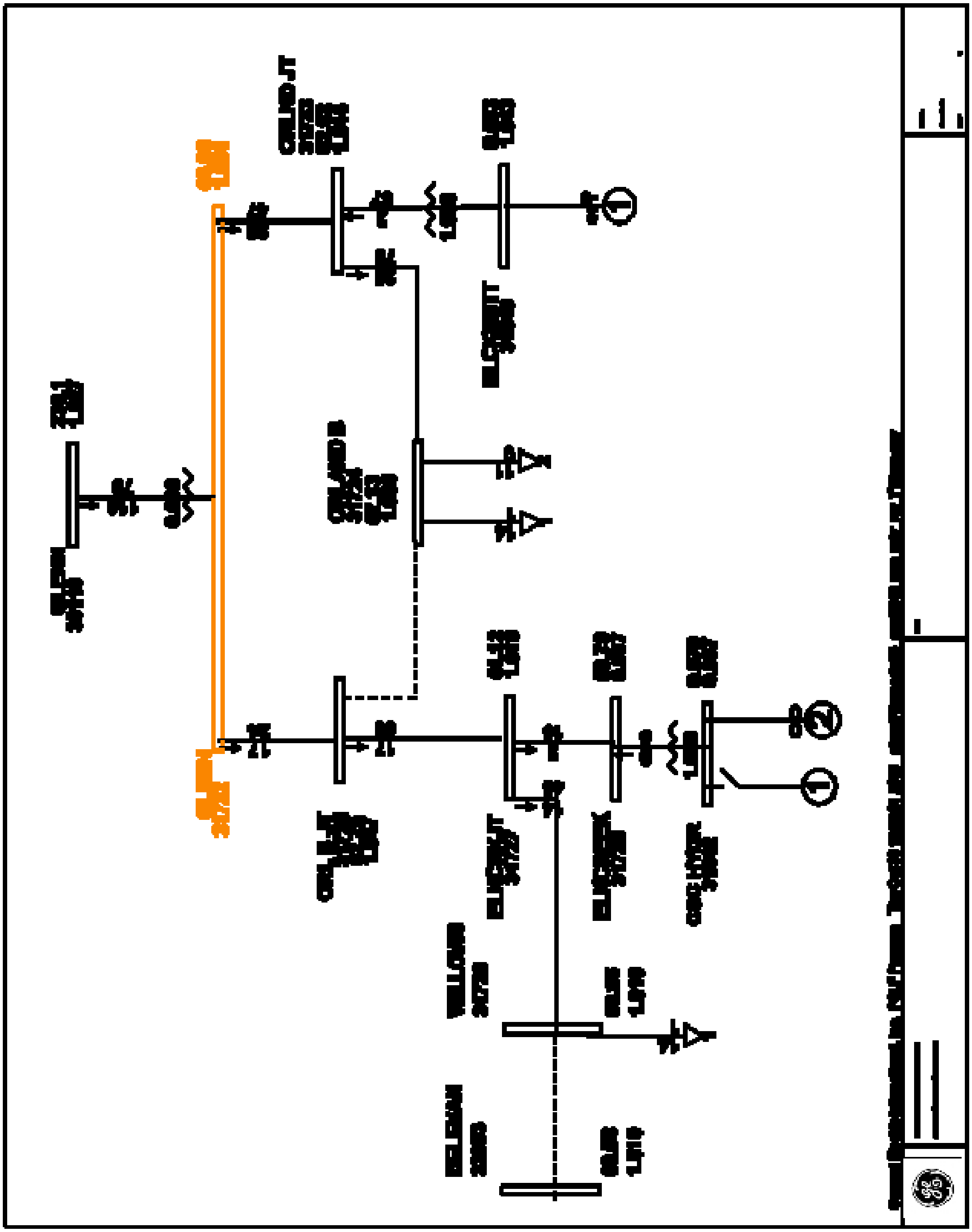


Figure 4-293: Post Project - Normal Conditions

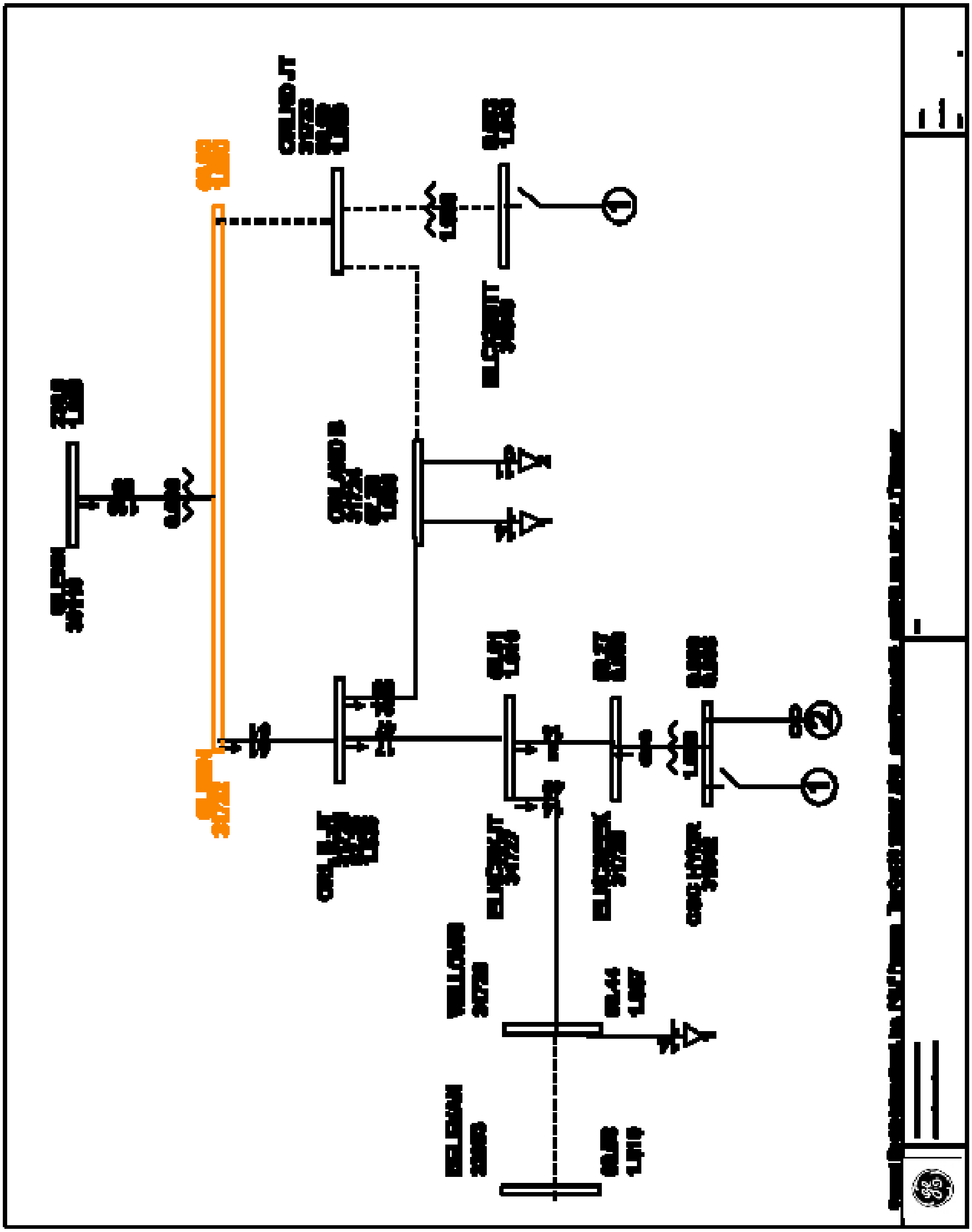


Figure 4-294: Post Project - Loss of Glenn 60 kV Line No.5 (L-1)

CHAPTER 5

Table of Contents

2012 Projects

Embarcadero-Potrero 230 kV Transmission

IN-SERVICE DATE

May 2012

PURPOSE AND BENEFIT

Reliability – NERC Compliance and Operational Flexibility. This project will increase the reliability of San Francisco's 230 kV system by installing a third 230 kV feed into Embarcadero Substation. Completion of this project would avoid potential electric load interruptions for the San Francisco downtown area following an N-1-1 or N-2 contingency condition.

Furthermore, this project will also increase the overall load serving capability for the San Francisco transmission system.

The Embarcadero-Potrero 230 kV Transmission Project is part of PG&E's plan and commitment to Mayor Newsom made in June 2008. PG&E believes that with the completion of the Embarcadero-Potrero 230 kV Transmission Project, along with other transmission projects that will be completed within the next few years, the electric transmission system can reliably meet long-term power demands in San Francisco while reducing its reliance on fossil-fuel fired generation within the City.

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROJECT

This project proposes to construct a new 230 kV line between Embarcadero and Potrero P.P. substations. This new line will be rated to handle a minimum of 1050 Amps for summer normal and summer emergency conditions. A new 230 kV circuit breaker, rated to handle a minimum of 1050 Amps, will be installed at Embarcadero. At Potrero, the 230 kV line will be terminated at the new 230 kV bus, and a new 230/115 kV transformer, rated to handle 420 MVA, will be installed to connect the 230 kV bus with the 115 kV buses.

This project is expected to cost between $130M and $150M.

BACKGROUND

Peak electric demand in the City of San Francisco (the City) is approximately 965 MW, with an expected growth rate of 10 MW per year. Mirant California's Potrero Power Plant, which has a maximum plant output of approximately less than 370 MW, is the only generation facility within the City. By 2010, Mirant California will be retiring Potrero Unit 3, which will reduce the maximum plant out to approximately 150 MW[1]. Thus, the majority of the City's power needs are satisfied by importing power from Martin Substation.

Specifically, power imported from Martin Substation is delivered to distribution substations within the City by separate 230 kV and 115 kV systems. For the 230 kV system, there are two 230 kV underground cables, which are each seven miles long, that import 230 kV power into the City from Martin Substation. Specifically, this 230 kV power is imported through the Martin-Embarcadero 230 kV underground cables (HZ cable Nos. 1 and 2) to serve Embarcadero Substation. These underground cables were installed in 1974 and each have a capability of 1,050 Amps (418 MVA). Current peak demand at Embarcadero Substation is over 260 MW with a projected annual growth rate of about 1%. Embarcadero Substation is a critical substation for the City since it supplies a large portion of the San Francisco downtown area.

For the 115 kV system, there are five 115 kV underground cables that import power into the City from Martin Substation. These cables were installed more than 30 years ago, with the oldest sections being almost 60 years old. Four of the cables are planned to be replaced under a maintenance replacement project. A peak demand of about 618 MW was recorded on the internal 115 kV system earlier this year. The internal 115 kV system is projected to increase annually by 6 MW per year.

Over the next two years there are planned projects that will improve the reliability of the San Francisco internal 115 kV system. These projects are:

- Larkin Circuit Breaker No. 192. This project proposes to upgrade protection equipment at Larkin Substation to normally close circuit breaker number 192. Closing in circuit breaker 192 will increase operational flexibility for the City and can potential reduce generation requirements for maintenance of the 115 kV internal system.
- Construction of a third Martin-Hunters Point 115 kV Underground Cable. This project is currently under construction and has planned completion date of April 2009.
- Trans Bay Cable (TBC) HVDC Project. This project, which is being constructed by Babcock & Brown, will deliver up to 400 MW of power from

---

[1] Potrero Generating Plant Units 4, 5, and 6 will be retrofitted to run on natural gas, and that the retrofit and operation costs of these units would be recovered under the terms of a Reliability Must Run (RMR) contract.

Pittsburg to Potrero substations. The TBC Project is expected to be operational in Spring 2010.

As previously mentioned, Embarcadero Substation is fed by two 230 kV cables. The underlying distribution connections to substations fed by the 115 kV system can only pick up approximately 10 MW of load from the 230 kV system. Therefore, loss of both 230 kV cables supplying Embarcadero Substation will result in the curtailment of approximately 250 MW of San Francisco downtown load. This potential load curtailment is expected to increase in magnitude in the future. Service to this critical load will only be restored after one cable is returned to service. This severely restricts maintenance clearances on the 230 kV system, and it puts a large block of load at risk every time a cable is cleared for maintenance. This will be a significant issue in the future when these cables need to be replaced.

STUDY CRITERIA

CAISO grid planning criteria

BASE CASE ASSUMPTIONS

This project was analyzed utilizing the approved basecases for the Greater Bay Area system, which was developed under the CAISO's Transmission Planning Process (TPP). Specifically, the San Francisco peak load modeling was based on the approved load forecasts provided in the current year CAISO TPP. This study assumed the following planned transmission and generation assumptions for the San Francisco system:

- Martin-Hunters Point 115 kV Underground Cable Project in-service
- Larkin Circuit Breaker 192 Project in-service
- San Francisco 115 kV Recabling Project in-service
- Trans Bay Cable HVDC Project in-service (retirement of Potrero Generating Unit 3)
- Mirant California's retrofit of Potrero Generating Unit Nos. 4, 5 and 6

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended because it does not address the potential loss of San Francisco load due to an N-1-1 or N-2 contingency of the Martin-Embarcadero 230 kV underground cables.

PROJECT SCHEDULE

- Environmental and Permitting Processes – CPCN Application filing by second half of 2009
- Design – Engineering design complete by first quarter 2011.
- Major Equipment – Cable procurement to start in 1st quarter 2011
- Construction – Construction schedule dependant on CPCN approval
- Operation Date – May 2012

KEY ISSUES

- Land-Use Restrictions and Environmental Concerns– This project will require a CPCN.
- Special Metering or Protection – None
- Common Mode Exposure Items – This project will address the N-1-1 and N-2 reliability issues associated with the Martin – Embarcadero 230 kV cables.
- Interaction with other Projects – Coupled with the retrofit of Mirant California's Potrero Generating Unit Nos. 4, 5 and 6, the total LSC for the San Francisco transmission system is expected to increase to approximately over 1,190 MW.

GEPSLF MODELING INFORMATION

```
#
# Construct a new 230 kV line from Embarcadero to Potrero substations
# Construct a new 230 kV bus at Potrero and install a 230/115 kV bank at Potrero.
#
# Model the conversion of Embarcadero 230 kV buses to BAAH (Maintenance Project)
#
# OLDSECDD  "FBUS=", "TOBUS=", "CKT=1", SEC=1, STATUS=, RPU=, XPU=, BPU=, MVA1=, MVA2=, MVA3=,
# MVA4=, MVA5=, MVA6=, MVA7=, MVA8=, OWN= "NCKT=" NSEC=, AREA=, ZONE=
 OLDSECDD   30685    30690      1       1      1
#
# Create a 230 kV bus at Potrero
#
# NEWBUSD   BUSNO, "NAME=",   BASKV=,     BUSTYPE=, VSCHED=1,   AREA=,  ZONE=,   VMAX=,    VMIN=,
 NEWBUSD   30698  "PTRRO230" BASKV=230   BUSTYPE=1 VSCHED=1.00 AREA=9  ZONE=309 VMAX=1.05 +
 VMIN=.95
# Create a 230 kV line from Embarcadero to Potrero. Use the parameters from the
#   existing 7-mile H-Z cables to model the new line. Assume a cable routing of
#   about 3.3 miles.  Underwater route would be shorter.
#
# NEWSECDD  "FBUS", "TOBUS", "CKT=1", SEC=1, RPU=,      XPU=,      BPU=,      MVA1=,     MVA2=,     MVA3=,
# MVA4=,      STATUS=1,
  NEWSECDD   30685   30698      1     SEC=1  RPU=.000311 XPU=.001641 BPU=.35625  MVA1=418.3 MVA2=418.3+
 MVA3=418.3 MVA4=418.3  STATUS=1
#
# Install a standard 420 MVA, 230/115 kV bank at Potrero
#
# NEW_TRAN   FBUS          TOBUS    CK        ZR          ZX          BMAG  MVA1      MVA2      MVA3      MVA4
#          VNOMF   VNOMT   MVABASE            STAT      TYPE      TAPF      ANGLP    REG       VMAX      VMIN
#          STEPP   TMAX    TMIN      TAPFP    TAPFS     GMAG      AREA    ZONE
 NEW_TRAN   33204          30698     1         0.001175  0.091892  -0.000334          420       462       420+
```

	462	120	230	420	1	11	1	0	35356	1.1	0.9+
	0.00625	1.025	.975	1.000	1.000	0.000212	9	309			
# END											

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagram
2. Pre and Post Project Power Flow Plots

Attachment 1: Scope Diagram

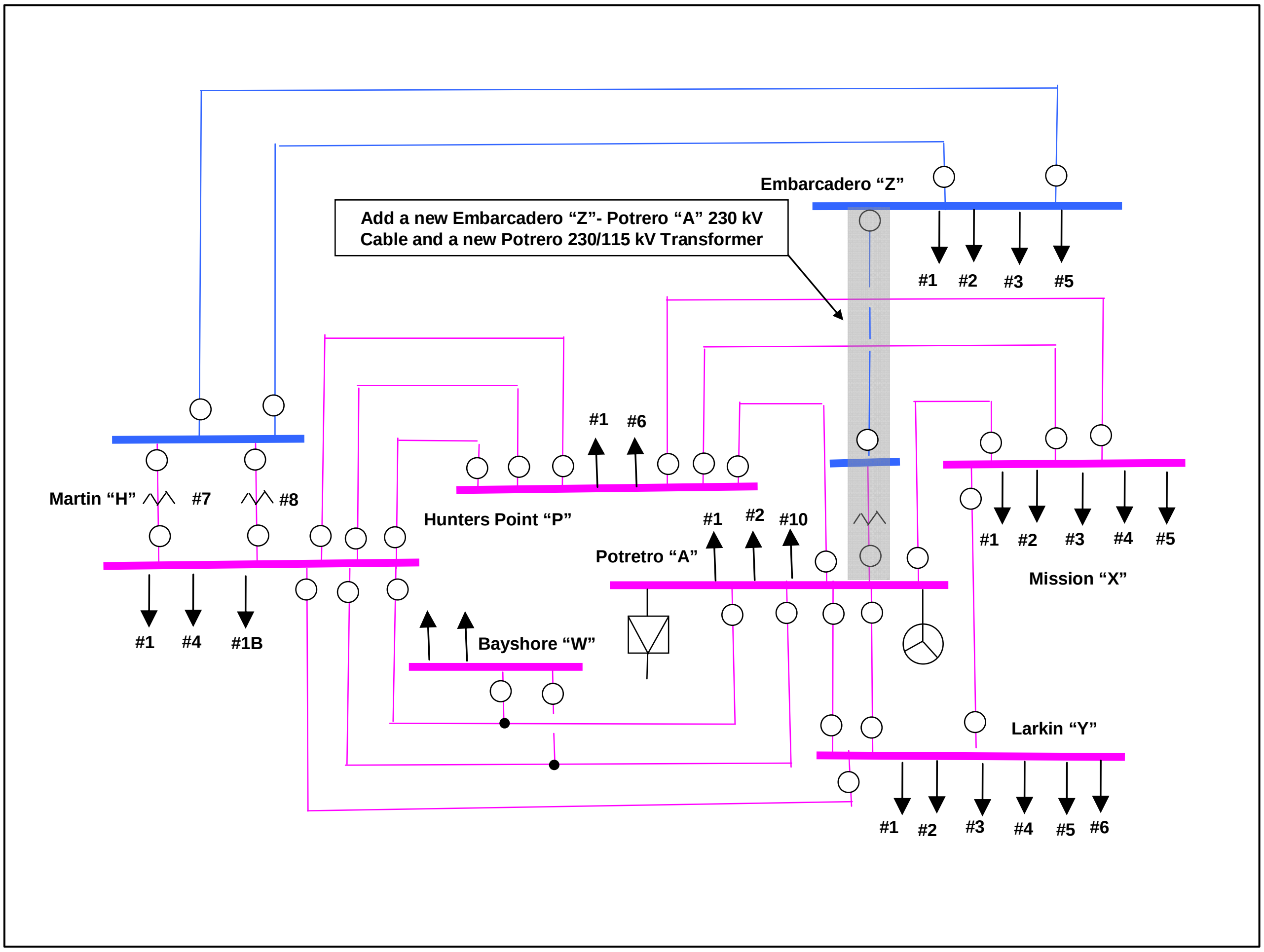


Figure 5-1: San Francisco Area

Attachment 2: Pre and Post Project Power Flow Plots

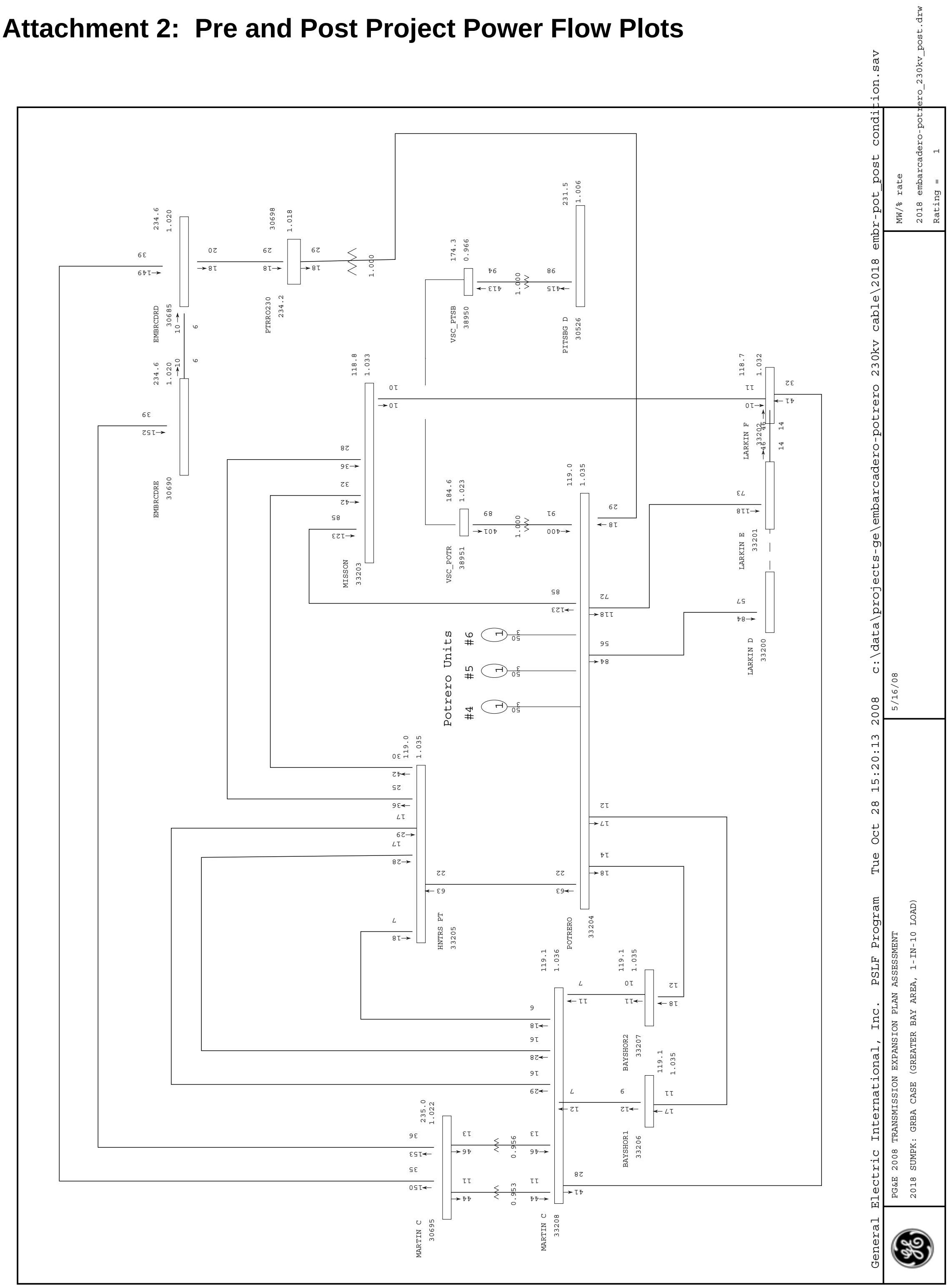


Figure 5-2: All Facilities In-Service, Year 2018 (Post-Project)

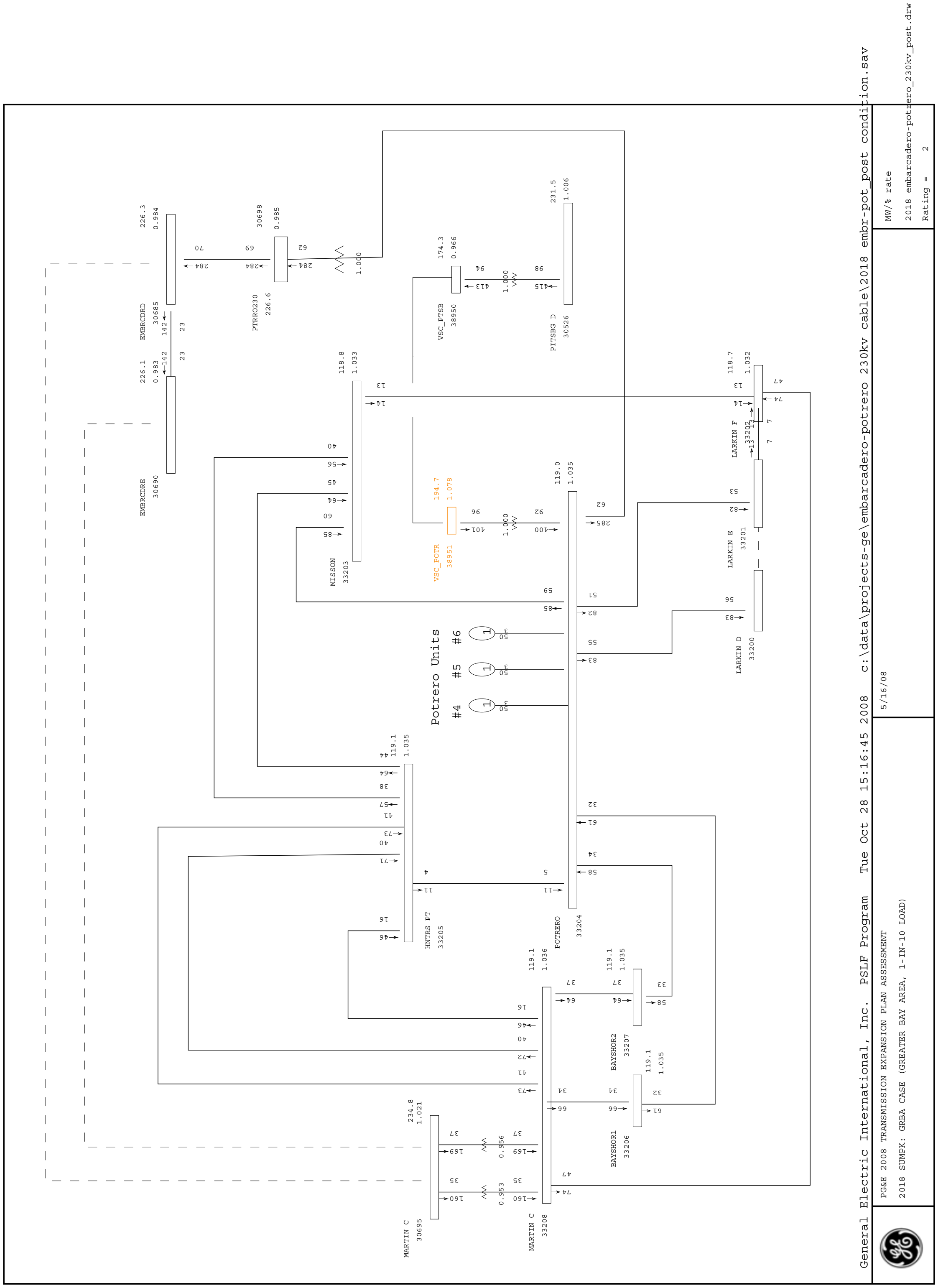


Figure 5-3: Outage of 230 kV H-Z Cable No. 1 & 2 Cable (N-1-1), Year 2018 (Post-Project)

CHAPTER 6

Table of Contents

2010 Projects

Country Club 60 kV Bus Upgrade

IN-SERVICE DATE

May 2010

PURPOSE AND BENEFIT

Reliability – NERC Compliance

PROJECT CLASSIFICATION

This is a new project.

BACKGROUND

The Country Club Substation is a distribution substation located in North Stockton. This substation is fed from the Stagg-Country Club Nos. 1 and 2 60 kV Lines. A third 60 kV circuit connects Country Club Substation to Hammer Substation and serves University of Pacific (UOP), Mettler and Mosher substations.

The existing 60 kV bus at Country Club is constructed with 1113 AAL conductors rated at 998 Amps normal and 1161 Amps emergency with 4 feet per second (fps) wind speed. The three circuit breakers (CB 32, CB 42, and CB 52) at Country Club Substation are rated at 1200 Amps. The associated disconnect and by-pass switches (SW 31, SW 33 and SW 35) for CB 32 are rated at 1200 Amps. The disconnect switch (SW 37) between CB 32 and CB 52 is also rated at 1200 Amps.

The Hammer Jct.-Country Club section (4.1 miles) of the Hammer-Country Club 60 kV Line is strung with 477 ACSS conductors rated at 1126 Amps normal and emergency.

Planning analysis identified that the bus section between CB 32 and CB 52 loads up to 108% in 2009 and up to 126% in 2018 during outage of the Stagg-Hammer 60 kV Line. In addition, the Hammer Jct.-Country Club section of the Hammer-Country Club 60 kV Line loads up to 105% in 2009 and up to 123% in 2018.

The Mosher Transmission Project, planned to be completed by May 2010, will connect Mosher Substation to Lockeford Substation in addition to Country Club and Hammer Substations. After completion of the Mosher Transmission Project, the overloading conditions mentioned above during outage of the Stagg-Hammer 60 kV Line would be mitigated until approximately 2017.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended because the thermal overloads are expected to exceed the emergency rating of the conductor.

Alternative 2: Transfer Mosher Substation to the Lockeford 60 kV System

This alternative proposes to transfer Mosher substation to the Lockeford system and reconductor Lockeford No. 1 60 kV Line. It also proposes to reconductor the Country 60 kV bus and re-rate the Hammer Jct. – Country Club section of the Hammer-Country Club 60 kV Line for 4 feet per second wind speed.

The transfer of Mosher Substation to the Lockeford system and the reconductor of the Lockeford No. 1 60 kV Line are being proposed under a separate project (The Mosher Transmission Project).

This alternative is the preferred solution. This project is expected to cost between $1M and $5M.

Alternative 3: Reconductor Country Club 60 kV Bus and Hammer-Country Club 60 kV Line

This alternative is similar to the proposed project except instead of re-rate it proposes to reconductor the Hammer Jct.-Country Club section of the Hammer-Country Club 60 kV Line (4.1 miles) with a higher rated conductor that is capable of carrying a summer emergency rating of at least 1400 Amps.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – None
- Construction – TBD
- Operation Date – May 2010

KEY ISSUES

- Land-Use Restrictions – None
- Environmental Concerns – TBD
- Special Metering or Protection – TBD
- Common Mode Exposure Items – TBD
- Interaction with other Projects or Studies – Mosher Transmission Project

ATTACHMENT

1. Scope Diagram

Attachment 1: Scope Diagram

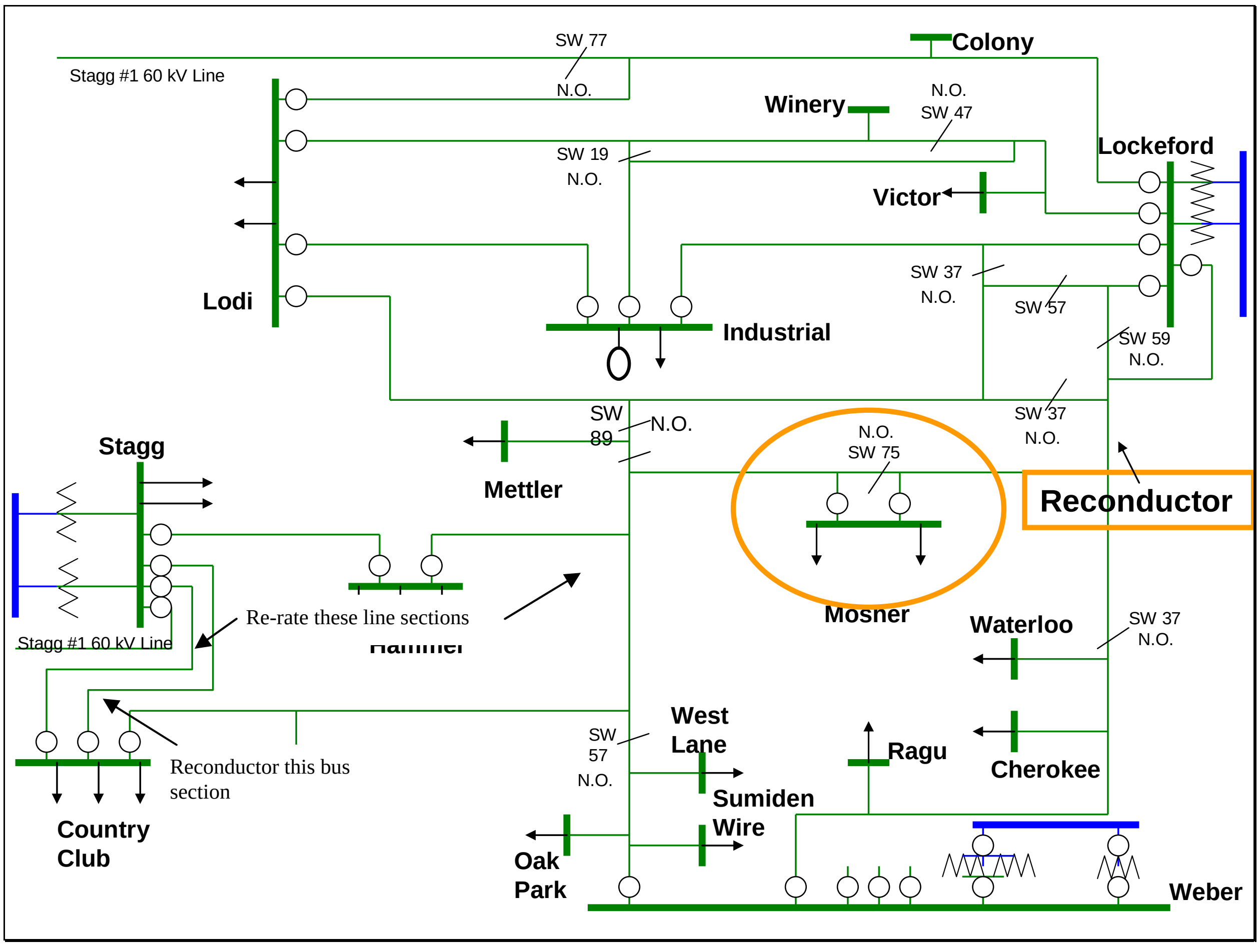


Figure 6-1: Scope Diagram

2012 Projects

Atlantic – Rio Oso – Gold Hill 230 kV Lines

TARGETED IN-SERVICE DATE

May 2012

PURPOSE AND BENEFIT

Reliability – NERC Compliance

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROPOSED PROJECT

The project scope is to reconductor the following transmission lines with conductors capable of carrying a minimum of 1,500 Amps for summer normal and emergency conditions:

1. Rio Oso – Atlantic 230 kV Line (18 miles) and
2. Rio Oso – Gold Hill 230 kV Line[1] (28.5 miles).

This is the recommended plan for the area. The plan provides the needed transmission capacity and is a pertinent in reducing the area's local capacity requirements.

The project is expected to cost between $30M and $40M. The large cost range is due to the unknown permitting and environmental aspects of the project.

BACKGROUND

The Rio Oso-Atlantic, Atlantic-Gold Hill, and Rio Oso-Gold Hill 230 kV lines are part of the bulk transmission system and share a common tower between Rio Oso and Gold Hill substations. Collectively, these lines deliver over 500 MW from north to south. The load centers in the area are located in southwestern Placer and El Dorado counties.

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[1] The Rio Oso-Gold Hill 230 kV Line shares transmission towers with the Atlantic-Gold Hill 230 kV Line for 11 miles between Atlantic and Gold Hill substations. To avoid potential problems with sway and clearance, both lines may need to carry the same conductor when on the same tower. This project may be expanded to include the reconductoring of the Atlantic-Gold Hill 230 kV Line to minimize environmental impacts and public disturbances.

Some of the major cities in these counties are Lincoln, Rocklin, El Dorado Hills, and Shingle Springs.

The City of Lincoln has been experiencing rapid economic growth and population increase in the past ten years. The Rio Oso – Atlantic 230 kV Line and the Rio Bravo-Rocklin (25 MW) and Sierra Pacific Industries-Lincoln (18 MW) help serve the demand in the City of Lincoln and the surrounding cities and communities.

The El Dorado Hills and Shingle Springs area is also a medium to high growth area with a forecast of over 300 MW by 2011. Electrically, this area connects to the 230 kV electric grid via the Gold Hill Substation.

Planning analysis concluded that during 2012 summer peak conditions the Rio Oso – Atlantic 230 kV Line could overload up to 1% of its emergency rating following an overlapping outage of the Ralston generator and the Rio Oso – Gold Hill 230 kV Line.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended because it does not accommodate capacity issues or the expected resources into the transmission system.

Alternative 2: Construct a new Rio Oso – Gold Hill 230 kV Line

This alternative proposes to construct a new 230 kV line, from Rio Oso to Gold Hill substations, with 2,300 Al conductors or equivalent. The distance for this transmission line is approximately 30 miles. Adding a new terminal at the Gold Hill Substation necessitates a more reliable 230 kV bus configuration. Specifically, the scope requires adding 12 new circuit breakers at the Gold Hill Substation and one new circuit breaker at the Rio Oso Substation.

The alternative is expected to cost around $35M to $50M.

Moreover, the new 230 kV line will require a specific permit from the California Public Utility Commission in order to site and construct the new transmission line. Although the allowance may be granted, PG&E may be required to construct the new transmission line a different route and location from those initially proposed resulting in a higher cost and a longer period to complete the project. Therefore, this alternative is not preferred due to its timing and higher cost.

Alternative 3: Loop the Rio Oso – Gold Hill 230 kV Line into Atlantic Substation

This alternative proposes to loop the Rio Oso – Gold Hill 230 kV Line into the Atlantic Substation.

The alternative is expected to cost around $5M to $15M.

This alternative is not preferred because it doesn't increase electric capacity to deliver power from potential resources located in the vicinity north Table Mountain Substation. Additionally, this alternative would require additional transmission line capacity upgrades as soon as 2013.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2012

KEY ISSUES

- Land-Use Restrictions – There are no land-use restrictions with this project.
- Environmental Concerns – TBD
- Special Metering or Protection – TBD
- Common Mode Exposure Items – None
- Interaction with other Projects or Studies – None

ATTACHMENTS

1. Scope Diagram

Attachment 1: Scope Diagram

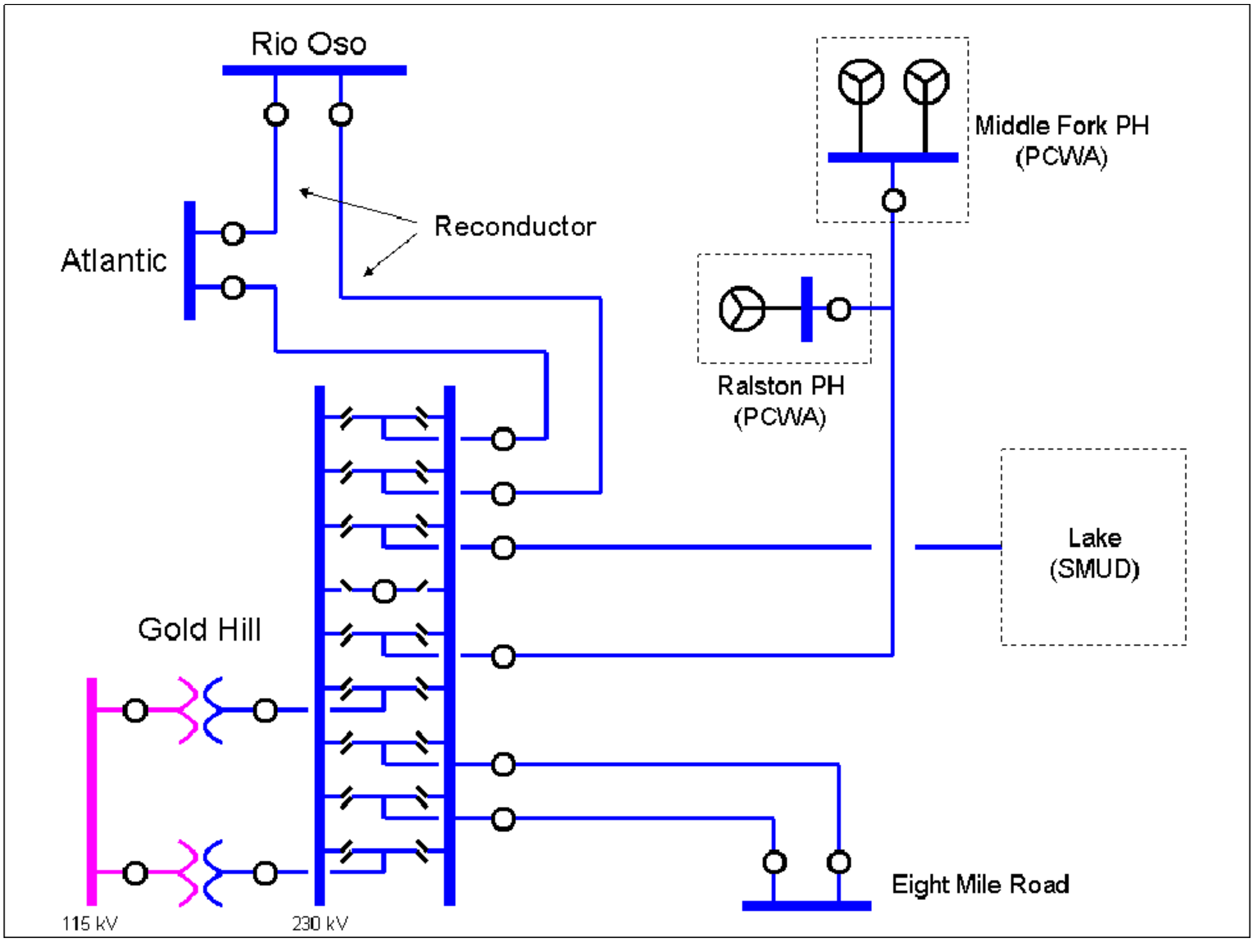


Figure 6-2: Scope Diagram

Cascade Area Reinforcement

IN-SERVICE DATE

May 2012

PURPOSE AND BENEFIT

Reliability – NERC Compliance

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROPOSED PROJECT

The scope is to add a 3-phase, 115/60 kV transformer rated at 100 MVA or larger at the Cascade Substation and install high side breakers.

The expected cost of this project is approximately between $7M and $12M.

BACKGROUND

PG&E's Cascade Substation is located in the Shasta County and is connected to the bulk transmission system via two 115 kV lines: Cascade - Delta and Cascade - Oregon Trail 115 kV lines. The Cascade Substation currently has one 3-phase 115/60 kV transformer rated at 76 MVA that steps down bulk power to serve local customers. These customers include Stillwater, Mountain Gate, Antler, French Gulch, Deschutes, Volta, Lewistown, among others. Failure of the Cascade 115/60 kV transformer could interrupt electric service to these customers. Service restoration to install a spare unit could take 24 hrs or more.

The Cascade system has local power plants which include hydroelectric facilities on Battle Creek (50 MW), Olsen Cogeneration (8.5 MW), and Neo Red Bluff Peaking Plant (50 MW). In addition to the internal generation, the Cascade Substation has a connection to PacifiCorp that operates in northern California and other western states. The assumption of the study is that PG&E imports 80 MW from PacifiCorp. The PacifiCorp imports, the local generation and the Cascade 115/60 kV Transformer No.1 are the key power supply facilities to the local transmission system in this area.

Based on the Cascade Substation arrangement, planning analysis concluded that the loss of the Cascade transformer will separate the tie to PacifiCorp. Thus, the Cascade 60 kV area will experience approximately 10 kV voltage drop between pre and post outage conditions in 2018. In addition to the voltage problems, starting 2011, loss of the Cascade Transformer overloads the 60 kV lines.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended because it does not address the reliability or the capacity issue on the Cascade 115/60 kV Transformer.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2012

KEY ISSUES

- Land-Use Restrictions – There are no land-use restrictions with this project.
- Environmental Concerns – TBD
- Special Metering or Protection – TBD
- Common Mode Exposure Items – None
- Interaction with other Projects or Studies – None

GEPSLF MODELING INFORMATION

Add second 100 MVA, 115/60 kV Transformer at Cascade Sub

NEW_TRAN 31468, 31580, CKT=2, ZR=0.0016, ZX=0.0276, BMAG=-0.0014, +
MVA1=100, MVA2=110, MVA3=100, MVA4=110, VNOMF=115, VNOMT=60, MVABASE=100, +
STAT=1, TYPE=1, TAPF=1, VMAX=1.05, VMIN=1.0, +
STEPP=0.01, TMAX=1.1, TMIN=0.9, TAPFP=1, TAPFS=1, AREA=3, ZONE=303

ATTACHMENTS

1. Scope Diagram

Attachment 1: Scope Diagram

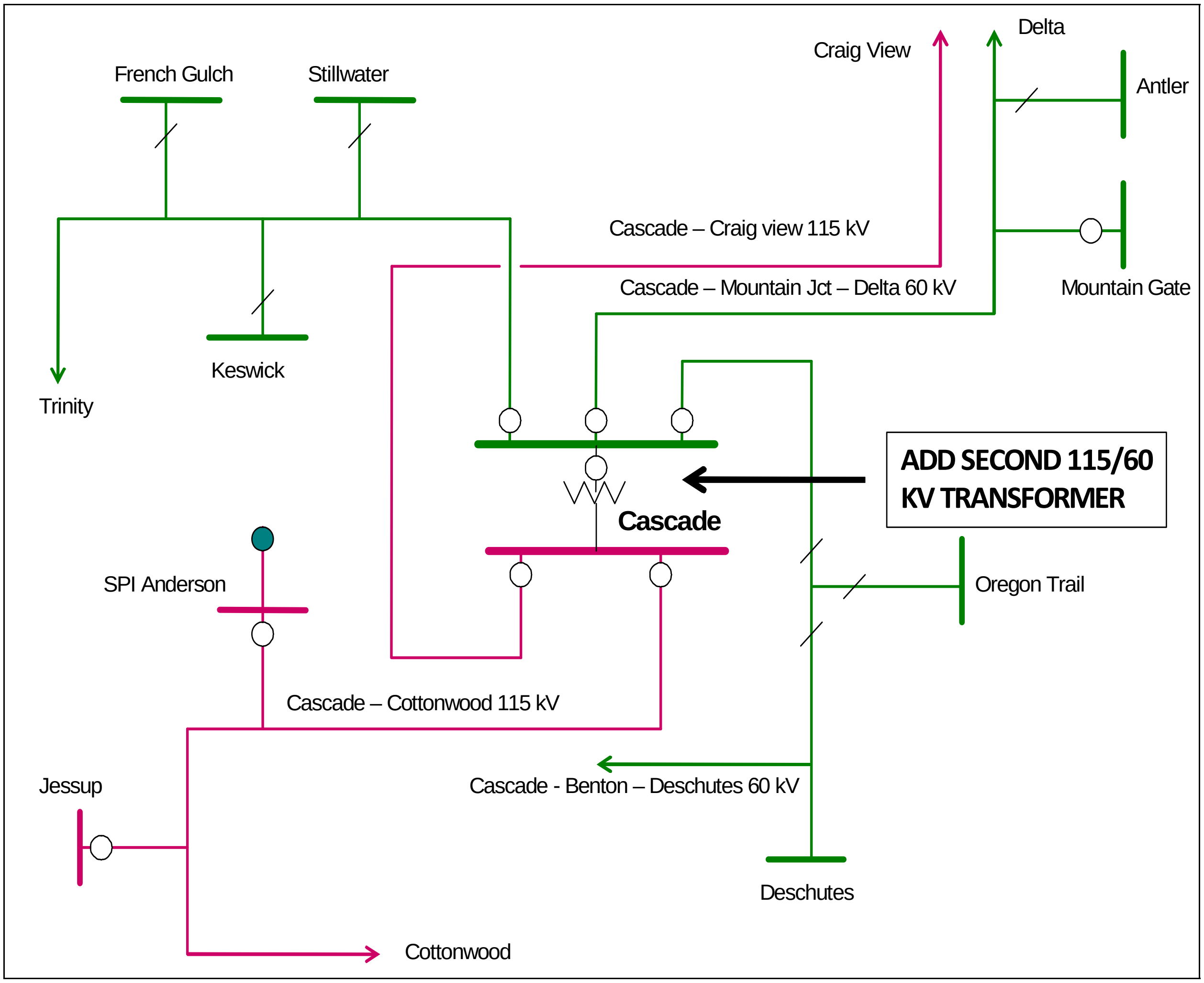


Figure 6-3: Scope Diagram

Manteca 60 kV Area Reinforcement

IN-SERVICE DATE

May 2012

PURPOSE AND BENEFIT

Reliability – Operational Flexibility

PROJECT CLASSIFICATION

This is a new project.

BACKGROUND

The Kasson Substation is located in the Stockton Division in Stanislaus County and has one 115/60 kV transformer bank. The 115/60 kV transformer bank provides support to the 60 kV transmission system through three transmission circuits. One circuit (Kasson-Louise 60 kV Line) is connected to the Manteca 60 kV system via the Manteca-Louise 60 kV Line.

Kasson 115/60 kV Bank No. 1 is comprised of three single-phase 25.4 MVA transformers. It has a normal rating of 76.2 MVA and an emergency rating of 91.4 MVA. This bank has no low side circuit breaker.

The Manteca 115/60 kV Bank No. 3 has a normal rating of 31.3 MVA and an emergency rating of 37.5 MVA.

The Kasson 60 kV system serves Banta, Carbona, Calvo, and Lyoth (WAPA) with direct connection to the Manteca 60 kV system which serves transmission customers, Louise and Gronemeyer (Sharpe) substations. The 2009 projected peak load for these substations is 52 MW and is forecast to increase at a rate of 1 MW or 1.9% per year.

Currently, loss of Kasson 115 kV bus (Category C) results to loss of 60 kV service to Banta, Carbona and Lyoth (a total load of approximately 45 MW in 2009). Planning analysis determined that the Manteca 60 kV system will not be able to pick-up all the load under this outage condition. It is projected to overload the Manteca Bank No. 3 by 80% and the Manteca-Louise 60 kV Line by 45% with the load transfer under the outage scenario in 2009.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY *CRITERIA*

CAISO grid planning criteria

ALTERNATIVE CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended because it does not mitigate the expected capacity constraints.

Alternative 2: Add Transformer Bank at Kasson and Reconfigure 60 and 115 Busses

The alternative proposes to install an additional 115/60 kV three-phase transformer at Kasson Substation with a normal rating of at least 200 MVA. Add 60 kV circuit breakers and reconfigure the existing 115 kV bus to the standard breaker and a half (BAAH) arrangement for two transformer banks and six transmission lines.

This alternative is expected to cost between $15M to $20M.

Alternative 3: Partial 115 kV Conversion

The alternative proposes to convert Banta and Carbona 60 kV Substations to 115 kV Substations.

This alternative is expected to cost between $20M to $30M.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2012

KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – TBD
- Special Metering or Protection - TBD
- Common Mode Exposure Items – None
- Interaction with other Projects or Studies – Carbona Reliability Project

ATTACHMENT

1. Scope Diagram

Attachment 1: Scope Diagram

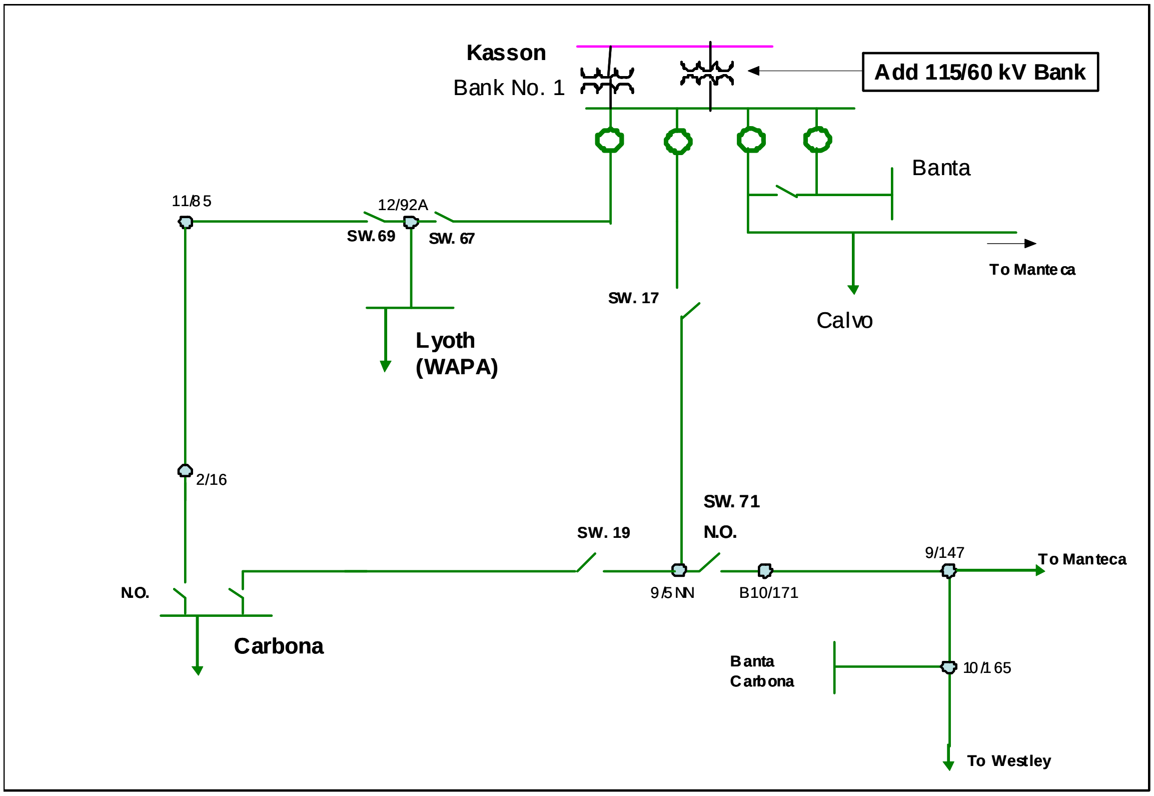


Figure 6-4: Scope Diagram – After Carbona Reliability Project

Missouri Flat Expansion

TARGETED IN-SERVICE DATE

May 2012

PURPOSE AND BENEFIT

Reliability – NERC Compliance and Operational Flexibility

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROPOSED PROJECT

The preferred alternative is to convert Missouri Flat Substation into a ring bus by adding two circuit breakers.

This project is expected to cost between $1M and $5M.

BACKGROUND

The El Dorado-Missouri Flat 115 kV Nos. 1 and 2, Missouri Flat-Gold Hill 115 kV Nos. 1 and 2, and Gold Hill-Clarksville 115 kV Lines serve the Gold Hill - El Dorado sub-area. The major cities in the area are Clarksville, Diamond Springs, Placerville, and Shingle Springs.

Power flow analysis indicates that loss of the El Dorado-Missouri Flat No. 2 115 kV Line decreases the 115 kV voltages in the area.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended because it does not help reduce the projected LCR.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2012

KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – TBD
- Special Metering or Protection – TBD
- Common Mode Exposure Items – TBD
- Interaction with other Projects or Studies – TBD

GEPSLF MODELING INFORMATION

```
#Missouri Flat Reconfiguration
#----------------------------------------------------------------------------------------------------
#Tie the two buses together at Missouri Flat to create ring bus
#CB's 412 and 422 are rated at 2,000 Amps
#
NEWSECDD  32261, 32260, CKT=1 SEC=1 RPU=0.0005 XPU=0.0005 BPU=0 +
        MVA1=398 MVA2=398 MVA3=398 MVA4=398 STATUS=1 AREA=5 ZONE=305 OWN=390
```

ATTACHMENTS

1. Scope Diagram

Attachment 1: Scope Diagram

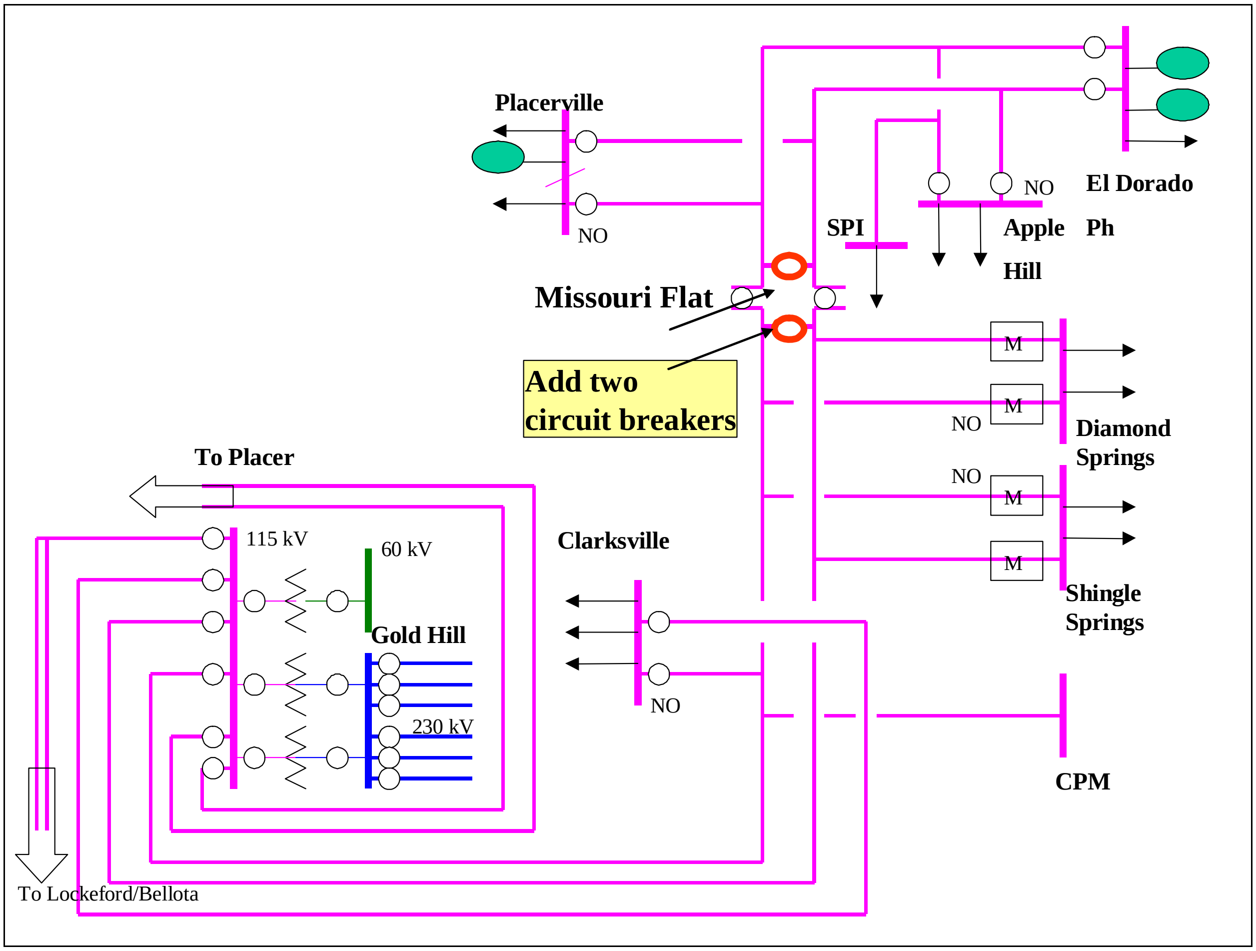


Figure 6-5: Scope Diagram

Rio Oso 115 kV Reactive Support

TARGETED IN-SERVICE DATE

May 2012

PURPOSE AND BENEFIT

Reliability – NERC Compliance and Operational Flexibility

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROPOSED PROJECT

The project scope is to install reactive support at Rio Oso Substation to address voltage concerns on the transmission system.

This project is expected to cost between $25M and $35M.

BACKGROUND

Under off-peak conditions, the Sierra and Sacramento transmission systems can experience high voltages. Currently, these high voltage issues are being managed through operational switching.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended. This alternative does not address the potential high voltage issues.

PROJECT SCHEDULE

- Environmental and Permitting Processes – None
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2012

KEY ISSUES

- Land-Use Restrictions – None
- Environmental Concerns – None
- Special Metering or Protection – None
- Common Mode Exposure Items – None
- Interaction with other Projects – TBD

Vaca Dixon - Sobrante - Moraga 230 kV Reinforcement

TARGETED IN-SERVICE DATE

May 2012 or later

PURPOSE AND BENEFIT

Access to renewable resources – This project increases electric transmission capacity and reliability for access to renewable resources.

PROJECT CLASSIFICATION

This is an existing project.

DESCRIPTION AND SCOPE OF PROJECT

- Reconductor approximately 20 miles of the Vaca Dixon – Moraga 230 kV Nos. 1 and 2 lines with 1113 SSAC conductor
- Install a switching station (with 8 line terminations) to connect together Vaca Dixon – Moraga 230 kV Nos. 1 and 2 lines and Lakeville – Sobrante 230 kV Nos. 1 and 2 lines
- Tie together the conductors of Vaca Dixon – Moraga 230 kV Nos. 1 and 2 lines to form one 230 kV line between the new switching station and Moraga (about 30 miles)

This project is expected to cost between $100 million and $200 million.

BACKGROUND

Vaca-Dixon – Contra Costa 230 kV lines have been identified in PG&E's Transmission Ranking Cost Report[2] as part of the network facilities that could require upgrades, which are common to resource developments in the vicinity of and north of Vaca-Dixon Substation if such resources must be delivered to load centers in the Greater San Francisco Bay Area and to the south (see Chapter 7).

If more resources would materialize after the reconductoring of the Vaca Dixon – Lambie – Contra Costa and Vaca Dixon – Peabody – Contra Costa 230 kV lines is complete, it would be necessary to further upgrade the transmission facilities south of Vaca Dixon. Therefore, the timing and scope of this project would be driven by the

[2] PG&E's 2005 Transmission Cost Ranking Report was filed in Order Instituting Investigation (OII) 00-11-001 on August 3, 2005.

amount of resource development between Round Mountain, Cottonwood and Vaca Dixon substations.

PG&E is investigating several options. They include:

ALTERNATIVES CONSIDERED

Option 1:

- Reconductor approximately 20 miles of the Vaca Dixon – Moraga 230 kV Nos. 1 and 2 lines with 1113 SSAC conductor
- Install a switching station (with 8 line terminations) to connect together Vaca Dixon – Moraga 230 kV Nos. 1 and 2 lines and Lakeville – Sobrante 230 kV Nos. 1 and 2 lines
- Tie together the conductors of Vaca Dixon – Moraga 230 kV Nos. 1 and 2 lines to form one 230 kV line between the new switching station and Moraga (about 30 miles)

Option 2:

- Reconductor the Vaca Dixon and Moraga 230 kV Nos. 1 and 2 lines

BASE CASE AND STUDY ASSUMPTIONS

The 2010 Summer Peak base case was developed from the power flow case that was prepared for the 2005 PG&E Expansion Plan Studies and represents the transmission network (including transmission projects approved by CAISO and PG&E), load forecast (1-in-5 year adverse weather system peak load), and expected generation retirements for year 2010. This base case was reviewed and approved by the CAISO. This base case was then modified to include new generation projects that have completed their System Impact Study (SIS) and Facility Study (FS) and the associated transmission projects approved by the generation developers, and the results of PG&E's 2004 Renewables Solicitation as of April 2005.

The 2010 off-peak base case was developed from the same 2008 light autumn case (modified from the WECC 08 LA1-S case) used in the 2004 study except that the load was updated to reflect the 2005 forecast, and the generation and transmission network were updated as necessary as described above for the 2010 Summer Peak base case.

The renewable resources assumed in the study are consistent with the results of the RRDR Report published by the CEC on September 30, 2003. These CEC results have been augmented based on information received by PG&E from potential renewables developers in response to PG&E's solicitation for information conducted in 2003, 2004 and 2005.

ATTACHMENTS

1. Scope Diagram

Attachment 1: Scope Diagram

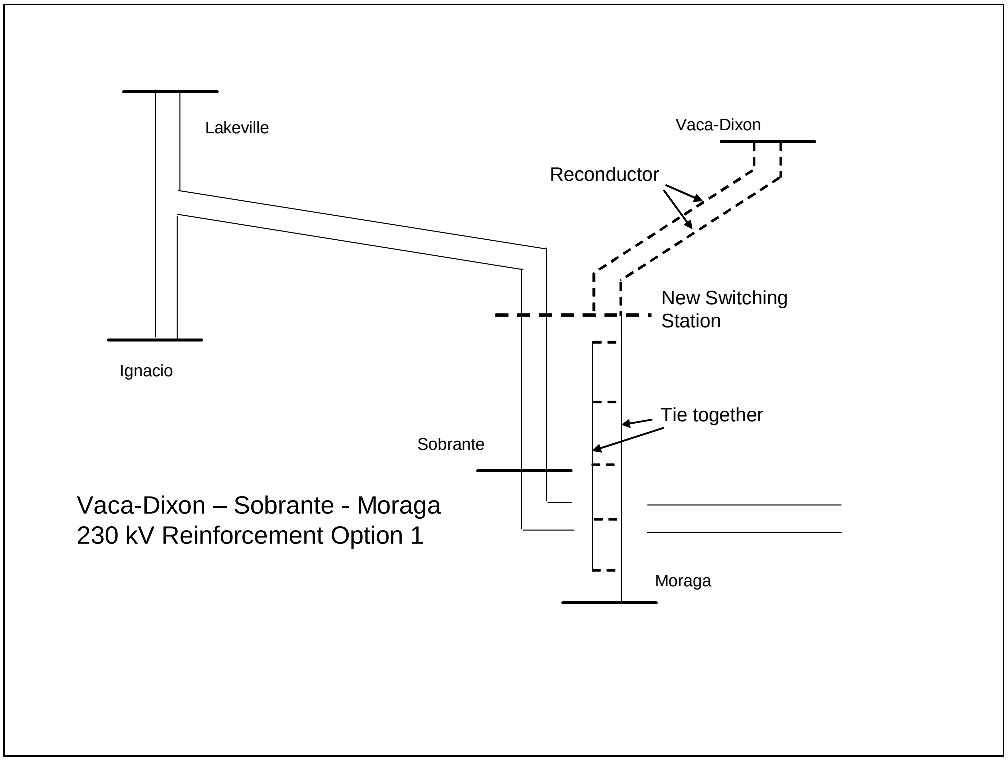


Figure 6-6: Scope Diagram - Option 1

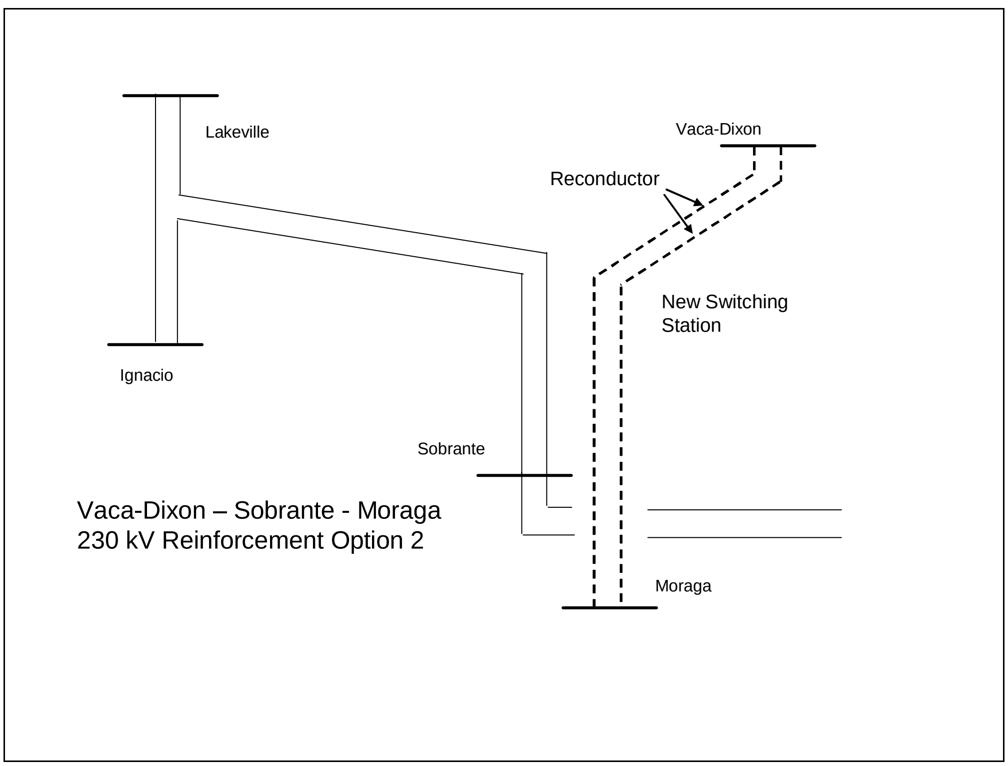


Figure 6-7: Scope Diagram - Option 2

Valley Springs No. 1 60 kV Line Reinforcement

IN-SERVICE DATE

May 2012

PURPOSE AND BENEFIT

Reliability – NERC Compliance

PROJECT CLASSIFICATION

This is a new project.

PROJECT SCOPE

This alternative proposes to reconductor sections of the Valley Springs No. 1 60 kV Line (13 miles) with a higher rated conductor that is capable of carrying a summer emergency rating of 742 Amps or higher. It also proposes to install voltage support to mitigate to potential low voltage problems.

This project is expected to cost between $8M and $10M.

BACKGROUND

Corral, Linden and Mormon substations are located between the Weber and Valley Springs substations. These distribution substations serve the majority of the area load through the Valley Springs No. 1 60 kV Line and the Weber – Mormon Jct. 60 kV Line. Other resources in the area come from two small hydro generator units at North Hogan Substation capable of 2 MW each.

Normal electric service to the Linden Substation is from the Weber – Mormon Jct. 60 kV Line. In abnormal conditions, the motor operating switches outside the substation swap Linden to its alternate source, the Valley Springs No. 1 60 kV Line.

This 60 kV line is over 24 miles and is comprised of 397 Al, 3/0 Cu and 4/0 Al conductors. Currently, the line is limited by the 3/0 Cu conductor from North Hogan and Corral and has a 4 feet per second wind speed assumption. The line is capable of 389 Amps normally and 447 Amps in emergency conditions.

Planning analysis identified that when Linden Substation transfers to the Valley Springs No. 1 60 kV Line, the voltages at Linden drop from 58.4 kV to 53.8 kV. In addition, the Valley Springs No. 1 60 kV Line loads up to 106% in 2011.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

ALTERNATIVES BEING CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended because the thermal overloads are expected to exceed the emergency rating of the conductor.

Alternative 2: Disable the Linden Substation Automatics and Install SCADA

This alternative proposes to disable the station automatics during the summer months to prevent high loading on the Valley Springs No. 1 60 kV Line should a Weber – Mormon Jct. 60 kV Line fault occur. It also proposes to install SCADA on Switch Nos. 27 and 29 outside the Linden Substation.

This alternative is preferred for the short term because it will mitigate the line overload and low voltage conditions until a long term solution is implemented.

Alternative 3: Transfer Mormon and Linden Substations to the 115 kV System

This alternative proposes to convert Mormon and Linden 60 kV substations to 115 kV substations served from the existing Stockton A-Lockeford-Bellota 115 kV No.1 or No. 2 Line.

This project is expected to cost between $5M and $15M.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2012

KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – TBD
- Special Metering or Protection – TBD
- Common Mode Exposure Items – TBD
- Interaction with other Projects or Studies – TBD

ATTACHMENT

1. Scope Diagram

Attachment 1: Scope Diagram

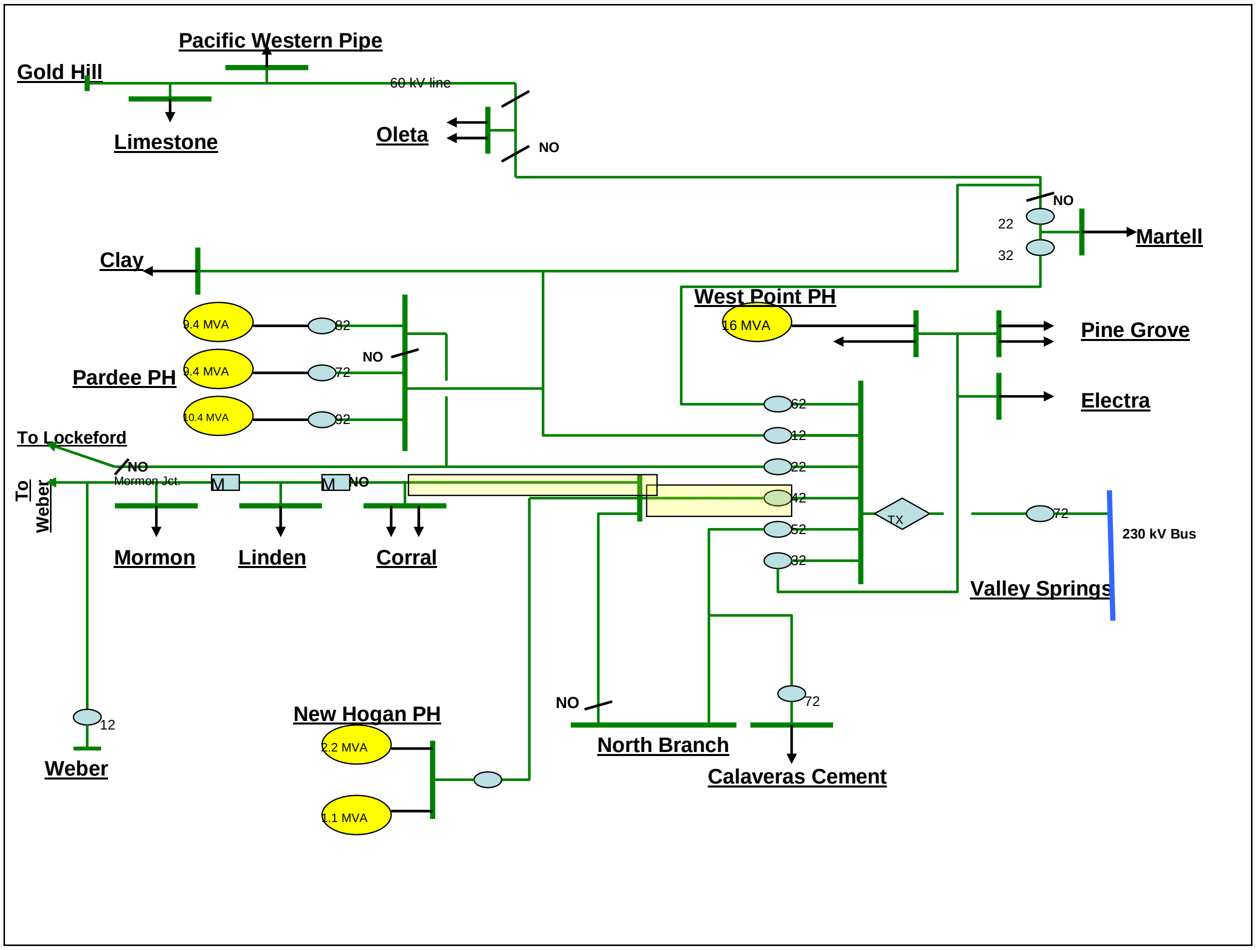


Figure 6-8: Scope Diagram

2013 Projects

Brighton – Davis 115 kV Reconductoring

TARGETED IN-SERVICE DATE

May 2013

PURPOSE AND BENEFIT

Reliability – NERC Compliance

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROJECT

The project scope is to reconductor the Brighton – Davis 115 kV Line with conductors capable of carrying a minimum of 1,100 Amps for summer normal and emergency conditions. If necessary, associated line terminal equipment would be upgraded. In addition, the project scope would require obtaining any necessary environmental and land permits to complete the reconductoring work.

The project is cost is between $5M and $10M.

BACKGROUND

Rio Oso and Brighton substations are key power system facilities serving the customers in Yolo and Solano Counties. There also is a 25 MW generator in the Yolo County that helps serve the local area demand, which includes the cities of Woodland, Davis, and West Sacramento. In addition, the University of California - Davis is located in the southern part of the City of Davis. The local area is expected to increase at 4 MW per year.

Electrically, these customers are served by Rio Oso – West Sacramento, Brighton – Davis, and West Sacramento – Brighton 115 kV Lines. All three lines are on towers. In fact, the Rio Oso – West Sacramento and West Sacramento – Brighton Lines share the same towers from West Sacramento to a point right outside Brighton Substation (13 miles).

Planning analysis concluded the Rio Oso – West Sacramento and Brighton – Davis 115 kV Line would exceed their emergency ratings in 2018 following the loss of the West Sacramento – Brighton 115 kV Line while the Woodland generator is unavailable.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended. This alternative does not address the potential overload issue.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2013

KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – TBD
- Special Metering or Protection – TBD
- Common Mode Exposure Items – TBD
- Interaction with other Projects or Studies – TBD

ATTACHMENT

1. Scope Diagram

Attachment 1: Scope Diagram

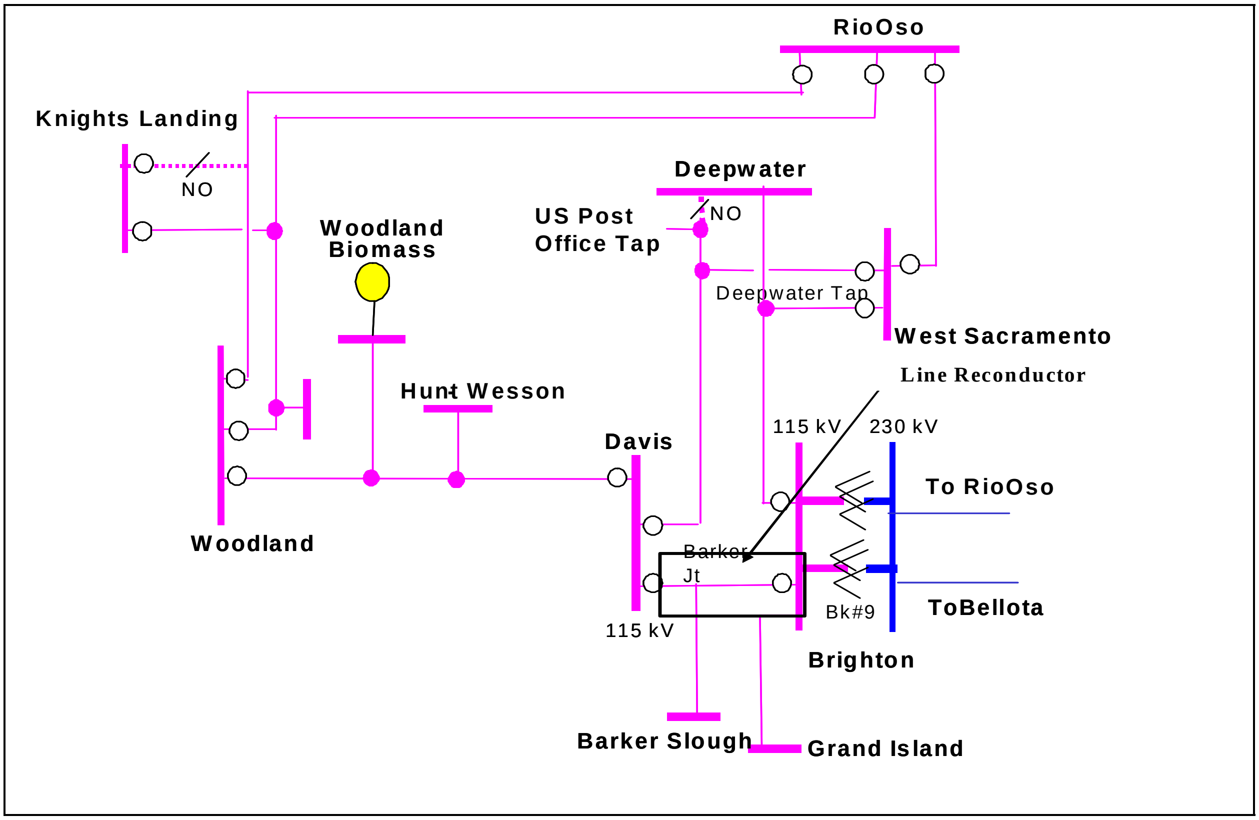


Figure 6-9: Scope Diagram

Central California Clean Energy Project

IN-SERVICE DATE

December 2013

PURPOSE AND BENEFIT

Reliability and Access to Renewable Resources

PROJECT CLASSIFICATION

This is a new project proposal.

DESCRIPTION AND SCOPE OF PROPOSED PROJECT

Based on findings from the TCSG, PG&E started investigating the feasibility of a line between the Midway and Gregg Substations. Upon subsequent studies, the northern terminus was revised to include a location east of Gregg Substation. Transmission planning studies for this project are being conducted through the CAISO Stakeholder Process. Fourteen alternatives are being investigated by PG&E (see Table 7-2), including opportunities for potential future interconnections with Southern California Edison (SCE) to support SCE's Big Creek Area load. Ten alternatives to supply Big Creek Area are being investigated by SCE in a regional planning effort.

The Central California Clean Energy Transmission (C3ET) Project would increase transmission import capacity north of Midway Substation to allow transmission of power from renewable resources from southern California. It would also provide a valuable option to facilitate PG&E to meet its renewable procurement targets in the event that not enough northern California renewable projects materialize.

The C3ET Project would relieve Path 15 congestion by increasing the Path 15 south-to-north transfer capability by about 1,250 MW, and is expected to reduce the annual Path 15 congestion to less than 100 hours.

The C3ET Project would increase import capability to the Yosemite and Fresno area by about 500 MW. The current Fresno Area Long-term Transmission Plan proposing to build a Gates – Gregg 230 kV Double-Circuit Tower Line (DCTL) by around the same time is being subsumed into the C3ET Project Study as one of the alternatives being investigated. As such, if the C3ET Project is selected as the preferred alternative and constructed, the Gates – Gregg 230 kV DCTL would not be needed (or could be deferred beyond the planning horizon).

The C3ET Project would increase the Helms PSP pumping window and enhance support of three Helms units pumping operation. Power flow study results show that the existing system cannot support three units pumping at Helms PSP under the summer off-peak condition studied. The system can only support two units pumping when the combined Yosemite and Fresno areas loads are below 1,300 MW, and single unit pumping at the load level below 1,550 MW. Based on the Fresno area load duration curve, the estimated annual pumping window available for one and two-unit operation are 5,350 and 2,665 hours, respectively. The pumping window is expected to narrow with future load growth.

For more information**, please see: http://www.caiso.com/1f42/1f42daf7415e0.html.**

Table 6-1: Proposed Alternatives being investigated by PG&E

1	Fresno 230 kV Reconductoring	Magunden – Rector 230 kV DCTL ("SCE-1")
2	Midway – E2 500 kV DCTL	Magunden – Rector 230 kV DCTL ("SCE-1")
2a	Midway – E2 500 kV DCTL with S2 Loop-In	
2b	Midway – E2 500 kV DCTL with S2-S3 Loop-In, Whirlwind – S3 500 kV Line	
2c	Midway – E2 500 kV DCTL with S2 Loop-In, Midway – Vincent #3 Upgrade	
2d	Midway – Gregg 500 kV DCTL	Magunden – Rector 230 kV DCTL ("SCE-1")
3	Midway – E2 500 kV SCTL with S2 Loop-In	
4	Whirlwind – E2 500 kV DCTL with S2 Loop-In	
5	Midway – E2 230 kV DCTL	Magunden – Rector 230 kV DCTL ("SCE-1")
6	Fresno – Big Creek 230 kV inter-tie	
7	Midway – McCall – E2 230 kV DCTL	Magunden – Rector 230 kV DCTL ("SCE-1")
8	Gates – Gregg 230 kV DCTL	Magunden – Rector 230 kV DCTL ("SCE-1")
9	Raisin 230 kV Switching Station	Magunden – Rector 230 kV DCTL ("SCE-1")
10	New generation 1000 MW in Fresno	Magunden – Rector 230 kV DCTL ("SCE-1")

BACKGROUND

In 2002, the Legislature passed the Renewable Portfolio Standard (RPS), which requires that certain retail sellers of electricity increase their sales of electricity from renewable energy sources by at least 1 percent per year, achieving 20 percent by 2017, at least. Since passage of the RPS bill, an Energy Action Plan was adopted by the California Energy Commission (CEC), the California Public Utilities Commission (CPUC), and the California Power Authority. The Energy Action Plan established in 2003, a more aggressive goal for renewable energy development with a target of 20 percent by 2010. Energy Action Plan II expresses the intention of the CPUC and the CEC to press forward toward Governor Schwarzenegger's goal of having 33% of California's electricity generated from renewable resources by 2020.

The 2005 CEC Strategic Value Analysis (SVA) identified the renewable resources in southern California of 4,676 MW in 2010 and 5,569 MW in 2017 that reflect a large majority of the total California renewable resource development potential. PG&E's 2005 Transmission Ranking Cost Report (TRCR) shows that there is no spare transmission capacity available for Midway cluster due to congestion on Path 15. The Central

California Clean Energy Transmission Project would increase transmission import capacity north of Midway Substation to allow accepting renewable resources from southern California. It would also provide a valuable option in the event enough northern California renewable projects do not materialize to allow PG&E to meet its renewable procurement target.

The existing Path 15 consists of the three 500 kV lines south of Los Banos Substation and four 230 kV lines north of Gates Substation. The existing Path 15 transfer limits are 3,265 MW from north to south and 5,400 MW from south to north. Path 15 is usually lightly loaded during system peak hours and heavily loaded with south-to-north flow during system off-peak hours. CAISO performed a production simulation study for a proposed 4000 MW of wind generation project at Tehachapi in southern California. The study results show the annual congestion on Path 15 could reach 2,573 hours by 2010. The Central California Clean Energy Transmission Project would relieve congestion by increasing the Path 15 south-to-north transfer capability by about 1,250 MW.

BASE CASE AND STUDY ASSUMPTIONS

The PG&E base cases that were developed as part of the 2007 expansion plan process were used for this study.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo
This alternative will result in reduced reliability

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – December 2013

KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – TBD
- Special Metering or Protection –TBD
- Common Mode Exposure Items – TBD
- Interaction with other Projects – TBD

Drum – Grass Valley – Weimar 60 kV Line

TARGETED IN-SERVICE DATE

May 2013

PURPOSE AND BENEFIT

Reliability – NERC Compliance

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION OF PROPOSED PROJECT

The project scope is to reconductor the Drum – Grass Valley – Weimar 60 kV Line (32 miles) with conductors capable of carrying a minimum of 450 Amps for summer emergency conditions.

The project is expected to cost between \$10M and \$20M. The large cost range is due to the unknown permitting and environmental aspects of the project. The expected in-service date is May 2013.

BACKGROUND

The Drum – Grass Valley – Weimar 60 kV Line is located in Placer County. This line provides transmission power to the Bonnie Nook, Shady Glen, Foresthill, Weimar, Halsey, Mountain Quarries, and Auburn distribution substations. These substations are also supported by local hydro generation from Rollins and Oxbow Powerhouses.

The Drum – Grass Valley – Weimar 60 kV Line is approximately 31 miles in length and is comprised of 4/0 ACSR, 397 ACSR, 2/0 Cu, 4/0 Cu, and 397 Al conductors. During the summer, Weimar Switch 79, which is located between Weimar and Halsey substations, is operated normally to reduce the line loading. The line is further protected by an SEL49 thermal relay at Drum CB 10 which would trip the Drum – Grass Valley – Weimar 60 kV Line for a thermal overload.

Planning analysis concluded that during 2014 summer peak conditions an outage of the Colgate – Grass Valley 60 kV Line overload the Drum – Grass Valley – Weimar 60 kV Line up to 3% of its emergency rating.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended. This alternative does not address the projected capacity issues.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2013

KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – TBD
- Special Metering or Protection – TBD
- Common Mode Exposure Items – None
- Interaction with other Projects or Studies – None

ATTACHMENTS

1. Scope Diagrams

Attachment 1: Scope Diagram

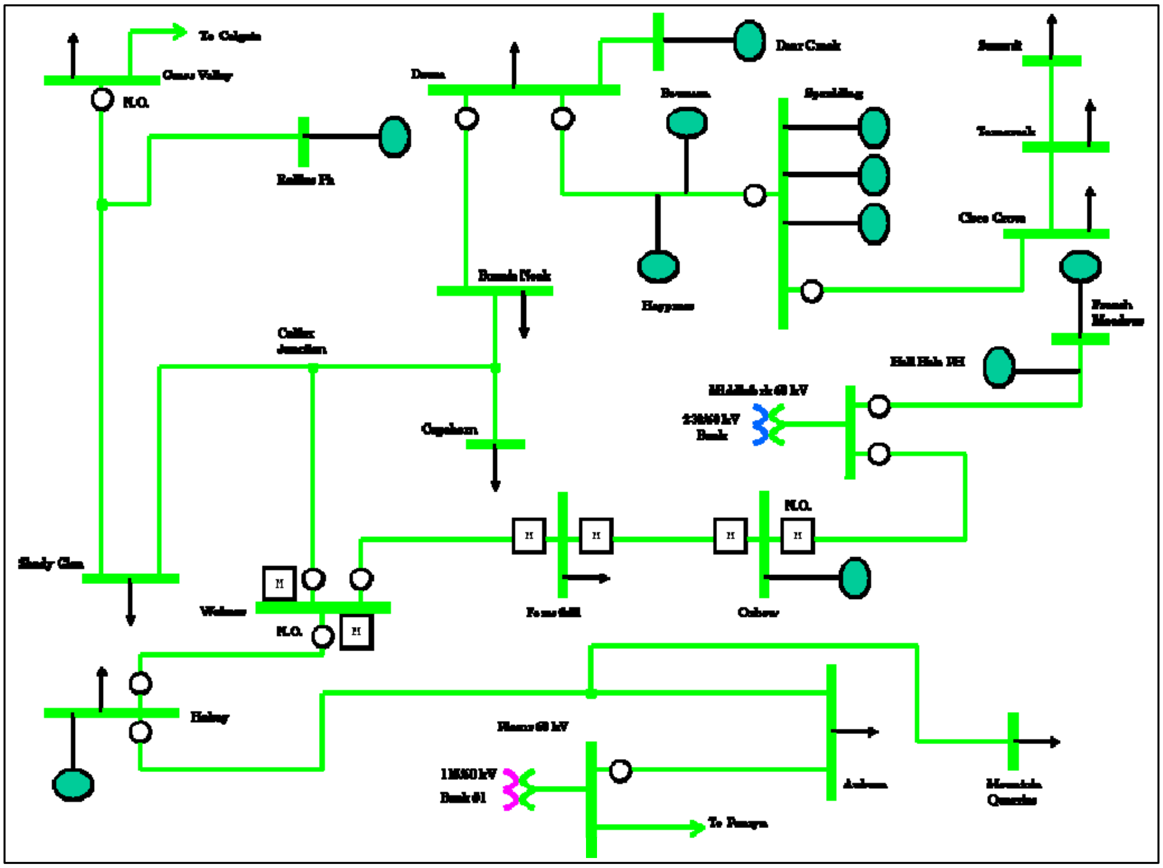


Figure 6-10: Scope Diagram

Essex Jct – Arcata – Fairhaven 60 kV Line Reconductoring

TARGETED IN-SERVICE DATE:

May 2013

PURPOSE AND BENEFIT:

Reliability – NERC Compliance

PROJECT CLASSIFICATION

This is an existing project.

DESCRIPTION AND SCOPE OF PROPOSED PROJECT

The project scope is to reconductor a 0.75 mile section of 2/0 Copper conductor with a conductor having at least 550 Amps summer coastal emergency rating.

This project is expected to cost between $1 million and $2 million.

BACKGROUND

The Essex Jct. – Arcata – Fairhaven 60 kV Line is located in Humboldt County. It provides electric service to PG&E customers through Orick, Big Lagoon, and Trinidad 60 kV substations. Several large industrial wood processing facilities in the area are also served by this transmission line. This line also serves as a backup source for Janes Creek Substation, which is normally served by the Humboldt No.1 60 kV Line.

Planning studies have concluded that during an outage of the Humboldt No. 1 60 kV Line, electric service to Janes Creek can be quickly restored by switching over to the Essex Jct. – Arcata – Fairhaven 60 kV Line. Studies reveal that thermal overloads can occur on this line during peak demand periods if all demand at Janes Creek Substation and Humboldt Flakeboard are transferred. The thermal overloads occur under forecast year 2018 summer peak demand conditions. Reconductoring the limiting sections of the Essex Jct. – Arcata – Fairhaven 60 kV Line will allow electric service to Janes Creek to be restored under most outage conditions. In addition, reconductoring this section will allow for the restoration of Humboldt Flakeboard under emergency conditions.

BASE CASE AND STUDY ASSUMPTIONS

The PG&E base cases that were developed as part of the 2008 expansion plan process were used for this study.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative will result in reduced reliability

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2013

KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – TBD
- Special Metering or Protection –TBD
- Common Mode Exposure Items – TBD
- Interaction with other Projects – TBD

ATTACHMENT

1. Scope Diagram

Attachment 1: Scope Diagram

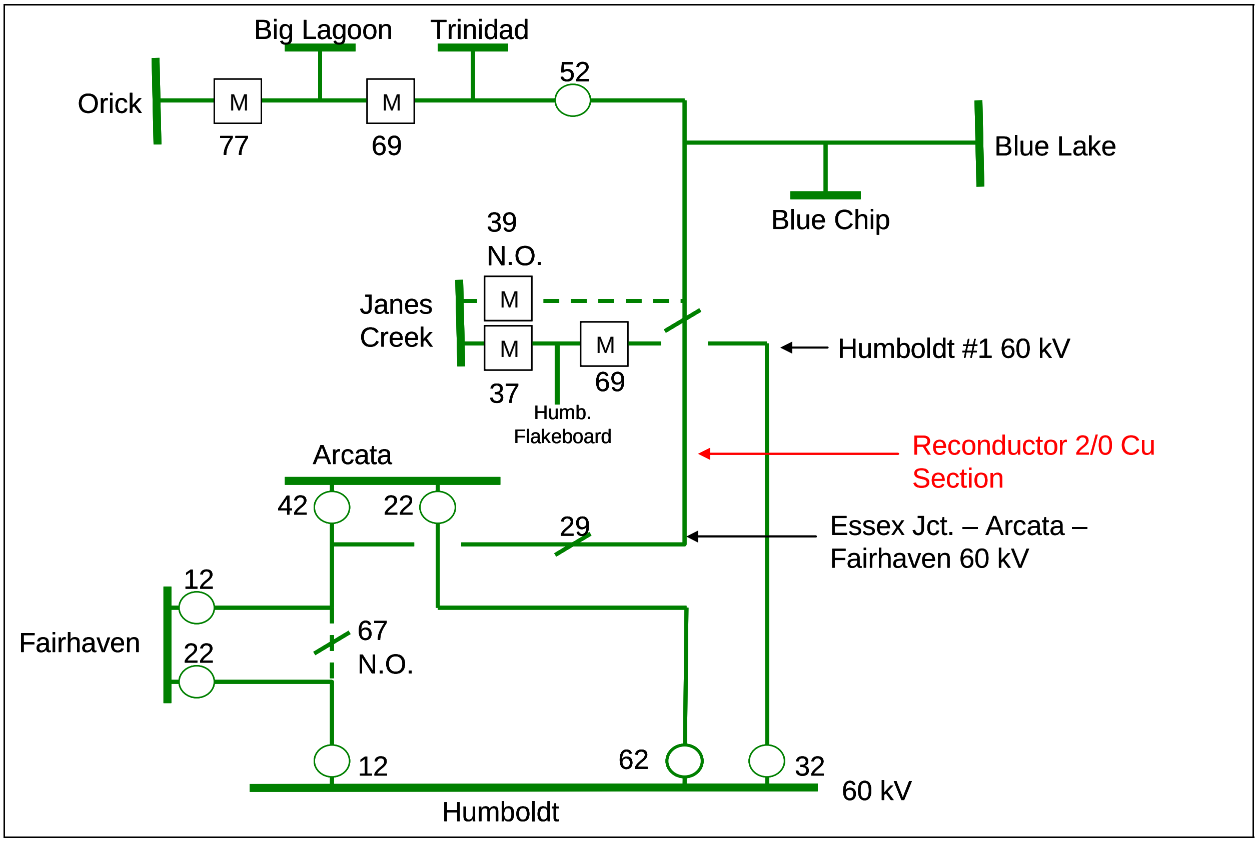


Figure 6-11: Janes Creek Area 60 kV System

Table Mountain – Vaca Dixon 230 kV Reinforcement

TARGETED IN-SERVICE DATE

May 2013 or later

PURPOSE AND BENEFIT

Access to renewable resources – This project increases electric transmission capacity and reliability for access to renewable resources.

PROJECT CLASSIFICATION

This is an existing project.

BACKGROUND

The Table Mountain - Vaca-Dixon 500 kV lines have been identified in PG&E's Transmission Ranking Cost Report[3] as part of the network facilities that could require upgrades, which are common to resource developments in the vicinity of and north of Cottonwood Substation and Table Mountain Substation if such resources must be delivered to load centers in the San Francisco Bay Area and to the south (see Chapter 4).

If more resources would develop, especially around the Table Mountain area after the completion of the Cottonwood - Vaca-Dixon 230 kV Capacity Increase Project (see Chapter 4) to install series capacitors on the four 230 kV lines, reinforcement south of Table Mountain Substation would be needed.

PG&E is investigating several options. They include:

Option 1:

- Reconductor the Table Mountain – Rio Oso, and Colgate – Rio Oso 230 kV lines
- Build a new Rio Oso – Vaca-Dixon 230 kV Line

Option 2:

- Reconductor the Table Mountain – Rio Oso and Colgate – Rio Oso 230 kV lines
- Reconductor the Rio Oso – Gold Hill and Rio Oso-Atlantic – Gold Hill 230 kV lines

[3] PG&E's 2005 Transmission Cost Ranking Report was filed in Order Instituting Investigation (OII) 00-11-001 on August 3, 2005.

If more resources would develop around the Round Mountain and Cottonwood areas, further reinforcement south of Cottonwood would be needed. PG&E is investigating the following options:

Option 3:

- Loop the Pit 1 - Cottonwood 230 kV Line into Round Mountain Substation
- Reconductor the four 230kV lines between Cottonwood and Vaca-Dixon substations

Option 4:

- Build a new Round Mountain – Cottonwood – Vaca-Dixon 230 kV Line

The need for and the scope of this project are based on an expectation that resources would develop as studied.

BASE CASE AND STUDY ASSUMPTIONS

The 2010 Summer Peak base case was developed from the power flow case that was prepared for the 2005 PG&E Expansion Plan Studies and represents the transmission network (including transmission projects approved by CAISO and PG&E), load forecast (1-in-5 year adverse weather system peak load), and expected generation retirements for year 2010. This base case was reviewed and approved by the CAISO. This base case was then modified to include new generation projects that have completed their System Impact Study (SIS) and Facility Study (FS) and the associated transmission projects approved by the generation developers, and the results of PG&E's 2004 Renewables Solicitation as of April 2005.

The 2010 off-peak base case was developed from the same 2008 light autumn case (modified from the WECC 08 LA1-S case) used in the 2004 study except that the load was updated to reflect the 2005 forecast, and the generation and transmission network were updated as necessary as described above for the 2010 Summer Peak base case.

The renewable resources assumed in the study are consistent with the results of the RRDR Report published by the CEC on September 30, 2003. These CEC results have been augmented based on information received by PG&E from potential renewables developers in response to PG&E's solicitation for information conducted in 2003, 2004 and 2005.

2014 Projects

Eagle Rock and Mendocino 115 kV Capacity Increase Project

IN-SERVICE DATE:

May 2014

PURPOSE AND BENEFIT:

Reliability – NERC Compliance

PROJECT CLASSIFICATION

This is an update to an existing project proposal

DESCRIPTION OF PROPOSED PROJECT

The project scope is to reconductor the Cortina - Eagle Rock 115 kV and Cortina – Mendocino 115 kV Lines, which are approximately 44 miles and 61 miles long, respectively. In addition, this proposal involves installation of a second 230/115 kV, 420 MVA, transformer at Cortina Substation.

This project is expected to cost between $50 million and $100 million.

BACKGROUND

Eagle Rock and Mendocino substations are located in the northern portion of PG&E's North Coast Division. These substations are the primary transmission substations in this part of the PG&E system. Power is imported into the Eagle Rock and Mendocino area through three 115 kV transmission lines. Two 115 kV lines come from Cortina Substation, about 40 miles to the east. One 115 kV line comes from Fulton Substation, about 40 miles to the south. Additional power is supplied to this load pocket by local generation from local geothermal power plants ("The Geysers").

Planning studies for projected 2018 peak demand conditions conclude that loss of the Cortina-Mendocino 115 kV Line overlapped with the Geyser No. 11 could potentially overload the Cortina-Eagle Rock 115 kV line 8% over its rerated summer emergency rating. These problems are exacerbated if The Geysers generation is reduced.

BASE CASE AND STUDY ASSUMPTIONS

The PG&E base cases that were developed as part of the 2008 expansion plan process were used for this study.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative does not address the projected low voltage and reactive margin conditions.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2014

KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – TBD
- Special Metering or Protection –TBD
- Common Mode Exposure Items – TBD
- Interaction with other Projects – TBD

ATTACHMENTS

1. Scope Diagrams

Attachment 1: Scope Diagram

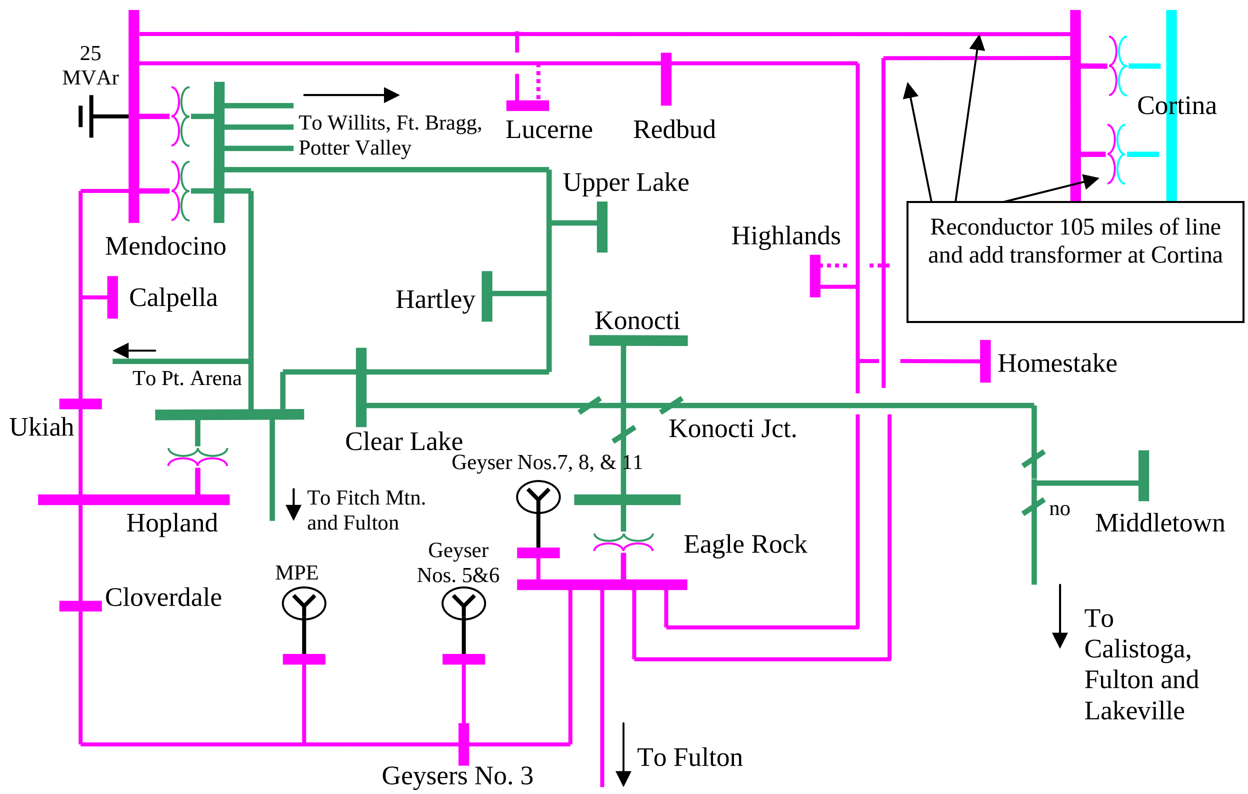


Figure 6-12: Eagle Rock and Mendocino Area

Eight Mile Road-Tesla 230 kV Lines Reconductor

IN-SERVICE DATE

May 2014

PURPOSE AND BENEFIT

Reliability - NERC Compliance

PROJECT CLASSIFICATION

This is a new project.

BACKGROUND

The Eight Mile Road-Tesla 230 kV transmission system serves electric customers in San Joaquin County. The power is delivered to Eight Mile Road, Stagg and Tesla Substations in the Stockton area. The power steps down from the 230 kV systems to the 21 kV (distribution) systems at Eight Mile Road, 60 kV systems at Stagg, and 115 kV systems at Tesla substations.

In the Stagg 60 kV system, the major load centers are Country Club, Hammer, Mosher, Stagg and the University of Pacific (UOP) substations in the North Stockton.

In the Tesla 115 kV system, the major load centers are Tracy, Lammers, Schulte, and Vierra substations.

In 2007, the Stockton area reached an electric peak of 1,507 MW. The City of Tracy and North Stockton has the highest projected growth for the division. The Stockton area is forecast to increase at a rate of 24 MW or 1.7% per year.

Planning analysis identified that the Eight Mile Road-Tesla 230 kV Line loads up to 98% in 2013 and up to 132% in 2018 during outage of either the Stagg-Tesla 230 kV Line or the Stagg 230/60 kV Transformer Bank No. 2. The Eight Mile Road-Stagg 230 kV Line loads up to 107% in 2018 during similar outage conditions. The Stagg-Tesla 230 kV Line loads to 101% in 2018 during outage of the Eight Mile Road-Stagg 230 kV Line. In addition, the Eight Mile Road-Tesla and Stagg-Tesla 230 kV Lines load up to 101% in 2013 during outage of the Tesla 230 kV Bus 1 Section E (Category C).

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended because it does not mitigate the expected capacity constraints.

Alternative 2: Re-conductor Eight Mile Road-Tesla 230 kV Double Circuit Tower Lines

This alternative proposes to reconductor the Eight Mile Road-Tesla (27 circuit miles), Eight Mile Road-Stagg (7 circuit miles), and Stagg-Tesla (24 circuit miles) 230 kV Lines with 795 ACSS conductors or equivalent.

This alternative is expected to cost between $30M and $50M.

Alternative 3: Add Third 230 kV Source at Stagg Substation

This alternative proposes to add a third 230 kV source to Stagg Substation from Tesla Substation. This alternative may not be feasible because of environmental and permitting concerns in the area.

This alternative is expected to cost between $20M and $30M.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2014

KEY ISSUES

- Land-Use Restrictions – There are no land-use restrictions with this project.
- Environmental Concerns – TBD
- Special Metering or Protection - TBD
- Common Mode Exposure Items – None
- Interaction with other Projects or Studies

ATTACHMENT

1. Scope Diagram

Attachment 1: Scope Diagram

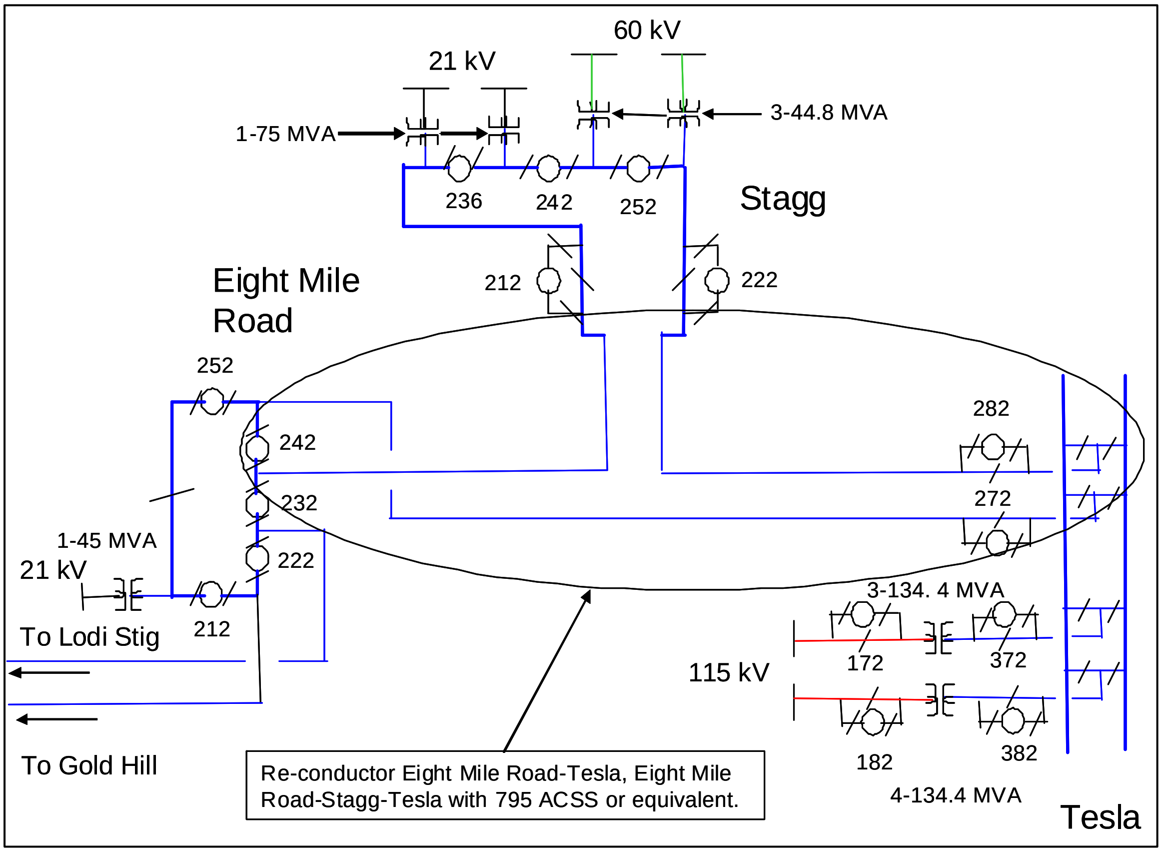


Figure 6-13: Scope Diagram

Lockeford – Lodi Area 60 kV Reinforcement

TARGETED IN-SERVICE DATE

May 2014

PURPOSE AND BENEFIT

Reliability - NERC Compliance

PROJECT CLASSIFICATION

This is a new project.

BACKGROUND

The Lockeford – Industrial, Lodi-Industrial, and Lockeford – Lodi Nos. 1, 2, and 3 60 kV Lines are located in San Joaquin County, within the Stockton Division. These lines provide 60 kV transmission power from Lockeford Substation to serve local area customers in the Lockeford and Lodi areas.

This 60 kV system serves five substations that include Colony, Lodi, Victor, Mondavi, and Industrial (owned by the City of Lodi). The City of Lodi is a member of the Northern California Power Agency (NCPA) and is the largest city served from the PG&E 60 kV transmission network. Another key source to the local area load is through a 25 MW combustion turbine (Lodi CT owned by NCPA) located in Lodi. The load growth for the 60 kV systems is minimal, with the exception of the City of Lodi that is expected to grow at approximately 2 MW per year.

Planning analysis determined that loss of the Lockeford – Lodi No. 2 60 kV Line while the Lodi CT is offline is projected to overload the Lockeford – Industrial 60 kV Line by 7% in 2018. Also in 2018, the Lockeford – Lodi Nos. 2 and 3 60 kV lines are projected to overload up to 4% following an outage of the Lockeford – Industrial 60 kV Line while the Lodi CT is offline.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended. This alternative does not address the potential overload issue.

Alternative 2: Reconductor 60 kV Lines Between Lockeford and Lodi Substations

This alternative proposes to reconductor a total of 17 miles on the Lockeford – Industrial (6.0 miles), Lockeford – Lodi No. 2 (6.5 miles), and Lockeford – Lodi No. 3 (4.5 miles) 60 kV lines with higher capacity rated conductors.

Alternative 3: Convert the Lockeford – Industrial system from 60 to 115 kV

This alternative proposes to add two 230/115 kV transformers at the Lockeford Substation and upgrade four 60 kV substations (Industrial, Victor, Mosher, and Mettler) and transmission lines to 115 kV service. Particularly, the transmission lines required for conversion are the Lockeford – Industrial, Industrial Tap, Lockeford No. 1 and portions of Lockeford – Lodi Nos. 2 and 3 and Lodi - Industrial Lines.

Alternative 4: Connect City of Lodi's Industrial Substation to the 230 kV System

This alternative proposes to upgrade Industrial Substation to a 230/60 kV substation and connect to the 230 kV system by constructing a 230 kV line from Eight Mile Road Substation to Lockeford Substation.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2014

KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – TBD
- Special Metering or Protection – TBD
- Common Mode Exposure Items – TBD
- Interaction with other Projects or Studies – Lodi-Industrial 60 kV Line Switch Upgrade

ATTACHMENT

1. Scope Diagram

Attachment 1: Scope Diagram

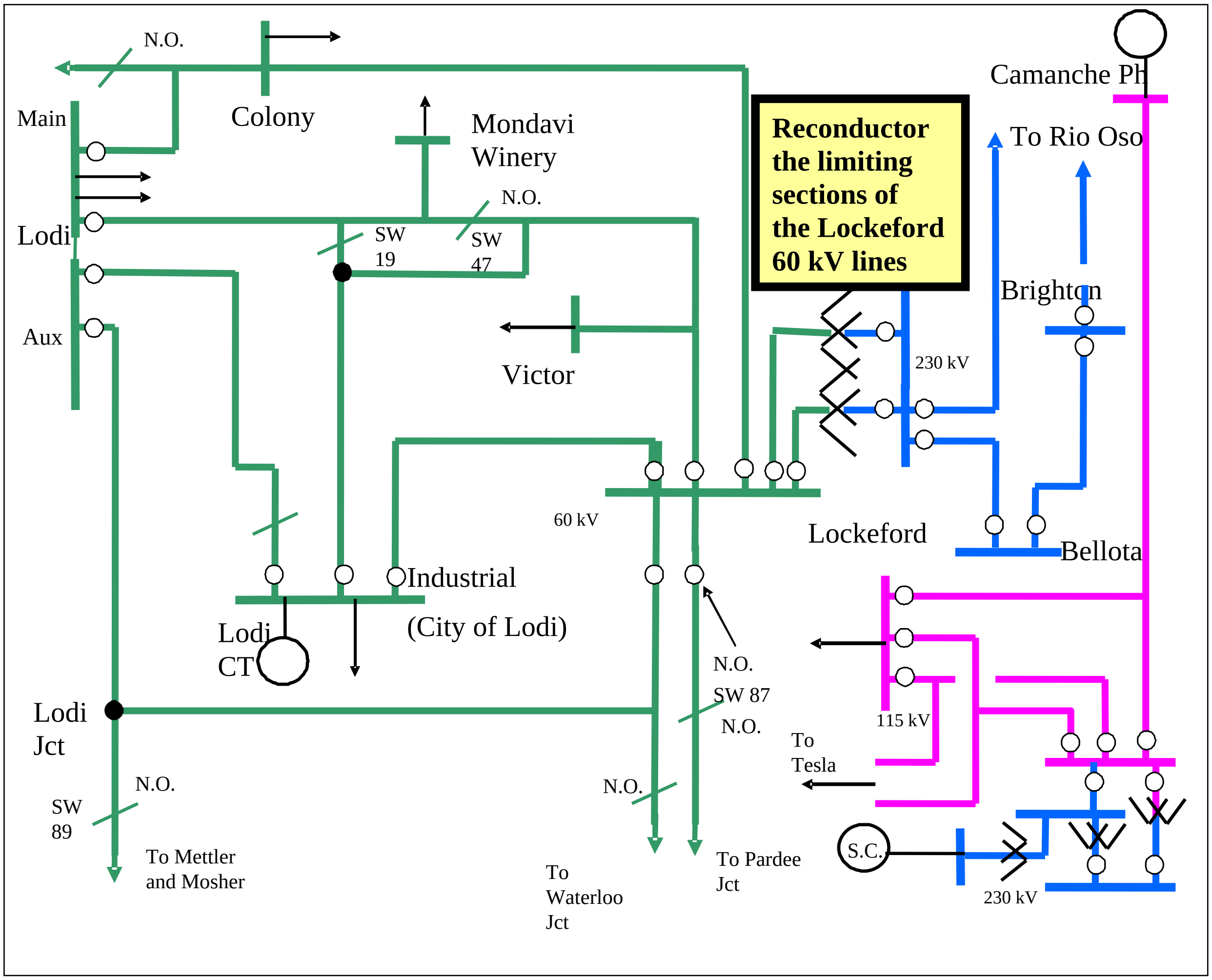


Figure 6-14: Scope Diagram

Oakhurst 115 kV Tap Reinforcement

TARGETED IN-SERVICE DATE

May 2014

PURPOSE AND BENEFIT

Reliability - NERC Compliance

PROJECT CLASSIFICATION

This is a new project.

BACKGROUND

The Oakhurst 115 kV Tap is located in Madera County, within the Yosemite Division. This tap line provides 115 kV transmission power from Kerckhoff Powerhouse (24 MW) and Chowchilla Cogen (26 MW) to serve local area customers in the Oakhurst and Coarsegold area.

The Oakhurst 115 kV Tap serves two PG&E substations that include Coarsegold and Oakhurst. The 2009 projected peak load in these substations is 48.4 MW and is forecast to increase approximately 1.91 MW or 3.4% per year.

The Oakhurst 115 kV Tap Line is strung with 4/0 ACSR (9.13 miles) conductor.

Planning analysis determined that the Oakhurst 115 kV Tap is projected to experience a normal overload of 11% in 2018.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended. This alternative does not address the potential overload issue.

Alternative 2: Reconductor the Oakhurst 115 kV Tap

This alternative proposes to reconductor approximately 18 miles of the Oakhurst 115 kV Tap with a higher rated conductor with a minimum rating of 690 Amps normal.

This alternative is expected to cost between $5M and $10M.

Alternative 3: Build a new 115 kV back-tie

This alternative proposes to convert the Wishon – Coppermine 70 kV Line and the Wishon – San Joaquin #3 70 kV Line to 115 kV. The scope also includes building a new 7 mile line to connect Oakhurst substation with San Joaquin Powerhouse #3, providing a second source for the Oakhurst and Coarsegold substations. To complete the loop, a 1.6 mile 115 kV Line will be constructed to connect Kerckhoff Powerhouse #2 to the converted Wishon – Coppermine 115 kV Line. The last part of this alternative is to reconductor approximately 18 miles of the Oakhurst 115 kV Tap with a conductor having a minimum rating of 690 Amps normal.

This alternative is expected to cost between $25M and $40M.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2014

KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – TBD
- Special Metering or Protection – TBD
- Common Mode Exposure Items – TBD
- Interaction with other Projects or Studies – TBD

Oakland Area Long Term Plan

IN-SERVICE DATE

May 2014

PURPOSE AND BENEFIT

Reliability – NERC Compliance

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROJECT

This project proposes to add a new Oakland J – Oakland C 115 kV Cable (Approximately 5 miles). In order for this facility to interconnect to the 115 kV transmission system in Oakland, the following additional projects are needed:

- Reconductor Moraga–Claremont “K” 115 kV Line No. 1 and 2
- Loop the existing Oakland “C”–“X” 115 kV Cable No. 3 into Oakland “L
- Add series reactors to the Moraga–Oakland “X” 115 kV Lines
- Add series reactor to the Claremont “K”-Oakland “D” 115 kV Lines
- Recable Oakland “D”-Oakland “L” 115 kV Line
- Recable Oakland “C”-Oakland “X” 115 kV Line No. 2
- Reconductor Grant - Eastshore 115 kV Line Nos. 1 & 2
- Separate cross tied circuit Oakland “J”–Grant 115 kV Line and reconductor (New Grant–Edes & Grant-Oakland “J” 115 kV Line)
- Close CB 125 at Edes 115 kV Substation
- Close Switch 197 at Owens Brockway 115 kV Substation

This alternative is expected to cost approximately $100M to $200M.

BACKGROUND

The Oakland Area, which is located in Alameda County, consists of electric customers from the city of Oakland, Alameda, Emeryville, Berkeley, San Leandro, San Lorenzo, Piedmont and Hayward. This area has approximately 300,000 electric customers that cover approximately 160 square miles. Peak electric demand in 2007 for the Oakland Area was roughly 699 MW, with an expected growth rate of approximately 6 MW or 1% per year.

Electric service to the Oakland Area is currently supplied by five 230/115 kV transformers at Moraga and Sobrante Substation; and by internal generation which are Duke Energy’s Oakland Power Plant and the City of Alameda’s Gas Turbines. These internal generators have a combined capability of producing approximate 200 MW of power. Thus, the majority of power needs for the area is satisfied by importing power from Sobrante and Moraga Substation.

There is a potential third electric transmission source into the Oakland Area via the Eastshore 230/115 kV transformers. Currently, the third source is not available due to a normally open switch on the Grant – Edes 115 kV Line.

The conductors in the Oakland Area vary depending on their location. The 115 kV transmission facilities in the Northern Oakland Area (NOA) are comprised of both underground cables and overhead transmission lines. The existing underground cables are over 50 years old and will soon require replacement. The 115 kV Transmission system in the Southern Oakland Area (SOA) is comprised of only overhead transmission lines.

Currently, power is imported to the NOA through eight 115 kV transmission lines, 6 of which comes from Moraga and two from Sobrante. The Moraga-X 115 kV Line Nos. 1, 2, 3 and 4 comprise of 4 of the eight 115 kV lines. It will be extremely difficult and costly to reconductor these four lines due to their geographical orientation. Power is imported to the SOA through four 115 kV Lines also from Moraga Substation. Thus, Moraga substation is a critical source of power for the Oakland Area.

By 2010, a third Oakland C-X 115 kV Cable will be installed. The addition of this cable is the first step in solving the capacity and reliability issues for the Oakland Area.

In order to perform routine maintenance work within the Northern Oakland Area, load is at risk unless generation is dispatched. As previously stated, the cables in the Oakland area are old and will soon need to be replaced. Either generation or load curtailment will be required to replace these aging cables. As electric customers in the area continue to grow, the amount of load at risk and generation required will only increase.

In addition, planning studies show that the following (N-2) contingencies will result in reliance on local generation:

1. Outages of Oakland K-D Cable Nos. 1 and 2 (N-2)
2. Outages of Oakland C-X Nos. 2 and 3 (N-2)
3. Outages of Oakland C-X No. 3 and Oakland D-L (N-2)

Furthermore, there are three Double Circuit Tower Line Outages (DCTL) which results in potential thermal and voltage concerns. The first is an outage of Moraga – Oakland J and Moraga – San Leandro No. 3 115 kV Lines (L-2) resulting in thermal concern on the Moraga – San Leandro 115 kV Line Nos. 1 and 2. The second is an outage of Moraga – San Leandro 115 kV Line Nos. 1 and 2 (L-2) resulting in potential thermal concerns on the Moraga – San Leandro 115 kV Line No. 3. Lastly, an outage of Eastshore – San Mateo and Pittsburg – San Mateo 230 kV Line resulting in potential thermal concerns on the Dumbarton – Newark 115 kV Line.

The propose project will increase the load serving capability and reliability of the transmission system within the Oakland Area.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended. This alternative does not address the potential reliability, thermal and voltage concerns for the Oakland Area.

Alternative 2: Construct a new Moraga-Oakland C 230 kV cable

This alternative is not recommended. This alternative proposes to construct a new 230 kV transmission line from Moraga substation to Oakland C substation. This alternative does not address the potential reliability, thermal and voltage concerns for the Oakland Area.

Alternative 3: Construct a new Oakland J-Oakland C 115 kV cable (Preferred Alternative)

This alternative is recommended. This alternative proposes to network the SOA and the NOA by constructing a new Oakland J-Oakland C 115 kV cable. This alternative addresses the potential reliability, thermal and voltage concerns for the Oakland Area.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2014

KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – TBD
- Special Metering or Protection – TBD
- Common Mode Exposure Items – None
- Interaction with other Projects – TBD

ATTACHMENTS

1. Scope Diagram

Attachment 1: Scope Diagram

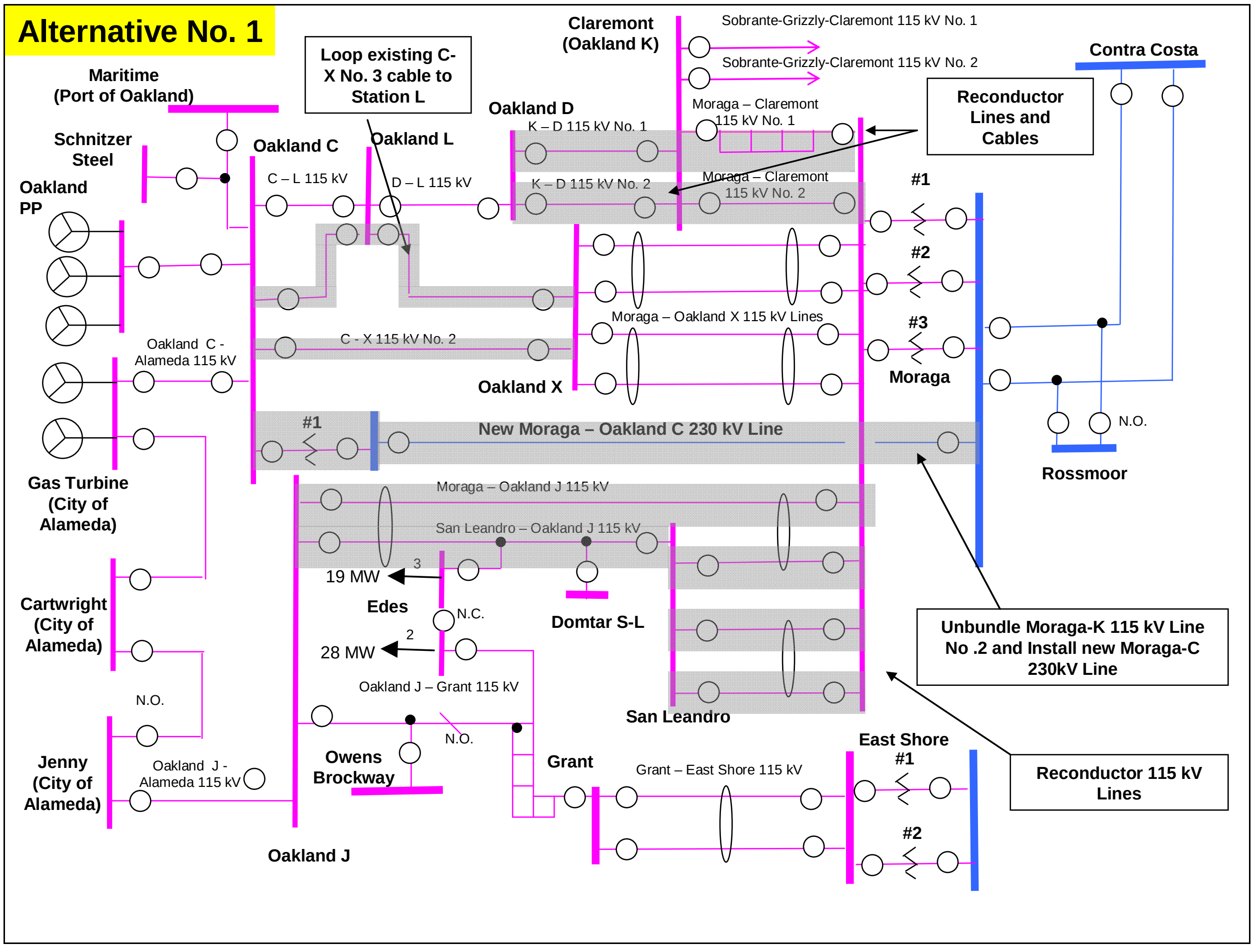


Figure 6-15: Oakland Area- Alternative 1

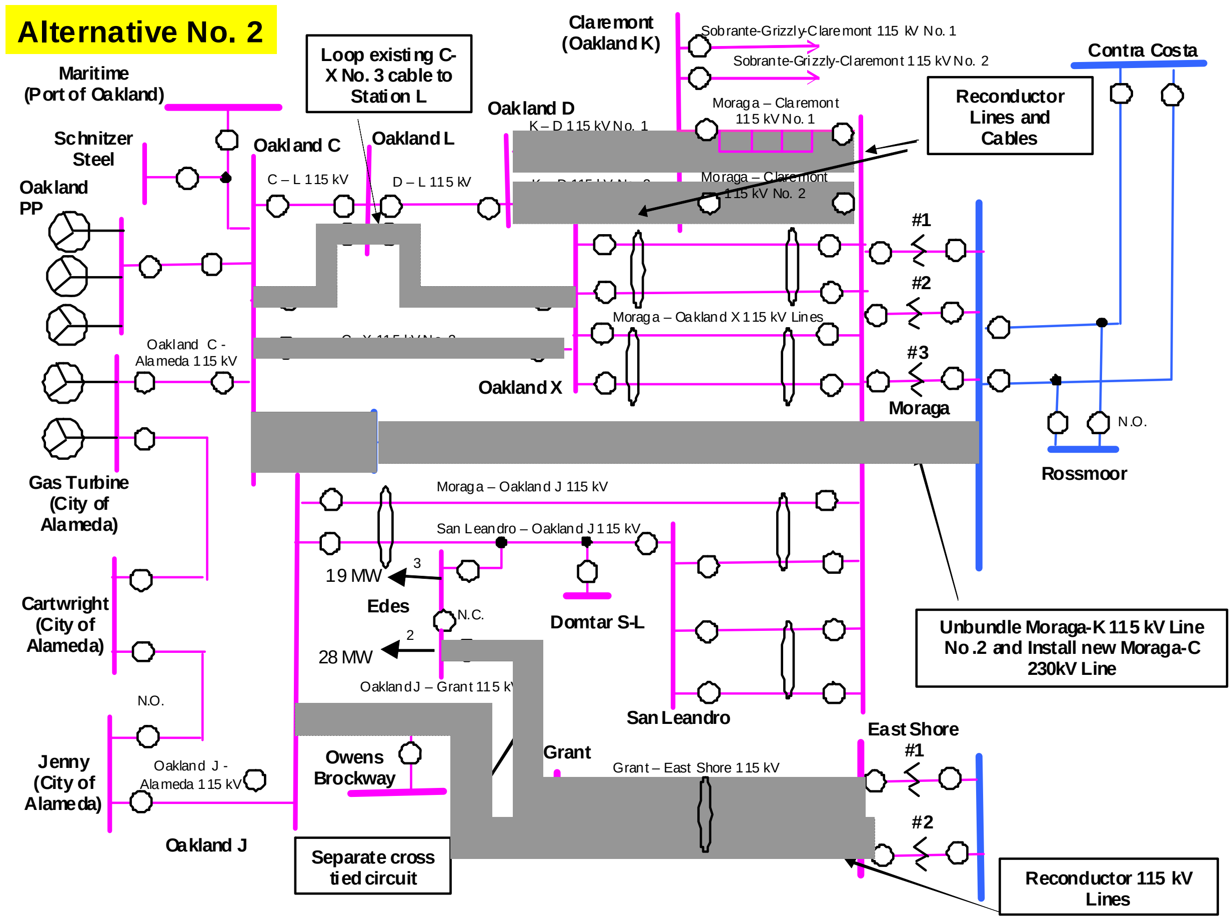


Figure 6-16: Oakland Area - Alternative 2

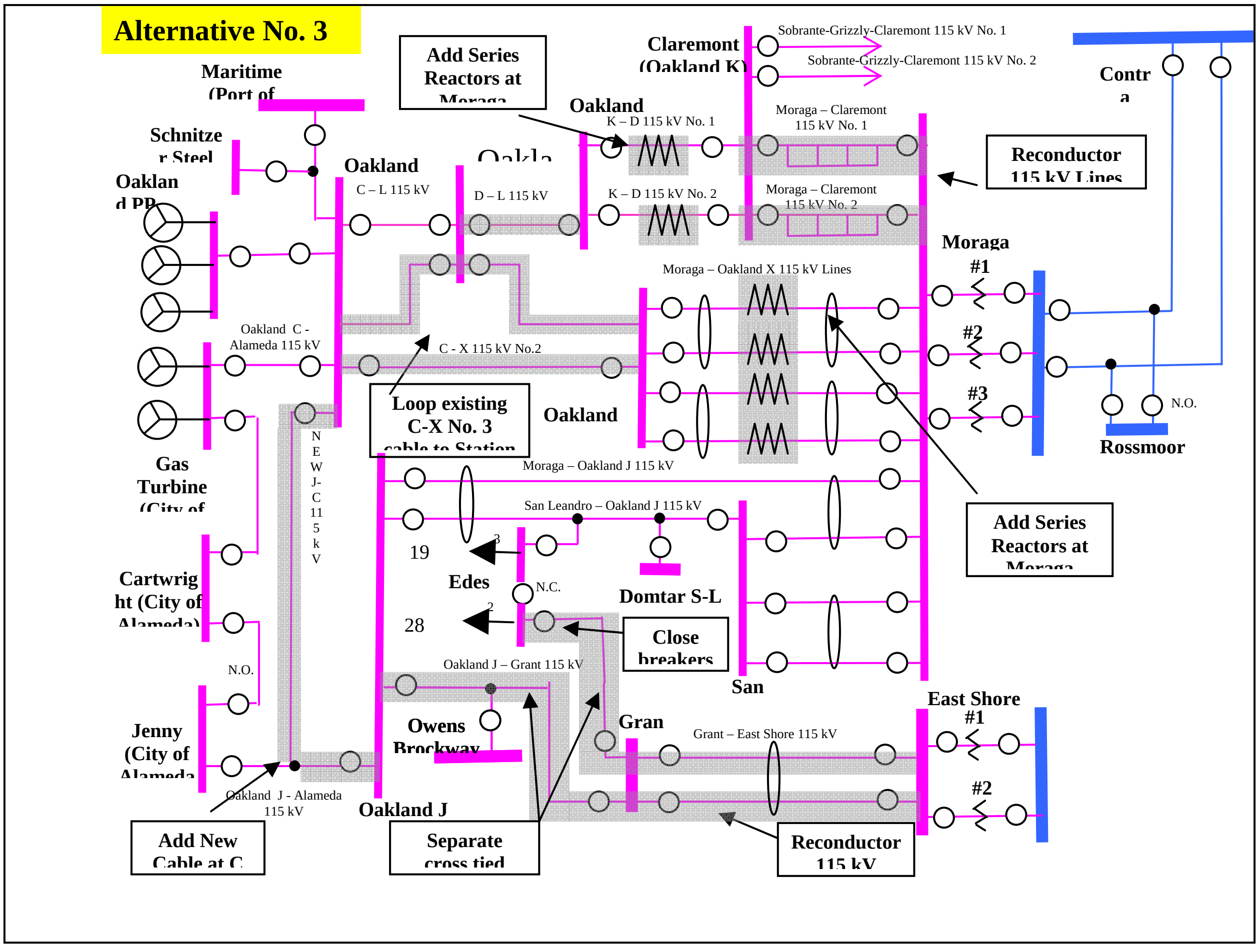


Figure 6-17: Oakland Area - Alternative 3 (Preferred Alternative)

South of Palermo 115 kV Reinforcement

TARGETED IN-SERVICE DATE

May 2014

PURPOSE AND BENEFIT

Reliability – NERC Compliance

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION OF PROPOSED PROJECT

The project scope is to reconductor the southern portions of the Palermo – Rio Oso Nos. 1 and 2 115 kV Lines. This project proposes to reconductor the following lines with 477 ACSS conductors:

1. Bogue – Rio Oso 115 kV Line (21.5 miles),
2. Palermo – Bogue 115 kV Line (8 miles) between Olivehurst and Bogue substations,
3. Palermo – Pease 115 kV Line (26.5 miles),
4. Pease – Rio Oso 115 kV Line (28 miles), and
5. Rio Oso – Nicolaus 115 kV Line (5.5 miles).

The project is expected to cost between $50M and $60M. The large cost range is due to the unknown permitting and environmental aspects of the project.

The CAISO previously approved the northern portion of this project as part of the 2003 Expansion Plan process. The approved scope is to re-construct sections of the existing Palermo-Rio Oso 115 kV double circuit tower line and re-conductor with 1,113 kcmil all aluminum conductor. This re-construction work would include a 40-mile section between Palermo and East Nicolaus substations. The re-conductor work would also include a 30-mile section between Palermo and Bogue Junction for a total of 70 circuit miles. The expected in-service date for this work is December 2009.

BACKGROUND

There are three Palermo – Rio Oso 115 kV lines located in the Yuba and Sutter counties. They range in length from 46 to 57 miles. These lines provide transmission power to the Honcut, Pease, East Marysville, Olivehurst, Bogue and East Nicolaus distribution substations.

In addition to providing 115 kV transmission power to local area electric customers, the Palermo – Rio Oso 115 kV lines also serve as a transmission path for bulk transmission power to travel. A large amount of this bulk transmission power is from nearby hydro generating facilities. There are several hydro power plants in the area, particularly along Feather River between Lake Almanor and Lake Oroville. Most of these plants are interconnected onto Table Mountain, Palermo and Rio Oso substations. A portion of the output from these power plants, going through the Table Mountain Substation, are then transported to load centers in the Sacramento area through the Palermo – Rio Oso 115 kV lines.

Planning analysis concluded that during 2009 summer peak conditions the Palermo – Bogue and Palermo – Nicolaus 115 kV Lines could overload up to 8% and 3% of its emergency rating, respectively, following an overlapping outage of the Greenleaf I generator and the Pease – Rio Oso 115 kV Line. In addition, the Bogue – Rio Oso and Pease – Rio Oso 115 kV Lines could overload up to 14% and 12% of its emergency ratings, respectively, following an overlapping outage of the Belden generator and the Colgate – Rio Oso 230 kV Line during 2010 summer peak conditions. Similarly, the Palermo – Pease 115 kV Line could overload up to 14% of its emergency rating following an overlapping outage of the Greenleaf II generator and the Table Mountain – Pease 60 kV Line.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended. This alternative does not address the projected capacity issues.

Alternative 2: Build a new Palermo-Rio Oso 115 kV Line

The proposed new line would be sized with 715 Al conductors and measure approximately 45 to 55 miles long. This alternative would also require Honcut Substation be normally fed from the Palermo-Pease 115 kV Line (normally open Switch 445 and normally close Switch 435 at the Honcut Junction) and transferring the alternate fed to East Marysville Substation from the Palermo - Nicolaus 115 kV Line to the new Palermo-Rio Oso 115 kV Line.

This alternative is expected to cost between $70 million and $100 million. This alternative is not recommended because of significant uncertainties in transmission line permitting requirements and its high cost.

PROJECT SCHEDULE

- Environmental and Permitting Processes - TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2014

KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – TBD
- Special Metering or Protection - TBD
- Common Mode Exposure Items – None
- Interaction with other Projects or Studies – T1002: Bogue Reconfiguration

ATTACHMENTS

1. Scope Diagrams

Attachment 1: Scope Diagram

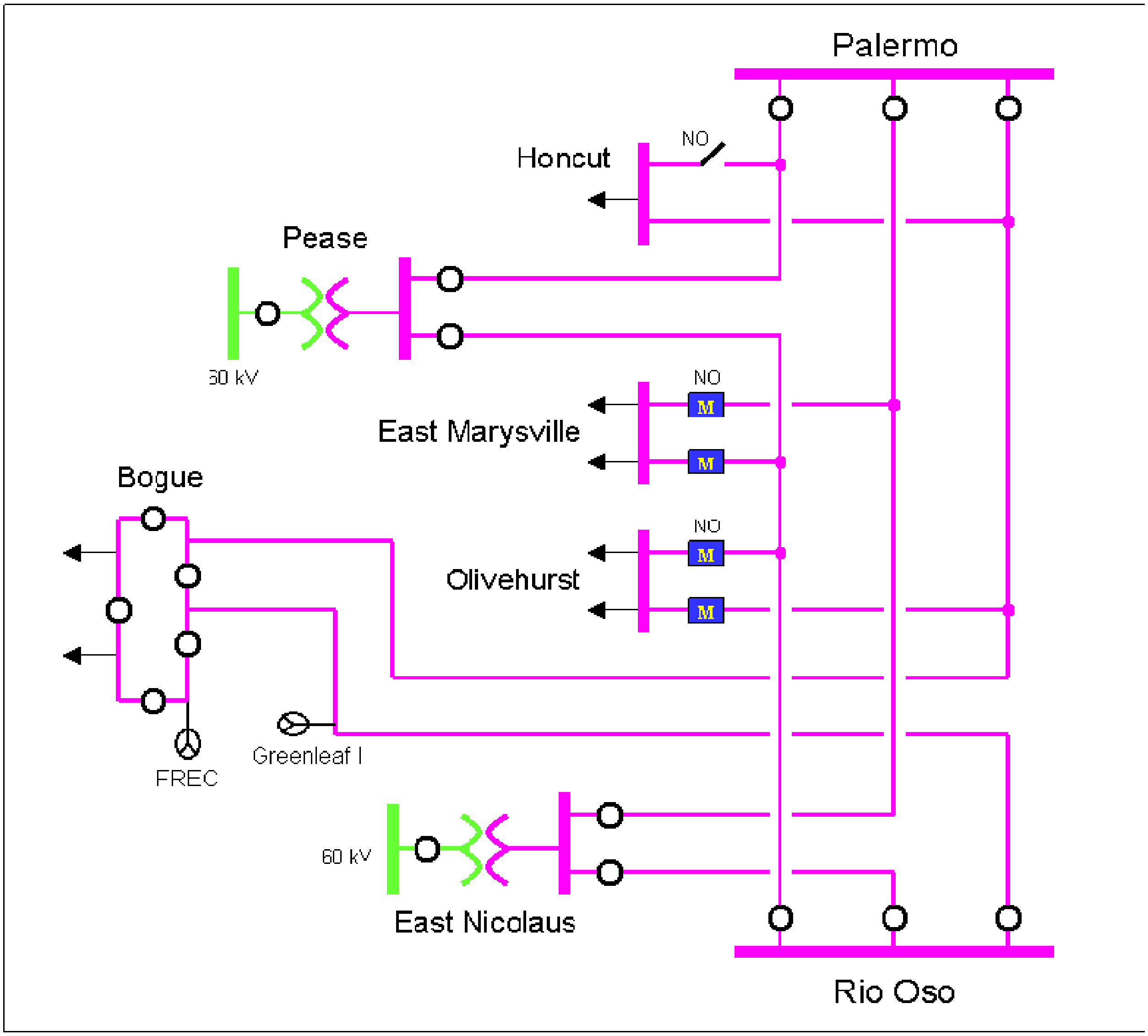


Figure 6-18: Scope Diagram

Vaca Dixon – Davis 115 kV Conversion

IN-SERVICE DATE

May 2014

PURPOSE AND BENEFIT

Reliability – NERC Compliance

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION OF PROPOSED PROJECT

A potential project alternative that is being investigated is the conversion of the existing Vaca Dixon – Dixon 60 kV system for 115 kV operation.

The project is cost is between $80M and $100M.

BACKGROUND

As demand continues to grow in the Vaca Dixon – Dixon 60 kV system, PG&E is evaluating various transmission expansion work to ensure adequate capacity and reliability levels are in place to meet the future demands of its end users.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative requires no system upgrades.

Alternative 2: Fulton Junction Switching Station and Reconfigure 115 kV System

This alternative proposes to build a new switching station at the Fulton Junction location. In addition, this alternative proposes to reconfigure local 115 kV lines to interconnect into new switching station.

Alternative 3: Reconductor and Rebuild 60 kV and 115 kV System

This alternative proposes reconductoring and rebuilding limiting 60 and 115 kV transmission lines with higher capacity conductors.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2014

KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – TBD
- Special Metering or Protection – TBD
- Common Mode Exposure Items – TBD
- Interaction with other Projects – TBD

ATTACHMENTS

1. Scope Diagrams

Attachment 1: Scope Diagrams

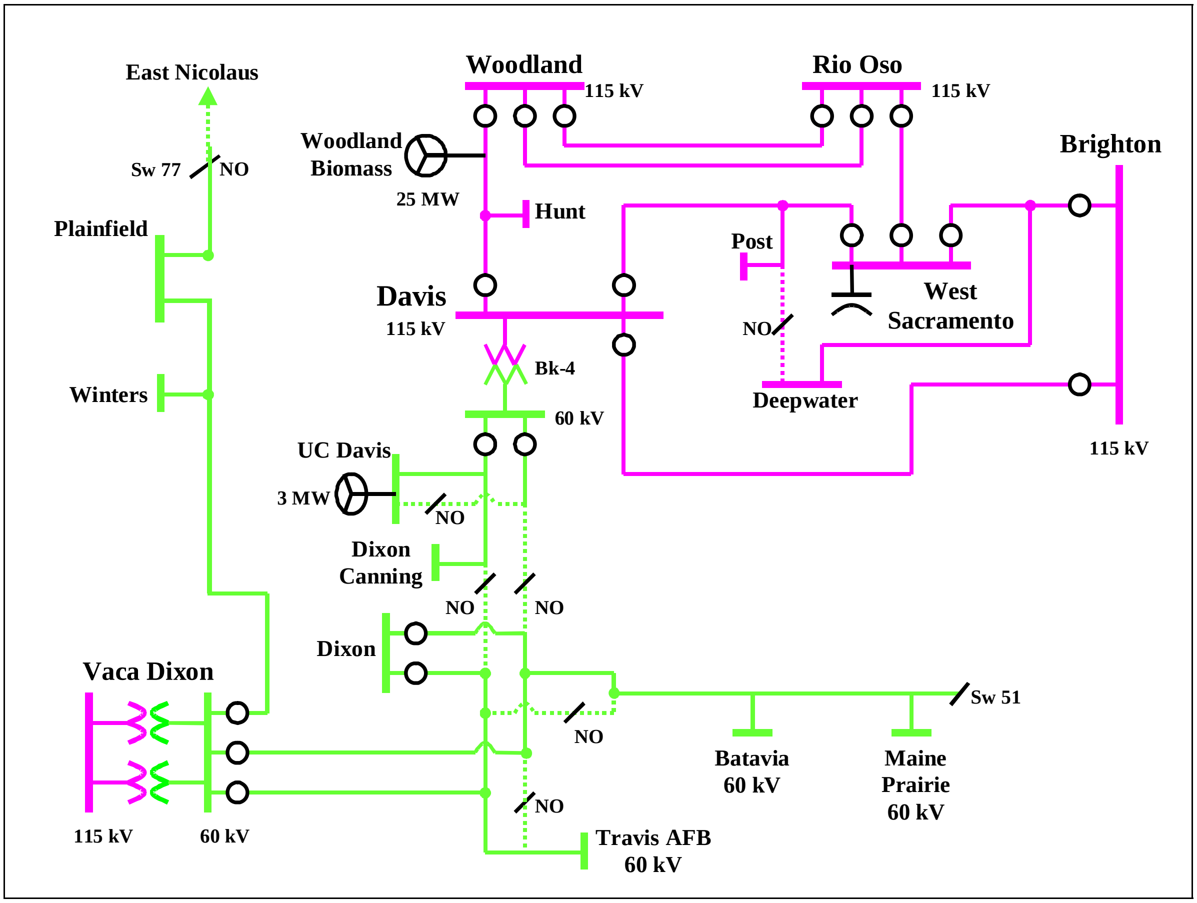


Figure 6-19: Existing System

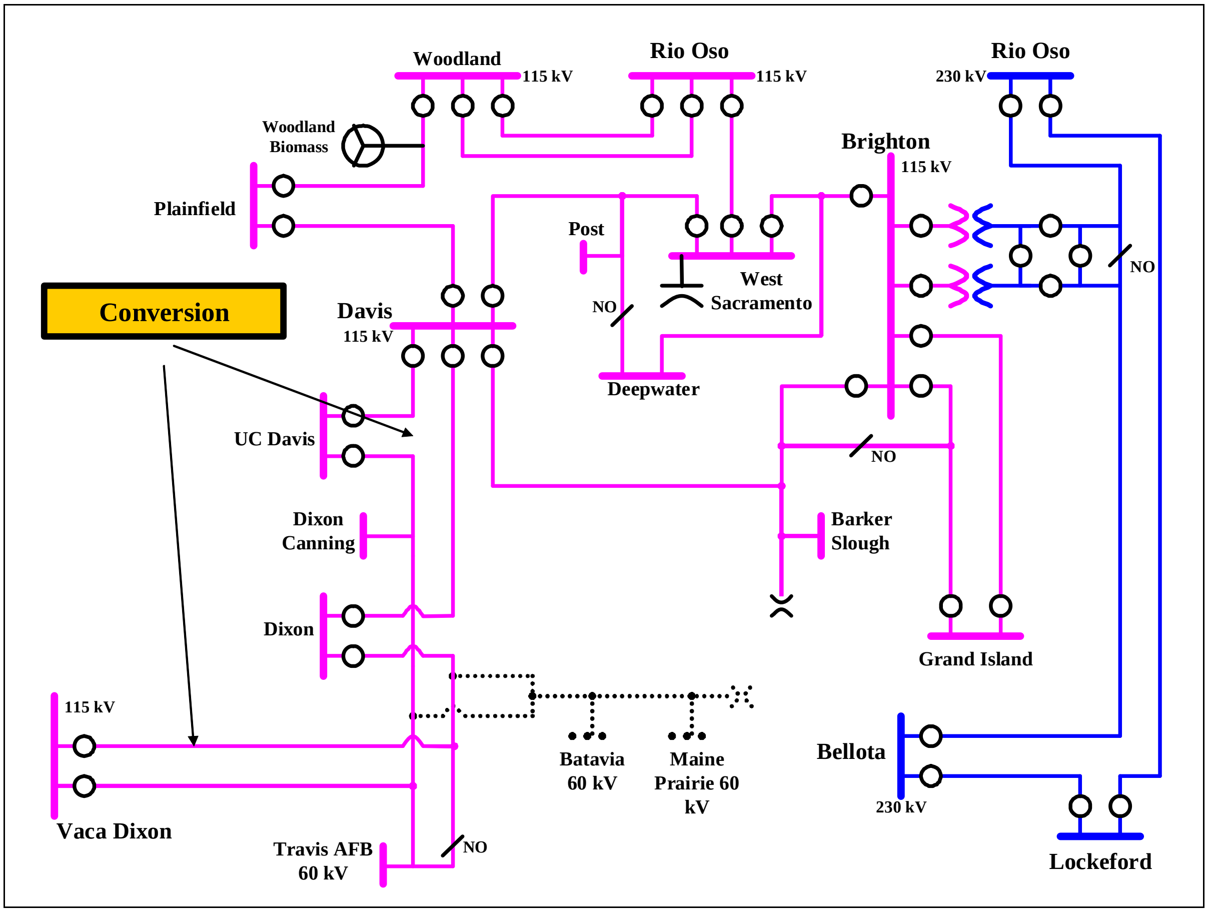


Figure 6-20: Scope Diagram

Valley Springs - Martell 60 kV Nos. 1 and 2 Lines Reinforcement

IN-SERVICE DATE

May 2014

PURPOSE AND BENEFIT

Reliability - NERC Compliance

PROJECT CLASSIFICATION

This is a new project.

BACKGROUND

The Valley Springs-Martell 60 kV Nos. 1 and 2 Lines are located in Amador County, within the Stockton Division. These lines provide 60 kV transmission power from Valley Springs 230/60 kV Substation to serve Clay, Ione, Martell, and AMFOR (owned by American Forest Products). Another key source to the area is the Pardee Powerhouse (PH) which is owned by East Bay Municipal Utility District (EBMUD). The Pardee PH is rated at 29 MW but usually generates 16 MW and less.

Normal electric service to Martell and AMFOR Substations during summer peak periods is from the Valley Springs-Martell 60 kV No. 1 Line. These substations can not be alternately served from the Valley Springs-Martell 60 kV No. 2 Line during loss of the No. 1 Line because it will overload the No. 2 Line.

The 2009 projected peak load in these substations is 54.6 MW including 2 MW at AMFOR Substation and is forecast to increase approximately 1.4 MW or 2.5% per year.

The Valley Springs-Martell 60 kV No. 1 Line is strung with 397.5 AAL (2.1 miles), #4/0 AAL (0.3 miles), and #2/0 CU (10.5 miles). The Valley Springs-Martell 60 kV No. 2 Line is strung with 715.5 AAL (8.1 miles), 397.5 AAL (2.1 miles), #4/0 AAL (8.3 miles), and #2/0 CU (7 miles).

Under the summer configuration, planning analysis shows that the Valley Springs-Martell 60 kV No.2 Line loads up to 101% in 2018 when Pardee PH is out of service.

Martell Substation could be served normally from both Valley Springs-Martell Nos. 1 and 2 lines to improve reliability. However, sections of either of the two lines could overload as much as 76% in 2013 during outage of either line when Pardee PH is out of service.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended. This alternative does not address load growth and reliability concerns.

Alternative 2: Reconductor Valley Springs-Martell 60 kV Nos. 1 and 2 Lines

This alternative proposes to reconductor approximately 13 miles on the Valley Springs-Martell 60 kV No. 1 Line and 18 miles on the Valley Springs-Martell 60 kV No. 2 Line with 715.5 AAL conductors or equivalent.

This alternative is expected to cost between $15M and $25M.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2014

KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – TBD
- Special Metering or Protection - None
- Common Mode Exposure Items - None
- Interaction with other Projects or Studies – None

ATTACHMENT

1. Scope Diagram

Attachment 1: Scope Diagram

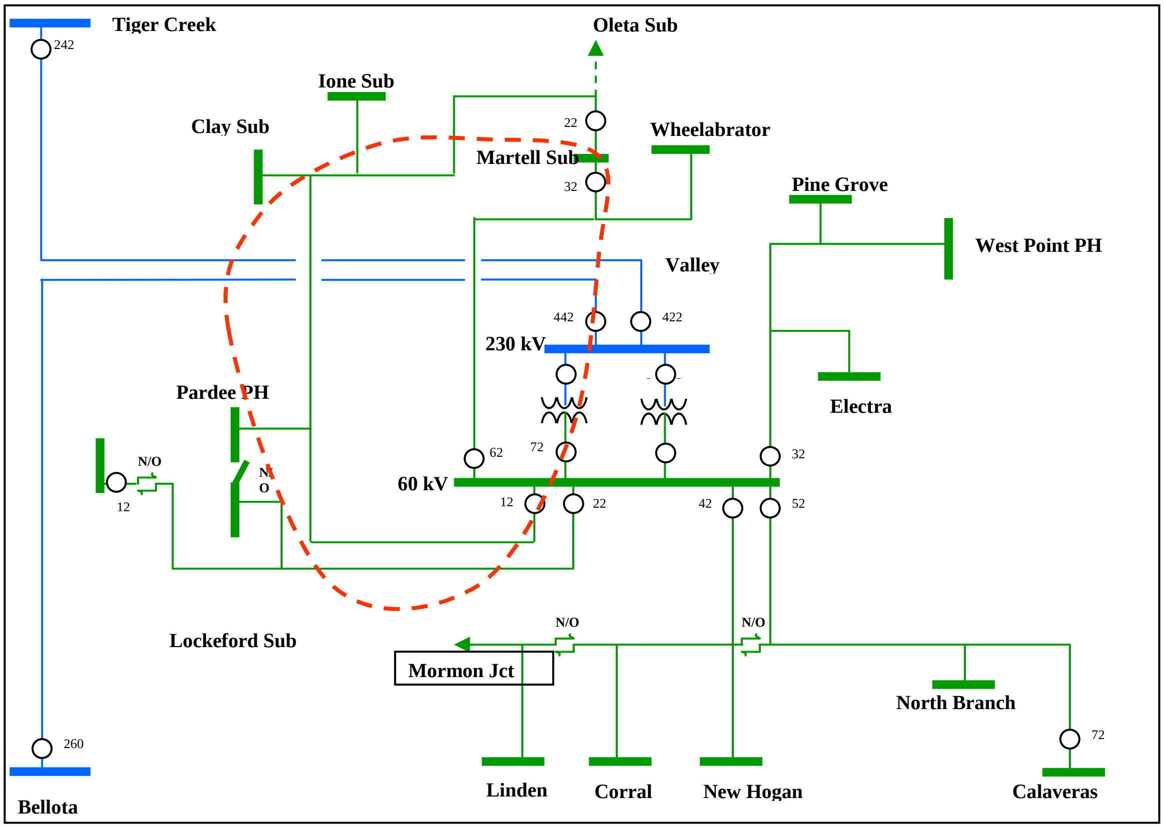


Figure 6-21: Scope Diagram

2015 Projects

Ashlan-Gregg and Ashlan-Herndon 230 kV Reconductor

TARGETED IN-SERVICE DATE

May 2015

PURPOSE AND BENEFIT

Reliability – NERC Compliance

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROJECT

The project scope is to reconductor a total of 13.5 miles on the Herndon-Ashlan (6.5 miles) and Gregg-Ashlan (7 miles) 230 kV lines with higher capacity rated conductors. If necessary, associated line terminal equipment would be upgraded. In addition, the project scope would require obtaining any necessary environmental and land permits to complete the reconductoring work.

This project is expected to cost between $5 million and $10 million.

BACKGROUND

The Herndon-Ashlan and Gregg-Ashlan 230 kV lines are key transmission lines that support the greater Fresno metropolitan area. Figarden is a distribution substation that is electrically connected to the 230 kV lines via a double tap connection. Ashlan is distribution substation that is electrically connected to the 230 kV lines via a loop connection.

Ashlan Substation is comprised of three 230/12 kV 70 MVA banks and serves a load total of 212 MW in 2008. There is substation space at Ashlan to accommodate a potential fourth distribution bank. The line section that connects Figarden Substation to the tap points of both the Herndon-Ashlan and Gregg-Ashlan 230 kV lines is comprised of two 1250 AA-UG underground cables. Figarden Substation has two 230/21 kV, 75 MVA banks, serving a load total of 133 MW in 2008. Distribution Planning has recently initiated a distribution capacity project to install a third 75 MVA distribution bank at Figarden. Figarden Bank No. 3 is projected to come online in May 2009.

Both the Herndon-Ashlan and Gregg-Ashlan 230 kV lines are normally rated for 743 Amps, each with an emergency rating of 850 Amps. The Herndon-Ashlan 230 kV line is approximately 6.5 miles long, consisting of both 795 ACSR and 1113 Al. The Gregg-Ashlan 230 kV line is also constructed of 795 ACSR and 1113 Al, and it is about 7 miles long.

Planning analysis determined that loss of either the Gregg-Ashlan or Herndon-Ashlan 230 kV line is projected to overload the remaining line by 5% in 2018.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended. This alternative does not address the potential overload issue.

Alternative 2: Convert 115 kV system to 230 kV and Loop Figarden Load

This alternative proposes to convert portions of the nearby Herndon-Sanger Number (No.) 1 and No. 2 to 230 kV. Only the distance from Herndon to Ashlan would be converted: approximately 14 miles. This would create another source to Ashlan and allow Figarden to operate as a fully looped station. Additional studies are needed to determine the substation space requirements to accommodate two new 230/115 kV banks and ultimately ten 230 kV elements at the Ashlan Substation.

Using unit costs, this alternative is between $30 million and $45 million.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2015

KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – TBD
- Special Metering or Protection – TBD
- Common Mode Exposure Items – TBD
- Interaction with other Projects or Studies – TBD

ATTACHMENTS

1. Scope Diagram

Attachment 1: Scope Diagram

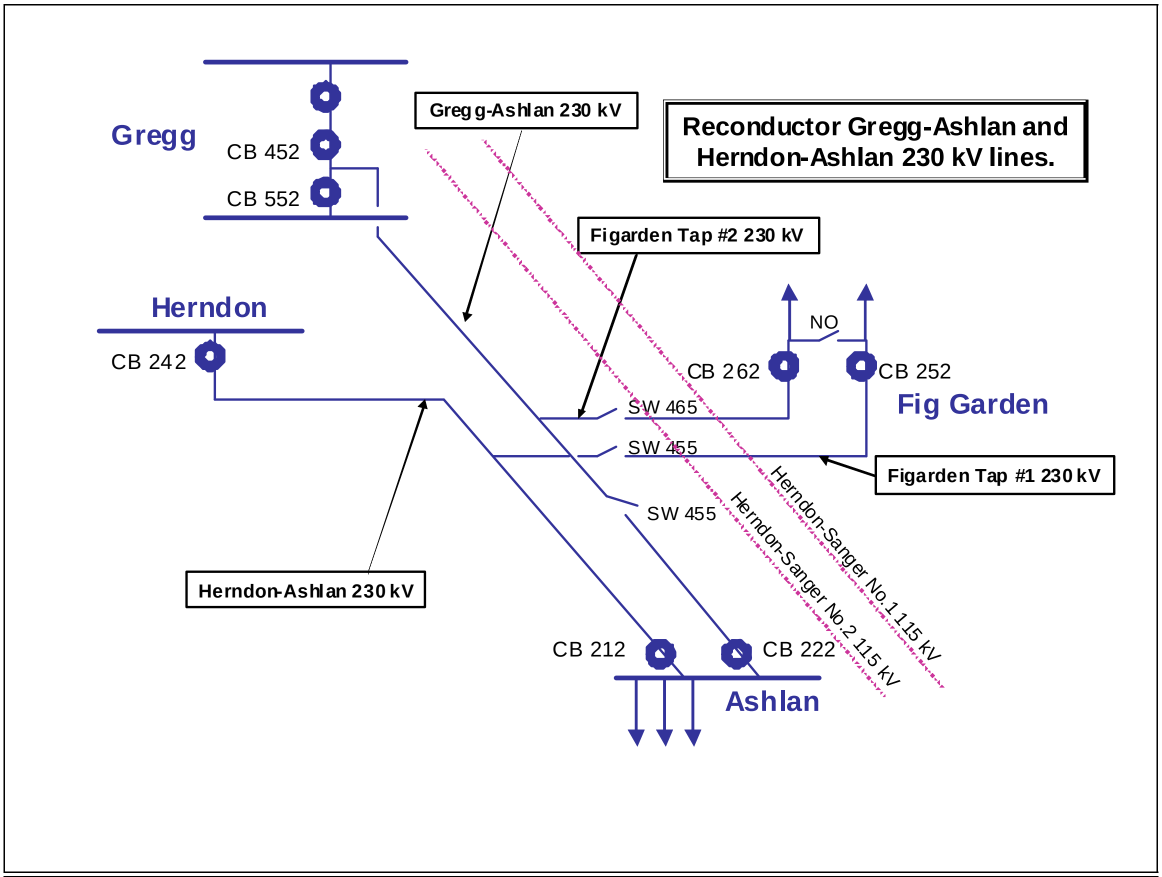


Figure 6-22: Proposed Scope Diagram

Atlantic – Placer Voltage Conversion

TARGETED IN-SERVICE DATE

May 2015

PURPOSE AND BENEFIT

Reliability – NERC Compliance

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROJECT

The project scope is to convert the Atlantic – Placer 60 kV system for 115 kV service.

This project is expected to cost between $50M and $60M. The large cost range is due to the unknown permitting and environmental aspects of the project.

BACKGROUND

Electric customers located between Atlantic and Placer substations in Placer County are served by a network of 60 kV transmission lines. Currently, there is one 60 kV line from Atlantic to Placer and a second 60 kV line between Atlantic and Del Mar substations.

Planning analysis concluded that the Placer 115/60 kV Transformer No. 1 would reach its capacity as electric demand continues to grow. This project would convert the 60 kV transmission lines and substation facilities to 115 kV. The completion of this project would provided the needed capacity to meet future growth, increase service reliability and reduce the loading on the Placer – Gold Hill 115 kV Lines.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended. This alternative does not address the potential overload issue.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2015

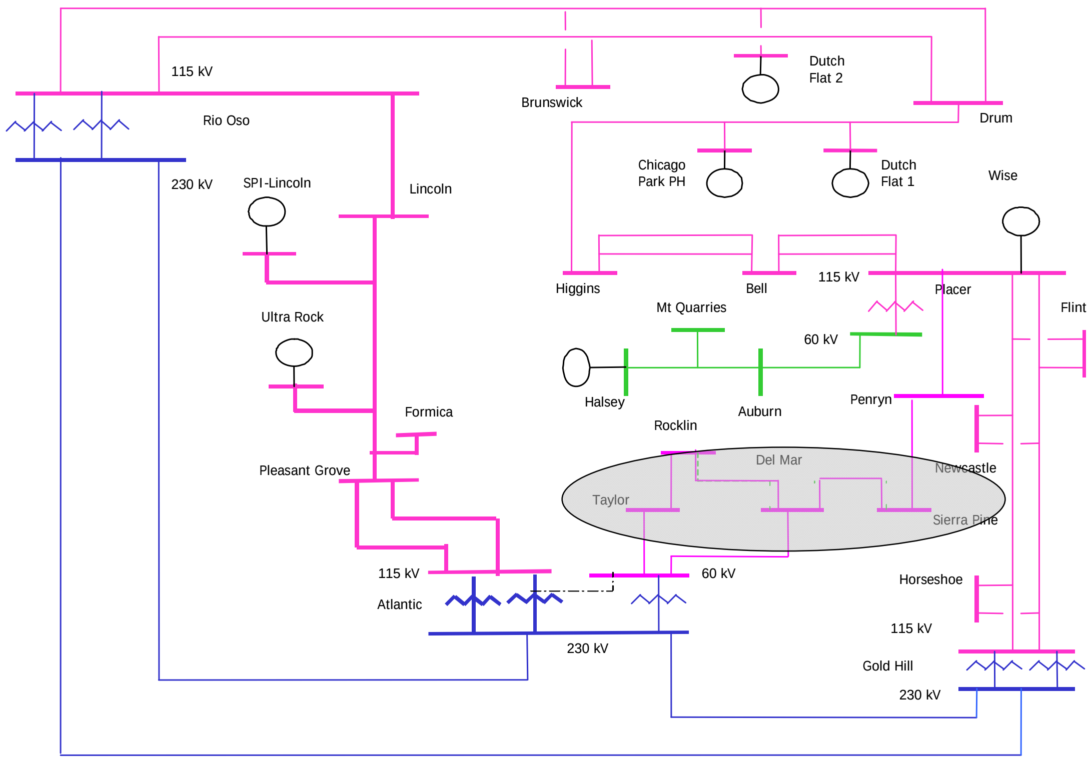
KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – TBD
- Special Metering or Protection – TBD
- Common Mode Exposure Items – TBD
- Interaction with other Projects or Studies – TBD

ATTACHMENTS

1. Scope Diagram

Attachment 1



Atlantic – Placer Long Term Plan

Figure 6-23: Scope Diagram

Bay Area Bulk Transmission Project

IN-SERVICE DATE

May 2015

PURPOSE AND BENEFIT

Reliability – NERC Compliance

PROJECT CLASSIFICATION

This is a new project proposal.

DESCRIPTION AND SCOPE OF PROJECT ALTERNATIVES

The Greater San Francisco Bay Area (GBA) long–term planning study is being conducted to determine what future combination of transmission system reinforcements and/or generation resources are required to serve the projected load levels within this area reliably. The GBA Study Group which includes representatives from CAISO, Silicon Valley Power, City and County of San Francisco, Western Area Power Authority, and PG&E participated in this study. In this study, the thermal performance of eleven transmission alternatives was assessed. The preliminary results indicate that the following transmission alternatives surpassed the power flow performance of the other alternatives:

1. Build a new 500/230 kV substation near Collinsville with two 500/230 kV transformers; loop the Vaca Dixon-Tesla (or Table Mountain-Tesla) 500 kV line to the new substation; build a new 230 DCTL between the new substation and Pittsburg Substation; and add a new 500/230 kV transformer at Tesla/Tracy.

2. Build a new 500/230 kV substation at Sunol (near Newark); loop the Tesla-Los Banos 500 kV Line into the new substation; re-configure some 230 kV lines at Newark (move termination from Newark to the new substation); reconductor some of the reconfigured 230 kV lines; and add a new 500/230 kV transformer at Tesla/Tracy.

3. Build a new 500/230 kV substation at Sunol (near Newark); loop the Tesla-Los Banos 500 kV Line into the new substation; re-configure some 230 kV lines at Newark (move termination from Newark to the new substation); reconductor some of the reconfigured 230 kV lines; build a new 230 kV DCTL from Contra Costa-Pittsburg; and build a new 230 kV DCTL from Vaca-Dixon – Contra Costa.

4. Build a new 230 kV DCTL from Contra Costa-Pittsburg; build a new 230 kV DCTL from Vaca-Dixon – Contra Costa; and build a new 230 kV line from Tesla/Tracy-Livermore-Newark/Northern Receiving Station. Additional transmission components needed in order to complete this alternative and will be determined in later studies (Proposed by WAPA and other participating MUNI's).

Each alternative would mitigate most, if not all, the thermal problems with a reduction of approximately 2,000 MW of generation within the Greater Bay Area. A complete economic comparison of each alternative as well as an examination of environmental impacts would be determined during the next phase of studies. It is recommended that these alternatives be evaluated in further detail in the next phase of the study.

BACKGROUND

The Bay Area is at the center of PG&E's service territory. Counties within the Bay Area include Alameda, Contra Costa, Santa Clara, San Mateo and San Francisco. In 2006, recorded total simultaneous peak electric demand for the Greater Bay Area was recorded at around 9,300 MW with a projected growth rate of approximately 1.1% per year.

The Bay Area's transmission system is served by a combination of in-area generation (nameplate capability 8,000 MW) and power imports from three major points at Vaca Dixon, Tesla, and Moss Landing.

Previous planning studies have concluded that the Bay Area's transmission system is sufficient in meeting peak electric demand over the next ten years. However, depending on a number of factors, such as electric demand growth, status of older generation units, and installation of newer generation resources, could influence the long-term outlook of the Bay Area's transmission capability.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO Grid Planning Criteria.

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended. This alternative does not address future capacity issues and reduce LCR.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2015

KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – TBD
- Special Metering or Protection – TBD
- Common Mode Exposure Items – None
- Interaction with other Projects – None

Kern-Lamont Area Reinforcement

IN-SERVICE DATE

May 2015

PURPOSE AND BENEFIT

Reliability – NERC Compliance

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROPOSED PROJECT

This project will provide transmission system reinforcements by increasing capacity to the Kern and Lamont area, located in Kern County. The project scope is to reconductor approximately 10 circuit miles of the Kern-Lamont and Kern-Stockdale 115 kV double circuit tower lines.

This project is expected to cost between $5M and $8M.

BACKGROUND

The Kern-Lamont line normally serves Tevis Bank No. 2, Arvin Edison, Grimmway-Malaga, and Lamont substations. The Kern-Stockdale 115 kV line shares common towers with the Kern-Lamont 115 kV line and normally serves Tevis Bank No. 1 and Stockdale Bank No. 1.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended because the thermal overloads are expected to exceed the emergency rating of the conductor.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – None
- Construction – TBD
- Operation Date – May 2015

KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – TBD
- Special Metering or Protection – TBD
- Common Mode Exposure Items – TBD
- Interaction with other Projects or Studies – TBD

ATTACHMENT

1. Scope Diagram

Attachment 1: Scope Diagram

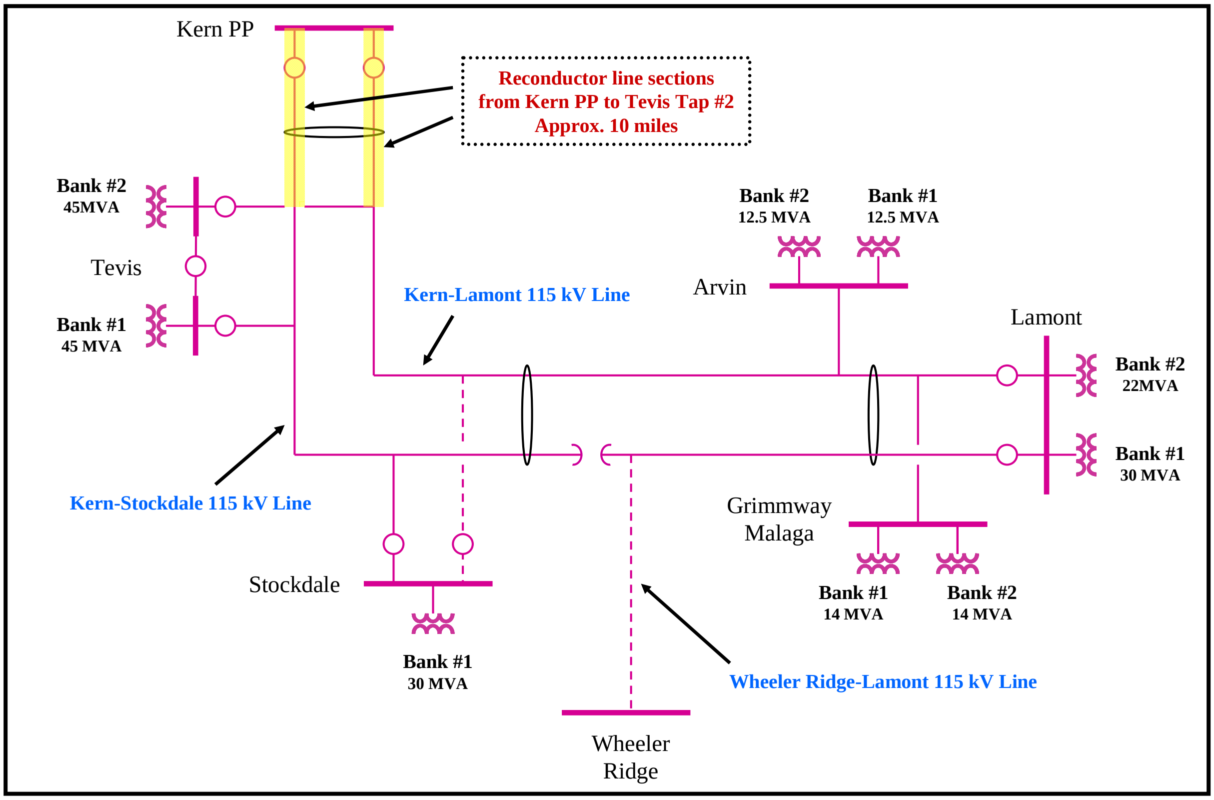


Figure 6-24: Scope Diagram

San Mateo and Moraga Synchronous Condenser Replacements

TARGETED IN-SERVICE DATE

May 2015

PURPOSE AND BENEFIT

Reliability – NERC Compliance

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROJECT

The project scope is to replace the San Mateo and Moraga synchronous condensers with newer facilities.

BACKGROUND

San Mateo and Moraga substations are two key transmission substations in the Bay Area. Both substations have synchronous condensers that, along with other reactive devices, provide voltage support to the Bay Area. These condenser installations are three units each and are rated at 113 MVAr and 144 MVAr, respectively.

The San Mateo and Moraga synchronous condensers are more than 40 years old and have started to show sign of aging and deterioration. These two projects would replace the existing synchronous condensers with Static Var Compensators.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended. This alternative does not address the potential overload issue.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2015

KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – TBD
- Special Metering or Protection – TBD
- Common Mode Exposure Items – TBD
- Interaction with other Projects or Studies – TBD

San Vicente 230/115 kV Substation

TARGETED IN-SERVICE DATE

May 2015

PURPOSE AND BENEFIT

Reliability – Tariff and Compliance

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROJECT

This project is proposing a new transmission substation in Soledad to interconnect the 230 kV system with the 115 kV system.

This project scope is to construct a new 230/115 kV substation in Soledad and reconductor sections of 115 kV lines. The Crazy Horse-Salinas-Soledad Nos. 1 and 2 115 kV lines and the Panoche – Coburn and Moss Landing – Coburn 230 kV lines will be looped into the new substation. Two, 403 MVA, 230/115 kV transformers will be installed at the new substation. The line sections (24.6 miles each for each line) from the new substation to the Natividad Switches will also be reconductored with conductors capable of carrying a minimum of 900 Amps under summer normal conditions and 1,000 Amps under summer emergency conditions.

This project is expected to cost between $50M and $60M.

BACKGROUND

Soledad Substation is at the end of the 115 kV system from Moss Landing that serves the Salinas – Hollister – Soledad area. A 24-mile long 115 kV DCTL serves Soledad Substation. Just north of Soledad Substation, along San Vicente Road, the 115 kV lines to Soledad Substation are within 1,000 feet of the 230 kV lines to Coburn Substation.

By 2018, an outage either 115 kV line into Soledad will result in 115 kV voltages below 109 kV. Second, a DCTL outage of the Moss Landing – Salinas 115 kV lines would result in voltages in Salinas and Soledad below 105 kV. Third, a catastrophic event affecting Moss Landing would knock out power to most of Central Coast Division, with most of the area without power until a portion of Moss Landing could be put back in service. Fourth, several windpower developers have proposed large windfarms near the 230 kV lines from Soledad down to King City; a connection into the 115 kV system at San Vicente would allow the wind power to directly supply Central Coast loads.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO. PG&E also performed sensitivity studies for this local area using local system peak conditions.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Convert Soledad Substation to 230 kV and connect it into the Moss Landing – Coburn 230 kV line

While this alternative removes Soledad from the 115 kV system, it is not recommended because it does not address voltage issues on the 115 kV system and it does not provide another source of power into the Central Coast 115 kV system.

PROJECT SCHEDULE

- Environmental and Permitting Processes – Spring 2011 through Summer 2013
- Design – Summer 2013
- Major Equipment – Fall 2013
- Construction – Fall 2013 through Spring 2015
- Operation Date – May 2015

KEY ISSUES

- Land-Use Restrictions – None
- Environmental Concerns – None
- Special Metering or Protection – None
- Common Mode Exposure Items – None
- Interaction with other Projects – None

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagram

Attachment 1: Scope Diagram

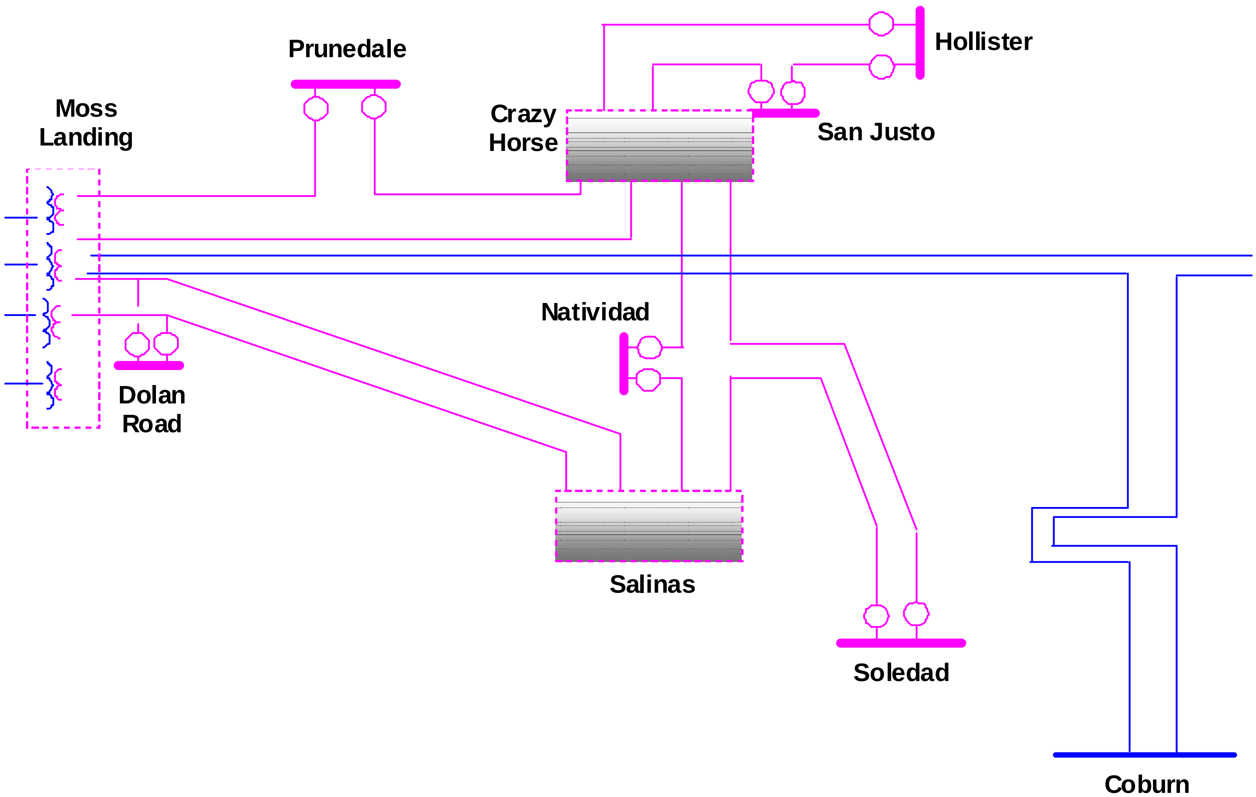


Figure 6-25: Pre-Project of Hollister-Salinas-Soledad 115 kV System

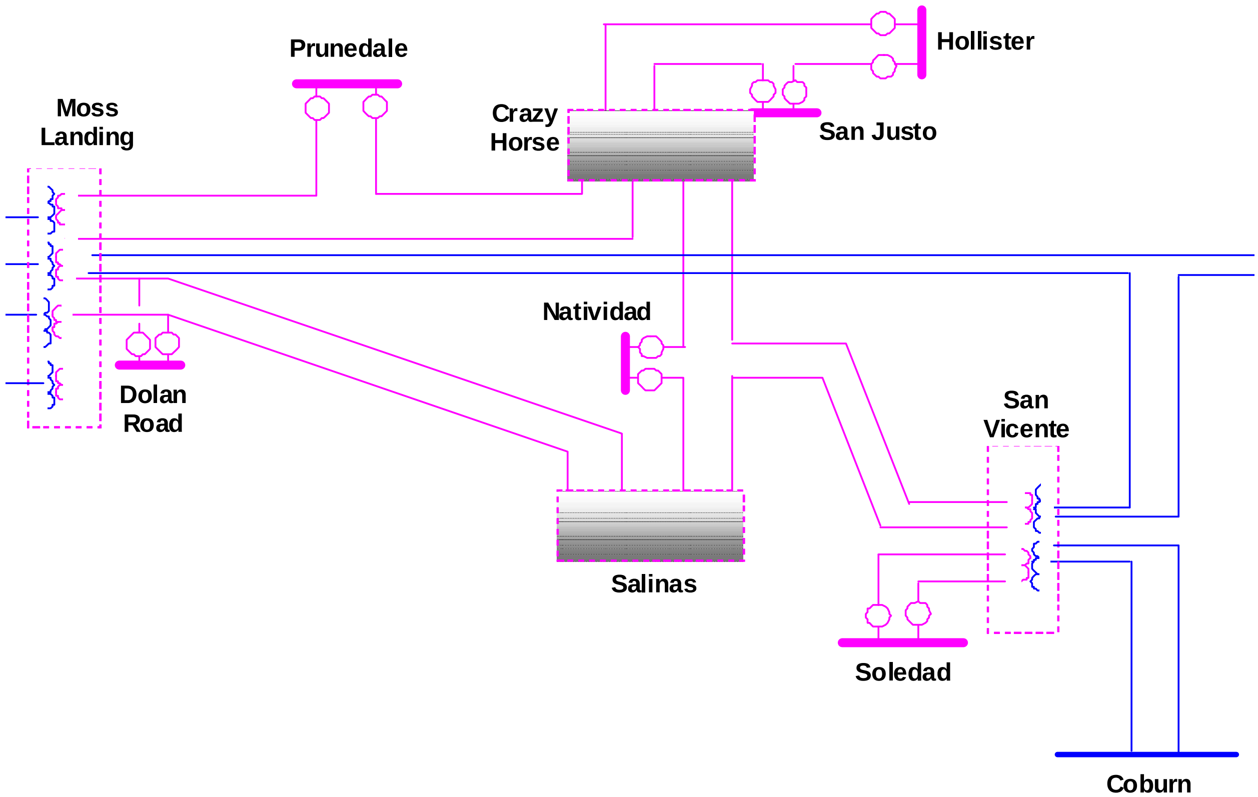


Figure 6-26: Post-Project of Hollister-Salinas-Soledad 115 kV System

2016 Projects

Borden – Coppermine 70 kV Upgrade

IN-SERVICE DATE

May 2016

PURPOSE AND BENEFIT

Reliability – NERC Compliance

DESCRIPTION AND SCOPE OF PROJECT

The project scope is to convert the Borden – Coppermine 70 kV system for 115 kV service. The new source for this line would come from Herndon Substation. A 115/70 kV Bank will be installed at Coppermine to support the Coppermine 60 kV system. The new Herndon-Coppermine 115 kV Line will have a direct tap connection to Woodward Substation.

This project is expected to cost between $25 million and $40 million.

BACKGROUND

Borden 70 kV transmission system serves about 20,000 electric customers in Madera and Fresno counties. Distribution substations located in this area include Auberry, Madera, Bonita, Canandaigua Winery, Cassidy, Coppermine, El Peco, Glass, Madera, River Rock and Tivy Valley. The 70 kV transmission system that support the customer demand in the northeastern Fresno County consists of the following transmission lines: Borden – Coppermine, Coppermine – Friant, Coppermine – Wishon, and Coppermine – Tivy Valley – Reedley 70 kV Lines.

Electric customers in the local northeastern Fresno 70 kV system are also supported by a group of small hydroelectric plants with 30 MW of installed capacity. These local hydroelectric plants are Crane Valley, San Joaquin and Wishon powerhouses, and Madera Irrigation District's Friant Powerhouse. The main import sources into the local northeastern Fresno 70 kV system are Borden and Reedley substations. Significant residential growth is anticipated in the greater northern Fresno area. As a result, a distribution capacity increase project has been initiated to upgrade Cassidy Bank No. 1 to a 115x70/12 kV 45 MVA bank and install 115 kV line circuit breakers by December 2009.

Planning analysis for projected summer peak conditions concluded that an overlapping outage of Borden – Coppermine 70 kV Line with Friant generation offline will cause low voltages in the Coppermine area.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended. This alternative does not address the potential low voltage issues.

Alternative 2: 115 to 70 kV Conversion from Borden

This alternative is not recommended. This alternative proposes to add a new 230/115 kV transformer at Borden and a 115/70 kV transformer at Coppermine. The current Borden-Coppermine 70 kV Line will be converted to 115 kV operation and the Coppermine-Crane Valley will also be converted to 115 kV.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2016

KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – TBD
- Special Metering or Protection – TBD
- Common Mode Exposure Items – TBD
- Interaction with other Projects or Studies – E1 Substation, and Shepherd Substation Interconnection

ATTACHMENT

1. Scope Diagram

Attachment 1: Scope Diagrams

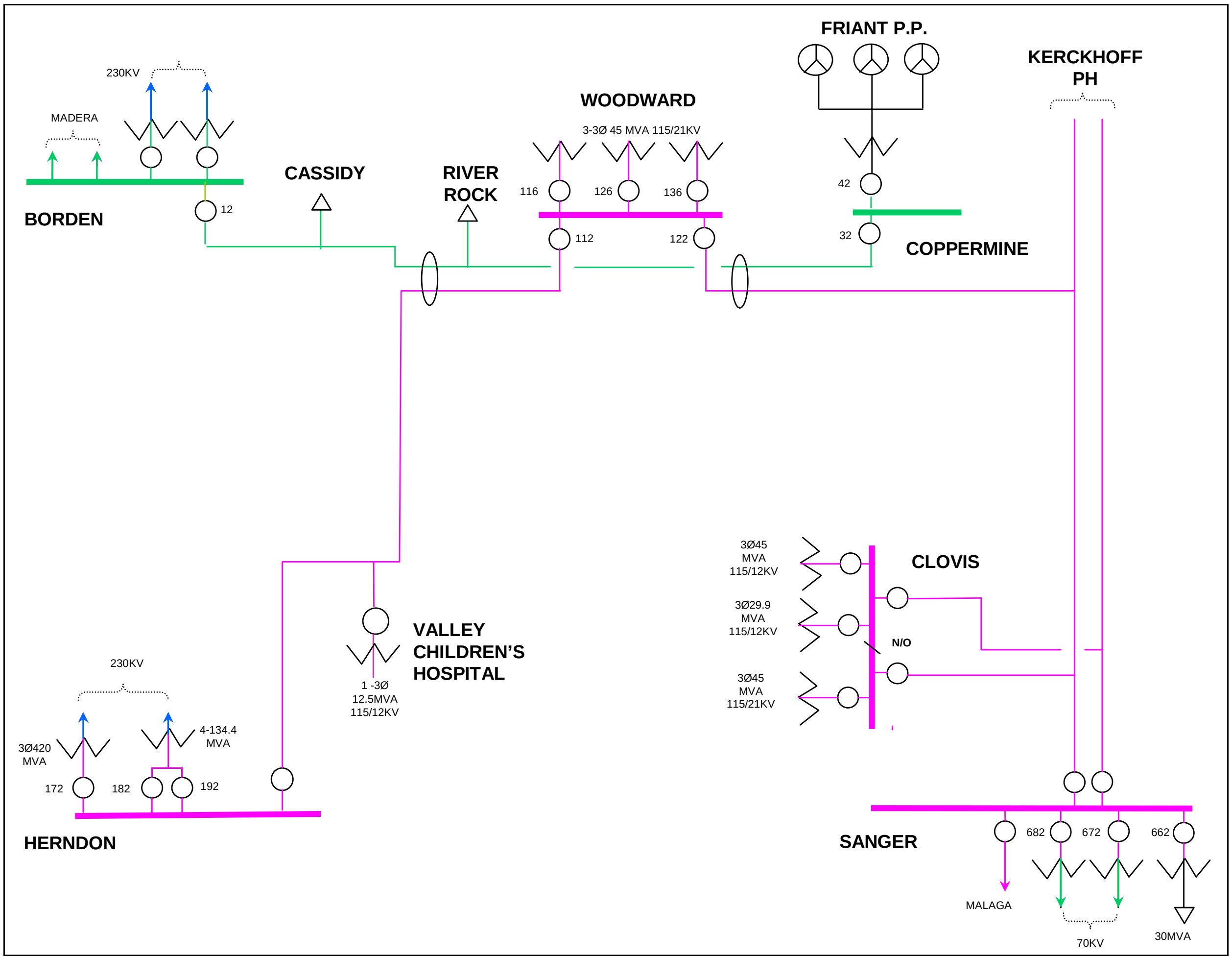


Figure 6-27: Existing Scope Diagram

Contra Costa Substation Reliability Improvement Plan

TARGETED IN-SERVICE DATE

May 2016

PURPOSE AND BENEFIT

Reliability – Operating Flexibility

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROJECT

The project scope is to loop the Contra Costa PP-Moraga 230 kV No.1 Line (approximately 27 miles) into Contra Costa Substation. The project scope may also include the upgrade of associated substation equipment to accommodate the additional lines into Contra Costa Substation. In addition, environmental and land permits may be required to complete the looping work.

This project is expected to cost between $10M and $15M.

BACKGROUND

Contra Costa Substation serves approximately 215 MW of load and 47,400 customers in East Contra Costa County. The substation is also a connection point for 130 MW of QF generation. The substation supplies load at 230, 115 and 60 kV. Contra Costa Substation serves 31,700 customers off two 230/21 kV distribution banks and 9,200 customers off one 115/21 kV distribution bank. 6,600 other customers are supplied from other stations on the 60 kV.

Contra Costa Substation currently lacks redundancy and has many single points of failure that will result in customer outages:

- One 230/115 kV Transformer Bank serves radial load off the 115 and 60 kV
- 115 kV Bus Relay trips entire 115 kV station
- 60 kV Bus Relay trips entire 60 kV station
- One 115/60 kV Bank serves radial load off the 60 kV (a second bank is on standby).
- The 230 kV is also supplied by only two 230 kV lines on the same towers.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended. This alternative does not increase the operation flexibility and reliability at Contra Costa Substation.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2013

KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – TBD
- Special Metering or Protection – TBD
- Common Mode Exposure Items – TBD
- Interaction with other Projects – TBD

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagrams

Attachment 1: Scope Diagram

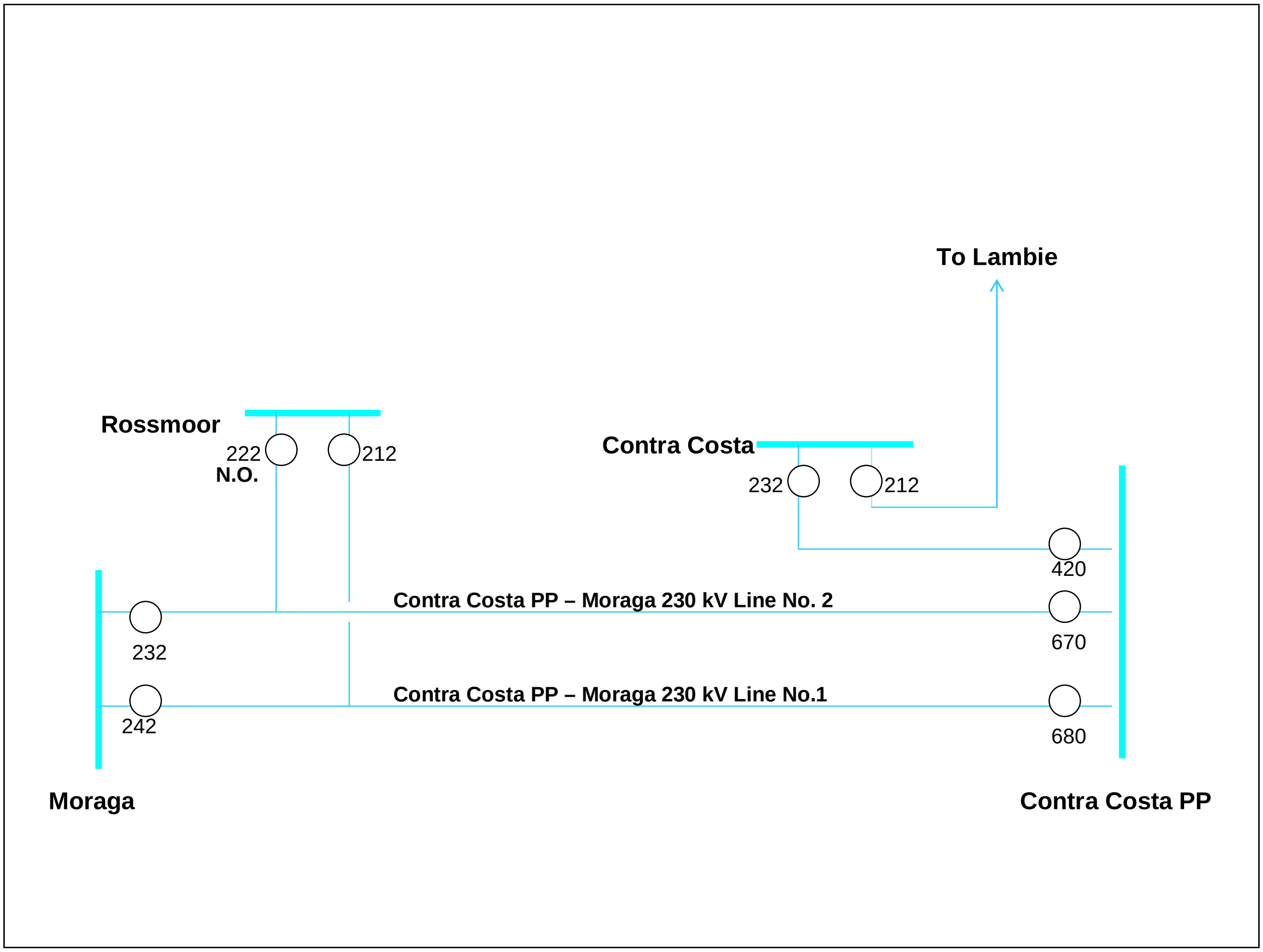


Figure 6-28: Scope Diagram (Existing)

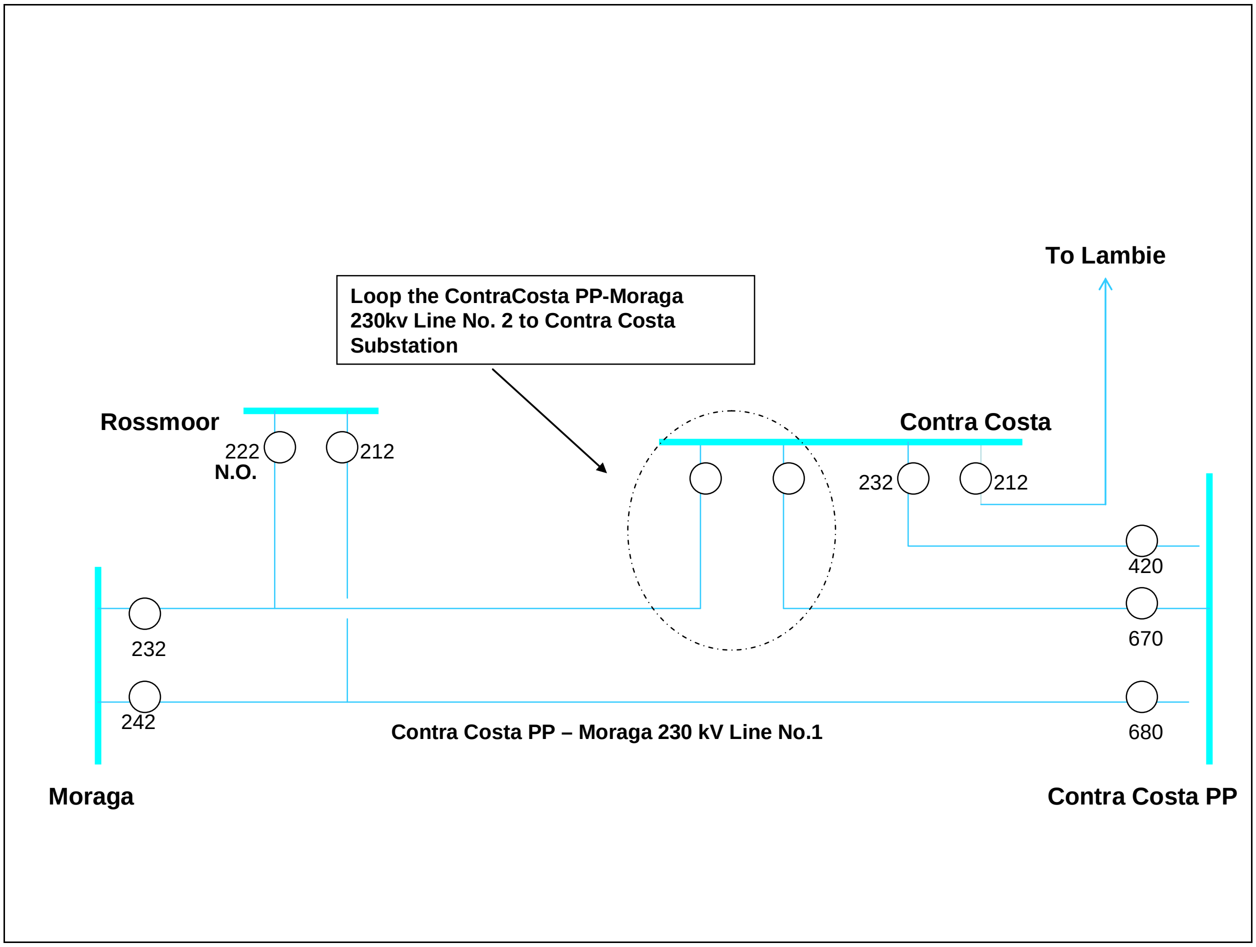


Figure 6-29: Scope Diagram (New Proposed)

Corcoran-Guernsey Area Reinforcement

IN-SERVICE DATE

May 2016

PURPOSE AND BENEFIT

Reliability – NERC Compliance

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROPOSED PROJECT

The scope is to convert Guernsey Substation to 115 kV operation and construct a new 2-mile 115 kV transmission line from Guernsey to GWF Switching Station. This project will also convert the Corcoran-Guernsey 70 kV Line to 115 kV operation. The existing Guernsey-Henrietta 70 kV Line will bypass Guernsey Substation.

The estimated cost for this alternative is $10M to $15M.

BACKGROUND

The Corcoran-Guernsey 70 kV Line is comprised of 13.5 miles of 266 aluminum conductor and serves as a normally open back-tie to between Corcoran and Guernsey substations. In an outage of the Guernsey-Henrietta 70 kV Line, the Corcoran-Guernsey 70 kV Line is the only other source to serve the load at Guernsey Substation. In a DCTL outage of the Kingsburg-Corcoran Nos. 1 and 2 115 kV lines, the Corcoran-Guernsey 70 kV Line can be closed in to serve the 70 kV load at Corcoran Substation. In both outage scenarios, the line does not have the transmission capability to support the entire Guernsey or Corcoran 70 kV load without experiencing voltage levels below the minimum acceptable operating limits of 63 kV. A maintenance project has been initiated to convert existing Corcoran 115 kV bus to a breaker-and-a-half (BAAH) arrangement. The Corcoran 70 kV bus will be removed or relocated as part of this maintenance project. The Corcoran-Angiola 70 kV Line is the only other 70 kV transmission line at Corcoran Substation and this line may also be a candidate for voltage conversion.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative limits the restoration ability at Guernsey Substation during an outage of the Guernsey-Henrietta 70 kV Line, and at Angiola Substation during an outage of the Kingsburg-Corcoran 115 kV line #1 and #2.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2016

KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – TBD
- Special Metering or Protection – TBD
- Common Mode Exposure Items – None
- Interaction with other Projects or Studies – None

GEPSLF MODELING INFORMATION

N/A

ATTACHMENTS

1. Scope Diagrams

Attachment 1: Scope Diagrams

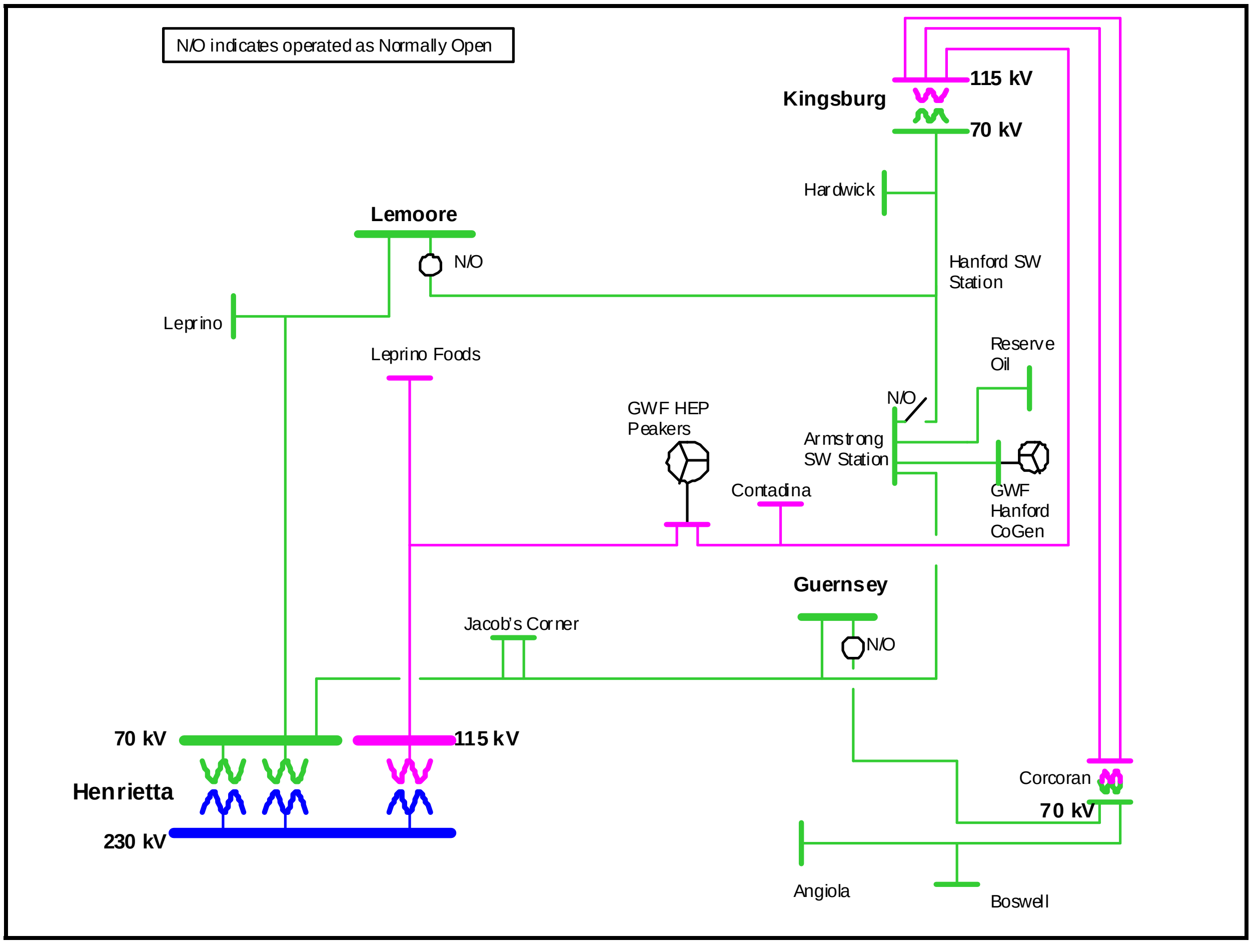


Figure 6-30: Existing Single Line Diagram

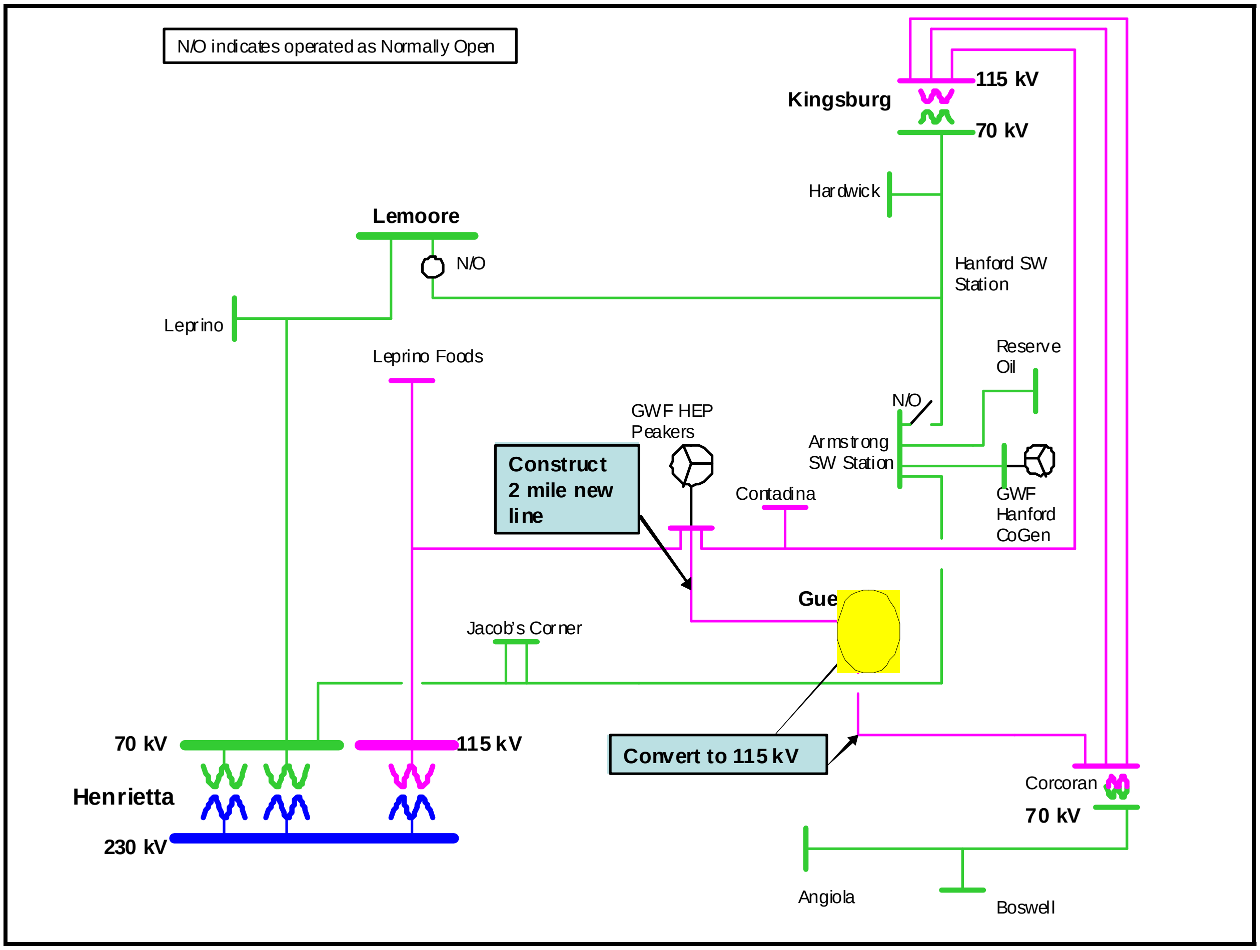


Figure 6-31: Proposed Scope Diagram

E1 Substation

IN-SERVICE DATE

May 2016

PURPOSE AND BENEFIT

Reliability – NERC compliance

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROJECT

This project scope is to construct a new 230/115 kV substation in Northern Fresno to help distribute bulk power to local subtransmission areas. The project proposes to loop both Gregg-Helms 230 kV lines and Kerckhoff-Clovis-Sanger 115 kV lines into the new substation, directly interconnect the Shepherd-Woodward Jct 115 kV Line in the new substation, and install two 230/115 kV transformers. Additional studies are still needed to finalize the plan of service.

This project is expected to cost between $50M and $70M.

BACKGROUND

Fresno County is one of the fastest growing counties in California. The area loads are mainly served by local hydro power plants and power is imported via 230 kV and 115 kV lines. The local generation consists of hydro plants and small gas-fired QFs. The largest generation plant in the Fresno area is the Helms Pumped Storage Plant. It has three pump-generating units rated at 404 MW each in the generating mode and 350 MW each in the pumping mode. The Gregg – Helms 230 kV Nos. 1 and 2 lines form a 230 kV path that delivers power from Helms PSP to Gregg Substation. From Gregg Substation power flows over six 230 kV lines that supply the 230 kV network at Borden, Figarden, Ashlan, Storey, and Herndon substations. Approximately, 500 MW of Helms PSP generation is supplied to Herndon Substation to support local 115 kV demand. The substations serving customers and communities connected to the local 115 kV transmission network include: Woodward, Clovis, Barton, Manchester, Bullard and Pinedale. Total peak demand for these areas was recorded at 730 MW with a projected growth rate of a 2% increase per year.

Planning analysis for projected summer peak conditions concludes that an outage of either Herndon 230/115 kV Transformer Nos. 1 or 2 is projected to overload the parallel Herndon 230/115 kV transformer. Furthermore, an outage of the Herndon – Woodward 115 kV Line is projected to overload Kerckhoff – Clovis – Sanger 115 kV Line. Conversely, the outage of Kerckhoff – Clovis – Sanger 115 kV Line is projected to overload the Herndon – Woodward 115 kV Line.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases approved by the 2008 expansion plan study group and the CAISO. Forecasted loads not included in the 2008 series base cases were used to model the initial load interconnected at Shepherd Substation.

STUDY CRITERIA

CAISO Grid Planning Criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended. This alternative does not address the potential overload issues.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2016

KEY ISSUES

- Land-Use Restrictions – Permitting of new substation
- Environmental Concerns – Land for new substation
- Special Metering or Protection – None
- Common Mode Exposure Items – None
- Interaction with other Projects – Borden-Coppermine Conversion, and Shepherd Substation Interconnection

ATTACHMENTS

1. Scope Diagrams

Attachment 1: Scope Diagrams

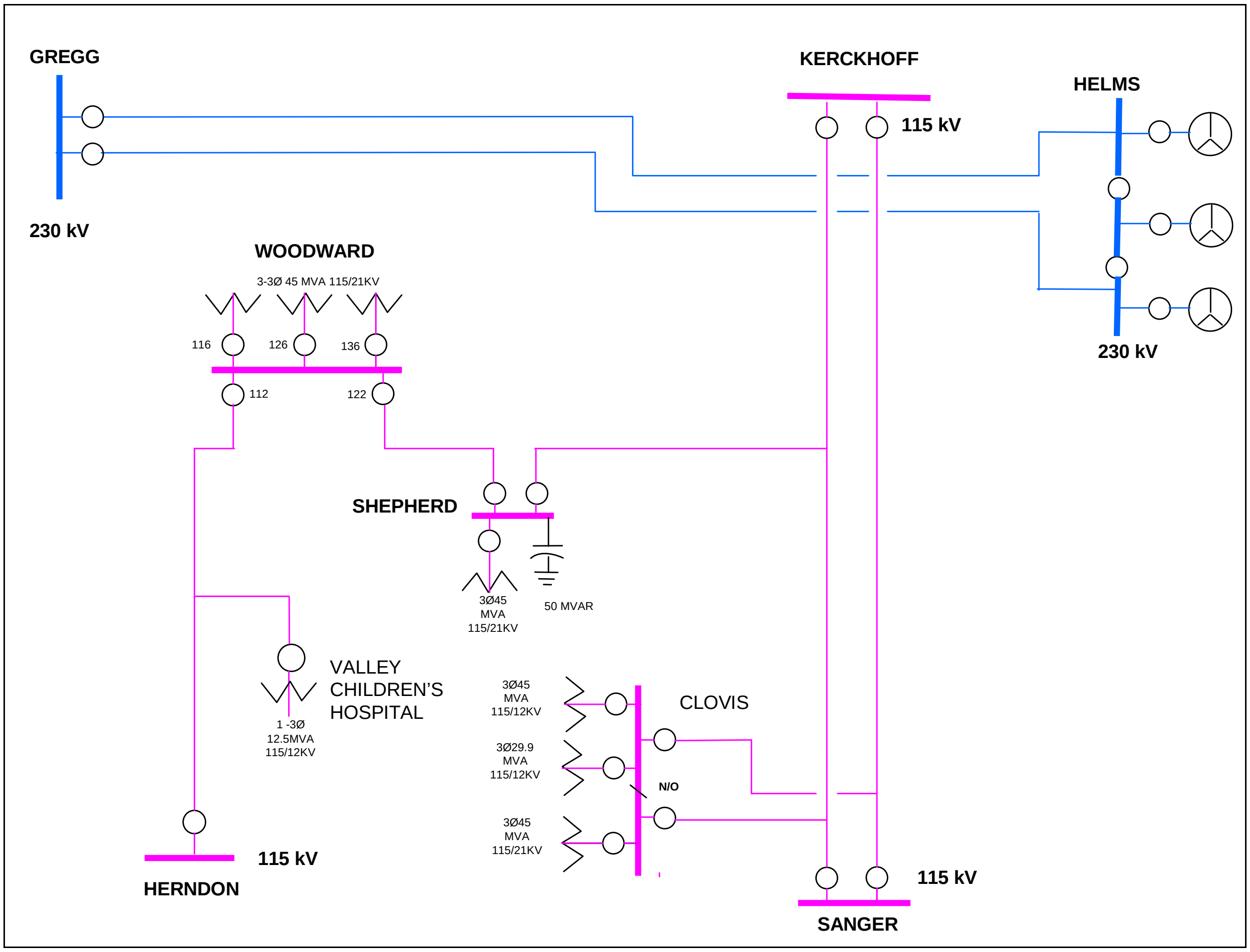


Figure 6-32: Existing Scope Diagram

Attachment 1: Scope Diagrams

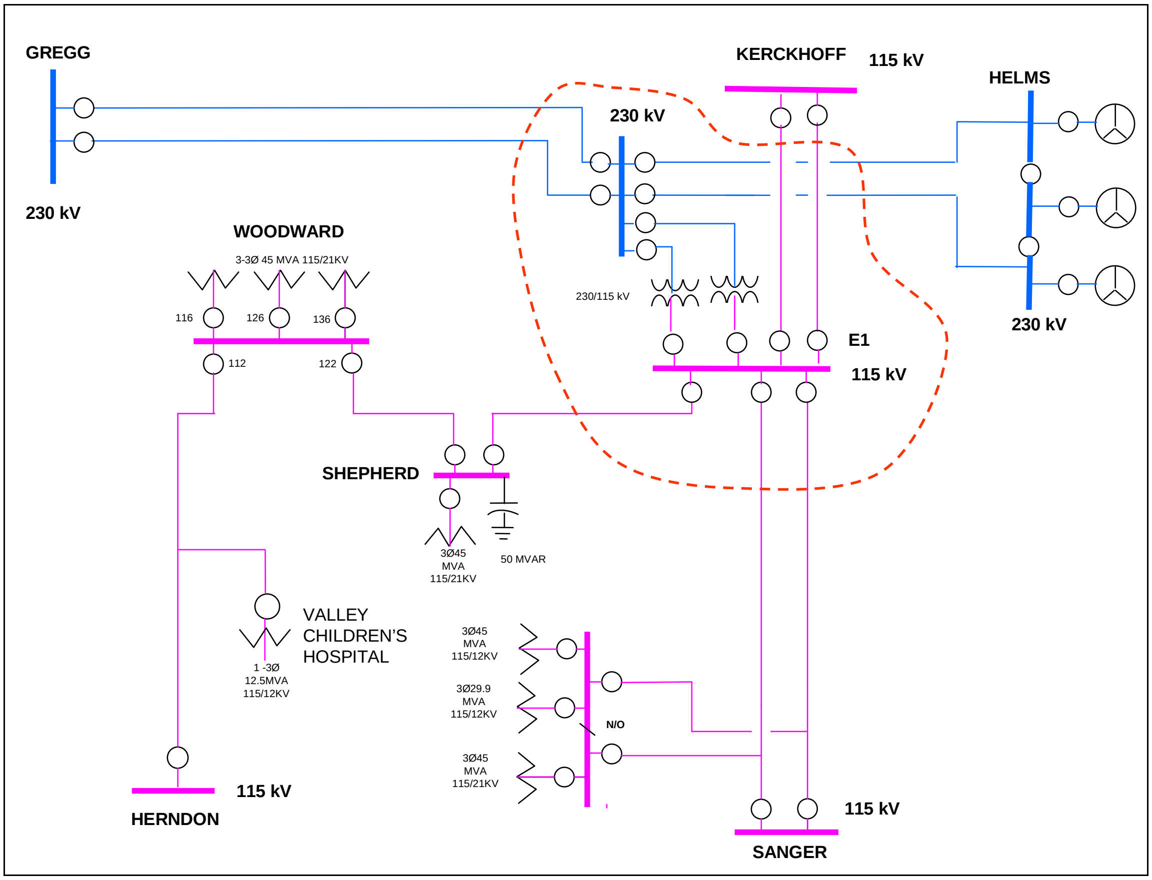


Figure 6-33: Proposed Scope Diagram

Lemoore Area Reinforcement

IN-SERVICE DATE

May 2016

PURPOSE AND BENEFIT

Reliability – Operational Flexibility

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROPOSED PROJECT

The scope is to convert the Henrietta-Lemoore 70 kV line to 115 kV operation and replace with higher capacity conductors. Lemoore Substation will be converted to 115 kV service. One mile of new 115 kV transmission line will be constructed from the Leprino Foods Tap 115 kV Line and terminate at Lemoore Substation. Upgrades needed at Henrietta Substation to accommodate the line conversion will be included as part of the scope. These upgrades include the addition of a second 230/115 kV transformer bank and the construction of a new 115 kV bus. Lemoore Substation will have the transmission line and bank capacity to operate as a fully looped 115 kV substation. The Leprino Foods 70 kV customer owned substation is electrically tapped of the Henrietta-Lemoore 70 kV and will be required to convert to 115 kV operation. The Lemoore to Hanford Switching Station section of the Kingsburg-Lemoore 70 kV line will be opened and designated as an idle facility.

The estimated cost for this alternative is $25M to $30M.

BACKGROUND

Lemoore Substation is located in Kings County and primarily serves electric customers in the city of Lemoore and surrounding areas. The 2007 electric peak demand was recorded at 45 MW, with a projected growth rate of 3.6% per year. The two 70/12 kV distribution transformer banks at Lemoore receive electric power via the Henrietta-Lemoore 70 kV Line, which is approximately nine circuit miles. Leprino Foods, a customer owned substation, is electrically tapped on the Henrietta-Lemoore 70 kV Line. The Kingsburg-Lemoore 70 kV Line is the only other transmission line serving Lemoore Substation. In an outage on the Henrietta-Lemoore 70 kV Line, an overload of 72%

could occur on the Hanford Switching Station to Lemoore section of the Kingsburg-Lemoore 70 kV Line. In addition, the voltage level on the 70 kV bus at Lemoore Substation could drop below 63 kV, the minimum acceptable operating level. To prevent this potential overload and low voltage conditions, the Kingsburg-Lemoore 70 kV Line is operated as normally open at Lemoore Substation. A maximum of 34 MW can be served via the Kingsburg-Lemoore 70 kV Line before load must be dropped at Lemoore Substation during this emergency condition.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended because it does not provide an adequate back-tie to Lemoore Substation in an outage of the Henrietta-Lemoore 70 kV Line.

Alternative 2: Reconductor the Kingsburg-Lemoore 70 kV Line

This alternative proposes to replace with higher capacity conductor the limiting sections, totaling 24 circuit miles, of the Kingsburg-Lemoore 70 kV Line. This alternative does not provide the improved voltage levels and added reliability associated with upgrading to 115 kV operation of the preferred alternative.

Alternative 3: Construct a new 70 kV transmission line from Henrietta Substation to Lemoore Substation

This alternative proposes to construct a new 70 kV transmission line originating at Henrietta Substation and terminating at Lemoore Substation. This alternative is projected to cost between $20M and $25 M. This alternative is not recommended, as the cost is similar to the preferred alternative, but does not provide the improved voltage levels and added reliability associated with upgrading to 115 kV operation.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2016

KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – TBD
- Special Metering or Protection – TBD
- Common Mode Exposure Items – TBD
- Interaction with other Projects or Studies – TBD

ATTACHMENTS

1. Scope Diagrams

Attachment 1: Scope Diagrams

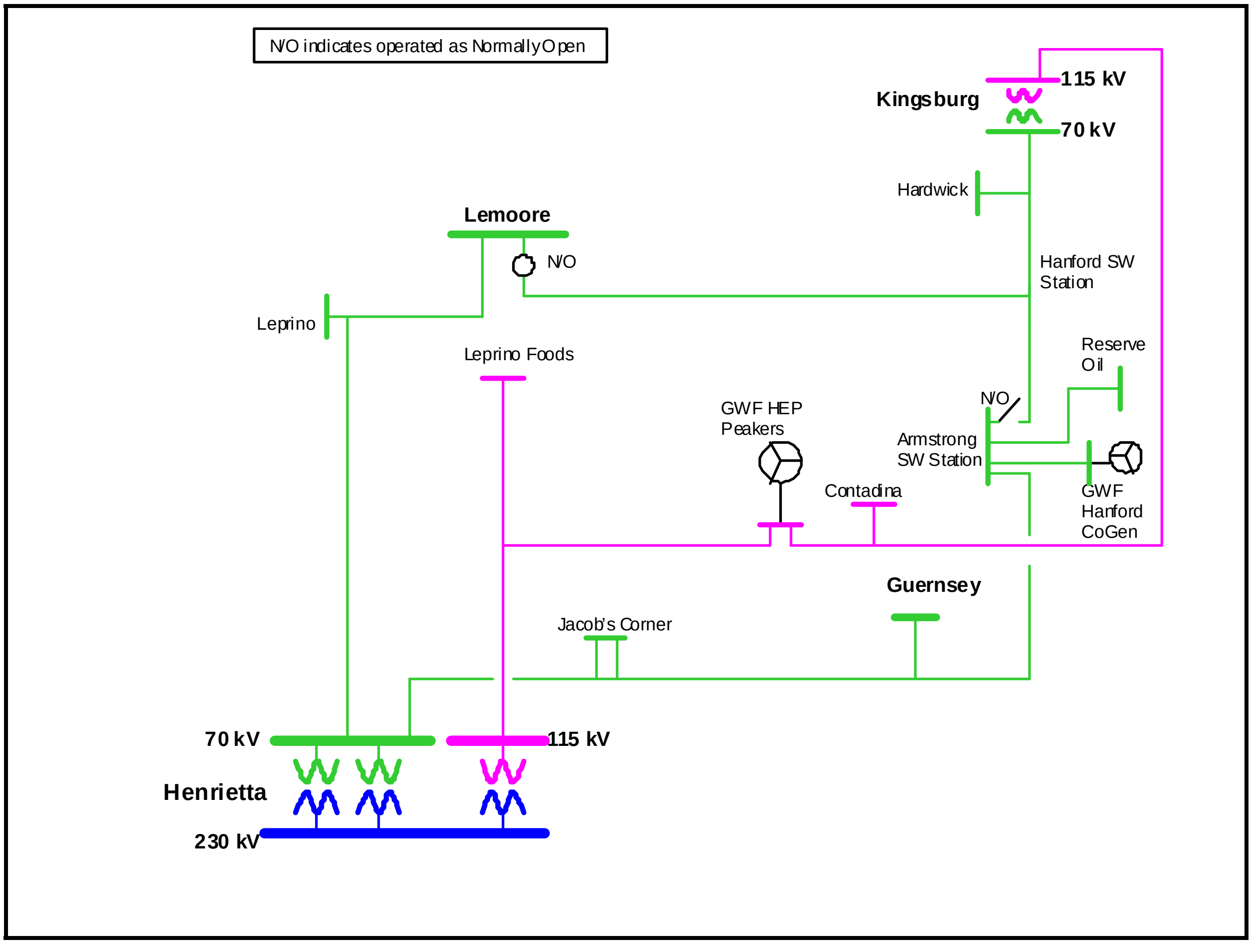


Figure 6-34: Existing Scope Diagram

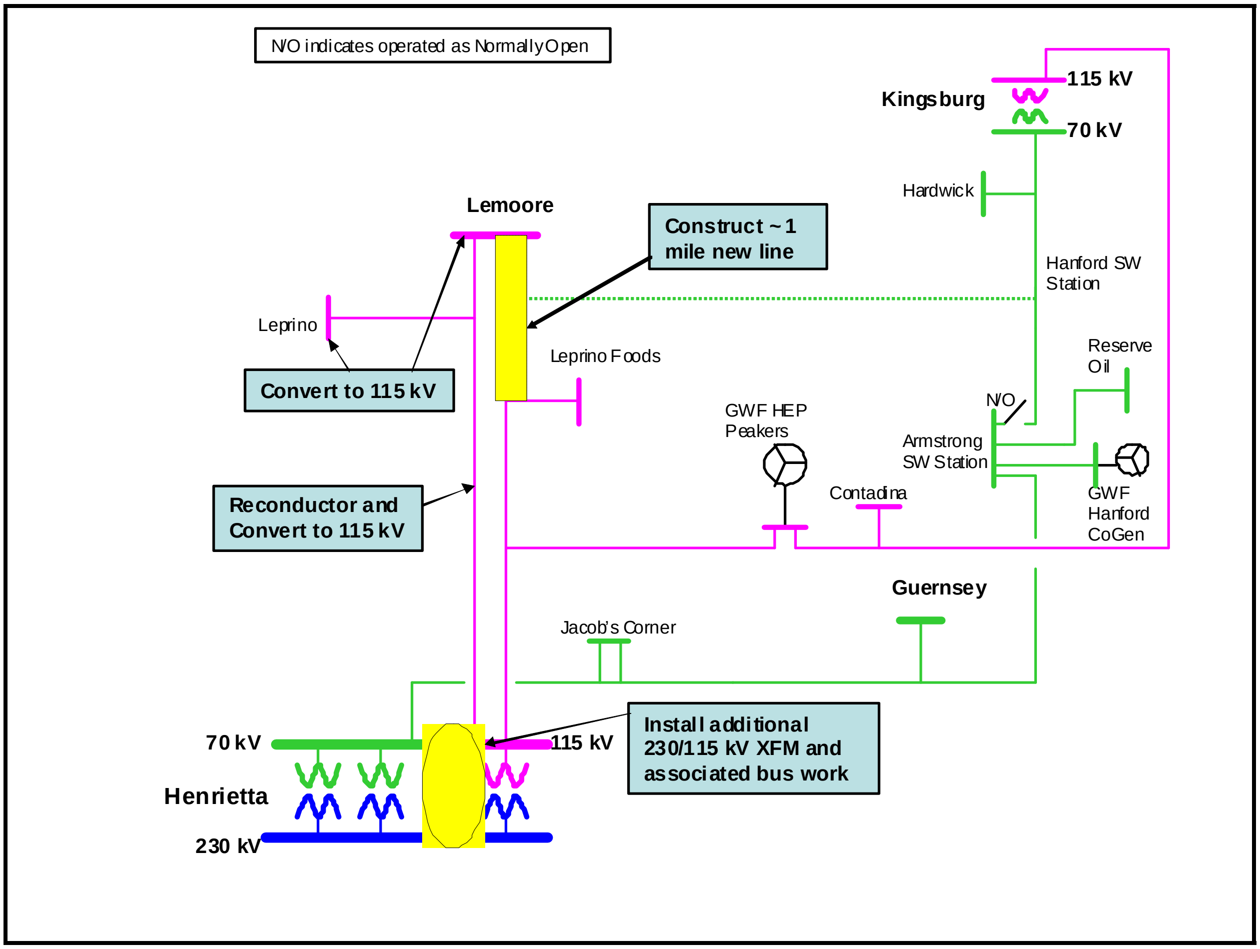


Figure 6-35: Proposed Scope Diagram

Paso Robles Area Reinforcement Project

IN-SERVICE DATE:

May 2016

PURPOSE AND BENEFIT:

Reliability – NERC Compliance

PROJECT CLASSIFICATION

This is a new project proposal

DESCRIPTION AND SCOPE OF PROJECT

This project scope is to install a 2nd 230/70 kV transformer at Templeton Substation and build a second Paso Robles-Templeton 70 kV transmission line (approximately 4.8 miles). Paso Robles Substation will have the transmission line and bank capacity to operate as a fully looped 115 kV substation. The existing Special Protection Scheme (SPS) at Paso Robles will be eliminated.

This project is expected to cost between $15M and $20M.

BACKGROUND

Paso Robles 70 KV Substation is located in San Luis Obispo County and currently serves about 60 MW of load demand via the Templeton-Paso Robles and the San Miguel-Paso Robles 70 kV lines.

Planning Studies conclude that an outage of the Templeton-Paso Robles 70 kV Line under summer peak conditions is projected to cause thermal overloads to the remaining San Miguel-Paso Robles 70 kV Line and cause voltages at Paso Robles and San Miguel to dip below 0.90 per unit value. A Special Protection Scheme (SPS) is currently employed at Paso Robles to guard against the Templeton-Paso Robles 70 kV Line outage.

BASE CASE AND STUDY ASSUMPTIONS

The PG&E base cases that were developed as part of the 2008 expansion plan process were used for this study.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative does not address the projected low voltage conditions.

Alternative 2: Build a new 230/ 70 kV Substation Tapping the Templeton-Gates 230 kV Line, New Line to San Miguel

This alternative proposes to build a new 230/ 70 kV transmission substation about 11.5 miles north of Templeton Substation. The Templeton-Gates 230 kV Line would loop into the new substation. A new 9-mile 70 kV line would be built from the new substation to San Miguel Substation. This alternative would also reconductor the San Miguel-Paso Robles 70 kV Line and install reactive support at Paso Robles Substation. The Special Protection Scheme (SPS) at Paso Robles would be removed.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2016

KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – TBD
- Special Metering or Protection –TBD
- Common Mode Exposure Items – TBD
- Interaction with other Projects – TBD

ATTACHMENTS

1. Scope Diagrams

Attachment 1: Scope Diagrams

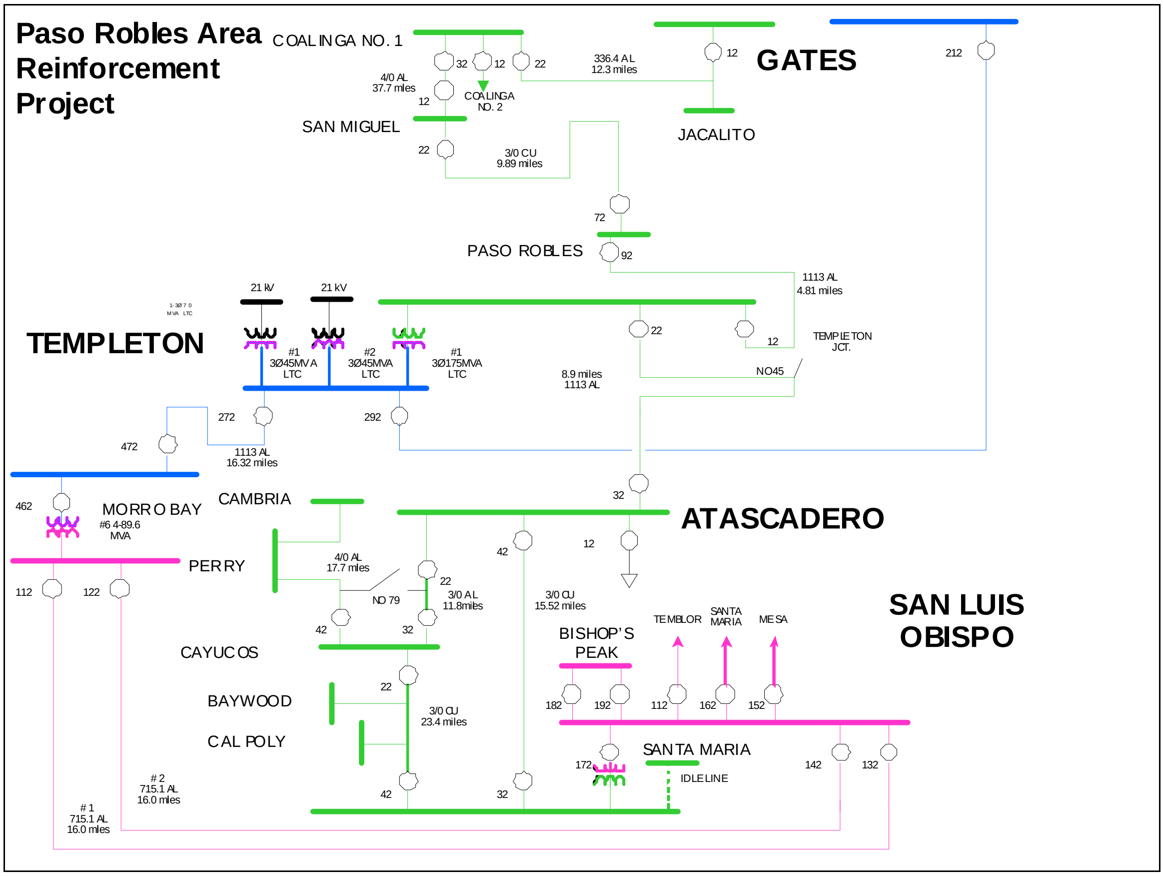


Figure 6-36: Scope Diagram-Existing System

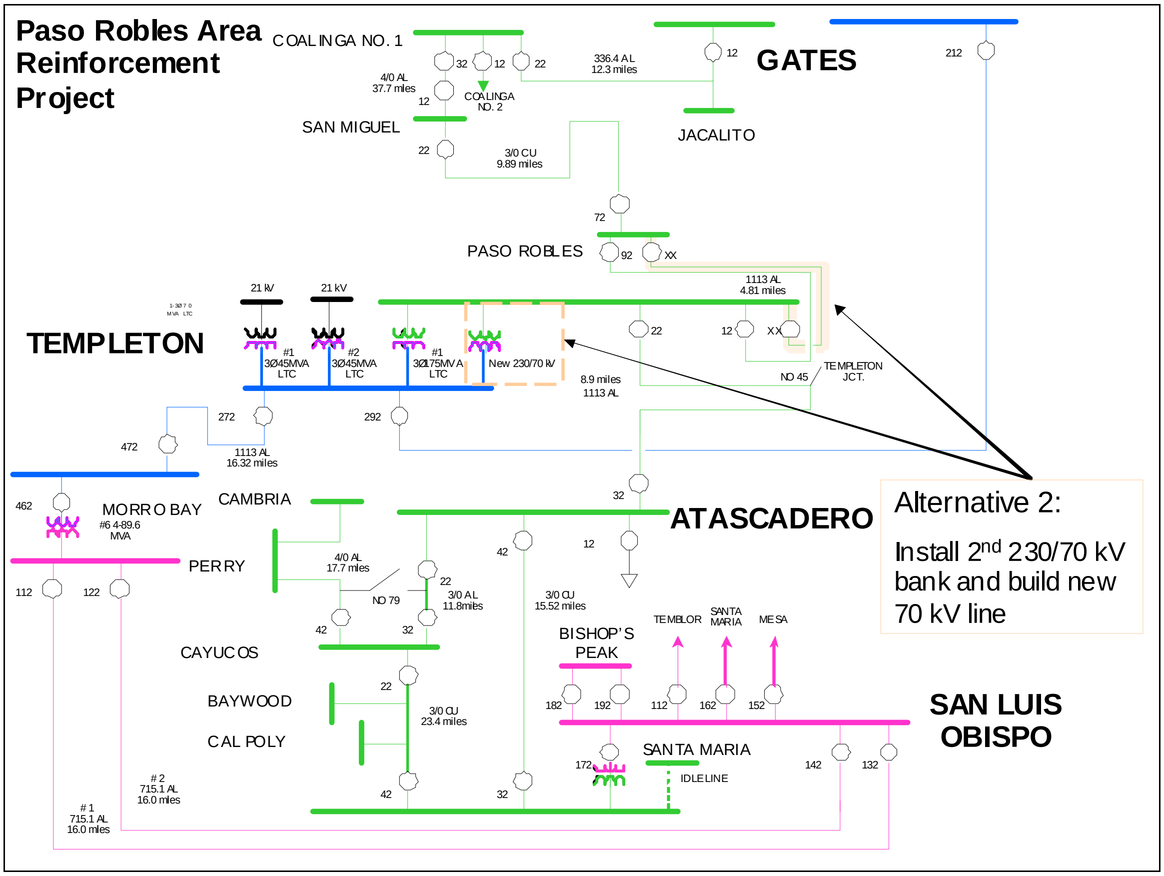


Figure 6-37: Scope Diagram-Alternative 2

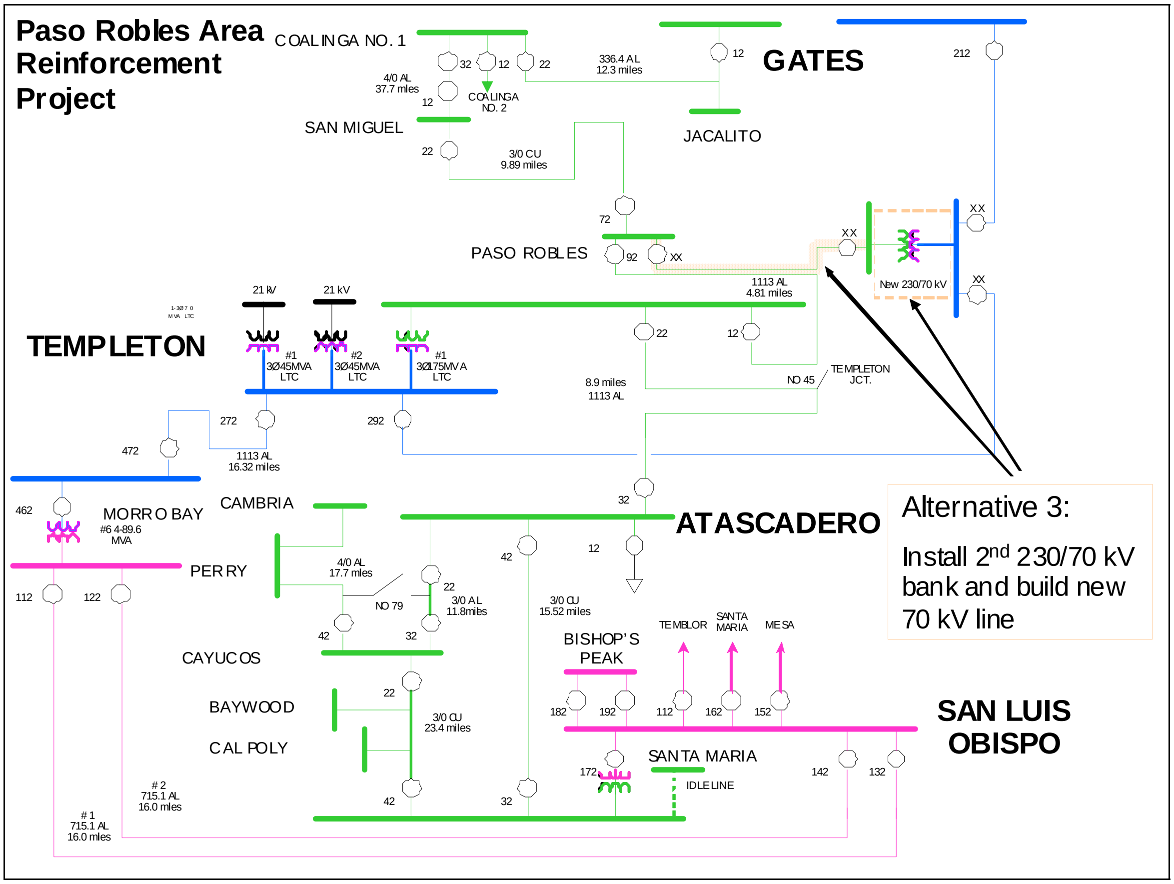


Figure 6-38: Scope Diagram-Alternative 3

Renfro Area 115 kV Reinforcement

IN-SERVICE DATE

May 2016

PURPOSE AND BENEFIT

Reliability – NERC Compliance

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROJECT

The project scope is to interconnect two new 115 kV transmission lines from Kern Power Plant to Renfro and Tupman Substations. Kern PP 115 kV bus will be expanded to accommodate the new transmission lines. The project scope is to also reconductor the Tupman Tap Nos. 1 & 2 115 kV lines (5 miles) with higher capacity rated conductors. Tupman and Renfro substations will have the transmission line and bank capacity to operate as a fully looped 115 kV substations.

This project is expected to cost between $10M and $20M.

BACKGROUND

The greater Tupman and Renfro area is located in Kern County. It is an area identified to see significant load growth based on the number of processed applications by agriculture customers to convert their diesel pumps to electric pumps. Several distribution capacity increase projects have been initiated to support this new load. A project to install a 2nd 45 MVA distribution bank at Renfro was completed in August 2007. A project to install a 2nd 45 MVA distribution bank at Tupman is projected to be completed in April 2009.

Planning Studies conclude that an outage of the Midway-Renfro 115 kV Line under summer peak conditions is projected to cause thermal overloads to the remaining Midway-Rio Bravo-Renfro 115 kV Line. A transmission capacity increase project has been initiated to reconductor the Midway-Renfro and Midway-Rio Bravo-Renfro 115 kV lines. Further transmission reinforcements are needed to allow Tupman and Renfro Substations to operate as fully looped stations.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Build new Midway-Tupman 115 kV Lines

This alternative proposes to build a new 115 kV double circuit tower line (DCTL) from Midway to Tupman Jct and reconductor the Tupman Tap Nos. 1 & 2 115 kV lines (5 miles) with higher capacity rated conductors. This alternative will create dedicated transmission lines between Midway and Tupman Substations.

Alternative 2: Convert Renfro Substation to 230 kV Operation

This alternative proposes to convert Renfro Substation to 230 kV operation by looping into the Midway-Kern 230 kV Line.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2016

KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – TBD
- Special Metering or Protection –TBD
- Common Mode Exposure Items – TBD
- Interaction with other Projects – TBD

ATTACHMENTS

1. Scope Diagrams

Attachment 1: Scope Diagrams

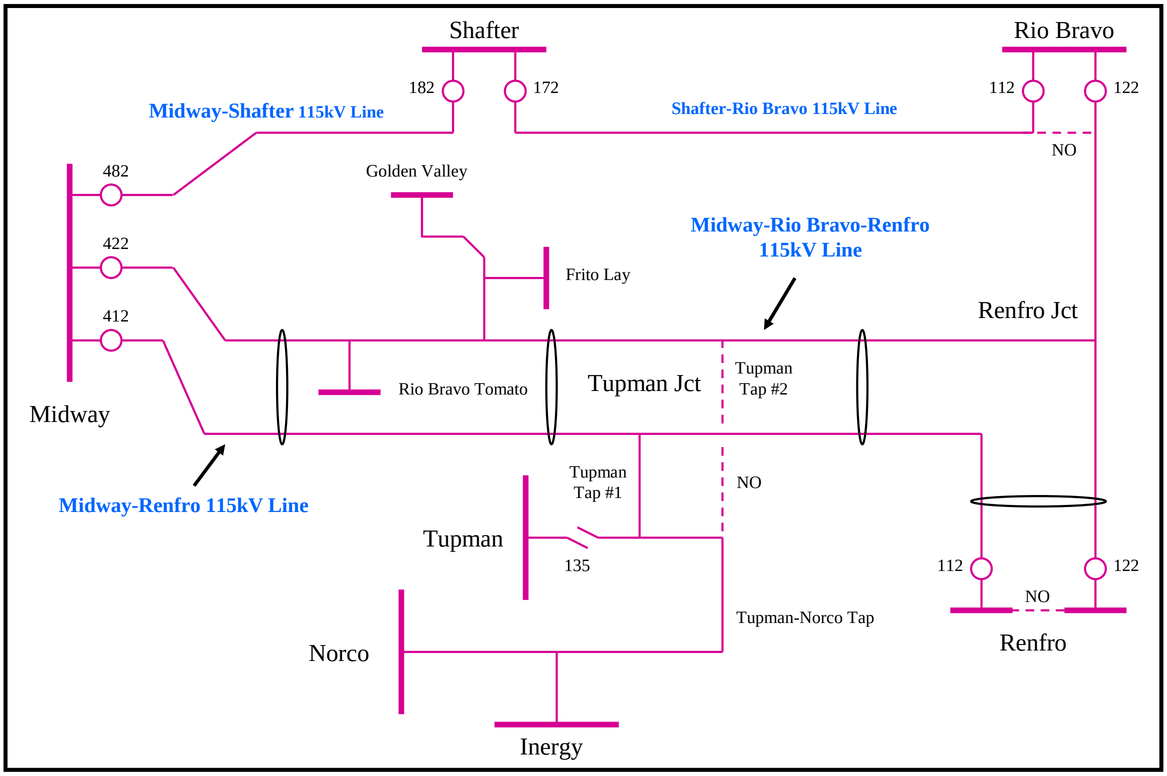


Figure 6-39: Existing Scope Diagram

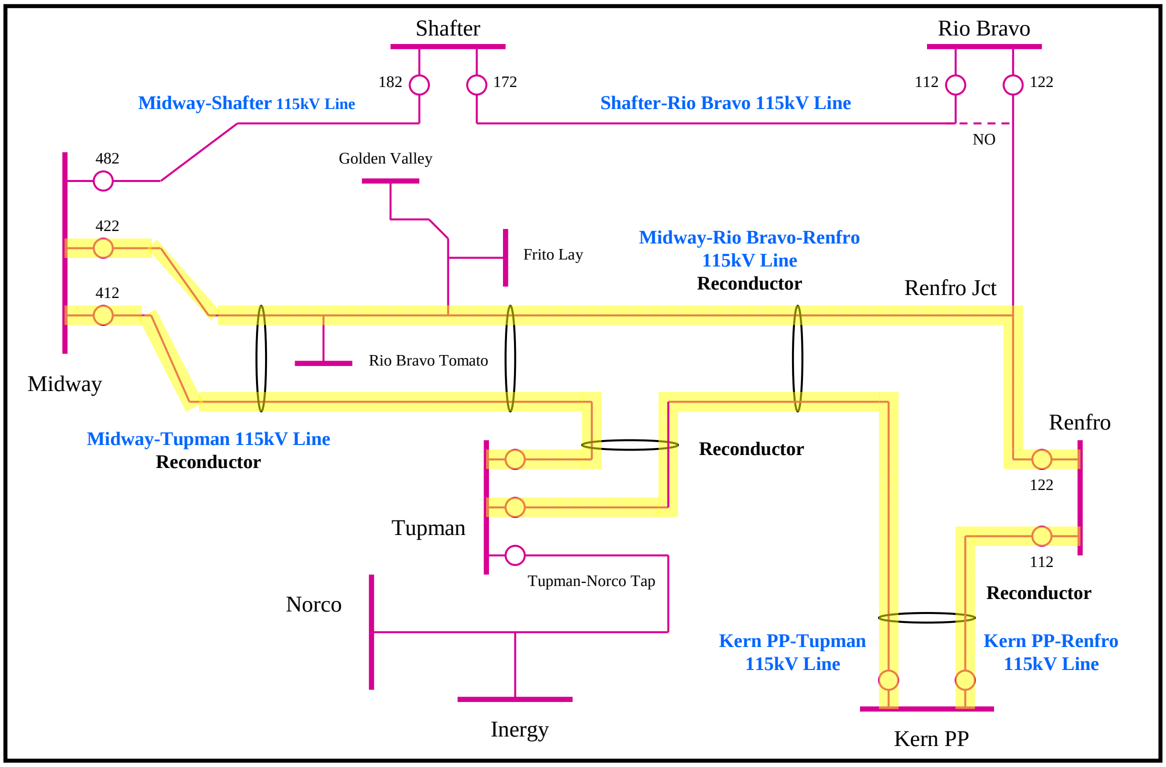


Figure 6-40: Scope Diagram

2017 Projects

Exchequer – Yosemite 70 kV Line Reconductor

TARGETED IN-SERVICE DATE

May 2017

PURPOSE AND BENEFIT

Reliability - NERC Compliance

PROJECT CLASSIFICATION

This is a new project.

PROJECT SCOPE

The project scope is to reconductor a total of 8.8 miles on the Exchequer - Yosemite 70 kV Line with conductors rated to handle a minimum of 440 Amps normal and 514 Amps emergency.

This project is expected to cost between $5M and $10M.

BACKGROUND

The Exchequer – Yosemite and Exchequer – Mariposa 70 kV Lines are located in Mariposa County, within the Yosemite Division. These lines provide 70 kV transmission power from MID's Exchequer Powerhouse (95 MW) to serve local area customers in the Mariposa area.

These two lines serve four PG&E substations that include Mariposa, Bear Valley, Indian Flat, and Yosemite. They also serve one customer-owned substation: Saxon Creek. The 2009 projected peak load in these substations is 32.4 MW and is forecast to increase approximately 0.7 MW or 2% per year.

The Exchequer – Bear Valley Jct. section of the Exchequer - Yosemite 70 kV Line is strung with 397.5 AAL (0.1 mile), #4/0 AAL (3 miles) and #1/0 CU (5.8 miles) conductors.

Planning analysis determined that loss of the Exchequer – Mariposa 70 kV Line is projected to overload the Exchequer – Bear Valley Jct. section of the Exchequer – Yosemite 70 kV Line by 2% in 2018.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended. This alternative does not address the potential overload issue.

Alternative 2: Re-rate the #1/0 CU Section of the Exchequer - Yosemite 70 kV Line

This alternative proposes to re-rate the Exchequer – Bear Valley Jct. section (#1/0 CU) of the Exchequer – Yosemite 70 kV Line for 4 feet per second (fps) wind speed at ratings of 291 Amps normal and 334 Amps emergency. The 4 fps ratings increase the current carrying capability by approximately 20%.

This alternative is expected to cost less than $1M.

Alternative 3: Reconductor the Exchequer - Yosemite 70 kV Line

This alternative proposes to reconductor a total of 8.8 miles on the Exchequer - Yosemite 70 kV Line with 397.5 AAL conductors with ratings of 440 Amps normal and 514 Amps emergency.

This alternative is expected to cost between $5M and $10M.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2017

KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – TBD
- Special Metering or Protection – TBD
- Common Mode Exposure Items – TBD
- Interaction with other Projects or Studies – TBD

ATTACHMENT

1. Scope Diagram

Attachment 1: Scope Diagram

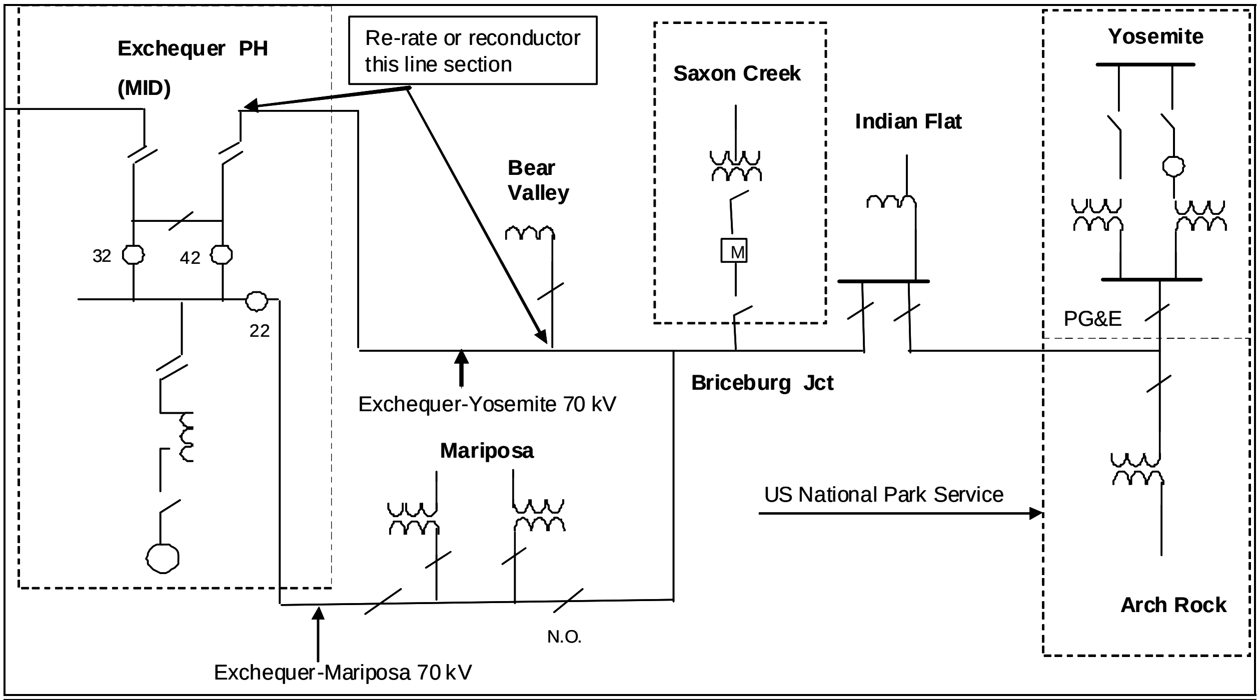


Figure 6-41: Scope Diagram

Los Banos-Oro Loma 70 kV Area Reinforcement

TARGETED IN-SERVICE DATE

May 2017

PURPOSE AND BENEFIT

Reliability – NERC Compliance

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROJECT

This alternative proposes to reconductor the Mercy Springs Jct.-Ortiga section (3.2 miles) of the Los Banos-Canal-Oro Loma 70 kV Line, Oro Loma-Dos Palos section (2.4 miles) of the Oro Loma-Canal 70 kV Line, and 715.5 AAL sections (12.7 miles) of the Los Banos-Livingston Jct.-Canal 70 kV Line. The new conductors for the Mercy Springs Jct.-Ortiga section, Oro Loma-Dos Palos section and Los Banos-Livingston Jct.-Canal section should be capable of at least 742 Amps, 514 Amps, and 975 Amps emergency ratings, respectively.

This alternative is expected to cost between $10M and $20M.

BACKGROUND

The Los Banos-Livingston Jct.-Canal, Los Banos-Canal-Oro Loma, Oro Loma-Canal, and Livingston-Livingston Jct. 70 kV Lines are located in Fresno County, within the Yosemite Division. These lines provide 70 kV transmission power from Los Banos 230/70 kV and Oro Loma 115/70 kV Substations to serve local area customers in the Los Banos, Livingston and Oro Loma areas. The Livingston load is also serve from a 115/12 kV substation at Livingston.

The 70 kV system serves these substations: Santa Nella, Canal, Ortiga, Santa Rita, Dos Palos, Mercy Springs and Wright Substations. They also serve two customer-owned substations: Chevron Pipeline (Los Banos) and Arburua (Texaco). The 2009 projected peak load in these substations is 129 MW and is forecast to increase approximately 3.5 MW or 2.7% per year.

The Los Banos-Livingston Jct.-Canal 70 kV Line is strung with 1113 AAL (1.4 miles) and 715.5 AAL (12.7 miles) conductors. The Mercy Springs Jct.-Ortiga section of the Los Banos-Canal-Oro Loma 70 kV Line is strung with 397.5 AAL (3.2 miles) conductors. The Oro Loma-Dos Palos section of the Oro Loma-Canal 70 kV Line is strung with #1/0 CU (1 mile) and #3/0 AAL (1.4 miles) conductors.

Planning analysis determined that loss of the Los Banos-Livingston Jct.-Canal 70 kV Line is projected to overload the Mercy Springs Jct.-Ortiga section of the Los Banos-Canal-Oro Loma 70 kV Line by 9% in 2018. The same line outage is projected to overload the Oro Loma-Dos Palos section of the Oro Loma-Canal 70 kV Line by 5% in 2018. The loss of the Los Banos-Canal-Oro Loma 70 kV Line is projected to overload the Los Banos-Livingston Jct.-Canal 70 kV Line by 5% in 2018.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended. This alternative does not address the potential overload issue.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2017

KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – TBD
- Special Metering or Protection – TBD
- Common Mode Exposure Items – TBD
- Interaction with other Projects or Studies – TBD

ATTACHMENT

1. Scope Diagram

Attachment 1: Scope Diagram

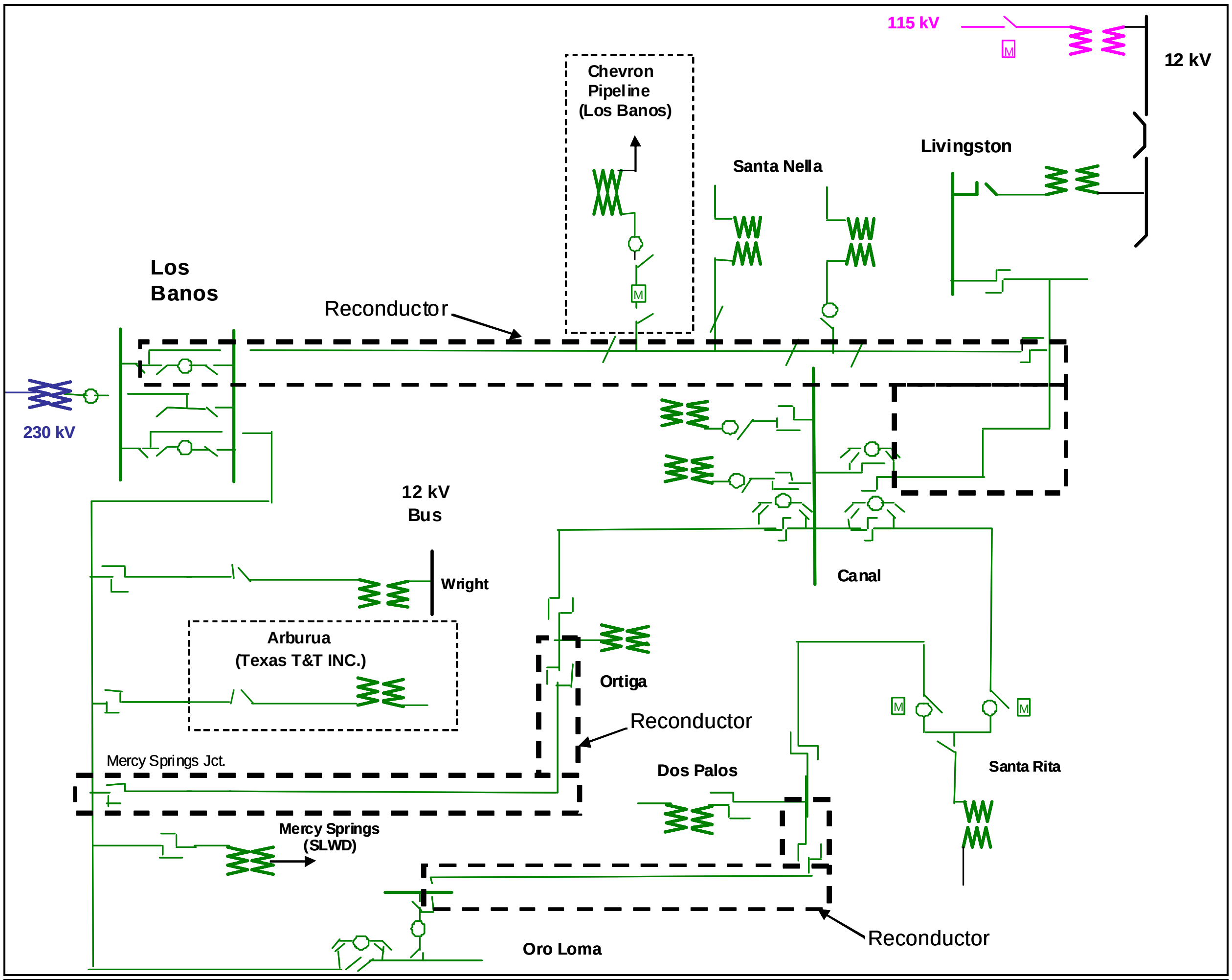


Figure 6-42: Scope Diagram

Monta Vista – Los Gatos – Evergreen 60 kV Project

IN-SERVICE DATE

May 2018

PURPOSE AND BENEFIT

Reliability – NERC Compliance

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROJECT

The project scope is to reconductor the limiting conductors of the Monta Vista – Los Gatos 60 kV Line (Approximately 9 miles) and the Evergreen – Los Gatos 60 kV Line (11 miles) with a conductor rated to handle a minimum of 700 Amps under summer normal conditions and a minimum 800 Amps under summer Emergency conditions. If necessary, associated line terminal equipment would be upgraded. In addition, the project scope would require obtaining any necessary environmental and land permits to complete the reconductoring work.

This project is expected to cost between $10M and $15M.

BACKGROUND

Los Gatos Substation, located in Santa Clara County, is served by two lines, Monta Vista – Los Gatos 60 kV Line and Evergreen – Los Gatos 60 kV Line. Monta Vista – Los Gatos 60 kV Line is approximately 11 miles long and consists of 336.4-19 AAC Conductors (9.1 miles), and 715.5-37 AAC Conductors (1.9 miles). It has a normal conductor rating of 525 Amps and a summer emergency conductor rating of 591 Amps. The section with 336.4-19 AAC conductors is already rated at 4 fps and must be reconductored. Evergreen – Los Gatos 60 kV Line is approximately 12 miles long and consists of 336.4-19 AAC Conductors (8.8 miles), 397.5-19 AAC Conductors (1.9 miles), and 715.5-37 AAC Conductors (0.6 miles). It has a normal conductor rating of 443 Amps and a summer emergency conductor rating of 500 Amps. The sections of 336.4-19 AAC and 397.5-19 AAC Conductors must be reconductored because a rerate is not enough to mitigate the overload

The Monta Vista – Los Gatos 60 kV Line and Evergreen – Los Gatos 60 kV Lines do not have adequate capacity to meet anticipated demands in the future. During forecasted 2018 summer peak load conditions, planning analysis indicates a 2% overload on the Monta Vista – Los Gatos line following an outage of the Evergreen – Los Gatos 60 kV Line (L-1). It also indicates a 4% overload on the Evergreen – Los Gatos line following an outage of Monta Vista – Los Gatos 60 kV Line.

The proposed project is to meet future electric demand increase, increase reliability and improve grid operation efficiency.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended. This alternative does not address the potential overload issue.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2018

KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – TBD
- Special Metering or Protection – TBD
- Common Mode Exposure Items – TBD
- Interaction with other Projects – TBD

GEPSLF MODELING INFORMATION

```
# Monta Vista - Los Gatos – Evergreen 60 kV Project
# Model Update
# Description:
# Change file is created to replace the Monta Vista - Los Gatos 60 kV Line and
# the Evergreen – Los Gatos 60 kV Line
#
# Exact model is not available at this moment.
#
#  Replace the Monta Vista - Los Gatos 60 kV Line
#
OLDSECDD  35455, 35460, CKT=1, SEC=1, STATUS=1,+
        RPU=0.040136, XPU=0.22015, BPU=0.002329, MVA1=73.05, MVA2=83.35, MVA3=101.01, MVA4=107.98
#
# Replace the Evergreen - Los Gatos 60 kV Line
#
OLDSECDD  35757, 35460, CKT=1, SEC=1, STATUS=0,+
        RPU=0.025099, XPU=0.12153, BPU=0.0013656, MVA1=73.05, MVA2=83.35, MVA3=101.01, MVA4=107.98
OLDSECDD  35756, 35757, CKT=1, SEC=1, STATUS=1,+
        RPU=0.019037, XPU=0.092174, BPU=0.0010357, MVA1=73.05, MVA2=83.35, MVA3=101.01, MVA4=107.98
OLDSECDD  35753, 35756, CKT=1, SEC=1, STATUS=1,+
        RPU=0.0012934, XPU=0.0062623, BPU=0.000070368, MVA1=73.05, MVA2=83.35, MVA3=101.01, MVA4=107.98
# END
```

ATTACHMENTS

1. Scope Diagram

Attachment 1: Scope Diagram

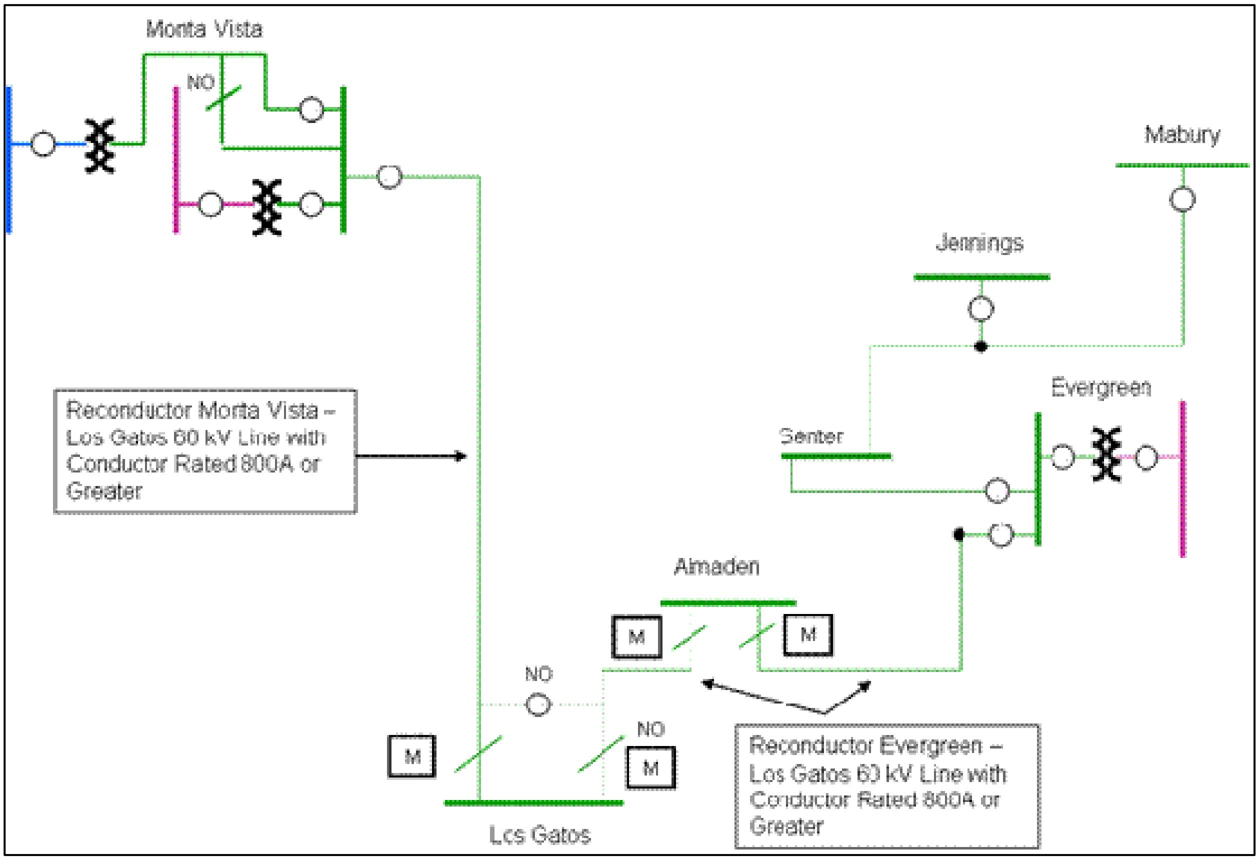


Figure 6-43: Los Gatos 60 kV Area

2018 Projects

Arco-Twisselman Area Reinforcement

IN-SERVICE DATE

May 2018

PURPOSE AND BENEFIT

Reliability – NERC Compliance

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROJECT

This project scope is to install a 2nd 230/70 kV transformer at Arco Substation and build a new 70 kV transmission line between Blackwell and Lost Hills Substations. The project scope is to also reconductor the Arco-Twisselman 70 kV Line with higher capacity rated conductors. Blackwell and Lost Hills substations will have the transmission line and bank capacity to operate as fully looped 70 kV stations.

This project is expected to cost between $17M and $25M.

BACKGROUND

The Arco 70 kV transmission system is located in Kern County. It is an area anticipated to grow. This is based on the large load increase requests by transmission customers to expand its oil drilling operations. The Arco 70 kV transmission system is a radial system that is supported by one 230/70 kV 135 MVA transformer at Arco Substation. A maintenance project has been initiated to upgrade Arco Bank 1 to a 180 MVA transformer. This project is anticipated to be completed by December 2010. The Arco-Twisselman 70 kV Line is a radial line that supports Twisselman, Nations Petroleum, and Lost Hills (Chevron) substations.

Planning Studies conclude that the Arco-Twisselman 70 kV Line is projected to experience normal thermal overloads under 2018 summer peak conditions. An outage of the Arco-Twisselman 70 kV Line will result in the loss of service to Twisselman, Nations Petroleum, and Lost Hills (Chevron) substations. An outage of Arco Bank No. 1 will result in the loss of service to the Arco 70 kV system.

BASE CASE AND STUDY ASSUMPTIONS

PG&E used base cases and assumptions approved by the 2008 expansion plan study group and the CAISO.

STUDY CRITERIA

CAISO grid planning criteria

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Build new Goose Lake-Lost Hills 115 kV Line

This alternative will build a new 14.5 mile 115 kV transmission line from Lost Hills to Goose Lake. Lost Hills will retain its 70 kV connection for back-up service.

PROJECT SCHEDULE

- Environmental and Permitting Processes – TBD
- Design – TBD
- Major Equipment – TBD
- Construction – TBD
- Operation Date – May 2018

KEY ISSUES

- Land-Use Restrictions – TBD
- Environmental Concerns – TBD
- Special Metering or Protection – TBD
- Common Mode Exposure Items – TBD
- Interaction with other Projects – TBD

ATTACHMENTS

1. Scope Diagrams

Attachment 1: Scope Diagrams

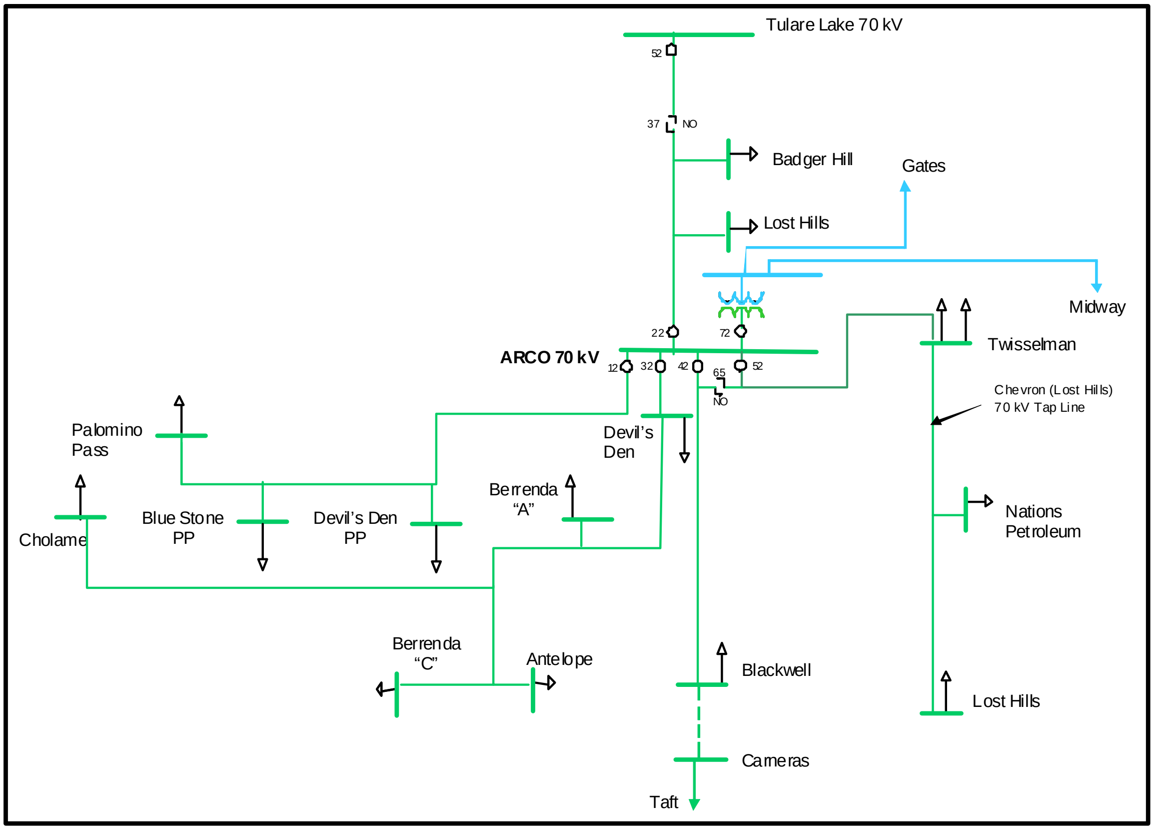


Figure 6-44: Existing Scope Diagram

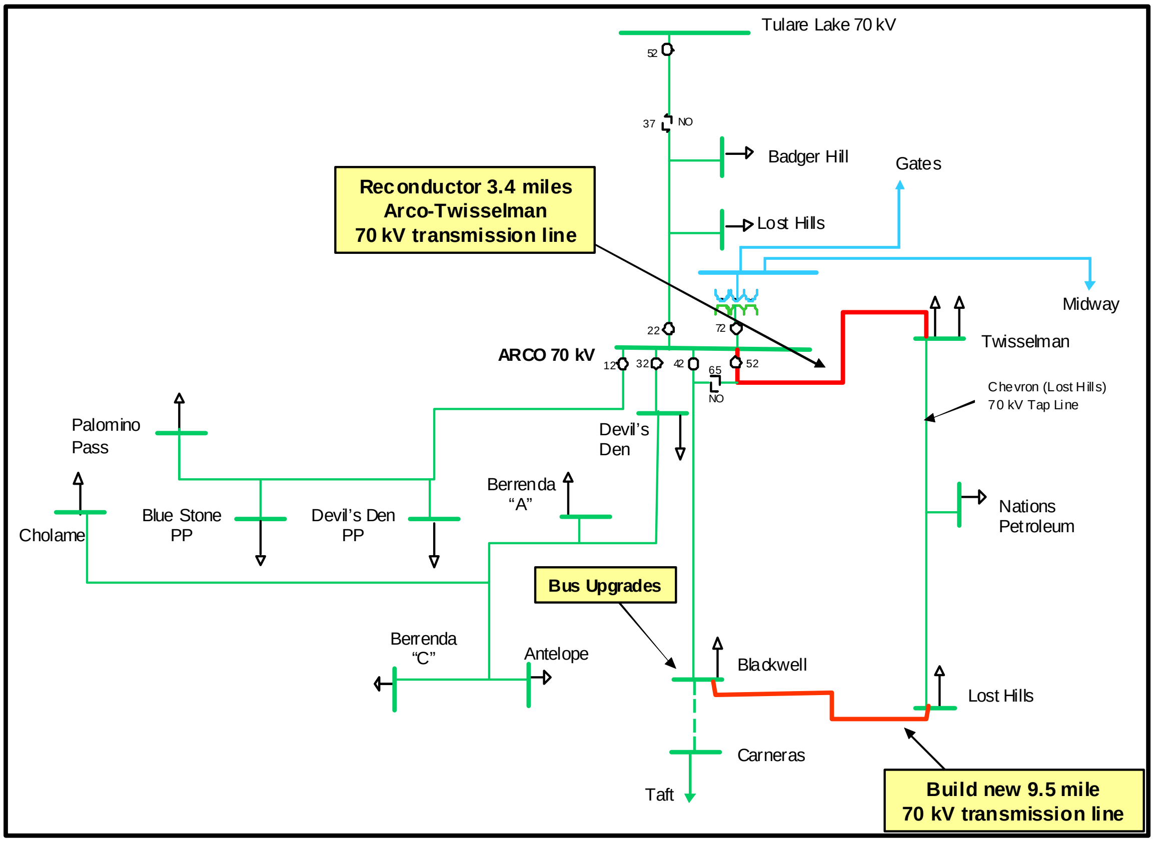


Figure 6-45: Scope Diagram

East Bay-Potrero 230 kV Transmission

IN-SERVICE DATE

May 2018

PURPOSE AND BENEFIT

Reliability – NERC Compliance and Operational Flexibility. This project will increase the reliability of the transmission system serving San Francisco by providing another source of power into San Francisco.

Furthermore, this project will also increase the overall load serving capability for the transmission system serving the San Francisco Peninsula.

The East Bay-Potrero 230 kV Transmission Project is part of PG&E's plan and commitment to Mayor Newsom made in June 2008. PG&E believes that with the completion of the East Bay-Potrero 230 kV Transmission Project, along with other transmission projects that will be completed within the next few years, the electric transmission system can reliably meet long-term power demands in San Francisco Peninsula while reducing its reliance on fossil-fuel fired generation.

PROJECT CLASSIFICATION

This is a new project.

DESCRIPTION AND SCOPE OF PROJECT

This project proposes to construct a new 230 kV line from the Easy Bay into Potrero P.P. Substation. This new line will be rated to handle a minimum of 1,100 Amps for summer normal and summer emergency conditions. New 230 kV circuit breakers, rated to handle a minimum of 1,050 Amps, will be installed at Embarcadero and at the substation in the East Bay. At Potrero, the 230 kV line will be terminated at the new 230 kV bus. Three substations are being considered in the East Bay for interconnection of this new line. These stations are: Moraga, Eastshore and Newark.

This project is expected to cost between $250M and $350M.

BACKGROUND

Peak electric demand in the City of San Francisco (the City) is approximately 965 MW, with an expected growth rate of 10 MW per year. Mirant California's Potrero Power Plant, which has a maximum plant output of approximately less than 370 MW, is the only generation facility within the City. By 2010, Mirant California will be retiring Potrero Unit 3, which will reduce the maximum plant out to approximately 150 MW[4]. Even with all three Potrero peakers on-line and the TransBay Cable (TBC) Project transmitting 400 MW into the City, almost half of the City's power needs will be supplied by importing power from Martin Substation.

Martin Substation is connected to the transmission system by 230 kV and 115 kV transmission lines that cross the Bay and come up the Peninsula. As electric demand increases in the City in the future, these existing 230 kV and 115 kV transmission lines will need to be reinforced, or the system will rely more and more on the Potrero peakers.

BASE CASE ASSUMPTIONS

This project was analyzed utilizing the approved basecases for the Greater Bay Area system, which was developed under the CAISO's Transmission Planning Process (TPP). Specifically, the San Francisco peak load modeling was based on the approved load forecasts provided in the current year CAISO TPP. This study assumed the following planned transmission and generation assumptions for the San Francisco system:

- Martin-Hunters Point 115 kV Underground Cable Project in-service
- Larkin Circuit Breaker 192 Project in-service
- San Francisco 115 kV Recabling Project in-service
- Trans Bay Cable HVDC Project in-service (retirement of Potrero Generating Unit 3)
- Mirant California's retrofit of Potrero Generating Unit Nos. 4, 5 and 6

STUDY CRITERIA

CAISO Grid Planning Criteria.

[4] Potrero Generating Plant Units 4, 5, and 6 will be retrofitted to run on natural gas, and that the retrofit and operation costs of these units would be recovered under the terms of a Reliability Must Run (RMR) contract.

OTHER ALTERNATIVES CONSIDERED

Alternative 1: Status Quo

This alternative is not recommended because it does not reduce future reliance on the Potrero peakers due to an [N-1-1] contingency of the TBC Project and the Jefferson – Martin 230 kV Line.

PROJECT SCHEDULE

- Environmental and Permitting Processes – CPCN Application filing by second half of 2012
- Design – Engineering design complete by first quarter 2015
- Major Equipment – Cable procurement to start in 1st quarter 2015
- Construction – Construction schedule dependant on CPCN approval
- Operation Date – May 2018

KEY ISSUES

- Land-Use Restrictions and Environmental Concerns– This project will require a CPCN.
- Special Metering or Protection – None
- Common Mode Exposure Items – This project will address the N-1-1 reliability issues associated with the TBC Project and the Jefferson – Martin 230 kV line.
- Interaction with other Projects – Coupled with the retrofit of Mirant California's Potrero Generating Unit Nos. 4, 5 and 6, the total [N-1-1] LSC for the transmission system serving the San Francisco Peninsula is expected to increase to over 1,300 MW.

MISCELLANEOUS DATA

- PG&E will construct, own, and finance the project
- PG&E will be the planned operator of the project

ATTACHMENTS

1. Scope Diagram

Attachment 1: Scope Diagram

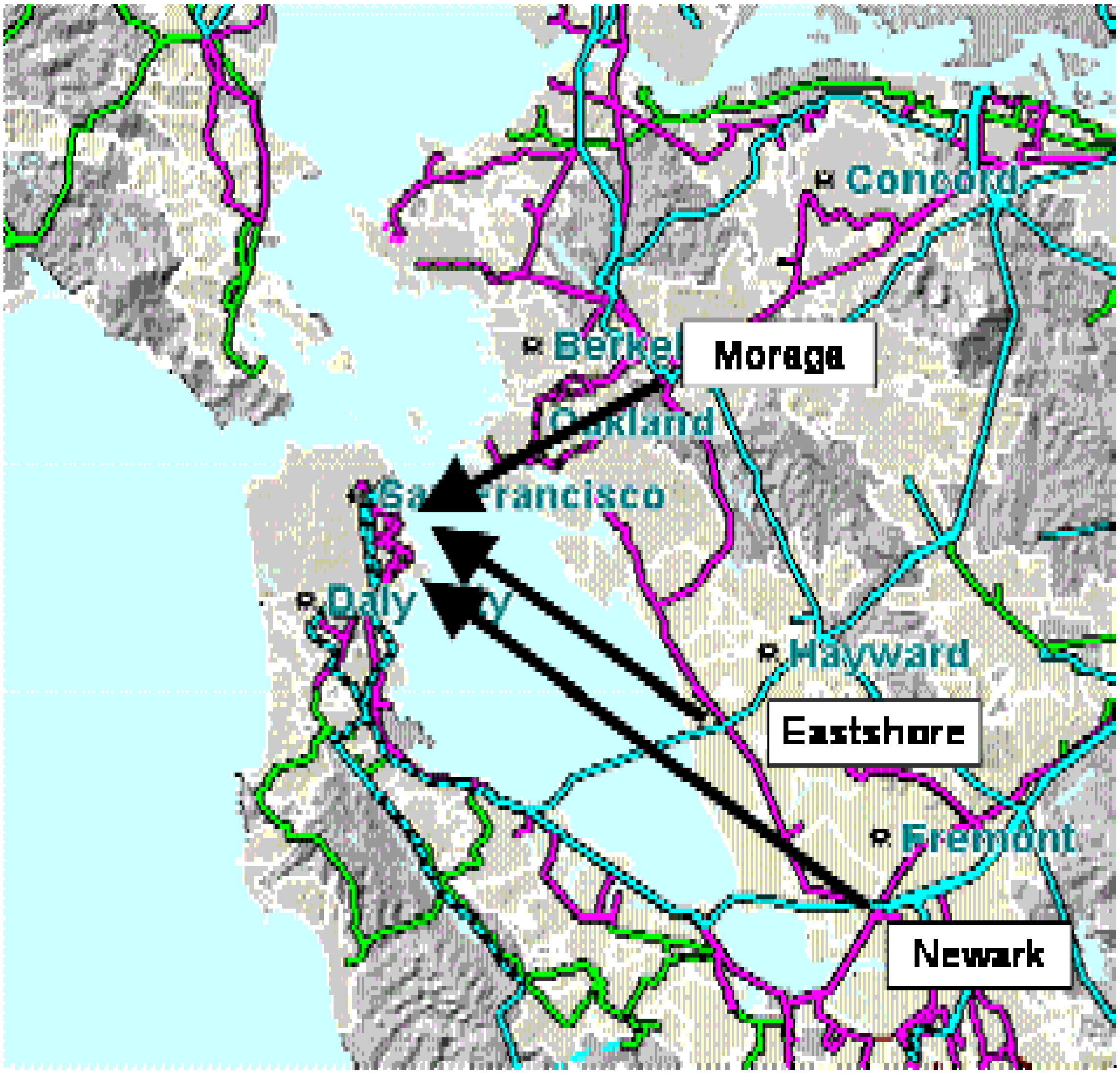


Figure 6-46: Potrero 115 kV Substation

CHAPTER 7

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Transmission Access to Renewables

There are a number of areas in California and in the WECC region with resources that could potentially enable California to meet its resource needs and also enable PG&E to meet its Renewable Portfolio Standard (RPS) goal in the future.

This Chapter and Chapter 8 discuss some of the recent activities that PG&E is pursuing in meeting its near-term and long-term procurement goals to achieve California's aggressive renewable energy targets of 20% by 2010 – 2013 on a delivered basis and to consider expanded renewables goals. It should be noted that both the projected renewable resource scenarios and the described regional transmission projects are at the conceptual studying stage. As such, no conclusion can be drawn as to the specific projects that would ultimately be pursued or their timing.

Recently a number of studies have already been (or are being) conducted in California and throughout WECC: For example, the Intermittency Analysis Project in the California Energy Commission's PIER Program, the Tehachapi Collaborative Study conducted under the direction of the California Public Utilities Commission and later at the CAISO, Canada/Pacific Northwest – Northern California Transmission Study, the Central California Clean Energy Transmission Project (formerly Midway – Gregg 500 kV Transmission Project), and the CAISO Renewables Integration Study, the California Energy Commission's (CEC's) Regional Integration of Renewables (RIR) for Northern California Study[1], and the Renewable Energy Transmission Initiative (RETI)[2] in particular. In this year's study, we intend to leverage the study results available to date and investigate the transmission plan from a broader long-term perspective. Results from the RIR and RETI are still preliminary at the time this report is being finalized. We expect, however, to incorporate the information from such studies in future assessment studies.

Transmission Requirements for Renewable Resource Portfolio

Various transmission projects around WECC[3] aimed at connecting and transmitting renewable resources to distant areas have also been proposed and are in varying stages of investigation.

The CEC also published in July 2007, the Intermittency Analysis Project (IAP) Final Report (CEC-500-2007-081)[4], which provides some updated information on the potential for renewable resource development in California. One scenario for the study year 2020 envisions the addition of about 19,073 MW of renewable resources (between

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1 http://www.pge.com/RIR

2 http://www.energy.ca.gov/reti/index.html

3 http://www.wecc.biz

4 http://www.energy.ca.gov/pier/final_project_reports/CEC-500-2007-081.html

2010 and 2020) to meet a 33% RPS target[5] for the State, of which about 5,000 MW would be located in Northern California and approximately 12,000 MW located in Southern California. While various potential RPS targets remain a subject of discussion, it would be prudent to investigate the potential impacts of this and other renewable resource scenarios.

The following assumptions were made regarding transmission requirements:

- Repowering existing renewable resources (*e.g.*, Altamont wind) would increase the energy production but not the capacity of the generating units so repowering would result in no or limited increases in transmission capacity requirements.

- Some amounts of resources can be located in areas such that they would have no or limited impacts on the transmission system.

- New resources in Pacific Northwest and Nevada would enter the CAISO Grid around PG&E's Round Mountain and Table Mountain Substations.

- Renewable resources located in Southern California would enter the PG&E system through PG&E's interconnection with Southern California Edison Company at PG&E's Midway Substation.

For the potential renewable resources located in Northern California, based on previous studies (for example, PG&E's Transmission Ranking Cost Reports[6]), some transmission capacity could be available for additional resources entering the PG&E system around Fulton Substation (from the Geysers area), and for <u>on-peak resources only</u> in the south-to-north direction around Midway Substation. Such resources would likely require no or limited transmission additions in the PG&E service area[7]. This amount based on the scenario in the IAP, could be about 3,700 MW for 2020 out of the 5,000 MW potential renewable resources in Northern California. This would leave about 1,300 MW, which may require additional transmission upgrades in Northern California.

It is not known how much of the 12,000 MW of potential renewable resources (identified in the IAP) located in Southern California would require transmission into Northern California. However, recent preliminary results from RETI Phase 1B Report[8] also indicates potentially large amount of renewables could be located in Southern California. We, therefore, have investigated the capability of the PG&E system to accept and transmit renewable resources into load centers in Northern California as part of prudent utility practice. Because the new information on renewable resources is still

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5 http://www.energy.ca.gov/2007publications/CEC-500-2007-081/CEC-500-2007-081-APA.PDF, Table 5-9, "Comparison of 2010 Tehachapi and 2020 Study Cases (New Renewables Only)".

6 See for example PG&E's Transmission Ranking Cost Report developed for its 2008 Renewables RFO (http://www.pge.com/includes/docs/pdfs/b2b/energysupply/wholesaleelectricsuppliersolicitation/renewableportfoliostdsori-ii_other-doc_pge_20070907-01.pdf)

7 Transmission reinforcements required to connect and deliver renewable resources located in area outside the PG&E Service Areas are outside the scope of this study, and thus were not investigated here.

8 http://www.energy.ca.gov/reti/documents/index.html

preliminary at the time this Expansion Plan is prepared, this assessment and transmission plan is based on information developed in 2007.

PG&E System Requirements North of Tesla Substation

Based on the reliability assessment study[9], with the transmission upgrades listed below, PG&E should be able to accommodate about 300 MW of power entering PG&E system around Round Mountain Substation and about 350 MW around Table Mountain Substation. Therefore, for all 2012 scenarios, the following transmission upgrade would be required, in addition to the transmission projects south of Vaca Dixon Substation already identified in PG&E's 2008 Expansion Plan:

1. For the 500 kV system:

    - For an outage of one of the Round Mountain – Table Mountain 500 kV line, install RAS to bypass the series capacitors at Round Mt. end of the remaining Round Mountain – Table Mountain 500 kV line.
    - For an outage of both Round Mountain – Table Mountain lines #1 and 2, continue to use the existing RAS to trip Round Mountain 500/230 kV transformer bank.
    - Expand existing RAS to trip additional generation for loss of the Table Mountain 500/230 kV transformer bank and following double 500 kV line outages south of Round Mountain and South of Table Mountain. The RAS design specifics will need to be developed based on the generator-specific as the interconnection requests are submitted through the Large Generator Interconnection Process (LGIP).

2. For the 230 kV and below system:

    In addition to the planned transmission upgrades, which were included in previous Transmission Expansion Plans:
    - T1030: Table Mountain – Rio Oso 230 kV Line Reconductoring & Tower Raises (EDRO May 2010, see Chapter 3)
    - Re-rate the Rio Oso – Brighton 230 kV Line (In service on 5/8/2008, see Appendix 1)
    - T1001: Atlantic – Rio Oso – Gold Hill 230 kV Lines (EDRO May 2012, see Chapter 6)
    - T686A: Palermo – Rio Oso 115 kV Line Reconductoring EDRO May 2010, see Chapter 3)
    - T985B: Rio Oso 230/115 kV Transformers (EDRO May 2012, see Chapter 3)
    - T962: East Nicolaus Area Reinforcement (EDRO May 2011, see Chapter 3)

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[9] Note that the reliability assessment study to develop PG&E's Expansion Plan models only those generation projects that met the ISO requirements in the base case, and not all generation project in the CAISO Interconnection Queue as required in the LGIP. As such, the transmission requirements could be different when assessed through the LGIP.

- T1002: Bogue Reconfiguration (EDRO May 2013, see Chapter 6)

The following upgrade may also be needed:

- T686D: South of Palermo 115 kV Reinforcement in conjunction with Project T1002.

However, depending on the renewable resource scenario beyond 2013 - 2014, the above transmission upgrades could be insufficient to accommodate the projected increases south of Round Mountain and Table Mountain Substations. Therefore, major transmission reinforcements, such as a new transmission line from Round Mountain south to the load centers in the San Francisco Bay Area and to the south, would likely be required. A study is being initiated to determine the transmission project(s) that would provide the most benefit to customers should the renewable resources materializes. More detailed discussion on a conceptual transmission plan is included in Chapter 8.

PG&E System Requirements between Tesla and Midway Substations

Studies performed in the Tehachapi Collaborative Study Group (TCSG) for the PG&E system north of Midway Substation shows that there is transmission capacity to support increased power transfer in the north-to-south direction, and to support on-peak power transfer in the south-to-north direction. There is no transmission capacity to support any increase in power transfer in the south-to-north direction during the off-peak period when the prevalent power transfer is also in the south-to-north direction.

To accommodate the as-available and base-load renewable resources from southern California, new transmission capacity is needed. PG&E has been investigating multi-purpose transmission projects, which can also provide other system benefits. One of these projects is the Central California Clean Energy Transmission Project to connect Midway Substation to the load centers in the Greater Fresno Area expected to be operational in 2013. This Project will be discussed further in Chapter 8.

CHAPTER 8

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500 kV Transmission Projects

To meet project load growth, continued investments in transmission infrastructure will be needed to bring future resources to safely and reliably serve the forecasted customer loads. Future transmission plans would depend in part on projections of future resource development. The Global Warming Solutions Act of 2006, Assembly Bill 32 sets an economy-wide cap on California greenhouse gas emissions at 1990 levels by no later than 2020. This is an aggressive goal that represents approximately an 11 percent reduction from current emissions levels and nearly a 30 percent reduction from projected business-as-usual levels in 2020. In addition, on November 17, 2008, Governor Arnold Schwarzenegger signed Executive Order S-14-08 requiring that California utilities reach the 33% renewables goal by 2020. Both developments would significantly impact the development and acquisition of resources by various entities, and thus, long-term transmission plan.

While the uncertainty in locations, amounts and types of future renewable resources introduce much uncertainty in any transmission plan, it would be prudent to investigate the potential transmission plans should it becomes necessary to deliver these renewable resource to the load centers. Because of the magnitude of the expected renewable resources and the need to allow for the shut-down of once-through cooling generators as well as to supply load growth, the conceptual transmission plans would likely need to include 500 kV transmission projects.

Northern California Long-term Transmission Plan

To ensure that the transmission plan to be investigated can interconnect and deliver renewables to meet a 33% RPS Target by 2020 to the load centers, we decided to start from a base case representing 2022 summer peak conditions.

1. Objective

This study is to develop conceptual transmission alternatives that would integrate potential renewable resources in northern California and access resources in the Pacific Northwest/Canada and in southern California to serve load growth in northern California.

This study represents the beginning of a series of studies. Further studies will evaluate different levels of RPS targets. It is also anticipated that information developed from the CEC Regional Integration of Renewable for Northern California (RIR)[1] and other related studies will be incorporated as this study moves forward. As such, the study results and conclusions will change.

1 For example, the RIR Study is developing 15 scenarios covering various assumptions of renewables development to support various assumed RPS targets for Northern California. (See http://www.pge.com/RIR)

2. Renewable Resources Scenario

The renewable resources scenario was based on PG&E's RPS contracts posted on the CEC web site[2] and a future renewable resource scenario assuming a renewable target of higher than 20% for 2022. While a number of targets and resource scenarios can be used, this study starts with an assumed RPS target for the California IOUs of 33% to provide a high-end renewable resource scenario for developing a conceptual transmission plan. Based on this assumption, PG&E would procure about 16,000 GWH of additional renewable energy by 2022 (above the renewable energy needed to meet a 20% target by 2010) to meet the 33% target. This study also assumes that northern California MUNIs would procure renewable energy with the same renewable resources mix scenarios to meet a 20% target by 2022.

Based on the renewables technologies assumed in the potential renewable resources identified in the CEC SVA and IAP Reports, the following two renewable resource (in MW) scenarios were used to develop the conceptual transmission alternatives. Both scenarios would result in the same amount of renewable energy (GWH):

- High imports from the Pacific Northwest and Canada:

  This renewable resource scenario would model a total of 9,700 MW of renewable resources (about 8,100 MW for PG&E and about 1,600 MW for northern California MUNIs) under the 2022 summer peak conditions studied. It includes about 1,400 MW of renewable resources located in northern California and an import of 2,900 MW from the Pacific Northwest and Canada, and 5,400 MW from southern California.

- High imports from southern California:

  This renewable resource scenario would model a total of 8,800 MW of renewable resources (about 7,200 MW for PG&E and about 1,600 MW for northern California MUNIs) under the 2022 summer peak conditions studied. It includes about 1,400 MW of renewable resources located in northern California and an import of 1,200 MW from the Pacific Northwest and Canada, and about 6,200 MW from southern California.

Other renewables scenarios will be developed and evaluated as the study progresses.

In order to accommodate this level of renewable resources, several Bay Area power plants were modeled off-line to balance loads and resources (see Table 8-1) with the transmission projects required to meet NERC/WECC and CAISO Planning Standards. The generators to be modeled off-line were selected based on the Draft Study Plan on "Mitigation of Reliance on Old Thermal Generation Including Those Using Once-Through Cooling Systems" being developed in the CAISO Stakeholder Study Group[3].

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2 http://www.energy.ca.gov/portfolio/contracts_database.html updated August 8, 2007
3 http://www.caiso.com/1c96/1c96dad822e50.pdf

Table 8-1
Bay Area Generation Modeled off-line

Bus #	Generator Bus Name	Pmax (MW)
33116	C.COS 6	340
33117	C.COS 7	340
36409	MORRO 3	340
36410	MORRO 4	340
33105	PTSB 5	325
33106	PTSB 6	325
30000	PTSB 7	720
36405	MOSSLND6	750
36406	MOSSLND7	750
33252	POTRERO3	210
	Total	4440

3. Study Base Cases

This study was based on 2022 summer peak base cases (a 15-year planning horizon) developed from PG&E's 2017 summer peak annual assessment base case (a07sum2017_gov.sav) modeling 1-in-5 year adverse weather load forecast and the above described renewable resource scenarios. The study base cases also models the Pacific Northwest/Canada to Northern California (CNC) Transmission Project, the 60 kV – 230 kV transmission additions identified in the 2007 Expansion Plan and the transmission projects necessary to allow the thermal units mentioned above to be off-line. As a starting point, this study assumes the alternative of building a 500 kV Bipolar DC line with a 3,000 MW (or 1,500 MW) conversion station (T1) in the Tesla/Tracy area for importing renewable resources from the Pacific Northwest and Canada. (The C3ET Project is not modeled in the base cases. It will be modeled as part of the overall transmission alternatives in the study.)

- High imports from the Pacific Northwest:

  The study base case models a total of 7,700 MW of import from the Pacific Northwest and Canada that includes 4,800 MW on the existing Path 66 and 2,900 MW on the 500 kV Bipolar DC line. Path 26 was modeled at 1,400 MW of south-to-north flow with the assumption that the 5,400 MW of renewable import from southern California would counter a north-to-south schedule of 4,000 MW.

- High import from southern California

  The study base case models a total of 6,000 MW of import from the Northwest and Canada that includes 4,800 MW on the existing Path 66 and 1,200 MW on the 500 kV Bipolar DC line. Path 26 was modeled at 2,200 MW of south-to-north flow with the assumption that the 6,200 MW of renewable import from southern California would counter a north-to-south schedule of 4,000 MW.

4. Power Flow Study Results for then existing Northern California Transmission System

The 2022 summer peak base cases would not converge without major voltage supports. It demonstrates the potential of voltage collapse in the Sacramento Valley area and Fresno area. The following fictitious synchronous condensers were modeled in the study base cases to improve voltages:

- Tracy 500 kV (1,000 MVAR)
- Elverta 230 kV (500 MVAR),
- Rio Oso 230 kV (300 MVAR),
- Gold Hill 230 kV (300 MVAR),
- McCall 230 kV (300 MVAR), and
- Wilson 230 kV (300 MVAR)

The 2022 summer peak base cases also show normal overload on the following facilities:

- Stagg – Tesla-E 230 kV line,
- Borden – Gregg 230 kV line,
- Storey – Gregg 230 kV line,
- Warnerville – Cottle B 230 kV line,
- Los Banos – Westley 230 kV line,
- Tracy 500/230 kV Bank #1 and #2,
- Tesla 500/230 kV Bank #2,
- Tracy – Hurley #1 and #2 230 kV lines, and
- Cottonwood – Roseville 230 kV line

The study results also show that, under the scenario of high imports from southern California, the Gates – Midway 500 kV line would load up to 100% of the summer normal pre-load rating of 2,230 amperes.

Therefore, the existing northern California transmission system would need major expansion in order to serve customer loads, accommodate an RPS target of about 33% and meet NERC/WECC Reliability Standards under the 2022 summer peak conditions studied. The existing system does not have spare capacity for connecting additional renewable resources in the Table Mt. area and the Round Mt/Cottonwood area.

5. Potential Alternatives for Northern California Transmission System (See Figure 8-1)

There are several potential major transmission expansion alternatives to be investigated for integrating renewable resources and serving load growth in the San Francisco Bay Area and Central Valley areas. Other alternative may be identified as the study moves forward.

Alternative 1: Build a Round Mt. – Rio Oso 500 kV Single Circuit Tower Line (SCTL), the proposed Central California Clean Energy Transmission Project (C3ETP), and a Bellota – E2 500 kV Double Circuit Tower Line (DCTL)

Alternative 1 is to build a Round Mt. – Rio Oso 500 kV SCTL from the north and a Midway – E2 – Bellota 500 kV DCTL from the south to serve WAPA's , SMUD's and PG&E's customers in the Central Valley areas and east side of PG&E. This alternative would include the following major transmission expansions:

1. Build a new Round Mt. – Rio Oso 500 kV SCTL

    a. Build a new Rio Oso 500/230 kV substation with two 500/230 kV 1,120 MVA transformer banks,
    b. Build a Round Mt. – Rio Oso 500 kV SCTL with 50% series compensation on new right-of-way,
    c. Build a 500 kV line termination at Round Mt. and Rio Oso,
    d. Build an Obanion – Rio Oso 230 kV DCTL (about 15 miles), and
    e. Open the existing Gold Hill – Lake 230 kV system tie.

2. Build the proposed Central California Clean Energy Transmission (C3ET) Project[4]

    a. Build a new 500 kV Substation (E2) located near Fresno with one 500/230 kV 1,120 MVA transformer bank,
    b. Build a Midway – E2 500 kV DCTL strung with two 2,300 kcmil AAL conductors (bundled),
    c. Build a 500 kV line termination for each circuit at Midway and E2, and
    d. Loop the Helms – Gregg #1 and #2 230 kV lines into the E2 Substation.

3. Build a new Bellota – E2 500 kV DCTL

    a. Build a new 500 kV Bellota Substation with two 500/230 kV 1,120 MVA transformer banks,
    b. Build a Bellota – E2 500 kV DCTL with 50% series compensation,
    c. Build a 500 kV line termination for each circuit at Bellota and E2, and
    d. Install 50% series compensation on the Midway – E2 500 kV DCTL.

Alternative 2: Build a Round Mt. – Obanion 500 kV SCTL, the proposed Central California Clean Energy Transmission Project (C3ETP), and an E2 – Bellota 500 kV DCTL

This alternative is similar to Alternative 1, except building a new Obanion 500/230 kV substation instead of Rio Oso 500/230 kV substation.

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[4] The alternative selected to include here is one of several alternatives are being investigated in a CAISO Stakeholder forum. This expansion plan will be updated as information is developed in that process.

Alternative 3: Build a Round Mt. – Gold Hill 500 kV SCTL, the proposed Central California Clean Energy Transmission Project (C3ETP), and an E2 – Bellota 500 kV DCTL

This alternative is similar to Alternative 1, except building a new Gold Hill 500/230 kV substation and a Round Mt. – Gold Hill 500 kV SCTL.

Alternative 4: Same as Alternative 1, except looping one of the Bellota – E2 500kV circuits into a new 500/230 kV substation near Walnut Substation in the MID and TID service area.

This alternative is similar to Alternative 1, except building a new 500/230 kV substation near Walnut Substation in the MID and TID area, and looping one of the Bellota – E2 500 kV circuits into the new 500/230 kV substation. This alternative would include the following additional major transmission expansions:

- Build a new 500/230 kV substation near Walnut Substation with one 500/230 kV 1,120 MVA transformer bank,
- Loop the Bellota – E2 500 kV #2 line into the new substation, and
- Install two 500 kV line terminations at the new substation.

This alternative would develop a strong 500 kV source to serve customers in the MID and TID area, and improve system reliability.

Alternative 5: Same as Alternative 2, except looping one of the Bellota – E2 500kV circuits into a new 500/230 kV substation near Walnut Substation in the MID and TID service area.

Alternative 6: Same as Alternative 3, except looping one of the Bellota – E2 500kV circuits into a new 500/230 kV substation near Walnut Substation in the MID and TID service area.

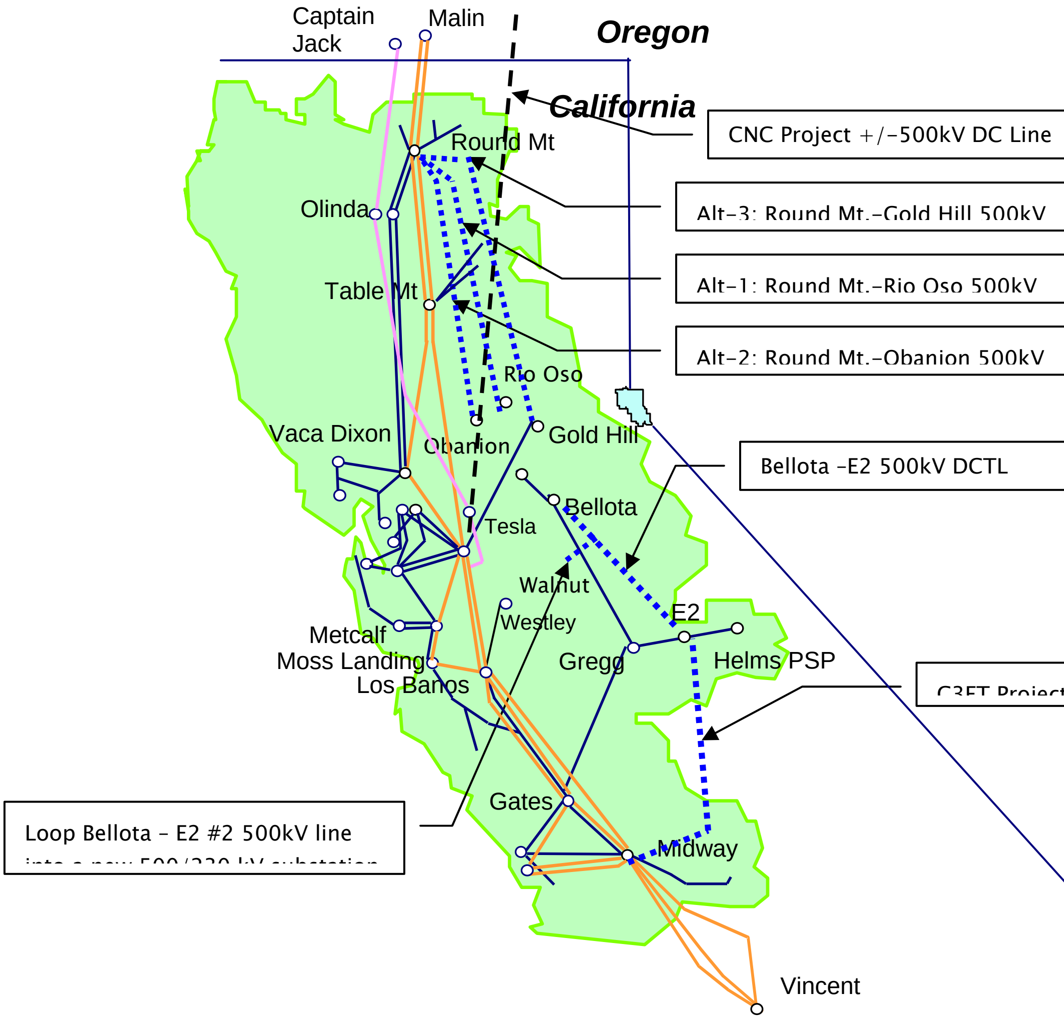

Figure 8-1: Northern California Long-term Transmission Plan

Central California Clean Energy Transmission Project

Based on findings from the TCSG, PG&E started investigating the feasibility of a line between the Midway and Gregg Substations. Upon subsequent studies, the northern terminus was revised to include a location east of Gregg Substation. Transmission planning studies for this project are being conducted through the CAISO Stakeholder Process. Fourteen alternatives are being investigated by PG&E (see Table 8-2), including opportunities for potential future interconnections with Southern California Edison (SCE) to support SCE's Big Creek Area load. Ten alternatives to supply Big Creek Area are being investigated by SCE in a regional planning effort.

The Central California Clean Energy Transmission (C3ET) Project would increase transmission import capacity north of Midway Substation to allow transmission of power from renewable resources from southern California. It would also provide a valuable option to facilitate PG&E to meet its renewable procurement targets in the event that not enough northern California renewable projects materialize.

The C3ET Project would relieve Path 15 congestion by increasing the Path 15 south-to-north transfer capability by about 1,250 MW, and is expected to reduce the annual Path 15 congestion to less than 100 hours.

The C3ET Project would increase import capability to the Yosemite and Fresno area by about 500 MW. The current Fresno Area Long-term Transmission Plan proposing to build a Gates – Gregg 230 kV Double-Circuit Tower Line (DCTL) by around the same time is being subsumed into the C3ET Project Study as one of the alternatives being investigated. As such, if the C3ET Project is selected as the preferred alternative and constructed, the Gates – Gregg 230 kV DCTL would not be needed (or could be deferred beyond the planning horizon).

The C3ET Project would increase the Helms PSP pumping window and enhance support of three Helms units pumping operation. Power flow study results show that the existing system cannot support three units pumping at Helms PSP under the summer off-peak condition studied. The system can only support two units pumping when the combined Yosemite and Fresno areas loads are below 1,300 MW, and single unit pumping at the load level below 1,550 MW. Based on the Fresno area load duration curve, the estimated annual pumping window available for one and two-unit operation are 5,350 and 2,665 hours, respectively. The pumping window is expected to narrow with future load growth.

For more information, please see http://www.caiso.com/1f42/1f42daf7415e0.html.

Table 8-2
Proposed Alternatives being investigated by PG&E

1	Fresno 230 kV Reconductoring	Magunden – Rector 230 kV DCTL ("SCE-1")
2	Midway – E2 500 kV DCTL	Magunden – Rector 230 kV DCTL ("SCE-1")

2a	Midway – E2 500 kV DCTL with S2 Loop-In	
2b	Midway – E2 500 kV DCTL with S2-S3 Loop-In, Whirlwind – S3 500 kV Line	
2c	Midway – E2 500 kV DCTL with S2 Loop-In, Midway – Vincent #3 Upgrade	
2d	Midway – Gregg 500 kV DCTL	Magunden – Rector 230 kV DCTL ("SCE-1")
3	Midway – E2 500 kV SCTL with S2 Loop-In	
4	Whirlwind – E2 500 kV DCTL with S2 Loop-In	
5	Midway – E2 230 kV DCTL	Magunden – Rector 230 kV DCTL ("SCE-1")
6	Fresno – Big Creek 230 kV inter-tie	
7	Midway – McCall – E2 230 kV DCTL	Magunden – Rector 230 kV DCTL ("SCE-1")
8	Gates – Gregg 230 kV DCTL	Magunden – Rector 230 kV DCTL ("SCE-1")
9	Raisin 230 kV Switching Station	Magunden – Rector 230 kV DCTL ("SCE-1")
10	New generation 1000 MW in Fresno	Magunden – Rector 230 kV DCTL ("SCE-1")

Canada/Pacific Northwest – Northern California Transmission Project

In August 2006, PG&E initiated a WECC Regional Planning Project Review for the Canada/Pacific Northwest – Northern California (CNC) transmission project. The project has a target north-to-south rating of 3000 MW and an operating date of December 2015. The Project is sponsored by Avista Corporation, British Columbia Transmission Corporation, PacifiCorp, and PG&E (Project Sponsors).

This proposed line has three key objectives. First, it would provide California with access to significant incremental renewable resources in British Columbia and the Pacific Northwest. Second, it would improve regional transmission reliability. Third, the project could provide other market participants with beneficial opportunities to use the facilities.

In November 2007, the Project Sponsors completed the WECC regional planning process[5] for the project, and submitted the Regional Planning Project Report to WECC. On December 1, 2008 WECC notified the Project Sponsors the approval of the Regional Planning Review Report. A copy of the report is posted on the project website www.pge.com/canada. Studies conducted during regional planning resulted in a conceptual Plan of Service (POS) involving the construction of AC facilities from Selkirk Substation (southeastern British Columbia) to northern Oregon; DC facilities from there to Collinsville (San Francisco Bay Area); and AC facilities from there to Tracy - - a total distance of about 1000 miles. This POS would best achieve the above objectives.

In October 2007, the Project Sponsors initiated the WECC Phase 1 rating process. The conceptual transmission plan for the study is shown in Figure 8-2.

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[5] In November 2008, the WECC Planning Coordination Committee (PCC) approved the report and notified PG&E that the Regional Planning Project Review was complete. The approval time was unusually lengthy because the report inadvertently was not distributed to PCC and the WECC Technical Studies Subcommittee for review until September 2008.

Since then the Project Sponsors have been engaged in analyzing a number of alternative plans of service for the project and have taken into account the development of seven other transmission projects in the Pacific Northwest with planned operating dates in the 2010-2015 period. This coordination was accomplished through the Transmission Coordination Work Group (TCWG) formed by the developers of these eight projects: Avista Corp, Bonneville Power Administration, British Columbia Transmission Corporation, Idaho Power Company, PacifiCorp, Pacific Gas and Electric Company, Portland General Electric, Sea Breeze Pacific-RTS and TransCanada. The TCWG has been successful in identifying the technical benefits of the alternative plans of service. See http://www.nwpp.org/tcwg/.

Based on the technical study results and the implementation cost of the various plans of service, an Initial POS was selected for the CNC project and was used as a starting point for establishing a WECC Phase 1 rating.

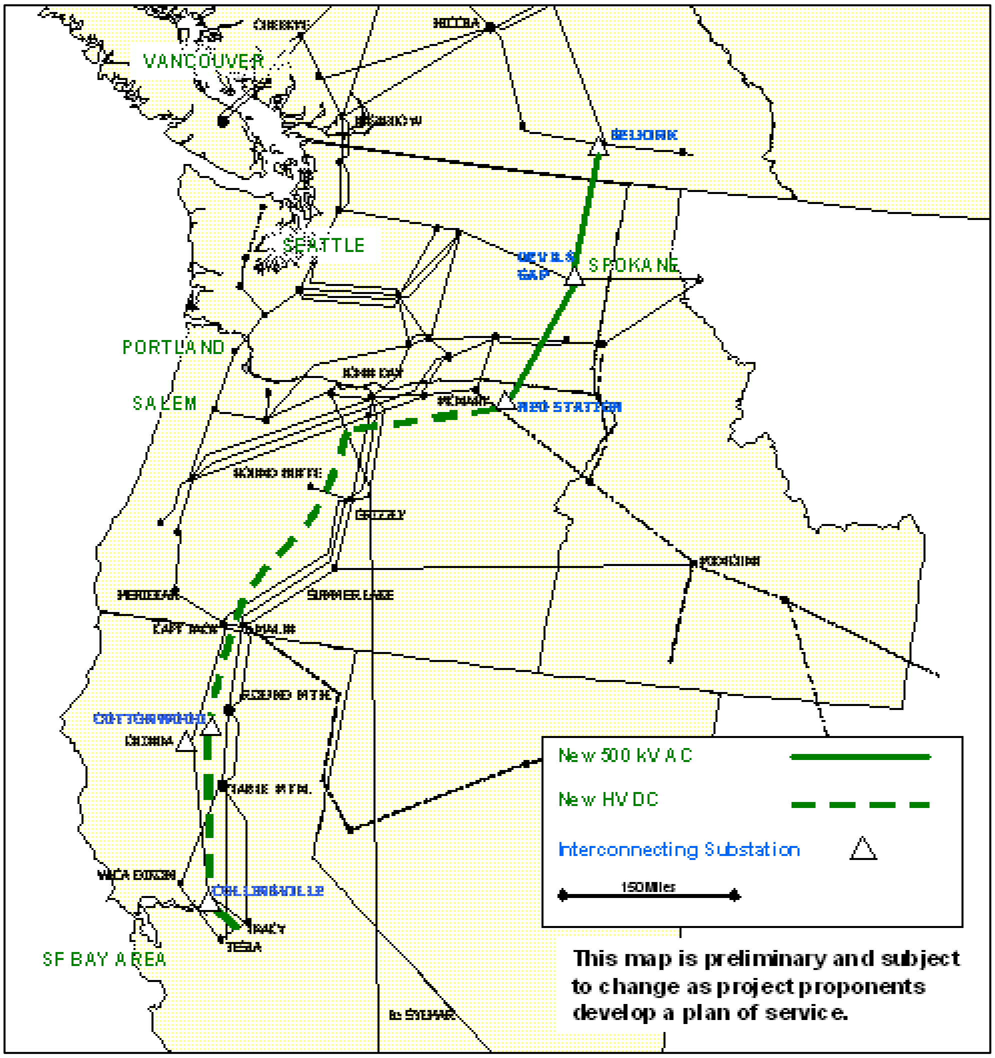

Figure 8-2: Proposed conceptual transmission plan for WECC Phase 1 Rating Process

The CNC Project involves the construction of approximately 1000 miles of HVAC and HVDC transmission lines from British Columbia to Northern California and interconnects with five or six existing and proposed substations. The Initial POS for the project is as follows:

a) A series compensated (up to 70%) 500 kV HVAC Double Circuit Tower Line (DCTL) from Selkirk Substation in the southeast British Columbia to Devil's Gap near Spokane, Washington and then to the proposed Northeast Oregon (NEO) Station and string 4-conductor bundled 666 kcmil ACSR.
b) A 3000 MVA, 500 kV HVAC to +/-500 kV HVDC Converter at the NEO Station.
c) A +/-500 kV HVDC line from the NEO Station to the proposed Collinsville Substation in the San Francisco Bay Area and string 3-conductor bundle 1272 kcmil ACSR.

d) A 3000 MVA, 500 kV HVAC to +/-500 kV HVDC Converter at Collinsville Substation.
e) A 500 kV Single Circuit Tower Line from Collinsville Substation to Tracy 2 Substation and string 2- conductor bundle 2300 aluminum
f) +/- 600 MVAR Static Var Compensators at each of the interconnection substations: Selkirk, Devil's Gap, Neo Station, Collinsville, Tracy and Cottonwood Area (if installed).
g) A remedial action scheme (RAS) to trip incremental resources scheduled on the CNC Project for outages of the project facilities. The outages for which such generation tripping or additional system element switching is required and the magnitude of that tripping will be determined in the WECC Phase 1 Comprehensive Progress Report.

<u>Possible Third Terminal</u>

h) A possible third HVDC terminal may be installed in the Cottonwood area in northern California and would consist of a 1000 -1500 MVA, 500 kV HVAC to +/- 500 kV HVDC Converter. This potential third HVDC terminal could be installed at the same time as or after part of or after the CNC Project is operation

A single line diagram of Initial POS is shown in Figure 8-3.

The details of the WECC Regional Planning Review for the proposed project can be found at www.pge.com/canada.

The Project Sponsors plan to submit the Comprehensive Progress Report for the WECC Phase 1 study to WECC in December 2008 and shortly thereafter initiate the WECC Phase 2 rating process for the north-to-south rating of the project.

The WECC Phase 1 rating process to establish a south-to-north rating for the project will be initiated in January 2009.

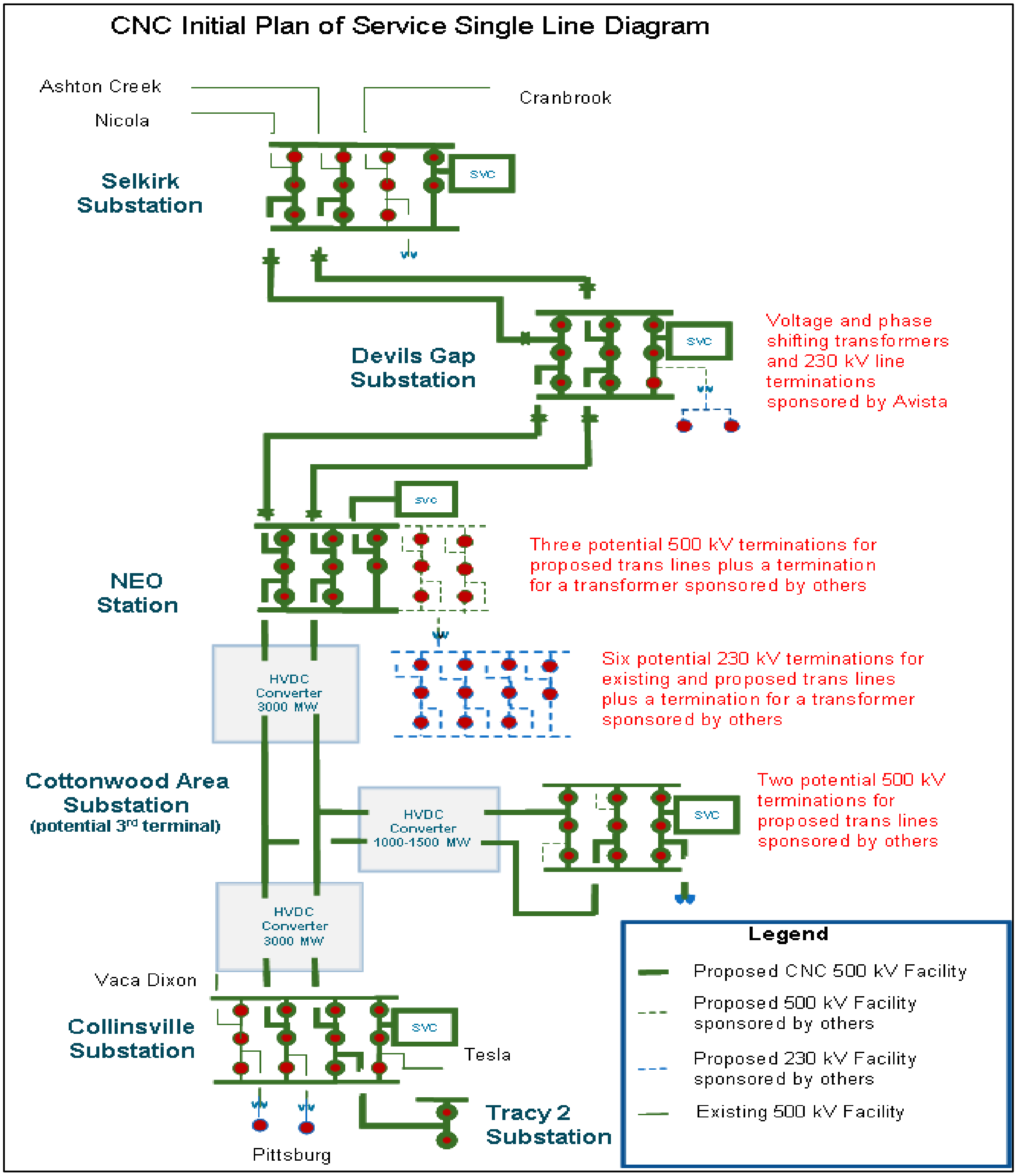

Figure 7-3: CNC Project Initial plan of service schematic for WECC Phase 1 Rating Process

Bay Area Bulk Transmission Project

The Greater San Francisco Bay Area (GBA) long–term planning study is being conducted to determine what future combination of transmission system reinforcements and/or generation resources are required to serve the projected load levels within this area reliably. The GBA Study Group which includes representatives from CAISO, Silicon Valley Power, City and County of San Francisco, Western Area Power Authority, and PG&E participated in this study. In this study, the thermal performance of eleven transmission alternatives was assessed. The preliminary results indicate that the following transmission alternatives surpassed the power flow performance of the other alternatives:

1. Build a new 500/230 kV substation near Collinsville with two 500/230 kV transformers; loop the Vaca Dixon-Tesla (or Table Mountain-Tesla) 500 kV line to the new substation; build a new 230 DCTL between the new substation and Pittsburg Substation; and add a new 500/230 kV transformer at Tesla/Tracy.

2. Build a new 500/230 kV substation at Sunol (near Newark); loop the Tesla-Los Banos 500 kV Line into the new substation; re-configure some 230 kV lines at Newark (move termination from Newark to the new substation); reconductor some of the reconfigured 230 kV lines; and add a new 500/230 kV transformer at Tesla/Tracy.

3. Build a new 500/230 kV substation at Sunol (near Newark); loop the Tesla-Los Banos 500 kV Line into the new substation; re-configure some 230 kV lines at Newark (move termination from Newark to the new substation); reconductor some of the reconfigured 230 kV lines; build a new 230 kV DCTL from Contra Costa-Pittsburg; and build a new 230 kV DCTL from Vaca-Dixon – Contra Costa.

4. Build a new 230 kV DCTL from Contra Costa-Pittsburg; build a new 230 kV DCTL from Vaca-Dixon – Contra Costa; and build a new 230 kV line from Tesla/Tracy-Livermore-Newark/Northern Receiving Station. Additional transmission components needed in order to complete this alternative and will be determined in later studies (Proposed by WAPA and other participating MUNI’s).

Each alternative would mitigate most, if not all, the thermal problems with a reduction of approximately 2,000 MW of generation within the Greater Bay Area. A complete economic comparison of each alternative as well as an examination of environmental impacts would be determined during the next phase of studies. It is recommended that these alternatives be evaluated in further detail in the next phase of the study.

COI Uprate Project

The Administrative Representatives under the Owners Coordinated Operation Agreement between PG&E, the Transmission Agency of Northern California (TANC), and the Western Area Power Administration (Western), collectively the Major California Owners of the California-Oregon Intertie (COI) are proposing to increase the non-simultaneous rating of the COI to 5,100 MW or more. Based on preliminary studies, the proposed 300 MW increase in the COI rating would be accomplished by:

- Increasing the series compensation level on the Captain Jack–Olinda 500-kV line,
- Increasing the amounts of reactive support (shunt capacitors) at Tracy, and
- Replacing and upgrading the series capacitors at Malin on the Malin–Round Mountain #2 500-kV line.

The main benefits of the project would include reduction in the number of occurrences of curtailments in the operating transfer capability (OTC) on the COI, and improved voltage support for the northern California and southern Oregon areas.

The Major California Owners initiated the WECC Regional Planning Project Review Process for the COI Uprate Project in November 2006. This project depends not only on satisfying the WECC regional planning and path rating processes, but also on reaching agreement with involved Northwest utilities, including PacifiCorp, which owns the Malin series capacitor bank on the Malin – Round Mountain #2 500-kV line, and BPA, which owns Captain Jack and operates the transmission path that connects the Northwest to COI. The in-service date is under evaluation.

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